A feasibility study into the use of marine gas engines for cogeneration.

A Thesis presented in partial fulfilment of the
Degree of Master of Science
in
Energy Systems and the Environment.

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ABSTRACT.

The aim of this thesis is to perform a feasibility study into the construction of a cogeneration plant, to provide 9.5MWe of electricity and 8 tonnes per hour of process steam, to meet the heat and power requirements of a large manufacturing company that is based in the West Midlands, England, UK.

The plant currently imports its electricity from the national grid system and produces its own steam, for process and heating requirements, from onsite oil fired package boilers.

However, the boiler plant is outdated and as part of the companys ongoing capital investment programme, in order to comply with the Integrated Pollution Prevention and Control Directive 1996, combined heat and power was identified as an alternative to installing a new package boiler plant. A cogeneration plant would also offer the benefit of independent power production for the site.

Through literature review, the cogeneration technologies that are currently available have been studied and marine gas engines were identified as the best available technology to meet the manufacturing plants needs.

A detailed study was then undertaken into the development of the cogeneration plant, including a technical assessment of marine gas engines, a thermodynamic assessment of the engines exhaust gas system and the waste heat recovery boiler, an assessment to determine the plants eligibility to be considered as good quality combined heat and power and a financial assessment, based on several natural gas fuel price and bank interest rate scenarios.

Finally, an analysis was carried out to determine the carbon emissions savings that could be achieved by the proposed plant and an environmental impact assessment was undertaken, to ensure that the development would comply with the Local Planning Authority guidelines.

TABLE OF CONTENTS.

INTRODUCTION.

The overall aim of this thesis is to perform a feasibility study into the use of marine engines to supply combined heat and power to a manufacturing site that is based in an industrial area of the West Midlands, England, United Kingdom.

The cogeneration plant must be capable of continuous operation at a base-load of 9.5MWe and should be able to produce up to 8 tonnes per hour of saturated steam at 7 bar pressure, for the adjacent manufacturing sites process steam and heating requirements.

The cogeneration plant is to be designed for 25 years of operation and any surplus power produced by the plant, will be sold to the national grid system.

During the winter period, the plant is expected to operate at 9.5MWe and to produce 8 tonnes per hour of steam, 24 hours per day and during the spring period the plant shall operate at 9.5MWe and produce 8 tonnes per hour of steam, from 6am to 10pm in the evening.

During the summer period, the manufacturing plant will only require 9.5MWe of power and 8 tonnes per hour of steam, between 6am and 10am in the morning, as the plant shall be undertaking its summer maintenance overhaul.

Finally, during the autumn period, the plant is expected to operate at 9.5MWe and 8 tonnes per hour of steam, between 6am and 10pm in the evening.

The actual dates for which the seasonal electricity and heat profiles are based upon are detailed in table 1.

The electricity and steam production profiles for the cogeneration plant on a seasonal basis are outlined in figures 1 to 8.

Winter period	lst Nov - 31st Jan
Spring period	1st Feb - 30th April
Summer period	1st May - 31st July
Autumn period	1st Aug - 31st Oct

Table 1 - Plant seasonal operation dates.

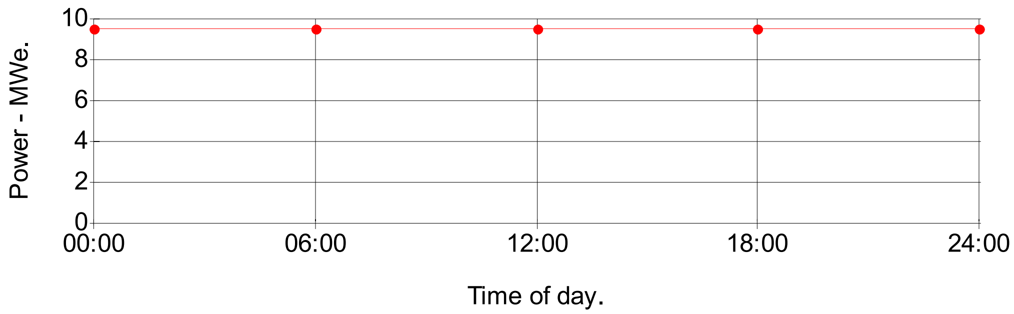


Figure 1 - Winter electricity generation profile.

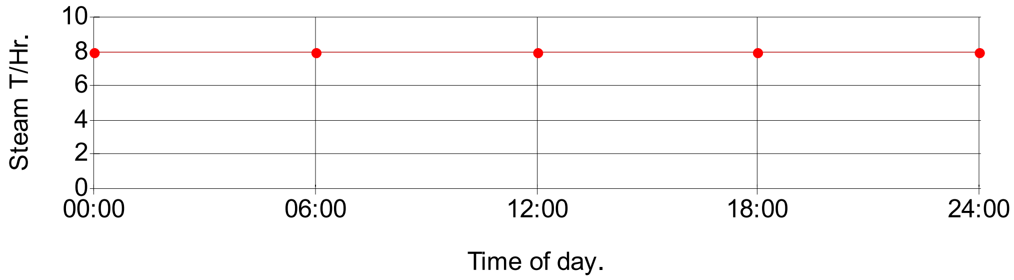


Figure 2 - Winter steam production profile.

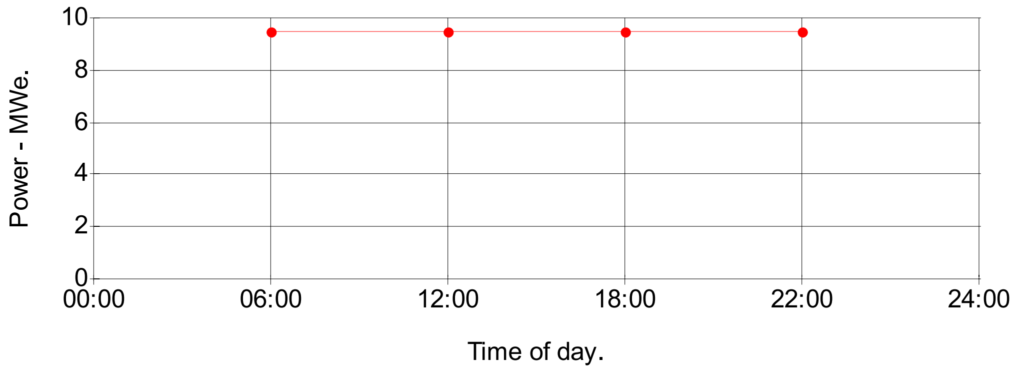


Figure 3 - Spring electricity generation profile.

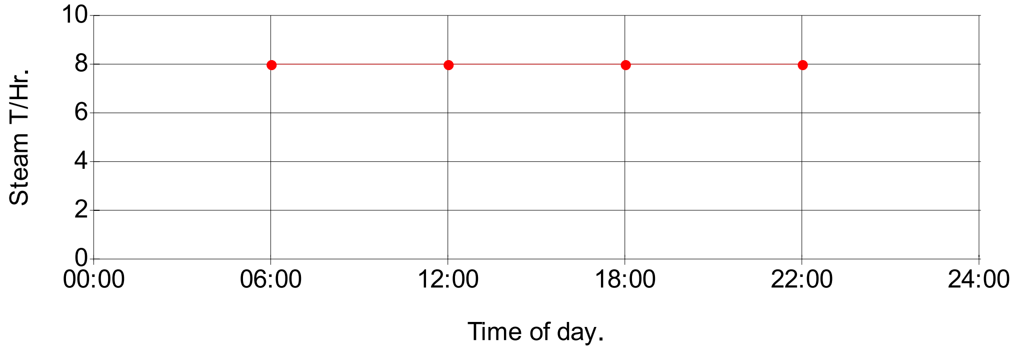


Figure 4 - Spring steam production profile.

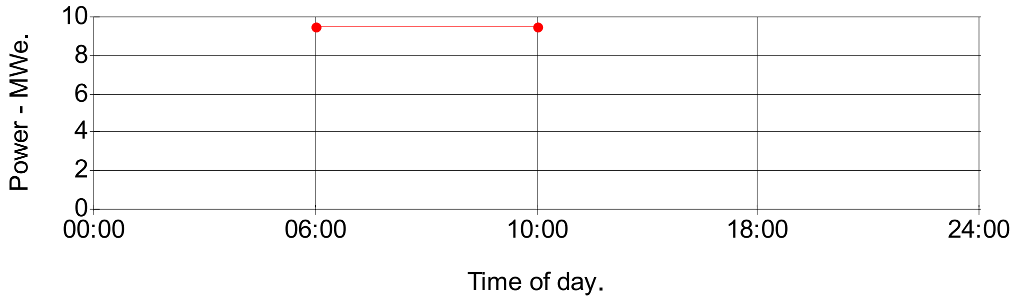


Figure 5 - Summer electricity generation profile.

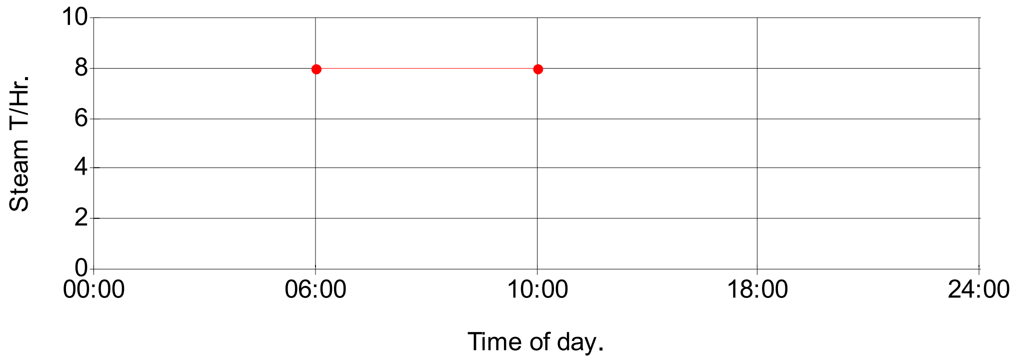


Figure 6 - Summer steam production profile.

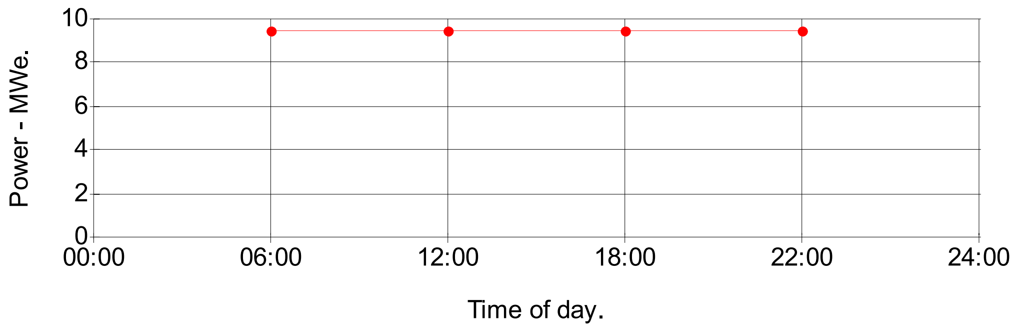


Figure 7 - Autumn electricity generation profile.

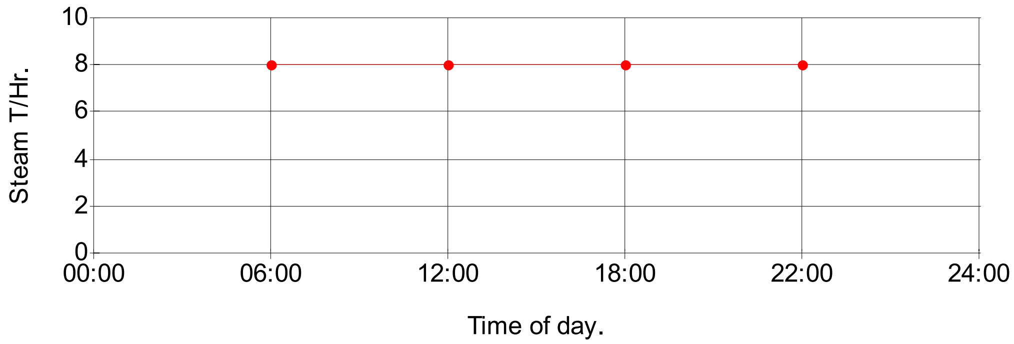


Figure 8 - Autumn steam production profile.

The steam that has been utilized in the manufacturing plants site will be returned to the cogeneration plants feed-water storage vessel as hot water at 8 tonnes per hour, 60ºC and 4 bar pressure.

METHODOLOGY.

In order to undertake a coherent feasibility study, the following objectives were set:

- To research the engineering and scientific principles behind combined heat and power production and to gain an overview of the types of commercially available cogeneration plant.

- To quantify the current installed cogeneration plant capacity in Europe and the United Kingdom and to evaluate the current European Union and the British Government's policies towards cogeneration.

- To develop an understanding of the Local Authority Planning and Consents procedures for the construction of a 9.5MWe cogeneration plant.

- Based, on the above literature review, to determine the best practicable means of generating combined heat and power for the proposed site, including a technical evaluation of the reciprocating engines that were selected for the plant.

- To undertake a thermodynamic assessment into the design of a heat recovery steam generator (waste heat boiler), in order to ensure that the plant can generate sufficient steam to meet the manufacturing plants process requirements.

- To assess the economic and financial risks associated with the proposed development and to calculate the carbon emissions savings from the proposed plant.

- To carry out an environmental impact assessment for the proposed development.

- Finally, to present the overall conclusions from the research conducted, as to whether the project is financially viable.

CHAPTER 1 - WHAT IS COGENERATION ?

Combined heat and power (CHP) or co-generation is a process that involves the simultaneous generation of usable heat and power. The most widely used designs of cogeneration plant are based upon reciprocating diesel or gas engines, gas turbines and steam turbine plant [1].

The heat energy that is contained within the gas turbine and reciprocating engines flue gases and from the steam turbine extractions (bled steam) can be recovered by passing the exhaust gases or steam through a heat exchanger, to produce hot water or steam for use in central heating systems, district heating systems, laundry plants and process plants.

The mechanical or shaft power that is produced by the reciprocating engine, gas turbine or steam turbine is normally used to drive an alternator to produce electricity. However, the power generated by the engine or turbine could also be used to drive a compressor, reduction gearbox, ships propeller or other motive device instead.

The main advantages of using cogeneration plants to produce on-site heat and power are that the process makes more efficient use of the fuel energy input and therefore increases the power plant efficiency.

Furthermore, the cogeneration process produces significantly less carbon dioxide emissions than would otherwise be produced from the separate production of heat using a package boiler and from the generation of electricity using a large decentralised fossil fired power station.

1.1 - TYPES OF COGENERATION PLANT.

There are five principle designs of cogeneration plant that are widely used around the world. These are:

1. Reciprocating engine based cogeneration plant.
2. Gas turbine based cogeneration plant.
3. Combined cycle gas turbine based cogeneration plant.
4. Pass out, condensing steam turbine based cogeneration plant (POCO).
5. Back pressure steam turbine based cogeneration plant.

1.1.1 - RECIPROCATING ENGINE BASED PLANT.

The two designs of reciprocating engine that are used in this type of cogeneration plant are the compression ignition diesel engine and the spark ignition gas engine [2,3].

The leading manufacturers of reciprocating engines for cogeneration are Man (Burmeister & Wain), Rolls Royce (Allen and Bergen diesels), Perkins diesels and Wartsila (Sulzer diesels).

These manufacturers produce a range of engines from 0.2MWe up to 20MWe, which can run on coal bed methane, diesel oil, heavy fuel oils, landfill gas and natural gas.

The reciprocating engine is usually coupled to an alternator in order to generate electricity and the engines exhaust gases are diverted through a heat exchanger to produce hot water or small quantities of steam.

It is also possible to recover the low grade heat energy from the reciprocating engines charge air, jacket water and lubricating oil cooling systems, in order to further increase the cycle efficiency of the cogeneration plant. However, it is standard for most plants to reject this heat energy to the atmosphere using a radiator type cooling system.

A typical reciprocating engine cogeneration plant would operate at an electrical efficiency of 25% and would have the potential to recover up to 39% of the fuel input as useful heat energy, based upon the gross calorific value of the fuel.

1.1.2 - INDUSTRIAL GAS TURBINE BASED PLANT.

The main type of gas turbines that are used in cogeneration plants are aero-derivative gas turbines. These plants would normally run on natural gas or diesel oil, although other fuels including naphtha can also be used.

The leading manufacturers of aero-derivative gas turbine plant are Caterpillar (Solar), General Electric, Rolls Royce and Ruston (Siemens) gas turbines, whose turbines range in power output from 3MWe to 50MWe [3,4].

These types of gas turbine are normally coupled to an alternator in order to generate electricity and their exhaust gases are passed through a heat recovery steam generator in order to produce large quantities of hot water or steam for heating or process requirements.

A standard industrial gas turbine cogeneration plant would normally operate at an electrical efficiency of around 22% and would have the potential to recover up to 47% of the fuel input as useful heat energy.

1.1.3 - COMBINED CYCLE GAS TURBINE BASED PLANT.

The two designs of combined cycle power plant are the single shaft and the multi-shaft combined cycle plant. These plants would normally run on natural gas or diesel oil fuels.

The leading manufacturers of combined cycle power plants are Alstom (ABB), General Electric and Siemens Westinghouse, whose gas turbines range in power output from 70MWe to 300MWe [5,6].

The single shaft design of power plant is more compact than a conventional combined cycle power plant and offers additional cost benefits as only one alternator is required in order to generate electricity.

With a multi-shaft combined cycle gas turbine power plant, there are normally one or more gas turbines, each producing electricity and steam from their own separate alternator and heat recovery steam generator. The steam is then fed to one large steam turbine in order to generate additional electricity.

A standard combined cycle gas turbine power plant would have an electrical efficiency of around 25%, with the potential to recover up to 49% of the fuel input as useful heat energy.

1.1.4 - PASS OUT, CONDENSING STEAM TURBINE BASED PLANT.

Steam would normally be produced in a coal, gas or oil fired boiler and would then be expanded in a pass out condensing steam turbine (POCO).

During the expansion process, some of the steam is extracted from the turbine cylinder at an intermediate pressure (bled steam) and then passed through a heat exchanger to produce hot water or steam, for process or district heating requirements, before being returned to the water / steam cycle as hot water [4].

The remainder of the steam would be fully expanded down to the condenser pressure, before exiting the turbine casing (Hence the name - condensing steam turbine).

1.1.5 - BACK PRESSURE STEAM TURBINE BASED PLANT.

Steam would again be produced in a coal, gas or oil fired boiler, before entering the back pressure steam turbine. The steam would then be either partly or wholly expanded in the steam turbine, before being exhausted from the turbine casing at the required pressure for the sites process steam requirements.

Pass out condensing steam turbine and back pressure cogeneration plant normally have electrical efficiencies of between 10% and 13%, with 61% of the fuel input being available as useful heat energy.

Table 2 illustrates the average electrical and thermal efficiencies for various types of cogeneration plant [7].

CHP prime mover	Electrical efficiency (% GCV)	Heat efficiency (% GCV)	Overall efficiency (% GCV)
Back pressure steam turbine	10	61	71
Pass out steam turbine	13	61	74
Gas turbine chp	22	47	69
Combined cycle gas turbine	25	49	74
Reciprocating engine	25	39	65
Average	21	52	72

Table 2 - Cogeneration plant electrical and thermal efficiencies.

1.2 - POWER PLANT EFFICIENCIES.

As previously stated, one of the main advantages that cogeneration plants offer over conventional power plants are that they are designed to able to recover the heat energy from the reciprocating engine or gas turbines flue gases that would normally be rejected to the power stations chimney or stack.

The additional heat energy that can be recovered by using a cogeneration system leads to an overall increase in the thermodynamic cycle efficiency of the plant. Figure 9 shows a sankey or energy balance diagram for a marine gas engine.

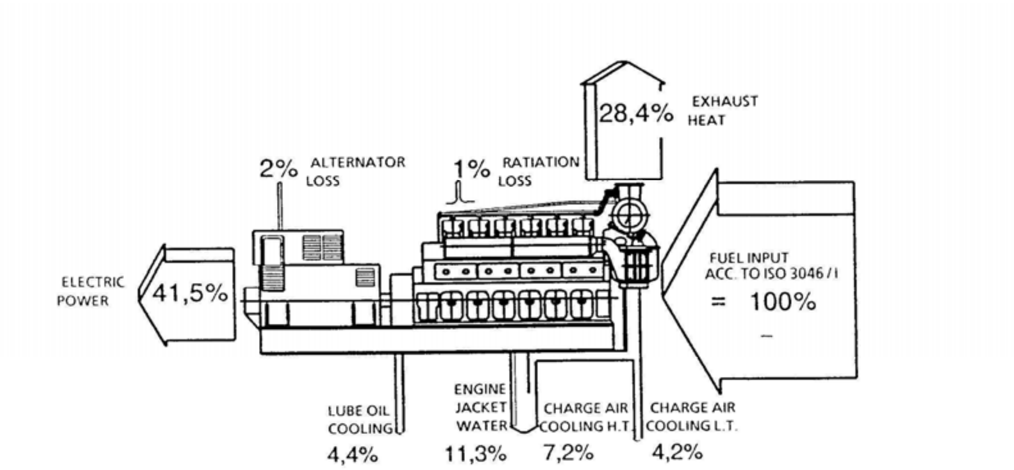


Figure 9 - Reciprocating gas engine sankey diagram.

1.2.1 - CONVENTIONAL POWER PLANT CYCLE EFFICIENCY.

The overall cycle efficiency of a conventional reciprocating engine power plant, based on the above diagram (See figure 9) would be defined as:

$$\text{Overall cycle efficiency} = \frac{\text{Power plant electrical output}}{\text{Power plant fuel input}}$$

$$\text{Overall cycle efficiency} = \frac{\text{Power plant electrical output}}{\text{Mass of fuel * Calorific value}} \qquad \frac{[J/s]}{[kg/s] * [J/kg]}$$

1.2.2 - COGENERATION PLANT CYCLE EFFICENCY.

Whereas, the overall cycle efficiency for a cogeneration plant, would be defined as:

$$\text{Overall cycle efficiency} = \frac{\text{Power plant electrical output + heat output}}{\text{Power plant fuel input}}$$

$$\text{Overall cycle efficiency} = \frac{\text{Power output} + m * Cp * (T2 - T1)}{\text{Mass of fuel * Calorific value of fuel}} \qquad \frac{[kg/s] * [J/kgK] * [K]}{[kg/s] * [J/kg]}$$

$$\text{Overall cycle efficiency} = \frac{\text{Power plant electrical output} + m * Cp * (T2 - T1)}{\text{Mass flow-rate of fuel * Calorific value of fuel}} \qquad [--]$$

Where m = Mass flow-rate of the engine exhaust gases - [kg / s].
T1 = Exhaust gas inlet temperature to boiler - [K].
T2 = Exhaust gas outlet temperature from boiler - [K].
Cp = Specific heat capacity of the exhaust gas - [J / kgK].

1.2.3 - HEAT ENERGY RECOVERED.

From the above equations, it can be seen that the following amount of heat energy could be recovered by the use of a heat exchanger or heat recovery steam generator, as part of a cogeneration plant:

$$\text{Heat energy recovered} = m * Cp * (T2 - T1) \qquad [W]$$

1.2.4 - INCREASE IN CYCLE EFFICENCY.

From the above equations, it can also be seen that the increase in overall cycle efficiency from using a heat exchanger or heat recovery steam generator as part of a cogeneration plant would be:

$$\text{Increase in cycle efficiency} = \frac{m * Cp * (T2 - T1) * 100}{\text{Mass of fuel * Calorific value of fuel}} \qquad [\%]$$

1.3 - POWER PLANT CARBON EMISSIONS.

The second major advantage of generating electricity and hot water or steam from cogeneration plants is that the carbon emissions produced by the plant are less than the total carbon emissions that would be produced from electricity only production using large fossil fired power stations and from heat only production using conventional package boilers [7].

A standard cogeneration plant burning natural gas fuel would produce carbon emissions of around 50gC per kWh of natural gas consumed. Table 3 details the actual carbon emissions for various cogeneration fuels.

Whilst, a conventional coal fired power station burning coal to produce electricity only, would emit 263gC per kWh of electricity generated and an oil fired package boiler producing hot water or steam would emit 98gC per kWh of heat energy produced. Tables 4 and 5 outline the carbon emissions from various types of fossil fired power station and heat only boiler plant.

CHP fuel	Carbon emissions in gC/kWh
Coal	89
Fuel oil	73
Gas oil	68
Natural gas	50

Table 3 - Cogeneration plant carbon emissions.

Fuel used	Efficiency range %	Average efficiency %	Delivered efficiency %	Carbon emissions in gC/kWh
Coal	32 - 37	36.4	34	263
Oil	25 - 37	27.1	25	268
Gas	32 - 52	45.1	42	119

Table 4 - Fossil fired power station efficiencies and carbon emissions.

Fuel used	Efficiency range %	Average efficiency %	Carbon emissons in gC/kWh heat output	% of total fuel mix
Coal	51 - 81	70	127	8
Oil	58 - 87	74	98	31
Gas	61 - 82	76	66	61
Average		75	81	100

Table 5 - Heat only boiler plant efficiencies and carbon emissions.

1.3.1 - CARBON EMISSION SAVINGS.

The actual amount of carbon emissions that maybe saved every year by installing a cogeneration plant, depends on the type of fossil fired generating capacity and heat only boiler plant that is being displaced by the cogeneration plant.

In general, the type of fossil fired generating plant that is being displaced is not known, as the electricity that is transmitted in the national grid system comes from various different types of generating plant.

It is therefore standard practice to use an average carbon emissions value of 183gC per kWh of electricity generated from conventional fossil fired power stations, when calculating the actual carbon emissions savings.

However, the fuel used in heat only boiler plant is normally known and it is therefore possible to calculate the emissions reduction from displacing it with a cogeneration plant.

1.3.2 - CARBON EMISSIONS.

It should be noted that where carbon emissions have been stated in this Chapter, then:
12 grams of carbon emissions = 44 grams of carbon dioxide gas emissions.

1.4 - ADVANTAGES OF USING COGENERATION.

The main advantages for factories, hospitals and other businesses installing their own cogeneration plants are that they can produce their own heat and power requirements, independently of external suppliers.

In the near future, this may be the overriding reason for the increased use of cogeneration in the United Kingdom, as many large coal fired power stations will be forced to close due to stricter carbon emissions regulations and because they are at the end of their useful working lives.

The possible impact of these closures may well be that there is an increased demand for electricity across the country, leading to rising electricity costs and power blackouts.

1.4.1 - PLANT AVAILABILITY.

The most modern cogeneration plants are able to operate at high availabilities of between 90% and 96% per annum, with minimal annual down-time for maintenance and service purposes.

1.4.2 - BLACKSTART CAPABILITY.

In the unlikely event of a total black-out or failure of the national grid system, then medium sized cogeneration plants that are based on diesel engines, gas engines and gas turbines would have an important role to play in restarting the national grid system, as they are able to start-up unassisted, without mains power being available.

The electricity generated by these cogeneration plants would then be used to restart the major items of auxiliary plant that are contained within large power stations across the United Kingdom, including the main boiler feed, condensate extraction and cooling water pumps, which are rated at around 2.0MWe each.

1.4.3 - ISLAND MODE CAPABILITY.

The vast majority of cogeneration plants can also operate in island mode operation, which means that they can generate electricity even when unconnected to the national grid system.

This is particularly beneficial for airports, hospitals, manufacturing plants and other industries who require uninterrupted power supplies 24 hours per day.

1.4.4 - PLANT CONSTRUCTION TIMES.

Most industrial gas turbine and reciprocating engine cogeneration plants are based on skid mounted units which are easy to install and connect to the local electricity distribution system.

These types of plant can also be constructed in several months, when required.

CHAPTER 2 - EU INSTALLED COGENERATION PLANT CAPACITY.

In 1998, the total installed capacity of cogeneration plants in the European Union [8] was 72,000MWe.

The countrys with the largest installed base of cogeneration plants were Germany (22,000MWe), Italy (9,500MWe), the Netherlands (8,500MWe), Denmark (7,000MWe) and Finland (5,000MWe).

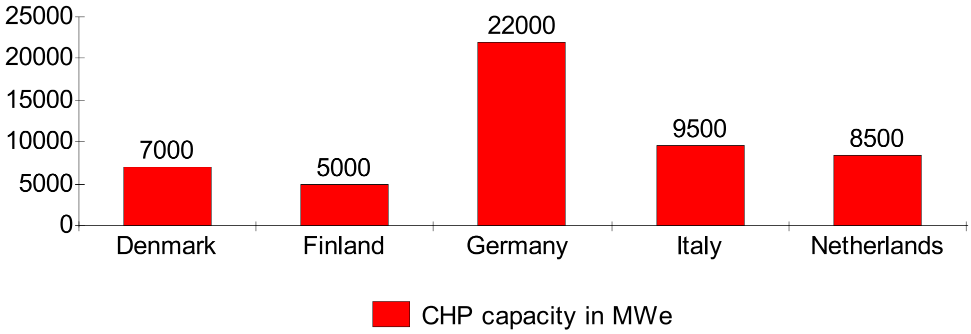


Figure 10 - European Union cogeneration plant installed capacity in 1998.

2.0.1 - EU ENERGY PRODUCTION FROM COGENERATION PLANTS.

When we compare the actual amounts of energy that were generated from cogeneration plants in 1998, then we find that the Netherlands produced the largest amount of energy from cogeneration (47,835 GWh per year).

They were closely followed by Italy who produced 44,856 GWh and then Germany who generated 41,770 GWh of energy per year.

The amounts of energy produced from cogeneration, by all European Countries, between 1994 and 1998 is shown in figure 11.

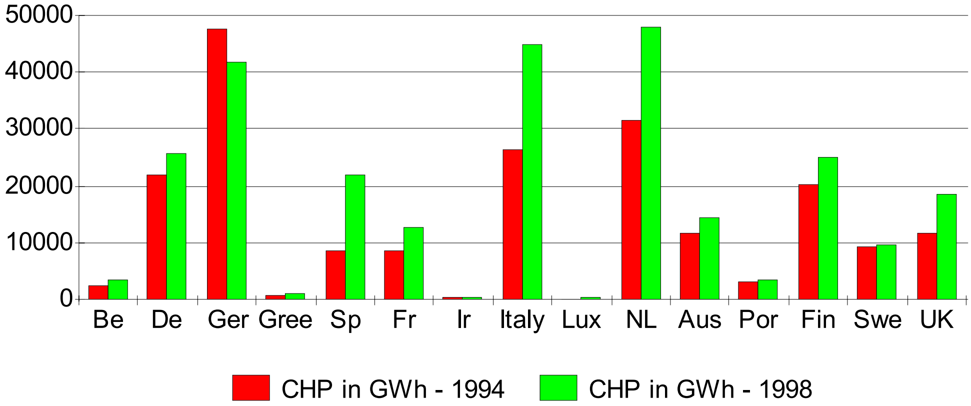


Figure 11 - Energy production from cogeneration plants in the European Union.

2.0.2 - EU COGENERATION MARKET SHARE.

Of all the countries in the European Union, Denmark, the Netherlands and Finland have the highest overall percentages of their total electricity requirements generated from cogeneration plants.

Denmark produced 62.3%, the Netherlands produced 52.6% and Finland generated 35.8% of their total electricity from cogeneration plants, whilst France, Greece and Ireland in contrast, only generated 2% of their total electricity requirements from cogeneration plants.

The changes in European Union cogeneration plant market share between 1994 and 1998 are illustrated in figure 12.

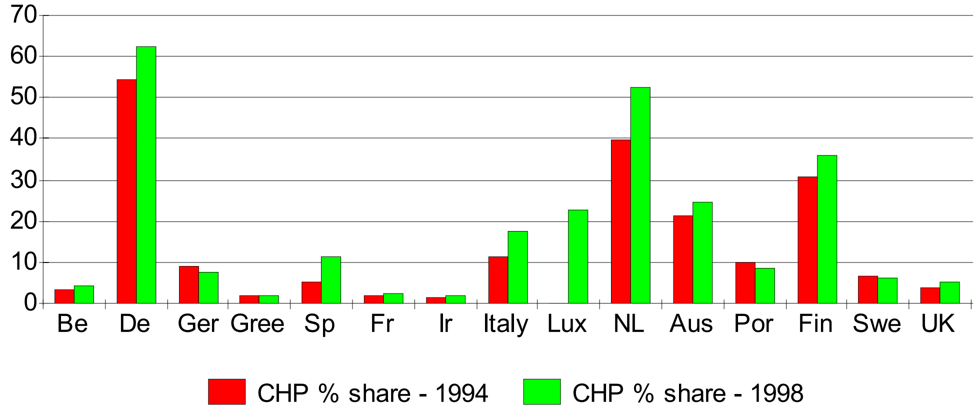


Figure 12 - European Union cogeneration plant market share.

2.1 – EU STRATEGY ON COGENERATION.

The European Union set out in its Cogeneration Strategy published in 1997, that it has an overall target of doubling the share of electricity production from cogeneration, from 8% in 1997, to 18%, by 2010 [9].

The scientific studies that were then carried out by the European Union suggested that if this target was met, then over 65 million tonnes of carbon dioxide emissions could be avoided every year.

2.1.1 - EU GREEN PAPER, A STRATEGY FOR THE SECURITY OF ENERGY SUPPLY.

The European Commission stated in its Green Paper titled "Towards a European Strategy for the Security of Energy Supply", published on the 29th November 2000, that Europe is currently dependent on external energy supplies for 50% of its total energy requirements [10].

The Green Paper predicts that external energy supplies will account for around 70% of all European Union energy requirements by 2030 and concludes that in order for the EU to reduce its dependence on foreign imports and to limit its emissions of greenhouse gases, then it would need to implement measures to reduce energy demand.

2.1.2 - EU POLICY ON SUSTAINABLE DEVELOPMENT.

The European Commission published its strategy "A Sustainable Europe for a Better World, A European Union Strategy for Sustainable Development" on the 15th May 2001 [11].

The main conclusions of the EU Sustainable Development Strategy were that there is a need for increased use of clean energy and clear action to reduce energy demand within all of the European Union countries.

2.1.3 - EU DIRECTIVE ON PROMOTION OF COGENERATION (2004/8/EEC).

In order to promote the use of high-efficiency cogeneration plant more effectively across all European Union countries and to comply with the recommendations of the EU Green Paper and the Sustainable Development Policy, the EU introduced a new Directive on the 11th February 2004, on the "Promotion of Cogeneration based on useful heat demand in the internal energy market" [12].

The aims of the Directive are to further the European Union's goals of reducing primary energy demand, improving energy security of supply, avoiding electricity network losses and reducing greenhouse gas emissions.

The Directive also aims to provide a framework within which cogeneration plants can overcome existing market barriers and advance the market share for cogeneration in all European Union countries.

The Directive stresses the need for Member Countries to implement support schemes (investment aid, tax exemptions, etc) with a minimum duration of at least four years, in order to give companies financial incentives to invest in cogeneration plant.

All Member States also need to ensure that any support for existing and future cogeneration plants is based upon the useful heat demand and the primary energy savings that can be achieved by using a cogeneration plant, in light of the possibility that other forms of renewable energy production maybe more efficient.

2.1.4 - INTEGRATED POLLUTION PREVENTION AND CONTROL DIRECTIVE (IPPC).

The European Union Integrated Pollution Prevention and Control Directive (1996) came into force in the United Kingdom on the 1st August 2000.

The Directive will be phased in to cover all sectors of British industry by the beginning of October 2007 [13].

The introduction of the Directive means that all large companies must provide documentary evidence of the condition of their plant with regards to pollution and emissions levels and to show that any processes that they use comply with the Best Available Techniques and Technologies, before they will be granted an IPPC Permit to continue operating.

It is widely anticipated that the IPPC Directive will force companies with old heat and power generation equipment to invest in new cogeneration plant, in order to fully comply with the Directive.

2.1.5 - LARGE COMBUSTION PLANTS DIRECTIVE.

The introduction of the revised Large Combustion Plants Directive (LCPD) also encourages all European Union Member states to move towards more efficient and cleaner means of generating electricity.

The Directive requires cogeneration plants to be developed where they are technically or economically feasible, bearing in mind the market and distribution situation [13].

2.2 - UK INSTALLED COGENERATION PLANT CAPACITY.

At the end of December 2002, there were a total of 1,539 cogeneration plants generating electricity in the United Kingdom. The total installed capacity of these plants was 4,742 MWe, which is equivalent to 6.1% of the United Kingdoms total installed generating capacity [14,15].

The number of cogeneration plants that have been built in the United Kingdom has also risen by 15% from 1,357 plants in 1998 to 1,561 plants at the end of 2001.

However, during 2002, the number of cogeneration plants that were actually generating electricity into the national grid system fell slightly, from 1,561 plants at the beginning of the year to 1,539 plants at the end of the year. This led to a reduction in total generating capacity of only 11MWe.

The main reasons for the small reduction in cogeneration capacity were because several owners mothballed their plants, due to the low wholesale electricity prices and the high cost of gas, which meant it was uneconomical for them to generate.

Figure 13 illustrates the number of operational cogeneration plants and their total installed capacity between 1998 and 2002.

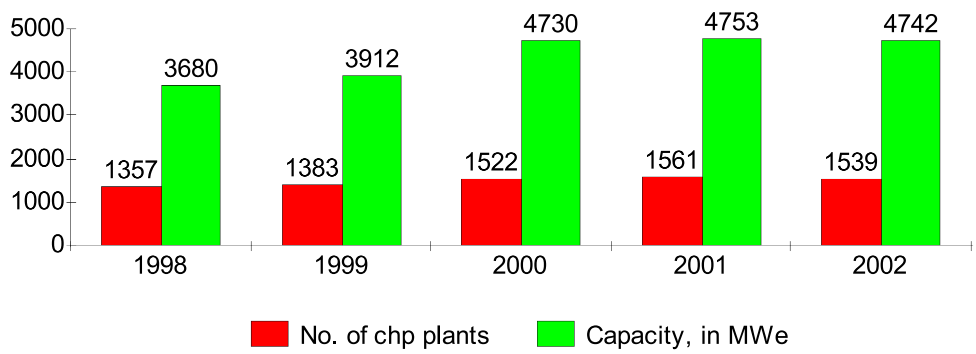


Figure 13 - UK cogeneration plant installed capacity.

2.2.1 - COGENERATION PLANT SIZE.

The majority of UK cogeneration plants, based on figures for 2002, were less than 1MWe in size, with plants with an electrical output of less than 100kWe accounting for 43.1% and plants with an output of up to 999kWe accounting for 40.6% of the total number installed.

Figure 14 shows the percentage of cogeneration plants that fall into each power output category.

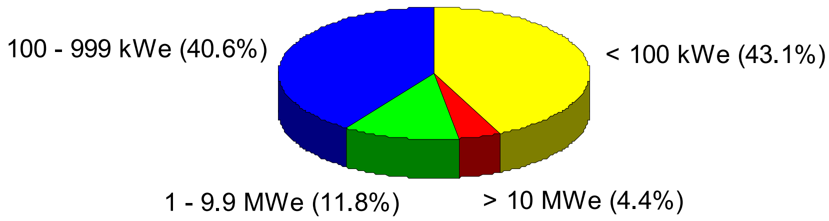


Figure 14 - Cogeneration plants installed by size.

2.2.2 - COGENERATION PLANT POWER OUTPUT.

The vast majority of the energy that is produced from cogeneration plants comes from plants that have an output of greater than 1MWe.

Cogeneration plants that have an output of between 1MWe and 9.9MWe currently account for 16% and plants with an output of greater than 10MWe account for a further 79.9% of the total energy that is produced from cogeneration.

Figure 15 shows the percentages of the total energy produced from cogeneration plants, depending on the size of plant.

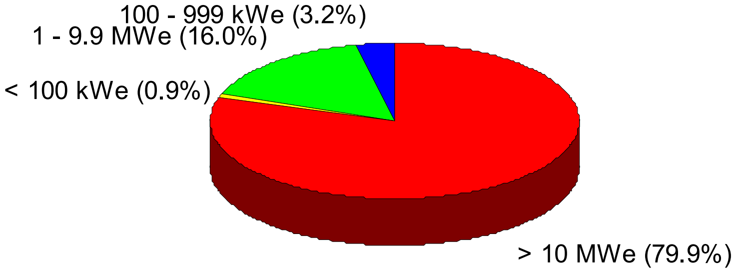


Figure 15 - Energy production depending on the cogeneration plant size.

2.2.3 - COGENERATION PLANT FUELS.

The principle fuel that is used in UK cogeneration plants is natural gas, which currently accounts for 64% of the fuel mix.

The breakdown of natural gas usage is as follows, 38% is used in combined cycle gas turbine plants, 11% in simple cycle gas turbine plants, 7% in gas engines and 5% in steam turbine plant.

The “other fuels” that are used in cogeneration plants are coke oven gas, gas oil and manufacturing process by-products which account for a further 15% of the fuel mix.

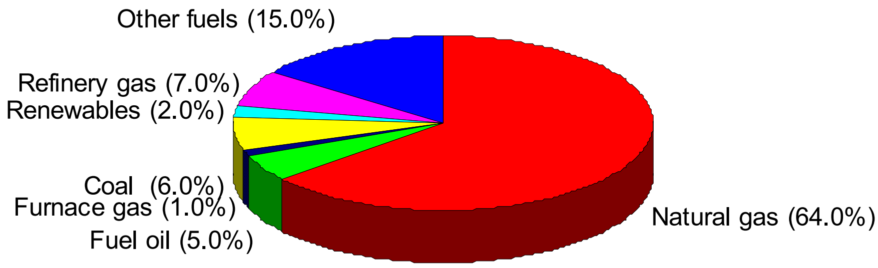


Figure 16 - Cogeneration plant fuel mix.

2.2.4 - INDUSTRIES USING COGENERATION.

There are four main industrial sectors in the United Kingdom which account for over three quarters of the demand for electricity that is produced from cogeneration plant.

These sectors are the chemical industry (32%), oil refineries (20%), the electricity supply industry (13%) and the paper and publishing industries (12.5%), respectively.

Figure 17 shows the principle industries that have installed cogeneration plants.

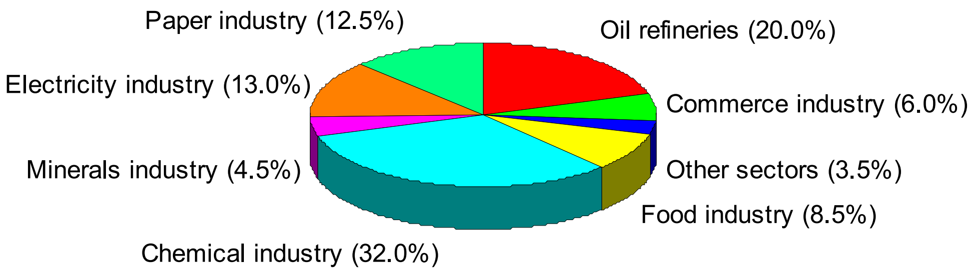


Figure 17 - Industries using cogeneration.

2.3 - UK ENERGY POLICY TOWARDS COGENERATION.

The Government has stated in the Energy White Paper 2003 that it has set a target for 10,000MWe of good quality cogeneration plants, as defined by CHPQA scheme, to be built in the United Kingdom by 2010. This would lead to a reduction in carbon emissions of 1.25 million tonnes every Year [16].

The Government has also stated that it will review the power station consents process to ensure that all new applications for permission to build power stations, will have submitted substantial documentation to prove that they have considered all economically viable options for cogeneration and community heating plants first, before being granted planning permission.

Furthermore, during the consultation process for the White Paper, many small cogeneration companies complained that they could not obtain quick and easy connection to the local electricity distribution network, as their was no financial incentive for the Distributed Network Operators (DNO) to connect them to the system.

Therefore, OFGEM has been tasked with looking into the possibility of implementing a financial incentive scheme to begin operation in April 2005, in order to counter the difficulties that were experienced by these companies.

2.3.1 - ENERGY EFFICIENCY OBLIGATION.

The Government introduced an Energy Efficiency Commitment (EEC) in April 2002. The commitment places legal obligations on all electricity and gas suppliers to achieve targets on the promotion of energy efficiency between 2002 and 2005 [17].

Cogeneration is therefore one of a number of measures that electricity and gas suppliers may use in order to meet their commitments under the Energy Efficiency Obligation.

2.3.2 - GOVERNMENT ESTATE.

The Minister for Sustainable Energy, Lord Whitty stated on the 26th February 2004, that all Government Departments are required to source at least 15% of their electricity requirements from good quality combined heat and power plants by 2010.

The Government has estimated that by 2010 that there is the potential for around 30 to 35MWe of installed cogeneration capacity on the Government Estate [18,19].

2.3.3 - CHP QUALITY ASSURANCE PROGRAMME (CHPQA).

The Government has recently set-up a new initiative called the Combined Heat and Power Quality Assurance (CHPQA) programme, in order to monitor the countrys progress towards meeting its target of 10,000MWe of installed cogeneration plant capacity by 2010.

The CHPQA programme provides a practical, robust and determinate methodology for assessing and defining good quality combined heat and power for all or part of a cogeneration plants fuel inputs and electricity outputs [20].

The programme also allows for responsible persons to apply for certification and registration of their cogeneration plant in accordance with the criteria for good quality combined heat and power and hence allows them to qualify for financial benefits including climate change levy exemption and enhanced capital allowances.

2.3.4 - CLIMATE CHANGE LEVY.

The climate change levy is an environmental tax, which came into force on the 1st April 2001. It is payable by all non-domestic users of energy including industry, commerce and the public sector, with exemptions from the levy for good quality combined heat and power.

The amount of Climate Change Levy that is applicable depends on the quantity of fossil fuel that is consumed. The Levy is charged at the rates specified in table 6 and is aimed at reducing fossil fuel energy consumption [21,22,23].

Electricity	0.43 pence / kWh
Natural gas	0.15 pence / kWh
Coal and Lignite	0.15 pence / kWh
Liquified Petroleum Gas	0.07 pence / kWh

Table 6 - Climate change levy charges.

2.3.5 - ENHANCED CAPITAL ALLOWANCES.

The Government introduced an enhanced capital allowances scheme in April 2001 as part of the wider climate change levy programme and all good quality cogeneration plants as defined under CHPQA rules are eligible for enhanced capital allowances [24].

Enhanced capital allowances are 100% first year capital allowances for businesses to invest in certain energy saving equipment.

The introduction of enhanced capital allowances gives businesses and energy service companies the opportunity to write off some of the cost of their investment in energy saving equipment, against the taxable profits of their business (tax relief), during the period in which they make the investment.

The types of energy saving equipment that are eligible for enhanced capital allowances include:

- Fuel storage and handling equipment.
- Gas and steam turbines, reciprocating engines, alternators and associated equipment.
- Heat recovery boilers, absorption chillers, heat rejection equipment.
- Silencers, exhaust stacks and related ancillary equipment.

However, the cost of the cogeneration plant buildings cannot be written off against a companies taxable profits.

2.3.6 - EXEMPTION FROM BUSINESS RATES.

It is possible for companies who generate electricity from cogeneration plants to be exempt from business rates.

For a company to gain exemption from payment of business rates, the sole or primary purpose of its property must be for the generation of electricity and the actual plant capacity must be at least 500kWe [17,21]

The cogeneration plant and machinery in the building will be exempt from business rates, if it is deemed as good quality cogeneration plant under CHPQA rules. However the actual building or structure that is used to house the cogeneration plant will still be subject to business rates.

It should be noted that companies who operate cogeneration plants on their site, but the primary function of the site is not for the production of electricity are not eligible for exemption of payment of business rates on their plant and equipment.

2.3.7 - ELECTRICITY GENERATION LICENCE EXEMPTION SCHEME.

On the 1st October 2001, the Government brought into force legislation relaxing the licence exemption criteria for all categories of local power generation and electricity supply [17].

The new licence criteria increases the limit of electricity that can be generated and supplied without a licence to:

- Supplies of no more than 5MWe, of which no more than 2.5MWe would be supplied to domestic customers.

- Furthermore, electricity supplies to a single customer or group of customers, provided these customers are based on the site where the electricity is generated or take the power directly over private wires, are also exempt.

The purpose of the license exemption scheme was to reduce the administrative burden that would be placed on many small generators becoming licensed electricity suppliers.

2.4 - UNITED KINGDOM EMISSIONS TRADING SCHEME.

The Emissions Trading Scheme [25] commenced in March 2002 and gives participating UK companies specific yearly emissions allowances (in carbon dioxide equivalent).

If a company exceeds its yearly emission's allowance, then they must purchase additional allowances from the market in order to make up the deficit. Conversely, if a company emits less than its allowance, then it can then sell its surplus credits to the market and therefore obtain some financial gain.

The aim of the Emissions Trading Scheme is to give financial incentives to companies who have high carbon dioxide emissions, in order that they reduce their emissions by investing in new plant and technology.

Cogeneration plant is therefore one of a range of options that maybe suitable for companies who wish to reduce their emissions from old or outdated boiler plant.

However, depending on the capital cost of investing in new plant and technology, it may be more cost effective for a company to purchase emissions credits from the market.

2.4.1 - EUROPEAN UNION EMISSIONS TRADING SCHEME.

The European Union has recently introduced new legislation to allow for a European Emissions Trading Scheme to commence operation on the 1st January 2005 [26].

The scheme will initially cover Europe wide emissions of carbon dioxide gas only, which is emitted from large mineral oil refineries, coke ovens, cement and glass manufacturing plants, metal ore extraction plants and steel production plants.

The scheme is similar to the UK Emissions Trading Scheme, however if a company exceeds its annual emissions limit and has not purchased sufficient credits from the market, then the European Union has the power to impose a financial penalty of 40 Euros for every tonne of carbon dioxide gas that exceeds the installation's limit.

2.5 - POWER PLANT PLANNING AND CONSENTS PROCEDURES.

Before any combined heat and power plant can be built in the United Kingdom it is subject to approval from either the Secretary of State for Trade and Industry or the Local Planning Authority [27,28,29].

The proposed development of a 9.5MWe Combined Heat and Power Plant that is being used as the basis for this thesis is subject only to the consent of the Local Planning Authority, under the Town and Country Planning Act 1990 (See Appendix F).

However, any proposal to build a new gas or oil fired power station, including cogeneration plants, above 10MWe in power output, is subject to Energy Policy Clearance from the Department of Trade and Industry, under Section 14(1) of the Energy Act 1976.

2.5.1 - THE LOCAL PLANNING AUTHORITY.

Once the plant developer has submitted proposals for the cogeneration plant, the Local Authority will study the details to ensure that any new buildings, structures or alterations to existing buildings are carried out in such a manner that the development is in keeping with the surrounding area.

The planning system is specifically designed to ensure that the countryside, historic buildings and sites of special scientific interest are not adversely affected by any proposed development.

In granting a consent, the Local Planning Authority will normally give “Deemed Planning Permission” with a number of planning conditions attached, in order to mitigate the impact of the development in terms of noise, access and landscaping on the surrounding area.

2.5.2 - ENVIRONMENTAL IMPACT ASSESSMENTS.

The application for planning permission should include a detailed environmental impact assessment, in order to allow the Local Authority to assess any potential environmental impact of the proposed development [30].

2.5.3 - PLANNING POLICY GUIDANCE NOTES.

The Government has recently set out its policies on planning issues at a national level in the Planning Policy Guidance Notes (PPG).

These notes provide comprehensive guidance to all Local Authorities and others, on the Governments planning policies, in order for them to comply with new European Union Directives [30].

For cogeneration plants that are proposed to be built in existing industrial areas or on waste or derelict ground, Planning Policy Guidance Note 4 states that these types of development are to be encouraged, wherever practicable, as they can help to regenerate the surrounding local area.

CHAPTER 3 - COGENERATION PLANT SELECTION.

From the literature review that was carried out in Chapters 1 and 2, diesel engines, gas engines and industrial gas turbines were identified as being the most suitable prime movers for the proposed cogeneration plant.

Table 7 below, details the principle characteristics of each prime mover [1].

Diesel	Power output range 0.2 - 20MWe.
engines	Operate at 750 - 1500 rpm.
	Run on marine diesel oils and heavy fuel oils.
	Requirement for fuel storage tanks and fuel heating equipment.
	Heat to power ratios of between 0.5 - 3.1 : 1
	Overall efficiencies of around 65%.
	Produce low pressure steam and medium temperature hot water.
	Suitable for cyclical operation.
	Requires jacket water and charge air cooling systems.
	Typical engine availability of between 85 - 90%.
	High noise levels at low frequency.
	Unit can be maintained by engine fitters, usually short overhaul periods.
	Exhaust gas emissions of 73 gC / kWh of oil consumed.
	Three off, 3.35MWe, KVGB-16 diesel engines = £2,580,000
Gas	Power output range 0.2 - 15MWe.
engines	Operate at 750 - 1500 rpm.
	Run on natural gas, landfill gas and naphtha.
	No requirement for fuel storage tanks.
	Heat to power ratios of between 1 - 3 : 1
	Overall efficiencies of around 65%.
	Produce low pressure steam and medium temperature hot water.
	Suitable for continuous and cyclical operation
	Requires jacket water and charge air cooling systems.
	Typical engine availability of between 90 - 96%.
	High noise levels at low frequency.
	Unit can be maintained by engine fitters, usually short overhaul periods.
	Exhaust gas emissions of 50 gC / kWh of gas consumed.
	Three off, 3.16MWe, KVGB-18 gas engines = £2,733,000.
Gas	Power output range 0.25 - 50MWe.
turbines	Operate at 16,000 - 18,000 rpm and geared down to 1500rpm.
	Run on natural gas, light fuel oils and naphtha.
	No requirement for fuel storage tanks.
	Heat to power ratios of between 1.5 - 5 : 1
	Overall efficiencies of around 69%.
	Produce high grade steam and high temperature hot water.
	Suitable for long term continuous operation.
	No requirement for water cooling systems.
	Typical turbine availability of between 90 - 96%.
	High noise levels at high frequency.
	Unit requires factory trained technicians for maintenance.
	Exhaust gas emissions of 50 gC / kWh of gas consumed.
	Two off, 4.7MWe, Typhoon industrial gas turbines = £2,700,000.

Table 7 - Characteristics of prime movers.

It was concluded that marine derivative gas engines would offer the best practicable means of producing 9.5MWe of electricity and 8 tonnes per hour of process steam for the manufacturing plant. The decision to opt for a cogeneration plant that is based on marine gas engines was made for the following reasons:

Firstly, although industrial gas turbines can offer high plant availability, low emissions, and are slightly cheaper than marine gas engines, they operate at extremely high speeds and are geared down to 1500rpm, in order to produce electricity. They are also more suited to applications where high grade steam and high temperature hot water are required.

Based on a cogeneration plant operating two 4.7MWe Typhoon industrial gas turbines, it would be possible to generate considerably more steam than is actually required by the manufacturing plant, as the gas turbines exhaust gas mass flow-rate and temperature are approximately 40.6 kg / s and 536ºC (See Appendix A).

This design of cogeneration plant would not make the best possible use of the heat energy that is contained within the gas turbines exhaust gases and it is also extremely likely that the plant would not meet the Combined Heat and Power Quality Assurance Scheme criteria for good quality cogeneration, as all of the heat energy that is contained within the exhaust gases would not be fully utilised. This would mean that the plant would not be eligible for climate change levy exemption and the plants financial viability would be reduced.

The main reasons for choosing not to opt for a diesel engine based cogeneration plant were that although the plant would be around £150,000 less than a gas engine plant, diesel engines would produce higher exhaust gas emissions than gas turbines and gas engines, the plant would also require large fuel oil storage tanks, oil purification equipment and all of the fuel oil pipe-work would need to be fitted with trace heating equipment, in order to prevent the heavy fuel oil from solidifying. The diesel engines would require more maintenance than gas turbines and gas engines, also.

Therefore, it was concluded that marine gas engines would be the best practicable option for generating combined heat and power, as they would be able to produce small amounts of low pressure steam. They also offer the benefit of low exhaust gas emissions and the natural gas for the plant could be supplied directly from the Transco mains gas network.

The gas engine cogeneration plant would also make more efficient use of the engines exhaust gases and it is therefore foreseen that the plant would meet the CHPQA criteria and would be exempt from climate change levy on all its fuel inputs and electricity outputs.

The following sections of this Chapter give a brief description of the lean burn gas engine and the other major items of plant and equipment that would be installed in a typical cogeneration plant.

3.1 - PLANT MAINS GAS PRESSURE REDUCING STATION.

The Transco mains gas transmission pipeline supplies natural gas at a pressure of 7 bar. The mains gas that enters the pressure reducing station is then throttled via control valves to give the desired gas pressure that is required by a particular company or site.

The gas is normally metered at inlet to the reducing station and at outlet to each individual customer, using an analogue and a digital type gas flow-meter.

A standard pressure reducing station would have a corrugated iron roof, with several vents located in it, in order to prevent the build up of natural gas, from leaks that may occur in the pipe system. The roof also helps to protect all the equipment inside the station from becoming corroded by the elements.

The reducing station should be enclosed on all four sides by an eight foot high barbed security fence, in order to protect the equipment from vandals and animals. Access to the reducing station, for authorised persons, would be through a padlocked gate.

Figures 18 and 19 show a typical mains gas pressure reducing station, including the gas outlet pipe.

Figure 18 - Photograph of a mains gas pressure reducing station.

Figure 19 - Photograph of a mains gas outlet pipe.

3.2 - GAS ENGINE DESIGN AND DEVELOPMENT.

In 1984, due to a downturn in the marine industry, Bergen diesels (now Rolls Royce diesels), started to develop a large, medium speed marine engine that could run on either natural gas, landfill gas or coke oven gas.

In order for them to reduce the costs of developing the new engine, they decided to convert several existing 4 stroke, turbocharged and inter-cooled, V twin, 250mm bore and 300mm stroke marine diesel engines to run specifically on these fuels [31,32].

The gas engines that they developed were based on the spark ignition lean burn otto cycle principle of engine operation.

A photograph of a 3MWe spark ignition gas engine and an engineering drawing detailing the engines overall dimensions, are shown in figures 20 and 21, below, for reference.

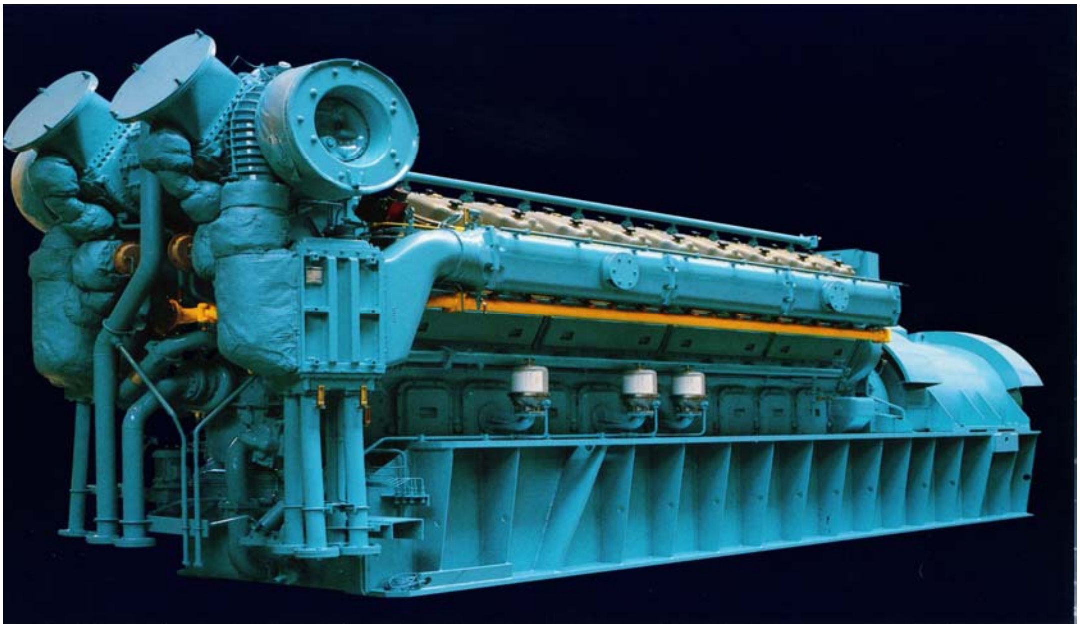


Figure 20 - Photograph of a 3MWe gas engine.

Note: The above gas engine is an 18 cylinder V design, with twin turbochargers and two stage charge air cooling. The yellow pipe indicates the main fuel gas inlet to each cylinder and the pre-ignition gas pipes are the small bore yellow pipes at the cylinder head level.

The dome shaped items that are connected to the engines crankcase doors are ventilators, which are fitted in order to prevent any of the lubricating oil vapour and the engines exhaust gases from building up inside the engines crankcase and causing an explosion.

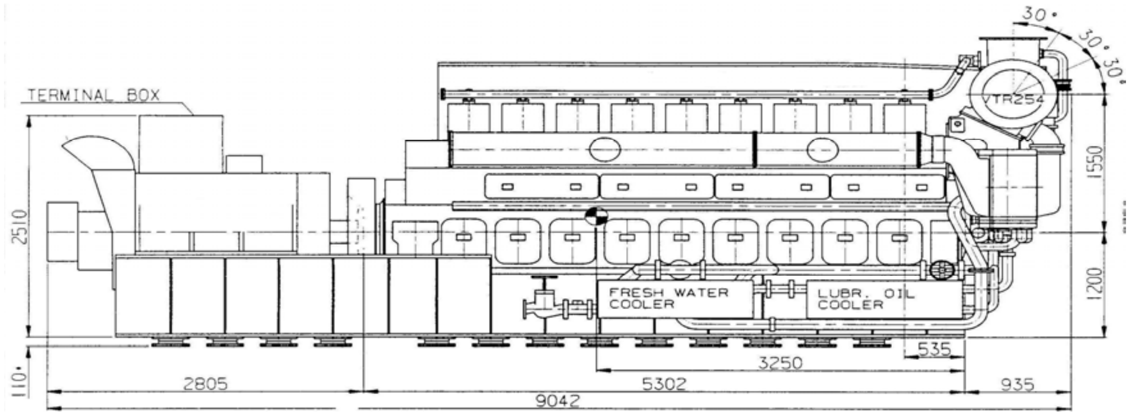


Figure 21 - Gas engine elevation drawing.

3.2.1 - LEAN BURN PRINCIPLE.

The lean burn principle of engine operation is a unique process, which can increase the power output and efficiency of a spark ignition engine, whilst also reducing the emissions of nitrous oxides, carbon monoxide and un-burnt hydrocarbons.

A conventional spark ignition engine would normally run rich with an excess air ratio of approximately 0.9 for best power output and for best fuel efficiency, the engine would normally run slightly lean with an excess air ratio of 1.25.

However, the performance and emissions that were produced by these engines was severely limited as the engines approached their knock limit at an excess air ratio of 1.3.

This led manufacturers to develop the lean burn engine, which was designed to extend the misfire and knock limits of the engine to cope with excess air ratios of 1.8 and above.

Figure 22 shows the increase in gas engine efficiency and the reduction in exhaust gas emissions that can be achieved by using lean burn technology.

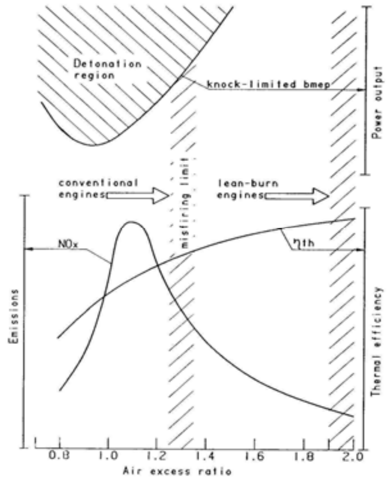


Figure 22 - Lean burn gas engine performance.

3.2.2 - IGNITION GAS PRE-CHAMBER.

In order for the manufacturers to design engines that were capable of running on very lean mixtures, it was necessary for them to redesign the engines combustion system, in such a manner that the ignition energy of the lean mixture would be increased sufficiently to allow the mixture to fire reliably.

This was achieved by designing a small ignition gas pre-chamber, which was incorporated into the engines cylinder head.

The central pre-chamber is fed with a very small, but controlled amount of pure fuel gas, by the engine control system, each time, just before the piston reaches top dead centre.

The gas is then ignited by a spark plug that is located inside the pre-chamber and the gas flame that is produced is then forced through a 6 hole pepper pot nozzle into the main combustion chamber at the bottom of the cylinder head.

The gas flame then acts as an external ignition source, by raising the ignition energy of the already highly compressed lean fuel gas and air mixture and causes it ignite just before the engines pistons reach top dead centre.

Figure 23 - Photograph of a gas engine cylinder head.

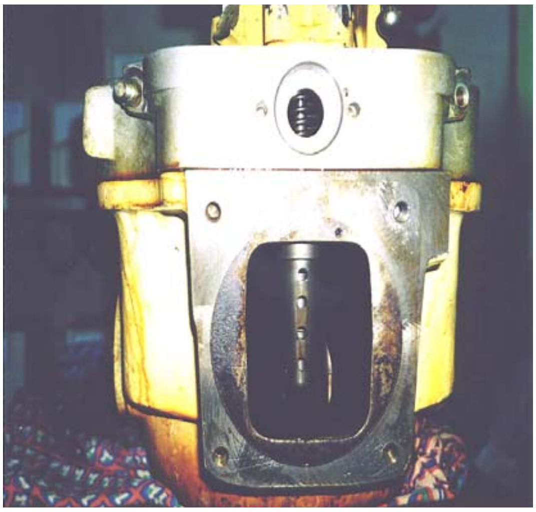


Figure 24 - Photograph of a gas engine cylinder head.

Note: The swage-lock connection at the top left of the cylinder head is used to supply fuel gas to the gas pre-ignition chamber. The top bore is connected to the main fuel gas inlet supply pipe and the bottom bore is connected to the turbocharger manifold.

3.2.3 - ENGINE CONTROL SYSTEM.

In order to run-up, run-down, increase or decrease the load on the engine, then an electrical signal must be sent to the engines governor system.

The governor system then automatically changes the position of the gas inlet throttle valves, which are mechanically linked to the air inlet flap admission valves, in order to ensure that the correct amounts of air and gas are admitted to each cylinder head, regardless of the speed or load that the engine is operating at.

The gas and air is then thoroughly mixed as it passes through the engine inlet valves and admitted into the respective engine cylinder, where it is then compressed to a high pressure.

The engine ignition central processing unit uses the signals from electrical pickups that are mounted on the engines flywheel and camshaft, to indicate when each cylinders respective piston is nearly at top dead centre and sends a 24 volt signal to an electrical coil that is mounted on each cylinder head (See figure 25).

The coil then steps up the 24 volt signal to a voltage of 40,000 volts and distributes the signal via short high tension lead to a single spark plug that is fitted inside each cylinders gas pre-ignition chamber.

The plug then sparks across its gap and ignites the pre-chamber ignition gas and as already stated above, the pre-chamber gas helps to raise the ignition energy of the lean mixture and helps it to combust more easily.

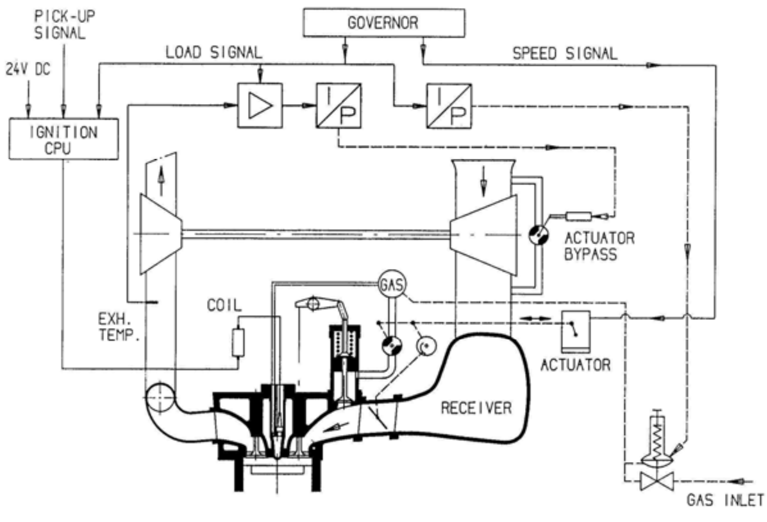


Figure 25 - Gas engine control system.

3.3 - RIGID AND RESILIENT ENGINE MOUNTING.

The floor foundations on which the gas engine shall be mounted are specifically designed to support both the weight of the engine and generator set, which can be up to 60 tonnes for a 3MWe engine package and to minimise any propagation of the engines vibration into the surrounding buildings and structures.

The engine and generator set are normally mounted on a skid arrangement, which is rigidly mounted on to the concrete floor foundations with anchor bolts.

As an alternative, a chock-fast “orange” material maybe used as the foundation material. Chock-fast is a compression load bearing material, it has a low viscosity and low surface tension and in liquid form it is easy to apply.

The depth of the foundations when using chock fast should be between 10 and 40mm, with the area of individual chock-fast slaps being no less than 130 cm^2.

As another alternative, the engine and generator set could also be resiliently mounted to the floor foundation, in order to isolate the engine from shock loading, including earthquakes.

The two main types of resilient mounting system are based on either steel springs with a rubber damper element fitted in-between or a rubber element bonded to a steel plate type design.

3.4 - TURBOCHARGERS AND AIR SYSTEMS.

All large marine gas engines are fitted with either a single or twin type turbochargers, depending on whether the engine is an in line or v type design.

The purpose of the turbocharger is to increase the engines efficiency and power output by passing the engines exhaust gases through an impulse turbine which is connected via a shaft to an air compressor, which consequently rotates faster and draws in additional quantities of combustion air to the engine.

The compressor then increases the combustion air pressure slightly, before it actually enters the engines cylinders.

3.4.1 - CHARGE AIR COOLING.

All marine engine turbochargers are also fitted with intercoolers, which can be of either a single stage or twin stage charge air cooling design.

The high temperature charge air cooler is cooled with water from the engines jacket water system and the low temperature charge air cooler is cooled by water from the raw water cooling system.

The purpose of the intercoolers is to cool the compressed air in the turbocharger, in order to reduce its volume, so that more air can then be drawn into the turbocharger.

The intercoolers also increase the area under the Temperature - Entropy diagram and thus they improve the engines power output and overall efficiency.

3.4.2 - ENGINE COMBUSTION AIR SYSTEM.

Each gas engine enclosure is normally supplied individually with combustion air, which is drawn in through louver type air filters, by a single forced draught fan which is located in the engines combustion air duct.

The combustion air filter is typically about 6 metres by 3 metres in size and is installed at roof level on one of the cogeneration plants exterior walls. These filters are designed to remove 95% of all airborne particles, that are greater than five microns in size.

The amount of air that is discharged by the forced draught fan into the engine room enclosure can be controlled by manually adjusting the guide vane position on the exhaust dampers.

Furthermore, the turbocharger air inlets are also fitted with fine blanket type air filters, in order to further purify the engine combustion air.

3.4.3 - ENGINE ROOM VENTILATION SYSTEM.

Each gas engine enclosure is also fitted with a ventilation system, in order to cool the gas engine and to maintain the engine enclosure temperature below 30 ºC.

The ventilation system also helps to remove any fuel gas that may have leaked into the engine enclosure from the gas supply pipes and to disperse any exhaust gases and lube oil vapour that may have leaked out of the exhaust gas manifold and the crankcase ventilators.

3.4.4 - STARTING AND CONTROL AIR SYSTEMS.

All cogeneration plants are equipped with compressed air systems, which provide each gas engine with starting air at a pressure of between 18 bar and 30 bar. The compressed air is also reduced in pressure to 7 bar, for use as control air for the pneumatic actuators that are installed in the plant.

It is standard practice for most cogeneration plants to be fitted with two full duty electrically driven and one full duty diesel driven air compressor, in order to ensure that the plant has sufficient starting and control air, at all times.

The starting air is admitted into each cylinder head by a solenoid type air release valve and the engine then run on starting air for about five seconds, before the fuel gas is admitted, in order to ensure that there is no fuel gas left in the exhaust system, as this could lead to an explosion or scavenge fire occurring.

3.5 - FUEL GAS SYSTEM.

The purpose of the engines fuel gas module is to regulate the pressure, flow-rate and purity of fuel gas that is supplied to the engine from the mains gas pressure reducing station.

The main component of the fuel gas module is the gas regulating line, which comprises of several gas filters, gas control valves and isolating valves, which remove any impurities in the fuel gas and regulate the pressure of the gas to a maximum of 2.3 bar at inlet to the engine. In the event of an engine trip, any fuel gas that remains in the system can be vented to atmosphere, via a vent line, also.

It should be noted that all gas engine manufacturers require detailed information on the composition of the fuel gas that will be burnt in their engines, as there is a risk that there can be a chemical interaction between the natural gas and certain types of engine lubricating oil.

Figure 26 - Engine fuel gas regulating system.

3.6 - LUBRICATING OIL SYSTEM.

The purpose of the lubricating oil system is to supply a sufficient flow of oil at a pressure of between 4 and 5 bar and a temperature of 60ºC, in order to lubricate and cool the engines main crankshaft bearings and the piston big end and small end bearings. The system also supplies oil at a reduced pressure of 0.5 bar to lubricate the rocker arms.

Each gas engine is fitted with a main shaft driven lube oil pump for normal operation and an electrical auxiliary pump for when the engine is off load.

3.6.1 - RAW WATER COOLING SYSTEM.

The purpose of the raw water cooling system is to supply a sufficient flow of water at an inlet temperature of 45ºC to cool the lubricating oil system and at an inlet temperature of 55ºC to cool the low temperature charge air cooler. The raw water is then cooled by passing it through an outdoor radiator system.

The raw water should also be mixed with antifreeze and an inhibitor, in order to prevent the system from freezing in Winter-time and to minimise the risk of corrosion, sediments and surface growths forming inside the pipe-system.

3.6.2 - JACKET WATER COOLING SYSTEM.

The purpose of the jacket water cooling system is to supply a sufficient flow of water at an inlet temperature of 45ºC to cool the high temperature charge air cooler.

The jacket water then passes into the engine block at a minimum temperature of 70ºC and cools the block, wet liners and the cylinder heads, before exiting the engine at 90ºC. The jacket water is then cooled by passing it through an outdoor radiator system, also.

Each gas engine is normally fitted with a shaft driven jacket water pump for normal operation and an auxiliary electrical driven jacket water pump, which will circulate the jacket water round the engine for fifteen minutes after the engine comes off load, in order to prevent the jacket water from boiling.

3.7 - EXHAUST GAS SYSTEM.

The engine exhaust system comprises of a lagged exhaust gas pipe, which leads the gases, firstly through a bellows arrangement, in order to minimise any thermal stresses in pipe. The gases are then led through a substantial length of pipe to the waste heat recovery boiler.

It is standard practice for the heat recovery boiler to be fitted with a bypass system, so that when steam or hot water is not required, then the engines hot exhaust gases can be diverted directly to the plants stack or chimney. This also allows for the water and steam systems to be isolated for routine maintenance purposes (See figure 27).

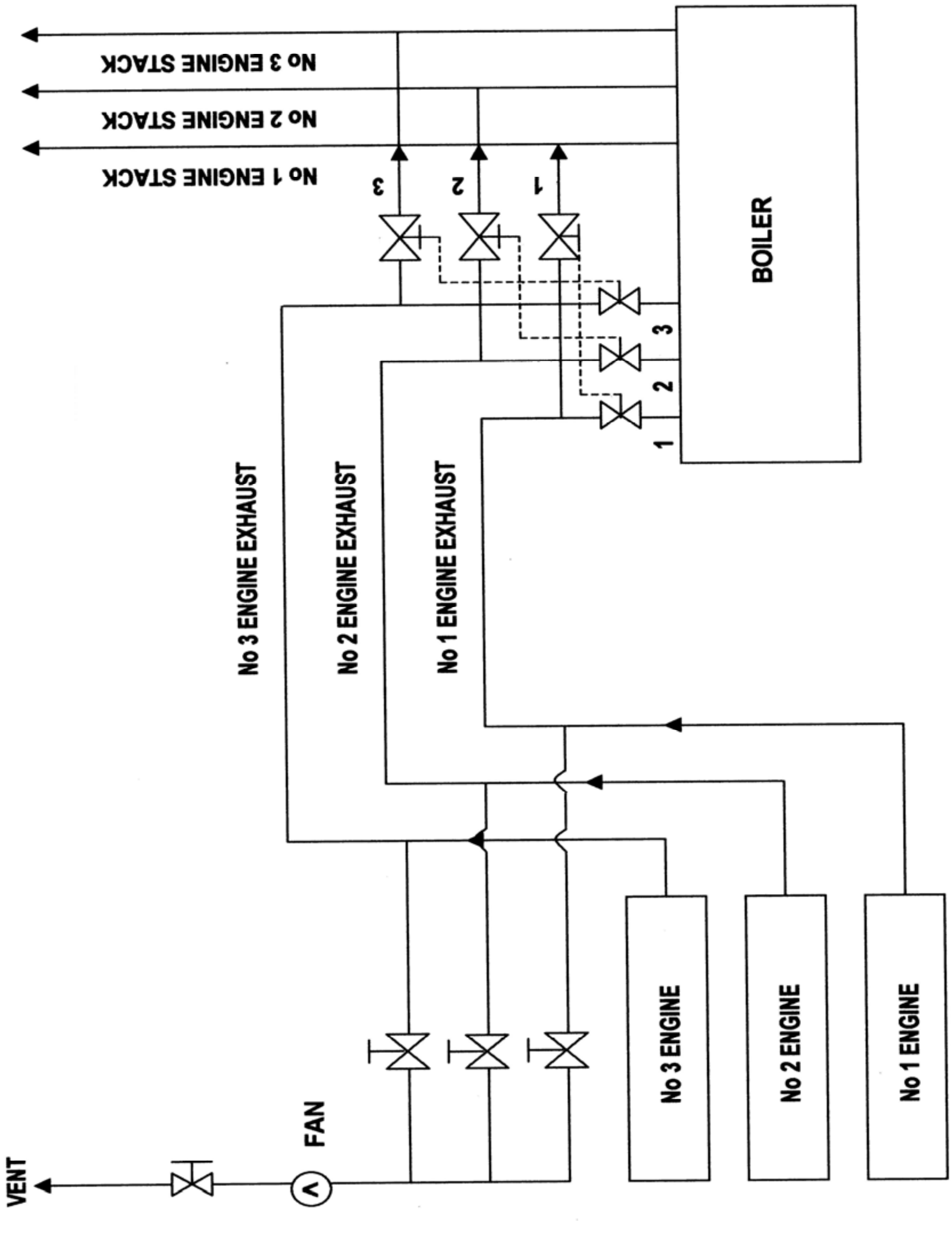
The exhaust gas manifold for each engine is also connected to an extractor fan, which discharges to the outside of the cogeneration plants building, in order that the exhaust system maybe purged of any fuel gas that may have accumulated in it, due to a failure of a gas engine to start.

3.7.1 - EXHAUST STACK.

The plants chimney or stack should be designed to have a positive height, above the roof levels of nearby buildings, in order to allow for a good dispersal of the engines exhaust gases.

The standard size of exhaust stack for a 9.5MWe cogeneration plant is around 35 metres in height.

Figure 27 - Engine exhaust gas system.



3.8 - ENGINE FIRE PROTECTION SYSTEM.

All cogeneration plants are required to ensure that they have installed suitable flammable gas detection, smoke detection, fire alarms, fire exits and fire protection equipment on their site before they will be issued with a Fire Certificate by the Fire Brigade and covered for loss by their insurance company.

A single gas engine enclosure would normally be fitted with at least two smoke and two gas detectors, that should be located at roof height at diagonally opposite ends of the engine enclosure.

Each engine should be also be protected by a carbon dioxide fire protection system.

The protection system normally consists of a bank of eight 35 kg carbon dioxide cylinders, that are connected to a series of spray nozzles that surround the engine on two sides and which are specifically set to give the best coverage of the engine.

When a fire is detected in the enclosure, then an electrical signal is sent to the outlet valve on the bank of carbon dioxide bottles, which releases the liquid carbon dioxide and causes it to expand into a gas as it exits the spray nozzles.

The nozzles allow the carbon dioxide gas to blanket the whole engine compartment and this reduces the oxygen levels in the vicinity of the burning material and causes the fire to go out naturally.

3.9 - CONDENSATE RETURN SYSTEM AND STEAM RAISING PLANT.

The condensate from the manufacturing company will be pumped to the new cogeneration plant and stored in a de-aerator tank, which will be located at a vertical height of 10 metres above the plants ground level.

The de-aerator tank acts as a high level feed water storage vessel and supplies a net positive suction head to the main boiler feed water pumps in order to prevent them from cavitating.

The boiler feed pumps will then pump the hot water directly into the heat recovery boiler, via two control valves, which control the flow of water to the boiler, depending on the engine load (See figure 28).

The feed water that is stored inside the de-aerator tank is normally dosed with sodium hydroxide (caustic soda) and tri-sodium phosphate, in order to control the feed-water alkalinity to an optimum pH of between 8.8 and 9.2 and to prevent the build up of scale on the boiler tubes, by converting the calcium and magnesium salts that are present in the feed-water into calcium and magnesium phosphates.

The feed water is also dosed with hydrazine, which acts as an oxygen scavenger and removes any dissolved oxygen that maybe present in the feed-water, as the dissolved oxygen can accelerate corrosion in the heat recovery boiler.

The feed water is dosed at outlet from the de-aerator and dosing is continued until the dissolved oxygen content falls below 0.007 parts per million. The hydrazine also acts as a weak alkali and any hydrazine not consumed in oxygen scavenging process, assists with raising the alkalinity of the feed-water.

3.9.1 - HEAT RECOVERY BOILER (HRSG).

The most common type of heat recovery boiler that is used in small-scale cogeneration plants is the single pass, counter flow, shell and tube design of heat exchanger.

In the counter flow design of heat exchanger, the engines exhaust gases are passed through the tubes of the heat recovery steam generator, whilst the hot water or condensate is circulated over the tubes in the opposite direction, by means of a small, single stage, centrifugal boiler feed-water pump.

The steam that is produced, is then led out of the top of the heat recovery boiler and through the steam pipe-work to the main steam leg, where it will then be routed into the manufacturing plants process steam system (See figure 28).

A portion of the steam produced by the heat recovery boiler is normally returned to the de-aerator tank, in order to maintain a high feed water temperature inside the tank, during all operating conditions, also.

For cogeneration plants using natural gas fuelled reciprocating engines, the minimum exhaust gas outlet temperature from the heat recovery boiler is around 120ºC to 130 ºC, due to heat exchanger design reasons and to ensure that the exhaust gases have sufficient buoyancy to rise up the stack.

For diesel engines the minimum exhaust gas outlet temperature from the boiler is around 170ºC, as below this temperature it is possible for the sulphur in the exhaust gases to condense and form sulphuric acid on the boiler tubes.

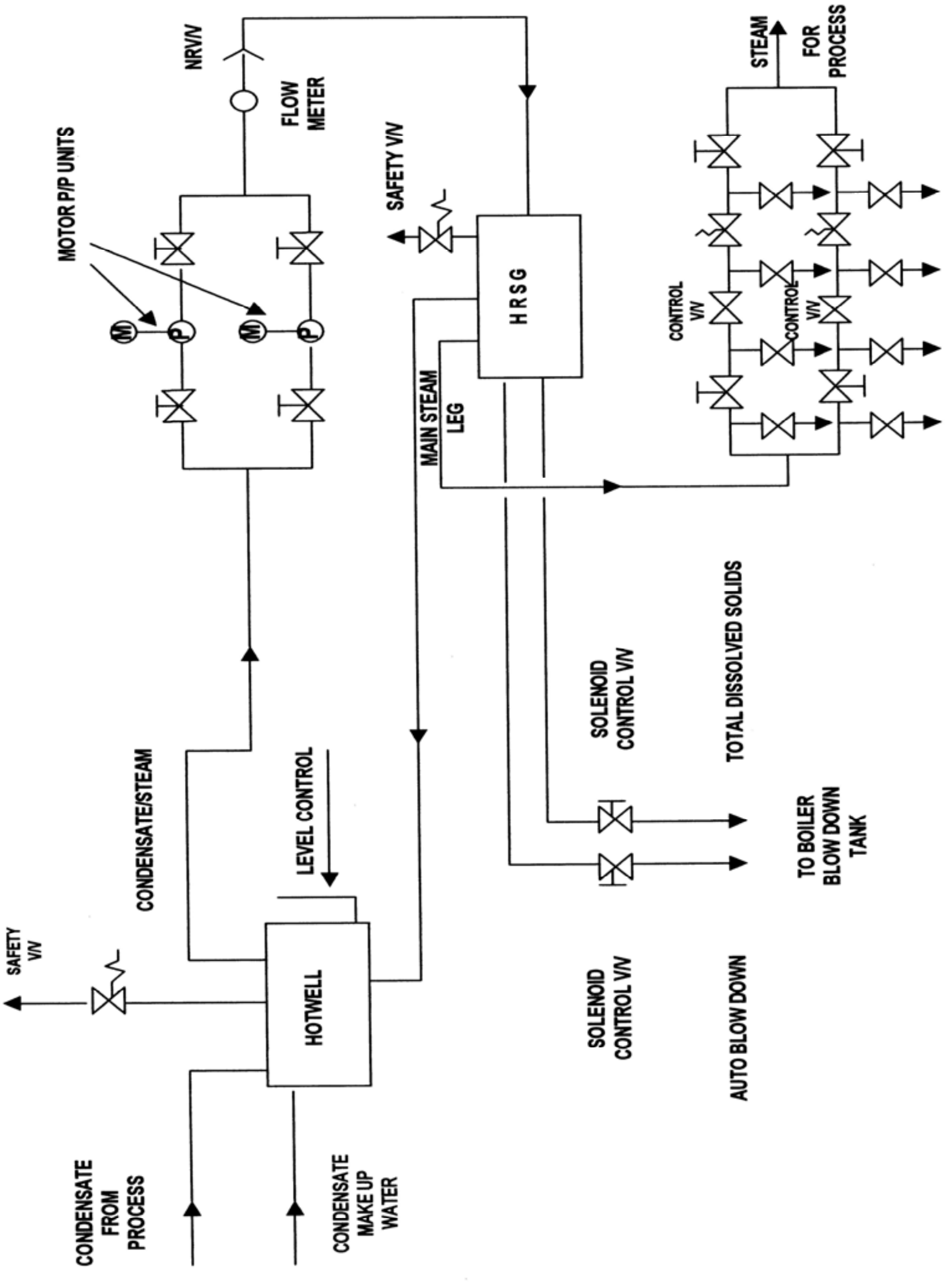
It should also be noted that for gas engine cogeneration plants, it is possible to install an economiser, which can extract the useful heat energy contained within the engines exhaust gases, down to an exhaust gas outlet temperature of 60ºC. However, this would increase the cost and complexity of building the plant.

3.9.2 - BOILER BLOWDOWN SYSTEM.

The purpose of the boiler blow-down system is to remove any concentrations of soluble substances, including calcium, magnesium and silica, that are present in the boiler feed water.

The heat recovery boiler is normally fitted with an automatic blow-down system, which automatically opens the blow-down valves at regular intervals for several minutes, in order to divert some of the steam to the blow-down vessel, where any total dissolved solids are removed and the steam vented off to the atmosphere.

Figure 28 - Cogeneration plant water / steam cycle.



CHAPTER 4 - TECHNICAL EVALUATION OVERVIEW.

The technical evaluation process firstly aimed to evaluate the Local Authority Planning and Consents procedures for the construction of the proposed cogeneration plant, in order to ascertain whether or not the project was likely to be granted "Deemed Planning Permission".

The second stage was then to identify engine manufacturers who would be in a position to supply large gas engines that are capable of producing a total power output of 9.5MWe.

The third stage of the process was to calculate the size of the engines exhaust gas pipes and to determine if there would be sufficient heat energy available from the selected engines exhaust gases to produce 8 tonnes per hour of saturated steam, at 7 bar pressure, in a waste heat recovery boiler.

Finally, the last stage of the process was to calculate whether or not the plant would qualify as good quality combined heat and power, under CHPQA rules, by completing the relevant CHPQA forms.

4.1 - PROPOSED SITE FOR THE COGENERATION PLANT.

The proposed site for the cogeneration plant is in an industrial area local to a large manufacturing plant in the West Midlands, England, UK.

There is a large amount of waste ground local to the manufacturing plant that could be used to site the cogeneration plant and because the proposed site is in an industrial area, it is anticipated that there will be little opposition from the local community.

It is also foreseen that the Local Planning Authority will have no objections to the proposed site for the plant as the land is currently lying vacant and the surrounding area would be regenerated as part of the construction process, thus complying with Planning Policy Guidance Note 4 on Urban Regeneration.

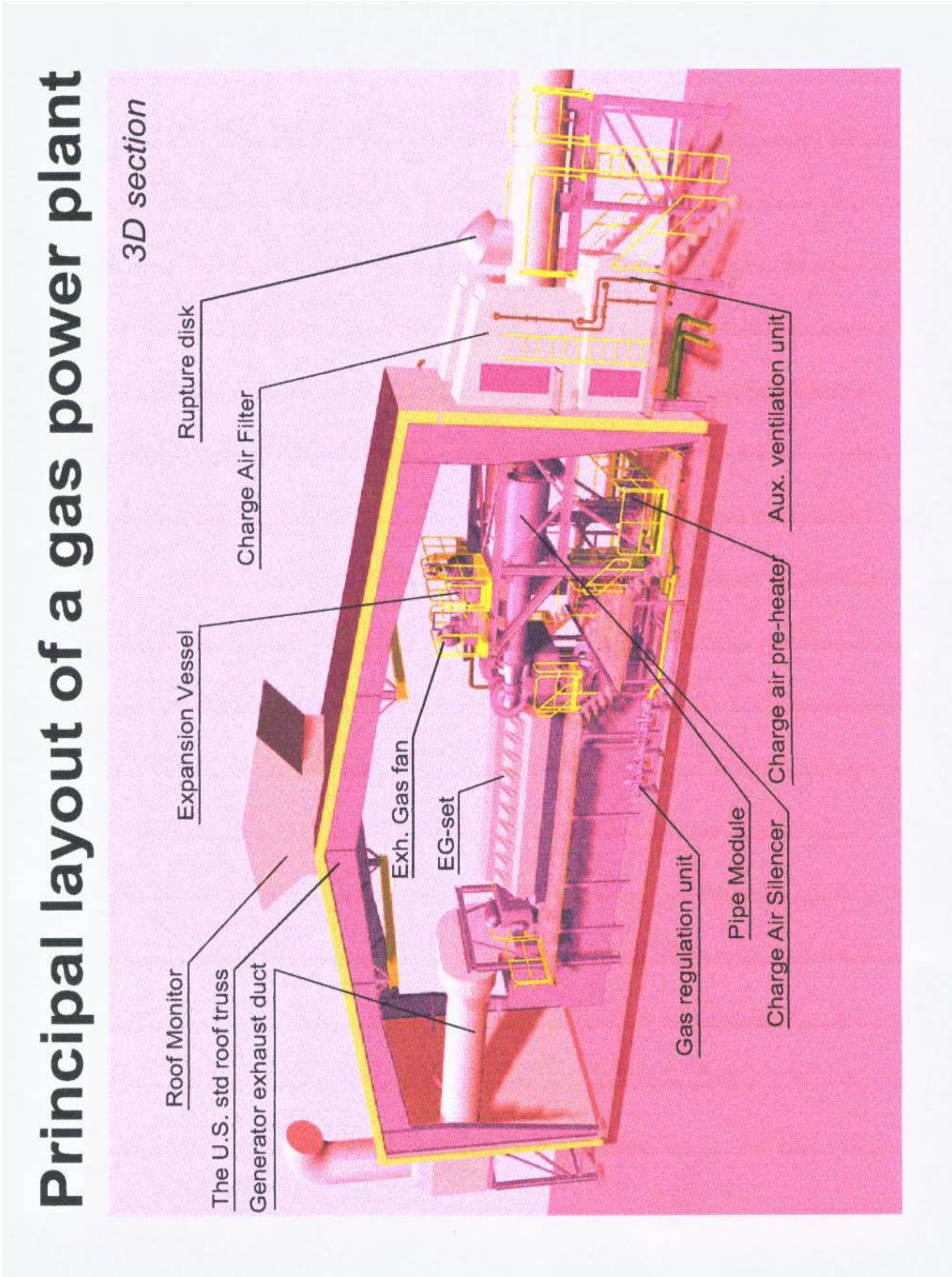
The cogeneration plant building would be sound-proofed to minimise any noise pollution and the area adjacent to the plant would be landscaped to minimise any visual impact.

A typical layout drawing and schematic drawing for the proposed plant are shown in figures 29 and 30.

Furthermore, an environmental impact assessment for the proposed plant is given in Chapter 6, also.

Figure 29 - Cogeneration plant engineering drawing.

Figure 30 - Cogeneration plant layout drawing.



4.2 - GAS ENGINE MANUFACTURERS.

The engine manufacturers listed in table 8, were identified from trade publications and the worldwide web as being in a position to supply gas engines for the proposed cogeneration plant [2,3,6].

The technical specifications for the various gas engines and the number of engines that would be required for the plant are also shown in the table.

Jenbacher gas engine	Type J616GS	2.19MW	1500 rpm	50Hz	5 reqd.
Jenbacher gas engine	Type J620GS	3.2MW	1500 rpm	50Hz	3 reqd.
Rolls Royce gas engine	Type KVGB16	2.81MW	1000 rpm	50Hz	4 reqd.
Rolls Royce gas engine	Type KVGB18	3.16MW	1000 rpm	50Hz	3 reqd.
Wartsila gas engine	Type 12V34SG	4.04MW	750 rpm	50Hz	3 reqd.
Wartsila gas engine	Type 18V34SG	6.06MW	750 rpm	50Hz	2 reqd.

Table 8 - Gas engine manufacturers and product range.

4.2.1 - SELECTION OF GAS ENGINE MANUFACTURER.

The Rolls Royce Bergen KVGB-18 and the Jenbacher J620GS gas engines were then identified as being the most suitable engines to meet the plants requirements for 9.5MWe of power.

The final decision as to which manufacturer to select to build the plant would then rest with the client and would be based upon the relative costs of each engine type and on the clients preference for a particular engine manufacturer.

The decision would also be influenced by the delivery date for the engines to site and on the earliest guaranteed plant start-up date.

The main reason for not choosing the Wartsila range of gas engines was that the 12V34SG and the 18V34SG engines produced 2.5MWe more power output than was actually required by the cogeneration plant.

4.2.2 - GAS ENGINE TECHNICAL INFORMATION.

The Jenbacher Engine Company and Rolls Royce Bergen Diesels were then contacted for technical information on their range of gas engines.

From the information received, it was possible to base the technical calculations used in this thesis on the Bergen KVGB-18 gas engine (See Appendix C).

The technical specification and operating conditions for the KVGB-18 gas engine at full and at part loads of 50% and 80% are shown in the tables 9 and 10.

Number of cylinders	18
Cylinder bore	250 mm
Piston stroke	300 mm
Engine M.C.R	3.16 MWe
Engine rated speed	1000 rpm
Exhaust mass flow-rate	21,000 kg / hour
Exhaust volume flow-rate	42,600 m^3 / hour
Exhaust temperature	520 ºC
Temperature after turbocharger	420 ºC

Table 9 - KVGB18 gas engine technical data (M.C.R).

Exhaust mass flow-rate at 80% load	17,550 kg / hour
Temperature after turbocharger	420 ºC
Exhaust mass flow-rate at 50% load	12,400 kg / hour
Temperature after turbocharger	400 ºC

Table 10 - KVGB18 gas engine technical data (50% & 80% M.C.R).

From the technical data sheet on the KVGB-18 gas engine, it was ascertained that the exhaust gas temperature at exit from the turbocharger would be approximately 420ºC.

Then, using basic heat transfer and fluid dynamics equations it was possible to calculate the ideal size of exhaust gas pipe and the heat loss in the exhaust gas pipe between the turbocharger outlet and the inlet to the waste heat recovery boiler, in order to calculate the exhaust gas inlet temperature to the boiler.

The actual thermodynamic calculations that were undertaken for the proposed plant are detailed in the following sections (See sections 4.3 to 4.6).

4.3 - CALCULATION OF THE EXHAUST PIPE SIZE AND HEAT TRANSFER COEFFICIENTS.

The exhaust gas volume flow-rate, for one engine operating at its maximum continuous rating is calculated as follows:

$$\text{M.C.R exhaust gas flow-rate} = \frac{\text{MCR exhaust gas volume flow-rate}}{3{,}600} \qquad \frac{[m^3 / h]}{[s / h]}$$

M.C.R exhaust gas flow-rate = 42,600 / 3,600 [m^3 / s]

M.C.R exhaust gas flow-rate = 11.833 m^3 / s.

4.3.1 - EXHAUST GAS VELOCITY.

When designing an exhaust gas system it is standard engineering practice to ensure that the exhaust gas velocity does not exceed 46 metres per second, due to noise and vibration constraints.

Therefore, the exhaust gas velocity was calculated first for a 24" exhaust pipe and then for a 36" pipe, in order to ascertain the ideal pipe diameter to minimise noise and vibration levels.

The exhaust pipe wall thickness, which the gas velocity calculations were based upon, was 0.375" (9.525mm), in order to minimise the overall weight of the pipe-work system (See ANSI Pipe Schedule - Appendix E).

4.3.2 - 24" PIPE GAS VELOCITY.

The exhaust gas velocity in the 24" exhaust pipe was calculated as follows:

Pipe outside diameter = 24" = 0.6096 metres.
Pipe wall thickness = 0.375" = 0.00953 metres.
Pipe inside diameter = 0.6096 - (2 * 0.00953) = 0.5905 metres.

$$\text{Pipe inside area} = \frac{3.14 * (\text{inside diameter})^2}{4} \qquad [m^2]$$

$$\text{Pipe inside area} = \frac{3.14 * (0.5905 * 0.5905)}{4} \qquad [m^2]$$

Pipe inside area = 0.2739 m^2.

$$\text{Exhaust gas velocity} = \frac{\text{Exhaust gas volume flow-rate}}{\text{Pipe inside area}} \qquad \frac{[m^3 / s]}{[m^2]}$$

$$\text{Exhaust gas velocity} = \frac{11.833}{0.2739} \qquad [m / s]$$

Exhaust gas velocity = 43.2 m / s.

4.3.3 - 36” PIPE GAS VELOCITY.

The 36” exhaust gas pipe dimensions and the gas velocity were calculated in the same way as for the 24” pipe.

The actual pipe dimensions and the gas velocity are given below:

Pipe outside diameter = 36” = 0.9144 metres.
Pipe wall thickness = 0.375” = 0.00953 metres.
Pipe inside diameter = 35.25” = 0.9144 - (2 * 0.00953) = 0.89535 metres.
Pipe inside area = 0.6296 m^2.
Exhaust gas velocity = 18.8 m / s.

The exhaust gas velocity in the 36” pipe was calculated as 18.8 m / s and by using this size of pipe we should be able to reduce the noise emanating from the exhaust gas system considerably.

4.3.4 - EXHAUST PIPE HEAT LOSS VARIABLES.

The heat loss from the exhaust gas pipe is dependent on a number of factors including the exhaust gas inlet temperature, the ambient outside air temperature, the length, inside and outside diameters and the thermal conductivity of the exhaust gas pipe and on the thickness and thermal conductivity of pipe insulation material.

The ambient air temperature inside the cogeneration plant building, will vary depending on the time of day and on the time of year and the heat loss from the exhaust pipes will be larger during colder ambient conditions.

The seasonal ambient air temperatures [33] for Central England are shown in table 11.

The thermal conductivities [34] for the steel exhaust gas pipe at various temperatures and for rock-wool insulation material at 100ºC are shown in the table 12.

Finally, the heat loss through the pipe is also dependent on the heat transfer coefficients for the exhaust gas and for the air surrounding the pipe insulation material.

Spring	15.3ºC
Summer	19.6ºC
Autumn	12ºC
Winter	9.3ºC

Table 11 - Seasonal ambient air temperatures.

Steel pipe at 27ºC	55 W / mK
Steel pipe at 127ºC	52 W / mK
Steel pipe at 227ºC	48 W / mk
Steel pipe at 327ºC	45 W / mK
Steel pipe at 427ºC	42 W / mK
Steel pipe at 527ºC	38 W / mK
Rockwool insulation at 100ºC	0.045 W / mK

Table 12 - Thermal conductivity values.

4.3.5 - EXHAUST GAS PROPERTIES.

The exhaust gas heat transfer coefficient can be calculated by using empirical heat transfer equations that relate to forced convection, as the exhaust gases can be thought of as being forced through the exhaust gas pipe by the upwards motion of the engines pistons in their respective cylinders during the exhaust stroke.

Unfortunately, there is very little thermodynamic data given in Rogers and Mayhew steam tables that relates to exhaust gases.

Therefore, in order to calculate the heat transfer coefficient of the exhaust gases, it has been necessary to use the thermodynamic data relating to carbon dioxide gas as an approximation [35].

Specific heat capacity	1122 J / kgK
Density	0.782 kg / m³
Dynamic viscosity	0.0000305 kg / ms
Thermal conductivity	0.04752 W / mK

Table 13 - Properties of carbon dioxide gas.

4.3.6 - EXHAUST GAS HEAT TRANSFER COEFFICIENT.

The Reynolds number of the exhaust gas flow must first be calculated in order to ascertain whether the gas flow is laminar or turbulent flow [34,36].

The Reynolds number is calculated as follows:

$$\text{Reynolds number} = \frac{\text{Gas density * Gas velocity * Pipe diameter}}{\text{Dynamic viscosity}} \qquad [\text{--}]$$

$$\text{Reynolds number} = \frac{0.782 * 18.8 * 0.89525}{0.0000305} \qquad [\text{--}]$$

<u>Reynolds number = 430,659.</u>

Since the Reynolds number is greater than 3,800, then the gas flow can be termed as turbulent flow.

4.3.7 - PRANDTL NUMBER.

The Prandtl number and the Nusselt number for forced convection and turbulent flow were then calculated in order to determine the value of the exhaust gas heat transfer coefficient.

$$\text{Prandtl number} = \frac{\text{Dynamic viscosity} * \text{Specific heat capacity}}{\text{Thermal conductivity}} \qquad [--]$$

$$\text{Prandt number} = \frac{0.0000305 * 1122}{0.04752} \qquad [--]$$

Prandtl number = 0.722.

4.3.8 - NUSSELT NUMBER AND HEAT TRANSFER COEFFICIENT.

$$\text{Nusselt number} = 0.0225 * (\text{Reynolds number})^{0.8} * (\text{Prandtl number})^{0.33} \qquad [--]$$

$$\text{Nusselt number} = 0.0225 * (430{,}659)^{0.8} * (0.722)^{0.33} \qquad [--]$$

$$\text{Nusselt number} = 0.0225 * 32{,}159 * 0.9 \qquad [--]$$

Nusselt number = 650.

$$\text{Nusselt number} = \frac{\text{Heat transfer coefficient} * \text{Pipe diameter}}{\text{Thermal conductivity}} \qquad [--]$$

$$\text{Heat transfer coefficient} = \frac{\text{Nusselt number} * \text{Thermal conductivity}}{\text{Pipe diameter}} \qquad [W / m^2K]$$

$$\text{Heat transfer coefficient} = \frac{650 * 0.04752}{0.89535} \qquad [W / m^2K]$$

Heat transfer coefficient = 34.5 W / m²K.

4.3.9 - HEAT TRANSFER COEFFICIENT FOR AIR.

The heat transfer coefficient for air, based on a natural convection process, has been calculated assuming that the temperature difference between the outside of the pipe lagging material and the ambient air is a maximum of 15 ºC [34,36].

$$\text{Heat transfer coefficient} = 1.34 * \left(\frac{\text{((Pipe lagging temperature - ambient air temperature))}}{\text{((Pipe diameter))}}\right)^{0.25}$$

$$\text{Heat transfer coefficient} = 1.34 * (15 / 0.9155)^{0.25}$$

Heat transfer coefficient = 2.7 W / m^2K.

4.4 - CALCULATIONS FOR THE EXHAUST PIPE HEAT LOSS.

The heat loss from the exhaust gas pipe, which has a layer of insulation surrounding it, can then be calculated by using the following equation:

$$\text{Heat loss through pipe} = Q = \frac{2 * 3.14 * L * (Tb - Ta)}{((1/r1ha + 1/r3hb + \ln(r2/r1)/k1 + \ln(r3/r2)/k2))}$$

Where	Q	= Pipe heat loss	[W]
	ha	= Heat transfer coefficient of the exhaust gas	[W / m²K]
	hb	= Heat transfer coefficient of air	[W / m²K]
	k1	= Thermal conductivity of the exhaust pipe at 427ºC	[W / mK]
	k2	= Thermal conductivity of the pipe lagging material at 100ºC	[W / mK]
	L	= Length of the exhaust gas pipe	[m]
	r1	= Inside pipe diameter / 2	[m]
	r2	= Outside pipe diameter / 2	[m]
	r3	= Outside radius of pipe + thickness of lagging	[m]
	Ta	= Exhaust gas temperature at inlet to the exhaust pipe	[K]
	Tb	= Ambient air temperature	[K]

Note: The heat loss value that is obtained by using the above equation will be a negative value, as Ta>Tb.

4.4.1 - EXHAUST GAS OUTLET TEMPERATURE.

The heat loss from the exhaust gas pipe can also be calculated by using the steady flow energy equation.

The heat loss value that would be obtained would be identical to that calculated by using equation 4.4, above.

$$Q - W = ma\,(h2 - h1) + ma\,(C2^2 - C1^2) / 2 + ma * g * (Z2 - Z1)$$ - Steady Flow Eq.

Where Q	= Pipe heat loss	[W]
C1	= Exhaust gas velocity at inlet to exhaust pipe	[m / s]
C2	= Exhaust gas velocity at outlet to exhaust pipe	[m / s]
Cp	= Specific heat capacity at constant pressure of the exhaust gas	[J / kgK]
g	= 9.81	[m / s^2]
h1	= Exhaust gas enthalpy at exhaust pipe inlet	[J / kg]
h2	= Exhaust gas enthalpy at exhaust pipe outlet	[J / kg]
ma	= Exhaust gas mass flowrate	[kg / s]
T2	= Exhaust gas temperature at exit from exhaust pipe	[K]
T1	= Exhaust gas temperature at inlet to exhaust pipe	[K]
W	= Work done on the exhaust gas	[W]
Z1	= Exhaust gas pipe inlet vertical height above reference point	[m]
Z2	= Exhaust gas pipe outlet vertical height above reference point	[m]

Assuming that:

- No work is done on the exhaust gas between the inlet and outlet pipes.
- The pipe inlet and outlet heights are at the same level above a known reference point.
- The pipe area is the identical at inlet and outlet.

Then the steady flow energy equation can be reduced to:

Heat loss through pipe = Q = ma * (h2 - h1) = ma * Cp * (T2 - T1)

The above equation can then be rearranged, in order to determine the exhaust gas temperature at inlet temperature to the heat recovery boiler:

Exhaust gas temperature at inlet to heat recovery boiler = T2 = T1 + (Q / (ma * Cp)).

The above equations were then used to calculate the heat loss through the exhaust gas pipe and the exhaust gas temperature at inlet to the heat recovery boiler, depending on the length of the pipe, the lagging material thickness and on the seasonal ambient air temperature.

The results are shown in the tables 14 to 18, for KVGB-18 gas engines operating independently and in parallel with one another.

The heat savings that can be achieved from using 6” and 9” lagging, instead of 4” lagging have also been calculated and are shown in table 19, for one engine operating at maximum continuous rating.

Lagging Thickness (")	Pipe Length (m)	Spring Heat Loss (kW)	Summer Heat Loss (kW)	Autumn Heat Loss (kW)	Winter Heat Loss (kW)
4"	30m	14.88	14.7	14.99	15.07
4"	50m	24.8	24.5	24.99	25.1
4"	70m	34.71	34.28	34.96	35.14
6"	30m	10.94	10.8	11.02	11.07
6"	50m	18.24	18.02	18.38	18.47
6"	70m	25.54	25.22	25.72	25.85
9"	30m	8.03	7.93	8.09	8.13
9"	50m	13.37	13.2	13.46	13.53
9"	70m	18.73	18.5	18.87	18.96

Table 14 - Seasonal pipe heat loss for one engine at 100% M.C.R.

Lagging Thickness (")	Pipe Length (m)	Average Heat Loss (kW)	Two Pipes Heat Loss (kW)	Three Pipes Heat Loss (kW)	Exhaust Temperature (ºC)
4"	30m	14.91	29.82	44.73	417.7
4"	50m	24.85	49.7	74.55	416.1
4"	70m	34.77	69.54	104.31	414.6
6"	30m	10.96	21.92	32.88	418.3
6"	50m	18.28	36.56	54.84	417.2
6"	70m	25.58	51.16	76.74	416
9"	30m	8.05	16.1	24.15	418.7
9"	50m	13.39	26.78	40.17	417.9
9"	70m	18.77	37.54	56.3	417.1

Table 15 - Average annual pipe heat losses for 1, 2 and 3 engines at 100% M.C.R.

Lagging Thickness (")	Pipe Length (m)	Average Heat Loss (kW)	Two Pipes Heat Loss (kW)	Three Pipes Heat Loss (kW)	Exhaust Temperature (ºC)
4"	30m	14.91	29.82	44.73	417.2
4"	50m	24.85	49.7	74.55	415.4
4"	70m	34.77	69.54	104.31	413.5
6"	30m	10.96	21.92	32.88	418
6"	50m	18.28	36.56	54.84	416.6
6"	70m	25.58	51.16	76.74	415.2
9"	30m	8.05	16.1	24.15	418.5
9"	50m	13.39	26.78	40.17	417.5
9"	70m	18.77	37.54	56.3	416.5

Table 16 - Average annual pipe heat losses for 1, 2 and 3 engines at 80% M.C.R.

Lagging Thickness (")	Pipe Length (m)	Spring Heat Loss (kW)	Summer Heat Loss (kW)	Autumn Heat Loss (kW)	Winter Heat Loss (kW)
4"	30m	14.15	13.97	14.26	14.33
4"	50m	23.58	23.27	23.76	23.88
4"	70m	32.99	32.57	33.25	33.42
6"	30m	10.39	10.26	10.48	10.53
6"	50m	17.34	17.11	17.48	17.57
6"	70m	24.27	23.96	24.46	24.59
9"	30m	7.63	7.53	7.69	7.73
9"	50m	12.71	12.54	12.8	12.87
9"	70m	17.81	17.58	17.95	18.04

Table 17 - Seasonal pipe heat loss for one engine at 50% M.C.R.

Lagging Thickness (")	Pipe Length (m)	Average Heat Loss (kW)	Two Pipes Heat Loss (kW)	Three Pipes Heat Loss (kW)	Exhaust Temperature (ºC)
4"	30m	14.17	28.34	42.51	396
4"	50m	23.62	47.24	70.86	393.8
4"	70m	33.06	66.12	99.18	391.3
6"	30m	10.41	20.82	31.23	397.2
6"	50m	17.38	34.76	52.14	395.4
6"	70m	24.32	48.64	72.96	393.6
9"	30m	7.65	15.3	22.95	398
9"	50m	12.73	25.46	38.19	396.6
9"	70m	17.85	35.7	53.55	395.3

Table 18 - Average annual pipe heat loss for 1, 2 and 3 engines at 50% M.C.R.

Lagging Thickness (")	Pipe Length (m)	Spring Heat Savings (kW)	Summer Heat Savings (kW)	Autumn Heat Savings (kW)	Winter Heat Savings (kW)
6"	30m	26.48%	26.53%	26.48%	26.54%
9"	30m	46.03%	46.05%	46.03%	46.05%
6"	50m	26.45%	26.44%	26.45%	26.41%
9"	50m	46.08%	46.12%	46.13%	46.10%
6"	70m	26.42%	26.43%	26.43%	26.43%
9"	70m	46.03%	46.03%	46.02%	45.98%

Table 19 - Energy savings from 6” and 8” lagging material.

<u>4.4.2 - DISCUSSION OF PIPE HEAT LOSS RESULTS.</u>

The heat loss from the exhaust gas pipes reduces considerably and the exhaust gas temperatures at inlet to the waste heat boiler correspondingly increase, for all pipe lengths and for engines operating at 50%, 80% and 100% M.C.R, as we increase the thickness of the pipe lagging material.

The average heat energy savings that can be obtained from using 6” and 9” lagging, instead of 4” lagging, are 26.5% and 46.05%, respectively.

The heat loss from the exhaust gas pipes is also greater in the autumn and winter seasons, because of the lower ambient outside air temperatures.

The exhaust gas temperature at exit from the gas engine remains constant at 420ºC, when the engine is operating at 80% and 100% M.C.R. However, the exhaust gas mass flow-rate is about 15% less at 80% load and this consequently has the effect of reducing the exhaust gas inlet temperature to the waste heat boiler.

Furthermore, when the engines are operating at 50% load, the exhaust gas temperature decreases to 400ºC and the exhaust gas mass flow-rate decreases to 12,400 kg / hour.

This decrease in the exhaust gas temperature causes the heat loss through the exhaust gas pipe to decrease, but because the exhaust gas mass flow-rate also decreases, this results in a lower overall temperature at inlet to the waste heat recovery boiler.

4.4.3 - EXHAUST PIPE DIMENSIONS.

Based on previous engineering experience, it was concluded that it would be necessary to have a separate exhaust gas pipe, for each of the three gas engines that would be installed at the proposed cogeneration plant.

From studying the layout drawings from a similar sized cogeneration plant, it was estimated that each exhaust gas pipe would be approximately 50 metres in length, inclusive of vertical sections of pipe-work and pipe bends.

Each exhaust pipe would be lagged with rock-wool insulation to a thickness of 9”, to keep the heat loss in the system to a minimum and to give the highest possible exhaust gas inlet temperature to the waste heat boiler.

Table 20 gives details of the heat losses that would be incurred in an exhaust gas system, which is based on three gas engines operating at 100% load, with a total length of 150 metres of 36” pipe, with 9” of lagging material surrounding it.

Lagging Thickness (")	Pipe Length (m)	Gas Engine Power Output (% M.C.R)	Three Exhaust Pipes Heat Loss (kW)	Exhaust Gas Temp to HRSG (ºC)
9"	50m	100%	40.17	417.9
9"	50m	80%	40.17	417.5
9"	50m	50%	38.19	396.6

Table 20 - Overall heat loss for three engines at 100% M.C.R.

4.5 - CALCULATIONS FOR THE STEAM PRODUCTION RATE.

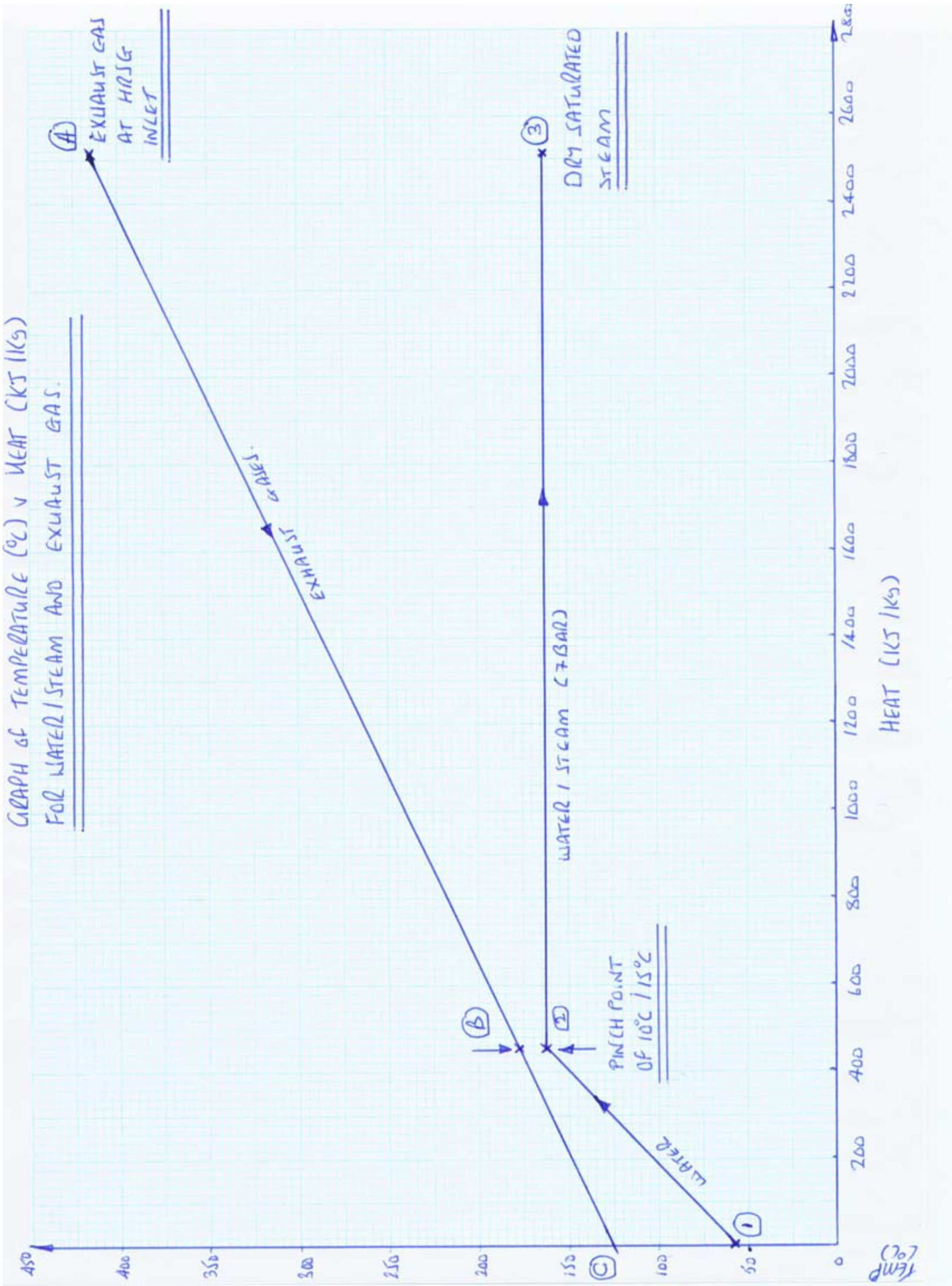
The first step in the process was to draw a table containing the relevant enthalpies, heat rates, pressures and temperatures for the water, steam and exhaust gases that will be present in the heat exchanger [37], as shown in the table 21.

The second step was then to draw a Temperature (ºC) v Heat (kJ/kg) graph in order to ascertain the exhaust gas outlet temperature from the waste heat recovery boiler, depending on whether a 10ºC or 15 ºC heat exchanger pinch point was used, as shown in figure 31.

State	Fluid	Pressure (bar)	Temperature (ºC)	Enthalpy (kJ / kg)	Heat (kJ / kg)
1	Water	7	60	251.1	0
2	Water / Steam	7	165	697	445.9
3	Steam	7	165	2764	2512.9
A	Exh. gas	/	417.9	/	2512.9
B	Exh. gas	/	175 / 180	/	445.9
C	Exh. gas	/	To calculate	/	0

Table 21 - Properties of water, steam and engine exhaust gases.

Figure 31 - Graph of Temperature (ºC) versus Heat (kJ/kg).



4.5.1 - CALCULATION OF THE EXHAUST GAS TEMPERATURE AT BOILER OUTLET.

The linear equation that is used to describe the exhaust gas cooling line can then be calculated from:

Y = mX + C

Where m = Gradient of exhaust gas cooling line.

C = Y intercept for exhaust gas cooling line.

Gradient, m = (Y2 - Y1) / (X2 - X1) [--]

Gradient, m = (417.9 - 175) / (2512.9 - 445.9) [--]

Gradient, m = 0.1175.

Y intercept, C = Y - mX [ºC]

Y intercept, C = 175 - (0.1175 * 445.9) [ºC]

Y intercept, C = 122.6 ºC.

Exhaust gas temperature at boiler outlet = 122.6 ºC.

4.5.2 - STEAM PRODUCTION RATE THEORY.

The heat energy that is contained within the engines exhaust gases between 417.9ºC and 122.6ºC is transferred to the hot water at 4 bar, 60 ºC, to produce saturated steam in the waste heat recovery boiler.

The amount of steam that can be produced by the waste heat boiler was calculated as follows:

Flux of heat energy into boiler = flux of heat energy out of boiler [W]

(Mw * h1) + (Mg * ha) = (Mw * h3) + (Mg * hc) [W]

Mw * (h3 - h1) = Mg * (ha - hc) [W]

Mw * (h3 - h1) = Mg * Cp * (Ta - Tc) [W]

Where ha = Enthalpy of exhaust gas at inlet to waste heat boiler [J / kg]

hc = Enthalpy of exhaust gas at outlet from the waste heat boiler [J / kg]

h1 = Enthalpy of water at inlet to waste heat boiler [J / kg]

h3 = Enthalpy of water at outlet from the waste heat boiler [J / kg]

Mg = Mass flow-rate of exhaust gas in / out of waste heat boiler [kg / s]

Mw = Mass flow-rate of water and steam in / out of the waste heat boiler [kg / s]

Cp = Specific heat capacity of exhaust gas [J / kgK]

Ta = Temperature of exhaust gas at inlet to waste heat boiler [K]

Tc = Temperature of exhaust gas at outlet from waste heat boiler [K]

4.5.3 - STEAM PRODUCTION RATE.

Mw * (h3 - h1) = Mg * Cp * (Ta - Tc)
Mw * (2764 - 251) * 1000 = 17.499 * 1100 * (417.9 - 122.6)
Mw * 2,513,000 = 5,684,200
Mw = 2.26 kg / s.
Mw = (2.26 * 3600) / 1000 tonnes per hour.
Mw = 8.136 tonnes per hour of steam.

From the above equations it was calculated that 8.136 tonnes per hour of steam could be produced from three KVGB-18 gas engines operating at 100% load, based on an exhaust gas inlet temperature of 417.9 ºC and a heat exchanger pinch point of 10 ºC.

The above calculations were repeated for one, two and three gas engines operating independently and in parallel with one another at 50%, 80% and 100% load and for heat exchangers with either a 10 ºC or 15 ºC pinch point.

The results from these calculations are shown in table 22.

Engine load (% M.C.R)	Exhaust gas inlet flow-rate to HRSG (kg / s)	Exhaust gas inlet temp. to HRSG (ºC)	Steam production at 10 ºC pinch point (tonnes / hour)	Steam production at 15 ºC pinch point (tonnes / hour)
1 Engine - 50%	3.44	396.6	1.46	1.43
1 Engine - 80%	4.875	417.5	2.26	2.22
1 Engine - 100%	5.833	417.9	2.71	2.66
2 Engines - 150%	9.273	410	4.17	4.09
2 Engines - 180%	10.708	417.7	4.97	4.88
2 Engines - 200%	11.667	417.9	5.42	5.32
3 Engines - 250%	15.1	413	6.88	6.75
3 Engines - 280%	16.541	417.8	7.68	7.54
3 Engines - 300%	17.499	417.9	8.13	7.98

Table 22 - Steam production rates.

4.5.4 - DISCUSSION OF RESULTS.

From table 22, it is evident that with three KVGB-18 gas engines operating at full load, it is possible to generate 8.13 tonnes and 7.98 tonnes per hour of steam, assuming a heat exchanger pinch point of either 10 ºC or 15 ºC.

Therefore, it should be practicable to generate sufficient steam for the manufacturing plants process requirements.

If one gas engine is off-load for maintenance purposes, then the cogeneration plant will still be able to supply the manufacturing company with 6.31MWe of electricity and either 5.32 or 5.42 tonnes per hour of process steam, respectively, depending on the pinch point temperature.

It should also be noted, however, that the KVGB-18 engine is an old design and that the latest version, the KVGB-18G4 can produce up to 3.6MWe of power and a slightly higher exhaust gas temperature, than the engine used for this case study.

It would therefore be anticipated that more than 5.42 tonnes per hour of steam could be produced from only two engines operating and this would assist to make up the shortfall in steam production to the manufacturing plant.

4.6 - EVALUATION OF THE COGENERATION PLANT OPERATING CONDITIONS.

The next phase of the feasibility study was to calculate the amount of electricity that would be produced and the amount of natural gas and lubricating oil that would be consumed by the three gas engines, under annual operation.

4.6.1 - DEFINITION OF PLANT AVAILABILITY.

The availability of the plant is defined as follows:

$$\text{Availability} = \frac{\text{Number of MWh generated during period}}{\text{Total number of MWh at 100\% availability}}$$

4.6.2 - CALCULATION OF NATURAL GAS ENERGY CONSUMPTION.

From the engine manufacturers operating data, the KVGB-18 gas engines specific energy consumption in MWh of natural gas, can be calculated, based on a net calorific value of 36.0 MJ / m³.

Natural gas burnt = 765 * 3 engines [m³ / h]

Energy consumed = 2,295 * 36 = 82,620 [MJ / h]

Energy consumed = 82,620 * 1,000,000 * 5488 [J / yr]

Energy consumed = 125,949.6 MWh per year, based on the N.C.V.

4.6.3 - CALCULATION OF SPECIFIC LUBRICATING OIL CONSUMPTION.

The lubricating oil consumption for one KVGB-18 gas engine operating at full load is 1.8 litres of oil per hour. Therefore, the lubricating oil consumption for three gas engines operating at full load would be 5.4 litres of oil per hour.

Table 23 gives details of the number of MWhours of electricity that would be generated and the natural gas and lubricating oil consumption, depending on the annual availability of the plant.

Plant load (MW)	Plant availability	Total number of hours generated	Electricity generated (MWh)	Fuel gas energy usage NCV - (MWh)	Lube oil consumption (litres)
9.471	1	5,488.0	51,976.8	125,949.6	29,635.2
9.471	0.99	5,433.1	51,456.9	124,689.7	29,338.7
9.471	0.98	5,378.2	50,936.9	123,429.7	29,042.3
9.471	0.97	5,323.4	50,417.9	122,172.0	28,746.4
9.471	0.96	5,268.5	49,898.0	120,912.1	28,449.9
9.471	0.95	5,213.6	49,378.0	119,652.1	28,153.4
9.471	0.94	5,158.7	48,858.0	118,392.2	27,857.0
9.471	0.93	5,103.8	48,338.1	117,132.2	27,560.5
9.471	0.92	5,049.0	47,819.1	115,874.6	27,264.6
9.471	0.91	4,994.1	47,299.1	114,614.6	26,968.1
9.471	0.9	4,939.2	46,779.2	113,354.6	26,671.7
9.471	0.89	4,884.3	46,259.2	112,094.7	26,375.2
9.471	0.88	4,829.4	45,739.2	110,834.7	26,078.8
9.471	0.87	4,774.6	45,220.2	109,577.1	25,782.8
9.471	0.86	4,719.7	44,700.3	108,317.1	25,486.4
9.471	0.85	4,664.8	44,180.3	107,057.2	25,189.9

Table 23 - Annual electricity generation and fuel consumption.

4.7 - CHPQA SCHEME TECHNICAL CALCULATIONS.

In order for the cogeneration plant to be eligible for enhanced capital allowances and for exemption of payment of business rates and climate change levy on its fuel input and on any electricity output to the grid, then the plant must meet certain criteria that is specified in the United Kingdom Combined Heat and Power Quality Assurance Scheme.

The overall objective of the Combined Heat and Power Quality Assurance Scheme is to provide a standard criteria for determining the fuel energy input and heat and power outputs from any cogeneration plant, against certain base-line levels.

For any new cogeneration plant to be certified as good quality under the CHPQA Scheme, then the plant must have a quality index of greater than 105 and a power efficiency of greater than 20%, under long term annual operation [20].

The quality index is based upon the useful heat output and power output efficiencies for the specific type of plant under consideration and is a measure of the overall efficiency of the plant.

4.7.1 - CALCULATION OF QUALITY INDEX AND POWER EFFICENCY.

The manufacturing plants heat output is based upon the amount of heat energy supplied from the cogeneration plant, against a reference value for the feed-water inlet temperature to the waste heat recovery boiler of 10ºC.

The fuel energy input to the cogeneration plant is based upon the plants annual gas consumption on a gross calorific value basis, as opposed to the net calorific value basis that is used by gas engine manufacturers when quoting their engines energy consumption.

It should be noted that for engines whose technical data is based on the net calorific value, then the engines efficiency is higher and its fuel energy consumption is lower, than that of an engine whose technical data is quoted on a gross calorific value basis.

The most relevant sections of the CHPQA Application Form F3, which were completed for the proposed cogeneration plant, are shown in figures 32 to 36.

4.7.2 - FUEL ENERGY CONSUMPTION BASED ON GROSS CALORIFIC VALUE.

The conversion from natural gas energy consumption based on net calorific value basis to a gross calorific value basis is shown below, using gas with a gross calorific value of 39 MJ / m3.

Energy consumed = 2295 * 39,000,000 [J / h]

Energy consumed = $8.9505 * 10^{10}$ [J / h]

Energy consumed = $8.9505 * 10^{10} * 5488$ [J / yr]

Energy consumed = $4.912 * 10^{14} / 3.6 * 10^{9}$ [MWh]

Energy consumed = 136,445.4 MWh per Year, based on G.C.V.

Table 23 above, was then adjusted to take into account the natural gas consumption on a gross calorific value basis and the new table, table 24, is shown below.

The values of heat and electricity production at 100% and 96% availability were then used as the basis for calculating whether the plant could be determined as good quality combined heat and power, under CHPQA rules.

Plant load (MW)	Plant availability	Total number of hours generated	Electricity generated (MWh)	Fuel gas consumption GCV - (MWh)	Heat / steam production (MWh)
9.471	1	5,488.0	51,976.8	136,445.0	33,193.0
9.471	0.99	5,433.1	51,456.9	135,080.1	32,861.0
9.471	0.98	5,378.2	50,936.9	133,715.1	32,529.0
9.471	0.97	5,323.4	50,417.9	132,352.6	32,197.5
9.471	0.96	5,268.5	49,898.0	130,987.7	31,865.5
9.471	0.95	5,213.6	49,378.0	129,622.7	31,533.4
9.471	0.94	5,158.7	48,858.0	128,257.8	31,201.4
9.471	0.93	5,103.8	48,338.1	126,892.8	30,869.3
9.471	0.92	5,049.0	47,819.1	125,530.4	30,537.9
9.471	0.91	4,994.1	47,299.1	124,165.4	30,205.8
9.471	0.9	4,939.2	46,779.2	122,800.4	29,873.8
9.471	0.89	4,884.3	46,259.2	121,435.6	29,541.7
9.471	0.88	4,829.4	45,739.2	120,070.6	29,209.7

Table 24 - Electricity production and natural gas consumption (GCV).

Figure 32 - CHPQA Form F3, Part 1, Site Information.

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Part 1: Scheme Identification & Site Information

1. SCHEME IDENTIFICATION

Site Name CONFIDENTIAL	Site ref.*
Company Name (Applicant) CONFIDENTIAL	Scheme ref.*

* If this is a completely new Scheme you must complete Form F1 and submit it to the CHPQA programme Administrator who will provide you with the Site and Scheme reference numbers. For a proposed upgrade to a CHP Scheme within the existing Scheme boundary, enter both the Site and Scheme reference numbers for the existing Scheme. For additional CHP outside the existing Scheme boundary, enter the Site reference only; the Administrator will provide the Scheme reference number.

2. BASIC INFORMATION

This information is required to set out the background and context of the proposed new or upgraded Scheme and to indicate its current state of development.

Sector (see GN 12.1):	CONFIDENTIAL
Site non-production hours:	100% AVAILABILITY — 3296 hours/year
Site production hours:	100% AVAILABILITY — 5488 hours/year
Site total operating hours:	100% AVAILABILITY — 5488 hours/year
Does this site have existing CHP Scheme(s)	YES ☐ NO ☑
If YES (A) is this proposal for an upgrade of an Existing Scheme? OR (B) is this proposal for an additional Scheme?	Enter A or B or other explanation, e.g. replacement of existing Scheme. REPLACEMENT OF HEAT ONLY BOILERS WITH A COGENERATION PLANT.
If there is an existing CHP Scheme on site, has the Scheme been registered with the CHPQA programme? If YES What is the Scheme reference number?	YES ☐ NO ☐ NOT APPLICABLE.
What are the overall objectives of the proposed Scheme/upgrade? (e.g. to better meet existing/increased site heat/power demand.)	INDEPENDANT PRODUCTION OF SITE ELECTRICITY AND HEAT REQUIREMENTS.
Provide a general description of the proposed Scheme (e.g. ownership, operation and maintenance arrangements, normal running hours, typical operation, and uses of heat and power outputs). (If there is insufficient space opposite, please provide the description as an Attachment).	9.5MW OF ELECTRICITY AND 8 TONNES PER HOUR OF SATURATED STEAM AT 7BAR PRESSURE.
What is the state of development of the proposed Scheme? (e.g. specification/tendering/detail design/procurement/construction/commissioning)	PROCUREMENT STAGE.
When do you expect to: (a) start construction (b) start commissioning (c) start Initial Operation (if known, see GN10.17)	State month and year for each phase:

DESIGN CALCULATIONS WERE BASED ON YEAR 2004 WHICH IS A LEAP YEAR (366 DAYS).

CHPQA Form F3
Final v1

Page 2 of 16

Figure 33 - CHPQA Form F3, Part 1, Site Energy Demands.

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3. SITE ENERGY DEMANDS

Period 1 (e.g. Winter, production campaign period 1, etc.)

Period: WINTER & SPRING Months: (e.g. Oct-Apr): 1ST NOV – END APRIL

Heat/Steam Demand:

Base 6048.3 kWth * for 3648 hours 100% AVAILABILITY

Peak 6048.3 kWth * for 3648 hours

Average: 6048.3 kWth * for 3502.1 hours 96% AVAILABILITY

Electricity Demand:

Base 9471 kWe for 3648 hours 100%

Peak 9471 kWe for 3648 hours

Average 9471 kWe for 3502.1 hours 96%

Period 2 (e.g. Summer, production campaign period 2, etc.)

Period: SUMMER & WINTER Months: (e.g. May-Sep): 1ST MAY – END OCT

Summer Period

Heat/Steam Demand:

Base 6048.3 kWth * for 1840 hours 100%

Peak 6048.3 kWth * for 1840 hours

Average: 6048.3 kWth * for 1766.4 hours 96%

Electricity Demand:

Base 9471 kWe for 1840 hours 100%

Peak 9471 kWe for 1840 hours

Average 9471 kWe for 1766.4 hours 96%

Predicted Future Annual Loads

Heat/Steam Demand:

Base ..... kWth * for ..... hours per annum NOT

Peak ..... kWth * for ..... hours per annum KNOWN

Average: ..... kWth * for ..... hours per annum

Electricity Demand:

Base ..... kWe for ..... hours per annum NOT

Peak ..... kWe for ..... hours per annum KNOWN

Average ..... kWe for ..... hours per annum

* In the space below (or on a separate, numbered attachment) show the calculation of heat demands kWth from the basic data (e.g. steam flow, pressure, temperature and specific enthalpy)

MASS FLOWRATE OF STEAM = 8 TONNES PER HOUR

= 2.222 kg/s

ENTHALPY OF STEAM AT 7 BAR 165°C = 2764 kJ/kg

ENTHALPY OF WATER AT 10°C = 42 kJ/kg

HEAT RATE = m°(hg − hf)

HEAT RATE = 2.222 × (2764 − 42) = 6048.3 kW

CHPQA Form F3 Page 3 of 16

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Figure 34 - CHPQA Form F3, Projected Scheme Performance Details.

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5. PROJECTED SCHEME PERFORMANCE DETAILS

Summarise the CHP process design and 3 anticipated operating cases in the table below. This information must be supported by Energy Flow Diagrams for each of the 4 cases (showing heat and material flows, Attachments 2 to 5), Site and Scheme Annual and Daily Heat Profiles (Attachments 6 and 7) and Load Duration Curves (Attachment 8). (See GN12.4 & GN12.5)

If the site has existing CHP within the same Scheme boundary as the proposed plant, provide information for the complete Scheme.

Stream No.	Description	Unit	Process design case 100% AVAILAB.	Projected average annual loads (See note below Table – supporting evidence))		MaxHeat under Long Term AO (See Standard Section 4 or GN10.14)	
				Initial Operation 96%	Long Term Annual Operation		
Scheme operating hours per year		hours	5488	5268.5	5268.5		
Energy Inputs (fuels on GCV basis and heat)							
	NATURAL GAS FUEL	MWh	136,445	130,987.7	130,987.7		
		kW					
		kW					
		kW					
		kW					
		kW					
	Total Energy Inputs	MWh	136,445	130,987.7	130,987.7		CHP_{TFI}
Power outputs (electricity generated and electrical equivalent of mechanical shaft power)							
	THREE GAS ENGINES	MWh	51,976.8	49,898	49,898		
		kW					
		kW					
		kW					
		kW					
		kW					
	Total Power Outputs	MWh	51,976.8	49,898	49,898		CHP_{TPO}
Heat outputs, energy flows (CHPQA basis - See GN 16.3)							
	HEAT CONTENT OF STEAM	MWh	33,193	31,865.5	31,865.5		
		kW					
		kW					
		kW					
		kW					
		kW					
	Total Heat Outputs	MWh	33,193	31,865.5	31,865.5		CHP_{QHO}

Table continued overleaf

Figure 35 - CHPQA Form F3, Part 3, Projected Annual and Max Heat Operation.

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Part 3: Scheme Performance for CHPQA

7. PROJECTED ANNUAL AND MAXHEAT OPERATION

Important: Where future heat demand is greater than present site demands, please attach evidence as a numbered Attachment of when future loads will come on stream. See GN3.

	Projected average annual loads (from Section 5) 96% Initial Operation	Long Term Annual Operation	MaxHeat operation (hrs)	Units
Energy inputs	130,987.7	130,987.7		MWh
Heat outputs	31,865.5	31,865.5		MWh
Power outputs	49,898	49,898		MWh
Heat efficiency (η_{heat})	24.3%	24.3%		%
Power efficiency (η_{power})	38.1%	38.1% *		%

* This figure is required in Part 4, Section 10

8. QI DEFINITION

Table 1 in the CHPQA Standard lists QI definitions for a variety of sizes and types of CHP Scheme. If your Scheme uses a mixture of conventional and alternative fuels you must calculate a weighted average QI definition using the table below. Take the conventional fuel X factor appropriate for your Scheme directly from Table 1 in the CHPQA Standard.

Fuel type	Fraction of Total (Fn)	Factors X	Factors Y	Weighted factors Fn x X	Weighted factors Fn x Y
Conventional fuels	1.0	200	125	200	125
Alternative fuel gases		240	125		
Biogas, Waste gas or Waste heat		300	140		
Biomass or solid or liquid Waste		400	140		
			Sum	X = 200	Y = 125

9. QUALITY INDEX (PROJECTED ANNUAL AND MAXHEAT OPERATION)

	X x Power Efficiency	+ Y x Heat Efficiency	= QI
Initial Operation	200 x 0.381	+ 125 x 0.243	= 106.6
Long Term Annual Operation	200 x 0.381	+ 125 x 0.243	= 106.6 *
MaxHeat under Long Term AO	____ x ____	+ ____ x ____	= ____ *

* These figures are required in Part 4, Section 10

CHPQA Form F3
Final v1

Page 8 of 16

Figure 36 - CHPQA Form F3, Part 4, Criteria For Good Quality CHP.

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Part 4: Criteria for Good Quality CHP

10.SCHEME PERFORMANCE INDICATORS

Scheme Power Efficiency under Long Term Annual Operation (from Section 7)	38.1 %
Scheme QI under Long Term Annual Operation (from Section 9)	106.6
Scheme QI at MaxHeat under Long Term Annual Operation (from Section 9)	

11.SELECTED THRESHOLD CRITERIA

With reference to the Threshold Criteria for Good Quality CHP set out in the CHPQA Standard, (Section 4 – Interpretation) and in GN42.16, select the Threshold Criteria you wish your Scheme to be assessed against.

QI threshold	105	(a) under Annual Operation OR (b) ~~at MaxHeat Operation~~ (delete as appropriate)
Power Efficiency threshold, %	20	under Annual Operation

Did your Scheme meet the QI Threshold ? (tick box) YES ☑ NO ☐

If YES then ➢ Proceed to Part 6 (Page 12)

If NO then ➢ Proceed to Part 5 (Page 10)

CHPQA Form F3 Page 9 of 16

Final v1

4.7.3 - ASSESSMENT OF COGENERATION PLANT AS GOOD QUALITY CHP.

The quality index and power efficiency for the proposed cogeneration plant were calculated to be 106.6 and 38.1%, respectively.

As the quality index and power efficiency are greater than the CHPQA threshold criteria of a quality index of 105 and a power efficiency of 20%, then the proposed plant would be eligible to register as good quality combined heat and power.

The plant would be entitled to exemption from the payment of climate change levy on its fuel input and electricity output to the grid and for enhanced capital allowances and exemption on business rates, also.

4.7.4 - OVERALL PLANT EFFICIENCY BASED ON GCV.

The overall efficiency of the proposed cogeneration plant when operating at 96% availability and based on the gross calorific value of the fuel energy input and on the CHPQA definition of heat energy output was calculated as follows:

$$\text{Plant efficiency (GCV)} = \frac{\text{Heat output} + \text{Power output}}{\text{Fuel Energy Input}} \qquad \frac{[\text{MWh}]}{[\text{MWh}]}$$

$$\text{Plant efficiency (GCV)} = \frac{31{,}865.5 + 48{,}898}{130{,}987.7} \qquad [--]$$

Plant efficiency (GCV) = 0.624 = 62.4%.

CHAPTER 5 - FINANCIAL APPRAISAL FOR THE PROPOSED PLANT.

In order to ascertain whether it would be economically viable for the manufacturing company to invest in a new cogeneration plant, a financial appraisal was undertaken to determine the break-even cost of generating heat and power from the plant.

The break-even cost was then compared to the average price paid by UK industry in 2003 to purchase a MWh of electricity from the National Grid, to determine the plants profitability.

5.0.1 - ANNUAL BANK REPAYMENT.

For the manufacturing company to be in a position to place an order for the construction of the cogeneration plant, then it would be necessary for them to obtain a bank loan, to cover the initial investment costs [38].

The amount of annual repayment on the bank loan could then be calculated by using the following equation:

$$\text{Annual repayment on bank loan} = \text{Initial investment} * \text{Capital recovery factor.}$$

$$\text{Annual repayment on bank loan} = \text{Initial investment} * \frac{i\,(1+i)^{n}}{((1+i)^{n}-1)}$$

Where initial investment = Amount of money borrowed from the bank - [£].
i = Bank interest rate per annum - [As a decimal].
n = Repayment period - [years].

5.0.2 - SPECIFIC COSTS METHOD.

The break-even or specific cost (£ / MWh) of generating electricity from the cogeneration plant could then also be calculated, as follows:

$$C = \frac{\text{Annual repayment + Fuel costs + O \& M costs + Taxes \& Insurance}}{\text{Number of MWh produced per Year}} \quad \frac{[£]}{[MWh]}$$

5.0.3 - INITIAL INVESTMENT.

The construction costs and prices for the capital plant and equipment to be installed in the cogeneration plant were obtained by contacting the relevant engineering manufacturers and suppliers.

The budget price for the overall construction and commissioning of the plant was estimated to be £3,965,652, neglecting the fees for the projects architects and consultants and a reserve that should be set aside to cover any cost over-runs, as shown in table 25.

The plants operation and maintenance costs were estimated at £108,035 per annum, as shown in table 26 and the lubricating oil costs are shown in table 27.

The plants fuel costs were calculated for six natural gas price scenarios, as the price of natural gas fluctuates significantly depending on the time of day and on the time of year and it also varies relative to the cost of crude oil, as shown in table 28.

Description of plant and equipment.	Delivery date on order.	Budget price. (£).
Three off Bergen KVGB - 18 gas engines.	6 - 8 months	£2,732,652
One off Senior Thermal heat recovery boiler.	6 months	£150,000
One off 35 metre, triple flue exhaust gas stack.	2 months	£50,000
150 metres of 36" standard schedule tube.	6 weeks	£33,000
All civil works, mechanical erection works and plant commissioning.	3 - 5 months	£1,000,000
Total budget price to build and commission a 9.5MW gas engine cogeneration plant.	1 year	£3,965,652

Table 25 - Cogeneration plant budget price.

Description of operation and maintenance costs.	Estimated cost per annum (£).
Operational Labour - two off plant fitters / technicians.	£46,000
Lubricating and hydraulic oil consumption.	£32,035
Tax and insurance on plant building and equipment.	£30,000
Total operational and maintenance costs per annum.	£108,035

Table 26 - Cogeneration plant operation and maintenance costs.

Plant load (MW)	Plant availability	Total number of hours generated	Electricity generated (MWh)	Lube oil consumption (Litres)	Annual lube oil costs
9.471	1	5,488.0	51,976.8	29,635.2	£33,429
9.471	0.99	5,433.1	51,456.9	29,338.7	£33,094
9.471	0.98	5,378.2	50,936.9	29,042.3	£32,760
9.471	0.97	5,323.4	50,417.9	28,746.4	£32,426
9.471	0.96	5,268.5	49,898.0	28,449.9	£32,035
9.471	0.95	5,213.6	49,378.0	28,153.4	£31,757
9.471	0.94	5,158.7	48,858.0	27,857.0	£31,423
9.471	0.93	5,103.8	48,338.1	27,560.5	£31,088
9.471	0.92	5,049.0	47,819.1	27,264.6	£30,755
9.471	0.91	4,994.1	47,299.1	26,968.1	£30,420
9.471	0.9	4,939.2	46,779.2	26,671.7	£30,086
9.471	0.89	4,884.3	46,259.2	26,375.2	£29,751
9.471	0.88	4,829.4	45,739.2	26,078.8	£29,417
9.471	0.87	4,774.6	45,220.2	25,782.8	£29,083
9.471	0.86	4,719.7	44,700.3	25,486.4	£28,749
9.471	0.85	4,664.8	44,180.3	25,189.9	£28,414

Table 27 - Annual lubricating oil consumption and costs.

Table 28 - Annual fuel gas costs.

Plant load (MW)	Plant availability	Total number of hours generated	Electricity generated (MWh)	Fuel gas consumption GCV - (MWh)	Annual cost of gas £3 / MWh	Annual cost of gas £4 / MWh	Annual cost of gas £5 / MWh	Annual cost of gas £6.5 / MWh	Annual cost of gas £8 / MWh	Annual cost of gas £9.5 / MWh
9.471	1	5488	51,976.8	136,445.0	£409,335	£545,780	£682,225	£886,893	£1,091,560	£1,296,228
9.471	0.99	5433.1	51,456.9	135,080.1	£405,240	£540,320	£675,401	£878,021	£1,080,641	£1,283,261
9.471	0.98	5378.2	50,936.9	133,715.1	£401,145	£534,860	£668,576	£869,148	£1,069,721	£1,270,294
9.471	0.97	5323.4	50,417.9	132,352.6	£397,058	£529,410	£661,763	£860,292	£1,058,821	£1,257,350
9.471	0.96	5268.5	49,898.0	130,987.7	£392,963	£523,951	£654,939	£851,420	£1,047,902	£1,244,383
9.471	0.95	5213.6	49,378.0	129,622.7	£388,868	£518,491	£648,114	£842,548	£1,036,982	£1,231,416
9.471	0.94	5158.7	48,858.0	128,257.8	£384,773	£513,031	£641,289	£833,676	£1,026,062	£1,218,449
9.471	0.93	5103.8	48,338.1	126,892.8	£380,678	£507,571	£634,464	£824,803	£1,015,142	£1,205,482
9.471	0.92	5049	47,819.1	125,530.4	£376,591	£502,122	£627,652	£815,948	£1,004,242	£1,192,539
9.471	0.91	4994.1	47,299.1	124,165.4	£372,496	£496,662	£620,827	£807,075	£993,323	£1,179,571
9.471	0.9	4939.2	46,779.2	122,800.4	£368,401	£491,202	£614,002	£798,203	£982,403	£1,166,604
9.471	0.89	4884.3	46,259.2	121,435.6	£364,307	£485,742	£607,178	£789,331	£971,485	£1,153,638
9.471	0.88	4829.4	45,739.2	120,070.6	£360,212	£480,282	£600,353	£780,459	£960,565	£1,140,671
9.471	0.87	4774.6	45,220.2	118,708.2	£356,125	£474,833	£593,541	£771,603	£949,666	£1,127,728
9.471	0.86	4719.7	44,700.3	117,343.2	£352,030	£469,373	£586,716	£762,731	£938,746	£1,114,760
9.471	0.85	4664.8	44,180.3	115,978.3	£347,935	£463,913	£579,892	£753,859	£927,826	£1,101,794

5.0.4 - CAPITAL RECOVERY FACTOR.

The capital recovery factor was calculated for bank interest rates of 4%, 6% and 8% and was based on a repayment period of 25 years.

$$\text{Capital recovery factor} = \frac{i\,(1 + i)^{n}}{((1 + i)^{n} - 1)}$$

$$\text{Capital recovery factor} = \frac{0.04 * (1 + 0.04)^{25}}{((1 + 0.04)^{25} - 1)}$$

Capital recovery factor = 0.064.

Table 29, below, gives the values of the capital recovery factor, depending on the bank interest rate.

Bank interest rates	Payback period	Capital recovery factor
4%	25 Years	0.064
6%	25 Years	0.0782
8%	25 Years	0.0937

Table 29 - Capital recovery factors.

5.0.5 - ANNUAL REPAYMENT.

The annual repayment on the initial investment of £3,965,652 - with 4% interest rates and a 25 year payback period was calculated, as below:

Annual repayment on bank loan = Initial investment * Capital recovery factor
Annual repayment on bank loan = £3,965,652 * 0.064
Annual repayment on bank loan = £253,802 per annum.

Total initial investment in plant and equipment	Annual repayment based upon 4% interest rate	Annual repayment based upon 6% interest rate	Annual repayment based upon 8% interest rate
£3,965,652	£253,802	£310,114	£371,582

Table 30 - Annual bank repayments.

5.0.6 - CALCULATION OF SPECIFIC COSTS.

The specific costs for the cogeneration plant to generate electricity, were calculated as follows:

$$C = \frac{\text{Annual repayment} + \text{Fuel costs} + \text{O \& M Costs} + \text{Taxes \& Insurance}}{\text{Number of MWh produced per Year}} \quad \frac{[£]}{[\text{MWh}]}$$

$$C = \frac{\text{Annual repayment} + \text{Fuel costs} + 108{,}035}{49{,}898\text{MWh per Year}} \quad \frac{[£]}{[\text{MWh}]}$$

Based on an annual bank repayment and fuel cost of £253,802 and £392,963 (96% availability), the specific cost to generate one MWh of electricity would be:

$$C = \frac{£253{,}802 + £392{,}963 + £108{,}035}{49{,}898 \text{ MWh}}$$

<u>C = £15.12 / MWh of electricity generated to break-even.</u>

The specific costs (£ / MWh) for the plant were then calculated based on an annual plant availability of 96% and for six natural gas price scenarios and three bank interest rate scenarios, as shown in Table 31.

Table 31 - Cogeneration plant balance sheet.

Bank interest rate	Annual repayment on loan	Cost Parameter	Fuel cost at 96% availab. £3 / MWh	Fuel cost at 96% availab. £4 / MWh	Fuel cost at 96% availab. £5 / MWh	Fuel cost at 96% availab. £6.50 / MWh	Fuel cost at 96% availab. £8 / MWh	Fuel cost at 96% availab. £9.50 / MWh
4%	£253,802	Break-even generating cost	£15.13 / MWh	£17.75 / MWh	£20.38 / MWh	£24.31 / MWh	£28.25 / MWh	£32.19 / MWh
//	//	Profit v £27.02 / MWh base	£11.89 / MWh	£9.27 / MWh	£6.64 / MWh	£2.71 / MWh	£-1.23 / MWh	£-5.17 / MWh
//	//	Profit on 49,898 MWh / Year	£593,287.20	£462,554.50	£331,322.70	£135,223.60	-£61,374.50	-£257,972.70
//	//	Less £56,169.2 for unavailability	-£56,169.20	-£56,169.20	-£56,169.20	-£56,169.20	-£56,169.20	-£56,169.20
//	//	**Total profit per Year**	**£537,118.00**	**£406,385.30**	**£275,153.50**	**£79,054.40**	**-£117,543.70**	**-£314,141.90**
6%	£310,114	Break-even generating cost	£16.26 / MWh	£18.88 / MWh	£21.50/ MWh	£25.44 / MWh	£29.38 / MWh	£33.32 / MWh
//	//	Profit v £27.02 / MWh base	£10.76 / MWh	£8.14 / MWh	£5.52 / MWh	£1.58 / MWh	£-2.36 / MWh	£-6.30
//	//	Profit on 49,898 MWh / Year	£536,902.50	£406,169.70	£275,437.00	£78,838.80	-£117,759.30	-£314,357.40
//	//	Less £56,169.2 for unavailability	-£56,169.20	-£56,169.20	-£56,169.20	-£56,169.20	-£56,169.20	-£56,169.20
//	//	**Total profit per Year**	**£480,733**	**£350,000.00**	**£219,267.80**	**£22,669.60**	**-£173,928.50**	**-£370,526.60**
8%	£371,582	Break-even generating cost	£17.49 / MWh	£20.11/ MWh	£22.74 / MWh	£26.68 / MWh	£30.61 / MWh	£34.55 / MWh
//	//	Profit v £27.02 / MWh base	£9.53 / MWh	£6.91 / MWh	£4.28 / MWh	£0.34 / MWh	£-3.59 / MWh	£-7.53 / MWh
//	//	Profit on 49,898 MWh / Year	£475,528.00	£344,795.20	£213,563.40	£16,965.30	-£179,133.8	-£375,731.90
//	//	Less £56,169.2 for unavailability	-£56,169.20	-£56,169.20	-£56,169.20	-£56,169.20	-£56,169.20	-£56,169.20
//	//	**Total profit per Year**	**£419,358.80**	**£288,626.00**	**£157,394.20**	**-£39,203.90**	**-£235,303.00**	**-£431,901.10**

5.0.7 - BREAK EVEN ANNUAL FUEL COSTS.

From the cogeneration plants balance sheet, it can be seen that above a certain natural gas price, then the plant starts to make a loss.

The actual natural gas price required for the cogeneration plant to break-even for the year can be calculated by setting the profit on 49,898MWh of electricity equal to £56,169.2, as below:

$$\text{Profit versus £27.02 / MWh base-line} = \frac{\text{Profit on 49,898MWh / Year}}{\text{49,898MWh / Year}}$$

$$\text{Profit versus £27.02 / MWh base-line} = \frac{\text{£56,169.2}}{\text{49,898}}$$

Profit versus £27.02 / MWh base-line = £1.1257 per MWh.

The break-even generating cost can then be calculated relative to the £27.02 per MWh base-line, as follows:

Breakeven generating cost = £27.02 / MWh - £1.1257 / MWh = £25.8943 per MWh.

The break-even generating cost is then entered into the specific costs calculation, for the particular annual repayment, in order to determine the annual fuel cost, which can then be divided by the number of MWh of gas consumed in one year, to give the overall breakeven price of gas.

$$C = \frac{\text{Annual repayment + Fuel costs + 108,035}}{\text{49,898MWh per Year}} \qquad \frac{[\text{£}]}{[\text{MWh}]}$$

$$\text{£25.8943} = \frac{\text{£253,802 + £108,035 + Annual fuel cost}}{\text{49,898MWh per Year}}$$

Annual fuel cost = £930,236.8

Annual fuel cost per MWh = $\frac{£930,236.8}{130,987.7\text{MWh}}$

Annual fuel cost per MWh = £7.1017.

Therefore, based on an annual natural gas price of £7.1017 per MWh and 4% interest rates, then the plant would break-even for the year.

The natural gas prices for the plant to break-even for the year, based on 6% and 8% interest rates are shown in the table 32.

Bank interest rate	Annual bank repayment	Break-even fuel gas price
4%	£253,802	£7.1017 / MWh
6%	£310,114	£6.6718 / MWh
8%	£371,582	£6.2025 / MWh

Table 32 - Breakeven natural gas prices.

5.0.8 - DISCUSSION OF PLANT FINANCIAL APPRAISAL.

Based on 4%, 6% and 8% annual bank interest rates and an average yearly industrial electricity price of £27.02 per MWh, then the proposed cogeneration plant would remain financially viable, so long as the wholesale natural gas price remained below £7.10, £6.63 and £6.20 per MWh of gas, respectively.

The actual price of purchasing natural gas from the energy market depends on the quantity of gas that you wish to buy and the price obtained would be subject to negotiation as part of a long term gas supply contract.

It is probable that considerable savings in natural gas prices could be achieved through negotiation, but, due to the competitive energy market in the United Kingdom, it was not possible to verify the actual wholesale gas price that could be obtained for the proposed plant.

The simple payback period for the plant, if a natural gas price in the region of £5 per MWh could be negotiated, would be between 14.4 years and 25 years, depending on the bank interest rate.

The capital cost of investing in the plant would be around £4 million pounds and depending on the value of the enhanced capital allowances that can be obtained for the plants machinery and equipment, it maybe possible to reduce the overall initial cost of the investment quite substantially.

This would have a “knock-on effect” of reducing the specific cost to produce one MWh of electricity, also.

The technical calculations that have been undertaken show that the plant is eligible to be defined as good quality combined heat and power, under CHPQA rules and would therefore be exempt from the payment of the climate change levy of £1.50 per MWh of natural gas that is burnt and £4.30 per MWh, on any electricity exports to the national grid system.

The plant would be able to further reduce its break-even costs to generate electricity, if it exported its surplus power to the National Grid system, when the manufacturing company does not require power, also.

<u>5.1 - CALCULATIONS FOR THE PLANTS CARBON EMISSIONS SAVINGS.</u>

The Department of Trade and Industry in collaboration with the Atomic Energy Authority Technology plc have produced a technical paper which details the actual calculations that should be undertaken in order to determine the amount of carbon emissions savings that can be made from generating electricity and heat in a cogeneration plant [39].

The technical calculations are based on the cogeneration plant offsetting carbon emissions that would otherwise be produced by the separate production of electricity in fossil fired power stations and steam production from heat only package boilers.

The paper gives specific emissions factors in gC / kWh of heat or electricity that is produced from various fossil fuel sources and the following sections (Sections 5.1.1 to 5.1.8) outline the various steps required, in order to calculate the carbon emissions savings for the proposed cogeneration plant.

<u>5.1.1 - FOSSIL FIRED POWER STATION EMISSIONS.</u>

The average emissions factor from a fossil fired power station in the United Kingdom is 183g of carbon per kWh of electricity that is generated.

Based on the proposed plant operating at 96% availability, the amount of carbon emissions that would be produced by an equivalent fossil fired power station generating the same amount of electricity would be:

Fossil fired power station carbon emissions = 183 gC / kWh of electricity generated.
Fossil fired power station carbon emissions = 0.183 tC / MWh of electricity generated.
<u>Fossil fired power station carbon emissions = 0.183 * 49,898 = 9,131 tonnes Carbon / year.</u>

<u>5.1.2 - OIL FIRED PACKAGE BOILER EMISSIONS.</u>

The emissions factor for a standard oil fired package boiler producing hot water or steam only is 98g of carbon emissions per kWh of heat energy output.

Based on the proposed plant operating at 96% availability, then the amount of carbon emissions that would be produced by the oil fired heat only boiler would be:

Oil fired package boiler carbon emissions = 98 gC / kWh of heat energy generated.
Oil fired package boiler carbon emissions = 0.098 tC / MWh of heat energy generated.
Oil fired package boiler carbon emissions = 0.098 * 31,865.5 = 3,123 tonnes Carbon / year.

5.1.3 - EQUIVALENT COGENERATION PLANT EMISSIONS.

The emissions factor for an equivalent cogeneration plant generating the same amount of heat and electricity is 50g of carbon emissions per kWh of natural gas that is burnt on a gross calorific value basis.

Cogeneration plant carbon emissions = 50 gC / kWh of gas that is burnt.
Cogeneration plant carbon emissions = 0.05 tC / MWh of gas that is burnt.
Cogeneration plant carbon emissions = 0.05 * 130,987.7 = 6,549 tonnes Carbon / year.

5.1.4 - ANNUAL CARBON EMISSIONS SAVING.

The amount of carbon emissions that can be reduced by using a cogeneration plant operating at 96% availability, is calculated as follows:

Carbon savings = (CE fossil electricity + CE oil boiler) - (CE cogeneration plant).
Carbon savings = (9,131 + 3,123) - (6,549) = 5,705 tonnes Carbon / year.

5.1.5 - ANNUAL CARBON DIOXIDE GAS EMISSION SAVING.

The annual carbon dioxide gas emissions savings could then be calculated as follows:

1 Tonne of carbon emissions = 3.667 tonnes of carbon dioxide gas emissions.
5,705 Tonnes of carbon emissions = 20,919 tonnes of carbon dioxide gas emissions / year.
Annual carbon dioxide gas emissions savings = 20,919 tonnes of carbon dioxide / year.

5.1.6 - EMISSIONS SAVINGS, INCLUDING FOR 4% UNAVAILABILITY.

The carbon emissions that would be produced from using imported fossil fired electricity and a standby oil fired boiler, to make-up for the shortfall in heat and power output, due to the 4% unavailability of the cogeneration plant, are then calculated as below:

Carbon emissions from 4% imported power = (51,976.8 - 49,898) * 0.183 [tC / MWh]
Carbon emissions from 4% imported power = 380 tonnes Carbon / year.

Carbon emissions from 4% oil fired boiler heat = (33,193 - 31,865.5) * 0.098 [tC / MWh]
Carbon emissions from 4% oil fired boiler heat = 130 tonnes Carbon / year.

Total carbon emissions from oil fired boiler & imported power = 510 tonnes Carbon / year.

The overall carbon emissions savings from the cogeneration plant operating at 96% availability would therefore be:

Overall carbon emissions savings = 5,705 - 510 = 5,195 tonnes Carbon / year.
Overall carbon dioxide gas savings = 5,195 * 3.667 = 19,050 tonnes CO2 / year.

5.1.7 - ANNUAL CARBON EMISSIONS SAVINGS.

Table 33 gives details of the carbon emissions savings that could be achieved for the proposed cogeneration plant operating at various availabilities.

It should be noted, however, that the table does not include for the carbon emissions which would be produced by the additional power and heat that that would need to be imported from the National Grid and from the manufacturing plants own standby oil fired package boilers, to make up for the unavailability of the cogeneration plant.

Table 33 - Cogeneration plant carbon emissions savings.

Plant load (MW)	Plant availability	Total number of hours generated	Electricity generated (MWh)	Carbon emissions fossil (TC)	Heat / steam production (MWh)	Carbon emissions heat (TC)	Total emissions (TC)	Fuel gas consumption GCV - (MWh)	CHP emissions (TC)	Carbon emissions savings (TC)	CO2 gas savings (T)
9.471	1	5488	51,976.8	9,512	33,193.0	3,253	12,765	136,445.0	6,822	5,942	21,791
9.471	0.99	5433.1	51,456.9	9,417	32,861.0	3,220	12,637	135,080.1	6,754	5,883	21,573
9.471	0.98	5378.2	50,936.9	9,322	32,529.0	3,188	12,509	133,715.1	6,686	5,824	21,355
9.471	0.97	5323.4	50,417.9	9,227	32,197.5	3,155	12,382	132,352.6	6,618	5,764	21,138
9.471	0.96	5268.5	49,898.0	9,131	31,865.5	3,123	12,254	130,987.7	6,549	5,705	20,919
9.471	0.95	5213.6	49,378.0	9,036	31,533.4	3,090	12,127	129,622.7	6,481	5,645	20,702
9.471	0.94	5158.7	48,858.0	8,941	31,201.4	3,058	11,999	128,257.8	6,413	5,586	20,483
9.471	0.93	5103.8	48,338.1	8,846	30,869.3	3,025	11,871	126,892.8	6,345	5,527	20,266
9.471	0.92	5049	47,819.1	8,751	30,537.9	2,993	11,744	125,530.4	6,277	5,467	20,048
9.471	0.91	4994.1	47,299.1	8,656	30,205.8	2,960	11,616	124,165.4	6,208	5,408	19,830
9.471	0.9	4939.2	46,779.2	8,561	29,873.8	2,928	11,488	122,800.4	6,140	5,348	19,612
9.471	0.89	4884.3	46,259.2	8,465	29,541.7	2,895	11,361	121,435.6	6,072	5,289	19,394
9.471	0.88	4829.4	45,739.2	8,370	29,209.7	2,863	11,233	120,070.6	6,004	5,229	19,176
9.471	0.87	4774.6	45,220.2	8,275	28,878.2	2,830	11,105	118,708.2	5,935	5,170	18,958
9.471	0.86	4719.7	44,700.3	8,180	28,546.2	2,798	10,978	117,343.2	5,867	5,111	18,738
9.471	0.85	4664.8	44,180.3	8,085	28,214.1	2,765	10,850	115,978.3	5,799	5,051	18,519

5.1.8 - DISCUSSION OF EMISSIONS SAVINGS.

The emissions savings that could be achieved by building the proposed cogeneration plant, based on an operational availability of 96%, were calculated as 5,705 tonnes of carbon or 20,919 tonnes of carbon dioxide gas per year. This would account for an annual carbon emissions reduction of 46.5%.

Whilst, the emissions savings that would be achieved if the manufacturing plant needed to import the 4% of its annual electricity and heat requirements from the National Grid and from a oil fired package boiler, due to the plants unavailability, would be 5,195 tonnes of carbon or 19,050 tonnes of carbon dioxide gas per year. This would account for an annual carbon emissions reduction of 42.4%.

CHAPTER 6 - ENVIRONMENTAL IMPACT ASSESSMENT FOR THE PROPOSED PLANT.

The following sections give a brief description of the factors that would need to be considered when submitting an environmental impact assessment to the Local Planning Authority in support of an application for “Deemed Planning Permission” to build a cogeneration plant.

6.0.1 - SITE GEOLOGY AND LANDSCAPING.

A ground analysis of the proposed site area should be carried out, to ensure that the site is geologically sound and surface scans of the area should also be done to identify any cables or drainage facilities running through the site area.

Soil samples should be taken from around the site area and should be sent to an independent laboratory for analysis for heavy metals and other ground level contaminants.

A survey of the surrounding landscape, local to the site should be carried out, to identify any key features of the proposed cogeneration plant that would require landscaping or screening.

6.0.2 - CONSTRUCTION SITE LAYOUT.

The construction site should be designed to accommodate all of the site staff and contractors offices (porto-cabins), mess rooms, changing facilities, covered workshop areas, canteen, first aid and male / female toilet and wash-room facilities.

Provision should also be made for all site services to be connected into the local clean water and sewerage systems.

6.0.3 - SITE SECURITY.

The site should have a secure fenced lay-down area for the storage of raw materials, equipment and containers for each contractor that is involved in the project. The site will also have 24 hour security staff, to cover security, goods incoming and other issues.

The site should also be fenced on all sides to prevent unauthorised access.

6.0.4 - LOCAL ROAD NETWORK.

All major “A class” roads leading to the proposed site should be checked as to their suitability (load bearing capacity and for width, height and length restrictions), in order for the transportation of all of the construction materials, capital plant and equipment that are required by the site.

The current traffic conditions, future traffic levels and all road junctions local to the proposed site should also be examined to ensure that the proposed site traffic levels do not have any adverse affect on the local population.

6.0.5 - SITE WORKING HOURS.

The site day-shift working hours should be scheduled in order to minimise any possible congestion on the roads and at road junctions local to the site and car sharing should be encouraged by the Contractor, wherever practicable.

6.0.6 - SITE CAR PARKING.

The Contractor should ensure that there is adequate provision for staff and contractors car parking on the site. The car park, access roads and paths on the site should be laid-out in a heavy gravel material, in order to ensure that any rainfall that occurs, has a minimal affect on the environment and the site working conditions.

6.0.7 - SITE SPEED LIMIT.

The speed limit on the proposed site should be set at 15 miles per hour maximum, for all vehicles, including cars, cranes, forklifts and lorries.

6.0.8 - ABNORMAL SITE LOADS.

All large, heavy or wide loads that are required by the site should be scheduled to be delivered during off peak hours, at night and at weekends in co-operation with the local police force, in order to ensure minimal disruption to the local traffic and the local population.

6.0.9 - STATUTORY NOISE REQUIREMENTS.

The plant should be constructed to the latest United Kingdom and European Union design standards and should comply with the statutory noise limits that are set down by the Environment Agency.

The size of the combustion and ventilation air duct openings should be limited, the plants engine enclosures should be sound proofed and the air cooled radiator systems should be located to the rear of the plant, to minimise noise levels.

All diesel generators, except those that are required for security lighting, should be shut-down after 8pm and during the hot commissioning phase, no boiler steam blow (steam purge) of the main steam legs should be permitted after 8pm, also.

6.1 - SITE REFUSE COLLECTION.

The Contractor should provide suitable refuse collection facilities for cardboard, paper and waste rubbish.

Special arrangements should also be made to dispose of antifreeze and inhibitor, cable drums, oil drums, damaged lagging, packing cases and wooden crates, waste lubricating and hydraulic oils, oily rags, scrap metal and civil works debris.

All storage and refuse skips should be provided with haps or metal covers, to prevent access by vermin and the burning of waste materials on site should be prohibited, also.

Furthermore, all refuse facilities, collection and disposal should be done by licensed companies, in accordance with ISO14001 Environmental Management System.

6.1.1 - STORAGE OF GAS CYLINDERS.

All gas cylinders, including acetylene, argon, oxygen and propane cylinders, that will be used on the site for burning, heating and welding operations, should be stored without hoses and regulators, in vented, outdoor, lockable-fenced compounds, when not in use.

This should minimise any risk of a gas explosion or fire occurring on the site. Furthermore, portable fire fighting equipment including carbon dioxide, dry powder and foam fire extinguishers shall be located at strategic points around the site.

6.1.2 - WELDING OPERATIONS.

During welding operations, it should be a site requirement that “welding screens” are positioned strategically to prevent any bystanders or observers from contracting “arc eye”.

Adequate ventilation and fume extraction equipment should also be used when burning or welding in confined spaces, also.

6.1.3 - RADIOGRAPHY.

The use of ionising radiation for non destructive testing (NDT) purposes should be carried out in accordance with the clients engineering, safety and permit for work procedures.

In all circumstances, radiography should be carried out at night, with only authorised personnel being allowed on site and all areas local to the procedure should be cordoned off, with warning notices posted.

It is also a statutory requirement for every company in the United Kingdom to inform the Health and Safety Executive when they intend to bring an ionising radiation source on to any type of site.

6.1.4 - CONTROL OF SUBSTANCES HAZARDOUS TO HEALTH.

All chemicals and other liquids shall be used and stored in accordance with the Control of Substances Hazardous to Health Regulations (COSHH).

The following chemicals, amongst others, shall be regularly used on site:

Caustic soda or sodium hydroxide - used to maintain boiler feed water pH.
Hydrazine - used as a boiler feed-water oxygen scavenger.
Hydrochloric acid - used to acid clean and treat (form magnetite) in boilers.
Tri-sodium phosphate - used to control sulphates and nitrates in boiler feed-water.
Ethylene glycol - used as an anti-freeze in raw and jacket water cooling systems.
Nalfleet inhibitor - used as a rust and fouling inhibitor in raw and jacket water systems.
Boiler feed water - disposed of in accordance with the relevant company procedures.
All types of oils - incl. engine lubricating oils, governor and turbocharger hydraulic oils.
Glues and adhesives - including evostick and hylomar gasket glues.
Paints - including zinc galvanising paint.

6.1.5 - EMERGENCY EYE WASH STATIONS.

The client should also provide emergency eye wash and emergency shower type installations at strategic points around the site, in order to deal with any chemical incidents that may occur.

6.1.6 - STANDARDS ON SITE.

The standards on the site should be monitored by the Site Manager (daily) and audited once per month by the clients Health and Safety Department to ensure that all Health, Safety, Environmental and Compliance matters are being carried out satisfactorily, as per the Construction, Design and Management Regulations and other related legislation.

All construction and commissioning work on the site should be carried out in accordance with the relevant standards including ISO9001 and the Health and Safety at Work Act 1973.

6.1.7 - ADDITIONAL INFORMATION ON ENVIRONMENTAL IMPACT ASSESSMENTS.

The Office of the Deputy Prime Minister has published a checklist of issues that that should also be considered for inclusion in an environmental impact assessment, as part of the planning process (See Appendix G).

CHAPTER 7 - DISCUSSION.

From the research that has been carried out in this feasibility study into the proposed development of a cogeneration plant in the West Midlands, England, it was found that marine gas engines would offer a reliable means of producing sufficient heat and power to meet the manufacturing plants requirements.

The technical and thermodynamic evaluation process concluded that three off Bergen KVGB-18 marine gas engines operating in parallel with one another, would be sufficient to produce enough power and heat to meet the plants requirements for 9.5MWe of electricity and 8 tonnes per hour of process steam.

If one gas engine is off-load for maintenance purposes, then 6.3MWe of electricity and either 5.32 or 5.42 tonnes per hour of process steam could still be produced from the plant, depending on the pinch point temperature of the waste heat recovery boiler.

The technical evaluation process calculated that the cogeneration plant would have a quality index of 106.6 and a power efficiency of 38.1% and would therefore meet the CHPQA Scheme criteria to qualify for registration as good quality combined heat and power.

As the plant can be considered as good quality combined heat and power, it shall be eligible to apply for climate change levy exemption on all of its fuel inputs and electricity outputs to the National Grid system.

Furthermore, without climate change levy exemption, the plant would not be financially viable, as natural gas would be charged with a levy of £1.50 per MWh of gas consumed and any electricity that was exported to the grid would also be levied at £4.30 per MWh.

Since the proposed cogeneration plant development will be less than 10MWe in power output, then the application for Planning Permission only needs to be submitted to the Local Planning Authority for approval.

This should save considerable time and expense as the application does not need to gain Energy Policy Clearance from the Department of Trade and Industry, under Section 14(1) of the Energy Act 1976.

The proposed site for the cogeneration plant is in an industrial area and it is therefore anticipated that the Local Planning Authority will have no objections to the development, as it will comply with Planning Policy Guidance Note 4 and help to regenerate the local area.

The overall cost to construct the plant was estimated at around £3,965,652, excluding architects and consultants fees and the operation and maintenance costs for the plant were estimated to be £108,035 per annum.

From the financial appraisal that was carried out for the plant, it was calculated that based on an average industrial price for natural gas and electricity in 2003 of £8 per MWh and £27.02 per MWh, respectively, then the plant would make a loss of £117,543.70, assuming 4% bank interest rates. However, if the lowest bank interest rate that could be obtained was 8%, then the plant would make an annual loss of £235,303.

The financial appraisal has shown that the plant is only viable if the wholesale cost of natural gas can be negotiated through a long term energy supply contract to a price of around £5 per MWh. If this can be achieved, then the plant would be able to make a profit of between £157,394.2 and £275,153.5, based on 8% and 4% interest rates, respectively.

The best option for the construction and subsequent operation of the plant would probably be for the manufacturing company to enter into a long term energy supply contract with a regional electricity and gas supply company, as the company would be able to supply or purchase natural gas at considerably reduced rates, than those which are available to industrial customers.

Furthermore, if the plant was owned by the electricity company and the sole purpose of the property was for the generation of power, then the plant would be eligible for exemption from business rates on all the plant and equipment that is contained within the cogeneration plants building.

Finally, the overall carbon emissions savings from the plant are estimated to be 5,195 tonnes of carbon or 19,050 tonnes of carbon dioxide gas per annum, compared to generating electricity in a conventional fossil fired power station and producing heat from an oil fired package boiler.

An overview of the actual steps that should be undertaken when carrying out a feasibility study into the use of combined heat and power is given in Appendix H.

7.1 - CONCLUSIONS.

The financial viability of the proposed cogeneration plant depends on the annual interest rate that can be agreed with the bank and on the actual wholesale electricity and natural gas prices that can be negotiated from the energy market.

If the lowest negotiable natural gas price that could be obtained, was to rise above a £6.50 per MWh and current industrial electricity prices remain low, at around £27.02 per MWh, then it would not be financially viable for the manufacturing company to invest in a new plant, as the payback period would be around 30 to 40 years.

In the near future, however, due to the closure of many of the countrys large coal fired power stations, it is anticipated that the cost of electricity will increase significantly and once the wholesale natural gas price levels out, then it is likely that the proposed development of the cogeneration plant would be financially viable for the manufacturing company.

7.2 - DIRECTION OF FUTURE WORK.

It is recommended that a detailed investigation is carried out into the financial benefits that can be obtained from enhanced capital allowances on cogeneration plant and machinery, as this may help to make the cogeneration plant more financially viable, as the initial capital investment in plant and machinery could be offset against the taxable profits of the business.

It is also recommended that a sensitivity analysis is carried to determine the consequences of changes in wholesale electricity prices on the financial viability of the proposed plant.

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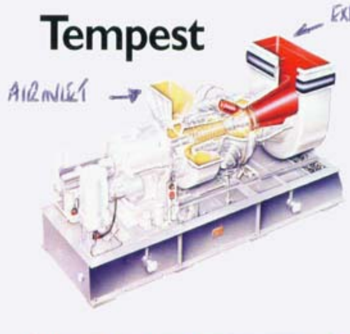
APPENDIX A - INDUSTRIAL GAS TURBINE TECHNICAL DATA SHEET.

Tempest



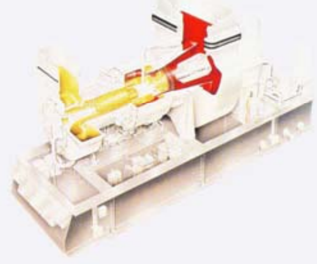
Tempest key benefit

Cold-end drive for a wide range of utility and industrial power generation applications.

Tempest

Fuel:		Natural Gas
Frequency:	Hz	50/60
Electrical output:	MW	7.7
Electrical efficiency:	%	30.7
Heat rate:	kJ/kWh	11,723
Turbine speed:	rpm	14,010
Compressor pressure ratio:		13.9
Exhaust gas flow:	kg/s	29.8
Exhaust gas temperature	°C	545
NOx emissions (with DLE)		
(corr. to 15% O_2, dry)	vppm	< 25
Turbine inlet temperature	°C	1,129

Tornado



Tornado key benefit

Low capital cost and fuel flexibility in a compact easy-to-install package.

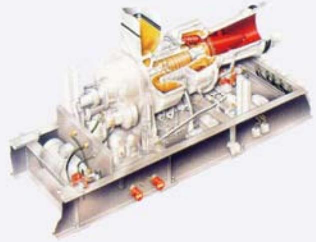
Tornado

Fuel:		Natural Gas	
Frequency:	Hz	50/60	50/60
Electrical output:	MW	6.45	6.75
Electrical efficiency	%	31.1	31.5
Heat rate:	Kj/kWh	11,579	11,418
Turbine speed:	rpm	11,085	11,053
Compressor pressure ratio:		11.85	12.3
Exhaust gas flow:	kg/s	28.2	29.3
Exhaust gas temperature	°C	471	466
NOx emissions (with DLE)			
(corr. to 15% O_2, dry)	vppm	< 25	< 25
Turbine inlet temperature	°C	995	996

Tornado (Mechanical Drive)

Fuel:		Natural Gas	
Output:	shp	9,160	10,300
Efficiency:	%	32.3	33.5
Heat rate:	Btu/shp-hr	7,875	7,597
Turbine speed:	rpm	9,600	10,450
Compressor pressure ratio:		11.9	12.6
Exhaust gas flow:	lb/s	61.6	64.9
Exhaust gas temperature	°C	476	480
NOx emissions (with DLE)			
(corr. to 15% O_2, dry)	vppm	< 25	< 25

Typhoon



Typhoon key benefit

A compact package for power generation and mechanical drive applications, onshore and offshore.

Typhoon

Fuel:		Natural Ga	
Frequency:	Hz	50/60	50/60
Electrical output:	MW	4.35	4.7
Electrical efficiency	%	30.0	30.2
Heat rate:	Kj/kWh	11,998	11,932
Turbine speed:	rpm	16,500	17,384
Compressor pressure ratio:		13.0	14.1
Exhaust gas flow:	kg/s	17.7	19.0
Exhaust gas temperature	°C	527	525
NOx emissions (with DLE)			
(corr. to 15% O_2, dry)	vppm	< 25	< 25
Turbine inlet temperature	°C	1,068	1,082

Typhoon

Fuel:		Natural Gas	
Frequency:	Hz	50/60	50/60
Electrical output:	MW	5.05	5.25
Electrical efficiency	%	30.2	30.2
Heat rate:	Kj/kWh	11,915	11,925
Turbine speed:	rpm	17,384	17,384
Compressor pressure ratio:		14.3	14.8
Exhaust gas flow:	kg/s	19.6	20.3
Exhaust gas temperature	°C	546	5[illegible]
NOx emissions (with DLE)			
(corr. to 15% O_2, dry)	vppm	< 25	< 25
Turbine inlet temperature	°C	1,112	1,115

Typhoon (Mechanical drive)

Fuel:		Natural Gas
Output:	shp	6,630
Efficiency:	%	32.5
Heat rate:	Btu/shp-hr	7,826
Turbine speed:	rpm	13,000
Compressor pressure ratio:		13.0
Exhaust gas flow:	lb/s	39.57
Exhaust gas temperature	°C	545
NOx emissions (with DLE)		
(corr. to 15% O_2, dry)	vppm	< 25

APPENDIX B - MARINE GAS ENGINE ENGINEERING DRAWING.

APPENDIX C - MARINE GAS ENGINE TECHNICAL DATA SHEET.

APPENDIX D - MARINE GAS ENGINE FUEL CONSUMPTION CHART.

SUBJECT TO COPYRIGHT - SEE HARD COPY.

APPENDIX E - ANSI PIPE SCHEDULE CHART.

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North River Road, Great Yarmouth
Norfolk NR30 1TE, England

tecflo
tecflo.co.uk

PLAIN END PIPE DIMENSIONS, WEIGHTS (Carbon, Stainless and Alloy Steel) PIPE SCHEDULES

Nominal pipe size mm/inch	OD mm	5s	10s	40s	80s	20	30	STD	40	60	XS	80	100	120	140	160	XXS
6 / 1/8	10.3		1.24 0.28	1.73 0.36	2.41 0.48			1.73 0.37	1.73 0.37		2.41 0.42	2.41 0.42					
8 / 1/4	13.7		1.65 0.51	2.24 0.64	3.02 0.80			2.24 0.63	2.24 0.63		3.02 0.80	3.02 0.80					
10 / 3/8	17.1		1.65 0.64	2.31 0.86	3.20 1.12			2.31 0.84	2.31 0.84		3.20 1.10	3.20 1.10					
15 / 1/2	21.3	1.65 0.82	2.11 1.01	2.77 1.30	3.73 1.65			2.77 1.27	2.77 1.27		3.73 1.62	3.73 1.62				4.78 1.95	7.47 2.55
20 / 3/4	26.7	1.65 1.04	2.11 1.31	2.87 1.71	3.91 2.24			2.87 1.69	2.87 1.69		3.91 2.20	3.91 2.20				5.56 2.90	7.82 3.64
25 / 1	33.4	1.65 1.33	2.77 2.13	3.38 2.55	4.55 3.29			3.38 2.50	3.38 2.50		4.55 3.24	4.55 3.24				6.35 4.24	9.09 5.45
32 / 1¼	42.2	1.65 1.68	2.77 2.76	3.56 3.46	4.85 4.56			3.56 3.39	3.56 3.39		4.85 4.47	4.85 4.47				6.35 5.61	9.70 7.77
40 / 1½	48.3	1.65 1.95	2.77 3.1	3.68 4.13	5.08 5.51			3.68 4.05	3.68 4.05		5.08 5.41	5.08 5.41				7.14 7.25	10.15 9.56
50 / 2	60.3	1.65 2.44	2.77 4.01	3.91 5.54	5.54 7.63			3.91 5.44	3.91 5.44		5.54 7.48	5.54 7.48				8.74 11.11	11.07 13.44
65 / 2½	73.0	2.11 3.77	3.05 5.36	5.16 8.81	7.01 11.64			5.16 8.63	5.16 8.63		7.01 11.41	7.01 11.41				9.53 14.92	14.02 20.39
80 / 3	88.9	2.11 4.60	3.05 6.59	5.49 11.52	7.62 15.59			5.49 11.29	5.49 11.29		7.62 15.27	7.62 15.27				11.13 21.35	15.24 27.68
90 / 3½	101.6	2.11 5.29	3.05 7.55	5.74 13.48	8.08 19.01			5.74 13.57	5.74 13.57		8.08 18.63	8.08 18.63				- -	- -
100 / 4	114.3	2.11 5.96	3.05 8.52	6.02 16.40	8.56 22.77			6.02 16.07	6.02 16.07		8.56 22.32	8.56 22.32		11.13 28.32		13.49 33.54	17.12 41.03
125 / 5	141.3	2.77 9.67	3.40 11.82	6.55 22.20	9.53 31.59			6.55 21.77	6.55 21.77		9.53 30.97	9.53 30.97		12.70 40.28		15.88 49.11	19.05 57.43
150 / 6	168.3	2.77 11.55	3.40 14.13	7.11 28.83	10.97 43.42			7.11 28.26	7.11 28.26		10.97 42.56	10.97 42.56		14.27 54.20		18.26 67.56	21.95 79.22
200 / 8	219.1	2.77 15.09	3.76 20.37	8.18 43.39	12.70 65.95	6.35 33.31	7.04 36.81	8.18 42.55	8.18 42.55	10.31 53.08	12.70 64.64	12.70 64.64	15.09 75.92	18.26 90.44	20.62 100.92	23.01 111.27	22.23 107.92
250 / 10	273.1	3.40 23.08	4.19 28.34	9.27 61.52	12.70 83.19	6.35 41.77	7.80 51.03	9.27 60.31	9.27 60.31	12.70 81.55	12.70 81.55	15.09 96.01	18.26 114.75	21.44 133.06	25.40 155.15	28.58 172.33	25.40 155.15
300 / 12	323.9	3.96 31.89	4.57 36.73	9.52 75.32	12.70 99.43	6.35 49.73	8.38 65.20	9.53 73.88	10.31 79.73	14.27 108.96	12.70 97.46	17.48 132.08	21.44 159.91	25.40 186.75	28.58 208.14	33.32 238.76	25.40 186.97
350 / 14	355.6	3.96 35.06	4.78 42.14			7.92 67.90	9.53 81.33	9.53 81.33	11.13 94.55	15.09 126.71	12.70 107.39	19.05 158.10	23.83 194.96	27.79 224.65	31.75 253.56	35.71 281.70	
400 / 16	406.4	4.19 42.41	4.78 48.26			7.92 77.83	9.53 93.27	9.53 93.27	12.70 123.30	16.66 160.12	12.70 123.30	21.44 203.53	26.19 245.56	30.96 286.64	36.53 333.19	40.49 365.35	
450 / 18	457.2	4.19 47.77	4.78 54.36			7.92 87.71	11.13 122.38	9.53 105.16	14.27 155.80	19.05 205.74	12.70 139.15	23.88 254.55	29.36 309.62	34.93 363.56	39.67 408.26	45.24 459.37	
500 / 20	508.0	4.78 60.46	5.54 70.00			9.53 117.15	12.70 155.12	9.53 117.15	15.09 183.42	20.62 247.83	12.70 155.12	26.19 311.17	32.54 381.53	38.10 441.49	44.45 508.11	50.01 564.81	
550 / 22	558.8	4.78 66.57	5.54 77.06			9.53 129.13	12.70 171.09	9.53 129.13	- -	22.23 294.25	12.70 171.09	28.58 373.83	34.93 451.42	41.28 527.02	47.63 600.63	53.98 672.26	
600 / 24	609.6	5.54 84.16	6.35 96.37			9.53 141.12	14.27 209.64	9.53 141.12	17.48 255.41	24.61 355.26	12.70 187.06	30.96 442.08	38.89 547.71	46.02 640.03	52.37 720.15	59.54 808.22	
650 / 26	660.4					12.70 202.72	- -	9.53 152.87	- -		12.70 202.72						
700 / 28	711.2					12.70 218.69	15.88 271.21	9.53 164.85	- -		12.70 218.69						
750 / 30	762.0	6.35 120.72	7.92 150.36			12.70 234.67	15.88 292.18	95.3 176.84	- -		12.70 234.67						
800 / 32	812.8					12.70 250.54	15.88 312.15	9.53 188.82	17.48 342.91		12.70 250.64						
850 / 34	863.6					12.70 266.61	15.88 332.12	9.53 200.31	17.48 364.90		12.70 266.61						
900 / 36	914.4					12.70 282.27	15.88 351.70	9.53 212.56	19.05 420.40		12.70 282.27						
950 / 38	965.2							9.53 224.54			12.70 298.24						
1000 / 40	1016.0							9.53 236.53			12.70 314.22						
1050 / 42	1066.8							9.53 248.52			12.70 330.19						
1100 / 44	1117.8							9.53 260.50			12.70 346.16						
1150 / 46	1168.4							9.53 272.25			12.70 351.82						
1200 / 48	1219.2							9.53 284.24			12.70 377.79						

Wall Thickness = mm
Weight = kg/m (plain end mass)
5S, 10S, 40S, 80S - ANSI B36.19

APPENDIX F1 - PLANNING PERMISSION APPLICATION FORM.

FOR OFFICE USE:
Application No. ....
Date Received ....

APPLICATION for PLANNING PERMISSION

Town and Country Planning Act 1990

Use this form if you want planning permission to carry out development other than works to an existing house or flat. **Please read the notes accompanying this form.**

PART A

1. Name & Address of Applicant

Name	
Address	
Postcode	
Tel (Home)	
Tel (Work)	
Mobile	
E-mail	

2. Name & Address of Agent (if any)

Name	
Address	
Postcode	
Tel (Home)	
Tel (Work)	
Mobile	
E-mail	

3. Application Site

• Address or location of site	
• Total site area (sq. metres or hectares)	
• Existing use of building / land	
If vacant: last previous use	
When that use ceased	

APPENDIX F2 - PLANNING PERMISSION APPLICATION FORM.

4. Proposed Development

- Describe the type and scale of the proposal

- Is any adjoining land owned or controlled by the applicant? Yes ☐ No ☐
  If yes, outline the land in blue on the location plan

- Does your proposal involve
  - erection of new building(s) Yes ☐ No ☐
  - alteration / extension of building(s) Yes ☐ No ☐
  - change of use of land / building(s) Yes ☐ No ☐
  - construction of a new access to a highway Yes ☐ No ☐
  - alteration of an existing access to a highway Yes ☐ No ☐
  - diversion / closure of a highway Yes ☐ No ☐
  - diversion / closure of a public footpath Yes ☐ No ☐
  - demolition of a dwelling(s) Yes ☐ No ☐

- Is your proposal for residential development? Yes ☐ No ☐
  If yes, state
  - Total number, size and type of dwellings (e.g. 3no. 2 bed houses)

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5. Type of Application - state which type of application you are making

- **Full Planning Permission** for a **change of use only**, not involving any building works Yes ☐ No ☐
- **Full Planning Permission** for new building works / extensions / engineering operations Yes ☐ No ☐
- **Full Planning Permission** for a change of use and external building works Yes ☐ No ☐
- **Outline Planning Permission** Yes ☐ No ☐

  If yes, are you submitting details of
  - Siting of buildings Yes ☐ No ☐
  - design and external appearance Yes ☐ No ☐
  - the means of access Yes ☐ No ☐
  - the landscaping of the site Yes ☐ No ☐

- **Approval of reserved matters following outline planning permission** Yes ☐ No ☐
  If yes, state
  - Date and reference number of outline planning permission
  - Which matters you are applying for
    - siting of building(s) Yes ☐ No ☐
    - design and external appearance Yes ☐ No ☐
    - the means of access Yes ☐ No ☐
    - the landscaping of the site Yes ☐ No ☐
- **Renewal of a temporary planning permission** Yes ☐ No ☐
  If yes, state

APPENDIX F3 - PLANNING PERMISSION APPLICATION FORM.

- Date and reference number of previous permission
- Time period required

- **Removal or variation of a condition(s) on a planning permission** Yes ☐ No ☐

  If yes, state
  - Date and reference number of previous permission
  - Condition(s) number

6. Additional Information

External materials

- State type, colour, manufacturer's product name and description if known

  Where a number of different materials are to be used, you may wish to list and show them separately on the plans

- Walls
- Roof(s)
- Windows
- Paths, roads and parking areas

Trees / Landscaping

- Will any tree, or part of a tree (including its roots), be removed or pruned? Yes ☐ No ☐

If yes, show which trees will be affected on the location plan or landscape plan

Parking

	Existing	Spaces Lost	New Spaces	Final Total
Total number of car parking spaces				
Car spaces for people with disabilities				
Cycle spaces / stands				

Drainage

- How will surface water be disposed of?
- How will foul drainage be disposed of?

Contaminated Land

Are you aware of any previous use of the site which may have caused contamination of the land ? Yes ☐ No ☐

If YES, have you supplied information of contamination and how the land is to be remediated? Yes ☐ No ☐

Rights of Way

Will the proposal affect any **public right of way?** Please tick box Yes ☐ No ☐

APPENDIX F4 - PLANNING PERMISSION APPLICATION FORM.

PART B To be completed for **all** non-residential applications (including change of use, new buildings and extensions)

1. Floorspace (gross external floorspace in square metres)

Use	Existing floorspace	Floorspace lost	New floorspace	Final total floorspace
• Industrial				
• Warehousing / storage				
• Offices (including Class A2)				
• Retail - gross				
- net				
• Other .... *(please state)*				

2. Employment

- Existing number of employees Full-time [ ] Part-time [ ]
- Additional number of employees Full-time [ ] Part-time [ ]

3. Hours of Operation

- Please state your proposed opening / operating hours [ ]

4. Traffic

Number of typical daily movements	Existing number		Estimated number (total)	
	in	out	in	out
• Cars / light vans				
• Heavy goods vehicles				

Servicing

- Does the proposal include space for loading / unloading goods? Yes [ ] No [ ]

If yes, provide details of deliveries including hours of operation, and location and size of loading area in a written statement and on the plans

5. Processes, Plant and Ventilation

- Will your proposal include a ventilation / fume extraction system? Yes [ ] No [ ]
- Will your proposal involve industrial processes or use of industrial machinery? Yes [ ] No [ ]

If you have answered yes to either question, provide details in a written statement and on the plans

6. Waste Disposal

- Will your proposal involve disposing of any trade effluents or trade refuse? Yes [ ] No [ ]

If yes, provide details of the nature, volume and proposed means of disposal in a written statement and on the plans.

7. Hazardous Materials

- Will the development involve the use or storage of hazardous materials? Yes [ ] No [ ]

If yes, provide details of the nature, volume and storage method/location of the material in a written statement and on the plans

APPENDIX G1 - ENVIRONMENTAL IMPACT ASSESSMENT FORM.

Appendix 5: Checklist of matters to be considered for inclusion in an environmental statement

This checklist is intended as a guide to the subjects that need to be considered in the course of preparing an environmental statement. It is unlikely that all the items will be relevant to any one project. (See paragraphs 31 and32 of the main text.)

The environmental effects of a development during its construction and commissioning phases should be considered separately from the effects arising whilst it is operational. Where the operational life of a development is expected to be limited, the effects of decommissioning or reinstating the land should also be considered separately.

Section 1

Information describing the project

1.1 Purpose and physical characteristics of the project, including details of proposed access and transport arrangements, and of numbers to be employed and where they will come from.

1.2 Land use requirements and other physical features of the project:

a. during construction;

b. when operational;

c. after use has ceased (where appropriate).

1.3 Production processes and operational features of the project:

a. type and quantities of raw materials, energy and other resources consumed;

b. residues and emissions by type, quantity, composition and strength including:

   i. discharges to water;

   ii. emissions to air;

   iii. noise;

   iv. vibration;

   v. light;

   vi. heat;

   vii. radiation;

   viii. deposits/residues to land and soil;

   ix. others.

1.4 Main alternative sites and processes considered, where appropriate, and reasons for final choice.

APPENDIX G2 - ENVIRONMENTAL IMPACT ASSESSMENT FORM.

Section 2

Information describing the site and its environment

Physical features

2.1 Population - proximity and numbers.

2.2 Flora and fauna (including both habitats and species) -- in particular, protected species and their habitats.

2.3 Soil: agricultural quality, geology and geomorphology.

2.4 Water: aquifers, water courses, shoreline, including the type, quantity, composition and strength of any existing discharges.

2.5 Air: climatic factors, air quality, etc.

2.6 Architectural and historic heritage, archaeological sites and features, and other material assets.

2.7 Landscape and topography.

2.8 Recreational uses.

2.9 Any other relevant environmental features.

The policy framework

2.10 Where applicable, the information considered under this section should include all relevant statutory designations such as national nature reserves, sites of special scientific interest, national parks, areas of outstanding natural beauty, heritage coasts, regional parks, country parks and designated green belt, local nature reserves, areas affected by tree preservation orders, water protection zones, conservation areas, listed buildings, scheduled ancient monuments, and designated areas of archaeological importance. It should also include references to relevant national policies (including Planning Policy Guidance notes) and to regional and local plans and policies (including approved or emerging development plans).

2.11 Reference should also be made to international designations, e.g. those under the EC `Wild Birds' or `Habitats' Directives, the Biodiversity Convention and the Ramsar Convention.

Section 3

Assessment of effects

Including direct and indirect, secondary, cumulative, short, medium and long-term, permanent and temporary, positive and negative effects of the project.

Effects on human beings, buildings and man-made features
3.1 Change in population arising from the development, and consequential environment effects.

3.2 Visual effects of the development on the surrounding area and landscape.

3.3 Levels and effects of emissions from the development during normal operation.

3.4 Levels and effects of noise from the development.

APPENDIX G3 - ENVIRONMENTAL IMPACT ASSESSMENT FORM.

3.5 Effects of the development on local roads and transport.

3.6 Effects of the development on buildings, the architectural and historic heritage, archaeological features, and other human artefacts, e.g. through pollutants, visual intrusion, vibration.

Effects on flora, fauna and geology
3.7 Loss of, and damage to, habitats and plant and animal species.

3.8 Loss of, and damage to, geological, palaeontological and physiographic features.

3.9 Other ecological consequences.

*Effects on land*3.10 Physical effects of the development, e.g. change in local topography, effect of earth-moving on stability, soil erosion, etc.

3.11 Effects of chemical emissions and deposits on soil of site and surrounding land.

3.12 Land use/resource effects:

a. quality and quantity of agricultural land to be taken;

b. sterilisation of mineral resources;

c. other alternative uses of the site, including the `do nothing' option;

d. effect on surrounding land uses including agriculture;

e. waste disposal.

Effects on water
3.13 Effects of development on drainage pattern in the area.

3.14 Changes to other hydrographic characteristics, e.g. groundwater level, water courses, flow of underground water.

3.15 Effects on coastal or estuarine hydrology.

3.16 Effects of pollutants, waste, etc. on water quality.

Effects on air and climate
3.17 Level and concentration of chemical emissions and their environmental effects.

3.18 Particulate matter.

3.19 Offensive odours.

3.20 Any other climatic effects.

Other indirect and secondary effects associated with the project
3.21 Effects from traffic (road, rail, air, water) related to the development.

3.22 Effects arising from the extraction and consumption of materials, water, energy or other resources by the development.

3.23 Effects of other development associated with the project, e.g. new roads, sewers, housing, power lines, pipe-lines, telecommunications, etc.

APPENDIX G4 - ENVIRONMENTAL IMPACT ASSESSMENT FORM.

3.24 Effects of association of the development with other existing or proposed development.

3.25 Secondary effects resulting from the interaction of separate direct effects listed above.

Section 4

Mitigating measures

4.1 Where significant adverse effects are identified, a description of the measures to be taken to avoid, reduce or remedy those effects, e.g.:

a. site planning;

b. technical measures, e.g.:

   i. process selection;

   ii. recycling;

   iii. pollution control and treatment;

   iv. containment (e.g., bounding of storage vessels).

c. aesthetic and ecological measures, e.g.:

   i. mounding;

   ii. design, colour, etc;

   iii. landscaping;

   iv. tree plantings;

   v. measures to preserve particular habitats or create alternative habitats;

   vi. recording of archaeological sites;

   vii. measures to safeguard historic buildings or sites.

4.2 Assessment of the likely effectiveness of mitigating measures.

Section 5

Risk of accidents and hazardous development

5.1 Risk of accidents as such is not covered in the EIA Directive or, consequently, in the implementing Regulations. However, when the proposed development involves materials that could be harmful to the environment(including people) in the event of an accident, the environmental statement should include an indication of the preventive measures that will be adopted so that such an occurrence is not likely to have a significant effect. This could, where appropriate, include reference to compliance with Health and Safety legislation.

5.2 There are separate arrangements in force relating to the keeping or use of hazardous substances and the Health and Safety Executive provides local planning authorities with expert advice about risk assessment on any planning application involving a hazardous installation.

APPENDIX H1 - COGENERATION PLANT DESIGN STAGES.

I. ELECTRICITY AND HEAT DEMAND PROFILES.

A. Determine the plant heat profiles on a seasonal basis.

B. Determine the plant electricity profiles on a seasonal basis.

C. Produce seasonal heat and electricity profile graphs.

II. COGENERATION PLANT SELECTION.

A. Undertake a technical evaluation of the available cogeneration plant technologies.

B. Select the most practicable technology for your plant or site.

III. PLANNING AND CONSENTS PROCESS.

A. If the proposed cogeneration plant is to be gas or oil fired and is greater than 10MWe in output, then Energy Policy Clearance is required from the Department of Trade and Industry, under Section 14(1) Energy Act 1976.

B. If the plant is less than 50MWe in output and is not gas or oil fired, then the development is subject to approval from the Local Planning Authority only, under the Town and Country Planning Act 1990.

IV. THERMAL ASSESSMENT.

A. Calculate the annual fuel input, heat output and electricity output for the plant in MWh, in accordance with the Combined Heat and Power Quality Assurance Scheme rules.

B. Calculate the quality index and power efficiency for the plant, under annual operation.

C. Determine if the plant is eligible to be classed as good quality combined heat and power, for its fuel inputs and electricity outputs.

APPENDIX H2 - COGENERATION PLANT DESIGN STAGES.

V. FINANCIAL ASSESSMENT.

A. Determine the bank interest rate which would be available for the proposed plant, depending on the repayment period.

B. Determine the initial capital investment costs for the plant and then calculate the annual bank repayment charges.

C. Determine the operation and maintenance costs, tax and insurance charges and wholesale fuel costs for the plant.

D. Calculate the plants overall specific costs (£ / MWh) and compare to the current energy costs of operating your plant or site.

E. Calculate the cost savings from investing in the new plant.

F. Determine the payback period for the plant.

VI. CARBON EMISSIONS.

A. Calculate the carbon emissions savings from the proposed plant.

VII. ENVIRONMENTAL IMPACT ASSESSMENT.

A. Carry out an Environmental Impact Assessment for the development.