

A GUIDE TO COGENERATION

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EDUCOGEN aims at creating the first European Education Tool on energy-efficiency through the use of cogeneration, working towards fully trained personnel within the cogeneration field.

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GUIDE TO COGENERATION

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GUIDE TO COGENERATION

AIM OF THE GUIDE

This Guide has been produced by COGEN Europe to explain the principles and applications of cogeneration. In compiling the Guide COGEN Europe has drawn the experience of its membership, especially the Cogeneration Policy Working Group. Our thanks to those individuals who provided data, comments and their time. In addition COGEN Europe has drawn upon some excellent documents produced by national programmes.

The Guide aims to provide a definitive explanation of cogeneration. It is designed to help policymakers and other professionals understand this energy solution, which is now receiving a great deal of positive attention, both for its energy efficiency and environmental benefits. The guide is also targeted at the growing number of students who are taking an interest in the subject.

The guide is divided into two parts:

- An general introduction to cogeneration and its principle¹ and benefits;
- A technical guide to the options available.

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PART ONE

WHAT IS COGENERATION?

The principle behind cogeneration is simple. Conventional power generation, on average, is only 35% efficient – up to 65% of the energy potential is released as waste heat. More recent combined cycle generation can improve this to 55%, excluding losses for the transmission and distribution of electricity. Cogeneration reduces this loss by using the heat for industry, commerce and home heating/cooling.

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

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

Through the utilisation of the heat, the efficiency of cogeneration plant can reach 90% or more. In addition, the electricity generated by the cogeneration plant is normally used locally, and then transmission and distribution losses will be negligible. Cogeneration therefore offers energy savings ranging between 15-40% when compared against the supply of electricity and heat from conventional power stations and boilers.

Because transporting electricity over long distances is easier and cheaper than transporting heat, cogeneration installations are usually sited as near as possible to the place where the heat is consumed and, ideally, are built to a size to meet the heat demand. Otherwise an additional boiler will be necessary, and the environmental advantages will be partly hindered. This is the central and most fundamental principle cogeneration.

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

THE BENEFITS OF COGENERATION

Provided the cogeneration is optimised in the way described above (ie sized according to the heat demand), the following benefits arise:

- Increased efficiency of energy conversion and use;
- Lower emissions to the environment, in particular of CO₂, the main greenhouse gas;
- In some cases, where there are biomass fuels and some waste materials such as refinery gases, process or agricultural waste (either anaerobically digested or gasified), these substances can be used as fuels for cogeneration schemes, thus increasing the cost-effectiveness and reducing the need for waste disposal;
- Large cost savings, providing additional competitiveness for industrial and commercial users, and offering affordable heat for domestic users;
- An opportunity to move towards more decentralised forms of electricity generation, where plant is designed to meet the needs of local consumers, providing high efficiency, avoiding transmission losses and increasing flexibility in system use. This will particularly be the case if natural gas is the energy carrier;
- Improved local and general security of supply - local generation, through cogeneration, can reduce the risk that consumers are left without supplies of electricity and/or heating. In addition, the reduced fuel need which cogeneration provides reduces the import dependency - a key challenge for Europe's energy future;
- An opportunity to increase the diversity of generation plant, and provide competition in generation. Cogeneration provides one of the most important vehicles for promoting liberalisation in energy markets;
- Increased employment - a number of studies have now concluded that the development of cogeneration systems is a generator of jobs.

Energy and cost savings

A well-designed and operated cogeneration scheme will always provide better energy efficiency than conventional plant, leading to both energy and cost savings. A single fuel is used to generate heat and electricity, so cost savings are dependent on the price-differential between the primary energy fuel and the bought-in electricity that the scheme displaces. However, although the profitability of cogeneration generally results from its cheap electricity, its success depends on using recovered heat productively, so the prime criterion is a suitable heat requirement. As a rough guide, cogeneration is likely to be suitable where there is a fairly constant demand for heat for at least 4,500 hours in the year.

The timing of the site's electricity demand will also be important as the cogeneration installation will be most cost effective when it operates during periods of high electricity tariffs, that is, during the day.

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

Environmental savings

In addition to direct cost savings, cogeneration yields significant environmental benefits through using fossil fuels more efficiently. In particular, it is a highly effective means of reducing carbon dioxide (CO₂) and sulphur dioxide (SO₂) emissions. Oxides of nitrogen (NO_x) are also generally reduced by the introduction of modern combustion plant.

CO₂ savings

The assessment of the carbon savings from a cogeneration project is hotly debated, as it is very difficult to prove what electricity it displaces. This issue has been at the heart of a long running discussion in European markets, with no agreement. Does the cogeneration scheme displace:

- a. The mix of electricity production in the country?
- b. The most marginal power plant on the system?
- c. The next power plant to be built by the power industry?
- d. The best theoretical power plant available?

Depending on the answer the savings in carbon dioxide can vary from 100 kg per MWh to more than 1000 kg MWh. The same issue faces all projects that displace other electricity generation.

It is reasonable to assume that most new cogeneration will be gas-fired at least in the next 10 years. For example, a gas turbine with waste-heat-boiler is used here to demonstrate the savings:

Cogeneration

Gas turbine with waste heat boiler	
Heat to power ratio	1.6
Efficiency	80%
Emissions of CO ₂ per unit of fuel	225 g/kWh
Emissions of CO ₂ per kWh of electricity	581 g/kWh

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

As explained later in this document, the current share of electricity produced from cogeneration in the EU is about 10%. The EU target is to reach 18% by 2010. The following table illustrates what this target could achieve in terms of CO₂ emissions reduction. The results are different depending on the fuel being displaced:

Fuel displaced	CO₂ savings
Coal electricity and coal boilers	342 Million Tonnes
Gas electricity and gas boilers	50 Million Tonnes
Fossil mix electricity and boilers	188 Million Tonnes

NO_x and SO₂ savings

To calculate NO_x and SO₂ savings, the same principle applies, it is necessary to look at what is being displaced. According to calculations made by ETSU, the following savings can be achieved by a gas turbine with a waste heat boiler:

Boiler replaced	NO_x	SO₂
Coal boiler	2.9 g/kWh	23.2 g/kWh
HFO boiler	2.9 g/kWh	23.4 g/kWh

WHERE IS COGENERATION SUITABLE?

Cogeneration has a long history of use in many types of industry, particularly in the paper and bulk chemicals industries, which have large concurrent heat and power demands. In recent years the greater availability and wider choice of suitable technology has meant that cogeneration has become an attractive and practical proposition for a wide range of applications. These include the process industries, commercial and public sector buildings and district heating schemes, all of which have considerable heat demand. These applications are summarised in the table below. The table also lists renewable fuels that can enhance the value of cogeneration, although fossil fuels, particularly natural gas, are more widely used.

Possible opportunities for application of cogeneration

Industrial

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

Buildings

- District heating
- Hotels
- Hospitals

- Leisure centres & swimming pools
- College campuses & schools
- Airports
- Prisons, police stations, barracks etc
- Supermarkets and large stores
- Office buildings
- Individual Houses

Renewable Energy

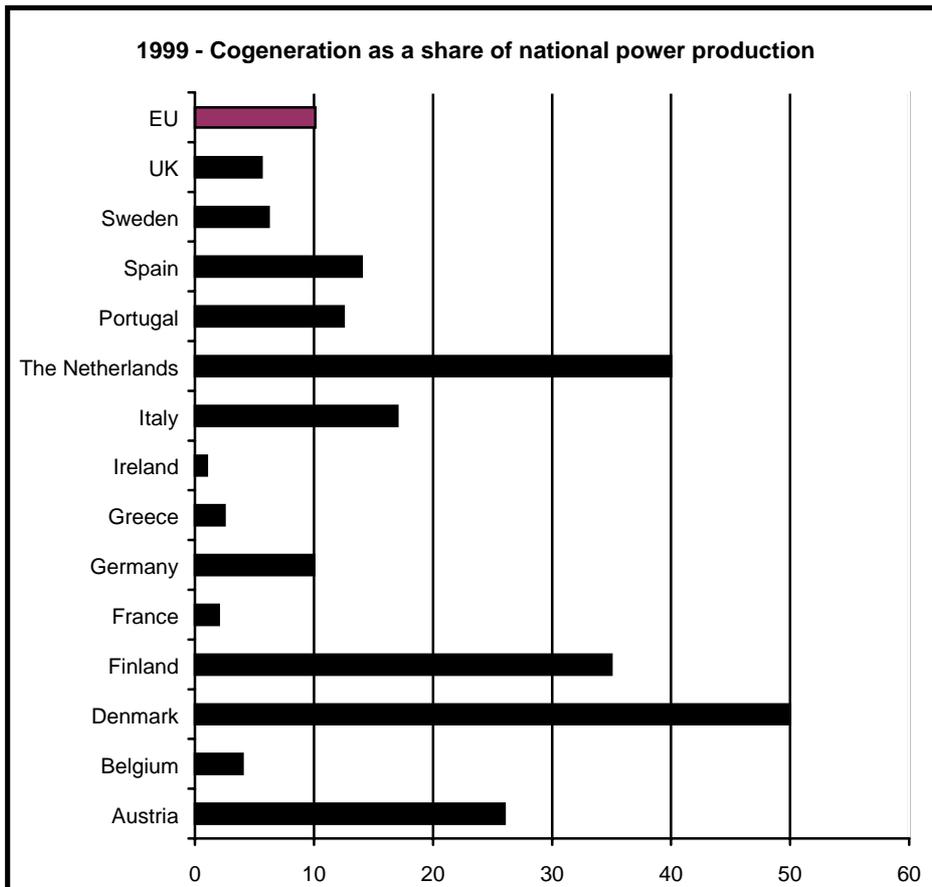
- Sewage treatment works
- Poultry and other farm sites
- Short rotation coppice woodland
- Energy crops
- Agro-wastes (ex: bio gas)

Energy from waste

- Gasified Municipal Solid Waste
- Municipal incinerators
- Landfill sites
- Hospital waste incinerators

COGENERATION IN EUROPE

The development of cogeneration in the European Union is characterised by a wide diversity, both in the scale of development and in the nature of that development. This diversity reflects differences in history, policy priorities, natural resources, culture and climate and has close links with the structure and activity of electricity markets. The following chart reflects, as far as possible, the state of development of cogeneration in the different countries (noting that countries collect data in different ways).



The chart demonstrates what can be achieved under certain circumstances. It is therefore worth outlining, in summary, the reasons for the successful development of cogeneration in the four most successful countries, Austria, Denmark, Finland and the Netherlands.

Austria

Austria has strong environmental policy credentials, and cogeneration has therefore always been regarded as a technology to be encouraged. Both industrial and district heating sectors have developed relatively well, the former through the benefits that the technology can bring to high energy intensity users and the later as to a response to energy price rises in the 1970s and central state support.

Denmark

Success of CHP development in Denmark has been due to government policy resolve to ensure that the technology can flourish. It has been achieved through significant subsidy and grant provision. Several factors have led to the government's determination to promote the technology:

- Existence of district heating networks. Most of the development has been achieved in this sector;
- Oil crisis at the beginning of the 70s. At the time, Denmark was 90% dependent on foreign oil. Nowadays, Denmark is self sufficient in oil and gas;
- Environmental concerns.

Finland

The development of cogeneration in Finland has not to such an extent been a consequence of specific political objectives and action. Finland has always been one of the most liberalised markets in Europe. The main reasons for the development of cogeneration have been:

- Absence of barriers;
- CHP was recognised as the most economic means of generating electricity;
- There tends –at least in the past, but maybe less so at present- greater acceptance in Finland for longer payback times;
- High demand for heating.

The Netherlands

The success in the Netherlands has been achieved through strong promotional activities and a clear positive policy framework introduced by the government. This has been through favourable gas tariffs, tax advantages, initial grants/subsidies and national targets.

Cogeneration market growth forecast

As the table above indicates, the share of cogeneration in the electricity production in Europe is about 10%. This is far from its full potential, which COGEN Europe estimates of at least 30% (and this can be supported by the fact that three countries have achieved this share). The European Commission, in its 1997 Strategy to Promote Combine Heat and Power, sets a target of 18% by 2010. In the current situation, due to uncertainties produced from incomplete liberalisation of the electricity markets in Europe, it is unlikely that this target will be reached without a reorientation of the policy framework. Political support for cogeneration and energy saving technologies from the different national governments is proven necessary.

HOW DOES COGENERATION WORK?

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

Cogeneration plant consists of four basic elements:

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

Depending on site requirements, the prime mover may be a steam turbine, reciprocating engine or gas turbine. In the future new technology options will include micro-turbines, Stirling engines and fuel cells. The prime mover drives the electricity generator and usable heat is recovered. The basic elements are all well established items of equipment, of proven performance and reliability.

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

Plants for industrial applications typically fall into the range 1-50 MWe, although some larger systems have been installed. It is difficult to define what is large and what is small, because every country has different sizes and different appreciations in this respect. In general, it can be said that from 1 MWe to 10 MWe it will be medium, and bigger than 10 MWe will be large. Non industrial applications cover also a full range of sizes, from 1 kWe for a domestic dwelling to about 10 MWe for a large district heating cogeneration scheme. Everything under 1 MWe can be considered small-scale. "Mini" is under 500 kWe and "micro" under 20 kWe.

Intensive developments over the past two decades have made a wide variety of equipment available, enabling cogeneration packages to be matched accurately to site requirements. Furthermore, legislation over this period has made it easier to install and operate cogeneration.

TECHNICAL STATUS OF COGENERATION

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

supplies around 10% of both the electricity generated and heat demand in the Community.

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

Some of the more minor barriers that face the remaining sites in these type of application, and which face sites in less traditional cogeneration applications, can be alleviated by technical developments.

THE ECONOMICS OF COGENERATION

In Member States where a more liberalised electricity market values cogenerated electricity transparently, cogeneration can usually be developed more freely than in markets where regulated tariffs are set. In 1995, COGEN Europe published a study “The Barriers to Combined Heat and Power in Europe” that demonstrated that many of the barriers to further development of cogeneration derived from the existence of monopolistic electricity markets. The most frequent barriers were:

- Too low tariffs for surplus cogenerated electricity sold to the grid;
- Very severe tariffs for standby power and, in particular, back-up power supply;
- Lack of freedom to ‘wheel’ (third party access) or, when allowed, too expensive to consider;
- Technical barriers. Cogeneration schemes need to fulfil certain technical and safety requirements for proper operation. Sometimes the procedures take too long and are not transparent enough.

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

However liberalisation, as reality has proven (at the time of writing this guide, the electricity and gas markets in Europe are being liberalised and there is a long way to go before full liberalisation is achieved) at least in the short term, brings new barriers if the market is not structured in such a way that allows for fair treatment. Recent experience brings the following set of barriers:

- Due to recent and on-going changes in the legal frameworks, uncertainty is playing a very dissuasive role in the investment decisions;
- The first effect of liberalisation has in many cases been a considerable reduction in the electricity prices. In some countries the prices have been lowered below

cost and this makes it unprofitable to invest in or run cogeneration plants. This is aggravated by the willingness of some governments to pay large sums of stranded cost to the electricity utilities and the massive overcapacity in old, inefficient power plants;

- Closely related to the last point, environmental costs are almost never included in the energy prices and neither are avoided costs for the use of the network;
- The adopted systems for access to the network are proving to be a new barrier in more than one country. Without going into great detail, it can be said that they are often very complicated to understand and expensive.

Because of the need to take a relatively medium term view (cogeneration is a relatively expensive capital investment), volatility and uncertainty in energy markets, tariffs or prices may deter potential investors. The economics of cogeneration are sensitive to the level of energy prices, and the differential between the price of the fuel used by the prime mover, and the value of the electricity and heat which is generated. To assist investors evaluate the impact of price changes requires that clear and transparent policies are used in the regulation and operation of energy markets, leading to relative stability and predictability of energy prices.

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

PART TWO

INTRODUCTION

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

Intensive developments over the past two decades have made a wide variety of equipment available, enabling cogeneration packages to be matched accurately to site requirements. Furthermore, legislation over this period has made it easier than ever before to install and operate cogeneration.

There are four broad categories of cogeneration application:

- small-scale cogeneration schemes, usually designed to meet space and water heating requirements in buildings, based on spark ignition reciprocating engines;
- large-scale cogeneration schemes, usually associated with steam raising in industrial and large buildings applications, and based on compression ignition reciprocating engines, steam turbines or gas turbines;
- large scale cogeneration schemes for district heating based around a power station or waste incinerator with heat recovery supplying a local heating network;
- Cogeneration schemes fuelled by renewable energy sources, which may be at any scale.

COGENERATION TECHNOLOGIES

Cogeneration plant consists of four basic elements:

- A prime mover (engine);
- An electricity generator;
- A heat recovery system;
- A control system.

Depending on the site requirements, the prime mover may be a steam turbine, reciprocating engine or gas turbine. The prime mover drives the electricity generator and waste heat is recovered. The basic elements are all well established items of equipment, of proven performance and reliability.

PRIME MOVERS

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

Currently available drive systems for cogeneration units include:

- Steam turbines;
- Reciprocating engines;
- Gas turbines;
- Combined cycle.

New developments are bringing new technologies towards the market. COGEN Europe expects some of these to become economically available from in the next ten years.

- Fuel cells;
- Stirling engine;
- Micro-turbines.

The following table summarises the main types of systems available, together with their typical size range, heat to power ratio, efficiency and heat quality.

Typical Cogeneration Systems

PRIME MOVER	FUEL USED	SIZE RANGE (MWe)	HEAT: POWER RATIO	ELECTRICAL GENERATING EFFICIENCY	TYPICAL OVERALL EFFICIENCY	HEAT QUALITY
PASS OUT STEAM TURBINE	ANY FUEL	1 to 100+	3:1 to 8:1+	10 - 20%	UP TO 80%	STEAM AT 2 PRESS OR MORE
BACK PRESSURE STEAM TURBINE	ANY FUEL	0.5 to 500	3:1 to 10:1+	7 - 20%	UP TO 80%	STEAM AT 2 PRESS OR MORE
COMBINED CYCLE GAS TURBINE	GAS BIOGAS GASOIL LFO LPG NAPHTHA	3 to 300+	1:1 to 3:1*	35 – 55%	73 - 90%	MEDIUM GRADE STEAM HIGH TEMPERATUR E HOT WATER
OPEN CYCLE GAS TURBINE	GAS BIOGAS GASOIL HFO LFO LPG NAPHTHA	0.25 to 50+	1.5:1 to 5:1*	25 – 42%	65 – 87%	HIGH GRADE STEAM HIGH TEMPERATUR E HOT WATER
COMPRESS. IGNITION ENGINE	GAS BIOGAS GASOIL HFO LHO NAPHTHA	0.2 to 20	0.5:1 to 3:1* Alfa value 0.9-2	35 – 45%	65 - 90%	LOW PRESSURE STEAM LOW AND MEDIUM TEMPERATUR E HOT WATER
SPARK IGNITION ENGINE	GAS BIOGAS LHO NAPHTHA	0.003 to 6	1:1 to 3:1 Alfa value 0.9-2	25 - 43%	70 - 92%	LOW AND MEDIUM TEMPERATUR E HOT WATER

* Highest heat:power ratios for these systems are achieved with supplementary firing.

Steam Turbines

Steam turbines have been used as prime movers for industrial cogeneration systems for many years. High-pressure steam raised in a conventional boiler is expanded within the turbine to produce mechanical energy, which may then be used to drive an electric generator. The power produced depends on how much the steam pressure can be reduced through the turbine before being required to meet site heat energy needs. This system generates less electrical energy per unit of fuel than a gas turbine or reciprocating engine-driven cogeneration system, although its overall efficiency may be higher, achieving up to 84% (based on fuel gross calorific value).

For viable power generation, steam input must be at a high pressure and temperature. Residual heat output is relatively low grade. Typical inlet steam conditions are 42 bar/400°C or 63 bar/480°C. The temperature required by the process dictates actual outlet steam conditions. The higher the turbine inlet pressure, the greater the power output, but higher steam pressures entail progressively greater boiler capital and running costs. Optimum pressure therefore depends on the size of the plant and the required process steam pressures. Steam cycles have the great advantage that the associated boiler plant can be designed to operate on virtually any fuel, including gas, heavy fuel oil (HFO), coal, residues and municipal or other wastes, and are often capable of operating on a range of fuels.

The plant is capital intensive because a high-pressure boiler is required to produce the motive steam. At existing sites, where steam systems are supplied by low-pressure boilers, it will be necessary to replace these boilers with high-pressure plant, possibly retaining the original equipment as stand-by.

Steam cycles typically produce a large amount of heat compared with the electrical output, resulting in a high cost installation in terms of Euro/kWe. However, the integration of an incinerator (burning a waste fuel, such as clinical waste, farm wastes or municipal solid waste) with a steam turbine based cogeneration unit can be cost-effective. Power outputs are generally greater than 500 kWe. Incineration however raises concerns over the production of undesirable emissions. As an alternative, some types of waste can be gasified and the resultant gas used to fuel a gas turbine (or possibly even a gas engine) installation.

Steam turbines fall into two types, according to exit pressure of the steam from the turbine:

- back-pressure turbines, in which exit pressure is greater than atmospheric;
- condensing turbines, in which exit pressure is lower than atmospheric and a condenser is required.

The simplest arrangement is the back-pressure turbine in which all the steam flows through the machine and is exhausted from the turbine at a single, relatively low pressure suitable for use on-site. Where more than one grade of heat is required, the higher grade is supplied by extracting 'pass-out' steam at the appropriate pressure part-way along the turbine. Such extraction carries a penalty in terms of reduced electrical output.

Fully condensing turbines maximise power output by expanding all the steam down to a vacuum using a condenser. This produces such low-grade heat that it is not a cogeneration proposition as a general rule. However, pass-out steam can be extracted (as from back-pressure turbines) to meet site heat demand. The site heat load governs back-pressure or pass-out/back-pressure steam turbines and so the power output is dependent on that heat load. However, a pass-out/condensing turbine frees the generator of this constraint.

In district heating cogeneration schemes, the turbine condenser may be operated near or even above atmospheric pressure. This ensures that the condenser cooling water picks up enough heat to supply the district heating circuit. Nevertheless, some pass-out steam may still be needed to top up the final temperature of the circulating water.

Gas Turbines

The gas turbine has become the most widely used prime mover for large-scale cogeneration in recent years, typically generating 1-100 MWe. A gas turbine based system is much easier to install on an existing site than high-pressure boiler plant and a steam turbine. On many sites plot space is at a premium, a factor weighing heavily in favour of gas turbines. This, together with reduced capital cost and the improved reliability of modern machines, often makes gas turbines the optimum choice.

The fuel is burnt in a pressurised combustion chamber using combustion air supplied by a compressor that is integral with the gas turbine. The very hot (900°C-1200°C) pressurised gases are used to turn a series of fan blades, and the shaft on which they are mounted, to produce mechanical energy. Residual energy in the form of a high flow of hot exhaust gases can be used to meet, wholly or partly, the thermal demand of the site.

The available mechanical energy can be applied in the following ways:

- to produce electricity with a generator (most applications);
- to drive pumps, compressors, blowers, etc.

A gas turbine operates under exacting conditions of high speed and high temperature. The hot gases supplied to it must therefore be clean (i.e. free of particulates which would erode the blades) and must contain not more than minimal amounts of contaminants which would cause corrosion under operating conditions. High-premium fuels are therefore most often used, particularly natural gas. Distillate oils such as gas oil are also suitable, and sets capable of using both are often installed to take advantage of cheaper interruptible gas tariffs. In principle, residual fuels may be used if sufficiently free of contaminants, although in practice this is rare in industrial cogeneration applications. LPGs and Naphtha are also suitable, LPG being a possible fuel in either gaseous or liquid form. Waste fuels such as biogas and landfill gas are applicable providing their calorific values (or to be more precise the wobble index) are relatively constant and their composition are consistent, ensuring that the hot gas leaving the combustion chamber is maintained at the

required temperature. Note that the hot gas leaving the combustion chamber when using a low calorific value fuel such as biogas will not be the same as when operating on natural gas – it is the mass flow through the turbine that determines power output.

Waste gases are exhausted from the turbine at 450°C to 550°C, making the gas turbine particularly suitable for high-grade heat supply. The usable heat to power ratio ranges from 1.5:1 to 3:1 depending on the characteristics of the particular gas turbine. The plant ingests three to four times more air than is required simply to supply oxygen for combustion. The excess air is necessary to ensure correct cooling of the components in the whole gas path. It also means that the final exhaust gases contain large quantities of oxygen that may be used to support the combustion of additional fuel. This technique (supplementary firing) may be used to increase exhaust gas temperatures to 1,000°C or more, raising the overall heat:power ratio to as much as 10:1 (although up to 5:1 is more typical). Supplementary firing, also known as boost firing, is highly efficient, as no additional combustion air is required to burn extra fuel. Efficiencies of 95% or more are typical for the fuel burned in supplementary firing systems. This technique is different from auxiliary firing, which does require additional combustion air, so is a less efficient method of raising temperature. Gas turbine systems consequently offer flexibility to serve variable heat loads and to meet higher temperature demands.

Exhaust gases can be used in either of the following ways:

- For direct firing and drying processes. The single flow of heat at high temperature is suitable for processes in which direct contact with combustion gases is permissible. This means that intermediate fluids (steam, hot water, heat transfer fluids) are unnecessary, and hence, in theory, the highest levels of thermal efficiency can be achieved. However, it is important to assess whether the direct use of the exhaust gases will affect product quality, and for this reason direct use is normally restricted to natural gas-fired gas turbines;
- To raise steam at medium or low pressure (normally 8-18 bar) for process or space heating in an open-cycle gas turbine cogeneration plant which comprises a gas turbine-alternator unit and a heat recovery boiler.
- To generate hot water, best for high temperature hot water applications where temperatures in excess of 140°C are required. In certain circumstances, they can also be applied to Air CHP systems;
- To raise steam in a HRSG at high pressure for use in a steam turbine (see later section on CCGT);

The 'shaft' efficiency (the proportion of heat in the primary fuel converted to mechanical power) can range from 20% to 45%, depending on the type of gas

turbine, its inlet temperature and pressure and other power-enhancing features. 25-35% is typical in practice.

It is possible to increase the turbine electrical generation efficiency, and to reduce levels of NO_x in the gases, through direct injection of steam into the combustion chamber, thus increasing volumetric flow through the turbine. The proportion of injected steam can be adjusted to follow electrical demand in situations of fluctuating steam and electrical demand. However, high-pressure, high quality steam is required, since steam injection will reduce engine life if the quality of the steam is poor. Therefore, the practice is more commonly associated with larger machines. Further, the system can be expensive to install and operate.

Gas turbines are available in a wide power output range from 250 kWe to over 200 MWe, although sets smaller than 1 MWe have so far been generally uneconomic due to their comparatively low electrical efficiency and consequent high cost per kWe output. This is starting to change (see section on new technologies).

The turbine is typically mounted on the same sub-base as its generator, with a step-down gearbox between the two to reduce the high shaft speed of the turbine to a speed suitable for the generator. A gas turbo-generator is extremely noisy and generally housed in an acoustic enclosure which, for industrial applications, is itself usually located in a factory-type building to provide weatherproofing and further noise attenuation. The enclosure also serves to contain the fire risk and to localise and minimise the fire prevention equipment required. Combustion air is taken from outside the enclosure. The intake ducting is fitted with filters to remove dust and a silencer to minimise noise. However, it is not necessary to install a gas turbine indoors. The acoustics enclosures can be of waterproof and sufficient noise attenuation fitted to reach very low levels (85 or 80 d BA are becoming accepted standards).

The substantial nature and conservative design of industrial gas turbines mean that they are inherently reliable and require minimal running maintenance. Shutdown maintenance is undertaken at extended intervals and is usually carried out by the manufacturer on a contract basis. Overall, about 96% reliability may be expected.

The gas turbine technology has been successful in developing NO_x reduction techniques. These techniques for gas turbines aim to reduce combustion chamber temperatures and thereby limit NO_x formation. This is often achieved by injection of water steam, which is traditionally used to boost power output, or more recently by dry low-NO_x burner system. Both control techniques substantially limit NO_x formation, nonetheless, where ultra low limits are specified, it can be necessary to employ end-of-pipe solutions such as Selective Catalytic Reduction (SCR). The technique chosen will depend upon the requirements of the national legislation or, in some instances, on more strict requirements imposed by local authorities or the host of the site. End-of-pipe system can provide negligible NO_x emissions, but they do require additional equipment and reagents, which often add considerable initial and operating cost to the CHP plant. End-of-pipe systems rely on abating emissions rather than minimising formation through engine design, so undetected system failures can result in high emissions.

Reciprocating Engines

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

The usable heat:power ratio range is normally in the range 0.5:1 to 2:1. However, as the exhaust contains large amounts of excess air, supplementary firing is feasible, raising the ratio to a maximum of 5:1. The pulsating nature of the delivery of exhaust gases from reciprocating engines makes boost firing difficult, so it is comparatively uncommon, although there are installations where the problems have been successfully overcome.

Engines and their lubricating oil must be cooled. This provides a source of heat for recovery, but it is generally low grade and is not always usable. In many applications the heat recovered from the cooling circuits and exhaust gases is cascaded together to produce a single heat output, typically producing hot water at around 100°C. Exhaust heat is always high grade, at up to about 400 °C, and represents up to half of the total heat produced by the engine.

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

Compression-ignition ('diesel') engines for large-scale cogeneration are predominantly four-stroke direct-injection machines fitted with turbochargers and intercoolers. Diesel engines will accept gas oil, HFO and natural gas. The latter is in reality a dual-fuel mode, as a small quantity of gas oil (about 5% of the total heat input) has to be injected with the gas to ensure ignition; as the engine can also run on gas oil only it is suited to interruptible gas supplies. Shaft efficiencies are 35 to 45%, and output range is up to 15 MWe. Cooling systems are more complex than on spark-ignition engines and temperatures are often lower, typically 85°C maximum, thereby limiting the scope for heat recovery. Exhaust excess air levels are high and supplementary firing is practicable. Compression-ignition engines run at speeds of between 500 and 1500 rev/min. In general, engines up to about 500 kWe (and sometimes up to 2 MWe) are derivatives of the original automotive diesels, operating on gas oil and running at the upper end of their speed range. Engines from 500 kWe to 20 MWe evolved from marine diesels and are dual-fuel or residual fuel oil machines running at medium to low speed.

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

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

The scale of these installations can make the cost of this after-treatment acceptable within the plant's overall capital and operating cost.

Spark-ignition engines are derivatives of their diesel engine equivalents and have their same parameter equivalents as 90°C cooling water. They can also use exhaust gases for heat recovery purposes; thus plants can be built with 160°C hot water of 20 bar steam output.

Traditionally, shaft efficiency was lower than for compression ignition engines, at between 27% and 35%, and the output range was limited to a maximum of around 2 MWe. The new above 3 MWe spark ignition engines use pre-chamber, where the mixture is stoichiometric (see below). The small engines do not have pre-chamber and they are called open chamber engines or conventional engines. Pre-chamber engines have 44% shaft efficiencies, exactly the same as bigger diesel engines. The output of a spark-ignition engine is a little smaller, typically 83% of the diesel engines, because of the possibility of knocking.

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

Spark-ignition engines operate on clean gaseous fuels, natural gas being the most popular. Biogas and similar recovered gases are also used but, because of their lower calorific value, output is reduced for a given engine size. Spark-ignition engines give up less heat to the exhaust gases (and correspondingly more to the cooling system) than diesel engines. The large lean-burn engines have typically 12% Oxygen in exhaust gases, and this can be used with supplementary firing. This typically requires some fresh air and has been used also in some cases during hours when the engine is not in operation.

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

- production of up to 15 bar steam utilising the heat of exhaust gases; and separate production of hot water at 85-90°C from the cooling system of the engine;
- production of hot water at 100°C, supplementing the temperature of cooling system water with heat from the gases;
- direct recuperation of the gases. Exhaust fumes can be used directly in certain processes, such as drying, CO₂ production, etc;
- generation of hot air. All the residual energies from the engine can be used, through the installation of suitable exchange devices, for the generation of hot air.

Reciprocating engines produce out-of-balance forces and require supports and foundations specially designed to absorb the severe vibrations created. Foundation requirements may be minimised, for example, by the use of pneumatic support systems that effectively transmit the dead-weight load only. Noise is marginally less

of a problem than with gas turbines, although the low frequency component can have a disproportionately disturbing effect on the human ear. This is more difficult to attenuate and extensive acoustic shielding is required.

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

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

Gas engines are operated under two distinct air/fuel ration regimes that have a market effect upon environmental performance:

- Stoichiometric engines;
- Lean-burn engines.

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

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

Stoichiometric engines tend to be smaller (typically <300 kW_e) than their lean-burn counterparts and are based upon standard vehicle engine blocks with adapted cylinder heads and spark ignition systems. In contrast, modern lean-burn engines have undergone extensive redesign of combustion chamber geometry, include sophisticated electronic controls and are fitted with turbochargers to boost power output and electrical efficiency.

As with gas turbines, SCR is used for highly special applications where ultra low NO_x emissions are required.

Cogeneration diesel plants HFO systems have been built in those places where gas is not available. This includes many islands and developing countries. In places where gas availability will arrive later, the plants can use HFO at the beginning and later switch to gas, or use HFO in winter and gas in summer.

Combined Cycles

Some large systems (power output generally greater than 3 MWe) utilise a combination of gas turbine and steam turbine, with the hot exhaust gases from the gas turbine being used to produce the steam for the steam turbine. This is called a combined cycle.

Gas turbine combined cycle (CCGT) systems have been adopted by public utility companies where supplies of natural gas are plentiful: power stations of up to 1,800 MWe have been constructed. In cogeneration applications of the CCGT, exhaust or pass-out steam from the steam turbine is used for process or other heating duties. The main advantage of CCGT cogeneration is its greater overall efficiency in the production of electricity, compared with the alternatives described above.

Combined cycles with gas turbines are the most common case, but they can also be designed with diesel engines. There are at least five cases running in the world.

NEW TECHNOLOGIES

Stirling engines

The Stirling engine is an external combustion device and therefore differs substantially from conventional combustion plant where the fuel burns inside the machine. Heat is supplied to the Stirling engine by an external source, such as burning gas, and this makes a working fluid, e.g. helium, expand and cause one of the two pistons to move inside a cylinder. This is known as the working piston. A second piston, known as a displacer, then transfers the gas to a cool zone where it is recompressed by the working piston. The displacer then transfers the compressed gas or air to the hot region and the cycle continues. The Stirling engine has fewer moving parts than conventional engines, and no valves, tappets, fuel injectors or spark ignition systems. It is therefore quieter than normal engines, a feature also resulting from the continuous, rather than pulsed, combustion of the fuel. Stirling engines also require little maintenance and emissions of particulates, nitrogen oxides, and unburned hydrocarbons are low. The efficiency of these machines is potentially greater than that of internal combustion or gas turbine devices.

There is a more than 60 years experience with this technology, what is newer is its use for micro-cogeneration boilers. For this type of boilers, there is a need for small engines with a capacity between 0.2 and 4 kWe. Gas turbines and even gas engines are unsuited for this kind of size (although the current smallest spark-ignition engine is 3 kWe), while the Stirling engine offers a good alternative.

The advantages of the Stirling engine are: less moving parts with low friction, no need for an extra boiler, no internal burner chamber, high theoretical efficiency and very suited for mass production. The external burner allows a very clean exhaust and gives the possibility of controlling the electrical output of the engine by reducing the temperature of the hot side. So there is the possibility of varying the electricity production regardless the need of thermal heat demand.

There are some low capacity Stirling engines in development or in the market. The electrical efficiency is still not very high and in the range of 10% (350 We engine); 12.5% (800 We engine) up to 25% (3,000 We engine), but it should be possible to design them with at least 25% electrical efficiency and total efficiency of 90%.

Microturbines

As explained in the section on gas turbines, systems smaller than 1 MWe have so far been uneconomic, but this is starting to change. Manufacturers are developing smaller and smaller systems and nowadays there are microturbines as small as 25 kWe. In general, microturbines can generate anywhere from 25 kWe to 200 kWe of electricity. Microturbines are small high-speed generator power plants that include the turbine, compressor, generator, all of which are on a single shaft as well as the power electronics to deliver the power to the grid. Microturbines have only one moving part, use air bearings and do not need lubricating oil. They are primarily fuelled with natural gas, but they can also operate with diesel, gasoline or other similar high-energy fossil fuels. Research is ongoing on using biogas.

Micro-turbines are smaller than conventional reciprocating engines, and capital and maintenance costs are lower. There are environmental advantages, including low NO_x emissions of 10-25 ppm (O₂ – 15% equivalent) or lower.

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

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

Fuel Cells

Fuel cells convert the chemical energy of hydrogen and oxygen directly into electricity without combustion and mechanical work such as in turbines or engines. In fuel cells, the fuel and oxidant (air) are continuously fed to the cell. All fuel cells are based on the oxidation of hydrogen. The hydrogen used as fuel can be derived from a variety of sources, including natural gas, propane, coal and renewables such as biomass, or, through electrolysis, wind and solar energy.

A typical single cell delivers up to 1 volt. In order to get sufficient power; a fuel cell stack is made of several single cells connected in series.

Even if fuelled with natural gas as a source of hydrogen, the emissions are negligible: 0.045 ppm NO_x, 2 ppm CO, 4 ppm HC.

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

- Their high efficiency is not compromised by small size and they operate high efficiency at low load;
- They have fewer moving parts and are not susceptible to wear-and-tear arising from the need to convert explosive combustion into mechanical energy;
- This provides reliable operation combined with infrequent servicing intervals, reducing maintenance costs and interrupted power supply associated with conventional plant;
- Siting flexibility allows by-product heat to be used, doubling energy efficiency.

A number of different types of fuel cells are being developed. The characteristics of each type are very different: operating temperature, available heat, tolerance to thermal cycling, power density, tolerance to fuel impurities etc. They are also in very different stage of development and some of them have not emerged from the laboratory. Some are approaching commercial breakthrough. This will be covered by other briefings from COGEN Europe.

Waste heat recovery units

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

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

- For effective heat transfer the temperature of the exhaust gases must remain above the temperature of the fluid to be heated. A minimum practical temperature difference of 30°C is typical;
- The exhaust gases must not be cooled to a temperature at which their buoyancy prevents them from rising from their point of discharge into the surrounding atmosphere, thereby ensuring proper dispersion of the gases under all weather conditions.
- The exhaust gases must not be cooled to a temperature at which acid condensation could occur. This risk is associated particularly with the combustion of oil fuels that contain some sulphur, as this can be condensed into sulphuric acid below certain temperatures.
- The latent heat of the water vapour in the exhaust gases can only be recovered by reducing the exhaust gas temperature to below 100°C, at which point the water vapour will condense into liquid form and release its latent

heat. Boilers designed to do this are more efficient, but the three previous constraints still apply, limiting the applications for this technique.

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

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

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

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

ADVANTAGES AND DISADVANTAGES OF EACH SYSTEM

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

	Advantages	Disadvantages
Steam Turbines	High overall efficiency; Any type of fuel may be used; Heat to power ratios can be varied through flexible operation; Ability to meet more than one site heat grade requirement; Wide range of sizes available; Long working life.	High heat:power ratios; High cost; Slow start-up.
Gas Turbines	High reliability which permits - long-term unattended operation; High grade heat available; Constant high speed enabling - close frequency Control of electrical output; High power:weight ratio; No cooling water required; Relatively low investment cost per kW _e electrical output Wide fuel range capability (diesel, LPG, naphtha, associated gas, landfill sewage); Multi fuel capability; Low emissions.	Limited number of unit sizes within the Output range; Lower mechanical efficiency than Reciprocating engines; If gas fired, requires high-pressure supply or in-house boosters; High noise levels (of high frequency can be easily alternated); Poor efficiency at low loading (but they can operate continuously at low loads); Can operate on premium fuels but need to be clean of dry; Output falls as ambient temperature rises due to thermal constraints within the turbine; May need long overhaul periods.
Reciprocating Engines	High power efficiency, achievable over a wide load range; Relatively low investment cost per kW _e electrical output; Wide range of unit sizes from 3 kW _e (there are 2,000 3 kW _e installations in Germany) upward; Part-load operation flexibility from 30% to 100% with high efficiency; Can be used in island mode (all ships do this) good load following capability; Fast start-up time of 15 second to full load (gas turbine needs 0.5 – 2 hours); Real multi-fuel capability, can also use HFO as fuel; Can be overhaul on site with normal operators; Low investment cost in small sizes; Can operate with low-pressure gas (down to 1 bar).	Must be cooled, even if the heat recovered is not reusable; Low power:weight ratio and out-of-balance Forces requiring substantial foundations; High levels of low frequency noise; High maintenance costs.
Stirling engines	Technical advantages: Much experience in high power range; Less moving parts with low friction; No internal burner chamber; High theoretical efficiency; Suitable for mass production. Advantages for micro-cogeneration: No extra thermal-boiler necessary; Electricity production independent from heat production; Very low emissions; Easy to control; Can be built as an interchangeable unit.	Little experience in low power range; Poor shaft efficiency by the existing machines (350 –800 Watt shaft power); Better efficiency at 3,000 Watt shaft power; First machines have been/are very expensive.

Micro turbines	High reliability due to small number of moving parts; Simplified installation; Low maintenance requirement; Compact size; Light weight; Acceptable noise levels; Fuelled by domestic natural gas resource with expanded fuel flexibility; Competitive costs when built in quantity; Low emissions; High temperature exhaust for heat recovery; Acceptable power quality.	Costs
Fuel cells	Low emissions and low noise; High efficiency over load range; Modular design, siting flexibility, short construction time; Automated operation, quick load changes, low maintenance; Many fuels, but require processing unless pure hydrogen. Flexible heat to power ratio; Low or high-grade heat, depending on design and fuel cell type.	Costs, durability, power density, start-up time, degradation; Corrosion for liquid electrolytes, Sulphur.

GENERATORS

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

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

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

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

COGENERATION HEAT:POWER RATIO

The ratio of heat to power required by a site may vary during different times of the day and seasons of the year. Importing power from the grid can make up a shortfall in electrical output from the cogeneration unit and firing standby boilers can satisfy additional heat demand.

Many large cogeneration units utilise supplementary or boost firing of the exhaust gases in order to modify the heat: power ratio of the system to match site loads.

Heat:power ratio is the measure generally used in, for example, the UK. Other countries may use the alpha value, which is the electricity to heat ratio. The greatest environmental benefits arise by maximising the alpha ratio for a particular cogeneration installation.

APPLICATIONS

INDUSTRIAL COGENERATION

Industrial cogeneration schemes are typically located on sites that have a high demand for process heat and electricity all year. Suitable examples are found in the refining, paper, chemicals, oil, greenhouses and textile sectors. The bulk of cogeneration capacity on industrial sites come from schemes of over 1 MW_e, and these tend to be designed on an individual basis to meet the specific requirements of each application. A much larger number of industrial sites have smaller systems, using technologies similar to the cogeneration systems used in buildings and commerce. Although numerous, these account for lower levels of total capacity.

The requirements for heat in industry are often in the form of steam and hence the majority of modern industrial cogeneration systems are based on gas turbines. A number of larger schemes use combined cycle cogeneration.

Industrial cogeneration installations can operate for 8000 hours/year or more. Therefore, in industrialised countries, the heat potential in industry is large enough to enable cogeneration to provide a significant proportion of - or in some cases all of - the baseload demand for electricity.

DISTRICT HEATING COGENERATION

District heating (DH) is one of the three main applications of cogeneration. The heat provided by cogeneration is ideal for providing space heating and hot water for domestic, commercial or industrial use. The use of DH networks is common in urban areas in northern, central and eastern Europe where the colder and longer winters require longer heating seasons, and hence entail longer running periods for the DH system. DH systems are commonly owned, and funded by public and/or municipal authorities.

A feature of cogeneration driven district heat is the option of fuel diversity to suit environmental, economic or strategic priorities. For example, DH systems are sometimes based on the incineration of municipal waste, and with adequate emission controls is a better environmental solution than disposing waste to landfill. DH systems are also able to use biomass.

The use of natural gas as a fuel gives added flexibility to district heating systems. Engines, providing electricity and heat, in combination with boilers, can introduce more cogeneration into existing DH networks.

The operation of a DH network faces a unique set of challenges. Modern distribution pipes have made it more economic to transport heat over considerable distances but the cost is still high. New networks require extensive civil works, and the appropriate permissions for planning and access. Historically the costs of building networks have been subsidised by local or national government but this type of funding is no longer as readily available as it has been in the past.

RESIDENTIAL AND COMMERCIAL COGENERATION

The cogeneration systems used in residential and commercial applications tend to be smaller systems, often based on 'packaged' units. Packaged units comprise a reciprocating engine, a small generator, and a heat recovery system, housed in an acoustic container. The only connections to the unit are for fuel, normally natural gas, and the connections for the heat and electricity output of the unit. These systems are commonly used in hotels, leisure centres, offices, smaller hospitals, and multi-residential accommodation.

Suitable reciprocating engines are normally stationary diesel or automotive engines that have been converted to run on natural gas. They can also be dual-fuelled. The heat recovery is via the engine's cooling circuits, and its exhaust so to ensure a high availability of electricity there must be a simultaneous use for the heat or heat storage facilities.

Larger applications are based on technology that is similar to the cogeneration systems used in industry, gas turbines, or larger reciprocating engines. Such systems are used in larger hospitals, large office complexes, universities and colleges.

TRIGENERATION

Trigeneration can be defined as the conversion of a single fuel source into three energy products: electricity, steam or hot water and chilled water, with lower pollution and greater efficiency than producing the three products separately.

There are different methods for coupling a conventional cogeneration system with a chiller either by compression (using heat to create cooling) or by absorption (cogeneration to drive refrigeration compressors).

Trigeneration can be applied to all the applications of cogeneration:

District cooling

In recent years district cooling has been considered in many locations as a method for meeting the space cooling requirements of buildings in the residential, commercial and, at times, industrial sector. It is particularly suitable in urban areas with high density arrangement offices and residential dwellings requiring air conditioning.

In this application absorption chillers are often favoured because they don't use chlorofluorocarbons and they can be used in conjunction with cogeneration systems for thermal and electrical energy. The chilling equipment can be based centrally, with chilled water piped to users, or can be located on the premises of

the user. The most economic choice will depend on the application and geographical distribution.

District cooling systems using absorption chillers often complement district heating systems, when both use heat supplied from a cogeneration plant. The heat demand in summer is lower than in winter and heat-driven district cooling, which requires the heat mainly in summer, can help to balance the seasonal demands for cogenerated heat. This increases the overall efficiency of the cogeneration system and therefore increases the environmental and other benefits that the system could bring.

District cooling is a recent concept, but is already relatively widely used in the USA and Japan. In Europe, there is awareness of the technology, but there is certainly less experience –with the possible exception of Sweden. An additional barrier that these systems face in Europe, apart of the fact that installing cooling increases the initial costs of the system considerably, is that the most suitable applications will be found in the South of Europe, which means, in countries where there is less experience of district heating (and where networks would have to be built), and hence less history among consumers or suppliers of the provision of this type of central energy.

- Cooling demand in industries

Many industries, in particular the food industry, lack sources of cold water during summer. River water is often at temperatures 25°C to 30°C rather than the 10°C to 15°C required.

Breweries for instance are very large consumers of refrigeration. Large quantities of beer must be cooled and stored in cooled place. In large dairies, refrigeration is required for milk cooling and for deep-frozen products. For deep-frozen food manufacturers, refrigeration demand for storage temperatures from -20°C to –30°C exist all year around.

- Cooling in individual buildings

These systems are used in hotels, sport and leisure centres and residential accommodation. The CHP systems are smaller units, normally based on engines (gas or diesel). The heat recovery is via the engine's cooling circuit and its exhaust. To ensure a high availability of electricity there must be a simultaneous use for the heat and the heat storage facilities. A method increasing the use of recovered heat is to produce cooling using absorption chillers. This allows the CHP system to run during the summer months, when the lower demand for heating would otherwise reduce the opportunity for system operation.

The barriers facing the growth of CHP combined with cooling, can be even more severe than the barriers for CHP growth. For the time being, it increases the costs of the system considerably. Nevertheless there is an expectation that this type of application will increase substantially in the next few years.

COGENERATION INSTALLATION

Operating strategies

For cogeneration plant there are three main operating regimes:

- the unit is operated to provide base load electricity and thermal output; any shortfall is supplemented with electricity from the public supply, and heat from stand-by boilers or boost heaters;
- the unit is operated to provide electricity in excess of the site's requirements, for export, whilst all the thermal output is used on site;
- the unit is operated to provide electricity for site, with or without export, and the heat produced is used on site with the surplus being exported to off-site customers.

One further option exists in which the cogeneration unit is operated primarily to provide electricity either for site use or for export, in conjunction with thermal trimming. Under these circumstances, excess thermal output is dumped (i.e. rejected to atmosphere via heat exchangers). However, the proportion of heat dumped reduces the overall efficiency of the plant. This type of scheme is a sub-optimal solution generally. The optimum regime for each site will depend on:

- electricity purchase and export tariffs;
- cost of fuel;
- availability of off-site heat customers;
- efficiency of stand-by heating plant;
- maintenance costs;
- other cogeneration operational costs (e.g. lubrication, auxiliary power requirement).

Connection to the public supply

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

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

It may be advantageous for some systems to be able to operate in island mode, that is, entirely independently of the public supply system. In particular, island mode enables the system to continue operating during times of public supply failure (a

parallel-only installation shuts down with the grid). The proportion of the site capable of operating under island mode depends on installed capacity and its characteristics. The practicalities of this mode of operation need to be carefully considered, as it may require load-shedding facilities that will add to the cost of the installation.

Standby Power and Cogeneration

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

Where the integration of cogeneration and standby is being considered for a new building or major refurbishment, a thorough risk analysis should be undertaken and specialist advice sought.

In cases where cogeneration alone is to provide the standby requirement, sufficient plant capacity and number of units must be provided to ensure security of supply and to cover maintenance downtime.

FUEL SUPPLY OPTIONS

Theoretically, almost any fuel is suitable for cogeneration. In practice, fossil fuels, especially natural gas (for economical as well as for environmental reasons) predominate, but municipal solid waste, certain industrial gases and biomass are also important. Overtime biomass and derived gases are likely to take the place that natural gas occupies now, as the technology becomes more available and cheaper and as environmental concerns increase. In Turkey, LPG or naphtha are used as stand-by fuels in case the gas supply is cut-off. Installations may be designed to accept more than one fuel. A widespread example in the UK is dual-fuel gas/fuel oil burning, where natural gas is bought at the lower-rate interruptible tariff and is replaced with fuel oil when gas supply is interrupted during periods of peak demand. In some cases cogeneration can be three or four fuel fired so that the operator can select to operate on the cheapest fuel.

Key factors in the choice of fuel are possible incentives offered for their utilisation and the quality of the fuel. Some countries offer incentives for the utilisation of better quality fuels, such as natural gas, biomass or biogas. Low-quality fuels are sometimes cheap (but this varies for country to country) but they incur significant extra costs (on-costs) for handling and burning and to meet environmental regulations. Good quality fuels are more expensive but have fewer or no on-costs. Fuels may be solid, liquid or gaseous, and either "commercial" or "waste". Commercial fuels are fossil fuels that are extracted and treated or refined and sold nationwide. Waste fuels are by-products or adjuncts of processing. Renewable energy fuels are not normally traded commercially so are usually only economically available in specific locations.

Commercial fuels:

- **Coal:** Coal has been long used in CHP schemes (especially in large district heating schemes in Eastern Europe and Denmark) but the size of many modern coal-fired stations means that they are unsuitable for smaller and industrial CHP applications, since they would produce more heat that could be used even if they were not located away from the major population centres. Coal-fired CHP schemes are nevertheless still widespread in countries where coal is plentiful and cheap. Many are old, relatively inefficient and polluting, but some new plants embody advanced coal combustion technology.
- Heavy and extra heavy fuel oils
- Gas oil (diesel)
- **Natural gas:** the use of natural gas in power generation has been growing since the 1980s. Its cheapness, flexibility and the fact that it releases less carbon dioxide emissions per megajoule delivered than coal and oil account for this popularity.
- LPG
- Naphtha

Common alternative fuels:-

Solid. There are various sources, such as wood off-cuts from furniture manufacturers; biomass from forestry and farming; domestic refuse, collected by municipal authorities and fired in large central plants; and waste tyres.

Liquid. Black liquor from wood pulp manufacture can be used.

Gaseous. Biogas, which is impure methane evolved during the decay of organic matter, e.g. sludge digester gas in sewage treatment works, landfill gas from municipal refuse tips, is suitable for cogeneration. Synthetically produced biogas can be produced from various other sources of solid and liquid waste, while process tail gases (from iron and steel works, chemical plants, refineries) can also be used as fuel.

The outstanding advantages of these fuels are their low or zero initial cost and the potential reduction or elimination of the cost of disposal. Potential disadvantages, however, are the on-costs of storage and handling, treatment and specialised combustion equipment that may be necessary.

SITE APPRAISAL

It is recommended that the appraisal of cogeneration be undertaken in two stages.

Stage 1 - An initial appraisal to determine whether it is worth committing the resources necessary to undertake a detailed feasibility study.

Stage 2 - If the initial appraisal shows that, in principle, cogeneration is a viable option for the site, then a second stage detailed technical appraisal should be undertaken. The study should be based on careful analysis of site energy demand to enable appropriate, cost effective cogeneration plant to be specified. It will also examine the effects on overall performance of plant optimisation, export of electricity and integration with any existing standby plant. At this stage, it is worth contacting the relevant government bodies to ascertain what assistance may be available.

The following table lists the questions that need to be considered at the initial appraisal stage.

Essential requirements for the successful implementation of cogeneration

		Yes/No
1.	Have all other energy saving measures been identified and either implemented or taken into consideration?	
2.	Is there a simultaneous base load requirement for electricity and heat which exceeds 20 kW and 50 kW respectively for more than 4,500 hours/year?	
3.	Is there a suitable fuel supply?	
4.	Is there suitable access and space for a cogeneration unit and is the location suitable with respect to other site functions (e.g. noise and exhaust)?	
5.	Are the fuel and electricity consumption records available on a monthly or more frequent basis?	
6.	If there are any site changes/developments planned, have the possible effects on the cogeneration size/economics been taken into account?	
7.		
8.	Is there a requirement to upgrade any part of the existing heating, electrical distribution or control system as a result of the cogeneration installation?	
9.	Is the proposed heat user near to the proposed cogeneration location and electrical distribution system?	
	Is there a likelihood that direct funding or an alternative route to funding is available?	

NOTE: with micro-CHP this check list is unsuitable as the market drivers for micro-CHP are quite different from other applications of cogeneration.

Site Energy Profiles

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

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

Electrical load profiles can be relatively easily determined using a portable load monitor. If major differences in consumption and load occur between normal weekdays and Saturdays or Sundays these must be determined. Also, if the monthly invoices demonstrate major seasonal variations in consumption (e.g. as a result of air conditioning loads in summer, or electric heating of portable buildings in winter) it may be necessary to use the load monitor to determine the time and duration of any such loads.

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

Correct sizing of the cogeneration unit is essential to the viability of the installation. Furthermore, the correct sizing and choice of the prime mover is only possible if the heat and electricity demands are clearly defined.

One final important point, cogeneration should not be sized based on a highly inefficient use of energy on the site. During the evaluation phase opportunities for reducing the site energy demand should be identified. Those that are cost-effective should be implemented. If they are not, then at least their impact needs to be taken into account in the sizing of the cogeneration plant. Failure to do this may result in an oversized and less economic cogeneration facility.

Other Factors

The location of the cogeneration system will also affect choice of plant. In particular, the following factors need to be considered:

- access to services, including electrical, heating and fuel supplies;
- noise emissions;
- exhaust emissions;
- ventilation and air quality requirements;
- delivery, access and positioning of the system;
- maintenance requirements.

Throughout the assessment, consider whether specialist advice would be helpful. The issues involved, especially on industrial sites, are often complex.

Selecting Appropriate Technologies for Specific Applications

The main indicators for selection of cogeneration plant are listed in the table below. In most cases, the choice of the prime mover will be determined by site requirements. This in turn will dictate the other items of plant.

Selection of prime movers for cogeneration

<p>Steam turbines may be the appropriate choice for sites where:</p> <ul style="list-style-type: none"> electrical base load is over 250 kWe there is a high process steam requirement; and heat:power demand ratio is greater than 3:1 cheap, low-premium fuel is available adequate plot space is available high grade process waste heat is available (e.g. from furnaces or incinerators) existing boiler plant is in need of replacement heat:power ratio is to be minimised, using a gas turbine combined cycle
<p>Gas turbines may be suitable if:</p> <ul style="list-style-type: none"> power demand is continuous, and is over 1 MWe (smaller gas turbines are just starting to penetrate the market) natural gas is available (although this is not a limiting factor) there is high demand for medium/high pressure steam or hot water, particularly at temperature higher than 140°C demand exists for hot gases at 450°C or above – the exhaust gas can be diluted with ambient air to cool it, or put through an air heat exchanger (Also consider using in a combined cycle with a steam turbine)
<p>Reciprocating engines may be suitable for sites where:</p> <ul style="list-style-type: none"> power, or processes are cyclical or not continuous low pressure steam or medium or low temperature hot water are required there is a low heat:power demand ratio when natural gas is available, gas powered reciprocating engines are preferred when natural gas is not available, fuel oil or LPG powered diesel engines may be suitable electrical load is less than 1 MWe - spark ignition (units available from 3 kWe to 10 MWe) electrical load greater than 1 MWe - compression ignition (units from 100 kWe to 20 MWe)

Although the table above will enable a broad choice of prime mover to be made, the final selection will be on the basis of the particular site requirements.

Other prime mover options are just starting to become available, such as micro-turbines, fuel cells and Stirling engines. These tend towards the small size ranges.

Considerations also include the long-term availability and cost of fuel, the cost of electricity purchased, including charges associated with the provision of a back-up supply, and the credit earned for any exported electricity. In addition, the service and technical support available from the equipment suppliers, and the proven reliability of particular machines, may have a significant bearing on the outcome of the selection procedure.

ECONOMIC ASPECTS

If the technical assessment shows that several alternative cogeneration schemes might be acceptable (as is frequently the case) an economic assessment needs to be prepared for each one before the final choice is made. During this evaluation there will be areas of interface with the technical assessment which may itself be

modified as a result. Some technical/financial re-iteration is to be expected in order to develop the optimum package.

Capital Cost

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

- cogeneration unit(s) and associated plant, installed, tested and commissioned;
- fuel supply, storage and handling;
- connection charges including reinforcement of local/national electricity networks;
- all associated mechanical and electrical services, installed and commissioned;
- any new buildings, modification to existing buildings, foundations and support structures;
- operator training, first set of spare parts and any special tools needed for servicing and repair;
- engineering design; compliance with planning and building regulations, environmental requirements, fire prevention and protection etc; and external professional services engaged to handle these matters.

Prices are obtained from the appropriate manufacturers, suppliers, contractors and engineering consultants or professional advisers and added together to arrive at a "first cut" capital cost. Avoided costs, i.e. those for plant and services which would have been replaced in any case, should be identified so that the marginal cost of cogeneration can be derived. The quotations should contain sufficient performance, delivery and cost information to enable:

- realistic running costs to be derived;
- provisional installation and cash outflow programmes to be drawn up.

Capital costs typically vary from Euro 500 per kW_e (for larger schemes) to more than Euro 1,800 per kW_e for the very small and depending on the choice of cogeneration plant and auxiliaries required.

For gas turbine and large reciprocating engine cogeneration plant, the prime mover/generator package and associated equipment (auxiliary systems, gas compressor and back-up distillate fuel storage) frequently represent 40-60% of total installed cost. The heat recovery equipment (heat recovery boiler and heat exchangers) and associated equipment (water treatment plant, boiler feedwater pumps and deaerator) can account for a further 15-30% of the costs, depending on boiler type, steam pressure and supplementary firing system. Electrical switchgear and protection equipment amounts to 5-15% and the balance is attributable to design, project management and installation (including piping, civil and building works).

For steam cycle cogeneration plant the high-pressure boiler is the single most expensive item, followed by the steam turbine/generator.

example, the reduced amount and different load profile of imported electricity may mean higher tariffs; the reduced and possibly intermittent loading of conventional boilers may have some effect on heat costs. In this case, the use of cogeneration running costs alone is insufficient and comparison of total site energy costs with and without cogeneration is necessary.

Existing energy costs are compiled from fuel and electricity bills, internal costs records etc., updated if necessary to current price levels. If existing site energy performance is capable of significant improvement by other energy efficiency measures, these should also be appraised as a complementary or even competing option to cogeneration.

Overall economics of cogeneration projects

Under favourable circumstances cogeneration projects can result in simple payback periods of three to five years, or sometimes even less. The economics of cogeneration projects are much more sensitive to changes in electricity price than to changes in fuel price; for example a 10% increase in electricity prices might reduce the payback period by 15% whereas a 10% reduction in fuel price would reduce the payback period by only 6%. Such a sensitivity analysis should be part of the feasibility study whatever method of economic analysis is employed.

Factors favouring short payback periods include:

- low investment cost;
- low fuel price;
- high electricity price;
- minimum cogeneration fuel price premium (compared with boiler fuel);
- high annual operating hours;
- high overall thermal efficiency.

FINANCING COGENERATION

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

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

Financing Options

There are two basic alternatives that may help to overcome the problems of justifying full self-financing of cogeneration. These schemes also have an effect on ownership and risk:

- to lease the plant, whilst undertaking all aspects of operation and maintenance;
- to offer the opportunity to a Energy Service Company (ESCO) company which will manage the facility and may finance and own the installation as well. This third party company would offer the client guaranteed outputs, thermal and electrical, at a discount against present and projected costs. ESCOs can provide a complete range of services, from design, finance, installation, operation, maintenance and monitoring. Most importantly, the ESCO should undertake the technical risk, whilst sharing the economic risk and profit with the client.

Numerous variations of these basic concepts are available: contracts are negotiated between the ESCO and the client to take account of the particular circumstances and requirements of the site. These include Build Own and Operate (BOO), Build, Own, Operate and Transfer (BOOT), and Joint Venture Company.

The choice between these types of contract is dependent upon the nature of the cogeneration (large or small), the company's investment and accounting policy, the level of financial risk the purchaser is willing to bear and the financial return required.

ANNEX I

GLOSSARY OF TERMS

The definitions given here relate specifically to the cogeneration context. Terms may have broader or alternative meanings in other contexts.

Absorption Refrigeration/Chilling

Refrigeration plant that uses heat instead of electricity as its principal energy source, and utilising, for example, water as a refrigerant and typically operating as a chiller unit serving air-conditioning and process cooling. Water vapour from the evaporator is absorbed in a substance having strong affinity for it (e.g. lithium bromide), from which it is separated by heat (generator), condensed and re-admitted to the evaporator. Minor amounts of electricity are required for solution and cooling water pumping.

Alternator

A machine whose shaft is driven by an engine or turbine and converts mechanical energy into alternating current (a.c.) electricity. More usually called a generator.

Auxiliary Firing

The burning of fuel (with its requisite air supply) on waste heat boilers when the generator set is not running but the site heat supply is to be maintained.

Availability

See Reliability.

Bar

A unit of pressure measure, equivalent to approximately 14.5 lbf/in² or 1 atmosphere (lbf/in² is commonly although less accurately expressed as lb/in² or psig).

Back-pressure Steam

The steam from the low-pressure end of a steam turbine.

Calorific Value (CV)

The heat available from a fuel when it is completely burnt, expressed as heat units per unit of weight or volume of the fuel. The gross or higher CV is the total heat available; the net or lower CV is the total heat less the latent heat of the water vapour from the combustion of hydrogen plus any water in the original fuel. The power industry tends to use net CV, the boiler industry gross CV.

CO, CO₂

Carbon monoxide, carbon dioxide respectively. Oxides of carbon produced by fuel combustion. CO represents incomplete combustion and can be burnt to CO₂, which is complete combustion.

Compression-Ignition

System used in reciprocating engines whereby fuel is injected after compression of the air and is ignited by the heat generated by compression. As pre-ignition is thereby eliminated, higher compression ratios than with spark-ignition engines can be utilised, with corresponding high energy conversion efficiency.

Condensing

The steam turbine mode whereby steam surplus to site requirements is expanded to the lowest practicable pressure (vacuum stage) to generate more electricity, then exhausted to a condenser and the condensate returned to the boiler.

Cylindrical Rotor Generator

A type of electricity generator. As frequency depends on the speed multiplied by the number of pole pairs, higher speeds require fewer poles and the exciting winding can be accommodated in radial slots machined into the periphery of the rotor.

Demand, Maximum Demand, Demand Profile

The rate at which energy is required, expressed in kW or MW. It is usually related to a time period, typically half an hour; e.g. 1 kWh used over half an hour is a demand rate of 2 kW. Maximum demand is the highest half hourly rate at which electricity is required during a month or year. Peak load or peak demand are the terms usually used for heat energy. A graph of demand rate over a typical day, for example, is the demand profile.

Diesel Engine

Takes its name from the famous German engineer Rudolf Diesel. A generic term for compression-ignition reciprocating engines, whatever the fuel used.

Dosing

The addition of conditioning chemicals to boiler feedwater or cooling water to protect plant from scaling, blocking, corrosion etc.

Dual-fuel

The use of two fuels in a prime mover or boiler. They may be alternatives e.g. with one as standby if the main fuel supply is interrupted, or simultaneous e.g. gas plus a small proportion of diesel used in compression ignition engines.

Excess Air

Reciprocating engines and gas turbines have to operate with far more air than is needed purely for the combustion of the fuel. This excess over requirements forms the major proportion of the exhaust gases and is termed excess air.

Fault Level

The maximum prospective current that can flow under a 3 phase short circuit condition. It should be noted that it can vary according to the point in the system at which the fault occurs. The magnitude of the fault level has a major influence on the choice and design of the equipment to be used.

Frequency

The number of times per second that alternating current changes direction. Frequency is expressed as cycles/second or Hertz (Hz) of alternating current. The public electricity supply in Europe is 50 Hz.

Feedwater Treatment

The conditioning of water to make it suitable for use in boilers and associated systems. It is specific to the composition of the water on site, type of boiler plant etc. and usually comprises some form of softening plus dosing.

Generator

An alternator or direct current (d.c.) generator. "Generator set" refers to the combination of prime mover and generator.

Heat Exchanger

A device in which heat is transferred from one fluid stream to another without mixing. There must obviously be a temperature difference between the streams for heat exchange to occur. They are characterised by the method of construction or operation, e.g. shell and tube, plate or rotary.

Heat Grade

A classification of heat source or heat requirement according to temperature. Up to 50°C would generally be classed low grade, otherwise grade limits vary according to the context. Typically, medium grade would be about 50°C to 150°C and high grade 150°C upwards.

Heat:Power Ratio

The amounts of heat energy and electricity produced by a CHP unit, expressed as a ratio. There is no agreed standard for its derivation and figures can vary depending on whether gross or net CV of the fuel is used for example, or heat output is total or practicably usable. When assessing prime movers, it is therefore essential that a consistent method is employed. Figures in this Report are based on gross CV and typically usable heat output.

High Temperature Hot Water

Pressurised hot water at 150°C to 200°C used for space heating and/or for processes.

In-duct Burner

A burner sited inside the duct of the air or gas stream it is heating, and thus also adding its combustion products to the stream. A typical method of supplementary firing where direct heat recovery is employed.

kV

Kilovolt = 1000 volts.

kW, kWe

Kilowatt, kilowatt electric. kW is used to express energy rate of production or demand, whatever the energy form entailed. kWe is specifically electricity, used e.g. to describe the generating capacity of a CHP set.

Load Factor

The average intensity of usage of energy producing or consuming plant expressed as a percentage of its maximum rating. Weekly load factor, for example, would be:

$$\frac{(\text{total output or consumption} \times 100)}{(\text{maximum hourly rating} \times 24 \times 7)} \%$$

Low Temperature Hot Water

Hot water at up to 100°C used for space heating and/or for low temperature processes.

Medium Temperature Hot Water

Pressurised hot water at 100°C to 150°C used for space heating and/or for processes.

MJ, GJ

Megajoules, Gigajoules. Units expressing quantity of heat energy. One GJ is roughly equivalent to 10 therms or 280 kWh.

MW, MWe

Megawatt, megawatt electric. As for kW, kWe, but 1 MW = 1000 kW.

Network

The distribution system which links energy production to energy usage. Mostly applied to electricity.

NO_x

A general term for oxides of nitrogen produced by fuel combustion, eventually discharged to atmosphere and considered deleterious emissions.

Parasitic

Adjective for the electricity used within the CHP plant itself and therefore reducing the amount available for beneficial use.

Particulates

Particles of solid matter, usually of very small size, derived from the fuel either directly or as a result of incomplete combustion and considered deleterious emissions.

Pass-out steam

Also called extraction steam. Steam taken part-way along a steam turbine to serve a requirement for that particular pressure, the balance remaining in the turbine to the exhaust stage to generate more power. There may be more than one pass-out tapping to serve differing site requirements.

Power Factor

kW (MW) divided by kVA (MVA), stated for a given point in an a.c. electricity network, e.g. the incoming supply to a consumer. Tariffs usually have a direct or indirect penalty charge for poor power factor (say below 0.95), which can be avoided by installing power factor correction equipment.

Premium

A general term to describe the quality of a fuel in terms of handling/storage, combustion, consistency of composition, pollutants etc., e.g. natural gas high premium, heavy fuel oil low premium. Fuel price usually follows premium value.

Prime Mover

A prime mover is the drive system for a CHP scheme. The systems that are currently available are all based on engines. There are three commonly used prime movers: gas turbines; reciprocating engines; steam turbines.

Reciprocating Engine

Strictly speaking, all prime movers are engines. When the mechanical power is produced by the to-and-fro ("reciprocating") movement of piston within cylinder, machines are so-called to distinguish them from purely rotating machines like turbines.

Reliability and Availability

These two factors are extremely important. CHP must operate over extended periods and in many cases is expected to be fully continuous, in order to be profitable. In practice, however, a prime mover requires maintenance that necessitates a scheduled shutdown at least once a year, and there may well be unscheduled stoppages in addition.

The reliability of a prime mover is therefore a measure of its susceptibility to unscheduled shutdown. Its availability takes into account all outages. The distinction between the two is often blurred and manufacturers' specifications and guarantees should be carefully scrutinised to ensure a true understanding. The time period used is typically a year of 8,760 hours. The formulae below illustrate one method of making the calculations:

$$\% \text{ Reliability} = \frac{T - (S+U)}{T - S} \times 100$$

$$\% \text{ Availability} = \frac{T - (S+U)}{T} \times 100$$

Where S = scheduled maintenance shutdown, U = unscheduled shutdown and T = time period when plant is required to be in service or available for service, all in hours per year.

Salient Pole Generator

A type of electricity generator. As frequency depends on speed multiplied by the number of pole pairs, lower speeds require more poles than can be accommodated within the rotor periphery. The exciting winding is therefore formed with copper strip or coils of wire attached to the surface of the rotor.

Sankey Diagram

Named from its originator. A diagram demonstrating graphically and in true proportion the energy flows in a system, starting with the energy sources at the left and showing losses, heat exchange loops etc. to the degree desired.

Shaft Efficiency

That percentage of its initial energy supply that a prime mover delivers as mechanical energy at its output shaft; NOTE - check whether gross or net CV is used to calculate input energy.

Shell and Tube Heat Exchanger

A unit having a bundle of tubes contained in a cylindrical shell. One fluid flows through the tubes, the other through the shell.

Shell Type Boiler

A cylindrical steam, hot water or thermal oil boiler, usually horizontal but may be vertical. The shell contains water or oil that is heated by the burner flame and combustion products in a chamber and tube or annular flue-ways inside the shell. Sometimes called a firetube boiler. A typical shell boiler is in fact a specialised shell and tube heat exchanger.

SO_x

A generic term for oxides of sulphur produced by the combustion of sulphur in the fuel, and considered as deleterious emissions. Their presence in flue gases can restrict thermal efficiency, because if the flue gas temperature is reduced below specific levels, highly corrosive sulphurous and sulphuric acids are deposited on heat exchange surfaces.

Spark-ignition

A reciprocating engine that utilises an electrical spark to ignite the compressed air/fuel mixture in the cylinders.

Superheated Steam

Steam whose temperature has been raised above the saturation temperature corresponding to its pressure. This is done almost exclusively to improve its power generating capacity when used in a steam turbine.

Supplementary Firing

The firing of additional fuel in the CHP heat recovery unit, utilising the hot oxygen present as excess air in the prime mover exhaust gases.

Synchronism

The condition whereby generator frequency and voltage levels match those of the public supply. When operating in parallel mode, it is obligatory to maintain these levels within closely specified limits.

Thermal Oil

A mineral oil used as a heat-carrying medium in preference to water or steam. Its major advantage is that high temperatures (up to 300°C) are feasible at pressures far lower than would be needed for steam.

Transformer (voltage)

A device with primary and secondary windings to convert the voltage of electricity from one value to another. Transformers may be step-up or step-down i.e. voltage increased or reduced, and there may be more than one secondary tapping to give a choice of output voltage.

Water Tube Boiler

The converse of a shell type boiler. Box-shaped, the enclosure acts as a combustion chamber and flue-ways, with the water or thermal oil inside tube bundles, connected to a cylindrical drum or drums. If superheated steam is required, saturated steam passes from the steam drum to a tube bundle mounted in the high temperature zone and then out to the steam turbine.

ANNEX II

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