Department for
Business, Energy
& Industrial Strategy

Combined Heat and Power – Technologies

A detailed guide for CHP developers – Part 2

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Contents

1 Introduction

A CHP plant consists essentially of an electrical generator combined with equipment for recovering and using the heat produced by that generator. The generator may be a prime mover such as a gas turbine or a reciprocating engine. Alternatively, it may consist of a steam turbine generating power from high-pressure steam produced in a boiler. In some cases, a CHP scheme may be a combination of prime mover(s), boiler(s) and steam turbine(s) as shown in the image below.

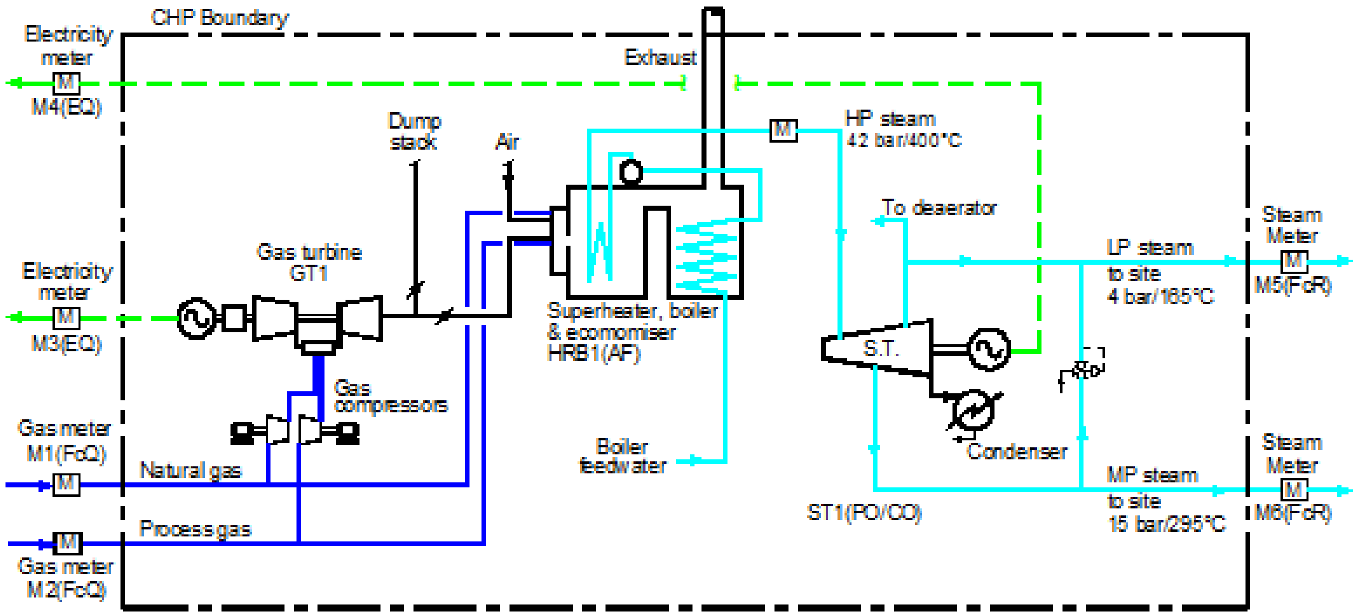


Figure 1: A combined cycle gas turbine CHP

CHP plant can be broadly placed into four categories:

- Packaged CHP, designed and supplied as complete units that can easily be connected to a building's electrical and heating systems.
- Custom-built CHP, designed and built to meet the specific requirements of the site.
- Micro CHP, designed to replace domestic/ small commercial scale boilers.
- Renewables CHP, designed to utilise renewable fuels and feedstocks.

There are also a number of technologies that can be used to improve the performance of CHP through enhanced heat utilisation. These include:

Absorption cooling: this allows the utilisation of additional CHP heat in absorption chillers to produce cooling which would otherwise have been produced using electrical chillers.

Heat storage: this allows the storage of excess CHP heat generated during off-peak periods for supply at times of peak heat demand.

2 What is Packaged CHP?

Packaged CHP are designed and supplied as complete units that can be easily connected to a building's electrical and heating systems. Typically, these units range in size from 50 kW to over 1 MW electrical capacity. They are usually provided with an integrated remote monitoring and control system.

What are the advantages of packaged CHP system?

- They are simple to integrate into site utilities.
- They are fit-and-forget systems.
- They require less training than other CHP systems.

What technologies are used?

- Packaged CHP typically use well-known technologies such as reciprocating internal combustion engines. Other technologies with development potential include fuel cells, organic Rankine cycle (ORC) and micro gas turbines.

2.1 CHP Packages

The main advantage of the packaged CHP system is that the unit can be manufactured and prepared at the supplier's premises and then delivered to site ready for off-loading and positioning. Most CHP packages are designed and supplied as complete units, selected to meet the reliability and availability requirements of the site and its energy demands. The package contains:

- A prime mover (either gas engine, small gas turbine, or fuel cell),
- the generator,
- heat recovery equipment, and
- associated pipework, valves, controls etc.

The equipment is mounted on a steel structure, and surrounded by an enclosure, which reduces noise levels in the adjacent area. The enclosure normally contains a control panel, which is accessible from outside the package. It can also usually be easily dismantled to provide access for maintenance purposes. Typical sizes and weights for packaged CHP units are given in Table 2-1.

Table 2-1: Typical sizes and weights of packaged CHP units

	Gas-engine CHP					Small-scale gas turbine CHP	
Electrical output (kWe)	60	100	300	600	1,000	60	100
Heat output (kWth)	15	130	430	880	1,300	100	150
Fuel consumption (kWin)	215	310	990	1,950	3,000	280	350
Package length (m)	2.9	2.9	4.0	6.5	8.0	2.0	2.9
Package width (m)	0.8	1.3	2.0	3.5	4.0	0.9	0.9
Package height (m)	1.8	1.95	2.4	2.6	3.5	1.6	1.9
Package weight (t)	2.5	4.0	8.0	12.0	16.0	1.0	2.0

The preparatory works for installing a CHP package are not complicated, the main requirements being:

- An area of ground on which the unit can be located. This area must be able to accept the imposed loads of the unit, and must be sufficiently-accessible for delivery and positioning. There should always be adequate free space around the package to provide access for maintenance purposes. Furthermore, it is common practice to locate CHP packages within a building to avoid exposure to external weather conditions and provide easy access to services.
- A piped supply of gaseous fuel for connection to the CHP package. This normally requires a pipework connection, which can be either located in a covered access duct

within the floor surface or attached to pipe supports and routed at high level within the building.

- Electrical cabling to connect the CHP package to an appropriate part of the site's electrical distribution system.
- An exhaust system to remove the exhaust gases from the engine or turbine to a point of discharge outside the building area.
- Access to the site hot water supply system.
- Suitable means to link to externally-located heat rejection equipment.
- Most packaged CHP applications supply heat via a hot water connection to a site distribution system, which takes the heat to its point of use. Some applications use an airflow to cool the engine or turbine and this heated air is then available for use on-site. Furthermore, some units pass their exhaust gases directly to the site for heating purposes, either separately or mixed with a heated airflow. Packages can also be designed to vary their heat outputs between air and water, according to variations in site demand.

2.2 Gas Engines

CHP Gas engines 'travel' the equivalent of 300,000-400,000 miles each year!

Gas-engine CHP packages are available in a range of electrical outputs – from less than 50 kW to around 2,000 kW. The electrical generating efficiency of these packages is typically around 30%-40%, and units can be operated at reduced load with very little drop in engine efficiency. The ratio of recoverable heat to electricity generated in a gas-engine package is typically around 1.5:1.

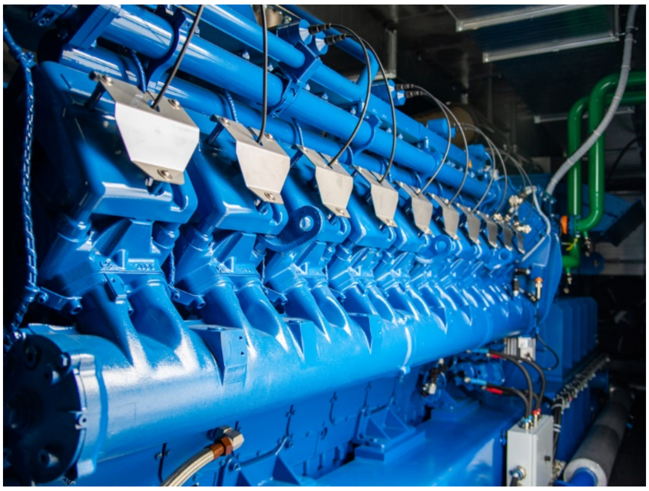


Figure 2: CHP Gas Engine

The gas engines used in CHP packages are internal combustion engines that operate on the same familiar principles as car engines, i.e. they use spark plugs to ignite the fuel in the engine and so are sometimes referred to as 'spark-ignition engines'. These engines have been designed for operation on a gaseous fuel, most commonly natural gas. Many engines can operate on supply pressures as low as 0.1 bar gauge (barg), the pressure at which gas is usually available from the gas supply system. In situations where the gas pressure is inadequate, a small pressure booster unit can be installed as part of the CHP package.

Since the CHP engine drives an electrical alternator, it must be designed to operate at constant speed and at exactly the same frequency as the mains supply, even though the fuel input and electrical output of the CHP package may be variable. The gas engines used in CHP packages typically operate at 1,500 rpm with the possibility of units above 1.3 MWe to operate at around 1,000 rpm.

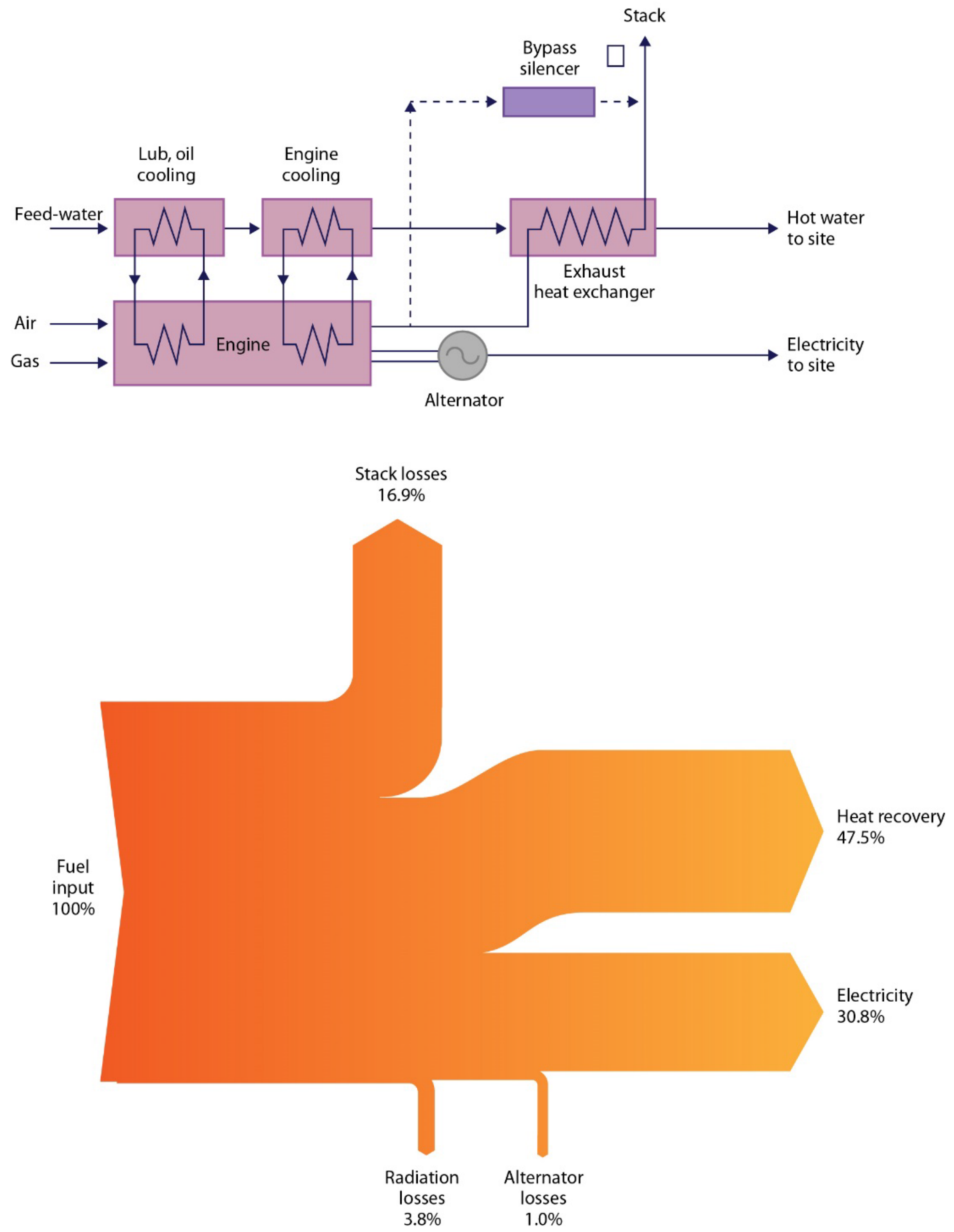


Figure 3: Energy flow diagram for Reciprocating Engine CHP

Engines and their lubricating oil must be cooled to prevent overheating. This cooling system provides heat in the form of hot water, which is produced whenever the engine is running, irrespective of whether or not it can be used. In a packaged CHP unit, the engine/lubricating oil cooling system is usually connected to a heat exchanger that also recovers heat from the engine exhaust. This helps to maximise the efficiency of the engine. Cooling system heat and exhaust heat are recovered in roughly equal proportions from a gas engine CHP package. The heat from the engine is typically at around 80°C, but some engines can operate using pressurised hot water, which delivers heat at up to 120°C.

If the recovered heat is not all required by the site, the surplus must be dissipated using a cooling system. Alternatively, the power output must be modulated to match heat demand. The cooling system is similar in principle to a vehicle engine's radiator and needs to be of sufficient capacity to maintain the flow of water to the engine at the correct temperature. All engines are equipped with automatic controls, which shut down the engine if it starts to overheat.

Gas engines vibrate, and the package design usually incorporates supports to dampen the effect of any vibrations on the floor beneath the package and on pipework. The noise levels from gas engines can also be a nuisance, particularly if the noise resonates within a building, and nearly all CHP packages are designed to act as effective acoustic enclosures to limit this problem. The enclosure itself is ventilated to avoid overheating.

All engines have moving parts, some of which suffer gradual wear and, therefore, require maintenance or replacement at regular intervals. Some of the routine maintenance tasks may be carried out while the engine is operating, but regular shutdowns for maintenance and servicing are also required. The total downtime is not excessive and high levels of engine availability can still be achieved (typically 90%).

2.3 Small Gas Turbines

The gas turbine has been the most widely used prime mover for large-scale, custom-built CHP typically running between 50,000 and 100,000 rpm.

The gas turbine has been the most widely used prime mover for large-scale, custom-built CHP in recent years but has not been available for smaller-scale packaged units. However, developments in design and material availability have resulted in the production of much smaller gas turbines, and these are now available as packaged CHP units in the 30-1,000 kW electrical output range.

Small-scale gas turbines require clean, dry gas as fuel, but are reasonably tolerant of changes in the constituents of the gas. An electrical generating efficiency of between 20% and 27% is achievable at full output, but efficiency drops if the unit is operated at part load. Heat to power ratios range from around 1.5:1 to 3:1. The turbines require fuel at a pressure of around 5 barg, which is above the supply pressure available in many locations, and a fuel gas booster unit is often required. The power consumption of this unit slightly reduces the overall efficiency of the

CHP package. Small-scale gas turbines with recuperators have higher electrical efficiencies – typically 26-28%.

Figure 4: A Gas Turbine

Small-scale gas turbines of >100 kW have the ability to raise steam via a waste heat boiler from the hot exhaust gas, although they have a lower electrical generation efficiency. Heat from 'micro' gas turbine CHP packages (30-100 kW) is usually provided as hot water, normally at around 80°C.These units incorporate a recuperator to improve their electrical efficiency and are, therefore, unable to produce steam.

Gas turbines produce very little vibration due to their very high speed of rotation – typically between 50,000 and 100,000 rpm. However, noise levels from these turbines can be significant, and the CHP package incorporates an acoustic canopy to limit this problem. The enclosure is usually ventilated to avoid overheating.

A gas turbine is physically smaller than a gas engine of the same electrical output. Compared with a gas engine (reciprocating), a gas turbine will achieve longer running intervals between maintenance periods. For major overhauls, the turbine unit is easily removed from the package and transported elsewhere; any work on its internal sections can be carried out at the supplier's premises. Many suppliers do this by an exchange system. The availability levels that can be achieved are high (typically 95%).

2.4 Fuel Cells

Fuel cells are electrochemical devices that convert the energy of a chemical reaction directly into electricity and heat. These devices enable high efficiency and low environmental footprint power and heat production.

Fuel cells are constituted by two electrodes (an anode and a cathode) separated by an electrolyte. In the case of solid fuel cells, a dense oxide conducting ion acts as an electrolyte. Oxygen supplied at the cathode (air electrode) reacts with the electrons from the external circuit to form oxide ions, which migrate to the anode (fuelled electrode) through the oxide ion conducting electrolyte. At the anode, oxide ions combine with the fuel (natural gas and syngas) to produce H_2O (and/or CO_2), liberating electrons. Electrons flow from the anode through the external circuit to the cathode. The overall cell reaction consists on the oxidation of fuel.

Fuel cells operate at high temperature, ranging from 650 oC to 1000 oC , depending on the cell materials. The most widespread used electrolytes are made up by yttria-stabilized zirconia (YSZ). Previous process design studies of micro- CHP using fuel cells claim electrical efficiency larger than 40%, achieving overall efficiency higher than 85% when syngas is used as fuel.

Fuel cells give the prospect of economic, energy and environmental advantages over existing electricity generation technologies in a wide range of applications. However, there remain technical and non-technical barriers to the successful commercial deployment of all types of fuel cell.

In terms of economic performance, the data available suggests that the technology could become commercially available by 2011, and could yield significant carbon and economic savings.

2.5 Reliability & Availability

Reliability and availability are very important issues for CHP packages, which must be able to operate continuously for extended periods to achieve the best economic returns. In practice, any engine or gas turbine CHP unit requires inspection and maintenance at least once a year, and this necessitates at least one planned shutdown annually. However, it is the equipment's susceptibility to additional, unscheduled stoppages that determines its reliability and actual availability over a given period of time.

Provision of a packaged CHP unit is often accompanied by:

- A contract for full maintenance of the equipment.
- Guarantees of plant availability, with penalties or bonuses payable according to actual achievements.

The distinction between reliability and availability is often poorly defined, and suppliers' guarantees should be carefully scrutinised to ensure a true understanding of what is being provided. The time period used is typically a year of 8,760 hours. The formulae that follow illustrate one method of making the calculations:

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

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

where:

S = scheduled maintenance shutdown (hours/year)

U = unscheduled shutdown (hours/year)

T = period when plant is required to be in service or available for service (hours/year).

Typical manufacturers' guaranteed figures for a packaged CHP unit might be as follows:

- Maximum scheduled outage (S) 438 hours per year (8,760 hours).
- Maximum unscheduled outage (U) 420 hours per year (8,760 hours).
- Using the formulae given:
- Guaranteed reliability = 8,760 - (438 + 420)/ 8,760 - 438   x 100 = 94.95%
- Guaranteed availability = 8,760 - (438 + 420)/ 8,760 x 100 = 90.21%

Reliability and availability vary for different sizes and types of CHP package, but the figures given represent typical levels that can be expected. Figures should be calculated for the planned operating regime, e.g. 17 hours per day.

2.6 Recovery and Use of Heat

The heat liberated from a CHP unit will consist, in the first instance, of:

- Hot exhaust gases.
- Hot water from the CHP cooling system.

This heat can be recovered through appropriate heat exchangers as:

- Low temperature hot water (LTHW) at <100ºC.
- High temperature hot water (HTHW) at 150-200ºC (from exhaust heat only in the case of an engine).
- Steam (from exhaust heat only in the case of an engine).
- Warm air.

The precise configuration will be determined by the end application. For certain processes, direct use of hot exhaust gas is appropriate.

Prime Movers and Electrical Generators: A Summary

Table 2-2 compares the two main types of CHP package and provides details of typical capacities and dimensions.

Table 2-2: CHP packages, outline data

	Gas-engine CHP					Small-scale gas turbine CHP	
Electrical output (kWe)	60	100	300	600	1,000	60	100
Heat output (kWth)	15	130	430	880	1,300	100	150
Fuel consumption (kWin)	215	310	990	1,950	3,000	280	350
Electrical efficiency (%)	27.9	32.3	30.3	30.8	33.3	21.4	28.6
Heat efficiency (%)	53.5	41.9	43.4	45.2	43.3	35.7	42.9
Package length (m)	2.9	2.9	4.0	6.5	8.0	2.0	2.9
Package width (m)	0.8	1.3	2.0	3.5	4.0	0.9	0.9
Package height (m)	1.8	1.95	2.4	2.6	3.5	1.6	1.9
Package weight (t)	2.5	4.0	8.0	12.0	16.0	1.0	2.0

Table 2-3: Summary of prime mover/electrical generator characteristics.

Type of plant	Typical output range	Typical fuels	Typical heat to power ratio	Grade of heat output
Gas engine	50-1,000kW	Natural gas, Landfill gas, Biomass or Mine gas	1.5:1	Low or Low/High
Small-scale gas turbine	30-1,000kW	Natural gas, Landfill gas, Biogas or Mine Gas	1.5:1 (up to 3:1 for some units)	Low or High

2.7 Site Installation

Although the decision to install a CHP package is determined largely by the potential financial benefits, certain practical aspects must also be considered. Many of these will already have been taken into account as part of the project feasibility assessment, but it is important to ensure that there are no unforeseen problems that could hinder the installation process. Issues to consider are:

- The air supply.
- Electrical connection.
- Exhaust system.
- Fuel supply.
- Heat output.
- Heat rejection equipment.
- Plant location.

2.7.1 Air Supply

Air is required in the engine for combustion, general cooling and ventilation. The supply of cooling and combustion air may be satisfied using either common or separate systems. In the case of very small installations (<100 kWe), it may be perfectly satisfactory to draw cooling and combustion air directly from the surrounding plant room without recourse to special ducting.

However, the plant room must have sufficient natural ventilation. In the case of larger engines, separate fresh air supply ducting may be required in order to obtain sufficiently cool combustion air.

Engine power output falls as charge air temperature increases. Care must, therefore, be taken with the location of combustion air intakes.

2.7.2 Electrical Connection

The CHP unit's generator (at 415 volts or 11 kilovolts, 50 Hz and three phase) must be connected to the site's electrical distribution system at an appropriate location. This may be via a spare breaker cubicle on an existing bus-bar or a new bus-section. Where a stand-by (Island Mode) facility is required, the maximum load imposed under Island Mode conditions must be within the generator's rated capacity.

In all cases, the site's electrical distribution system and grid in-feed must be checked to ensure that system fault levels are satisfactory and that switchgear is appropriately rated.

There are requirements to be met when connecting a generator to any part of the public electricity supply are contained in Electricity Association publication.

When connecting a generator to any part of the public electricity supply certain requirements needs to be met which are available in Electricity Association publications.

The power generated by a packaged CHP plant is almost always three-phase alternating current at 50 Hz, usually at 415V. Where the site electrical system at the point of connection is at a higher rating, e.g. 11kV, then an 11kV generator may be used. Alternatively, a 415V generator may be used and linked to a step-up transformer, the latter supplying electricity to the site at 11kV.

There are usually 2 modes for setting up the electrical supply connections:

- Parallel mode.
- Island mode.

Parallel Operation

Parallel Mode operation occurs in almost all CHP plants in the UK and refers to the ability to have top-up and back-up power as an essential facility to ensure security of site power supplies.

The site on which a CHP package is installed is almost always connected to the local area electricity supply system, and the CHP generator must supply its power output to the site in conjunction with this system. This is achieved by having the electrical switchgear connections between the CHP plant, the site and the local area system all closed, with the CHP plant and the local area system operating electrically locked together. This is known as ‘Parallel Mode’ operation, and it has a number of operational benefits:

- The local area supply system can provide any site power demands that are in excess of the power output of the CHP plant. This is known as ‘top-up’ power.
- The local area supply system can instantaneously meet the total site demand in the event of the CHP plant shutting down suddenly. This is known as ‘back-up’ or ‘stand-by’ power. Back-up is normally achieved without any loss of site power supply.
- Power can be passed from the site into the local area supply system if the net output from the CHP plant exceeds the site demand. This is known as ‘export’ power. This facility requires special metering facilities to be incorporated in the connection between the site and the local area system. The cost of implementation compared with the resulting revenues often makes export an uneconomic option.

It is essential to discuss the implications of installing a CHP package for Parallel Mode operation with the local distribution network operator (DNO) and obtain the latter’s approval. The DNO will need to carry out basic studies to assess the impact of any generation plant connected to its network. It will also usually stipulate any design and operating requirements deemed necessary for safe system operation. Installation of a CHP package and its operation in Parallel Mode may involve modifications to the site electricity connection. In some cases, it may be necessary to increase the capacity of the connection.

For a CHP system to operate in Parallel Mode, there are important features that must be incorporated in the design of both the CHP plant and the site electrical system:

- The CHP package must be fitted with synchronising equipment, so that the phasing of electrical power from the alternator can be matched with that of the local supply system. Connecting the generator when it is not synchronised will cause serious and expensive damage to electrical equipment, as well as causing a prolonged power outage.
- The site electrical system must be equipped with suitable protection equipment, so that the generator is automatically and instantaneously disconnected in the event of any problems with the electrical system. This protection equipment typically monitors conditions such as voltages, currents and the positions of automatic switches and circuit breakers.
- The site electrical equipment, including the CHP package, must not be capable of causing excessively high peak currents in the event of a major system fault, such as accidental damage to cabling or switchgear. If the anticipated peak currents are in excess of the capacity of the switchgear and other equipment in the local area supply system, the CHP plant may need specific design and operating procedures. This situation is relatively rare with packaged CHP units, and nearly all installations affected in this way have successfully achieved the requirements.

There are technical requirements that must be met for a CHP package to operate in parallel with the local area supply system, and these will be decided in conjunction with the DNO that owns and operates that system. These requirements will depend on the design and operating characteristics of both the local area system and the CHP plant, and their purpose is to protect equipment on either side of the connecting point from the effects of a fault occurring on the other side. The CHP supplier as part of the CHP supply package, be made responsible for initiating any necessary discussions and then meeting the agreed requirements.

Island Operation

Where a site has sufficient on-site switching facilities within its electrical system, a CHP package can operate in island mode providing power during an outage in the local area system. This requires the site to have the ability to disconnect from the local area system, and to ensure that the load connected to the CHP package is within its generating capacity. Under these conditions, the CHP package can be operated in 'Island Mode' to meet some of the site demands. If the site has specific demands where loss of power for a prolonged period would cause significant loss or disruption, the CHP package should be connected to the appropriate part of the site electrical system so that it can provide the back-up power when necessary. If this facility is used, the CHP package will have to be shut down before the site reconnects to the local area system, and then be restarted and synchronised as normal.

Although a gas-fired CHP package can provide backup power, it should not be used as an emergency stand-by power source to protect vital areas of demand such as healthcare facilities and computer systems. Gas engines and turbines are not suited to automatic restarting (sometimes when cold) and the take-up of full load output in a matter of seconds. This is a role requiring other equipment such as a diesel engine generator.

2.7.3 Exhaust System

The primary function of the exhaust system is to carry the products of combustion away from the engine safely. As engines are often located in basements, and exhaust outlets are typically at roof level, careful consideration must be given to exhaust duct routing and insulation to contain heat, vibration and noise. Catalytic converters may be included in the exhaust system, either separately or combined with silencers. Care must be taken to ensure that exhaust gases are not recirculated into the building or engine intake systems. Guidance on the avoidance of recirculation may be found in the CIBSE Technical Memorandum on Minimising Pollution at Air Intakes.

Ventilation air from the engine enclosure must be exhausted. Whether existing plant room systems are used or an independent system is installed will depend on the volume flow rate required for engine ventilation and on permitted temperatures in surrounding areas.

2.7.4 Fuel Supply

An essential part of the infrastructure supporting the operation of a CHP package is the system through which the gaseous fuel is provided.

The gas supply to a CHP unit may need to be uprated from the existing site supply to take account of the increased gas demand. Furthermore, if the supply pressure is too low a gas booster/compressor will need to be added.

What is Packaged CHP?

Natural gas is by far the most common fuel for packaged CHP units. The supply of natural gas to a user is by pipeline from the national distribution network, much of which is owned and operated by Transco. The gas is put into the system at its connections with the onshore and offshore sources by a number of gas providers or ‘shippers’, which provide gas to the user and pay Transco or other pipeline operators for use of the distribution system.

The installation of a gas-fired CHP package will usually increase the site’s consumption of gas, as the new plant will generate both heat and power and will usually be operational for a large proportion of the year. As well as the increase in total annual gas consumption, there will usually be an increase in the maximum rate of consumption. It is, therefore, important to establish whether the local gas supply system and the existing site gas connection can meet the new peak requirement. If not, it may be necessary to increase the capacity of the existing site connection.

- Modifications of this type need to be discussed with the system operator (usually Transco), or with an independent company that offers a service managing all aspects of gas connections. A number of key issues need to be defined during these discussions:
- The anticipated annual gas consumption. It is important to remember that many suppliers quote the fuel consumption of their plant as NCV, while the consumption data supplied for gas connection assessment must be given as GCV.
- The anticipated maximum rate of gas consumption. This is usually expressed in MW or in therms per hour. Again, the data must be quoted as GCV.
- Gas supply pressures. Where the intention is to install a gas turbine CHP package, it is usually more cost-effective to have the gas supply at the supply pressure required by the CHP unit. This avoids the costs associated with installing and operating pressure-boosting equipment.
- The likely route for new supply pipework and the location of metering and pressure regulating equipment. The general preference is for the metering and regulating equipment to be close to the site boundary. This means that the pipework beneath the public highway is owned by the pipeline operator, while pipework on the site is the responsibility of the CHP plant installer and owner.

While gas supply system modification may be an option in some instances, it may be simpler and more effective in other cases to install a separate new gas supply to a CHP plant, while leaving the existing system in place, unaltered. This has the advantage of avoiding disruption to other site functions, and it may allow the new gas supply to be provided at the pressure required by the CHP package.

A new gas connection to the site can be provided either by Transco or by other companies offering the necessary specialist services. The metering and regulating equipment will usually incorporate safety shut-off valves, together with vents designed for the safe release of trapped gas in the event of a problem with the system. The design and installation of the pipework, valves etc. are required to meet appropriate standards and specifications.

It is important to ensure that the pipework routing is clearly marked on the site drawings, and it is usual to install markers on the surface to help confirm pipework location. Once installed, the connection and pipework require little or no maintenance or attention, apart from routine checks.

2.7.5 Heat Output

Heat is available from a gas engine as:

- Exhaust gas at 400°C (up to 600°C from a gas turbine).
- Engine cooling water at 80°C.

Connection to the site heat system should be at its lowest temperature possible (normally the return feed to the boilers) to maximise the heat recovered. Swimming pool heating is an ideal use for the heat generated by a CHP unit. Alternatively, a connection may be made to the boiler return of a low temperature hot water (LTHW) system.

Where steam is the site heat transfer medium, the CHP may generate steam directly in the exhaust gas heat exchanger. In this case, only a proportion of the engine heat will be recovered.

In all cases where heat is recovered from the engine cooling circuit, a heat exchanger will be fitted between the engine and site circuits, keeping the two water circuits separate.

It is important to consider heat distribution in conjunction with heat recovery, as the distance between the heat load and the CHP package influences the cost of the pipework needed to connect the CHP unit to the site.

Unless the exhaust gases are used directly for heating or drying, the heat output from packaged CHP units is usually in the form of hot water. The heat is transferred to the user via a closed loop ‘flow and return’ pipework system. The ‘flow’ pipework delivers hot water at about 80°C to the point at which heat is transferred to the user. The water then passes into the ‘return’ pipework and is returned to the CHP package at a temperature that is about 10°C lower than the flow temperature. The closed nature of the loop means that the hot water is not used directly but acts as a heat transfer medium. This allows the addition of small quantities of chemical to the water to improve the system’s resistance to frost and corrosion.

In many cases, the CHP package will be installed on a site where a hot water flow and return system already exists, and it may be possible to make connections to the appropriate parts of the existing circuit. There are essentially two ways of connecting a CHP unit in this situation:

- In series, as a bypass in a suitable return to the boilers.
- In parallel with the boilers with conventional boiler plant.

What is Packaged CHP?

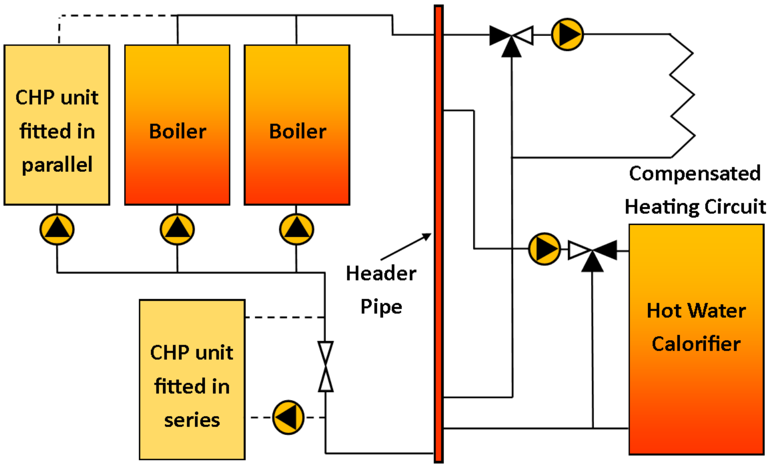


Figure 5: A schematic diagram for a CHP Unit with boilers

Connection in series is most frequently used with existing installations, since it creates the minimum interference with existing flow and control arrangements. Connection in parallel is preferred for completely new installations, especially where the CHP unit is likely to supply a significant proportion of the total heat load. In both cases, it is usually possible to connect the CHP package into the existing heat system in such a way that it adds its heat upstream of the existing boilers or water heaters. The existing boilers then operate as top-up or stand-by facilities for the CHP plant.

When the heat output from a CHP package cannot be used on the site, and power output must be maintained, a cooling system needs to be incorporated within the flow and return pipework. This is often referred to as a 'dump radiator' and is normally controlled by a valve connected to a temperature sensor on the return water inlet to the CHP package. If the water temperature exceeds a set level, the valve opens to pass water into the dump radiator and directly back to the return pipework system.

In order to comply with the requirements for Good Quality CHP and calculate the Quality Index, a suitable method of measuring the heat energy supplied to the site (rather than dumped) must be provided.

The hot water system must be designed to achieve the rates of flow and the return water temperature that will allow continuous operation of the CHP package. The system pipework must be of the correct diameter, and it must incorporate sufficient pumping capacity to maintain the correct flow and temperature conditions. It is common to equip the system with duty and stand-by pumps to ensure maximum availability. Furthermore, the pumps must be selected to operate with the dump radiator system in full or partial use, or with the hot water flow all passing to the site. It is also important to ensure that heat distribution systems have sufficient levels of thermal insulation to prevent heat loss and minimise hazards. The system must also incorporate the means of isolating individual plant items for maintenance, while allowing others to continue operating.

2.7.6 Heat Rejection Equipment

Engines produce more heat than power. All of the heat liberated by the engine must be dissipated or the engine will overheat and fail. Ideally, this heat will be utilised by the site heat load. In practice, this cannot be realised.

There are three options:

- Modulate the engine output to reduce electricity and heat generation when heat energy is not being fully utilised.
- Dump excess heat into radiators or some other heat sink to enable full electrical output to continue.
- A combination of 1 and 2 above.

If there are periods where the full electrical output is required from the CHP plant, but the heat load will be absent, then the heat rejection equipment must be capable of dumping the full heat output of the CHP plant. This will happen if, for example:

- The CHP plant must provide a stand-by or auxiliary supply and the heat load must be assumed to be the worst case.
- There are periods of zero heat load, but full electricity output is required (e.g. in summer).

In most situations, for instance in hotels, leisure centres and hospitals, a background heat load is always present (usually the hot water supply), and the heat rejection equipment can be sized to be less than the full heat load, with modulation of output as a secondary method of balancing the heat load. At present, turbines have less flexibility in this respect.

The normal means of rejecting unwanted heat will be by fan-cooled heat rejection units. These units must be sited so that they:

- Ensure a supply of cool air at all times.
- Avoid discharging warm air into other cooling equipment, windows, air-conditioning ducting and spaces where people may stand or walk.
- Comply with planning rules.
- Avoid noise. Fans are inherently noisy. Reducing the air velocities involved can reduce noise levels but the units required are usually larger and more expensive. Another option is to fit silencers. Variable speed fans should also be considered as these alter noise levels and power consumption in line with cooling demands.
- The design of heat rejection units should incorporate design margins that allow for:
- Fouling (normal = 10%).
- Variability in engine heat output (normal = 5-10%).
- An appropriate ambient design temperature (25-30°C) - noting that the units will probably be in greatest use in the hottest weather.

2.7.7 Plant Location

The location of the CHP plant needs to be considered carefully as there are several factors that affect the choice of its position:

- The plant must be sited where it can remain for a long period of time without disrupting or obstructing normal site use, either initially or in the future. There must be sufficient space to allow access for maintenance purposes and also to house any auxiliary equipment.
- The plant must be sited on foundations that are suitable for the loads imposed by the plant; this may require the construction of a concrete base.
- The plant must be located in a position from which the recovered heat can be passed into the site heating systems. This will usually involve installing some new hot water pipework, but it is preferable to keep the length of this pipework to a minimum.
- The plant must be connected to the site electrical distribution and fuel supply systems. These connections influence plant location, although the routing and installation of fuel pipework and electrical cabling are usually less complex and expensive than the pipework for the hot water connections.
- The CHP plant may require the installation of a new chimney, and this should be taken into account when choosing the plant location.
- Although most CHP engines and gas turbines are supplied with acoustic enclosures, noise is produced by the plant and its auxiliary equipment. Since the plant may operate almost continuously, its location should, where possible, minimise the impact of the noise emitted.
- The location should allow provision to be made for storing additional fuel (e.g. additional boiler backup fuel), lubricants and other items necessary for effective plant operation.

2.8 Fuels

Heat from fuel is the main source of energy for CHP plants. This energy is released by burning the fuel with air to produce high-temperature combustion gases. If burned in a confined space, some of the energy released pressurises the exhaust gases, thereby providing the power to drive an engine or gas turbine and generate electricity. The exhaust gases are subsequently released at a lower pressure and temperature: they can then be the main source of heat for on-site use. Packaged CHP units are normally based on engines, although gas turbines can be used. Units are designed to operate on gaseous fuel only, usually using natural gas provided through the national supply system. Some units are capable of operating on other gases such as gaseous waste fuel, which may be available locally as by-products of other plants or processes. Some typical fuel calorific values have been included as a guide.

2.8.1 Natural Gas

Gas is also considered to be the 'cleanest' fuel because its exhaust contains lower levels of potentially harmful gases.

Natural gas is extracted from underground sources and distributed by pipework throughout most parts of the UK. It consists of a high proportion of hydrocarbon gases – mainly methane – with small quantities of non-fuel gases such as nitrogen and carbon dioxide. Natural gas contains virtually no sulphur or contaminants. Although distribution pipework is required on-site, together with a housing for metering and pressure regulating equipment, there are no handling or storage costs.

Natural gas is widely available in most parts of the UK. It is purchased from one of a number of suppliers and is transported through the national gas distribution system. Since packaged CHP units do not have the capability to operate on other fuels, purchasers/installers must make an economic choice between an interruptible and a firm gas supply. If the packaged CHP purchaser/installer opts for interruptible supplies, a cheaper tariff is granted in exchange for the right of the gas shipper or National Grid plc to interrupt supplies on a certain number of days in each year. During each interruption, all electricity requirements must be imported, and heat must be available from other sources such as oil-fired boilers or gas boilers on a firm supply. It is possible to have both firm and interruptible supplies to a site.

If a firm supply is adopted, then CHP availability will not be compromised but gas costs will be higher. The cost of the gas is determined on an individual contract basis and will reflect factors such as location and the required quantity and capacity of supply. In all cases, the actual prices charged are a result of contract negotiation and can be fixed for periods of up to three years or more, thereby providing a relatively stable fuel supply cost.

The quality and consistency of natural gas are high, and the fuel can be used directly in a CHP package without any treatment or filtration. The composition of the natural gas supply at any location will vary slightly from time to time, according to a number of supply and operational factors, but the variations are not significant and do not usually affect the operation of a gas-fired CHP package.

For the larger packaged CHP units, a compressor may be necessary to raise the incoming gas supply to a suitable pressure for injection into the engine.

2.8.2 Gaseous Waste Fuel

A number of activities, for example landfill, sewage treatment and some industrial processes, produce gaseous waste fuels. In many cases, the gases are produced on a continuous basis and are available for use in a packaged CHP unit, although their composition and quality will usually vary. Historically, such gases have often been allowed to escape into the air, or have been flared, but it has long been realised that this can cause significant damage to the environment, and so the use of these gases as fuel is encouraged.

The waste gases from landfill sites and sewage plants and those from coal mining activities are usually methane-based, often with small quantities of other hydrocarbons and larger proportions of inert gases. These gases can sometimes contain compounds of chlorine and other contaminants such as water and will require some filtration or treatment before they can be used. CHP packages based on gas engines can operate on these fuels, although the engine design must be configured for the particular fuel. Consistency of supply and composition are key issues. The nature of these fuel sources is such that heat loads may or may not be present. Sewage treatment plants, for example, have a readily available heat load, whereas landfill sites seldom do.

Gases from industrial processes may also be suitable for packaged CHP units, although fuel composition can sometimes render the gas unsuitable for use in an engine. Fuel composition is determined by the nature of the process in which the gases are produced. Any sulphur in the gas will result in the production of sulphur dioxide in the exhaust, which is potentially corrosive as well as being environmentally damaging. Some gases may need to be filtered and dried prior to use. In all cases, the CHP package must be selected for use with the particular fuel envisaged. Consistency of supply is also an important issue.

In some chemical processes, gas turbines can provide a convenient and economic way of disposing of solvents.

2.8.3 Fuel Calorific Values

The use of gross or net calorific value varies with industry. Engine and gas turbine manufacturers, for example, report efficiency on a net basis, whereas UK boiler manufacturers use gross as the basis for reporting efficiencies. However, all fuel is purchased on the basis of its gross value, and site energy consumption is always expressed in terms of gross, so it is important to use gross calorific value in the energy analysis relating to CHP feasibility.

This Guide uses gross calorific value throughout. Any energy balance derived will vary with the calorific value used for the calculations, and this, in turn, results in different thermal efficiency figures for combustion plant and equipment. Great care must, therefore, be exercised in any analysis and interpretation of performance data.

Table 2-4: Typical properties of selected fuels

Fuel	CV (MJ/m^3) as normally expressed		Contaminants (%)	
	Gross	**Net**	**Sulphur**	**Water**
Natural gas	38.0	34.2	-	Trace
Landfill gas	20.0	18.0	Trace	Trace
Mine gas	21.0	18.9	Trace	5.0

The calorific value (CV) of a fuel is the heat available from that fuel when it is completely burned, expressed as heat units per unit of fuel weight or volume. The gross, or higher, figure is determined in the laboratory using a calorimeter. It can be defined as the total heat liberated by the complete combustion of the fuel. It is determined by measuring the heat removed when cooling the products of combustion to a standard reference temperature, and it includes latent heat recovered from condensation of the water vapour component. This water vapour forms as a result of the combustion of any hydrogen contained within the fuel.

The net, or lower, value is determined by calculation and equals the gross minus the latent heat of the water vapour formed during combustion of the fuel. For natural gas, the lower figure is around 89% of the higher.

2.8.4 Monitoring & Control Systems

The main components of a CHP installation each have their own control and monitoring systems, which are interconnected to provide a single integrated system for a CHP package. Here are links to section taking an in depth view of Control System, long-term performance monitoring and metering systems.

2.8.5 Control Systems

The main components of a CHP installation each have their own control and monitoring systems, which are interconnected to provide a single integrated system for a CHP package. The system controls usually incorporate condition-monitoring equipment, which provides warnings and automatic shutdown in the event of component malfunction, and which also assists in the long-term management and operation of the plant.

Control systems are now usually based on high integrity programmable logic controllers (PLCs) and include all the metering, control and protection systems required for the safe start-up, operation and normal shutdown of the equipment. All safety interlocks for emergency shutdown are normally hard-wired between the plant items and the main control panel.

A CHP package operates for long periods of time with no control by, or supervision from, site staff. As a result, it is common practice to connect the control and monitoring system to some wider network, such as a Building Management System or, more commonly, to a remote control and monitoring system operated by the supplier or operation and maintenance contractor. There are several advantages to this approach:

- The CHP package can be controlled and monitored by the same system that controls and monitors site heat and electricity use.
- The unit can be stopped and started safely by the wider controls system.
- Fuel consumption and heat and electricity output can be monitored as part of the site's energy management activities.

2.8.6 Long-Term Monitoring

Performance monitoring is a key function of modern control systems. It can be used for several purposes:

- To detect potential faults, malfunctions etc. at the earliest possible stage so that they can be promptly rectified or prevented.
- To monitor operating conditions and facilitate the planning of maintenance activities.
- To calculate the cost savings achieved.
- To monitor data for CHPQA certification needed for CCL exemption.

Optimisation takes the monitoring and control of the CHP system one step further, and seeks to maximise the economic benefits, by repeated calculation of the costs and benefits of operating the CHP unit. This can be carried out on-line, using continuously updated real-time data, or off-line, using a download or snapshot of data or manual data input.

The logic for carrying out this procedure is not complicated. However, the value of the outputs from a CHP package can change over short periods of time (for example, with changes in site energy demand), making frequent reassessment of the costs and benefits essential. Some of the values are set by external factors. The avoided cost of buying electricity is the main factor affecting the achievable cost savings, and CHP electricity produced during low-cost periods under time of day and seasonal tariffs has less value. At certain times, it may be better to shut down the CHP package, buy electricity from outside sources and provide heat from alternative sources. This is often the preferred option at night, given current night-time electricity tariffs.

When CHP energy is supplied under an energy supply contract, some contractors offer two-tier billing as an incentive for longer and more cost-effective operation. In two-tier billing, a lower rate is enjoyed when more than a certain volume of energy in a given period has been used.

2.8.7 Metering

Metering of fuel input to CHP, and electricity and heat outputs, is good practice. Metering allows sites to confirm that their CHP scheme is maintaining performance and hence cost savings. This is emphasised as one of the requirements of the CHPQA programme, necessary for schemes to gain CCL exemption. For CHPQA metering requirements, see the Guidance Notes available on the website.

3 Custom CHP

Custom CHP systems are designed and built to meet the specific requirements of the site. These systems are usually integrated into the site's utilities and services. Typically, these schemes range in size from generating 1 MWe to 100s of MWe generating capacity.

What are the advantages?

- Custom designed for customers' requirements.
- More flexible than packaged systems.
- Typically more efficient than packaged systems.
- Typically longer service intervals than packaged systems.

What technologies are used?

Custom CHP systems typically use well known technologies, current development favours open and combined cycle turbine systems due to their high reliability and lower costs at high generating capacities.

3.1 CHP Fuels

Heat from fuel is the main source of energy for CHP plants. This energy (calorific value) is released by burning the fuel with air to produce high-temperature combustion gases. If burned in a confined space, some of the energy released pressurises the exhaust gases, providing the power to drive a gas turbine or an engine and generate electricity. The exhaust gases are subsequently released at a lower pressure and temperature, if they are then passed through a heat recovery heat exchanger they can provide the main source of heat for on-site use.

It should be noted that some fuels cannot be burned in gas turbines or engines. These fuels include solid fuels such as coal and wastes and contaminated liquid or gaseous fuels which would damage the prime mover. In these instances the fuel is burnt in a boiler and the heat released from the fuel raises pressurised steam. The steam is then used to drive a turbine and generate electricity. Once the power has been generated the steam is discharged from the turbine at a reduced temperature and pressure however there is still enough energy present to allow the stream to provide a source of heat.

In general, the flexibility of its supply, storage and use influences the cost of a fuel. Commercial fuels such as natural gas and the lighter oils are highly valued and viewed as premium quality fuels as a result they are relatively expensive to buy but do not require expensive handling equipment. In the case of natural gas, there are two supply tariffs: the higher 'firm' tariff where the customer requires a continuous supply of gas, and the lower 'interruptible' tariff where customers are prepared to accept interruptions in the supply during periods of peak demand,

and to switch to an alternative fuel. Natural gas and refined oil fuels are widely available from producers and distribution companies.

Non-premium fuels, such as coal, heavy oils and alternative fuel materials, are cheaper to buy but incur significant on costs for handling, burning and meeting environmental standards. These fuels are sometimes produced or left over from industrial processes or domestic activities and are only economic viable if they are available for use locally because of the high transport costs.

CHP installations may be designed to accept more than one fuel. This provides purchasing flexibility and improved security of supply, but there is usually an additional installation cost for this facility. Furthermore, fuel choice may be limited in practice by the emission requirements of an environmental permit.

The most widespread example of operation using more than one fuel is dual-fuel combustion involving gas and oil. The natural gas is bought under the advantageous interruptible tariff and is used as the main fuel. Distillate oil is used when the gas supply is interrupted during periods of peak gas demand or is otherwise unavailable.

A back-up fuel – natural gas or oil – may also be required for systems burning a solid or waste product, either to bridge shortfalls in supply or to initiate combustion. True multi-fuel firing, where two or more fuels are used simultaneously, is feasible but rarely necessary, and hence it is seldom encountered. Municipal solid waste incineration plants are self-sustaining, but some waste incineration plants may be multi-fuel units, requiring a continuous supplement of premium fuel to ensure proper combustion of the wastes.

3.1.1 Commercial Fuels

There are four main types of commercial fuel: natural gas, distillate oils, heavy fuel oils, and coal. Coal and oils are supplied in bulk and have simple tariff structures based on the quantity delivered to the site by road or rail. The following sections provide some additional detail on each of the main commercial fuels natural gas, distillate oils, heavy fuel oils and coal.

Natural Gas

Natural gas is normally drawn from a continuous supply and is purchased from a supplier. The cost of the gas is determined on an individual contract basis and will reflect factors such as location, the required quantity and capacity of supply, and the degree of supply security required. In all cases, the actual prices charged are a result of contract negotiation and can be fixed for periods of, typically, up to three years, thereby providing a relatively stable fuel supply cost. Natural gas is extracted from underground sources and distributed by pipework throughout most parts of the UK. It consists of hydrocarbon gases – mainly methane – and generally contains no sulphur or contaminants. Although distribution pipework is required on-site, together with a housing for metering and pressure regulating equipment, there are no handling or storage costs. However, in many cases, the CHP plant will need to incorporate specialist equipment to boost the supply pressure of the gas, and this can consume significant amounts of electrical power.

Natural gas is suitable for a very wide range of combustion equipment, including boilers, gas turbines, gas engines, and compression-ignition engines operating in dual-fuel mode. Gas is also considered to be the ‘cleanest’ fuel because its exhaust contains lower levels of potentially harmful gases. Although the constituents of natural gas generally remain consistent, there are variations according to the operating practices of the supply system and its gas sources, and these variations may influence the performance and output of some gas turbines and engines.

Distillate Oils

Distillate oils are produced and traded on the world market, and prices are liable to fluctuate as a result of international factors. Gas-oil is the main distillate oil. It is a product of petroleum refining and is specified in Class A2 and Class D of British Standard BS 2869. Gas-oil is widely used in industry throughout the UK, and also forms the basis for diesel fuel for road vehicles. A lighter distillate oil, often referred to as kerosene, is specified in Class A1 of BS 2869.

The properties and composition of gas-oil are more consistent than those of heavy fuel oil. Gas-oil is a much lighter fuel, remaining liquid at normal ambient temperatures and, therefore, easier to store and handle: it is also usable at temperatures down to as low as -10°C. Furthermore, apart from small quantities of sulphur, gas-oil contains effectively no contaminants, although poor combustion can result in a dirty exhaust containing hydrocarbon particle and carbon monoxide emissions. Gas-oil is a suitable fuel for boilers, engines and gas turbines but, because of its relatively high cost, it is not usually an economic option for CHP, except as a secondary or stand-by fuel, or as a pilot fuel for gas-fuelled compression-ignition engines.

Heavy Fuel Oils

Heavy fuel oils are produced and traded on the world market, and prices are liable to fluctuate as a result of international factors. Heavy fuel oils are mixtures of residuals from petroleum refining. These oils are highly viscous liquids, which are almost solid at normal ambient temperatures and need to be heated to facilitate storage and pumping prior to combustion. This is one of a number of costs which also include the installation and operation of specialist storage and handling facilities. Heavy fuel oils are suitable for use in boilers, and can also be used in larger diesel engines, as long as the oil has been correctly heated and filtered.

The properties and composition of heavy fuel oils are more consistent than those of coal, and standards have been set which define the main properties of commercial heavy fuel oils and set limits for contaminants, viscosity etc. Commercially available heavy fuel oils comprise Class G and Class H of BS 2869, and these contain sulphur and other organic compounds, plus small amounts of water, sediment and ash. Environmental legislation sets limits to the sulphur content of these fuels if they are to be widely used.

Coal

UK coal is partly deep-mined and partly from opencast sources, and is relatively expensive. Its prices are influenced by the cost of imported coal supplies but are relatively stable. It is generally considered a non-premium fuel for three reasons:

- It contains water, ash, sulphur and other substances that are potentially harmful or corrosive.
- It is more difficult to burn effectively and cleanly, particularly in smaller-scale plants.
- Coal is also more costly to transport, handle and store than premium fuels.

Coal is not a single uniform fuel, and its composition and availability are not consistent. Particular grades of coal, in terms of size and quality, are produced and marketed to suit different applications, and a particular coal user may be supplied from distant sources if more local coals are not of the appropriate for the process. In addition to the costs of purchasing the coal, other costs will be incurred for site storage and handling, ash disposal, meeting environmental requirements etc.

In CHP installations, coal is generally used to fuel steam-raising boilers, and this requires coal with suitable physical properties. Considerable R&D work has gone into the application of specialised combustion systems such as the fluidised bed. Fluidised bed gasifiers may also be used to generate syngas fuel from the coal for direct use in a gas turbine or IGCC. However these technologies are not widely deployed.

Coal is normally purchased on a contract basis, with the price for a given supply over a defined period fixed according to agreed supply conditions.

3.1.2 Waste Fuel

Using waste as fuel has two outstanding advantages:

- The low or zero cost of the fuel itself
- The potential for reducing or eliminating the cost of waste disposal

Potential disadvantages include the costs of storage and handling, treatment prior to combustion, specialised combustion equipment, and flue gas clean-up facilities etc. It should be noted that the cost of specialized equipment may be offset by the low cost of the fuel.

Solid Waste Fuel

Examples of solid waste fuel include wood off-cuts from furniture manufacturers, biomass from forestry and farming, waste tyres and domestic refuse.

The successful combustion of this waste usually requires specialised technology, with the heat produced being used essentially to produce steam for electricity generation and CHP.

Municipal collection and centralised systems have realised the full benefit of waste-fuelled CHP by generating power and providing heat to community heating schemes for example.

Gaseous Waste Fuel

Sources of Alternative Gaseous Fuel include:

- By-Product Gases, products from industrial processes such as blast furnace gas, coke oven gas and refinery fuel gas,
- Biogas: gas produced by the anaerobic digestion (AD) of biological materials (such as sewage gas, landfill gas, food processing waste, pharmaceutical waste and municipal waste,
- Waste Gas / Heat: waste gases such as carbon monoxide or volatile organic compounds, or waste heat such as the exhaust gas from high temperature processes, or as a product of exothermic chemical reactions.

It should be noted that some gas fuels can be used in engines or gas turbines, taking advantage of the higher electrical efficiencies of these designs over steam cycles.

Liquid Biofuels

Liquid biofuels including the following products:

- 'bioethanol': ethanol produced from biomass and/or the biodegradable fraction of waste,
- 'biodiesel': a methyl-ester produced from vegetable or animal oil, of diesel quality,
- 'biomethanol': methanol produced from biomass,
- 'biodimethylether': dimethylether produced from biomass,
- 'bio-ETBE (ethyl-tert-butyl-ether)': ETBE produced on the basis of bioethanol. The percentage by volume of bio-ETBE that is calculated as biofuel is 47%;
- 'bio-MTBE (methyl-tert-butyl-ether)': a fuel produced on the basis of biomethanol. The percentage by volume of bio-MTBE that is calculated as biofuel is 36%;
- 'synthetic biofuels': synthetic hydrocarbons or mixtures of synthetic hydrocarbons, which have been produced from biomass;
- 'pure vegetable oil': oil produced from oil plants through pressing, extraction or comparable procedures, crude or refined but chemically unmodified, when compatible with the type of engines involved and the corresponding emission requirements.

Liquid Waste Fuel

Liquid Waste is defined by CHPQA as biological or non-biological origin from domestic and industrial activity (such as tallow, fats and biological oils, spent solvents, tank washings, recycled used oil and refinery asphaltic oil not covered by HODA).

3.1.3 Fuel Calorific Value

The calorific value (CV) of a fuel is the heat available from that fuel when it is completely burned, expressed as heat units per unit of fuel weight or volume.

The gross, or higher, value is determined in the laboratory using a calorimeter. It can be defined as the total heat liberated by the complete combustion of the fuel. It is determined by measuring the heat removed when cooling the products of combustion to a standard reference temperature, and it includes latent heat recovered from condensation of the water vapour component. This water vapour forms as a result of the combustion of any hydrogen molecules contained within the fuel, and the vaporisation of any moisture present.

The net, or lower, value is determined by calculation and equals the gross calorific value minus the latent heat of the water vapour formed from the combustion of hydrogen and from any moisture present in the fuel.

The net value is more representative of the heat available in practice when fuels are burned in equipment such as furnaces and boilers. The latent heat of the water vapour contained in exhaust gases is not normally recoverable, except where low-temperature heat recovery involving condensation is used.

The use of gross or net calorific value varies with industry. Engine and gas turbine manufacturers, for example, use net calorific value, whereas UK boiler manufacturers use gross when stating the efficiency of their plant. Importantly all fuel is purchased on the basis of its gross value, and site energy consumption is always expressed in terms of gross calorific value (GCV), so it is important to use gross calorific value in the energy analysis relating to CHP feasibility.

Any energy balance derived will vary with the calorific value used for the calculations, and this, in turn, results in different thermal efficiency figures for combustion plant and equipment. Great care must, therefore, be exercised in any analysis and interpretation of performance data. The following table summarises the relationship between gross and net calorific value for the most common CHP fuels.

Table 3-1 Commercial fuels: the ratio between gross and net CV

Fuel	Ratio of gross/net CV
Natural Gas	1.109
Gas-oil	1.067
Heavy fuel oil	1.060
Bituminous coal	1.040*

*Depends on moisture content as fired

Table 3-2 Typical properties of selected fuels

	CV as normally expressed[1]		Contaminants (%)		
	Gross	**Net**	**Sulphur**	**Water**	**Ash**
Coal (All Consumers)	27.2 MJ/kg	25.8 MJ/kg	1.2	10.0	8.0
Wood Pellets[2]	18.3 MJ/kg	16.9 MJ/kg	0.4	10	Trace
Heavy fuel oil	43.3 MJ/litre	40.7 MJ/litre	2.0	0.3	0.04
Gas-oil	45.3 MJ/kg	42.6 MJ/kg	0.15	0.05	0.01
Natural gas	39.6 MJ/m³	35.7 MJ/m³	-	Trace	-
Landfill gas	21-25 MJ/m³	19–23MJ/m3	Trace	Trace	-
Mine gas	21.0 MJ/m³	18.9 MJ/m³	Trace	5.0	-

Alternative Fuels

Alternative Fuels are all fuels except conventional fossil fuels as described either by the Finance Bill 2000 as a taxable commodity, or by the Hydrocarbon Oil Duties Act 1979 and covered by Excise Duty. Such fuels include:

- Any gas in a gaseous state that is of a kind supplied by a gas utility.
- Any petroleum gas, or other gaseous hydrocarbon, in a liquid state.
- Coal and lignite.
- Coke, and semi-coke, of coal or lignite.
- Petroleum coke.

[1] For most recent calorific values of different fuels check DUKE's data as values presented in this guide are from 2016 (https://www.gov.uk/government/statistics/dukes-calorific-values)
[2] 10% Moisture Content

- Hydrocarbon oil or road fuel gas within the meaning of the Hydrocarbon Oil Duties Act 1979 (HODA).

Using renewable sources for fuel has two advantages:

- The low or zero carbon associated with the fuel itself.
- The energy security of a sustainable fuel.

Potential disadvantages include the costs of cultivation, storage and handling, treatment prior to combustion, specialised combustion equipment, and flue gas clean-up facilities. However, the cost of specialised equipment may be offset by the low cost of the fuel.

Examples of renewable fuels include:

- **Biogas**: gaseous fuel produced by the anaerobic digestion (AD) of organic materials.
- **Liquid biofuels**: liquid fuel for transport produced from biomass including manufactured liquid biofuels such as biodiesel and bioethanol as defined in the EU Biofuels Directive.
- **Biomass**: which includes agricultural residues, waste wood, straw, milling residues, prunings and sewage treatment residues. It also includes energy crops – plant crops planted after 31st December 1989 and which are grown primarily for the purpose of being used as fuel or which are one of the following: miscanthus giganteus; salix or populus.
- **Wood Fuels**: Commercial-grade wood fuels (such as clean woodchips, logs and wood pellets, but specifically excluding energy crops and waste wood, which are classed as biomass).

3.2 Prime Movers

The prime mover is the mechanical machine which drives the alternator, it is the heart of the CHP system, so its correct selection is vital for a successful installation. The three main factors governing this selection are:

- The fuel(s) available.
- The grade (temperature) of heat required on-site.
- The heat to power ratio (the ratio of recoverable heat to electrical output).

There are a variety of prime movers available, the most common categories are:

- Gas Turbines.
- Reciprocating Engines.
- Steam Turbines.

- Combined Cycle.
- Reliability & Availability.
- Summary of Prime Movers.

3.2.1 Gas Turbines

Gas turbines are the most widely used prime movers for modern custom-built CHP plants. They are available in a wide range of power outputs, from less than 1 MW to more than 200 MW. They are inherently very reliable and have a minimal running maintenance requirement. Furthermore, when operating continuously at optimum efficiency, they can achieve a long-term availability of 94-98%.

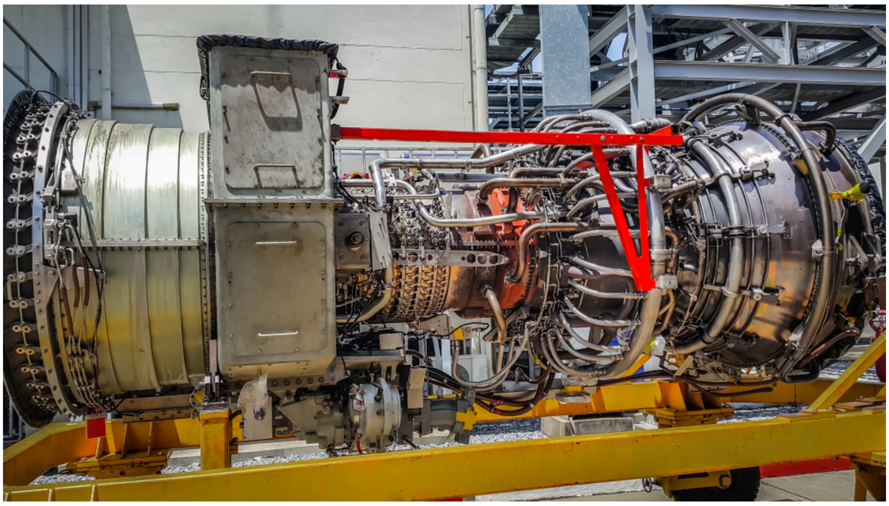


Figure 6: A gas turbine

Gas turbines produce exhaust gases at 400-550°C. Although these gases can sometimes be used directly for processes such as drying, they are more often passed to a heat recovery boiler for the production of hot water or steam. Where the site's heat requirement exceeds the heat available in the exhaust gases, or is variable, a burner can be incorporated in the ducting between the turbine and the heat recovery boiler to increase the temperature of the exhaust gases and improve the heat output of the plant. This is called supplementary firing.

The most popular fuel for a gas turbine is natural gas, although other gaseous fuels can be used such as biogas, landfill gas and mine gas. Many installations use natural gas on the cheaper interruptible tariff, with gas-oil as the standby fuel.

The gas turbine has been the most widely used prime mover for large-scale CHP in recent years. It uses pressurised combustion gases from fuel burned in one or more combustion chambers to turn a series of bladed turbine wheels and rotate the shaft on which the blades are mounted. This shaft delivers the power output from the turbine, some of which is required to drive the compressor that provides the high pressure air intake for the turbine. The remainder of the power drives the external load, usually an electrical generator. The air compressor and generator may be driven from a common shaft single-shaft machines) or they may be independently driven (dual- and multi-shaft machines).

External air is drawn into the gas turbine through the turbine's compressor stage: fuel is burned in the pressurised and heated airflow, and the resulting exhaust flow is discharged from the combustion chambers at a temperature in the range 900-1,200°C. The exhaust flow passes through the power turbine section where its heat and pressure energy is used to spin the rotor which provides the rotating shaft-power from the turbine. The exhaust gases are discharged at 450-550°C: in a CHP scheme, these gases are a source of heat energy for the site. The gas turbine is particularly capable of supplying high-grade heat when used in a CHP application. The ratio of usable heat to power ranges from 1.5:1 to 3:1 in a system without supplementary firing, depending on the characteristics of the individual gas turbine.

Gas Turbine Fuel Capabilities

A gas turbine operates under exacting conditions of high speed and high temperature. The air and fuel supplied to it must, therefore, be clean, i.e. free of particles that would erode the blades, and contain minimal amounts of any contaminants that would cause corrosion under operating conditions. A high standard of air filtration is, therefore, essential, and premium fuels are most often used, with natural gas being the most popular. Other suitable fuels include:

Distillate oils such as gas-oil – gas turbine sets that are capable of using both gas and gas-oil are often installed to take advantage of interruptible gas tariffs.

Waste fuels such as biogas, landfill gas and mine gas, as long as their CV and composition are sufficiently consistent to allow the temperature of the hot gas leaving the combustion chamber to be controlled at the required level.

Residual oils, if sufficiently free of damaging contaminants, although these are rarely used in practice in industrial CHP applications.

Combustion techniques for producing clean hot gases from solid and other 'difficult' fuels have been developed, but these are not yet ready for general application in the size range of gas turbine CHP plant considered here.

Custom CHP

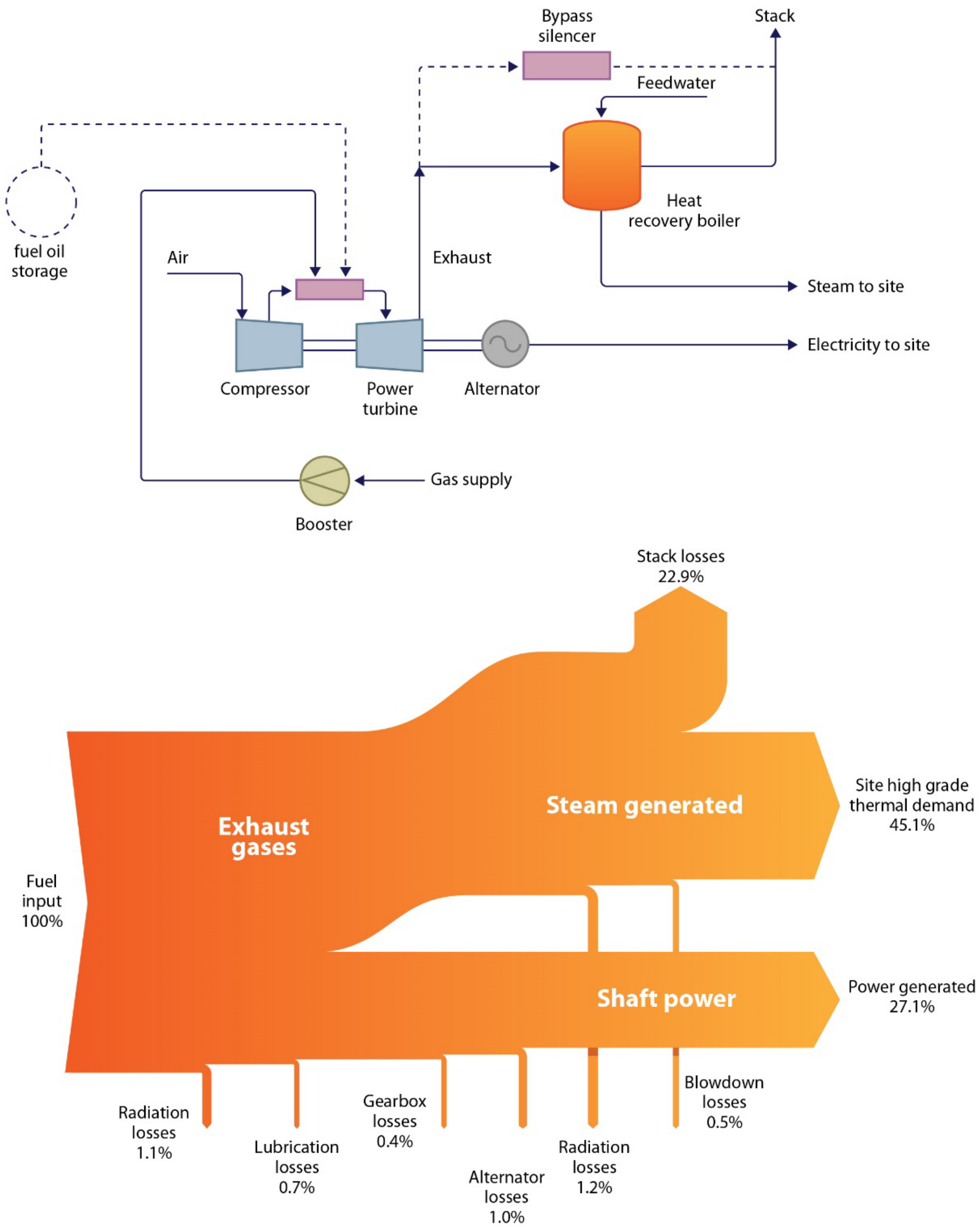


Figure 7: Energy Flow Diagram for a gas turbine CHP

Gas Turbine Development

Gas turbine development has traditionally served two distinct applications – aero and industrial:

The aero engine demands the maximum power-to-weight ratio, rapid speed variation, a rapid on/off facility to suit intermittent use, and fast servicing and repair. These demands are met by using special and costly materials for operation at temperatures of around 1,200°C, plus enhanced technical sophistication generally, together with modular construction to simplify servicing/repair.

Industrial gas turbines are heavier and more robust, and operate at lower inlet temperatures of about 900°C (combustion chamber temperature). They use cheaper and more conventional materials, operate at constant speed and run continuously for long periods between maintenance shutdowns.

The need for improved efficiency has prompted the increasing adoption of aero-derivative machines and technology for industrial gas turbine applications, and differences between the two types of machine are diminishing.

Gas Turbine Performance

The generation efficiency (the proportion of energy in the gas turbine fuel converted to electrical output at the generator terminals) can range from 20% to 35% (Gross basis), depending on the inlet temperature and pressure and any power-enhancing facilities employed. About 30% (Gross) is typical in practice. Gas turbines, however, need to be operated at or near their full rated output: the efficiency of smaller, single-shaft machines deteriorates markedly when operated below full rated output, although the larger twin-shaft units have a better part-load performance.

Gas turbines are available in a wide range of power outputs, from less than 1 MW to more than 200 MW.

However, it is not common in the current energy market to find cost-effective CHP applications for turbines of less than 5 MW. Turbine efficiency in the 1-5 MW range is lower than for larger machines – often below 25% – and, in comparison with larger turbines, the cost of supplying and installing smaller units does not fall pro rata with output. Micro turbines, in the 50-250 kW range are now being developed and are available as CHP units.

A gas turbine has to take in more air than is required solely for the combustion of its fuel. The presence of this excess air means that the exhaust gases contain sufficient residual oxygen for extra fuel to be burned in the exhaust stream before it enters the heat recovery unit. ‘Supplementary firing’, as this is called, can have significant benefits in terms of fuel efficiency and plant operation. It can raise the overall heat to power ratio to 5:1 and offers valuable flexibility in meeting variable heat loads. It also enables the flue gas temperature to be raised to suit higher-temperature applications.

There are several other ways of increasing the power output and efficiency of gas turbines. The most significant are the addition of intercoolers, re-heaters and regenerators. The first two improve the efficiency of the compressor and power turbines respectively, but require them to be split into two stages. The third reduces the primary fuel consumption but restricts the amount of heat available for site use.

Steam or water injection can also be used to enhance power output, although this does cause a minor reduction in CHP efficiency. High-pressure, high-quality steam is required for steam injection and, consequently, this practice is more commonly encountered on the larger machines. Water injected into a gas turbine must be of very high purity to avoid the risk of damage to the equipment. Injecting either water or steam can be used as an emissions reduction technique.

The use of machines incorporating any or all of these arrangements depends on the trade-off between increased complexity/capital cost and the benefits that can be realised.

Gas Turbine Installation Issues

In a power generation application, a turbine is typically mounted on the same sub-base as the alternator, with a step-down gearbox between the two to reduce the high shaft speed of the turbine to that of the alternator. A suitable foundation is required for the sub-base. Gas turbines are extremely noisy and are generally housed in an acoustic enclosure, which is usually located in a factory-type building to provide weatherproofing and further noise attenuation. Enclosures are fitted with fire and gas detection systems and have a system for fire suppression. The enclosure is ventilated with ambient air, and the intake ducting is fitted both with filters to remove dust and with a silencer to minimise noise.

Gas turbines have inherent high reliability and a minimal running maintenance requirement. Shutdown maintenance is required at extended intervals and is usually carried out by the manufacturer on a contract basis. Overall, an availability of about 95% can be expected.

Gas Turbine Pro & Cons

The advantages and disadvantages of the gas turbine are summarised below.

Table 3-3 Advantages and disadvantages of gas turbines

Advantages	Disadvantages
Potential operational flexibility in heat to power ratio using supplementary firing. High reliability permitting long-term unattended operation. Provision of high-grade heat. Constant high speed enabling close frequency control of electrical output. High power-to-weight ratio. Low cooling water requirement. Low foundation loads.	Limited number of units available in a given output range. Lower electrical efficiency than reciprocating engines. Requires high-pressure supply or on-site boosters for gas firing. High noise levels, but mitigated by acoustic enclosure. Poor efficiency at low loading.

3.2.2 Reciprocating Engines

The reciprocating engines used in CHP systems are internal combustion engines that operate on the same principles as their petrol and diesel automotive counterparts. They are efficient and can achieve long-term availability levels of 85-92%, depending on how hard the engine is worked.

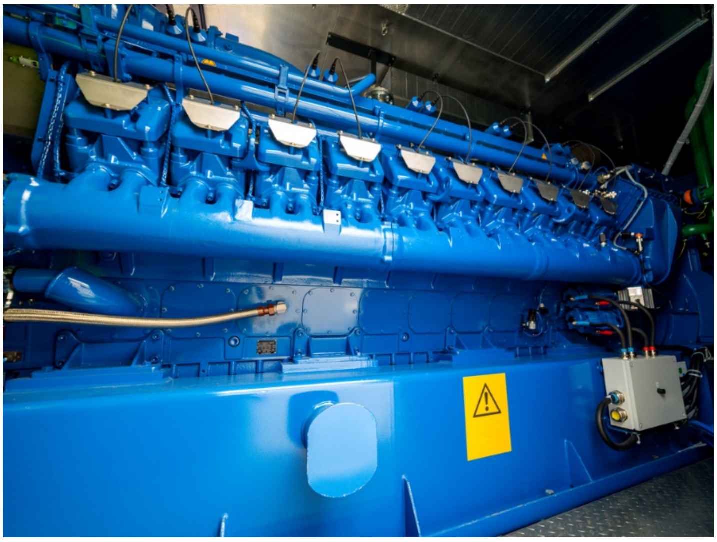


Figure 8: A reciprocating engine

Heat produced by the engine can be recovered from two sources:

- The engine exhaust – gases at a temperature of about 400°C.
- The engine and lubricating oil cooling systems – hot water typically at 80°C.

There are two types of reciprocating engine used in CHP systems:

- Spark-ignition gas engines are available at outputs of up to around 4MW, and operate on gaseous fuel only.
- Compression-ignition ('diesel') engines are available at power outputs of up to 15MW and can be designed to operate on gas-oil, heavy fuel oil or a mixture of gas (up to 95%) and oil (5%).

The reciprocating engines used in CHP systems are internal combustion engines that operate on the same familiar principles as their automotive engine counterparts. Their efficiency is inherently better than that of gas turbines, and there is very little drop in engine efficiency when operated at part load. The usable heat to power ratio ranges from about 1:1 to 2:1 and, as the exhaust can contain large amounts of excess air, supplementary firing is sometimes feasible, which could raise the ratio to 5:1.

Engines and their lubricating oil must be cooled and there is, therefore, a 'compulsory' supply of heat in the form of hot water at up to 120°C.This is produced irrespective of whether or not it can be used. Exhaust heat, on the other hand, is available at temperatures of up to about

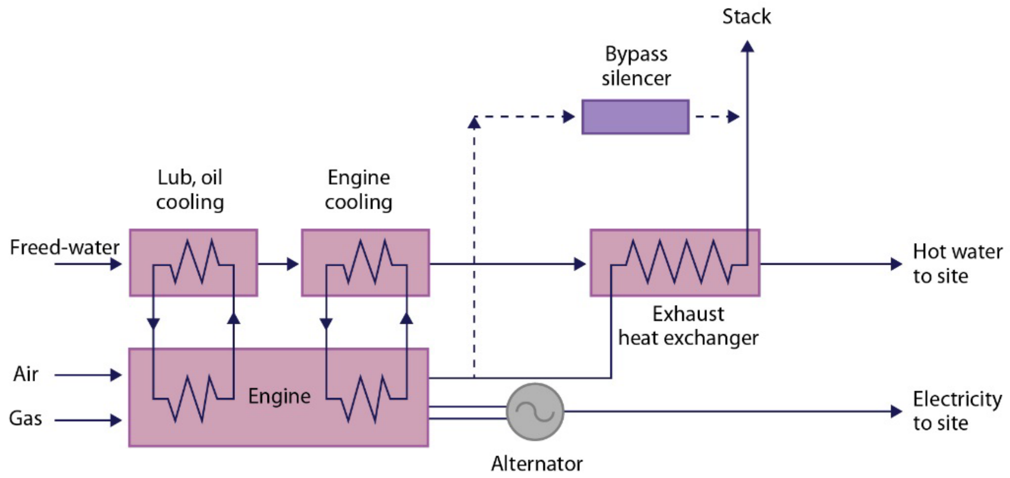
400°C. Cooling and exhaust heat comprise roughly equal proportions of the total heat produced by the engine.

There are two types of engine, classified by their method of ignition as spark ignition gas engines or compression ignition gas engines. It is worthwhile considering the installation & maintenance of reciprocating engines.

Spark-ignition Gas-engines

Spark-ignition gas-engines are virtually all derivatives of their diesel engine equivalents. They generally offer a lower capital cost per kW than a compression-ignition engine, although shaft efficiency is also lower at up to 35%. A wide range of engine sizes is available, up to a maximum of around 4 MW. The engine cooling system typically delivers temperatures in the range 70-80°C, although temperatures of up to 110°C can be achieved.

Spark-ignition engines give up less heat to the exhaust gases (and correspondingly more to the cooling system) than diesel engines and they operate with less excess air. As a result, supplementary firing is rare. Where engines operate at high jacket and exhaust temperatures; this extends the scope for on-site use of the recovered heat but reduces overall levels of efficiency. Spark-ignition engines are suited to smaller and simpler CHP installations, often with cooling and exhaust heat recovery combined to provide low-pressure steam or medium/low temperature hot water to site.



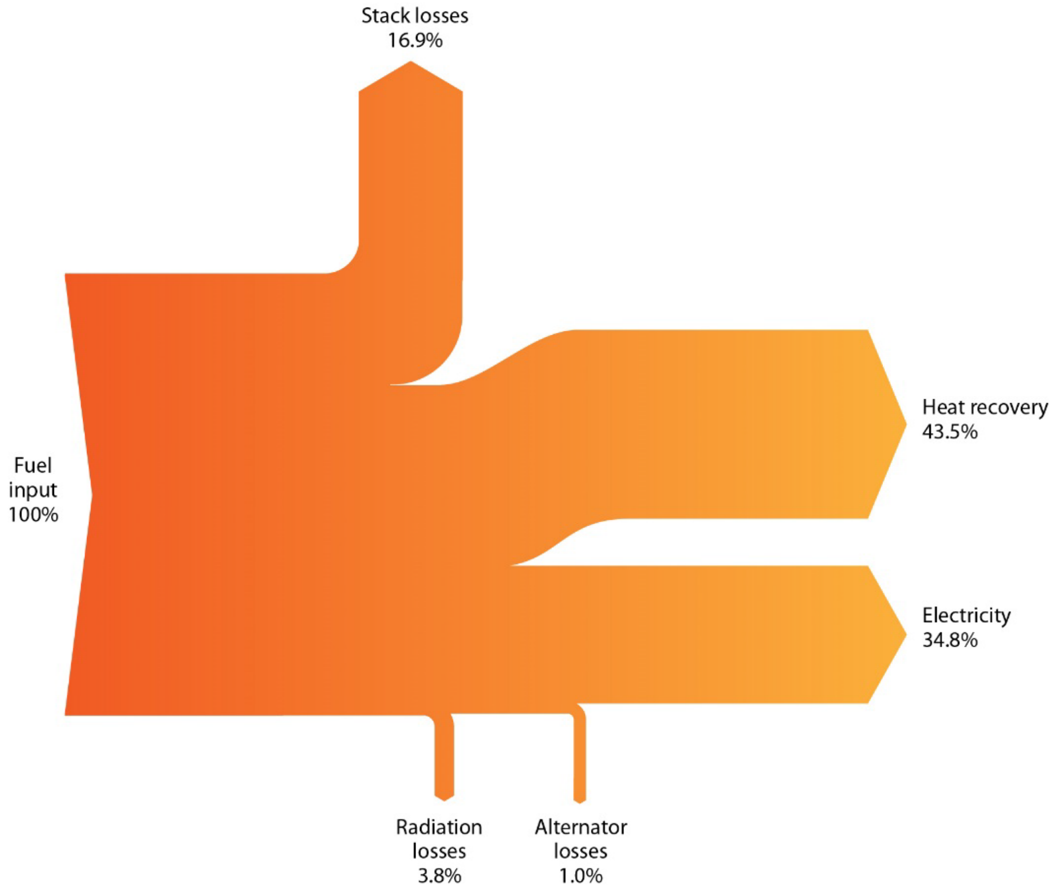


Figure 9: Energy flow diagram for a CHP Engine with heat exchanger

Compression-ignition Engines

Compression-ignition ('diesel') engines for large-scale CHP are predominantly four-stroke, direct-injection machines fitted with turbochargers and intercoolers. Diesel engines will accept gas-oil and can also be designed to operate on heavy residual fuel oils and natural gas. Operation on natural gas is, in reality, a dual-fuel mode, as a small quantity of oil (about 5% of the total heat input) has to be injected with the gas to ensure ignition. As this engine can also run at full output on oil as an alternative fuel, it is suited to the interruptible gas tariff. Shaft efficiencies are 35-45%, and the output range is from 1 MW up to 15 MW. Cooling systems are more complex than on spark-ignition engines, and temperatures are lower (typically 85°C maximum), thereby limiting the scope for heat recovery. Exhaust excess air levels are high and supplementary firing is practicable.

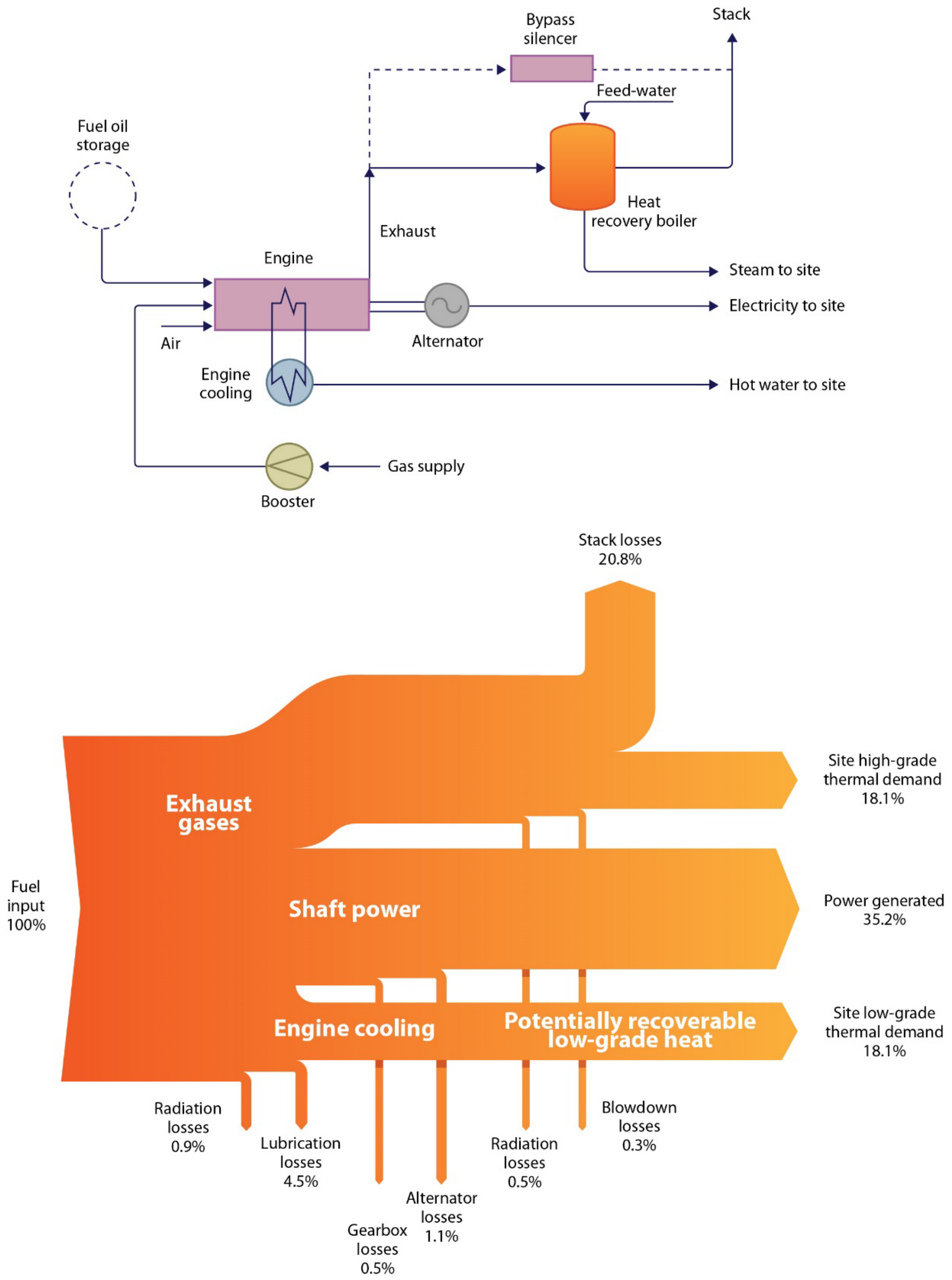


Figure 10: Energy flow diagram for a CHP engine with Heat Recovery Boiler

Compression-ignition engines run at speeds up to 1,500 rev/min. In general, engines up to about 2 MW CHP engine and its energy balance (GCV) are derivatives of the original automotive diesels, operate on gas-oil and run at the upper end of the speed range. Above 2 MW, they evolved from marine diesels and are dual-fuel or residual oil machines running at medium to low speed.

Installation & Maintenance

All but the largest reciprocating engines are generally supplied with the engine and alternator mounted on a single steel framework, but with the heat recovery and other auxiliary systems located elsewhere, according to site requirements. These engines produce more vibration than gas turbines, and require supports and systems to suppress the effect of vibrations on their foundations. Such systems include spring or flexible mountings, and pneumatic supports, which effectively transmit only the dead-weight load onto the foundations. The noise from reciprocating engines is lower frequency than that from gas turbines and can be more difficult to attenuate. Very large engines are rarely enclosed in acoustic enclosures, but their turbochargers may be.

Reciprocating machines such as engines have more moving parts, some of which wear more rapidly than components in purely rotating machines such as gas turbines. Engines may also require some maintenance to be carried out during operation. Regular shutdowns for maintenance and servicing are also required. These can be carried out by the supplier or by other specialists. Maintenance is required at more frequent intervals than for gas turbines, although 85-92% availability is typical. Reciprocating engines consume lubricating oil in moderate quantities.

The relative advantages and disadvantages of reciprocating engine prime movers are summarised below.

Table 3-4 : Advantages and disadvantages of the reciprocating engine prime mover

Advantages	Disadvantages
High power efficiency, achievable over a wide load range. Wide range of unit sizes. Can be conveniently installed as multiple units for larger installations or for the efficient handling of variable (e.g. seasonal) demands	Must be cooled, even if the heat recovered is not re-usable. A large proportion of the heat output is low- or medium-grade heat from the jacket and lubrication oil cooling. Low power to weight ratio. Requires acoustic enclosure. Great care required to prevent vibration and noise transmission through subsoil and structures. Exhaust emissions are relatively high.

3.2.3 Steam Turbines

The steam turbine is an important CHP option because it can use the energy derived from any fuel – solid, liquid or gaseous. The fuel is burned in a boiler, and the resulting high-pressure steam is then ‘let down’ through the turbine, generating electricity and providing lower pressure steam or hot water for site use. Steam turbine CHP is very reliable, and turbines can achieve a long-term availability of up to 99%. Units are available with power outputs of 0.5MW upwards.

Figure 11: A steam turbine

Custom CHP

Steam turbine CHP is usually the technology of choice when a cheap, non-premium fuel (e.g. waste material) is available that can only be used once the energy it contains has been released and turned into steam. It is also particularly suited to sites where the heat requirement is high in relation to the power demand. The number of such sites is declining as the use of electricity increases. However, steam turbines can be used in conjunction with a gas turbine to increase the total output of electricity. In these ‘combined cycle’ applications, high-grade exhaust heat from the gas turbine is fed to a heat recovery boiler, and the steam produced is passed to a steam turbine to generate additional electricity. The lower pressure steam from the steam turbine is then available for site use.

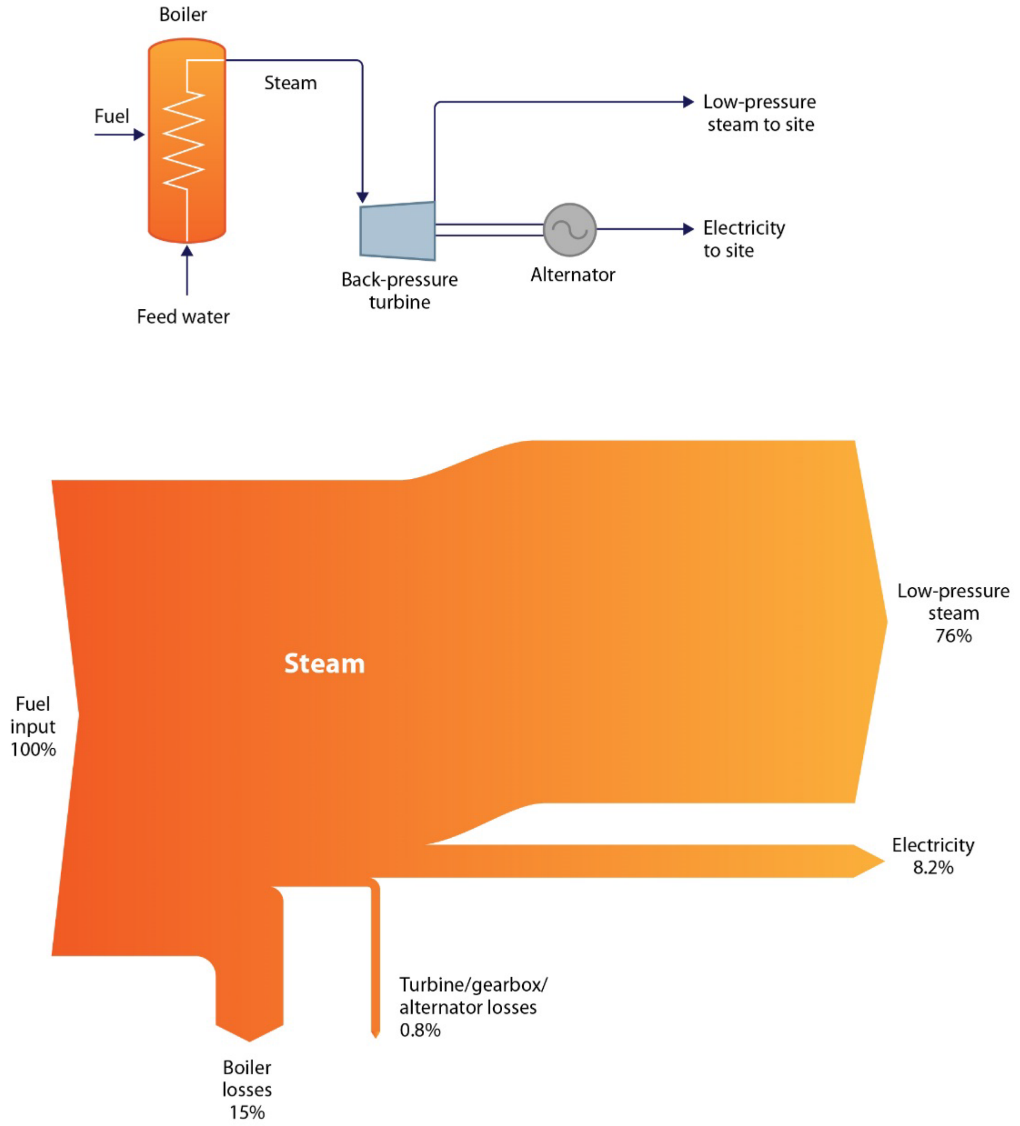


Figure 12: Energy flow diagram for a steam turbine CHP

In the steam turbine, one or more sets of blades attached to the turbine rotor are driven round by steam as it expands from high to lower pressure. The power produced depends on how far the steam pressure can be reduced through the turbine before being extracted to meet other site heat energy needs. The simplest arrangement is the back-pressure turbine, where all the steam flows through the machine and is exhausted from the turbine at the pressure required by the 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. The rest of the steam continues to the exhaust, thereby generating further power, and exits to the process at the lower pressure. Power output may be maximised by expanding the steam down to a vacuum using a condenser and ejectors to maintain the vacuum. This produces heat at such a low grade that it is not generally useful thereafter. Steam turbine sets are designated by their operating mode(s), e.g. back-pressure, pass-out/back-pressure, condensing and pass-out/condensing.

Steam turbine CHP only produces significant amounts of power when the steam input is at high pressure/temperature and the heat output is relatively low-grade. In order to maximise the power generation, higher steam pressures are frequently selected, increasing both the capital costs of the steam boiler and plant running costs. The optimum choice is a compromise between output and costs that reflects plant size and the pass-out/backpressures required.

Steam-turbine CHP has more limited applications than gas turbine and engine-based systems. For new applications, steam turbines are usually the technology of choice when a very cheap, low-premium fuel not suitable for internal combustion engines is available. It is, in fact, the only electrical generator option that can use the energy derived from any fuel or from by-product process heat (e.g. the steam generated in heat recovery boilers – particularly in the chemicals industry).

The ratio of usable heat to power in a steam turbine CHP set is unlikely to be less than 3:1 and may be 10:1 or more. This plus the increasing use of electricity by industry, has restricted steam turbine CHP applications.

Despite these apparent disadvantages, steam turbines share many of the attributes of gas turbines, notably reliability, high speed, no great out-of-balance forces to impose undue foundation requirements etc. The level of noise produced is not as high as with gas turbines. Steam turbines are usually housed in turbine houses adjacent to boiler-houses.

There is no ‘typical’ steam turbine CHP set, as each is very specific to its site conditions.

Combined Cycle

Combined cycle systems are usually applied to gas turbine sets, as these produce the highest grade heat. This heat allows steam to be generated at a pressure that is high enough to optimise steam turbine power while still providing the site with low-pressure steam or its equivalent in the form of hot water.

Combined cycles of this type convert 40% or more of the original fuel energy into electricity and, if supplementary firing is also employed, provide the most flexible CHP systems currently available. The application of combined cycle technology is particularly suited to sites that require both low- and high-pressure steam, as the latter will dictate the selection of a high-pressure boiler plant regardless of the CHP plant. The illustration shows a typical combined cycle plant in schematic and Sankey diagram form.

Custom CHP

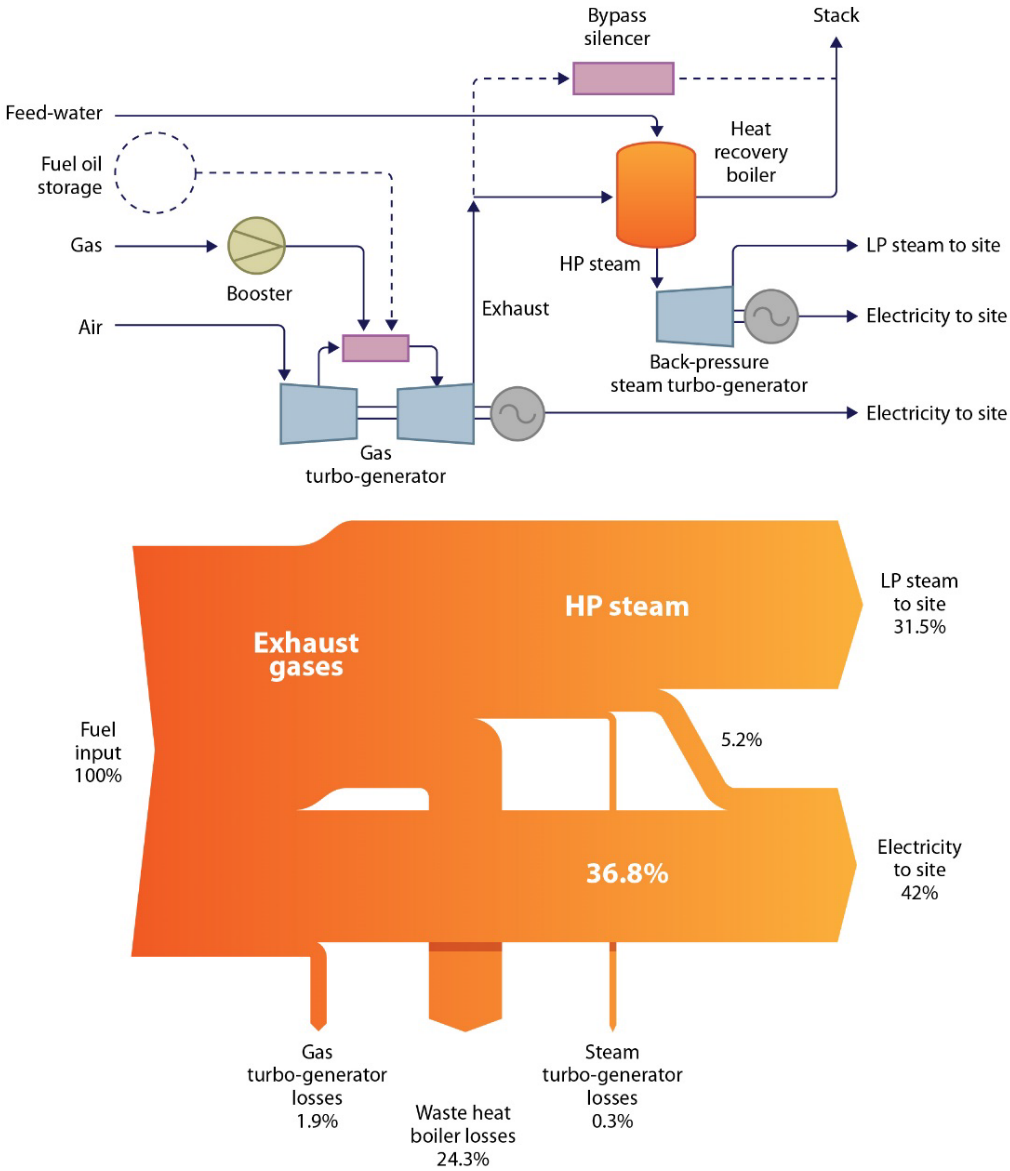


Figure 13: Energy Flow diagram for a combined cycle gas turbine CHP

The steam turbine is an important CHP option because it can use the energy derived from any fuel – solid, liquid or gaseous. The fuel is burned in a boiler, and the resulting high-pressure steam is then ‘let down’ through the turbine, generating electricity and providing lower pressure steam or hot water for site use. Steam turbine CHP is very reliable, and turbines can achieve a long-term availability of up to 99%. Units are available with power outputs of 0.5 MW upwards.

Steam turbine CHP is usually the technology of choice when a cheap, non-premium fuel (e.g. waste material) is available that can only be used once the energy it contains has been released and turned into steam. It is also particularly suited to sites where the heat requirement is high in relation to the power demand. The number of such sites is declining as the use of electricity increases. However, steam turbines can be used in conjunction with a gas turbine to increase the total output of electricity. In these ‘combined cycle’ applications, high-grade exhaust heat from the gas turbine is fed to a heat recovery boiler, and the steam produced is passed to a steam turbine to generate additional electricity. The lower pressure steam from the steam turbine is then available for site use.

Gas turbine exhaust gases provide a high-grade heat output that can be used either directly or indirectly (usually as steam) in processes with a demand for high-temperature heat. On sites where there is no requirement for high-grade heat, or where additional electricity would have a greater value, the steam generated from the exhaust gases may be passed to a steam turbine to generate additional electricity. This arrangement is known as a combined cycle.

3.2.4 Prime Mover/Electrical Generator Reliability and Availability

Prime mover/electrical generator reliability and availability are factors of extreme importance. CHP plant must be able to operate over extended periods and, in many cases, virtually continuously, to achieve the maximum economic returns. In practice, any prime mover/electrical generator requires maintenance, and this necessitates a scheduled shutdown at least once a year. However, it is the equipment's susceptibility to additional, unscheduled stoppages that determines its reliability and actual availability over a given period of time.

The distinction between reliability and availability is often blurred, and manufacturers' specifications and guarantees should be scrutinised carefully to ensure a true understanding. The time period used is typically a year of 8,760 hours. The formulae illustrate one method of making the calculations:

% Reliability = T - (S + U)/ T - S x 100

% Availability = T - (S + U)/ T x 100

where:

S = scheduled maintenance shutdown (hours/year)

U = unscheduled shutdown (hours/year)

T = period when plant is required to be in service or available for service (hours/year).

Typical manufacturers' guaranteed figures for a compression-ignition engine burning heavy fuel oil are:

Maximum scheduled outage (S) 876 hours per year (8,760 hours).

Maximum unscheduled outage (U) 438 hours per year (8,760 hours)

Using the formulae given: 8,760 - (876 + 438)/ 8,760 - 876 x 100Guaranteed reliability = 94.4%

Guaranteed availability = 8,760 - (876 + 438)/ 8,760 x 100 = 85.0%

Reliability and availability vary for different types of prime mover/electrical generator:

- For gas turbine CHP schemes operating continuously at optimum efficiency, long-term availability levels in the 94-98% range have been achieved1.
- Steam turbines can confidently be expected to have availabilities of up to 99%.
- For reciprocating engines, it is realistic to expect availabilities in the 85-92% range, depending to some extent on the operation of the site and how hard the engine is worked. (N.B. An engine pushed close to its limit is likely to need significantly more maintenance).

3.2.5 Prime Movers Summary

The following table provides a summary of the main CHP prime movers and electrical generators.

Table 3-5: Summary of prime mover / electrical generator characteristics

	Typical output range	Typical fuels	Typical heat to power ratio	Grade of heat output
Gas turbine	0.5 MW upwards	Natural gas, gas-oil, landfill gas, biogas or mine gas	1.6:1, up to 5:1 with supplementary firing	High
Compression-ignition engine	2 MW upwards	Natural gas + 5% gas-oil, heavy fuel oil	1:1 - 1.5:1, up to 2.5:1 with supplementary firing	Low and high
Gas engine	Up to 4 MW	Natural gas, landfill gas, biogas, mine gas	1:1 - 1.7:1	Low and high
Steam turbine	0.5MW upwards	Any, used to produce steam	3:1 - 10:1	Medium
Combined cycle	10MW	As gas turbine	Down to 0.7:1	Medium

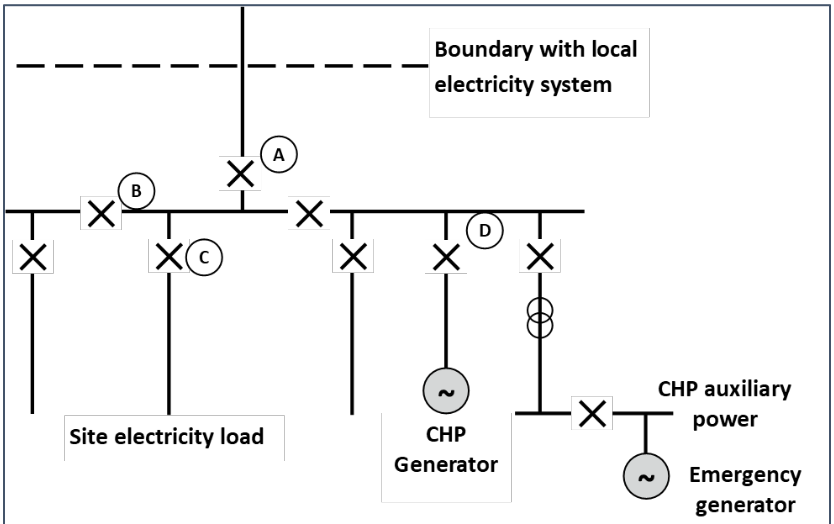
3.3 CHP & External Utilities

While a small number of CHP systems do operate completely independently of the local electricity supply system, the majority operate on sites that maintain a connection to the local system. There are two advantages to this:

- Provided the necessary controls and procedures are in place, the site can draw on the local supply if it needs more electricity than the CHP plant can provide or if the CHP plant is out of action for maintenance or other reasons.
- Power that is surplus to site requirements can be exported to the electricity supply system.

The power generated by a CHP plant is almost always three-phase alternating current at 50 Hz, at voltages ranging from 400 to 11,000 volts – occasionally even higher. Selection of the voltage for power generation is determined by two main factors:

- The voltage at which the site is connected to the external grid, and at which power is distributed around the site.
- The selected power output of the CHP generator, which places practical and cost limitations on the size and rating of installed equipment and cable.



In normal Parallel Mode all circuit breakers are closed. If the local system fails, the CHP can be operated in Island Mode. Breaker A is opened and the CHP plant feeds the site load, which can be limited by opening Breaker B, or Breakers B and C.

When the local system is restored, the CHP plant is synchronised with the local system, and Breaker A is then closed to restore Parallel Mode. Breakers B and C are then closed to restore full supply to the site.

If the failure of the local system trips the CHP generator, it can be restarted using power supplied from the emergency generator to the CHP auxiliary power system.

Figure 14 - Circuit Breaker Schematic

3.3.1 Natural Gas Supplies

Natural gas is the most common fuel for CHP plants: this is a reflection of its price, availability, wide range of applications and the lower environmental impact of its exhaust gases.

The supply of natural gas to a user is by pipeline from the national distribution network, much of which is owned and operated by National Grid Gas plc. The gas is put into the system at its connections with the onshore and offshore sources by a number of gas providers or 'shippers'; they provide gas to the user and pay National Grid Gas plc or another pipeline operator for use of the distribution system.

The installation of a gas-fired CHP plant almost always increases the site's consumption of gas, as the new plant generates both heat and power and usually operates for a large proportion of the year. As well as the increase in total annual gas consumption, the maximum rate of consumption usually increases, and this often requires the uprating of an existing site gas connection. In addition, the gas supply pressure required for operating a gas turbine or a gas engine is often higher than the existing site supply pressure, necessitating the use of pressure-boosting equipment.

Any modifications to the site's gas supply connection need to be discussed with the pipeline operator (usually National Grid Gas plc), and there are a number of key issues that need to be defined in considering a new gas connection:

The anticipated annual gas consumption, which is a function of the CHP plant's average fuel consumption and the anticipated number of running hours, must be identified. It is also important to remember that many suppliers quote the fuel consumption of their plant as NCV, while the consumption data supplied for gas connection assessment must be given as GCV.

The anticipated maximum rate of gas consumption, usually expressed in MW or in therms per hour, must be defined. Normally, gas turbines will consume more fuel, and generate more power, at lower ambient air temperatures, so the value given must reflect the maximum hourly consumption. Again, the data must be quoted as GCV.

The supply pressure stipulated should reflect the requirements of the selected prime mover. It is always more cost-effective to have gas supplied at as high a pressure as possible: pressure boosting equipment such as a fuel gas compressor consumes significant quantities of electrical power.

The potential routing for new supply pipework, together with the location of metering and pressure-regulating equipment must be determined. The general preference is for the metering and regulating equipment to be close to the site boundary, so that the pipework beneath the public highway is owned by the pipeline operator, while pipework on the site is the responsibility of the CHP plant installer and owner.

When adding a CHP plant, it is important to take into consideration the site's likely future gas requirements, both as a whole and for each individual area of consumption. Some parts of the site – for example, process plant, office heating and catering services – may need their gas supplies to be on a 'firm' tariff basis. Other supplies, such as those for a boiler-house area, may well be purchased on an 'interruptible' tariff basis where the plant has the capability to operate on an alternative fuel such as gas-oil. A CHP plant is often associated with the boiler-house area of a site, and can sometimes share an existing gas supply connection. However, gas supplies on different tariffs often come from different supply pipework at different pressures.

In some cases, it may be simpler and more effective to install a separate new gas supply to a CHP plant, without making any alteration to the existing system. This has the advantage of avoiding disruption to other site functions, and it may allow the new gas supply to the CHP plant to be provided at a higher pressure to match the requirements of the prime mover.

A new gas connection to the site can be provided either by National Grid Gas plc or by other companies offering the necessary specialist services. The metering and regulating equipment will usually incorporate safety shut-off valves, together with vents designed for the safe release of trapped gas in the event of a problem with the system. The design and installation of the pipework, valves etc. are required to meet appropriate standards and specifications. It is important to ensure that the pipework routing is marked clearly on the site drawings, and it is usual to install markers on the surface to help confirm pipework location. Once installed, the connection and pipework require little or no maintenance or attention, apart from routine checks.

3.3.2 Coal & Oil Supplies

For CHP plants operating on coal or oil, the technical issues relating to the provision of fuel are mainly those of delivery, handling and storage. Deliveries by road or rail are off-loaded into site storage facilities from where they are delivered to the CHP plant. There are specialist engineering requirements for the handling and storage of both coal and oil, which must be taken into consideration. In particular, provision must be made to minimise the risks of fire, spillage or escape, and to contain such problems when they do arise, thereby preventing dangerous incidents or environmental damage. The quantities stored should be determined on the basis of the need to maintain site energy provisions in the event of a supply disruption caused by the weather, shortages, or other events.

3.3.3 Parallel Mode Operation

Parallel Mode operation occurs in almost all CHP plants in the UK, since the ability to have top-up and back-up power is regarded as an essential facility to ensure security of site power supplies. The alternative is to incorporate sufficient plant to provide the required level of supply security without the availability of the local area supply system. This usually requires the addition of a significant amount of stand-by plant that is rarely used, with its associated installation and maintenance costs.

For a CHP plant to be able to supply its power output to the site, it is usually connected to the site electrical system in such a way that it can operate in conjunction with the local area electricity supply system. This is achieved by having the electrical switchgear connections between the CHP plant, the site and the local area system all closed, with the CHP plant and the local area system operating electrically locked together. This is known as ‘Parallel Mode’ operation, and it has a number of operational benefits:

- The local area supply system to which the site is connected can provide any site power demands that are in excess of the net power output of the CHP plant: this is known as ‘top-up’ power.
- The local area supply system can instantaneously meet the total site demand in the event of the CHP plant shutting down suddenly: this is known as ‘back-up’ or ‘stand-by’ power. Back-up is normally achieved without any loss of site power supply.
- Power can be passed from the site into the local area supply system if the net output from the CHP plant exceeds the site demand: this is known as ‘export’ power. This facility requires special metering facilities to be incorporated in the connection between the site and the local area system.

If a CHP system is to operate in Parallel Mode, there are certain important features that must be incorporated in the design of both the CHP plant and the site electrical system:

- The CHP generator(s) must be equipped with synchronising equipment, so that the phasing of power from the alternator can be matched with that of the local supply system before it is connected to that system by closing the switchgear. Connecting the generator in an unsynchronised situation may cause serious and expensive damage to electrical equipment, as well as causing a prolonged period without power supplies.
- The generator, and the switchgear through which the site is connected to the local supply system, must be equipped with suitable protection equipment, so that the generator is automatically and instantaneously disconnected in the event of any system instability. This protection equipment typically monitors conditions such as voltages, peak currents and the positions of automatic switches and circuit breakers.
- The combined equipment of the site and the generator must not be capable of causing excessively high peak currents in the event of a major system fault, such as accidental damage to cabling or switchgear. If the anticipated peak currents are in excess of the capacity of the switchgear and other equipment in the local area supply system, the CHP plant may need special design and operating procedures to overcome this situation. There are many CHP installations at which this has been accomplished successfully.

The technical requirements that must be met if a CHP plant is to be operated in parallel with the local area supply system will be defined by the distribution network operator (DNO) that owns and operates the system. These requirements will depend on the design and operating characteristics of both the local area system and the CHP plant, and are designed to protect equipment on either side of the connecting point from the effects of a fault occurring on the other side.

3.3.4 Island Mode Operation

A few CHP plants are installed without an electrical connection to an external electricity system, often as a result of the site's location or special circumstances. These sites operate in 'Island Mode'. They have the benefit of avoiding the costs of installing external site connections, but they have to manage their provision and consumption of power with no top-up or backup supplies. This usually requires a high level of installed plant capacity to ensure power availability at all times.

However, many of the sites that operate CHP plants in Parallel Mode also have the facility to operate in Island Mode. This provides them with the particularly useful capability of providing power to the site when the local area electricity system has suffered a supply failure. Some sites consider that their CHP plant avoids the need to install back-up power provisions for emergency use.

If a period of Island Mode operation is planned, it is relatively simple to ensure that the site demand is set at a level that does not exceed the net power output of the CHP plant. Once this is established, the connection to the local area system is disconnected by opening the circuit breaker(s).The site can then operate in Island Mode, with the CHP output modulating to meet site demand.

The change from Parallel to Island Mode may occur instantaneously when the local area supply system suffers an outage. In this situation, it should be possible for the CHP plant to continue supplying the site load without interruption, on condition that the site load can be immediately limited to the output level of the CHP plant. This is usually achieved using load monitoring and control equipment, which can automatically disconnect selected parts of the site load. If this load limitation cannot be achieved, the CHP plant will usually shut down when there is a failure in the local area system with which it is operating in parallel. The site will then lose all power supplies.

However, as long as the site system has facilities to disconnect selected supply circuits within the site, the CHP plant can quickly be restarted to provide site power up to its maximum output level. This usually requires prompt action by the site electrical engineering staff in operating circuit breakers according to a prepared procedure. It is also necessary for the CHP plant to be equipped with a back-up power source to enable it to be restarted in the absence of any external power source. This backup will usually comprise a small stand-by diesel generator. If the site has other stand-by generation facilities, power can be made available from these sources to restart the CHP plant.

3.3.5 Electrical System Stability

A vital characteristic of any power system is its ability to maintain 'stability', that is to remain in full operation when disturbed by conditions such as load changes and system faults. An initial stability study is an important part of the detailed feasibility study, but a further study is usually required as part of the project design. This study must take into account any system design features that arise from the requirements of Parallel Mode operation. It must also be based on the actual electrical characteristics of the chosen CHP plant and its associated electrical systems.

The study should include a detailed analysis of network equipment, operational sequences, load flows, fault levels etc. It may conclude that specific design requirements and operational constraints will need to be incorporated in the CHP plant. It may also identify modifications to the local area supply system that need to be carried out. Although these modifications will be carried out by the distribution network operator (DNO), the costs of the work will need to be met as part of the CHP installation cost.

3.4 Boilers & Heat Recovery

The essence of successful CHP is the beneficial use of the heat produced as a by-product of generating electricity. This heat is contained in the exhaust gases from a prime mover, or in the cooling systems.

In the most straightforward cases, the heat from the prime mover is used directly, without conversion to steam or hot water. Examples include the use of exhaust gases for drying, or the use of hot water from cooling systems for heating purposes. However, the direct use of exhaust gases involves contact with the material to be heated, which may cause damage to the product, particularly where non-premium fuels are being used. Similarly, while engine cooling water can, in theory, be used directly in applications such as space heating, it is desirable in practice for the cooling circuits to be self-contained and to include additives to avoid scaling and corrosion. Heat from the engine cooling water is, therefore, transferred by heat exchangers to separate heating water circuits.

In the majority of CHP plants, it is effective heat recovery that is the essence of success. In most instances, some form of heat recovery equipment is needed to convert the heat generated by the prime mover into the form or forms required by the site, and to deliver it to the heat users. By far the most common heat recovery methods used are steam generation from gas turbine and engine exhaust gases, and water heating from medium- and low-grade heat sources, such as engine exhausts and cooling systems.

3.4.1 Heat Recovery Boilers

The term ‘boiler’ is widely used throughout the engineering industry for all equipment that produces steam or hot water, even though the water in a hot water ‘boiler’ does not actually boil.

The boiler is an essential component of any industrial CHP installation. It recovers heat from the exhaust gases of either a gas turbine or a reciprocating engine and, in its simplest form, is a heat exchanger through which the exhaust gases pass and in which heat is transferred to the boiler feed-water to raise steam. The cooled gases then pass to the exhaust pipe or chimney and are discharged into the atmosphere. This form of heat recovery does not change the composition or constituents of the exhaust gases from the prime mover.

The exhaust gases discharged from gas turbines and reciprocating engines contain significant quantities of heat and typical examples are shown in the following table. However, not all of this heat can be recovered in a boiler.

Table 3-6: Typical heat content of exhaust gases

	Gas turbine	Reciprocating engine
% of energy input contained in exhaust gases	60-70	35-40
Exhaust gas temperature	450-550°C	300-450°C

There are several factors that prevent total heat recovery:

- For effective heat transfer to take place, 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 which contain some sulphur, as the sulphur oxides produced can be condensed into sulphuric acid below certain temperatures.
- The latent heat of the water vapour in the exhaust gases can be recovered only 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.
- Steam boilers contain sections in which different stages of the steam-raising process are carried out. The main section of the boiler is the evaporator section where the heat from the exhaust gases turns water into steam. Many boilers also have an economiser section, in which the feed-water is preheated by extracting as much heat as possible from the exhaust gases before they are discharged. Furthermore, some boilers have a super-heater section to increase the steam temperature to meet individual site requirements.

Boilers that heat pressurised hot water usually consist of a single section, in which the tubes containing the combustion gases are contained in a boiler shell which is completely filled with the water to be heated.

The type of boiler used is determined largely by the required temperature and pressure of the steam or water produced. The most frequently used design is a fire-tube or shell boiler in which the hot exhaust gases pass through a bank of tubes fitted within the main body of the boiler. Finned tubes may sometimes be used to extend the heat exchange surface area, thereby improving efficiency and minimising unit size. The boiler contains the fluid to be heated and operates marginally above the required pressure of that fluid. This type of boiler is generally limited to a maximum pressure of 25 bar and a maximum temperature of 300°C.There are also practical limits to the design and construction of fire-tube boilers.

Beyond these limits, it is normal to use water-tube units. In this type of boiler, the tubes contain the water and the exhaust gases pass around the tubes and transfer heat inwards from the outer surface of the tubes.

One typical feature of the heat recovery boiler, when compared with a conventional fuel-burning unit, is that its physical size is usually greater for the same boiler output. There are, essentially, two reasons for this:

- 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.
- Heat recovery 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.

3.4.2 Supplementary & Auxiliary Firing

The exhaust gases from a gas turbine or engine contain around 15% oxygen, and this allows supplementary firing to be carried out in the exhaust before it passes into the boiler. Furthermore, because this exhaust is already hot, supplementary firing achieves a higher combustion efficiency than conventional boilers, enabling the same boiler output to be achieved with lower fuel consumption and reduced CO2 emissions. Efficiencies of up to 88% (GCV) can be achieved, which compares well with the 80% efficiency typically associated with natural gas combustion in a conventional boiler.

Because supplementary firing takes place in a low-oxygen gas stream, this form of combustion will often produce significantly lower oxide of nitrogen (NOX) levels than boilers using ambient air. Furthermore, the combined NOX emissions generated by the prime mover and the supplementary firing unit will usually be much lower than those that would arise if both plant items were operated separately.

Supplementary firing is usually carried out using in-duct burners, although conventional boiler burners (register burners) may be used in conjunction with water-tube heat recovery boilers. In the case of reciprocating engine sets, the supplementary firing facilities must be designed to operate satisfactorily with a pulsating exhaust gas flow.

Auxiliary firing involves the provision of an air supply to the supplementary burner in place of the turbine or engine exhaust gases, thereby enabling the boiler to provide heat energy to the site when the CHP generator set is not operating. Thermal efficiency will be lower than for conventionally fired boilers, but this is of marginal significance as long as operation under these conditions represents only a small proportion of total running time. The availability of auxiliary firing can avoid the need for other stand-by boiler plant.

Supplementary and auxiliary firing improve both the overall cost-effectiveness and the flexibility of CHP plant. However, there are restrictions on the extent to which this approach can be used, and these are determined by limitations imposed by the materials or by the construction of the heat recovery boiler. Supplementary/auxiliary firing entails additional capital cost and this, in conjunction with the operating cost savings, has to be compared with the alternative of maintaining conventional boiler plant for heat top-up or stand-by purposes.

Supplementary firing can raise the overall heat to power ratio of a CHP plant to up to 5:1 and offers valuable flexibility in meeting variable heat loads. It also enables the flue gas temperature to be raised to suit higher-temperature applications.

3.4.3 Fluidised Bed Combustion

The use of a fluidised bed allows the combustion of any form of solid fuel, thereby broadening the range of fuels that can be used, particularly for supplementary firing. Fluidised beds also offer the potential for cleaner combustion. It is possible to reduce the level of noxious emissions by adding material that reacts chemically with the NOX and SO2 produced during the combustion process.

A fluidised bed consists of a bed containing sand or fine aggregate, which is kept in a fluidised state by passing air up through the bed. The fuel is burned in the fluidised bed, sometimes with gas or oil, and the resulting hot exhaust gases pass to heat recovery sections of the boiler. This type of system can also use the exhaust gases from a turbine or engine in place of the fluidising air, creating a form of supplementary firing.

The application of fluidised bed combustion to CHP is not common. The technology is not cost-effective for the average size of CHP plant in the UK, and it involves relatively complex design and operation. Furthermore, it is not possible to shut down and start up a fluidised bed within the timescales and with the ease of operation required of most CHP schemes.

3.4.4 Heat Distribution & Heat networks

It is important to consider heat distribution in conjunction with heat recovery, as the distance between the heat user and the CHP plant, and the form in which the heat is required by the user, will influence the design of the CHP plant.

In the case of direct use of the heat from exhaust gases, the ductwork for transporting the exhaust gases is relatively bulky and must be well insulated. Installation costs will limit the distance over which a system of this type can be used. Furthermore, the performance and use of gas turbines and, to a lesser extent, engines is adversely affected by the exhaust system back-pressure, and this also limits the length of exhaust ductwork that can supply a direct heat use.

The same limitations apply to the siting of an exhaust heat recovery boiler, and it is normal for a CHP plant to be located adjacent to an existing central boiler plant – and often integrated within it. The heat recovered from a CHP plant is frequently distributed using the existing systems connected to the central boiler-house, and the existence of an existing system is an important factor in determining CHP plant design and location.

On decentralised sites, where heat uses are widely dispersed, the size and location of the CHP plant are constrained by the available heat demand within the adjacent area. It may be cost-effective to recover heat from a CHP plant and distribute it in a single, thermally efficient form such as steam or thermal oil. However, there is a limit to the distance such systems can cover without the costs of installation and operation becoming prohibitive. On many decentralised sites it may, therefore, be more beneficial to install several CHP units adjacent to the users of the recovered heat, but this does require a fuel distribution system and also the availability of suitable connections to site electrical systems.

3.5 Minimising Emission

All fossil fuel combustion produces carbon dioxide and water vapour in quantities that are a direct function of the carbon and hydrogen content of the fuel consumed. If the fuel contains sulphur, then a corresponding quantity of sulphur dioxide ($SO2$) will be produced.

In addition, the combustion process produces nitrogen oxide (NO) and nitrogen dioxide (NO2), the combination generally being referred to as oxides of nitrogen (NOX). These oxides are created by a high-temperature chemical reaction between the oxygen and nitrogen present in the air. The presence of these oxides in the atmosphere is considered to have harmful effects, and there is a general objective to minimise NOx emissions from all combustion plant, including CHP plant. For larger CHP plants, limits on SO2 and NOX emissions are set by environmental legislation. There are specific sections on minimising spark ignition engine emissions, and exhaust gas emissions treatment.

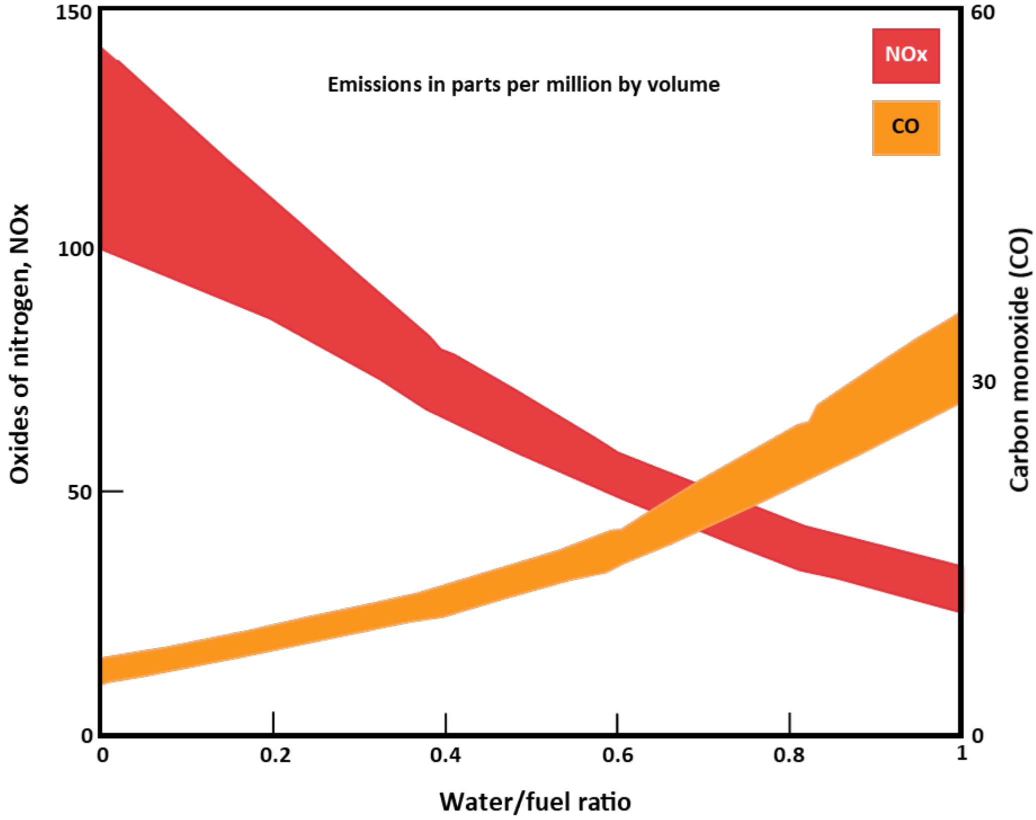


Figure 15 - Emissions of Oxides of Nitrogen (NOx) and Carbon Monoxide (CO)

3.5.1 Suppressing NOx

Various techniques and systems for limiting the production of NOx in combustion systems already exist. The most significant of these is to reduce the average temperature within the combustion zone. Specific information is provided with regard to:

- Gas Turbines
- Compression-ignition engines
- Boilers

Gas Turbines

At present, all gas turbines can be installed and operated to comply with the emissions limits currently required by pollution control legislation

Water or steam injection

Injecting water or steam into the turbine combustion chamber limits NOX formation by reducing the average combustion temperature. The typical rate of steam or water injection is 50-100% of the fuel input rate. Although this procedure has the additional advantage of slightly increasing turbine output, there are disadvantages, notably a minor reduction in CHP system efficiency and a possible increase in carbon monoxide (CO) levels in the exhaust as water or steam levels are increased – the result of partial quenching of the flame.

To avoid turbine damage, the water or steam injected must have a high degree of purity. Even so, injection tends to reduce the life of some of the turbine components and has operating cost implications for the turbine and its associated systems. Gas and gas-oil firing systems can usually incorporate water or steam injection, and virtually all gas turbines can be fitted with this facility.

The equipment needed to treat and inject water or steam into a gas turbine increases the capital cost of a CHP scheme by around 2-3%. Operating costs typically rise by 1-2%.

Low-NOX burners

Low-NOX burners, sometimes known as dry low-NOX (DLN), have been developed for large gas turbines and are now available for the majority of smaller turbines. The burners are designed to operate with a lower-temperature flame to reduce NOX emissions. At present, some of these burners can burn only gaseous fuels in low-NOX mode and have no capability to burn gas-oil as a stand-by fuel. This limits their application on sites that use interruptible gas tariffs and, therefore, have a dual-fuel requirement.

Catalytic control

Current research is seeking to incorporate catalysts into turbine combustion systems but has yet to establish the feasibility, durability and cost-effectiveness of the catalytic control of NOX emissions in gas turbines.

Compression-ignition Engines

The technique currently used to reduce NOX emissions from compression-ignition engines involves adjusting the design and operation of the engine. An engine can be set up to give maximum power output, maximum energy efficiency or minimum NOX emissions, and the configurations vary in terms of factors such as valve and injector timing, compression ratio, cylinder pressure and intercooling. An engine configured for minimum NOX emissions will not necessarily operate at maximum efficiency, and there will, therefore, be a marginal increase in CO2 emissions. Another technique for achieving lower NOX emissions from compression-ignition engines is to use a relatively high level of excess air in the combustion chamber, thereby reducing average combustion temperatures.

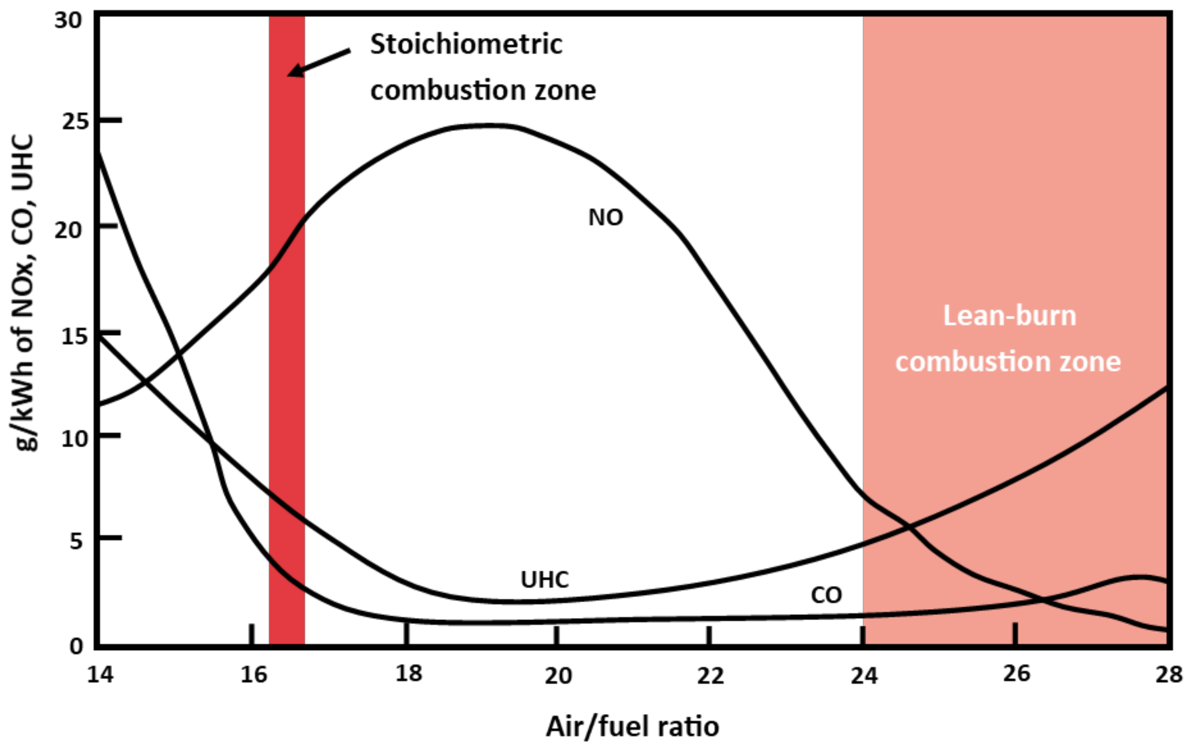


Figure 16 - Emissions at Differing Air-to-Fuel Ratios

Several control techniques are also being researched to reduce NOX emissions, although none of these has yet proved feasible or cost-effective in long-term operation. They include:

- Emulsification of water in liquid fuels.
- The introduction of water spray into the combustion air intake.
- Partial recirculation of cooled exhaust gases into the combustion air.

Boilers

Recent developments in burner design provide a more accurate control of combustion, reducing average temperatures and NOX levels. This has resulted in lower NOX emissions from many industrial boilers, both new and existing.

For CHP plants, the supplementary firing burner has the benefit of a lower oxygen content in the combustion zone and a higher combustion efficiency. This results in lower NOX emissions per unit of energy available. A CHP installation with supplementary firing can, given the correct design and operation, achieve the required emissions limits under all operating conditions.

3.5.2 Minimising Emissions from Spark-ignition Gas Engines

The quantities of nitrogen oxides, carbon monoxide and unburned hydrocarbons (UHC) in a gas engine exhaust are influenced by the quantity of air mixed with the fuel in the engine. If the mixture contains exactly enough air to burn the fuel (in the case of natural gas about 17 parts of air per unit of gas), combustion is stoichiometric and there is no oxygen in the resulting exhaust. Under these conditions, it is possible to add a special catalytic converter to the exhaust system. This ‘three-way catalyst’ converts nitrogen oxides, carbon monoxide and unburned hydrocarbons into water, CO2 and nitrogen, giving a much cleaner and less harmful exhaust.

Another recent development is the ‘lean-burn’ engine, which runs with a high level of excess air (typically about 50%).These engines produce low NOX levels, but emissions of unburned fuel are higher, requiring the use of an ‘oxidation catalyst’ to convert this unburned fuel into carbon dioxide and water.

Catalytic converters have now been developed that allow these new engine types to give cleaner exhausts and lower emissions. These are reliable, affordable and long-lived. A comparison of stoichiometric and lean-burn gas engines is given in Table 3-7.

Table 3-7: Comparison of stoichiometric and lean-burn gas engines

Stochiometric engines	Lean burn engines
Accurate air/fuel control needed for the application of a three-way catalytic converter.	Air/fuel mixing achieved using standard equipment and giving stable air/fuel ratio.
Higher electrical output for the same size of engine.	Higher thermal efficiency giving lower CO2 emissions.
Higher temperatures giving increased wear and higher maintenance costs.	Lower cylinder temperatures giving longer component life and lower maintenance costs.
Increased oil deterioration because of higher nitration rates. Higher NOx output if catalyst not used.	Longer oil and spark plug life.
	Higher unburned fuel output if catalyst not used.
	Risk of combustion instability if air/fuel ratio is too high.

3.5.3 Exhaust Gas Emissions Treatment

A number of techniques for exhaust gas treatment have been developed in recent years to reduce the concentration of specific emissions produced by combustion processes. All have been proven in service before being made widely available, but commonly add to the operating costs of a CHP plant and reduce efficiency by using additional energy. Producing the required feedstock materials also consumes energy. These techniques have generally been used only where it is necessary to comply with specific legislative or air quality requirements, and their application is not expected to increase in the UK. These processes are large -scale process plants in their own right, and their capital and operating costs cannot usually be justified.

Selective Catalytic Reduction

Selective catalytic reduction (SCR) is a proven technique for reducing NOX levels in an exhaust stream by up to 90%. The process has been widely used in America and Japan, but has been applied to very few CHP or power generation plants in the UK.

The technique involves blending ammonia (NH_3) with the exhaust stream and passing the mixture through a catalyst, where NOX and NH_3 are converted to nitrogen and water. The catalytic reduction occurs at an exhaust temperature of around 300-400°C.This is a disadvantage in a CHP application, particularly if prime movers have high exhaust temperatures, as the system design required may be more complex. The SCR control system must minimise the amount of excess NH_3 remaining in the exhaust after the conversion process, particularly in exhaust from a fuel containing sulphur.

At present, the application of SCR to CHP installations is envisaged only in special circumstances, for instance in areas with high background NOX levels.

The overall cost of installing and operating SCR would be prohibitive in almost all CHP installations in the UK.

Non-catalytic Reduction

Non-catalytic reduction (NCR) has been applied in some boiler plant to reduce NOX emissions by up to 70%. Ammonia or urea is added in the combustion zone to convert NOX to nitrogen and water. However, this technique requires a temperature range within the combustion zone of between 900°C and 1,000°C if it is to be successful. Under normal operating conditions, the combustion zone temperatures of most boilers will be below this range.

The NCR technique is applied successfully in energy from-waste plant to achieve compliance with EC Directives.

Flue Gas Desulphurisation

The wet technique consists of an absorption zone in which a mixture of water and ground limestone (Calcium carbonate CO_3) is sprayed into the exhaust gases. A series of chemical reactions takes place, with the limestone slurry absorbing SO_2 from the exhaust. This is then passed into an oxidation zone where gypsum is produced as a by-product.

Various proven techniques for the removal of sulphur dioxide from exhaust gases are used in a number of countries worldwide. Flue gas desulphurisation (FGD) is already installed and operating at some large coal-fired power stations in the UK as part of the flue gas treatment programme required by the EC Directive on Large Combustion Plant.

The gypsum may subsequently be used in the building industry as a substitute for its mined or quarried counterpart. However, there is a limit to the amount that can be used in this way, and gypsum may need to be disposed of as a waste material.

Although the efficiency of sulphur dioxide removal can be as high as 90%, using wet FGD to achieve a high reduction in the SO_2 content of an exhaust gas is usually only practicable or cost-effective for large-scale applications such as central power stations.

Dry sorbent desulphurisation systems, based on the injection of powdered limestone or hydrated lime, are fitted to a few UK combustion processes. They can achieve worthwhile SO_2

reductions, and use bag filters to collect solid gypsum waste from the exhaust systems. Similar systems have been developed using sodium bicarbonate powder.

The dry sorbent system is one of the cheaper sulphur abatement techniques for industrial-sized CHP plants and can achieve an SO2 removal efficiency of up to 75%. Nevertheless, the installation and operating costs will have a significant effect on the viability of the operation and, in many cases, using fuels with a lower sulphur content will be the preferred option.

3.6 Absorption Cooling

Absorption cooling is a technology that allows cooling to be produced from heat rather than from electricity.

A site with a large and continuous cooling demand, and perhaps a declining demand for heat, may consider replacing a conventional electricity-based cooling system with absorption cooling – a system that uses heat instead of electricity for the cooling process.

Converting an electrical load into a heat load in this way has several advantages:

- It reduces the site's demand for electricity.
- It increases the options for heat use.
- It 'irons out' some of the seasonal peaks and troughs in the requirement for heat.
- In some cases, using heat for cooling can turn a marginal CHP case into a viable option.

Absorption cooling, at its simplest, is a technology that allows cooling to be produced from heat rather than from electricity. It uses an evaporator and condenser in the same way as refrigeration by mechanical vapour compression, but it replaces the compressor in the conventional system with a chemical absorber and a generator. A pump provides the necessary change in pressure. When a prime mover provides electricity, heat and cooling via an absorption chiller it is often referred to as trigeneration.

3.6.1 Absorption Cooling Technology

Absorption cooling is based on the strong affinity of certain pairs of chemicals to dissolve in one another.

Absorption cooling, at its simplest, is a technology that allows cooling to be produced from heat rather than from electricity. It uses an evaporator and condenser in the same way as refrigeration by mechanical vapour compression, but it replaces the compressor in the conventional system with a chemical absorber and a generator. A pump provides the necessary change in pressure.

Absorption cooling is based on the strong affinity of certain pairs of chemicals to dissolve in one another. Well proven examples include lithium bromide (in solution) and water, and ammonia and water.

Absorption cooling using water and a strong, water-based lithium bromide solution operates as follows:

- Refrigerant (water) is evaporated by the return leg of a chilled water system in a low-pressure vessel – the evaporator. This cools the chilled water coils.
- The lithium bromide solution in the absorber draws refrigerant water vapour from the evaporator and absorbs it, diluting the solution. The absorption process generates heat which needs to be removed.
- The weakened solution is pumped to a higher pressure and passed from the absorber, via a heat exchanger, to the generator. The heat exchanger improves the system's efficiency.
- Heat from an appropriate heat source (e.g. waste heat/heat from a CHP unit) is applied in the generator, the absorbed water is driven off and passed to the condenser, and the absorbing liquid is returned, again via the heat exchanger, to the absorber.
- The condensed water is returned to the evaporator.

As absorption chillers have minimal moving parts, they are reliable and have low maintenance requirements.

Absorption cooling, like conventional cooling, requires heat dissipation facilities. Furthermore, the amount of heat rejected from an absorption cooler is greater than the amount rejected from an electrically driven chiller of equivalent capacity, so the heat dissipation unit will need to be larger.

Cooling towers are usually relatively inexpensive to install and are an effective method of heat dissipation, but they require regular, effective treatment and maintenance to minimise any health risks.

Alternative options include:

- Dry air coolers. These are similar to vehicle engine radiators but are much larger and are usually fitted with electrical fans to force air through the cooler. Because they are less effective at rejecting heat than wet cooling towers, they are larger than the latter for a given duty. The dump radiator referred to in Section C3.3 is usually a dry air cooler.
- Adiabatic coolers. These operate as dry air coolers until ambient temperatures reach a set threshold, e.g. 23°C, at which point water is sprayed over the cooling coils to increase the rate of heat dissipation by introducing evaporative cooling.

3.6.2 Trigeneration

Some sites that might consider installing CHP plant also have a large and continuous cooling demand, for example for process cooling or for air-conditioning. In this instance, it is worth considering absorption cooling.

Furthermore, if a site is to maximise the financial benefits of CHP, all the heat output of the package should be used on-site. Where a site has a greater demand for electricity than for heat, it is often the heat demand that determines the size of the CHP unit, and the unit produces less electricity than the site requires. Where a site of this type also has a cooling requirement, absorption cooling offers two potential advantages:

- Most of the electricity used to meet the cooling demand is converted into a heat load, thereby reducing the site electrical demand and increasing the use of heat. This can materially alter the site's heat to power ratio, perhaps turning a hitherto marginal case for CHP into a viable option. In some cases, it may even encourage specification of a larger CHP unit that will economically generate more electricity.
- The heat load for absorption cooling often arises when the site heating demand is at its lowest. Absorption cooling can, therefore,' iron out' some of the seasonal peaks and troughs in heat demand and extend profitable CHP running time. This can allow both new and existing CHP units to operate more efficiently.

Most CHP packages produce hot water at around 80-90°C, which is suitable for use by a single-effect absorption chiller.

3.7 Control Monitoring System

3.7.1 Control Systems

Control systems are usually based on high integrity programmable logic controllers (PLCs) and include all the metering, control and protection systems required for the safe start-up, operation and normal shutdown of the CHP plant equipment. All safety interlocks for emergency shutdown are normally hard-wired between the plant items and their own control panels. The individual equipment PLCs may be linked to a distributed control system (DCS) or a supervisory control and data acquisition (SCADA) system with data processing units (DPU), data storage, and operator and engineer interfaces located in a main control room.

The main components of a CHP installation each have their own dedicated control systems with panels that may be local to the equipment or in a control room. The main modules are the generating set(s), comprising the prime mover and the alternator, and the heat recovery equipment, typically a heat recovery boiler. Prime mover controls usually incorporate condition-monitoring equipment, which provides warnings and automatic shutdown in the event of component malfunction, and which also assists in the long-term management and operation of the plant.

Combustion equipment for supplementary or auxiliary firing interfaces with the boiler control system, although the burners will usually have their own burner management and burner control panels. Other associated equipment, such as electrical switchgear, gas compressors, heavy fuel oil treatment plant, and boiler feed-water treatment and supply units, may also have dedicated control systems.

The DCS may monitor and have full master control of the operation of some equipment, for example the electrical switchgear or the boiler (excluding burner management), but have more limited control functions for other equipment such as the generating set. A SCADA system communicates with equipment PLCs and other control systems and provides a user interface, data storage and connection to other software such as an optimisation package. Control and monitoring functions, apart from safety interlocks, are transmitted to and from the DPUs via serial links.

There may also be remote access to current and historical operating data, or the annunciation of alarm conditions though a site-wide data network or by specific modem connections. This may even permit some control functions to be carried out remotely, particularly where an energy management company operates the CHP system.

3.7.2 Long term performance

Performance monitoring is a key function of modern process control systems. Monitoring of a wide range of parameters can be used for a variety of purposes:

To detect faults, malfunctions, under-performance etc. at the earliest possible stage so that they can be promptly rectified.

To enable fine tuning and optimisation of the equipment.

To facilitate modifications in order to respond to alterations in site energy loads, new or amended electricity supply tariffs, fuel price/availability fluctuations etc.

To audit the return on investment.

Optimisation takes the monitoring and control of the CHP system one step further and seeks to maximise the economic benefits of the installation. Optimisation may be on-line, using continuously updated real-time data, or off-line, using a snapshot of current or historical data or manual data input. On-line optimisation may be open loop, advisory mode only, or closed loop where the optimiser is allowed to adjust the operating parameters of the CHP system.

The logic for achieving this optimum is not inherently complex. However, because benefit levels can vary markedly over short periods of time (for example, with changes in site energy demand and heat to power ratio), complexity inevitably increases. Some benefit variations are external. The price of bought-in electricity is the main yardstick for profitability, and CHP electricity produced during the low-cost periods of time of day and seasonal tariffs is less competitive, as is surplus exported electricity.

3.8 Designing a complete CHP Plant

The design of the plant and all its components and services must be carried out in accordance with a range of statutory requirements, technical specifications and other considerations.

Up to this point the main individual items of plant and equipment that are part of a CHP installation have been considered separately. It is essential to consider how they are put together to form a complete installation. Each individual plant item fulfils a specific purpose, and continuous operation of the whole plant depends on the reliable performance of all of the separate components.

3.8.1 Fuel Supply Systems

The fuel supply systems must provide the prime mover with the required quantity of fuel, at the right temperature and pressure, so that it can operate continuously. Some prime movers, particularly gas turbines, may be capable of operating on different fuels and, in this case, the fuel supply systems need to be capable of changing from one fuel to the other without the plant shutting down.

Natural gas supply systems may need to incorporate a compressor to increase the fuel supply pressure to the prime mover. In some cases, the requirement may be for a large, multi-stage compressor, which is a significant plant item requiring specialist design and installation. Different types of compressor are suited to particular applications: screw compressors are appropriate for smaller gas turbine plant requiring fuel at up to 25 bar; reciprocating units are suitable for larger turbines and where a higher fuel pressure is required. Many spark-ignition engines require a gas supply at up to 5 bar, and smaller fan-based compression units are suitable for this type of application.

Gas compressor installations must be carefully designed to ensure delivery of fuel at the correct pressure: they must be able to respond to changes in fuel demand by the prime mover; and they need to ensure safe operation, avoiding the hazards that are inherent in the use of pressurised fuel.

Gas-oil is often the back-up fuel for gas turbine installations, and the gas-oil supply system must be designed to come into operation immediately in the event of a gas supply shutdown, whether planned or unexpected. The system needs to have either a pumped supply in continuous operation, or a storage tank located at high level within the CHP plant. This should ensure that gas-oil at the correct pressure is available at the turbine fuel inlet as soon as it is required. Gas-oil storage tanks must be provided adjacent to the CHP plant, and these must be of sufficient capacity to provide for full operation during a period of gas interruption. Other factors affecting storage capacity are site location and the availability of gas-oil at short notice.

Heavy fuel oil, which is used in boiler plant and in a few large engines, requires a system similar to that for distillate oil, but with one fundamental difference: heavy oil needs to be kept hot if it is to remain in a liquid state that can be pumped through pipework. All the pipework and storage tanks, therefore, need to be insulated, and tanks must be fitted with integral heaters. Heavy fuel oil also tends to contain small quantities of solids, and sometimes traces of water. These need to be removed from the oil by filtration or other treatment before the oil is supplied to the point of use.

4 Renewable CHP

The key benefit of CHP generation is that much of the heat which would otherwise be wasted from power only generation is recovered for additional uses, thereby reducing overall fuel consumption and atmospheric emissions of greenhouse and polluting gases. Renewable CHP generation reduces further still the carbon intensity of power generation through the use of carbon neutral, renewable fuels.

Many of the technical aspects of Renewables CHP are the same as conventional fossil fuel fired CHP and further information can be found here. However, there are a number of other technical aspects which are specific to renewables CHP:

4.1 Renewable CHP Fuels

There a numerous renewable biomass feedstock's which are suitable as fuel for CHP plant, either directly or by firstly converting them to a secondary fuel. A renewable CHP plant operator can obtain feedstock from external sources, their own dedicated biomass feedstock production activities or waste materials arising from onsite operations. Renewable fuels can be placed into the following three categories:

- Solid biomass.
- Liquid biofuels.
- Gaseous biofuels.

Responsibly sourced renewable fuels are considered carbon neutral in that they only release CO2 which was absorbed whilst growing. However, there is carbon emissions associated with their cultivation, processing, transport etc. which results in a nett carbon emission, although this is highly dependent on the source and type of fuel used. These carbon emissions are however generally significantly lower than those from fossil fuels. Consequently, renewable fuel fired CHP plants can achieve additional CO2 emissions reductions over equivalent fossil fuel fired CHP plant. Their use as fuel for CHP plants can benefit the operator through reduced (or zero) fuel costs and CO2 emissions whilst attracting revenues from various UK Government incentives.

Although the use of biomass fuels can improve security of supply it is of paramount importance that adequate fuel is stored to alleviate short term supply disruptions, and supplies are secured for the duration of the project.

4.1.1 Solid Biomass

Solid biomass fuel refers to non-fossilised carbon based solid materials derived from plant or animal matter. Examples of solid biomass fuels include:

Wood Fuels: Commercial-grade wood fuels (such as clean woodchips, logs and wood pellets, but specifically excluding energy crops and waste wood, which are classed as biomass)

Biomass: includes agricultural residues, waste wood, straw, milling residues, prunings and sewage treatment residues. It also includes energy crops- plant crops planted after 31st December 1989 and which are grown primarily for the purpose of being used as fuel or which are one of the following: miscanthus giganteus, salix or populus.

The moisture content of solid biomass fuel affects the amount of energy available for conversion to useful heat. The total energy content of a unit of any fuel is known as its gross calorific value (GCV). When wet fuels are burned some of the energy contained, known as latent heat of vaporisation, is used to evaporate the moisture. This energy is not normally recoverable and is lost in water vapour exiting through the boiler's exhaust stack. The remaining energy in a unit of fuel is known as its nett calorific value (NCV). Latent heat increases with moisture content and thus unprocessed wet fuels, such as freshly felled wood are poor fuels. The moisture content of solid biomass feedstock can be reduced through seasoning and, if required, subsequent drying processes.

Solid biomass fuels can be utilised for direct combustion or converted into a secondary gaseous or liquid renewable fuel via a fuel conversion process.

Solid Biomass Fuel Storage

Solid biomass fuels vary in physical characteristics and energy density. Generally solid biomass fuels are bulky and have low energy densities compared to solid fossil fuels. Consequently, in order to store the same equivalent energy input as a fossil fuel fired system, a solid biomass fired system requires significantly greater volumetric storage capacity.

Solid fuel storage and handling is expensive and increases with capacity. However, it is important to ensure adequate fuel storage is provided to minimise risk of disruption to fuel supply. The most suitable type of fuel store for solid biomass fuel depends on space available and the physical characteristics of the fuel. There are two main types of storage types for solid biomass:

- Subterranean bunkers
- Above ground structures

Subterranean bunkers are suited to installations where land is at a premium or where there are aesthetic issues. Fuel deliveries are simple and allow the use of various types of delivery vehicle. This type of fuel storage is however expensive due to the requirement of deep excavation and reinforced walls. However, once constructed much of the area above the store can be utilised for other purposes.

Above ground structures include sheds and silos and are cheaper and easier to construct than below ground storage. However, these fuel stores generally require the use of specialist vehicles for fuel deliveries and land take can be significant. Silos are only suitable for storage of fuels that flow freely such as pellets and grains whereas sheds are suitable for almost all solid fuel types. In some cases, existing structures can be adapted to store solid biomass fuels which may reduce the overall project capital cost.

4.1.2 Liquid Biofuels

Manufactured liquid biofuels such as bioethanol and biodiesel are produced primarily for use as transport fuel by processing solid biomass via industrial conversion processes. The production of manufactured liquid biofuels is highly energy intensive and, although suitable, is not favoured for use as fuel in CHP.

Bioethanol

Bioethanol is produced by processing suitable solid biomass feedstock in a fermentation and distillation based process. Typical feedstock's for bioethanol are energy crops with a high sugar content including sugarcane, maize, corn and wheat.

Biodiesel

Biodiesel resembles conventional fossil fuel diesel and can be utilised in conventional diesel engines and light oil fired boilers. The fuel is produced by transforming vegetable oils and animal fats into fatty esters (biodiesel) via a conversion process such as transesterification. Vegetable oils can be extracted from various oily feedstock's including rapeseed, soybean and jatropha.

4.1.3 Gaseous Biofuels

Biogas

Biogas is produced by the decomposition of organic matter in the absence of oxygen by anaerobic bacteria in anaerobic digesters and landfills. The composition of biogas is highly heterogeneous and dependent on the material being digested but is mostly made up of methane and CO2. Raw biogas is saturated with water and contains certain trace compounds such as hydrogen sulphide and siloxanes which must normally be removed prior to utilisation as a fuel. Biogas is suitable for use in gas engines, gas turbines and steam boilers.

Synthesis gas

Solid biomass can be converted into a secondary gaseous fuel via advanced thermal conversion processes known as gasification and pyrolysis. These processes produce a low to medium calorific value gas know as synthesis gas (syngas). Syngas is a mixture of gases whose composition is dependent on the conversion process conditions and composition of the feedstock. The primary components of syngas are carbon monoxide, hydrogen and methane, with smaller quantities of carbon dioxide, nitrogen and other hydrocarbon gases. Synthesis gas may also contain undesirable components such as hydrogen sulphide, tars and particulates which must be removed prior to utilisation in internal combustion engines or boiler plant.

4.2 Fuel Conversion Technologies

There is a diverse range of renewable fuels that can be utilised as fuel or feedstock for CHP either through direct combustion or by firstly being transformed in to a secondary fuel via a conversion process. There are three main routes available for utilising renewable feedstocks for CHP applications:

- Direct combustion.
- Anaerobic digestion.
- Gasification.

4.2.1 Direct Combustion

The technologies available for the direct combustion of solid fuels are very mature and reliability is high. Depending on the prime mover technology used systems are available from >300 kWe, although smaller systems are now beginning to come to the market. There are two main direct combustion technologies suitable for solid fuel fired renewable CHP; moving grates and fluidised beds. These technologies differ on how the fuel is introduced, fuel and air are mixed and how the fuel moves within the combustion chamber.

The prime mover technologies available to convert the thermal energy released from the combustion of solid biomass into power are limited to steam turbines or Organic Rankine Cycle (ORC) turbines. Although these technologies have low power to heat ratios they are reliable and offer a high degree of operational flexibility.

Solid fuel fired renewable CHP systems are less capable of meeting fluctuating heat and power demand compared to gas or liquid fuel fired systems, preferring relatively consistent demand profiles. Heat accumulators are often integrated into solid fuel fired systems to increase operational flexibility and ameliorate against changes in demand for heat.

Unlike gas or liquid fuel fired CHP systems, solid fuel fired systems generate significant quantities of ash. Consideration must therefore be given to ash disposal or utilisation during development phases.

Moving Grates

Moving grate furnaces are highly fuel flexible and capable of burning very wet fuels due to the inherent ability to dry fuels within the combustion chamber itself. Fuel is introduced on to the moving grate and is slowly passed towards the ash pit as a result of the inclination and motion of the grate. As the fuel travels along the grate it is dried before igniting, allowing very wet fuels to be burnt. Primary air is introduced from underneath the grate with secondary air required for complete combustion introduced above the burning fuel.

Combustion can be optimised for various fuels by adjusting the speed and inclination of the grate and the rate at which fuel and air is supplied into the combustion chamber. Where waste fuels controlled under the Waste Incineration Directive (WID) are used, moving grate systems include supplementary gas or oil firing capability. Supplementary firing is used during warm up and to ensure the furnace temperature does not fall below 850 °C. Moving grate systems have a relatively high space requirement due to the large grate and combustion area, and additional equipment required.

Fluidised Beds

The use of a fluidised bed allows the combustion of any form of solid fuel, thereby broadening the range of fuels that can be used, particularly for supplementary firing. Fluidised beds also offer the potential for cleaner combustion. It is possible to reduce the level of noxious emissions by adding sorbents, such as limestone, that reacts chemically with the SO2 produced during the combustion process.

Fluidised bed furnaces consist of a hot bed of suspended inert particles such as sand or fine aggregate. Fuel is introduced onto the bed where it mixes with hot inerts, burning fuel and air causing it to ignite. The fuel and bed particles are suspended by the upwards flow of combustion air supplied from below, achieving highly efficient mixing of fuel, air, ash and bed particles. The resulting hot gases are passed to the heat recovery section of the boiler to raise steam. Some fluidised bed systems include gas or oil firing capability for start-up and supplementary heating if required. This type of system can also use the exhaust gases from a turbine or engine in place of the fluidising air, creating a form of supplementary firing.

The excellent mixing within fluidised beds achieves high combustion rates and efficiencies therefore reducing fuel residence time within the combustion chamber. Highly efficient fuel air mixing also makes it possible to burn a wide variety of fuels with varying particle shapes and sizes, moisture content and calorific values. Typical combustion temperatures range between 750 °C and 950 °C thereby reducing the emission of gaseous pollutants, particularly NOx.

Fluidised bed combustion systems are more compact than other solid biomass fired direct combustion systems of equivalent thermal capacity. Suitable applications for renewables CHP are larger systems where annual utilisation is high and heat and power demands are relatively consistent.

4.2.2 Anaerobic Digestion

Anaerobic digestion (AD) is the accelerated decomposition of biodegradable material in the absence of oxygen by anaerobic bacteria known as anaerobes. This process can be carried out in purpose built vessels known as anaerobic digesters for the purpose of producing a medium calorific value gaseous fuel known as biogas. AD also produces a stabilised nutrient rich solid by-product known as digestate which, depending on the digester feedstock, can be used as a soil improver.

AD is suitable for the conversion of wet biomass material into biogas. Typical digester feedstocks include sewage sludge, industrial effluent and food wastes although the use of wet energy crops such as rye grass is increasing in popularity. Solid biomass which is high in lignin, such as wood and straw, is resistant to anaerobes and is therefore not suitable as feedstock for digesters.

Anaerobic digesters can operate on a batch, semi continuous or continuous cycle basis and can be categorised as either mesophilic or thermophilic; Mesophilic digesters operate between temperature 30 °C and 40 °C with optimum digestion and gas production rates achieved at a temperature of approximately 35 °C. Thermophilic digesters operate between 50 °C and 60 °C with optimum digestion and gas production rates achieved at 55 °C. Thermophilic digesters have significantly faster digestion and higher gas production rates than mesophilic digesters. However, due to the lower operational temperatures, mesophilic digesters require significantly less heating than thermophilic digesters and therefore consume less energy. Consequently, mesophilic digesters are preferred in the UK and Northern Europe due to the low ambient temperatures experienced during the winter period.

Biogas is suitable for use in boilers, gas engines and gas turbines and it is common practise to utilise biogas in CHP units for simultaneous generation of heat and power. The heat generated by the CHP units is primarily utilised for digester heating with surplus heat available for secondary uses such as greenhouse heating or for distribution to other users via a district heating network.

4.2.3 Gasification

Solid biomass fuels can be converted into a secondary gaseous fuel, known as synthesis gas (syngas) via the gasification process. Gasification is the thermal degradation of carbonaceous feedstock by partial oxidation in an environment where there is insufficient oxygen available for full oxidation to occur. During gasification, partially-oxidised products are formed including carbon monoxide and hydrogen as well as other hydrocarbons such as methane. Each of these gases have an energy value and contribute to the calorific value of the syngas. Fully oxidised gases such as carbon dioxide and water vapour are also formed during gasification and along with inert gases in the flue gas, such as nitrogen, dilute the syngas and reduce its overall calorific value.

There are several types of gasifier design which are classified according to the method in which the oxygen carrier is introduced:

- Updraft
- Downdraft
- Crossdraft

Fluidised bed

The composition of syngas produced by gasification is dependent on feedstock composition and moisture content, process conditions and the carrier used to introduce a controlled quantity of oxygen into the gasifier. There are three types of carrier used to introduce oxygen into a gasifier; air, pure oxygen or steam. Air-fed gasifiers are the most simplistic but due to the presence of nitrogen produce low calorific value gas. Gasifiers which utilise pure oxygen are capable of producing syngas with much higher calorific values but are more complex and expensive than air fed systems due to the requirement of air separation plant. Pyrolytic gasifiers utilise steam instead of free oxygen and tend to produce syngas with high quantities of hydrogen which may be suitable for use in fuel cell based CHP systems. Air and oxygen fed gasification are exothermic with heat required for the reactions provided from heat released during partial combustion of the feedstock. Pyrolytic gasification is endothermic and consequently requires indirect heating due to the absence of free oxygen which allows partial combustion to occur. Heat for pyrolytic gasification can be supplied by burning part of the biomass feedstock, syngas or residual char produced the gasification process.

Depending on the process conditions and feedstock used, raw syngas also contains contaminants in varying concentrations including tars, particulates, alkali metals and nitrogen, sulphur and chlorine compounds. These substances must be removed to inhibit erosion, corrosion and deposition in downstream equipment such as boilers, gas engines or gas turbines and to prevent environmental problems arising from their emission.

The use of syngas as a fuel is potentially more efficient than burning the biomass feedstock directly in a conventional steam boiler for power generation via steam turbines. This is because syngas can be used in prime movers with higher electrical efficiencies such as gas turbines, gas engines and fuel cells.

4.3 Biomass Organic Rankine Cycle (ORC) CHP

An ORC system converts thermal energy into electrical energy, with thermal energy leaving the system at low temperature being recovered via a water circuit. The system needs a biomass boiler, where the working fluid is pumped to a boiler, evaporated and passed through an expansion device (e.g. turbine). After expansion through the turbine, the working fluid passes through a condenser heat exchanger, where heat is transferred to a hot water circuit for use. At this point the working fluid is condensed, pumped back to the boiler and the process repeated. In some ORC systems thermal oil is used to provide heat to the ORC which evaporates the working fluid.

In the ORC process, designed as a closed cycle, the organic working fluid is:

- Preheated and evaporated by means of thermal exchange with thermal oil (or water);
- Expanded in a turbine that drives a generator;
- Cooled (still in the vapour phase) in a regenerator which has also the function of preheating the organic fluid (thus increasing the electric efficiency, due to a cycle internal heat recovery);
- Condensed in an exchanger in which it transfers heat to the cooling water circuit;
- Pumped at the operating pressure required by the working fluid pump cycle.

The selection of working fluids in this kind of thermal cycles is a key factor. The working fluid should exhibit low freezing and boiling point, high density, low viscosity, reasonable price and good availability. Commercially available refrigerants as well as silicon based oils are used as working fluids for this technology. Most promising ORC cycles exhibit electrical efficiency from 6% to 15% for power outputs between 100 and 2000 kW.

4.4 Screw expanders

Screw expanders (or steam expanders) use a rotary-type positive-displacement mechanism for producing power generation. In general, the working fluid for these devices is saturated steam that is expanded from approx. 15-16 bar to 1-2 bar. Commercially available device allow electricity generation up to 200 kWe. Screw expanders are incorporated in conventional Rankine cycles, leading to electrical efficiency in the interval from 4 to 7%.

5 Micro CHP

Micro CHP is simply CHP on a small scale, with the prime mover generating less than 50 kW of electricity (kWe), although most domestic micro CHP generate between 1 - 5 kWe.

Micro CHP units are available as direct replacements for domestic boilers and are eligible for support under the FiT scheme, provided the electrical capacity is 2 kWe or less.

What are the advantages?

- Potential to save money on domestic energy utility bills.
- Potential to save up to 2 tonnes of carbon per person per year.
- Opens the potential for distributed generation reducing grid losses.
- Micro CHP units could be fitted into the home.
- They operate quietly, reducing disruption.

What technologies are used?

The first micro CHP units that were available tended to favour the use of Stirling engines or external combustion engines. These units tend to have very high heat to power ratios and heat capacities that are too large for many domestic applications. However, micro CHP units that utilise fuel cell and internal combustion engine technologies are now becoming available. These are available at much lower heat capacities and heat to power ratios making them suitable for use in many homes

6 Absorption cooling

Absorption cooling is a technology that allows cooling to be produced from heat rather than from electricity.

A site with a large and continuous cooling demand, and perhaps a declining demand for heat, may consider replacing a conventional electricity-based cooling system with absorption cooling – a system that uses heat instead of electricity for the cooling process.

Converting an electrical load into a heat load in this way has several advantages:

- It reduces the site's demand for electricity.
- It increases the options for heat use.
- It 'irons out' some of the seasonal peaks and troughs in the requirement for heat.
- In some cases, using heat for cooling can turn a marginal CHP case into a viable option.

Absorption cooling, at its simplest, is a technology that allows cooling to be produced from heat rather than from electricity. It uses an evaporator and condenser in the same way as refrigeration by mechanical vapour compression, but it replaces the compressor in the conventional system with a chemical absorber and a generator. A pump provides the necessary change in pressure. When a prime mover provides electricity, heat and cooling via an absorption chiller it is often referred to as trigeneration.

6.1 Absorption Cooling Technology

Absorption cooling is based on the strong affinity of certain pairs of chemicals to dissolve in one another.

Absorption cooling, at its simplest, is a technology that allows cooling to be produced from heat rather than from electricity. It uses an evaporator and condenser in the same way as refrigeration by mechanical vapour compression, but it replaces the compressor in the conventional system with a chemical absorber and a generator. A pump provides the necessary change in pressure.

Absorption cooling is based on the strong affinity of certain pairs of chemicals to dissolve in one another. Well proven examples include lithium bromide (in solution) and water, and ammonia and water.

Absorption cooling using water and a strong, water-based lithium bromide solution operates as follows:

Absorption cooling

- Refrigerant (water) is evaporated by the return leg of a chilled water system in a low-pressure vessel – the evaporator. This cools the chilled water coils.
- The lithium bromide solution in the absorber draws refrigerant water vapour from the evaporator and absorbs it, diluting the solution. The absorption process generates heat which needs to be removed.
- The weakened solution is pumped to a higher pressure and passed from the absorber, via a heat exchanger, to the generator. The heat exchanger improves the system's efficiency.
- Heat from an appropriate heat source (e.g. waste heat/heat from a CHP unit) is applied in the generator, the absorbed water is driven off and passed to the condenser, and the absorbing liquid is returned, again via the heat exchanger, to the absorber.
- The condensed water is returned to the evaporator.

As absorption chillers have minimal moving parts, they are reliable and have low maintenance requirements.

Absorption cooling, like conventional cooling, requires heat dissipation facilities. Furthermore, the amount of heat rejected from an absorption cooler is greater than the amount rejected from an electrically driven chiller of equivalent capacity, so the heat dissipation unit will need to be larger.

Cooling towers are usually relatively inexpensive to install and are an effective method of heat dissipation, but they require regular, effective treatment and maintenance to minimise any health risks.

Alternative options include:

- Dry air coolers. These are similar to vehicle engine radiators but are much larger and are usually fitted with electrical fans to force air through the cooler. Because they are less effective at rejecting heat than wet cooling towers, they are larger than the latter for a given duty. The dump radiator referred to in Section C3.3 is usually a dry air cooler.
- Adiabatic coolers. These operate as dry air coolers until ambient temperatures reach a set threshold, e.g.23°C,at which point water is sprayed over the cooling coils to increase the rate of heat dissipation by introducing evaporative cooling.

6.2 Trigeneration

Some sites that might consider installing CHP plant also have a large and continuous cooling demand, for example for process cooling or for air-conditioning. In this instance, it is worth considering absorption cooling.

Absorption cooling

Furthermore, if a site is to maximise the financial benefits of CHP, all the heat output of the package should be used on-site. Where a site has a greater demand for electricity than for heat, it is often the heat demand that determines the size of the CHP unit, and the unit produces less electricity than the site requires. Where a site of this type also has a cooling requirement, absorption cooling offers two potential advantages:

- Most of the electricity used to meet the cooling demand is converted into a heat load, thereby reducing the site electrical demand and increasing the use of heat. This can materially alter the site's heat to power ratio, perhaps turning a hitherto marginal case for CHP into a viable option. In some cases, it may even encourage specification of a larger CHP unit that will economically generate more electricity.
- The heat load for absorption cooling often arises when the site heating demand is at its lowest. Absorption cooling can, therefore,' iron out' some of the seasonal peaks and troughs in heat demand and extend profitable CHP running time. This can allow both new and existing CHP units to operate more efficiently.
- Most CHP packages produce hot water at around 80-90°C, which is suitable for use by a single-effect absorption chiller.

7 Heat Storage

Some CHP technologies are slow to respond to changes in ‘heat' demand and are not well suited to short cycling (frequent turning on and off). Whereas the prime movers technologies used in CHP can respond relatively quickly to changing power demand, heat generation plant is much less capable, particularly from cold or when fired by solid fuels. One approach is to use heat rejection radiators to disperse excess heat generated during peak power demand periods. However, this is a waste of energy and reduces both energy savings and economic benefit which could be achieved by installing CHP.

A superior approach is to install heat accumulators which can be used to store excess heat generated during off-peak periods for supply at times of peak heat demand (reducing the total installed capacity of plant required). This decouples heat production from heat demand, improving the operational flexibility of CHP plant. Heat accumulators are effectively large water tanks; as heat is absorbed the temperature rises and as heat is extracted the temperature decreases.

Heat accumulators can specifically be used with CHP plants to allow maximum electricity generation at times when heat demand is not as high (by storing any excess heat generated).This enables CHP plants to operate at times when revenue from electricity sales are highest and allows the heat generated to be made available at a later time when electricity revenue is not as favourable. Heat accumulators can also be used to supply heat during routine maintenance, minimising disruption to heat users.

The heat stored in heat accumulators is not normally of appropriate grade for power generation. However, heat accumulators can be used to assist in balancing power demand variations and allow boiler plant to operate in a state of hot standby. This can significantly improve the ability of boiler plant to respond to variations in heat demand from prime movers.

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