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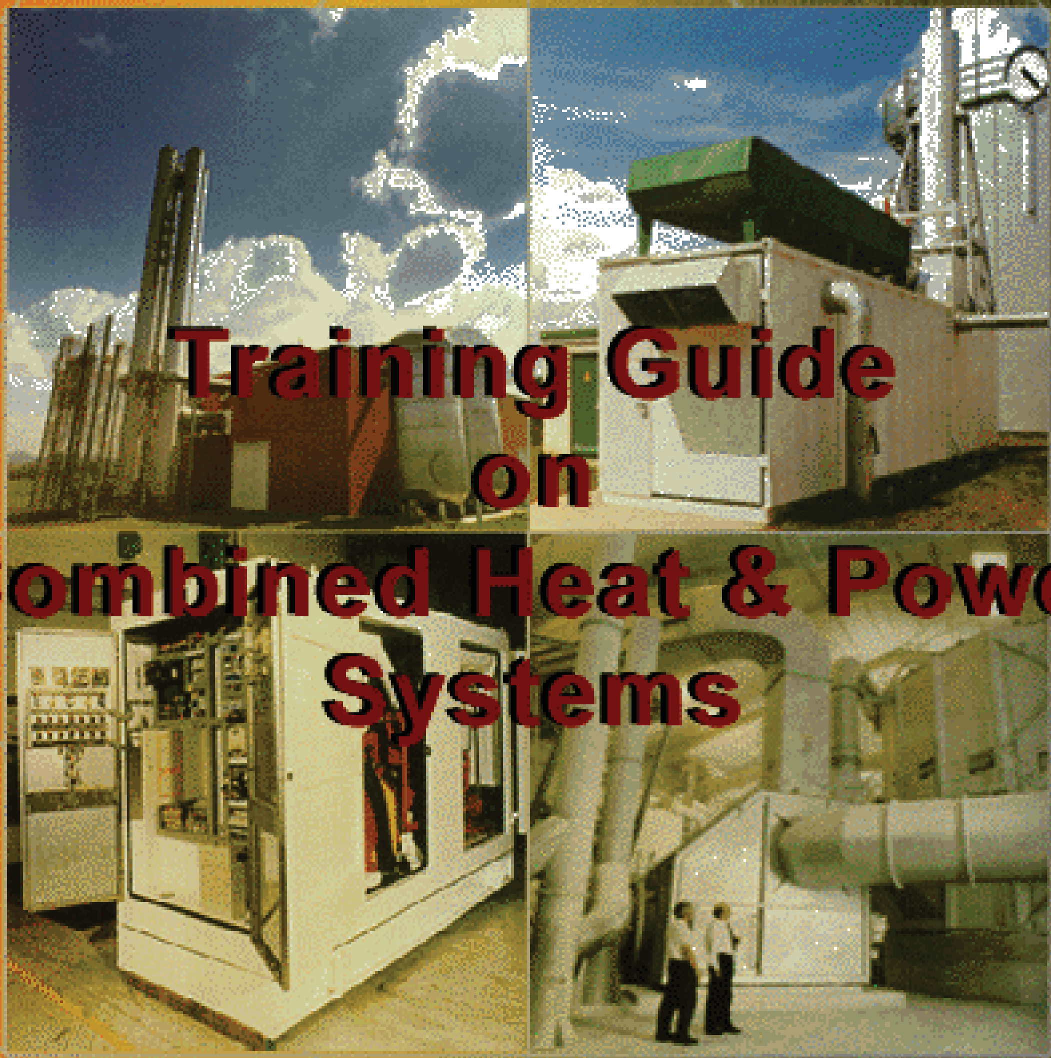

Training Guide on Combined Heat & Power Systems

ΚΑΠΕ
CRES

ZREU

The present edition constitutes part of a series of three Training Guides published by the partnership of the SAVE II Programme 1999 project with Contract No: XVII/4.1031/Z/99-021, entitled: “Guide for the Training of Engineers in the Combined Heat and Power related issues”. More specifically, this is the English version of the Training Guide, which is completed with the Greek and German versions of the Guide, prepared by the Centre for Renewable Energy Sources (CRES) and the Zentrum für rationelle Energieanwendung und Umwelt GmbH (ZREU), respectively.

The aim of these publications is to comprise a useful and practical tool for Engineers and other scientists that are going (or wish) to be occupied in the field of Cogeneration or Combined Heat and Power (CHP). The project was co-financed from the SAVE II Programme of the Directorate General for Energy and Transport (DG TREN) of the European Commission. Dr. Charalambos Malamatenios, who is the Head of CRES Training Department, coordinated the project that was implemented from January 2000 until June 2001.

CRES, the project contractor, prepared Chapters 2 (Mr. E. Mathas), 3, 5 and 8 (all three prepared by Mr. St. Mengos – collaborator of CRES Training Dept.) of the Guide (Mr P. Choustoulakis and Dr. Ch. Malamatenios were also involved in the preparation of texts on behalf of the CRES Training Dept.). The German partner ZREU carried out Chapters 1, 4, 6 and 8, whose authors were Mr. Klaus Grepmeier, Dr. Alexandra Babeck, and Mrs Cosima Möller. The unification of all texts (together with any corrections and/or additions needed), in order to be presented as one and continuous script, was made by Dr. Ch. Malamatenios (Head of CRES Training Dept.).

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1.1. THE CONCEPT OF COGENERATION

Combined heat and power (CHP) systems (also known as cogeneration) generate electricity (and/or mechanical energy) and thermal energy in a single, integrated system (see figure 1.1). This contrasts with common practice where electricity is generated at a central power plant, and on-site heating and cooling equipment is used to meet non-electric energy requirements. The thermal energy recovered in a CHP system can be used for heating or cooling in industry or buildings. Because CHP captures the heat that would be otherwise be rejected in traditional separate generation of electric or mechanical energy, the total efficiency of these integrated systems is much greater than from separate systems.

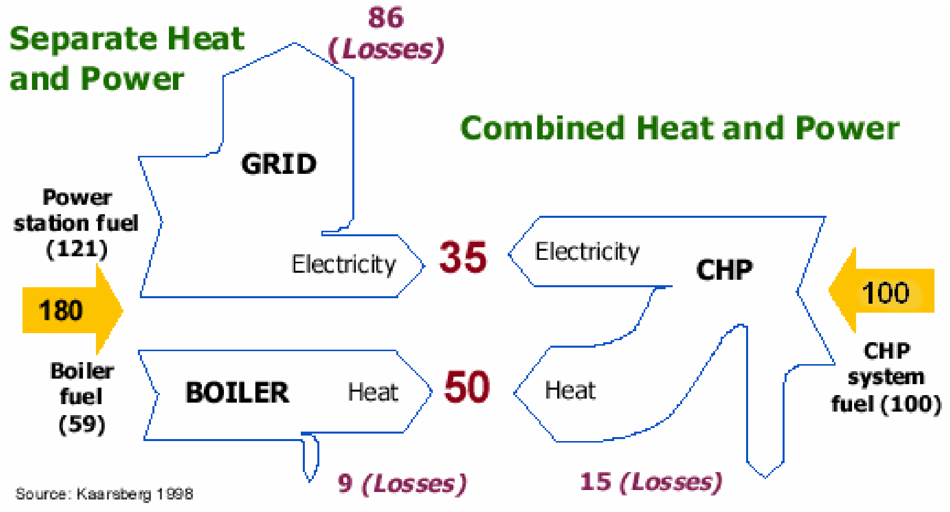


Figure 1.1. Conventional energy system versus cogeneration system

CHP is not a specific technology but rather an application of technologies to meet end-user needs for heating and/or cooling energy, and mechanical and/or electrical power. Recent technology developments have "enabled" new CHP system configurations that make a wider range of applications cost-effective. New generations of turbines, fuel cells, and reciprocating engines are the result of intensive, collaborative research, development, and demonstration by government and industry. Advanced materials and computer-aided design techniques have dramatically increased equipment efficiency and reliability while reducing costs and emissions of pollutants.

Conventional electricity generation is inherently inefficient, converting only about a third of a fuel's potential energy into usable energy. The significant increase in efficiency with CHP results in lower fuel consumption and reduced emissions compared with separate generation of heat and power. CHP is an economically productive approach to reducing air pollutants through pollution prevention, whereas traditional pollution control achieved solely through flue gas treatment provides no profitable output and actually reduces efficiency and useful energy output.

The efficiency of the overall system results from an interaction between the individual efficiencies of the power and heat recovery systems.

Since there are two or more usable energy outputs from a CHP system, defining overall system efficiency is more complex than with simple systems. The system can be viewed as two subsystems, the power system (which is usually an engine or turbine) and the heat recovery system (which is usually some type of boiler). The efficiency of the overall system results from an interaction between the individual efficiencies of the power and heat recovery systems.

The most efficient CHP systems (exceeding 80 percent overall efficiency) are those that satisfy a large thermal demand while producing relatively less power. As the required temperature of the recovered energy increases, the ratio of power to heat output will decrease. The decreased output of electricity is important to the economics of CHP because moving excess electricity to market is technically easier than is the case with excess thermal energy. However, there currently are barriers to distributing excess power to market.

Table 1.1. Overall view of CHP systems [Source: Onsite Sycom (1999)]

	Heat and power stations		**Block-type thermal power stations**		
	Heat and power station with steam turbine	Combined cycle station with gas turbine	Block-type thermal power station with gas turbine	Block-type thermal power station with industrial engine	Micro-scale CHP-unit with car engine
Driving system	Steam turbine	Gas and steam turbine(s) combined	Gas turbine	Industrial Otto engine with three-way catalytic converter, lean-mix engine or diesel engine with SCR catalytic converter[2]	
Fuel	Coal, heavy oil (fluidised bed combustion); natural gas, heating oil (conventional steam vessel)	Natural gas/fluid gas, light heating oil, gasified coal (in the future)		Natural gas/fluid gas, biogas (sewage works, agriculture, waste dump gas), light heating oil/biogenic fuels	
Level of temperature	Up to 500 °C	Up to 300 °C	Up to 550 °C	Up to 100 °C	Up to 100 °C
Main fields of application (examples)	District heating	District heating	Process heat for industry, hospitals	Local heating networks, single	Detached family house settlements,

			(steam, hot water)	buildings (hospitals, big administration buildings)	single buildings (schools, hotels, small commercial enterprises)
Range of capacity	5 – 1000 MW_{el}	20 – 100 MW_{el}	1 – 10 MW_{el}	20 – 1000 kW_{el}	5 – 15 kW_{el}
Cogeneration indexl[1)]	0.30 – 0.60	0.80 – 1.20	0.40 – 0.60	0.55 – 0.65	0.35 – 0.45
El. efficiency	0.25 – 0.35[3)] 0.30 – 0.40[4)]	0.40 - 0.50	0.20 – 0.35	0.30 – 0.40	0.25 – 0.30
Overall efficiency	0.45[5)] – 0.85	0.55[5)] – 0.85	0.75 – 0.85	0.85 – 0.90	0.85 – 0.90
Advantages	Waste heat recovery at huge power stations	Low investment costs, high cogeneration index	High temperature level, process heat	Small dimension, compact construction, high overall efficiency	
[1)] Cogeneration index = power production/heat production [2)] SCR remove nitrogen by urea [3)] Back pressure turbine, maximum heat decoupling [4)] Bleeding turbines, maximum heat decoupling			[5)] Assumption: Only a very small amount of the produced heat is recovered. (Huge power stations are often built far away from the heat consumers; that is why in general only a small part of the produced heat can be used).		

1.2. COGENERATION PRINCIPLES

1.2.1. Heat engines

The following basic options of cogeneration are basically distinguished (some newest technologies are not referred herein):

- Cogeneration with steam turbine:
  They are operated by hard coal, brown coal, oil, wood, waste, peat or nuclear fuel. Steam is the medium by which thermal energy is converted into mechanical energy.
- Cogeneration with gas turbine:
  Oil and gas are the only suitable fuels. The working medium is the exhaust gas of the combustion chamber.
- Cogeneration in combined cycle:
  The high heat and oxygen content of the gas turbine exhaust gases is used in a second process with a steam turbine.
- Cogeneration with reciprocating engine:
  The chemical bounded energy of natural gas or diesel for example is directly transformed by combustion into mechanical energy.

All the above technologies are able to produce both electrical and thermal energy, and are characterized as “heat engines”. More specifically, the heat engine is defined as: “*a device that converts heat energy into mechanical energy*” or, more exactly, “*a system that operates continuously and only heat and work may pass across its boundaries*”. Moreover, the operation of a heat engine can best be represented by a thermodynamic cycle. Some examples are the Otto, Diesel, Brayton, Stirling and Rankine cycles.

1.2.2. Internal combustion engines

Among the most widely used and most efficient CHP prime movers are reciprocating (or internal combustion) engines. Several types of these engines are commercially available, but two designs are of most significance to stationary power applications, namely four cycle- spark-ignited (Otto cycle) and compression-ignited (diesel cycle) engines. The essential mechanical parts of Otto-cycle and diesel engines are the same. They both use a cylindrical combustion chamber in which a close fitting piston travels the length of the cylinder.

The piston is connected to a crankshaft that transforms the linear motion of the piston within the cylinder into the crankshaft rotary motion. Most engines have multiple cylinders that power a single crankshaft. Both Otto-cycle and four stroke diesel engines complete a power cycle in four strokes of the piston within the cylinder. Strokes include:

1) introduction of air (or air-fuel mixture) into the cylinder,
2) compression with combustion of fuel,
3) acceleration of the piston by the force of combustion (power stroke), and
4) expulsion of combustion products from the cylinder.

The primary difference between Otto and diesel cycles is the method of fuel combustion. An Otto cycle uses a spark plug to ignite a pre-mixed fuel-air mixture introduced to the cylinder. A diesel engine compresses the air introduced in the cylinder to a high pressure, raising its temperature to the ignition temperature of the fuel that is injected at high pressure.

1.2.2.1. Otto cycle

Several engines may be approximated by an Otto cycle (figure 1.2), such as petrol engines and gas engines. The Otto cycle is an ideal air standard cycle that consists of four processes:

- 1 to 2: Isentropic compression;
- 2 to 3: Reversible constant volume heating;
- 3 to 4: Isentropic expansion;
- 4 to 1: Reversible constant volume cooling.

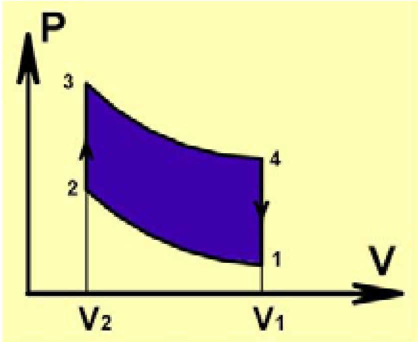


Figure 1.2. P-V diagram for an Otto cycle

The thermal efficiency of an Otto cycle with a perfect gas as working fluid is:

$\eta=1-(T_4-T_1)/(T_3-T_2)$

while it can be shown that the above relation can be reduced to the following one:

$\eta=1-r^n$ (1.1)

where r $(=V_1/V_2)$ is the compression ratio, and n $(=1-\gamma)$ is a constant depending on the specific heat capacity.

1.2.2.2. Diesel cycle

The Diesel cycle (figure 1.3) is an ideal air standard cycle that also consists of four processes:

- 1 to 2: Isentropic compression;
- 2 to 3: Reversible constant pressure heating;
- 3 to 4: Isentropic expansion;
- 4 to 1: Reversible constant volume cooling.

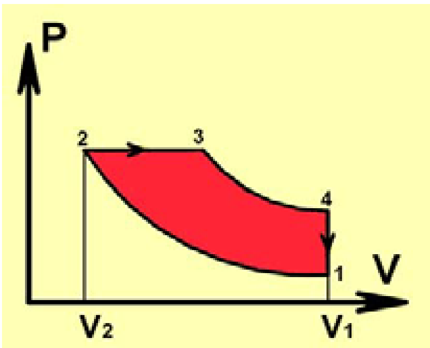


Figure 1.3. P-V diagram for a Diesel cycle

By defining the compression ratio r as: $r= V_1/V_2$, and the cut-off ratio β as: $\beta=V_3/V_2$, the thermal efficiency of a Diesel cycle with a perfect gas as working fluid is:

$\eta= 1-[r(\beta^n-1)]/[(\beta-1)\gamma r^n]$ (1.2)

where n $(=\gamma)$ is a constant depending on specific heat capacity.

1.2.3. Gas turbines

Gas turbines use hot gases generated directly from the combustion of fossil fuels. The hot gas expands through the blades on the turbine rotor causing them to move. The gas turbine process is shown in figure above. The process 3-4, presented in the T-s diagram (figure 1.4) of the open cycle gas turbine shown in figure (left), corresponds to an irreversible but approximately adiabatic expansion of combustion gases.

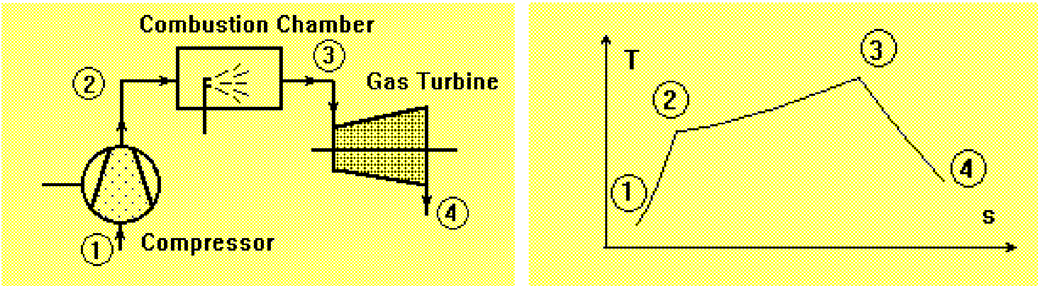


Figure 1.4. Schematic of an open cycle gas turbine (left) and its T-s diagram (right)

The work output of the turbine is:

□ $_{out}$ = □ (h_3-h_4)

where □ is the mass flow of hot gases, h_3 is the enthalpy of hot gases at inlet, and h_4 is the enthalpy of exhaust gases. The isentropic efficiency of the turbine is:

$$\eta = \frac{h_3 - h_4}{h_3 - h_{4s}} \qquad (1.3)$$

1.2.3.1. The Brayton (or Joule) cycle

The thermodynamic cycle associated with the majority of gas turbine systems is the Brayton cycle, which passes atmospheric air, the working fluid, through the turbine only once. The thermodynamic steps of the Brayton cycle include compression of atmospheric air, introduction and ignition of fuel, and expansion of the heated combustion gases through the gas producing and power turbines. The developed power is used to drive the compressor and the electric generator. Primary components of a gas turbine are shown in figure 1.5 below.

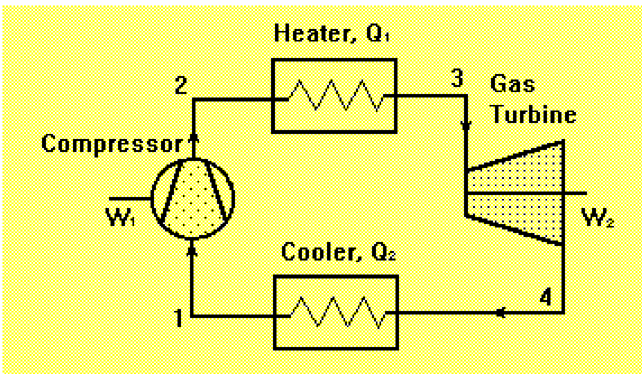


Figure 1.5. A closed cycle gas turbine unit

Both the heat supplied and rejected from the Brayton cycle occur at constant pressure, therefore this cycle is also known as constant pressure cycle. The cycle, which the T-s and P-V diagrams are presented in figure 1.6 below, consists of four processes:

- 1 to 2: Isentropic compression;
- 2 to 3: Isobaric heat supply;
- 3 to 4: Isentropic expansion;
- 4 to 1: Isobaric heat rejection.

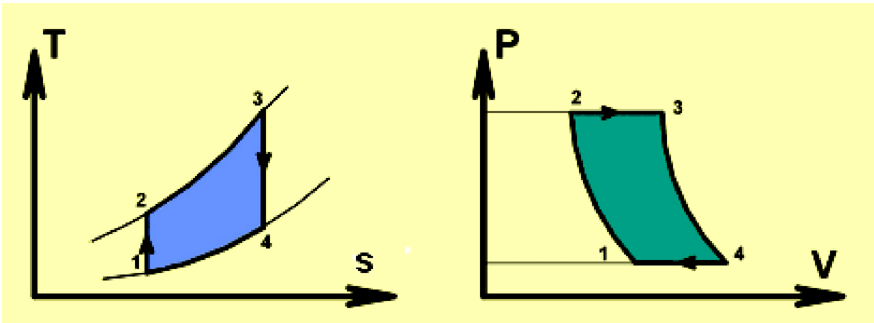


Figure 1.6. T-s and P-V diagrams for a Brayton cycle

The work input to the cycle (compressor) □ $_1$ and the work output of the cycle (gas turbine) □ $_2$ are:

□ $_1$= □ $(h_2\text{-}h_1)$ and □ $_2$= □ $(h_3\text{-}h_4)$

where □ is the mass flow of the cycle. The heat supplied to the cycle (heater) $\dot{Q}_1$ and the heat rejected from the cycle (cooler) $\dot{Q}_2$, respectively, are:

$\dot{Q}_1$ = □ $(h_3\text{-}h_2)$ and $\dot{Q}_2$ = □ $(h_4\text{-}h_1)$

The thermal efficiency of a Brayton cycle with a perfect gas as working fluid is:

$\eta = 1-(T_4-T_1)/(T_3-T_2)$

It can be shown that the above relation can be reduced to the following one:

$$\eta = 1 - r^{n} \qquad (1.4)$$

where r (=P_2/P_1) is the pressure ratio, and n (=$-1+1/\gamma$) is a constant depending on the specific heat capacity of air.

1.2.4. Steam turbines

A steam turbine is captive to a separate heat source and does not directly convert a fuel source to electric energy. Steam turbines require a source of high-pressure steam that is produced in a boiler or heat recovery steam generator (HRSG). Boiler fuels can include fossil fuels such as coal, oil and natural gas or renewable fuels like wood or municipal waste. The steam turbine may consist of several stages, each of which can be described by analysing the expansion of steam from a higher pressure to a lower pressure.

The thermodynamic cycle for the steam turbine is the Rankine cycle, although a number of different cycles are also used, such as the Reheat, the Regenerative and the Combined cycle. The Rankine cycle is the basis for conventional power generating stations and consists of a heat source (boiler) that converts water to high-pressure steam. The steam flows through the turbine to produce power and may be wet, dry saturated or superheated. The steam exiting the turbine is condensed and returned to the boiler to repeat the process, as is shown in the figure below.

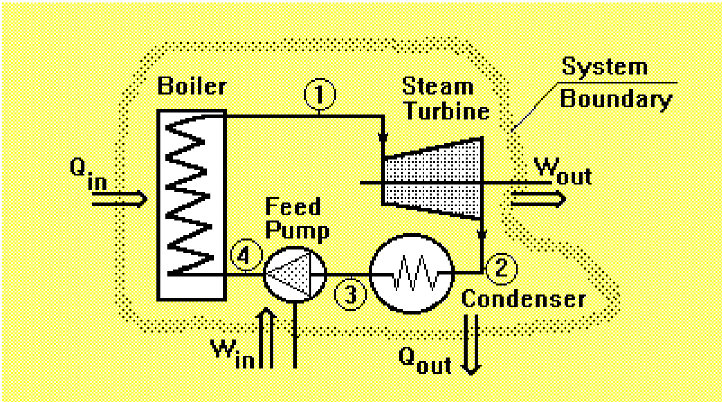


Figure 1.7. The stages of a complete steam-turbine system

Considering the steam turbine shown in the cycle above, the output power of the turbine at steady flow condition is:

$P = \square\ (h_1\text{-}h_2)$

where □ is the mass flow of the steam through the turbine, and h_1 and h_2 are the specific enthalpies of steam at the inlet and outlet of the turbine respectively. The efficiency of steam turbines is often described by the isentropic efficiency for the expansion process. The presence of water droplets in the steam will reduce the efficiency of the turbine and cause physical erosion of the blades. Therefore the dryness fraction of the steam at the outlet of the turbine should not be less than 0.9.

1.2.4.1. The Rankine cycle

The Rankine cycle corresponds to a heat engine with vapour power cycle. The common working fluid is water. The cycle consists of four processes (see figure 1.8):

- 1 to 2: Isentropic expansion (steam turbine);
- 2 to 3: Isobaric heat rejection (condenser);
- 3 to 4: Isentropic compression (pump);
- 4 to 1: Isobaric heat supply (boiler).

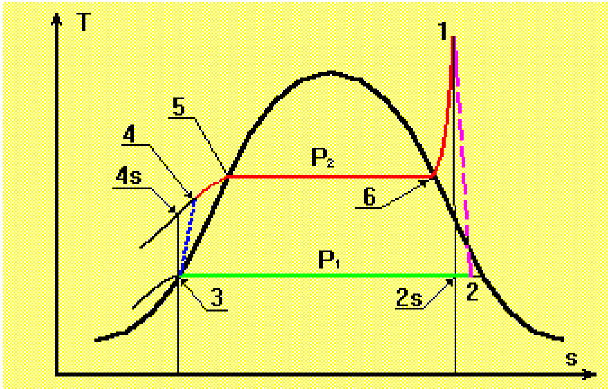


Figure 1.8. T-s diagram for a Rankine cycle

The work output of the cycle (steam turbine) $\square_1$ and the work input to the cycle (pump) $\square_2$ are respectively:

$\square_1 = \square\, (h_1\text{-}h_2)$ and $\square_2 = \square\, (h_4\text{-}h_3)$

where $\square$ is the mass flow of the cycle. The heat supplied to the cycle (from the boiler) $\dot{Q}_1$ and the heat rejected from the cycle (at the condenser) $\dot{Q}_2$ are respectively:

$\dot{Q}_1 = \square\, (h_1\text{-}h_4)$ and $\dot{Q}_2 = \square\, (h_2\text{-}h_3)$

The net work-output of the cycle is: $\square = \square_1 - \square_2$, and the thermal efficiency of a Rankine cycle is then defined as:

$$\eta = \square / \dot{Q}_1 \qquad (1.5)$$

The efficiency of the Rankine cycle is not as high as the Carnot cycle, but the cycle has less practical difficulties and is more economic.

1.2.5. Combustion principles

1.2.5.1. Fuel types

Fuels used in boilers consist of hydrocarbons including alkynes (C_nH_{2n-2}), such as the acetylene (n=2), alkenes (C_nH_{2n}), such as the ethylene (n=2), alkanes (C_nH_{2n+2}), such as the octane (n=8). A typical combustion reaction involves an atom of carbon with two atoms of oxygen with a generation of heat, according to the following generic combustion reaction:

$$C + O_2 \rightarrow CO_2 + Heat \qquad (1.6)$$

The heat generated in the combustion reaction is referred to as the heating value *HV* or the calorific value (*CV*) of a fuel, expressed as heat units per unit of fuel weight or volume.

Two analyses are typically used to determine the basic components of a fuel. The first one is called proximate analysis and determines the fuel content in percentage by weight of moisture, the volatile matter, fixed carbon, ash, and sulfur. The second analysis is referred to as the ultimate analysis and determines the fuel content in percentage by weight of carbon, hydrogen, nitrogen, and oxygen. It should be noted that the heating value of a fuel increases with its carbon content.

Tables 1.2 and 1.3 provide the results of respectively proximate and ultimate analyses for coal extracted from two sites in the US. Table 1.4 illustrates the results of the ultimate analysis of another solid fuel: wood. As it is evident, pine has higher carbon content (by weight) and thus higher heating value.

Table 1.2. Results of proximate analysis of coal extracted from two sites in the US

Coal Type	*Moisture*	*Volatile Matter*	*Fixed Carbon*	*Ash*	*Sulphur*
Lackawana, PA	2.0	6.3	79.7	12	0.6
Weld, CO	24.0	30.2	40.8	5	0.3

Table 1.3. Results of ultimate analysis of coal extracted from two sites in the US

Coal Type	*Carbon*	*Hydrogen*	*Oxygen*	*Nitrogen*	*Heating Value*
Lackawana, PA	93.5	2.6	2.3	0.9	13000
Weld, CO	75.0	5.1	17.9	1.5	9200

Table 1.4. Results of ultimate analysis of selected wood types

Wood Type	*Carbon*	*Hydrogen*	*Oxygen*	*Nitrogen*	*Heating Value*
Oak	49.5	6.6	43.7	0.2	7980
Pine	59.0	7.2	32.7	1.1	10400
Ash	49.7	6.9	43.0	0.3	8200

Liquid or distillate fuels are generally graded in different categories depending on their properties. For fuel oils, there are 6 different grades depending on the viscosity. Table 1.5 provides the heating values and common usage of 5 oil fuels commonly sold in the US. Fuel oil No 3 has now been incorporated as part of fuel oil No 2.

Table 1.5. Heating value and specific gravity of oil fuels used in the US

Oil Grade	*Specific Gravity*	*Heating Value KWh/litre (MBtu/gal)*	*Applications*
No. 1	0.805	9.7 (134)	For vaporizing pot-type burners
No. 2	0.850	10.4 (139)	For general purpose domestic heating
No. 3	0.903	10.9 (145)	For burners without preheating
No. 5	0.933	11.1 (148)	Requires preheating to 75-95 °C
No. 6	0.965	11.3 (151)	Requires preheating to 95-115 °C

Similar grades are used for diesel fuels, with diesel No 1 used for high-speed engines, and diesel No 2 used for industrial applications and heavy cars. The liquid petroleum gas (LPG) is a mixture of propane and butane, while natural gas is a mixture of methane and ethane.

1.2.5.2. Heating values of fuels

Typically, the heating value is given when the fuel is dry. The moisture actually reduces the heating value of fuels according to the following simplified equation:

$$HV = HV_{dry}.(1-M) \tag{1.7}$$

where, M is the moisture content of the fuel. In addition, the heating value of fuels decreases with the altitude. As a rule of thumb, the heating value reduces by 4% for every 300 m increase in the altitude. Moreover, the heating value is dependent on the phase of water/steam in the combustion products.

If H_2O is in liquid form, the heating value is called Higher Heating Value (*HHV*) or Gross Heating Value (*GHV*). When H_2O is in vapour form, the heating value is called Lower Heating Value (*LHV*) or Net Heating Value (*NHV*). The *GHV* is determined in the laboratory using a calorimeter, which measures the heat removed when cooling the products of combustion to a standard reference temperature. Thus, it includes the 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 *NHV* (or *LHV*) is determined by calculation, and equals the *GHV* minus the latent heat of the water vapour formed from the combustion of hydrogen and from any moisture present in the fuel. The NHV 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.

Fuel is normally purchased on the basis of its *GHV*, and site energy consumption is always expressed in terms of *GHV*, so it is important to use *GHV* in the energy analysis relating to CHP feasibility. Any energy balance derived will vary with the *HV* 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 1.6 outlines the typical properties of selected fuels.

Table 1.6. Typical properties of selected fuels

Fuel	***CV as normally expressed***		***Contaminants %***		
	Gross	***Net***	***Sulphur***	***Water***	***Ash***
Steam coal	30.6 MJ/kg	29.7 MJ/kg	1.2	10.0	8.0
Wood waste	15.8 MJ/kg	14.4 MJ/kg	0.4	15	Trace
Heavy fuel oil	41.2 MJ/litre	38.9 MJ/litre	2.0	0.3	0.04
Gas-oil	38.3 MJ/litre	36.0 MJ/litre	0.15	0.05	0.01
Natural gas	38.0 MJ/m^3	34.2 MJ/m^3	-	Trace	-
Landfill gas	20.0 MJ/m^3	18.0 MJ/m^3	Trace	Trace	-
Mine gas	21.0 MJ/m^3	18.9 MJ/m^3	Trace	5.0	-

1.2.5.3. Combustion emissions

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 (SO_2) will be produced. In addition, the combustion process produces nitrogen oxide (NO) and nitrogen dioxide (NO_2), the combination generally being referred to as oxides of nitrogen (NO_x).

These oxides are created by a high-temperature chemical reaction between the oxygen and nitrogen present in the air. There are three main mechanisms for their formation:

- thermal NO_x;
- fuel NO_x;
- prompt NO_x.

The rate at which these different reactions proceed is strongly influenced by the combustion process – temperature and air/fuel ratio are particularly important.

Thermal NO_x is the most important contributor and is formed from a reaction of nitrogen and oxygen in the combustion air, starting in the primary combustion zone but largely occurring in the secondary zone. Formation is strongly governed by temperature and the reaction proceeds very quickly at temperatures above 1,300°C. Fuel NO_x is formed at lower temperatures (around 700°C) and occurs within the flame through a reaction with chemically bound nitrogen present in the fuel. The third type, prompt NO_x, is less significant and is formed in the presence of hydrocarbon radicals in the flame front.

Different fuels have varying inert content and therefore burn at different flame temperatures, which affects NO_x formation. Coal and heavy fuel oils produce higher levels of NO_x emission than lighter oils and natural gas, and this is reflected in emissions/environmental legislation that specifies separate limits for the different fuel types (limits on SO_2 emissions are also set by legislation). The presence of these oxides in the atmosphere is considered to have harmful effects, and there is a general objective to minimise NO_x emissions from all combustion plant, including CHP plant. Table 1.7 provides a summary of existing NO_x reduction techniques.

Table 1.7. Summary of NO_x reduction techniques [Source: ZREU]

	Reciprocating engines	***Gas turbines***
No limits	• Stoichiometric engines	• Standard turbines
TA-Air 500 mg/m³, 5% O_2 and 150 mg/m³, 15% O_2 respectively	• Lean-burn engines with λ-control • Stoichiometric engine with 3-way catalytic converter	• Dry low-NO_x burners • Steam/water injection
Half TA-Air 250 mg/m³, 5% O_2 and 75 mg/m³, 15% O_2 respectively	• Lean-burn engines with λ-control and 2-way catalytic converter • Stoichiometric engine with 3-way catalytic converter	• Dry low-NO_x burners • Steam/water injection
Special applications	• Selective catalytic reductions	• Selective catalytic reduction

	(SCR) – applied for CO_2-rich atmospheres in greenhouses	(SCR)

1.2.6. Performance indices of cogeneration systems

Before proceeding with the description of cogeneration technologies, and after the brief discussion made above on the heat engines and combustion principles, it is necessary to define certain indices that reveal the thermodynamic performance of a cogeneration system and facilitate the comparison of alternative solutions (systems). Numerous indices have appeared in the literature, but the most important of them are defined in the following.

The *efficiency of the prime mover* (e.g. of gas turbine, Diesel or Otto engine, steam turbine, etc.) is defined as:

$$\eta_m = \frac{\dot{W}_S}{\dot{H}_f} = \frac{\dot{W}_S}{\dot{m}_f H_u} \tag{1.8}$$

where $\dot{W}_S$ is the shaft power of the prime mover, $\dot{H}_f$ is the fuel power (flow rate of the fuel energy) consumed by the system ($\dot{H}_f = \dot{m}_f H_u$), $\dot{m}_f$ is the fuel mass flow rate, and H_u the lower heating value of fuel. It must be noticed that, in Europe, the analysis is usually based on the lower heating value (*LHV*). In the U.S., the higher heating value (*HHV*) H_o is usually used.

The *electrical efficiency* of the generation system is:

$$\eta_e = \frac{\dot{W}_e}{\dot{H}_f} = \frac{\dot{W}_e}{\dot{m}_f H_u} \tag{1.9}$$

where $\dot{W}_e$ is the net electric power output of the system (the electric power consumed by auxiliary equipment has been subtracted from the electric power of the generator). Moreover, the *thermal efficiency* of the heat production part of the system is:

$$\eta_{th} = \frac{\dot{Q}}{\dot{H}_f} = \frac{\dot{Q}}{\dot{m}_f H_u} \tag{1.10}$$

where $\dot{Q}$ is the useful thermal power output of the cogeneration system. Finally, the *total energetic efficiency* of the cogeneration system is:

$$\eta = \eta_e + \eta_{th} = \frac{\dot{W}_e + \dot{Q}}{\dot{H}_f} \tag{1.11}$$

The quality of heat is lower than the quality of electricity and is decreasing with the temperature at which it is available (i.e. the quality of heat in the form of hot water is lower than the quality of heat in the form of steam). Consequently, it is probably not proper to add electricity and heat, as it appears in equation (1.11), and sometimes a comparison between systems based on the energetic efficiency may be misleading. Even though energetic efficiencies are most commonly used up to now, a more accurate thermodynamically evaluation and a more fair comparison between systems can be based on exergetic efficiencies.

There are also other important parameters to be considered in CHP power systems, such as the *power to heat ratio* (*PHR*):

$$PHR=\frac{\dot{W}_e}{\dot{Q}} \tag{1.12}$$

and the *fuel energy savings ratio:*

$$FESR=\frac{\dot{H}_{fS}-\dot{H}_{fC}}{\dot{H}_{fS}} \tag{1.13}$$

where $\dot{H}_{fS}$ is the total fuel power for separate production of $\dot{W}_e$ and $\dot{Q}$, $\dot{H}_{fC}$ is the fuel power of the cogeneration system producing the same amounts of $\dot{W}_e$ and $\dot{Q}$. In order for a cogeneration system to be a rational choice from the point of view of energy savings, it must be: *FESR*>0.

Equations (1.9)-(1.12) lead to the following relations:

$$\eta=\eta_e\left(1+\frac{1}{PHR}\right) \tag{1.14}$$

$$PHR=\frac{\eta_e}{\eta_{th}}=\frac{\eta_e}{\eta-\eta_e} \tag{1.15}$$

These equations help in determining acceptable values of the power to heat ratio, when the electrical efficiency of a system is known, given the fact that the total efficiency does not exceed typically 90%. It should be mentioned that, the power to heat ratio is one of the main characteristics for selecting a cogeneration system for a particular application.

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

$$FESR=1-\frac{PHR+1}{\eta\left(\frac{PHR}{\eta_W}+\frac{1}{\eta_Q}\right)} \tag{1.16}$$

It can also be written

$$\dot{H}_{fS}=\dot{H}_{fW}+\dot{H}_{fQ}=(\dot{m}_f H_u)_W+(\dot{m}_f H_u)_Q \tag{1.17}$$

$$\dot{H}_{fW}=(\dot{m}_f H_u)_W=\frac{\dot{W}_e}{\eta_W} \quad \text{and} \quad \dot{H}_{fQ}=(\dot{m}_f H_u)_Q=\frac{\dot{Q}}{\eta_Q} \tag{1.18}$$

where the indices *W* and *Q* denote the separate production of electricity and heat (e.g. by a power plant and a boiler), respectively. Thus, if a CHP system with a total efficiency η=0.80 and a power to heat ratio *PHR*=0.60 substitutes a power plant of efficiency η_W=0.35 and a boiler of efficiency η_Q=0.35, then from equation (1.16) results: *FESR*=0.325. This means that the cogeneration reduces the total energy consumption by 32.5%.

The performance of a system depends on the load and on the environmental conditions. On the other hand, the degree of utilization of the energy forms produced is affected by the initial selection (design) of the system, the cogeneration strategy (operational control) and the matching between the production and use of the useful energy forms. For these reasons, integral indices over a period of time, e.g. annual indices, are often more important than instantaneous or nominal indices, since they are more revealing of the real performance of the system.

Furthermore there are legal aspects, which make integral values of indices significant. For example, according to the relevant to cogeneration issues law in Greece, in order for a CHP system to be eligible for the benefits granted to cogeneration, it must have an annual total efficiency of at least 65% in the industrial sector, and at least 60% in the tertiary sector. But, in all the above, electric, thermal and fuel powers were used (energy per unit time), which results in values of the indices valid only in a certain instant of time or at a certain load.

All the above definitions are also valid if power is replaced by energy in a certain period of time; then, integral values of the indices are obtained, which reveal the performance of the system over this period. For example, equation (1.11) can be also written as:

$$\eta_a = \frac{W_{ea} + Q_a}{H_{fa}} \tag{1.19}$$

where W_{ea} is the electric energy produced by the CHP system during a year, Q_a is the annual thermal energy production, and H_{fa} is the energy of fuel consumed during a year. Equation (1.19) then provides the annual total efficiency η_a of the system.

1.3. CLASSIFICATION OF COGENERATION SYSTEMS

1.3.1. Types of cogeneration concepts

By 1900 the first inkling of what it is known today as “cogeneration” existed in some large cities and industrial plants. The prime mover for the generators were reciprocating steam engines, usually exhausting at low pressure into steam mains delivering the low–pressure steam into the heating and process systems. This way, the first “topping” cogeneration plants were born, named from the simultaneous generation of electricity and thermal energy for use in the plant processes.

The terminology was not appended to the process until the 1970s, and the term “topping” refers to the fact that electric power is generated by the prime mover as a primary function and the thermal energy discarded from by prime mover is then used for the plant processes. The other arrangement, where the electric power is generated from by product steam, is known as “bottoming power”. Thus, there are two main types of cogeneration concepts: "topping cycle" plants, and "bottoming cycle" plants.

There are four types of topping cycle cogeneration systems. The first type burns fuel in a gas turbine or diesel engine to produce electrical or mechanical power. The exhaust provides process heat, or goes to a heat recovery boiler to create steam to drive a secondary steam turbine. This is a combined-cycle topping system. The second type of system burns fuel (any type) to produce high-pressure steam that then passes through a steam turbine to produce power. The exhaust provides low-pressure process steam. This is a steam-turbine topping system.

A third type burns a fuel such as natural gas, diesel, wood, gasified coal, or landfill gas. The hot water from the engine jacket cooling system flows to a heat recovery boiler, where it is converted to process steam and hot water for space heating. The fourth type is a gas-turbine topping system. A natural gas turbine drives a generator. The exhaust gas goes to a heat recovery boiler that makes process steam and process heat. A topping cycle plant always uses some additional fuel, beyond what is needed for manufacturing, so there is an operating cost associated with the power production.

Bottoming cycle plants are much less common than topping cycle plants. These plants exist in heavy industries, such as glass or metals manufacturing, where very high temperature furnaces are used. A waste heat recovery boiler recaptures waste heat from a manufacturing heating process. This waste heat is then used to produce steam that drives a steam turbine to produce electricity. Since fuel is burned first in the production process, no extra fuel is required to produce electricity.

1.3.2. Operation modes of cogeneration systems

A mode of operation is characterized by the criterion on which the adjustment of the electrical and useful thermal output of a cogeneration system is based. There are various modes of operation possible, the most distinct of those being the following:

a. *Heat-match mode*: The useful thermal output of a cogeneration system at any instant of time is equal to the thermal load (without exceeding the capacity of the cogeneration system). If the generated electricity is higher than the load, excess electricity is sold to the grid; if it is lower, supplementary electricity is purchased from the grid.
b. *Base thermal load matching mode*: Here, the cogeneration system is sized to supply the minimum thermal energy requirement of the site. Stand-by boilers or burners are operated during periods when the demand for heat is higher. The prime mover installed operates at full load at all times. If the electricity demand of the site exceeds that which can be provided by the prime mover, then the

remaining amount can be purchased from the grid. Likewise, if local laws permit, the excess electricity can be sold to the power utility.

c. *Electricity-match mode*: The generated electricity at any instant of time is equal to the electrical load (without exceeding the capacity of the cogeneration system). If the co-generated heat is lower than the thermal load, an auxiliary boiler supplements for the needs; if it is higher, excess heat is rejected to the environment through coolers or the exhaust gases.
d. *Base electrical load matching mode*: In this configuration, the CHP plant is sized to meet the minimum electricity demand of the site based on the historical demand curve. The rest of the needed power is purchased from the utility grid. The thermal energy requirement of the site could be met by the cogeneration system alone or by additional boilers. If the thermal energy generated with the base electrical load exceeds the plant's demand and if the situation permits, excess thermal energy can be exported to neighbouring customers.
e. *Mixed-match mode*: In certain periods of time the heat-match mode is followed, while in other periods the electricity-match mode is followed. The decision is based on considerations such as the load levels, the fuel price and the electricity tariff at the particular day and time.
f. *Stand-alone mode*: There is complete coverage of the electrical and thermal loads at any instant of time with no connection to the grid. This mode requires the system to have reserve electrical and thermal capacity, so that in case a unit is out of service for any reason, the remaining units are capable of covering the electrical and thermal load. This is the most expensive strategy, at least from the point of view of initial cost of the system.

In general, the heat-match mode results in the highest fuel utilization rate (fuel energy savings ratio - *FESR*) and perhaps in the best economic performance for cogeneration in the industrial and building sectors. In the utility sector, the mode of operation depends on the total network load, the availability of power plants and the commitments of the utility with its customers regarding supply of electricity and heat.

However, applying general rules is not the most prudent approach in cogeneration. Every application has its own distinct characteristics; there is a variety of cogeneration systems (according to the type of the technology, size, configuration); the design of a cogeneration system can be tailored to the needs of the user; the design of a cogeneration system affects the possible modes of operation, and vice versa. Moreover, the technical and economic parameters may change with the day and time during the operation of the system.

All these aspects make it necessary to reach decisions not by rules of thump only, but by systematic optimisation procedures, based on mathematical programming, for both the design and operation of the system. For the operation of cogeneration systems, in particular, microprocessor-based control systems are available. They can provide the capability to operate in a base load mode, to track either electrical or thermal loads, or to operate in an economic dispatch mode (mixed-match mode).

In the latter mode, the microprocessor can be used to monitor cogeneration system performance, including:

- the system efficiency and the amount of useful heat available;
- the electrical and thermal requirements of the user, the amount of excess electricity which has to be exported to the grid, and the amount of heat that must be rejected to the environment;
- the cost of purchased electricity and the value of electricity sales, as they may vary with the time of the day, the day of the week, or season.

Using the aforementioned data, the microprocessor can determine which operating mode is the most economical, even whether the unit should be shut down. Moreover, by monitoring operational parameters such as efficiency, operating hours, exhaust gas temperature, coolant water temperatures, etc., the microprocessor can help in maintenance scheduling. If the system is unattended, a telephone line can link the microprocessor with a remote monitoring centre, where the computer analysis of the data may notify the skilled staff about an impending need for scheduled or unscheduled maintenance. Furthermore, as part of a data acquisition system, the microprocessor can produce reports of system technical and economic performance.

2.1. PRIME MOVER OPTIONS

2.1.1. Introduction

Combined heat and power (CHP) technologies produce electricity or mechanical power and recover waste heat for process use. Conventional centralized power systems average less than 33% delivered efficiency for electricity in Europe and the US. On the other hand, CHP systems can deliver energy with efficiencies exceeding 90%, at the same time reducing significantly the emissions per delivered MWh. This chapter provides a description of the leading CHP technologies primary components, their efficiency, size, and any relevant technology advancements.

As regards prime movers, the technologies presented herein include reciprocating engines, steam and gas turbines, micro-turbines and fuel cells. All CHP technologies are commercially available for on-site generation and combined heat and power applications. Several barriers, including utility interconnection costs and issues, environmental regulations and technology costs have kept these technologies from gaining wider acceptance. Many of the technologies are undergoing incremental improvements to decrease costs and emissions while increasing efficiency.

The business environment is witnessing dramatic changes with energy market deregulation, utility restructuring and increased customer choice. As a result of these changes, CHP will gain wider acceptance in the market. Selecting a CHP prime mover technology for a specific application depends on many factors, including the amount of power needed, the duty cycle, space constraints, thermal needs, emission regulations, fuel availability, utility prices and interconnection issues.

2.1.2. Reciprocating Engines

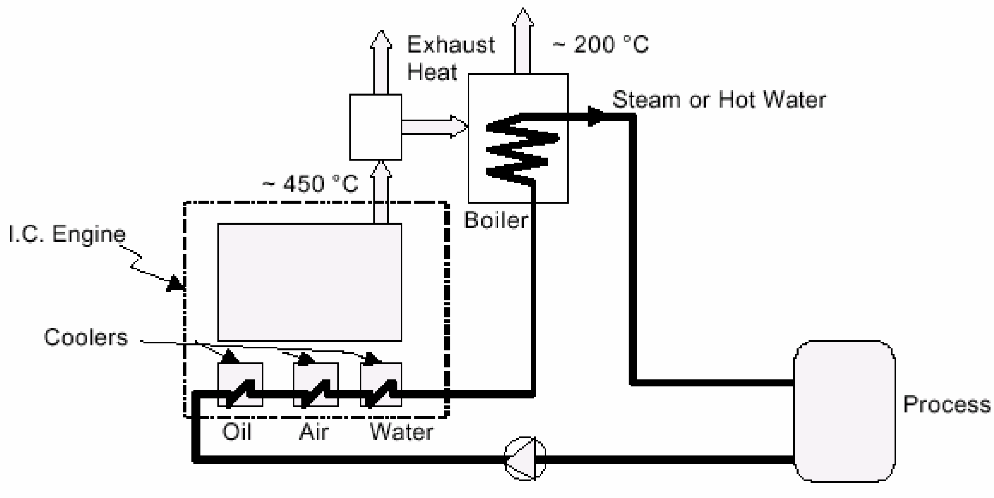


Figure 2.1. Schematic diagram of reciprocating engine cogeneration

Reciprocating engines, also known as internal combustion (IC) engines, are mostly employed in low and medium power cogeneration units. The lower and upper limits of engine sizes are often a function of the fuel in use; these can range from 50 kW to

10 MW for natural gas, from 50 kW to 50 MW for diesel, and 2.5 MW to 50 MW for heavy fuel oil. One of the major advantages of reciprocating engines is their higher electrical efficiency as compared to other prime movers. There are mainly two sources of heat for recovery, the exhaust gases at high temperature and the engine jacket cooling water system at low temperature, as is shown in figure 2.1.

The two main types of internal combustion engines employed in cogeneration systems are diesel engines and Otto engines. The characteristic feature of the Otto engine is that an electric spark from a spark plug ignites a mixture of fuel and air, and this is why it is known widely as a spark-ignition engine. The Otto engine in power generation applications may be either a gasoline engine or a diesel engine converted to have spark-ignition operation. Gasoline engines have ratings ranging from 20 kW to 1.5 MW. The spark-ignition engines converted from diesel engines and running on natural gas are available in ratings from 5 kW to 4 MW.

The Otto engines operate at speeds between 750-3000 rpm and have electrical efficiencies of 25-35%. These engines can run on different fuels such as gasoline, natural gas, producer gas, and digester gas. As opposed to Otto engines, fuel is injected into the diesel engine cylinders in which it mixes with air and is ignited by the heat generated when the pistons compress the fuel/air mixture, and this engine is often known as a compression-ignition engine. Diesel engines can generally be classified into two main categories, i.e. two-stroke and four-stroke engines.

The *two-stroke engine* is also known as a low-speed engine, and is characterized by ignition taking place once every revolution, and by the engine running at a speed below 200 rpm, delivering an output of 1-50 MW at a high electrical efficiency of 45-53%. In a *four-strike engine*, ignition takes place during every other revolution. This engine can be divided into two categories:

- *Medium speed engines*, which run at speeds between 400 and 1000 rpm and can have ratings between 0.5 and 20 MW, with electrical efficiencies of 35-48%.
- *High-speed engines* that operate at speeds between 1000 and 2000 rpm, with ratings between a few kW and about 2 MW, and electrical efficiencies of 35-40%.

Diesel engines can run on a variety of fuels, such as diesel, heavy fuel oil, light fuel oil, LPG, natural gas, producer gas, digester gas, etc. The diesel engines that are converted to gas engines are also known as dual-fuel engines. In their operation, the main fuel is gas, which is ignited by a small quantity of pilot oil, usually diesel oil. The pilot oil is used to make sure that the gas in the cylinder will ignite. Diesel engines running in gas engine mode can be classified in another way into two groups, namely the low-pressure dual-fuel engines and high-pressure dual-fuel engines.

In the operation of *low-pressure dual-fuel engines*, gas at low pressure, i.e. 3-5 bar, is mixed with the engine combustion air during the induction cycle. The gas/ combustion air mixture is compressed in the cylinder and is ignited at the top dead centre by a small amount (approximately 5%) of diesel oil being injected into the cylinder and ignited in the usual manner. Low-pressure dual-fuel engines have relatively low ratings and efficiencies. The system is sensitive to variations in gas quality.

Gas is compressed outside the engine in a separate compressor in a *high-pressure dual-fuel engine* up to 250 bar and is injected into the cylinder with a minor amount of pilot oil when the piston is in the vicinity of the top dead centre. High-pressure dual-fuel engines have higher ratings and efficiencies and they are not sensitive to the gas quality. High-pressure dual-fuel engines are available in both two-stroke and four-stroke versions.

Today, manufacturers are producing variously sized, high-output, and highly efficient packaged units that are used in a variety of small- to medium-sized applications. These modular, quiet, and clean engines are used not only in backup or peak shaving situations, but also to supply base load electricity to a growing number of facilities. Packaged IC engines can provide facilities with the following (relative to other CHP technologies):

- Low start-up and operating costs;
- Reliable onsite and clean energy;
- Ease of maintenance;
- Wide service infrastructure.

2.1.3. Gas turbines

Gas turbines (also referred to as combustion turbines) are used throughout the world as an effective way to simultaneously produce useful power and heat from a single fuel source. Combustion turbines, ranging in size from 500 kilowatts to hundreds of mega-watts, produce electricity through their generators while providing useful heat captured from the turbine exhaust flow. Recent technological advances are directed towards developing high-efficiency, low-emission natural-gas-fired turbines to provide an environmentally superior technology solution for CHP applications.

Gas turbines for continuous duty are traditionally divided into two groups on the basis of differences in design philosophy:

- The *aero-derivative gas turbine* is more or less derived from an aircraft propulsion engine. The characteristics of these turbines are low specific weight, low fuel consumption, high reliability, etc. The advantages of aero-derivative gas turbines are high levels of efficiency and a compact and modular design with easy access for maintenance. However, because skilled service personnel are required, gas turbines of this type are often taken off the site for maintenance. They require a relatively high specific investment cost, high quality fuel and may experience a lowering in output and efficiency after a long period of operation.
- The *industrial gas turbine*, also referred to as the heavy duty or heavy frame gas turbine, is a robust unit constructed for stationary duty and continuous operation. It has a somewhat lower efficiency than the aero-derivative type, but usually maintains its performance over a longer period of operation. Maintenance can be

easily carried out on site, and industrial gas turbine usually has a lower specific investment cost than its aero-derivative counterpart. Furthermore, it has the ability to make use of low quality fuel.

The performance of a gas turbine depends on the pressure and temperature of ambient air that is compressed. Since the ambient conditions vary from day-to-day and from location-to-location, it is convenient to consider some standard conditions for comparative purposes. The standard conditions used by the gas turbine industry are 15^{o}C, 1.013 bar (14.7 psia) and 60% relative humidity, which are established by the International Standards Organization (ISO). The performance of gas turbines is expressed under ISO conditions.

Gas turbines operate in different cycle configurations. Simple-cycle gas turbines (fig. 2.2) are the concept of a single shaft machine (with compressor and turbine on the same shaft) that includes an air compressor, a burner, and a power turbine driving an electric generator. Simple-cycle gas turbines are generally used in small generation capacities less than 25 megawatts. A recuperated gas turbine is the same as a simple-cycle turbine, except for the addition of a recuperating heat exchanger that captures exhaust energy to preheat the com-pressed air before it enters the burner.

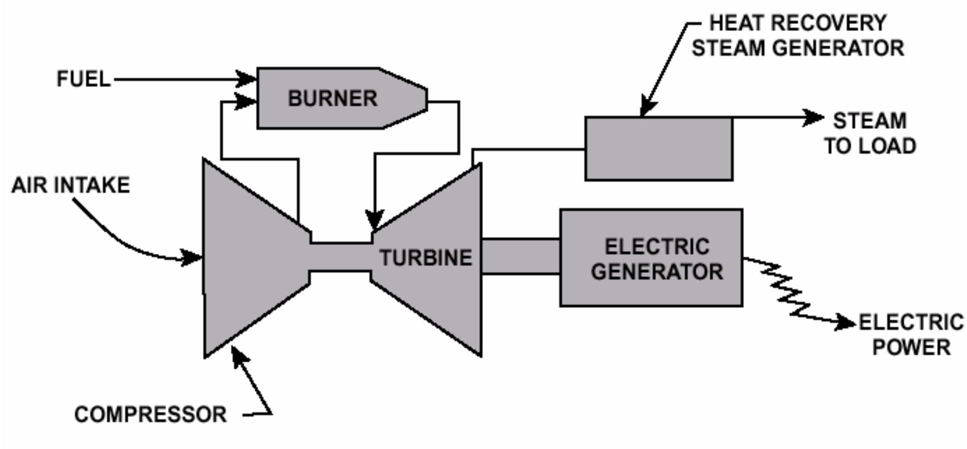


Figure 2.2. Simple-cycle gas turbine

Recuperative gas turbines are also primarily used in small generation applications (less than 25 megawatts). A combined cycle consists of a combustion turbine with a heat recovery steam generator (HRSG) in series with an electric generating steam turbine (figure 2.3). The waste heat from the combustion turbine produces steam at the HRSG that fuels the steam turbine to produce electricity.

Combined cycle systems have improved greatly over the years, and today advanced systems (such as the Steam Turbine Assisted Cogeneration – STAC - System) are specifically designed to optimise the variance between electrical and thermal load requirements. During periods of higher electrical demand, all or a majority of the steam output from the HRSG can be sent through the steam turbine to create additional electrical output. In contrast, during periods of higher thermal demand, all or part of the steam from the HRSG can be used for process needs at the facility.

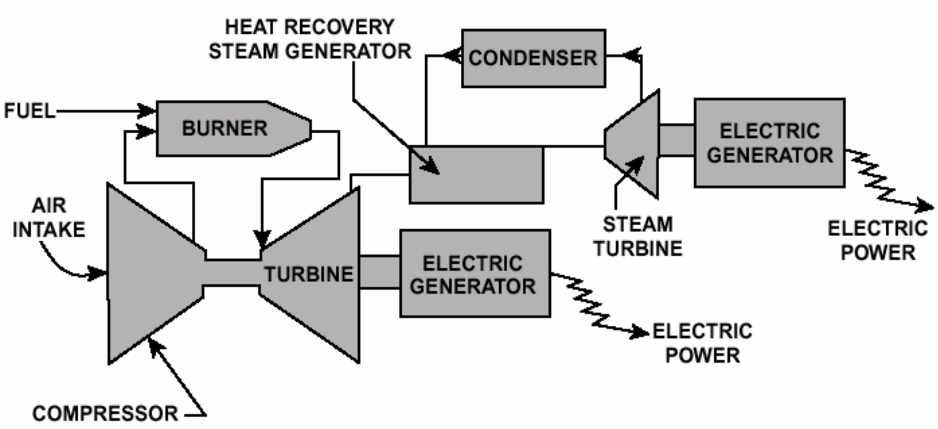


Figure 2.3. Combined-cycle system

Low maintenance, high quality waste heat, and electric efficiencies varying between 25 and 40% make combustion turbines an excellent choice for CHP applications larger then 5 MW. Capital costs for gas turbines vary between \$300-\$900 per kW installed.

2.1.4. Steam Turbines

Steam turbines are the most commonly employed prime movers for cogeneration applications, particularly in industries and for district heating. The technology is well proven in applications having demand for both electricity and large quantity of steam at high and low pressures. Some steam turbine manufacturers are over 100 years old and have products ranging from a few kW to 80 MW. However, turbines below 2 MW may be uneconomical, except where the fuel has no commercial value. The two types of steam turbines most widely used are the backpressure and the extraction-condensing types, presented in figure 2.4.

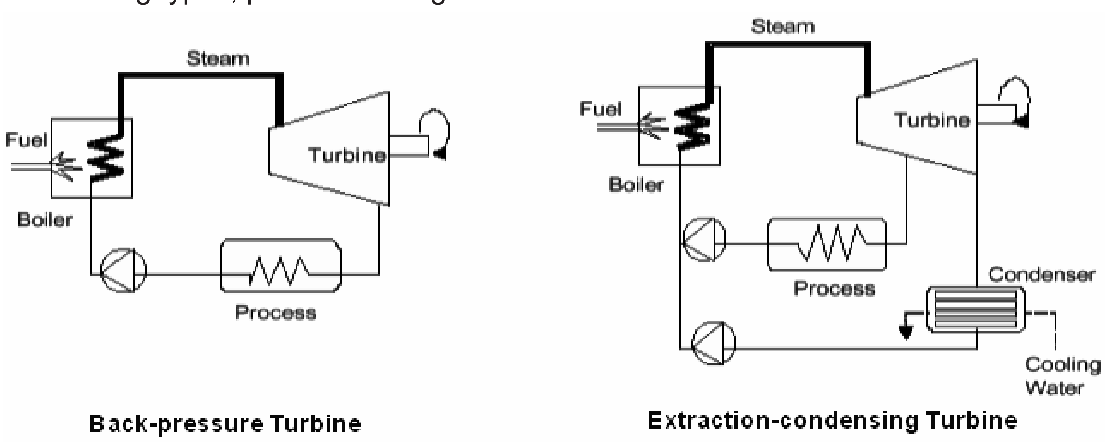


Figure 2.4. The two types of steam turbine cogeneration systems

A cogeneration system using a backpressure steam turbine consists of a boiler, the turbine, a heat exchanger and a pump. In the steam turbine, the incoming high-pressure steam is expanded to a lower pressure level, converting the thermal energy of high-pressure steam to kinetic energy through nozzles and then to mechanical power through rotating blades. Thermal energy of the turbine exhaust steam is then transferred to another fluid, water, air, etc., in a heat exchanger, providing heat to the processes. For instance, the air heated by a heat exchanger can be used to dry products in food processing industries.

Depending on the pressure (or temperature) levels at which process steam is required, backpressure steam turbines can have different configurations. The most common types of backpressure steam turbines are shown in figure 2.5. In extraction and double extraction backpressure turbines, some amount of steam is extracted from the turbine after being expanded to a certain pressure level. The extracted steam meets the heat demands at pressure levels higher than the exhaust pressure of the steam turbine.

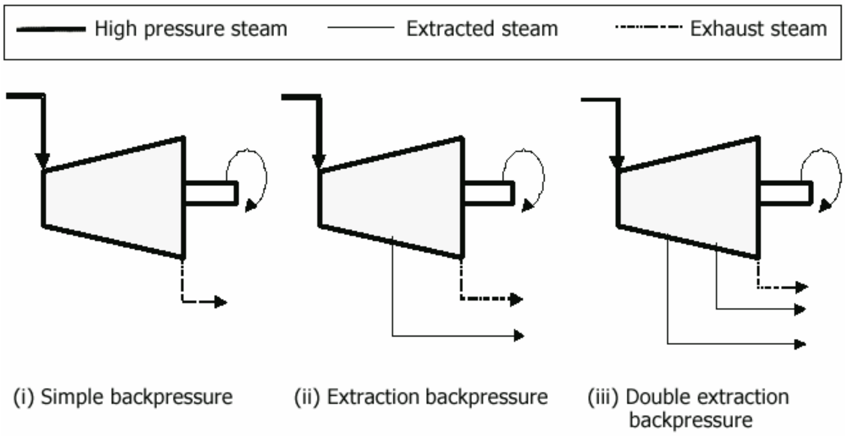


Figure 2.5. Different configurations for backpressure steam turbines

In the case of a reheat cycle, steam is extracted from the turbine and reheated in the boiler during the expansion process. Reheat cycles improve the overall thermal efficiency and eliminate any moisture that may form as the steam pressure and temperature are lowered in the turbine. Steam turbines may also include a regenerative cycle, where the steam is extracted from the turbine and used to preheat the boiler feed-water.

The heat extracted from the steam in extraction-condensing systems is optimised by exhausting the steam from the turbine at less than atmospheric pressures. The extraction-condensing turbines have higher power to heat ratio in comparison to backpressure ones. Although condensing systems need more auxiliary equipment, such as the condenser and cooling towers, better matching of electrical power and heat demand can be obtained where electricity demand is much higher than the steam demand and the load patterns are highly fluctuating.

The efficiency of a backpressure steam turbine cogeneration system is the highest. In cases where 100% backpressure exhaust steam is used, the only inefficiencies are gear drive and electric generator losses, and the inefficiency of steam generation. Therefore, with an efficient boiler, the overall thermal efficiency of the system could reach as much as 90%. The overall thermal efficiency of an extraction condensing turbine CHP system is lower than that of backpressure turbine system, basically since the exhaust heat cannot be utilized (normally lost in the cooling water circuit).

However, extraction condensing CHP systems have higher electricity generation efficiencies, but these usually fall in the range of 20% to 40%, with a boiler/steam turbine installation cost ranging from $800-$1000/kW. The incremental cost of adding a steam turbine to an existing boiler system or to a combined cycle plant is approximately $400-$800/kW.

2.1.5. Micro-turbines

A new class of small gas turbines called micro-turbines is emerging for the distributed resource market. Several manufacturers are developing competing engines in the 25-250 kW range, however, multiple units can be integrated to produce higher electrical output while providing additional reliability. Most manufacturers are pursuing a single shaft design wherein the compressor, turbine and permanent magnet generator are mounted on a single shaft supported on lubrication-free air bearings. These turbines operate at speeds of up to 120,000 rpm and are powered by natural gas, gasoline, diesel, and alcohol.

The dual shaft design incorporates a power turbine and gear for mechanical drive applications and operates up to speeds of 40,000 rpm. Micro-turbines are a relatively new entry in the CHP industry and therefore many of the performance characteristics are estimates based on demonstration projects and laboratory testing. The operating theory of the micro-turbine is similar to the gas turbine, except that most designs incorporate a recuperator to recover part of the exhaust heat for preheating the combustion air. As shown in figure 2.6, air is drawn through a compressor section, mixed with fuel and ignited to power the turbine section and the generator.

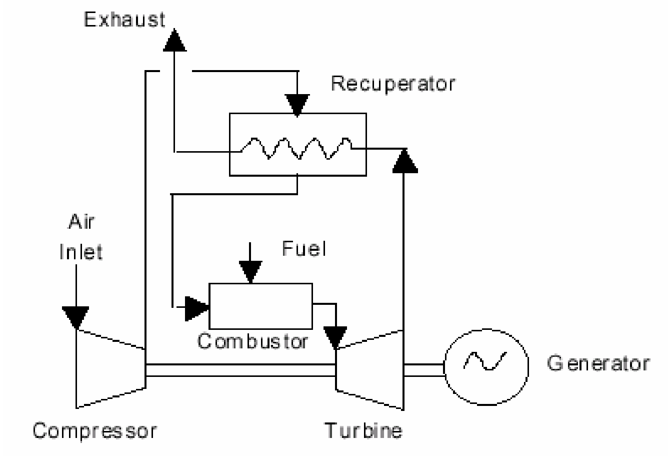


Figure 2.6. Schematic of a recuperated micro-turbine

Their compact and lightweight design makes micro-turbines an attractive option for many light commercial/industrial applications. Micro-turbines are being developed in the near term to achieve thermal efficiencies of 30% and NO_x emissions less than 10 ppm. It is expected that performance and maintenance requirements will vary among the initial offerings. Installed prices of $500-1000/kW for CHP applications are estimated when micro-turbines become mass-produced.

2.1.6. Fuel cells

Fuel cells are an exciting technology that convert hydrogen-rich fuels, such as natural gas, into electricity and heat through an extremely quiet and environmentally clean process. Fuel cells generate electricity through an electrochemical process in which the energy stored in the fuel is converted directly to electricity (catalytic reaction).

There are three main components that govern the operation of a fuel cell:

1. *Hydrogen reformer*, a fuel processor that extracts hydrogen from a fuel source (such as natural gas, bio-mass, or propane).
2. *Fuel cell stacks*, which are electrolyte materials situated between oppositely charged electrodes, where the hydrogen fuel generates DC power in an electro-chemical reaction.
3. *Inverter*, that converts DC outputs to AC power.

Figure 2.7 provides a visual example of the energy flows. The operating conditions of a fuel cell are determined by the electrolyte; therefore, fuel cells are identified by the electrolyte employed in the process.

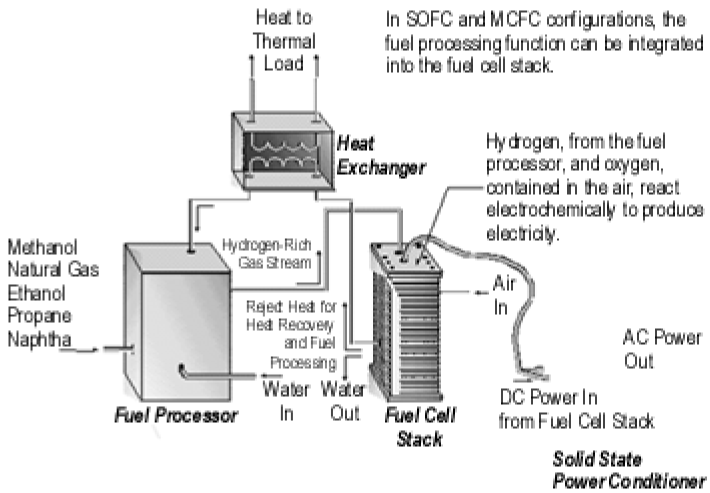


Figure 2.7. Fuel cell schematic

Several fuel cell technologies are operating and under development today:

- *Phosphoric acid* fuel cells (PAFC) are most common because they were the first fuel cell types to become commercially available. They have an acid electrolyte and operate at relatively low-temperatures (about 150°C). Units sized at 200 kW with 700,000 Btuh of thermal heat recoverable in the form of hot water are commercially produced.
- *Molten carbonate* fuel cells (MCFC) are relatively high-temperature units, operating in excess of 600°C. MCFCs are designed for large-scale applications on the order of 50 to 100 MW. The high-temperature exhaust gases can be used in a combined cycle system, creating an overall efficiency of about 80 percent.
- *Solid oxide* fuel cells (SOFC) also operate at high-temperatures, 600 to 1000°C. At these temperatures, a natural gas-powered fuel cell does not require a

reformer. A variety of 20 to 25 kW SOFC units have been tested, and units up to 150 kW are planned.

- *Proton exchange membrane* fuel cells (PEMFC) operate at low temperatures (about 80°C). Manufacturers are targeting units in the range of 7 kW to 250 kW. Their very low thermal and noise signatures might make them especially useful for replacing military generator sets.

Pollution from fuel cells is so low that several Air Quality Management Districts in the United States have exempted fuel cells from requiring a permit to operate. Today's natural gas-fired fuel cells operate with an electrical conversion efficiency of 35 to 40% and are predicted to climb to the 50 to 60% range in the near future. When recovered heat from the fuel cell process is used to capacity by a facility, efficiencies can exceed 85%. And as with micro-turbines, multiple fuel cells can be synchronized to meet changing demand needs.

The major barrier to fuel cell market acceptance is their high first cost, that is $3,000 to $3,500 per kilowatt installed. Experts predict that fuel cell costs will have to come down below $1,000 per kilowatt before any significant non-government subsidized market transformation takes place. Growing public interest and increased competition of manufacturers will play a major role in driving down the price over the next few years.

2.1.7. Technology summary

Different cogeneration technologies were examined in the above, some emerging and some already established. Table 2.1 offers a comparison of the technical and economical parameters distinguishing CHP technologies.

Table 2.1. CHP technology characteristics

	Diesel Engine	**Natural Gas Engine**	**Steam Turbine**	**Gas Turbine**	**Micro-turbine**	**Fuel Cells**
Electric Efficiency (LHV)	30-50%	25-45%	30-42%	25-40% (simple) 40-60% (combined)	20-30%	40-70%
Size (MW)	0.05-5	0.05-5	Any	3-200	0.025-0.25	0.2-2
Footprint (m^2/kW)	0.02	0.02-0.029	<0.01	0.002-0.06	0.014-0.14	0.06-0.37
Installation Cost (€/kW)	700-1350	700-1350	700-900	650-850	450-1150	>2700
O&M cost (€/kWh)	0.005-0.007	0.007-0.014	0.004	0.002-0.007	0.002-0.01	0.003-0.014
Availability	90-95%	92-97%	Near 100%	90-98%	90-98%	>95%
Hours between overhauls	25,000-30,000	24,000-60,000	>50,000	30,000-50,000	5,000-40,000	10,000-40,000
Start-up time	10 sec	10 sec	1 hr – 1 day	10min – 1 hr	60 sec	3 hrs-2 days
Fuel pressure (psi)	<5	1-45	N/a	120-500 (may require compressor)	40-100 (may require compressor)	0.5-45
Fuels	Diesel and	Natural gas,	All	Natural gas,	Natural gas,	Hydrogen,

	residual oil	biogas, propane		biogas, propane, distillate oil	biogas, propane, distillate oil	natural gas, propane
Noise	Moderate to high (building enclosure)	Moderate to high (building enclosure)	Moderate to high (building enclosure)	Moderate (enclosure supplied with unit)	Moderate (enclosure supplied with unit)	Low (no enclosure required)
NO_x emissions (kg/MWh)	1.4-15	1-12.7	0.8	0.14-1.8	0.18-1	<0.01
Uses for heat Recovery	Hot water, LP steam, district heating	Hot water, LP steam, district heating	LP-HP steam, district heating	Direct heat, Hot water, LP-HP steam, district heating	Direct heat Hot water, LP steam,	Hot water, LP-HP steam
CHP output (Btu/kWh)	3,400	1,000-5,000	N/a	3,400-12,000	4,000-15,000	500-3,700
Useable Temp. for CHP (^oC)	80-480	150-260	N/a	260-600	205-345	60-370

2.2. ELECTRIC POWER GENERATORS

All cogeneration systems, with the exception of fuel cells that produce electricity directly, require an electric generator driven by the prime mover. Reciprocating engines operate at speeds that are compatible with the generators speeds, so a direct drive with no reduction gear is the rule. Single-shaft turbines usually operate at high speeds, and a reduction gear is therefore needed.

Multi-stage steam turbines or multi-shaft gas turbines can operate the shaft connected to the generator at lower speeds, which are compatible with the speeds of the generators. Generator efficiency typically lies in the range 95-98%, although small asynchronous generators or generators operating at partial load may have efficiencies which are as low as 85%, since the efficiency decreases nonlinearly with the load.

2.2.1. Principles of electrical machines

Rotating electric machines are electromechanical transducers converting electrical energy into mechanical (motors) or, the reverse, mechanical energy into electrical energy (generators). The essential link in this chain of conversion is the energy of the electromagnetic field developed in the machine's "air gap" by the currents flowing in the "windings". The main parts of a rotating electric machine are shown in figure 2.8.

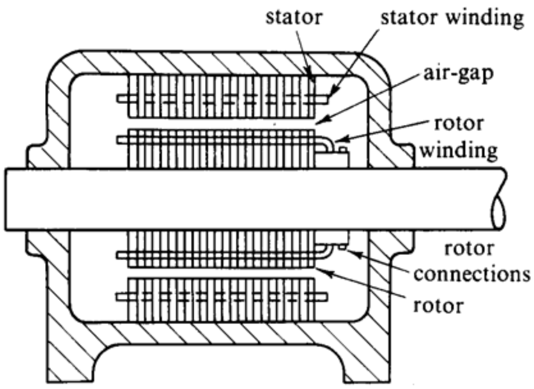


Figure 2.8. Basic rotating machine

The stator and rotor windings are usually formed in such a way that the electromagnetic flux in the air gap is, approximately, sinusoidally distributed. In this case, the developed electromagnetic torque, due to the interaction of the stator and rotor fields, is proportional to the magnitude of each field (i.e., to the value of the stator and rotor currents, i_s and i_r) and the sinus of the angle θ of the vectors representing the fluxes in the air gap: $T_e = K\, i_s\, I_r \sin\theta$, where K is a machine constant.

Thus, the development of a mean electromagnetic torque in the steady-state operation of the machine requires a constant (time-invariant) angle θ between the stator and rotor fields. This essential requirement is met in a different way for each of the three main types of electrical machines that are:

- Synchronous machines.
- Asynchronous (or Induction) machines.
- Direct Current (DC) machines.

2.2.2. Synchronous machines

In synchronous machines, the stator winding is “distributed” in order to obtain a sinusoidal distribution of the magnetic flux along the air gap. The rotor winding may be concentrated or uniformly distributed on a cylindrical rotor. When each of the phase windings is arranged so that it spans $60^o+60^o=120^o$ and a symmetrical three-phase voltage system is applied, a “rotating field” is developed in the air gap, with angular velocity equal to the frequency of the applied voltage, as shown in figure 2.9.

F_a represents the axis of the magnetic field at an instant when the currents of the winding I-I’ have their maximum instantaneous values (large dots and crosses in part I of the winding). After a time interval t, such that $\omega t=60^o$, the currents in part III of the winding, corresponding to another phase, are maximum, as shown in 2.9(b), etc. This process results in the generation of a “rotating field” and is valid for symmetrical multi-phase windings fed by symmetrical systems of voltages of equal number of phases.

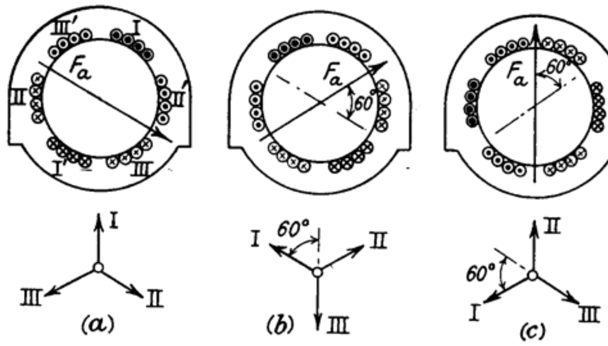


Figure 2.9. Rotating fields

The angular velocity of the rotating field is called the “synchronous speed”. The excitation current, i.e. the direct current (DC) required for the coils around the magnetic poles (field windings), is provided either by a separate DC generator that is mounted on the same shaft and driven by the same prime mover, or by a static rectifier (self excited generators). The “equivalent circuit” of fig. 2.10(b) can describe the behaviour of a synchronous machine, schematically shown in fig. 2.10(a), where only one phase is retained (the other phases are identical, simply displaced by 120^o).

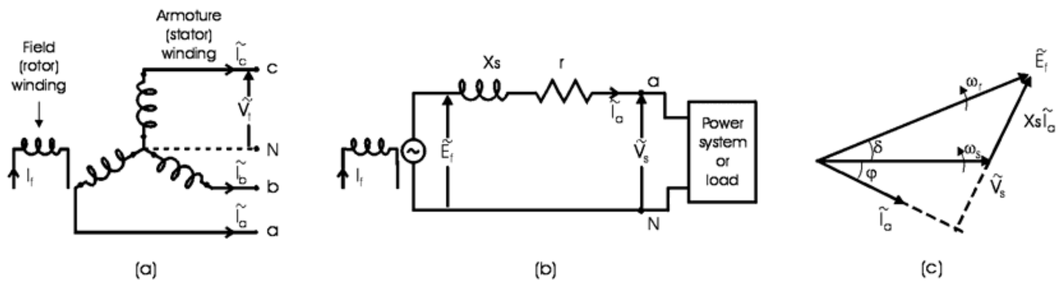


Figure 2.10. Equivalent circuit of a synchronous machine

The vector diagram of figure 2.10(c) corresponds to operation with inductive load. When the generator feeds an independent load, the angular frequency ω_s of the induced terminal voltage $\tilde{V}_s$ will be equal to the rotor speed ($\omega_s = \omega_r$). Consequently, the angle δ between the electromotive force $\tilde{E}_f$ and $\tilde{V}_s$ will remain constant. When the generator operates in parallel to a large power system, the angular frequency of the terminal voltage ($\omega_s = 2\pi f_s$) is imposed by the system. In order for the generator to remain “in synchronization” with the power system (i.e. maintain a constant “torque-angle” δ), its rotor must rotate at exactly the same speed, $\omega_r = \omega_s$.

The generator shown in figure 2.10 has only two poles, although in practice generators usually have more than two poles. In the case of a p-pole generator, rotating with a “mechanical speed” ω_m (or n in RPM), the angular frequency of its terminal voltage will be: $\omega = p/2 \cdot \omega_m = p/2 \cdot 2\pi \cdot n/60 = 2\pi f$. That is:

$$n = \frac{120f}{p} \tag{2.1}$$

Therefore, in order to produce voltages of the standard 50 Hz frequency, the rotor must be rotated with: n=6000/p RPM. Thus, for p=2 n=3000 RPM, for p=4 n=1500 RPM, for p=6 n=1000 RPM, etc.

2.2.3. Asynchronous (induction) machines

Asynchronous generators do not have an internal source of excitation current (reactive power); they are similar to induction motors. Therefore, such a generator can operate only if it is connected to an external source of reactive power, such as the utility grid. If the grid fails, then the operation of the generator is discontinued. If stand-alone capability is required, e.g. to serve a house far from the utility grid, an external exciter can be installed.

The stator of a three-phase induction machine is similar to that of a synchronous machine, being constructed by laminated ferromagnetic material, with the three-phase winding residing in slots cut in its inner surface. The same material is used for the construction of the rotor, with slots lying on its outer surface. There are two distinct types of rotors, namely:

(a) the “wound rotor” type, where the rotor winding is similar to that of the stator, with its terminals connected to slip rings, and
(b) the “squirrel-cage” type, where the rotor winding consists of aluminium or cooper bars embedded in the slots and shorted at both ends by end-rings.

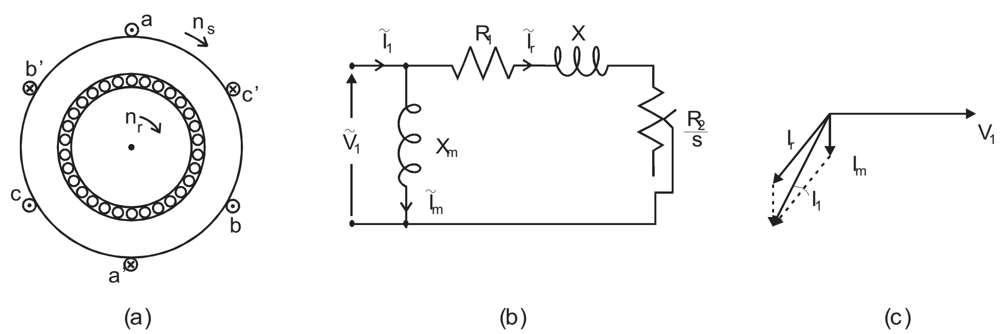


Figure 2.11. Equivalent circuit of three-phase induction machine

The simplified “equivalent circuit” of figure 2.11(b) can describe the operation of the induction machine, with R_1 the resistance of the stator winding, R_2 the resistance of the rotor winding “referred” to the stator, X the sum of the leakage reactance of the stator and rotor windings (the latter referred to the stator), and X_m the “magnetizing” reactance. The corresponding vector diagram for generator operation of the machine is shown in figure 2.11(c). When the three-phase stator winding is connected to a symmetrical 3-phase voltage system, a rotating field will be established in the air gap.

The rotational speed will be n_s=60ω_s/2π, where ω_s is the synchronous speed. If the rotor rotates with n_r (rpm), then the bars (or the conductors of the conventional winding) of the rotor will cut the magnetic lines of this field with an angular velocity: ω_s–ω_r=2π (n_s–n_r)/60, resulting in the development of voltages/currents of frequency:

$$f_2 = \frac{1}{60}(n_s - n_r) \quad (2.2)$$

for a two-pole machine. The difference between the rotor speed n_r and the synchronous speed n_s of the rotating field is defined as “slip”:

$$s = \frac{n_s - n_r}{n_s} = \frac{\omega_s - \omega_r}{\omega_s} \quad (2.3)$$

From (2.3) it results: $n_r = (1–s)\, n_s$ or $\omega_r = (1–s)\, \omega_s$. Also, from (2.2), the frequency of the rotor voltages and currents will be:

$$f_2 = \frac{1}{60} s n_s = s f_s \quad (2.4)$$

The frequency sf_s is called “slip frequency”. The induced rotor currents also establish a field rotating with respect to the rotor with a speed: $n_2 = 60 f_2 = 60 s f_s = s n_s$. But, as the rotor is rotating at n_r, the induced rotor field rotates in the air gap at a speed: $n_r + n_2 = (1–s)\, n_s + s\, n_s = n_s$. Therefore, both the stator and the induced rotor fields rotate in the air gap at the same synchronous speed n_s, i.e. they are stationary with respect to one another, and consequently a mean torque is developed.

2.2.4. Generator selection

The size of a synchronous generator may be specified in kilowatts or kVA. Obviously the user is most interested in kW but the kVA rating is almost equally important. The kVA rating is the rated voltage multiplied by the rated maximum current, and the kW output is given by the kVA multiplied by the power factor (cosφ). Most interconnected generators are required to control power factor as well as supply Watts, so the kW output of a machine is not all that there is to it. Rated generator voltage is also quite an important economic consideration.

In general, the higher the voltage the lower the internal losses in the generator will be, but it is not economical to build small generators for high voltages. As a rule of thumb, 480V is most economical up to 500 kVA; 4160V is best at 750kVA and larger; and 13.8kV should be used at 2500 kVA and larger. At the same time, the cost of switchgear and transformers has to be factored, and if the generator will be added to an existing system, the choice of voltage may be governed by investment in existing equipment.

Therefore, to find a solution, the cost of all equipment that must be purchased for each voltage level is factored against electrical losses over the expected life of the set-up. In synchronous machines, the unit itself provides the excitation current and consequently it can operate independently of or isolated from any external source of power. This is why synchronous generators are used in most of the cogeneration systems and they are the obvious choice in larger applications. On the other hand, asynchronous generators, which do not have an external source of excitation current but are simple and low cost devices, are used in low power applications, usually lower than 200 kW.

It is important to remember that the CHP plant requires electricity to drive auxiliary pumps, fans etc. This parasitic load could be 1% of the generator output with a gas turbine and 3% with a compression-ignition engine, while if there is a need to boost gas supply pressure, a further 6% could be required for the gas compressor. Additional power may also be needed to run heat recovery plant auxiliaries. Steam turbine CHP can have very high parasitic consumption depending on boiler pressure and temperature conditions, waste fuel preparation/handling, etc.

2.3. HEAT RECOVERY

2.3.1. Heat recovery options

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. Therefore, heat from the engine cooling water is transferred by heat exchangers (plate or shell-and-tube) to separate heating water circuits.

Thus, 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. In all cases the heat exchangers used are of shell and tube or plate designs, varying in complexity according to the demand placed on the system.

2.3.2. 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 Table 2.2. However, not all of this heat can be recovered in a boiler.

Table 2.2. Typical heat content of exhaust gases

	Gas Turbine	***Reciprocating Engine***
Percentage 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 that contain some sulphur, as the sulphur oxides produced can be condensed into sulphuric acid below certain temperatures, this way causing corrosion of the chimney.
- 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 that 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.

Therefore, heat recovery boilers are not ‘off-the-shelf’ items, as 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 have to provide the quantity of heat that can be recovered, and the temperature at which the exhaust gas will be discharged from the boiler.

2.3.3. Heat recovery in reciprocating engines

The energy of the fuel is released during combustion and is converted to shaft work and heat. Shaft work drives the generator, while heat is liberated from the engine through coolant, exhaust gas and surface radiation. Approximately 60-70% of the total energy input is converted to heat that can be recovered from the engine exhaust and jacket coolant, while smaller amounts are also available from the lube oil cooler and the turbocharger's intercooler and after-cooler (if so equipped). Steam or hot water can be generated from recovered heat that is typically used for space heating, reheat, domestic hot water and absorption cooling.

A typical heat balance diagram of a gas engine is shown in figure 2.12. About 25% of the heat recovered from the engine cooling system (cooling water, oil cooler and inlet air cooler) is low grade at a temperature of about 95^{o}C. Engine exhaust heat is 10-30% of the fuel input energy. Exhaust temperatures of 455°-650°C are typical, but only a portion of the exhaust heat can be recovered since exhaust gas temperatures are generally kept above condensation thresholds. Most heat recovery units are designed for a 150°-180°C exhaust outlet temperature to avoid the corrosive effects of condensation in the exhaust piping.

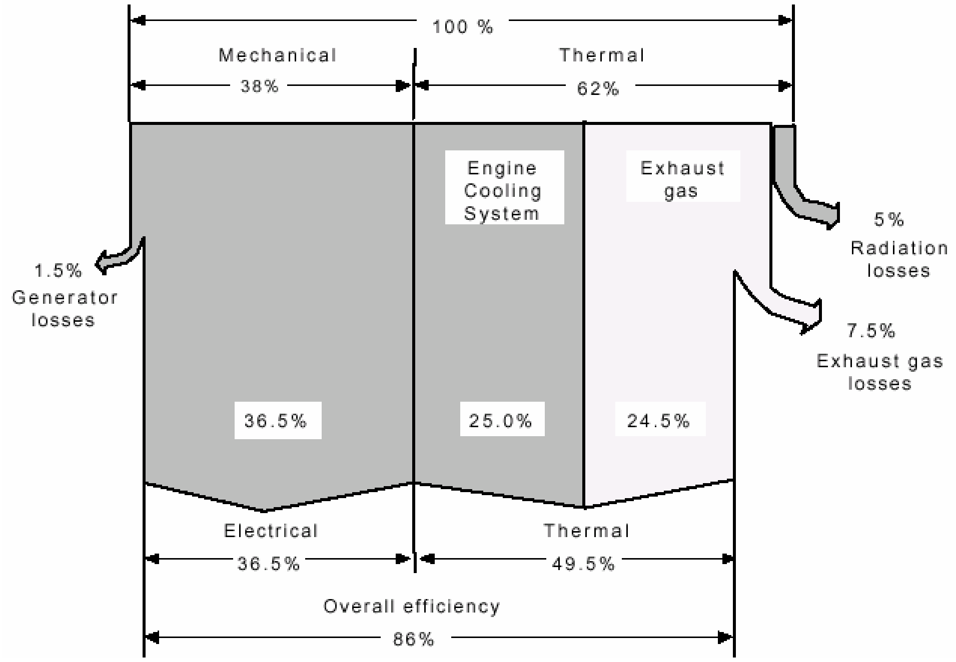


Figure 2.12. Typical heat balance of a gas engine

Considering the same power output, the amount of heat recoverable at high temperature is lower than that for the gas turbine. That is why cogeneration with reciprocating engine is more commonly used for producing hot water/hot air (to about 110°C) or low-pressure steam (15 psig). However, medium pressure steam can be generated by employing supplementary firing, since exhaust gases from gas engines have an O_2 content of about 15%. By recovering heat in the water jacket and exhaust, approximately 70-80% of the fuel's energy can be effectively utilized from a typical spark-ignited engine. Table 2.3 illustrates this fact.

Table 2.3. IC engine generation process *

	Without Heat Recovery	***With Heat Recovery***
Engine output at flywheel	**35%**	**35%**
Unrecoverable heat	65%	21%
Recoverable heat	0%	**44%**
Total useful energy	**35%**	**79%**

* Values are approximated. Figures total 100%. Values in bold represent useful energy

The most common method of recovering engine heat is the closed-loop cooling system. These systems are designed to cool the engine with the forced circulation of a coolant through engine passages and an external heat exchanger. An excess heat exchanger transfers engine heat to a cooling tower or radiator when there is excess heat generated. Closed-loop water-cooling systems can operate at coolant temperatures between 90°-120°C.

Ebullient cooling systems cool the engine by natural circulation of a boiling coolant through the engine. This type of cooling system is typically used in conjunction with exhaust heat recovery for the production of low-pressure steam. Cooling water is introduced at the bottom of the engine where the transferred heat begins to boil the coolant, generating a two-phase flow. The formation of bubbles lowers the density of the coolant, causing a natural circulation to the top of the engine.

The coolant at the engine outlet is maintained at saturated steam conditions and is usually limited to 120°C and a maximum of 15 psig. Inlet cooling water is also near saturation conditions and is generally 2°- 3°C below the outlet temperature. The uniform temperature throughout the coolant circuit extends engine life, contributes to improved combustion efficiencies and reduces friction in the engine.

2.3.4. Heat recovery in steam turbines

Heat recovery methods from a steam turbine use exhaust or extraction steam. Heat recovery from a steam turbine is somewhat misleading since waste heat is generally associated with the heat source, in this case a boiler either with an economizer or an air pre-heater. A steam turbine can be defined as a heat recovery device. Producing electricity in a steam turbine from the exhaust heat of a gas turbine (combined cycle) is a form of heat recovery.

The amount and quality of the recovered heat is a function of the entering steam conditions and the design of the steam turbine. Exhaust steam from the turbine can be used directly in a process or for district heating. Or it can be converted to other forms of thermal energy including hot water or chilled water. Steam discharged or extracted from a steam turbine can be used in a single or double-effect absorption chiller. A steam turbine can also be used as a mechanical drive for a centrifugal chiller.

2.3.5. Gas turbine heat recovery

The simple cycle gas turbine is the least efficient arrangement since there is no recovery of heat in the exhaust gas. Hot exhaust gas can be used directly in a process or by adding a heat recovery steam generator (HRSG), which is one of the major components of a gas turbine CHP system, exhaust heat can generate steam or hot water. In this case, the exhaust gas at 500-550^{o}C is cooled in the HRSG to about 150^{o}C to extract useful heat.

A temperature of 150^{o}C is recommended at the outlet of the HRSG to avoid condensation of exhaust gases. At lower temperature levels, gases such as SO_x and NO_x would form acids along with the condensation and corrode the materials of

HRSG. For larger gas turbine installations, combined cycles become economical, achieving approximately 60% electric generation efficiencies with the use of the most advanced utility-class gas turbines.

The heat recovery options available from a steam turbine used in the combined cycle can be implemented to further improve the overall system efficiency. Since the gas turbine exhaust gases are oxygen rich (typically 14 to 17%), as a result of the need for high excess air in the combustion chamber (to avoid very high gas temperatures that can affect the turbine), additional combustion through supplementary firing can be supported. A duct burner is usually fitted within the HRSG to increase the exhaust gas temperature at efficiencies of 90% and greater.

2.3.6. Heat recovery in micro-turbines and fuel cells

In the case of micro-turbines, hot exhaust gas from the turbine section is available for CHP applications. As was presented previously, most designs incorporate a recuperator that limits the amount of heat available for CHP. Recovered heat can be used for hot water heating or low-pressure steam applications.

Significant heat is released in a fuel cell during electrical generation. The PAFC and PEMFC operate at lower temperatures and produce lower grades of waste heat generally suitable for commercial and industrial CHP applications. The MCFC and SOFC operate at much higher temperatures and produce heat that is sufficient to generate additional electricity with a steam turbine or a micro-turbine hybrid gas turbine combined cycle.

2.4. CONTROL AND MONITORING SYSTEMS

2.4.1. Control systems

All the basic sub-systems that constitute the cogeneration system must operate efficiently as an integral system with optimised performance to produce the greatest benefit. In this respect, prime movers must be regulated to respond to changing load conditions, generators must hold frequency and voltage within close limits, while the heat recovery equipment must deliver energy to the required demand. Additionally, overrides and safeguards must be built-in to ensure safety and plant protection.

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.

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 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 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 (see figure 2.13) 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.

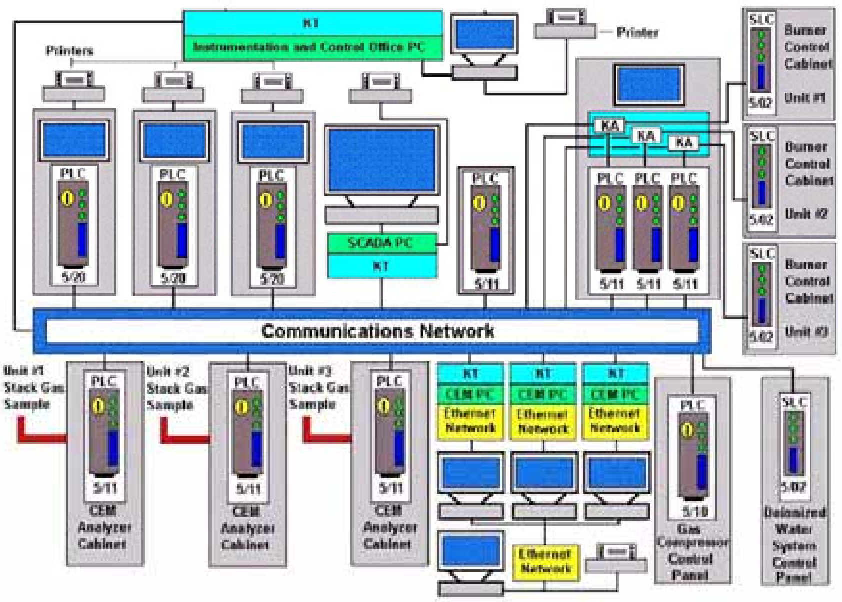


Figure 2.13. Central power plant monitoring and control system

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.

2.4.2. Long-term performance monitoring

Performance monitoring is a key function of modern process control systems. Monitoring of a wide range of parameters can be used in order to:

- detect faults, malfunctions, under-performance etc. at the earliest possible stage so that they can be promptly rectified,
- enable fine tuning and optimisation of the equipment,
- facilitate modifications in order to respond to alterations in site energy loads, new or amended electricity supply tariffs, fuel price/availability fluctuations etc.,
- audit the return on investment.

Taking as an example a typical prime mover, the gas turbine, the list of variables to be monitored and controlled includes: firing temperature, inlet-air temperature and relative humidity, barometric pressure, air-filter pressure drop, water/steam injection rate, exhaust back-pressure, power factor, the fuel temperature and LHV (lower heating value), just to name a few. Any CHP system constitute a multi-component integrated power plant, whose operating characteristics are continually changing due to ambient conditions, loading, and equipment maintenance and degradation.

Thus, a cogeneration plant control system must be able to support the growing need for high-speed and secure control within the automation system. In the cases that there is already a comprehensive energy monitoring system on site, it should be relatively easy to incorporate the CHP monitoring procedure, otherwise a new system is required, having the provision to be extended in the future. Apart from the operating variables already mentioned, there are others that are used by a *Preventive Maintenance System*, to minimise sudden system shutdowns.

For a turbine, the above mentioned variables are the vibration and phase angle at each bearing, shell, rotor and differential expansion, total control-valve position, speed, rotor eccentricity, steam temperatures, shell and bearing metal temperatures, thrust-bearing wear, exhaust pressure, etc. The latest technique used in critical large CHP systems is acoustic emission, where piezoelectric sensors mounted on critical parts of the system, allow the user to forecast the useful life of components.

Optical sensors can measure many system parameters, including temperature, pressure, strain, voltage, current, electric field, and chemical concentrations. Fiber-optic sensors detect responses to external influences in the intensity, phase or wavelength of light signals transmitted along an optical fibre. They are non-electric presenting no spark-hazard, small in size, carrying large amounts of information and non intrusive.

Silicon sensors are another type used to measure pressure and flow. Using elastic oscillation traits of single-crystal silicon, these sensors are suitable for digital signal processing. Measuring bulk levels was traditionally done with gage glasses even though a thermally stable sensitive semiconductor strain gage is used nowadays. Overall, the trend is towards sensors providing digital signal processing so that a central control system can safely and accurately monitor and control the power plant.

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.

3.1. HEAT RECOVERY AND DISTRIBUTION DEVICES

3.1.1. Heat recovery boilers and the exhaust system

One important aspect of a heat recovery boiler is its control of the exhaust gas input. Normal CHP plant operation is determined by the prime mover. The heat recovery boiler is located downstream of the turbine or engine exhaust gas outlet and, therefore, tends to ‘get what it is given’. Although the boiler has no control over the temperature, flow rate or constituents of the exhaust gases, it must be able to operate within its design and safety limits.

So, in order to control the heat input to the boiler, a set of control dampers can be installed in the ductwork between the prime mover and the boiler, with a bypass duct into which exhaust gases can be diverted. This allows the heat input and output of the heat recovery boiler to be controlled, while the prime mover output remains unaltered. If necessary, the prime mover can even operate for short periods without any heat recovery.

The system also allows the prime mover to be started up in isolation from the boiler, and the dampers can then be used to gradually increase the heat flow into the boiler, minimising thermal stress. The exhaust gases must pass from the boiler outlet to atmosphere using the appropriate ductwork and chimney. The exhaust flow rate of gas turbines and engines is higher than that of a normal boiler of similar size, and the ductwork and chimney must be sized both to ensure the correct velocity and temperature of gases at the discharge point, and to keep pressure losses to a minimum.

With most gas turbines, and with some engines, it may be necessary to incorporate a silencer unit within the exhaust system to minimise noise levels emitted from the exhaust discharge point. In some cases, the heat recovery boiler provides sufficient noise attenuation for the main exhaust gas, and a silencer is required only in the exhaust gas bypass ductwork. In other cases, where noise is a significant consideration, it may be necessary to locate the silencer immediately downstream of the prime mover.

3.1.2. Supplementary and auxiliary firing

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. The exhaust gases from a gas turbine or reciprocating engine contain around 15% oxygen, and this allows supplementary firing to be carried out in the exhaust before it passes into the boiler.

Since 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 CO_2 emissions. Efficiencies of up to 88% 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 (NO_x) levels than boilers using ambient air.

Furthermore, the combined NO_x 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 both improve 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.

3.1.3. Heat output from the CHP package

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 pipe-work 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’ pipe-work system.

The ‘flow’ pipe-work 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’ pipe-work 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 (figure 3.1):

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

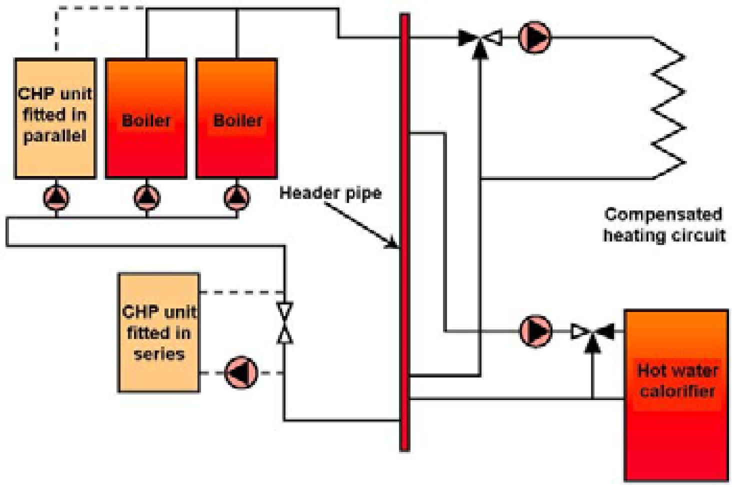


Figure 3.1. CHP unit connection methods with a conventional boiler plant (series and parallel)

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 pipe-work. 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 pipe-work system.

In order to comply with the requirements for good quality CHP, 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 pipe-work 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.

3.1.4. Distribution of heat

The heat from the cogeneration system can be distributed under different conditions. The best thermal distribution for the HVAC system must be suitably selected and its cost and dimension must be well designed. Table 3.1 summarises the various thermal distribution systems.

Table 3.1. Thermal distribution systems

System	***Applications***	***Advantages / Disadvantages***
Steam:		
Low pressure	• Heating system. • Single-stage absorption chiller.	• Lower heat loss than high pressure system • More complex start-up and shutdown
High pressure (1000 kPa to 1400 kPa)	• Two-stage absorption chiller.	• High temperature available • With condensate return: high construction - low operating cost. • Without condensate return: low construction - high operating cost due to the loss of condensate thermal energy and compensate water and its chemical treatment. • More complex start-up and shutdown
Hot water:		
High temperature (up to 200 °C)	• Heating system. • Single-stage absorption chiller. • Large HVAC systems.	• Smaller pipes than high-pressure system. • Lower operating costs
Low temperature (less than 80 °C)	• Heating system. • Single-stage absorption chiller. • Large HVAC system.	• Lower heat loss

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, of reciprocating 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. Therefore, on many decentralised sites it may 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.

3.1.4.1. Valves and fluid-handling devices

Flows of steam and water require piping, valves, and all other adjuncts of fluid-handling systems. Valves isolate the turbine and control steam flow both approaching the turbine and in the turbine itself. Steam supply to the power-generating turbine can be either a primary flow at maximum throttle conditions or a flow of reheat steam at practically the same temperature, but somewhat lower pressure. A current trend in operation requires large valves able to handle bypass flow at high-pressure drop.

Accompanying these valves are de-super-heater units and series-orifice pressure reducers. Smaller valves of more conventional design control drains, lubricating oil flow, and other auxiliary flow functions. The throttle-trip valve is a valve used in small turbines (fig. 3.2), serving the twin function of steam throttling and closing off of steam supply upon loss of turbine driven load for any reason. Turbine over speed causes the valve to trip and close in a small fraction of a second, leaving only the steam in the turbine steam chest and nozzles available to accelerate the machine.

The valve in the figure has a motor operator, but simpler ones may be manually actuated. Whatever the actuation, the valve always has the vital attribute of quick and automatic closure at a pre-selected over speed. Certain characteristics of this valve are common to many other turbine-inlet valves. For example, the disc or plug is guided to assure correct approach to the seat and prevent excessive sideways movement under steam-flow buffeting. The spindle is slender, to reduce packing-friction load, and therefore the bottom support is beneficial.

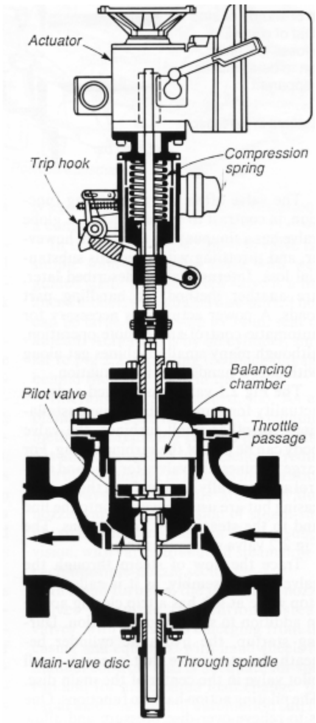


Figure 3.2. A throttle/trip valve

Control valves for large turbines have many design refinements for high-pressure, high-flow-rate work. Stem guidance and disc guidance are ample. What resembles a cage in the stop valve is a baffle to prevent excessive buffeting and steam impact against the valve disc. Leak off lines take away steam/ water mixtures that get past the packing and close clearances of the valve stems. The newer electro-hydraulic control systems that have replaced the mechanical hydraulic have smaller actuators, although the closure springs and feedback linkage are still bulky.

Valves for bypass operation must be capable for high flow rates and high-pressure drop. In addition, de-superheating may occur in the valve itself since the combination of pressure reduction and water injection is an attractive option. Figure 3.3 gives an idea of a large high-pressure bypass valve, which also de-superheats. The valve is simple, with straight flow passages, a large, well-guided stem for rigidity in the high-velocity buffeting flow, and water injection in the narrow annular passage at the seat.

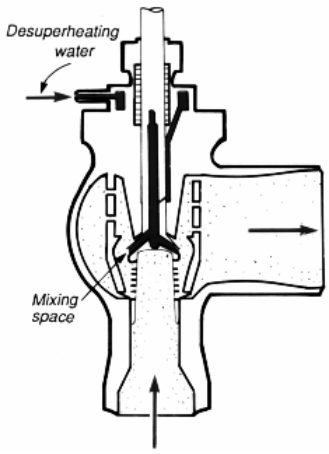


Figure 3.3. Bypass valves

Good mixing of water in the steam flow is essential for effective de-superheating, and the mixing must prevail over a wide flow range for both water and steam. The external control system can govern the amount and proportion of the water, but it is the valve itself and the adjacent piping that determine whether the mixing is effective. Water droplets impacting at high speed against cooler metal can be destructive, and this is also a key consideration in bypass valve and piping design.

Choice of materials, although important, probably is secondary in respect to the layout of the water nozzles and downstream flow path. Heater-drain valves, which remove the water from heaters under the direction of the control system, are in adverse conditions, exposed to flashing water, cavitation, and erosion. Advanced designs of control valves are tried constantly, which call for flows from highly throttled to wide open.

Pumps, very common in pipe-works and other processes, can have an indirect effect on performance in regard to efficiency and reliability. Their two main classes are condensate and condenser circulating-water pumps. Lube-oil pumps, although critical for service, are small and highly developed. The trend now is away from shaft-driven and to separately powered oil pumps. The condensate pump removes water from heaters and drains, thereby preventing water backup into the steam passages of the turbine.

The can type vertical pump is common. Circ-water pumps are generally vertical too, and operate in wet pits. The condensate pump handles water that is highly pure and free of solids, but the circ-water pump must work with water of various qualities. Mere redundancy and excellent design and workmanship of pumps do not assure highest reliability and availability.

3.1.4.2. Steam-lines considerations

Piping directly connected to the steam turbine influences performance and reliability. The main-steam leads are highest in interest, because they carry high-pressure steam from the steam generator to the stop and control valves. These lines are long, chiefly vertical drops in large units, leading from near the top elevations of the super-heater down to the turbine floor or below. Reheat lines carry h-p section exhaust back to the reheat elements in the steam generator and then out to the intermediate-pressure section. These lines are much larger than are the h-p leads, and the hot-reheat lines are at nearly the same temperature as the main-steam leads.

Crossover piping, carrying steam between i-p and low-pressure turbine sections, is mounted on the turbine itself. Most crossover lines run above (or below) the turbine sections. The crossover piping has not given unusual trouble in the past. A major problem with large steam lines serving the turbine is potential of failure through cracking. This has become especially acute in the older units that are being kept in service. Consignment of units to cycling or occasional use aggravates the problem.

Inspection of the main-steam leads and reheat lines, now commonplace, is often a problem, however.

The extent of inspection is an important decision. Removing old asbestos-containing insulation to expose welds and critical fittings for examination and inspection is expensive and can be dangerous in itself. Nevertheless, if any possible areas of failure are passed over, potential liability is astronomical. Another example of the complicating factors in older lines is the possibility of seam-welded sections that were installed inadvertently without knowledge of the owners. Methods of inspection and permanent recording are therefore crucial.

Dye-penetrant inspection finds surface cracks, but in practice is limited to pre-selected problem areas. Interpretation is easy and reliable. Ultrasonic inspection is widespread. It covers the wall volume in welds and at elbows and other regions that stress studies judge to be critical. Several crawler devices that carry ultrasonic transducers inside a pipe are being perfected and perhaps will make removal of insulation unnecessary. Interpretation of findings is fairly simple, but the method has not been totally reliable, passing over some defects and giving spurious alarms at times.

Acoustic emission for steam-line inspection is in experimental stage at present. It requires installing a series of piezoelectric sensors along a piping run and then taking data during a run up of stress in the pipe. Defects in the pipe wall reveal themselves by emitting bursts of acoustic energy as stress increases. Considerable calibration and signal interpretation are needed. Pipe insulation need be removed only locally at the sensor mount points. The method detects many flaws as well as ultrasonic does but also gives spurious indications and passes over real ones.

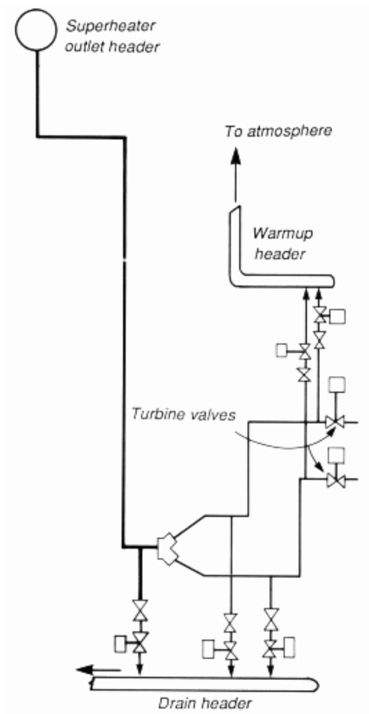


Figure 3.4. Draining of steam lines

Draining of steam lines (figure 3.4), not only prevent water hammer but also protect the sensitive turbine blading from water-slug effects, it is a task for small piping and valves, with some help from permanently open orifices. In the main steam leads, for example, the heating of the mass of pipe metal during start-up causes condensation. Water may be removed from the steam generator, as well. Other piping adjacent to the turbine needs warming, too, which means water removal.

Drain lines take away the water from the lower parts of the piping. Other drains remove water from upstream immediately. The drain system must take into account not only the warming-up but also abnormal conditions in which water is forced back into the turbine piping. Because of the sensitivity of turbines, completeness of water removal is important. Even a small puddle of water, when blasted at high speed into a turbine, can result in serious damage.

3.2. 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. Thus, an essential part of the infrastructure supporting the operation of a CHP plant is the provision of fuel, and the following sections focus on fuel supply systems.

3.2.1. 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 made by pipeline from the national distribution network. 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. The maximum rate of consumption usually increases also, and this often requires the uprating of an existing site gas connection.

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 compressors are suited to particular applications, namely screw compressors are appropriate for smaller gas turbine plant requiring fuel at up to 25 bar, while 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. Moreover, 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. Companies offering the necessary specialist services can provide a new gas connection to the site.

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 pipe-work, valves etc. are required to meet appropriate standards and specifications. Once installed, the connection and pipe-work require little or no maintenance or attention, apart from routine checks. Any modifications to the site's gas supply connection need to be discussed with the pipeline operator.

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 (Net Calorific Value), while the consumption data supplied for gas connection assessment must be given as GCV (Gross Calorific Value).
- 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, since pressure-boosting equipment such as a fuel gas compressor consumes significant quantities of electrical power.
- The potential routing for new supply pipe-work, 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 pipeline operator owns the pipe-work beneath the public highway, while pipe-work 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 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 pipe-work 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.

3.2.2. Coal, oil and other fuels 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. 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, that is the heavy oil needs to be kept hot if it is to remain in a liquid state that can be pumped through pipe-work. All the pipe-work 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.

Handling biomass residues depends mainly on the fuel granulometry and moisture content. Coarse residues can be transformed into homogeneous mass by crushing and chipping. Reduction of the moisture content by drying represents two main advantages: increases in the fuel heating value, and decrease in the fuel losses through fermentation during storage. Suitable technologies are available in the market to cover the handling, drying and storage requirements of different types of biomass fuels.

There are specialist engineering requirements for the handling and storage of various fuels, which must be taken into consideration. In particular, provision must be made to minimize 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. ELECTRICAL SUPPLY SYSTEMS

3.3.1. Utility interconnections

A CHP plant, in order to be able to supply its power output to the site, 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 of the system.

There is also a number of CHP plants that 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 back-up 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. As is shown in figure 3.5, in normal parallel mode all circuit breakers are closed. If the local system fails, 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 synchronized 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.

When a change from parallel to island mode occurs instantaneously, 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.

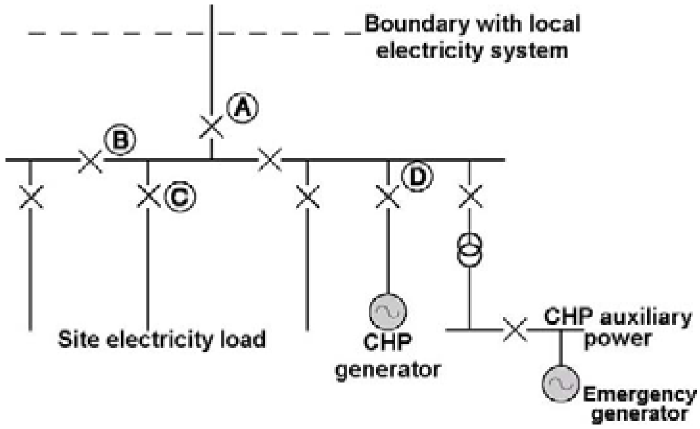


Figure 3.5. Parallel and island mode operation

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 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 back-up 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.

Requirements for interconnection with public utilities' grids vary from country to country, from operator to operator, and from one electric utility to another, depending upon generation equipment, size, and host utility systems. Interconnection equipment requirements increase with the generator size and voltage. In general, complexity of the utility interface depends on the mode of transition between parallel and stand-alone (or island mode) operation. The plant connection to the electric grid must have an automatic control utility tiebreaker and the associated protective relays.

When a cogeneration system is integrated into the utility system, a number of issues must be taken into account, such as control and monitoring, metering, protection, stability, voltage, frequency, synchronization, and reactive compensation for power factor, safety, power system imbalance, voltage flicker and harmonics. Utility interconnection with onsite CHP technologies is currently a burdensome and lengthy process. This laborious process causes a certain degree of apprehension and disincentive for facilities considering CHP projects.

3.3.2. Voltage regulation

An in-plant generator is connected and operates in parallel with the utility network. This is because power factor (or reactive power flow) is in close relation with voltage control of the generator and the voltage of the utility supply. The power factor is a way of representing the extent to which alternating current drawn by the plant is out of phase with the voltage. It is expressed as the ratio of real power (Watts) to apparent power (Volts x Amps). Most industrial plants draw a lagging current and have a power factor somewhere between 70% and 95%.

When in-plant generation is involved the concept of power factor becomes less useful, because it is difficult to tell whether the power factor is leading or lagging. That's why utilities talk about reactive current - the component of the total current that is 90 deg out of phase with the voltage. This leads to the concept of reactive power, normally expressed in VARs (volt-amperes reactive). The power output of a generator is controlled by the means of the torque applied to its shaft by the prime mover. The VARs output is controlled by the modification of the field excitation.

This function can be valuable in an industrial plant. If an in-plant generator is overexcited, it produces VARs as well as Watts, and these VARs flow into the plant's motors to provide their excitation current. This reduces the amount of VARs the motors draw from the utility system. It is exactly the same as installing power-factor correction capacitors to correct a poor power factor in a plant. The voltage at which the utility supplies power to a plant is seldom constant, though it is supposed to be held within ± 5% of the nominal value.

An in-plant generator coupled to a system with a varying voltage must have its excitation constantly adjusted according to the plant voltage, and a voltage regulator does this automatically. A transformer produces a signal proportional to voltage, and the regulator adjusts excitation to a level at which the generator would produce the same voltage when operates isolated. This excitation level is then trimmed to control the flow of VARs from the generator. To do this, an instrument known as a cross-current control transformer senses the flow of reactive current from the generator and sends a trimming signal to the voltage regulator.

If adjacent plant equipment draws a badly lagging power factor, additional control of the generator excitation may be needed in the form of a power-factor controller. This is a unit that measures plant power factor and trims the generator VARs output to ensure that the plant doesn't draw excess VARs from the utility. The dynamic range of the generator's voltage regulator must be able to cover the full range of supply voltage and control VARs flow at the same time.

VARs control gets to be more of a problem when the size of the in-plant generator is large compared with the capacity of the utility inter-tie. In such a case, it is preferable to let the in-plant generator set the plant voltage, while the utility inter-tie acts only to cover peaks. Problems occur if the tie voltage drops while the plant generator tries to maintain the voltage at the rated level. The result is that VARs flow from the in-plant generator into the utility network, adding to line loss and voltage drop, even though they are flowing in the opposite direction to the power.

The solution is a load tap changer on the main plant transformer or voltage regulators in the utility tie line. A load tap changer is a motor-driven switching device with multiple contacts that can adjust the transformer ratio in response to variations in the incoming voltage. A voltage regulator is an autotransformer connected in series with the main transformer. The choice between them is an economic issue. With the load tap changer in place the utility supply voltage is automatically adjusted to the nominal plant value, so that voltage regulators on the in-plant generators can control the flow of VARs while holding a constant plant voltage.

3.3.3. Fault control

An in-plant generator may decrease the capacity of the load drawn from the utility, but it will almost certainly increase the available short-circuit current in at least some parts of the plant. This means that heavier switchgear may be required, and this must be included in the capital cost of interconnection. The maximum short-circuit current that could flow in the event of a fault at any point in the plant distribution network depends on the short-circuit current given by the utility, and the total line impedance from the utility connection to the point of the fault.

When a plant distribution network is designed, the available short-circuit current must be calculated at various points of the network, and the switchgear specified must have an appropriate short-circuit capacity. Short-circuit currents can be reduced by the use of a high-impedance transformer and by inserting reactors into the circuit, but the voltage drop and the electrical losses caused by all these additions must be weighed against the savings obtained by using lighter switch-gear.

3.3.4. Protection

Once a generator is interconnected and operates in parallel with the utility network, it becomes part of a vast sophisticated system. Thus, it needs sophisticated protection against what the network can induce to the generator, and protection against what the generator can induce to the network. When a company employs its own electrical and relay engineers and wants to connect to the utility, specialized engineers from both the company and the utility must meet and determine the needs for each of the interconnection components and each of the protective devices.

As the number of interconnections increases and the technical sophistication of the average customer/generator decreases, there is a necessity of some standardization into the protection package and its cost reduction. Forward-thinking utilities have produced printed guidelines attempting to delineate exactly the equipment needed for different types of interconnection. Some of these publications are very specific, while others are quite general.

Isolation of the customer's generator occurs when the utility breaker opens for any reason. This leaves the customer's generator coupled to the full plant load and to any adjacent customers that are connected downstream of the tripped breaker. In such an event, it is almost inevitable that the generator will be grossly overloaded and will immediately start to drop both in voltage and frequency, with possibly damaging results. Thus, in any interconnected system, the customer's main breaker must trip whenever utility power is interrupted.

Usually under- or over-frequency relays are suitable to cause this trip. Typically, these are set at 59 and 61 Hz so that, as soon as the generator output reaches these frequency limits, the breaker trips. But it is just possible that the customer's governor works better than expected, so that the generator maintains exactly 60 Hz for a few seconds after being isolated. For this reason, most utilities are also insisting on over- and under-voltage relays in addition to the frequency relays.

Automatic re-closing of utility breakers can be catastrophic for the generator. If the in-plant generators have fallen well out of phase by the time the utility breaker re-closes, the resulting shock can be enough to shear the generator shaft - not to mention the electrical damage that will be done. There is no way that plant breakers can operate fast enough in this situation to prevent damage. The only safe protection is to keep the in-plant generator off the line until the utility system has stabilized.

The utility may or may not agree to inhibit automatic re-closing if the customer's breaker is still closed. Normally, this is done with a voltage relay on the customer's side of the breaker, which prevents re-closing if the line is working. Re-closing of the customer's breaker presents further problems, since this breaker must not close onto a dead utility line or onto a working line to which is not synchronized. If the utility won't provide an interlock between breakers or agree to inhibit automatic re-closing, then a time delay is needed to ensure that the utility system has been stabilized.

Synchronizing equipment is required for both the customer's main breaker and for individual generator breakers, which can be either an automatic synchronizer or a synchronization check relay. In the latter case, the generators are synchronized and the breaker closed manually, but the check relay prevents re-closing out of synchronization. If the plant becomes disconnected from the grid, the main breaker's synchronizer allows the plant to re-interconnect without stopping the generators. Conversely, the synchronizers on the generator breakers enable the generators to be taken in and out of service without interrupting the plant's operations.

Relay settings are an endless source of misunderstanding between the utility and the producer. This is mostly because the utility's standard approach is to drop a producer off line when a trouble is detected, while the customer's main interest is uninterrupted power for the plant. Thus, even if the utility has published protection requirements and has inspected the relaying on a system, there may be no clear-cut agreement on how relay trip limits should be set. A typical problem is voltage surges on the utility's line caused by the switching of banks of power-factor correction capacitors.

Utility-quality relays are a must for most interconnection jobs. There is no real standard to differentiate a utility- from an industrial-quality relay; basically, the utility-quality relay is a much heavier, more costly piece of equipment in which trip setting can be adjusted accurately to known values. It has operation indicators showing that it has tripped and why it has tripped (e.g. over- or under-voltage), and its guts can be removed for servicing without breaking the connection. By comparison, the industrial relay is a packaged solid-state device with simple dials to adjust settings. Accurate coordination of industrial relays can be accomplished only by trial and error.

3.4. OTHER TECHNOLOGICAL ISSUES OF CONCERN

3.4.1. Trigeneration and absorption cooling

3.4.1.1. The concept of Trigeneration

The heat from the cogeneration system can be used for different systems, including HVAC systems for heating or cooling of buildings. The coupling of the cogeneration system with the heating system of a building is simple. The main difference to the conventional systems is the heat source equipment and the thermal characteristics of the available heat. The associated use of cogeneration system with the cooling system of the building can improve very much the economic benefits. However, the benefits should be well analysed, otherwise the important adaptation of the HVAC system could induce an unfeasible cost.

This technique is called trigeneration. Trigeneration is the concept of deriving three different forms of energy from the primary energy source, namely, heating, cooling and power generation. Also referred to as CHCP (Combined Heating, Cooling and Power generation), this option allows having greater operational flexibility at sites with demand for energy in the form of heating as well as cooling. The heat recovered from CHP systems can be used in HVAC systems, as indicated in the next table.

Table 3.2. The use of heat recovered by the HVAC system

HVAC SYSTEM	*COGENERATION SYSTEM*	
Heating/cooling	**Gas turbine**	**IC engine**
Low-temperature (hot water 40-60°C)	YES	YES
High-temperature (hot water 80-100°C)	YES	YES
Single-stage absorption chiller (low-pressure steam, 100 kPa)	YES	YES
Two-stage absorption chiller (high-pressure steam, 860-1000 kPa)	YES	SOME

The trigeneration system is improved when absorption chillers are used (figure 3.6). In this case the main energy consumption is heat, which can be provided integrally by the cogeneration system. However these systems can also use conventional vapour compression chillers, with or without the use of absorption chillers. In this case the main consumption comes from electrical power. If the work produced by the cogeneration system is used to produce electricity, the mechanical chillers can use this energy. The use of absorption chillers together with mechanical chillers can in certain cases, improve the whole system's performance.

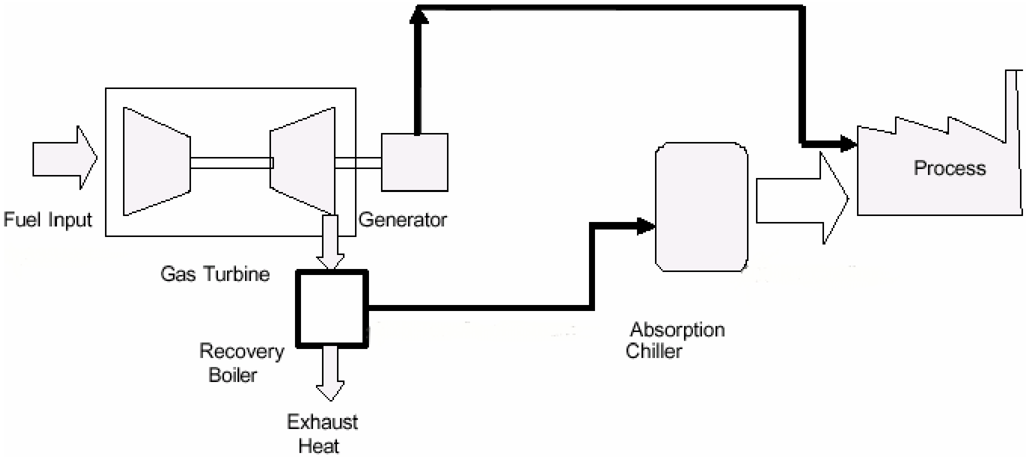


Figure 3.6. Schematic diagram of power generation and absorption cooling

3.4.1.2. Chillers

Different kinds of chillers can be used to produce the required cooling, namely mechanical chillers, absorption chillers and desiccant chillers. The coupling of the cogeneration and cooling production can be done by the energy sources required by the cooling system and provided by the cogeneration system. Table 3.3 summarises this coupling. The use of mechanical chillers can be coupled with the cogeneration systems, which use the electricity produced. The electricity produced by the cogeneration system can be used for the compressors of the chillers.

Table 3.3. Main energy sources in trigeneration systems

Chiller	*Energy source from generation*	*Main output of trigeneration*
Mechanical	Electricity	Thermal energy (refrigeration)
Absorption	Heat (and electricity)	Thermal energy and electricity
Desiccant	Heat (and electricity)	Thermal energy and electricity

The heat energy source that supplies the single-stage absorption chillers can be hot water (up to 150°C) or low-pressure steam (up to 100 kPa). The cogeneration system can provide the chillers with these heat energy sources. The heat energy source that supplies the two-stage absorption chillers can be steam at 790 - 830kPa. This steam can be produced by exhaust gas from a cogeneration system (gas-fired engine). However this means that the cooling production depends on the gas-fired engine. As a solution a conventional fired boiler can be installed to produce steam while the cogeneration system is out of service or to provide the peak needs.

Thus, instead of using mechanical energy, absorption chillers use heat to provide a working fluid (the refrigerant), which can be expanded and cooled as part of a refrigeration cycle. For example, in a lithium bromide/water absorption cycle, heat drives water vapor out of a LiBr solution (the absorbent) under a vacuum (P_1=0.07 atmospheres). The water vapor is then cooled to ambient temperature and condenses (still at P_1); then it is further cooled by expansion to a ten-time lower pressure (P_2) where it condenses by extracting heat from the cooling load.

Finally it is pumped back into the LiBr solution, where it is reabsorbed due to its chemical affinity with LiBr. Table 3.4 presents the range of thermal COPs and temperatures for various absorption chillers. The most efficient triple-effect chillers are in the same range as the COP of an electric chiller, in terms of primary energy. However, because absorption chillers' first cost is higher - per ton (i.e., for 3.5 kW of heat extraction) installed - heat-driven absorption chillers now comprise a fairly small portion of the chiller market. Of these, most are gas-fired.

Table 3.4. Characteristics of four different absorption chillers (Source: Devault 1998; Erickson 1996)

Chiller Type	Thermal COP	Temperature Range (^oC)
Half-effect	0.35	80 – 100
Single-effect	0.70	100 – 120
Double-effect	1.1	150 – 170
Triple-effect	>1.6	170 – 200

The few that are waste-heat driven are almost exclusively single-effect chillers. Of the small-scale CHP technologies, only turbines have outlet temperatures high enough to drive double- and triple- effect chillers. Thus, the commercialization of turbines will greatly expand markets for CHP to such non-traditional markets as office buildings with their large cooling loads. If CHP heat is available in a new building without existing chillers, it will pay, on a life-cycle basis, to invest in absorption chillers for turbines and possibly for the other technologies. In an existing building, however, early retirement of an existing electric chiller may not be cost effective.

However, lack of CFCs (i.e., expensive CFC replacement) for electric air-conditioning is likely to lead to improved relative economics for absorption chillers. Despite a phase out of production of ozone-depleting chlorofluorocarbon (CFC) refrigerants completed in 1995, many centrifugal and screw compressors still use them. A recent survey showed that approximately 70% of the chillers that used CFCs in the early 1990s remain dependent on CFCs (ARI 1998). Simultaneously, new technologies, such as highly efficient triple-effect absorption chillers (COP >1.7) are about to enter the market.

3.4.2. Silencers

It is necessary to provide a means of noise attenuation in all facilities where noise and vibration creates an environmental problem. There are many designs in the market for all kind of plants ranging from the simple exhaust silencer for the small reciprocating engine to large integrated complex designs for the multi-MW power plants.

3.4.2.1. Acoustic housings and enclosures

Enclosures range in design from single skinned acoustically lined panels to multi-inch thick composite wall designs with about 40-60 dBA reductions. Acoustically treated containers can be furnished with inlet/outlet silencers, specially treated acoustic walls, air handling equipment, fire suppression, special lighting, extensive exhaust silencing systems, fuel sub-bases, acoustically treated inlets/outlets, special hardware and any other option that the plant may require.

A broad range of silencers is available from suppliers, from standard silencers for general-purpose applications to custom models to fit most plants. Silencers are usually manufactured from aluminised steel, stainless steel or carbon steel depending upon the application and size. Typical standard silencers are:

- Standard reactive silencers in single-inlet/single-outlet and dual-inlet/single-outlet configurations;
- Combination catalytic converter silencers;
- Spark arrestor silencers;
- Absorptive silencers for both discharge and inlet applications;
- Combination reactive/absorptive silencers,
- Compressor/blower silencers;
- Gas turbine silencers.

3.4.2.2. Other ways of noise attenuation

Most engine installations require that all piping to and from the engine be supplied with flexible connectors. Typical market products to meet these needs are stainless-steel exhaust connectors which incorporate engine-mating and silencer-mating flanges, “Y” exhaust connectors for dual-outlet engines which are cost-effective and highly adaptable and stainless-steel braided connectors for flexibility in rigid water and fuel lines which suit any flange or piping arrangement.

Designed specifically for rugged generator-set applications, the vibration isolators provide an inexpensive way of isolating engine and gen-set vibration from buildings and structures. Side dampers, level adjustment and a non-skid sound pad are the usual features of such designs. Flexible connectors provide little compensation for thermal expansion in exhaust piping. For example, an 8” diameter exhaust pipe will expand approximately 7” per 30 metres at a temperature of 450^{o}C.

To compensate for this expansion, multiple-ply stainless-steel expansion bellows are used which allow for axial expansion. Moreover, when an exhaust pipe or tube exits a building, the pipe should be isolated from the wall. For this purpose, wall and roof thimbles are used with features such as self-supporting roof thimbles incorporating the exhaust silencer and roof-mounting into the design of the thimble.

4. APPLICATIONS

4.1. INTRODUCTION

The market for CHP can be divided into three categories: industrial plants, district energy systems, and small-scale commercial and residential building systems. The industrial sector represents the largest share of the current installed capacity and is the segment with the greatest potential for near-term growth. Large industrial CHP systems are typically found in the petroleum refining, petrochemical, or pulp and paper industries.

These systems have an installed electricity capacity of greater than 50 Megawatts electric (MW_e) (often hundreds of MW_e) and steam generation rates measured in hundreds-of-thousands of pounds of steam per hour. Some facilities of this type are merchant power plants using combined cycle configurations. They are generally owned by an independent power producer that seeks an industrial customer for the steam and sells the electricity on the wholesale market. Sometimes the thermal customer may also contract for part of the electric power.

District energy systems (DES) are a growing market for CHP. DES distribute steam, hot water, and/or chilled water from a central plant to individual buildings through a network of pipes. DES provide space heating, air conditioning, domestic hot water, and/or industrial process energy. DES represent an important CHP market because these systems significantly expand the amount of thermal loads potentially served by CHP. In addition, DES aggregate thermal loads, enabling more cost-effective CHP.

District energy systems may be installed at large, multi-building institutional campuses such as university, hospital, or government complexes or as merchant thermal systems providing heating (and often cooling) to multiple buildings in urban areas. The addition of CHP to existing district energy systems represents an important area for adding new electricity generation capacity.

With the arrival of low-cost, high-efficiency reciprocating engines, and the prospect of cost- effective, micro-combustion turbines, CHP is now becoming potentially feasible for smaller commercial buildings. This area, sometimes called "self-powered" buildings, involves the installation of a system that generates part of the electricity requirement for the building, while providing heating and/or cooling. Packaged systems, such as the reciprocating engines from Waukesha and Caterpillar, have a capacity beginning at 25 kilowatts electric (kW_e). This size range makes it possible to install CHP in smaller commercial applications, like fast-food restaurants, as well as larger commercial buildings.

The CHP supply market is beginning to develop. Besides these above end-use markets, four major categories of players are emerging:

- Project developers

- Equipment manufacturers
- Engineering and construction firms
- Energy supply companies

These groups offer a range of alternatives from design/build to build/own/operate to comprehensive energy supply services.

4.2. TERTIARY SECTOR

4.2.1. Background

While the small-scale (<1 MW) CHP units have had a successful track record in Europe in a wide range of building applications, this sector is currently the smallest CHP sector in the United States. Sites with a large hot water demand, such as colleges, hospitals, hotels, and some restaurants, appear to be the most attractive potential markets (see Major 1995 for an excellent set of case studies from around the world). Data on small-scale CHP systems is sparse.

More specifically, the following types of establishment frequently combine a sufficiently large heat load with a fairly constant electrical load:

- Hotels
- Hospitals
- University campuses and boarding schools
- Office buildings
- Swimming pools and leisure centres
- Stores and supermarkets

This list is certainly not complete and there are many other places where CHP will also be feasible (barracks, museums, etc.).

Hotels: Hotels that accommodate over 50 bedrooms often have a heat demand for space heating and catering for as much as 18 hours per day over a long period. Furthermore the electricity demand is fairly constant, so CHP units can be applied very effectively.

Hospitals: Energy demand in hospitals tends to be continuously high throughout almost the full day and over most of the year. A high heat load is combined with a high electrical demand, and all electricity generated can be used on site. Furthermore, professional staff is often available to maintain and operate cogeneration plant. For these reasons CHP can be very profitably installed in hospitals.

University campuses: At campuses, some boarding schools and other educational institutions, thermal and electrical energy demand is high for a sufficiently long period to make this type of establishment suitable for the application of CHP.

Office buildings: A high space-heating demand in winter is often combined with cooling requirements in summer in an office building. Because of a sometimes high lighting load, electrical demand may be high and constant for 10-12 hours per day, over almost the entire year, making it possible for a CHP unit to operate for approximately 4000 hours per year. If no cooling capacity is required, the application of CHP in an office building is questionable since, in that case, insufficient operating hours can usually be achieved.

Swimming pools and leisure centres: The demand for both thermal and electrical energy for 12-14 hours per day throughout the year. Thermal energy is required to heat the pool water, ventilation air and domestic hot water, and electricity is needed to operate pumps and lighting. Furthermore, at pool water temperatures below 30° C the application of a condenser in the exhaust system of the prime mover can increase the overall efficiency of the CHP system to over 90%.

Supermarkets: Large stores and supermarkets often show a high demand for space heating and cooling energy, while lighting levels are high for 10-12 hours per day. Most of the energy consumption is attributable to the electrical loads required to meet sales objectives (bright lighting), preservation of foodstuffs (cold stores and refrigerated displays), and air conditioning.

4.2.2. Case study - Jurys Hotel and Towers - DUBLIN

This hotel, located in Ballsbridge, Dublin, consists of two adjoining hotel blocks. The main hotel comprises 300 bedrooms, function rooms, restaurants, lounges, pubs, a leisure center with swimming pool and a business center. The separate tower block contains a further 100 bedrooms. With a substantial year-round demand for electricity and heat, this hotel is an ideal location for the installation of a Combined Heat and Power unit. Prior to the installation of the CHP plant, the heating services for the hotel were provided by two ageing steam boilers, each rated at 4765 kg/h.

Inenco recommended the installation of a $300kW_e$ CHP plant, and the replacement of the existing steam boilers with two 1400kg/h boilers for the laundry and two 2200kW low pressure hot water boilers. Temp Technology supplied the CHP unit chosen. The plant is integrated into the hot water system, with hot water being circulated via the CHP unit in the primary water loop before returning to the boilers. Therefore, the boilers are only required to supply the make-up heat for raising water to the desired temperature (90°C).

Table 4.1. CHP technical data

Type: Dorman 6DTg	***Electrical Power: 304kW (30%)***

Heat Output: 445kW (45%)	***Fuel Input: 999kW***

The total useful energy conversion efficiency of 75% in normal operation compares favourably with efficiencies of approximately 35% at large power stations.

4.2.3. Outlook

CHP may soon become economically attractive for small (<1 MW) commercial buildings, and even residential buildings, because of improvements in technologies and smaller customers' concerns that they might face higher prices under retail competition. The small-scale CHP buildings market (self-powered buildings) includes systems that generate some or all of their building electricity while providing heating. Some systems produce cooling using engine-driven chillers and new, smaller, highly efficient absorption chillers.

The near-term prospect for total capacity contributed by this segment is modest, considering their small size. However, the long-term prospects for CHP in buildings are more promising. From 1988 to 1998, CHP capacity in the U.K. has almost doubled, representing an average growth rate of 9 per cent per annum for the period (CHPA 1998). Government incentives in the U.K. led to the installation of 612 small, engine-based CHP units between 1992 and 1997 (CHPA 1998).

If policy in other countries follows this example, much progress can be made in this sector. Technological developments, such as more reliable and lower-emitting gas-engine-based packages, as well as a host of new, small-scale applications such as micro-turbines and fuel cells, are being made. While the barriers previously discussed apply to small-scale systems, installation and operating costs are the most significant for this sector.

4.3. INDUSTRY

4.3.1. Background

The industrial sector represents the largest and best-characterized CHP segment world-wide. It is also the CHP segment with the greatest potential for near-term growth. The majority of this capacity exists in industrial sites with large steam loads. In 1994, three industrial sectors, pulp and paper, chemicals, and petroleum refining, accounted for 85 percent of all industrial cogenerated electricity in the US. Pulp and paper accounted for 41 percent or 59 TWh; the chemicals industry accounted for 33 percent or 47 TWH; and petroleum refining made up ten percent or 14 TWh of cogenerated electricity (EEA 1998).

The CHP systems in these industries typically generate more than 25 MW of electricity (though sometimes hundreds of MW) and have steam generation rates that measure in the range of hundreds of thousands of pounds of steam per hour (EEA

1998). These plants are generally owned by an independent power producer that seeks an industrial customer for the steam, reducing their net operating costs in order to improve their competitiveness in selling electricity. In the following industry sectors combined heat and power finds application:

Agrofood: In the sugar industry, autonomous electricity generation with steam turbines (back pressure turbines) is common. New markets are not expected as long as there are no new sugar plants in construction. There is a large potential for CHP, however, in all other sectors of the agrofood industry.

Brewing: Many breweries are too small for CHP. Increasing potential for CHP depends on realistic prices for electricity, which must be sold to public networks (the best conditions are to be found in Germany, the U.K., Italy, Portugal and Spain). CHP in a closed cycle in breweries is difficult because of the nature of the brewing process (batch process).

Bricks/ Heavy clay: There is a high potential for the application of CHP with gas turbines and combustion engines. Suitable concepts exist for this sector and a big market potential is expected.

Cement: Back pressure or gas turbine generation might have a possible application in the sector, depending on the energy market. Potential applications are the use of waste heat from clinker cooling with steam super-heater and steam turbine for supply of process energy, and direct heating from gas turbine exhaust gases for pre-heater and pre-calciner.

Ceramics: Cogeneration with combined cycles and direct heat gas turbines has been successfully demonstrated for this sector (e. g. Germany). Big market potentials are expected for this sector.

Chemicals: CHP has commonly been applied in this sector. Big market potentials are expected in this sector for improved technologies including waste heat recovery from production processes.

Paper: Potential application of CHP for integration of different energy processes: steam supply, dryer heating electricity generation. Back-up from the public network is normally required.

Textiles: The ratio of thermal energy / electricity demand in the sector seems ideal for CHP with gas turbines. Minimum power of 800 kW_e is required for plants to be suitable for CHP.

4.3.2. Case study - Buchanan Flooring

When Buchanan Flooring LLC planned their new plant in Aliceville, Alabama, cogeneration was a consideration right from the very start. According to Bruce

Nesmith, plant manager for the producer of hardwood flooring (also known as strip flooring), they needed a dependable and economical way to handle disposal of the large volume of waste from their operation.

Each daily eight-hour shift produces 48 tons of waste, primarily sawdust. Hauling the waste away was viewed as a marginal solution. There were buyers for the waste, and the price was potentially acceptable. However, the biggest issue was dependability: would these buyers always be there, and would they always want the full volume of waste the flooring operation produced? Cogeneration was a logical choice to assure that waste disposal would always be available and would be economically viable over the long haul.

In Buchanan's operation, rough hardwood planks are kiln-dried for approximately one week prior to processing into flooring. Steam is required for the kiln's operation. The plant's wood waste fuels the boiler that produces steam. But this steam is at a high pressure, about 19 bar. The kiln uses steam at about 0.8 bar. Such low-pressure steam is one of the outputs of the steam-driven turbine generator (figure 4.1). The other is electricity.

Figure 4.1. The turbine generator installation

4.3.2.1. Electricity uses

The electricity generated from this process is used to power the plant's production operations, yielding significant reduction of their power bill from the local utility company. During periods when the plant is not consuming all the electricity the generator can produce, excess capacity is shuttled next door to the plant's sister company, Buchanan Lumber Company, a provider of some of the flooring firm's raw material. The lumber mill uses refrigeration kilns with a strong continuous demand for power, making them an obvious "customer" for the excess power. A single utility connection serves both plants, and multiple meters are in place to allow Buchanan to verify savings being realized by the cogeneration operation.

4.3.2.2. Plant overview

The plant operation at Buchanan is relatively simple. The saws and milling machines in the plant are connected to a vacuum system that collects dust and carries it to a storage silo (figure 4.2). Larger pieces of wood that are not handled by the vacuum system are fed through a hog that grinds them into pieces small enough for the boiler's fuel feed system to handle. Conveyors feed the wood dust to the boiler. Steam from the boiler drives the turbine generator. Low pressure steam from the turbine generator is fed to the kilns (figure 4.3), with excess steam piped to condensers which reduce it to water that is then re-circulated to the boiler's feed-water system.

Figure 4.2. One of several saws and milling machines connected to a plant-wide industrial vacuum system

Figure 4.3. Buchanan's two kilns

Based on referrals from other local operations similar to theirs and their assessment of experience and expertise, Buchanan chose SEECO, a Birmingham, Alabama-based firm, to provide the cogeneration system. As part of the basic service offered, SEECO performed a feasibility study that established estimates of the savings Buchanan could expect and that helped to size the system.

This system includes a Coppus turbine, GE generator, two air-cooled condensers manufactured by SEECO (fig.4.4), a motor control centre, steam piping, and all of the other associated electrical and mechanical elements that make up a cogeneration system. SEECO performed all the installation for the system, which started operating the end of June 1999.

Figure 4.4. The system's air-cooled condensers

What about results? Buchanan is certain enough of the system's value that they have indicated they will expand the system whenever their manufacturing operation grows to the point that they need to add a second shift, which would greatly increase the amount of waste being generated.

4.3.3. Outlook

Although the larger industrial systems (>50 MW) currently dominate, analysts predict that if current market barriers are removed, both large and mid-sized (1 to 50 MW) industrial CHP facilities could expand rapidly in the next decade. The expansion of the mid-sized systems, a largely untapped market, is due to the confluence of several factors: new, smaller technologies; innovative energy service firms; and the need to replace thousands of boilers that provide process steam to smaller manufacturing plants. Replacing or re-powering these boilers offers a large potential for adding new electricity generation capacity in the 1 to 50 MW size range.

4.4. DISTRICT HEATING/COOLING

4.4.1. Background

District heating and cooling is the distribution of heating (hot water, steam) and cooling (cold water) energy transfer mediums from a central energy production source, to meet the diverse thermal energy needs of residential, commercial and industrial users. Thermal energy needs or demands include space heating and cooling systems for maintaining human comfort, domestic hot water requirements, manufacturing plant process heating and cooling system requirements, etc. In many of the systems that have been established around the world, both district heating and district cooling have not been provided. For example in Europe, where moderate summer temperatures prevail, most district thermal energy systems provide heating capability only.

District cooling has only recently become more widespread, with the most prevalent application being in North America, where summer temperatures can, over extended periods, reach extremes of 30°C to 40°C. There are a number of factors that must be weighed when determining whether or not a district heating (DH) or district heating and cooling (DHC) system should be implemented in a particular community. These factors include local economic and climatic conditions, viability of competing alternative energy supply systems, local energy production and utilization efficiency considerations, local environmental benefits, and differing producer and user perspectives on the significance of benefits of district systems.

In general terms, DHC systems can be defined as the production of heating (hot water or steam) and cooling (chilled water) energy at one or more sources, and subsequent distribution of the thermal energy via pipelines to "district" users. A typical DHC system is therefore comprised of three subsystems:

- *thermal energy generation*: where steam or hot water in the case of district heating, and chilled or cold water in the case of district cooling, are produced,
- *thermal energy distribution*: where the thermal energy medium (steam or water) is distributed via pipelines from the production sources to the network of users, and
- incorporation of the thermal energy at the user's (customer's) location.

The concept of DHC is similar to potable water distribution or electric power generation and distribution systems. A combination of residential, commercial and industrial users may be involved with varying uses of the thermal energy including space heating and cooling, domestic hot water heating, plant process heating and cooling, etc. A district heating and/or cooling system differs fundamentally from a conventional system in that, in the case of the latter, thermal energy is produced and distributed at the location of use.

Examples of conventional systems include home heating and cooling with, respectively, furnaces and air conditioners, electric heating of offices, package boilers/chillers providing heating/cooling of apartment complexes, and a dedicated boiler plant providing heat to an industrial facility. There are many factors regarding DHC systems that must be considered in determining whether or not implementation of a particular system is preferred.

These include economic criteria, viability of competing systems, local climatic conditions, user characteristics such as load density, total load requirements, characteristics of the heating and cooling systems currently in place, developer's perspectives, local utility considerations, local and global environmental impacts, and others. All of these factors will likely have a bearing on decisions made regarding the viability of a particular DHC system.

4.4.2. System considerations

Although varying from country to country and city-to-city, certain conditions must generally prevail in order for a DHC system to be viable compared to conventional systems. Heating and cooling load densities, that is the heating/cooling requirements per unit area, should be relatively high. The very nature of a DHC system dictates this criterion since it becomes uneconomical to distribute energy to sparsely populated areas where distribution piping costs and thermal "losses" become comparatively high. Generally speaking, a relatively high total heating/cooling load is preferred since improved operating efficiencies can be realized at larger facilities, and since economies of scale favour larger installations.

Apartment complexes, hospitals, universities, groups of office buildings, and factories are all energy user candidates that meet the above prerequisites well. Many major cities around the world meet much of their heating requirements through district heating. DHC systems that service areas of the City beyond the high-density building zones typically result when adjacent housing densities are fairly high and/or several inexpensive sources of thermal energy are available. Examples of relatively inexpensive thermal energy include waste heat recovery from energy-from-waste facilities, from large power generation plants, and from gas turbine combined cycle cogeneration plants.

Without such local opportunities for DHC supply and utilization, city-wide applications become borderline candidates at best. A partial list of cities with well developed district heating systems would include Paris, Helsinki, Stockholm, Copenhagen, Moscow, New York, Boston, San Francisco, Toronto and Tokyo. In Sweden, Finland and Denmark, district-heating supplies 30, 39 and 42 percent, respectively, of the entire countries' heating demand, serving downtown core areas to urban and suburban residential areas.

4.4.3. Thermal energy generation

DHC systems, owing to the fact that they are usually connected to a diverse group of customers with varying load requirements, must typically accommodate a relatively large total heating/cooling load with potentially wide variations from season to season. Since individual customers often experience their peak loads at different times of the day, the central production plant's daily characteristic load curve tends to be smoothed out, with the peak demand reduced, compared to the sum of all the individual peak loads. Thus, the installed total capacity of a DHC system can be less than that of conventional decentralized systems - a distinct advantage of a district system.

Depending on total system peak and average load requirements and the load variations from day- to-day and season-to-season, DHC plants of varying complexity can and have been developed. A relatively simple DHC system might utilize a single energy production facility, comprising for example an oil or gas fired boiler (heating) and an electrically driven centrifugal chiller (cooling). Multiple units may also be selected to more efficiently meet base, intermediate and peak loads, as well as providing standby capacity and increased system reliability.

More complicated DHC systems might utilize several different energy production facilities, such as EFW (energy-from-waste - normally from municipal, commercial and industrial waste incineration), waste heat from manufacturing plant processes, absorption chillers, heat pumps, coal-fired boilers. Other sources of heat for DH system include geothermal, cement kilns, biomass (burning of wood-pulp, peat, straw, etc.) and solar collectors. In the case of these more complicated thermal energy production systems, the energy sources selected and the manner in which they are used depend on local fuel prices, availability of such alternatives, proximity of the load to such sources, environmental sensitivities, and other factors.

4.4.4. Case study - Lutherstadt Wittenberg

Country: Germany	Electrical output: 6,224 kW
Location: Wittenberg	Thermal output: 7,948 kW
City: Lutherstadt Wittenberg	Use of electricity: The electricity is sold to the utility company
Start of operation: 1995	
Primary fuel: Natural gas	Type: 4 x JMS 616 GS-N.LC

The cogeneration plant in Wittenberg is an excellent example of the successful replacement of old-fashioned power plants by state-of-the-art cogeneration plants. Because of increasing demand for environmentally friendly energy the local authorities of Wittenberg decided to change from coal to natural gas as primary energy for new power plants. The energy supply of a newly build district in Lutherstadt Wittenberg was realized with a cogeneration plant from Jenbacher.

About 20,000 people will be supplied with heat from the new cogeneration plant through a district-heating network. The produced electricity is fed into the grid of the local utility company on a voltage level of 6.3 kV. In addition to the reduction of 22,000 tons of CO_2 the new energy concept reduces carbon monoxide (CO) emissions by 70% and sulfur dioxide (SO_2) emissions by more than 95%. Also important to mention is the reduction of ash emissions to a nearly insignificant value.

4.4.5. Case study – District heating of Cham (Switzerland)

Wasserwerke Zug AG (WWZ) is operating a so-called “total energy system” in a new development area in the centre of Cham. The plant consists of a central heating plant with a district-heating scheme, and uses the nearby River Lorze as both a hot and cold source by means of a water-to- water heat pump. The equipment is the first of its kind in Switzerland, and features a cogeneration plant with a heat pump in a single unit. This design makes a range of operating modes possible, although the plant is more complex as a result. Initial results indicate that the design performance will be achieved as soon as building development reaches completion.

4.4.5.1. The principle of operation

The aim of the project was to demonstrate the feasibility of an integrated design concept for an energy efficient installation for space heating and domestic hot water for several buildings in a new development area. Other aims were to produce electricity at the same time, to introduce air-cooling for the public buildings together with recycling waste heat, and to reduce pollutants through the use of natural gas and a catalytic converter. A project study indicated that all of these aims would best be achieved by means of a co-generation unit combined with a water-to-water heat pump.

The design of the installation incorporated all equipment into a centralised machine room. From there, heat is distributed to users via a network of pipes. One third of the heat is distributed directly as hot water with no intermediate heat exchanger. This makes it possible to achieve a low return temperature and thus ensure efficient performance of the heat pump. The remaining energy is transferred to end users via plate heat exchangers in sub-stations.

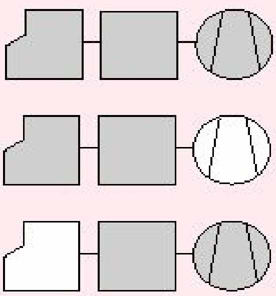
Mode of operation: Gas engine Generator Heat pump	Description	Rated power (kW)		Hours of operation [hrs/year]
		therm.	electr.	
	Total energy system: Electricity and heat production exploiting river water	573	89	2300
	Cogeneration unit: Electricity production (peak rate) and heat production	350	155	3200
	Electric heat pump: Cooling public building (Refrig. cycle)	240	66 (use)	≈100
	Heat production (Heat pump)	225	71 (use)	<100
	2 Dual-fuel boilers with low-NO_x burners Rated power [kW]	755/935	–	–

Figure 4.5. Mode of operation and design values (Source: Caddet)

The so-called "total energy system" consists of:

- a 543 kW Otto gas engine with a three-way catalytic converter;
- a 187 kW electricity generator;
- a water-to-water heat pump with 243 kW thermal output.

All three units are coupled magnetically and mounted on a single rotor, which makes a range of operating modes possible, each with its own characteristics (see figure 4.5).

The total energy system supplies heat for space heating and domestic hot water, as well as electricity. In summer the system is also used to cool the public building. In addition, an air-to- water electric heat pump with a thermal output of 42 kW and an electricity consumption of 13 kW has been installed to recover waste heat from the machine room. Next to this total energy system, two dual-fuel (gas and oil) boilers with low-NO_X burners were installed, to cover peak loads. Design data of the integrated system are given in table 4.2 and the energy flow is shown in figure 4.6.

Table 4.2. Design data (Source: Caddet)

Total heat load	**1442 kW**
Heat pump refrigerant	**HCFC-22**
Flow and return temperatures in heat distribution system	**60/40°C**
Flow and return temperatures for domestic hot water	**65/35°C**
Heat production	**3250 MWh/year**
Electricity production	**750 MWh/year**
Gas consumption	**3600 MWh/year**
Oil consumption	**260 MWh/year**

The local heating network was installed in the centre of Cham, Switzerland. The development consists of commercial and industrial buildings, a terraced house with five apartments, a bank, a public building with library, and a hotel with a restaurant. The installation is operated automatically when there is heat demand. It may also be remote controlled from WWZ in Zug.

During electricity peak rate periods in winter the cogeneration unit is mainly out of operation. This is done to maximise revenue from electricity. During the electricity off-peak period, particularly in the mornings when heat demand is high, the complete system is brought into operation. In winter, the dual-fuel boilers can be switched to oil by WWZ to reduce peak demand in the gas network. In summer, the system may be configured as an electric heat pump in order to cool the public building. The extracted heat is used to produce domestic hot water.

Owing to the complexity of the energy system, several problems were encountered at the commissioning stage. One particular problem concerned high return temperatures from users. The refrigerant had to be changed from the original CFC-12, now banned, to HCFC-22. As a result, return temperatures above 40°C can lead to malfunctioning of the heat pump. As the system configuration is new, engineers still have insufficient experience in working with it.

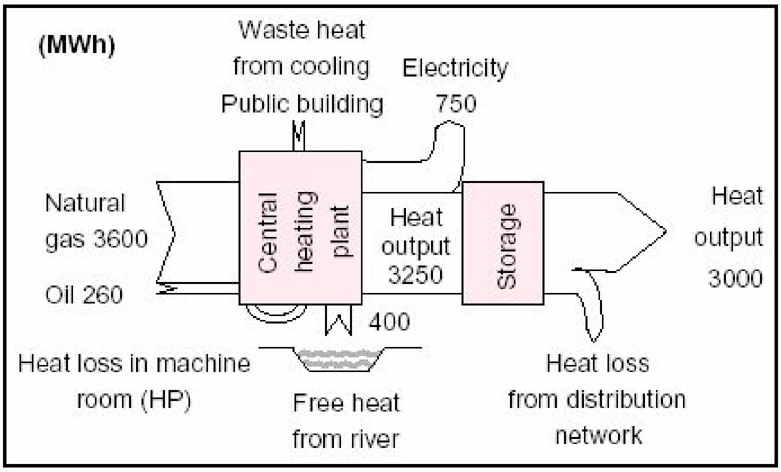


Figure 4.6. Energy flow diagram in design values (Source: Caddet)

The machine room contains a range of analogue and digital measuring equipment, and transmits performance data to a remote supervisory control system at WWZ in Zug. Table 4.3 summarises the results of these measurements for the period April 1992 to April 1993. Although these results have not yet been fully analysed, operation times indicate that anticipated performance values will be achieved as soon as building development is complete, all buildings are fully occupied, and the problems detected during commissioning are rectified. The system achieved annual energy (heat and electricity) savings of about 20% in comparison to a conventional system.

Table 4.3. Measured operation data (Source: Caddet)

HOURS OF OPERATION	
Total energy system (cogen-unit + hp)	473 hrs
Cogen unit alone	2685 hrs
HEAT PRODUCTION	
Total energy system / cogeneration unit	1140 MW
Total (including boilers)	1542 MW
ELECTRICITY PRODUCTION	
Total energy system / cogeneration unit	452 MWh
EFFICIENCY	
Total energy system / cogeneration unit (without distribution heat losses)	103%
Complete system (incl. Boilers and distribution losses)	92%

Wasserwerke Zug AG (WWZ) is a regional public utility, private owned within the structure of a joint stock company. They supply natural gas, water and electricity to 12 villages in the Canton Zug area, as well as operating a cable television and radio network.

4.4.5.2. Economics

The total cost of the energy system is about €3 million. Included in this price is the distribution network with piping, pumps, and meters in each building. The over-cost in comparison to a conventional system is €1.5 million. More than half of this cost is covered by WWZ. The rest is covered by end users, whose additional cost is compensated for by the omission of boilers, chimneys, etc., which would otherwise have been installed. The users carry the cost of heat distribution in each building.

In 1996, the following extensions to the plant were planned:

- heat recovery from a new X-ray institute;
- space heating and domestic hot water supply to a new residential complex (Badmatt), the new Cham parish administration buildings (Mandelhof), and other municipal buildings.

When these extensions are complete, it is expected that the plants work-load will increase, and that its overall efficiency will improve as a result.

4.5. APPLICATIONS ACCORDING TO THE PRIME MOVERS

4.5.1. Application of reciprocating engines

Reciprocating engines are typically used in CHP applications where there is a substantial hot water or low-pressure steam demand. When cooling is required, the thermal output of a reciprocating engine can be used in a single-effect absorption chiller. Reciprocating engines are available in a broad size range of approximately 50kW to 5,000kW suitable for a wide variety of commercial, institutional and small industrial facilities.

Reciprocating engines are frequently used in load following applications where engine power output is regulated based on the electric demand of the facility. Thermal output varies accordingly. Thermal balance is achieved through supplemental heat sources such as boilers.

4.5.2. Application of steam turbines

In industrial applications, steam turbines may drive an electric generator or equipment such as boiler feed water pumps, process pumps, air compressors and refrigeration chillers. Turbines as industrial drivers are almost always a single casing machine, either single stage or multistage, condensing or non-condensing depending on steam conditions and the value of the steam. Steam turbines can operate at a single speed to drive an electric generator or operate over a speed range to drive a refrigeration compressor.

For non-condensing applications, steam is exhausted from the turbine at a pressure and temperature sufficient for the CHP heating application. Back-pressure turbines can operate over a wide pressure range depending on the process requirements and exhaust steam at typically between 5 psig to 150 psig. Back-pressure turbines are less efficient than condensing turbines; however, they are less expensive and do not require a surface condenser.

4.5.3. Application of gas turbines

Gas turbines are a cost effective CHP alternative for commercial and industrial end-users with a base load electric demand greater than about 5 MW. Although gas turbines can operate satisfactorily at part load, they perform best at full power in base load operation. Gas turbines are frequently used in district steam heating systems since their high quality thermal output can be used for most medium pressure steam systems.

Gas turbines for CHP can be in either a simple cycle or a combined cycle configuration. Simple cycle applications are most prevalent in smaller installations typically less than 25 MW. Waste heat is recovered in a HRSG to generate high or low-pressure steam or hot water. The thermal product can be used directly or converted to chilled water with single or double effect absorption chillers.

4.5.4. Application of fuel cells

The type of fuel cell determines the temperature of the heat liberated during the process and its suitability for CHP applications. Low temperature fuel cells generate a thermal product suitable for low-pressure steam and hot water CHP applications. High temperature fuel cells produce high-pressure steam that can be used in combined cycles and other CHP process applications. Although some fuel cells can operate at part load, other designs do not permit on/off cycling and can only operate under continuous base load conditions. For stationary power, fuel cells are being developed for small commercial and residential markets and as peak shaving units for commercial and industrial customers.

In a unique innovation, high temperature fuel cells and gas turbines are being integrated to boost electric generating efficiencies. Combined cycle systems are being evaluated for sizes up to 25 MW with electric efficiencies of 60-70% (LHV). The hot exhaust from the fuel cell is combusted and used to drive the gas turbine. Energy recovered from the turbine’s exhaust is used in a recuperator that preheats air from the turbine’s compressor section. The heated air is then directed to the fuel cell and the gas turbine. Any remaining energy from the turbine exhaust can be recovered for CHP.

5.1. INITIAL CONSIDERATIONS

5.1.1. Introduction

Cogeneration is a proven technology that saves fuel resources, but it does not necessarily imply any assurance of economic benefits. Irrespective of all its technical merits, the adoption of cogeneration would principally depend on its economic viability, which is very much site-specific. The equipment used in cogeneration projects and their costs are fairly standard, but the same cannot be said about the financial environment that varies considerably from one site and country to another.

The best way to assess the attractiveness of a cogeneration project is to conduct a detailed financial analysis and compare the returns with the market rates for investments in projects presenting similar risks. Well-conceived cogeneration facilities should incorporate technical and economic features that can be optimised to meet both heat and power demands of a specific site. A comprehensive knowledge of the various energy requirements of the site, as well as of the cogeneration plant characteristics is essential to derive an optimal solution.

As a first step, the compatibility of the existing thermal system with the proposed cogeneration facility should be determined. Important user characteristics that need to be considered include electrical and thermal energy demand profiles, prevalent costs of conventional utilities (fossil fuels, electricity), and any physical constraints of the site. A factor that should not be overlooked at this stage is the need for reliable energy supply, as some industrial processes and commercial sites are extremely sensitive to any disruption of energy supply that may lead to production losses.

To fully exploit the cogeneration installation throughout the year, potential candidates for cogeneration should have the following characteristics:

a. adequate thermal energy needs, matching with the electrical demand;
b. reasonably high electrical load factor and/or annual operating hours;
c. fairly constant and matching electrical and thermal energy demand profiles.

These are essential for the full exploitation of the cogeneration installation. Moreover, part-load operation of the plant should be avoided, which would otherwise have affected the economic viability of the project.

5.1.2. Considerations for CHP project development

A cogeneration project is the same as any other commercial energy efficiency project requiring high investment, relatively long pay-back period, and presenting certain financial risks. Therefore, the steps that should be normally followed in developing a cogeneration facility would be quite the same as those employed for any investment project (see figure 5.1). Projects will obviously vary from one to another on the basis of factors such as who is the project developer, what is the size of the project, who is financing the project, etc.

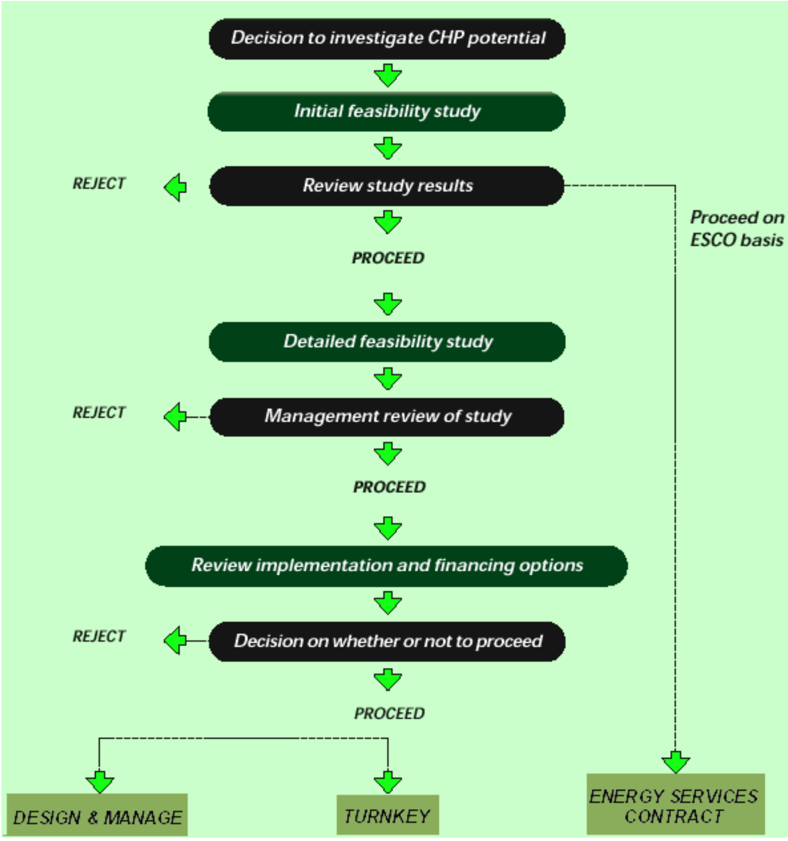


Figure 5.1. Typical steps for cogeneration project development

Prior to undertaking any economic analysis to assist the commercial benefit of a cogeneration project, there is a number of technical parameters that need to be considered first, such as those summarized below:

- Heat-to-power ratio;
- Quality of thermal energy needed;
- Electrical and thermal energy demand patterns;
- Fuel availability;
- Required system reliability;
- Local environmental regulations;
- Dependency on the local power grid;
- Option for exporting excess electricity to the grid or a third party, etc.

Most of these concerns are further discussed below.

CHP represents a major capital investment and thus is always in competition with other energy efficiency projects. Although the principle of cogeneration is relatively straightforward, the development process for any given CHP installation consists of a number of separate steps. Each one of these steps is an essential component of the whole development procedure and must be competently and thoroughly undertaken if the project is to be successfully designed and installed, and then operated effectively throughout its lifespan.

The development process requires a significant commitment in terms of time and special and multi-discipline expertise, thereby incurring both cost and effort. Proper management of the process is important if the proposed CHP plant is to maximize the potential benefits to its future operator. The instigator and manager of the development procedure will need to ensure that the necessary managerial skills are made available and applied effectively.

In concluding, the following should be born in mind when considering a CHP scheme:

- Adequate preparation is the key to a successful installation. The arguments in favour of CHP are complex to both engineers and non-engineers. Therefore, any project proposals need to be rational and clear and to consider all the arguments and options.
- The financial returns have to be at least equal to other potential capital projects.
- There are a number of different methods of financing and operating CHP, each of which has its own distinct benefits and drawbacks.

5.2. PROCEDURE FOR SYSTEM SELECTION AND DESIGN

5.2.1. Background

Prior to any consideration of cogeneration, the potential changes in the site energy requirements must be thoroughly investigated. Energy saving measures, demand-side management procedures and any changes in processes can not only be cost-effective, but also affect the type, size and economics of the CHP system. The selection of the optimum cogeneration system should be based on criteria specified by the investor and user of the system, considering economic performance, energy efficiency, uninterrupted operation, or other performance measures.

The question posed above can be stated more explicitly as a set of decisions that have to be made regarding:

- the type of cogeneration technology (steam turbine, gas turbine, reciprocating engine, combined cycle, etc.),
- the number of prime movers and the nominal power of each of them,
- heat recovery equipment,
- the need of thermal or electricity storage,
- interconnection with the grid (one-way, two-way, no connection at all),
- operation mode of the system (i.e. operating electrical and thermal power at any instant of time).

Furthermore, the availability of heat may lead to the investigation of the feasibility of absorption cooling, which will affect the load and consequently the design of the system. Any decisions should take into consideration various legal and regulatory requirements, which may impose limits on design and operation parameters, such as the noise level, emission of pollutants, total operating efficiency, etc. Developing and planning a cogeneration (or tri-generation, if absorption cooling is to be included) installation requires significant time, effort, and investment. Hence, it is prudent to approach the task in a series of steps.

The whole activity from the initial conception to the final design can be divided in three stages:

1. Preliminary assessment.
2. Feasibility study and system selection.
3. Detailed design.

The first stage requires less work, typically only one to two days, and helps the designer to determine whether further efforts are justified. The actions to be performed in each stage are described in brief in the following sections.

5.2.2. Preliminary assessment

An inspection of the site is performed in order to reach a first assessment on whether or not the technical conditions are such that cogeneration could be economically viable. This is why this stage is also called “walk-through analysis”. Aspects that are examined in this step include:

- Technical issues:
  - ➢ The level and duration of the electrical and thermal loads.
  - ➢ The energy saving measures that could be implemented before cogeneration.
  - ➢ Any plans for changes in processes, which would affect electrical and thermal loads.
  - ➢ The compatibility of the thermal loads with the heat provided by available cogeneration technologies.
  - ➢ The effect that cogeneration may have on the need to install and operate of other equipment such as boilers, absorption chillers, emergency generator.
- Site conditions:
  - ➢ The availability of space for siting the cogeneration system.
  - ➢ The ability to interconnect with the electrical and thermal system of the facility.
  - ➢ Zoning and/or environmental limitations that would preclude cogeneration.
- Economics: The average retail electric price, fuel costs, required return of investment or payback should be examined, in order to make sure that the fuel and electric rates support the development of a CHP plant.

As regards data collection during this stage, at the very minimum, the following data must be collected, reviewed and analysed:

➢ <u>Electrical requirements</u>

1. Average demand during operating hours _____kW

➢ <u>Thermal requirements</u>

1. Form of thermal energy use _____ steam _____ hot water _____ other
2. What is the primary application for thermal energy at the plant? __________
3. Average demand during operating hours _____ kgr/hr, Btu/hr, kJ/hr (circle correct units)
4. Required conditions _____ kgr/hr, Btu/hr, kJ/hr

➢ Operating conditions
1. Nominal operating hours per year _____
2. Number of hours per year that electrical and thermal loads are simultaneously at or above average values _____

➢ Energy rates
1. Average retail electric rate _____ cent€/kWh
2. Fuel price _____ €/mmBtu, €/therm, €/litre (circle appropriate units)

After finishing collecting and analysing all data describing the plant's energy use, the designer should go through a logical progression about the site's situation, as shown in the figure 5.2 below, which provides an introductory flow-chart to help the designer to evaluate the initial suitability of a CHP installation in a specific site. Once the progression of questions has been completed with success, simplified CHP payback estimators can be used in order to derive whether the development procedure can proceed to its next step.

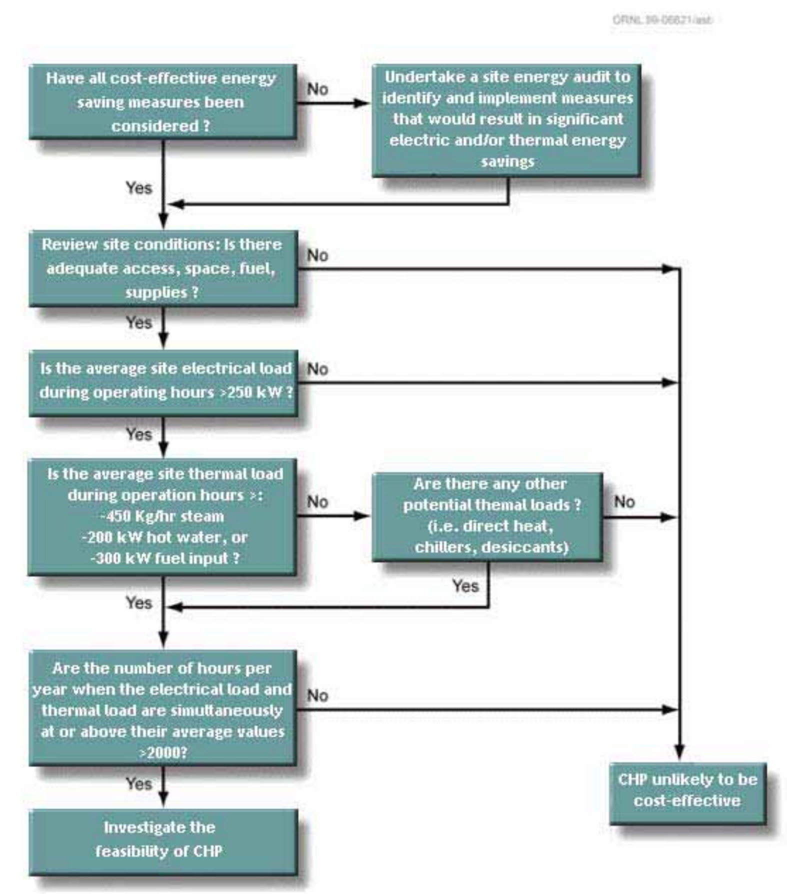


Figure 5.2. Flowchart for the initial evaluation of the suitability of a CHP system

Even though the aforementioned are referring to an existing facility, similar aspects are examined also when a new facility (either building or industry) is under design. In fact, in such a case, the integration of the cogeneration system with the rest of the installations is much easier and it has greater potential for improving the economic viability of the investment. In large projects, a pre-feasibility study might be advisable for a better assessment at this stage.

5.2.3. Feasibility study and system selection

This is the most crucial stage of the whole procedure, which will determine whether cogeneration is viable or not and which is the best CHP system for the particular application. It includes the following actions.

1. Collection of data and drawing of load profiles for the various energy forms needed (electricity, heat in the form of steam at various pressure and temperature levels, or in the form of hot water at various temperatures, cooling requirements, etc.). Load profiles can be drawn for typical days of the week, for weekends, for various months and seasons.
2. Collection of information about electricity and fuel tariffs, as well as about legal and regulatory issues.
3. Selection of the cogeneration technology that can provide the quality of heat (as regards the medium, its pressure and temperature) required. The power to heat ratio may be an additional criterion for the selection but not a very strict one, because it can be changed either by additional equipment (e.g. augmented heat recovery, thermal storage, supplementary firing) or by a decision to cover part of the electrical or thermal load.
4. Selection of the number of units and of the capacity of each unit. From the point of view of energy efficiency, the selection should be such that the major part of the co-generated heat is used, avoiding rejection to the environment.
5. Selection of the operation mode and calculation of the energy and economic measures of performance. Calculations can be repeated for various operation modes.

Actions 3, 4 and 5 should be repeated for other combinations of technology, number and capacity of units, additional equipment and operation modes. At the end of this procedure, the system with the best performance is selected, and a single- or multi-criteria approach can be followed for this purpose. Moreover, a study of the environmental, social and other effects of the selected system has to be performed in this step of the entire procedure.

Apart from the data already collected during the walk-through analysis stage, the following data must be collected, reviewed and analysed in the frame of this stage:

- <u>Electrical requirements</u>

1. Minimum demand during operating hours _____kW
2. Peak demand during operating hours _____kW
3. Annual electricity consumption _____kWh

- Thermal requirements
  1. Minimum demand during operating hours _____ kgr/hr, Btu/hr, kJ/hr
  2. Peak demand during operating hours _____ kgr/hr, Btu/hr, kJ/hr

- Energy rates
  1. Peak demand charge (if applicable) _____ €/kW/month

In cases where there is a strong phase shift between the electrical and thermal loads, it is useful the designer to examine the technical and economic feasibility of thermal storage or electrical storage (not common), in order to increase the utilization of co-generated electricity and heat. The selection of type, the design and the control of the storage unit are of crucial importance for the energy and economic performance of the whole system.

After collecting and analysing the necessary energy and cost data, the next step is to select a potentially suitable CHP system. In doing this, a range of equipment data should be obtained from suitable suppliers, who will normally be willing to provide technical and cost information on their products. Attention has to be paid in the fact that the data related to plant performance should reflect the typical running conditions of the plant over its expected lifespan, and not the peak operating conditions for the plant when it is new.

Information should be obtained for a number of options, and should include:

- Electrical output, which should include data relating to the power consumption of the CHP plant's own motors etc., so that the net output can be defined.
- Heat output that can be recovered for use on-site, including data on the flow rate and temperature of the fluid in which the heat is contained.
- Fuel consumption of the equipment, taking care to ensure that this can be expressed in gross calorific value terms.
- The cost of supplying and installing the equipment.
- The dimensions and weight of the equipment.
- The approximate cost per kWh generated that should be allowed for servicing and maintaining the equipment.
- Any essential auxiliaries that are not contained within the scope of the equipment.
- After-sales services (on-site maintenance provision, availability of parts, etc.).

As it is obvious, the multitude of variations of system structure and operation modes makes an exhaustive search very difficult (if at all possible) by conventional means. Several computer programs have been developed to aid the designer and are commercially available, which differ from each other with respect to the range of applicability and depth of analysis. One step further is the application of mathematical optimisation procedures for the system design and operation.

5.2.4. Identifying a CHP plant of an appropriate output

Initial selection of CHP plant is often dictated by two factors:

- The site heat demand, in terms of quantity, temperature etc., which can be met using heat from the CHP plant.
- The base-load electrical demand of the site, that is the level below which the site electrical demand seldom falls.

Sizing on heat demand will maximise energy and environmental savings. Depending on the heat to power ratio of site energy demands, sizing to match the heat requirements will result in a scheme that may offer a surplus of electricity generation (e.g. during the night), or may require top-up electricity supplies (e.g. at times of peak electricity demand). Then, the economics of exporting the electricity become a key issue in determining economic CHP plant size.

Factors that need to be taken into account include the quantity of electricity to be exported, the customer, the price agreed, the time of day/year, and any fixed up-front costs, such as upgrades required by the public electricity supplier and local electricity network. Once the electrical output of a CHP plant has been selected, the recoverable heat available from either a gas turbine or an engine can be compared with the site's heat demand. This comparison must take into account the temperature and form in which the heat can be recovered.

Ideally, this procedure will identify a size and type of the CHP plant where all the electricity and recovered heat can be used on-site. In cases where all the electrical power can be used but there is a surplus of recoverable heat, it may be worth considering a smaller unit. If all the recovered heat from the CHP plant can be used, but the electrical demand exceeds the output, it may be better to select a larger unit. There must be sufficient total plant to meet site heat demands at all times, and this sometimes results in plant being sized to meet the site heat load, with surplus electricity available for export.

Ultimately, prime mover/electrical generator selection depends on the overall cost savings that can be achieved, and the aim of the calculation procedure is to identify the optimum plant selection. It has to be mentioned that, the unit value of avoided electricity purchase is greater than the value of recovering an equivalent amount of heat energy. Therefore, the selection of CHP plant with the greatest energy efficiency is not always the one with the greatest financial benefits.

5.2.5. Detailed design

For the system selected in the previous stage, a detailed study should follow, which also requires a much greater degree of commitment. Its aim is to arrive at accurate information and results that will allow the project developer to make firm decisions about the technical, legal, commercial and financial viability of the proposed CHP scheme. Much of the work is similar in principle to that carried out in the initial feasibility study, and there should be no major change in the overall objective of the CHP evaluation procedure.

To provide a meaningful result, the level of detail and accuracy must be as high as possible. Thus, there may be need to collect more accurate and detailed information about load profiles and repeat actions 4 and 5 of the initial feasibility study stage at a higher depth, in order to either verify or slightly modify the main characteristics of the system. Detailed technical specifications of the main unit(s) are written down, including capacity, efficiency and controls, as well as the emissions, noise and vibration levels. Specifications for other major components have also to be prepared.

Finally, the location site of the system is selected and the design study is performed producing the necessary drawings for construction or modification of the building (if needed) and for the foundations of the system. Construction drawings are prepared also for fuel supply (including tanks, if necessary), air inlet and exhaust gas ducts, piping, electric circuitry and grid interconnection. The study must be specified and prepared in enough detail to produce a final report and conclusions that will be sufficiently comprehensive for the managerial staff to decide whether or not to proceed to CHP implementation.

5.3. ASSESSMENT OF IMPORTANT TECHNICAL PARAMETERS

5.3.1. Site energy demands

5.3.1.1. Future energy demands

It is important to as accurately as possible define the future energy loads that will need to be met by the CHP plant, and by any other site energy supply plant. Past consumption data that can be obtained from site utility bills usually provide a good indication of future demands, but it is also important to take site-specific factors into account when assessing future energy requirements. The energy demand data need to be subdivided to a high level of detail – preferably down to daily demand profiles, which may differ according to time of the year, day of the week, etc.

For heat use, the demand must be subdivided according to the different heat load temperatures and other demand conditions. Specific data requirements include:

- *Electricity demand data*: The electricity supplier may be able to provide a load profile for a 24-hour period, a week, or even for a whole year. Where this is not possible, electrical current flows can be measured using clamp-on meters linked to a data logger. Careful interpretation is necessary to account for production and non-production periods, any variations in production trends, seasonal changes in electricity demand etc., and to generate the appropriate annual, seasonal or daily profiles, as the ones presented in figure 5.3.

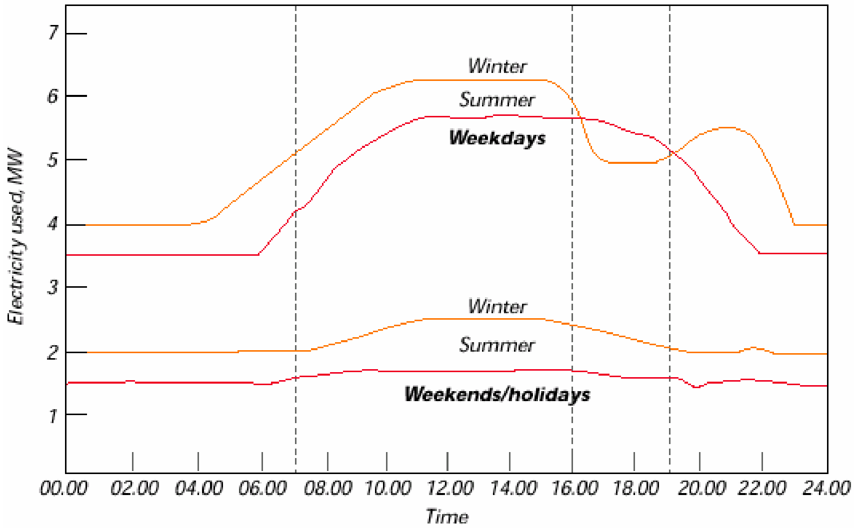


Figure 5.3. An example of site electricity load profiles (GPG 227, 1997)

- *Heat demand data*: Heat loads can be more difficult to assess, particularly steam ones. It may, therefore, be necessary to carry out a detailed survey of heat uses, including the type and grade of heat used in each case, and to combine this with hourly or half-hourly readings of boiler fuel or steam/heat meters over a typical 24-hour period. The required heat load values can be derived from fuel flow rates and system loss calculations. It is important to remember that the measurements taken represent the situation at one particular time period. As with electricity, careful interpretation is needed to generate appropriate annual, seasonal and daily load profiles. Figure 5.4 shows an example of daily heat load profiles.

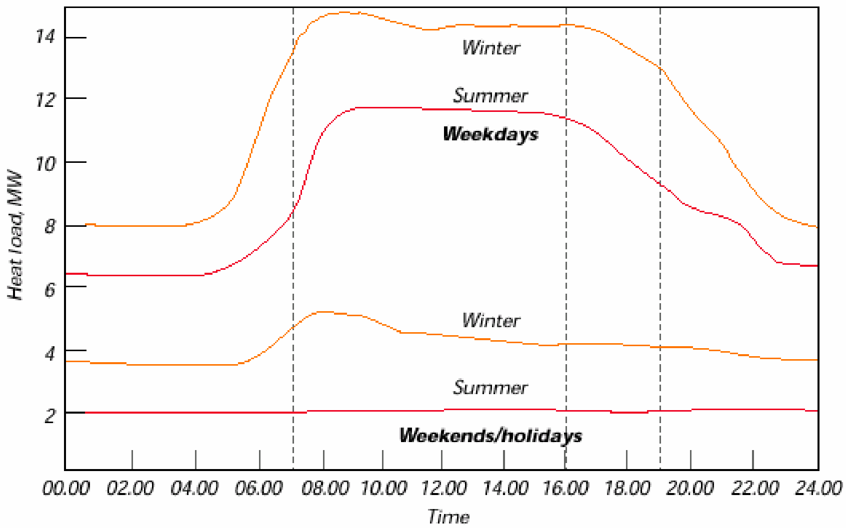


Figure 5.4. An example of site heat load profiles (GPG 227, 1997)

- *Likely future changes in demand*: It is very important to assess the effect of future changes in demand, which are usually associated with the implementation of energy efficiency measures, the introduction of new production or other facilities, discontinued processes, or changes in operation. Thus, heat loads are likely to be reduced by the future implementation of energy conservation measures or by the introduction of local metering, charge allocation, and other incentives for plant operators. Consumption data forecasts are needed for the expected lifespan of the potential CHP system (minimum of ten years). If demands are forecast to change in the future, then data for each year should be provided wherever possible. The greater the level of detail provided, the greater will be the potential accuracy of the subsequent financial evaluation.

5.3.1.2. Timing of demands

Since CHP produces heat and power simultaneously, it is essential to consider the extent to which the site has concurrent heat and power demands that can use the outputs of a CHP installation. This requires a time-based assessment of the site's energy demands. Some sites have fairly constant levels of demand over long periods of time, with minor variations resulting from occasional changes in plant availability or site activity.

Other sites have defined and predictable changes in demand that are associated with regular working patterns, e.g. nighttime or weekend shutdowns. Sites that require large amounts of energy for space heating will usually show significant variations between winter and summer heat demands. For the purposes of the initial feasibility study, it is sufficient to consider the site consumption over a one-year period, and then sub-divide this period into a maximum of eight time bands, according to actual site demand conditions.

The split would typically be based on distinctions between:

- daytime and nighttime,
- weekday and weekend,
- summer and winter.

Once a decision has been taken on the appropriate number of time periods, the electricity and heat demand data must be assessed and recorded in such a way that they can be readily used to calculate the potential energy cost savings. While this will inevitably require a certain amount of averaging, this approach provides a sufficient degree of accuracy at this stage of the evaluation process.

5.3.2. Factors affecting the selection of the suitable CHP plant

While selecting the appropriate for the site cogeneration system, the designer should always consider some specific technical parameters that assist in defining the type and operating scheme of different alternative systems to be selected. The most important of them are briefly described in the following.

5.3.2.1. Heat to power ratio

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

Basic heat-to-power ratios of different cogeneration systems in use are presented in Table 5.1, along with some other technical parameters. As it is shown, the steam turbine cogeneration system can offer a large range of heat-to-power ratios.

Table 5.1. Heat-to-power ratios and other parameters of cogeneration systems

Cogeneration System	*Heat-to-power ratio (kW_{th} / kW_e)*	*Power output (per cent of fuel input)*	*Overall efficiency (per cent)*
Back-pressure steam turbine	4.0-14.3	14-28	84-92
Extraction/condensing steam turbine	2.0-10.0	22-40	60-80
Gas turbine	1.3-2.0	24-35	70-85
Combined cycle	1.0-1.7	34-40	69-83
Reciprocating engine	1.1-2.5	33-53	75-85

5.3.2.2. Quality of thermal energy needed

The thermal requirements of the end-user may dictate the feasibility of a CHP system or the selection of the prime mover. Gas turbines offer the highest quality heat that is often used to generate power in a steam turbine. Gas turbines reject heat almost exclusively in its exhaust gas stream. The high temperature of this exhaust can be used to generate high-pressure steam or lower temperature applications, such as low-pressure steam or hot water.

Larger gas turbines (typically above 25 MW) are frequently used in combined cycles where high-pressure steam is produced in the heat recovery heat generator (HRSG) and is used in a steam turbine to generate additional electricity. The high levels of oxygen present in the exhaust stream allows for supplemental fuel addition to generate additional steam at high efficiency. Some of the developing fuel cell technologies, including molten carbonate fuel cells (MCFC) and solid oxide fuel cells (SOFC), will also provide high quality rejected heat comparable to a gas turbine.

Reciprocating engines and the commercially available phosphoric acid fuel cells (PAFC) produce a lower grade of rejected heat. Therefore, heating applications that require low-pressure steam (e.g. 1 bar) or hot water are most suitable for these technologies, although the exhaust from a reciprocating engine can generate steam up to 7 bar. These engines typically have higher efficiency than most gas turbines in the same output range and are a good fit where the thermal load is low relative to electric demand.

Reciprocating engines can produce low and high-pressure steam from its exhaust gas, although low-pressure steam or hot water is generally specified. Jacket water temperatures are typically limited to 100°C, so that jacket heat is usually recovered in the form of hot water. All the jacket heat can be recovered if there is sufficient demand, however only 40-60% of the exhaust heat can be recovered to prevent condensation of corrosive exhaust products in the stack that will limit equipment life.

5.3.2.3. Fuel supply

A potential system issue for gas turbines is the supply pressure of the natural gas distribution system at the end-user's property line. Gas turbines need minimum gas pressures of about 8 bar for small turbines with substantially higher pressures for larger turbines. Assuming that there is no high-pressure gas service, the local gas distribution company would have to construct a high-pressure gas line, or the end-user must purchase a gas compressor. The economics of constructing a new line must consider the volume of gas sales over the life of the project.

Gas compressors may have reliability problems especially in the smaller size ranges. If "black start" capability is required, then a reciprocating engine may be needed to turn the gas compressor, adding cost and complexity. Reciprocating engines and fuel cells are more accommodating to the fuel pressure issue, generally requiring less than 3.5 bar. Reciprocating engines operating on diesel fuel storage do not have fuel pressure as an issue; however, there may be special permitting requirements for on-site fuel storage.

Diesel engines should be considered where natural gas is not available or is very expensive. These engines have excellent part load operating characteristics and high power densities. In most localities, environmental regulations have largely restricted their use for CHP. Thus, diesel engines are almost exclusively used for emergency power or where uninterrupted power supply is needed such as in hospitals and critical data operating centres. As emergency generators, diesel engines can be started and achieve full power in a relatively short period of time.

5.3.2.4. Noise levels

Although fuel cells are relatively expensive to install, they are being tested in a number of sites typically where the cost of a power outage is significant to lost revenues or lost productivity, and where uninterrupted power is mandatory. Their relatively quiet operation has appeal and these units are being installed in congested commercial areas. Locating a turbine or engine in a residential area usually requires special consideration and design modifications to be acceptable.

Engine and turbine installations are often installed in building enclosures to attenuate noise to surrounding communities. Special exhaust silencers or mufflers are typically required on exhaust stacks. Gas turbines require a high volume of combustion air, causing high velocities and associated noise. Inlet air filters can be fitted with silencers to substantially reduce noise levels. Gas turbines are more easily confined within a factory-supplied enclosure than reciprocating engines.

Reciprocating engines require greater ventilation due to radiated heat that makes their installation in a sound-attenuating building often the most practical solution. Gas turbines require much less ventilation and can be concealed within a compact steel enclosure.

5.3.2.5. Other issues of concern

Some energy consuming facilities require very reliable power and/or heat supply. For instance, a pulp and paper industry cannot operate with a prolonged unavailability of process steam. In such instances, the cogeneration system to be installed must be modular, i.e. it should consist of more than one units, so that the shut down of a specific unit will not be able to seriously affect the energy supply as a whole. On the other hand, if the CHP system is to be installed as a retrofit, it must be designed so that the existing energy conversion systems, such as boilers, can still be of use.

Dissociation is also needed on whether the CHP system will be grid-dependent or a grid-independent one. A grid-dependent system has access to the grid to buy or sell electricity. The grid-independent system is also known as a “stand-alone” system that meets all the energy demands of the site. It is obvious that, for the same energy consuming facility, the technical configuration of the cogeneration system designed as a grid-dependent system would be different from that of a stand-alone system.

5.3.2.6. Regulatory and local planning issues

The technical consideration of CHP system must take into account whether the local regulations permit electric utilities to buy electricity from the operators or not. The size and type of the system could be significantly different if the export of electricity to the grid is allowed. Moreover, almost all CHP installations will require a planning consent, unless contained within an existing site building, which means that issues such as access, visual impact, noise, construction activity, etc. should be addressed. The installation of a new chimney will require authorisation from the Local Authorities.

In UK, planning consent is required from the Department of Trade and Industry (DTI) for gas-fired CHP schemes with capacity over 10 MW, and for all CHP schemes over 50 MW capacity. Moreover, the local environmental regulations can limit the choice of fuels to be used for the proposed cogeneration systems. If the local environmental regulations are stringent, some available fuels cannot be considered because of the high treatment cost of the polluted exhaust gas and, in some cases, the fuel itself.

Larger CHP plants will most probably require authorisation from the corresponding Environment Agencies regarding emissions and wastes. In particular, large plants installed within urban areas will need to demonstrate that they are not causing breaches of air quality standards and targets. Plants may also require approval from other regulatory bodies regarding their use of gas as a fuel. In some instances, local community organisations may consider that their views on the installation of a new plant should be considered.

5.3.3. Practical aspects of installing a CHP plant

Although the financial viability of a CHP plant is a crucial factor in assessing its feasibility, there are practical aspects that must be considered even from the initial feasibility study stage. Many of these will be considered in more detail in the later stages of the assessment process, but it is important to ensure that there are no practical obstacles that cannot be overcome as part of the normal CHP design and development process or that will probably involve excessive costs.

The location of the CHP plant needs to be considered carefully at an early stage, as there are several factors that help to determine its optimum 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 auxiliary equipment.
- The plant must be sited on foundations that are suitable for the static and dynamic loads imposed by it, which may require the construction of a concrete base or, in some cases, the installation of piles.
- The plant must be located in a position from where the recovered heat can be passed into the existing and future site heating systems. This will usually involve installing some new steam or hot water pipe-work.
- The plant must be connected to the site electrical distribution and fuel supply systems. The availability of such connections merely influence plant location.
- The CHP plant may require the installation of a new chimney.
- Although most CHP turbines and engines are supplied with acoustic enclosures, the plant and its auxiliary equipment produce noise. Since the plant may operate almost continuously, its location should minimise the impact of the noise emitted.
- The CHP plant must be connected to the existing site energy systems, and this may require some modification of utility connections to the site, together with provisions for storing additional fuel, water, lubricants etc.

5.4. FINANCIAL ASSESSMENT OF A CHP PROJECT

5.4.1. Key parameters for the economic analysis

Cogeneration may be considered economical only if the different forms of energy produced have a higher value than the investment and operating costs incurred on the cogeneration facility. In some cases, the revenue generated from the sale of excess electricity and heat or the cost of availing stand-by connection must be included. More difficult to quantify are the indirect benefits that may accrue from the project, such as avoidance of economic losses associated with the disruption in grid power, and improvement in productivity and product quality.

The major factors that need to be taken into consideration for the economic evaluation of a cogeneration project are the following:
1. the required initial investment;
2. all operating and maintenance costs;
3. the fuel price;
4. the price of energy purchased and sold.

Initial investment is the key variable that includes many items in addition to the cost of the cogeneration equipment. To start with, one should consider the cost of pre-engineering and planning. Barring a few exceptional cases, the plant owner/operator would normally hire a consulting firm to carry out the technical feasibility of the project, before identifying suitable alternatives that may be retained for economic analysis. If the cogeneration equipment needs to be imported, the prevailing taxes and duties to the equipment cost should be added.

If the system owner plans to purchase cogeneration components from different suppliers and assemble them on site, then the cost of preparing the site, for civil, mechanical and electrical works, as well as for acquiring of all auxiliary items, such as electrical connections, piping of hot and cold utilities, condensers, cooling towers, instrumentation and control, etc. should be taken into account. Table 5.2 provides an example of the breakdown of typical costs for a 20 MW_e gas turbine CHP plant.

Table 5.2. Cost breakdown (in US$) of a 20 MW_e gas turbine CHP plant

Component/service type	***Costs***	
Gas turbine plant equipment		**9,000,000**
➢ Gas turbine gen-set package	8,100,000	
➢ Auxiliary systems	370,000	
➢ Fuel gas compressor / skid	420,000	
➢ Back-up distillate storage	110,000	
Steam production equipment		**2,580,000**
➢ Heat recovery boiler with auxiliary firing	1,840,000	
➢ Water treatment system	320,000	
➢ Condenser, feed-water pumps	420,000	
Electrical components		**850,000**
➢ Substation transformers	320,000	
➢ Switch gear and controls	110,000	
➢ Utility interconnections	420,000	
Services and installation		**4,680,000**
➢ Engineering design	1,100,000	
➢ Civil works	630,000	
➢ Control & maintenance room	320,000	

➢ Electrical field work ➢ Mechanical field work ➢ Freight and handling	840,000 1,470,000 320,000	
Total plant cost		**18,810,000**
➢ Equipment, design and installation ➢ Contingency (approx. 10%)	17,110,000 1,700,000	

If cogeneration is being adopted as a retrofit at an existing site, the cost items will depend greatly on the existing facilities, some of which may be retained while others will be discarded, replaced or upgraded. The cost of land may be a crucial factor at some sites where cogeneration facility is commissioned, particularly in the case of urban buildings or when additional space is required for storage and handling of fuel.

Integration of the cogeneration plant into the existing set-up may lead to some economic losses to the plant operator (e.g. production downtime). Costs associated with such losses should be included in the total project cost. Annual costs incurred due to the cogeneration plant, such as the insurance fees and property taxes should also be included in the analysis. These are often calculated as a fixed percentage of the initial investment.

The operation and maintenance (O&M) costs should include all direct and indirect costs of operating the new cogeneration facility, such as servicing, equipment overhauls, replacement of parts, etc. The cost of employing additional personnel, as well as their training needed, for operating the new facility must also be taken into account. Present technology allows complete automation of small pre-packaged and pre-engineered units, helping to reduce the O&M costs considerably.

Fuel costs may form the largest component of the operating expenditures. If cogeneration is added to an existing plant, only the fuel cost in excess of that used earlier for the separate heat and power generation may be considered. Since the cogeneration plant is expected to operate for a long time period, escalation of the fuel price over time should be included in a realistic manner.

The price of energy purchased and sold is a decisive parameter. This includes the net value of electricity or thermal energy that is displaced, as well as any excess electricity or thermal energy sold to the grid. A good understanding of the electric utility's tariff structure is important, which may include energy and capacity charge, time-of-use tariff, stand-by charges, electricity buy-back rates, etc. As for the fuel, there should be provision to account for electricity price escalation with time. This is particularly true where utilities depend heavily on fuel in their power generation-mix.

5.4.2. Tools for the financial analysis of CHP projects

Regardless of whether the cogeneration project is a totally new facility or a retrofit of an existing operation, the project will be implemented only if it is financially attractive. There are a number of financial indicators to measure the attractiveness of a project.

Some indicators are also used to compare several energy retrofit projects in order to decide which one is the best alternative.

The sizing of the cogeneration system is sometimes carried out by financial analysis in grid dependent cases, where there is an option for importing electricity instead of self-generation of all the electricity. In such cases, the optimum size of cogeneration would correspond to a system that has the minimum annual total cost (or maximum annual net profit). The most commonly employed financial indicators for studying the feasibility of a cogeneration system are the payback period (*DPB* or *SPB*), the net present value (*NPV*), and the internal rate of return (*IRR*).

The easiest and basic measure of the financial attractiveness of a project is the payback period (*PBP*). It reflects the length of time *Y* (expressed typically in years) required to recover an initial investment (CF_0), which is calculated by:

$$CF_0 = \sum_{k=1}^{Y} \frac{CF_k}{(1+d)^k} \tag{5.1}$$

where CF_k is the cash flow during year *k* and *d* is the discount rate. If the payback period *Y* is less than the lifetime of the project *N* ($Y<N$), then the project is considered as economically viable. The value of *Y* obtained using equation (5.1) is typically called discounted payback period (*DPB*), since it includes the value of money.

In most of the calculations, the time value of money is neglected in the payback period method. In this case, *Y* is called simple payback period (*SPB*) and results as the solution of the following equation:

$$CF_0 = \sum_{k=1}^{Y} CF_k \tag{5.2}$$

In the case where the annual net savings are constant ($CF_k=A$), the simple payback period can be easily calculated as the ratio of the initial investment over the annual net savings: $Y=CF_0/A$.

The net present value (*NPV*) – or Net Present Worth (*NPW*) - of a stream of annual cash flows is the sum of discounted values of all cash inflows and outflows over a certain time period (e.g. the lifetime of the project *N*). For a cogeneration project, the initial investment costs are assumed as cash outflows and the net annual energy cost savings (or net annual benefits) as cash inflows. Thus, *NPV* is expressed as:

$$\begin{aligned} NPV &= -CF_0 + \frac{CF_1}{(1+d)} + \frac{CF_2}{(1+d)^2} + \ldots.. + \frac{CF_N}{(1+d)^N} + \frac{S}{(1+d)^N} \\ &= -CF_0 + \sum_{k=1}^{N} \frac{CF_k}{(1+d)^k} + \frac{S}{(1+d)^N} \end{aligned} \tag{5.3}$$

where *S* is the salvage value of the project.

For a project to be economically viable, the net present value has to be positive or at worst zero ($NPV \geq 0$). Obviously, the higher the *NPV* the more economically sound is the project. The net present value method is also often called “net savings method”, since the revenues are often due to the cost savings from implementing the project. When cogeneration system alternatives of different capacities are being compared, the net present value is an important financial parameter. The project that has the highest net present value would be chosen as the best alternative system.

The internal rate of return (*IRR*) is defined as the discount rate (*d*) that equates the present value of the future cash inflows of an investment to the cost of the investment itself. Actually, the *IRR* is the rate of return that the project earns. The equation for calculating the internal rate of return is given as:

$$\begin{aligned} 0 &= -CF_0 + \frac{CF_1}{(1+IRR)} + \frac{CF_2}{(1+IRR)^2} + \ldots.. + \frac{CF_N}{(1+IRR)^N} + \frac{S}{(1+IRR)^N} \\ &= -CF_0 + \sum_{k=1}^{N} \frac{CF_k}{(1+IRR)^k} + \frac{S}{(1+IRR)^N} \end{aligned} \qquad (5.4)$$

Manual computation of *IRR* generally requires an iterative procedure. One starts with an assumption of the rate first and calculates the net present value of the cash flow stream. If the *NPV* is negative, the process is repeated with a lower assumed *IRR*.

The iterative process would be repeated until the net present value becomes zero (or nearly zero). However, many personal computer spreadsheet programs and some hand-held financial calculators have the ability to compute the *IRR* from a stream of cash flows. To judge the suitability of a cogeneration project, comparison is made between *IRR* and the discount rate (or the required minimum rate). If *IRR* happens to be less than the discount rate, the project would be rejected.

5.4.3. Assessment of financial feasibility of CHP projects

Once the potential operator is satisfied with the rough payback period of a specific cogeneration project, a common and simple procedure of financial feasibility of that particular alternative may be pursued, as shown in figure 5.5.

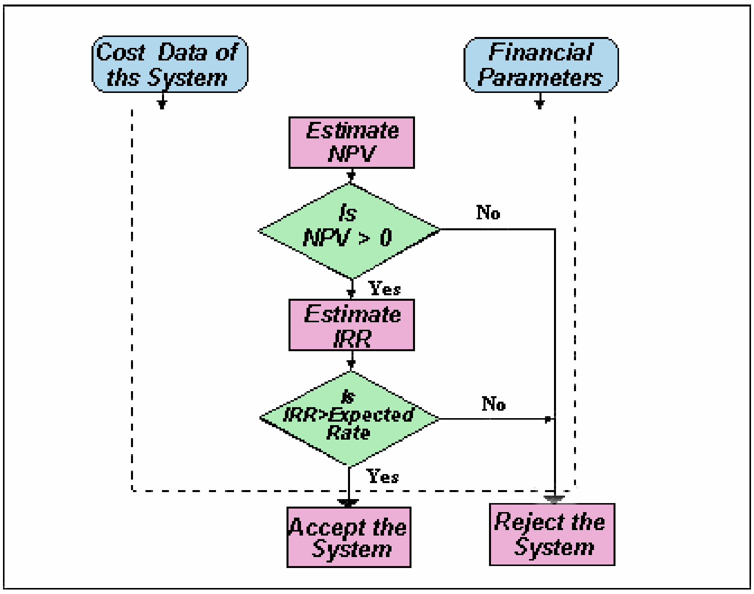


Figure 5.5. Flowchart of cogeneration feasibility analysis

In the estimation of the *NPV* for a CHP project, the total investment costs are taken as cash outflows, and cash inflows are the difference between the annual total cost of the cogeneration system and that of the conventional energy supplies. Sometimes the total discounted costs of different cogeneration alternatives are estimated instead of the *NPV* of a single alternative, e.g. in the case of a grid independent project. All the cash outflows are considered and discounted to the present value. The option that has the least discounted costs would be selected as the best system.

Investment decisions are based on the above-mentioned financial indicators that are calculated from cash flow streams. The cash flows are estimated based on a number of factors such as future costs, interest rates, fuel costs, expected investment levels, tax rates, etc. Therefore, changes in these parameters affect drastically the financial indicators and investment decisions. It is necessary to analyse how the value of a financial indicator (e.g. internal rate of return) changes when one or more of the input parameters (e.g. discount rates, fuel prices, investment costs) deviate by a certain amount (or percentage) from the expected value.

The above procedure is known as the sensitivity analysis. If the system to be installed has no access to the utility grid, the financial feasibility study will lead to the best cogeneration alternative, since the sizing of different alternatives would have been carried out in the technical feasibility study. Financial indicators are estimated for each cogeneration system retained after the technical feasibility study. The best cogeneration alternative that has the highest *NPV* (or the least total discounted cost) would be selected.

For systems having access to the utility grid, the optimum size of alternative cogeneration systems is determined by the financial feasibility study. The optimum size of each alternative would be that which has the highest net present value (or least discounted cost). After sizing each alternative system, the best alternative that has the highest net present value (or least discounted cost) would be selected.

Normally, the determination of the optimum size of a particular cogeneration system is performed by computer software, because it is a repetitive and time-consuming process, dealing with a large number of variables and parameters. The objective function of the optimisation process may be the maximization of the net present value or the minimization of the total discounted costs. Finally, the best CHP system would be identified after the sensitivity analysis is carried out, to make sure whether the selected system is still financially attractive with possible variations in the values of some critical parameters.

5.4.4. Sensitivity analysis

In an initial feasibility study, the calculation of cost savings and installed plant costs is based on estimates or forecasts of a number of variables. It is important to assess the likely impact of changes in certain of these variables as such changes can affect the costs, savings, and the payback period. This assessment is called a sensitivity analysis. The variables to be considered in any sensitivity analysis include:

- CHP operating hours;
- electricity and heat demands;
- unit prices for fuel and electricity;
- plant installation costs;
- plant maintenance costs.

When considering the impact of a variation in operating hours, it is important to recognise that the cost savings from a CHP installation do not vary linearly with annual operating hours, since a disproportionate part of the savings is made during periods when electricity prices are higher. Hourly cost savings vary by a factor of more than ten between the peak winter electricity tariff periods and the low summer night-time tariff periods. The sensitivity analysis illustrates the differences in cost savings that can result from reduced plant availability at different times of the year.

When considering changes in the costs of fuel and electricity, there are three points of concern:

- If the costs of electricity increase (or decrease), so do the energy cost savings associated with the CHP plant.
- If the costs of fuel increase, the energy cost savings associated with the CHP plant decrease, and vice versa.
- In terms of cost per unit of energy supplied, electricity is significantly more expensive than primary fuels, and the economics of CHP schemes are, therefore, much more sensitive to changes in the unit price of electricity. At current typical prices, a 10% increase in electricity prices improves the payback on a typical CHP scheme by 10-15%, while, for comparison, a 10% decrease in fuel prices

improves the payback by 3-5%. The combined effect of both changes would be to improve the simple payback by between 12% and 18%.

Figure 5.6 provides an indication of the likely effect of different energy prices on a specific CHP project payback period (*p* stands for British pennies).

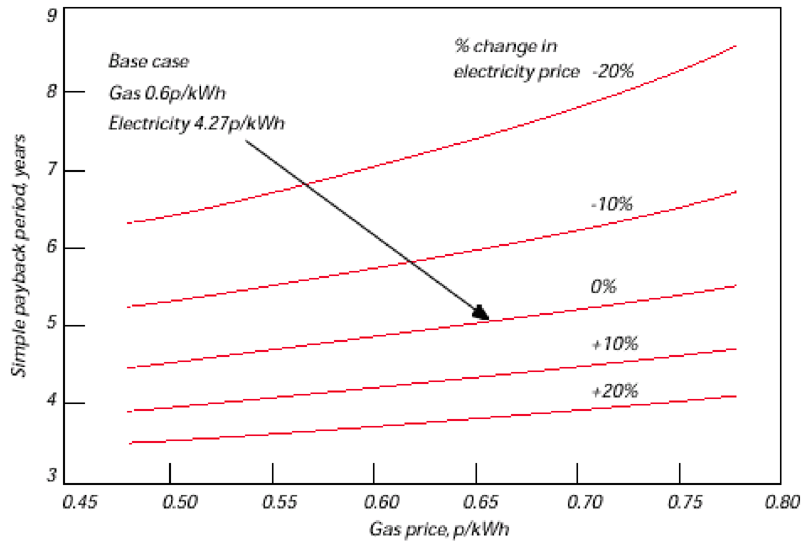


Figure 5.6. Effect of energy prices on project payback (GPG 43, 1999)

6.1. LEGAL AND INSTITUTIONAL FRAMEWORK CONDITIONS

6.1.1. Background

The changing energy policy in Europe influences the profitability of CHP plants immensely. With the newly liberalised electricity market, the prices for electricity went down. This had a negative impact on the profitability of CHP plants. On the other hand, the depletion of fossil fuels, but also environmental concerns (such as climate change), show the importance of energy saving technologies and energy efficiency measures. The use of CHP presents a substantial potential for increased energy efficiency and reduced environmental impacts, therefore it is of strategic importance.

The production of electricity from CHP plants is considered to be a priority area for the EU as well as for many Member States. Several Programmes on Community level support CHP. On national level, the importance of CHP has been translated into legal text in many cases. According to a study realised by the ZREU and CRES[1] nearly 60% of CHP experts have a strong interest in learning more about legal and institutional framework conditions. As they change quite often and are sometimes rather complex, there is a high need for information on this issue.

6.1.2. European Union law

The Community has promoted the concept of CHP since 1974 when an industrial expert group was set up to investigate the possibilities of improving the conversion efficiency of thermal power stations. In the White Paper "An Energy Policy for the European Union" the Commission committed itself to present a strategy offering a coherent approach for the promotion of Combined Heat and Power. New EU initiatives are influencing the future structure and function of Europe's energy industries. This creates a new situation for CHP with less price stability and increased environmental concern.

CHP should play an important role in this new framework. Therefore, it is of tremendous importance that efforts to promote CHP are consistent with the new industry dynamic. The Commission has published a Communication to the Council and the European Parliament proposing a Community strategy to promote combined heat and power and to dismantle barriers to its development.

6.1.2.1. Communication from the Commission to the Council and the European Parliament: “A Community strategy to promote combined heat and power and to dismantle barriers to its development” (15.10.97)[2]

[1] "Guide for the training of engineers in CHP issues, Training Needs Study for Germany and Greece” (2000)
[2] COM (97) 514 final

Several community measures in support of CHP exist. In spite of a Council Recommendation (88/611/EEC) of November 1988 dealing with the promotion of co-operation between public utilities and auto-producers of electricity essentially using renewables, waste fuels and CHP, whose main purpose was to remove legal and administrative obstacles, there were still constraints to be removed if CHP was to realise it's potential. The relationship between auto producers and electricity production utilities and the lack of progress in achieving the internal electricity market were considered as the main obstacles for CHP development.

The Energy Charter Treaty introduces a framework for energy co-operation and trade between the signatories. The treaty addresses a number of issues, including transit of energy supplies, energy efficiency, and foreign investment in energy plant. The Energy Efficiency Protocol, when implemented by all partners, will represent an important new framework for CHP in the signatory countries. In the Protocol, support to promotion of CHP and measures to increase the efficiency of District Heating are explicitly mentioned.

The Directive concerning the liberalisation of the electricity internal market offers the possibility to Member States to give priority to CHP plants when the system operator is dispatching generating installations.

Objective of the strategy is a doubling of the current share of CHP from 9% to 18% of the total gross electricity generation of the Community by the year 2010. The strategy underlines the importance for Member States to develop their own national strategies and objectives. The main focus of the effort has to lie with the Member States. The Commission underlines the need for all Member States to set specific objectives for CHP.

6.1.2.2. European Union programmes supporting CHP

CHP constitutes an important element of the Community CO_2 reduction policies and a priority. An increased share of funding to CHP by EU programmes is foreseen. The Commission has included CHP in most of the existing funding programmes:

<u>JOULE/THERMIE</u>: There is a continued need for the further technological development of CHP technologies. These developments include improvements to cost effectiveness, adaptation of new types of application, integration of non-conventional fuel process and improvements of combustion systems to meet tight emissions standards. Biomass as a fuel for CHP systems deserves specific support. This applies also to the use of new coal cycles and energy from waste technologies.

<u>SAVE/ALTENER</u>: These programmes are designed to find solutions to overcome non-technical barriers that restrict the use of energy efficiency and renewable energy technologies. SAVE increased its support to actions promoting CHP. The ALTENER programme continuous to promote market penetration of biomass-fired boilers including CHP schemes.

PHARE, TACIS, SYNERGIE and MEDA: The PHARE and TACIS programmes are initiatives for the Central and Eastern European Countries, the New Independent States and Mongolia. They provide support to the process of transformation of these countries to market economies and to strengthen democracy. Energy is one of the main priorities of TACIS and CHP projects are frequently supported especially in conjunction with the existing CHP based District Heating Networks.

The SYNERGIE programme promotes the international co-operation in the energy sector and finances actions promoting CHP in Latin America and Asia. This programme can be an important vehicle for the promotion of CHP applications in a wide range of third countries.

For the Euro-Mediterranean partnership (MEDA), energy and environment are sectors where particular attention should be paid. Promotion of CHP through technical assistance and preparatory studies related with district cooling presents an environmental and economic challenge for the countries in this region.

STRUCTURAL FUNDS: Less favoured European Regions can be granted Community support for the development of energy efficiency schemes. In Greece CHP is one of the priorities of the operational programme for energy. The Commission encourages Member States to adopt the development of CHP as a priority of national energy programmes financed by the above funds.

6.1.2.3. Internalisation of external costs

The internalisation of external costs is a key priority for the integration of environment into other Community policy areas. Energy taxes can act as a stimulus reinforcing CHP's competitiveness in the field of electricity and heat production. CHP is a means of improving energy efficiency and of reducing pollutant emissions and as such the principle of internalisation of costs could stimulate the use of CHP technologies.

The Commissions examines ways in which it can integrate the energy and environmental benefits of CHP in its taxation policy. Financial instruments such as Third Party Financing are encouraged for CHP investments in industry and in the tertiary sector.

6.1.2.4. Action plan to improve energy efficiency in the European Community[3]

An estimated economic potential for energy efficiency improvement of more than 18% of present energy consumption still exists today in the EU as a result of market barriers that prevent the satisfactory diffusion of energy-efficient technology and the efficient use of energy. The action plan outlines policies and measures for the removal of these barriers and the realisation of this potential. Meeting the

[3] COM (2000) 247

Community-wide target of doubling the use of cogeneration to 18% of EU electricity production by 2010 is expected to avoid over 65 Mt CO2/year by 2010.[4]

The SAVE Programme will be used as the principal co-ordinating arm of the Action Plan, both as a basis for preparing common action and to provide the means of implementation and evaluation at Community level. Other Community programmes, including the 5th Framework Programme, are also important in this process.

The time frame for the Action Plan covers essentially the period to 2010 and much of its impact will be measurable until then and beyond. Most of the actions, however, will be initiated during the present lifespan of SAVE and other ongoing Community programmes up to and including 2002.

<u>Measures to integrate energy efficiency into non-energy policies and programmes</u>: *Regional and urban policy and programmes* have potentially large energy efficiency dimensions. The guidelines for the *Structural Funds* give priority tot he investment by industry in energy-efficient and innovative technologies, such as CHP.

<u>Initiatives to strengthen and expand existing successful energy efficiency policies and measures</u>: The impact of energy market liberalisation on the penetration rate of cogeneration and the development of improved financing mechanisms will be followed closely, as will RTD in the area. The Commission proposal for a revision of the Council Directive on polluting emissions from large combustion plants[5] will require that new plants apply CHP where feasible, making provisions for the use of biomass and promoting efficient production with fossil fuels.

The Community-wide target of raising the use of cogeneration to 18% of EU electricity production by 2010 will be pursued through numerous strengthening policies and measures, often in co-operation with Member States. Measures will address i.e. the technical barriers and costs associated with connection to the grid. The table shown below gives an overview of the initiatives taken in the framework of the Action Plan for Energy Efficiency.[6]

Table 6.1. Initiatives of the Action Plan for Energy Efficiency

[4] European Cogeneration Review, July 1999
[5] Council Directive 88/609/EEC
[6] Annex I of the Action Plan to Improve Energy Efficiency in the European Community

CHP			
Initiatives promoting increased use of CHP installations will cover a range of different sectors, including industry, the domestic and tertiary sector and the heating sector. The target for wider use of CHP will be followed by legislative measures, higher priority in programmes, and a number of other actions aimed at improving co-ordination of promotional activities, market monitoring etc.			
Definition of action	**Current status and timetable**	**Action by**	**Comments (financing, impact, etc)**
a. Legislative measures			
Large Combustion Plant Directive. Amended 88/609 Directive proposed.	Under discussion in Council.	Parliament, Council.	No cost for EU budget. Feasibility studies. CHP a priority
Member States to promote CHP through national actions.	New proposal 2000.	Commission, Member States	No cost for EU budget. Possibly in an Amended *Directive 93/76/EEC.*
Reform of agricultural policy and production of biomass for use in CHP.	Proposals under debate.	Commission.	Cost calculations not yet available.
b. Programmes			
Projects promoting CHP in industry, the domestic and tertiary sectors, the power sector and the heating sector in many Community and national programmes.	Ongoing.	Commission, Member States, Member State organisations	Includes 5th Framework Programme and Energy Framework Programme (SAVE).
Use of Structural Funds. - Member State proposals according to amended regulations.	Under discussion 2000-2006.	Commission, Member States.	
c. Other Action			
Co-ordination of Commission activities conceming CHP. Ad hoc working group for information exchange.	New initiative.	Commission.	No additional cost.
Follow-up groups for the transposition of Directives 96/92 (Intemal electricity market) and 98/30 (Intemal gas market). To avoid obstacles for CHP.	Ongoing.	Commission, Member States.	No additional cost.
CHP Statistics (data collection). Monitoring of CHP penetration in the European energy market.	Ongoing.	Commission, Eurostat.	0,1 MEuro/year.
Directors-General for Energy Committee. National programmes for the promotion of CHP discussion.	To be proposed during 2000.	Commission, Member States.	No additional cost.
Actions supporting Cross-border strategies for promotion of CHP at regional level. (with energy authorities, utilities, CHP producers etc.)	New initiative.	Commission, Member States, energy industry.	Cost of pilot actions.
Promotion of CHP through public and technology procurement initiatives.	New initiative.	Commission.	Costs of studies and pilot actions to be made available.

6.1.2.5. Directive concerning the common rules for the internal market in electricity[7]

[7] Directive 96/92/EC, OJ L027, 30/01/1997 p. 0020-0029

As already mentioned above, the Directive on common rules for the internal electricity market influenced the profitability of CHP plants negatively. Nevertheless, the Directive takes into consideration environmental protection and energy efficiency measures and encourages the use of renewable energy and the production of electricity from CHP for the construction of new generating capacity.[8] As for the transmission system operation, a Member State may require the system operator, when dispatching generating installations, to give priority to generating installations using renewable energy sources or waste or producing combined heat and power.[9] This is also valid for the distribution system operation.[10]

6.1.2.6. EU Directive on the promotion of electricity from RES in the internal market (forthcoming) [11]

The Directive on the promotion of electricity from renewable sources of energy (RES) concerns CHP only indirectly, as far as CHP is produced from RES. Member States are required to establish national targets for the consumption of electricity from renewable sources. However, it is doubtful that Member States will accept binding national targets.

Public support for electricity from RES is deemed to be necessary, in particular as long as electricity prices in the internal market do not reflect the full social and environmental costs and benefits of energy sources used. The need for public support in favour of renewable energy sources is thus recognised in the Community guidelines for state aid for environmental protection. In the medium term, it is however necessary to adapt support schemes to the principles of the developing internal electricity market. Until a Community wide framework is established, national support schemes are subject to the Community state aid rules.

6.1.3. The situation in Germany

6.1.3.1. Law for the protection of the production of electricity produced from combined heat and power plants

Due to the liberalisation of the electricity market and its restricting impacts on the CHP development, the German Government has adopted a law for the protection of the production of electricity produced from combined heat and power plants. The purpose of the law (KWK Vorschaltgesetz) is the temporally restricted protection of existing (operating since before 1 January 2000) CHP facilities of public utilities.

Thus, an electric supply company, supplying final consumers, must operate the CHP plant. The supply company must have operated already as energy supplier on the 31 December 1999. Included is power produced in CHP plants from coal, lignite, gas, oil

[8] *idem*, Chapter III Article 5 line 1 (b) (e)
[9] *idem*, Article 8 line 3
[10] *idem*, Article 11 line 3
[11] Commission proposal, currently in the co-decision procedure

or waste, owned for at least 25% by an electric supply company. The power produced from CHP must be at least 10% of the total annual power production of the plant.

The network operator is obliged to connect the CHP plant to the grid and to pay a minimum price of 0.045 Euro/kWh. This minimum compensation is lowered each year (on the 1^{st} of January) by 0.026 Euro/kWh. The law is restricted until the end of 2004 provided that a CHP Development Law has not come into force before. The law does not cover CHP plants in the industrial, private and commercial field. There is no clear definition of CHP. The definition given is too wide and may include installations producing power from CHP but not using the heat.

For the future, the CHP Development Law should serve as the most effective instrument to reach the target of doubling the share of CHP from 12% (1998) to 24% until 2010. This law is expected to come into force in summer 2001 and will probably be based on a quota model for CHP electricity. The basics of the discussed quota model are:

- The legislator lays down a quota for CHP electricity production that will be raised every year. The aim is to raise the share of CHP in electricity supply from 12% to 24%.
- Each CHP producer gets a certificate by the regulation authority corresponding to his yearly electricity production. Each electricity supplier has to buy certificates according to the quota. The certificates are tradable. The prices are formed by offer and demand.
- If an electricity supplier has not bought enough certificates, he has two years time to buy the missing certificates with a penalty rate (10%). After this period, he has to pay a surcharge of 0,03 Euro/kWh
- Foreign electricity suppliers also have to buy certificates according to the quota.

6.1.3.2. The ecological tax reform

On April 1, 1999, existing taxes on petroleum products were increased and a new tax on electricity was introduced. One of the objectives is to reduce CO_2 emissions by 25% (from 1990 level) by the year 2005. The ecological tax reform (Gesetz zum Einstieg in die ökologische Steuerreform, 3 March 1999; Gesetz zur Fortführung der ökologischen Steuerreform, 12 December 1999) has consequences on the market situation on CHP production, as they are subject to a favourite treatment under the law.

- Exemption from electricity tax:

  Electricity produced in installations with a normal capacity up to 2 MW_{el} is set free from the electricity tax if the electricity is used for covering the own demand or those of third parties within this installation or in a neighbouring living or industrial area (advantage in 2000 0,012 Euro/kWh electricity; the tax shall rise yearly 0,005 Euro/kWh until it reaches 0,02 Euro/kWh in 2003).

Third party financed electricity produced in CHP plants with a capacity up to 2 MW_{el}, is exempted from the electricity tax for the quantity of electricity that is consumed on a contractual basis in the neighbourhood.

If electricity is produced for own requirements from biofuels, installation with a capacity up to 5 MW is exempted from the electricity tax.

In all cases, if the capacity of the installation is above the limits, the installation in question is fully subject to the tax.

- Exemption from oil tax:

  Combined heat and power plants with an annual or a monthly efficiency of at least 70% are completely exempted from the oil tax (advantage gas CHP: 0,018 Euro/kWh "old" oil tax for gas, plus 0,016 Euro/kWh "new" oil tax). The consideration of monthly efficiency is valid since 01.01.2000 and includes electricity driven installations, which are operated as CHP in winter. These installations did not profit from the oil tax rebate before, as the annual efficiency of these installations was under 70% (due to the un-combined electricity production in summer).

  Combined heat and power plants with an annual efficiency of at least 60% are only exempted from the "new" oil tax (0,16 Euro/kWh).

Only supplemental electricity from the grid will fall under the electricity tax when operating a CHP plant for self-production (third party financing included). Only fuel used in the heating boiler will be subject to the oil tax. With respect to the complete heat production in the boiler and a 100% purchase of electricity from an electric supply company, the operator of a standard CHP plant (50 kW_{el} and 6000 operating hours in 2000) saves some 6300 Euro Ecological Tax per annum.

Small CHP installations are therefore more competitive. However, these exemptions from the tax have only been authorised until the 30 March 2002 by the European Commission.

6.1.3.3. Renewable Energy Law

The overall objective of the Renewable Energy Law (Gesetz für den Vorrang erneuerbarer Energien, 25.02.2000) is to contribute towards doubling the share of renewable energy in the electricity market from 5% to 10% by 2010, in line with the targets set in the European Commission's White Paper on Renewable Energy (1997).

By setting specific tariffs for each renewable energy technology based on its real costs, the new law clearly recognises the contribution of renewable energy to reducing greenhouse gas emissions and saving fossil fuel reserves. It's aims are to initiate a self sustaining market for renewables by compensating for the distortions in the conventional electricity market, and simultaneously to create a critical mass through a massive market introduction programme that does not put an additional burden on the taxpayer. The Renewable Energy Law also includes both digressive and differentiating elements, as well as a regular bi-annual revision process which allows for regular adjustments in response to technological and market developments.

As regards CHP, the regulations concerning electricity production from biomass, methane, or sewer gas are especially interesting. For electricity produced from methane or sewer gas, the minimum compensation is 0,075 Euro/Wh. This compensation is limited to 500kW$_{el}$, while for the electricity produced above 500kW the minimum compensation is 0,07 Euro/kWh.

For electricity produced from biomass, a compensation of 0,1 Euro/kWh stands for installations with a capacity up to 500 kW$_{el}$, a compensation of 0,09 Euro/kWh for further capacity until 5MW$_{el}$, and a compensation of 0,08 Euro/kWh for further capacity until 20 MW$_{el}$. There is no clear definition of biomass yet, and the question arises whether contaminated material will be considered as biomass. The compensation for new installations will be lowered yearly by 1%.

6.1.4. The situation in Greece

6.1.4.1. Overview

The public power corporation (PPC) holds up-to-now the exclusive right to transmit and distribute electricity in Greece, and produces 99.1% of the country's electricity production. The implementation of law 2244/94 of October 1994 has ended a forty-five year monopoly on electric power production by the state owned PPC. This law allows the private sector to establish and operate power stations to produce energy from renewable sources and natural gas, either for their own use or for resale to the PPC. A major task to achieve is the implementation of the EU Directive 96/92 regarding the single European market in electricity.

Greece was given a time-extension for the implementation of this Directive. Law 2773/99, activated in February 2001, opens the electricity market up to 34%. Large consumers (with an annual consumption of more than 100GWh) can choose their electricity supplier. Additional parts of the market will be liberalised after three years of the first application of the Law, according to the directions of the EU Directive 96/92. A Regulatory Authority for Energy (RAE) has been established and an authority responsible for the grid operation/management is expected to follow soon.

6.1.4.2. The Operational Programme for Energy (OPE)

The operational programme for energy, which exists since 1997, provides public co-financing to investments in Greece concerning implementation of energy efficiency measures and/or applications of renewable energy sources. Three quarters of the total public co-financing funds constitute support from the European Commission's

Regional Structural Funds. The rest is Greek State contribution. Co-financing is provided to investments within the Greek territory, up to a total investment budget of 2,93 million Euro. Cogeneration of Electricity and Heat is included in Energy saving (Measure 2.2). Biomass Application are co-financed under Measure 3.2 (Renewable Energy Sources).

The total budget of the proposed investment should be no lower than 293,000 Euro. Eligible for submission of proposals are Legal Entities under private law or consortia of such entities, which meet certain criteria. The percentage of public co-financing is 35% for Cogeneration of Electricity and Heat, and 45% for Biomass Applications. The investors own capital should be at least 20% of the total investment budget; this may include capital provided through a third party financing scheme.

The total budget of the investments that have been financed from 1997 till today is 440 million Euro, corresponding to 150 million Euro for energy saving (measure 2.2) and 290 million Euro for RES applications (Measure 3.2). During the three OPE calls for investments during years 1997, 1998 and 1999, the following CHP projects, shown in Table 6.2, with their respective calculated electric and thermal energy production, have been licensed and co-financed:

Table 6.2. Licenses approved by OPE under measure 2.2 / A2 [Source: CRES]

FIRM	ACTIVITY	INSTALLED POWER (kW)	ELECTRIC ENERGY (MWh)	THERMAL ENERGY (MWh)
BIOKARPET	Textiles	2478	20042	43366
BIOHARTIKI	Paper	4822	33718	86469
ETEM	Alum. frames	257	1628	4142
PROMITHEUS	Natural gas	19909	173213	459179
ATHINEON	Hotel	748	6025	25596
MAILIS	Packaging	1600	12800	31290
KOTHALI	Ceramics	4500	35640	69300
AMYLOUM	Starch	1350	9200	76684
	TOTAL	**35664**	**292266**	**796026**

Additionally, there are two large CHP projects in their final stages of construction, using city waste released biogas as a fuel (Table 6.3). These are also supported by the Operational Programme for Energy (OPE, Measure 3.2) and are utilising the biogas, which was up to now just burned or left to pollute the atmosphere. The electrical power, produced by gas turbines, will be sold to the national grid (PPC) in both cases, while the thermal power will be utilised for drying the mud in the first project and for the mechanical recycling of non-organic city-waste in the second one.

Table 6.3. Licenses approved by OPE under measure 3.2 / B5 [Source: CRES]

FIRM	ACTIVITY	INSTALLED POWER (MW)	ELECTRIC ENERGY (MWh)	THERMAL ENERGY (MWh)
EYDAP	Public Water Co.	7.37	64,000	70,000
VEAL	Municipal company	13.00	107,000	109,000
	TOTAL	**20.37**	**171,000**	**179,000**

6.1.4.3. Other relevant laws

The Greek policy concerning investment activity in energy efficient and/or renewable energy technologies is contained in a number of laws that establish a variety of financing mechanisms and incentives for investors in the public and private sectors. Grants for equipment and facilities, interest rate subsidies, tax-free allowances, extra depreciation rates, lower social security contributions and favourable tax rates are indicative of the incentives provided.

National Development Law 2601/98 (on private investment): The objective of this law is the reinforcement of private investments in Greece with a view to achieve/promote the regional development targets, increase the employment rate, promote the competitiveness of Greek enterprises, restructuring of the production sector, exploitation of existing opportunities for the secondary sector in Greece and abroad, environmental protection and energy conservation.

This law provides a new framework for the provision of subsidies for productive investments. It foresees subsidies in the form of partial funding of the cost of capital expenses, loan interest or leasing, or, alternatively, as partial funding of the loan interest and tax breaks. Subsidies depend on geographical region, but there are some exceptions where they are uniform over the entire country. Among those exceptions are investments and equipment leasing for electricity production from RES or cogeneration. The maximum subsidy rates apply in these cases, irrespective of the region in which the project will be carried out.

Moreover, special incentives for investments over 29 and 73 – 180 million Euro for expansion of existing units and establishment of new ones respectively in specific sectors. The paragraph XIII of article 3, entitled "Eligible business activities - aided expenditures", states:

"Expenditures for investments concerning the utilisation of renewable sources of energy, switch from liquid fuels or electricity to gas fuels, treated waste from domestic industries, recovery of lost heat, as well as electricity and heat co-production are covered by the law. Furthermore, expenditures for investments concerning energy saving, provided that the investment shall not pertain to manufacturing equipment but rather to driving/operating equipment and installations of the plant, and that a decrease of at least 10% in energy consumption will result from such investment".

Uniform aid rates apply to investments or programmes for electricity and heat co-production. These are:

(i) Grant 40%

(ii) Interest subsidy 40%

(iii) Leasing subsidy 40%

or, alternatively

(i) Tax allowance 100%

(ii) Interest subsidy 40%

This law is in force since April 1998, beneficiaries are a wide range of enterprises in various sectors.

Law 2244/94 (Electricity Production from Renewable Energy Sources): The "Renewable Energy Law" was launched in 1994, covering also CHP from RES and natural gas. In April 1995, a Ministerial Decree (8295/19.4.1995) was issued clarifying the administrative process and tackling the issues related to the licenses for installation and operation of electricity producing plants. In the same decree, a sample contract between the PPC and the electricity producer is presented, where the details regarding the buying-back rate and the grid connection terms are included.

Two categories of electricity producers are defined, namely self-producers, who generate electricity to cover their own consumption and sell only surplus to the PPC, and independent power producers, who sell all their electricity production to the PPC.

The law removes previous restrictions for the independent production of electricity from RES and natural gas, with a new maximum capacity of up to 50 MW for independent producers. On the other hand, the PPC is obliged to buy all energy produced by independent producers under an initial 10 years contract. At the same time, the PPC retains the exclusive right to supply third parties with electricity. The law also defines explicitly the essential components of the payback tariff system for the power producers, correlating it with PPC's kWh selling price.

6.1.5. The situation in other EU countries

Austria: Neither legal framework nor policy incentives concerning the promotion of CHP are clearly identified. But environmental targets are particularly high (CO_2 is targeted to fall by 50% from 1988 levels by 2000), and emissions standards are among the tightest in Europe. This could foster the development of CHP to some extent.

Belgium: No significant political incentive to promote the technology exists. In 1994, though, a federal initiative to promote cogeneration came forward. The project to establish a single, national promotional organisation to stimulate a wider development of CHP (energy efficiency efforts are, otherwise, the responsibility of the regions) was foreseen.

Denmark: Denmark's Action Plan for a sustainable energy development sets a target of reducing CO_2 emissions by 20% by the year 2000. Apart from renewable, sole cogeneration will be allowed for new electricity generating capacity. To develop small-scale technology, the plan proposes the conversion of existing district heating systems into small-scale schemes fuelled by gas, waste or biofuels (all plants should be converted by 1998).

Small-scale back-up community heating plants (usually coal or oil fired) will also have to be converted to CHP systems. A range of government support measures was decided in 1994. They include a carbon tax, subsidies and grants. Electricity produced by decentralised CHP plants based on natural gas is supported with 13.7 Euro/MWh. If the electricity is produced on renewable sources the support is even 50.7 Euro/MWh.

Finland: Though 30 % of its electricity production is based on CHP, this situation is not the consequence of a specific political action. The fundamental reasons of this high development is more due to the absence of barriers, the fact that CHP is recognised as being the most economic means of generating electricity, that there is a greater acceptance of longer payback times and, finally, that heating demand is high. But one has to keep in mind that almost all CHP concerns the industrial and district heating sectors.

France: Fairly recently, efforts have been made to promote cogeneration through governmental incentives. The government supports cogeneration by exempting natural gas and low sulphur heavy fuel oil from certain taxes when used in cogeneration plants. Other fiscal incentives include exceptional amortisation of equipment on a 12 months period, and exemption of the local taxes (*taxe professionnelle*).

By law, EDF, the national electricity utility, has to buy surplus electricity produced by CHP sites that satisfy certain technical conditions. New tariffs for electricity sales to the grid have been recently decided and they should contribute to a better expansion of CHP technology. A national organisation (Club Cogénération) aims towards its development.

Ireland: Included in its national CO_2 abatement strategy, announced in October 1993, is an Alternative Energy Requirement, for which 75 MW cogeneration capacity target has been decided. The programme will be assisted by a combination of grant assistance and support the price of electricity generated.

Italy: Ever since 1990, the environment for CHP has been favourable. Policy has been clearly directed to ensure that CHP plays an important part in the country's electricity and heat arrangements. The National Energy Plan of 1988 and subsequent laws have promoted alternative forms of electricity production (auto-producers can freely produce electricity for their own needs without limit or sell it to ENEL). Fiscal advantages and establishment of attractive prices for sales of electricity to the grid have been introduced. Grants have become available. For small-scale units, fuel tax benefits have been decided.

Luxembourg: The Parliament adapted a general law on energy efficiency on 5 August 1993 to provide a Framework for a range of measures to cut emissions of CO_2 and reduce energy dependency. In the context of implementing this law, a

Regulation on CHP and electricity generation from renewable sources for units with a maximum capacity of 1.5 MW_e was adapted on 30 May 1994. Its goal is to remove the legal and administrative barriers to the role of electricity to the public grid and to stimulate such sales by setting attractive prices for auto-producers.

The Netherlands: Netherlands stands as one of the European countries where cogeneration development has been greatly successful thanks to strong promotional activities and a clear and positive policy framework introduced by the government. In 1990, the government produced the National Environment Policy Plan, which included the goal of stabilising CO_2 emissions at the 1990 level by 1995, with a further target of 5% by 2000.

Cogeneration is expected to play an important role in this plan, with an important increase of the capacity (from 2200 MW_e to 3000MW_e in 1995, and a target up to 8000 MW_e for 2000), aided by subsidised investment in all sectors, including non-residential buildings and housing (annual budget of 26 millions, 2 for housing). CHP is also likely to be given a boost through government's new plan for waste management, which will require the maximum amount of energy to be recovered wherever incineration is used.

Besides, in 1988, was created an independent, non-profit organisation devoted to the promotion of CHP. It works mainly at bringing together the different parties involved (utilities, gas industry, users), providing technical and financial advice, and publishing information. It now concentrates an important part of its actions toward the promotion of CHP in buildings, using experience of CHP in other sectors to stimulate the application of CHP in the residential and commercial sectors.

Portugal: The new legislation aiming towards liberalisation of production and distribution of electricity sectors includes measures to encourage the development of industrial cogeneration. But concerning its use in buildings, no specific measures have yet been taken.

Spain: In 1980, an energy conservation law laying down an attractive legal framework for auto-production and CHP, mainly through tariff incentives, was introduced. IDAE (the national energy centre) started a programme in 1986 to promote CHP, through technology dissemination, technical support to potential users and investment financing. This third-party financing helped 24 projects (for a total capacity of 200MW). National targets for cogeneration by year 2000 (amounting up to 2222MW_e) have been set, within the National Energy Plan.

Sweden: At present, the building of 50 new non-fossil fuel bases cogeneration projects, ranging from 40kW to 40MW is being subsidised.

UK: CHP has been placed at the centre of the UK government strategy to stabilise CO_2 emissions. It is scheduled to provide 1/10 of the total targeted reduction in emissions. The total target capacity announced in 1994, included in UK's climate change programme, reaches 5000MW by year 2000. Small-scale schemes are included in the promotion programme of CHP on which works the national CHP Association. Moreover, information dissemination through «Good Practice guides» is taking part in the promotion of small-scale CHP in a large variety of building types.

A programme of financial support towards new schemes was decided in 1994, funded by the government-backed Energy Saving Trust. The public sector, particularly the health services, has been strongly promoted (representing over half of all CHP installations with 653 sites in 1995). Besides, a CHP grants programme supporting small-scale cogeneration in the residential sector has recently been decided and amounts to £ 2 million.

In addition, liberalisation of the market is facilitating growth in the provision of integrated energy services, through several type of measures:

- relaxation of the electricity licensing regime (the majority of small supplies from on site CHP schemes have been exempt)
- relaxation of the re-supply of electricity
- changes on the on-site supply rules
- relaxation of capital finance rules
- establishment of a de-minim's limit allowing exportation up to 500 kW_e without a supply licence.

6.2. FINANCIAL INSTRUMENTS

6.2.1. Financing problems

Lack of available and affordable financing is a critical barrier that manufacturers and other business operators face as they consider CHP systems. Plenty of capital is available nationally and on a European level, but many potential operators have trouble on gaining access to the money they need at affordable rates. This is especially true for small producers, who often have great difficulty in securing financing, since many of them cannot obtain capital for long-term investments in plant and equipment.

The key issues that companies face when seeking private sector financing are:

- the types of financing available to companies pursuing projects like CHP;
- the conventional lenders and their reaction to risk, which affects their view of innovative projects like CHP;
- factors in choosing the right lender – and how the lender may “choose” the borrower; and
- lack of basic information on public-sector program types.

There exist plenty of private financing sources, ranging from traditional banks to energy service companies (ESCOs) to various vendor-financing schemes. Moreover, millions of Euros are available through a number of European and national programs. Businesses must get a sense on which are the most appropriate and gain an understanding of how these public and private financing offerings work. They must also be able to show that their needs coincide with program missions, and that their projects can be shaped to meet lender eligibility requirements and program award criteria.

Traditional financing is difficult to get. In addition, the normal problems associated with underwriting reviews of loan applications are complicated by several factors, including:

- the lender uncertainty about the viability of proposed process-related changes, like CHP;
- the lender adversity to operations involving new technologies; and
- environmental uncertainties that many lenders associate with manufacturing projects (in terms of lender liability and collateral devaluation).

Financing institutions typically limit their lending to low-risk propositions. There are a number of reasons for this; one of the most important is lenders' concern over how their own regulators will view the viability of their bank operations and lending practices. In practice, this means that lenders are most comfortable with certainty, with things they know, and processes they understand. As a result, many often view innovations or new technologies as "red flag" situations to be avoided in favour of other types of lending.

Many small producers, in fact, are not able to land long-term capital or construction loans at any price; they are viewed as too risky. Their owners often lack enough collateral to meet underwriting requirements or enough cash to meet loan processing costs and environmental assessment requirements. While product development initiatives, new technologies, and efficiency improvements receive a lot of attention from public and corporate leaders, bank underwriters often shun them. Innovative projects without a record of success and certainty often do not compete well in financial markets because lenders, looking to their own bottom line, are not sufficiently convinced that they will be repaid.

Companies seeking financial assistance to improve their energy efficiency, production processes, and overall competitiveness – including installation of CHP systems – have an array of financing options to choose from, including:

- commercial loans,
- lease-purchase or vendor financing,
- energy services or third party financing (e.g. through ESCOs),
- retained earnings or company cash flow,
- National or EU financial assistance.

Businesses need to remember that the most appropriate approach will vary, company by company, depending on a number of factors: such as the size of the operation, the nature of investment needed, primary purpose of capital proceeds, financial health of the company, etc. In each case, financing options can be divided into two key categories, namely those that appear on a company's balance sheet and those that do not (Table 6.4).

Table 6.4. Possible financing methods for CHP projects

Capital purchase or "on-balance-sheet" financing	***Operating lease or "off-balance-sheet" financing***
Financed by: - Internal funding - Debt finance - Leasing	Financed by: - Equipment supplier - Energy services company - Other sources of funding

In the first case, the capital purchase of a CHP plant will appear on the company's balance sheet as a fixed asset. A capital purchase is generally funded using internal sources, external finance or a mixture of these two. In the second case, two types of organisation can arrange or supply off-balance-sheet financing for CHP plant; namely equipment supply organisations and energy services company (ESCO) contractors. The usual approach involves an operating lease.

6.2.2. On-balance-sheet financing options

6.2.2.1. Internal funding

With internal funding, the company itself provides the capital for the CHP installation. In this way, it retains full ownership of the project and should reap the maximum potential benefits. At the same time, the company bears a considerable element of technical and financial risk, although the degree of this risk can vary with the installation option chosen. For instance, where a company places the work with a turnkey contractor, the contract terms may reduce the risk the company has to bear by placing more of it on the contractor.

Similarly, the terms of contracts with consultants, equipment suppliers and sub-contractors can be designed to minimise the investment risk. Internal financing is not necessarily an easy option. Although CHP is a long-term investment, it will often have to compete with other potential business projects that are closer to the company's core area activities. Furthermore, it may have to compete within a short-term appraisal environment. Thus, obtaining approval for CHP as a self-financed project may prove to be a problem.

Although a company normally pools all of its existing sources of finance so that it is not possible to state which one has been used to fund which new project, each form of capital nevertheless has a cost associated with it. Therefore, it is usual to calculate a composite rate that represents the average cost of capital weighted according to the various sources of finance, which is known as the weighted average cost of capital (WACC).

6.2.2.2. Debt finance

A new debt plus some internal funding often fund a large capital purchase. As with full internal financing, the residual technical and financial risks remain with the investing company, apart from those that lie with suppliers and contractors. At the same time, the company retains the full benefits of the installation. With new debt, it is possible to match an appropriate source of capital to a specific project. In particular, the borrowing timescale can be matched to the timescale of requirements, i.e. short-term finance should be obtained for short-term cash needs, and long-term finance for long-term needs, such as a CHP plant.

For example, if a company planning to invest in a CHP plant intends to generate a flow of savings/income over a period of 15 years, that company should attempt to finance the plant over the same period. If this is not possible, then the borrowing timescale should, at least, be as long as the payback period for the project plus the period required for recovering the 'cost of money'. In this way, the repayment schedule can be financed out of the savings/income generated by the CHP system.

6.2.2.3. Leasing

Leasing is a financial arrangement that allows a company to use an asset over a fixed period. There are three main types of such an arrangement:

- Hire purchase.
- Finance lease (also known as 'lease' or 'full pay-out lease').
- Operating lease (also known as 'off-balance-sheet' lease- discussed later).

Under a hire purchase agreement, the purchasing company becomes the legal owner of the equipment once all the agreed payments have been made. For tax purposes, the company is the owner of the equipment from the beginning of the agreement. The basis of the finance lease arrangement is the payment by the company of regular rentals to the leasing organisation over the primary period of the lease. This allows the leasing organisation to recover the full cost – plus charges – of the equipment.

Although the company does not own the equipment, it appears on its balance sheet as a capital item and the company is responsible for all maintenance and insurance procedures. At the end of the primary lease period, either a secondary lease – with much reduced payments – is taken out, or the equipment is sold second-hand to a third party, with the leasing organisation retaining most of the proceeds of the sale.

With finance leasing, the leasing organisation obtains the tax benefits, and these are passed back, in part, to the company in the form of reduced rentals. In principle, the rental can be paid out of the energy savings, thereby assisting cash flow. Finance leasing may have tax advantages over internal and debt financing if the company has insufficient taxable profits to benefit from the tax allowances available on capital expenditure. With this route, the level of financial and technical risk taken on by the company is similar to that of a self-financed project.

6.2.3. Off-balance-sheet financing options

This option, also known as “third party financing” (TPF), seems to be an adequate instrument to face financial issues. It was developed to help companies finance investment without affecting their balance sheets. A user of an efficient and environmentally friendly concept such as CHP does not finance the initial outlay. Instead the operator reimburses the technology supplier by making payments related to the performance of the technology installed.

Other forms of TPF include energy services contracts provided by energy service companies (ESCOs) or utilities, which through CHP can offer new services to their customers. A wide variety of arrangements are possible. Under these contracts, an energy service provider agrees with the user on the site needs for heating, lighting, power, etc. It is the responsibility of the contractor to find the most economic method of providing these services, which often involves installing a cogeneration plant. This investment is made and managed by the ESCO, who covers it in the charges for the energy services.

The efficiency of cogeneration means that these charges will be lower than the previous site energy costs. In this scenario, all sides of the financial deal profit. Different Community programmes can promote this financial scheme stimulating activities and coordinating interested parties. The European Investment Bank (EIB) in the period 1992-1996 supported CHP with loans amounting 1,195 MECU. This effort is important and EIB should strengthen its support to CHP projects in industry and the tertiary sector.

6.2.3.1. Equipment supplier finance

An equipment supplier may, as an alternative to outright purchase, offer a leasing package to the generator. The equipment supplier will normally design, install, maintain and, sometimes, operate the CHP system. A common commercial arrangement is for the energy to be supplied at prices that incorporate agreed discounts on the open market price. The operator pays for the fuel and agrees to buy the electricity and/or heat generated at the agreed price.

To assure the equipment supplier of a continued income from the sale of utilities to the company throughout the 5-10 year contract period, the generator may be required to make a commitment in the form of a substantial standing charge, a lease payment or a high ‘take or pay’ volume of the energy supplied. This arrangement transfers most of the technical risk from the company to the equipment supplier.

However, the generator’s savings are also significantly lower than under a capital purchase arrangement. The operator also retains the risks relating to fuel price fluctuations. This form of financing arrangement has commonly been used to finance small, ‘packaged’ engine-based CHP systems.

6.2.3.2. ESCO contracts

As outlined previously, an ESCO arrangement can vary widely. In some instances, the ESCO contractor will design, install, finance, operate and maintain a CHP plant on the generator’s site. In other cases, the company subcontracts only the operation and maintenance of a CHP plant that has been installed by other contractors under a design and manage or turnkey arrangement. In both cases, the ESCO contractor supplies heat and power to the company at agreed rates. The ESCO contractor may also take responsibility for fuel purchase and for other on-site energy plant.

From a financing point of view, the basis of such an agreement is the transfer of CHP plant capital and operating costs, together with all the technical and operating risks of CHP, from the end-user to the ESCO contractor. The generator’s savings in this case would normally be less than under a capital purchase arrangement, because the ESCO contractor needs to recover the cost of the capital investment and cover operating costs, overheads and profit. However, under certain circumstances, the savings can be greater than with a capital purchase arrangement.

For example, the ESCO contractor may be able to size a CHP plant to meet the heat requirement of the company and produce surplus electricity that can be exported and sold. The operator will still receive only part of the value of the energy savings but, because the energy savings are greater, the operator’s share may have a value greater than the savings that would have been achieved under a smaller capital purchase scheme. The ESCO contractor will also be able to increase the benefits compared with an in-house solution by avoiding the learning curve costs.

Different ESCO contractors may produce widely differing proposals, depending on the operator’s requirements and the ESCO contractor’s objectives. Among the many variables to be resolved will be:

- who will operate the plant on a day-to-day basis and, therefore, bear the performance risk,
- who will maintain the plant, and/or
- who will own the plant at the end of the initial agreement period of 10-15 years and at what on-going cost.

Any transaction with an ESCO contractor still involves a long-term commitment by the producer. Evidence will also be needed to satisfy the producer’s auditors that the arrangement is an operating lease and not a finance lease. If ownership transfer to the company is implied or stated in the contract, the arrangement must appear on the company’s balance sheet. It should also be noted that an ESCO contract and finance are not intrinsically linked. It is possible to enjoy the core benefits of an ESCO arrangement, that are cost reduction and operational risk transfer, irrespective of the finance route chosen.

6.2.4. Making the choice between options

Choosing an appropriate method of financing will depend on the state of the company's profit/loss account and balance sheet and also on the degree of risk and benefit associated with the project. If a CHP system operator opts for a capital purchase, i.e. an on-balance-sheet approach to funding, it may obtain the maximum benefits but it will also carry all the risk. A capital purchase may produce the highest NPV, but the initial cash flow will be negative.

As already discussed, many producers will not, or cannot, provide the funds for the capital purchase of a CHP plant. There are several reasons for this:

- The return on investment for such a project may be lower than – and would, therefore, have an adverse impact on – the company's return on capital employed.
- Even if the return on investment is satisfactory, there may be other, more attractive claims on the company's cash resources.
- A capital purchase may increase the company's gearing or reduce liquidity to unacceptable levels.

Therefore, this company may prefer an off-balance-sheet financing option. Where a scheme is financed under an operating lease arrangement, the overall NPV will be lower than for the capital purchase option, but the cash flow will always be positive – unless the project is only marginally viable or the lender's charges for money borrowed are high.

Much ingenuity has been expended by ESCOs in devising schemes that combine the off-balance-sheet advantages of operating leases with retention of the benefits of capital purchase. However, in recent years, accounting standards have become increasingly strict. It is possible to involve an ESCO contractor with a project, regardless of the financing method chosen. Such a company may well have a valuable role to play in managing and lessening the risks to the end-user.

6.2.5. Joint ventures

A number of large-scale CHP schemes have recently been funded as joint ventures between the end-user and an ESCO contractor. Joint ventures are a highly specific form of legal entity and are normally only warranted for large, complex schemes that can justify the high set-up costs. In such cases, the joint venture serves to 'ring fence' the operation and limit the financial liabilities of the partners.

7. CHP SYSTEM INTEGRATION AND COMMISSIONING

7.1. PROJECT IMPLEMENTATION

7.1.1. Possible implementation routes

Once an appropriate rating and configuration for the CHP plant has been agreed, the next step is to convert the findings of a positive feasibility study into an operational plant. Obviously, the installation of a CHP plant will require significant amounts of time, effort and money, and a company/owner that lacks these resources may see no benefit in evaluating the potential for CHP. However, there are ways in which a company can obtain the necessary resources and assistance that will allow it to resolve these issues.

It is therefore important, from the start, to have a clear idea of the various options available for the purchase, installation and on-going operation of a CHP plant. Essentially there are three broad approaches:

- In-house resources.
- Turnkey procedure.
- Energy services procedure.

Each of these has various options within it, and each involves a different level of responsibility and reward. An outline of these three main approaches, with their advantages and any other implications, is given in the following.

7.1.1.1. In-house resources

If a company wishes to maximise its involvement in the design, procurement and installation of a CHP plant, it may opt for an "in-house resources" project, in which the company is fully involved in every aspect of plant design, installation and management. This demands a high level of both resources and operational and management expertise (in-house or specialist consultant). At the same time, it offers important advantages as regards the equipment selection and installation, staff involvement and contractor management. On completion of the project, the company owns the plant and is responsible for its operation and performance, while retaining all the cost savings achieved.

7.1.1.2. Turnkey procedure

A turnkey project is one in which a single contractor – sometimes the equipment supplier – assumes responsibility for implementing the whole project, from detailed design, through purchasing and installation, to commissioning and testing. The owner has less influence on plant selection and optimisation, and responsibility for ensuring that all plant items work together rests with the contractor. On completion, the plant is handed over to the company; the company pays for it and thereafter owns it.

In many cases, the owner will operate and manage the plant itself, thereby assuming responsibility for plant performance and reliability, and also retaining all of the cost savings. In other cases, the owner will appoint an integrated energy services company (ESCO) to operate and manage the plant on its behalf.

7.1.1.3. Integrated energy services procedure

The scope of the ESCO option can vary widely. In some instances, the owner will set up a contract with an ESCO by which the latter designs, installs, finances, owns, operates and maintains a CHP plant on the company's site, providing the company with metered electricity and heat. In other cases, the company subcontracts the operation and management of a CHP plant that was installed by other contractors under an "in-house resources" or a "turnkey" option.

The ESCO may also be responsible for fuel purchasing, the operation and maintenance of boilers and other on-site energy equipment, the operation and maintenance of site energy distribution systems, the purchase of imported electricity when required, and the export and sale of surplus electrical power. Adopting the ESCO option allows the owner to benefit from CHP while limiting its financial outlay to the managerial and legal input required in setting up the necessary contract.

The detailed and site-specific nature of such a contract means that it must cover the quantity, condition and reliability of energy supplies, the systems for metering those supplies, the charges to be paid, and any variations to these charges with time and circumstances. It will also need to cover a range of issues relating to tenancy of the land and buildings, access to the plant, the use of common facilities, and various site-specific conditions. Since the ESCO is also responsible for the finance and on-going plant operation, the net savings to the owner are lower than if it was financing and operating the plant itself.

7.1.2. Specification of requirements

Precise specification of the objectives that a CHP scheme has to fulfil is fundamental to any type of scheme on any site. The scheme requirements will probably need to be refined as outline and detail design proceeds until a point is reached when a minimum functional specification (MFS) is produced as one of the initial tasks in the implementation phase. The responsibility for specification of the objectives will lie with the prospective owner of the facility, i.e. either the host company (or its engineer) or the energy supply company.

The MFS document must include and should comprise the fundamental statements:

(i) what the owner requires from the plant in terms of heat and electricity output (specified in both total energy and maximum capacity terms) and required availability;

(ii) what are the conditions under which the plant is expected to operate;

(iii) the facilities that the owner is to make available for the construction (and, possibly, the long-term operation) of the facility;

(iv) the date on which the work is to start on site and the date by which the owner requires the facility to be available for service;

(v) guarantees and liquidated damages for non-compliance.

7.1.3. The tender and design procedure

The first major step of the project's implementation involves the preparation and issue of tender documents (ITT – Invitations to Tender). Each implementation route has a different tender process:

- An in-house resources approach will concentrate on the specification and performance of individual units of equipment and services, each of which is an essential component of the overall CHP plant.
- Procuring a turnkey project will mean that the owner needs to focus on a performance specification and on ensuring that the contractor, while competing in what is usually a capital-cost-driven market, will be able to work with the long-term performance and operability of the plant in mind.
- Entering into an energy services contract requires the owner to focus on the performance contract, on long-term confidence in the contractor, on whether it can work comfortably with the contractor's staff on-site throughout the contract period, and on maintaining a fair balance of financial gain between the owner and the contractor in the long term.

7.1.3.1. In-house resources projects

The preparation of an in-house resources' tender is a major undertaking, since it involves overall design of the project and then the specification and tendering of a number of separate equipment or services packages. A typical project would consist of between five and ten tender packages, each highly detailed in terms of equipment and service supply. Where a number of detailed specifications are prepared, a vital area of the design work is to ensure that the interfaces between each one are correctly managed and specified, to ensure compatibility.

The detailed nature of the specifications improves the chances of achieving rapid, compliant and cost-effective bids. The number of suppliers invited to quote for each component package should be limited to the minimum necessary to ensure that specified requirements are met at the best possible price. It is often worth asking potential tenderers to demonstrate their experience and capabilities by supplying examples of similar work that has been carried out successfully. An ability to work on a complex project in close proximity with other contractors is particularly important.

Most companies have their own tender evaluation procedures, and the typical methods of checking the technical and contractual contents of a tender against the specified requirements are usually equally applicable to a CHP project. The key factors that will determine the final selection include issues such as total project cost, project timescale, and guaranteed plant performance and its effect on on-going energy and maintenance costs. It is vital that the minimum guaranteed energy performance of the prime mover/electrical generator(s) is clearly stated.

Some plant items may be offered with comprehensive maintenance contracts that guarantee equipment performance and availability, based on a fixed cost per hour of operation. The energy efficiency and operating costs of major plant items can have a significant effect on the long-term economics of the project, and hence on its viability. The owner should, therefore, re-run the detailed feasibility study's energy and cost savings analysis, feeding in the energy and cost performance changes (positive or negative) identified during the tender process.

It is also important to check the compatibility of preferred suppliers' equipment. The final list of suppliers should provide a total package with no gaps and no overlaps. It may be necessary to involve several suppliers in negotiations to obtain mutual agreement regarding the termination points of their area of activity, so that responsibility for achieving effective connections at common boundaries is clearly defined.

7.1.3.2. Turnkey projects

In the case of a turnkey project, the specification will be related more to the plant's capability and function than to details of its design and construction. However, the specification need to be precise on issues such as land availability, location and the design of interfaces with other site installations, and also on procedures for testing and demonstrating the plant's capabilities. Where an owner has significant expertise in CHP and feels capable of carrying some aspects of the plant design responsibility, the tender invitation will incorporate a detailed list of the plant items required.

On the other hand, the owner may simply specify a CHP plant that meets a certain performance specification. The more detailed the specification in the tender the greater the degree of responsibility and workload taken on by the owner. Normally, the tender would be issued to a minimum of three contractors that can demonstrate the necessary experience and expertise in the total design and construction of similar energy projects. In some cases, it may be appropriate to advertise for interested tenderers and then carry out a pre-qualification exercise.

Evaluation of tender responses results in a decision on both the plant and contractor selection. It will require a major input of resources and expertise. Tenders should be reviewed in detail and compared against a checklist of the key factors that were identified in the tender documents. Key factors would include the following:

- Project cost.
- Plant output and performance guarantees.
- Project timescale.

- Plant position and dimensions.
- Contractual terms and conditions.
- Plant interfaces with existing site.
- On-going maintenance support.

The key factors that will determine the final selection of preferred tenderer include issues as the total project cost, project timescale, the guaranteed plant performance and its effect on on-going energy and maintenance costs. The evaluation procedure should include a comparison of costs and savings with those identified in the detailed feasibility study. Contract negotiation follows from tender evaluation, and the owner's objective at this stage is to place an order for installation of the CHP plant with the preferred tenderer.

The contract procedure involves preparing and negotiating the terms of the supply and installation process, and finalising and agreeing all the details. It is at this stage that any problems or omissions in the specifications and tenders will often come to light, and legal expertise is important to ensure that both parties understand the contractual requirements of the CHP project. The contract terms, often based on standard formats, must cover issues of costs and payments, the scope of work to be carried out, project schedule, inspection and testing of plant, and performance guarantees and liabilities.

7.1.3.3. Energy services contract projects

The preparation of an ESCO tender focuses on producing a performance-related specification rather than a detailed technical one, and on inviting tenderers to submit an offer relating to a contract for supplies of energy. Since the proposed CHP plant is likely to remain a property of the contractor, the tender needs to concentrate on specifying:
- the contractual issues of importance, and
- the physical and operational connections between the site and the contractor.

The tender documents will need to contain as much information on the site and its requirements as possible, without setting limits and constraints that will make the project appear unattractive to potential contractors. In parallel with the tender preparation, it is important for the owner to prepare a summary of the objectives it is seeking to fulfil by selecting the ESCO contract option. This should state the importance of each objective and its priority to ensure that subsequent stages in the tender procedure are performed correctly.

Initial selection of tenderers responding to an ITT involves potential contractors in significant amounts of time and effort, since it involves site visits, initial plant design work, and a contractual proposal. Therefore, it is common for the owner to hold a meeting with each tenderer to establish a level of mutual trust and understanding. This initial screening by the owner is important to ensure a reasonable level of compatibility with the contractual requirements of the tenderer. It should enable the owner to draw up a realistic shortlist of tenderers.

The owner should also examine each potential tenderer's business policies and owner background, as these may well have an influence on the selection decision. If the owner requests a full and comprehensive ESCO tender response, there is a possibility that the on-going workload and cost for both parties can escalate to levels that are difficult to manage. Experiences of this nature have resulted, in some cases, in the adoption of a simplified tender procedure, which is often preferred by potential ESCO tenderers to limit their time and cost exposure at this stage.

With a simplified tender procedure, the owner focuses on the selection of a contractor that can meet the specified requirements in principle, without finalising all the contract details. At this stage, the tender specification should focus on the levels of service to be provided, and on defining the criteria that will be used to judge the responses. This approach provides indicative levels of service and cost, and confirms the contractor's ability to meet the levels of service that have been specified.

The abbreviated tender and budget proposal can be used as the basis for selecting a contractor with whom the CHP project can now be developed. If an agreement is drawn up between the owner and the selected contractor, this should define the obligations of each party, based on the tender and its response, and often involve a commitment by the owner to work exclusively with the selected contractor. Such an agreement will often require an appropriate level of transparency in the development process and costings, to enable mutual trust and confidence.

The alternative to a development agreement with a selected tenderer is to follow up receipt and evaluation of the initial tender responses with a revised specification to selected tenderers, whose previous responses have established an appropriate level of confidence in their abilities, inviting them to submit a full tender response. Even a full tender submission of this type is unlikely to contain a detailed contract ready for acceptance. Contract details at this stage will usually be limited to indicative terms of agreement, charges and variation schedules, and performance guarantees.

The full tender and contract evaluation step may be reached either by working with a single selected contractor, or by receipt of full tender submissions. Tender evaluation needs to concentrate on certain key issues:
- Annual energy and operating cost savings.
- Effect on owner finances.
- Guarantees on security of supply.
- Basis for charges and variations.
- Acceptability of contract terms.
- Options on and effects of early contract termination.
- Sanctions and penalties applicable to either party for non-performance.
- Flexibility for changes to contract or CHP plant.

The owner also needs to compare the contents of tenders with the originally set objectives. Whether the full tender process has involved one or more tenderers, the final stage is the negotiation and agreement of a comprehensive contract covering every aspect of the full energy supply service. These negotiations can often be prolonged and detailed, but they are the key to concluding the mutually beneficial contract on which the success of the CHP plant depends.

Typical issues that need to be defined in the contract include:

- Performance guarantees and obligations of each party.
- Levels of supply and charges, metering systems, and fuel and energy records.
- Compliance with statutory requirements on a wide range of issues.
- Insurance and liabilities.
- Provisions for ownership of plant on termination or expiry of contract.
- Confidentiality and exchange of information.

7.1.4. Project risks and project management

The five main categories of risk associated with a CHP project are:

1. Construction risk:
    - Time, cost, quality;
    - Sponsor's ability to arrange construction;
    - Experience and standing of contractor;
    - Soundness of technology;
    - Terms of main construction contract:
        - fixed price/turnkey,
        - penalties/bonuses,
        - incentives,
        - force majeure,
        - commissioning,
        - subcontracting.
2. Operation risk:
    - Experience of operator;
    - Maintenance of performance levels;
    - Cost constraints.
3. Fuel supply risk:
    - Availability;
    - Specification;
    - Price.
4. Off-take risk:
    - Quantity;

- Capacity charge/energy charge;
- Base unit price;
- Indexation;
- Term of contract;
- Take-or-pay;
- Penalties for non-supply;
- Status of off-taker.

5. Political risk:
    - Legislation;
    - Taxation;
    - Environmental controls.

The identification, quantification and allocation of these risks are a specialised skill requiring technical, financial and insurance advice. The contractual approach to project implementation should enable risks to be correctly identified and allocated. It is essential that risks should be allocated to the party who can best control those risks. A number of options are available to the owner in the implementation of the CHP scheme. For example, if the owner has ample resources (which is unlikely nowadays) he may choose to manage the whole project himself.

A more likely approach is the owner to appoint a consulting engineer to do this on its behalf, which would then define the scope of the project, specify its performance and monitor the progress of construction and financial expenditure. The owner, either by himself or with the assistance of a consulting engineer, may place a turn-key contract for the whole scheme. In this case, the consulting engineer would audit the progress of the contract and give the owner reassurance that the work will be completed on time and to specification.

It will be apparent from the activities previously described that the project manager will have a major responsibility not only for the management of the technical interfaces involved in the project but also for the various complex commercial interfaces between the various 'contracts' (real or pseudo) which make up the entire scheme. To conclude, there is no single implementation methodology that is correct for a particular size of scheme or a particular industry application.

There are many schemes which have been examined from a technical standpoint and which have been shown to give good (sometimes excellent) internal rates of return but which have failed to obtain corporate consent. In most of these instances their failure could have been avoided if the scheme had been delineated as a series of interlocking contracts (both internal and external). Only by careful commercial analysis in this way, and the apportionment of risk across the interfaces between the contracts, can a scheme be successfully implemented.

Potential owners of such schemes, unless already operating as successful energy supply companies, should seek professional advice at the outset. The advice should not only cover the technical aspects but also the financial aspects, risk identification and allocation and the possible sources of fuel. CHP schemes on large sites can bring considerable financial benefits but experts in the field should prepare the case for their adoption and the planning of their implementation.

7.2. CONTRACTUAL TERMS, RESPONSIBILITIES AND LIABILITY

7.2.1. Background

The various contractual relationships that can exist in a typical medium-scale CHP scheme are illustrated in figure 7.1. The four main relationships are:

(i) The contract for the long-term operation and maintenance (O&M) of the CHP facility.

(ii) The contract(s) for the design and construction (D&C) of the scheme.

(iii) The fuel supply contract.

(iv) The contract(s) for the heat and electricity off-take.

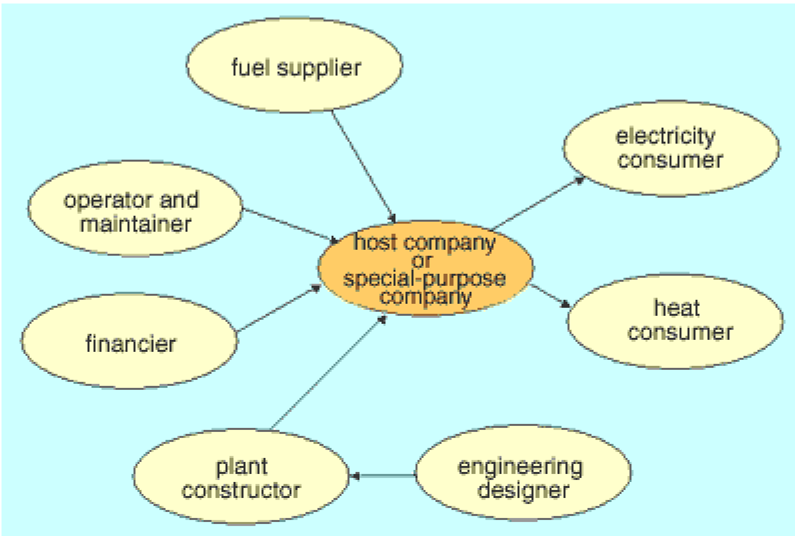


Figure 7.1. Contractual relationships [Source: Burdon (1994)]

Some of these relationships, in reality, may be pseudo-contracts, i.e. they do not exist in a commercial sense, but may be 'internal' contracting arrangements between different parts of the host company organisation. For example, a 'contract' may be drawn-up for O&M to cover the activities of the host company's maintenance staff. 'Market testing' might be adopted from time-to-time to ensure that the host company's internal costs were truly competitive with external organisations set up specifically to provide the required service.

Another pseudo-contract could be the contract for heat and electricity off-take, the parties in this case being the host company's 'energy centre' and its production facility. Again, market testing could be adopted by the latter to ensure that the in-house energy centre made available to it the energy it required at the best cost. Whether such contracts are pseudo or not, one of the parties to each of the contracts described will be the host company, or one of its internal profit centres. At the beginning of the project implementation phase the host company may wish to form a special purpose company (SPC) to develop the scheme.

This SPC may be a wholly owned subsidiary company or its equity may be shared with another party e.g. a Regional Electricity Company. It is also possible that the SPC could be wholly owned by an organisation entirely independent of the host company, e.g. an energy supply company. Where the host company decides not to own the scheme, then a scheme may be implemented by an energy supply company on a site provided by the host company. There is no shortage of organisations able and willing to do this.

7.2.2. Design and construction contract

One of the most important contracts in any CHP scheme is that for the design and construction (D&C) of the facility. Many large host company organisations have a centralised engineering function that may have the necessary capabilities and expertise to correctly design and specify a CHP facility (in-house resources). Those that don’t have such facilities will need to employ a consulting engineer to provide a design, and draw up an MFS for a turnkey contract and evaluate the tenders.

The method of design and the manner in which the plant is to be built under any turn-key or D&C contract should be left entirely to the contractor. The MFS will serve as the basic statement of requirements on which prospective plant manufacturers and contractors will be asked to submit prices. There will, of course, be the particular commercial and contractual terms and conditions included in any such invitation in addition to the MFS.

Adjudication of the offers received will be carried out on the basis of two fundamental criteria:

(i) first cost, i.e. the capital cost, present valued if necessary where complex terms of payment are involved;
(ii) continuing cost, i.e. costs associated with the long-term operation and maintenance of the plant including factors associated with its efficiency in processing or converting primary fuel into secondary energy, the labour requirements and costs of consumables (other than primary fuel) in operating the plant on a day-to-day basis and the cost of maintaining the plant. These should include not only the costs of routine spares, but also the costs of the down time, incurred in such maintenance activities, over the lifetime of the plant. The incidence, over time, of these costs needs to be identified so that their present value can be calculated.

It will be obvious that the enquiry document issued to prospective bidders must include in the conditions of tendering a requirement on the bidder to produce the necessary data to allow this adjudication to be undertaken including information by which the availability and reliability of the plant can be assessed. It is always useful to acquaint the prospective bidder of the method by which the adjudication of tenders will be made. This will enable him more accurately to meet the needs of the owner. Completion of adjudication of the bids received will allow a decision on the prospective builder of the plant to be made.

The above procedures describe the methodology employed in a typical design and construct or turnkey contract, where the contractor is made responsible for the complete package of works and its ultimate performance. An alternative to this approach would be a multiple contract arrangement where the owner or his engineer specifies and procures the individual components in the scheme and has them assembled as a complete working package. In this arrangement some of the risk associated with cost, performance and completion date would have to be borne by the owner, in return for the benefit of more competitive prices.

On a medium-scale CHP project (which is unlikely to exceed about 50-60 million Euros in value) the arrangement is rarely adopted. It would certainly not be possible to accept such an arrangement where limited recourse financing of the scheme was to be adopted, unless the owner provides cast iron parent company guarantees. All major plant contractors are willing and able to accept a D&C contract where the owner's requirements are clearly defined.

The D&C contract should be written to include a specific completion date for the scheme by which is meant a date on which the plant is proven (by testing) to comply with the MFS, in terms of efficiency of fuel conversion and reliability in the form of an extended operational run at full load and, last but not least, quality of emissions. If the MFS is properly written and accurately describes the owner's requirements for the plant and the facilities (such as site conditions, fuel specification etc.) that he will make available to the contractor, the scope for errors or inadequacy in the as-built plant should be considerably reduced.

This, in turn, should minimise the likelihood of claims for additional payments and/or time to completion arising under the contract. Very often, providers of funding under a project finance arrangement will demand that an independent engineer scrutinises a D&C contract to ensure that it is complete and comprehensive. Another area in the D&C contract that is vitally important is that of guarantees. These can be liquidated damages on a 'per cent per week' basis for lateness in completion but need also to allow for defects and failures.

The latter are notoriously difficult to draft so as to comprehensively and accurately cover the required eventualities and to be acceptable to both of the parties involved. Essential aspects to be covered by defects and failure guarantees include:

- repair or replacement of faulty components;

- availability requirements;
- guaranteed efficiencies;
- the levels of emissions.

The guarantees must be carefully worded so that salient parameters are precisely defined and capable of being measured; the method of measurement should be defined. Damages, as compensation for non-compliance with specified requirements, may not be appropriate in all cases; for example, where a fundamental breach of contract is involved. The construction phase of the project, particularly on large projects, often gives rise to another role for the consulting engineer.

A consulting engineer is often employed by a project owner as an 'independent engineer' to audit the quality of the construction work as it progresses (and sometimes the detailed technical design also - particularly design changes), verify interim payments to the contractor which may be due under the contract terms of payment and generally report on the progress of the project on a regular basis to the owner. Again, many of these auditing tasks are required by the banks involved in the funding of a project financed on a limited recourse basis.

7.2.3. Operation and maintenance contracts

The O&M contract is possibly the most important of the contractual relationships shown on figure 7.1, for it is the successful execution of this contract (probably over a period of 5-15 years) that will determine the efficiency, reliability and availability of the plant. Whether an external organisation is employed to provide O&M services, or they are provided from within the host company organisation itself, a proper framework of responsibilities - just as in any contractual situation - must be set up if the CHP facility is to operate reliably at minimum cost. Careful operation and high-quality/skilled maintenance are essential if CHP plant is to give maximum availability.

Various options are open for the O&M of CHP plant. Where an energy supply company simply sells heat and power from an on-site facility, the way in which the plant is operated and maintained is only of interest to the host company, in so far as poor standards of service will give rise to poor availability. The guarantees written into the energy purchase contract should cover shortfalls in this respect. Where the host company owns the plant but has little or no experience of its own in running, maintaining and repairing complex machinery, such as a gas turbine, it may contract out its operation and maintenance to a third party. This situation gives rise to some major imbalances of risk and reward, and makes the drafting of the O&M agreement extremely important.

If the elements of annual cost in a typical medium-scale gas-turbine-based plant are analysed, it will be evident that there is a fundamental disparity between the three major components (calculated on a uniform 'per kW per year' basis). For example:

- Fuel = 300 Euro,

- Capital = 120 Euro,
- O&M = 18 Euro.

Given this substantial imbalance, it is pointless thinking in terms of financial penalty for unsatisfactory performance. Whilst the O&M contractor would resist any penalty as a matter of course, the magnitude of any equitable penalty that might be agreed in an O&M contract could not possibly match the potential loss to the owner if the plant is not available.

The owner's risks are clearly far larger than the operator's and it is therefore essential for the owner to gain as much confidence as possible that the operator is, and will remain, competent and successful. In the manufacturing industry, confidence is achieved that a product will perform the task it is required to do, both effectively and reliably, through quality control; this is achieved through the incorporation of a quality assurance system into all stages of manufacture of the product. The same concept can be incorporated into an O&M contract for CHP plant.

Essential elements in such a contract would include:

(i) Specification of the plant.

(ii) Term of agreement.

(iii) General duties:
- — operate according to statutory consents,
- — maximise capacity and availability,
- — minimise outages (both scheduled and forced),
- — maintain, test and inspect plant,
- — repair damage, deterioration and malfunction.

(iv) Operation:
- — arrange dispatch of output to process or host company,
- — provide trained and qualified staff,
- — maintain records of costs and performance,
- — maintain safety standards and good industrial relations.

(v) Maintenance:
- — routine inspection,
- — routine testing,
- — routine maintenance and repair services,
- — maintain spare parts inventory,
- — keep records,
- — maintain statutory register,
- — maintain plant status report.

(vi) General:
- — report to Owner,
- — prepare O&M budgets and programmes.

(vii) Incentives:
- — efficiency adjustment,
- — availability adjustment.

Many organisations provide an O&M service for medium-scale CHP plant and it is possible to solicit competitive tenders for such a service based on a carefully drawn-up inquiry document encompassing the above major issues and responsibilities.

7.2.4. Off-take contracts

The energy off-take contract is likely to be denominated in secondary energy terms. A difficult aspect of any composite energy contract, where both steam and electricity are derived from CHP plant, is the attribution of cost to the individual outputs of steam and electricity. This difficulty may make the relative pricing of the two components rather arbitrary. Another point to be borne in mind in a combined cycle CHP scheme is the inverse relationship between electrical output and heat output as the graph in figure 7.2 for a large CHP scheme shows.

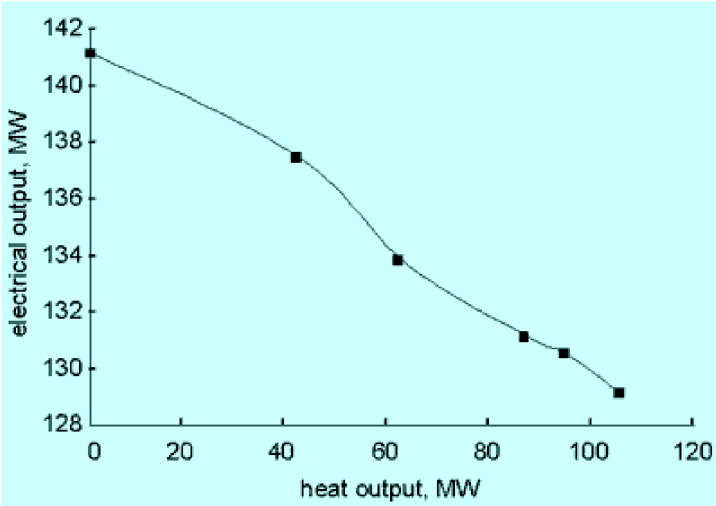


Figure 7.2. Variation in electrical output with heat output for a combined-cycle CHP scheme [Source: Burdon (1994)]

The slope of the line on the graph indicates an approximate 9:1 relationship between incremental heat output and incremental electrical output. This suggests that, in such a scheme, the value of steam per kWh on an opportunity cost basis could be set at about one-ninth that of electricity. CHP installations are often said to be either heat-led or electricity-led. In the former case the plant is sized on the known heat load and the electricity that is generated is used on the site to lower the maximum demand and reduce the annual electrical energy consumption from the REC's system.

In some respects, the CHP plant can be regarded as simply a complex steam raising plant, albeit of lower efficiency and greater capital cost than a boiler, which produces electricity as a valuable by-product. Where this by-product cannot be used by the host company (instances where the heat demand profile matches the electricity demand profile in thermal cycle terms are so unusual as to be virtually non-existent) the surplus will be sold to the REC who will often offer a non-too-generous payment for the privilege of taking the excess energy.

In many cases, the scheme will be sized so as to minimise the production of spill energy, i.e. it will supply the base load electricity demand only which often means that additional boiler plant will have to be installed to meet the peak heat requirements of the site. Figure 7.2 also depicts the possibility of the whole of the electrical output being sold to an electricity company, on special terms, which then sells to the host company whatever it needs under a 'normal' commercial contract.

In some circumstances, particularly where there is a fairly steady heat load over the whole year as, for example, in a paper mill, the electricity 'by-product' can be of greater value per kWh than the spill energy referred to above. In CHP installations which are of significant size, i.e. >30MW$_e$, and where multiple machines are installed to give high security of supply to a continuous process - thus implying high availability of capacity to a prospective external electricity purchaser - it may be possible to contract the whole of the electrical output from the plant to a single purchaser on far better financial terms than would be available for spill energy.

In such an arrangement, the entire site requirements for electricity would be purchased from a REC as if CHP did not exist on the site. *It is a well-known fact that sites that consume at least 51% of the energy from an embedded generator are exempt from paying the non-fossil levy. Some reconsideration of the definition of a 'site' and the appropriateness of the 51% figure is understood to be in progress at present and further encouragement of CHP may well arise via modification of these in due course.*

This may well encourage other large electricity consumers in the vicinity of the host site to be directly supplied and benefit from the remission of the levy on the supply taken. The legislation and regulations governing the connection of embedded generators to the REC's system are formidable and encourage many potential CHP owners to see them as barriers to entry into the CHP scene no less severe than those which existed before electricity privatisation.

The costs of making the connection into the local distribution system in terms of protective gear requirements, substation reinforcement etc. can be extremely expensive. In fairness to the RECs, however, it has to be said that local distribution networks - from 132kV downwards - were never intended to accept significant in-feeds of generation. Consequently, problems with fault level and system voltage regulation are almost always bound to arise. Their solution costs money.

7.3. INSTALLATION OF A CHP SYSTEM

7.3.1. Managing the installation

Careful management is an essential part of the installation process. This applies not only to management of the plant’s construction and installation, but also to other related issues such as health and safety, planning and contractual responsibilities.

Installation of the CHP plant is carried out by contractor(s) who are working on the owner's site. Between them, the parties carry all the responsibility for installing the plant safely, within agreed time and budget limits, so that it meets the specified performance. The division of responsibilities between the owner and the contractor(s) varies with the project implementation procedure that has been adopted.

7.3.3.1. In-house resources project

Where the owner retains overall responsibility for installation procedures, as in the case of the in-house resources project, the project management team will need to plan and co-ordinate the timing of delivery and installation for individual items of equipment to ensure an integrated installation procedure.

In the case of large projects, the necessary resources may not be exclusively available in-house, so external resources from an engineering or consultancy organisation may be appointed to carry out this task in conjunction with the owner, or on its behalf. There are obvious advantages in maintaining continuity throughout the project, with the same team responsible for plant design, specification and installation.

7.3.3.2. Turnkey project

In a turnkey project installation, the contractor is responsible for the overall design and installation of the CHP plant, and the contractor's project management team has extensive responsibilities for all aspects of the work. The owner will be responsible for a range of issues that allow the contractor to carry out the work, for example site access, utility connections to the new plant, and the planning of any aspects of the project work that require co-ordination between existing site operations and the CHP plant.

It is also important for the owner to maintain a monitoring role to ensure that the plant is being built as specified. It is much easier to tackle installation problems as they arise, rather than to have them rectified later, thereby incurring considerable delay and disruption. Monitoring is often achieved using a system of regular project inspections and site meetings with the contractor.

7.3.3.3. Energy services contract project

In the case of an ESCO project, the owner still has responsibilities relating to the issues that allow the contractor to carry out the work – site access, utility connections to the new plant, and the planning of any aspects of the project work that require co-ordination between existing site operations and the CHP plant.

However, since the ownership and operation of the CHP plant will remain with the contractor, the owner has relatively little involvement in plant installation issues. In some cases, a representative of the organisation financing the plant may be appointed to monitor and report on plant installation work.

7.3.2. Minimising the disruption

Where a CHP plant is to be installed on an existing operational site, the ideal arrangement is to have a designated area, possibly within its own ‘boundary fence’, that is independent of the rest of the site. The contractor will have access to this area for storing materials brought on to the site, for constructing the new plant and for maintaining office and support facilities. Some ESCO arrangements make the existence and retention of a boundary fence a specific contract requirement, so that there is a clear demarcation between the areas of ownership and responsibility of the two main parties involved.

On many sites, where space is limited or where a CHP plant is being integrated into existing energy supply systems, this ideal arrangement is unlikely to be possible. In these instances, the project specification or contract should clearly define those areas that are to be used for plant installation and support services. This is essential if project work is to be planned and organised to minimise day-to-day disruption to normal site operation. Regular liaison between the owner and the contractor is also essential to ensure minimum disruption of one by the other.

Because the new plant will ultimately have to be connected to the existing heat and power networks, the duration and timing of this operation (possibly during a planned site shutdown) need to be agreed at an early stage. If the integration and connection of the CHP plant cannot be achieved without prolonged disruption to site energy supplies, it may be necessary to arrange the provision and siting of temporary boiler plant and other facilities.

7.3.3. Varying the specification

During the course of the project planning and installation process, there will inevitably be occasions when, for a range of reasons, it is impractical for the contractor(s) to follow the specification precisely. Situations of this type need to be resolved swiftly and openly by discussion between the owner and the contractor. A variation to the specification can then be agreed and recorded. There are sometimes cost implications that the owner will have to meet, but a contingency is generally built into the project costs to allow for these.

Sometimes, these situations can be used as opportunities for improving plant performance by taking advantage of enhanced equipment that is available. It is important to agree a mechanism for Variation Orders as part of the initial contract. It is possible that the contractor may wish to maximise the number of variations, perhaps to compensate for inadequacies in his original design or tender.

It is the responsibility of the owner's project management team to ensure that any variations are entirely appropriate and justified before agreeing to them. The contract conditions usually impose financial penalties on the contractor for failing to meet the agreed completion date. However, some contract arrangements may incorporate a bonus mechanism giving the contractor an incentive for early completion, particularly where this would be of value to the owner.

7.4. COMMISSIONING AND TESTING PROCEDURE

7.4.1. Background

Plant commissioning is carried out by the contractor(s) as part of completion of the installation work. Its purpose is to verify that all of the equipment functions correctly, both as individual components and within overall plant operation. The completed plant must operate correctly within its specified limits. It must respond to all automatic and manual control functions and instructions, without any malfunction, failure or cause of hazard.

This must apply during full start-up and shutdown procedures, both manually and automatically initiated. Commissioning often takes longer than expected, and will inevitably reveal some defects in component performance or system design: that is its purpose. The objective of commissioning is to ensure the complete elimination of any such defects or problems, so that the plant achieves its specified design output, and its performance and reliability levels.

Where the owner is purchasing the CHP plant, the plant is available for use as soon as commissioning and testing is complete, and responsibility for plant operation and management is handed over by the contractor(s). It is, therefore, essential for the specification to include details of the full range of tests that must be carried out on completion of plant commissioning to demonstrate that the plant meets the specified requirements in every respect.

7.4.2. Types of tests

A range of tests of different types and levels is usual, although not all will be required in every instance. The tests normally required for completing successively the CHP system commissioning procedure are described herein.

Factory testing involves running the equipment at its design rating before it leaves the factory, and checking that its operating parameters meet the specified requirements. The test is usually witnessed by a member of the owner project team, and should include a start-up from cold conditions, a period of running (including basic response to controls), and a shutdown of the equipment. During the running period, measurement of fuel input and power output may be carried out.

On the other hand, initial site testing is carried out once all the equipment has been assembled into a functioning CHP plant and the electrical and heat connections have been made. These tests demonstrate that individual plant items, and the entire CHP plant, are able to perform satisfactorily under the appropriate range of conditions.

Reliability testing is usually a contractual requirement that is carried out once commissioning has been completed. It involves a prolonged running period (e.g. up to 15 days) during which the entire CHP plant and its auxiliary equipment must perform as it would during normal operation, in conjunction with all of the site systems to which it is now connected. The test period should contain minimum periods of plant operation in its different modes, e.g. on each of its specified operating fuels, and under different load conditions and other parameters.

The plant should respond to all normal control operations, both manual and automatic, and also function correctly in the event of a shutdown of any plant item. The test is witnessed and recorded by the owner's project team, and proof of reliability is that, throughout the duration of the test, there is no failure of the plant or its associated systems. If the test is not successful, the contractor(s) are usually required to rectify any problems, and the test is then repeated.

Performance testing is carried out either after or in conjunction with the reliability test, and is intended to demonstrate that the CHP plant achieves the guaranteed performance levels. These are usually defined in the contractor's tender, but may be modified subsequently by mutual agreement. They usually cover parameters such as:

- Electrical and heat outputs.
- Fuel consumption.
- Electrical consumption by plant auxiliaries.
- Noise.
- Exhaust emissions.

The test must demonstrate that the plant meets the specified performance parameters over an agreed period, which may range from a few hours to three days. If the plant fails these performance tests, the contractor will be required to make good the plant deficiencies and repeat the tests. If the defects cannot be rectified and the plant is unable to meet its specified performance, the contractor would normally be expected to incur financial penalties to recompense the owner for the plant's performance deficiencies.

Finally, availability monitoring is usually carried out on a continuous basis after handover of the CHP plant to the owner. It is sometimes the subject of contractual guarantees relating either to individual components or to the plant as a whole. In some cases, comprehensive long-term contracts with equipment suppliers may be used to cover related issues such as plant maintenance, availability and performance.

7.4.3. Specific aspects of CHP project testing

There are a few key aspects of CHP project testing where the nature and rigour of the testing programme differ from traditional projects and where small differences in result can have profound effects. Areas that should be considered when specifying test content and procedure are summarised below. For instance, the accuracy of instrumentation must be agreed in the specification for a performance test, and any meter tolerance should be disregarded when assessing the test results. The test specification should require the use of high-quality calibrated instruments.

It must be mentioned that, fuel consumption and power output are reasonably easy to measure in a test, but the thermal output is much less easy to verify accurately. In particular, the mass flow and heat content of a prime mover exhaust is difficult to measure. A procedure for measuring thermal output must be agreed prior to the test, preferably in the initial specifications.

Generator set guaranteed performance is of major importance. Most manufacturers will resist the request for performance guarantees at levels other than full output, but it is beneficial to specify performance guarantees at other output levels, even if these incorporate wider tolerances. Irrespective of the output levels at which performance is guaranteed, it is beneficial to test performance at a range of output levels, and to determine the performance of the heat systems at these outputs as well as that of the prime mover.

Moreover, if the use of an alternative or back-up fuel is specified, the tests must verify the ability of the plant to switch between fuels without shutting down and with minimum loss of power output. The ability to switch fuels in either direction should be tested, together with the ability to start the plant on either fuel from both hot and cold engine conditions.

8.1. INTRODUCTION

CHP power plants must be correctly selected, designed and installed if they are to perform well. The selection should take account of the correct size of the system and requires careful scrutiny of existing heat and electricity profiles, provision of any necessary heat dump facility and arrangements for the sale of any surplus electricity. Otherwise results can be disappointing. However, regardless of how well designed and installed the system might be, the optimum results and maximum running hours will only be obtained through the proper management of the plant's operation and maintenance (O&M).

Establishing the right O&M arrangements from the outset and proper monitoring of the plant performance throughout its life are crucial to the long-term viability of a CHP installation. CHP power plants are required either to operate continuously or, more commonly, during the 17 hours of daytime and evening, when mains electricity costs are high. CHP units also need to be shut down occasionally for maintenance, adjustment or repair. With proper care, and allowing for normal maintenance and occasional faults, an availability of 90% or more can be expected, whether based on 17 hours per day or on continuous operation.

Availability is the term most often used to provide a measure of a CHP installation's performance. It is defined as the probability a system to operate satisfactorily at an instant of time. Another measure of a CHP system's performance is its reliability, which is defined as the probability a system to operate satisfactorily at a certain period of time under pre-specified conditions.

A simplified approach to calculate the reliability (R) and availability (A) of a CHP plant is by applying the equations

$$R = \frac{T-(P+U)}{T-P} \times 100\% \quad (8.1)$$

$$A = \frac{T-(P+U)}{T} \times 100\% \quad (8.2)$$

where:
T = total desirable time period of operation (hours)
P = outage time period for planned/scheduled maintenance (hours)
U = outage time period for unplanned maintenance (hours).

Attention has to be paid to the reference basis, since the time period T can be equal to the total number of hours in a year (8,760) or equal to a user-selected maximum desirable time period of operation (e.g. 5,000 hours per year). In both cases, annual average values of reliability and availability are obtained, but with a different reference time basis. If not otherwise stated, it is considered that T = 8,760 h.

Even if the plant is functional, other factors, such as the low heat load, may prevent its operation. The "utilization" or "load factor" is the ratio of actual use of the plant or equipment to the maximum possible use. It is normally defined as:

$$Utilisation = \frac{R}{T} \times 100\% \qquad (8.3)$$

where *R* is the annual hours run. For example, a CHP unit operating for 5,000 h/year out of a possible 8,760 h/year is described as operating at a load factor of 57%.

8.2. CHP PLANT OPERATION

8.2.1. Basics of operation

Once the CHP system (power plant) installation has been completed, the required levels of performance and availability, and the associated economic benefits, can only be achieved and optimised if the system is correctly operated and maintained. There are examples of effective and efficient CHP systems failing to deliver the anticipated benefits because of a lack of emphasis on the on-going management of system operations and maintenance.

Effective operation of a CHP plant requires the continuous monitoring both of the site energy demands, and of the tariffs and costs associated with meeting those demands. Monitoring must be used as a means of continuously evaluating the most economic use of the plant, taking into account its performance and efficiency, its maintenance costs and the costs of external energy sources such as electricity and gas. One typical scenario arising is that during the overnight period, it may be cheaper to supply electricity from external sources and to use back-up heat supply system, than to operate the CHP plant.

It is equally important to be aware of the future maintenance costs that are being built up by operating the plant. This is particularly important where the costs of plant operation and the costs of plant maintenance are managed by separate budget holders. At the same time, plant operation must not be constrained by inadequate maintenance budgets that prevent the optimum energy performance of the plant from being achieved.

The use of monitoring and advisory systems to help with the decision-making on plant operations is considered in more detail later on, since many industrial CHP plants incorporate numerous items of equipment, which may include fired boilers and auxiliary devices, such as compressors, chillers, etc. Thus, overall system control techniques need to be flexible enough to ensure optimum performance of the whole installation. There are varying levels of automation that can be used to achieve the required level of control.

8.2.2. CHP plant control strategy

The operation of a CHP plant/unit requires the effective use of an overall control strategy to ensure that key objectives are achieved. This strategy must include the means of achieving:

- Plant condition monitoring - to ensure optimum reliability and performance.
- Efficiency of energy conversion and recovery.

The overall objective is to minimise costs and maximise savings.

Power generation differs from the operation of conventional boilers and requires different skills and techniques, particularly in relation to the control and monitoring associated with operating electrical generators in parallel with the local electricity system. A CHP power plant also incorporates heat transfer systems that must be correctly controlled to ensure the safe long-term operation of the equipment, and to recover heat for beneficial use. Furthermore, a CHP plant may incorporate auxiliary equipment such as supplementary firing and gas compression system.

8.2.2.1. Control systems associated with individual plant items

CHP plant consists of a number of core system items - gas turbines, engines, boilers, compressors etc. Each will be installed with its own control panels and systems to provide basic control functions such as start-up, shutdown, modulation etc. These systems also provide alarms and automatic shutdown as part of plant protection, and it is common for certain key condition parameters to be fed from one system control panel to another. Each control system needs to have a range of inputs and outputs in order to function as part of an integrated control and monitoring system.

Operating features normally incorporated in the control systems of individual plant items may include:

- Start-up and shutdown procedures.
- Normal operating parameters, with alarms and automatic shutdown facilities.
- Protection of individual motors and components.
- Input and output of condition signals.
- Modulation in response to control inputs.
- Synchronisation with the local electricity supply system.
- Monitoring of vibration.

Some control systems can also store historical data of CHP plant conditions. This provides important information for maintenance scheduling and failure diagnosis. The capabilities of individual plant control systems to be integrated within overall plant monitoring schemes should be a key factor in plant and system selection.

8.2.2.2. Monitoring and advisory systems

Some CHP plants use a centralised monitoring and advisory system that provides a continuous flow of information to the plant operator. The system may also be configured to provide advice and warnings to the plant operator but without making automatic changes to plant operation. Such a system is based on the extensive monitoring of a wide range of plant operating conditions; some of these may be integral to individual control systems, while others may be site-specific additions to improve overall plant operation.

Monitoring and advisory systems are often preferred where plant-operating decisions have to take account of factors that cannot be defined for computer-based control. The use of this type of control and monitoring regime requires constant attendance or the immediate availability of a plant operator or supervisor to make decisions and to initiate the appropriate control actions.

A plant monitoring system will collect current and historical data for a wide range of plant parameters, while it can store and process data to provide information for evaluation and plant diagnostic purposes. Typical parameters would include:

- heat and power outputs,
- fuel consumptions,
- water consumption,
- ambient air conditions.
- gas pressure and temperature,
- exhaust and cooling system conditions,
- exhaust gas constituents,
- electricity import and export metering,
- predictions of site energy load patterns.

In order to make effective use of the monitoring and data collection facilities, an on-line computer system would contain additional management information, together with the necessary programming to enable the system to provide advice to the operator, or to make and implement plant operating decisions. The management input to such a system would include:

- fuel tariffs,
- water costs,
- electricity purchase and export tariffs,
- plant maintenance costs,
- utility safe revenues,
- costs of alternative supply provisions,
- fixed costs associated with start-up or shutdown, and/or
- environmental constraints on operations.

A typical onboard monitoring package records over 70 items of primary operating data, status and alarm signals. The combined use of monitoring and advisory functions enables reliable and cost-effective plant operation to be achieved by manual operation. This would include decisions on optimum plant operation and on plant priority and sequencing. It may also include total shutdown at times when alternative energy supplies are more cost-effective.

8.2.2.3. Distributed systems for total plant control

Some CHP plants use distributed control systems (DCS), with semi-autonomous, computer-based control of the individual plant control panels, and the higher-level supervision of plant operating procedures in an overall plant control protocol. Systems of this type will incorporate a wide range of automatic responses to defined events, such as component or plant failures, changes in heat and power plant conditions, and variations in site load. In other words, they will make and carry out automatic control decisions regarding plant operation.

As with the plant monitoring and advisory systems, these systems are based on extensive monitoring of a wide range of plant operating conditions, some of which may be integral within individual plant control systems, while others are site-specific additions. The individual equipment PLCs are linked to the DCS, which may monitor and have full control of the operation of some equipment, such as the electrical switchgear or the boiler (excluding the burner), but with more limited control functions for other equipment, such as the generating set.

A distributed control system ensures effective monitoring and operation, including remote control where appropriate. Interventions by site staff tend to be infrequent and staffing levels can be low with only shift supervision required. This type of system tends to be used in plants that have relatively uncomplicated system control requirements, such as those that operate continuously without changes in load or output.

8.2.2.4. Manual control of individual plant systems

The other option is where a CHP plant has no overall control or monitoring system but is operated and controlled manually according to the information provided by each plant control panel. This is sometimes the preferred option where it is compatible with other site operation and control methods, and where the installation of centralised monitoring or control is not cost-effective.

8.2.3. Planning and managing plant shutdowns

Any CHP prime mover/electrical generator will require planned shutdowns for servicing, and the preparation and scheduling of these outages are essential. The costs of shutdown include not only the labour and materials for carrying out the planned work, but also the additional costs of meeting the site's heat and power requirements from other sources. These costs are not insignificant and must be taken into consideration when deciding on the timing and duration of a shutdown.

For example, it is not generally advisable to carry out planned maintenance on a CHP plant when electricity costs are high, for instance during midweek daytime periods in winter. Furthermore, it maybe cost-effective to minimise the duration of the shutdown by having work continue outside 'normal' working hours; usually, the extra cost of labour may be offset by the reduced costs and duration of alternative heat and power supplies.

On the other hand, packaged CHP are normally operated and maintained under a contract. Then, it is wise to ensure that service vehicles and equipment have ease of access for when maintenance must take place. Downtimes can be increased simply because no provision was made for this.

8.2.4. Staff training

Irrespective of the type of plant installed, effective operation requires proper training of the site staff who will be responsible for that plant - not only plant operators and maintenance staff, but also site managerial staff. Depending on site manning levels and operating hours, there will need to be enough trained people to provide cover for shift working, for planned or sudden staff absences, and for the progression of staff to other jobs.

Lack of training can be disruptive to the cost-effective and reliable operation of a CHP plant. Staff need to be trained not only in the hands-on use of the plant but also in the overall philosophy and purpose of the plant, in the monitoring of its condition and performance, and in building good working relationships with the suppliers that provide on-going technical support. Nevertheless, there is an important need for staff to be educated about the benefits of the CHP plant so that they make best use of the energy.

Training must be undertaken as part of the CHP installation procedure, in order for the staff to become skilled and ready to operate the new plant as soon as it is ready to run. This can be complemented by ensuring that staff is involved in the final stages of plant installation, when the plant is commissioned and tested by the installers. It is usually considered essential for staff to undertake the training provided by equipment suppliers, who often specify a training programme with regular updates and refresher courses as part of the overall service provided. Off-site training, at the suppliers' premises or at other plants, can also be highly beneficial.

8.2.5. Safety issues relating to plant operation

The installation of a CHP plant usually requires the adoption of new safety systems and procedures, particularly regarding the operation and maintenance of the prime mover/electrical generator. For example, the use of natural gas within an enclosed area will need a review of ventilation facilities, and the installation of gas detectors may be considered appropriate, possibly connected to an automatic gas shut-off valve.

Regular testing of plant conditions will be required, and all changes to the plant must be accompanied by an assessment of any risks and hazards that may arise as a result. It is important to keep proper records of plant safety tests, together with the maintenance and equipment schedules.

8.3. CHP PLANT MAINTENANCE

8.3.1. Maintenance options

CHP plants require effective and reliable monitoring and maintenance to provide the appropriate levels of reliability and efficiency. The maintenance complexity and frequency varies for different system items, and this influences the options for selecting the best source of maintenance and repair expertise. Responsibility for the plant maintenance usually rests with the plant owner or operator. This may be the site owner, a contractor that installed the plant under an energy services company contract or equipment supplier finance (ESF) arrangement, or a contractor to whom all aspects of plant operation and maintenance have been subcontracted.

More specifically, under an ESF arrangement, the CHP supplier designs, finances, installs, operates and maintains a CHP system with a guaranteed annual output for a period of typically ten years. The site owner provides the space for the plant, but is not responsible for paying for any part of the installation. The supplier's costs are recouped by selling the electricity generated to the site owner, who provides all the fuel consumed by the CHP unit and receives the heat output without additional charge.

On the other hand, under a contract offered by energy services companies (ESCO) – also known as contract energy management (CEM) –, a CHP system is treated as one cost saving element in a total package. Depending on the circumstances, the contractor may employ a CHP equipment supplier to install, monitor and undertake specialised maintenance and repairs of a CHP system. The contractor's own staff will perform routine inspections, non-specialised maintenance and management of the complete system.

It is common for some maintenance work on specialised system items, such as gas turbines and engines, to be contracted out to the equipment manufacturer or supplier or to other specialist organisations. The level to which a plant owner or operator will retain or subcontract these responsibilities will depend on the expertise available in-house and on the degree to which there is a desire to subcontract the risks and liabilities associated with plant performance and availability.

While the use of in-house resources maybe appropriate for minor maintenance tasks such as routine plant checks, lubrication, oil changes, filter changes, set point adjustments etc., it is normally necessary to have major work, whether planned servicing and overhauls, or breakdown repair work, carried out under maintenance contracts with the original equipment supplier. Most CHP system suppliers offer fully comprehensive maintenance packages, often associated with long-term performance guarantees.

In all cases, the establishment of a suitable long-term maintenance contract should be considered as part of the equipment procurement procedure. It should cover all the maintenance needed to achieve a defined level of plant availability. This approach allows a CHP operator to make better decisions on the total life-cycle costs and benefits of the project. The contract should also provide for some assurance regarding the quality and suitability of replacement parts and components.

8.3.2. Maintenance contracts for CHP plant

Maintenance of the CHP prime mover/electrical generator is the second largest component of CHP operating and maintenance (O&M) costs after fuel purchases. Almost without exception, it will require the expertise of the equipment manufacturer or a specialist maintenance contractor for a significant amount of the necessary work. There are various levels of contracted-out maintenance agreement that may be available, but the choice of service must be considered in conjunction with the degree of responsibility for performance and availability that comes with the contract.

Typical contract options would include the following:

- Planned maintenance only, whereby the maintenance contractor carries out only a predefined list of maintenance tasks to a predetermined time schedule. This would include all labour costs, and may include or exclude the cost of providing replacement parts and materials.
- Remote monitoring of plant parameters to provide a diagnosis of plant condition.
- Availability of 24-hour telephone support from suppliers' maintenance experts.
- Call-outs to unplanned outages or breakdowns within a specified time period.
- Comprehensive maintenance cover, which include all parts and labour costs associated with both planned and unplanned maintenance requirements.
- Performance and availability guarantees, with contractual targets for plant performance and availability, which are linked to financial penalties for non-achievement and bonuses for exceeding the contractual targets.
- Availability and installation of exchange or replacement system to cover periods of prolonged outage associated with failure or servicing requirements.

The actual range of options available will vary from one manufacturer to another, and can be varied according to the levels of staffing and expertise that the plant operators may have. The cost of the maintenance options selected can be expressed as a function of plant hours run, or as a cost per unit of power produced. These costs will obviously be higher for the more comprehensive levels of maintenance and service, but this does provide the benefit of risk transfer and enables the CHP plant operator to plan ahead with a high level of certainty on maintenance costs.

Performance guarantees cost more but, depending on the circumstances, the extra cost may be recovered either by the profit from the extra availability achieved or from the payments made if the CHP unit fails to perform as expected. Efficiency guarantees should also be included to avoid deteriorations in performance due to inadequate maintenance. The maintenance contract costs (typical values are given in table 8.1 below) usually increase on an annual basis, according to an appropriate published cost index.

Table 8.1. Typical maintenance costs* (in 1997 prices – p stands for Pennies)

Option	***CHP output***	
	50-150 kW_e	***200-800 kW_e***
Service only – with remote monitoring and including consumables	0.6 – 0.7 p/kWh	0.3 – 0.5 p/kWh
Comprehensive service – with remote monitoring – for a minimum period of five years	1.1 – 1.3 p/kWh	0.6 – 0.9 p/kWh
Comprehensive service – with remote monitoring and performance guarantees – for a minimum period of five years	1.3 – 1.5 p/kWh	0.9 – 1.3 p/kWh

* Based on 5,584 annual operating hours, i.e. 365 days at 17 hours/day with 90% availability

8.3.3. Maintenance requirements for CHP prime movers/electrical generators

8.3.3.1. Gas turbines

Gas turbines are designed to operate for long periods without significant maintenance work, as they generally function under continuous load and operating conditions that are well within their design criteria. A typical gas turbine can operate with only occasional inspection and minor adjustment for up to 30,000 running hours before its first major service overhaul, provided that:

- All of its auxiliary systems continue to function correctly.
- Items such as filters, lubrication etc. are maintained.
- Turbine internal surfaces are kept clean.

It should then continue to function without the need for major maintenance until an extensive service overhaul is carried out after around 60,000 running hours. Given correct maintenance, the economic life of a gas turbine should be well in excess of 100,000 running hours. However, the complexity of turbine's design and manufacture means that the periods of outage for servicing and overhaul are significant, running into several weeks, and some work may require the turbine to be returned to a specialist maintenance facility.

In these cases, the temporary availability of an exchange unit, or of a temporary replacement, may be a worthwhile consideration. Although a gas turbine will operate for long periods of time without maintenance, it is usual for it to be shutdown at least once a year for checks and minor adjustments, and to allow maintenance staff to carry out a boroscope inspection of the internal parts of the turbine.

Furthermore, it is important that certain conditions and parameters are kept within the tightly specified limits:

- Fuel quality and temperature must be maintained. The presence of small solid particles, liquid drops, or constituents that produce corrosive conditions or deposits on the turbine blading will accelerate the rate of wear and degradation within the turbine.

- Combustion air must be filtered to a high degree of cleanliness to avoid the ingress of airborne particles or substances that will contaminate or corrode the turbine.
- If steam or water is injected into the turbine, this must be of high purity to avoid accelerated wear to the turbine.
- The cooling and lubricating systems must operate as specified to avoid excessive component temperatures.

In addition, the rate of wear in a gas turbine is significantly affected by the number of times the turbine is stopped and started, since each stop/start cycle involves temperature changes and material expansion and contraction within the turbine. Maintenance costs can triple for a turbine that is cycled every hour versus a turbine that is operated for intervals of 1,000 hours. Operating the turbine over the rated design capacity for significant time periods will also dramatically increase the number of hot path inspections and overhauls.

Maintenance costs of a turbine operating on fuel oil can be approximately three times that as compared to natural gas. Typical maintenance costs for a gas turbine fired by natural gas are in the 0.003-0.005 $/kWh range (varying among dealers). Given correct maintenance and operation, a gas turbine should achieve an average annual availability of around 95%.

8.3.3.2. Reciprocating engines

A reciprocating engine requires servicing and overhaul at more frequent intervals than a gas turbine, although the servicing periods are not as long, nor is the work as specialised. Although these engines require the correct operating conditions, they are not as sensitive as gas turbines to variations in the fuel and air supplies, etc. However, correctly maintained reciprocating engines from reputable manufacturers are at least as reliable as gas engines. The engines used for CHP applications are generally diesel engines converted for operation with natural gas, LPG or sewage gas.

They run at a constant, moderate speed and with lower mechanical and thermal loads than the equivalent diesel engines, which help to ensure reliable operation and relatively less wear than in an engine subject to widely varying loads and frequent starts from cold. The maintenance requirements for CHP engines are similar in principle to those for vehicle engines, e.g. filters become clogged, combustion products accumulate within cylinder heads and exhaust systems, and bearings and rubbing surfaces wear.

Many engines require a brief shutdown for some routine maintenance as frequently as every 500 hours of operation, while a period of 1,000 hours without a shutdown is unusual. The time interval for overhauls is recommended by the manufacturer, but is generally between 12,000 and 15,000 hours of operation for a top-end overhaul and

24,000 to 30,000 for a major overhaul. A top-end overhaul entails a cylinder head and turbo-charger rebuild. A major overhaul involves piston/ring replacement and crankshaft bearings and seals.

Laboratory oil testing is used by maintenance engineers and oil companies to decide when to change engine oil and as a method of detecting a variety of engine faults. Oil tests are carried out to detect four main classes of contamination and/or deterioration, more specifically:

- excessive oxidation, nitration, acidity, viscosity and other conditions;
- the presence of water or glycol (may indicate leakage in the cooling system);
- the presence of metals (may indicate excessive wear of bearings or other engine components);
- non-metallic debris (detected by particle counting).

For larger installations, lubricating oil and diesel fuel may be tested for the presence of water and other contaminants when they are delivered to the site.

Most servicing and overhaul work on engines is relatively straightforward and is carried out on site. The work often requires the replacement of heavy components, and many engine installations have overhead lifting equipment installed as part of the system. Preparing sub-assemblies, such as exchange cylinder heads, for speedier replacement, can reduce the duration of some of the major work. With smaller engines, it is often more economical to replace the complete engine with a factory-reconditioned unit rather than overhaul it on site.

Given correct maintenance and operation, skilled repair and component replacement when necessary, engines can last for many years. Moreover, a gas engine should achieve an average annual availability of around 88% to 92%. Typical outline requirements and maintenance intervals are summarised in Appendix 1, while typical O&M costs, including an allowance for overhauls, vary between 0.01 and 0.015 $/kWh.

8.3.3.3. Steam turbines

As long as the conditions of the steam fed into the turbine are kept within specified levels of purity, temperature and dryness, the components of a steam turbine should suffer very little wear over prolonged periods of operation. It is also important to maintain lubrication of the main bearings. The oil lubrication system must be clean and at the correct operating temperature and level to maintain proper performance.

Other items include inspecting auxiliaries, such as lubricating-oil pumps, coolers and oil strainers, and check of safety devices, such as the operation of over-speed trips. Steam turbine maintenance costs are typically less than $0.004 per kWh. Given correct maintenance and operation, a steam turbine should achieve an average annual availability of up to 99%.

8.3.3.4. Micro-turbines

Micro-turbines have substantially fewer moving parts than engines, and are designed to be as maintenance-free as possible. The single shaft design with air-bearings will not require lubricating oil or water, so maintenance costs should be below those of conventional gas turbines. Micro-turbines that use lubricating oil should not require frequent oil changes, since the oil is isolated from combustion products. Of course, routine maintenance of air/fuel filters, ignitors, thermocouples, and fuel injectors, is important for warranties that guarantee specific efficiencies and equipment life spans. Only an annual scheduled maintenance interval is planned for micro-turbines. Maintenance costs are being estimated at 0.006-0.01$/kW.

8.3.3.5. Fuel cells

The electrodes within a fuel cell that comprise the "stack" degrade over time reducing the efficiency of the unit. Fuel cells are designed such that the "stack" can be removed. It is estimated that "stack" replacement is required between four and six years when the fuel cell is operated under continuous conditions. Maintenance also covers other components, such as air filters, water treatment beds, pressure vessels, motors, valve actuators, and pressure piping systems. The maintenance cost for PAFC (200 kW), including an allowance for periodic stack replacements, has been in the range of \$0.02-\$5 per kWh. Improvements should bring the cost to the end user down to \$0.015/kWh over the twenty-year life of the unit.

8.3.4. Maintenance requirements for site systems

A CHP plant is always installed as part of an integrated system for supplying heat and power to other parts of a site; it will, therefore, be linked to other units providing top-up and back-up facilities, so that the site's heat and power demands are always met. The site systems will also incorporate fuel supplies for the site, a site connection to the local electricity system, and the auxiliary equipment that is necessary for the on-going operation of the CHP plant.

Proper design, maintenance and operation of all parts of the mechanical and electrical systems are essential to provide guaranteed continuity of site energy supplies and the high levels of CHP availability associated with maximum cost savings. System design should take account of the need for energy supply continuity. This will require sufficient boiler and energy plant to allow maximum energy demands to be met when the CHP plant is off-line. It is also important to make design provisions for planned and unplanned maintenance work by including duty and stand-by provisions for key items, such as pumps and filters.

Another key provision on many sites is the facility for boosting the supply pressure of the natural gas to the gas turbine or engine. Again, it may be prudent to provide some level of stand-by plant to prevent the CHP plant being off-line in the event of a gas compressor problem. Bearings and electrical insulation may deteriorate if the CHP unit is left out of action for long periods. In addition, control systems of CHP units contain temperature and other sensors that can deteriorate and electronic components that can fail. CHP unit alternators are normally very reliable and need little attention beyond cleaning and checking the insulation.

Guidance on the operation and maintenance of a site's heating and electrical distribution systems should be contained in the O&M manuals supplied when the system was installed. Some systems are of particular importance if a CHP plant is to operate efficiently and reliably, and failure of any of these can result in CHP plant shutdown. It is essential to carry out a planned programme of testing and maintaining these systems. This is usually undertaken when the prime mover is serviced.

The site systems involved include:

- *Cooling systems*: All gas turbines, engines and compressors produce heat that must be disbursed in effective cooling systems to avoid damage or automatic shutdown as a result of excessive coolant temperatures. All cooling systems should be fitted with duty and stand-by pumps and filters, and must be kept clear and free-flowing. Cooling systems that use electric fans and radiators must be checked and maintained regularly to minimise noise and vibration levels. If evaporative cooling towers are used water treatment for corrosion and bacterial growth is essential.
- *Gas detection*: Most CHP equipment is located within enclosures to minimise noise levels in the surrounding system area. These enclosures are frequently fitted with gas detection equipment to warn of potentially dangerous conditions in the event of a gas escape.
- *Ventilation*: Some CHP equipment requires controlled ventilation to maintain air temperatures within correct limits and to avoid the risk of gas or vapour build-up in the event of an escape.
- *Gas-oil systems*: Gas turbines are often specified and designed to use gas-oil as a back-up fuel in the event of an interruption to gas supplies. This back-up fuel system often lies idle and unused for long periods, and it is important to make regular checks to ensure that the system is ready to operate fully when needed.
- *Bypass ductwork*: Some CHP plants are equipped with a bypass in the exhaust ductwork. This serves as a means of controlling the exhaust gas flow into a heat recovery unit, and also of passing exhaust gases directly to atmosphere if necessary. The dampers that control the exhaust gas flow must be maintained and checked at regular intervals to ensure that they operate correctly.
- *Effluent catchments*: Although CHP plants produce very little liquid effluent, it is important to ensure that any potential spillage of oils, coolant, etc. is confined using catchment pits or basins, and that any drain valves are fitted with locks and tested at regular intervals.

8.4. CHP PLANT PERFORMANCE MANAGEMENT

8.4.1. Importance of the efficient system management

Regardless of how a CHP system is purchased and which operating and maintenance regime is adopted, optimum results and maximum system running hours often depend on how well the entire system and its O&M procedure are managed. A senior member of staff should therefore be made responsible for CHP operations and for the overall management of the CHP system.

The duties of the person given this responsibility should include:

- Managing O&M contracts, including ESF and energy services contracts.
- Ensuring effective liaison with the contractor and establishing a good working relationship with common aims.
- Auditing CHP system operations regularly to ensure that the expected performance is being achieved.
- Ensuring that obvious CHP system malfunctions or abnormalities are attended to promptly (particularly malfunctions not covered by specific guarantees).
- Reviewing contracts and agreements periodically to identify and then negotiate any changes that may be desirable.
- Studying contractors' reports and invoices.
- Communicating with the local gas and electricity suppliers and ensuring compliance with current regulations.
- Ensuring that suitably trained and qualified people are available on-site to undertake the functions for which the site's technical staff remain responsible. This may include operation, maintenance and repair of all the engineering systems that interface with the CHP system.
- Managing the engagement of specialist local contractors.
- Ensuring that health and safety requirements are met. The plant can be CE marked and a Certificate of Conformity issued, if the requirements of relevant Regulations are met. Clearly, customers should look for validation, which will help them to discharge their health and safety duties. However, such validation is not a guarantee that the plant will run safely and the safety of the plant should continue to be assessed and monitored.
- Establishing responsibility for the disposal of waste (e.g. spent lubricating oil), and ensuring that disposal is undertaken in accordance with environmental regulations.
- Confirming that the contractor is officially registered and that the fitters have the appropriate certified training.

8.4.2. Plant condition monitoring

Condition monitoring of the CHP plant constitutes an important part of preventive maintenance, since:

- Monitoring the temperature levels of various sections of an engine or gas turbine can give indications of component deterioration or advance warning of maintenance requirements.

- The regular sampling and analysis of engine lubricating oil can provide a considerable amount of information on plant condition. The presence of water or other liquid contaminants, or of metallic or non-metallic solids, provides an indication of excessive wear or leakage, while the condition of the oil itself, such as its acidity and viscosity, gives valuable information on engine condition.
- Monitoring the frequency and amplitude of vibration and noise from a system gives an indication of its condition.

On-line condition monitoring is now applied to nearly all gas turbines, and to a wide range of the larger engines. The monitoring also extends to the alternators that are connected to these prime movers. Monitoring is generally carried out using sensors with electrical outputs that feed information to a data collection and logging system attached to the plant control system. The data can be extracted and collated for local or off-site review. Condition monitoring will also provide alarms and automatic shutdown instructions to the plant control system.

8.4.3. Auditing CHP plant performance

CHP plants are installed at a significant capital cost to provide long-term savings in running costs. However, these expected savings may not be achieved unless the CHP plant performs as well as predicted. Engine performance may deteriorate or fall short of the supplier's performance guarantee. Loss of running hours - or extended running hours at part load - can result in lost profit. Excess heat dumping also reduces profitability.

Regular auditing and review of CHP plant performance is therefore strongly recommended. Contractors generally provide detailed monthly reports of CHP unit performance, except for matters that are not under their control. However, these reports may need to be verified and correlated with other data to obtain a complete picture of the plant's performance.

The detailed audit objectives, which are:

- the verification that the contractor’s reports and other information present a fair picture of the plant’s performance and that cost/benefit and other financial targets are being achieved;
- the identification of unexpected shortfalls in unit performance or running hours, which may require investigation and subsequent adjustment to the plant;
- the assistance of forward budgeting and contract supervision in cases where future ESF or energy services contract terms may be adjusted, depending on plant performance, fuel prices, etc.

will depend on the site's requirements and the form of contract under which the CHP plant has been installed and is being operated and maintained.

Provided the appropriate instruments are installed, monitoring the technical performance of a CHP plant is reasonably straightforward. The data needed can either be gathered manually or by automatic data logging, using one of the energy monitoring kits available as an extra for many CHP plants. The following table summarises the main methods of collecting the information required for an audit of CHP plant performance. The collected data should be entered in a spreadsheet (set up for the form of analysis required) or analysed and presented in some other format.

Table 8.2. Monitoring methods for the audit of a CHP plant

Parameter	***Data source***
Fuel input (kWh)	➢ Read from the CHP unit's gas/oil meter or, in some cases, estimated from the site's gas/oil meter readings. Notes: a. Gas/oil usage may need to be converted from the volume measured to kWh. b. Gas/oil unit costs can be derived from the site's fuel bills and from gas/oil supply contracts. c. Recording the unit's fuel consumption allows comparisons with previous years and highlights discrepancies (in certain cases, fuel consumption will increase following the installation of a CHP unit).
Electrical output (kWh)	➢ Read from the CHP unit's energy meter. Notes: a. Some electrical/parasitic loads, such as those for external heat pumps and fans, may need to be estimated and subtracted from a CHP unit's gross output. These loads may be included within the CHP unit but connected after the meter. b. Avoided electricity costs can be determined from the mains electricity costs shown on electricity bills. c. Comparison of the site's electricity consumption and costs with previous years will highlight any discrepancies.
Electricity exports	➢ Where export power metering is installed, the quantity and value of the electricity exported form the site can be determined from electricity bills. ➢ Where there are no arrangements to export power, export should be prevented.
Running hours	➢ From the hours run meter of the CHP unit.
Electricity costs under an ESF scheme	➢ Can be derived from the ESF contract documents and invoices.
Net heat output	➢ Obtained by heat metering. Notes: a. The heat meter senses the water flow rate through the CHP unit and the difference between the flow and return temperatures. b. The heat meter should also be capable of measuring the quantity of heat lost through the heat dump radiators (if existing).
O&M costs	➢ From site records and taken into account the costs of materials.
Contract costs	➢ Derived from the contract documents and relevant invoices.

8.4.4. Plant performance monitoring

Performance monitoring is essential to ascertain whether plant outputs and efficiencies are consistent with those demonstrated in the performance tests prior to handover (which should themselves reflect the performance and efficiency of the original equipment specification). Plant performance should be monitored and recorded to show changes in key parameters, such as output and fuel consumption, and to provide information on other parameters that are known to affect performance, such as air temperature and pressure.

It is also important to monitor the rate at which plant performance changes, as this provides an important basis for planning maintenance tasks and plant overhauls. In addition to monitoring for system management purposes, there will be a need to monitor the input and outputs of the CHP plant in order to assess its overall annual performance. This procedure will be required if system is to demonstrate its achievement of the necessary standards for exemption from the relevant levies on supplies of fuel and electricity.

However, the original performance data will have been specified - and demonstrated during site performance tests - under 'new and clean' conditions, and plant output and efficiency will deteriorate between both minor and major servicing activities. Also, for a gas turbine, actual plant performance on-site is significantly affected by the backpressure in the exhaust ductwork and chimney. This is particularly relevant in the case of a CHP scheme that has heat recovery equipment installed in the exhaust system.

A gas turbine will suffer a long-term degradation in efficiency and output as a result of a gradual deterioration in the condition of the turbine blading, and other components. This degradation would typically be 3-4 % of electrical output during the period between major services, and would largely be restored by work carried out as part of a major service. A degradation of up to 5% over the total life of the turbine would be typical.

In addition, a gas turbine will suffer from short-term degradation of output caused by fouling of the blades in the compressor section of the turbine. This problem is caused by contaminants in the combustion air drawn into the turbine, and the rate of degradation is affected by local air quality and the efficiency of filtering. The degree of degradation can be up to 5% of output within a week, but this can be alleviated by use of the compressor washing systems that are built into any CHP gas turbine.

A gas turbine is usually fitted with both online and off-line washing systems:

- The on-line system injects washing fluid into the turbine compressor during normal turbine operation, and the procedure can usually be carried out in less than 30 minutes. The washing fluid evaporates and is discharged with the exhaust gases.
- The off-line system requires a turbine shutdown for a period of between one and four hours: the system operates with the turbine spinning at slow speed, and a quantity of liquid effluent is produced. The off-line system is obviously more costly to carry out, but it is a more effective method of cleaning the turbine and restoring power output levels.

The usual approach is to use the plant monitoring system, in conjunction with an assessment of the operating costs and benefits, to produce a planned schedule of both on-line and off-line washing procedures. It is often more cost-effective to carry out off-line washing overnight when the costs of purchasing electricity from alternative outside sources are lowest.

The effect of the short-term degradation and the washing procedures is that turbine output varies in a way that is illustrated in the 'saw-tooth' graph shown in figure 8.1. The short-term drop in output is restored almost to its original level by the on-line washing, and this cycle occurs typically over a period of one week or less. The more gradual longer-term decline in output, which is restored by off-line washing, occurs with a cycle time of typically 2 to 4 weeks. In addition, there is the long-term degradation of turbine performance that is largely restored by the major overhauls at around five-yearly intervals.

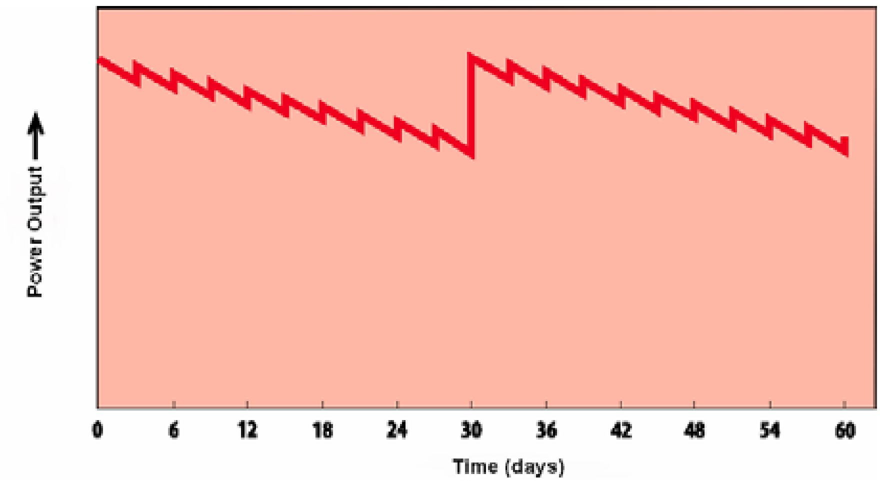


Figure 8.1. Example of "saw-tooth" degradation in gas turbine

An engine will also suffer from degradation in output, but for different reasons. An engine is largely unaffected by small amounts of contamination in the combustion air, although it is important to change the inlet air filter as recommended. Engine performance degradation is almost entirely caused by the gradual wear of components in the engine: spark plugs, in particular, require regular attention and replacement to maintain engine performance. Other items that need regular attention include air filters, valve clearances and turbo-charger operation.

The degradation in engine performance varies in a similar 'saw-tooth' pattern to that associated with a gas turbine, but with a much lower rate of output decline and a longer time period for each cycle. Short-term degradation, typically 3-5% of output, occurs over a period of around 1,000 running hours and is restored by routine attention to spark plugs, valves etc. Longer-term degradation occurs during the period between major overhauls, which are carried out, typically, every 5,000 running hours.

APPENDIX 1

Typical checklist of an engine powered CHP plant maintenance requirements

TWICE A WEEK
Check oil level.
Inspect for fluid leaks, unusual noises or parts working loose.
Check CHP running records, trend logs and fault records of the site engineering system.
Report abnormalities to the maintenance engineer.
MONTHLY (500 - 750 HOURS OF OPERATION)
Check starter battery condition.
Sent engine lubricating oil samples for analysis.
Change oil filter.
Check gas train filter and replace, if necessary.
Check cylinder compression ratios.
Adjust valve clearances.
Check gas pressure and adjust gas/air mixture.
Check for oil or water leaks and repair.
Inspect and lubricate control linkages.
Clear and re-gap spark plugs.
Check exhausts system backpressure.
Check exhausts emissions.
Check operation of auxiliary pumps, fans and other equipment.
ALTERNATE MONTHS (1,000 – 1,500 HOURS)
Change oil if condition of oil samples indicates need.
Renew spark plugs if badly worn.
Measure and reset bale clearances.
Replace worn rocker cover gaskets.
Fit new engine air filter element and replace if necessary.
Check the condition and tension of belt drives.
Check the starter motor operation.
Check to operation of the monitoring system and controls.
EVERY SIX MONTHS (4,000 HOURS)
Check the condition and performance of the external ventilation system of the engine enclosure.
Using an approved bearing condition vibration monitor, check the condition of the alternator and auxiliary pump/fan bearings.
Inspect and clean the heat dump radiators.
ANNUALLY (8,000 HOURS)
Replace engine coolant.
Clean exhaust gas heat exchangers.
Check the condition of all the wiring and measure its electrical insulation.
Check sensors, controls, safety systems and electrical protection devices.
Check ignition system.

EVERY 3-5 YEARS, DEPENDING ON HOURS RUN (30,000 HOURS)
Inspect, overhaul and replace as necessary, the engine's major mechanical parts, including: cylinder heads and valve gear; big ends; pistons; cylinder liners; etc.
Inspect, and overhaul as necessary, auxiliary pumps and fans.
Replace after cooler core.
Inspect the alternator and its bearings.

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2. Elliot, R. and Spurr, M. (1994): “Implementation of a medium-scale CHP scheme”: www.aceee.org/pubs/ie983.htm

3. Elliot, R. and Spurr, M. (1999): “Combined Heat and Power: Capturing Wasted Energy”, Amercian Council for and Energy-Efficient Economy (ACEEE), 1999.

4. Major, G. (1995): “Small-scale Cogeneration”. Sittard, The Netherlands: CADDET-Energy Efficiency ANALYSES SERIES No. 1, International Energy Agency, Organization for Economic Cooperation and Development. Revised.

5. European Commission (1997): Communication from the Commission to the Council and the European Parliament: “A Community strategy to promote combined heat and power and to dismantle barriers to its development”, COM (97) 514 final.

6. European Commission (2000): “Action plan to improve energy efficiency in the European Community”, COM (2000) 247.

7. ONSITE SYCOM (1999): “Review of Combined Heat and Power Technologies” Report created for the California Energy Commission under grant number 98R020974.

8. “The Manager’s Guide to Packaged Combined Heat and Power Systems”, Published by DETR.

9. “The Manager’s Guide to Custom-built Combined Heat and Power Systems”, Published by DETR.

10. ZREU and CRES (2000): "Guide for the training of engineers in CHP issues, Training Needs Study for Germany and Greece”.

Recommended Readings

Energy Efficiency Best Practice Programme Publications

- Introduction to large scale combined heat and power - Good Practice Guide 43, Published by DETR.
- The long-term performance of a combined-cycle CHP installation – Good Practice Case Study 208, Published by DETR.

- The long-term performance of a gas turbine combined heat and power installation – Good Practice Case Study 220, Published by DETR.
- Small-scale combined heat and power for buildings – Good Practice Guide 176, Published by DETR.
- Combined heat and power (CHP) in universities – Good Practice Guide 204, Published by DETR.
- Financing Large Scale CHP for Industry and Commerce – Good Practice Guide 220, Published by DETR.
- The operation and maintenance of small-scale combined heat and power – Good Practice Guide 226, Published by DETR.
- How to appraise CHP - Good Practice Guide 227, Published by DETR.
- Guide to community heating and CHP – Good Practice Guide 234, Published by DETR.
- Combined heat and power in hospitals – Good Practice Guide 267, Published by DETR.
- A corporate policy on combined heat and power – Good Practice Case Study 210, Published by DETR.
- Combined heat and power in the Government Estate – RAF Coningsby – Good Practice Case Study 275, Published by DETR.

CHPA Publications

- Guidelines for the Preparation of Technical Specifications for Small Scale CHP Installations.
- Putting Residential CHP to Work – The Support Available.
- Focus on CHP for Buildings and Industry.
- CHP – Putting Energy Efficiency to Work.
- Small-scale CHP for Industry.

Other Publications

- The CHPQA Standard: Quality Assurance for Combined Heat and Power – Issue 1, November 2000, Published by DETR.
- Combined Heat and Power – A Practical Guide to the Evaluation, Development, Implementation, and Operation of Cogeneration Schemes, Energy Publications, Livanos House, Granhams Road, Cambridge CB2 5LQ

- Small-scale combined heat and power for buildings, Applications Manual AM12: 1999, Published by CIBSE/DETR