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The European Educational Tool on Cogeneration

Second Edition, December 2001

This document has been elaborated in the framework of the EDUCOGEN project. EDUCOGEN aims to develop the integration of cogeneration within technical universities and engineering colleges. The project has been co-financed by the European Commission under the SAVE programme. More information on EDUCOGEN, and electronic versions of this and additional publications, are available on the project's webpage on http://www.cogen.org/projects/educogen.htm.

The first edition of this document was published in April 2001. A major part of it has been elaborated in the National Technical University of Athens under the co-ordination of Prof. Frangopoulos.

The second edition from November 2001 contains a new chapter on electrical interconnection issues created in the University of Dundee under the co-ordination of Dr Bruce Ramsay.

Together with this second edition, a number of case studies will be provided in a separate publication. These case studies have been elaborated within the European SAVE project PROSMACO (http://www.cogen.org/projects/prosmaco.htm).

The chapters on the current status, prospect, and frameworks for cogeneration reflect the situation before 2001. Several changes have occurred in the countries described and the chapters are therefore not entirely up to date any more. The complementary study of recent information sources is therefore strongly recommended.

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1 DEFINITION AND HISTORICAL DEVELOPMENT OF COGENERATION

The usual (conventional) way to cover needs in electricity and heat is to purchase electricity from the local grid and generate heat by burning fuel in a boiler, a furnace, etc. However, a considerable decrease in total fuel consumption is achieved, if cogeneration (known also as combined heat and power, CHP) is applied.

> *Cogeneration is the thermodynamically sequential production of two or more useful forms of energy from a single primary energy source.*

The two most usual forms of energy are mechanical and thermal energy. Mechanical energy is usually used to drive an electric generator. This is why the following definition, even though restrictive, often appears in the literature:

> *Cogeneration is the combined production of electrical (or mechanical) and useful thermal energy from the same primary energy source.*

The mechanical energy produced can be used also to drive auxiliary equipment, such as compressors and pumps. Regarding the thermal energy produced, it can be used either for heating or for cooling. Cooling is effected by an absorption unit, which can operate through hot water, steam or hot gases.

During the operation of a conventional power plant, large quantities of heat are rejected in the atmosphere either through the cooling circuits (steam condensers, cooling towers, water coolers in Diesel or Otto engines, etc.) or with the exhaust gases. Most of this heat can be recovered and used to cover thermal needs, thus increasing the efficiency from 30-50% of a power plant to 80-90% of a cogeneration system. A comparison between cogeneration and the separate production of electricity and heat from the point of view of efficiency is given in Figure 1, based on typical values of efficiencies.

Cogeneration first appeared in late 1880’s in Europe and in the U.S.A. During the early parts of the 20^{th} century most industrial plants generated their own electricity using coal-fired boilers and steam-turbine generators. Many of the plants used the exhaust steam for industrial processes. It has been estimated that as much as 58% of the total power produced by on-site industrial power plants in the U.S.A. in the early 1900’s was cogenerated.

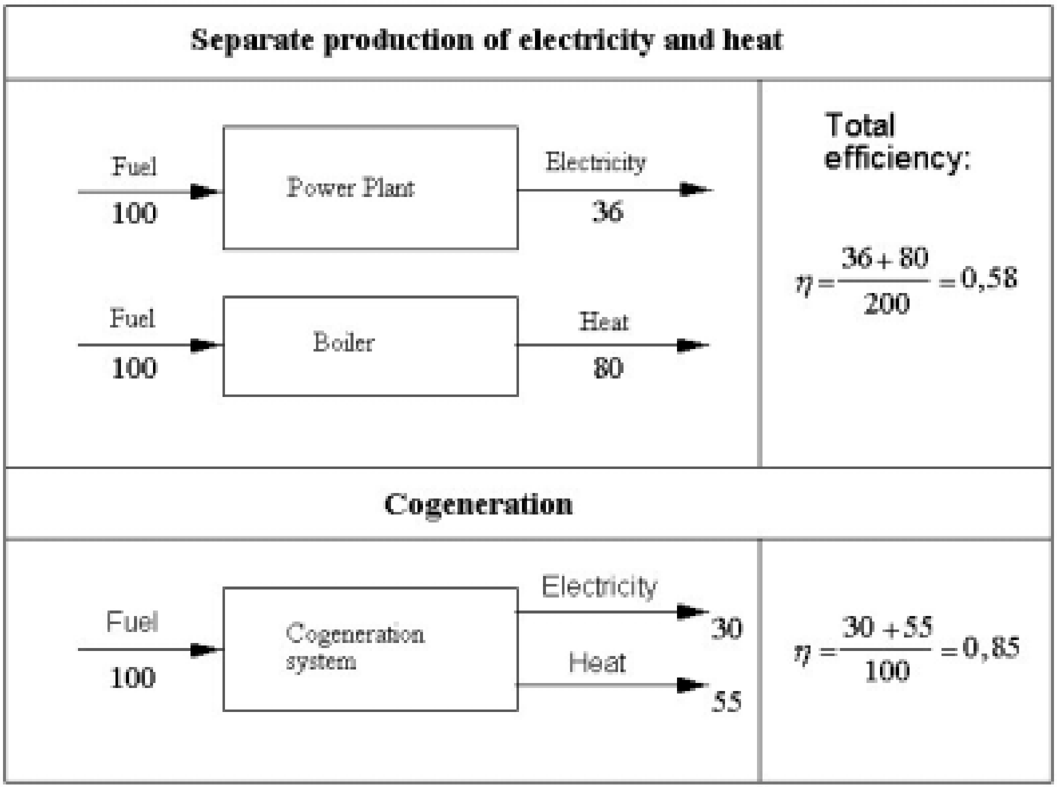


Figure 1: Efficiency comparison between cogeneration and separate production of electricity and heat. (Numbers below arrows represent units of energy in typical values.)

When central electric power plants and reliable utility grids were constructed and the costs of electricity decreased, many industrial plants began purchasing electricity and stopped producing their own. As a result, on-site industrial cogeneration accounted for only 15% of total U.S. electrical generation capacity by 1950 and dropped to about 5% by 1974.

Other factors that contributed to the decline of industrial cogeneration were the increasing regulation of electric generation, low energy costs which represent a small percentage of industrial costs, advances in technology such as packaged boilers, availability of liquid or gaseous fuels at low prices, and tightening environmental restrictions.

The aforementioned trend in cogeneration started being inverted after the first dramatic rise of fuel costs in 1973. Systems that are efficient and can utilise alternative fuels have become more important in the face of price rises and uncertainty of fuel supplies. In addition to decreased fuel consumption, cogeneration results in a decrease of pollutant emissions. For these reasons, governments in Europe, U.S.A. and Japan are taking an active role in the increased use of cogeneration. Methods of stimulating the use of cogeneration are seen in three major forms: (i) regulations or exemption from regulations, (ii) monetary incentives, and (iii) financial support of research and development. They are described in Chapter 10, while developments of cogeneration in the recent years, not only in the industrial but also in other sectors, are presented in Chapter 9.

Research, development and demonstration projects realised during the last 25 years led to a significant improvement of the technology, which now is mature and reliable. New techniques are also under development, such as fuel cells. More information about cogeneration technology is given in Chapter 3.

2 PERFORMANCE INDICES OF COGENERATION SYSTEMS

Before proceeding with the description of cogeneration technologies, it is necessary to define certain indices, which reveal the thermodynamic performance of a cogeneration system and facilitate the comparison of alternative solutions (systems). Numerous indices have appeared in the literature. The most important of those are defined in this chapter:

Efficiency of the prime mover **(e.g. of gas turbine, Diesel engine, steam turbine):**

$$\eta_m = \frac{\dot{W}_s}{\dot{H}_f} = \frac{\dot{W}_s}{\dot{m}_f H_u} \tag{2.1}$$

where

$\dot{W}_s$ shaft power of the prime mover

$\dot{H}_f$ fuel power (flux of the fuel energy) consumed by the system:

$$\dot{H}_f = \dot{m}_f H_u \tag{2.2}$$

$\dot{m}_f$ fuel mass flow rate,

H_u lower heating value of fuel.

Electrical efficiency:

$$\eta_e = \frac{\dot{W}_e}{\dot{H}_f} = \frac{\dot{W}_e}{\dot{m}_f H_u} \tag{2.3}$$

where $\dot{W}_e$ is the net electric power output of the system, i.e. the electric power consumed by auxiliary equipment has been subtracted from the electric power of the generator.

Thermal efficiency:

$$\eta_{th} = \frac{\dot{Q}}{\dot{H}_f} = \frac{\dot{Q}}{\dot{m}_f H_u} \tag{2.4}$$

where $\dot{Q}$ is the useful thermal power output of the cogeneration system.

Total energy efficiency **of the cogeneration system:**

$$\eta = \eta_e + \eta_{th} = \frac{\dot{W}_e + \dot{Q}}{\dot{H}_f} \tag{2.5}$$

The quality of heat is lower than the quality of electricity and it is decreasing with the temperature at which it is available. For example the quality of heat in the form of hot water is lower than the quality of heat in the form of steam. Consequently, one may say that it is not very proper to add electricity and heat, as it appears in Eq. (2.5). It is true that sometimes a comparison between systems based on the energy efficiency may be misleading. Even though energy efficiencies are most commonly used up to now, a thermodynamically more accurate evaluation and a more fair comparison between systems can be based on exergetic efficiencies defined in the following. For a comprehensive presentation of exergy and exergetic analysis, see related literature, e.g. Kotas (1995), Bejan et al. (1996).

Exergetic thermal efficiency:

$$\zeta_{th} = \frac{\dot{E}_Q}{\dot{E}_f} = \frac{\dot{E}_Q}{\dot{m}_f \varepsilon_f} \tag{2.6}$$

where

$\dot{E}_Q$ flux of energy corresponding to $\dot{Q}$,

$\dot{E}_f$ flux of fuel exergy:

$$\dot{E}_f = \dot{m}_f \varepsilon_f \tag{2.7}$$

ε_f specific exergy (exergy per unit mass) of fuel.

Total exergetic efficiency:

$$\zeta = \eta_e + \zeta_{th} = \frac{\dot{W}_e + \dot{E}_Q}{\dot{E}_f} \tag{2.8}$$

Power to heat ratio:

$$PHR = \frac{\dot{W}_e}{\dot{Q}} \tag{2.9}$$

Fuel energy savings ratio:

$$FESR = \frac{\dot{H}_{fS} - \dot{H}_{fC}}{\dot{H}_{fS}} \tag{2.10}$$

where

$\dot{H}_{fS}$ total fuel power for separate production of $\dot{W}_e$ and $\dot{Q}$,

$\dot{H}_{fC}$ 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 (2.3)-(2.5) and (2.9) lead to the following relations:

$$\eta = \eta_e \left(1 + \frac{1}{PHR}\right) \tag{2.11}$$

$$PHR = \frac{\eta_e}{\eta_{th}} = \frac{\eta_e}{\eta - \eta_e} \tag{2.12}$$

Equations (2.11) and (2.12) 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%.

Example 2.1. Let $\eta_e = 0.40$ and 0.65 $\leq \eta \leq$ 0.90. Then, Eq. (2.12) results in the range: 1.6 ≥ PHR ≥ 0.8.

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

$$\mathrm{FESR} = 1 - \frac{\mathrm{PHR}+1}{\eta\left(\frac{\mathrm{PHR}}{\eta_W} + \frac{1}{\eta_Q}\right)} \tag{2.13}$$

It can be written

$$\dot{H}_{fS} = \dot{H}_{fW} + \dot{H}_{fQ} = (\dot{m}_f H_u)_W + (\dot{m}_f H_u)_Q \tag{2.14}$$

$$\dot{H}_{fW} = (\dot{m}_f H_u)_W = \frac{\dot{W}_e}{\eta_W} \tag{2.15}$$

$$\dot{H}_{fQ} = (\dot{m}_f H_u)_Q = \frac{\dot{Q}}{\eta_Q} \tag{2.16}$$

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

Example 2.2A cogeneration system with a total efficiency η_Q = 0.80 and a power to heat ratio PHR = 0.6 substitutes a power plant of efficiency $\eta_w = 0.35$ and a boiler of efficiency $\eta_Q = 0.35$. Then, Eq. (2.13) gives FESR = 0.325, i.e. the cogeneration reduces the total energy consumption by 32,5%.

In the previous definitions, electric, thermal and fuel power is used (energy per unit time), which results in values of the indices valid in a certain instant of time or at a certain load. All the previous equations are valid also if power is replaced by energy in a certain period of time; then, integral values of the indices are obtained, which reveal the performance of the system over this period. For example, Eq. (2.5) can be written

$$\eta_a = \frac{W_{ea} + Q_a}{H_{fa}} \tag*{(2.5)$_a$}$$

where

- W_{ea} electric energy produced by the cogeneration system during a year,
- Q_a thermal energy produced during a year,
- H_{fa} energy of fuel consumed during a year.

Thus, Eq. (2.5)$_a$ gives the annual total efficiency η_a of the cogeneration system.

The performance of a system depends on the load and on the environmental conditions. On the other hand the degree of utilisation 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, because they are more revealing of the real performance of the system.

Furthermore there are legal aspects, which make integral values of indices significant.

3 CONTEMPORARY COGENERATION TECHNOLOGIES

Most cogeneration systems can be characterised either as *topping systems* or as *bottoming systems*. In topping systems, a high temperature fluid (exhaust gases, steam) drives an engine to produce electricity, while low temperature heat is used for thermal processes or space heating (or cooling).

In bottoming systems, high temperature heat is first produced for a process (e.g. in a furnace of a steel mill or of glass-works, in a cement kiln) and after the process hot gases are used either directly to drive a gas-turbine generator, if their pressure is adequate, or indirectly to produce steam in a heat recovery boiler, which drives a steam-turbine generator.

Indicative temperature ranges for the two types of systems are given in Figure 2:

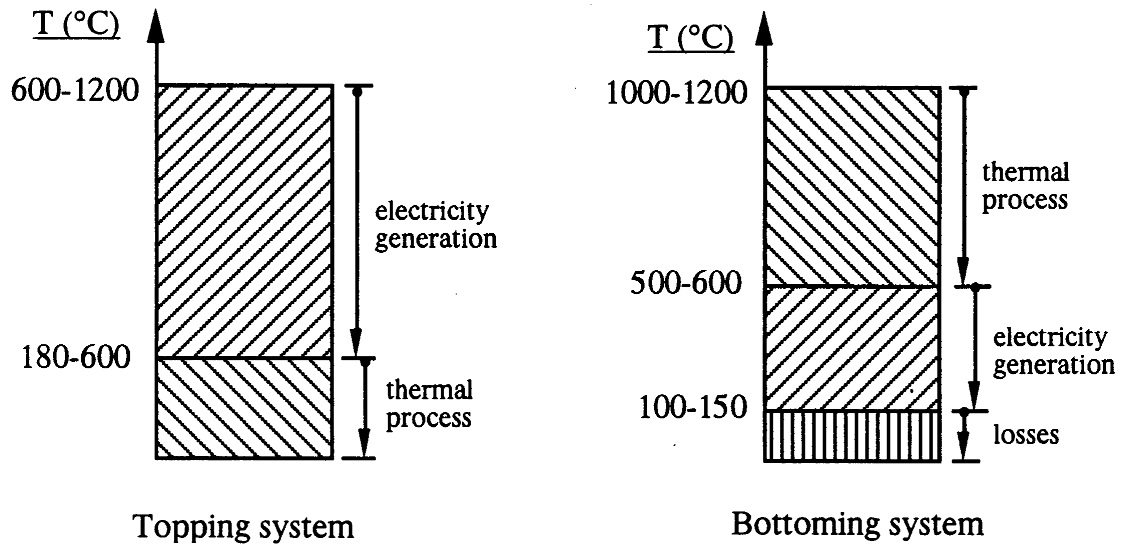


Figure 2: Indicative temperature ranges for topping and bottoming cogeneration systems

In the following chapters, various cogeneration technologies are described.

3.1 STEAM TURBINE COGENERATION SYSTEMS

A system based on steam turbine consists of three major components: a heat source, a steam turbine and a heat sink. The system operates on the Rankine cycle, either in its basic form or in its improved versions with steam reheating and regenerative water preheating. Most of the generation capacity installed since the early 1900’s is based on systems of this type.

The most common heat source is a boiler, which can burn any type of fuel or certain combinations of fuels, and produces superheated steam. In place of a boiler, nuclear reactors can be used. On the other hand, the system can use renewable energy such as biomass or concentrated solar radiation. Even waste by-products can be burned, provided the boiler is equipped with proper pollution abatement units.

The operating conditions can vary in a wide range. For cogeneration applications, steam pressure can range from a few bars to about 100 bar; in the utility sector, higher pressures can also be used. Steam temperature can range from a few degrees of superheat to about 450°C, and, in the utility sector, to about 540°C. The power output is usually in the range of 0.5-100 MW, even though higher power is also possible.

Steam turbine systems have a high reliability, which can reach 95%, high availability (90-95%) and long life cycle (25-35 years). The installation period is rather long: 12-18 months for small units, up to three years for large systems.

3.1.1 Main Configurations of Steam Turbine Cogeneration systems

There are several configurations of steam turbine cogeneration systems, which are described in brief in the following chapter. The flow diagrams are simplified in order to depict the basic configurations without details; thus, steam reheating, if any, regenerative water preheating and auxiliary equipment are not drawn.

3.1.1.1 Back-pressure steam turbine systems

It is the simplest configuration. Steam exits the turbine at a pressure higher or at least equal to the atmospheric pressure, which depends on the needs of the thermal load. This is why the term "back-pressure" is used. It is also possible to extract steam from intermediate stages of the steam turbine, at a pressure and temperature appropriate for the thermal load (Figure 3). After the exit from the turbine, the steam is fed to the load, where it releases heat and is condensed. The condensate returns to the system with a flow rate which can be lower than the steam flow rate, if steam mass is used in the process or if there are losses along the piping. Make-up water retains the mass balance.

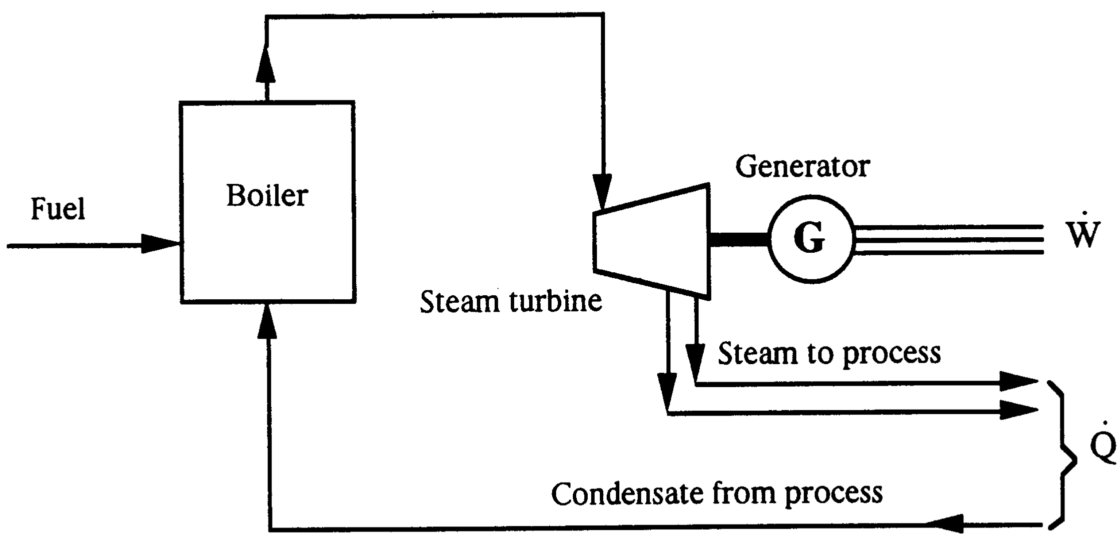


Figure 3: Cogeneration system with back-pressure steam turbine

The back-pressure system has the following advantages:

- Simple configuration with few components.
- The costs of expensive low pressure stages of the turbine are avoided.
- Low capital cost.
- Reduced or even no need of cooling water.
- High total efficiency, because there is no heat rejection to the environment through a condenser.

However, it has certain disadvantages:

- The steam turbine is larger for the same power output, because it operates under lower enthalpy difference of steam.
- The steam mass flow rate through the turbine depends on the thermal load. Consequently, the electricity generated by the steam is controlled by the thermal load, which results in little or no flexibility in directly matching electrical output to electrical load. Therefore, there is need of a two-way connection to the grid for purchasing supplemental electricity or selling excess electricity generated. Increased electricity production is possible by venting steam directly to the atmosphere, but this is very inefficient, it results in waste of treated boiler water and, most likely, in poor economic as well as energetic performances.

A way to reach some flexibility is to extract steam from the turbine for regenerative feed-water heating. The thermal output is then reduced with all the heat of condensation of the extracted steam, while the mechanical output is less reduced, because extracted steam still delivers work through its incomplete expansion. The total efficiency remains nearly unchanged.

3.1.1.2 Condensing steam turbine systems

In such a system, steam for the thermal load is obtained by extraction from one or more intermediate stages at the appropriate pressure and temperature (Figure 4). The remaining steam is exhausted to the pressure of the condenser, which can be as low as 0.05 bar with corresponding condensing temperature of about 33°C. It is rather improbable for such a low temperature heat to find a useful application and consequently it is rejected to the environment.

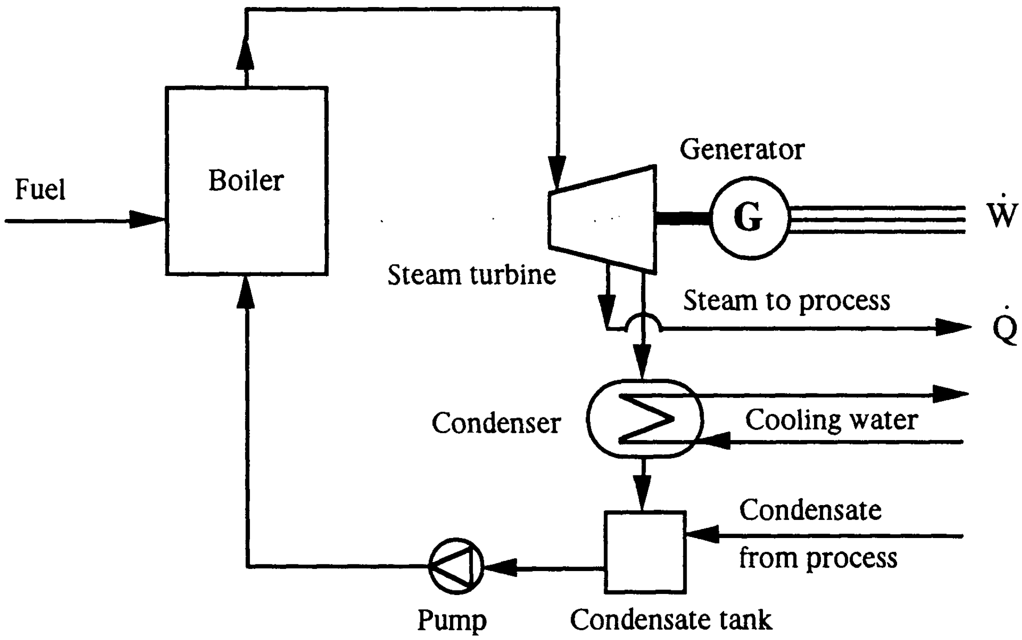


Figure 4: Cogeneration system with condensing steam turbine

Extracted steam can also be used for regenerative feedwater heating, which improves the Rankine cycle efficiency, and for driving auxiliary equipment.

In comparison to the back-pressure system, the condensing one has a higher capital cost and, in general, a lower total efficiency. However, it can control the electrical power independently, to a certain extent, of the thermal load by proper regulation of the steam flow rate through the turbine.

3.1.1.3 Bottoming cycle steam turbine systems

Many industrial processes (e.g. in steel mills, glass-works, ceramic factories, cement mills, oil refineries) operate with high temperature exhaust gases (1000-1200°C). After the process, the gases are still at high temperature (500-600°C). Instead of releasing them directly into the atmosphere, they can pass through a heat recovery steam generator (HRSG) producing steam, which then drives a steam turbine. Thus, the energy of fuel is first used to cover a thermal load and then to produce electricity by a steam turbine system in a bottoming cycle (Figure 5).

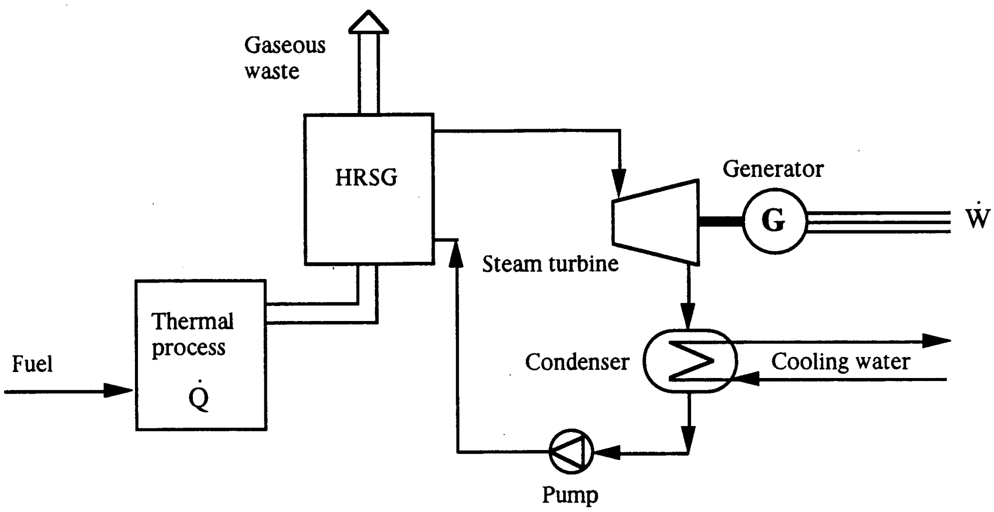


Figure 5: Bottoming cycle cogeneration system with condensing steam turbine

In Figure 5, a condensing steam turbine is shown. Alternatively, a back-pressure turbine can be used, if conditions make it preferable. Of course with either the condensing or the back pressure turbine extraction can be applied, if needed.

3.1.1.4 Bottoming Rankine cycle systems with organic fluids

These systems are usually referred to as organic Rankine cycles (ORC).

In the bottoming cycle of Fig. 3.4, water is the working fluid, which evaporates by heat recovery at high temperature (500°C or higher). However, when heat is available at relatively low temperatures (80-300°C), organic fluids with low evaporation temperatures can be used, such as toluene, improving the heat recovery and the performance of the system. ORC's can be effective also in geothermal applications, where only low temperature heat is available. In certain cases, the working fluid can be a mixture of two different fluids such as water and ammonia, which increases the cycle efficiency.

Organic fluids have two major disadvantages in comparison to water. (i) They are more expensive than water, and losses of the fluid can result in significant costs. (ii) Fluids such as toluene are considered hazardous materials and must be handled accordingly. Safety and materials-handling systems can also increase ORC system cost. (iii) Thermal stability of some organic fluids appears to be limited. (iv) Their lower heat of vaporisation as compared with water leads to higher mass flow rates and higher pumping power, resulting in some lowering of the efficiency.

Some advantages of organic fluids have to be recognised : (i) Their higher molecular weight leads to a lower number of stages and consequently to lower turbine costs. (ii) For most organic fluids, the absolute value of the slope of the line of separation between liquid-vapour and pure vapour-domains in a (t,s) diagram is larger than for water. As a consequence, the rate of condensation inside the turbine is lower.

The electric power output of these systems is in the range 2 kW–10 MW. The electric efficiency is low, 10–30%, but of importance is the fact that such a system produces additional power with no fuel consumption.

The installation time of small units (up to 50 kW), and especially those appropriate for applications in the commercial-residential sector, are 4-8 months, while for larger systems it is 1–2 years. There are no statistical data available regarding the reliability of ORC systems. It is estimated that their annual average availability is 80–90%. The expected life cycle is about 20 years.

3.1.2 Thermodynamic Performance of Steam Turbine Cogeneration Systems

3.1.2.1 Efficiency and PHR of steam turbine systems

The total energy efficiency is relatively high (60–85%) and decreases only slightly at partial load. However, the electrical efficiency is low (values in the range 15–20% are not seldom), which results in low power to heat ratio (PHR = 0.1–0.5). In general, the higher the temperature required for process steam is, the lower the electrical efficiency is. The electrical efficiency can be increased to a certain extent by increasing the pressure and temperature of steam at the turbine inlet.

Back-pressure steam turbine systems.

When all the thermal energy of steam is utilised and the condensate returns from the processes with no supplementary cooling and no heat rejected to the environment, the total efficiency may reach 85%. Since the generated electrical power is proportional to the steam flow rate towards the process, the value of the power to heat ratio, PHR, remains approximately constant during load changes.

Condensing steam turbine systems.

The heat rejected through the condenser results in a lower total efficiency. Main advantage of these systems is the capability to change the electrical and thermal power independently, inside certain limits, and consequently to change the value of PHR.

Bottoming cycle steam turbine systems.

The electrical efficiency is typically in the range 5–15%. This is a low value, but it is important that electricity is produced from thermal energy, which otherwise would be rejected to the environment.

3.1.2.2 Partial load operation of steam turbines

Optimum performance of a steam turbine typically occurs at approximately 95% of the rated power. Since most turbines used in cogeneration systems are multistage devices designed for a specific application, often having both condensing and extraction capabilities, the part-load characteristics are unique to each turbine. The turbine manufacturer will provide a performance map such as the one illustrated in Figure 6. The map in Figure 6 has been developed for a condensing/extracting turbine and relates throttle flow (flow rate of steam at the turbine inlet) to turbine electrical and thermal power output; the latter is determined by the extraction flow rate, which appears in the map.

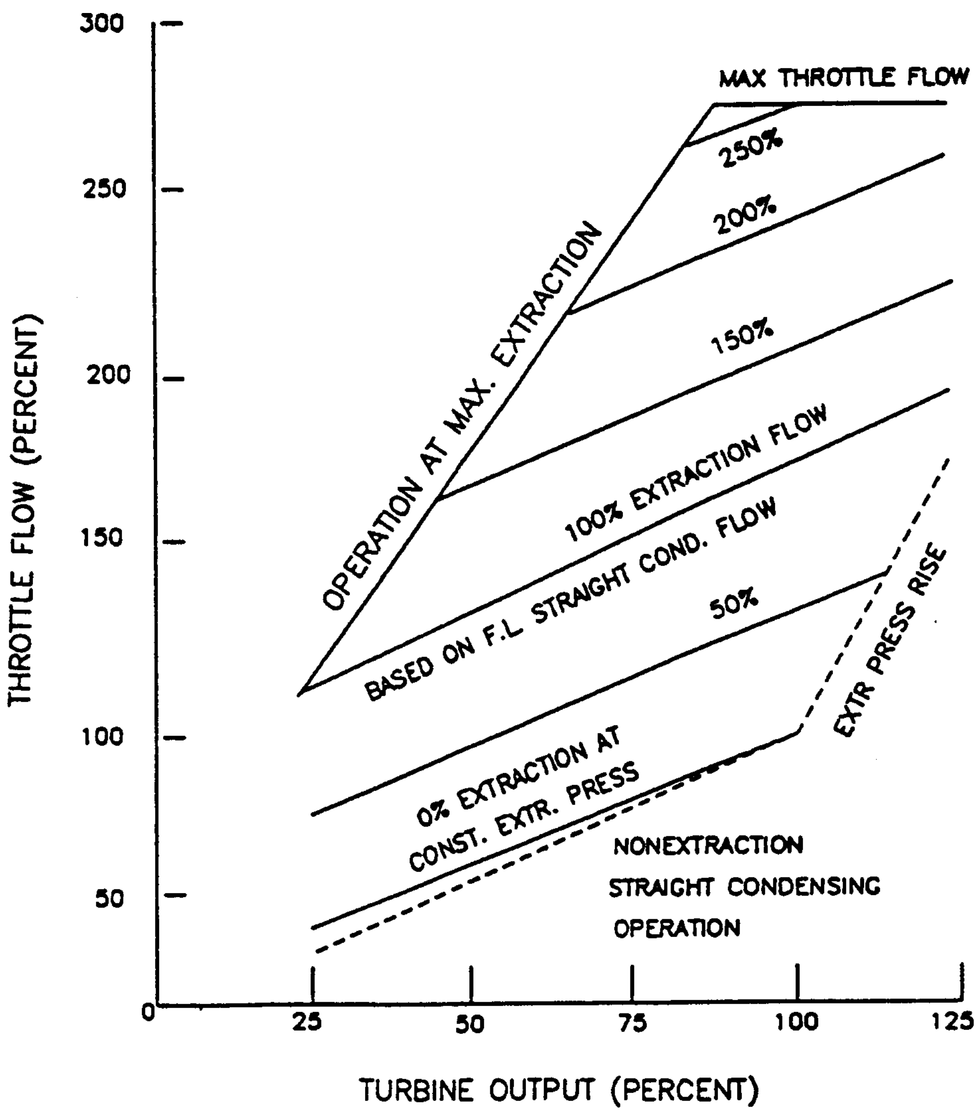


Figure 6: Steam Turbine performance map (Orlando 1996)

3.2 GAS TURBINE COGENERATION SYSTEMS

Gas turbines either in a simple cycle or in a combined cycle (Chapter 3.2) are the most frequently used technology in recent cogeneration systems of medium to high power. Their electric power output ranges from a few hundred kilowatts to several hundred megawatts. On the other side of the spectrum, recent research and development aims at the construction of micro turbines, which have a power output of a few kilowatts.

Gas turbines have been developed as either heavy-duty units for industrial and utility applications, or as lightweight, compact and efficient aircraft engines. These engines are modified for stationery applications, in which case they are called “aeroderivative turbines”. In general, they are capable of faster start-ups and rapid response to changing load. Both gas turbine designs have been successfully used for cogeneration having as main advantages low initial cost, high availability, fast and low-cost maintenance, fuel-switching capabilities, high quality heat which can easily be recovered, and high efficiencies in larger sizes. In addition, the commercial availability of packaged units helped in their widespread applications.

3.2.1 Gas Turbine Cycles

A gas turbine can operate either in open cycle or in a closed cycle.

3.2.1.1 Open-cycle gas turbine cogeneration systems

Most of the currently available gas turbine systems in any sector of applications operate on the open Brayton (also called Joule cycle when irreversibilities are ignored) (Figure 7): a compressor takes in air from the atmosphere and derives it at increased pressure to the combustor. The air temperature is also increased due to compression. Older and smaller units operate at a pressure ratio in the range of 15:1, while the newer and larger units operate at pressure ratios approaching 30:1.

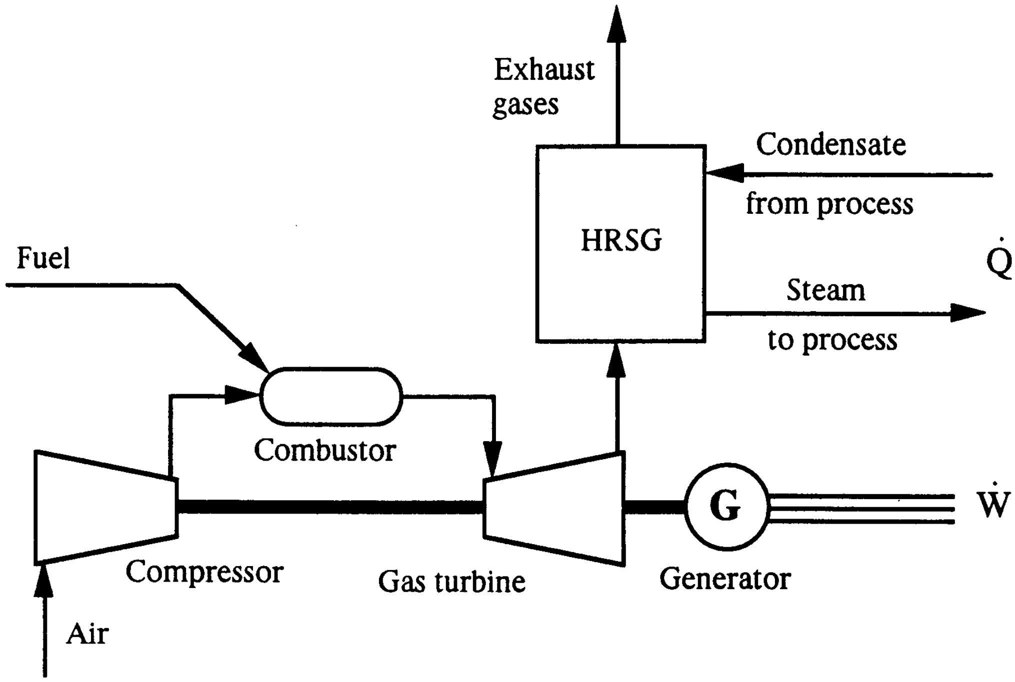


Figure 7: Cogeneration system with open-cycle gas turbine

The compressed air is delivered through a diffuser to a constant-pressure combustion chamber, where fuel is injected and burned. The diffuser reduces the air velocity to values acceptable in the combustor. There is a pressure drop across the combustor in the range of 1–2%. Combustion takes place with high excess air. The exhaust gases exit the combustor at high temperature and with oxygen concentrations of up to 15–16%. The highest temperature of the cycle appears at this point; the higher this temperature is, the higher the cycle efficiency is. The upper limit is placed by the temperature the materials of the gas turbine can withstand, as well as by the efficiency of the cooling blades; with the current technology it is about 1300°C.

The high pressure and temperature exhaust gases enter the gas turbine producing mechanical work to drive the compressor and the load (e.g. electric generator). The exhaust gases leave the turbine at a considerable temperature (450-600°C), which makes high-temperature heat recovery ideal. This is effected by a heat recovery boiler of single-pressure or double-pressure, for more efficient recovery of heat. Triple-pressure is also possible but not very usual, because it makes the system more complex and expensive, which is not always justified.

The steam produced can have high quality (i.e. high pressure and temperature), which makes it appropriate not only for thermal processes but also for driving a steam turbine thus producing additional power. In the latter case a combined cycle system is obtained, which is described in Chapter 3.4.

Instead of producing steam, the exhaust gases after the turbine can be used directly in certain thermal processes, such as high-temperature heating and drying.

In any of the aforementioned applications, it is possible to increase the energy content and temperature of the exhaust gases by supplementary firing. For this purpose, burners are installed in the exhaust gas boiler, which use additional fuel. Usually there is no need of additional air, since the oxygen content in the exhaust gases is significant, as mentioned above.

Cogeneration systems with open cycle gas turbines have an electrical power output usually in the range 100 kW–100 MW, not excluding values outside this range. A variety of fuels can be used: natural gas, light petroleum distillates (e.g. gas oil, Diesel oil), products of coal gasification. The use of heavier petroleum distillates (fuel oil) in mixtures with light ones is under investigation and it may prove successful. Also, non-commercial fuel gases, produced during the catalytic cracking of hydrocarbons in petroleum refineries, are used as fuels in gas turbines. However, attention has to be paid to the fact that the turbine blades are directly exposed to the exhaust gases. Consequently, the combustion products must not contain constituents causing corrosion (such as chemical compounds of sodium (Na), potassium (K), calcium (Ca), vanadium (Va), sulfur (S)) or erosion (solid particles larger than a certain size). In order to prevent these effects, there may be need of fuel treatment or exhaust gas treatment before they enter the turbine.

The installation time for gas turbine cogeneration systems of up to 7 MW_e is about 9–14 months, and it may reach two years for larger systems. The reliability and annual average availability of gas turbine systems burning natural gas are comparable to those of steam turbine systems. Systems burning liquid fuels or gaseous by-products of chemical processes may require more frequent inspection and maintenance, which results in lower availability. The life cycle is 15–20 years and it may be critically affected by a low quality fuel or poor maintenance.

3.2.1.2 Closed-cycle gas turbine cogeneration systems

In the closed-cycle system (Figure 8), the working fluid (usually helium or air) circulates in a closed circuit. It is heated in a heat exchanger before entering the turbine, and it is cooled down after the exit of the turbine releasing useful heat. Thus, the working fluid remains clean and it does not cause corrosion or erosion.

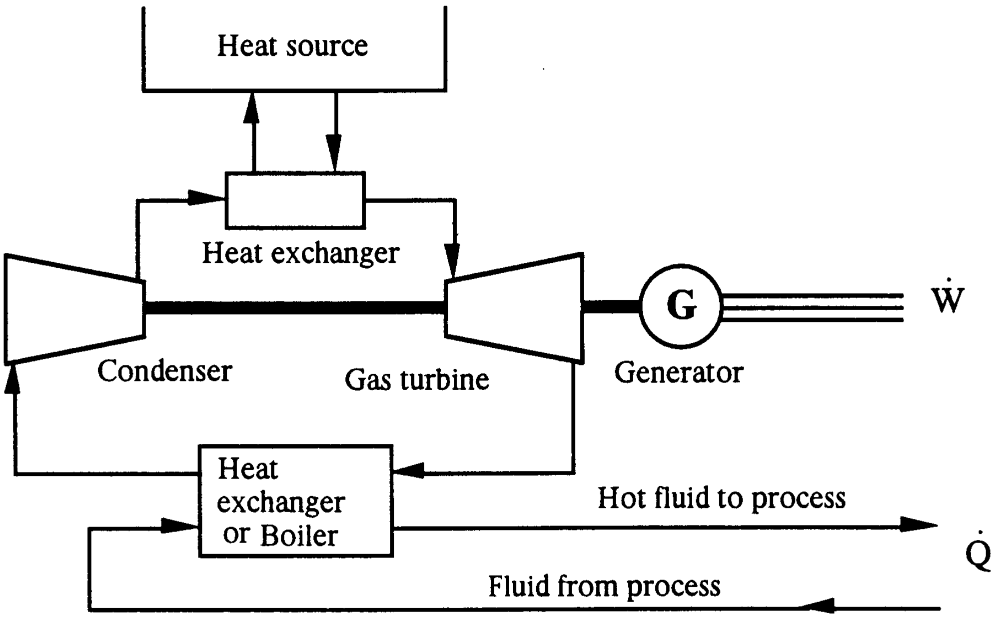


Figure 8: Cogeneration system with closed-cycle gas turbine

Source of heat can be the external combustion of any fuel, even city or industrial wastes. Also, nuclear energy or solar energy can be used.

Systems of this type with a power output of 2–50 MW_e operate in Europe and Japan, but their number is rather small.

After accumulation of experience, the reliability of closed-cycle systems is expected to be at least equal to that of open-cycle systems, while the availability is expected to be higher thanks to the clean working fluid.

3.2.2 Thermodynamic Performance of Gas Turbine Cogeneration Systems

3.2.2.1 Efficiency and PHR at rated power

The nominal electric efficiency (i.e. the efficiency at rated power) of small to medium gas turbine systems is usually in the range of 25–35%. Larger systems built recently have reached electric efficiencies of 40–42% by means of high temperature of exhaust gases at the turbine inlet (1200-1400°C). The total efficiency is typically in the range of 60–80%. The power to heat ratio (PHR) is in the range 0.5–0.8.

A significant portion of the turbine power output, often exceeding 50%, is consumed to drive the compressor, thus resulting in a relatively low electric efficiency (e.g. in comparison to a reciprocating engine of similar power). In cases of high pressure ratios, intercooling of the air at an intermediate stage of compression can be applied, which reduces the work required for compression. A significant increase in electric efficiency is also achieved by regenerative air preheating, i.e. preheating of air with exhaust gases. In such a case the recoverable heat from the exhaust gases after the regenerative heat exchanger decreases and the value of PHR increases. In the case of cogeneration, as well as for combined gas-steam cycles, the addition of a regenerative air preheater is not justified.

The maximum recoverable heat depends on the minimum temperature acceptable in the exhaust gases. If the fuel contains sulphur, the exhaust gas temperature can not be lower than 140-165°C, in order to avoid the sulphuric acid dew point. If the fuel is practically free of sulphur, as is the case with natural gas, the exhaust gas temperature can be as low as 90-100°C.

3.2.2.2 Effect of ambient conditions and partial load on power output and efficiency of gas turbine systems

Air enters the compressor at ambient conditions. This initial temperature and density of air dictate the amount of work required for compression, the fuel that can be burned, the fuel required to achieve a specified turbine inlet temperature. As a result, the net power output, the efficiency, the exhaust gas flow rate and temperature at the turbine exit (consequently the recoverable heat) are functions of the ambient conditions, which are far from weak.

Manufacturers normally specify the capacity (power output) and performance of a gas turbine at ISO standard conditions: 15°C, 60% relative humidity, at sea level. In addition, the performance is typically specified without pressure losses in the inlet and exhaust ducts. The effect of these losses for typical single-shaft turbines is illustrated in Figure 9:

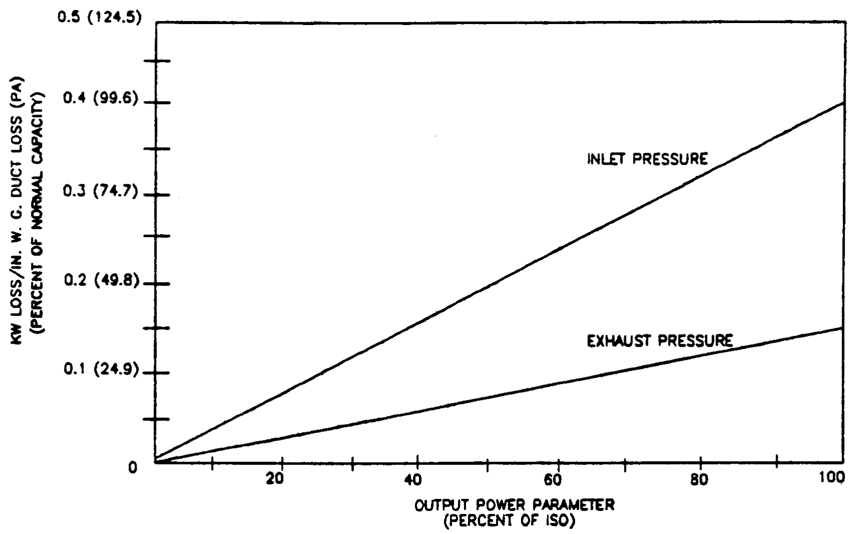


Figure 9: Effect of inlet and exhaust duct pressure losses on gas turbine capacity (Orlando 1996)

The capacity of the turbine decreases as ambient temperature or altitude increases. The capacity may decrease by about 2–4% for each 300 m increase in altitude. Partial load has a strong effect on efficiency: decreasing load causes a decrease in electrical efficiency. Figure 10 gives an example of performance map showing the relationship between ambient temperature, capacity, fuel energy required, and load. Alternatively, graphs such as those in Figure 11 - Figure 13 can be provided. As with the steam turbines, it is necessary to consult the manufacturer for performance maps or graphs of each particular gas turbine.

If a gas turbine system is to operate over long periods of time in an environment of high temperature, precooling of the inlet air may be economically feasible. Mechanical, evaporative or absorption chillers may be used; the final choice will be dictated by a feasibility study. It is interesting to note that absorption chillers may operate with turbine exhaust gas heat as the main source of energy.

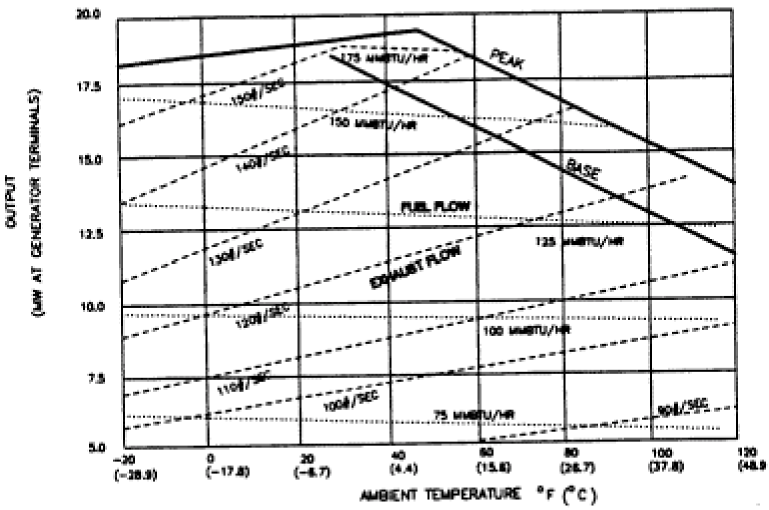


Figure 10: Gas turbine performance map (Orlando 1996)

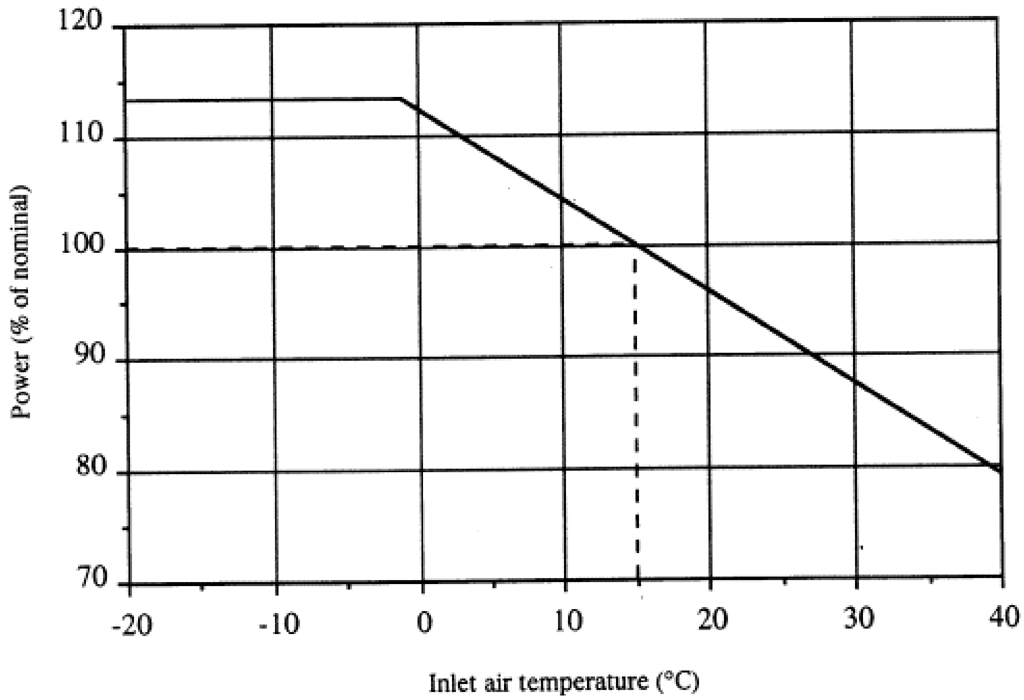


Figure 11: Effect of inlet air temperature on the power output of a gas turbine

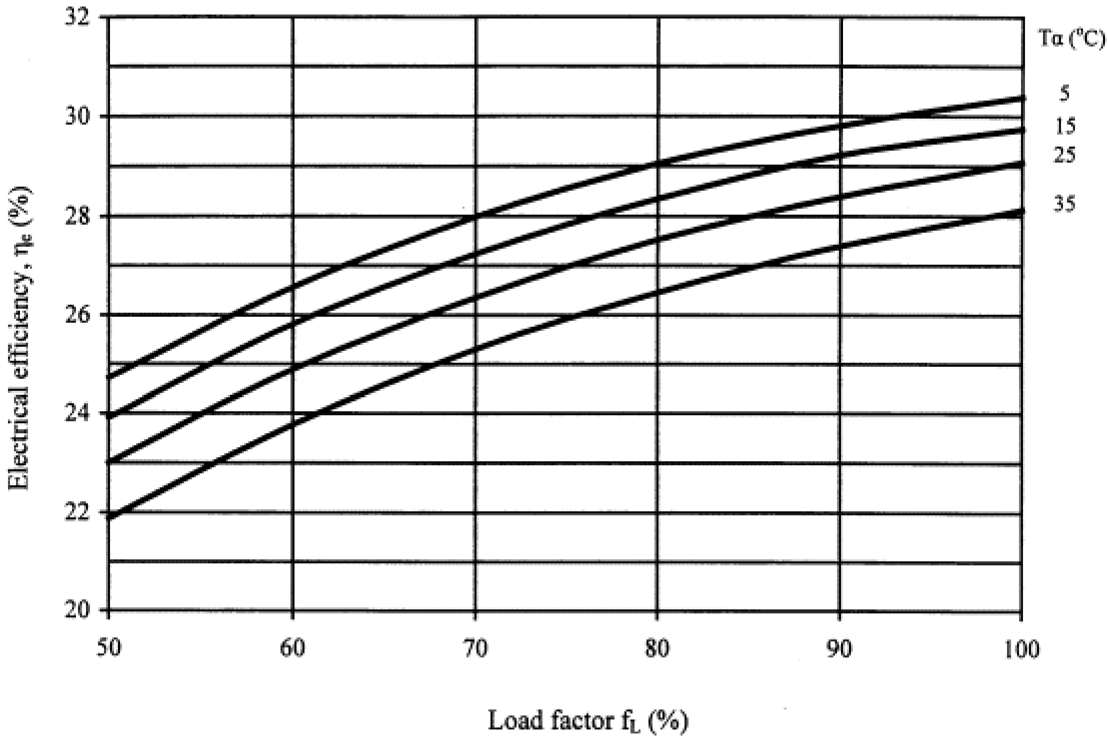


Figure 12: Effect of load and inlet air temperature on the electric efficiency of a gas turbine system

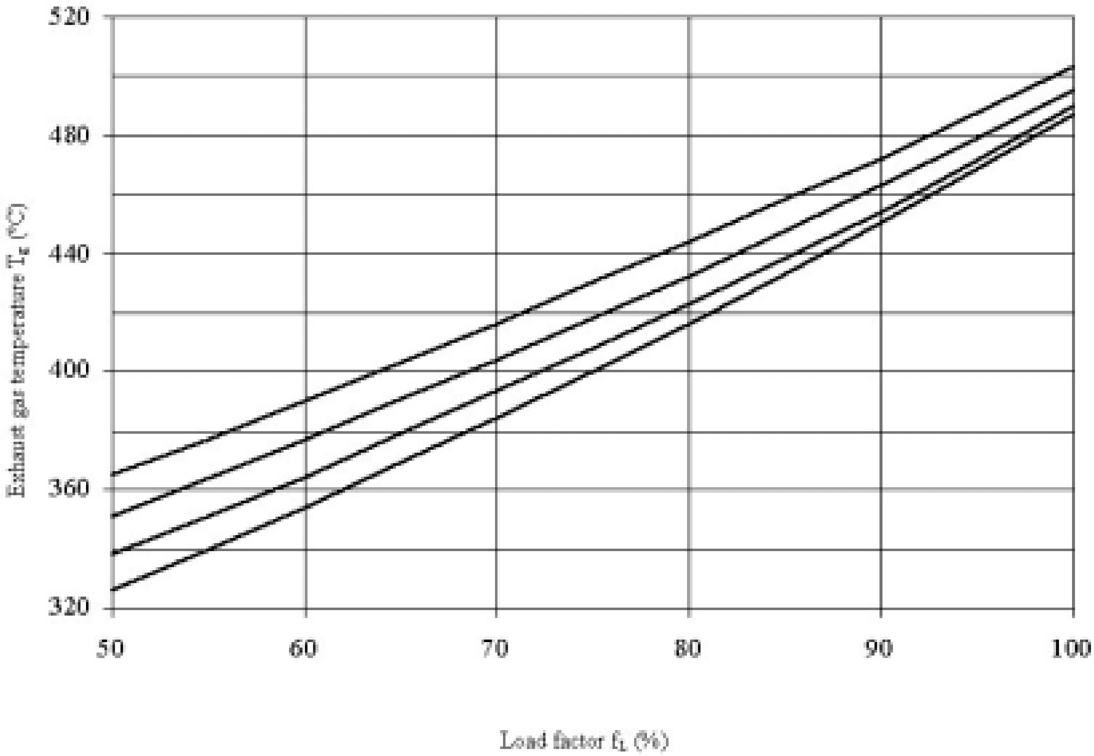


Figure 13: Effect of load and inlet air temperature on gas turbine exhaust gas temperature.

3.3 RECIPROCATING INTERNAL COMBUSTION ENGINE COGENERATION SYSTEMS

Reciprocating internal combustion engines have high efficiencies, even in small sizes. They are available in a variety of sizes in a broad range (75 kW–50 MW). They can use a broad variety of gaseous and liquid fuels, and have good availability (80–90%). These characteristics have made them the first choice, up to now, for cogeneration applications in the institutional, commercial and residential sector, as well as in the industrial sector when low to medium voltage is required.

3.3.1 Types of Reciprocating Internal Combustion Engine Cogeneration Systems

One way to classify the systems is based on the internal combustion engine cycle: Otto cycle and Diesel cycle. In an Otto engine, a mixture of air and fuel is compressed in each cylinder and the ignition is caused by an externally supplied spark. In a Diesel engine, only air is compressed in the cylinder and the fuel, which is injected in the cylinder towards the end of the compression stroke, ignites spontaneously due to the high temperature of the compressed air.

Otto engines can operate on a broad range of fuels such as gasoline, natural gas, propane, sewage plant gas, landfill methane. They are often called “gas engines”, if they use gaseous fuel. Diesel engines operate on higher pressure and temperature levels, and for this reason heavier fuels are used: Diesel oil, fuel oil and, in large two-stroke engines, residual fuel oil.

Another classification of the cogeneration system is based on the size of the engine:

a) Small units with a gas engine (15–1000 kW) or Diesel engine (75–1000 kW).

b) Medium power systems (1–6 MW) with gas engine or Diesel engine.

c) High power systems (higher than 6 MW) with Diesel engine.

Gas engines of the following types are commercially available.

a) Gasoline engines of cars, converted to gas engines. Usually, they are small engines (15–30kW), light, with high power to weight ratio. The conversion has a rather small effect on efficiency, but it decreases the power output by about 18%. Mass production results in low cost of the engines, but their life cycle is relatively short (10000–30000 hours).

b) Diesel engines of cars, converted to gas engines. Their power is up to about 200 kW. Conversion is necessary on pistons, cylinder heads and valve mechanism, which are imposed by the fact that ignition will be effected not by compression only but by a spark. Conversion usually does not cause power reduction, because it is possible to adjust the excess air properly.

c) Stationary engines converted to gas engines or originally designed and built as gas engines. They are heavy duty engines manufactured for industrial or marine applications. The power output reaches 3000 kW. Their robustness increases the initial cost, but reduces maintenance needs and prolongs the life cycle (15–20 years). They are capable of running continuously at high load.

d) Dual-fuel stationary engines. They are Diesel engines with a power output of up to 6000 kW. Natural gas is the main fuel, which is ignited not by a spark, but by injection of Diesel oil towards the end of the compression stroke. Of the total fuel energy required, about 90% is provided by the natural gas and 10% by the Diesel oil. They also can have the capability to operate either with the aforementioned dual fuel or with Diesel oil only, which, of course, increases the capital and maintenance cost.

Regarding fuels of gas engines, landfill gas and sewage gas are of particular importance as a means not only of resource utilisation but also of environmental protection. Both landfill gas and sewage gas are very well suited for the operation of gas engines, since the knock-resistant methane and the high content in CO_2 permit a methane number of over 130. Another opportunity to utilise the energy potential of waste is through the process of pyrolysis (decomposition of substances by heat). The resultant pyrolysis gas can be used in a gas engine.

One of the most important properties regarding the use of gas in a gas engine is its knock resistance. This is rated according to the methane number. Highly knock-resistant methane has a methane number of 100. In contrast to this, butane has a methane number of 10 and hydrogen with a methane number of 0 lies at the bottom of the scale (Table 1).

Table 1: Methane number of gaseous fuels

Fuel		**Methane** number
Name	Composition	
Hydrogen	H_2	0
Methane	CH_4	100
Ethylene	C_2H_4	15
Ethane	C_2H_6	43.7
Propylene	C_3H_6	18.6
Propane	C_3H_5	33
Butane	C_4H_{10}	10
Carbon monoxide	CO	75
Natural gas (Typical)	CH_4 88.5 % C_2H_6 4.7 % C_3H_6 1.6 % C_4H_{10} 0.2 % N_2 5.0 %	72-98
Sewage gas	CH_4 65 % CO_2 35 %	134
Landfill gas	CH_4 50 % CO_2 40 % N_2 10 %	136

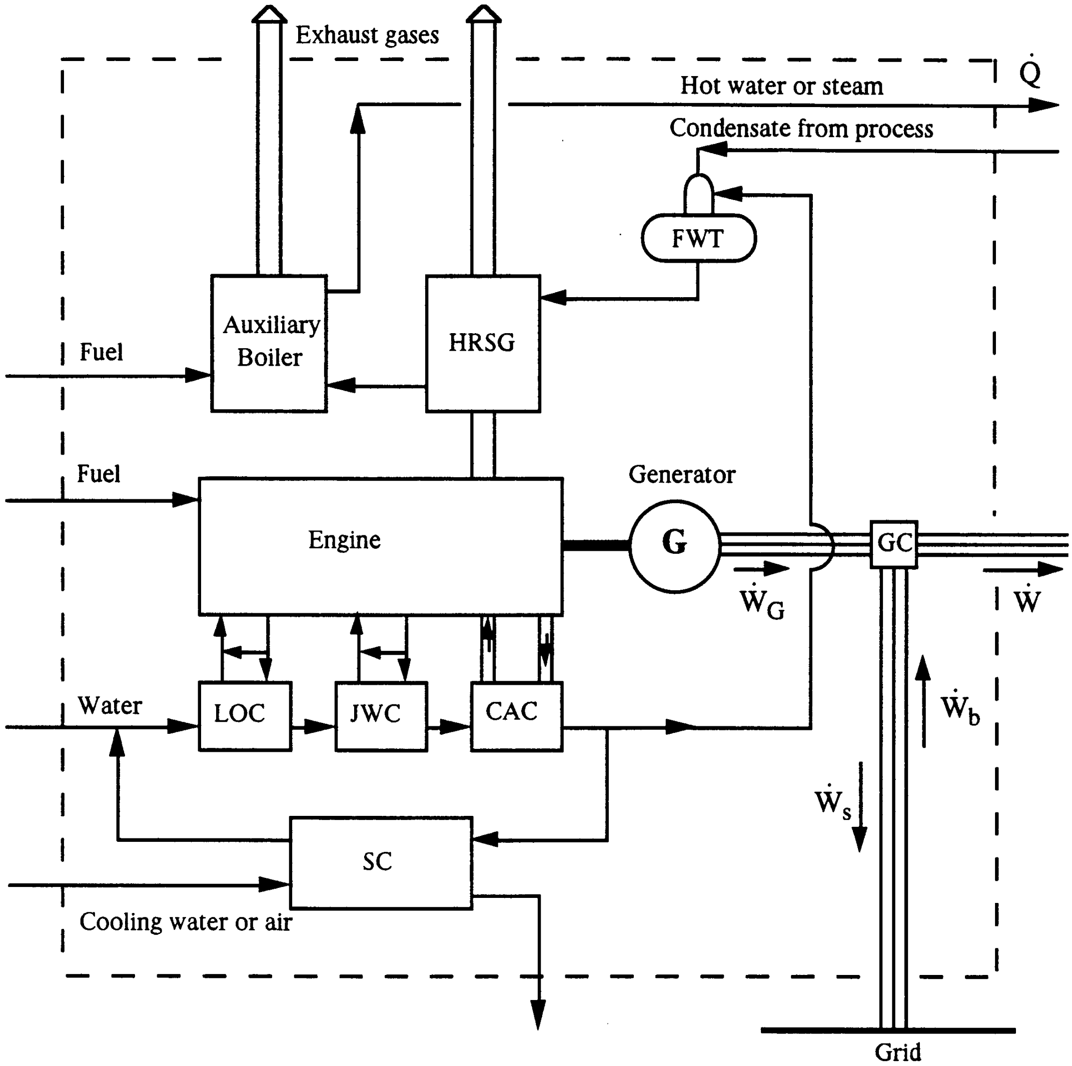
Diesel engines are classified as high-speed, medium-speed and low-speed engines. Table 2 gives the speed and power ranges for each type; the limits are not meant to be absolutely strict.

Table 2: Speed and power range of Diesel engines.

Type	Speed (RPM)	Power (kW)
High-speed	1200 – 3600	75 – 1500
Medium-speed	500 – 1200	500 – 15000
Low-speed	100 – 180	2000 – 50000

As with the gas turbines, exhaust gases of reciprocating internal combustion engines can be used either directly in thermal processes or indirectly, e.g. through a heat recovery boiler. Their temperature is in the range of 300-400°C, i.e. significantly lower than that of gas turbines. This is why additional heating may more often be necessary with these engines. It can be obtained either by supplementary firing in the exhaust gas boiler (supply of air is necessary, because there is no significant oxygen content in the exhaust gases) or by an auxiliary boiler. Large engines may make the combined cycle economically feasible (see chapter 3.4).

Figure 14 illustrates a more or less all-inclusive flow diagram of such a system, without being the only possible configuration (in particular with respect to the arrangement of heat exchangers). The engine drives the generator. Four heat exchangers recover heat from fluids necessary for the operation of the engine: lubricating oil cooler, jacket water cooler (closed circuit of the engine), charge air cooler, and exhaust gas heat exchanger (or boiler). The recovered heat produces hot water and steam, as in Figure 14, or it may be used for other thermal processes. In small engines, the available heat may not be sufficient to make steam production feasible; in such a case only hot water is delivered. On the other hand, in a naturally aspirated engine there is no charge air cooler.



LOC: lubricating oil cooler
JWC: jacket water cooler
CAC: charge air cooler

SC : supplementary cooler
FWT : feedwater tank
GC : grid connection

Figure 14: Flow diagram of a cogeneration system with reciprocating internal combustion engine

With heat recovery from the three coolers, water is heated up to 75-80°C. The pre-heated water enters the exhaust gas heat exchanger where it is heated up to 85-95°C, or it is evaporated. Medium size engines usually produce saturated steam of 180-200°C, while large units can deliver superheated steam at pressure 15–20 bar and temperature 250-350°C. The minimum exhaust gas temperature at the exit of the heat exchanger is 160- 170°C for fuels containing sulphur, like Diesel oil, or 90-100°C for sulphur-free fuels like natural gas.

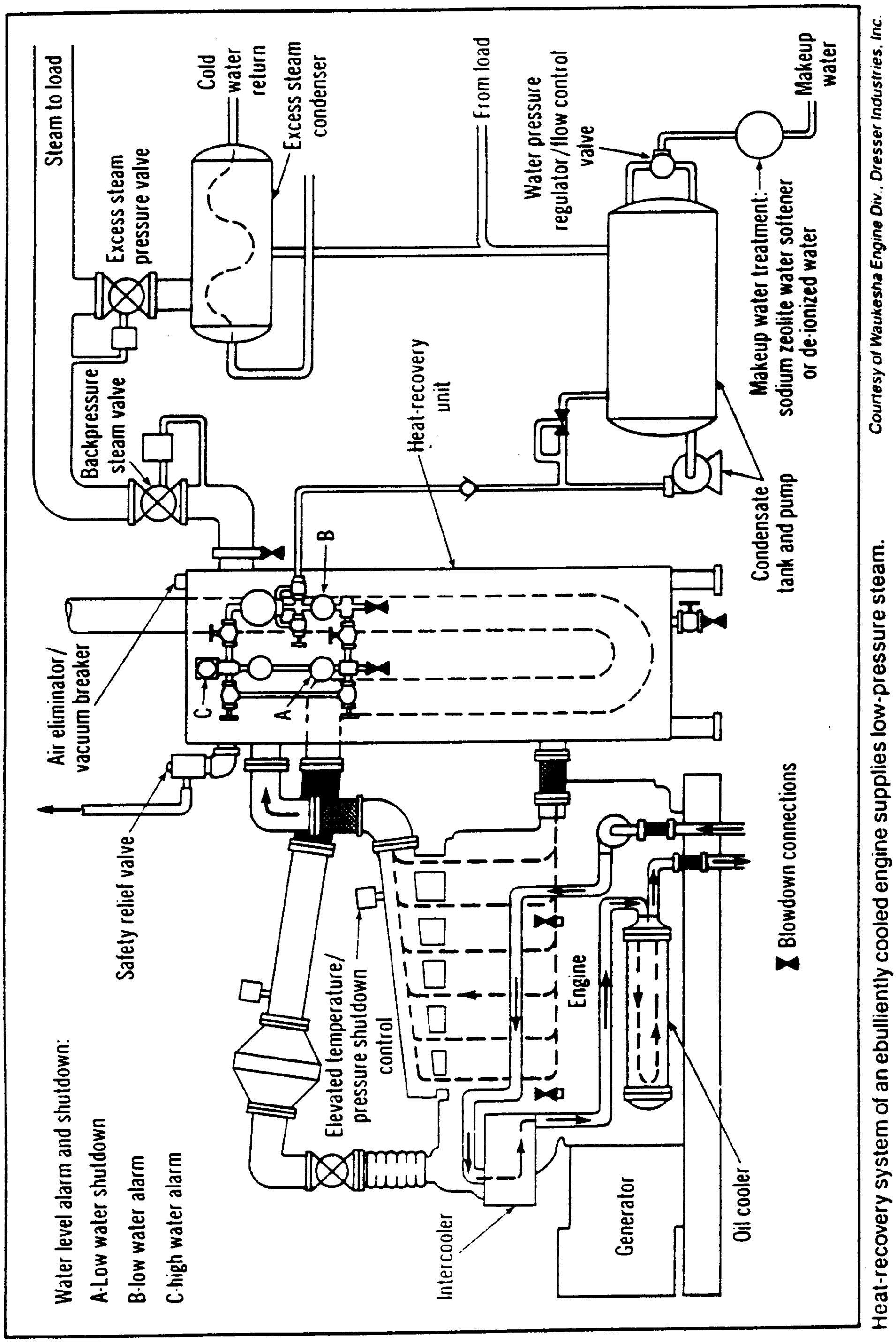


Figure 15: Cogeneration with ebulliently cooled engine (courtesy from Waukesha)

A particular type of cylinder cooling is the ebullient cooling. In an ebulliently cooled engine, the coolant (e.g. water) enters the engine as a pressurised liquid at its boiling point. It absorbs heat from the engine and changes phase (evaporates). Not all of the coolant changes phase. Therefore, heat transfer from the engine to the coolant occurs at a constant temperature, which causes lower thermal stress to the engine. The coolant in the engine, which is a mixture of liquid and vapour, has a lower density than the coolant that enters the engine, and consequently it rises to the top of the engine. After exiting the engine, the mixture enters a steam separator, where steam is separated from the mixture to serve the thermal process. A system with ebulliently cooled engine is illustrated in Figure 15. As an alternative to ebullient cooling, a forced-circulation system operating at higher than usual pressure and temperature in the range of 120-130°C can produce low-pressure steam.

Supercharging increases the power output for the same size of engine. Usually supercharging is effected by a turbocharger (there may be more than one in large engines): a gas turbine operates by the exhaust gases of the engine and drives an air compressor. The air temperature at the exit of the compressor is high (120-140°C) and its density low. In order to increase the mass of air in the cylinder (and consequently the mass of fuel and the power of the engine) it is necessary to cool the air before its entrance to the cylinders. There are two typical levels of air temperature at the exit of the cooler: low temperature (about 45°C), and high temperature (about 90°C).

Low temperature results in higher power output, but the recovered heat is of restricted use, because the water temperature at the cooler exit is low (30-35°C). Such a temperature level can be selected if there is need of preheating feedwater coming at a temperature of 10-25°C. However, if water enters the system at a temperature of 60-70°C, as is the case with central heating networks of buildings, then the high temperature level may be preferable, because it increases the total efficiency of the cogeneration system by 3–5%. The temperature level also affects the positioning of the air cooler relative to the other coolers along the water path. This is one of the reasons why the arrangement illustrated in Figure 14 is not the only possible.

3.3.2 Thermodynamic Performance of Cogeneration Systems with Reciprocating Internal Combustion Engine

3.3.2.1 Efficiency and PHR at rated power

Small and medium size engines have an electric efficiency of 35–45%, while modern large engines (tens of megawatts) achieve efficiencies at the order of 50%. The total efficiency of the cogeneration system is in the range of 70–85%. The power to heat ratio is in the range of 0.8–2.4, the highest of the three systems examined up to this point.

3.3.2.2 Effect of ambient conditions, quality of fuel and partial load on the performance of the systems

Reciprocating internal combustion engines are less sensitive than gas turbines in changes of ambient conditions or load.

Naturally aspirated engine power decreases by about 3% for each 300 m increase in altitude. For turbocharged engines, the effect of altitude depends on the individual manufacturer’s design. In some cases a decrease of power by about 2% for each 300 m increase in altitude is reported, but in other cases no decrease is noticeable at altitudes up to 1500 m.

The power output decreases by about 1% per 5.5°C increase in ambient temperature. The use of heated air should be avoided.

Engine specifications are given for a certain type and heating value of fuel. For the same type of fuel, the power output is, to a first approximation, proportional to the fuel heating value.

Reciprocating internal combustion engines maintain their efficiency over a wide range of operating loads. Manufacturers give partial load performance in the form of either tables or graphs. Examples are given in Table 3 and the following figures.

Table 3: Examples of partial load performance of gas-engine cogeneration units.

Nominal shaft power	kW	827			1500		
Load	%	100	75	50	100	75	50
Electric power	kW_e	803	601	398	1464	1092	724
Thermal power	kW_{th}	1018	800	578	1536	1245	935
Heat sources:							
Supercharging air cooler	%	5.9	3.2	0.2	7.4	5.1	2.7
Lubricating oil cooler	%	4.4	4.9	6.0	5.2	6.0	7.6
Jacket water cooler	%	13.8	17.3	21.0	8.8	10.9	12.7
Exhaust gases	%	25.0	24.6	24.2	22.2	23.4	24.7
Thermal efficiency	%	49.1	50.0	51.4	43.6	45.4	47.7
Electrical efficiency	%	37.6	37.6	35.3	41.5	39.8	36.9
Total efficiency	%	86.7	87.6	86.7	85.1	85.2	84.6
Water temperature:							
supply	°C	90	87	83	90	86	82
return	°C	70	70	70	70	70	70

Data are valid under the following conditions:

Fuel: natural gas with lower heating value H_u=34.200 kJ/Nm^3

Maximum jacket water temperature 90°C

Cooling of exhaust gases down to 120°C

Useful heat supplied in the form of hot water.

Uncertainty in values of thermal power ±8%.

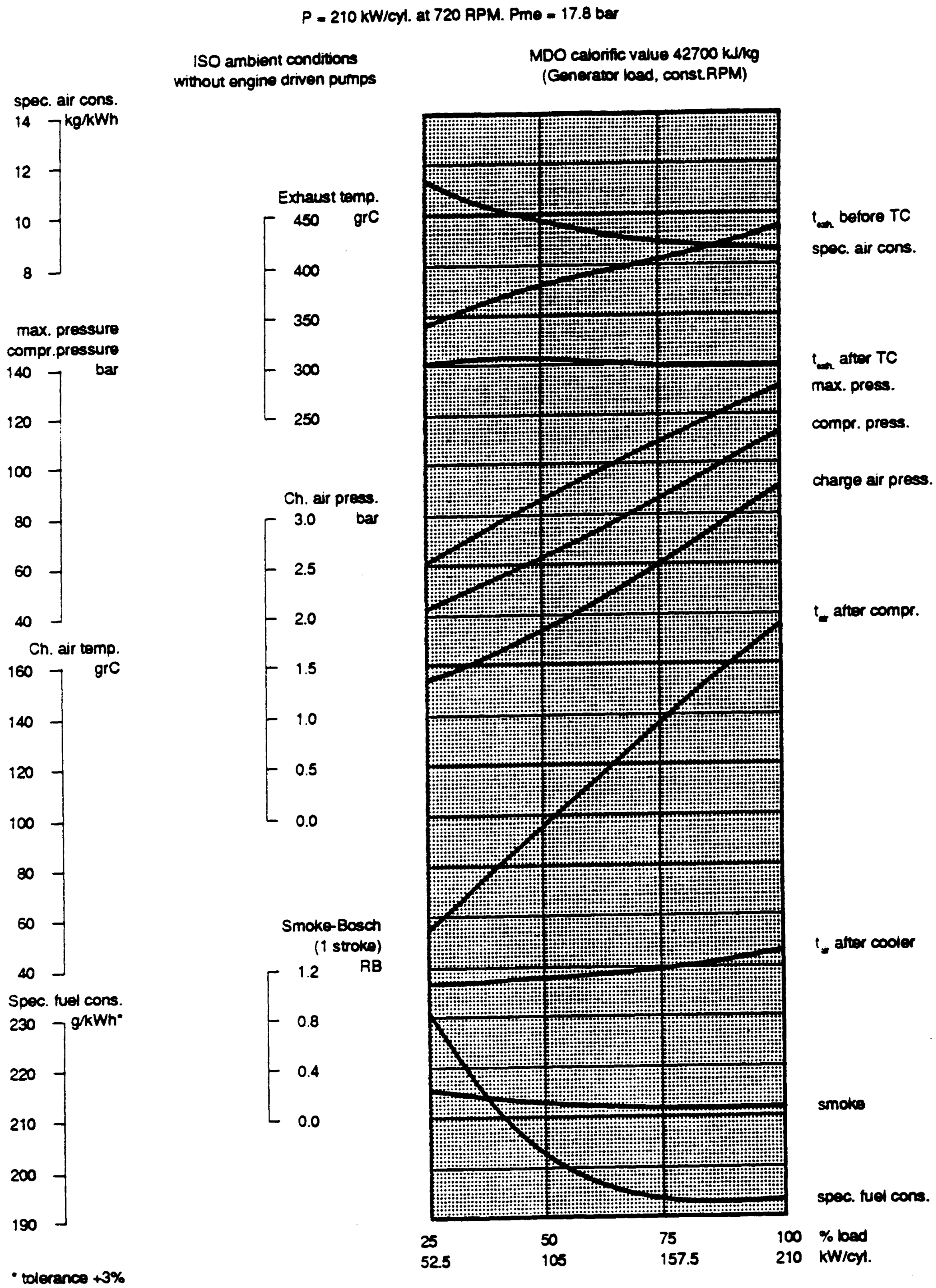


Figure 16: Performance curve of reciprocating internal combustion engine

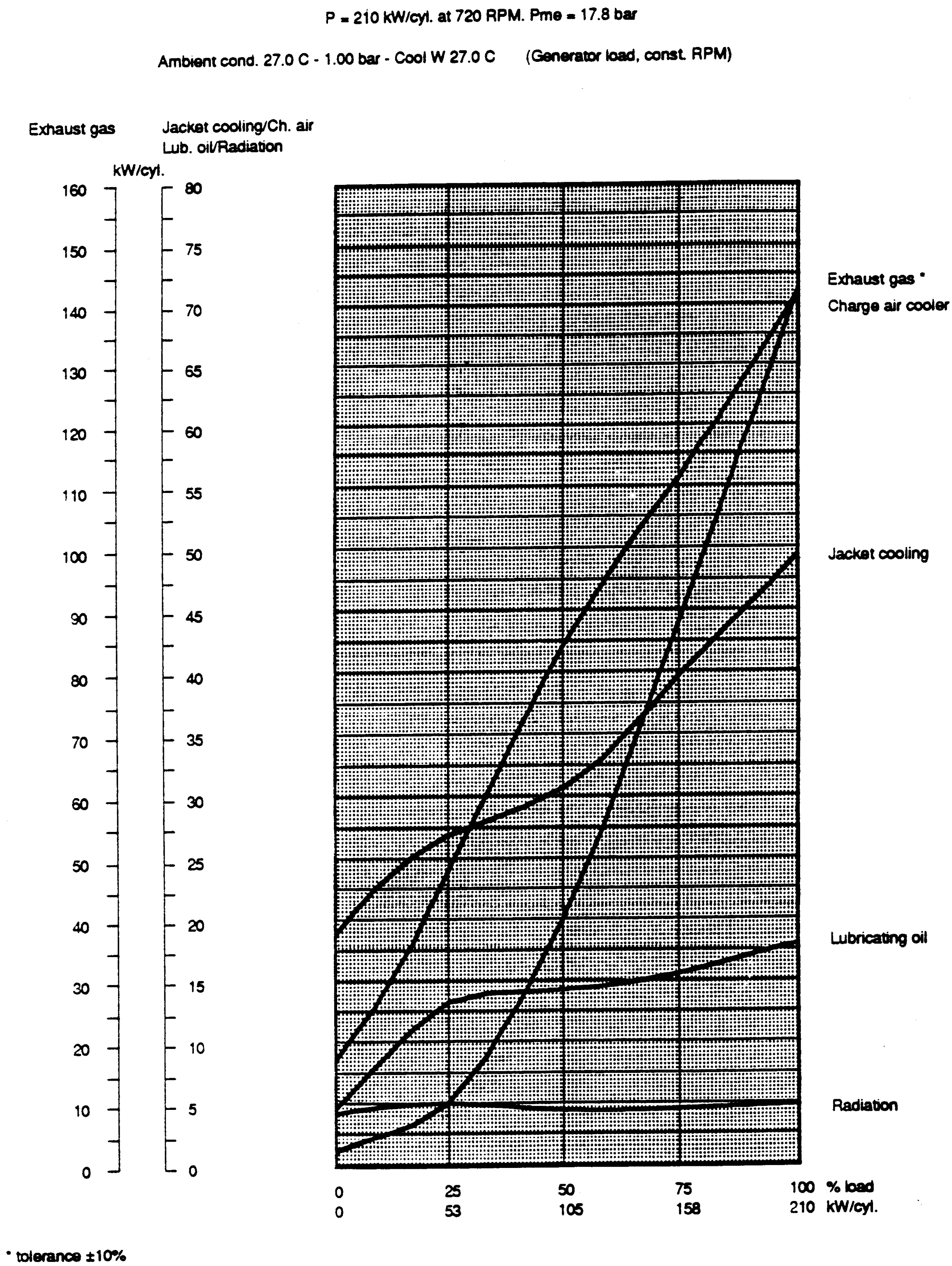


Figure 17: Heat balance of reciprocating internal combustion engine

3.4 COMBINED CYCLE COGENERATION SYSTEMS

The term "combined cycle" is used for systems consisting of two thermodynamic cycles, which are connected with a working fluid and operate at different temperature levels. The high temperature cycle (topping cycle) rejects heat, which is recovered and used by the low temperature cycle (bottoming cycle) to produce additional electrical (or mechanical) energy, thus increasing the electrical efficiency.

3.4.1 Combined Joule – Rankine Cycle Systems

The most widely used combined cycle systems are those of gas turbine – steam turbine (combined Joule – Rankine cycle). They so much outnumber other combined cycles that the term "combined cycle", if nothing else is specified, means combined Joule – Rankine cycle. A simplified diagram of such a system with the main components only is given in Figure 18, while Figure 19 illustrates in more detail a system with a double-pressure boiler and gives its performance characteristics. Double- or triple-pressure steam boilers enhance the heat recovery and increase the efficiency, but make the system more complex; they are used in large systems.

In Figure 18, the steam turbine is a backpressure one. Of course this is not the only configuration. Condensing turbine is also possible, while extraction can also be used with either the backpressure or the condensing turbine.

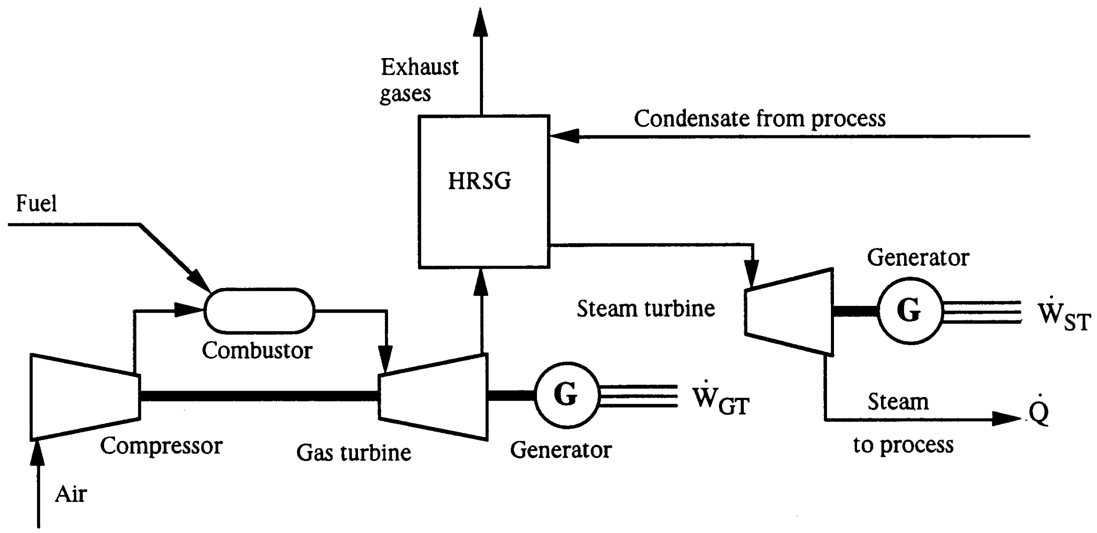


Figure 18: Joule-Rankine combined cycle cogeneration system with back pressure steam turbine

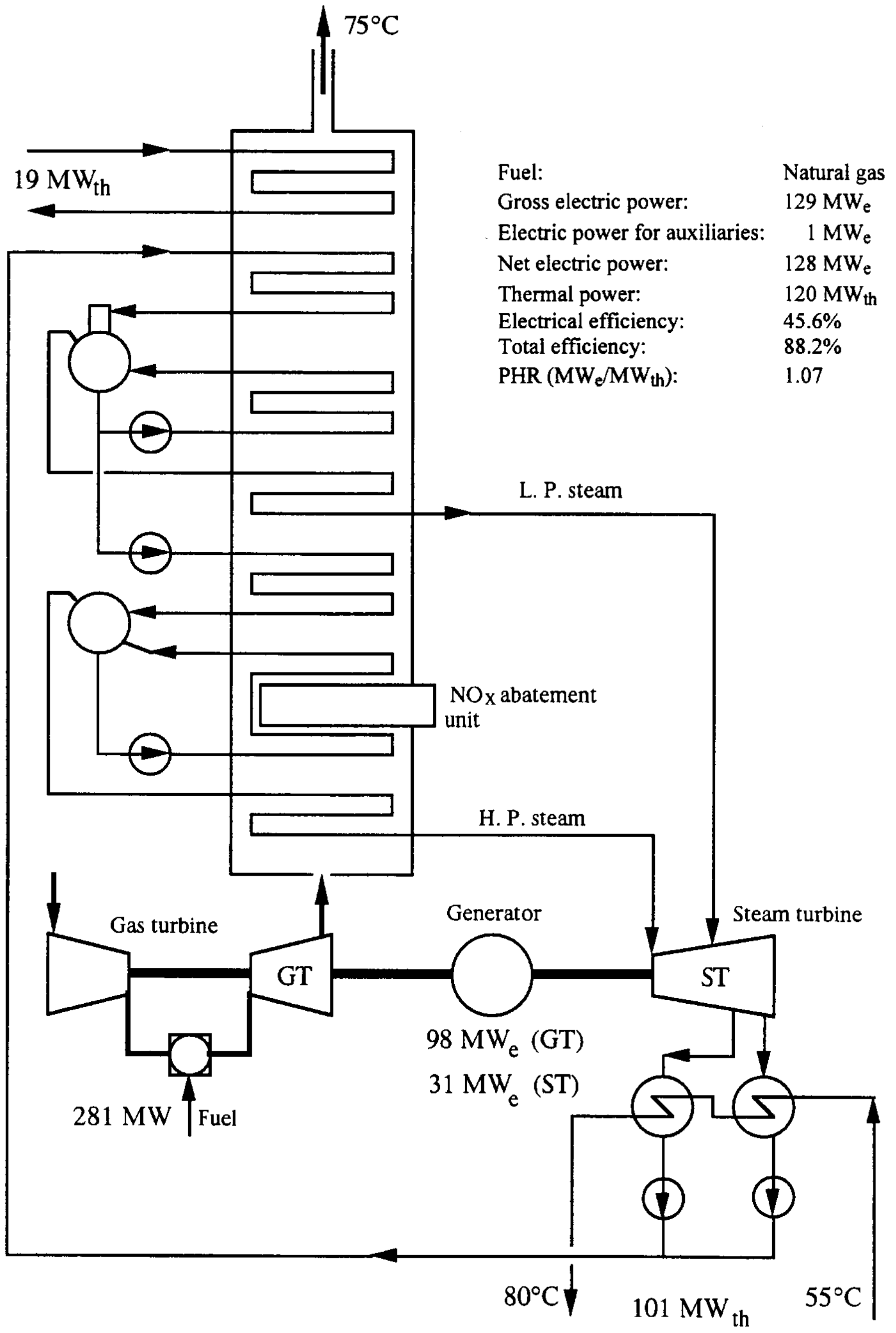


Figure 19: ASEA STAL combined cycle system with extraction / condensing steam turbine (IEA, 1988)

The maximum possible steam temperature with no supplementary firing is by 25-40°C lower than the exhaust gas temperature at the exit of the gas turbine, while the steam pressure can reach 80 bar. If higher temperature and pressure is required, then an exhaust gas boiler with burner(s) is used for firing supplementary fuel. Usually there is no need of supplementary air, because the exhaust gases contain oxygen at a concentration of 15–16%. With supplementary firing, steam temperature can approach 540°C and pressure can exceed 100 bar. Supplementary firing not only increases the capacity of the system but also improves its partial load efficiency.

Initially, combined cycle systems were constructed with medium and high power output (20–400 MW). During the last years, also smaller systems (4–15 MW) have started being constructed, while there is a tendency to further decrease the power limit. The power concentration (i.e. power per unit volume) of the combined cycle systems is higher than the one of the simple gas turbine (Joule) or steam turbine (Rankine) cycle. Regarding the fuels used, those mentioned for gas turbines (Chapter 3.2) are valid also here.

The installation time is 2–3 years. It is important to note that the installation can be completed in two phases: the gas turbine subsystem is installed first, which can be ready for operation in 12–18 months. While this is in operation, the steam subsystem is installed.

The reliability of (Joule – Rankine) combined cycle systems is 80–85%, the annual average availability is 77–85% and the economic life cycle is 15–25 years.

The electric efficiency is in the range 35–45%, the total efficiency is 70-88% and the power to heat ratio is 0.6–2.0. The electric efficiency can be increased further; in fact, contemporary combined cycle systems producing electric power only (no heat to process) can have efficiencies approaching 60%. However, these systems do not qualify as cogeneration systems.

3.4.2 Combined Diesel – Rankine Cycle Systems

It is also possible to combine Diesel cycle with Rankine cycle. The arrangement is similar to that illustrated in Figure 18 or Figure 19, with the difference that the gas turbine unit (compressor – combustor – gas turbine) is replaced by a Diesel engine. Medium to high power engines may make the addition of the Rankine cycle economically feasible.

Supplementary firing in the exhaust gas boiler is also possible. Since the oxygen content in the exhaust gases of a Diesel engine is low, supply of additional air for the combustor in the boiler is necessary.

3.5 FUEL CELL COGENERATION SYSTEMS

A fuel cell is an electrochemical device, which converts the chemical energy of fuel into electricity directly, without intermediate stages of combustion and production of mechanical work.

The direct conversion of chemical energy of a fuel to electrical energy by a hydrogen-oxygen fuel cell was achieved for the first time in 1839 by Sir William Grove, in London. Since that time, the development of fuel cells has been one of the most difficult technological problems. Systematic research during the last 30–40 years has been fruitful and several pilot plants have been built and operated successfully. Certain types of fuel cells are available, although at high cost. Fuel cells are still considered as an emerging technology and very promising both for electricity generation and for cogeneration. Since it is not widely known yet, it is useful to present the basic principle here in brief.

3.5.1 Basic Operation Principle of Fuel Cells

In its basic form (Figure 20) a fuel cell operates as follows: hydrogen reacts with oxygen in the presence of an electrolyte and produces water, while at the same time an electrochemical potential is developed, which causes the flow of an electric current in the external circuit (load). The following electrochemical reactions take place on the two electrodes:

Anode: $$H_2 \rightarrow 2H^+ + 2e^- \quad (3.1)$$

Cathode: $$2H^+ + \frac{1}{2}O_2 + 2e^- \rightarrow H_2O \quad (3.2)$$

Thus, the total reaction is: $$H_2 + \frac{1}{2}O_2 \rightarrow H_2O \quad (3.3)$$

At the anode, ions and free electrons are produced. Ions move towards the cathode through the electrolyte. Electrons move towards the cathode through the external circuit, which includes the load (external resistance). The reaction is exothermic. The released heat can be used in thermal processes.

The required hydrogen is usually produced from hydrocarbons, most frequently natural gas, by a process known as *reforming*, which can be either external or internal to the fuel cell unit, depending on the type of the fuel cell (Chapter 3.5.2). Also, it can be produced by electrolysis of water. In certain types of fuel cells, carbon monoxide can be used as fuel, instead of hydrogen, as it is explained in Chapter 3.5.2.

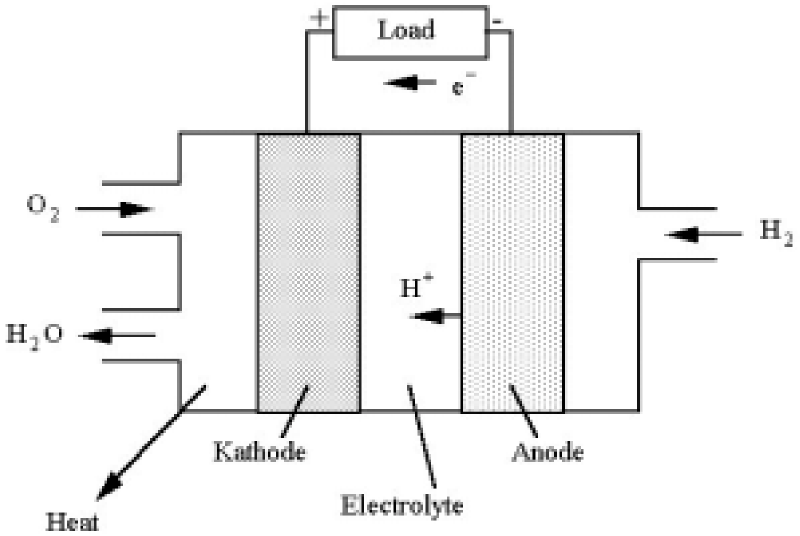


Figure 20: Basic principle of a hydrogen – oxygen fuel cell

A single cell develops an electric voltage slightly lower than 1 Volt. The proper number of cells connected in series produce the required voltage, while with parallel connection the required power is produced. Thus, a stack of cells is created. A direct current is produced; a (usually static) inverter is used to transform the direct current to alternating current of the appropriate voltage and frequency.

3.5.2 Types of Fuel Cells

Several classifications of fuel cells have appeared in the literature throughout the years. The most prevailing one is based on the type of the electrolyte.

3.5.2.1 Alkaline fuel cells (AFC)

Potassium hydroxide (KOH), which is the most conducting of all alkaline hydroxides, is the electrolyte, at a concentration around 30%. Pure hydrogen is the fuel and pure oxygen or air is the oxidiser. Alkaline fuel cells operate at a temperature 60-80°C. This is why they are characterised as low temperature fuel cells. The operating pressure in some cases is a few atmospheres, but most often it has been the atmospheric pressure.

Alkaline fuel cells have been used in NASA's Apollo mission. Today they are still used in space applications. Also they are one of the most attractive systems for transportation applications. Units with a power up to 100 kW have been constructed.

3.5.2.2 Polymer electrolyte fuel cells (PEFC)

They are also known with the initials PEM (Polymer Electrolyte Membranes). The electrolyte consists of a solid polymeric membrane, which is sandwiched between two platinum-catalysed porous electrodes. The operating temperature is around 80ºC and the operating pressure 1-8 atm. PEFC units with a power output up to 100 kW have been constructed.

3.5.2.3 Phosphoric acid fuel cells (PAFC)

PAFC is at the moment the most advanced fuel cell technology for terrestrial applications. Packaged units of 200-250 kW_e are already commercially available for electricity generation or cogeneration, while demonstration systems of 25 kW–11 MW have been constructed in Europe, USA and Japan.

Phosphoric acid (H_3PO_4) is the electrolyte. Hydrogen is produced by an external reformer from fuels such as natural gas or methanol. Air is the oxidiser. The operating temperature is around 200ºC, which makes PEFC's attractive for cogeneration applications, in particular in the tertiary sector.

3.5.2.4 Molten carbonate fuel cells (MCFC)

Molten alkali carbonate mixture, retained in a porous lithium aluminate matrix, is used as the electrolyte. The eutectic mixture consists of 68% Li_2CO_3 and 32% K_2CO_3, which at the operating temperature of 600-700ºC is at liquid phase. The fuel consists of a gaseous mixture of H_2, CO and CO_2, which is obtained with reforming of hydrocarbons such as natural gas, or with coal gasification. The high operating temperature makes internal reforming possible. For this purpose, the heat released by the fuel cell itself is used. The following reactions occur:

Anode:
$$H_2 + CO_3^{--} \rightarrow H_2O + CO_2 + 2e^- \quad (3.4)$$

$$CO + CO_3^{--} \rightarrow 2CO_2 + 2e^- \quad (3.5)$$

Cathode:
$$CO_2 + \frac{1}{2}O_2 + 2e^- \rightarrow CO_3^{--} \quad (3.6)$$

Total reaction:
$$H_2 + CO + O_2 \rightarrow H_2O + CO_2 \quad (3.7)$$

Carbonate ions are transferred through the electrolyte. In order to sustain the flow of ions, carbon dioxide is supplied continuously with air at a molar fraction of O_2/CO_2 equal to ½. This need increases the complexity of the system and the processes. However, there is no need of an external reformer: when, for example, natural gas is the fuel, catalysts are inserted in the pipes supplying the gas, which reform the preheated (with heat released by the system) fuel.

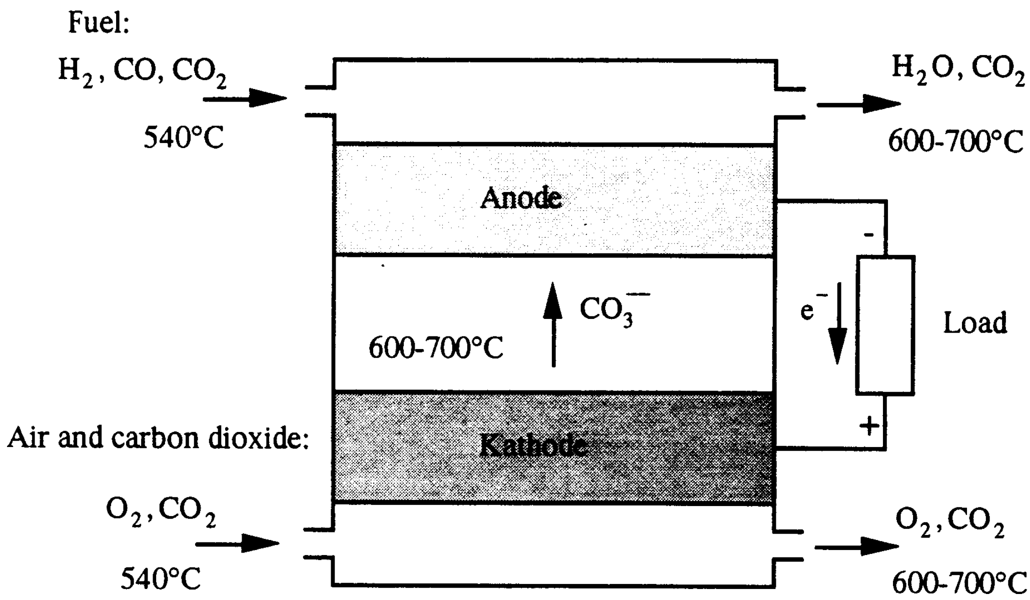


Figure 21: Basic principle of a molten carbonate fuel cell

MCFC's have good prospects for utility and industrial applications of medium to large size (at the order of MW). Efficiencies higher than 50% are expected. The high temperature available heat can be used either for thermal processes (cogeneration) or in a bottoming cycle for additional power production. Experimental units have been constructed, but the MCFC technology is still at the development phase.

3.5.2.5 Solid oxide fuel cells (SOFC)

The solid oxide fuel cell is an all-solid-state power system, which uses yttria-stabilised zirconia (Y_2O_3-ZrO_2), a ceramic material, as the electrolyte layer. It operates at temperatures of 950-1000 ºC. Pure hydrogen or a mixture of H_2 and CO is used as fuel, which is produced with internal reforming of hydrocarbons or with coal gasification.

When pure hydrogen is the fuel, the reactions are the following.

Anode: $$H_2 + O^{--} \rightarrow H_2O + 2e^- \quad (3.8)$$

Cathode: $$\frac{1}{2}O_2 + 2e^- \rightarrow O^{--} \quad (3.9)$$

Total reaction: $$H_2 + \frac{1}{2}O_2 \rightarrow H_2O \quad (3.10)$$

When a mixture of H_2 and CO is used as fuel, the reactions are the following.

Anode: $$CO + O^{--} \rightarrow CO_2 + 2e^- \quad (3.11)$$

Cathode: $$\frac{1}{2}O_2 + 2e^- \rightarrow O^{--} \quad (3.12)$$

Total reaction: $$CO + \frac{1}{2}O_2 \rightarrow CO_2 \quad (3.13)$$

In the case of SOFC, CO_2 does not re-circulate from the anode to the cathode.

SOFC's also have good prospects for utility and industrial applications of medium to large size (at the order of MW) with efficiencies higher than 50%. The system provides high quality waste heat, which is ideal for cogeneration or for additional power production by a bottoming cycle. It is envisaged that units at the order of tens of megawatts can be combined with a gas turbine – steam turbine combined cycle: hot gases exiting the cell stack will drive a gas turbine. After the exit from the gas turbine they will pass through an exhaust gas boiler producing steam for thermal processes or for additional power production by a steam turbine. Conceptual applications of this type are illustrated in Figure 22 and Figure 23.

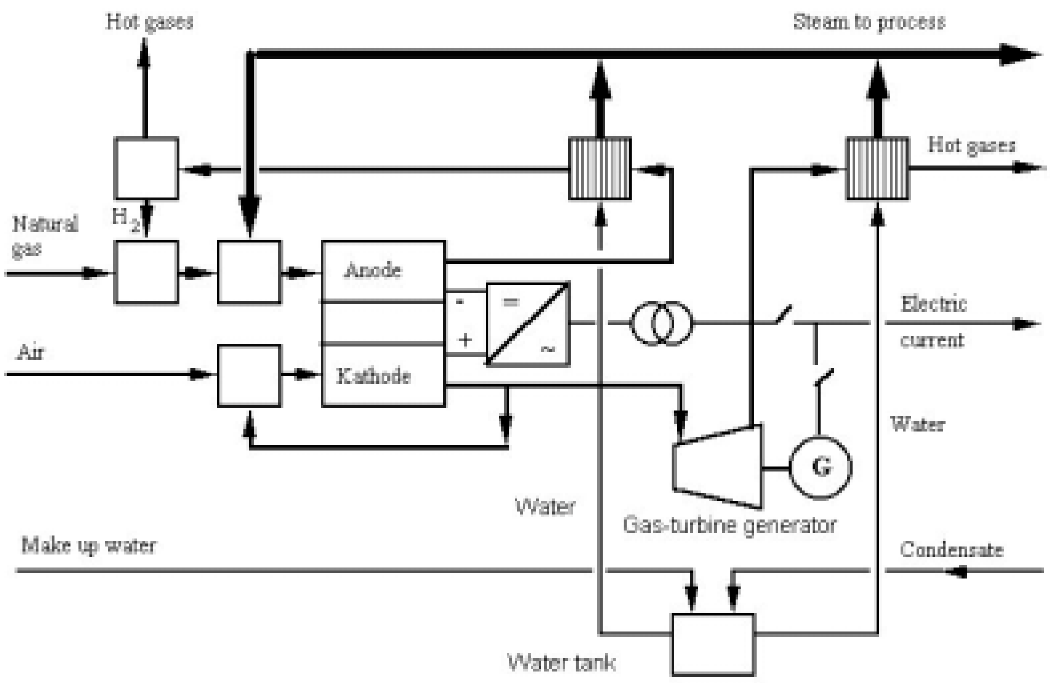


Figure 22: Cogeneration system with solid oxide fuel cell for applications in the tertiary sector[1]

[1] Figure 22 and Figure 23 are based on concepts presented in [Drenckan, Lezuo and Reiter, 1990], with some modifications.

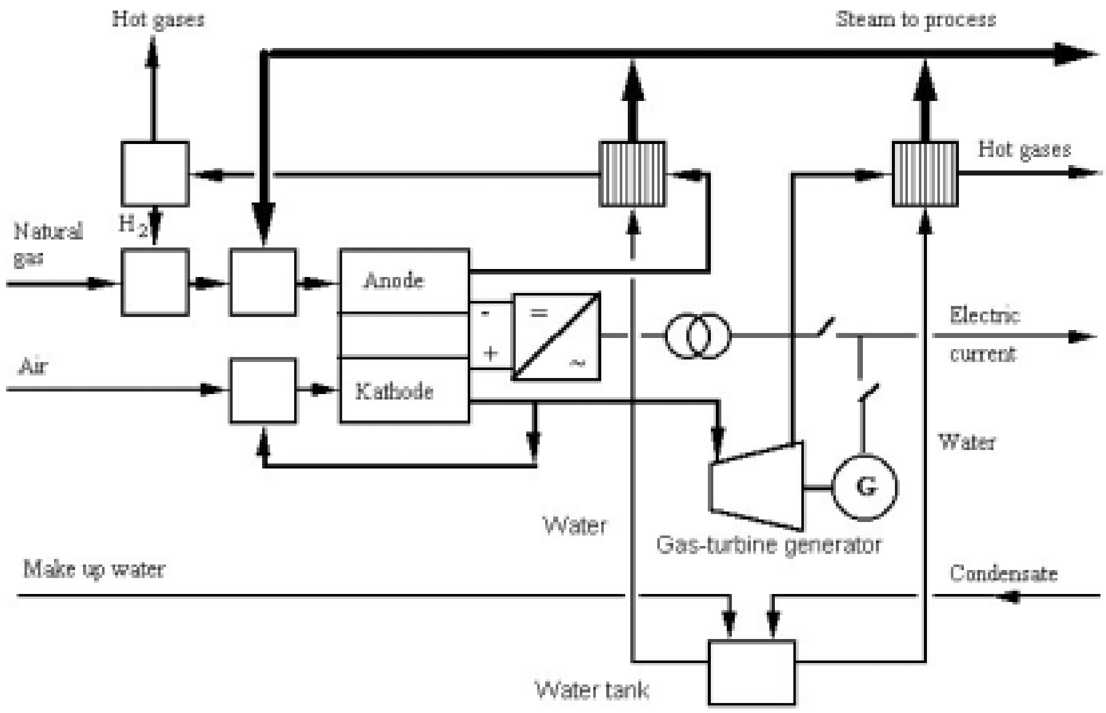


Figure 23: Cogeneration system with solid oxide fuel cell for applications in the industrial sector.

3.5.3 Thermodynamic Performance of Fuel Cells

The efficiency of power plants operating on a thermodynamic cycle has an upper limit, which is equal to the Carnot efficiency. For example, this limit for a Rankine cycle operating with maximum steam temperature of 540°C at an environment with temperature 25°C is 63.3%. Fuel cells convert the chemical energy of the fuel to electricity directly, with no intervention of a power cycle. Consequently, Carnot efficiency is not applicable for fuel cells and their efficiency theoretically can reach 100%.

In practice, several losses in the various components of a fuel cell system, which consists of the fuel reformer, the cell stack, the inverter and the auxiliary equipment, result in efficiencies much lower than 100%. Thus, the electric efficiency of phosphoric acid fuel cell units, which are commercially available, is in the range of 37-45%, and it depends on the quality of fuel and the operating temperature. At a 50% load, the efficiency is equal to and sometimes higher than the efficiency of full load. The total efficiency of a cogeneration system reaches 85-90%, while the power to heat ratio is in the range 0.8-1.0.

As the technology develops further, and in particular for the molten carbonate and solid oxide fuel cells, electric efficiencies higher than 50% are expected. Integrated with gas- and steam-turbine combined cycles, systems based on molten carbonate fuel cells are expected to have electric efficiency of 55-60%, while for systems based on solid oxide fuel cells the expected electric efficiency is 60-65%.

3.5.4 Fuel Cell Perspective

The great promise of fuel cells as a mean of efficient production of electric energy from the oxidation of fuel was recognised nearly from the beginning. Their main advantages are the following:

- High efficiency, which remains high and fairly constant over a wide range of load conditions.
- Modular construction, which makes it easy to build units with the desired power output.
- Low emission level.
- Very low noise level, since there are no major rotating equipment.

The very low emission and noise level make the fuel cell units particularly appropriate for applications in the residential and tertiary sector (house, office buildings, hospitals, hotels, etc.). The main drawbacks are their high capital cost and the relatively short lifetime. Research and development to solve certain technological problems is continued. On the other hand, the use of less expensive material and mass production is expected to decrease the capital cost.

3.6 STIRLING ENGINE COGENERATION SYSTEMS

Cogeneration is also possible with Stirling engines. This technology is not fully developed yet and there is no wide-spread application, but there is an increasing interest because of certain advantages: prospect of high efficiency, good performance at partial load, fuel flexibility, low emission level, low vibration and noise level.

Perhaps the technology is not widely known, therefore it is helpful to present the basic principle first.

3.6.1 Basic Principle of Stirling Engines

A patent for the first Stirling engine was granted to Robert Stirling, a Scottish minister, in 1816. It was one of the most amazing inventions of its kind, being well in advance of all pertinent scientific knowledge of its time. In this respect, it is worth recalling that Sadi Carnot published his *"Reflections on the motive power of fire"* in 1824, while Joule established the mechanical equivalent of heat, and thus laid the foundations for the First Law of Thermodynamics, in 1849.

The ideal Stirling cycle, which is reversible, can be described with reference to Figure 24. The positions of the pistons are shown at the four extreme state points of the cycle as seen in the pressure-volume and temperature-entropy diagrams. Process 1-2 is an isothermal compression process, during which the heat is removed from the engine at the cold sink temperature. Process 3-4 is an isothermal expansion process, during which heat is added to the engine at the hot source temperature. Processes 2-3 and 4-1 are constant-volume displacement processes, in which the working gas (usually air, helium or air) is passed through the regenerator. During the process 4-1 the gas gives its heat up to the regenerator matrix, to be recovered subsequently during the process 2-3. The regenerator substantially improves the efficiency of the cycle. It comprises a matrix of fine wires, porous metal, or sometimes simply the metal wall surfaces enclosing an annular gap.

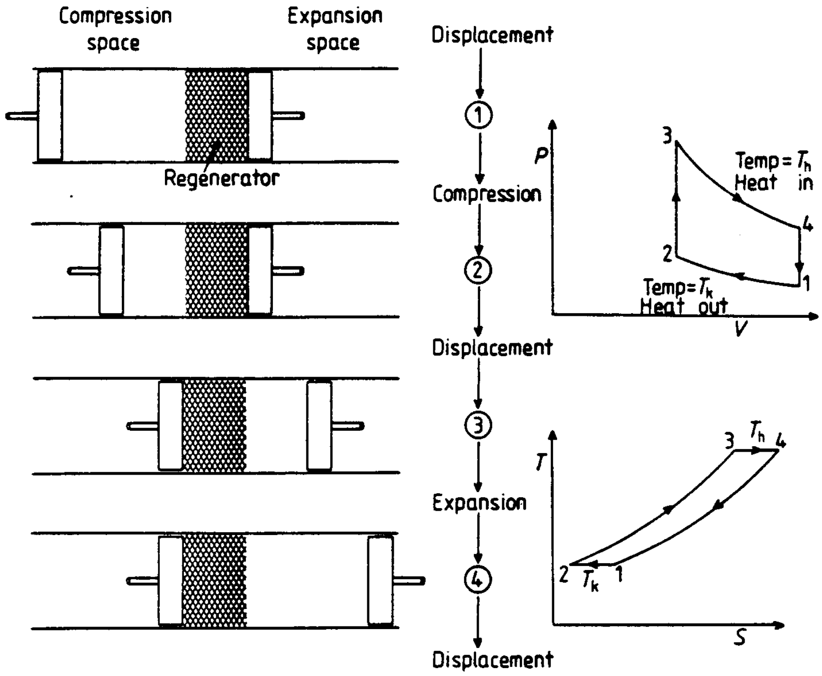


Figure 24: The ideal Stirling cycle (Urieli and Berchowitz 1984)

The external combustion allows for use a variety of fuels: liquid or gaseous fuels, coal, products of coal liquefaction or gasification, biomass, urban wastes, etc. It is possible to change fuels during operation, with no need to stop or make adjustments on the engine. Nuclear or solar energy may also be the source of heat.

3.6.2 Stirling Engine Configurations

The configurations of Stirling engines are generally divided into three groups, known as Alpha, Beta and Gamma arrangements (Figure 25). Alpha engines have two pistons in separate cylinders, which are connected in series by a heater, regenerator and cooler. Both Beta and Gamma engines use displacer-piston arrangements, the Beta engine having both the displacer and the piston in the same cylinder, whilst the Gamma engine uses separate cylinders (Figure 25). A cross section view of an Alpha-type engine is illustrated in Figure 26.

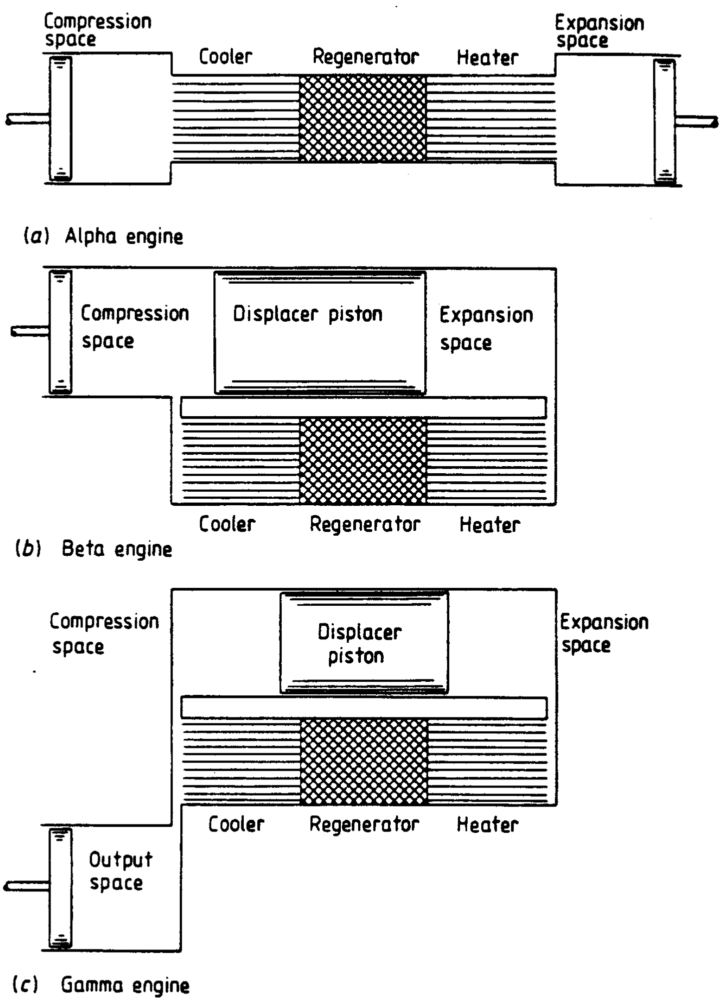


Figure 25: Classification of Stirling engines (Urieli and Berchowitz 1984)

Drive methods may be broadly divided into two groups: the cinematic and the free-piston drives. Cinematic drives may be defined as a series of mechanical elements such as cranks, connecting rods and flywheels, which move together so as to vary the working spaces in a prescribed manner. They are considered as the conventional design. On the other hand, free-piston drives use the working gas pressure variations to move the reciprocating elements, work being removed by a device such as a linear alternator.

Alpha configurations have been mainly pursued for automotive applications. Their main advantage is the simple way in which it can be compounded in compact multi-cylinder configurations, enabling an extremely high specific power output.

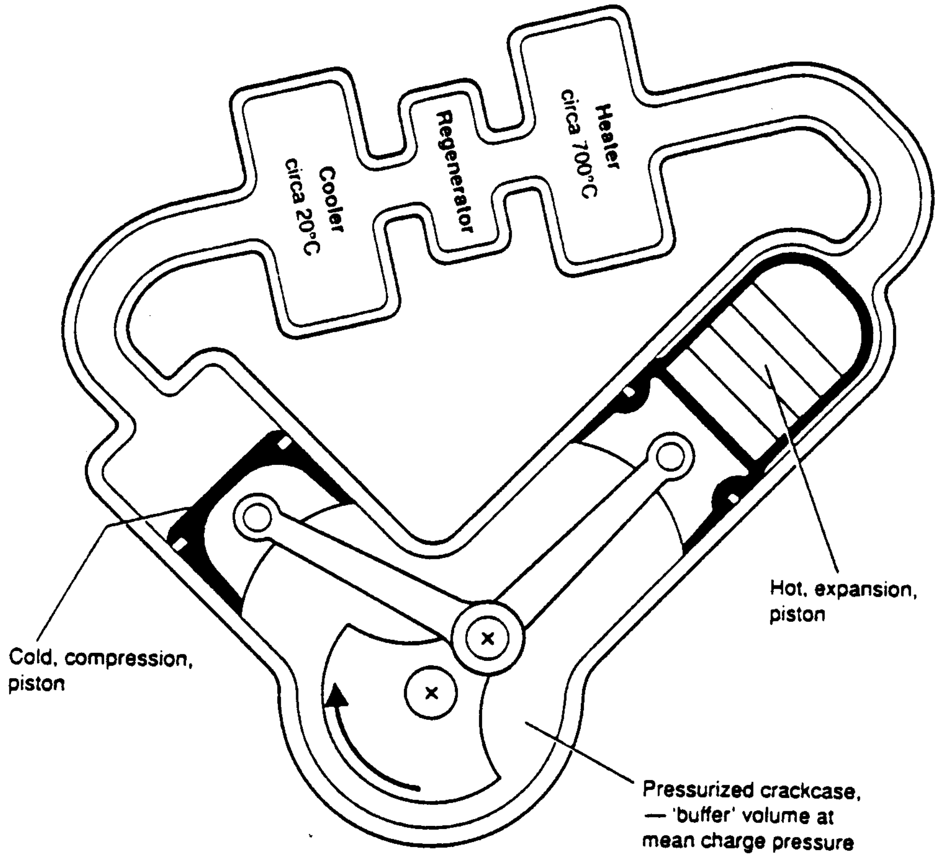


Figure 26: Alpha-type Stirling engine (SES 1993)

Beta configuration is the classic Stirling engine configuration and it is the original Stirling's engine arrangement. The free-piston engines invented and developed by William Beale at Ohio University in the late 1960's are of the Beta type [Lane and Beale, 1996].

Gamma engines tend to have somewhat larger dead (or unswept) volumes than either the Alpha or Beta engines. This often leads to a reduction in specific power. Therefore, they are used when the advantages of having separate cylinders outweigh the power disadvantage.

3.6.3 Developments in Stirling Engine Technology

Initially, research and development was aiming at car engines of power 3-100 kW. Then, the effort was reoriented towards engines of power 1-1.5 MW with an expected lifetime of 20 years. Since the technology is still at the development phase, there are no statistical data for reliability and availability, but it is expected that they will be comparable to those of Diesel engines. The working gas operates on a closed path and it does not participate in the combustion. Thus, the moving parts of the engine are not exposed to combustion products; as a result, their wear is reduced as compared to an internal combustion engine. However, special sealings are needed to avoid leakage of the high pressure working gas and its loss to the environment, as well as passing of the lubricating oil from the crankcase to the internal side of the cylinder. One of technical difficulties encountered up to now is the construction of effective sealings with long lifetime.

The free-piston engine mentioned above has evolved as a solution to the sealing problems. The free piston with an attached linear alternator can be hermetically sealed so as to contain the working gas for extended periods and the working gas itself serves as lubricant. The piston performs an harmonic oscillation, which causes the compression-expansion of the gas, while a displacer serves to move the gas between hot and cold heat exchangers. At present, the power of these engines is restricted to several tens of kilowatts. Their characteristics are well suited for micro-cogeneration applications.

3.6.4 Performance of Stirling Engine Cogeneration Systems

The Stirling cycle has the capability of efficiencies higher than those of the Rankine or Joule cycles, because it more closely approaches the Carnot cycle. Currently, the electric efficiency is at the order of 40%, and an increase to the level of 50% is expected. In particular, the free-piston engines for micro-cogeneration have electric efficiencies of 30-35%. The total efficiency of Stirling engine cogeneration systems is in the range of 65-85% and the power to heat ratio is 1.2-1.7.

Properly designed Stirling engines have two power pulses per revolution; in addition, the combustion is continuous. These features make them running very smoothly, with vibration level lower than that of reciprocating internal combustion engines. The continuous combustion results also in lower emissions and noise level.

More information on Stirling engines can be found in the specialised literature, such as in OTA (1983), Urieli and Berchowitz (1984), SES (1993), EEO (1993), Lane and Beale (1996).

For convenient reference, the main technical characteristics of the cogeneration technologies described in the previous chapters are presented in Table 4.

Table 4: Technical characteristics of cogeneration systems

System	Electric power	Annual average availability	Electric efficiency %		Total efficiency	Power to heat ratio
	MW	%	Load 100%	Load 50%	%	—
Steam turbine	0.5-100*	90-95	14-35	12-28	60-85	0.1-0.5
Open cycle gas turbine	0.1-100	90-95	25-40	18-30	60-80	0.5-0.8
Closed cycle gas turbine	0.5-100	90-95	30-35	30-35	60-80	0.5-0.8
Joule-Rankine combined cycle	4-100*	77-85	35-45	25-35	70-88	0.6-2.0
Diesel engine	0.07-50	80-90	35-45	32-40	60-85	0.8-2.4
Reciprocating internal combustion engine package	0.015-2	80-85	27-40	25-35	60-80	0.5-0.7
Fuel cells	0.04-50	90-92	37-45	37-45	85-90	0.8-1.0
Stirling engines	0.003-1.5	85-90 (expected)	35-50	34-49	60-80	1.2-1.7

* The value 100 MW is a usual upper limit for industrial applications. Systems of this type can have higher capacities too.

4 Cogeneration plants Electrical Interconnection Issues

The previous chapters have reviewed topics such as design, types of technologies, thermodynamics, finance, and economics for cogeneration plants. Here, a preamble into the technical problems of integrating cogeneration plants into power systems networks is given.

By and large, cogeneration plants growth has come as a result of technology development and the implementation of governmental policies world-wide. These policies are mainly driven by environmental concerns and are aimed at a) the optimal utilisation of natural resources - energy efficiency, and b) the encouragement of the utilisation of gas as a primary source of energy. Both objectives are intended to substantially reduce polluting emissions dumped into the atmosphere, which affect life and ecosystems in the planet.

Despite the energy efficiency and environmental merits, there are many factors to be considered when carrying out a cogeneration project. Political views aside, it is the associated economic viability that favours or discourages the implementation of cogeneration technology. The required electrical interconnection costs could prove onerous for the overall project execution, thus writing off the execution of a cogeneration project.

These costs will depend on the site location, the existing network topology at the connection point, the network interconnection assets, utility charges for use of system, the overall system condition and its adjacent system's load capabilities.

While some of the above costs can be kept under the developer/owner's control some others are out of his influence. Undoubtedly, the developer/owner can exert some resolve on the adopted technology and the level of automation employed on the site. However, most of the technical needs will be conditioned by the existing overall system circumstances at the connection point. More important, these will be coupled with the required equipment to preserve the power system functioning safely and reliably in view of the potential impact of the generating sets on the overall network's performance.

In every application it is necessary to consider the effect of the new generators. The most common effects are: a) on the fault rating of the local system and associated protection equipment, b) on the transient recovery behaviour of the local system, and c) on the electromechanical effects within the generators themselves.

In general, the technical questions affecting the integration of cogeneration plants into Transmission and Distribution networks are:

1) The Generator type
2) Site Location at Transmission and Distribution Networks.
    i) Island Mode
    ii) Satellite Mode
3) Protection
    i) Grounding
    ii) Fault Levels
    iii) Island and Satellite Mode
        - Synchronising
        - Loss of Mains
4) Load Flow and Losses
5) Voltage Regulation
6) Stability

Each of the above subjects could be treated individually, and by themselves are very broad fields of study. In the ensuing chapters these will be briefly discussed merely to outline their relevance.

4.1 GENERATORS TYPE

Electric a.c. generating sets can be of two types, synchronous generators and induction (asynchronous) generators. The use of any of the above machines poses advantages and disadvantages depending on their operating conditions and attached load along with its corresponding supply system.

There is great disparity between these two types of generators both during normal (steady state) and during abnormal (transient) conditions. These should be carefully considered in choosing either machine.

In general, AC generators involve the conversion of mechanical energy to electrical energy. This is done in the air-gap space between the fixed winding (stator) and the rotating winding's (rotor) outside edge, when the rotor is driven by a prime mover transferring mechanical power. Energy conversion takes place in the form of a suitable magnetic field, commonly known as magnetic flux, which is produced in the air gap and keeps flowing from the rotor winding and induced into the stator winding or vice versa. In synchronous generators the rotor, through a winding known as the field or excitation winding, provides the magnetic flux. Its rotational motion induces a rotating magnetic field to the winding of the stator. The process is reversed for induction generators, a rotating magnetic field, generally supplied from an existing a.c. power network, is induced in the rotor winding. The rotor winding is spun at a speed above the magnetic field velocity in order to generate power, else it will function as an induction motor.

4.1.1 The Synchronous Generator

If the rotor of a machine is driven at a rated speed by a prime mover will produce a rotating magnetic field at a rated frequency, e.g. 50 Hz, through its rotor winding, which will then be induced in the stator winding and will generate a voltage with the same frequency of the rotor. If 50 Hz currents are made to circulate in the stator windings, the corresponding magnetic field will intermingle with the magnetic flux in the air-gap space resulting in the transfer of mechanical energy from the rotor to electrical energy on the stator. As both fields rotate in synchronism, the machine is known as a synchronous generator.

For the above to occur the following premises should be present; a) a prime mover rotating the rotor at a given speed, b) a source of d.c. current feeding into the rotor winding to generate the necessary magnetic field in the air-gap space, and c) the winding must have a certain number of poles which coupled with the prime mover velocity will generate a magnetic field of the required frequency.

When the generator operates at rated speed and voltage and a resistive load is connected to it, then current will flow in the stator windings in phase with the voltage. The second electromagnetic field in the air-gap space will not be in phase with that produced by the excitation winding, although both are in synchronism. The interaction of these fields will transmit energy across the air-gap in the form of real power (kW) in proportion to the power absorbed by the load. The displacement between the two fields is known as the load angle.

The load angle will vary in accordance with the type of load. If the load current is purely reactive the two electromagnetic fields (the stator current and the rotor current electromagnetic fields) are in phase. The polarity of the two fields will depend on whether the generator current is reactive lagging or leading the voltage. When applying such a load the generator voltage will either increase or decrease and the Automatic Voltage Regulator will adjust the excitation (rotor) current to restore the voltage.

The ability of synchronous generators to be able to control voltage and frequency with a degree of accuracy enables them to be synchronised with an existing supply system.

Synchronous generators are selected if the delivery of mechanical power is constant. Generally they are more expensive and with a more complicated construction than induction generators. This is because they require synchronising equipment and an excitation system.

Conversely, synchronous generators can operate at virtually any power factor, thus allowing independent control of reactive power for a given real power output. That is, the synchronous generator can either provide reactive power to the network, which is its normal modus operandi, or can work with zero reactive power flow, or could operate by drawing reactive power from the supply.

4.1.2 The Induction Generator

The induction machine can work in both generator mode and motor modes. By and large induction motors are the most widely use electrical machines. Functionally, both regimes are similar, they basically differ in the way that the rotor speed is controlled.

In principle, if the stator winding is connected to an electrical network of suitable voltage and frequency, then it can produce a synchronously rotating magnetic field in the air-gap space of the machine. If the rotor is rotated at the same speed as this magnetic flux, then no energy is transferred. If the difference in speed between the rotor and the air-gap rotating field is reduced, the rotor-induced frequency would be reduced in proportion to the difference or “slip”. Slip is considered positive if the rotor is running below synchronous speed and negative when above it.

The short-circuited rotor winding (via cage winding or through some impedance) produces currents whose magnetic field interacts with that existing in the air-gap space producing energy transfers across the air-gap. The direction of this energy transfer can be either way beyond the stator winding onto the network, or to the rotor winding. This will depend on whether the slip is positive or negative. Positive slip transfers energy from the stator to the rotor, whereas negative slip transfers energy from the rotor to the stator.

For the above to happen, reactive power is drawn from the supply to produce the basic air-gap magnetic field, or flux. Hence, induction machines always require reactive power (kVAr) from the power supply, which is the normal model of operation.

Reactive power can either be drawn from the grid or through a device of variable capacitance connected locally to the machine. Generators working in parallel with the grid are called mains-excited Asynchronous Generators and those with a variable capacitance are called self-excited Asynchronous Generators. The latter are capable of operating in isolation from a network and in this respect are similar to synchronous generators. Attention must be paid to the value of capacitance used since the voltage generated can exceed the rated value if the capacitance is larger than required, thus damaging the equipment.

Asynchronous generators (AG) are not synchronised in the same way as synchronous generators (SG). The AG is driven to synchronous speed using its prime mover and then it is connected to the network. A transient magnetising pulse of current will be drawn from the supply, which will rapidly decay to the value of steady kVAr required to magnetise the generator.

Induction generators are cheaper and easier to construct, with simpler excitation starting and control systems. Induction generators will always draw a virtually constant supply of magnetising VArs, operating power factor deteriorating rapidly at low real power outputs.

4.1.3 Dynamic Characteristics

Dynamic operating characteristics for both types of generators are different. An induction generator, following a short circuit, will exhibit dissimilar transient currents, especially due to the lack of a specific winding. Thus, its short circuit "transient" current decays to zero merely leaving the "subtransient" component of fault current.

Lower values of rotor resistance resulting from technological progress in the search of improved efficiencies has led to effects on the decay time of the subtransient current and the duration of the fault current.

In a SG a variation of the load angle provokes the transfer of energy between the electrical system and the mechanical rotating system. An analogous energy transfer in the AG requires a "slip" or speed difference between the rotor and the constant synchronous speed. The above implies that SG poses more rigid electromechanical motion than AG and reacts better to transient changes.

4.1.4 Unbalanced and harmonic Loads

Unbalanced loads create unbalanced currents, with corresponding asymmetries in relation to their phase angles, across the phases of the generators.

The above conditions are similar for loads containing harmonic currents or voltages, since harmonic components behave similarly to the unbalanced phase-sequence components.

These currents/voltages can produce motoring or generating power in addition to an increase in losses, hence an increase in winding heating, and a reduction in operating efficiency. This means degradation of the overall performance of either type of generator.

Induction generators introduce no additional harmonic voltages into the power system. The squirrel cage rotor tends to dampen out harmonic disturbances. Conversely, SG contains odd harmonic voltages where the 3^{rd}. harmonic is the one of largest weight in magnitude and importance.

To avoid harmonics going to the system a delta-wye transformer can be used. The harmonic currents will circulate in the delta windings. The transformer will increase the total installed cost of the machine.

4.1.5 Comparison of SGs and AGs Main Distinctive Features

Synchronous generators

- They can work as stand-alone sets, without the need of external power supply.
- Operate at constant speed
- They can provide active power at zero kVAr, they can also provide reactive power or both.
- Power transmitted depends on the load angle
- They require an excitation system.
- Usually more expensive.
- They require synchronising equipment.

Induction generators

- Always require a source of reactive power.
- They must have a slip, and its magnitude changes the power flow.
- Usually cheaper than synchronous generators.
- Simpler excitation and control systems.
- They do not need to be synchronised to the grid.
- Reliable and robust designs
- Lack of an excitation winding results in a contribution to short circuit currents largely owing to the subtransient components.
- Unbalanced and harmonic loads may cause larger losses than in synchronous generators.

4.2 THE UTILITY AND COGENERATION PLANT INTERCONNECTION ISSUES

The implementation of cogeneration technology varies across countries depending on several factors, such as existing electricity tariffs, the power sector regulatory framework, the lack or the existence of a domestic environmental policy promoting energy efficiency, fuel availability and the existence of an adequate fuel transport infrastructure, and technical requirements on the site.

However, the features found to be significant to a firm considering investment in cogeneration are:

a) The incremental capital cost of equipment to produce electricity

b) The incremental operating costs (fuel, maintenance, etc.,)

c) The price of purchased electricity

d) The buyback rate for electricity sold to the utility

e) Heat demand

f) Operating hours (Load factor)

g) Engineering and thermodynamic characteristic of the boiler and cogeneration technology chosen

Depending on the above factors the implementation of cogeneration plants may be considered at intensive energy consumption level or at a more widely spread uptake with lower intensity of energy consumption. Therefore uptake of cogeneration plants has different markets. cogeneration application can be found in the industry, hotels and the health and leisure sectors, where considerable heat requirements exist providing high thermal efficiencies, as well as in district heating. This in turn can prove decisive in the connection of cogeneration plants at high voltage Transmission Networks (for large industrial sites and district heating) or at a lower voltage Distribution Networks. The implementation of cogeneration at either of the above voltage levels brings about different technical implications in view of the potential point of coupling between the cogeneration plant and the utility. These are briefly mentioned below.

4.2.1 Site Location at Transmission and Distribution Networks.

Decisive in the overall implementation of the cogeneration project is the operational state of the neighbouring power system and the existing topology of the host network at the point of supply. The project developer has little control over the above aspects, yet much of the technical details associated with the interconnection are reliant upon them.

While many new concepts have been introduced in the technico-economical jargon of power systems studies in the last decade, one thing has not changed –the obligation to serve while maintaining quality and security of supply. Consequently, basic network development planning techniques are still in place encompassing tasks such as; forecast demand and energy needs, the identification of capacity and fuel supply, and the definition of transmission and distribution requirements to assure reliability.

Reliability is a conceptual view involving investment in assets redundancy to secure power supply to load centres. For that reason, although from the viewpoint of a non-utility generator owner/operator only a simple transmission connection is necessary, either for power back-up or power delivery, the supplying/receiving utility may require a double circuit transmission connection.

As a result, the definition of the cogeneration plant power capacity/needs and its location is followed by the designation of possible alternative connections to the transmission/distribution network. The engineering formulation of the connection includes: number of circuits required, circuit configuration, transmission/distribution voltage, conductor size, generator output, conductor phase spacing, distance to point of connection, and use of existing transmission/distribution and upgrading of functioning facilities.

- **Number of Circuits**. A single circuit connection provides a simple link to deliver power. Yet, it does not provide for a single contingency outage condition. Thus, while the line is not energised the plant is unable to export or import power setting off the corresponding commercial and technical losses. A double circuit connection means that power is delivered even if one circuit trips out. The latter improves plant Forced Outage Rates.

- **Circuit Configuration**. There are a large number of possible connections, the most commons are:
  - **<u>Single Circuit Radial Connections</u>**
    - Simple Radial Single Circuit
    - Radial Tap Three Terminal Line
    - Radial Connection with Selective Switching
    - Radial Connection with Circuit Breakers

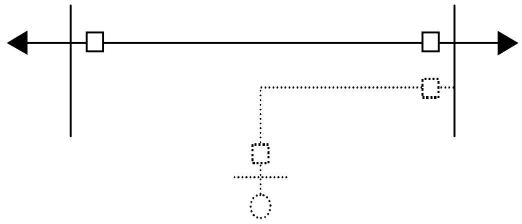


Figure 27: Simple Radial Single Circuit

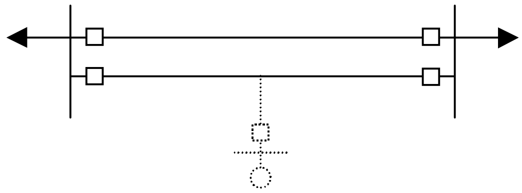


Figure 28: Radial Tap Three Terminal Line

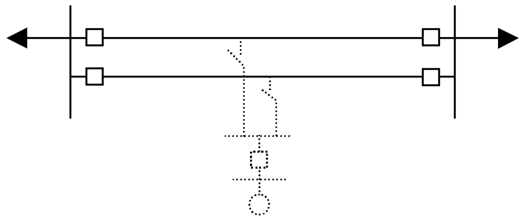


Figure 29: Radial Connection with Selective Switching.

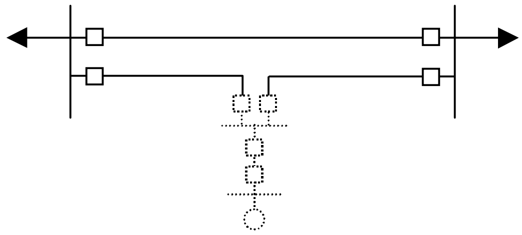


Figure 30: Radial Connection with Circuit Breakers.<u>Double Circuit Connections</u>

- Double Three Terminal Lines with Selective Switching
- Double Three Terminal Line with Circuit Breakers
- Double Circuit Looped Connection

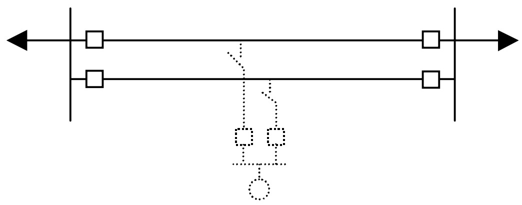


Figure 31: Double Three Terminal Lines with Selective Switching.

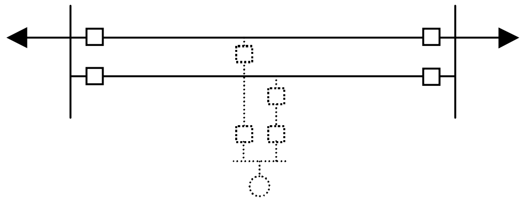


Figure 32: Double Three Terminal Line with Circuit Breakers.

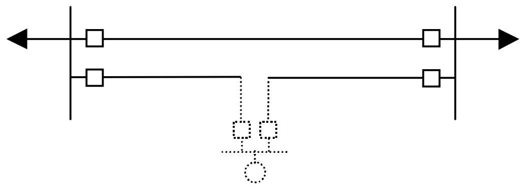


Figure 33: Double Circuit Looped Connection

Each of the above configurations possesses its technical advantages and disadvantages, as well as the corresponding economic implications. A complete discussion of their technicalities is readily found in specialised literature on Electric Distribution and Transmission Systems Engineering.

- **Transmission/distribution voltage**. The voltage at the point of common coupling together with the distance of the interface link will define the interconnection voltage. Smaller generators can be directly connected at generator voltage. Larger generators will require step up transformers.
- **Conductor Size**. Standard engineering design and economic principles define the conductor size. Utilities prefer maintaining standard sizes as this reduces spare parts and maintenance costs.

4.2.1.1 Island Mode

The Island Mode implies a cogeneration plant running absolutely unconnected to another source of power (network). Consequently, the generating sets determine the system frequency and voltage.

A synchronous generator provided with adequate excitation and frequency control systems will not have major troubles operating in this regime. Conversely, an induction generator cannot offer any advantages in this mode because it does not provide the adequate frequency and voltage levels. An induction generator has the disadvantage that the frequency is proportional to the prime mover speed and the slip difference varies with the load being supplied. Besides, the generated voltage depends on the supply of capacitative kVAr, to be able to cope with load conditions it will require a considerably variable kVAr supplier.

There may be circumstances that justify the implementation of a combination of SGs and AGs, where the SGs supply the reactive power needed by the AGs. The lower costs of AG may justify their use.

4.2.1.2 Satellite Mode

Operating in this mode involves a local system analogous to the island mode, but still connected to a much larger system. This regime holds the same advantages as the island mode, but the SGs have the advantage to be able to compensate for the connection impedance, thus maintaining a stable voltage. Without them there would be a voltage drop in the island as the load increases.

Also the SG holds the following benefits/values to the host network:

- Black Start Capacity
- Frequency Response
- Reserve

4.2.2 Protection

A cogeneration plant potentially can improve the overall performance of the host network including the operation, protection and control either in steady state or during transient periods.

However, the above is not always the case, the cogeneration plant can also bring forth adverse impacts. Hence the needs to correctly understand the technical factors involved. For instance, there can be a reversal of real and reactive power flows, inappropriate voltage regulation, changes in fault levels, system or plant instability, and unnecessary operation of protection devices. Therefore, each installation integrating a cogeneration plant must be designed to be compatible with the host network to which is to be connected.

Utilities tend to provide simpler protection at distribution voltage level. As the voltage level increases, their normal protection becomes more complex to achieve greater security. In most countries, utilities establish nominal limits for technical parameters. These parameters are controlled through electricity supply regulations defined by the electricity companies.

In the UK the necessary provisions on electricity company requirements are documented in Engineering Recommendations G59/1 and G75, and Technical Report 113 available from The Electricity Association[2].

Pertinent factors related to the protection of the inter-tie between the host utility and the cogeneration plant are discussed in the subsequent headings.

4.2.2.1 Earthing (Grounding)

During normal operation, the grounding method used is not very important. The importance of the grounding method becomes significant when the network endures faults. Earthing methods applied across utilities are diverse, they can be:

- **Ungrounded**. No intentional ground –some grounding is present due to potential of measuring devices and capacitive coupling of electrical gear.
- **Solidly multi-grounded.** Connected through ground connection with no impedance intentionally inserted. Ground is placed in several grounding points.
- **Solidly uni-grounded.** Connected through ground connection with no impedance intentionally inserted.
- **Resonant-grounded.** Connected through inductive reactance to offset system capacitive reactance.
- **Resistively grounded.** Connected to earth through a neutral resistor to limit ground current.
- **Reactively grounded**. Connected to earth through impedance.

[2] 30 Millbank, London SW1P 4RD.

Each one of the above methods has advantages and shortcomings depending on the place and the system of fitting, accordingly each one has applications for different purposes. Discussion of these can be found in Kojovic (2001).

In general the main rationale of earthing devices is due to safety issues. The magnitude of a ground-fault current depends on the system voltage, faulted-feeder parameters, and the grounding resistance. Grounding became a necessity as a result of the increase of power systems load densities that led to the uptake of higher voltage levels. In ungrounded systems the magnitude of the ground fault current depends on the faulted feeder parameters and the systems parameters, mainly its stray capacitance. The return path for the fault currents is the stray capacitance to ground of the two unfaulted phases of that feeder and the unfaulted phases of all other feeders connected to the same power transformer.

Ground fault currents became too high under ungrounded schemes causing problems of high overvoltage, increased step and touch voltages, and the inability to self-extinguish arcs. Grounding, therefore is meant for:

a) A means of reducing fault current magnitudes.

b) Personnel and plant safety.

c) Reducing interruptions to a minimum

d) Limiting transient voltage magnitudes

e) Limiting damage to equipment when a fault occurs.

Since the main parameters influencing fault currents are the current sources themselves, the introduction of generators to transmission and distribution networks increases the magnitudes of existing fault levels. This is discussed further in the following chapter. The increase of fault current magnitudes in some cases call for upgrading existing protection equipment. Consequently, in designing a plant distribution system that will have non-utility generation, the matter of grounding deserves serious and special attention. The subject of grounding is directly related to ground relaying for the protection of the plant distribution system as well as safety to personnel.

The issue of earthing is particularly acute in distribution networks since these were originally intended for a passive role. Traditional utility design practice meant that power would flow from the higher voltage level to the lower voltage level. Existing earthing and protection arrangements were intended to work under such understanding.

The introduction of cogeneration in distribution networks radically alters the above philosophy. To begin with, the connection of a generator in distribution networks may cause reversal of power flows. Secondly, earthing arrangements have not been installed considering the perspective of running generators in distribution systems. In the UK for instance, distribution networks are earthed at a single point and resistors or reactors may be used in reducing the fault current magnitudes. When a generator is running in parallel with a distribution network, it will be a requirement that its neutral be isolated from earth. However, whenever the generator is operating in an islanded system, its neutral must be connected with earth in order to provide required safety standards.

It is likely that when running islanded that the distribution network earth will be disconnected, and the generator will have to arrange to make a connection to earth for these times. Such an arrangement will have to be automatic if there is to be no interruption to supplies.

Also, not every grounding system will fit the purpose of safety. For example, generators are designed so that windings shall withstand the mechanical forces resulting from a bolted three-phase short circuit at the machine terminals.

However, the most recurrent fault is the single-line to ground. If the generator is solidly grounded fault currents are likely to exceed the design-rated fault current (see 2). Thus, the choice of the grounding system should be thoroughly made in coordination with the host electric utility.

4.2.2.2 Fault Levels

As mentioned earlier, each generator contributes towards short-circuit current magnitudes. This contribution must be taken into account carefully when considering connection to a distribution network. Existing operational state of the host distribution plant, including the switchgear, may be close to rated operating values without the contribution of the new generators. Hence, the short-circuit contribution of the prospective generator will probably exceed the technically allowed effective values, thus demanding upgrade of the protection equipment and feeder rating. Jenkins, et.al (2000) and Strbac (1998) clearly demonstrate the short-circuit contribution of new generators in the host network. Figure 34 from (3) exemplifies the increase of short circuit currents.

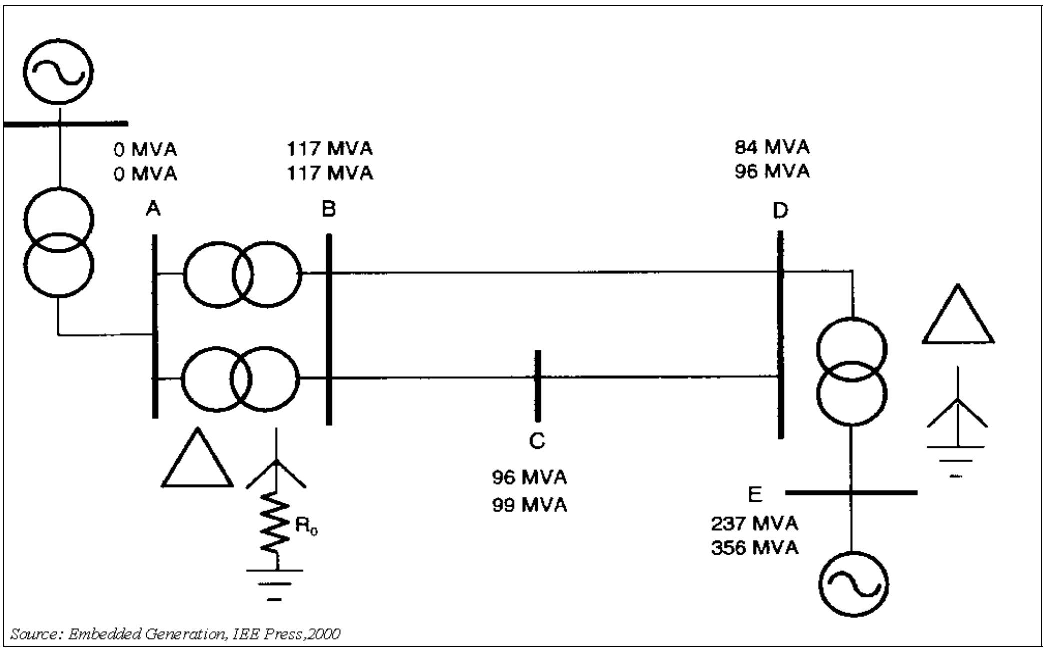


Figure 34: Fault levels with and without a cogeneration plant. (Cogeneration plant is lower right, higher fault levels are with cogeneration running)

Even if series reactors could be introduced to mitigate the current value, this will come with a price, besides in some circumstances this may result in excessive voltage regulation and generator instability.

Consequently, every possible technical solution will increase the connection cost, whose refund will probably be either imposed over a period of time if the distribution network owns the connection or in the form of a one-off disbursement if the cogeneration developer owns the network.

4.2.2.3 Satellite and Island Modes

Protection arrangements will have to be able to operate in islanded and non-islanded mode. The difficulty arise as standard protection envisages higher levels of fault power than may be available from a generator on its own.

The protection of the cogeneration site from internal faults is quite uncomplicated. Fault current from the distribution network is the main parameter to detect the fault and traditional protection schemes and techniques are used to protect the location. Conversely, protecting the distribution network from short-circuit contributions from the cogeneration plant is often more complicated. Because of its technical arrangement and operating regime its contribution to asymmetrical (short-circuit) faults is limited. On the other hand, small synchronous generators must be equipped with sophisticated exciters in order to make available fault current significantly above the required values.

The above conditions the protection systems to rely on the distribution circuit fault and proceed to isolate the cogeneration plant site. The above may be followed for the plant generating sets tripping through their over/undervoltage, over/under frequency protection or loss-of-mains protection.

As a result of the above, two issues are important - during the fault interlude it must be made sure that the generator is not going to back feed the remaining system and precaution should be taken to avoid out-of-synchronism reclosure. Second, if the distribution system is re-established following an interruption of supply, synchronising back the cogeneration plant must be done so that the procedure is made safely and securely. These matters are discussed below.

Loss of Mains

The loss of supply from the network causes significant challenges to the connected generators of a cogeneration plant, especially if they are connected to distribution networks. Reclosers of switchgears may re-energise the network during short duration losses of main voltage. These reclosers are especially common on rural overhead networks. If the generators of a cogeneration plant remain operating in islanding mode then

- the cogeneration plant could be reconnected to the distribution system while both are out of synchronism.
- if the cogeneration plant was operating with the neutral of the generator isolated from earth, then this condition may stay put even when it has been isolated from the network. The above is prohibited due to stipulated regulations.

Hence, it becomes important to install protection devices capable of detecting the loss of mains voltage from the host utility to avoid undesirable conditions and proceed to execute the corresponding actions. These actions will depend on the actual scenarios of the site. Depending on whether the site is a net power importer or exporter, i.e. the site load exceeds or does not reach the site's generating capabilities, the protecting devices to detect loss of main voltage could be reverse power relays, undervoltage and under frequency relays or Loss of Mains (LOM) relays using rate of change of frequency (ROCOF) or change of phase angle.

LOM relays are susceptible to operation during wider system disturbances. As a result they are being fitted with neutral voltage displacement (NVD) protection to ensure disconnection when a HV earth fault occurs.

However, the LOM relays must operate within the dead-time of any autorecloser in order to avoid out-of-phase reconnection.

Synchronising

To synchronise the island back to the system, the appropriate equipment at the point of reconnections is necessary. This implies that the protection must be designed to ensure minimum differences between the magnitude and phase of the two voltage sources to be interconnected when closing the switchgear.

There must be reasonable balance between the load and the generation, and there needs to be a reasonable balance when the island is established. This might have implications for the generator running regime at all times.

This is required to avoid voltage step changes and disproportionate mechanical stress on the generator at the moment of connection.

Consequently, control room arrangements must be in place to deal with these events which are complicated if there is more than one generator or power station in the island.

4.2.3 Load Flow and Losses

When the power exported by the cogeneration plant to the utility grid is absorbed locally this decreases the power transmitted along the line. This in turn results in the possible deferment of network investment, a reduction in network losses and a reduction in voltage drop.

The relation between power flows and voltages is determined by the following expression:

$$VL = VG - \Delta V - j\delta V$$

Where ΔV and jδV are the components of the voltage drop across the line.

These voltage drops occur due to energy dissipation (ΔV) and energy stored (jδV) in Magnetic Fields or Electric Fields. Magnetic Energy is stored as long as current keeps flowing through an inductor (transformer/machines coils and windings). Whereas, electric fields result from the potential difference between two points (overhead lines and earth), i.e. the separation of unlike charges.

The component of the voltage drop in phase with the generator voltage is given by:

$$\Delta V = \frac{RP_G + XQ_G}{V_G}$$

Equation 1: Voltage drop due to energy dissipation.

Since the resistance of transmission lines is usually negligible compared to their reactance, the above results in the following expression:

$$\Delta V = \frac{XQ_G}{V_G}$$

Equation 2: Voltage drop due to energy dissipation.

The above is not the case for Distribution networks where both, the resistance and the reactance should be taken into consideration.

The component of the voltage drop in quadrature with the generator voltage is given by:

$$\delta V = \frac{XP_G + RQ_G}{V_G}$$

Equation 3: Voltage drop due to energy dissipation.

Since the resistance of transmission lines is usually negligible compared to their reactance, the above results in:

$$\delta V = \frac{XP_G}{V_G}$$

Equation 4: Voltage drop due to energy dissipation.

As before, this is not the case for Distribution networks.

Equation 2 shows that changes in voltage magnitude are caused by transmission of reactive power in transmission lines, whereas Equation 4 shows that phase shifts between voltages are due mostly to the transfer of active power in transmission lines. Therefore, a large difference in voltage magnitude between two buses results in a large transfer of reactive power. Conversely, if there is a large difference in angle between the voltages at two buses connected by a line, there will be a large transfer of active power.

On the other hand, distribution networks are designed for passive operation (minimum real time intervention), where power flows from the source of power to the load. Network equipment is designed to accommodate the loads experienced on the network making provision for contingencies under abnormal conditions (security).

The introduction of embedded generation may bring about benefits and/or disadvantages associated with the re-distribution of power flowing across distribution networks. For instance,

- Re-distribution of power flows and inappropriately sized generation may exceed originally designed capabilities or adversely affect network losses.
- On the other hand, network losses could also be reduced due to the redistribution of power flows.

These merits or drawbacks are appreciated graphically in the sequence of illustrations taken from (3) below.

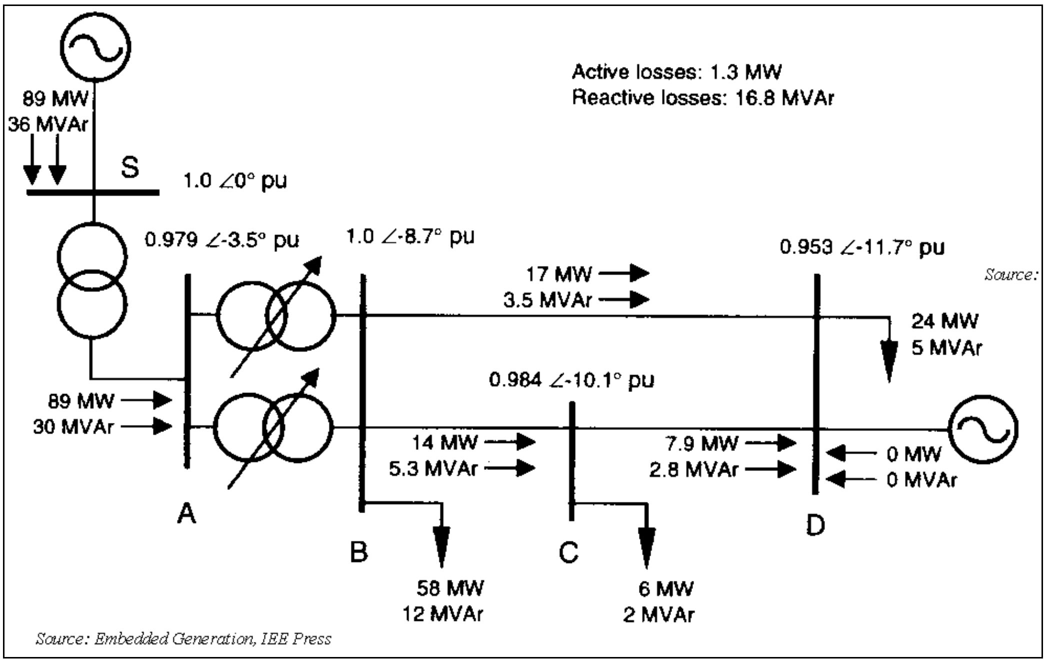


Figure 35: Power Flows - System at Max. Load and no cogeneration plant input.

The illustration above depicts a system at given conditions and it shows the power flows across the transmission lines. As can be appreciated the cogeneration plant is not operating.

The introduction of the cogenerator substantially reduces losses in the system as can be appreciated in Figure 36.

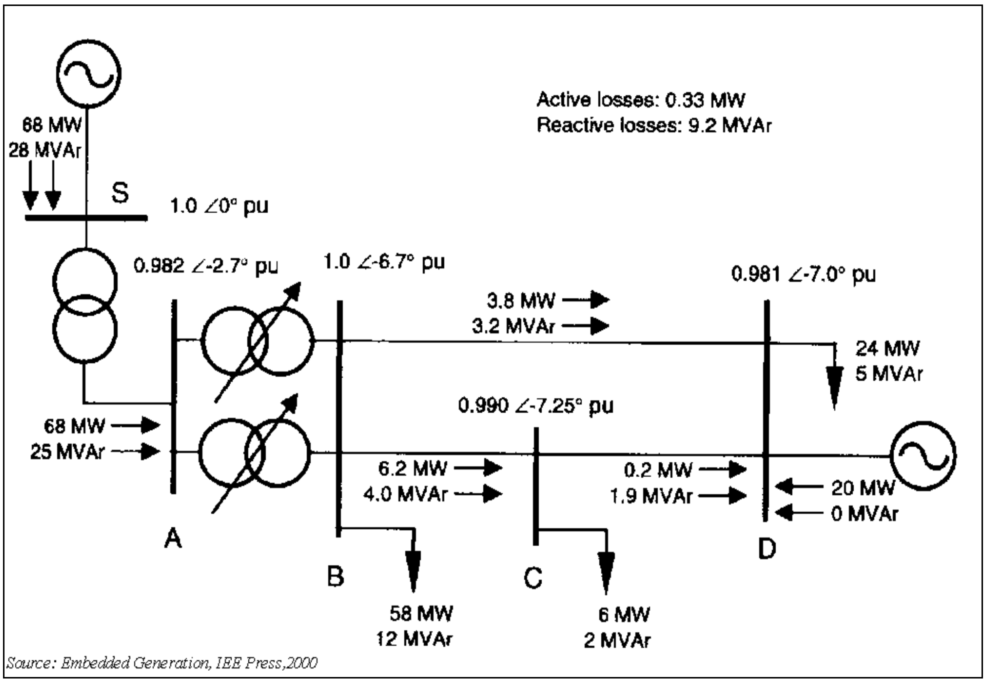


Figure 36: Cogeneration Generator running at Power Factor of 1.0 and Max Load.

However, as Figure 37 demonstrates, further reduction of losses is possible if the cogeneration plant generates reactive power. This is possible with an overexcited synchronous generator, on the other hand an under-excited synchronous generator or an induction generator absorbing reactive power results in a smaller voltage rise at the expense of increased losses within the system.

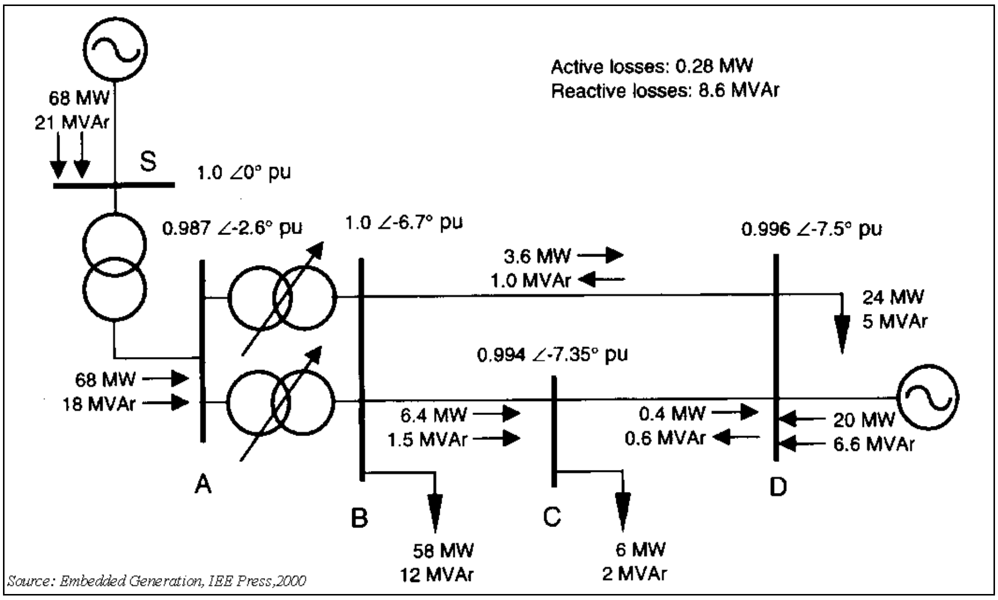


Figure 37: cogeneration Generator operating at Power Factor of 0.95 lagging (producing reactive power) and Max Load.

At times of low load values the plant producing maximum capacity may reverse the flow of power from the distribution system to the transmission system. This has been illustrated in Figure 38 below.

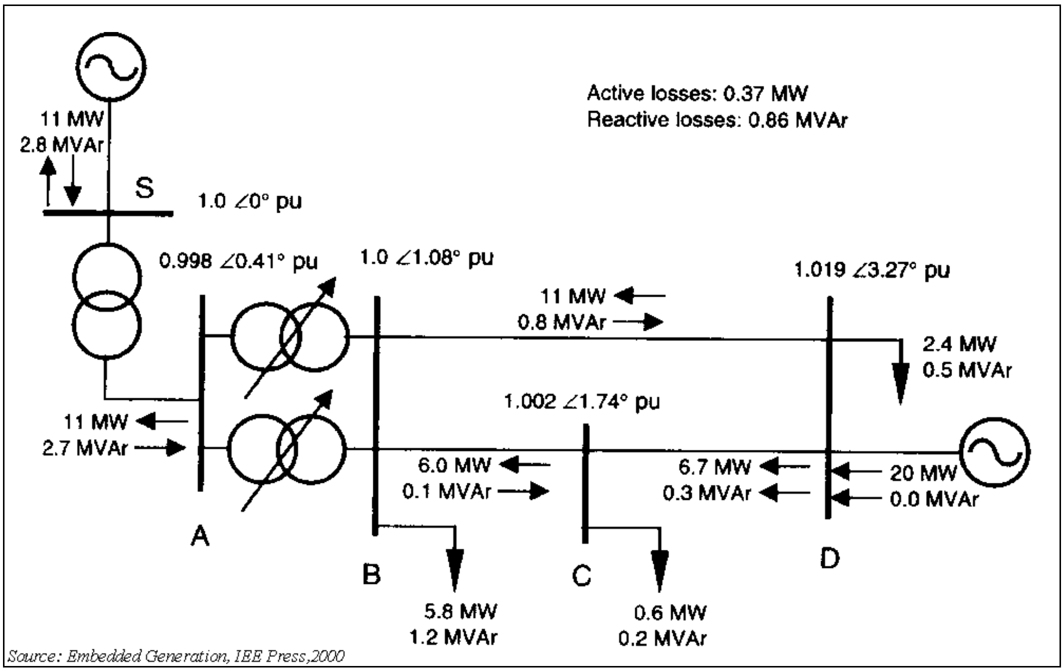


Figure 38: cogeneration Generator at Power Factor of 1.0 and Min. Load.

There are concerns that this power flow reversal can interfere with the voltage regulation function of tap-changing transformers.

4.2.4 Voltage Regulation

Depending on the existing operating conditions the embedded generator may:

a) Produce reactive power (power factor lagging)

b) Absorb reactive (power factor leading)

c) Neither of the above (unity power factor)

This was illustrated in the previous chapter. Thus, the introduction of a cogeneration plant potentially has the capacity to support voltage control. That is, absorb or produce reactive power when the network requires voltage compensation. The above, will be dependent on the generating technology adopted, as explained in chapter 4.1.

In spite of this, the CHP plant also has the capacity to disrupt voltage control if not adequately operated. For instance, because rural loads are usually scattered the networks are design to make maximum use of voltage variations - long lines with small conductors. Feeder tapering is common practice to supply low rural loads on 11kV networks.

Generation connected to rural 11 kV circuits tends to increase voltages, potentially above statutory limits, thus having an impact on feeder's ratings.

Voltage must be maintained within fixed statutory limits, e.g. +10% and –5% for 11/0.45 kV in the UK. This is normally done through tap-changing actions of transformers. However, tap changing at low voltage level is usually carried out by off-load tap changing transformers. In which case, given the situation when the CHP plant is connected at the remote end of a radial network, depending on the plant size it may be needed to alter the tap position of one or more of the transformers along the feeders. If the CHP trips or is shut down the voltage at the remote end can fall below the statutory limits.

Also, as explained in the previous chapter, the cogeneration plant has the potential to disrupt voltage regulation functions of tap-changing transformers. This is because the Automatic Voltage Controller is usually fitted to the secondary winding of the supply transformer. When power flowing through the transformer is reversed, the transformer causes errors in the operation of the voltage sensing relay and consequently in the tap-changing device.

4.2.5 Stability

Transient instability is caused by large disturbances due to load changes in switching operations or electrical faults. The mismatch between the mechanical power input and electrical power output causes rotor acceleration or deceleration with a corresponding variation of rotor angle. The generator's response will depend on fault type, electrical distance from disturbance, inertia of rotating mass and automatic governor/AVR action.

Induction generators that overspeed draw large reactive currents, thus pushing down the network voltage and leading to instability. Connection procedures require that transient and steady-state stability studies be conducted to analyse the potential capabilities of the new plant to disrupt the normal operation of the system.

5 APPLICATIONS OF COGENERATION

Cogeneration applications are usually classified with reference to the sector they appear:

a) utility sector,

b) industrial sector,

c) building sector (called also residential-commercial-institutional sector),

d) rural sector.

Cogeneration opportunities in each sector and related information are mentioned in the following.

5.1 COGENERATION IN THE UTILITY SECTOR

Thermal power plants can either be built as or converted to cogeneration systems supplying with heat nearby cities or part of a city, industries, greenhouses, fisheries, water desalination plants (in particular on islands or in countries with scarce water resources), etc. The distance of the users of heat from the plant and their dispersion are of crucial importance for the feasibility of the project.

When a city or a district is supplied with heat, the system is also called a "district heating cogeneration system". In district heating applications, in addition to the distance and dispersion of users, the thermal power required and the annual number of degree-days are important parameters for the feasibility. In most of the cases the economic distance for transfer of heat does not exceed 10 km; in exceptional cases it may reach 30 km.

In hot climates, district cooling during the summer may also be economically feasible. In such a case, heat supplied by the plant is used to drive an absorption cooling or air-conditioning unit. It is possible to have central coolers and distribute cold water to the users or to have local units. In the second case there is no need of cold water network; the hot water or steam network is used throughout the year.

Two other applications, which can be mentioned here, are landfills and sewage treatment plants. In both cases, a fuel gas is produced, which can fuel a gas engine cogeneration unit. Another alternative for city wastes, instead of being buried in landfills, is to be burned in boilers of steam turbine cogeneration systems. The heat produced can serve near-by communities. In particular for the sewage treatment plants, heat is required for the digestion tanks.

5.2 INDUSTRIAL COGENERATION

Many industrial processes require heat in order to be completed. They are classified according to the temperature level of the required heat:

a) Low temperature processes (lower than 100°C), e.g. drying of agricultural products, space heating or cooling, domestic hot water.

b) Medium temperature processes (100-300°C), e.g. processes in pulp and paper industry, textile industry, sugar factories, certain chemical industries, etc. In these processes heat is usually supplied in the form of steam.

c) High temperature processes (300-700°C), e.g. in certain chemical industries.

d) Very high temperature processes (higher than 700°C), e.g. in cement factories, primary metal industries, glass works.

Significant cogeneration potential exists in the following industries:

- food and beverage,
- textile,
- lumber,
- pulp and paper,
- chemicals,
- petroleum refineries,
- cement,
- primary metals.

Lower but non-negligible potential exists also in the following industries:

- glass,
- ceramics,
- wood.

Figure 39 and Figure 40 show the electrical load, the thermal load, the power to heat ratio and the number of operation hours per year for a number of industries in the U.S. These parameters are the first to evaluate when a cogeneration system is to be selected for a particular application.

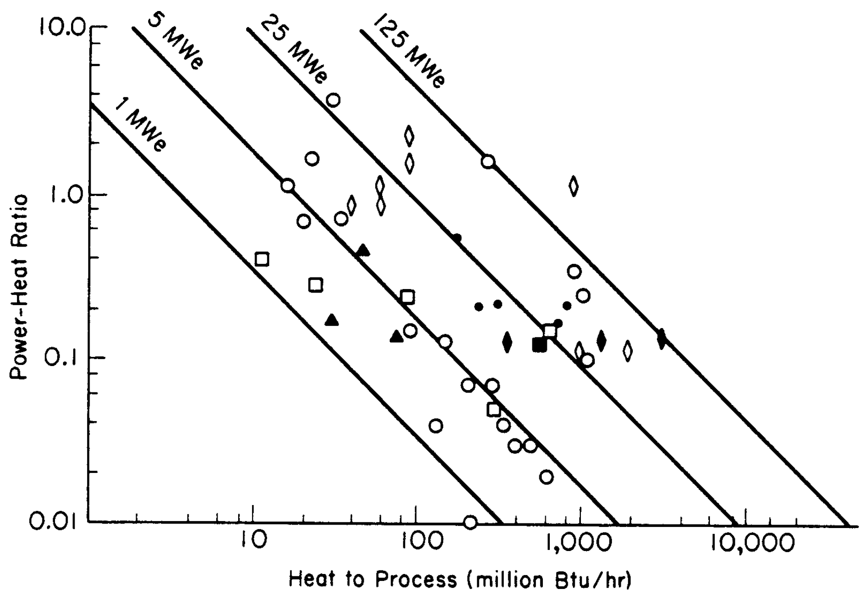


Figure 39: Load characteristics of industrial processes (Belding 1982)

Most of the industries with significant cogeneration potential have certain processes, which produce or reject heat at such a quantity and quality (temperature) that it is feasible to recover this heat for appropriate use. On the other hand, certain industrial processes (such as catalytic cracking in oil refineries) have fuel gases as a by-product, which can be burned either in a boiler or in the cogeneration system itself.

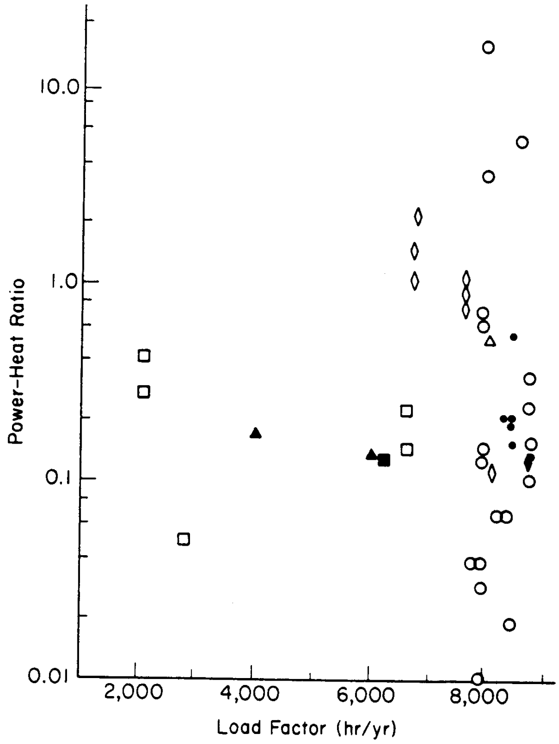


Figure 40: Power to heat ratio and operation period of industrial processes (Belding 1982)

Pulp and paper industry has large amounts of burnable wastes (process wastes, bark, scraps, and forestry residues unsuitable for pulp) that can be used as fuels in cogeneration systems.

In steel industry, off gases from the open-hearth steel making process provide a ready source of fuel to produce steam for driving blast furnace air compressors and other uses. Lately, open-hearth process is replaced by small scale mills that use electric arcs and have little or no thermal demand. However, if a user for thermal output can be found, cogeneration still can be applied.

In cement industry, bottoming-cycle cogeneration is applicable, in which heat of the kiln exhaust gas is recovered and used to produce steam for electricity generation. Other energy saving measures may have reduced the temperature of the kiln gas considerably. In such a case cogeneration may not be feasible.

Of particular interest is the application of cogeneration in industrial zones or parks. The electrical and thermal load of all the industries together is much higher than those of each individual industry. Furthermore, the duration of load is longer and the variation with time is much smaller than that of each industry in considered separately. These conditions are ideal for cogeneration by a central system.

5.3 COGENERATION IN THE BUILDING SECTOR

A combination of electrical and thermal load with level and duration appropriate for cogeneration often appears in buildings such as the following:

- houses and apartment buildings,
- hotels,
- hospitals,
- schools and universities,
- office buildings,
- stores, supermarkets, shopping centres,
- restaurants,
- swimming pools and leisure centres.

The list is not meant to be complete; in other buildings cogeneration may be feasible.

Cogenerated heat is used for domestic hot water, space heating or cooling, laundry facilities, dryers, swimming pool water heating. An indication of the electrical power required in various types of buildings is given in Table 5.

Table 5: Typical electrical load ranges in buildings.

Building	Electric load (kW)
Restaurants	50 – 80
Apartment buildings	50 – 100
Supermarkets	90 – 120
Hotels	100 – 2000
Hospitals	300 – 1000
Shopping centres	500 – 1500
Schools, universities	500 – 1500
Office buildings	500 – 2000

From the point of view of heating and cooling demands, three subsectors can be identified: (a) hospitals and hotels, (b) apartment buildings, (c) office buildings. Each one of these subsectors has its own profile. Other buildings (such as universities and stores) have load profiles which are combinations of the profiles of the three subsectors. The feasibility study and more so the final design of a cogeneration system must be based on the load profiles of the particular building; peak or average load values are not sufficient, because they may lead to wrong results and decisions.

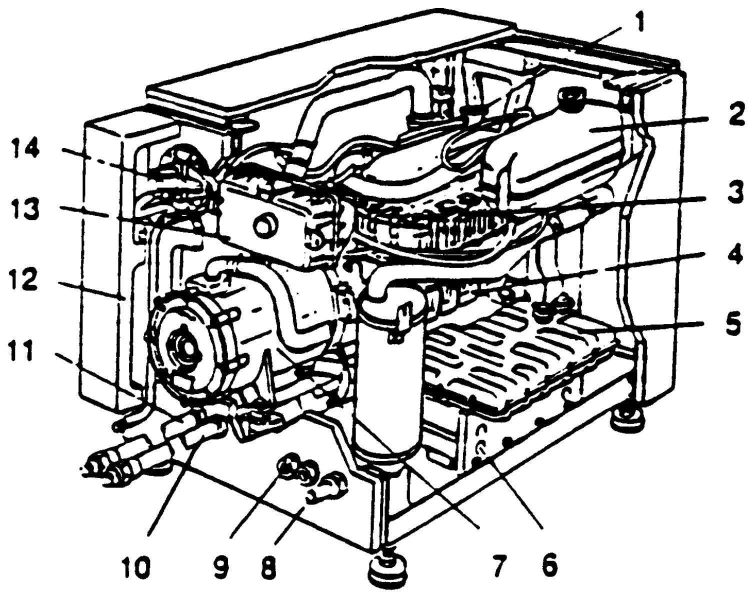
Feasibility studies have shown that in cold climates, like in north European countries, long space heating periods may make cogeneration economically viable. In hot climates, like in south European countries, space cooling in addition to space heating is necessary in most of the cases in order for cogeneration to be economically feasible.

The availability of natural gas and of standardised packaged cogeneration units gave a boost to cogeneration applications in buildings in certain European countries (e.g. United Kingdom, The

Netherlands) during the last decade. Packaged units for buildings have an electrical power output in the range 10-2000 kW and they have the following advantages:

- low cost,
- high power density (power per unit of volume),
- fast and easy installation (they are ready for connection with the electrical and piping network),
- automatic operation with no need of continuous attendance by specialised personnel.

The units usually have a reciprocating internal combustion engine. Liquid fuels can be used, but the most frequent fuel is natural gas, which is clean, relatively cheap, and which does not require storage. Figure 41 illustrates a small unit, which can be installed, e.g., in houses. Larger units are of the form illustrated in Figure 42. In order to reduce the noise to acceptable levels, acoustic enclosures, acoustic dampers and special noise-absorbing materials are used. In the upper power range of applications gas turbines can also be used.



1. Engine: Fiat 127
2. Water tank
3. Exhaust gas/water heat exchanger
4. Oil/water heat exchanger
5. Oil pan
6. Water/water heat exchanger
7. Electric generator
8. Exhaust gas outlet
9. Electrical connection
10. Hot water outlet
11. Cold water inlet
12. Thermal and acoustic insulation
13. Air inlet
14. Natural gas inlet

Figure 41: Standardised packaged cogeneration unit Fiat TOTEM 15 kW

Remote monitoring of cogeneration units contributes to the success of cogeneration applications in buildings. Microprocessors installed on the unit monitor the values of crucial operation parameters (temperatures, pressures, speed, voltage, etc.). The data are transmitted by a dedicated telephone line to a central computer. When the analysis of the data shows an oncoming failure, a maintenance team comes on site and performs the repair work before the failure occurs. A specialised company may monitor and take care of many units. Remote monitoring networks of this type operate in the United Kingdom successfully [CHPA 1992, EEO 1992].

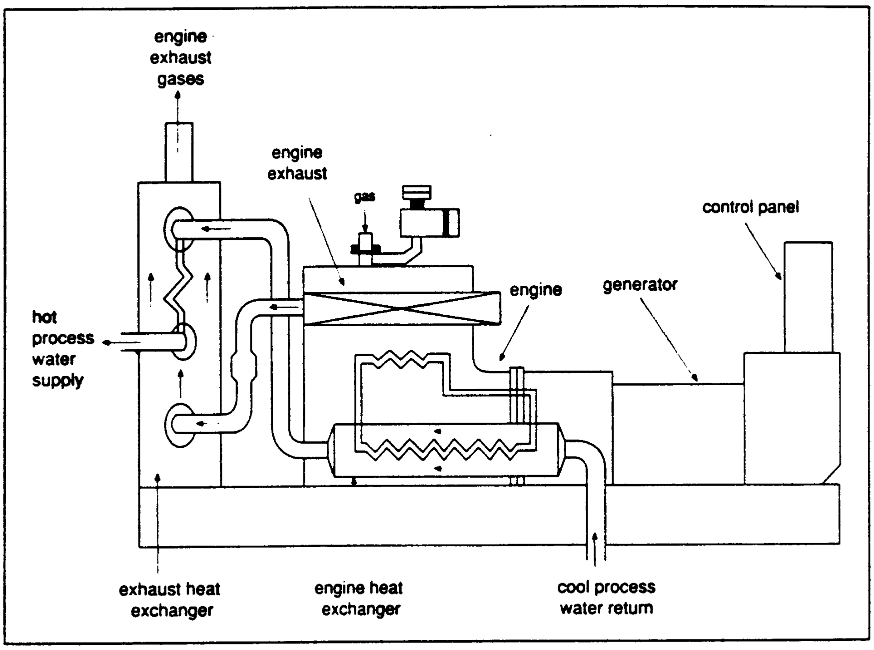


Figure 42: Main components of a small-scale packaged cogeneration unit with reciprocating internal combustion engine (Jennekens, 1989)

5.4 RURAL COGENERATION

Cogeneration is not widespread in the rural sector, but its application can result in energy savings and economic benefits in rural communities. Promising rural applications of cogeneration include ethanol production, drying crops or wood, and heating greenhouses, animal shelters, or homes.

Cogeneration units burning petroleum products or natural gas are always a possibility. However, of more interest and benefit to the rural communities are technologies that can use locally available biomass fuels such as crop residues, wood, and animal wastes. Gasifiers that convert crop residues or wood to low or medium heating value gas can be connected with internal combustion engines, which have been properly modified for long and trouble-free operation with this fuel. Such gasifiers are commercially available. Anaerobic digestion of animal wastes from confined livestock operations also could be used to produces biogas (a mixture of 60% methane and 40% carbon dioxide) to fuel an internal combustion engine. Anaerobic digestion has the advantage of solving a waste disposal problem, while producing not only biogas, but also an effluent that can be used directly as a solid conditioner, dried and used as animal bedding, or possibly treated and used as livestock feed [OTA, 1983].

Cogeneration can have significant economic and fuel savings advantages in rural communities and on farms. It can allow significant economic expansion (from new jobs and from increased revenue due to sales of energy products) by using local resources without increasing the base demand for energy.

There are also environmental benefits with this application. Prior to cogeneration, the residue was burned in an incinerator (it is not allowed to dump it) with heavy emission of pollutants due to incomplete combustion. In addition to these pollutants, there were also the emissions from burning the aforementioned quantities of liquid fuels. After cogeneration, not only the emissions from the substituted liquid fuels have been eliminated, but also the emissions from the residue have been decreased, because of the much better conditions of combustion in the boiler.

6 IMPACTS OF COGENERATION

Cogeneration can have both beneficial and adverse effects on the depletion of non-renewable energy (fuel) resources, on the utility system of a region or a country, on the environment, as well as on the society. Potential adverse effects could be mitigated substantially, if the cogeneration system is properly selected, designed, and sited, if it is carefully integrated in the energy system of the region, including existing and planned future energy supplies, and it is properly maintained and operated throughout its lifetime. A more detailed presentation of the effects follows.

6.1 IMPACTS ON FUEL UTILIZATION

All cogeneration systems, if properly designed and operated, save fuel energy, because they have higher efficiency than the efficiency of separate production of electricity and heat (Figure 1, page 8). For example, according to typical values of Figure 43, a steam-turbine cogeneration system reduces fuel energy consumption by about 15% with respect to the separate production of electricity by a steam power plant and of heat by a boiler; a Diesel engine system reduces fuel energy consumption by about 25% with respect to the separate production of electricity by a Diesel-engine generator and heat by a boiler. However, whether a cogeneration system saves an expensive, imported and non-renewable fuel such as oil, depends on the fuel used by the cogeneration system and the fuels used by the systems for the separate production of electricity and heat, which are displaced.

In addition to being more efficient than the separate production of electricity and heat, cogeneration systems save fuel energy for one more reason: usually they are much closer to the load than central power plants, thus reducing or even eliminating the losses of electrical energy along the transportation and distribution network, which can be as high as 8-10% of the electric energy at the source.

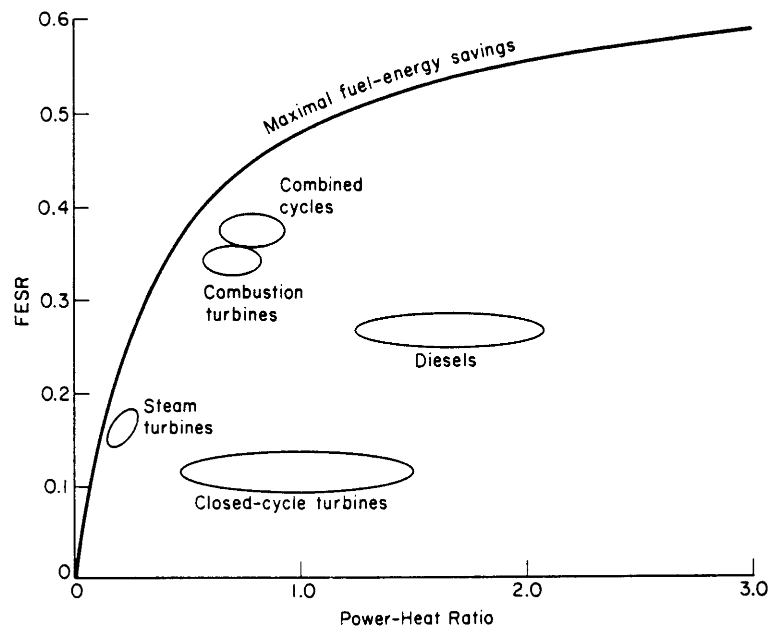


Figure 43: Relationship between fuel energy savings ration (FESR) and power to heat ration (PHR) for various cogeneration technologies (Belding 1989)

The selection of cogeneration technologies and of the fuels used should be in accordance with a long term regional or national energy planting (e.g. reduction of fuel oil imports, increase of renewables, rational use of natural gas, etc.).

6.2 IMPACTS ON ELECTRIC UTILITIES

In many places, utilities need to construct new power plants in order to either replace old ones or increase the capacity in view of an increase in demand. In these cases cogeneration can offer significant economic savings for utilities and it can be an attractive alternative to central power plants for the following reasons:

- Cogeneration adds new capacity and reduces the need for new investments in central power plants.
- The relatively small size of cogeneration systems and short construction lead-time can provide more flexibility than large base-load power plants for utilities in adjusting to unexpected changes in demand; furthermore cogeneration is a more cost-effective form of insurance against such changes than the overbuilding of central station capacity.
- Due to short construction lead-time, cogeneration can significantly reduce interest costs during construction, and consequently the overall cost of providing electricity.

Many cogeneration units operating in parallel and connected to the grid increase the reliability of power supply, but they can have a negative effect on the stability of the network, if they are not properly connected to the grid. To avoid problems of this type, the interconnection should follow certain standards and be performed in close co-operation with the utility. More details on electrical interconnection issues are provided in Chapter 4.

In places where utilities have an over-capacity or where they are committed to major construction programs that cannot be deferred, expansion of cogeneration could have a substantial negative economic impact on utilities. If large industrial and commercial sites have their own cogeneration systems and drop out of the utility's load, then the fixed costs of the utility must be divided by a lower quantity of electricity produced, thus resulting in higher electricity rates. In the long run, such a competition could be beneficial to the utility by reducing the need for new capacity, relieving financial pressures and lowering rate levels. But until the construction planning and budget is adjusted, the short-term negative effects could be significant.

One solution to the competition posed by cogeneration is for utilities to own cogeneration systems. Where cogeneration is economically competitive with other types of capacity additions, utilities could (or should) invest in it. Whether this is possible or not, or under which condition it is possible, depends on the legal and regulatory framework of a country.

6.3 ENVIRONMENTAL IMPACTS

6.3.1 Effects on Air, Water and Soil Quality

In addition to saving fuel and financial resources, cogeneration can also yield a reduction in polluting emissions, because it uses fuel more efficiently. The efficiency has a direct impact on emissions, as it is shown in Figure 44, provided the fuel used for cogeneration is not of lower quality than the fuel(s) used for the separate production of electricity and heat. In addition to the direct decrease in emissions, the reduced fuel consumption is accompanied by an indirect decrease in emissions in the rest of the fuel cycle: exploration, extraction, refining, processing, transportation, and storage.

However, it is not always certain that cogeneration will decrease total emissions; it depends on the cogeneration technology, the technologies used for separate production of electricity and heat, and the fuels used in themselves. It is also possible to have a decrease in a pollutant (e.g. CO_2) but an increase in another (e.g. NO_x). The importance of this subject makes it necessary to treat it quantitatively in a separate chapter (Chapter 6.4).

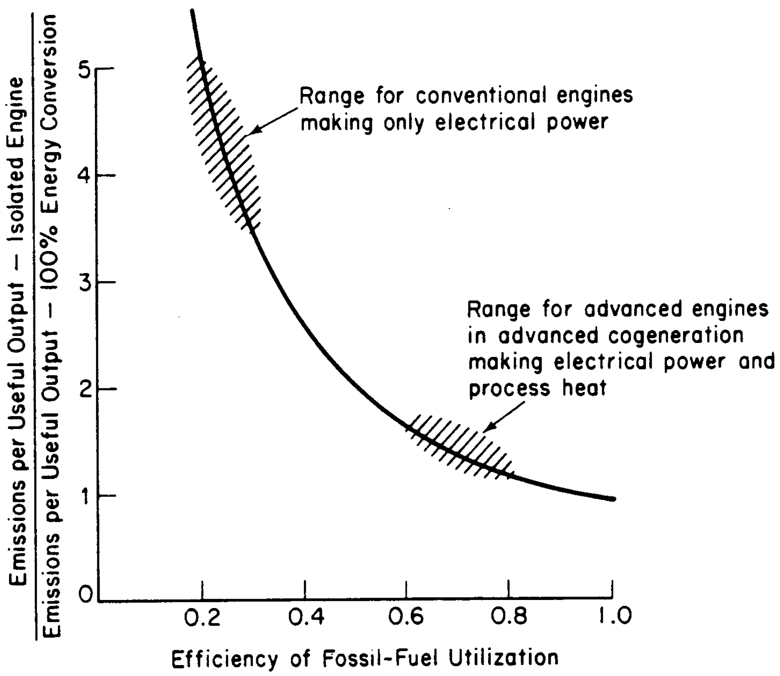


Figure 44: Impact of efficiency on emission of pollutants (Belding 1982)

When many small and dispersed cogeneration units replace a central power plant, improvement of the air quality is not certain. Central power plants are usually located in remote areas; they have pollution abatement equipment and tall stacks for dispersion of pollutants. On the contrary, cogeneration units are usually located close or inside urban areas and can have an adverse impact on local air quality.

Of the available cogeneration technologies, Diesel and Otto engines (gas engines) have the greatest potential for negative impacts on air quality, primarily due to the high (but usually controllable) emissions of nitrogen oxides and unburned hydrocarbons. These engines are the most common for cogeneration in buildings. Their shorter (than those in central power plants) stacks and the tall buildings, which inhibit the dispersion of pollutants, result in a higher total population exposure to pollutants. The effect of tall buildings in air currents and, thus, on pollutant dispersion is referred to as "*urban meteorology*". Urban meteorology can cause plumes to downwash or to be trapped and recirculated in the artificial canyons created by urban buildings, and can therefore result in very high local pollution levels during certain wind conditions. If at the same time temperature inversion occurs, the problem becomes much more severe.

Even though potential impacts on air quality are the primary environmental concern for cogeneration, also soil and water pollution, noise, and cooling tower drift may be important. Soil and water pollution can result from fuel transportation and handling, waste disposal (sludge, ash, degraded lubricating oil), blowdown from boilers and wet cooling systems, runoff from coal piles. Noise is emitted by the cogeneration system itself and by the increased traffic due to the erection and operation of the system. Cooling tower drift can also be a nuisance for those living in the vicinity.

The aforementioned adverse effects may pose a problem in urban areas. In order to minimise these effects on the population, certain prerequisites should be satisfied if a cogeneration system is to be installed and operated inside a building or, in general, in urban areas:

- Careful selection of the site.
- Selection of cogeneration technology with low emissions of pollutants.
- Installation of pollution abatement and control equipment.
- Installation of elastic foundation and sound insulation and attenuation (Chapter 6.3.2).
- Construction of a stack higher than the surrounding buildings.
- Provision for safe collection and removal of liquid and solid wastes.

These measures may be costly in certain cases, and the persons involved may tend to ignore or avoid them. In order to prevent the consequences, a strong permit review process should be established by the government or the municipality.

Fuel cells are expected to be much more user and environment friendly, thanks to their much lower emissions and noise level.

6.3.2 Noise and Vibration

Source of noise is not only the cogeneration system but also the increased traffic related to the erection and operation of the system (e.g. trucks supplying the system with fuel and/or other material, and removing wastes). Careful scheduling is perhaps the only way of reducing nuisance from traffic. Specific measures can be taken to reduce the noise coming from the system itself.

Cogeneration units have to comply with existing regulations, which specify maximum levels for noise emissions in order to protect people who live or work nearby. A couple of examples are given below [Jennekens, 1989].

Noise emitted by an internal combustion engine is usually higher than 95 dB(A). In industrial installations, a noise level of 80 dB(A) or lower is usually considered that it will not cause any hearing problems, in the long run. For housing districts, lower limits are specified, which depend on the particular place and, perhaps, time of the day. Consequently, measures have to be taken to lower the noise level to the acceptable limits. When a cogeneration unit is to be placed in the basement of a building, the following requirements must be satisfied:

- Limit noise in the room itself using an acoustic enclosure, which will reduce the noise by at least 25 dB(A). Use acoustic dampers in the combustion air inlet channel. Use noise-absorbing materials on the walls.
- Limit noise to rooms in the immediate vicinity. Reinforce the construction of walls, ceilings and floors. Limit the number of windows and doors to a minimum.
- Limit noise to the outside. Use acoustic dampers on the exhaust gas channels.

If a cogeneration unit is to be placed in the basement or on the roof of a building, in addition to the aforementioned measures for noise reduction, special attention should be given to avoid transmission of vibrations through the building structure. For this purpose, the engine is placed on an elastic foundation and, if needed, additional equipment for absorbing or damping the vibration is used.

Often the cheapest solution to noise and vibration problems, which is also a solution when there is not enough space inside, is to place the cogeneration unit outside the building in a container equipped with noise reduction systems. A well-built container with silencers in the intake and exhaust ducts and in the container ventilators, with noise-reducing insulation, double doors and no other openings can reduce the noise level of a cogeneration unit to 30 dB(A) at 60 m from the container.

6.4 EFFECTS OF COGENERATION ON AIR QUALITY

The most important issue regarding the environmental impacts is whether cogeneration improves or degrades air quality. This issue is especially critical in urban areas, where air quality may be lower than the national average, and the tolerance for additional emissions may be small.

Assessment of the effects of cogeneration on air quality is often complicated, because effects vary from one location to the other. For example, the effect may be positive (decreased emissions) in the vicinity of the central power plant serving the region, but it may be negative (increased emissions) at the site where the cogeneration system is located. This difference makes it necessary to perform the analysis at two levels: local level, global level. These subjects are treated qualitatively and, to the extent possible, quantitatively in the following.

6.4.1 Exhaust Gas Emissions

The components of the exhaust gases, which are of concern because they are hazardous, are the following:

- carbon dioxide (CO_2),
- carbon monoxide (CO),
- nitrogen oxides (NO_x),
- sulfur oxides (SO_x, usually sulfur dioxide: SO_2),
- unburned hydrocarbons (C_xH_y, also symbolised with the letters HC or UHC),
- solid particles, called also “particulates”.

Laws and regulations specify maximum emission levels for power plants. They usually are applicable for cogeneration systems too. Some countries may have a special legislation for cogeneration systems.

Table 7 on page 85 gives typical levels of uncontrolled emissions for various cogeneration technologies. It should be mentioned that the emission level depends on the cogeneration technology, the year of manufacture, the condition (age) of the unit, the rated power, the load of operation (percent of the rated power), the type and quality of the fuel used, the operation of pollution abatement equipment, etc. Consequently, it is evident that tables such as Table 7 are appropriate for first estimates only. Accurate assessment of a system should be based on data pertinent to the particular case.

6.4.1.1 CO_2 Emissions

Carbon dioxide emissions depend primarily on the type, quality and quantity of the fuel used. To a satisfactory approximation, complete combustion can be assumed, which is very close to reality, when combustion takes place with excess air and the combustion equipment is in good condition and adjusted correctly. Then, the quantity of the emitted CO_2 is calculated by the equation

$$m_{CO_2} = \mu_{CO_2} m_f \tag{5.1}$$

where

$$\mu_{CO_2} = \frac{44}{12} c \tag{5.2}$$

$$m_f = \frac{E}{\eta H_u} \tag{5.3}$$

m_{CO_2} mass of emitted CO_2,

μ_{CO_2} emissions of CO_2 per unit mass of fuel (e.g. kg CO_2/kg fuel),

c mass content of carbon in fuel (e.g. kg C/kg fuel),

m_f mass fuel consumption,

E useful energy produced by the system,

η efficiency of the system, based on the lower heating value of fuel,

H_u lower heating value of fuel.

Equations (5.1) – (5.3) are applicable not only to cogeneration systems, but to any system burning fuel. For example, when they are applied to a power plant or a cogeneration system, E is the electricity produced and η is the electrical efficiency, η_e, as defined by Eq. (2.3). If they are applied to a boiler, E is the useful thermal output of the boiler, Q, and η is its thermal efficiency, η_Q as it appears in Eq. (2.16). Typical values of c, μ_{CO_2} and H_u for various fuels are given in Table 5.1.

It has to be clarified that if the values of the parameters appearing in Eqs. (5.2) and (5.3) change for any reason (e.g. change in efficiency due to partial load, change in quality and consequently in c and H_u of fuel), then the total CO_2 emitted during a period of time results as an integral over time (or summation over various times intervals) of Eq. (5.1).

Reduction of CO_2 emissions

The only way to decrease the CO_2 produced for a certain quantity of useful energy production is to increase the efficiency of the fuel utilization (if the fuel remains the same). However, the quantity of CO_2 finally released to the environment would be lower than the one produced, if CO_2 could (at least partially) be used in a process. Large-scale applications, perhaps not easily combined with cogeneration, include the enhancement of crude oil and coal recovery from oil wells and coal mines, respectively. Also, CO_2 can be used with hydrogen for production of synthetic hydrocarbons. More close to cogeneration applications is the use of CO_2 for enhancing the growth rate of plants cultivated in greenhouses.

6.4.1.2 *Emissions of CO and HC*

In spite of the excess air, at certain points in the combustion region the conditions are such that molecules of carbon monoxide are not further oxidised to carbon dioxide, or molecules of hydrocarbons are not burned to produce carbon dioxide and water vapor. The quantities of these two constituents in the exhaust gases are kept at a minimum; significant amounts would indicate low efficiency of combustion due to improper mixing of fuel with air, or bad operating conditions.

There is no simple way to calculate the concentration of CO and HC in the exhaust gases. Experimental measurements performed by the manufacturers are used to derive results such as those presented in Table 7 to Table 9.

Reduction of CO and HC emissions

Proper maintenance and adjustment of the combustion equipment is absolutely necessary to keep CO and HC emissions inside specified limits. If a system does not satisfy legal limits or if further reduction is required, then a catalytic converter can be installed to promote the oxidation of both CO and C_xH_y. Supplementary air may be required for this oxidation, in particular if low excess air is used in the combustion.

6.4.1.3 *NO_X Emissions*

Nitrogen oxides are formed in the combustion process from nitrogen chemically bound in the fuel or present in the air. It is the pollutant that causes the greatest concern and legislative attention; the toxic effects of NO_X occur at concentrations which are at least 10 times lower than the levels at which CO becomes toxic.

Research and development in combustion equipment succeeded in reducing NO_X emissions from gas turbines by nearly an order of magnitude during the last years. Also, boilers and steam power plants have relatively low NO_X emissions (Tables 5.2 – 5.4). However, Diesel and gas engines have much higher levels, which are due to the high combustion temperature and pressure. In the remaining of this subsection, attention will be focused on these engines, because they are mostly used for cogeneration in buildings, where the air quality problem is more severe.

The most important parameters that determine the level of NO_X formation in a Diesel or gas engine are

- the combustion temperature in the primary zone of combustion chamber,
- the retention time in the primary combustion zone,
- the combustion pressure,
- the mixing rate of air and fuel.

The stoechiometric air ratio

$$\lambda = \frac{\text{real mass of combustion air}}{\text{stoichiometric mass of combustion air}} \tag{5.4}$$

often called “lambda ratio” for convenience, has a direct or indirect effect on the aforementioned parameters and, consequently, on the NO_X emissions. It also affects CO and HC emissions, efficiency and power output of the engine. An example of this effect is given by Figure 45.

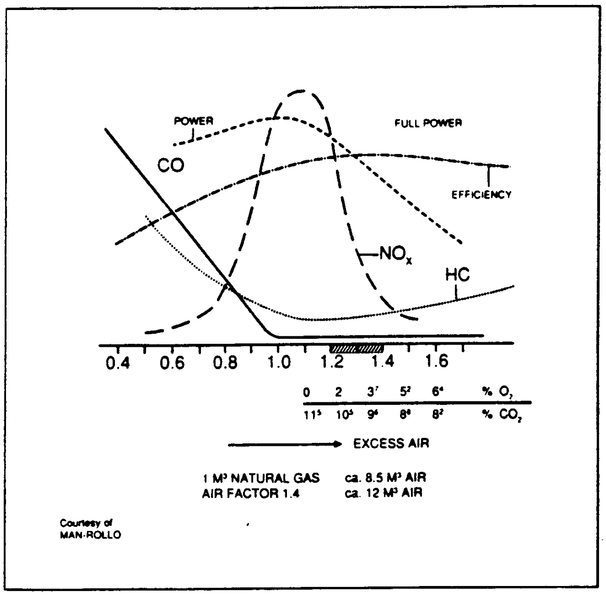


Figure 45: Effect of stoichiometric air ratio (λ) on NOx, CO and HC emission, power output and efficiency of a gas engine (Jennekens 1989)

Reduction of NO_X emissions

In gas turbines, low-NO_X burners, steam injection in the combustion chamber and catalytic reduction of the exhaust gases are the most usual techniques for NO_X abatement.

The methods for reduction of NO_X emissions in Diesel and gas engines could be classified in two categories:

- active reduction of NO_X formation through modified engine design and operation,
- passive reduction of NO_X in the exhaust gases.

Active reduction of NO_X

Several methods are used by the manufacturers, which aim at reducing the combustion temperature and achieving complete and quick combustion:

- *Delaying the ignition timing.* It decreases the temperature in the cylinder. However, it has adverse effects on the power output and efficiency of the engine, which limits the period by which the ignition timing may be delayed.
- *Changing the stoechiometric air ratio (λ).* As shown in Fig. 5.3, NO_X emissions are maximum at $\lambda \cong 1.1$ (for the particular engine). They can be reduced either by rich combustion ($\lambda < 1$), or by lean combustion ($\lambda > 1.1$). Values of $\lambda < 0.9$ are not acceptable, because they cause excessive formation of CO and HC (incomplete combustion). The value of λ finally selected is the result of a compromise between low emissions and high power and efficiency. Supercharging helps in meeting NO_X limits with no loss of power.
- *Air-fuel control.* During partial load operation, the air and fuel flow rate must be controlled so that the performance of the engine is good and the emissions are low. The values of λ at partial load may be considerably different than the value at nominal power.

- *Exhaust gas recirculation (EGR).* Part of the exhaust gases (up to 40%) is combined with the air and fuel mixture. Thus, the mixture entering the cylinders has a lower heating value. Consequently, the maximum combustion temperature is lower resulting in decreased NO_X formation. However, EGR may lead to increased corrosion rate, and decreased power output and efficiency.

Passive reduction of NO_X

While active techniques aim at decreasing the quantity of NO_X produced during combustion, passive techniques aim at decreasing the NO_X content in the exhaust gases by catalytic reduction of NO_X to nitrogen and oxygen. Catalytic converters can be divided into two groups:

- *Non-selective catalytic reduction (NSCR).* As the name implies (non-selective), it reduces not only NO_X, but also CO and C_XH_Y. This is why the devices are called three-way catalytic converters. The process is based on the property of rhodium to temporarily bind oxygen present in NO_X, thus releasing the nitrogen. The oxygen subsequently reacts with CO and C_XH_Y to form CO_2 and H_2O. Control of λ is of utmost importance in the proper functioning of the converter, because exhaust gases must have no oxygen. For this reason, such a converter can be used only with rich-burn engines (low λ) or engines with exhaust gas recirculation (EGR). The effect of λ on the conversion efficiency of the process is illustrated in Figure 46. As it is shown in the figure, the operating margin with respect to λ values is narrow. The conversion reactions are exothermic. If too much unburned fuel leaves the engine, it will result in too high temperatures in the converter, causing damage. EGR and non-selective catalytic converters reduce NO_X emissions by 80-90%, CO by about 80% and HC by about 50%.

- *Selective catalytic reduction (SCR).* It is used to reduce only NO_X in the exhaust gases. It is used with engines which operate with excess air, such as two-stroke, supercharged, and lean-burn engines. Ammonia (NH_3) has to be added in the exhaust gas for the NO_X reduction. The cheapest way is to inject liquid ammonia solution into the converter. Since the quantity of the solution depends on the load of the engine, a control system is required to adjust the flow of ammonia.

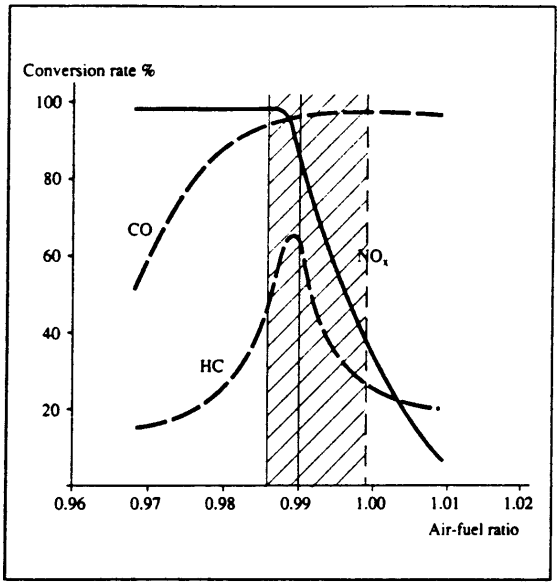


Figure 46: Effect of stoichiometric air ratio (λ) on conversion of non-selective catalytic reduction (Jennekens 1989)

A more detailed discussion of the NO_x reduction techniques appears in Jennekens (1989). The effect of these techniques on NO_x reduction, and on engine capacity and efficiency is indicated in Table 10 on page 88. The decreases given in the table are relative; for example an efficiency reduction of 3% on an efficiency of 33% results in an absolute decrease in efficiency of 1%, i.e. from 33% to 32%. Results are given for various engines characterised by the values of λ: type A engines with $\lambda = 1$, type B engines with $\lambda = 1.1$-1.4, and type C engines with $\lambda > 1.4$. All reductions are related to the normal operating conditions of the engines.

6.4.1.4 *SO_x Emissions*

Sulphur present in the fuel appears in the exhaust gases as sulphur oxides, primarily as sulphur dioxide (SO_2). If it is considered that all sulphur is burned to SO_2, then the mass of emitted SO_2 is

$$m_{SO_2} = 2\left(1 - r_{SO_2}\right) s\, m_f \qquad (5.5)$$

where

m_{SO_2} mass of emitted SO_2 with the exhaust gases,

r_{SO_2} SO_2 retention factor,

s mass content of sulphur in fuel (e.g. kg S/kg fuel),

m_f mass fuel consumption.

For liquid and gaseous fuels, it is $r_{SO_2} = 0$. For solid fuels burned on a grate or in a fluidised bed, retention of part of SO_2 may occur in the solid material. In such a case, it is $r_{SO_2} > 0$. The exact value of r_{SO_2} depends on the particular equipment. With natural gas, SO_x is usually of no concern, because the sulphur content in the fuel is very low.

Reduction of SO_2 emissions

It is possible to remove up to 95% of SO_2 from the exhaust gases by flue gas desulphurisation techniques using, e.g., water and limestone (post-process abatement). These techniques are applied on rather large plants. For smaller systems, like those of small to medium size cogeneration, the use of low-sulphur fuel is more economical; fuels with a high sulphur content (e.g. fuel or Diesel oil) are chemically treated in the refinery and low-sulphur fuels are produced (pre-process abatement). In case of solid fuels burned on a grate or in a fluidised bed, retention of SO_2 by mixing limestone with the combustible material is also possible (process abatement).

6.4.1.5 Emissions of particulates

Particulates are of concern primarily for plants burning solid fuel, e.g. coal, and for Diesel engines burning fuel oil or Diesel oil (Table 7 on page 85). For the former, filters or scrubbers are installed. For the latter, good quality fuel and proper control of combustion are the means to keep particulates emission at acceptable levels.

6.4.2 Emissions Balances

It is useful to compare a cogeneration system with the separate production of electricity and heat (systems replaced by cogeneration) from the point of view of pollutant emissions. This can be done with an emissions balance for each pollutant. However, the balance equation, and consequently the result, depends on the boundary of the region under study. In the separate production of electricity and heat, electricity usually comes from central power plants, which are far from the cogeneration site, while heat in produced locally by boiler(s). If all sources of pollutants are taken into consideration, no matter where they are, *a global balance* is obtained. If only on site sources are considered, *a local balance* is obtained.

6.4.2.1 Global emissions balance

The balance equation for pollutant X is written

$$\Delta m_X = m_{XC} - m_{XW} - m_{XQ} \quad (5.6)$$

where

Δm_X mass difference of emitted pollutant X due to cogeneration; if $\Delta m_X > 0$, cogeneration causes an increase in X emissions,

m_{XC} mass of emitted pollutant X with cogeneration,

m_{XW} mass of pollutant X emitted for the separate production of the same quantity of electricity, W, as that produced by cogeneration,

m_{XQ} mass of pollutant X emitted for the separate production of the same quantity of heat, Q, as that produced by cogeneration.

If emissions are calculated using data such as those of Table 7 - Table 9, then the following equations are applicable:

$$m_{XC} = \hat{\mu}_{XC} W \qquad (5.7)$$

$$m_{XW} = \hat{\mu}_{XW} W \qquad (5.8)$$

$$m_{XQ} = \hat{\mu}_{XQ} Q \qquad (5.9)$$

where

$\hat{\mu}_{XC}, \hat{\mu}_{XW}, \hat{\mu}_{XQ}$ specific emissions of pollutant X (mass per useful energy) for cogeneration, separate production of electricity and separate production of heat, respectively, (Table 7 - Table 9 or data from manufacturers),

W electrical energy produced by cogeneration,

Q useful thermal energy produced by cogeneration.

If detailed information is available for the variation of the specific emissions with the load of the units or with other operation parameters, then Eqs. (5.7) – (5.9) should be replaced with time integrals or summations.

Examples of global emissions balances for six different combinations of cogeneration systems and systems for separate production of electricity and heat are given in Table 5.6. Specific emissions from Table 7 - Table 9 have been used. As the examples demonstrate, an impressive reduction of CO_2 emissions is achieved: 50-100 kg per 100 kWh of cogenerated electricity. Even with the lower value, i.e. 50 kg/100 kWh_e, for every TWh (10^9 kWh) of cogenerated electricity, a reduction of 500000 tons of CO_2 emissions is achieved. If in the European Union an increase of cogenerated electricity by 100 TWh per year is achieved, which is considered possible, then the annual CO_2 emissions will be decreased by 50 million tons! This fact, together with other advantages of cogeneration mentioned in previous chapters, justify the measures and incentives for promotion of cogeneration.

Attention has to be paid to the fact that certain cogeneration technologies, e.g. Diesel engines, may result in an increase of CO, NO_x and HC emissions. If such a system is to be installed in a sensitive area, then the implementation of pollution reduction techniques (Chapter 6.4.1) might be necessary.

When natural gas replaces other fuels, such as fuel oil, emissions of SO_x and particulates nearly vanish (a reduction by 90-99.8% is achieved).

6.4.2.2 Local emissions balance

If, in case of separate production, electricity would come from a central power plant far from the site of cogeneration system, then locally the balance is between cogeneration and the boiler for separate production of heat. Equation (5.6) is simplified to the form

$$\Delta m_X = m_{XC} - m_{XQ} \qquad (5.10)$$

where the symbols are the same as in Eq. (5.6).

As an application example, global and local emissions balances of a gas engine cogeneration system as compared with three different combinations of systems for separate production of electricity and heat have been performed. Data and results are given in Table 11. Values of specific emissions have been taken not from Table 7 - Table 9 but from data available for particular systems. The importance of the boundary of the region, for which the analysis is performed, is revealed by the results of Table 12.

Table 6: Typical properties of fuels for calculation of CO_2 emissions.

Fuel	Carbon content ($c \cdot 100$)	CO_2 emissions μ_{CO_2}	Lower heating value of fuel (H_u)
	%	kg CO_2/kg fuel	kJ/kg
Natural gas	75	2.75	49000
Diesel oil	83	3.05	42500
Fuel oil 0.7% S	86.5	3.17	41500
Fuel oil 2% S	85	3.12	41000
Peat*	58	2.13	7800
Lignite*	64	2.35	24000
Coal*	80	2.93	30000

* Data are valid for fuel with no moisture and ash.

System	Fuel	Electrical efficiency (%)	Specific emissions (gr/kWh_e)					
			CO_2	CO	NO_x	HC	SO_x	Particulates
Diesel	Diesel 0.2% S	35	738.15	4.08	15.56[(2)]	0.46	0.91	0.32
	Dual[(1)]		593.35	3.81	11.30[(3)]	3.95	0.09	0.04
Gas engine	Natural gas	35	577.26	2.80	1.90	1.00	≈0	≈0
Gas turbine	Natural gas	25	808.16	0.13	2.14	0.10	≈0	0.07
	Diesel 0.2% S		1033.41	0.05	4.35	0.10	0.91	0.18
Gas turbine-low NO_x	Natural gas	35	577.26	0.30	0.50	0.05	≈0	0.05
Steam turbine (new)	Coal	25	1406.40	0.26	4.53	0.07	7.75	0.65
	Fuel oil		1100.00	≈0	1.94	0.07	5.18	0.65
	Natural gas		808.16	≈0	1.29	0.26	0.46	0.07
Fuel cells (PAFC)	Natural gas	40	505.10	0.03	0.03	0.05	≈0	≈0

(1) 90% of energy supplied by natural gas and 10% by Diesel oil.
(2) Engines of modern designs emit 11-12 gr NO_x/kWh_e.
(3) Engines of modern design emit 7-8 gr NO_x/kWh_e.

Table 7: Typical values of uncontrolled emissions from cogeneration systems

System	Fuel	Efficiency (%)	Specific emissions (gr/kWh$_e$)					
			CO_2	CO	NO_X	HC	SO_X	Particulates
Steam turbine (old)	Coal 3% S	34	1034.12	0.18	3.13	0.05	19.87	1.41
	Fuel oil 1% S	31	887.06	0.18	3.18	0.05	4.76	0.23
	Natural gas	31	651.74	0.09	3.04	0.18	≈0	0.05
Steam turbine (new)	Coal	31*	1134.20	0.18	2.50	0.05	6.00	0.14
	Fuel oil low sulfur	31	887.06	0.18	1.36	0.05	3.63	0.14
Gas turbine	Diesel oil	34	759.86	0.55	2.40	0.18	0.14	0.18
	Natural gas	34	594.24	0.55	1.95	≈0	≈0	0.05
Gas turbine low NO_x	Natural gas	38	531.68	0.30	0.50	≈0	≈0	0.04

* Lower efficiencies of new steam turbine systems are due to NO_x and SO_2 abatement equipment

Table 8: Typical values of emissions from central power plants

System	Fuel	Specific emissions (gr/kWh_{th} of useful heat)					
		CO_2	CO	NO_x	HC	SO_x	Particulates
Boiler for hot water	Natural gas	252.55	0.03	0.19	0.02	≈0	0.02
	Diesel 0.2% S	322.94	0.06	0.25	0.02	0.37	0.03
Steam boiler	Coal	439.50	0.08	1.36	0.02	2.32	0.20
	Fuel oil	343.73	0.06	0.57	0.02	1.55	0.20
	Natural gas	252.55	0.03	0.39	≈0	≈0	0.02
Industrial steam boiler	Coal 2% S	439.50	0.16	1.12	0.08	5.65	0.98
	Fuel oil 1% S	343.73	0.06	0.78	0.02	2.03	0.30
	Natural gas	252.55	0.03	0.33	≈0	≈0	0.03

An 80% efficiency of the boiler has been considered.

Table 9: Typical values of emissions from water and steam boilers

Table 10: Effects of NO_X reduction techniques [Jennekens, 1989].

Action	NO_x reduction	Electrical efficiency reduction	Capacity reduction
	%	%	%
Delayed ignition			
Type A, $\lambda = 1.05$	30	3	3
Type B, $\lambda = 1.25$	40	3	3
Type C, $\lambda = 1.4$	50	3	3
Leaner operations			
Type A, $\lambda = 1.05$	n.a.		
Type B, $\lambda = 1.25$	50	0	5
Type C, $\lambda = 1.4$	50	2	5
Enriched operations			
Type A, $\lambda = 1.05$	20	1	-5
Type B, $\lambda = 1.25$	n.a.		
Type C, $\lambda = 1.4$	n.a.		
EGR (max 15% to $\lambda = 1$)			
Type A, $\lambda = 1.05$	30	3	10
Type B, $\lambda = 1.25$	70	6	0
Type C, $\lambda = 1.4$	n.a.		
Catalytic reduction			
Type A, $\lambda = 1.0$	95	1	0
Type B, $\lambda = 1.0$ + EGR	95	6	0
Type C, $\lambda = 1.0$ + SCR	85	1	0

n.a. = not applicable.

Pollutant	Systems under comparison											
	C1 – S1		C1 – S2		C2 – S1		C2 – S2		C3 – S1		C3 – S2	
	gr	%	gr	%	gr	%	gr	%	gr	%	gr	%
CO_2	-51024	-46.2	-88458	-59.9	-62454	-52.0	-99888	-64.3	-70791	-46.7	-108225	-57.2
CO	+320	+524.6	+357	+1487	-33	-52.4	+4	+15.4	-68	-100.0	-31	-100.0
NO_x	+812	+255.3	+802	+244.5	-290	-85.3	-300	-85.7	-283	-68.7	-293	-69.4
HC	+375	+1875	+388	+5543	-15	-75.0	-2	-28.6	+4	+18.2	+17	+188.9
SO_x	-208	-95.9	-794	-98.9	-273	-99.3	-859	-99.8	-415	-90.0	-1001	-95.6
Particulates	-44	-91.7	-40	-90.9	-51	-91.1	-47	-90.4	-77	-91.7	-73	-91.3

Cogeneration systems

C1. Dual-fuel Diesel engine (90% of energy from natural gas, 10% from Diesel oil); $\eta_e = \eta_{th} = 0.35$ (PHR = 1).

C2. New gas turbine fueled with natural gas; $\eta_e = 0.35$, η_{th}=0.45 (PHR = 0.778).

C3. New steam turbine fueled with natural gas; $\eta_e = 0.25$, $\eta_{th} = 0.55$ (PHR = 0.455).

Systems for separate production of electricity and heat

S1. Gas turbine fueled with Diesel oil and industrial steam boiler with fuel oil.

S2. New steam turbine plant fueled with coal and industrial steam boiler with fuel oil.

Negative sign indicates reduction of emissions with cogeneration.

Percent values are given with reference to the separate production of electricity and heat.

Table 11: Examples of global emissions balance: comparison of cogeneration with separate production of electricity and heat (results per 100 kWh$_e$)

System specifications: Natural gas, $\dot{W} = 1000\ kW_e$, $\dot{Q} = 1300\ kW_{th}$, $\eta_e = 0.38$, $\eta_{th} = 0.494$
Operation: 5000 h/a

Specific emissions of systems (gr/kWh of useful energy)

System	CO_2	CO	NO_x	SO_x	HC	Particulates
Gas engine	531.7	2.5	1.7	≈0	4.5	≈0
Power plant-Lignite	1250	0.18	1.2	1.5	0.05	1.5
Power plant-Fuel oil	900	0.18	1.6	14.5	0.05	1.4
Boiler-Diesel oil (0.2%S)	323	0.06	0.25	0.37	0.02	0.03
Boiler-Natural gas	253	0.03	0.19	≈0	0.02	≈0

Global emissions balances (kg/a)

Case	Power plant	Boiler	CO_2	CO	NO_x	SO_x	HC	Particulates
1	Lignite	Diesel oil	- 5,691,500	+ 11,210	+ 875	- 9,905	+ 22,120	- 7,695
2	Fuel oil	Diesel oil	- 3,941,500	+ 11,210	- 1,125	- 74,905	+ 22,120	- 7,195
3	Fuel oil	Natural gas	- 3,486,500	+ 11,405	- 735	- 72,500	+ 22,120	- 7,000

Local emissions balances (kg/a)

Case	Power plant	Boiler	CO_2	CO	NO_x	SO_x	HC	Particulates
1	Lignite	Diesel oil	+ 558,500	+ 12,110	+ 6,875	- 2,405	+ 22,370	- 195
2	Fuel oil	Diesel oil	+ 558,500	+ 12,110	+ 6,875	- 2,405	+ 22,370	- 195
3	Fuel oil	Natural gas	+ 1,013,500	+ 12,305	+ 7,265	0	+ 22,370	0

Table 12: Example of annual global and local emissions balances of a gas-engine cogeneration system

6.5 ECONOMIC AND SOCIAL IMPACTS

Cogeneration has attracted attention not only for its benefits or adverse effects on energy efficiency, the environment, and utility planning and operations, but also for its possible implications on the economic and political institutions traditionally involved in the supply and demand of electrical and thermal energy. Many analysts feel that, as global reserves of oil and natural gas dwindle, major changes must occur in the technical, economic, and institutional context for energy supply and demand in industrialised societies. Cogeneration is likely to be a part of these energy system changes.

Moreover, many people advocate the use of dispersed generating technologies not solely because of the perceived technical, economic, or environmental advantages, but also due to the belief that an energy system based on these technologies will be more compatible with traditional democratic, participatory, and pluralistic institutions than a strategy based on continued reliance on large-scale centralised technologies [OTA, 1983].

Certain economic impacts on electric utilities have been mentioned in chapter 6.2. Detailed results of a study for the economic impacts of cogeneration on utilities in the U.S.A. are reported in OTA (1983).

Cogeneration may also benefit the national economy, if it results in reduction of the total expenses for imported fuels. Furthermore it may have important social and economical implications in sectors such as business development patterns, and the role of policies in energy supply; they are briefly outlined in the following.

- As advanced cogeneration technologies with greater fuel flexibility emerge, new business opportunities should arise for supplying alternate fuels such as municipal solid waste, biomass, synthetic liquid and gaseous fuels. These opportunities can be captured not necessarily by the existing utilities, but by local authorities (municipalities) or private entrepreneurs.
- Cogenerators will more likely purchase a complete cogeneration system from vendors acting as intermediaries between manufacturers and purchasers. These vendors will be able to offer a wider range of packaged systems than a single manufacturer, and to tailor the system to a user's specific needs. They also may evolve as total service companies offering repair and maintenance too.
- Cogeneration may need financial assistance. Traditional lending institutions such as banks could become financiers for this type of projects, but new schemes such as Third Part Financing (TPF) companies can be established.

It is usual that central power plants are built in large sizes and located in remote areas. Construction and operation of these plants causes a relocation of many working persons from their hometown to the place of the plant. Conversely, cogeneration units are of smaller size and are installed more close to inhabited areas. Their dispersion in many places creates new job opportunities locally. As a result the work force remains in the area, and the whole activity related with the construction, operation and maintenance of the cogeneration system, as well as with the opportunities potentially created due to the availability of electricity and heat, contributes to the economic development of the local society.

7 ECONOMIC ANALYSIS OF COGENERATION SYSTEMS

In addition to being energy efficient, a cogeneration system must be economically viable in order to proceed with the investment. In this chapter, information for capital, operation and maintenance costs of cogeneration systems is given, criteria of economic performance are defined, a procedure for economic assessment is developed, and application examples are presented. It must be emphasised that cost information given here is indicative and it can be used for first estimates only. Furthermore, cost changes with time. Therefore, the final decisions should be based on cost data provided by companies which will supply, install and, perhaps, maintain the equipment.

7.1 COST OF COGENERATION SYSTEMS

In order to perform a feasibility study or an economic analysis, there is need to know the cost for constructing and operating a system. Related information is given in this chapter.

7.1.1 Investment Cost

Investment cost is also called capital cost or initial cost or first cost. It consists of equipment cost, installation cost, and "soft" (called also "project" or "engineering and management") costs.

7.1.1.1 Equipment costs

Equipment costs consist of the cost for purchase of the equipment, including any taxes, and transportation on the site. They depend on the components comprising the system and their particular specifications. The most important of those are the following.

- *Prime mover and generator set.* Power output, alternative fuel capability, generator voltage, emission control techniques in prime mover, noise reduction.
- *Heat recovery and rejection system.* Required media (steam, hot or chilled water), quality of thermal energy (pressure and temperature), number of pressure and temperature levels required, emission control equipment, water treatment unit.
- *Supplementary firing.* Additional thermal capacity, alternative fuel capability.
- *Exhaust gas system and stack.* Exhaust gas temperature, single or multiple stacks for multiple engines, emission control equipment, need for bypass valve.
- *Fuel supply.* Interconnection with fuel supply system, storage capability, fuel metering; in particular for natural gas, need for compressor, if the line pressure has to be increased.
- *Control board.* Extent of automation, requirements for unattended operation, inter-connection with the user's facility.
- *Interconnection with the electric utility.* Connection line, one- or two-way connection, safety and metering equipment.
- *Piping.* Connection with the water, steam, compressed air (if needed) circuits.
- *Ventilation and combustion air systems.* Ducts, filters, sound attenuation equipment.

- *Shipping charges.*
- *Taxes*, if applicable.

7.1.1.2 Installation costs

They consist of:

- Installation permits,
- Land acquisition and preparation,
- Building construction,
- Installation of equipment,
- Documentation and as-built drawings.

Some of these costs may not be applicable, e.g. if the space is already available for the cogeneration system.

7.1.1.3 "Soft" (or project) costs

Design and professional service fees for the analysis, planning and development of a cogeneration system are frequently referred to as soft costs. They may be in the range of 15-30% of the equipment and construction cost. The most significant professional fees and other costs are the following.

- Architectural / engineering design fees.
- Construction management fees.
- Environmental studies and permitting costs.
- Special consultants and inspectors.
- Legal fees.
- Letters of credit.
- Training.

Additional costs may incur under certain financial arrangements (e.g. interest paid during construction, bank fees, debt insurance).

In budget estimates, a contingency or allowance for unforeseen costs is taken into consideration. Early in the design process, the contingency may be in the range of 15-20%. At the completion of the design, when uncertainty is reduced, the contingency may be reduced to 5%. Examples of investment costs breakdown are given in the following tables:

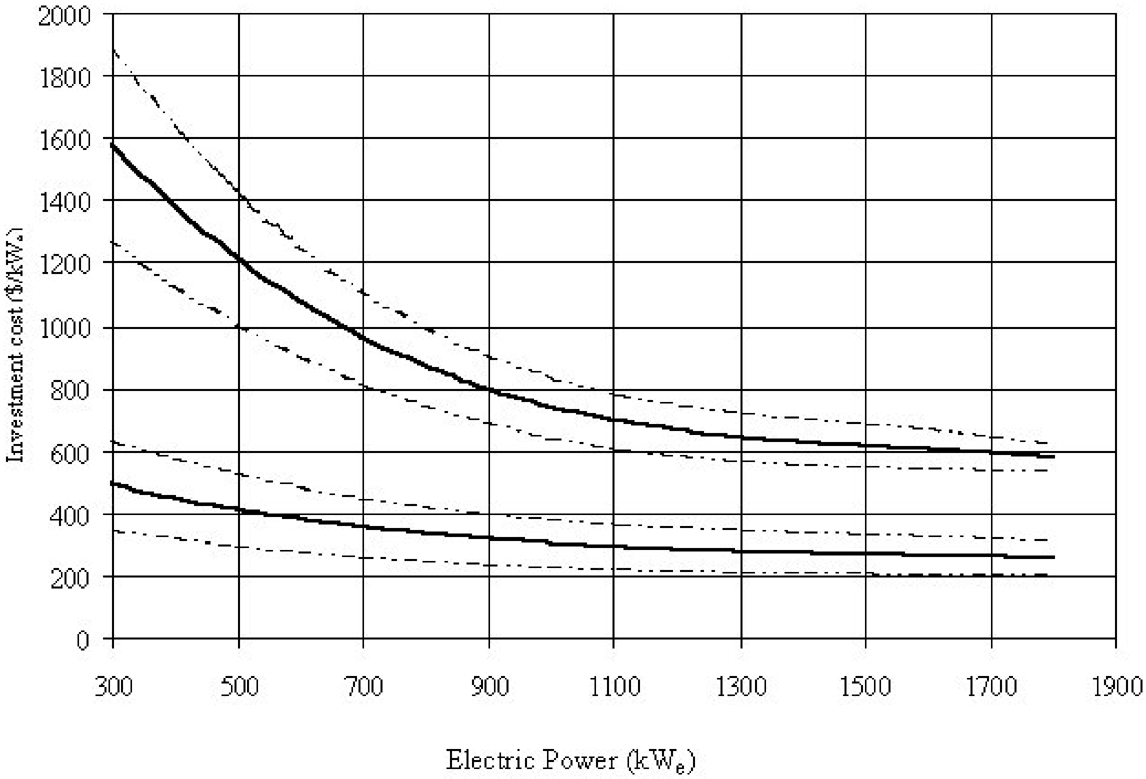
Table 13: Breakdown of investment costs for small-scale cogeneration [Jennekens, 1989].

Type of cost	% of total
Cogeneration unit including heat recovery equipment	55
Instrumentation, regulation and control	15
Auxiliary systems	5
Connection to grid	5
Civil work and/or acoustic enclosure	10
Installation and commissioning	5
Project costs	5
Total	100

Table 14: Examples of breakdown of investment costs for a gas turbine and a steam turbine cogeneration system [Belding, 1982].

Type of cost	% of total	
	Gas-turbine(1)	Steam-turbine(2)
Turbinen-Generator	34	50 (3)
Heat recovery steam generator	20	-
Instrumentation, regulation, control	4	3
Auxiliary systems	7	4
Connection to grid	3	6
Civil work (land, buildings, roads)	6	11
Engineering and construction management	11	11
Contingency	15	15
Total	100	100

(1) Nominal power 10 MW.
(2) Non-condensing turbine. Nominal power 30 MW.
(3) Boiler cost is included.



Cogeneration module	Complete system
• Engine • Generator • Cooling circuit of the engine	• Cogeneration module • Electrical equipment • Adaptation of the heating system • Cooling • Ventilation • System control • Building, foundation • Fuel supply • Permission to install and operate

Figure 47: Specific investment cost of small-scale cogeneration systems with reciprocating internal combustion engine.

It is evident that the investment cost of a cogeneration project depends on a lot of factors, which characterise the particular project. Any generalised costs cannot be useful but only for an initial and very rough estimate. For this purpose, cost information published in the literature has been used to draw the graphs appearing in Figure 47 - Figure 49 -. Costs obtained form these figures may have an uncertainty of ± (20-25)%. In Figure 47 in particular, dotted lines indicate the uncertainty zone.

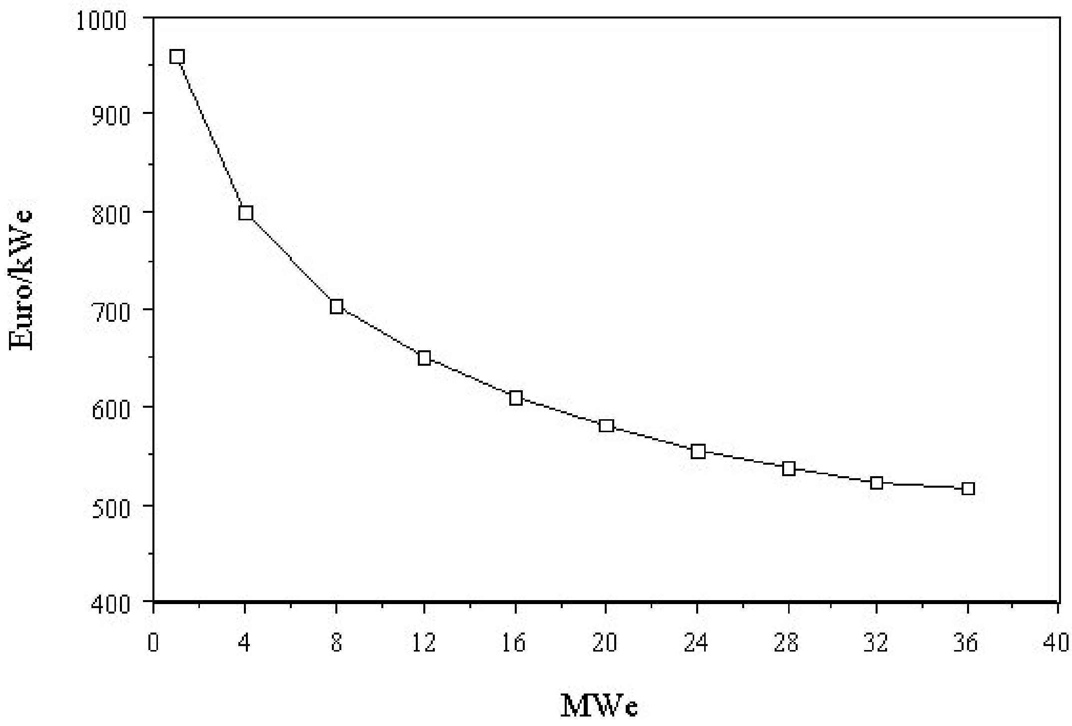


Figure 48: Specific investment cost of Diesel-engine cogeneration systems.

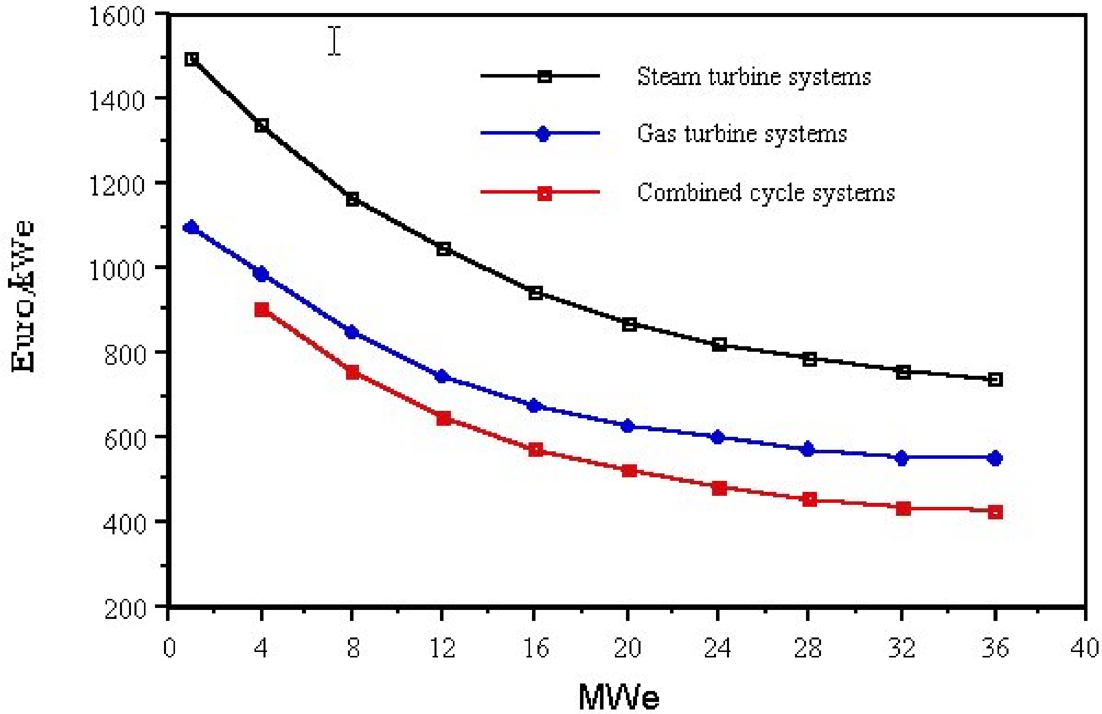


Figure 49: Specific investment cost of medium- to large-scale cogeneration systems.

7.1.2 Operation and Maintenance Costs

Operation and maintenance costs depend to a certain extent on decisions taken at the design and construction phase of the system. It is possible that actions reducing the initial cost may lead to increased operation and maintenance costs, with a negative impact on the total economic performance of the project. The major operation and maintenance costs are the following.

Fuel is usually the most significant operation cost, which may reach 80% of the total operation cost. An exception can be when fuel is a by-product of a process or it is produced by wastes. The particular fuel tariff or the agreement between the cogenerator and the fuel supplier have to be taken into consideration in calculating fuel cost. Much lower costs are due to other consumables, such as lubricating oil, make up water and chemicals.

Personnel costs depend on the size of the system and the degree of automation. Smaller cogeneration systems (up to about 10 MW) can operate unattended. Medium-size systems (10-30 MW) will typically require attended operation (one person may be sufficient). Larger systems will require attended operation with two or more persons. If the system includes an exhaust gas boiler, then safety regulations may require attended operation even for smaller systems. If solid fuel is used, then increased personnel may be required. It is important to clarify whether additional personnel is needed, or if the personnel already available (e.g. in an industry) can operate the system. In the latter case, the incremental personnel cost will be zero.

Maintenance costs depend on factors such as type of prime mover, type of fuel, operation cycle, operating environment. Heavy-duty engines usually require less maintenance than light-weight engines. The use of heavier or dirty fuels and operation in a dirty environment will increase maintenance costs. Frequent cycling (starting up and close down) will increase thermal stresses, which results in increased maintenance costs. If skilled personnel is available on site, then the incremental maintenance cost will be lower. A variety of maintenance contracts may also be available; if such a contract is signed, it will directly affect the cost. If a performance monitoring system is installed with the capability to identify and predict potential failures, then maintenance as-needed instead of as-scheduled can be followed. In such a case, it is expected that maintenance costs will be reduced.

Insurance adds also to the operation costs. It may be only for equipment failure, or it may be extended also to loss of income, loss of savings, or business interruption. The cost of insurance varies depending on the type of prime mover, the equipment performance history, and the system design and operating mode. It can be in the range of 0.25-2% of the capital cost. In some cases, particularly for smaller units, the insurance may be covered under the owner's overall insurance program at no additional cost.

Other operation costs include administrative and management fees, taxes, interest on loan (if any).

It can be considered that operation and maintenance costs consist of fixed and variable costs. Fixed costs are those which occur no matter whether the system operates or not. Variable costs depend on the operation load and schedule of the system. Detailed logistics are needed to separate the costs of a particular system into these two categories.

As with the investment cost, operation and maintenance costs are system-specific. For a first estimate only, cost information published in the literature can be used, which often does not separate between fixed and variable costs, but provides average costs. This is the case with the values given in Table 15.

Table 15: Maintenance costs for cogeneration systems.

System	Maintenance cost* (Euro/MWh$_e$)
Steam turbine	2.3 – 1.5
Gas turbine	5.4 – 4.6
Combined cycle	5.4 – 4.6
Reciprocating engine	9.2 – 5.8
* Lower values are applicable to larger systems.	

7.2 DEFINITIONS OF CERTAIN ECONOMIC CONCEPTS

In economic analysis, certain parameters are used to evaluate measures of economic performance, which are used as criteria for any decisions regarding the investment. For reader's convenience and in order to avoid any misunderstanding, pertinent definitions are given in the following. More detailed explanations can be found in the literature [Thuesen and Fabrycky (1984), Peters and Timmerhaus (1980)].

7.2.1 Economic Parameters

7.2.1.1 Interest and interest rate

The term *interest* is used to designate a rental amount charged by financial institutions for the use of money. The amount of capital, on which interest is paid, is called *principal*. *Interest rate* is defined as the amount of interest per unit of principal in a unit of time. There are two aspects of interest rate:

- *Borrowing interest rate*. It is paid out as a result of borrowing funds. Interest paid in this connection is a cost.
- *Market interest rate*. It is received as a result of investing funds, either by loaning it or by using it in the purchase and operation of a facility. Interest received in this connection is gain or profit. Market interest rate can also be the expected or desirable return on an investment.

7.2.1.2 Economic life-cycle of an investment

The economic life-cycle of an investment is considered equal to the time required in order to recover the initial investment and the desirable returns on the investment. If equipment cost is a significant part of an investment, the economic life-cycle must be equal to or shorter than the real (technical) life of the major equipment.

7.2.1.3 Inflation and inflation rate

In general, the cost of goods and services increases with time (inflation). A decrease has also occurred in certain periods of time (deflation), but it is rather a seldom exception. The increase in prices per unit of time is called inflation rate; it is usually expressed as an annual percentage rate representing the increase in prices over a one-year time span. Deflation is characterised by a negative inflation rate.

Inflation rate can be different for different goods and services, e.g. equipment, labour, fuel, spare parts, etc. The inflation rate has a compounding effect.

7.2.1.4 Present worth (or present value)

The value of money change with time. If a principal P is invested at the present time (t = 0), the accumulated amount of principal and interest in the future, after N time periods, will be

$$F = P \cdot \prod_{t=1}^{N} (1 + d_t) \tag{6.1}$$

where d_t is the market interest rate during the period t. Any time period can be used: day, month, six-months, year, etc; a year is the most usual one.

Conversely, the amount of money, which must be invested at the present time in order to have a certain amount accumulated at a definite time in the future, is determined by the equation

$$P = \frac{F}{\prod_{t=1}^{N} (1 + d_t)} \tag{6.2}$$

The amount P is called the *present worth* (or *present value*) of the future amount F.

If the interest rate d is considered constant throughout all the time periods, then Eq. (6.2) takes the form

$$P = \frac{F}{(1 + d)^N} \tag{6.3}$$

Since d is used to discount future amounts to their present worth, it is called also *market discount rate*. The present worth of a past cash flow can be determined by the equation

$$P = F \cdot \prod_{t=-1}^{-n} (1 + d_t) \tag*{(6.2)′}$$

or, if d_t is considered constant:

$$P = F(1 + d)^n \tag*{(6.3)′}$$

An example of applying Eq. (6.2)′ or (6.3)′ is for calculating the present worth of the initial investment, when the expenses have been taking place during the construction period of several years.

7.2.1.5 *Present worth factor*

If a cash flow (expense or revenue) is repeated in every time period for N periods and it only changes due to inflation, then the present worth of all the N amounts is determined by the equation

$$P = \sum_{t=1}^{N} P_t = A \cdot PWF(N, i, d) \tag{6.4}$$

where

A	the first amount,
PWF	present worth factor,
i	inflation rate in a time period (e.g. annual inflation rate)
d	market discount rate.

If it can be considered that the cash flow occurs at the beginning of each period, then the present worth factor is determined by the equation

$$PWF(N, i, d) = \sum_{t=1}^{N} \frac{(1+i_t)^{t-1}}{(1+d_t)^{t-1}} = \begin{cases} \dfrac{x^N - 1}{x - 1}, & i \neq d \\ N, & i = d \end{cases} \tag{6.5}$$

where $\quad x \equiv \dfrac{1+i}{1+d} \quad (6.6)$

Equation (6.6) and the last part of Eq. (6.5) are valid only if i and d are considered constant with time.

If it can be considered that the cash flow occurs at the end of each period, then

$$PWF(N, i, d) = \sum_{t=1}^{N} \frac{(1+i_t)^{t-1}}{(1+d_t)^{t}} = \begin{cases} \dfrac{1}{d-i}\left[1 - \left(\dfrac{1+i}{1+d}\right)^N\right], & i \neq d \\ \dfrac{N}{1+i}, & i = d \end{cases} \tag{6.7}$$

The last part of Eq. (6.7) is valid only if i and d are considered constant with time.

7.2.1.6 *Capital recovery factor*

Let it be considered that a deposit of amount P is made today at an interest rate d. The depositor wishes to withdraw the same amount A at the end of each period, so that when the last withdrawal is made, there should be no funds left on deposit. The amount A is determined by the equation

$$A = P \cdot CRF(N, d) \tag{6.8}$$

where CRF is the *capital recovery factor*, determined by

$$CRF(N, d) = \frac{d(1+d)^N}{(1+d)^N - 1} = \frac{d}{1 - (1+d)^{-N}} \tag{6.9}$$

Equations (6.8) and (6.9) are used also to calculate the annualised capital cost A of an investment P, as well as the depreciation of equipment. The depreciation is charged as a cost by making equal charges each year, the first payment being made at the end of the first year.

7.2.1.7 Constant and actual values

In an economic analysis, cash flows can be represented in terms of either actual values or constant values.

Actual value or *current value* represents the real amount of money received or disbursed at any instant of time.

Constant value represents the hypothetical purchasing power of future receipts and disbursements in terms of purchasing power of money at a certain base year. This base year can be arbitrarily selected, although it is often assumed to be time zero, i.e. the beginning of the investment or the beginning of the economic life-cycle of the system.

The conversion of actual values at a particular point in time to constant values (based on purchasing power N years earlier) at the same point in time is performed by use of the inflation rate. The following equation is valid:

$$F' = \frac{F}{\prod_{t=1}^{N}(1+i_t)} = \frac{F}{\left(1+\bar{i}\right)^N} \tag{6.10}$$

where

- F actual amount of money,
- F' converted to constant values amount,
- i_t annual inflation rate during year t,
- $\bar{i}$ average annual inflation rate for the N years:

$$\bar{i} = \left[\prod_{t=1}^{N}(1+i_t)\right]^{1/N} - 1 \tag{6.11}$$

Investments in cogeneration systems are capital-intensive, and they often have long pay-back periods. Therefore, it is more accurate to work with expenses and revenues converted to constant values.

In order to perform an economic analysis based on current values, there is need to know the annual inflation rates. However, most analyses are concerned with future outcomes of proposed investments, and the estimation of actual- or constant-value cash flows must be based on estimated future inflation rates. In order to avoid estimating such an uncertain parameter as the future inflation rate, and also in order to simplify the calculations, an analysis based on constant values can be performed. An approach in between is the following: the general (average) inflation rate is considered equal to zero, and the differential inflation rate of a particular good and service (e.g. fuel, labor, spare parts) is estimated, which is the difference between the particular inflation rate and the general inflation rate. In this way, the uncertainty could be decreased.

Equation (6.10) converts the cash flow F at N in the actual-value domain to a cash flow F′ at N in the constant-value domain. Thus, the inflation rate i is used to convert from one domain to the other at the same point in time.

To transform values to their equivalencies at different points in time within the actual-value domain, the market interest rate d is used, Eqs (6.2), (6.3).

The *inflation-free rate* d′ is the basis for computing equivalencies in the constant-value domain. Thus, the equations

$$P' = \frac{F'}{\prod_{t=1}^{N}\left(1+d'_t\right)} \tag{6.12}$$

or, if d′ is constant with time, in a simplified form

$$P' = \frac{F'}{\left(1+d'\right)^N} \tag{6.13}$$

determine the constant-value equivalence at t = 0, P′, of the constant-value cash flow F′ at t = N. Therefore, equivalencies in the constant-value domain should be computed by means of inflation-free rate d′.

If the constant-value base year is time zero, then at time zero actual values and constant values have identical purchasing power. If analysis in either the actual-value domain or the constant-value domain is to be considered, the equivalent amount at time zero in either domain must be equal. Based on these arguments, the following relationship among i, d and d′ can be proved:

$$d' = \frac{1+d}{1+i} - 1 \tag{6.14}$$

Which of the domains will be selected for the analysis will depend on whether the result is to be in actual or constant value, whether the cash flow estimates are in actual or constant values, and on the ease of executing the calculations.

7.2.2 Measures of Economic Performance

A measure or index of economic performance is used either as an indication of whether an investment (e.g. in a cogeneration system) is viable in itself, or as a basis for comparison among alternative investments (e.g. among various cogeneration systems or among cogeneration and completely different activities). The most common measures, which are appropriate also for investments in cogeneration, are defined below. In certain cases, there is need of a reference system, for comparison. If not otherwise specified, the conventional approach for covering electrical ant thermal needs will be considered as reference, i.e. purchase of electricity from the grid and production of heat by a boiler on site.

7.2.2.1 Net present value of the investment (NPV)

It is called also *net present worth.* It is the present worth of the total profit of an investment, which results as the difference between the present worth of all expenses and the present worth of all revenues, including savings, during the life cycle of the investment (system). A general expression for the net present value is

$$NPV = \sum_{t=0}^{N} \frac{F_t}{\left(1+d_t\right)^t} \tag{6.15}$$

where F_t is the profit or net cash flow (revenue + savings – expenses) in year t. Including savings is of particular importance for the economic assessment of systems such as cogeneration systems and renewable energy technologies.

The term “profit” here is used with a general meaning: F_t can be negative, when the net result of year t is a loss. F_0, in particular, usually represents the present worth of the investment (t = 0) and it is negative. If the construction period has lasted for a few years, Eq. (6.2)′ or (6.3)′ can be used to calculate the present worth of each year’s expenses. Their summation is F_0.

There are three characteristic situations:

- NPV > 0: The investment is economically viable under the specified conditions (N, d). The return on investment is higher than d.
- NPV = 0: The investment is economically viable and it has a return on the investment equal to d.
- NPV < 0: The investment is not viable economically, under the specified conditions (N, d).

7.2.2.2 Internal rate of return of investment (IRR)

It is called also rate of return or return on investment (ROI). It is defined as the interest rate that causes the present worth of a series of expenses to be equal to the present worth of a series of revenues. Alternatively, it is defined as the interest rate that will result in zero NPV. That is, the internal rate of return of an investment is the market discount rate d which satisfies the equation:

$$NPV = \sum_{t=0}^{N} \frac{F_t}{\left(1+d^*\right)^t} = 0 \tag{6.16}$$

Hence:

$$IRR = d^* \tag{6.17}$$

Let’s assume that

$$x \equiv \frac{1}{1+d^*}$$

Then, Eq. (6.16) is written

$$F_0 + F_1 x + F_2 x^2 + \ldots + F_N x^N = 0 \tag{6.18}$$

The Nth-degree polynomial has N roots, but of practical meaning are only those which result in $0 \le d^* < \infty$ ($0 < x \le 1$). Very often, there is only one root in this interval. However, in case of multiple roots in the interval, since there is no rational means for judging which of them is the most appropriate for determining economic performance, the common practice is to avoid the IRR as a measure of economic performance.

7.2.2.3 Payback period

There are two definitions of the payback period, as given below.

Simple payback period (SPB)

It is defined as the length of time required to recover the investment cost (first cost) from the net cash flow produced by that investment with no consideration of interest rate (d = 0). If F_0 is the investment cost and F_t is the net cash flow in period t, then the simple payback period is defined as the smallest value of N that satisfies the expression

$$\sum_{t=0}^{N_{min}=SPB} F_t \ge 0 \tag{6.19}$$

In preliminary assessments, F_t is often considered constant (i.e. it does not change with t): $F_t = F$. Then Eq. (6.19) leads to:

$$SPB = \frac{-F_0}{F} \tag{6.20}$$

which, of curse, gives a positive value of SPB, if $F > 0$; otherwise the investment results in a loss.

The simple payback period is calculated easily, but it has serious deficiencies because it does not consider:

- the time value of money,
- the performance of the investment after the payback period, including the magnitude and timing of cash flows and the expected life of the investment.

Because of these limitations, the simple payback period tends to favour shorter-lived investments, which in many cases is economically unsound: investments with longer SPB may have a higher NPV, which in the long run is preferable.

The simple payback period can be justified as a criterion of investment only in situations where there is a high degree of uncertainty concerning the future and a firm is interested in its cash position and borrowing commitments.

Discounted payback period (DPB)

It is defined as the length of time required to recover the investment cost and the desirable interest from the net cash flow produced by the investment. The discounted payback period is equal to the smallest value of N that satisfies the expression

$$\sum_{t=0}^{N_{min}=DPB} \frac{F_t}{(1+d)^t} \geq 0 \tag{6.21}$$

If F_t can be considered constant with time in constant values, i.e. $F_t = F$, then an analytic solution of Eq. (6.21) is obtained:

$$DPB = \frac{-\ln\left(1+\frac{F_0}{F}d\right)}{\ln(1+d)} \tag{6.22}$$

There are investments which have a reasonable simple payback period, but their discounted payback period shows that the investment cost will never be recovered.

An investment is considered economically viable with the payback period as a criterion, if its payback period satisfies the investor's expectations.

7.2.2.4 Benefit to cost ratio (BCR)

It is defined as the ratio of the present worth of total benefit to the present worth of total cost of an investment throughout its life cycle N:

$$\mathrm{BCR} = \frac{\sum_{t=1}^{N} \frac{B_t}{(1+d_t)^t}}{\sum_{t=0}^{N} \frac{C_t}{(1+d_t)^t}} \tag{6.23}$$

where:

B_t benefit in year t,

C_t cost in year t; in particular, $C_0 = -F_0$.

An alternative definition is obtained if the annual cost is subtracted from the annual benefit:

$$\mathrm{BCR}' \equiv \frac{\sum_{t=1}^{N} \frac{B_t - C_t}{(1+d_t)^t}}{C_0} = \frac{\sum_{t=1}^{N} \frac{F_t}{(1+d_t)^t}}{-F_0} \tag{6.24}$$

Then, it can be proved easily that:

$$\mathrm{BCR}' = 1 - \frac{\mathrm{NPV}}{F_0} \tag{6.25}$$

It is clear that the two definitions lead to different results. In fact, if $\mathrm{BCR} \geq 1$, then $\mathrm{BCR}' > \mathrm{BCR}$. More accurately, BCR' could be called “net benefit to initial cost ratio”.

An investment is economically viable with the benefit to cost ratio as a criterion, if it is BCR ≥ 1.

7.3 PROCEDURE FOR ECONOMIC ANALYSIS OF COGENERATION SYSTEMS

The measures defined in chapter 7.2.2 are used to assess the economic viability and performance of an investment in a cogeneration system, as well as to compare investments in alternative systems. In order to calculate the value of each measure using the equations of the previous chapter, there is need to estimate (a) the initial cash flow, F_0, and (b) the net cash flow F_t in year t ≥ 1. A procedure for these estimates is presented in the following.

7.3.1 Initial Cash Flow (F_0)

Vendor quotations or information from other sources (e.g. Chapter 7.1) is used to estimate the investment cost C of the system, where C is considered as the present worth of the cost (time t = 0). If there is need, instructions given in Chapter 7.2.2.1 can be used to determine the present worth of costs occurring during the years of construction.

In certain countries, investment grants are provided for promotion of cogeneration. They are given with no obligation on cogenerator’s side, other than observing certain standards, in particular regarding the real operating efficiency of the system. In addition, the investor may borrow a certain amount of money from a bank or another institution. In order to take these possibilities into consideration, it is written

$$F_0 = C_g + L - C = \left(c_g + \ell - 1\right)C \tag{6.26}$$

where

- C investment cost of the system,
- C_g amount of grant,
- L amount of loan,
- c_g grant as a fraction of the investment cost: $c_g = C_g/C$,
- ℓ loan as fraction of the investment cost: $\ell = L/C$.

Of course, zero values for C_g or L are acceptable and do not cause any problems with the rest of the calculations.

7.3.2 Net Cash Flow for the Years of Analysis (F_t, $t \geq 1$)

7.3.2.1 Annual operation profit

The operation of a cogeneration system causes expenses, but it also results in savings (avoided cost of electricity that otherwise would be purchased from the grid and heat that would be produced by a boiler), and also in revenues, if excess electricity is sold. The *annual operation profit* of the cogeneration system is defined as

$$f_t = \left(C_e + R_e + C_h - C_f - C_{om}\right)_t \tag{6.27}$$

where

- C_e avoided cost of electricity, i.e. cost of electricity that, if not cogenerated, it would be purchased from the grid,
- R_e revenue from selling excess electricity, if any,
- C_h avoided cost of heat, i.e. cost of heat that, if not cogenerated, would be produced by boiler(s),
- C_f cost of fuel for the cogeneration system,
- C_{om} operation and maintenance cost (except fuel) of the cogeneration system.

Subscript t indicates the year ($t = 1, 2, \ldots, N$).

The avoided cost of electricity, C_e, is a function of the cogenerated electricity which is consumed on site, and on the tariff structure for electricity supplied by the grid, which may consider not only energy, but also power, power factor, time of the day, peak demand, etc. A cost component which is often overlooked, but it may be non-negligible, is an increase of the electricity bill due to taxes: utilities often include some tax imposed on behalf of a government body (state and/or local municipality). For example, such a tax of 8% on the total cost of electricity is imposed on apartments in Athens. Since all these parameters are site-specific, it is not possible to give a general expression for C_e here.

The revenue R_e from excess electricity sold to the grid or to a third party is a function of the electrical energy and of the tariff structure for electricity sold to the grid or of the agreement between the parties involved. For the same reasons as with C_e, no general expression for R_e will be attempted here.

The avoided cost of heat includes cost of fuel for the boiler that would produce the thermal energy, if not cogenerated, as well as other operation and maintenance expenses for the boiler and related auxiliary equipment. The fuel cost is a function of the fuel quality and the fuel tariff structure. In the simplest case, where a constant unit cost of fuel applies, the cost of fuel for the boiler during a year is calculated by:

$$C_{fB} = c_{fB} m_{fB} = c_{fB} \int_t \frac{\dot{Q}}{H_{uB} \eta_B} dt = c_{fB} \frac{Q}{\overline{H}_{uB} \overline{\eta}_B} \tag{6.28}$$

where

c_{fB} cost per unit mass of fuel for the boiler,

m_{fB} mass of fuel that would be consumed by the boiler during the year,

$\dot{Q}$ useful thermal power at a certain instant of time,

Q annual useful thermal energy produced by the cogeneration system,

H_{uB} lower heat value of fuel for the boiler,

η_B efficiency of the boiler,

$\overline{H}_{uB}$, $\overline{\eta}_B$ annual average values of H_{uB} and η_B, respectively.

Capital cost of boiler is usually not taken into consideration, because it is assumed that a boiler would be installed anyway for back up. However, if this is not the case, then the capital cost of boiler should be included.

The cost of fuel for the cogeneration system is a function of the fuel quantity and the fuel tariff structure. If a constant unit cost can be assumed, then it can be written

$$C_f = c_f m_f = c_f \int_t \frac{\dot{W}}{H_u \eta_e} dt \cong c_f \sum_i \frac{\dot{W}_i}{H_{ui} \eta_{ei}} \Delta t_i \tag{6.29}$$

where

c_f cost per unit mass of fuel for the cogeneration system,

m_f annual fuel consumption of the cogeneration system,

$\dot{W}$ electric power output at a certain instant of time,

H_u lower heating value of fuel for the cogeneration system,

η_e electrical efficiency at load $\dot{W}$ of the cogeneration system.

The last term in Eq. (6.29) substitutes the integral with a summation over periods of time Δt_i defined so that in each period i a steady-state operation at power $\dot{W}_i$ can be assumed. The number of periods can be as large as necessary for an accurate estimation of fuel consumption.

The operation and maintenance costs of the cogeneration system can be categorised in fixed and variable costs:

$$C_{om} = C_{omf} + C_{omv} \tag{6.30}$$

where

C_{omf} fixed operation and maintenance costs, i.e. costs which do not depend on the useful energy produced by the system,

C_{omv} variable operation and maintenance costs, i.e. costs which are functions of the production rate.

If no detailed information is available, values such as those given in Table 15 on page 98 can be used which, however, do not distinguish the two types of cost (they include both types).

Additional terms can be included in Eq. (6.27), if necessary. For example, cogenerated heat can be used to drive an absorption air conditioning unit, in which case the compression air conditioning unit is not operated. Then, avoided costs related to the compression unit should be included in Eq. (6.27) with a positive sign, while operating costs related to the absorption unit should be included with a negative sign. In such a case, proper modification of the investment cost might be required, depending on assumptions about the reference system and the alternative configuration.

7.3.2.2 Annual net cash flow (F_t)

In order to determine the annual net cash flow due to the investment in cogeneration, there is need to know the taxation system, the terms of loan (if any), the method of depreciation. Certain assumptions will be made in the following, which will allow to complete the procedure. Proper modifications will be necessary for different conditions.

The following equations will be used

$$F_t = f_t - A_{Lt} - r_T T_t \,, \quad t = 1, 2, \ldots, N-1 \tag{6.31}$$

$$F_t = f_t - A_{Lt} - r_T T_t + SV_N \,, \quad t = N \tag{6.32}$$

where

F_t net cash flow in year t,

f_t operation profit in year t, Eq. (6.27),

A_{Lt} equal yearly payments of principal and interest for repayment of the loan,

r_T tax rate,

T_t taxable income in year t, due to cogeneration,

SV_N salvage value of the investment at the end of the economic life cycle, i.e. at the end of year N.

If a fixed-rate loan is assumed, then the annual amount for repayment of the loan is calculated by the equation

$$\left.\begin{array}{ll} A_{Lt} = L \cdot CRF(N_L, r_L), & t = 1, 2, \ldots N_L \\ A_{Lt} = 0, & t > N_L \end{array}\right\} \tag{6.33}$$

where

N_L time periods (e.g. years) for loan repayment,

r_L loan interest rate.

The taxable income in year t due to cogeneration is determined by the equation

$$T_t = f_t - D_t - I_{Lt} \tag{6.34}$$

where

D_t accounting depreciation charge during year t,

I_{Lt} loan interest charged for year t.

If a straight-line depreciation is assumed, it will be

$$\left.\begin{array}{ll} D_t = \dfrac{C}{N_D}, & t = 1, 2, \ldots, N_D \\ D_t = 0 & t > N_D \end{array}\right\} \tag{6.35}$$

where N_D the time periods (e.g. years) for depreciation. Alternative methods of depreciation are described in the literature (Thuesen and Fabrycky, 1984).

The loan interest charged for each year, if a fixed rate is applied, is calculated as follows. The repayment schedule is made up of a portion for the payment of principal and a portion for the payment of interest on the unpaid balance. The amount, for which the interest for the period is charged, is the remaining balance at the beginning of the period. A loan payment received at the end of an interest period must first be applied to the interest charge. The remaining amount is then utilised to reduce the outstanding balance of the loan. To translate this schedule into steps for calculations, certain definitions are needed:

L_t unpaid part of loan at the beginning of year t.

For t = 1, it is $L_1 = L$.

I_{Lt} interest charged for the year t:

$$I_{Lt} = r_L L_t \tag{6.36}$$

ΔL_t reduction of the unpaid part of loan at the end of year t:

$$\Delta L_t = A_{Lt} - I_{Lt} \tag{6.37}$$

L_{t+1} unpaid part of loan at the beginning of the year t + 1:

$$L_{t+1} = L_t - \Delta L_t = L_t - A_{Lt} + I_{Lt} \tag{6.38}$$

Of course, Eqs. (6.36) – (6.38) are applied for the N_L years only. After repayment of the loan it is

$$I_{Lt} = 0, \qquad t > N_L \tag{6.39}$$

At this point the procedure is completed: everything needed for calculating the measures of economic performance of an investment in cogeneration is obtained by means of the previous equations and the accompanying instructions.

A comment should be made here: The procedure presented in this chapter is based on certain considerations and assumptions. In spite of the attempt to be generally applicable, it is impossible to incorporate all the different situations that are encountered in practice. It is left to the reader to make the modifications that may be needed for each particular application.

7.4 BENEFIT TO THE NATIONAL ECONOMY DUE TO COGENERATION

The construction and operation of cogeneration systems may affect the national economy in several ways, direct or indirect (creation of new job positions, increased production of goods and services, etc.). Here, the attention will be focused on one particular aspect: the effect of cogeneration in savings of foreign currency.

7.4.1 Shadow Price and the Conservation of Foreign Currency

A country is usually not self-sufficient in production resources, and consequently it has to import certain goods. If it has abundant products to export, it will receive foreign currency in return, and can use this freely to import other needed goods. However, if a country has few products which can be exported, its stock of foreign currency will be limited and must be rationed for essential imports.

If a country spends its stock of foreign currency, two consequences must be considered. (i) In depleting its foreign currency reserves, a country cannot import foreign goods unless foreign countries will grant loans or invest in that country. (ii) In spending money outside of its boundaries, the country is withdrawing money from internal circulation. As a result, production will fall, and unemployment may be caused. In order to avoid these consequences, governments must conserve their stocks of foreign currency.

One of the problems the countries are facing is how to assess the worth of their foreign currency stock. For this purpose, the shadow price concept is used. In fact, the World Bank uses this as a basis for development investment. It is defined as follows [Mitchell, 1980]:

> *The shadow price is a ratio with which the landed price of imported goods or services in local currency is multiplied by the government of the importing country, in order to assess the value of the item against the loss of foreign currency from reserves of its central bank.*

It is clarified that the private investor is not concerned with shadow prices. The shadow price can be used as a tool by a government in assessing the viability of its own, or of the private sector's projects. The shadow price is determined by the state. If the balance of payments were extremely adverse, a high shadow price would be adopted to ration foreign currency, whereas if it were favourable over a long period, the shadow price would be unity. Of course, the shadow price is abstract and it can vary continually.

It is noted that the shadow price can be applied also to exported goods or services. Application of the shadow price either on imported or on exported goods or services can reveal whether it might be justified for a government to subsidise an activity, as well as which is the maximum justified level of subsidy.

7.4.2 Application of Shadow Price to Cogeneration Projects

In the following analysis, it is assumed that central power plants are state-owned. Cogeneration may result in foreign currency savings in a number of ways: (a) by substituting electricity produced by central power plants operating on imported fuels; (b) by reducing the need for future investments in new central power plants; (c) by energy savings at a national level due to the higher total energy efficiency of cogeneration systems. The benefit and cost to the national economy is estimated as follows.

The annual savings of foreign currency due to substitution of electricity produced by central power plants is estimated by the equation

$$B_{en} = \frac{W \cdot c_{fcn} \cdot S}{H_{un} \cdot \eta_n} + \dot{W}_n \cdot c_n \cdot CRF_n \tag{6.40}$$

where

W annual electricity production of cogeneration system,

c_{fcn} unit cost of fuel of central power plants to the national economy (e.g. taxes are not included),

S shadow price of foreign currency,

H_{un} lower heating value of fuel saved by central power plants due to cogeneration,

η_n efficiency of central power plants that would provide the electricity, if not cogenerated,

$\dot{W}_n$ electric capacity avoided by central power plants due to cogeneration,

c_n specific investment cost (cost per unit of power) of new central power plants to the national economy,

CRF_n capital recovery factor for the national economy.

The annual savings of foreign currency due to cogenerated heat, which is not produced by a conventional boiler is estimated by the equation

$$B_{hn} = \frac{Q \cdot c_{fBn} \cdot S}{H_{uB} \cdot \eta_B} \tag{6.41}$$

where

c_{fBn} cost per unit mass of boiler fuel to the national economy,

Q, H_{uB}, η_B same as in Eq. (6.28).

If the cogeneration system uses imported fuel, then its cost to the national economy has to be taken into consideration:

$$C_{fn} = c_{fn} m_f S \tag{6.42}$$

where

c_{fn} cost per unit mass of fuel of the cogeneration system to the national economy,

m_f annual fuel consumption of the cogeneration system, Eq. (6.29).

Part of the operation and maintenance cost, except of fuel, may be paid in foreign currency (e.g. for importing spare parts). The related cost to the national economy is

$$C_{omn} = C_{omf} \times S \tag{6.43}$$

where C_{omf} the part of the operation and maintenance cost paid in foreign currency.

The net benefit to the national economy is thus derived:

$$B_n = B_{en} + B_{hn} - C_{fn} - C_{omn} \tag{6.44}$$

7.5 EXAMPLES OF ECONOMIC ASSESSMENT OF COGENERATION

Three simplified examples of applying the procedure described in the previous chapters are presented here, as they have been worked for conditions in Greece [Frangopoulos et al., 1994].

7.5.1 Description of systems

Three systems have been selected for application of the procedure:

1. Commercial – building Sector: Packaged cogeneration unit with gas engine burning natural gas.
2. Industrial Sector: Diesel-engine cogeneration system burning fuel oil.
3. Industrial Sector: Gas-turbine cogeneration system burning natural gas.

The energy performance characteristics of the systems are given in Table 16:

Table 16: Energy performance of the systems under study.

Application	Electric power	Power to heat ratio	Electrical efficiency	Total* efficiency
	$\dot{W}$ (kW)	PHR (-)	η_e (-)	η (-)
A	500	0.7	0.32	0.777
B	2000	1.0	0.40	0.800
C	6000	0.6	0.30	0.800
* It results from PHR and η_e by applying Eq. (2.12)				

7.5.2 Technical and Economic Parameters and Assumptions

The economic performance of the systems will first be assessed for a nominal set of parameter values given in Tables 6.5 and 6.6. Next, the effect of uncertainty in the values of certain parameters will be studied by a sensitivity analysis.

The reference case for comparison of the systems will be the purchase of electricity from the grid and production of heat by a boiler. Grid connection at the medium voltage is considered.

Regarding the operation of systems, the following assumptions are made:

1. The system operates at full capacity (nominal power).
2. All cogenerated heat is utilised.
3. The system operates for 11 months per year. Scheduled maintenance is performed during the month the system is out of service. This month may coincide with the vacation period of the enterprise, if such a period exists.

The fraction of electricity consumed on site is symbolised by I. Two cases are examined for each system: I = 1 ; I = 0.7

In the second case there is excess electricity, which is sold to the grid.

Table 17: Values of technical parameters.

Lower heating value	
• Natural gas	36400 kJ/Nm^3
• Fuel oil	40180 kJ/kg
Efficiency of boiler	
• Natural gas	80%
• Fuel oil	75%
Efficiency of fuel-oil central power plants	37%

Table 18: Values of economic parameters

Economic life cycle of the investment (N)			
• Commercial and building sector		10 years	
• Industrial sector		15 years	
• Central power plants and national economy		20 years	
Average annual market interest rate (d)		10%	
All inflation rates		0%	
Shadow price of foreign currency (S)		1.25	
Grid electricity tariff			
		Commercial	Industrial
Contracted power	(Euro/kW·month)	7.21	5.8
Energy: First 400 kWh/kW	(Euro/kWh)	0.04	0.03
Remaining kWh	(Euro/kWh)	0.03	0.02
Price of electricity sold to the grid (Euro/kWh)		0.38	
Unit costs of fuels			
Natural gas			
Commercial sector:	Cogeneration	0.1 Euro/Nm^3	
	Other applications	0.17 Euro /Nm^3	
Industrial sector:	Cogeneration	0.09 Euro /Nm^3	
	Other applications	0.1 Euros/Nm^3	
Cost of fuel oil		0.1 Euro /kg	
Cost of natural gas to the national economy		0.06 Euro /Nm^3	
Reference year for economic parameters: 1994			

7.5.3 Consumption of Fuel and Production of Electricity and Heat

Based on the assumption made in the previous chapter the following equations are written:

$$H_F = \frac{\dot{W}}{\eta_e}\Omega$$

$$W_I = \dot{W}\frac{\Omega}{M} \cdot I$$

$$W_s = \dot{W}\frac{\Omega}{M}(1 - I)$$

$$Q = \frac{\dot{W}}{PHR} \cdot \Omega$$

where

- H_F annual consumption of fuel energy by the cogeneration system,
- W_I cogenerated electricity consumed on site per month,
- W_s cogenerated electricity sold to the grid per month,
- Q annual cogenerated useful heat, number of operating hours per year,
- M number of operating months per year,
- I fraction of cogenerated electricity consumed on site.

The results for three values of Ω (4000, 5000 and 6000 h/year) and two values of I (1 and 0.7) are presented in the following two tables:

Table 19: Consumption of fuel energy and production of heat.

Application	Fuel energy consumption H_F (GJ/year)			Useful heat production Q (GJ/year)		
	Hours of operation per year			Hours of operation per year		
	4000	5000	6000	4000	5000	6000
A	22500	28125	33750	10286	12857	15429
B	72000	90000	108000	28800	36000	43200
C	288000	360000	432000	144000	180000	216000

Table 20: Cogenerated electricity consumed on site and sold to the grid per month.

Application	Electricity consumed on site W_I (MWh/month)			Electricity sold to the grid W_S (MWh/month)		
	Hours of operation per year			Hours of operation per year		
	4000	5000	6000	4000	5000	6000
	I = 100%					
A	181.8	227.3	272.7	0	0	0
B	727.3	909.1	1090.8	0	0	0
C	2181.8	2727.3	3272.7	0	0	0
	I = 70%					
A	127.3	159.1	190.9	54.5	68.2	81.8
B	509.1	636.4	763.6	218.2	272.7	327.2
C	1527.3	1909.1	2290.9	654.5	818.2	981.8

7.5.4 Economic Assessment of the Applications

For each system, costs and benefits have been evaluated for a certain set of parameter values (Table 17 and Table 18). The results are given in Table 21 for the operating conditions specified in the same table.

Table 21: Costs and benefits of cogeneration systems for the specified conditions

Economic figure	A	B	C
	Gas engine 500 kW	Diesel engine 2000 kW	Gas turbine 6000 kW
Investment cost (million Euro)	0.43	1.56	4.79
Annual period of operation (hours)	5000	6000	6000
Electricity consumed on site (%)	100	100	100
Annual cost of fuel (x100 000 Euro)	0.81	2.81	
Annual O&M cost (x100 000 Euro)	0.20	0.79	1.88
Annual avoided cost (x100 000 Euro)			
of electricity	1.43	5.06	16.55
of heat	0.63	1.13	7.25
Annual operation profit before taxes (x100 000 Euro)	1.05	2.57	9.48

In order to assess the economic viability of each cogeneration application, the net present value (NPV), the internal rate of return (IRR) and the discounted payback period (DPB) are evaluated for periods of operation in the range 4000 – 7000 h/year and for 100% or 70% of electricity consumed on site. The results are presented in the following.

Application A. Gas-engine cogeneration system of 500 kW_e in the commercial – building sector

Systems of this type are appropriate for the commercial – building sector, and this is why such an application has been selected as one of the examples.

The effect of the annual operation period and of the percentage of electricity consumed on site on the economic performance of the investment is illustrated in Figure 50 and Figure 51. Under the specified conditions and assumptions, cogeneration is economically viable for operation periods longer than 5000 h/year and for 100% of cogenerated electricity consumed on site. The internal rate of return is higher than the market interest rate (10%). The payback period of 6.5 – 5.6 years is not particularly low, but it can be acceptable for this type of investments.

Application B. Diesel-engine cogeneration system of 2000 kW_e operating on fuel oil in the industrial sector

Diesel-engine cogeneration systems have a high power to heat ratio, which makes them appropriate for many industrial applications.

According to Figure 52 and Figure 53 for the particular example, the investment is marginally viable when the operation period is longer than 6000 h/year and 70% of cogenerated electricity is consumed on site. The main reason for the low performance of this application is the low value of thermal energy as a product, due to the low value of fuel oil.

Application C. Gas-turbine cogeneration system of 6000 kW_e operating with natural gas in the industrial sector

Gas-turbine cogeneration systems produce high temperature heat, which is useful in many industrial applications.

The results of economic evaluation for the particular application example, which are illustrated in Figure 54 and Figure 55, show that the investment is viable for periods of operation longer than 6000 h/year.

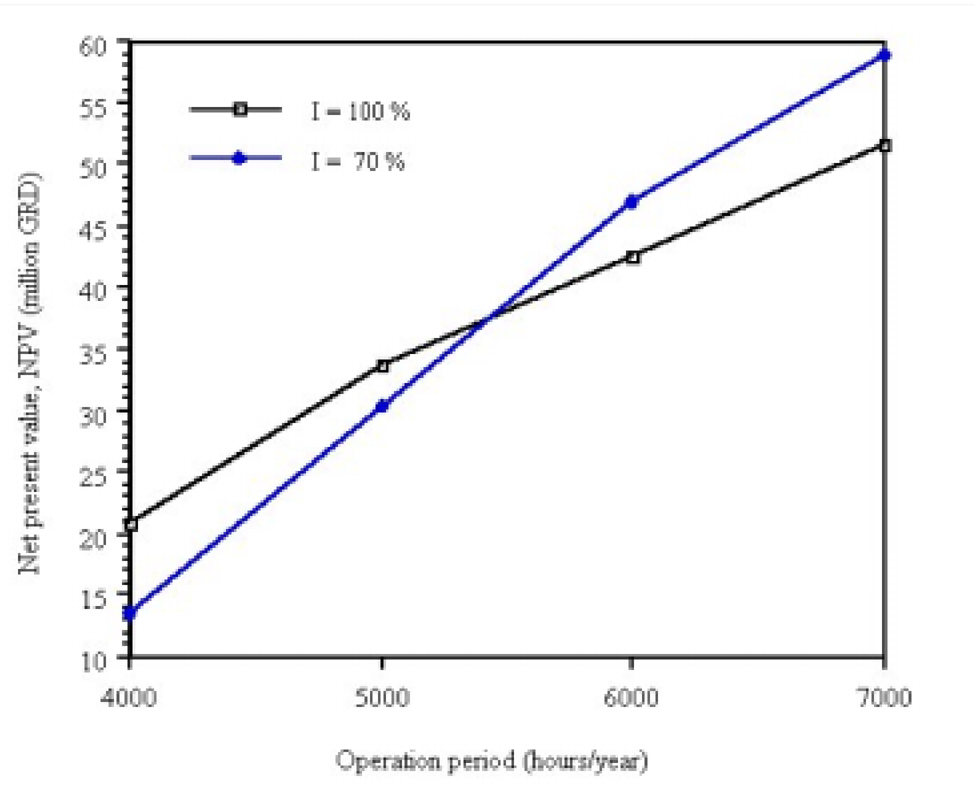


Figure 50: Net present value of application A (Gas Engine, 500 kW$_e$, in building).

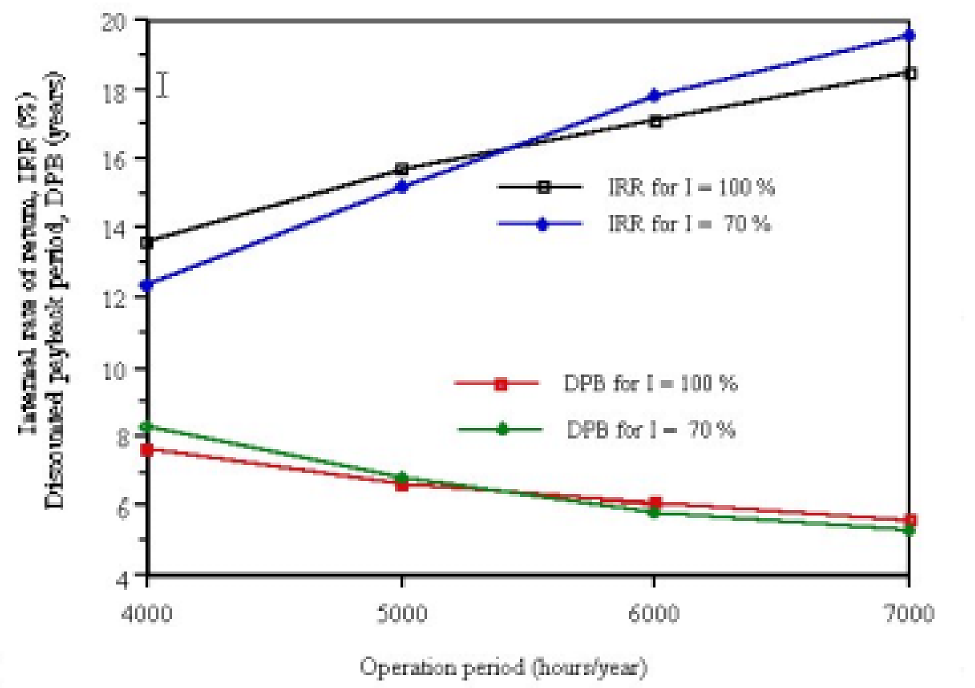


Figure 51: Internal rate of return and discounted payback period of application A (Gas Engine, 500 kW$_e$, in building).

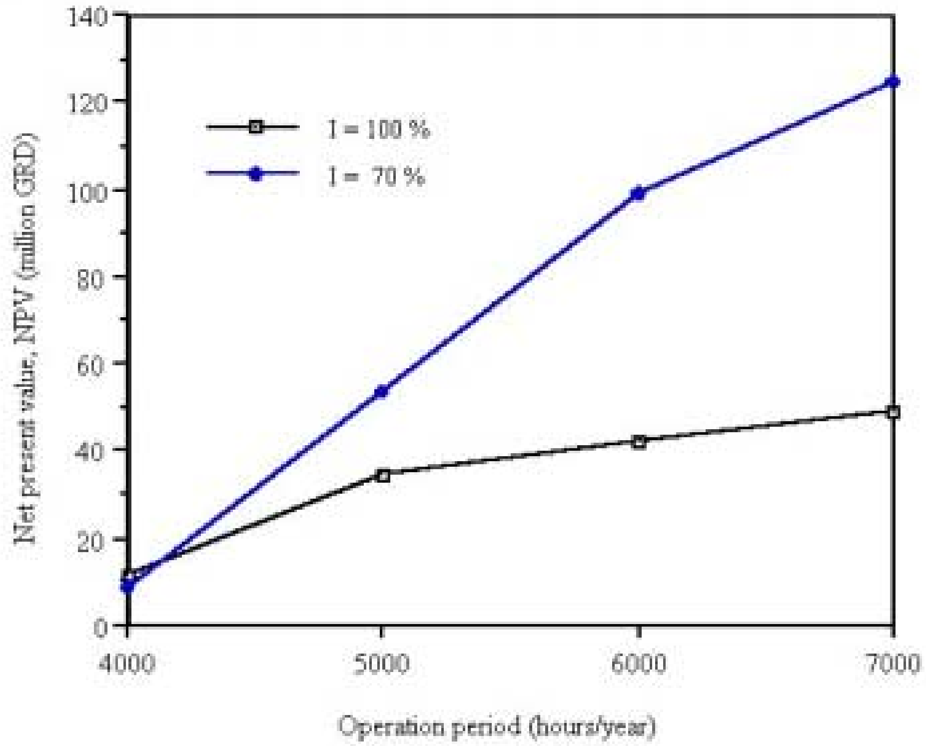


Figure 52: Net present value of application B (Diesel Engine, 2000 kW$_e$, with fuel oil in industry).

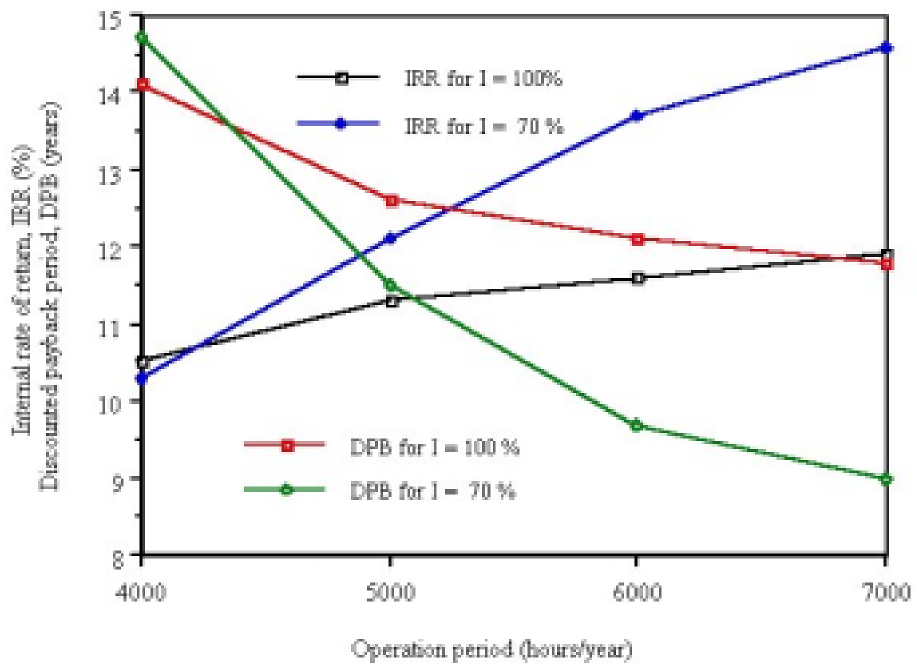


Figure 53: Internal rate of return and discounted payback period of application B (Diesel Engine, 2000 kW$_e$, with fuel oil in industry).

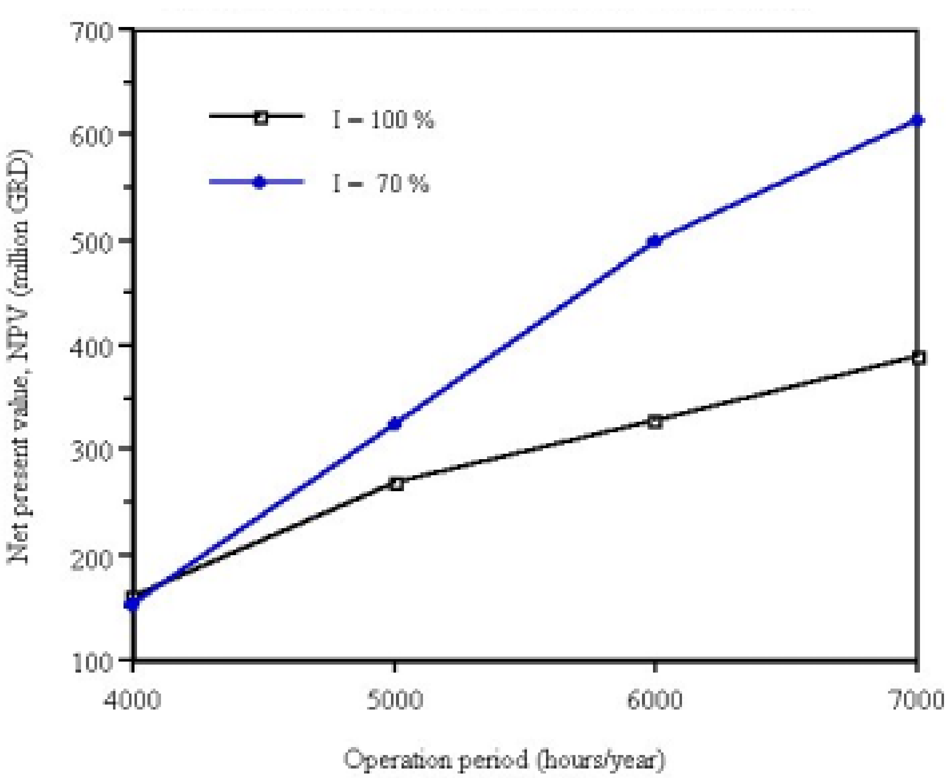


Figure 54: Net present value of application C (Gas turbine, 6000 kW$_e$, with natural gas in industry).

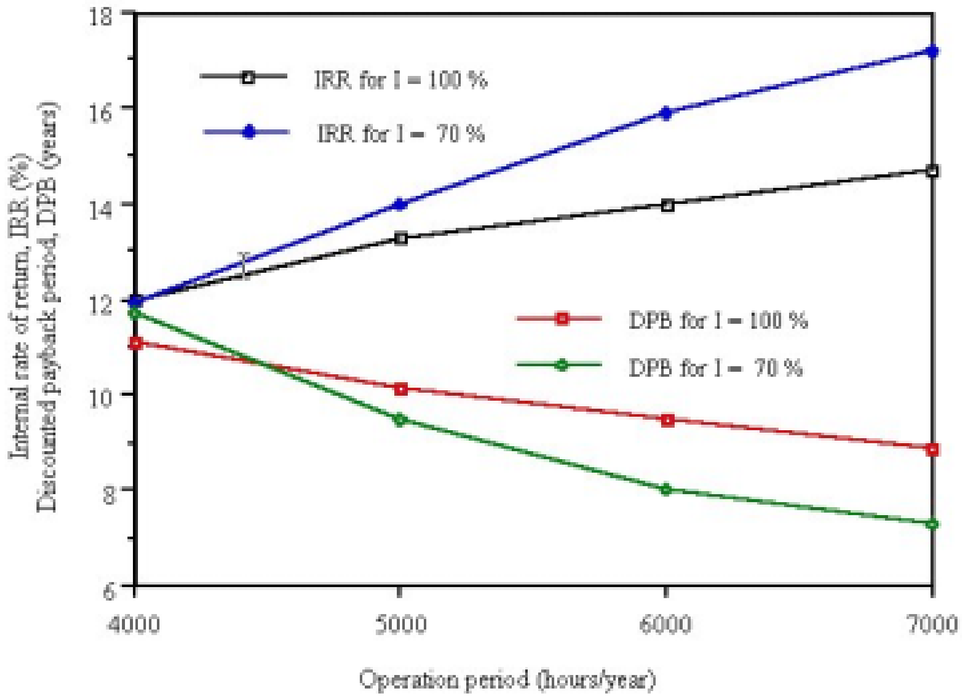


Figure 55: Internal rate of return and discounted payback period of application C (Gas turbine, 6000 kW$_e$, with natural gas in industry).

7.5.5 Parametric study

The values of several parameters, in particular of economic parameters, which are used in the economic analysis, are more or less uncertain, either because they are predictions of future values (e.g. natural gas tariff had not been established yet in Greece at the time these examples were worked out) or because they change with time. Therefore, after the analysis based on the nominal set of parameter values (Tables 6.5 and 6.6), a parametric study must be performed, i.e. a study of the effect that a range of values of crucial parameters will have on the economic performance of the investment.

There are various methods of parametric study; the graphical one will be followed here. The analysis can be performed with respect to any uncertain parameter. Here, it will be restricted to only three parameters, changing the value of one parameter at a time:

d average annual market interest rate,

c_f unit cost of fuel for the cogeneration system,

c_g percentage of grant on investment cost.

The annual operation period is kept constant at 5000 h for application A, and 6000 h for applications B and C.

It is worth noting that the economic analysis combined with a sensitivity analysis reveal not only the conditions which make the investment economically attractive to the private investor and end user, but also the benefits that such an investment can bring to the national economy. Thus, the type and level of incentives for promotion of cogeneration can be determined (e.g. percentage of grants on investments). Furthermore, the results of the analysis can help in the formulation of tariffs for fuel (e.g. natural gas) and electricity for cogeneration applications.

The results of sensitivity analysis are presented in Figure 56 - Figure 58. Some brief comments follow.

Application A

The effect of fuel cost on the economic viability of such a system is significant. An appropriate tariff structure for natural gas in Greece is necessary. It should be noted that the unit cost of natural gas in other European countries is much lower than the equivalent of 0.1 Euro/Nm^3 (in 1994 prices).

Given the fact that investments in cogeneration are capital intensive, a grant on investment is considered necessary. The results show that even a low percentage, at the order of 10%, improves significantly the economic viability for the private investor.

Application B

Diesel-engine cogeneration systems operating on fuel oil are economically attractive for industries with long perspectives of viability. The nominal set of parameter values results in measures of economic performance not particularly favourable: IRR = 11.6%, DPB = 12.1 years. The two measures can reach values of economic viability if at least one of the following changes occur:

- Grant on investment: from 0% to 20 – 25%
- Market interest rate: from 10% to 5 %.

Application C

Gas-turbine cogeneration systems have high capital and operating costs (including fuel). The investment becomes economically viable either by a unit fuel cost lower than 0.1 Euro/Nm^3 or by a grant on investment at the order of 10 – 20%.

Note

The application examples are included in order to demonstrate how the procedure presented in previous chapters can be applied. The results and comments are valid for the systems studied in a particular environment under certain assumptions, with no claim of general validity.

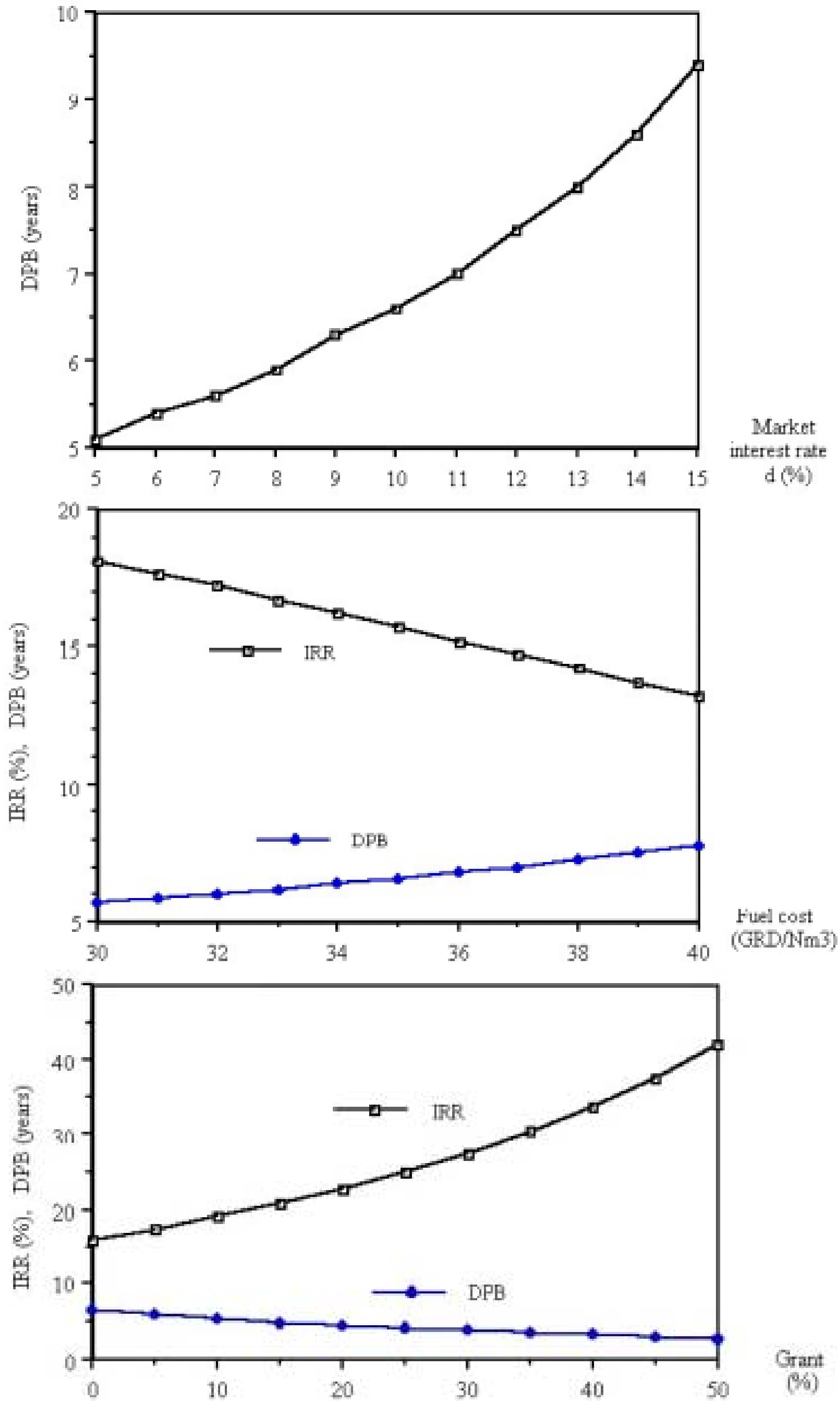


Figure 56: Results of a parametric study for application A.

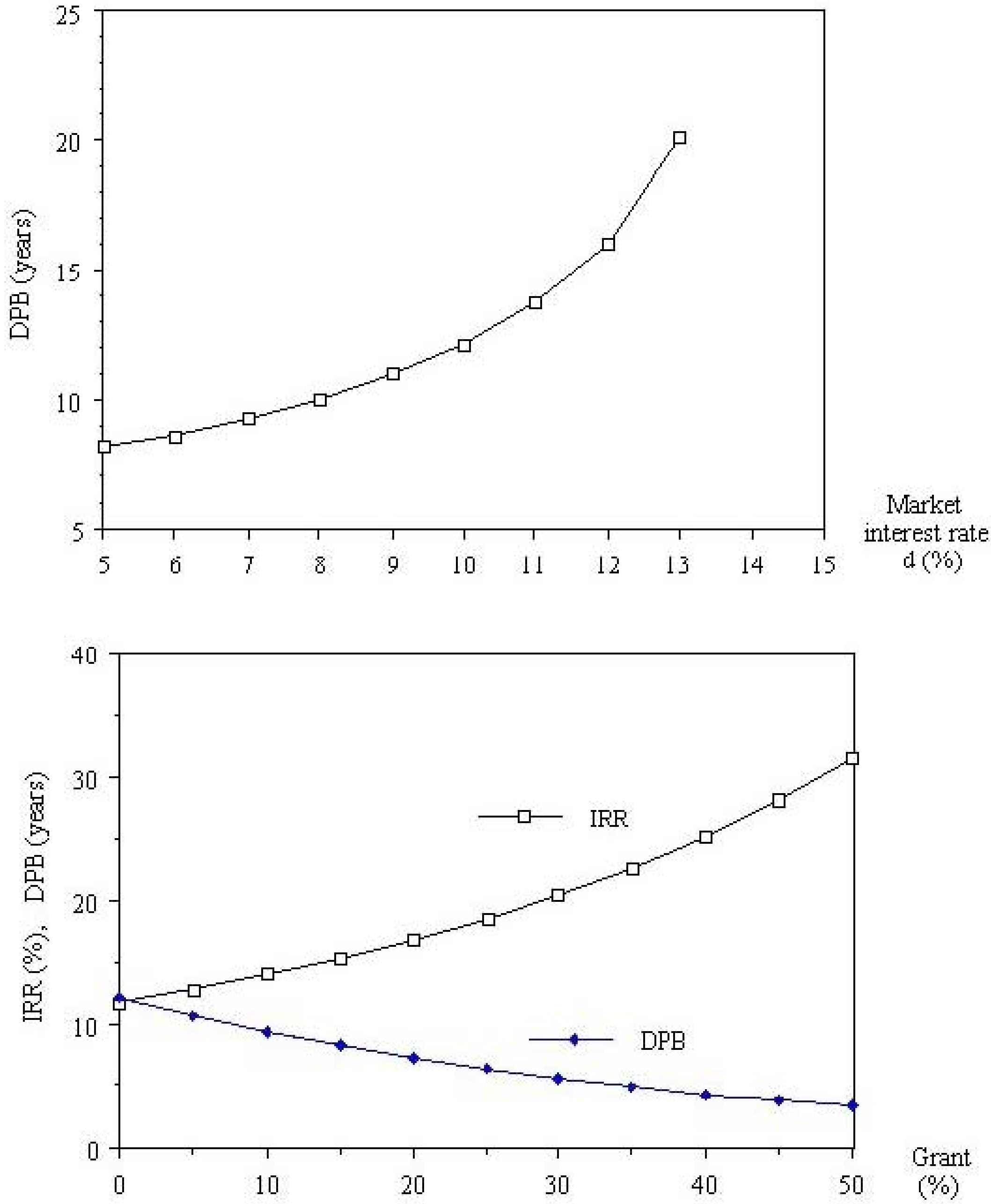


Figure 57: Results of a parametric study for application B.

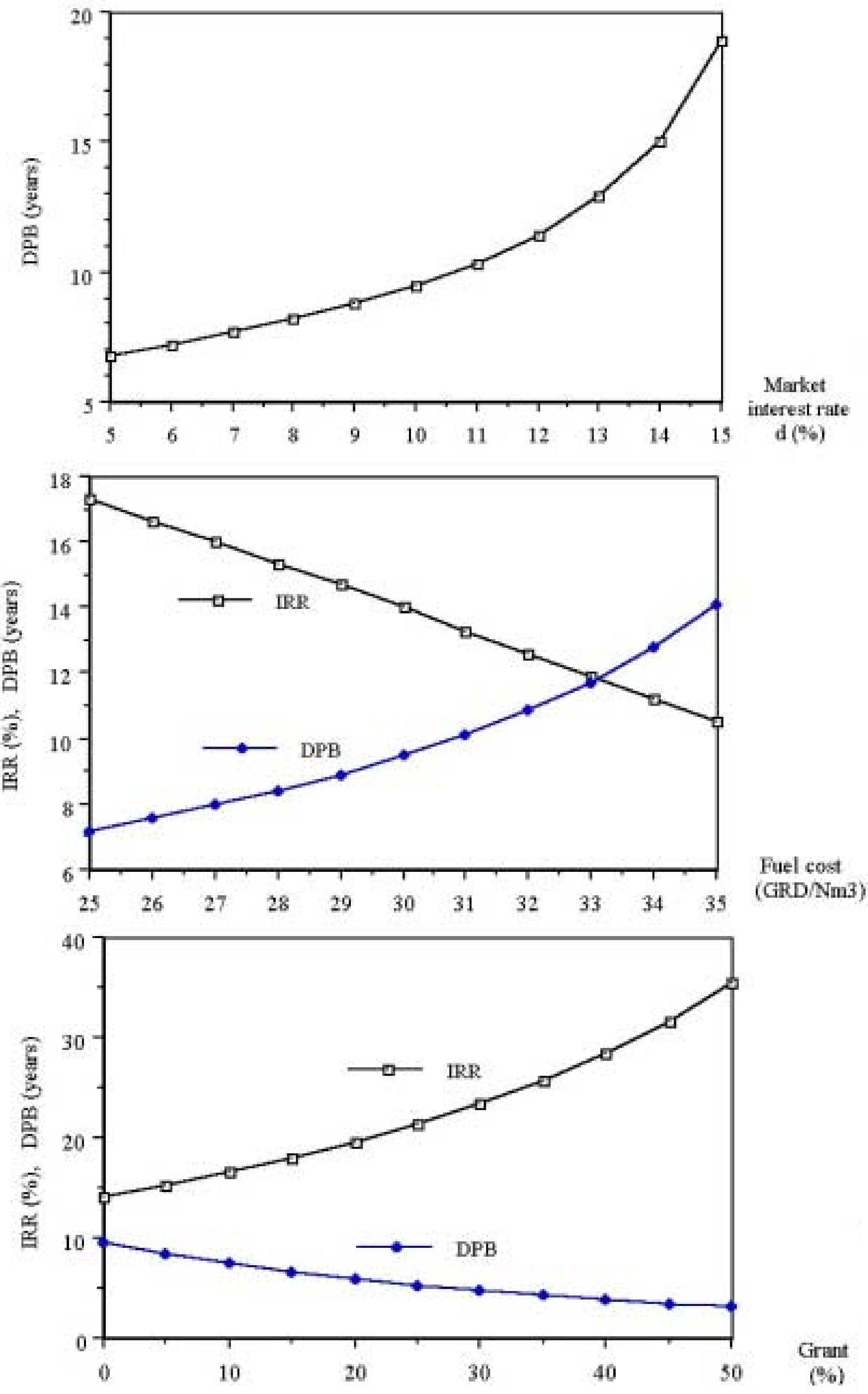


Figure 58: Results of a parametric study for application C.

7.5.6 Benefit to the National Economy

The procedure presented in Chapter 7.4 has been applied to the three systems; the results are given in the following Table.

Table 22: Benefit to the national economy due to the cogeneration systems (Results for operation of 6000 h/year.)

Application	Investment	Benefit to the national economy	
	Euro/kW	Euro/kW	% on investment
A	868	248	29
B	781	371	48
C	799	332	42

The benefit to the national economy is significant for all three cases. The lowest benefit comes from the cogeneration unit in the building sector (A) due to its higher investment cost per kW_e and its lower total efficiency. Applications B and C give a benefit higher than 40% of the investment cost. The results in the 3rd and 4th column of the table can be considered as the maximum level of grant on investment that the national economy could offer to the private investors for promotion of cogeneration. Alternative means of transferring at least part of the benefit to the private investors are the subsidy on loan interest rates, income tax deduction, subsidy on unit price of electricity sold to the grid. Of course, the type and level of incentive must be determined by a careful study in each case, so that the total benefit is maximised.

8 OPTIMAL DESIGN AND OPERATION OF COGENERATION SYSTEMS

In Chapter 7.5 examples of economic assessment of specified cogeneration systems under certain simplifying assumptions have been presented. A much more difficult problem is to determine which is the best cogeneration technology and system design for a particular application, and which is the best operation mode at any instant of time. The word “best” itself needs to be defined quantitatively to the extent possible. This problem is addressed in the following chapters.

8.1 PROCEDURE FOR SYSTEM SELECTION AND DESIGN

Before any consideration of cogeneration, potential changes in energy requirements must be investigated. Energy saving measures, demand-side management, changes in processes can not only be cost-effective in themselves but also affect the type, size and economics of the cogeneration 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 in the introductory paragraph 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.),
- number of prime movers and nominal power of each one,
- heat recovery equipment,
- need of thermal or electric 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 investigation of the feasibility of absorption cooling (if required), which will affect the load and consequently the design of the system.

Any decisions should take into consideration also legal and regulatory requirements, which may impose limits on design and operation parameters such as noise level, emission of pollutants, total operating efficiency.

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 actions to be performed in each stage are described in brief in the following chapters.

8.1.1 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. Aspects which are examined include the following:

- Level and duration of electrical and thermal loads.
- Energy saving measures that could be implemented before cogeneration.
- Any plans for changes in processes, which would affect electrical and thermal loads.
- Compatibility of thermal loads with the heat provided by available cogeneration technologies.
- Availability of space for siting the cogeneration system.
- Ability to interconnect with the electrical and thermal system of the facility.
- Effect that cogeneration may have on the need to install and on the operation of other equipment such as boilers, emergency generator, compression or absorption chillers.

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 installation is much easier and it has greater potential for improving the economic viability.

In large projects, a pre-feasibility study might be advisable for a better assessment at this stage.

8.1.2 Feasibility Study and System Selection

It is the crucial stage, which will determine whether cogeneration is viable and which is the best 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, heat 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. Details are given in Chapter 8.2.
2. Collection of information about electricity and fuel tariffs, as well as about legal and regulatory issues.
3. Selection of cogeneration technology that can provide the quality of heat (medium, pressure, temperature) required. The power to heat ratio might be an additional criterion for selection but not very strict, because it can be changed either by additional equipment (e.g. augmented heat recovery, supplementary firing, thermal storage) 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 cogenerated heat is used, avoiding rejection to the environment. This subject is treated in more detail in Chapter 8.5.
5. Selection of the operation mode (operation modes are described in Chapter 8.3) and calculation of the energy and economic measures of performance. Calculations can be repeated for various operation modes. A more systematic approach is described in Chapter 8.5.1.

6. Actions 3, 4 and 5 are repeated for other combinations of technology, number and capacity of units, additional equipment and operation mode.
7. The system with the best performance is selected. A single- or multi-criteria approach can be followed.
8. A study of the environmental, social and other effects of the selected system is performed.

In cases where there is a strong phase shift between the electrical and thermal load, it is useful to examine the technical and economic feasibility of thermal storage or (not so common) electrical storage, in order to increase the utilization of cogenerated electricity and heat. The selection of type, the design and the control of the storage unit is of crucial importance for the energy and economic performance of the whole system, but these subjects are beyond the scope of this text.

The multitude of variations of system structure and operation mode 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 range of applicability and depth of analysis [Orlando (1988), EPRI (1988)]. One step further is the application of mathematical optimisation procedures for the system design and operation (Chapter8.5).

8.1.3 Detailed Design

For the system selected in Stage II a detailed study follows. There may be need to collect more accurate and detailed information about load profiles and repeat actions 4 and 5 of Stage II 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 not only capacity, efficiency and controls, but also emissions, noise and vibration levels. Specifications for other major components are also prepared.

The location site of the system is finally 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 for fuel supply (including tanks, if necessary), air inlet and exhaust gas ducts, piping, electric circuitry and grid interconnection.

8.2 LOAD CURVES

8.2.1 Load Profiles

The electrical and thermal loads of a facility are functions of time. Each particular form of energy needed has its own profile: electricity, direct use of exhaust gases, high-pressure steam, low-temperature steam, hot water, cold water, etc. Furthermore, the peaks of the various loads usually do not occur at the same time. To select a system on the basis of average loads, most probably will result in low annual total efficiency, low annual fuel energy savings ratio and poor economic performance. Ideally, the study should be based on knowledge of each particular load (energy form) in each one of the 8760 hours of the year, not to mention changes of load from year to year. In between the two extremes there are simplified presentations of the reality, which are used according to the stage in the whole procedure. The difficulty always is how to collect the pertinent data and to process those in order to produce more or less accurate profiles.

For a new facility, one source of useful information is other similar facilities, for which data are available; however, changing design practices, technology and process changes and increased concern for energy savings and environmental protection may result in significant reduction in energy requirements of new buildings or industries. Another source is the design studies for processes (in an industry) and for heating, ventilation and air conditioning of buildings. Estimation for buildings can also be based on parameters such as average consumption per unit volume of occupied space, average hot water consumption per occupant, always combined with typical daily distribution applicable in the particular type of building. More elaborate procedures use specialised computer software for load predictions.

For existing facilities, electric and natural gas utilities may be able to provide energy profile data. Alternative sources may be fuel bills, on-site data management systems, steam charts and powerhouse logs. Production logs may also provide data that are useful in estimating energy requirements. Previous studies of energy use, energy saving techniques and demand-side management may provide useful information too. An investigation should be made to reveal energy uses that can not be served by cogeneration; for example, fuel bills may include fuel used for cooking or even for vehicles. Proper deduction is necessary in such cases. On the other hand, in order to determine the amount of thermal energy used, the boiler efficiency has to be taken into consideration, as it results from actual measurements.

Certain thermal loads are known functions of ambient conditions. For example, space heating loads are functions of the ambient temperature. For many cities, analytic equations for calculating the average ambient temperature as a function of time for the 8760 hours of the year have been developed by regression analysis of climatic data. Thus, simple models can be developed in order to determine the seasonal variations of space heating load.

If satisfactory data are not available, before proceeding to the final selection and sizing of the cogeneration system, there might be need to conduct a monitoring program in co-operation with the utility and/or by temporary installation of metering devices. The monitoring program may also serve in distinguishing among the various uses of energy forms.

Any plans for future additions, demolitions or modifications to the facility and its processes should be taken into consideration for predicting future loads.

It is not seldom that available data may contain inaccuracies due to several causes: inaccurate meters, errors in reading, incorrect process of raw data, etc. Therefore, it is strongly recommended to cross-check the accuracy and consistency of data. For example, if data are available on both fuel consumption and steam production of a boiler, it is good practice to compute the boiler efficiency; an unreasonable value of efficiency is an indication of errors in the data.

The aim of all the effort described in the previous paragraphs is to develop hourly load profiles for each day of the year. It is not necessary, and perhaps not practically possible, to have 365 different profiles. Depending on the available information, load profiles are drawn for groups of similar (from the point of view of load) days, as they are characterised by the month or season, and the day of the week (weekdays, weekends). Examples are shown in Figure 59 - Figure 62:

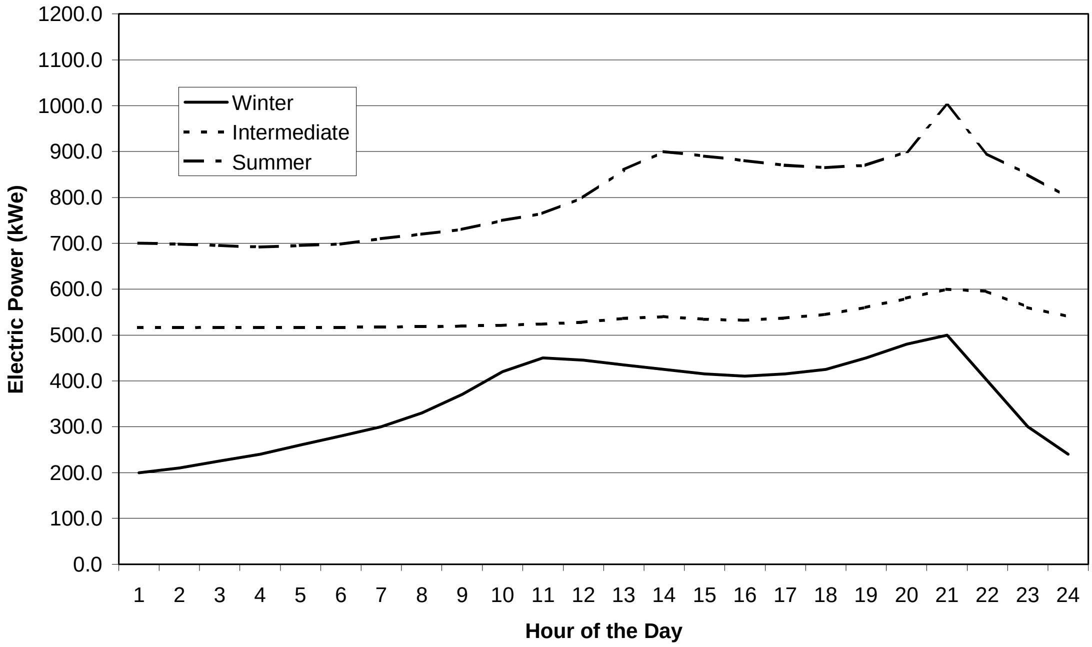


Figure 59: Hourly electric power profiles for typical days in winter, intermediate season and summer in a hotel.

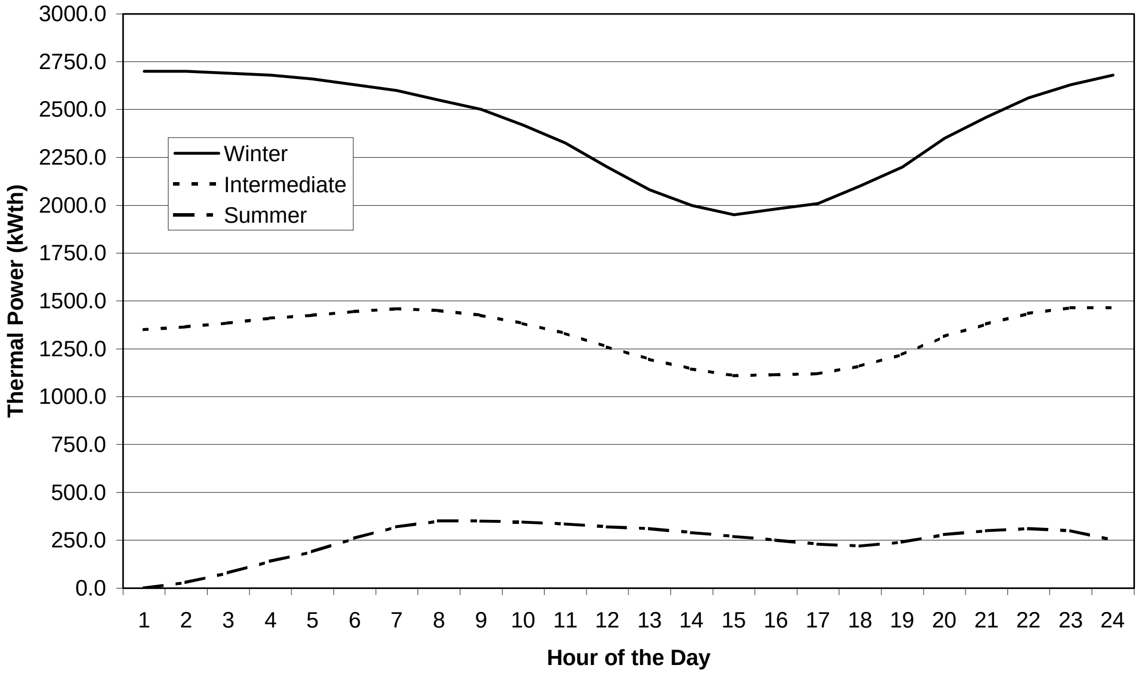


Figure 60: Hourly thermal power (space heating and hot water) profiles for typical days in winter, intermediate season and summer in a hotel.

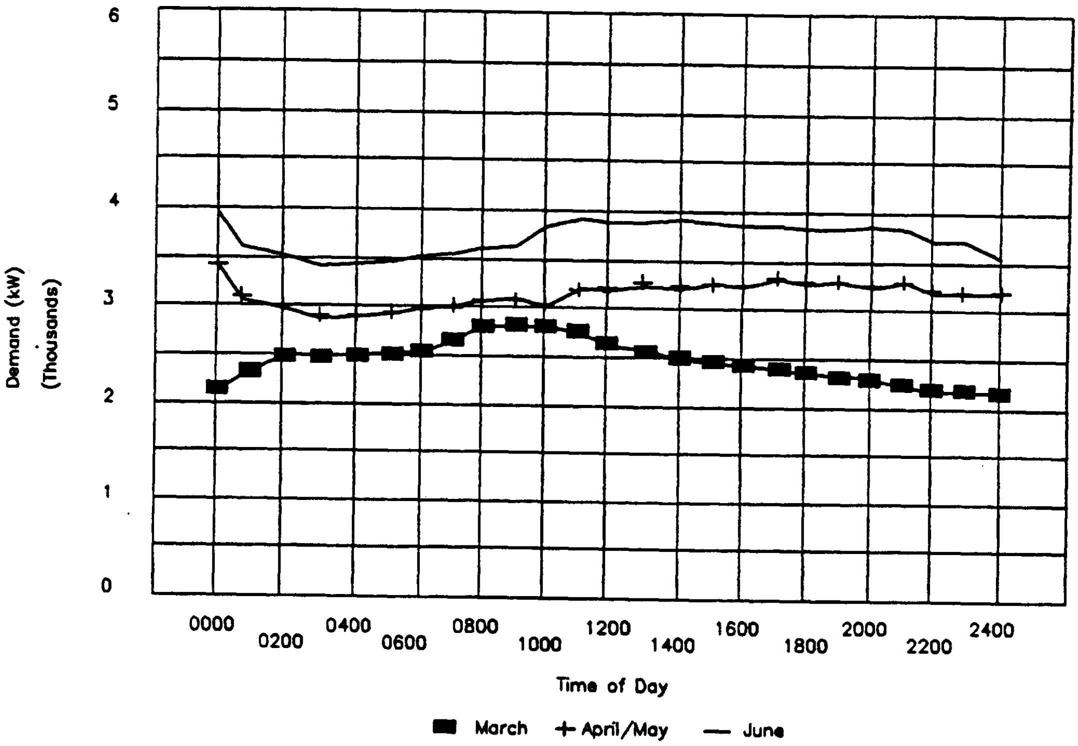


Figure 61: Hospital weekday profiles by season (Orlando 1996)

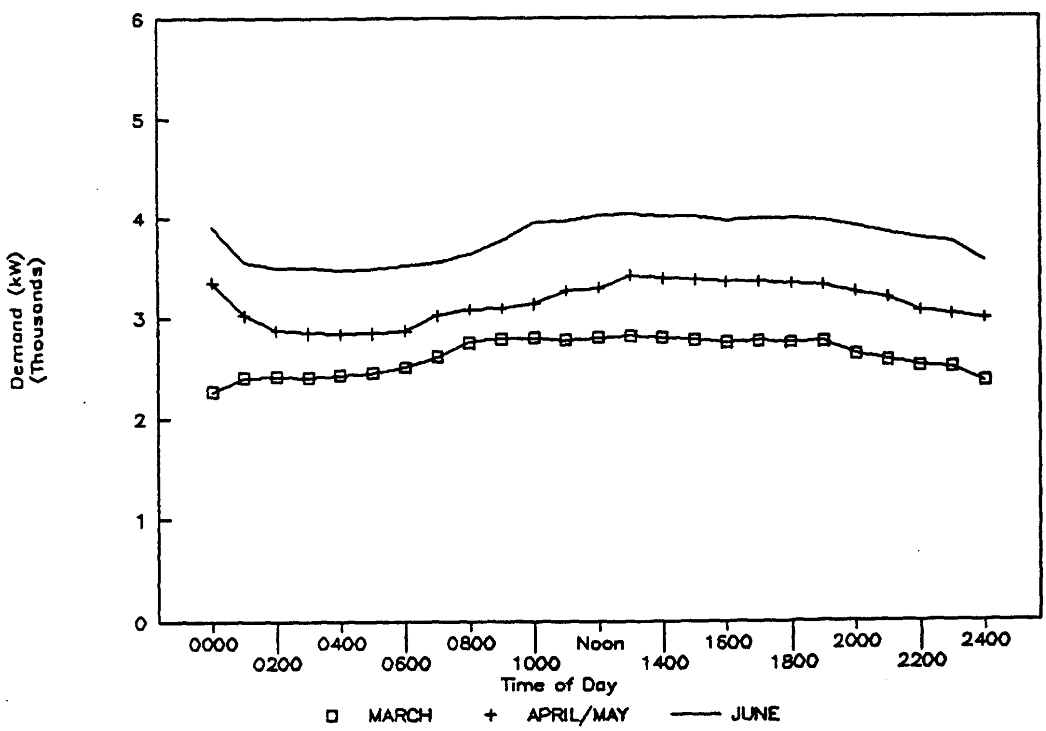


Figure 62: Hospital weekend profiles by season (Orlando 1996)

8.2.2 Load Duration Curves

After the load profiles, it is useful to draw the load duration curve for each form of energy, which shows the number of hours (usually in a month or year) that the required power exceeds a certain level. The co-ordinates of the graph can be either in absolute values (kW, hours) or as percentages (% of maximum demand, % of time). An example is illustrated in Figure 63:

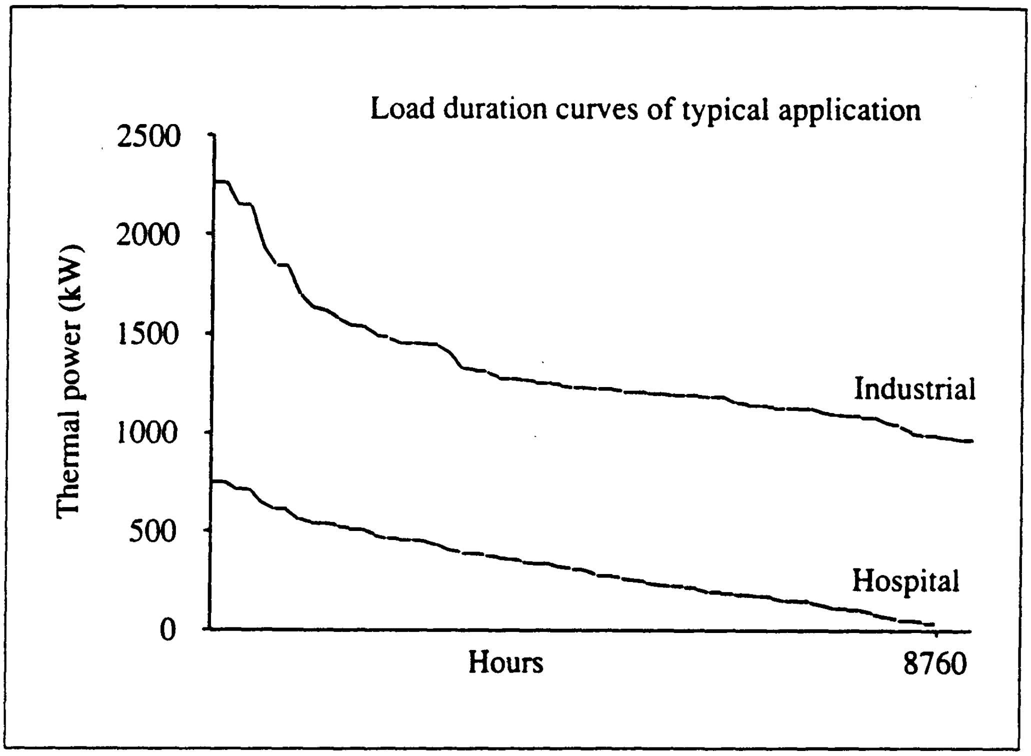


Figure 63: Example of Load duration curves (Jennekens 1989)

Load duration curves give an indication about the base-load and peak requirements and can help in sizing a system. An example is illustrated in Figure 64, which gives the load curve of a facility having a peak demand of 4800 kW. Let it be assumed that three engine-generator sets are installed, each one having a rated output of 1000 kW. According to Figure 64, generator No. 1 is operated at rated output all the time; generator No. 2 is operated at an average of approximately 95% of rated output; generator No. 3 is operated at an average of approximately 65%. Partial load performance of the engines must be taken into consideration, since it results in lower energy efficiency. Other combinations of number of engine-generators and rated output can be studied with the help of the same load duration curve. Of course, in each case, the use of cogenerated heat must also be investigated and thermal load duration curves are to be examined in parallel.

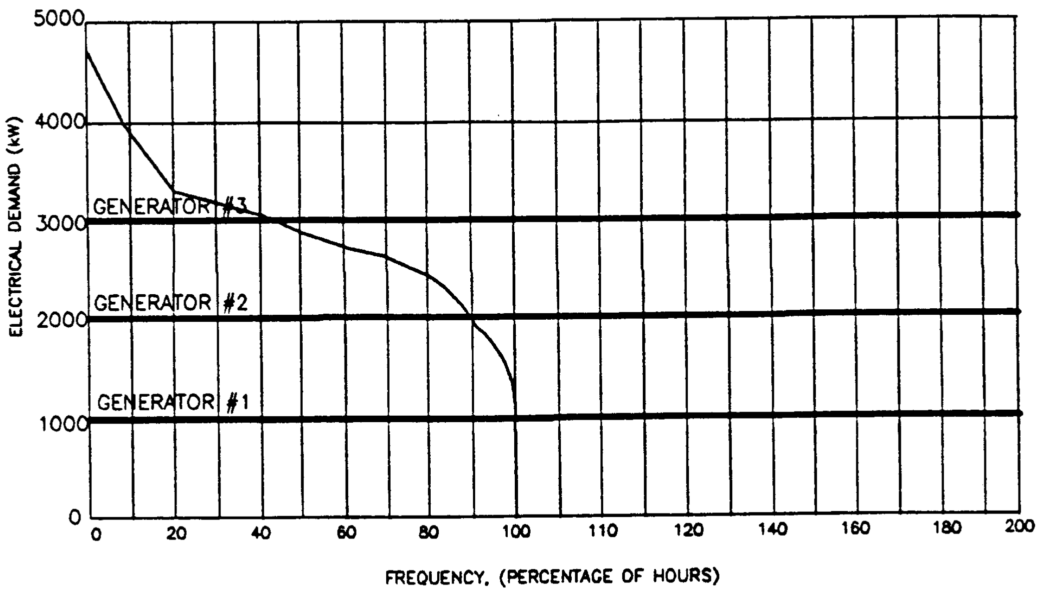


Figure 64: Load duration curve and multiple generators (Orlando 1996)

8.2.3 Capacity – load Curves

By integrating to determine the area under the load duration curve, the capacity – load curve is obtained, which relates the power demand to the total site load (energy) that occurs at or below a specific power level. An example is given in Figure 65.

According to Figure 65, the particular facility will use almost 90% of the energy required during a month at power levels that are equal to 70% of the peak or less. Consequently, if an engine-generator set is installed, sized at 70% of the peak power, it will supply 90% of the energy required during the month. In order to increase the energy supply from 90% to 100%, an increase of only 11%, the capacity of the generator must be increased from 70% to 100%, i.e. by 43%. Increasing the capacity and consequently the cost of a system by more than 40% to increase the energy used on site by only 11% may not be very cost-effective, unless it is possible to sell excess electricity to the grid under favourable economic terms. Again, it is necessary to consider whether or not the cogenerated heat is used to a satisfactory level.

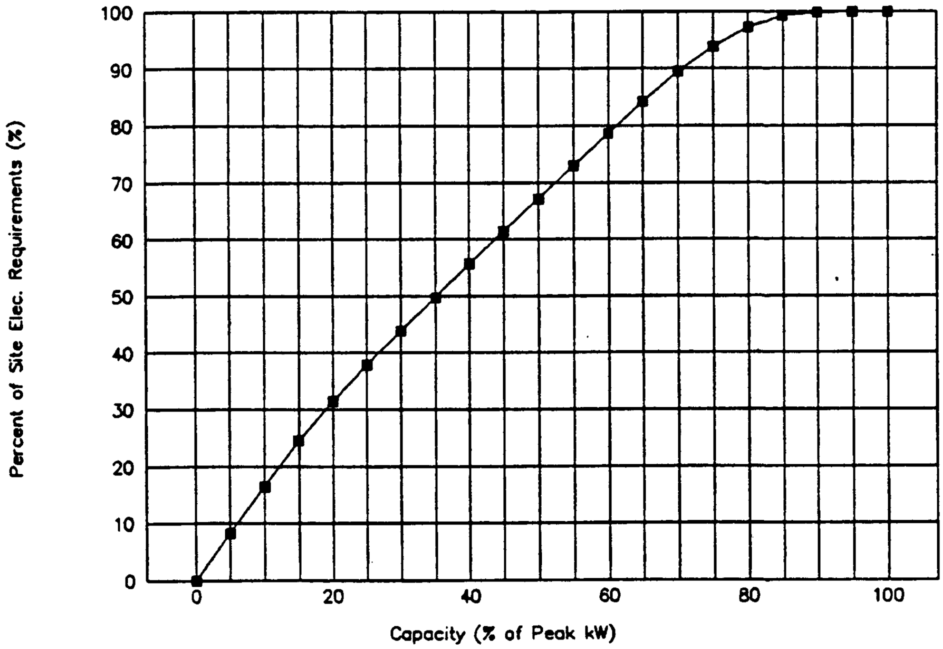


Figure 65: Example of capacity – load curve for one month (Orlando 1996)

8.3 OPERATION MODES OF COGENERATION SYSTEMS

A mode of operation is characterised 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) *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 cogenerated 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.

c) *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.

d) *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) 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 (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; 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 or even whether the unit should be shut down. Moreover, by monitoring operational parameters such as efficiency, operating hours, exhaust gas temperature, coolant water temperatures, the microprocessor can help in maintenance scheduling. If the system is unattended, the microprocessor can be linked by a telephone line with a remote monitoring center, 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.

8.4 SIMULATION AND PERFORMANCE EVALUATION OF SYSTEMS

The purpose of the analysis is to calculate the measures of energy and economic performance as they have been defined in Chapters 2 and 7. In particular for the measures of energy performance, annual values are of particular interest. In order to reach this goal there is need to construct a model of the system, i.e. a mathematical description of the system consisting of data, rules, inferences and equations, where the word "system" here includes not only the cogeneration unit(s) but also the facility, as it is described by the various loads.

The model can be a crude one, based on average demands and nominal or average performance of cogeneration units, or an accurate one, based on demands for each hour of the year and real performance of the cogeneration units, as it is affected by partial load and ambient conditions. The designer may select the one or the other, or something in between, depending on the stage of development, and the available information and resources. However, he/she should be aware that the crude model most probably will produce inaccurate results, inappropriate even for a preliminary assessment.

Hour-by hour models may stay at various levels of approximation (and, consequently, accuracy). For example, they may use: only a couple of days (e.g. weekday, weekend) for each season or each month; seven days a week for each season or month; every hour of a typical year (8760 hours). At any level of approximation, for each hour of the day quantities such as the following are determined, taking into consideration any decisions regarding the operation mode of the cogeneration system:

- electrical and thermal loads of the facility (load profiles already created and used),
- power output of each cogeneration unit (zero values are acceptable),
- power used on site,
- power purchased from or sold to the grid,
- cogenerated heat produced by each unit,
- cogenerated heat utilised from each unit,
- fuel consumption of each cogeneration unit,
- fuel consumption of boilers for supplementary heat,
- avoided fuel consumption of boilers due to cogeneration.

Depending on the electricity (and perhaps fuel) tariff structure, there may be need to produce cumulative results for each day or month. At the end of the year, quantities such as the following are calculated:

- annual number of operation hours of each cogeneration unit (it is verified that it does not exceed the expected availability; otherwise, the calculations have to be repeated with a modified operation mode),
- average electrical load factor of each cogeneration unit,
- percentage of cogenerated electricity used on site,
- percentage of required energy in each form covered by cogeneration,
- annual electrical efficiency of each cogeneration unit,
- annual thermal efficiency of each cogeneration unit, based on the utilised heat,
- annual total efficiency of each cogeneration unit (summation of the annual electrical and thermal efficiency),
- fuel energy consumption for separate production of electricity and heat,
- fuel energy savings ratio.

In a detailed hour-by-hour model, the effect of ambient conditions both on energy requirements and on cogeneration system performance is taken into consideration explicitly. Also, site loads can be modelled by considering factors such as building occupancy, type and performance of heating, ventilating and air conditioning system (e.g. compression or absorption units), process requirements, etc. Furthermore, hour-by-hour models allow for accurate calculation of cost for purchased electricity or revenue from selling excess electricity, if rates depend on the hour of the day.

The calculations for energy performance are repeated for each characteristic year throughout the lifetime of the system. Also in each year, various costs are calculated according to the approach described in Chapter 7. At the end, the measures of economic performance are calculated.

With simple models, calculations can be executed by a hand-held calculator. With more elaborate models, computer modelling and simulation is rather necessary; this is more so, when the effects of alternative system configurations and assumptions or of process changes on the performance have to be studied. The designer may find it more efficient and not very difficult to develop a custom-made software, instead of using a commercial one.

For each particular site, energy and economic performance measures are calculated for various configurations of cogeneration systems (number of units, capacity of each unit, heat recovery equipment, etc.). For each configuration, the calculations can be repeated with various models of operation, as well as with various assumptions on the values of technical and economic parameters, in particular those subject to an uncertainty. Based on the results, decisions can be reached on which of the examined systems is the most appropriate for the particular application.

8.5 OPTIMIZATION OF COGENERATION SYSTEMS

8.5.1 Formulation and Solution Procedure of the General Optimisation Problem

According to the procedure described in Chapter 8.4, which is the usual practice, alternative solutions to the cogeneration problem (i.e. alternative systems, from the point of view of configuration and capacity, operating under various pre-specified modes) are evaluated technically and economically, and the one with the best overall performance is revealed. However, except of simple applications, the variety of solutions is such that it is extremely difficult and time consuming, if at all possible, to identify and evaluate each one of them. In these cases, a much more efficient procedure to identify the best solution is to apply mathematical optimisation methods.

The complete optimisation problem can be stated in the form of questions interwoven with each other: Which are the configuration (set of interconnected equipment) of the system, the design characteristics of the components, and the operating strategy (mode) that lead to an overall optimum? The degree if freedom increases in multiproduct systems with production rates not always specified, as it is the case with cogeneration systems. Furthermore, time dependent operation adds one more dimension.

In mathematical terms, the optimisation problem is stated by the objective function

$$\min F(\mathbf{x},\mathbf{y},\mathbf{z}) \tag{7.1}$$

subject to the constraints

$$h_i(\mathbf{x},\mathbf{y},\mathbf{z}) = 0, \quad i = 1, 2, \ldots, I \tag{7.2}$$

$$g_j(\mathbf{x},\mathbf{y},\mathbf{z}) \le 0, \quad j = 1, 2, \ldots, J \tag{7.3}$$

where **x**, **y**, **z** the sets of independent variables for operation, design specifications and synthesis (configuration), respectively. Equation (7.1) is written as a general statement, which is applicable also when maximisation is the real objective: maximisation of a function is equivalent to minimisation of its negative or inverse value.

Examples of objective functions in cogeneration system optimisation are the following:

- maximisation of total efficiency,
- maximisation of fuel energy savings ratio,
- maximisation of net present value,
- maximisation of internal rate of return,
- maximisation of benefit to cost ratio,
- minimisation of the payback period.

Among the operation independent variables (**x**) is the power output of each cogeneration unit. Examples of independent variables for design (**y**) are the rated power of each unit, pressures and temperatures of fluids (if not strictly specified by processes), nominal efficiencies, etc. The independent variables for synthesis (**z**) indicate whether or not certain components exist in the system; the number of similar cogeneration units is an example; alternatively, the nominal power of a unit may be an independent variable for synthesis: a zero value indicates that the unit does not exist in the optimal configuration.

The equality and inequality constraints, Eqs (7.2) and (7.3), respectively, are nothing more than the model of the system (Chapter 8.4), technical limits, and limits imposed by rules, regulations and contracts.

In each time interval defined in such a way that a steady-state operation of the system can be assumed (e.g. each hour, in an hour-by-hour model), an operation optimisation problem can be stated by the operation objective function

$$\min f(\mathbf{x}) \tag{7.4}$$

subject to those of the constraints, Eqs. (7.2) and (7.3), which are related to the operation of the system. Examples of operation objective functions are the following (each one calculated for the particular time interval):

- maximisation of total efficiency,
- maximisation of fuel energy savings ratio,
- maximisation of operation profit.

The last one is calculated by an equation similar to Eq. (6.27), where the subscript t indicates the particular time interval and not the whole year.

The optimal solution is obtained when the synthesis of the system (components the system is composed of), the design characteristics of equipment and the operation mode in each time interval are determined, which satisfy the overall objective, Eq. (7.1). the complete optimisation problem can be solved by a two-level procedure, where

Level A: corresponds to synthesis and design optimisation,

Level B: corresponds to operation optimisation.

The problem is solved with the following steps (the letter A or B is written in front of the step number to indicate the level where the step belongs):

A1. Select an initial set of values $\mathbf{y}°$, $\mathbf{z}°$ for the design and synthesis independent variables.

A2. Solve the operation optimisation problem. For the first time interval:

- B1. Select an initial set of values $x°$ for the operation independent variables.
- B2. Evaluate the operation objective function $f(x)$ by Eq. (7.4).
- B3. Search for the optimum set x^*.
- B4. Calculate the optimum value of the operation objective function, $f(x^*)$.

Repeat steps B1 – B4 for each time interval in the period of analysis (one or more typical years).

- A3. Evaluate the overall objective function $F(\mathbf{x}^*, \mathbf{y}, \mathbf{z})$ by Eq. (7.1).
- A4. Search for the optimum sets $\mathbf{y}^*$, $\mathbf{z}^*$.
- A5. Calculate the optimum value of the overall objective, $F(\mathbf{x}^*, \mathbf{y}^*, \mathbf{z}^*)$.

The solution procedure includes two searches for optimum: steps B4 and A4. Optimisation methods based on linear or non-linear mathematical programming are used for this purpose, which are implemented by a user-made or commercially available software. In particular for step A4, a combination of a generic algorithm with a mathematical programming algorithm has often been more effective. More information about optimisation procedures can be found in the literature [Reklaitis et al. (1983), Floudas (1995), Frangopoulos (1991a, b), Frangopoulos et al. (1996), Manolas et al. (1997), Cerri et al. (2000)].

The steps of level B described above are valid under the assumption that any decisions about the operation of the system in a time interval do not affect the decisions for other time intervals. If this assumption can not be made, then dynamic programming techniques are required, which are beyond the scope of this text.

8.5.2 Design and Operation Optimisation

Very often, the synthesis of the system under study is predetermined. In such a case $\mathbf{z}$ is known, and the problem is to determine the optimal design and the optimal operation mode in each time interval, i.e. to determine $\mathbf{x}^*$ and $\mathbf{y}^*$. The problem is solved by the two-level procedure described in Chapter 8.5.1, with the only difference that steps A are applied with $\mathbf{y}$ only as independent variables, since $\mathbf{z}$ is known.

As an example, let a cogeneration system be considered with a gas turbine and a double pressure exhaust gas boiler. The set $\mathbf{y}$ may include the nominal power output of the gas turbine, the low and high steam pressures and temperatures at design point, the nominal steam production rate at each pressure level. The set $\mathbf{x}$ in each time interval may include the power output, the steam production rate at each pressure level.

If, for any reason, the operation mode in each time interval is predetermined, then the problem is simplified to a design optimisation one. It is solved by the A-level steps described in Chapter 8.5.1 with only $\mathbf{y}$ as independent variables, while step B2 of level B is only used to evaluate the function $f(\mathbf{x})$ for the known $\mathbf{x}$ in each time interval, which is required in order to calculate the objective function F.

8.5.3 Operation Optimisation

For a completely specified system (both synthesis and design specifications are given), operation optimisation in each time interval can be performed (steps B1 – B4), in order to determine the optimum operation mode. At the end, the best performance of the given system in the particular application is determined. The procedure can be repeated for various systems and a comparison among them can be made, based on the optimum performance of each system.

8.5.4 Sensitivity Analysis

Many assumptions and parameters are involved in the formulation and solution of an optimisation problem, and more so if economics are included. After solving the problem for a particular set of assumptions and parameters (called "nominal set"), it is necessary to determine the sensitivity of the solution to changes in the assumptions and parameters. This is called *sensitivity analysis*. There are several reasons for performing a sensitivity analysis:

1. To find one or more parameters with respect to which the optimal solution is very sensitive. If such parameters exist, a change in the corresponding system features could be examined.
2. To reveal additions or modifications to the system, which could improve the overall performance. For example, information can be obtained on whether increasing the capacity or introducing energy storage could be advisable.
3. To reveal the effect of imprecisely known parameters on the optimal solution. Some parameters may have a considerable uncertainty. Sensitivity analysis can indicate whether it is worthwhile to expend resources to obtain better estimates of these parameter values. On the contrary, it may be revealed that the solution is not sensitive to parameters, which initially were thought of being critical; hence they need no further refinement.

The information thus obtained is often so important, that the sensitivity analysis may be equally or even more valuable than the optimal solution itself.

Two methods of sensitivity analysis are described here.

Parametric study

The optimisation problem is solved repeatedly for several values of a parameter in a certain range, while the values of all the other parameters are kept constant. The results are presented in graphs, where the optimum values of the independent variables and of the objective function are drawn as functions of the parameter. The approach is similar to the one presented in Chapter 7.5.5.

On a two-dimensional graph the simultaneous effect of up to two parameters can be illustrated clearly. Three-dimensional graphs can illustrate the simultaneous effect of three parameters. Beyond that number the graphical representation is not clear or possible.

Uncertainty evaluation

Let p_j , $j = 1, 2, \ldots$, be the parameters with respect to which a sensitivity analysis is needed, and Δp_j the uncertainty (change) in parameter p_j.

The uncertainty (change) in the optimal value of the objective function due to uncertainty in the parameter p_j is given by:

$$\Delta F^{*} = F^{*}\left(p_j + \Delta p_j\right) - F^{*}\left(p_j\right) \cong \left(\frac{\partial F^{*}}{\partial p_j}\right)\Delta p_j \tag{7.5}$$

The maximum possible uncertainty in the optimum value of the objective function due to the uncertainties in a set of parameters is given by :

$$\Delta F^{*}_{max} \cong \sum_j \left|\frac{\partial F^{*}}{\partial p_j}\right| \Delta p_j \tag{7.6}$$

The most probable uncertainty in the optimum value of the objective function due to uncertainties in a set of parameters is estimated by :

$$\Delta F^{*}_{prob} \cong \sqrt{\sum_j \left[\frac{\partial F^{*}}{\partial p_j}\Delta p_j\right]^2} \tag{7.7}$$

It may not be easy to evaluate analytically the partial derivatives appearing in Eqs. (7.5)-(7.7). Then, numerical evaluation is performed, replacing derivatives with finite differences at the vicinity of each p_j. Also it should be noted that the variation of p_j must be small compared to the value of p_j (small $\Delta p_j/p_j$), in order for the results obtained by Eqs. (7.5)-(7.7) to have a satisfactory accuracy.

Such an analytical approach does not give the direct impression of a graphical one, but it can handle any number of parameters simultaneously.

9 CURRENT STATUS AND PROSPECTS OF COGENERATION

9.1 INTRODUCTION

On 4 June 1993, ministers of the 23 countries* of the International Energy Agency (IEA) met in Paris. Seeking to create the conditions in which the energy sectors of their economies can make the fullest possible contribution to sustainable economic development and the well being of their people and of the environment, they adopted the following set of "shared goals" [Coroyannakis, 1993]:

- Diversity, efficiency and flexibility within the energy sector as basic conditions for long term energy security;
- The ability to respond promptly and flexibly to energy emergencies;
- The environmentally sustainable provision and use of energy;
- The need to encourage and develop more environmentally acceptable energy sources;
- Improved energy efficiency that can promote both environmental protection and energy security in a cost effective manner;
- Continued research, development and market deployment of new and improved energy technologies;
- Undistorted energy prices that enable markets to work efficiently;
- Free and open trade and a secure framework for investment that contribute to efficient energy markets and energy security;
- Co-operation among all energy market participants helps to improve information and understanding, and encourage the development of efficient, environmentally acceptable and flexible energy systems and markets.

It is interesting to note that the introduction of more cogeneration in IEA countries is compatible and consistent with each one of the nine shared goals.

It is interesting to look also at the three EU goals for Energy Policy:

1. Security of supply;
2. Industrial competitiveness;
3. Environmental protection.

As with the IEA shared goals, cogeneration fits perfectly into the three EU goals. Further, it is actually one of the few technologies that fits into the three of them.

It therefore comes as no surprise that most IEA countries (where all EU countries are included) have introduced policies to encourage cogeneration. It is important to point out from the beginning,

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* Australia, Austria, Belgium, Canada, Denmark, Finland, France, Germany, Greece, Ireland, Italy, Japan, Luxembourg, Netherlands, New Zealand, Norway, Portugal, Spain, Sweden, Switzerland, Turkey, United Kingdom, United States.

however, that the degree of encouragement and penetration of cogeneration systems varies considerably among IEA countries -and even among EU countries themselves- for a number of reasons. In addition, development of cogeneration in some non-OECD countries, and in particular in Central and Eastern Europe, took place in the past, under conditions that are not consistent with accepted principles of economic efficiency and energy conservation.

9.2 EU POLICIES AFFECTING COGENERATION

As noted above, EU Energy Policy has three main goals:

1. Security of supply;
2. Industrial competitiveness;
3. Environmental protection.

Energy Policy is an issue that is still very much at the hands of the EU Member States, and what they do has much more effect than what the EU does. The 15 EU countries have in the past chosen very different energy policies, and this is what explains the very different shares of cogeneration development (see Chapter 9.3). At the moment there are however a number of items that are being directed at EU level that will have a crucial impact in the development of cogeneration in the future. These items can be divided in three groups:

- Liberalisation of the Electricity and Gas markets;
- Environmental protection;
- Strategy to promote CHP and Action Plan to Promote Energy Efficiency.

9.2.1 Liberalisation of the Electricity and Gas Markets[3]

The Council of Ministers agreed on the Directive to liberalise the Electricity Market at the end of 1996, after six years of negotiations. The Directive obliges a market opening of at least 25% of the European Electricity market by 19 February 1999. This should be progressively increased to 28% by 2002 and 33% by 2005.

The progress in the implementation of this Directive is very different in each Member State, most have liberalised much further (Spain, Germany, the Netherlands, Finland, Sweden, etc.), while other have chosen to liberalise just what the Directive requires. However the general tendency is to liberalise further than required and the European Commission is now asking for a speed up of the liberalisation process. According to most recent declarations, the Commission is aiming at a full liberalisation by 2004.

This Directive to liberalise the Gas market was agreed about one and a half-years later than the Electricity Directive. The liberalisation process is similar: Member States have to liberalise gradually and partially their gas market. The deadline for the first step was 10 August 2000. As with the Electricity Directive, the tendency is to liberalise faster and further than what the Directive requires.

[3] Directive 96/92/EC of 19 December 1996 concerning common rules for the internal market of electricity and Directive 98/30/EC of 22 June 1998 concerning common rules for the internal market of natural gas.

9.2.2 Environmental protection

Here not the only, but the most important issue at the moment is Climate Change. The contribution of the electricity industry to greenhouse gas emissions is enormous, and it is easier to regulate than transport and the building sector –the other two large contributors.

In December 1997, in the framework of the Climate Change negotiations in Kyoto, the EU committed itself to reduce its greenhouse gas emissions by 8% for the period between 2008-2010 in relation to its 1990 levels. This commitment is then distributed with different targets among the EU member states. Cogeneration has been widely recognised –both at EU and member state level- as a technology that can make a major contribution to achieving these targets. This presents a major opportunity for the technology, as long as the recognition is translated into practice when defining the policies to its encourage use. Both the EU and the member states are now in the process of defining these policies. Examples of what member states are doing are defined in Chapter 9.3.

At the EU level for the time being there are two main documents:

- The Community Strategy to Promote CHP and dismantle the barriers to its development;
- The Action Plan to Promote Energy Efficiency.

9.2.3 The Strategy to promote CHP and Action Plan to Promote Energy Efficiency[4]

Very briefly, both are EU Policy documents recognising the importance of cogeneration to achieve the Climate Change commitments and defining possible instruments to promote the technology at EU level. Probably the most interesting element is the definition of a target in the Strategy. When the Strategy was issued in 1997, the share of electricity produced from cogeneration in the EU was about 9%. The Strategy sets a target of achieving 18% by 2010. However, possible measures and instruments aiming to achieve this target have so far not been defined into depth.

9.2.4 Contribution of cogeneration to electricity Production

Figure 66 shows the percentage of electricity produced from cogeneration in the EU in 1999. It has to be pointed out, that despite the major efforts made by the EU Statistical Office (Eurostat) to achieve a common way of collecting cogeneration statistics, member states still collect them in a different way, and therefore the statistics are not directly comparable. They serve however to give an idea.

[4] Communication from the Commission on a Strategy to Promote Combined Heat and power (CHP) and dismantle the barriers to its development (COM (97) 514 final) and Communication from the Commission on an Action Plan to improve Energy Efficiency.

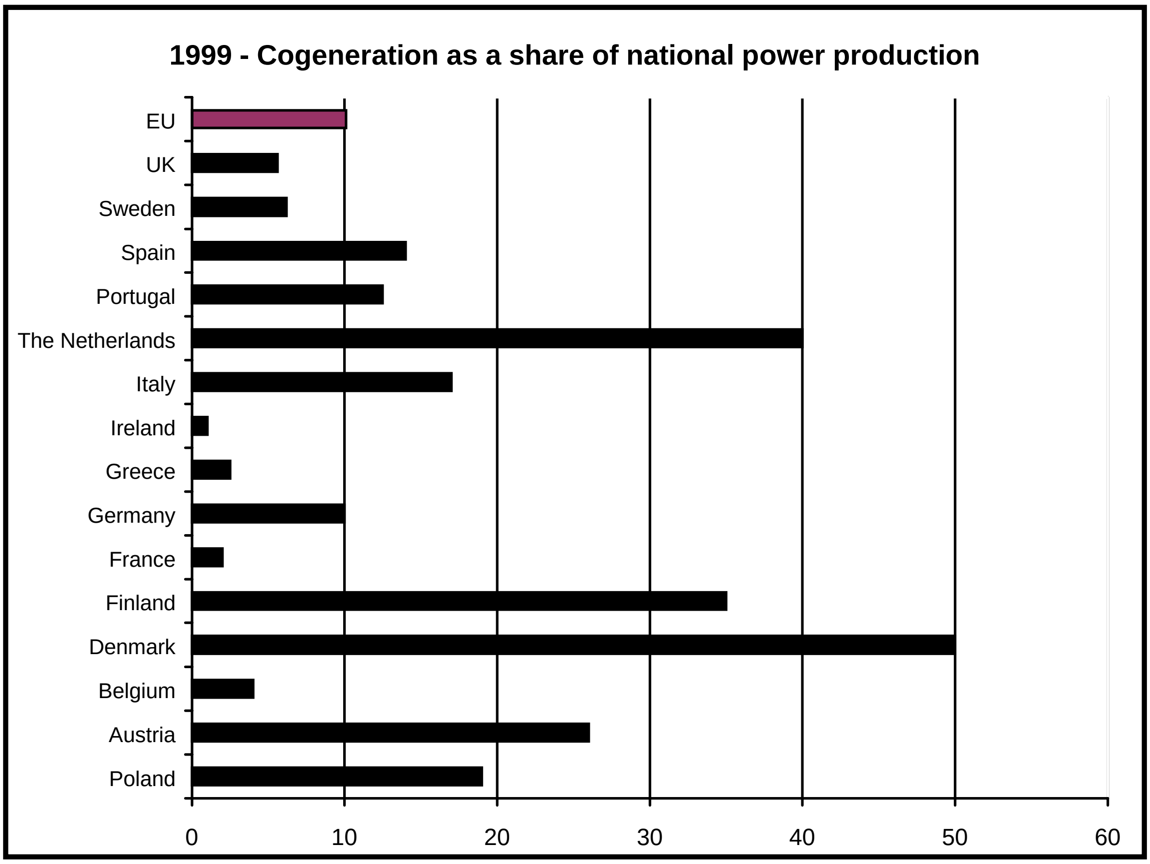

Figure 66: Cogeneration as share of national power production in EU countries in 1999

It should also be noted that the quantities of electricity reported in the graph do not always reflect the extent to which power plants actually operated in cogeneration mode. For example, since plants designed as extraction/condensing can be operated entirely in condensing mode, electricity output from such a plant does not imply that waste heat was actually used. This is especially true for countries where there is a high share of district heating, where the demand for heat varies with the season. However, a number of countries reflect this when collecting the statistics.

It is very difficult to gather trustworthy data of the share of heat produced by cogeneration in the different countries, since a number of countries simply do not collect this. Therefore this has not been included.

Despite the differences in the way of collecting the statistics one thing becomes immediately clear: there is a great diversity in the development of cogeneration in the EU. Clearly, the main reason for this has been the different political choices that governments have done in energy matters.

9.3 ACTIONS TO PROMOTE COGENERATION

As already pointed out, it is universally recognised that cogeneration is one of the most important techniques for more efficient use of fuels, savings in physical and economical resources, and protection of the environment. Attempts have been made in many countries to remove the barriers and promote cogeneration. Various incentives have been used, such as relatively high price for excess electricity sold to the grid and grants on investments. Other measures have included spreading of related information, energy auditing and analysis of data, support of research and development, etc.

Most of these measures were designed in a moment when most of the barriers to the development of cogeneration derived from the existence of monopolistic electricity and gas markets. The most frequently mentioned barriers to cogeneration in the EU when the markets were not liberalised were:

- low price paid for the surplus of electricity to the grid,
- high fees for top-up and back-up supplies,
- no possibility of third party access,
- predatory pricing against possible competition.

These barriers should be lifted in a truly liberalised market.

However, at this moment we are in a transition situation due to the liberalisation of the Electricity and the Gas markets. The process has major consequences both in terms of both barriers to cogeneration and promotional actions. The liberalisation process is far from being completed and therefore the best word to describe the current market situation is uncertainty, which has hindering effect in terms of investment. Further, the first effect of electricity liberalisation in many countries has been a sharp decline in electricity prices, sometimes below production costs. This is not sustainable in the long term and so electricity prices are starting to increase again. Liberalisation should in principle have beneficial effects for cogeneration development, but only if environmental costs are fully included in energy prices. This is far from being the situation at this moment. There is hope however, and many governments acknowledge the need to continue promoting cogeneration in a liberalised market, in recognition to its environmental benefits. Here are some examples of different promotional measures taken by some members states.

9.3.1 UK

The UK government has explicitly acknowledged the need to promote cogeneration in a liberalised market. To this effect, a new Climate Change Levy has been established, and cogeneration of a certain quality has been exempted from this levy. The government has just finished working on the definition of the quality criteria.

9.3.2 Germany

Germany is the country in Europe were liberalisation has had the most detrimental effects to cogeneration. This is due to price wars between the utilities that has provoked that electricity is being sold below production costs. This has already started to change and electricity price is raising again, but meanwhile about 20 GWe of cogeneration capacity has been close down in the last two years. As a result the government has agreed to take a number of measures:

- **Ecological Tax Reform**: cogeneration with a global efficiency of 70% or more exempted from paying electricity and gas taxes;
- **Emergency Plan**: It is compulsory to buy electricity from cogeneration with an extra subsidy of 0.03 DM/MWh. This amount decreases gradually each year;
- **Quota model**: Every company supplier electricity to a final consumer must supply a certain percentage from cogeneration. This will be combined with a system of green certificates.

9.3.3 Portugal

A new tariff structure for the electricity fed into the grid has been approved. This must be paid according to the avoided cost. The avoided cost formula contains the following components:

- Fixed component: production and transport
- Variable components: avoided investment, consumption price index and capacity
- Environmental factors

It needs to be pointed out that it is compulsory for the grid to purchase electricity from cogeneration.

Further, most EU countries have associations to promote cogeneration and such associations have also been established at European and international level: The European Association for Promotion of Cogeneration (COGEN EUROPE) and the International Cogeneration Alliance.

9.4 COGENERATION POTENTIAL AND FUTURE PROSPECTS

As already described, the share of electricity produced from cogeneration in the EU is around 10%. The European Commission has established a target to achieve a share of 18% by 2010. COGEN Europe estimates that this potential is in fact of at least 30%. After all, three countries have already achieved a higher share. However, in the current situation of market stagnation due to the liberalisation process and the uncertainties derived of it, even the 18% target is unlikely to be achieved. It is very important that both the EU and the member states establish clear policies and actions aiming at achieving this targets if the Climate Change commitments are to be met.

9.5 RESEARCH, DEVELOPMENT AND DEMONSTRATION PROGRAMMES

The European Union has long ago recognised the significance of cogeneration in energy savings and protection of the environment. This is why numerous research, development and demonstration projects on cogeneration and district heating have been supported by programmes such as JOULE, THERMIE, SAVE, VALOREN, Community Demonstration Programme.

Even though cogeneration is already a mature technology, the effort to improve the systems (with respect to energy efficiency and adverse effects on the environment), to develop new technologies and to use renewable sources of energy is continued. Examples of this activity in certain countries are the following.

Denmark: Attempts are made to promote the use of natural gas and to develop systems operating on biomass. There is need of technical improvements for biomass-burning systems to become competitive.

Switzerland: There are programmes for development of low-emission cogeneration systems and of design tools for optimisation of cogeneration systems.

Japan: In 1991, a programme was initiated, supported by the state, to develop phosphoric acid fuel cells with a capacity of 1 MW for autogeneration and 5 MW for grid connection. The work is extended to larger systems of various types of fuel cells. Also, programmes are under way for the development of cogeneration systems with gas turbine or reciprocating internal combustion engine, which will have small volume, high efficiency, low emissions and low cost.

United Kingdom: Research and development is performed with the following objectives:

- cost reduction of equipment,
- improvement of system reliability,
- compliance with regulations for environmental protection,
- development of new systems such as fuel cells,
- use of biofuels in cogeneration systems.

The Government, through the Energy Efficiency Office, and the Combined Heat and Power Association (CHPA) are among the strongest supporters of these activities.

USA: The Department of Energy – Office of Industrial Technologies initiated the “Advanced Cogeneration Programme” in 1978, with objective to support the industry for development of advanced cogeneration systems with high efficiency and low emissions. In parallel, it published and distributed special reports and brochures with technical information on cogeneration.

Research and development of fuel cells and Stirling engines is also carried on.

10 REGULATORY AND FINANCIAL FRAMEWORK FOR COGENERATION

This chapter has been analysed for different European countries in which legal, tariff and financial conditions are different from one another. This analysis has been done for Poland, United Kingdom, Belgium, Denmark and the Netherlands.

10.1 POLAND

10.1.1 Legal framework

There is no specific legal framework for cogeneration in Poland. General provisions in the 1997 Energy Law apply. There have been a few attempts to establish some kind of framework to support cogeneration, but these have all failed.

There is no obligation upon the distribution companies to purchase electricity from cogeneration, but in general they do purchase it. They are obliged to purchase electricity from renewables, but there is no exact definition of renewables.

The generator producing electricity from cogeneration needs to obtain a licence if the installed capacity of the unit exceeds 50 MWe.

10.1.2 Progress towards the liberalisation of the electricity and gas markets

10.1.2.1 Structure of the electricity market

The electricity sector has three separate components:

- **Generation**, which consists of the power plants described in the above chapter on statistics.
- **Transmission**, is carried out by the Polish Power Grid Company.
- **Distribution** is undertaken by 33 public companies.

Power plants must sell their output to either PPGC or to the regional energy distribution company within their area. As a result of the 1997 Energy Law, plant owners are able to negotiate directly with other regional distributors or industrial customers.

The Energy Law came into force on 4 December 1997. It introduces competition in generation and supply and regulates the activities of transmission and distribution, which are considered natural monopolies. It further provides a plan for liberalisation of energy prices, limiting the state's power to fix prices. The Law also introduces competition in other areas of the energy sector. The system has been very much based on the UK system, with a spot market and a regulator (the Office of Energy Regulation).

10.1.2.2 Structure of the natural gas market

Poland has very important reserves of coal and lignite and little indigenous natural gas reserves. For this reason, the use of natural gas is not very widespread. Environmental concerns and the obligations to meet EU standards and Kyoto commitments are changing the situation. Right now gas is only used in primary energy production (covering a little over 8% in 1993) and not in power production.

The 1997 Energy Law provides of a plan to replace coal with other energy fuels. The scope of renewables is limited, except for biomass, which is becoming increasingly important, and therefore the main way forward will be the use of natural gas. Polish energy policy envisages an increase in natural gas demand from the current 10 billion cubic metres to 27 billion cubic metres by the year 2010. All this increase will have to come from imports. In September 1996 long-term contract assuring large amounts of natural gas delivery from deposits in Russia was signed between Polish government and Russia. This contract will enable gas delivery for the energy sector, industry and residential customers in Poland (including new Polish and foreign investors).

The Polish Oil and Gas Company is the only producer of natural gas. It holds monopoly on import, transmission, storage and distribution and enjoyed a formal monopoly for oil and gas exploration until 1991, but then this became open to domestic and foreign companies. The 1997 Energy Law provides for a framework to open the gas sector to competition.

The Polish Oil and Gas Company also negotiates with other foreign gas suppliers in order to secure the gas amount needed to balance future gas demand and secure gas imports from different sources. Negotiations with Dutch company Gasunie (delivery of about 2 billions m^3) and with Norwegian supplier (delivery of up to 5 billions m^3) are particularly advanced.

10.1.3 Promotional policies

There is no specific support for cogeneration in Poland, but recently an association for its promotion, KOGEN Polska, has been created. This is the national member for COGEN Europe in Poland.

10.2 UNITED KINGDOM

10.2.1 Progress towards the liberalisation of the electricity and gas markets

10.2.1.1 Structure of the electricity market

The electricity market in the UK is divided in three areas with different structures:

- England and Wales;
- Scotland;
- Northern Ireland.

The electricity market in England and Wales was a pioneer in the liberalisation process and this model has inspired many countries.

Before the reform of the electricity industry under the 1989 Electricity Act, the electricity industry in England and Wales was dominated by one large generating and transmission company: the Central Electricity Generating Board (CEGB), which sold electricity to 12 area distribution boards, each of which served a franchised supply area.

Under the new restructuring, the CEGB was divided into three parts: National Power and PowerGen (which became the two large fossil-fired generators) and Nuclear Electric. Only Nuclear Electric remained in public ownership until 1996, the two other were immediately privatised. Nowadays the main generators are National Power, PowerGen, British Energy (the private successor to Nuclear Electric), Magnox Electricity and Eastern Group. There are an increasing number of independent generators.

The ownership and operation of the transmission system were transferred to the National Grid Company (NGC), which was put in charge of facilitating competition. It was also given responsibility for administering financial settlement following the trading of electricity in the wholesale competitive market through NGC settlements Ltd. The RECs, became the majority joint owners of NGC until December 1995, when NGC was floated on the stock market.

Each REC supplies electricity to a franchise market in its region, but customers with a maximum demand of 100 kWe or more may buy from any supplier. Full competition is scheduled to take place from June 1999, although in some areas very small customers were able to benefit from competition earlier than this, from 14 September 1998 (this means that there has been a delay, since the 1989 Electricity Act had set April 1998 as deadline to achieve full competition). At the time of finalising this report, full market opening had been achieved.

Power is traded through an open commodity market, the Pool. All major generating companies have to sell their electricity into the Pool. The Pool is a very complex mechanism in continuous evolution and development, and the government has decided to undertake a major reform (see later).

Each generating unit has to declare by 10 am each day its availability to the market, together with the price at which it is prepared to generate, for each and every half hour of the following day. The units are then called to generate by the NGC in ascending order of price. The most expensive unit used establishes the system marginal energy price that all others receive for that half hour. There is an additional pricing mechanism designed to provide an incentive for the provision of generating capacity.

This form of price setting produces volatility of prices that is not welcome by either buyers or sellers. To overcome this, the pool has been overlaid with short and long-term contracts to make capacity and energy prices more predictable. These are called 'contracts for differences' and involved an agreed 'strike price' (an agreed price per kWh) for a specific quantity of electricity and a specified period of time. About 90% of the electricity sold by major generating companies is covered by contracts, both with the RECs and with individual large customers. Only around 10% of the electricity sold is paid at pool prices.

According to the government, 'contract for differences' have kept the prices artificially high and have allowed companies to bid their electricity at zero price to ensure that they could sell it and there have been further distortions. For example the regulator applied a cap on pool prices, and required the major generators to sell capacity. The pool price cap resulted in a depression in export prices for cogeneration plants. To remove these distortions the electricity regulator has consulted with the industry and drawn up proposals to replace the pool with new trading arrangements. In outline these are:

- The end of central despatch for large power stations;
- A bilateral forwards and futures market, which can be on a long term basis of several years;
- A short-term screen-based exchange, working 24 hours to 4 hours before the trading period;
- A balancing market, open 4 hours before real time, operated by the System Operator;
- A mandatory settlement process to resolve imbalances between demand and generation.

The new arrangements were due to be in place by April 2000 - however much work is still required to agree the procedures and to implement the trading systems. As a result it is not yet clear what the impact will be on smaller generators such as cogeneration. A few of the concerns are that:

- The Pool price as a visible reference disappears;
- Generators may pay more for stand-by and top-up power;
- Export from cogeneration may be seen as a distress sale, as most cogeneration is tied to an industrial steam load and must run;
- The costs of entering the new markets may be too high for smaller generators;

These issues have been recognised by the electricity regulator and government and options such as trading clubs and the use of a reference price for cogeneration contracts will be explored. Essentially, the Government wishes to ensure that the post-Pool arrangements provide long-term assured access to fair market prices for cogeneration.

10.2.1.2 Electricity markets in Scotland and Northern Ireland

The electricity market in Scotland has been dominated by two vertically integrated companies: Scottish Power and Hydro Electric and the nuclear generator, Scottish Nuclear and there is no pool. Scottish Nuclear (now British Energy) was not a vertically integrated company, but it was guaranteed sales of electricity to Scottish Power and Scottish Hydro Electric (now called Scottish and Southern). Generation, transmission, distribution and supply are treated as separate business and have separate regulatory regimes. There is Third Party Access to the transmission and distribution systems. However, almost no cogeneration has developed in this market environment.

In Northern Ireland, there are three main generating companies: Nigen, Premier Power and Coolkeeragh Power. The largest power plant, Ballylumford, accounts for almost half of Northern Ireland's generating capacity. Generating companies are obliged to sell their output to Northern Ireland Electricity, which has a monopoly of transmission and distribution and a right to supply customers in their province, but other companies are able to compete in supply to the customers. The electricity network is not yet interconnected to Great Britain. There is very little cogeneration in Northern Ireland.

A regulatory system was established to create a competitive industry operating in an efficient manner and providing full protection to customers against companies with monopoly powers. It is headed by the Director General of Electricity Supply (DGES) for England, Wales and Scotland. Northern Ireland has its own DGES. The Directors General of Electricity Supply grant licences, monitor compliance with licence requirements, protect customers in respect of price, quantity and continuity of supply and determine disputes within the industry. If a dispute cannot be solved it may referred to the Monopolies and Mergers Commission (MMC).

The Office of Electricity Regulation (OFFER) assists the DGES in carrying out his duties and functions. In Great Britain the offices of OFFER and OFGAS (the gas regulator) are currently being combined, with a single Director General and in the long term a combined function. The Office for Regulation of electricity and gas (OFREG) and Consumer's Committee assist the DGES in Northern Ireland.

10.2.1.3 Structure of the gas market

The structure applies to England, Wales and Scotland.

Until recently, the gas market was dominated by a vertically integrated monopoly, British Gas, which was privatised in 1986. In 1995, the Gas Act was passed and British Gas was obliged to separate its activities. Competition was fully achieved in May 1998. This was achieved gradually, and it started in 1986, when the Gas Act provided for competition in gas to consumers burning more than 25,000 thermie a year. In 1992, the threshold was lowered to include companies using 2,500 thermie a year or more.

British Gas was separated into two new companies: BG plc (responsible for pipeline activities and mainstream operations) and Centrica (responsible for gas sales in competition with other gas traders. Confusingly, the British Gas name is shared between the two companies. In UK activity, Centrica has the rights to use the British Gas name, whilst BG plc has these rights outside the UK.

Gas competition has encouraged more than 60 suppliers to join the market and has resulted in average prices to industrial and commercial users falling by 53% in real terms over the past five years.

Transco, an independent part of the BG plc, owns the national distribution network. Transco is responsible for shipping and storing gas (as well as laying new pipelines and repairing gas leaks). In the past, an independent regulator (Ofgas) oversees the industry, setting the formulae for prices, promoting competition, and resolving disputes between customers, shippers and Transco. This function is being combined with OFFER to form a joint gas and electricity regulator.

10.2.2 Impact of the electricity and gas market reform on cogeneration

The impacts of privatisation and then liberalisation have had a significant impact on the prospects for cogeneration, as has the response to global climate change.

Initially in 1990 the UK set a target for UK cogeneration of 4,000 MWe for the year 2000. Good progress was made towards this target from 1990 to 1992. Following the Rio Earth Summit in 1992 there was a growing recognition of the contribution cogeneration could make to reducing CO2 emissions. In 1993 the target was therefore revised upwards to 5,000 MWe. The progress of cogeneration since 1988 is shown in the chart below:

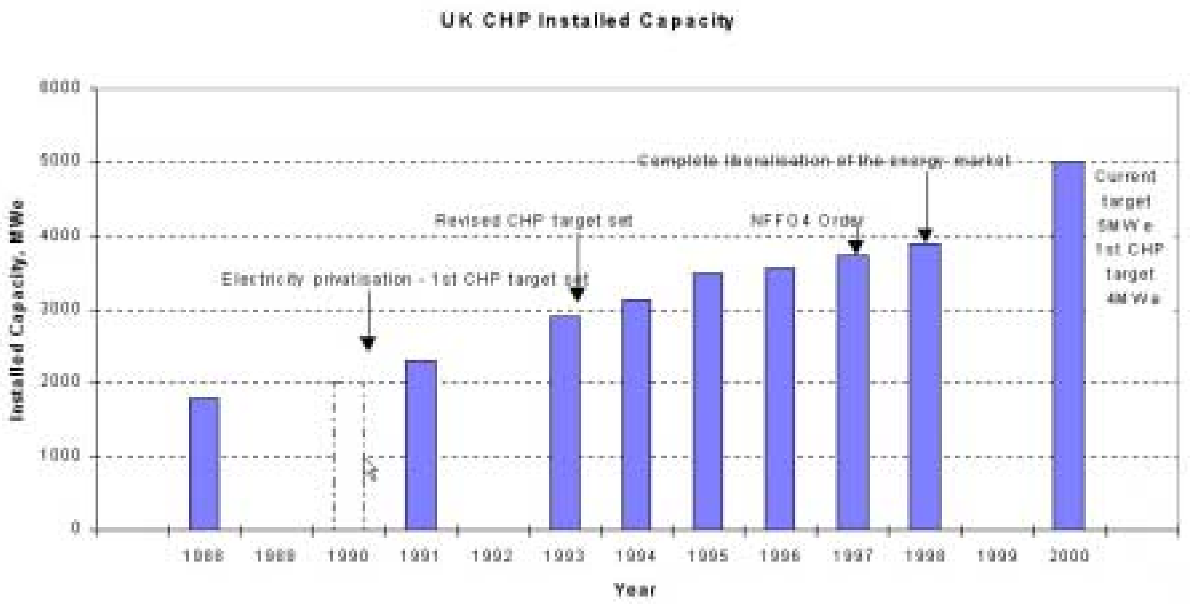

Figure 67: Development of installed cogeneration capacity in the UK 1988-98

The most important aspects of liberalisation which have affected the cogeneration market are:

Sale of Electricity

Prior to privatisation it was difficult for an independent generator to sell electricity to other consumers. This limited the scope for matching cogeneration size to site heat requirements as any electricity which was above the site's own requirements could only be sold at an unattractive rate. Direct sales are now possible but are subject to a number of restrictions.

Firstly, a supply licence is required if the level of sales is above 0.5 MWe over the public network or above 100 MWe if on site or over private wires. All licensed suppliers are subject to regulation by Offer, which imposes significant obligations and costs.

Secondly the local electricity company will charge for the use of its wires to supply another consumer. These charges are based on the costs of distributing electricity all the way from the interface with the transmission system down to the local network where the consumer is connected. So that when a site with cogeneration supplies a neighbouring site with electricity they pay a share of the costs of running the entire network - even if they are only a few hundreds of metres apart. The level of these Distribution Use of System (DUoS) charges is specific to each site, but is typically from 0.2 to 0.5 p/kWh. In one case a cogeneration plant has installed a dedicated cable 3 km long to supply a customer and thus avoids the DUoS charges.

As a result sale to the local electricity company is the most common option. However the prices paid are based on the Pool Selling Price (around 2.5 p/kWh) and may include an allowance for the transmission costs that are avoided. However the price paid does not include any allowance for the benefit of generation embedded in the distribution system. As these costs are greater that the avoided transmission costs, the prices paid to embedded cogeneration plants do not fully reflect the benefit to the system of electricity provided close to consumers.

So while liberalisation has provided some opportunity for electricity sales - there are substantial restrictions. These restrictions are locked into the methods used to privatise and regulate the electricity industry. For example to be an attractive prospect for privatisation the local electricity companies needed to have a secure future – and a secure income. They derive most of their income and profit from the DUoS charges levied on other suppliers and generators. As this is core to their business it will be some time before significant changes to the price regulations on electricity distribution are made which could overcome these issues.

Diversification of Utilities

A further key change is the role that the private electricity companies take in the development of cogeneration projects. This takes several forms. The major UK generators have substantial cogeneration businesses that develop, finance and operate cogeneration plants under a long term Energy Services contract. Indeed the top five UK cogeneration developers are generation companies. These projects are usually designed with substantial levels of electricity export. This is sold to consumers via the generators electricity supply business - which is already carrying the costs and obligations of a regulated supply activity. Well over 50% of the UK's recent cogeneration capacity has been built under these long-term Energy Services contracts. While these overcome the problems of scarce capital in industry they do require a 10 to 15 year contract. Many industrial companies are unable to make such long-term commitments.

The Regional Electricity Companies also have cogeneration businesses, but these are smaller than the generators. When located in a competitor's supply area an investment in cogeneration provides a profitable way to capture the cogeneration site as a consumer and may also provide a competitive way to supply other customers in the same area. However should a competitor wish to establish a cogeneration plant in their own supply area the attitude of the electricity company to cogeneration may become more hostile.

Prices and Uncertainty

One of the greatest impacts of liberalisation has been the impact on prices of gas and electricity. The marginal price between electricity and gas is the key economic driver for cogeneration. Since privatisation the price of electricity has fallen steadily. For a medium sized industrial electricity consumer have fallen in real terms by 24% from 1990 to 1998. There is a strong expectation that prices will continue to fall. Hence many industrial and commercial organisations are prepared to make energy savings through falling prices and better commercial negotiation of energy supply contracts rather than invest in cogeneration.

The market in gas prices has also seen substantial changes, with prices falling in real terms by 44% from 1990 to 1998. These price falls accelerated in the mid 1990s as a number of new gas fired CCGT power stations were unable to use their allocations of gas resulting in a surplus and very low prices. Since then prices have started to rise which when coupled to falling electricity prices has subdued the market for cogeneration over the last two years.

Overall the one of the most important effects of the UK electricity experiment has been to make the future for energy prices less certain. As investment in cogeneration requires a long term view of the profitability of the scheme uncertainty over energy prices is a major factor in delaying or postponing investment in new schemes.

10.2.3 Remaining barriers

The main obstacles to the further development of cogeneration in the UK are:

- low electricity prices is a very important barrier, which is to become even more serious if prices are going down further, as has been predicted;
- As a consequence of the low electricity prices, payback time is very long (often more than 5 years);
- gas prices are rising;
- Generators need supply licences for supply over 500 kWe off site. This might be a barrier;
- Technical regulations relating to grid connection can be a barrier to developers/users who are not already part of the electricity supply industry.

Prospects appear rather positive in the UK if government policy is looked at, however, the main driver to implement a cogeneration project is its profitability and this might be difficult if electricity prices continue to lower, especially if at the same time gas prices increase.

10.3 BELGIUM

10.3.1 Current legal framework

Since 1 January 1989, cogeneration has been the responsibility of the regions, while its development receives priority in the framework of the Belgium National Programme to reduce CO_2 emissions. This programme forecasted that cogeneration in the industrial sector would amount to 500 MWe by 2000 (255 MWe in Flanders and 245 MW in Wallonia). A further potential of 200 MWe further is considered possible in the service sector (124 MWe in Flanders, 46 MWe in Wallonia and 30 MWe in Brussels Capital region). Other studies estimate even higher potentials.

The National Equipment Programme for Electrical Energy and Transport (1995-2005) calls for the development by 2005 of 1,000 MWe of decentralised power production, mainly consisting of industrial cogeneration, through greater co-operation between the electricity sector and industry and manufacturing. The Federal government seeks to increase this target of 1,000 MWe to between 1,500 MWe – 2,000 MWe.

In the framework of the National Equipment Programme, the Control Committee for Electricity and Gas (CCEG), responsible for pricing policy, was given the task of reviewing the development of the cogeneration market and to recommend improvements in its development. Following its recommendations, there are new conditions that apply since 1 July 1998. Whether the purpose has really been achieved is subject for debate.

Formally, there are no restrictions to build new plants and sell surplus electricity to the grid in Belgium. There are no fixed tariffs, these have to be negotiated, but under certain technical conditions, the tariffs are regulated. As just mentioned, new conditions apply since July 1998. There are different cases that apply to units not built and operated in partnership with Electrabel or SPE. These are set out below.

General tariff for the purchase of surplus electricity to autoproducers

This tariff applies to autoproducers in general, irrespective of whether they are cogenerators or not. The only condition is that they export at voltage level of 15 kV or less. The tariff varies depending on the time of the day and the season.

Contract for the purchase of guaranteed electricity produced from 'quality cogeneration' units

This formula is a contract between the cogenerator and an electricity production or distribution company. This means that it contains reciprocal obligations concerning supply of electricity and remuneration:

- The cogenerator must supply a guaranteed electrical capacity ($kW_{guaranteed}$) for the whole duration of the contract;
- The electricity company must purchase this guaranteed capacity at previously agreed conditions and price.

The conditions are to be reviewed periodically for the new contracts.

This framework contract has the aim of developing cogeneration during the transition period until the transposition of the Electricity Directive. The contract is for a first phase available for contracts signed during the period until the implementation of the Electricity Directive, and for installations with a maximum installed capacity of 50 MWe. After this first phase, the situation will be evaluated. The possibility of signing this new contract is valid until 500 MWe of new installed capacity have been developed for the period 1998-2005. However, there is a lower limit of 250 MWe of new installed capacity until results are evaluated.

What is quality cogeneration?

The contract is optional for cogeneration fulfilling certain quality standards: "Quality cogeneration" is a gas-fired cogeneration installation whose functioning allows for savings of primary energy of 15%, in relation to the separate generation of heat and electricity from a reference installation. The reference installation is a 375 MWe CCGT connected to the 150 kV grid and operating more than 7,000 hours per year.

The guaranteed electrical capacity has to be between 100 kWe and 50 MWe and cannot be higher than the total installed capacity of the installation. It applies to a client on a single site.

The duration of the contract is between 5 and 10 years. The purchase conditions are valid during the whole duration of the contract. There is an optional clause that allows both partners to end the contract earlier, when there is a case of strong variation of the economic environment (e.g. the effects of transposition of the electricity and gas directives).

Avoided costs of the sector: the proposed prices for the purchase of electricity from cogeneration are the result of the addition of three factors representing the avoided costs of (future) development of the electricity sector:

- Avoided production costs
- Avoided network costs
- Avoided fuel costs

Any surplus electricity generated not included in the guaranteed capacity has to be purchased by the electricity company, but its remuneration does not benefit from the annual component for guaranteed capacity.

Stand-by and top-up supplies for cogeneration: For clients with 'quality cogeneration', as defined above, there is a maximum price determined by function of the relative size of the cogeneration.

Cogeneration that satisfies the "quality" standard also gets a better gas tariff and Distrigaz is now helping to finance some projects. The global finance available is 400 million BEF for a period of 5 years. Distrigaz will contribute a maximum of 50% of the total investment, with a ceiling of 5 million BEF.

10.3.2 Progress towards the liberalisation of the electricity and gas markets

The structure of the energy sector presents a complicated picture, mainly due to the division of competence between the Federal government and the regions.

The Federal government is responsible for, among other things, the Equipment Plan (which relates to proposals from the electricity sector to the government regarding electricity generation and transmission facilities), and tariffs. The regions are responsible for the distribution of electricity and gas, for heating networks and for energy efficiency.

The National Energy Committee and the Control Committee on Electricity and Gas (CCEG) are the principal regulatory authorities. The latter makes recommendations on tariffs (it must ensure that they are structured in the general interest) and on the Equipment Plan. It is made up of representatives of the trade unions and the employers' organisations, public authorities at both federal and regional levels and of the gas and electricity sector. Autoproducers are not represented. Decisions in the CCEG are taken by consensus, with Electrabel an influential player. With the new Law, these two Committees continue their tasks only for captive customers.

10.3.2.1 Structure of the electricity market

The production of electricity, although in principle free in Belgium, is dominated by Electrabel, established following the merger of three private electrical concessionaires in 1990. In 1998, Electrabel was responsible for about 88% of total electricity production in Belgium. SPE was responsible for 8% of production.

The remaining production (about 4%) is accounted for by autoproducers, a share of which is cogeneration. However, most cogeneration capacity share has been developed in partnership with Electrabel.

Municipalities have a monopoly in the distribution of gas and electricity. Some are 'mixed', where the municipalities are associated with Electrabel, and some 'pure', formed only by municipalities. These companies have an obligation to supply to consumers who are not industrial energy users or autoproducers.

Medium and high voltage clients can be supplied directly by producers and can therefore choose between direct and indirect supply (the tariff differs accordingly).

The transmission network is owned by 'Societé pour la Coordination de la Production de Transport de Electricité' (CPTE), responsible for dispatching, management and maintenance of the network. Electrabel and SPE own the company.

It is therefore clear that the influence of Electrabel is important in all aspects of the operation of the electricity market

10.3.2.2 Progress towards liberalisation

Belgium was given one extra year and doesn't have to implement the Electricity Directive until February 2000. However, a new Law was approved in April (Loi relative à l'organisation du marché d'électricité). Some elements in the proposal are:

- New generation is subject to licensing procedure. The Law provides for an 'indicative programme for generation means' which will be set up by the Regulator (after the approval of the Gas Law named Commission de Regulation de l'électricité et du gas), and approved by the Energy Minister. It will be reviewed every third year each time looking ten years forward;
- Access to the market will be twofold: regulated TPA for eligible customers; and negotiated TPA for transits and high volume transmission. As for pricing, the Finance Minister will set maximum prices (after recommendation from CCEG) for non eligible final customers, in order to ensure that they will benefit from productivity savings, and also to avoid cross-subsidies. They will be uniform across the country. Surprisingly, maximum prices may also be decided for eligible customers. The Law does not exclude distance-dependent transmission tariffs;
- As for market opening, the Law states the following:
  - final customers consuming more than 100 GWh per year (this includes both, consumption and self-production), are eligible as from the start,
  - taking into account the evolution of the electricity market in other Member States of the EU, other categories of final customers will progressively be declared eligible at dates to be set,
  - All clients will be eligible by 31 December 2006, the latest,
  - Distribution companies are eligible for the volume of electricity consumed by eligible customers on their distribution network. In any case, they will be entirely eligible from 1 January 2007.
- The Transmission System Operator will be responsible for power flow management, operation, maintenance, and development of the networks. The TSO will be proposed by network owners and appointed by the Minister for a renewable duration of twenty years. There are possibilities to cancel the appointment due to poor performance. It will be a public company, i.e. legally independent from production, which will only be entitled to operate in network management and directly related business. The Ministry will decide on its managing bodies, the independence of staff, 'corporate governance' modalities, the development of the network, etc., as well as on the grid code. The TSO's staff must respect confidentiality of information or they will be prosecuted;
- The Regulator will be called "Electricity Regulation Commission" (now, after approval of the Gas Law, Electricity and Gas Regulation Commission – see below). Its powers cover the so-called "liberalised market" and the TSO. Its duties include a consulting role to the public authorities, as for the organisation and operation of the market, and also a mission of monitoring the related legislation. The Regulator has conciliation and arbitration powers as well as punitive powers with

up to fines of BEF 80 million. The so-called "regulated market", i.e. non-eligible customers, is the responsibility of the current Control Committee for Electricity and Gas;

- The Law includes the possibility for authorities to impose Public Service Obligations on utilities. The former will be entitled to take measures to allow for compulsory purchase of power from renewables at a minimum price. Mechanisms for compensating additional costs may also be set up by those authorities. This might be financed through a supplementary charge on transmission tariffs, through a levy on all or part of "objectively defined" categories of energy consumers or market players.

There are two mentions to cogeneration in the Law:

- The Transmission network operator will give cogeneration (and renewables) priority for dispatching, as far as possible;
- The public authorities may set up minimum prices for the purchase of power from cogeneration, provided the schemes complies with certain quality standards to be fixed by the public authorities as well.

10.3.2.3 Structure of the gas market

Distrigaz manages import, transport and storage of natural gas. Distribution is handled in the same way as with electricity. Distrigaz was a public company until two years ago, when it was sold to Tractebel by the government.

At the end of April 1999 a new Law liberalising the gas market was approved (Loi relative à l'organisation du marché du gas). According to the Law, eligible customers are the following:

- Gas-fired power generators are automatically eligible, regardless their consumption level;
- For cogenerators and autoproducers, the authorities may impose a threshold for minimum annual consumption to be classified as eligible customers. This threshold may not exceed 5 million m^3 of gas per year for production unit;
- Final clients connected to the network and consuming over 25 million m^3 of gas per year on a consumption site basis are automatically classified as eligible customers. This threshold will lower to 15 million m^3 from 10 August 2003 and to 5 million m^3 from 1 October 2006. All consumers will be eligible from 1 October 2010.

10.3.3 Promotional policies

There are no explicit programmes that support cogeneration development directly, but there are a number of incentives, including tax advantages and direct grants, available for energy saving investment based on Federal legislation. There are also grants provided by the regions and local authorities.

In the Wallonian region, a number of incentives are provided for cogeneration projects in the framework of some general energy efficiency programmes such as AGEBA, and ECHOP (these are programmes only for the public sector).

The industry and tertiary sectors can benefit from a fiscal abatement for investment in energy efficiency, which include cogeneration projects. Further, the Wallonian region has provided financial contribution for the operation of COGENSUD, the organisation promoting cogeneration in Wallonia. It has also put into force an auditing procedure for buildings, with the aim of encouraging cogeneration in the service sector.

In Flanders, subsidies for ecological investments such as water and waste treatment can also be allocated to cogeneration investments, with a maximum of 21% of the investment depending on the type of enterprise and the part of the region. Specific regional taxes on water consumption and on municipal wastes will be focused on the development of future cogeneration systems.

The region of Flanders also provides funding for Belcogen (the association promoting cogeneration in Flanders). This funding comprises 50% of its budget.

Climatic cogeneration that fulfils the criteria for “quality cogeneration” with a maximum installed capacity of 10 MWe can calculate its annual availability on the basis of peak hours from November to March, when benefiting from the purchase contract of guaranteed capacity.

10.3.4 Remaining barriers

As described above, theoretically, cogeneration may benefit from certain advantages, but things change when they are put into practice. To illustrate this, one of our members has provided us with a case study. This is a project that they unsuccessfully tried to develop:

The scheme was a standard cogeneration scheme at a paper mill. The steam demand is 15 tonnes of steam per hour and the electricity demand was 10 MWe, both fairly constant. The plant would need to operate 8,500 hours per year. This scheme could be built economically anywhere in Europe, except in Belgium. In Europe there are about 300 similar projects.

The first problem is the tariffs. In this case the tariff that the operator would have to pay if there was not cogeneration is type C (this tariff continues to apply, because of the quality criteria, after a cogeneration scheme is installed), made up by:

- 20% annual capacity charge, impossible to avoid by installing a cogeneration plant;
- 20% monthly capacity charge, sometimes payable, because the plant may have to cease of operate in some months for maintenance;
- 60% energy charge.

Moreover, back up and top up of electricity if you build a cogeneration plant is prohibitively expensive. With these tariffs, the Belgian arrangements will make the plant twice as expensive as in the Netherlands over a ten-year life.

The second problem is the definition of cogeneration. To benefit from reduced tariffs and favourable connection arrangements, the concept of “quality cogeneration” was designed. Only “quality cogeneration” can get these advantages. However, this concept was in fact designed to prevent these smaller schemes from being built.

$$C=\{E/0.55+Q/0.90-1\}/0.2 > 0.75 = \text{GOOD COGENERATION.}$$

The criteria comes from the following reasoning:

- 0.55: Combined Cycle Gas Turbine base-load plant;
- 0.90: Gas fired condensing boilers;
- 0.2: The gain over these two that cogeneration has to achieve.

Moreover, this formula ignores any transmission and distribution losses. This is an impossible hurdle for smaller projects and ignores the local benefits. It is explicitly designed to prevent competition from decentralised systems.

The Grouping of Belgium Autoproducers of Electricity (GABE) wrote a position paper in April 1998 that was sent to the Ministry of Economy and Telecommunications. Their points can be summarised as follows:

'*Potential for CHP*: At the request of Electrabel, VITO and the Wallonian Institute evaluated the cogeneration potential in Belgium. In the least favourable case, this potential was estimated to be 3,000 MWe and in the most favourable 4,000 MWe.

Effective potential for cogeneration in the middle term

The estimated potential can not be realised under the current market conditions. However, the initial potential of 1,000 MWe could be substantially increased under the following conditions:

- *Possibility for the industrial to choose its partner:* Under the current conditions, Electrabel is the only possible partner, especially if the electricity output is higher than the demand. Electrabel gets all the electricity produced and sells the heat to the industry at a price that ensures very high profits for Electrabel. The industrial has no means to lower the price. Many projects have been cancelled due to this.
- *The possibility for the partner that is not Electrabel of selling surplus electricity at an incentive price.* The current price paid is based on the avoided cost. The reference installation to calculate the avoided costs is a 375 MWe CCGT. No account is taken of:
    - the coal installations inscribed in the last Equipment Plan,
    - the lowering of the performance of the installation as time passes by;
    - the fact that the economic life of a CCGT is limited to about 15 years.

Moreover, Electrabel:

- Has taken as gas price the average price paid at the border and not the average price really paid in the Pool and even less the price of the Statoil contract specifically negotiated for the CCGTs;
- Calculates the annual fixed premium on the bases of the availability during peak hours during the whole year (except July and August) of the contracted capacity delivered to the network, when peak demand for heat and electricity are only in wintertime'.
- Conditions in Belgium are improving very slowly, and market liberalisation should bring new opportunities. It remains to be seen what the new conditions for cogeneration in the liberalised market will be. Technically, the potential for further development is good.

10.4 DENMARK

10.4.1 Current legal framework for cogeneration

Cogeneration has developed successfully because of strong supporting policies combining legislation, planning procedures and tax incentives. Legislation has not always been necessary because political agreement has usually been sufficient. This has been based on the fact that power companies have usually (but not always, see below) agreed to play an active and positive role in the development of cogeneration.

The 1976 Electricity Supply Act and the 1979 Heat Supply Act, revised in 1990, are currently in force. The second has been more important for the development of cogeneration. This Act:

- Placed an obligation on municipalities to ensure that local cogeneration projects are developed and become successfully operative. Municipalities were made responsible for the establishment of cogeneration or biomass projects in all DH areas with more than 1 MW of heat capacity.
- Enabled the Ministry of Energy to issue guidelines for cogeneration planning. This has been used to insist that cogeneration supply at least 90% of the local heat market.
- Municipalities were given the right to impose compulsory connection to DH networks and forbid new electrical heating installations in DH areas. The purpose of these rules was to improve the economy of DH.
- The pricing of heat and electricity are regulated by two pricing Committees under the Ministry of Industry and Trade.
- In December 1991, the Parliament approved the introduction of a carbon tax. This tax contained important incentives for cogeneration, especially small-scale, which are explained in the later chapter dealing with promotional policies.

In 1995, ELSAM announced its intention not to pay for the long-term marginal costs to decentralised cogeneration plants, but only for the short-term marginal costs. As a result, an amendment was introduced to the Electricity Supply Act. Subsection 1 of Section 9a says:

"Electricity-supply enterprises conveying electricity shall purchase electricity generated by small-scale combined heat-and-power plants or by electricity-production facilities utilising biogas, waste or other renewables. *The price of the electricity supplied shall be such as to cover the costs to the purchasing electricity undertaking of producing and transporting the electricity, including fuel and operating costs, etc., and long-term construction costs […]".*

The amendment entered into force on the 1 January 1998, after the European Commission had confirmed its compatibility with EU competition rules. Before this amendment, the obligation of the utilities to buy surplus power from cogeneration was not stated in the Law.

Point iii) of Subsection 1 of Section 9e says: "the electricity enterprises are at all times responsible so as to fulfil the obligation of securing environmentally benign electricity production, including:

1. The purchase of electricity from small-scale combined-heat-and-power plants and electricity-production facilities utilising renewables in consideration for payment in accordance with the provisions of the legislation

2. The construction and operation of environmentally benign production facilities as mentioned in 1), the purchase of electricity produced by such facilities, and the implementation of such research and development projects as are required to effect such expansion, and
3. The purchase of electricity from other combined heat-and-power plants, which are obliged to supply district heat, as and where the electricity cannot be sold at prices covering the necessary production costs".

This is considered a public service obligation and subsection 5 of Section 9d says that the transmission operator may refuse to enter into an agreement concerning access to the network, where necessary to fulfil these obligations.

Given the obligation to open the electricity market deriving from the Electricity Directive, a Parliamentary Agreement had been reached at the time of writing to proceed to it (see later chapter). Concerning cogeneration, the following has been agreed:

- Small-scale cogeneration and industrial cogeneration plants will continue under the present settlement rules until further notice;
- The special cogeneration guarantee, which up to 2006 makes it possible to prioritise production from large-scale cogeneration plants if these should encounter financial difficulties, is to remain in operation.
- Cogeneration plants will continue to be subject to supply commitment to heat customers. This is intended to protect heat consumers from the costs being passed on to them. Price regulation is to ensure that it is only the costs that result from the current principles for sharing the cogeneration advantage that are included in the price of heat supplied by cogeneration plants.

10.4.2 Promotional policies

Behind virtually every development of cogeneration in Denmark has been a promotional policy. The first thing to say is that the commitment is not to build any new plants that are not cogeneration, but the fact is that I/S Nordjyllandsvaerket is constructing a 400 MWe coal-fired power plant at Limfjorden that will produced power for ELSAM (although it will also supply some heat to the local district heating companies in the area).

The Danish Energy Agency has recently written a report "Combined Heat and Power in Denmark" that contains a summary of recent government incentives to promote cogeneration in Denmark. This summary is reproduced here:

- **1992-1996**
  Investment subsidy for conversion of district heating into small-scale cogeneration and to biomass if the conversion results in higher heat prices for heat consumers. DKK 50 million has been allocated per year for a five-year period from 1992-1996.
- **1992**
  Investment grants for new district heating networks and rehabilitation of existing networks in cases of compulsory connection to the grid.

  Subsidy for electricity production sold to the grid from small-scale cogeneration and industrial cogeneration based on natural gas or renewables. The subsidy is DKK 100 per MWh, but cogeneration based on biogas, and straw or wood-fired pilot or demonstration plants, receive an additional premium of DKK 170 MWh.

Investment subsidies for energy efficiency measures in industry and trade, including cogeneration.

- **1992**
  Investment subsidies for installation of central heating in pre 1995 houses in areas with district heating supplied from cogeneration plants in order to increase the penetration of district heating and accelerate the expansion of the large district heating systems, mainly in the major cities. DKK 150 million per year have been allocated for this purpose between 1993 and 2002, amounting to a total of DKK 1.5 billion.
- **1995**
  Introduction of green taxes on trade and industry. The entire tax yield is returned to trade and industry as investment grants. In the period between 1996 and 1999 this will amount to DKK 2.6 billion of which approximately 40% expects to be allocated to industrial cogeneration.
- **1997**
  The subsidy for small-scale cogeneration based on waste or natural gas has recently been cut to DKK 70/MWh. Green field cogeneration with district heating is exempted from the reduction and thus still receives DKK 100/MWh.
- **1997**
  The subsidy for industrial gas-fired cogeneration was simultaneously reduced to DKK 70/MWh in 1997 and limited to a period of eight years for plant with an installed capacity of less than 4 MWe. Industrial cogeneration plants larger than 4 MWe receive the premium for a period of six years.

At the time of writing, the Electricity Directive had not been fully implemented in Denmark. However, on 1 January 1998, a new Electricity Supply Act went into force as a first step on the road to competition and in March 1999, a parliamentary agreement concerning new legislation, had been reached (see below).

Structure of the electricity industry

The Danish electricity industry is organised into two independent areas, organised into the associations ELSAM- for the West of Denmark- and ELKRAFT –for the East of Denmark-, which in effect have until now been vertically integrated monopolies. The two networks are not interconnected. The regional associations are responsible for planning, load dispatching, and operation of the transmission grid and international connections. ELKRAFT is connected to Sweden and Germany and ELSAM to Germany, Norway and Sweden. The two networks are to be themselves connected shortly after the year 2000. 105 distribution companies own the eight central generation plants that account for 75% of the electricity production in Denmark. The generators own the two regional associations. The remaining 25% of the electricity is produced by independent cogeneration plants and wind turbines.

The system has been highly regulated by legislation and by negotiated agreements between central government, or the regional authorities, and the electricity industry.

The distribution companies, owned by the municipalities or by consumer co-operatives, hold the exclusivity of supply within their territory (demarcated by negotiated agreements between the distribution companies). In general, the distribution companies within a region own the regional power company.

Danish utilities have started to adapt their organisational structure to a more liberalised market for electricity:

- The ELSAM association was split into three parts: ELSAM power generation, ELSAM system operator and the ELFOR distribution association. All ELSAM's transmission activities were transferred to ELTRA from 1 January 1998. Thus, ELTRA took over the entire transmission network in Jutland and Funen, including the international interconnections. The partners of ELTRA are the 64 consumer-owned distribution undertakings, which own the six Jutland-Funen electricity utilities region-wise. ELTRA ensures that renewable energy and electricity from local cogeneration plants are given priority.
- ELKRAFT, as Eastern Denmark's system operator, established a separate unit, ELKRAFT System, to take charge of the system operation. The unit is headed by a manager who reports directly to ELKRAFT's managing director. ELKRAFT System prepares and manages procedures and payment on grid access and is responsible for the public service obligations.

On the basis of the 1998 Electricity Act, there is a limited openness of the electricity market, regulated in Section 9d of the Electricity Supply Act:

- Subsection 1: Distribution companies with an annual supply of electricity in excess of 100 GWh may conclude contracts for the direct supply of electricity with electricity producers mentioned in subsection (3) and with foreign suppliers of electricity;
- Subsection 2: Final consumers with annual electricity consumption in excess of 100 GWh per site may conclude similar contracts as mentioned in subsection (1);
- Subsection 3: Electricity producers with annual production in excess of 100 GWh may conclude contracts concerning the direct sale of electricity with each other and with the buyers mentioned in subsections (1) and (2) and contracts concerning the direct sale or purchase of electricity to or from foreign parties;
- Subsection 4: Where so requested by the parties mentioned in subsections (1) to (3), the electricity enterprises concerned shall negotiate access to the electricity-supply network in order to allow contracts for the direct supply of electricity. In the course of such negotiations, no electricity enterprise involved may exploit its position in any manner causing or liable to cause harmful effects on competition.
- Subsection 7 allows for the possibility of determining lower thresholds in terms of eligible producers and customers. As a result of this limited openness, there are now a few big customers buying electricity from the Swedish utility, Sydkraft.

In March 1999, the political parties reached an agreement on the future of the electricity sector. The agreement should be passed into Law later this year without any substantial modifications. Main elements of the agreement are:

- **Market opening:** Full market opening is to be implemented before the end of 2002. This will be gradually achieved: consumers with an annual consumption in excess of 10 GWh will be free to choose their supplier by 1 April 2000, and consumers consuming more than 1 GWh per place of consumption before the end of the year 2000.

- **Unbundling:** The current distribution companies will continue to function as grid companies. If they commit themselves to other tasks than grid operation, the activities must be corporately unbundled.

The main features of the future structure will largely consist of the following type of companies:

- Production and trading companies: in the future they will be run as ordinary commercial companies;
- Grid companies: responsible for operating the grid. They will be controlled by directly or indirectly elected consumer representatives. The grid is to function as a public infrastructure which, against payment, is at the disposal of all users of electricity under objective and non-discriminatory terms.
- Supply obligation companies: which are to offer electricity supplies to all consumers in the supply area. They are to ensure that all consumers are offered standard package of energy-saving services supplied at reasonable conditions. This task is of special importance in the transition period leading to full market-opening, but the obligation is to be maintained once this is achieved in order to ensure that in particular small consumers with little mobility and limited possibilities for acting in the commercial electricity market are protected.
- System responsible companies: which will continue to bear responsibility for security of supply, co-ordination of the total electricity system, implementation of special demonstration and development programmes for using environmentally friendly ways of electricity production.

  A number of services, including supply commitment and grid access will be covered by new price regulation. This is to ensure than competition and incentives for energy saving are not discouraged.
- Regulator: An independent Energy Supervisory Board will be created. It will fulfil a special sector-specific supervisory and complaints function in relation to the energy sector. Its members will represent juridical, economic, commercial, environmental and technological expertise.

The Danish gas network was established during the 1980s and since then it has gradually been extended to the entire country. The network is based on west-east and north-south transmission pipelines.

By 1996, natural gas had achieved a share of 15% of energy supply and this share is to increase to 20% by 2000. Export to Germany and Sweden is expected to grow to approximately 3.5 billion Nm^3 by the year 2000, according to the Danish Energy Agency.

Natural gas is produced by Dansk Undergrunds Consortium (A.P. Møller, Shell and Texaco) and the state owned Dansk Naturgas A/S (DANGAS) is the only buyer (it has monopoly over transportation, storage and trading, the monopoly right to import was lifted in 1994). DANGAS owns the transmission system and two large underground storage facilities with a total capacity around 600 Nm^3. DANGAS has the obligation to supply up to 2.6 bcm to municipally owned regional distribution companies, each of which distributes gas within a defined geographical area). DANGAS and the regional distribution companies sell gas to large industrial customers and small-scale cogeneration plants. DANGAS sells to the power plants.

The regional companies are non-profit companies, and prices only reflect "justified" costs, as determined by the Price Commission. Because of restrictions on the commercial operation of the companies, capital for the development of the gas system was raised by loans, and the gas distribution companies are now heavily in debt.

In order to prepare the Danish gas sector for the future EU internal market for natural gas, a plan to reorganise the sector is currently being prepared. This is being done through a dialogue between the gas industry and the government.

According to Brancheforeningen for Decentral Kraftvarme (Association for Decentralised Cogeneration) if the gas market is only opened to the limit that the Directive prescribes (33% 10 years after the entry into force of the Directive) it will only benefit the bigger consumers (i.e. centralised cogeneration plants). This could actually happen, since the Danish gas grid is not yet paid for. There is still a debt of DKK 15-20 billion.

10.4.3 Remaining barriers

- A very important barrier at the moment is the uncertainty. The government is discussing new legislation and nobody is sure of what will come. So everybody is waiting.
- Most of the cogeneration potential in Denmark has actually been developed. The remaining potential lies in the industrial sector and at a later stage, in micro cogeneration.
- The decrease in the subsidy to industrial cogeneration from DKK 100/MWh to DKK 70/MWh has increased the payback time to at least four years. This is unacceptable to most of the Danish industry, but will be acceptable for energy service companies.
- Gas is relatively expensive, and the price is not likely to decrease in the near future. At the same time electricity is quite cheap. Unlike what will happen in other countries, it is possible that liberalisation produces an increase in the electricity prices rather than a decrease.
- There is 50% electricity over-capacity in Denmark.
- ELSAM has not had a very co-operative attitude towards decentralised cogeneration. As already mentioned, in 1995, it announced its intention not to pay for the long-term marginal costs, at the same time, it tried to make decentralised cogeneration schemes pay large amounts for connection to the grid. Now both problems are solved (see above for payment of surplus electricity). The grid has to give grid access and pay connection costs. In the area of ELSAM, the development of cogeneration has been more due to co-operative district heating companies that have been building new capacity and converting existing coal-based district heating plants. ELKRAFT's attitude has been completely different. Its reaction to cogeneration development has been to try to get hold of most of the cogeneration capacity in its region. Nowadays, most of the heat produced in the ELKRAFT area (90%) is generated in large-scale plants owned by ELKRAFT-utilities. Moreover, these companies also own half of the small-scale capacity.

Denmark stands as the biggest performer in cogeneration development in Europe and this has been achieved through a very supportive government policy that will continue in the future. The main drawback for future development comes from the fact that most of the potential has been realised.

10.5 THE NETHERLANDS

10.5.1 Legal framework for cogeneration

In January 2004 the total energy market in the Netherlands will be liberated (from January 2002 all large customers will be free, the greatest part of the market). There will be no more legal framework for cogeneration.

For the captive customers the Electricity act of 1998 arranges a number of matters in respect to cogeneration. Relevant articles are:

- article 51
- article 52 (a and b)

Article 51:

"The Licence holder shall be obliged to accept an offer for the supply of electricity if this offer is made by a protected customer and the said customer generates electricity by a combined heat and power station, […], and such installation or power station has a capacity of no more than 2 MWe".

The licence holder is the company with a licence to supply to captive customers in the area. The minister has to set the prices that the Licensed Company has to pay for this electricity. The Law amending the 1998 Electricity Act introduces a new Article 52 setting some principles.

Article 52

Before 1 October of each year, taking account of Article 52a, every License-holder shall send Our Minister a proposal relating to the amount payable by that License-holder for the supply of electricity generated in a manner as referred to in Article 51.

Article 52 a

1. Our Minister shall determine the payment referred to in Article 52, taking account of:

   a. The importance of reliable, renewable, efficient and environmentally friendly operation of electricity supplies and

   b. The formula:

   $v_t = p_t - (y_t/100)\, p_t$

   where:

   v_t = the amount payable in period t;

   p_t = the rate for the supply of electricity to domestic households in period t, fixed pursuant to Article 41;

   y_t = the allowance for the average value added of the services relating to the supply of electricity by all License-holders in period t.

2. Our Minister shall determine the allowance for the average value added of the services relating to the supply of electricity by all Licence-holders.
3. If a proposal, within the meaning of Article 52, is not submitted to Our Minister in time, Our Minister shall fix the payment at his own initiative, subject to the provisions of Clauses 1 and 2 of this Article.

Article 52 b

1. The payment shall take effect as of a date to be fixed by Our Minister, until 1 January of the year following the date on which the decision determining the payment takes effect.
2. If the payment for the following year has not yet been fixed on the date referred to in Clause 1 of this Article, the payment shall apply until the date on which the decision fixing the amount for the following year takes effect.
3. Every Licence-holder shall make a copy of the payment that applies to it available for public inspection at all its establishments.

10.5.2 Promotional policies

In a letter from the Minister to the chairman of the Lower House (3 October 2000) the following promotional policies are proposed:

- Increase of the Energy Investment Tax deduction from 40% to 55%[5]
- Maintaining the exempt of Regulating Energy Tax for electricity for private usage (existing and new cogeneration-installations).
- A support of 0.5ct/kWh for cogeneration electricity supplied to the grid (existing and new cogeneration-installations), with an upper limit of 200 GWh/year. [1)]
- The DTe (the Dutch supervisor on the energy market) will investigate possibilities to award avoided grid losses and investments to the cogeneration operator.
- An investigation to possibilities of promotional policy on the basis of the actual CO2 performance of the various energy saving options.

The Minister aims with this promotional policy for an increase of cogeneration capacity with 1300 - 2000 MW in 2010.

At an earlier stage the fuel taxes on electricity and cogeneration-gas were converted to an increase of the Regulating Energy Tax on electricity. This measure was necessary to create the same conditions in the Netherlands as in the neighbour countries. The measure does not promote cogeneration since the less efficient coal fired plants will have the largest benefit per kWh produced.

10.5.3 Progress towards the liberalisation of the gas and electricity markets

The Dutch Electricity Act of 1998 regulates the liberalisation of the electricity market. An important aspect is the separation of distribution and supply. What used to be one company, the EDC, is now divided into a (regional) grid operator and an electricity trading company, both independent. Access to the electricity grid is organised by regulated TPA (Third Party Access).

Since the Act became partially operative (1 August 1998), production of electricity is liberalised in the Netherlands. However until 1 January 2001 there was an agreement between production and distribution because of existing contracts. This means 2001 is the first year of a for the greater part liberalised electricity market. For cogeneration with a capacity below 2 MWe was made an exception so they remained protected. Protected means that the company that holds the licence to supply captive customers in the area is obliged to accept the electricity offered by these protected producers.

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[5] The sum of the electrical efficiency plus two thirds of the thermal efficiency must be at least 65%

On the consumer side, the market opening will be done gradually.

- Big producers (above 2 MWe, which makes about 850 market participants) and industrial consumers are already free to trade.
- In January 2002, the market will open for middle size consumers (which makes a further 54,350 customers). Middle size consumers according to the Law are those with a total transmission value of more than 3x80 A and an available electrical capacity of no more than 2 MWe per connection.
- Consumers with a total transmission value of no more than 3x80 A will remain captive until 31 December 2003. In 2004 all consumers will be free.

The gas market is also in the process of liberalisation. The main gas supplier and distributor, N.V. Nederlandse Gasunie, owns the main gas infrastructure in the Netherlands. The new Gas Law is partially operative since the first of August 2000. At the first of January 2001 the total Gas Law will become active.

The new Gas Law contains the following aspects:

- The Law foresees a gradual market opening (implies free choice of the gas supplier):
  - Large customers (> 10.000.000 m^3 of gas per year per connection) are already free;
  - In January 2002 the market will be open for large customers (> 1.000.000 m^3 of gas per year per connection);
  - In January 2004 the gas market will be open for all customers.
- Gas transport companies are obliged to open their gas grid for third parties. This means the Gasunie keeps it central role and the access to the grid is based on negotiated (TPA) third party access.
- Supervision on the execution and observe of the Law is postulated at the NMa (Nederlandse Mededingingsautoriteit). The NMa can assign tasks to the DTe.
- The Minister has to consent to the privatisation of the energy companies.
- An independent grid administrator will be pointed out for the gas grid.

Gasunie has introduced a new tariff structure, the Commodity Services System (CSS). The CSS discriminates between commodity, capacity, transport, delivery and insurance costs. For most of the industry, the difference between the old and the new tariff in terms of final price is low. However for small customers with irregular off take the new structure could be disadvantageous, especially in the case of space heating.

10.5.4 Remaining barriers for cogeneration

As in every country, the main problem is uncertainty because of the changes in the legal framework and the electricity and gas prices.

- Over capacity of electricity production, what leads to low electricity prices.
- Currently high gas prices.
- Unfavourable transport tariffs for both electricity and gas.

The development of cogeneration in the Netherlands has been a success story. However at this moment the policy toward cogeneration is not sufficient.

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