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Cogeneration

Technologies, Optimisation and Implementation

Edited by
Christos A. Frangopoulos

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Cogeneration

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Preface

Cogeneration of electricity and heat was initiated in 1880–1890 and soon reached a level that most of the electricity needed in the industrial sector at least in the United States of America in the early 1900s was supplied by cogeneration systems. After several decades of decline, the interest and the investments in research, development and applications of cogeneration were revitalised in the 1970s, when it was realised that rejecting more than 50% of the energy contained in fuels burned in power plants to the environment in the form of heat, with no utilisation, was disastrous for both the depletion of non-renewable energy resources and the negative effects on the environment.

During the 40 years that followed, cogeneration technology has reached maturity, and several books on the subject have been published. So, the reader may wonder what one more book could add to the related body of knowledge. It is important to note that cogeneration has many aspects: technical, economic, financial, environmental and legal. All these aspects are treated in the available bibliography, but an integrated treatment that shows how they are interweaved was still missing. Furthermore, the design and operation has been addressed with a conventional approach based on common experience and comparison with alterative options. However, such a treatment may not lead to the technically and economically best system, due to the complexity of cogeneration systems and the fact that conditions, such as loads and the tariff systems, change with time. Instead, the formal application of mathematical optimisation at three levels (synthesis, design specifications and operation) is proposed and presented here.

The book is intended for instructors and students at advanced undergraduate as well as graduate level, for professional engineers who design, build and operate cogeneration systems, and for researchers on analysis and optimisation of energy systems. Fundamental knowledge of Engineering Thermodynamics is necessary for better understanding of the analysis of the systems, whereas knowledge of optimisation techniques is necessary for better understanding of the related chapter and for applying optimisation on cogeneration systems.

I would like to thank the Institution of Engineering and Technology, UK, for inviting me to act as the editor of the book, and its personnel for supporting me throughout this endeavour.

Many thanks are due to all the authors of the various chapters, who accepted the invitation to contribute to the book. Without their cooperation, it would be impossible to present so many diverse aspects of cogeneration.

Special thanks are due to Dr. Jacob Klimstra, who joined the effort since the beginning and had a crucial role not only in writing and reviewing several chapters, but also in contributing to the development of the whole content of the book.

Also, I take the opportunity to thank all my collaborators in projects related to research and promotion of cogeneration, as well as the members of legislative committees I participated in, who helped me not only in completing the tasks successfully, but also in better understanding cogeneration and its complexities.

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October 2016

Short biographies

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Christos A. Frangopoulos is a Professor Emeritus at the School of Naval Architecture and Marine Engineering of the National Technical University of Athens (NTUA), Greece. His research focuses on the development and application of methods for analysis, evaluation and optimisation of synthesis, design and operation of energy systems (including cogeneration systems), by combining thermodynamic, economic and environmental considerations. He has lectured extensively on cogeneration. He is a member of the editorial boards of several scientific journals related to energy.

Other authors

Lucyna Czarnowska is an Assistant Professor at Silesian University of Technology since 2014. She has an extensive experience in thermo-ecological cost, cumulative energy and exergy, dispersion of pollutants in the air and external environmental cost. She focuses on CO_2 emission from power plants, refinery and cement industry. Currently, she is involved in two projects, which are funded by Norway Grants in the Polish-Norwegian Research Programme. Moreover, she is an academic teacher of environmental impact and thermoeconomic evaluation in energy sector.

Jacob Klimstra (Ph.D.) worked at Gasunie Research in Groningen, NL, on all aspects of the gas transport and supply chain, including reciprocating engine optimisation and cogeneration of electricity and heat. He was also the Head of Department of Industrial Gas Applications at Gasunie Research. Subsequently, he was employed by Wärtsilä Power Plants, as senior specialist on energy issues and engine-driven power systems. Currently, he works as a consultant (www.klimstra.nl). He wrote many papers about energy use and electricity production and frequently gives presentations.

Mats Östman is currently working as a Senior Development Manager in Wärtsilä Energy Solutions, renewables and storage business line, where he is responsible for development activities, related to concepts and systems within the electrical engineering discipline. He graduated in Vaasa, Finland, with a Bachelor's degree in electrical engineering. He joined Wärtsilä in 1995, currently focusing on energy storage and grid connection related topics.

Wojciech Stanek was graduated from Silesian University of Technology in 1994. In 1998, he obtained Ph.D. degree and in 2009 D.Sc. degree. In 2011, he was awarded by Polish Academy of Sciences for Excellent D.Sc. Thesis. He is an Associate Professor at the Silesian University of Technology. Fields of his interests are power and cogeneration plants, mathematical modelling of energy management in power sector and industrial plants, advanced exergy analysis and ecological assessment of production processes by means of exergy analysis.

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Chapter 1

Introduction

Christos A. Frangopoulos

1.1 Definition of cogeneration

The electric and thermal loads at one or more sites (building, industrial unit, etc.) are usually covered by purchasing electricity from the local electricity network and by generating useful heat by burning a fuel in a boiler or a furnace located at the site. However, the production of electricity in a power plant is accompanied by production of heat, which results in a huge waste of energy in case the heat is rejected to the environment via the exhaust gases and the cooling circuits of the plant. Most of this heat can be recovered and used to cover thermal loads, thus converting the power plant to a cogeneration system, which increases the efficiency of fuel use from 40%–50% to 80%–90%.

Many definitions of cogeneration (called also Combined Heat and Power) have appeared in legislature and in the general literature. The following one is proposed here:

> *Cogeneration is the simultaneous generation of work and useful heat from the same primary energy source.*

Work shall mean either mechanical or electric energy [1,2]. Mechanical energy, for example produced by a turbine or an internal combustion engine, can drive a generator for electricity production or other equipment such as a compressor and a pump. It is also possible to have direct conversion of energy chemically stored in fuel into electricity by means of, for example, fuel cells.

The recovered thermal energy can be used for heating purposes and/or for cooling by means of additional equipment such as absorption chiller. The use of thermal energy for desalination by means of distillers is also an application of increasing interest. Thus, terms such as *trigeneration* and *polygeneration* have appeared to describe systems with three or more useful products, but these products are obtained with additional equipment, whereas the core system is the cogeneration system as defined above.

1.2 Historical development of cogeneration

Cogeneration first appeared in Europe and the USA in 1880–1890. During the first decades of the twentieth century, most industrial units had their own power plants for electricity production, usually operating on coal. Many of those were cogeneration systems, supplying thermal energy (usually in the form of steam) to the industrial processes. It is impressive to mention that in the USA in the early 1900s, about 58% of the total electric power generated on-site in industrial plants was coming from cogeneration systems.

A period of decline followed, which is due to several reasons: (i) Construction of reliable central power plants and utility grids supplying electricity at low cost, thus making the on-site generation less attractive. (ii) Increasing regulation of electricity generation. (iii) Availability of liquid and gaseous (primarily natural gas) fuels at low cost. (iv) Technological advances such as the construction of packaged boilers. (v) Stricter environmental regulations. As a consequence for example in the USA, the on-site industrial cogeneration accounted for only 15% of the total electricity generation capacity by 1950 and decreased to about 5% by 1974.

The abrupt increase of fuel costs in 1973 accompanied by uncertainty in fuel supplies and increased awareness regarding the environmental pollution made cogeneration more than relevant again. Information about the new period is given in Chapter 11.

1.3 Structure of the text

The primary goal of cogeneration is the increase of the primary energy utilization rate or, in other words, the primary energy savings. It is beyond doubt that the use of energy is directly related with the economy and the economic development at both local and global level. Which is the pattern of energy resource availability and use and what is the position and role of cogeneration? Chapter 2 attempts to answer these questions.

The increased interest in cogeneration after 1973 has been accompanied with advances in cogeneration technologies. A variety (with respect to type, size and operating characteristics) of cogeneration systems is available today. Related information is given in Chapter 3.

The electrical part of a cogeneration system is of particular importance. The types of generators, power quality control, grid interconnection and network stability are subjects treated in Chapter 4.

The applications of cogeneration can be classified in four main sectors: utility, industrial, commercial (or building) and agricultural sector. Applications in these sectors as well as the use of cogenerated heat for water desalination and the capability of combining cogeneration with renewable energy are presented in Chapter 5. Cogeneration in the transport sector goes without saying. The engine of a car or a ship, for example, covers all three loads: propulsion, electrical energy and thermal energy. Therefore, this sector is not included in the text.

Chapter 6 presents the types of fuels appropriate for cogeneration systems with their properties and specifications. Information about combustion-related emissions is also given.

The thermodynamic analysis, that is the quantitative assessment of a cogeneration system from the point of view of fuel utilization, is the subject of Chapter 7. Efficiencies based either on energy or exergy and the primary energy savings ratio are defined. In addition, a crucial question, having also economic importance, is answered: what is the cogenerated electricity and how is it calculated? Numerical examples and two appendices help in clarifying the concepts and the calculation procedures.

The reduction in fuel consumption achieved by cogeneration has, in general, as a direct consequence the reduction of emissions. However depending on the technology and fuel used, it is possible that certain emissions may increase. The procedure for a detailed assessment of cogeneration from the point of view of environmental performance at both local and global level either in absolute terms or in comparison with the separate production of electricity and heat is presented in Chapter 8.

One of the advantages of cogeneration is the increase of reliability of supply of energy products. As any technical structure, cogeneration systems too are subject to failure. Reliability, availability, maintenance philosophies, redundancy and its effect on reliability are subjects treated in Chapter 9.

Primary energy savings and reduction of the adverse effects on the environment may not be sufficient for the investment on cogeneration to be decided, if the investment is not economically viable. The economic analysis of cogeneration systems is the subject of Chapter 10. Information about construction and operation costs is given, economic parameters and measures of economic performance are defined, and a procedure for assessment of the economic performance of cogeneration systems is presented. In addition, the effect of internalization of external environmental costs on the economic performance and methods for distributing the cost of a system to its products are presented.

The importance of cogeneration in primary energy savings and reduction of emissions, as well as its direct and indirect effects on the electricity system, prompted several countries and the European Union to issue regulations and laws for cogeneration. Chapter 11 presents the regulatory and legal framework of cogeneration established by major countries, its effect on promotion of cogeneration, as well as the impact of electricity and gas liberalization on cogeneration.

The selection of the type and size of a cogeneration system for a particular application, its integration with the facility it serves on one hand and with the utility network on the other, and the operating strategy are crucial issues for its technical and economic performance. These subjects are tackled in Chapter 12.

Experience is of paramount importance for the proper design and operation of a cogeneration system. However, the systems and the operating environment (both technical and economic) become more and more complex, and experience alone may not be able to find the best solution. Use of simulation models for prediction of performance of a system and, in connection with optimisation procedures, for determining the optimal system design and operation mode can be of invaluable help. These subjects are treated in Chapter 13.

Chapter 14 presents successful examples of cogeneration projects.

Cogeneration is already a mature technology, but there is always room for improvement of already widely used technologies, whereas new technologies appear on the horizon. Combination of cogeneration with renewables is gaining increasing interest. Current activity on research and development of cogeneration is the subject of Chapter 15.

The text closes with summary and conclusions in Chapter 16.

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[2] Hatsopoulos G.N. and Keenan J.H. *Principles of General Thermodynamics*. Huntington, NY: Publishing Company; 1981.

Chapter 2

Energy use in the world and the benefits of cogeneration

Jacob Klimstra

2.1 Energy and the global economy

2.1.1 Introduction

The substantial growth in wealth level in the world since the beginning of the twentieth century is primarily based on energy use. Fossil fuels feed the machines and processes that enable a tremendous productivity growth and supply of consumption articles. A modern diesel tractor is at least by a factor 1,000 more powerful than a human labourer with a spade. Nitrogen fertiliser is produced with fossil fuel and drastically enhances agricultural productivity. Containerships with a propulsion power of up to 90 MW and aeroplanes with up to 140-MW jet power enable global trading and travel. Electricity allows easy communication and offers tremendous calculating power with computers. Air conditioning facilitates comfortable living in otherwise uninhabitable climates and refrigeration makes long-time storage of food possible. So far, energy has been very affordable compared with the benefits it offers. Consequently, energy consumption has increased at a speed as if the resources would be infinite. People in the deprived regions of the world can only be lifted out of poverty by offering them affordable energy. Fear of depletion of the cheap-fuel resources coupled with increasing anxiety of excessive global warming have led to advocate cogeneration of heat and electricity and to support for a drastic increase in renewable energy. This section will describe the relationship between energy use and the global economy.

2.1.2 The growth pattern in energy use

The International Energy Agency (IEA) in Paris and the Energy Information Agency (EIA) in the USA publish a wealth of information on global energy use [1,2]. Also country-related data is available from these institutes. Figure 2.1 shows the increase of the total primary energy supply (TPES) in the world since the year 1970. In 2013, TPES in the world was by a factor 2.2 higher than in 1970. This equals an average annual increase of roughly 2 per cent. The 34 countries associated in the Organisation for Economic Cooperation and Development (OECD) are the ones with on the average a high-wealth level per inhabitant and are often referred to as

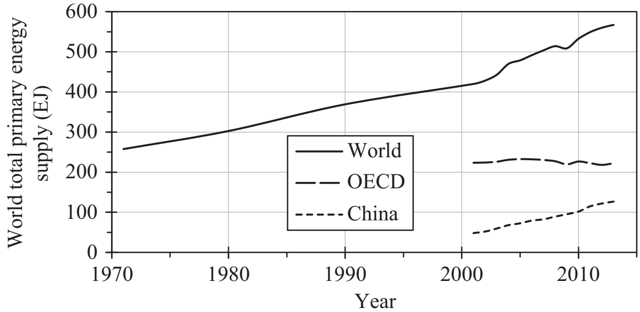

Figure 2.1 The increase in primary energy supply since 1970 [1,3,4]

the developed countries. Figure 2.1 reveals that the primary energy supply to these countries stayed close to constant from 2000 to 2013. Part of that is caused by two major economic downturns, but a higher fuel efficiency of industrial processes and road vehicles also helped. The transfer of energy-intensive manufacturing from the OECD to China and Asia Pacific plays however an important role in this. TPES in China increased by a factor two in only one decade. It is expected that the positive trend in primary energy supply will continue, especially because of developments in sub-Saharan Africa and the poorer countries in Asia. The per capita energy use in Africa is only 16 per cent of that in the OECD countries. If the Republic of South Africa and the northern African countries are excluded, the average sub-Saharan African citizen receives a primary energy supply of only 12 per cent of that of the average OECD citizen. A drastically increased energy supply to the poor regions is needed to create living standards closer to those of the rest of the world.

The drawback of energy consumption is the associated CO_2 emission. On average, each ton of consumed fuel releases 2.5 t of CO_2. The current level of greenhouse gas emissions is already so high that many researchers and politicians consider it as excessive. However, the trends in energy consumption do not reflect a decrease but rather the opposite. The point is that the value of energy for enhancing the wealth level is very high compared with the cost and price of it. This creates a substantial challenge for the world.

For electric energy, the growth curve is even steeper than that of TPES. This is illustrated in Figure 2.2. The electricity supply increased by a factor 4.9 in 32 years' time. It clearly proves the growing role of electricity as an energy carrier. Part of it is caused by the increasing application of electronics. In 2010, these popular tools used already 5 per cent of the worldwide electricity supply [5], and the current trend in electricity consumption is 6 per cent increase per year [1]. The annual growth rate in energy use in China is about 8 per cent, which is unprecedented in the world; it more than compensates for the flat energy supply pattern in the OECD.

The implementation of techniques with improved energy efficiency such as cogeneration and increased emphasis on services has noticeably reduced the energy intensity of the economy. Figure 2.3 shows that in 1970, some 16 MJ of primary energy supply was required for every US$ of gross domestic product (GDP) in the

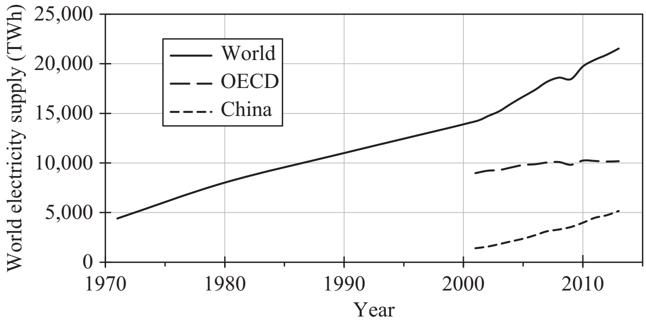

Figure 2.2 The increase in world electricity use since 1970 [1]

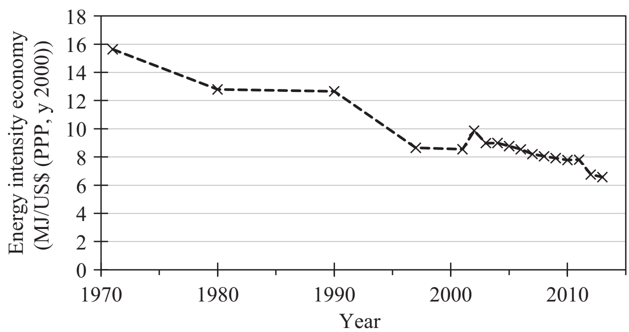

Figure 2.3 The energy intensity of the world economy expressed in MJ/US$ (Purchase Power Parity, year 2000 US$) [1]

world economy. In this diagram, the US$ is expressed in year 2000 US$ to eliminate the effect of inflation. Further, purchase power parity (PPP) is used to compensate for the difference in purchasing power of the US$ in the different countries in the world. In the year 2014, only 6 MJ was required for every US$ (year 2000) in the world economy. This is an improvement of nearly a factor 2.7 in 35 years. Yet, this trend in improving the energy intensity does not compensate for the increase in energy demand as shown in Figure 2.1. The extent of the role of energy in the economy is apparent since, even with only 6 MJ per US$ (year 2000), roughly 1 l of oil equivalent or 1 m^3 of natural gas is needed to create 6 US$ (year 2000) in the economy.

In contrast with the public opinion, the bulk of primary energy in economically developed countries is not directly used in households, but it fuels industrial and commercial activities. Therefore, energy is rather a wealth creator than primarily a luxury product. That is the reason why it is appropriate to express the GDP per person as a function of primary energy supply. The positive effect of energy supply to an economy is clearly demonstrated in Figure 2.4. Apparently, people can only be lifted from poverty by giving them access to affordable energy. The relationship between TPES per person and GDP (PPP) per person is however not linear.

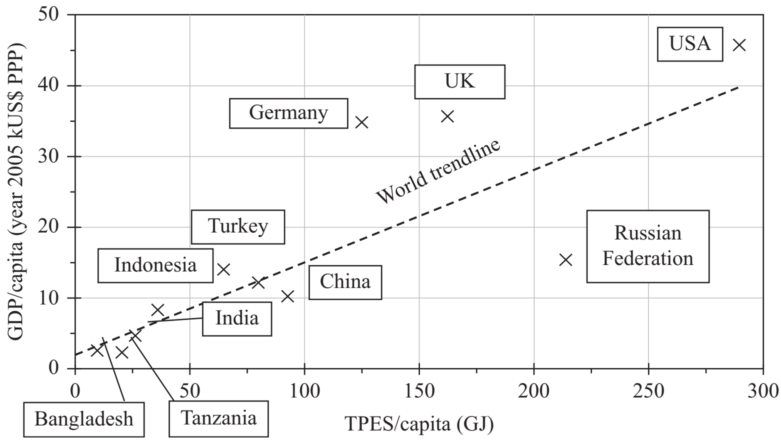

Figure 2.4 The wealth level expressed as GDP (PPP) per person as a function of the primary energy supply per person for the year 2013 [1]

Countries having sufficient indigenous fuel supply tend to have a relatively high-energy intensity of the economy, since the fuel is cheap. The Russian Federation is a clear example of this, although the harsh climate in the wintertime also plays a role. Germany and the United Kingdom appear to use their energy input much more effectively than the USA. If the USA would have the same energy intensity of the economy as these two European Union (EU) countries, its primary energy consumption could decrease by 35 per cent. Tanzania and Bangladesh are examples of African and Asian countries having much poverty. Such countries can only reach the current average-wealth level in the world of US$ 12,000 per capita if their per capita energy supply increases by at least a factor five. The 1.25 billion people in India need on average a factor three more energy per person to reach the current global average. If no special measures are taken, such as a further improvement of energy efficiency and renewable energy, the aspirations to pull the world out of poverty will require huge amounts of fossil fuel. Extrapolating the world's primary energy supply trend with fossil fuels only will ultimately lead to depletion of the fuel resources and to escalating fuel prices. The level of greenhouse gas emissions will reach unsustainable values in that case.

2.2 Fuel use for electricity generation, heating, transportation and industrial processes

Fuels are used for industrial, commercial and domestic applications as well as for electricity generation and for transportation. In many cases, the primary energy contained in the basic fuel is only partly used in the final application. Crude oil has to be refined in most cases before it can be used to fuel road transportation. This makes that the final oil consumption contains less energy than the original fuel.

Table 2.1 The distribution of final energy consumption based on coal, oil products and gas over the different sectors for the year 2013 [1]

Application	**Coal 44.8 EJ**	**Oil products 155.6 EJ**	**Natural gas 58.7 EJ**
Power plants + industry	35.4 EJ	13.1 EJ	21.8 EJ
Transportation	0.1 EJ	99.2 EJ	4.1 EJ
Non-energy	2.7 EJ	25.2 EJ	6.5 EJ
Others (domestic heating, commercial, agricultural)	6.6 EJ	18.1 EJ	21.3 EJ

This applies especially for coal-type fuels such as black coal, lignite and peat. Coal-type fuels are much used in power plants having a world-average efficiency of electricity production of 36.4 per cent in 2013. Natural-gas-fired power plants including combined heat and power (CHP) had an average efficiency of 40.7 per cent. By definition, the total final consumption (TFC) of energy equals TPES minus the conversion losses before the energy is offered to the end user. Most of the conversion losses occur in power plants and refineries. However, the loss in fuel efficiency at the end users, such as that of domestic heating systems and in car engines, has not been taken into account in the TFC. In the year 2013, the TFC in the world was 389 EJ, and the TPES was 567 EJ. This means that 31.4 per cent of the TPES was lost in energy conversion processes. In 1973, the TPES loss was only 23.5 per cent. The increase in loss is primarily caused by the growing fractional consumption of electricity and transportation fuels. In 1973, electric energy was 9.4 per cent of TFC, whereas in 2013, it was already 18.0 per cent. CHP can play an important role in reducing the conversion loss of TPES into TFC. Table 2.1 compares the TFCs of coal, oil and natural gas. Coal is primarily applied in power plants and in for example blast furnaces. Oil products are still convenient fuels for transportation. Natural gas is much used for heating of buildings and for electricity production and as feedstock for nitrogen-based fertilisers.

Figure 2.5 shows that energy types are responsible for the TFC of electricity. Figure 2.5 is, therefore, not the distribution of primary energy consumption for the production of electricity. It means that for example 21.7 per cent of the electricity supply is produced with natural gas. Oil is often used at remote locations or on islands, where a coal-based plant is not suitable for size reasons. Expectations were that gradually increasing oil prices and concern for the environment would result in a conversion from oil to liquefied natural gas (LNG) for at least the larger oil-fired power plants. However, the sharp drop of the crude oil prices at the end of 2015 has at least temporarily reduced enthusiasm for such conversions. The 16.3 per cent fraction of electricity produced with hydro power is expected to decrease with increased production of electricity. The number of suitable sites for hydro power is limited and environmental concerns are a restriction for further expansion. The ‘other’ category combines the electricity production based on geothermal heat, wind power, solar power and biomass.

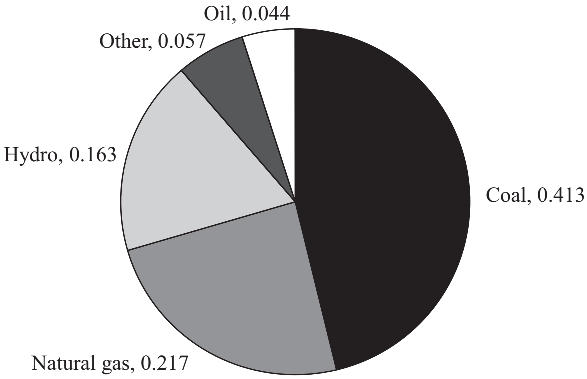

Figure 2.5 Fractions of energy types responsible for the total final consumption of electric energy, year 2013 [1]

Local cogeneration of electricity and heat is generally based on natural-gas-fired installations. However, especially in colder climates, district heating in combination with coal-fired power stations can be common practice. Estimates are worldwide that about 8 per cent of electricity is produced either with local cogeneration or in large power plants in combination with district heating [6]. The advent of much renewable electricity sources based on solar radiation and wind will require electricity to heat conversion with heat pumps. At the same time, the volatility of these renewable sources requires flexible back-up capacity for producing electricity and heat in combination with heat storage. Natural-gas-fired cogeneration installations are very suitable for this. It is expected that as long as carbon capture and storage is not technically and economically mature, the role of coal for electricity production will decrease. Homes and buildings constructed according to minimum energy use will no longer be connected to a gas distribution grid but either use district heating or electrical heat pumps. Natural gas will primarily have a back-up function for electricity production in combination with cogeneration.

2.3 Fuel resources and depletion

Without concern for depletion of fuel resources and emissions, the cheapest solution for electricity and heat production is normally the first choice. Although a coal-fired power plant is more expensive than a gas-fired one, coal traditionally shown reasonable constant prices, apart from sudden jumps in 2008 just before the economic crises and directly after 2010 when the economy recovered somewhat (Figure 2.6). This is in contrast with the prices of natural gas, which were often linked to that of oil. Russian gas went up in price by a factor 6.5 from the year 1999 to 2005. Shale gas development in the USA made that the price of natural gas traded at the Henri Hub became even lower per unit of energy than coal in the years from 2010 to 2012. The Henri Hub is a major gas exchange site in the USA that has a large effect on the

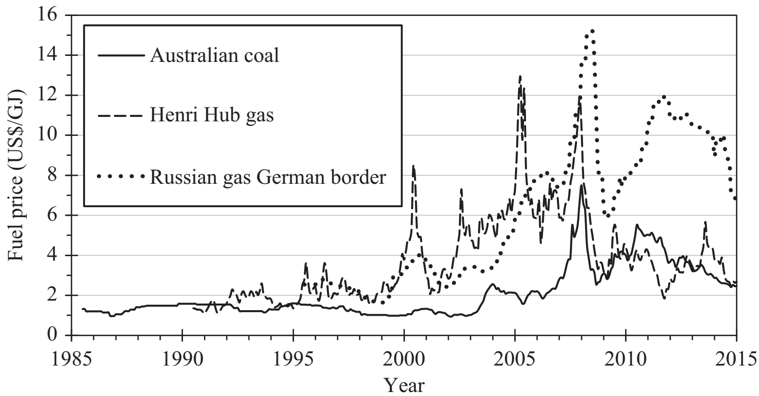

Figure 2.6 Fuel price development for coal and pipeline natural gas [7]

gas price. The low price of natural gas in the USA had a depressing effect on the demand for coal so that the coal prices also dropped. The background is that there is more competition with coal because of its widespread resources that can easily be globally traded and transported. South-African coal did closely overlap the Australian coal prices in Figure 2.6. Natural gas supply is in practice more monopolistic, also because of the associated fixed pipeline connections and long-term price agreements with the suppliers. LNG helps somewhat in opening up the market for natural gas, but not yet to such an extent that for example Russian gas is at parity with Henri Hub gas. The relatively high gas price in Europe has as a consequence that many electricity producers switched from gas to coal. Unfortunately, also many private owners of cogeneration plants in Europe had difficulty in keeping their units profitable, also because of low electricity prices caused by subsidies for renewable sources.

Although the price of pipeline natural gas and especially that of coal is relatively low by the year 2015 and the price of crude oil has dropped by almost a factor three in 2015, the question is what the fuel prices will do in the future. Commodity prices normally depend primarily on the availability and the presence of competition. When the energy supply trend of the first decade of the twenty-first century will continue, the TPES from fossil fuels will have increased from 520 EJ in 2013 to 835 EJ in 2040 (Figure 2.7). One reason for growth is the estimated population growth from 7.2 billion in 2014 to 9 billion in 2040. The other reason is the aspiration for economic growth in economically developing countries, which might mean at least tripling of the energy use in for example India. In its New Lens Scenarios [8], Shell predicts a primary energy use of some 620 EJ based on coal, oil and gas in 2040, while an ExxonMobil scenario predicts some 735 EJ will be needed at that time [9]. According to the scenarios by Shell and ExxonMobil, improving the efficiency of energy use is the primary measure to limit the growth in the input of fossil fuels.

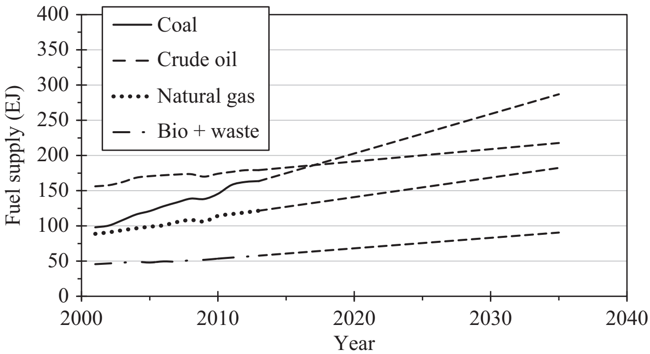

Figure 2.7 Linear extrapolation of the fuel supply till 2035 based on the 2001–2015 data

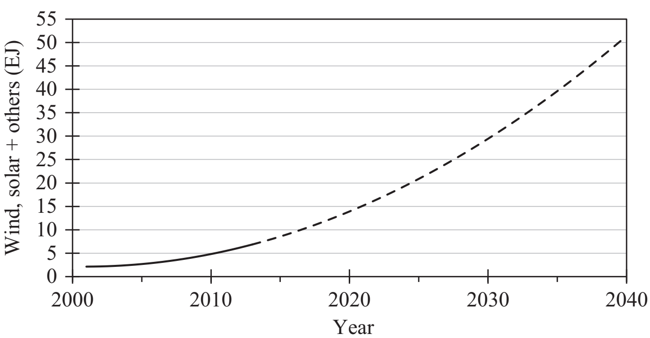

Figure 2.8 Extrapolation of the growth in wind, solar and some other renewable energy until the year 2040

Public opinion is it that a wide scale application of renewables will soon make fossil fuels obsolete. In 2013, however, the contribution of solar- and wind-based energy and some other sources to the global TPES was only 1.2 per cent and if the current trend continues, only 51 EJ will come from these renewables in the year 2035 (Figure 2.8). Many countries in Asia Pacific are increasingly using coal to fuel their power stations, since renewables and imports of LNG are considered as too expensive. This means that it is highly probable that the fuel use increase as depicted in Figure 2.7 will be close to reality, unless drastic policy measures are taken. Considering the agreements during the COP21 conference in Paris on combating greenhouse gas emissions, such drastic measures are needed, but the associated efforts are almost beyond imagination. The world economy is very much addicted to fossil fuels.

With respect to price developments, the question is how fast a reduction in the economically available resources of fuels will create an upward price

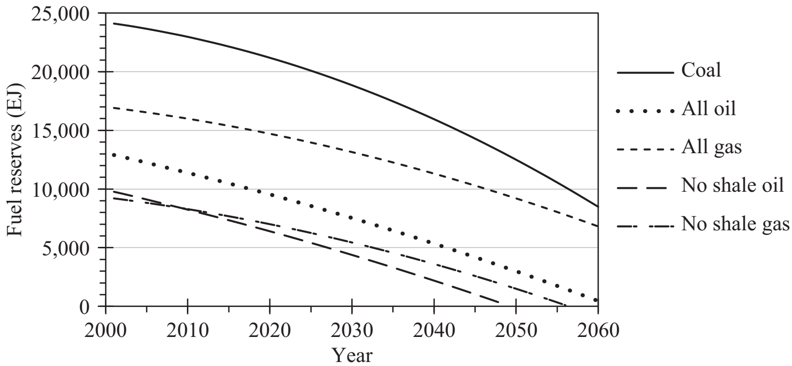

Figure 2.9 Dwindling fuel reserves in case the current consumption trend continues

move compared with the downward trend in the time span from 2000 to 2015 (Figure 2.6). There will be a moment that the competition between suppliers leading to low prices is no longer sustainable. The World Energy Council (WEC) and the EIA give close to identical figures for the reserves, including shale oil and shale gas. In Figure 2.9, the even further extrapolated fuel consumption patterns given in Figure 2.7 have been subtracted from the estimated reserves for the year 2011. The reserves include shale oil and shale gas. If the bitumen-type resources are added to the oil reserves, some 30,000 EJ of oil reserves might exist. It will be clear that a continuation of the current trend in fuel use will lead to shortages in easy recoverable oil and gas in a time span of less than half a century. This applies even if the use of fossil fuels will only increase by 25 per cent from 2015 to 2040, that is, half of the current trend. If legal measures to decrease greenhouse gas emissions will not force all actors to rapidly implement energy savings, future price developments will be the driving factor for improving efficiencies.

2.4 Energy savings potential with cogeneration

The previous sections in this chapter have clearly shown that without substantial measures, the goals to reduce the emission of greenhouse gases and the avoidance of a fast depletion of fossil fuels with the associated price escalations will not be reached. Many sources mention that the amount of heat wasted during electricity production and industrial activities is enough to cover a substantial part of the demand for heat. In the European Union, the demand for heat in terms of energy is by about a factor 2.5 higher than that for electric energy. Cogeneration of electricity and heat is therefore an excellent way to save fuel. A recent example of a special technique made fuel efficiency for cogeneration of almost 98 per cent possible by including an electric heat pump [10]. Such an installation can turn 1 GJ of fuel energy based on the lower heating value into 133 kWh (=480 MJ) of electric energy and 500 MJ of heat at 110 °C. The most advanced power plants with combined cycle gas turbines have a fuel to electricity efficiency of 61 per cent. This does not include the transmission and distribution losses, which on average are 8 per cent of the generated electricity. The average energy efficiency of supplying electricity to the end users is close to 35 per cent in the world. Presumed that 18 PWh of the electric energy supplied in the year 2013 is produced with fossil fuels, this has possibly required $18 \times 3.6/0.35 = 185$ EJ of fossil fuel. If all that electricity had been produced via cogeneration with a combined efficiency of 85 per cent, 90 EJ of heat would have been recovered from electricity generation and used. That is a substantial fraction of the roughly 130 EJ of heat supply that originates from fossil fuels. From an estimated 10 per cent electricity generation by cogeneration including district heating, an achieved energy saving of some 10 EJ is a realistic value for the year 2013. That equals about 2 per cent of the global use of fossil fuels in 2013. The CO_2 emission reduction fraction will be in the same range. A more widespread application of cogeneration can effectively help to lower the use of fuels as well as the emission of greenhouse gases. If 50 per cent of electricity demand would be covered by cogeneration, 50 EJ energy savings are possible. Investment costs cannot be a barrier, since the kW price of cogeneration installations is in the same range as that of gas-fuelled large power plants.

2.5 Capabilities for back-up for renewables

If the goals for a society with much-reduced greenhouse-gas emissions have to be reached, there is no other option than to implement a system that primarily uses electricity as the energy carrier. The electric energy will primarily originate from solar radiation, from wind, from biomass and waste, from nuclear power plants and may be from fuel-based central plants that use carbon capture and storage. Cogeneration installations will be an integral part of the energy supply system of urban areas and industrial sites, offering high energy efficiency, reliability and flexibility. It will be impossible to rely only on solar and wind energy and other options such as wave energy and geothermal energy by the year 2050. The time span is too short for that and the state of the art of the technology is such that fuel-based energy will still be required. Biomass can partly fulfil the need for fuel-based energy, but especially natural gas will still have to play an important role. In all cases where fuel is used, cogeneration has to be applied to maximise fuel efficiency and minimise emissions.

It is especially the volatile nature of solar- and wind-based energy that requires flexible and fast back-up. Modern cogeneration installations based on gas turbines and especially those based on reciprocating engines can start and stop rapidly and frequently. Their response to a request for a sudden change in output is also much higher than that of a traditional steam-based power plant. In case of a lack of sunshine and wind, such units can produce the required heat and electricity. In case of a high output from PV panels and wind turbines, the cogeneration units can be stopped, whereas any required heat can effectively be produced from electricity with a heat pump with a coefficient of performance of at least five. Heat storage can help for smoothing

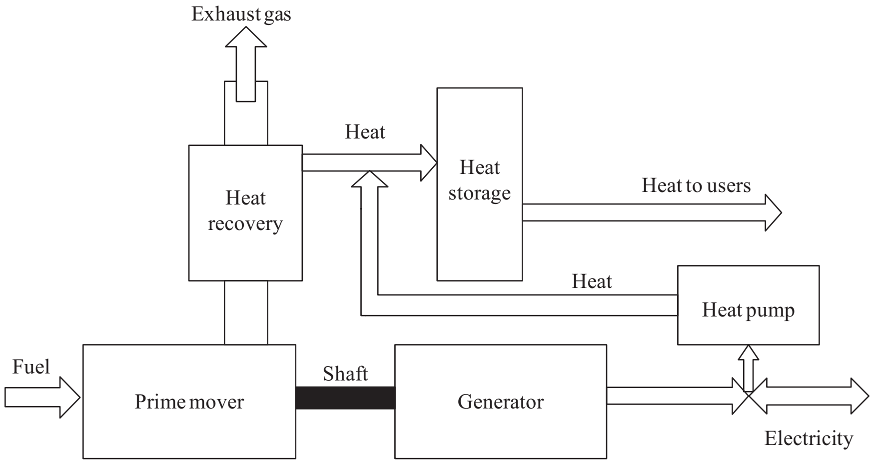

Figure 2.10 Schematic of a cogeneration installation with an integrated heat pump and heat storage

any discrepancies between heat production and demand. Figure 2.10 schematically represents such a system. The utilisation factor of such cogeneration units will be much lower than that in the times that base load was still required from fuel-based power plants. Nevertheless, adequate remuneration schemes have to ensure that cogeneration can fulfil its crucial role in energy savings and renewables back-up.

Moving away from large central power plants towards smaller local electricity production with cogeneration also helps to improve the reliability of electricity supply. An uninterrupted supply of electricity is crucial for a society relying completely on energy and information streams. Local and regional electricity supply systems that can operate independently from a central balancing system, if needed, can ensure that most activities can continue in case of interruptions in the central system. It is therefore foreseen that cogeneration of electricity and heat will rapidly play an increasing role in the society.

Acronyms

CHP	combined heat and power
EIA	Energy Information Agency
GDP	gross domestic product
IEA	International Energy Agency
LNG	liquefied natural gas
OECD	Organisation for Economic Cooperation and Development
PPP	purchase power parity
TFC	total final consumption

TPES	total primary energy supply
WEC	World Energy Council
Units of energy	
EJ	Exajoule: 10^{18} J
GJ	Gigajoule: 10^{9} J
PWh	Petawatt hour: 10^{15} Wh = 10^{12} kWh

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Chapter 3

Cogeneration technologies

Jacob Klimstra

3.1 Introduction

This chapter gives an overview of the available cogeneration technologies and their performance. The basis of cogeneration is always that the bulk of the heat released during a process of converting fuel energy into mechanical or electrical energy is not wasted but economically used. The machine that converts the fuel into mechanical energy and heat is often called the prime mover. Common prime movers are gas turbines, reciprocating engines and more recently also fuel cells. Mechanical energy can be converted into electrical energy with an electric generator, whereas heat can be transformed into chill with an absorption chiller. Heat exchangers are an integral part of cogeneration installations. Heat pumps are also increasingly used in such installations.

The performance aspects of cogeneration technologies have to be judged against the intended application. Until recently, the market value of electrical energy was always much higher than that of the same amount of thermal energy. The reason was threefold: (i) electrical energy is much more versatile than heat, (ii) the equipment to produce electricity from fuel is more expensive than a fuel-burning boiler, and (iii) the fuel efficiency of a boiler is higher than that of a power plant. Nowadays, in areas where much electricity is produced with wind turbines and solar panels, the wholesale market value of electric energy can be very low or even negative during times of high winds and much sunshine. A high price volatility of electric energy means that future cogeneration technologies need to be increasingly flexible, with a high turn-down ratio of the power output and often frequent starting and stopping.

Apart from the energetic performance and operational aspects such as flexibility and availability of a cogeneration installation, the exhaust emission limits are increasingly determining the applicability of a machine. Legislators generally use the best reference (BREF) and best available technology (BAT) of a typical technology for determining the emission limits. Emission limits encompass values for example for nitrogen oxides, carbon monoxide, dust, soot, hydrocarbons and aldehydes. Next to that, sufficient noise reduction should be possible. Also maintenance schedules are important. Cogeneration applied in a chemical process plant of a refinery, for example, should have maintenance intervals equal to those of the plant.

This chapter will explain how the different performance aspects are related with the design of the prime mover. The reciprocating engines cover the largest part of this chapter, as cogenerators are often much more involved with the operational aspects of these engines rather than with gas turbines, steam turbines or fuel cells.

3.2 Gas-turbine-based cogeneration systems

3.2.1 The gas turbine concept and its fuel efficiency

A gas turbine can run on liquid fuels as well as on gaseous fuels. The difference between a gas turbine and a steam turbine is that combustion takes place in a gas turbine as an integral part of the machine, whereas the steam used in a steam turbine is always produced outside the steam turbine. The expression 'combustion turbine' is increasingly used nowadays, as that more clearly explains the difference from a steam turbine.

A gas turbine consists of a compressor that substantially increases the pressure of the intake air, before the air is heated by combustion of a fuel such as oil or natural gas. Such a compressor can be of an axial or radial (centrifugal) design. An axial compressor consists of a number of rows of rotor and stator blades. The combustion of fuel results in heating of the medium, which substantially increases the volume of the initial air flow so that downstream of the combustion chamber much more volume than upstream is available for expansion over a turbine. This makes that the turbine has sufficient power to drive the air compressor, while still mechanical power is left at its shaft for driving for example a generator or a pump. Consequently, there are three basic processes in a standard gas turbine: compression, combustion and expansion. Figure 3.1 illustrates the configuration of a gas turbine as it is commonly used in a cogeneration application. The idealised thermodynamic process is called the Joule cycle or the Brayton cycle. Saravanamuttoo *et al.* [1] give a comprehensive explanation of the thermodynamic processes in gas turbines. Figure 3.2 presents a cogeneration system based on four gas turbines in parallel.

The real processes in a gas turbine deviate from those of the idealised thermodynamic cycle. The heat losses of the air compressor and expansion turbine to

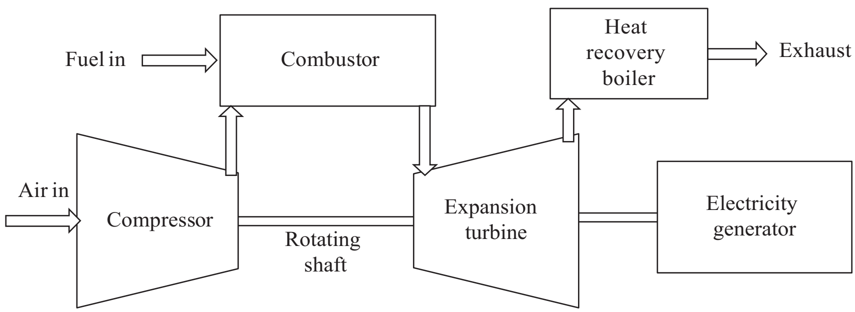

Figure 3.1 The basic processes of a gas turbine for cogeneration purposes

Figure 3.2 A cogeneration installation based on four 3.6 MW aero-derivative gas turbines in a paper factory (courtesy of CENTRAX)

the surroundings are negligible because of the high flow velocity and, consequently, low residence time. In thermodynamic terms, these processes are called adiabatic. However, these processes are not isentropic due to flow friction losses and turbulence creation. Next to that, some backflow exists at the blade tips as the clearance between the rotor and the stator can never be zero. The fuel efficiency of a gas turbine is therefore always lower than that of the idealised thermodynamic cycle.

Up to a certain point, a higher pressure ratio, that is the ratio of the air pressure at the combustor entrance and the ambient pressure, generally results in higher fuel efficiency for producing mechanical energy. Depending on the design of the gas turbine, the pressure ratio ranges from 10 to almost 40. A high air pressure in the combustor means that the fuel inflow needs to be at least at that pressure. This is no problem for liquid fuels, but natural gas supply pressures at industrial sites are often limited to 0.8 MPa. Large power stations can generally be supplied with the much higher pressure available in gas transmission pipelines. If the supply pressure of the gas is insufficiently high, a gas compressor is required. This will consume electric energy and introduces an extra element that wears and can break down.

The consequence of a high pressure ratio, for a certain fuel flow rate, is also a high temperature at the intake of the expansion turbine, often called the TIT (turbine inlet temperature). Special materials and extensive cooling of the first row of blades of the turbine allows TIT values of over 1,600 °C. It is easier in larger turbines to take measures for blade cooling than in smaller turbines. Figure 3.3 illustrates that the gross efficiency of larger gas turbines is generally higher than that of smaller machines. The machines with a relatively high efficiency of over 40% in the 50–80 MW range are aero-derivative gas turbines. These machines are

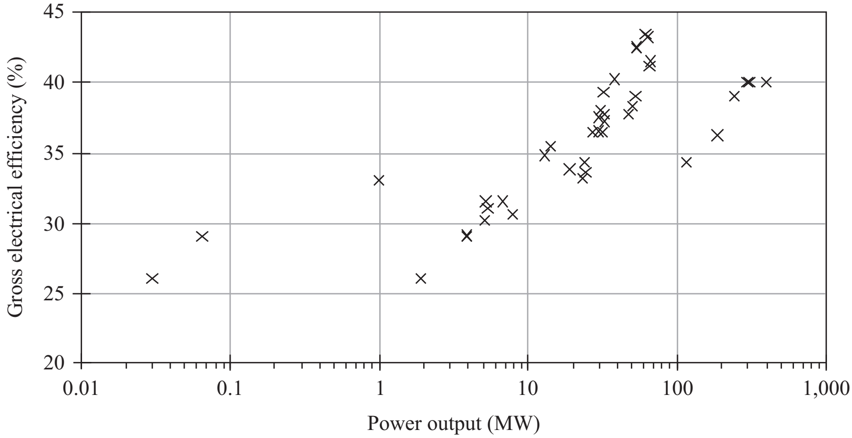

Figure 3.3 Examples of the gross electric efficiency of gas turbines, which is higher for larger machines and high-pressure machines

often of a special design, with two rotors running at different speeds, the so-called twin spoolers. Their pressure ratio ranges between 32 and 40.

3.2.2 Exhaust gas emissions limits for gas turbines

Concern about the environment makes that restrictions have been set on the emissions of undesirable species of gas turbines. Such species are the oxides of nitrogen (NO_x), hydrocarbons (HC), carbon monoxide (CO) and aldehydes (R-HCO). In Europe, the Large Combustion Plant (LCP) Directive gives the limit values for installations with a thermal input higher than 50 MW. This thermal input is based on the lower heating value of the fuel. The NO_x limit for new single-cycle gas turbines is 50 mg/m^3 and the CO limit is 100 mg/m^3, both at the reference condition of 15% O_2 in dry exhaust gas. In case the electrical efficiency of the gas turbine exceeds 55% in cogeneration applications or in case the combined cogeneration efficiency exceeds 75%, the NO_x limit is 75 mg/m^3 at 15% O_2. Some countries have stricter rules than the LCP Directive. In the Netherlands for example the 50 mg/m^3 limit applies for all gas turbines fuelled by natural gas, irrespective of the fact that they have a fuel input smaller than 50 MW or that they are applied in cogeneration installations.

Typical gas turbines used for aeronautical purposes have so-called diffusion type burners, where the fuel is injected directly into the air stream entering the combustor. This gives a very stable flame with a wide turn-down ratio in power output. In this case, very high temperatures will occur locally while also quenching of the flame occurs in very fuel-lean areas. As a result, such combustors have relatively high NO_x, CO and hydrocarbon emissions. The strict emission limits for land-based installations prohibit the use of such simple diffusion burners. Most stationary gas turbines are nowadays equipped with premixed burners. Here, the fuel and combustion air are being premixed before combustion occurs so that a homogenous mixture results. By using a considerable amount of extra combustion air compared with the minimum amount of air required for complete combustion of the fuel, the flame temperature can be kept low, which results in a low specific NO_x production.

The flame stabilises on a bluff body. The combustion chamber is basically an acoustic resonator and care has to be taken that interaction of the heat release by the flame and acoustic waves in the combustor will not induce resonance. Such resonance results in a typical noise and vibration production, the so-called rumble, which is destructive for the gas turbine. Changes in turbine load or gas composition can induce this rumble, but also be the cause of flashback or blow-off of the flame. Large gas turbines with premixed combustion are often equipped with pressure and temperature sensors that can detect undesired conditions in the combustors. Users of gas turbines have to bear in mind that changes in load or in fuel composition generally negatively affect the emissions of NO_x and CO.

3.2.3 Controllability of the power and heat output

In many cogeneration applications such as for district heating, commercial buildings and chemical process plants, it can be necessary to control either the heat output or the electrical output or even both. This means that the driving gas turbine cannot always run at full output or that supplementary firing to produce more heat has to be used. Supplementary firing means that a burner is installed upstream of the heat recovery boiler schematically given in Figure 3.1. Such a burner uses the exhaust gas of the gas turbine as its oxygen source. The exhaust gas of the turbine contains at least 15% of oxygen, which is sufficient for burning additional fuel. Especially nowadays with the fluctuating electricity prices, it is often necessary to vary the output of a gas turbine.

Decreasing the output of a prime mover, such as a gas turbine in a cogeneration installation, results in a lowering of the electrical efficiency. A gas turbine with a simple configuration has no bleed valves that blow-off part of the compressed air at lower loads and has no inlet guide vanes that can control the air intake flow. In this case, the so-called Willans line is a convenient means to determine the fuel consumption as a function of the load. When lowering the output of a gas turbine at constant running speed, many losses such as back flow, flow friction and mechanical friction stay the same in an absolute sense. That means that these losses have a relatively higher decreasing effect on the efficiency when the output of the turbine decreases. Ultimately, at zero output, still a substantial amount of fuel is required to keep the turbine running. Many tests with actual installations have shown that the fuel consumption and the power output of machines with a constant configuration are generally linearly related. The line showing this relationship is the Willans line. Figure 3.4 shows an example of the Willans line of a gas turbine with an efficiency of 35% at full output and a fuel consumption at zero load of 25% of that at full output. The linear relationship between power output and fuel consumption does not apply if a gas turbine has been equipped with for example bleed

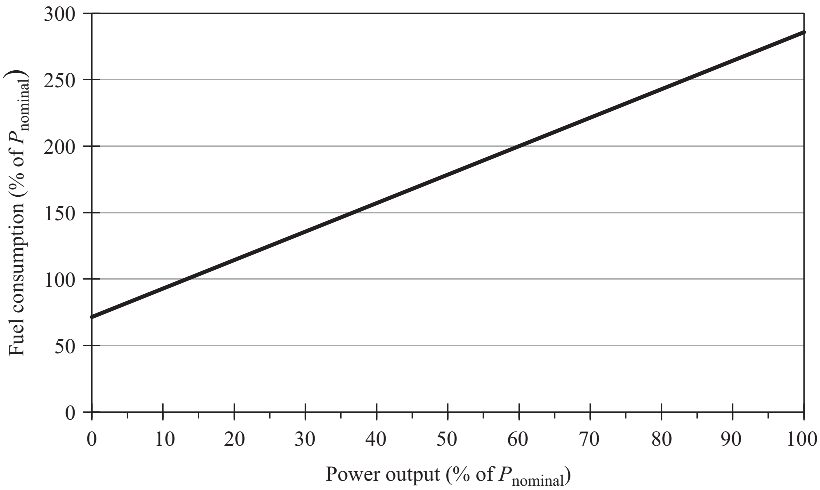

Figure 3.4 An example of a Willans line, showing a linear relationship between fuel consumption and power output of a gas turbine

valves in the air compressor; such bleed valves change the characteristics of the machine in a certain load range.

Although not all gas turbines are of such a simple design that a linear relationship between fuel consumption and power output applies, the Willans line is generally a convenient tool to obtain a first impression of the fuel efficiency of the electricity production depending on the power output. The Willans line in Figure 3.4 results in the fuel efficiency curve as shown in Figure 3.5. At 60% load, the efficiency has dropped to 30%, which means that in that case the fuel consumption per kWh is a factor 35/30 or 17% higher than at nominal output (=100% load). In many cases, the output of a gas turbine cannot be varied in a wide range because of flame stability and emission issues. Some gas-turbine types change over from premixed combustion to diffusion-type combustion in the lower load range.

In many cogeneration applications, it is not the electrical output that has to be varied but the heat output. The heat produced by many cogeneration applications based on gas turbines is used for steam production. Steam is a versatile energy carrier in chemical process plants. The heat released by a gas turbine is almost completely available in the exhaust gas and has a temperature level around 500 °C in most cases, which is very suitable for steam production. In case no supplementary firing is available, the steam production can be changed by changing the power output of the gas turbine. However, the heat released in the exhaust of the turbine does not decrease linearly with the power output. This is because the fuel efficiency of the turbine decreases with the power output, and therefore, the heat fraction increases with decreasing power output. In case a constant combined efficiency of for example 85% is presumed and the fuel efficiency curve of Figure 3.5 is used, the heat production depending on the power output can be easily calculated. The result

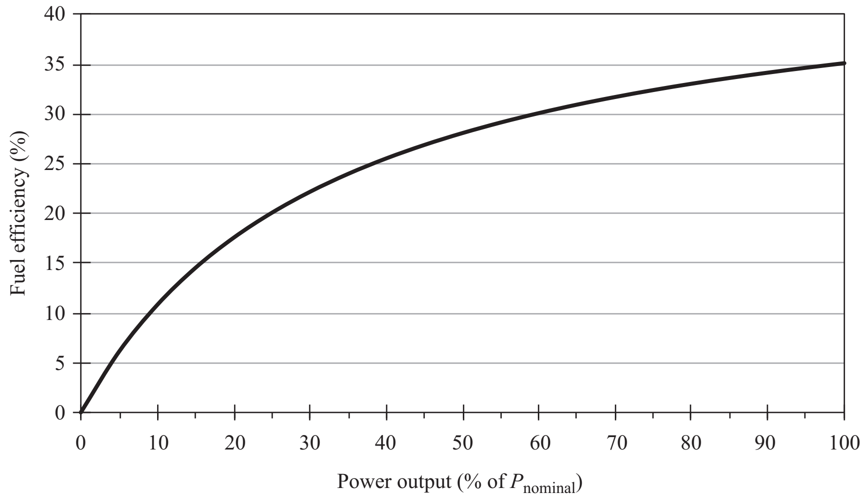

Figure 3.5 Example of the lowering of the fuel efficiency of a gas turbine with decreasing power output

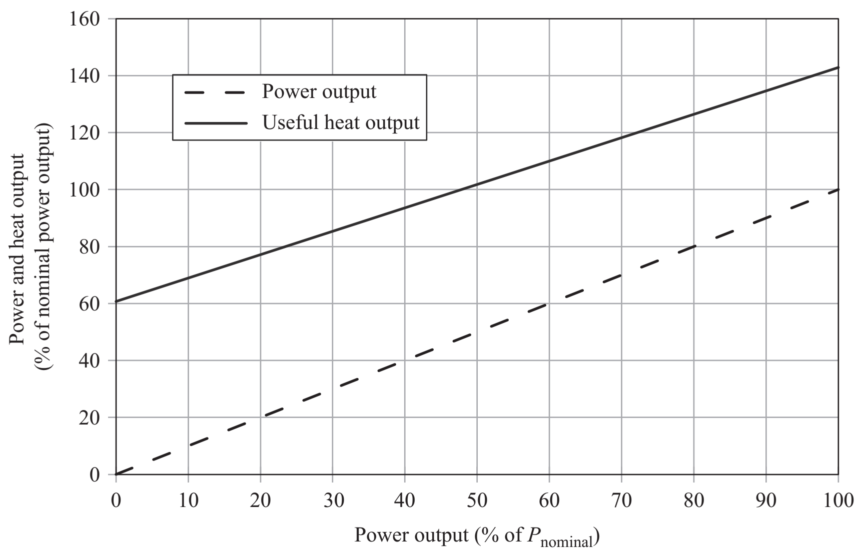

Figure 3.6 The heat output of a gas turbine decreases relatively slowly with the power output

is depicted in Figure 3.6. If the power output decreases from 100% to 60% of the nominal power, the useful heat output decreases from 143% to 110% of the nominal power, which is a reduction of only 23%. This is the major reason that supplementary firing is preferred, if the steam production has to be changed in a wider range.

If the fuel efficiency of the gas turbine would have been higher, for example 45% at nominal output, the fuel efficiency curve would have been more flat in the upper load range resulting in a better controllability of the steam production.

3.2.4 Maintenance aspects

Gas turbines are of such a design that prolonged running for thousands of hours is normally possible. The lubricating oil for the bearings is not in contact with the flames in the combustion chamber, and therefore, the thermal stress on the oil is low. It is the air compressor that has to be cleaned regularly from deposits notwithstanding extensive filtering at the intake. In most cases, the cleaning can be carried out while the machine is running. The blades, especially those of the expansion turbine, suffer from thermal stress and ultimately cracks can occur that reduce the strength of the blades. Also, the combustion chamber is exposed to high temperatures. Starting and stopping are heavy contributors to the thermal stress. That is the reason that the concept of equivalent running hours has been introduced. A high load increase rate, high load decrease rate and especially sudden stops at full load (trips) are causing creep in the hot zones resulting in a high number of equivalent running hours. In case of required maintenance and repairs, cooling of the machine can take more than a day. In case of aero-derivative gas turbines, the prime mover requiring maintenance can often be lifted from the installation and replaced by a spare unit. When replacing the prime mover in such a case, the installation can run again within a day.

Maintenance actions for gas turbines are often based on condition monitoring of the rotating elements and on boroscopic inspection of stationary parts such as the combustion chamber. Thermocouples at crucial locations such as the expansion turbine intake are continuously monitoring the temperature. The isentropic efficiency of the air compressor can easily be determined by measuring the temperatures and pressures upstream and downstream of the compressor. If the isentropic efficiency decreases, this is an indication of compressor fouling or excessive wear of the compressor blades. Cleaning of the compressor blades, which can be carried out on-line, can restore the isentropic efficiency to some extent. Absolute vibration sensors at the turbine housing and relative vibration sensors at the bearings can indicate if unbalance, shaft misalignment or loose elements are present. Proximity sensors can show the wear rate of thrust bearings. Fingerprints of these quantities, taken at as-new conditions and after overhauls, can serve as benchmarks for a proper condition.

3.2.5 The effect of ambient conditions on gas turbine performance

The performance data of gas turbines are normally given at ISO conditions (15 °C, 101.5 kPa and 60% relative humidity of the intake air). As a gas turbine is a flow machine, meaning that it draws in a certain volume of air at a certain running speed, the intake mass flow depends on the density of the air. If the intake air has for example a temperature of 40 °C instead of 15 °C, the density of the air is a factor $(273.15 + 15)/(273.15 + 40)$ lower meaning that the mass flow of the intake air at 40 °C is 92% of the one at 15 °C. This negatively affects the available output of the

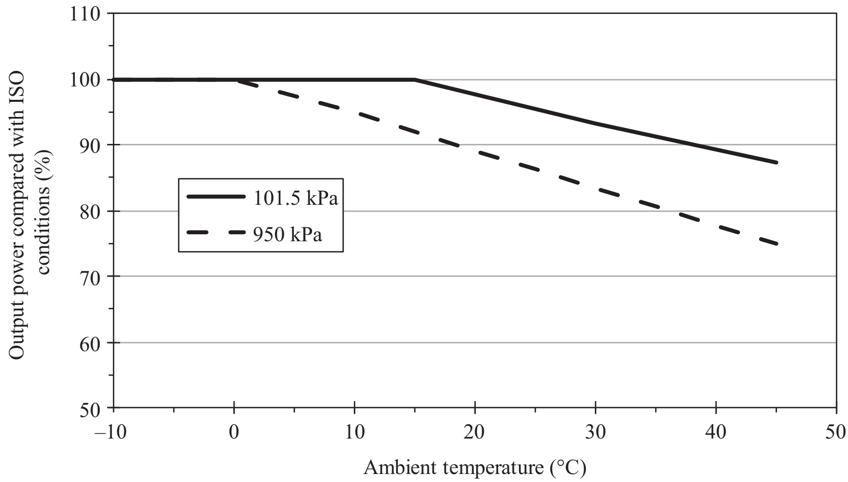

Figure 3.7 Decline in gas turbine output caused by ambient temperature and pressure

gas turbine, even more than the air density ratio, because a lower output means that the relative effect of the losses on the fuel efficiency becomes higher. In theory, the output of gas turbines is higher than at ISO conditions for temperatures below 15 °C. However, mechanical load restrictions can mean that the allowed power output does not exceed the value at ISO conditions. Figure 3.7 is an example of the turbine output deterioration caused by the ambient temperature and ambient pressure.

3.2.6 Special designs

Some gas turbine installations have been equipped with a recuperator and/or an intercooler. A recuperator consists of a heat exchanger in the turbine exhaust which heats up the compressed intake air downstream of the air compressor. This enhances the fuel efficiency of the turbine. A drawback is that the recuperator operates at a high temperature, which requires slow heating up after starting to avoid damage to the heat exchanger. In addition, the exhaust gas downstream the recuperator is much colder than in case of no recuperator. An intercooler between two stages of an axial air compressor makes that the compression process proceeds closer to isothermal which saves compression energy.

In the so-called Cheng cycle patented by Prof. D. Y. Cheng from the University of Santa Clara in 1976, a heat-recovery steam generator is positioned in the turbine exhaust and the steam produced is injected upstream of the turbine, so that the turbine is expanding combustion end products as well as steam. This further improves the fuel efficiency. In addition, steam injection into the combustion chamber lowers the NO_x production.

Small gas turbines can operate at a high running speed of up to 100,000 rpm and use a directly coupled generator to produce electricity or drive a 50 or 60 Hz generator via a gearbox. In case of a directly coupled generator and a running speed higher than 3,000 rpm (50 Hz) or 3,600 rpm (60 Hz), the high-frequency voltage of the generator has to be converted to 50 or 60 Hz.

3.3 Reciprocating internal combustion-engine-based cogeneration systems

3.3.1 The background and basic concept

Reciprocating engines (recips) are also called reciprocating internal combustion engines or piston engines. The current reciprocating engine concept is widely applied as a prime mover for transport applications in cars, trucks, trains and ships. Also mobile equipment such as compressors and generators at building sites as well as shovels and draglines, is powered by recips. The power capacity of recips ranges from less than 500 W to more than 90 MW per machine. First concepts of reciprocating engines stem from the year 1673, when the scientist Christiaan Huygens (1629–95) made a drawing of a piston engine based on the barrel of a canon. After many years of trial and error, Nikolaus August Otto (1832–91) invented the four-stroke spark-ignited engine in 1876. This concept is still the basis of our modern recips that are running on petrol, fuel oil or gas. The history of the invention of the first four stroke engine is described in [2]. Rudolf Diesel (1858–1913) developed the compression–ignition engine, commonly known as the Diesel engine.

The first gas engines found their application primarily in small- and medium-size companies for driving machines. In the beginning of the twentieth century, local power plants used already engines of up to 3.7 MW to drive electricity generators. However, soon the engines in factories were replaced by electric motors, while power stations became large plants based on coal-burning boilers and steam turbines. After the Second World War, stationary reciprocating gas engines were almost solely used in sewage and landfill gas plants and for driving gas compressors in pipeline transmission systems. A big change came at the end of the 1970s after the oil crisis. Policy makers suddenly became aware of the fact that fuels are precious commodities from finite resources. Cogeneration of heat and electricity would have a fuel efficiency far superior than that of large power plants. Support schemes were created for applying cogeneration wherever possible. The reciprocating engine appeared to be the first choice as a prime mover in the power range up to 5 MW. Their fuel efficiency was much better than that of gas turbines of the same capacity, and their running speed of between 750 and 3,600 rpm was much more suitable for driving a generator than the high running speed of small gas turbines. Next to that, packagers and local maintenance organisations were much more familiar with recips than with gas turbines.

Diesel engines for cogeneration applications are generally applied at remote areas and islands, where no gas is easily made available. Light diesel fuel is too expensive for cogeneration applications, and therefore, heavy fuel oil is used most of the time. Heavy fuel oil is a residue from refineries. The properties and quality of diesel fuels are described in Chapter 6.

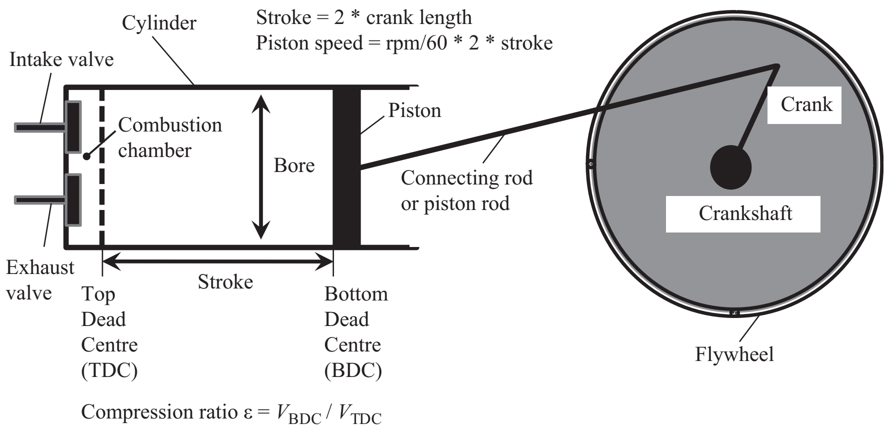

Figure 3.8 The basic elements of a reciprocating engine

Figure 3.8 gives the basic elements of a reciprocating engine. The engine process starts with the piston at top dead centre (TDC), while the intake valve is open. The intake and exhaust valves are operated by a separate shaft, the camshaft, which is driven by the crankshaft via a gearwheel. The camshaft rotates at half the speed of the crankshaft. The engine cycle starts when piston moves from TDC to bottom dead centre (BDC) and draws in fresh combustible mixture. This is the intake stroke. The intake valve closes when the piston is near BDC. Subsequently, the piston moves from BDC to TDC, while the intake and exhaust valves are closed. This is the compression stroke. When the piston approaches TDC, a spark plug ignites the compressed mixture and the combustion progresses from the point of ignition through the combustible mixture. The combustion process is therefore not an explosion, where the whole combustion chamber contents react at once, but it is a relatively smooth process. The spark plug is normally centrally positioned in the cylinder head in between the intake and exhaust valves. The small volume of the cylinder when the piston is near TDC is called the combustion chamber. During the combustion process, the cylinder pressure increases substantially. This means that during the following expansion stroke, when the piston moves from TDC to BDC, the cylinder pressure is much higher than during the compression stroke. During this expansion stroke, much more energy is delivered via the crankshaft to the flywheel than drawn from it during the compression stroke. When the piston approaches BDC, the exhaust valve is opened by action of the camshaft and the bulk of the cylinder contents escapes via the exhaust. The piston then moves back to TDC and pushes out most of the remaining combustion end products. This is the expulsion stroke. When the exhaust valves close near TDC, just a fraction of the original combustion end products remains in the combustion chamber. These mix with the fresh combustible mixture that enters the cylinder when the intake valve opens and the next cycle begins. In total, four strokes during two revolutions of the flywheel complete a cycle. The details of the idealised thermodynamic cycle of the reciprocating engine and of the practical engine process are properly explained in [3]. To improve performance, modern gas engines are increasingly equipped with turbochargers and with an intake and exhaust valve timing deviating from the original cycle.

3.3.2 The practical gas engine

Part of the heat released during the combustion process is transferred to the relatively cool cylinder walls, and therefore, less heat is available for producing work. Moreover, the work carried out in the engine cylinders on the pistons is not fully transferred to the crankshaft that drives the generator. Friction between the pistons and the cylinders and in the bearings next to parasitic losses for driving the camshaft and the oil and water pumps consume part of the energy. As with all prime movers, the effect of the losses on the fuel efficiency can be reduced by increasing the output of the machine. Turbochargers increase the intake pressure of engines, and by means of that, more combustible mixture can be pumped into a cylinder of a given bore and stroke.

Figure 3.9 illustrates the basic concept of a turbocharged engine. The mass flow through the compressor and the turbine is the same, but the temperature of the exhaust gas upstream of the turbine ranges between 500 and 600 °C, depending on the design. This means that the volume flow over the turbine is much higher than that over the compressor. Hence, the turbine is able to drive the compressor even if the exhaust pressure upstream of the turbine is lower than the intake pressure

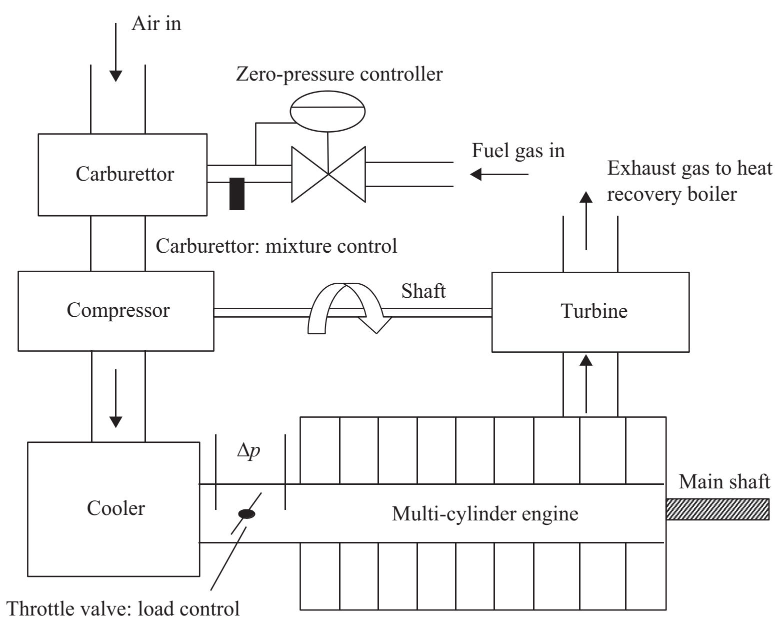

Figure 3.9 Schematic representation of a turbocharged engine

downstream of the throttle valve. The throttle valve controls the mixture flow to the engine and via that the power output. The carburettor in combination with the zero-pressure controller prepares the combustible mixture.

The turbocharger therefore increases the output of the engine as it supplies more combustible mixture to the cylinders. Therefore, more heat is released inside the cylinders compared with the case of no turbocharger. If the air-to-fuel ratio and therefore the medium temperatures would stay the same, the absolute heat losses to the combustion chamber walls would not change substantially. This means that the relative heat losses decrease when using turbocharging. In addition, the turbocharger makes it possible to increase the air-to-fuel ratio. This decreases the temperatures of the medium inside the cylinders so that the absolute heat losses to the cylinder wall also decrease. The relative heat losses also decrease with increasing cylinder bore as in that case the ratio of combustion chamber area and volume decreases. Less cold area of the combustion chamber per unit of heat released means that the relative heat losses are lower. However, as the bore–stroke ratio can only be varied in a small range and the mean piston speed is not allowed to exceed 10 m/s because of lubrication issues, the rotating speed of the engine shaft has to be reduced when the bore is substantially increased. Engines in the bore range over 45 cm generally run at 500 rpm shaft speed when driving a 50 Hz generator. Engines with a bore between 30 and 45 cm run at 750 rpm, whereas for a bore between 20 and 30 cm, a speed of 1,000 rpm is common. Engines with a bore below 20 cm can run at 1,500 rpm. Depending on the manufacturer, there is always some overlap in these ranges. It will be clear that in case an engine has a higher running speed, the residence time of the hot gases in the cylinders during a full cycle is lower, which consequently decreases the heat losses per cycle. A benefit of a higher running speed is more powerful from the same amount of construction material, which helps to reduce the capital costs. A means to reduce the friction losses between piston and cylinder is to increase the length of the piston rod. For a longer piston rod, the sideward pushing forces on the piston are lower. However, such a construction heightens the machine and therefore costs more material and more installation space.

3.3.3 The fuel efficiency

The thermodynamic cycle as applied in the four-stroke engine with constant-volume combustion has theoretically the highest achievable fuel into work conversion efficiency of all prime mover concepts [4]. In the so-called standard-air cycle, the fuel into work conversion efficiency η only depends on the compression ratio ε and the ratio of specific heats $k = c_p/c_V$:

$$\eta = 1\left\{1 - \left(\frac{1}{\varepsilon}\right)^{k-1}\right\} \cdot 100\%$$

The value of k is 1.4 for air at ambient conditions. In an engine running on a stoichiometric mixture of fuel and air, where in theory exactly sufficient air is available for complete combustion, the value of k can be as low as 1.32. A low

k value substantially lowers the theoretically achievable efficiency. As an example, for a compression ratio ε of 15, the fuel efficiency according to the idealised standard-air cycle decreases from 66% to 56% when the k value drops from 1.4 to 1.3. This is one of the reasons why fuel lean mixtures are used as in that case, the property of the cylinder medium more closely approaches that of air.

In practice, the compression ratio ε cannot be raised at liberty. The peak pressure in the cycle might exceed the value acceptable for the integrity of the engine. Moreover, the temperature of the yet unburned mixture will become very high due to compression in case of an excessively high compression ratio. In that case, spontaneous auto-ignition can occur in the yet unburned mixture part that exists before the progressive flame front has travelled through it. Combustion caused by auto-ignition is called as knocking. Knocking combustion is destructive for an engine due to the impulse-type heat release and the resulting shock waves that remove the relatively cold boundary layer at the walls of the combustion chamber. The tendency to auto-ignition not only depends on the mixture temperature, but also on the fuel properties, the pressure and the air ratio λ.[1] A stoichiometric fuel–air mixture with by definition a λ value of 1.0 will much more easily knock than for example a mixture of $\lambda = 2.0$ where by definition 100% extra air is present. Engines running on a combustible mixture with a λ noticeably higher than 1.0 are called lean-burn engines. The knock tendency of gaseous fuels is expressed in the so-called methane number (MN). Table 3.1 gives the MN of some typical gases.

The composition of gaseous fuels depends on the source and subsequent treatment of the gas. Some pipeline gases, such as the current Russian gas exported to Europe, consist of 99% of methane and have a MN of over 95. Libyan gas has only 82% of methane and some 13% of ethane and a MN of only 66. The MN of gaseous fuels can be determined with the so-called AVL–MWM method, which is specified in the standard EN 16726 [6]. The performance specifications of gas engines in data sheets are normally given for a MN of 80 and higher. For a MN lower than 80, the compression ratio has to be lowered or the power output has to

Table 3.1 The methane number of typical gaseous fuels [5]

Fuel	Methane number
Methane	100
Ethane	44
Propane	32
Butane	8
Hydrogen	0
LPG (60% propane and 40% butane)	25
Biogas (60% methane and 40% carbon dioxide)	140

[1]Air ratio, λ, is the ratio of the real air mass flow rate divided by the air mass flow rate for stoichiometric combustion.

be reduced when compared with the situation for a MN of 80 and higher. Both measures have a decreasing effect on the fuel efficiency. A compression ratio ε of 12 is a common value for most gas engines applied in cogeneration installations.

Increasing the specific output per cylinder helps to improve the fuel efficiency. The specific output per cylinder is generally expressed by the brake mean effective pressure (*bmep*). The *bmep* is the imaginary net mean pressure acting on the piston during half of the cycle of a four-stroke engine, whereas the net pressure on the piston in the other half of the cycle is zero. The *bmep* can be found from the shaft power, the running speed and the swept volume per cylinder:

$$bmep = \frac{P_{engine\ shaft} \cdot n_c}{\text{Number of cylinders} \cdot \frac{rpm}{60} \cdot V_{swept\ per\ cylinder}}$$

where *bmep* is the brake mean effective pressure (kPa), $P_{engine\ shaft}$ is the power measured at the engine shaft (kW), n_c is the number of revolutions per power stroke (for a 4-stroke engine: $n_c = 2$), *rpm* is the running speed in revolutions per minute, and $V_{swept\ per\ cylinder}$ is the displacement volume per cylinder:

$$V_{swept\ per\ cylinder} = 0.25\,\pi\,\text{bore}^2 \times \text{stroke}\left(\text{m}^3\right).$$

As an example, a 20-cylinder engine with a bore of 340 mm, a stroke of 400 mm, a running speed of 750 rpm and a shaft power of 10 MW has a *bmep* of 2,200 kPa = 22 bar. The *bmep* is generally expressed in bar. A naturally aspirated engine running on a stoichiometric mixture ($\lambda = 1.0$) can have a *bmep* of about 12 bar; otherwise, knocking combustion might occur. The 10 MW engine in the example is a turbocharged lean-burn engine running at about λ =2.0. As mentioned earlier, a high *bmep* and a lean mixture help to decrease the effect of the losses on the fuel efficiency. The latest designs have resulted in engines with a *bmep* of 26 bar with a fuel efficiency of almost 50%. Such engines are equipped with two-stage turbocharging with a heat exchanger in between the two air compressors to more closely approach isothermal compression of the air. This helps to improve the efficiency of the turbocharging process. To avoid knocking with such a high *bmep*, the intake valves are closed way before BDC so that the effective compression stroke of the engine is smaller than the expansion stroke. This helps to lower the combustible mixture temperature and pressure during the combustion process. Early intake valve closure is called Miller timing [7].

The gross efficiency of reciprocating-engine driven cogeneration installations ranges between 25% and almost 50%. If the engines do not have shaft-driven water and oil pumps, the electrical energy required to drive the pumps reduces the electrical efficiency of the cogeneration installation. One has also to bear in mind that the rules in ISO 3046 are often applied in data sheets which allows ±5% tolerance in fuel consumption. That means that an installation having 40% electrical efficiency in a data sheet with ISO 3046 has in practice 38% electrical efficiency. Also, the power factor cos φ of the generator in performance data sheets is often taken at 1.0. In reality, the power factor is often 0.85, meaning that the generator has a slightly reduced efficiency in practice due to the higher current for the rated power.

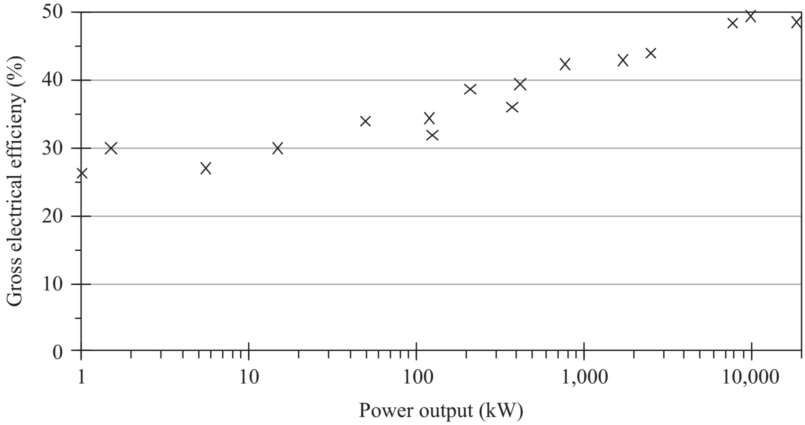

Figure 3.10 The gross electrical efficiency of typical gas-engine driven cogeneration systems

As a rule of thumb, the electrical efficiency at cos $\varphi = 0.85$ is a factor 0.99 lower than at cos $\varphi = 1.0$. Figure 3.10 clearly shows that larger machines have the highest efficiency, as is the case with gas turbines.

3.3.4 The heat sources

The energy balance of a reciprocating-engine driven cogeneration installation is more complicated than that of a gas turbine. For a recip, there can be up to six separate sources of heat, whereas for the gas turbine only the exhaust gas heat is relevant. Figure 3.11 shows the heat sources in case of single-stage turbocharging for an engine running at nominal load. The fuel input is based on the lower heating value of the fuel and the values given are for nominal load of the engine. All energy fractions are given as a percentage of the energy input with the fuel. In contrast with small naturally aspirated engines, the heat available from the engine block via the jacket water is here only 6.5%. The temperature of the jacket water is normally about 85 °C, but values up to 110 °C are also possible. The lubricating oil is also used for cooling the piston crowns, and it receives some heat from the engine block and from friction in the bearings. The lubricating oil heat is often available at a level between 40 and 50 °C and comprises 5% of the fuel energy in this example.

The sensible heat of the exhaust gas downstream of the turbine of the turbocharger has a temperature level of 400 °C and equals 30% of the fuel energy. This temperature level is suitable for producing steam. The turbine transfers 11% of the fuel energy to the compressor via a rotating shaft. This is about a quarter of the energy available at the crankshaft of the engine. In this example, the compressor increases the intake air from an absolute ambient pressure of 1 bar to an absolute pressure slightly higher than 3.6 bar. That makes it possible that the engine in this example has a *bmep* of 22 bar for an air ratio λ of 2.0.

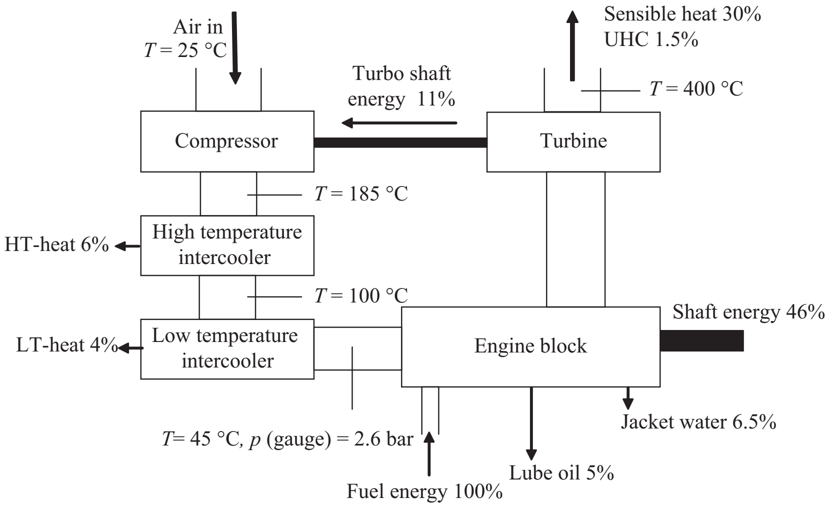

Figure 3.11 Example of the fuel energy balance of a reciprocating engine at nominal load

The intake temperature of the engine cylinders has to be relatively low. There are three main reasons for that. The density of the intake flow is inversely proportional with the absolute temperature and a high intake temperature will therefore reduce the power capacity of the engine. The tendency to knocking combustion increases rapidly with the temperature and too high an intake temperature will therefore require a reduction in compression ratio and power capacity. Finally, high process temperatures increase NO_x formation as that process is exponentially sensitive to temperature. The intercooler has been split up in two sections as the usefulness of heat at a temperature level close to 100 °C is generally higher than that of heat at a temperature below 50 °C.

The energy balance in this example is completed by 1.5% of unburned hydrocarbons and by 1% heat loss from the engine block to the surroundings. The heat loss from the engine block is often called radiation loss, but in practice, it is mainly convection from the engine block to the surrounding air. Ultimately, three levels of heat are available. The heat from the low temperature (LT) intercooler combined with that of the lube oil cooler yields 9% of the fuel energy at a temperature level of about 50 °C. Combining the high temperature (HT) intercooler heat with the jacket water heat gives 12.5% of the fuel energy at about 85 °C. The ultimate cogeneration efficiency depends on the temperature level that the exhaust gas will be cooled from the 400 °C before it exits via the stack. If that exit temperature would be 100 °C, a quarter of the sensible heat downstream of the turbine will escape to the environment. The electrical energy will be close to 45% of the fuel energy. In case also the heat available at 50 °C and at 85 °C is used, the combined cogeneration efficiency will be $9 + 12.5 + 22.5 + 45 = 89\%$. In some cases, the exhaust gas can be cooled to such an extent that condensation of the water vapour occurs. A cogeneration efficiency close to 100% based on the lower heating value is possible then.

3.3.5 Controllability of the electricity and heat output

The change in heat output of a reciprocating engine with the shaft power is more complicated to determine than that of a gas turbine because of the many heat sources. However, the concept of the Willans line with a linear relationship between the fuel consumption and the power output as a fraction of the nominal output works well. Cogeneration installations driven by a reciprocating engine are normally not run at loads lower than 40% for economic reasons. The fuel efficiency starts to become less attractive at such low loads, while the maintenance costs per running hour are roughly the same as at nominal load.

The absolute heat loss from the engine block to the surroundings remains approximately constant over the full load range, because the temperature of the coolant is thermostatically kept at a constant value. When the engine is running at 30% load, the power transferred from the exhaust side to the intake side by the turbocharger is becoming very low, meaning that the intercoolers do not cool the air downstream of the compressor anymore. If the HT intercooler is integrated in the jacket water cooling system, heat will be rather transferred to the intake air than removed. The LT intercooler has to remove that heat and is transferring it to the low temperature heat circuit. Figure 3.12 is illustrating how the output from the different heat sources changes with the engine output. Skip firing can be applied with engines equipped with controlled fuel injection per cylinder. This means that the fuel supply to a number of cylinders can be cut off so that the output of the engine can be lowered further than in case of reducing the output of all cylinders [8].

In large reciprocating-engine driven cogeneration installations, the useful heat production follows the power output closely, as can be seen in Figure 3.13. This is

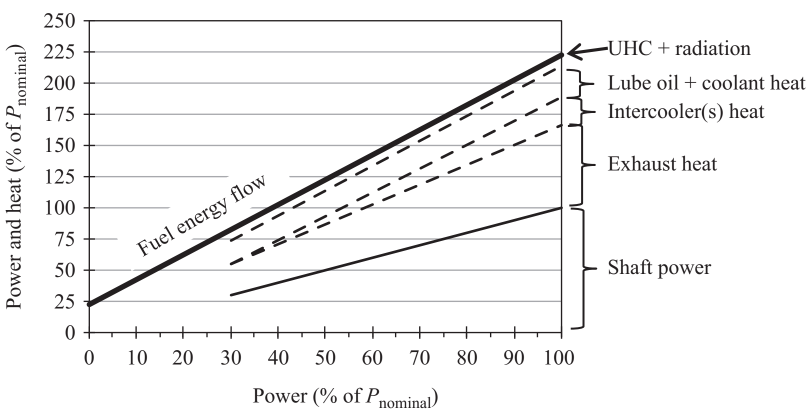

Figure 3.12 Fuel energy, shaft power and heat flow depending on the output power of the engine (cumulative representation)

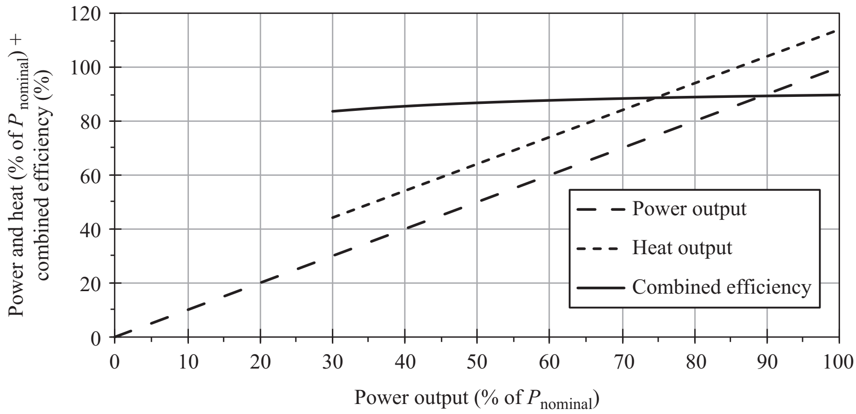

Figure 3.13 Example of the heat output change with the power output and the combined heat and power efficiency for a stack temperature of 85 °C

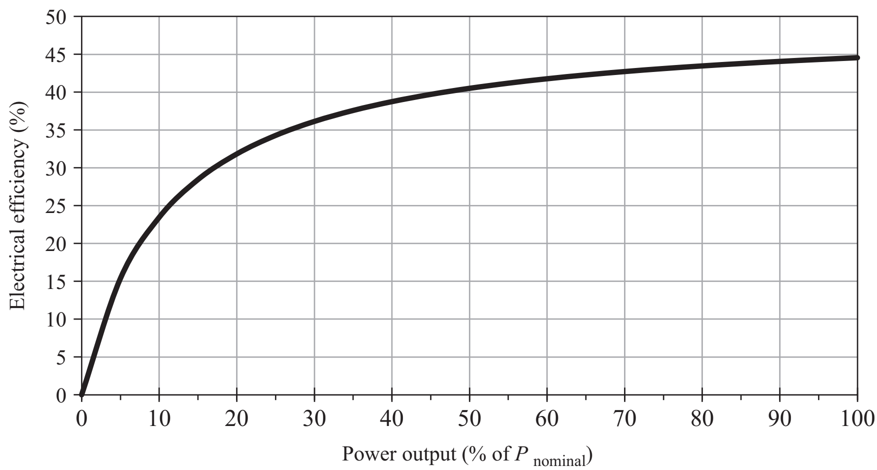

Figure 3.14 The electrical efficiency of the cogeneration unit of Figure 3.11

beneficial in case the installation has to vary its heat output as is often the case, for example, for district heating systems and space heating of buildings. The main cause of this is that the electrical efficiency of a cogeneration unit driven by a prime mover having a high efficiency at nominal load decreases very little with load in the upper load range. Figure 3.14 shows the electrical efficiency of the cogeneration unit of Figure 3.11, which has an electrical efficiency of close to 45% at nominal power output. At 60% of the nominal output, the electrical efficiency is still 42%. The heat output decreases from 114% to 74% of the nominal electrical power when the power output decreases from 100% to 60%.

3.3.6 Fuel–air mixture preparation and control

The air ratio λ is affecting the emissions, the fuel efficiency, the power output stability and the reliability of a reciprocating gas engine. That is the reason that much attention has to be given to the preparation and control of the fuel–air mixture. For spark-ignited engines and dual-fuel engines, there are two basic different ways of preparing the fuel–gas air mixture. Engines with a power capacity lower than 1 MW are generally equipped with a fuel and air mixer – the carburettor – based on a venturi. The fuel gas is drawn into the air via holes in the throat of the venturi. The pressure drop in the venturi roughly varies with the square of the air-flow velocity. In the fuel flow towards the venturi throat is an adjustable restriction, the so-called main adjustment bolt. The fuel pressure upstream of this bolt is kept equal to that of the air pressure upstream of the venturi with a so-called zero-pressure controller. This construction ensures that the fuel gas flow is closely following the air flow and that variations in atmospheric pressure do not affect the air ratio λ. Consequently, the λ value is independent of the air flow and therefore of the engine load, at least in a certain load range. The carburettor often has a facility to ensure that the fuel–air mixture is close to stoichiometric at low loads to improve the running stability and starting of the engine. This can for example be done with an offset in the zero-pressure controller or with a small bypass of the main adjustment bolt. The carburettor is generally positioned upstream of the compressor of the turbocharger to improve the homogeneity of the fuel–air mixture. Attempts to design carburettors that produce homogenous mixtures directly downstream of the venturi generally failed. It is not easy to mix flows of gases having different densities and carburettors are very sensitive to small deviations in flow symmetry. Designs with a carburettor directly connected to an intake manifold have suffered from inhomogeneity, with one cylinder bank sometimes knocking due to rich mixtures and the other bank misfiring due to too lean mixtures [9]. However, a mixture of fuel gas and air can be considered as fully homogenous after passing the compressor of the turbocharger and the intercooler.

For larger engines, generally at least those with a power capacity above 5 MW, the presence of a large volume of ignitable mixture upstream of the intake valves in lengthy systems can cause destructive explosions in case of backfiring. Backfiring is caused by for example leaking intake valves or retarded combustion in the cylinders. That is one of the reasons that large spark-ignited engines and dual-fuel engines are equipped with fuel injection directly upstream of the intake valves. Electromagnetic valves are controlled to admit a fuel flow during the intake stroke of the relevant cylinder. The pressure difference over the valve and the duration of the opening determine the amount of gas admitted during the intake stroke. A computer-based controller has to regulate the opening time of the valves as well as the fuel pressure depending on the engine load.

An important property of a gaseous fuel is the Wobbe Index (*WI*). The *WI* is the heating value of a gaseous fuel divided by the square root of the density of the fuel divided by the density of air at standard conditions. Gas suppliers often use the higher heating value of the gas, whereas the reciprocating engine and gas turbine sectors often use the lower heating value. The *WI* based on the lower heating value is roughly 90% of the *WI* based on the higher heating value. Chapter 6 will go more into detail of the *WI*. Here, it is important to know that in case of carburettors as well as fuel injection, the λ varies inversely in proportion with the *WI*

$$\lambda' = \frac{WI}{WI'} \cdot \lambda$$

If for example the *WI* increases from 45 to 50 MJ/m^3, the λ will decrease from 1.80 to 1.62, if no corrective measures are taken with the main adjustment bolt in case of a carburettor or with the pressure difference over the electromagnetic valves or the duration of the opening of these valves.

In addition, the air temperature affects the air ratio λ as prepared by carburettors upstream of the turbocharger, if it differs from the gas temperature. For engines with gas injection, this is not an issue if the intake air temperature after the charge-air cooler is controlled at a fixed value, which is generally the case. In most cases, the air temperature inside the enclosure of a cogeneration installation is also thermostatically controlled at a fixed value. In case the air temperature varies as the gas temperature remains the same, the λ is inversely proportional with the square root of the absolute air temperature.

$$\lambda' = \sqrt{\left(\frac{T}{T'}\right)} \cdot \lambda$$

The requirements with respect to emissions and performance are nowadays so strict that the air ratio has to be fine-tuned with a dedicated control system. Some manufacturers use the power output of the generator as an indicator of the load of the engine and measure the absolute temperature and absolute pressure in the intake manifold. If the manifold pressure is lower than normal for the given manifold temperature and the load, the mixture is apparently too rich. Other manufacturers use a thermocouple in each cylinder head as an indicator of the actual λ value at a given load. Thermocouples downstream of the exhaust valves are also used as an indicator of the λ. Modern designs even apply fast responding pressure transducers in each cylinder to check if the combustion process is progressing as expected. Some solutions adjust the position of the main adjustment bolt in the gas supply to control the air-to-fuel ratio. In other cases, the air supply by the turbocharger is controlled with bypass valves of the turbine or the compressor of the turbocharger.

In Diesel engines running on liquid fuels only, the mean air ratio for a given load can only be controlled by adapting the air flow rate supplied by the turbocharger. Diesel engines do not operate on a homogenous mixture. The fuel injected has to mix with the air already present in the cylinders and that means that a whole range of λ values occur in the combustion chamber of a Diesel engine, from pure fuel up to pure air. That is the reason that the basic NO_x emission of Diesel engines is much higher than that of gas engines, since locally very high temperatures exist in the combustion chambers of a Diesel engine.

In gas–Diesel engines, the engine process is the same as in a pure Diesel engine. The fuel gas is injected into the cylinders at a high pressure (35 MPa) via nozzles in an injector that is also used for the liquid fuel. The gas–liquid ratio can be adjusted in a wide range. The mean air ratio is controlled in the same way as for a Diesel engine running on liquid fuels.

3.3.7 Maintenance aspects

Many components of a reciprocating engine are subjected to wear. The lubricating oil suffers from oxidation and viscosity increase due to contact with hot areas and from nitrification because of contact with combustion end products. The lube oil has many tasks, such as avoiding metallic contact between engine parts that move with respect to each other, removing of wear products, avoiding corrosion, and cooling of the piston crowns and bearings. Although filters are applied to remove the wear products from the oil, the oil is aging and has to be replaced regularly. The replacement is normally triggered by data from oil analysis that takes place at fixed intervals, generally by the oil supplier or by the maintenance company. The electrodes of the spark plugs also wear because of erosion during the sparking. The breakdown voltage of the spark-plug gap is directly related with the gap width and the ignition system is limited in increasing the breakdown voltage. Some modern engines are equipped with breakdown voltage monitoring, which reveals the state of the spark-plug gap. The injectors of Diesel engines are also subjected to wear, to erosion, and to carbon build-up and therefore have to be maintained at regular intervals. Further, the intake and exhaust valves and their seats wear from the impact of frequent opening and closing and from thermal stress. Also the cylinder liner, pistons and bearings are subjected to wear. Table 3.2 gives a typical maintenance schedule for reciprocating gas engines.

For the maintenance schedule according to Table 3.2, about 2.5% of the running time is required for regular maintenance. Some additional time is required for unforeseen repairs. On average, the installation is available for 97% of the time. The latest engine designs have a maintenance interval of 8,000 h, with a major overhaul after 32,000 h or after 5 years of operation [10]. Such a schedule is more suitable for the continuous operation of chemical process plants.

Table 3.2 A typical maintenance schedule for a reciprocating engine

Maintenance type	**Frequency (running hours)**	**Work required (hours)**
Minor	1,000	3
Small	2,000	8
Medium	12,000	72
Major	16,000	260
Large	24,000	120

3.3.8 Exhaust gas emissions limits for reciprocating engines

The main undesirable emission species of spark-ignited reciprocating engines and compression–ignition engines are the oxides of nitrogen (NO_x), hydrocarbons (HC), carbon monoxide (CO), aldehydes (R-HCO) and soot or dust (PM). Limitations for the emissions of cogeneration installations depend on the legislation of individual countries and of special measures by local authorities. Chapter 8 deals in more detail with the environmental impact of cogeneration installations. Tables 3.3a and 3.3b give some emission limits valid in the year 2016 for the USA. Other countries often apply limits in the same range, although locally and nationally more severe limits can apply. This is especially the case if the local air quality is at stake.

Table 3.3a Federal emission limits for natural gas engines >560 kW (values in g/kWh)

NO_x	**CO**	**VOC**	**CH_2O**
1.34	2.68	0.94	0.15

Table 3.3b Federal emission limits for compression ignition engines >370 kW (values in g/kWh)

NO_x	**CO**	**NHMC**	**PM**
0.67	3.5	0.19	0.03

3.3.9 Response time to required load changes

Cogeneration systems will increasingly be considered as active elements in the electricity supply system with a clear role for keeping the system stable and reliable. In the past, cogeneration installations were supposed to disconnect from the grid in case of calamities such as a bolted short circuit or a black-out. At present, however, decentralised generation encompasses a growing fraction of the total generating capacity and will therefore carry responsibility for the quality of the supply of electricity. This means that cogeneration units connected to the grid have to be able to switch on or shut down when required by the transmission system operator, adapt their output when required and ride through grid faults within certain specifications. Therefore, the allowed speed of starting and stopping becomes increasingly important as well as the response time to required load changes.

Modern gas engines can deliver 100% output from standstill in less than five minutes, provided the oil and coolant temperature are kept at a prescribed value. Diesel engines are even faster. Stopping from full load can be achieved in a few minutes. Close to instantaneous stopping at full load can also happen in case of a trip, but this is less desirable because of the resulting thermal stress on the engine.

For a Diesel engine with electronically controlled injection, as is the case with for example common-rail systems, the response to requested load changes is very fast as the work stroke of the cylinders follows immediately the fuel injection action. In addition, Diesel engines can temporarily run on a low air ratio without the risk of knocking combustion. It is the turbocharger response which forms the largest limitation. For gas engines with per-cylinder fuel injection, the fuel–air mixture has to be drawn into the cylinders during the intake stroke followed by the compression stroke, before the combustion starts with the following work stroke. Such a gas engine is always one revolution of the crankshaft slower than a Diesel engine. This adds however only 40 ms to the response time compared with that of a Diesel for engines running at 1,500 rpm. For an engine running at 500 rpm, the extra delay time is consequently 120 ms. In practice, this additional response time is hardly relevant as, in case of a fuel gas with a MN higher than 80, a fuel-injected gas engine can still increase its output from 75% to 100% in 4 s.

A gas engine equipped with a carburettor for the mixture preparation and a throttle valve for load control has a slower response time to required load changes than a fuel-injected engine. This is because, first, the load control system has to change the opening of the throttle valve, second, the flow into the intake manifold has to change, and third, the carburettor system has to adapt the gas flow to the new air flow. It takes also some time before the intake manifold has filled up to reach the newly desired pressure value. As in the case of the fuel-injected gas engine, the intake and compression stroke have to be completed before the combustion process begins. Ultimately, cogeneration installations driven by reciprocating engines can meet the requirements for offering ancillary services for grid stability and for participating in electricity markets.

3.4 Fuel-cell-based cogeneration systems

3.4.1 The concept of a fuel cell

Fuel cells convert energy chemically stored in fuel into electrical energy via oxidation without combustion. That means that the high combustion temperatures that stimulate the formation of NO_x will not be reached, whereas no hydrocarbon emissions and soot occur because no fuel can escape to the exhaust. The fuel cell consists of two electrodes with in between an electrolyte which conducts ions. The voltage created provides the exchange of electrons that takes place in an external circuit. Figure 3.15 shows the principle. The type of electrolyte determines the name of the fuel cell.

Much subsidised research on fuel cells has taken place in the second half of the twentieth century. Predicted fuel to electricity conversion rates much higher than those of gas turbines and gas engines as well as the low emissions had created high expectations. However, many barriers were encountered and, although some fuel-cell types are commercially available now, the high costs in combination with much improved performance of competing technologies make the fuel cells that are not common practice in cogeneration installations. The capital investment per unit

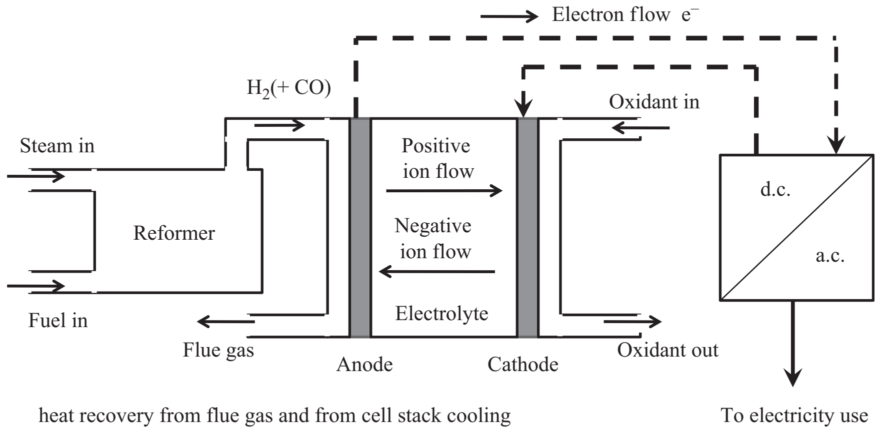

Figure 3.15 The concept of a fuel cell with a reformer and d.c. to a.c. converter

of electric power is roughly a factor 5–10 higher than that of a gas turbine or reciprocating engine.

Phosphoric acid fuel cells and polymer electrolyte fuel cells can only handle hydrogen as their electrolyte is poisoned by CO. In Figure 3.15, a reformer is positioned upstream of the actual fuel cell. Such a reformer converts hydrocarbons into hydrogen by using a shift reaction with steam. For methane (CH_4), the following processes take place:

$$CH_4 + H_2O \xrightarrow{T} 3H_2 + CO$$

$$CO + H_2O \xrightarrow{T} H_2 + CO_2$$

Ultimately, the steam reforming process produces four molecules of H_2 from one molecule of CH_4. The process has a fuel efficiency between 70% and 85%. The output of a fuel cell is a direct current, so to supply electric energy into a power distribution grid, a d.c. to a.c. converter is required. Such a converter has an efficiency of about 90%. Both the reformer and the d.c. to a.c. converter therefore reduce the efficiency of a fuel-cell-based cogeneration installation. The voltage of an individual cell is about 1 V. To create a suitable voltage level, multiple cells have to be put in series, in so-called stacks. Although the theoretical efficiency of a fuel cell is high, compressors are needed to obtain the required pressure for the fuel at the electrodes, which naturally consumes energy. An expander (a turbine) in the exhaust can recover part of that energy. Such a solution can be compared with the turbocharger of a reciprocating engine.

In the following sections, the phosphoric acid fuel cell (PAFC), the molten carbonate fuel cell (MCFC), and the solid oxide fuel cell (SOFC) will be discussed. The other fuel cell types are not relevant for cogeneration applications. Because the fuel cells are still under further development and a limited operating experience is present, no general data for maintenance schedules is available yet.

3.4.2 The phosphoric acid fuel cell

In a phosphoric acid fuel cell, liquid H_3PO_4 is the electrolyte. Hydrogen ions travel from the anode to the cathode through the electrolyte and the electrons travel from the anode to the cathode through the external circuit. The temperature of the electrolyte has to be between 150 and 210 °C; otherwise, the electrolyte is not conductive. The electrolyte is quite aggressive and is enclosed in carbon paper. The electrodes are covered by platinum, which acts as a catalyst. Platinum is an expensive material and it is poisoned by sulphur. Therefore, the fuel and the air providing the required oxygen have to be sulphur free. The fuel cell can tolerate only a very small fraction of CO, up to 1.5%, as it poisons the anode. If the fuel is a hydrocarbon, the shift process in the reformer has therefore to be very thorough. In practice, the fuel efficiency of a PAFC ranges between 37% and 47%. The electric power output ranges from 200 to 400 kW [11,12]. Heat is available at about the same temperature as that of the electrolyte. There are not many practical applications of PAFCs in cogeneration installations because of the high costs.

3.4.3 The molten carbonate fuel cell

In a molten carbonate fuel cell, the electrolyte is a mixture of Li_2CO_2 and K_2CO_3, which is kept at a temperature between 600 and 700 °C. Here, CO_3^{2-} ions travel from the cathode to the anode, while the electrons travel from the anode to the cathode. The electrolyte is very corrosive, and therefore, a ceramic enclosure is required. This MCFC is also very sensitive to sulphur, meaning that the fuel and air have to be absolutely sulphur free. The limit is 1 ppm of sulphur. The high temperature of the fuel cell allows internal reforming of hydrocarbons. In addition, high-quality steam can be produced because of the high process temperature. The fuel cell is not poisoned by CO, so a full shift of the fuel to hydrogen is not necessary. In fact, CO acts as fuel too, being oxidised to CO_2. The fuel efficiency ranges from 45% to 55%. The electric power of commercially available units ranges between 100 kW and 1 MW. Problems with MCFCs can be carbon depositing on the electrodes and vaporisation of the electrolyte into the fuel gas. The start-up time is quite long because of the high operating temperature.

3.4.4 The solid oxide fuel cell

The ceramic electrolyte of a solid oxide fuel cell consists of $Y_2O_3ZrO_2$, which is conductive for oxygen ions in the temperature range between 800 and 1,000 °C. In this fuel cell type, oxidation takes place at the anode, in contrast with other fuel cell types. The high process temperature enables internal reforming of hydrocarbons into H_2 and CO. A proper control of the temperature of the ceramic during starting, operation and stopping is important to avoid cracking of the material. That is why sometimes external reforming is applied to protect the cell from undesired temperature gradients [13]. This cell type is also very sensitive to sulphur. Reported efficiencies range from 45% to 60% for a power range between 100 W and 3 MW. Especially, the SOFC is regarded as suitable for cogeneration purposes in homes and other buildings. Problems encountered are rapid performance deterioration and still relatively high investment costs. Polarisation and ohmic losses can limit the output voltage. Researchers investigate possibilities for integrating SOFCs with a gas turbine. Such a hybrid solution can yield high electric efficiencies.

3.5 Rankine and combined cycle cogeneration systems

3.5.1 General overview

Next to the technologies for cogeneration described in the preceding sections, some large-scale and very small-scale methods for cogeneration of electricity and heat exist, where the heat is not resulting from a process in a prime mover. A well-known example is district heating in combination with a large steam-based power plant. In chemical process plants, steam is often distracted from one or more stages of a steam turbine for utilisation in the process. This steam turbine can be directly fed from a boiler or be part of a combined cycle system of a gas turbine and a steam turbine or of a reciprocating combustion engine and steam turbine. Another example is an emerging technology based on an organic Rankine cycle (ORC). Here, relatively low temperature residual heat is converted into electricity with a system basically identical to that of the steam-based cycle, but here the temperature levels are much lower than in case of steam.

3.5.2 Steam-based cogeneration

Cogeneration for district heating applications in combination with steam-turbine-based electricity production was long applied before local cogeneration became popular. In steam-based power plants for electricity production only, the steam leaves the steam turbine at a pressure close to vacuum. This is enabled by condensing the steam after the turbine in a heat exchanger where the heat can be rejected to cooling towers, rivers, lakes or the sea. Steam-based condensing power plants with ultra-supercritical boilers might reach a fuel to electricity efficiency of 45%. District heating systems operate generally at forward temperatures in the range of 70 to 110 °C and return temperatures between 40 and 60 °C. In such cases, the steam that exits the steam turbine is first used to heat up the return of the district heating system, so that the pressure downstream of the steam turbine is not close to vacuum. The same applies in case of a combined cycle, where the exhaust gas of a gas turbine is fed into heat recovery steam generator to produce steam for a steam turbine. For chemical process cogeneration applications, steam might be required at a higher pressure and temperature than at the exit of the steam turbine. In such cases, steam can be drawn from upstream of the steam turbine or from in between the first and second or the second and third stage of the steam turbine. The electrical and combined fuel efficiency and the ratio of heat and electricity depend on the amount of steam withdrawn from the process. It will be clear that the electrical efficiency will decrease if steam is drawn from the process, especially in case of using steam at the higher pressure levels.

Figure 3.16 An example of a bubbling fluidised bed cogeneration installation with an electrical output of 7.6 and 14 MW heat output (courtesy of Valmet, Finland)

Steam generation based on boilers using biomass or on waste incinerators will increasingly be used as combined heat and power (CHP) units (Figure 3.16). For smaller units up to roughly 5 MW electric output, grate burners are often used. A grate burner consists of a rotating grate to which the fuel is added centrally while the flame progresses through the biomass. For larger units, fluidised bed combustion systems ensure a complete combustion of the biomass or waste. Cogeneration systems running on wet biomass that use condensation of the exhaust gas can reach fuel efficiencies over 100% based on the lower heating value [14].

3.5.3 The organic Rankine cycle

The ORC is basically the same technique as the steam cycle, but the working medium is of organic origin. Butane, pentane, and hexane are just a few examples of the many choices for the medium [15]. The advantage of a suitable organic fluid is the lower boiling temperature than that of water, so that use can be made of low-temperature residual heat. ORC systems can use heat sources in the temperature range between 80 up to 500 °C. For temperatures over 400 °C, preference is generally given to the steam-based Rankine cycle. A good overview of commercially available ORC systems can be found in [16]. The electric power capacity covers the range between 6 kW and 8 MW. Applications are found in many industries such as the dairy, ceramic and chemical sectors. ORCs are also used to enhance the electrical efficiency of engine-driven cogeneration installations. The heat to electricity efficiency ranges between 16% and 20%. As a result, the electrical output of an engine-based cogeneration installation can be increased by almost 10%. Therefore, the fuel efficiency for electricity production can be improved from for example 40% to 44% by applying an ORC. Although some heat has to be rejected at a low temperature for condensing the fluid, quite some heat remains available for heating purposes.

3.6 Miscellaneous technologies with minor potential for cogeneration

In the late twentieth century, many technologies have been investigated for small-scale cogeneration, the so-called micro and mini CHP. The economic value of electricity was still much higher than that of heat and attempts were made to make gas-fired appliances that would produce heat as well as sufficient electric power to supply a home or a small building. A goal was also to make the boilers for domestic heating self-supporting with respect to feeding the pumps and ventilator. In that case, a black-out would not stop a heating appliance from running. A widespread application of small-scale CHP might also reduce the national fuel utilisation. However, the advent of solar PV panels and batteries for domestic applications has reduced the interest in self-powered gas-fired appliances and micro cogeneration.

3.6.1 Thermo-electric generators

Thermo-electric generators were seen as a maintenance free solution. In this case, multiple thermocouples would be put in series and subjected to heat. The investment costs are however quite high, between € 10/W and € 20/W. The fuel efficiency of the electricity production is quite low, about 2–5%, but that is no problem in case the main purpose of the appliance is heat production. However, the efficiency is too low to reach the electric power to heat power ratio of an average home.

3.6.2 Thermo-photo-voltaic generators

Thermo-photo-voltaic (TPV) generators are another option. In this case, the burner in an appliance has to create a high temperature at a surface with high radiating properties. Photo-voltaic cells have to pick up this radiation and convert it into electric energy. The required temperature exceeds 1,100 °C, which means that special burners and special materials are required [17]. High combustion temperatures on the contrary, also increase the formation of NO_x. The fuel to electricity efficiency ranges between 5% and 1%. The output of such TPV systems is about 1 W/cm^2. Fraas [17] expects costs of US$ 1.5/W for installations larger than 1 MW. This might be a solution for large industrial applications, but probably not for commercial small-scale cogeneration applications.

3.6.3 Thermo-ionic converters

Thermo-ionic converters use the mechanism that electrons can escape from a suitable material if the temperature is high enough. These electrons can travel to a much colder collector and that results in a voltage difference between the emitter and the collector. Typical emitter temperatures are between 1,300 and 1,500 °C and the collector temperature ranges between 400 and 700 °C. The conversion efficiency from fuel to electricity can be up to 10%. Again, the high temperatures of the materials are a basic obstacle for creating a commercial success.

3.6.4 Stirling engines

Stirling engines use a heat source outside the engine. The external heat is transferred to a medium in a sealed construction. Two pistons that move 90° out of phase are generally present. One of them transports the gaseous medium from a cold side to a hot side and vice versa. The pressure of the medium increases by the contact with the hot side and the work piston uses that pressure to push a crankshaft or to drive a linear generator. An advantage of such an engine is the possibility of continuous combustion in a burner which can help to reduce emissions. Further, the combustion end products are not in contact with the lubricating oil, so that the oil deteriorates much slower than in an internal combustion engine.

The working medium has to be able to quickly and effectively accept and reject the heat. Hydrogen and helium are suitable media for that because of their low density and relatively high heat capacity. High heat transfer areas are required to enable sufficiently fast heat transfer. Nevertheless, the running frequency of the Stirling engine remains limited. Issues can arise from wear particles in the lubricating oil blocking the channels of the heat exchangers. In addition, special measures have to be taken to ensure that the working medium does not escape via the bearings of the crankshaft. Stirling engines in the power range up to 75 kW have been developed; for larger engines the heat exchanger becomes excessively large. The low power density (kW/m^3, kW/kg) of Stirling engines compared with internal combustion engines make the technology expensive. Extensive commercial application of Stirling engines for cogeneration purposes is not foreseen. Fuel efficiencies of prototypes of up to 40% have been reported.

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Chapter 4

Electrical engineering aspects

Mats Östman

4.1 Cogeneration plant electrical system overview

This chapter will describe the electrical system in a cogeneration plant. The general set-up will be described in this section. The various generator types will be described in Section 4.2, the system interconnection and aspects of control and stability in Section 4.3, active power control in Section 4.4, and reactive power in Section 4.5.

4.1.1 Cogeneration plant electrical system

The electrical system in a cogeneration plant does not differ to a large degree from any other thermal generation facility. The mechanical energy generated by the prime mover is converted into electrical energy and then distributed through cables, switchgears and transformers either for the cogeneration facility's internal use or to be sold on the electricity market or both.

Figure 4.1 shows a typical layout of the electrical system of a combustion engine cogeneration plant. Electrical power is generated by the combustion engine generating sets using synchronous generators (GSs) for conversion of mechanical power to electrical power (1). The electrical power is distributed through medium-voltage (MV) cables to an MV switchgear (2). From the MV switchgear, power is distributed out to the grid through step-up transformers (3) and an outdoor switchyard (4). The facilities' own consumption of electricity is distributed through an auxiliary transformer (7) and low-voltage switchgear (8). From the low-voltage switchgear, the common auxiliaries (6) and the ventilation units (13) are supplied with low-voltage cables. Critical equipment such as the control system (14) is supplied from a direct current (DC) system (10).

4.1.2 Grid connection technologies

From the electrical system point of view, the main division of technologies does not lie in the prime mover type nor in the fuel source, but rather in the way that the electricity is produced and the way the connection to outer systems is made. One can generally discern between two major interconnection technologies: (1) synchronously connected and (2) indirectly or non-synchronously connected.

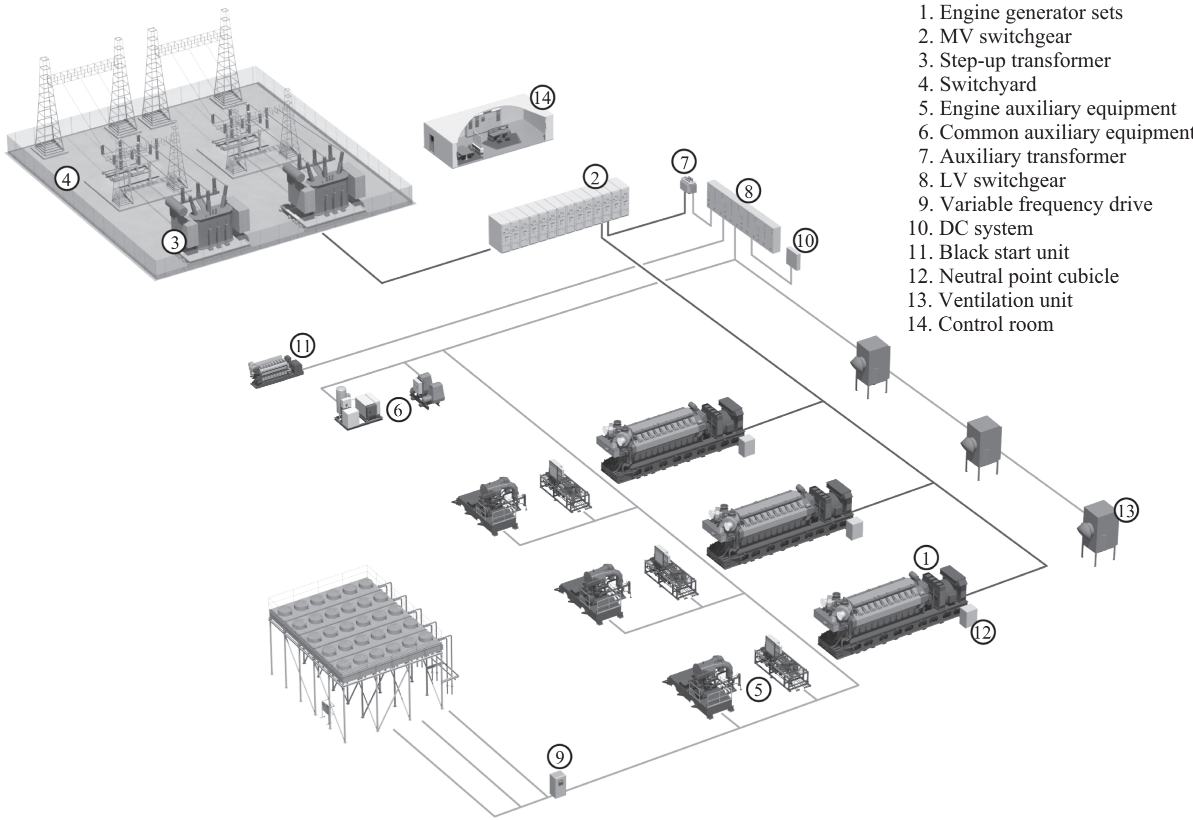

Figure 4.1 Typical electrical layout of a combustion engine cogeneration facility. © Wärtsilä. Reproduced with the permission of Wärtsilä Finland Oy

This division between technologies is also in the core of ENTSO-E 'Network Code for Requirements for Grid Connection Applicable to all Generators' (NcRfG) [1], where technical requirements pertaining to grid connected generator units are laid out.

Broadly speaking, synchronously connected facilities are those that use GSs for the conversion of the mechanical energy to electrical energy and are connected to the electrical system without the use of power electronic equipment. Non-synchronously connected facilities are those who use asynchronous generators, DC-generators or other electrical sources with or without power electronic equipment between the generator and the electrical system.

Traditional thermal generation and hydro-plants almost always use GSs. Many of the renewable technologies and smaller cogeneration units such as micro-turbines or fuel cells are non-synchronously connected with the use of power electronics.

4.2 Types of generators

The device used for converting the mechanical/thermal energy into electrical energy and the way the cogenerating unit is connected to the electrical system (through a power converter or direct connection) determines to a large extent the set-up, capability and the characteristics of a cogeneration facility in terms of active and reactive power control and island mode operation capability. Therefore, the power conversion technologies available and the active and reactive power control choices are given emphasis in this section.

4.2.1 The synchronous generator

In many ways, one can say that the use of the GSs in the production of electrical energy is the backbone of any electrical system. Power plants with GSs provide the reference system frequency, system inertia, voltage control and short-circuit current necessary for the operation of the electrical networks all around us today. Cogeneration plants larger than tens of kW up to several hundred MW typically use GSs for generation of electricity. GSs are thus found in a wide variety of cogeneration installations driven by both gas and steam turbines, hydro-turbines and combustion engines.

Figure 4.2 shows the main constructional set-up of a GSs: rotor (1), stator (2), exciter and diode bridge (3), and structural parts (4).

4.2.1.1 Construction and types

From an electrical functionality perspective the GS is built up from three essential elements, the stator (armature), the rotor (field) and the exciter system. The exciter produces a DC for the DC rotor winding. The rotor winding produces a magnetic field, which again induces an alternating current (AC) in the stator winding.

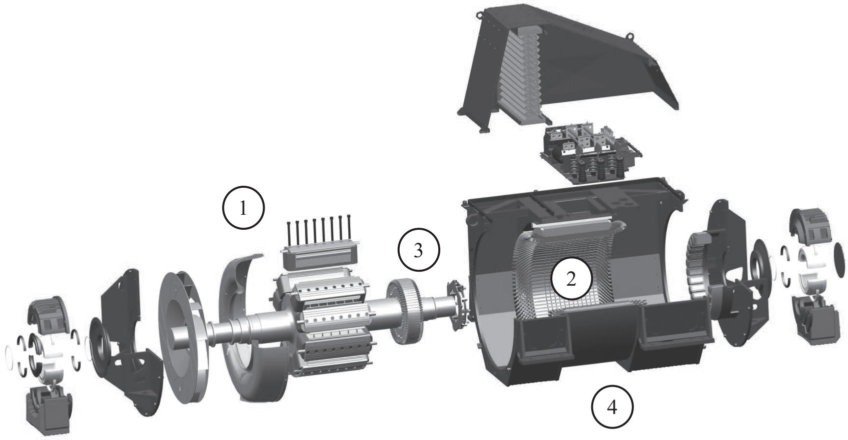

Figure 4.2 The build-up of a brushless synchronous machine describing the main functional parts. © ABB. Reproduced with the permission of ABB Oy, Motors and Generators

The mechanical speed of the rotor determines the electrical frequency of the stator voltage. The synchronous speed of the machine is given by the following relationship:

$$n = \frac{120f}{P} \tag{4.1}$$

where n is the machine speed in rpm, f is the frequency in Hz, and P is the number of poles.

Consequently, a generating unit running at 750 rpm will have a generator with eight poles for a 50-Hz system. This can many times be seen in the manufacturers' type designation ending with an 8 or 08 for a 750-rpm machine.

A synchronous machine rotor winding and thus machine type can further be divided into two different types: round rotor and salient pole type. In a salient pole rotor, the rotor poles are projecting outwards from the rotor surface, therefore the term 'salient' is used, whereas a round rotor is cylindrical and has parallel slots on the surface to place rotor windings [2]. Whether a round rotor or salient pole construction is used is mainly decided by the rotational speed. For a high rotor speed of 1,500–3,000 rpm (two to four poles) a round rotor construction is typically considered to be mechanically more feasible and consequently for less than 1,000 rpm (six poles), a salient pole construction is more common. Deviations to this rule of thumb exist on the basis of manufacturers' practice.

A further major type division lies in the excitation system (ES). For synchronous machines, the ES can basically be of two types: 'static excitation' and 'brushless excitation'.

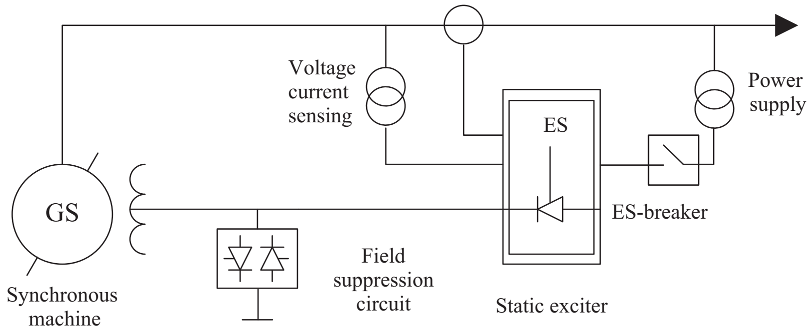

Figure 4.3 Schematic view of a synchronous machine with a static excitation system

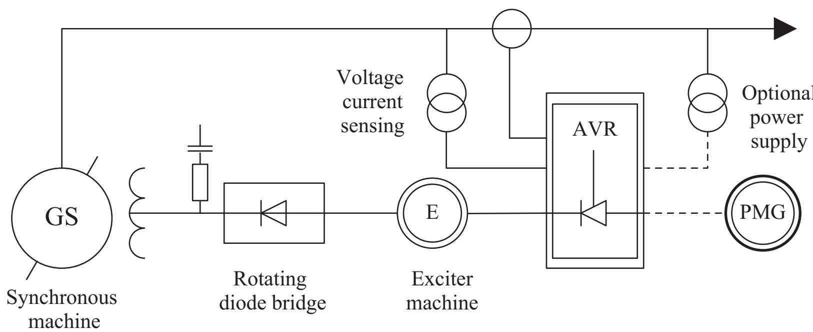

Figure 4.4 Schematic view of a synchronous machine with a brushless excitation system

With a static ES, the DC required to build up the main field is fed directly to the rotor circuit using a brush system or slip rings (Figure 4.3). This design is typically used for large GS.

In small and medium sized synchronous machines, the most commonly used ES is of the so-called brushless type, where there is no mechanical interconnection with brushes for excitation current supply. Instead, there is an exciter machine mounted on the generator shaft (Figures 4.2 and 4.4), which operates with induction similarly to the main machine. A DC is fed from the automatic voltage regulator (AVR) to the exciter machine, which amplifies and creates an AC, which is again altered to a DC required for the main field in a diode bridge.

Both systems have their advantages and disadvantages. A static system is able to provide negative field forcing and has generally a faster response, but it is more costly and the brush system requires regular maintenance. The machine may also require special fire quenching due to the possibility of accumulated carbon dust from the brushes. A brushless system introduces an additional time delay due to the exciter machine and cannot provide negative field forcing. A brushless system is less costly and virtually maintenance free.

In the end of the day in terms of performance (ability to provide steady state and transient voltage control), both systems are more or less equal, provided that the complete excitation control system has been adequately designed taking into account the characteristics of the main machine and the electrical network conditions at the connection point.

4.2.1.2 Reactive power control

The ES is responsible together with the AVR to supply and regulate the field current to maintain the voltage at generator terminals within the generator capability curve or P/Q diagram (Figure 4.5). The operational area and restrictions may be slightly different for different generator designs. However, in general, the following apply. The active power capability shown in vertical direction in the diagram is always restricted by the mechanical input power from the prime mover (2). The reactive power capability shown in horizontal direction in the diagram is in the area restricted by the stator (1), rotor (3) current limits on the positive (inductive) side. On the negative (capacitive) side, the minimum excitation limit (4) and the stability limit (5) of the generator limit the reactive power capability.

The adjustment of system voltage via reactive power is done by increasing the excitation, that is creating a stronger magnetic field, which results in providing reactive power to the system, whereas decreasing the excitation is weakening the magnetic field, thus withdrawing reactive power.

Under short-circuit conditions, a GS is capable of delivering a high short-circuit current, six to ten times the nominal current, for a limited time. A typical

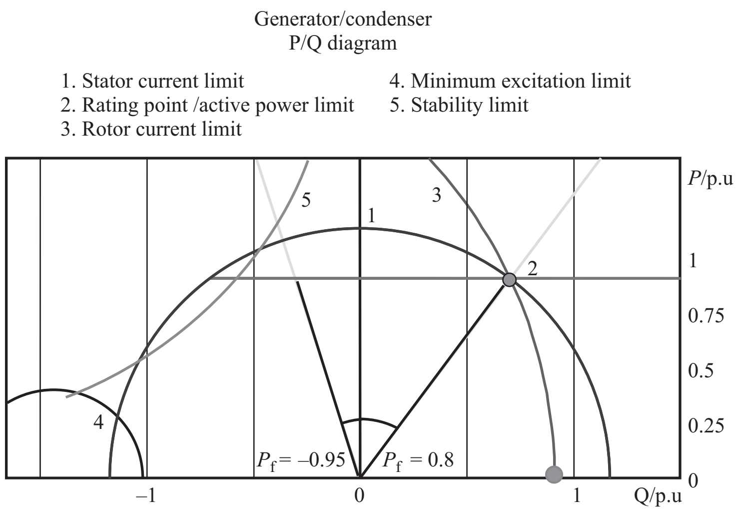

Figure 4.5 Synchronous generator capability diagram example including operational limits

specification is that the generator has to deliver a steady short-circuit current in excess of 2.5–3 times the nominal current for 5–10 s. The short-circuit current is thereby enabling current actuated relays and fuses to work in a selective manner.

The high short-circuit current capability is also important for system stability reasons, as the high amount of predominantly reactive power fed from a GS as a result of a short circuit helps to stabilize the system voltage during and after a fault.

The various voltage control principles, that is either droop control, fixed reactive power or fixed power factor control, depend on the voltage level of network, network status and operational principles of the transmission or distribution system operator. The different control philosophies are detailed in Section 4.5.

A GS is typically designed to perform its primary duty within a voltage range of ±5% and a frequency limit of ±2% according to the IEC 60034-1 standard [3]. Excursions from nominal voltage and frequency will cause, for example, additional heating or other various undesirable effects on the generator components. This has to be taken into account in the design, if a large voltage and frequency capability is desired. For example, a high voltage to frequency ratio will increase the magnetic flux in the stator winding, which might damage the insulation or stator core steel.

To further complicate the issue, the problem is actually three dimensional, as the effect of voltage and frequency variations is depending on the operational point of the machine.

High-grid voltage at a leading power factor may be within the generator design capability as the thermal stress on the rotor is less, but not at a lagging power factor, where it is higher. This can be seen from the line (3) in Figure 4.5. Low-grid voltage at lagging power factor may be within the generator design capability, but not at leading power factor, where the generator stability limit illustrated by the line (5) in Figure 4.5 might be reached.

4.2.2 The asynchronous generator

4.2.2.1 Typical use in cogeneration

Smaller cogeneration units like small steam turbines, small hydro-turbines, gas expanders and small reciprocating engines may sometimes use an induction generator or asynchronous generator. This type of generator is based on the principles of an ordinary squirrel-cage electrical motor to produce electrical power. Asynchronous motors can operate as generators by increasing the rotor speed above the synchronous speed. Because they are based on the same basic principle as an ordinary electrical motor, they are relatively cheap and have simple controls. Today, induction generators are many times found in wind power applications either directly coupled with or without soft starting and power factor correction, or connected through power electronic converters to the grid.

4.2.2.2 Construction

As the induction generator can work both as an electrical motor and as a generator, it may be prudent to take a closer look on the working principle. Figure 4.6 gives a general overview of a modern large induction-machine construction. The induction

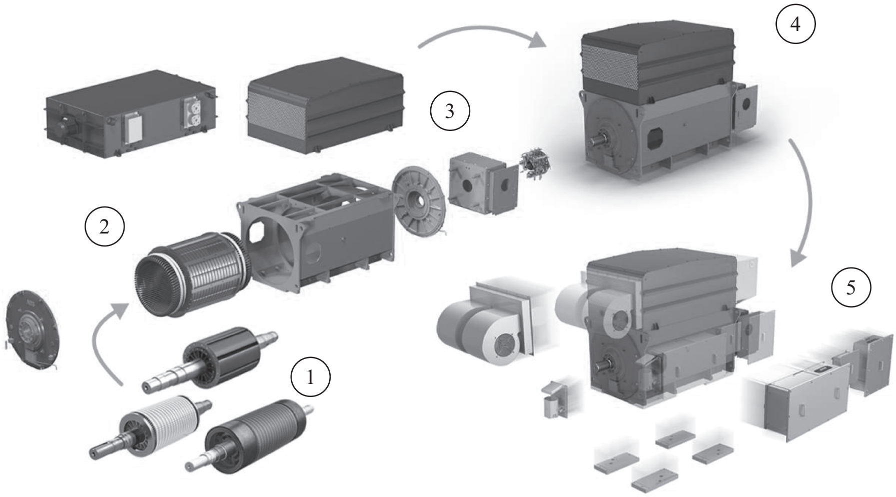

Figure 4.6 Build-up of a large induction machine describing the main functional parts. © ABB. Reproduced with the permission of ABB Oy, Motors and Generators

generator is from electrical functionality perspective made up from two essential parts: the rotor (1) and the stator (2). The active parts are enclosed in a steel structure with a bearing and cooling assembly (3), which is building up the basic machine (4). The basic machine can then be further equipped with accessories such as forced cooling fans and various terminal boxes (5).

In motor operation, the rotor is pulled behind the stator flux, with a slip frequency (positive slip). Slip frequency is the difference between synchronous speed and the speed of the rotor under load. The greater the load applied on the motor shaft the greater the slip until a specific point, where the relationship between torque and load is not directly anymore proportional and further increase in slip would not anymore yield an increase in torque on the shaft.

In generator operation, a prime mover (turbine or engine) is driving the rotor above the synchronous speed (negative slip). The induction machine now operates as a generator sending power back to the electrical grid. Because the stator is tied to the electrical system, the output frequency and voltage is regulated by the power system. The frequency at which power is generated is thus independent of the prime mover speed variations, which then only affect the output of the machine. This makes the induction generator an attractive alternative for cogeneration units which, due to their nature, have a varying shaft speed. As the output frequency is tied to the network frequency, a very accurate speed control is not necessary.

As there is no field winding, ES or permanent magnet poles provide DC excitation, as in the case of GSs. The induction generator is not by itself able to start and operate as a stand-alone unit. An induction generator requires externally supplied current to be able to start. A common way is to start the generator as an electrical motor and later clutch in the prime mover when the generator has reached

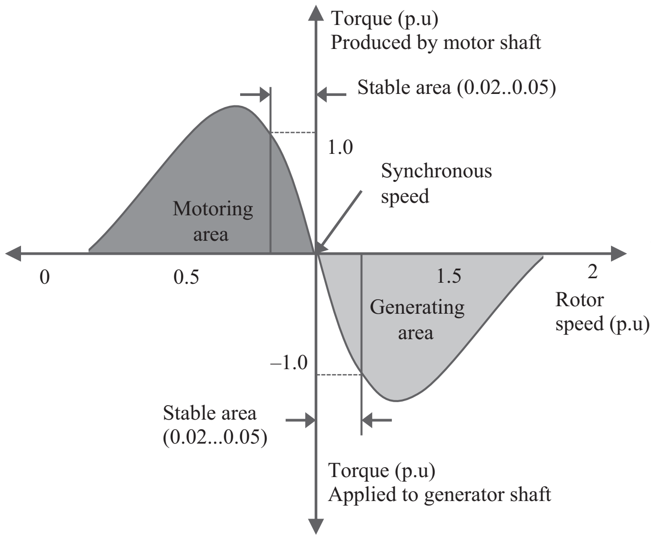

Figure 4.7 Operational principle of an induction machine, showing motor and generator operational area

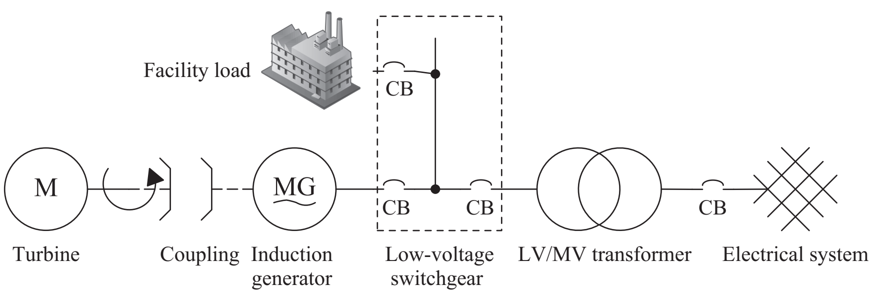

Figure 4.8 Schematic overview of grid connection of an induction generator

its rated speed. After the clutch-in, torque can be applied to the machine shaft to increase the rotor speed and electrical power is produced along the principle described in Figure 4.7 and illustrated in Figure 4.8.

4.2.2.3 Reactive power control

Because the rotor field always lags behind the stator field, the induction generator always requires reactive power, regardless of whether it is operating as a generator or as a motor. An induction generator usually draws its excitation power from the electrical grid to which it is connected. This reactive current draw is many times unwanted as utilities may impose penalties for excessive reactive power consumption. To avoid this, induction generators can be self-excited by using external capacitors. Care has however to be taken when applying external capacitors.

Self-excitation of the generator during a power outage is many times unwanted, as it may create a hazardous motoring, overvoltage situation or unintended island operation. This can occur if the reactive current compensation provided by the capacitors or other capacitive elements like cables closely match the required reactive power for stable operation.

Cogeneration units with asynchronous generators employ voltage and frequency, and reverse power based protection to detect abnormal operating conditions and islanding, and to remove the unit from operation would islanding occur.

4.2.3 The power-converter system

4.2.3.1 Typical use in cogeneration

Cogeneration units based on fuel cells generate DC electricity, and micro-turbines produce electrical power via a high-speed permanent magnet or induction generator. Both require an adoption to the mains frequency of either 50 or 60 Hz before connection to the electrical grid.

4.2.3.2 Construction

For fuel cells depending on the configuration, the DC voltage is approximately 24 to 150 V DC [4]. As the output voltage is of DC and is load dependent, a power electronic converter (DC–AC) is needed to convert the DC into mains frequency and voltage. Often the converter includes an intermediate DC–DC stage for controlling the load and maintaining a stable voltage on the fuel cell stack. The converter uses a pulse-width modulation technique at high frequencies (kHz range) to generate an AC output at 50 or 60 Hz. The schematic overview is illustrated in Figure 4.9.

The micro-turbine produces electricity via a high-speed generator (10,000–30,000 rpm) and uses a power electronic converter in a similar fashion as the fuel cells to adjust the frequency of the generated electricity to match the system frequency either AC–DC–DC–AC or DC–AC (Figure 4.10). An alternative solution to match main's frequency is to go through a speed reduction gearbox driving a conventional induction generator to generate power at 50 or 60 Hz. In this case, the grid connection would be as shown in Figure 4.8.

Power conversion comes however with an efficiency penalty, which is dependent on the method and technology and is in the order of 4%–8% [5].

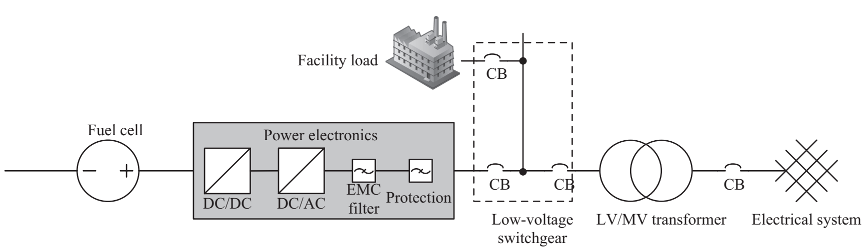

Figure 4.9 Schematic overview of the grid connection of a fuel cell

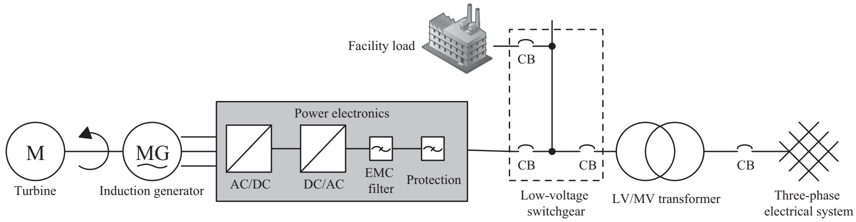

Figure 4.10 Schematic overview of the grid connection of a micro-turbine

In addition, the power converter converting the high-frequency AC power into 50 or 60 Hz mains also typically employs active and passive filters for harmonic distortion control in the output. Depending on the design, a power electronic converter will also have reactive power control capability.

Many micro-turbines and fuel cells can generally be equipped with controls that allow the unit to be operated in parallel or in island mode, if the primary energy source permits. The frequency drive additionally internally incorporates many of the grid and system protection features, such as overcurrent protection, islanding detection and over/under voltage protection, which can be tailored for the local interconnection requirements.

4.2.3.3 Reactive power control

Reactive capability of converters differs from that of synchronous machines, because converters are normally not power, thermal or stability limited, as the synchronous machines. Power electronic systems are typically limited by the power electronic converters internal voltage, temperature and current limits [6].

With power converters, there is a choice to be made how the capability of the device is to be utilized. Traditionally, the choice was to utilize the available current capacity for active power production only. In this way, the cost of the power converter was minimized and the control simplified.

Today, many grid codes specify that a generating unit above a certain size has to have the possibility for voltage control in a way similar to a synchronous machine. In addition to this, the cogeneration units host facility may benefit from a reactive power control capability, to either reduce or avoid reactive power draw penalties or benefit from a potentially more steady voltage profile. To conclude, today the reactive power capability is almost always needed for one of the above reasons, and a design strategy has to be made accordingly.

The reactive power control strategy can typically follow two different paths. The first choice is to keep capacity in reserve so that the power converter has reactive capability at its rated active power, operating similarly to a conventional GS where active power is always limited by the prime mover. This is illustrated by the dash-dotted line in Figure 4.11: as more reactive power is imported or exported the active power capability is sustained. The second strategy is to give priority to reactive power in the controls. Here no spare capacity is held in reserve so that, when reactive power is needed, the converter will reduce its active power,

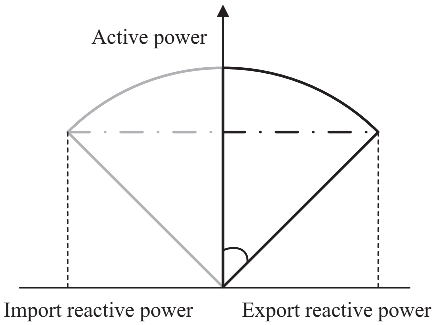

Figure 4.11 Schematic of reactive power control

if needed, to keep within the device ratings. This characteristic is illustrated by the solid line in Figure 4.11.

Both strategies have advantages and disadvantages. Holding capacity in reserve is a good choice when the cogeneration unit is expected normally to work close to its rated output, and at the same time there is a need for reactive current control. With this strategy, it may also be easier to fulfil different grid code requirements and other control requirements.

However, when the converter is operating at its peak active power rating at unity power factor, the inverter may be less efficient than if it is at its rated capacity [7]. If the cogeneration unit is not expected to work at its rated power for a prolonged time, then the 'spare' capacity can be used for reactive power control and at those rare times, when both full active power and reactive power is needed, priority can be given to reactive power control. The advantage here is that the converter can be utilized more effectively, and spare capacity does not have to be costed for.

Frequency converters are normally designed for operation from 90% to 110% of rated voltage. The capability to export reactive power may be restrained as the voltage increases, because of internal over-voltage limitations within the frequency drive. The capability to export reactive power may also be restrained as voltage decreases because of current limits. On the other hand, the capability to import reactive power normally will increase with increasing voltage [6].

Dynamic reactive capability from converters can be provided almost instantaneously in a manner similar to that of synchronous machines. This can be used to compensate system voltage variations during transient events such as short circuits. The limitation here is mainly from the short-time current capability of the inverters which, compared to a synchronous machine, is limited.

As reactive power production using power converters can impact to some degree on the losses, thus on the economics under its entire life time, fixed capacitors or reactors are many times used to shift the dynamic reactive capability towards the lagging or leading side, respectively, as required by the facility or grid codes.

Table 4.1 Summary of power conversion equipment relative characteristics

Features	Synchronous generator	Induction generator	Converter
Island operation	●●●	–	●●
Black start capability	●●●	–	●●
Reactive power control	●●●	–	●●
Dynamic voltage control	●●●	–	●●
Short-circuit current	●●●	●●	●
Simplicity	●●	●●●	●●
Cost	●●	●●●	●●

4.2.4 Summary of electrical power conversion

As has been discussed in this section, the selection of power conversion type, synchronous, induction generator or power converter, will have a large influence on the behaviour and characteristics of the cogeneration system from an electrical perspective. The different technologies have their respective strengths and weaknesses as outlined above. What solution is best fitting depends on many factors that can be technical in nature, such as reactive power control capability or inertia. Other factors may be economical or operational. Table 4.1 gives a summary of the relative merits of the various technologies that may serve as a support for decision-making.

4.3 Network stability considerations

4.3.1 The challenge of the future

Our traditional electrical systems are undergoing a phase of fundamental change. ENTSO-E, the European network of Transmission Operators, talks about changes of 'unprecedented scale', and notes that the generation system of the future will be based on a vast number of distributed and power electronics based generators, which are variable and only partly dispatchable generation based [8].

Traditionally, system stability via controlling of active and reactive power has relied on the characteristics and availability of conventional power generators using GSs. This is true also for the majority of the installed cogeneration units. In case, a substantial fraction of power generation is derived from indirectly connected sources, insufficient dispatchable and controllable traditional generating capacity can be present. Renewable generation (Figure 4.12) cannot fully be dispatched in the traditional sense and many times does not contribute to system reserves, system inertia and voltage control. Consequently, a major integration challenge in the case of much renewable energy sources lies in reliably balancing of generation and load. Cogeneration units, especially those using GSs and having controllable active and

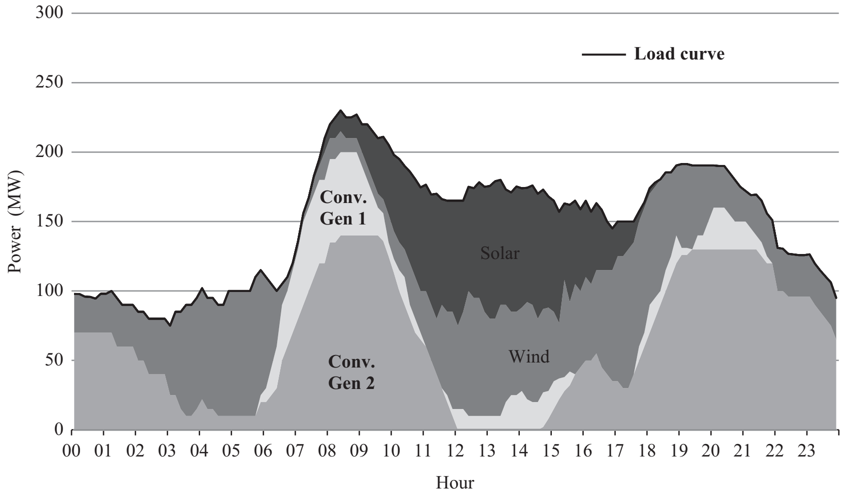

Figure 4.12 Illustration of the generation mix in a system with a high degree of renewable generation

reactive power, can provide valuable system services such as active power reserves, system inertia and voltage support.

4.3.2 The role of inertia in a power system

Inertia in a power system improves the frequency stability by limiting the rate of change of frequency in the case of sudden imbalance between generation and load. The main source of inertia in any electrical power system is the kinetic energy stored in the rotating masses of electrical machines, notably GSs and motors. A decrease of the relative amount of natural inertia from conventional generation and load in the system will require faster response of generators and higher ramping capability to arrest the frequency dip or rise to safe values.

In principle, inertia can also be provided by some indirectly connected generation technologies using power converters as a response to a sudden frequency deviation. This is done using fast acting active power control. The solution mimics the inertia response of a traditional GS. The drawback of this solution is that some active power always has to be kept in reserve or be provided by energy storage.

4.3.3 The role of a cogeneration unit in island operation

The presence of a cogeneration facility offers an opportunity of locally reducing the impact of power outages or disturbances by enabling an island operation of the cogeneration installation and parts of the surrounding network. An ‘island’ in this context is a part of a power system, which has been separated from the main power system and is operated independently.

Economic considerations may represent a decisive factor, if a cogeneration facility is designed to work independently from the main grid. Generally, one can

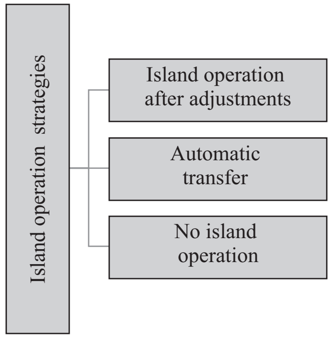

Figure 4.13 Schematic overview of island operation strategies

say that the more sensitive the host facility process is towards disturbances, the more attractive is the case for island operation, not only when the grid is unavailable, but many times also as a precaution for expected grid disturbances, as for example when severe weather conditions are expected, which may affect the electrical supply quality.

Utilities may also see opportunities for island operation of cogeneration, which may represent an important means for the utilities to reduce the costs of unavailability for long outages. Other valuable services can be to provide system inertia and active and reactive power control in islanded or weak systems.

The capability to function in an island is not given, and the choice of generator type affects the capability and behaviour.

Three different approaches to islanding can be discerned: (1) no island operation capability, (2) island operation after changes, and (3) automatic transfer to island operation [9] (Figure 4.13).

Generally, it can be said that a cogeneration unit using a GS is well suited to island operation. The GS has an internal voltage source and is not reliant on outer system for reactive power. The synchronously connected unit is further equipped to provide short-circuit current and inertia to an islanded system. Cogeneration units using power converters for grid connection can also be suitable for island operation, if designed for such duty, whereas units with induction generators are not suited for island operation, for the reasons discussed in Section 4.2.

Sometimes island operation capability is not wanted. The reasons for this can be, for example, safety aspects, lack of energy need during an electrical system outage or simply economic considerations.

If island operation is desired, the easiest transfer to island operation is through an outage. That is the cogeneration unit is stopped and the necessary changes such as changing control scheme and load adjustments are made before resuming operation. This, however, may not be suitable for cogeneration units feeding sensitive loads or when an outage is not acceptable as this may entail some system down time.

An automatic transfer to island mode operation requires a transfer strategy and engineering to make the transfer possible. As a minimum, the following aspects need to be considered:

- The size and extent of the island system need to be well defined.
- The minimum requirements on power supply quality need to be defined for transition and island system operation.
- The cogeneration unit needs to be sized to supply the active and reactive load in the islanded system.
- The cogeneration unit is able to control reliably the voltage and frequency of the islanded system within power quality framework and given load.
- A reliable indication of the transfer to island operation and back must be available.

Islanding status information is crucial, as operational control many times has to be adjusted, when there is a transfer from parallel with grid to island operation. This can, for example, be a transfer from heat demand control (in heat demand control the output of the cogeneration unit is controlled based on the need of steam or hot water in an industrial process) to frequency control. Island status information can be in form of status indications of interfacing breakers or through special types of protection devices based on voltage wave form shift or rate of frequency change. Here, it is however important to recognize that most voltage- or frequency-based protection has an inherent dead band, meaning that, if the available load is equal to the production of the cogeneration unit, then the island may not be automatically detected; therefore, many times the most reliable indication is based on interfacing breaker status indication.

Black start capability is an important consideration for cogenerating units that require mechanical or control changes before island operation or for units that intend to sell a service for network restoration to utilities. Many larger cogeneration units based, for example, on reciprocating engines or gas turbines with GSs are well suited for this duty, if the auxiliary systems are designed accordingly. Cogeneration units having induction generators are not directly suited for this duty, and those using power converters may be suited but may need some form of energy storage (batteries) to provide the initial start-up power.

4.4 Cogeneration unit active power control

4.4.1 General overview

Traditionally in many cogeneration plants, the principal product is heat or steam generation for the use in various industrial or district heating and cooling applications. This means that the electrical output of the cogeneration installation essentially varies with the need of those processes which have to be fulfilled at any time. This approach gives a limited ability to pursue active power-control strategies or market-oriented services.

In order to actively participate in the electrical markets, work in both islanded conditions and parallel with grid, and especially selling ancillary services, it is important to have a basic understanding of the capability of the installation and select an appropriate active and reactive power control strategy.

Sections 4.4.2–4.5.6 will discuss some of the main considerations and show general system response characteristics. The author recognizes that in the following sections, many simplifications have been taken. The intention, however, is not to go into detailed control logics or exact response characteristics but to give a basic overview.

4.4.2 Active power control strategies

Active power control strategies are not only dependent on the primary energy use as discussed in the previous section. The control strategy is also dependent on the operational situation of the cogeneration unit, that is if the unit is parallel with grid or if it is islanded. Figure 4.14 gives an overview of the different control strategies available depending on the parallel with grid or islanded status.

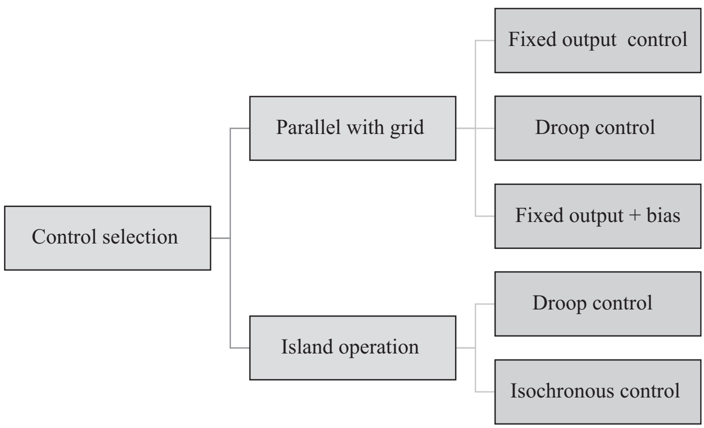

Figure 4.14 Schematic overview of active power control selection based on parallel with grid or island operation

4.4.3 Traditional droop control

Droop control is a universal operating mode that is available in almost all conventional generation technologies. The droop principle uses the system frequency to find a common operational point and load sharing between generator units without external communication needs.

This means that parallel units with the same droop characteristic can respond to an increase or decrease in frequency by increasing or decreasing their active power outputs simultaneously. The increase in active power output will counteract

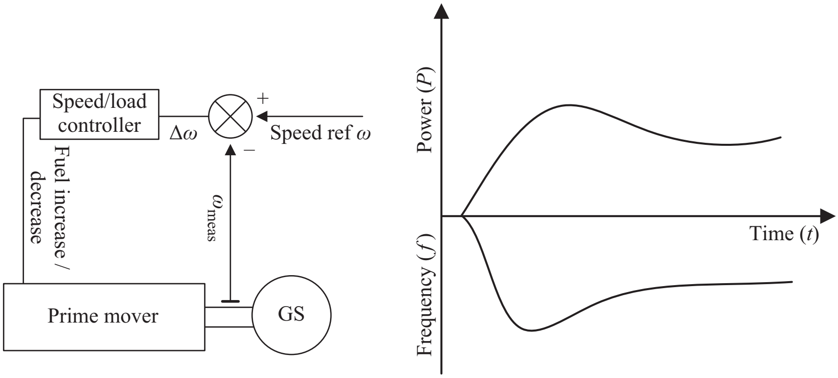

Figure 4.15 Schematic overview of droop system response to a sudden change in grid frequency

the reduction in frequency, and the units will settle at active power outputs and frequency at a steady-state point on the droop curve.

Droop settings are normally expressed in per cent (%). The setting indicates the percentage change of the measured frequency (f) or speed (ω) to cause a change in generating unit load from 0% to 100%. For example, a 4% frequency droop setting means that for a 4% change in frequency, for example from 50 to 48 Hz in a 50-Hz system, the unit's power output should change from no-load to full-load.

Figure 4.15 shows a simplified droop control schematic and a generation unit response to a sudden change of frequency when in droop mode. The controller senses a frequency or speed decrease. The difference ($\Delta\omega$) between reference speed (refω) and measured speed (ω_{meas}) is used by the speed/load controller to calculate the needed fuel increase, in order to increase the output according to the droop curve. The frequency decline is arrested, but it will stabilize at a value lower than nominal.

For a cogeneration facility that is intended to operate in droop mode, this behaviour has to be factored in when deciding on the active power control strategy, especially if the frequency variations would be frequent or show large excursions. A directly coupled heat or steam generation would vary with the system frequency. As can be seen from Figure 4.15, a droop-based response will not automatically bring the system or unit back to nominal frequency. The unit will settle on a frequency along the droop line. To bring back the system to nominal frequency, an outer control loop or a manual control has to be employed.

4.4.4 Fixed output control

When operating in fixed output control, also called kilowatt (kW) or megawatt (MW) control, the generating unit is largely independent of the system frequency. The target of this control mode is to achieve a steady output. The fixed power control algorithm controls the generation unit output based on the active power

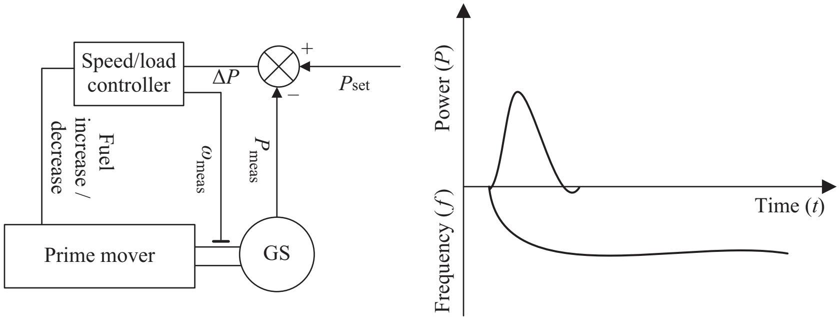

Figure 4.16 Schematic overview a fixed output control response to a sudden change in grid frequency

actual value. Figure 4.16 shows a simplified control diagram of a fixed power controller and a generator unit response to a sudden change of frequency, when in fixed power control. The controller acts only on the difference (ΔP) between the requested power (P_{set}) and the measured power (P_{meas}). Frequency or speed is measured for safety control only. As can be seen in Figure 4.16, a cogeneration unit working in fixed output control will not be sensitive to a change in network frequency; after the initial transient, the output will again be controlled to the set output value (P_{set}).

This operational strategy may be preferred when the heat generation is directly coupled. A control signal representing the thermal energy need in terms of heat or steam by the primary process can at any time control the output of the prime mover and variation in system frequency will not affect the output and heat generation to any larger degree. A cogeneration unit operating in parallel with a large system and required to meet set generation schedules can also benefit from a fixed output control strategy.

4.4.5 Fixed output control with frequency bias

A generating unit that is working on fixed power control will obviously not react on a frequency deviation. It will continue to try to keep its output stable at the set value irrespective of frequency variations according to the principle in Figure 4.16. This also entails in traditional control philosophy that, in order for the unit to participate in frequency control, it has to be switched over to droop control.

In modern controls, this switchover to droop control can be avoided by adding a frequency bias functionality to the fixed power control. By introducing this biasing functionality, the generating unit can have the benefits of the fixed power control and at the same time be able to respond and support the system during abnormal frequency conditions.

The functionality of the biasing is very simple: The generating unit operates normally at a fixed output set by the process need or system operator. If the frequency goes out of the insensitivity area, the generating unit will respond to a frequency change (Δf) by either increase or decrease of its output (Figure 4.17).

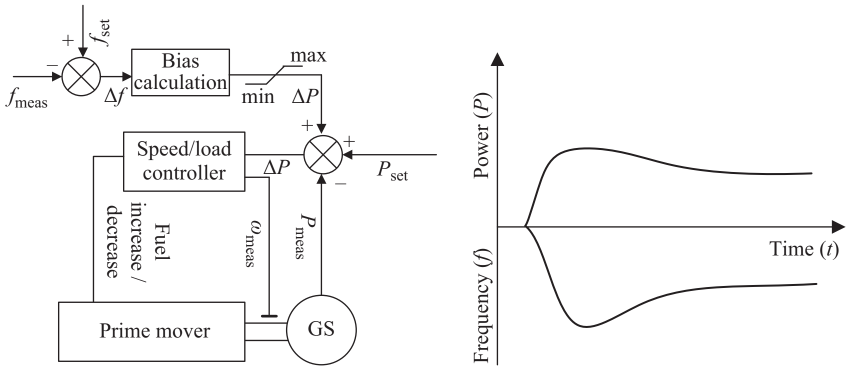

Figure 4.17 Schematic overview a fixed output control with frequency bias response to a sudden change in grid frequency

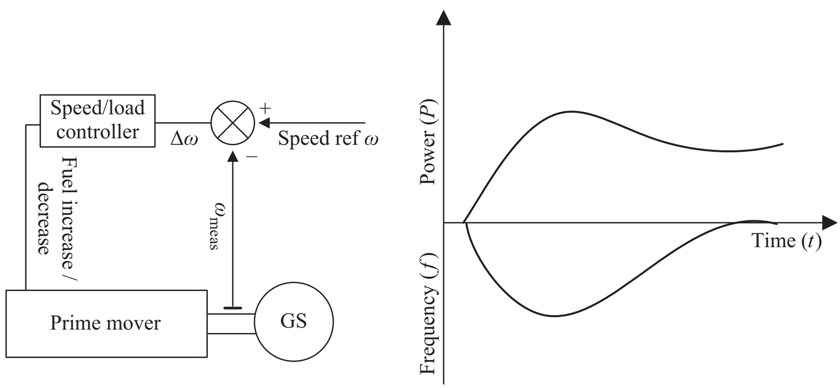

Figure 4.18 Schematic overview an isochronous control response to a sudden change in grid frequency

The biasing functionality works in the way that it assigns a pre-defined offset load reference (ΔP) based on the frequency deviation (Δf) to the fixed output set by the plant or system operator.

4.4.6 Isochronous control

The isochronous control mode is only applicable in island mode. The aim of isochronous control or 'zero droop' control is to control to a pre-set frequency. In isochronous control, this is always a nominal frequency. When subject to a load increase or decrease, the generating unit will detect the related change in frequency or rotational speed and adjust its output to again reach the pre-set or nominal speed value. The controller senses a frequency or speed decrease. The difference ($\Delta\omega$) between reference speed (refω) and measured speed (ω_{meas}) is used by the speed/load controller to calculate the needed fuel increase, to increase the output to bring the unit again to nominal speed or frequency (Figure 4.18).

4.4.7 Conclusion on active power control strategies

The choice of active power strategy directly affects the cogeneration unit behaviour in steady-state control and during disturbances. The optimal control strategy depends on many different variables, such as electric network environment, heat demand, frequency control capability and others. Simple droop control has many advantages, especially the possibility to parallel different generating units and allow those to share load without an extensive communication infrastructure. Droop control is also considered a ‘safe’ operation mode when operating in an islanded network. Fixed output control gives the possibility of operating the cogeneration unit to a target output, irrespective of frequency variations, which may be desirable when accurate and stable power or heat supply is crucial.

Isochroous control or zero droop control has the advantage of allowing the generating unit to try to keep the target frequency in island operation without having to resort to cascade (supplementary) control.

Advanced unbundled systems with a developed ancillary services market on the other hand have different needs. Here, the possibility of the additional control flexibility of fixed output control + frequency bias can give additional benefits, allowing to contract ancillary services (primary and secondary control) within firm boundaries. Both bias control and droop control behave much in the same way as far as continuous frequency control is concerned.

4.5 Cogeneration unit reactive power control strategies

4.5.1 General overview

Active power control in AC systems is related with active power transfer from generation to load, where generation and load have to be matched at all times to maintain the frequency. Reactive power demand from load and supply circuits have also to be matched in a similar way at all times to keep the voltage within certain limits. Reactive power is essential for some electrical appliances such as motors and transmission circuits, lighting systems and others. Thus, generators have to provide the required active power as well as reactive power; otherwise, the electrical system cannot remain functional.

Cogeneration units irrespectively of the connection technology, except induction generators, have the ability to take part and help to control also reactive power and voltage locally. Indeed, one of the advantages of cogeneration is that the generation is close to the load; thus, reactive power does not have to be transferred over long distances. Taking into account the limitations of the connection technologies, the control strategies for reactive power that are available are more or less the same irrespective of the connection technologies, with the exception of induction generators.

4.5.2 Reactive power control strategies

Reactive power management strategies in a cogeneration plant are highly dependent on the technology used and the type of cogeneration unit. A cogeneration unit

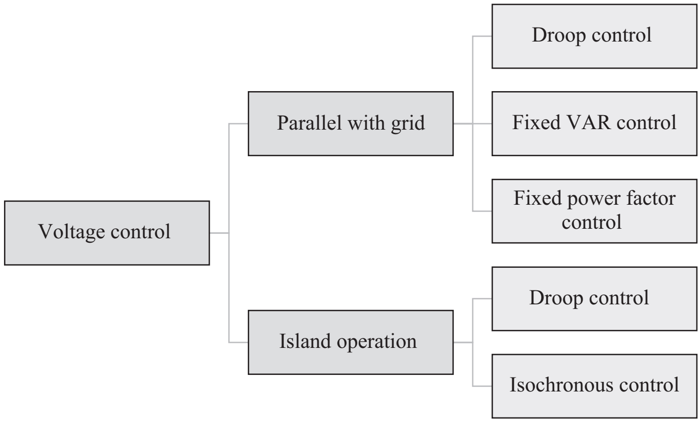

Figure 4.19 Schematic overview of reactive power control selection based on parallel with grid or island operation

equipped with an induction generator is not by itself capable of an active reactive power management scheme; rather, it is limited to compensate some of its reactive power drawn from the network.

A cogenerating unit, which has a connection to the electrical system through power electronics, has approximately the same possibility as a GS to generate and absorb reactive power as previously discussed, but at a price of some loss of efficiency. And finally, a cogenerating unit with a GS can both generate and absorb reactive power within its design limits.

The control strategies, available to pursue for cogeneration units with reactive power control capabilities, can be divided into the following basic control principles: (1) droop control, (2) power factor control, and (3) constant VAR control. Sometimes also a fourth and fifth alternative is used which is called isochronous control and cross current compensation; however, these operational modes are more sophisticated and outside the main control modes presented in this chapter.

Which control principle to use is many times dependent on the utility where the cogeneration unit is attached, the choice and need of the facility where the cogeneration unit is connected and the operation mode, that is if the cogeneration unit is parallel with the grid or not. The various control principles are summarized in Figure 4.19. Power factor control and reactive power control are only available when the unit operates in parallel with an electrical grid. Droop control is available for both parallel with grid and island operation.

4.5.3 Voltage droop control

Voltage droop control has similar characteristics as speed droop control, but the parameters are different. In voltage droop control, the intention is to control reactive power by means of controlling the generator excitation or the power converter for units using power electronics. The droop principle uses the system voltage to

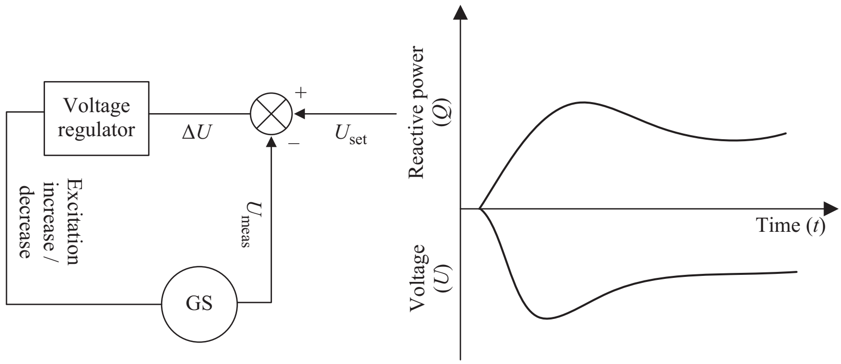

Figure 4.20 Schematic overview of droop system response to a sudden change in voltage

find a reactive power operational point and load sharing between generator units. This means that if a unit is running in voltage droop control, the reactive load will vary as a function of the voltage. The changes in reactive load will be shared among parallel units in proportion, providing that the droop settings and nominal voltage are the same. Normal droop range lies between 2% and 8%, where 4% is a commonly used droop setting (Figure 4.20).

4.5.4 Power factor control

Power factor control is a method of controlling the generator excitation and reactive load when the generator is running in parallel with the grid. When in power factor control, the AVR is trying to match the reactive load proportionally to the active load so that the set reactive to active power ratio is maintained. In this control mode, voltage is still measured but used for safety only, preventing the generating unit to go into too high or low voltage (Figure 4.21).

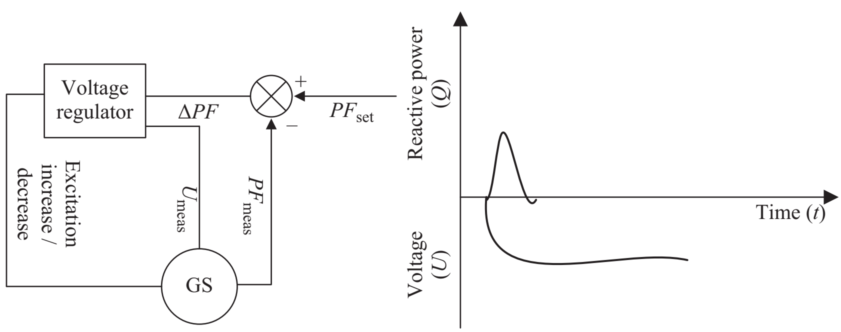

Figure 4.21 Schematic overview of a power factor control system response to a sudden change in voltage

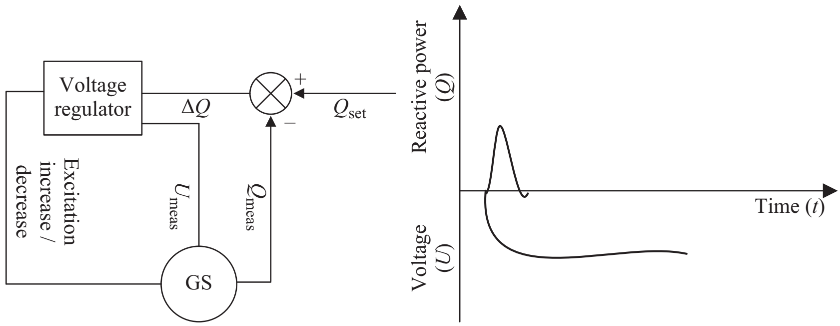

Figure 4.22 Schematic overview of a fixed VAR control system response to a sudden change in voltage

4.5.5 Constant reactive power control

Constant reactive power control, or VAR control, is a method of controlling the generator excitation and reactive power when parallel with grid. In this control mode, the AVR tries to match the reactive power set-point given by the operator, independently of the active power. In this control mode, voltage is still measured but used for safety only, preventing the generating unit to go into too high or low voltage (Figure 4.22).

4.5.6 Conclusion on reactive power control strategies

The choice of reactive power strategy depends on many different variables, such as electric network environment, prevailing regulation and others. Simple droop control has again many advantages, especially the possibility to parallel different generating units and allow those to share reactive load without an extensive communication infrastructure. Droop control is also considered a 'safe' operation mode when operating in an islanded network. Fixed output controls such as power factor control or fixed reactive power or VAR control gives the possibility of operating the cogeneration unit to a target reactive power output, irrespective of voltage variations as long as those are within the equipment limits. Power factor control allows for an automatic increase/decrease in reactive power delivery according to the set power factor whereas a fixed VAR control allows for a control of reactive power independent of the active power.

Acronyms

AC	alternating current
AVR	automatic voltage regulator
CB	circuit breaker
DC	direct current
EMC	electromagnetic compatibility

ES	excitation system
G/MG	induction generator–motor
GS	synchronous generator
LV	low voltage
MV	medium voltage
PMG	permanent magnet generator
rpm	revolutions per minute
VAR	volt ampere reactive

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Chapter 5

Applications of cogeneration

Jacob Klimstra

5.1 Introduction to applications of cogeneration

The most usual way of classifying the applications of cogeneration is by the sector where they appear, while the most important sectors of cogeneration applications are the following:

- Utility sector
- Industrial sector
- Commercial sector (also called 'building sector' or 'commercial–institutional sector')
- Agricultural sector

Highlighting the various applications in the aforementioned sectors is the main scope of this chapter. Furthermore, the interest in integrating cogeneration with renewable energy is increasing; therefore, brief-related information is also given. In addition, desalination is of particular importance in areas with scarcity of water. The possibility of using cogeneration for desalination is also presented.

5.2 Cogeneration in the utility sector

In the utility sector, heat supply to customers via district heating systems has been common practice for many decades. This is especially the case in countries with cold winters such as Finland and many East-European countries. In the year 2012, district heating provided 9 per cent of the heating demand in the European Union [1]. The main fuel in this case was gas (40 per cent), followed by coal (29 per cent) and biomass (16 per cent). Finland and Sweden are examples of countries where much biomass is used for heating purposes, while natural gas is the main energy source for heating in Italy and the Netherlands. In most cases, the heat source is rejected heat from power stations. Also boilers fuelled by coal, biomass, oil or natural gas are used to produce the required heat. In hotter areas, such as the Middle East, district cooling systems exist, where customers are provided with cooling via chilled water. In traditional systems with poorly insulated metal pipelines, the heat losses of district heating systems can be substantial. In modern systems with properly insulated plastic pipes, the heat losses are low.

It is noted that users of the heat supplied by utilities, either through a district heating network or directly, can be not only buildings but also users such as industries, greenhouses, fisheries and water desalination plants.

Typical supply temperatures of district heating systems vary between 80 and 130 °C, while the return temperature can be as low as 60 °C. Lower temperatures are not allowed in hot water systems because of the risk of legionnaire's disease caused by bacteria development.

The role of large power stations for electricity supply is gradually decreasing because of the introduction of renewable electricity sources based on wind and sunshine. Smaller power stations fuelled by biomass are however gaining in importance for district heating. The role of utilities in the application of cogeneration systems will be more diverse in the future. In order to reduce the consumption of fossil fuels and the emission of greenhouse gases, integration of electricity use and that of heat and chill is imperative. Driven by for example municipal policy measures, local utilities increasingly draw up an overview of sources where heat is normally wasted and try to match the available heat with the local demand. Heat storage facilities and heat pumps, preferably driven by renewable electricity, are part of the new system and tend to at least partly replace back-up boilers. Even the energy requirement of inner-city transport such as by trams and possibly other electric vehicles will be an integral part of the system. Information technology will take care of a continuous optimum matching of heat and electricity production on the one hand and demand on the other. Cogeneration installations fuelled by natural gas or by biofuels can carry out much of the balancing and serve as a back-up in case of low wind and solar output. Most modern dwellings that are not connected with district heating will be equipped with electric heat pumps. The distribution of natural gas will be generally restricted to cogeneration installations and industries.

An example of a utility where the new approach has already been integrated is HanseWerk Natur GmbH. In 2015, this German utility operated 150 district heating systems in the metropolitan area of Hamburg and the States of Schleswig-Holstein, Mecklenburg-Vorpommern and Nordniedersachsen. The pipelines of their district heating systems cover a total length of 900 km. Next to natural gas, they convert biogas, landfill gas and sewage gas into electricity and heat. In addition to using their 200 own combined heat and power (CHP) units, HanseWerk Natur integrates the heat output of a number of cogeneration units owned by their customers into the district heating systems. Some 40,000 customers are provided with a total of 1.3 TWh of heat per year, equivalent to 4.7 PJ. Heat storage is an important part of the system, since it enables a decoupling of electricity and heat use patterns. HanseWerk Natur operates a combination of 65 cogeneration installations as a virtual power plant. This enables them to participate in the German power market by not only producing kilowatt–hours but also offering operating reserves and control power. Such a virtual power plant is very convenient in the German power system, which is characterised by a fluctuating output of a large installed base of solar panels and wind turbines. The benefit of having multiple individual CHP-generating units combined into a virtual power plant offers an unsurpassable high probability of complying with the capacity offered on the market. It also provides super flexibility in power output at a high efficiency. Heat storage is of course an essential element in this. The German government is convinced that a proper integration of electricity and heat production and use is the precondition for a further expansion of renewable energy. Also the European Commission sees this as a major tool in reducing the dependence on fossil fuels. Utilities are indispensable in this integration process, and cogeneration will be a major tool for them.

Incinerators for municipal and industrial waste require a minimum size, since much effort has to be put into cleaning of the exhaust gas. In addition, proper mixing of the waste streams is required to obtain a suitable combustible mixture. However, if the distance between the waste source and the incinerator becomes too large, the energy use for transportation becomes too high. Typical regional incinerators vary in size between 800 and 3,000 t of waste per day. The electricity production rate ranges between 500 and 900 kWh/t. The electric power output of incinerators is therefore between 15 and 65 MW. Their actual energetic performance depends on the composition of the waste and on the amount of heat supplied to heat users.

5.3 Cogeneration in the industrial sector

The industrial sector is a major user of heat and electricity. In the economically developed world, about a third of all primary energy use goes to industry. Industries such as brick factories and large-scale agricultural product dryers primarily use heat, while for example aluminium and copper smelters use almost only electricity. Many other industries, such as refineries, dairy factories and chemical process plants need both heat and electricity, albeit in different proportions. The optimum technique to be applied for industrial cogeneration depends on the characteristics of the industrial processes. Chemical process plants such as refineries operate continuously for time spans of around 1 year before maintenance is required. A cogeneration unit which is integrated into their processes should have an identical maintenance interval. In case high-pressure and high-temperature steam is required, a gas turbine as the prime mover is the preferred option. In case also a high fraction of hot water is needed, such as in the dairy sector, reciprocating engines can be used as the prime movers for the cogeneration installation. If the electricity price is considerably higher than the fuel price, meaning that a positive spark spread exists, a factory that primarily needs heat can decide to produce the heat with a cogeneration unit and export the electricity to the public grid or to a neighbour who needs much electricity. Alternatively, a factory that needs much more electricity than heat can sell the heat from the cogeneration installation to a neighbour or to a district heating system of a utility. In all these cases, the economic and legal boundary conditions have to be positive and stable during a long time span.

Governments are responsible for a fair and stable policy climate in this respect, if they want to achieve a long-term optimisation of energy use. Changing subsidy schemes and an inconsistent policy can turn an excellent possibility for energy savings via cogeneration suddenly uneconomic. A cogeneration installation is capital intensive and the amortisation easily takes some 5 years. A negative example is where emission levies and taxes on natural gas can raise the gas price to 10 €/GJ, whereas the wholesale price of electricity is only 36 €/GWh equalling 10 €/GJ due to subsidies for renewable electricity sources.

A few examples of cogeneration applications in industries are presented in the following.

5.3.1 Cogeneration for a paper mill

An example of industrial cogeneration is a paper mill that processes 650,000 t of recovered paper per year and turns it into corrugated cardboard for the packaging sector [2]. Some 100 truckloads with recovered paper arrive at the factory gates each day. The one million bales of recycled paper are processed in the factory during 360 days/year; the process only stops in the week of Christmas. The input flow of recycled paper is first cleaned of dirt and ink. The cleaned solution of 1 per cent of paper fibre in water has to be substantially dehydrated. The first step in this process is based on gravity and vacuum processing and does therefore not require much energy. The next step is pressing of the fibre sludge, which also requires not much energy. Heat is required for the removal of the final amount of water from the fibre. To this end, the moist fibre passes two trains of large cylinders that are heated by steam. Four gas-turbine-driven cogeneration installations in parallel have each an electric power capacity of 3.6 MW. They provide the bulk of the electricity and heat required for the paper treatment process. Three of the four units have a heat recovery only boiler. One unit has a boiler that facilitates supplementary firing for creating some flexibility in the production of steam. The electrical efficiency of each cogeneration unit is close to 29 per cent and the total efficiency including heat utilisation is 88 per cent. In case no cogeneration would be used, the total primary energy use of the factory would be 27 per cent higher.

5.3.2 Cogeneration in the dairy and bakery industry

The dairy industry and industrial-size bakeries use much energy for product drying. In contrast with common belief, bread baking is primarily a drying process at relatively low temperature of 260 °C at maximum. In drying processes for dairy products, the maximum temperature is 200 °C, in order to avoid product damage and auto-ignition of the milk powder. In contrast with drying of agricultural products such as grass and alfalfa, indirect product drying with filtered and consequently heated air is most common in bakeries and dairy factories. Table 5.1 gives some typical specific energy demand values for dairy products.

Electricity demand in the dairy industry is roughly a quarter of the total energy demand. This means that a typical cogeneration plant produces more electricity than needed in a factory if the installation has to cover the full heat demand.

Table 5.1 Typical energy demand for dairy factory products [3]

Product	Specific energy use (MJ/kg)
Milk powder	11.9
Whey powder	14.2
Cheese	4.7
Pasteurised milk	1.2

In addition, many processes in the dairy industry are batch processes resulting in a variable energy demand. Nevertheless, many dairy factories have already a cogeneration plant. A typical modern spray dryer for milk and whey can have a capacity of up to 30 t/h, so the heat demand can be close to 100 MW. This is however still an exception and units of 1 t of product per hour are common practice. Expectations are that techniques such as steam recompression and electric heat pumps will increasingly be used in this industry sector, thus increasing electricity demand and lowering heat production demand. This will improve the matching of a cogeneration plant and remove the need to export much electricity to the grid.

In bakeries, about 5 MJ of energy is needed to process 1 kg of flour into edible products. The ratio between electricity use and heat use depends on the size of the ovens and the local energy price. In countries without a gas grid, it is common practice to use oil or electricity for heating the ovens. In a gas-based bakery, the electricity demand is about a fifth of the total energy demand. Baking is a typical batch process, and it generally takes place in the early morning when the public electricity demand is relatively low. Exporting excess electricity to the grid is therefore not a realistic option. Typical industrial ovens have a heat demand between 150 kW and 1 MW. The industrial bakery sector is therefore not a priory a convenient application of cogeneration. An option is to install a combination of electrical ovens and hot-air ovens to facilitate the use of cogeneration.

5.3.3 Cogeneration in the beer brewery industry

A typical figure for the energy consumption of industrial beer production is between 0.8 and 1 MJ/l. As a rule of thumb, a third of this energy use is as electricity and two-thirds is for heating purposes. Bottling and boiling are responsible for viz. 30 per cent and 23 per cent of the heat demand. Cooling the end product consumes about 40 per cent of the total electricity use. Cogeneration of electricity and heat offers therefore a good possibility for primary energy savings in the brewing industry. In case generating sets with a high electric efficiency are used, electric energy has to be exported to the grid when the cogeneration installation covers the whole heat demand. It is not absolutely necessary to use steam for the cleaning process of the bottles; hot water of close to 100 °C is sufficient, and therefore, reciprocating engines and gas turbines can both be used in beer breweries.

A typical brewery with an annual production of 500 million litres can accommodate a cogeneration plant of about 5 MW of electrical power. The primary energy savings compared with central electricity generation are almost 20 per cent. An example of a large brewery is the Heineken facility in Zoeterwoude, the Netherlands, where 1,350 million litres of beer are produced per year. Heineken uses cogeneration in order to lower its CO_2 and primary energy footprints.

5.3.4 Cogeneration in a sewage sludge incineration plant

The sewage streams of cities and municipalities in most developed countries are treated before the effluent is released to open water systems. In many cases, the biogas resulting from the fermentation process is used in reciprocating engines to produce electricity for the public grid and heat for the treatment process. A residual product of sewage treatment is sewage sludge. This sewage sludge has to be incinerated in order to remove leftovers from medicines, hormonal material and toxic organic elements. As an example, the sewage of the close to 17 million inhabitants of the Netherlands results in about 1.5 million tonnes of sludge per year. SNB in the province of Noord-Brabant processes 30 per cent of this sludge, and this makes the facility the largest operating one of its kind in the world (Figure 5.1).

The SNB plant receives 50 truckloads of sludge every day. The sludge as delivered by the trucks consists of 75 per cent of water, since otherwise, it cannot be pumped and handled. Before the sludge enters one of the four incinerators in

Figure 5.1 The insertion of the heat recovery steam generator in a sewage sludge plant (photograph by www.voog.nl and courtesy of NEM)

parallel, it is dried to a slurry with 40 per cent solid material. The heating value of this slurry is sufficiently high so that it can burn without an external fuel supply. The 24 h/day–7 days/week incineration process releases so much heat that enough steam can be produced for the pre-drying process and for removal of the ammonia from the condensate. In addition, two incinerators have been equipped with 60-bar steam boilers, thus making available sufficient steam to drive a steam-turbine generator with a power capacity of 3.5 MW. That covers the bulk of the electricity demand of the pumps, ventilators and the electrostatic dust filters. It makes the incinerator facility by 95 per cent self-sufficient with respect to energy. In this case, a combustion process with a heat-recovery steam generator and a steam turbine is producing the driving power for the cogeneration installation instead of a reciprocating engine or gas turbine. An interesting aspect of this installation is that part of the exhaust gas is led to a neighbouring facility, where the CO_2 is used for lime production. This further lowers the ecological footprint of the process.

5.4 Cogeneration in the commercial sector

Hospitals, hotels, swimming pools and data handling centres are examples where the demand for electricity per unit of area is quite high. An indoor swimming pool with dimensions of 50 m by 25 m in a moderate climate requires on the average 1 GWh of electricity and 10 TJ of heat per year [4]. Much of the electricity is needed for the pumps and the ventilation equipment. The ratio of thermal energy to electrical energy is therefore about 2.8, which is very suitable for a cogeneration installation. A cogen unit with an electric power of 120 kW matches well with such an energy demand. The combined efficiency of such a cogeneration unit can be very high, since the relatively low water temperature allows for at least a partial condensation of the water vapour in the exhaust gases.

5.4.1 Cogeneration in hotels

The specific energy use per square metre of hotels depends largely on the location, the national building regulations, the size of the hotel and the facilities offered. An in-house swimming pool, laundry services and catering all increase the energy demand. In hot areas, air conditioning can consume much energy. A higher luxury level also tends to increase the specific energy use. Reference [5] gives a good overview of typical energy consumption values of hotels. The electricity use varies between 70 and 250 kWh/m^2/year, while heating consumes between 350 MJ/m^2 and 2 GJ/m^2/year. Domestic water heating requires between 400 and 800 MJ/m^2/year. Taking a 10-min shower at home costs roughly 25 MJ. By presuming an average hotel room area of 40 m^2, with 60 per cent occupancy, this would turn into a heat demand of about 140 MJ/m^2/year. However, the costs of a shower are included in the room rate and many hotel guests take a long shower in the morning as well as one in the evening. Further, much hot water is required for daily cleaning and for the restaurant kitchen. For a hotel with 100 rooms of 40 m^2 each, an annual electricity use of 0.5 GWh can be a good estimate. The fuel demand for heating and domestic water of 6 TJ/year can be a good average value. In such a case, a cogeneration installation of around 100 kW that runs primarily in the evening hours, when the electricity consumption peaks, can offer good energy savings. A combination with heat storage will facilitate the matching of the cogeneration installation. The unit can also provide emergency power in case of grid problems.

5.4.2 Cogeneration in hospitals

A hospital requires even more energy per square metre than a hotel. An example of an integrated cogeneration installation can be found at the academic hospital of Utrecht, the Netherlands. In a hospital of such a size, with approximately 1,000 beds and a polyclinic, the electricity demand can be between 2.6 and 9 MW depending on the local circumstances. The heat demand lies between 3 and 15 MW, while the chill demand ranges between 2 and 12 MW. A total of 4 MW for electricity, 6 MW for heat and 6 MW for chill can be taken as average values. This offers excellent opportunities for cogeneration. The hospital in Utrecht has three gas-engine-driven cogeneration units, each one with slightly more than 2-MW electric power output that can run in parallel to the public grid. Hot water is produced with the heat from the jacket water and the intercoolers of the three engines. Steam is produced by leading the exhaust gas around 400 °C to a heat-recovery steam generator. The steam is used to drive an absorption chiller and finds application in other purposes such as cleaning. A separate gas-fuelled steam boiler is used for balancing the steam demand.

Normally, the cogeneration units run in parallel to the public grid. The grid is used for electrical balancing and for back-up in case of tripping of an engine and in case of maintenance. If the grid fails, use can shortly be made of an uninterruptable battery-based power supply during which time a diesel engine starts up automatically. Electricity for the priority users such as operating theatres is ensured all the time, while the other users are reconnected as soon as the diesel unit and the cogeneration units produce sufficient electricity. Figure 5.2 schematically illustrates the installation.

In order to optimise the utilisation of the investment in the cogeneration installation, the Utrecht hospital has matched the installation in such a way that only the average demand for electricity can be produced. This means that during the day-time peak, electric energy will be imported from the grid. This is illustrated in Figure 5.3, where the solid line gives the typical pattern of the electricity demand during a day. During the night, only two cogeneration units are running at about 60 per cent of their nominal output, in order to create instantaneous back-up capacity in case one unit trips. Exporting electricity to the grid during the night is uneconomic because of the then low electricity price. From 7 a.m. to 11 p.m., all three units are running at about nominal output. Some electricity is exported between 7 a.m. and 8 a.m. as well as between 6 p.m. and 11 p.m., when electricity prices are favourable, especially during the wintertime. This approach is an example that can apply for many cogeneration opportunities.

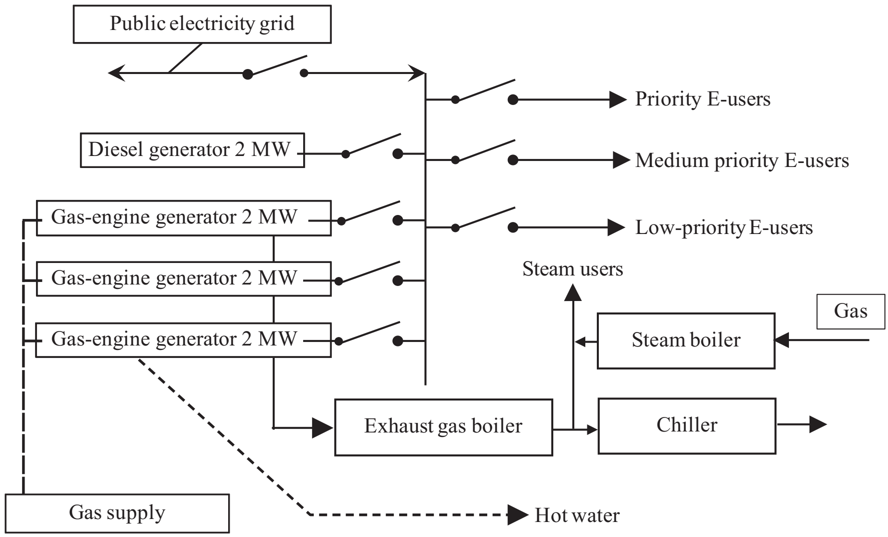

Figure 5.2 Schematic representation of the energy supply installation of a hospital

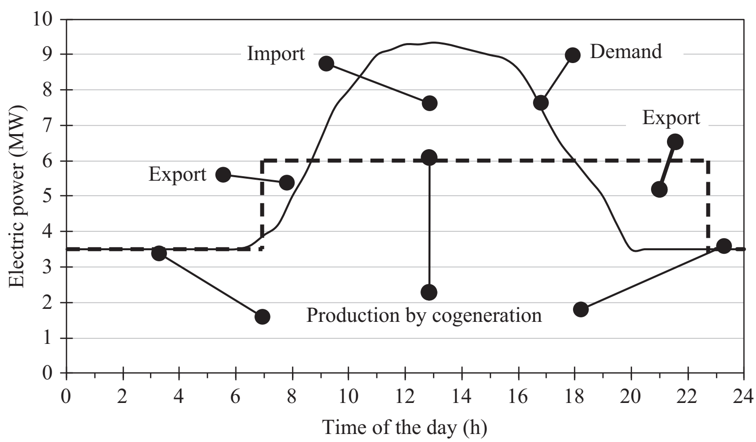

Figure 5.3 Example of a running strategy for the electricity production by a cogeneration plant of a large hospital

5.4.3 Cogeneration for data centres

According to [6], data centres that handle and store the huge amount of data in the world consumed about 416 TWh of electric energy in 2015. That was about 3 per cent of the global electricity supply. It is expected that the use of data centres will drastically increase in the near future, resulting in a doubling in energy demand every 4 years. The data processing equipment uses a large fraction of the electricity supply and most of the heat released has to be cooled away. In countries with cold climates, this cooling can be done by using ambient air or water. In many locations, however, heat pumps ensure that the excess heat is removed from the data processing and storing equipment.

The fact that power demand for data handling and that for cooling are close to the same, cogeneration of electricity and chill can be effectively applied. Primary energy savings can amount up to 40 per cent when using the heat rejected from the prime movers for absorption chilling. Using multiple prime movers in parallel can improve the security of energy supply which is crucial for data centres. This is especially of interest for the larger units with a power demand in the 100-MW region.

5.5 Cogeneration in the agricultural sector

5.5.1 Greenhouse applications

For many decades, cogeneration has been an energy-efficient solution to cover the energy needs of greenhouses in moderate and colder climates. Such greenhouses have to be heated to create an optimum growing climate for the plants. In addition, in order to increase productivity in case of no sunshine, artificial assimilation lighting is used to stimulate growth. Furthermore, the exhaust gas of the cogeneration units is used to supply CO_2 to the plants. In a closed greenhouse, the concentration of CO_2 is rapidly decreasing because the plants use it for building carbohydrates via photosynthesis. Plants show the highest growth rate if the CO_2 concentration in the surrounding air is roughly a factor two higher than that in ambient air. This depends to some extent on the type of crop. Before the exhaust gas of a cogeneration installation can be fed into the greenhouse, it has to be catalytically cleaned to reduce the NO_x and ethylene/ethene (C_2H_4) concentrations to very low values to avoid damage to the crop. Ethene is a ripening agent for plants signalling to neighbouring plants that their seeds have to be released. This release of seeds is commonly called a rotting process. The maximum allowed concentration of ethylene in the greenhouse is 8 ppb, while that for NO is 250 ppb and for NO_2 it is 130 ppb [7]. The required cleanliness of the catalytically treated exhaust gas depends on the dilution factor in the greenhouse and the ventilation factor. It is imperative to have sensors in the exhaust that check the outgoing concentration of the harmful species. The cleaning technology is common practice for a number of decades already.

The heating demand of a greenhouse depends to a large extent on the ambient conditions such as the outside air temperature and the amount of sunshine. Further, the construction of the greenhouse has an effect. The sun typically provides some 30 TJ/ha of heat per year in a moderate climate. To keep the greenhouse warm during times of little sunshine and low ambient temperature, an additional 10 TJ/ha/year is on average required. If this additional heating takes place in a presumed time span of 2,500 h, the average power capacity of the heat supply is about

1.1 MW/ha. A gas-engine-driven cogeneration installation with an electric power of 800 kW is able to provide this heat capacity. Using assimilation lighting can roughly double the per hectare product yield of a greenhouse. An installed power capacity for sodium lamps of 60 W/m^2 is a typical value for assimilation lighting [8]. That equals 600 kW of electric power per hectare. A cogeneration installation with a heat accumulator and an auxiliary boiler therefore nicely matches the average heat and electricity demand of a greenhouse. In most cases, the cogeneration installations run in parallel with the public electricity grid so that it is possible to export electricity in case of attractive prices during peak demand in the grid.

Notwithstanding the good match of heat and electricity demand in greenhouses, the application of cogeneration based on natural gas-fired installations is threatened. Better insulated greenhouses, heat supply based on waste heat from third parties, solar heat stored in aquifers during hot time spans and cheap electricity from wind turbines during the night all diminish the opportunities for cogeneration in greenhouses. Replacing sodium lamps by light emitting diode (LED) lights reduces the electricity demand by some 50 per cent. Yet, opportunities exist for cogeneration installations that can act as back-up for wind- and solar-based electricity. In that case, proper remuneration should exist for the back-up capacity and the ancillary services.

5.5.2 Product drying

Cogeneration is energetically a good option for the local drying of crops such as grass, and alfalfa that will be used for cattle feed. In this case, the exhaust gas is diluted with ambient air that is preheated by making use of the low-temperature heat of the cogeneration installation, including the radiation heat. The resulting flow has a temperature of around 200 °C. Higher temperatures will deteriorate the product quality and increase the risk of fire. An installation with an electric power of 600 kW matches the heat demand of a typical dryer. A bottleneck is at times the low price of coal compared with that of gas in combination with a low remuneration for electricity exported to the public grid.

5.6 Cogeneration in combination with renewable energy

Figure 2.10 in Chapter 2 has already shown a solution how cogeneration can act as a balancer and integrator for electricity from wind turbines and solar panels, while natural gas generally is the fuel of choice. Cogeneration installations can also use biogas, bio-oil or biomass. In case of a direct use of biomass, a combustion process in a boiler is converting the biofuel energy into heat, which produces steam to drive a turbine–generator combination. Sewage gas and landfill gas are commonly used in cogeneration installations. Anaerobic digesters can convert biomass into biogas suitable for use in gas turbines and reciprocation engines. Pyrolysis is another methodology where biomass is heated to produce the so-called product gas consisting of hydrogen, carbon monoxide, carbon dioxide and nitrogen. The challenge with pyrolysis gas is to sufficiently remove soot. Soot has a detrimental effect on prime movers, since it creates deposits inside the prime movers.

A typical example of cogeneration based on residues from farming is the mesophilic fermentation of maize, grain residues and liquid manure to produce biogas consisting of about 60 per cent methane and 40 per cent carbon monoxide. Also verge grass from motorways can be used as a feedstock for this. Such grass is not suitable for cattle feed because of deposits from traffic. Care should be taken that the proper mix of biomass is offered in the digester. Part of the heat is needed to keep the fermentation at a temperature between 25 and 40 °C. Mesophilic bacteria perform best at this temperature range. The electricity use of the digester installation itself is relatively low and the bulk of the electricity produced has to be fed into the local distribution grid. A high fraction of the heat can be used to heat buildings in the vicinity or for example greenhouses.

Examples exist where a neighbouring asparagus grower uses the heat to keep the soil at a temperature suitable to increase productivity and to extend the growing season. The fermentation process makes biogas that is saturated with water vapour. This water vapour has to be removed from the gas before it is supplied to the prime mover. Otherwise, the gas might pass a cold pipeline section and condensation might occur, especially in the wintertime. Condensation should be avoided at all costs, since a swallow of liquid or a continuous liquid stream has a destructive effect on prime movers. Properly designed biogas installations are therefore equipped with a gas dryer directly after the fermentation process followed by a heater, while the transport pipes to the prime mover are insulated to prevent condensation of the residual moisture in the gas. A typical cogeneration installation running on farm residues has an electrical output between 2 and 10 MW.

Much larger biomass using installations, with an output power of several hundred megawatts, use fluidised bed gasification of the biomass. Here, the combustion process is controlled with oxygen or steam supply in such a way that under-stoichiometric combustion takes place. In this case, the properties of the biomass or the residual fuels are of less importance. It is even possible to partly use coal or peat in the process. The product gas can be fed into an existing boiler to produce steam for a steam turbine whereas the heat released can be used for district heating or in a process plant [9].

5.7 Cogeneration and desalination

The availability of fresh water of good quality is considered identically crucial to society as the availability of affordable energy. Some regions in the world are that arid that fresh water is insufficiently available anyhow for providing drinking water and water for irrigation. In other places, the consumption rate of water has risen so drastically that the natural replenishment is by far insufficient. Population growth and global warming also play a role in increasing the scarcity of fresh water. The world is covered for a large part by oceans, but the typical salt content of seawater is close to 3.5 per cent, which is way too high for drinking water and irrigation.

Reverse osmosis with semipermeable membranes is increasingly used nowadays to produce fresh water from seawater. Electric energy is needed to power the pumps that drive the permeation. The specific electricity consumption lies between 3.5 and 5.5 kWh/m^3. In case free heat is available from power stations, distributed generation or industries, multi-effect distillation or multi-stage flash distillation (MSF) form an energy efficient cogeneration option [10,11]. The typical heat demand for MSF is 290 MJ/m^3 of water produced. The temperature of the heat used for MSF ranges between 90 and 110 °C. The electricity use is about 3 kWh/m^3. This means that an electricity-generating unit of 20 MW having 40 per cent electrical efficiency and consequently a heat availability of close to 22.5 MW can produce about 280 m^3 of fresh water per hour. The electricity consumption of the distillation process is only 4 per cent of the output of the generator.

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Chapter 6

Fuels for cogeneration systems

Jacob Klimstra

6.1 Introduction

Technically, any fuel can be used as a source of primary energy for cogeneration. Biomass, municipal waste, fuel oil, coal, gaseous fuels, and even nuclear fuel can be used in case the fuel conversion technique has been designed to use that kind of fuel. A coal-fired power plant can co-fire biomass in case either the combustion system or the fuel has been adapted. Special reciprocating engines, the so-called dual-fuel engines, can instantaneously switch over from a liquid fuel to a gaseous fuel and vice versa during running. Gas turbines and gas engines can run on a wide range of gases, but tuning to a typical gas quality is required for optimum performance. Nuclear power plants can supply hot water for district heating, but their primary energy supply is limited to nuclear fuel. Biogases have to be cleaned from certain components before they can reliably be used. In almost any case, a specific cogeneration technique can only perform well on a narrowly defined fuel quality for which it has been tuned.

This chapter will highlight the properties of fuels of interest for cogeneration systems and discuss the consequences for the combustion process and the emissions. The fuel properties partly determine the fuel efficiency and the emissions. Also combustion velocity and combustion stability are important issues. Examples of typical fuel properties are the volumetric or mass-based heating value and the minimum specific air requirement for complete combustion. The ignition range and auto-ignition properties are other properties of interest. Exceeding the fuel quality range for which the process has been tuned can introduce serious safety and performance issues. There is a direct relationship between the fuel composition and the carbon dioxide (CO_2) emissions, but also other undesirable combustion end products depend on the fuel composition.

6.2 Types and properties of fuels

6.2.1 Gaseous fuels

6.2.1.1 The heating value

There is general agreement on the definitions for the heating value of a fuel (also known as calorific value), but the boundary conditions differ to some extent.

The higher heating value, H_h (also known as upper, gross or superior heating value), is the amount of energy released by complete combustion of the fuel at a constant absolute pressure of 101.325 kPa, when the combustion products have been cooled to the starting conditions while the water produced by the combustion process is fully condensed. For the lower heating value, H_l (also known as net or inferior heating value), the water in the combustion end products is not condensed at the starting conditions. A gaseous fuel such as carbon monoxide (CO) does not contain hydrogen, so that the upper and lower heating values are the same. As the starting and end temperature for the combustion process, either 298.15 K or 288.15 K is used in the various standards, and this is causing some confusion. Using 298.15 K (25 °C) seems more relevant than 288.15 K, since cooling the combustion end products to below 25 °C is hardly practical. The difference in the heating value resulting from the two reference initial and end temperatures is not significant for most applications, especially when H_l is concerned. In case, the heating value is expressed per unit of volume of the gas, the so-called volumetric heating value in MJ/m^3, the temperature chosen for the density of the gas has a noticeable effect. Some standards use 273.15 K (0 °C) for calculating the density, but others use 288.15 K (15 °C). The density of a certain gas at 288.15 K is lower than that at 273.15 K by a factor 0.95, and the volumetric heating value is consequently also lower by that factor. In this chapter, a temperature of 273.15 K will be used for the density. If the heating value is gravimetric, which is mass-based (MJ/kg), the temperature for which the density applies plays no role. Heating values of gases are increasingly expressed in kWh (1 kWh = 3.6 MJ), but this chapter will not follow that. The kWh is not a coherent SI unit, and it was traditionally reserved for use in the case of electric energy.

In energy conversion techniques such as gas turbines, gas engines and high-temperature fuel cells, condensation of the water vapour in the combustion end products is not possible in the machine itself. A proper comparison of the fuel efficiency of these techniques is only relevant for the performance of the application if the lower heating value of the fuel is used. The use of the lower heating value is therefore a common practice in performance data sheets for these techniques. In cogeneration applications however, condensation of the water vapour in the exhaust can be possible and that is why for the energy balance of the total installation, the higher heating value is sometimes used. In some applications, such as for greenhouse soil heating, most of the latent heat from the condensation is captured and used. That might lead to an efficiency exceeding 100 per cent, if based on the lower heating value. Therefore, the higher heating value is sometimes used for the energy balance of the installation. In this chapter, the lower heating value of the fuels will be used unless otherwise stated.

The gravimetric heating value of gaseous fuels consisting of pure hydrocarbons does not show large differences from fuel to fuel. The volumetric heating value of these hydrocarbons increases, however, substantially with the density of the fuel. Table 6.1 gives the heating value of a number of common basic gases [1]. The conditions for the volume given are often referred to as the 'normal' conditions, with the symbol Nm^3 or m^3(n) for the normal cubic meter, or 'standard' conditions. Using an N in the unit is confusing, since it is the symbol for the newton, the unit of force in the SI system.

Gas volume flow meters are commonly used with cogeneration installations to measure the amount of consumed fuel energy. Such meters are equipped with pressure and temperature sensors that convert the operating conditions into the standard conditions. They also serve to show the instantaneous energy flow into the installation for performance monitoring purposes. Variations in the heating value of the fuel give rise to inaccuracies in the measured energy supply, unless a calorimeter continuously measures the actual volumetric heating value. Pipeline natural gas and liquefied natural gas (LNG) consist of multiple components, although the volumetric methane content is generally more than 80 per cent. Gases with a heating value higher than that of methane are often called high calorific gases. Gases with a large fraction of inert gases such as nitrogen (N_2) or CO_2 are called low calorific gases. Biogas can contain up to 45 per cent of CO_2, whereas some gas fields have natural gas with up to 15 per cent of nitrogen or in some cases up to 40 per cent of CO_2.

6.2.1.2 The stoichiometric air requirement

The composition of a fuel determines the specific stoichiometric air requirement of that fuel. The stoichiometric air requirement of a fuel is the minimum amount of air theoretically required to ensure complete combustion. It is the oxygen (O_2) in the air that is required for the oxidation of the fuel. The oxygen content of ambient air depends primarily on the relative humidity of the air. Dry air contains 20.94 per cent of oxygen. Standard wet air can be defined as air at 20 °C with a relative humidity of 50 per cent [1]. Such standard wet air contains 1.15 per cent of water vapour and 20.70 per cent of oxygen. In tropical areas, the relative humidity can be, for example, 100 per cent at 35 °C. The water vapour volume is then 5.5 per cent, and the oxygen content is only 19.8 per cent. It will be clear that more air is required for complete combustion in the case of a higher relative humidity of that air. The specific standard wet air requirement for stoichiometric combustion of the gases in Table 6.1 is given in Table 6.2.

Table 6.1 The volumetric and gravimetric heating value of a number of gases (conditions 101.325 kPa and 273.15 K for the volume, 288.15 K for combustion) [1]

Gas	**Symbol**	**Density (kg/m^3)**	**H_i (vol.) (MJ/m^3)**	**H_i (grav.) (MJ/kg)**	**H_s (vol.) (MJ/m^3)**	**H_s (grav.) (MJ/kg)**
Methane	CH_4	0.717	35.882	50.044	39.819	55.536
Ethane	C_2H_6	1.355	64.353	47.493	70.305	51.886
Propane	C_3H_8	2.011	93.207	46.349	101.234	50.340
Butane	C_4H_{10}	2.701	123.466	45.711	133.691	49.497
Pentane	C_5H_{12}	3.454	156.629	45.347	169.269	49.001
Hydrogen	H_2	0.090	10.779	119.767	12.741	141.567
Carbon monoxide	CO	1.250	12.634	10.107	12.634	10.107

Table 6.2 The standard wet air requirement or stoichiometric air requirement of certain fuel gases (reference conditions 273.15 K, 101.325 kPa; values in m^3/m^3 [1])

CH_4	C_2H_6	C_3H_8	C_4H_{10}	C_5H_{12}	H_2	CO
9.67	17.06	24.66	32.67	41.43	2.41	2.41

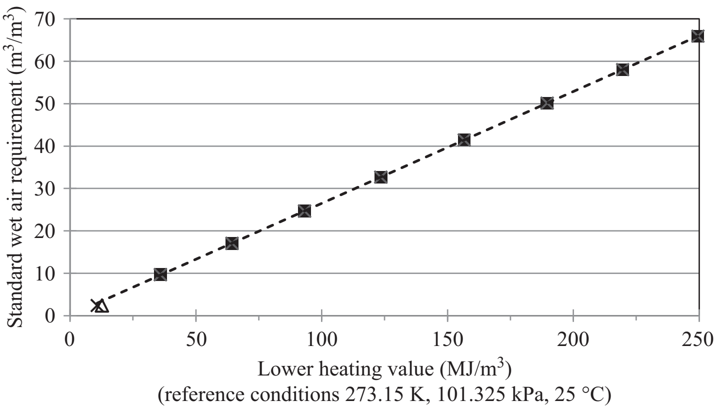

Figure 6.1 The stoichiometric standard wet air requirement depending on the lower heating value of the alkanes, CO and H_2 [1]

It appears that the standard wet air requirement for stoichiometric combustion of the alkanes (C_nH_{2n+2}), is linearly proportional with the lower heating value (Figure 6.1). The alkanes are the major energy carriers of natural gas. Even CO, indicated by the *x* in Figure 6.1, closely follows the line for the alkanes. Hydrogen, indicated by the triangle, has a slightly lower specific air requirement than the alkanes. This linear relationship is quite useful in practice, since if the lower heating value of a fuel gas of unknown composition is available, its stoichiometric air requirement can easily be estimated.

6.2.1.3 The Wobbe index

For cogeneration applications, the Wobbe index of gaseous fuels is an important quality indicator. In almost all gas applications, a pressure difference is used to force the gas through a flow restriction into the combustion air. For a given restriction with coefficient c and a fixed pressure difference Δp, the gas flow rate $\dot{V}_{gas}$ through the restriction depends only on the density of the gas:

$$\dot{V}_{gas}^2 = \frac{\Delta p}{c \cdot (1/2)\rho_{gas}} \tag{6.1}$$

As Δp and c are constant, this can be rewritten as:

$$\dot{V}_{gas} = k \cdot \sqrt{\frac{1}{\rho_{gas}}} \tag{6.2}$$

The energy flow rate $\dot{H}_{fuel\,gas}$ with the gas flow is the product of the volumetric lower heating value and the gas volume flow rate:

$$\dot{H}_{fuel\,gas} = H_l \cdot \dot{V}_{gas} \tag{6.3}$$

By using (6.2) for substituting $\dot{V}_{gas}$:

$$\dot{H}_{fuel\,gas} = k \cdot H_l \cdot \sqrt{\frac{1}{\rho_{gas}}} \tag{6.4}$$

If the right hand side of (6.4) is constant, the energy flow with the fuel gas is constant, even for different values of the gas density and the lower heating value. If the constant $\rho_{air} = 1.293\ \mathrm{kg}/m^3$ is added in the nominator of (6.4) in order to make the square root dimensionless, the Wobbe index (*WI*) with the unit MJ/m^3 results:

$$WI_l = H_l \cdot \sqrt{\frac{\rho_{air}}{\rho_{gas}}} \tag{6.5}$$

For a constant WI_1, the energy flow based on the lower heating value through a flow restriction is constant for a given Δp, and consequently the stoichiometric air requirement for that gas flow is constant. It generally means that, if the *WI* of a fuel gas is constant, no adjustments have to be made to the appliance if the gas composition changes. If the higher heating value is used for the *WI*, the subscript h is used instead of the subscript l. For most hydrocarbon-based gases, the WI_l is 90 per cent of WI_h. Limited changes in *WI* are often acceptable for the gas application. Since the air ratio λ varies inversely with the *WI*, large changes in the *WI* require correcting of the setting of the restriction in the gas supply. Automatic air-to-fuel ratio control systems can only correct for a limited range in *WI*. *WI* variations larger than ± 1.5 MJ/m^3 can give rise to issues with respect to fuel efficiency, harmful emissions and combustion stability. Table 6.3 gives a number of WI_l values for natural gases available in the world.

Table 6.3 Examples of values of the Wobbe index based on the lower heating value of certain commercially available fuel gases (reference conditions 273.15 K, 101.325 kPa and 25 °C; values in MJ/m^3)

Danish gas	**Libyan LNG**	**Qatar LNG**	**Groningen gas**	**Russian gas**	**Biogas**
45.40	51.42	49.42	39.51	47.92	21.27

6.2.1.4 Further gas specifications

Natural gas specifications also give the hydrocarbon dew point, the water dew point, and the maximum concentration of trace components such as sulphur and mercury. A typical value for the hydrocarbon dew point is −2 °C and for the water dew point −8 °C [2]. In very cold climates, these dew point values have to be lower, since condensation in the gas supply has to be avoided at any costs. Swallows of liquid hydrocarbons in the gas stream will lead to severe overload of the gas application and possibly to explosions. Water in the system can lead to corrosion and flame extinguishment.

Many natural gas standards have 30 mg/m^3 of total sulphur (S) as a maximum. Sulphur is often present in wellhead gas and removed by the gas supplier to a level compliant with the ruling standard. Many countries use so-called mercaptans as odorant in the gas for safety reasons; otherwise, leaking gas cannot be smelled. Mercaptans contain sulphur and therefore add to the total sulphur content of gaseous fuels. Sulphur causes SO_2 emissions leading to smog and acid rain, stimulates corrosion and causes a rapid ageing of oxidation catalysts. Sulphur-free odorants are available, and the suppliers of cogeneration installations advocate a drastic reduction of the allowed concentration of sulphur in the gas.

The concentration of other species, such as mercury and chlorides, are often restricted to the minimum detection level. Landfill gas contains xyloxanes, a contaminant containing silicon that originates from cosmetics such as shampoo. During combustion in gas turbines and gas engines, the xyloxanes will decompose and silicon will be released, which is destructive for the machines. Xyloxanes are often removed from the biogas with active carbon. The concentration of dust is also limited, since it can cause erosion and the build-up of slack.

The methane number (*MN*) as an important gas quality indicator has already been introduced in Chapter 3. Reciprocating gas engines show the best performance for a methane number exceeding 80. Most natural gases have a methane number higher than 70. The *MN* of gaseous fuels can be improved by removing part of the higher hydrocarbons. Removal of higher hydrocarbons is common practice at gas wells, where the gas is treated for pipeline transportation to the customers. Although reciprocating engines are able to use 100 per cent hydrogen ($MN = 0$) as a fuel, the engine power output is generally reduced in that case to less than 50 per cent of that for natural gas with a *MN* exceeding 80.

6.2.2 Liquid fuels

6.2.2.1 Liquid fuels for cogeneration applications

Liquid fuels are generally classified into crude oil, distillate fuels, residual fuels, and bio-oil. Crude oil is the raw material from the oil production wells. Distillate liquid fuels are produced from crude oil in a refinery and residual fuels are left-overs from the refinery process. Although liquid fuels are still frequently used in gas turbines and Diesel engines in power plants on remote locations and on islands, such sites are generally not suitable for cogeneration. Liquid fuels of fossil origin are therefore not common practice in cogeneration installations. If liquid fuels are used as an energy source for cogeneration, it is generally in Diesel engines. Petrol is a typical fuel for spark-ignition engines for transport applications. In dual-fuel cogeneration installations in applications where running independent from the public grid is crucial, such as in the case of hospitals and military sites, liquid fuels are used as a back-up for natural gas. Bio-oils such as palm oil and jatropha oil have been popular for a while as renewable energy sources, but questions arose with respect to the ecological impact and the costs. Tests with bio-fats gave rise to severe odour problems and excessive wear especially of the injection equipment due to the acidity and the poor lubricity. Attempts are also made to convert biomass into fuel oil via pyrolysis. Pyrolysis oils have however a very high acidity and are therefore not suitable for Diesel engines.

6.2.2.2 Typical quality indicators for liquid fuels

The heating value and the specific air requirement are less crucial properties for liquid fuels than gaseous fuels used in Diesel engines for the following reason. The fuel is injected into the combustion chamber and subsequently vapourises and mixes with the already compressed air via a diffusion process. The combustion chamber contains much more air than required for stoichiometric combustion. Changes in the heating value of the fuel will be automatically compensated for with the power output control system by adapting the duration of the fuel injection. The lower heating value of refined bio-oils and fossil-based Diesel fuels ranges between 38 and 44 MJ/kg.

A very important characteristic of liquid fuels for Diesel engines is their ignitability. For spark-ignited engines, a high auto-ignition temperature of the fuel is important, but for Diesel engines the opposite is required. The willingness to ignite of distillate Diesel fuels is expressed in the cetane number. Cetane has by definition a cetane number of 100, whereas alpha-methyl naphthalene was given a cetane number of 0. The cetane number of automotive Diesel fuels generally ranges between 46 and 60. The ignitability of residual fuels can be approached with the calculated carbon aromaticity index *CCAI* [3] based on the fuel density ρ in kg/m^3 at 15 °C and the kinematic viscosity ν in mm^2/s. T is the absolute temperature in Kelvin:

$$CCAI = \rho - 140.7 \log[\log(\nu + 0.85)] - 80.6 - 210 \ln\left(\frac{T}{323}\right) \tag{6.6a}$$

or

$$CCAI = \rho - 140.7 \log[\log(\nu + 0.85)] - 80.6 - 483.54 \log\left(\frac{T}{323}\right) \tag{6.6b}$$

Fuels with a *CCAI* below 840 will easily ignite in a Diesel engine. Diesel engines designed for heavy fuel oil can accept *CCAI* values of up to 870. Heavy fuel oil has also to be filtered upstream of the injection to remove water and undesirable components.

Other relevant characteristics of a liquid fuel are its kinematic viscosity and its density. The density affects the penetration depth of the fuel into the combustion chamber. A high-viscosity hampers an easy evaporation. A high kinematic viscosity requires a higher pumping pressure of the fuel pump, which increases the wear rate. Engines running on heavy fuel are equipped with viscosity control devices that decrease the viscosity by increasing the fuel temperature. Increasing the fuel temperature T also helps to improve the ignitability.

Further liquid fuel quality characterisers are ash content, water content, sulphur content and acidity. Ash consists of carbon residue and of minerals and additives in the fuel. Ash leads to wear of, for example, injection equipment and piston rings. Ash is also a source of dust emissions which are increasingly limited by legislation. Water causes wear in the injection system. Excessive sulphur in the fuel acidifies the lubrication oil resulting in early ageing and sludge formation. Lubricating oil has the ability to neutralise acid components to a certain extent. The additive package of the lubricant has always to be matched with the fuel and the engine. Sulphur stimulates corrosion of the engine parts and the exhaust system. It also causes harmful emissions of SO_2. Acidity of the fuel results in corrosion and subsequent erosion of the fuel injection system. Even a limited acidity can reduce the life of fuel pumps and injectors to just a few hundred hours. Table 6.4 is an example of a specification for bio-derived Diesel fuel.

6.2.3 Solid fuels

Solid fuels cannot be used directly by gas turbines, reciprocating engines and fuel cells. Cogeneration systems running on solid fuels are therefore primarily based on combinations of a boiler and a steam turbine. Wood is the very first fuel used by mankind, and it is professionally used for co-firing together with coal in large coal-fired plants. Smaller plants based on grate burners or fluidised-bed systems can operate on 100 per cent wood. Black coal and brown coal (lignite) are typically fuels for larger power plants. Other solid fuels are industrial and municipal waste and farm residues. Solid fuels generally require some treatment before they can be fed to a combustion system. Coal can be pulverised, wood can be ground to an acceptable particle size, and biomass can be upgraded by torrefaction. Torrefaction involves anaerobic heating of the biomass so that it loses moisture and becomes more brittle. Coal and lignite are popular fuels for power plants owners because of the low price per MJ. Restrictions on the CO_2 emissions of energy use are threatening the use of coal and lignite as long as carbon capture and sequestration is far from economic. According to [4], biomass and waste covered 10.3 per cent (57.8 EJ) of the total primary energy supply (TPES) in 2013, primarily in developing countries for cooking and heating. In 2013, coal, lignite and peat were responsible for 28.9 per cent of TPES. Reference [5] estimates that 7.5 per cent of electricity will be produced with biomass in 2050, compared with only 1.5 per cent in 2013. To ensure the required high fuel utilisation efficiency, most of this biomass should be used in cogeneration installations.

The heating value of solid fuels depends largely on the composition. Most types of wood with a moisture content of 20 per cent have a lower heating value

Table 6.4 An example of a specification for bio-derived Diesel fuel (courtesy of Wärtsilä

Property	**Unit**	**Limit**	**Test method reference**
Viscosity, max.	cSt at 40 °C	100	ISO 3104
Injection viscosity, min.	cSt	1.8–2.8	
Injection viscosity, max.	cSt	24	
Density, max.	kg/m^3 at 15 °C	991	ISO 3675 or 12185
Ignition properties			FIA test
Sulphur, max.	% mass	0.05	ISO 8754
Total sediment existent, max.	% mass	0.05	ISO 10307-1
Water, max. before engine	% volume	0.20	ISO 3733
Micro carbon residue, max.	% mass	0.30	ISO 10370
Ash, max.	% mass	0.05	ISO 6245
Phosphorus, max.	mg/kg	100	ISO 10478
Silicon, max.	mg/kg	10	ISO 10478
Alkali content (Na+K), max.	mg/kg	30	ISO 10478
Calcium, max.	mg/kg	50	ISO 10478
Flash point (PMCC), min.	°C	100	ISO 2719
Pour point, max.	°C		ISO 3016
Cloud point, max.	°C		ISO 3015
Cold filter plugging point, max.	°C		IP 309
Copper strip corrosion (3 h at 50 °C), max.		1b	ASTM D130
Steel corrosion (24/72 h at 20, 60 and 120 °C), max.		No signs of corrosion	LP 2902
Acid number, max.	mg KOH/g	5.0	ASTM D664
Strong acid number, max.	mg KOH/g	0.0	ASTM D664
Iodine number, max.		120	ISO 3961

of about 15 MJ/kg. The density of wood depends very much on its type: acacia has a density of 900 kg/m^3, while willow and poplar have only 450 kg/m^3. The water content is the major reason for the low lower heating value of wood: the heating (4.187 kJ/kg K) and especially the evaporation of the water (2.26 MJ/kg) takes much energy. This also applies, for example, for peat and lignite. Figure 6.2 illustrates how the gravimetric lower heating value of peat decreases rapidly with increasing water fraction. The attainable combustion temperature with moist fuels is consequently also lower than that for fuel oil or for natural gas. Table 6.5 gives some examples of the gravimetric lower heating value of a range of solid fuels.

The relatively low gravimetric heating value of coal compared with that of oil and natural gas stems from the fact that its energy content comes primarily from carbon, whereas it can have between 15 and 35 mass per cent of ash without any heating value. Pure carbon (C) has a lower heating value of 32 MJ/kg, whereas hydrogen, an important constituent of oil and gas, has 119.8 MJ/kg.

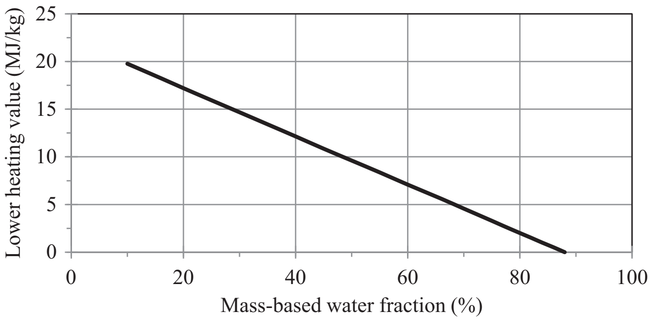

Figure 6.2 The lower heating value of peat depending on the moisture content [6]

Table 6.5 Examples of the gravimetric lower heating value of a number of solid fuels

Fuel	Lower heating value (MJ/kg)	Fuel	Lower heating value (MJ/kg)
Black coal (Indonesia)	25.7	Lignite (11% humidity)	22
Black coal (India)	17.3	Wood pellets (10% humidity)	20
Wood (20% humidity)	15	Household waste	24
Bagasse (40% humidity)	9	Industrial waste	12.5

6.3 Fuel- and combustion-related emissions

Combustion of fuels inevitably leads to emissions. The main species resulting from combustion are CO_2 and water (H_2O). Water vapour can locally lead to fog formation and absorption of sunshine by clouds emanating from the stack. CO_2 is a major greenhouse gas. High temperatures during combustion stimulate the production of nitrogen oxides (NO_x) from the nitrogen and oxygen present in the combustion air. NO_x can also result from oxidation of nitrogen present in the fuel. NO_x is poisonous, causes acid rain and plays a role in smog formation. Carbon monoxide, hydrocarbons and partially oxidised hydrocarbons such as aldehydes result from incomplete combustion. These species have certain toxicity and their concentration in exhaust gas is therefore limited by legislation in most countries. Sulphur is present in many fossil fuels and in some biofuels. Sulphur oxidises in a combustion process to SO_2. Solid fuels and heavy fuel oil often contain incombustible species (ash) resulting in dust emissions. Trace elements in fuel such as mercury, chlorides and zinc are undesirable from a health point of view. This section will further discuss the various undesirable emissions and highlight some abatement technologies.

Table 6.6 The specific CO_2 emission due to combustion of a number of fuels based on the lower heating value [1]

Fuel	Methane	Average natural gas	Propane	HFO	Black coal	Lignite
CO_2 (g/MJ):	54.8	56	64.6	80	98	109

6.3.1 Greenhouse gas emissions

CO_2 is the major greenhouse gas that is produced by combustion of fossil fuels, biofuels and waste. Other greenhouse gases are methane that results in case some natural gas escapes the combustion process, and nitrous oxide (N_2O) which can be produced in improperly tuned exhaust gas cleaning catalysts. The CO_2 emission per MJ of fuel energy depends very much on the fuel type. Table 6.6 gives some typical CO_2 emissions per unit of fuel energy based on the lower heating value.

The CO_2 emission to produce 1 kWh of electric energy with a cogeneration installation depends on the fuel and the energy conversion efficiency of the process. For a cogeneration installation running on natural gas with a fuel energy to electric energy conversion efficiency of 45 per cent, the CO_2 emission per kWh equals $56/0.45 \times 3.6 = 448$ g/kWh. The factor 3.6 stems from the fact that 1 kWh equals 3.6 MJ. However, the avoided CO_2 emission for such a cogeneration installation in the case of a combined fuel efficiency of 90 per cent is $56 \times 3.6/0.95 = 212$ g/kWh when presuming an efficiency of 95 per cent of the avoided separate boiler. The net CO_2 emission of the cogeneration installation for electricity production is therefore $448 - 212 = 236$ g/kWh. A coal-fired central power plant without utilisation of the released heat has a specific CO_2 emission of $98/0.45 \times 3.6 = 784$ g/kWh in the case of a fuel conversion efficiency of 45 per cent. The coal-fired power plant therefore produces a factor $784/236 = 3.3$ more CO_2 per kWh than the cogeneration installation in this example. This is a substantial achievement in reducing the CO_2 emissions by cogeneration compared with coal-fired generation. The figures for the coal-fired plant will of course be better if it is providing heat for a district heating system.

One might argue that carbon capture and storage (CCS) is much more difficult for smaller cogeneration installations than for a 1 GW coal-fired power plant. However, CCS is estimated to cost between 60 and 80 €/t of CO_2 removed. This turns to between 5 and 6 € cents per kWh of CO_2 removal costs, which will make central coal-fired generation uneconomic. It is also estimated that the extra energy required for capturing, transporting and storing CO_2 can reduce the fuel efficiency of the power plant by at least a quarter. That means that the basic CO_2 emission of such a coal-fired plant will be close to 1 kg/kWh. If CCS reduces the CO_2 emissions by 90 per cent, the remaining specific CO_2 emission of the coal-fired plant with CCS is still 100 g/kWh.

The current generation of reciprocating engines running on natural gas loses around 2 per cent of the fuel as unburned hydrocarbons, equalling roughly 400 mg/MJ of CH_4 based on the lower heating value of the fuel. For a fuel to electricity efficiency of 45 per cent, this equals 3.2 g/kWh. For a presumed mass-based CO_2 equivalent of 23 for methane (in other words, since methane has 23 times stronger effect than CO_2 as greenhouse gas), the additional emission of greenhouse gas, again as the CO_2 equivalent, equals $23 \times 3.2 \approx 74$ g/kWh. Engine manufacturers and catalyst developers are working on reducing the hydrocarbon emissions of reciprocating engines via design improvements and the application of oxidation catalysts. Sulphur in the fuel gas drastically reduces the life of oxidation catalysts, and it is, therefore, important to decrease the sulphur content of natural gas as much as possible.

6.3.2 NO_x emissions

NO_x in the exhaust gas of combustion installations originates primarily from nitrogen and oxygen present in the air required for oxidation of the fuel under the influence of high temperatures. This is the so-called Zeldovich mechanism. The production of NO_x can be minimised by sub-stoichiometric combustion, where the bulk of oxygen is consumed by the fuel. This results in high CO and H_2 production, which have to be removed catalytically or in a subsequent oxidation step with additional air.

In petrol-fuelled automotive engines, the three-way catalyst serves to reduce the emissions of CO, HC and NO_x. Stationary gas turbines and spark-ignited reciprocating gas engines generally use fuel-lean premixed mixtures. In this case, a three-way catalyst cannot be used, since a close to stoichiometric mixture is required for that. In fuel-lean mixtures the combustion temperature is so low that the NO_x production level is often sufficiently low to meet the legal emission limits. In some countries that have difficulties with the ambient air quality and excessive acidifying emissions, selective catalysts (SCR = selective catalytic reduction) are applied to decrease the NO_x production. This is also the case for Diesel engines, where the diffusion type combustion makes it impossible to create internal engine conditions to decrease the NO_x production as low as that of spark-ignited engines. In selective catalytic reduction, ammonia (NH_3) reacts with NO_x to produce nitrogen and water. Ammonia is very poisonous and therefore difficult to store and handle safely. That is why for cogeneration installations urea is preferred as the reducing agent. Urea decomposes in the hot exhaust gas upstream of the catalyst via so-called pyrolysis or thermolysis and produces ammonia.

A multiple of units is used to express the NO_x emission of combustion installations. Sometimes it is expressed as mass units per energy unit of the fuel (g/GJ), where for the fuel energy the lower heating value is used. Another way is to use g/kWh, where the kWh refers to the net electric energy produced. In legislation, often the mg/m^3 of dry exhaust gas is used for a fixed oxygen percentage of 3, 5, or 15 per cent in the dry exhaust gas. The measurement equipment applied gives the volumetric concentration in parts per million (ppm) in the dry exhaust gas. The ppms have to be converted into mass-based units by using the density of the species. For a cogeneration installation running on natural gas with an electrical efficiency of 45 per cent, 100 g/GJ (fuel) of NO_x equals 0.8 g/kWh (electric),

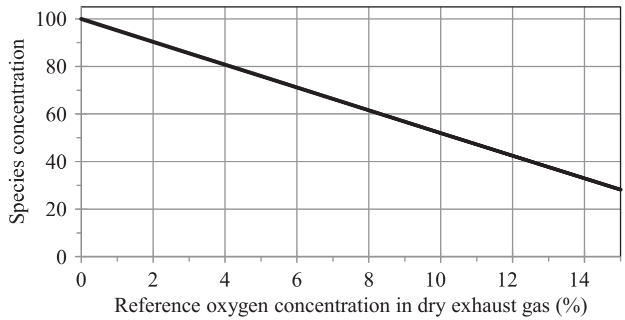

Figure 6.3 The species concentration depending on the reference percentage oxygen in dry exhaust gas

326 mg/m^3 at 5 per cent O_2 and 121 mg/m^3 at 15 per cent O_2 of dry exhaust gas. It equals 59 ppm at 15 per cent O_2 in dry exhaust gas. Figure 6.3 can help to convert the different concentrations depending on the reference value for oxygen. Conversions can be performed easily by applying the equation as follows:

$$c_{i,2} = \frac{20.95 - (c_{O_2})_2}{20.95 - (c_{O_2})_1} c_{i,1} \tag{6.7}$$

where $c_{i,1}$ is the concentration of species i in the exhaust gas corresponding to oxygen concentration $(c_{O_2})_1$, $c_{i,2}$ is the concentration of species i in the exhaust gas corresponding to oxygen concentration $(c_{O_2})_2$.

All concentrations in (6.7) are expressed in percentage points.

6.3.3 SO_2 emissions

Sulphur oxide emissions originate primarily from combustion of sulphur (S) components in the fuel. Lubricating oil can also contain sulphur, but the SO_2 emissions resulting from burning part of that oil are very low. Heavy fuel oil and coal, lignite and peat can have high sulphur concentrations. For coal, 1 mass per cent of sulphur is quite common, whereas lignite can have up to 3 per cent of S. Heavy fuel oil can have up to 4.5 mass per cent of sulphur. The molar mass of SO_2 is twice as high as that of S. For a lower heating value of 40 MJ/kg of the HFO and 1 per cent of S, the SO_2 emission is 500 g/GJ (fuel) and in the case of fuel efficiency for electricity production of 45 per cent, this turns into 40 g/kWh. The acidifying effect of SO_2 is a factor 1.44 higher than that of NO_2. Legislation has restricted the emission of SO_2 to such low values that power plants using sulphur containing fuels need exhaust gas cleaning equipment. Even a sulphur content of 30 mg/m^3 $\approx$ 0.004 mass per cent in natural gas, as the maximum specified in some standards, is too much to ensure an economic life of fuel cells and oxidation catalysts.

SO_2 can be removed from exhaust gas by injecting slurry of limestone ($CaCO_3$) into the flue gas in a spray tower, where it will react to gypsum ($CaSO_4$) that can be captured. Sea water can also be used for scrubbing the exhaust gas since

Table 6.7 Average chemical compositions of waste [4]

Variable	Unit	Industrial waste	Residue building- and demolishing waste	Household waste
Lower heating value	MJ/kg	12.4	11.5	24.1
Water	% wt	27.6	14.7	27.3
Ash	% wt	14.5	26.7	20.8
Cl	% wt	0.38	0.27	1.01
F	% wt	0.02	0.01	0.01
S	% wt	0.17	0.47	0.4
Zn	mg/kg	428	312	320
V	mg/kg	<10	<10	48
Sn	mg/kg	<20	20	0.1
Sb	mg/kg	19.2	5.0	13.3
Pb	mg/kg	331	146	243
Ni	mg/kg	27	7.7	90
Mo	mg/kg	8.3	<10	43
Mn	mg/kg	266	102	190
Hg (not volatile)	mg/kg	0.1	0.11	0.1
Cu	mg/kg	294	442	447
Cr	mg/kg	59	32	132
Co	mg/kg	<5	<5	77
Cd	mg/kg	<0.7	<0.5	22
As	mg/kg	<10	<15	9.3
Ba	mg/kg	438		
Se	mg/kg	<20	<20	
Te	mg/kg	<0.4		
Tl	mg/kg	<0.4		

it absorbs SO_2. This naturally requires the presence of sea water, which is only an economic option for combustion installations close to the sea or on board of ships. The exhaust gas cleaning systems require quite some space, practically the same area as required for the generating unit itself. Such solutions are only economic for cogeneration installations in the higher power range, where heat is provided for district heating.

6.3.4 CO, aldehydes and ash emissions

Carbon monoxide and aldehydes (R-CHO) emissions originate from incomplete combustion of hydrocarbons. Incomplete combustion can occur due to a bulk or a local lack of air or by quenching of a flame against relatively cold surfaces. CO is poisonous, but its toxicity is a factor 600 lower than that of NO_2. The maximum concentration in air for an exposure of 1 h is 0.2 mg/m^3 for NO_2 and 30 mg/m^3 for CO. Yet, legislators generally limit the emissions of both species to close to the same values. Aldehydes are known to be carcinogenic. An example for the maximum exposure level of formaldehyde (H-CHO) is 0.15 mg/m^3 during 8 h. CO and aldehydes can be removed from the exhaust gas of combustion installations with oxidation catalysts. The minimum temperature required for this oxidation is around 300 °C.

During the combustion of especially solid fossil fuels, wood, HFO and waste, particulate matter and undesired species such as chlorides and mercury can be present in the combustion end products. Dust, especially the smaller particulates PM 10 and PM 2.5, can penetrate into the lungs and cause health problems. Chlorides can be emitted as hydrochloric acid (HCl) and dioxins, which are very toxic. Especially waste can contain up to 1 mass per cent of chlorine (Cl). Table 6.7 gives an example of typical concentrations of various species in waste. Coal and waste also contain mercury (Hg), which is also a toxic element. Incinerators and many coal-fired boilers are now equipped with cleaning devices such as electrostatic filters, wet scrubbers and fabric filters to reduce the emissions of the undesirable species to acceptable values. Permanent monitoring of the processes and frequent checking of the performance of the cleaning equipment and sensors helps to ensure that the legal limits for the emissions of undesirable species are not exceeded.

Acronyms

CCAI	calculated carbon aromaticity index
CCS	carbon capture and storage
HFO	heavy fuel oil
LNG	liquefied natural gas
MN	methane number
PM	particulate mater
SCR	selective catalytic reduction
TPES	total primary energy supply
WI	Wobbe index

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Chapter 7

Thermodynamic analysis

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7.1 Introduction to thermodynamic analysis of cogeneration systems

The purpose of this chapter is to provide the means for evaluation of the performance of cogeneration and trigeneration systems from the point of view of useful energy products, primary energy consumption and primary energy savings. The correct definition and calculation of efficiencies and the primary energy savings are important in order not only to obtain a clear picture of what cogeneration can achieve but also to reveal whether a particular system is eligible for economic incentives provided in several countries for promotion of cogeneration, such as subsidy on investment, guaranties of origin and special tariff for electricity coming from high efficiency cogeneration.

A cogeneration system may operate at a variety of loads and external conditions. Thus, an analysis on the design point only may lead to overestimation of its thermodynamic performance. If these results are then used for evaluation of its economic performance, they may give a wrong picture of the economic viability of the investment. For this reason, an example with off-design performance will also be presented in this chapter.

7.2 Indexes of thermodynamic performance

A multitude of indexes (or figures of merit) have appeared in the literature for evaluation of the thermodynamic performance of cogeneration systems [1–5]. The most important of those, which have sound thermodynamic basis, will be presented in this section. Before we proceed with the definitions of indexes, there is need to clarify the following.

The usual expression "cogeneration of electricity and heat" hides the fact that in cogeneration, one of the products can be mechanical energy, driving other equipment, such as pumps, compressors, and others. In thermodynamics, the word "work" expresses either mechanical or electrical energy [6,7]. Consequently, a more general expression would be "cogeneration of work and heat."

The word "fuel" is used for convenience, but it will imply any form of primary energy used by the system.

7.2.1 Efficiencies based on energy

A cogeneration system uses energy contained in the fuel and the oxidant (usually air) to produce work and useful heat. No matter how efficient a system is, part of the input energy is an unavoidable loss to the environment, which depends on the state of development of the particular cogeneration technology. It may be the case, for example, due to improper design and operation that only part of the remaining thermal energy is recovered as useful heat, whereas the rest is wasted to the environment (Figure 7.1).

With the help of Figure 7.1, the energy balance of the system at any instant of time is expressed with the following equation:

$$\dot{E}_f + \dot{E}_a = \dot{W} + \dot{H}_{CHP} + \dot{H}_w + \dot{H}_{ul} \tag{7.1}$$

where $\dot{E}_f$ is the energy per unit of time coming with the fuel (kW), $\dot{E}_a$ is the energy per unit of time coming with the air (kW), $\dot{W}$ is the mechanical or electrical power output, depending on the type of system (kW), $\dot{H}_{CHP}$ is the useful heat flow rate (kW), $\dot{H}_w$ is the waste heat flow rate (avoidable losses to the environment) (kW), $\dot{H}_{ul}$ is the unavoidable losses to the environment (kW).

The chemical energy of the fuel is expressed with its heating value. The lower heating value, H_u, will be used throughout this chapter, with the consideration that the exhaust gases leave the system at a temperature high enough, so that any water in the exhaust gases is in the form of steam. The value of H_u is given with respect to a reference state (p_0, T_0), which is usually the following:

$$p_0 = 1\ \text{atm} = 1.01325\ \text{bar} \qquad T_0 = 25\ ^\circ\text{C} = 298.15\ \text{K}$$

In general, the fuel enters the system at a state (p_f, T_f) and consequently its total energy flow rate is

$$\dot{E}_f = \dot{m}_f \left[H_u + \left(h_f - h_{f0} \right) \right] \tag{7.2}$$

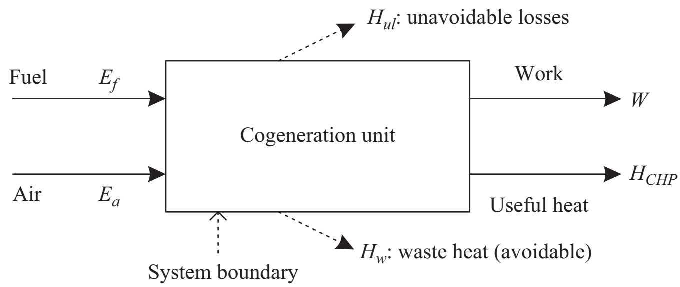

Figure 7.1 Input and output energy flows in a cogeneration system

where H_u is the lower heating value per unit mass of fuel (kJ/kg), $\dot{m}_f$ is the mass flow rate of fuel (kg/s), h_f is the specific enthalpy of fuel at (p_f, T_f), (kJ/kg), h_{f0} is the specific enthalpy of fuel at (p_0, T_0), (kJ/kg).

If the effect of pressure can be neglected, then (7.2) takes the form:

$$\dot{E}_f = \dot{m}_f \left[H_u + c_{pf} \left(T_f - T_0 \right) \right] \tag{7.3}$$

where c_{pf} is the specific heat capacity of the fuel at constant pressure (an average value between the temperatures T_0 and T_f is usually sufficient for the calculations).

In a similar way, the energy flow rate coming with the air considering the same reference state is:

$$\dot{E}_a = \dot{m}_a (h_a - h_{a0}) \tag{7.4}$$

where $\dot{m}_a$ is the mass flow rate of air (kg/s), h_a is the specific enthalpy of air at (p_a, T_a), (kJ/kg), h_{a0} is the specific enthalpy of air at (p_0, T_0), (kJ/kg).

If the effect of pressure can be neglected, then (7.4) takes the form:

$$\dot{E}_a = \dot{m}_a c_{pa} (T_a - T_0) \tag{7.5}$$

where c_{pa} is the specific heat capacity of air at constant pressure (an average value between the temperatures T_0 and T_a is usually sufficient for the calculations).

It goes without saying that, if the pressure or temperature of fuel or air is increased above (p_0, T_0) by means of equipment inside the boundary of the system, then the energy associated with these changes of state is not taken into consideration. For example, this is the case of fuel and air preheating by means of exhaust gases of a boiler or the increase of pressure of fuel in an internal combustion engine by a pump driven by the engine.

The definition of the various efficiencies will be facilitated, if we distinguish two types of cogeneration systems: systems with a prime mover (e.g., a turbine, an internal combustion engine) driving a generator, and systems with direct conversion of fuel energy into electricity (e.g., fuel cells), as depicted in Figure 7.2(a) and (b), respectively.

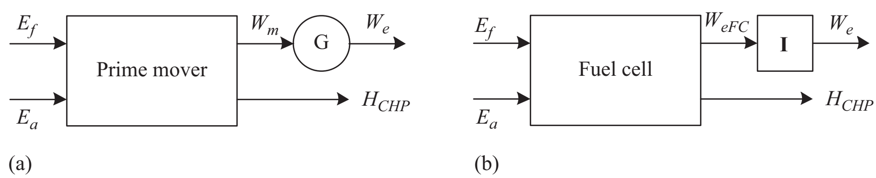

Figure 7.2 (a) Cogeneration system with prime mover driving a generator
(b) Cogeneration system with fuel cell and inverter

For systems such as the one in Figure 7.2(a), the following efficiencies are defined:

Mechanical efficiency: $$\eta_m = \frac{\dot{W}_m}{\dot{E}_f + \dot{E}_a} \tag{7.6}$$

Electrical efficiency: $$\eta_e = \frac{\dot{W}_e}{\dot{E}_f + \dot{E}_a} = \eta_m \eta_G \tag{7.7}$$

The additional symbols in (7.6) and (7.7) are the following:

$\dot{W}_m$ is the mechanical power produced by the prime mover (kW),
η_G is the efficiency of the generator:

$$\eta_G = \frac{\dot{W}_e}{\dot{W}_m} \tag{7.8}$$

The system of Figure 7.2(b) consists of a fuel cell producing direct current and an inverter, which converts the direct current into alternating current of the desired voltage and frequency. For such a system, the following efficiencies are defined:

Efficiency of the fuel cell: $$\eta_{FC} = \frac{\dot{W}_{eFC}}{\dot{E}_f + \dot{E}_a} \tag{7.9}$$

Electrical efficiency: $$\eta_e = \frac{\dot{W}_e}{\dot{E}_f + \dot{E}_a} = \eta_{FC} \eta_I \tag{7.10}$$

The additional symbols in (7.9) and (7.10) are the following:

$\dot{W}_{eFC}$ is the electrical power of direct current produced by the fuel cell (kW),
η_I is the efficiency of the inverter:

$$\eta_I = \frac{\dot{W}_e}{\dot{W}_{eFC}} \tag{7.11}$$

Of course, if the direct current produced by the fuel cell is used directly without conversion to alternating current, then it is $\eta_e = \eta_{FC}$.

For both types of systems in Figure 7.2, the following efficiencies are defined:

Thermal efficiency: $$\eta_h = \frac{\dot{H}_{CHP}}{\dot{E}_f + \dot{E}_a} \tag{7.12}$$

Total efficiency: $$\eta = \eta_e + \eta_h = \frac{\dot{W}_e + \dot{H}_{CHP}}{\dot{E}_f + \dot{E}_a} \tag{7.13}$$

As is mentioned at the beginning of this section, the system may produce mechanical energy which drives equipment (e.g., a pump or a compressor) directly, without converting it into electrical energy. In such a case, the total efficiency of the system is:

$$\eta = \eta_m + \eta_h = \frac{\dot{W}_m + \dot{H}_{CHP}}{\dot{E}_f + \dot{E}_a} \tag{7.14}$$

From a strict thermodynamic point of view, it is not proper to add work and heat, as in (7.13) and (7.14), because the quality of heat is lower than the quality of work. Furthermore, the quality of heat is decreasing with decreasing temperature at which it is available. Therefore, the comparison of systems based on energy efficiencies may sometimes be misleading. Thermodynamically, the evaluation of a system is more accurate, and the comparison between systems is more fair, if it is based on exergetic efficiencies; this is the subject of the next subsection.

Note 1: The preceding equations contain quantities (power and mass flow rate) related to a certain instant of time, which may also be applicable for a period of time, if it can be assumed that the system operates under steady-state conditions throughout this period. However, such an operation can seldom be achieved in practice: the loads, the environmental conditions and other operating parameters change with time, and with them also the efficiency of the system changes. It is also important to assess the performance of the system during a period of time (1 h, 1 week, 1 year, etc.), depending on the purpose of the analysis.

The energy balance equation for a period of time, τ, is written as follows:

$$\left(E_f + E_a\right)_\tau = \left(W + H_{CHP} + H_w + H_{ul}\right)_\tau \tag{7.15}$$

where each term represents energy (kJ) in this period, obtained by integration over time of the related power or energy flow rate:

$$Y_\tau = \int_\tau \dot{Y}\, dt \quad \dot{Y} = \dot{E}_f, \dot{E}_a, \dot{W}, \dot{H}_{CHP}, \dot{H}_w, \dot{H}_{ul}, \tag{7.16}$$

All the efficiencies defined by (7.6)–(7.14) can be calculated for the whole period τ using the same forms of equations and replacing $\dot{Y}$ with Y_τ. For example, (7.7) for the electrical efficiency for the period τ is written as:

$$(\eta_e)_\tau = \left(\frac{W_e}{E_f + E_a}\right)_\tau = (\eta_m \eta_G)_\tau \tag{7.17}$$

In practice, it may be difficult to have each form of energy as a continuous function of time over the period τ and, consequently, the integration indicated by (7.16) may not be possible. It is easier, however, to discretize the period τ in several time intervals defined in such a way that it can be considered, to a good approximation, that a steady-state operation is valid in each interval. Then, the integrals can be replaced with summations over these time intervals. This approach will be applied in examples presented in this chapter.

In the following, in order not to complicate the whole presentation, the various quantities will be written without the dot and the subscript τ. In each application, it will become clear whether the analysis refers to an instant or to a period of time.

Note 2: The units are given besides the explanation of a symbol for a better understanding. However, all the equations are applicable with any consistent system of units.

7.2.2 Efficiencies based on exergy

The use of exergy in the analysis of energy systems, in general, and cogeneration systems, in particular, very often gives a significantly different picture from the analysis based on energy. This is why it is worth including here simple aspects of exergy analysis. For the convenience of the unfamiliar reader, fundamental knowledge on exergy is provided in Appendix 7.A.

In words, exergy of a system is defined as the maximum theoretical useful work obtainable from the system as this is brought into complete thermodynamic equilibrium with the thermodynamic environment, while interacting with this environment only. Equations to calculate exergy in certain cases are given in Appendix 7.A, whereas more complete information can be found in the related literature [8–10].

For systems such as the one in Figure 7.2(a), the following exergetic efficiencies are defined:

Mechanical exergetic efficiency: $$\zeta_m = \frac{W_m}{\mathcal{E}_f + \mathcal{E}_a} \tag{7.18}$$

Electrical exergetic efficiency: $$\zeta_e = \frac{W_e}{\mathcal{E}_f + \mathcal{E}_a} = \zeta_m \zeta_G \tag{7.19}$$

The additional symbols in (7.18) and (7.19) are the following:

$\mathcal{E}_f$ is the exergy of fuel (kJ), $\mathcal{E}_a$ is the exergy of air (kJ), ζ_G is the exergetic efficiency of the generator:

$$\zeta_G = \frac{W_e}{W_m} = \eta_G \tag{7.20}$$

The equality between ζ_G and η_G expressed by (7.20) is due to the fact that the exergy of mechanical or electrical energy is equal to the energy itself, as explained in Appendix 7.A.

For systems such as the one of Figure 7.2(b), the following efficiencies are defined:

Exergetic efficiency of the fuel cell: $$\zeta_{FC} = \frac{W_{eFC}}{\mathcal{E}_f + \mathcal{E}_a} \tag{7.21}$$

Electrical exergetic efficiency: $$\zeta_e = \frac{W_e}{\mathcal{E}_f + \mathcal{E}_a} = \zeta_{FC} \zeta_I \tag{7.22}$$

where ζ_I is the exergetic efficiency of the inverter:

$$\zeta_I = \frac{W_e}{W_{eFC}} = \eta_I \tag{7.23}$$

As with the generator, the equality between ζ_I and η_I expressed by (7.23) is due to the fact that the exergy of electrical energy is equal to the energy itself, as explained in Appendix 7.A.

For both types of systems in Figure 7.2, the following exergetic efficiencies are defined:

$$\text{Thermal exergetic efficiency:} \qquad \zeta_h = \frac{\mathscr{E}^H_{CHP}}{\mathscr{E}_f + \mathscr{E}_a} \tag{7.24}$$

$$\text{Total exergetic efficiency:} \qquad \zeta = \zeta_e + \zeta_h = \frac{W_e + \mathscr{E}^H_{CHP}}{\mathscr{E}_f + \mathscr{E}_a} \tag{7.25}$$

where $\mathscr{E}^H_{CHP}$ is the exergy of the useful heat H_{CHP} supplied by the cogeneration system.

If the system produces mechanical energy that drives equipment (e.g., a pump or a compressor) directly, without converting it into electrical energy, then the total exergetic efficiency of the system is given by the equation:

$$\zeta = \zeta_m + \zeta_h = \frac{W_m + \mathscr{E}^H_{CHP}}{\mathscr{E}_f + \mathscr{E}_a} \tag{7.26}$$

7.2.3 Electricity to heat ratio

One of the most important characteristics of a cogeneration technology is the quantity of heat that can be recovered and used per unit of electrical energy.[1] This is expressed by the *electricity to heat ratio* defined by the equation:

$$\sigma = \frac{W_e}{H_{CHP}} \tag{7.27}$$

In the cogeneration literature, this is known as *power-to-heat ratio*, but this term has two drawbacks: (1) unintentionally, it compares power, which is energy per unit of time (kW), with heat, which is energy (kJ), and (2) power is any form of energy per unit of time and not only electricity.

[1]From this place on, it will be considered for simplicity that one of the products of the system is electricity. The reader can easily modify the equations, if the product is mechanical energy driving other equipment directly.

Taking (7.7), (7.12), and (7.13) into consideration, the following relationships are obtained:

$$\sigma = \frac{\eta_e}{\eta_h} = \frac{\eta_e}{\eta - \eta_e} \tag{7.28}$$

$$\eta = \eta_e\left(1 + \frac{1}{\sigma}\right) \tag{7.29}$$

Taking into consideration the fact that the total efficiency of a cogeneration system is usually not higher than 85%–90%, these relationships help in making reasonable estimates of the value of the electricity to heat ratio, if the electrical efficiency is known, and vice versa. For example, if $\eta_e = 0.40$ and $0.80 \leq \eta \leq 0.90$, then $1 \geq \sigma \geq 0.8$.

7.2.4 Primary energy savings

7.2.4.1 Primary energy savings of a cogeneration system

It is important to calculate the primary energy savings achieved by a cogeneration system in comparison to the reference system for separate production of electricity and heat, which is usually a power plant and a boiler, respectively.

For simplicity, it will be considered here that air enters all systems at (p_0, T_0) and consequently, according to (7.4) its energy is zero: $E_a = 0$. Then, (7.7) is solved for the primary energy (fuel) required by the cogeneration system in order to produce W_e and H_{CHP}:

$$E_f = \frac{W_e}{\eta_e} \tag{7.30}$$

The primary energy required for separate production of electricity is:

$$E_{fer} = \frac{W_e}{\eta_{er}} \tag{7.31}$$

where η_{er} is the electrical efficiency of the reference system for the separate production of electricity, for example, the efficiency of a power plant, including the transportation and distribution network from the power plant to the site of the cogeneration system. The primary energy required for the separate production of heat is:

$$E_{fhr} = \frac{H_{CHP}}{\eta_{hr}} \tag{7.32}$$

where η_{hr} is the efficiency of the reference system for the separate production of heat, for example, the efficiency of a boiler. Then, the *primary energy savings* achieved by the cogeneration system is given by the equation:

$$PES = E_{fer} + E_{fhr} - E_f \tag{7.33}$$

The *primary energy savings ratio* is defined by the equation:

$$PESR = \frac{PES}{E_{fer} + E_{fhr}} = 1 - \frac{E_f}{E_{fer} + E_{fhr}} \tag{7.34}$$

It can be proved that the preceding equations lead to the following equivalent expressions for the primary energy savings ratio:

$$PESR = 1 - \frac{\sigma + 1}{\eta[(\sigma/\eta_{er}) + (1/\eta_{hr})]} \tag{7.35a}$$

$$PESR = 1 - \frac{1}{(\eta_e/\eta_{er}) + (\eta_h/\eta_{hr})} \tag{7.35b}$$

7.2.4.2 Primary energy savings of a trigeneration system

In principle, trigeneration system can be any system with three products. The term is used here for a system producing three forms of energy: electrical (or mechanical) energy, thermal energy for heating, and thermal energy with cooling effect. A trigeneration system consists of a cogeneration unit and a heat-driven chiller, such as an absorption chiller (Figure 7.3), and has three energy products: electricity W_e, energy for heating H_h, and energy for cooling Q. It is emphasized that all three forms of energy are supplied during the same time period. The primary energy savings will be calculated with reference to the separate production of electricity by a power plant, heat by a boiler, and cooling by an electrically driven compression chiller (Figure 7.4) [4].

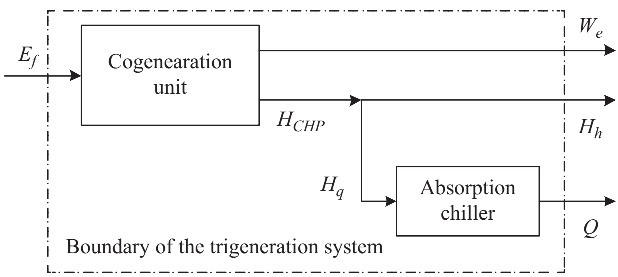

Figure 7.3 Simplified diagram of a trigeneration system [4]

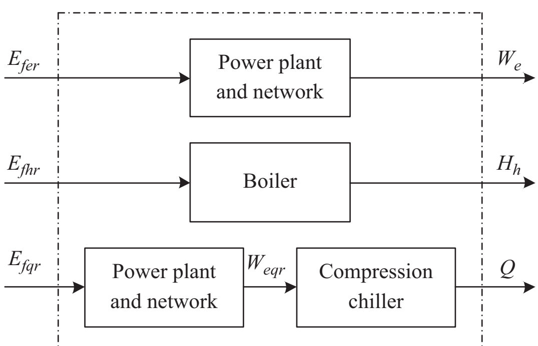

Figure 7.4 Reference system for a trigeneration system [4]

The thermal energy produced by the cogeneration unit is split into two parts (Figure 7.3):

$$H_{CHP} = H_h + H_q \tag{7.36}$$

where H_h is the useful heat supplied by the cogeneration unit to thermal loads, H_q is the useful heat supplied by the cogeneration unit to the absorption chiller.

The operation of the absorption chiller is characterized by the equation:

$$COP_a = \frac{Q}{H_q} \tag{7.37}$$

where COP_a is the coefficient of performance of the absorption chiller, Q is the cooling energy supplied by the absorption chiller.

Equations (7.30) and (7.31) are valid also here, whereas (7.32) takes the form:

$$E_{fhr} = \frac{H_h}{\eta_{hr}} \tag{7.38}$$

The compression chiller requires electric energy

$$W_{eqr} = \frac{Q}{COP_c} \tag{7.39}$$

where COP_c is the coefficient of performance of the compression chiller. This electric energy is produced by a power plant with the expense of fuel energy given by the equation:

$$E_{fqr} = \frac{W_{eqr}}{\eta_{er}} = \frac{Q}{COP_c \cdot \eta_{er}} \tag{7.40}$$

Having the energy of all fuels appearing in Figures 7.3 and 7.4 known, the primary energy savings and the primary energy savings ratio of the trigeneration system can be calculated:

$$PES = E_{fer} + E_{fhr} + E_{fqr} - E_f \tag{7.41}$$

$$PESR = \frac{E_{fer} + E_{fhr} + E_{fqr} - E_f}{E_{fer} + E_{fhr} + E_{fqr}} = 1 - \frac{E_f}{E_{fer} + E_{fhr} + E_{fqr}} \tag{7.42}$$

With an elaboration of the preceding equations, the following expression is obtained:

$$PESR = 1 - \frac{1}{(\eta_e/\eta_{er}) + (\eta_{ht}/\eta_{hr}) + \left(\eta_q/COP_c \cdot \eta_{er}\right)} \tag{7.43}$$

where two additional efficiencies appear:

Thermal efficiency of the trigeneration system: $$\eta_{ht} = \frac{H_h}{E_f} \tag{7.44}$$

"Cooling efficiency" of the trigeneration system: $$\eta_q = \frac{Q}{E_f} \tag{7.45}$$

It is worth noting that, if there is no cooling, the trigeneration system is reduced to a cogeneration unit, it is $\eta_q = 0$, $\eta_{ht} = \eta_h$, and (7.43) becomes identical to (7.35b). Thus, even though from a strict thermodynamic point of view "cooling efficiency" may not make sense, it is defined here because it leads to a form of the *PESR* of a trigeneration system, which is an extension of the *PESR* of a cogeneration system.

In (7.43), the coefficient of performance of a compression chiller appears, which is justified as follows. For the evaluation of a cogeneration system, there is need to specify reference values of efficiencies for the separate production of electricity and heat. For a trigeneration system, there is need in addition to specify a reference value of efficiency for production of cooling energy. Since cooling is usually provided by a compression chiller, the coefficient of performance of such a chiller is selected as reference value.

It is noted that, even though COP_a does not appear explicitly in (7.43), it is hidden in η_q:

$$\eta_q = \frac{Q}{E_f} = \frac{H_q \cdot COP_a}{E_f} \tag{7.46}$$

Attention has to be paid to the fact that the energy products H_h and Q, and the parameters η_{ht}, η_q, and COP_a are not independent of each other, and they cannot be specified arbitrarily; they must satisfy (7.12), (7.36), (7.37), (7.44), and (7.45).

Example 7.1 Efficiencies and primary energy savings of a cogeneration system

The system of Figure 7.5 is studied, which operates on natural gas and produces electricity and heat in the form of hot water or steam.

- Data

Lower heating value of fuel:		$H_u = 46{,}000$ kJ/kg
Specific chemical exergy of fuel:		$\varepsilon_f^{CH} = 48{,}000$ kJ/kg
Nominal electric power output:		$\dot{W}_e = 20{,}000$ kW
Electrical efficiency:		$\eta_e = 0.36$
Exhaust gas mass flow rate:		$\dot{m}_g = 69.5$ kg/s
Temperatures of exhaust gas:	$T_{g1} = 450$ °C	$T_{g2} = 120$ °C
Specific heat capacity of exhaust gas:		$c_{pg} = 1.15$ kJ/kg K
Efficiency of the exhaust gas boiler:		$\eta_B = 0.95$
Properties of water entering the EGB:	$p_1 = 2$ bar	$T_1 = 40$ °C
Reference value for separate production of electricity:		$\eta_{er} = 0.48$
Reference value for separate production of heat:		$\eta_{hr} = 0.90$

Air and fuel at reference pressure and temperature.

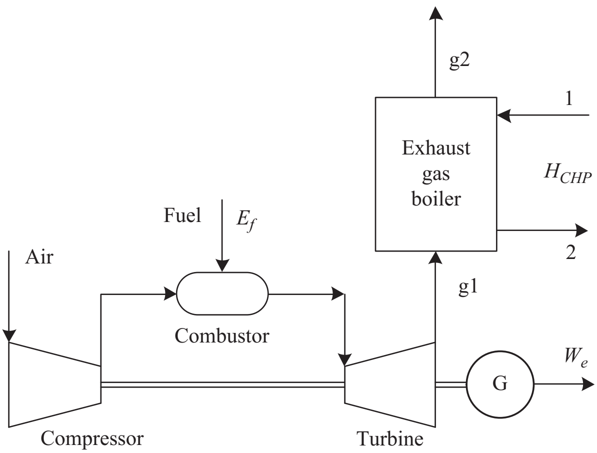

Figure 7.5 Simplified diagram of a gas-turbine cogeneration system

- Requested

Efficiencies based on energy and exergy, and primary energy savings for three alternative cases regarding the fluid at the exit of the boiler:

Case A: Water with	$p_2 = 5$ bar	$T_2 = 90$ °C
Case B: Saturated steam with	$p_2 = 20$ bar	$T_2 = 212.37$ °C
Case C: Superheated steam with	$p_2 = 20$ bar	$T_2 = 400$ °C

- Solution

The properties of water and steam are taken from steam tables.

Certain results are valid for all cases:

Fuel power (energy flow rate): $\dot{E}_f = \dfrac{\dot{W}_e}{\eta_e} = 55,556\ \text{kW}$

Fuel consumption: $\dot{m}_f = \dfrac{\dot{W}_e}{\eta_e H_u} = 1.20773\ \text{kg/s}$

Fuel exergy flow rate: $\dot{\mathscr{E}}_f = \dot{m}_f \varepsilon_f^{CH} = 57,971\ \text{kW}$

Useful heat: $\dot{H}_{CHP} = \dot{m}_g c_{pg}(T_{g1} - T_{g2})\eta_B = 25,056\ \text{kW}$

Thermal efficiency: $\eta_h = \dfrac{\dot{H}_{CHP}}{\dot{E}_f} = 0.451$

Total efficiency: $\eta = \eta_e + \eta_h = 0.811$

Electricity to heat ratio: $\sigma = \dfrac{\dot{W}_e}{\dot{H}_{CHP}} = 0.7982$

Electrical exergetic efficiency: $\zeta_e = \dfrac{\dot{W}_e}{\dot{\mathscr{E}}_f} = 0.345$

Fuel energy for separate production of electricity: $\dot{E}_{fer} = \dfrac{\dot{W}_e}{\eta_{er}} = 41,667 \text{ kW}$

Fuel energy for separate production of heat: $\dot{E}_{fhr} = \dfrac{\dot{H}_{CHP}}{\eta_{hr}} = 27,841 \text{ kW}$

Primary energy savings: $PES = \dot{E}_{fer} + \dot{E}_{fhr} - \dot{E}_f = 13952 \text{ kW}$

Primary energy savings ratio: $PESR = \dfrac{PES}{\left(\dot{E}_{fer} + \dot{E}_{fhr}\right)} = 0.2007 = 20.07\%$

Properties of water at the inlet of the boiler (specific enthalpy and entropy):

$$h_1 = 167.6 \text{ kJ/kg} \qquad s_1 = 0.572 \text{ kJ/kg K}$$

The following equations are applied for each one of the cases A, B, and C:

Mass flow rate of water or steam that can be heated from state 1 to state 2: $\dot{m}_2 = \dfrac{\dot{H}_{CHP}}{h_2 - h_1}$

Exergy flow rate of the useful heat: $\dot{\mathscr{E}}^H_{CHP} = \dot{m}_2(\varepsilon_2 - \varepsilon_1) = \dot{m}_2[h_2 - h_1 - T_0(s_2 - s_1)]$

Thermal exergetic efficiency: $\zeta_h = \dfrac{\dot{\mathscr{E}}^H_{CHP}}{\dot{\mathscr{E}}_f}$

Total exergetic efficiency: $\zeta = \zeta_e + \zeta_h$

The results for each one of the three cases are presented in Table 7.1.

- Comments on the results

All the available heat in the exhaust gas (except of losses indicated by η_B) is recovered in all three cases, and this is why the primary energy savings is the same.

As the quality of heat (pressure and temperature of water—steam) increases from Case A to Case C, the thermal and total exergetic efficiencies also increase but remain always much lower than the thermal and total energetic efficiencies.

Table 7.1 Results for the three cases of Example 7.1

Parameter	Case A	Case B	Case C
h_2 (kJ/kg)	377.3	2,797.2	3,248.7
s_2 (kJ/kg)	1.1922	6.3367	7.1296
$\dot{m}_2$ (kg/s)	119.487	9.52863	8.1323
$\dot{\mathscr{E}}^H_{CHP}$ (kW)	2,961.78	8,769.2	9,156.6
ζ_h (–)	0.0511	0.1562	0.1648
ζ (–)	0.3961	0.5162	0.5248

The higher the temperature difference between the heating and heated fluid, the higher the irreversibility of the heat transfer process and the lower the exergy increase of the heated fluid ($\dot{\mathscr{E}}^{H}_{CHP}$ in this example).

The exhaust gas boiler can exploit only the temperature component of exergy of the exhaust gas. The decrease of temperature from T_{g1} to T_{g2} causes a decrease of the physical exergy of exhaust gas, which can be calculated by application of (7.A.18), keeping the temperature term only:

$$\begin{aligned}\dot{\mathscr{E}}^{T}_{g1\to2} &= \dot{m}_g c_{pg}\left(T_2 - T_1 - T_0\,\ell n\frac{T_2}{T_1}\right)\\ &= 69.5\cdot 1.15\cdot\left(723.15 - 393.15 - 298.15\cdot\ell n\frac{723.15}{393.15}\right)\\ &= 11{,}853\ \text{kW}\end{aligned}$$

Of course, $\dot{\mathscr{E}}^{H}_{CHP}$ remains always lower than $\dot{\mathscr{E}}^{T}_{g1\to2}$ and the difference, which is the exergy destruction due to irreversible process, decreases with decreasing temperature difference between the two fluids. Let also be mentioned that $\dot{\mathscr{E}}^{T}_{g1\to2}$ represents the maximum possible mechanical power that could be obtained from the exhaust gas with physical processes (no chemical reactions), if they were reversible.

Example 7.2 Effect of partial load operation on the thermodynamic performance of a cogeneration system

The system of Example 7.1 is considered operating under various load conditions during a year, which can be approximated by four modes of operation, as given in Table 7.2.

The values of T_{g2}, c_{pg}, η_B, η_{er}, and η_{hr} remain the same with those in Example 7.1.

- Requested

The efficiencies and the primary energy savings in each mode of operation, as well as in the whole year.

Table 7.2 Data for the Example 7.2

Mode	Duration, τ (h/year)	Load factor, f (%)	$\dot{W}_e$ (kW)	η_e (–)	$\dot{m}_g$ (kg/s)	T_{g1} (°C)
1	1,000	100	20,000	0.36	69.5	450
2	1,000	80	16,000	0.34	69.3	400
3	3,380	60	12,000	0.31	69.2	355
4	1,100	40	8,000	0.26	69.1	308
Total	6,480					

- Solution

For comparison, it is significant to calculate first the primary energy savings for the whole year, if the system would operate at 100% load throughout all of the 6,480 h.

$$\text{Annual fuel energy:} \qquad E_f = \frac{\dot{W}_e \tau}{\eta_e} = 360,000,000 \text{ kWh}$$

Annual fuel energy for separate production of electricity:

$$E_{fer} = \frac{\dot{W}_e \tau}{\eta_{er}} = 270,000,000 \text{ kWh}$$

Annual fuel energy for separate production of heat:

$$E_{fhr} = \frac{\dot{m}_g c_{pg} (T_{g1} - T_{g2}) \eta_B \tau}{\eta_{hr}} = 180,406,710 \text{ kWh}$$

$$\text{Annual primary energy savings:} \quad PES = 90,406,710 \text{ kWh}$$

The annual efficiencies and primary energy savings ratio are the same as in Example 7.1.

The results for each mode of operation and the annual values are presented in Table 7.3.

Table 7.3 Results for the Example 7.2

Mode	W_e **(kWh)**	E_f **(kWh)**	H_{CHP} **(kWh)**	η_e **(–)**	η_h **(–)**
1	20,000,000	55,555,556	25,056,488	0.36	0.45102
2	16,000,000	47,058,824	21,198,870	0.34	0.45048
3	40,560,000	130,838,710	60,049,874	0.31	0.45896
4	8,800,000	33,846,154	15,611,694	0.26	0.46125
Annual	85,360,000	267,299,243	121,916,926	0.31934	0.45611
Mode	η **(–)**	E_{fer} **(kWh)**	E_{fhr} **(kWh)**	***PES*** **(kWh)**	***PESR*** **(–)**
1	0.81102	41,666,667	27,840,542	13,951,653	20.07
2	0.79048	33,333,333	23,554,300	9,828,810	17.28
3	0.76896	84,500,000	66,722,083	20,383,373	13.48
4	0.72125	18,333,333	17,346,327	1,833,506	5.14
Annual	0.77545	177,833,333	135,463,251	45,997,342	14.68

- Comments on the results

It is worth noting that, even though the annual time of operation remains the same (6,480 h), the partial load operation reduces the *PES* from 90,406,710 kWh (full load operation) to 45,997,342 kWh, a reduction by 49%, which can be detrimental for the economic viability of the system. On the other hand, the *PESR* is reduced by about 27%, from 20.07% to 14.68%, whereas in one of the modes it is as low as 5.14%.

7.3 Procedure for determination of electricity cogenerated with useful heat

7.3.1 What is the issue?

By definition, cogeneration is the simultaneous production of work and useful heat from the same primary energy source. Thus, cogenerated work is the work produced in conjunction with useful heat. The question arises: is all the work produced by a cogeneration system, cogenerated work?

Let us consider a system that uses 100 kW of fuel energy and produces 50 kW of electricity, and 35 kW of useful heat, with zero waste heat. Thus, the system has a total efficiency of 85%, which is the maximum technically possible, since there is no waste heat. In such a case, it is reasonable to say that all electricity is produced in conjunction with useful heat, and consequently it is cogenerated electricity.

In a certain period of time, the system uses again 100 kW of fuel energy and produces 50 kW of electricity but, due to several reasons (e.g., decreased thermal loads), it produces only 20 kW of useful heat, whereas there is waste heat of 15 kW rejected to the environment. Under these conditions, part of the produced electricity is not associated with useful heat but with waste heat, and consequently, it is not cogenerated electricity. The procedure to determine the cogenerated electricity (called also CHP electricity [11]) and the related efficiencies are presented in this section, adapted from [4].

The subject is not only of academic but also of economic interest, because, as mentioned in the Introduction of this chapter, in many countries there are financial incentives, among those being special tariffs for cogenerated electricity or for "high efficiency cogeneration," meaning a total efficiency higher than a certain threshold [11–13].

7.3.2 Distinction between cogeneration systems without loss and with loss of work production due to useful heat production

Before we proceed, it is useful to distinguish the cogeneration systems in two types, depending on whether the production of useful heat is associated with decrease of work production or not.

In systems such as internal combustion engines and gas turbines, heat can be recovered and used with no decrease of the produced work. On the contrary, in systems such as the one in Figure 7.6 with extraction-condensing steam turbine, increase of the useful heat H_{CHP} by increasing the mass flow rate of the extracted steam causes a decrease of the produced work, as shown in Figure 7.7. For systems of this type, the power-loss coefficient, β, is defined:

$$\beta = \frac{\dot{W}_{e,\,\max} - \dot{W}_e}{\dot{H}_{CHP}} \tag{7.47}$$

where $\dot{W}_e$ is the electric power produced at a certain operating point of the cogeneration system, $\dot{H}_{CHP}$ is the useful heat rate produced in conjunction with $\dot{W}_e$, $\dot{W}_{e,\,\max}$ is the maximum electric power, produced when $\dot{H}_{CHP} = 0$ (e.g., closed extraction).

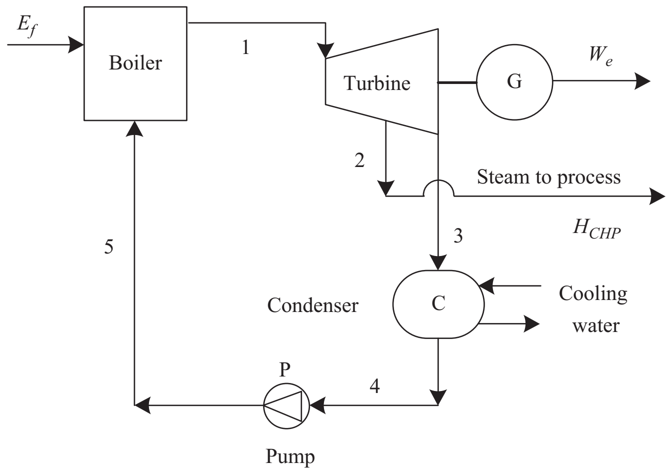

Figure 7.6 Simplified diagram of a cogeneration system with extraction-condensing steam turbine

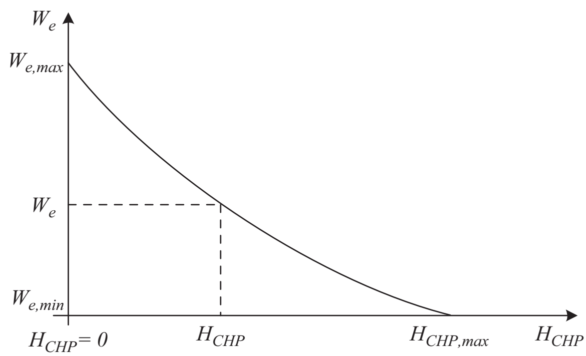

Figure 7.7 Decrease of the electricity produced by the system of Figure 7.6 with increase of the useful heat production

Of course, (7.47) is valid if $\dot{W}_e$ is replaced with $\dot{W}_m$, if mechanical power is the product of the system.

In general, the function $W_e\,(H_{CHP})$ is nonlinear (Figure 7.7) and, consequently, β is not constant, but a function of H_{CHP}.

7.3.3 Splitting the cogeneration unit in CHP and non-CHP parts

As stated in Section 7.3.1, if a cogeneration system has no waste heat ($H_w = 0$), then all the work is cogenerated work, that is it is produced in conjunction with useful heat. If, however, part of the heat that could be recovered is wasted ($H_w > 0$), then part of the work is not produced in connection with useful heat. In such a case, it is interesting and useful to split the cogeneration system into CHP and non-CHP

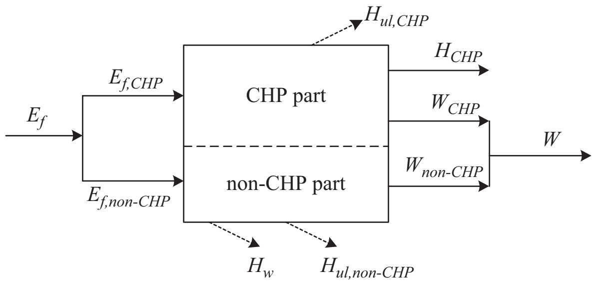

Figure 7.8 CHP and non-CHP parts of a cogeneration system [4] (W can be replaced with W_e or W_m, depending on the application)

parts[2] and determine the work production, the fuel consumption, and the efficiencies of each part. The basic principles for this splitting are stated here, whereas quantitative aspects will be presented in Section 7.3.4. Furthermore, a justification for this splitting is provided with the Example 7.3.

It is reasonable to assume that there are unavoidable losses corresponding to each part, but all the waste heat is associated with the non-CHP part only (Figure 7.8). Thus, the efficiency of the CHP part is equal to the maximum technically possible efficiency or to an appropriate value specified by convention.

In cogeneration systems with no loss of electric power due to useful heat production, no matter whether useful heat is produced or not, the fuel is consumed for the electricity production. Therefore, it is reasonable to split the fuel into two parts in proportion to the electricity corresponding to each part. Consequently, the electric efficiency for both parts is the same, and it is equal to the electric efficiency of the whole system.

In cogeneration systems with loss of electric power due to useful heat production (e.g., the system of Figure 7.6), it is considered that the non-CHP part has an electric efficiency equal to the efficiency of the system when operating with no useful heat production (e.g., steam extraction closed).

These principles will be applied in the following sections.

7.3.4 Procedure to calculate the cogenerated electricity and related parameters

7.3.4.1 Definitions

The definitions of certain terms, not appearing in the preceding, are given in this subsection.

Threshold value of total efficiency (η_{thr}): It is the minimum value of the total efficiency of a cogeneration system, in order to be considered that there is no waste heat,

[2]In order not to confuse the reader, who may be familiar with existing literature, the abbreviation CHP is kept here, instead of CHW (combined heat and work), which is more accurate according to the remark at the beginning of Section 7.2.

that is, $H_w = 0$ (Figure 7.1). The value of η_{thr} is defined by convention, and it reflects the current technological level. In [12], for example, the following values are specified:

$\eta_{thr} = 0.80$ for systems with gas turbine combined cycle or extraction – condensing steam turbine,
$\eta_{thr} = 0.75$ for other cogeneration technologies.

These values are rather conservative: current well designed and operated systems can achieve higher efficiencies.

Full cogeneration mode: A cogeneration system operating with maximum technically possible heat recovery from the system itself is said to be operating in *full cogeneration mode* [11]. In full cogeneration mode, there is no waste heat ($H_w = 0$). Consequently:

A cogeneration system is considered operating in full cogeneration mode, if its total efficiency is at least equal to the threshold value (η_{thr}) specified for the particular technology.

CHP electricity[3] *and non-CHP electricity:* In the case of full cogeneration mode, all electricity is considered *combined heat and power electricity* ($W_{e,CHP}$) [11]. For periods when the plant does not operate in full cogeneration mode, part of the electricity is not produced in conjunction with useful heat; this is called *non-CHP electricity* ($W_{e,non\text{-}CHP}$).

The procedure for calculating $W_{e,CHP}$ and $W_{e,non\text{-}CHP}$ is presented in the following subsection.

CHP fuel energy means the fuel energy, based on lower heating value, needed in a cogeneration process to cogenerate CHP electrical and/or mechanical energy and useful heat in a reporting period ($E_{f,CHP}$ in Figure 7.8).

Non-CHP fuel energy means the fuel energy, based on lower heating value, needed in a cogeneration process for production of non-CHP electrical and/or mechanical energy in a reporting period ($E_{f,non\text{-}CHP}$ in Figure 7.8).

The term *fuel* is used with a broader meaning: It includes energy input coming not only in the form of combustibles (real fuels), but also in the form of steam and other heat imports, process waste heat, and others. "Fuel inputs" should be measured in equivalent energy units referred to the main fuel used to produce the inputs of energy in forms, other than real fuel. Returned condensate from the cogeneration process (in the case of steam output) is not considered to be fuel input.

Two more efficiencies are defined here, which will be used in the following:

η_{cog}: It is the total efficiency of a cogeneration system, when it operates with the maximum heat recovery the particular system can achieve.

[3]The term *CHP electricity* is synonymous to *cogenerated electricity*, and it will be used in the following, for uniformity with existing literature and legislation.

η_{CHP}: It is the total efficiency of the CHP process, that is, of the CHP part of the cogeneration system (Figure 7.8). It is specified that:

$$\eta_{CHP} = \eta_{cog} \quad \text{if} \;\; \eta_{cog} \geq \eta_{thr} \tag{7.48a}$$

$$\eta_{CHP} = \eta_{thr} \quad \text{if} \;\; \eta_{cog} < \eta_{thr} \tag{7.48b}$$

$\eta_{e,\,\max}$: It is the electrical efficiency of a cogeneration system with a condensing-extraction steam turbine, when it operates in fully condensing mode (extraction closed in Figure 7.6). More generally, it is defined for any system where the production of useful heat results in decrease of produced work.

7.3.4.2 Calculation of the power-to-heat ratio in full cogeneration mode, CHP electricity, non-CHP electricity, and fuel consumptions

If a cogeneration system under certain operating conditions uses fuel energy E_f, has a power-loss coefficient β, and produces electricity W_e and useful heat H_{CHP}, then the produced electricity and the electrical efficiency of the system operating with no useful heat production, but with the same fuel consumption, is calculated by the equations:

$$W_{e,\max} = W_e + \beta H_{CHP} \tag{7.49}$$

and

$$\eta_{e,\max} = \frac{W_{e,\max}}{E_f} \tag{7.50}$$

This applies to any system where the production of useful heat results in decrease of electrical or mechanical power, such as a system with extraction-condensing steam turbine. With such a system, $W_{e,\max}$ is obtained in fully condensing mode of operation. For any cogeneration system that does not exhibit decrease of electrical and/or mechanical power due to useful heat production, it is $\beta = 0$ and (7.50) results in $\eta_{e,\max} = \eta_e$.

If the value of β is not known, but the value of $W_{e,\max}$ is known from operational data, then the value of β is obtained by (7.47).

The power-to-heat ratio in full cogeneration mode is calculated by the equation (the proof is given in Appendix 7.B):

$$\sigma_{CHP} = \frac{\eta_{e,\max} - \beta\eta_{CHP}}{\eta_{CHP} - \eta_{e,\max}} \tag{7.51a}$$

If for a particular system it is $\beta = 0$, then (7.51a) takes the simpler form:

$$\sigma_{CHP} = \frac{\eta_e}{\eta_{CHP} - \eta_e} \tag{7.51b}$$

The CHP electricity is given by the equation:

$$W_{e,CHP} = \sigma_{CHP} \cdot H_{CHP} \tag{7.52}$$

The non-CHP electricity is given by the equation:

$$W_{e,non-CHP} = W_e - W_{e,CHP} \tag{7.53}$$

The fuel consumed by the cogeneration system for the production of $W_{e,CHP}$ and H_{CHP} (or, in other words, the fuel consumed by the CHP part of the unit) is given by the equation:

$$E_{f,CHP} = \frac{W_{e,CHP} + H_{CHP}}{\eta_{CHP}} \tag{7.54}$$

The fuel consumed by the cogeneration unit for the production of $W_{e,non\text{-}CHP}$ is given by the equation:

$$E_{f,non\text{-}CHP} = E_f - E_{f,CHP} \tag{7.55}$$

The electrical efficiency of the CHP part is as follows:

$$\eta_{e,CHP} = \frac{W_{e,CHP}}{E_{f,CHP}} \tag{7.56}$$

The thermal efficiency of the non-CHP part is by definition equal to zero, whereas the thermal efficiency of the CHP part is defined as:

$$\eta_{h,CHP} = \frac{H_{CHP}}{E_{f,CHP}} \tag{7.57}$$

The total efficiency of the CHP part is:

$$\eta_{CHP} = \eta_{e,CHP} + \eta_{h,CHP} \tag{7.58}$$

The electrical efficiency of the non-CHP part is given by the equation:

$$\eta_{e,non\text{-}CHP} = \frac{W_{e,non\text{-}CHP}}{E_{f,non\text{-}CHP}} \tag{7.59}$$

If for a certain cogeneration system and period, it is $\eta \geq \eta_{thr}$, then (7.51) and (7.52) result in $W_{e,CHP} = W_e$, that is, if the total efficiency of a cogeneration system during a period of time is at least equal to the threshold value specified for the particular technology, then the whole electricity produced is CHP electricity.

7.3.4.3 Calculation of the primary energy savings of the CHP and non-CHP parts

The primary energy savings of the complete system is calculated with the procedure described in Section 7.2.4.

- Primary energy savings of the CHP part

The primary energy savings of the CHP part is given by the equation

$$PES_{CHP} = E_{fer,CHP} + E_{fhr} - E_{f,CHP} \tag{7.60}$$

where $E_{fer,CHP}$ is the fuel energy required by a power plant (reference system) to produce $W_{e,CHP}$:

$$E_{fer,CHP} = \frac{W_{e,CHP}}{\eta_{er}} \tag{7.61}$$

The primary energy savings ratio of the CHP part is:

$$PESR_{CHP} = \frac{PES_{CHP}}{E_{fer,CHP} + E_{fhr}} = 1 - \frac{E_{f,CHP}}{E_{fer,CHP} + E_{fhr}} \tag{7.62}$$

or

$$PESR_{CHP} = 1 - \frac{1}{\left(\eta_{e,CHP}/\eta_{er}\right) + \left(\eta_{h,CHP}/\eta_{hr}\right)} \tag{7.63}$$

- Primary energy savings of the non-CHP part

The primary energy savings of the non-CHP part is given by the equation

$$PES_{non-CHP} = E_{fer,non-CHP} - E_{f,non-CHP} \tag{7.64}$$

where $E_{fer,non\text{-}CHP}$ is the fuel energy required by a power plant (reference system) to produce $W_{e,non\text{-}CHP}$:

$$E_{fer,non\text{-}CHP} = \frac{W_{e,non\text{-}CHP}}{\eta_{er}} \tag{7.65}$$

The primary energy savings ratio of the non-CHP part is:

$$PESR_{non\text{-}CHP} = \frac{PES_{non\text{-}CHP}}{E_{fer,non\text{-}CHP}} = 1 - \frac{E_{f,non\text{-}CHP}}{E_{fer,non\text{-}CHP}} \tag{7.66}$$

It can be proved that:

$$PES_{CHP} + PES_{non-CHP} = PES \tag{7.67}$$

Example 7.3 Calculation of CHP and non-CHP electricity and other parameters with and without electricity decrease due to production of useful heat

Two different systems are studied in this example, both operating on natural gas: system A consisting of an internal combustion engine, and system B consisting of a gas turbine combined cycle. System B exhibits electricity decrease due to useful heat production, whereas system A does not. The example is taken from [4] with certain modifications.

Data from annual operation are given in Table 7.4, together with threshold and reference values of efficiencies, obtained from [12] and [13], respectively. The electric efficiency reference value, in particular, is calculated as follows: It is considered that both systems have been constructed after 2006, and the initial reference value

Table 7.4 Data for the Example 7.3

Symbol	Units	System A	System B
W_e	GWh	4	1,574
H_{CHP}	GWh	2	1,488
E_f	GWh	10	4,295
β	–	–	0.24
η_{cog}	–	0.60	0.82
η_{thr}	–	0.75	0.80
η_{er}	–	0.4515	0.485625
η_{hr}	–	0.90	0.90

Table 7.5 Results for the Example 7.3

Symbol and units	Equation	System A	System B
η_e (–)	(7.7)	0.40	0.3665
η_h (–)	(7.12)	0.20	0.3464
η (–)	(7.13)	0.60	0.7129
η_{CHP} (–)	(7.48)	0.75	0.82
$W_{e,max}$ (GWh)	(7.49)	*	1,931.12
$\eta_{e,\,\max}$ (–)	(7.50)	*	0.4496
σ_{CHP} (–)	(7.51)	1.1429	0.6826
$W_{e,CHP}$ (GWh)	(7.52)	2.2857	1,015.7
$W_{e,non\text{-}CHP}$ (GWh)	(7.53)	1.7143	558.3
$E_{f,CHP}$ (GWh)	(7.54)	5.7143	3,053.3
$E_{f,non\text{-}CHP}$ (GWh)	(7.55)	4.2857	1,241.7
$\eta_{e,CHP}$ (–)	(7.56)	0.40	0.3327
$\eta_{h,CHP}$ (–)	(7.57)	0.35	0.4873
$\eta_{e,non\text{-}CHP}$ (–)	(7.59)	0.40	0.4496
E_{fer} (GWh)	(7.31)	8.8594	3,241.2
E_{fhr} (GWh)	(7.32)	2.2222	1,653.3
PES (GWh)	(7.33)	1.0816	599.5
$PESR$ (%)	(7.34)	9.76	12.25
$E_{fer,CHP}$ (GWh)	(7.61)	5.0625	2,091.5
PES_{CHP} (GWh)	(7.60)	1.5704	691.5
$PESR_{CHP}$ (%)	(7.62)	21.56	18.47
$E_{fer,non\text{-}CHP}$ (GWh)	(7.65)	3.7969	1,149.7
$PES_{non\text{-}CHP}$ (GWh)	(7.64)	−0.4898	−92
$PESR_{non\text{-}CHP}$ (%)	(7.66)	−12.9	−8

*Non-relevant.

of efficiency is 0.525. This is multiplied with a correction factor, which is obtained as follows: The electricity of both systems is consumed on site. The voltage of system A is 400 V, and the related correction factor is 0.86. The voltage of system B is 6,000 V, and the related correction factor is 0.925 [13]. Thus

for system A: $\eta_{er} = 0.525 \cdot 0.860 = 0.4515$
for system B: $\eta_{er} = 0.525 \cdot 0.925 = 0.485625$

The results are presented in Table 7.5. It is considered that $E_a = 0$.

- Comments on the results

In the Directive [12], high efficiency cogeneration is defined the cogeneration that achieves more than 10% energy savings. According to legislature in several countries, in order for a cogeneration system and the electricity it produces to be eligible for economic and financial benefits, it must be a high-efficiency cogeneration system. System A, because of poor design and operation, does not satisfy this requirement as a whole, but the CHP part has *PESR* higher than 10%. Thus, at least the CHP electricity can receive the benefits.

System B at nominal conditions has an efficiency of 82%, but the real annual efficiency is 71.29%, due to partial load operation. As a consequence, only part of the electricity is CHP electricity.

In this example, harmonized efficiency reference values dictated by the Directive [12] have been used. However, the real energy savings depend on the efficiency of the local electricity network, which can be much lower, in particular, in the case of small, isolated networks such as those on islands. It would be interesting and useful to calculate the energy savings with both harmonized and local efficiency reference values in applications of cogeneration.

Nomenclature

c	speed, m/s
c_p	specific heat capacity, kJ/kg K
CHP	combined heat and power
COP	coefficient of performance
e	specific energy, kJ/kg
E	energy, kJ
$\mathscr{E}$	flow exergy, kJ
g_e	acceleration of gravity, m/s^2
h	specific enthalpy, kJ/kg
H	heat, kJ
H_h	useful heat supplied by the cogeneration unit to thermal loads
H_q	useful heat supplied by the cogeneration unit to the absorption chiller
H_u	lower heating values, kJ/kg
$\dot{m}$	mass flow rate, kg/s
n_i	molar quantity of constituent i, kmol
p	pressure
PES	primary energy savings

$PESR$ primary energy savings ratio
Q cooling energy
R ideal gas constant, kJ/kg K
s specific entropy, kJ/kg K
T temperature
u specific internal energy, kJ/kg
v specific volume, m^3/kg
W work, kJ
x molar fraction
Z height above a reference level, m

Greek symbols

β power-loss coefficient
ε specific flow exergy, kJ/kg
η energetic efficiency
ζ exergetic efficiency
μ_{i0} chemical potential of constituent i of the system at (p_0, T_0), kJ/kmol
μ_{i00} chemical potential of constituent i of the system in the environment, kJ/kmol
ξ specific exergy of a closed system, kJ/kg
Ξ exergy of a closed system, kJ
σ electricity to heat ratio
τ period of time

Subscripts

0 reference state
a air
a absorption chiller
B boiler
c compression chiller
cog cogeneration
C Carnot (efficiency)
e electrical
f fuel
FC fuel cell
g exhaust gas
G generator
h thermal (efficiency)

I	inverter
m	mechanical
M	mixture
q	cooling
r	reference value
t	trigeneration
thr	threshold value
ul	unavoidable losses
w	waste (heat)

Superscripts

^{o}	standard environmental conditions
CH	chemical
H	heat
KN	kinetic
PH	physical
PT	potential

Overmarks

$(\dot{\ })$	power, kW
$\sim$	molar property

Appendix 7.A Fundamentals of exergy

7.A.1 Definition of exergy

For the convenience of the reader, fundamental aspects of exergy are presented in this appendix, whereas for a better knowledge, a study of the related literature is necessary [8–10].

It is true that energy is characterized not only by quantity, but also by quality. For example, the higher the temperature of a quantity of thermal energy, the higher its quality, because it can drive more processes, and it can give more work, if it is used in a thermal system. A thermodynamic property that expresses this fact is the exergy, defined as follows:

> *Exergy is the maximum theoretical useful work obtainable from an energy system as this is brought into complete thermodynamic equilibrium with the thermodynamic environment, while interacting with this environment only.*

7.A.2 Exergy of work and heat

Based on the aforementioned definition, the exergy of mechanical or electrical energy is equal to the energy itself. Thus, with reference to Figure 7.1, it is written as

$$\mathscr{E}^{W} = W \tag{7.A.1}$$

A quantity H of thermal energy available at temperature T can give theoretically the maximum work, if it is used in a Carnot cycle. With a reference temperature T_0, this work, and consequently the exergy of thermal energy, is given by the following equation:

$$\mathscr{E}^{H} = \eta_C H \tag{7.A.2}$$

where η_C is the efficiency of the Carnot cycle:

$$\eta_C = 1 - \frac{T_0}{T} \tag{7.A.3}$$

7.A.3 Exergy of a closed system

The exergy of a closed system (e.g., a substance in a container) consists of various components. The specific exergy, that is the exergy per unit of mass, is given by the equation:

$$\xi = \xi^{PH} + \xi^{KN} + \xi^{PT} + \xi^{CH} + \cdots \tag{7.A.4}$$

The components are the following:

Physical exergy (it is called also thermomechanical exergy):

$$\xi^{PH} = (u - u_0) + p_0(v - v_0) - T_0(s - s_0) \tag{7.A.5}$$

Kinetic exergy: $$\xi^{KN} = e^{KN} = \frac{c^2}{2} \tag{7.A.6}$$

Potential exergy: $$\xi^{PT} = e^{PT} = g_e Z \tag{7.A.7}$$

Chemical exergy: $$\xi^{CH} = \frac{1}{m} \sum_i (\mu_{i0} - \mu_{i00}) n_i \tag{7.A.8}$$

The symbols appearing in (7.A.5)–(7.A.8) have the following meaning:

u, v, s — specific internal energy (kJ/kg), specific volume (m^3/kg), and specific entropy (kJ/kg K) of the system at state (p, T),

u_0, v_0, s_0 — specific internal energy, volume, and entropy of the system at the reference state (p_0, T_0); usually it is considered

$$p_0 = 1 \text{ atm} = 1.01325 \text{ bar}$$
$$T_0 = 25\ ^\circ\text{C} = 298.15 \text{ K}$$

e^{KN} specific kinetic energy (kJ),
e^{PT} specific potential energy (kJ),
c speed of the system (m/s),
g_e acceleration of gravity (m/s^2),
Z height of the system above a reference level (m),
m mass of the system (kg),
μ_{i0} chemical potential of constituent i of the system at (p_0, T_0) (kJ/kmol),
μ_{i00} chemical potential of constituent i of the system in the environment (kJ/kmol),
n_i molar quantity of constituent i (kmol).

The total exergy of the system and its components are given by the following equations:

$$\Xi = m\xi \quad \Xi^j = m\xi^j \quad j = PH, KN, PT, CH \tag{7.A.9}$$

The dots ($\cdots$) in (7.A.4) indicate that there may be other components of exergy too, such as nuclear exergy, exergy of electric or magnetic field, and others, but they are omitted for brevity. Instead of explicit application of (7.A.8), chemical exergy of various substances can be obtained directly from tables published in the literature [8–10].

7.A.4 Flow exergy

The specific exergy of a flowing substance is given by the equation:

$$\varepsilon = \varepsilon^{PH} + \varepsilon^{KN} + \varepsilon^{PT} + \varepsilon^{CH} + \cdots \tag{7.A.10}$$

The components are the following:

$$\text{Physical exergy:} \qquad \varepsilon^{PH} = (h - h_0) - T_0(s - s_0) \tag{7.A.11}$$

$$\text{Kinetic exergy:} \qquad \varepsilon^{KN} = \xi^{KN} = \frac{c^2}{2} \tag{7.A.12}$$

$$\text{Potential exergy:} \qquad \varepsilon^{PT} = \xi^{PT} = g_e Z \tag{7.A.13}$$

$$\text{Chemical exergy:} \qquad \varepsilon^{CH} = \xi^{CH} \tag{7.A.14}$$

In (7.A.11), h (kJ/kg) is the specific enthalpy of the substance at state (p, T), and h_0 is the specific enthalpy of the substance at state (p_0, T_0). The same is valid for the specific entropy s and s_0.

The total exergy of the flowing substance and its components are given by the equations:

$$\mathcal{E} = m\varepsilon \quad \mathcal{E}^j = m\varepsilon^j \quad j = PH, KN, PT, CH \tag{7.A.15}$$

In many applications, the difference of physical exergy between two states appears, which is obtained by application of (7.A.12):

$$\varepsilon^{PH}_{1\to 2} = \varepsilon^{PH}_2 - \varepsilon^{PH}_1 = (h_2 - h_1) - T_0(s_2 - s_1) \tag{7.A.16}$$

7.A.5 Physical flow exergy of ideal gas and of mixture of ideal gases

The ideal gas approximation, that is the assumption that the specific heat capacity of a gas is function of temperature only (not of pressure), is satisfactory in many applications. The specific physical flow exergy of an ideal gas is given by the following equation:

$$\varepsilon^{PH} = \int_{T_0}^{T} c_p \, dT - T_0 \int_{T_0}^{T} c_p \frac{dT}{T} + R\, T_0 \, \ell n \frac{p}{p_0} \tag{7.A.17}$$

where c_p is the specific heat capacity of the ideal gas (kJ/kg K), R is the ideal gas constant (kJ/kg K).

If the perfect gas approximation is acceptable, that is the assumption that the specific heat capacity of a gas is constant (independent of both pressure and temperature), then (7.A.17) takes the simpler form:

$$\varepsilon^{PH} = c_p \left(T - T_0 - T_0 \, \ell n \frac{T}{T_0} \right) + R T_0 \, \ell n \frac{p}{p_0} \tag{7.A.18}$$

The molar physical exergy (i.e., the exergy per mole) of a mixture of ideal gases is given by the equation:

$$\tilde{\varepsilon}_M^{PH} = \sum_i x_i \tilde{\varepsilon}_i^T + \tilde{R}\, T_0 \, \ell n \frac{p}{p_0} \tag{7.A.19}$$

where:

$$\tilde{\varepsilon}_i^T = \int_{T_0}^{T} \tilde{c}_{pi} dT - T_0 \int_{T_0}^{T} \tilde{c}_{pi} \frac{dT}{T} \tag{7.A.20}$$

x_i molar fraction of constituent i in the mixture,
$\tilde{c}_{pi}$ molar heat capacity of constituent i of the mixture (kJ/kmol K).

If the perfect gas approximation is acceptable, then (7.A.20) takes the simpler form:

$$\tilde{\varepsilon}_i^T = \tilde{c}_{pi} \left(T - T_0 - T_0 \, \ell n \frac{T}{T_0} \right) \tag{7.A.21}$$

7.A.6 Physical flow exergy of incompressible fluids

For an incompressible fluid, the specific heat capacity c_p is a function of the temperature only, whereas the specific volume v is constant. The physical flow exergy of such a fluid is given by the equation:

$$\varepsilon^{PH} = \int_{T_0}^{T} c_p \, dT - T_0 \int_{T_0}^{T} c_p \frac{dT}{T} + v(p - p_0) \tag{7.A.22}$$

If c_p can be considered constant (usually an average value between the two states gives satisfactory results), then a simpler form is obtained:

$$\varepsilon^{PH} = c_p\left(T - T_0 - T_0\,\ell n\frac{T}{T_0}\right) + v(p - p_0) \tag{7.A.23}$$

Appendix 7.B Power-to-heat ratio in full cogeneration mode

Equation (7.51a) for the power-to-heat ratio in full cogeneration mode has been obtained from [14]. The proof is transferred here from [4].

By definition it is $$\sigma_{CHP} = \frac{W_{e,CHP}}{H_{CHP}} \tag{7.B.1}$$

Consequently, $$W_{e,CHP} = \sigma_{CHP} H_{CHP} \tag{7.B.2}$$

If a cogeneration unit with a condensing-extraction steam turbine under certain operating conditions produces electrical energy W_e and useful heat H_{CHP}, then the electrical efficiency of the system operating in fully condensing mode (i.e., with no useful heat production) is calculated by the equation[4]:

$$\eta_{e,\max} = \frac{W_e + \beta H_{CHP}}{E_f} \tag{7.B.3}$$

which is derived from (7.49) and (7.50).

A fundamental assumption is made that the electrical efficiency of the non-CHP part of a cogeneration system is equal to $\eta_{e,\max}$:

$$\eta_{e,non\text{-}CHP} \equiv \frac{W_{e,non\text{-}CHP}}{E_{f,non\text{-}CHP}} = \eta_{e,\max} \tag{7.B.4}$$

It is:

$$W_{e,non\text{-}CHP} = W_e - W_{CHP} = W_e - \sigma_{CHP} H_{CHP} \tag{7.B.5}$$

$$E_{f,non\text{-}CHP} = E_f - E_{f,CHP} = E_f - \frac{W_{e,CHP} + H_{CHP}}{\eta_{CHP}} \tag{7.B.6}$$

$$W_{e,CHP} + H_{CHP} = \sigma_{CHP} H_{CHP} + H_{CHP} = (\sigma_{CHP} + 1) H_{CHP} \tag{7.B.7}$$

From (7.B.3):

$$W_e = \eta_{e,\,\max} E_f - \beta H_{CHP} \tag{7.B.8}$$

[4]More generally, this applies to any system where the production of useful heat results in decrease of electrical or mechanical power.

Equations (7.B.4)–(7.B.7) lead to the following:

$$\eta_{e,\max} = \frac{W_{e,non\text{-}CHP}}{E_{f,non\text{-}CHP}} = \frac{W_e - \sigma_{CHP}H_{CHP}}{E_f - \left[\left(W_{e,CHP} + H_{CHP}\right)/\eta_{CHP}\right]}$$
$$= \frac{W_e - \sigma_{CHP}H_{CHP}}{E_f - [\{(\sigma_{CHP}+1)H_{CHP}\}/\eta_{CHP}]} \Rightarrow$$

$$\eta_{e,\max}E_f - \frac{\eta_{e,\max}}{\eta_{CHP}}(\sigma_{CHP}+1)H_{CHP} = W_e - \sigma_{CHP}H_{CHP}$$
$$= \eta_{e,\max}E_f - \beta H_{CHP} - \sigma_{CHP}H_{CHP} \Rightarrow \frac{\eta_{e,\max}}{\eta_{CHP}}(\sigma_{CHP}+1) = \beta + \sigma_{CHP}$$

Solution of the last equation with respect to σ_{CHP} gives the requested equation:

$$\sigma_{CHP} = \frac{\eta_{e,\max} - \beta\eta_{CHP}}{\eta_{CHP} - \eta_{e,\max}} \tag{7.51a}$$

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Chapter 8

Environmental impacts of cogeneration

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8.1 Introduction

Application of cogeneration may have both positive and negative effects on depletion of non-renewable energy resources, on the environment, and on the society. Environmental effects, in particular, can be distinguished in effects on air, water, and soil quality, as well as on noise and vibration.

Since cogeneration increases the efficiency of fuel utilization, it can lead to decreased emission of pollutants to the environment. Furthermore, since the whole fuel cycle includes steps such as exploration, extraction, refining, processing, transportation, and storage, not only the direct emissions from the use (burning) of fuel, but also the emissions of the whole fuel cycle can be decreased. However, depending on the cogeneration technology and the fuel used, it is possible that certain emissions may increase with cogeneration.

Another issue is the following: central power plants, usually located far from urban areas, are equipped with pollution-abatement equipment, and the exhaust gases are dispersed by tall stacks. If the electricity produced by a central power plant is to be produced by relatively small and dispersed cogeneration systems that are close, even inside urban areas, then the effect of cogeneration on the particular environment may be negative.

In addition to the effect on air quality, the installation and operation of a cogeneration system may cause soil and water pollution due to fuel transportation and handling, as well as waste disposal (sludge, ash, and degraded lubricating oil).

In order to minimize the adverse effects of a cogeneration system, in particular if it is to be installed in a densely populated area, certain measures have to be taken, such as the following:

- careful selection of the site,
- selection of cogeneration technology with low emissions,
- installation of pollution control and abatement equipment,
- installation of elastic foundation, as well as sound insulation and attenuation,
- construction of a stack higher than the surrounding buildings, and
- provision for safe collection and removal of liquid and solid wastes.

The effects on the environment and the society are often interrelated: increased pollutants have an adverse effect on the health of the population, the building, the flora, and fauna.

The aforementioned indicate that a careful assessment of each particular application of cogeneration from the environmental point of view is necessary, so that proper measures to be taken early enough. The purpose of this chapter is to present a procedure for such an evaluation.

8.2 Definitions and emissions impact categories

The correct definition and calculation of environmental effects in correlation to fuel allocation are necessary to obtain a clear picture of what is possible to gain in environmental protection by using cogeneration systems. Environmental local and global impacts of cogeneration in general can be related to (i) depletion of non-renewable natural resources and (ii) release of emissions and other harmful wastes into the environment. These adverse effects are directly connected to each other. The use of non-renewable natural resources is accelerated by the neutralization or avoidance of the harmful waste substances. Moreover, the level of emissions and the pollution caused by them are dependent on the fuel consumption in the cogeneration system.

The following terms are defined:

- "Emission," based on the Directive 2010/75/EU [1], should be understood as the direct or indirect release of substances, vibrations, heat or noise from individual or separated sources in the installation into air, water, or land.
- "Pollution" means the direct or indirect introduction, as a result of human activity, of substances, vibrations, heat or noise into air, water, or land, which may be harmful to human health (HH) or the quality of the environment, results in damage to material property, or impair or interfere with amenities and other legitimate uses of the environment.
- "Direct emission" will be called emission produced by a plant locally during its operation.
- "Cumulative emission" will be called emission related to the whole cycle of a fuel, which includes steps such as exploration, extraction, refining, processing, transportation, storage, recycling, and decommissioning.

The environmental impacts of emissions can be estimated for four main areas of protection: HH, natural resource depletion, quality of ecosystem, and man-made environment (ME) [2]. Some of them are divided into various impact categories that are presented in Table 8.1 [3]. The impact categories are divided into midpoint and endpoint impact categories. The endpoint category—damage to HH, damage to ecosystem diversity (ED), damage to resource availability (RA), and damage to the ME—are directly related to areas of protection. Although an important link between midpoints and endpoints exists, the quantitative connections are established only for some of them.

Table 8.1 Connection between midpoint and endpoint impact categories [3]

Midpoint impact category	Endpoint impact category			
	HH	**ED**	**RA**	**ME**
Climate change	+	+		+
Terrestrial acidification		+		
Freshwater eutrophication		+		
Human toxicity	+			
Particulate matter formation	+			
Agricultural land occupation		+		
Water depletion			+	
Mineral resource depletion			+	
Fossil fuel depletion			+	
Noise	+			
Vibration	+			
Corrosion and defects in construction building materials				+

Most of the waste products such as harmful substances, heat, or noise released from different processes to the surroundings are dispersed in the environment at local and global level. The harmful substances react with various environmental components, and their impacts on the environment are defined by midpoints and endpoints. Moreover, dispersion of harmful substances leads to environmental damage, as well as damage of products manufactured by humans. These damages cause direct and indirect destruction of natural resources.

Direct destructions occur due to damage in forests, fields, or water, whereas indirect destruction is due to compensation or prevention of damages. Harmful substances cause various diseases, leading to the restricted activity days and work loss days, or in extreme cases, to death of people; moreover, they affect the construction elements of machines, buildings, or transportation equipment and cause their corrosion or other defects. Harmful wastes that are captured, mitigated, or neutralized do not cause direct damage to the surroundings; however, the installations where these actions occur, cause the degradation of natural resources due to the requirement of additional resource for their construction, maintenance, and operation.

The degree of destruction of natural resources depends on the location of the emission source and the primary concentration of the harmful substances in the environment. Nowadays, the most developed model of pollutant dispersion connected with other environmental and economic aspects is presented in ExternE methodology [4,5], which will be applied also here for cogeneration systems.

8.3 Effects on air quality

The most important concern regarding the environmental effects of cogeneration is the effect on air quality, in particular because cogeneration systems are often installed near or inside urban areas. Thus, gaseous emissions may decrease in the area of the power plant substituted by the cogeneration system, but may increase in the place where the system is installed. Thus, a careful balance of emissions with and without cogeneration has to be performed in order to assess the consequences and take appropriate measures for reducing the impact and protect the environment and the population.

8.3.1 Irreversibility, fuel use, and emissions

The positive energetic and ecological effects of cogeneration arise from the reduction (shortening) of the chain of irreversible thermodynamic processes. The thermodynamic perfection of the process can be investigated through exergy analysis. Fundamentals of exergy analysis are provided in Appendix 7.A (Chapter 7). Exergy, defined as the maximum ability to perform work with respect to the ambient environment, represents the common measure of energy carriers quality, for example, heat and electricity generated in a combined heat and power (CHP) plant. Each loss of exergy leads directly to a reduction in the ability to perform useful work [6]. Shortening the chain of the productive processes by CHP application leads to the decrease of the exergy losses that were accompanying these processes, with a consequence the reduction of the fuel consumption while maintaining the same level of production.

The reduction of fuel consumption causes reduction of harmful emissions and greenhouse gases (GHGs) that entail lower impact on the environment. Figure 8.1 shows the connection between fuel ($\mathscr{E}_f$), product ($\mathscr{E}_p$), exergy losses ($\delta\mathscr{E} = \delta\mathscr{E}_D + \delta\mathscr{E}_L$), emissions, and their impact on the environment. For the same product, fuel consumption and emissions are lower in case 2, because of reduction in exergy losses—internal $\delta\mathscr{E}_D$ caused by process irreversibility and external $\delta\mathscr{E}_L$ caused by generation of waste products (e.g., flue gases).

In this case, fuel means chemical energy or exergy (E_f, $\mathscr{E}_f$), whereas the product expresses exergy of both heat and electricity ($\mathscr{E}_p$). Figure 8.1 shows that the emission level depends on the fuel consumption, which is dependent on exergy efficiency.

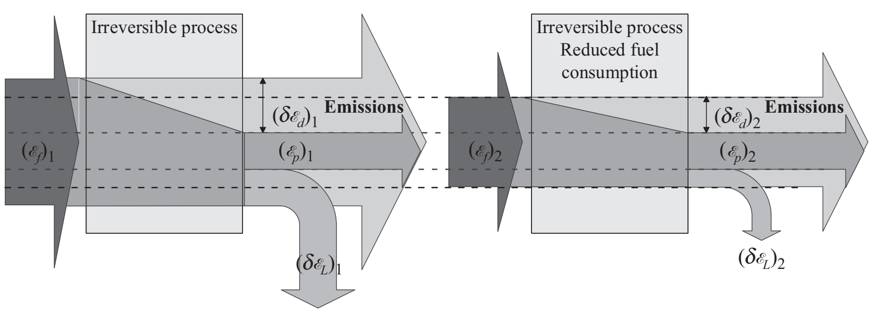

Figure 8.1 Exergy losses and environmental impacts
Legend: 1—regular fuel consumption, 2—lower fuel consumption with the same production as in case 1.

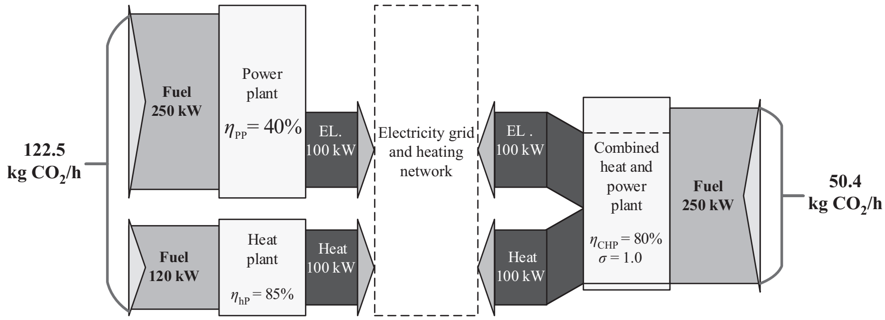

Figure 8.2 Direct primary energy and CO_2 savings due to CHP

Application of cogeneration can lead to significant savings in primary energy consumption, which directly decreases various waste products generation, for example, harmful substances or GHGs. The simplified evaluation of interaction between energy effects and emissions of cogeneration resulting from improved thermodynamic performance by reducing the primary energy consumption is presented in Figure 8.2.

According to Figure 8.2 and the definition of primary energy savings ratio of (7.34), from Chapter 7, the reduction of chemical energy consumption in the presented example is as follows[1]:

$$\mathrm{PESR} = \frac{\dot{E}_{f\mathrm{PP}} + \dot{E}_{fHP} - \dot{E}_{f\,\mathrm{CHP}}}{\dot{E}_{f\mathrm{PP}} + \dot{E}_{f\mathrm{HP}}} = 32.4\%$$

where $\dot{E}_{f\mathrm{PP}}$ is the chemical energy consumed in reference power plant (250 kW); $\dot{E}_{f\mathrm{HP}}$ is the chemical energy consumed in reference heat plant (120 kW); and $\dot{E}_{f\mathrm{CHP}}$ is the chemical energy consumed in cogeneration plant (250 kW).

As an example, the reduction of direct CO_2 emissions will be considered. If the fuel of all three systems (power plant, heat plant, and CHP plant) were the same, the reduction would be the same as the fuel reduction (32.4%). The values in Figure 8.2 are based on the following assumptions:

1. the separate production of heat and electricity is based on coal combustion, whereas the CHP plant is fueled by natural gas,
2. direct CO_2 emissions factor of hard coal (hc) combustion: $e_{\mathrm{CO2\,hc}} = 92.0\,\mathrm{g/kJ}$,
3. direct CO_2 emissions factor of natural gas (ng) combustion: $e_{\mathrm{CO2\,ng}} = 56.0\,\mathrm{g/kJ}$ [7].

[1]Throughout this chapter, the subscripts *PP*, *HP*, and *CHP* will denote the power plant, the heat plant (e.g., a boiler), and the cogeneration plant as a whole, respectively.

Then the result is:

$$\Delta e_{CO2} = \frac{\left(\dot{E}_{f\mathrm{PP}} + \dot{E}_{f\mathrm{HP}}\right)e_{\mathrm{CO2\,hc}} - \dot{E}_{f\,\mathrm{CHP}}e_{\mathrm{CO2\,ng}}}{\left(\dot{E}_{f\mathrm{PP}} + \dot{E}_{f\mathrm{HP}}\right)e_{\mathrm{CO2\,hc}}} = \frac{122.5 - 50.4}{122.5} = 58.9\%$$

Thus, fuel switching has a significant effect on emissions, which is positive (further reduction of emissions) in this example.

8.3.2 Estimation of direct gaseous emissions

The exhaust gases of combustion contain many substances. Of high concern, due to their impact on the environment, are carbon dioxide (CO_2), carbon monoxide (CO), nitrogen oxides (NO_x), sulfur oxides (SO_x, usually taken into consideration as sulfur dioxide, SO_2), unburned hydrocarbons (a mixture of hydrocarbons, referred to as UHC), and solid particles (also called "particulates").

The quantity of each emission depends on the type and quantity of fuel, the cogeneration technology, the age and state of the particular equipment, the operating conditions, the abatement units, if present, and others. The mass flow rate of emitted substance k due to use if fuel f is given by the equation:

$$\dot{m}_{kf} = \dot{E}_f\, e_{kf} \tag{8.1}$$

where e_{kf} is the direct emission factor of substance k due to combustion of fuel f, and $\dot{E}_f$ is the energy flow rate of fuel:

$$\dot{E}_f = \dot{m}_f H_{uf} \tag{8.2}$$

$\dot{m}_f$ is the mass flow rate of fuel f, and, H_{uf} is the lower heating value of fuel f.

Equations (8.1) and (8.2) are valid also without the dot: mass and energy, instead of mass flow rate and energy flow rate.

The estimation of e_{kf} by means of basic principles is possible in simple cases only, while for other cases, emission factors from literature or manufacturers are used, as it will be demonstrated in the following sections.

8.3.2.1 Estimation of CO_2 emissions

If combustion takes place with excess air, and the combustion equipment is in good condition and adjustment, then complete combustion can be assumed, according to the reaction:

$$C + O_2 = CO_2$$

Taking into consideration the molar masses of C, O_2, and CO_2 (12, 32, and 44, respectively), the following equation is derived:

$$m_{CO_2} = \frac{44}{12} m_C = \frac{44}{12} c_f m_f = \frac{44}{12} c_f \frac{E_f}{H_{uf}} \tag{8.3}$$

where m_C is the mass of carbon in the fuel; m_f is the fuel burned; c_f is the mass content of carbon in fuel: $c_f = m_C/m_f$; and E_f is the energy of the fuel burned, based on the lower heating value.

Table 8.2 Typical values of lower heating value and specific CO_2 emissions of fuels [8]

Fuel	**Carbon content (c_f 100) (%)**	**CO_2 emissions $\mu_{CO_2 f}$ (kg CO_2/kg fuel)**	**Lower heating value H_{uf} (kJ/kg)**
Natural gas	75	2.75	49,000
Diesel oil	83	3.05	42,500
Fuel oil, 0.7%S	86.5	3.17	41,500
Fuel oil, 2%S	85	3.12	41,000
Peat*	58	2.13	7,800
Lignite*	64	2.35	24,000
Coal	80	2.93	30,000

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

Comparison of (8.3) with (8.1) gives the equation for the direct emission factor of CO_2:

$$e_{CO_2 f} = \frac{44}{12}\frac{c_f}{H_{uf}} \tag{8.4}$$

One more useful parameter is obtained from (8.3), the specific emissions of CO_2, that is, the mass of emitted CO_2 per unit mass of fuel:

$$\mu_{CO_2 f} = \frac{44}{12}c_f \tag{8.5}$$

Depending on the available information, either $e_{CO_2 f}$ or $\mu_{CO_2 f}$ can be used for the calculations. Typical values of $\mu_{CO_2 f}$ and H_{uf} for certain fuels are given in Table 8.2.

Of course, CO can also be present in the exhaust gases, which results in a decrease of CO_2, which can be taken into consideration and modify the results of (8.4) and (8.5) properly. However, the quantity of CO is orders of magnitude lower than the quantity of CO_2 and, consequently, the error introduced by accepting the results of (8.4) and (8.5) with no correction is negligible.

8.3.2.2 Estimation of SO_2 emissions

Combustion of fuel containing sulfur results in a mixture of sulfur oxides with SO_2 as predominant. If complete combustion of sulfur to SO_2 is considered, then the reaction equation is the following:

$$\mathrm{S} + \mathrm{O}_2 = SO_2$$

Taking into consideration the molar masses of S, O_2, and SO_2 (32, 32, and 64, respectively), the following equation is derived:

$$m_{SO_2} = \frac{64}{32}m_S = \frac{64}{32}s_f m_f = 2s_f\frac{E_f}{H_{uf}} \tag{8.6}$$

where m_S is the mass of sulfur in the fuel, and s_f is the mass content of sulfur in fuel: $s_f = m_S/m_f$.

Comparison of (8.6) with (8.1) gives the equation for the direct emission factor of SO_2:

$$e_{SO_2\,f} = 2\frac{s_f}{H_{uf}} \tag{8.7a}$$

One more useful parameter is obtained from (8.6), the specific emissions of SO_2, that is, the mass of emitted SO_2 per unit mass of fuel:

$$\mu_{SO_2\,f} = 2s_f \tag{8.8a}$$

If SO_2 abatement equipment is installed, then the final emission of SO_2 into the environment is given by the equations:

$$e^a_{SO_2\,f} = \left(1 - \eta_{SO_2}\right)e_{SO_2\,f} = 2\left(1 - \eta_{SO_2}\right)\frac{s_f}{H_{uf}} \tag{8.7b}$$

or

$$\mu^a_{SO_2\,f} = \left(1 - \eta_{SO_2}\right)\mu_{SO_2\,f} = 2\left(1 - \eta_{SO_2}\right)s_f \tag{8.8b}$$

where η_{SO_2} is the efficiency of the abatement equipment or, in other words, the fraction of the initial quantity of SO_2, which is abated.

8.3.2.3 Estimation of emissions by use of empirical data

If the estimation of emissions by application of basic principles is not possible, then empirical factors available in the literature or provided by manufacturers of equipment can be used. Examples of factors are given in Tables 8.3–8.5.

Table 8.3 Emission factors for selected CHP plants expressed in g/GJ of fuel [9]

Emission species	Natural gas CHP 50–1,000 kW$_e$ Lean burn motor and no catalyst	Natural gas CHP 160 kW$_e$ Lambda 1 motor and three-way catalyst	Diesel CHP 200 kW$_e$ SCR and oxidation catalysts
Nitrogen oxides	70.00	15.00	70.00
Carbon monoxide	160.00	48.00	150.00
Carbon dioxide	56,000.00	56,000.00	73,700.00
Methane	80.00	23.00	12.00
NMVOC*	10.00	2.00	50.00
Sulfur dioxide	0.55	0.55	50.00
Dinitrogen monoxide	5.00	2.50	5.00
Particulates, <25 μm	0.15	0.15	1.00

*Non-methane volatile organic compounds.

Table 8.4 General information and emissions factors for selected power technologies (emissions factors are expressed per unit of fuel consumption) [10,11]

Power plant data including emissions	Units	IGCC			EXPC	SCPC	NGCC	CHP avg
		GEE R+Q	CoP E-Gas FSQ	Shell	Sub-critical	Super-critical		
Gross power output	MW_e	748	738	737	583	580	565	
Net power output	MW_e	622	625	629	550	550	555	
Coal flow rate	kg/s	58.83	57.95	55.02	55.11	51.60		
Natural gas flow rate	kg/s						21.08	Fuel: natural gas
Chemical energy of fuel	MW	1,595	1,574	1,494	1,495	1,399	1,106	
Net plant HHV efficiency	–	0.39	0.40	0.42	0.37	0.39	0.50	
HHV	MJ/kg	27.11	27.17	27.16	27.12	27.12	52.45	
CO_2	kg/GJ	84.69	85.55	84.69	87.70	87.70	50.73	56
SO_2	g/GJ	0.52	5.03	1.81	36.89	36.89	0.00	0.55
NO_x	g/GJ	25.37	21.07	21.07	21.07	30.09	3.87	15
PM	g/GJ	3.05	3.05	3.05	5.59	5.59	0.00	0.15

CHP, fed by natural gas with three-way catalyst lambda 1; CoP E-Gas FSQ, ConocoPhillips gasifier technology; EXPC, existing pulverized coal; GEE R+Q, General Electric energy radiant only; IGCC, integrated gasification combined cycle; NGCC, natural gas combined cycle; SCPC, supercritical pulverized coal; Shell, Shell Global Solutions (Shell) gasifiers [11].

Table 8.5 Emission factors for solid fuels combustion, kilograms of emission per ton of fuel [12]

Emission	Pulverized boilers			Mechanical grid			Boilers with fixed grid					
	Deslagging		Cyclonic	More than 20 t/h	5–20 t/h	Less than 5 t/h	Coal				Coke	
	Wet	Dry					Water		Steam			
							nt	fr	nt	fr	nt	fr
Dust	6p	9p	1.5p	3p	2.5p	2p	1p	2p	1p	2p	1p	2p
SO_x	19s	19s	19s	17s	16s	16s	16s	16s	16s	16s	16s	16s
NO_x	14.5	8.5	27.4	4.3	3.4	3.0	1.7	2.6	1.7	2.6	2.6	3.0
CO	1	1	1	1	3.5	5.0	45	45	45	45	25	25

Notes: The results of calculation are expressed in kg/t; mass fraction of the dust (p) and sulfur (s) in the fuel should be expressed as a percentage; nt, passage of natural air; fr, passage of forced air.

8.3.3 Local and global balance of direct gaseous emissions

In order to compare cogeneration with separate production of electricity and heat from the point of view of gaseous emissions, an emission balance for each emitted substance has to be performed at both local and global levels. The equations will be written in a way that positive numbers indicate reduction of an emission with cogeneration (emission "savings"), in the same way as positive PES indicates reduction of fuel consumption with cogeneration.

- Local balance of direct emissions

With no cogeneration, the electricity may come from a power plant far from the site, the emissions of which do not reach the users of electricity, while heat is produced locally by, for example, a boiler. In such a case, the emissions balance of an emitted substance is written:

$$\Delta \dot{m}_k = \dot{m}_{k\,\mathrm{HP}} - \dot{m}_{k\,\mathrm{CHP}} \tag{8.9}$$

It is worth noting that certain cogeneration technologies, for example, internal combustion engines, may have increased emissions of CO, NO_x, and UHC, compared to central power plants. If such a cogeneration system is to be installed in a densely populated area, then it may be necessary to install pollution abatement equipment.

- Global balance of direct emissions

It is considered that cogeneration replaces electricity coming from a power plant and heat produced by a boiler. The difference in the quantity of an emitted substance, no matter where the plants are located, is given by the equation:

$$\Delta \dot{m}_k = (\dot{m}_{k\mathrm{PP}} + \dot{m}_{k\,\mathrm{HP}}) - \dot{m}_{k\,\mathrm{CHP}} \tag{8.10}$$

where $\dot{m}_{k\,\mathrm{PP}}$ is the emission of substance k in separate production of electricity (kg/s); $\dot{m}_{k\,\mathrm{HP}}$ is the emission of substance k in separate production of heat (kg/s); and $\dot{m}_{k\,\mathrm{CHP}}$ is the emission of substance k in cogeneration (kg/s).

As with the PES, positive value of $\Delta \dot{m}_k$ means that cogeneration "saves" emissions, that is, it reduces emissions compared to the separate production of electricity and heat.

The importance of performing both global and local balances will be highlighted by the following example.

Other considerations may lead to different expressions for the emissions balance; the reader can develop the equation that is pertinent to the particular application.

Example 8.1 A user is currently supplied with electricity from a power plant located far away, so that its emissions do not reach the user, while heat is produced locally by a boiler. The installation of a cogeneration unit with a gas engine is investigated with two options: (i) a unit with no catalyst and (ii) a unit with a three-way catalyst. The unit will produce 1,000 kW_e of electricity and 1,125 kW_h of heat. Additional data are given in Table 8.6. The effect of the cogeneration unit on the local and global environment referred to direct gaseous emissions is requested.

Table 8.6 Data for the Example 8.1

Item	**Power plant**	**Boiler**	**CHP unit**	
			No catalyst	**With catalyst**
Fuel	Coal	Natural gas	Natural gas	Natural gas
Efficiency, η	0.40	0.90	0.85	0.85
e_{CO_2}, kg/GJ	90	56	56	56
e_{CO}, g/GJ	17	7	160	48
e_{NO_x}, g/GJ	21	20	70	15
e_{SO_2}, g/GJ	37	0.55	0.55	0.55
e_{UHC}, g/GJ	5	5	80	23
e_{part}, g/GJ	6	1	0.15	0.15

- Solution

  Using the power output and the efficiency of each facility, the chemical energy flow rates of the fuels are obtained:

$$\dot{E}_{f\,\mathrm{PP}} = \frac{1{,}000\ \mathrm{kW}}{0.40} = 2,500\ \mathrm{kW_{hc}}, \qquad \dot{E}_{f\,\mathrm{HP}} = \frac{1{,}125\ \mathrm{kW_e}}{0.90} = 1,250\ \mathrm{kW_{ng}}$$

$$\dot{E}_{f\,\mathrm{CHP}} = \frac{2{,}125\ \mathrm{kW_h}}{0.85} = 2,500\ \mathrm{kW_{ng}}$$

The effect of cogeneration on local and global direct emissions is determined by (8.9) and (8.10), respectively. The results are summarized in Table 8.7.

According to the results for the particular technologies considered, cogeneration increases local direct emissions (except of particulates). At global level, CO_2, SO_2, and particulates are decreased, CO and UHC are increased either with or without a catalyst, while NO_x is increased with no catalyst and decreased with a catalyst. The positive effect of a catalyst is also evident from the results at both local and global level.

Table 8.7 Results of the Example 8.1

Emission	**Local balance**		**Global balance**	
	No catalyst	**With catalyst**	**No catalyst**	**With catalyst**
$\Delta\dot{m}_{CO_2}$, kg/h	−252	−252	+558	+558
$\Delta\dot{m}_{CO}$, g/h	−1,408.5	−400.5	−1,255.5	−247.5
$\Delta\dot{m}_{NO_x}$, g/h	−540	−45	−351	+144
$\Delta\dot{m}_{SO_2}$, g/h	−2.475	−2.475	+330.5	+330.5
$\Delta\dot{m}_{UHC}$, g/h	−697.5	−184.5	−652.5	−139.5
$\Delta\dot{m}_{part}$, g/h	+3.15	+3.15	+57.15	+57.15

- A note of caution
  The results obtained are strongly influenced by the assumptions made and the values of parameters considered. They should not be used to draw any general conclusions regarding the effect of cogeneration.

8.3.4 The various substances that affect global warming

The various gaseous substances that affect global warming are called GHGs and include compounds of three or more atoms. The most frequently mentioned compounds are carbon dioxide, methane, and nitrous oxide. The industrial plants, including CHP facilities, are obliged to monitor the GHG emissions. The global warming potential (GWP), which is assigned to various GHG, is a characterization factor describing the radiative forcing impact of one mass-based unit of a given GHG relative to that one of carbon dioxide over a given period of time. GWP is expressed in carbon dioxide equivalent CO_{2e}, which is the unit for comparing the radiative forcing of a GHG to that one of carbon dioxide. The list of GHG and their GWP is developed by Intergovernmental Panel on Climate Change (IPCC) [7]. For example, the GWP of methane is estimated to be 28 kg CO_{2e}/kg CH_4.

Example 8.2 The influence of the CHP application process on the reduction of global direct CO_2 emissions obtained due to the savings of the chemical energy consumption in comparison with the separate heat and power generation will be demonstrated in this example.

Application of (8.10) and (8.1) gives the following equation for the relative change of global direct CO_2 emissions (change with respect to the CO_2 emission, $m_{CO_2,PPHP}$, of the separate production of electricity by a power plant and heat by a heat plant):

$$\frac{\Delta m_{CO_2}}{m_{CO_2,PPHP}} = \frac{\left(m_{CO_2PP} + m_{CO_2HP}\right) - m_{CO_2CHP}}{m_{CO_2PP} + m_{CO_2HP}}$$

$$= \frac{\left(E_{fPP}\, e_{CO_2PP} + E_{fHP}\, e_{CO_2HP}\right) - E_{fPP}\, e_{CO_2CHP}}{E_{fPP}\, e_{CO_2PP} + E_{fHP}\, e_{CO_2HP}} \tag{a}$$

Let us consider that the cogeneration system, as well as the power plant and the heat plant it replaces, use the same fuel. Then it is:

$$e_{CO_2PP} = e_{CO_2HP} = e_{CO_2CHP} \tag{b}$$

and (a) takes the form:

$$\frac{\Delta m_{CO_2}}{m_{CO_2,PPHP}} = \frac{\left(E_{fPP} + E_{fHP}\right) - E_{fPP}}{E_{fPP} + E_{fHP}} = \text{PESR} \tag{c}$$

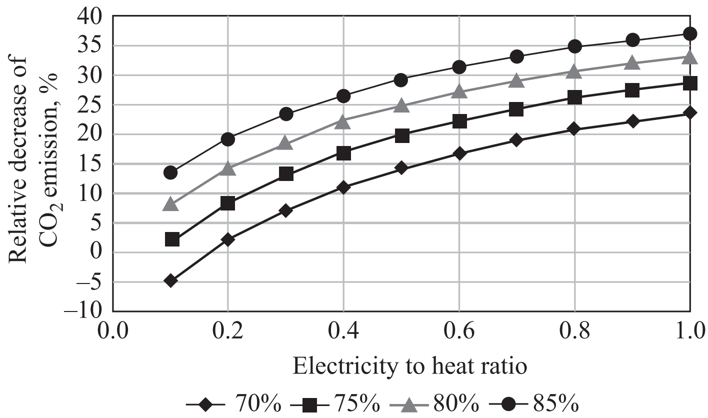

Figure 8.3 Global change of direct CO_2 emission due to application of cogeneration

The preceding equation (c) and (7.35a) of Chapter 7, give the following equation (with the symbols used in this chapter):

$$\frac{\Delta m_{CO_2}}{m_{CO_2,PPHP}} = 1 - \frac{\sigma + 1}{\eta_{CHP}[(\sigma/\eta_{PP}) + (1/\eta_{HP})]} \tag{d}$$

where σ is the power to heat ratio (–); η_{PP} is the efficiency of the power plant (–); η_{HP} is the efficiency of the heat plant (–); and η_{CHP} is the total efficiency of the cogeneration system (–).

The effect of σ and η_{CHP} on the relative change of the direct CO_2 emission is depicted in Figure 8.3, which has been drawn for $\eta_{PP} = 0.40$ and $\eta_{HP} = 0.80$. Negative values mean that the CO_2 emission increases with cogeneration.

8.3.5 Allocation of fuel and emissions of a cogeneration system to its products

In the analysis of multi-product systems, it is often interesting and useful to allocate the resources used (either physical or economic) to its products. In cogeneration systems, for example, the fuel used can be allocated to the two products—electricity and heat. If this is done, then the emissions can be divided between the two products, in proportion to the allocated fuel. The difficulty, however, arises from the fact that, mathematically, there are two unknowns and only one equation. Thus, there is need of additional considerations in order to perform the allocation. Three of the most usual methods for this purpose are the following [6,13]:

1. *Energy method (physical division)*: The chemical energy of fuel is allocated between heat and electricity in proportion to the electricity-to-heat ratio. The basic drawback of this approach is the lack of consideration of the

thermodynamic quality of heat and electricity. As a result, the fuel allocated to heat production is overestimated.

2. *Method of avoided costs* (*method of replaced process*): The first step of this approach is to determine the main product (e.g., heat) and by-product (e.g., electricity). Then the by-product is burdened with an equivalent of fuel consumption as it would be in the replaced process, with the assumption that the amount of by-product remains the same in both cases. However, this method requires the subjective assumption of main product, by-product, and the parameters of avoided process. In some cases, it can lead to unreasonable results [14].
3. *Exergy method (exergy allocation)*: As presented in Figure 8.1, the fuel consumption and amount of generated waste products in the production process are strictly dependent on the exergy losses or the exergy efficiency. For this reason, the exergy allocation method is used here as the most advantageous approach to energy as well as emission allocation of cogeneration process to its products.

The local exergy costs of products (specific exergy consumption ratio) are taken into account for cost allocation in the exergetic method. This cost is defined as the total fuel exergy consumption ($\mathscr{E}_f$) necessary to obtain the exergy of useful product ($\mathscr{E}_p$) and in the case of CHP process, it can be expressed as follows:

$$k = \frac{\mathscr{E}_f}{\mathscr{E}_p} = \frac{\alpha_f \dot{E}_{f\mathrm{CHP}}}{\dot{H}_{\mathrm{CHP}}[(T_m - T^\circ)/T_m] + \dot{W}_e} \tag{8.11}$$

where $\dot{W}_e$ is the electric power generated in CHP (kW); $\dot{H}_{\mathrm{CHP}}$ is the heat flux produced in CHP plant (kW); $\mathscr{E}_f$ is the total exergy of fth fuel feeding the CHP system (kW); $\mathscr{E}_p$ is the total exergy of useful products of the CHP system (kW); T_m is the mean thermodynamic temperature of produced heat carrier (K); and T° is the ambient temperature (K).

The ratio of chemical exergy of fth fuel per unit of lower heating value is defined by the equation:

$$\alpha_f = \frac{\mathscr{E}_f}{H_u} \tag{8.12}$$

where H_u is the lower heating value of the fuel (MJ/kg or MJ/kmol).

Using the specific exergetic cost of CHP products, k, the chemical energy of fuel burdening production of heat in CHP can be determined as follows:

$$\dot{E}_{f\ \mathrm{CHP}\ h} = \dot{H}_{\mathrm{CHP}} \frac{T_m - T^\circ}{T_m} \frac{k}{\alpha_f} \tag{8.13}$$

The consumption of chemical energy of fuel due to the electricity generation in CHP can be determined by:

$$\dot{E}_{f\ \mathrm{CHP}\ e} = \dot{W}_e \frac{k}{\alpha_f} \tag{8.14}$$

with the requirement that the following balance has to be fulfilled:

$$\dot{E}_{f\ \mathrm{CHP}\ e} + \dot{E}_{f\ \mathrm{CHP}\ h} = \dot{E}_{f\ \mathrm{CHP}} = \frac{\dot{W}_e + \dot{H}_{\mathrm{CHP}}}{\eta_{\mathrm{CHP}}} \tag{8.15}$$

where η_{CHP} is the total energetic efficiency of cogeneration system.

After determining the fuel allocation to heat and electricity, the local ecological effects (direct emissions of harmful substances) can be assessed using (8.1). The appropriate assumption of the specific emissions burdening the fuel combustion is necessary for local and global balances of emissions and thermo-ecological cost (TEC) analysis.

Example 8.3 This example shows the application of the proposed method for fuel and emissions allocation in CHP, using SO_2 as a representative substance for the evaluation (similar is the procedure for other substances too). A comparison is also made between CHP and the separate production of electricity and heat with respect to SO_2 emission. The following cases are distinguished:

- CASE A
  - cogeneration: CHP—hard coal;
  - reference systems: PP—hard coal; HP—hard coal.
- CASE B
  - cogeneration: CHP—hard coal;
  - reference system: PP—hard coal; HP—natural gas.
- CASE C
  - cogeneration: CHP—natural gas;
  - reference systems: PP—natural gas; HP—hard coal.
- Input data

In the following table, rows no. 4–5 and 7–9 present data; the other rows present the results. In addition, the following parameters are given:

Direct SO_2 emission factor of hard coal combustion:	$e_{\mathrm{SO2\ hc}} = 0.22\ \mathrm{g/MJ}$
Direct SO_2 emission factor of natural gas combustion:	$e_{\mathrm{SO2\ ng}} = 0.08\ \mathrm{g/MJ}$
Thermodynamic mean temperature:	$T_m = 393\ \mathrm{K}$
Ambient temperature:	$T^{\circ} = 278\ \mathrm{K}$
Exergy to energy factor of hard coal:	$\alpha_{hc} = 1.09$
Exergy to energy factor of natural gas:	$\alpha_{ng} = 1.04$

Data and results of the Example 8.3

No.	Item	Formula	Unit	Value		
				Case A	Case B	Case C
1	Type of fuel burned in CHP	f		hc	hc	ng
2	Type of fuel burned in PP	f		hc	hc	ng
3	Type of fuel burned in HP	f		hc	ng	hc
4	Heat production	H_{CHP}	MJ	1,000.00	1,000.00	1,000.00
5	Power-to-heat ratio	σ	–	0.30	0.30	1.00
6	Electricity production	$W_e = \sigma H_{\mathrm{CHP}}$	MJ	300.00	300.00	1,000.00
7	CHP energy efficiency	η_{CHP}	–	0.75	0.75	0.85
8	PP energy efficiency	η_{PP}	–	0.40	0.40	0.60
9	HP energy efficiency	η_{HP}	–	0.80	0.90	0.75
10	Fuel consumption CHP	$E_{f\ \mathrm{CHP}} = (H_{\mathrm{CHP}} + W_e)/\eta_{\mathrm{CHP}}$	MJ	1,733.33	1,733.33	2,352.94
11	Carnot factor	$\eta_{\mathrm{C}} = (T_m - T^{\circ})/T_m$	–	0.29	0.29	0.29
12	CHP-specific exergy consumption	$k = \alpha_f\, E_{f\ \mathrm{CHP}}/(W_e + H_{\mathrm{CHP}}\eta_C)$	MJ/MJ	3.19	3.19	1.89
13	Fuel energy CHP—heat	$E_{f\ \mathrm{CHP}\ h} = H_{\mathrm{CHP}}\, \eta_C\, k/\alpha_f$	MJ	855.88	855.88	532.65
14	Fuel energy CHP—electricity	$E_{f\ \mathrm{CHP}\ e} = W_{\mathrm{e}}\, k/\alpha_f$	MJ	877.46	877.46	1,820.29
15	Fuel consumption PP	$E_{f\ \mathrm{PP}} = W_e/\eta_{\mathrm{PP}}$	MJ	750.00	750.00	1,666.67
16	Fuel consumption HP	$E_{f\ \mathrm{HP}} = H_{\mathrm{CHP}}/\eta_{\mathrm{HP}}$	MJ	1,250.00	1,111.11	1,333.33
17	SO_x emission CHP—heat	$E_{f\ \mathrm{CHP}\ h}\, e_{\mathrm{SO2}\ f\ \mathrm{CHP}}$	g	188.29	188.29	42.61
18	SO_x emission CHP—electricity	$E_{f\ \mathrm{CHP}\ e}\, e_{\mathrm{SO2}\ f\ \mathrm{CHP}}$	g	193.04	193.04	145.62
19	SO_x emission CHP—total	$E_{f\ \mathrm{CHP}}\, e_{\mathrm{SO2}\ f\ \mathrm{CHP}}$	g	381.33	381.33	188.24
20	SO_x emission PP	$E_{f\ \mathrm{PP}}\, e_{\mathrm{SO2}\ f\ \mathrm{PP}}$	g	165.00	165.00	133.33
21	SO_x emission HP	$E_{f\ \mathrm{HP}}\, e_{\mathrm{SO2}\ f\ \mathrm{HP}}$	g	275.00	88.89	293.33
22	SO_x balance for heat production	$E_{f\ \mathrm{HP}}\, e_{\mathrm{SO2}\ f\ \mathrm{HP}} - E_{f\ \mathrm{CHP}\ h}\, e_{\mathrm{SO2}\ f\ \mathrm{CHP}}$	g	86.71	−99.40	250.72
23	SO_x balance for heat production (relative)		%	31.53	−111.83	85.47
24	SO_x global boundary	$\left(E_{f\ \mathrm{HP}}\, e_{\mathrm{SO2}\ f\ \mathrm{HP}} + E_{f\ \mathrm{PP}}\, e_{\mathrm{SO2}\ f \mathrm{PP}}\right) - E_{f\ \mathrm{CHP}}\, e_{\mathrm{SO2}\ f\ \mathrm{CHP}}$	g	58.67	−127.44	238.43
25	SO_x global boundary (relative)		%	13.33	−50.20	55.88

Table 8.8 Description of analyzed cases

Case	Plant type	Efficiency (%)	Electricity to heat ratio	Fuel
1	CHP	75	0.1	Hard coal
2	CHP	85	0.1	Hard coal
3	CHP	75	0.3	Hard coal
4	CHP	85	0.3	Hard coal
5	CHP	75	0.5	Natural gas
6	CHP	85	0.5	Natural gas
7	CHP	75	1.0	Natural gas
8	CHP	80	1.0	Natural gas
9	PP+HP	40/80	N/A	Hard coal
10	PP+HP	60/90	N/A	Natural gas
11	PP+HP	35/70	N/A	Hard coal
12	PP+HP	50/80	N/A	Natural gas

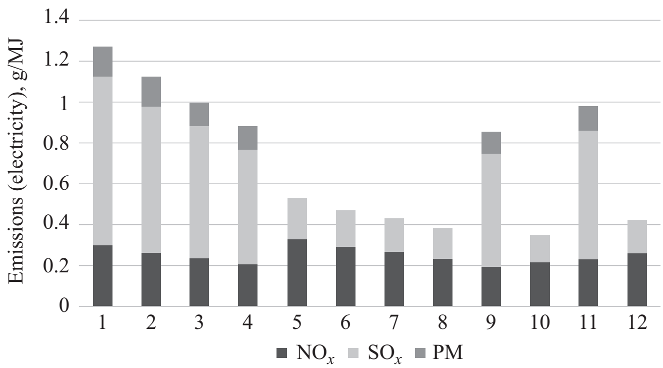

Figure 8.4 Emissions burdening electricity for the 12 cases presented in Table 8.8

In addition to the preceding numerical example, the exergetic procedure of fuel allocation between CHP products is applied for determination of NO_x, SO_2, and dust emissions burdening separately heat and electricity production in CHP plants. For comparison, the same emissions are calculated also for power plants and heat plants. The considered cases are listed and described in Table 8.8. The results of calculations for heat and electricity are presented in Figures 8.4 and 8.5. The cases from 1 to 8 concern CHP plants, whereas the cases from 9 to 12 concern separate electricity and heat production. The plants are considered to be fed with hard coal (cases 1–4, 9, and 11) and natural gas (cases 5–8, 10, and 12).

The additional data needed to prepare Figures 8.4 and 8.5 are as follows:

- Direct NO_x emission factor of hard coal combustion: $e_{NOx\ hc} = 0.08\ g/MJ$
- Direct NO_x emission factor of natural gas combustion: $e_{NOx\ ng} = 0.13\ g/MJ$
- Direct PM emission factor of hard coal combustion: $e_{PM\ hc} = 0.04\ g/MJ$
- Direct PM emission factor of natural gas combustion: $e_{PM\ ng} = 0.00\ g/MJ$

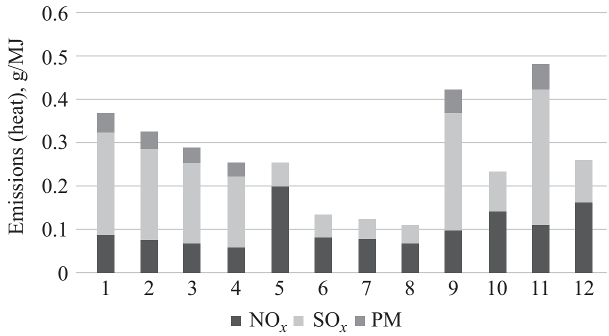

Figure 8.5 Emissions burdening heat for the 12 cases presented in Table 8.8

The case A of the preceding example in particular, corresponds to the cases 3 and 9 in Figures 8.4 and 8.5.

As presented in Figures 8.4 and 8.5, the total emissions burdening the combined heat and power generation strongly depend on the CHP efficiency and the power to heat ratio. In the case of low values of these parameters, the emissions in separate power and heat generation may be lower than in a combined plant (e.g., comparison of cases 1 and 9). However, if one takes into account the parameters corresponding to the high-efficiency cogeneration (e.g., comparison of cases 4 and 9 as well as 8 and 10 or 12), the emissions of pollutants are significantly lower than in the case of the separate production of heat and electricity.

8.3.6 Cumulative emissions—the case of greenhouse gases

The analysis of local and global environmental effects of cogeneration based only on direct emissions is inadequate due to the following reasons:

1. Different impact categories are interconnected; for example, emissions of harmful substances lead to environmental losses and increased demand for resources to compensate these losses. Moreover, the environmental assessment should allow us to analyze how emissions influence the resources depletion.
2. Actual environmental losses cannot be measured by emissions expressed in mass units only.
3. Total ecological effects cannot be assessed by local effects only. For example, determination of CO_2 emissions only from combustion process is not enough in cases when there are significantly high emissions in the stages of extraction and fuel transportation as in the case of natural gas transported over long distances.

For these reasons environmental assessment methods such as TEC, the cumulative GHG emissions and external environmental costs should be applied for the complex evaluation of CHP from ecological point of view. These methods are explained in the following, starting with the *cumulative emissions* method.

Direct emissions appear at the end-user stage during fuel combustion. However, emissions can burden also other stages of the production chain leading to the end-user. In the case of fuels, three main stages that should be taken into account are extraction, processing, and delivery of fuel to the end-user. Emissions determined for the whole chain are called *cumulative emissions*.

Mining, processing, and fuel delivery can also be burdened with significant GHG emissions. In the case of coal mines, methane emission appears, whereas in the case of natural gas transportation by pipelines, leakages occur. The local results can be radically changed by taking into account these environmental impacts. For this reason, a cumulative calculus should be applied to assess the total impact of different energy sources on emissions. Such a balance in the case of GHG emissions takes the following form [7]:

$$e_j^* = \sum_i \left(a_{ij} - f_{ij}\right) e_i^* + \sum_k (\mathrm{GWP})_k e_{kj} \tag{8.16}$$

where e_j^* is the cumulative emission of GHGs in the jth production branch; e_i^* is the coefficient of cumulative emission of GHGs burdening the ith product; $(\mathrm{GWP})_k$ is the coefficient of GWP of the kth gas; e_{kj} is the coefficient of direct emission of the kth GHG in jth production branch; a_{ij} is the coefficient of the consumption of ith domestic product consumed in jth considered branch (unit of ith domestic product per unit jth product e.g., kg/kg); f_{ij} is the coefficient of by-production of ith domestic product per jth product (unit of ith by-product per unit jth product e.g., kg/kg).

Furthermore, based on results of calculation of cumulative emissions by means of (8.16), the life cycle emissions (LCE) can be determined. In such case, the total LCE burdening the production of considered useful product can be determined by means of the following equation [7]:

$$\mathrm{LCE} = \tau_n \sum_j \dot{m}_i e_i^* + \frac{1}{\tau_j}\left[\sum_l m_l e_l^* (1 - u_l) + \sum_r m_r e_r^*\right] \tag{8.17}$$

where τ_j is the nominal lifetime of the jth machine, device, installation, or building (years); τ_n is the average time of exploitation of the jth considered machine, device, installation or building, in other words annual operation time with nominal capacity (h/year); $\dot{m}_i$ is the nominal mass flow rate of ith product used in jth production process (kg/h); m_l is the amount of lth product used for the construction of jth considered machine, device, installation, or building (kg); m_r is the amount of rth product used for the maintenance of jth considered machine, device, installation or building (kg); u_l is the expected recovery rate of the lth material after the end of operation phase of jth considered machine, device, installation, or building (kg/kg).

Emissions of GHG in full cycle by means of (8.16) and (8.17) have been investigated by Stanek and Białecki in [7]. Table 8.9 presents the comparison of direct and LCA GHG emissions for coal and imported natural gas, whereas Table 8.10 gives an example of the quantities of substances emitted during each one of the three phases of a natural gas combined cycle (NGCC) plant, that is, construction, operation, and decommissioning.

Table 8.9 Comparison of direct and cumulative emissions from fuels [7]

No.	Fuel	Direct emission ($t\ CO_2/TJ$)	Cumulative emission ($t\ CO_{2e}/TJ$)
1.	Coal	92.0	95.8
2.	Coal (with methane leakage)	92.0	101.6–104.8
3.	Natural gas (GWP = 30, 4.2% leak)	56.0	96.9

Table 8.10 Comparison of direct emissions from NGCC in different phases in LCA (results in kg/MWh of plant output)

Emissions	Plant construction	Plant decommissioning	Plant operation
SO_x as SO_2	8.56 E−04	2.5 E−04	1.11 E−03
NO_x as NO_2	5.74 E−04	3.53 E−04	2.76 E−03
PM	3.47 E−04	2.32 E−04	0 E−03
CO_2	2.94 E−01	9.05 E−02	3.67 E+02
$CO_{2\text{-eq}}$	3.03 E−01	9.92 E−02	3.67 E+02

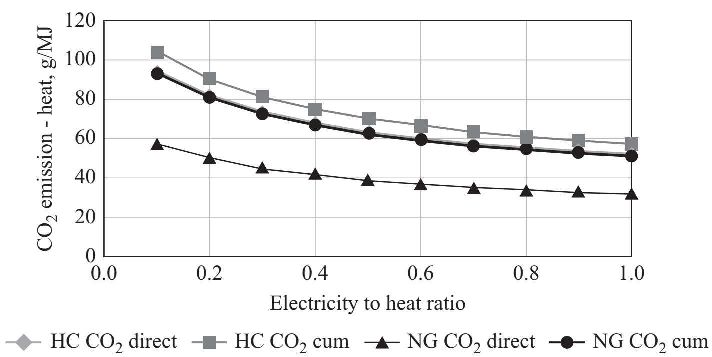

Figure 8.6 CO_2 emission burdening heat produced in CHP and in HP

The necessity of application of cumulative emissions calculus in the case of GHG is evident. The direct emission of CO_2 is 1.6 times higher for coal than for natural gas. The cumulative ratio is only at the level of 1.05–1.08. In other words, the GHG emissions burdening hard coal are quite similar to those of natural gas transported from huge distances. Figures 8.6 and 8.7 present results of direct and cumulative GHG emissions burdening production of electricity and heat. The results are obtained for CHP energy efficiency $\eta_{CHP} = 0.80$ and for electricity to heat ratio changing from 0.1 to 1.0.

It can be observed that the electricity-to-heat ratio σ has significant influence on CO_2 emission burdening both heat and electricity. In the case of CHP fed by

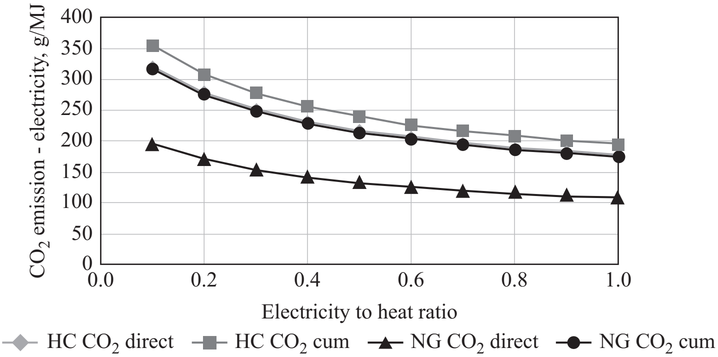

Figure 8.7 CO_2 emission burdening electricity produced in CHP and in PP

coal, the change of electricity-to-heat ratio from $\sigma = 0.1$ to $\sigma = 0.3$ leads to reduction of direct emissions by 21%. In the case of CHP fed by natural gas, changing the electricity-to-heat ratio from $\sigma = 0.5$ to $\sigma = 1.0$, the reduction reaches the level of 18%. The cumulative GHG emissions (LCE) evaluation also has significant meaning. In the case of CHP fed by coal ($\sigma = 0.3$), the cumulative-to-direct emission ratio is on the level 1.1. For CHP fed with natural gas and $\sigma = 1.0$, the ratio is equal to 1.62. It proves again that the necessity for cumulative emission calculus, especially in the case of fuels burdened with relatively high external emissions (e.g., natural gas transported by huge distances).

8.3.7 Dispersion and impacts of pollutants on the environment and the society—the external environmental cost

In this section, the environmental impacts are evaluated on the basis of three air emissions (SO_2, NO_x, and dust) released from CHP. In the case of SO_2 and NO_x, the boundary for local scale is limited by the regions set arbitrarily within the European countries, whereas the global scale shows the influence of emission released in one location to other regions. In the case of dust, the boundary for local scale is determined by surrounding 10,000 km^2. It is noted that the cumulative emissions are released in different areas and can also be understood as global emissions.

A variety of ecosystems causes differentiated requirements on elements and chemical compounds in various places around the world. The analysis presents the environmental impact of emissions released from CHP in relation to local and global level. It should be noted that only some emissions will remain in the surrounding area, whereas others will be transported to other territories. The environmental analysis should be carried out taking into account each affected type of area to adequately assess the potential impact. The released emissions cause effects on the various types of terrestrial ecosystems starting from the vicinity of the emission point.

The emission causes damages to the environment and the society in the vicinity of the system as well as in distant areas, even in other countries, that are in the trajectory of pollutant dispersion. The method used for estimating environmental damages, which is based on the Impact Pathway Approach (IPA) [5], was developed within the *Externalities of Energy* project (ExternE) and applied in the EcoSense software [4]. Results obtained using the IPA method are expressed in monetary values; however, the external costs arising from pollutant damages are not reflected in the market prices of the products.

The externalities of pollutants from power plants or other human activities depend primarily on the location of this activity. The same amount and types of the emissions cause different effects at different places, as the adverse impacts on the society and the environment are strongly related to population density, site-specific meteorological data, infrastructure, and others. According to [5], the definition of externalities is as follows:

> *Externalities are the costs and benefits that arise when the social or economic activities of one group of people have an impact on another, and when the first group fails to account adequately for their impacts.*

The first step of IPA requires the quantities of various pollutants emitted at a particular location in one of the 65 subregions in Europe or 6 regions outside Europe, such as Turkey or Egypt. In the second step, the atmospheric pollutant transport module is used, taking into account wind speed and direction, baseline (current) concentrations of pollutants, and chemical transformation of pollutants (the marginal changes in the ambient conditions). The third step consists of the environmental impact assessment using the dose–response functions (DRF). The DRF relates the quantity of a pollutant that affects a receptor to the physical impact on this receptor, for example, the number of hospitalizations [15]. Finally, the external cost of pollution is assessed on the basis of the aggregated results obtained in previous steps.

The externalities refer to local and regional level. The local level is defined as an area of 10,000 km^2, and the calculations in this area are performed using a 10×10-km^2 grid. The regional level covers the whole Europe, and the calculations in this area are performed using a 50×50-km^2 grid. The grid of Europe has been created by the European Monitoring and Evaluation Programme. Figure 8.8 shows a 50×50-km^2 grid of Poland, which represents a relatively large country (312,679 km^2) [16] divided into three subregions separated by darker lines. A smaller country, such as Greece (131,957 km^2) [16], is not divided into subregions. Each element has its own grid coordinates (x, y), which are in correlation with the geographical coordinates.

In the EcoSense software, the background concentration of pollutants is implemented, which is partly presented in Figure 8.8. Different colors or shades of grid elements show the concentration of PM_{coarse} in the year 2007 due to combustion in energy and transformation industries (stationary sources). PM_{coarse} denotes a coarse particulate matter, defined as the integrated mass of aerosols with a dry particulate diameter between 2.5 and 10 μm.

One of the features of the EcoSense is to show the local and regional impact of plant located in a particular place on other countries. The EcoSense uses advanced meteorological data combined with dispersion models to assess the impact of

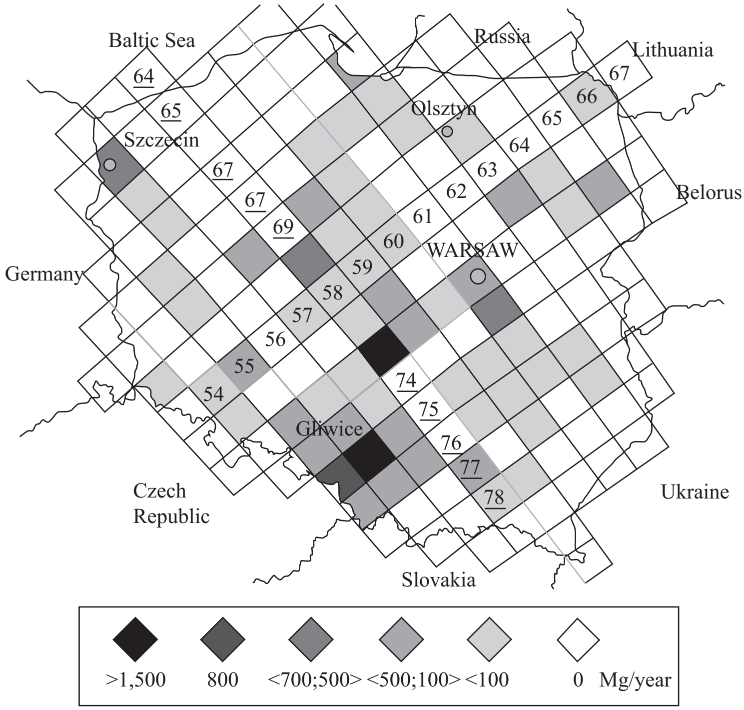

Figure 8.8 *50 × 50-km² grid of Poland with concentration of PM_{coarse} in the year 2007 [17]*

emissions from a particular location on other regions. The trajectory model from the Centre on Emission Inventories and Projections (CEIP) web page is used to present the trajectory of a particular amount of a pollutant from the initial location.

The runtime options are as follows:

- initial location 53.47°N 20.27°E,
- trajectory direction—forward,
- start day: January 1, 2009,
- GDAS Meteorological Data,
- duration of release 48 h,
- starting height of emission release—250-m AGL.

The trajectories presented in Figure 8.9 start from Polish location and during 315 h go to Russia or the southern Europe. The trajectory that the emissions will follow strongly depends on the weather conditions. Also, the level above the ground is changing with the time.

The DRFs are inherent part of the impact pathway analysis, since the damage can be quantified when the corresponding function is available. The DRF is a function of the concentration of a pollutant in the ambient air and absorption of the pollutant by crops, body, or material. However, the ecosystems have a natural

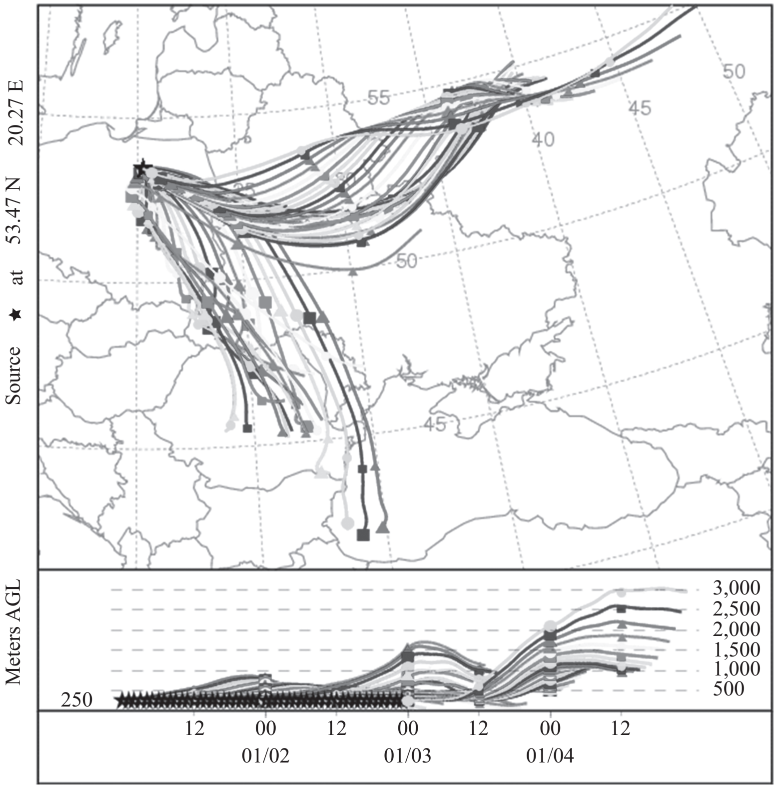

Figure 8.9 Trajectory model of particles released from Polish location [18]

repair mechanism that can prevent or counteract damage up to a particular limit. A "fertilizer effect" occurs at low doses of pollution in the analyzed area. In the case of the DRF of NO_x and SO_2 on crops, a low dose of these pollutants can increase the crop yield. A fertilizer effect can occur with pollutants that provide trace elements needed by an ecosystem [5].

Based on the DRF results, expressed, for example, in years of life lost (YOLL) or day per $\mu g/m^3$, the monetary evaluation is conducted. Then, for each endpoint, the monetary value is estimated; for example, life expectancy reduction is estimated at a level of 40,000 EUR per YOLL that is 26 EUR/$\mu g/m^3$ of particles less than 2.5 μm. This 26 EUR/$\mu g/m^3$ is the external cost of life expectancy reduction caused by particles lower than 2.5 μm and refers to the persons of any age.

8.3.8 Thermo-ecological cost

8.3.8.1 Presentation of the methodology

TEC enables the applications of exergy analysis in the field of environmental aspects. The TEC proposed by Szargut [6,17,19] is an evaluation tool applied to measure the efficiency of natural resources management. It combines exergy, as a resource's quality indicator, and cumulative calculus. TEC of a product fulfilling

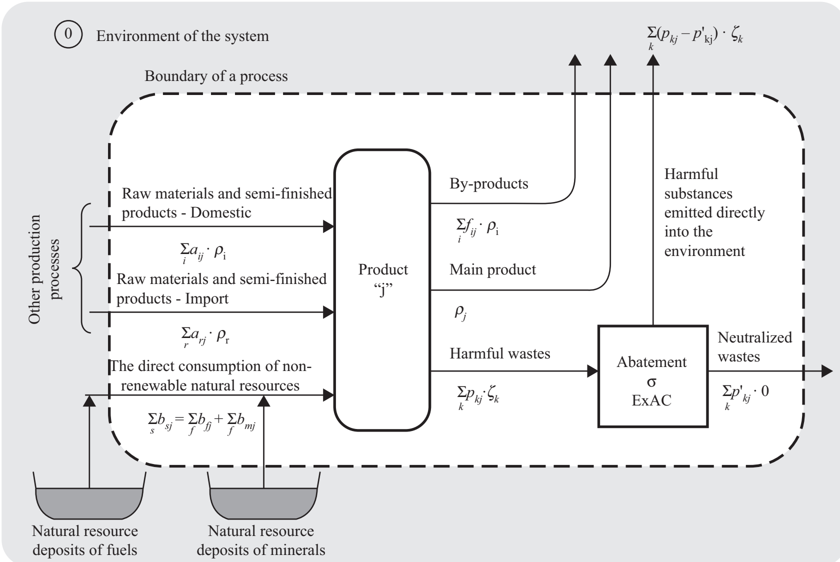

Figure 8.10 The idea of TEC balance equation

the rules of exergy cost theory is expressed in units of exergy per unit of product and is defined as the cumulative consumption of non-renewable natural resources burdening this product, increased by a supplementary term accounting for the necessity to abate or compensate the negative effects of harmful wastes rejection to the natural environment [6,20]. Using the TEC method, the global evaluation of emission can be done with possibility to compare with other environmental impacts. The scheme of TEC balance is presented in Figure 8.10.

According to the scheme of TEC balance presented in Figure 8.10, the equation for calculation of the TEC takes the following form [6,17,21,22]:

$$\rho_j + \sum_i \left(f_{ij} - a_{ij}\right)\rho_i = \sum_s \varepsilon_{sj} + \sum_k p_{kj}\zeta_k \tag{8.18}$$

where ρ_j is the total value of the TEC of major product of the jth considered process, of the remaining processes belonging to the system; ε_{sj} is the exergy of the fuel and of the mineral raw material immediately extracted from nature, per unit of the jth major product; a_{ij}, f_{ij} are the coefficients of the consumption and by-production of the ith domestic semi-finished product per unit of the jth major product; p_{kj} is the coefficient of the production of the kth rejected waste product per unit of the jth major product; ζ_k is the total TEC of compensation of the deleterious impact of the kth rejected waste product.

TEC resulting from emission of harmful substances to the natural environment is calculated as [6,17]:

$$\zeta_k^* = \frac{\mathscr{E}}{\mathrm{GDP} - \sum_k P_k w_k} w_k \tag{8.19}$$

where $\mathscr{E}$ is the exergy extracted per year from the domestic non-renewable natural resources; GDP is the gross domestic product [23]; P_k is the annual production of the kth aggressive component of waste product rejected to the environment in the considered region; w_k is the monetary factor of harmfulness of kth substances (externalities).

8.3.8.2 Application examples

Example 8.4 In the case of a potential power plant located in Olsztyn, using the EcoSense Software, the total external cost results in 880 €/MWh; in addition, this cost is the sum of individual external costs related to each of 64 regions. As it can be foreseen, the highest cost is in Poland and is equal to 304.5 €/MWh. The power plant located in Olsztyn adversely affects the population of nearest surrounding countries such as Ukraine, where the external cost is 125.8 €/MWh, Germany and Russia, where the cost is 66.2 and 60.2 €/MWh, respectively.

In this study, the indicators resulting from externalities and given in Table 8.11 are taken into account to evaluate cogeneration systems: the external cost of pollutants and the exergetic cost of environmental losses compensation due to selected pollutants [17,20]. The values of the TEC obtained are given in Table 8.12.

The next example is presented to explain how to calculate the total TEC and the partial TEC of the fuel, emission, and CO_2 abatement.

Table 8.11 External cost of pollutants and exergetic cost of environmental losses compensation due to these pollutants [17,20]

City	w_k (€$_{2008}$/kg)			ζ_k^* (MJ/kg)		
	SO_2	NO_x	PPM	SO_2	NO_x	PPM
Olsztyn	12.04	10.00	6.07	92.14	76.50	46.45
Warsaw	12.04	10.00	6.44	92.14	76.50	49.26
Gliwice	14.52	7.91	8.75	110.58	60.24	66.64
Szczecin	12.64	9.72	6.72	96.42	74.26	51.34
Average	12.81	9.41	7.00	97.82	71.88	53.42

Table 8.12 TEC of fuels [17,20,24]

Fuel	TEC, MJ*/MJ
Biogas (bg)	0.12
Hard coal (hc)	1.12
Natural gas (ng)	1.06
Electricity from grid (el)	3.60

Example 8.5 In this simplified example, the TEC calculation is presented. The method was applied to TEC analysis, which gave the results presented in Table 8.13 and in Figures 8.11–8.14.

Figures 8.11 and 8.12 present results of TEC for electricity and heat produced, whereas Figures 8.13 and 8.14 present results of emission part of TEC in CHP and in reference plants (HP and PP). Assumptions for the calculations are the same as presented in Table 8.8.

It can be concluded that taking into account the TEC of heat production (Figures 8.11 and 8.13) both—total TEC encompassing fuel, emissions, and CO_2

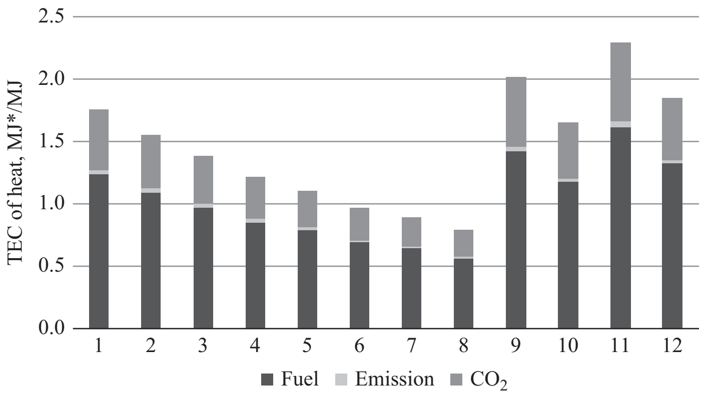

Figure 8.11 TEC of heat in CHP and in HP for the 12 cases presented in Table 8.8

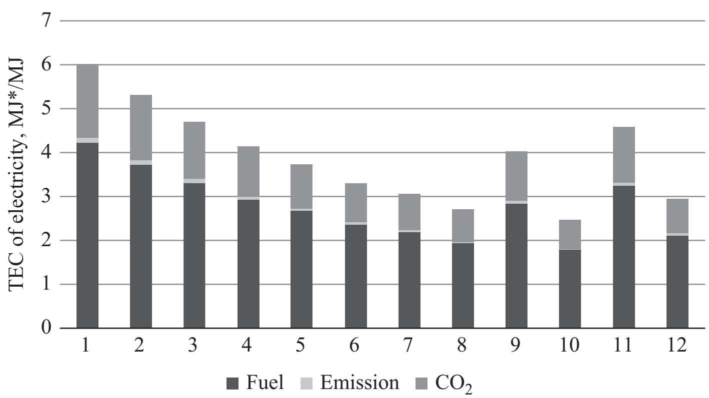

Figure 8.12 TEC of electricity in CHP and in PP for the 12 cases presented in Table 8.8

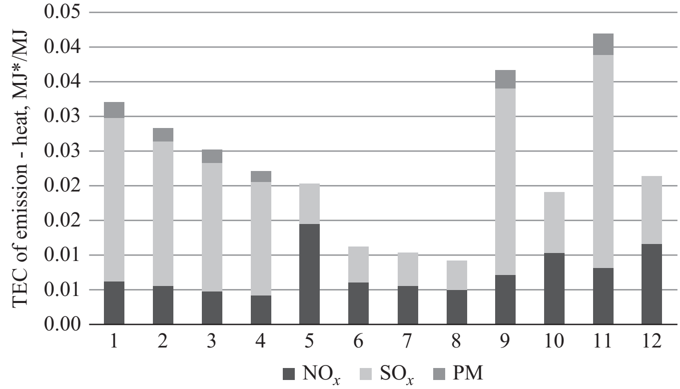

Figure 8.13 TEC (emission part) of heat in CHP and in HP for the 12 cases presented in Table 8.8

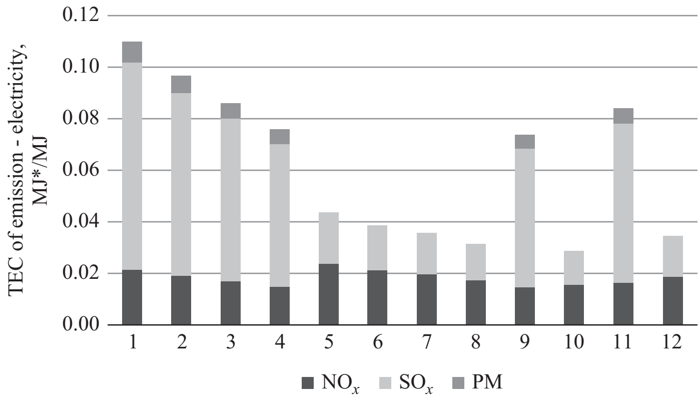

Figure 8.14 TEC (emission part) of electricity produced in CHP and in PP for the 12 cases presented in Table 8.8

Table 8.13 Data and results of Example 8.5

No.	Item	Formula	Unit	CASE HP-Q	CASE PP-Eel	CASE CHP-Q	CASE CHP-Eel
1.	Heat production	$P_1 = H_{\mathrm{CHP}}$	MJ	1,000	–	1,000	–
2.	Electricity production	$P_2 = W_e$	MJ	–	300	–	300
3.	Fuel energy	E_f	MJ	1,333.30	857.14	855.88	877.46
4.	Specific exergy consumption	$a_{fp} = \mathscr{E}_f / P_i$	MJ/MJ	1.33	2.86	0.86	2.92
5.	NO_x emission	$p_{\mathrm{NO}x}$	g/MJ	0.1	0.20	0.07	0.23
6.	SO_2 emission	$p_{\mathrm{SO_2}}$	g/MJ	0.275	0.55	0.19	0.64
7.	PM emission	p_{PM}	g/MJ	0.05	0.10	0.03	0.12
8.	CO_2 emission	$p_{\mathrm{CO_2}}$	g/MJ	127	254.00	86.96	297.17
9.	TEC fuel part	$\rho_f = a_{f.p}\rho_i$	MJ/MJ	1.49	3.20	0.96	3.28
10.	TEC emission part	$\rho_\zeta = \sum p_i \zeta_i$	MJ/MJ	0.04	0.07	0.03	0.09
11.	TEC GHG	$\rho_\sigma = \sum p_{\mathrm{CO_2}} \sigma_{\mathrm{CO_2}}$	MJ/MJ	0.56	1.12	0.38	1.31
12.	TEC TOTAL	$\rho = \sum \rho_i$	MJ/MJ	2.09	4.39	1.37	4.67

impacts as well as the part related to emissions at global scale in all considered cases, the introduction of CHP leads to the global environmental savings. In the case of electricity (Figures 8.12 and 8.14), only the application of high-efficiency cogeneration leads to savings. Total TEC encompassing production of heat and electricity as a whole is lower in the case of CHP even with the lower efficiencies of analyzed CHP processes. The presented system analysis confirms again that application of high-efficiency cogeneration characterized by relatively high electricity to heat ratio (e.g., 0.3 for coal and 1.0 for natural gas) can lead to significant ecological benefits in global scale.

8.3.9 Thermo-ecological indicators of environmental benefits and results for selected bio-CHPs

The methodology of TEC and cumulative emissions LCE, briefly explained in previous sections, has been applied for the evaluation of the influence of biomass utilization in CHP on the ecological effects. Three indexes are proposed to evaluate the ecological advantages of biomass utilization for energy production in CHP [24]:

Index of natural resource savings (NRS):

$$\mathrm{NRS} = \frac{\Delta m_f\left(\rho_f + \sum_k p_{k.f}\zeta_k + p_{\mathrm{CO_2}}\sigma_{\mathrm{CO_2}}\right)}{m_{\mathrm{bio}}\left(\rho_{\mathrm{bio.LCA}} + \sum_k p_{k.\mathrm{bio}}\zeta_k\right)} \tag{8.20}$$

where Δm_f is the decrease of non-renewable fuel consumption (kg); m_{bio} is the consumption of the biomass (kg); $p_{k.\mathrm{bio}}.p_{k.f}$ is the amount of waste kth substance rejected to the environment burdening the combustion of conventional (f) and renewable (bio) fuel (kg/kg); ρ_F is the TEC of avoided consumption of non-renewable fuel (MJ/kg or MJ/MJ); $\rho_{\mathrm{bio.LCA}}$ is the TEC in full life cycle of biomass (MJ/kg); ζ_k is the TEC of compensation losses in environment caused by rejection of kth contaminant (MJ/kg); p_{CO2} is the total amount of CO_2 generated in jth production branch (kg/kg or kg/MJ); σ_{CO2} is the cumulative exergy consumption of non-renewable resources due to the CO_2 removal in abatement installation (MJ/kg).

The NRS expresses the level of exergy consumption decrease of non-renewable resources, which results from the non-renewable fuel replacement Δm_f by the amount of biomass m_{bio}. The non-renewable fuel Δm_f is burdened with TEC>1, whereas biomass m_{bio} is burden with TEC<1, which is characteristic of renewable resources. This index can be interpreted as the cumulative efficiency of non-renewable exergy savings due to application of biomass.

Index of GHGs cumulative emission reduction Δ(GHG):

$$\Delta(\mathrm{GHG}) = \frac{\Delta m_f\, e^*_{\mathrm{GHG}f}}{m_{\mathrm{bio}}\left(e^*_{\mathrm{GHG\,bio}} - e_{\mathrm{CO2\,bio}}\right)} \tag{8.21}$$

where e^*_{GHG} is the cumulative GHG emissions factor, kg/kg; e_{CO2} is the direct CO_2 emissions factor, kg/kg.

The Δ(GHG) is expressed as the relative cumulative reduction of GHG emissions. It results from decrease of consumption of fossil fuel Δm_f burden with the cumulative emission related to external emission of GHG burdening the unit of consumed biomass m_{bio}. The external emissions of GHG from unit of mass of biomass $\left(e^*_{GHG\ bio} - e_{CO2\ bio}\right)$ results, for example, from transport or cultivation of biomass, whereas it does not take into account the direct emissions of $CO_{2.bio}$ which in the case of biomass is zero due to the closed natural loop.

Index of natural resources savings resulting from decrease of GHG emissions NRS_{GHG}:

$$NRS_{GHG} = \frac{\Delta m_f \, e^*_{GHG} \, \sigma_{CO2}}{m_{bio} \, \rho_{bio.LCA}} \tag{8.22}$$

The reduction of GHG emissions expressed by the Δ(GHG) leads to the savings of natural resources. The avoided emissions of the CO_2 result in the exergy savings of non-renewable natural resources for CO_2 removal. For this reason, it leads finally to the reduction of non-renewable resources consumption in the amount of $e^*_{GHG} \cdot \sigma_{CO_2}$ per unit of saved fossil fuel. The natural resources that comprise equivalent of this savings are equal to the cumulative exergy consumption that has to be spent to produce a unit of biomass for the energy sector.

Table 8.14 presents main results of annual mass, energy balance, GHG avoidance and natural resources avoidance in comparison with coal for selected bio-CHP (AFB—atmospheric fluidized bed gasification technology. FICFB fast internally circulated fluidized bed gasification technology. PFB pressurized fluidized bed gasification technology).

Table 8.14 Selected results of evaluation of the selected bio-CHP plants [24]

Gasification technology	**AFB**	**AFB**	**AFB**	**PFB**	**PFB**	**FIC**	**FIC**
Heat from cogeneration (PJ)	110.4	247.6	100.1	125.4	126.3	77.6	97.8
Electricity from cogeneration (GWh)	23.38	34.93	44.03	27.92	40.28	16.5	38.1
Wet biomass consumed m_{bio} (Mt)	44.28	71.30	44.28	41.90	41.90	41.9	41.9
Saved coal Δm_F (kt)	6.90	13.41	9.68	6.79	9.69	7.05	9.51
CO_2 emission reduced $\Delta m_F e_{CO_2}$	52.09	76.33	54.36	56.14	56.31	53.3	53.0
NRS	6.0	8.7	10.1	7.5	10.7	7.8	10.5
Δ(GHG)	22.4	27.0	31.4	23.3	33.3	24.2	32.6
NRS_{GHG}	4.9	6.0	6.9	5.1	7.3	5.3	7.2

The high ecological benefit of biomass conversion is confirmed by the obtained results. In the case of savings of non-renewable natural resources, the TEC of biomass plant is 6.0−10.7 times lower than the TEC of plant fuelled by non-renewable chemical energy. It leads to the conclusion that the share of biomass, and non-renewable CHP plants should be maximized within the area of economic profitability. GHG emission is one of the most important issues in the application of biomass energy. The index Δ(GHG) is between 4.9 and 7.3. It is scientifically confirmed that the problem is global, but the technology selection based on single economic criterion of profitability maximization often limits this problem to local scale.

8.4 Effects on water and soil quality

8.4.1 Effects on water quantity and quality

Water, besides non-renewable resources of fossil fuels and minerals, is one of the crucial resources. According to ISO 14046:2014 [25], *water availability* is the extent to which humans and ecosystems have sufficient water resources for their needs. Water availability depends on the location and timing. The temporal and geographical coverage and resolution for evaluating water availability is needed for environmental analysis. Water quality can also influence availability; for example, if quality is not sufficient to meet user needs, then there is no availability of water. Land and water management (e.g., forestry, agriculture, conservation of wetlands, hydropower) can modify water availability (e.g., regulating river flows and recharging groundwater). If water availability only considers water quantity, it is called water scarcity.

The CHP systems, such as a reciprocating engine, combustion turbine, micro turbines, and fuel cells, use almost negligible amounts of water [26,27]. Water consumption in boiler/steam turbine CHP system is similar to the separate heat and power generation. Water consumption for selected power technologies is presented in Table 8.15 [26,27].

The applied system approach of natural resources assessment through TEC analysis can also be used for water evaluation. The following values of TEC have

Table 8.15 Water consumption of selected power technologies (m^3/GJ)

Technology	Open-loop	Closed-loop reservoir	Closed-loop cooling tower
Coal	0.315	0.405	0.505
Natural gas CC	0.105	0.137	0.190

been obtained from [23]: for demineralized water 34.0 MJ/m^3, industrial water 12.5 MJ/m^3, and fresh water 22.8 MJ/m^3. For known consumption of water in a CHP technology, the evaluation of TEC resulting from this consumption should let for direct comparison with other ecological impacts such as fuel consumption, emission, and GHG emissions on global scale.

Assuming that demineralized water is used, the following TEC of water related to electricity can be obtained: coal PP 0.010–0.017 MJ*/MJ$_e$ and natural gas power plant 0.003–0.006 MJ*/MJ$_e$. Having in mind that the TEC of electricity generated in CHP may vary between 2 and 6 MJ*/MJ$_e$, it can be concluded that the impact of cooling is negligible in the evaluation of whole resources cycle.

8.4.2 Effects on soil and water quality caused by the emissions

Production based on the resources obtained from nature is exposed to various positive or adverse effects of substances contained in the surroundings. As an example, the eutrophication effect is not harmful until the critical load in the surrounding ecosystem is reached. Enrichment of ecosystems with nutrients is essential to ensure sustainable products development. Different midpoints and endpoints should be considered to assess the environmental impact on the water and soil.

The various chemical compounds containing nitrogen or the pure nitrogen (N_2) significantly influence the biological expansion of the terrestrial ecosystems. The site-generic acidification impact is expressed as the area of the ecosystem within entire deposition area that exceeds the critical level of acidification as a consequence of the additional emission referred to the functional unit (f.u.)

$$I_{\mathrm{MP}}^{\mathrm{SG}} = \mathrm{CF}_{\mathrm{MP}.s}^{\mathrm{SG}} \cdot E_s \tag{8.23}$$

where $I_{\mathrm{MP}}^{\mathrm{SG}}$ is the impact of site-generic terrestrial midpoint (e.g., eutrophication and acidification in 0.01 m^2/f.u.); $\mathrm{CF}_{\mathrm{MP}.s}^{\mathrm{SG}}$ is the characterization factor of site-generic terrestrial mid-point (e.g., eutrophication and acidification) for substance (s); E_s is the emission of substance (s) (in g/f.u).

Site-dependent characterization factor is defined for the geographical region where the emission takes place (area of unprotected ecosystem = m^2 UES):

$$I_{\mathrm{MP}}^{\mathrm{SD}} = \mathrm{CF}_{\mathrm{MP}.s}^{\mathrm{SD}} \cdot E_s \tag{8.24}$$

where $I_{\mathrm{MP}}^{\mathrm{SD}}$ is the impact of site-dependent terrestrial mid-point (e.g., eutrophication and acidification in 0.01 m^2/f.u.), $\mathrm{CF}_{\mathrm{MP}.s}^{\mathrm{SD}}$ is the characterization factor of site-dependent terrestrial midpoint (e.g., eutrophication, acidification for substance(s) in country or region (i)), and E_s is the emission of substance(s) (in g/f.u).

The impact of site-generic and site-dependent terrestrial eutrophication is presented in Figure 8.15, whereas the data used for calculation are presented in Table 8.16. Four different cases are analyzed; each case should be understood as "Case i shows the area of ecosystem that becomes unprotected by the emissions from the CHP fuelled by F with the efficiency 80% and power-to-heat ratio σ related to MJ of produced P."

Table 8.16 Parameters used in analyzed cases

Case, *c*	Units	Fuel, *f*	Product, *p*	CHP efficiency, η	Power-to-heat ratio, σ
A	0.01 m^2/MJ_h	Gas	Heat	0.8	0.8
B		Coal			0.2
C	0.01 m^2/MJ_e	Gas	Electricity		0.8
D		Coal			0.2

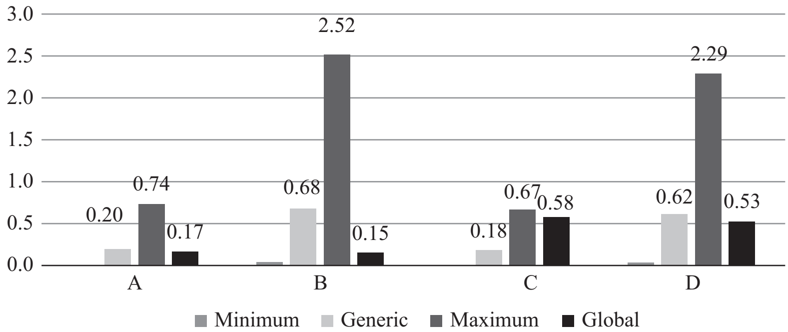

Figure 8.15 Impact of site-generic and site-dependent terrestrial eutrophication due to NO_x for the cases A, B, C and D presented in Table 8.16, expressed in 0.01 m^2/MJ_h or 0.01 m^2/MJ_e

For each case, the minimum and maximum values of terrestrial eutrophication impact on soil are presented. Moreover, Figure 8.15 shows the averaged value indicated as "generic," which can be used when the average impact of CHP is considered. Generic is used regardless of the location and emission dispersion. The value of "global" case takes into account the distribution of emitted pollutants from selected location to the countries that are threatened by these emissions. In the analyzed global case, the dispersion of emissions causes a lower impact on the environment than the generic one. Moreover, if the total emission remains at the starting position (CHP location), higher impact on the environment would be caused.

Figures 8.16 and 8.17 show four cases A–D, for which characteristics are given in Table 8.16. In addition, the SO_2 and NO_x indicate the emission for which the impact is calculated. For each case, the minimum, generic, maximum, and global values of terrestrial acidification impact on soil are presented. In the analyzed global case of acidification caused by SO_2, the dispersion of emissions causes a lower impact on the environment than the generic one. Moreover, if the total emission remains at the starting position (CHP location), a higher impact on the environment would be caused. Whereas in the case of eutrophication caused by NO_x, the impact on the environment would be higher, the acidification caused by NO_x is lower than that one caused by SO_2. The influence of all substances should be analyzed and taken together to obtain the actual impact on the environment.

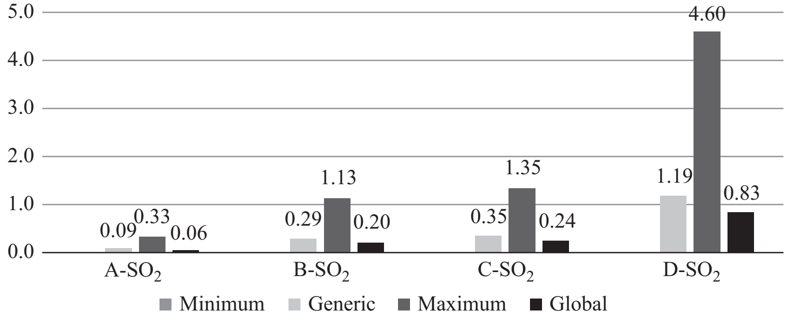

Figure 8.16 Impact of site-generic and site-dependent terrestrial acidification due to SO_2 for the cases A, B, C and D presented in Table 8.16, expressed in 0.01 m^2/MJ_h or 0.01 m^2/MJ_e

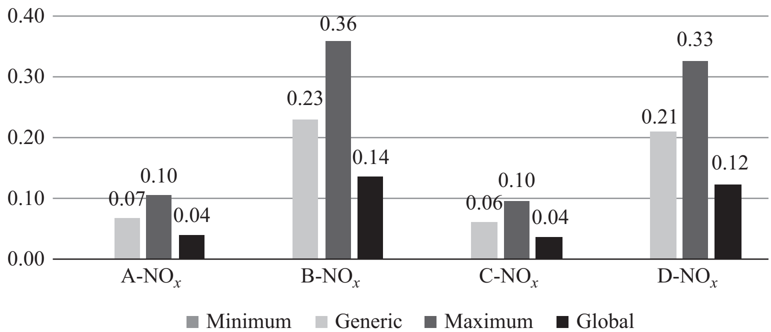

Figure 8.17 Impact of site-generic and site-dependent terrestrial acidification due to NO_x for the cases A, B, C and D presented in Table 8.16, expressed in 0.01 m^2/MJ_h or 0.01 m^2/MJ_e

8.5 Legal emission limits and emission trading

"Emission limit values," based on the Council Directive 96/61/EC [28], means the mass, expressed in terms of certain specific parameters, concentration, and/or level of an emission, which may not be exceeded during one or more periods of time. Moreover, the emission limit values for substances normally apply at the point where the emissions leave the installation. Emission limit values are specified in the Directive 2010/75/EU and presented in Tables 8.17 and 8.18.

According to the Directive 2010/75/EU [29], all emission limit values shall be calculated at a temperature of 273.15 K, a pressure of 101.3 kPa and after correction for the water-vapor content of the waste gases and at a standardized O_2 content of 6% for solid fuels, 3% for combustion plants other than gas turbines and gas engines using liquid and gaseous fuels and 15% for gas turbines and gas engines. In the case of combined cycle gas turbines with supplementary firing, the standardized O_2 content may be defined by the competent authority, taking into account the specific characteristics of the installation.

Table 8.17 Emission limit values (mg/Nm³) for SO_2. NO_x and dust for combustion plants using solid or liquid fuels with the exception of gas turbines and gas engines [29]

Total rated thermal input (MW)	Emission limit values (mg/Nm³) for SO_2		Emission limit values (mg/Nm³) for NO_x		Emission limit values (mg/Nm³) for dust	
	Coal. lignite and other solid fuels	Biomasses	Coal. lignite and other solid fuels	Biomass and peat	Coal. lignite and other solid fuels	Biomass and peat
50–100	400	200	300 400*	250	30	30
100–300	200	200	200	200	25	20
>300	150 200†	150	150 200‡	150	20	10

*In the case of pulverized lignite combustion.
†In the case of circulating or pressurized fluidized bed combustion.
‡In the case of pulverized lignite combustion.

Table 8.18 Emission limit values (mg/Nm³) for SO_2. NO_x, and dust for combustion plants using gaseous fuels with the exception of gas turbines and gas engines [29]

	Emission limit values (mg/Nm³) for SO_2	Emission limit values (mg/Nm³) for NO_x	Emission limit values (mg/Nm³) for dust
In general	35	100*	5

*Gas turbines (including CCGT) 50 mg/Nm³. and gas engines 75 mg/Nm³.

Table 8.19 Fee for exceeding selected emission

Emission*	Fee for the emission in 2016
Sulfur dioxide (EUR/kg)	0.13
Carbon dioxide (EUR/Mg)	0.07
Particulate matter (EUR/kg)	0.08–8.20
Nitrogen oxides (as NO_2), (EUR/kg)	0.13

*1 EUR = 4.2 PLN.

In Polish conditions, the Council of Ministers Decrees [30] defines the fee, which should be paid always even though the emission limits are not exceeded. In the case when the limits are exceeded, the installation is not allowed to work. In Table 8.19, the fees expressed in EUR per kg or Mg of emission for the year 2016 are presented.

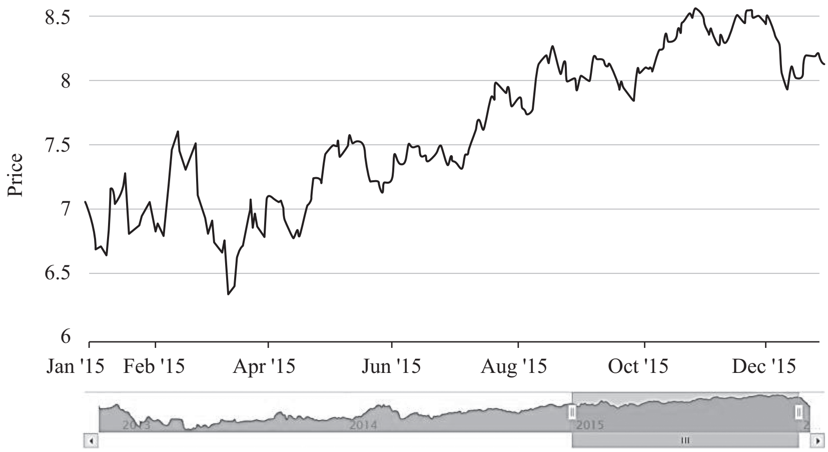

Figure 8.18 Intraday prices expressed in EUR/tCO_2 [33]

Table 8.20 Selected CHP plants and their total number of allowances in the year 2015 [34,35]

CHP owner	**CHP name**	**The total number of allowances* in 2015 (Mg/year)**
CEZ Chorzow S.A. [36]	CHP Chorzow	125,956
PGNiG TERMIKA S.A.	CHP Siekierki	885,331
EDF Polska S.A.	CHP Krakow	408,193
TAURON Cieplo S.A.	CHP Bielsko-Biala EC 2	59,047
Cartiera del Chiese S.p.A.	Centrale di Cogenerazione Cartiera del Chiese	12,809
STUDIUM Power and Service scarl	Centrale termica e cogenerazione AOU "Federico II"	14,662
Società Elettrica in Morbegno c.p.a.	Centrale di cogenerazione e teleriscaldamento	9,842
COFELY ITALIA SPA	Cogenerazione elyo presso michelin cuneo	41.891

*Number for the facility which is specified in the National Allocation Plan for Emission Allowances.

In addition to the fees, the CO_2 trade market is operating based on the EC policy [31]. An "allowance" to emit 1 t of CO_{2e} during a specified period is valid only for meeting the requirements of Directive 2003/87/EC. These allowances can be engaged in EU emissions trading system (EU ETS) [32], which is organized to prevent climate change and efficiently reduce industrial GHG emissions. The intraday prices expressed in EUR/tCO_2 for the year 2015 are presented in Figure 8.18 [33]. Table 8.20 shows four selected CHP plants in Poland and their CO_2 limits defined in the Polish regulation.

8.6 Noise and vibration

"Environmental noise," based on the Directive 2002/49/EC [37], means unwanted or harmful outdoor sound created by human activities, including noise emitted by means of transport, road traffic, rail traffic, air traffic, and from sites of industrial activity. The EC regulation defines the "noise mapping" that refers to the presentation of data on an existing or predicted noise situation in terms of a noise indicator, indicating breaches of any relevant limit value in force, the number of people affected in a certain area, or the number of dwellings exposed to certain values of a noise indicator in a certain area. CHP plants measure the level of noise to comply with the EC directives. The obtained data are processed in each agglomeration to prepare the noise maps. The example of noise mapping is presented for CHP plant located in Chorzow, Poland. The plant consists of CFB Boiler OF 420 produced by Foster Wheeler and SIEMENS turbine. The gross electric power is 113 MW_e, whereas the generated heat is 180 MW_h. Figure 8.19 shows the map indicating the level of noise, the terrain of CHP is indicated in light gray, which means that the level is lower than 55 dB. Places indicated 55–60 and 60–65 dB do not belong to the CHP plant. The level of noise expressed in decibels is presented in Table 8.21.

The noise-emission data can be obtained from measurements carried out on the basis of the following international standards:

- ISO 8297: 1994 "Acoustics–Determination of sound power levels of multisource industrial plants for evaluation of sound pressure levels in the environment – Engineering method."
- EN ISO 3744: 1995 "Acoustics–Determination of sound power levels of noise using sound pressure – Engineering method in an essentially free field over a reflecting plane."
- EN ISO 3746: 1995 "Acoustics–Determination of sound power levels of noise sources using an enveloping measurement surface over a reflecting plane.:
- ISO 1996-2:1987 "Acoustics–Description and measurement of environmental noise – Part 2: Acquisition of data pertinent to land use."
- ISO 1996-1:1982 "Acoustics–Description and measurement of environmental noise – Part 1: Basic quantities and procedures."

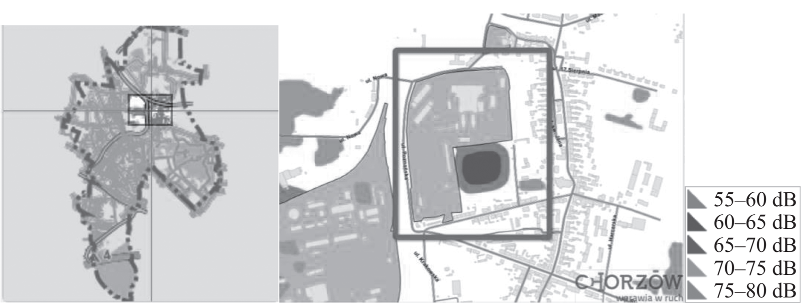

Figure 8.19 Map indicating the level of noise [38]

Table 8.21 Maximum permitted noise levels (reckoned as the equivalent noise level over the specified period) in decibels (dBA) [39]

	Day (7 AM–7 PM)	**Evening (7 PM–11 PM)**	**Night (11 PM–7 AM)**
Noise sensitive premises	60	55	50
Residential premises	65	60	55
Commercial premises	70	65	60

Table 8.22 Exposure action value and exposure limit value based on Directive 2002/44/EC [40]

Vibration	**Exposure action value (m/s^2)**	**Exposure limit value (m/s^2)**
Hand-arm vibration	2.5	5
Whole-body vibration	0.5	1.15

Currently, the life cycle assessment methodologies present limited information about the noise impact on the surroundings. The environmental analysis indicates that the impact of noise could also be assessed.

Vibrations, based on the Directive 2002/44/EC [40], are defined in two levels:

- “Hand-arm vibration” means the mechanical vibration transmitted to the human hand-arm system, which entails risks to the health and safety of workers, in particular vascular, bone or joint, neurological or muscular disorders.
- “Whole-body vibration” means the mechanical vibration transmitted to the whole body, which entails risks to the health and safety of workers, in particular lower back morbidity and trauma of the spine.

For the vibration, the exposure action value and exposure limit value have the limits presented in Table 8.22.

In addition, according to Directive 2006/42/EC [41] the machinery must be designed and constructed in such a way that risks resulting from vibrations produced by the machinery are reduced to the lowest level, taking into account the technical progress and the availability of means of reducing vibration, in particular at source.

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Chapter 9

Reliability and availability

Jacob Klimstra

9.1 Introduction

Anyone intending to buy and operate a cogeneration installation aims for a machine of good quality. In response, manufacturers and packagers never fail to highlight the quality of their products when advertising and when talking with customers. Immediately, however, the question arises to what quality means. Quality can have many aspects. For electricity supply, quality can mean that power is continuously available with the right voltage and frequency. For a heating device, quality can mean that it produces heat with high fuel efficiency and low emissions at every moment that the user wants it. Reliability and availability are often mentioned as quality indicators. Maintainability and technical life are some of the elements that determine reliability and availability. Prospective owners and operators of cogeneration plants should master the relevant definitions and the many aspects related with reliability and availability. They should understand what the implications of the quality aspects are for the economical application of the installation.

This chapter will first discuss the definitions of the relevant quantities. These definitions depend to some extent on the nature of a product and the specific demands of the user. In addition, based on the definitions, a methodology is given to express reliability and availability in terms of numbers. Further, this chapter provides the statistical background to determine the required redundancy to reach the desired output reliability. That helps to define the optimum maintenance philosophy and the amount of reserve capacity.

Many consumables such as light bulbs are used till the time they fail. For a complex installation such as a cogeneration plant, however, running to failure might result in irreparable damage. With a common understanding of the quality indicators reliability and availability, users and suppliers of cogeneration equipment are better able to match the expectations and the real performance of the product. Ultimately, users of cogeneration installations value good reliability higher than for example no deviations in fuel efficiency. Reliability issues can mean that the installation is limited in its availability, which is not only a nuisance but results in negative economic consequences.

9.2 Definitions

9.2.1 Component reliability

Cogeneration machinery has some typical parts, sometimes called consumables, which will be replaced regularly without repairs. Typical examples are the spark plugs of reciprocating engines and the igniter of gas turbines. The reliability of such parts is by definition the probability that they will operate for a specified period of time under the design conditions without failure [1]. A spark plug can fail immediately after installation due to a manufacturing error or an incorrect action by the person who carried out its mounting. Those are problems in the so-called early region of failure. Such early faults can be reduced to a minimum by well-described working procedures during manufacturing and mounting, and by testing the end product before installation. Spark plugs and igniters wear because of electrode erosion, thermal and mechanical stress as well as deposits accumulation. The estimated reliability function of properly mounted, good quality, spark plugs might be like the curve of Figure 9.1. A component reliability of a spark plug of 0.9 at 4,000 h means that 10 per cent of a batch of spark plugs will at average have failed after 4,000 h. For a 20-cylinder engine with 20 spark plugs, it means that during 4,000 h of running, probably two of such spark plugs have failed. After 5,500 h, the reliability might be only 0.4, meaning that in the case of 20 sparks plugs, 12 might have failed, causing 12 undesirable stops, with the bulk of them happening in the time span between 5,000 and 5,500 running hours. The latter case might be unacceptable for the operator of a cogeneration installation. The reliability of every consumable part of the installation has to be known in order to determine an optimum replacement strategy by weighing consumable replacement costs, maintenance time costs and costs of undesired stops.

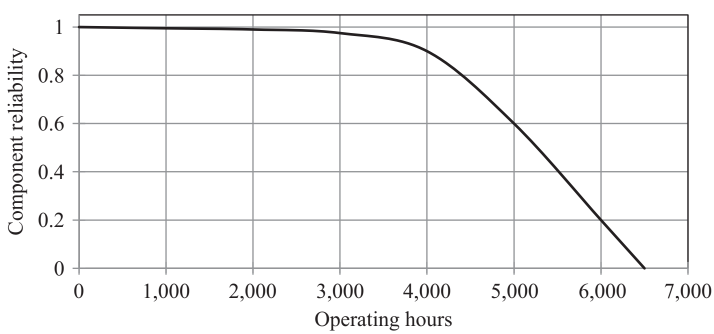

Figure 9.1 Example of the component reliability of a consumable component

9.2.2 Operational availability

In order to estimate the probability that an installation such as a cogeneration unit can perform its duties, the operator first has to know the fraction of the time that the unit is available for operation. Insight in the availability helps to optimise contracts for electricity and heat supply and for determining the need for back-up capacity. Many opinions exist about the definition of availability. By definition, the operational availability *OA* is the time remaining when the maintenance actions are subtracted from the total time divided by the total time:

$$OA = \frac{\text{average time between maintenance actions}}{\text{avg time between maint. actions} + \text{maintenance time} + \text{logistic delay}} \times 100\%$$

For a cogeneration unit, the typical total time for maintenance actions is 1,000 h during a running time of 40,000 h. This renders an operational availability of 97.5 per cent. The time required for maintenance actions includes the actual maintenance time and the logistic delay of deliverance of the spare parts. In case of a unique installation or a remote location, the spare parts logistics might take more time than otherwise. The maintenance time also depends on the crew that carries out the maintenance work. Working in shifts with sufficiently skilled personnel can substantially shorten the work compared to the case that a single mechanic unfamiliar with the unit does the work. In the case of for example weekend stops and summer stops because of lack of heat and electricity demand, the bulk of the maintenance work might be carried out during those times.

The time caused by unscheduled outage is not included in the definition of operational availability as given above. Unscheduled outage can be caused by real failure of the equipment, by mistakes of the operators or by nuisance trips from inadequately functioning control and monitoring equipment. Such outages are commonly expressed as unreliability. Unreliability is also closely connected with the reproducibility of the wear rate and wear pattern of components of the installation. Also inadequate maintenance decreases the reliability. The next section will more closely discuss system reliability.

9.2.3 System reliability

Many definitions exist for reliability and here system reliability will be explained. A complex installation such as a cogeneration unit consists of many components that can only run in dependence of most of the other components. Figure 9.2 is an example of the ignition system of a single cylinder of a spark-ignited gas engine with a central ignition control box. This is a chain of interrelated elements in series. In this case, the series system is the connecting cable between the controller and high-voltage coil, the high-voltage coil itself, the connecting cable between the coil and the spark plug and the spark plug itself. The connecting cables normally have very high component reliability, but they sometimes fail due to lose connection points. The component reliability of each cable plus its connectors might be

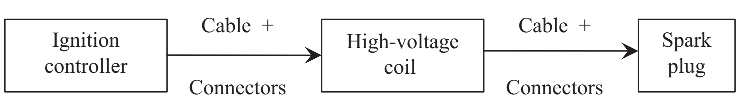

Figure 9.2 Example of a series chain of components

99.99 per cent at a certain moment in time. The ignition coil might have a component reliability of 99.9 per cent and the spark plug one of 99 per cent. The combined reliability of the series chain is then $0.9999 \times 0.999 \times 0.9999 \times 0.99 = 0.989$, equalling 98.9 per cent. This method is based on the so-called product rule. In this example, the reliability of the series chain is hardly lower than that of the spark plug, but the example illustrates the mechanism. In real life, connection points sometimes have a much lower reliability than 99.99 per cent.

The combined component reliability of the total ignition system of all engine cylinders is determined by a number of series systems in parallel with each other. Actual machines for cogeneration have so many components in series and in parallel that it is impossible in practice to determine the installation reliability based on the combined component reliabilities. Manufacturers, packagers and experienced maintenance experts aim at designing, testing, optimising and maintaining the installation to such an extent that the reliability of the total system becomes acceptable. A good installation should be able to run between 97 per cent and 99 per cent of the time that it is scheduled to run. The sector therefore uses the following definition for the installation reliability:

$$\text{Reliability} = \frac{\text{scheduled running time} - \text{unscheduled outage time}}{\text{scheduled running time}} \times 100\% \qquad (9.1)$$

Other ways to express the reliability are the *mean time between failures* or the *mean time between undesired stops*. This is useful when many trips occur which do not cause lengthy outages. An undetected lose connection might be the cause. Poor or delayed maintenance, low-quality replacement parts, bad fuels and unintended applications can severely reduce the reliability of a cogeneration installation. Issues can also arise in case the cogeneration installation is not properly matched with the heating system. Suddenly occurring high return water temperatures caused by switching off of large heat users or by oscillating temperature control valves can result in undesired trips of the cogeneration plant. *Nuisance trips* occur due to for example sensor failure, improper mounting of sensors or lose contacts. In many cases, a poor reliability does not arise because of a bad basic design but because of neglect and poor operation and maintenance approaches.

9.3 Maintenance philosophies

Running to failure, a typical maintenance approach for consumables, is no option for cogeneration installations. Wearing parts have to be repaired or replaced before they break down, especially when there is risk of *collateral damage*. Losing a front-row blade of the axial compressor of a gas turbine generally means that the whole machine will be damaged. The first alternative for running to failure is *preventive maintenance*. Preventive maintenance means that wearing parts are replaced in regular time intervals before their component reliability has reached an unacceptable value. Determining the component reliability is a matter of combining design technology with practical running experience. *Replacement intervals* can be gradually lengthened if proof is found of sufficient remaining life of the components. This is often done in close cooperation between suppliers and customers. Prototypes can be tested on their required maintenance with launching customers under special arrangements. Preventive maintenance is also called *periodic maintenance* or *proactive maintenance*.

Predictive maintenance and *on-condition maintenance* based on measuring wear rates of critical components is increasingly used now that computers have made data acquisition and analysis easy. Sampling and analysing lubricating oil at regular intervals helps to allow oil replacement at a moment that it is really required rather than replacing the oil at fixed intervals. Temperature and pressure sensors can reveal the process conditions and efficiencies. Absolute vibration sensors in combination with frequency analysis can detect unbalance, misalignment and lose parts of rotating machinery. Relative vibration sensors, the so-called proximitors, can detect abnormalities of radial and axial journal bearings. Torque sensors can reveal if the rotational speed stability is correct. Running conditions are coupled to wear rates so that one can for example take into account that starting and stopping of a gas turbine or of a steam-based installation are adding extra wear. This extra wear is expressed in *equivalent running hours*. A sudden trip at full load gives for example more equivalent running hours than stopping after a gradual decrease of the load. Taking regular *fingerprints* of the operating behaviour of the installations or *continuous monitoring* of the sensors' output is increasingly used to improve the reliability and availability. In addition, condition-based maintenance can in some cases reveal which parts have to be replaced soon so that the logistic delay can be shortened.

The time required for maintenance can also be shortened by a proper built-in maintainability. Easy access to parts that have to be replaced or repaired is a prerequisite. Manufacturers increasingly try to utilise a sectional approach, with direct access to the relevant elements without the need of dismantling a large number of other parts. Also the room in which the installation is placed should facilitate maintenance actions by offering sufficient space for the tools and spare parts. An often neglected issue for installations is also the noise level in which the maintenance crew has to work. High noise levels limiting communications are tiring and reduce the concentration level of the workers. A solution where cogeneration units in parallel are separated by solid walls greatly helps to improve working conditions so that the maintenance time can be reduced and the quality of maintenance is improved.

In purchase and maintenance contracts, clarity should exist about the time span for which a guaranteed operational availability and reliability applies. Sometimes only values are given until a lengthy and costly overhaul is needed. In addition, responsibilities have to be clear in case of a major breakdown such as a broken shaft that almost requires a re-build of the prime mover or generator. Situations exist where installations have been unable to run for several months because of disputes between users, suppliers and insurance companies. The user of the cogeneration plant is then often obliged to generate heat with a boiler and purchase electricity from the public grid, which can be very costly.

An optimum maintenance and operation strategy in combination with good agreement and communication between operator, supplier and maintainer is a prerequisite for obtaining a high reliability and availability of a cogeneration installation. This should be an integral part of the decision process when purchasing a cogeneration plant.

9.4 Redundancy

The previous sections have shown that a 100 per cent availability and reliability of a cogeneration installation is not possible. The same applies to all other electricity producing machinery such as those in large central power plants. Regular maintenance is required and occasionally problems occur that result in standstill and repairs. Customers of electricity depend increasingly on the presence of electric power. An example is the electricity supply to a hospital. There, the heat and electricity supply is often provided by cogeneration installations to save energy but also to increase the probability of an uninterrupted electricity supply. In such a case, the public grid generally serves as the back-up for electricity supply, while boilers can produce the required heat if the cogeneration installation is not able to run. However, in order to maximise the probability of the presence of electric power, the best approach is to have a number of cogeneration units in parallel that can operate independently. That results in the so-called redundancy, which in an engineering context means that extra elements have been included in a system to create a higher availability. This section will explain how redundancy improves the probability that sufficient electric power is present.

The public grid uses many generators in parallel to create a sufficiently high probability of electricity supply. The grid operator ensures that not all generators run at full output but have rapidly available reserve power, the so-called primary, secondary and tertiary reserves. As soon as one power plant fails, the primary reserves ensure that the frequency does remain within agreed limits. Deployment of the primary reserves triggers the secondary reserves to take over the task of the primary reserves and to restore the grid frequency to the standardised value. Ultimately, the tertiary reserves take over the role of the secondary reserves so that the primary and secondary reserves are able to fulfil their job as soon as another power plant fails. Most of the local black outs that are experienced by customers do not therefore occur because of failed power plants but because of problems with transformers, power lines and switch gear. The probability of electricity supply in economically developed countries reaches values of over 99.99 per cent (Table 9.1).

For cogeneration installations, the required redundancy depends on the typical application. For a greenhouse owner, where the heat is used to create a constant climate for the crop, the electricity is used for assimilation lighting and the exhaust gases for CO_2 fertilisation, short stops for regular maintenance are not detrimental for the growth process. Longer stops can however be very costly since in that case, the required electricity and CO_2 have to be bought from a third party. There are many applications of cogeneration where a temporary loss of only part of the output

Table 9.1 The average time per year without electricity depends on the probability of electricity supply

Probability of electricity supply (%)	**Average time per year of no supply**
99	3.7 days
99.9	9 h
99.99	53 min
99.999	5 min

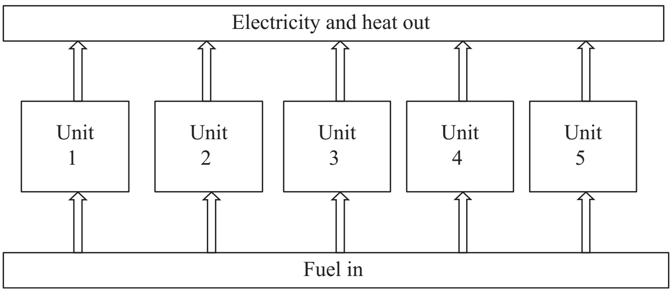

Figure 9.3 Five units in parallel that can operate independently

is not a problem. An example is again a hospital, where less crucial applications of electricity can be switched off for a while. Supply is then only ensured for preferential groups. In many cases, it is preferable to have a number of cogeneration units in parallel. This not only increases the availability of at least a part of the installed capacity, but creates also flexibility in case the load is not constant. Variable loads occur depending on the time of the day and on the season.

The method to determine the combined reliability of a number of cogeneration units in parallel will now be explained. In Section 9.2.3, the concept of reliability of series systems has already been discussed. By definition, the units in a parallel system can operate independently of each other. Figure 9.3 is an illustration of five independent generating units in parallel. If the reliability of one unit is known, the product rule as applied earlier for the series system reveals the probability that all units will run. For an individual reliability of 99 per cent per unit, this yields a probability P that all five units intended for operation are running of:

$$P(\text{all five units are running}) = 0.99 \cdot 0.99 \cdot 0.99 \cdot 0.99 \cdot 0.99 = 0.95099$$

Consequently, the probability that at least one unit will not be able to run due to unreliability is approximately 5 per cent. This is exclusive of the time required for regular maintenance. It might be disappointing to learn that the probability that all units will run is lower than the reliability of a single unit, but this is the logical consequence of having more than one unit in a system. One can however use an

Table 9.2 The five different configurations/permutations where one unit is not able to run in case of five units in parallel (X = not able to run due to unreliability)

Permutation	**Situation**				
	Unit 1	**Unit 2**	**Unit 3**	**Unit 4**	**Unit 5**
1	X	O	O	O	O
2	O	X	O	O	O
3	O	O	X	O	O
4	O	O	O	X	O
5	O	O	O	O	X

approach that in the case of five installed units, four units are able to carry the load. One of the units can then serve as the spare unit. This offers also the possibility to carry out maintenance with one unit while the remaining four are in operation and still supply all the required energy. Such a solution might be preferable in for example the case of a hospital or a data co-location centre. When presuming that all five units are operationally available for running, the operator will like to know what the probability is that at least four units out of five are running. Table 9.2 shows that there are five different configurations where exactly one out of five units is not able to run because of its unreliability. In the theory of statistics, this is expressed as five different permutations.

The probability that exactly four out of five units intended for operation are running can be determined with a combination of the product and sum rule. The probability that permutation 1 occurs for an individual reliability of 99 per cent (0.99), and therefore a probability that a unit is not running of 1 per cent (0.01), equals:

$$P(\text{permutation } 1) = 0.01 \cdot 0.99^4 = 0.009606$$

Since there are five different permutations in this case, the combined probability that one out of five units is not running is the sum of the results of each permutation: $5 \times 0.009606 = 0.04803$ equalling 4.803 per cent. Consequently, exactly four out of five units in parallel will be running during 4.8 per cent of the time in case of an individual reliability of 99 per cent. We found earlier that the probability that all the five units intended for operation were running is 95.099 per cent. Therefore, the probability that at least four units are running is $95.099 + 4.803 = 99.902$ per cent. Therefore, in the case of five units running in parallel where four units are able to carry the demand in load, insufficient power caused by unreliability is on the average present only 0.10 per cent of 8,760 h equalling almost 9 h per year. In case, the cogeneration installation would consist of only one unit with a reliability of 99 per cent, the output would on the average not be available during 88 h per year due to unreliability.

The advantage of having multiple units in parallel is even more pronounced if it is allowed to temporarily have a lower combined output than normally required.

The probability that for example two out of five units are not able to run is much smaller than that one out of five cannot run when required. The calculation procedure is basically the same as for the case of one unit failing. However, the number of permutations is 10 in this case. Therefore, the probability that exactly three units are running is 0.097 per cent and the probability that at least three units are running is $95.099 + 4.803 + (10 \times 0.0097) = 99.999$ per cent. This results in on average only 5.3 min per year of less power than what three units can generate. The probability of exactly three units running has been found by using again the sum and product rule which shows that the probability of one of the 10 permutations occurring equals in this case:

$$P(\text{permutation 1}) = 0.01^2 \cdot 0.99^3 = 0.000097 = 0.0097\%$$

The so-called binomial distribution as discovered by the Swiss scientist and mathematician James Bernoulli (1654–1705) gives the probability that an event will happen exactly m times out of n trials [1]. Thus, (9.2) can be used to determine the probability P of exactly m out of n generating units running for a unit reliability of R:

$$P(m \text{ out of } n \text{ running}) = \frac{n!}{m! \cdot (n-m)!} R^m \cdot (1-R)^{n-m} \tag{9.2}$$

where $n! = 1 \times 2 \times 3 \times \cdots \times n$ and:

$$\text{Number of permutations} = \frac{n!}{m! \cdot (n-m)!} \tag{9.3}$$

Consequently, it is not necessary to make an overview of the permutations such as in Table 9.2, which can be cumbersome in case of many units working in parallel as a virtual power plant.

The preceding step-by-step procedure is expressed in general terms as follows. The probability that at least m out of n units in parallel are running is given by the equation:

$$P(\text{at least } m \text{ out of } n \text{ running}) = R^n + \sum_{j=1}^{n-m} \frac{n!}{(n-j)! \cdot j!} R^{n-j}(1-R)^j, \quad m < n \tag{9.4}$$

The probability that all n out of n units are running is given by the equation:

$$P(\text{all } n \text{ units are running}) = R^n \tag{9.5}$$

An alternative expression is the following [2]:

$$P(\text{at least } m \text{ out of } n \text{ running}) = 1 - \sum_{i=0}^{m-1} \frac{n!}{i! \cdot (n-i)!} R^i (1-R)^{n-i} \tag{9.6}$$

which is valid also for $m = n$.

Having a number of cogeneration units in parallel offers substantial advantages for creating higher supply reliability than in case of a single unit. It has been shown how to calculate the probability that a required output is available. Next to that, having a number of units in parallel creates the possibility to carry out maintenance on one unit while the others are still able to run. By properly determining the minimum required reliability of supply of electricity and heat, the necessary redundancy can be calculated. If the public electricity grid has a high reliability and offers back up capacity at an economically attractive price, it might not be necessary to create redundancy in a cogeneration installation itself. This requires however a back-up boiler to produce the required heat if the cogeneration unit is not available.

A clever maintenance strategy helps to improve the reliability of a number of cogeneration units in parallel. Operators often try to create close to equal running hours on the units. The consequence is however that a common problem which develops over time will appear most probably at close to the same moment. A case is known where all four cogeneration installations in a hospital broke down within a time span of a few weeks because of a teething problem that occurred after a certain number of running hours. It is much better to apply a strategy where one of the units is used as a forerunner. Wear-related problems leading to unforeseen stops will first show up at the forerunner and measures can be taken with the remaining units before damage occurs. In addition, ensuring that one of the units has less running hours than the others makes that this unit can serve as the back-up unit. Such a strategy will more probably lead to a satisfactory performance of the cogeneration system.

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Chapter 10

Economic analysis of cogeneration systems

Christos A. Frangopoulos

10.1 Introduction to economic analysis of cogeneration systems

Cogeneration systems are capital-intensive installations. Even if a cogeneration system has high-energy efficiency, it will not be possible to proceed with the investment unless it is also economically viable. The procedure for evaluation of the economic performance of cogeneration systems is presented in this chapter, supported with information about the various types of costs, definition of the most important of the economic parameters and measures used for evaluation, as well as examples of economic analysis. Two additional issues are also tackled: (a) the distribution of costs of a cogeneration system among its energy products and (b) the effect of the internalization of environmental externalities on the cost of covering energy needs either by a cogeneration system or by the conventional approach, that is separate production of work and heat.

Care has been exercised so that the values of costs given here to be realistic. However, they can be considered indicative only, as they change with place and time. Consequently, the economic performance evaluation of any cogeneration project should be based on cost information obtained for the particular project.

Additional information on costs and economic analysis can be found in [1–9].

10.2 Types of costs

There may be several ways of categorizing costs of cogeneration systems, but, broadly speaking, two major categories are (a) the installed capital cost and (b) the operation and maintenance (O&M) cost. They are described in the following section.

10.2.1 Installed capital cost

The installed capital cost includes all the expenses for constructing the system, until it is ready for operation. It includes the following costs.

10.2.1.1 Equipment costs

Equipment costs include costs for purchase of the equipment and transportation on site. The most important of those are the following.

Prime mover and generator set

The cost depends on the type of prime mover, fuel (or fuels) used, power output, voltage and, if available, emission control and noise reduction.

Heat recovery equipment and related piping

The cost depends not only on the quantity, but also on the quality (pressure and temperature) of the delivered thermal energy, for example low-temperature water, saturated steam of low pressure, superheating steam of high pressure and others.

Exhaust gas boilers, in particular, can be equipped with supplementary firing (using the same fuel with the prime mover or a different one), thus increasing the thermal energy supplied to the loads and increasing the cost.

Exhaust gas system and stack

The cost depends on factors such as the exhaust gas flow rate and temperature, exhaust gas treatment, if available, and bypass valve, if needed for partial load operation.

Fuel supply

The cost includes fuel-supply infrastructure, fuel storage and metering. For natural gas, in particular, there may be need of compressor for increasing the pressure to the level required by the prime mover, if the line pressure is low.

Ventilation and combustion air supply

Ducts, filters and sound attenuation equipment are included.

Control board

The cost depends primarily on the degree of automation and, in particular, on whether the system will be capable for unattended operation.

Interconnection with the electric utility

Interconnection equipment includes the connection line, as well as safety and measuring equipment. The cost depends also on whether the interconnection is one-way or two-way (capability of both buying and selling electricity).

Shipping and taxes

In addition to expenses for transportation of equipment to the site, import or other types of taxes may be applicable.

10.2.1.2 Installation costs

Installation costs may include installation permits, land acquisition and preparation, building construction (except if the cogeneration system is small and the space is already available), installation of equipment, documentation and as-built drawings.

10.2.1.3 Project costs

They are called also 'soft' costs. The most important of these are the following:

- Engineering fees for the analysis, design, planning and development of a cogeneration system
- Construction management fees
- Environmental studies and permitting costs
- Legal fees
- Letters of credit
- Training of personnel (except if it is included in the cost of equipment)
- Project financing (costs due to, e.g. interest during construction)
- Contingency (allowance for unforeseen costs).

10.2.1.4 Examples of installed capital costs

As is written in the introductory Section 10.1, costs of cogeneration systems depend not only on the technology, but also on place and time. In addition, they are affected by several factors, such as special agreements and discounts possibly offered by manufacturers, emissions regulations in the particular area, local labour availability and rates, needs for infrastructure (i.e. whether the system is to be located on a bare field or on a site with existing roads and networks of electricity, water, fuel) and others. Therefore, values given in this section are indicative only.

Examples of cost breakdown are given in Tables 10.1 and 10.2. The values have been derived by processing data provided in [5]. It is worth mentioning that early in the design phase, the contingency may be in the range of 15%–20%, whereas at the completion of the design it may be reduced to 3%–5%.

For a steam turbine-based cogeneration system, it is more difficult to give typical values of cost and cost breakdown, because of the complexity and the variety of configurations and fuels burned that make nearly every installation to be

Table 10.1 Examples of installed cost breakdown of gas engine cogeneration systems (values in %)

Nominal net power output (kW_e)	100	1,121	9,341
Equipment cost			
Gen-set package	48.28	15.85	40.13
Heat recovery	8.62	21.13	12.21
Interconnect/Electrical	8.62	4.23	1.74
Exhaust gas treatment	0.00	21.13	10.47
Total equipment	65.52	62.34	64.55
Labour and materials	17.24	15.60	16.12
Project and construction management	4.31	9.34	9.70
Engineering and fees	8.62	7.39	2.09
Project contingency	3.28	3.13	3.21
Project financing	1.03	2.20	4.33
Total	100.00	100.00	100.00

Table 10.2 Examples of installed cost breakdown of gas-turbine cogeneration systems (values in %)

Nominal net power output (kW_e)	**3,304**	**9,950**	**20,336**
Equipment cost			
Combustion turbine	26.47	36.03	39.65
Electrical equipment	9.70	6.63	4.83
Fuel system	6.92	5.99	5.53
Heat recovery steam generator	6.73	5.50	5.85
Exhaust gas treatment	6.35	5.00	4.91
Shipping	1.27	1.28	1.28
Total equipment	57.44	60.43	62.05
Building	4.05	2.97	2.05
Construction	20.33	19.90	19.44
Project and construction management	6.26	5.14	4.37
Development fees	6.02	6.21	6.28
Project contingency	3.70	3.15	2.90
Project financing	2.20	2.20	2.91
Total	100.00	100.00	100.00

Table 10.3 Indicative installed cost breakdown of steam turbine-based cogeneration systems

Item	**Cost (%)**
Steam turbine-generator	6
Solid-fuel boiler	26
Site preparation	9
Electrostatic precipitator	9
Other equipment	9
Engineering and construction	41
Total	100

custom-designed. An indicative cost breakdown is given in Table 10.3, based on information provided in [5].

Due to economies of scale, the unit installed capital cost, that is the cost per kW_e of net power output, decreases with increasing power. As examples, the graphs of Figures 10.1 and 10.2, which have been obtained with data provided in [5], and of Figure 10.3 are presented. It is noted that Figures 10.1 and 10.2 are based on costs in the United States, whereas Figure 10.3 is based on costs in the United Kingdom.

For the unit installed cost of cogeneration systems with back-pressure steam turbines, Reference [5] gives values in the range 1,100–670 US\$/kW_e for net power output in the range of 500–15,000 kW_e, respectively.

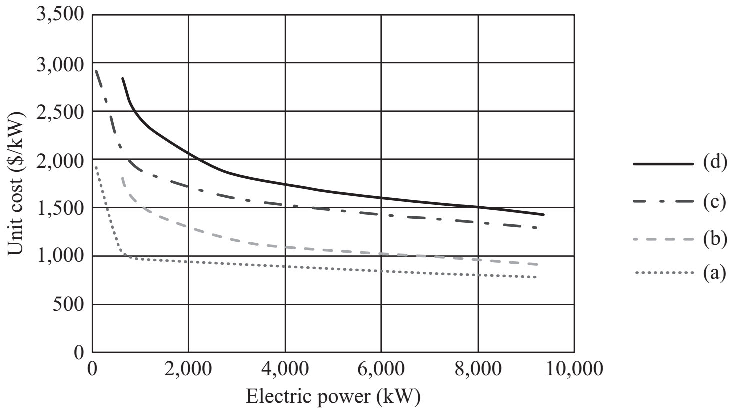

Figure 10.1 Unit capital cost of gas-engine cogeneration systems (values in 2013 US\$/kW$_e$). (a) Equipment, no exhaust gas treatment, (b) equipment with exhaust gas treatment, (c) installed, no exhaust gas treatment, and (d) installed with exhaust gas treatment

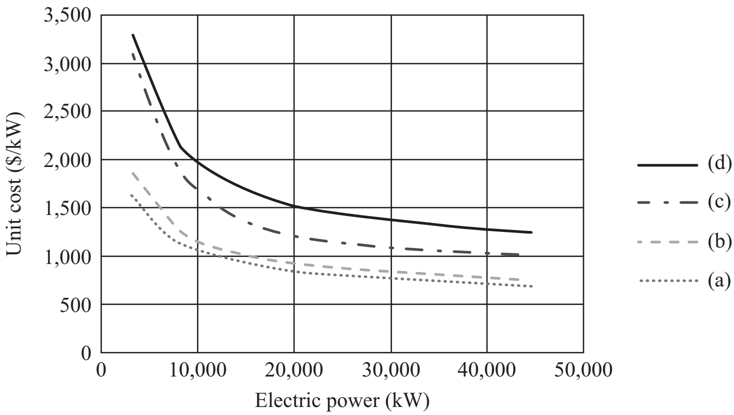

Figure 10.2 Unit installed capital cost of gas-turbine cogeneration systems (values in 2013 US\$/kW$_e$). (a) Equipment, no exhaust gas treatment, (b) equipment with exhaust gas treatment, (c) installed, no exhaust gas treatment, and (d) installed with exhaust gas treatment

10.2.2 Operation and maintenance costs

10.2.2.1 Main components of operation and maintenance costs

The most important O&M costs are the following [5,7].

Fuel costs

Fuel costs constitute the major part of the O&M costs and that is why they are often given in separate of the other O&M costs. They depend on the particular fuel tariff

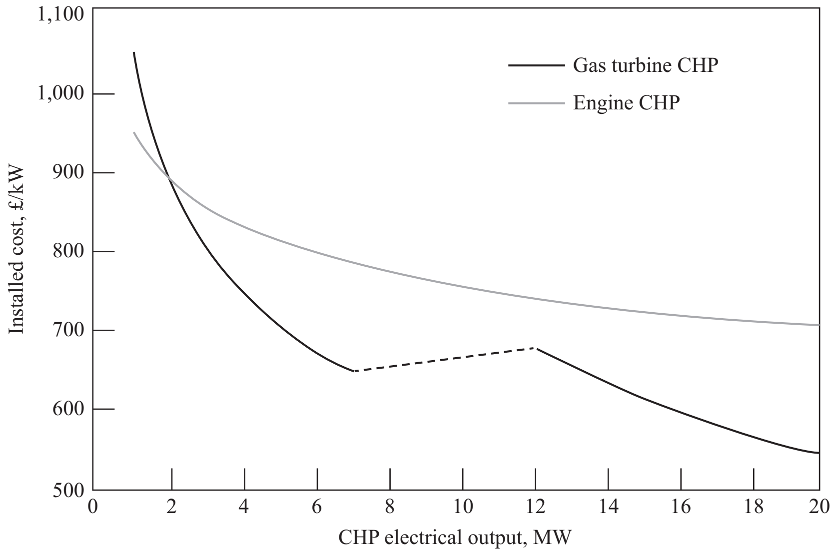

Figure 10.3 Unit installed capital cost of cogeneration systems (values in 2013 UK£/kW$_e$ [6])

or on any special agreement between the cogenerator and the fuel supplier. It is possible that the fuel of a cogeneration system can be a by-product of a production process, as for example is the fuel gas produced in oil refineries. In such cases, the cost of fuel is much reduced or even zero.

Costs of consumables other than fuel

They include costs of lubricating oil, make up water, chemicals for water treatment, chemicals for pollution reduction and others. They are much lower than the cost of fuel.

Personnel costs

They depend on the type and size of the system, the number of operation hours per day (one, two or three shifts), as well as the degree of automation. Fully automated systems (small to medium size) can operate unattended, whereas larger systems require continuous presence of qualified personnel. Safety regulations may impose attended operation even for smaller systems, if they contain boiler(s). On the other hand, use of solid fuels usually increases the personnel costs.

If qualified personnel who can attend the system is already available, as in certain industries, then the additional personnel cost for the cogeneration system can be significantly reduced or even zero.

Maintenance costs

There are two basic maintenance approaches: (a) maintenance as-scheduled, that is maintenance in intervals pre-specified by the manufacturer, and (b) maintenance as-needed, which is based on continuous performance monitoring of the system and analysis of the data, which indicates the type and timing of action needed. On the other hand, maintenance can be performed by on-site skilled personnel, if available, or by specialized companies either on-call when needed, or with signed contract. Both the approach and the way maintenance is performed affect the cost. The costs also depend on the type of cogeneration system, the type of fuel, the operating conditions and others. For example, in the case of systems with internal combustion engines, heavy-duty engines, in general, require less maintenance than light-weight engines. Frequent cycling (start-up and shut down) increases thermal stresses and, consequently, maintenance costs. Use of solid fuel or heavy liquid fuel with impurities results in higher maintenance costs.

Insurance costs

Insurance may cover equipment failure only, or it may be extended to loss of income, loss of savings or interruption of business. In addition to the type of coverage, insurance costs depend on the type of prime mover, the equipment performance history, and the system design and operating mode. The annual insurance costs can be in the range of 0.25%–2% of the installed capital cost, whereas in certain cases, in particular for smaller units, the insurance may be covered under the owner's overall insurance programme at no additional cost [7].

Environmental costs

The construction and operation of energy conversion systems causes adverse effects to the society and the environment. For example, mining of materials for construction may cause deforestation and land degradation in the particular area. Pollutants emitted during construction and operation cause health problems of people and have negative impact on flora and fauna, as well as on buildings and monuments. Several studies have been performed in order to estimate the costs due to these effects [10,11].

Other operation costs

In addition to the aforementioned, there may be management fees, taxes, interest on loan (if applicable) or other expenses related to the particular case.

10.2.2.2 Estimation of operation and maintenance costs

The O&M costs depend on the particular system. The cost of fuel, which is the major component, is calculated in separate, taking into consideration its consumption and the tariff in the particular place. For a first estimate of the remaining O&M costs, information found in the open literature can be used. They are given in two forms: (a) the annual O&M cost as a percentage of the installed capital cost, or (b) cost per unit of electric energy produced. Indicative values are given in Tables 10.4 and 10.5. The values in Table 10.5 are based on information given in [5].

Economies of scale are evident also in Table 10.5: larger systems have lower O&M cost per MW_e.

The O&M costs consist of *fixed* and *variable* costs. Fixed costs are those which occur no matter whether the system operates or not. Variable costs are those which depend on the quantity and quality of the energy products of the cogeneration system. There is need of detailed logistics in order to separate the O&M costs into

Table 10.4 Average annual O&M cost except fuel of cogeneration systems as percentage of the installed capital cost

Type of system	O&M cost (%)
Steam turbine with heavy fuel oil	2.6
Steam turbine with lignite	4
Gas turbine	4.5
Diesel engine	6
Combined cycle	4
Steam bottoming cycle	2

Table 10.5 O&M cost except fuel of cogeneration systems per unit of electric energy produced

Type of system	Power range (MW)	O&M cost ($/MW$_e$)
Steam turbine	0.5–several hundred	10–6
Gas turbine	3–45	13–9
Gas engine	0.1–9.5	25–8.5
Micro-turbine	0.03–0.95	13–9

fixed and variable costs. The values in Tables 10.4 and 10.5 include both fixed and variable costs.

10.3 Definition of economic parameters

The economic performance of an investment is evaluated by means of certain measures, which are defined in Section 10.4. These measures are calculated by means of certain economic parameters, which are defined in this section.

10.3.1 Interest and interest rate

Initially, the term *interest* was used to denote a rental amount charged by the financial institutions for the use of money [8]. The amount of capital, on which interest is paid, is called *principal*. *Interest rate* is the amount of interest paid per unit of principal in a unit of time. Usually, it is expressed as a percentage of principal per year.

Later on, the concept was extended to earning assets, which 'borrow' from their owner, repaying through the earnings generated [8]. Thus, there are two aspects of interest rate:

1. *Borrowing interest rate*: It is paid for borrowing funds. Interest paid for such a purpose is a cost.
2. *Market interest rate*: It is received as a result of investing funds, either by loaning the funds or by using these for the purchase and operation of a

facility, such as a cogeneration system. In such a case, interest is a gain or profit. The term is used also to denote the expected or desirable return on investment (ROI).

Both interest rates are determined by market forces, involving supply and demand, but they can be affected also by the economic policy.

10.3.2 Price index

The prices of commodities (goods or services) change with time, as they are affected by many factors in the economy, such as increase of productivity, availability or scarcity of goods, government policies and others. In most cases, the cumulative effect of these factors is an increase of prices, even though the opposite can occur, as for example with the price of computers.

The change of the price of a commodity is expressed with the *price index*, which is the ratio of the price of the particular commodity at a certain time to the price at an earlier time. Usually, a certain year in the past is selected as the base year, and the price index is expressed as the ratio of prices multiplied by 100:

$$I_b^a = \frac{p_a}{p_b} \cdot 100 \tag{10.1}$$

where I_b^a is the price index of year a with respect to base year b, p_a is the price in year a, and p_b is the price in year b.

Price indexes are calculated not only for individual commodities, but also for classes of products. For example, *Equipment Price Indexes* are regularly published in the journal *Chemical Engineering*, which refer to boilers, heat exchangers, chemical equipment, electricity generating plants and others.

Furthermore, composite indexes are determined, such as the *Consumer Price Index*, the *Producer Price Index* and others. The Consumer Price Index, which is the most common index, represents the change in retail prices of a selected set of purchases including clothing, food, housing, transportation and utilities, required to maintain a fixed standard of living for the 'average' consumer [8].

Price indexes can be used to estimate the cost of a commodity in different time periods as follows: if the cost in year i is known, then the cost in year j is given by the following equation:

$$C_j = C_i \frac{I_j}{I_i} \tag{10.2}$$

where C_i and C_j are the cost in year i and j, respectively; and I_i and I_j are the price index of the particular commodity in year i and j, respectively.

10.3.3 Inflation and inflation rate

In general, the costs of commodities increase with time, and this increase is called *inflation*. The increase per unit of cost and time is called *inflation rate*, and it is usually expressed as a percentage per year.

In certain periods of time, a decrease of costs has occurred, which is called *deflation*, but this is a rather seldom phenomenon. *Deflation rate* is expressed as negative inflation rate.

The inflation rate is different for different goods and services, for example equipment, fuel, labour, spare parts and others. The annual inflation rate of a commodity can be calculated using the price index of the commodity with the following equation:

$$f_{k,t} = \frac{I_{k,t} - I_{k,t-1}}{I_{k,t}} \tag{10.3}$$

where $f_{k,t}$ is the annual inflation rate of commodity k in year t, and $I_{k,t-1}$ and $I_{k,t}$ are the price index of the commodity k in year $t-1$ and t, respectively.

An average inflation rate, f_t, is calculated using the following equation:

$$f_t = \frac{\mathrm{CPI}_t - \mathrm{CPI}_{t-1}}{\mathrm{CPI}_t} \tag{10.4}$$

where CPI_t and CPI_{t-1} are the consumer price index in year t and $t-1$, respectively.

For energy conversion systems such as cogeneration systems, in particular, since the cost of fuel is more erratic than the other expenses, it is usual to consider a separate inflation rate for the cost of fuel, usually higher than the average inflation rate.

10.3.4 Life cycle and life-cycle cost

The life cycle of a system begins with the identification of the need that the system will serve and ends with decommissioning and dismantling of the system. The whole life cycle consists of three main phases (Figure 10.4):

1. acquisition, which includes research, development, planning, design, construction, test and evaluation, and deployment,
2. O&M, and
3. decommissioning and dismantling.

Life-cycle cost includes all the expenses incurring during all this period. Life-cycle analysis at the beginning of the project attempts to estimate all costs and achieve a balance between the acquisition costs and the costs of O&M. It is important to mention that decisions taken in the acquisition phase have a strong

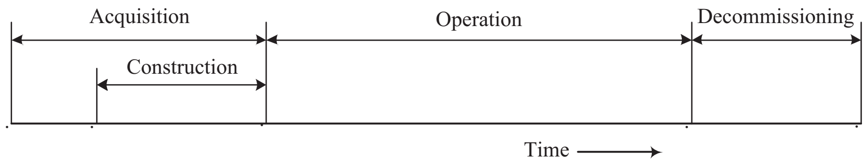

Figure 10.4 Life cycle of a system

impact on the costs not only of this phase, but also of the O&M. In optimisation of a system, minimization of the life-cycle cost is often the objective function.

Relatively recently, the concept of life cycle has been extended 'from cradle to grave', that is from mining of the materials required for the construction of the components and of the whole system, to dismantling of the system, recycling of materials or rejection of materials to the environment. Thus, the concept of life-cycle cost has been extended also and includes, in addition to the conventional costs, the cost to the society and the environment caused by all the activities, such as costs due to emission of pollutants, degradation of the environment and others.

10.3.5 Estimation of the value of money in time

10.3.5.1 The time value of money

A certain amount of money available today is of higher value than the same amount available in the future, because it can be invested and thus increased with the interest. This fact is depicted in Figure 10.5: If 1 € is available today, the available amount after N years will be equal to 1 € plus the interest gained throughout the years. If, however, 1 € is available after N years, there will be no increase.

One more reason that makes the value of money to change with time is the fact that the purchasing power of money changes with time due to inflation or deflation.

The effect of both earning and purchasing power of money are taken into consideration in order to determine the value of money in time.

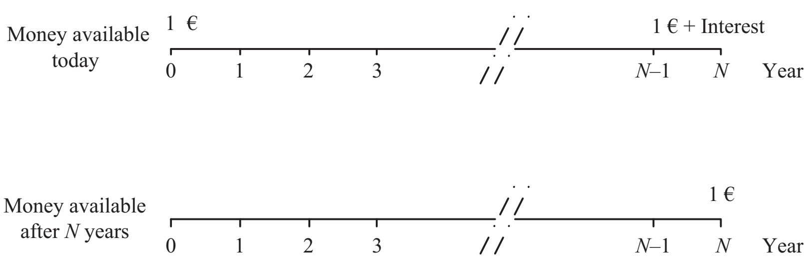

Figure 10.5 Illustration of the time value of money

10.3.5.2 Present and future worth of money

If a principal P is invested at the present time ($t = 0$), the accumulated amount of principal and interest after N time periods (future amount, F) will be:

$$F = P \cdot \prod_{n=1}^{N} (1 + i_n) \tag{10.5}$$

where i_n is the market interest rate during the period n. One year is the most common time period. However, any other period can be used: day, month, quarter (3 months), 6 months and others. Conversely, the amount of money P that has to be invested at the present time, in order to have accumulated amount F after N time periods, is given by the following equation:

$$P = \frac{F}{\prod_{n=1}^{N} (1 + i_n)} \tag{10.6}$$

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

If the interest rate can be considered constant over all time periods, then (10.6) takes a simpler form:

$$P = \frac{F}{(1 + i)^N} \tag{10.7}$$

According to (10.6) and (10.7), the interest rate i is used to discount future amounts to their present worth; for this reason, it is called also *market discount rate*.

In economic analysis of cogeneration systems, it is usual to consider $t = 0$, the time that the operation starts. Then, all the expenses for the system acquisition occurred in the past. The present worth of a past cash flow F is given by the following equation:

$$P = F \cdot \prod_{n=-1}^{-N} (1 + i_n) \tag{10.8}$$

If i_n can be considered constant over all time periods, then (10.8) takes a simpler form:

$$P = F(1 + i)^N \tag{10.9}$$

10.3.5.3 Present worth factor

There are types of cash flows (expenses or revenues) that occur at the beginning or the end of each time period for N periods and change due to inflation only. The amount of such a cash flow at the time period n is given by the following equation:

$$C_n = A(1 + f)^{n-1} \tag{10.10}$$

where A is the cash flow in the first period, and f is the inflation rate.

Equation (10.10) is valid for constant inflation rate. If f changes with time, an equation similar to (10.5) can be used.

If the cash flow occurs at the beginning of each period, its present value is:

$$P_n = A\frac{(1 + f)^{n-1}}{(1 + i)^{n-1}} \tag{10.11}$$

If it occurs at the end of each period, its present value is:

$$P_n = A\frac{(1 + f)^{n-1}}{(1 + i)^n} \tag{10.12}$$

If a cash flow is repeated in every time period for N periods, then the present worth of all the N amounts is:

$$P = \sum_{n=1}^{N} P_n \tag{10.13}$$

If the cash flow changes due to inflation only, then the present worth of all the cash flows can be calculated by the following equation:

$$P = A \cdot \mathrm{PWF}(N, f, i) \tag{10.14}$$

where A is the first amount, and PWF is the present worth factor. Introducing (10.11) or (10.12) into (10.13), the following expressions are obtained.

For cash flows at the beginning of each period:

$$\mathrm{PWF}(N, f, i) = \sum_{n=1}^{N} \frac{(1+f)^{n-1}}{(1+i)^{n-1}} = \begin{cases} \dfrac{x^N - 1}{x - 1}, & f \neq i \\ N, & f = i \end{cases} \tag{10.15}$$

where:

$$x \equiv \frac{1+f}{1+i} \tag{10.16}$$

For cash flows at the end of each period:

$$\mathrm{PWF}(N, f, i) = \sum_{n=1}^{N} \frac{(1+f)^{n-1}}{(1+i)^{n}} = \begin{cases} \dfrac{1}{i-f}\left[1 - \left(\dfrac{1+f}{1+i}\right)^N\right], & f \neq i \\ \dfrac{N}{1+f}, & f = i \end{cases} \tag{10.17}$$

10.3.5.4 Capital recovery factor

Let it be considered that an amount P is deposited today at an interest rate i, and the depositor wishes to withdraw the same amount A at the end of each period, so that after N periods there should be no funds left on the deposit. It can be proved that the amount A is determined by the following equation:

$$A = P \cdot \mathrm{CRF}(N, i) \tag{10.18}$$

where CRF is the capital recovery factor, which is determined by the following equation:

$$\mathrm{CRF}(N, i) = \frac{i(1+i)^N}{(1+i)^N - 1} = \frac{i}{1-(1+i)^{-N}} \tag{10.19}$$

Equations (10.18) and (10.19) are used also in order to calculate:

1. the annualized capital cost A of an investment P,
2. the depreciation of equipment, and
3. the equal payments A that have to be made at the end of each period, in order for a loan P with interest rate i to be paid off at the end of N periods.

Equation (10.18) can be solved for P:

$$P = \frac{A}{\mathrm{CRF}(N, i)} \tag{10.20}$$

Equation (10.20) gives the present worth of a total of N equal amounts A that are deposited or invested at the end of each period with interest rate i.

It is worth noting that, if $f = 0$, then (10.17) and (10.19) lead to the following equality:

$$\mathrm{PWF}(N, 0, i) = \frac{1}{\mathrm{CRF}(N, i)} \tag{10.21}$$

10.3.5.5 Constant and actual values

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

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

Constant value is the hypothetical purchasing power of future receipts and disbursements in terms of purchasing power of money at a certain base year. The base year can be arbitrarily selected, but it is often assumed to be time zero, that is 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:

$$F' = \frac{F}{\prod_{n=1}^{N} (1 + f_n)} = \frac{F}{\left(1 + \overline{f}\right)^N} \tag{10.22}$$

where F is the actual amount of money, F' is the amount converted to constant values, f_n is the annual inflation rate during year n, and $\overline{f}$ is the average annual inflation rate for the N years:

$$\overline{f} = \left[\prod_{n=1}^{N} (1 + f_n)\right]^{1/N} - 1 \tag{10.23}$$

Investments in cogeneration systems are capital-intensive, and they often have long payback periods. Therefore, it is more accurate to work with cash flows converted into constant values.

In order to perform an economic analysis based on current values, there is need to know the annual inflation rates. However, most analysts 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 commodity (e.g. fuel, labour and 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 (10.22) converts the cash flow F at N in the actual-value domain into a cash flow F' at N in the constant-value domain. Thus, the inflation rate f is used to convert from one domain into 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 i is used (see (10.7) and (10.8)).

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

$$P' = \frac{F'}{\prod_{n=1}^{N} \left(1 + i'_n\right)} \tag{10.24}$$

or, if i' is constant with time, in a simplified form:

$$P' = \frac{F'}{(1 + i')^N} \tag{10.25}$$

determine the constant-value equivalence P' at $t = 0$, 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 i'.

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 f, i and i' can be proved:

$$i' = \frac{1 + i}{1 + f} - 1 \tag{10.26}$$

The domain to 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.

10.4 Measures of economic performance

The economic performance of a cogeneration system and of any investment can be evaluated either in itself or in comparison to other investments by means of certain measures or indexes. The most common of those are the net present value (NPV), the net present cost (NPC), the present worth cost (PWC), the internal rate of return (IRR), the payback period and the benefit-to-cost ratio (BCR) of the investment, which are presented in the following subsections.

10.4.1 Net present value of the investment

NPV of an investment is the present value of the profit of the investment, which is the difference between the present value of all the revenues and the present value of all the expenses. Savings occurred because of the investment (e.g. cogeneration system) are included in the revenues. As the present value is called also present worth (Section 10.3.5.2), the NPV is called also *net present worth*. In general terms, it can be given by the following equation:

$$\mathrm{NPV} = \sum_{n=0}^{N} \frac{F_n}{(1+i_n)^n} \tag{10.27}$$

where F_n is the net cash flow of year[1] n:

$$F_n = (\text{revenue} + \text{savings} - \text{expenses})_n \tag{10.28}$$

The reason for including savings in (10.28) is the following: It is possible that a cogeneration system or a renewable energy system, for example, is not used in order to sell its energy products, but in order to save energy coming from outside and, consequently, to save expenses. It is possible also that there are both revenues and savings if, for example, after covering the energy needs of the user, excess electricity is sold to the grid.

In (10.27), $n = 0$ usually corresponds to the instant when the system starts operating. Consequently, F_0 is the present worth of the first cost of the investment, which is a negative number. If the construction of the system lasted for a few years, then F_0 is calculated by (10.8) or (10.9). On the other hand, F_N may include the salvage value of equipment, if any.

With the NPV as a performance criterion of the investment, the following characteristic cases can be encountered:

1. $\mathrm{NPV} > 0$: For the values of N and i specified, the investment is economically viable; the ROI (Section 10.4.2) is higher than i.
2. $\mathrm{NPV} = 0$: The investment is economically viable for the particular values of (N, i); the ROI is equal to i.
3. $\mathrm{NPV} < 0$: The investment is economically not viable for the particular values of (N, i).

[1]For convenience from this point on, $n = 1, \ldots, N$ will represent years of analysis.

10.4.2 Net present cost and present worth cost

If the purpose of an investment is primarily to cover needs and not to produce revenues, then a more appropriate measure of performance is the NPC. For example, this is the case of a cogeneration system that covers the energy needs of the user and may sell only excess electricity or heat, if any, to other consumers. For generality, it can be written as:

$$\mathrm{NPC} = -\mathrm{NPV} = \sum_{n=0}^{N} \frac{-F_n}{(1+i_n)^n} \tag{10.29}$$

Of interest is also the PWC of the investment, which is the present worth of all the expenses during the life cycle of the investment. This is why it is called also *life-cycle cost*. In general, it can be expressed by the following equation:

$$\mathrm{PWC} = \mathrm{PWC}_c + \mathrm{PWC}_{om} \tag{10.30}$$

where PWC_c is the PWC of capital and PWC_{om} is the PWC of O&M.

It is clarified that PWC does not include any revenue.

With NPC or PWC, alternative investments for covering the needs are evaluated, and the one with the lowest value of NPC or PWC is preferable.

Of interest is also the average annual cost of the investment, which is given by the following equation:

$$\mathrm{AC} = \mathrm{PWC} \cdot \mathrm{CRF}(N, i) \tag{10.31}$$

In a cogeneration system, for example, AC can be used in order to determine the unit cost of the energy products, which gives the low limit of the selling price to be specified. The procedure is presented in Section 10.5.

10.4.3 Internal rate of return

The IRR also called *return on investment* (ROI) is defined as the interest rate that results in zero NPV of the investment. Consequently, IRR is the solution of the following equation:

$$\mathrm{NPV} = \sum_{n=0}^{N} \frac{F_n}{(1+\mathrm{IRR})^n} = 0 \tag{10.32}$$

With IRR as a performance criterion, the investment is economically justified, if the value of IRR is satisfactory to the investor. It is worth noting that there is no need to know the value(s) of the interest rate i in order to calculate the value of IRR.

Equation (10.32) can be written in the form:

$$F_0 + F_1 x + F_2 x^2 + \cdots + F_N x^N = 0 \tag{10.33}$$

where:

$$x = \frac{1}{1+\mathrm{IRR}} \tag{10.34}$$

Equation (10.33) has N solutions, but of practical interest are those which result in $0 \leq \mathrm{IRR} < \infty$ (i.e. $0 < x \leq 1$). There is often only one root in this interval, in which case IRR can be used as a measure of economic performance. In the case of many roots, however, the use of IRR is avoided, because there is no rational way of judging which of the many roots really characterizes the performance of the investment [8].

10.4.4 Payback period

The payback period can be defined in two ways, as explained in the following.

10.4.4.1 Simple payback period

It is defined as the length of time required to recover the first cost of an investment from the net cash flow produced by the investment for interest rate equal to zero ($i = 0$) [8]. Thus, it is the smallest value of N that satisfies the following equation:

$$\sum_{n=0}^{N_{\min}=\mathrm{SPB}} F_n \geq 0 \tag{10.35}$$

where F_0 is the first cost of the investment, and F_n is the net cash flow of year n.

If it can be considered that F_n does not change with time, that is $F_n = F$, then (10.35) leads to the following equation:

$$\mathrm{SPB} = \frac{-F_0}{F} \tag{10.36}$$

It is reminded that F_0 is a negative number and, consequently, $-F_0$ is a positive number. Thus, simple payback period (SPB) is positive if F is positive. If F is negative, the investment results in loss.

The SPB has serious deficiencies, because it does not consider

1. the time value of money,
2. the performance of the investment after the SPB, as it is characterized by the magnitude and timing of cash flows and the expected life of the investment [8].

With the SPB as a measure of economic performance, one would select an investment with short SPB, whereas an investment with longer SPB may have a higher NPV, which is preferable. The SPB can be justified as performance criterion of an investment only if there is a high degree of uncertainty concerning the future, and a firm is interested in its cash flow position and borrowing commitments [8].

10.4.4.2 Discounted payback period

It is also called dynamic payback period (DPB). It is the length of time required to recover the investment cost and the desirable interest from the cash flow produced by the investment. The discounted payback period (DPB) is the smallest value of N that satisfies the expression [8]:

$$\sum_{n=0}^{N_{\min}=\mathrm{DPB}} \frac{F_n}{(1+i_n)^n} \geq 0 \tag{10.37}$$

If it can be considered that F_n and i_n for $n = 1 - \mathrm{DPB}$ do not change with time, that is $F_n = F$ and $i_n = i$, $n = 1 - \mathrm{DPB}$, then (10.37) has an analytic solution with respect to DPB:

$$\mathrm{DPB} = \frac{-\ln\left(1 + \dfrac{F_0}{F} i\right)}{\ln(1+i)} \tag{10.38}$$

With the DPB as a measure of economic performance, an investment is considered economically viable, if its DPB satisfies the investor's expectations.

It is noted that an investment may have an acceptable SPB, but its DPB is so long (e.g. longer than the life time of equipment in the case of cogeneration) that in fact the investment cost will never be recovered.

10.4.4.3 Benefit-to-cost ratio

It is defined as the ratio of the present worth of the total benefit (revenue, savings) to the present worth of the total cost of the investment throughout its life cycle:

$$\mathrm{BCR} = \frac{\sum_{n=1}^{N} \dfrac{B_n}{(1+i_n)^n}}{\sum_{n=0}^{N} \dfrac{C_n}{(1+i_n)^n}} \tag{10.39}$$

where B_n is the benefit in year n, and C_n is the cost in year n. For $n = 0$, it is $C_0 = -F_0$.

There is also the following alternative definition of the BCR:

$$\mathrm{BCR}' = \frac{\sum_{n=1}^{N} \dfrac{(B_n - C_n)}{(1+i_n)^n}}{C_0} = \frac{\sum_{n=1}^{N} \dfrac{F_n}{(1+i_n)^n}}{-F_0} \tag{10.40}$$

Equations (10.27) and (10.40) lead to the following equality:

$$\mathrm{BCR}' = 1 - \frac{NPV}{F_0} \tag{10.41}$$

It is clear from the defining (10.39) and (10.40) that BCR and BCR$'$ are not equal. Furthermore, if it is BCR ≥ 1, then it is BCR $>$ BCR$'$.

A more accurate name for BCR$'$ is the *net benefit to initial cost ratio*.

With the BCR as a measure of economic performance, an investment is considered economically viable, if it is BCR ≥ 1.

10.5 Procedure for economic analysis of cogeneration systems

The term 'economic analysis' implies the calculation of the values of the various measures of economic performance, as they are defined in Section 10.4, in order to assess the investment in cogeneration in itself, as well as in comparison to alternative investments (alternative means of covering the energy needs of a consumer).

In order to do so, there is need to calculate the first cost of the investment, F_0, and the net cash flow F_n of each year n. The procedure presented in the following is based on certain considerations and assumptions, which will be clearly stated [7,12]. The interested reader can adapt the procedure to the specific conditions applicable in the case under study.

10.5.1 Estimation of the initial cash flow (F_0)

There are various approaches for estimating the first cost (or installed cost), C_0, of a cogeneration system, and an uncertainty is associated with each approach. A few examples are the following:

1. Estimation of the order of magnitude based on known cost of similar previous installations. Uncertainty higher than $\pm 30\%$.
2. Estimation based on the main specifications of the system. Uncertainty up to $\pm 30\%$.
3. Preliminary estimation of the cost based on sufficient data regarding the system. Uncertainty up to $\pm 20\%$.
4. Estimation based on complete data regarding the system, but before finalizing the design and the specifications of the system. Uncertainty up to $\pm 10\%$.
5. Detailed calculation based on the final design and complete specifications of the system. Uncertainty up to $\pm 5\%$.

At an early stage, information from the literature, such as the one given in Section 10.2.1.4, can be used. For the final decision, however, vendor quotations are rather necessary.

If the construction may take a few years, then (10.8) or (10.9) can be used in order to calculate the present worth of the first cost.

In order to determine the initial cash flow, F_0, there is need to take into consideration the financial conditions in the particular case. For example, investment grants may be provided in order to promote the application of cogeneration. On the other hand, part of the required capital may come from a loan. Under these considerations, the initial cash flow is given by the following equation:

$$F_0 = C_g + L - C_0 = \left(c_g + \ell - 1\right) C_0 \tag{10.42}$$

where C_0 is the first cost (installed cost) of the system, C_g is the amount of grant, L is the amount of loan, c_g is the grant as a fraction of the first cost: $c_g = C_g / C_0$ and ℓ is the loan as a fraction of the first cost: $\ell = L / C_0$.

Equation (10.42) can be properly modified according to the conditions applicable in each particular case.

10.5.2 Estimation of the net cash flow for the years of analysis (F_n, $n \geq 1$)

10.5.2.1 An expression for F_n

The net cash flows in the years of analysis depend on the financial conditions (e.g. terms of loan), the taxation system, the method of depreciation, the electricity and heat tariffs and others. Consequently, it is rather impossible to describe a generally applicable procedure. In order not to leave the presentation in abstract and, consequently, not very useful terms, certain assumptions will be made along the way. Modification of the procedure is necessary, if different conditions prevail.

The net cash flow of year n can be calculated with the following equation:

$$F_n = \begin{cases} f_n - A_{Ln} - r_T T_n, & n = 1,\ 2,\ \ldots,\ N-1 \\ f_n - A_{Ln} - r_T T_n + \mathrm{SV}_N, & n = N \end{cases} \tag{10.43}$$

where f_n is the operation profit in year n (Section 10.5.2.2), A_{Ln} is the equal annual payments of principal and interest for repayment of the loan (Section 10.5.2.3), T_n is the taxable income in year n due to cogeneration (Section 10.5.2.4), r_T is the tax rate, considered constant throughout the years, and SV_N is the salvage value of the investment at the end of year N.

The salvage value depends on the number of years, the type of system, the maintenance schedule and others. Details are beyond the limits of this book, but the interested reader can find related information in books such as [3,8,9]. A procedure for calculation of f_n, A_{Ln} and T_n based on certain assumptions is presented in the following paragraphs.

10.5.2.2 Annual operation profit (f_n)

The annual operation profit is the difference between the revenues and the expenses due to the operation of the cogeneration system. The revenues include also the avoided cost of electricity and heat, that is the cost that would occur if the electricity were purchased from the grid and the heat were produced by a boiler. Under these considerations, the annual operation profit is given by the following equation:

$$f_n = \left[K_e + K_h + R_e + R_h - C_f - C_{om}\right]_n \tag{10.44}$$

where K_e is the avoided cost of electricity, that is cost of electricity that would be purchased from the grid, if it were not produced by the cogeneration system; K_h is the avoided cost of heat, that is cost of heat that would be produced by one or more boilers, if it were not produced by the cogeneration system; R_e is the revenue from selling excess electricity, if any; R_h is the revenue from selling excess heat, if any; C_f is the cost of fuel for the cogeneration system; and C_{om} is the O&M cost of the cogeneration system (except fuel).

All the costs and revenues are referred to year n, as indicated by the subscript ($n = 1, 2, \ldots, N$).

General expressions for the aforementioned costs and revenues cannot be given here, because they depend on the local conditions, but certain considerations are mentioned in the following, which may be helpful.

The avoided cost of electricity, K_e, is a function of the quantity of the electric energy produced by the cogeneration system and consumed on site, as well as of the tariff structure for electric energy supplied by the grid. This usually includes terms related to level of power (peak demand) and power factor during a certain period of time and, of course, to electric energy, whereas the time of the day may affect the cost. Attention is drawn to the fact that certain types of national or municipal taxes may be included in the electricity bill. If they are connected to the cost of electricity (e.g. as a percentage of that cost), then they should be included in K_e; if, however, they are introduced as a fixed amount, independent of the electricity cost, then they should be ignored.

The avoided cost of heat, K_h, comprises the cost of fuel that would be required by boiler(s) in order to produce the same amount of thermal energy, if it were not produced by the cogeneration system, as well as other O&M expenses of the boiler(s) and the associated auxiliary equipment. The cost of fuel depends on the type and quantity of the fuel (Chapter 7 can help in calculating it), as well as on the structure of the fuel tariff.

Regarding the capital cost of the boiler(s), the following cases may appear: If the boiler(s) would be installed anyway for backup in the case of unavailability of the cogeneration system, then the capital cost is not taken into consideration. If, however, the existence of the cogeneration system makes the installation of the boiler(s) unnecessary or if the thermal power of the installed boiler(s) is reduced, then the avoided capital cost should be taken into consideration.

The revenues R_e and R_h from selling excess electricity and heat depend on the quantity of the energy sold and on the particular tariff structure or on the agreement between the parties involved.

Chapter 7 helps in calculating the quantity of the fuel used by the cogeneration system. Then the fuel cost structure in the particular place and time is used in order to determine the cost of fuel, C_f.

As mentioned in Section 10.2.2.2, the O&M costs (excluding fuel) usually consist of fixed and variable costs:

$$C_{om} = C_{omf} + C_{omv} \tag{10.45}$$

where C_{omf} is the fixed O&M costs, that is, costs that do not depend on whether the system operates or not, and C_{omv} is the variable O&M costs, that is, costs that occur when the system operates; they are usually expressed as functions of the useful energy produced.

If information about O&M costs of the particular system under evaluation is not available, then values such as those in Tables 10.4 and 10.5 can be used for a first estimate of C_{om}, even though they do not distinguish between fixed and variable costs.

Equation (10.44) is based on certain considerations and assumptions. If other conditions apply for a particular system, then the equation has to be modified. Let us assume, for example, that part of the heat produced by the cogeneration unit is supplied to an absorption chiller and as a result, the compression air-conditioning unit operates at reduced load or it is shut down. The annual operation profit of the 'trigeneration' system is given by the following equation:

$$f_n = \left[K_e + K_h + C_{comp} + R_e + R_h - C_f - C_{omc} - C_{oma}\right]_n \tag{10.46}$$

where C_{comp} is the avoided operation cost of the compression air-conditioning unit (primarily cost of electricity, but also O&M cost), C_{omc} is the O&M cost of the cogeneration unit, and C_{oma} is the O&M cost of the absorption air-conditioning unit.

In such a case, the first cost of the absorption unit will be included in C_0, whereas for the capital cost of the compression unit, the same comment as the aforementioned about the boiler(s) is valid.

10.5.2.3 Payments of principal and interest of loan (A_{Ln})

It will be assumed that the loan interest rate is constant. Then, the annual amount for repayment of the loan is given by the following equation:

$$A_{Ln} = \begin{cases} L \cdot \mathrm{CRF}(N_L,\ r_L), & n = 1,\ 2,\ \ldots,\ N_L \\ 0, & n > N_L \end{cases} \tag{10.47}$$

where N_L is the number of years for repayment of the loan, and r_L is the loan interest rate.

10.5.2.4 Taxable income (T_n)

Reduced expenses due to the operation of a cogeneration system have as consequence the increase of the taxable income. On the other hand, the depreciation of equipment and the loan interest rate are usually deducted before the application of taxes. Under these considerations, the taxable income due to cogeneration is given by the following equation:

$$T_n = f_n - D_n - I_{Ln} \tag{10.48}$$

where D_n is the depreciation in year n, and I_{Ln} is the loan interest charged in year n.

For simplicity, a straight-line depreciation will be assumed here, in which case D_n is given by the following equation:

$$D_n = \begin{cases} \dfrac{C_0}{N_D}, & n = 1,\ 2,\ \ldots,\ N_D \\ 0, & n > N_D \end{cases} \tag{10.49}$$

where N_D is the period (number of years) for depreciation. More elaborate methods of depreciation are described in the literature [8,9].

In addition to the assumption of constant loan interest rate, the calculation of I_{Ln} will be based on the following considerations: The annual repayment consists of a portion for the payment of principal and a portion for the payment of interest on the unpaid balance. The interest for year n is charged on the remaining balance at the beginning of this year. A loan payment received at the end of a year must first be applied to the interest charge. The remaining amount is then used to reduce the outstanding balance of the loan. These considerations lead to the following steps for calculation of I_{Ln}:

Interest charged for year n:

$$I_{Ln} = r_L L_n \tag{10.50}$$

For $n = 1$, it is $L_1 = L$

Reduction of the unpaid part of the loan at the end of year n:

$$\Delta L_n = A_{Ln} - I_{Ln} \tag{10.51}$$

Unpaid part of the loan at the beginning of year $n + 1$:

$$L_{n+1} = L_n - \Delta L_n = L_n - A_{Ln} + I_{Ln} \tag{10.52}$$

Equations (10.50)–(10.52) are applied for $n = 1, 2, \ldots, N_L$. After repayment of the loan, the interest charged is zero:

$$I_{Ln} = 0, \quad n > N_L \tag{10.53}$$

With the procedure described in this section, the measures of economic performance presented in Section 10.4 can be calculated. It is emphasized once more that this procedure is based on specific considerations and assumptions that have been made, in order not to stay in an abstract presentation, but to have a concrete and applicable approach. An adaptation of the procedure to different conditions may be required.

10.6 Costing of thermal and electrical and/or mechanical energy

10.6.1 Statement of the problem

If a cogenerated product (electricity and/or heat) is to be sold, there is need to set a price. The actual cost of each cogenerated product may serve as the basis for this purpose, even though it is not the only factor affecting the price. On the other hand, the price of each cogenerated product not only affects the cost of other products or services but also may work for or against cogeneration. Therefore, the total cost of a system has to be allocated to the energy products in a fair and equitable manner.

If the energy product were one only (electricity or heat), then its average unit cost would be given by the following equation:

$$c_u = \frac{\mathrm{AC}}{E} \tag{10.54}$$

where AC is the average annual cost of the system, as given by (10.31) and E is the annual quantity of the energy product.

With two or more energy products, however, the pertinent equation, based on the principle that the total cost of the system must be equal to the cost of all the products, is written as:

$$\mathrm{AC} = \sum_k c_{uk} E_k \tag{10.55}$$

where c_{uk} is the unit cost of the kth energy product and E_k is the kth energy product.

The problem is that (10.55) is one equation with k unknowns, the values of c_{uk}. Thus, in order for these values to be determined there is need of additional equations, which can be derived by proper analysis of the system and/or assumptions regarding allocation of the total cost among the products. Various methods have appeared, which differ from each other in the way the system is analysed or in the assumptions made. The most common methods are described in the following.

In order to make the presentation clear without jeopardizing the generality, a cogeneration system with three products will be considered (work, i.e., mechanical or electric energy, high-temperature heat and low-temperature heat) and each method will be applied to this system. The cost balance in this case is written as:

$$\mathrm{AC} = c_{uw}W + c_{uh}H_h + c_{ul}H_l \tag{10.56}$$

where W is the annual production of work (mechanical or electric energy), H_h is the annual production of high-temperature heat, H_l is the annual production of low-temperature heat, and c_{uw}, c_{uh}, c_{ul} are the unit cost of work, high-temperature heat and low-temperature heat, respectively.

Annual quantities are considered here, but any other period of time can be considered.

10.6.2 Methods of cost allocation

The most common methods of cost allocation will be presented in this subsection, whereas more elaborate approaches can be found in the literature [13–15].

10.6.2.1 Equality method based on energy

The assumption in this method is that the unit cost is the same for all energy products and is expressed with the following equation:

$$c_{uw} = c_{uh} = c_{ul} = c_u \tag{10.57}$$

In other words, the cost is allocated in proportion to the energy content of the products. Then (10.56) can be solved, and the result is:

$$c_{uw} = c_{uh} = c_{ul} = c_u = \frac{\mathrm{AC}}{W + H_h + H_l} \tag{10.58}$$

10.6.2.2 Equality method based on exergy

In this method, the cost balance is written as

$$\mathrm{AC} = c_{uw}^{ex}W + c_{uh}^{ex}\mathscr{E}_h + c_{ul}^{ex}\mathscr{E}_l \tag{10.59}$$

where $\mathscr{E}_h$ is the exergy content of the annual production of high-temperature thermal energy, $\mathscr{E}_l$ is the exergy content of the annual production of low-temperature thermal energy, and c_{uw}^{ex}, c_{uh}^{ex}, c_{ul}^{ex} are the unit cost of electric exergy, high-temperature thermal exergy and low-temperature thermal exergy, respectively.

The reader is referred to Chapter 7 for the definition and further explanations on exergy.

In addition, the assumption is made that the unit exergy cost is the same for all energy products and is expressed with the following equation:

$$c_{uw}^{ex} = c_{uh}^{ex} = c_{ul}^{ex} = c_{u}^{ex} \tag{10.60}$$

In other words, the cost is allocated in proportion to the exergy content of the products. Then (10.59) can be solved and the result is:

$$c_{uw}^{ex} = c_{uh}^{ex} = c_{ul}^{ex} = c_{u}^{ex} = \frac{\mathrm{AC}}{W + \mathscr{E}_h + \mathscr{E}_l} \tag{10.61}$$

The cost per unit of energy is calculated with the equations:

$$c_{uw} = c_{uw}^{ex}\frac{W}{W} = c_{uw}^{ex} \qquad c_{uh} = c_{uh}^{ex}\frac{\mathscr{E}_h}{H_h} \qquad c_{ul} = c_{ul}^{ex}\frac{\mathscr{E}_l}{H_l} \tag{10.62}$$

The disadvantage of the equality method based on energy is that the unit cost of heat (of either high or low temperature) is the same with the unit cost of electricity, even though the quality of heat is lower than the quality of electricity and the lower the temperature of the available heat the lower its quality. The equality method based on exergy does not have this disadvantage.

10.6.2.3 By-product heat method

In this method, the work (mechanical or electric energy) is considered the main product, whereas heat is by-product. The work is assigned the cost that would have if it were purchased or produced alone in a power plant. Thus, c_{uw} is known. In addition, it is assumed that:

$$c_{uh} = c_{ul} \tag{10.63}$$

Then (10.56) is solved to give:

$$c_{uh} = c_{ul} = \frac{\mathrm{AC} - c_{uw}W}{H_h + H_l} \tag{10.64}$$

10.6.2.4 By-product work method

There are situations where heat would have to be produced to meet process requirements, even if no power were produced. In such a case, work may be viewed as a by-product. Therefore, heat is assigned the cost it would have if it were purchased or produced in a boiler. Thus, c_{uh} and c_{ul} are known. Then (10.56) is solved for c_{uw}:

$$c_{uw} = \frac{\mathrm{AC} - (c_{uh}H_h + c_{ul}H_l)}{W} \tag{10.65}$$

This method usually results in unit cost of heat significantly higher than the cost obtained with the other methods.

10.7 Internalization of external environmental costs and their effect on the economic performance of cogeneration systems

10.7.1 Introductory remarks and definitions

In the 1970s and 1980s, the primary concern in designing and operating energy systems was the efficiency and the fuel consumption. In the 1990s, it started being more and more widely accepted that 'private decisions to produce and consume electricity will better reflect society's desires for environmental quality by internalizing the external costs of electricity production' [16]. Today, this statement is applicable not only to electricity production, but to any energy conversion process.

Costs of an industrial activity included in the price paid by the consumer are called 'internalised'. Some of those are related to environmental protection (e.g. costs of catalytic converters), and they are called 'internal environmental costs'. Other environmental costs related to the activity are borne by the society in general and they are not paid for, for example in electricity bills. The unpaid costs are called 'external environmental costs'. Some people who bear these costs may not benefit from the particular industrial activity, as is the case of trans-boundary pollution [17]. From the point of view of the society as a whole, the following is valid for the cost of energy supply.

$$\begin{aligned}\text{Total cost} &= \text{internal general cost} + \text{internal environmental cost}\\ &\quad + \text{external environmental cost}\end{aligned}$$

Several attempts have been made in order to estimate the effects of the pollution on the environment and the society and assess those in monetary terms; a brief presentation of the early attempts appears in [17]. The most comprehensive up to now seems to be the ExternE approach [11] aided with the EcoSense software [18]. Applications of this approach are presented in [19,20].

It is true that the effects of pollution and their assessment in monetary terms depend on the local conditions (e.g. population density, dispersion of pollutants, etc.) and, consequently, the results are valid for a particular place only. Furthermore, due to incomplete knowledge of the effects and the difficulty in their monetization, the results have an uncertainty. In spite of these difficulties, an attempt to estimate the environmental externalities and take those into consideration in the economic evaluation of energy systems makes far more sense than ignoring them.

10.7.2 Evaluation and internalization of external environmental costs

The study here will be restricted to gaseous emissions of the systems, that is thermal pollution, noise, vibration and other adverse effects will not be considered. However, the procedure can be extended to include these effects also, if sufficient information is available.

The first step is to calculate the quantities of the various emissions of the cogeneration system and of the alternative systems for production of electricity and heat.

The procedures and the data provided in Chapters 7 and 8 help in this step. Next, a method is applied in order to estimate the external environmental cost of each emission. It will be considered here that this cost is expressed as a constant number per unit mass of the emission. Then (10.44) takes the form:

$$f_n = \left[K_e + K_h + R_e + R_h + C_{env} - C_f - C_{om}\right]_n \tag{10.66}$$

The new term, C_{env}, is the external environmental cost, which is given by the following equation:

$$C_{env,n} = \sum_j c_{env,j} m_{jn} \tag{10.67}$$

where m_{jn} is the mass of emitted substance j in year (or period) n, and $c_{env,j}$ is the unit external environmental cost of substance j.

Similar terms are introduced in the cost estimation of the separate production of electricity and heat for fair treatment.

10.8 Examples of economic analysis of cogeneration systems

Example 10.1 Economic evaluation of a cogeneration system

A gas-turbine cogeneration system operating with natural gas is to be installed in an industry, in order to replace electricity supplied by the grid and heat produced by a natural gas boiler. All the electricity generated by the system will be consumed on site.

For simplicity, it will be considered that the system will operate at nominal power for 7,480 h/year, equally distributed in 11 months, whereas 1 month will be available for the annual inspection and maintenance. The bill for the electricity coming from the grid is issued every month, and it consists of two parts: contracted power and consumed electric energy. Additional technical and economic data are given in Tables 10.6 and 10.7.

Table 10.6 Technical data for Example 10.1

Electric power	$\dot{W}_e = 30\ \mathrm{MW_e}$
Thermal power (useful heat flow rate)	$\dot{H} = 37{,}668\ \mathrm{kW_{th}}$
Exergy content of thermal power	$\dot{\mathscr{E}}^H = 12{,}745.7\ \mathrm{kW_{th}}$
Fuel consumption of the gas turbine	$\dot{V}_f = 2.251\ \mathrm{Nm^3}/s$
Efficiency of the boiler	$\eta_B = 0.90$
Lower heating value of natural gas	$H_u = 36{,}400\ \mathrm{kJ/Nm^3}$
Number of operating hours per year	$\tau_a = 7{,}480\ \mathrm{h}$

Table 10.7 Economic data for Example 10.1

Installed unit cost of the cogeneration system	$c_0 = 1{,}000$ €/kW$_e$
Salvage value at the end of the life cycle	$SV_N = 0$
Construction period	2 years
Payments (percentage of the total cost)	
Equity at the beginning of the first year of construction	$1 - c_g - l$
Grant at the end of the first year of construction	$c_g = 0.35$
Loan at the end of the second year of construction	$l = 0.45$
Life cycle of the system	$N = 20$ years
Depreciation period (straight line depreciation)	$N_D = 15$ years
Loan period	$N_L = 10$ years
Loan interest rate	$r_L = 0.07$
Market interest rate	$i = 0.12$
General inflation rate	$f = 0.03$
Fuel inflation rate	$f_f = 0.04$
Contracted power charge per month	$c_P = 8.9602$ €/kW$_e$
Electric energy charge: the first 400 kWh/kW per month	$c_{e1} = 0.05337$ €/kWh$_e$
the remaining energy per month	$c_{e2} = 0.03535$ €/kWh$_e$
Unit cost of natural gas	$c_f = 0.20$ €/Nm^3
Fixed annual O&M cost	C_{omf} = 4% of C_0
Variable O&M cost	c_{omv} = 5 €/MWh$_e$
Income tax rate	$r_T = 0.35$
Annual insurance cost	C_{ins} = 0.5% of C_0

- Requested

(i) The NPV, DPB and IRR of the investment.
(ii) The sensitivity of NPV, DPB and IRR with respect to the first cost C_0 and the unit cost of fuel c_f. For this purpose, it is suggested to draw graphs of NPV, DPB and IRR vs. C_0 and c_f in the range 70%–130% of the values given in Table 10.7.
(iii) The PWC of the system.
(iv) The average unit cost of electricity, c_e (€/MWh$_e$), and heat, c_h (€/MWh$_{th}$), if the cost is allocated to the products
   (a) with the equality method based on energy,
   (b) with the equality method based on exergy.

Solution

- Item (i)

The end of the construction period, that is the beginning of the operation period, will be considered as time zero for the calculation of the present worth.

Installed cost of the cogeneration system:

$$C_0 = c_0 \dot{W}_e = 1,000 \frac{€}{\mathrm{kW_e}} 30,000\ \mathrm{kW_e} = 30 \cdot 10^6\ €$$

Equity at the beginning of the 2-year construction period:

$$F_{-2} = \left(c_g + \ell - 1\right) C_0 = (0.35 + 0.45 - 1) \cdot 30 \cdot 10^6\ €$$
$$= -0.20 \cdot 30 \cdot 10^6\ € = -6 \cdot 10^6\ €$$

Present worth of F_{-2} (10.9):

$$F_0 = F_{-2}(1+i)^2 = -6 \cdot 10^6 (1 + 0.12)^2 = -7.5264 \cdot 10^6\ €$$

The annual operation profit for the first year (10.44) for $n = 1$, is calculated as follows:

Number of hours of operation per month: $\tau_m = \tau_a / 11 = 7480/11 = 680$ h

Electric energy produced per month: $W_m = 30{,}000$ kW $\cdot$ 680 h $= 20.4 \cdot 10^6$ kWh
First 400 kWh/kW: $W_{m1} = 400$ kWh/kW $\cdot$ 30,000 kW $= 12 \cdot 10^6$ kWh
Remaining electric energy: $W_{m2} = W_m - W_{m1} = 8.4 \cdot 10^6$ kWh

First-year cost of electricity, which is avoided due to cogeneration:

$$K_{e1} = 11\left(c_P \dot{W}_e + c_{e1} W_{m1} + c_{e2} W_{m2}\right) = 13.268046 \cdot 10^6 €$$

In writing this equation, it is considered that the contracted power can be reduced by $\dot{W}_e = 30$ MW$_e$ due to the operation of the cogeneration system. It is also possible that the contracted power is not reduced for safety, in the case of failure of the cogeneration system. In such a case, the term $c_P \dot{W}_e$ is not taken into consideration.

First-year cost of heat, which is avoided due to cogeneration:

$$K_{h1} = \frac{c_f \dot{H}_{CHP} \tau_a}{H_u \eta_B} = \frac{0.20\ €/\mathrm{Nm^3} \cdot 37,668\ \mathrm{kW} \cdot 7,480\ \mathrm{h} \cdot 3,600\ \mathrm{s/h}}{36,400\ \mathrm{kJ/Nm^3} \cdot 0.90}$$
$$= 6.192454 \cdot 10^6 €$$

First-year cost of fuel for the cogeneration system:

$$C_{f1} = c_f \dot{V}_f \tau_a = 0.20\ €/\mathrm{Nm^3} \cdot 2.251\ \mathrm{Nm^3/s} \cdot 7,480\ \mathrm{h} \cdot 3,600\ \mathrm{s/h}$$
$$= 12.122986 \cdot 10^6 €$$

First-year O&M cost of the cogeneration system:

$$C_{om1} = C_{omf} + C_{omv} + C_{ins} = 0.04 \cdot C_0 + c_{omv} \dot{W}_e \tau_a + 0.005 \cdot C_0$$
$$= 2.472 \cdot 10^6 €$$

First-year operation profit (there is no revenue with this system) (10.44):

$$f_1 = 13.268046 \cdot 10^6 + 6.192454 \cdot 10^6 - 12.122986 \cdot 10^6 - 2.472 \cdot 10^6$$
$$= 4.865514 \cdot 10^6 €$$

Depreciation (10.49):

$$D_n = \begin{cases} \dfrac{30 \cdot 10^6\,€}{15} = 2 \cdot 10^6\,€, & n = 1,\ 2,\ \ldots,\ 15 \\ = 0, & n > 15 \end{cases}$$

Loan: $L = \ell \cdot C_0 = 0.45 \cdot 30 \cdot 10^6 = \ 13.5 \cdot 10^6 €$
Capital recovery factor of loan (10.19): $\mathrm{CRF}(N_L,\ r_L) = 0.142378$
Annual amount for repayment of the loan (10.47):

$$A_{Ln} = \begin{cases} L \cdot \mathrm{CRF}(N_L,\ r_L) = 1.922096 \cdot 10^6\,€, & n = 1,\ 2,\ \ldots,\ 10 \\ = 0, & n > 10 \end{cases}$$

Interest charge for the first year (10.50): $I_{L1} = 0.07 \cdot 13.5 \cdot 10^6\,€ = 945,000\,€$

Taxable income of the first year (10.48):

$$T_1 = 4.865514 \cdot 10^6 - 2 \cdot 10^6 - 945000 = 1.920514 \cdot 10^6\,€$$

Reduction of the unpaid part of the loan at the end of the first year (10.51):

$$\Delta L_1 = 1.922096 \cdot 10^6 - 945,000 = 977,096\,€$$

Net cash flow of the first year (10.43):

$$F_1 = 4.865514 \cdot 10^6 - 1.922096 \cdot 10^6 - 0.35 \cdot 1.920514 \cdot 10^6$$

$$= 2.271238 \cdot 10^6\,€$$

The calculations are repeated for the remaining years, taking into consideration the inflation. They have been performed using an Excel spreadsheet, and the results are presented in Table 10.8. The requested measures of economic performance have the following values:

$$\mathrm{NPV} = 11.271049 \cdot 10^6\,€, \quad \mathrm{DPB} = 4.54\,\text{years}, \quad \mathrm{IRR} = 0.2489 = 24.89\%$$

- Item (ii)
  Figures 10.6–10.8 depict the requested effects. The subscript n in the ratios c_0/c_{on} and c_f/c_{fn} refers to the 'nominal' values, that is, the values given in Table 10.7.
- Item (iii)
  It will be considered that the cost of the system consists of the equity, the fuel cost, the O&M cost and the return of the loan, while for simplicity tax effects are ignored (an alternative consideration is made in Example 10.2). The results of the calculations are given in Table 10.9.
- Item (iv)
  Average annual cost of the system (10.31):

$$\mathrm{AC} = \mathrm{PWC} \cdot \mathrm{CRF}(N,\ i) = 157,826,779\,€ \cdot 0.1338788 = 21,129,657\,€$$

Table 10.8 Calculation of the net present value, dynamic payback period and return on investment of the cogeneration system (values in €)

n	C_e	C_h	C_{om}	C_f	f_n	A_n	L_n	A_{Ln}	I_{Ln}	ΔL_n	T_n	F_n	$F_n/(1+i)^n$	$\sum_n F_n/(1+i)^n$
0												−7,526,400	−7,526,400	−7,526,400
1	13,268,046	6,192,454	2,472,000	12,122,986	4,865,514	2,000,000	13,500,000	1,922,096	945,000	977,096	1,920,514	2,271,238	2,027,891	−5,498,509
2	13,666,087	6,378,227	2,546,160	12,607,905	4,890,250	2,000,000	12,522,904	1,922,096	876,603	1,045,493	2,013,646	2,263,377	1,804,350	−3,694,159
3	14,076,070	6,569,574	2,622,545	13,112,221	4,910,878	2,000,000	11,477,411	1,922,096	803,419	1,118,678	2,107,459	2,251,171	1,602,339	−2,091,820
4	14,498,352	6,766,661	2,701,221	13,636,710	4,927,082	2,000,000	10,358,733	1,922,096	725,111	1,196,985	2,201,971	2,234,296	1,419,936	−6,718,84
5	14,933,303	6,969,661	2,782,258	14,182,178	4,938,528	2,000,000	9,161,748	1,922,096	641,322	1,280,774	2,297,205	2,212,409	1,255,381	583,496
6	15,381,302	7,178,751	2,865,726	14,749,466	4,944,862	2,000,000	7,880,974	1,922,096	551,668	1,370,428	2,393,193	2,185,148	1,107,064	1,690,560
7	15,842,741	7,394,113	2,951,697	15,339,444	4,945,713	2,000,000	6,510,546	1,922,096	455,738	1,466,358	2,489,975	2,152,125	973,512	2,664,072
8	16,318,023	7,615,937	3,040,248	15,953,022	4,940,690	2,000,000	5,044,188	1,922,096	353,093	1,569,003	2,587,597	2,112,935	853,379	3,517,451
9	16,807,564	7,844,415	3,131,456	16,591,143	4,929,380	2,000,000	3,475,185	1,922,096	243,263	1,678,833	2,686,117	2,067,143	745,432	4,262,884
10	17,311,791	8,079,747	3,225,399	17,254,789	4,911,350	2,000,000	1,796,352	1,922,096	125,745	1,796,352	2,785,606	2,014,292	648,548	4,911,432
11	17,831,144	8,322,140	3,322,161	17,944,980	4,886,143	2,000,000	0	0	0	0	2,886,143	3,875,993	1,114,255	6,025,687
12	18,366,079	8,571,804	3,421,826	18,662,779	4,853,277	2,000,000	0	0	0	0	2,853,277	3,854,630	989,388	7,015,075
13	18,917,061	8,828,958	3,524,481	19,409,291	4,812,248	2,000,000	0	0	0	0	2,812,248	3,827,961	877,270	7,892,345
14	19,484,573	9,093,827	3,630,215	20,185,662	4,762,522	2,000,000	0	0	0	0	2,762,522	3,795,639	776,663	8,669,008
15	20,069,110	9,366,642	3,739,122	20,993,089	4,703,541	2,000,000	0	0	0	0	2,703,541	3,757,302	686,445	9,355,453
16	20,671,183	9,647,641	3,851,295	21,832,812	4,634,717	0	0	0	0	0	4,634,717	3,012,566	491,415	9,846,867
17	21,291,319	9,937,070	3,966,834	22,706,125	4,555,430	0	0	0	0	0	4,555,430	2,961,030	431,257	10,278,125
18	21,930,058	10,235,182	4,085,839	23,614,370	4,465,032	0	0	0	0	0	4,465,032	2,902,271	377,410	10,655,535
19	22,587,960	10,542,238	4,208,415	24,558,944	4,362,839	0	0	0	0	0	4,362,839	2,835,845	329,261	10,984,795
20	23,265,599	10,858,505	4,334,667	25,541,302	4,248,135	0	0	0	0	0	4,248,135	2,761,288	286,254	11,271,049

NPV = 11,271,049 €
DPB = 4.54 years
IRR = 0.2489

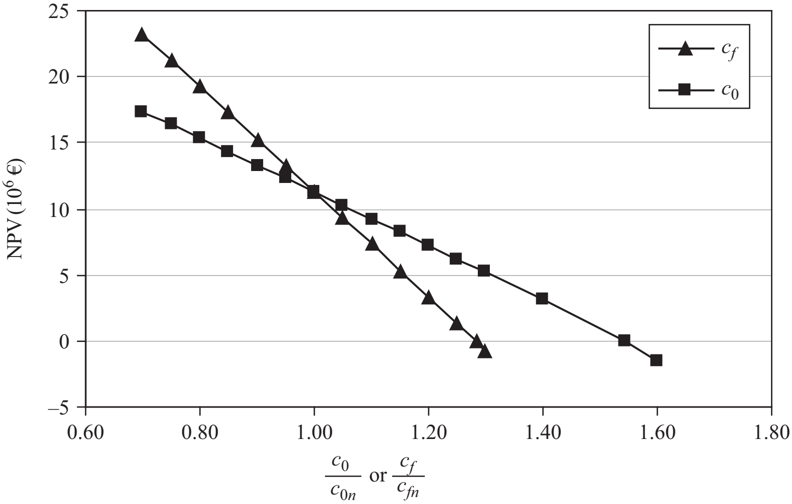

Figure 10.6 Effect of capital and fuel cost on the net present value (NPV) of the investment

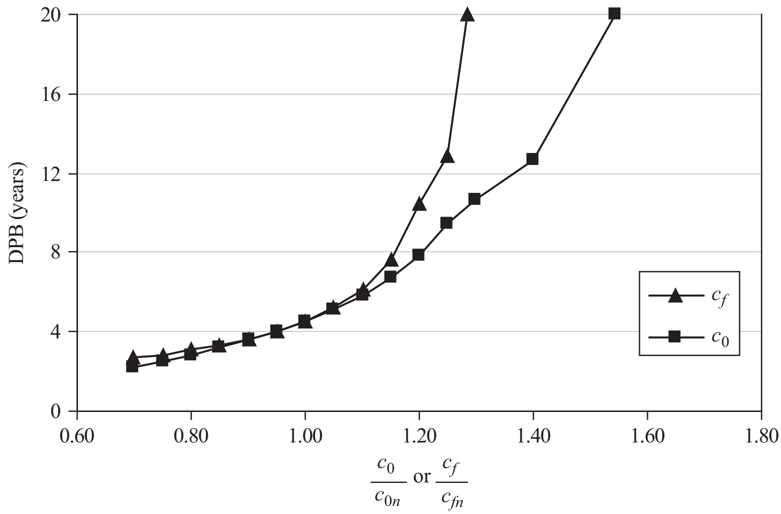

Figure 10.7. Effect of capital and fuel cost on the dynamic payback period (DPB) of the investment

– *Case (a)*

Annual production of electric energy:

$$W_a = 30,000\,\mathrm{kW}_e \cdot 7,480\,\mathrm{h} = 224,400,657\,\mathrm{kWh}_e$$

Annual production of thermal energy:

$$H_a = 337,668\,\mathrm{kW}_{\mathrm{th}} \cdot 7,480\,\mathrm{h} = 281,756,640\,\mathrm{kWh}_{\mathrm{th}}$$

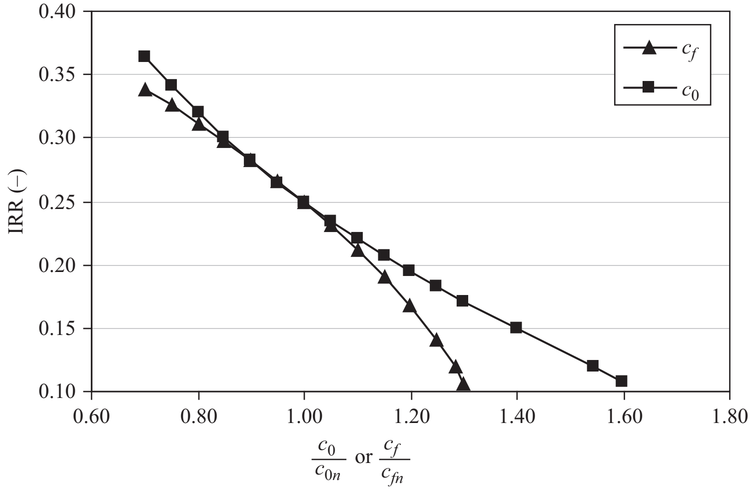

Figure 10.8 Effect of capital and fuel cost on the internal rate of return (IRR) of the investment

Table 10.9 Calculation of the present worth cost (PWC) of the system (values in €)

n (year)	C_{om}	C_f	A_{Ln}	C_n	$C_n/(1+i)^n$	$\sum_n C_n/(1+i)^n$
0				7,526,400	7,526,400	7,526,400
1	2,472,000	12,122,986	1,922,096	16,517,082	14,747,395	22,273,795
2	2,546,160	12,607,905	1,922,096	17,076,161	13,613,011	35,886,806
3	2,622,545	13,112,221	1,922,096	17,656,862	12,567,806	48,454,612
4	2,701,221	13,636,710	1,922,096	18,260,028	11,604,578	60,059,189
5	2,782,258	14,182,178	1,922,096	18,886,533	10,716,726	70,775,915
6	2,865,726	14,749,466	1,922,096	19,537,287	9,898,198	80,674,113
7	2,951,697	15,339,444	1,922,096	20,213,238	9,143,442	89,817,555
8	3,040,248	15,953,022	1,922,096	20,915,366	8,447,366	98,264,921
9	3,131,456	16,591,143	1,922,096	21,644,695	7,805,294	106,070,215
10	3,225,399	17,254,789	1,922,096	22,402,284	7,212,936	113,283,151
11	3,322,161	17,944,980	0	21,267,141	6,113,795	119,396,946
12	3,421,826	18,662,779	0	22,084,605	5,668,568	125,065,514
13	3,524,481	19,409,291	0	22,933,771	5,255,828	130,321,342
14	3,630,215	20,185,662	0	23,815,877	4,873,200	135,194,543
15	3,739,122	20,993,089	0	24,732,210	4,518,482	139,713,025
16	3,851,295	21,832,812	0	25,684,108	4,189,634	143,902,659
17	39,66,834	22,706,125	0	26,672,959	3,884,766	147,787,425
18	4,085,839	23,614,370	0	27,700,209	3,602,124	151,389,549
19	4,208,415	24,558,944	0	28,767,359	3,340,085	154,729,634
20	4,334,667	25,541,302	0	29,875,969	3,097,145	157,826,779
						PWC = 157,826,779 €

Unit cost of energy (10.58): $c_{uw} = c_{uh} = \frac{\mathrm{AC}}{W_a + H_a} = 0.041745$ €/kWh

– *Case (b)*

The annual production of electric exergy is equal to the annual production of electric energy.

Annual production of thermal exergy:

$$\mathscr{E}_a^H = 12,745.7\ \mathrm{kW_{th,ex}} \cdot 7,480\ \mathrm{h} = 95,337,836\ \mathrm{kWh_{th,ex}}$$

Unit cost of exergy (10.61): $c_{uw}^{ex} = c_{uh}^{ex} = \frac{\mathrm{AC}}{W_a + \mathscr{E}_a^H} = 0.066084$ €/kWh$_{ex}$

Unit cost of electric energy with allocation based on exergy (10.62):

$$c_{uw} = c_{uw}^{ex} = 0.066084\ €/\mathrm{kWh}_e$$

Unit cost of thermal energy with allocation based on exergy (10.62):

$$c_{uh} = c_{uh}^{ex} \frac{\mathscr{E}_h}{H_h} = 0.022361\ €/\mathrm{kWh_{th}}$$

Example 10.2 Internalization of environmental externalities

Three alternative solutions are investigated for covering the needs in electricity and heat of an enterprise:

A. A steam-turbine cogeneration system operating with biomass, which is available in the area.
B. A steam-turbine cogeneration system operating with fuel oil.
C. Purchase of electricity from the grid and production of heat by a local boiler.

Technical and economic data are given in Tables 10.10–10.12, including specific emissions of each alternative and the external environmental cost of each emitted substance. In addition, it is considered that any annual expenses and the depreciation are tax-deductible (environmental externalities are not considered expenses).

The PWC of each solution is requested without and with internalization of environmental externalities.

Solution

- *Development of the analytic procedure*

As there is neither grant nor loan, the PWC can be calculated with the following equation:

$$\mathrm{PWC} = C_0 + \sum_{n=1}^{N} \frac{C_n}{(1+i)^n} \tag{10.68}$$

Table 10.10 Technical specifications of the alternative solutions

Loads	
Net electric power output to processes:	$\dot{W}_{net} = 3{,}800$ kW
Thermal power to processes:	$\dot{H} = 13{,}125$ kW
Annual operation (600 h × 12 months):	$\tau = 7{,}200$ h/a
Biomass cogeneration system (A)	
Electric power for auxiliaries:	$\dot{W}_{aux,A} = 400$ kW
Electric power output of the generator:	$\dot{W}_A = 4{,}200$ kW
Lower heating value of biomass:	$H_{uA} = 16{,}000$ kJ/kg
Biomass consumption:	$\dot{m}_{fA} = 5{,}900$ kg/h
Fuel oil cogeneration system (B)	
Electric power for auxiliaries:	$\dot{W}_{aux,B} = 150$ kW
Electric power output of the generator:	$\dot{W}_B = 3{,}950$ kW
Lower heating value of fuel oil:	$H_{uB} = 40{,}180$ kJ/kg
Fuel oil consumption:	$\dot{m}_{fB} = 2{,}194$ kg/h
Grid and boiler (C)	
Fuel oil consumption:	$\dot{m}_{fC} = 1{,}337$ kg/h

Table 10.11 Specific emissions of the alternative solutions

Substance (*j*)	**Specific emissions (μ_j)**			**External environmental cost**
	Biomass	**Fuel oil**	**Grid**	
	kg *j*/kg fuel	**kg *j*/kg fuel**	**kg *j*/kWh$_e$**	**€/kg *j***
CO_2	1.736[a]	3.1064	1.0341	0.019
CO	0.005	0.0005	0.00018	1.160
NO_x	0.002	0.003	0.00031	3.440
SO_2	0.0	0.049	0.015	4.130
UHC[b]	0.0001	0.0002	0.00005	0.161
Particulates	0.0015	0.002	0.0008	2.800

[a]The CO_2 emission of biomass is given here for completeness, but it is not taken into consideration in the calculations, because biomass is considered neutral with respect to CO_2 emissions.
[b]Unburned hydrocarbons.

where C_n is the total cost of O&M in year n of each alternative. As there is no loan, it can be written as

$$C_n = \left[C_e + C_f + C_{om} + r_T T + C_{env}\right]_n \tag{10.69}$$

where C_e is the cost of electricity purchased from the grid (applicable in system C only), C_f is the cost of fuel, C_{om} is the O&M cost, r_T is the tax rate, T is the taxable income, and C_{env} is the external environmental cost.

Table 10.12 Values of economic parameters for the alternative solutions

General	
Life cycle and period of analysis:	$N = 20$ years
Period of straight line depreciation:	$N_D = 10$ years
Market interest rate:	$i = 0.10$
General inflation rate:	$f = 0$
Fuel inflation rate (above the general inflation rate):	$f_f = 0.01$
Tax rate:	$r_T = 0.35$
There is neither grant nor loan	
Biomass system (A)	
First cost:	$C_{0A} = 9.24 \cdot 10^6$ €
Specific O&M costs:	$c_{omA} = 0.005$ €/kWh$_e$
Unit cost of biomass:	$c_{fA} = 0.04$ €/kg
Fuel oil system (B)	
First cost:	$C_{0B} = 5.3325 \cdot 10^6$ €
Specific O&M costs:	$c_{omB} = 0.002$ €/kWh$_e$
Unit cost of fuel oil:	$c_f = 0.14$ €/kg
Electric grid and boiler (C)	
First cost (of boiler only):	$C_{0C} = 0.6563 \cdot 10^6$ €
Specific O&M costs of the boiler:	$c_{omC} = 0.0004$ €/kWh$_e$
Unit cost of fuel oil:	$c_{fC} = 0.14$ €/kg
Contracted power charge per month:	$c_P = 3.1$ €/kW$_e$
Electric energy charge:	$c_e = 0.067$ €/kWh$_e$

Based on the information regarding taxes, the taxable income is given by the following equation:

$$T_n = \left[R - C_e - C_f - C_{om} - D\right]_n \tag{10.70}$$

where R_n is the revenue in year n. Here, it is $R_n = 0$. Then, substitution of (10.70) into (10.69) gives the following equation:

$$C_n = (1 - r_T)\left(C_e + C_f + C_{om}\right)_n - r_T D_n + C_{env,n} \tag{10.71}$$

where D_n is given by (10.49).

Equation (10.71) is substituted into (10.68), and it is taken into consideration that each term changes from year to year due to inflation only and, consequently, (10.14) is valid. Then, the following equation is obtained:

$$\text{PWC} = C_0 + (1 - r_T)\left(C_e + C_f + C_{om}\right) - r_T D + C_{env} \tag{10.72}$$

where

$$C_f = C_{f1} \cdot \text{PWF}\left(N, f_f, i\right) \tag{10.73}$$

$$\begin{aligned} &C_e = C_{e1} \cdot \text{PWF}(N, f, i), \quad C_{om} = C_{om1} \cdot \text{PWF}(N, f, i), \\ &C_{env} = C_{env1} \cdot \text{PWF}(N, f, i) \end{aligned} \tag{10.74}$$

$$D = D_1 \cdot \mathrm{PWF}(N_D,\ 0,\ i) \tag{10.75}$$

If the last term in (10.72) is ignored, the PWC with no environmental externalities is obtained:

$$\mathrm{PWC}_0 = C_0 + (1 - r_T)\left(C_e + C_f + C_{om}\right) - r_T D \tag{10.76}$$

It is considered that the expenses occur at the end of each year and therefore the present worth factors in (10.73)–(10.75) are given by (10.17).

The external environmental cost of the first year is given by the following equation:

$$C_{env1} = \dot{m}_f \tau \sum_j \mu_{jf} c_{env,j} + \dot{W}_{net} \tau \sum_j \mu_{je} c_{env,j} \tag{10.77}$$

where the first term corresponds to fuel consumption, whereas the second term corresponds to electricity from the network and it is applicable to alternative C only.

- *Calculations*

– *Present worth factors:*

Equation (10.17) → $\mathrm{PWF}\left(N,\ f_f,\ i\right) = 9.09585$

Equations (10.21) and (10.19) → $\mathrm{PWF}(N,\ 0,\ i) = 8.51356$

$\mathrm{PWF}(N_D,\ 0,\ i) = 6.14457$

– *Biomass system (A):*

$C_e = 0$ $\quad$ $C_{f1A} = c_{fA} \dot{m}_{fA} \tau = 1,699,200$ €$/a$

$C_{om1A} = c_{omA} \dot{W}_A \tau = 151,200$ €$/a$ $\quad$ $D_{1A} = 924,000$ €$/a$

$C_{env1A} = 723,902$ €$/a$

As mentioned in Table 10.11, CO_2 is not taken into consideration.

– *Fuel oil system (B):*

$C_e = 0$ $\quad$ $C_{f1B} = c_{fB} \dot{m}_{fB} \tau = 2,211,552$ €$/a$

$C_{om1B} = c_{omB} \dot{W}_B \tau = 56,880$ €$/a$ $\quad$ $D_{1B} = 533,250$ €$/a$

$C_{env1B} = 4,390,306$ €$/a$

– *Electric grid and boiler (C)*:

$C_{e1C} = 1,974,480$ €$/a$ $\quad$ $C_{f1C} = c_{fC} \dot{m}_{fC} \tau = 1,347,696$ €$/a$

$C_{om1C} = c_{omC} \dot{H} \tau = 37,800$ €/a $\quad$ $D_{1C} = 65,630$ €$/a$

$C_{env1C} = C_{env1C,boiler} + C_{env1C,grid} = 2,675,406 + 2,328,915 = 5,004,321$ €$/a$

The remaining results are given in Table 10.13.

Table 10.13 Results of Example 10.2

Cost item	**Biomass system A**	**Fuel oil system B**	**Grid and boiler C**
C_0	9,240,000	5,332,500	656,300
C_e	0	0	16,809,861
C_f	15,455,668	20,115,945	12,258,441
C_{om}	1,287,251	484,252	321,813
D	5,677,580	3,276,590	403,268
PWC$_0$	**18,135,744**	**17,575,821**	**19,618,731**
C_{env}	6,162,983	37,377,140	42,604,587
PWC	**24,298,727**	**54,952,961**	**62,223,318**

According to the results in Table 10.13, the environmental cost has a strong effect on the PWC, which becomes critical in systems B and C, the environmental cost of which is much higher than the conventional PWC (PWC$_0$). Without environmental externalities, system B is the most cost-effective. However, with environmental externalities, system A is by far the most economically sound.

In spite of the uncertainty in estimating environmental costs of emissions, as mentioned in Section 10.7.1, the contribution of C_{env} to the total cost is so strong that it is not prudent to be ignored.

Nomenclature

A_L	annual payment of principal and interest
AC	annual cost
B	benefit
BCR	benefit-to-cost ratio
C	cost
C_g	grant
c_u	unit cost
CRF	capital recovery factor
D	depreciation
DPB	discounted or dynamic payback period
E	energy
$\mathscr{E}$	exergy
F	future value
F_n	net cash flow in year n
f	inflation rate

H	heat
I	price index
I_L	loan interest
i	market interest rate
IRR	internal rate of return
K	avoided cost
L	loan
m	mass
$\dot{m}$	mass flow rate
N	number of years of the analysis
NPC	net present cost
NPV	net present value
P	present value
PWC	present worth cost
PWF	present worth factor
R	revenue
r_L	loan interest rate
r_T	tax rate
SPB	simple payback period
SV	salvage value
T	taxable income
W	work (electric or mechanical energy)
$\dot{W}$	power

Greek symbols

η	efficiency
μ	specific emissions
τ	period of time (number of hours)

Subscripts

0	first cost
B	boiler
c	capital
D	depreciation
e	electricity/electrical
env	environmental
f	fuel
g	grant
h	heat/thermal

ins	insurance
L	loan
n	year
om	operation and maintenance
omf	fixed operation and maintenance
omv	variable operation and maintenance
T	tax
w	work

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Chapter 11

Regulatory and legal framework of cogeneration

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11.1 Introduction

This chapter presents the regulatory and legal framework of cogeneration. It is known that the first commercial combined heat and power (CHP) unit started its operation in 1882, in New York, United States, producing both electrical and thermal energy using waste heat, in order to heat nearby buildings, operating in a non-regulatory environment. But in the late 1800s, new regulations were enacted in the United States of America to promote rural electrification, by constructing centralised power plants, which discouraged decentralised ones, like those for cogeneration.

At the beginning of twentieth century, steam and electricity were most wanted by both European and US industries and power plants; so, they adapted their systems to cogenerate both steam and electricity. In 1950s, the US industrial cogenerated electricity was primarily for self-consumption; during the 1960s there was, still, a constant interest for cogeneration, but by late 1970s, the need to conserve energy resources became a top priority by the political establishment of the United States of America. As a supportive policy for cogeneration, the Public Utility Regulatory Policies Act (PURPA) was enacted, which had a crucial influence on the advancement of cogeneration for long periods.

Regarding the world's second largest energy consumer, China, according to the International Energy Agency (IEA), cogeneration is widely used and supported due to the country's vast industrial base, its strong economic development and its policies to minimise the GHG emissions [1].

Despite the supporting policies for the promotion of cogeneration in Europe, The United States of America and elsewhere, the world's share of cogenerated electricity was around only 9% in 2010 [2]. In 2015, cogeneration saved in Europe around 200 million tonnes of CO_2 per year [3].

In the next 20 years, studies indicate that at least 25% of world's electricity production could come from cogeneration [4]. This potential can come from industrial, district heating and cooling (DHC), buildings and agricultural applications, from further penetration of micro-CHP, biomass CHP and of new technologies, such as organic Rankine cycles, polygeneration and fuel cells. These are emerging markets, where the opportunities for increasing the proportion of cogeneration and expanding the routes to market are plentiful [5]. In order to achieve all these, strong regulatory and legal frameworks are needed to be established and operated.

This chapter explains the current achievements and the future outcomes on CHP's regulatory and legal frameworks in major countries.

11.2 European policy on energy efficiency and on cogeneration

11.2.1 The general framework

In the past two decades, the European Energy policy has undergone significant changes, as it shifted from National to European level, mainly taking into consideration EU environmental policies, in particular those regarding global Climate Change. Under this prism, the mandatory targets of '20-20-20', set by the European Council in 2007, should be examined, because by 2020, the commitment is that EU will reduce its CO_2 emissions by 20%, will achieve 20% reduction of its primary energy compared to 1990 and 20% of its produced electricity will come from renewable energy sources, RES. On this basis, respective binding targets were set for each member state (M-S). Working to reach these targets, EU enriched its legislation with three fundamental energy directives in the areas of RES and energy efficiency, including cogeneration. They were put in force starting from 2009, preparing the Union also for the steps ahead, targeting 2030 and possibly even further, 2050.

These directives are, namely, the 'Renewable Energy Directive (2009/28/EC) – RED' of 23 April 2009, the 'Energy Performance of Buildings Directive (2010/31/EU) – EPBD' of 19 May 2010 and the 'Energy Efficiency Directive (2012/27/EU) – EED' of 25 October 2012. It is worth noting, though, that the first EU Directive referring inclusively on high-efficiency cogeneration was the Directive 2004/8/EC, issued on 11 February 2004 titled 'On the promotion of cogeneration based on a useful heat demand in the internal energy market and amending Directive 92/42/EEC', which repealed in 2012, as fully transposed to EED (2012/27/EU). This directive is called 'the Cogeneration Directive'.

The consistent and systematic EU policy for the promotion of renewable energy, which started back in the 1990s, and in particular the Directive 2009/28/EC 'on the promotion of the use of energy from renewable sources and amending and subsequently repealing Directives 2001/77/EC and 2003/30/EC' combined with tools to integrate renewables into the electricity market resulted in massive RES deployment in the EU energy markets. In the mid-2010s, technological development for the exploitation of renewable energy sources and economies of scale reduced the cost for electricity produced by RES, which thus became cost-competitive and affordable for EU's businesses and citizens. European RES policies support the European economy. For example, in 2013, the RES sector generated 137 billion € in turnover, with a 6% increase from the previous year

(2012). The European RE sector employs 1.15 million people, representing over two renewable-energy-related jobs per 1,000 inhabitants, which is twice that of the world standard. The Renewable Energy Directive [6] establishes an overall policy for the production and promotion of energy from renewable sources in the EU. The directive requires the EU to cover at least 20% of its total energy needs by RES by 2020. To achieve this EU target, the RE Directive, 2009/28/EC, specifies binding national renewable energy targets for each M-S, taking into account its starting point and overall renewables' potential. These national targets range from a low of 10% for Malta to a high of 49% for Sweden. Each EU M-S sets out the plan how to meet these targets and the general course of the RE policy in its National Renewable Energy Action Plans (NREAPs). Progress towards national targets is measured every 2 years, when EU countries publish their NREAP reports.

The RE Directive promotes cooperation not only between M-S, but also with third-level countries outside the EU to help them meet their renewable energy targets. This cooperation can take the form of statistical transfers of RE or joint RE projects or joint RE support schemes.

It is strongly believed, based on recorded data, that EU will achieve the target of 20% RE electricity production by the end of 2020 [7].

The second, in chronological order, energy-related directive is the 'Energy Performance of Buildings Directive (2010/31/EU) – EPBD' (OJ, 19 May 2010). Cogeneration is specifically encouraged within the EPBD as one of the 'high efficiency alternative systems' [8] and is covered by Eco-Design and Energy Labelling legislation, as part of space heaters' delegated regulations (Lot1) [9].

The necessity for improving energy performance of European buildings was realised a long time ago by many European countries, especially in the North, after the first oil crisis in the mid-1970s. So, during the past 40 years, countries such as the United Kingdom, Denmark, Sweden and Ireland made a lot of efforts and allocated considerable financial resources and technological effort to promote energy efficiency in buildings. A significant part of these resources was allocated to research and development of new construction materials and techniques, efficient heating, cooling, lighting and development of new technical standards, certification schemes, calculation methodologies and others.

So, it can be said that during these years, the EU passed a learning curve with successes and lessons learnt in the area of energy efficiency in buildings.

The implementation of the first EPBD – 2002/91/EC started a new period, when the EU M-S introduced 'compulsory minimum energy performance requirements' for the whole building and its schemes for inspection of boilers and air-conditioners. The EPBD covers all types of buildings, that is residential, offices, public buildings and others. The scope of its provisions on certification does not, however, include certain types of buildings, such as historic buildings, industrial sites and others.

The key requirements set by the Directive are the common framework for a methodology to calculate the integrated energy performance of buildings, including cogeneration among other energy efficiency measures, with attention to micro-cogeneration (<50 kW_e), the application of minimum energy performance requirements for new buildings and existing buildings with a total useful floor area over 1,000 m^2, that are subject to major renovation, the energy certification of new and existing buildings, whenever constructed, sold or rented; this obligation also includes all buildings with a total useful floor area over 1,000 m^2, which are occupied by a public authority and frequently visited by the public, and the regular inspection of boilers and central air-conditioning systems in buildings and in addition an assessment of heating installations with boilers more than 15 years old.

With the adoption of the recast EPBD (2010/31/EU) in May 2010, M-S faced new challenges, as its leading issues are the move towards new and retrofitted nearly zero-energy buildings by 2021, and the application of a cost-optimal methodology for setting minimum requirements for both the building envelope and the HVAC and electrical systems.

The EPBD (recast) imposes further requirements, beyond those already initially set by the Directive 2002/91/EC, as (a) the concept of 'nearly zero energy building, NZEB', a building that has a very high energy performance; (b) the obligation for all EU M-S according to which, by the end of 2020, all newly constructed buildings should be NZEB and from the beginning of 2019 all new buildings occupied and owned by public authorities should be only NZEB. This creates a compulsory obligation for M-S to develop their national plans to investigate methods and ways on how to increase the number of NZEB.

Also, the recast EPBD made vital changes from the initial Directive, as it now requires that (a) the threshold of the 1,000 m^2 for major renovations is lowered further to 500 m^2, from 9 January 2013 and to 250 m^2, from 9 July 2015; (b) the concept of 'cost-optimal' is introduced when setting the minimum energy performance requirements; and (c) the requirement for an inspection report for building envelope improvements, for the audited heating and A/C systems should be issued after each inspection, containing the results and recommendations for cost-effective improvements. At this point, the role of cogeneration systems (mainly micro-CHP, meaning units up to 50 kW_e) is critical. It is clear that the Energy Performance Certificate (EPC) is important in achieving the goal of the EPBD (recast), which is to support the transition of the real estate sector towards energy efficiency.

So, the main strategic priorities for the implementation of EPBD recast are summarised as (a) improved target local policies and inclusive policies for building users; (b) financial engineering to leverage EU regional funds, that is more incentives and reduced risks; (c) more campaigns targeting stakeholders with more information and training of professionals and technicians, involved in the building sector.

The most recently published EU Directive is the so-called EED 2012/27/EU[1] [10]. The amended Directives 2009/125/EC and 2010/30/EU were 'to establish a

[1]Directive 2012/27/EC of the European Parliament and of the Council of 25 October 2012 'on energy efficiency, amending Directives 2009/125/EC and 2010/30/EU and repealing Directives 2004/8/EC and 2006/32/EC'.

framework for the setting of eco-design requirements for energy-related products' and 'on the indication by labelling and standard product information of the consumption of energy and other resources by energy-related products', respectively. The Directive 2012/27/EC is repealing Directive 2004/8/EC [11], which was exclusively related to high-efficiency cogeneration of heat and power, HECHP. The amended Directive 92/42/EEC was 'on efficiency requirements for new hot-water boilers fired with liquid or gaseous fuel'.

The EED contains a number of measures intended to increase energy efficiency across the European Union. It establishes a common framework of binding measures for the promotion of energy efficiency in order to ensure the achievement of the Union's '20-20-20' headline energy efficiency target and to pave the way for further energy efficiency improvements, beyond 2020.

The EED is a document with the legal weight of European law, consisting of 29 articles divided into 5 chapters, and 15 annexes, the most important for the promotion of cogeneration being Chapter 3, 'Efficiency in Energy Supply', Articles 7, 14 and 15.

The major issues, that EED is tackling for the further penetration of energy efficiency systems, measures and techniques are:

1. cogeneration of heat and power, CHP;
2. DHC networks, DH & DC;
3. energy services companies, ESCO; and
4. cost–benefit analysis, CBA, which is, now, becoming the main instrument for economic analysis of all energy efficiency technologies and measures.

A short presentation of articles and annexes referring mainly to cogeneration is given in the following sections.

11.2.1.1 Article 7: Energy efficiency obligation schemes

Article 7 requires for the M-S to deliver a certain quantity of final energy savings in end-use sectors, an important aspect for achieving the overarching 20% target; this target is cumulative, meaning that it is based on incremental annual savings that deliver a total volume of savings at the end of the obligation period, in 2020.

Article 7 sets a general binding target for each M-S to deliver 1.5% cumulative annual energy end-use savings, which can cover a significant percentage of the volume of savings that the indicative national target must deliver. The gap produced shows how the combination of the indicative targets with their respective measures and the binding savings, required by Article 7, must add up to the total amount of savings required by the EU target.

Article 7.2 provides possible exemptions that lower the target volume of energy savings to a limited degree, as M-S may choose to progressively phase in the 1.5% target: that is 1% in 2014 and 2015; 1.25% in 2016 and 2017; and 1.5% in 2018, 2019 and 2020 and, also, M-S may exclude part or all of the energy sold to emission trading system industries from the calculation (Article 7.2(b)).

11.2.1.2 Article 14: Promotion of efficiency in heating and cooling

Article 14 deals with the promotion of efficiency in heating and cooling, including the cogeneration of heat and power. The article requires M-S to quantify their cogeneration potential, but did little, in practice, to promote the use of it. It is important to note that before the EED, DHC technologies did not benefit from promotional legislation at EU level. As a consequence, it was estimated that an untapped potential of 25 Mtoe, within the EU, remained for cogeneration at the time the EED was being developed. The definitions, reference values and methodology of the Cogeneration Directive have been carried over to the EED.

Figure 11.1 presents in a methodological manner how Article 14 works during its implementation phase.

As Figure 11.1 shows, M-S should carry out by 31 December 2015 or, for certain cases, by mid-February 2016, a 'comprehensive assessment – CA' of the potential for the application of HECHP and efficient DHC systems, by identifying 'Heat/Cool' areas in each M-S for industrial and commercial use. Annex VIII

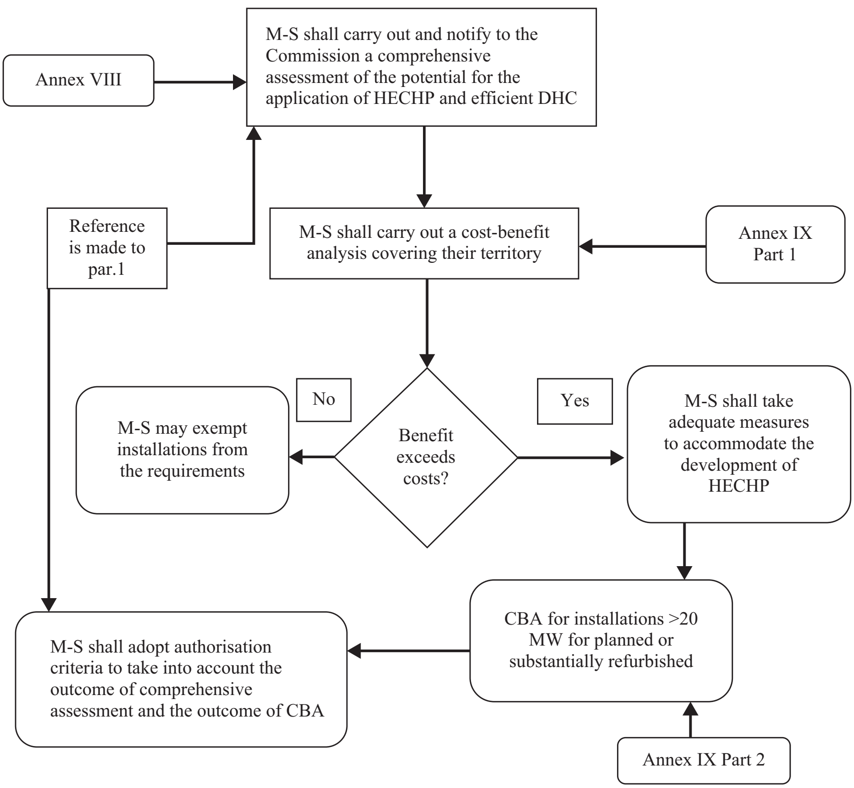

Figure 11.1 Flow chart 'How article 14 works' [12]

contains all the required information for the CA, including a CBA according the specifications set out in Annex IX, part 1, covering the territory of the M-S, its climate conditions, economic feasibility and technical suitability.

In case the CBA is positive, then, according to Annex IX, part 2, each M-S shall take adequate measures to accommodate the development of HECHP. Also, for each installation with thermal output higher than 20 MW_{th}, a CBA is mandatory, and all relevant permits should take into account the outcome of the CBA.

11.2.1.3 Article 15: Energy transformation, transmission and distribution

Article 15 addresses efficiency aspects of the transformation, transmission and distribution of gas and electricity, including the operation of energy markets. Article 15 sets out a number of requirements intended to promote efficiency in the transformation, transmission and distribution of energy and to remove those incentives in transmission and distribution tariffs that are unfavourable to the overall efficiency (including energy efficiency) of the generation, transmission, distribution and supply of electricity.

Article 15 sets out that national regulatory authorities shall ‘pay due regard’ to energy efficiency when implementing any measure to develop and improve the network infrastructures; it suggests that incentives be granted to Dispatch System Operators (DSOs) and Transmission System Operators (TSOs) to develop efficient programmes and services consistent with both the ‘Third Energy Package’ and climate and energy package objectives, including the deployment of smart grids; M-S must remove any incentives in tariffs that are detrimental to efficiency or which might hamper the participation of demand response in balancing markets and ancillary services procurement; M-S had to ensure that an assessment is undertaken of the energy-efficiency potentials of their gas and electricity infrastructure, and ‘concrete measures and investments are identified for the introduction of cost-effective energy efficiency improvements in the network infrastructure, with a timetable for their introduction’.

A framework will be established for access to the grid and dispatching of electricity for HECHP. It requires that, while ensuring grid security, TSOs and DSOs:

- guarantee the transmission and distribution of electricity from HECHP;
- provide priority/guaranteed access to the grid for HECHP and
- provide priority of dispatch of electricity from HECHP.

In 2011, the EU mandated the establishment of European Network Codes as a prerequisite for the creation of an internal energy market. These codes ensure security of supply and further integrate low carbon generation.

The development of these network codes by European Network of Transmission System Operators for Electricity (ENTSO-E) creates this unique opportunity to fulfil the objectives of Article 15.

11.2.1.4 Annex I–II–X: General principles for the calculation of electricity from cogeneration–Methodology for determining the efficiency of the cogeneration process–Guarantee of origin for electricity produced by HECHP

As stated earlier, the EED (2012/27/EU) is amending Directives 2009/125/EC, titled 'establishing a framework for the setting of Eco-design requirements for energy-related products' and 2010/30/EU, titled 'Indication by labelling and standard product information of the consumption of energy and other resources by energy-related products' and repealing 2004/8/EC Directive, titled 'on the promotion of cogeneration based on a useful heat demand in the internal energy market and amending Directive 92/42/EEC'.

Annex I, Annex II and Annex X of EED include all basic articles of the Cogeneration Directive (2004/08/EC), which came into force in February 2004. In general, the Cogeneration Directive outlines an enabling policy framework for the EU to expand further the deployment of cogeneration in M-S.

The Cogeneration Directive encourages the use of high-efficiency cogeneration in the production of heat and power as a successful and well-developed technique delivering primary energy savings. The background policy objectives were security of supply and energy savings; cogeneration, as a highly energy efficient, technologically mature approach for generating electricity and providing useful heat was a key enabler for improving the efficiency of electricity production from fossil fuels.

One of the main achievements of the Cogeneration Directive has been the codification for Europe of what is meant by high-efficiency cogeneration, which was defined as the cogeneration plant in operation which saves a minimum 10% primary energy compared to separate production of heat and electricity, based on the same fuel.

The Cogeneration Directive sets the support framework through state aid for environmental protection, thus allowing M-S to actively support cogeneration. Implementing the Cogeneration Directive, several M-S, such as Germany, Belgium, Portugal and others, have followed these support mechanism structures, increasing their share of cogenerated electricity. Support is restricted to 'good quality' schemes that really do save energy, a scheme, which fulfils the criteria of at least 10% savings of primary energy compared to separate production. The reporting provisions of the Directive have produced an assessment from each M-S of the economic potential of cogeneration, which remains to be developed by 2020 [13].

It was a common feeling among experts that the implementation of the energy-related directives described previously had been relatively poor, with the exemption of RED.

In 2007, all EU M-S have made a strong political commitment to the '20-20-20' targets, knowing that this commitment requires strong dedication, work and effort to achieve the final output. In reality, many EU M-S moved fast to implement the directives with clear procedures and transparency, whereas other M-S transposed the directives with delay, beyond deadlines, losing critical time and just before legal actions have been taken against them by EC, or often transposed these directives with a view of meeting only the minimum requirements, avoiding changes to existing national laws. However, on the other hand, all actors, within the value chains of the sectors covered in the EED, such as industry, buildings, appliances, transport or energy supply, have a vested interest in supporting timely, proper and effective implementation. If the '20-20-20' targets are not met, a sustainable, secure and affordable energy system will be outstandingly difficult and expensive to be achieved and Europe will face a serious setback in its position as world leader in the fight for climate change.

11.2.2 Examples of policy development in European countries

11.2.2.1 Policy development of cogeneration in Germany

Germany has been pursuing ambitious climate and energy policies over the past 10 years, setting ambitious national GHG, renewable and energy efficiency targets for 2020. The German government has been pursuing the 'Energy Transition-Energiewende' strategy, published in 2011, aiming at shifting from fossil fuels and nuclear power to more renewable energy in its energy mix taking into consideration its 2011 decision to phase out nuclear energy by 2022.

The German Energy Concept outlines a long-term strategy, drawing the country's energy and climate objectives for 2050. GHG emissions are to be cut by 40% by 2020 and by at least 80% by 2050 compared to 1990 levels. In order to achieve this, RE targets were set at 18% of total energy supply and 35% of the gross electricity consumption by 2020, whereas RES are expected to account for 60% of the total energy supply and 80% of the total electricity consumption by 2050.

Energy efficiency goals are also playing a vital role in the energy transition strategy, as primary energy consumption shall be reduced by 20% by 2020 and 50% by 2050. All these commitments created a favourable environment for the cogeneration sector.

Germany has a long tradition on the promotion of cogeneration, based on a sound, legal framework, as well as with appropriate financial mechanisms to support high-capital investments, as cogeneration provides many benefits, both in primary energy saving and in protecting the environment.

In 1999, within the 'Ecological Tax Reform' law, Germany introduced the first support mechanism for cogeneration units satisfying certain efficiency conditions, in the form of exemption of cogeneration fuel input from the fuel tax on diesel heating oil and natural gas. In January 2013, due to a revised EU energy taxation exemption permission, put in action in 2003, the 100% fuel tax exemption had to be limited to a depreciation time of 10 years for the cogeneration plants. Also, cogenerated electricity delivered from small-scale cogeneration units up to 2 MW_e to users in the near vicinity of the cogeneration stations was exempted from the electricity tax of 20.5 €/MWh.

In 2001, a preliminary cogeneration law, the so-called KWK-Vorschaltgesetz was introduced, which supported cogenerated electricity to be delivered into the public grid by bonus payments and applied only to existing cogeneration plants.

In 2002, the ‘Cogeneration Modernisation Law’ was introduced, supporting cogenerated electricity to be fed into the public grid, which also covered new cogeneration installations up to 2 MW_e and provided investments for the modernisation of cogeneration plants with capacity higher than 2 MW_e.

In 2004, an additional bonus payment for cogeneration of electricity from bioenergy was introduced into the renewable energy law. This led in the following years to a substantial growth in bioenergy cogeneration installations. This cogeneration bonus was abandoned with the last amendment of the RES law, in 2012. Since then, in principle, the total electricity produced from bioenergy was considered as cogenerated, but there were some important exemptions leading, in practise, to reduced cogeneration with bioenergy.

In 2009, by an amendment to the cogeneration law, new cogeneration plants with capacity higher than 2 MW_e were also included in the support scheme mechanisms, and the existing bonus payments were extended to all high-efficiency cogeneration plants, including the autoproducers. In addition, investment grants were introduced for grids of heat produced by cogeneration plants.

In 2011, a monitoring study on the effect of the cogeneration law was carried out, indicating that without further amendments of the law, only a maximum 20% of the existing cogeneration share would be possible to be in operation by 2020.

For a period of more than 10 years (1999–2011), cogeneration in Germany has shown a notable and steady increase, as Figure 11.2 shows [14].

As a consequence, and regarding the target of 25% share of cogenerated electricity in German energy mix declared in 2007, the revised Cogeneration Law

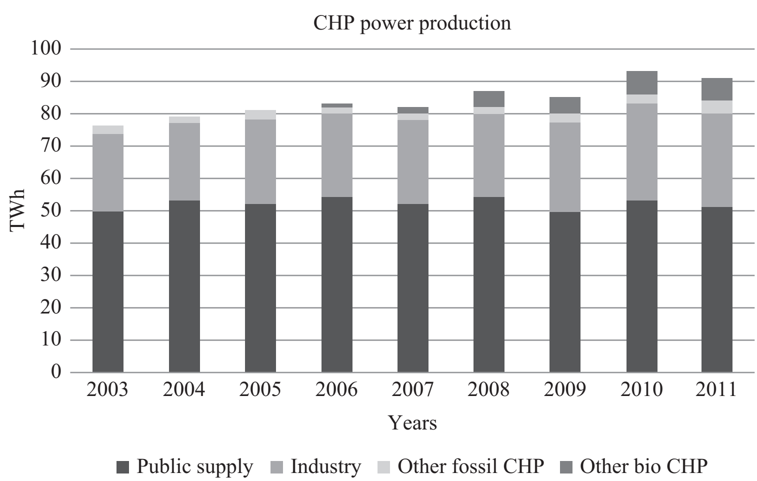

Figure 11.2 Cogenerated electricity in Germany

of 2012 provided certain substantial improvements of the incentives for investments in new cogeneration plants and modernisation of old plants. Aiming at facilitating the support scheme for private cogeneration operators for installations up to 2 MW_e, the option of an immediate pay out of the total support for 30,000 h at the start of the operation was introduced. This means that the German government was paying in advance, as an incentive to the cogenerators, a maximum of 60,000 GWh of cogenerated electricity.

This transition accelerated the development of RES, and it also raised the awareness for cogeneration as a solid option of a combined strategy for decarbonisation of the energy system.

Complementary to this Cogeneration Law, an additional support mechanism for micro-CHP units, up to 20 kW_e, was launched in 2012, providing investment grants, according to their electrical capacity, from 1,500 to 3,500 € per installation.

In 2011, following the Fukushima nuclear disaster in Japan, the German government has decided to substitute nuclear power production by 2022; this transformation process is called ‘the Energy Transition-Energiewende’.

The German government’s energy targets up to 2030 are shown in Table 11.1.

Energy market liberalisation, economic slowdown and unfavourable electricity and gas prices, due to the fluctuations mainly of gas prices, make the development of the cogeneration sector to slow down, and the 25% target may not be reached (Table 11.1). Thus, German policy-makers decided to mitigate this by improving the existing policy instruments.

In 2012, recast legislation brought about enhanced measures for cogeneration. The 2012 Cogeneration Law features higher premiums for electricity produced in cogeneration mode, re-states the priority access to the grid principle for cogeneration and gives support for heat networks and storage. Moreover, the 2012 Renewable Energy Law introduces an obligation on biomass electricity producers, which enhances the opportunity for cogeneration to develop further. These measures, along with the micro-CHP Incentive Programme, are considered to contribute positively towards closing the gap of cogeneration share in total power production between the level of 12.4% in 2013 and the 25% target to be attained by 2020. Review of the Cogeneration Law is foreseen towards achieving the binding target of 25% in the near future.

Table 11.1 Energy and climate objectives of the German government [15]

	2010	**2020**	**2030**
Phasing out of nuclear power by the end of 2022			
Decreasing greenhouse gas emissions, compared to 1990 (%)	23	40	55
Renewable energy share of electricity production (%)	17	35	50
Cogeneration share of electricity production (including bio-CHP) (%)	15	25	NA

In 2014, the German cogeneration market was one of the largest in Europe, as cogeneration plants generated approximately 78.67 TWh of electricity in 2013, which represents 12.4% of Germany's total electricity production [16].

11.2.2.2 Policy development of cogeneration in the Netherlands

Sustainability, competitiveness and de-carbonisation are among the main concerns that drive the energy strategy in the Netherlands. In all recent energy reports and especially in the 2011 one, the Dutch government outlined the importance of meeting required energy demand through a diverse energy mix that would include all reliable and sustainable forms of energy, such as RES, and energy efficiency. So, the Dutch government, as the German one, plans to achieve these goals by transposing EU's energy and climate target at national level by increasing its share of RE in gross final consumption to 16% by 2020 from 4% that was in 2010. Regarding emission reduction, the Netherlands is setting up to decrease its GHG emissions by 80%–95% in a long-term GHG reduction objective by 2050.

The Dutch cogeneration sector saw rapid growth in the 1990s, as the legislative framework created a supportive environment for long-term high-capital investments, in combination with low gas prices. So, the installed capacity of cogeneration was more than doubled in the period between 1990 and 2000. The cogeneration capacity was mainly located in industry, in horticulture (mainly of high-technology greenhouses equipped with selective catalytic reduction system for pure CO_2) and in district heating plants.

After 2000, the above-recorded growth slowed down, as the transition to a liberalised energy market fuelled uncertainty, rewarding short-term investments and investments in RES sector. Between 2005 and 2008, cogeneration capacity tripled in the horticulture sector, driven by the ability of these applications to follow the electricity market price signal, using storage of heat to maintain high efficiency status required by the 2004/8/EC Directive. Since 2009, the installed cogeneration capacity in the Netherlands remains stable, caused by the loss of SDE+ (Stimulering Duurzame Energieproductie) state support for cogeneration, which was more favourable for RE projects [photo-voltaic (PV), wind, biomass, etc.], whereas the real decline started in 2010, due to unfavourable energy market conditions and lack of compensating support for energy production using cogeneration. Still, the Dutch cogeneration sector has been one of the best performing sectors in Europe, with 51.8% of the total generated electricity coming from cogeneration plants in 2011 [17].

According to the Dutch Central Statistics Office, centralised cogeneration plants represented 39.8% of the total installed electrical cogeneration capacity in 2012. Together with the agriculture and horticulture sector (24.1%) and the industry (26.0%), it amounts to 90% of the total installed electrical cogenerated capacity. The agriculture and horticulture sector and services represent, respectively, 63.7% and 28.3% of the 4,408 cogeneration installations in the Netherlands. Most cogeneration plants are fired with natural gas (66%), whereas industrial gases, waste gas, biomass and waste accounted for 23.8% of the cogeneration energy mix. The 2013 Dutch National Energy Agreement reconfirmed the halt to cogeneration support in the Netherlands, leading to a probability that the cogeneration sector will be halved by 2020.

However, studies [4] suggest that in the Netherlands with specific measures proposed, it should be possible by 2030 to exploit an economic potential of 16.1 GW_e of installed cogeneration capacity, which will result in primary energy savings of 42 TWh/year and annual CO_2 savings between 12 and 15 million tons in 2030. This can become a reality if the Dutch political establishment reverts to a comprehensive Dutch cogeneration or efficiency policy.

11.3 Regulatory and legal framework in countries outside Europe

11.3.1 Regulatory and legal framework in the United States of America

Cogeneration has a long tradition of more than 130 years in the United States of America. Currently, it accounts for roughly 12% of total US electricity generation and comprises about 9% (85 GW_e at about 3,300 sites) of total generating capacity [18]. Cogeneration in the United States of America is heavily concentrated in states with heavy industry (e.g. Texas alone has 20% of the total US installed cogeneration capacity) and only about 12% of existing cogeneration capacity is deployed at commercial or institutional facilities, mainly large office buildings, university campuses, hospitals, hotels, athletic facilities and others. From all cogeneration units, nearly three quarters of cogeneration capacity uses natural gas as fuel, and nearly half of all cogeneration sites use reciprocating engines. The US cogeneration is characterised by large cogeneration systems of 100 MW_e or more in capacity.

Regarding the regulatory and legal framework for cogeneration in the United States of America, the milestone for its promotion was the law titled PURPA, which was passed by the US Congress in 1978. This law had an impact on both the cogeneration and the electric utility industries, as it mandated the electric utilities to purchase electricity from non-utility-owned RES and cogeneration plants.

So, PURPA became the strong driving force for the development of RES, for the flourish of cogeneration and for the creation of competitive wholesale energy market in the United States of America. In simple words, PURPA marked in the United States of America a new era for the development of resource saving projects such as cogeneration, whereas in the past, utilities avoided the purchase of electricity and heat (steam and hot water) from this type of facilities. PURPA allowed cogenerators to buy electricity from utility companies at fair prices and required the utilities to purchase electricity in ‘avoided cost’ – the cost the utility would have paid to produce that electricity. PURPA contained a provision that required local utilities to buy excess power from the so-called qualifying facilities – QF at favourable rates, equivalent to ‘avoided costs’, which was higher than the price companies paid for purchasing electricity from the utilities.

In most cases, cogenerated electricity was cheaper than utility-generated electricity, because fuel was used to produce two products, steam for industrial purposes and electricity, either for self-consumption and/or for sale to the grid. The advantage for cogenerators was that they could produce and sell electricity, without being subject to the regulations on security registration or on prices that utilities were forced to endure.

The next growth factor was a result of PURPA regulations changes required by the Energy Policy Act (EPA) of 2005. So, as EPA provided, the Federal Energy Regulatory Commission (FERC) issued new rules and regulations, whereby utilities were no longer required to buy electricity from QFs, when those facilities have access to competitive electricity markets and, second, new-cogeneration QFs were not 'electricity-based facilities', taking advantage of cogeneration incentives. It should be added that this is the period that EU issued its Directive (2004/8/EC) on high-efficiency cogeneration, based on useful heat, with all requirements for a cogeneration unit to be classified as a high-efficiency one.

The wide deployment of cogeneration over the previous years slowed down between 2006 through 2009, mainly due to higher natural gas prices and to the economic uncertainty in the United States of America during that period.

In addition, two federal legislations passed by the Congress, one titled 'Energy Improvement and Extension Act' in 2008 and the other 'American Recovery and Reinvestment Act' in 2009. They encouraged again the deployment of cogeneration by providing tax incentives, the so-called 'CHP investment tax credit and accelerated depreciation', along with substantial funding for selected cogeneration projects.

Executive order issued by the Federal Government in 2012, provided for 40 GW_e of CHP capacity to be added by 2020, taking US cogeneration capacity up to 130 GW_e, with additional potential for 65 GW_e for both the industrial and commercial/institutional sectors [19]. In August 2012, US President issued the US Executive Order for accelerating investment in industrial energy efficiency, which promoted cogeneration and sent a clear message that US government will work to expand the share of cogeneration in its energy mix in the coming years by stating that

> *Instead of burning fuel in an on-site boiler to produce thermal energy and also purchasing electricity from the grid, a manufacturing facility can use a CHP system to provide both types of energy in one energy efficient step. Accelerating these investments in our Nation's factories can improve the competitiveness of United States manufacturing, lower energy costs, free up future capital for businesses to invest, reduce air pollution, and create jobs. US institutions will coordinate and strongly encourage efforts to achieve a national goal of deploying 40 gigawatts of new, cost effective industrial CHP in the United States by the end of 2020.*

In August 2015, the US Environmental Protection Agency (EPA) released its final version of the Clean Power Plan (CPP) aiming at reducing carbon emissions by 32% below 2005 levels by 2030 and to provide America's first national standard to limit pollution from power plants. The states are expected to show compliance with the recommendations by 2022, on a gradual 'slip path' of emissions reductions by 2030. The plan is being authorised under existing primary legislation, the Clean Air Act (CAA). The US administration expects that implementing these emissions limits will cost \$8.4 billion annually by 2030. After the plan entered into the Federal Record, it has been challenged in the Courts by at least 15 states, which have largely invested in the coal industry and which do not have distributed energy schemes planned or in operation. They propose that they can operate either on a rate-based system, where they are allowed a certain level of emissions per MWh or on a mass-based quota that sets an allowance for aggregate total emissions. CPP will affect states depending on which system they choose to operate.

Distributed energy is expected to benefit from the CPP, as decentralised, small-scale power production, such as solar, wind power, harness biogas, biomass, geothermal power and cogeneration can be aggregated to meet regular demand often linked with main grids.

In February 2016, the US Supreme Court stayed implementation of the CPP pending judicial review. The Court's decision was not on the merits of the rule and the final decision is expected in the near future [20].

11.3.2 Policy development of cogeneration in PR of China

China is moving towards to the world's leading energy consumer and it began to use cogeneration in the 1980s, when the central government policy encouraged cogeneration in north China's district heating plants, using technical assistance from the former Soviet Union. The commercial development of cogeneration started in the late 1980s and quickly spread through China.

In the first decade of the twenty-first century, China has experienced colossal investment in its power generation sector, fired mainly by coal, oil and gas. The installed capacity of thermal power stations has grown from 210 GW_e in 2001 to 710 GW_e, by the end of 2010, with tendency to overtake the US' 875 GW_e of thermal power generation capacity by 2020. In 2010, cogeneration installation capacity reached 167 GW_e, accounting for 23% of total thermal power capacity, presenting significant opportunities for Chinese and foreign equipment suppliers.

Referring to the recent regulatory framework for cogeneration in China, two major actions can be identified: one, dated in 2011, the National Development and Reform Commission, the National Energy Administration and the Ministry of Finance released a government plan entitled 'Guiding Opinions of the Deployment of Gas-Fired Distributed Energy' [21], the only recent document on these national goals, which had set goals to develop 5 GW_e of gas-fired combined cooling, heating and power (CCHP) by 2015 and 50 GW_e by 2020. It is important to note that these cogeneration targets are underpinned by detailed energy policies in China's 12th Five-Year Plan for Energy Development, which runs from 2011 to 2015. It includes a number of major policy targets, with an indirect bearing on the market for cogeneration and was unveiled in January 2011 by China's State Council. At its heart, this plan is a blueprint for greater energy security and reduced energy intensity, just the priorities that favour cogeneration. More specifically, there is a number of important targets related to the role of natural gas in the energy mix, primarily doubling its share of the total, of raising proven conventional gas reserves by 3.5 trillion m^3 and building 44,000 km of natural gas pipelines, as well as the production of 6.5 billion m^3 of shale gas per year by 2015, increased to 80 billion m^3 by 2020. It is clear that the further penetration of natural gas in the Chinese energy mix will increase the share of cogeneration. On promoting policies for cogeneration, a paper titled 'The 12th Five Year Plan for the Development of City Gas', issued in June 2012 will serve as the vehicle for the penetration of cogeneration in the commercial/tertiary sector over the coming years.

China has already made significant moves to diversify its access to natural gas via signing of agreements to import liquefied natural gas from its neighbours and pipeline gas from Central Asia and, most recently, from Russia. In March 2013, Moscow and Beijing signed a historic deal, where Russia will deliver 38 billion m^3 of NG each year to China, starting in 2018, with an option to increase it to 60 billion m^3 annually. In 2011, China consumed about 130 billion m^3, indicating the importance of the agreement in terms of security of supply.

In March 2013, the State Grid Corporation of China [22], the country's largest state-owned utility, indicated that it would permit easier access to the power grid for small distributed energy resource power projects, up to 6 MW_e, fuelled by natural gas, such as cogeneration.

On local state level, the Shanghai government has released a plan stipulating that gas-fired cogeneration projects will be offered a subsidy of CNY 1000 (US$ 152–€ 139.2) per kW of installed cogeneration capacity and will have priority to supply cogenerated electricity to the national grid. That incentive rises to an additional CNY 2000 (US$ 304–€ 278.4), if, after 2 years of operation, the project can prove it has been operating at more than 70% efficiency.

In conclusion, the cogeneration industry in China is developing rapidly, with an annual growth rate of installed capacity of about 20%, and it is expected that, by 2020, the total installed cogeneration capacity will reach 900–1,000 GW_e [23], taking into account that there is a strong regulatory support framework and security of supply.

11.3.3 Policy development of cogeneration in Japan

The Japanese government's last Energy Policy review in 2010 concluded that nuclear power would remain a major energy source, partly to help Japan meet its Kyoto protocol targets and due to the fact that nuclear was seen as the most efficient method of generating low-cost electricity. After the 2011 earthquake and tsunami and the massive economic recovery and regional reconstruction programme, all that changed and they began to consider various options. Natural gas and coal are other fuel options that offer large potential for power generation, thus the energy policy is uncertain and the further promotion of cogeneration is at stake.

Japan was already an important cogeneration user and has recently seen growing uptake of residential fuel cell micro-CHP systems. However, the development of new industrial and commercial cogeneration installations has slowed, mainly due to relatively low prices for electricity exported to the grid.

According to the Advanced Cogeneration and Energy Utilisation Centre (ACEJ), formed by merging the former Japan Cogeneration Centre and the Centre for Natural Gas Development [24], by mid-2010, Japan's cogeneration capacity, excluding fuel-cell applications, totalled 9,440 MW_e across 8,444 sites, out of which 7,473 MW_e were installed at 2,125 sites nationwide in the industrial sector, whereas the commercial sector's cogeneration systems totalled 1,967 MW_e at 6,317 sites. Attention should be given to cogeneration systems with RE, as biofuel fires 112 CHP units at 77 sites, totalling 503 MW_e. Wood biomass accounts for 477 MW_e or 95% of biofuel-powered CHP. Other fuel sources include sewage sludge, food waste and livestock waste. Direct burning is used in 475 MW_e of biofuel-powered CHP.

Although commercial cogeneration has outstripped industrial cogeneration in terms of site numbers, many commercial cogeneration systems stopped operating after 2006, as gas prices increased. Industrial cogeneration systems tend to be larger than cogeneration systems in the commercial sector. Japan's industrial cogeneration units are mostly gas-fuelled, using gas pipelines supplied by local city gas companies. Cogeneration units installed in commercial buildings also use pipe gas as their main fuel source.

Cogeneration in Japan is divided into three phases of growth; the first began in the late 1980s, before the nation's economy crisis; the second in the mid-1990s and ended with the 1997 Asian financial crisis. The third-cogeneration growth phase peaked in 2004 and then slowed until the end of 2008, when the turmoil of global economic crisis started.

Japan introduced institutional reforms and deregulation for the cogeneration market since mid-1980s and since then, cogeneration systems have been installed in increasing numbers. These reforms served as major factors for the growth of cogeneration in Japan. The major institutional improvement and deregulation for the promotion of cogeneration in Japan [25] dated 30 years, including, among others, the establishment of guidelines on technical requirements for interconnection of cogeneration systems and other facilities with the utility grid; introduction of a backup power supply scheme for users in the commercial sector (1986); the approval of the trading of generated electricity between the owner and the tenants of a single building; relaxation of regulations for hazardous fuels (1987); the establishment of feed-in-tariffs for cogenerated electricity (1992); the approval of gas-fired generating system used both continuously or for emergency purposes (1994); the relaxation of periodical inspection requirements for small-scale gas turbine generators with a capacity of 10 MW_e or less (1998); the relaxation of pre-operation and periodic inspection requirements for gas turbine generators of less than 1 MW_e, for fuel cell – mainly polymer electrolyte membrane fuel cell (PEMFC) – generators of less than 500 kW_e (1995, 2000 and 2001); the liberalisation of electricity retail businesses serving customers with a demand of 2 MW_e in 2000, 500 kW_e or more in 2004 and 50 kW_e or more in 2005.

It is clear that all these measures indicate a strong political will by the Japanese government to promote capital intensive investments such as cogeneration, either with the introduction of a series of institutional reforms or by the introduction of taxation system for cogenerators to allow them a 7% tax exemption on the acquisition cost for a cogeneration unit or a 30% exemption for the accelerated capital allowance. The role of the Development Bank of Japan and of the Japan Finance Corporation was critical, as they offer long-term and low-interest loans for small and medium enterprises for cogeneration projects.

The assessment of how cogeneration installations have been affected by the 2011 earthquake is, currently, a critical issue. With the Fukushima nuclear plant now shut off and other nuclear plants offline for deep inspection, Japan's electricity supplies are significantly squeezed. Also, the outlook for industrial cogeneration in Japan is uncertain, due to the damage from the 2011 earthquake.

It is believed, though, that new factories, which will replace wrecked facilities, will incorporate cogeneration. Also, companies are installing standby or backup power generation facilities, which could include cogeneration units. In their efforts to reduce electricity consumption in Tokyo and earthquake-affected regions, several firms have shifted working hours to off-peak periods. The government has also introduced short-term fuel oil and diesel engine maintenance subsidies to help companies install backup power generation facilities.

According to the International Energy Authority (IEA), cogeneration could generate annually 199 TWh in Japan by 2030, if a strong policy network backs it [26]. The earthquake has undermined Japan's population confidence in nuclear power; so, cogeneration seems to have benefited, especially if electricity companies raise purchase prices to buy in more electricity.

11.4 Impact of electricity and gas liberalisation on cogeneration

11.4.1 Introduction to EU electricity and gas liberalisation

Until the late 1970s, vertically integrated companies, with the exclusive right to sell electricity/gas and a corresponding obligation to supply them, operated EU electricity and gas systems. Also during that period, EU M-S were reluctant to abolish their sovereignty on energy systems, apart from few exemptions. In the early 1980s, the United Kingdom proceeded to a full liberalisation of its energy systems, following the strong political will of the then UK government, beyond overwhelming society's reactions to these changes.

For many M-S, the vertically integrated energy companies were seen of strategic importance for security of supply and for their overall economy. The setting up of monopolistic central stations, whether owned or only regulated by public authorities, resulted in lack of competition, high costs, possible engineering excellence but little commitment to cost minimisation. A serious weakness of the system was that those who planned, managed and operated the system did not carry any risk, and they were vulnerable to any type of corruption. Consumers had no role other than to switch apparatuses on and off and paying monthly bills.

The so-called globalisation process that started in the mid-1980s, along with the rapid technology advancement of small-scale technologies (i.e. PV, wind, cogeneration units, etc.), changed this situation, because pressure was put on the governments to reduce energy prices and permit new entries to their energy systems, as the existing energy scene was changing and changing really fast. This new process of opening electricity and gas markets to competition is called 'liberalisation of electricity and gas markets', as de jure or de facto national monopolies or oligopolies in these sectors had to be broken down [27].

The European Commission's White Paper on the completion of the internal market [28] and the entry into force of the Single European Act were turning points on the liberalisation of energy market process in Europe. In the above-mentioned report published in June 1988, the EC stated clearly its determination to enforce the general provisions of the EEC Treaty in the energy sector. In 1990, two directives in the field of transparency of electricity prices [29] and international electricity transit [30] were adopted. Both directives remained modest in scope and influenced slightly the organisation of the national electricity systems. In 1991, the EC moved further, setting up expert groups to study whether competition could be introduced in energy sector, in reality, if it were possible to give 'independent' electricity producers access to the grids. The output of these studies was formulated in a draft Directive proposal in 1992, based on the following three 'new' principles:

1. 'Regulated' and/or 'negotiated' third-party access (TPA) to the grid,
2. abolition of exclusive rights in the production of the vertically integrated companies by a licensing system, and
3. 'Unbundling' and 'administrative separation' of the monopolistic functions of transmission and distribution production from the competitive activities of generation and supply of the vertically integrated companies.

This draft electricity directive was negotiated for more than 3 years with M-S and different energy lobbies, until 1996, when the first Electricity Directive, establishing 'common rules for the internal market in electricity' finally was adopted [31] and, a year and a half later, a similar first Gas Directive opening up the gas markets was also adopted [32].

In 2000, in Lisbon, the EC decided to speed up the liberalisation process of both sectors – electricity and gas – in order to create a fully open internal energy market in EU. The EC, having studied all drawbacks from the implementation of these two directives and the possibilities of functioning the energy markets more efficiently, prepared two new directives, the so-called 'Second Electricity and Gas Directives', which were adopted in 2003 [33]. It is important to state, at this point, that the most important point of these directives is the will of the legislator that, by mid-2007, all consumers (industrial, commercial, residential, etc.) will be free to choose their electricity and/or gas supplier(s).

By mid-2005, it became clear to all actors that the existing shortcomings made unavailable the full opening of the energy markets by the proposed time horizon (mid-2007). These shortcomings can be distinguished into structural issues in vertical integration of supply, lack of transparency in market access and operations, shortages of gas transmission capacity, regulatory problems and gaps especially in cross-border interconnections and trade and distortion of regulated retail prices.

All the above, along with the slow implementation of these directives by many M-S led the EC to conduct a sector enquiry and on its basis to announce its 'Third Energy Package', submitted in September 2007, which was consisting of five new proposals, aiming at promoting further the Liberalisation of Electricity and Gas in all EU M-S:

1. amendment of the second Electricity Directive,
2. amendment of the second Gas Directive,
3. regulation establishing an Agency for the Cooperation of Energy Regulators,
4. regulation amending Electricity Regulation, 1228/2003/EC [34], and
5. regulation amending Gas Regulation, 1775/2005/EC [35].

In January 2007, in parallel to the above-mentioned changes and reforms, the EC proposed the so-called Climate Package, leading to the adoption of the important commitments to protect the climate, the so-called 20-20-20, by the European Council in March 2007.

11.4.2 EU energy liberalisation and its impact on cogeneration

A thorough examination of the implementation of the liberalisation of electricity and gas markets in EU for the past 20 years and its impact on cogeneration shows that the required structural changes, that the markets had to undergo, were kept to minimum, at least, in the majority of M-S.

As an example, in electricity market, the first Electricity Directive in 1996, barely tackled the issues related to the connection of RES and HECHP. The RES Directive, 2009 (Article 7) and the Cogeneration Directive in Article 8 tried to overcome these issues by clearly mandating M-S to guarantee their transport and sets out principles regarding the allocation of costs relative to their connection with the network. Those principles should be based on objective, transparent and, above all, non-discriminatory criteria, taking into consideration all costs and benefits associated with the connection of cogenerators to the network. Still, the situation remained unchanged; so, the EED set up again the above-described principles, requiring also a more solid action by M-S.

Another issue is associated with the balancing markets, which allow a market-based procurement of balancing energy within a single M-S or control area (i.e. Nordic pool). It is known that electricity consumption is affected by many parameters, such as local conditions, time period and season. So, as consumption over time is not predictable, it results in an imbalance between supply and demand and, therefore, of the electricity producers' contractual obligations. So, the role of local TSO is crucial in order to maintain the balance of the electricity systems. These interventions are costly, and the 2003/54/EC Directive, in Article 11 (7), stated that balancing rules have to be objective, transparent and non-discriminatory. Many M-S have established balancing markets, but still there are problems, especially for large cogenerators, to access these markets, as these markets are dominated by one or, in some cases, a few, mainly fossil-fuelled, national suppliers, who did not permit any easy entrance to the balancing markets.

As a general comment, it can be said that more work is needed at the EU M-S electricity network level to facilitate the integration of more cogeneration. This work should be targeted to remove remaining electricity network barriers to distributed generation relative to large central production, such as authorisation, access and tariffs and others. This will accelerate the creation of new network services markets at European level, based on demand response, capability availability, local balancing, DSO support and storage and markets ability to tackle the new-era's electricity challenges.

Likewise, in the gas market, the EU strives to introduce regulation-for-competition in NG markets by applying principles for the market reform, TPA, unbundling and independent regulation, as the first Gas Directive described in 1998. According to a study, 'in case of European gas market reform, most of the actual regulatory functioning is finally determined on the level of institutional arrangements within the M-S'. Therefore, we distinguish between European legislation on the formal level and regulation on the level of institutional arrangements [36]. So, it becomes clear that the M-S position on their energy policy (i.e. gas market liberalisation) can affect the required institutional arrangements.

In reality in the past decade, the United Kingdom, Denmark, the Netherlands, Germany and Sweden moved steadily forwards, towards fully liberalised gas markets, resulting in a notable increase of their cogeneration units operating in their energy systems. Other M-S moved more slowly towards the requirements of the second Gas Directive (2003) and the 'Third Energy Package' (2007).

Similar barriers, discussed earlier for the electricity sector, are detected in the gas sector. As mentioned in Section 11.2.2, the transition period to a fully liberalised energy market in the Netherlands created uncertainty to the actors, including the cogenerators, and rising gas prices slowed down the previous recorded growth of cogeneration.

The gas price, referring in the Netherlands case, is a very critical issue for the promotion of cogeneration. As a rule of thumb, it is well known that 'a high carbon price favours use of gas, whereas a low carbon price promotes coal'. This was a reality in Europe the past years, as during the initial stages of energy liberalisation, the gas prices were very competitive and cogeneration flourished, and then, when these prices increased, along with the high concentration of the gas market, the situation for cogeneration became less attractive, especially for small- and medium-sized cogeneration. All in the energy markets are well aware that the economics of any cogeneration plant depends heavily on the difference between the fuel price the operator pays for the primary fuel and the electricity price, which the operator can get for the electricity the plant generates, the so-called spark spread. The economics of cogeneration are, therefore, sensitive to changes in both the electricity tariff and the primary fuel price. In the past years, the EU is experiencing a period of particularly difficult spark spread challenges for cogenerators using gas. Low wholesale electricity prices have coincided with relatively high gas prices, resulting in either partial load operation or switching off the system [37].

11.5 Conclusions

Cogeneration is considered by the world energy market as a mature energy-efficient technology, which has a long history of operation and proven experience, as it is dated since the early 1880s. Cogeneration can be applied in all aspects of modern technology life, where there is a need for 'useful heat' and electricity, starting from large industrial units of 100 MW_e to small-scale commercial applications, up to 1 MW_e ending to micro-CHP units for residential sector of 1 kW_e. Cogeneration can be fuelled almost by all fuels, providing serious environmental and financial benefits to its users.

In spite of all the above-mentioned, the percentage of the world's cogenerated electricity remains low, around 9%, despite the strong regulatory and legal supporting framework by all the industrial countries of the world.

Analysis of the existing cogeneration policies applied worldwide shows that a variety of parameters are affecting the growth of local cogeneration markets, namely:

1. Legal and regulatory framework is strong in all industrial countries; for example, EU has issued two directives referring exclusively to high-efficiency cogeneration in a period of less than 10 years (2004 and 2012), and the United States of America had a long tradition of promoting cogeneration for almost 40 years (PURPA, 1978). However, it is clear that these policies alone are not enough and other, more targeted, actions are required by governments to assist cogeneration to operate freely and without prejudice in liberalised energy markets.
2. The fluctuation of the energy prices and their taxation in local markets play an important role not only in the feasibility of cogeneration projects but also in their daily operation.
3. A crucial parameter is the level of liberalisation of the local energy markets. It is important to note that cogeneration is having difficulties to improve in both 'closed-to-slow-opening' markets as well as to fully liberalised ones.

The promotion of cogeneration in EU in the coming years until 2030, or even 2050, will be based on two important parameters that can unlock its potential: fuel diversification and status of the micro-CHP, according to [37]. Regarding fuel diversification, there is a steady shift in cogeneration fuels towards increased use of renewable 'fuels'. Geothermal, concentrating solar and a range of bio-based fuels are currently used in CHP and the penetration of renewables reached 16.3% in 2012. The principle of cogeneration is fuel-independent: whatever the fuel, a combined heat and power approach uses that fuel's energy content in the most efficient manner. The development of bio-based gaseous fuels to be used in CHP mode rather than solid fuels is a more electrically efficient route for these materials and provides a very high-efficiency solution. Using CHP for heat and power makes renewable resources more sustainable. Both Sweden and Denmark, well advanced in the use of bioenergy, have highlighted the additional potential they see for the future [38]. As for micro-CHP, there is a strong design and manufacturing competence in Europe, as well as legal support in EU, the United States of America, Japan and elsewhere. Micro-CHP products are now available from most boiler manufacturers in Europe, and the sector is investing heavily, including fuel cells. The sector needs to bring product cost down, and governments should consider the advantages in assisting manufacturers and users through the early stages of production and operation to volume.

Concluding, it is safe to say that in many industrial countries, there are in place all required legal and regulatory policies – even though there are still obstacles and barriers – and the willingness of the political establishment to promote further cogeneration and increase the existing percentage of cogenerated electricity in their energy mixtures. As this is not proven to be enough, more work and targeted actions are needed to overpass existing difficulties, in order higher penetration of cogeneration to be reached worldwide, by 2020, or 2030, or even 2050 and millions of tonnes of CO_2 saved worldwide.

Acronyms

ACEJ	Advanced Cogeneration and Energy Utilisation Centre of Japan
CA	comprehensive assessment
CHP	combined heat and power
CPP	clean power plan
EPA	Environmental Protection Agency
DHC	district heating and cooling
DSO	distribution system operator
EED	Energy Efficiency Directive
EPA	Energy Policy Act
EPBD	Energy Performance Building Directive
EC	European Commission
ENTSO-E	European Network of Transmission System Operators for Electricity
EPC	Energy Performance Certificate
EU	European Union
FERC	Federal Energy Regulatory Commission
GHG	greenhouse gas
HECHP	high-efficiency cogeneration of heat and power
IEA	International Energy Agency
IEA	International Energy Authority
M-S	EU Member States
Mtoe	metric tons of oil equivalent
NG	natural gas

NREAP	National Renewable Energy Action Plans
NZEB	Nearly Zero Energy Building
OJ	Official Journal of EU
PEMFC	polymer electrolyte membrane fuel cell
PURPA	Public Utility Regulatory Policies Act
PV	photovoltaic
RED	Renewable Energy Directive
RES	renewable energy sources
TPA	third-party access
TSO	transmission system operator
QF	qualifying facilities

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Chapter 12

Selection, integration and operation of cogeneration systems

Jacob Klimstra

12.1 Procedure for system selection and design

Although cogeneration clearly reduces the consumption of primary energy compared with separate production of heat and electricity, any intended application requires a proper selection and design process. In this process, the typical electricity and heat demand characteristics of the application site have to be closely examined. Also the temperature levels of the required heat have to be known. Ultimately, the financial investment in a cogeneration installation has to yield positive results; otherwise a project is a-priori not viable. Therefore, the costs of capital, fuel, maintenance and operation have to be weighed against the costs of buying electricity from the grid and producing heat with boilers. Further, the consequences of changing emission levels at a location with respect to legal limits, local air quality and possible emission charges have to be taken into account.

Planning permission is required from the municipality and that might affect the choice of technology. The operator of the electricity grid might have special requirements for connecting the cogeneration installation to the local grid. This can result in high costs, for example when a long additional high-power cable has to be installed. A cogeneration operator such as a municipal utility can have completely different boundary conditions than an industry. If the utility operates a district heating network and supplies electricity as well, the process of matching the installation with demand can be much easier than for an industry that has to match its own demand for energy. Nimbly deciding about investing in a cogeneration installation because of the nice idea of primary energy savings is a risky affair.

12.1.1 Determination of the electricity and heat demand

First of all, a rough determination of the typical electricity and heat demand of an existing or new site is required. Chapter 5 gives examples of some typical applications of cogeneration with their power and heat demand. One often sees that load duration curves such as Figure 12.1 are used to express the heat demand and electricity demand of a building or a process during an extended period of time. Such a curve gives only a global insight in the applicability of a cogeneration

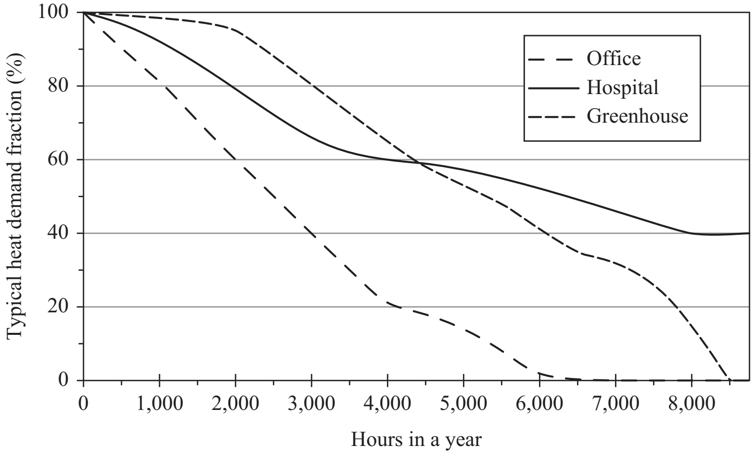

Figure 12.1 An example of load duration curves for heat demand in a moderate climate [1]

installation of a given size. It shows at least roughly that dimensioning a cogeneration installation for covering the peak in heat demand will result in full-load running during only a very limited time. In most cases, an investment in cogeneration is often only economically viable if at least 3,000 running hours at full load can be achieved. Curves, such as Figure 12.1, however do not show the short-term variability in heat demand or in electricity demand, which is needed for a proper matching.

For an existing site, the best way of determining the temperature levels and the variability in heat demand as well as the electricity demand is via measurements. Electricity and heat demand have to be measured conjointly with high temporal resolution in order to check for their time-wise correlation. An issue can be that demand depends heavily on the time of the day, the week or the season. Some industries typically operate in batch processes which can show heavy fluctuations in energy demand. Dairy factories with their typical batch processes when making cheese or milk powder differ from, for example refineries in this respect. For a cogeneration installation at a new energy-using site, the designers of the new process have to provide accurate information about the required electricity and heat and/or chill levels and patterns. Computer simulations can also be helpful in determining the energy demand characteristics.

In some cases, the heat application requires a close to constant supply temperature. In other cases, a constant steam supply pressure is needed. For space heating, the supply temperature as well as the hot water flow generally depends on the ambient temperature. It is therefore needed to have a good insight in the time-related heat flows, temperature levels and, in case of steam, the required steam properties. For electricity, it is important to check what the characteristics of the demand are. If the public grid can be used for balancing electricity production and demand in an economically attractive way, a cogeneration installation can be fully matched on heat demand. The price of electric energy from the public grid often depends on the time of the day and nowadays increasingly on the output level of intermittent renewable electricity sources. In some cases, governments offer subsidies for electricity produced by cogeneration or remove levies for the use of grids. Even that aspect has an effect on the electrical matching of a cogeneration system to its application.

12.1.2 Measurement equipment for determining the energy flows

For measuring the pattern in electricity demand of an existing site, clamp on current transformers (current clamps) in combination with data recorders offer a simple solution with high temporal resolution. For measuring the heat, chill and steam demand pattern, the method is more complicated. The best sensors for determining the supply and return temperatures are Pt100 sensors. The electrical resistance of these sensors is close to linearly proportional with the medium temperature, whereas the value of the electrical resistance can be accurately measured with a three or four-wire resistance meter. A high accuracy is required in case the supply and return temperature of the heating system do not differ much. If the return temperature is only 15 K lower than the supply temperature, a measurement error of 1 K gives already 6.7 per cent error in the heat flow. Direct contact of the temperature sensor with the heat transporting fluid is highly recommended in such cases. Care should be taken at what location the temperature sensor is inserted in a pipe. Especially at short distances from heat exchangers, large cross-sectional differences in local flow and temperature can be present in a pipe. It is always recommendable to check the temperature profile in a cross section of a pipe before the indication of a temperature sensor is taken for granted. Identical precautions have to be taken with flow measurements. Flow meters should be positioned at least ten diameters from disturbances such as bends and cross section changes. Orifice flow meters notoriously suffer from inaccuracy in case of not fully developed flow patterns.

Also the fuel supply flow has often to be measured in order to determine the energy consumption at a site. Gas meters for commercial and industrial customers are normally equipped with an automatic correction device for pressure and temperature. Domestic gas meters do not have that device and only measure the volume that passes the meter at a slightly higher pressure than atmospheric. This means that the same gas volume at an atmospheric pressure of 1,025 mbar contains almost 8 per cent more energy than at an ambient pressure of 950 mbar in case of a fixed temperature. The energy content of a given volume of gas changes inversely proportionally with the absolute temperature. Therefore, a given gas volume at a temperature of 15 °C has 3.5 per cent less energy than that volume at a temperature of 5 °C. With the increasing integration of different gas supply systems and gas coming from different sources, the heating value of the gas can also vary. The heating value in a given group of gas quality such as the H-gas group can easily vary $\pm$5 per cent around the average value. A calorimeter can be used to measure the actual heating value of a gas, but such a measurement system is quite expensive and it requires frequent calibration. Also gas meters should not be positioned close after and before a bend or another flow disturbing element. Sometimes it is required to use a flow straightener upstream of a gas meter.

12.1.3 Fuel options

The type of fuel is also part of the system selection procedure for a cogeneration installation. Gaseous fuels offer the best possibilities for low emissions and high fuel efficiency but gas is not available at every site where heat and electricity is required. At some locations, home heating is the preferential use of gas and a limited gas supply can mean that other gas users are asked to disconnect from the gas grid during cold spells. In case the supply of gas is not guaranteed, dual-fuel engines have the ability to run on liquid fuel as a backup.

In some cases the type of fuel is predetermined, as in case of biogas from a sewage plant or landfill gas from municipal waste. In case coal, lignite or peat is the only available fuel, a boiler with a steam turbine driven generator is the only option for cogeneration. Reciprocating engines and gas turbines can run on natural gas, flare gas, biogas and oil. At oil production sites, it is increasingly forbidden to vent the associated gas to the atmosphere. Flaring of the gas has also negative environmental consequences and it is a waste of fuel. At such sites, gas–diesel engines can be used that can run on almost any combination of gaseous and fuel oil.

The electricity produced and the heat released can often be used for the oil production process. In each case, the (variation in) quality of the fuel and the price are important topics in the decision process for cogeneration. Fuel price stability, preferably achieved via long-term contract, helps very much to establish an economically viable life of a cogeneration installation.

12.2 Integration of cogeneration in heat supply systems

The actual design and building process of a cogeneration system requires special skills, especially when considering the layout and characteristics of the heat using system. In case of multiple heat users connected to a cogeneration installation, the characteristics of the hydraulic system will vary depending on the demand of the individual users. Even well designed and simulated systems need a proper fine-tuning after the integration of a cogeneration system. Manually adjustable flow restrictions and control-system operated variable valves are required to ensure an adequate and stable application of the cogeneration installation. The control unit often has to include multidimensional systems to handle the differences in system time constants and delay times depending on heat demand. Also the in-parallel operation of multiple cogeneration units and boilers requires much control attention. Improperly tuned system can easily result in system instability and undesired intermittent operation. This chapter can only give a general overview of some of the aspects, since complete books can be written about the static and dynamic behaviour of complex heat using systems. National installers' associations have often made available comprehensive manuals explaining all the issues of integration of heat sources and heat users.

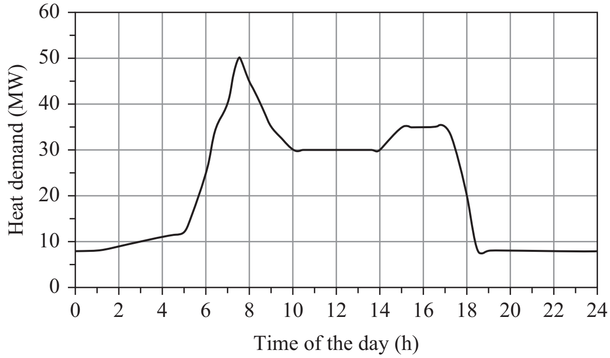

Figure 12.2 An example of a heat demand curve for an office complex

12.2.1 Matching size and demand

Typical heat load duration curves such as in Figure 12.1 do not offer enough information for the matching of a cogeneration installation with demand. The heat demand of a foreseen application might be a total of 600 MWh during 24 h, but that does not mean that the peak load is 600/24 = 25 MW. The half-hourly heat demand pattern of a complex of large office buildings might be as depicted in Figure 12.2, with a peak in the morning just before the working hours start. Cogeneration could then be dimensioned to produce 30 MW of heat from 6 am to 5 pm. The heat demand during the remaining time, as well as the peaks above 30 MW, has to be covered by boilers. However, in case heat storage is available, the cogeneration units might run from 4 am to 8 pm and produce the total heat demand. The heat stored in the buffer is released then during the night and the peak hours.

The heat demand pattern for a greenhouse differs completely from that of an office. The aim is to keep the temperature in a greenhouse constant, which means that most heating is required when there is no sunshine. That is also the time when assimilation lighting is used. Therefore, cogeneration installations in greenhouses make most of their running hours during the night. Greenhouses can also have growth areas in batches. An area that is not used temporarily does not have to be heated and lighted. However, there are also times that the full area is in use. For reasons of output flexibility and redundancy, it is recommended not to serve a greenhouse with a single cogeneration unit. Having a number of units in parallel offers the possibility to run only that number of units that are required to cover the actual load. Running a cogeneration unit at part load is often not economic. Chapter 9 has already shown that having a number of units in parallel substantially increases at least some output availability. Examples are known where a cogeneration user had to buy electricity from the grid and produce heat with boilers for an extended time span due to calamities in case of a single unit. Also the boilers for heating during peak hours or low-load hours should consist of a number of units in parallel. A cascading approach with multiple units in parallel (Figure 12.8) offers many advantages, also during maintenance efforts [2].

12.2.2 Hydraulic integration

Proper hydraulic integration of a cogeneration installation and heating boilers in parallel with the heat using system is crucial to reach a technical and economic optimum [3]. Too many examples are known where the hydraulic integration was neglected resulting in frequent tripping of the cogeneration installation and failure to deliver the required heat. A simple approach such as indicated in Figure 12.3 does not work in general. However, a system that is too complicated does not work either because of the difficulty to control the interaction of the different elements, especially during transients in heat demand (proper arrangements are described in Section 12.2.2.2 and Figure 12.5).

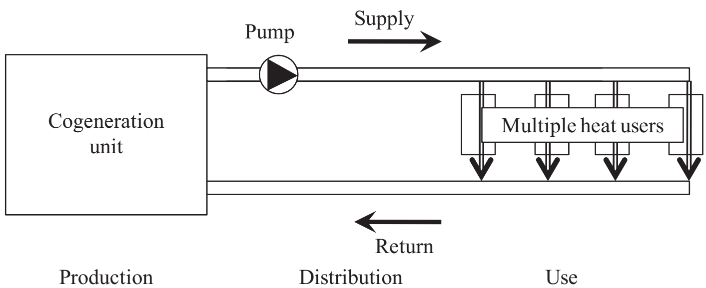

Figure 12.3 Simplistic approach of heat supply with a cogeneration unit

A cogeneration unit might require that certain elements such as the jacket water, the oil cooler and the intercooler of a turbocharged reciprocating engine are kept at their own fixed temperature level. That might be not the case for an exhaust gas heat exchanger. A return temperature that heavily fluctuates can hamper the proper operation of the cogeneration unit(s). Some elements that have to be cooled might therefore require an individually thermostatically controlled hydraulic circuit separated from the heating circuit by means of heat exchangers. Also the fluid that transports the heat might be different. To ensure a long component life, each element in the chain might need its own specifications for the cooling fluid, such as the corrosion inhibitor type, the concentration of minerals and the maximum oxygen content. The heat supply might also have to comply with typical demands such as a fixed supply temperature as in case of sanitary water supply, a fixed supply pressure as in case of steam or a fixed hot water flow for process applications.

One should bear in mind that the heat production of an individual cogeneration unit cannot vary to the same extent as that of a boiler. A modern modulating boiler, industrial, commercial or domestic one, can vary its heat output down to 15 per cent of its nominal value. In most cases, the turn down ratio of the mechanical power output of gas turbines is limited to 70 per cent and that of reciprocating engines to 50 per cent of the nominal output. There are engines on the market that can turn down their electrical output to 10 per cent of the nominal value, but such running is in general not applicable in case of cogeneration. The background is partly economical, since the maintenance cost per kWh produced will increase when lowering the output, and the electrical efficiency will decrease. The other major reason is that a lower electrical efficiency at a lower load results in relatively more heat output, so that it becomes difficult to substantially reduce the heat output by decreasing the electrical output. For a gas-turbine installation, the heat production can generally be controlled between 100 and 80 per cent, while for a reciprocating engine, it is roughly between 100 and 60 per cent. In some cases, it is also difficult to maintain a low emission level in a wide output range of engines and turbines. In case the nominal electrical output of the cogeneration unit is required all the time, ancillary firing upstream of the exhaust gas heat exchanger, boilers in parallel, temporary heat storage and even emergency coolers can be used to vary the heat output of the cogeneration unit. Start–stop operation is another possibility, although some prime mover types suffer substantially from frequent starts and stops. In addition, simply maintaining the temperature of the supplied heat at a fixed value is not easy in case of start–stop operation.

12.2.2.1 The heat recovery circuits of a reciprocating engine

Recovering the heat from a reciprocating engine is more complicated than that of a gas-turbine installation. For a gas turbine, the heat dissipated by the lubricating oil cooler is relatively small so that it is not used most of the time. Next to that, the temperature level of the lubricant heat is much lower than that of the heat recovery unit in the exhaust gas stream. The heat recovery unit in the exhaust stream of a gas turbine is often called the Heat Recovery Steam Generator. In contrast with gas turbines, a turbocharged reciprocating engine-based cogeneration installation can have six different heat sources as shown in Figure 12.4, with different temperature levels.

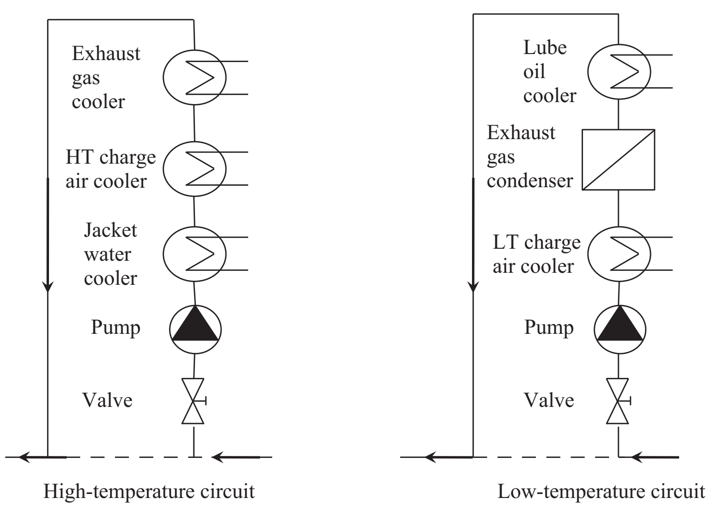

Figure 12.4 The six heat sources of a reciprocating engine divided into a low- and high-temperature circuit

In Figure 12.4, the heat production has been split up in two different circuits: the low-temperature (LT) part with a maximum supply temperature of about 70 °C, and the high-temperature (HT) part with a maximum supply temperature of about 110 °C. The two circuits can also be put in series in case it can be ensured that the maximum return temperature is very low.

The LT charge air cooler has its own control circuit maintaining the temperature of the air that enters the intake receiver of the engine in a narrow low range. A higher intake air receiver temperature results in higher NO_x production, lower knock resistance and lower power output of the engine. If the set value of the air receiver temperature is exceeded, it results in a turning down of the engine power output, or even a trip. In some applications, the LT return temperature from the heat user is always higher than that required for the LT intercooler. In such cases, the LT intercooler heat is rejected via an ambient air heat exchanger. The exhaust gas condenser does not need a temperature control circuit, since the more the exhaust gas temperature can be lowered, the better it is for the fuel efficiency. Therefore, the fluid of the heat supply system can flow directly through the condenser.

Recent cogeneration installations even use a heat pump to lower the temperature of the exhaust gases and thus produce more applicable heat [4]. In cases with a heat sink at a very low temperature, such as soil heating in a greenhouse, the exhaust gas condenser can have its own circuit. The exhaust gas temperature can be lowered to below 25 °C in such cases. The lube oil cooler has its own temperature control circuit, which is generally combined with a filter system that removes undesired particulates from the lube oil stream. The lube oil leaving the cooling circuit has a cooling function for the bearings and the piston crowns. Cooling of the lube oil also results in an acceptable temperature of the oil in the crankcase. Lube oil temperatures locally exceeding about 170 °C can result in evaporation of the lighter components and thus in undesired viscosity increase. Next to that, carbon layers from overheated oil might be created resulting in increased wear and tear.

The HT cooling circuit first passed the jacket water cooler. The jacket water temperature is generally controlled by its own internal circuit to in between 85 and 90 °C. Exceeding that temperature can lead to excessive temperatures of the cylinder liners and thus to lubricating problems. Also cavitation can result, which is damaging especially in the cylinder head area where the intake and exhaust valve seats are located. The next heat source is the HT intercooler for the intake air after compression. The temperature of the compressed air entering this intercooler can be close to 200 °C in case of highly turbocharged engines. Temperature control of the HT intercooler is not crucial, since the LT intercooler ensures that the air that enters the intake receiver gets the proper temperature. The final element of the HT heat sources is the exhaust gas heat exchanger. The goal is to reach the lowest possible exhaust gas temperature so that a cross-flow heat exchanger is generally applied. Also here, the fluid of the heating system can flow directly through the exhaust gas cooler, unless that fluid cannot meet the requirements for the cooling liquid of the heat exchanger.

12.2.2.2 Options for coupling the distribution and the user system

The simplistic approach of connecting the heat users to a cogeneration system as shown in Figure 12.3 does not work in practice [3]. The flow of the distribution system would fully depend on the demand and be blocked if the demand is, temporarily, zero. That would negatively affect the operation of the cogeneration installation. A first solution can be a manually adjustable valve in a bypass at the heat user site to ensure at least a minimum flow (Figure 12.5(a)). An advantage of such a solution is that the bulk of the flow goes via the users, resulting in a relatively low return temperature, which helps to improve the combined fuel efficiency of the cogeneration installation.

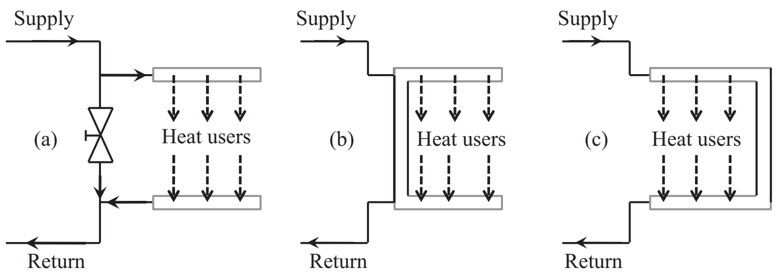

Figure 12.5 Three different configurations for connecting the heat users with the distribution system [2]

A second option is the application of a so-called short circuit or shunt (Figure 12.5(b)) at the user site, where the combined flow is less dependent on the users. If the heat users open up their circuits because of heat demand, part of the flow will go past these users in this case. Adjustable restrictions in the pipes have to ensure that differences in flow restrictions of the heat exchangers can be compensated for. If there is no heat demand, all the supply flow goes via the short circuit, resulting in a return temperature that equals the supply temperature. This is a signal for the cogeneration unit that there is no demand for heat.

A third option (Figure 12.4(c)) closely resembles that of Figure 12.4(b). Here, the interconnection between the supply and the return is at a different location. Also this solution can guarantee a sufficient and close to constant supply flow. For low heat demand, the return temperature to the heat source is high. In case of the so-called mixing approach, the three-way valve is again controlled by the heat user. The flow through the user is constant under all circumstances.

If the heat use is dominated by one large user, such as an absorption cooler, instantaneous switching off of that user will in case of solutions (b) and (c) lead to a sudden plug flow of hot water arriving at the cogeneration installation via the return line. A return temperature of say 95 °C suddenly arriving in the LT-circuit of the cogeneration installation will certainly lead to a trip. Proper design of the heat distribution system is required to avoid that the cogeneration unit is exposed to excessive temperatures.

12.2.2.3 Temperature and flow control arrangements

Figure 12.6 shows three basic simplified measures to control the heat supply to the user. In case of the so-called distribution approach, a three-way valve action is controlled by the heat user, such as with a signal from a room thermostat. In the case of maximum heat demand, all the flow goes via the heat user. In the case of no heat demand, all the flow bypasses the heat user and returns to the heat source or to other users.

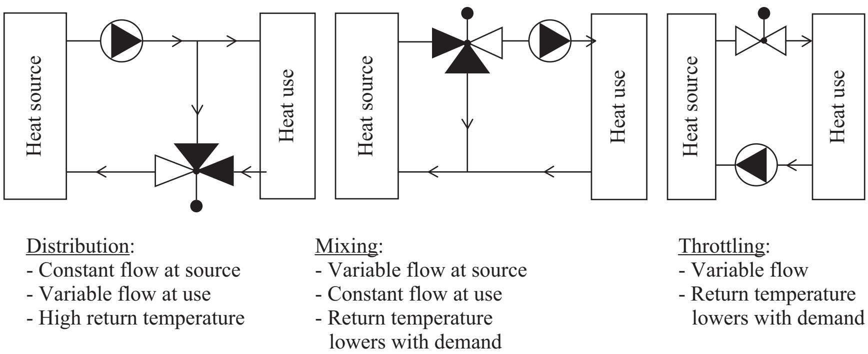

Figure 12.6 Three basic options for controlling the heat distribution to users: distribution, mixing and throttling [1]

In the case of high heat demand, the flow to the user is coming from the heat source and returns fully to the heat source. In the case of low heat demand, the flow at the user site is circulated past the three-way valve. The return flow to the heat source is zero in case of no heat demand. In the case of a low heat demand, the return temperature to the heat source becomes quite low, which is good for the fuel efficiency. For the throttling system, the opening of a control valve is determined by the heat user. The flow varies both at the user side and at the source side. In case of no heat demand, the flow becomes zero. The return temperature will decrease close to linearly with the flow. A better solution to control the flow than a throttle valve is a supply pump with a variable running speed. Such variable-speed pumps are generally applied in heating systems nowadays as part of energy-saving programmes.

Each of the three approaches has its own pros and cons. Practical heating systems can consist of a number of different configurations as depicted in Figure 12.6 in parallel. A sanitary water system might require a constant supply temperature, while a simple heating-only system might require a supply temperature depending on the ambient conditions. As stated earlier, specialist involvement is required for properly matching supply and demand.

12.2.2.4 Cogeneration units operating in parallel with boilers

The heat demand at many applications depends on the weather and the time of the day, as has been discussed in Section 12.2.1. At times of a low heat demand, it can be uneconomic to use the cogeneration installation. Too frequently switching the

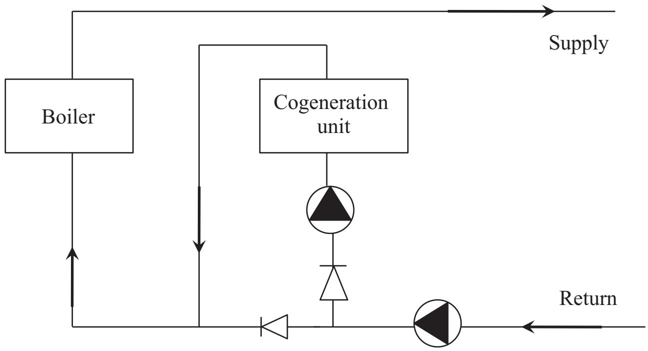

Figure 12.7 A simple configuration of a cogenerating unit and boiler in series [5]

cogen unit on and off should be avoided. A boiler with a variable heat output can then produce the required heat. A possible configuration for this is shown in Figure 12.7. In this case, the return-water feed pump of the cogen unit is switched off in case of very low heat demand. When the heat demand increases, the cogen unit can be switched on while the boiler is switched off. The hot water stream still passes the boiler in this case, which leads to some heat losses via the chimney of the boiler. Closing a valve in the exhaust duct of the boiler will solve this problem to a large extent. In case of a heat demand higher than what the cogen unit itself can produce, the boiler will add additional heat to the water flow. An issue of this solution is that the boiler will receive a relatively high return temperature in case of high heat demand, so that the efficiency of the boiler is negatively affected: condensation can no longer occur.

Much attention has to be given to optimising the control strategy. If the combined heat output of this configuration is controlled by keeping the supply temperature constant, too much heat input from the boiler can increase the temperature of the return line to a value that is too high for the cogen unit. Another option is to measure the heat demand with a flow meter and two temperature sensors, one in the supply line and one in the return line. The product of the temperature difference and the flow is a measure of the heat demand, which can be used for control optimisation. In case of a heating circuit with relatively little water content, the inertia of the heating system will be small resulting in unstable operation when the heat demand fluctuates rapidly.

A configuration where the boilers always receive the lowest possible return temperature is depicted in Figure 12.8. The number of units in parallel can be optimised for the typical application. Here, the cogeneration unit runs in parallel with the boilers. Such a set-up is often called a cascading system, since the amount of running units depends on the heat demand. This solution avoids too much running of individual units on part load; part load is often negative for the fuel efficiency and for the maintenance costs. Such a modular build-up of a series of standard mass-produced smaller boilers is often much cheaper to install than a special large dedicated boiler. It also creates redundancy. Maintenance can be

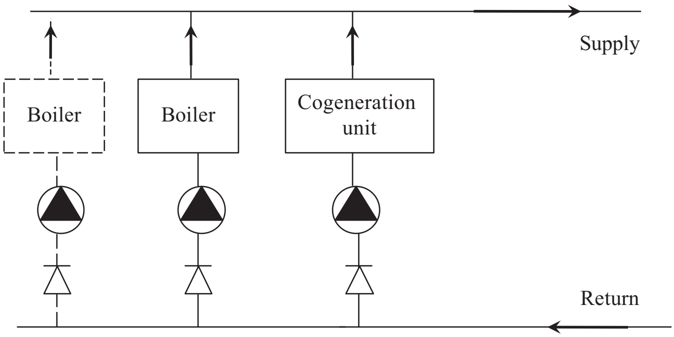

Figure 12.8 A so-called cascading system with the cogen unit and boilers in parallel

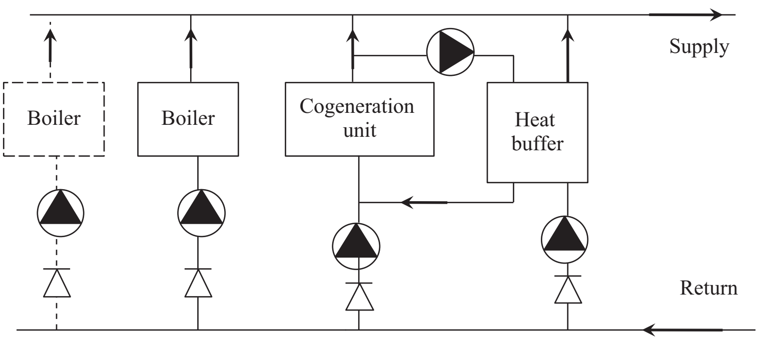

Figure 12.9 The insertion of a heat storage buffer to create a more stable operation of the cogeneration unit [5]

carried out on one unit, while the others remain available. The same applies to some extent for the cogeneration installation, as discussed earlier. However, the advantage of a large boiler is its relatively high water content, which tends to stabilise the heating system, since it acts as a buffer. Again, a proper control strategy is required here to ensure that the boilers do not push the cogen unit out of operation. In addition, a heat distribution system with little water content will easily lead to frequent switching on and off of the heat sources. This is not a problem for the boilers, but the cogen unit needs more stability.

A heat buffer in combination with a cogeneration installation helps to create a more stable operation with less frequent switching on and off of the cogeneration installation as well as the boilers. An example of the integration of such a buffer is shown in Figure 12.9. Multiple different configurations are however possible. In case the boilers have already been switched off due to less than maximum heat demand and even less heat is required than the minimum production of the cogeneration unit, heat from the cogen unit can be stored in the buffer. When the buffer is fully charged, the cogeneration unit can stop. The remaining heat demand can then be covered for a while by the buffer. Large buffers can also help to enable electricity production during times when there is hardly any heat demand. This can be very economic during peak hours in public electricity use. Large water-based buffers are available nowadays, with storage capacities in district heating systems of up to 100,000 m^3. Such a large system can store about 14 TJ for a temperature difference of 35 K, that is heating up from 60 to 95 °C. Such a large buffer can release 400 MW of heat during 10 h. Storage tanks for domestic, commercial and agricultural cogeneration applications are also available. Their sizes range generally from 500 l to 5,000 m^3.

In some applications, it can occur that the cogeneration unit has to produce electricity while there is hardly any heat demand and any installed buffers are fully loaded. In such cases, an emergency cooler is installed that can dissipate the produced heat to the ambient air. Such a situation is no longer cogeneration, but it might be profitable in case of high electricity prices and necessary in case of emergency operation, for example hospitals. Permanent heat-dissipation coolers are required when the return temperature exceeds the maximum temperature allowed for the low-temperature intercooler of reciprocating engines. The loss in combined fuel efficiency is then limited. As mentioned earlier, the availability of industrial-size heat pumps can help in lowering the return temperature upstream of the cogeneration installation and transform the heat to a higher temperature heat suitable for utilisation.

12.3 Summary of possible integration problems

This section will highlight a series of common problems experienced during integration of cogeneration systems. Even after extensive design efforts and simulations, problems do occur at the implementation stage or during occasional unusual situations at the user side, sometimes caused by human error. An interesting summary of such situations, including solutions, is found in [1], which is unfortunately only available in Dutch. The lack of much international literature on the subject is caused by the fact that most problems occurring are typically solved by plumbing engineering rather than by a scientific approach. Much knowledge exists at dedicated installers of combined heat and power (CHP), but such organisations do not often publish their results.

The return flow to a cogeneration installation might reach such low values that the internal circuits for intercooling, lube oil cooling and jacket water cooling cannot reject their heat anymore resulting in a trip. Solutions can be a minimum flow sensor in the return flow that signals to the cogeneration installation that it has to stop. The application of a heat buffer, to which the flow past the coolers can be diverted, also helps. Too high a return temperature can occur at part load in case solely distribution type control systems are used (Figure 12.6). Conversion (partly) to a single-path system with a variable speed pump can solve the problem, but care should be taken that the flow does not reach too low values. Also too large shunts in the system to guarantee a minimum flow can lead to high return temperatures.

The control system might not have the proper strategy to arrange for the optimum combined action of the cogeneration unit and the in parallel or in series boilers. A simple arrangement based on the measured supply or return temperature is often inadequate. Measurement of the actual heat demand will provide the necessary information in such cases.

The water content of the supply circuit might be too small to guarantee a stable operation. Limited water content is on the one hand facilitating a quick response to changes. On the other hand, it also introduces a high sensitivity to sudden changes in heat demand that will lead to instable operation of the cogeneration installations and the boilers.

The distribution of the heat over the different user sections can also be inadequate due to lack of adjustable flow restrictions to optimise the flow over the different user sections. For systems with much variability in heat consumption between the users, it might even be necessary to install computer-controlled valves in certain sections.

Insufficient heat exchanger area at the heat user site to comply with the peak heat demand during cold spells results in the requirement of excessively high supply temperatures. Such high temperatures can exceed the value allowed for the cogeneration installation. The obvious solution is to increase the heat exchange area at the user site.

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Further Reading

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Chapter 13

Simulation and optimisation of synthesis, design and operation of cogeneration systems

Christos A. Frangopoulos

13.1 Introduction to simulation and optimisation of cogeneration systems

In Chapters 7, 8 and 10, indexes have been defined and procedures have been described for evaluation of cogeneration systems from the point of view of thermodynamic, environmental and economic performance, respectively. In order to perform this evaluation, there is need either to measure or to compute certain operating parameters such as electrical, mechanical and thermal energy produced, pollutants emitted, fuel consumption and various costs in a certain period of time. In order to compute these parameters, there is need to construct the simulation model of the system, which consists of a set of equations that describe the performance of the system by mathematical terms.

The simulation model is also a prerequisite for optimisation of the system, that is for determining the best structure, nominal (design) specifications and operating point of the system at each instant of time, taking into consideration the technical and economic conditions prevailing at this instant.

The development of simulation models and the optimisation of the synthesis (structure), design and operation of cogeneration systems are the subjects of this chapter.

13.2 Development of simulation models

Even in existing systems, it is not always easy or practical to measure every operating parameter needed, in order to calculate the performance indexes [efficiencies, primary energy savings, emission of pollutants, net present values (NPVs), etc.] of a system. Then, there is need to calculate these parameters; of course, this is unavoidable, for example, at the design stage of a system. In order to perform these calculations, a mathematical model of the system is constructed, which consists of data, rules, inferences and equations. It is worth noting that the 'system' may include not only the cogeneration equipment, but also the facility served by cogeneration. This is the case, for example, when cogenerated heat is supplied to a building, the thermal needs of which depend on the weather conditions changing with time.

The model can be simple, assuming, for example, steady-state operation of the system at nominal conditions (design point). This is the case, for example, with the treatment presented in [1], where a cogeneration system consisting of a regenerative gas turbine and a single-pressure exhaust gas boiler operating continuously at the nominal load is studied. The model consists of 21 technical equations derived by an analysis of the system using thermodynamics and heat transfer, and six economic equations, that is equations that give capital and operating expenses as functions of design and operation characteristics of the system. This simulation model consisting of 27 equations is used for both technical and economic performance evaluation, as well as optimisation of the system [1].[1]

However in the real world, cogeneration systems operate under diverse conditions changing with time (load factors, pressures and temperatures of fluids, environmental temperature, cost of fuel, etc.). Simple models, like the aforementioned, may produce unrealistic results, which give a wrong impression about the system performance. A hint is given by Example 7.2, in Chapter 7. Therefore, for more reliable results, more elaborate models are needed, which give the performance of a system as function of the conditions prevailing at a certain instant of time (load factor, environmental conditions, etc.). In developing these models, information given by the manufacturers of particular equipment in the form of tables or graphs can be used with regression analysis in order to develop analytic equations, which are incorporated in the model of the system. The related literature is rich; only few examples are given by [2–9].

The complete simulation model can be developed by the user [1–5]. Alternatively, commercially available software containing simulation models of at least some of the system components can be used in order to build the simulation model of the complete system [6–9].

The simulation models can be distinguished in two broad categories: (i) static models, appropriate for steady-state operation, and (ii) dynamic models, appropriate for conditions changing with time, including transients (e.g. load increase or decrease). For performance evaluation in long time intervals, for example 1 month or 1 year, it can be considered that the transients take very small part of the whole period and consequently they can be ignored. In such a case, it can be considered that the whole period of operation consists of time intervals with conditions that are different among the intervals, but steady-state operation applies in each interval. Then, static models can be applied. If, however, the question how the system responds to changing conditions is to be answered, or if the system contains storage of thermal or electric energy, which can be charged or discharged, then the use of a dynamic models is necessary [7–10]. These issues will be further clarified with examples in the following sections.

[1]Space limitations do not allow to transfer in this chapter all the details of the examples mentioned. It is hoped that the readers can find the publications of interest.

13.3 Performance evaluation of cogeneration systems

The technical, environmental and economic performance of a cogeneration system, either existing or under study, is evaluated by means of indexes such as those defined in Chapters 7, 8 and 10, respectively, which are repeated here for convenience.

Technical indexes:

- Electrical, thermal and total efficiency based on energy or exergy.
- Power-to-heat ratio (PHR)
- Primary energy savings ratio (PESR)
- Cogenerated electricity (or work, in more general terms).

Environmental indexes:

- Balance of greenhouse gas emissions
- Balance of pollutants.

Economic indexes:

- Net present value of the investment (NPV)
- Net present cost (NPC)
- Present worth cost (PWC)
- Internal rate of return (IRR)
- Discounted payback period (DPB)
- Benefit-to-cost ratio (BCR).

In order to calculate these indexes, there is need to measure or estimate operation parameters such as the following (in addition to first cost of the system):

- Power output of the cogeneration system
- Power used on site
- Power sold to or purchased from the grid
- Thermal energy supplied by the cogeneration system
- Fuel consumption of the cogeneration system
- Fuel consumption for the separate production of the cogenerated electricity and heat
- Fuel consumption by boilers for supplementary heat
- Quantities of emitted greenhouse gases and pollutants
- Cost of fuel
- Cost of purchased electricity
- Revenue from electricity sold to the grid
- Operation and maintenance cost.

Each parameter can be determined for any instant of time, but integration over time to give results per hour, month and year or for the whole life of the system are also important, if not necessary. The simulation model mentioned in the preceding section, either alone or in conjunction with measurements, will help in producing the results.

Practically, the expression ‘for any instant of time’ can be interpreted ‘for each one of the 8,760 hours of the year’. If it is not possible (or, for any reason, not necessary) to obtain this detailed information, then various levels of approximation can be decided, as for example, calculations based on (i) one typical 24-h day per season, (ii) one typical 24-h day per month, (iii) two typical 24-h days per season (weekday, weekend), (iv) two typical 24-h days per month (weekday, weekend) and others. Of course, the more coarse the time interval is, the less accurate the results are.

Performance evaluation (either alone or in combination with optimisation) of alternative systems for a particular application at the stage of feasibility study is necessary in order to select the most appropriate system, which then will be studied in detail and optimised properly.

13.4 Mathematical optimisation of cogeneration systems

13.4.1 Definition of optimisation

In mathematical optimisation, a goal called *objective function* is specified and is expressed as a mathematical function of certain variables. Then, optimisation can be defined as follows:

> *Optimisation is the act of obtaining the best result under given circumstances or, expressed more formally, the process of finding the conditions, that is the values of variables, that give the minimum (or maximum) of the objective function under specified constraints.*

In the literature on energy systems, the word *optimisation* is often used, even in cases where the attempt is not to find the minimum (or maximum) of a figure of merit, but only to find a better (lower or higher) value. In these cases, the proper word is *improvement* and not *optimisation*.

13.4.2 The need and importance of optimisation in cogeneration

A cogeneration system is requested to supply a facility, the *user*, with electrical and/or mechanical and thermal energy, perhaps at various pressure and temperature levels. In a conventional design procedure, the aim is to reach a *workable* system, that is a system that performs the assigned tasks under the imposed constraints. However, under the pressure of scarcity of physical and economic resources and of the deterioration of the environment, having just a *workable* system is not satisfactory. What is needed is the *best* system. Thus, given the energy needs of the user, questions such as the following can be posed:

- What is the best type of cogeneration system to be used?
- Should the system consist of one cogeneration unit or of a combination of units?

- What is the best configuration (components and their interconnections) of each unit?
- What are the best technical characteristics of each component and, consequently, of the whole unit (capacity, material, dimensions, etc.)?
- What are the best flow rates, pressures and temperatures of the various working fluids?
- What is the best operating point of the system at each instant of time?

Hidden in the preceding questions are questions such as the following:

- Should the system be capable of covering exactly the needs of the user or a two-way connection to the grid should be installed for selling excess electricity or purchasing additional electricity, if needed?
- Should the system operate at electricity match, heat match or another mode at a certain instant of time?

Let it be mentioned that many of the aforementioned questions are interrelated. For example, selling excess electricity or purchasing additional electricity depends on the capacity (nominal power output) of the system.

The innumerable combinations of types of systems, specifications of components and possible operating modes, make it impossible for the designer to evaluate every combination and select the best one. Also, for the operator of an existing system it can be impossible to evaluate all the alternative modes of operation, in particular if the loads can be covered by various combinations of operating components, and select the best one. Therefore, mathematical optimisation can be applied, which will reveal the best (under certain criteria and constraints) design and the best operational point of the system automatically, with no need for the designer to study and evaluate one by one the multitude of possible alternatives.

Application of optimisation has additional positive side effects, such as the following:

- It saves time and increases the designer's creativity.
- It increases the quality of the energy services while reducing costs, thus increasing the competitiveness.
- It increases safety and reliability.
- It helps in observing strict pollution regulations, and saving energy and material resources.

13.4.3 Levels of optimisation

The questions posed in Section 13.4.2 reveal that optimisation of a cogeneration system can be considered at three levels (Figure 13.1):

A. *Synthesis optimisation.* The term 'synthesis' implies the components appearing in a system and their interconnections. The synthesis (called also *structure*) of a system is usually depicted by the flow diagram of the system.
B. *Design optimisation.* The word 'design' here is used to imply the technical characteristics (specifications) of the components and the properties of the

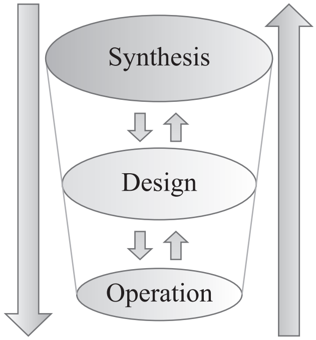

Figure 13.1 The three inter-related levels of optimisation

substances entering and exiting each component at the nominal load of the system. The nominal load is usually called the 'design point' of the system. One may argue that design includes synthesis too. However it is convenient to distinguish the three levels of optimisation, and this is why the word 'design' will be used to identify this level, whereas the synthesis is considered a distinct level.

C. *Operation optimisation.* For a given system (i.e. a system with specified synthesis and design) under specified conditions, the optimal operating point is requested, as it is defined by the operating properties of components and substances in the system (speed of revolution, power output, mass flow rates, pressures, temperatures, composition of fluids, etc.) at a certain instant of time.

Of course if complete optimisation is the goal, each level cannot be considered in isolation from the others. Consequently, the complete optimisation problem can be stated by the following question:

> *What is the synthesis of the system, the design characteristics of the components and the operating strategy that lead to an overall optimum?*

13.4.4 The role of time in optimisation of cogeneration systems

During its lifetime, a cogeneration system operates under various internal and/or external conditions. Optimisation at one set of conditions only (e.g. 'design' or 'nominal' point) does not lead, in general, to the best value of the objective function integrated over the whole life of the system. Therefore, intertemporal optimisation is needed, which can be described as follows:

> *Intertemporal optimisation is the optimisation that takes into consideration the various operating conditions that a system encounters throughout its life time and determines the mode of operation at each instant of time that results in the overall minimum or maximum of the general objective function.*

Optimisation problems can be characterised as *static* or *dynamic*. In static optimisation problems, the values of variables are requested that give minimum or maximum to an objective function. In dynamic optimisation problems, the variables, the functions and the parameters may be time dependent; thus, the variables as functions of time are requested that give minimum or maximum to an objective function. Two definitions from the literature are copied here for clarity:

> *Dynamic optimisation problems (DOP's) are those whose specifications change over time during the optimisation procedure, thus resulting in the change over time of the global optimum values of the independent variables* [11].
>
> *Dynamic optimisation is the process of determining control and state histories for a dynamic system over a finite time period to minimize a performance index* [12].

The expression 'to minimise a performance index' is not restrictive, since the maximum of a function coincides with the minimum of the negative of the same function.

Combining the aforementioned definitions, it could be said that, if the various modes of operation are independent of each other, that is, no mode affects or is affected by any other mode, then an intertemporal static optimisation is at hand. If, however, there is a direct or indirect interdependency among modes (as is the case, e.g., of a cogeneration system with energy storage), then intertemporal dynamic optimisation is needed.

13.4.5 Formulation and solution methods of the static optimisation problem

13.4.5.1 Mathematical statement of the static optimisation problem

The general optimisation problem is usually stated mathematically as follows [13–15]:

$$\underset{\mathbf{x}}{\text{minimise}}\ \ f(\mathbf{x}) \tag{13.1}$$

with respect to $\quad \mathbf{x} = (x_1, x_2, \ldots, x_n)$ (13.2)

subject to the constraints

$$h_i(\mathbf{x}) = 0 \quad i = 1, 2, \ldots, m \tag{13.3}$$

$$g_j(\mathbf{x}) \leq 0 \quad j = 1, 2, \ldots, p \tag{13.4}$$

where $\mathbf{x}$ is the set of all the independent variables, h_i are the equality constraint functions ('strong' constraints), which constitute the simulation model of the system and are derived by an analysis of the system (energetic, exergetic, economic, etc.), g_j is the inequality constraint functions ('weak' constraints) corresponding to design and operation limits, safety requirements, state regulations and others.

For cogeneration system optimisation, in particular, it is often helpful to arrange the independent variables into three sets:

$$\mathbf{x} \equiv (\mathbf{v}, \mathbf{w}, \mathbf{z}) \tag{13.5}$$

where **v** is the set of independent variables for operation optimisation (load factors of components, mass flow rates, pressures and temperatures of streams, etc.), **w** is the set of independent variables for design optimisation (nominal capacities of components, mass flow rates, pressures and temperatures of streams, etc.), **z** is the set of independent variables for synthesis optimisation; there is only one variable of this type for each component, indicating whether the component exists in the optimal configuration or not; it may be a binary (0 or 1), an integer, or a continuous variable such as the rated power of a component, with a zero value indicating the non-existence of a component in the final configuration.

Then, (13.1) is written as

$$\underset{\mathbf{v},\mathbf{w},\mathbf{z}}{\text{minimise}}\ f(\mathbf{v}, \mathbf{w}, \mathbf{z}) \tag{13.6}$$

For a given synthesis (structure) of the system, that is for given **z**, the problem becomes one of design and operation optimisation:

$$\underset{\mathbf{v},\mathbf{w}}{\text{minimise}}\ f_d(\mathbf{v}, \mathbf{w}) \tag{13.7}$$

Furthermore, if the system is completely specified (both **z** and **w** are given), then an operation optimisation problem is formulated:

$$\underset{\mathbf{v}}{\text{minimise}}\ f_{op}(\mathbf{v}) \tag{13.8}$$

Maximisation is also covered by (13.1), since

$$\min_{\mathbf{x}} f(\mathbf{x}) = \max_{\mathbf{x}}\{-f(\mathbf{x})\} \tag{13.9}$$

13.4.5.2 Objective functions

The decision regarding which criterion is to be optimised is of crucial importance. Objective function for a cogeneration system can be the maximisation of efficiency, minimisation of fuel consumption, maximisation of the primary energy savings, minimisation of emitted pollutants, maximisation of the NPV, minimisation of the PWC, maximisation of the IRR, minimisation of the payback period and others.

In a complex world, a single objective may result in a system that does not satisfy other requirements. Consequently, the final design may deviate from, for example, the least cost one, in order to take environmental, social, aesthetic or other aspects into consideration. Methods have been developed under the name 'multi-objective optimisation', which attempt to take two or more objectives into consideration simultaneously [16,17]. The optimum point they reach does not satisfy each objective in isolation, but it corresponds to a compromise, often subjective, of the various objectives. Multi-objective optimisation can also be written in the form of (13.1), but only if the various objectives are combined into one objective function by means of weighting factors.

13.4.5.3 Independent variables

Each component and the system as a whole is specified by a set of quantities. Certain of those are fixed by external conditions (e.g. environmental pressure and temperature, fuel price) and are called *parameters*. The remaining are *variables*, that is their value may change during the optimisation procedure. Those variables, the values of which do not depend on other variables or parameters, are called *independent variables*. The rest can be determined by the solution of the system of equality constraints, and they are called *dependent variables*. The number of dependent variables is equal to the number of equality constraints. Thus, the task of the optimisation procedure is to determine the values of the independent variables $\mathbf{x}$. Of course, if the number of equality constraints is higher than the number of all the variables, then the problem is over-specified, and there is no room for optimisation.

13.4.5.4 Equality and inequality constraints

The functions appearing in (13.3) and (13.4) are expressions involving design characteristics and operating parameters or variables of the components as well as the system as a whole. For example, the required mass flow rate of steam in a steam turbine is given as a function of the power output and the properties of steam at the inlet and outlet of the turbine. On the other hand, the safety and operability of the system impose inequality constraints such as the following: speed of revolution not higher than a certain limit; quality (dryness) of steam at the exit of the steam turbine not lower than a certain limit and others. The set of equality and inequality constraints is derived by an analysis of the system and constitutes the mathematical model of the system (Section 13.2).

A word of caution: Describing reality by mathematics is not an easy task, and it is often accompanied by simplifying assumptions, which introduce inaccuracies. This is mentioned not in order to deter one from applying modelling and optimisation techniques, but to make it clear that the solution (synthesis, design or operation point) reached is optimal only under the assumptions made in modelling the system; and it is as close to the real optimum as any discrepancies between model and reality allow. However, most probably, if care has been exercised, it is closer than a decision based only on past experience or similar preceding designs.

13.4.5.5 Methods for solution of the static optimisation problem

In spite of their apparent generality, there is no single method available for solving efficiently all the optimisation problems stated by (13.1)–(13.4). Several methods have been developed for solving different types of optimisation problems. They are known as *mathematical programming methods*, and they are usually available in the form of mathematical programming algorithms. They can be classified into three broad categories:

1. *Search methods:* They calculate the values of the objective function at a number of combinations of values of the independent variables and seek for the optimum point. They do not use derivatives. The search may be random or systematic, the second one usually being more efficient.
2. *Calculus methods:* They use first and (some of them) second derivatives; this is why they are also called *gradient methods*. In general, gradient methods converge faster than the search methods, but in certain cases they may not converge at all.
3. *Stochastic or evolutionary methods:* Methods and algorithms such as genetic algorithms (GA), simulating annealing, particle swarm optimisation, neural networks belong to this category. Even though some of those are in fact search methods, they are usually placed in a separate category [18–23].

If the objective function is continuous, by applying a search method the exact optimum can only be approached, not reached, by a finite number of trials, because only discrete points are examined. However, the region, in which the optimum point is located, can be reduced to a satisfactorily small size at the end of the procedure. On the other hand, there are problems for which search methods may be superior to calculus methods, as for example in optimisation of systems with components available only in finite, discrete sizes.

Two of the most successful methods for optimisation of energy systems, including cogeneration systems, are the *generalised reduced gradient* (*GRG*) and the *sequential quadratic programming* (*SQP*) method [13,14]. A combination of a stochastic algorithm (genetic or particle swarm algorithm) with a deterministic algorithm (GRG or SQP) has been also successful in energy systems optimisation. The first one performs a coarse search of the feasible space and locates a number of possible optimum points, whereas the second one locates the exact optimum point [4,24].

13.4.5.6 Decomposition

If an optimisation problem is of separable form, that is, if it can be written in the form

$$\min_{\mathbf{x}} f(\mathbf{x}) = \sum_{k=1}^{K} f_k(\mathbf{x}_k) \tag{13.10a}$$

subject to

$$\mathbf{h}_k(\mathbf{x}_k) = 0 \quad k = 1, 2, \ldots, K \tag{13.10b}$$

$$\mathbf{g}_k(\mathbf{x}_k) \leq 0 \quad k = 1, 2, \ldots, K \tag{13.10c}$$

where the set $\mathbf{x}$ of the independent variables is partitioned into K disjoint sets,

$$\mathbf{x} = \mathbf{x}_1, \mathbf{x}_2, \ldots, \mathbf{x}_k, \ldots, \mathbf{x}_K \tag{13.11}$$

then the problem can be decomposed into K separate subproblems:

$$\min_{\mathbf{x}_k} f_k(\mathbf{x}_k) \tag{13.12a}$$

subject to

$$\mathbf{h}_k(\mathbf{x}_k) = 0 \tag{13.12b}$$

$$\mathbf{g}_k(\mathbf{x}_k) \leq 0 \tag{13.12c}$$

Each subproblem is solved independently from the other subproblems, and the solution thus obtained is the solution of the initial problem too. As each subproblem has a smaller number of independent variables and constraints than the whole problem, its solution is much easier; this is the main reason for applying decomposition.

The main application is the decomposition of a system into subsystems (or components), in which case f_k and $\mathbf{x}_k$ are the objective function and the set of the independent variables for the kth subsystem (or component). Another application of decomposition is in operation optimisation over a number of independent time intervals (if it can be assumed that the operation in a time interval does not affect the operation in other time intervals, Section 13.4.4).

13.4.5.7 Multi-level optimisation

The synthesis–design–operation optimisation of complex systems under time-varying operating conditions involves a large number of variables and constraints. If the available optimisation algorithm(s) cannot handle the whole optimisation problem successfully in a single step (single level), then multi-level optimisation may help.

In multi-level optimisation, the problem is reformulated as a set of subproblems and a coordination problem, which preserves the coupling among the subproblems. Multi-level optimisation can be combined with decomposition either of the system into subsystems or of the whole period of operation into a series of time intervals or both [25–28].

As an example, let the synthesis–design–operation optimisation of a cogeneration system be considered. The overall objective function can be written (constraints are not written here, for brevity) as

$$\min_{\mathbf{x},\mathbf{z}} f(\mathbf{x}, \mathbf{z}) \tag{13.13}$$

where $\mathbf{x}$ is the set of independent variables for operation, $\mathbf{z}$ is the set of independent variables for synthesis and design (it specifies existence of components and the design characteristics of components and of the system as a whole).

It is also considered that the period of operation consists of K time intervals independent of each other, the set $\mathbf{x}$ can be partitioned into K disjoint sets (13.11) and an objective function can be defined for each time interval

$$\min_{\mathbf{x}_k} \phi_k(\mathbf{x}_k) \tag{13.14}$$

The overall objective function f depends on ϕ_ks, without necessarily being a simple summation of these. Then, the optimisation problem is reformulated as a two-level problem, as follows.

First-level problem (operation optimisation)
For a fixed set **z***,
Find $\mathbf{x}_k^*$ that minimises $\phi_k(\mathbf{x}_k, \mathbf{z}^*)$, $k = 1, 2, \ldots, K$.

Second-level problem (synthesis and design optimisation)
It is stated as follows:
Find a new **z*** which minimises $f(\mathbf{x}^*, \mathbf{z})$, where **x*** is the optimal solution of the first-level problem.

The procedure is repeated until convergence is achieved. The iterative steps are the following (the roman numbers I and II indicate the first- and second-level problem, respectively).

II.1. Select an initial set of values $\mathbf{z}^{\mathrm{o}}$ for $\mathbf{z}$.
- I. Solve the K first-level optimisation problems. For the first problem ($k = 1$):
  - I.1 Select an initial set of values $\mathbf{x}_1^{\mathrm{o}}$ for $\mathbf{x}_1$.
  - I.2 Call the first-level optimisation algorithm to solve the problem stated by (13.14) for $k = 1$. The solution gives the optimum set $\mathbf{x}_1^*$.

  Repeat steps I.1 and I.2 for $k = 2, 3, \ldots, K$. Thus, the optimum vector **x*** is obtained.

II.2. Use the results of first-level to evaluate the overall objective f, and check for convergence (i.e. whether the optimality criteria are satisfied). If convergence has not been reached, select a new set of **z** and go to step I.1.

Steps II.1 and II.2 are in fact performed by the second-level optimisation algorithm.

In practice, it has been often successful to use a genetic algorithm for the second-level and a nonlinear programming algorithm (e.g. GRG or SQP) for the first-level optimisation problem.

13.4.6 Formulation and solution methods of the dynamic optimisation problem

13.4.6.1 Mathematical statement of the dynamic optimisation problem

The dynamic optimisation problem can be formulated using a differential-algebraic equation (DAE) formulation. The DAE system consists of differential equations that describe the behaviour of the system, such as mass and energy balances, and algebraic constraints that ensure thermodynamic consistency or other physically meaningful relations-limits imposed on the problem. A general DAE optimisation problem can be stated in implicit form as follows [29–32]:

$$\underset{\mathbf{z}(t),\mathbf{y}(t),\mathbf{u}(t),t_f,\mathbf{w}}{\text{minimise}} \quad J\left[\mathbf{z}(t_f),\mathbf{y}(t_f),\mathbf{u}(t_f),t_f,\mathbf{w}\right] \tag{13.15}$$

subject to

$$\mathbf{H}[\dot{\mathbf{z}}(t),\mathbf{z}(t),\mathbf{y}(t),\mathbf{u}(t),t,\mathbf{w}] = 0 \tag{13.16}$$

$$\mathbf{G}[\dot{\mathbf{z}}(t),\mathbf{z}(t),\mathbf{y}(t),\mathbf{u}(t),t,\mathbf{w}] \leq 0 \tag{13.17}$$

with initial conditions

$$\mathbf{z}(0) = \mathbf{z}^0 \tag{13.18}$$

point conditions

$$\mathbf{P}_s[\mathbf{z}(t_s),\mathbf{y}(t_s),\mathbf{u}(t_s),t_s,\mathbf{w}] = 0, \quad t_s \in \left[t_0,t_f\right] \tag{13.19}$$

and bounds

$$\mathbf{z}^L \leq \mathbf{z}(t) \leq \mathbf{z}^U \tag{13.20a}$$

$$\mathbf{y}^L \leq \mathbf{y}(t) \leq \mathbf{y}^U \tag{13.20b}$$

$$\mathbf{u}^L \leq \mathbf{u}(t) \leq \mathbf{u}^U \tag{13.20c}$$

$$\mathbf{w}^L \leq \mathbf{w} \leq \mathbf{w}^U \tag{13.20d}$$

$$t_f{}^L \leq t_f \leq t_f{}^U \tag{13.20e}$$

where J is the scalar objective functional, $\mathbf{H}$ is the differential-algebraic equality constraints, $\mathbf{G}$ is the differential-algebraic inequality constraints, $\mathbf{P}_s$ is the additional point conditions at times t_s (including t_f), $\mathbf{z}$ is the differential state profile vector, $\mathbf{z}^0$ is the initial values of $\mathbf{z}(t)$, $\mathbf{y}$ is the algebraic state profile vector, $\mathbf{u}$ is the control (independent variables) profile vector, $\mathbf{w}$ is the time-independent variables vector, t_f is the final time.

The scalar functional J that represents the objective function of the optimisation problem can have various forms. A general form for continuous time commonly used in optimisation of energy systems is the one known as Bolza form

$$J\left[\mathbf{z}(t_f),\mathbf{y}(t_f),\mathbf{u}(t_f),t_f,\mathbf{w}\right] = Q\left[\mathbf{z}(t_f),\mathbf{y}(t_f),t_f,\mathbf{w}\right] + \int_{t_0}^{t_f} F[\mathbf{z}(t),\mathbf{y}(t),\mathbf{u}(t),t,\mathbf{w}]dt \tag{13.21}$$

that consists of the function Q at the end of the time interval t_f and the integral of the function F over the time horizon.

If an optimisation problem in discrete time is at hand, then the mathematical statement takes a discrete form, as follows. The time period $[t_0, t_f]$ is divided into N time intervals of length Δt_n, so that $t_f - t_0 = N \cdot \Delta t_n$ and the integral in (13.21) is replaced by a summation over the N time intervals, whereas the variables are discrete vector sequences [e.g. $\mathbf{u} = \{\mathbf{u}_1, \mathbf{u}_2, \ldots, \mathbf{u}_N\}$]. The discrete problem then is stated as follows:

$$\underset{\mathbf{z},\mathbf{y},\mathbf{u},t_f,\mathbf{w}}{\text{minimise}}\ J\big(\mathbf{z},\mathbf{y},\mathbf{u},t_f,\mathbf{w}\big) = Q(\mathbf{z}_N,\mathbf{y}_N,N,\mathbf{w}) + \sum_{n=1}^{N} F(\mathbf{z}_n,\mathbf{y}_n,\mathbf{u}_n,n,\mathbf{w}) \tag{13.22}$$

subject to constraints appropriately written for each time interval.

The crucial feature of this formulation is that the objective function, as it is stated by (13.22), is additively separable across time, which enables the use of optimal control theory or dynamic programming (DP) to solve the problem.

The explanations written in the preceding about the objective functions, the independent variables and the constraints of the static optimisation problems are more or less applicable to the dynamic optimisation problems too.

13.4.6.2 Methods for solution of the dynamic optimisation problem

Indirect methods

Indirect methods include the calculus of variations (COV) and DP.

COV was introduced and developed in the 1960s [33,34]. With COV, the problem is approached via variational methods and the Pontryagin's Maximum Principle [33] is applied. In this approach, the problem is transformed into a two-point boundary value problem (TPBVP) and solved accordingly. The procedure works fairly well for unconstrained problems, but the solution of the TPBVP is still difficult to be achieved especially with the addition of the profile inequalities. These methods are, in general, focused on using necessary conditions for optimality.

DP was developed at the same time as COV, primarily to deal with combinatorial optimisation problems [35]. The method is based on Bellman's Principle of optimality:

> *An optimal policy has the property that whatever the initial state and decisions are, the remaining decisions must constitute an optimal policy with regard to the state resulting from the first decision* [35].

DP is suitable for solving complicated and multi-stage decision problems by tracing the optimal strategy. It is based on the concept that, if the current state and the planned decision of a system are known, an optimal policy formed in the future will be independent of the past policy already formed. This method is mostly applied to multi-stage sequential decision problems, where the objective function equations are non-differentiable, mainly due to the fact that they are in discrete form (the functional J contains summations of terms over time).

Direct methods

In the direct methods, the problem is approached by applying a certain level of discretisation that converts the original continuous time problem into a discrete one. The direct methods can be divided into two sub-categories, according to the level of discretisation applied: *sequential methods* and *simultaneous methods*.

In the sequential methods, discretisation of only the independent variables profiles (control variables) is performed. They are also known as *partial discretisation methods* or *decomposed methods*, the last name being justified by the fact that the system under optimisation is decomposed into the control and state variables, and only the control variables are discretised and treated as optimisation variables [36].

The problem can be solved in certain cases via DP, but mainly it is solved by nonlinear programming methods (e.g. steepest descent, quasi-Newton methods, successive quadratic programming, SQP), whereas the state variables are determined by integration of the DAE's via computer software solvers, simulation tools and others.

In the simultaneous methods, complete discretisation of both the control and state variables takes place. Various NLP methods and full discretisation techniques can be used for the solution. Their basic characteristic is that they solve the DAE system only once, at the optimum point [30].

13.4.7 On-line and off-line operation optimisation of cogeneration systems

As mentioned in Section 13.2, the simulation model of a system can be developed with a combination of theoretical approach and equations describing the performance of system components, which have been developed by regression analysis of data for the particular equipment, when available.

The model can be used for off-line operation optimisation either at the design stage, in order to evaluate the future performance of the system, or at the real operation stage, after the system has been built. An example of off-line operation optimisation of an industrial combined cycle cogeneration system is given in [2].

Attention is drawn to the fact that the performance of components deteriorates with time and in order for the optimisation to give correct results, there is need to measure crucial operating parameters of equipment and update the models accordingly. This procedure is also called open-loop operation optimisation.

On-line optimisation is also possible by integrating the optimiser with the control system [37]. Furthermore, in the closed-loop procedure, a data acquisition system is installed in connection with the control system, which contains simulation and optimisation software. Collected data are used to update the models automatically, and the optimal control is performed on-line.

The data collected can also be used for evaluation of the condition of equipment and scheduling of maintenance (condition-based maintenance). In this way, the reliability and availability of the system increase and the unscheduled shut down is avoided, with direct positive effect on the economic performance of the system.

Taking into consideration that the operation and maintenance cost of a cogeneration system, including the cost of fuel, is at the order of 70%–80% of the life-cycle cost, the operation optimisation becomes more than important.

13.4.8 Sensitivity analysis

13.4.8.1 Sensitivity analysis with respect to parameters

It is also called simply *sensitivity analysis* or *parametric analysis*.

The optimisation problem is initially solved for a certain set of values for the parameters. However, the values of many parameters (e.g. costs) are not known with absolute accuracy, but they are derived as a result of statistical estimates or predictions for the future. Therefore, it is necessary to perform a sensitivity analysis, that is to study the effect that a change in the values of important parameters may have on the optimal solution. This effect can be revealed by at least two methods, as explained below.

Preparation of graphs

The optimisation problem is solved for several values of a single parameter, whereas the values of the other parameters are kept constant. Then, graphs are drawn, which show the optimal values of the independent variables and of the objective function as functions of the particular parameter.

Evaluation of the uncertainty of the objective function

If p_j, $j = 1, 2, \ldots$ are the parameters of the optimisation problem, one or more of the following quantities are evaluated.

Uncertainty of the objective function due to the uncertainty of a parameter:

$$\Delta F = \frac{\partial F}{\partial p_j} \Delta p_j \tag{13.23}$$

Maximum uncertainty of the objective function due to the uncertainties of a set of parameters:

$$\Delta F_{\max} = \sum_j \left| \frac{\partial F}{\partial p_j} \right| \Delta p_j \tag{13.24}$$

The most probable uncertainty of the objective function due to the uncertainties of a set of parameters:

$$\Delta F_{\text{prob}} = \sqrt{\sum_j \left[\frac{\partial F}{\partial p_j} \Delta p_j \right]^2} \tag{13.25}$$

If the sensitivity analysis reveals that the optimal solution is very sensitive with respect to a parameter, then one or more of the following actions may be necessary:

- attempt for a more accurate estimation of the parameter (decrease of the uncertainty of the parameter),
- modifications in the design of the system with the scope of reducing the uncertainty,
- changes in decisions regarding the use of (physical and economic) resources for the construction and operation of the system.

Since these actions may be of crucial importance for the implementation of a project, a careful sensitivity analysis may prove more useful than the solution of the optimisation problem itself.

13.4.8.2 Sensitivity analysis of the objective function with respect to independent variables

There are cases where the optimum value of an independent variable cannot be selected in practice. For example, pipes are available at standard sizes. If the diameter of a pipe is an independent variable and the available optimisation algorithm treats it as a continuous variable (not a discrete one), then the optimum value of the diameter may not be one of the standard sizes. Consequently in practice the diameter will not be equal to the optimum one. As another example, gas engines and gas turbines are available in discrete sizes. In such cases, it is useful to study the effect of a deviation from the optimum value of an independent variable to the value of the objective function.

The sensitivity of the optimum solution with respect to the independent variable x_i is revealed by the values of the following derivatives at the optimum point:

$$\left.\frac{\partial f(\mathbf{x})}{\partial x_i}\right|_{\mathbf{x}^*} \qquad \left.\frac{\partial x_j}{\partial x_i}\right|_{\mathbf{x}^*}, \qquad j \neq i$$

or with the differences

$$\left.\frac{\Delta f(\mathbf{x})}{\Delta x_i}\right|_{\mathbf{x}^*} \qquad \left.\frac{\Delta x_j}{\Delta x_i}\right|_{\mathbf{x}^*}$$

Note: The term 'sensitivity analysis' will imply the sensitivity analysis with respect to the parameters, except if it is specified differently.

Further details on sensitivity analysis are given in the literature [13–15].

13.5 Optimisation examples

For a gradual introduction to applications of optimisation, the operation optimisation of a simple cogeneration system is presented first, followed by more complex examples.

Example 13.1 Operation optimisation of a simple cogeneration system

A simple operation optimisation problem is presented first, as an introductory example. The operation optimisation of a real industrial combined cycle cogeneration system by use of an elaborate simulation model based on specifications of the particular components is presented in [2].

Statement of the problem

The cogeneration unit consists of a Diesel engine-generator and an exhaust gas boiler. A two-way connection to the grid allows selling extra electricity, if any, and purchasing additional electricity, if needed. An auxiliary boiler is also installed for supplementary thermal energy, if the thermal energy supplied by the exhaust gas boiler is not sufficient to cover the load. The same type of fuel is used by both the Diesel engine and the auxiliary boiler.

The electricity and heat load curves of the user indicate that the annual operation can be approximated with five periods of constant load in each period, as written in Table 13.1. The table gives also the duration of each period, as well as the cost of electricity bought from the grid, c_e, and the price of electricity sold to the grid, p_e. Table 13.2 gives the values of technical and economic parameters of the cogeneration system.

The optimum electric power output of the cogeneration system in each one of the five periods is requested, that is the power output that minimises the cost of covering the energy needs of the user, with the profit taken into consideration in the cost function with negative sign. It is considered that the capital cost of the system is sunk (a different treatment of the capital cost is presented in the next example) and that the values of the efficiency and the power-to-heat ratio of the cogeneration unit remain approximately the same at partial load.

Table 13.1 Data for the five characteristic periods of operation

Period	$\dot{W}$ **(kW$_e$)**	$\dot{Q}$ **(kW$_{th}$)**	t **(h/year)**	c_e **(€/kWh)**	p_e **(€/kWh)**
1	25,000	15,000	1,000	0.044	0.030
2	20,000	14,000	2,000	0.059	0.035
3	20,000	14,000	2,000	0.059	0.044
4	20,000	15,000	1,000	0.059	0.015
5	15,000	12,000	1,000	0.044	0.030

Table 13.2 Technical and economic parameters of the cogeneration system

Lower heating value of fuel	$H_u = 42{,}000$ kJ/kg
Nominal electric power output of the cogeneration system	$\dot{W}_{en} = 25{,}000$ kW$_e$
Electric efficiency of the cogeneration system	$\eta_e = 0.48$
Power to heat ratio of the cogeneration system	PHR = 1.6
Efficiency of the auxiliary boiler	$\eta_{AB} = 0.88$
Cost of fuel	$c_f = 0.235$ €/kg
Operation and maintenance cost of the cogeneration system[a]	$c_{om,c} = 2$ €/MWh$_e$
Operation and maintenance cost of the auxiliary boiler[a]	$c_{om,AB} = 0.8$ €/MWh$_{th}$

[a]Except of fuel.

Formulation and solution of the optimisation problem

Under the assumptions stated in the preceding paragraph, the objective function takes the form

$$\dot{C} = c_f \frac{\dot{W}_e}{\eta_e H_u} + c_f \frac{\dot{Q}_{\mathrm{AB}}}{\eta_{\mathrm{AB}} H_u} + c_{om,c}\dot{W}_e + c_{om,\mathrm{AB}}\dot{Q}_{\mathrm{AB}} + c_e\dot{W}_{eb} - p_e\dot{W}_{es} \tag{13.26}$$

where $\dot{C}$ is the total cost for covering the energy needs per unit of time, including any profit from selling excess electricity with negative sign, $\dot{W}_e$ is the electric power output of the cogeneration unit, $\dot{Q}_{\mathrm{AB}}$ is the thermal power of the auxiliary boiler, $\dot{W}_{eb}$ is the electric power bought from the grid, if needed, $\dot{W}_{es}$ is the electric power sold to the grid, if there is excess power.

If $\dot{W}_e$ were known, then the other operating variables appearing in (13.26) could be evaluated with the following steps:

$$\begin{array}{llll} \text{If} \quad \dot{W} \geq \dot{W}_e & \text{then} \quad \dot{W}_{eb} = \dot{W} - \dot{W}_e & \dot{W}_{es} = 0 \\ \text{If} \quad \dot{W} < \dot{W}_e & \text{then} \quad \dot{W}_{eb} = 0 & \dot{W}_{es} = \dot{W}_e - \dot{W} \end{array}$$

Thermal power of the exhaust gas boiler: $\dot{Q}_{\mathrm{EGB}} = \dot{W}_e/\mathrm{PHR}$

$$\begin{array}{ll} \text{If} \quad \dot{Q} > \dot{Q}_{\mathrm{EGB}} & \text{then} \quad \dot{Q}_{AB} = \dot{Q} - \dot{Q}_{\mathrm{EGB}} \\ \text{If} \quad \dot{Q} \leq \dot{Q}_{\mathrm{EGB}} & \text{then} \quad \dot{Q}_{\mathrm{AB}} = 0 \end{array}$$

Thus, the optimisation problem has only one independent variable, namely, the electric power output $\dot{W}_e$ of the cogeneration unit. The numerical solution has been obtained by the Golden Section Search [13] and the results are presented in Table 13.3.

For comparison, if a heat-match mode of operation is decided for all time intervals, then the total annual cost is 6,396,400 €, which is higher than the optimal cost by 80,854 € (1.28%). On the other hand, if an electricity-match mode of operation is decided for all time intervals, then the total annual cost is 6,418,547 €, which is higher than the optimal cost by 103,001 € (1.63%).

Table 13.3 Optimisation results

Period	$\dot{W}_e$ **(kW)**	$\dot{Q}_{\mathrm{EGB}}$ **(kW)**	$\dot{Q}_{\mathrm{AB}}$ **(kW)**	$\dot{W}_{eb}$ **(kW)**	$\dot{W}_{es}$ **(kW)**	$\dot{C}$ **(€/h)**
1	25,000	15,625	0	0	0	1,099.1
2	22,400	14,000	0	0	2,400	900.8
3	25,000	15,625	0	0	5,000	879.1
4	20,000	12,500	2,500	0	0	938.5
5	19,200	12,000	0	0	4,200	718.1

Total annual cost: $C_a = 6{,}315{,}546$ €.

Comments on the results:

1. The cost of electricity, c_e, is high enough in all periods, so that the cogeneration unit covers all the electric load.
2. When the price of electricity, p_e, is high enough (period 3), then it is profitable to operate the unit at the nominal power and sell the excess electricity to the grid.
3. For moderate values of p_e (periods 2 and 5), the unit operates at such power, that the thermal load is covered. There is also excess electricity sold to the grid, but lower than that in period 3.
4. For very low value of p_e (period 4), the cogeneration unit covers the electric load, but there is need of supplementary heat from the auxiliary boiler.

These comments are applicable to the particular example. Even though some of those indicate general trends, it should not be considered that all comments are applicable in every case.

Example 13.2 Dynamic operation optimisation of a trigeneration system

The operation of a trigeneration system including storage of hot and cold water is presented here in brief. Further details can be found in [10].

- *Nomenclature for the particular example*

A	external surface area of a water storage tank (m^2)
C_{ac}	annualised capital cost (€)
C_{ci}	investment cost of component i (€)
C_e	annual cost of electricity purchased from the grid (€)
C_f	annual cost of fuel (€)
C_m	annual maintenance cost (€)
C_p	annual personnel cost (€)
C_{tot}	total annual cost (€)
COP	coefficient of performance
CRF	capital recovery factor
c_{ci}	specific investment cost of component i, that is investment cost per unit of product, as defined by (13.28) (e.g. €/kWh)
c_p	specific heat capacity (kJ/kg K)
$c_{ji,k}$	constant parameters
G	Gompertz function (S-curve)
$\dot{H}_{fcog}$	energy flow rate of the fuel consumed by the cogeneration unit (kW)
m	mass (kg)
$\dot{P}_{Di}$	production rate of component i at the design point (e.g. electric power output of the cogeneration unit, $\dot{W}_{Dcog}$, in kW)
P_i	annual useful product of component i (e.g. annual electricity production of the cogeneration unit, in kWh)

$\dot{Q}_{abs}$ thermal power required by the absorption chiller (kW_{th})
$\dot{Q}_B$ thermal power of the boilers and the burner of the hot water tank (kW_{th})
$\dot{Q}_{cog}$ useful thermal power of the cogeneration unit (kW_{th})
$\dot{Q}_{cog,us}$ utilised thermal power of the cogeneration unit (kW_{th}) (the difference $\dot{Q}_{cog} - \dot{Q}_{cog,us}$ is wasted)
$\dot{Q}_{cons}$ heat flow rate supplied to the building complex (kW_{th})
T temperature (°C)
t time (h)
$t_{ai,max}$ maximum expected period of operation of component i, taking into consideration reliability and availability (h)
U overall heat transfer coefficient (kW/m^2 K)
$\dot{W}_b$ electric power bought from the grid (kW_e)
$\dot{W}_{chel}$ electric power consumed by the compression chillers (kW_e)
$\dot{W}_{cog}$ electric power of the cogeneration unit (kW_e)
$\dot{W}_{cons}$ electric power consumed by the building complex, excluding the compression chillers (kW_e)
$\mathbf{x}$ set of independent variables

- *Greek letters*

$\dot{\Psi}$ cooling power (kWc)

- *Subscripts*

B boiler
abs absorption chiller
amb ambient
$chel$ compression chillers, electrically driven
cog cogeneration unit
$cons$ consumed by the building complex
cwt cold water storage tank
D design point
hwt hot water storage tank
N nominal value
r room

Description of the system

The energy needs of a building complex are covered by electricity coming from the local network and by its own energy system consisting of the following main components (Figure 13.2):

- one gas-engine cogeneration unit,
- natural gas boilers,
- electrically driven compression chillers,
- one absorption chiller,
- one hot water storage tank with its own natural gas burner,
- one cold water storage tank.

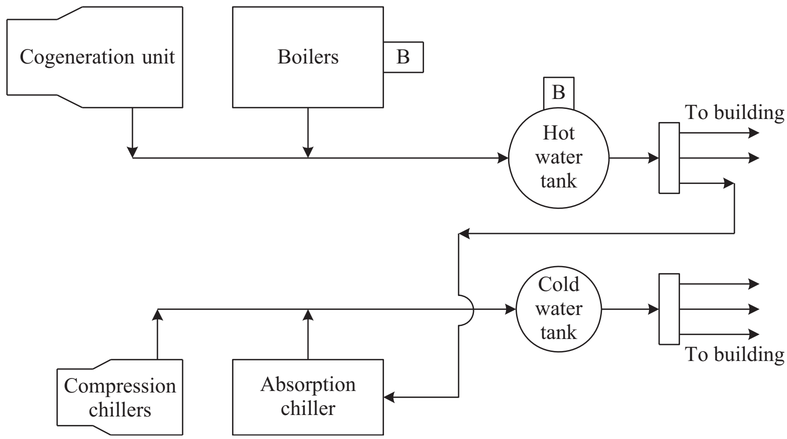

Figure 13.2 Simplified diagram of the energy system (only the supply lines of hot and cold water are depicted)

The boilers and the compression chillers have sufficient capacity to cover the needs of the building, even when the cogeneration unit and the absorption chiller are not operating.

Hot water, coming either from the cogeneration unit or from the boilers, is stored in the hot water tank, wherefrom it is supplied to the building and to the absorption chiller. A natural gas burner installed on the tank can compensate for thermal losses up to a certain extent, if needed. Cold water, coming either from the compression chillers or from the absorption chiller, is stored in the cold water tank wherefrom it is supplied to the building.

The building operates from Monday through Friday. The accuracy achieved is considered satisfactory here, if it is assumed that the change of the energy needs with time is represented with one typical day for each month and nine time intervals of constant needs in each one during each typical day. Indicatively, the loads for the typical days of January and July are given in Table 13.4. The electric load, $\dot{W}_{cons}$, does not include the electric power required by the compression chillers. If this power is added, then the electric power output of the cogeneration unit is lower than the total electric loads, and consequently there is no excess electricity to be sold to the grid.

Thermal loads include space heating and supply of hot water. The constant cooling load appearing in periods that the external temperature is low (such as in January) is due to rooms with equipment that produce heat, and there is need to keep these rooms at a certain temperature.

The load is considered constant in each time interval (Table 13.4), but the cooling power output of the absorption chiller may change with time following the Gompertz function (as explained in the following), depending on whether the unit is turned on or off, as dictated by the optimiser. Any missing cooling power is supplemented by the compression chillers.

Table 13.4 Level and duration of the building energy needs in a typical day of January and July

Time period	**Δt (h)**	**$\dot{W}_{cons}$ (kW$_e$)**	**$\dot{Q}_{cons}$ (kW$_{th}$)**	**$\dot{\Psi}_{cons}$ (kW$_c$)**	**$\dot{W}_{cons}$ (kW$_e$)**	**$\dot{Q}_{cons}$ (kW$_{th}$)**	**$\dot{\Psi}_{cons}$ (kW$_c$)**
		January			**July**		
00–06	6	0	0	0	0	0	0
06–08	2	455	1,380	700	455	465	1,130
08–10	2	580	1,690	700	580	465	1,650
10–12	2	625	1,530	700	625	465	2,060
12–14	2	650	1,360	700	650	465	2,430
14–16	2	635	1,320	700	635	465	2,620
16–18	2	605	1,420	700	605	465	2,490
18–20	2	465	1,210	700	465	465	2,070
20–24	4	0	0	0	0	0	0

Table 13.5 Main specifications of the energy system components at the design point

Item	**Value**
Electric power of the cogeneration unit	540 kW$_e$
Thermal power of the cogeneration unit	759 kW$_{th}$
Thermal efficiency of the boilers	0.91
Cooling power of the absorption chiller	206 kW$_c$
Coefficient of performance of the absorption chiller at nominal load	0.7

Certain specifications of the main components of the system at the nominal load (design point) are given in Table 13.5, whereas the values of the economic parameters considered are given in Table 13.6.

Objective function and constraints

The minimisation of the total annual cost for covering the energy needs of the building is selected as the objective function, which consists of the annualised capital cost, and the costs for personnel, maintenance, fuel and electricity purchased from the grid:

$$\min C_{tot} = C_{ac} + C_p + C_m + C_f + C_e \tag{13.27}$$

The annualised capital cost is given by the equation:

$$C_{ac} = \sum_i c_{ci} \cdot P_i = \sum_i \frac{C_{ci} \cdot \mathrm{CRF}_i}{\dot{P}_{Di} \cdot t_{ai,\max}} \cdot P_i \tag{13.28}$$

Table 13.6 Nominal values of economic parameters

Parameter	Value
Installed cost of the cogeneration unit	1,300 €/kW$_e$
Installed cost of the boiler[a]	25 €/kW$_{th}$
Installed cost of the compression chillers	140 €/kW$_c$
Installed cost of the absorption chiller	250 €/kW$_c$
Maintenance cost of the cogeneration unit	0.010 €/kWh$_e$
Maintenance cost of the boiler	0.001 €/kWh$_{th}$
Maintenance cost of the compression chillers	0.0023 €/kWh$_c$
Maintenance cost of the absorption chiller	0.0026 €/kWh$_c$
Personnel overtime cost	15 €/h
Cost of natural gas for the cogeneration unit	0.032 €/kWh$_f$
Cost of natural gas for the boilers	0.040 €/kWh$_f$
Unit cost of electricity supplied by the grid	0.10039 €/kWh$_e$
Value added tax	0.13
Market interest rate	0.08

[a]The value given here is relatively low; it should not be considered as generally applicable.

Equation (13.28) is based on the consideration that the capital (investment cost) of component *i* is 'consumed' by the end of its technical life, which corresponds to a total number of units of useful product and, if the component is not used in a certain time period, there will be 'life' left to be used in another period, more profitably. Thus, each unit of product bears with it a portion of the investment cost. It is often written in the literature that the capital cost can be considered sunk for operation optimisation. At least in the case studied here, this is not correct and may lead to wrong decisions regarding the mode of operation of a system. For example if the capital cost is ignored, then the marginal cost of electricity produced would be much lower and the unit might be put in operation even in periods with very low cost of electricity purchased from the network.

The cost of personnel is due only to overtime that the operation of the trigeneration system may require, whereas the operation during the normal working hours is covered by the technical team that works in the complex anyway.

The maintenance cost is considered here as proportional to the annual production of a component, the cost of fuel is proportional to the fuel consumption and the cost of electricity is proportional to the electric energy purchased from the grid, with the proportionality factors given in Table 13.6.

The optimisation is subject to certain equality constraints such as the following.

As there is no storage of electric energy, the electric energy produced by the cogeneration system plus the energy bought from the grid, must be equal to the total electric load, consisting of the power absorbed by the compression chillers and the power for any other load, as given in Table 13.4:

$$\dot{W}_{cog} + \dot{W}_b = \dot{W}_{cons} + \dot{W}_{chel} \tag{13.29}$$

Energy balance in the hot water storage tank:

$$m_{hwt}c_p \frac{dT_{hwt}}{dt} = \dot{Q}_{cog} + \dot{Q}_B - \dot{Q}_{abs} - \dot{Q}_{cons} - (UA)_{hwt}(T_{hwt} - T_r) \tag{13.30}$$

Energy balance in the cold water storage tank:

$$m_{cwt}c_p \frac{dT_{cwt}}{dt} = \dot{\Psi}_{cons} - \dot{\Psi}_{abs} - \dot{\Psi}_{chel} - (UA)_{cwt}(T_{cwt} - T_r) \tag{13.31}$$

The left-hand side of (13.30) represents the change in the thermal energy stored in the tank, which is due only to temperature change, because the mass of water in the storage tanks remains constant. The right-hand side contains the inflow of thermal energy coming from the cogeneration unit and the additional burner and the outflow of thermal energy towards the absorption unit, the various thermal loads and to the environment (thermal losses). A similar explanation can be written for (13.31).

There are also inequality constraints such as the following:

$$0.3 \cdot \dot{W}_{Dcog} \leq \dot{W}_{cog} \leq \dot{W}_{Dcog} \quad \text{or} \quad \dot{W}_{cog} = 0 \tag{13.32}$$

$$0.1\dot{\Psi}_{Dabs} \leq \dot{\Psi}_{abs} \leq \dot{\Psi}_{Dabs} \quad \text{or} \quad \dot{\Psi}_{abs} = 0 \tag{13.33}$$

$$80\ ^\circ\mathrm{C} \leq T_{hwt} \leq 95\ ^\circ\mathrm{C} \tag{13.34}$$

$$7\ ^\circ\mathrm{C} \leq T_{cwt} \leq 12\ ^\circ\mathrm{C} \tag{13.35}$$

Equations (13.32) and (13.33) are due to the fact that there is a technical lower limit on the operating power of the cogeneration unit and the absorption chiller. If a value lower than the lower limit is derived during the optimisation procedure, then the power output is set automatically equal to zero. The limits on the hot and cold water temperatures, (13.34) and (13.35), are specified by the effective operation of the central heating and cooling systems, respectively.

Additional equality and inequality constraints are derived with the simulation of the system.

Simulation of the system

The main components of the system are simulated by taking into consideration external performance characteristics obtained either from the literature or from information given by the manufacturers. The partial load performance of the cogeneration unit is described by the equations for calculation of the energy flow rate of the fuel consumed and of the useful heat produced as functions of the electric power output:

$$\dot{H}_{fcog} = \sum_{k=0}^{2} c_{fcog,k}\left(\dot{W}_{cog}\right)^k \tag{13.36}$$

$$\dot{Q}_{cog} = \sum_{k=0}^{2} c_{Q_{cog},k}\left(\dot{W}_{cog}\right)^k \tag{13.37}$$

For the boilers and the auxiliary burner of the hot water storage tank, a constant efficiency is assumed (Table 13.5). The coefficient of performance of the compression chillers at nominal load is calculated as a function of the ambient temperature:

$$\mathrm{COP}_{chel} = \sum_{k=0}^{2} c_{chel,k} (T_{amb})^k \quad T_{amb} \text{ in } {}^\circ\mathrm{C} \tag{13.38}$$

while the simplifying assumption is made that it remains constant at partial load. A more elaborate simulation is performed for the absorption chiller, as follows.

The heat flow rate required for the operation of the absorption chiller at nominal load (design point) is given by the equation:

$$\dot{Q}_{D\,abs} = \frac{\dot{\Psi}_{D\,abs}}{\mathrm{COP}_{D\,abs}} \tag{13.39}$$

At partial load, the following equation is applicable:

$$\dot{Q}_{abs} = \dot{Q}_{D\,abs} \sum_{k=0}^{2} c_{Q_{abs},k} \left(\frac{\dot{\Psi}_{abs}}{\dot{\Psi}_{D\,abs}} \right)^k \tag{13.40}$$

The transient behaviour of the absorption chiller is represented by the Gompertz function (S-curve), which takes two forms, one for load increase from zero to nominal load and one for load decrease from nominal to zero load (Figure 13.3), expressed by (13.41) and (13.42), respectively:

$$G_{incr}(t) = ab^{c^t} - ab \tag{13.41}$$

$$G_{decr}(t) = 1 - ab^{c^{1.75t}} + ab \tag{13.42}$$

where t is elapsed time in minutes and

$$a = 1.228455, \quad b = 0.000128, \quad c = 0.810818.$$

Thus, it is

$$\dot{\Psi}_{abs}(t) = G(t) \cdot \dot{\Psi}_{D\,abs} \tag{13.43}$$

The heat flow rate required by the absorption chiller for operation during transients is given by the equation:

$$\dot{Q}_{abs}(t) = \frac{\dot{\Psi}_{abs}(t)}{\mathrm{COP}_{abs}(t)} \tag{13.44}$$

where:

$$\mathrm{COP}_{abs}(t) = \mathrm{COP}_{D\,abs} \sum_{k=0}^{6} c_{\mathrm{COP}_{abs},k} \left(\frac{\dot{\Psi}_{abs}(t)}{\dot{\Psi}_{D\,abs}} \right)^k \tag{13.45}$$

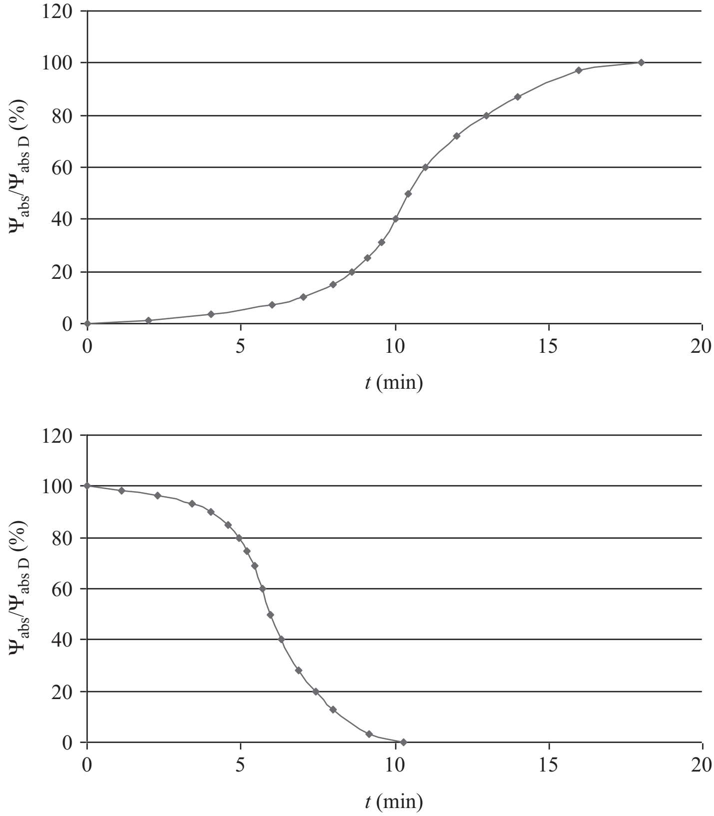

Figure 13.3 Gompertz function for load increase and decrease

It is interesting to note that the thermal power required for the operation of the absorption chiller at a certain cooling output under steady state, (13.40), is different from the thermal power required at the same cooling output in transients (13.44).

In the preceding, the most important parts of the simulation have been presented, whereas further details can be found in [10].

Independent variables and solution procedure of the optimisation problem

The objective function, the equality constraints derived by the analysis of the system and the number of parameters with externally imposed values leave the optimisation problem with four degrees of freedom. The solution of the problem, as described in the following subsection, is facilitated if the electric power output of the cogeneration unit, $\dot{W}_{cog}$, the thermal power output of the boilers and the burner of the hot water tank, $\dot{Q}_B$, the cooling power of the absorption chiller, $\dot{\Psi}_{abs}$, and the cooling power of the compression chillers, $\dot{\Psi}_{chel}$, at each instant of time are the independent variables (decision variables). Thus,

$$\mathbf{x} = \left(\dot{W}_{cog}, \dot{Q}_B, \dot{\Psi}_{abs}, \dot{\Psi}_{chel}\right) \tag{13.46}$$

It is noted that $\dot{Q}_B$ and $\dot{\Psi}_{chel}$ are treated as independent variables and consequently the temperatures in the storage tanks (T_{hwt} and T_{cwt}) are dependent variables (state variables). If there were no storage tanks, $\dot{Q}_B$ and $\dot{\Psi}_{chel}$ would be dependent variables.

As is explained in the preceding, there is interdependency between the time intervals of a typical weekday. On the other hand, during the weekend the building complex is not in operation, but the existence of storage tanks bridges the gap between Friday and Monday. Under these conditions, optimisation for each time interval individually is not correct. Instead, the time intervals of a whole week are treated simultaneously. For this purpose, instead of four (13.46), the number of independent variables is:

$$n = 4\frac{\text{variables}}{\text{interval}} \times 9\frac{\text{intervals}}{\text{day}} \times 7\frac{\text{days}}{\text{week}} = 252 \text{ variables} \tag{13.47}$$

Thus, the initial point for the optimisation consists of the values of all these variables plus the initial conditions required for the numerical solution of the differential equations (13.30) and (13.31).

The optimisation problem, which is discretised in the aforementioned way, is solved by use of the SNOPT software [38], based on the SQP algorithm. The software is supplemented with subroutines for the calculation of the dependent variables and the objective function. Numerical differentiation and integration is performed wherever is needed.

Optimisation results for the nominal set of data

The results for the nominal set of data, that is for the values of parameters given in Tables 13.4–13.6, are given in Table 13.7 (for 2 months only, January and July, in order to save space). Table 13.7 gives the optimum values of the independent and important dependent variables.

It is noted that during the cold period (January), the thermal energy produced by the cogeneration unit is used to cover thermal loads, and it is not economical to use thermal energy from the boilers to drive the absorption chiller; therefore, it is $\dot{\Psi}_{abs} = 0$, and the cooling load is covered by the compression chillers. The temperature in the hot water storage tank is kept at the lower limit (80 °C), an indication that it is not economically justified to store thermal energy above a certain limit.

During the hot period (July), the absorption chiller operates at its capacity. It is interesting to note that in certain time intervals, the temperature in the cold water storage tank drops to the lower limit (7 °C), thus preparing the system to cover the cooling load at the peak of the day.

In order to check the effectiveness of the optimisation procedure, the total cost for covering the energy needs obtained with optimisation for the typical day of each month has been compared with the cost resulting with typical pre-determined operation modes, namely, heat-match operation of the cogeneration unit, electricity-match operation of the cogeneration unit and no operation of the

Table 13.7 Optimisation results for the nominal set of data (Tables 13.4–13.6) (the two columns under each one of T_{hwt}, T_{cwt}, and $\dot{\Psi}_{abs}$ correspond to the beginning and the end of each time period)

Time period	$\dot{W}_{cog}$ (kW)	$\dot{Q}_{cog}$ (kW)	$\dot{Q}_{cog,us}$ (kW)	$\dot{Q}_B$ (kW)	T_{hwt} (°C)		T_{cwt} (°C)		$\dot{\Psi}_{abs}$ (kW)		$\dot{Q}_{abs}$ (kW)	$\dot{\Psi}_{chel}$ (kW)
January												
00–06	0	0	0	0	80.0	79.5	12.0	12.3	0	0	0	0
06–08	540	759	759	625.7	79.5	80.0	12.3	12.0	0	0	0	701.0
08–10	540	759	759	932.2	80.0	80.0	12.0	12.0	0	0	0	700.2
10–12	540	759	759	772.2	80.0	80.0	12.0	12.0	0	0	0	700.2
12–14	540	759	759	602.2	80.0	80.0	12.0	12.0	0	0	0	700.2
14–16	540	759	759	562.2	80.0	80.0	12.0	12.0	0	0	0	700.2
16–18	540	759	759	662.2	80.0	80.0	12.0	12.0	0	0	0	700.2
18–20	540	759	759	452.2	80.0	80.0	12.0	12.0	0	0	0	700.2
20–24	0	0	0	0	80.0	79.7	12.0	12.2	0	0	0	0
July												
00–06	0	0	0	0	80.0	79.6	12.0	12.4	0	0	0	0
06–08	540	759	759	0	79.6	80.9	12.4	7.0	0	189.080	283.6	973.4
08–10	540	759	759	0	80.9	80.7	7.0	7.0	189.1	206	293.9	1,444.9
10–12	540	759	759	0	80.7	80.5	7.0	7.0	206	206	294.2	1,854.6
12–14	540	759	759	0	80.5	80.4	7.0	12.0	206	206	294.2	2,210.0
14–16	540	759	759	0	80.4	80.2	12.0	12.0	206	206	294.2	2,414.4
16–18	540	759	759	0	80.2	80.0	12.0	12.0	206	206	294.2	2,284.4
18–20	540	759	609.8	0	80.0	82.2	12.0	12.0	206	80.517	127.9	1,985.3
20–24	0	0	0	0	82.2	80.0	12.0	12.0	80.5	0	6.8	0

trigeneration system. If, instead of the optimal operation, heat-match is selected, the cost increases in certain days by about 5%; with electricity match the cost increases by about 1.2%, and if the trigeneration system does not operate at all, the cost increases by up to 24% in certain days.

Examples of sensitivity analysis

The effect of the values of several parameters on the optimal results has been studied and presented in [10]. As examples, the effect of the cost of fuel and electricity coming from the grid is presented here (Figures 13.4–13.6).

It can be calculated analytically (on the basis of marginal costs) that there exists a critical value of the fuel cost for the cogeneration unit:

$$c_f^{crit} = 1.41 c_{fN} \tag{13.48}$$

For fuel cost higher than this value, the installation and operation of an absorption chiller is not justified economically. Figure 13.4 presents a verification: Values of the fuel cost higher than the critical one lead to zero cooling energy supplied by the absorption chiller. As a consequence during the summer period, when the thermal

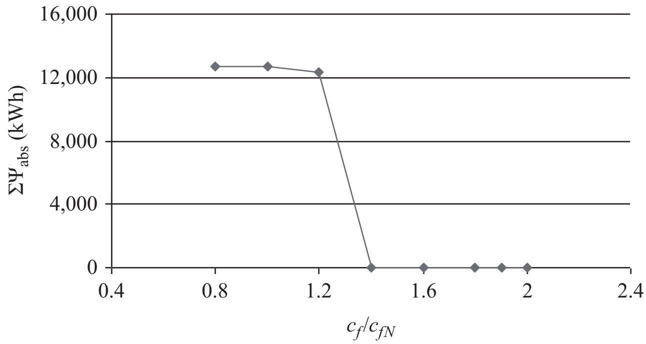

Figure 13.4 Effect of the cost of fuel on the total cooling energy supplied by the chiller

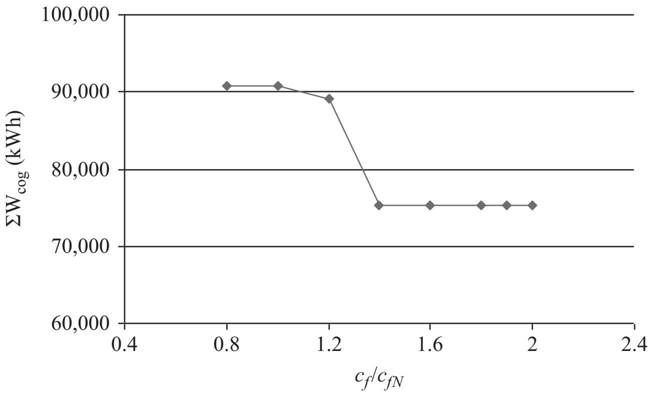

Figure 13.5 Effect of the cost of fuel on the total electric energy supplied by the cogeneration unit

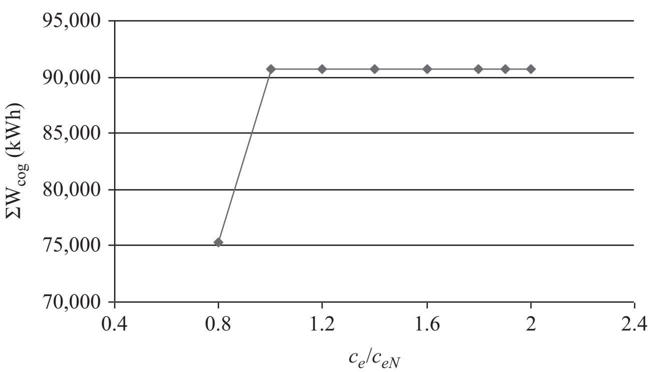

Figure 13.6 Effect of the cost of electricity on the total electric energy supplied by the cogeneration unit

load is lower than the nominal thermal output of the cogeneration unit, the optimisation leads to a power output lower than the nominal one, so that there is no heat wasted. This is the reason for the abrupt drop in the total electric energy produced by the cogeneration unit for values of fuel cost higher than the critical one (Figure 13.5).

In a similar way, it can be calculated analytically that there exists a critical value of the electricity cost purchased from the network:

$$c_e^{crit} = 0.78 c_{eN} \tag{13.49}$$

For electricity cost lower than this value, it is more economical to cover the total cooling load with compression chillers. The installation and operation of an absorption chiller is not justified economically, and the operating point of the cogeneration unit is adjusted accordingly during the summer period (Figure 13.6).

Example 13.3 Optimisation of synthesis, design and operation of a cogeneration system taking reliability into consideration

The effect of reliability aspects on the three-level optimisation of a cogeneration system is presented here in brief. More details can be found in [4,39].

Description of the generic system

A cogeneration system is considered, which supplies a production facility with electricity, high-pressure steam and low-pressure steam, all functions of time. The load profiles are approximated by considering that a typical year of operation consists of 12 characteristic time periods, with loads and duration as given in Table 13.8, where $\dot{W}_D$ is the electric power (demand), $\dot{Q}_{\mathrm{HP}}$ is the thermal power in

Table 13.8 Load profile of the production facility and ambient temperature

Period τ	Δt **(h)**	$\dot{W}_D$ **(kW$_e$)**	$\dot{Q}_{\mathrm{HP}}$ **(kW$_{th}$)**	$\dot{Q}_{\mathrm{LP}}$ **(kW$_{th}$)**	T_a **(°C)**
1	1,376	9,700	13,650	3,094	25
2	688	8,900	10,800	2,958	20
3	280	7,600	7,500	2,720	25
4	568	3,500	3,150	1,360	20
5	1,360	9,700	11,819	2,758	10
6	680	8,200	9,720	2,460	5
7	264	7,600	7,200	2,460	10
8	560	3,700	4,200	1,200	5
9	1,184	9,900	10,920	2,820	30
10	592	9,000	8,400	2,640	25
11	224	8,000	6,000	2,550	30
12	448	3,600	2,640	1,350	25

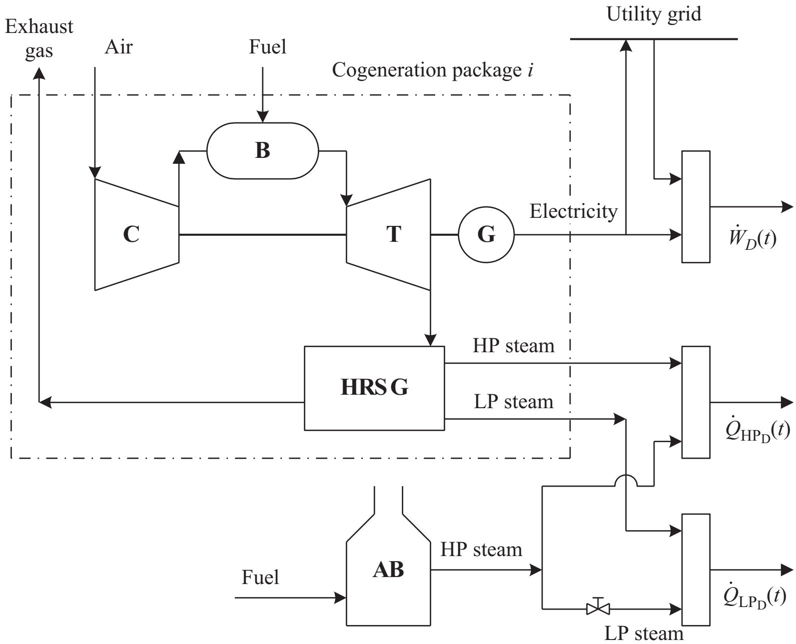

Figure 13.7 Generic cogeneration system with N_{cgmax} cogeneration packages

the form of high pressure steam, $\dot{Q}_{\mathrm{LP}}$ is the thermal power in the form of low pressure steam, and T_a is the environmental temperature, which affects the performance of the cogeneration system.

The system consists of one or more cogeneration packages; each package contains a gas turbine-generator unit, a heat recovery steam generator (HRSG) and related auxiliary equipment. Supplementary or backup heat (steam) is supplied by an auxiliary boiler, included in the system. A two-way connection to the electricity grid is envisaged, which provides supplementary or backup power, and absorbs any excess electricity produced by the system.

The synthesis (configuration) of the system is not pre-specified, but it is the result of synthesis optimisation. A generic system (a super-configuration) is considered, which consists of an adequate number of cogeneration packages (Figure 13.7). The number of packages that will finally appear in the system is to be determined by the synthesis optimisation.

Statement of the optimisation problem

Maximisation of the NPV of the investment is selected as the overall optimisation objective function:

$$\max \mathrm{NPV} = -C + \sum_{n=1}^{N_e} \frac{F_n}{(1+i)^n} + \mathrm{SV} \tag{13.50}$$

where C is the initial cost of the system, F_n is the annual net operating profit for the year n, i is the market interest rate, N_e is the period of economic analysis (number of years), and SV is the salvage value at the end of the period of economic analysis.

The minimisation of the operation cost of the cogeneration system after taxes is selected as the objective function for operation in each time interval:

$$\min \dot{\Phi}_\tau = \left(\dot{C}_{op} + \dot{C}_l\right)_{cg,\tau} + \dot{Z}_{cg,\tau} - \dot{B}_{el,\tau} \tag{13.51}$$

where $\dot{C}_{opcg,\tau}$ is the operation cost rate of the cogeneration system in period τ, $\dot{C}_{lcg,\tau}$ is the penalty on the cogeneration system, if the loads are not covered due to its failure (13.52), $\dot{Z}_{cg,\tau}$ is the capital cost rate of the cogeneration system, and $\dot{B}_{el,\tau}$ is the profit (benefit) from selling excess electricity to the grid.

The capital cost is not considered sunk, but it is treated as in Example 13.2. On the other hand, an issue that arises when operating costs under partial failure are evaluated, is whether there will be a penalty (surcharge) in case the system cannot cover the loads. Such a penalty depends on the estimated economic loss of the production facility due to power deficiency or loss. In this example, a production loss cost is applied, which is considered as a linear function of the various forms of power deficiency or loss:

$$\dot{C}_\ell = c_{W_\ell}\dot{W}_\ell + c_{\mathrm{HP}_\ell}\dot{Q}_{\mathrm{HP}_\ell} + c_{\mathrm{LP}_\ell}\dot{Q}_{\mathrm{LP}_\ell} \tag{13.52}$$

where $\dot{W}_\ell$, $\dot{Q}_{\mathrm{HP}_\ell}$, and $\dot{Q}_{\mathrm{LP}_\ell}$ are the electricity, the high-pressure steam heat and the low-pressure steam heat, respectively, which is not covered due to equipment failure. Thus at the optimal solution, increased costs for increased reliability and availability are balanced against reduced penalties for not covering energy needs.

The independent decision variables for synthesis and design optimisation are of two types: integer binary numbers representing the existence or non-existence of a cogeneration package in the system (set of synthesis variables **z**), and real numbers representing the nominal electric power output of each cogeneration package (set of design variables **w**). The nominal capacity of each unit is restricted to be in certain limits (e.g. imposed by the available technology), whereas the total installed capacity must not exceed a certain limit (e.g. imposed by state regulations).

The independent variables of operation optimisation (set of operation variables **v**) are also of two types. There are binary variables representing whether a unit operates or not and real variables representing the load factor of a cogeneration package. Technical limitations to the load factor are taken into consideration as constraints. In addition, the total annual efficiency of the system has a lower limit imposed by state regulations in order for the system to be registered as a cogeneration system. Many more equality and inequality constraints are derived by the analysis of the system.

Thermodynamic and economic model of the system

The gas turbine performance is simulated by regression analysis and grey-modelling techniques applied on a number of commercial gas-turbine performance data. Two sets of correlations have been developed: one to express the nominal performance characteristics as functions of the nominal electric power output of a cogeneration package, $\dot{W}_N$:

$$Y_N = Y_N\left(\dot{W}_N\right) \tag{13.53}$$

and the other for the simulation of performance under partial load:

$$Y = Y\left(\dot{W}_N, T_a, f_L\right) \tag{13.54}$$

where Y is a technical characteristic of the unit (such as the electric efficiency, η_e, the exhaust gas temperature, T_g, and the mass flow rate of the exhaust gases, $\dot{m}_g$), T_a is the ambient temperature, and f_L is the load factor of the unit.

A double-pressure HRSG is considered.

The economic model of the system consists of equipment cost functions, simulations of electricity, fuel and water tariffs, and operating costs. The installed unit cost of a gas turbine set is expressed as a function of the nominal electric output:

$$c_{u,GT} = c_{u,GT}\left(\dot{W}_N\right) \tag{13.55}$$

which is obtained by regression analysis of cost data from the market. Similar modelling schemes are applied for the HRSGs and the auxiliary boiler with their auxiliary equipment.

Reliability considerations

The state space method (SSM) has been applied in order to determine the probabilities of each failure condition of the system, and the reliability block diagram analysis has been applied in order to calculate the dependability characteristics (i.e. failure rate, repair rate and failure on demand rate) of the major components and of the whole system [4,39,40]. The results are given in Tables 13.9 and 13.10.

Table 13.9 Dependability characteristics of the main components

Component	Failure rate λ (10^{-6} h^{-1})	Repair rate μ (10^{-4} h^{-1})
Gas turbine compressor	75	417
Gas turbine expander	51	417
Gas turbine electronics	66	277
Boiler tube	68	104
Boiler fuel system	70	208

Table 13.10 Dependability characteristics of the main subsystems

Dependability characteristic	Subsystem		
	Cogeneration package	Auxiliary boiler	Utility grid
Failure rate λ (10^{-6} h^{-1})	2,000	1,157	942
Repair rate μ (10^{-4} h^{-1})	208	104	2,500
Failure upon demand (10^{-6} h^{-1})	234	20	942

Procedure for the solution of the optimisation problem

The two-level approach described in Section 13.4.5.6 has been followed for the solution of the problem. It is considered that the operation in each time period (Table 13.8) is steady state and that there is no interdependency among time periods.

For the numerical solution of the optimisation problems, a genetic algorithm [18] coupled with a deterministic one, namely, GRG2 [41], is used.

The optimisation problems of both levels are mixed integer nonlinear programming problems. The GA is used in order to find the optimum values of the integer variables and near optimum values of the real variables. The deterministic algorithm is used afterwards in order to find the optimum values of the real variables using as an initial estimate the output of the GA.

The decomposition of the overall optimisation problem into two levels entails the iterative solution of the 12 operation subproblems (Table 13.8) for every solution step of the synthesis and design problem. After the optimisation operation of the fully operational state, the resulting optimal solution, which includes the determination of active and passive redundancy, is used by the SSM for reliability analysis. Then, a third set of optimisation problems is solved by the Intelligent Functional Approach [25,26] for operation under partial failure in each time interval.

Numerical results

The synthesis–design–operation optimisation problem of the cogeneration system is solved for given load conditions (Table 13.8) and a certain set of parameters (e.g. electricity and fuel tariffs) without and with reliability considerations. The main results are presented in Table 13.11.

With no reliability considerations, the optimum system consists of one cogeneration package of 8,092 kW_{el}. With reliability, two cogeneration packages of 5,003 kW_{el} and 2,289 kW_{el} are derived as the optimal configuration. Furthermore, the optimum value of the profit in the various time intervals is decreased by about 12%, whereas the optimum value of the overall objective, NPV, is decreased by 18.8%. However, this decrease should not mislead us: If reliability analysis is performed for the system which is optimal with no reliability considerations (one unit of 8,092 kW_e) and a penalty is imposed when the loads are not covered due to equipment failure, then its NPV drops from 3,730,829 to 2,575,671 €, a reduction by about 31%. Thus, in fact, optimisation with reliability considerations increases the NPV from 2,575,671 to 3,028,760 €, that is an increase by 17.6%.

With both considerations (with or without reliability), the optimum operation point of the system is the one corresponding to heat match (the cogenerated heat is used and not rejected to the environment).

Example of sensitivity analysis

The optimisation procedure may give a value for the power output of a gas turbine not available in the market. Therefore, it is interesting to investigate the effect that a gas turbine of different power output than the one derived by optimisation, but close to this one, could have on the objective function (NPV, in this case).

Table 13.11 Optimisation results

Optimisation level	**Reliability considerations**		
	No	**Yes**	
Optimal synthesis	**One unit**	**Two units**	
Optimal design	$\dot{W}_N = 8{,}092$ **kW**	$\dot{W}_{N1} = 5{,}003$ **kW**	$\dot{W}_{N2} = 2{,}289$ **kW**
	Operation		
τ	f_{L1}	f_{L1}	f_{L2}
1	1.000	1.000	1.000
2	1.000	1.000	0.814
3	0.705	1.000	0.000
4	0.000	0.000	0.880
5	1.000	1.000	1.000
6	0.791	1.000	0.000
7	0.671	1.000	0.000
8	0.000	0.000	1.000
9	1.000	1.000	0.876
10	0.773	1.000	0.000
11	0.602	0.944	0.000
12	0.000	0.000	0.743
NPV (€)	3,730,829	3,028,760	

Table 13.12 Effect of the gas turbine power output on the net present value of the system

Units	**Reliability considerations**				
	No		**Yes**		
	$\dot{W}$ **(kW)**	**NPV (€)**	$\dot{W}_1$ **(kW)**	$\dot{W}_2$ **(kW)**	**NPV (€)**
Available[a]	7,918	3,719,354	5,046	2,206	2,996,537
Optimum	8,092	3,730,829	5,003	2,289	3,028,760
Available[a]	8,132	3,729,127	5,089	2,400	2,913,602

[a]Units available in the market. They were selected so that the total power output is the closest to the optimum from below and above.

In Table 13.12, the values of NPV with the optimum gas turbine sizes and with the closest sizes available in the market are given.

The results in Table 13.12 demonstrate that the NPV does not change significantly. This outcome can be explained by the fact that the initial cost of such a system is a small part of the NPV, as mentioned in Section 13.4.7.

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Chapter 14

Examples of cogeneration projects

Costas G. Theofylaktos

14.1 Introduction

The scope of this chapter is to present successful cogeneration projects. As written in Chapter 5, there are four main sectors of cogeneration applications: utility, industrial, commercial (called also building), and agricultural sector; district heating can be categorized in the utility sector. Therefore, the example projects will be presented in the following by the application sector.

Undoubtedly, there are innumerable successful cogeneration projects worldwide, and the intention here is not to give an exhaustive list (it would be rather impossible) but to give only a few characteristic examples. The selection was necessarily restricted to combined heat and power (CHP) plants with data available in the open literature only, so that revealing proprietary information is avoided.

The eight applications of cogeneration, presented in this chapter, are covering all types of technologies (i.e., internal combustion engines, combined cycle, steam turbine, gas turbine, etc.), all major fuels used (i.e., natural gas, biomass, coal, etc.), all various capacities (i.e., micro, small-scale, and large), and all sectors of the economy (i.e., utility, industrial, commercial, and agricultural), so that the reader can form an integrated overview and understanding of modern cogeneration projects.

14.2 Cogeneration in district heating

14.2.1 The Siekierki CHP plant, Warsaw, Poland

Siekierki is the largest CHP plant in Poland, operating initially with hard coal, supplying heat to the EU's largest district-heating system, in the city of Warsaw. The district-heating facility consists of eight (8) steam boilers and nine (9) steam turbines. The total installed electrical capacity of the CHP plant is 622 MW_{el}, and the total heat capacity is 1,193 MW_{th}. Additional units include six (6) peak water boilers of 844 MW_{th}.

The annual electricity generation is estimated at 2,000 GWh and the annual heating generation at 1,617 GWh.

The Siekierki CHP plant was initially constructed in 1961, and it was fully renovated during the period 2001–09. These improvements include:

- reconstruction of one boiler with $DeSO_x$ installation
- replacement of two turbines for increasing CHP capacity
- installation of electrostatic precipitators to reduce ash emissions
- installation of new accumulator of 5,760 GJ to improve the power-to-heat ratio
- a biomass co-combustion installation for 70 kt of biomass yearly.

The environmental "green certificate" scheme was the driving force for the continuous improvements of the district-heating facility.

Relevant data for this CHP plant was taken from [1].

14.2.2 The Ziepniekkalns CHP plant, Riga, Latvia

The Latvian heat supplier company Rigas Siltums built a new biomass CHP plant in 2013 for supplying better quality heating and sanitary hot water on constant basis to the residents of a neighborhood of Riga, called Ziepniekkalns.

The CHP plant consists of a steam-turbine system of 4 MW_{el} electrical capacity and 22 MW_{th} heat capacity operating with wood, mainly woodchips, as the main fuel. The annual operating period of the CHP plant is 5,250 h. The annual electricity production is 21 GWh_e, and the annual heat production is 97.5 GWh_{th}.

The project has many success factors such as:

- it uses RES, as fuel; that is, 152,000 m^3-woodchip/year, widely available in the country
- it keeps the heat generation and distribution with high efficiency and at affordable costs for consumers
- the project operates with the lowest environmental impact, as the CO_2 is reduced by 23,778 t annually
- the cogenerated electricity is fed to the network receiving the feed-in-tariff, defined by Latvian Energy law.

The total investment cost of the plant was 16 mil Euros; 5.6 mil Euros were given through EU Cohesion Funds for Latvia and the remaining by loans.

Relevant data for this CHP plant was taken from [2].

14.3 Industrial cogeneration plants

14.3.1 Cogeneration in the pulp and paper industry: The UIPSA CHP plant, La Pobla de Claramunt, Barcelona

The pulp and paper industry is, undoubtedly, an energy-intensive industrial sector. The average energy costs for pulp and paper industry are at the order of 16% or, in certain cases, up to 30% of production costs. The heat produced during the pulp and paper production process can be used to generate electricity in CHP installations, as the one described here.

In a report of the EU Strategic Energy Technology Information System, SETIS, it is estimated that only 40% of cogeneration potential capacity has been installed in the pulp and paper industry [3].

The UIPSA CHP installation, constructed in 2008, is based on a combined cycle with natural gas as fuel, an aeroderivative 28-MW_e gas turbine, a 3.9-MW_e steam back-pressure turbine, and a 1.7-MW_e condensation turbine to modulate excess steam. The steam generator produces high and low pressure steam and has a biogas post-combustion stage.

This CHP project has many success factors:

- the CHP plant replaced an old 7-MW_e CHP plant, with a new of latest high-efficiency technologies and best equipment available,
- the project is technically and financially viable, as the plant is well designed, taking into account future growth perspectives of the UIPSA industry,
- the cogenerated electricity is fed to the Network receiving the feed-in-tariff, defined by Spanish Energy law.

One of the main operational difficulties of the CHP plant is the "spread price," the difference between the price of the fuel used by the CHP and the price of the electricity generated and the priority grid access and dispatch for CHP electricity sold back to the national grid [4]. The total investment cost of the plant was 25 mil Euros, covered by loans.

Relevant data for this CHP plant were taken from [1].

14.3.2 Cogeneration in the primary metal industry: The Aughinish Alumina CHP plant, Askeaton, Limerick, Ireland

Bauxite mining requires relatively low-energy inputs, compared to other steps in the aluminum production process, with less than 1.5 kg of fuel oil and less than 5 kWh of electricity consumed per ton of bauxite extracted. The bauxite-refining process requires significantly higher energy, primarily in the form of heat and steam; the main fuel sources are natural gas, coal, and fuel oil and are combusted on-site. The average specific energy consumption is about 14.5 GJ/t of alumina, including electrical energy of about 150 kWh/t Al_2O_3. The greenhouse gas (GHG) emissions from alumina production are related to fuel combustion, and they are about 1 t of CO_2 per ton of alumina produced [5].

Referring to Aughinish Alumina, AAL, the CHP plant commenced operation in 1983 as an 800,000 t/a alumina refinery. The refinery has been modernized and expanded, and it is now operating at 1.95 million t/a alumina production rate. Approximately 70% of the bauxite processed by AAL is imported from W. Africa with the rest from Brazil. The finished product, alumina, is exported for further processing through smelting to aluminum metal. AAL accounts for more than 35% of EU alumina production.

The CHP plant consists of two gas turbines (GTs) with a capacity of 80 MW each, utilizing natural gas with distillate oil available for backup purposes. The GTs drive electricity generators and the exhaust gases are exploited via heat recovery steam generators to generate 150 t/h each of steam at high pressure, which is subsequently used in the process plant. Exhaust gases exit to the atmosphere via two stacks, one for each turbine. The use of NG as the main fuel instead of oil eliminates SO_x emissions and the use of low NO_x burners reduces NO_x emissions.

The main success factors of this CHP project are the following:

- Due to the nature of the process used at AAL for alumina production and post-extraction processing, and as energy represents the most economically significant impact to the process, the industry was designed with energy efficiency in mind, where heat recovery and power efficiency are two of the key process efficiency targets that receive close scrutiny.
- AAL is the first process plant certified to Management System Standard and the only alumina refinery to receive independent third-party certification for energy management.

Relevant data for this CHP plant were taken from open sources on the web [6].

14.4 Cogeneration in the commercial (building) sector

14.4.1 CHP plant in Hospital Central de la Defensa "Gomez Ulla," Madrid, Spain

Hospitals are among the most complex and most energy-intensive facilities, using at least twice as much energy per square meter, compared to commercial office buildings. The operation of a hospital is anything but simple. Hospitals can cut costs by making their energy use more efficient. In most cases, hospitals are ideal candidates for CHP systems, as they are functioning 365 days a year, 24/7 and they are requiring round-the-clock both electrical energy and thermal energy, in the form of sanitary hot water, heating, and steam, as well as cooling energy. But cogeneration systems are not suitable for every hospital, a priori. Their cost-effectiveness needs to be evaluated on a case-by-case basis. In determining a CHP system's viability, there are several important considerations:

Incentives and energy rates: Many electricity and gas utilities are implementing "friendly tariffs" that facilitate CHP. Some utilities charge hospitals a standby rate, so that the utility can provide the infrastructure to support all of a hospital load in the event that the CHP plant fails. Interconnection agreements and permits all should be discussed with the utility. All incentives should be, therefore, determined.

Prime mover type: Designers must choose equipment that best fits the hospital's thermal and electrical loads and power quality requirements.

This CHP installation in "Gomez Ulla" hospital consists of a 5.8-MW_e/6.1-MW_{th} plant (two gas engines), using natural gas as fuel. The plant operates 24 h/day for covering the electric and thermal loads of the whole hospital. Heat is used for kitchens, laundry, and sterilization, hot water for heating and sanitary hot water.

The annual electricity generation is estimated at 45 GWh with an annual heating generation of 47 GWh.

The project has many success factors such as:

- significant reduction of electricity costs (2.8 mil Euros in 2008)
- minimization of GHG emissions
- increase of energy efficiency, availability, reliability, and maintenance parameters
- 16% of primary energy is saved during the CHP operation, along with a high percentage of greenhouse gas emissions
- the cogenerated electricity is fed to the network receiving the feed-in-tariff, defined by the Spanish Energy Law.

The total investment cost of the plant was 5.5 mil Euros, covered by own funds and loans.

Relevant data for this CHP plant was taken from [1].

14.4.2 "Hypo Alpe Adria" Trigeneration System, Tavagnacco, Italy

Combining a typical cogeneration system with an absorption refrigeration system allows utilization of seasonal excess heat for cooling, if required. Up to 80% of the thermal output of the cogeneration plant is thereby converted to chilled water. In the trigeneration, the annual capacity utilization and the overall efficiency of the cogeneration plant can be increased significantly.

The "Hypo Alpe" CHP plant consists of an internal combustion engine of 1.06 MW_e/1.27 MW_{th}, operating on natural gas. In addition, two boilers of 1.2 and 2 MW_{th} each have been installed. The cooling plant includes two compression chillers of 1 MW and an absorption chiller of 0.5 MW of cooling capacity. The whole trigeneration plant is supplying with heating and/or cooling and sanitary hot water a hotel, a bank headquarters, and a swimming pool, in the city of Tavagnacco, in NE Italy.

The annual electricity generation is estimated to 2.37 GWh with an annual heating generation of 2.57 GWh.

The project has many success factors such as:

- it keeps the heat generation and distribution with high efficiency at affordable costs
- the plant is equipped with an automatic control system, capable for unattended operation
- cogenerated electricity is passed into public grid.

The environmental "green certificate" scheme and tax reductions were the driving forces for this trigeneration investment.

The total investment cost of the plant was 2.8 mil Euros, covered by own funds.

Relevant data for this CHP plant were taken from [1].

14.4.3 Micro-CHP plant in De Clare Court, Haverfordwest, Pembrokeshire, UK

Two micro-CHP units of 5.5 kW_e, each of three-phase electricity and 12.5-kW_{th} thermal output, were installed in order to supply heating and sanitary hot water, and therefore thermal comfort, to a 40-flat elderly home, in De Clare Court in Haverfordwest, Pembrokeshire in the United Kingdom. The four-stroke single cylinder internal combustion engine (ICE) micro-CHP plant operates 20 h/d all year.

The annual electricity generation is estimated to 0.08 GWh with an annual heating generation of 0.182 GWh.

The project has many success factors such as:

- it provides heat generation and distribution with high efficiency
- the project operates with the lowest environmental impact, as the CO_2 is reduced by 25 t annually
- cogenerated electricity is passed directly into the building electric circuits.

The total investment cost of the plant was 30,000 Euros, covered by own funds.

Relevant data for this CHP plant were taken from [1].

14.5 Cogeneration in the agricultural sector

14.5.1 The Agritex Energy S.A. CHP plant, Alexandria, Greece

Cogeneration systems can be used to meet the energy demands of the agriculture industry, providing reliable heat and power in rural areas that may not have consistent access to the electric grid or natural gas. CHP can be also ideal for biogas applications. Potential candidates in agricultural CHP applications include crop processing, dairy and animal farming, horticulture, and greenhouses. In many high-technology, innovative greenhouses mainly with hydroponic cultivations, where cogeneration systems are operating, the temperature is kept constant, sufficient lighting is provided, and the environment is enriched with CO_2, for plant growth. This enrichment is based on the fact that, when natural gas is burnt in gas engines, nearly 1.8 kg of CO_2 is produced per m^3 of natural gas. This CO_2 is present in the exhaust gas in a concentration of approximately 5%–6% by volume. After exhaust gas is purified with special catalytic converters (selective catalytic reduction and oxidation), it is cooled down by a heat exchanger to around 50 °C and supplied to the greenhouse for CO_2 enrichment. This technique increases the harvest yield significantly.

The system presented here has all of the aforementioned advantages. It is owned by “Agritex Energy s.a.,” a Greek firm, which is one of the largest agricultural companies with hi-tech greenhouses in the country. The installation is situated in Alexandria, NW Greece and is a hydroponic cultivation of different clusters of tomatoes.

The CHP plant consists of three (3) internal combustion engines of a total electrical capacity of 4.97 MW_e and heat capacity of 6.210 MW_{th}, with NG as the main fuel. The annual electricity production is 28.02 GWh_e, and the heat generation is 35 GWh_{th}. The thermal energy produced by the CHP plant is used to cover the thermal demands of a 10-ha greenhouse, where cluster tomato is produced following the hydroponic technology. In addition, CO_2 emissions are used to increase the CO_2 concentration inside the greenhouse providing extra C to the tomato plants enriching their fertilization uptake. The above tasks aim to decrease the cost of heating and increase plant's performance, resulting in more competitive agricultural products.

The project is the result of a successful strategy as follows:

- Greek legislation concerning the use of CHPs on greenhouse production became friendlier in 2011 by binding the price of energy with the price of natural gas. Since then, new investments have been carried out in this sector (50 ha of greenhouses in 20-MW_{th} CHP's capacity), providing 25,000 t of high-quality agricultural products,
- another factor of CHP success on agriculture is the implementation of subsidy on new CHPs investments.

The total investment cost of the plant has been financed by own funds and loans.

Relevant data for this CHP plant was taken from [7].

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Chapter 15

Research and development on cogeneration

Christos A. Frangopoulos

15.1 Introduction

Cogeneration has been applied for more than a century and, consequently, it can be considered a mature technology. However, new challenges, such as increased awareness of the depletion of fuels and other natural resources, the pollution of the environment beyond acceptable limits and the scarcity of water in many areas on earth, give the impetus for a continuous research and development (R&D) on cogeneration systems. Samples of this activity are given in this chapter, arranged by the focus subjects of R&D. The reference list cannot be exhaustive; it is indicative only.

15.2 Advancements in cogeneration technologies

Certain technologies of cogeneration, both widely applied and under investigation, have been presented in Chapter 3. The ingenuity and curiosity of human beings, prompted by specific needs in certain cases, make the improvement of existing and the invention of new techniques a never-ending process. Samples of this process are presented in brief in this section.

15.2.1 Steam systems

The reciprocating steam engine was the first engine harnessing the energy of steam to produce mechanical energy (eighteenth century). Recently, a rotary steam engine for cogeneration was studied, which operates on steam of relatively low pressure (less than 10 bar) and temperature (150–180 °C) and its electrical power is in the range 1−20 kW_e [1]. Heat is provided in the form of low-temperature steam exiting the engine. The engine can be integrated with a biomass-fuelled boiler.

Of course, improvements in the steam turbine systems are continuing both at the component level (improvement of efficiency) and at the system level (primarily improvement of efficiency by increased pressure and temperature of steam).

15.2.2 Combined cycles

Combined cycle power plants are known for their high power output, in order to be economically viable. In [2], it is demonstrated that proper selection of components and design of the system can make a small-scale combined cycle cogeneration system feasible. In the system studied in [2], instead of the conventional micro-turbine, a cheaper automotive turbocharger is used in a closed topping cycle with an external biomass combustor, whereas a micro-steam expander is used for the bottoming cycle. The electric and thermal power output is at the order of 80 kW_e and 130 kW_{th}, respectively. The whole system is optimised by a genetic algorithm.

15.2.3 Organic Rankine cycles

Organic Rankine cycles (ORCs) are well known for their capability of exploiting low-temperature waste heat. The selection of the proper operating fluid for a particular application has been the subject of continuous research and more so because certain fluids are gradually phased out due to their impact on the environment. Other important issues are the selection of the proper configuration of the ORC (there are various alternatives) and its integration with the rest of the system, in particular if there are various sources of heat of different temperature levels. Integration with renewable energy sources such as biomass and solar energy is also investigated [3–6].

15.2.4 Fuel cells and hybrid systems

Fuel cells are attractive for cogeneration due to their high efficiency, low emissions and low noise level. Phosphoric acid fuel cells were the first type developed and commercially available for cogeneration. Today, however, the interest is directed primarily towards high-temperature fuel cells (solid oxide and molten carbonate) for their high efficiency and capability to operate on a variety of fuels and towards polymer electrolyte fuel cells for their simplicity in structure, low-temperature operation and relatively fast response to changing load. Two weak points that are subject to continuous research for improvement are the low life span of the fuel cells and high investment cost of the system [7–9].

Both high- and low-temperature fuel cells can be combined with gas turbines to form hybrid systems for further increase of efficiency. The development of efficient configurations and the determination of the optimal values of parameters affecting the performance of the system are subjects of continuous research [10–12].

15.2.5 Thermoelectric generators

Thermoelectric generators, even though still expensive, attract the interest, and they are investigated for cogeneration applications thanks to their advantages: As they are solid state, they do not have moving parts, which results in operation with no noise and minimal maintenance. They use various sources of thermal energy such as solar energy or thermal energy in exhaust gases [13,14]. Selection of the proper thermoelectric material, which depends on the particular operating conditions, is the main subject of investigation.

15.2.6 Nuclear plants

Large cogeneration nuclear power plants in the utility sector are in operation, which supply district heating networks of cities. For the heating in towns of lower size, smaller systems would be required. As an example, such a system is studied in [15] with electric and thermal power output of 4.4 MW_e and 10 MW_{th}, respectively. The thermal energy is given to a district heating network with supply and return temperatures of 95 and 65 °C, respectively. Constant electric load but variable thermal load was considered; therefore, thermochemical energy storage was studied, in order to store unused thermal energy.

The industrial application of nuclear cogeneration plant was the subject of R&D of the ARCHER project (Advanced High-Temperature Reactors for Cogeneration of Heat and Electricity R&D), which was funded by the European Union from 2011 to 2015. The results are reported in [16]. A system with a 600-MW_{th} nuclear reactor was designed, which supplies a nearby industrial facility with process steam at two temperature levels: 500 and 300 °C. Various aspects were investigated, such as integration of the system with the industrial facility, fuel properties, materials of components, safety, environmental impact and economic performance. Regarding the last one, it was concluded that 'the HTR is only viable when it is employed in combination with cogeneration and will not be economically attractive as an electricity only production facility' [16].

15.3 Cogeneration and renewable energy

There are two general forms of combining cogeneration with renewables: (i) Renewable energy, for example biomass, can be the fuel of a cogeneration system. (ii) A cogeneration system can be integrated with one or more renewable energy systems, in order to serve certain loads. In both cases, there are still subjects of R&D, as it is explained in brief in the following for the main forms of renewable energy that can be combined with cogeneration, namely, biomass, solar and geothermal energy.

15.3.1 Biomass

Biomass is available in any of the three states (solid, liquid and gaseous) with a variety of compositions that make it necessary to develop proper components for the system and investigate their reliability and availability [2]. Particularly, challenging is the use of biogas in fuel cells [7]. Solid biomass can be converted into liquid or gas, which may lead to completely different cogeneration system. The selection of the state of the fluid and the type of system can be far from trivial [17].

15.3.2 Solar energy

Solar thermal energy can be the primary energy of an ORC system. As mentioned in Section 15.2, there is a variety of ORC configurations. Furthermore, there is a variety of solar thermal systems. Thus, the selection of the types of systems for a certain application and their integration, in particular if there is storage of thermal energy, are subjects that need careful consideration, open to further R&D [5,6]. Also, cogeneration systems based on a Stirling engine operating on solar thermal energy are subjects of investigation [18].

Integration of a cogeneration system with a solar photovoltaic system and storage of electric energy is also subject of R&D [19,20]. Solar radiation concentrated by Fresnel lens and a thermoelectric generator have also investigated experimentally for cogeneration of electricity and warm water [13].

In a broader sense, the word *cogeneration* is used also to imply the simultaneous production of electricity and distilled water. Such a system is studied in [21], which consists of a solar collector with evacuated tubes and a semi-transparent photovoltaic module.

15.3.3 Geothermal energy

There are two main types of systems harnessing the geothermal energy for work production and, consequently, cogeneration: (i) If the pressure and temperature of the geothermal water are at adequate level, steam is produced by a single- or multi-flash evaporator, which drives a steam turbine [21]. (ii) For low pressure and temperature of the geothermal water, ORC systems are more appropriate [22]. In both cases, the structure of the system and the determination of the operating properties are subjects of investigation. In the second case, an investigation of the best organic fluids is also needed.

15.4 Storage of thermal and electric energy

The availability of energy in excess of the load in certain periods of time and the deficit in other periods makes the storage of energy technically justified and often economically feasible.

15.4.1 Storage of thermal energy

Even though storage of thermal energy has been applied for many decades (e.g. in connection with solar energy), it is still the subject of R&D for applications in general and for cogeneration in particular [5,15,20,23–25]. The size of the storage, directly related to the duration (e.g. diurnal, weekly and seasonal), has to be optimized for each particular application, in connection with the storage medium. New storage media and processes are continuously developed and tested. In more complex systems, such as combinations of cogeneration with solar energy-producing electricity, heating and cooling, the integration of the storage unit with the rest of the system, including the cooling equipment, has to be carefully studied.

15.4.2 Storage of electric energy

Electric energy storage has been more difficult than thermal storage, due to size and weight of the batteries. It is rather short-term storage due to high investment costs and decay of stored energy. Recent advances in batteries, driven primarily by the electric car industry, make storage of electricity a possibility in cogeneration too. The type of battery, its size, performance and control are subjects of investigation [19,20].

15.5 Reduction of emissions

As mentioned in Chapter 8, cogeneration may increase the direct emissions at local level. Use of low-emissions technology and fuel is always an option [8]. Furthermore, R&D on reduction of emissions from cogeneration systems is imperative and can be performed at three stages:

1. Control of the combustion process. In internal combustion engines, for example, the optimal control of injection timing, spark advance timing (wherever applicable), excess air ratio and valve opening is the goal [26].
2. After treatment. Catalytic converters are the most usual technique, but innovative methods such as re-combustion of the exhaust gases have been proposed [27].
3. Control at the system level. If the thermal and electric load can be covered by a variety of energy sources, which sources will operate at each instant of time and at what load can be determined by optimal control strategies [28].

There is strong activity on R&D related to all three stages.

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Chapter 16

Summary and conclusions

Christos A. Frangopoulos

The average worldwide energy efficiency of supplying electricity to end-users is about 35%. As a consequence, 65% of the energy contained in fuels is wasted directly or indirectly as heat to the environment. The needs in thermal energy are much higher than the needs in electrical energy. In Europe, for example, the ratio of thermal-to-electrical energy demand is about 2:5. Thus, waste heat recovered from power plants and industrial processes can cover a significant part of the thermal energy needs. Cogeneration can exactly perform this task, raising the fuel utilization fraction to as high as 90%–95%.

As the thermal energy cannot be transferred through long distances because of losses on the way, the users of thermal energy have to be close to the site of electricity generation. In many cases, this happens with no effort. Furthermore, long-term planning can bring together electricity generators and users of heat, as for example in industrial parks.

Currently, there is a tendency towards distributed generation of electricity, thanks to its advantages. Cogeneration can very well fit in this new structure.

A variety of types, sizes and operating properties of cogeneration systems is available so that it is not difficult to select the one that best satisfies the needs for a particular application. Having being applied for more than a century, cogeneration is already a mature technology. It is interesting to note, however, that research and development is strong in both improving the old techniques from the point of view of efficiency, reliability and emissions, and devising new, in particular, for exploitation of low-temperature waste heat and for combination of cogeneration with renewable energy (solar, biomass and geothermal). New challenges also are due to the wide application of distributed generation, which includes cogeneration systems; they are primarily related to control and stability of the electric network, which requires the development of proper equipment and software.

Any type of primary energy can be used in cogeneration systems: from solar and other renewable to nuclear energy, with all types of fuels, both fossil and biofuels, in between.

The applications of cogeneration are unlimited: from small units of 1–2 kW serving individual homes (micro-cogeneration) to large plants of hundreds of megawatts supplying industrial processes with electricity and heat or connected to electricity distribution and district heating networks. Starting with the core cogeneration unit of two energy products (electricity and heat), additional equipment can be installed leading to a *trigeneration* or even *polygeneration* system. The additional products can be cold air or cold water by means of a chiller, fresh water by means of a distillation unit and even hydrogen by means of, for example, a water electrolyzer. Thus, it would not be an exaggeration to say that only imagination is a limit to the applications of cogeneration.

The first goal of a cogeneration system is to save energy in comparison to the separate generation of electricity and heat. Careful application of thermodynamic analysis based on energy and exergy is necessary in order to safeguard that the system does save energy and to quantify the savings. This assessment has to be performed before implementation of the project and also throughout its life time, hand-in-hand with the design and operation procedures, taking into consideration the profiles of the energy products needed, either as predicted at the design phase or as they are recorded during the operation, as well as the partial load performance of the system.

Due to economic incentives given to cogeneration systems and to participation of cogeneration systems in liberalized electricity markets, long discussions have been made as to what *cogenerated electricity* is, that is what portion of the electricity produced by a cogeneration system can be considered as produced in connection with useful heat. A method based on thermodynamic analysis of a system appeared recently in the literature and is included in this text.

By saving primary energy (fuel), it is expected that cogeneration would decrease the emissions too. However, if electricity generated by a clean fuel (e.g. natural gas) in a power plant is substituted by electricity coming from a cogeneration system operating on coal or heavy fuel, then certain emissions may not decrease. Also, a cogeneration system installed close to an inhabited area produces emissions not existing before in this area. These aspects are mentioned in order not to deter one from applying cogeneration, but to emphasize the need for a careful assessment of the environmental consequences, so that proper measures for pollution abatement are taken in time.

In assessing the technical and economic performance of a cogeneration system, there is a need to take into consideration that, even though highly reliable, the system needs certain time for maintenance, and it may be subject to sudden failure. Therefore, the reliability and availability of the system have to be estimated in order to determine the time the system can really operate and to schedule the maintenance actions. Otherwise, its performance may be overestimated. The installation of one or more parallel units increases the reliability and availability of the whole system.

Even though cogeneration systems are characterized as capital-intensive, the investment cost is not more than 10%–20% of the life-cycle cost of the system (in certain cases, even lower than 10%). Therefore, the correct picture of the performance will be given by a life-cycle estimation of the cost, which includes operation and maintenance. The most important measures of economic performance are the present worth cost of covering the energy needs, the net present value of the investment, the internal rate of return and the dynamic payback period. The first two of these are the most appropriate for a long-term investment policy.

One more benefit of cogeneration is the increase of the security of supply of electricity. Cogeneration installations are also very suitable as backup for intermittent renewable sources of energy.

The increasing concern about the adverse effects of energy systems on the environment led to the development of methods for quantitative estimation of the effects, expressed both in technical and economic terms. As a result, the external environmental cost of a system can be estimated. The next step is the internalization of this cost, that is the addition of the external environmental cost to the conventional cost of the system. The result can be surprising: examples show that, depending on the type of system and the fuel used, the present worth of the environmental cost can be from 30% up to 200% of the conventional present worth cost of the system. It is true that assessing the adverse effects on the environment and monetizing those is not an easy task, and the results produced for the environmental costs of emissions may have an uncertainty. However, it is much safer to estimate environmental costs and consider those during the economic analysis of the system than to ignore those completely. It can be also revealing in comparative assessment of alternative systems.

In order for a cogeneration system to show all its advantages for energy savings, reduction of emissions and economic profitability, it has to be properly selected for each particular application, integrated to the facility it serves and operated. Important aspects to consider are the characteristics of the electric and thermal loads: voltage, frequency, electric power, carrier of thermal energy (air, water, steam, direct use of exhaust gas, etc.), level(s) of pressure and temperature, mass flow rate(s) and fluctuation of those with time (load curves). Based on this information, a systematic procedure based on the experience of the designer can lead to the proper system. Regarding the operation, two characteristic modes are the *electricity match* and the *heat match* mode of operation. In the first case, the electric power of the system is controlled to be equal to the electric load. If extra heat is produced, it has to be rejected to the environment, whereas if additional heat is needed, it can be produced by a boiler. In the second case, the thermal power recovered is controlled to be equal to the thermal load, whereas connection to the electricity network will supply additional electricity, if needed, or absorb any excess electricity. Anything in between is possible. The *island mode* is also possible, in which case the system is not connected to any external network. Of course, there is interdependency between the mode of operation and the structure and size of the cogeneration system. The island mode is more demanding, because the system must have proper structure and sufficient redundancy in order to cover all loads under any circumstances with no external contribution.

It goes without saying that the experiences of the designer and operator are more than important for the proper selection and operation of a cogeneration system. However, existence of a variety of loads changing with time on one hand and changing market environment on the other hand may make it rather impossible to determine the best system configuration, design specifications and operating mode at every instant of time by experience alone. Here come simulation and mathematical optimisation methods to help in designing the best system and in determining the best operating mode at each instant of time, with no need to pre-specify whether it will be electricity match or heat match. The word ‘best’ implies that a goal is selected (e.g. minimization of the life-cycle cost, maximization of the net present value, etc.), and it is expressed as a mathematical function. Simulation of the system gives the information needed in order to calculate the value of the function, whereas an optimisation algorithm determines the values of the variables (design and operation characteristics of the system) that give the minimum (or maximum) value of the function. The improvement of the economic performance achieved in this way is far from negligible.

It was recognized in the 1970s and beyond that cogeneration can be a strong instrument in primary energy savings and in reducing CO_2 and other emissions. Thus, promotion of cogeneration has been one of the goals in energy policy and for this purpose, special laws and regulations started being issued, first in the United States of America and then in other countries worldwide as well as in the European Union. Also, the International Energy Agency in Paris recommends cogeneration as an effective means to reduce fossil fuel consumption.

Among other subjects, rules for the cogeneration systems to be eligible for financial and economic incentives have been issued, as well as for their participation in the electricity market. The gap between the fuel and electricity price affects crucially the economic viability of cogeneration. Furthermore, it is noted that cogeneration may have difficulty in penetrating both ‘close-to-slow-opening’ and fully liberalized electricity markets. Thus, the regulatory and legal framework needs to be updated from time to time.

Index

Cogeneration

Technologies, Optimisation and Implementation

Cogeneration, also called combined heat and power (CHP), refers to the use of a power station to deliver two or more useful forms of energy, for example, to generate electricity and heat at the same time. All conventional, fuel-based plants generate heat as by-product, which is often carried away and wasted. Cogeneration captures part of this heat for delivery to consumers and is thus a thermodynamically efficient use of fuel, and contributes to reduction of carbon emissions. This book provides an integrated treatment of cogeneration, including a tour of the available technologies and their features, and how these systems can be analysed and optimised.

Topics covered include benefits of cogeneration; cogeneration technologies; electrical engineering aspects; applications of cogeneration; fuels for cogeneration systems; thermodynamic analysis; environmental impacts of cogeneration; reliability and availability; economic analysis of cogeneration systems; regulatory and legal frameworks; selection, integration and operation of cogeneration systems; simulation and optimisation; synthesis, design and operation; examples of cogeneration projects; research and development of cogeneration; summary and conclusions.

This book is intended for instructors and students at advanced undergraduate as well as graduate level, for professional engineers who design, build and operate cogeneration systems, and for researchers on analysis and optimisation of energy systems.

About the Editor

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