Chapter 10
District Energy Systems

10.1 Introduction

During the past decade, increasing local and global problems regarding energy, the environment, and the economy have created one of the biggest challenges for human beings to combat through sustainable solutions. District energy systems (DESs) for distributed heating and/or cooling, known also as district heating and cooling (DHC) systems, appear to be part of the solutions. In some situations, for example in the case of a major power plant, it may appear economically attractive to build a pipe network that distributes the ejected heat among a number of residential/commercial/industrial users covering a territory around the central power plant. Cogeneration, geothermal, or solar energy systems are the most suitable for being coupled to DHC. Steam, hot or cold water, or ice slurry can be used as heat-conveying fluids. The opportunity of using a DES must be judged first on an economic basis by comparison of the life-cycle cost (LCC) with the cost of other competing systems, such as electrically driven heat pumps at the user's location. There also are some ecological benefits because CO_2 or other emissions can be reduced and controlled better from a central plant rather than from distributed locations. In general, one recognizes that district heating (DH) as well as district cooling (DC) may be advantageous whenever a central source can be made available to distribute heat and/or cold to residential, commercial, or industrial consumers.

Most of the Rankine cycle–based power plants in operation nowadays eject an enormous amount of condensation heat into a cooling tower or a lake, even though it is obvious that by using the ejected heat to some purpose the overall efficiency is greatly augmented. If instead of ejecting it, the heat is distributed to a number of users over a territory around the power plant, one has a district heating system. Up to the present, this philosophy of design has been applied in a limited fashion in many European and North American countries, where the planned economy and political will allowed for large capital investments in network infrastructure.

Basically, DESs convert the primary energy in a commodity (heating and/or cooling) that can be bought or sold. The energy distributed by a DES can provide space heating, air conditioning, refrigeration, domestic hot water, and industrial

İ. Dinçer and C. Zamfirescu, *Sustainable Energy Systems and Applications*,
DOI 10.1007/978-0-387-95861-3_10, © Springer Science+Business Media, LLC 2011

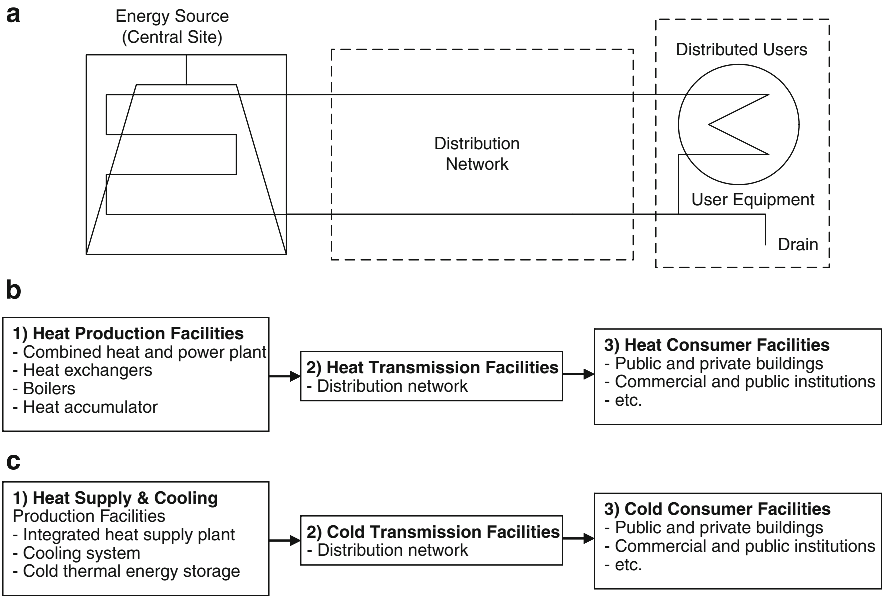

Fig. 10.1 (**a**) A general layout of a district energy system and basic flowcharts for (**b**) district heating and (**c**) district cooling applications

process heating and cooling, and often cogenerates electricity locally. Even more recently, there has been an attempt to look at the hydrogen production options in a combined or integrated form.

There can be a large number of central sources suitable for DHC: fossil fuels (coal, natural gas, oil, or other petroleum products) and nuclear-based power plants with cogeneration of electric power and heat, geothermal energy exploitation facilities, solar collector fields, city waste incinerators, and any combination of these. Typically, the carrier fluids are steam or hot or cold water and the more recently developed ice slurry, which is a mixture of water, ice particles, and antifreeze. The chilled water or the ice slurry can be produced by heat-driven absorption chillers (e.g., lithium bromide or ammonia–water), steam turbo-chillers, or steam ejectors, or mechanically driven vapor compression chillers.

The overall layout of a DES consisting of a central heat/cold production, a distribution network, and user equipment at consumers' locations is illustrated in Fig. 10.1a. The fluid carrying the thermal energy can be completely recirculated in a closed loop, or partially or totally drained (e.g., in the case of steam) at the users' locations. Figure 10.1b illustrates a district heating system layout. In this case, at the heat production site, there can be a combined heat and power (CHP) plant, a fuel boiler, a thermal storage system, or a combination of these. The primary source can be fossil fuel or biomass, nuclear, geothermal, or solar energy. Through the heat transmission network, hot water or steam may circulate, depending on the design option. At the user's site, various heat exchangers can be used to

Table 10.1 Some technical aspects of DES

Land use	Specific thermal load (MW/ha)	DES desirability
Downtown, skyscrapers	>0.70	Very favorable
Downtown, multistoried buildings	0.51–0.70	Favorable
City center; multifamily apartments, commercial building settings	0.20–0.50	Possible
Two-family residential building	0.12–0.20	Questionable
Single-family residence	<0.12	Unfeasible

Data from (Karlsson 1982)

serve for space heating, water heating, or industrial process heating. Figure 10.1c presents the general district cooling system layout. In this case, at the central site, a primary thermal energy (in general, in the form of a hot source) is converted into cold thermal energy. This can be done through an absorption chiller. An alternative is to use an electrically driven chiller. The central production site can also be equipped with a cold thermal energy storage system that has the advantage of allowing for cooling load levelizing (this is a better match for cold production and demand) during the day, week, or season.

In general, the most expensive component of a DES is the piping network made from a combination of field-insulated and preinsulated pipes either embedded in a concrete tunnel or buried in the ground, or a combination of the two. Its capital cost may range between 50% and 75% of the total. The user's equipment is assumed to be the least expensive, and can be formed from simple heat exchangers and distribution/regulating valves.

The fact that the distribution network is relatively expensive makes DHC systems most attractive in major cities, high-density building clusters, tall buildings with high thermal (heat or cold) load, and industrial parks. In Table 10.1, we quantify the desirability of a DES as a function of the land use and the specific thermal load. When cooling and heating is required simultaneously (e.g., in the case of industrial processes or if a refrigerated storage facility that requires cooling is in the vicinity of building settings that require heating), this can be economically advantageous because a central large capacity heat pump can generate both cooling and heating at a lower cost than individual on-site units.

The DHC systems are expected to provide other environmental and economic benefits:

- Reduced local/regional air pollution
- Increased opportunities to use ozone-friendly cooling and heating technologies
- Infrastructure upgrades and development that provide new jobs
- Enhanced opportunities for electric peak reduction through chilled water or ice storage
- Increased feasibility of thermal energy storage at the central location for better energy management
- Better part-load capability and efficiency (multiple units can be used to adjust to variable demand)
- Increased fuel flexibility

- Better energy security
- Better energy efficiency, lower operating and maintenance costs, specifically in large facilities
- Concentration of specialized personnel at the central plant location for better economics
- Better building economics by not needing on-site personnel for boiler or chiller surveillance
- Possibility of expansion to accommodate future growth (of network and central plant)
- Reducing the costs related to metering of the distributed energy
- Better noise and environment pollution control; CO_2 sequestration facilitated at the central location

The DHC's potential can be realized through policies and measures to increase awareness and knowledge of these systems; recognize the environmental benefits of district energy in air quality regulation; encourage investment; and facilitate the increased use of district energy in government, public, commercial, industrial, and residential buildings.

During the past few decades, there have been various key initiatives taken by major energy organizations (e.g., the International Energy Agency [IEA], the U.S. Department of Energy, Natural Resources Canada, etc.) on the implementation of DHC systems all over the world as one of the most significant ways to (1) maximize the efficiency of the electricity generation process by providing a means to use the waste heat, saving energy while also displacing the need for further heat-generating plants; (2) share heat loads, thereby using plants more effectively and efficiently; (3) achieve fuel flexibility and provide opportunities for the introduction of renewable sources of energy as well as cogeneration and industrial waste heat.

Furthermore, the IEA has developed a strategic document (IEA 2004) as an implementing agreement on DHC, including the integration of CHP, focusing on the following:

- Integration of energy-efficient and renewable energy systems for limited emissions of greenhouse gases
- Community system integration and optimization, use of waste thermal energy, renewable energy and CHP, for a better environment and sustainability
- Reliability, robustness, and energy security for effective maintenance and management of buildings
- Advanced technologies for an improved system integration, including information systems and controls
- Dissemination and deployment for rapid changes to foster energy efficiency and sustainability

Here, we present the historical development of DES, and we discuss some technical, economical, environmental, and sustainability aspects of these systems, their performance evaluation tools in terms of energy and exergy efficiencies, and LCC and life-cycle savings. The use of LCC or life-cycle savings criteria for evaluating the feasibility of DHC versus other competing systems is discussed. Several design aspects of the DHC system are introduced. Some case studies and several numerical examples are also presented to highlight the importance of exergy use as a potential tool for system analysis, design, and improvement.

10.2 Distributed Energy Systems Description

The central energy source and the distribution network are two capital intensive components of the DES. It is important to understand the role and structure of these two subsystems, their development, the status of the present technology, and their future role as related to environment and sustainability. First, we briefly follow the historical dissemination and evolution of DES in the world; thereafter, we comment on the importance of cogeneration as central source for distributed energy systems. In this section, flow diagrams of DHC networks, piping layouts, and other technological and design issues are discussed.

10.2.1 Historical Development and Perspectives of District Energy Systems

The development of district heating systems traces back to antiquity when the Roman Empire developed thermaes (public baths) supplied by centrally heated water. Probably, the oldest DH system that is in operation today is the one created in the early fourteenth century in Chaudes-Aigues Cantal, a village in France. This system distributed warm water through wooden pipes and is still in use today. The first commercial DH system was created by Birdsill Holly in Lockport, New York, in 1877 (Dincer and Hepbasli 2010). In this system, the boiler is used as the central heat source and the system supplies a loop consisting of steam pipes, radiators, and even condensate return lines. At first, the system attracted a dozen customers. Only 3 years later, it served several factories as well as residential customers and had extended to a ~5-km loop.

The largest commercial district heating system in the United States that has operated continuously since 1882 is installed in New York (ConEd 2008). In addition to providing space and water heating, steam from the system is used in restaurants for food preparation, as process heat in laundries and dry cleaners, as well as in power absorption chillers for air conditioning.

The city of Paris operates a geothermal district heating system that delivers hot water at ~65°C, while the city of Vienna has a district heating system totaling a capacity of over 5 GWh/year. In Germany the district heating system has a market share of about 14%; the former Soviet Union, during the Communist era, developed most of its coal power plants as cogeneration units to supply heating to neighboring buildings (Skagestad and Mildenstein 2002).

The roots of district cooling (DC) systems go back to the nineteenth century. A DC system was initially introduced as a scheme to distribute clean, cool air to houses through underground pipes. Probably the first known DC system began operations at Denver's Colorado Automatic Refrigerator Company in late 1889. In the 1930s, large DC systems were created for Rockefeller Center in New York City and for the U.S. Capitol buildings in Washington, DC. So far few European cities have adopted DC systems for applications (National Academy of Sciences 1985).

It is believed that district energy in Canada began in London, Ontario, in 1880. The London system was built in the form of a group of systems serving the university, hospital, and government complexes. The University of Toronto is known to have developed a DH system in 1911 that served the needs of the university. The first commercial DH system in Canada was established in 1924 in the city of Winnipeg's commercial core. Canada boasts the site of one of the northernmost DESs in North America: Fort McPherson, located in the North West Territories. The Canadian District Energy Association (CDEA) was created in 1993 in recognition of the fact that the emerging Canadian district energy industry needed to create a common voice to promote DHC applications. It aims to exchange and share information and experience with its stakeholders. It has also been instrumental in helping to provide a forum for the exchange of ideas and information, and in identifying and addressing key technical and policy issues to advance the use of district energy in Canada. As a recent application of a district energy system, the city of Toronto has been using cold deep water from the Lake Ontario and heating from fuel-based cogeneration plants; for further information, see Enwave (2005).

10.2.2 Cogeneration as a Key Part of District Energy Systems

Cogeneration, also referred to as CHP, is the simultaneous sequential production of electrical and thermal energy from a single fuel. During the past couple of decades, cogeneration has become an attractive and practical proposition for a wide range of thermal applications, including DHC. Some examples are the process industries (pharmaceuticals, paper and board, cement, food, textile, etc.); commercial, government, and public sector buildings (hotels, hospitals, swimming pools, universities, airports, offices, etc.); and DHC schemes. Figure 10.2 shows a comparison of both conventional power systems and cogeneration systems. The main drawback in the conventional system is the amount of intensive heat losses, resulting in some drastic drops in efficiency.

The key question is how to overcome this and make the system more efficient. The answer is clear: by cogeneration. In this regard, we minimize the heat losses, increase the efficiency, and provide the opportunity to supply heat to various applications and facilities. The overall thermal efficiency of the system is the percent of the fuel converted to electricity plus the percent of fuel converted to useful thermal energy. Typically, cogeneration systems have overall efficiencies ranging from 65% to 90%.

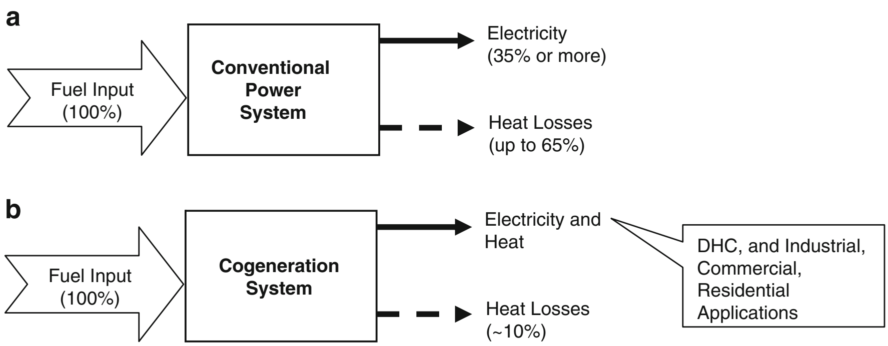

Fig. 10.2 Illustration of (**a**) a conventional power system and (**b**) a cogeneration system

The key point here is that the heat ejected from one process is used for another process, which makes the system more efficient, compared to the independent production of both electricity and thermal energy. Here, the thermal energy can be used in DH and/or DC applications. Heating applications basically include generation of steam or hot water. Cooling applications basically require the use of absorption chillers that convert heat to cooling. Numerous advanced technologies are available to achieve cogeneration, but the system requires an electricity generator and a heat recovery system for full functioning.

As mentioned above, cogeneration has been widely adopted in many European countries for use in industrial, commercial/institutional, and residential applications. It currently represents 10% of all European electricity production and over 30% of electricity production in Finland, Denmark, and the Netherlands. In Canada, however, cogeneration represents just over 6% of national electricity production (Strickland and Nyboer 2002). This relatively lower penetration is attributed to Canada's historically low energy prices and to electric utility policies for the provision of back-up power and the sale of surplus electricity. Despite these conditions, cogeneration has been adopted in some industrial applications, notably the pulp and paper and chemical products sectors, where a large demand for both heat and electricity exists. There are several classic technologies currently available for cogeneration, such as steam turbines, gas turbines, combined cycles (both steam and gas turbines, and reciprocating engines (gas and diesel). In addition, there has been increasing interest in using new technologies, namely, fuel cells, microturbines, and Stirling engines. Note that heat output from the system varies greatly depending on the system type. The output can range from high-pressure, high-temperature (e.g., 500–600°C) steam to hot water (e.g., 90°C). High-pressure, high-temperature steam is considered high-quality thermal output because it can meet most industrial process needs. Hot water is considered as low-quality thermal output because it can be used only for a limited number of DHC applications.

Cogeneration can be based on a wide variety of fuels, and individual installations may be designed to accept more than one fuel. While solid, liquid, or gaseous fossil

Table 10.2 Main characteristics and technical aspects of cogeneration systems

Technology	Fuel type	Capacity (MW_e)	Electrical efficiency (%)	Overall efficiency (%)	Average capital cost (US$/$kW_e$)	Average maintenance cost (US$/kWh)
Steam turbine	Any	0.5–500	7–20	60–80	900–1,800	0.0027
Gas turbine	Gaseous and liquid fuels	0.25–50 or more	25–42	65–87	400–850	0.004–0.009
Combined cycle	Gaseous and liquid fuels	3–300 or more	35–55	73–90	400–850	0.004–0.009
Reciprocating engines	Gaseous and liquid fuels	0.003–20	25–45	65–92	300–1,450	0.007–0.014
Microturbines	Gaseous and liquid fuels	–	15–30	60–85	600–850	<0.006–0.01
Fuel cells	Gaseous and liquid fuels	0.003–3 or more	35–50	80–90	–	–
Stirling engines	Gaseous and liquid fuels	0.003–1.5	~40	65–85	–	–

Data from UNEP (2005)

fuels dominate currently, cogeneration from biomass fuels is becoming increasingly important. Sometimes fuels are used that otherwise would constitute waste, such as refinery gases, landfill gas, agricultural waste, or forest residues. These substances increase the cost-efficiency of cogeneration (UNEP 2005). Table 10.2 lists cogeneration technologies and their fuel type, capacity, efficiency, average capital cost, and maintenance cost.

10.2.3 Technological Aspects

Many DHC systems do not include both DH and DC. For example, in Europe, where moderate summer temperatures prevail, most DESs provide heating capability only. DC has only recently become more widespread, with the most prevalent application being in North America, where summer temperatures can, over extended periods, reach extremes of 30° to 40°C.

In order to implement a DH, DC, or DHC system in a community, there are several factors that must be weighed in a feasibility study for determining whether or not a DH, DC, or DHC system is suitable. Some essential factors include energy, exergey, the environment, economics, social criteria, operating conditions, fuel availability, efficiency considerations, local benefits, viability of competing systems, local climatic conditions, users' characteristics, load density, total load requirements, characteristics of heating and cooling systems currently in place, the developer's perspectives, and local utility considerations.

Note that a DH or DC system differs fundamentally from a conventional system because, in the case of the latter, thermal energy is produced and distributed at the location of use. Examples of conventional systems include residential heating and

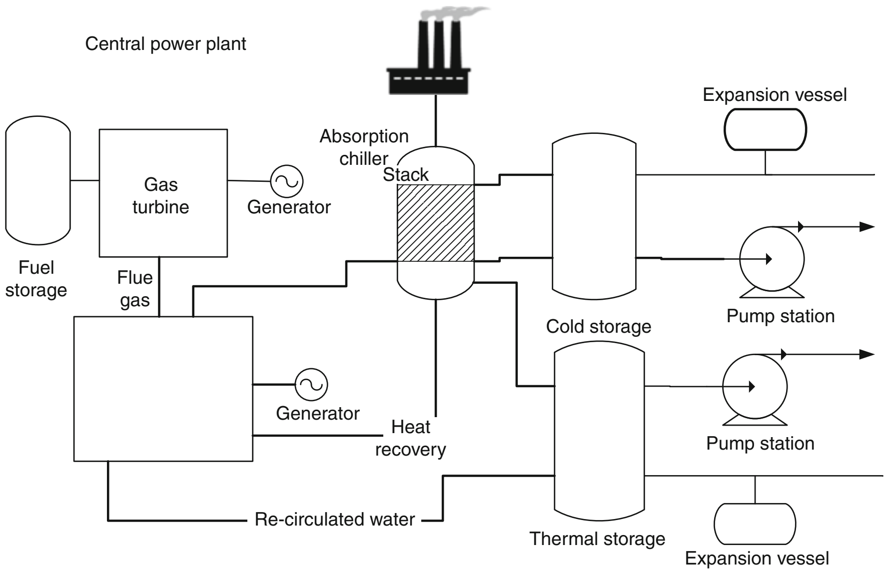

Fig. 10.3 Example of a hybrid gas turbine/steam Rankine cycle CHP facility

cooling with, respectively, furnaces and air conditioners; electric heating of offices; package boilers/chillers providing heating/cooling of apartment complexes; and a dedicated boiler plant providing heat to an industrial facility. The feasibility of a DHC system therefore must be compared to that of a convectional system.

A possible layout of a CHP central plant is shown in Fig. 10.3. In this example, the CHP unit is fueled with oil or natural gas and consists of a gas turbine engine cascaded with the steam boiler of a Rankine cycle. After being used to heat the steam cycle, the flue gas still possesses energy, which is directed toward the generator of an absorption chiller and then released into the atmosphere with possible prior filtering and CO_2 separation and sequestration. The refrigeration effect produced by the absorption chiller is carried by a selected heat transfer fluid (cold water or ice slurry) that supplies the cold distribution line. On this line, a cold storage facility can also be mounted, as illustrated in the figure. The pumping station and thermal expansion tanks equip also the central plant. The facility can be designed so that the heat ejected by the Rankine cycle could be upgraded with the heat ejected by the condenser of the absorption chiller and delivered to the heat distribution line. The heat distribution line itself can be equipped with a thermal storage tank based either on sensible heat storage (hot water) or on latent heat storage (in phase change materials). Both the gas turbine and steam turbine turn an electrical generator at their shaft, and the CHP site is equipped with all the needed electrical equipment to deliver power to the grid.

A number of issues must be addressed when designing a CHP plant that serves a DES. A decision must be made regarding the thermal carrier. Knowing the type of thermal energy carrier is compulsory for designing the heat exchangers for heat and

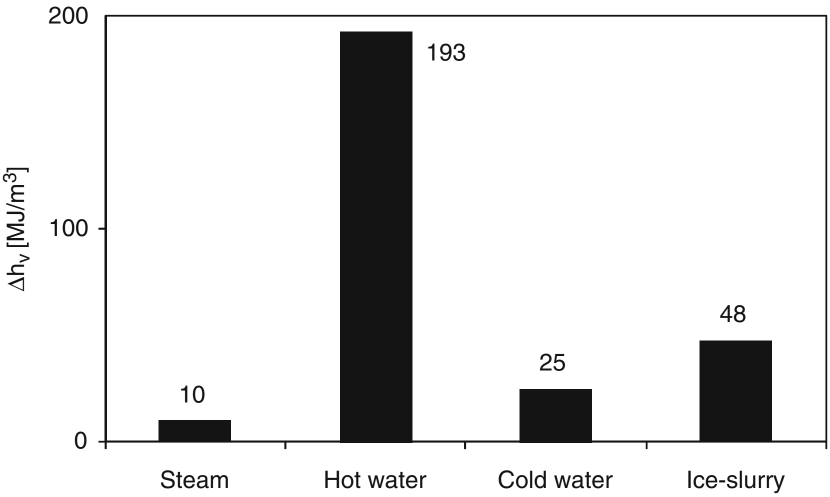

Fig. 10.4 Volumetric specific enthalpy variation of steam (at 8 bar from saturated vapor to 80°C subcooled liquid), hot water (from liquid saturated at 170°C and cooled to 120°C), cold water (from 4° to 10°C), and ice slurry (water–ethanol at 0°C, from 30% slurry to 0%)

cold recovery. The first thermophysical property that has to be analyzed is the heat capacity (or latent heat) of the carrier. In the case of heat, one must choose between steam and hot water. Here, the key question may be at what temperature the network should operate. There are several temperature thresholds as given below as a practical guide:

- Above 175°C supply temperature for high-temperature networks
- 120–175°C for average-temperature district heating
- Below 120°C for low-temperature district heating
- 4°C supply temperature for cold water at district cooling
- 0°C or slightly below if ice slurry is used for district cooling

Based on heat capacity (or latent heat) and the specific volume of the thermal carrier fluid, one can easily derive the specific volumetric enthalpy (measured in kJ/m^3) and compare this parameter to other options. Figure 10.4 shows the calculated value of specific volumetric enthalpy of high-temperature steam, water, and ice-slurry. Even though on a mass basis the enthalpy of steam is the highest, on a volumetric basis the steam enthalpy is the lowest among all options because of steam's high-specific volume. As a consequence, steam pipes have a higher diameter than water pipes and therefore are more costly. However, the condensate return pipe has a smaller diameter than the hot water return pipe, and this somehow compensates for the costs. Ice slurry's, specific volumetric enthalpy is about double that of chilled water because the latent heat of melting is stored in ice slurry. The ice-slurry properties can be calculated based on data taken from Bel et al. (1996).

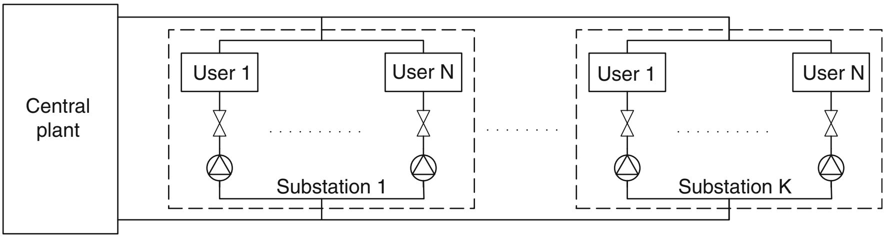

Fig. 10.5 Layout example of a primary and secondary distribution system

If cogeneration is not the adopted solution for a central power plant, heat could be produced using commercially available boilers fueled with coal, oil, or natural gas. Custom-made solutions can be devised for biomass combustion or city waste incinerators with heat recovery. Absorption refrigeration is the preferred method to produce cold water if heat is generated at the central plant. As an alternative, electrically- or heat engine–driven mechanical chillers can be adopted. In general, the chilled water is produced at 5°C and it returns at 7°C. The lower value of produced chilled water is 4°C (due to water density anomaly), and the maximum return temperature can go up to 10°C. Ice slurry can be generated either in mechanical ice scrapers or fluidized bed ice scrapers or in water turbo-refrigerators. Typically, the temperature of the ice slurry is slightly below 0°C.

Thermal and cold storage can be used at a central plant for better efficiency and adaptation to a variable load. With an appropriate thermal energy storage strategy, the capacity and the associated investment in heat or cold thermal energy generators can be reduced.

The layout of the distribution network can consist of a primary circuit that delivers the thermal carrier to a number of substations working in parallel. Each substation may include pumps for pressure head rebuilding, and it distributes the working fluid among a number of users connected in parallel. A typical network diagram is presented in Fig. 10.5.

Two flow control strategies are possible: (1) constant flow and variable temperature difference, or (2) variable flow and constant temperature difference. In the first approach, the flow rate is maintained constant and well balanced for all users. As a consequence of demand variation among users, the return temperature adjusts so that it meets the load. The variable flow/constant temperature control strategy is met to enhance the system efficiency by a better use of flow exergy. That is, if one keeps the temperature level constant, the specific exergy of the circulated streams is maintained constant, too, and the system efficiency is thus maximized. The flow rate can be adjusted either by flow-throttling with modulating valves or by using variable speed pumps.

At the user's location, it is preferable to design a temperature (or enthalpy) drop as large as possible so as to minimize the pumping power and reduce the diameter of distribution pipes (therefore their capital cost). Based on the current practice, the temperature drop for a district heating system is taken to be 22 K or larger (ASHRAE 2008). The users' equipment (e.g., radiators) can be directly connected to the network, or indirectly via a heat exchanger. In the indirect connection, the heat exchanger transfers the heat from the distribution network to the users' equipment, creates a pressure separation between the district network and the building network (for safety reasons, it is preferred that the distribution network in buildings operates at low pressure), and separates the water quality treatment of the inner and outer networks.

10.3 Environmental Impact

Problems with energy supply and use are related not only to global warming but also to such environmental concerns as air pollution, acid precipitation, ozone depletion, forest destruction, and emission of radioactive substances. These issues must be taken into consideration simultaneously if humanity is to achieve a bright energy future with minimal environmental impact. Much evidence exists to suggest that the future will be negatively impacted if humans keep degrading the environment. One solution to both energy and environmental problems is to encourage much more use of DHC applications.

Numerous fuels are used at DHC plants, including various grades of oil and coal, natural gas, refuse, and other biofuels such as wood chips, peat, and straw. The combustion of such fuels may produce environmentally hazardous products of combustion, and thus flue gas cleaning devices and other emission reduction measures are often incorporated. Some measures are usually required under increasingly strict legislation, before approval to operate a facility is granted. Examples of pollution control equipment used at DHC plants include acid gas scrubbers. These systems typically utilize hydrated lime to react with the moisture, SO, and other acid gases in the flue gases discharged from the combustion system. With such systems, the lime–acid and gas–water vapor reaction products are efficiently collected by electrostatic precipitators as particulate matter. Bag filters are also utilized in many applications to capture the particulate matter as well as the acid gas scrubbing reaction products. Conventional oil/gas fired boilers utilizing low NO_x and burners to dramatically reduce NO_x emissions are also becoming more common. Flue gas recirculation to reduce NO_x emissions has also been proven to be effective. Other emission control or reduction techniques can be introduced with DHC systems, including optimization of combustion efficiency (i.e., reduces CO_2, CO, and hydrocarbon emissions) through the use of modern computerized combustion control systems, and utilization of higher quality and lower emission producing fuels. By addressing these issues, it is apparent that heating and cooling systems that minimize the quantity of fuel and electrical power required to meet the users' needs result in a reduced impact on the environment.

In addition, DHC systems that comprise several different types of thermal energy generation plants can optimize plant and system efficiency by utilizing, whenever possible, the thermal energy sources with the highest energy conversion efficiencies for base and other partial load conditions. The sources with the poorer conversion efficiencies can then be utilized only to meet peak loads. Essentially, improved efficiency means the use of less fuel for the same amount of energy produced which in turn results in the conservation of fossil fuels, reduced emissions of pollutants, improved air quality, and reduced use of chlorofluorocarbon (CFC) refrigerants, if any, in DC applications.

The DHC systems are well suited to combine with electric power production facilities as cogeneration plants. The amalgamation of these two energy production/utilization schemes results in a substantial improvement in overall energy conversion efficiency since DH systems can effectively utilize the otherwise wasted heat associated with the electric power production process. A district system meeting much or all of its load requirements with waste heat from power generation facilities has a positive environmental impact, as fuel consumption within the community is reduced considerably. Conservation of fossil fuels and a reduction of combustion-related emissions are resultant direct benefits of such a DHC system.

The centralized nature of DHC energy production plants results in a reduced number of emission sources in a community. This introduces the potential for several direct benefits.

The higher operating efficiency afforded by larger, well-maintained facilities translates directly to reduced fuel consumption, which in turn results in the conservation of fossil fuels and reduced emissions. Higher operating efficiency of the combustion process (where parameters such as temperature, combustion air and fuel input levels, residence time, etc., are closely monitored) also impacts emission production in that the concentration of certain pollutants produced, particularly CO_2 and NO_x, is reduced.

Furthermore, measures to increase energy efficiency can reduce environmental impact by reducing energy losses. From an exergy viewpoint, such activities lead to increased exergy efficiency and reduced exergy losses (both waste exergy emissions and internal exergy consumption).

A deeper understanding of the relations between exergy and the environment may reveal the underlying fundamental patterns and forces affecting changes in the environment, and help researchers better address environmental damage.

The second law of thermodynamics is instrumental in providing insights into environmental impact. The most appropriate link between the second law and environmental impact has been suggested to be exergy, in part because it is a measure of the departure of the state of a system from that of the environment. The magnitude of the exergy of a system depends on the states of both the system and the environment. This departure is zero only when the system is in equilibrium with its environment.

In order to achieve the energy, economic, and environmental benefits that DHCs offer, the following integrated set of activities should instituted (Dincer 2000):

- *Research and development*. Research and development priorities should be set in close consultation with industry to reflect its needs. Most research is conducted through cost-shared agreements and falls within the short-to-medium term.

Partners in these activities should include a variety of stakeholders in the energy industry, such as private sector firms, utilities across the country, provincial governments, and other federal departments.

- *Technology assessment*. Appropriate technical data should be gathered in the lab and through field trials on factors such as cost benefit, reliability, environmental impact, safety, and opportunities for improvement. These data should also assist in the preparation of technology status overviews and strategic plans for further research and development.
- *Standards development*. The development of technical and safety standards is needed to encourage the acceptance of proven technologies in the marketplace. Standards development should be conducted in cooperation with national and international standards writing organizations, as well as other national and provincial regulatory bodies.
- *Technology transfer*. Research and development results should be disseminated through the sponsorship of technical workshops, seminars, and conferences, as well as through the development of training manuals and design tools, web tools, and the publication of technical reports.

Such activities also encourage potential users to consider the benefits of adopting DHC applications and using renewable energy resources. In support of developing near-term markets, a key technology transfer area is the acceleration of the use of cogeneration and DHC applications, particularly for better efficiency, cost-effectiveness, and the environment.

10.4 Role in Sustainable Development

Sustainable development requires a sustainable supply of clean and affordable energy resources that do not have negative societal impacts (Dincer and Rosen 2005). Supplies of such energy resources as fossil fuels and uranium are finite. Green energy resources, such as solar and wind, are generally considered renewable and therefore sustainable over the relatively long term.

Sustainability often leads local and national authorities to incorporate environmental considerations into energy planning. The need to satisfy basic human needs and aspirations, combined with the increasing world population, makes the need for successful implementation of sustainable development increasingly apparent. Here are the factors that are essential to achieve sustainable development in a society:

- Information about and public awareness of the benefits of sustainability investments
- Environmental education and training
- Appropriate energy and exergy strategies
- The availability of renewable energy sources and cleaner technologies
- A reasonable supply of financing
- Monitoring and evaluation tools

The key point here is to use renewable energy resources in DHC systems. As known, not all renewable energy resources are inherently clean in that they cause no burden on the environment in terms of waste emissions, resource extraction, or other environmental disruptions. Nevertheless, the use of DHC systems almost certainly can provide cleaner and more sustainable energy than can increased controls on conventional energy systems.

To seize these opportunities, it is essential to establish a DHC market and gradually build up the experience with cutting-edge technologies. The barriers and constraints to the diffusion of DHC use should be removed. The legal, administrative, and financing infrastructure should be established to facilitate planning and the application of geothermal energy projects. Government could/should play a useful role in promoting geothermal energy technologies through funding and incentives to encourage research and development as well as commercialization and implementation in both urban and rural areas.

Environmental concerns are significantly linked to sustainable development. Activities that continually degrade the environment are not sustainable. For example, the cumulative impact on the environment of such activities often leads over time to a variety of health, ecological, and other problems. Clearly, a strong relation exists between efficiency and environmental impact, since, for the same services or products, less resource utilization and pollution is normally associated with increased efficiency (Dincer 2002).

Improved energy efficiency leads to reduced energy losses. Most efficiency improvements produce direct environmental benefits in two ways. First, operating energy input requirements are reduced per unit output, and pollutants generated are correspondingly reduced. Second, consideration of the entire life cycle for energy resources and technologies suggests that improved efficiency reduces environmental impact during most stages of the life cycle.

In recent years, the increased acknowledgment of humankind's interdependence with the environment has been embraced in the concept of sustainable development. With energy constituting a basic necessity for maintaining and improving standards of living throughout the world, the widespread use of fossil fuels may have impacted the planet in ways far more significant than first thought. In addition to the manageable impacts of mining and drilling for fossil fuels and discharging wastes from processing and refining operations, the greenhouse gases created by burning these fuels are regarded as a major contributor to the global warming threat. Global warming and large-scale climate change have implications for food chain disruption, flooding, and severe weather events.

The use of renewable energy sources in DHC systems with cogeneration can help reduce environmental damage and achieve sustainability.

Sustainable development requires not just that sustainable energy resources be used, but that the resources be used efficiently. The authors and others feel that exergy methods can be used to evaluate and improve efficiency, and thus to improve sustainability. Since energy can never be "lost," as it is conserved according to the first law of thermodynamics, while exergy can be lost due to internal irreversibilities, this suggests that exergy losses, which represent potential not used, particularly from the use of nonrenewable energy forms, should be minimized when striving for sustainable development. The next section discusses the exergy aspects of thermal systems and presents an efficiency analysis for performance improvement.

Furthermore, some environmental effects associated with emissions and resource depletion can be expressed based on physical principles in terms of an exergy-based indicator. It may be possible to generalize this indicator to cover a comprehensive range of environmental effects, and research in line with that objective is ongoing.

Although this book discusses the benefits of using thermodynamic principles, especially exergy, to assess the sustainability and environmental impact of energy systems, this area of work is relatively new. Further research is needed to provide a better understanding of the potential role of exergy in such a comprehensive perspective. This includes the need for research to (1) better define the role of exergy in environmental impact and design, (2) identify how exergy can be better used as an indicator of potential environmental impact, and (3) develop holistic exergy-based methods that simultaneously account for technical, economic, environmental, and other factors.

10.5 Thermodynamic Analysis

The analysis of any thermal system is based on thermodynamics because it allows for performance quantification, comparison with other systems, and design optimization. Using the exergy method, through thermodynamic analysis one can identify where and how a preliminary design can be improved to obtain a better final design. If an existent system is analyzed, the expected outcome of the exergy method is represented by the identification and quantification of losses (or irreversibilities). Measures may often be taken thereafter for improving the system's performance. In what follows, the main approaches regarding thermodynamic analysis and design optimization of DES are presented, and illustrative numerical examples are given.

We now analyze the energy fluxes through the DES component by component. With the help of Fig. 10.6, the energy fluxes at the central source of a distributed energy system for cooling, heating, and power (CHP) can be inventoried. The general "black-box" model of the central CHP plant is represented in Fig. 10.6a. There, the primary energy flux $\dot{E}_s$ that enters the "black-box" is indicated. The primary energy could be the energy carried by a specific fuel (coal, natural gas, petroleum, biomass) or any other forms of thermal energy (e.g., solar, geothermal, nuclear) (Fig. 10.6a).

In the figure, the input thermal energy flux is converted into electrical power, cold, and heat in the CHP plant. Each of these conversions has a certain associated efficiency. Therefore, one can define the conversion efficiency for electrical power, heat, and cooling, respectively, as

$$\eta_e = \frac{\dot{W}}{\dot{E}_s};\ \eta_h = \frac{\dot{Q}_h}{\dot{E}_s};\ \eta_c = \frac{\dot{Q}_c}{\dot{E}_s}. \tag{10.1}$$

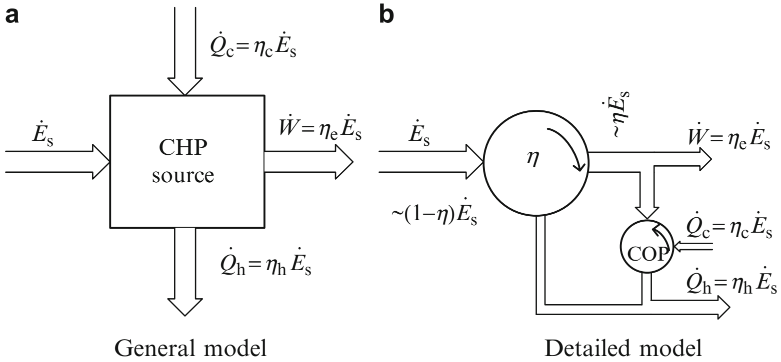

Fig. 10.6 Thermodynamic models of a cooling, heating, and power cogeneration system

The exergy efficiency counterparts of Eq. (10.1) is written noting the exergy of the primary energy flux $\dot{E}_s$ with $\dot{E}x_s$, and the temperature levels at which the heat and the cold are available with T_h and T_c, respectively. Thus, one has

$$\psi_e = \frac{\dot{W}}{\dot{E}x_s};\ \psi_h = \frac{\dot{Q}_h(1-(T_0/T_h))}{\dot{E}x_s};\ \psi_c = \frac{\dot{Q}_c(1-(T_0/T_c))}{\dot{E}x_s}, \tag{10.2}$$

where T_0 represents the environment temperature.

Figure 10.2b shows the main components of a typical CHP plant regardless of the primary fuel. The plant consists of two thermodynamic cycles. The first cycle converts with the efficiency η the primary energy flux $\dot{E}_s$ into electricity; this amounts to electrical power $\sim\eta\dot{E}_s$ as it is indicated in the figure. At the same time, the heat rejected by the cycle is $\sim(1-\eta)\dot{E}_s$. A part of the produced electrical energy is used to drive the compressor of a chiller having the role of producing cold water for the DHC system. One can design the chiller such that it discharges heat into the ambient air at the same temperature level as the power plant. Therefore, the heat ejected by the chiller $\dot{Q}_c(\mathrm{COP}+1)/\mathrm{COP}$ upgrades the heat ejected by the power plant $(1-\eta)\dot{E}_s$. Note that the chiller coefficient of performance is defined by "cold" delivered over work input $\mathrm{COP} = \dot{Q}_c/\dot{W}_c$.

A figure of merit f_s that quantifies the energy efficiency of the system can be introduced as the sum of the efficiencies for cooling, heating, and power generation. Note that the term f_s cannot signify energy efficiency because summation of heat and work does not have a clear physical sense, and it can have values even over unity. Similarly, the total exergy efficiency of the CHP system results as a summation of the particular components. Therefore,

$$\left.\begin{aligned} f_s &= \eta_e + \eta_h + \eta_c \\ \psi_s &= \psi_e + \psi_h + \psi_c \end{aligned}\right\}. \tag{10.3}$$

The energy balance over the heat distribution network, that is the second component of the DES, can be derived if one assimilates the network with two parallel pipes connecting the CHP side with the user's side, as illustrated in Fig. 10.7. The energy "introduced" into the distribution network is represented by the heat energy $\dot{Q}_{\mathrm{h}}$ and the pumping energy $\dot{W}_{\mathrm{p}}$. Some heat $\dot{Q}_{\mathrm{L}}$ is lost through the insulation. Analogously, some heat is gained through the insulation of cold distribution networks. On the user's side, the heat $\dot{Q}_{\mathrm{h,u}}$ is delivered (this is denoted with $\dot{Q}_{\mathrm{c,u}}$ for cooling).

The energy balance for the system shown in Fig. 10.7 is written as

$$\dot{Q}_{\mathrm{h}} + \dot{W}_{\mathrm{p}} = \dot{Q}_{\mathrm{h,u}} + \dot{Q}_{\mathrm{L}}, \tag{10.4}$$

where $\dot{Q}_{\mathrm{h,u}}$ represents the useful heat delivered to the users. The amount of energy consumed to convey this heat to the user's site includes the input heat energy at the central source side $\dot{Q}_{\mathrm{h}}$ and the pumping energy $\dot{W}_{\mathrm{p}}$. Therefore, the energy efficiency of the network can be defined by

$$\eta_{\mathrm{L,h}} = \frac{\dot{Q}_{\mathrm{h,u}}}{\dot{Q}_{\mathrm{h}} + \dot{W}_{\mathrm{p}}} = \frac{\dot{Q}_{\mathrm{h,u}}}{\dot{E}_{\mathrm{s}}(\eta_{\mathrm{h}} + f_{\mathrm{p}})} = \frac{1}{1 + \dot{Q}_{\mathrm{L}} / \dot{Q}_{\mathrm{h,u}}}, \tag{10.5}$$

where the second part of Eq. (10.5) was obtained by noting $f_{\mathrm{p}} = \dot{W}_{\mathrm{p}} / \dot{E}_{\mathrm{S}}$, and the third part by making use of Eq. (10.4).

For writing the exergy balance, it is useful to assume that the distribution network operates at an equivalent temperature $\overline{T}_{\mathrm{L}}$. Following this assumption, note that in the model represented in Fig. 10.7 the heat flux $\dot{Q}_{\mathrm{h}} = \dot{m}\,(h_1 - h_4)$ is "discharged" into the distribution line at the $\overline{T}_{\mathrm{L}}$. As a consequence, the corresponding entropy variation in the fluid stream is $\Delta\dot{S}_{\mathrm{h}} = \dot{m}\,(s_1 - s_4)$. It therefore results that the generated entropy in this process is $\Delta\dot{S}_{1-4} = \dot{Q}_{\mathrm{h}} / \overline{T}_{\mathrm{L}}$; from this the last relationship yields the definition of the equivalent line temperature:

$$\overline{T}_{\mathrm{L}} = \frac{h_1 - h_4}{s_1 - s_4}. \tag{10.6}$$

We now observe that according to the model proposed in Fig. 10.3, the useful heat $\dot{Q}_{\mathrm{h,u}}$ is delivered to be used at the network equivalent temperature $\overline{T}_{\mathrm{L}}$. Therefore, the exergy flux at the user's side is given by $\dot{Q}_{\mathrm{h,u}}(1 - (T_0/\overline{T}_{\mathrm{L}}))$ and then, accordingly, the network exergy efficiency is

$$\psi_{\mathrm{L,h}} = \frac{\dot{Q}_{\mathrm{h,u}}(1 - T_0/\overline{T}_{\mathrm{L}})}{\dot{Q}_{\mathrm{h}}(1 - T_0/\overline{T}_{\mathrm{L}}) + \dot{W}_{\mathrm{p}}}. \tag{10.7}$$

In an analogous manner with Eqs. (10.6) and (10.7), it is possible to define energy $\eta_{\mathrm{L,c}}$ and exergy $\psi_{\mathrm{L,c}}$ efficiency for a cold distribution line.

The last component of the DES system is the user. At the user's place, the delivered heat (or cold) serves some purpose (e.g., heating or cooling a space). For space heating purposes, it is customary to use radiators (static heating corps), while for space cooling fan coils are used. In a real situation, a part of the thermal energy that is delivered to the user's building is lost (e.g., heat losses through insulation or through the building envelope). Therefore, one can define energy and exergy efficiency at the user's side. In a general case, the heat received by the user from the distribution line can be used both for space heating and service water heating. If one denotes $\overline{T}^{\mathrm{s}}_{\mathrm{h,u}}$ the average temperature at the user's radiators or fan-coil units, and with $\overline{T}^{\mathrm{w}}_{\mathrm{h,u}}$ the temperature at the water heater, then the corresponding energy and exergy efficiencies are

$$\begin{aligned}\eta_{\mathrm{h,u}} &= \frac{\dot{Q}^{\mathrm{s}}_{\mathrm{h,u}} + \dot{Q}^{\mathrm{w}}_{\mathrm{h,u}}}{\dot{Q}_{\mathrm{h,u}}} \text{ and } \psi_{\mathrm{h,u}} \\ &= \frac{\dot{Q}^{\mathrm{s}}_{\mathrm{h,u}}\left(1 - \left(T_0\big/\overline{T}^{\mathrm{s}}_{\mathrm{h,u}}\right)\right) + \dot{Q}^{\mathrm{w}}_{\mathrm{h,u}}\left(1 - \left(T_0\big/\overline{T}^{\mathrm{w}}_{\mathrm{h,u}}\right)\right)}{\dot{Q}_{\mathrm{h,u}}\left(1 - \left(T_0/\overline{T}_{\mathrm{L}}\right)\right)}, \text{ respectively.} \qquad (10.8)\end{aligned}$$

In analogy, the energy and exergy efficiencies of the space cooling equipment are written as

$$\eta_{\mathrm{c,u}} = \frac{\dot{Q}^{\mathrm{s}}_{\mathrm{c,u}}}{\dot{Q}_{\mathrm{c,u}}} \text{ and } \psi_{\mathrm{c,u}} = \frac{\dot{Q}^{\mathrm{s}}_{\mathrm{c,u}}\left(1 - \left(T_0\big/\overline{T}^{\mathrm{s}}_{\mathrm{c,u}}\right)\right)}{\dot{Q}_{\mathrm{c,u}}\left(1 - \left(T_0/\overline{T}_{\mathrm{L}}\right)\right)}, \text{ respectively,} \qquad (10.9)$$

where in Eqs. (10.7) to (10.9) the equivalent line temperature refers to either heat or cold distribution situations.

In general, during the cold season hot water is distributed, while during the hot season chilled water or ice slurry is distributed. However, a system may be useful that distributes simultaneously heating and cooling (e.g., for some industrial parks); in this case, two distribution networks must exist. Therefore, one may define the figure of merit quantifying the energy efficiency of DES in three forms, namely, for district heating (index DH), district cooling (index DC), and district heating and cooling (index DHC), respectively:

$$\left.\begin{aligned} f_{\mathrm{DH}} &= \eta_{\mathrm{e}} + \eta_{\mathrm{h}}\eta_{\mathrm{L,h}}\eta_{\mathrm{h,u}} \\ f_{\mathrm{DC}} &= \eta_{\mathrm{e}} + \eta_{\mathrm{c}}\eta_{\mathrm{L,c}}\eta_{\mathrm{c,u}} \\ f_{\mathrm{DHC}} &= \eta_{\mathrm{e}} + \eta_{\mathrm{h}}\eta_{\mathrm{L,h}}\eta_{\mathrm{h,u}} + \eta_{\mathrm{c}}\eta_{\mathrm{L,c}}\eta_{\mathrm{c,u}} \end{aligned}\right\}. \qquad (10.10)$$

An analogue set of equations can be written for the exergy efficiency counterparts, in which the symbol f is replaced by ψ. Note that for calculating the electrical efficiency η_{e} the pumping power $\dot{W}_{\mathrm{p}}$ must be extracted from the power generated by the CHP plant in order to obtain the correct results.

Example 10.1

A geothermal district heating system (GDHS) is devised to provide heat to a large university campus. The harvested thermal energy is available at 90°C and at a flow rate of 120 kg/s. At the central station, a shell and tube heat exchanger that recirculates the water through the geothermal loop is placed while the reinjected water temperature is 75°C. The power consumption to run the pumps is 75 kW. The heat exchanger loses 2% of thermal energy through insulation. In the distribution network, hot water is circulated at a rate of 60 kg/s with the associated electricity consumption of 25 kW and has the maximum temperature of 85°C. The hot fluid reaches the user's location with 70°C temperature and leaves it with 60°C. An amount of 5% from the delivered heat at the user's location is lost due to imperfect insulation. Calculate the energy and exergy efficiency of the system and its components.

Solution. The rate of thermal energy harvested is $\dot{Q}_{\mathrm{harv}} = \dot{m}c_{\mathrm{p}}\Delta T = 120 \times 4,185 \times 15 = 7.5\,\mathrm{MW}$.

The total electrical energy needed to drive the pumps of the system (wells $\dot{W}_{\mathrm{w}}$ plus distribution network $\dot{W}_{\mathrm{L}}$) is $\dot{W} = \dot{W}_{\mathrm{w}} + W_{\mathrm{L}} = 75 + 25 = 100\,\mathrm{kW}$.

Therefore, the primary energy of the system is the sum $\dot{E}_{\mathrm{s}} = \dot{Q}_{\mathrm{harv}} + \dot{W} = 7.6\,\mathrm{MW}$.

The heat loss through insulation is $2\% \times \dot{Q}_{\mathrm{harv}} = 0.15\,\mathrm{MW}$ and the thermal energy delivered to the network is $\dot{Q}_{\mathrm{h}} = (100 - 2)\% \times \dot{Q}_{\mathrm{harv}} = 7.35\,\mathrm{MW}$.

The thermal energy efficiency of the source is therefore

$$\eta_{\mathrm{h}} = \frac{\dot{Q}_{\mathrm{h}}}{\dot{E}_{\mathrm{S}}} = \frac{7.35}{7.60} = 0.98.$$

The exergy associated with the harvested heat having the average temperature $\overline{T}_{\mathrm{harv}} = (75 + 90)/2 = 82.5°\mathrm{C} = 355.65\,\mathrm{K}$ is $\dot{E}x = (1 - (T_0/\overline{T}_{\mathrm{harv}}))\dot{Q}_{\mathrm{harv}} = (1 - (300/355.65))7.5 = 1.17\,\mathrm{MW}$ and the exergy of the primary energy flux is $\dot{E}x_{\mathrm{s}} = \dot{E}x + \dot{W} = 1.17 + 0.1 = 1.27\,\mathrm{MW}$.

The exergy associated with the heat delivered by the geothermal facility to the distribution line is

$$\dot{E}x_{\mathrm{h}} = \left(1 - \left(\frac{T_0}{\overline{T}_{\mathrm{harv}}}\right)\right)\dot{Q}_{\mathrm{h}} = \left(1 - \left(\frac{300}{355.65}\right)\right)7.35 = 1.15\,\mathrm{MW}.$$

The exergy efficiency of the heat generating source of the district geothermal energy system is therefore $\psi_{\mathrm{h}} = \dot{E}x_{\mathrm{h}}/\dot{E}x_{\mathrm{S}} = 0.98/1.15 = 0.85$.

The heat delivered to all users is calculated based on total flow rate, and the temperature difference at the user's location $\dot{Q}_{\mathrm{h,u}} = \dot{m}c_{\mathrm{p}}\Delta T = 60 \times 4185 \times (70 - 60) = 2.511\,\mathrm{MW}$.

Therefore, the energy efficiency of the distribution network is $\eta_{\mathrm{L,h}} = \dot{Q}_{\mathrm{h,u}}/(Q_{\mathrm{h}} + \dot{W}_{\mathrm{L}}) = 2.511/(7.35 + 0.025) = 0.34$.

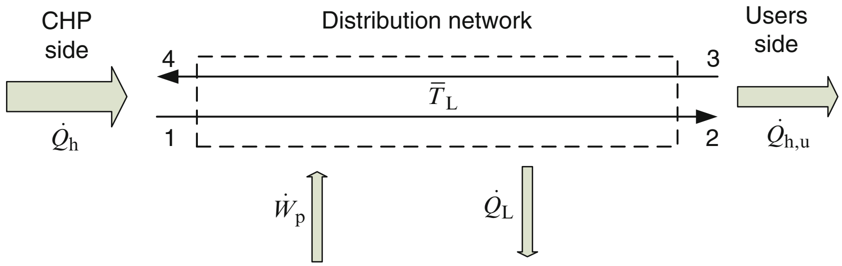

Fig. 10.7 Thermodynamic model of the distribution network

The temperature difference in the secondary circuit of the geothermal heat exchangers is calculated with $\Delta T_{\mathrm{h}} = \dot{Q}_{\mathrm{h}}/(\dot{m}c_{\mathrm{p}}) = 7.35 \times 10^6/(60 \times 4,185) = 29.3°\mathrm{C}$.

The temperature of water in the return pipes, with reference to Fig. 10.7, is $T_4 = T_1 - \Delta T_{\mathrm{h}} = 85 - 29.3 = 55.7°\mathrm{C} = 328.85\,\mathrm{K}$; therefore the average temperature is $\overline{T} = (T_1 + T_4)/2 = 70.85°\mathrm{C} = 344\,\mathrm{K}$. One can estimate the density of water to be $\rho = 1{,}000\ \mathrm{kg/m^3}$ and the enthalpy variation $\Delta h_{1-4} = h_1 - h_4 = c_{\mathrm{p}}\Delta T_{\mathrm{h}} = 4,185 \times 29.3 = 122.62\,\mathrm{kJ/kg}$. Derived from the first and second law combination, the entropy variation on the lines is $\Delta s_{1-4} = s_1 - s_4 = (\Delta h_{1-4} - \Delta P_{1-4}/\rho)\ /\overline{T} = (122.62 - 3 \times 10^5/1,000/1,000)/344 = 0.357\,\mathrm{kJ/kg\,K}$.

The equivalent line temperature results in $\overline{T}_{\mathrm{L}} = (h_1 - h_4)/(s_1 - s_4) = 122.62/0.357 = 343.47\,\mathrm{K}$.

The exergy associated with the heat and work received by the distribution network is $\dot{E}x_{\mathrm{h}} = (1 - (T_0/\overline{T}_{\mathrm{L}}))\dot{Q}_{\mathrm{h}} + \dot{W}_{\mathrm{L}} = (1 - (300/343.47)) \times 7.35 + 0.025 = 0.955\,\mathrm{MW}$.

The exergy associated with the heat delivered by the distribution network is $\dot{E}x_{\mathrm{h,u}} = (1 - (T_0/\overline{T}_{\mathrm{L}}))\dot{Q}_{\mathrm{h,u}} = (1 - (300/343.47)) \times 2.511 = 0.318\,\mathrm{MW}$.

The exergy efficiency of the distribution line is therefore $\psi_{\mathrm{L,h}} = \dot{E}x_{\mathrm{h,u}}/\dot{E}x_{\mathrm{h}} = 0.318/0.955 = 0.33$.

The heat delivered to the users for space and water heating is $\dot{Q}^{\mathrm{s}}_{\mathrm{h,u}} + \dot{Q}^{\mathrm{w}}_{\mathrm{h,u}} = (1 - 0.05)\dot{Q}_{\mathrm{h,u}} = 0.95 \times 2.511 = 2.38\,\mathrm{MW}$ and the efficiency of the user's installation is $\eta_{\mathrm{h,u}} = \dfrac{\dot{Q}^{\mathrm{s}}_{\mathrm{h,u}} + \dot{Q}^{\mathrm{w}}_{\mathrm{h,u}}}{\dot{Q}_{\mathrm{h,u}}} = \dfrac{2.38}{2.511} = 0.95$. Assuming the average temperature of water at the user's location $\overline{T}_{\mathrm{h,u}} = (60 + 70)/2 = 65°\mathrm{C} = 338.15\,\mathrm{K}$ to be the same for both space and water heating, one obtains the exergy efficiency of the users' facility:

$$\psi_{\mathrm{h,u}} = \frac{\left(\dot{Q}^{\mathrm{s}}_{\mathrm{h,u}} + \dot{Q}^{\mathrm{w}}_{\mathrm{h,u}}\right)\left(1 - \left(T_0/\overline{T}_{\mathrm{h,u}}\right)\right)}{\dot{E}x_{\mathrm{h,u}}} = \frac{2.38 \times (1 - (300/338.15))}{0.318} = 0.84.$$

The results of the system energy and exergy efficiencies are summarized below:

Location	η	ψ
Central plant	0.98	0.85
Network	0.34	0.33
User's site	0.95	0.84
Total	0.32	0.23

One may observe that most of the losses are network losses; therefore, to increase the system efficiency one has to provide better insulation of the hot water distribution lines.

10.6 Economic Analysis

Economic analysis of distributed energy systems is of fundamental importance because the thermodynamic analysis provides the information needed for the LCC. The LCC is useful for two reasons: (1) it allows for a feasibility study of the distributed energy system, by comparing it with other technical alternatives (e.g., using electrically driven heat pumps at distributed locations), and (2) it represents the objective function for optimization of the design (i.e., one has to minimize the LCC to obtain a better design). The fundamentals of economic analysis of sustainable energy systems are discussed in Chapter 18. In this section, the theory is applied for the particular case of DHC systems for deriving the LCC. The peculiarity of DESs is that they reduce or eliminate the costs associated with installation, maintenance, administration, repair, and operation of the on-site equipment for cooling and heating. These factors reflect in the relative weight of the components of LCC. Moreover, the costs associated with auxiliary equipment for local generation and the building space occupied by them can reach 20% to 30% of the total operating costs (ASHRAE 1999).

As a preliminary step for calculating the LCC of any system, the analysis period must be established. The analysis period is taken to be equal to the life-time of the system. In some cases, it may be useful to determine the total cost for the period of the loan that finances the investment. In order to determine the lifetime of a distributed energy system, the service lifetimes of the main system components must be estimated. In Table 10.3, typical service lifetimes of important components of DES are given. Table 10.4 gives the average costs of electrically driven residential heat pumps that are normally used in nondistributed energy systems (for the purpose of comparison with a nondistributed system).

The analysis results tabulated in Tables 10.3 and 10.4 show that most elements of the DES (e.g., piping/network, hot water or steam radiant heater, base-mounted pumps, and absorption chillers) have service lifetimes of over 20 years. In contrast, equipment specific to local heat and cold generation (heat pumps, electric radiant heaters, gas or electric water heaters) has a service lifetime of 10 to 15 years.

The LCC of the system can be expressed in constant currency, which is the present worth of money, and includes several components. Chapter 18 discusses the main parameters of economic analysis that we now apply to the DES case:

(a) *Capital cost*. The capital cost may be considered the most important component of the DES LCC because it is the highest. The capital cost is that part of the LCC that does not depend on the system outcome and it pays for the

Table 10.3 Service life-time of typical components of DES

Component	Lifetime (years)
Air-to-air heat pump (or air conditioner)	15
Water-cooled heat pump	15
Electric radiant heater	10
Hot water or steam radiant heater	25
Fan-coil unit	20
Piping/network	30
Thermal insulation	20
Fired boiler	25
Electric boiler	15
Gas or electric water heater	13
Electrically driven chiller	20
Absorption chiller	23
Pumps (base mounted)	20
Reciprocating engines	20
Steam turbines	30

Data from ASHRAE (1999)

Table 10.4 Specific costs of various components of district energy systems

Category	Specific cost	Remarks
Cooling plant	425–740, US$/kW	Includes building infrastructure, chillers, heat exchangers, pumping station, piping, controls
Heating plant	150–230, US$/kW	Includes boilers, building infrastructure, stacks, pumps, piping, controls
Gas turbine power plant	400–600, $/kW	Power plant + afferent infrastructure
Coal fires power plant with scrubber	1,300, $/kW	
Hydropower	1,500, $/kW	
Geothermal power plant	1,900, $/kW	
Solar thermal power plant	3,100, $/kW	
Solar photovoltaic	4,800, $/kW	
Advanced nuclear power plant	2,100, $/kW	
Fuel cell power plant	4,500, $/kW	
Distribution network	1,600–4,100, $/m	Direct buried chilled water pipes
	2,400–4,900, $/m	Direct buried preinsulated heating pipes
	1,600–3,200, $/m	Inaccessible tunnels
	11,500–49,000, $/m	Walkable tunnels
Radiators or fan-coil units	50–150, $/kW	

Data from ASHRAE (2008) and JcMiras (2008)

initial investment. The main component of the capital cost is the infrastructure, namely, the pipe network and associated work related to installing the pipelines. Depending on the economic scenario, it is possible to include in the capital cost of DES the equipment at the users' locations (e.g., fan coils, hot water radiant heaters, etc.). In any case, the lifetime cost is reimbursed by the substantial contribution of the users, who pay for the service. However, an initial large investment is needed to install the DES system, and this investment comes from government subsidies, bonds, endowments, and loans. Therefore, the capital cost is divided into the down payment and the cost of loan. The main components of the capital costs are as follows:

- Cost of the pipes
- Cost of the insulation
- Cost of work associated with infrastructure development/installation
- Cost of the pumping station
- Heat exchanger costs (condensers, boilers, etc.)
- Cost of the chiller
- Testing and balancing
- Other costs

If one denotes the capital cost with C, and f_{Loan} is the fraction of the capital cost that is paid through a loan ($f_{\mathrm{Loan}} < 1$), then the down payment is

$$C_{\mathrm{Down}} = (1 - f_{\mathrm{Loan}})C. \tag{10.11}$$

The rest of the capital C_{Loan} comes from the loan with the interest rate r_{Loan}, while the business represented by DES has to assume an associated discount rate r. For an accurate analysis, both rates must account for the average inflation I, that is, they are "converted" in the form of real rates with $r_{\mathrm{real}} = (r_{\mathrm{market}} - i)/(1+i)$. The cost of the loan at rate r_{Loan} is discounted by the business rate r; therefore, with the notations for capital recovery factor introduced in Chapter 18, the cost of the loan is

$$C_{\mathrm{Loan}} = \frac{(A/P, r_{\mathrm{Loan}}, N_{\mathrm{Loan}})}{(A/P, r, N_{\mathrm{Loan}})} f_{\mathrm{Loan}} C, \tag{10.12}$$

where N_{L} is the number of years for the loan repayment, which in general differs from the system's lifetime N. Now, the principal of the loan repayments is tax deductible; if one notes t the incremental income tax, then the total deduction for the loan cost is (according to Chapter 18)

$$D_{\mathrm{Loan}} = t\left[\frac{(A/P, r_{\mathrm{Loan}}, N_{\mathrm{Loan}})}{(A/P, r, N_{\mathrm{Loan}})} - \frac{(A/P, r_{\mathrm{Loan}}, N_{\mathrm{Loan}}) - r_{\mathrm{Loan}}}{(1 + r_{\mathrm{Loan}})(A/P, r'_{\mathrm{Loan}}, N_{\mathrm{Loan}})}\right] f_{\mathrm{Loan}} C, \tag{10.13}$$

where $r'_{\mathrm{Loan}} = (r - r_{\mathrm{Loan}})/(1 + r_{\mathrm{Loan}})$ is the effective loan interest rate.

Therefore, the present worth of the invested capital C_{P} is given by Eqs. (10.11) to (10.13), namely, the sum of the down payment and the loan cost from which the tax deduction is extracted:

$$C_{\mathrm{P}} = C_{\mathrm{Down}} + C_{\mathrm{Loan}} - D_{\mathrm{Loan}}. \tag{10.14}$$

(b) *Depreciation*. A DES is always viewed as a large investment of which the value depreciates over time. The depreciation is proportional with the capital cost and the incremental income tax. Depending on the law in place, the depreciation can be assessed based on "straight line" schedule,

$$D_{\mathrm{Dep}} = t(P/A, r, N)\, C/N, \tag{10.15}$$

or based on the so-called sum-of-the-yearly-figures schedule

$$D_{\mathrm{Dep}} = 2t[N - (P/A, r, N)]/[rN(N+1)], \tag{10.16}$$

where one takes the years of depreciation equal to the lifetime of the system.

(c) *Tax credit*. Distributed energy systems are eligible for receiving tax credits because by improving efficiency they can contribute to CO_2 emission reduction, promoting clean energy alternatives and achieving a better environment. If one denotes with t_{cred} the tax credit, then the capital investment is reduced proportionally with the invested capital, namely,

$$D_{\mathrm{cred}} = t_{\mathrm{cred}} C. \tag{10.17}$$

(d) *Salvage value*. At the end of the lifetime, the system has a depreciated value known in economics as the *salvage value*. The salvage value for a DES can be thought of as the sum of worth of all equipment (pump, chillers, heat pumps, piping, etc.) that can be valorized by the end of the service time (or lifetime) of the system. The salvage value is proportional to the invested capital and is given by

$$D_{\mathrm{salv}} = f_{\mathrm{salv}}(P/F, r, N)C(1 - t_{\mathrm{salv}}), \tag{10.18}$$

where r is the real discount rate of the business and t_{salv} is the tax perceived by the government when the salvage is valorized; this tax can be different from the income tax; the factor $(1 - t_{\mathrm{salv}})$ represents the amount of money that the business earns after tax, on amount that discounts the capital investment.

(e) *Tax on property*. At least a part f_{prop} of the invested capital C is present in the form of property. For example, the business that owns and/or administers the DES is the proprietary owner of the equipment and the buildings that accommodate the business; the distribution lines may be in the property of the district. In this case, a tax on the property (denoted here with t_{prop}) has to be paid by the business; this tax is deductible. Therefore, the cost of the property tax is

$$C_{\mathrm{prop}} = f_{\mathrm{prop}} C t_{\mathrm{prop}} (1 - t). \tag{10.19}$$

(f) *Other periodic and random costs*. Among the periodic costs paid during the lifetime of the DES are the costs related to operation, maintenance, and insurance.

These costs may be modeled as a fraction of the capital costs of the system, and are tax deductible:

$$C_{\mathrm{omi}} = f_{\mathrm{omi}} C(P/A, r, N)(1-t). \quad (10.20)$$

Furthermore, during the lifetime of the system some singular or random replacement, disposal, or overhauls may occur. Let us assume that $f_{\mathrm{r,k}}C$ is a random cost occurring in the year k. In this condition, the present worth of this cost, including the tax deduction is

$$C_{\mathrm{r,k}} = f_{\mathrm{r,k}} C(P/F, r, k)(1-t). \quad (10.21)$$

(g) *Cost of operating energy*. The link between economic and thermodynamic analysis is made through the cost of the operating energy. Assuming the energy production occurs at a uniform rate, the cost paid on fuel for the first year (or first analysis period, e.g., the first month) is

$$C_{\mathrm{oe},1} = \frac{Q_1}{\mathrm{HHV_f}\eta} p_1, \quad (10.22)$$

where Q_1 is the amount of heat or cold energy (e.g., in MJ) delivered by the system in each period, $\mathrm{HHV_f}$ represents the heating value of the fuel (e.g., in MJ/kg), η is the energy efficiency, and p_1 is the fuel price for the first period per unit of mass (e.g., in $/kg). An alternative to Eq. (10.22) that is more comprehensive is proposed here based on exergy efficiency:

$$C_{\mathrm{oe},1} = \frac{E_1}{e_{\mathrm{f}}\psi} p_1, \quad (10.23)$$

where E_1 is the amount of heat or cold energy (e.g., in MJ) delivered by the system in each period, e_{f} represents the specific exergy of the fuel (e.g., in MJ/kg), and ψ is the exergy efficiency. The cost introduced by Eq. (10.23) can be called the *cost of operating exergy*.

The total cost of the operating energy, or exergy, whichever one adopts for analysis, is discounted with the fuel effective rate that accounts for the real discount rate r of the business and the real fuel price escalation rate r_{e}; this is $r'_{\mathrm{e}} = (r - r_{\mathrm{e}})/(1 + r_{\mathrm{e}})$. Moreover, the cost of fuel is tax deductible, thus

$$C_{\mathrm{oe}} = C_{\mathrm{oe},1} \frac{1-t}{(A/P, r'_{\mathrm{e}}, N)}. \quad (10.24)$$

Summing up Eqs. (10.14) to (10.21) and (10.24), which includes the adopted alternative for the cost of the operating energy or exergy, one obtains the LCC as

$$C_{\mathrm{Life}} = C_{\mathrm{P}} + C_{\mathrm{prop}} + C_{\mathrm{omi}} + \sum C_{\mathrm{r,k}} + C_{\mathrm{oe}} - (D_{\mathrm{Dep}} + D_{\mathrm{cred}} + D_{\mathrm{salv}}). \quad (10.25)$$

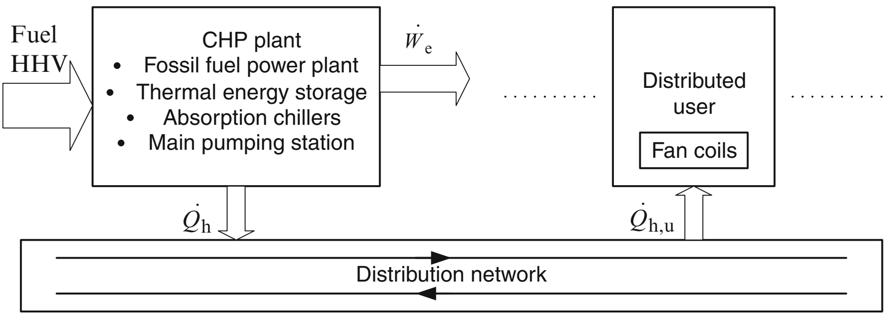

Fig. 10.8 A DES as studied in Example 10.2

Example 10.2

We now estimate the LCC of the DES illustrated in Fig. 10.8 that uses a CHP coal plant with scrubber and serves a territory of 1 km^2, using following input data:

- peak electrical power $P_e = 100\ \mathrm{MW_e}$
- load factor $l = 68\%$
- efficiency hth = 30% (thermodynamic cycle), hme = 95% (mechanical to electrical)
- price of coal for the first year $c_{coal} = \$2.5/\mathrm{GJ}$ and $r_e = 10\%$ price escalation rate
- heat losses at power plant $f = 5\%$
- absorption chillers' coefficient of performance (COP) = 0.8
- specific cost of cooling plant $c_c = \$500/\mathrm{kW}$
- Cost of distribution line $c_L = \$4{,}000/\mathrm{m}$
- Length of pipe network $L = 5$ km
- Fan coil unit cost $c_{fc} = \$100/\mathrm{kW}$
- Number of years of service $N = 20$
- Inflation rate $i = 1\%$, market discount rate $r_m = 6\%$, market loan rate $r_{mL} = 5\%$
- Other financial parameters $f_{Loan} = 0.8$, $t = 40\%$, $t_{cred} = 2\%$, $f_{salv} = 10\%$, $t_{salv} = 20\%$, $f_{prop} = 50\%$, $t_{prop} = 25\%$, and $f_{omi} = 1\%$.

Solution

- Annual electrical energy production is $E_{ey} = 365\,\mathrm{days} \times 100 \times 10^6\,\mathrm{MW} \times 24 \times 3,600\,(\mathrm{s/day}) \times 0.68 = 2.1\,\mathrm{PJ}$.
- The power plant's coal-to-electrical efficiency is $\eta_{PP} = \eta_{th}\eta_{me} = 0.3 \times 0.95 = 0.285$.
- Annual consumption of primary energy (coal) is $E_{py} = E_{ey}/\eta_{PP} = 2.1\,\mathrm{PJ}/0.285 = 7.4\,\mathrm{PJ}$.
- Annual cost of coal fuel $c_{fy} = E_{py} \times c_{coal} = 7.5 \times 10^6\,\mathrm{GJ} \times 2.5\$/\mathrm{GJ} = \$18.75\,\mathrm{million/year}$.
- Amount of annual rejected heat $Q_{0y} = (1 - \eta_{PP})E_{py} = 5.29\,\mathrm{PJ}$.
- Recovered heat with 5% losses $Q_{hy} = (1 - \phi)Q_{0y} = 0.95 \times 5.29 = 5.02\,\mathrm{PJ}$.
- Cold energy production, yearly $Q_{cy} = COP\, Q_{hy}(3\ \text{summer months}/\text{year's 12 months}) = 0.975\,\mathrm{PJ}$.

- Needed total chiller capacity $\dot{Q}_c = (Q_{cy}/4 \text{ summer months}) \times (1/(30 \times 24 \times 3,600)) = 94\,\text{MW}$.
- Cost of chillers $C_c = \$500/\text{kW} \times 94,000\,\text{kW} = \$47\,\text{million}$.
- Number of fan-coil units at the users' locations (assumed in average 1 kW/unit) $Q_{fcy} = 1,000\,\text{W} \times (365 \times 24 \times 3,600)\text{s} = 32\,\text{GJ}; N_{fc} = Q_{hy}/Q_{fcy} = 30,500\,\text{units}$.
- Cost of the distribution network $C_L = L \times c_L = 5,000 \times 4,000 = \$20\,\text{million}$.
- Cost of the coal fired power plant $C_P = c_P \times P_e = \$1,300,000/\text{MW} \times 100\,\text{MW} = \$130\,\text{million}$.
- Total fan coil cost $C_{fc} = c_{fc} \times N_{fc} \times \dot{Q}_{fc} = \$3\,\text{million}$.
- Capital cost as follows:
  - Central plant $C_{cp} = C_P + C_c = 130 + 47 = \$177\,\text{million}$.
  - Distribution lines $C_L = \$20$ million.
  - User's $C_{fc} = \$3$ million.
  - Total CHP cost $C = \$200$ million.
- Down payment $C_{Down} = (1 - 0.8) \times 200 = \$40$ million.
- Cost of the loan $C_{Loan} = ((A/P, 0.04, 20)/(A/P, 0.05, 20)) \times 0.8 \times 200 = \$\ 147\,\text{million}$.
- Tax deduction on loan using Eq. (10.13) and $r'_{Loan} = (5-4)/(1+4) = 0.2$, therefore $D_{Loan} 0.4[(0.0736/0.08) - (0.0736 - 0.04)/(1.04 \times 0.2053)] \times 0.8 \times 200 = \$48.8\,\text{million}$.
- Therefore, the total worth of capital is $C_P = C_{Down} + C_{Loan} - D_{Loan} = 40 + 147 - 48.8 = \$138.2\,\text{million}$.
- The depreciation of the capital, assumed linear – Eq. (10.15) $D_{Dep} = 0.4 \times (P/A, 0.05, 20) \times 200/20 = \$50\,\text{million}$.
- Tax credit $D_{Cred} = t_{cred} \times C = 0.02 \times 200 = \$4\,\text{million}$.
- Salvage worth $D_{salv} = 0.1 \times (P/F, 0.05, 20) \times 200 \times (1 - 0.2) = \$42.4\text{million}$.
- Tax paid on property $C_{prop} = 0.5 \times 200 \times 0.25 \times (1 - 0.4) = \$15\,\text{million}$.
- Cost of operation, maintenance, and insurance $C_{omi} = 0.01 \times 200 \times (P/A, 0.05, 20)(1 - 0.4) = \$5\,\text{million}$.
- Total cost of fuel (coal) $C_{oe} = \$18.75\,\text{million} \times [(1 - 0.4)/(A/P, r'_e, 20)] = \$377.5\,\text{million}$, where $r'_e = ((5 - 10)/101) = -0.045$ is the real discount rate for coal price.
- The LCC is

$$
\begin{aligned}
C_{Life} &= C_P + C_{prop} + C_{omi} + C_{oe} - (D_{Dep} + D_{cred} + D_{salv}) \\
&= 138.2 + 15 + 15 + 377.5 - (50 + 4 + 42.4) \\
&= 168.2 + 377.5 - 96.4 = \$450\,\text{million}.
\end{aligned}
$$

10.7 Case Studies

Here we present an efficiency analysis, accounting for both energy and exergy considerations, for two case studies: (1) a cogeneration-based DES, and (2) a geothermal district heating system (GDHS).

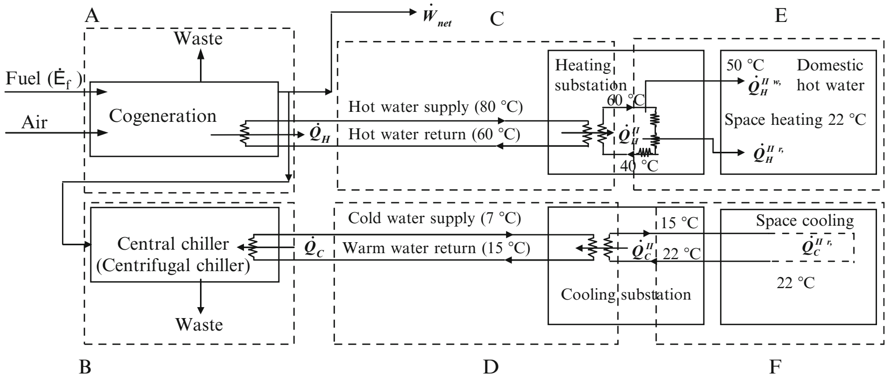

Fig. 10.9 Simplified diagram of the cogeneration-based DES at Edmonton Power [modified from Rosen et al. (2004, 2005)]

10.7.1 Case Study I

The system considered in this case study is a major cogeneration-based DHC project in downtown Edmonton, Alberta, Canada (Edmonton Power 1991, MacRae 1992), having (1) an initial supply capacity of 230 MW (thermal) for heating and 100 MW (thermal) for cooling; (2) the capacity to displace about 15 MW of electrical power used for electric chillers through DC; and (3) the potential to increase the efficiency of the Rossdale power plant that would cogenerate to provide the steam for the DHC system from about 30% to 70%. The design includes the potential to expand the supply capacity for heating to about 400 MW (thermal). The design incorporated central chillers and a DC network. Screw chillers were to be used originally and absorption chillers in the future. Central chillers are often favored because (1) the seasonal efficiency of the chillers can increase due to the ability to operate at peak efficiency more often in a central large plant, and (2) lower chiller condenser temperatures (e.g., 20°C) can be used if cooling water from the environment was available to the central plant, relative to the condenser temperatures of approximately 35°C needed for air-cooled building chillers. These two effects can lead to large central chillers having almost double the efficiencies of distributed small chillers.

There are two main stages in this case study as taken from Rosen et al. (2004, 2005). First, the design for cogeneration-based DHC (Edmonton Power 1991, MacRae 1992) is evaluated thermodynamically. Then, the design is modified by replacing the electric centrifugal chillers with heat-driven absorption chillers (first single- and then double-effect types) and reevaluated.

The cogeneration-based DES considered here (Fig. 10.9) includes a cogeneration plant for heat and electricity, and a central electric chiller that produces a chilled fluid. Hot water was produced to satisfy all heating requirements of the users, at a temperature and pressure of 120°C and 2 bar, respectively. The heat was

Table 10.5 Monthly heating and cooling load breakdown (in %) in the design area of Edmonton, Alberta

	Period 1 (winter)								Period 2 (summer)					
	Oct.	Nov.	Dec.	Jan.	Feb.	Mar.	Apr.	Total	May	June	July	Aug.	Sep.	Total
Heating	6.90	12.73	16.83	18.67	14.05	12.95	7.34	89.46	2.39	1.56	1.34	1.92	3.33	10.54
Cooling	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10.62	22.06	32.00	26.80	8.52	100

Data from Edmonton Power (1991)

distributed to the users via heat exchangers, DH grids, and user's heat exchanger substations. A portion of the cogenerated electricity was used to drive a central centrifugal chiller, and the remaining electricity was used for other purposes (e.g., export, driving other electrical devices, etc.). The central chiller produces cold water at 7°C, which is distributed to users via DC grids. The system, which uses electric chillers, is divided into six subsections within three categories. On the left are production processes, including cogeneration of electricity and heat (A) and chilling (B). In the middle are district-energy transport processes, including DH (C) and DC (D). On the right are end-user processes, including user heating (E) and user cooling (F).

For the cogeneration-based DES using absorption chillers, the design was modified by replacing the electric chiller with single-effect absorption chillers. Hot water was produced at 120°C and 2 bar to satisfy all heating requirements of the users and to drive the central absorption chillers. A small portion of the cogenerated electricity was used to drive the absorption solution and refrigeration pumps, and the remaining electricity was used for purposes other than space cooling. This cogeneration-based DES was then further modified by replacing the electric centrifugal chillers with double-effect absorption chillers. The system was similar to the cogeneration-based DES using single-effect absorption chillers, except that higher quality heat (170°C and 8 bar) was produced to drive the double-effect absorption chillers.

For the analysis, the year was divided into two seasonal periods (see Table 10.5). Period 1 (October to April) has an environmental temperature of 0°C and was considered to be a winter period with only a heating demand. Period 2 (May to September) has an environmental temperature of 30°C and was considered to be a summer period with a cooling demand and a small heating demand for hot water heating. The small variations in plant efficiency that occur with changes in environmental temperature are ignored here.

The overall energy efficiency of the proposed cogeneration plant was 85%, the electrical efficiency (i.e., the efficiency of producing electricity via cogeneration) was 25%, and the heat production efficiency was 60%. Also, the total heating requirement of the buildings in the design region was $\dot{Q}_{\mathrm{H}} = 1,040\,\mathrm{GWh/year}$ for space and hot water heating, and the cooling requirement was $\dot{Q}_{\mathrm{C}} = 202\,\mathrm{GWh/year}$ for space cooling. The total fuel energy input rate can be evaluated for the cogeneration plant using electric chillers as $\dot{E}_{\mathrm{f}} = 1{,}040/0.6 = 1733\,\mathrm{GWh/year}$. Since 33 GWh/year of this cooling was provided through free cooling, the cooling requirement of the chilling plant was 169 GWh/year (Edmonton Power 1991).

The COP of the single-effect absorption chiller used here was taken to be 0.67, a typical representative value. Therefore, the annual heat required to drive the single-effect absorption machine was $\dot{Q}_{\mathrm{gen}} = 169/0.67 = 252\,\mathrm{GWh/year}$. The total fuel energy input rate of the cogeneration plant can thus be evaluated as $\dot{E}_{\mathrm{f}} = (1{,}040 + 252)/0.6 = 2,153\,\mathrm{GWh/year}$ [for details, see Rosen et al. (2004, 2005)].

As mentioned above, steam was required at higher temperatures and pressures to drive the double-effect absorption chillers, and more electricity was curtailed as a higher quality of heat or more heat was produced. The overall energy efficiency of the proposed cogeneration plant was unchanged (85%) in period 2. Only the electrical and heat efficiencies are changed due to more heat being produced in this period, when the absorption chiller was in operation. Thus, the electrical efficiency (i.e., the efficiency of producing electricity via cogeneration) was 25% and 21% in periods 1 and 2, respectively, and the heat production efficiency was 60% and 64% in periods 1 and 2, respectively. The COP of the double-effect absorption chiller used here was taken to be 1.2, a typical representative value. Therefore, the annual heat required to drive the double-effect absorption machine was $\dot{Q}_{\mathrm{gen}} = 169/1.2 = 141\,\mathrm{GWh/year}$. The total fuel energy input rate to the cogeneration plant can be evaluated as the sum of the fuel energy input rate to the plant in two periods. Thus, $\dot{E}_{\mathrm{f}} = 1,942\,\mathrm{GWh/year}$ [for details, see Rosen et al. (2004, 2005)].

The average supply and return temperatures, respectively, were taken as 80°C and 60°C for DH, and 7°C and 15°C for DC. The supply and return temperatures, respectively, were taken as 60°C and 40°C for the user heating substation, and 15°C and 22°C for the user cooling substation. Furthermore, the users' room temperature was considered constant throughout the year at 22°C for DH; the equivalent temperature was 70°C for the supply system and 50°C for the user substation, while for DC the equivalent temperature was 11°C for the supply system and 19°C for the user substation.

Table 10.6 shows that 89.46% and 10.54% of the total annual heat loads occur in periods 1 and 2, respectively. Since there was assumed to be no space heating demand in period 2, the 10.54% quantity was taken to be the heat needs for water heating (which was assumed constant throughout the year). Table 10.6 also presents the space cooling breakdown in period 2. Annual energy transfer rates for the cogeneration-based DES are shown in Table 10.7, with details distinguished where appropriate for the three chiller options considered. The data in Table 10.7 are used to calculate exergy efficiencies for the systems for each period and for the year.

Edmonton Power had annual free cooling of 33 GWh/year; the cooling requirement of the chilling plant was 169 GWh/year. The COP of the centrifugal chiller in the design was 4.5. Thus, the annual electricity supply rate to the chiller was $\dot{W}_{\mathrm{ch}} = 169/4.5 = 38\,\mathrm{GWh/year}$. For the chilling operation, including free cooling and electrical cooling, COP = (169 + 33)/38 = 5.32. The net electricity output ($\dot{W}_{\mathrm{net}}$) of the combined cogeneration/chiller portion of the system was 433 − 38 = 395 GWh/year, where the electrical generation rate of the cogeneration plant was 433 GWh/year. Similarly, for the chilling operation, including free cooling and

Table 10.6 Annual energy transfer rates (in GWh/year) for the cogeneration-based DHC system in Edmonton, Alberta

Type of energy	Period 1, $T_0 = 0°C$	Period 2, $T_0 = 30°C$
District heating, $\dot{Q}_H$	$0.8946 \times 1{,}040 = 930$	$0.1054 \times 1{,}040 = 110$
Water heating, $\dot{Q}_H^{u,w}$	(22 GWh/yr/mo.) $\times$ 7 mo. $= 154$	$0.1054 \times 1{,}040 = 110$ (or 22 GWh/yr/mo.)
Space heating, $\dot{Q}_H^{u,s}$	$930 - 154 = 776$	0
Space cooling, $\dot{Q}_C$	0	$1.00 \times 202 = 202$
Electric chiller case		
Total electricity, $\dot{W}$	$0.8946 \times 433 = 388$	$0.1054 \times 433 = 45.6$
Input energy, $\dot{E}_f$	$0.8946 \times 1{,}733 = 1{,}551$	$0.1054 \times 1{,}733 = 183$
Single-effect absorption chiller case		
Heat to drive absorption chiller, $\dot{Q}_{gen}$	0	$1.00 \times 252 = 252$
Total electricity, $\dot{W}$	$0.8946 \times 433 = 388$	$25/60(110 + 252) = 151$
Input energy, $\dot{E}_f$	$0.8946 \times 1{,}733 = 1{,}551$	$(110 + 252)/0.6 = 603$
Double-effect absorption chiller case		
Heat to drive absorption chiller, $\dot{Q}_{gen}$	0	$1.00 \times 141 = 141$
Total electricity, $\dot{W}$	$0.8946 \times 433 = 388$	$(21/64)(110 + 141) = 82$
Input energy, $\dot{E}_f$	$0.8946 \times 1{,}733 = 1{,}551$	$(110 + 141)/0.64 = 391$

Data from Rosen et al. (2004, 2005)

single-effect absorption cooling, COP = 202/252 = 0.80, and for double-effect absorption cooling COP = 202/141 = 1.43. It should be noted that the work required to drive the solution and refrigeration pumps was very small relative to the heat input to the absorption chiller (often less than 0.1%); this work was thus ignored here.

Table 10.7 lists the energy and exergy efficiencies evaluated for the individual subsystems, several subsystems comprising selected combinations of the individual subsystems, and the overall system for cogeneration-based DES using electric chillers, single-effect absorption chillers, and double-effect absorption chillers. Overall energy efficiencies are seen to vary, for the three system alternatives considered, from 83% to 94%, respectively, and exergy efficiencies from 28% to 29%, respectively. Table 10.7 demonstrates that energy efficiencies do not provide meaningful and comparable results relative to exergy efficiencies when the energy products are in different forms. For example, the energy efficiency of the overall process using electric chillers is 94%, which could lead one to believe that the system is very efficient. The exergy efficiency of the overall process, however, is 28%, indicating that the process is far from ideal thermodynamically. The exergy efficiency is much lower than energy efficiency because the heat is being produced at a temperature (120°C) much higher than the temperatures actually needed (22°C for space heating and 40°C for hot-water heating). The low-exergy efficiency of the chillers is largely responsible for the low-exergy efficiency of the overall process. The exergy-based efficiencies in Table 10.7 are generally lower than the energy-based ones because the energy efficiencies utilize energy quantities that are in different forms, while the exergy efficiencies provide more meaningful and useful results by evaluating the performance and behavior of the systems using electrical

Table 10.7 System and subsystem efficiencies for the cogeneration-based DES, for several types of chillers

	Efficiency (%)					
	Energy (η)			Exergy (ψ)		
System	Centrifugal chiller	1-stage absorption chiller	2-stage absorption chiller	Centrifugal chiller	1-stage absorption chiller	2-stage absorption chiller
Individual subsystems						
Cogeneration	85	85	85	37	37	37
Chilling	450[a]	67[a]	120[a]	36	23	30
District heating (DH)	100	100	100	74	74	74
District cooling (DC)	100	100	100	58	58	58
User heating (UH)	100	100	100	54	54	54
User cooling (UC)	100	100	100	69	69	69
Combination subsystems[b]						
Cogeneration + chilling	94	83	88	35	35	35
District energy (DE)	100	100	100	73	73	73
User energy (UE)	100	100	100	53	53	53
Cogeneration + DH	85	85	85	34	35	34
Cogeneration + DH + UH	85	85	85	30	31	31
Chilling + DC	532[a]	80[a]	143[a]	21	14	18
Chilling + DC + UC	532[a]	80[a]	143[a]	14	9	12
DH + UH	100	100	100	40	40	40
DC + UC	100	100	100	41	41	41
Cogeneration + Chilling + DE	94	83	88	32	32	32
DE + UE	100	100	100	40	40	40
Overall process	94	83	88	28	29	29

Data from Rosen et al. (2004, 2005)

[a]These are coefficient of performance (COP) values when divided by 100

[b]DE = DH + DC and UE = UH + UC

equivalents for all energy forms. The results for cogeneration-based DESs using absorption chillers (single-effect and double-effect absorption chillers) and electric chillers are, in general, found to be similar [for details, see Rosen et al. (2004, 2005)].

For cogeneration-based district energy, where electricity, heating, and cooling are simultaneously produced, exergy analysis provides important insights into the performance and efficiency for an overall system and its separate components. This thermodynamic analysis technique provides more meaningful efficiencies than energy analysis, and pinpoints the locations and causes of inefficiencies more accurately. The present results indicate that the complex array of energy forms involved in cogeneration-based DESs make them difficult to assess and compare thermodynamically without exergy analysis. This difficulty is primarily attributable to the different nature and quality of the three product energy forms: electricity, heat, and cool. The results are expected to aid designers of such systems in development and optimization activities, and in selecting the proper type of system for different applications and situations.

10.7.2 Case Study II

Geothermal district heating has been given increasing attention in many countries during the last decade, and many successful geothermal district heating projects have been reported. In order for district heating to become a serious alternative to existing or future individual heating and/or cooling systems, it must provide significant benefits to both the community in which it is operated and the consumers who purchase energy from the system. Further, it must provide major societal benefits if federal, state, or local governments are to offer the financial and/or institutional support that are required for successful development (Bloomquist and Nimmons 2000).

The case here is the Izmir-Balcova GDHS, which is one example of a high-temperature district heating application in Turkey. The Balcova region is about 7 km from the center of the Izmir province, located in the western part of Turkey, and is endowed with considerably rich geothermal resources. The Izmir-Balcova geothermal field (IBGF) covers a total area of about 3.5 km^2 with an average thickness of the aquifer horizon of 150 m. In the district heating system investigated here, there are two systems, namely, the Izmir-Balcova GDHS and the Izmir-Narlidere GDHS. The design heating capacity of the Izmir-Balcova GDHS is equivalent to 7,500 residences. The Izmir-Narlidere GDHS was designed for 1,500-residence equivalence but has a sufficient infrastructure to allow a capacity growth to 5,000-residence equivalence. The outdoor and indoor design temperatures for the two systems are 0° and 22°C, respectively. Figure 10.10 is a schematic of the IBGF, where the Izmir-Balcova GDHS, the Izmir-Narlidere GDHS, and hotels and official buildings heated by geothermal energy are included. The Izmir-Balcova GDHS consists mainly of three cycles: (1) energy production cycle (geothermal well loop and geothermal heating center loop), (2) energy distribution

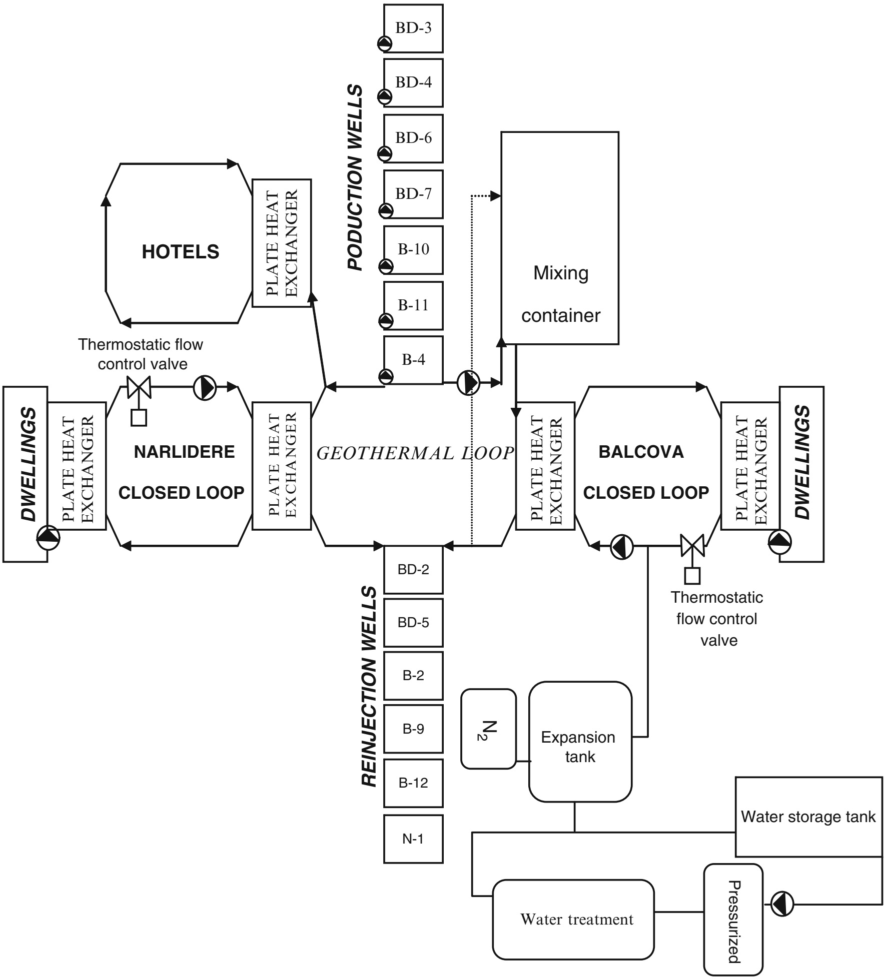

Fig. 10.10 A schematic of the Izmir-Balcova-Narlidere geothermal district heating system [modified from Ozgener et al. (2004)]

cycle (district heating distribution network), and (3) energy consumption cycle (building substations). As of the end of 2001, there are 14 wells ranging in depth from 48 to 1,100 m in the IBGF. Of these, seven and six wells are production and reinjection wells, respectively, while one well is out of operation. The well head temperatures of the production wells vary from 95° to 140°C, with an average value of 118°C, while the volumetric flow rates of the wells range from 30 to 150 m^3/h. Geothermal fluid, collected from the seven production wells at an average well head temperature of 118°C, is pumped to a mixing chamber, where it is mixed with the reinjection fluid at an average temperature of 60° to 62°C, cooling the mixture to 98° to 99°C. This geothermal fluid is then sent to two primary plate-type heat exchangers and is cooled to about 60° to 62°C, as its heat is transferred to the secondary fluid. The geothermal fluid whose heat is taken at the geothermal center is reinjected into the reinjection wells, while the secondary fluid (clean hot water) is transferred to the heating circulation water of the building by the heat exchangers of the substations. The average conversion temperatures obtained during the operation of the Izmir-Balcova GDHS are, on average, 80°/57°C for the district heating distribution network and 65°/45°C for the building circuit. By using the control valves for flow rate and temperature at the building substations, the needed amount of water is sent to each housing unit and the heat balance of the system is achieved (Hepbasli and Canakci 2003).

In the following, we give the main relations for mass, energy, and exergy flows along with the energy and exergy efficiencies for the Izmir-Balcova GDHS [for further information, see Ozgener et al. (2004)].

The mass balance equation is written as follows:

$$\sum_{i=1}^{n} \dot{m}_{\mathrm{w,tot}} - \dot{m}_{\mathrm{r}} - \dot{m}_{\mathrm{d}} = 0, \tag{10.26}$$

where $\dot{m}_{\mathrm{w,tot}}$ is the total mass flow rate at the well head, $\dot{m}_{\mathrm{r}}$ is the flow rate of the reinjected thermal water, and $\dot{m}_{\mathrm{d}}$ is the mass flow rate of the natural direct discharge.

We define the energy efficiency as follows:

$$\eta_{\mathrm{system}} = \frac{\dot{E}_{\mathrm{useful,HE}}}{\dot{E}_{\mathrm{brine}}}. \tag{10.27}$$

The geothermal brine exergy input from the production field is calculated as follows:

$$\dot{E}x_{\mathrm{brine}} = \dot{m}_{\mathrm{w}}\left[\left(h_{\mathrm{brine}} - h_0\right) - T_0\left(s_{\mathrm{brine}} - s_0\right)\right]. \tag{10.28}$$

The exergy destructions in the heat exchanger, pump, and the system itself are calculated using:

$$\dot{E}x_{\mathrm{dest,HE}} = Ex_{\mathrm{in}} - \dot{E}x_{\mathrm{out}} = \dot{E}x_{\mathrm{dest}}, \tag{10.29}$$

$$\dot{E}x_{\mathrm{dest,pump}} = \dot{W}_{\mathrm{pump}} - \left(\dot{E}x_{\mathrm{out}} - \dot{E}x_{\mathrm{in}}\right), \text{ and} \tag{10.30}$$

$$\dot{E}x_{\mathrm{dest,system}} = \sum \dot{E}x_{\mathrm{dest,HE}} + \sum \dot{E}x_{\mathrm{dest,pump}}. \tag{10.31}$$

Here, we define the exergy efficiency as follows:

$$\psi_{\mathrm{sys}} = \frac{x_{\mathrm{useful,HE}}}{\dot{E}x_{\mathrm{brine}}} = 1 - \frac{x_{\mathrm{dest,sys}} + \dot{E}x_{\mathrm{reinjected}} + x_{\mathrm{naturally\ discharged}}}{\dot{E}x_{\mathrm{brine}}}. \tag{10.32}$$

In this study, the reference environment was taken to be the state of the environment at which the temperature and the atmospheric pressure are 13.1°C and 102.325 kPa, respectively, which were the values measured at the time when the GDHS data were obtained. For analysis purposes, the actual data were taken from the Balcova GDHS on January 1, 2003, and the respective thermodynamic properties were obtained based upon these data. It is important to note that the number of the wells in operation in the IBGF may vary depending on the heating days and operating strategy.

Using Eq. (10.26), the total geothermal reinjection fluid mass flow rate is 111.02 kg/s at an average temperature of 66.1°C and the production well total mass flow rate is 148.19 kg/s, and the natural direct discharge of the system is then calculated to be 37.17 kg/s on January 1, 2003. This clearly indicates that in the Balcova GDHS, there is a significant amount of hot water lost through leaks in the hot water distribution network.

The exergy destructions in the system particularly occurs in terms of the exergy of the fluid lost in the pumps, the heat exchanger losses, the exergy of the thermal water (geothermal fluid) reinjected, and the natural direct discharge of the system, accounting for 3.06%, 7.24%, 22.66%, and 24.1%, respectively, of the total exergy input to the Balcova GDHS. Both energy and exergy efficiencies of the overall Balcova GDHS are investigated for system performance analysis and improvement and are determined to be 37.60% and 42.94%, respectively.

In the GDHSs, the temperature difference between the geothermal resource and the supply temperature of the district heating distribution network plays a key role in terms of exergy loss. In fact, the district heating supply temperature is determined after the optimization calculation. In this calculation, it should be taken into account that increasing the supply temperature results in a reduction of investment costs for the distribution system and the electrical energy required for pumping stations, while it causes an increase of heat losses in the distribution network. Unless there is a specific reason, the district heating supply temperature should be higher in order to increase the exergy efficiency of the heat exchangers and hence the entire system. Besides this, in the design and operating condition of the primary heat exchangers, a temperature approach of about 3°C is desired. On the other hand, dropping the district heating supply temperature increases the amount of building heating equipment to be oversized. Oversizing does not mean only cost, but also more exergy production due to unnecessarily inflated pumping, pipe frictions, etc. In this regard, there is an optimum district flow rate and the minimum possible exergy loss (mainly due to pumping), of which determination is planned as future work to be conducted.

10.8 Concluding Remarks

This chapter presented some historical background on DESs along with cogeneration and GDHS applications, and discussed some technical, economic (especially life-cycle costing), environmental, and sustainability issues and performance evaluations tools in terms of energy and exergy analyses for such DHC systems. Case studies have also been presented to highlight the importance of exergy use as a potential tool for system analysis, design, and improvement. The benefits have been demonstrated by using the principles of thermodynamics via exergy to evaluate energy systems and technologies as well as environmental impact. Thus, thermodynamic principles, particularly the concepts encompassing exergy, can be seen to have a significant role to play in evaluating energy and environmental technologies.

Nomenclature

$\dot{E}x$ Exergy rate, W
f Figure of merit
h Specific enthalpy, kJ/kg
$\dot{m}$ Mass flow rate, kg/s
$\dot{Q}$ Heat rate, W
s Specific entropy, kJ/kg K
T Temperature, K
$\dot{W}$ Work rate, W

Greek Letters

η Energy efficiency
ψ Exergy efficiency

Subscripts

0 Reference state
c Cooling
c,u Useful cooling
DC District cooling
DH District heating
DHC District heating and cooling
e Electrical
h Heating
h,u Useful heat
L Line
S Source or system

Superscripts

$\overline{()}$ Average value
s Radiators and fan coils
w Water heater

References

ASHRAE 1999. Handbook of Heating, Ventilating and Air Conditioning Applications, SI eds., American Society of HVAC&R, Atlanta, GA.
ASHRAE 2008. Handbook of Applications, SI eds., Chapter 11: Owning and operating costs. American Society of HVAC&R, Atlanta, GA.
Bel O., Hunyadi-Kiss I., Zweig S., Lallemand A. 1996. Thermal study of an ice slurry used as refrigerant in a cooling loop. International Institute of Refrigeration (IIR) Commissions B1, B2, E1, E2-Aarhus (Denmark).
Bloomquist R., Nimmons J. 2000. Geothermal district energy. In: Course on Heating with Geothermal Energy: Conventional and New Schemes, Lienau P.J. eds., WGC-2000 Short Courses, 8-10 June, Kazuno, Japan, pp. 85–136.
ConEd 2008. Consolidated Edison Company of New York. http://www.coned.com/ (accessed on November 6, 2008).
Dincer I. 2000. Renewable energy and sustainable development: a crucial review. *Renewable and Sustainable Energy Reviews* 4:157–175.
Dincer I. 2002. The role of exergy in energy policy making. *Energy Policy* 30:137–149.
Dincer I., Hepbasli A. 2010. District energy systems. In: Encyclopedia of Energy Engineering Technology, Capehart B.L. ed., Chapter 43. CRC Press, New York.
Dincer I., Rosen M.A. 2005. Thermodynamic aspects of renewables and sustainable development. *Renewable and Sustainable Energy Reviews* 9:169–189.
Edmonton Power 1991. City of Edmonton District Energy Development Phase. Section 2: Engineering Report.
Enwave 2005. History of District Energy. Internet source http://www.enwave.com/enwave/view.asp?/solutions/heating/history (accessed on November 6, 2008).
Hepbasli A, Canakci C. 2003. Geothermal district heating applications in Turkey: a case study of Izmir–Balcova. *Energy Conversion and Management* 44:1285–1301.
IEA 2004. Implementing agreement on district heating and cooling including the integration of CHP. Strategy Document. International Energy Agency, Paris.
JcMiras 2008. Estimated Capital Cost of Power Generating Plant Technologies. Internet source http://www.jcmiras.net/surge/p130.htm (accessed on November 7, 2008).
Karlsson T. 1982. Geothermal district heating the Iceland experience. UNU Geothermal training Programme. Iceland, Report 1982–4.
MacRae K.M. 1992. Realizing the Benefits of Community Integrated Energy Systems. Canadian Energy Research Institute, Calgary, Alberta.
National Academy of Sciences 1985. District Heating and Cooling in the United States: Prospects and Issues. Committee on District Heating and Cooling, National Research Council.
Ozgener L., Hepbasli A., Dincer I. 2004. Thermo-mechanical exergy analysis of Balcova geothermal district heating system in Izmir, Turkey. *ASME Journal of Energy Resources Technology* 126:293–301.
Rosen M.A., Le M.N., Dincer I. 2004. Thermodynamic assessment of an integrated system for cogeneration and district heating and cooling. *International Journal of Exergy* 1:94–110.

Rosen M.A., Le M.N., Dincer I. 2005. Efficiency analysis of a cogeneration and district energy system. *Applied Thermal Engineering* 25:147–159.

Skagestad B., Mildenstein P. 2002. District heating and cooling connection handbook. International Energy Agency.

Strickland C., Nyboer J. 2002. Cogeneration Potential in Canada–Phase II. Report for Natural Resources Canada.

UNEP 2005. Cogeneration, Energy Technology Fact Sheet, Division of Technology, Industry and Economics-Energy and Ozone Action Unit. Internet source http://www.uneptie.org/energy (accessed at November 6, 2008).

Study Questions/Problems

10.1 Define district energy systems and explain their benefit.

10.2 List some technical characteristics of district energy systems.

10.3 Explain the benefit of cogeneration with respect to power-only generation.

10.4 Consider the general system from Fig. 10.3. Make reasonable assumptions regarding the efficiency of each unit and then determine the efficiency of the overall system.

10.5 Describe how district energy systems benefit the environment.

10.6 Describe the role of district energy systems in sustainable development.

10.7 A GDHS provides heat from the harvested thermal energy that is available at 80°C and a flow rate of 200 kg/s. At the central station, the heat exchanger that recirculates the water through the geothermal loop is placed while the reinjected water temperature is 50°C. The power consumption to run the pumps is 150 kW. The heat exchanger loses 1% of thermal energy through insulation. In the distribution network, hot water is circulated at a rate of 80 kg/s with the associated electricity consumption of 35 kW and has the maximum temperature of 70°C. The hot fluid reaches the user's location with 65°C temperature and leaves it with 55°C. An amount of 7% of the delivered heat at the user's location is lost due to imperfect insulation. Calculate the energy and exergy efficiency of the system and its components.

10.8 Define the life-cycle cost in the context of distributed energy systems.

10.9 List and explain the main cost components of a distributed energy system.

10.10 What represents the capital cost and how it can be estimated?

10.11 Define "depreciation" and explain its calculation.

10.12 Define the "cost of operating energy" and explain its calculation.

10.13 Estimate the life-cycle cost of the district energy system illustrated in Fig. 10.8 that used a CHP coal plant with a scrubber and a served a territory of 2 km^2, for the following input data: peak electrical power $P_e = 200$ MW$_e$; load factor $l = 75\%$; efficiency 25% (power cycle), 90% (mechanical to electrical); price of coal for the first year $c_{coal} = \$3.0$/GJ and $r_e = 10\%$ price escalation rate; heat losses at power plant $f = 5\%$; absorption chillers' COP = 0.6; specific cost of cooling plant $c_c = \$600$/kW; cost of distribution line $c_L = \$4{,}100$/m; length of pipe network $L = 10$ km; fan coil unit cost $c_{fc} = \$110/\text{kW}$; number of years of service $N = 30$; inflation rate $i = 1\%$, market discount rate $r_m = 6\%$, market loan rate $r_{mL} = 5\%$; other financial parameters $f_{Loan} = 0.8$, $t = 40\%$, $t_{cred} = 2\%$, $f_{salv} = 10\%$, $t_{salv} = 20\%, f_{prop} = 50\%$, $t_{prop} = 25\%, f_{omi} = 1\%$.

10.14 In order to assess the feasibility of the district energy system presented in Example 10.2, compare its life-cycle cost to a system that uses local heating and cooling through vapor compression heat pumps. Each heat pump unit has the capacity of 1 kW for both the cooling and the heating mode. The cost of a heat pump/air condition unit is $800/kW. To make the two systems equivalent, the number of heat pump units is the same as the number of fan coils, that is 30,500 units. In the local heat pump case, there is no need of a heat and cold distribution network, therefore the capital investment is lower; however, the electricity/fuel consumption is larger.

10.15 Using the cost analysis presented in the text, perform a parametric study to determine the optimum diameter of a pipe if the flow rate and the length are imposed.

10.16 Conduct a parametric study to determine the optimal thickness of the insulation of a buried pipe.