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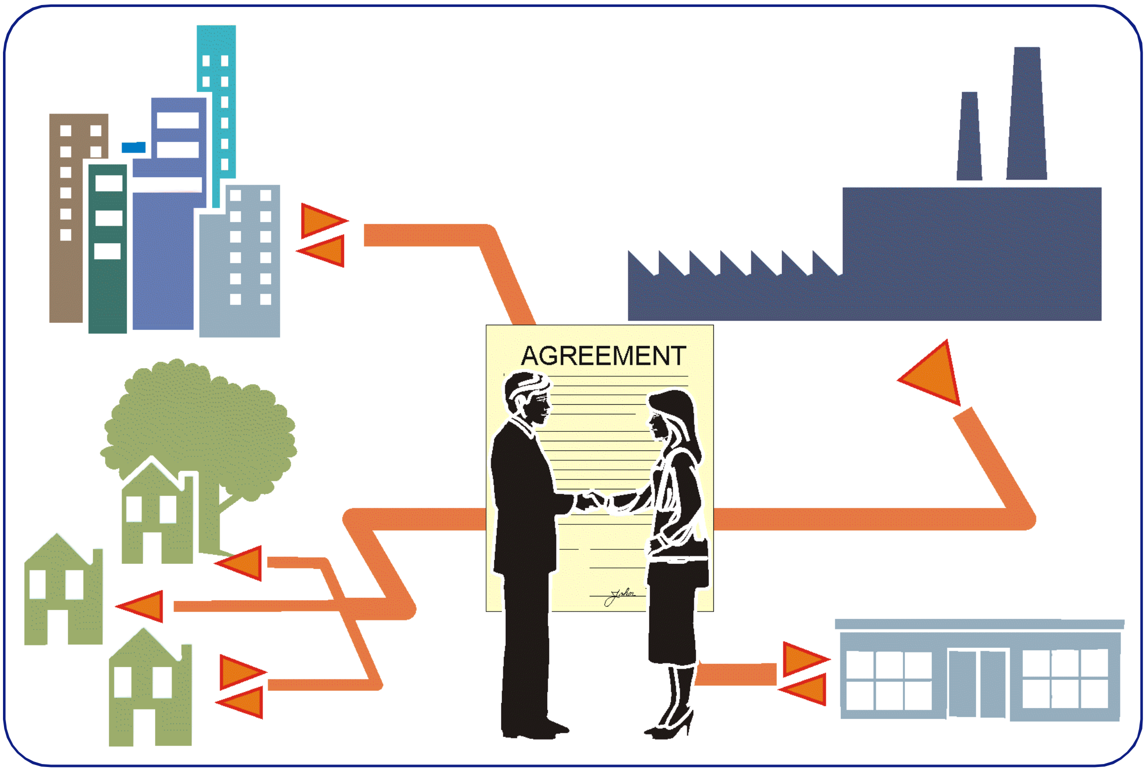

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Technical features for heat trade in distributed energy generation

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Avainsanat energy production, heat markets, heat trade, district heating, combined heat and power, CHP, distributed energy, simulation, network operators, district heating networks

Abstract

Liberated heat market works mainly like a liberated electric market in Nordic countries with the exception that heat market works within a local district heating network. There are producers, customers, a network operator and a system operator as there exist in the electric market. Physical actors are the traditional large scale producers that sell heat to customers connected to the district heating network, and the end users, that would also be small-scale producers using a micro-CHP or a boiler. They would buy heat from other producers or sell heat to customers through the network. The liberated heat energy market will also need the transmission-network-company that takes care of the temperatures, pressures and hydraulic balance of the heating network. A balance-sheet-operator is also needed to coordinate the heat contracts between producers and customers as well as to take care of reserve capacity, spot and future markets and billing.

The requirements for the district heating network design in the heat trading context are an aspect that still requires further attention. Our simulations showed that temperature changes were occasionally quite rapid in some parts of the network. They were caused by stagnation of flow in some loops of the network, where flows come from different directions. Small producers seem to bring more time-varying factors into the system. This might lead to a new district heating network design approach where temperature variations can be minimized.

The four different physical connection types for the small scale producer in the building side were studied and the recommended connection version was found. The recommended connection version is type 3, in which the small scale producer is connected to the DH-network via heat exchanger. This connection has advantages compared to the other versions: it does not bring any changes to the standard modular substation unit in buildings, it is a safe solution to the user (no water leaks) and to the DH network (no gas leak problems), it is easy to control, it is suitable for new installations and renovations, and maintenance of the CHP unit does not cause any problems to the DH operation. In general, we found out that the physical connection will need standardized rules, in which the quality and the performance of the connection unit are unambiguously defined, same way as the current Finnish Energy

Industries/District Heating Department's (earlier Finnish District Heating Association) guidelines do for the district heating substations. However, these new building level guidelines of the small scale producer were not defined in this study.

Real option analysis is adopted to evaluate the risks of investment when electricity price and heat price are uncertain.

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Keywords energy production, heat markets, heat trade, district heating, combined heat and power, CHP, distributed energy, simulation, network operators, district heating networks

Tiivistelmä

Vapaa lämpökauppa toimii samalla periaatteella kuin pohjoismainen vapaa sähkökauppakin. Vapaa lämpökauppa toimii kuitenkin paikallisesti kaukolämpöverkon vaikutuspiirissä, jossa toimivat tuottajat, kuluttajat, verkko-operaattori ja tasevastaava, kuten sähkömarkkinoillakin. Kaukolämpöverkossa toimivat suuret tuottajat, kuten ennenkin, ja kuluttajat, jotka voivat toimia pieninä tuottajina mikro-CHP:n tai kattilan ylijäämälämmöllä. Kuluttajat voivat vapaasti valita lämmön toimittajansa sopimuksella. Verkon toimintaa hoitaa verkko-operaattori, joka vastaa verkon ylläpidosta: lämpötilasta, paineesta ja verkon hydraulisesta tasapainosta. Taseoperaattori vastaa tuottajien ja kuluttajien välisistä lämpösopimuksista, reservikapasiteetista, spot- ja futuurimarkkinoista sekä laskutuksesta.

Simulointilaskelmat osoittivat, että lämpökauppa voi aiheuttaa nopeita lämpötilan muutoksia verkon joissakin osissa. Lämpökaupan seurauksena myös virtaukset voivat pysähtyä joissakin verkon osissa ja vaihtaa suuntaa, mistä voi seurata nopeita lämpötilan ja paineen vaihteluita verkossa. Lämpöverkon vapauttaminen saattaa asettaa verkon suunnittelulle uusia vaatimuksia, jotta kaikki kuormitustilanteet pystytään hallitsemaan.

Projektissa tutkittiin myös neljä erilaista pientuottajan kytkentävaihtoehtoa verkkoon. Suositeltavin kytkentä oli lämmönsiirtimellä toteutettu vaihtoehto. Vaihtoehto on nykyisen modulaarisen lämmönjakokeskuksen kaltainen. Se on turvallinen niin tuottajan kuin verkko-operaattorin kannalta, helposti säädettävä ja sopii sekä uudistuotantoon että saneerauksiin. Kytkentämoduulille tarvitaan selkeät tekniset ja laadulliset vaatimukset nykyisen kaukolämmönjakokeskuksen tavoin.

Investointien riskien hallintaa sähkön ja lämmön hintaepävarmuuden vallitessa käsiteltiin reaalioptioanalyysimenetelmällä.

Preface

This is a final report of the project "Technical features for heat trade in distributed energy generation". The project group consisted of researchers Kari Sipilä (project manager), Jussi Ikäheimo, Juha Forsström, Jari Shemeikka, Åsa Nystedt, Krzysztof Klobut, Ari Laitinen and Jenni Jahn from VTT. VTT is the Technical Research Center of Finland.

The project group wishes to thank the executive group of the project for the good guidance, questions and support during the project. The executive group members were:

Jari Kostama, chair	Finnish Energy Industries (former Finnish District Heating Association)
Veikko Hokkanen	Helsinki Energy
Rauli Saarela	Turku Energia
Veli-Matti Mäkelä	Mikkeli Polytechnic
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Jukka Hyvärinen	LPM-Group
Jerri Laine	TEKES until 1.4.2004
Martti Korkiakoski	TEKES from 1.4.2004

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Two conference papers are produced during this project: (1) Åsa Nystedt, Jari Shemeikka, Krzysztof Klobut & Jussi Ikäheimo. 2005. Case analyses of heat trading between buildings connected by a district heating network. VTT Building and Transport. Heat SET 2005, Heat Transfer in Components and Systems for Sustainable Energy Technologies 5.–7. April 2005, Grenoble, France. (2) Åsa Nystedt, Jari Shemeikka, Krzysztof Klobut, Jussi Ikäheimo & Kari Sipilä. 2005. Analysis of heat trade potential in a group of buildings connected by district heating network. VTT Technical Research Centre of Finland. CLIMA 2005 conference 9.–12.10 Lausanne, Switzerland (abstract accepted).

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Symbols and definitions

CHP	Combined Heat and Power
micro-CHP	small scale CHP, production capacity less than 100 kW
Electrical load tracking strategy	Calls for micro-CHP plant to have an electrical capacity that exceeds the minimum electrical requirement for the facility. The micro-CHP plant output power changes in response to the needs of the facility.
Thermal load tracking strategy	The CHP-system is designed to follow the thermal load of the facility. Power that is generated during the course of supplying the thermal load is used by the facility to replace purchased electric power. The excess power can often be sold to the utility.
Electrical base load strategy	Micro-CHP plant is designed to supply the minimum amount of power required by the facility. Therefore, the micro-CHP plant can operate at peak power output continuously.
Thermal base load strategy	The CHP-system is designed to meet the minimum thermal load. Thermal energy to meet peak loads is provided by an auxiliary heat source, such as a boiler. Electrical power is purchased from or sold to the grid to balance the electrical demand for the facility with the power supplied by the fuel cell system.

1. Introduction

The district heating (DH) sector supplies heat to more than 100 million people in Europe (Russia excluded). The total DH-capacity is more than 2 million MW and the length of DH-network is more than 400 000 km in Europe. District heating has a higher residential market share in Central and Eastern European countries (appr. 40%) and also in Finland, Sweden and Denmark than in the present EU Member States in average (10%). District Heating (DH) has an upward trend in several EU Member States. Meanwhile, in Central and Eastern Europe, while DH's share in the residential market is stable, production in 2000-century has significantly decreased compared to the 80's and 90's. District heating is also rapidly increasing in Far-East especially in South Korea.

The share of DH produced in CHP plants is high in most of the "old EU Member States". The Netherlands has the highest share, with approximately 94% of district heat produced in CHP plants. Finland has built plenty of big CHP plants connected to DH networks. DH-heat produced in CHP plants represents about 75% of the total DH-supply. However small CHP plants (less than 20 MWe) stand for 18% of the produced heat.

Distributed energy supply is a production of electricity, heat or cooling in local network or a production in buildings. The electricity production is liberated in electricity network of Finland and Nordic countries. Customers can order their electricity among many alternative suppliers. Electricity trade is also possible by the same principle in local network, thus a consumer can produce electricity in small-scale CHP plant (micro-turbine, diesel or wind power) and sell it to the other consumer.

Liberated heat trade can be carried out by the same principle as electricity trade in local district heating network. A small-scale producer can sell heat produced in his CHP or boiler plant to customer(s) through the local DH-network. A network operator takes in the heat from a small-scale producer and gives out the heat to the customer, which has done an agreement with the producer. The network operator keeps up the temperature and pressure in the DH-network. The network operator can also build reserve capacity connected to the network and make contracts with producers.

Heat trade features, actors and technical impacts for DH-network as well as a connection of small-scale heat producer to the network are analysed in this report. Case studies are calculated in real DH-network of one large and one small town in Finland.

The heat trade liberation is studied also in recent years in Sweden. The heat trade liberation as far as known is not carried out anywhere.

2. District heating and heat trading – prospects in the EU

2.1 District heating in the EU

2.1.1 General

The district heating (DH) sector supplies heat to more than 100 million people in Europe (Russia excluded). In Figure 1 the district heating production and its residential market share are seen. District heating has a higher residential market share in Central and Eastern European (CEE) countries (approximately 40%) than in the present EU Member States (10%). (Constantinescu 2003.)

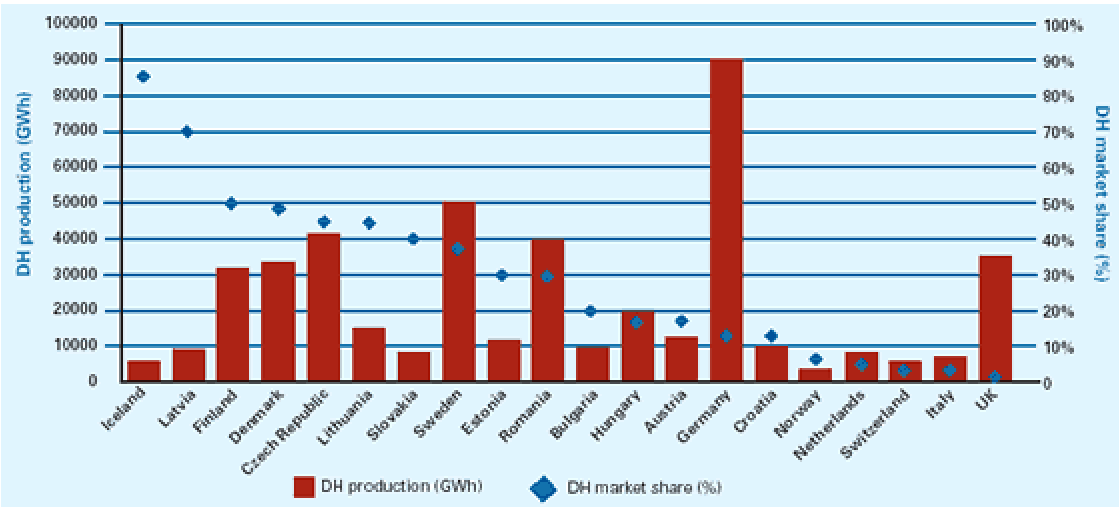

Figure 1. District heating production and residential market share (Constantinescu 2003).

District Heating (DH) has an upward trend in several EU Member States. Meanwhile, in Central and Eastern Europe, while DH's share in the residential market is stable, production in 2003 has significantly decreased compared to 1999.

Figure 1 gives a overview of the production and its market shares in the residential sector. Germany has the biggest DH production (88 000 GWh/year). In the Czech Republic the production numbers are high (41 000 GWh/year). The market share is between 1% (Great-Britain) and 50% (Finland). In Latvia the market share of DH in residential buildings is as high as 70%. (Constantinescu 2003.)

In Figure 2 we see that CHP production is more common in "Western EU-countries" (EU members before 1. May 2004) than in Eastern European countries. The fuel use is more diversified in the Western European countries. In Eastern Europe much more coal is used whereas renewable energy sources and waste are more common in Western European countries.

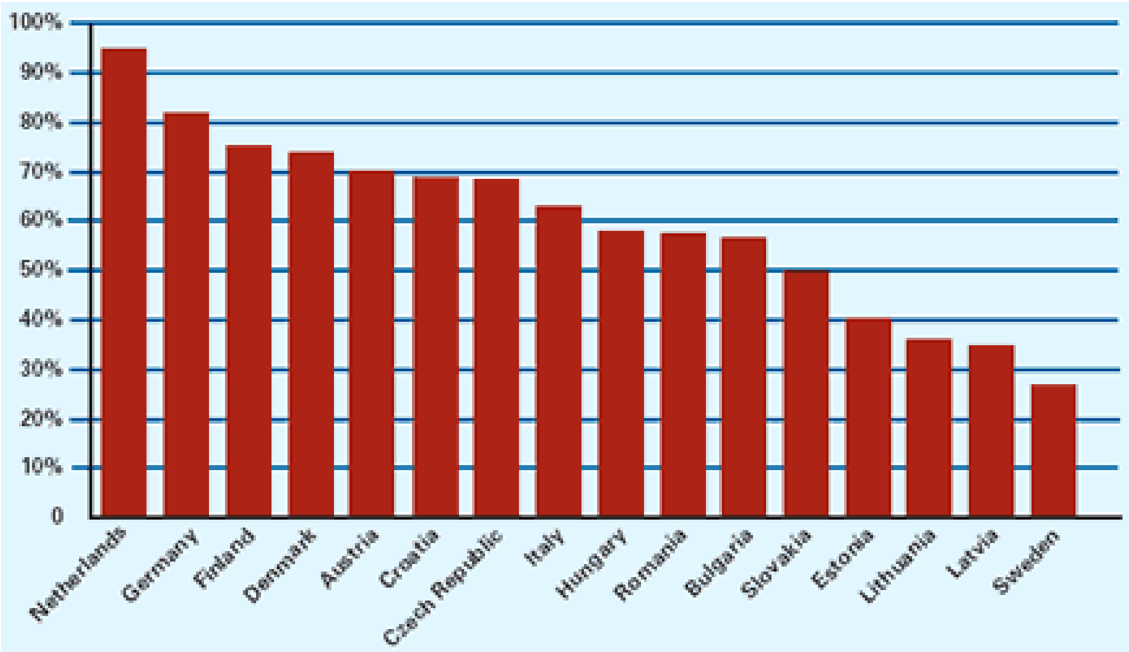

Figure 2. CHP share in DH production 2001 (Constantinescu 2003).

Compared with 1999, the DH production has grown in most of the Western European countries. The biggest growth was in Italy (7,4%), Austria (7,4%) and Sweden (6%). (Constantinescu 2003.)

The DH power demand in buildings has decreased. The refurbishment of the networks and buildings and better insulated new buildings has lead to a decrease of the energy demand per heated m³.

2.1.2 CHP production

The share of DH produced in CHP plants is high in most of the "old EU Member States". The Netherlands has the highest share, with approximately 94% of district heat produced in CHP plants. An estimate value (weighted average) for the "old EU countries" surveyed (Austria, Denmark, Finland, Germany, Italy, the Netherlands, Sweden) shows that the average share of CHP in DH production is around 67%. (Constantinescu 2003.) Both in the Netherlands and in France, it is believed that the

CHP sector will be the strongest application sector in distributed energy systems (Frost &Sullivan 2002).

Finland is often regarded as a country with functional systems with big CHP plants connected to DH networks. Yet small CHP plants (less than 20 MWe) stand for 18% of the produced heat. (IEA rapport; A Comparison of distributed CHP/DH with large-scale CHP/DH 2005.)

In Denmark, there are many agreements and regulations promoting decentralized generation as a form of small-scale CHP (Frost & Sullivan 2002).

In Eastern European countries, the share of DH produced in CHP plants is lower than in Western EU countries, varying between 35% and 69%. The approximate average (weighted average for CEE countries surveyed) of DH produced in CHP plants is about 52%. However the increase of CHP share in DH production, as well as the development of integrated supply concepts at local level (incineration plants, use of waste heat), represent a challenge for the DH sector in the region. (Constantinescu 2003.) In the Czech Republic and Hungary the largest application segment for distributed energy production will be CHP bolstered by demand for process and heat and small-scale district heating. Also in Latvia and Lithuania small scale CHP is believed to be a key sector. (Frost & Sullivan 2002.)

Industry-based power generation (for its own internal use) in Poland accounts for about eight billion kWh annually, of which more than six billion kWh is produced from combined-heat-and-power (CHP) cogeneration. Nearly 16 billion kWh is generated annually from district heating CHP plants. Overall, more than 15% of Poland's total electricity generation is generated in conjunction with heat. (Office of fossil energy.) Poland is regarded as having the largest potential for distributed generation in central and eastern Europe by far and the most important segment is CHP (Frost & Sullivan 2002).

2.1.3 Fuels used in district heating

The predominant fuels used for the CHP/DHC sector in Western EU countries are coal (34%) and natural gas (31%). Renewables represent an average of 11%, the rest being split among waste, oil and other sources (such as industrial waste heat). Figure 3 illustrates the degree of fuel diversification in EU countries. (Constantinescu 2003.)

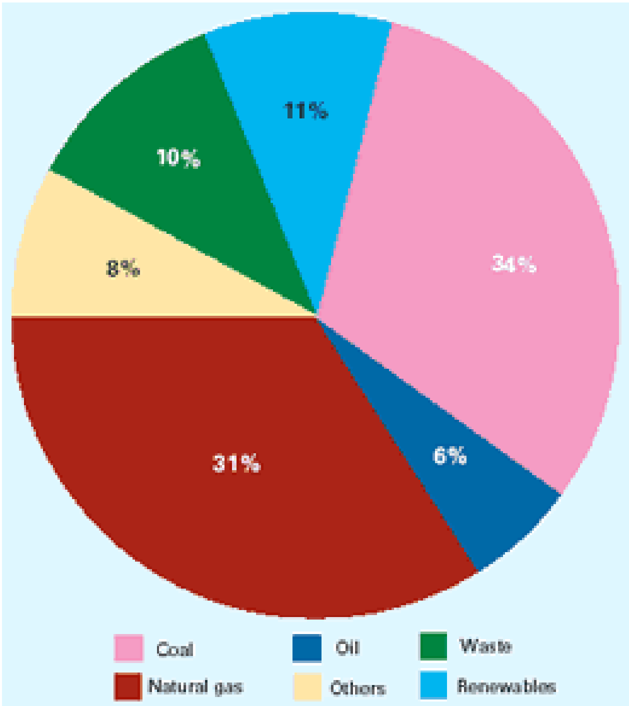

Figure 3. Fuels used for district heating in Western EU countries (Constantinescu 2003).

Iceland is a special case where 96% of the DH heat comes from geothermal sources. In the Netherlands and Italy use a large share of natural gas for CHP/DH production: 81% and 63% respectively. Coal is used more in Germany and Denmark, where it accounts for more than 40% of the total. (Constantinescu 2003.)

In comparison with 1999, most of the selected western EU countries showed a decrease in the share of natural gas (due to price increases) and a slight increase in renewables, coal and biomass. In Eastern European countries coal and oil are used more and renewables and waste are used much less (see Figure 4).

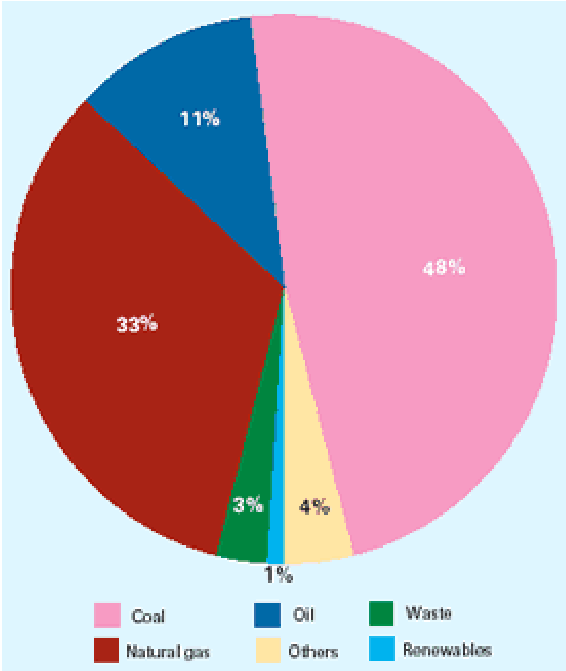

Figure 4. Fuels used for district heating in Eastern European countries (Constantinescu 2003).

In Poland, Czech Republic and Slovakia, coal is predominant. In the Baltic States, as well as in Bulgaria, Hungary, Romania and Croatia, natural gas has a significant share – higher than 50% (Estonia excepted). (Constantinescu 2003.)

In Eastern European countries the use of natural gas has increased to some extent compared to 1999. In some cases the use of renewable sources has increased a bit.

2.1.4 District cooling

District cooling continues its expansion in Western EU Member States, especially in Nordic Europe (Sweden, Norway) but also in Italy and Switzerland. Depending on the local conditions, a variety of technologies are used: absorption chillers, compressors and seawater.

Table 1 provides an overview of DC production and capacities for 2001 in some EU Member States and in Norway and Switzerland.

Presently, DC is almost non-existent in Eastern European countries. However, DC has started to be considered as an option for projects, particularly in connection with the development of the service sector (shopping centres, administrative buildings, offices, etc.).

Table 1. District cooling in different countries (Constantinescu 2003).

District Cooling	Austria	Finland	Italy	Holland	Sweden	Norway	Switzerland
Production (GWh)	3,9	4,4	62,5	22	427	28,3	3
Capacity (MW)	7,5	6,3	99	8,3	406	9	2

2.1.5 Legislation, market and ownership

Some of the Eastern European countries have developed specific DH/heat legislation. For example, Hungary issued a district heat law and Estonia is preparing one. In Croatia and Lithuania, DH aspects are addressed in heat laws. In the Czech Republic and Romania, DHC/CHP is seen as part of the energy conservation policy and a cost-effective tool for implementing energy efficiency measures. In Bulgaria, Hungary, Romania, Latvia and Slovakia, the DH sector is considered a public service and is regulated as such.

In most of the Western EU countries surveyed, a specific law for DH is not foreseen in the legislative framework (except in Denmark). District heating is considered as a business function, driven mainly by market forces. However, CHP/DHC fulfils tasks of general economic interest, mainly in relation to environmental policies.

In Finland and Sweden no license is required for generating or selling electricity. Distributed electricity generation is basically competing in the same conditions as any electricity but there is some tax relief for electricity generated from renewable energy sources. In Sweden the Electricity Act is giving some favours to small scale produced electricity. In Norway, the Energy Act requires licensing of all installations for the production, trading and distribution of electricity. (Frost & Sullivan 2002.)

CHP is supported in most of the Eastern European countries. Support measures include, among others: a guaranteed price level for CHP electricity (Estonia and Latvia for certain capacities), and a purchasing obligation for the electricity supplied by CHP plants (Bulgaria, Czech Republic, Hungary, Slovakia).

The DH prices in EU Member States surveyed vary in the range of 27–69 €/MWh (31–79 US$/MWh). Some countries apply a favourable value-added tax (VAT) for the DH sector (UK and Iceland). However, in France the VAT level is higher for DH (19.6%) than for electricity and gas (5.5%).

Various mechanisms are used for financing DH rehabilitation and modernization in Eastern European countries. They range from direct governmental support to the use of third-party financing and leasing of capacity. However, private sector investments (mainly foreign) have an increasing importance – often being associated with the privatization process. In some cases, international financial institutions have played a catalytic role as well. In CEE countries, DH prices are situated in the range of 13–41 €/MWh.

In most Western EU Member States, DH companies are either municipal or privately owned (Sweden, Finland, UK). As DH is a local business, the municipalities play an important role. Conversely, DH companies in these countries are acting in a market-driven environment, and with the liberalization of the energy market, new trends such as mergers and take-overs create new structures.

In most Eastern European countries, DH companies are owned by municipalities. In Bulgaria, Croatia, Slovakia and Latvia the DH systems are partially owned by the state. Recent developments in the ownership structure of the DH companies in Eastern European countries are mostly related to the restructuring process. Leasing, privatization and public-private partnerships are used in several countries as a method of attracting financial sources for reforming and refurbishing DH schemes. In Figure 5 the ownership structures of DH systems in Eastern European countries are seen.

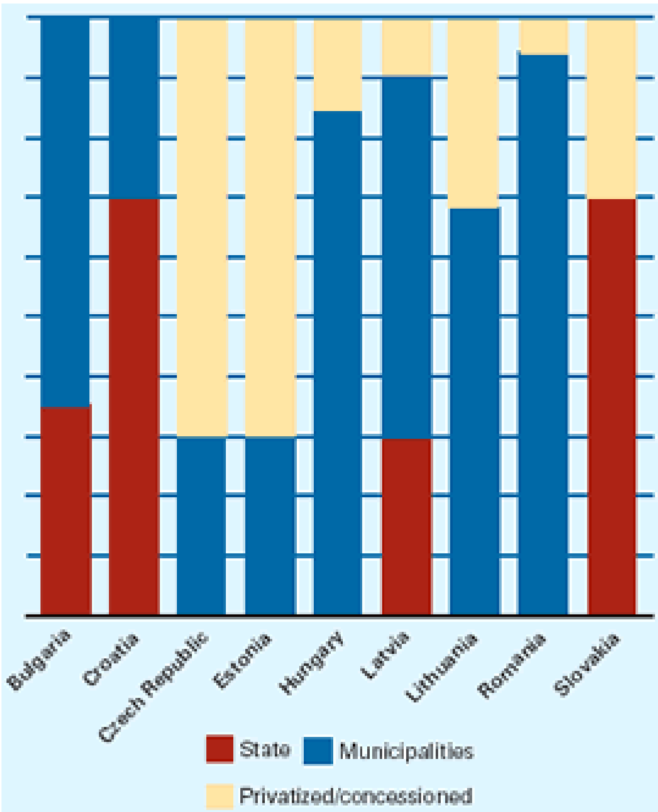

Figure 5. Ownership structures of DH systems in Eastern European countries (Constantinescu 2003).

2.2 Research activities concerning heat trading

In order to find out the future prospects for heat trading we made a small questionnaire to research scientists in the energy field that have been involved in the IEA ECBCS Annex 37 and Annex 42 projects. In the questionnaire questions were asked about the future of district heating in general and about research activities concerning heat trading. Answers were received from Great-Britain, Norway, Sweden, Germany, Italy and Switzerland. It needs to be emphasized that answers were given by individual experts and should not be considered as 100% facts.

In Great-Britain district heating was believed to become more common. New district heating networks will be built. The growth of DH might be hindered by its bad reputation among consumers. This bad reputation results from technical problems about a decade ago. Today these problems are, however, solved. Heat trading was seen as an idea to be reckoned with but it has not yet been studied further.

In Norway there is an interesting situation. There is a duty to connect to the DH network if there is one close enough. In Norway direct electrical heating is very common. The installation of a water based heating system is rather expensive which leads to the situation that although the consumer is connected to the DH network the DH is used only for heating the domestic hot water. This situation becomes expensive for the energy company which pays for the DH connection but does not sell very much energy. In Oslo an extension of the DH network is being planned.

In Sweden both district heating and district cooling (DC) are common and they are believed to continue being an important factor for the energy sector in the future. Heat trading has been studied to some extent; the following reports have been published about heat trading:

- Nordvärme, TPA (Third Party Access), Öppna fjärrvärme.
- "Safer DH costumers – an increased transparency and keeping the electricity and DH market separate." (Original title: "Tryggare fjärrvärmekunder – ökad transparens och åtskillnad mellan el- och fjärrvärmeverksamhet.") Published by the Swedish government.
- "Technical prospects for third party access in the DH network." (Original title: "Tekniska förutsättningar för tredjepartstillträde i fjärrvärmenäten.") Published by the Swedish government.

In Germany heat trading has been considered to some extent but nothing concrete has been done. It is, however, believed to be an interesting subject that would be worth to study in more detail.

In Italy both district heating and district cooling are in an expansion phase.

In Switzerland DH is used in many cities. In Basel the energy for district heating is produced with bioenergy and in many other cities waste is being used as fuel. The energy markets are being liberalised in Switzerland and it is believed that heat trading could be a considerable option in the future. The issue has not been studied further.

2.3 Micro CHP in Europe

Micro-CHP is not yet very widely used. It has, however, been forecasted that its use will become more common. The gas network plays an important role in the future prospects of micro-CHP plants. The climate has also an effect on the profitableness of micro-CHP plants. (Dentice d'Accadia et al. 2003.)

Germany is expected to be an important market area. It has been forecasted that in the year 2006, 50 000 micro-CHP plants will be sold in Germany. Also the markets of Great-Britain and the Netherlands are expected to have a large growth. According to the forecasts the amount of plants sold would be 38 000 in Great-Britain and 17 000 in the Netherlands. Italy, Austria, Switzerland and Belgium are markets that are expected to grow to some extent, the amount of sold pieces being between 5000 and 7000. (Dentice d'Accadia et al. 2003.)

For the rest of the Europe quite slow growth is expected due to climate and the lack of gas networks (Dentice d'Accadia et al. 2003).

In Great-Britain there is a strong belief that there is a great future for micro-CHP plants. It has been forecasted that electrical production capacity of micro-CHP plants of up to 22 GW could be a reality. This would be larger capacity than nuclear power today. Micro-CHP is considered to be cost-effective, also without subsidies, and environmentally friendly. In these considerations it has been assumed that micro-CHP plants would replace gas heating. The outstanding prospects for micro-CHP plants are supported by the fact that 18 million out of 23 million homes, have gas heating. It has been estimated that 12 million homes would be potential micro-CHP consumers. (Harrison 2003a.)

In the EU it has been estimated that there would be 40 million potential micro-CHP consumers. 200 million tons of CO_2 would be unproduced if this potential would be covered. It has been estimated that by the year 2010 one million pieces of micro-CHP plants is sold. (Harrison 2003b.)

In Poland micro-CHP technology is rather new technology. The interest towards gas motor- and gas turbine technology started in the mid 90's. Until now just a few plants have been installed. (Kalina 2003.)

Table 2. Summary table of chapter 2.

	DH Trend	Heat trading?	Other comments	CHP share in DH production	DH is "public service" / "market oriented	microCHP, estimated installation by 2006	DC, capacity [GWh]	DC, production [MW]	Approach for promoting of DH/CHP/Renewables? (World energy council, 2004)
UK	↗	Could be a considerable solution, no further research	1)		Market oriented	38 000			
Norway	↗		2)		Market oriented	Slow growth	28,3	9	
Sweden	↗	Some research has been done		28%	Market oriented	Slow growth	427	406	
Germany	→	Has been considered		81%	Market oriented	50 000			
Austria	↗			70%	Market oriented	5 –7000	3,9	7,5	
Italy	↗	Some activities		63%	Market oriented	5–7000	62,5	99	
Finland				75%	Market oriented	Slow growth	4,4	6,3	Do not promote DH/CHP as such, but apply investment incentives, tax relief or other means designed to enhance efficiency and use of renewables.
NL				94%	Market oriented	17 000	22		
Switzerland		Could be a considerable solution, no further research			Market oriented	5–7000	3		
DK				73%		Slow growth			
Belgium					Market oriented	5–7000			
Croatia	↘			69%		Slow growth			
Czech Republic	↘			69%		Slow growth			Promote CHP through obligatory purchase of electricity produced during production of heat.
Hungary	↘			58%	Public service	Slow growth			Designate protected areas for DH on environmental grounds, but develop CHP under market conditions; promote use of renewables and waste in DH/CHP.
Romania	↘		3)	57%	Public service	Slow growth			Promote CHP on the basis of least cost analysis; promote the rehabilitation of DH/CHP systems; redirect subsidies to investments.
Bulgaria	↘			57%	Public service	Slow growth			
Slovakia	↘			50%	Public service	Slow growth			
Estonia			4)	40%		Slow growth			
Lithuania			4)	35%		Slow growth			Support DH/CHP systems and renewable technology.
Latvia			4)	33%	Public service	Slow growth			Promote renewables in small CHP.
Poland			4)			Slow growth			Set purchase obligations for heat from urban waste, renewables and electricity from CHP.
Slovenia	↘					Slow growth			Promote use of biomass.

Other comments

1) DH has a bad reputation due to technical problems in the past.
2) Duty to connect to DH network, DH used only for DHW.
3) There has been extensive disconnection from district heating in favour of gas-fired individual boilers (Euroheat & Power 2005).
4) Modernisation of DH networks is an urgent problem because many of the networks are in a poor state of repair (Euroheat & Power 2005).

3. Open heat trade markets

3.1 Actors in the heat trade market

Liberated heat market works mainly like a liberated electric market in Nordic countries with the exception that the heat market works within a local district heating network There are producers, customers, network operators and system operators as they exist in the electric market (Figure 6).

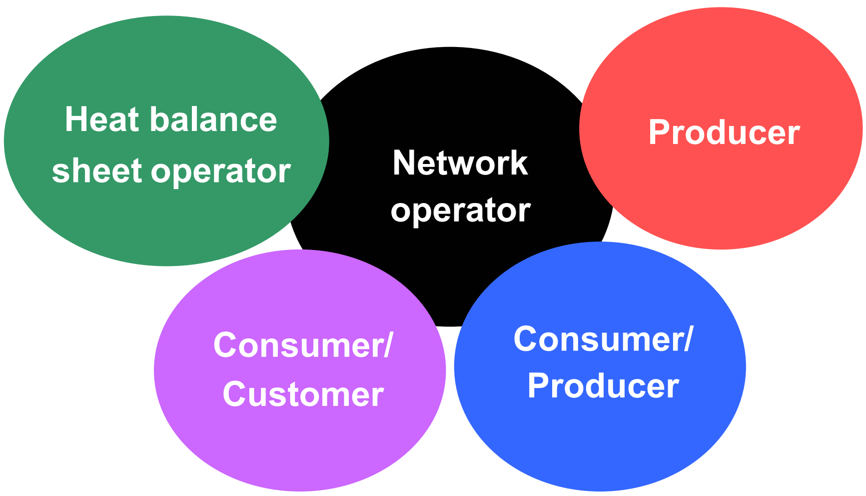

Figure 6. Heat family in local district heating network.

Physical actors in the liberated heat trade market are the traditional large scale producers that sell heat to customers connected to the district heating network, and the end users, that would also be small-scale producers using a micro-CHP or a boiler. They would buy heat from other producers or sell heat to customers through the network. The liberated heat energy market will also need the transmission-network-company that takes care of the temperatures, pressures and hydraulic balance of the heating network. Network-company is also responsible for services and enlarging the network when necessary. A balance-sheet-operator is also needed to coordinate the heat contracts between producers and customers as well as to take care of reserve capacity, spot and future markets and billing. The network operator can also be a balance-sheet-operator, especially in small networks.

3.2 Objectives for the liberated heat trade market

The main objectives for the liberated heat trade market are to promote a competition within the local DH-network, to produce heat in more economical ways and to use more effective production units. However, the quality of the heat and minimum environmental impacts must be ensured. This means:

- Temperature, pressure and water quality must be ensured.
- Combined electricity and heat production (CHP) must be promoted.
- New more effective techniques of utilisation should be ensured.

Furthermore freedom for the consumer to choose a supplier must be ensured. Consumers and producers must also have equal contract possibilities to be connected to the DH-network and the network operator must not disturb the competition in the network. Energy and emission taxes or subvention by the authorities must not imbalance the competition situation between energy production technologies.

The district heating network operation should be separated from the production like in the electricity side. Then the network operator works more transparently and it is easier to see the transport cost.

The reserve capacity must be ensured also within the network based on constructed capacity and agreements. New district heated areas growing and enlarging the old ones must be ensured, if it is economically feasible.

There are also some problems, which might arise from the heat trade liberation. We give only some questions without no answer:

- How do we guarantee that the economical targets come true from the point of view of the whole heating system, not only of producer, network or consumer side?
- How could the minimum heat load of CHP plant be advanced in summer time? It is possible that annual utilization time of large centralized CHP plant could be shortened?
- How could utilization of DH return temperature be advanced for low energy use and who's business it is?
- Is it possible that nobody wants to invest in large CHP plants?

3.3 Heat market actors and their roles

3.3.1 Heat Producer

A heat Producer supplies heat and utilizes it in his own heating purposes and makes a heat contract for a limited period with some customer(s), which is connected to the network. The heat producer has duties and rights:

- The Producer makes a heat contract with customer and transportation contract with a network operator.
- The Producer must be connected to the network with a heat exchanger (or directly) before starting the heat supplying to the customer. The connection must be accepted by the network operator.
- The Producer must pay a connection charge accepted by a competition officer.
- The Producer supplies heat energy based on the contract into the DH-network with contracted fixed effect or within contracted minimum and maximum effect in contracted period.
- The Producer supplies heat in right temperature, which is normally as a function of outdoor temperature.
- The Producer is responsible for the reserve capacity within his contracts to consumers even if the supplier will leave the heat market before the contract is closed.

3.3.2 DH-Network operator

A Network operator is an organization, which is responsible for the district heating network. The local network service must be separated from production, but the Network operator can also make a contract with producers and make heat supply contracts with customers. The network operator has duties and rights:

- The Network operator will use, maintain and build the network within feasible and economical activities.
- The Network operator keeps up the pressure, temperature and is responsible for the quality of the DH-network's water.
- The Network operator is responsible for network's reliability and security.
- The Network operator will measure the input and output heat at the producers and the consumers within DH-network.
- The Network operator will connect or accept connection of producers and consumers to the network.

- The Network operator is responsible for peak and reserve capacity by his own capacity and other actors capacity based on contracts.
- The Network operator defines the heat transfer tariff, which will be accepted by a competition officer.

3.3.3 Balance sheet operator

A Balance sheet operator is an organization, which coordinates the whole system. The Balance sheet operator has duties and rights:

- keep up the thermal effect and energy balance sheet within the DH-network
- keep up the connected heat load and inform the network system operator for the coming winter heat load period
- inform and control the network operator for the coming days
- control peak load and reserve capacity
- keep up the heat contract bank of producers
- keep up the heat exchange market: spot and future markets
- collect invoice data measured by Network operator and channel incomes to heat producers and the DH-network operator.

3.3.4 Consumer – customer

Consumers are customers, who buy the heat and pay the bills. The customer has duties and rights:

- The customer will be connected to the DH-network with a heat substation designed for connected heat capacity. The Network operator will accept the connection of the substation design.
- The customer must pay a connection charge to the network operator accepted by competition officer.
- The customer's substation must work within agreed temperature and pressure limits. Minimum ΔT and Δp must be guaranteed.
- Consumer can change a heat supplier without any new connecting and measurement charge.

3.4 Heat supply areas in heat trade markets

Heat supply areas will be formed around the producers (Figure 7). The producer or producer/consumer wants to make contracts with those, who are located close enough to it. The service area would be changed based on the time period for contracts. The service area is limited by pump capacity of the producer. The producer can enlarge his active network area by adding his pumping capacity. The producer can make contracts also outside his active area, but the active producer in the area or network operator supplies the heat to the consumer (e.g. A_{prod} make a contract with A1 in area C or C_{prod} a contract with C1 and C2 in area A; see Figure 7). The original contract supplier pays the transmission and second hand supplier cost. The heat demand and supply must be in balance all the time in the network. A network operator measures heat amount of every consumer and producer in DH-network.

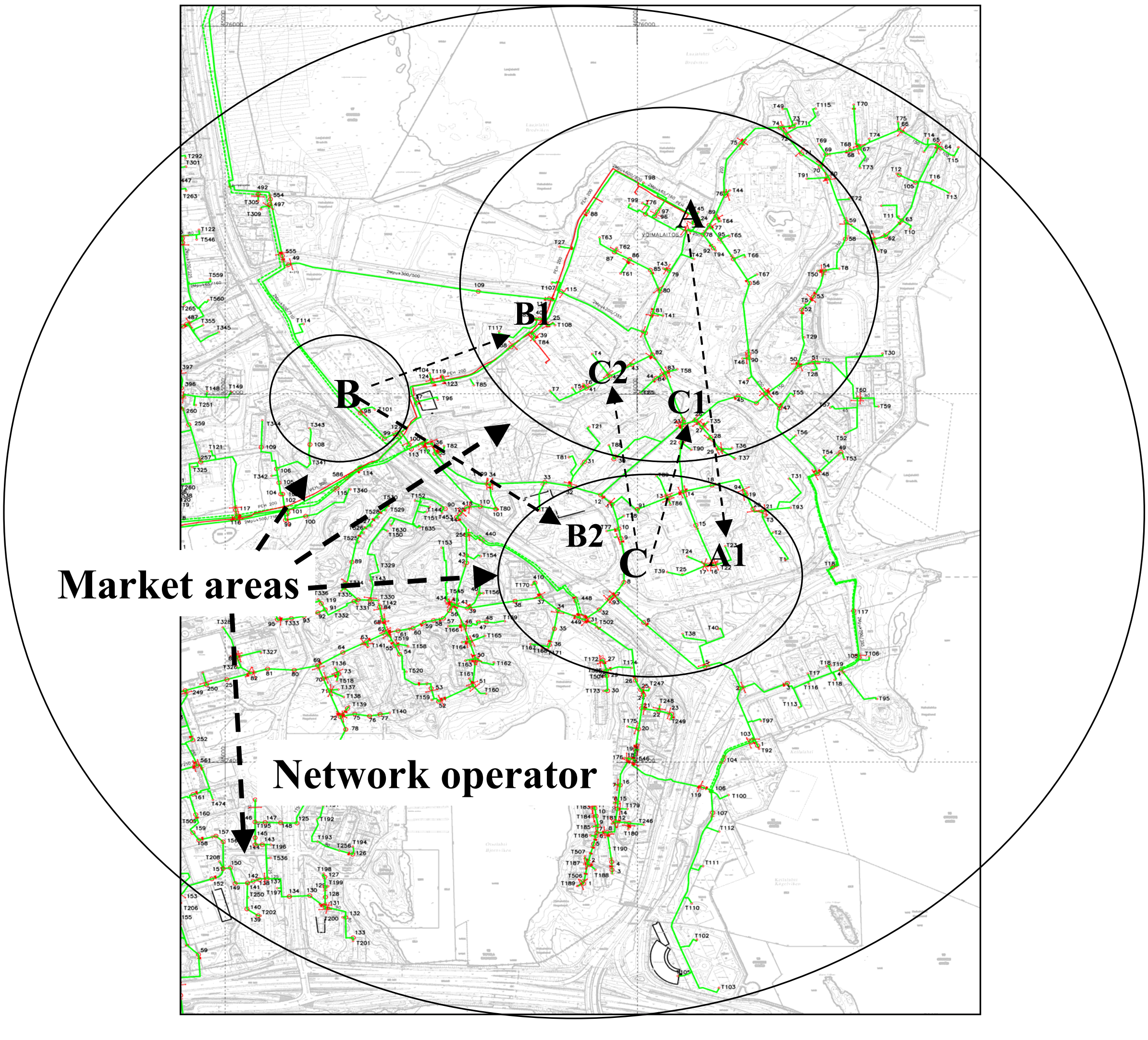

Figure 7. Heat trade market divided among four actors in the DH-network.

3.5 Heat and cash flows in heat trade markets

The cash and heat flows in local DH-markets are presented in figure 8. A heat balance sheet operator collects money from consumers and will divide it to producers and network operator based on contracts and heat energy measured by the network operator. The consumer pays energy and ordered capacity fare to producer based on the contract. The producer pays to the network operator contracted transfer capacity and transmission fare. The producer is responsible also for reserve capacity or must insure it by contracts with network operator or some other producer.

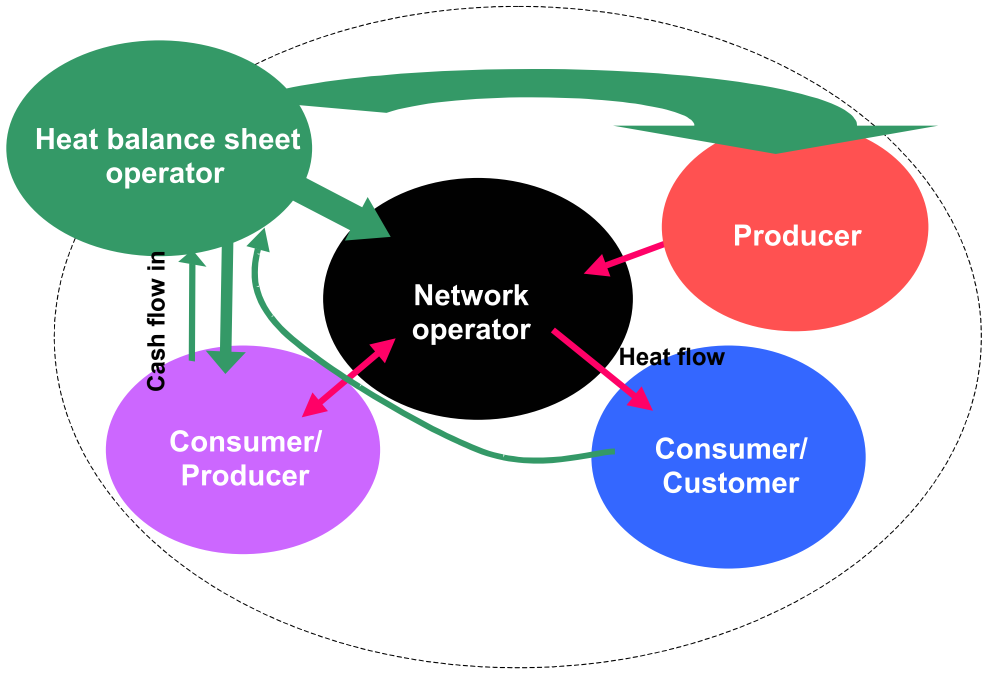

Figure 8. Cash and heat flows in local district heating markets.

3.6 Balance sheets in heat trade market

Heat balance sheet operator takes care of the capacity and transmission balance as well as the reserve capacity through contract balance.

Heat capacity balance sheet:

$$\phi_{th} = \sum_{i=1}^{n} (\phi_i + \phi_{ireserve}) \text{ i=[1 .... n] hours} \quad (1).$$

Energy balance sheet:

$$Q_{th} = \sum_{j=1}^{n} (\phi_j + q_{nj} + P_{nj}) \cdot t_j \text{ j=[1 ... n] hours} \quad (2)$$

where q_{nj} is heat loss of the network and P_{nj} is the required pumping capacity.

Contract balance sheet:

$$\Phi_{ct} = \sum_{i=1}^{N} (\Phi_i + \Phi_{reserve}) \cdot t_i = 1{,}2 \cdot \sum_{j=1}^{M} \Phi_j \cdot t_j \quad \text{i=[1 ... N], j=[1 ... M]} \qquad (3)$$

where M is number of consumers and N number of producers and t_i and $t_{,j}$ are the contract period.

The market may consist of basic contracts continuing until further notice, from one month to one year short contracts and some kind of spot markets 24 hours ahead like in the Nordic electric market. Future contract can be brought for the next heating season. The heat balance sheet operator is responsible for heat trade. The heat capacities and contracts must be in balance including the reserve capacity. The reserve capacity should be at least 20% of the total system capacity divided in units equal to the largest unit in actor's area. A coming heat boiler capacity in next heating season can be sold as futures to consumers.

All the heat trade and contracts will be done on line through internet communication. This is a big potential to software companies to develop software, which can take care of the heat trade balance sheet. Also producers and producer/consumers need software for making decision when to buy or sell heat. If electricity production is included, one more decision component will appear.

3.7 Economic considerations of heat trade

Above it was shown that new production, which captures a certain share of consumption demand, can affect pumping powers and heat loss power. In addition, if the new producer uses a network which is owned by another company it is only fair that they pay a certain compensation to the owner. These pay for maintenance and operation of the network (e.g. measurements) as well as provide a return for the investment. Consequently the new producer should be responsible for three other classes of cost in addition to the heat production itself: pumping, heat loss and costs of network. Let us think about each of these in turn.

3.7.1 Pumping cost

Naturally a producer takes care of pumping at his own plant. However, as seen above, a new producer can also affect the pumping cost of other producers. This effect may be in either direction and it is difficult to predict without an accurate computer model. Also the effect depends on temperature. The natural operator of this model would be the owner of the network, which in most cases is currently also the sole producer of heat. This creates the problem that the model operator may be tempted to report increased pumping costs for his own pumps due to introduction of new production. The operator of the model should therefore be a neutral party. One possibility is that the network ownership is transferred totally into a different company, which does not produce heat.

In the system where a producer pays other producers for increased pumping cost, the order or production is important. Suppose a new producer B starts producing and the pumping cost of an old producer A is reduced drastically. A now pays the new producer B for this benefit. But if producer B exists first and A starts later, pumping cost of B is reduced. However, now B pays to A although the end result in the physical network is exactly the same. This makes the system rather complicated. But there is a sound reason behind this. There is no reason why the old producer should get a free lunch by doing nothing, when the new producer causes the pumping costs to decrease.

In addition to this compensation system there are two other possibilities. The first one is that everyone pays only for his own pumping cost. The second possibility is that pumping costs are summed and everyone pays a share which is proportional to his heat production. These may lead to a higher total pumping cost than the compensation system. Especially in the second system there is little incentive for a producer to try to minimize pumping costs. The second system should, however, be applied to booster pumps because they are not tied to production but help the operation of the network.

3.7.2 Heat loss cost

One possibility of assigning the costs of heat loss is according to heat produced. There must be some producer who is responsible for the physical supply of the thermal power which covers heat losses, call his *balance manager*. This producer does not set his production beforehand but produces according to the physical demand of the network. The difference between his real production and power asked by his customers is the sum of heat loss and differences between power demanded and power actually consumed by all the consumers. Here power demanded means the expected power demand, which may be constant if the consumer has made contract for constant power. Otherwise it may be read from load curve typical to the consumer class. Also the balance manager handles the possible difference between power demanded and power produced.

There is a possible compensation system for heat loss too. If the introduction of new producer decreases total heat losses, the balance manager will pay him for that. In the opposite case the new producer has to pay extra to the balance manager. What makes this complicated is that the compensation can depend on temperature. If this system is applied, compensation has to be recalculated also when a producer changes the run order of his plants.

Figure 9 shows an example of this system. Originally there are three equally large producers. They also share the costs of heat loss equally. A new producer joins so that it takes an equal amount of customers from every old producer, resulting in four equally large producers. However, in this process total heat losses increase. Then the new producer is alone responsible for this increase (in the figure designated as “B”). In addition she will pay his share of the previous total losses (“A”).

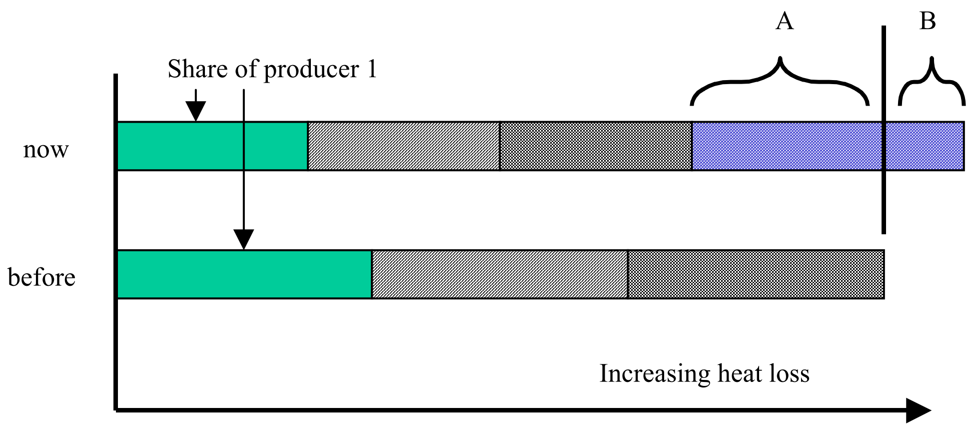

Figure 9. Example of the heat loss compensation system. Here the lower column describes the situation before when three producers are present. The upper column describes situation when a new producer has joined. In both cases all participating producers produce the same power. In the upper column the heat loss for which the new producer is responsible has been divided into two parts, A and B.

Naturally there should be a mechanism which prevents the balance manager from reporting too high heat losses.

3.7.3 Capital cost

Assigning the capital costs is difficult. For example in electricity transmission networks there are varying practices. In Finland the transmission cost is independent of the location of seller and buyer. In some countries seller and buyer both pay a transmission fee which depends on their location. Note that the transmission fee in electricity transmission networks corresponds to a fee which includes both pumping cost and capital cost in heat distribution networks. There is no corresponding component for heat loss cost in electricity transmission networks. The assigned capital cost in heat distribution network does not have to reflect the difficulty of heat transmission because this is already included in pumping cost.

There are arguments for both constant and location-dependent capital costing. Suppose the capital cost assigned to producers were independent of location. Then if the customer A and the producer B are close to each other, the fee may seem excessive compared to the transmission distance. In the extreme case, the producer would build his own pipeline to the customer. On the other hand, if the capital cost assigned to producers were somehow dependent on the distance between the customer and the producer, the producer would have to pay a high fee for selling to a distant buyer. But in some cases his production just replaces production at a plant C which may be very close to the producer A. This cost model could limit selling to distant customers although there is no physical reason why.

Also, in the location-dependent capital costing model, rationally acting producers would outsource their heat production to plants which are located close to customers (Figure 10). This would not necessarily change the physical situation but would allow producers to avoid high shares of network capital cost.

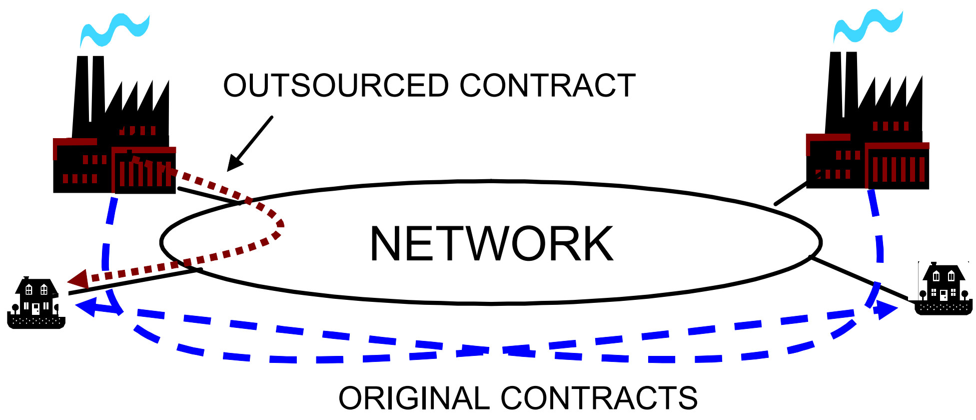

Figure 10. When two producers each sell to customers which are located close to the other producer, they can reduce the total producer-to-customer distance by outsourcing production from each other.

A location-independent capital cost would probably be simpler, considering also the fact that it is difficult to measure the extent of the network which is needed for transmission to a distant buyer. In this model the capital costs would be assigned to producers according to their annual production.

In addition to the distribution of capital cost, the total amount must be determined. Clearly this is a certain annual percentage of the investment plus maintenance and operating costs. Again we may use the capital asset pricing model to calculate a fair return. As the beta's of district heat producers are low, the fair return is close to risk-free interest rate. Note that according to this model the return should vary in line with interest rates. If this is allowed, the market risk of investment returns is still decreased, leading to a lower beta and lower fair return requirement.

3.7.4 Misuse of dominant position

The network companies, which in most cases currently have a monopoly of heat production in the network, hold a dominant position after new producers have joined. They wish to maintain their market share as close to 100% as possible. According to Buzzel and Gale (1987) high market share is correlated with high profits. Although this may not be so with a uniform product such as heat, it is certainly true for 100% market share when prices are not sternly regulated. For this reason the network companies may try to misuse the position in various manners and make life difficult for new actors.

The network company can apply *predatory pricing*, i.e., lower prices below costs and hope that this will drive away any competition. Naturally the company should have enough liquid assets or borrowing capacity to be able to perform this. If the newcomer is also a rich company, this will not work. Of course, such a manoeuvre is very risky and it is also banned in seventh article of the Finnish Act on Competition Restrictions. The attractiveness naturally depends on the magnitude of monopoly profits which are collected in the present situation.

A variant of predatory pricing is based on the fact that the network company has a control of the physical network. They might adjust average pressure, valves or run order of plants so that it is difficult for the new producers to feed heat into the network. This way costs increase for both the network company and the new producer. This is also a risky venture. Naturally the new producer must have asked for a statement about how much power could be fed into the network at the location they have planned. The network company could be required to guarantee a certain feed capacity.

4. The technologies of the distributed generation

4.1 Introduction

Many fuel cell and cogeneration component models have been developed with the intention of modelling microscopic or high-frequency phenomena e.g. changes in temperature within a cylinder of a CHP unit or changes in fuel concentration within a fuel cell. Such models are not suitable for incorporation into building energy calculation nor heat trade simulation. Most component models continue to be coded for a particular simulation tool and portability remains a problem; dedicated component models require translation and a re-write before being suitable for use in another simulation code. In addition to an expanding number of simulation codes, over the last decade the range of systems encountered in building simulation has also been increasing. Given the fact that micro-cogeneration is a relatively new phenomenon and that there is an inevitable time-lag between the evolution of the technology and the development of building simulation models, there are as-yet very few fuel cell or cogeneration models that have been specifically developed for building simulation and could be applied in heat trade simulation (Ferguson et al. 2003).

In preparation for the new IEA/ECBCS Annex 42 FC-COGEN-SIM (2004–2007) international collaboration effort, the existing fuel cell models have been reviewed. It has been concluded that model development work will need to be undertaken within the annex with regard to developing fuel component models suitable for domestic systems simulation (<10 kW), which incorporate dynamics, are adaptable and are capable of running with multi-fuels. (Kelly 2004.)

4.2 Fuel cell types

A fuel cell converts the chemical energy of a fuel and oxygen continuously into electrical energy (Figure 11). Typically, the fuel is hydrogen. Thus, the energy incorporated in the reaction of hydrogen and oxygen to water will be transformed into electrical energy. The “secret” of fuel cells is the electrolyte which separates the two reactants, hydrogen and oxygen, to avoid an uncontrolled explosive reaction. Basically, the fuel cell consists of a sandwich of layers which are placed around this central electrolyte: the anode at which the fuel is oxidized, the cathode at which the oxygen is reduced, and bipolar plates which feed the gases, collect the electrons, and conduct the reaction heat. To achieve higher power of fuel cells, a number of single cells are connected in series. This is called a fuel cell stack.

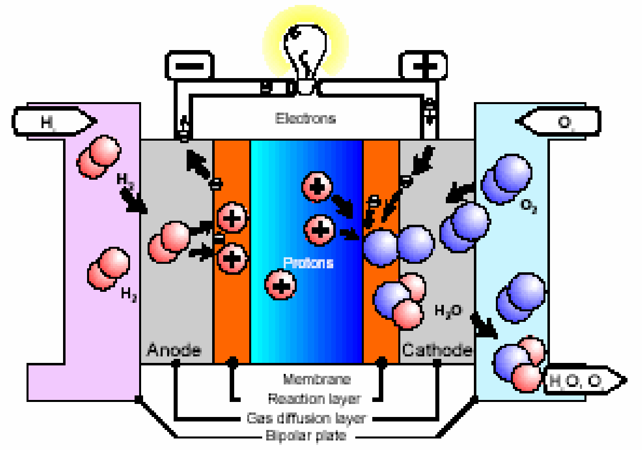

Figure 11. Basic construction of a fuel cell: example Polymer Electrolyte Fuel Cell (Pehnt & Ramsohl 2003).

Fuel cells can be categorised according to the electrolyte material and, correspondingly, the required operating temperatures into low, medium and high temperature applications (Table 3). Although the higher operating temperatures of MCFC and SOFC result in decreasing thermodynamic efficiencies, the better kinetics as well as the option to use the high temperature exhaust gas (e.g. in gas turbines) more than offset this efficiency reduction. In addition, high temperature fuel cells offer the advantage of internal reforming, i.e. the heat produced in the electrochemical reaction is simultaneously used for reforming natural gas or other fuels into hydrogen inside the stack, thus decreasing the required cooling effort while efficiently using the heat. Also, high temperature fuel cells have lower purity requirements of the fuel. Whereas AFCs are sensitive to CO2 and PEFC to CO impurities, CO2 acts in high-temperature fuel cells as inert gas only, and CO can even be used as a fuel.

Table 3. Types of fuel cells and main characteristics (Pehnt & Ramsohl 2003).

	AFC	PEFC	DMFC	PAFC	MCFC	SOFC
Electrolyte	KOH	Proton conducting membrane	Proton conducting membrane	Phosphoric acid	Carbonate melt	Y stabilised ZrO_2
Temperature	60–90 °C	60–90 °C	80–130 °C	200 °C	650 °C	800–1000 °C
Ion	OH^-	H^+	H^+	H^+	CO_3^{2-}	O^{2-}
$\eta_{system,el}$ **(natural gas)**		30–42%		38–42%	50–55% (w/ST >55%)	30–55% (w/GT >60%)
$\eta_{system,el}$ **(hydrogen)**		38–50%		47–50%	n.a.	n.a.
Favoured application	Space, military, portable	Mobile, portable, CHP	Mobile, portable	CHP	CHP, CC	CHP, CC
Power range [kW_{el}]		2–200		50–10 000	200–100 000	2–100 000
Status	First commercial production	Prototypes, first comm. production	Research	Small series production (200 kW_{el})	Demonstration	Demonstration

ST: Steam turbine; GT: Gas turbine; CHP: Combined Heat and Power Production; AFC: Alkaline Electrolyte Fuel Cell; PEFC: Polymer Electrolyte Membrane Fuel Cell; DMFC: Direct Methanol Fuel Cell; PAFC: Phosphoric Acid Fuel Cell; MCFC: Molten Carbonate Fuel Cell; SOFC: Solid Oxide Fuel Cell; n.a. not available.

4.3 Fuel cell systems

Fuel cell systems include (Figure 12) not only the fuel cell stack but also

- a fuel processor to allow operation with available hydrocarbon fuels
- a power conditioner to regulate the output power of the cell and where necessary convert it to alternating current
- an air management system to deliver air at the proper temperature, pressure and humidity
- a thermal management system to remove heat from the stack and to transfer heat among various system components
- in some cases a water management system to ensure that water is available for fuel processing and reactant humidification.

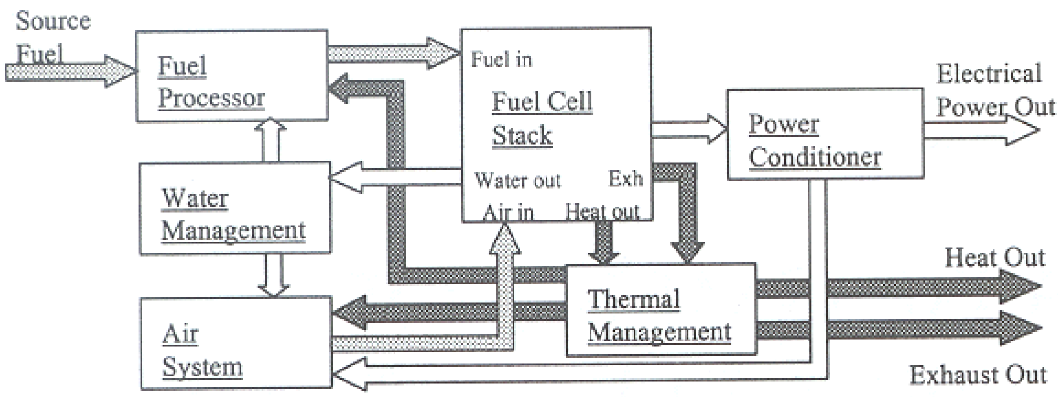

Figure 12. Fuel cell system schematic (Ellis 2002).

The low-temperature stacks, PEMFC and PAFC, require more extensive fuel processing and yield thermal energy at a lower temperature. The high-temperature stacks, MCFC and SOFC, are more flexible in their fuel requirements and yield thermal energy at a higher temperature. All four types have similar requirements with respect to power conditioning.

4.3.1 Fuel processing

PEMFCs and PAFCs require hydrogen for operation. MCFCs and SOFCs can use hydrogen and carbon monoxide as fuel and may even be able to reform a simple hydrocarbon, such as methane, to a usable fuel within the cell. In addition virtually all fuels require some type of "clean-up" operation. The major types of reforming and cleaning processes are

- steam reforming (highly endothermic process)
- partial oxidation
- autothermal reforming (like partial oxidation and steam reforming, autothermal reforming produces a fuel that requires further processing for use in PEMFCs and PAFCs)
- shift conversion (exothermic reaction)
- gas clean-up (variety of processes that can occur upstream or downstream of the fuel reformers and shift converters. PEMFCs require CO concentrations lower than 10 ppm!).

Clearly, the fuel processor is a complex system. Consequently, it is difficult to scale economically to small sizes. The development of compact, efficient, and economical fuel processors that respond quickly to load changes is currently an active area of research. (Ellis 2002.)

4.3.2 Power conditioning

The power conditioning system modifies the fuel cell electrical output to meet the needs of the application that can belong to one of the following types:

- Grid independent applications in which the fuel cell is the sole provider of power to the load.
- Back-up power applications in which two power sources (e.g. utility grid as primary and FC as supporting source) are required to improve reliability but do not provide power simultaneously.
- Parallel power applications in which the fuel cell and utility power operate simultaneously.
- Utility interconnect applications in which the fuel cell not only provides power to the application but also can supply power into the utility grid.

In all four types of applications, the power conditioning system

- regulates the voltage provided by the fuel cell system
- transforms DC power from the fuel cell into AC power for the application
- provides reactive power to match the power factor of the application
- provides power to fuel cell auxiliary devices
- interfaces with the electrical load and the fuel cell system controls.

Because the present utility grid is essentially designed to be a one-way conduit of power, the interconnection of distributed power systems such as fuel cells with the utility grid is currently an important area of research and development. (Ellis 2002.)

4.3.3 Air management

Air is required for the fuel cell stack and for the fuel processor. Air is generally supplied by a compressor at pressures 2 to 10 atmospheres. The flow rate of air is determined by the reaction rate of the oxygen at the cathode. The air system has an important effect on the fuel cell system performance – efficiency improves with increasing air pressure. However, if the compressor power is provided by the fuel cell stack, the best system performance occurs at an optimum operating pressure.

In addition to the air compressor, the air supply system includes heat exchangers and humidifiers (for the PEMFC) to ensure that the temperature and humidity of the air stream are compatible with the stack.

4.3.4 Thermal management

The thermal management system consists of the network of heat exchangers, fans, pumps, and compressors. They are all required to provide for stack cooling, heat recovery for cogeneration, and reactant preheating or precooling. The amount of heat released during the fuel cell reaction is comparable to the amount of electricity that is provided. This heat must be removed and a portion of it can be recovered to meet the thermal needs of a cogeneration application. In PEMFCs and PAFCs stack cooling is accomplished by circulating a heat transfer fluid through cooling channels in the stack. Heat transferred to the coolant can be recovered and used to meet the thermal needs of the building application. In MCFCs and SOFCs cell cooling is provided by the anode and cathode gas streams, which leave the stack at a higher temperature than at which they enter. In these high-temperature stacks, heat transfer from the cell reaction may also be used to supply energy to the endothermic fuel reforming reaction. (Ellis 2002.)

4.3.5 Water management

Water is required for fuel processing in all fuel cell systems and also for humidification of the reactant gases in the PEMFC. Since water is produced by the cell reaction it can often be condensed from the exhaust stream and reused.

4.3.6 Efficiency

Figure 13 provides an example of representative energy flows for a PAFC fuel cell system. Values for the fuel processor and power conditioning system are estimates. In this example the fuel processor is approximately 85% efficient, the fuel cell stack is operating at 49%, and the inverter has an efficiency of 95%. The overall electrical conversion efficiency is 40%. Approximately 40% of the input energy is available as thermal energy at temperatures ranging from 40 °C to 80 ºC. Finally, 20% of the input energy cannot be economically recovered and is discharged to the surroundings through the exhaust gas and the power conditioner heat loss. The cogeneration efficiency reflects not only the electrical power but also the useful thermal energy available from the fuel cell system. The overall cogeneration efficiency of the example plant is 80%.

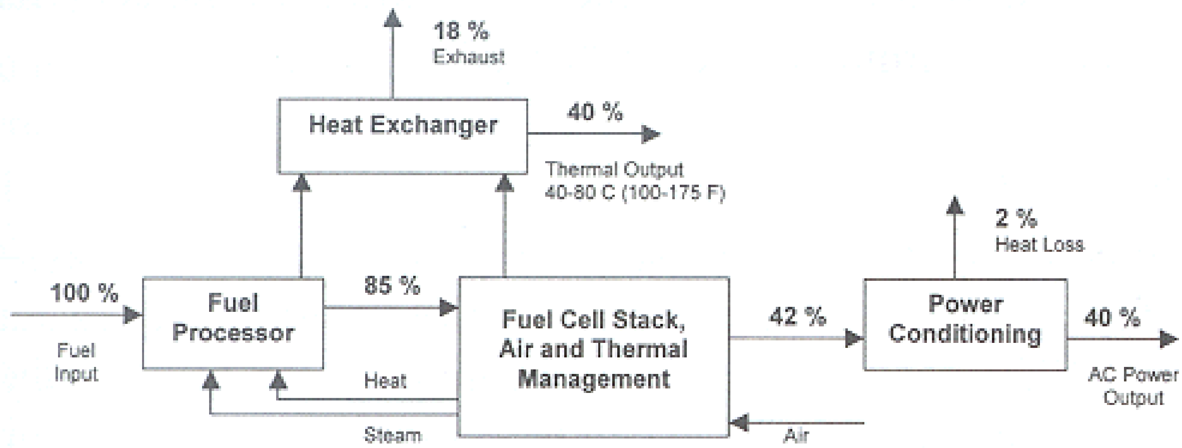

Figure 13. Block diagram for PAFC power plant (Ellis 2002).

4.3.7 Cogeneration strategies

There are four basic strategies that are likely to be implemented with a fuel cell cogeneration system:

- *Electrical load tracking strategy* calls for the fuel cell to have an electrical capacity that exceeds the minimum electrical requirement for the facility. The fuel cell output power changes in response to the needs of the facility. The thermal output of the fuel cell system is used whenever possible, otherwise it is simply rejected to the atmosphere. A separate heat source is required to provide thermal energy when the waste heat from the fuel cell is not adequate.
- With a *thermal load tracking strategy*, the system is designed to follow the thermal load of the facility. Power that is generated during the course of supplying the thermal load is used by the facility to replace purchased electric power. The excess power can often be sold to the utility.

- With an *electrical base load strategy*, the fuel cell system is designed to supply the minimum amount of power required by the facility. Therefore, the fuel cell system can operate at peak power output continuously. Additional power for meeting the peak power needs of the facility is purchased from the utility. A shortage of thermal energy is compensated by a separate thermal source such as a boiler.
- With a *thermal base load strategy* the system is designed to meet the minimum thermal load. Thermal energy to meet peak loads is provided by an auxiliary heat source, such as a boiler. Electrical power is purchased from or sold to the grid to balance the electrical demand for the facility with the power supplied by the fuel cell system.

Other conventional cogeneration strategies, including *peak shaving* and *economic dispatch*, would call for fuel cell operation during only limited periods. Due to relatively high first cost of fuel cell systems, such strategies are not likely to be attractive. (Ellis 2002.)

4.3.8 Economic considerations

There is a variety of techniques for evaluating the economic merits of a fuel cell cogeneration system. Simple techniques can be implemented with minimal data but give results that can be misleading and that must be interpreted with caution. More complex techniques require extensive data collection (usually hourly system modelling) and numerous calculations but can yield more accurate results. Furthermore, they require a more thorough understanding of the assumptions and interrelationships inherent in the analysis.

The simplest type of analysis consists of comparing the cost of electricity generated by the cogeneration system to the cost of electricity available from the utility. The cost of co generated electricity is estimated by determining capital, maintenance and utility costs on a $/kWh basis. The electricity cost is reduced by the value of the thermal energy produced. These calculations are reflected in the following equation:

$$COE = \frac{(A/P,n,r)\cdot CC}{EFLH \cdot FP} + \frac{C_1 \cdot FC}{\eta_E} + MC - \frac{C_1 \cdot F_1 \cdot \varepsilon_T \cdot FC}{\eta_E \cdot \eta_A} \qquad (4)$$

where

(A/P,n,r)	is annual cost factor for a fuel cell life of n years and an interest rate, r
CC	is capital cost of the fuel cell system (€)
EFLH	is number of equivalent full-load hours, which corresponds to the number of hours at full power that would be required to produce the amount of energy supplied by the system during the year (hours)

FP	is rated or full-load power of the fuel cell system (kW)
C_1	is conversion factor relating the units for the fuel energy to the units for electrical energy (e.g., 3.412 MBtu/kWh)
FC	is fuel cost (€/kWh)
MC	is maintenance cost (€/kWh)
η_E	is average electrical conversion efficiency of the fuel cell system
η_A	is efficiency of the thermal source displaced by the thermal energy of the fuel cell system
F_1	is thermal use factor that reflects the fraction of thermal energy from the fuel cell system that can be used within the facility
ε_T	is fraction of the fuel energy supplied to the fuel cell that is available as usable thermal energy from the system.

In this expression, the first term represents the annualized cost of the fuel cell spread over the annual amount of electricity produced. The number of periods, n, should correspond to the life of the whole system. The stack life will be shorter, but the cost of stack replacement will he treated as a maintenance cost. The second term is the fuel cost per unit of electricity produced. The third term is the maintenance cost per unit of electricity produced. This term must include routine annual maintenance costs plus a sinking fund to periodically replace the fuel cell stack. The final term reflects the value of the thermal energy that would have been required from an alternative system, such as a boiler, but that is instead provided as a by-product of fuel cell operation. The amount of thermal energy provided by the fuel cell may exceed that which is required by the facility. Or, the need for thermal energy may not coincide with the availability of thermal energy from the fuel cell. The factor, F1, indicates the average fraction of thermal energy from the fuel cell system that can actually be used to replace energy from other sources. The value of F cannot exceed 1.0 and is further restricted by

$$F_1 \leq \frac{r_{TE} \cdot \eta_E}{\varepsilon_T} \tag{5}$$

where r_{TE} is the annual average thermal electric ratio for the building.

The cost of electricity, as calculated by previous equation, can be compared with the average cost of electricity for the facility to determine whether electricity can be provided more economically with the fuel cell system.

This simplified approach to evaluating a fuel cell cogeneration system has two major drawbacks.

First, the factor, F1, which determines the extent to which thermal energy is recovered, is difficult to estimate. A careful determination of this factor would require hour-by-hour knowledge of the electrical and thermal energy profiles. Furthermore, incorporation of this information would greatly complicate the approach.

Another problem with the simplified approach is the determination of the cost of electricity supplied by the utility. An average cost of electricity can be calculated based on annual cost and annual energy use in kWh. However, this cost is really only applicable when comparing the option of supplying all of the electricity on-site to purchasing all of the electricity from the utility. In other cases, when only a fraction of the electricity is generated on-site, the challenge is to properly evaluate the cost of utility-furnished electricity that is replaced by on-site electricity. Depending on the utility pricing structure, this cost can vary with the time of day, the season of the year, and the electricity demand and energy use history for the facility.

The cost of electricity can certainly be determined, but doing so may require a very detailed calculation that incorporates hour-by-hour electricity data. Thus, the "simplified approach" actually only looks simple because the complexity is hidden in the values of the thermal use factor F1, and the average electricity cost. The method is only as accurate as the determination of these values. (Ellis 2002.)

4.4 Performance characteristics

The performance of fuel cell systems is a function of the type of fuel cell and its capacity. The optimization of electrical efficiency and performance characteristics of fuel cell systems poses an engineering challenge because fuel cell systems are a combination of chemical, electrochemical, and electronic subsystems. (Onovwiona 2003.)

4.4.1 Electrical efficiency

Due to the several subsystem components of a fuel cell system, laid out in series, the electrical efficiency of the system is a product of the efficiencies of the individual sections. The electrical efficiency of a fuel cell can be calculated as:

$$\eta_{el,HHV} = \eta_{fps} \cdot \eta_{H_2} \cdot \eta_{stack} \cdot \eta_{pc} \cdot \frac{HHV_f}{LHV_f} \qquad (6)$$

where

η_{fps}	=	fuel processing subsystem efficiency
	=	(LHV of hydrogen generated / LHV of fuel consumed)
η_{H_2}	=	fraction of hydrogen actually consumed in the stack

η_{stack}	=	(Operating Voltage / Energy Potential ~1.23 volts)
η_{pc}	=	AC power delivered / (DC power generated)
	=	(auxiliary loads are assumed DC loads here)
HHV	=	higher heating value of fuel
LHV	=	lower heating value of fuel

For example for PAFC fuel cell:

$$\eta_{el,HHV} = (84\%)_{fps}(83\%)_{H_2}(\tfrac{0.75V}{1.23V})_{stack}(95\%)_{pc}(0.9)_{HHV/LHV} = 36\%$$

Performance data for fuel cell systems collated by Energy Nexus Group is presented in table 4.

Table 4. Performance characteristics of fuel cell based cogeneration systems (Onovwiona 2003).

Performance Characteristics	**System 1**	**System 2**	**System 3**	**System 4**	**System 5**
Fuel Cell Type	PEMFC	PEMFC	PAFC	SOFC	MCFC
Nominal Electricity Capacity [kW]	10	200	200	100	250
Electrical Efficiency [%], HHV	30%	35%	36%	45%	43%
Fuel Input kW	29	586	557	234	586
Operating Temperature [^{o}C]	70	70	200	950	650
Cogeneration Characteristics					
Heat Output [kW]	12	211	217	56	128
Total Overall Efficiency [%], HHV	68%	72%	75%	70%	65%
Power / Heat Ratio	0.77	0.95	0.92	1.79	1.95
Effective Electrical Efficiency [%], HHV	53.6%	65.0%	70.3%	65.6%	59.5%
HHV = Higher Heating Value					

Source: Energy Nexus Group (2002).

4.4.2 Emissions

The fuel cell systems have the potential to produce very few emissions (Table 5). The major source of emissions is the fuel processing subsystem because the heat input required for the reforming process is derived from the anode-off gas that contains approx. 8–15% hydrogen, combusted in a catalytic burner.

Table 5. Estimated fuel cell emissions characteristics (Onovwiona 2003).

Emissions Analysis	**System 1**	**System 2**	**System 3**	**System 4**	**System 5**
Fuel Cell Type	PEMFC	PEMFC	PAFC	SOFC	MCFC
Nominal Electricity Capacity [kW]	10	200	200	100	250

Electrical Efficiency [%], HHV	30%	35%	36%	45%	43%
Emissions					
NOx [ppm_V @ 15% O_2]	1,8	1,8	1,0	2,0	2,0
NOx [g/MWh]	27	27	14	23	27
CO [ppm_V @ 15% O_2]	2.8	2.8	2.0	2.0	2.0
CO [g/MWh]	32	32	23	18	18
Unburnt Hydrocarbons [ppm_V @ 15% O_2]	0.4	0.4	0.7	1.0	0.5
Unburnt Hydrocarbons [g/MWh]	5	5	5	5	5
CO_2 [kg/MWh]	617	531	515	413	431
Carbon [kg/MWh]	168	143	141	111	118

4.4.3 Costs

Fuel cell based cogeneration system capital costs consist of costs of subsystems. The stack subsystem is estimated to represent 25–40% of equipment costs, the fuel processing subsystem represents 25–30% of equipment costs, the power and electronics subsystem represents 10–20% of equipment costs, the thermal management subsystem represents 10–20% of equipment costs, and ancillary subsystems represent 5–15% of equipment costs (Table 6).

Table 6. Estimated costs for typical fuel cell based cogeneration systems ($/kW) (Onovwiona 2003).

Installed Cost Component	**System 1**	**System 2**	**System 3**	**System 4**	**System 5**
Fuel Cell Type	PEMFC	PEMFC	PAFC	SOFC	MCFC
Nominal Electricity Capacity [kW]	10	200	200	100	250
Equipment Costs (2002 $/kW)					
Packaged Cost	4 700	2 950	3 850	2 850	4 350
Grid Isolated Breakers	250	100	100	120	100
Materials and Labour	100	272	272	250	280
Total Process Capital	5 050	3 322	4 222	3 220	4 730
Other Site Costs (2002 $/kW)					
Project and Const. Management	280	124	124	168	112
Engineering and Fees	90	52	52	72	60
Contingencies	80	94	94	30	90
Interest during Construction	0	8	8	10	8
Total Installed Cost (2002 $/kW)	**5 500**	**3 600**	**4 500**	**3 500**	**5 000**

Source: Energy Nexus Group (2002).

4.5 Other distributed energy generation systems

Properties of different small CHP generation systems are compared by means of polar diagram's in the following figures 14–17. Different features of the systems are valued using a scale from 0 (worst) to 5 (best). (Vartiainen et al. 2002, Valkiainen et al. 2001.)

Power plants based on gas or diesel engines consist of piston engine, generator, and waste heat recovery system (when CHP). Their typical features are: low costs, high efficiency, wide power range and ability to run on different fuels. Internal combustion engine power plants are modular, i.e. standardised units can easily be combined. Their weak points include noise and high emissions.

Gas turbines consist of turbine itself, generator and compressor to compress supply air. Advantages of gas turbines are small size and reasonable costs. However disadvantages include poor efficiency at part load and high temperature of flue gas (400–600 °C).

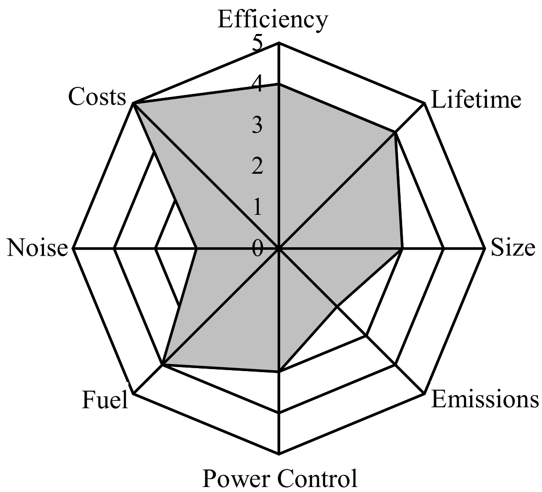

Figure 14. Features of diesel and gas engines (Valkiainen et al. 2001).

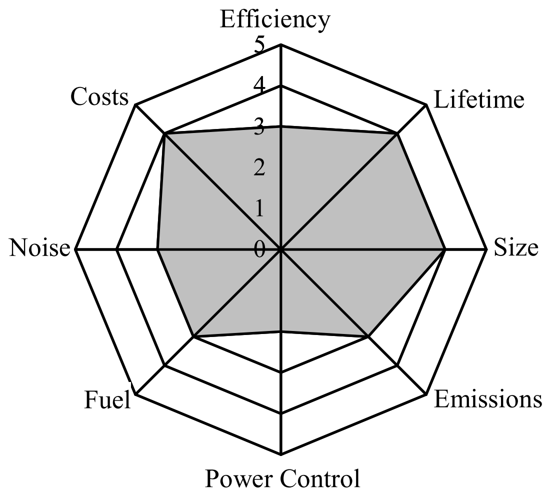

Figure 15. Features of gas turbines (Valkiainen et al. 2001).

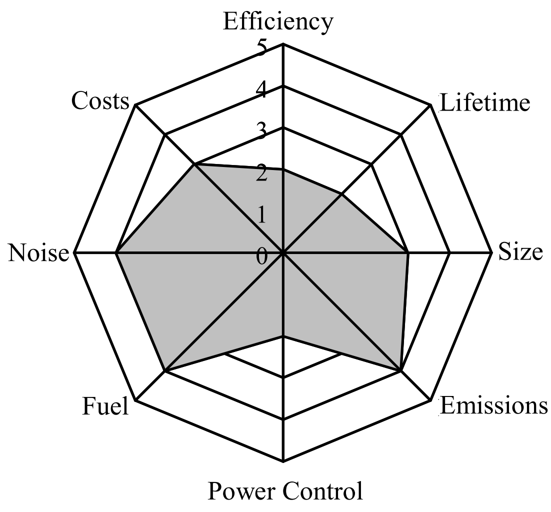

Figure 16. Features of Stirling engines (Valkiainen et al. 2001).

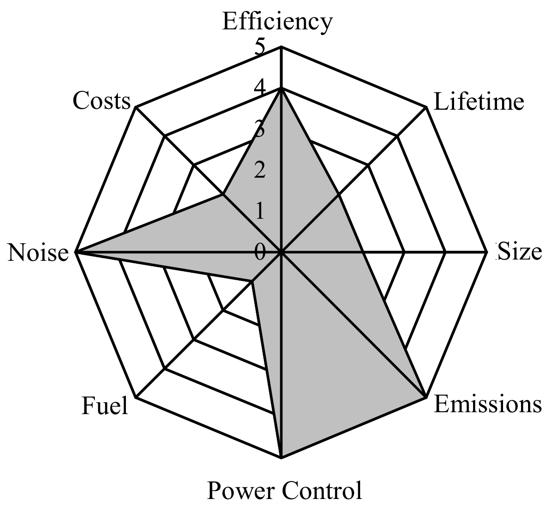

Figure 17. Features of fuel cells (Valkiainen et al. 2001).

Stirling engine differs from internal combustion engine by the fact that cylinder is closed and combustion process takes place outside of it. Piston is moved by pressure changes due to heating and cooling of working gas (Figure 18).

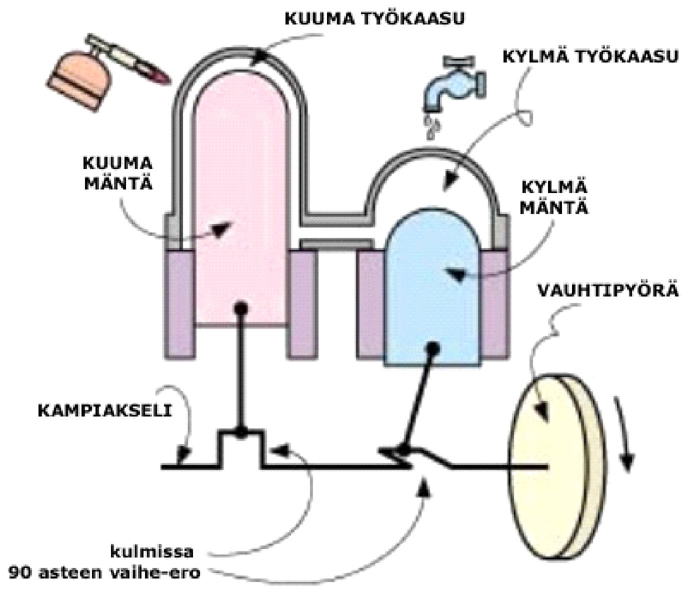

Figure 18. Operation principle of Stirling engine (NMRI 2004).

External combustion process provides a possibility for application of different fuels, but efficiency of electricity generation remains relatively low. Advantages of Stirling engine, when compared with internal combustion engines, include stable combustion, low noise and emissions and longer maintenance intervals.

Advantages of fuel cells are high efficiency (also at part load), low noise and emissions. Disadvantages are very high costs and fuel quality requirements.

In Table 7 an estimation is given regarding how well different technologies fit different types of buildings in terms of application as distributed energy generation systems and typical electrical efficiencies of different distributed generation technologies are displayed in Figure 19.

Table 7. Estimated technical applicability of different technologies to different buildings (Valkiainen et al. 2001).

Building type	**Gas and diesel engines**	**Gas turbines**	**Stirling engines**	**Fuel cells**
Single family house	-	--	++	++
Attached row house	+	-	++	++
Apartment house	+	-	+	+
Office building	+	-	-	+
Hotel, spa, etc.	++	+	-	+
Green house	++	+	--	+
Small industry: workshop, sawmill etc.	++	++	--	+
District heating	++	+	--	+

Fitting category: -- very poor - poor + good ++ excellent.

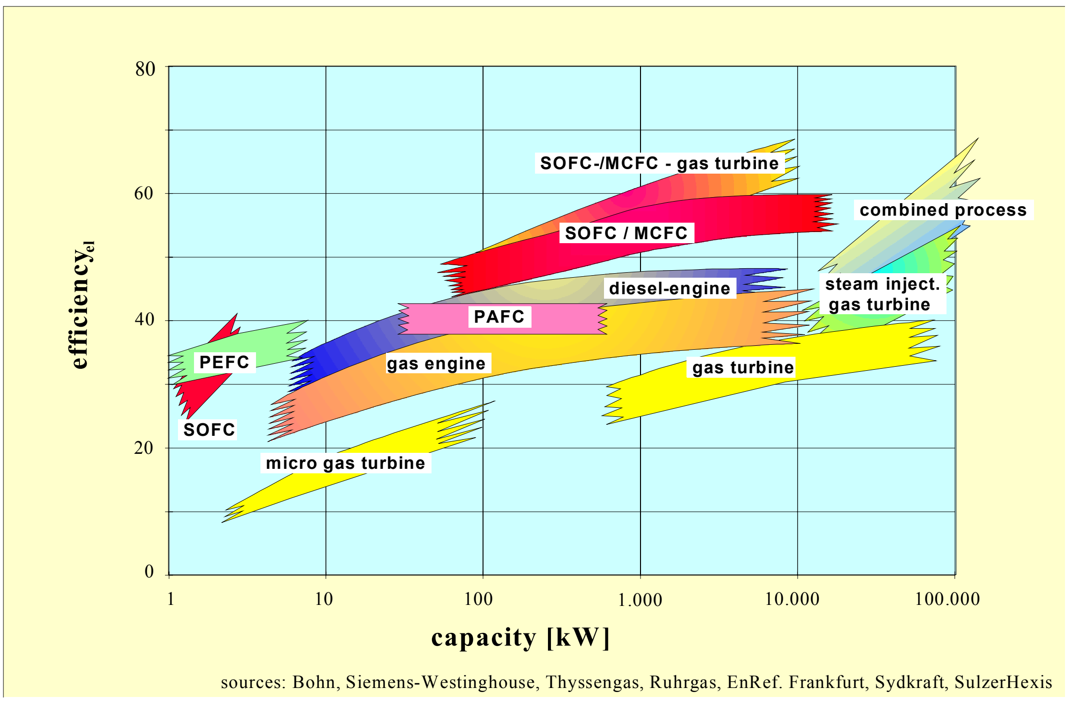

Figure 19. Electrical efficiency performance of different technologies as a function of capacity (Birnbaum & Weinmann 2003).

5. Sample cases of the applicability of the heat trade concept

5.1 Case 1: the hydraulic performance of the DH-network in the city of Turku

5.1.1 The effects of heat trade on the district heating network

Currently the network company is the sole provider in each district heating network. Whereas in some cases the network company does not produce all of the heat energy itself, customers cannot buy the district heat energy from other sources. For this reason producers of district heat are interpreted to have a dominant market position among the customers who have chosen district heat as their method of space heating. *Heat trade* is defined here as the existence of more than one producer in the network and the ability of customers to choose their heat provider. In other words, the market of heat is opened for competition. In the extreme case producers of heat can be very small, e.g. equivalent to the power need of one building.

Heat trade changes the structure of heat production so that the company that receives bids from customers increases its production, and the company who previously provided the heat for the bidding customers must reduce production. Here it was assumed that each new producer makes a contract with a customer for a specific power, which may be time-dependent. Each new company then produces just as much as it has made contracts. However, this does not apply to the network company. The network company's job is, besides producing heat, to take care of the network, i.e., to act as network operator. It provides the difference of contract power demand and actual demand as well as power which compensates heat losses.

The distribution network places restrictions on heat trade. It places two different types of constraints:

1) pressure constraints
2) temperature change constraints.

The pressure constraint refers to the fact that the maximum pressure that the feed pipes can withstand is finite. New produces can change the geographical distribution of production so that distribution is no longer possible without exceeding the maximum pressure. It is also possible that pressure in some return pipe becomes so low that evaporation takes place on the suction side of a pump. In this case the impeller is quickly damaged. Which situation may occur depends on the average pressure of the network and the producer's altitude and location.

The temperature change constraint refers to the fact that the time derivative of temperature in a certain pipe should not exceed a given limit value. This value is usually taken as ten degrees per hour. The reason behind this is that heat expansion places a stress on pipes and joints.

These constraints can be thought of as (mathematically speaking) hard constraints, which cannot be violated. Of course, heat trade can lead to higher costs, although a situation is not directly impossible for the network. The costs arise from high pressure losses in heat distribution, which leads to high pumping costs. The basic reason behind this is that the geographical distribution of production changes into one for which the network was not originally designed.

5.1.1.1 The effect of run order

Pressures, pressure losses and temperature changes depend also on which order each producer runs its plants as a function of demand. As far as pumping costs are considered, the most advantageous location for production is often where the pressure difference between the feed and return lines is smallest. The pressure differences change as a result of new production: the value we should look at is the pressure difference *after* production has started.

Mathematically speaking the pumping power at a plant is

$$P_{pump} = \frac{P_h}{\eta \cdot \left(T_{feed} - T_{return}\right) \cdot c_p \cdot \rho} \left(p_{feed} - p_{return}\right) \quad (7)$$

where P_h is the heat power of the plant, T_{feed} feed temperature T_{return} return line temperature, p_{feed} feed pressure, p_{return} return line pressure, η pumping efficiency, c_p specific heat of water and ρ density of water. The quantities are measured when the plant is running.

In practice, however, the run order is not set merely according to pumping costs but according to plant types and fuels.

The plant which is the last in the run order, changes its production power according to demand. When a company loses customers, the plant decreases power and vice versa. The location of the last plant in run order of the company who loses a contract and, on the other hand, of the company who gets a new contract, determine the effects of the transaction in the network. If the two plants are close to each other and connected with an uncongested line, then the transaction has a minimal pressure effect.

The following shows the importance of run order to pressures in case of heat trading. The figures below show an example what might be the pressure effect of a certain shift of production from one producer to another. The abscissa shows location along a pipeline. The network here has one main pipeline with branches extending to consumers. Production here is mainly on the right, near node 19, although there are smaller power stations scattered all over. Consumption is located more or less evenly along the pipeline. Figure 20 represents the situation before production has shifted. Figure 21 represents the situation after. In Figure 21 an old producer has given up some production to a new company. Unfortunately the last plant in the run order of the old producer is located on the left, where not too much production is available. The new company's plant again is located on the right where plenty of production exists already. The result can be seen from the figures: pressure losses and thus absolute pressures rise considerably. However, if the old company's regulating plant had been on the right too, the pressure effect would have been small.

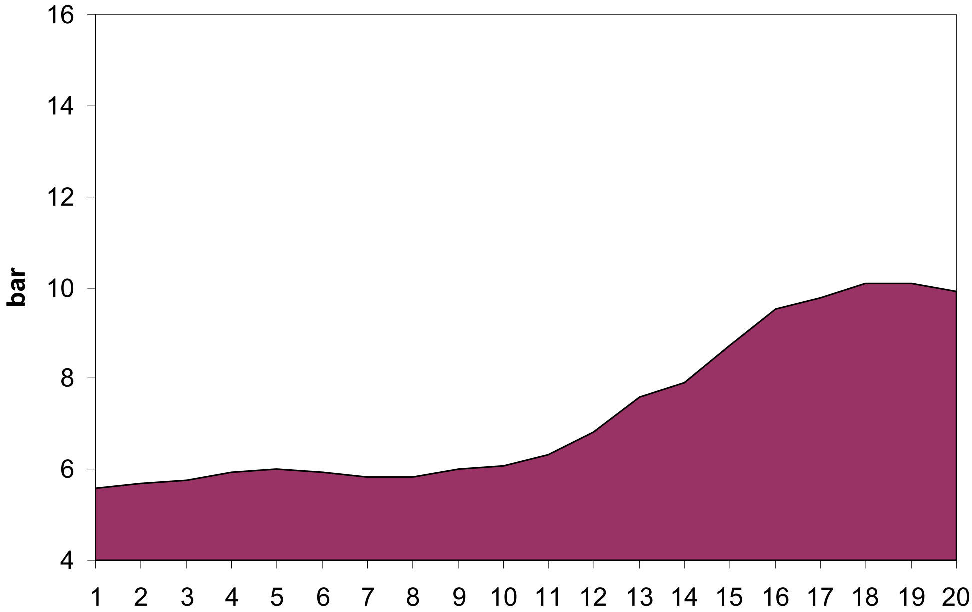

Figure 20. Pressure in feed line, initial situation. Abscissa denoted the node position along a main pipeline.

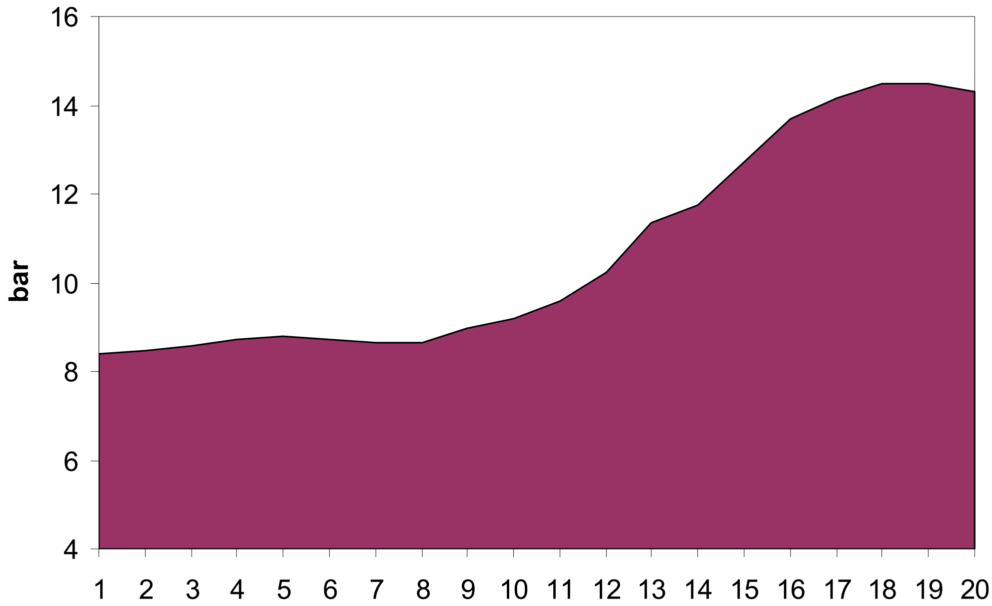

Figure 21. Pressure in feed line, situation after some production has shifted from a plant located in node 5 to new plant located in node 19.

5.1.2 Turku as an example case

The district heating network of Turku, a city of 200,000 people in southwestern Finland, had 2075 customers and maximum power of 847 MW as of 2003. The network comprised 290 km of pipelines and several power plants (Figure 22). However, the bulk of the heat comes from Fortum's (an energy producer) coal plant from the neighbouring town Naantali in an underground tunnel.

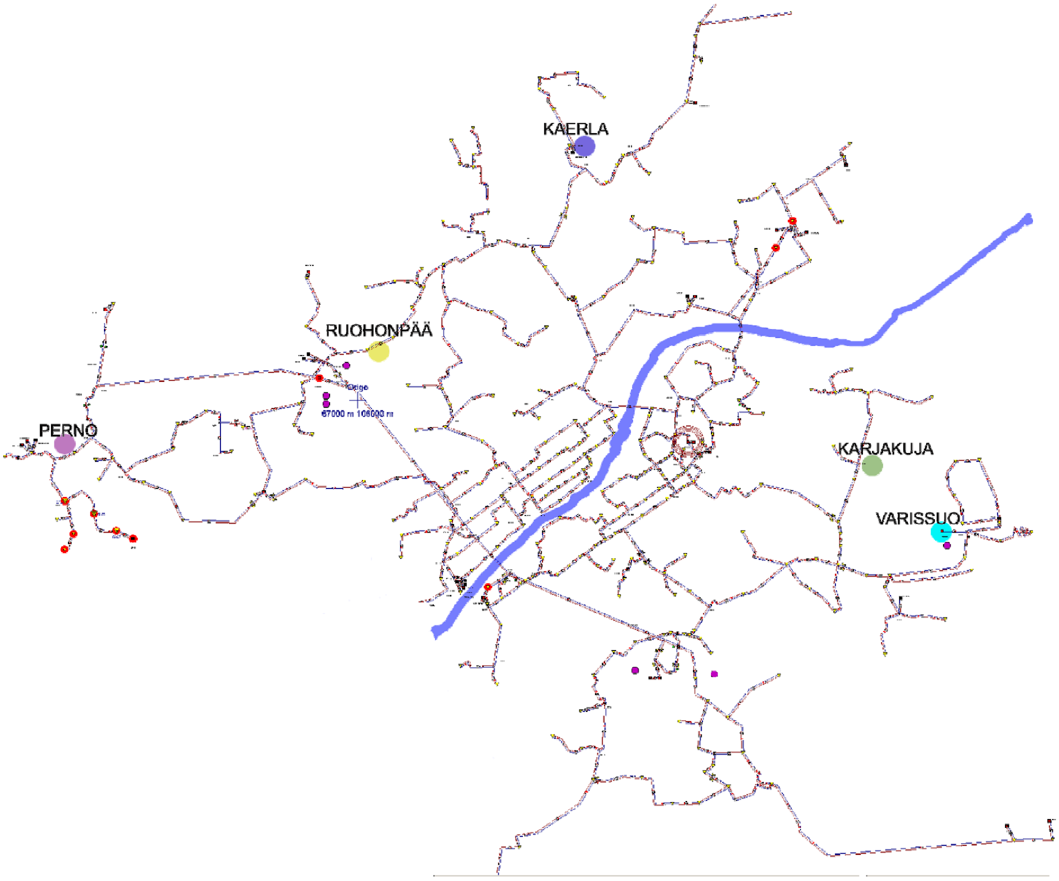

Figure 22. The district heating network of Turku. The blue line is Aurajoki river, the names indicate imaginary new plants.

Turku Energia power company uses the Grades Heating program for network simulation. The network model made with this program was given to VTT. The model includes information about pipes, consumer powers and cooling temperatures as well as plant run orders. The program can be used to calculate flows, pressures, heat losses, pumping powers etc. The network model was also transformed into form which could be read by VTT's own simulation program, developed by the author. This allowed a dynamic simulation as function of time.

Example cases were simulated in Turku network. In these a new producer is located at a certain position in the network and starts producing. Turku Energia network company accordingly reduces power from the last plant in run order to accommodate the extra power coming from the new plant. Figure 23 shows the run order and powers of Turku Energia plants. The first plant HRK00 is an imaginary plant which represents the heat flow from Fortum's plant. The power of this heat source is 300 MW.

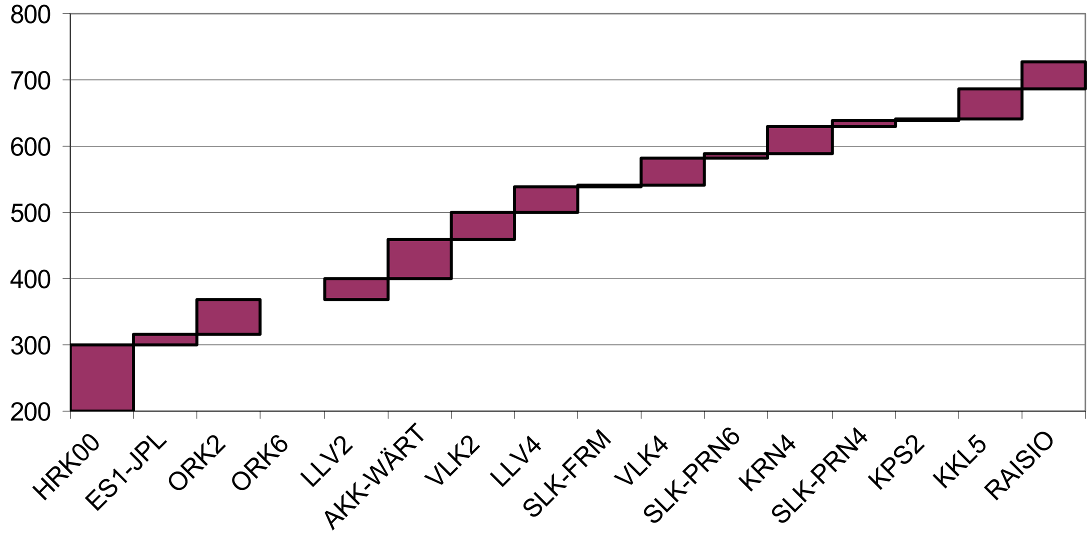

Figure 23. Run order of thermal power plants in Turku. The abscissa shows abbreviated plant names, the ordinate shows power in megawatts.

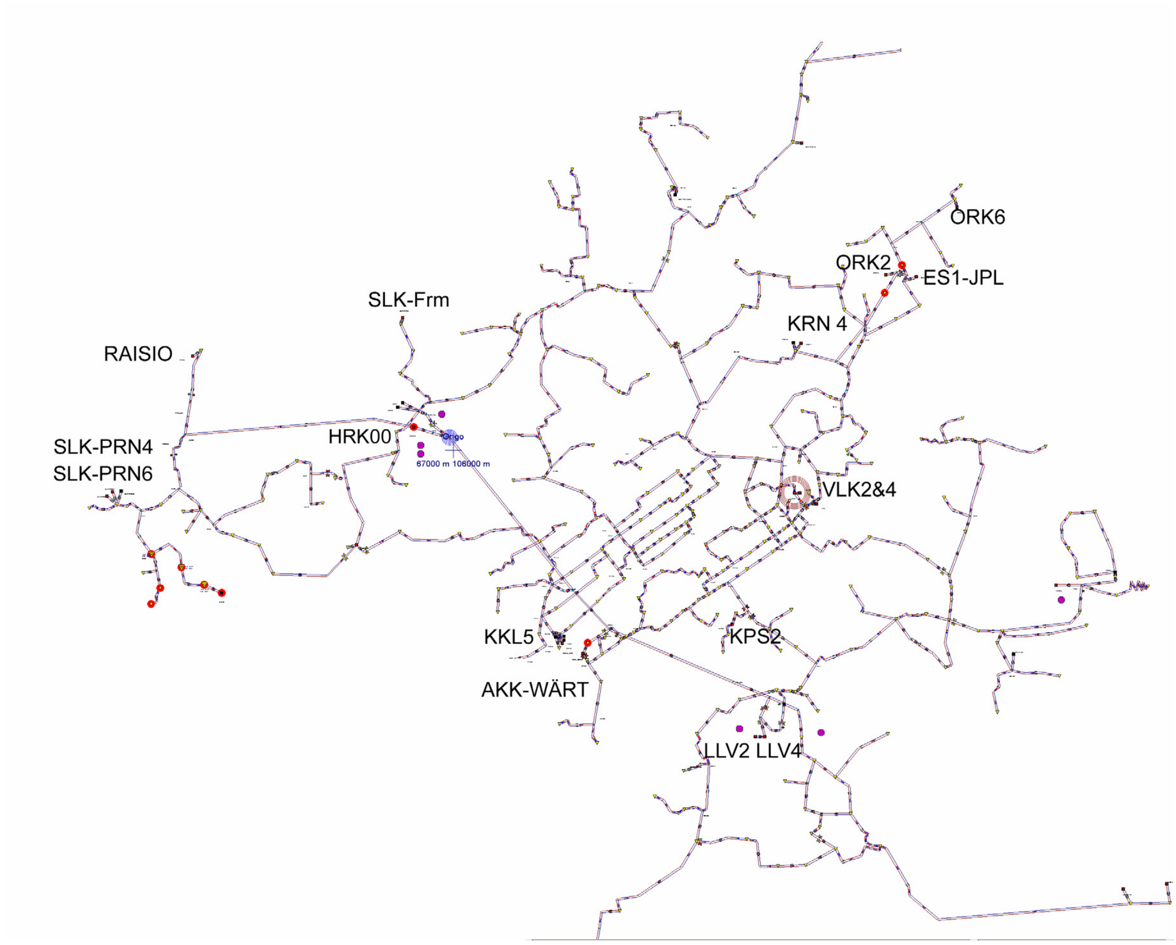

Figure 24. Locations of different power plants in the network.

Heat trading was assumed to happen on the level of larger plants (Figure 24). Micro-CHP's which can even be installed inside normal buildings, were not considered. It is natural that the effect on pressures depends on temperature. This is because at different outdoor temperatures flows and location of the regulating plant are different. Three outdoor temperatures were used in simulation: 0 °C, –11 °C and –25 °C.

5.1.2.1 New plant located in Ruohonpää

The imaginary new plant "Ruohonpää" is located near Härkämäki. Figures 25–27 show how the total pumping power changes as the plant in Ruohonpää increases power. The figure separates power which is consumed by pumps of Turku Energia and pumps at the new plant. Each point in the figure represents a static situation, so the transient phase is not considered.

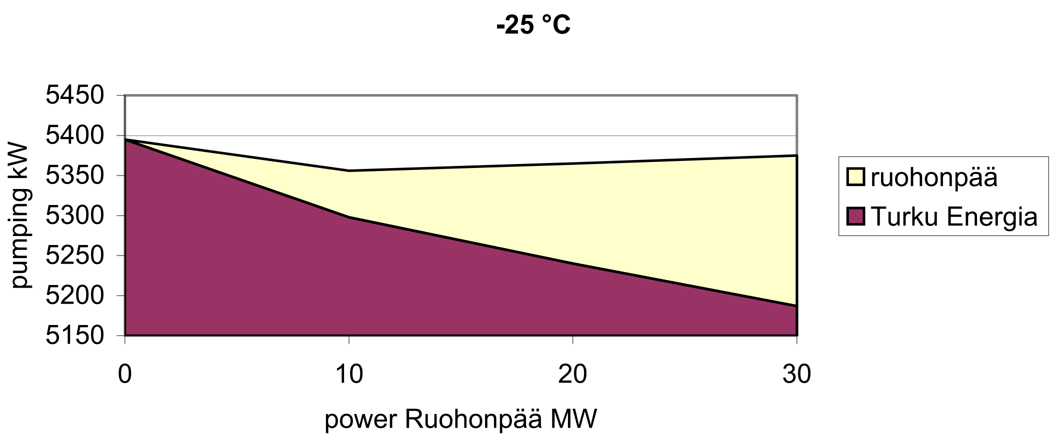

Figure 25. Electric power of pumps when the new plant located in Ruohonpää produces the thermal power indicated on the abscissa and outdoor temperature is –25 °C. The figure separates the pumping power of the new plant and pumps of the network company. It seems that the pumping power reaches a minimum when the new plant produces around 10 MW.

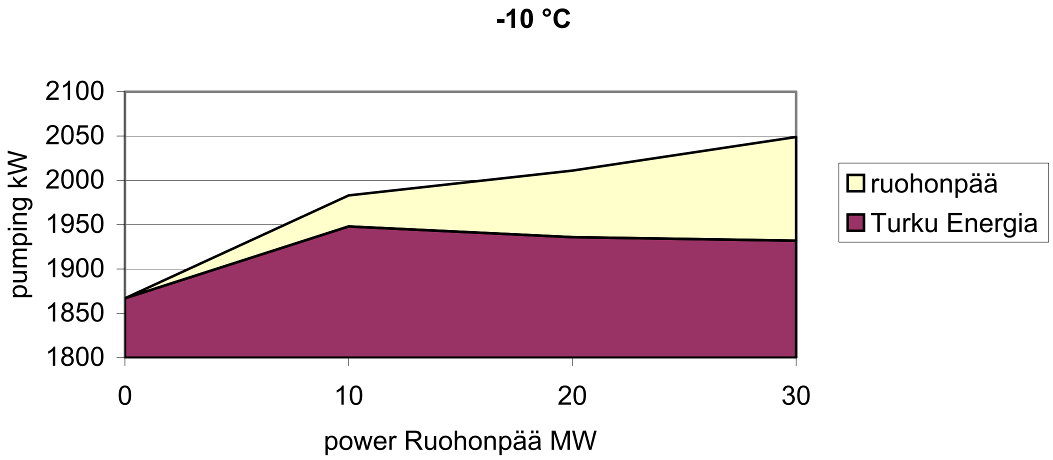

Figure 26. Electric power of pumps when the new plant located in Ruohonpää produces the thermal power indicated on the abscissa and outdoor temperature is –10 °C. The figure separates the pumping power of the new plant and pumps of the network company. Total pumping power rises monotonously. Also the pumping power of the network company rises in the beginning.

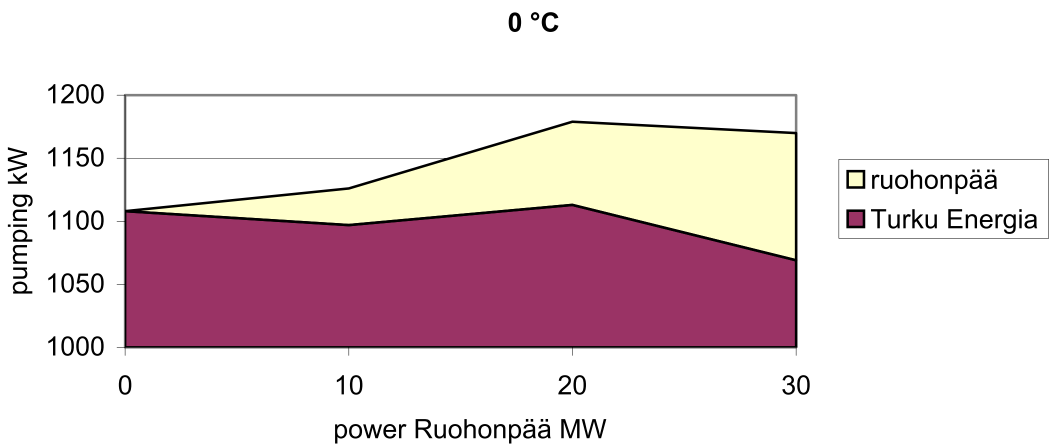

Figure 27. Electric power of pumps when the new plant located in Ruohonpää produces the thermal power indicated on the abscissa and outdoor temperature is –25 °C. The powers are not monotonous nor unimodal.

This example makes it clear that as the new plant (Figure 28) changes pressures all over the network, it can affect pumping powers of existing plants. The pumping power of the regulating plant naturally changes also because its thermal power changes. If the network company's pumping power as proportion to its thermal power increases because of the introduction of a new producer, the new producer should pay the network company's excess cost. In the opposite case the network company should credit the new producer. In practise, however, this is difficult because there should be a neutral party who calculates each producer's pumping cost.

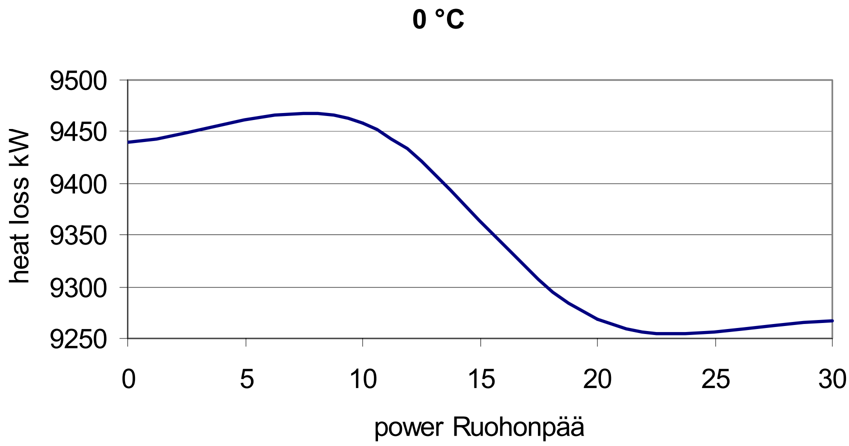

Figure 28. Total heat losses of the network when the new plant located in Ruohonpää produces the thermal power indicated on the abscissa and outdoor temperature is 0 °C.

5.1.2.2 New plant at Karjakuja

The imaginary plant Karjakuja is located near the edge in the very east of the network. The pressure difference around this location is normally small so it is easy to pump heat into the network. For example when the plant thermal power is 10 MW the pressure difference between return and feed lines is roughly 4 bar (outdoor temperature –25 °C). The pressure difference at the regulating plant of Turku Energia is in the same conditions more than 8 bar (plant KKL5). What happens is that the total pumping power goes down rather steeply as a function of the thermal power of Karjakuja plant. Naturally the pumping power of Turku Energia also goes down. Table 8 shows how much the pumping power of Turku Energia decreases when Karjakuja plant produces 5% of the total thermal power needed in each temperature (e.g. 35 MW at –25 °C temperature). It can be seen that the pumping power required from Turku Energia decreases – in low temperatures by a considerable amount.

Table 8. Change of Turku Energia pumping power when the imaginary plant Karjakuja produces 5% of total heat demand (relative to Turku Energia producing all heat).

Outdoor Temperature	Change of Turku Energia pumping power when Karjakuja produces 5% of heat demand
0 °C	–17%
–10 °C	–17%
–25 °C	–31%

The pumping powers are shown more accurately below in Figures 29–31. The total pumping power is monotonously decreasing as a function of Karjakuja thermal power except at –25 °C, when the minimum is reached when Karjakuja produces around 30 MW. Production in Karjakuja also decreases the network maximum pressure which is found on the feed side of plant HKR00. Heat losses of the network are presented as a function of Karjakuja heat supply in Figure 32, when the outdoor temperature is 0 °C.

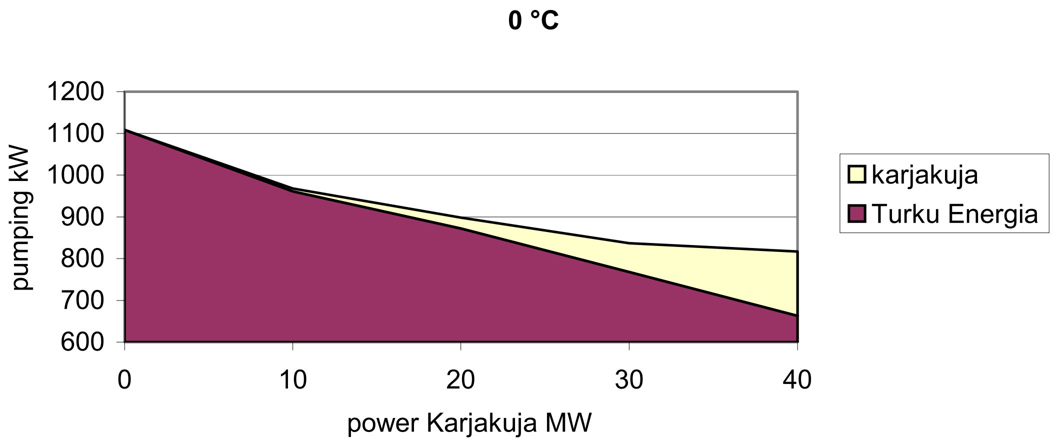

Figure 29. Electric power of pumps when the new plant located in Karjakuja produces the thermal power indicated on the abscissa and outdoor temperature is 0 °C.

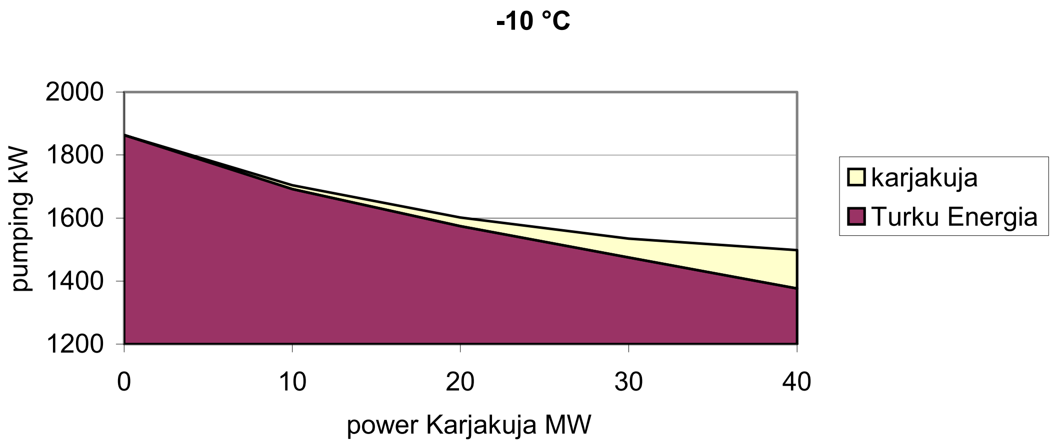

Figure 30. Electric power of pumps when the new plant located in Karjakuja produces the thermal power indicated on the abscissa and outdoor temperature is –10 °C.

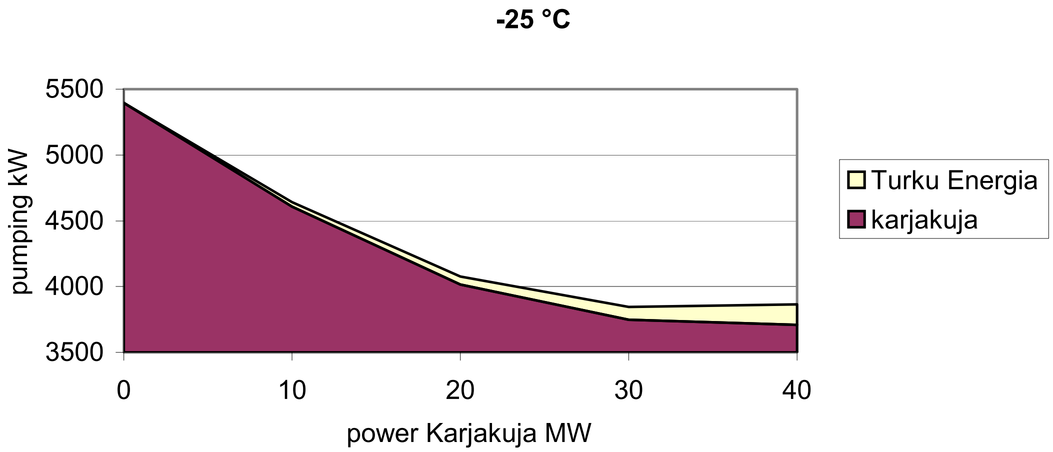

Figure 31. Electric power of pumps when the new plant located in Karjakuja produces the thermal power indicated on the abscissa and outdoor temperature is –25 °C.

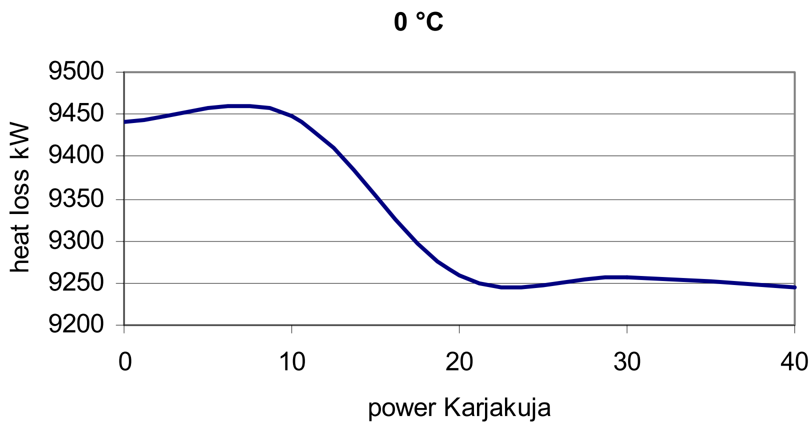

Figure 32. Total heat losses of the network when the new plant located in Karjakuja produces the thermal power indicated on the abscissa and outdoor temperature is 0 °C.

5.2 Case 2: a small town Kaskinen

In this case we examined whether a community could be self sufficient with respect to heat by using small building scaled CHP plants and attempted to explore the consequences of such a energy system. We also aimed to find out if an optimal solution could be defined for the community. This means we searched for an answer to the question in what types of buildings should the micro-CHP plants be installed and with what kind of an operating strategy should they be operated in order for the community to be energetically self sufficient.

A simple computer software was developed to enable the calculations of heat and electricity demand and production for a group of buildings for each hour of the year. Seven different building types with different consumption profiles were included in the study (detached houses, terraced houses, apartment buildings, hospitals, educational buildings, offices, assembly buildings). For the residential and the office buildings both new and old buildings were included in the study. Table 9 shows all the different building types that were programmed in the software to describe the case community.

Table 9. Buildings of the case community considered in the simulations.

Building type	m³	% of total
Commercial building	5160	2,1
New office	17318	7,1
Old office	20781	8,6
Old apartment building	71240	29,4
New apartment building	30680	12,7
Hospital	5344	2,2
Educational building	7371	3,0
Assembly builing	13650	5,6
Old detached house	44030	18,2
New detached house	18870	7,8
Old terraced house	5200	2,1
New terraced house	2600	1,1

Cases that have been studied in this research are listed in Table 10. In the following of this paper the capital letter found in the table will be used as a reference to describe the case in the figures.

Table 10. Cases used in the study.

A	100% degree of decentralisation
B	75% degree of decentralisation
C	50% degree of decentralisation
D	25% degree of decentralisation
E	"Optimal solution"
F	CHP in all except detached and terraced houses
G	CHP only in residential buildings
H	CHP only in residential buildings, constant production

There was a central CHP plant connected to the network and it was assumed that each building could be equipped with an individual micro-CHP plant, which is able to provide heat (and electricity) to satisfy the demand of the building itself or for sale.

In our study we have assumed that for each produced kWh of electricity, two kWh of heat was produced.

5.2.1 The buy-and-sell potential of heat trading

The case town has both residential and non residential buildings. It is estimated that 70% of the residential buildings are old and 30% new. The age of the buildings affects the energy demand curves. Simulations answered the question whether the town could be self-sufficient in terms of heat or electricity production. Could the community sell out some heat or electricity or did it need to buy from the centralized energy production?

First three cases are presented here in more detail. Subsequently the rest of the cases are included in comparison and discussion of annual results.

5.2.1.1 Case A: 100% Decentralization

As a base case, the degree of decentralization was set to 100%, which means that all the buildings have their own micro-CHP plants. The plants follow electrical load tracking strategy. In this base case the town was completely self-sufficient with respect to heat from June to September (Figure 33). In these months heat could be sold to the district heating network. Further analysis showed that when the degree of decentralization was lower, the system naturally needed more heat from the centralized production. The results are calculated as monthly average values for each hour during the day.

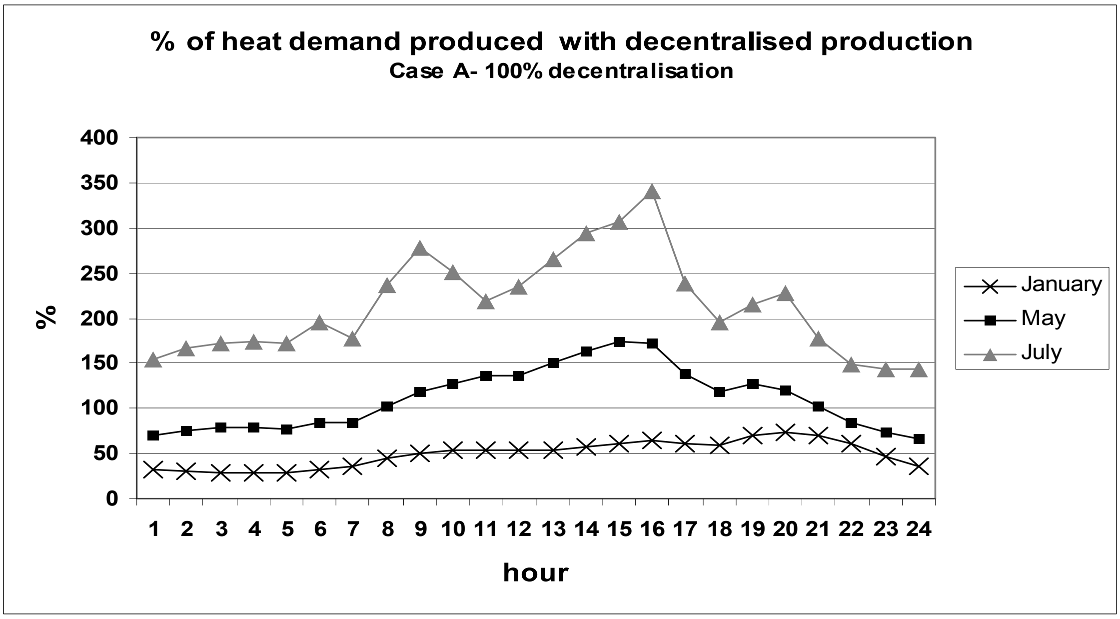

Figure 33. Share of heat demand covered by decentralized production in Case A. (Micro-CHP plant in all buildings, electric load tracking strategy.) Monthly average hours for one day for three different months.

5.2.1.2 Case F: Decentralized Production in Other Than Small Detached and Terraced Houses

Another case that was examined was the case when micro-CHP plants are installed in all building types other than small detached houses and terraced houses. The micro-CHP plants follow an electric load strategy. The degree of decentralization in the building types with micro-CHP plants is 100%. This means that all of the buildings, except detached and terraced houses have a micro-CHP plant. In this case the whole community is self-sufficient with respect to heat from June to September. The excess heat from the buildings with a micro-CHP plant covers the heat demand of the small detached and terraced houses. During these months, there is excess heat production up to 250% of the total demand (see Figure 34). A question to take into account in this case is whether there is capacity in the district heating network to handle this excess heat production and are there buyers for this heat.

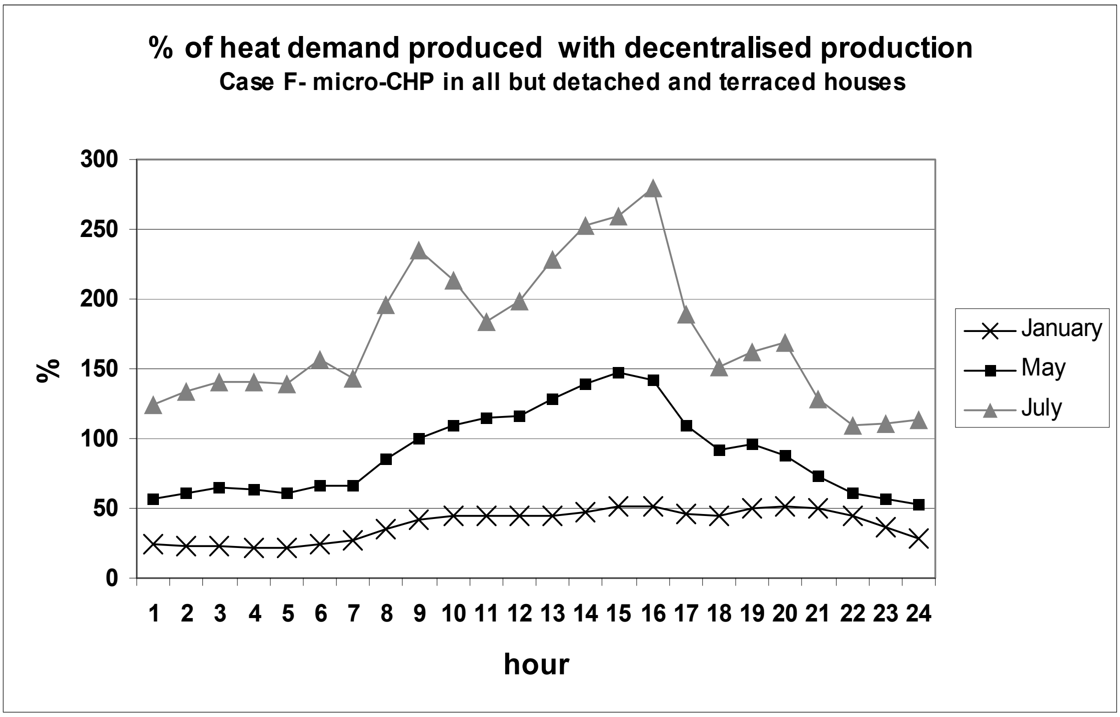

Figure 34. Share of heat demand covered by decentralized production in Case F. (Micro-CHP plants in all other building types but detached and terraced house. Plants operating with electric load tracking strategy.) Monthly average hours for one day for three selected months.

5.2.1.3 Case E: Optimal Solution

An optimal solution was empirically searched for. By optimal we mean that the share of distributed energy production should be possibly close to 100% all the time, i.e. centralized heat production wouldn't be needed at all and the excess decentralized heat production would be zero. The community would, in other words, be self-sufficient and not have very much excess heat production. The closest we got to this optimal case was a solution where the share of distributed energy production varied between 55 and 200% of the total demand, the 200% being just a peak at 3–4 pm (Figure 35).

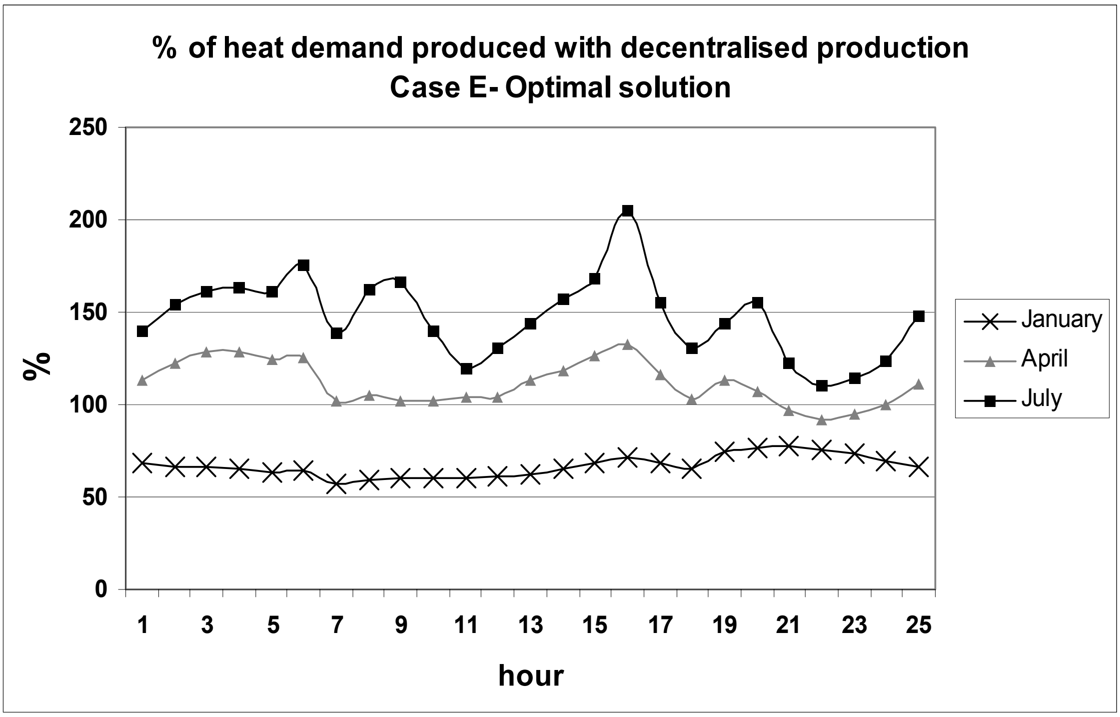

Figure 35. Share of heat demand covered by decentralised production in Case E. ("Optimal case" with micro-CHP plants in commercial and apartment buildings.) Monthly average hours for one day for three selected months.

We found this solution by modifying Case F so as to allow different settings for CHP plants in summer and in winter in all but the apartment houses. The seasonal switch changes were not made in the apartment buildings since it was assumed that they more seldom than other building categories have professionals handling their technical service systems. In the winter, the micro-CHP plants were set to produce constantly 125% of their maximum electricity demand, this figure being only 25% in the summer. In the apartment buildings, the micro-CHP plants followed an electric load strategy all the time. In this case considerable amount of electricity was being sold during the winter; in the summer electricity was needed from the centralized production. Since prices are higher in the winter than in the summer, this was a positive thing for the producer.

5.2.1.4 Comparing Different Cases

In Figure 36 we can see the centralized heat production for five different cases. Four cases had micro-CHP plants in all types of buildings, the first case having them in 100% of all buildings (case A), second 75% (case B), third 50% (case C) and the fourth case having micro-CHP plants in only 25% of the buildings (case D). The fifth case is the "optimal solution" described earlier (case E). We see that when the degree of decentralization is lower than 50% centralized heat production is needed even in the summer months. In the optimal solution curve we can clearly see that the parameters for the micro-CHP plants are changed in May and September. In this case the community produces some excessive heat during the summer and early spring and late autumn. The excessive production is, however, not as large as in the case with 100% decentralization.

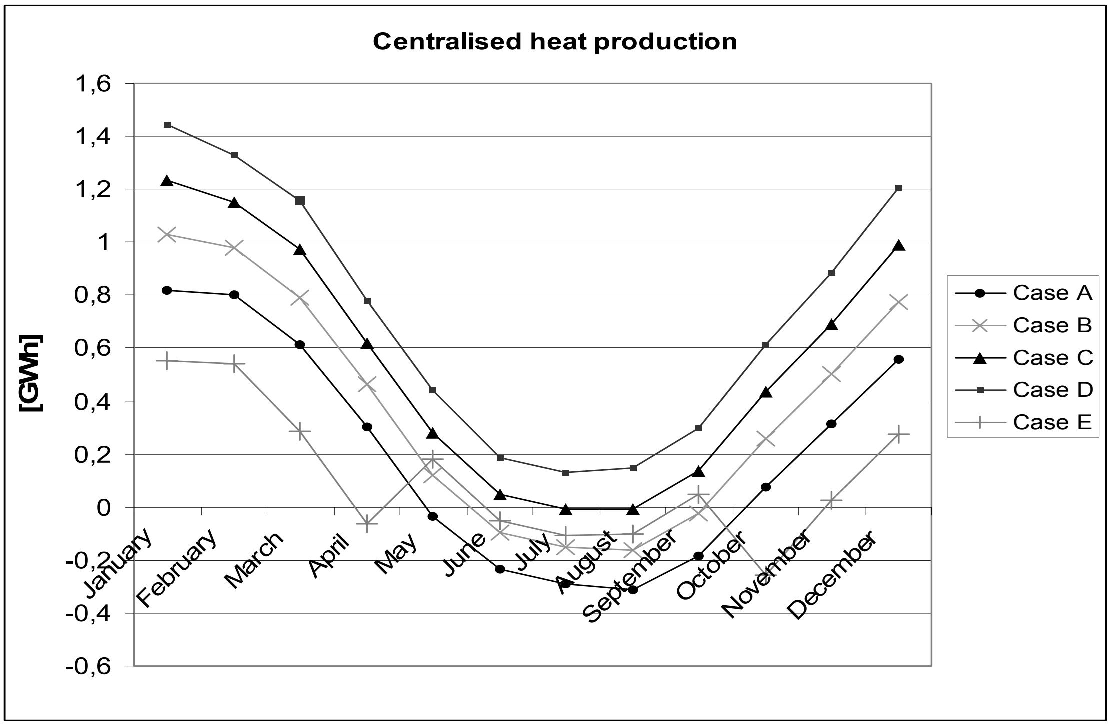

Figure 36. The need for centralized heat production for different cases. Average value for each month during a year.

In Figure 37. Net heat from centralized production, decentralized production and excessive heat production for different cases. Cases described in Table 10 we see that the amount of heat needed from the centralized production varies between 0,46 and 8,62 GWh/year the total yearly heat demand of the community being 10,68 GWh. The worst case is the case with a decentralization degree of only 25%. The best case is having micro-CHP plants in only residential buildings but running them with a constant production. This case, however, produces a lot of excessive heat which the optimal case, case E does not do as much.

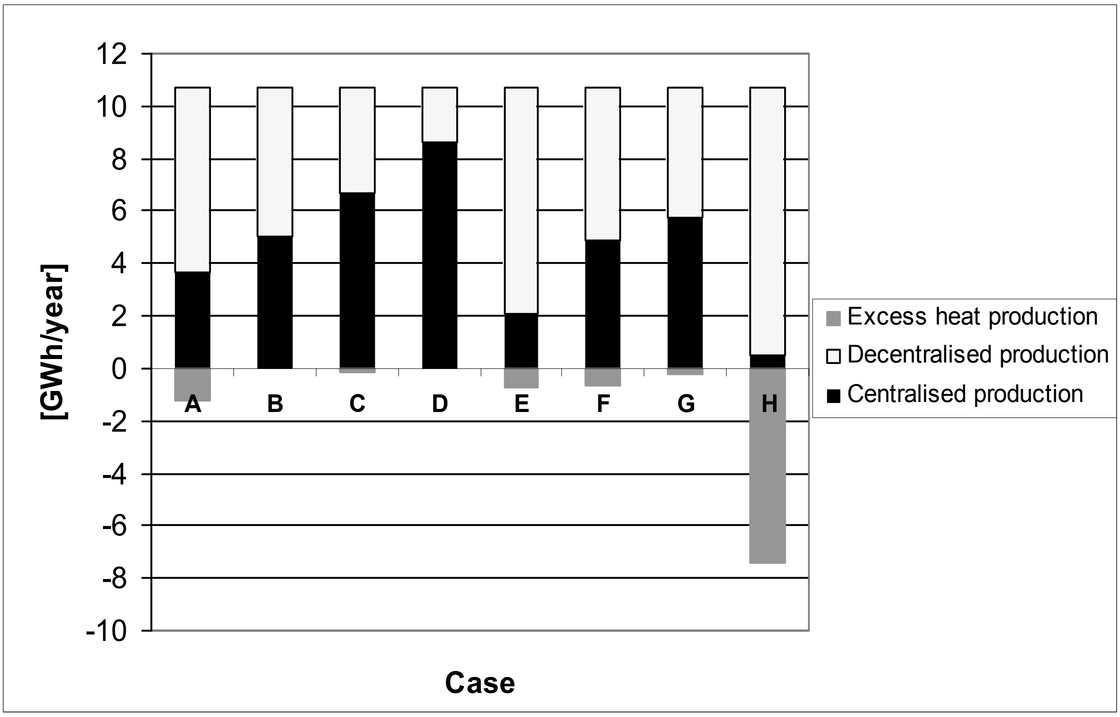

Figure 37. Net heat from centralized production, decentralized production and excessive heat production for different cases. Cases described in Table 10.

Figure 38 shows the need for centralized electricity production for some cases. When micro-CHP plants are installed only in residential buildings and operating with constant electricity production (case H), the community has a lot of excessive electricity production. When the case is otherwise the same but the plants have an electric load tracking strategy (case G) there is constantly a need for centralized electricity production. This is quite natural since the residential buildings produce all of their electricity demand but no excessive electricity to cover the need of the other buildings in the community. We get approximately the same result from the case where plants are installed in all other building types but not in detached and terraced houses (case F). In the “optimal case” (case E) there is excessive electricity production from October to April. In the summer centralized electricity production is needed. Since electricity prices tend to be higher in the winter when the overall demand is higher in Finland, it is a good thing to sell electricity in the winter and buy it in the summer.

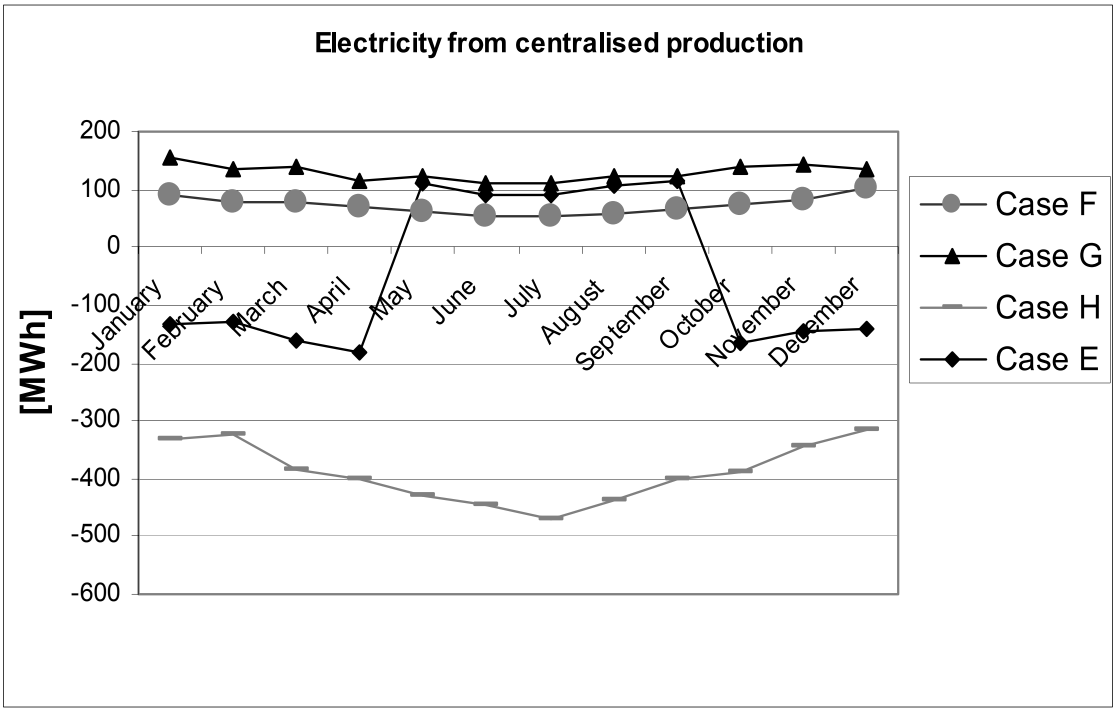

Figure 38. Centralised electricity production for different cases. Average value for each month during a year.

5.2.2 The hydraulic performance of the DH-network

As for Turku we studied the effect of mid-sized producers on the network state and pumping costs. Kaskinen is a small network where such large producers cannot exist. The total maximum heat demand in this network is about 10 MW. In this case we studied the effect of micro-sized heat producers, which can be installed inside existing buildings. These can be for example micro turbines or fuel cells.

The main producer in Kaskinen is Metsä-Botnia plant located in the southeast corner of the network (Figure 39). In normal situation other producers are not present. The largest consumer is Finnforest factory in the south end of the network. In addition there is a 12 MW stand-by plant in the south part of the town centre. The network consists of a total of 14 km of pipelines.

Figure 39. Kaskinen district heating network (source Con-JAC ab). The yellow circles are consumers. Metsä-Botnia plant is located in the southeast corner of the network (indicated as M-B).

Software which was previously developed for dynamic simulation of district heating networks was employed in the study. Simulation is based on finite element method, which divides the pipes into parts and each part is assumed to be in constant temperature during one time-step. Other features of the software are:

- Thermal powers and feed temperatures of plants can be time-dependent.
- Consumer cooling can depend on feed temperature.
- Pumps can be located either at plants or in pipes (booster pumps).
- The model does not calculate fast temperature changes (minute-level) fully correctly.

Simulations with the software are processor-intensive. Simulation of one-week period took six hours on Pentium III 800 MHz machine. Therefore only one week was simulated for both winter and summer conditions.

For simulation purposes micro-CHP (combined heat and power) plant was given to 19 consumers. These small plants were assumed to be fuel cells, whose ratio of power production or heat production was 0.5. The fuel cells were controlled according to the consumer's electric power demand. This led to the fact that the heat demand of the consumer could be either positive or negative. In the latter case the consumer had to sell the excess heat to the network. This did not cause a problem since there was a sufficient amount of consumption. In practise it was arranged so that Metsä-Botnia plant accommodated the extra production by reducing its output power.

The net thermal power demand of the consumer was thus

$$P_{h,net}(t) = P_h(t) - P_e(t) \cdot \frac{1}{\alpha}, \tag{8}$$

where P_h is the thermal power demand in absence of micro-CHP (gross demand), $P_{h,net}$ is the net thermal power demand and P_e is the consumer's electric power covered by the micro-CHP. α is the power to heat ratio.

In this stage it was not studied whether it is beneficial for someone to buy the excess heat produced by a consumer, in other words, what would become the price level of this excess heat. However, in the Kaskinen case these fuel cell producers would have to compete with the Metsä-Botnia plant, whose production cost is low. It is unlikely that selling to the network would be profitable. It was assumed that the consumers output the excess heat to the network regardless of the price they get.

Another thing affecting the possibility of selling to the network is the temperature of the water produced by the fuel cell. A polymer exchange membrane produces water whose temperature is around 70 degrees, so it is as such not sufficiently hot to be fed to the feed line. A solid oxide fuel cell does not have this problem. It was assumed that temperature is not a problem for the small producers.

Heat demands in absence of micro-CHP were estimated for each hour of the year based on temperature data of Helsinki in 1979 (Figure 40). The fact that the temperatures are from a different town is not important because natural variation from year to year exists. For consumer cooling we used an estimate by Turku Energia, which gave a linear dependence between feed temperature and cooling.

The initial data such as P_h and $P_{h,net}$ were given for each hour of the week. The simulation software then interpolates this data as needed. Flows were updated once in eight minutes. Time-step in temperature calculation was five seconds. This is necessary because temperature fronts can advance rapidly in the network.

For both summer and winter two cases were simulated. In the first case micro-CHP plants are shut off and in the second case they are working. The first case is equal to the normal operation of the network. We then compared changes in temperatures, pressures and pumping costs. The average pressure of the network was set so that the return line pressure at Metsä-Botnia plant was 5 bar.

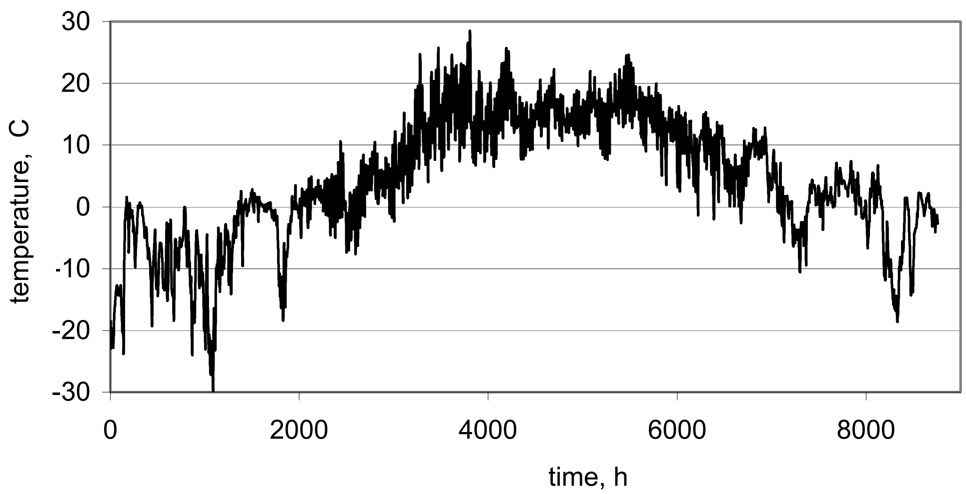

Figure 40. Hourly temperatures (smoothed) of the example year. These were used to determine the gross heat demand needed by consumers. X-axis shows the hour of the year.

5.2.2.1 Winter cases

The winter week consisted of hours of the year 1–168, which means that it is situated between 1st and 6th of January. Figure 41 shows the consumers' summed heat demand. Notice that in addition to the 24 hour period there is a 12 hour period. Figure 42 again shows the micro-CHP summed heat production for the same period. Daily variation is significant.

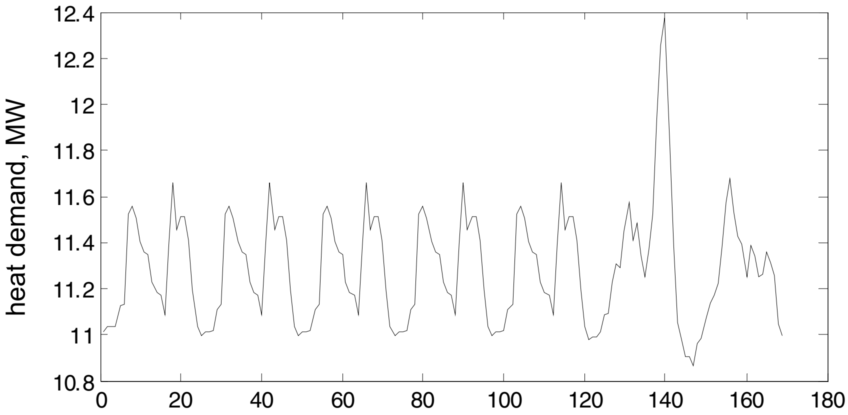

Figure 41. Total heat gross demand of consumers P_h *during the winter week. X-axis shows the hour of the week. Notice the 12 hour period.*

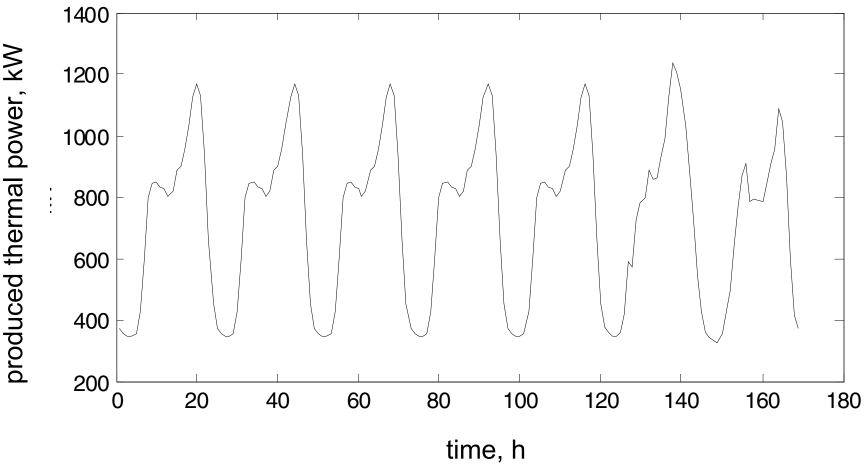

Figure 42. Summed thermal power of small producers during the winter week. X-axis shows the hour of the week.

The heat demands of all consumers could not be estimated based on the typical load curves of different consumer types. The demands of these consumers were estimated on the one hand based on the connected powers given by Kaskisten Energia company and on the other hand based on general experience. The demands are given in Table 11.

Table 11. Winter gross demands for consumers whose demands could not be estimated based on the typical load curves.

Consumer	Power
Finnforest, node 29	3500 kW
Finnforest, node 28	1500 kW
Greenhouse, node 26	2500 kW
Greenhouse, node 27	1500 kW
Church	Same as three single-family houses
Metal industry, node 19	40 kW
Small industry, node 18	40 kW
Fire station	Same as two single-family houses
Railway station	10 kW

Figure 43 shows the feed line pressures in consumer and junction nodes during the one week period. It can be seen that small producers have no significant effect on pressures. The critical consumer, where pressure difference is the smallest, is Finnforest in the south end of the network.

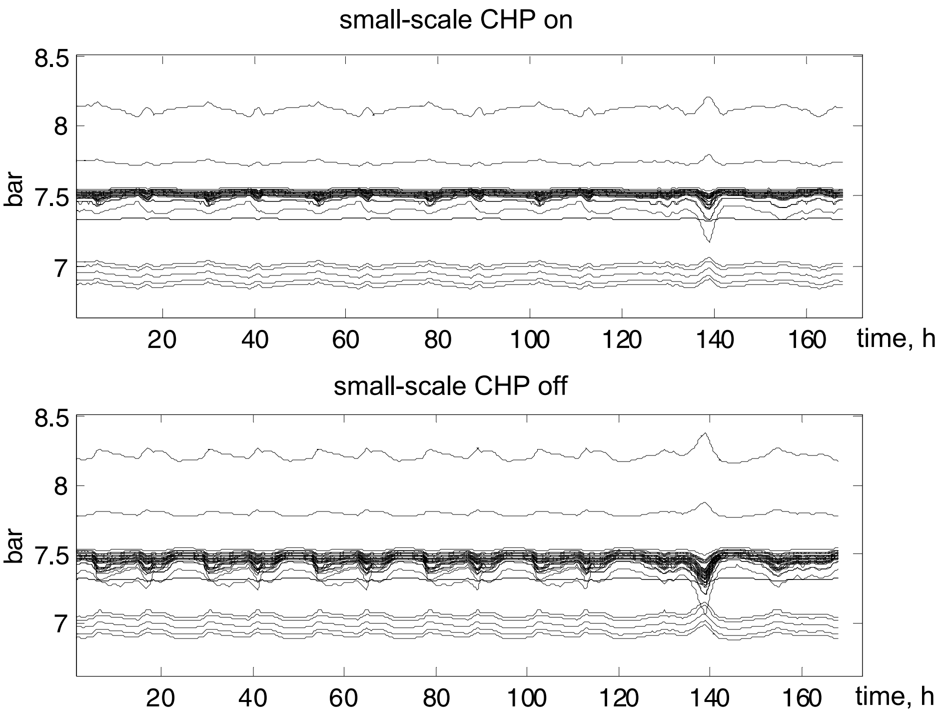

Figure 43. Pressures at consumer and junction nodes in winter when micro-CHP's are on (upper graph) and off (lower graph). Abscissa shows the hour of the week.

Figure 44 represents the total pumping electric power during the winter week. The figure assumes a 50% pumping efficiency which is normal in small pumps. Pumping power decreases a little when the micro-CHP's are turned on but the difference is small. Also, in practise there may be no difference because small pumps, such as those at the small producers, have poor efficiency. It would probably not pay to install an inverter control in these pumps, which further decreases efficiency.

Temperature changes were dramatic in some parts of the network. Figure 45 shows feed line temperature at a node in the town centre. Temperature changes up to 14 degrees per hour. The reason for this is that flow is stagnant on the east side of this node. Here the flows, which come from different directions in the town centre supply loop, come together. Sometimes the flows change which causes cold water to rush into the consumer's heat exchanger. Temperatures vary rapidly also in other nodes in this neighbourhood. The area is shown in Figure 46.

Generally speaking temperature changes were more drastic when micro-CHP's were on. Small producers bring more time-varying factors into the system. They can create additional changing low-flow connections in their vicinity.

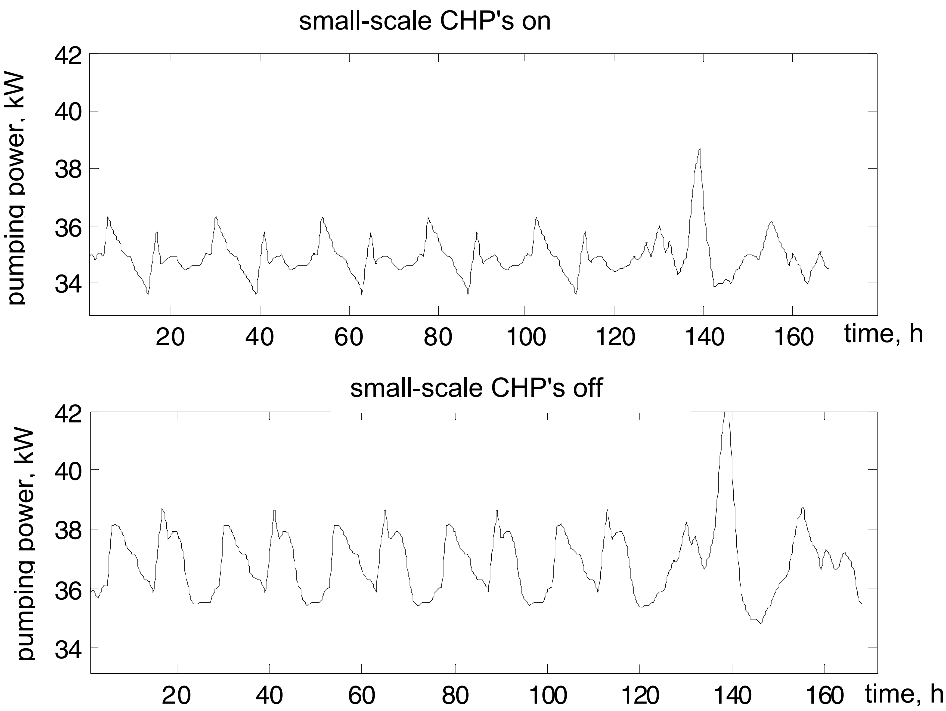

Figure 44. Total pumping power as a function of power in winter when micro-CHP's are on (upper graph) and off (lower graph).

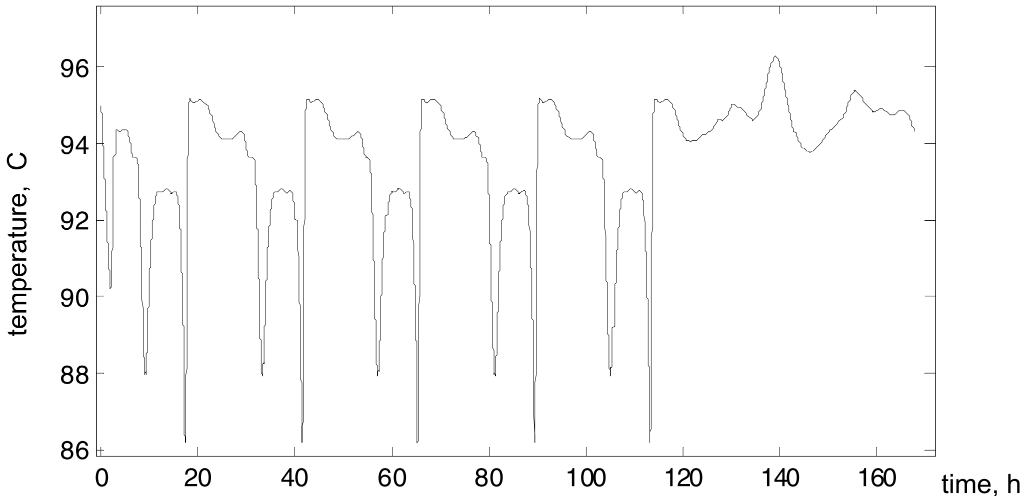

Figure 45. One of the nodes where temperature varies most rapidly. In the graph shown is feed line temperature at the node at crossroads of Raatihuoneenkatu and Puistokatu. In this picture micro-CHP's were off. Abscissa shows the hour of the week.

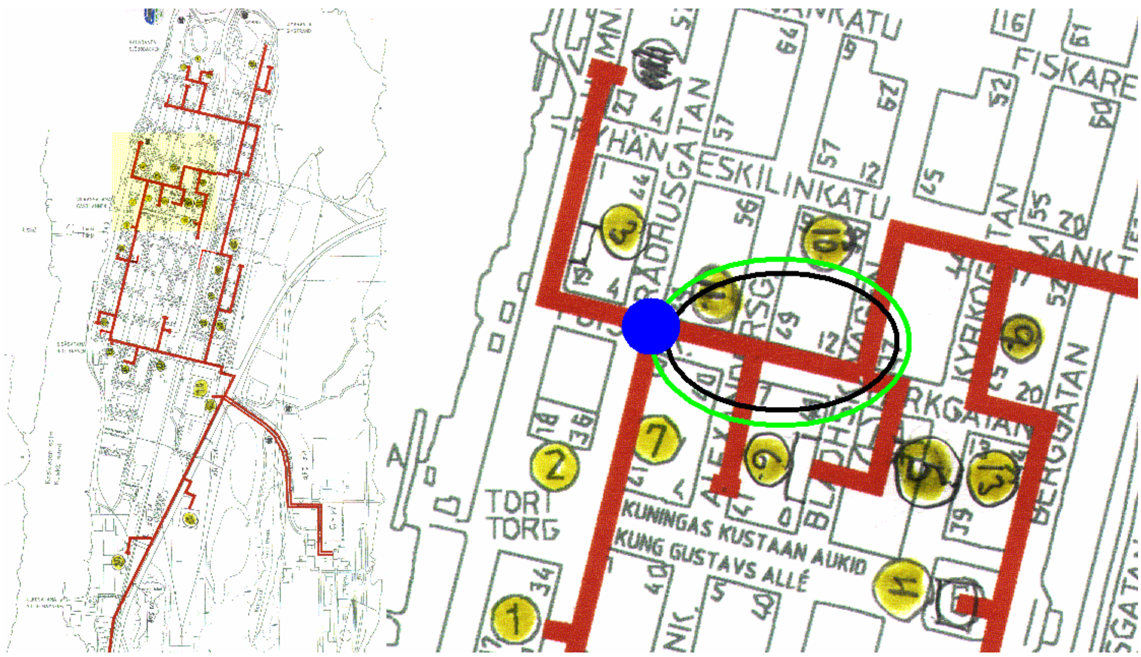

Figure 46. The blue dot shows the node whose temperature is graphed above. The circled pipe is a low-flow pipe where flows coming from different directions meet.

Figure 47 shows the average temperature of most important nodes. There is slightly more variation in the average temperature when micro-CHP's are on.

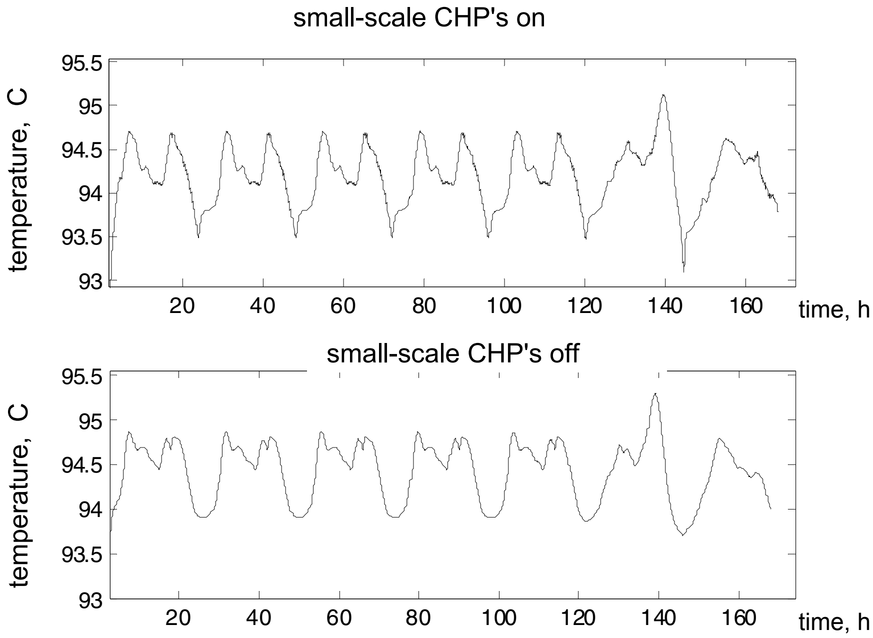

Figure 47. Average temperature of consumer and junction nodes in the winter. Abscissa shows the hour of the week.

In the winter the consumer with the lowest pressure difference was in all cases the Finnforest factory (node 29), which is visible in Figure 39 (it is slightly below the lower edge). The distribution of demand between nodes 28 and 29 (which belong to Finnforest) was not, however, known.

5.2.2.2 Heat trade in summer

The summer week consisted of the hours of year 4000–4167. In other words the week is between June 16th and 23th. Hourly heat demands of most consumers were obtained as before. As for winter, the demands of some consumers had to be estimated based on general experience and subscription powers reported by Kaskisten Energia network company. Table 12 shows these.

Table 12. Heat demands from consumers whose demand could not be estimated from typical load curves. The values are for summer.

Consumer	Power
Finnforest, node 29	2000 kW
Finnforest, node 28	500 kW
Greenhouse, node 26	300 kW
Greenhouse, node 27	200 kW
Church	Same as two single-family houses
Metal industry, node 19	20 kW
Small industry, node 18	20 kW
Fire station	Same as two single-family houses
Railway station	5 kW

Figure 48 shows the total demand during the summer week. 12-hour period is clear. The level of demand is about one third of that of winter.

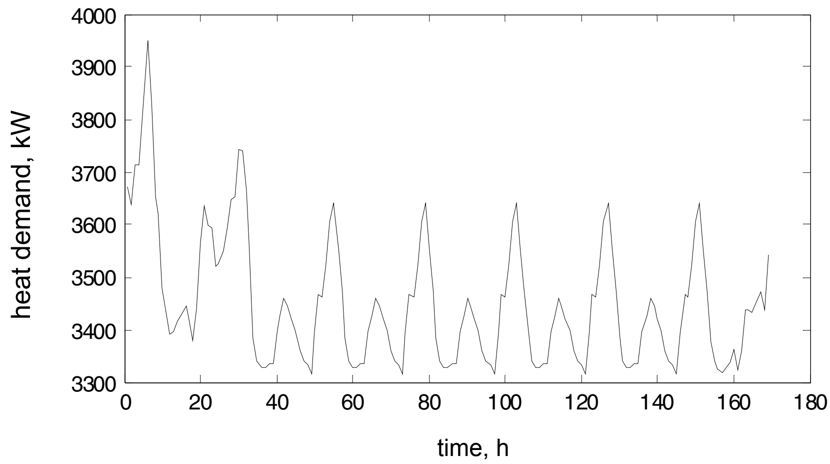

Figure 48. Total heat demand during the summer week (kW). Abscissa shows the hour of the week.

In Figure 49 the total power of small producers is shown. Daily variation is clear.

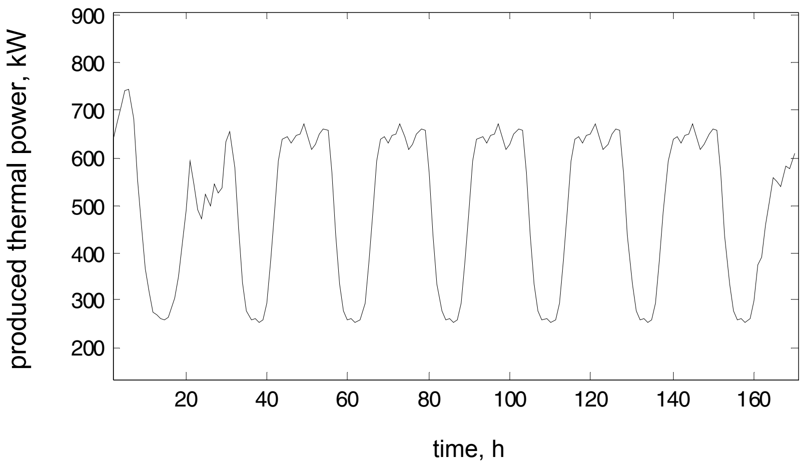

Figure 49. Hourly thermal power of small producers during the summer week (kW). Abscissa shows the hour of the week.

Again it can be seen that small producers have little effect on pressures. This is because pressure losses in the town centre are generally small and power of small-scale production is not too large. Average temperature is a bit higher when small producers are working. In the summer heat losses are large and hot water produced by small producers right in the town centre is welcomed.

In Figure 50 temperature changes are shown. These refer to about eight minute intervals but the numbers have been converted into hourly values. The X-axis shows the number of observations in which a certain temperature change, or larger, could be observed. It can be seen that when the small producers were off, the maximum change was about three degrees an hour but when they were on, the maximum change was about 20 degrees an hour.

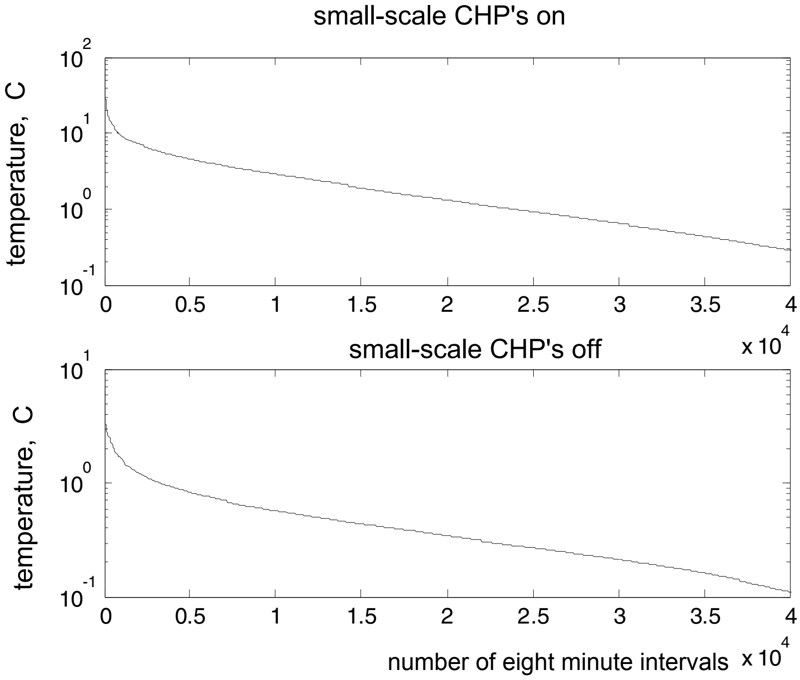

Figure 50. Duration curves of temperature changes in pipes. Here all pipes have been taken into the same duration curve. In the upper graph micro-CHP's are on, in lower graph they are off. Abscissa shows the number of observations. Ordinate shows the temperature change.

Let us look at an example why temperature changes are large when small producers are working. Figure 51 below shows the temperature of pipe 31 as a function of time. The pipe leads to a consumer who has a micro-CHP installed. The figure shows several sharp upward slopes during which the consumers draws power from the network. This causes temperature to rise rapidly. At other times the flow is almost stagnated and water inside the pipe cools down. This can of course be prevented by better controlling the micro-CHP.

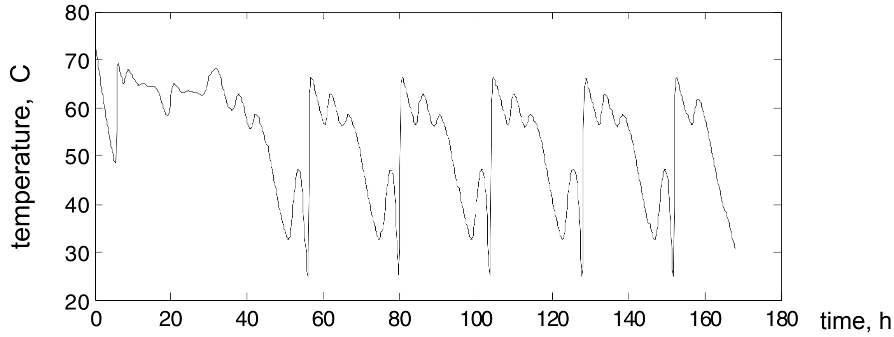

Figure 51. Temperature during the summer week in pipe 31, which feeds to several single-family houses in the north of the network.

There was no significant difference in the required pumping power, whether small producers are working or not. There can be differences which are due to differing efficiencies and regulation methods.

5.2.3 Contract between pulp factory and saw mill

Heat trade is presently on-going in Kaskinen in the form of one large contract. The Finnforest factory buys heat from Metsä-Botnia pulp factory. For this purpose it rents the transmission pipe from the network company (Kaskisten Energia). Naturally Metsä-Botnia provides the pumping power for this connection. The rent it pays should cover the maintenance expenses of the pipeline plus provide a fair return for the investment.

Maintenance and operating expenses of the pipeline were assumed to be 1.3 euro/a for each meter of pipeline. Total length of the pipeline is about 1400 m. The capital cost was estimated with annuity formula. According to the *capital asset pricing model* the opportunity cost of capital is the risk-free rate plus *market risk* (also called *beta*) times risk premium for market investment. The latter is the difference between a risk-free interest rate and expected return in the stock market. The hard part is of course estimating beta. Naturally, if either Finnforest or Metsä-Botnia shuts down, the pipeline becomes useless. This will not happen unless they encounter serious difficulties so pipeline investment is less risky than investments of these companies on the average. Betas of forest industry companies are more risky than the market in general (beta >1.0), so in this case we could guess beta to lie around 0.3…0.5. If we take risk premium to be 8 percent (Dimson et al. 2001) and risk-free real rate 1 percent, opportunity cost of capital would be 3.4…5.0 percent.

Table 13. Annual cost of capital plus maintenance expenses of the pipeline between Metsä-Botnia and Finnforest. 50 years payback time was used in the calculation.

Real required return on investment (%)	Annual cost
4	8 400 €
5	9 500 €
6	11 000 €

Table 13 shows the resulting annual cost from capital which is paid back in constant annual real amounts, and the indicated return is provided. The cost also includes maintenance and operating cost (not pumping) which is typical for small networks.

5.3 Case 3: heat trading from the perspective of an individual building

The building types that have been studied were the same as in the previous case: detached house, terraced house, apartment house, office building, business building, health care building, educational building and assembly building. An assembly building refers for example to a sports hall or a community center. In most of the cases a new building was compared to a similar old one. In an old building the electricity consumption was a bit lower than in a similar new building, but the heat consumption was much higher than in a new building. The analysis was based on hourly heat and electricity demands by building type.

In the analysis micro-CHP plants were used in all of the buildings. The main focus was on plants that were sized according to the electricity consumption. The amount of heat produced was a by-product from the electricity production, and did not always cover the whole heat demand needed. In most cases it was needed to buy the missing heat from the centralized district heating production. Generally the micro-CHP plant did not produce enough heat to cover the need for the whole year, because of the seasonal variation of the heat demand: winter high and summer low. In this study it was studied which building types produced more heat than needed and when, and which building types were able to buy this excess heat at the right moment. If there was not enough demand for the produced heat, it was sold to the district heating network. It was assumed that the network was always able to receive the excess heat from the micro-CHP plants. There might be a possibility to use a thermally activated cooling in the district heating network for a better utilization of the excess heat at summer times, even though this possibility was not studied.

This study showed that there was not a clear possibility for heat trading between different building types, if every building had a micro-CHP plant. The heat trading was possible to some extent between an office building and buildings with no micro-CHP plant. In the search for the best heat demand-supply match, there are numerous alternatives of building-combinations. Even though the building's demand and sales do not always meet each other, the potential of heat trade seems to be interesting, and offers a great way for buildings to exploit differences in consumption profiles.

5.3.1 Analysis of the heat trade potential for different building types

First, buildings with a micro-CHP, that follows the electricity demand up to the percentage of sizing plant, were studied. The percentage of sizing describes the amount of available capacity divided by the peak load of the building. When the percentage of sizing was 50%, the µCHP-plant could produce, at the most, only half of the required electrical peak power demand. Calculations were made with 100, 80, 50 and 25 percentages of sizing. Using 100%, 80% and 50% as percentages of sizing did not change much the results. The reason for this was that the consumption usually had a momentary peak that caused the maximum electric power demand. In other words the electric power was rarely at its highest value. The percentage of sizing determined a new value for the µCHP-plant's electric power. Most of the time the consumption was so low, that the electric power was able to follow it. Usually just the consumption peaks were left outside the production range.

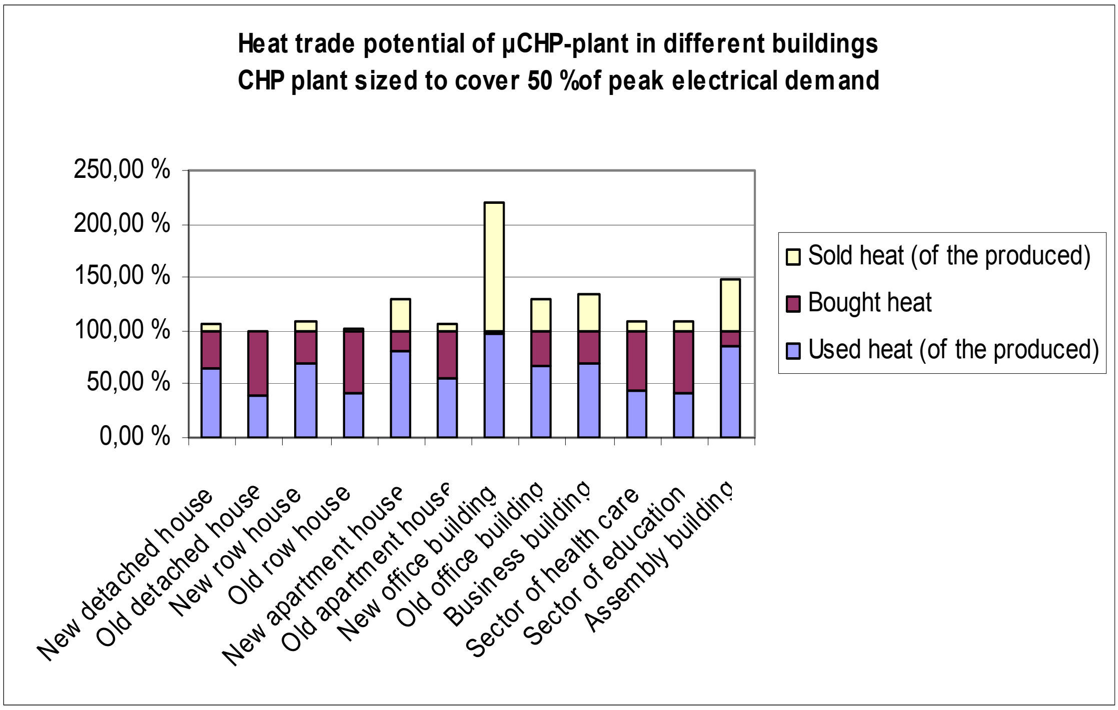

Figure 52. The heat trade potential for different building-types with a µCHP-plant. The µCHP-plant had an electric load tracking strategy and was sized to cover 50% of the electrical peak load. The sold, bought and used amounts of heat are in relation to the building's heat demand. The level of 100% represents the building's heat annual demandl.

The heat trade potential of a µCHP-plant was calculated for all of the buildings, and can be seen in Figure 52. The sold, bought and used heat for all the building types are calculated in relation to their heat demand. The level of 100% represents the building's annual heat demand.

All the building-types were studied separately and compared to each other. Values were calculated for the sold, bought and used heat, for the different percentages of sizing during one year. See Figure 53 for an example of a new office building in a Nordic climate. The amounts of bought and produced electricity with the different percentages of sizing were also calculated. For each building the amount of sold heat per month over the year, was calculated for the different percentages of sizing. And finally, the average potential for selling heat during each hour was studied for different months, with the sizing being 100% of the electrical peak load.

The new office building and assembly building were the only ones that could produce enough heat to almost fulfill the annual demand, as seen in Figure 52. The office building produced 170% more heat than needed, as can be seen in Figure 53, which shows the sold, bought and used heat of a new Finnish office building. The micro-CHP-plant has an electric load tracking strategy. The light part represents the building's potential for heat sales in relation to its own heat demand. A huge part of the annual heat sales potential occurs during summertime, when the heat demand is low. The most common amount of produced heat, among the buildings, was 60–80% of the total heat demand. The old detached house could produce only 40% of its heat demand.

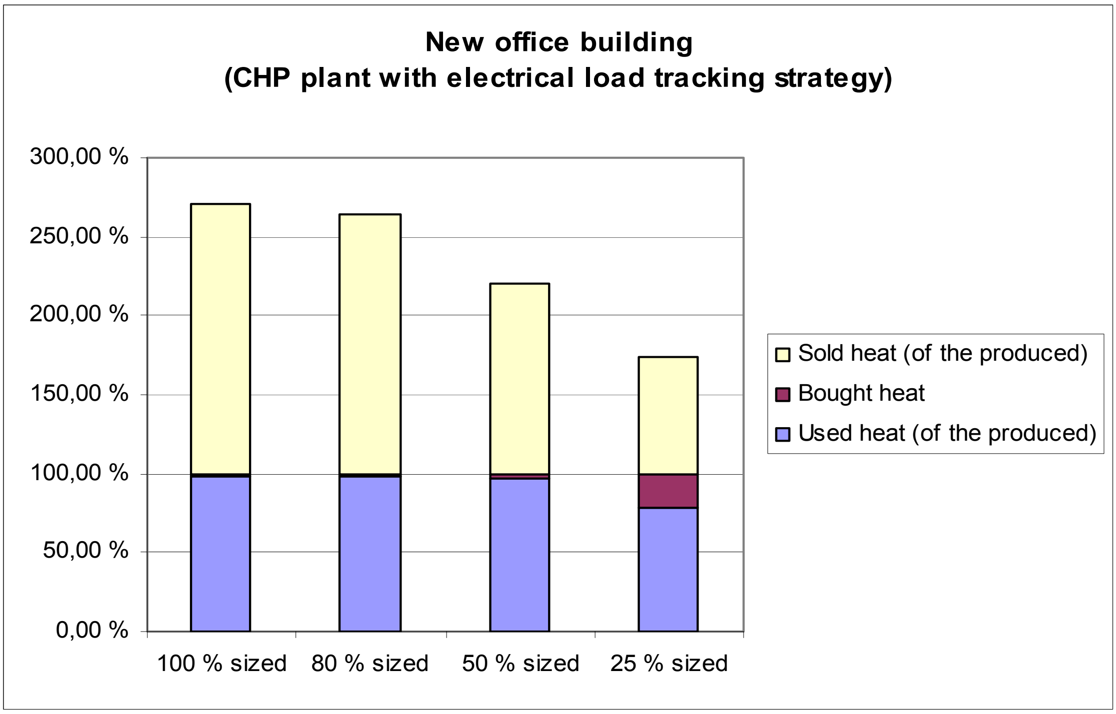

Figure 53. The sold, bought and used heat of a new office building. The μCHP-plant is sized according to the electricity consumption. The production follows the electricity consumption. The yellow part represents the buildings potential for heat sales in relation to its own heat demand. It must be noted that a huge part of the annual heat sales potential occurs during summertime.

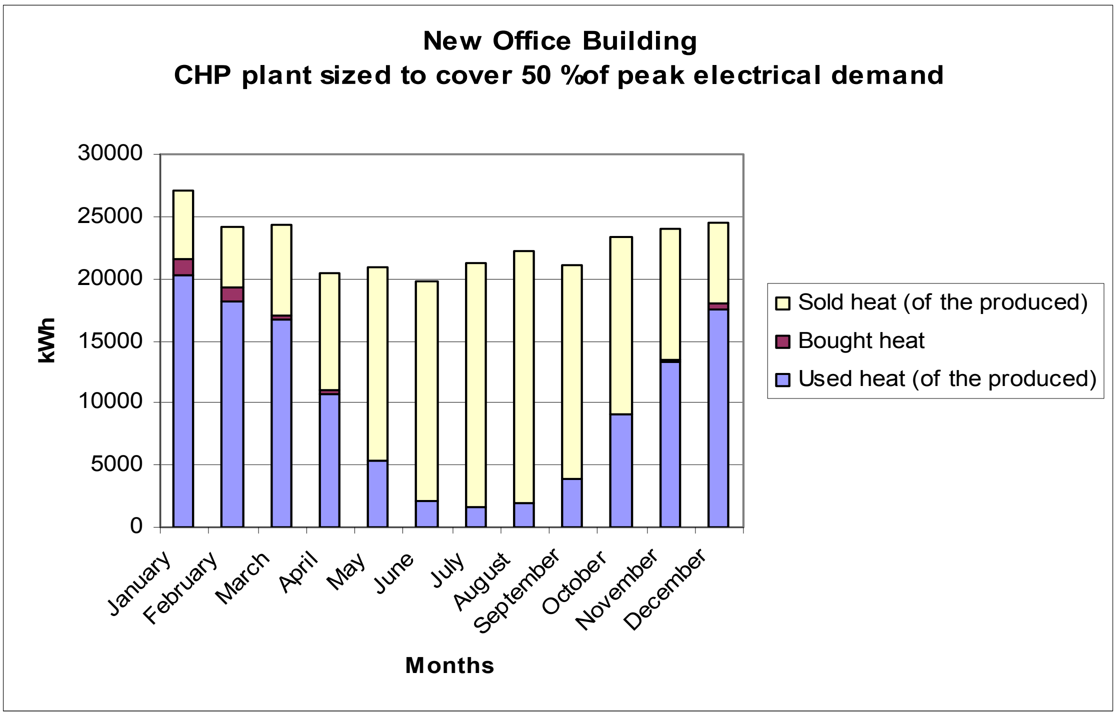

Figure 54. The monthly amounts of sold, bought and used heat, for a new office building. The µCHP-plant has an electric load tracking strategy sized to cover 50% of peak electrical load.

Figure 54 shows the monthly amounts of used, bought and sold heat for a new office building. The µCHP-plant has an electric load tracking strategy sized to cover 50% of peak electrical load. As seen, the heat demand in summertime is very low; therefore there is much excess heat to be sold. All the buildings had most excess heat production during the summer months, when the demand was the lowest. The new apartment house, new office building, business building and assembly building had, however excess heat to sell almost during each month of the year. The residential buildings have their highest heat demand during evenings. The rest of the building types have their peak demand during day time.

5.3.2 Analysis of the electricity trade potential for different building types

This chapter is very similar to the previous one. The difference is that the µCHP-plants have a thermal load tracking strategy and electricity was produced as a by-product from the heat production. The plant was sized to cover 100, 80, 50 and 25 percentages of peak heat demand.

All the buildings were again studied separately and compared to each other. Values were calculated for the sold, bought and used electricity, for the different percentages of sizing during one year. In the research the amount of bought and produced heat was also calculated with the different percentages of sizing. For each building the amount of sold electricity per month was calculated for a year, for the different percentages of sizing. Finally, the average potential for selling electricity during each hour was studied for different months, with the sizing being 100 percentages.

The old building's heat demand is higher than that of the new ones; therefore the old ones had large amounts of excess electricity produced. The electricity consumptions for both new and old buildings are quite equal. Only the old detached house and the old terraced house are able to fulfil their electricity demand. The new office building produces only 36% of the electricity demand. During the winter months there is usually produced more electricity than needed, which is valuable because of the high electricity price at that moment. This excessive electricity production is caused by the electricity being a by-product from the heat production which is higher in the winter.

5.3.3 A comparison of the buildings

In this part of the study the buildings were compared with each other to find a good combination of two buildings. Figure 4 shows the specific heat consumption of each building type. The new buildings and the assembly building have the lowest demands while the old buildings and the sector of health care have the highest demands. The specific heat consumption varies between 18 and 62 kWh/m^3.

The comparison was made for two different cases, the first being when the μCHP-plant had an electrical load tracking strategy and the second being when the μCHP-plant had an electrical base load strategy. Different building types were combined with each other, in the search for the perfect match. The study showed that there were not any building combinations that met each other's demand and supply at hourly level during a day.

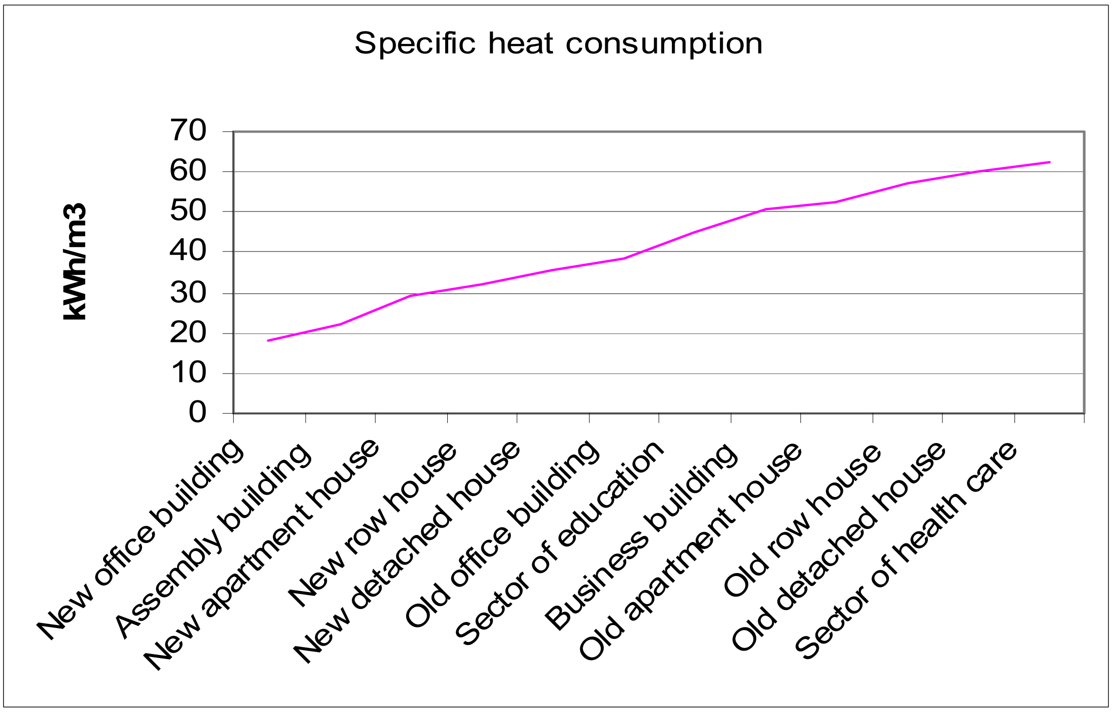

Figure 55. The specific heat consumption of the buildings studied.

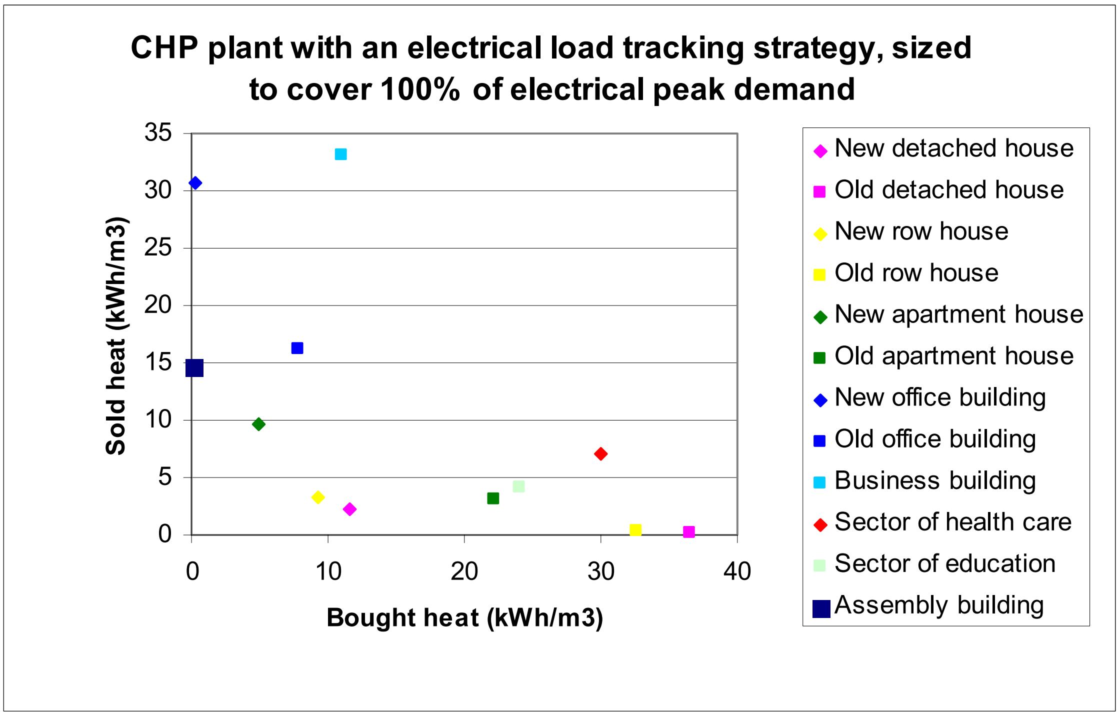

Figure 56. The bought and sold heat per m^3 for each building, with electrical load tracking strategy, sized to 100% of the peak demand

Figure 56 shows the relation between each building’s bought and sold amount of heat per m^3, when the micro CHP plant has an electrical load tracking strategy and is sized to 100% of peak demand. The new office building and the assembly building produces almost all the heat they need themselves. But the sector of education has to buy much more heat than it is able to sell. According to the picture, the new office building could be able to supply for example the educational building, with the amount of heat needed. But that is not the case at hourly level, because both buildings have their heat demand peak during the same hours of the day, at 7 a.m. and 6 p.m. The extra heat from the new office building would however, cover partly the heat deficit of the sector of education. But then again, if it is possible to store the heat, the excess heat can be utilized better. The problem is that most of the excessive heat production of the buildings happens in the summer months, when the heat demand is the smallest. In most of the cases, combining different building types leads to an even bigger amount of excess heat production during summer and even bigger need to buy more heat produced by centralized heat production during winter. The hourly potential of produced excess heat was combined between different buildings, in the search for a constant and low amount of excess heat.

In the case where a building with a constant electricity production was combined with a building with a production following the demand, the heat demand was best fulfilled. Figure 57 shows an example of the new apartment house’s and health care building’s combined average heat sales potential during a day. This value is given for February, April, July and October, to represent four seasons of the year. The new apartment house has an electrical base load strategy and the health care building has electrical load tracking strategy. The μCHP-plants are sized to cover 100% of electrical peak demand. The demand is not completely fulfilled during the winter time, but the remaining needs of heat can be bought from the centralized production. The huge difference between the summer and winter months is due to the cold winter climate in Finland. In summer time, then again, there is much excess heat that must be sold outside of these combined buildings.

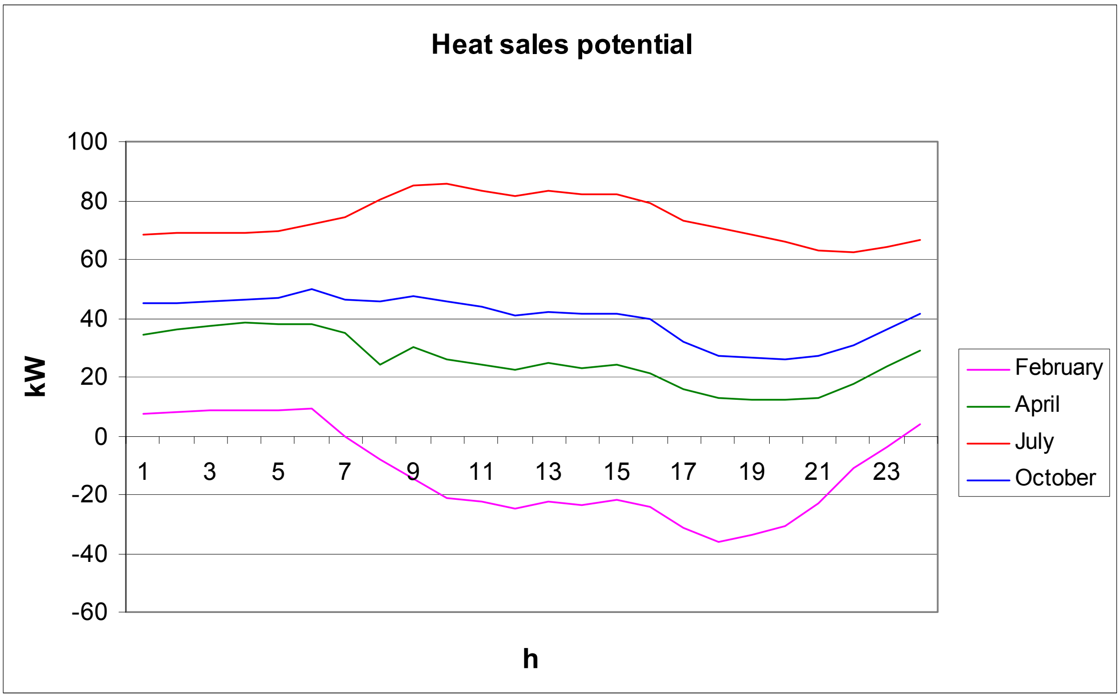

Figure 57. The new apartment house's and the health sector's combined average heat sales potential during a day, when µCHP-plant has an electrical load tracking strategy (health sector's buildings) and an electrical base load strategy (new apartment buildings) and is sized to cover 100% of peak demand. The huge difference between the summer and winter months is due to the cold winter climate in Finland.

5.3.4 Conclusions

The main focus in this research was the feasibility of heat trading. The most interesting buildings were those with a µCHP-plant with an electrical load tracking strategy and an electrical base load strategy. The buildings produced independently most of the needed electricity and the heat was generated as a by-product. The percentage of sizing describes the amount of electrical peak demand covered by the CHP plant. 100, 80, 50 and 25 were used as percentages of sizing. The production was either constant or followed the electricity consumption.

Because of the fact that most of the excess heat produced by the buildings is concentrated to the summer season, it may be difficult to sell the exceeding heat because of lack of demand. Some of the building types were also able to produce some excess heat during the winter as well, when it is much easier to sell it. These were assembly buildings, business buildings, new apartment houses and old apartment houses.

In the case with electrical load tracking strategy, the new office building and assembly building were able to produce nearly all the heat they needed by their own means. This was not the case for the other buildings, which had to buy remarkable amounts of heat to fulfill their annual heat demands. With combining the sales potentials of the different building-types, an ideal solution was searched for, where two buildings' daily heat sales potentials and heat demands would meet each other. That kind of a solution was not found. The daily heat demands and heat surpluses for each building were in most cases overlapped and from combining different cases followed an even greater surplus of heat in summer and need to buy more heat in winter. If it would be possible to store heat, the heat surplus could be utilized better.

There might be a possibility to use a thermally activated cooling in the district heating network for a better utilization of the excess heat. This possibility was, however, not studied further.

In the other case, where there was an electrical base load strategy sized to cover 100% of electrical peak demand, huge amount of excess heat was generated as a by-product. Combining a building with an electrical base load strategy sized to a building with an electrical load tracking strategy, the heat demand was better met.

When the CHP plant had an electrical base load strategy and was sized to cover 100% of electrical peak demand, the new office building produced the largest amount of excess heat. When combining a new office building with any other building, which has an electricity production that follows the consumption, almost all the needed heat was covered. And still, during most part of the year, there was still extra heat left to be sold. When combining a new office building with a health care building or educational building, the heat demand was not fulfilled completely. The new office building was able to produce the needed heat for 30 new detached houses and could after that, still produce excess heat momentary up to 110 kW. The 30 detached houses produce heat, with a micro-CHP plant with an electrical load tracking strategy. Respectively the excess heat would be sufficient for 10 new terraced houses, 13 old detached houses, 4 old terraced houses or 3 new apartment houses.

When a building with a CHP-plant with a electrical base load strategy, was combined with another building, the other building does not have to have any own electricity production. The other building can just be a receiving part. With the excess heat gained from a new office with a CHP plant with a electrical load tracking strategy, it is possible to cover the needs of 17 new detached houses, with no own production at all.

The new office is a building that filled its whole heat demand (with a base load strategy) and produced enough excess heat to cover the heat demand of another building partly.

The rest of the heat demand was covered from the centralized production or with a separate μCHP-plant.

The best benefit was gained when the heat demand of as many buildings as possible was fulfilled each month. For example the new office building could, with a CHP plant with an electrical base load strategy, fulfill completely the annual heat demand of 49 new detached houses (no own production) in July and 17 new detached houses (no own production) in January. In this way the amount of excess heat was minimized.

In the search for the best heat demand-supply match, there are numerous alternatives of building-combinations. Even though the building's demand and sales do not always meet each other, the potential of heat trading seems to be interesting, and offers a great way for buildings to exploit differences in consumption profiles. Further research is needed to evaluate the heat trading potential at community level, where some buildings have a micro-CHP plant and some buildings are traditional consumers.

6. The hydraulic connection between the DH-network and the building

When a connection of micro-CHP unit or boiler and its possibility to sell heat are considered, some technical boundary conditions of the hydraulic system (= district heating network + building-side network) should be taken care of. There are several boundary conditions, some of them even conflicting with each other. The connection should be

- safe to the end user
- cost efficient
- hydraulically stable (e.g. no pressure shocks to either side of networks)
- easy to install to the existing DH-systems e.g. for renovations
- easy to control, e.g. its temperature control should be stable
- commercially reliable, e.g. dividing the selling and purchasing parts of the energy at the measurement level should be accurate and easy
- able to change automatically the selling or buying mode.

The following sections present some ways to couple a micro-CHP unit to the district heating network. The connections presented include only the parts of the CHP that are needed in the DH connection. This means that for example the possible additional cooling networks that are needed to run the CHP unit are excluded. The supplementary cooling system is needed in a case when the cooling capacity of building heating and DH networks is not enough to run the unit for the electricity production.

In general, the physical connection will need standardized rules, in which the quality and the performance of the connection unit are unambiguously defined, same way as the current Finnish District Heating Associations' guidelines do for the district heating substations.

6.1 The connection types of the micro-CHP unit at building level

In this section four different possibilities to connect a small scale heat production unit (for example a boiler or micro-CHP-unit) at building level are presented. The connection can be made directly to the DH-network or to the consumer's heating network. One connection type can have at the same time advantages and disadvantages. The applicability of the presented micro-CHP connection types and their pros and cons are discussed. Only one direct (no heat exchanger) connection to DH network is presented. A preliminary study showed that there should always be a heat exchanger because of the safety reasons. Finally this section presents the recommended version of the connection.

Figure 58 presents typical Finnish substation connection without micro-CHP.

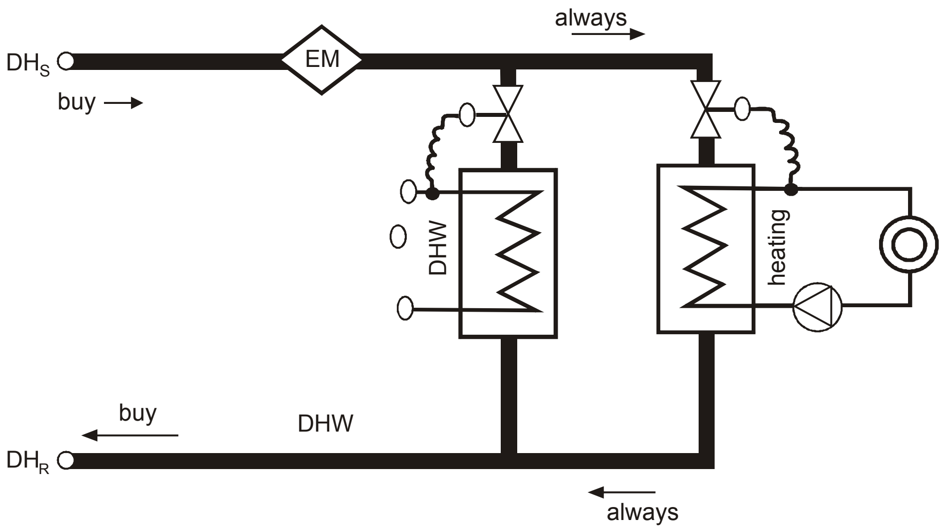

Figure 58. Typical district heating substation connection in Finland without micro-CHP.

6.1.1 Type 1: The connection to the consumer's heating network side

Figure 59 shows building level CHP plant connected directly to the consumer heat distribution side (secondary side). In this case the extra heat from the CHP is sold upstream of the DH network i.e. to the supply side (primary side).

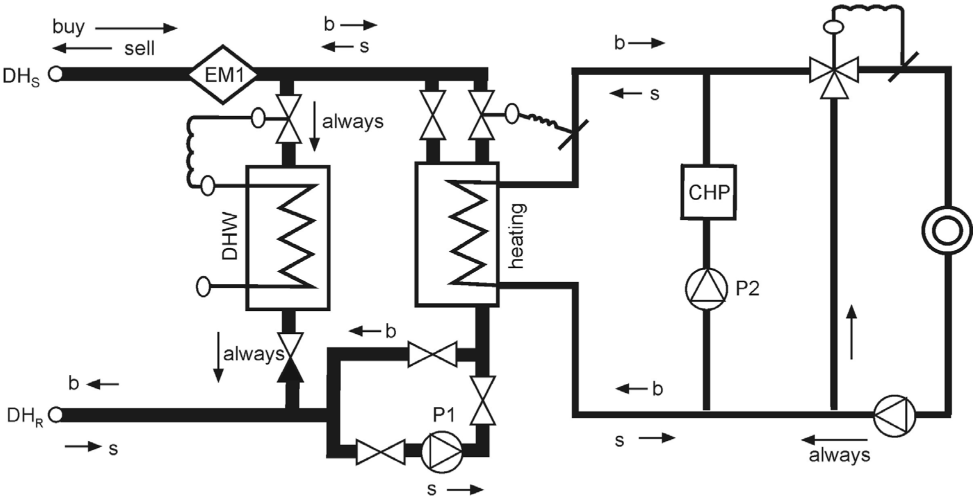

Figure 59. CHP connected to the consumer's heating network. Heat is sold upstream of the DH network.

This connection requires some modifications to the standard indirect substation configuration. For example two by-pass pipes to the heating heat exchanger and two extra pumps are needed to enable the selling of the heat to the supply side of the DH network: one pump to the primary side (P1) and one to the secondary side (P2). The supply water temperature of the CHP plant must be higher than the supply water temperature of the DH network to be able to sell heat. This temperature is usually too high for the distribution network of the building side. This is why a 3-way mixing valve is needed in the secondary side to reduce decrease the temperature to an acceptable level.

Good things with this connection are that it does not require extra heat exchangers and only one energy meter (EM) is needed (Table 14). The EM should measure the energy flows in both directions (i.e. when buying and selling heat). This is possible for example with magnetic flow meters. On the other hand the connection brings along complications both to primary and secondary side couplings.

Table 14. Pros and cons of the case where CHP plant is connected to the consumer's heating network and heat is sold upstream of the DH network.

Pros	***Cons***
No extra heat exchangers are needed (indirect connection from the DH point of view)	Modularity of the substation configuration is not possible with the standard unit
Construction pressure of CHP is the same as the pressure of the secondary side i.e. 10 bar	Complicated secondary side configuration
"Big" heat exchanger works better in the buying mode	Dimensioning of the heating heat exchanger should be done according to the selling mode of the plant –> possibly bigger heat exchanger
Only one energy meter is needed	Using the heat for DHW purposes is a bit complicated
	High temperatures in secondary side cause " re-dimensioning" of expansion vessels

6.1.2 Type 2: The direct connection to the DH-network side without heat exchanger

A schematic diagram of the direct connection of the CHP plant to the DH network side where heat is sold upstream is shown in Figure 60. This connection does not mean any changes to the normal substation unit nor to the secondary connections. To sell heat upstream a pump is needed and to control the temperature of the CHP feed water (outlet temperature can be too high) a three-way mixing valve and controllers are needed.

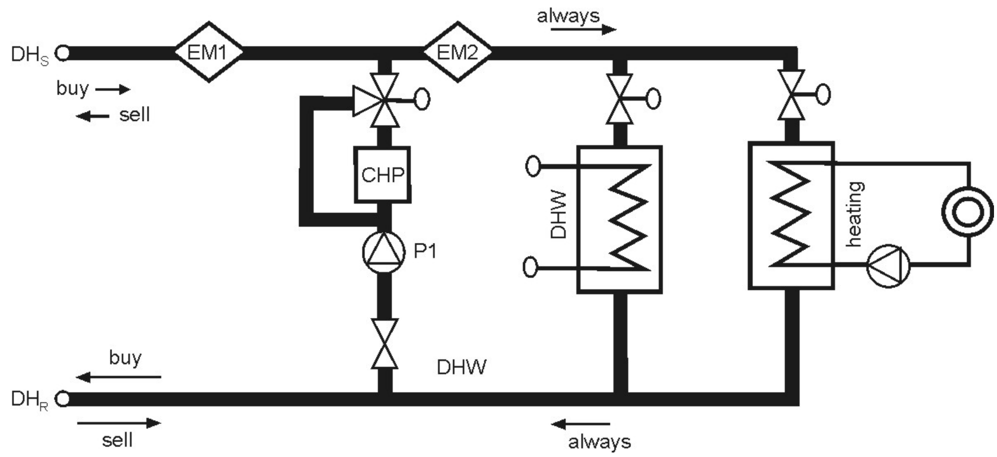

Figure 60. Direct connection of the CHP plant to the DH network. Heat is sold upstream of the DH network.

This configuration is both simpler and cheaper than the other connections presented (Table 15). But direct connection of the CHP plant to the DH network is also hazardous in the case of damage in the CHP plant which may cause DH water to flood into the building. This is one reason why DH network owners do not like this arrangement alternative. Direct connection is not only sensitive to water leaks but also gas leaks are possible. Gas leaks can cause corrosion problems in the network pipes. Because of the direct connection the CHP plant must sustain the pressures that occur in the primary network, which in Finland in existing networks is in many cases 16 bar. Direct connection without an extra heat exchanger is advantageous to CHP plant working at low temperature levels.

Table 15. Pros and cons of the case where CHP plant is connected directly to the DH-network and heat is sold upstream of the DH network.

Pros	***Cons***
No extra heat exchangers are needed.	Direct connection to the DH network is a leak hazard. Water and gas leaks are possible
Modularity of the substation configuration is possible with the standard unit	Construction pressure of CHP is the same as the pressure of the primary side i.e. 16 bar
Simple and cheap	Extra pump is needed to sell heat upstream
Suitable for CHP plants with low working temperature	

6.1.3 Type 3: The connection to the DH-network side with heat exchanger

In this case the CHP plant is connected indirectly with a heat exchanger to the DH-network; see Figure 61. This is more or less the same connection as the type 2 connection described in chapter 6.1.2 but safer in terms of leak problems.

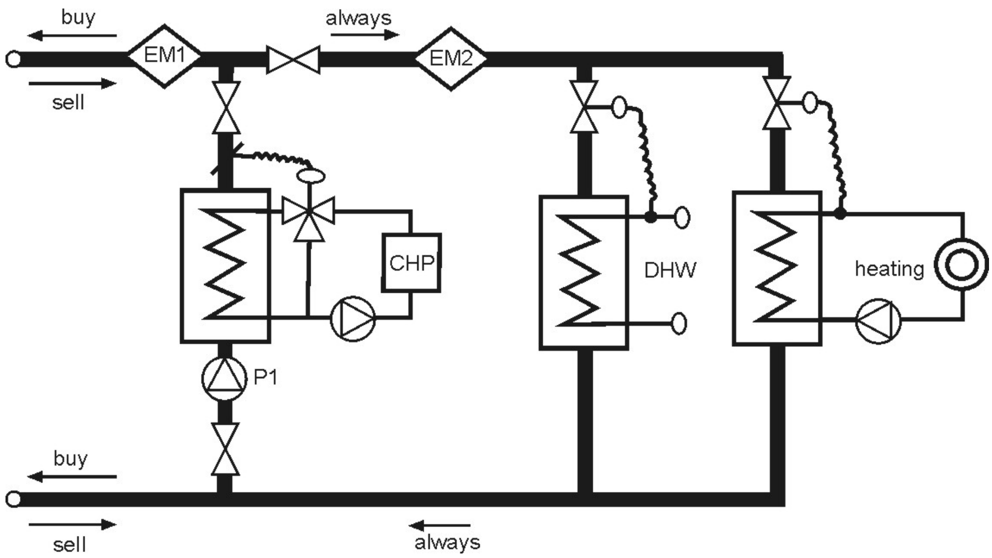

Figure 61. Indirect connection of CHP plant to the DH-network with heat exchanger, heat is sold upstream.

This version seems to be the most suitable one of the presented connections to combine a CHP unit to DH network. It is safe concerning leaks (water and gas), easy to control and suitable both for new installations and renovations (Table 16).

Table 16. Pros and cons of the case where CHP plant is connected indirectly to the DH-network and heat is sold upstream of the DH network.

Pros	*Cons*
Modularity of the substation configuration is possible with the standard unit	More complicated and more expensive than direct connection
Safe solution regarding water and gas leaks	Extra heat exchanger and secondary network are needed
Good controllability	Extra pump is needed to sell heat upstream
Construction pressure of CHP is not dependent of the pressure in DH-network	

6.1.4 Type 4: The return-pipe connection of CHP plant to the DH-network

The return-pipe connection enables selling of the heat to the return-side of the DH-network. Here CHP plant is installed in an extra pipeline taken from the return pipe of the substation (Figure 62). In this connection heat can not be utilized directly in the building where the CHP plant is but all the heat is sold to the DH-network and all the heat that is needed is purchased from the DH-network. This arrangement creates situations where the return temperature to the main plant is higher than in normal case. A high return water temperature ruins the efficiency of the steam turbine in the main CHP-plant and this should be taken into account in the pricing of the sold heat.

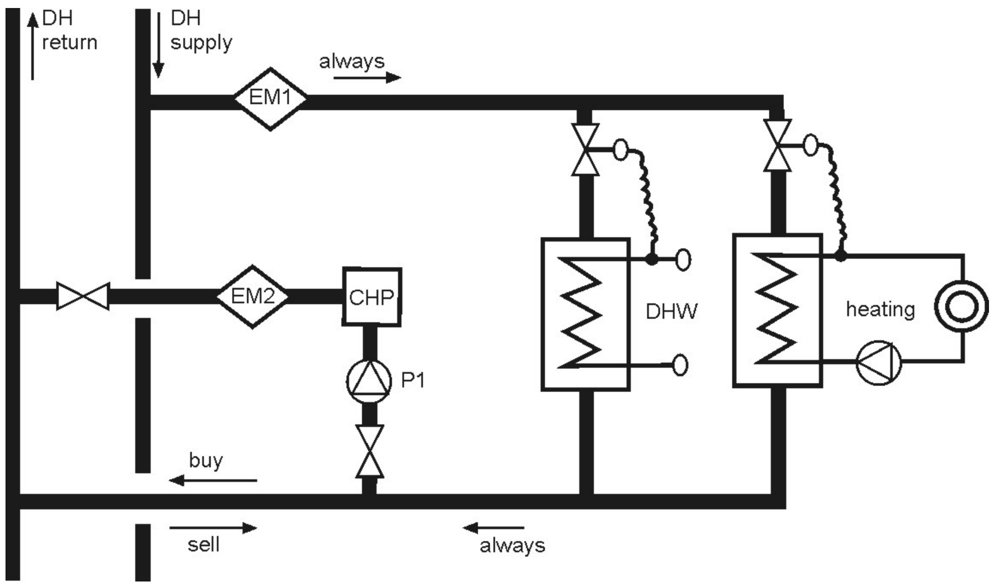

Figure 62. Direct connection of CHP plant to the DH-network return pipe, heat is sold downstream.

This connection does not need any changes to the normal substation unit (Table 17). An extra pump is needed in the CHP pipeline to overcome the pressure losses of the branch. Pump is also needed in the case where the building does not use any energy but CHP plant produces heat that could be sold to the DH-network. Special care must be taken to avoid situations where there is no flow in the return manifold. Otherwise the flow starts to circulate in a loop where the CHP plant is and the temperatures will rise too high and prevent the selling.

Table 17. Pros and cons of the case where CHP plant is connected directly to the DH-network return pipe and heat is sold downstream of the DH network.

Pros	***Cons***
Modularity of the substation configuration is possible with the standard unit	Direct connection is a leak (water, gas) hazard
Enables CHP plants that work on low temperature	Construction pressure of CHP is the same as the pressure of the primary side i.e. 16 bar
Connection is simple	Extra pump is needed to sell heat downstream
Hydraulic problems concerning the DH network are probably smaller than selling upstream	Special attention is needed to avoid water looping in CHP branch
	Complicated pricing of sold heat

6.1.5 Recommended connection

The recommended connection version is type 3 presented in chapter 6.1.3. This connection has many advantages compared to the other versions: it does not bring any changes to the standard modular substation unit in buildings, it is a safe solution to the user (no water leaks) and to the DH network (no gas leak problems), it is easy to control, it is suitable for new installations and renovations, and maintenance of the CHP unit does not cause any problems to the DH operation.

7. Real options, investments and strategy in open heat trade market

7.1 Introduction

In an increasingly uncertain and dynamic global market place managerial flexibility has become essential for firms to successfully take advantage of favourable future investment opportunities, respond effectively to technological changes or competitive moves, or otherwise limit losses from adverse market developments. Thinking of future investment opportunities as "real options" has provided powerful new insights that in many ways have revolutionized modern corporate resource allocation (Mun 2002).

Real options emphasizes the importance of waiting or staging flexibility (carrying out the project step by step), suggesting that managers should either "wait and see" until substantial uncertainty is resolved and the project is more clearly successful, requiring a premium over the zero-NPV critical value, or they should stage the decision so that they can revise the situation at critical milestones to either proceed to the next stage or abandon. During the waiting or staging period, new information can be revealed that might affect the desirability of the project; if future developments turn out worse than expected, the firm has implicit insurance protecting it against downside losses by choosing not to proceed with the project. Real options also introduces a new insight with respect to the role and impact of uncertainty on investment opportunity value that runs counter to conventional thinking. Since management is asymmetrically positioned to capitalize fully on upside opportunities while it can limit losses on the downside, more uncertainty can be beneficial for option value. More can be gained from opportunities in highly uncertain or volatile markets because of the exceptional upside potential and limited downside losses that result from management's flexibility to continue or not proceed with the project.

From a strategic perspective, of course, it may not always be beneficial to "wait and see". For example, by making an early strategic R&D investment, a firm may not only develop more cost-efficient or higher-quality products or processes that can result in a sustainable cost or other competitive advantage, but may be able to positively influence competitive behaviour and earn a higher market share down the road. In some cases a firm anticipating competitive entry may make a strategic investment commitment (e.g., in excess production capacity) early on such that it can pre-empt competition altogether. Therefore, optimal investment timing generally involves a trade-off between wait-and-see flexibility and the "strategic value" of early commitment. Moreover, early investing may itself open up a set of new options embedded in the commercial project (e.g., to later expand, abandon, or switch to alternative uses), whose value may also be enhanced by higher uncertainty, but is realized through early investing. Thus, the presumed depressive impact of uncertainty on investment is not that clear cut. The above new considerations of investment under uncertainty suggest the need to adopt an expanded or strategic NPV criterion, able to capture management's flexibility to alter planned investment decisions as future market conditions change as well as the strategic value of competitive interactions – besides the value of expected cash flows from committed assets.

New valuation methods, such as real options and Monte Carlo simulation, do not completely replace the traditional approaches. Rather, the new analytics complement and build upon the traditional approaches – in fact, one of the precursors to performing real options and simulation is the development of a traditional model.

7.1.1 Definition of a real option

A real option is the right, but not the obligation, to take an action (e.g., deferring, expanding, contracting, or abandoning) at a predetermined cost called the exercise price, for a predetermined period of time – the life of the option.

The value of a real option depends on six basic variables:

1. *The value of the underlying risky asset.* In case of real options this is a project, investment, or acquisition. If the value of the underlying asset goes up, so too does the value of the option. One of the important differences between financial and real options is that the owner of a financial option cannot affect the value of the underlying (e.g., a share of a company's stock). But, the management that operates a real asset can raise its value and thereby raise the value of all real options that depend on it.

2. *The exercise price.* This is the amount of money invested to exercise the option if you are "buying" the asset (with a call option) or the amount of money received if you are "selling" it (with a put option). As the exercise price of an option increases, the value of the call option decreases and the value of the put option increases.

3. *The time to expiration of the option.* As the time to expiration increases, so does the value of the option.

4. *The standard deviation of the value of the underlying risky asset.* The value of an option increases with the riskiness of the underlying asset because the payoffs of a (call) option depend on the value of the underlying exceeding its exercise price and the probability of this increases with the volatility of the underlying.

5. *The risk-free rate of interest over the life of the option.* As the risk-free rate goes up, the value of the option also increases.

6. *The dividends.* The dividends that may be paid out by the underlying asset will be lost to competitors who have fully committed if we are still in the "wait-and-see" phase. Increasing cash flows lost will clearly decrease the value of the option.

7.1.2 Practical issues using traditional valuation methodologies

Traditional methods assume that the investment is an all-or-nothing strategy and do not account for ***managerial flexibility****;* the concept that *management can alter the course of an investment over time when certain aspects of the project's uncertainty become known*. The essence of real options is to take into account management's ability to create, execute and abandon strategic and flexible opportunities.

There are several potential problem areas in using a traditional discounted cash flow calculation on strategic optionalities. These problems include undervaluing an asset that currently produces little or no cash flows, the non-constant nature of weighted average cost of capital (WACC) discount rate through time, the estimation of an asset's economic life, forecast errors in creating the future cash flows, and insufficient test for plausibility of the final results. Real options, when applied using an options theoretical framework, can mitigate some of these problematic areas.

In a stochastic world using deterministic models like the discounted cash flow may potentially grossly underestimate the value of a particular project. A deterministic discounted cash flow model assumes at the outset that all future outcomes are fixed. If this is the case, the discounted cash flow model is correctly specified as there would be no fluctuations in business conditions that would change the value of a particular project. In essence, there would be no value in the non-existing flexibility!

7.1.3 Comparing net present value and the real options approaches

Both approaches consider all cash flows over the life time of a project, both discount cash flows back to the present, and both use market opportunity costs of capital. Therefore, both approaches are discounted cash flow approaches. Yet they are fundamentally different and the net present value (NPV) approach is a special case of the real options approach. We could say that NPV is a real options approach that assumes no flexibility in decision making.

This is an example of a case in which the formalism of mathematics helps to clarify the issue (Copeland & Antikarov 2001). The net present value of a project is often written as

$$NPV = -I + \sum_{t=1}^{N} \frac{E(FCF_t)}{(1+WACC)^t} \tag{9}$$

where E(FCF) means expected value of FCF (free cash flow). FCF is defined as revenues minus costs and taxes.

Note that the uncertainty of cash flows is not explicitly modelled in the NPV approach. One merely discounts expected cash flows. In reality there are many paths of possible free cash flows that might be realized between the start of the project and its finish. None of them are mapped out when we use NPV. That is because the NPV approach is constrained to precommitting today to a go or no go decision. It uses only information that is available today. Mathematically, this is equivalent to taking the maximum of a set of possible mutually exclusive alternatives:

$$NPV \text{ rule:} \quad MAX_{t=0}\left\{0, E_0(V_T - X)\right\} \tag{10}$$

where $E_0(V_T - X)$ means expected value of the project at a future time point t = T as seen at a time point t = 0, and X is the exercise value of the option, i.e. the investment cost. The problem solution is to compare all possible mutually exclusive routes to determine their value, $\left(V_T\right)$, and to choose the best among them.

Real options takes a different perspective. Mathematically, a call option is an expectation of maximums (not a maximum of expectations):

$$ROA \text{ rule:} \quad E_{t=0}(MAX_{t=T}\left\{0, V_T - X\right\}) \qquad (11).$$

From an options perspective, a project is undertaken, at a future time, if and only if $V_T > X$. If we use the NPV rule, the project is accepted at t = 0 if and only if the expectation at time zero is such that $E_0(V_T) > X$.

The two approaches will be the same if there is no uncertainty, because then the actual future value, V_T, will equal the current expectation of the future value, $E_0(V_T)$.

An analogy of driving car over a long distance may help here. Think of situation of making a trip from Paris to Rome. First you plan a route that is the best using your criteria. And then, off you go, following your carefully planned route – until you encounter a traffic jam, or unplanned detour. This, of course, is unexpected. The NPV approach is like assuming that you can drive the expected route – no detours, no traffic jams, no bad weather – no ability to respond to uncertainty. The real options paradigm assumes that we will be making decisions down the road, based on the future scenarios that we might encounter. Decisions are made when information about the state of nature is revealed ($MAX_{t=T}$). For example, we will deviate from our planned route if construction forces a detour, but we will make the optimal decision given information available at a future date, $t=T$.

7.2 Examples of Real Options

Although real options exist in most businesses, they are not always easy to identify. Real options can be classified into three main groups: invest/grow options, defer/learn options, and disinvest/shrink options (Dixit & Pindyck 1994). In turn, real options can be further defined within these broader headings. Below is a list of seven common real options. We define them separately; however, it should be noted that many options are interrelated. What follows is a starting checklist:

Invest/Grow Options

- **Scale up**. This is where initial investments scale up to future value-creating opportunities. Scale-up options require some prerequisite investments. For example, a distribution company may have valuable scale-up options if the served market grows.
- **Switch up**. A switch – or flexibility – option values an opportunity to switch products, process, or plants given a shift in the underlying price or demand of inputs or outputs. One example is a utility company that has the choice between three boilers: natural gas, fuel oil, and dual-fuel. Although the dual-fuel boiler may cost the most, it may be the most valuable, as it allows the company to always use the cheapest fuel.
- **Scope up**. This option values the opportunity to leverage an investment made in one industry into another, related industry. This is also known as link-and leverage. A company that dominates one sector of e-commerce and leverages that success into a neighbouring sector is exercising a scope-up option.

Defer/Learn

- **Study/start**. This is a case where management has an opportunity to invest in a particular project, but can wait some period before investing. The ability to wait allows for a reduction in uncertainty, and can hence be valuable. For example, a real estate investor may acquire an option on a parcel of land and exercise it only if the contiguous area is developed.

Disinvest/Shrink Options

- **Scale down**. Here, a company can shrink or downsize a project in midstream as new information changes the payoff scheme. An example would be an airline's option to abandon a non-profitable route.
- **Switch down**. This option places value on a company's ability to switch to more cost-effective and flexible assets as it receives new information.
- **Scope down**. A scope-down option is valuable when operations in a related industry can be limited or abandoned based on poor market conditions and some value salvaged. A conglomerate exiting a sector is an example.

Real option advocates believe that real options thinking should permeate all corporate strategy decisions. This includes recognizing the options that arise from certain strategic actions as well as identifying and exercising valuable options that exist in the firm. Investors must be attuned to the fact that stock prices may incorporate real options value. This options value is often not obvious from just looking at current businesses. The goal is to identify those companies that have options and are most likely to exercise them prudently.

7.2.1 What We Know About Real Options and Investment under Uncertainty

The insight and implications of viewing investment opportunities through a real options lens can be quite powerful. Below professor Trigeorgis summarizes a dozen insights or important main implications of now-standard real options analysis (Trigeorgis 2002):

1. Uncertainty and flexibility are key determinants of the value of an asset or firm and call for an expanded valuation criterion.

   The traditional valuation paradigm based on cash flows from *expected* plans under the implicit assumption of passive management has proven inadequate. The role of uncertainty in the presence of managerial flexibility is not necessarily penalizing as conventional wisdom would have us believe. Greater variability of potential outcomes around the expected (mean) result may be beneficial in the presence of options. Managerial flexibility to revise decisions when there are deviations from the expected plans introduces beneficial asymmetry in the distribution of project value returns by enabling value-creation opportunities to be exploited fully while limiting downside losses by choosing not to proceed or abandon. The resulting skewing of the probability distribution of expected project returns toward a more positive outcome calls for an Expanded NPV criterion to also capture the additional value of managerial operating flexibility and other strategic interactions:

Expanded NPV = passive NPV + Option Premium (ROV)

Based on this expanded criterion, it can be seen that it may now be justified to accept projects with negative passive NPV of expected cash flows (if this is offset by a larger option premium or real option value as a result of additional flexibility and strategic value), or delay projects with positive NPV until a later time when Expanded NPV can be maximized under uncertainty.

2. Managerial flexibility or real option value may be higher (other things the same)
   - for industries with higher uncertainty
   - for investment opportunities with longer horizons or that can be delayed longer
   - when (real) interest rates are higher
   - for multi-stage (compound) options.

3. Higher uncertainty tends to increase the value of the option to defer investment – provided there are no “dividends” or other early-exercise benefits, strategic interactions or other embedded options.

   The flexibility to delay or “wait and see” enables acquiring more or better information and making a more informed future decision, potentially avoiding a mistake from premature investment in case things develop unfavourably. This higher value to “wait-and-see” necessitates a higher critical investment threshold, i.e., project value must be at a significant premium above the required investment cost, before investing and sacrificing the option to wait is justified.

4. If one can reverse a decision with ease or little cost, it is easier to make it in the first place.

   A multinational corporation would find the decision to enter a new foreign country easier if it can get out with limited damage in case of unfavourable developments. This principle holds also in general contexts beyond business investment.

5. Under uncertainty, it is prudent to stage an investment or proceed with decision plans in stages.

   Staging the investment or decision plans provides valuable flexibility to continue to the next stage or to abandon midway. Continuation, e.g. financing of subsequent stages in Venture Capital, should be contingent on the success of earlier stages.

6. Multi-stage opportunities may have significant growth (compound) option value that may justify making strategic investments despite having negative NPV.

Consider, for example, a two-stage growth option. The first stage involves investing in a manufacturing facility in Spain to introduce a new product that is expected to generate moderate cash flows from the Spanish market. The second stage would involve a ten-fold expansion into the broader European market 3 years later. The first-stage NPV of the expected cash flows from investing in the Spanish market is negative, and committing now to enter the European market on an expanded scale seems ten times as bad. But the company does not have to commit now. Instead, it has an option to "wait and see" how the Spanish and European demand develops and expand to the European market if and only if it appears favourable to do so 3 years from now. The opportunity to expand in Europe, valued as an option, may well offset the negative NPV of the first-stage investment and justify making this strategic multistage investment on strategic grounds. Empirically, companies in industries with higher uncertainty that involve multistage (compound) options tend to have a higher proportion of their stock price deriving from growth opportunities, providing an indirect confirmation of the validity of real option predictions.

7. If investing creates other options within the project then more uncertainty would also increase the flexibility value of these other embedded options – increasing the value of early investing in the first place. For this reason higher uncertainty would not necessarily suppress or delay investment.

8. In the presence of competition in an oligopoly setting, early investment may have strategic value by influencing the equilibrium actions of competitors in a way beneficial to the investing firm or even by pre-empting competitive entry in some cases.

   The option value of waiting must be traded off against the strategic value of early investing. When the investment benefits are proprietary and the pioneer can get stronger at the expense of its competitor, it should commit to an early investment strategy if the competitor will retreat and cut its market share under quantity competition as the pioneer expands its own market share. However, when the benefits are shared, thereby benefiting the competitor as well, and a competitor would respond aggressively, it should follow a flexible "wait and see" strategy rather than subsidizing an aggressive competitor while itself paying the full cost.

9. Competitive pressure may induce firms to invest prematurely resulting in a suboptimal prisoner's dilemma situation, e.g., in a "winner takes all" innovation race.

   Each of the two firms being afraid that it may be pre-empted by the other and loose all, would rush to invest prematurely, rather than wait which may be the preferred outcome. A joint research venture may enable the two firms to more fully appropriate the flexibility value from waiting by coordinating and jointly optimizing against demand uncertainty – besides sharing and saving on the investment cost. A limitation is that in collaborating a firm gives up the possibility to outwit its rivals and gain a competitive advantage or strategic value over the other firm.

10. Multiple options embedded in a project may interact, i.e., option value additivity may break down.

    The value of a portfolio or combination of embedded options typically is less than the sum of separate or independent option values. The error from adding up separate option values may be of the same order of magnitude – but in the opposite direction – as the error from ignoring options altogether. That is, a wrongly executed options analysis can be as dangerous as a naïve NPV analysis.

11. Options to switch provide valuable flexibility and risk management value.

    Traditional mean-variance portfolio theory based on the notion that risk is undesirable and must therefore be minimized is inadequate. With options to choose the best of several alternatives or options to switch from one "mode" of operation or being to another, lower correlation tends to increase the relative volatility and option value of a flexible system. When the value of one alternative drops, an option to choose the best or switch to another alternative is worth more if the value of that second alternative tends to increase. For this reason, multinational corporations operating in several countries would prefer to select the next strategic location so as to have lower correlation with the existing structure; not so much in order to diversify and reduce risk, but rather so as to increase the relative volatility and option value of the flexible network. Risk is not necessarily something bad to be avoided, but rather can be seen as a window of opportunity for the more flexible and innovative corporations to create more value by leveraging on opportunities while limiting losses.

12. When switching among operating "modes" or strategies, the presence of significant switching costs – e.g., to enter, exit, or shut down – may induce a "hysteresis", inertia or delay or lag effect.

    Even though immediate switching may be attractive based on short-term cash-flow considerations, it may be long-term optimal to wait, e.g., due to a high cost or probability of switching back later. Examples involving hysteresis effects include continuing operation of a currently unprofitable mine or oil field despite temporarily suppressed prices, the Japanese auto producers who once they entered the US market in profitable times kept hanging-on in the US despite incurring losses in subsequent years, lags in hiring and firing by companies as business moves to an up and down cycle, delays in seeking divorce despite an unhappy marriage etc. All these cases involve irreversible or costly-to-reverse decisions which justify delaying a switch for a while since a re-switch back to the current situation is either infeasible or would occur only after a costly impairment of infrastructure, goodwill etc.

7.2.2 Four-step process for applied work

Real options analysis can be defined by a four step process developed by Copeland (Copeland 1998) in demanding practical work in projects applying real options:

1. **Compute the base case present value without flexibility at *t = 0*.**
   a. The objective is to compute the base case present value at time zero.
   b. This is a traditional present value calculation.

2. **Model the uncertainty using event trees.**
   a. The objective is to understand, how the present value develops over time.
   b. A Monte Carlo simulation model is defined and the identified uncertainties are characterised. The result of the simulation is the *variability of the profitability* of the project. This is the main input in building the event tree.
   c. The event tree is a binomial tree of the future possible states of a project. It does not have flexibility in it.
   d. The present value of the project is the same as in step 1.

3. **Identify and incorporate managerial flexibilities creating a decision tree.**
   a. The objective is to analyze the event tree to identify and incorporate managerial flexibility to respond to new information.
   b. Flexibilities, that is, decision possibilities, are incorporated into event trees which transforms them into decision trees.
   c. Flexibility changes the risk characteristics of a project and thus the cost of capital change.

4. **Conduct real options analysis (ROA).**
   a. The objective is to value the total project using simple algebraic methodology and Excel spreadsheet.
   b. It is like dynamic optimisation starting from the end and going backwards to the other end, to the present time point.
   c. ROA will include the base case present value without flexibility plus the option (flexibility) value.

It is important to note that the traditional net present value (NPV) is the basis of the analysis. If there are no flexibilities present or the uncertainty is non-existent then the RO analysis ends up with the same result as the traditional NPV:

NPV = Benefits – Costs

Option value = RO value

Total value = NPV + Option value

As step four reveals, the ROA analysis uses dynamic programming approach. The possible states of the project are created by the binomial lattice in step two. This lattice is based on the Monte Carlo simulation on the project's profitability. Once the event tree (binomial lattice) has been created the identified options are defined. Then the problem arises: Which of the options, if any, should be exercised and at what kind of a situation to obtain the maximum benefits? This problem is solved in step four by dynamic programming.

Dynamic programming works backwards in time. For a problem with n time periods, the procedure starts by finding the best decision at each of the nodes i at time n-1 and assigns a value, denoted by V(n-1,i), to each such node. This V-value is the optimal present value that could be obtained if the investment (option exercise) process were initiated at that node.

To find that value, each possible arc (two in a binomial lattice) starting from node i is examined. The sum of the cash flow of the arc and the one-period discounted V-value at the node reached by the arc is evaluated. The V-value of the originating node i is the maximum of those sums. After completing this procedure for all the nodes at n-1, the procedure then steps back to the nodes at n-2. Optimal V-values are found for each of those nodes by a procedure that exactly parallels that for the nodes at n-1. The procedure continues by working backward through all time periods, and it ends when optimal V-value is assigned to the initial node at time zero. Examples of this procedure, and in options and investments in general, can be found e.g. in Copeland and Antikarov (2001) and Lueberger (1998).

7.3 Concluding remarks

Real options analysis is not an equation or a set of equations. It is both an analytical process as well as a decision analysis thought process. It can even be said that half of the value of real options is simply thinking about it. The other half of the value is split equally between the two: i) model definition and getting the right numbers; and ii) explaining the results and insights so that the optimal decisions can and will be made when it is appropriate to do so.

8. Summary

Liberated heat market works mainly like a liberated electric market in Nordic countries with the exception that the heat market works within a local district heating network There are producers, customers, network operator and system operator as there exist in the electric market. Physical actors in the liberated heat trade market are the traditional large scale producers that sell heat to customers connected to the district heating network, and the end users, that would also be small-scale producers using a micro-CHP or a boiler. They would buy heat from other producers or sell heat to customers through the network. The liberated heat energy market will also need the transmission-network-company that takes care of the temperatures, pressures and hydraulic balance of the heating network. Network-company is also responsible for services and enlarging the network when necessary. A balance-sheet-operator is also needed to coordinate the heat contracts between producers and customers as well as to take care of reserve capacity, spot and future markets and billing.

The main objectives for the liberated heat trade market are to further a competition within the local DH-network, to produce heat in more economical ways and to use more effective production units. However, the quality of the heat and minimum environmental impacts must be ensured. This means that

- temperature, pressure and water quality must be ensured
- combined electricity and heat production (CHP) must be furthered
- new more effective techniques of utilisation should be ensured.

The district heating network operation should be separated from the production like in the electricity side. Then the network operator works more transparently and it is easier to see the transport cost.

The market may consist of basic contracts continuing until further notice, from one month to one year short contracts and some kind of spot markets 24 hours ahead like in the Nordic electric market. Future contract can be bought for the next heating season. The heat balance sheet operator is responsible for heat trade. The heat capacities and contracts must be in balance including the reserve capacity. A coming heat boiler capacity in next heating season can be sold as futures to consumers.

Distributed energy systems have in recent years become more interesting. We use the term “micro-CHP” when referring to building-scale combined heat and power generation plant. A vision of self-sufficiency of buildings in terms of electricity production makes the research of micro-CHP plants interesting. In this study a new aspect was brought to the issue of distributed energy production by exploring the possibilities of trading not only electricity but also heat.

Heat trade simulations were done for a limited population of buildings connected to the district heating network in a small town Kaskinen in western Finland. Simulations were designed to answer the question whether the town could be self-sufficient in terms of heat or electricity production, could the community sell out some heat or electricity or did it need to buy from the centralised energy production. Analysis showed that when the degree of decentralisation was lower, the system naturally needed more heat from the centralised production. An optimum solution was found regarding the amount and placement of the micro-CHP plants in different types of buildings. Our limited simulations showed that heat trading theoretically could be a functional way to develop decentralised energy systems. There is a potential advantage to be utilised when buildings with consumption profiles different in shape and/or timing are connected through a district heating network.

We also checked the hydraulic performance of the district heating network to make sure that there are no any network based restrictions for the heat trade. Typically the network places two different types of constraints: (1) pressure constraints and (2) temperature change constraints. The pressure constraint refers to the fact that the maximum pressure that the feed pipes can withstand is finite. New producers can change the geographical distribution of production so that distribution is no longer possible without exceeding the maximum pressure. It is also possible that the pressure in some return pipe becomes so low that evaporation takes place on the suction side of a pump. Whatever situation may occur depends on the average pressure of the network and the producer's location and current running mode (purchase or sell). The temperature change constraint refers to the fact that the time derivative of temperature in a certain pipe should not exceed a given limit value. This value is usually taken as ten degrees per hour. The reason behind this is that the heat expansion places a stress on pipes and joints. From the technical point of view, selling of the heat to the network did not cause a problem. Only the temperature changes were larger compared with the traditional centralised system when micro-CHP's were on. Small producers brought more time-varying factors into the system. They can create additional changing low-flow connections in their vicinity. It was seen that small producers have quite little effect on network pressures.

The four different physical connection types for the small scale producer in the building level were studied and the recommended connection version was found. When a connection of micro-CHP unit or boiler and its possibility to sell heat are considered, some technical boundary conditions of the hydraulic system (= district heating network + building-side network) should be taken care of. There are several boundary conditions, some of them even conflicting with each other. The physical connection should be

- safe to the end user
- cost efficient
- hydraulically stable (e.g. no pressure shocks to either side of networks)
- easy to install to the existing DH-systems e.g. for renovations
- easy to control, e.g. its temperature control should be stable
- commercially reliable, e.g. dividing the selling and purchasing parts of the energy at the measurement level should be accurate and easy
- able to change automatically the selling or buying mode.

The recommended physical connection version is type 3, in which the small scale producer is connected to the DH-network via a heat exchanger. This connection has advantages compared with the other versions: it does not bring any changes to the standard modular substation unit in buildings, it is safe solution to the user (no water leaks) and to the DH network (no gas leak problems), it is easy to control, it is suitable for new installations and renovations, and maintenance of the CHP unit does not cause any problems to the DH operation.

In general, we found out that the physical connection will need standardized rules, in which the quality and the performance of the connection unit are unambiguous defined, in the same way as the current Finnish District Heating Associations' guidelines do for the district heating substations. However, these new building level guidelines of the small scale producer were not defined in this study.

Real option analysis is adopted to evaluate the risks of investment when electricity price and heat price are uncertain. Real options analysis is not an equation or a set of equations. It is both an analytical process as well as a decision analysis thought process. It can even be said that half of the value of real options is simply thinking about it. The other half of the value is split equally between the two: first, model definition and getting the right numbers; and second, explaining the results and insights so that the optimal decisions can and will be made when it is appropriate to do so.

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Title
Technical features for heat trade in distributed energy generation

Abstract

Liberated heat market works mainly like a liberated electric market in Nordic countries with the exception that heat market works within a local district heating network. There are producers, customers, a network operator and a system operator as there exist in the electric market. Physical actors are the traditional large scale producers that sell heat to customers connected to the district heating network, and the end users, that would also be small-scale producers using a micro-CHP or a boiler. They would buy heat from other producers or sell heat to customers through the network. The liberated heat energy market will also need the transmission-network-company that takes care of the temperatures, pressures and hydraulic balance of the heating network. A balance-sheet-operator is also needed to coordinate the heat contracts between producers and customers as well as to take care of reserve capacity, spot and future markets and billing.

The requirements for the district heating network design in the heat trading context are an aspect that still requires further attention. Our simulations showed that temperature changes were occasionally quite rapid in some parts of the network. They were caused by stagnation of flow in some loops of the network, where flows come from different directions. Small producers seem to bring more time-varying factors into the system. This might lead to a new district heating network design approach where temperature variations can be minimized.

The four different physical connection types for the small scale producer in the building side were studied and the recommended connection version was found. The recommended connection version is type 3, in which the small scale producer is connected to the DH-network via heat exchanger. This connection has advantages compared to the other versions: it does not bring any changes to the standard modular substation unit in buildings, it is a safe solution to the user (no water leaks) and to the DH network (no gas leak problems), it is easy to control, it is suitable for new installations and renovations, and maintenance of the CHP unit does not cause any problems to the DH operation. In general, we found out that the physical connection will need standardized rules, in which the quality and the performance of the connection unit are unambiguously defined, same way as the current Finnish Energy Industries/District Heating Department's (earlier Finnish District Heating Association) guidelines do for the district heating substations. However, these new building level guidelines of the small scale producer were not defined in this study.

Real option analysis is adopted to evaluate the risks of investment when electricity price and heat price are uncertain.

Keywords
energy production, heat markets, heat trade, district heating, combined heat and power, CHP, distributed energy, simulation, network operators, district heating networks

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Lämpökaupan tekniset ratkaisut hajautetussa energian tuotannossa

Tiivistelmä

Vapaa lämpökauppa toimii samalla periaatteella kuin pohjoismainen vapaa sähkökauppakin. Vapaa lämpökauppa toimii kuitenkin paikallisesti kaukolämpöverkon vaikutuspiirissä, jossa toimivat tuottajat, kuluttajat, verkko-operaattori ja tasevastaava, kuten sähkömarkkinoillakin. Kaukolämpöverkossa toimivat suuret tuottajat, kuten ennenkin, ja kuluttajat, jotka voivat toimia pieninä tuottajina mikro-CHP:n tai kattilan ylijäämälämmöllä. Kuluttajat voivat vapaasti valita lämmön toimittajansa sopimuksella. Verkon toimintaa hoitaa verkko-operaattori, joka vastaa verkon ylläpidosta: lämpötilasta, paineesta ja verkon hydraulisesta tasapainosta. Taseoperaattori vastaa tuottajien ja kuluttajien välisistä lämpösopimuksista, reservikapasiteetista, spot- ja futuurimarkkinoista sekä laskutuksesta.

Simulointilaskelmat osoittivat, että lämpökauppa voi aiheuttaa nopeita lämpötilan muutoksia verkon joissakin osissa. Lämpökaupan seurauksena myös virtaukset voivat pysähtyä joissakin verkon osissa ja vaihtaa suuntaa, mistä voi seurata nopeita lämpötilan ja paineen vaihteluita verkossa. Lämpöverkon vapauttaminen saattaa asettaa verkon suunnittelulle uusia vaatimuksia, jotta kaikki kuormitustilanteet pystytään hallitsemaan.

Projektissa tutkittiin myös neljä erilaista pientuottajan kytkentävaihtoehtoa verkkoon. Suositeltavin kytkentä oli lämmönsiirtimellä toteutettu vaihtoehto. Vaihtoehto on nykyisen modulaarisen lämmönjakokeskuksen kaltainen. Se on turvallinen niin tuottajan kuin verkko-operaattorin kannalta, helposti säädettävä ja sopii sekä uudistuotantoon että saneerauksiin. Kytkentämoduulille tarvitaan selkeät tekniset ja laadulliset vaatimukset nykyisen kaukolämmönjakokeskuksen tavoin.

Investointien riskien hallintaa sähkön ja lämmön hintaepävarmuuden vallitessa käsiteltiin reaalioptioanalyysimenetelmällä.

Avainsanat
energy production, heat markets, heat trade, district heating, combined heat and power, CHP, distributed energy, simulation, network operators, district heating networks

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The liberated heat market works locally mainly like a liberated electric market in Nordic countries. There are producers, customers, network operator and system operator as there exist in electric market. The liberated heat energy market will need the transmission-network-company – separated from the production – that takes care of the temperatures, pressures and hydraulic balance of the heating network.

The district heating network design in the heat trading context requires further attention. Simulations showed that temperature changes were occasionally quite rapid in some parts of the network. They were caused by stagnation of flow in some loops of the network, where flows come from different directions. This might lead to a new district heating network design approach where temperature variations can be minimized.

Among four different physical connection types for the small scale producer was recommended the connection, where the small scale producer is connected to the DH-network via heat exchanger. The physical connection will need standardized rules, in which the quality and the performance of the connection unit are unambiguous defined in the same way like for the district heating substations.

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