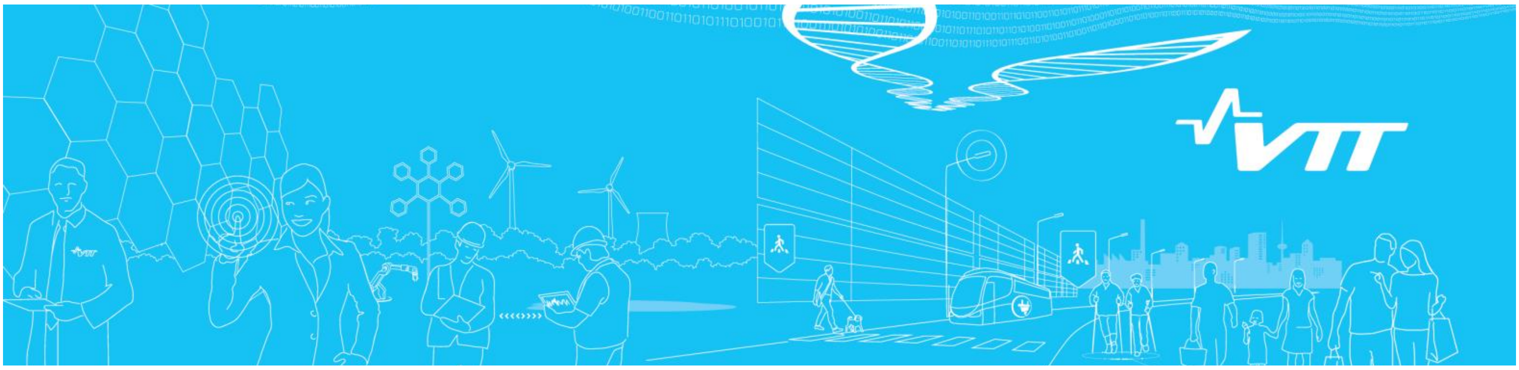

RESEARCH REPORT

ENERGINORGE 387-2015
VTT-R-00587-15

Nordic heating technology solution pathways

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Summary

The report presents the results of a sub-study of district heat production technology development for the Norwegian Flexelterm research program. The objective is to describe potential and likely technology changes on the production side, including storages, in the next 20-30 years that can affect the role of district and area heating systems in the Nordic countries Norway, Sweden, Denmark and Finland. As the Nordic countries are quite different and have their own idiosyncrasies, a short overview of each of them is given.

Heating network system developments can and do affect how and when district heat is produced and by whom. Technological aspects such as heat storages and low temperature networks are looked at. The main focus, however, concerns heat production technologies on a district and area heating scale from renewable energy sources, primarily biomass and heat pumps, but also other technologies such as solar and deep geothermal heat. Quantitative estimates of energy efficiencies and investment costs are the primary target. Whereas a multitude of references for the cost items and efficiencies power production are to be found, detailed estimates for combined heat and power or heat-only boilers are much harder to come by.

Technology changes are to be expected, but they are not only technology or cost driven but, more often than not, politically driven. What is more, there is often not just one district heating technology that dominates, but a multitude, and each Nordic country will favour some more than others because of local conditions, market structure and historical development.

Bio-CHP will increase either through the market or by political push. Also, all kinds of distributed generation and area networks are expected to increase in locations where the prices of heat and/or electricity are high, such as Denmark.

Confidentiality	Public

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Preface

The report presents the results of a sub-study of district heat production technology development for the Norwegian Flexelterm research program, here represented by Erik Trømborg from the Institutt for naturforvaltning, NMBU, via EnergiNorge, represented by Solgun Furnes. This VTT research report 00587-15 is published in the EnergiNorge publication series with the number 387-2015.

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29.3.2015

Göran Koreneff

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Abbreviations

BFB	Bubbling fluidised bed
BTES	Borehole thermal energy storage
CCGT	Combined cycle gas turbine
CCS	Carbon capture and storage
CFB	Circulating fluidised bed
CHP	Combined heat and power
COP	Coefficient of performance
CSP	Concentrating solar [thermal] power
DH	District heating
ETS	European trade system
EUA	Emission unit allowances
ICE	Internal combustion engine
IED	EU Industrial emissions directive
IGCC	Integrated gasification combined cycle
MCP	Medium-sized combustion plant
MW	Megawatt
MSW	Municipal solid waste
ORC	Organic ranking cycle
PEMFC	Proton exchange membrane fuel cell
RDF	Refuse-derived fuel
RES	Renewable energy sources
RES-E	Electricity from renewable energy sources
SOFC	Solid oxide fuel cell
SPF	Seasonal performance factor
UTES	Underground thermal energy storages

1. Introduction

1.1 Research target: foreseeable changes in Nordic heat network related technologies

The objective is to describe potential and likely technology changes on the production side, including storages, in the next 20–30 years that can affect the role of district and area heating systems in the Nordic countries Norway, Sweden, Denmark and Finland.

As these findings are going to be used in energy models such as Balmorel, quantitative estimates of energy efficiencies and investment costs, where available, are the primary target. The main areas of interest are biomass and CHP, heat pumps and thermal storages. Fossil technologies are not of interest.

1.2 Research outline

As the Nordic countries are quite different and have their own idiosyncrasies, a short overview of them is given. Finland, Sweden and Denmark have strong DH penetrations in urban areas and the focus is on them, especially as the recipient of the report has a much better knowledge of the Norwegian situation. Some trends are visible while some future trends can be anticipated based on the knowledge of the current situation.

Heating network system developments can and do affect how and when district heat is produced and by whom. More technological aspects thereof are looked at here: heat storages and low temperature networks.

The main focus, however, is on heat production technologies from renewable energy sources, primarily biomass and heat pumps, on a district and area heating scale. Other technologies such as solar and deep geothermal heat are also studied, but not as intensely.

Generally used sources such as the International Energy Agency (IEA 2010), the International Renewable Energy Agency (IRENA 2015), the Annual Energy Outlook of the US Energy Information Administration (EIA AEO 2014) and the World energy council (WEC 2013) were studied, but they are mainly concerned with the costs of power generation. Where CHP is included, not enough information is given about the plants and what is included in the costs and the overall level of detail is not is not good enough for the target here.

1.3 Limitations to the research scope

District heating (DH) is here understood to mean larger heating systems involving more than a handful of end-users. District heating systems exist in most larger Nordic cities and also in many smaller municipalities. Area heating is in this report seen as very small and local district heating systems with an annual demand of at least 1 GWh. Micro-scale CHP and boilers are outside the scope of this study.

District and area heating will be affected by technology developments on the end-user side. One of the main factors already eating away at DH demand is the increased use of heat pumps, not only in DH houses but also as a means of switching away from DH. With new low-energy building codes coming into effect in 2020 in the EU, the heat demand is much lower in new houses, which means that low investment cost solutions are strong contenders. Other technological advancements concern auxiliary heating sources, for example solar thermal collectors, and comfort heating sources such as electric floor heating, for example in bathrooms. End-user technologies are not part of this study.

Industrial heat production is not part of this study. As fossil based technologies are on their way out in Europe and in the Nordic countries, almost no focus is put on them either.

2. Status quo of area/district heating systems in Nordic countries

District heating has a strong market position in Denmark, Sweden and Finland, and generally it will remain so, but the demand for DH will start to decrease towards 2030–2050. Current customers will mostly remain; however, their loads may change in line with energy efficiency improvements in both old and new houses, both in terms of insulation and reuse of heat, and the increased use of air heat pumps, secondary electric heating (bathroom floors, incoming air preheater) or solar heating as auxiliary heat sources.

DH will retain one of its most competitive features for the customer: it is a very carefree heat supply. DH is also able to utilise different fuels and production modes such as CHP and boilers, industrial or tertiary (i.e. service) sector waste heat sources, and heat from waste making it very competitive locally. Although end-users have the possibility to have CHP themselves, the costs of micro- or mini-scale CHPs are much higher than those of DH-sized units.

The prospects for DH systems differ country by country. Taxation and subsidies play a big role in the formation of the prospects, but all kind of regulations, political decisions on EU, national or regional levels, and local market aspects are also strongly involved. In Finland, a possible future EU-based change in the renewable energy status of forest residues and difficulties in getting licenses for new peat production areas might affect the profitability of most inland DH networks, as they are more and more relying on peat and local forest-based biomass. In Sweden (and to a small degree in Finland), high DH prices in some networks are already driving end-users to switch to heat pumps.

CHP itself is already an important factor in the Nordic power system. Figure 1 shows the share of CHP of the gross electricity production in each of the countries. Denmark has the highest share followed by Finland, where, however, almost as much electricity is received from industrial CHPs as from DH CHPs. The share of CHP is increasing, especially thanks to green certificates. The importance of CHPs for Norway’s electricity production is almost negligible.

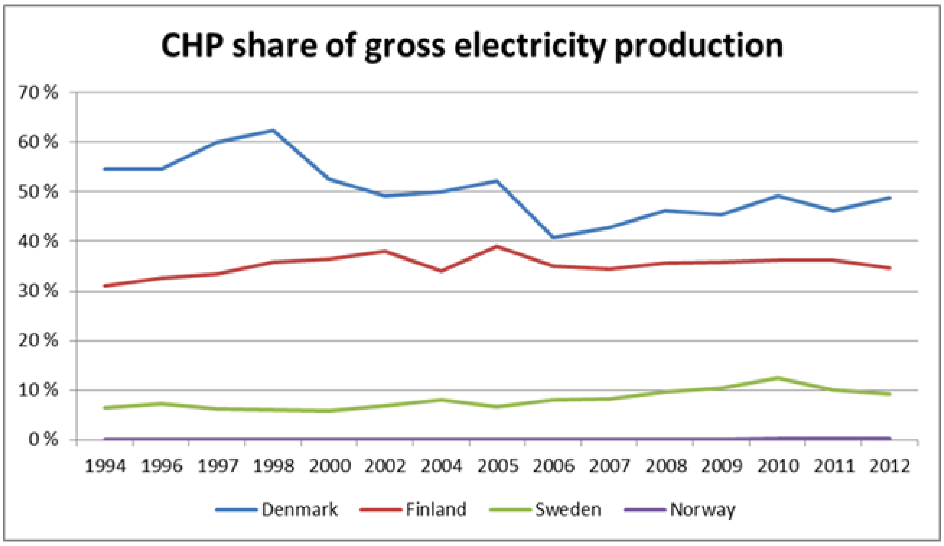


Figure 1. The share of CHP of gross electricity production in the Nordic countries.(Data source: Eurostat 2014)

VTT uses a global model, TIMES-VTT[1], to assess, among other things, the developments in the heating sector in the Nordic countries. The TIMES-VTT model is a partial equilibrium model of the global energy system based on linear optimization. Assuming efficient markets and perfect foresight, the model calculates a market equilibrium solution through cost minimisation for energy production, conversion and end-use under specified energy demand projections, technology assumptions and policies (e.g. targets for emissions levels or global temperature). This is done on a global scale using 15 areas, where each of the Nordic countries of this study comprises one area. The model base year is 2005 and the results are calibrated for the year 2010 using mainly IEA statistics[2] (see e.g. IEA 2015). The calibration itself was not part of this study. Even though the target is to have the results match the realised data, there will be discrepancies. All individual results will not exactly match the statistics; especially this is noteworthy for the relatively small Norwegian district heating sector. And there are classification differences between the model and the statistics, for example for industrial and district heat, especially if compared to statistics other than those from the IEA. The model results for Finland have been calibrated extensively, also using national sources; this is less the case for the other countries. The EU 20-20-20 targets as well as the EU 2030 targets will be met. For EU countries this means that the national renewable energy targets as well as the greenhouse gas targets for the non-trade sectors will be met. Norwegian and Swedish electricity certificate targets will also be met. The greenhouse targets of the emission trading system will also be met. Figure 2 shows how the division (bioenergy, oil and gas, district heat, electricity and other) of the final energy for heating is estimated to develop from 2010 to 2050 in 10 year steps according to TIMES-VTT. The overall heating demand is estimated to decrease by nearly 40%, but district heating will remain a strong competitor.

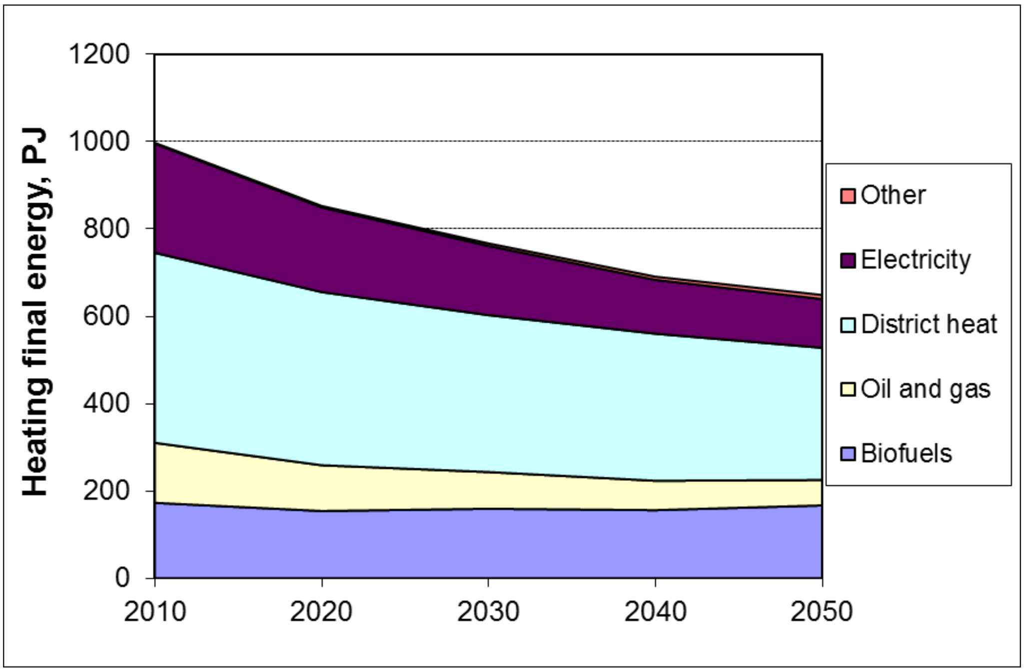


Figure 2. Estimated heating development in the Nordic countries 2010–2050 according to TIMES-VTT.

[1] The TIMES-VTT energy system model is based on the TIMES energy system modelling framework developed under the IEA Energy Technology Systems Analysis Programme (ETSAP) and the global ETSAP-TIAM model (Loulou et al. 2005, Loulou & Labriet 2007).
[2] IEA energy statistics differ from Eurostat statistics, which in turn differ from national statistics, and one of the main differences is how industrial CHP is handled and the fuels allocated. IEA statistics are usually delivered by national statistics bureaus just as EU statistics and national statistics.

Energy efficiency development of the building sectors, that is the change in the specific heat demand, in the Nordic countries is expected to follow the separately modelled Finnish rate. The building volume itself is dependent on the population growth.

2.1 Sweden

2.1.1 Status quo and idiosyncrasies

District heating is very popular and widespread in Sweden. According to Eurostat (2014), derived heat (here district heating) net production was 54.6 TWh and final consumption 52.3 TWh in 2012.

Most of the DH came from thermal power plants, 49.0 TWh, including 5.2 TWh from flue gas condensation. Heat pumps delivered 5.8 TWh and electric boilers 0.2 TWh. Waste heat from industry is 4.8 TWh, bringing the total production up to 59.8 TWh, a higher value than Eurostat gave. (SCB 2013)

It appears that heat from flue gas condensation is not included in the Eurostat statistics, which therefore also give delivery losses of only 2.2 TWh.

CHP production, of which over 70% is bio-CHP (IEA 2011), in DH networks is a very recent development. There was no need for CHP electricity as Sweden had ample nuclear and hydro based production, but with an open Nordic market and the introduction of green certificates,[3] CHP and especially bio/waste-CHP has been successful. Waste accounted for about 10 TWh of DH heat (Eurostat 2014). The gas network is very restricted in Sweden and comprises only the South-West coastal area with, e.g., Malmö and Gothenburg. The only (deep) geothermal heat is utilised at Lund,[4] where 20 °C lukewarm water is pumped up from a depth of 700 meters and then used as input for heat pumps. There are also DH market developments; for example, as of 2012 Stockholm has opened a heat test market, where large end-users, e.g. stores and server halls, can deliver excess heat to the network.

The division of heating sources for residential and tertiary sectors between 2000 and 2012 are presented in Figure 3. The market share of DH is constantly increasing in both sectors at the expense of oil heating. The DH market share is strong in the tertiary sector (the service sector is usually located in cities and local centres). That said, district heating is facing tough competition in some networks. Energy component based tariffs can be seen as expensive and end-users have started to convert from DH to ground source or to install auxiliary air/air heat pumps.

[3] Peat is also eligible for green certificates in Sweden.
[4] http://www.kraftringen.se/Om-Kraftringen/Hallbarhet/Nagra-exempel-ur-var-hallbarhetsresa/Geotermi/

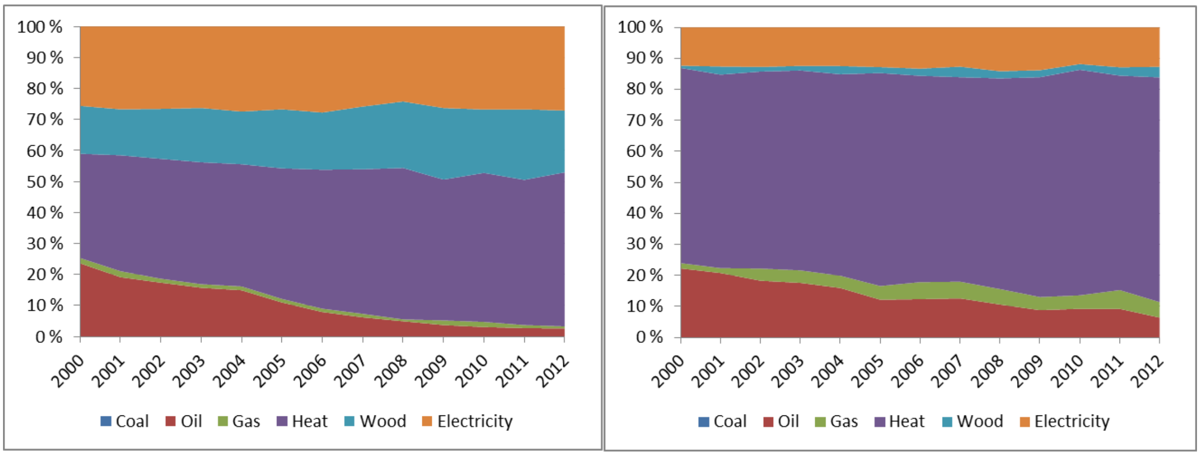


Figure 3. Residential (left) and tertiary sector heat sources in Sweden 2000–2012. Here heat stands for purchased heat, i.e. district or area heat. Data source: Enerdata 2014.

2.1.2 Assessment of future heat production by technology

According to TIMES-VTT results, see Figure 4, DH is estimated to decrease towards 2050. CHP production is also estimated to decrease in the next five years. The reason is that the increase of hydro, wind and nuclear capacity in the Nordic countries up to 2020 is diminishing the need for CHP produced electricity.

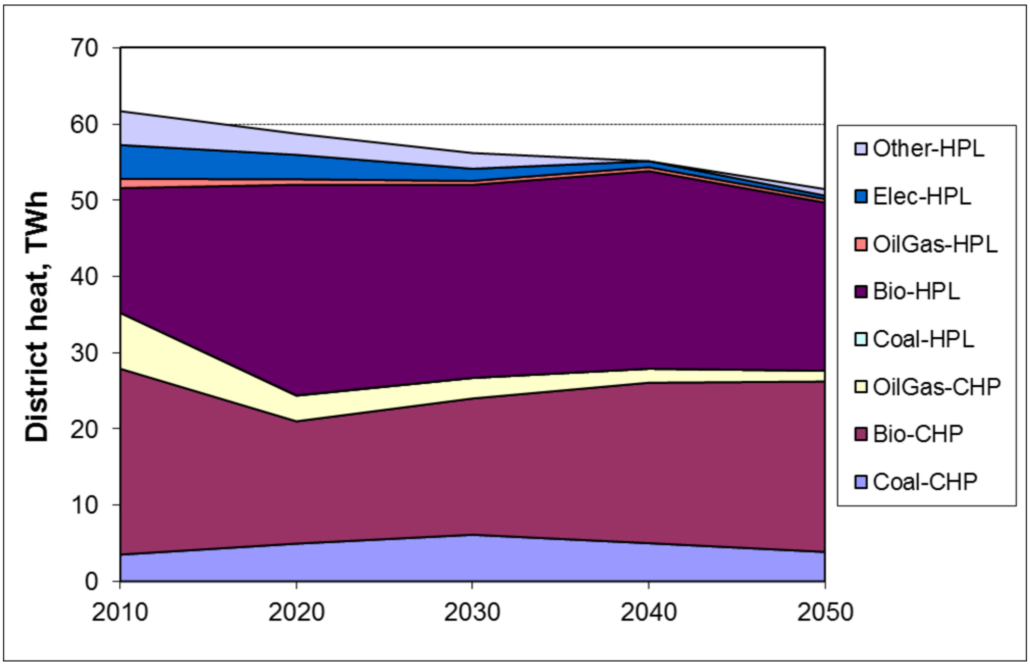


Figure 4. Assessment of the development of DH in Sweden by TIMES-VTT. HPL stands for heat-only boiler. Bio includes waste, coal includes peat and elec(tricity) includes heat pumps.

2.2 Denmark

2.2.1 Status quo and idiosyncrasies

District heating is very popular and widespread in Denmark. According to Eurostat (2014), derived heat (here district heating) net production was 36.8 TWh and final consumption 30.0 TWh in 2012.

Most of the DH came from CHP plants, 27.5 TWh. As for energy sources, nearly 7 TWh was from waste, 11 TWh from solid biofuels (mainly straw), 9 TWh from both coal and natural gas. (Eurostat 2014)

The large coal CHP units in Denmark are traditional condensing power plants that have been converted to extraction power plants by law and their main task is still the production of electricity, which is why electricity from CHP plants is only partly CHP electricity; otherwise it is condensing power production. If the old extraction units are far away from the actual heat consumption, heat can be transferred to the DH networks through high temperature (e.g. 120 °C) pipes.

The division of heating sources for residential and tertiary sectors between 2000 and 2012 is presented in Figure 5. The market share of DH is slowly increasing in both sectors at the expense of oil heating although biomass is showing a much stronger increase in the residential sector. The DH market share is strong in the tertiary sector (the service sector is usually located in cities and local centres).

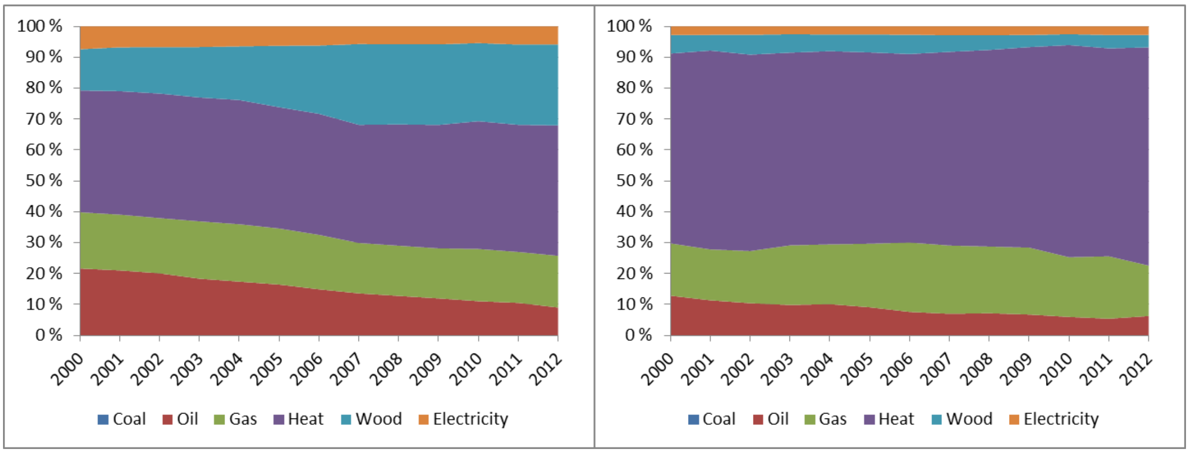


Figure 5. Residential (left) and tertiary sector (right) heat sources in Denmark 2000–2012. Here heat stands for purchased heat, i.e. district or area heat. Data source: Enerdata 2014.

2.2.2 Assessment of future heat production by technology

According to TIMES-VTT results, see Figure 6, DH is estimated to decrease. CHP production is also estimated to decrease in the next five years before increasing again. The reason is that the increase of hydro, wind and nuclear capacity in the Nordic countries up to 2020 is diminishing the need for CHP produced electricity.

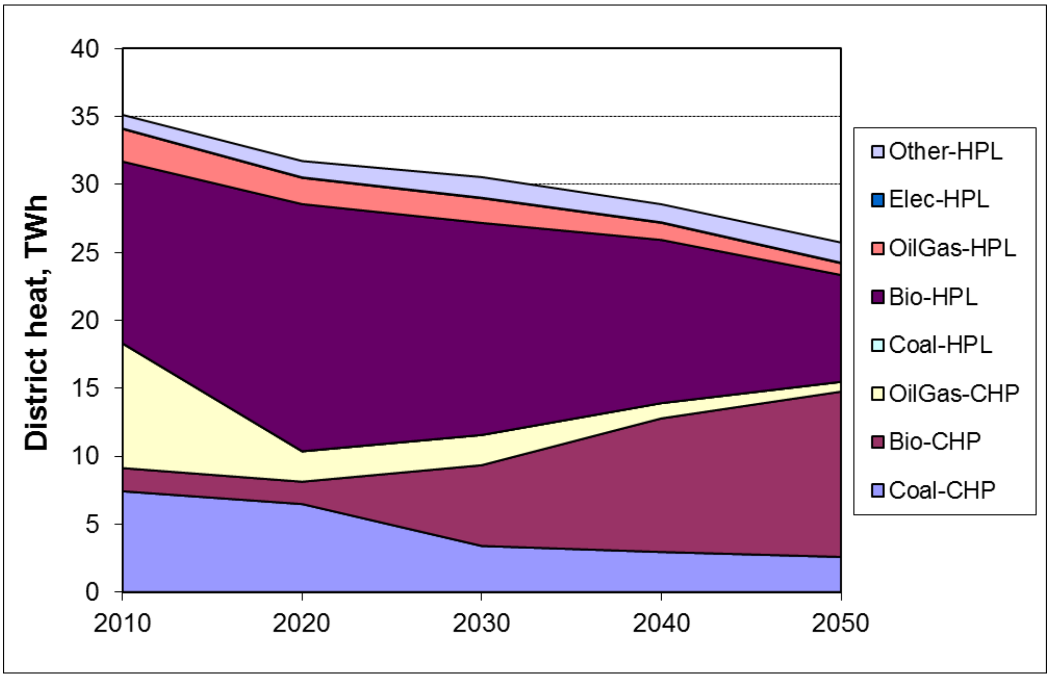


Figure 6. Assessment of the development of DH in Denmark by TIMES-VTT. HPL stands for heat-only boiler. Bio includes waste, coal includes peat and elec(tricity) includes heat pumps.

The market share (based on floor area) of DH is expected to keep rising, see Figure 7, as is the floor area. Small scale district heating, or area heating as we have used in this report, is expected to grow from 2015 onwards but the share will remain low. Energy efficiency improvements make the TIMES-VTT heat demand decrease scenario plausible even if the building stock is expanding. As Denmark is planning to have half the country's power production come from wind in the near future, the balancing of the power system becomes more and more crucial. District heating with CHP, electric boilers and heat pumps as well as heat storages will be essential in that task.

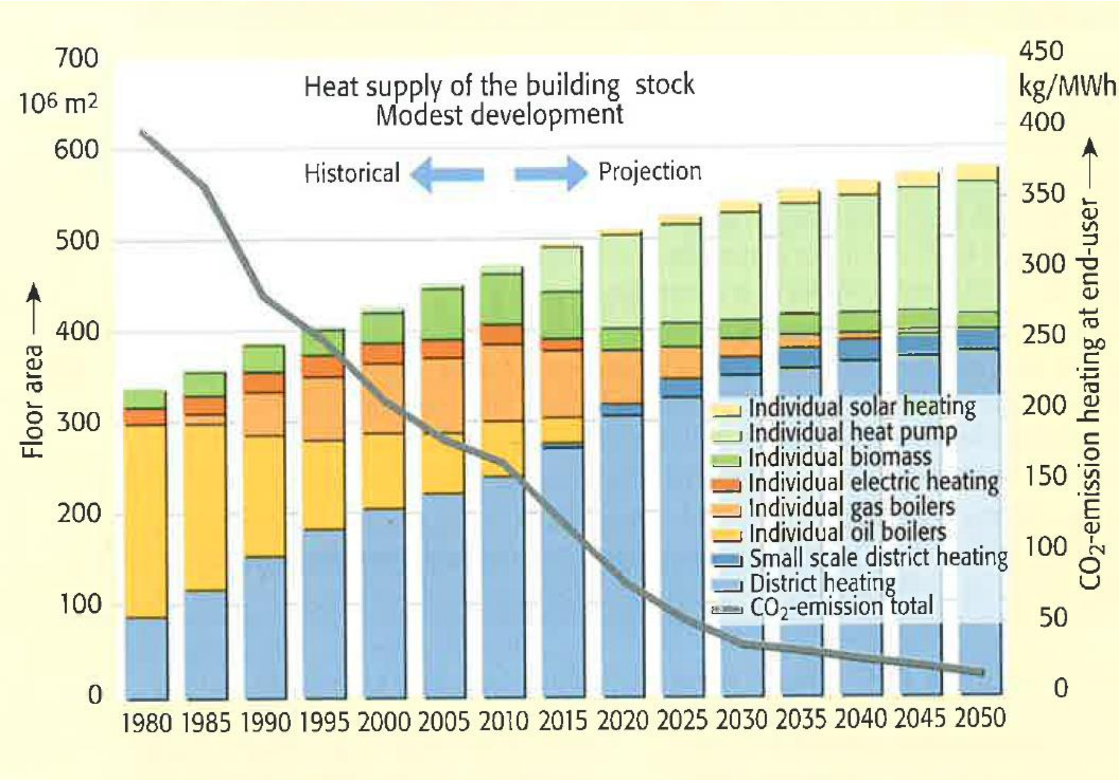


Figure 7. The market share of heating sources for the floor area of the Danish building stock 1980-2050 according to a strategic study by Aalborg University and Ramboll. (Source: EuroHeat&Power 2012b)

As Denmark has high electricity and DH prices, alternative renewable energy based DH solutions such as geothermal or solar heat are quite popular.

The deeper geothermal resources in Denmark are mainly located in to two deep, low-enthalpy sedimentary basins, the Norwegian–Danish Basin and the North German Basin. Comprehensive research based on seismic and well data, primarily from previous hydrocarbon exploration campaigns, has shown that the fill of the Norwegian–Danish Basin contains several formations with sandstones of sufficient quality and temperature to serve as geothermal reservoirs. However, Denmark has no pronounced high-temperature hot spot areas (Mahler et al. 2013).

With current technology and cost levels, geothermal deep heat has good potential mainly in Aalborg, but all of Denmark is full of potential, but low enthalpy, geothermal heat resources as can be seen in Figure 8.

In Denmark there are three geothermal heat plants supplying DH networks: in Copenhagen Margretheholm, Thisted and the most recent in Sønderborg. More than 10 geothermal DH plants are planned to be built including an installation in Greater Copenhagen with expected capacity of 65 MW_{th}. (Geo DH 2014a)

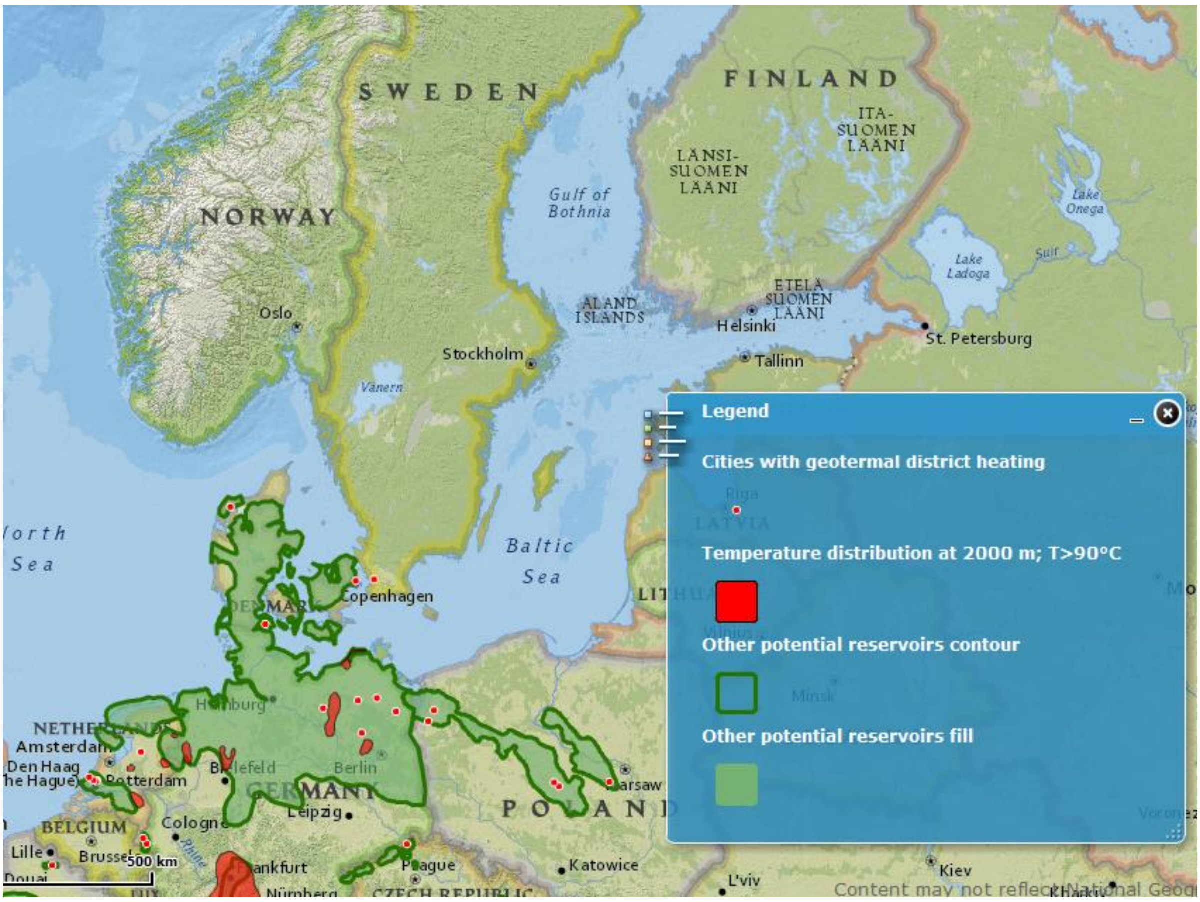


Figure 8. Deep geothermal heat sources according to EU project Geo DH Europe (GeoDH 2013, 2014a). Red areas have temperatures above 90 °C at 2 000 m depth and green areas have other reservoir potentials. Red spots indicate DH networks using geothermal heat. Source: Interactive map at http://loczy.mfgi.hu/flexviewer/geo_dh/

Solar district or area heating is quite widespread in Denmark, see Figure 9. Solar is stored in seasonal heat storages, i.e. borehole clusters and pit storages. Denmark has also what it calls smart district heating consisting of solar collectors, heat storages, heat pumps and CHP.

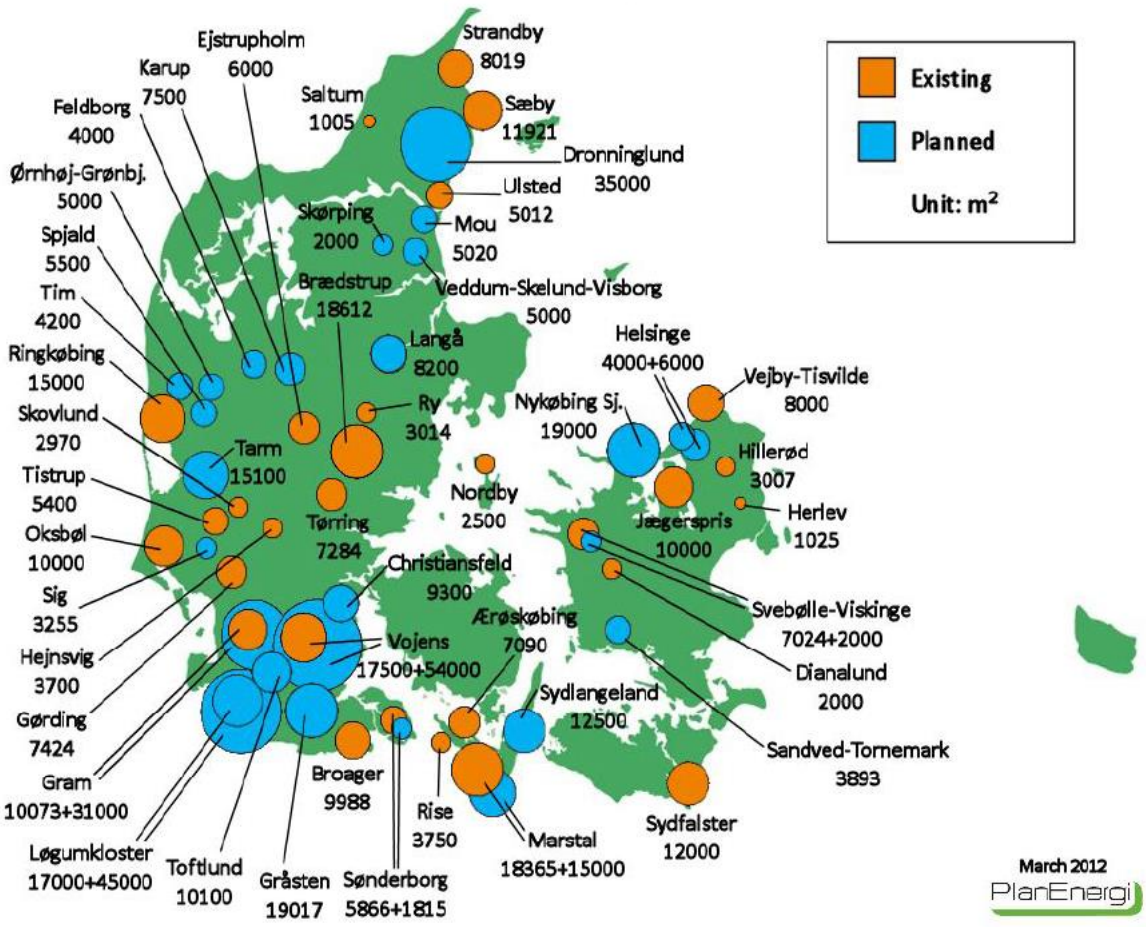


Figure 9. Existing and planned solar district heating in Denmark (Source: EuroHeat&Power 2012a)

2.3 Finland

2.3.1 Status quo and idiosyncrasies

District heating is very popular and widespread in Finland. According to Eurostat (2014), derived heat (here a large chunk not district heating) net production was 54.5 TWh and final consumption 49.8 TWh in 2012. As derived heat means heat produced and sold, this can also include industrial CHP, if the owner of the production facility is not the industry partner. Several CHPs produce both DH and industrial steam.

The actual production and consumption of DH in Finland in 2012 was 37.1 TWh and 34.0 TWh, respectively. Of the production, 69.2%, less than normal, was CHP production and the main fuels were natural gas (27%), coal (25%), peat (16%) and forest wood (14%). There are 168 towns with district heating included in the statistics and 66 DH CHP plants. (Energiateollisuus 2013)

Most of the DH production takes place in large fossil fuel fired backpressure CHP units in cities, but on the other hand, the main fuel in most DH networks is wood and other biofuels, followed by peat. More rural or smaller DH networks find it easier to fulfil their heat needs with local forest wood and peat while cities generally depend on fossil fuels. The gas network comprises only the Southern part of Finland. Aside from a few exceptions, MSW boilers are a very recent phenomena in Finland.

The division of heating sources for residential and tertiary sectors between 2000 and 2012 is presented in Figure 10. The market share of DH in the residential sector has been quite constant, where wood and electricity (including heat pumps) have increased their share. The market share of DH in the tertiary sector has a growing trend.

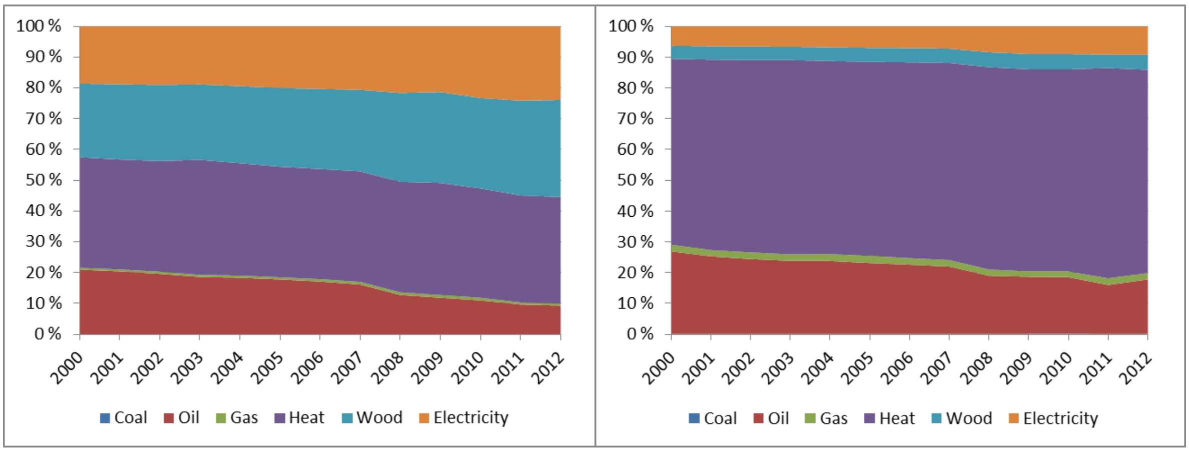


Figure 10. Residential (left) and tertiary sector (right) heat sources in Finland 2000–2012. Here heat stands for purchased heat, i.e. district or area heat. Data source: Enerdata 2014.

2.3.2 Assessment of future heat production by technology

According to TIMES-VTT results, see Figure 11, DH as a whole and CHP heat are estimated to decrease towards 2050. Heat from bio-CHP is expected to increase towards 2050 and heat from bio heat-only boilers is expected to increase towards 2040. The use of gas for heating is expected to decrease.

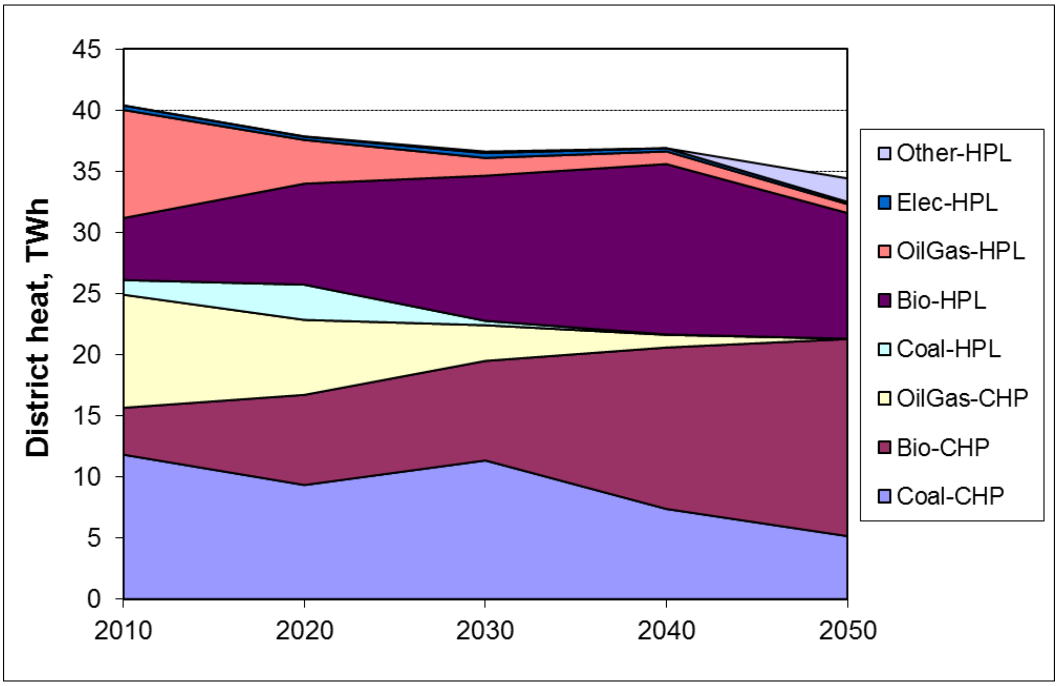


Figure 11. Assessment of the development of DH in Finland by TIMES-VTT. HPL stands for heat-only boiler. Bio includes waste, coal includes peat and elec(tricity) includes heat pumps.

The general political target in Finland is to reduce the use of coal dramatically the next ten years. The local politicians in Helsinki, for example, are planning either to convert existing coal CHPs to use 40% pellets/torrefied biomass, to demolish them and build a new multi-fuel power plant, or to gasify biomass at the source and use the gas network to transport the gas to Helsinki. The effect on EU greenhouse gas emissions is null, as the freed emission rights will then be used elsewhere, making citizens of Helsinki pay for hot air.

As for peat, it is partly recognised as a worse greenhouse gas fuel than coal, but on the other hand, peat is domestic and thus strengthens the Finnish self-sufficiency. Peat is also an important factor in increasing biomass use for power and heat.

DH producers pay fuel taxes for heat produced from fossil fuels but do also have to buy CO_2 emission allowances if the DH network exceeds 20 MW, raising the cost of DH and diminishing its competitiveness.

The potential increase in the use of forest wood (mostly stumps, tops, branches, small-dimensioned wood, fiber wood) in the production electricity and heat is estimated to be 14–19 TWh from 2012 to 2030 and to decrease a little after that, to 14–17 TWh, by 2050. The division between industrial and DH use is not given. (TEM 2014)

2.4 Norway

2.4.1 Status quo and idiosyncrasies

District heating is mostly small-scale in Norway. According to Eurostat (2014), derived heat (not all district heating) net production was 6.6 TWh and final consumption 4.4 TWh in 2012.

One third of the derived heat production came from waste CHP, over 10% from electric boilers and 6% from heat pumps. As for energy sources, waste stood for roughly half and solid biofuels for 13%. (Eurostat 2014)

The division of heating sources for residential and tertiary sectors between 2000 and 2012 are presented in Figure 12. The market share of DH, although low, is increasing in both sectors. Electricity is dominating heating in both sectors.

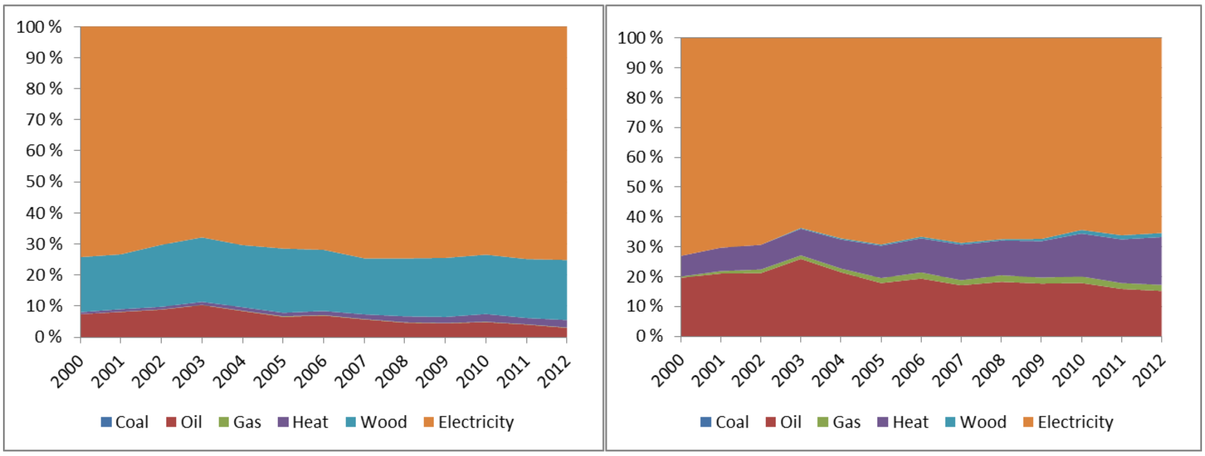


Figure 12. Residential (left) and tertiary sector (right) heat sources in Norway 2000–2012. Here heat stands for purchased heat, i.e. district or area heat. Data source: Enerdata 2014. As the source doesn't have statistics on electricity use for heating in Norway, it was assumed that heating comprises 80% of all residential electricity use and 50% of all service sector electricity use.

2.4.2 Assessment of future heat production by technology

District heat has grown substantially, see Figure 13, doubling between 2004 and 2013. NB: TIMES-VTT is calibrated according to IEA database (IEA 2015) and the IEA and Norwegian statistics differ too much for us to present TIMES-VTT results. In addition, TIMES-VTT model results for Norway have not been calibrated to match the expected steep population growth, which is one reason why the Norwegian results show a decline of DH similar to that of the other Nordic countries.

IEA is probably the only source which gives a reasonable trustworthy division of heat produced between CHP and heat-only boilers as well as between different fuel sources for derived heat production of nearly all the countries in the world, which is a necessity for a global model. National sources can give additional information, but in many cases it is not in a usable format. For example the Norwegian statistics (SSB 2015a,b) for 2010 give a much smaller heat production than IEA (2013) estimates (6183 GWh) with the specific district heat statistics (SSB 2015b) estimating a smaller heat production (4833 GWh) than the energy balances (SSB 2015a) reveal (5569 GWh). However, if we look at fuels used for gross DH production (SSB 2015c), we see that the total amount reaches 6162 GWh, quite close to the IEA value.

Norwegian national statistics do not include a division of heat production between CHP and heat-only boilers. The different statistics and VTT model results for 2010 are presented in Table 1 to help the reader comprehend the difficulties with using and choosing statistics. The IEA statistical ‘heat’ is diffuse for Norway, which is why there is no such DH production type in the model. The model fulfils the heat demand by increasing the oil & gas production instead.

Table 1. Derived heat production 2010 in Norway according IEA (IEA 2013) and Norway statistics (SSB 2015a, b, c) compared to TIMES-VTT results.

	TWh	Coal	Oil & gas	Bio & waste	Electri-city	Heat	Geoth., solar, ...	Total	Derived heat production	Comments
IEA	CHP	0.07		1.54	0.01	0.01		1.63	6.18	Energy balances of OECD countries (2013 edition)
	Heat-only	0.00	1.01	1.93	0.66	0.89	0.07	4.56		
VTT	CHP	0.01		0.98				0.99	5.85	Heat pumps electr. included in electricity. Chem. ind. heat for DH can't be modelled (=> Oil & gas)
	Heat-only	0.01	2.24	1.77	0.83			4.85		
Norway SSB Energy balance	CHP	(1.1)	(0.1)	(1.8)					5.57	NB! (Fuel use values). CHP also includes fuels for power. Inclusive district cooling ~0.1 TWh
	Heat-only		(1.1)	(2.2)	(0.8)					
Norway SSB DH	District heat		1.09	2.46	0.66	0.21	0.41 HP		4.83	DH net production. Heat pump (HP) and industrial waste heat (Heat) declared separately.
Norway SSB fuels for DH	District heat		1.16	3.96	0.84	0.20			6.16	Fuels used for gross DH production

CHP heat production is estimated to decrease in the next five years by TIMES-VTT before increasing again. The reason is that the increase of hydro, wind and nuclear capacity in the Nordic countries up to 2020 is keeping the market price down and thus diminishing the need for CHP produced electricity. The low market price of electricity can also affect the DH growth itself in the next five to ten years.

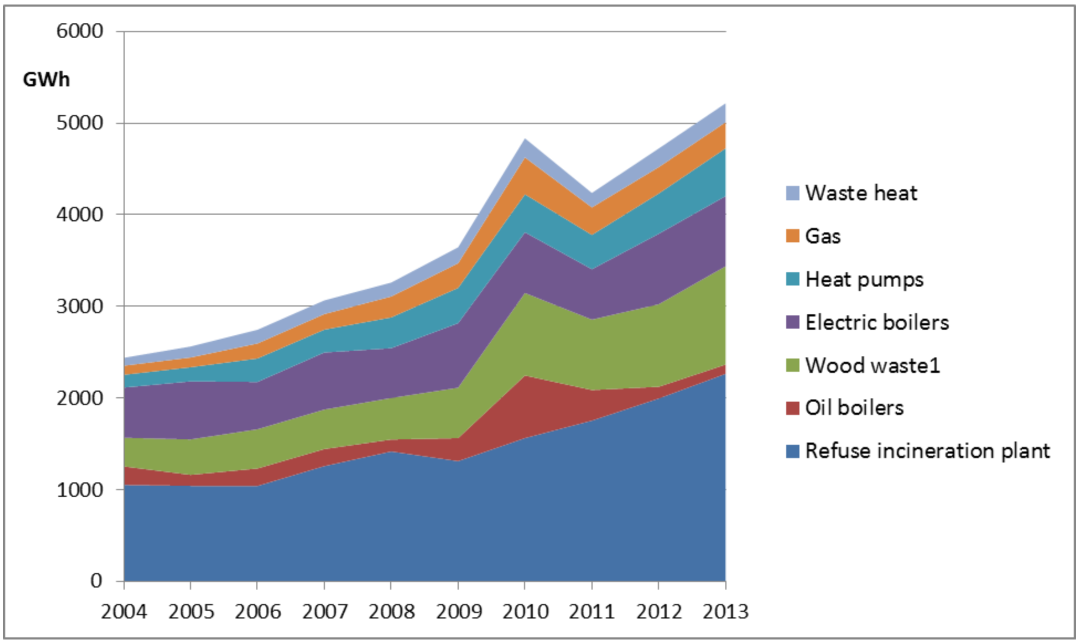


Figure 13. Net production 2004–2013.of district heating by type of heat central in Norway. Data source: SSB 2015b.

Conversion of existing buildings to DH can be expensive, as they do not necessarily have central heating but direct electric heating in the dwellings. New building sites are, on the other hand, easier, especially in dense and high constructions related to cities.

3. Network and system related technology changes

3.1 Heat storages

The system value of heat storages is increasing as power and heat systems are based more and more on renewables. Even though heat storage technologies are not expected to develop that much, increased use will be a driving force for technology development; however, as most heat storage technologies are mature, the technology development might not be that impactful.

3.1.1 Power/heat system related demands and possibilities for flexibility

The Nordic power system will see an increase in RES-E both as a result of EU RES and CO_2 mitigation targets. This means that intermittent power production such as wind power will also increase sharply in the next 20–30 years. Wind power alone might well surpass 30 GW, as the plans for the next ten years will bring the capacity to around 20 GW. Even as the transmission networks are strengthened, there will not be enough transmission network capacity to be fully able to utilise existing hydro reservoirs to balance the system. Energy storages are needed, but since electricity storages, hydrogen (or methane) power-to-gas and gas-to-power systems, and compressed air energy storages are and may remain very expensive (and with energy losses), heat storages, especially in connection with CHP power plants, electric boilers and/or district heating networks, form a competitive solution.

A CHP power plant can react to low electricity prices by reducing production. The desired heat can instead be produced by electric boilers or derived from heat storages. During times of high electricity market prices, CHP plants could increase their production, if they are not at maximum, and store the excess heat in heat storages for later use. This type of heat storage use for power system balancing is well suited for short term (hourly to daily to weekly) cycles and thus for wind and solar power intermittency. Heat storages are not a solution for seasonal variability of the power system, as they do not increase the electricity during the higher load times of winter.

District or area heat networks themselves have been using heat storages for decades. The most common way is to use a short-term storage, for example 10,000 m^3 of water, in the daily cycle to improve the efficiency of the heat production. The most profitable plants (CHP, solid fuel boilers) are often at their full capacity during daytime and the exceeding heat demand is produced using more expensive production forms. Using a heat storage, heat from the more cost efficient plant can be stored during the night, when the heat demand is lower, and retrieved during the day instead of using the more expensive heat production. The technology of these short-term cycle heat storages is ready and the expected improvements are small.

Seasonal heat storages have also been used for decades, but to a much smaller extent. Seasonality itself already implies that the amount of energy to be stored is huge and this, in turn, has implications for the size of the storage: it must be huge. The physical size sets restrictions on the usability: seasonal storages are not a solution for larger district heating networks, but can be very useful for smaller, e.g. Norwegian, area heating networks. For example, in Denmark, solar heating is utilised by seasonal storage of heat in large pit stores. Surplus heat from e.g. industry or waste incineration could be stored the same way. Seasonal storage is applicable also for individual smaller or larger users, especially if the storages also can be used for cooling during the summer. As seasonal storages are used in annual cycles, investment costs have to be very low per MWh storage capacity to be economical. Seasonal storages have often been related to aquifers, where the main cost is the drilling of a couple of boreholes. As aquifers can only be used where they exist, other more costly solutions such as borehole or pit storages are also used, especially where cheap usable heat sources can be found.

3.1.2 Heat storage technologies

Seasonal underground thermal energy storages (UTES) are typically cave or borehole cluster storages, where the losses minimise in 4–5 years as the storage surroundings get settled. These storages have high efficiencies, up to 90%. Aquifers can also be used as seasonal storages, although the non-existence of local aquifers restricts their wide spread use. Examples of UTES can be found in Akershus University Hospital (Norway) and Nydalen Industrial Park (Norway), and an aquifer based at Arlanda in Stockholm, Sweden. (IEA 2014).

The borehole thermal energy storage (BTES) system in Akershus consists of 228 borehole wells with depths of 200 metres and a 8 MW combined ground source heat pump and ammonia chiller; the total cost was 19.5 million USD. It supplies 85% of the total heating demand of the Baerum heating district. (IEA 2014)

The Nydalen Industrial Park BTES system has 180 boreholes (depth 200 m) and a series of ground source heat pumps, in total 6 MW heating and 0.5 MW cooling capacity to a total cost of 10.5 million USD. The system provides 80% of the heating for the area’s school campus, hotel and an assortment of residential and commercial buildings. (IEA 2014)

Pit storage systems use shallow pits, which are dug and filled with a suitable heating medium such as gravel and water. The pit is then isolated and covered. Water is pumped into and out of these pits to provide a heating or cooling resource. One example can be found in the Marstal district heating system in Denmark. The 75,000 m^3 pit storage had a cost goal of approximately 35 million USD. (IEA 2014)

The characteristics of a seasonal heat storage in water pits in Danish conditions are shown in Table 2.

The Heat Roadmap Europe 2050 (EuroPower&Heat 2012a) estimate of heat storage cost is presented in Table 3. The lifetime of the heat storage is 20 years. With this cost level, a once per year heating cycle would result in heat costs well above 100 €/MWh, even if the stored heat were free.

Table 2. Characteristics of a seasonal heat storage in water pits in Denmark. Source: Energistyrelsen 2012

Technology	Seasonal heat storage in water pits					
	2015	2020	2030	2050	Note	Ref
Energy/technical data						
Store volume (m3)	60000					
Storage capacity, kWh/m3	60-80					2
Efficiency, %	80-95				A	3
Construction time (years)	0.5	0.5	0.5	0.5		3
Technical lifetime (years)	20	20	20	20	B	3
Financial data						
Specific investment costs (€ per m3)	35	35	34	30	C	1;3;3;3
Electricity consumption (MWh/year)	40				D	3
O&M (% of investment per year)	0.7					3

References:

1 "Seasonal heat storages in district heating networks", Ellehauge & Kildemoes and Cowi, July 2007. A project (Preheat) funded by Intelligent Energy – Europe and the Danish systems operator

2 Dirk Mangold: "Seasonal Heat Storage. Pilot projects and experiences in Germany". Presentation at the PREHEAT Symposium at Intersolar 2007, Freiburg, Germany, June 2007.

3 Planenergi (Danish company; www.planenergi.dk), which in 2010 is installing a 60,000 m3 pit store in Northern Jutland.

Notes:

A The storage loss depends on several parameters, such as store volume, insulation, whether a heat pump is part of the system etc. The stated interval covers a large store, storage temperature 85-90 C, without (80%) and with (95%) a heatpump to discharge the store.

B The most critical part is the cover. The technical lifetime depends much on the water temperature. The lifetime of the store may be extended by reinvesting in a new cover.

C 2010: Budget cost for a 60,000 m3 pit. The cost development assumes a 10-20% reduction from 2020 to 2050, caused by replication of pits, pipes, pumps, heat exchangers and control system. For other store volumes, please refer to paragraph 'Additional remarks' above.

D Electricity for internal pumps etc. only. If a heat pump is used, the drive electricity shall be added.

E Cost data are the same as in the 2010 catalogue, however inflated from price level 2008 to 2011 by multiplying with a general inflation factor 1.053

Table 3. Costs of heat storage. Data source: EuroHeat&Power 2012a

Type	Investment costs €/MWh	Fixed O&M % of inv.
Heat storage	2700	0.7

Short term storages are typically hot water tanks operating in daily or weekly cycles. They have good efficiencies and the heat losses are around 1 °C per day.

Thermochemical heat storages have been on the agenda for decades. The idea is, for example, to transport excess industrial or power plant heat to suitable heat demands. As all transport costs depend on the energy densities, heat compression can improve competitiveness. Thermochemical storage uses reversible chemical reactions to store heat in the form of chemical compounds and which is then released in exothermic reactions. (IEA 2014)

Molten salt storages are mostly used in connection with concentrating solar power (CSP), where the superfluous heat is stored from day to night. Here the stored high temperature heat is in the form of molten salt, and it is used to produce high temperature steam that can be directly used to drive a steam turbine.

Aquifers, caves and borehole storages themselves will not change. As the storages are capital intensive and the capital expenditure is mainly drilling costs, any improvements in that sector are valuable. Drilling technology has seen great improvements in recent years in combination with fracking techniques, but for straightforward relatively shallow drilling there are no foreseeable technology changes. As for really deep drilling, going below 4,000 metres and more, the technology could be improved (see the Espoo case in Chapter 4.4.3).

Water tank technology will not change much. Large water tanks can be in steel or concrete. Steel is more economical and the characteristics of a steel tank heat storage are presented in Table 4. The specific costs decrease with increasing volume. (Energistyrelsen 2014)

Table 4. Characteristics of large steel tank for heat storage. Source: Energistyrelsen 2012

Technology	**Large steel tanks for heat storage**					
	2010	**2020**	**2030**	**2050**	**Note**	**Ref**
Energy/technical data						
Storage capacity, kWh/m3	60-80					1
Efficiency, %	95				A	
Environment						
Financial data						
Specific investment costs (€ per m3)	160-260				B	2
O&M						

References:

1 Dirk Mangold: "Seasonal Heat Storage. Pilot projects and experiences in Germany". Presentation at the PREHEAT Symposium at Intersolar 2007, Freiburg, Germany, June 2007.

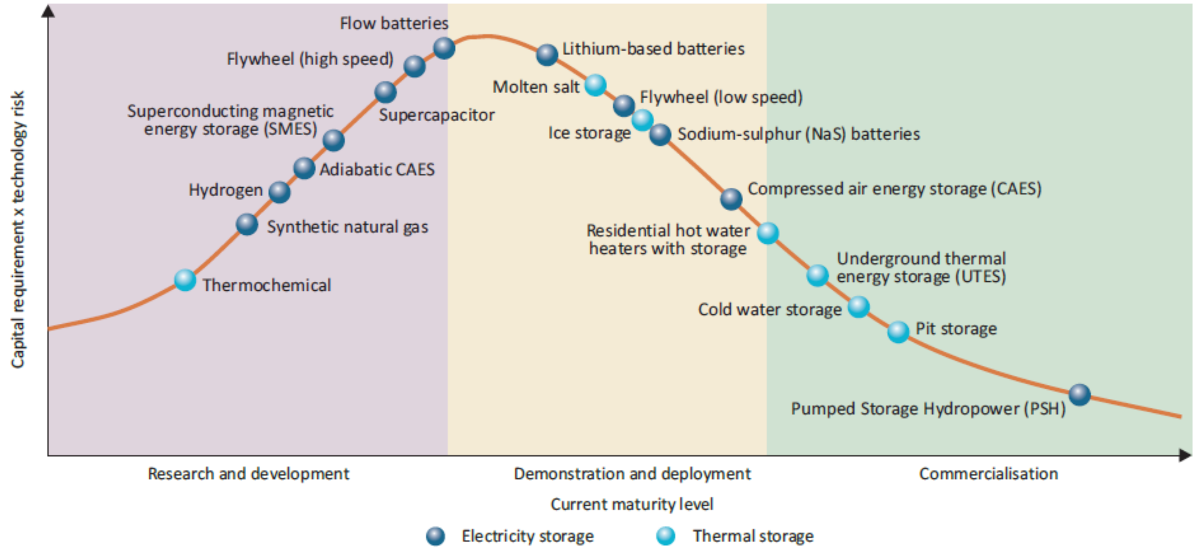
2 "Heat storage technologies". Report, June 2007, from the PREHEAT project, funded by the Intelligent Energy – Europe programme (www.preheat.org).

Notes:

A This is an example: A 10,000 m3 store operating between 90 and 50 C, an outdoor temperature of 5 C, and a storage cycle of one week. Cf. description above under 'Additional remarks'.

B Store volume 10,000 m3.

The maturity level of different heat storages is shown in Figure 14. The main storages suitable for DH and area networks are mature.



Source: Decourt, B. and R. Debarre (2013), "Electricity storage", *Factbook*, Schlumberger Business Consulting Energy Institute, Paris, France and Paksoy, H. (2013), "Thermal Energy Storage Today" presented at the IEA Energy Storage Technology Roadmap Stakeholder Engagement Workshop, Paris, France, 14 February.

Figure 14. The maturity level of different energy storages. Source: IEA 2014.

3.2 New heating networks

3.2.1 Low temperature heating networks

The near future DH network may be based on low pressurised hot water with supply temperatures as low as 60 °C. Especially as heat loads are decreasing, even existing DH networks could lower temperatures and still manage to distribute needed amounts of heat, although end-user heat exchangers would have to be changed. For totally new building areas, low temperature area or district heating networks are already a feasible alternative.

One advantage is in lower investment costs, as cheaper materials can be used. Another advantage is that heat production and distribution is more favourable: low temperature waste heat can be utilised, heat pumps will have better coefficients of performance (COP), CHPs have better power-to-heat ratios with lower DH temperatures, and losses are smaller.

And why not take things a step further? Future DH networks could well have temperatures of 40–45 °C, enough for floor space heating, with additional end-user sited heating (heat pumps using DH, electric heating, solar heat systems, etc.) for domestic hot water.

3.2.2 Smart heat networks

Smart district heating combines renewable energy technologies and thermal storages in such way that the district heating system is linked in a very flexible and constructive way with the electricity market. Main features of a smart district heating system are: long term heat storage, solar collectors, heat pumps, and CHP.

The heart of a smart district heating system is the storage. With a large thermal storage you can use cheap 'excess' electricity to make heat for use later when the heat is actually needed and you can run the CHP unit when you have good price for the electricity – regardless of whether there is a need for heat. Also a solar system of course benefits from having heat storage: the more heat storage available, the higher solar fractions can be achieved. Introducing heat pumps makes electrical heating more energy efficient and reduces the need for storage volume as the storage can then be cooled to very low temperatures. (IEA SHC 2011)

In operation since 2007, Drake Landing Solar Community in Okotoks, Alberta, Canada is the first solar seasonal storage community in North America. It is an area heating network that matches Nordic climate conditions. It has solar collectors on top of garage roofs, generating 1.5 MW_{th} on a typical summer day, and the heat is collected and stored in short-term thermal storage tanks and additionally in a borehole seasonal thermal storage (144 holes stretching 37 m below ground). The distribution network offers temperatures of 35–50 °C. It took five years for the seasonal storage to reach its potential of being able to increase the solar fraction to 97% in 2011/12. The overall incremental capital cost per house is 83,000 CAD for the 52 homes compared to a conventional natural gas furnace. Post-calculations have shown, that the incremental cost would be only 59,000 CAD per home in a hybrid system where the storages are reduced, the distribution network temperature is 10–32 °C and each house has a 2-ton heat pump utilising the network heat. However, estimates for a larger system of 1000+ homes land at roughly 18,000 CAD per home with and without heat pumps. (IEA 2014, Wong & Thornton 2013)

The Dutch town of Duindorp has an area heating network supplying 800 homes with heat from the sea. It is special insofar as the network temperature is 11 °C, and each home has a heat pump. The network temperature matches summer sea temperatures and the network is directly heated through a heat exchanger. During the winter, the water is heated at the sea inlet with a central heat pump to 11 °C. (Energi&Miljö 2014)

Borehole based ground source heat pump systems can often also be used for both heating and cooling. During cooling, the heat pump excess heat is stored in the boreholes and it is then used during the heating phase where a higher borehole temperature improves the COP.

The Marstal district heating system comprises a thermal pit storage, presented previously, a 15,000 m^2 solar thermal plant, a CHP system consisting of a 4 MW wood chip fired boiler and a 0.75 MW_e organic ranking cycle power unit, and a 1.5 MW heat pump using CO_2 as refrigerant.

4. Heat production technology developments

It is good to keep in mind that the utilisation of area or district heating technologies differs from the utilisation of power production technologies insofar as the localisation is much more important. Whereas a power plant is only part of a larger power market, the DH CHP is part of a very local heat market as well as the larger power market. Each heating network is different, with its own mix of alternative heat sources, which means, for example, that a CHP plant may be profitable in one network but not in another. Some fuels are restrictive, e.g. straw and forest residue, as the price of transport can form a major part of the fuel price and may rise heavily with distance. However, even though pellets are more expensive, the transport distance doesn't influence the price as heavily as with unprocessed raw fuel since the volumetric heating value is higher. Peat co-firing with biomass improves combustion and prevents boiler fouling; however, a boiler planned for co-firing of peat and wood cannot be directly used for wood-only burning, at least without using additives or elemental sulphur. More rural DH networks have ample biomass sources within reasonable vicinity but the price of coal inland is higher than at the coast. Coastal cities, on the other hand, do not have ample biomass sources in the vicinity but coal can be delivered by ships directly at the plants.

There won't be only one bio CHP technology in use in the future, but several. The main criterion is profitability, estimated for each case separately. Because DH networks are mainly owned by municipalities, the investment decision is not always purely economic. It can be coloured by, for example, green preferences, NIMBY-mindedness or local employment considerations. There is a big political discussion in Helsinki about whether a functioning coal CHP power plant should be decommissioned in advance, before its lifetime, to make Helsinki emit less CO_2. If and when Nordic countries politically force coal out, their decision will have a negligible effect on the climate because it allows more polluting units elsewhere in Europe to stay in operation longer. Interestingly enough, in the German background study (Leitstudie 2012) for die Energiewende, coal CHP doesn't decrease much by 2050.

An ideal model would optimise investments in each DH network separately. With the same market price for electricity, a CHP that replaces heat from an oil heat-only boiler is much more profitable than a CHP that replaces heat from a coal heat-only boiler.

Bio-oils are already used to a large degree. For example, in Sweden, with a few exceptions, bio-fuels are used in converted peak load boilers and back-up boilers originally fired with fossil oil, and 4.3% of all fuel use in DH networks is bio-oils, e.g. pine oil or palm oil (Sandgren 2010). Also biofuels other than bio-oils are used in oil heat-only boilers. For example, Fortum is using pyrolysis oil from wood in Joensuu in Finland.

There are different sources available for quotes on the present cost levels, for example the 'Norwegian Kostnader ved produksjon av kraft og varme' by Norges vassdrags- og energidirektorat (2011). A very comprehensive report set on production costs and their developments in both pdf and excel format is to be found at the Danish Energy Agency (DEA 2015). The report, with technology data for generation of electricity and district heating, energy storage and energy carrier generation and conversion, and its update (Energistyrelsen 2012, 2014) are very extensive and could very well be used directly as a presentation of the status quo of costs and efficiencies of current CHP and heat technologies and their developments. A new and almost as extensive Swedish report (Nohlgren et al. 2014) with data, e.g., for bio combustion plants, is also available. While the Danish reports are in English, the Swedish one is in Swedish, so it brings some added value to refer to it here.

The present Nordic costs in this report are, thus, based on the aforementioned Swedish report (Nohlgren et al. 2014). The presented costs are exclusive fuel costs. The costs have been determined using realised investment costs etc. and for CHP units include total plant costs, i.e. the heat related costs are not separated. There is a serious lack of literature dealing with future heat and CHP production costs and efficiency developments, as most sources concentrate only on power production costs. The cost and efficiency estimates presented here are just that, estimates, and as estimates they also depend on a multitude of assumptions of which some are known and others are not. It is always risky to mix estimates from different sources, which is why we have tried to use fewer but more all-encompassing sources.

4.1 Bio CHP

4.1.1 Status quo of costs and efficiencies

The typical capacities, costs and efficiencies of the main biomass related CHP technologies are presented in Table 5. The original costs in Swedish crowns have been converted to euros with a currency exchange rate of 9.1. The electricity and district heat capacities and efficiencies given in the table are on a net basis. All fluidised bed CHPs, as well as the waste CHP, are assumed to be equipped with flue gas condensers that increase the (low temperature) heat production. Heat production capacities and total efficiencies given in brackets are for plants without the flue gas condensers. With flue gas condensation, the total efficiencies of CHPs can increase by nearly 20 percentage points, resulting in total efficiencies around 105% (NB! The lower heat value is used in power and heat sector efficiency assessments which makes >100% efficiencies possible when flue gases are condensed.) Availability describes the reliability of the technology – it is the percentage of time that the plant would be down due to failure if operated according to schedule.

The data for combined cycle gas turbines (CCGT) and gas internal combustion engines (ICE) in the table is for natural gas usage. The power plants could also be used with upgraded bio-derived gas although the current commercially viable alternative is only upgraded biogas. Bio-derived gas production and upgrading costs are not included in the data. The costs depend on gasification technology, purification level, used fuel and size of operation (Hansen 2011).

Bio ORC CHP (Organic Rankine Cycle) is a small-scale technology which is able to utilise lower temperature heat sources than traditional steam-water Rankine cycle CHP plants. In ORC, water is replaced by an organic compound, with phase-change (liquid to gas) taking place at lower temperature than with water. Thermal oil is used as a transfer medium from the heat source (e.g. flue gases) into the organic compound cycle. In the Bio ORC CHP, the heat source is flue gases from biomass combustion.

Circulating fluidised bed (CFB) and bubbling fluidised bed (BFB) boilers are able to burn a variety of fuels including low grade biofuels. BFB boilers are typically used for smaller scale installations (20–100 MW_{fuel}) due to lower investment costs and are especially suitable for moist, woody biomass fuels. The larger units are often CFBs (100–500 MW_{fuel}). However, for waste fuels CFB is often the technology of choice, even in the 50 MW_{fuel} range, and there are BFB boilers up to 300 MW_{fuel}.

'Waste' in the table refers to a grate boiler using municipal solid waste (MSW) as fuel, while 'RDF CFB' refers to a CFB boiler using refuse-derived fuel (RDF). While CFB boilers are capable of firing various fuels, MSW (basically the plastic garbage bags collected from homes) as such can only be utilised in grate-fired boilers. CFBs need the fuel to be in small particle size (less than some 60–100 mm) and glass, metals and other impurities can also be problematic. In grate-fired units, plastic garbage bags can be burned as they are. These grate-fired units, however, have quite low electrical efficiencies.

RDF, the form of waste based fuel suitable for CFBs, is produced mostly from commercial and industrial waste but pre-separated municipal solid waste (MSW) fraction can also be used as starting material. In RDF plants, the starting material is often already pre-sorted and in the process the unwanted material (glass, stones, PVC, metals etc.) is further removed in several size-reduction, screening and other separation steps (such as ferrous and non-ferrous metal removal).

The ready RDF consists largely of combustible components such as paper, cardboard, plastics and wood. The price of RDF is of course less favourable than the price of MSW (plants actually get money for accepting MSW), as RDF needs quite a lot of processing. Furthermore, the electrical efficiency of a CFB firing 100% RDF is quite low also as RDF is clearly a more challenging fuel than woody biomass, for example. The challenging nature of RDF is also reflected in the investment cost, especially as the classification of RDF as waste necessitates more efficient flue gas cleaning etc.

Other type of problematic fuels for fluidised bed boilers are straw and similar agro-biomasses. They are known to cause severe problems such as bed agglomeration, which makes their use in fluidised combustion tricky. Basically, these kinds of fuels would need to be co-fired as only a small share together with other fuel types. In Table 5, the fluidised bed boilers are assumed to use woody biomass.

Table 5. Status quo of CHP costs and efficiencies. Data source: Nohlgren et al. 2014.

CHP Type	Capacity MWe	MWth	Avail-ability %	η_{el} %	η_{total} %	Life span years	Investment (overnight) k€/kWe	Fixed O&M €/kWe,a	Variable O&M €/kWhe
CCGT	40	26	98	49	81	25	1,2	11,0	2,7
	150	97	98	51	84	25	0,9	9,9	2,7
Bio-CFB/BFB	5	19 (15)	96	22	104 (86)	25	6,9	157,1	2,3
	10	29 (22)	96	27	105 (86)	25	5,7	115,4	2,3
	30	83 (62)	96	28	105 (86)	25	4,4	76,9	2,3
	80	194 (147)	96	31	106 (88)	25	3,6	54,9	2,3
Waste	20	91 (72)	95	19	105 (87)	25	11,9	345,1	4,4
RDF CFB	20	75 (58)	95	22	104 (86)	25	8,4	208,8	6,0
Gas ICE	0,1	0	95	38	89	15	1,5	109,9	2,0
	1	1	95	40	86	15	1,1	80,2	2,0
Bio ORC	2	13	96	13	98	15	8,2	206,0	-

Small-scale production alternatives are especially studied by Kjellström (2012), and Table 6 gives an overview of costs and efficiencies.

Table 6. Status quo of small-scale CHP costs and efficiencies. Costs in Swedish crowns (SEK). Source: Kjellström 2012.

Conversion process	Steam plant conventional turbine		Steam plant, screw expander		Organic Rankine Cycle			Up-draft gasifier and IC-engine	Externally fired gas turbine
Exhaust gas condensor	**no**	**included**	**no**	**included**	**no**	**included**	**no**	**no**	**no**
Rated performance									
Heat output kW(h)	11 200	12 800	6 250	7 750	9 600	12 000	3 146	3 500	550
Electric output kW(e)	2 600	2 600	750	750	2 220	2 220	689	1 768	250
Bio-oil output kW(f)	-	-	-	-	-	-	-	886	-
Fuel input kW(f)	15 100	15 100	8 140	8 140	13 800	13 800	4 460	6642	941
Electric yield	0,23	0,20	0,12	0,10	0,23	0,19	0,22	0,50	0,45
Overall efficiency %	91	102	86	104	86	103	86	93	85
Marginal electric efficiency	97	88	62	99	72	93	71	98	76
Performance at minimum heat load									
Heat output kW(h)	3 600	3 600	No data	No data	2 400	2 400	787	875	No data
Electric output kW(e)	300	300			374	374	115		
Bio-oil output kW(f)	-	-			-	-	-		
Fuel input kW(f)	4 590	4 590			3 340	3 340	1 085		
Electric yield	0,08	0,08			0,16	0,16	0,15		
Overall efficiency %	85	85			83	83	83		
Marginal electric efficiency	51	51			56	56	54		
Investment									
Total MSEK	127	136	66,2	70,4	115	122	57,2	135	10,5
Specific SEK/kW(e)	48 800	52 300	88 300	93 900	51 800	55 000	82 900	76 400	42 600
Emission data									
NO_x g/MWh(f)	209	209	209	209	209	209	209	504	209
Operating costs									
Fixed O&M % of investment	1,7	1,7	1,7	1,7	1,7	1,7	1,7	2,5**)	1,7
Operators personyear/a*)	5	5	5	5	5	5	2	2	2
Variable O&M SEK/MWh(f)	32	32	32	32	32	32	32	32	32

*) At 600 000 SEK/personyear **) Full service contract offered by the supplier

For smaller CHPs using wood in the range 50–500 kW_e, the investment costs depend on size technology. For example, in the study by Haavisto from 2010 the price of a micro-turbine from Talbotts Biomass Energy Ltd drops from 5,500 €/kW_e to 1,880 €/kW_e when the size increases from 100 kW_e to 500 kW_e. Gasification&ICE seems to fare best at the lower capacity range, Gasek Oy offers a 50 kW_e combo for 2,400 € per kW_e. ORC CHP is clearly more expensive than the alternatives (Haavisto 2010).

4.1.2 Foreseeable technology changes

Technology changes resulting in new production alternatives are already in the semi-commercial stage or being planned or prototyped, especially related to gasification as will be looked at in Chapter 4.1.2.1 and oxy-fuel combustion in Chapter 4.1.2.2. Not only is the production side seeing changes, but also biomass fuels are developing (Chapter 4.1.2.3).

The production technologies and costs in Table 5 might also experience improvements towards 2050. IEA estimates for bio power improvements are shown in Table 7. The original costs in US dollars are converted to euros with a currency exchange rate of 1.37. The improvements can be assumed to be similar for bio CHP. However, it is not clear what technologies IEA has for 2010 and for 2030, although the assumption is that they differ. As the electrical efficiencies of CHP power plants in the Nordic countries, as given by Table 5, are already near or even better than the high ends here given for 2010 and more close to the values for 2030, one could assume that the status quo of Nordic technology now is what it will be in 2030 more broadly.

Table 7. Foreseen cost and efficiency developments for biopower production 2010–2030. Data source: IEA 2012.

Bio power	ηel		Investment		O&M	
Capacity	2010	2030	2010	2030	2010	2030
MWe	%	%	k€/kWe	k€/kWe	%/inv.	%/inv.
<10	14-18	16-20	4.4-7.2	3.5-5.7	5.5-6.5	5.5-6.5
10-50	18-33	23-38	2.8-4.2	2.3-3.4	5-6	5-6
>50	28-40	33-45	1.8-3.1	1.4-2.5	3-5	3-5

*IEA estimates are for electricity production, so a CHP will be more expensive

The input to TIMES-VTT has as an assumption an overall efficiency improvement in mature technologies of 1–2 percentage points towards 2030 and an additional 1 percentage point improvement to 2050. The power-to-heat ratio is expected to improve by 10–15% by 2030 and by roughly 20% by 2050. The costs will not decrease much.

In their World Energy Investment Outlook (IEA WEIO 2014), IEA estimates that biomass power plant costs will decrease only slowly towards 2035 (see Figure 15). It can be assumed that biomass CHP will experience a similar development.

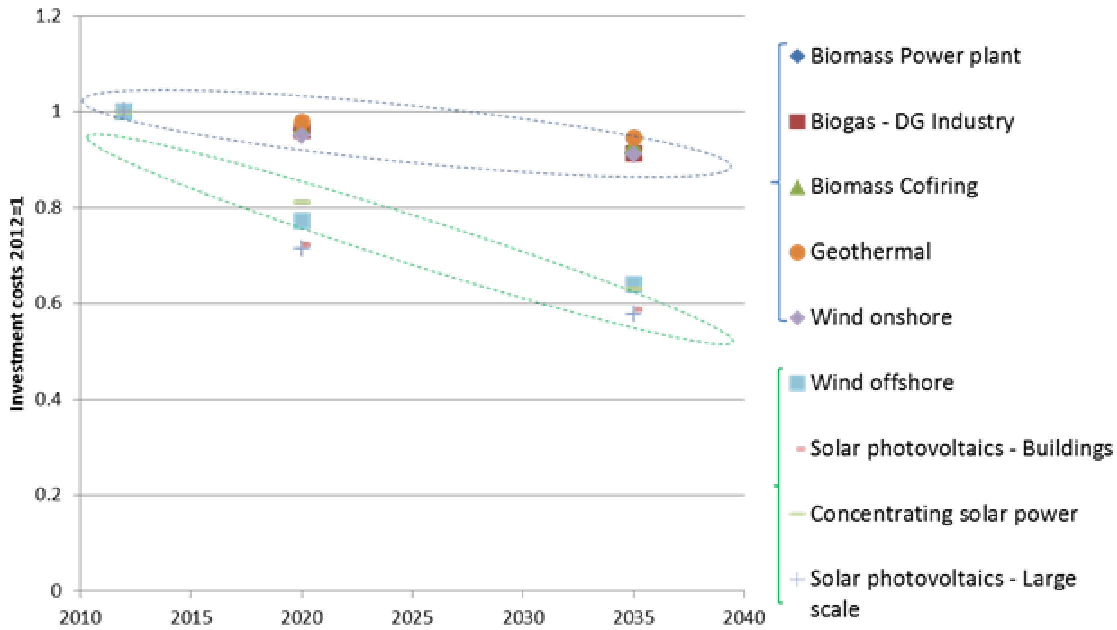


Figure 15. Investment cost decline expectations for the RES-E. (Source: IEA WEIO 2014)

4.1.2.1 Gasification

Gasification itself is not just one technology, but a mixture of methods and conditions and uses as presented in Table 8.

Table 8. Gasification characteristics and classification according to Breitholtz (2011).

Pressure	*Oxidiser*	*Process*	*Ash*	*Fuel*	*Size*	*Application*
Atmospheric Pressurised	Air Oxygen Steam	Fixed bed BFB CFB Entrained flow Transport reactor Flame gasification	Slagging Non-slagging	Coal Biofuel Oil Gas Waste	Small 0-10 MW Medium 10-50 MW Large 50-200 MW Huge 200-2000 MW	Combustion engines Combustible gas for industrial furnaces Fossil fuel replacement by bio/waste in power plants IGCC Transport fuels Synthetic NG

Table 9 presents semi-commercial and future biomass CHP technologies based on gasification. Gasification offers possibilities to increase power-to-heat ratios, especially when integrated with combined cycle gas turbines (IGCC), but also in waste-to-energy and industrial applications.

Burning of waste, for example, is not technically easy and steam values are usually comparably low resulting in low electric and total efficiencies as described earlier. Steam parameters are limited due to corrosion of boiler tubewalls and superheaters caused by the alkali (Na, K) and heavy metal (Zn, Pb) chlorides that will form when waste derived fuel is used. With gasification, the resulting gas can first be cleaned of these harmful compounds and then be used in a steam boiler with high steam parameters and thus high electrical efficiency. This has been demonstrated in the Kymijärvi II gasifier located in Lahti, Finland, where RDF is first gasified in CFB gasifiers and the resulting gas is cleaned before being fed to a dedicated gas-fired CHP boiler with a high electrical efficiency. The plant started operation in 2012 and is the first of its kind. The performance and cost data in Table 9 are based on this unit. The fuel power of the Kymijärvi II plant is 160 MW and it produces 50 MW electricity (net) and 90 MW district heat, which translates to 31% net electrical efficiency which is clearly higher than that of a typical CFB RDF CHP boiler (Table 5). However, there have been problems with the gas cleaning filters becoming plugged due to which the plant has had to replace 50% of RDF with recycled wood. Thus, there are still some technological developments needed in gas cleaning (e.g. Simell et al., 2014).

A biomass based IGCC (BIGCC) would have a good power-to-heat ratio but gas purification challenges remain; thus BIGCC is considered a future technology. As it is, gasification gas is not clean enough for gas turbines or gas motors (Nohlgren et al. 2014). Some BIGCC's were built in the 90s, one for example in Värnamo, Sweden, but active development ended 2004 as large gas turbine manufacturers started concentrating on larger units for coal gasification (Nohlgren et al. 2014).

Clean gasification gas could also be used in internal combustion engines. The total efficiency of a small, 1 MW_e, biomass integrated gasification internal combustion engine (BIGICE) is quite low but markedly better for the larger one, according to Nohlgren et al.(2014). Small-scale downdraft gasification, a technique used already during the Second World War, has a poor carbon conversion, however (Hannula & Kurkela 2012).

Table 9. Semi-commercial and future CHP technologies. Data source: Nohlgren et al. 2014

CHP Type	Capacity MWe	Capacity MWth	Avail-ability %	η_{el} %	η_{total} %	Life span years	Investment (overnight) k€/kWe	Fixed O&M €/kWe,a	Variable O&M €/kWhe
BIGCC**	40-75	39-82		42-43	83-90		2,3-2,5	47,6-74,2	3,5-3,8
RDF Gasification*	50	90	95	31	87	25	3,9	208,8	6,0
BIGICE*	1	2	96	26	79	15	6,6	133,0	2,0
	5	10	96	31	91	15	5,7	114,3	2,0

*Semi-commercial technologies

** Future technologies

4.1.2.2 Oxy-fuel combustion

Oxy-fuel combustion is currently considered to be one of the major technologies for CO_2 capture in power plants. In oxy-fuel combustion fossil fuels are combusted in a mixture of recirculated flue gas and oxygen, rather than air. The remainder of the flue gas, which is not recirculated, is rich in carbon dioxide and water vapour. The challenge is the significant energy penalty due to O_2 supply and CO_2 processing.

Using biomass in power plants with CCS makes it possible to achieve 'negative CO_2 emissions'. Estimated efficiencies and costs for a large scale (482 MW_{fuel}) oxy-fuel combustion bio CFB CHP with and without CCS are shown in Table 10.

Table 10. Cost and efficiencies of a large scale oxyfuel bio CFB CHP with or without CCS in 2015, 2030 and 2050. Data source: VTT.

Oxy-fuel CHP combustion CFB 482 MWfuel	Unit	No CCS 2015	No CCS 2030	No CCS 2050	CCS 2015	CCS 2030	CCS 2050
Investment	€/kWfuel	720	720	720	1140	1140	1140
Fixed O&M	€/kWfuel	16	16	16	24	24	24
Variable O&M	€/MWhfuel	3,2	3,2	3,2	3,3	3,3	3,3
Technical life cycle	years	40	40	40	40	40	40
Electricity efficiency	%	32 %	33 %	34 %	20 %	22 %	26 %
Heat efficiency	%	56 %	56 %	56 %	73 %	73 %	73 %
CO2 emissions	t/MWhfuel	0,00	0,00	0,00	neg.	neg.	neg.

4.1.2.3 Torrefaction

Torrefaction is the production of ‘biocoal’, i.e. charcoal like products, from biomass. In torrefaction biomass is at 200 to 300 °C under atmospheric conditions and in the absence of oxygen transforming it to a dry coal-like product. Often the end product is pelletized in order to increase energy density and to improve handling properties. The main advantage of torrefied biomass is that it is quite similar in use to ordinary coal. Pulverized coal plants have stringent requirements for fuels (particle size, moisture etc.) and thus using wood chips, for example, is troublesome because they need to be dried and pulverised in mills designed for biomass, before they can be injected into the burners. Torrefied biomass pellets, on the other hand, can be co-fired in existing pulverized coal combustion plants with minor or no modifications at all as their energy density is quite close to that of coal, they are hydrophobic and they can be ground in coal mills (Wilén et al. 2013). However, there are no power plants that have experience with long term use of torrefied biomass or with using very high co-firing shares. Thus, corrosion, ashes, storage, and optimum/maximum share in the fuel mix, among other factors, are still at least partly open questions.

Torrefaction can be seen as a temporary solution to extend the use of existing pulverized coal plants such as some of the largest coastal coal CHP plants in Finland, especially Hanasaari and Salmisaari CHP plants in Helsinki. It does not, however, make sense to use torrefied pellets in fluidised bed boilers, which are capable of using lower grade biomass fuels that are significantly cheaper.

The long distance transport of raw biomass (for example wood chips or straw) is expensive, such that biomass is usually transformed to more energy dense forms such as pellets. Torrefied pellets offer some advantages over the traditional ‘white pellets’ such as better grindability which can make them the preferred choice. As the production of white or torrefied pellets is costly – torrefied pellets are over twice as expensive as forest residue chips –, the optimal fuel solution depends on the transport form or forms, distance, amounts, frequencies, fuel storage capabilities and, of course, the combustion technology.

4.2 Biomass heat-only boilers

4.2.1 Status quo of costs and efficiencies

The main biomass-related technologies are presented in Table 11. The original costs in Swedish crowns are converted to euros with a currency exchange rate of 9.1. The larger wood chip boilers in the table are assumed to have flue gas condensation, which can increase thermal output and efficiency by as much as 20% (Nohlgren et al. 2014).

In 2008 the European Commission estimated pellet boilers to cost less than 355 $€_{2007}/kW_{th}$ for a 50 kW_{th} boiler system with a hot water reservoir and a pellet silo. The total O&M (fuel cost probably excluded) was estimated to be 15 $€_{2007}/kW_{th}$. The efficiency of the boiler was 84%. (EC 2008)

Table 11. Status quo of biomass boiler costs and efficiencies. Data source: Nohlgren et al. 2014.

Boiler Type	Capacity MWth	Investment (overnight) k€/kWth	Fixed O&M €/kWth,a	Variable O&M €/kWhfuel
Pellet boiler	0.1-1	1.1	14.9	1.6
	1-10	0.7	7.5	1.6
Wood chips boiler with flue gas condenser	> 10	0.7	13.2	2.0

4.2.2 Foreseeable technology changes

As smaller and smaller boilers are equipped with flue gas condensing units, their efficiencies will improve but investment costs will increase. Even new household gas boilers are equipped with flue gas condensers as a standard in Europe today, which can indicate that even small bio boilers from 0.1 MW_{th} upwards might be installed with condensers.

IEA (2012) estimates bio boiler investment costs to decrease from 2010 to 2030 as shown in Table 12. The original costs in US dollars are converted to euros with a currency exchange rate of 1.37. The author's assumption is that they are not equipped with condensers.

Table 12. Investment costs of bio boilers 2010 and 2030. Data source: IEA 2012.

Bio heat Capacity MWth	Fuel type	Investment 2010 k€/kWth	Investment 2030 k€/kWth	User type
0.1-0.2	Pellets	0.4-0.9	0.3-0.6	Commercial
0.35-1.5	Wood chips	0.4-0.6	0.3-0.4	Commercial
3.5-5.0	Wood chips	0.4	0.3	Industry

4.3 Large scale heat pumps

4.3.1 Status quo of costs and efficiencies

District heating utilises large scale heat pumps at several locations. Sea water heat pumps are used, for example, in Drammen and Stockholm. Even if the surface of the sea freezes, the sea bed temperature stays at 4 °C or above. Sewage return water has moderate temperatures, resulting in a high COP. Sewage return water heat pumps are in use, for example, in Oslo, Turku and Helsinki. The heat pump in Helsinki at Katri Vala is also used for combined district heating and district cooling during part of the year, improving the overall benefit.

Large end-users and area heating are also using heat pumps more and more, often in combination with other sources, see Chapter 3. For example, low temperature heat storages can be utilised for heating with heat pumps. Ground source heat pumps (GSHP) with boreholes tens or even a couple of hundred metres down are used by single family houses, semi-detached houses, apartment houses and for service or industry sector buildings, and their popularity is growing. As Cogen Europe (2011) puts it: 'Heat pumps will play a much more significant role in space heating in 2050'.

In 2008 the European Commission estimated the capital cost of a 100 kWth geothermal heat pump to be 500 $€_{2007}/kW_{th}$; however, the range was large, 200–1150 $€_{2007}/kW_{th}$. The total O&M (electricity cost probably included) was estimated to be 39 $€_{2007}/kW_{th}$.

4.3.2 Foreseeable technology changes

Heat pumps are getting to be mature technology. The coefficient of performance (COP) is

$$COP = \eta \frac{T}{\Delta T}$$

where the isentropic efficiency η is around 0.45–0.65. The isentropic efficiency depends on mechanical losses and refrigerants. The temperature (in Kelvin) and the temperature difference can become more beneficial with low temperature networks as well as with low-energy houses. Theoretical maximum COP of a 90 °C/45 °C district heating network (T=273+90 and ΔT =45) is 8.1 while it is 13.5 for a 65 °C/40 °C district heating network (T=273+65 and ΔT =40).

Whereas COP is given for full load, a heat pump's performance varies depending on load and environment. With a better regulated but costlier heat pump system, COP at partial load can be improved. (Fahlén 2012)

Often a seasonal performance factor (SPF) is used instead of COP to describe the heat pump system over a longer time perspective taking into account temperature changes in the environment (especially important for air heat pumps) as well as partial loads etc.

Nabe et al. (2011) estimate that the SPF of ground source heat pumps in Germany will increase from 3.21 in 2010 to 4.05 in 2030 in old houses and from 3.97 to 4.80 in new houses. The differences are influenced by the changes in the operational environment.

The Heat Roadmap for Europe 2050 (EuroPower&Heat 2012a) estimate of large scale heat pump cost is presented in Table 13. It is unclear what type of heat pump is used and what cost items are included; the estimate for an individual heat pump investment is 30% lower than today, but the lifetime is 5 years shorter, 15 years. The cost estimate is given in relation to electric power.

Table 13. Cost of large scale heat pumps. Data source: EuroHeat&Power 2012a

Type	Investment costs €/kWe	Fixed O&M % of inv.
Large scale heat pump	2700	0.2

4.4 Other production alternatives

4.4.1 Large scale solar heating

Solar thermal area or district heat is widespread in Denmark with 30 installations, nine of which are among the ten largest in Europe. It is not so widespread in the other Nordic countries, however, with Norway and Sweden each having only one installation at the end of 2013 (Mauthner and Weiss 2014). The costs of large scale solar heat are presented in Table 14.

Solar heating costs in Denmark are typically as low as between 30 and 40 €/MWh, which corresponds to a natural gas price of 35 €/MWh. The calculations are made assuming O&M to be annually 1% of investment. (IEA SHC 2011)

Table 14. Costs of large scale solar heat. Data source: EuroHeat&Power 2012a

Type	Investment costs €/(MWh per year)	Fixed O&M % of inv.
Solar thermal	440	0.001

Today's solar thermal technologies are mature. If we look at hot household water, similar solar collectors could manage 61–66% of the demand in Stockholm, 68–75% in Zürich and 74–80% in Milan. If we add the heat demand for a detached low energy house, we see that while the collector manages to fulfil 50% of the energy demand in Stockholm, it fulfils 66% in Zürich and 72% in Milan. (Faninger 2010).

4.4.2 Waste heat

Industrial waste heat is already commonly in use, at least in Finland and Sweden. The Finnish remaining industrial waste heat potential is 1.4 TWh with traditional heat exchangers and 2.8 using heat pumps. (TEM 2013)

Exhaust air heat pumps are more and more used in also DH apartment houses and detached houses (Boss 2012). They could also be a heat source for possible low temperature heat networks in the future.

4.4.3 Deep direct geothermal heat

Geothermal DH technology is quite mature, having been in use for 50 years, and geothermal DH installations are quite competitive. However, geothermal space and district heating systems are capital intensive. The main costs are generated by initial investment costs for production and injection wells, down-hole and surface feed pumps, pipelines, and monitoring and control equipment. Operating expenses, nevertheless, are much lower than in conventional systems, consisting of pumping power, system maintenance, operation and control. Generating costs and selling prices are usually around 60 €/MWh thermal, within a range of 20 to 80 €/MWh thermal. (Geo DH 2014)

The capital expenditures for geothermal in a future project in Ile de France in the Val de Marne department in the Paris area (Geo DH 2014) are expected to be roughly 1.2 M€/MW_{th} and the operating expenditures 0.11 M€/MW_{th}, not counting electricity needs which are 1 to 10 heat produced. The temperature cycle is assumed to be 40 °C in and 70 °C out. However, the European average investment cost for geothermal heat is 1.5–2.2 M€/MW_{th} (Geo DH 2012, 2013).

As can be seen in Figure 8, and also confirmed by Euroheat&Power (2012a), of the Nordic countries only Denmark has notable deep geothermal potentials with temperatures between 40 °C and 60 °C at 2000 m depths, and Aalborg in the North has even temperatures above 60 °C.

However, aquifers or porous layers such as the one in Lund, Sweden, are not a must anymore, as recent developments in drilling and hydraulic fracking technologies have opened the door for Enhanced Geothermal Systems (EGS) based on hot dry rock (HDR) techniques.

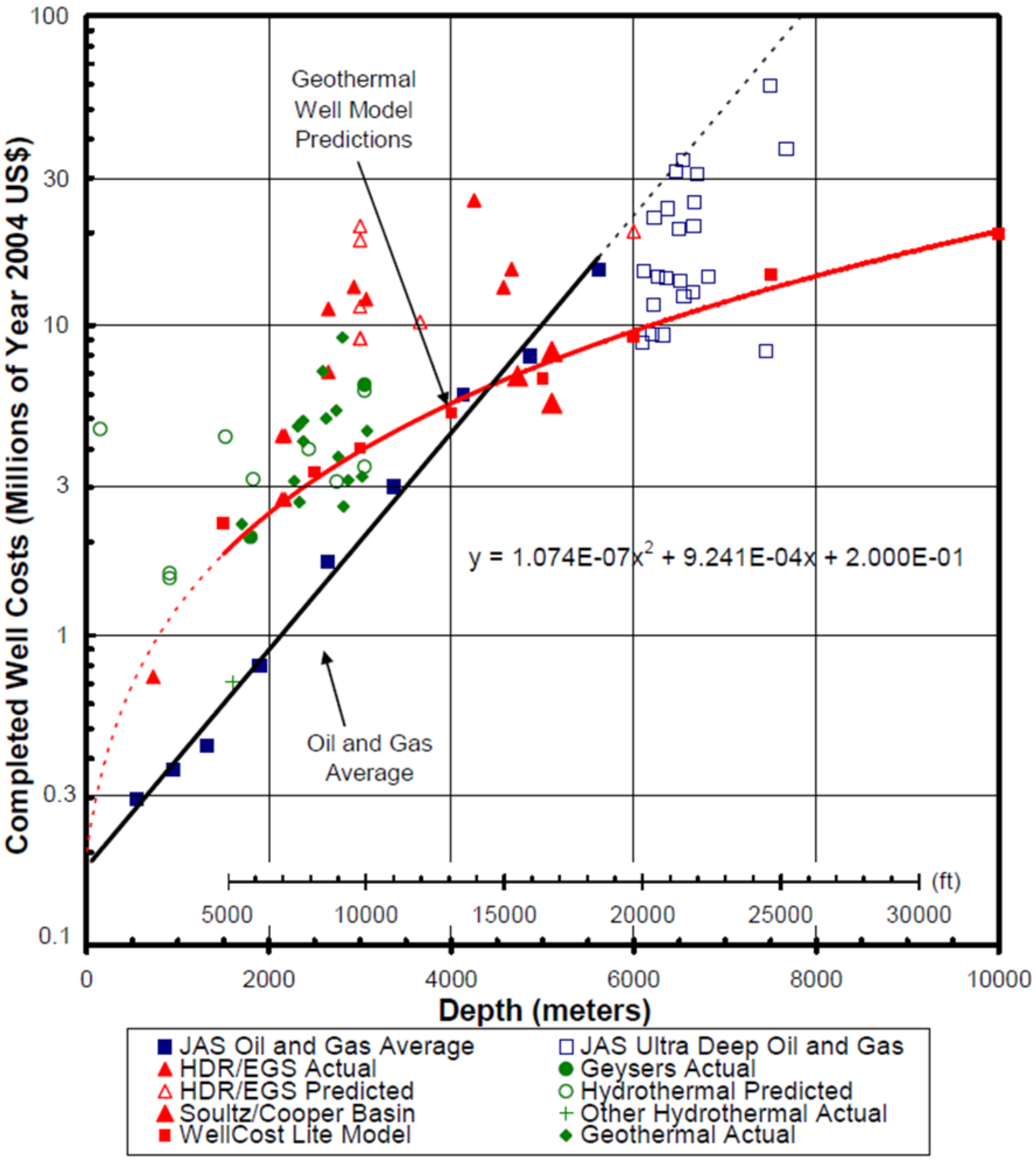


Figure 16. Geothermal drilling costs as a function of depth. Source: Thorsteinsson 2008)

High temperatures increase drilling costs for deep wells and pressure losses increase with depth, slowing down progress rate. As drilling technology is still developing, if pressure losses are managed and as temperatures are kept at DH levels, new doors can be opened for the Nordic countries. For example, St1 and Fortum announced a joint venture in November 2014 for a 40 MW_{th} geothermal plant in Espoo, Finland (Kauppalehti 2014). Estimated temperature gradient in the area is about 20 °C/1000 m and the planned well depth is about 6 km with a target temperature of 90 °C.

Data for a geothermal heat-only plant using an electric heat pump is shown in Table 15. Instead of an electric heat pump, an absorption heat pump could be used. Electric heat pumps can in some cases extract more geothermal energy than absorption heat pumps. They may cool the geothermal water below the approx. 10–20°C obtainable using absorption heat pumps and their drive energy may constitute a smaller part of the heat output. On the other hand, electricity is in general substantially more expensive than heat, making electric heat pumps more expensive to operate. (Energistyrelsen 2014)

Table 15. Geothermal heat-only plant with electric heat pump, characteristics and costs in Denmark. Source: Energistyrelsen 2014

Technology	**Geothermal heat-only plant with electric heat pump- 70 C, Denmark**					
	2015	**2020**	**2030**	**2050**	**Note**	**Ref**
Energy/technical data						
Temperature of geothermal heat (degrees C)	approx. 70					1
Heat from geothermal source (%)	100	100	100		B	1
Electricity demand, heat pump (%)	17	17	17		B	1
Heat generation capacity (%)	117	117	117		B	1
District heat forward temperature, winter (C)	85	85	85			1
Electricity consumption for pumps etc. (%)	8	8	8		A,B	1
Technical lifetime (years)	25	25	25			1
Construction time (years)	4-5	4-5	4-5			1
Financial data						
Specific investment (M€ per MJ/s geothermal heat)	1.6	1.6	1.6			2
O&M excl. electricity consumption (€/year per MJ/s geothermal heat)	37,000	34,000	34,000			2

References:
1 Dansk Fjernvarmes Geotermiselskab, 2011
2 Estimated by Danish Energy Agency and Energinet.dk, 2011.

Notes:
A Earlier versions of this document showed an electricity consumption of approx. 9 %. However, the exact consumption will always depend on the local situation. For similar conditions (temperature, depth and permeability) the electricity consumption for pumps will be comparable, irrespective of whether a steam driven or electricity driven heat pump is used for heat extraction. The estimated consumption has thus been adjusted to match the consumption of the steam driven system described further above.

B Percentage of geothermal heat

4.4.4 Electric boilers

Electric boilers were quite common in Nordic DH systems in the 1980s. The nuclear power plants were up and running, hydro resources were in use, resulting in occasional power surpluses which were sucked up with electric boilers. Electric boilers are returning as they are used to balance intermittent wind production in the power market, especially when used in combination with a heat storage. Electric boilers are mature technology.

4.4.5 Hydrogen systems and/or fuel cells

Hydrogen systems are expensive and not a solution for district heating per se. As the power system will need a lot of variable production management, hydrogen systems are one possibility towards 2050. Hydrogen can be used for transport, which may be the main target, but also in power production for balancing purposes. For this reason, the operating hours may be too few for CHP profitability, but in combination with heat storages, CHP might prove feasible. Cogen Europe (2011) sees micro-CHP as a more of a solution for non-urban areas.

Fuel cells are power production plants that use hydrogen. Ongoing fuel cell manufacturing is more aimed at micro-CHPs for end-users and may be a possibility for small area heating networks. Figure 17 shows how poorly solid oxide fuel cells (SOFC) and proton exchange membrane fuel cells (PEMFC) compete against reciprocating engines (ICE) and Stirling engines according to the FC Eurogrid project. All micro-CHP solutions are very unprofitable.

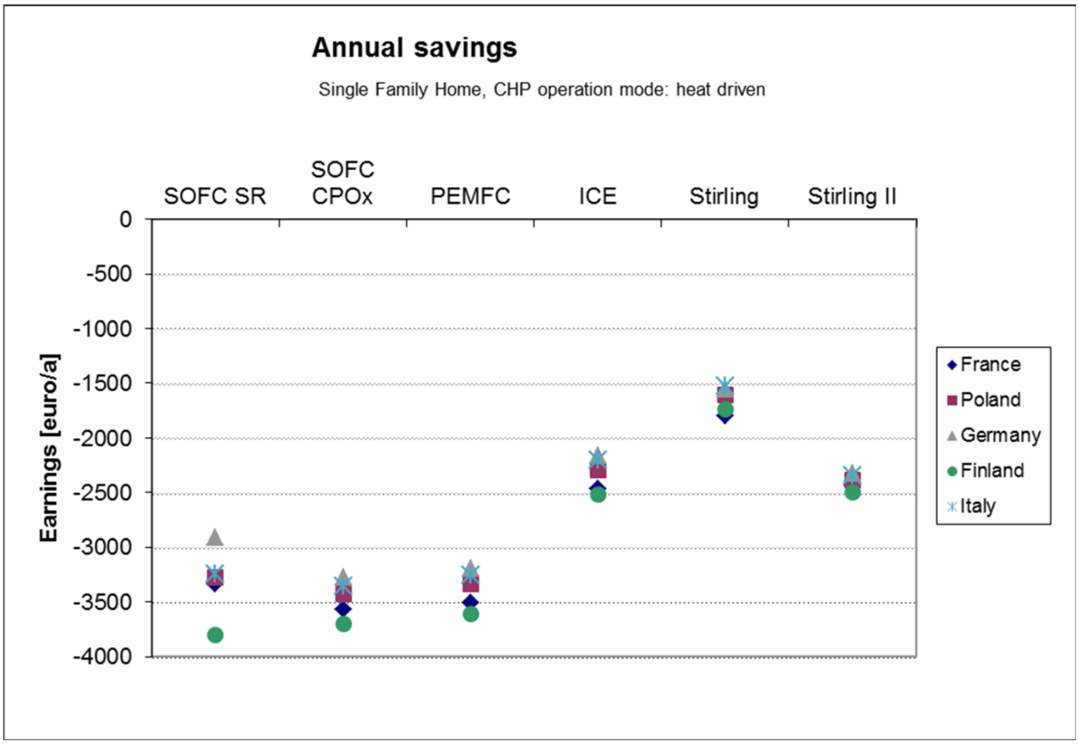


Figure 17. The competitiveness of different micro-CHP's for single family houses in different climate and price environments. Each installation includes a heat storage, and the CHP's are run to follow the heat demand not the power demand.

The development 2010–2050 of SOFC's are estimated by VTT according to two scenarios, Business-as-usual and Optimistic, and are presented in Table 16.

Table 16. Fuel cell cost and efficiency developments of solid oxide fuel cells 2010–2050 according to two scenarios, Business-as-usual (BAU) and Optimistic.

Fuel cell, BAU	Size (MWe)	2	3	4	5
SOFC	**Unit**	**2010**	**2020**	**2030**	**2050**
Investment	€/kWe	4000	2500	1500	1000
Fixed O&M	€/kWfuel				
Variable O&M	€/MWhfuel	60	50	30	20
Technical life cycle	years	10	10	10	10
Electricity efficiency	%	40 %	50 %	60 %	65 %
Heat efficiency	%	40 %	40 %	30 %	30 %

Fuel cell, optimistic	Size (MWe)	2	10	15	20
SOFC	**Unit**	**2010**	**2020**	**2030**	**2050**
Investment	€/kWe	4000	2500	1000	800
Fixed O&M	€/kWfuel				
Variable O&M	€/MWhfuel	60	30	20	10
Technical life cycle	years	15	15	15	15
Electricity efficiency	%	40 %	50 %	60 %	70 %
Heat efficiency	%	40 %	40 %	30 %	20 %

The target given by the METI technology roadmap for residential cogeneration systems by 2020-–30 in Japan is 2,750 €$_{2007}$/kW according to Staffell (2009).

From learning-by-doing, the price of Japanese 1kW PEMFC systems has fallen by 20% for each doubling of production volume. Prices are therefore projected to fall from 15,000 £$_{2009}$ in 2009 to 6,000 £$_{2009}$ within 10±5 years, determined primarily by the speed and scale of deployment world-wide. A commercially viable price of around 3,000 £$_{2009}$ is, however, expected to be two decades away, and widely held targets of under 1,000 £$_{2009}$ per kW are argued to be unobtainable with current technologies due to the requirement for extensive balance of plant and auxiliary systems. (Staffell 2009)

Large PEMFC systems might fare better as the balance of plant will form a smaller share of the total costs and as auxiliary systems, for example a peak/reserve gas burner, are not needed specifically for DH fuel cells.

4.4.6 Nuclear CHP

Small-scale nuclear power plants, around 200 MW, have again surfaced in the public consciousness. They could be CHP plants. The idea is not new; there were already plans 30–40 years ago for small scale passive nuclear CHP plants, SECURE.

As mentioned earlier in the report, Helsinki may have to make big changes in the next 5 to 10 years. In 2009 in Finland, Fortum applied for permission for a new nuclear power plant at the same time as TVO and Fennovoima, but was the only one not to receive it. Fortum brought forward the alternative to build the new nuclear power plant as a CHP plant and transport the heat from Lovisa, 100 km away, via a pipeline to Helsinki and the capital area. It is possible that Fortum will once again apply for a permit in the coming years, as the old Lovisa units' operation permits run out 2027 and 2030.

4.5 Other factors influencing technologies, availabilities and costs

4.5.1 The competition for biomass

Biomass will be a scarcity by 2030–2050, when not only the food industry, pulp and paper industry and the wood industry, but also the transport and chemical sectors will compete for it along with the energy industry and end-user heating. For example biomass based pyrolysis oil is used in Joensuu, Finland, in heavy fuel oil boilers for DH. This is not done because it is the optimal commercial/end-use solution for the utilisation of pyrolysis oil, but because the oil grade is not good enough yet for transport usage. The competition for biomass will be at least European if not global.

4.5.2 EU Directives for medium-sized combustion plant emissions

In December 2013 European Commission released a clean air policy package. A part of the package is a proposal for a new directive to control SOx, NOx and particulate emissions from medium-sized, between 1 MW and 50 MW, combustion installations (MCP-directive, see Table 17). An industrial emissions directive (IED) (2010/75/EU) for large combustion plants, >50 MW_{boiler}, is already in force.

The planned MCP directive's planned restrictions for particulates will increase the costs for solid fuels, especially biomass, and the levels might even be difficult to achieve, as scrubbers with heat recovery (the economic solution) will not suffice; solid fuel plants would thus become costlier and less competitive. The MCP is planned to be in force by 2025 for new plants and 2030 for old plants. Plants operating less than 500 hours per year have it a bit easier.

Table 17. Planned MCP directive emissions compared to current legislation in Finland. Source: Pirhonen 2014.

Fuel input	MCP directive	Current legislation in Finland
Existing solid biomass combustion plants		
10-50 MW_{fuel} solid biomass	30 mg/Nm³	50 mg/Nm³
5-10 MW_{fuel} solid biomass		150 mg/Nm³
1-5 MW_{fuel} solid biomass	45 mg/Nm³	200 mg/Nm³
New solid biofuel combustion plants		
10-50 MW_{fuel} solid biomass	20 mg/Nm³	40 mg/Nm³
5-10 MW_{fuel} solid biomass		50 mg/Nm³
1-5 MW_{fuel} solid biomass	25 mg/Nm³	200 mg/Nm³

MCP will increase the cost of a10 MW solid fuel boiler with 2 €/MWh_{th} , of a 2 MW boiler with 7 €/MWh_{th} and of a 1 MW boiler with 10-11 €/MWh_{th}. (Pirhonen 2014)

4.5.3 CO_2 and RES targets

The European – and partly global – targets for the reduction of greenhouse gases are affecting power and heat production systems. The EU target for 2030 is already being formed and general targets for 2050 have been given. The main tool for implementing the targets is the emissions trade. The price of an emission right of one tco_2 is low at the moment, but will rise as tougher CO_2 reductions are strived for.

The EU has a target for RES towards 2020, with national sub-targets, and is on the way formulating one for 2030. However, as recent experience has shown, it is highly uneconomic to have two competing targets, and thus the RES target is set to be subordinate and also valid only on the EU level, not on the national level.

Any changes or twists in the plot will and do affect the competitiveness of the technologies and also which technologies will be more researched and developed than others.

5. Summary and conclusions

Technology changes are to be expected, but they are not only technology or cost driven but more often than not politically driven. What is more, there is often not just one district heating technology that dominates, but a multitude, and each Nordic country will favour some more than others because of local conditions, market structure and historical development.

For example, biomass based DH CHP is a very wide area ranging from small area district heating networks burning local energy crops to large cities combusting bio-based fuel derivatives from far away, from power plants burning sorted and standardized bio pellets to plants burning unsorted waste and MSW.

Bio-CHP will increase either through the market or by political push. All kinds of distributed generation and area networks are expected to increase, and especially smart DH networks using a variety of RES and small scale resources: solar heat, CHP, heat pumps and storages. However, the increase in small scale operations will be stronger in locations where the price of heat and/or electricity are high, e.g. in Denmark, and weaker there where strong DH networks already exist, e.g. in Finland.

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