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Improving district heat sustainability and competitiveness with heat pumps in the future Nordic energy system

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Abstract

District heating (DH) in Nordic countries largely relies on efficient large-scale combined heat and power (CHP) production. The currently low electricity market price has diminished the economic competitiveness of CHP production. Production of DH increasingly happens in thermal heat-only boilers, increasing long-term environmental impacts. An alternative is the use of large-scale heat pumps (LHPs). Utilization of LHPs in hours of low electricity price could be economically advantageous to producers, reduce carbon emissions from burning fuels, and aid in balancing the production and consumption of electricity in a future energy system where electricity production from variable renewable energy is increasing rapidly.

Keywords: heat pump; district heat; energy system modeling; variable renewable energy; CHP

1. Introduction

Nordic district heating (DH) is in large part produced in efficient, large-scale combined heat and power (CHP) plants. For peak and backup operation and small networks, likewise common heat-only boilers (HOBs) are

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preferred. This dynamic is set to change, if the market price of electricity in the Nordic countries (Finland, Sweden, Denmark, and Norway) remains at a low level. The current price level is not sufficient for long-term investments in a large share of existing CHP plants [1]. We expect this to lead to a trend of replacing ageing DH CHP plants with HOBs in the Nordic countries, and this has already been noted in Finland [1] and Denmark [2].

As the relative profitability of CHP in DH production is decreasing due to a low market price of electricity, the same reason is increasing the relative profitability of large-scale heat pumps (LHPs), which produce heat with electricity. Although they are already in use in Nordic DH networks [3], their operational environment is greatly improved with a low price level of electricity. Moreover, even if the price of electricity on average does increase (as expected by many authorities (see e.g. [4–6])), the ongoing rapid growth in the share of variable renewable energy (VRE) based electricity production is expected to bring about more volatility and seasonality into electricity prices, accentuating price peaks and valleys [7]. This will open the possibility for DH producers with LHP capacity to benefit not only from price highs with CHP electricity production, but also from price lows that make heat production from LHPs more economical than from HOBs.

Electricity production in the Nordic countries has notably low carbon emissions. This is due to the technology mix utilized: in 2015, most of electricity production was divided between hydro (58%), nuclear (19%), CHP (11%), and wind power (9%) [8–12]. Due to the marginal cost based pricing system in the Nordic electricity market, the hourly emissions of electricity production (per megawatt-hour) are tied to the amount of hourly production.

Production of DH, in contrast with electricity production, is mostly based on burning fuels, fossil or renewable. In 2015, main technologies utilized were CHP (54% of production), and HOB (estimated at 30% of production) [9], [11], [13–15]. Because there is necessarily only limited trade between DH networks, the networks are limited to the same set of fuels at all times. On the national level, the fossil fuel share in DH production is around 55%, 15%, 40%, and 5% in Finland, Sweden, Denmark, and Norway, respectively, as collected in [16]. Corresponding total DH productions were 35, 52, 35, and 7 TWh, respectively [8], [9], [11], [15].

In the future, an increasing number of DH networks could utilize LHPs in DH production. These LHPs can have a coefficient of performance (COP) of over 3 [17], meaning they can provide thermal energy three times as much as they consume as electricity. In this vision, DH networks would become linked to the electricity market, and they would be able to utilize low-CO_2 and low-priced electricity for heat production when it is available [18].

While the addition of a single LHP to a DH network is a pure investment consideration, the addition of a large total capacity of LHPs to DH networks may affect the whole electricity market. Due to marginal pricing in the Nordic electricity market, the price of electricity (theoretically) increases with each additional megawatt-hour of demand. For example, 500–1000 MW_e of LHP capacity operating simultaneously will increase the total electricity demand corresponding to the total production of a medium-to-large power plant, necessarily affecting the hourly market price. Implications of this dynamic are discussed in depth in [19]. It is important to model the electricity market, along with DH production, in order to understand the system level effects of a large increase in DH LHP utilization.

In this work, we focus on the electricity market perspective of increasing LHP capacity in Nordic DH networks. Our goal is to quantify how a sizeable increase in LHP electricity consumption in the cheapest hours of the year would affect the overall operation of the electricity market and the operation of DH networks. We assess the effects of LHP capacity additions in scenarios with differing electricity production capacities and yearly electricity demands. Our results show that LHPs have the potential to decrease the cost of DH production, to decrease fuel use in the whole Nordic electricity and DH system, and counteract the low price level in the Nordic electricity market.

Nomenclature

CHP	Combined heat and power
COP	Coefficient of performance (heat pumps)
DH	District heating
HOB	Heat-only boiler
LHP	Large-scale heat pump
VRE	Variable renewable energy

2. Literature review

District heat became a part of the energy systems of Nordic countries aided by a wide range of possibilities, including efficient CHP heat and electricity production, utilization of communal waste, and a reduction of dependency on foreign fuels [16]. With these and other standpoints in mind, all Nordic countries support DH utilization with political and/or economic measures.

With a start (historically) as more of an electricity and oil saving heating device than a large-scale heating option, heat pumps had a harder time becoming widespread in the Nordic heating market than DH (see e.g. [20]). Especially the utilization of LHPs in DH systems is quite rare (currently about 1300 MW_{th} [21], a total of 600 MW_{th} of units listed in [22]), even though at least one such operation has existed in Sweden already since the 1970s [17].

Heat pump utilization for heating is different in nature from heat production with thermal processes in more conventional ways. Instead of direct heat production (as in an electric boiler), an LHP transfers heat from a heat source to a higher temperature, consuming electricity in the process. An LHPs COP, which describes the heat transferred per electricity consumed, is highest with the smallest temperature differences between the heated and cooled streams. For this reason, LHPs are installed near a heat source of sufficient size, stability and temperature. The availability of such heat sources is a requirement for investment in LHPs. Lund and Persson [23] have studied the sizes and locations of potential DH LHP heat sources in Denmark, showing that there are potential heat sources nearby almost all DH networks. However, local potentials relative to heat demand favor smaller networks. Lund and Persson have considered such LHP heat sources as industrial excess heat, supermarkets, waste water, ground water and water in rivers, lakes, and seas. Corresponding heat sources can be expected to be suitable also in other Nordic countries due to similar climates.

The potential of LHP heat production in the DH system of Greater Copenhagen has been assessed by Bach et al. [24] using the Balmorel modeling tool. Their results indicate clear potential for LHP usage with the LHP capacity of 260 MW_{th}, corresponding to around 10% of current yearly heat demand in the network with ca. 3500 full load hours. According to the authors' 2025 scenario, the LHPs will have ca. 4000 full load hours. The authors additionally make tests to determine whether the COP of heat pumps needs to be modeled seasonally, or whether a constant value may be used. Based on the results, a constant COP value is sufficient for high level modeling, such as this work.

Schweiger et al. [18] estimate the technical and economic potential of power-to-heat in Swedish district heating to 2 TWh/a in their (year 2050) scenario with 70 TWh/a wind power. They analyze the potential with electric boilers, and state that with LHPs the potential would be lower by a factor of 2–4, because DH demand is a notable limiting factor. A thermal storage with a capacity corresponding to 25% of daily demand is found to improve the potential by 9%. Hast et al. [25] also report that total DH production costs can be reduced with heat storage in a network with a large LHP (20 MW_{th}) relative to network peak demand (ca. 115 MW_{th}). Lund et al. [2] find clear socio-economic benefits from adding an LHP capacity between 2 and 4 GW_{th} to the Danish energy system. They state that LHPs for DH are not currently a feasible investment due to the Danish tax structure, and call for regulatory changes to encourage investment. The investment cost of for a small LHP unit is estimated in [26] to be 0.7 M€/MW_{th}. The corresponding estimates are 0.15 M€/MW_{th} for a small electric boiler, and 0.7 M€/MW_{th} for a small wood chip boiler.

Levihn [17] offers practical insight into the DH network in Stockholm, where heat pumps have long been in use, integrated to CHP plants. The insights include that the combination of LHPs and CHP allows wide heat production optimization based on electricity price, and that a COP of 3.3–3.5 can be achieved in the DH network that has a 65–115 °C supply interval.

3. Modeling method

We model the Nordic electricity market using the Enerallt electricity and DH model, which has been discussed in detail in [27]. New implementations to the model regarding the modeling of hydro power production and the pricing of CHP electricity production were presented in [28]. In the following, we present briefly the key operating principles of the Enerallt model.

Enerallt simulates the electricity market and DH production in the Nordic area on an hourly level. The simulation considers price areas or countries set up by the user and the electric interconnection capacities between them. In the version of Enerallt used in this work, the exchange of electricity between the Nordic countries and the external power markets is modeled as a set of fixed profiles from the reference year (here 2014). Enerallt is an especially capable model for modeling the hydro-dominated Nordic power market. With it, we can assess the effects of specific power production and consumption changes to the overall Nordic market.

3.1. District heating modeling

The DH demand of each modeled area is divided for different fuels and technologies based on plant capacities (for technologies) and historical fuel shares (for fuels). This is done because each area may contain numerous separate DH networks, which are tied to specific fuels and technologies. The division of DH demand is meant to capture this inflexibility as accurately as possible.

After the division, DH production is planned hourly for the whole year. Heating demand divided for HOBs is produced with HOBs, and the demand divided for CHP is produced by CHP plants and compensated with HOBs where necessary. Before these technologies are used, there is the possibility to produce heat from variable sources, here LHPs.

For CHP, it is not known at the time of DH planning if the electricity produced will be cleared in the market (if the area price is sufficiently high). The marginal cost of CHP electricity is additionally fuel (and area) dependent. Thus, the actual CHP production (cleared in the market) differs from the planned one both in amount and fuel distribution.

The share of CHP heat that is planned in the DH modeling, but is not purchased in the market, is replaced with HOB heat. On the other hand, if CHP electricity production is not planned (i.e. not all CHP heating capacity is needed), large CHP plants will offer their electricity production capacity to the electricity market as condensing power. It should be noted that without heat storage implemented (which is the case in this work), this methodology is electricity market focused, and the fuel mix changes resulting from the inflexibility of CHP production are not always realistic. However, this minor issue is mostly relevant in emission comparisons between DH technology scenarios.

3.2. Electricity market modeling

The electricity market simulation is made in a way that closely resembles the operation of the Nordpool Spot market. The simulation is carried out in three main steps, consecutively for each hour. First, the electricity demand is determined for each area. This includes LHP electricity demand from the DH modeling step. The electricity demand is not dependent on the price of electricity. Next, electricity supply (i.e. sell bids to the market) is determined. This happens by consolidating the marginal price and capacity combinations of the power production technologies. Third, the electricity market is simulated by determining first the system price of electricity, followed by the area price determination that considers the interconnection capacities between countries or price areas. As a result of this last calculation, also the production technologies, transmission line use, and other market outcome features become clear.

The method of hydro power modeling has a large impact on simulations of the Nordic electricity market. In this work, hydro power capacity is categorized based on country and storage capacity. Each category of capacity follows the reference year (here 2014) system price profile, which has been scaled first for each storage capacity category to reflect possibility to delay production, and then for each country to reflect the potential for profit with the available inflow. The latter scaling is done by running the model iteratively to find price levels that lead to the expected hydro power total yearly production in each country. A detailed description of the method used is available in [28].

4. Scenarios

We show the impact of LHPs on the electricity market and DH production in three different scenarios, which are projections of the electricity production and consumption developments in the Nordic area from year 2014 to 2030.

The base scenarios (without LHP capacity) have been presented in an earlier work [28]. From here on, we will use the word "scenario" for describing all "cases" (simulations with a specific LHP capacity) that are based on the same base scenario. Because LHP operation is very dependent on the price level on the electricity market, we assess the impact of LHPs in three scenarios with different qualities. The first is Scenario 2014, modeled with available data from that year. The second is Scenario 2030A, where wind power capacity has more than doubled from 2014, and nuclear capacity has increased, among other changes. Electricity and heating demands are unchanged. The third scenario is Scenario 2030B, which is identical to 2030A, except that electricity demand has increased from 2014 by 43 TWh (from national forecasts [4], [29–31]). The demand of DH is kept constant between the scenarios in order to show the effects of the LHPs clearly. In reality, according to the IEA Nordic Energy Technology Perspectives 2016 report [6], DH demand will fall in 2013–2050 about 1% annually, on average. Because of the tight connection between DH and CHP, we keep also CHP capacities constant over the scenarios. Nordic-level information about the scenarios is shown in Table 1. Detailed descriptions of the scenarios can be found in [28].

The LHP capacity to the base scenario is added identically in all cases. The capacity is set for a number of periods of 12+ hours so that the capacity is available for a total of 4000 hours with the lowest possible average system price, with the system prices of the appropriate base scenario with no LHP capacity. The purpose of this is to simulate LHP utilization in hours in which CHP production would be the least profitable or feasible. The LHPs are set to produce heat in connection with (and with priority over) existing CHP plants.

Table 1. Key attributes of the modeled scenarios.

	2014	2030
Hydro power	50,317 MW_e	51,843 MW_e
Nuclear power	11,200 MW_e	12,300 MW_e
CHP	15,280 MW_e	15,280 MW_e
–Of which large plants	9,484 MW_e	9,484 MW_e
Condensing power	9,146 MW_e	0 MW_e
Wind power	10,600 MW_e	28,800 MW_e
Solar power	627 MW_e	985 MW_e
Electricity demand	377 TWh	377 TWh (in 2030A)
		420 TWh (in 2030B)
Carbon emission price	5 €/tCO_2	20 €/tCO_2

4. Results and discussion

In this section, we present results from adding 0–2000 MW_e of LHP capacity into the scenarios described in the previous section. We analyze the effects of LHP capacity increases in a logical manner, starting from effects on electricity production, moving on to effects on the electricity market, and to discussing the effects on the technologies and costs of heat production in the three scenarios. Finally, we analyze the sustainability of LHPs in the Nordic area.

In Figure 1, we show electricity production in CHP and condensing power plants in the Nordic countries in each scenario with a range of added LHP capacity. Clearly, total electricity production will increase by the consumption of the LHPs. This increase is approximately 3 TWh with 1000 MW_e of HP capacity, and 5 TWh with 2000 MW_e of HP capacity in all scenarios.

The increase in electricity production happens in condensing and CHP electricity production in Scenarios 2014 and 2030B. In Scenario 2030A, there is unused nuclear power capacity in the low electricity price hours because of the high share of VRE electricity production with low marginal costs. Thus, the increase in electricity consumption leads to an increase in nuclear power production specifically, due to its low marginal cost of production.

The total CHP power production decreases in each scenario with increasing LHP capacities. An exception to this observation is Scenario 2030B with 0–1000 MW_e of LHP capacity. There, CHP power production does decrease in

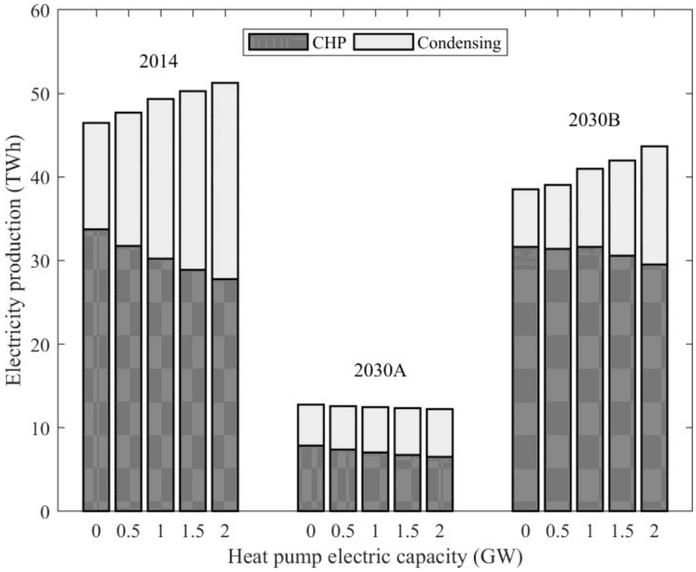

Figure 1. Production of CHP and condensing mode electricity in the three scenarios with different amounts of large-scale heat pump capacity. The base scenario is indicated at the top of each group of bars.

the hours when LHPs are running (like in the other scenarios), but this increases the average yearly electricity price so much that CHP production increases in other hours. These opposing changes in production approximately cancel each other out. The electricity price increase is not limited to the hours in which LHPs are running due to the myopic hydro production modeling method.

Regarding the changes in condensing and CHP power production shown in Figure 1, it should be noted that we do not consider DH heat storage or thermal inertia in this paper. Thus, CHP electricity production is restricted to satisfying the DH demand on each single hour. Compared to reality, this causes the model to overestimate the share of condensing power at the expense of CHP electricity production.

The system price of electricity is important in an effort to understand the dynamics of the Nordic electricity market concerning LHP capacity increases. In Figure 2, the system price is shown for each scenario with a set of LHP electric capacities. In the figure, the median system price and the range from the 25th to the 75th percentiles of hourly electricity prices during the modeled year are shown for each case. The implications of Figure 2 are tightly linked to those of Figure 1. For Scenario 2014, the system price increases steadily with increasing LHP capacities. This steadiness of change is interestingly visible also in Figure 1. For Scenario 2030B, the price increase is steeper, and perhaps surprisingly not linear. For Scenario 2030A, the price increase is practically nonexistent, with nuclear power remaining as the typical marginal price setting technology. It should be noted that in practice Scenario 2030A is discussed here as a scenario that is indicative of a more general oversupply situation. The authors of this paper do not believe such a low price level would be in practice possible without subsequent corrective adjustments in the market. However, modeling these adjustments is outside the scope of this work, and the scenario is included due to its value as an indicative scenario.

As is visible from the above discussion, the analyzed changes in heat and electricity production have interrelations that are not trivial. As examples, LHP capacity addition may cause an average price increase that causes the amount of CHP electricity production to increase. At the same time, this price increase would make LHP heat production less profitable. The consequences of these types of interrelations depend on the proportions of the studied system: the capacity of LHPs vs CHP, the share of CHP of total yearly heat production, the fuel mix of the CHP and condensing power plants, the fuels' relative prices, and other similar relationships. The issue of LHP operation affecting the electricity price (and hence, the profitability of the LHPs) is handled in a simple manner here, as LHP operation hours in all cases are chosen from the lowest price hours in the scenario without LHPs.

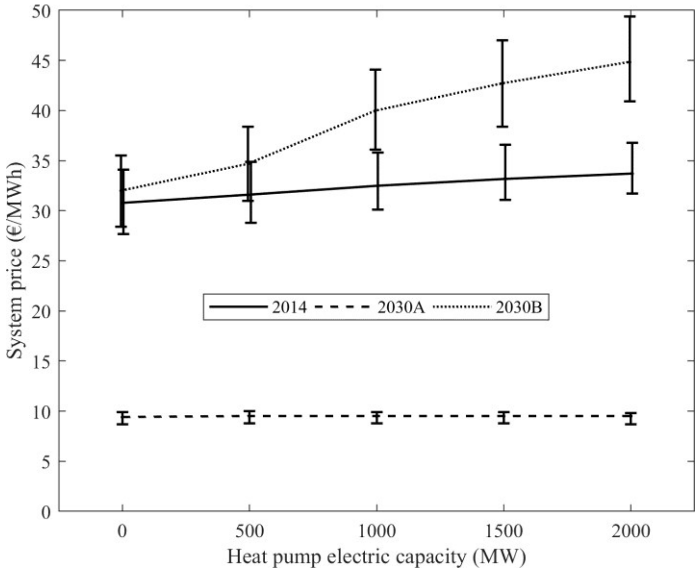

Figure 2. The median system price in the scenarios with different large-scale heat pump capacities. The vertical bars represent price variation during the year, specifically the 25th and 75th percentiles of the hourly system price.

In Figure 3, the total cost of heat production in the whole Nordic area is calculated for each scenario and case. In the calculation, variable heat production costs are considered for all plants. For LHPs, these are the cost of electricity plus an additional cost of 2 €/MWh_{th} for DH production (see [26]). For CHP, revenue from electricity sales is calculated separately from costs. For both CHP and LHP, the price of electricity is the area price of the hour of consumption or production. The total cost of heat production with CHP electricity revenue subtracted is shown with a white circle. Investment costs are not considered in the calculations.

It is seen from Figure 3 that the effects of LHPs on heat production costs are not decidedly linear. The only linearity in the figure that is common to all scenarios is the fact that the net cost of heat production decreases in each scenario with the addition of LHP capacity. The mechanism for the decreasing total cost varies in the scenarios. In Scenario 2014, the cost of CHP heat production decreases (due to the decrease in production), but it decreases more than the reduction of revenues from CHP electricity (due to the increasing system price). In Scenario 2030A, a straightforward cost decrease is seen due to the low cost of LHP heat production, which in turn is caused by the low price of electricity. In Scenario 2030B, the cost of heat production (not considering revenues) stays relatively unchanged compared to Scenario 2014 with different LHP capacities. However, revenue from CHP electricity increases with the LHP capacity (as the system price increases), causing the decline in the total heat production cost.

Next, we discuss the results regarding the sustainability of DH from two viewpoints: i) fuel consumption and CO_2 emissions, and ii) the long-term viability of the technology and fuel mix. The latter viewpoint is related to economic and system infrastructure issues, of which the economic side has been discussed above.

Our results indicate CO_2 emission reductions, if the fuel mix does not change. The total fuel consumption in DH and electricity production in the Nordic area is decreased by the addition of 2000 MW_e of LHP capacity by 5, 18, and 7 TWh (2%, 10%, and 3%) for Scenarios 2014, 2030A, and 2030B, respectively. This implies a significant potential for CO_2 emission reductions. The overall emission reductions in electricity and DH production depend on how the marginal power production fuels change because of LHP operation. The main fuels are coal, peat, natural gas, and biomass. As biomass is supported with financial mechanisms in all countries considered, we can assume that the fuel use reductions will be largely targeted at fossil fuels, such as coal. Because we have not modeled thermal inertia or heat storage of DH networks in this work, the current results do not realistically represent the dynamic of fuel mix changes from the LHP capacity additions.

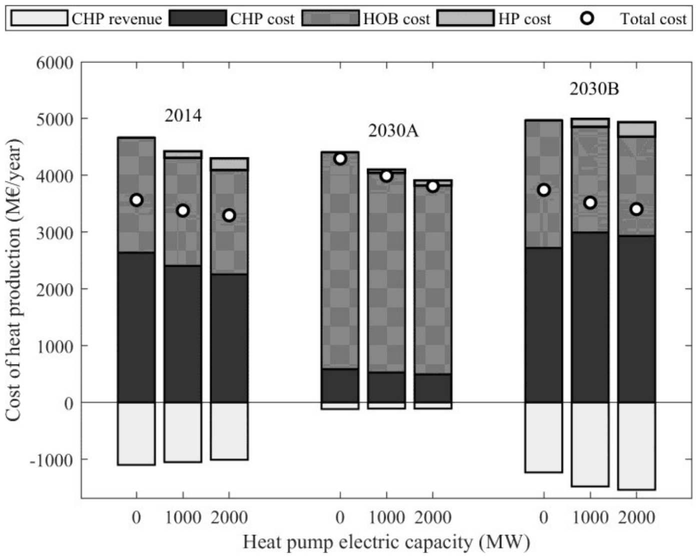

Figure 3. Costs of heat production from CHP, heat-only boiler, and large-scale heat pump units in the scenarios with different large-scale heat pump capacities. The revenue from CHP electricity production is shown separately from CHP heat production costs as a negative cost. The total net cost of heat production is marked with a white circle. The base scenario is indicated at the top of each group of bars.

The utilization of LHPs can be argued to increase the robustness of DH as a part of a low-CO_2 energy system. The diversification of heat production to power-to-heat technologies will improve flexibility of production in DH networks. This creates robustness against fuel and electricity price fluctuations in the future. From the perspective of the electricity and DH system, the interconnection of the two sectors is a vital early step in progressing towards a "smart energy system" as visioned in [32]. The interconnection of the sectors may in the future add flexibility to electricity demand (e.g. through utilizing heat storages) and help in integrating a higher share of VRE in energy production than would be possible without its flexible use in the DH sector.

5. Conclusions

In this work, we analyzed three heat and electricity production scenarios for the Nordic area. We simulated the addition of varying amounts of DH LHP capacity to each scenario to investigate the effects this has on the electricity market and DH production. In our analysis, the LHPs were added to networks with existing CHP plants. Heat production by LHP was prioritized over CHP in 4000 hours with low electricity prices, where CHP production was less profitable or infeasible in the scenario without LHPs.

According to our results, the addition of LHPs into the DH systems decreases DH production operating costs in all examined scenarios by 8–12%, with taxes on LHP excluded. However, the market price of electricity increases at the same time by 0–40%, with the highest increase occurring in our high electricity demand scenario 2030B. As a result, the revenues of CHP plants increase relative to a unit of heat production. The electricity price increase is a positive impact for the Nordic electricity market that is currently experiencing a period of low electricity prices, which hinders investment in new electricity production capacity.

When LHP heat production is added to a base scenario, CHP heat and electricity production typically decreases. This is not the case in Scenario 2030B, where with low LHP capacities the decrease is compensated by higher production in hours without LHP heat production. This is due to an overall increase in the price of electricity. Because we did not consider thermal inertia and heat storage in this work, condensing production is overall higher than it would be in reality, at the expense of CHP electricity production. Regardless of the decrease of CHP energy production, the total fuel consumption in the Nordic electricity and DH system decreases in all examined scenarios due to the addition of LHP capacity. This is made possible by the high COP (3.0) of the LHPs. The decrease in total fuel consumption (7–18 TWh in 2030) indicates significant potential for emission reductions.

In addition to the described benefits, LHPs strengthen the interconnection between the electricity and DH markets. This is seen as an important development in research into future energy systems (e.g. [32]). The interconnection allows the usage of VRE and other inflexible electricity production for heating, increasing the potential for low-CO_2 DH production beyond biomass utilization. The diversification of technologies also has benefits for DH networks through added robustness against future energy market trends. For example, periods of low electricity price will become increasingly common with the growing share of VRE in total electricity production. Networks with LHP capacity can benefit from such periods. There is also potential for additional revenues from LHP operation from intra-day or balancing electricity markets, which are not analyzed in this work.

As next steps for future research, heat inertia and storage should be included in the model used in this work. Additionally, LHP operating hours should be set incrementally and iteratively to the scenarios to improve the representation of the production planning done in DH networks.

In this paper, we have shown that LHP utilization has a selection of potential benefits to the future Nordic energy system, from economic and environmental benefits in DH production to the improvement of electricity system flexibility. Based on this, we suggest that policymakers should ensure that taxation or political barriers do not impair the feasibility of new LHP projects.

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