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# Economic incentives for flexible district heating in the Nordic countries

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ABSTRACT

By analysing four types of district heating plants, ranging from fully integrated with an electricity system (combined heat and power and electric boiler) to no integration with an electricity system (wood chip boiler), operation and investment incentives for flexible district heating plants under current Danish, Finnish, Norwegian and Swedish framework conditions have been investigated. Hourly-based operation optimisation over 20 years using the modelling software energyPRO showed that the largest investment incentive in Finland, Norway and Sweden was for combined heat and power with an electric boiler. This is largely driven by subsidies. Conversely, the less-subsidised Danish case incentivised investment in wood chip boilers. Untaxed biomass is the major energy source in all scenarios, while electricity use is limited. Capacity component-based tariffs can eliminate operation of electric boilers, while less costly energy component-based tariffs can increase the operation of electric boilers. Heat storage was found to be a no-regrets solution for optimising operation and lowering costs in all cases.

***Keywords:***

District heating;
Flexibility;
Thermal storage;
Energy taxation;
Electricity grid tariffs;

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## 1. Introduction

The energy share from renewable sources of the total primary energy supply in the Nordic countries Denmark, Finland, Norway and Sweden was 27–43% in 2014. Present EU-wide policy targets include an increase in the EU 2014 15% gross share of renewable energy in energy consumption to at least 27% by 2030 [1], and decarbonisation goals for 2050 [2] are likely to further increase the share of renewable energy in the Nordic region. If a significant portion of this additional renewable energy stems from variable renewable electricity (VRE) production, such as solar photovoltaics and wind power, there could be an increased future need for flexibility in energy systems (*flexibility* is defined in Section 2.1). As of 2015, Denmark had the largest penetration of VRE among the Nordic countries, where wind power corresponded to 50% of Danish net electricity generation.

Increased coupling among the energy sectors is emphasised as a pertinent challenge for policy makers by IEA [3] and can lead to energy systems that are flexible and able to integrate VRE [4], summarized under the term *smart energy systems* [5]. Smart energy systems by definition span several sectors and flexibility can thus be offered by a multitude of technological options. A comprehensive overview of such flexibility options has been provided by Lund et al. [6], where examples include hydropower capacity, electric vehicles,

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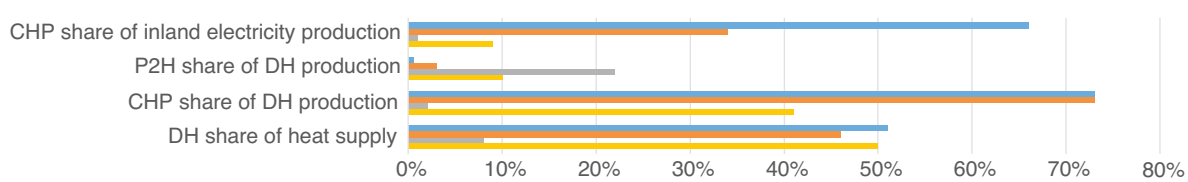
## Abbreviations

CHP: Combined heat and power
CT: Capacity component-based electricity transmission and distribution grid tariff
DH: District heating
DK: Denmark
DSO: Distribution system operator
EB: Electric boiler
ET: Energy component-based electricity transmission and distribution grid tariff
FI: Finland
HS: Heat storage
LCOH: Levelised cost of heat
NETP: Nordic Energy Technology Perspectives 2016
NO: Norway
O&M: Operation and maintenance
OB: Oil boiler
P2H: Power-to-heat
PUD: Preferred unit for dispatch
SE: Sweden
T&D: transmission and distribution
VRE: Variable renewable energy
WCB: wood chip boiler

individual consumers, hydrogen and synthetic fuels production, and heating and cooling. Coupling and smart energy systems are therefore considered enablers for renewable-based, less expensive and resource-efficient energy systems [7,8].

Several studies have indicated that the interface between the electricity system and the district heating (DH) system is an important aspect of energy system integration [7–9]. Furthermore, the potential of flexible DH technologies for sector coupling has been demonstrated in both real-world deployment in the Nordic countries and in the literature [4,6,10]. Combined heat and power (CHP) and power-to-heat technologies (P2H), i.e. heat pumps and electric boilers (EB), are relevant flexibility providers for DH systems [4,6,10–13]. As an example of the impact of introducing increased electricity demand flexibility (e.g. from P2H), Tveten et al. [14] have demonstrated a 7.2 TWh/year increased integration of VRE in Northern Europe by 2030. Connolly and Mathiesen define such introduction of CHP and P2H as two of the key stages in a transition to a 100% renewable energy system [15]. In addition, studies have shown that the deployment and use of heat storage (HS) is an important enabler of the flexible operation of both CHP and P2H [16–19]. Increased flexible coupling of heat to an electricity system would thus be one step towards a smart energy system, where the integration of VRE can be facilitated by the flexible operation of DH plants.

Energy consumption in Nordic countries in 2013 amounted to 115 TWh DH and 345 TWh electricity [20]. Figure 1 presents the share of CHP for national electricity production, of P2H for DH-production, of CHP for DH-production and of DH for total heat demand in each of the Nordic countries [21]. Norway is an exception because




| | DH share of heat supply | CHP share of DH production | P2H share of DH production | CHP share of inland electricity production |
|---|---|---|---|---|
| Denmark | 51% | 73% | 1% | 66% |
| Finland | 46% | 73% | 3% | 34% |
| Norway | 8% | 2% | 22% | 1% |
| Sweden | 50% | 41% | 10% | 9% |

Figure 1: Characteristics of district heating for Nordic energy systems in 2014. Data based on Euroheat & Power [21] and national statistics.

the DH sector is relatively small, compared to the other Nordic countries. The share of heat production from heat pumps and EB for DH is insignificant in all countries except Norway and Sweden, where heat pumps comprise the largest share of P2H production. HS are generally applied in all countries except Norway, where the operational practice is that generation follows heat demand rather than utilising HS [22].

While earlier framework conditions have generally accommodated a large deployment of DH in Denmark, Finland and Sweden, incentives for further investment in flexible DH technologies are less clear for the Nordic countries. As indicated by Difs [23] and Jacobsen and Zvingilaite [24], national regulation can be unconducive for flexible Nordic energy systems. Therefore, national regulation in Nordic countries encompassing taxes, subsidies and electricity tariffs was explored during this study. Specifically, investment incentives in flexible DH technologies were identified and investigated for new DH plants. Sandberg et al. compared framework conditions for DH in the Nordic countries in general [25]. Skytte et al. [26] explored the impact of DH technologies on marginal operation costs in Denmark, Norway and Sweden; Sneum et al. examined policy impacts on operation and investment incentives of DH in the Baltics [27]; and Trømborg et al. [28] analysed the impact of framework conditions for generic heat-only DH plants on operation and profitability. Munksgaard and Olsen [29] evaluated the impact of taxation on investment, and Kirkerud et al. [30] investigated the impact of electricity tariffs in Nordic countries. The novelty of this study is to extend existing knowledge by providing a holistic picture of the investment and operational conditions for new DH capacity in the Nordic countries. We do so by analysing how current policy and regulation align with assumed societal needs for increased flexible DH capacity in the energy system. In summary, the study answers the question:

*How do HS, current electricity transmission and distribution grid tariffs, taxes and subsidies incentivise investment in and operation of flexible DH technologies in the Nordic countries?*

The methodology is described in Section 2, followed by the results of the analyses in Section 3. Results are discussed in Section 4. The conclusions are presented in Section 5. The acknowledgement is given in Section 6, the references are listed in Section 7 and the appendix is provided in Section 8.

## 2. Methodology

Taxes, subsidies and electricity transmission and distribution (T&D) grid tariffs were analysed in aggregate along with HS to determine their impacts on operation and investment incentives. Models for four types of DH plants were developed using the analysis tool energyPRO. Each type of plant had a different degree of coupling to the electricity system, representing different options for potentially flexible interactions in the DH-electricity interface. Furthermore, for each country, the model was subjected to the current (2016) levies and subsidies applicable for each Nordic country. The outcomes of these feasibility studies indicate whether the current economic framework conditions incentivise investment in flexible DH plants of the chosen type and to what degree HS impacts economic feasibility.

### 2.1. Definition of flexibility

During this study, incentives for investment in potentially flexible DH technologies were analysed. While an analysis of flexibility in itself is outside the scope of this study, it is important to define flexibility because it is a characteristic assigned to the technologies addressed in this study.

In recent years, flexibility in energy systems has received comprehensive coverage in both grey literature and academic literature, such as IEA [4], Denholm and Hand [31], Holttinen et al. [32] and Lund et al. [6]. In this study, flexibility is characterised by the ability of a DH-technology to provide frequent increases or decreases in its consumption or production of electricity according to signals from the electricity system, such as the use of P2H during hours when electricity prices are low, CHP electricity production during hours when electricity prices are high and the use of HS to supply heat when demanded. This electricity-oriented definition is in line with the DH-electricity focus applied by Salpakari et al. [33] as well as with the definitions applied by Lund [6] and Mathiesen [5] from a broader energy system perspective.

Thus, to accommodate flexibility in the energy system, investment incentives for DH technologies should favour those technologies which enable interactions in the DH-electricity interface. Furthermore, the flexibility of these technologies should not be impeded by operational barriers. The operational focus in this study is thus not to determine the flexibility of a

given plant but rather to clarify the impact of operation on the economic feasibility of flexible DH technologies.

## 2.2. Operation and investment analysis

By analysing the economic framework conditions and the presence of HS, the operational patterns, and subsequently the investment incentives, were explored for flexible and inflexible configurations of DH plants in Nordic countries. This section introduces each of the three concepts.

Electricity T&D grid tariffs are set by grid companies—transmission and distribution system operators—to cover the cost of using the grid. Electricity T&D grid tariffs vary in terms of design and magnitude among countries and regions but are typically constructed as *grid tariff = fixed component + energy component + capacity component*. Variations in structure and volume can be explained by factors such as customer types and connection level and can induce different operational patterns in P2H technologies because they impact the marginal cost of operation. In turn, operational patterns can be decisive for the economic feasibility of the technology or plant. This study focused on local distribution grid tariffs for business customers with an installed capacity of 10 MW and a high voltage connection of 10-20 kV (DH plants), and the costs embedded in those. For the electricity T&D grid tariffs included in this study, Finland, Norway and Sweden all apply capacity components, which are set by the highest electricity consumption in MW per month and a reduced energy component per MWh electricity consumed. Denmark applies only energy components. In Norway and Sweden, some grid companies allow so-called non-prioritised tariffs for devices interruptible on short notice such as P2H. Non-prioritised tariffs can be structured as a reduced or removed capacity component and an energy component, which is the same or higher than under the capacity component-based tariff scheme. To explore the impact of capacity component-based electricity grid tariffs (CT) as well as energy component-based electricity grid tariffs (ET), it was assumed that all countries provide both tariff options.

In contrast to electricity T&D grid tariffs, taxes and subsidies do not necessarily reflect the costs of using a product but can be applied to address externalities or for fiscal purposes [29]. Like electricity T&D grid tariffs, taxes and subsidies impact the marginal operation costs and thereby the operation. This impact was explored by subjecting the scenarios to a removal of all taxes and subsidies, whereby it was determined how taxes and subsidies impacted the operation of the DH plants analysed.

HS can allow improved utilisation of least-cost technologies by enabling a decoupling between heat demand and electricity prices. For CHP and P2H technologies, this means that they can operate when electricity prices are respectively high or low regardless of the correlation with heat demand.

### *2.2.1. Operation analyses using energyPRO simulation software*

The quantitative analyses were conducted as techno-economic studies of four different types of DH plants for each of the Nordic countries. This allowed for a comparison of the impacts of taxes and subsidies and the use of HS. Operation optimisation was conducted using the DH simulation software energyPRO because this is a proven tool that has been applied in industries and academia (e.g. [34,35]) for performing techno-economic feasibility studies, scenario analyses and simulations of operations for DH plants [28,36]. energyPRO optimises operation on an hourly level with deterministic results to obtain the lowest heat production cost, and it also considers the availability of HS capacity.

Inputs for the model include temperatures, energy demands, technologies and costs, some of which impact the marginal heat production cost. As illustrated in Figure 2, operation depends on the marginal heat production cost in relation to the electricity price, here termed *preferred unit for dispatch* (PUD). In the example provided in Figure 2, the inclining lines represent P2H, which is PUD in periods with low

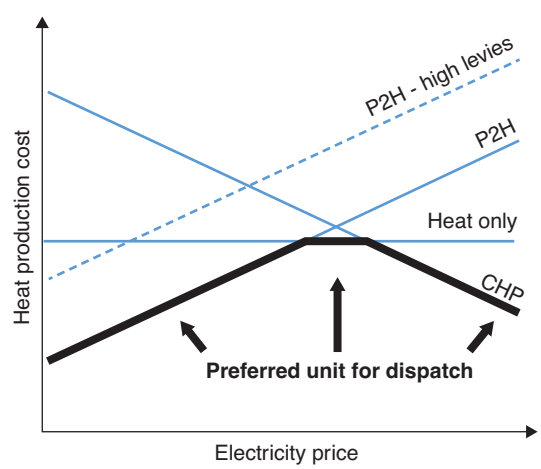



Figure 2: PUD and marginal heat production costs in a DH plant with heat-only boilers, P2H and CHP

electricity prices. Whereas electricity spot prices define the general tendency of an inclination/declination in costs, electricity T&D grid tariffs, taxes and subsidies determine the internal relations between each unit. This is exemplified by the dotted line, where due to high levies, P2H has relatively higher marginal heat production costs than P2H without levies (solid line), and therefore it is only PUD in periods with very low electricity prices.

The analyses conducted using energyPRO were based on a perfect foresight regarding electricity prices, which means that the models were optimised using known future electricity prices. This could potentially lead to unrealistically perfect hour-by-hour load-following in the DH production of CHP and EB. To address this issue, CHP and EB were only allowed to operate in full load. This operation, which is based on power market bids for full loads, is seen in real Danish CHP plants. The day-ahead electricity spot market prices are applied in the modelling. For further details on additional power markets, Sorknæs et. al [37] have provided insights on the ability of CHP to integrate VRE through the ancillary services markets. Further details on the optimisation using energyPRO can be found in [38].

### *2.2.2. Feasibility study of investment incentives*

For a DH plant to offer flexibility, it must exist in an energy system. To exist, there must be an investment. Thus, in addition to operational aspects, investments in flexible DH technologies are important for securing the availability of flexible technology options.

Combining the operational costs and revenues from the energyPRO simulations with investments allows for microeconomic feasibility studies of the technologies applied in the scenarios. In turn, this provides a means of comparison between scenarios, indicating the most profitable/least costly projects. In practice, comparisons were done on the levelised cost of heat (LCOH), i.e. the discounted sum of expenses, income and energy calculated over the lifetime of the project. Discounting was performed at a nominal rate of 4%, reflecting the current low cost of capital and low risk for such long-term projects in the Nordic countries. All income and expenditures were subject to inflation (1.5 to 2.3% varying over years) based on projections by the Danish Energy Agency [39]. Investment costs were based on The Norwegian Water Resources and Energy Directorate [40]. The project period spans from 2015 (investment year) and 2016 (first year of operation) to 2035 (final year of operation), where components with a remaining lifetime were decommissioned at a linear scrap value for hardware costs. Revenue from sales of heat was not included in the study because this is represented by the LCOH. LCOH thus indicates the cost of supplying heat, where lower is better because it is assumed that the economically rational *profit-maximizing investor will select the production technology having the lowest long run production costs taking into consideration the present tax regime including subsidies* [29]. LCOH calculation followed the normal approach for the levelised cost of energy, as seen in Eq. (1).

$$LCOH = \frac{\sum_{t=0}^{n} \frac{TC_t}{(1+r)^t}}{\sum_{t=0}^{n} \frac{q_t}{(1+r)^t}} \tag{1}$$

Where

- *LCOH*: levelised cost of heat
- *n*: number of years
- *t*: given period
- *r*: discount rate
- $TC_t$: total cost in period *t*
- $q_t$: heat production in period *t*

$TC_t$ is specified in Eq. (2) because taxes and other variable costs were a significant part of this study. The energyPRO operational optimisation included the parameters marked in *italics*.

$$TC_t = \mathrm{I_t}\ \mathrm{IS_t} + \mathrm{FOM_t} + VOM_t + F_t + E_t + T_t + TF_t + TV_t - E_t - S_t \tag{2}$$

Where

- $I_t$: investment cost in period *t*
- $IS_t$: investment subsidy in period *t*
- $FOM_t$: fixed operation and maintenance cost in period *t*
- $VOM_t$: variable operation and maintenance cost in period *t*
- $F_t$: fuel cost in period *t*
- $E_t$: spot electricity cost in period *t*
- $T_t$: tax ($CO_2$, energy and public service obligations) in period *t*
- $TF_t$: capacity component-based electricity T&D grid tariff in period *t*
- $TV_t$: energy component-based electricity T&D grid tariff in period *t*
- $E_t$: revenue from electricity sales in period *t*
- $S_t$: energy dependent subsidy in period *t*

### 2.3. Technologies, framework conditions and their combined variations

For this study, four different combinations of DH technologies were chosen to reflect potential investment options under policies for the increased use of renewable energy in the DH system. Each of these technology combinations described DH plants in varying degrees of potential flexibility in the DH-electricity interface. Thus, the combinations ranged from inflexible (large wood chip boiler [WCB]) to flexible production and consumption (backpressure wood chip CHP and EB). All technology combinations were required to satisfy the same heat demand of 40 GWh (2016) and were supplemented with an oil boiler (OB) as a fall-back option, providing capacity for backup and peak load. Each technology combination, ordered from A through D, is detailed in Table 1. The terms *baseload, mid-load* and *peak load* indicate a level of operation (load) according to the design assumption for a typical plant. A water-based 2000 $m^3$ storage was included in scenarios with HS. This volume corresponds to one to three days of heat demand in similar sized DH plants in Denmark.

The technological combinations were subjected to three overall conditions to determine impacts on investment incentive and operation. Specifically, we evaluated the operational impact of taxes and subsidies, and the impact on investment incentive and operation of HS and electricity T&D grid tariffs.

Together, the technological combinations and conditions provided a set of scenarios, which are shown in Figure 3. Analysing each scenario for each of the four countries under study yielded 96 different operation analyses, whereof the economic feasibility (LCOH) was analysed for the 48 studies with tax.

### 2.4. Data and assumptions

The impact of electricity T&D grid tariffs, taxes, subsidies and HS on incentives for operation and investment were the focal points of this study. To analyse taxes, subsidies and electricity T&D grid tariffs, it was necessary to conduct extensive reviews of their levels and designs for each country. The regulations for heat and electricity production vary among the countries, e.g. depending on the categorisation under the European Emissions Trading System or to which customers the DH is supplied. This review combined desk research, dialogue with national authorities and dialogue with national partners in energy academia (Technical University of Denmark, Aalto University in Finland, Norwegian University of Life Science and the Swedish Royal Institute of Technology) to ensure validation. To the best of the authors' knowledge, the data are thus comprehensive for electricity T&D grid tariffs, taxes and subsidies as of 2016.

Changes in heat demand and price levels of wood chips, electricity and oil followed the projections from the dataset of the Carbon Neutral Scenario in the Nordic Energy Technology Perspectives (NETP) [42], which for this purpose was considered the most comprehensive and valid source of data considering the geographical region and time period. The projected increases in wind power (2014: 7%, 2040: 24%) and electricity prices are illustrated in Figure 4.

Heat demand (40 GWh) is dependent on outdoor temperatures, which have been adjusted to the area of the capital of each of the four countries.

Levies on $NO_x$ and $SO_2$ emissions are not included, as these are negligible in all countries in comparison to the levies included in this review. Electricity T&D grid tariff design and magnitude can vary greatly within countries and was thus selected from the capital areas of each country. Financial regulations (e.g. corporate tax regulation, depreciation rules), reactive power charge and trade on the ancillary services markets are outside the scope of this study.

Table 2 presents the wood chip and oil prices. The oil price is set at an average common price. Electricity prices

**Table 1: Technological combinations considered. Capacities and load shares are based on Norsk Energi and Thema Consulting Group [41]**

| | Baseload | Mid-load | Peak load | | |
|---|---|---|---|---|---|
| **Technological combination** | **5.4 $MW_{TH}$ 45% of peak load, low fuel price** | **6.6 $MW_{TH}$ 55% of peak load** | **12 $MW_{TH}$ 100% of peak load, low investment cost** | **Flexible technology: Production** | **Flexible technology: Consumption** |
| A | Wood chip CHP | EB | OB | X | X |
| B | Wood chip CHP | WCB | OB | X | |
| C | WCB (12 $MW_{TH}$) | — | OB | | |
| D | WCB | EB | OB | | X |

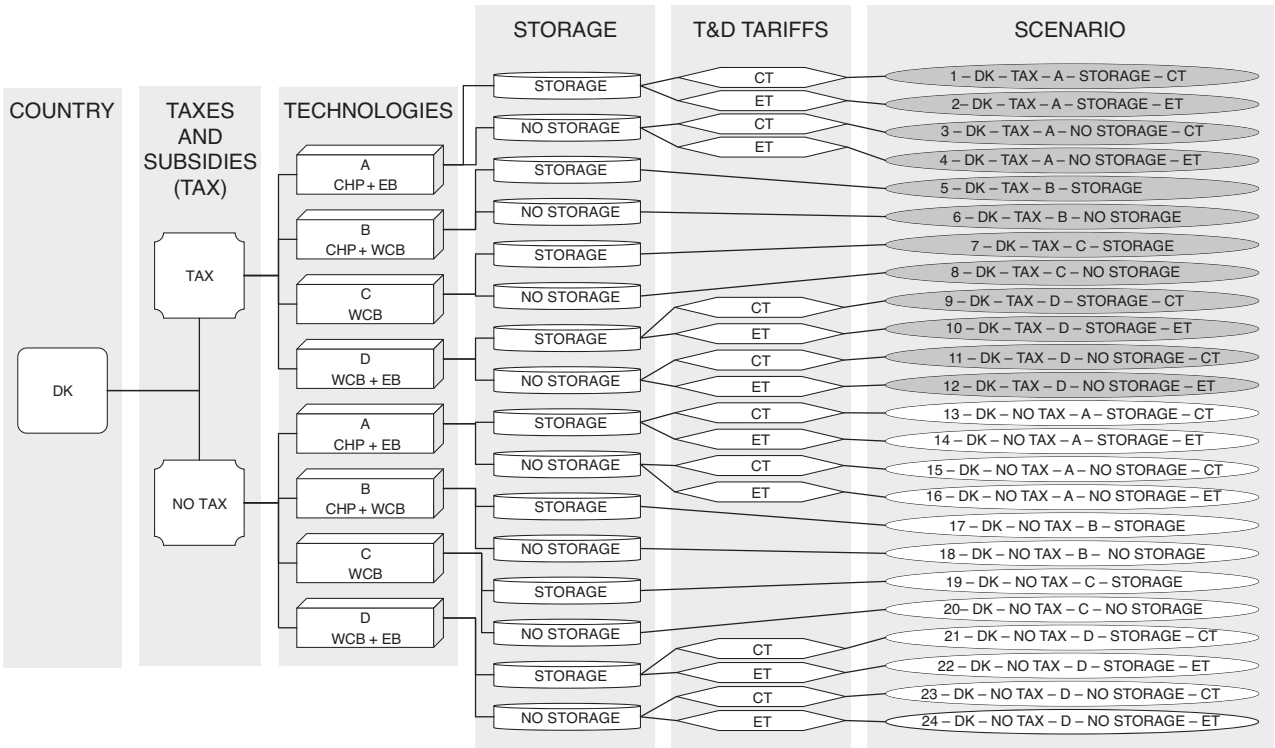
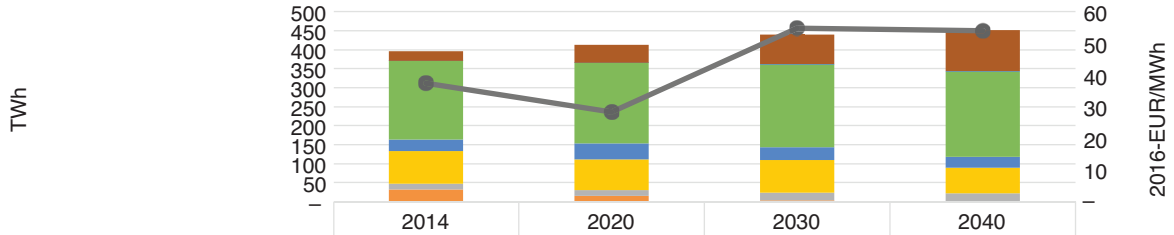



Figure 3: Structure of scenarios with Denmark as example. Analyses were conducted respectively with and without tax and subsidies, and storage, on the technological combinations. Furthermore, the technological combinations with EB were subjected to electricity T&D grid tariffs, leading to a total of 24 scenarios for each country. Shaded scenarios include taxes and subsidies, and formed the economic analysis resulting in values on LCOH. 'TAX' defines both taxes and subsidies in the figure




| | 2014 | 2020 | 2030 | 2040 |
|---|---|---|---|---|
| Wind | 26 | 47 | 78 | 108 |
| Solar | 1 | 1 | 1 | 1 |
| Hydro | 206 | 213 | 217 | 225 |
| Biofuels and Waste | 31 | 42 | 33 | 28 |
| Nuclear | 86 | 81 | 87 | 68 |
| Natural gas | 16 | 15 | 20 | 20 |
| Coal and other fossils | 31 | 15 | 4 | 0 |
| Oil | 0 | 0 | – | – |
| Electricity price - Nordics | 37 | 28 | 55 | 54 |

Figure 4: Projected development in the Nordic countries: electricity generation mix (left axis), electricity prices (right axis) [42]

are based on hourly variations for each country from the Nordic electricity exchange Nord Pool Spot. All prices are from 2016 and were projected for the future using the annual averages of the NETP 2016 [43]. NETP is exploring a transition to a carbon neutral energy system in 2050. Thus, the NETP energy prices were assumed to provide a framework suitable for the micro-economic perspective of the present study, especially due to the assumption that a Nordic energy system will become increasingly reliant on renewable energy.

Table 3 displays the taxes, subsidies and electricity T&D grid tariffs applied in this study. The origins of the taxes and subsidies that dictate taxation have been reviewed by Sneum et al. [22]: Tax exemption for biomass is motivated by its characteristic as a locally available and secure fuel, a renewable and $CO_2$-neutral fuel and—perhaps most importantly—a fuel that is difficult to tax due to its availability in many forms. Subsidies for CHP are not directly motivated by increasing a flexible operation but rather by security of supply and priority for energy efficiency. All countries are applying levies for EB operation. In countries where electricity production traditionally has been based on fossil fuel and thermal technology, these levies tend to be higher because taxation has been applied to prevent the use of electricity for heating.

**Table 2: Fuel prices in 2016 based on national statistics and the European Commission [44]**

| Fuel price – EUR/MWh | DK | FI | NO | SE |
|---|---|---|---|---|
| Oil | 28.1 | 28.1 | 28.1 | 28.1 |
| Wood chips | 22.8 | 21.3 | 19.0 | 19.9 |

Capacity components in electricity T&D grid tariffs vary in design and volume among and within countries. For this study, we applied capacity components with the following characteristics: Denmark has none, Finland a constant, Norway a seasonal and Sweden a seasonal component, which is also dependent on time of day. The seasonal variations shown in Figure 5 indicate high prices during cold periods.

Investment costs, which are subdivided into hardware components and labour costs, are displayed in Table 4. The labour cost shares of investments have been adjusted according to the relative labour costs in each country, while the hardware costs remain fixed for all countries. Financing was not included in the capital cost. The considerable additional cost of the wood chip CHP is explained by the additional costs that electricity generation entails. Those include the steam turbine itself, generator and high-pressure boiler [40]. Similar cost ranges and differences among technologies are found in The Danish Energy Agency's technology overview [45]. Fixed operation and maintenance are the same for all countries under each scenario.

Table 5 presents the technological assumptions. The project period (20-year economic lifetime) is longer than the technical lifetime of the WCB. Hence, reinvestment is necessary. Remaining lifetimes of technologies are included as linearly reduced scrap values.

## 3. Results

In this section, results from the operational and LCOH analyses are presented based on how heat production is distributed among technologies and based on the

**Table 3: 2016 levels of taxes, electricity T&D grid tariffs and subsidies. All numbers in EUR/MWh unless otherwise stated. *DK CHP subsidy active until 2019. For NO and SE, the subsidy is in the form of green certificates. [c] Under capacity component-based tariff. [e] Under energy component-based tariff. Energy and capacity tariffs can vary according to time of day and seasonal variation. ** Maximum subsidy granted in the scheme. 50% subsidy is assumed for this study.**

| Country | Electricity tax | CO2 tax | Energy tax – oil | Subsidy on bio CHP elec. prod.* | Subsidy on bio CHP heat production | Subsidy on investment | DSO energy component [EUR/MWh] | DSO capacity component [EUR/MW/month based on monthly max.] |
|---|---|---|---|---|---|---|---|---|
| DK | 28.9 | 30.3 | 26.5 | 20.1 | – | – | 7.8-30.7[ce] | 0 |
| FI | 22.5 | 10.4 | 8.5 | – | 20.0 | – | 6.1-11.4[c]<br>8.7-21.4[e] | 2 900 |
| NO | 0.5 | 8.9 | 15.7 | 137.9 | – | 50%** | 1.6-2.7[ce] | 860-11 828 |
| SE | 30.8 | 30.4 | 17.3 | 137.9 | – | – | 3.0[c]<br>5.1[e] | 6 759 |

components that comprise the LCOH. The former indicates whether and how technologies are operated; the latter provides insight into the most economically attractive solution. Both contribute to understanding the incentive to invest in flexible DH for different scenario variations, and are conducted for HS and electricity T&D grid tariffs. Analyses of scenarios with and without taxes and subsidies provide insight on operational impacts, whereas analyses of LCOH without taxes and subsidies are irrelevant in this business economic perspective. Thus, only the operational side is analysed for taxes and subsidies.

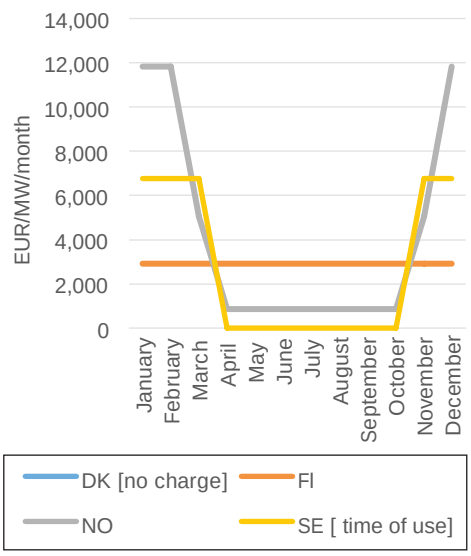



Figure 5: Seasonal variations of capacity component-based tariffs. DK has none. For SE, it applies during certain hours of a day

### 3.1. Operational and economic impacts of HS

The distribution of heat production for the scenarios used to determine the operational impact of HS is shown in Figure 6. Without exception, HS allows for improved utilisation of least-cost technologies. Therefore, baseload technology displaced mid- and peak load technologies, and mid-load technology displaced peak load technology (except in the Norwegian WCB + EB scenario, where EB displaces WCB due to low electricity cost).

While the CHP, EB and WCB can supply heat during periods with peak demand, their minimum load constraints do not permit operation during periods with a low demand. The absence of HS eliminates the opportunity to save excess production for periods with a low demand, which instead must be supplied by technologies without these constraints. At medium load levels, the WCB can operate, while only the OB can operate during low load levels.

Cost components and LCOH for scenarios with and without HS are presented in Figure 7. The trend is similarly clear to that of heat production: in scenarios

**Table 4: Investment costs divided into labour and hardware costs. Cost of CHP is based on electricity output. *No references found for the labour-hardware distribution of costs for HS. Cost data are from the Norwegian Water Resources and Energy Directorate [40] and the Danish Energy Agency [45], while labour cost weights are based on Eurostat statistics**

| | Labour costs [EUR per MW] | | | | Hardware costs [EUR per MW] |
|---|---|---|---|---|---|
| **Technology** | **DK** | **FI** | **NO** | **SE** | |
| WCB | 3 054 | 2 538 | 4 301 | 3 226 | 602 151 |
| OB | 7 558 | 6 281 | 10 645 | 7 984 | 55 645 |
| EB | 8 016 | 6 661 | 11 290 | 8 468 | 62 903 |
| Wood chip CHP | 1 244 409 | 1 034 086 | 1 752 688 | 1 314 516 | 3 239 785 |
| EUR for a 2000 $m^3$ HS* | 313 011 | 260 108 | 440 860 | 330 645 | |

**Table 5: Lifetimes, efficiencies and minimum loads for DH technologies [40,41,45]. Flue gas condensation assumed for the CHP, leading to the high total efficiency.**

| Technology | Heat efficiency | Electric efficiency | Minimum load | Technical lifetime (years) |
|---|---|---|---|---|
| Wood chip CHP | 77% | 28% | 100% | 25 |
| EB | 98% | – | 100% | 20 |
| WCB | 89% | – | 25% | 15 |
| OB | 92% | – | 0% | 20 |

with HS, the improved utilisation of the least-cost technologies is reflected by lower costs than without HS. The cost difference is most pronounced in scenarios with CHP in Finland, Norway and Sweden. This is explained by the improved ability to utilise the CHP and HS in combination and thereby to enhance the revenue from electricity sales and subsidies. Finally, the Norwegian 50% investment support visibly impacts the investment cost for all Norwegian scenarios.

### 3.2. Operational and economic impacts of electricity T&D grid tariffs

The distribution of heat production for the scenarios used to determine the operational impact of electricity T&D grid tariff is shown in Figure 8. Because Denmark only has energy component-based tariffs, the values are the same regardless of the type of electricity T&D grid tariff. Differences can be observed between CT and ET in Finland and Norway, where scenarios with ET display a higher production for EB than scenarios with CT. For both countries, operating the EB under CT for relatively few hours with low electricity prices per month, would entail a considerable monthly capacity charge that outweighs the money saved on EB production.

Cost components and LCOH for scenarios with CT and ET are presented in Figure 9. The operational results for Finland and Norway, where OB under CT is replaced by EB under ET, are mirrored in the reduced LCOH. In

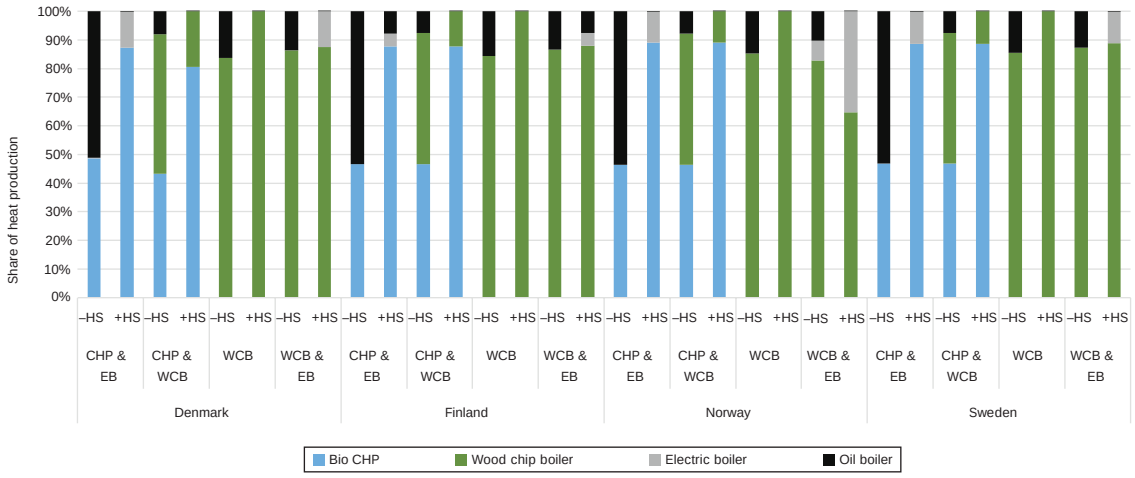



Figure 6: Shares of heat production in scenarios with and without HS, all with tax and ET

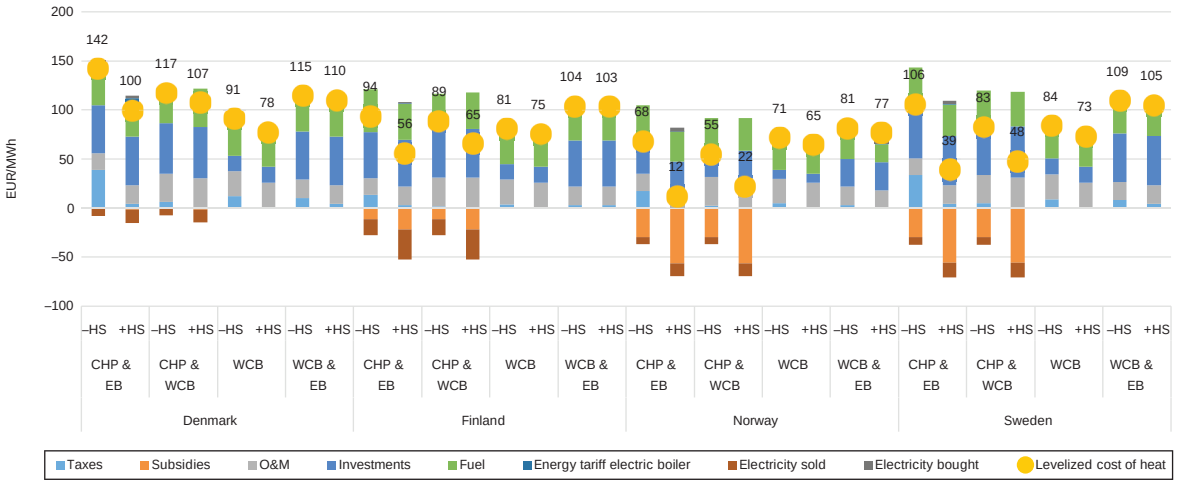



Figure 7: LCOH divided by cost components in scenarios with and without HS, all with tax and ET

Finland only to a limited degree, due to the electricity and ET costs almost outweigh the oil costs. In Norway to a larger degree, since electricity and ET costs are relatively lower.

### 3.3. Operational impacts of energy taxes and subsidies

The distribution of heat production for the scenarios used to determine the operational impact of taxes and subsidies is shown in Figure 10. Absence of taxes and subsidies in all cases leads to the WCB, EB and OB displacing CHP production. This happens as the CHP is generally subject to subsidies, while EB and OB are subject to taxes. When taxes and subsidies are removed, boiler technologies will become less costly (technologies increasing as PUD), displacing the costlier CHP production (technology decreasing as PUD). This finding applies in all CHP scenarios.

Absent taxes and subsidies, the share of additional EB and OB production, and the distribution among the two technologies, are subject to national fuel and electricity prices, and the electricity T&D grid tariffs. In all countries but Denmark, EB share increases significantly, and to a larger share than OB. In the Danish case, the relatively high winter ET of 24.6 EUR/MWh (lowest is Norway with 2.7 EUR/MWh), impedes operation on EB regardless of taxes.

A further cause of the considerable increase in OB in most cases without taxes and subsidies, is an expected

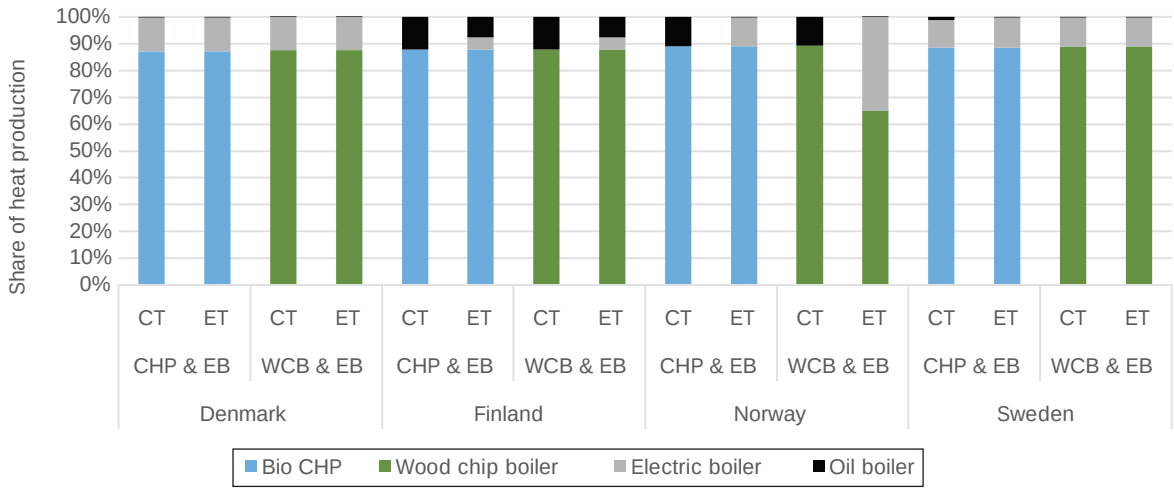



Figure 8: Shares of heat production in scenarios with CT and ET, all with tax and HS

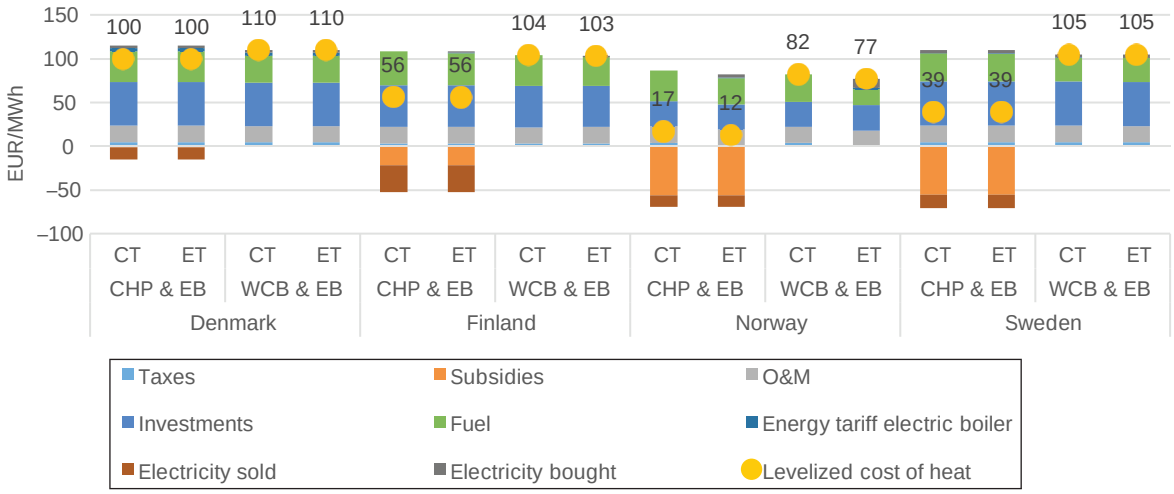



Figure 9: LCOH divided by cost components in scenarios with CT and ET, all with tax and HS

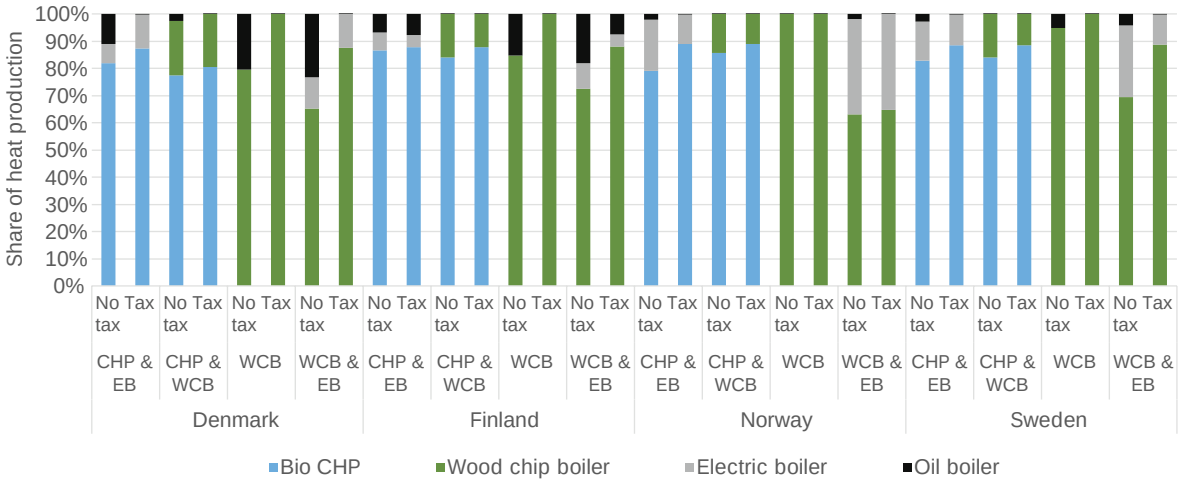



Figure 10: Shares of heat production with and without tax, all with ET and HS

decrease in oil prices around 2020. This temporarily makes oil cheaper than biomass for 1–3 years, depending on country.

### 3.4. Sensitivity analysis

Considering the LCOH, electricity prices and wood chip prices comprise significant shares, where e.g. electricity revenue reduces the total cost between 11 and 28%. Thus, both electricity prices and wood chip prices might impact the outcome of the analysis because both are significant drivers for revenue from the electricity spot market (and to a smaller degree, costs related to EB consumption) and costs for fuel use in WCB and CHP, respectively.

When analysing the sensitivity to electricity prices, a span of +/– 10 EUR/MWh on the hourly electricity price was explored. The sensitivity analysis was conducted for the scenario with wood chip CHP + EB, ET, by comparing the results to the LCOH of the combination with a large WCB. Figure 11 displays the results of the sensitivity analyses. The analyses indicated that all scenarios are robust despite the changes in electricity prices because the LCOH of the CHP + EB technological combination remained higher (DK) or lower (FI, NO, SE) than the WCB technological combination regardless of electricity prices.

For the sensitivity analysis of wood chip prices, a span of +/– 5 EUR/MWh was added to the price. As with the electricity prices, the sensitivity analysis on wood chip prices was conducted on the technological combinations CHP + EB and WCB by comparing the

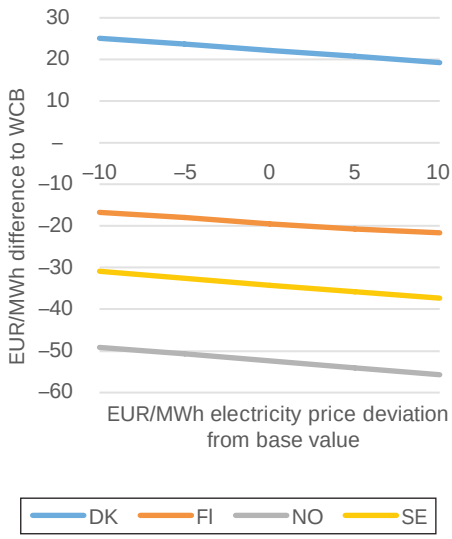



Figure 11: Sensitivity analysis of 5 and 10 EUR/MWh higher or lower electricity spot prices. Horizontal scale depicts the change in electricity prices. Vertical scale depicts the difference in LCOH of the CHP + EB technological combination to WCB. Negative values indicate that the CHP + EB LCOH is lower than that of the WCB

results with the LCOH of CHP + EB and WCB at each wood chip price level. Figure 12 displays the results of the sensitivity analyses. The LCOH of CHP + EB remained higher (DK) or lower (FI, NO, SE) than WCB regardless of biomass prices. This indicates that the price changes would not induce a shift in production technology but would merely increase or decrease the production cost for the same technologies.

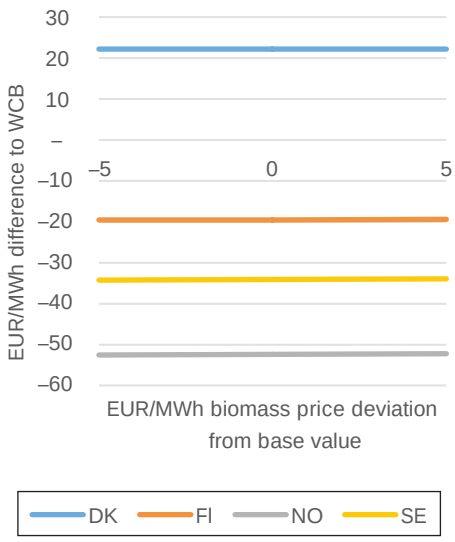



Figure 12: Sensitivity analysis of 5 EUR/MWh higher or lower wood chip prices. Horizontal scale depicts the change in wood chip prices. Vertical scale depicts the difference in LCOH of the CHP + EB technological combination to WCB. Negative values indicate that the CHP + EB LCOH is lower than that of the WCB

The findings of the study are thus robust to changes in electricity prices as well as wood chip prices.

## 4. Discussion of results on operation and investment incentives

HS increased the use of both CHP and EB and generally allowed for the increased utilisation of the least-cost heat technology, thereby reducing demand for peak load operation.

Electricity T&D grid tariffs had a negligible impact on the operation of EB in Denmark (where there are no CT) and Sweden (where time-of-use tariffs allowed EB to operate at night). In Finland and Norway, CT hindered all operation of EB. Consequently, no CT were paid in either scenario.

Absence of taxes and subsidies showed that CHP in all cases would surrender production to EB, OB and WCB. This is due to the distribution of taxes and subsidies among technologies, where CHP is generally subject to subsidies, and EB and OB are subject to taxes. A general removal or reduction of current taxes and subsidies thus relatively benefits boiler technologies more than CHP.

Also, absence of taxes and subsidies resulted in an increased use of the oil boiler. This indicates that the significant Nordic fossil fuel taxes are working to reduce the consumption of oil.

CHP operates close to baseload with 6-7000 full-load hours in all cases with HS, regardless of subsidies, taxes and electricity T&D grid tariffs. Whereas the subsidies improve the general economy, and thereby the investment incentive for the CHP-based plant significantly, current subsidies have a limited impact on the operation of the CHP. This is exemplified by Figure 13, which shows the baseload operation of the CHP (middle), while the EB charges the HS (bottom) during periods with low electricity prices (top). This operation is higher than the 4 000 full-load hours for biomass CHP as indicated by Norsk Energi and Thema Consulting Group [41].

Regarding LCOH, there is a clear picture of the preferred technologies in Finland, Norway and Sweden, as illustrated in Table 6. In these countries, the subsidised wood chip CHP with EB and storage drives the costs down, while the preferred technology in Denmark is the single WCB.

Previous studies have identified challenges for CHP. Investment and re-investment in small-scale CHP are reported as infeasible in Denmark, Finland, Norway and Sweden [46–50], while subsidised biomass-based CHP can be profitable in Norway [46] if investment costs are lowered or electricity prices rise, as argued by Keppo and Savola [48]. Contrary to the present study, Sneum et al. similar study on the Baltics [27] showed investment incentives for WCB + EB, due to lower subsidies for electricity production. Furthermore, Sneum et al. found smaller impacts of T&D grid tariffs in the Baltics, due to a lower annually paid tariff structure.

## 5. Conclusion

Four different technology combinations for DH plants in four different countries yielded a total of 96 operation analyses and a subsequent 48 studies of LCOH. The results show the ways HS, current electricity T&D grid tariffs, taxes and subsidies, affect investment incentives for a set of flexible and inflexible technologies in small-scale DH model plants.

Investment incentives are represented by LCOH, and operations have been examined regarding the share of energy production on flexible and non-flexible technologies. The results are robust to variations in biomass and electricity prices.

- HS is in all cases a no-regrets solution because it allows for the increased use of the least expensive technologies, thereby generally reducing LCOH.

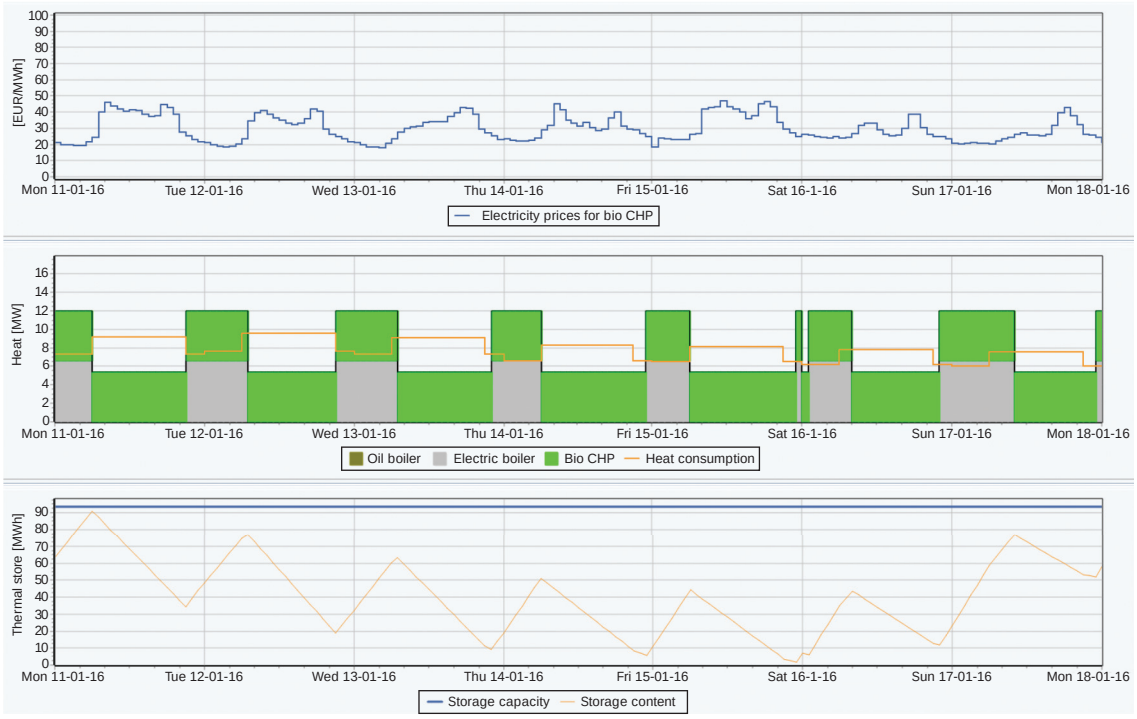



Figure 13: Baseload operation of CHP supplemented with EB. Excerpt of simulation of Denmark in January

**Table 6: LCOH (EUR/MWh) for all scenarios with tax. The colour scale is read vertically and indicates the LCOH for each country, where green is low, yellow is intermediate and red is high**

| Technological combination | Electricity T&D grid tariffs | Storage | DK | FI | NO | SE |
|---|---|---|---|---|---|---|
| A – Wood chip CHP + EB | CT | Storage | 100 | 56 | 17 | 39 |
| | | No storage | 142 | 94 | 68 | 106 |
| | ET | Storage | 100 | 56 | 12 | 39 |
| | | No storage | 142 | 94 | 68 | 106 |
| B – Wood chip CHP + WCB | | Storage | 107 | 65 | 22 | 48 |
| | | No storage | 117 | 89 | 55 | 83 |
| C – Large WCB | | Storage | 78 | 75 | 65 | 73 |
| | | No storage | 91 | 81 | 71 | 84 |
| D – WCB + EB | CT | Storage | 110 | 104 | 82 | 105 |
| | | No storage | 115 | 104 | 82 | 109 |
| | ET | Storage | 110 | 103 | 77 | 105 |
| | | No storage | 115 | 104 | 81 | 109 |

- For electricity T&D grid tariffs, CT charged as a monthly cost, triggered by the highest load demand on the grid during that month, is detrimental to the use of P2H. Preferable alternatives include schemes such as the ET explored in this study, time-of-use tariffs varying over the day, or changing CT to be lower and charged annually. More ambitious would be dynamic tariffs that carries through signals to P2H from the electricity market. This approach could potentially also increase use of P2H under the Danish electricity T&D grid

tariffs, which are considerable compared to the other Nordic countries.

- Taxes and subsidies hardly affect the operation of CHP, but subsidies considerably affect LCOH and investment incentive for CHP. Despite the lack of operational impact, subsidies could instead be allocated on investment (as in Norway), to maintain investment incentive, and reduce the distortion of signals from the electricity market.
- Biomass-based heat production outperforms electricity-based heat production in all scenarios. A general removal of taxes and subsidies moderately increases the operation of EB in FI, SE and NO. If there is a fiscal priority for maintaining revenue from energy taxation and/or to increase use of electricity, measures to level the playing field for P2H could be to introduce taxes on the generally untaxed biomass, and to provide targeted reduction of electricity taxes for large-scale P2H.
- In almost all cases, an absence of taxes and subsidies provides an increased incentive for the operation of the OB, a consequence which neither increases operation of flexible technologies nor reduces emissions. Current taxes and subsidies thus generally helps reducing OB use.

### 4.1. Future work

In this study, barriers for flexibility were considered framework conditions that limit the incentive for investing in CHP and EB. A full removal of these barriers might not necessarily be beneficial because these might simultaneously be drivers for other priorities in society or in the energy system. The adjustments of taxes and subsidies as well as electricity T&D grid tariff structures induce a need for analysing the incentives for the operation and investment of technologies in the DH-electricity interface not only at the plant level but for the energy system as a whole.

## 5. Acknowledgement

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## 6. Appendix

Heat production (GWh total) with and without HS. All with taxes and subsidies and ET.

LCOH (EUR/MWh) with and without HS. All with taxes and subsidies and ET.

Heat production (GWh total) with CT and ET. All with HS and taxes and subsidies.

LCOH (EUR/MWh) with CT and ET. All with HS and taxes and subsidies.

Heat production (GWh total) with and without tax. All with HS and ET.