Sustainable Energy Technologies and Assessments 34 (2019) 157–172

Contents lists available at ScienceDirect

Sustainable Energy Technologies and Assessments

journal homepage: www.elsevier.com/locate/seta

Robust decision making analysis of BECCS (bio-CLC) in a district heating and cooling grid

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A R T I C L E I N F O

Keywords:
Bio-CLC
BECCS
District heating
Cogeneration
Robust decision-making

A B S T R A C T

Additional investments to negative emission technologies, such as reforestation or bioenergy with carbon capture and storage (BECCS), are required to achieve Paris Agreement targets. Chemical-looping combustion of biomass (Bio-CLC) is an under-the-development combustion technology that could provide relatively low cost negative CO_2 emissions. We modelled Bio-CLC units as a part of a city-level district heating and cooling (DHC) grid based on literature and our experimental work with Bio-CLC pilot plants. We applied robust decision-making (RDM) to identify preconditions that favour Bio-CLC over certain competing investment options.

In the selected case study, a Bio-CLC unit had a 50% chance to be profitable (10% Internal rate of return or better) around the level of 10 €/tCO_2 net income from captured bio-CO_2. If the net income from captured bio-CO_2 was below 10 €/tCO_2, as currently, large heat pumps with COP of 3.5 were the most robust of the studied investment options. Traditional bio-CHP performed better than large heat pumps only when electricity market price was above 50 €/MWh and biomass price below 20 €/MWh. Performed RDM analysis provides a systemic background for both technology developers and DHC operators when considering the competitiveness of the technology in an uncertain future.

Introduction

Bioenergy with carbon capture and storage (BECCS) is a key technology to produce negative emissions in long-term emission reduction scenarios [1–3]. Forever, the actual development of BECCS is progressing quite slowly. In May 2019, there were only a handful of operational BECCS demonstration plants: four in ethanol production plants, two in municipal solid waste incinerators, and one power and heat sector. The total CO_2 capturing capacity of these demonstration plants were approximately two MtCO_2 per year, but only one of the demo-plants stored the captured CO_2 while others vented it to atmosphere [4,5]. The current global development of BECCS is in a strong contrast to many integrated assessment model scenarios that utilize BECCS both in power and heat sector and in industry with total volumes up to 15 GtCO_2/year by 2050 [1,2].

Chemical-Looping Combustion of biomass (bio-CLC) is an under-the-development combustion technology that could enable lower cost negative CO_2 emissions than conventional carbon capture technologies [6]. This study builds up on the experience gained from bio-CLC pilot unit operations in the authors' institutes Chalmers University [7–10], Sintef [11], and VTT Technical Research Centre of Finland [12]. We have performed a large base of the bio-CLC experiments within the Nordic Energy Research project "Negative CO_2" project [13].

Future bio-CLC boilers will be very similar to current Circulating Fluidized Bed (CFB) boilers, which represents current best practice for combustion of biomass in the scale 100–200 MWth. The striking similarities between existing CFB boilers and future CLC boilers suggest that the capital expenditures as well as the operation expenditures will be fairly similar for the two technologies. Therefore, cost and performance estimations for current best practice bio-CFB boilers could, if appropriately tweaked, be used with a degree of confidence also for future bio-CLC boilers. Based on the pilot plant operations and larger scale designs, we evaluate a range of parameters used in the energy system modelling of a full-size bio-CLC unit equipped with CO_2 capture and compression facility, see Section "Modelling parameters for bio-CLC units".

The focus of this study is to estimate under which assumptions bio-CLC CCS unit would be a profitable investment for district heating

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https://doi.org/10.1016/j.seta.2019.05.005
Received 5 December 2018; Received in revised form 7 May 2019; Accepted 16 May 2019

companies. This provides additional and crucial information for both investors and technology developers.

The operation of bio-CLC unit and the profitability of the investment depends on the studied energy system, due to existing capacity, available resources, and local costs such as fuel prices and taxes. To put our modelling in the context and to provide more relevant results, we study the investments as a part of the case study energy system and cover a broad uncertainty ranges for the studied parameters. We also estimate how robust investment bio-CLC plant could be by comparing the bio-CLC CCS investment to alternative investment options including large heat pumps, biomass heat only boiler, and biomass combined heat and power (CHP) unit.

Methods, model, and case studies

The DHC model

The district heating and cooling (DHC) model simulates the annual operations of DHC network from the DHC network operator perspective. It is a local operational model where investments can be modelled by running the model several times according to different investment options. The model structure and equations are documented in the Appendix A. The model is validated in the Appendix B. Previous versions of the model has been used previously in two studies [14,15].

The DHC model simulates the annual operation of a DHC grid by minimizing the annual costs, which include fuel costs, costs of bought electricity, profits from the sold electricity, O&M costs, start costs, annualized investment cost, CO_2 emission fees, additional costs related to captured CO_2, and possible revenues from the captured bio-CO_2. The model has perfect foresight in a sense that it knows the input, such as heat demand, for the whole year in advance. This does not mean a perfect model, but it rules out stochastic simulations where, for an example, weather uncertainties have an impact on the modelling result.

The foundation of the model is that it has to balance production, storages, and demand of district heating (DH) and district cooling (DC) at hourly level acknowledging unit operational constraints. The consumption of DH and DC and the price of the electricity are modelled as predefined hourly time series. The DHC model does not maintain the balance of fuels or electricity and thus, the model can buy fuels, sell electricity, and buy electricity from markets based on predefined prices. As in the case of real DHC operators, a single unit in the model sells electricity by market price and buys electricity by market price plus grid fees and taxes.

The DHC model groups DH and DC production units in four categories: NGCCs, CHPs, heat only boilers, and large heat pumps. The user can define NGCCs and CHPs in greater detail than heat only boilers or heat pumps. NGCCs and CHPs have options to, for an example, include a condensing turbine (to maximize electricity generation) or to allow reduction (to increase DH production). Table 1 presents the general characteristics of each unit type. In addition to production units, the DHC model has storages for DH and DC. Heat only boilers are modelled linearly and they have fewer details than NGCCs and CPHs to reduce the model solving time and to allow running of larger number of model runs to cover broader ranges for input parameters.

In the current model version, CCS option is included only for CHPs. If CCS option is enabled, the unit can capture a share of the emitted CO_2 emissions. We have split the CO_2 emissions to biogenic and fossil, which allows the modelling of negative CO_2 emissions from BECCS. The CO_2 capture is always on if enabled in the input data and CCS units are not flexible in that sense. In the modelling, CCS units receive a certain compensation for each captured CO_2 ton. Compensation can be set to zero or negative. See chapter 2.2 for assumed parameter values, Appendix A for model equations, and Appendix B for model validation.

Table 1
Properties of production unit types.

	NGCCs	CHPs	Heat only boilers	Large heat pumps
capacity unit*	MW_{fu}	MW_{fu}	MW_{fu}	MW_{DH}
Maximum fuel power (MW_x)	x	x	x	x
Minimum fuel power (MW_x)	x	x		
Electricity and DH efficiency, depending on fuel power	x	x		
DH and DC efficiency, constant			x	x
Reduction, max (MW_{steam})	x	x		
Condensing turbine (% efficiency)	x	x		
Maintenance break (predefined days)	x	x		
Ramping limit (% of MW_x/h)		x		
Minimum online time (days)	x	x		
Minimum offline time (days)	x	x		
Annual availability (% of hours)		x		
Seasonal availability (% of hours)		x		
CO_2 capture efficiency (%)		x		
Additional cost of captured CO_2 (€/tCO_2)		x		
Investment cost (k€/MW_x)	x	x	x	x
Fixed O&M (k€/MW_x/year)	x	x	x	x
Variable O&M (€/MWh_x)	x	x	x	x
Start cost (€)	x	x		

* Unit capacities are defined either by fuel power (NGCCs, power plants, and boilers) or by maximum production of DH (heat pumps). In the table, MW_x refers either MW_{fu} or MW_{DH} depending on unit type.

Case study localization

In this study, the DHC model has been localized to Helsinki, Finland. We assume a reference year 2030 for our case study. We also assume that current energy policy initiatives will be passed and the Helsinki DHC operator has to phase out the coal power in the city's energy mix by 2030 [16]. In addition, the case study year implies likely increasing CO_2 prices in the EU ETS.

We assume that the lifetime of all other existing units except coal CHPs could be extended to 2030 [17]. Helsinki has decided to investment to additional 300 MW of biomass heat only boilers, large heat pumps, and heat storages [18]. For this study, we study one reference unit mix, which includes existing units and already decided investments. We compare this reference scenario to five optional investment decisions that would replace the oldest NGCC unit (NGCC 1). Table 2 summarizes the assumed units and their capacities in our six different decision scenarios. In the modelled case studies, units produce electricity to the Nordic electricity markets and provide district heating to local clients.

The biomass prices vary much depending on the quality and source of the wood. Prices in the Nordic region range from approximately 10 €/MWh for waste wood, 20 €/MWh for wood chips, and 30 €/MWh for wood pellets. Southern Finland has high demand for biomass, but lower availability leading to situations where units might have to operate with higher cost wood pellets. The uncertainty in the biomass price increases also due to uncertainties in the EU LULUCF legislation and amount of biomass needed for other uses [19]. The prices of natural gas and oil are assumed to slightly increase from the current levels with 30% variance in the fuel prices. Taxes are assumed to remain in the current levels (Table 3). Studied ranges are relatively broad, but that gives better overview in the robust analysis.

The remaining system parameters are prices of electricity, prices of CO_2, and the demand of DH and DC (Table 4). We model the perspective of DHC operator, which receives the energy price of electricity when selling and has to pay energy price and other costs when buying electricity e.g. for DH heat pumps. Energy cost of electricity is based on

Table 2
Units and their capacities in the studied scenarios.

	Unit	Fuel	Thermal power	Electricity	DH	DC	DH storage	DC storage
			MW	MW	MW	MW	GWh	GWh
Common to all decision options	NGCC 2	Natural Gas	997	486	432			
	Oil boilers	Oil	1480		1350			
	Natural gas boilers	Natural Gas	723		665			
	Biomass boilers	Biomass	400		368			
	Heat storages	–			250		14	
	Large heat pumps	Waste heat, electricity		−30	108	75		
	Sea water cooling	Electricity		−3.5		70		
	Absorption cooling	DH, electricity		−1.8	−35	35		
	Cooling Storages	–				58		0.7
Opt 1 (Ref)	NGCC 1 (existing)	Natural Gas	358	165	162			
Opt 2	Biomass boilers (new)	Biomass	400		400			
Opt 3	Biomass CHP (new)	Biomass	2x200	128	280			
Opt 4	Bio-CLC, CHP (new)	Biomass	2x200	116	280			
Opt 5	DH heat pumps, COP 3.5 (new)	Waste heat, electricity		114	400	100		
Opt 6	DH heat pumps, COP 2.5 (new)	Heat from sea, electricity		160	400	100		

Table 3
Assumed fuel prices (2018 euros) and other fuel parameters.

	Natural Gas			Biomass			Oil		
	min	ref	max	min	ref	max	min	ref	max
Fuel cost (€/MWh)	19	27	35	15	25	35	31.5	45	58.5
CHP tax (€/MWh)		12			0			–	
Heat tax (€/MWh)		17			0			22	
CO_2 emissions, fossil (tCO_2/MWh)		0.201			0			0.264	
CO_2 emissions, bio (tCO_2/MWh)		0			0.360			0	

Table 4
Assumed system parameters. All prices are in 2018-Euros.

	min	ref	max
Annual average electricity price (€/MWh)	20	40	60
Electricity grid costs and taxes (€/MWh)	25	35	45
CO_2 price (€/tCO_2)	20	40	100
Net income from captured bio-CO_2 (€/tCO_2)	−30	10	60
DC demand (TWh)	0.3	0.4	0.5
DH demand (TWh)	6	6.5	7

2014 prices in the Finnish market region and other costs are based on actual grid costs and taxes in Finland [20]. We assume roughly 20% variance in these parameters in our analysis.

The price of a CO_2 allowance unit was at the level of 20 €/tCO_2 in the EU ETS at October 2018, but on the other hand, neighbouring Sweden has implemented very high carbon point tax for fossil fuels in power plants with rates up to 120 €/tCO_2 [21]. The Swedish tax does not apply to Helsinki but provides an upper limit for the analysis.

Captured CO_2 could generate both costs and income to the bio-CLC unit operator. To simplify the modelling and presentation of results, we sum all the costs, incomes, and/or subsidies due to captured CO_2 to one parameter called 'net income from captured bio-CO_2'. As a reference value for the analysis, we assume 10 €/tCO_2 'net income from captured bio-CO_2'. Today's situation forms the low end for the estimate where the net income would equal roughly −30 €/tCO_2 as a sum of 0 €/tCO_2 income, 0 €/tCO_2 subsidies, and assumed 30 €/tCO_2 transport and storage cost [22]. The higher end case would be a situation where bio-CLC unit would receive almost 100% compensation from the negative CO_2 emissions based on a high CO_2 price.

The Helsinki city estimated that the city's DH demand will be 6.5 TWh at 2030 and DC demand will be 0.4 TWh [23]. We assume roughly 10% variance in these parameters in our analysis.

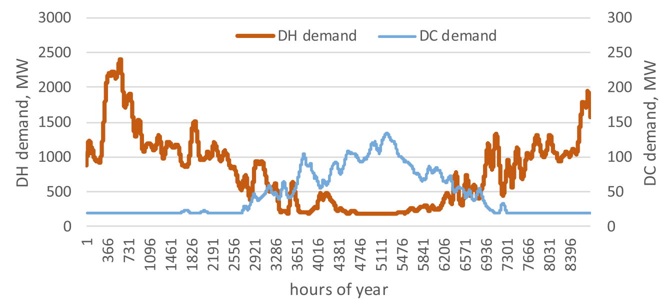

Fig. 1. Hourly demands of district heating and cooling.

Fig. 1 shows an estimated hourly distribution of demands. Estimates are based on the total annual demand and 24 h smoothed hourly temperature series from 2014. The minimum demand of DH represents the hot water use and the minimum demand of DC represents the base load of larger users that need DC throughout the year.

Modelling parameters for bio-CLC units

A short description of the bio-CLC technology will be provided below. The full description is provided in the previous publications [24–26] and comparison to conventional CCS technologies is provided in a recent review [27].

Parameters for the bio-CLC unit need to be proportionate and comparable with competing technologies. To assure consistency, we have adopted parameters for existing technologies (decision options 2, 3, 5, 6) from DEA power plant catalogue [28] and compiled the bio-CLC parameter sets (decision option 4) based on these numbers. DEA assumes that all new biomass units would have the flue gas condenser and could reach above 100% total efficiency when calculated from the lower heating values.

The main source for bio-CLC unit parameters is from a design and cost study of 1000 MW_{th} boiler for chemical looping combustion of coal [6] and recent bio-CLC pilot unit experiments in Sweden, Finland, and Norway. The bio-CLC parameters are estimates, because no large-scale bio-CLC units have been built, but we use ranges to study the uncertainty for the parameters.

The fundamental principle of CLC is that the fuel is oxidized in two distinctive steps using two separate reactor vessels, commonly referred to as air reactor and fuel reactor [26]. A solid oxygen carrier (e.g. metal oxide) performs the task of transporting oxygen between the two reactor vessels. In the fuel reactor, the fuel reacts with oxygen provided with the oxygen carrier particles and thereby forms CO_2 and H_2O. In the air reactor, the reduced oxygen carrier is regenerated by reacting with O_2 provided with air. Thus, fuel and air are not directly mixed. Pure CO_2 is obtained after cooling and condensing steam to water in the fuel reactor stream. The net energy released in the system as a whole is the same as for conventional combustion. Unlike other technologies for CO_2 capture, there is only minor energy penalty for gas separation to receive CO_2 for sequestration. 100% CO_2 capture rate is readily achieved with gaseous fuels. For solid fuels, it is still possible to achieve nearly 100% capture rate, albeit leakage of char from the fuel reactor is here a possibility that would reduce capture rate.

The most commonly proposed way to design a CLC boiler and the one envisioned here is to utilize Circulating Fluidized Bed (CFB) reactors with oxygen carrier particles as bed material [29]. In this design, the oxygen carrier would be particles in the size range 0.1–0.4 mm, i.e. comparable to fine sand. The reactor temperature would be in the range 800–1050 °C. CLC can process all kinds of fuels. Biomass is quite suitable due to its high content of volatile gases and because the char generated during pyrolysis typically is comparably reactive. There is currently more then 10 000 h of operation of CLC pilot reactors using these basic principles, so the concept has been shown to work well [24].

As pointed out in the introduction CLC boilers based on the principles described above would be very similar to conventional CFB boilers [6]. Further, CFB boilers are currently the technology of choice for biomass combustion in the scale 100–300 MWth and the only available technology that would allow for scale-up to larger sizes. The principal difference between a CFB boiler and a CLC boiler is that the latter would need to be divided into two separate but interconnected sections (e.g. fuel reactor and air reactor). In principle, this could be achieved with an insulated reactor wall and some creative plumbing. A few additional tweaks would likely also be needed (e.g. with respect to flue gas cleaning) but the difference in design between a current CFB boiler and a first generation CLC boiler could be expected to be minor.

The physical size of the plant and most of its main components would remain essentially the same. No major new equipment would be needed, aside from CO_2 compressor if transport and storage were desired. The standard bed material, which for biomass would be high-grade silica sand, would need to be replaced with chemically active oxygen-carrier particles. Here various by-products from metallurgic industries or cheap and environmentally benign mineral ores (e.g. iron ore, manganese ore) would be adequate [25]. The similarities between existing CFB boilers and proposed CLC boilers suggest that the capital expenditures as well as the operation expenditures will be comparable for both technologies.

From modelling perspective, the most important differences between a bio-CLC unit and a normal circular fluidized bed (CFB) boiler, are captured CO_2, lower electricity efficiency, higher investment cost, and higher variable costs (Table 5).

The following assumptions have been made with respect to the performance of CLC plants:

- CO_2 capture rate has been assumed 98% for the base case, with 95% as low end and 100% as high-end estimations. This is based on experimental studies in pilot reactors [7] and previous assumptions for large facilities [8].
- Compared to a conventional bio-CHP unit a bio-CLC unit would have increased internal power consumption for CO_2 compression to > 100 bar. This has been assumed to translate to a 2.5%-points electric efficiency penalty, which is a typical assumption for CCS for solid fuels.
- There will also be an internal power demand for generation of small amount of pure O_2 for flue gas treatment, so called O_2 polishing. Based on a study for large facilities [6] this requirement has been assumed to correspond to a 0.5%-points efficiency penalty. This number is derived from the assumption that 10% of the oxidation will have to be done with O_2 and is reasonably consistent with experimental studies in pilot reactors [8], albeit biofuels with low volatile content (e.g. wood char) provides somewhat better performance than that while biofuel with high volatile content (e.g. white wood pellets) provides somewhat worse performance.
- Altogether, this implies a 3%-points electric efficiency penalty for the base case compared to a conventional CHP unit. In the low end estimation have set the efficiency penalty to 5%-point, which could be valid if the internal power consumption for flue gas cleaning and fans would turn out to be unexpectedly high. The high end estimation for the efficiency penalty have been set to 1%-point, which could be valid if some of the potential intrinsic advantages of the CLC-concept (e.g. reduced air-to-fuel ratio, improved steam data due to lack of ash in the air reactor, more efficient flue gas cleaning since impurities are concentrated in fuel reactor stream) were to be fully realized.
- The efficiency with respect to heat production is assumed to be unaffected since both facilities utilize flue gas condensation. The energy penalty to total efficiency will therefore be dependent only on the electric efficiency penalty.
- For the base case, a 20% increase in investment cost for bio-CLC unit in comparison to bio-CHP unit have been assumed, reflecting the need for dividing the reactor vessel into two parts, additional flue gas treatment and additional fans and compressors. This number is quite possibly the one which is the most difficult to estimate based on available information currently and it seems reasonable to believe that early first-of-a-kind facilities may be costlier than that. The lower and higher estimations represents ± 20% from the baseline. Lower investment cost could potentially be achieved due to reduced vessel size due to reduced air-to-fuel ratio, reduced riser height, or reduced cost for flue gas cleaning [6].
- Variable O&M are higher for bio-CLC than for bio-CHP due to the need for oxygen carrying bed material, which could be expected to be more expensive than silica sand. The base case suggests a cost increase of 0.6 euro/MWh and has been calculated based on a bed material consumption of 3 kg/MWh (rule of thumb value for sand consumption in a bio-CHP unit) and a cost increase of 200 euro/ton (approximate price difference between basic mineral based oxygen carrier such as ilmenite and high-grade silica sand). The low end estimation is based on a bed material consumption of 3 kg/MWh and

Table 5
Modelling parameters for biomass CHP and biomass CLC CHP units. All prices are in 2018-Euros.

Parameter	Bio CHP	Bio-CLC CHP			Unit
	(CFB boiler)	min	ref	max	
Maximum thermal power	200		200		MW_{fu}
Minimum thermal power	80		80		MW_{fu}
Reduction, max	50		50		MW_{steam}
Electricity efficiency in max power	0.32	0.27	0.29	0.31	MW_{elc}/MW_{fu}
DH efficiency in max power	0.7	0.7	0.7	0.7	MW_{DH}/MW_{fu}
eff SUM, max fuel	1.02	0.97	0.99	1.01	
Electricity efficiency in min power	0.27	0.22	0.24	0.26	MW_{elc}/MW_{fu}
DH efficiency in min power	0.72	0.72	0.72	0.72	MW_{DH}/MW_{fu}
eff SUM, min fuel	0.99	0.94	0.96	0.98	
Ramp limit	100%		100%		% of MW_{fu}/hour
Min online time	0.5		0.5	2	days
Min offline time	0.5		0.5	2	days
Maintenance break duration	21	14	21	28	days
CO_2 capture efficiency	–	95%	98%	100%	
Investment cost (overnight)	1000	960	1200	1440	k€/MW_{fu}
Fixed O&M	29	23	29	35	k€/MW_{fu}
Variable O&M	0.5	0.6	1.1	3.5	€/MWh_{fu}
Start cost	3000	2000	3000	4000	€

a cost increase of 20 euro/ton (e.g. use of metallurgic slags) while the high end estimation is based on a bed material consumption of 10 kg/MWh and a cost increase of 300 euro/ton (e.g. use of more expensive minerals such as high-grade manganese ore).

- Some other parameters have been assumed to have the same characteristics as bio-CHP for the base case. Considering the high degree of similarity between bio-CLC and bio-CHP these assumptions seems justifiable. However, the analysis considers certain variance levels, see Table 5.

Methods

Profitability of investments depends on unit specific assumptions, system assumptions, and the number of units that will be built. For an example, all new investments perform better if the existing units in the studied DHC system have high operation costs.

We evaluate the profitability of the investments with internal rate of return (IRR). Net cash flows required to calculate the net present values (NPV) are calculated as differences of annual operation costs of the whole DHC system in reference scenario and each investment option. The investment costs are annualized over 20 years.

We run the DHC model multiple times to study the assumed uncertainty ranges in the input parameters. First, we vary one parameter at time to identify the most critical parameters and uncertainties for each investment option. Finally, we calculate over 1400 futures that leads to roughly 8000 model runs due to six investment options. In these model runs, we vary the selected parameters and study which investment option would be the most profitable (highest IRR) in each future.

In our analysis, we aim to identify preconditions that favour certain technologies over each other and to classify assumptions that are unfavourable to certain technologies. We try to find investment decisions that are the most robust in an uncertain future. This kind of robust decision making (RDM) analysis should bring more information about enabling and disabling conditions for technology developers, energy companies, and politicians. The method has been demonstrated earlier e.g. by Forsström [30] and Hall et al. [31].

We consider all parameters independent in the analysis, e.g. improved efficiency of the unit does not add costs or increased natural gas price does not increase electricity price. In reality, this is not the case. For an example, fuel prices and electricity prices are linked and the studied parameters should be linked. On the other hand, current tax levels or tariff systems might change and change how various parameters are currently linked. The linking of uncertainty of the parameters would require further studies.

Results and discussion

In the reference case (cf. Table 2), existing large heat pumps have the lowest marginal costs and run before other units (Fig. 2, top) while heat only boilers and NGCCs cover the remaining heat load. Biomass heat only boilers have lower marginal cost than other remaining units when assuming the default input parameters. The marginal costs of NGCC units and biomass heat only boilers can be quite close and the dispatch order depends on electricity, fuel, and CO_2 prices. With the assumed default parameters, biomass heat only boilers dispatch before NGCCs. With CO_2 prices below 20 €/tCO_2, higher electricity prices or higher biomass prices, NGCC units would dispatch before biomass heat only boilers.

The operation logic and dispatch order of the studied DHC grid changes when the model is run with bio-CLC units (Fig. 2, bottom part). With assumed default parameters, the bio-CLC units are the ones with the lowest marginal costs and run as many hours as possible. They reduce their production only during the summer when there is not enough DH demand. Maintenance breaks are scheduled to summer to increase the full load hours (FLH). In addition, active use of DH storages increases FLH of bio-CLC units during summer and low demand periods in spring and autumn. In reference case, the DH storages help to avoid shut downs of NGCC units, but storages have more load cycles in the case with bio-CLC units.

System parameters have considerably larger impact on the internal rate of return (IRR) of bio-CLC investment than unit parameters (Fig. 3). Both parameter sets are important, but uncertainty in a single system parameter can change the IRR of the bio-CLC investment up to ± 10%, while the most significant single unit parameters had impact up to ± 3%.

The two most critical uncertainties are the net income from captured bio-CO_2 (€/tCO_2) and biomass price (€/MWh). Biomass price depend both on location and market conditions, but the net income from captured bio-CO_2 depends mostly on the legislation, subsidies, transport costs, and storage costs. The third significant parameter is natural gas price (€/MWh), which defines the competitiveness of the NGCCs and gas boilers and, thus, indirectly the profitability of the bio-CLC units.

Assumed uncertainty ranges in investment cost, CO_2 price, and annual electricity price have each roughly a ± 3% impact on the IRR. Other remaining parameters are less important and had relatively smaller impact on the uncertainty of the calculated IRR. These are all important when preparing for a real demonstration case, but are by an order less significant than the most critical parameters.

We varied one parameter at time in these uncertainty estimates. In reality, certain parameters could be linked, e.g. plant efficiency and investment cost or the price of the fuels and electricity. The effect of these linked parameters should be explored in further studies.

We made a similar analysis also to other investment options and noted that the IRR of large heat pump investments is the most sensitive to electricity related parameters and IRR of biomass units to biomass price. The natural gas price has a strong impact to the IRR of the all studied alternative investments (Fig. 4). Five parameters changed the profitability order of the studied investment options. Higher CO_2 price and higher DH demand improved IRR values of all investment options, but did not change the profitability order.

In general, heat pumps with COP of 3.5 (Hpu-3.5 in Fig. 4) seem very robust investment and have the highest IRR in most of the studied cases. However, we varied only one parameter at time in Fig. 4. This is a simplified method to study the order of impact and significance of each parameter to different technologies. In reality, all parameters can have different values than our default assumptions and we need to randomize selected parameters, run a large amount of scenarios, and study the impact from that large set of model runs.

Some studied parameters had only minor impact on any of the studied technologies. For an example, the oil is used only during the highest peak load hours and the assumed variance in the oil price affected the calculated IRRs only slightly. Similarly, the studied variability in the DC demand had only a minor impact on the studied investments. This could be changed if the DC volumes would be tenfold to assumed levels at 2030, but the DC demand is likely to remain much smaller than DH demand in Helsinki.

Based on assessments summarized in Figs. 3 and 4, we chose to vary the following six parameters: biomass price, natural gas price, CO_2 price, net income from captured bio-CO_2, electricity price, and electricity grid costs and taxes. We randomized input parameters for 1400 futures and modelled six investment options for each future, totalling 8400 model runs.

From these runs, the bio-CLC investment was successful in 930 futures (rank 1 or 2 of the studied 6 investment options) and failed in 260 futures (rank 5 or 6). The most robust technology was heat pump with COP of 3.5 succeeding in 1030 futures and failing in none (Fig. 5). The ranking was done solely based on the IRR. Investment options could be ranked based on multi-criteria analysis and additional metrics, e.g. employment and GHG emissions, but in this figure, we consider only the IRR.

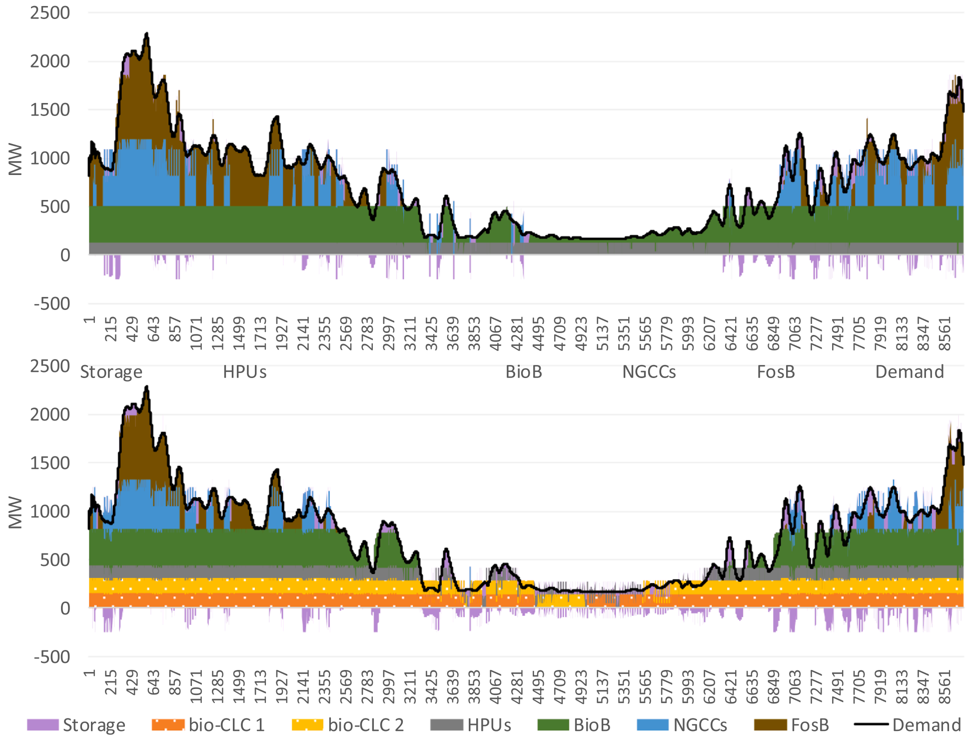

Fig. 2. Hourly operation of units in two cases: reference case at top and investment option 4 (2 × 200 MW bio-CLC units) at bottom. HPUs: Existing large heat pumps (Table 2), BioB: biomass heat only boilers, FosB: natural gas and oil heat only boilers.

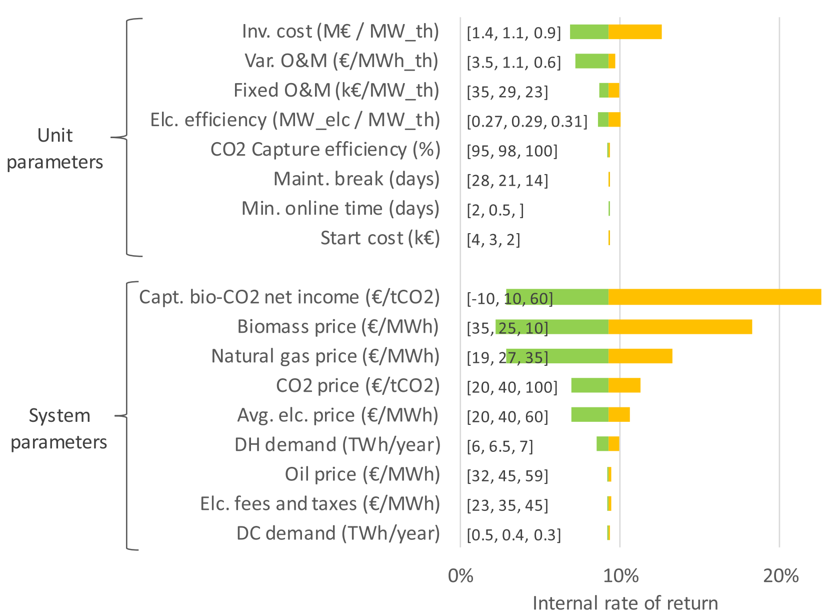

Fig. 3. IRR of two bio-CLC CHP units with sensitivity analysis. Variables are grouped to unit specific parameters and system specific parameters and sorted by significance.

The three most robust technologies had distinct input parameter ranges where they were the most successful (Fig. 6). Bio-CLC technology required net income from captured bio-CO_2 to be the most profitable investment option. This requires profits by selling CO_2 as a raw material or some kind of subsidies, e.g. a compensation based on the current CO_2 price or an investment subsidy. The CO_2 price for fossil fuels is not enough, because that does not provide income from the negative emissions.

When studying systems with lower than 5 €/tCO_2 net income from captured bio-CO_2, large heat pumps excelled with low electricity prices or high biomass prices and conventional bio CHP gradually replaced large heat pumps if assuming cheaper biomass or more expensive electricity. Interestingly, during low electricity price or high biomass price, large heat pumps with COP 3.5 were more profitable than bio-CLC up to net income levels of 30 €/tCO_2.

It is important to recognize, that local resources of e.g. waste heat to achieve COP of 3.5 might be limited. In these situations, the DHC operator might want to build those units first and then see the profitability

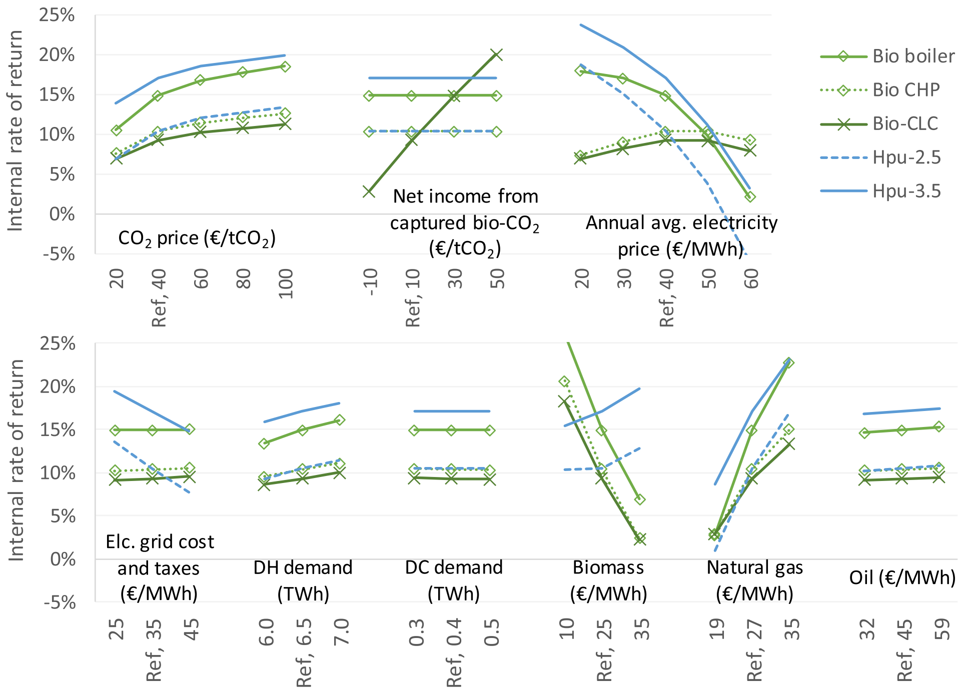

Fig. 4. IRR of studied investment options (cf. Table 2) under different system assumptions.

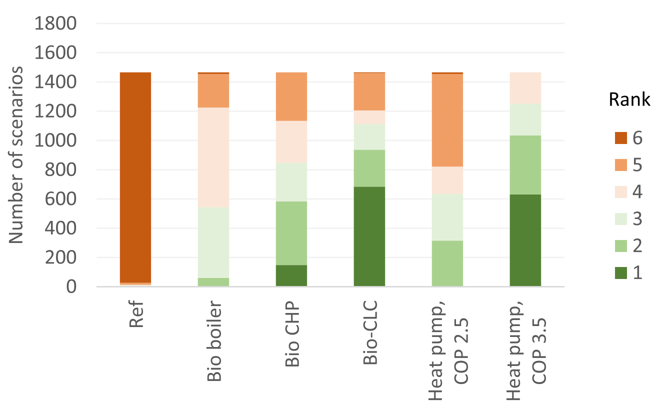

Fig. 5. Rank of different investment options (highest IRR) in simulated scenarios.

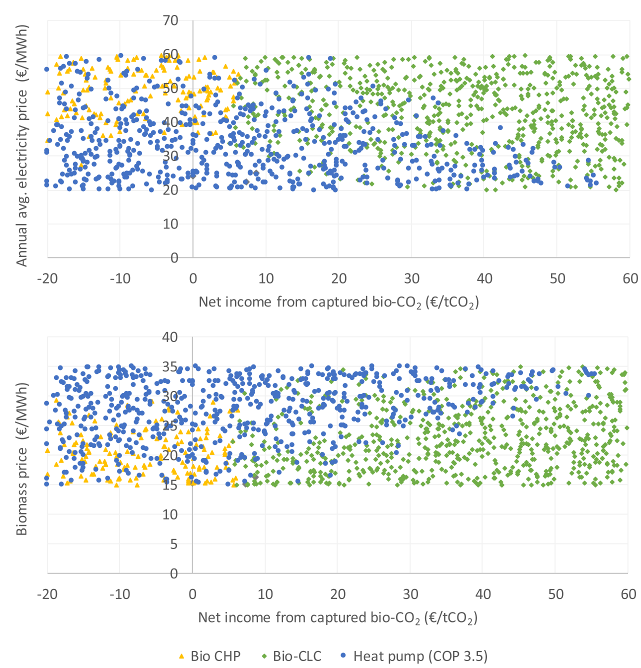

Fig. 6. The most profitable investment option (measured by IRR) presented by uncertainty ranges of prices of biomass, electricity price, and net income from captured bio-CO_2.

order of the remaining options. Fig. 7 is drawn as Fig. 6, but the analysis is redone without large heat pumps with COP of 3.5. In such case, bio CHP and bio-CLC perform the best in larger ranges of assumed input parameters. In addition, biomass heat only boilers become the most profitable options in some cases. Nevertheless, this does not influence the conclusion that bio-CLC investment is the most successful only if it receives around 10 €/tCO_2 net-income from captured bio-CO_2.

When looking only at the bio-CLC investment option (cf. Table 2), the adopted assumption of uncertainties gives a 50% chance for bio-CLC investment to be profitable (10% IRR) around the level of 10 €/tCO_2 net income from captured bio-CO_2 (Fig. 8).

We defined the net income as a sum of costs, subsidies, possible compensation based on CO_2 price in EU ETS, and possible profits from selling captured CO_2 to companies who could is it as raw material. For an example, the 10 €/tCO_2 net income level should be interpreted in a way that if transport to geological storage costs 30 €/tCO_2 (−30 €/tCO_2 income) the required incomes and subsidies should equal 40 €/tCO_2. Alternatively, if a company using bio-CO_2 as raw material pays 2 €/tCO_2 to bio-CLC unit operator, the sum of other incomes, subsidies and costs should be at the level of 8 €/tCO_2.

Companies can reduce these uncertainties by, for an example, making long-term supply deals of fuel or secure the electricity prices in future markets. On the other hand, the broad ranges used here, can be interpreted also as uncertainty in energy taxation that companies have much smaller possibility to affect.

Conclusions and discussion

According to literature, operations on pilot and demonstration

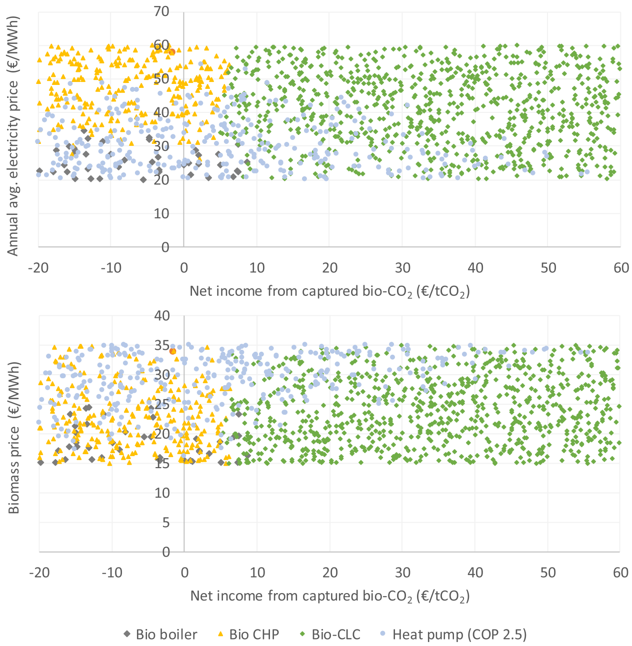

Fig. 7. The most profitable investment option when excluding large heat pumps (COP 3.5).

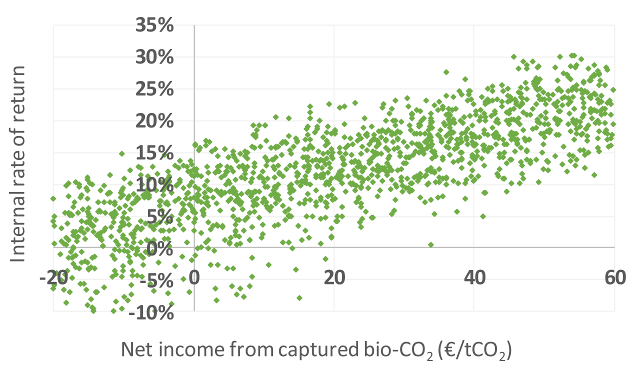

Fig. 8. IRR of the bio-CLC investment in modelled scenarios.

plants, and our analysis here, the bio-CLC technology could provide relatively cheap negative emissions. According to our modelling, the profitability level (10% IRR) could be reached around 10 €/tCO_2 net income from the captured bio-CO_2. We defined the net income as a sum of costs, subsidies, possible compensation based on CO_2 price in EU ETS, and possible profits from selling captured CO_2 to companies who could is it as raw material. The energy losses at plant and compressing the CO_2 are accounted before the estimated net income level.

However, it is possible that investment in bio-CLC units is profitable but the district heating and cooling grid operator still invests to some other technology. Decision makers base their investment decisions on many factors including relative profitability of alternative investments, estimated development of the system and policies, uncertainties, the size of investment, employment effect, available resources, other local conditions, etc. A robust investment is successful in a wide range of possible futures. It does not have to be always the best option, but it should rarely be the worst.

Large heat pumps with COP of 3.5 were the most robust of the studied investment options. Large heat pumps with COP 3.5 performed well in 71% of the studied futures and were poor only with high electricity prices, high transmissions costs, or high electricity taxes. Bio-CLC units were the most robust investments if they received a 10 €/tCO_2 or higher net-income from the captured bio-CO_2. The bio-CLC technology performed poorly without net-income from captured bio-CO_2. Other risk-zones for the bio-CLC technology were high biomass prices around 30 €/MWh and low electricity prices around 30 €/MWh.

It is likely that DHC operators will first invest to the most profitable and the most robust technology, and then start looking for additional investments if required. To simulate this, we did the same analysis, but without large heat pumps with COP of 3.5. With this assumption, the bio-CLC, bio CHP, and large heat pumps with COP of 2.5 are the most robust options. In this second analysis, the bio-CLC investment was the most profitable in a slightly number of futures, but still required roughly 10 €/tCO_2 net income from the captured bio-CO_2 to be the most robust of the studied investment options.

We outline our own analysis to the technical performance, costs, and direct CO_2 emissions of the BECCS in the studied case study. Other studies have adopted a broader viewpoint on the sustainability of the BECCS and have concluded that BECCS technologies can be either sustainable and produce negative emissions or fail in both metrics [32,33]. The main things to consider are direct and indirect land use change, sustainability of the feedstock, energy consumption and emissions related to transport of fuel and CO_2, and assumed substitution in the energy system [34]. Common results of the aforementioned studies have been that the sustainability of BECCS is highly dependent on the individual supply chains and should be inspected case-by-case.

Funder

The article was written as a part of the 'Negative CO_2' project funded by Nordic Energy Research and partly with in-kind funding of the participating research institutes.

Appendix A. DHC model documentation

The model operates on hourly resolution and has a perfect foresight over the modelled year. To reduce the solve time of mixed integer programming (MIP) model, the on/off variables are modelled in predefined half days, i.e. first half day h1 consists of hours t1…t12, h2 consists of hours t13…t24, etc. The mapping set between corresponding t and h is called th. In addition, we have defined sets Tr (t2 … t8760) and Hr (h2…h730) to model the operational constraints. Table A.1 presents the symbols used in the equations.

Energy balance

The Energy balance equation is the foundation of the DHC model requiring that demand in each grid (DH and DC) equals production, conversions between grids, storage charges, and storage discharges at hourly level. We have not included a loss of load or spill variables, which would allow the model to overproduce and loss the production. The DHC model does not maintain the balance of fuels or electricity and thus the model can buy fuels, sell electricity, and buy electricity from markets based on predefined prices.

$$p_{g,t}^{demand} = v_{g,t}^{\mathrm{prod}} + v_{g,t}^{\mathrm{convertIn}} - v_{g,t}^{\mathrm{convertOut}} - v_{g,t}^{\mathrm{storageIn}} + v_{g,t}^{\mathrm{storageOut}}$$

where

Table A.1
Symbols used in the model equations.

Subscripts	Description
v	Variable (linear)
vb	Variable (binary)
vi	Variable (integer)
p	Parameter
g	Grid; district heating (DH) or district cooling (DC)
u	Unit
U	Set of units u
Gt	Gas turbine (subunit)
St	Steam turbine (subunit)
Ct	Condensing turbine (subunit)
f	Fuel
t	Hour index
T	Set of hours (t1 … 8760)
Tr	Subset of time steps (t2 … t8760)
h	Half day index
H	Set of half days (h1 … h730)
Hr	Subset of half days (h2 … h730)
th	Set mapping corresponding t and h

$$v_{g,t}^{\text{prod}} = \sum_u v_{g,u,t}^{prod}$$

$$v_{g,t}^{\text{convertIn}} = \sum_{\{g2,u\}\in U_{g2,u,g}^{\text{convert}}} (v_{g2,u,g,t}^{\text{convert}})$$

$$v_{g,t}^{\text{convertOut}} = \sum_{\{g2,u\}\in U_{g,u,g2}^{\text{convert}}} (v_{g,u,g2,t}^{\text{convert}} \times p_u^{\text{inputRatio}})$$

$$v_{g,t}^{storageIn} = \sum_u v_{g,u,t}^{charge}$$

$$v_{g,t}^{storageOut} = \sum_u v_{g,u,t}^{discharge}$$

Production unit types

The DHC model has four different unit types that can produce DH and DC: NGCCs, CHPs, heat only boilers, and heat pumps. Each unit type has different level of details to add required operational characteristics and constraints, and to maintain reasonable simulation times. Heat only boilers and large heat pumps are modelled without MIP variables and with fewer details than NGCCs and CPHs to reduce the model solving time and to allow running of larger number of model runs to cover broader ranges for input parameters (Table A.2).

Table A.2
Properties of production unit types.

	NGCCs	CHPs	Heat only boilers	Large heat pumps
capacity unit*	MW_{fu}	MW_{fu}	MW_{fu}	MW_{DH}
Maximum fuel power (MW_x)	x	x	x	x
Minimum fuel power (MW_x)	x	x		
Elc and DH efficiency, depending on fuel power	x	x		
DH and DC efficiency, constant			x	x
Reduction, max. (MW_{steam})	x	x		
Condensing turbine (% efficiency)	x	x		
Maintenance break (predefined days)	x	x		
Ramping limit (% of MW_x/h)		x		
Minimum online time (days)	x	x		
Minimum offline time (days)	x	x		
Annual availability (% of hours)		x		
Seasonal availability (% of hours)		x		
CO_2 capture efficiency (%)		x		
Additional cost of captured CO_2 (€/tCO_2)		x		
Investment cost (k€/MW_x)	x	x	x	x
Fixed O&M (k€/MW_x/year)	x	x	x	x
Variable O&M (€/MWh_x)	x	x	x	x
Start cost (€)	x	x		

* Unit capacities are defined either by fuel power (NGCCs, power plants, and boilers) or by maximum production of DH (heat pumps). In the table, MW_x refers either MW_{fu} or MW_{DH} depending on unit type.

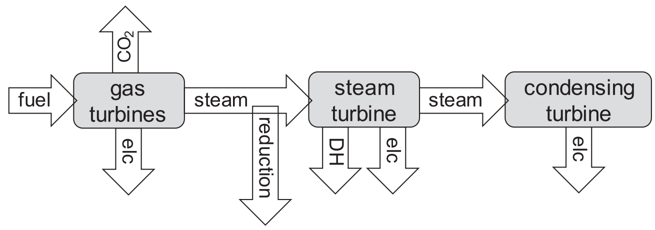

Fig. A1. Flow chart of NGCC units modelling in the DHC model.

In addition to production units, the DHC model has conversion units from DH to DC (absorption cooling) and storage units for both DH and DC.

NGCC units

The main difference between NGCCs and CHPs is that NGCC units have two gas turbine sub-units with their own on/off variables. In addition, we have not modelled CCS option for NGCC and NGCCs are very flexible and do not need ramping limits at hourly level. Fig. A.1 presents the flowchart of NGCC unit modelling.

On/off variables are defined for gas turbines. First gas turbine (Gt1) indicates the on/off status of the whole NGCC unit.

$$\forall\ \{u\} \in U^{\mathrm{NGCC}}:\ vb_{u,Gt,h\in Hr}^{onOff} = vb_{u,Gt,h-1}^{onOff} + vb_{u,Gt,h-1}^{start} - vb_{u,Gt,h}^{stop}$$

Implicitly, this means that minimum online and offline times for NGCC units are 12 h.

For NGCC units, the steam balance equation of the gas turbines is

$$\forall\ \{u\} \in U^{\mathrm{NGCC}}:\ v_{u,t}^{fuelUse} = \sum\nolimits_{Gt} (v_{u,\mathrm{Gt},t}^{elcProd-Gt} \times 1.04 + v_{u,\mathrm{Gt},t}^{steamOut-Gt})$$

where multiplication factor 1.04 for electricity generation describes energy losses in electricity production. Fuel use is limited to following ranges [0, $\mathrm{p}^{\mathrm{minFuelPower}} - \mathrm{p}^{\mathrm{maxFuelPower}}$] with binary on/off variable.

The steam balance equation of the steam turbine is

$$\forall\ \{u\} \in U^{\mathrm{NGCC}}:\ \sum\nolimits_{Gt} (v_{u,\mathrm{Gt},t}^{steamOut-Gt} \times p_u^{\mathrm{GtSteamEff}}) = v_{u,t}^{reduction} + (v_{u,t}^{elcProd-St} \times 1.04 + v_{u,t}^{steamOut-St}) + v_{u,t}^{steamIn-Ct}$$

The total electricity production of NGCC units

$$v_t^{elcProd} = \sum\nolimits_{u\in U^{\mathrm{NGCC}}} (v_{u,t}^{elcProd-Gt} + v_{u,t}^{elcProd-St} + v_{u,t}^{elcProd-Ct})$$

where

$$v_{u,t}^{elcProd-Gt} = \sum\nolimits_{Gt} (v_{u,\mathrm{Gt},t}^{\mathrm{fuelUse}} \times p_u^{\mathrm{GtEfficiency}} - vb_{u,Gt,h\in th}^{onOff} \times p_u^{\mathrm{GtConstant}})$$

$$v_{u,t}^{elcProd-St} = v_{u,t}^{\mathrm{steamIn-St}} \times p_u^{\mathrm{StEfficiency}} - vb_{u,Gt=Gt1,h\in th}^{onOff} \times p_u^{\mathrm{StConstant}}$$

$$v_{u,t}^{elcProd-Gt} = v_{u,t}^{\mathrm{steamIn-Ct}} \times p_u^{\mathrm{CtEfficiency}}$$

And the total DH production of NGCC units

$$\forall\ \{u\} \in U^{\mathrm{NGCC}}:\ v_{g=DH,u,t}^{prod} = v_{u,t}^{steamOut-St} + v_{u,t}^{reduction} - v_{u,t}^{effLossAtPartialLoad}$$

where $\mathrm{V}^{\mathrm{effLossAtPartialLoad}}$ is a linearized heat loss-term that is zero at maximum fuel power and has user-defined value $\mathrm{p}^{\mathrm{effLossFactor}}$ at minimum fuel power, e.g. $\mathrm{p}^{\mathrm{effLossFactor}} = 0.03$ would equal a 3 percentage point decrease in district heating production when operating at minimum load. Typical thermal efficiency losses in large NGCC units are small, but this additional parameters allows more realistic modelling of the plant efficiency and keeps the formulation identical with power plants where this loss-term is needed more.

Options for reduction and condensing turbine are switched off if parameters $\mathrm{p}^{\mathrm{maxReduction}}$ or $\mathrm{p}^{\mathrm{CtEfficiency}}$ are zero in the input data.

CHPs

The process chart of CHPs is slightly simpler than for NGCCs, because one boiler replaces multiple gas turbines (Fig. A.2). For the remaining process, the modelling is the same than for NGCC units.

CHPs have only one on/off variable

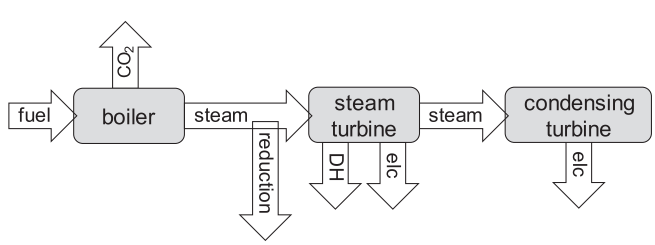

Fig. A.2. Flow chart of CHPs in the DHC model.

$\forall \{u\} \in U^{\mathrm{PP}}: vb^{onOff}_{u,h\in Hr} = vb^{onOff}_{u,h-1} + vb^{start}_{u,h-1} - vb^{stop}_{u,h}$

For CHPs, the steam balance equation of the steam turbine is

$\forall \{u\} \in U^{\mathrm{PP}}: v^{fuelUse}_{u,t} \times p^{\mathrm{efficiencyPP}}_{u} = v^{reduction}_{u,t} + (v^{elcProd-St}_{u,t} \times 1.04 + v^{steamOut-St}_{u,t}) + v^{steamIn-Ct}_{u,t}$

where multiplication factor 1.04 for electricity generation describes energy losses in electricity production. Fuel use is limited to following ranges [0, $\mathrm{p}^{\mathrm{minFuelPower}} - \mathrm{p}^{\mathrm{maxFuelPower}}$] with binary on/off variable.

The total electricity production of CHPs

$\forall \{u\} \in U^{\mathrm{PP}}: v^{elcProd}_{u,t} = v^{elcProd-St}_{u,t} + v^{elcProd-Ct}_{u,t}$

where

$v^{elcProd-St}_{u,t} = v^{fuelUse}_{u,t} \times p^{\mathrm{efficiencyPP}}_{u} \times p^{\mathrm{StEfficiency}}_{u} - vb^{onOff}_{u,h\in th} \times p^{\mathrm{StConstant}}_{u}$

$v^{elcProd-Gt}_{u,t} = v^{\mathrm{steamIn-Ct}}_{u,t} \times p^{\mathrm{CtEfficiency}}_{u}$

And the total DH production

$\forall \{u\} \in U^{\mathrm{PP}}: v^{prod}_{g=DH,u,t} = v^{steamOut-St}_{u,t} + v^{reduction}_{u,t} - v^{effLossAtPartialLoad}_{u,t}$

where $\mathrm{V}^{\mathrm{effLossAtPartialLoad}}$ is a linearized heat loss-term that is zero at maximum fuel power and has user-defined value $\mathrm{p}^{\mathrm{effLossFactor}}$ at minimum fuel power, e.g. $\mathrm{p}^{\mathrm{effLossFactor}} = 0.03$ would equal a 3 percentage point decrease in district heating production when operating at minimum load. Typical thermal efficiency losses are small, but this set-up allows additional flexibility in the modelling.

Equations allow modelling electricity only power plants by setting $\mathrm{p}^{\mathrm{maxReduction}} = 0$ and calculating a $\mathrm{p}^{\mathrm{effLossAtPartialLoad}}$ in a way that the equation above produces always 0. Also heat only units could be modelled when $\mathrm{p}^{\mathrm{StEfficiency}}$ and $\mathrm{p}^{\mathrm{CtEfficiency}}$ are zero, but we have defined these as separate heat only boilers to reduce simulation time. In the case of combined heat and power (CHP) production, options for reduction and condensing turbine are switched off if parameters $\mathrm{p}^{\mathrm{maxReduction}}$ or $\mathrm{p}^{\mathrm{CtEfficiency}}$ are zero in the input data.

If ramping limit constraint is enabled, the model compares the production of two consecutive hours setting a maximum limit to the change. If ramping limit has smaller value than minimum power, equations become more complicated as the power plant has to be able to shut down and start even though the change to the minimum load would be greater than the maximum ramp limit.

Upward ramp limit

$\forall \{u\} \in U^{\mathrm{PP}\,\&\,unitRampLimit}$:

$v^{fuelUse}_{u,t\in Tr} < (v^{\mathrm{fuelUse}}_{u,t-1} + p^{\mathrm{rampUpLimit}}_{u} \times p^{\mathrm{maxFuelPower}}_{u} \times vb^{onOff}_{u,(h-1)\in th}) + vb^{start}_{u,(h-1)\in th} \times p^{\mathrm{minFuelPower}}_{u}$

Downward ramp limit

$\forall \{u\} \in U^{\mathrm{PP}\,\&\,unitRampLimit}$:

$v^{fuelUse}_{u,t\in Tr} > (v^{\mathrm{fuelUse}}_{u,t-1} - p^{\mathrm{rampDownLimit}}_{u} \times p^{\mathrm{maxFuelPower}}_{u} \times vb^{onOff}_{u,(h-1)\in th}) - vb^{stop}_{u,h\in th} \times p^{\mathrm{minFuelPower}}_{u}$

Online constraints limit the minimum online and offline times when enabled.

Minimum offline time

$$\forall \{u\} \in U^{\mathrm{PP}\,\&\,unitOnlineLimit}: vb^{onOff}_{u,h} < \sum_{Hr=h-p^{minDownTime}_{u}}^{h-1} (vb^{stop}_{u,Hr})$$

Minimum online time

$$\forall \{u\} \in U^{\mathrm{PP}\,\&\,unitOnlineLimit}: vb^{onOff}_{u,h} > \sum_{Hr=h-1-p^{minUpTime}_{u}}^{h-2} (vb^{start}_{u,Hr})$$

where minimum online time is summed from one half day earlier than minimum offline time, because due to ramp limit equations, start variables are in the previous half day and stop variables are at the same half day block.

Annual limit of the activity factor (AFA) sets a maximum limit to the annual sum of onOff variable

$$\forall \{u\} \in U^{\mathrm{PP}\,\&\,unitAfaLimit}: \sum_{h\in H} (vb^{onOff}_{u,h}) < p^{\mathrm{maxAfa}}_{u} * 730$$

where 730 is a scaling factor of the AFA-limit that is given in range [0…1] in the input data.

Seasonal activity factor (AFS) limit is identical to annual limit, but the summation is limited to predefined 3 month blocks (Dec-Feb, Mar-May, Jun-Aug, Sep-Nov). The total number of half days in these periods is 180, 184, 184, and 182 consecutively. The actual implementation consists of 4 equations that are all the same form, but with different summing period and constant for the amount of half days in the season.

$$\forall \{u\} \in U^{\mathrm{PP}\,\&\,unitAfsLimit}\colon \sum_{h \in H^{\mathrm{season}}} (vb_{u,h}^{onOff}) < p_u^{\mathrm{maxAfs}} * p^{\mathrm{halfDaysInSeason}}$$

Boilers

Boilers are modelled very simply to save computational time. The error caused due to this decision was studied by modelling the boilers as PP units. As a result, the difference was quite small in our long term planning case study, because boilers units often had many small subunits and those operated only during the peak demand hours.

The operation of boiler units is described by one equation

$$\forall \{u\} \in U^{\mathrm{boiler}}\colon v_{u,t}^{fuelUse} \times p_u^{\mathrm{efficiencyBoiler}} = v_{DH,u,t}^{prod}$$

Heat pumps

Heat pumps produce DH from waste heat sources and can cogenerate district cooling. Often one large heat pump units have multiple subunits that can operate individually, but cannot vary their power and have to operate at full power.

$$\forall \{u\} \in U^{\mathrm{HPU}}\colon v_{g=DH,u,t}^{prod} = vi_{u,t}^{subUnitsOnline} \times p_u^{\mathrm{maxDHPower}}$$

$$\forall \{u\} \in U^{\mathrm{HPU}}\colon v_{u,t}^{elcUse} = v_{g=DH,u,t}^{prod} \times \frac{1}{p_u^{\mathrm{hpuCOP}}}$$

Some large heat pumps can produce also district cooling

$$\forall \{u\} \in U^{\mathrm{HPU}}\colon v_{g=DC,u,t}^{prod} = v_{g=DH,u,t}^{prod} \times p_u^{hpuDCratio}$$

Conversion units

DC can be converted from DH or produced from ambient cooling sources, e.g. from the sea water.

$$\forall \{u\} \in U^{convert}\colon v_{g=DC,u,t}^{\mathrm{convertIn}} = v_{g=DH,u,t}^{\mathrm{convertOut}} \times p_u^{\mathrm{inputRatio}}$$

If $\mathrm{p}^{\mathrm{inputRatio}} = 0$, the unit does not consume DH and is considered a free cooling unit. The operations require electricity that is consumed as a ratio of converted DC.

$$\forall \{u\} \in U^{convert}\colon v_{u,t}^{\mathrm{elcUse}} = v_{g=DC,u,t}^{\mathrm{convertIn}} \times p_u^{\mathrm{elcUseFactor}}$$

Storage units

Storages can store DH or DC and balance the production and demand, but there is a storage loss factor. The storage balance equation

$$\forall \{u\} \in U^{storage}\colon v_{g,u,t\in Tr}^{\mathrm{storageLevel}} = v_{g,u,t-1}^{\mathrm{storageLevel}} \times p_u^{\mathrm{storageLossRate}} + v_{g,u,t}^{\mathrm{storageIn}} - v_{g,u,t}^{\mathrm{storageOut}}$$

To decrease the calculation time, we assume that storage starts and ends empty. This is a minor assumption as the existing and planned storage sizes are relatively small and equal the production of few hours.

System equations

The objective equation adds all the costs, including possible net profits from captured bio-CO_2, annualized investment costs, and annualized decommission costs.

$$v^{\mathrm{obj}} = \sum\nolimits_{t\in T} (v_t^{\mathrm{variableOmCost}} + v_t^{\mathrm{fuelCost}} + v_t^{\mathrm{taxCost}} + v_t^{\mathrm{CO2Cost}} + v_t^{\mathrm{elcCost}})$$

$$+ \sum\nolimits_{h\in H} (v_h^{\mathrm{startCost}}) + p^{\mathrm{investmentCost}} + p^{\mathrm{decommissionCost}} + p^{\mathrm{fixedOmCost}}$$

where

$$v_t^{\mathrm{variableOmCost}} = \sum\nolimits_{u\in U^{NGCC|PP|boiler}} (v_{u,t}^{\mathrm{fuelUse}} \times p_u^{\mathrm{varOmCosts}}) + \sum\nolimits_{u\in U^{HPU}} (v_{DH,u,t}^{prod} \times p_u^{\mathrm{varOmCosts}})$$

$$v_t^{\mathrm{fuelCost}} = \sum\nolimits_u (v_{u,t}^{\mathrm{fuelUse}} \times p_{\{u\}\in f_u}^{\mathrm{fuelCost}})$$

$$v_t^{\mathrm{taxCost}} = \sum\nolimits_u (v_{u,t}^{\mathrm{DHprod}} \times p_{\{u\}\in f_u}^{\mathrm{DHprodTax}} \times p_u^{\mathrm{unitSpecificTaxModifier}})$$

$$v_t^{\mathrm{CO2Cost}} = \sum\nolimits_u (v_{u,t}^{\mathrm{CO2emissions}} \times p^{\mathrm{CO2Cost}}) + \sum\nolimits_{u\in U^{\mathrm{CCS}}} (v_{u,t}^{\mathrm{capturedCO2}} \times p^{\mathrm{netProfitFromCapturedBioCO2}})$$

$$v_t^{\mathrm{elcCost}} = \sum\nolimits_u (v_{u,t}^{\mathrm{elcUse}} \times p_t^{\mathrm{elcMarketCost}} + v_{u,t}^{\mathrm{elcUse}} \times p^{\mathrm{elcGridCostAndTax}} - v_{u,t}^{\mathrm{elcProd}} \times p_t^{\mathrm{elcMarketCosts}})$$

$$v_h^{\text{startCost}} = \sum_{u \in U^{PP}} (vb_{u,h}^{\text{start}} \times p_u^{\text{startCost}}) + \sum_{u \in U^{NGCC}} (vb_{u,Gt=Gt1,h}^{\text{start}} \times p_u^{\text{unitStartCost}} + vb_{u,Gt=Gt2,h}^{\text{start}} \times p_u^{\text{GtStartCost}})$$

$$p^{\text{investmentCost}} = \sum_{\text{u} \in U^{new}} (p_u^{\text{investedCapacity}} \times p_u^{\text{investmentCost}} \times p^{\text{annualization}})$$

$$p^{\text{decommissionCost}} = \sum_{\text{u} \in U^{decom}} (p_u^{\text{deCommissionedCapacity}} \times p_u^{\text{decommissionCost}} \times p^{\text{annualization}})$$

$$p^{\text{fixedOmCost}} = \sum_u (p_u^{\text{capacity}} \times p_u^{\text{fixedOmCost}})$$

where

$$p^{\text{annualization}} = \frac{p^{\text{discountRate}}}{1 - (1 + p^{\text{discountRate}})^{(} - p^{\text{timeHorizon}})}$$

$$v_t^{\text{CO2emissions}} = \sum_u (v_{u,t}^{\text{fuelUse}} \times p_{\{u\} \in \boldsymbol{f}_u}^{\text{fuelFossilCO2EmissionFactor}} - v_{u \in U^{\text{CCS}},t}^{capturedCO2})$$

$$\forall \{u\} \in U^{\text{CCS}}: v_{u,t}^{capturedCO2} = v_{u,t}^{\text{fuelUse}} \times p_{\{u\} \in \boldsymbol{f}_u}^{\text{fuelFossilCO2EmissionFactor}} \times p_u^{\text{CO2CaptureRate}} +$$

$$v_{u,t}^{\text{fuelUse}} \times p_{\{u\} \in \boldsymbol{f}_u}^{\text{fuelBioCO2EmissionFactor}} \times p_u^{\text{CO2CaptureRate}}$$

The split between biogenic and fossil CO_2 emissions allows the modelling of negative CO_2 emissions from BECCS. In the current model version, CCS option is included only for power plants. The total emissions can be negative if there is enough BECCS compared to fossil CO_2 emissions. In these cases the CO_2 cost can be negative. Implicitly this means that BECCS units receive a compensation based on the amount of captured CO_2 and assumed CO_2 price.

Capacity investments

Invested capacity for each scenario is decided by user and not optimized by the model.

Appendix B. DHC model validation

We validate here the documented version of the model by setting the input data according to historical data and comparing the model results to actual production statistics for four years 2014–2017. We use several indicators to compare the results to statistics, including fuel consumption, CO2 emissions, cogenerated electricity, cogenerated DH, etc.

Input data

Input data consists of three main sections: units and their parameters, system parameters, and time series. See chapter 2.2 and Appendix I for explanations of each group and their properties.

For the period from 2014 to 2017 the case study system of Helsinki DHC grid had 2 NGCC units, 2 CHP units and a large number of smaller heat only boilers that are grouped according to their fuels (Table B.1). In addition, there was one large heat pump unit for the whole period and another one for years 2016 and 2017. The system had small heat and cooling storages and additional cooling capacity from seawater cooling and absorption cooling.

System parameters include DH and DC demand, fuel taxes, fuel prices, electricity grid fee, and CO_2 tax (Table Fuel taxes on heat production from Statistics Finland (Table B.2). The DH and DC demands are from statistics and cover actual consumption, net imports with neighbouring cities, and distribution losses. Fuel taxes are according to tax levels in Finland. Fuel prices are based on statistics Finland, which publishes national averages, but we adjusted them for the case study due to long-term contracts that the local DHC operator had. In addition, the model has only one annual price for fuels when, in reality, prices may vary much during the year affecting the merit order.

Table B.1
Units in the validation model runs.

Unit	Fuel	Thermal power	Electricity	DH	DC	DH storage	DC storage
		MW	MW	MW	MW	GWh	GWh
NGCC 1	Natural gas	358	165	162			
NGCC 2	Natural gas	997	486	432			
Coal CHP 1	Coal	726	204	420			
Coal CHP 2	Coal	506	155	300			
Coal boiler	Coal	211		190			
Oil boilers	Oil	1500		1350			
Natural gas boilers	Natural gas	769		692			
Biomass boilers	Biomass	0		0			
Heat storages	–			20		2.1	
Large heat pumps, block 1	Waste heat, electricity		−35	105	75		
Large heat pumps, block 2 (from 2016 onwards)	heat from DC, electricity		−7	22	14		
Sea water cooling	Electricity		−3.5		70		
Absorption cooling	DH, electricity		−1.8	−35	35		
Cooling Storages	–				58		0.7

Table B.2
Demands, tax levels, and fuel costs in the validation model runs.

Parameter	Unit	2014	2015	2016	2017
DH demand	GWh	6883	6403	7062	7059
DC demand	GWh	133	125	141	141
Coal tax, CHP	€/MWh	12.8	14.3	16	17.1
Coal tax, HOB	€/MWh	18.7	21.8	25.2	27
Coal fuel cost	€/MWh	12	11.5	10	11
Natural gas tax, CHP	€/MWh	8	11.1	12.1	12.9
Natural gas tax, HOB	€/MWh	11.5	15.4	17.4	18.6
Natural gas fuel cost	€/MWh	20.5	17	22.7	27.5
Oil tax, HOB	€/MWh	17	19.5	22.3	23.9
Oil fuel cost	€/MWh	35	35	35	35
Electricity grid fee	€/MWh	35	35	35	35
CO_2 tax	€/tCO_2	5	6.5	3	7

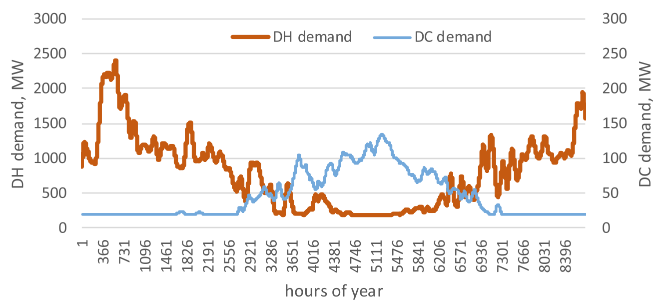

Fig. B.1. Hourly demands of district heating and cooling in the validation model runs.

Hourly time series for electricity market prices are from Nordpool historical market data for Finnish market region from 2014 to 2017. Annual average electricity prices were quite stable and varied from 29.7 €/MWh at 2015 to 36 €/MWh at 2014.

Fig. B.1 shows an estimated hourly distribution of DH and DC demands for 2014. Estimates are based on the total annual demand and 24 h smoothed hourly temperature series from 2014. The minimum demand of DH represents the hot water use and the minimum demand of DC represents the base load of larger users that need DC throughout the year. For years 2015 to 2017, these time series are scaled according to the total demand.

Comparing results to statistics

The total amount of generated DH matches statistics exactly as it is an input assumption (Table B.3). The amount CO2 emissions and cogenerated heat and electricity (NGCCs and CHPs) is reasonably close with statistics with an average deviation of ± 3%.

When looking the consumption of individual fuels, the model succeeds in simulating the consumption of coal and natural gas (Table B.4). We did not add multifuel plants to the model despite the small amount of cogenerated biomass with coal. These coal plants will phase out by 2030 and new plants will likely be based on single fuels, e.g. biomass. The DHC did not capture the small full load hours of oil-based capacity (from 70 h at 2017 to 140 h at 2016), because the grid has excess capacity and can operate almost without the oil plants that had the largest marginal cost. This error has few likely causes: all plants need a certain amount of annual operation hours to remain usable and the grid might need additional balancing during the high heating loads. We did not model the minimum annual operation hours or the grid balancing. Relative error in oil consumption is large, but the total error in system level results is small.

The modelled large heat pumps had slightly larger variability compared to the statistics than CHP and NGCC plants (Table B.5). In statistics, the full load hours vary from 3600 at 2014 to 4400 at 2017. In the model runs, the FLH vary from 2900 at 2014 to 5000 at 2017. The error in the large heat pumps is relatively larger because their DH capacity is only 3.5% of the total DH capacity and small variations in the CHP and NGCC operation might have a relatively large impact on the large heat pump operations.

Overall, these results show the DHC model succeeds in describing the operation logic and manages to approximate the actual operations when compared to annual statistics. There are no public monthly statistics of the operations.

Table B.3
Produced DH, cogenerated electricity, and CO2 emissions in statistics and validation model runs.

	Statistics, GWh				Modelled, GWh				Error, %			
	2014	2015	2016	2017	2014	2015	2016	2017	2014	2015	2016	2017
Generated DH	6883	6403	7062	7059	6883	6403	7062	7059	0%	0%	0%	0%
… of which cogenerated DH	5738	5659	5733	5945	6090	5598	5954	5840	+6%	−1%	+4%	−2%
Cogenerated electricity	4824	4664	3977	3933	4916	4643	3865	3534	+2%	−0.4%	−3%	−10%
CO_2 emissions	3157	2908	3269	3255	3334	2938	3266	3140	+6%	+1%	−0.1%	−4%

Table B.4
Fuel use in statistics and validation model runs.

Fuel use	Statistics, GWh				Modelled, GWh				Error, %			
	2014	2015	2016	2017	2014	2015	2016	2017	2014	2015	2016	2017
Coal	4971	4232	6895	7265	5585	4301	7022	6960	+12%	+2%	+2%	−4%
Biomass (co-fired with coal)	0	34	185	231	0	0	0	0	–	–	–	–
Natural gas	7333	7541	4579	4122	7448	7596	4726	4206	+2%	+0.7%	+3%	+2%
Oil	175	181	213	101	6	0	13	10	−97%	−100%	−94%	−91%
SUM, total	12,479	11,987	11,871	11,718	13,038	11,897	11,761	11,175	+4%	−0.8%	−0.9%	−5%

Table B.5
Large heat pump operation in statistics and validation model runs.

	Statistics, GWh				Modelled, GWh				Error, %			
	2014	2015	2016	2017	2014	2015	2016	2017	2014	2015	2016	2017
HP electricity	121	127	125	146	97	141	134	164	−20%	+11%	+7%	+13%
HP production, DH	375	422	491	565	310	451	521	641	−17%	+7%	+6%	+14%

Appendix C. Supplementary data

Supplementary data to this article can be found online at https://doi.org/10.1016/j.seta.2019.05.005.

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