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On the way towards smart energy supply in cities: the impact of interconnecting geographically distributed district heating grids on the energy system

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Abstract

A linear continuous optimization model with an hourly time resolution was developed in order to model the impact of subsequent interconnections of different DH grids. The municipality of Sønderborg was chosen for a case study and interconnections of five currently disconnected DH grids were assessed. Moreover, the impact of industrial waste heat on the DH supply was also assessed. In the reference year (2013) two out of four interconnections proved to be economically viable. The results for the future energy system (2029) showed that interconnecting geographically distributed DH grids reduces primary energy supply by 9.5%, CO_2 emissions by 11.1% and total system costs by 6.3%. Inclusion of industrial waste heat in the fully interconnected DH grid reduced primary energy supply for an additional 3%, CO_2 emissions for an additional 2.2% and total system costs for an additional 1.3%. The case of the future energy supply system with interconnected DH grids and installed industrial waste heat recuperation results in the lowest primary energy demand, emissions and costs. Finally, the benefits of the interconnected DH grid, in terms of system flexibility, CO_2 emissions, total costs and energy efficiency, proved to be much greater in the future energy system.

Keywords:

Local Communities; CO_2 emissions; Renewable Energy Systems; Energy System Optimization; GIS; Zero Carbon

1 Introduction

Worldwide, understanding the harmful consequences of climate change is receiving ever more attention. During the 2015 Paris Climate Conference (COP21), the first ever legally binding global climate deal was agreed upon, committing all the countries involved to make an impact on the climate change, starting from the year 2020. The parties agreed to keep the global temperature rise below 2°C compared to the pre-industrial level, and aiming for the maximum increase of only 1.5°C. Carbon neutrality is aimed for by the second half of the century [1]. Moreover, the focus of the 2016 Climate Change Conference in Marrakech (COP22) was on adopting a work plan, developing a framework for implementation and discussing possible issues of the COP21 agreement, with the main emphasis on overcoming barriers for the agreement to become fully operational [2].

Reviewing the energy planning models available, Mancarella [3] made a comprehensive paper about the concepts and evaluation methods of multi-energy systems. The author summarized the general motion towards the integrated energy system planning, as opposed to the classical approach to energy system planning where its sectors are treated separately. Furthermore, one of the main conclusions was that the integrated energy system modelling is beneficial compared to the classical approach. The integrated energy system planning also goes by the name of "the smart energy system" approach, where the power, heat and gas sectors (including mobility) are modelled together in order to detect synergies between the sectors and achieve a cheaper and technically more robust energy system [4]. It is an especially useful approach in modelling 100% renewable energy systems. The study in [5] indicates that the holistic approach of smart energy systems, where different sectors are integrated and district heating (DH) is the major link between the heat and electricity sector in urban areas, can help to avoid large-scale integration of costly electricity storage.

Increasing the DH share is one way of improving the energy efficiency in energy systems where a heating demand is present. Furthermore, it allows a better integration of the power and heating sectors which facilitates the integration of intermittent energy sources, such as wind power and photovoltaics. Xiong et al. [6] showed in the case of China that implementation of the scenario with the expanded DH grid could lead to the 50% reduction in the primary energy supply for the building heating sector compared to the reference case. Moreover, total system cost in the heating sector would be approximately 15% lower compared to the reference case. The EU recently released its first ever heating and cooling strategy where the European Commission argued that a strategy of decarbonising the heating and cooling sectors would save around €40 billion in gas imports and €4.9 billion in oil imports yearly [7].

Böttger et al. showed for the case of Germany that electric boilers can be a promising technology for balancing the power grid. Thus, integration of power and heating systems proved to be beneficial for the whole energy system [8]. Capuder & Mancarella argued that although there is a growing interest in the integrated energy planning approach, it is still arguable to which extent the efficiency can be improved from coupling different energy vectors [9]. They developed a synthetic mixed-integer linear optimization model suitable for evaluating the characteristics of different multi-generation options. They concluded that flexible integrated schemes with combined heat and power plants (CHP) and electric heat pumps, supported by thermal energy storage, can bring a significant operational and investment cost savings. Moghaddam et al. developed a comprehensive model for self-scheduling of an energy hub to supply cooling, heating and electrical demands of a building [10]. Although they focused on the building level of planning, they also showed the importance of integrated planning of different energy needs. One important way a future district heating system could develop in is the utilization of excess heat from industry and agriculture. This would allow increased energy efficiency in the system as less heat would be lost in industrial processes, as well as increase the competition among the DH suppliers, compared to the common monopolistic position of heat suppliers today. A regional case study of utilizing excess heat was done by Sandvall et al. for the case of Sweden [11]. Their results are not straightforward and show that from the system's point of view, CO_2 emissions only decrease in the long run, while in the short run they can even increase.

In Denmark, due to the first and second oil crises, a paradigm shift towards RES happened during the 1970s, as an effort to increase the security of energy supply. The current Danish Government set a target to phase out use of all fossil fuels and to achieve a low carbon society by 2050 [12]. As a part of the same set of policies, Denmark plans to phase out the use of all coal, as well as oil for heating purposes [13]. As a part of the policy to increase the energy efficiency, Denmark expanded its DH. Today, about 60% of the Danish heating energy demand comes from the DH. In their paper about reaching a 100% renewable energy system of Denmark in 2050, Lund & Mathiesen showed that DH will still represent a major role in meeting the heating needs [14]. The authors argued that DH systems in 2050 would consist of CHPs and boilers, mainly driven by biomass, large-scale heat pumps and excess heat from industrial processes. Moreover, parallel to the penetration of intermittent renewable sources in the power sector, a transition to the low-temperature 4th generation DH systems in the period from 2020 to 2050 has been anticipated [15]. Li & Svendsen developed a model of hypothetical low temperature DH network in Denmark and their analysis concluded that such systems are characterized by significantly lower heat losses than traditional systems, as well as by reduced exergy losses [16]. All of the above proves the importance of the DH in Denmark. Improving any part of the DH system can lead to large savings in the total system costs on a country level. Furthermore, internalizing the external costs can show further benefits of the DH systems. Zvingilaite showed for the case of the Danish heat and power sector that the inclusion of human health-related externalities in energy system modelling can lead to results with an 18% decrease in the total health costs and an 4% decrease in the total energy system costs , compared to models where such externalities are excluded [17].

Some authors have focused on the integration of geographically distributed DHs, on the possibility of establishing pricing mechanisms similar to day-ahead electricity markets and on addressing the problem of the monopolistic position of DH suppliers when they also operate the DH grid. Gebremedhin & Moshfegh first modelled a locally deregulated integrated district heating system [18]. They developed the MODEST tool for analyses and assessed the potential of connecting 7 geographically dispersed DH systems. However, their conclusions were vague and uncertain. Further development of their model was carried out by Karlsson et al. [19]. They concluded that the economic potential for a heat market in three different Swedish DH systems amounts to between 5 and 26 million €/year with payback times ranging from two to eleven years. Moreover, they showed that connecting different DH grids can reduce the total CO_2 emissions. However, their economic indicator is a bit unclear, as it is a mix of a business-economic and a socio-economic one. Syri & Wirgentius developed a model which simulates a day ahead heat market, in the same fashion as the well-known day-ahead electricity spot market operates today [20]. They adopted the model for the city of Espoo in Finland and concluded that an open heat market can be beneficial for all parties involved and significant fuel savings could be achieved. Kimming et al. recently showed the beneficial outcome of vertically integrated local fuel producers into district heating systems [21]. Their proposed integration can lead to the reduction of greenhouse gas (GHG) emissions and lower the production costs/heat price, if there is an incentive to utilize locally produced fuels.

In order to assess both the economic and technical benefits that can be obtained by interconnecting adjacent district heating systems, a model was developed that represents different DH systems with their geographical bounds, together with the power and gas sectors. Moreover, it is an hourly model which can easily cope with modelling of large amounts of intermittent power sources. The model allows users to assess the feasibility of interconnecting different DH systems from a technical and socio-economic point of view, as well as to analyse the possible changes in the scheduling of each heat supplying plant that may occur after the interconnection of systems has been implemented. The novelty of this model compared to the previously developed ones is the representation of the whole energy system together with the representation of physical boundaries of DH systems on an hourly basis, which does not cause problems in modelling the large amounts of intermittent sources. Moreover, it can optimize utilization rates of different energy plants, as well as investments in new ones. The model developed and the results presented could be used for further understanding of impacts of DH systems on the flexibility of the power sector.

As opposed to the electricity grid whose size of the transmission grid allows many different suppliers to connect and interact with different types of demand, DH grids are geographically constrained to usually only densely populated regions. Sometimes heat suppliers are also the owners of the DH grid which then constitutes a complete monopoly. Another solution is when heat suppliers and the DH grid are operated by at least two different independent bodies. The competition among suppliers can lead to the increased operational efficiency and consequently costs of energy production can be reduced, when equal access to the distribution network is secured to all suppliers [22]. However, even if the latter condition is satisfied, in smaller cities it is often the case that there is only one company supplying all the heat. This can lead to inefficiencies in the system as the lack of competition among the suppliers might drive them away of the reduction of the production costs. The authors of this paper developed a model which can assess the technical and economic benefits of connecting adjacent DH grids and allowing a larger integration between the power and heating sectors. Furthermore, the model developed allows optimizing investments in the energy sector taking into account current investments as sunk costs, i.e. costs that occurred and cannot be recovered anymore. This can allow planners to assess whether an existing DH system can be improved and become cheaper in terms of socio-economic costs.

Thus, the aim of the model is to be used for assessing whether the integration of adjacent district heating grids can lead to the fuel savings (if more energy efficient heat producers can supply their energy to a larger number of customers) or reduced CO_2 emissions (if lower emission emitters are deployed more often after they get the chance to supply more customers), in the same time not threatening to economic competitiveness of the energy system. In case of positive results of the chosen case studies, it would be an important contribution towards meeting the European as well the as Danish national climate policy goals.

Following the description of the developed model in the subsequent chapter, a case study chosen in this paper is described in chapter 3. Results of the case studies, showing the outcome of the considered interconnections between different DH systems for both the current and the future energy system, are presented in chapter 4, followed by the discussion of the results, including a comparison with other work in the field, and finishing with the most important conclusions of this paper.

2 Methods

2.1 Model description

The model developed is a linear continuous programming model which makes it possible to run it on personal computers, although there is a vast amount of variables used. Although models such as TIMES and MARKAL use decomposition techniques and typical days to represent one year, it is argued that this representation cannot account for weather variations properly [23]. Also, it cannot represent a consistent criterion to select days or weeks or to assess the validity of assumptions [24]. Furthermore, problems concerning the representation of flexible energy technologies and storage plants have been detected [25]. In order to cope with these issues, the authors of this paper have decided to represent the energy system during the one year using an hourly temporal resolution. Although building an optimization model with numerous technologies and with an hourly time-resolution can lead to significant computational challenges, it is beneficial that all the possible relations between the weather data (wind speeds and solar insolation), prices of the commodities on the markets (day ahead el-spot market), seasonal, monthly, weekly and daily demand variations as well as storage technology dynamics can be taken into account. The model seeks to find the least cost solution of the energy system. Its outputs are the hourly generation of different technologies, heat storage levels in every hour during the year and capacities of the energy plants. Furthermore, the model calculates post-optimization total primary energy supply (PES) and CO_2 emissions.

Socio-economic costs were used to represent the costs of the energy system. Socio-economic costs are a good way to represent the *true* costs imposed on society from operating an energy system as it takes a broad perspective into account when reporting the costs. Generally, socio-economic costs do not take taxes and subsidies into account (as opposed to business-economic costs) as they are considered to be internally redistributed within the society. Detailed discussion on the difference between socio-economic and business-economic costs when analysing energy systems can be found in [26]. In our approach, investment costs, fixed and variable operating and maintenance (O&M) costs, fuel costs and CO_2 emissions price were taken into account when calculating the total socio-economic cost of the energy system. Although the concept can be expanded by including other negative health externalities such as NO_x, CO and SO_2 emissions, as well as the potential for job creation, it was left outside of the scope of this paper as it is less clear how these costs should be internalized.

2.2 Mathematical description

The developed linear continuous model consists of an objective function, inequality constraints, equality constraints as well as upper and lower bounds. In order to make it easier to follow the equations, abbreviations of the equation terms can be seen in the Nomenclature chapter.

2.2.1 Objective function and variables

The objective function in this model is set to minimize the total annual socio-economic costs:

$$\begin{aligned}\min Z = &\sum_{i=1}^{n}\left(fix\_O\&M_i + lev_{inv_i}\right)x_i + \sum_{j=1}^{m}\left(var\_O\&M_j + \frac{fuel_j}{\eta_j} + CO2_j \cdot CO2_{inten_j}\right)x_j \\ &+ \sum_{k=1}^{p}\left(el\_imp\_exp_k + gas\_imp\_exp_k + dies\_imp_k + petr\_imp_k\right)x_k\end{aligned} \tag{1}$$

The first term in (1) represents the fixed O&M costs and levelized investments in generation capacity over the lifetime of an energy plant. The second term calculates the variable, fuel and CO_2 emission costs while the last term calculates expenditures for electricity, gas, diesel and petrol import or electricity and gas export. As no generation of fuels usually exists in smaller regions (at a municipal level), diesel and gasoline cannot be exported outside of the system's boundaries in this model. However, if needed, this constraint can be easily removed. Note that the x_i set of variables are capacity variables and thus, their unit is MW, while x_j and x_k are generation, import or export amounts in an hour. Hence, their unit is MWh.

Levelized investments are calculated using (2):

$$lev\_inv_i = inv_i \cdot \frac{dis\_rate_i}{1-(1+dis\_rate_i)^{-lifetime_i}} \tag{2}$$

In order to make it easier to follow the inequality and equality constraints, the variables x_i, x_j and x_k are further associated with indices in order to make it clear what type of their output is and what type of fuel they use. A description of the indices can be found in Table 1. Generally, the first index describes the ordinal number of technology, the second index describes the type of the output from a certain technology and the third index describes the fuel type that the technology is using. In the case of heat generation and storage technologies, a fourth index specifies in which of the geographically separated DH systems the technology operates.

Table 1. Explanation of variables.

Variable	Subdivision	Subdivision 2	Explanation	
x_j	$x_{j,EL}$	$x_{j,EL,gas}$	Hourly generation of technologies which generate electricity and are driven by gas	
		$x_{j,EL,biomass}$	Hourly generation of technologies which generate electricity and are driven by biomass	
		$x_{j,EL,other}$	Hourly generation of technologies which generate electricity and are driven by other fuel types	
	$x_{j,heat}$	$x_{j,heat,gas}$	$x_{j,heat,gas,t}$	Hourly generation of technologies which generate heat, are driven by gas and operate in the DH system t (t represents the number of geographically separated DH systems; $number\ of\ DH\ grids = 1,2..t$)
		$x_{j,heat,biomass}$	$x_{j,heat,biomass,t}$	Hourly generation of technologies which generate heat, are driven by biomass and operate in the DH system t
		$x_{j,heat,other}$	$x_{j,heat,other,t}$	Hourly generation of technologies which generate heat, are driven by other fuel types and operate in the DH system t
		$x_{j,heat,storage\_ch}$	$x_{j,heat,storage\_ch,t}$	Hourly charge of heat to the heat storage operated in the DH system *t*
		$x_{j,heat,storage\_dis}$	$x_{j,heat,storage\_dis,t}$	Hourly discharge of heat from the heat storage operated in the DH system *t*
	x_{j,an_dig}	Generation of gas after CO_2 removal in anaerobic digester (*an_dig* denotes anaerobic digestion)		

2.2.2 Inequality and equality constraints

Inequality constraints represent the heating demand to be met in each DH grid, as well as the electricity, gas, diesel and gasoline demand to be met by the generation technologies or from import in each hour during the year. The number of hours in one year was set to 8,760. Mathematically, this can be represented in the following way (note that due to the simplification of representation, the *sum* sign has been dropped out in the following notation):

The set of constraints for meeting the heat demand in each DH grid are modelled in (3):

$$x_{j,heat,gas,t} + x_{j,heat,biomass,t} + x_{j,heat,other,t} + x_{j,heat,storage\_dis,t} - x_{j,heat,storage\_ch,t} \geq heat\_dem_t \qquad (3)$$

In order to model a connection of two or more DH grids, the constraint presented in (4) needs to be adopted:

$$\begin{aligned} x_{j,heat,gas,1} &+ x_{j,heat,biomass,1} + x_{j,heat,other,1} + x_{j,heat,storage_{dis},1} - x_{j,heat,storage_{ch},1} \\ &+ x_{j,heat,gas,2} + x_{j,heat,biomass,2} + x_{j,heat,other,2} + x_{j,heat,storage_{dis},2} - \\ x_{j,heat,storage\_ch,2} &+ \cdots + x_{j,heat,gas,t} + x_{j,heat,biomass,t} + x_{j,heat,other,t} + x_{j,heat,storage_{dis},t} \\ &- x_{j,heat,storage\_ch,t} \geq heat_{dem_1} + heat_{dem_2} + \cdots + heat\_dem_t \end{aligned} \qquad (4)$$

The index *t* in the upper constraint represents the number of DH grids one wants to connect.

Furthermore, the set of constraints for meeting the electricity demand is defined in (5):

$$x_{j,EL,gas} + x_{j,EL,biomass} + x_{j,EL,other} + \ el\_imp\_exp_k \geq el\_dem \qquad (5)$$

Equation (6) shows the set of constraints for meeting the gas demand:

$$x_{j,an\_dig} + gas\_imp\_exp_k - \frac{x_{j,heat,gas,t}}{\eta_j} - \frac{x_{j,EL,gas}}{\eta_j} \geq gas\_dem \qquad (6)$$

The set of constraints for meeting the gasoline and diesel demand is given in (7) and (8):

$$dies\_imp_k \geq dies\_dem \qquad (7)$$

$$petr\_imp_k \geq petr\_dem \qquad (8)$$

In (9), the set of constraints for assuring that the capacity of energy plants is large enough for the peak production of the specific technology is shown:

$$x_j \leq x_i \cdot t \qquad (9)$$

where t denotes the time of one hour. Thus, $x_i \cdot t$ has the unit of MWh.

Moreover, it needs to be assured that the capacity of the transmission grid, gas grid and fuel grid is large enough for importing/exporting different types of energy in each hour, which is defined in (10):

$$x_k \leq x_i \cdot t \qquad (10)$$

Equations (9) and (10) are valid for every hour throughout the year. Finally, there are constraints for biomass consumption and maximum CO_2 emissions that can be optionally imposed in the model, presented in (11) and (12):

$$CO2_{inten_j} \cdot x_j + CO2_{inten_k} \cdot x_k \ \leq CO2_{cap} \qquad (11)$$

$$\frac{x_{j,EL,biomass}}{\eta_{j,EL}} + \frac{x_{j,heat,biomass}}{\eta_{j,heat}} \leq bio\_cap \qquad (12)$$

The second term in constraint (11) denotes that the emissions of the energy coming in or out of the system boundaries are also taken into account.

Heat storage can be modelled in several ways. However, in order to avoid the implementation of for-loops, which increases the computational time significantly, this model uses an equality constraints set for each hour r:

$$heat\_level_r = heat\_level_{r-1} + x_{j,heat,storage\_ch,r} - x_{j,heat,storage\_dis,r} \tag{13}$$

Furthermore, in the first and the last hour of the year, storage level is set to zero:

$$heat\_level_1 = heat\_level_{8760} = 0 \tag{14}$$

Finally, the discharged energy from the storage needs to be lower or equal to the storage content in the hour before:

$$heat\_level_{r-1} \geq x_{j,heat,storage\_dis,r} \tag{15}$$

2.2.3 Upper and lower bounds

The decision of upper and lower bounds can be set by the modeller for each specific case. However, it should be noted that variables denoting import and export of the electricity and gas are unconstrained in sign, as they are positive for import of energy and negative for export of energy across the system boundaries:

$$el\_imp\_exp_k, gas\_imp\_exp_k \cdots unconstrained\ in\ sign$$

In this model, export of diesel and petrol fuels has not been considered.

All other variables need to be positive in sign. However, the infrastructure, including energy plants, being already built shall be modelled as sunk costs, i.e. costs that have already occurred and cannot be recovered anymore. Thus, eventual new investments need to be feasible enough to compensate for the sunk costs in order to reduce the total socio-economic cost of the energy system. Sunk costs of the energy plants already being built are modelled by setting the lower bounds of capacity variables of these energy plants to the output capacities of the plants. In that way, the model takes these investments into account when minimizing the total socio-economic cost of the system, while the capacity of already built energy plants will be available for energy generation.

It should be noted that any energy storage, such as gas, biogas or fuel storages, can be modelled in the same manner using (13) and (14).

2.2.4 Exogenous variables

Individual demand for heating, as well as industry demand for fuel types not considered here (such as coal) shall be entered into the model exogenously. In that way, the emissions and the cost of these types of energy can be accounted for in the model.

2.3 Indicators

One can distinguish between the economic and technical indicators used in the model. Economic indicators are represented by the total annual socio-economic cost, while the indicator of the technical feasibility of the system is the CO_2 emission level. However, it should be noted that the objective value of the model is to minimize the total socio-economic costs, while the CO_2 emission level can (but does not need to) be constrained using the CO_2 emission capacity. In any case, CO_2 emissions are calculated post-optimization.

Furthermore, in order to calculate the feasibility of interconnections between different DH grids, several economic indicators were used. In this paper, economic evaluation was conducted using the net present value (NPV) method. NPV sums up all payments related to the investment (both positive and negative) over a certain period of time, incorporating the discount rate to the temporal distribution of the payments.

Investment in piping needed for connecting two DH grids is considered as a cost occurring in the beginning of the project, while the difference between total socio-economic costs before and after connecting the DH grids is considered as saving, occurring at the end of each year during the project lifetime. The investment and the savings are the input payments (the investment as a negative payment and savings as a positive payment) for the calculation of NPV values.

In order to make it easier to assess the results, as well as to increase their clarity, the dynamic payback time and internal rate of return (IRR) values were calculated. The dynamic payback time determines how long it takes for the net present value of the annual payments to cover the investment, while IRR represents the discount rate at which the net present value is equal to zero.

Generally, a project is considered to be profitable if NPV is higher than zero, the dynamic payback time is lower than the defined project lifetime and the IRR is higher than the discount rate.

2.4 Investment calculation in the interconnecting piping

In order to carry out a feasibility analysis of different cases, the price of the interconnecting pipes had to be assessed. As the transmission piping is the sole investment compared to the official plans for the energy transition of the region, its careful and accurate estimation is of crucial importance. As the price highly depends on the pipe diameter, it was necessary to determine the nominal diameter (DN) of each of the interconnecting pipes. A comprehensive description of district heating and cooling systems, from the fundamental idea to the detailed elaboration of system functioning, economics and planning has been provided by Frederiksen & Werner in their book “District Heating and Cooling” [27]. Among other methods, theories, examples and descriptions, they offer two very useful relations. The first is the relation between velocity of the flow in district heating pipes and the pipe diameter, whereas the second is the relation between the pipe diameter and the investment price of district grid expansion expressed per meter of the piping length, based on investments in Swedish district heating networks. As the maturity of Swedish DH system, as well as its market share, is pretty similar to those of Danish DH systems, it is considered that the same relations are applicable for the case of a DH system located in Denmark. The pipe diameter was determined using the relation between the velocity of the flow and the pipe diameter, according to the following set of equations:

$$\dot{m}_{max} = \frac{\phi_{max}}{c_w * \Delta T} \tag{16}$$

Where:

$\dot{m}_{max}$ - maximum mass flow of the water transferred through the pipes, kg/s

ϕ_{max} - maximum heat capacity transferred through the pipes, W

c_w - specific heat capacity of water, 4.187 kJ/(kg*K)

ΔT – water temperature difference, K

$$q_{v,max} = \frac{\dot{m}_{max}}{\rho_w} \tag{17}$$

Where:

$q_{v,max}$ - maximum volume flow of the water transferred through the pipes, kg/s

ρ_w - water density, 1000 kg/m^3

$$A_p = \frac{q_{v,max}}{v_f} \tag{18}$$

Where:

A_p- cross area of the pipe, m^2

v_f - flow velocity, m/s

$$DN = 2 * \sqrt{\frac{A_p}{\pi}} * 1000 \tag{19}$$

Where DN is nominal diameter of the pipe in millimetres.

Knowing the maximum hourly heat capacity transferred through each pipe, which is one of the outputs of the developed mathematical model, and using (16) and (17), it was possible to calculate the maximum hourly volume flow of the water going through the pipes. The flow velocity was determined using (18) and (19) and an iterative method of matching the flow speed and the diameter of new transmission piping. The final result was the pipe nominal diameter for each of the cases.

Furthermore, knowing the nominal diameter of each pipe and using the relation between the pipe diameter and the investment price of piping per meter of the length reported in [27], it was possible to estimate the piping price. It is important to emphasize that the reported relation distinguishes between four different areas where an investment can be made: inner city areas, outer city areas, park areas and construction site areas. In this case, the transmission pipes are connecting DH systems between towns, which can be considered as outer city areas. Hence, reported values for outer city areas were used in this paper. Detailed results of the piping price estimation steps are given in section 4.2.

3 Case study

The Danish municipality of Sønderborg was chosen as a case study in this work. It is a medium-sized municipality in a Danish context with approximately 75,000 inhabitants and an area of around 496 km^2. The largest town in the municipality is Sønderborg town with a population of about 27,500; other towns in the municipality have a population of less than 7,000. The municipality has the goal of becoming CO$_2$ neutral by the year 2029. This goal and the municipality’s efforts to reach the goal, such as the operation of the ProjectZero office [28], make Sønderborg an interesting case study and furthermore leads to good availability of data and future projections about its energy system.

Table 2 shows the final energy consumption in the municipality in 2013 by type. The total final energy consumption was 2.15 TWh, leading to the emission of 500 kilotons* of CO_2.

Table 2. The total final energy consumption and CO_2 emissions in Sønderborg municipality in the year 2013 [29].

	Final energy consumption (GWh/year)	CO_2 emissions (kton/year)
District heating	488	42
Individual heating	438	104
Electricity (classical)**	442	158
Process energy	270	64
Transport	510	133
Total	**2,148**	**500***

**In the report used as a reference for the base year, CO_2 emissions from waste incineration plant were calculated as zero. However, using the recommendation from Danish energy agency, a part of the CO_2 emissions from waste incineration plant has to be taken into account. This would account for additional 28.57 kilotons of CO_2 emissions during the year.*

*** Electricity consumption for district heating, individual heating, process energy and transport is not included in the value for classical electricity consumption in the table. Electricity demand for powering cooling devices is included in the value.*

As in the most municipalities in Denmark, DH plays a large role in the heating sector of Sønderborg's energy system. There are currently five separate DH systems in operation in the municipality, Sønderborg town DH being the largest by far. The gross consumption in each DH system is shown in Table 3.

Table 3. Heat generation capacity in 2013 and the gross district heating production in Sønderborg municipality's five district heating networks [29].

DH production by network*	Installed capacity (MW)	Production (GWh/year)	Storage capacity** [m^3]
Sønderborg	201.5	349.0	4,000 (232.4 MWh)
Gråsten	46.7	41.6	8,500 (493.9 MWh)
Augustenborg	28.6	35.3	-
Nordborg	24.1	33.3	-
Broager	24.9	28.3	4,500 (261.5 MWh)
Total	**325.8**	**487.6**	

** The heating year 2013 refers to the period from July 2013 until June 2014. The data has been corrected for degree days.*

***Storage size of the tank coupled with the solar district heating plant in Sønderborg was obtained from* [30]. *Storage size for other two storages were scaled depending on the capacities of the solar district heating plants*

Sønderborg municipality is currently a net importer of electricity. The total electricity consumption in the municipality in 2013 (including electricity for heating, process and transport) was 502 GWh. Electricity generation within the municipal borders was 91 GWh in the same year, corresponding to 18% of the total consumption. There is currently no gas or biogas production in the municipality. All natural gas consumed in the municipality is therefore imported from the national gas distribution grid.

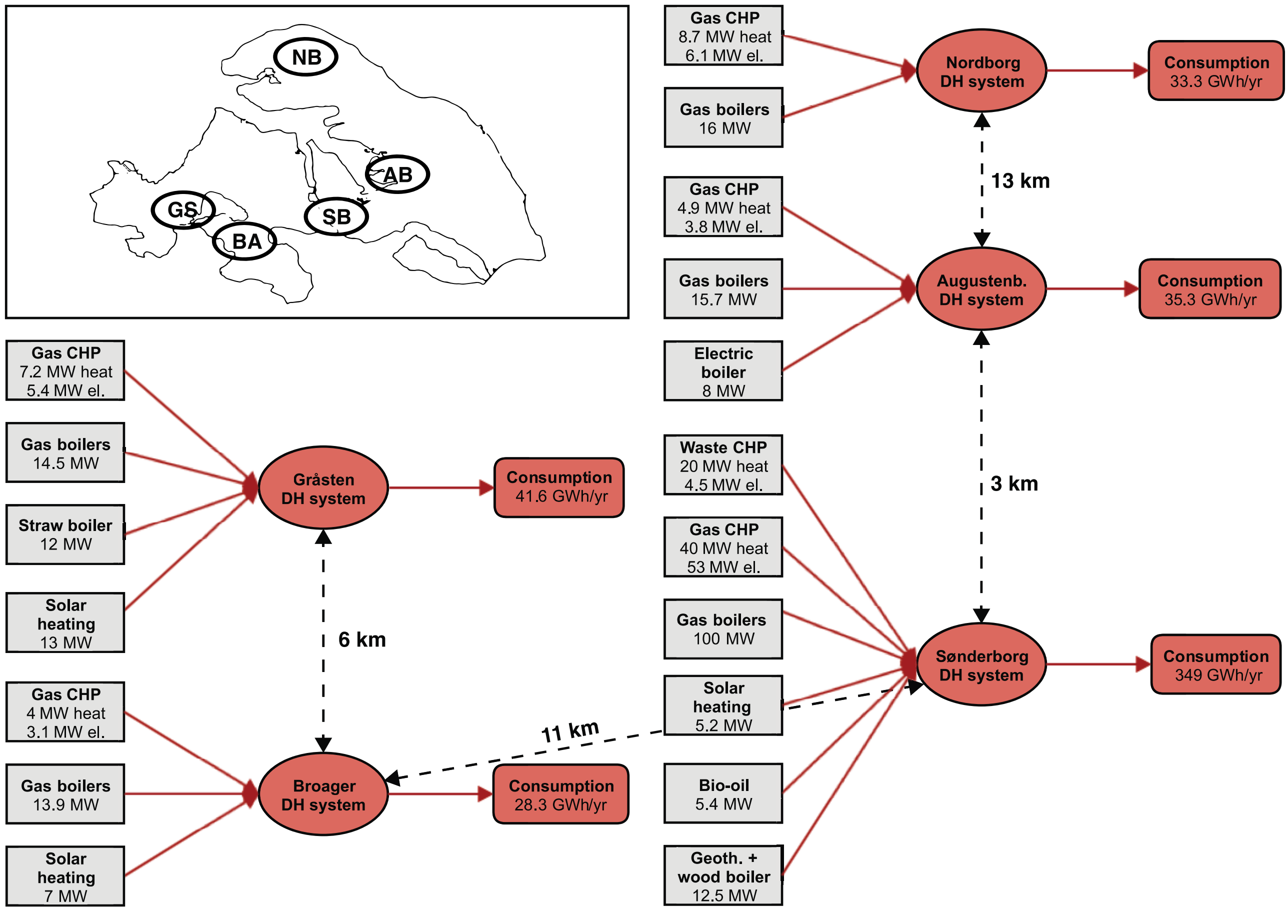

Figure 1. A schematic representation of Sønderborg municipality's five DH systems. For each DH system, the power plant types and installed capacities are shown on the left and the total annual gross heat consumption (2013 values) is shown on the right. Possible future interconnections between the DH systems are shown with dashed lines, along with the approximate straight-line distance between adjacent DH systems. Inset: The geographical outlines of Sønderborg municipality, with the locations of the five district heating systems shown in circles.

As mentioned in the methodology chapter, the investment costs of the already existing energy plants are modelled as sunk costs. Thus, the capacity variables presented in Table 4 (including the ones from the Figure 1) will be set as a lower bound for the system in the reference year.

Table 4. The installed capacities and the electricity generation in Sønderborg municipality in 2013 by power plant type [29].

Electricity production	Installed capacity 2013 (MW)	Production 2013 (GWh)
Waste incineration CHP	4.5	36
Natural gas CHP	71.4	14
Wind turbines	14.6	29
Photovoltaics	14.8	12
Total	**103.8**	**91**

Although the majority of the electrical energy was imported in the reference year, it is interesting that 67% of the municipal electricity production came from renewable sources (according to the Danish Energy Agency 55% of waste incineration produced electricity can be regarded as renewable [31]). However, 80% of the total municipal electricity demand was met by importing electricity [29].

3.1 Case studies in the reference year

After setting up the model for the Sønderborg case, the model was validated by comparing the results with the figures presented above. The outcome of the model for the reference year will be designated as a case I. Case II represents the Sønderborg system after the DH system of Sønderborg (town) and Augustenborg have been connected. In case III, Broager DH will be connected with Sønderborg and Augustenborg DH grids. In case IV, Gråsten DH is connected and finally, in case V Nordborg DH is connected with other DH grids. Thus, in case V all the DH systems are interconnected, as opposite to case I, in which none of the DH systems are interconnected. For the sake of clarity, the interconnections between different DH systems are presented in the Table 5, too. Please refer to Figure 1 in order to make it easier to understand the ordering of DH systems being interconnected.

Table 5. Description of interconnections in different cases

Case	Interconnected DH systems
I	5 separated DHs
II	Merged Sønderborg (town) and Augustenborg
III	Merged Broager, Sønderborg and Augustenborg
IV	Merged Gråsten, Broager, Sønderborg and Augustenborg
V	Merged all five DH

The model assumes that as soon as one interconnection has been made, the investment in it represents a sunk cost as the system cannot be returned to the starting point. Thus, after the interconnection between Sønderborg and Augustenborg has been set (case II), the two merged different DH systems present a new system that is a starting point for the following mergers. Hence, savings after merging the Broager in case III are the difference in total socio-economic costs between case II and case III, and not between the starting case (case I) and case III. Furthermore, investment in piping for merging Broager (case III) is only calculated as a piping construction between Broager and Sønderborg, as it is assumed that the piping between Sønderborg and Augustenborg has been built already. The same principle goes for cases IV and V.

Hourly electricity and gas consumption profiles were obtained from the Danish electricity and gas transmission system operator (TSO) for the modelled region. As a part of the ongoing CITIES project [32], an hourly measured data from 53 district heating customers were obtained for Sønderborg. As the yearly district heating consumptions were provided by the respective district heating providers, an hourly pattern was estimated by scaling the available hourly data to the yearly consumption values.

3.2 Case studies for the year 2029

As previously mentioned, the municipality of Sønderborg intends to become CO_2 neutral by 2029. A roadmap for achieving this has been reported in [33]. However, the final steps in the transition have not been planned yet, as the CO_2 emissions upon implementing all currently planned measures are reported to be 130 ktons (not including the 28.57 ktons of CO_2 emissions from the waste incineration plant), mainly from the transportation sector. Furthermore, in the mentioned report, due to the constraints of the model being used (EnergyPLAN [34]), DH systems were considered as interconnected. However, it was not specified at all how this interconnection should be achieved or what the costs of achieving this transition would be.

In order to assess the potential consequences of interconnections between different DH systems in 2029, case VI was modelled as a reference case that can be compared with the official plans, having all the DH systems separated, as it is the situation today. On the other hand, case VII was modelled with the energy plants capacities stated in the official plan, however this time with all the DH systems interconnected. Capacities that are changed in comparison with the reference year are shown in Table 6.

Table 6. Capacities of energy plants according to the official plans [33]

	Installed capacity 2013 (MW)	Installed capacity 2029 (MW)
Anaerobic digestion	0	42
Gas boilers	105	55
Geothermal heat coupled with absorption heat pump*	0**	12.5
Biomass boilers	19	28
Large scale heat pumps	0	50 (heating capacity)
Solar heating	24	24
Heat storage	988 MWh	2,300 MWh
Wind turbines	14.6	180
Photovoltaics	14.8	60

**Geothermal heat at 44 °C is boosted to 82 °C via a biomass driven absorption heat pump* [35]. *If the geothermal heat is considered as "free" heat, this combination can be modelled as a biomass boiler with $\eta=135\%$*

***This unit started to be tested in the year 2013; hence, its generation started to be calculated only from the year 2014 and therefore it is not present in the reference year (2013)*

Case studies modelled in this way also allow a comparison between the socio-economic benefits of connecting DH systems when electricity and gas imports are dominating the system, as it is the case in the reference year, and when electricity and gas exports are dominating the system, as according to Sønderborg municipality's roadmap for the year 2029.

The demand for electricity, gas and district heating was adopted from the ProjectZero's official plan for transition towards the carbon neutral Sønderborg in the year 2029 [36]. An important aspect of the plan is that the demand for district heating is expected to rise from 487.6 GWh to 535.7 GWh, although significant energy efficiency measures are expected to be adopted. The reason for the latter is the active policy towards connecting buildings to the DH grid whenever socio-economic costs prove to be favourable towards it. More specifically, the project report [36] states that an additional 18% of the heating demand will be converted to DH, while the total energy savings for heating will amount to 35% compared to the 2007 consumption levels.

The coefficient of performance (COP) for the large scale heat pumps, used in the calculations for the year 2029, was assumed to be fixed at 3.0. A proper and detailed discussion whether this assumption is valid was carried out in [37]. The authors concluded that there was not much difference between the scenarios with and without the assumption of a fixed COP, as it changes only by a few percent on a weekly basis due to the inertia of the temperature of the heat source.

3.3 Waste heat potential in the year 2029

An additional two cases were developed in order to assess the potential impact of waste heat from the nearby industry on the future district heating grid. This was done both for the geographically distributed and interconnected cases. One should recall here that the case VI presents the anticipated DH system in the year 2029 where no interconnections are made, while case VII presents the fully interconnected DH system of the year 2029.

Case VIII presents the same energy supply mix as case VI, except that the additional waste heat from industry was assumed to be available for supply to the geographically distributed DH systems. Case IX presents the same industrial waste heat supply potential as in case VIII, but in the fully interconnected DH grid.

The investment cost in the waste heat recuperators and connection piping to the DH grid were taken into account as a single investment, levelized during the equipment lifetime and reported as a part of the total system costs. Investment and fixed operating and maintenance costs are as reported in Table 9, while variable operating and maintenance and fuel costs were set to zero, as this heat would otherwise be wasted.

A screening of the industry located within the municipality revealed that the tile works factories had the largest potentials, as well as the most suitable supply temperatures, for delivering waste heat to the DH grid. Appropriate allocation of waste heat resources could be elaborated more as part of futher work using Pinch Analysis [38]. An example of recovering waste heat in the cement production for the case of a cement factory in Croatia, using the principals of Pinch Analysis, was presented in [39].

In the present case, there were in total five tile work factories that were operating in 2013; two near the Gråsten DH grid and three near the Broager DH grid.

Out of the total consumed energy, an estimated share of the energy that could be fed into the DH grid as a waste heat was taken from [40]. The data for the cement industry was used for the tile works factories as it was found that the temperature levels of the waste heat of cement and tile works industries are fairly similar [41]. Detailed estimation of the industrial waste heat potential can be seen in Table 7.

Table 7. Industrial waste heat potential estimation of the suitable factories located in the municipality

Plant	Heating oil [GWh]	Ngas [GWh]	Coal/coke [GWh]	Electricity [GWh]	Waste heat [GWh]	Closest DH	Distance to closest DH [km]	Ref
Gråsten Teglværk	0.75	38.50	0	4.50	9.60	Gråsten	0.20	[42]
Petersen Tegl Egernsund	0.34	3.30	18.47	2.15	5.43	Broager	2.35	[43]
Carl Matzens Teglværker	0.30	13.75	0	1.22	3.35	Gråsten	2.42	[44]
Bachmanns Teglværk	0.35	0.00	0	10.00	2.21	Broager	3.21	[45]
Vesterled Teglværk	0.40	55.00	0	5.50	13.29	Broager	4.10	[46]
Total	1.78	110.55	18.47	23.37	33.89			

The table leads to the conclusion that in case VIII, the two factories located near the Gråsten DH system can deliver the waste heat only to the Gråsten DH system, while the three factories located in the vicinity of Broager DH system can deliver their heat only to the Broager DH system. On the other hand, in case IX, industrial waste heat from all the five factories is delivered to the fully interconnected DH grid.

3.4 Modelling the case study

This specific case study, using the methodology described in this paper, consists of the following matrix sizes in the model:

Table 8. Matrix sizes of the optimization problem

	Size of the matrix
Objective function	595,750 x 1
Inequality constraints	674,520 x 595,750
Equality constraints	52,560 x 595,750
Upper bounds	595,750 x 1
Lower bounds	595,750 x 1

Taking into account that Matlab uses 8 bytes of memory for storing one number of type *double*, the problem stated above would present a significant amount of random access memory (RAM) to be loaded. Specifically, if all the numbers would be of type double, the problem stated in Table 8 would require almost 3.5 terabytes (TB) of RAM memory. However, by exploiting the fact that the most of the numbers inside the matrices are equal to zero, using the sparse function, the memory need can be significantly reduced. In this specific case, the memory needed for constructing the optimization problem is equal to 57 megabytes (MB). For fully loading all the variables and the optimization model, the RAM requirements rise to approximately 80 MB. However, this shows that the implementation of models with a complexity on this level requires the utilization of the sparsity of matrices.

Several cost assumptions have been used to obtain the results. Technology costs occurring in the case study are shown in Table 9.

*Table 9. Technology cost sheet used for the case study**

	Investment cost [€/MW]	Fixed O&M [€/MW]	Variable O&M [€/MWh]	Fuel cost [€/MWh]	Lifetime	Ref
Solar thermal heating	562,000	1,500	1.00	0	30	[47]
Geothermal heating with absorption heat pump	1,600,000	37,000	0	0	25	[48]
Large scale heat pump	680,000	5,500	12.93	**	20	[48]
Biomass boiler	800,000	0	5.40	***	20	[48]
Gas boiler	100,000	3,700	5.40	***	35	[48]
Electric boiler	75,000	1,100	13.43	0	20	[48]
Waste CHP	8,500,000	16,500	23.00	0	20	[48]
Gas CHP	1,050,000	250,000	3.90	44.00 [49]	20	[50]
Wind turbine (onshore)	1,200,000	36,000	1.00	0	20	[48]
PV	1,000,000	30,000	1.00	0	30	[48]
Waste heat recuperators	160,000	4,000	0	0	20	[51]

and piping connection to DH						
Anaerobic digestion	10,000,000	54,000	5.60	0	20	[52]
Seasonal heat storage [€/m^3]	35	0.01	-	0	20	[48]

**storage costs are not included in costs of specific technologies (e.g. boilers or CHPs), but they are given separately at the bottom of the table*

***the cost of the electricity on the Nordpool day ahead market increased for transmission and distribution tariff (changes hourly)*

****please refer to the Table 10*

The CO$_2$ intensities were obtained from the Danish Energy Agency [53], while the discount rate was set to 4%, which is the rate recommended by the Danish Ministry of Finance for socio-economic analyses [54]. CO$_2$ emissions of imported electricity were set to the average emissions of all the electricity generation in Denmark, equalled to 0.478 tCO$_2$/MWh. Carbon dioxide intensity of the electricity generation is expected to fall down until 2029. In [55], the Danish TSO calculated expected CO$_2$ intensity of the electricity generation to be 0.3 tCO$_2$/MWh in the year 2024. Using linear extrapolation and the latter two values, estimated CO$_2$ intensity of the electricity production for the year 2029 was 0.22 tCO$_2$/MWh.

Increased losses in the DH grid, after the interconnections are implemented, are another consideration that needs to be taken into account. As reported in [56] for the DH system in Iceland, using well-insulated piping for the main distribution line with the length of 18 km led to a temperature drop of 1.5^{o}C along the way. As the model developed here is not a dynamic one with the feedback loops included, losses of the DH grid needed to be assumed. In order to estimate the losses and still be on the safe side, the situation in which all the heat to the newly connected DH grids would come from central DH system in Sønderborg (town) as the worst case has been chosen. By taking into account the supply and return temperatures of 75/50^{o}C, additional heat losses of 1.5% of the total gross DH supply were added on top of the total DH heat demand.

Optimization was run using the Gurobi® 6.5.0 solver using the Matlab® R2015b interface to build the model. The personal computer (PC) used to run the model has Intel® Core i7 CPU processor working at frequency of 2.60 GHz, 8 GBs of RAM memory and 220 GBs of storage on an SSD hard-disc. The operating system was 64-bit Windows 7 Enterprise. On the described PC, one run of the optimization model takes between 30 and 120 seconds.

3.5 Fuel, electricity and CO$_2$ prices

Assumptions made by the Danish TSO, Energinet.dk, were used to determine prices of fuels used in the system both in 2013 and 2029. The prices are shown in Table 10. Their assumptions are based on the International Energy Agency's (IEA) data, except for the biomass price, which follows assumptions made by the Danish Energy Agency (DEA) [57]. An increase in the fuel prices in the period 2013-2029 is expected for all the fuels, on average being 16.08%. The price of fuel oil is expected to increase the most in this period, or by 22.44%, whereas natural gas price is expected to show the least increase, or for 10.12%.

An hourly distribution of electricity prices in 2013 was obtained from [58], where the data for day-ahead spot market in Western Denmark (DK-West) was used, as Sønderborg municipality is located in that region. For the future system in 2029, assumptions regarding the average electricity price growth made by Energinet.dk were used to modify the hourly distribution throughout the year. All fuel and electricity prices are presented in Table 10.

Table 10. Fuel prices used in the model for the system in the year 2013 and 2029 [57]

	2013	2029
Coal [€/MWh]	10.47	12.58
Natural gas [€/MWh]	32.71	36.02
Fuel oil [€/MWh]	46.11	56.46
Biomass [€/MWh]	28.81	32.17
Average electricity price [€/MWh]	38.98	61.34

As already mentioned when describing how the socio-economic costs were calculated in the methods section, internalized climate change externality in terms of costs of CO_2 emission allowances were taken into account in a form of average emissions price. CO_2 emission price was set to 4.5 €/t in 2013 [59] and 25.37 €/t in 2029 [57].

4 Results

4.1 Validating the model

In order to validate the model, a comparison of its results with the official data on primary energy consumption in Sønderborg municipality has been made. The result can be seen in Table 11.

Table 11. A comparison of the model's output and the official data

Total energy consumption	Consumption – official data (GWh/yr) [29], [33]	Model reference case (case I) (GWh/yr)	Difference [%]	CO_2 emissions (including waste) – official data (kton/yr)	Model reference case (case I) (kton/yr)
Gas	571.9	571.3	-0.11%	528.57	521.88
Coal	13.6	13.6	0.00%		
Heating oil	116.0	116	0.00%		
Wood and straw	188.1	213.1	13.31%		
Individual heat pumps	21.2	21.2	0.00%		
Individual electric heating	53.5	53.5	-0.01%		
Waste consumption	212.5	215.4	1.36%		
Classical electricity	442	440.5	-0.34%		
Diesel and gasoline	506.8	506.3	-0.09%		
Other and unknown	22.4	0	-100.00%		
Total	2,148	2,151	0.14%		

Comparing the output of the reference case in the model with the data obtained from the official publications, a similar consumption per fuel types has been obtained. With the exception of biomass and waste consumption, all the other fuels differ by less than 1%. A slightly higher difference occurs in the biomass consumption. It can be seen that almost all the “Other and unknown” energy source reported in official publications is met by biomass driven plants in the developed model. Difference in CO_2 emissions is 1.27% and thus, the technical side of the system is modelled in a representative way. To summarize, the figures in total do not vary significantly from the values from the official data. Hence, based on the modelled system, the developed optimization model is considered to be validated.

4.2 Price calculation of DH piping

A quantitative description of the steps presented in section 2.4., as well as the final results of the nominal diameter and the piping price, are given in Table 12.

Table 12. Results of the piping price estimation

	Case II	Case III	Case IV	Case V
Max heat capacity [MW]	142.26	142.26	122.90	18.00
Max mass flow [kg/s]	849.39	849.39	733.93	107.57
Max volume flow [m^3/s]	0.85	0.85	0.73	0.11
Flow speed [m/s]	3.00	3.00	3.00	2.00
Cross area of the pipe [m^2]	0.28	0.28	0.24	0.05
Pipe diameter [m]	0.60	0.60	0.56	0.26
DN [mm]	600.56	600.56	558.26	261.76
Pipe price [€/m]	1400.00	1400.00	1297.00	747.00

To validate the estimation, a comparison with other sources was performed. For example, the Danish Energy Agency [60] suggests the price of 18-22 k€/TJ[1] for the conventional DH network, while authors in [61] used the similar price of 20 k€/TJ for the conventional DH network in their study. Using the price for the conventional network, results within the same order of magnitude are obtained.

4.3 Results of the case study for the current state of Sønderborg's energy system

The heat generation results of the first five cases, the ones that assess the impact of interconnecting the currently disconnected DH systems in the Sønderborg municipality, are presented in this section. Please refer to Table 5 in order to see the order of connection of the different DH systems.

For simplicity, all the gas fired CHP plants (5 in total), gas boilers (5), biomass boilers (2) and solar DH plants (3) production are reported together in the figure.

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[1] Taking into account description in the footnotes of the reference [60], and accounting for the usage of single piping technology, the cost of 20 k€/TJ can be expressed as 523 €/m. However, those costs also include smaller branch pipes which reduce the cost per meter of piping as they have lower diameters than the main piping. It could not be exactly distinguished between costs for main piping and branch piping from the reference.

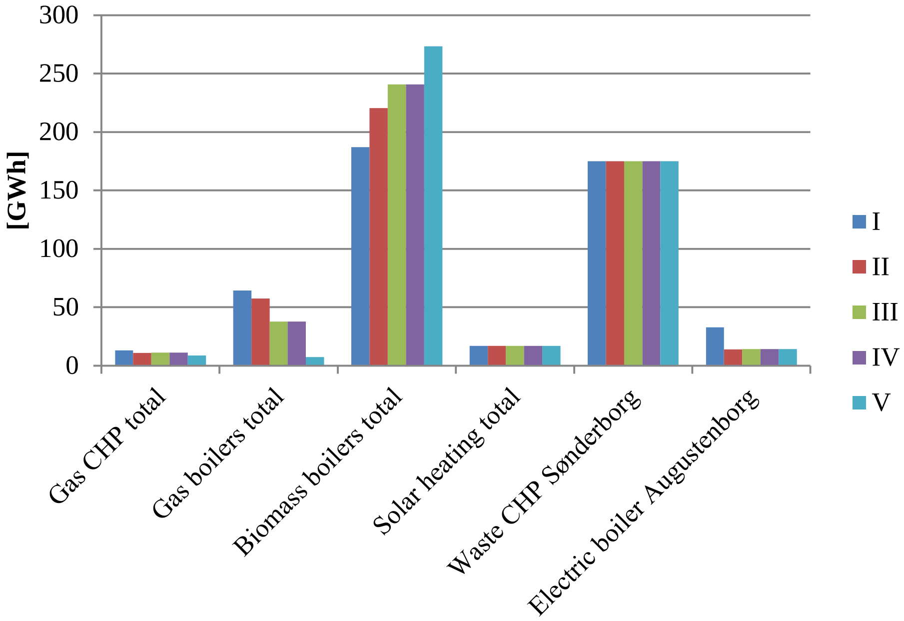

Figure 2. Heat generation in DH in different cases

After interconnecting Sønderborg (town) and Augustenborg DH systems (case II), the heat production from gas CHP plants, gas boilers and electric boilers decreased, while the heat generation from biomass boilers increased. The generation from solar DH plants and the waste CHP plant remained the same, at the maximum utilization rates.

Adding an interconnection to the Broager DH system (case III) caused further decrease in gas boiler generation, while the biomass boilers produced a significantly higher amount of heat. This is the same pattern as in case II. Generation of heat from the electric boiler slightly rebounded compared to the second case, while the solar DH and waste CHP plants are still being utilized at the maximum levels.

In case IV, an interconnection to the Gråsten DH system has been added. It is interesting to note here that no major changes in the heat generation occurred compared to case III. The reason is that the biomass boilers that were preferred over the gas boilers in the previous cases are already maximally utilized in the peak times and the peaks in the demand still had to be met by the gas boilers. It can be concluded that the increase in the utilization of biomass boilers will happen only when interconnecting with a DH system that does not have a biomass boiler in its generation portfolio.

Finally, case V showed that the gas CHP plant and the gas boiler in Nordborg reduced their outputs upon interconnecting the Nordborg DH system with the rest of the DH network in the municipality. This heat demand was instead met by the biomass boilers from Sønderborg and Gråsten. As in all the other cases for the reference year, waste CHP and solar DH outputs remained the same as in the previous cases.

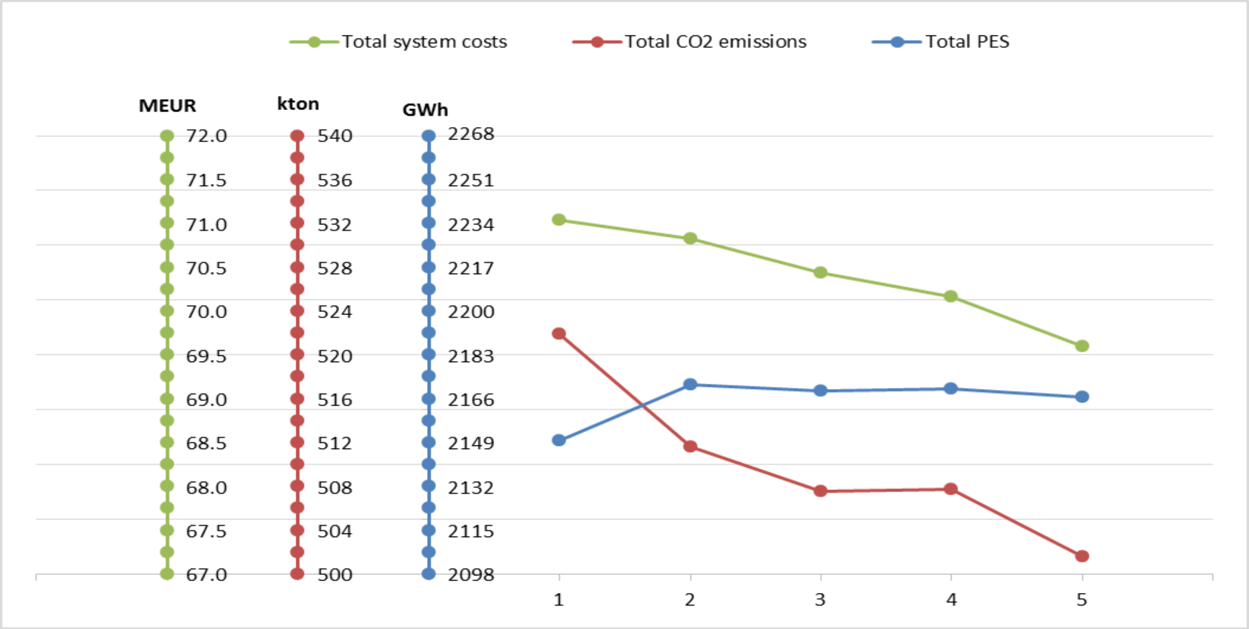

Figure 3. Total system costs, CO_2 emissions and primary energy supply in the cases I-V

The total system costs, primary energy consumption and CO_2 emissions are presented in Figure 3. It can be observed that with every new interconnection of DH systems, the total system costs and CO_2 emissions decrease, while the primary energy supply slightly increases in case II and remains approximately constant in other cases. The reason for the slight increase in PES is that the heat production from the gas boilers is replaced by heat production from the biomass boilers which have a slightly lower efficiency. Furthermore, upon the interconnection of DH grids additional losses in the heat transmission grid of 1.5% of the total heat demand in the municipality need to be compensated for in the model.

The largest CO_2 reductions occurred in cases II and V, a decrease of 2% and 1.2%, respectively. Those are the cases in which a significant amount of heat production from the gas boilers is replaced by the production from the biomass boilers. In total, CO_2 emissions reduced by 3.9% between cases I and V. It is worth mentioning again that the imported electricity has a CO_2 intensity of 0.478 tCO_2/MWh in the year 2013, while biomass is considered as CO_2 neutral.

In general, the presented five cases showed that the running costs of the biomass boilers are lower than those of the gas driven and the electric boilers. Furthermore, in the energy system of 2013 the operation of the gas fired CHP plants with the electricity sold on the electricity spot market has replaced by the biomass driven heat only boilers. The cheapest options for the generation of heat are the solar DH systems and the waste CHP plant. Those plants were maximally utilized already in the reference case (case I), where no additional interconnections were made.

The reason for falling CO_2 emissions upon the subsequent interconnections of DH systems can be seen in Figure 4. Increasing the heat generation levels from biomass, while reducing the heat production levels from the gas driven plants, can be directly linked to the falling CO_2 emissions.

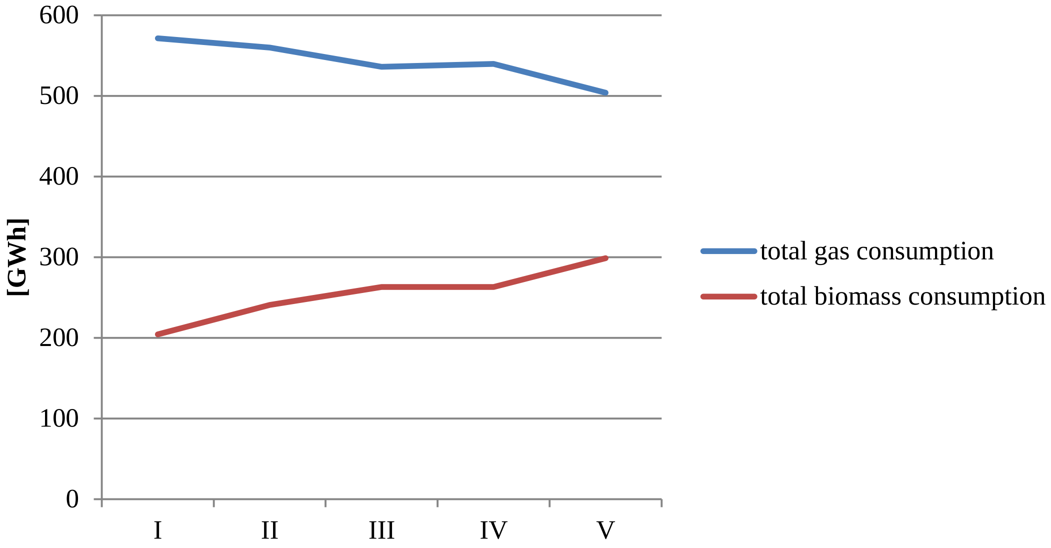

Figure 4. Total gas and biomass consumptions in the first five cases

The economic results of the investment can be seen in Table 13. For the chosen discount rate and the system in the year 2013, investments are profitable for cases II and V, while cases III and IV have a negative NPV value.

Table 13. Economic results of different cases – note that savings for each case were calculated as the difference in total system costs in comparison to the previous case. Thus, savings in case II present the difference in total system costs between case II and case I. Other cases follow the same principle.

	I	II	III	IV	V
Total system costs [M€]	70.969	70.75	70.332	70.04	69.432
Difference (savings) [M€]	Reference	0.219	0.418	0.292	0.608
Pipe length [m]	-	3,000	11,000	6,000	13,000
Specific pipe cost [€/m]	-	1,400	1,400	1,297	747
Pipe cost [M€]	-	4.2	15.4	7.782	9.711
NPV [M€]		0.13	-7.13	-2.00	2.32
IRR		4.21%	0.41%	2.15%	5.54%
Discounted payback time [years]		37.16	-	-	25.97

It is important to emphasize here that the chosen discount rate and the lifetime of the project are factors that significantly influence the economic results. An additional economic indicator such as IRR can therefore reveal otherwise hidden profitability information. As the investment in transmission piping is considered to be an investment in the infrastructure itself, the chosen project lifetime was set to be the same as the infrastructure lifetime, i.e. 40 years. This value was confirmed in both technology datasheet issued by the Danish Energy Agency and Energinet.dk (the Danish TSO) [60] and the Stratego Project carried out by different partners [61]. Furthermore, the discount rate of 4% was chosen as a recommendation from the Danish Energy Agency. If one would like to choose different discount rate, IRR presents a good indicator of the discount rates at which the investment would break-even.

The cash flow of the investments is presented in Figure 5.

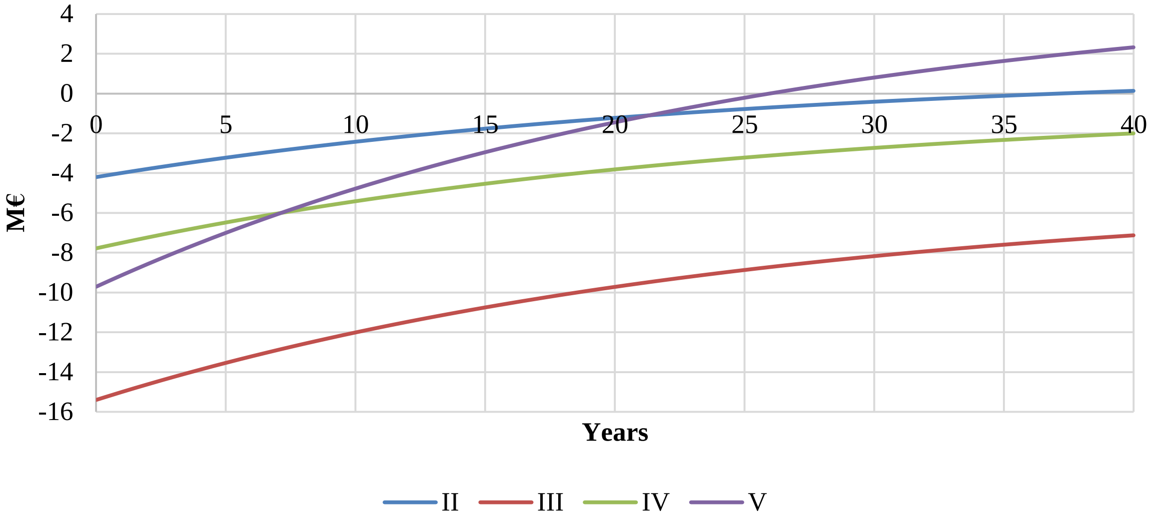

Figure 5. Cash flow of investments in different cases

It can be seen that the investment in the case V (interconnection between Nordborg DH and other DH systems) was recovered the quickest, as well as that it was the most profitable investment, having the largest NPV value during the project lifetime. The slope of curves reveals that the chosen discount rate of 4% has a significant impact on the present value of future income that will be achieved in the later stages of the project lifetime, diminishing a long-term income. This is another example of the importance of setting the right discount rate.

4.4 Results of case study for the energy system in 2029

Case studies VI and VII were modelled upon the implementation of planned capacities of new energy plants by the year 2029 as stated in Table 6. Case VI corresponds to the five DH systems without any interconnections, while case VII corresponds to the system with interconnected DH systems. Case VIII presents case VI supplemented with the industrial waste heat from the nearby tile works factories, while case IX presents the fully integrated DH system (the system of case VI) supplemented with the industrial waste heat.

Compared to the current energy system of the municipality, the system in 2029 is dominated by electricity and gas exports, which is the result of planned investments in renewable energy sources, mainly in wind, PVs and anaerobic digestion technologies.

The difference between the power and gas sectors of Sønderborg municipality in the reference year and the year 2029, according to the official development plans, can be seen in Figure 6.

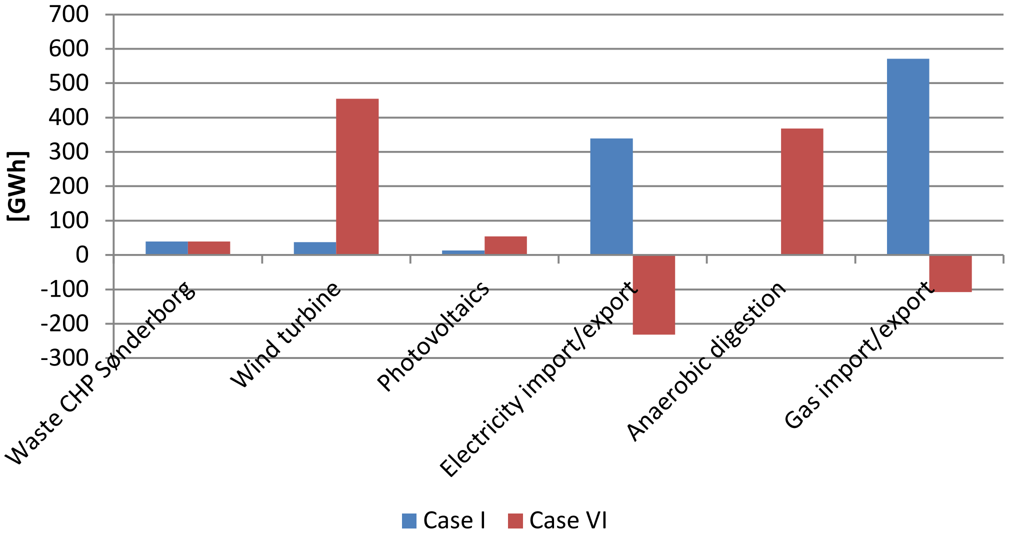

Figure 6. Generation of the power and gas sectors of the Sønderborg municipality. Negative values denote energy export from Sønderborg municipality.

The generation of heat by different energy plants before and after interconnecting the DH systems for the year 2029 is presented in the Figure 7. Please note that the order of the presented cases in Figure 7 is VI, VIII, VII, IX, in order to be easier to compare cases without interconnected DH systems (cases VI and VIII) and two cases with fully interconnected DH systems (VII and IX).

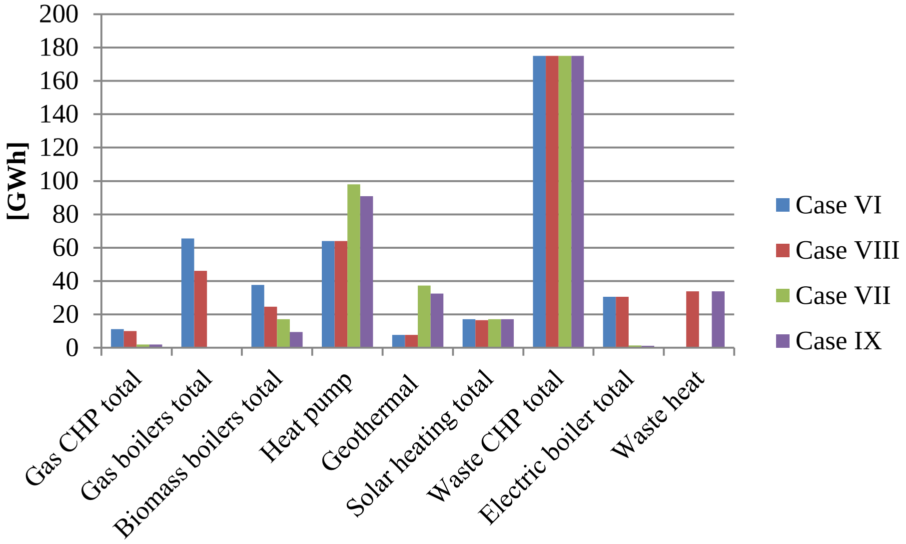

Figure 7. Heat generation from different sources in the year 2029

After interconnecting the DH grids, the large scale heat pump and the geothermal heat plant (which is coupled with a biomass-fired absorption heat pump) had a much larger utilization rate, compared to the systems without interconnections. On the other hand, the electric and biomass boilers decreased their utilization rate significantly. Moreover, the generation from the gas driven CHP plant reduced while the gas heat only boilers were not utilized at all. The solar heating DH plants and the waste CHP plant are being maximally utilized in all the cases.

In case VIII, industrial waste heat available in Broager and Gråsten DH systems replaced the generation of gas and biomass boilers, as well as the gas CHP plant. In the interconnected DH system (case IX), industrial waste heat caused a slight reduction of heat generation in the large scale heat pumps, biomass boilers and geothermal heat source coupled with the absorption heat pump.

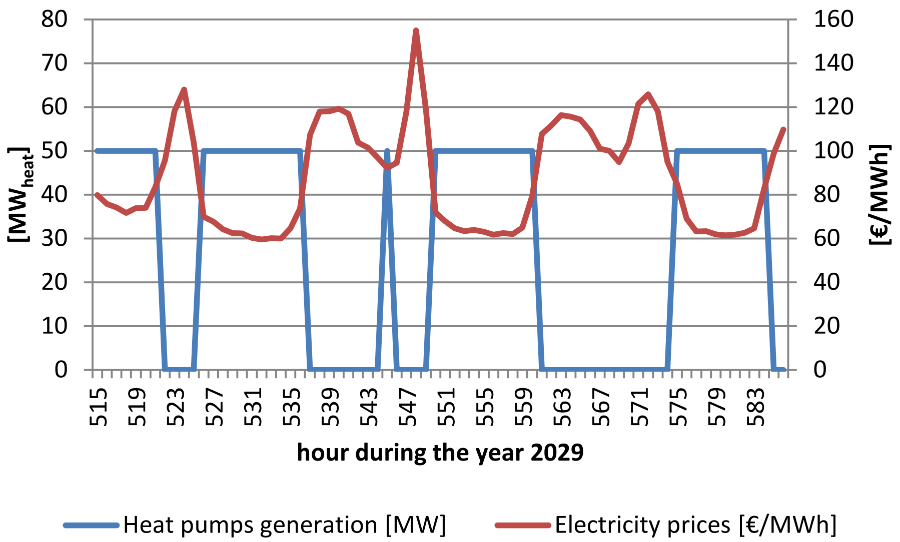

Figure 8. Heat pumps operation (heat generation capacity) in relation to power prices on the wholesale market during three days - case VIII.

It is interesting to observe the operation of the heat pump in relation to the wholesale electricity prices which is shown in Figure 8. A negative correlation between the two variables is observed; as the electricity price goes down, the heat generation from heat pumps goes up and vice versa. In the interconnected DH system, a larger number of customers can be supplied by a technology existing at the specific location. Therefore, the large scale heat pump can be better utilized, increasing the amount of electricity demand in the periods of lower electricity prices.

The differences in the economic and technical indicators in the four cases carried out for the year 2029 are presented in Figure 9.

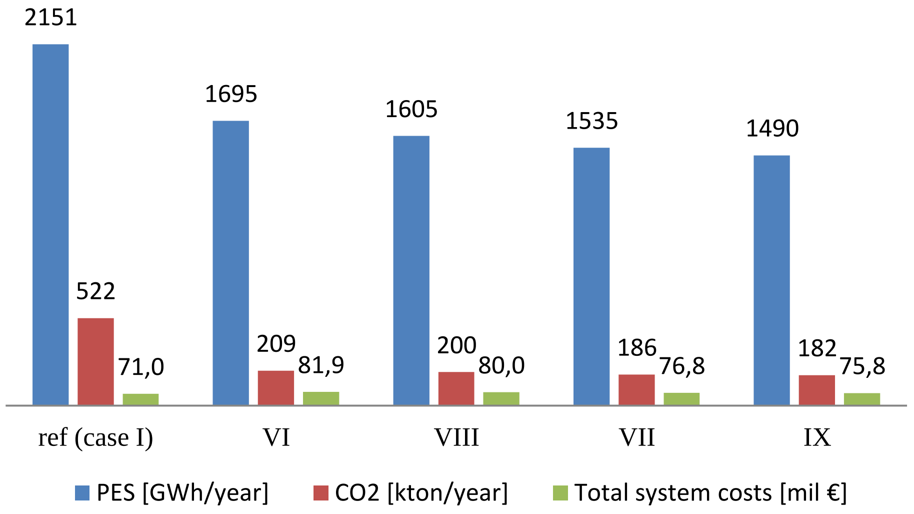

Figure 9. Results of cases VI, VIII, VII and IX and comparison with the reference case.

It can be seen that in the year 2029 (cases VI and VII), an interconnection of all the DH systems is beneficial according to all three indicators. Furthermore, both cases with the industrial waste heat fed into the DH grid showed better results in all three indicators presented. Note here that the investment in the waste heat recuperators and the connecting piping to the nearest DH system were levelized during the lifetime of the plant and are included in the reported total system costs.

Comparing case VII to case VI, the savings in PES amounted to 9.5%, the CO_2 emissions were 11.1% lower and the total system costs were reduced by 6.3%. Detailed economic results of the investment in the transmission piping and the accompanying economic indicators are presented in Table 14.

Table 14. Economic results for the system in the year 2029

	VI	VII
Total system costs [M€]	81.93	76.77
Difference (savings) [M€]	0	5.167
Pipe length [m]	0	33,000
Pipe cost [M€]	0	37.093
NPV [M€]		65.18
IRR		13.85%
Discounted payback time [years]		8.63

Significantly better results are achieved when the industrial waste heat was fed into the DH grid even in the geographically distributed DH systems (case VIII), as it can be seen in Figure 9. However, compared to the distributed DH grids, in the case of fully interconnected DH grid (case IX), PES was reduced by 7.2%, CO_2 emissions by 8.9% and total system costs by 5.1%. Thus, the best outcome was reached in the last case, with the fully interconnected DH system, as well as with the industrial waste heat fed into the grid.

4.5 Sensitivity analysis

In order to check the robustness of the model, a sensitivity analysis for different parameters was carried out. The most important parameter for the feasibility of the investment in interconnection of the DH systems is the piping price. Hence, the impact of varying piping price has been checked and the impact on economic indicators of investment can be seen in

Figure 10. The sensitivity analysis was carried out for case VII (fully interconnected DH grids in the year 2029) as this was the best performing case without considering waste heat from industry.

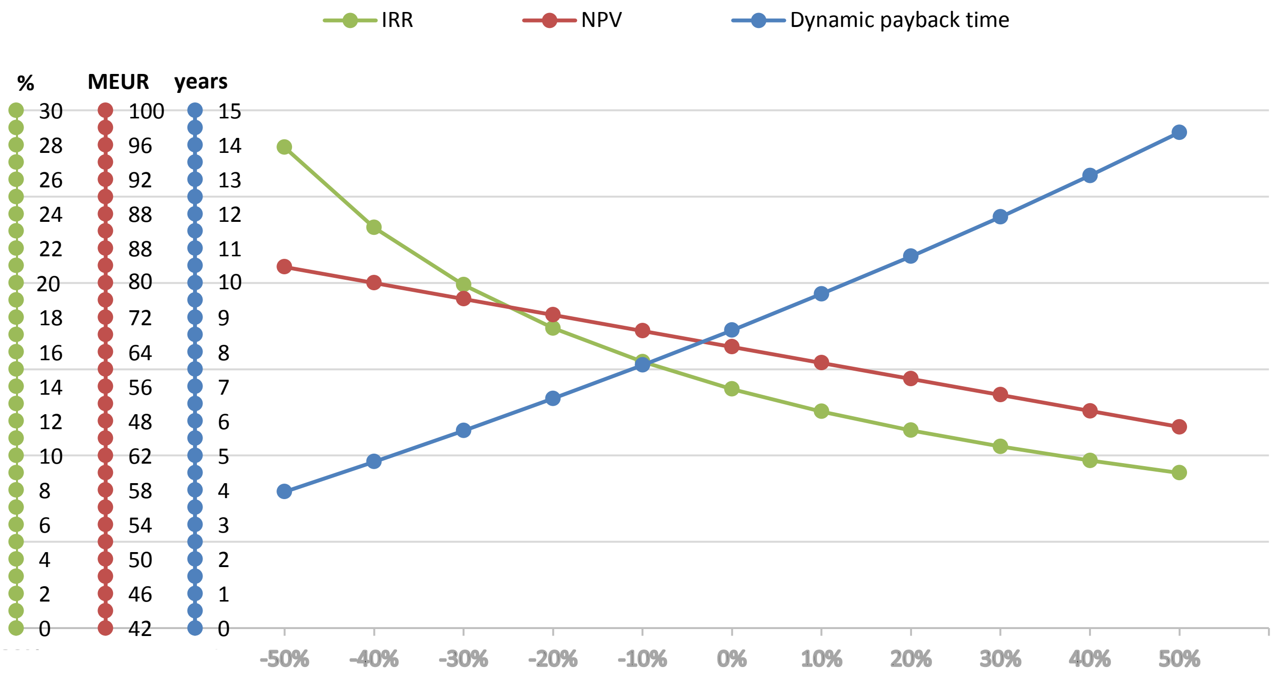

Figure 10. Sensitivity analysis carried out for the piping price of case VII.

Figure 10 reveals that NPV and dynamic payback time have an almost linear relationship with the change in total piping costs. On the other hand, the IRR curve clearly shows that for a reduced piping cost the internal rate of return rose much steeper than it reduced in the case of increased piping cost. This behaviour can guide future researchers to try to find further economies of scale when calculating interconnections of different DH systems as a relatively small reduction in piping investment can cause a significantly better rate of return.

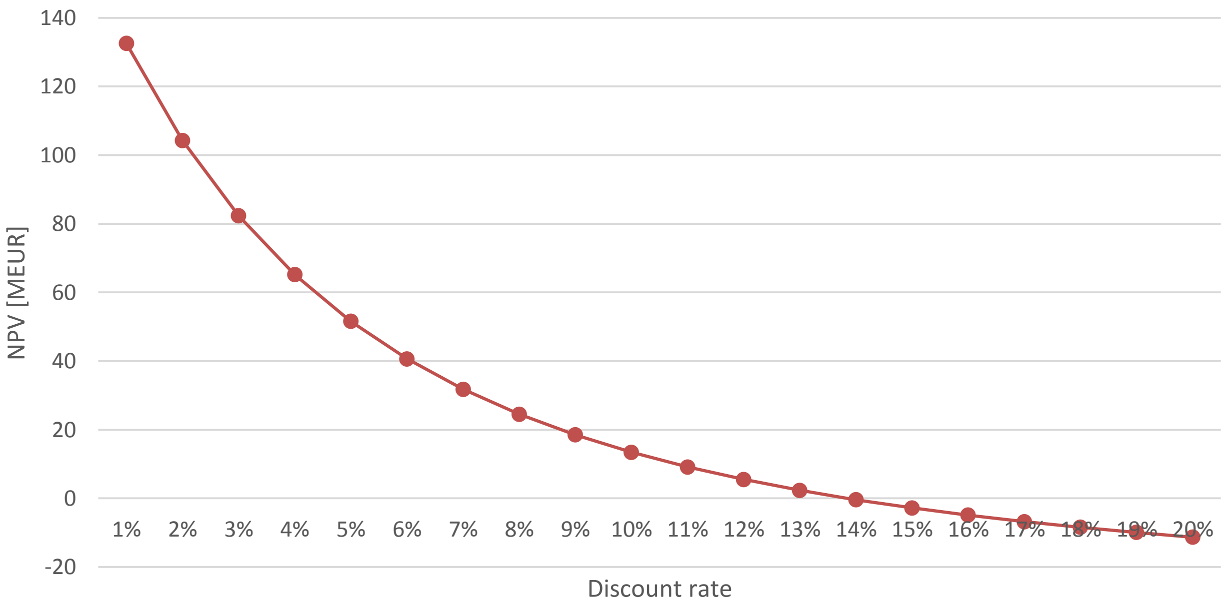

Figure 11. Impact of change in the discount rate on the NPV

Figure 11 shows how the NPV changes when the discount rate grows and drops. It can be seen that the increase of NPV, for lower discount rates, is much steeper than the decrease of NPV, for the case of higher discount rates. This leads to the conclusion that even small support, in a form of a lower discount rate, can improve the economic performance of this kind of investment significantly, whereas higher rates do not influence the NPV to such extent. It is once again shown that the IRR for this case is 13.85% (the point where the NPV equals zero).

Furthermore, sensitivity analysis was carried out for the following parameters in the cases developed for the year 2029: CO_2 price, heat storage size, electricity and biomass prices. However, none of these changes caused the total system costs to change by more than 1%, even for changes in the selected parameters of up to 50%.

5 Discussion

Firstly, when building an optimization model, it can be of crucial importance what type of optimization is chosen. For example, Ommen et al. modelled an energy system consisting of CHPs, heat pumps and boiler units with the objective function to minimize the total running costs [62]. They have examined three different optimization types, linear programming (LP), mixed-integer programming (MIP) and non-linear programming (NLP) and showed that the operation times of different plants differed significantly when different optimization methods were chosen. They concluded that MIP and NLP better represented the real operation; however, they acknowledged the enormous increase in computation time when using the latter two methods compared to the LP. Furthermore, they optimized only according to the running costs, which made their number of variables lower than in the model developed in this paper. In order to cope with the enormous number of variables, and adopting an hourly time-resolution to represent intermittent energy sources in a satisfactory way, the authors of this paper decided to use a linear continuous optimization method which assured that the problem is solvable in the reasonable amount of time, in the same time keeping the major important relations that represented the modelled energy system in a realistic way. The latter was proven when validating the model for the reference year.

There are different energy modelling tools available under different licenses that are suitable for analysis of district heating systems. The overview of the energy modelling tools was done in [63]. Two types of software that were often used for district heating systems are Termis [64] and EnergyPRO [65].

Termis software receives live data from SCADA system as well as forecast information about weather conditions through the data interface. Based on the latter data it predicts future consumption up to three days in advance. It is a good software for simulating the network, running short-term optimization, maintenance planning and detecting failures. It can be used to optimize supply and/or return temperature, pressure, flow, etc. Compared to the model developed in this paper, one can note that it is better suited for short-term optimization, used for real-time operation scheduling, while the developed model is better suited for detecting system impacts of installed capacity changes within the system. Furthermore, Termis cannot optimize new capacities that could be potentially beneficial for reducing business-economic or socio-economic costs. Finally, it focuses on district heating grid, without taking into account other energy sectors such as the power and gas sectors.

EnergyPRO is a modular input-output simulation tool that can be used for different purposes such as calculating the optimal operation of the energy plant, making detailed investment analysis, modeling industrial cogeneration and trigeneration systems, simulating energy plants participating on different electricity markets and analyzing the interaction between separate energy plants [65]. Some examples of large scale systems modelling are simulation of the whole energy system for the city of Pecs, Hungary [66], simulation of the Tallinn district heating network [67] and for a theoretical case representing the typical Danish DH system [68]. In all the mentioned cases it was only used to calculate the operating costs of the system, without taking into account the capital expenses. Investment analysis carried out by the model usually focuses on the single plant investment, as opposed to the total socio-economic costs of the system. Furthermore, similarly to Termis, it is also a simulation tool, meaning that the installed capacities need to be set by the user prior to the model run. Hence, the capacity optimization can only be carried out by manual iteration procedure. Thus, the model developed in this paper with its current features, as well as possibilities that were not used in this paper due to already lengthy case studies, such as constraining the biomass consumption, CO_2 emissions and optimizing new investments by taking into account sunk costs of already made investments present a valuable upgrade from the described two models. Finally, the model developed in this paper incorporates investments as a part of socio-economic costs, inclusion of sunk costs in the model was possible. These are the costs of current investments that already occurred and cannot be recovered anymore. Thus, potential new investments, such as connecting piping that was modelled in this case study, need to be economically feasible not only comparing the running costs, but also the investments costs of already existing technologies, too. This can significantly alternate the investment results. One can notice in our results that upon interconnection of district heating grids (cases VII and IX), gas boilers were not dispatched during the year while electric boilers and gas CHPs had very low utilization rate. However, as these investments were already made, they were included in the calculation of the total socio-economic costs and investment in piping had to compete with these costs, too. The potential of inclusion of sunk costs in the model opens a possibility to make more detailed economic analysis of the possibility to add emerging technologies in the current energy systems in a future research.

In order to show important differences between the current energy system and the envisaged future energy system, the one that is targeted with the official plans and roadmaps, nine different case studies were developed. Five case studies were developed for the reference year, in order to validate the model itself, as well as to present differences when connecting different DH grids, each one with their own specifics in energy supply and demand. It is important to note from these cases that no general correlation between the diameter of the transmission pipe, length of the piping and the viability of the investment could be reached. This shows that it is important to approach each local energy system separately and that no general conclusions should be made from a single case. This conclusion is in line with the previously published work, such as [15] and [16], in which many different cases showed that the economic and technical figures of integration of DH systems is dependent on the type of energy producers present in the DH system. Moreover, it was showed from these cases that the energy supply mix of the DH system being integrated with the interconnecting transmission pipe is more important than the distance between the DH systems itself. The latter also points to the possibility that some of the DH suppliers could end up with much lower utilization rates of their plants in case of new interconnections to their grid. This could cause an opposition to the interconnection of the grids, even if the society as a whole would benefit from it.

Two interconnections were feasible and two were not for the energy system in the reference year. The best economic results were obtained in case V, although the distance of Nordborg DH to the rest of the system was the largest. The reason for this is the energy supply mix of Nordborg DH system, being heavily focused on expensive gas fired heating plants. Case II was the other economically beneficial case in the reference year. The connected area was previously supplied by a gas fired CHP and a gas boiler, as well as electric boiler. Furthermore, the distance of the transmission piping was the lowest in case II of all the cases. Hence, it can be concluded that savings in the running costs due to the lower utilization of gas driven plants and electric boiler were larger than the investment in the transmission piping. On the other hand, cases III and IV had biomass boiler and solar district heating plants incorporated in the system, besides the gas fired technologies. As these technologies were not utilized significantly more than in the interconnected systems than in the geographically the distributed systems (as they reached maximum capacity quickly), savings in running costs could not recover the investment in the transmission piping. However, IRR values of all the cases were positive which means that changing the discount rate could also change the economic feasibility of the investment. As investments in interconnections are long-term and low-risk infrastructure projects, in the current economic circumstances of the European financial market, one could argue for choosing a lower discount rate than the one proposed by the Danish Energy agency (4%) that was used here. However, the somewhat ambiguous and vague results of the economic indicators of the current system can significantly change if the proposed changes for the future energy system in Sønderborg will take place as planned.

To take into account the latter reasoning, two case studies (cases VI and VII) were developed following the official publications, reports and roadmaps of the stakeholders involved into the transition of the Sønderborg municipality to a net zero carbon energy system. The energy import dependant system of today is envisaged to become a net exporter of both electricity and gas, while achieving a carbon free heating system in the same time. In order to achieve this, a much higher capacity of intermittent renewable energy sources will be a part of the energy mix in the year 2029. By interconnecting DH systems, the whole energy system can become cheaper and more flexible. This is shown in case VII, in which the discounted payback period for the investment in the infrastructure was only 8.62 years. An important conclusion here is that the infrastructure investment that is not clearly seen as economically beneficial in the system of today can be a very beneficial investment in the future energy system. Thus, it is important to take into account a future development of the energy system when calculating feasibility of the specific infrastructure investment, as focusing only on the present energy system can lead to the erroneous decisions for the future. One can note from Figure 8. that the large scale heat pumps operated in periods of lower electricity prices and not in periods of relatively high electricity prices. This finding shows that heat pumps are suitable to take advantage of the relatively low power prices that occur when large amount of intermittent power generation pushes the electricity prices down or when there is a lack of demand for electricity. This should also be a guide for any consideration of energy supply in future smart energy systems; detecting if the possibilities of integration of DH systems positively impacts the integration of fluctuating RES in the power sector. Such a realization could not be made by solely focusing on the power sector. The latter also confirms that the integration of power and heat sectors leads to a technically better system that is able to integrate the same amount of intermittent sources in a cheaper way, with less harmful emissions, and in a more energy efficient way.

Furthermore, due to different laws, privacy of business data and other hindrances, the amount of industrial waste heat potential is often hard to assess, which leaves it outside of the focus of the research or official plans for energy transition. Cases VIII and IX were developed specifically for that purpose and they both showed significant primary energy savings, a CO_2 emissions reduction and lower socio-economic costs. It is important to note here that all three indicators improved already when feeding the industrial waste heat into the distributed DH systems (case VIII), becoming even better when the DH grids were fully interconnected (case IX). Hence, more emphasis should be put on future research in the industrial waste heat potential, as these potentials can be relatively simple to integrate, while beneficial in both technical and economic terms. Finally, different pricing mechanisms of DH systems should be developed that would fairly value the waste heat in different periods of time as this heat can be competing with the waste incineration plants, geothermal plants and others. For the combination of many prosumers in DH systems, with a more complex energy supply portfolio, especially if DH systems would in general start to be physically interconnected more often, the constant average yearly price per energy unit in different periods will make it more complex to bolster energy integration of prosumers.

Some more technical statements can be made by reflecting on all the cases. Generally, CHP plants do not seem to have a suitable economic justification for large-scale operation, although these types of plants are generally considered as very energy efficient and capable of reducing CO_2 emissions significantly. Partially the reason for this behaviour can be found in the relatively high gas prices in the reference year (2013). It would be probably a more beneficial situation if biomass fired CHP plant would be installed instead of some (or all) gas fired CHP plants. Furthermore, each subsequent DH grid interconnection caused a decrease in the production of gas boilers and an increase in the generation of biomass boilers. Moreover, biomass boilers also replaced a part of electric boiler generation, as shown in case II.

In the case of geographically distributed DH systems, industrial waste heat replaced part of the production from gas boilers, biomass boilers and gas CHPs. In the case of fully interconnected DH grids, the waste heat replaced a part of biomass boilers generation, as well as heat pump and geothermal heat source coupled with absorption heat pump. In the latter case the gas boilers did not produce any heat at all. As the waste heat not fed into the DH grid would be wasted otherwise, all of these changes in generation of different heat producers caused improvements in both economic and technical indicators.

Sensitivity analysis showed that the only significant parameter is investment in the piping itself. Especially important is the finding about the IRR behaviour when the piping cost was changing. Reductions in the piping costs caused IRR to ascend much steeper compared with descend of the same indicator when the piping investment cost was increasing. Hence, it can be concluded that the modelled system is relatively robust and that economies of scale should be sought for when calculating the piping investment, as a relatively small decrease in the piping price could increase the viability of the potential investment significantly, measured with the IRR indicator. One should also note that piping distances between different DH systems were assumed to be straight lines. However, a detailed feasibility study should be carried out to check whether this assumption is viable. If not, the economic indicators would be less beneficial, as shown by the sensitivity analysis presented in *Figure 10*, although they would remain positive in the year 2029 even for the increase in piping investment of 50%.

When focusing on differences in CO_2 emissions and the total system costs of cases I and V and cases VI and VII, it is important to notice the necessity of a geographically correct representation of the physical boundaries of the DH systems. Modelling all the DH systems as a single point systems, in an aggregated manner, would lead to the underestimation of both CO_2 emissions and socio-economic costs. To clarify this issue further, the district heating system represented in an aggregate manner is the same system as in the case V, while the truly represented district heating system of today is the system in the case I. Thus, the difference between the results of these two cases can be seen as the error in representation of the DH systems as an aggregated one.

The results of this paper can be compared with other similar case studies. In the case study for local DH in Sweden, carried out by Gebremedhin and Moshfegh, the results showed that expanding the system boundary allowed different actors to participate on the heat market [18]. However, the possibility of increased cogeneration plants operation by connecting DH systems was not confirmed [18]. The latter finding was the same in our case study, while the former one is somewhat different. In the case study carried out in this paper, a lower number of heat producers were being dispatched but more often, as more efficient plants could be utilized to deliver the energy for wider range of consumers. The results of the case study carried out by Karlsson et al. showed that connecting the separated systems into one large system enhances the possible profits when looking at the total system, resulting in the payback times between two and eleven years [19]. This paper supports this conclusion as the discounted payback period for the year 2029 (case VII) was 8.63 years in the case of fully interconnected systems. Kimming et al. carried out four scenarios based on biomass fired heating plants, with different distribution distances, and compared it with a reference case, in which a gas driven heating plant was being utilized [21]. They concluded that the biomass based options, even when increased transportation distances are taken into account in life-cycle analysis, had lower climate impact compared to the gas driven heating plant [21]. The latter finding was confirmed by our case study, as upon interconnection of the DH systems the biomass boilers were utilized more often. This reduced the CO_2 emissions compared to the case of the disconnected DH systems, where more utilization of gas fired plants resulted in higher CO_2 emissions.

6 Conclusions

The following main conclusions can be drawn from the current model and case study:

- For the current energy systems, two out of four DH interconnections are economic feasible with the IRR of 4.21% and 5.54%. Compared with the chosen discount rate of 4%, two other investments were not feasible as their IRRs were 0.41% and 2.15%. After the last interconnection was set in place, the total socio-economic costs were 2.2% lower than in the reference case.
- Connecting all the five DH systems in the energy system anticipated for the year 2029 has a payback time of only 8.63 years. Moreover, the investment proposed leads to the savings in PES amounting of 9.5%, 11.1 %lower CO_2 emissions and reduced total system costs by 6.3%.
- In the case of industrial waste heat being available for supplying heat to the DH grid, in the case of fully interconnected DH grid (case IX), PES was reduced by 7.2%, CO_2 emissions by 8.9% and total system costs by for 5.1% compared to the industrial waste heat being fed into distributed DH systems. Thus, the best outcome was reached in the last case, with the fully interconnected DH system, as well as with the industrial waste heat fed into the grid.
- There is no correlation between the length of the interconnections or pipe diameters and the economic indicators of the investments. Thus, the investment in interconnection depends on the energy mix of the DH supply plants being interconnected.
- Large-scale heat pumps, with the average electricity price levels similar to current ones, completely replace the production of all the boilers, including the electricity, biomass and gas ones.
- Interconnecting the DH systems is beneficial in both the current energy system and the anticipated system in the year 2029. However, in the future system dominated by the generation of electricity from intermittent sources in the power sector, the benefits of interconnecting the DH systems are far greater according to all three indicators: total system costs, primary energy consumption and CO_2 emissions. Connecting DH grids brings more flexibility to the system, making it cheaper, less environmentally harmful and more energy efficient to integrate intermittent energy sources in the power sector.

7 Acknowledgments

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Abbreviations

BAU Business-as-usual
CHP Combined Heat and Power
COP Coefficient of Performance
COP21 2015 Paris Climate Conference
DEA Danish Energy Agency
DH District Heating
EU European Union
GHG Greenhouse Gas
IEA International Energy Agency
IRR Internal Rate of Return
LP Linear Programming
MB Megabytes
MIP Mixed-Integer Programming
NLP Non-Linear Programming
NPV Net Present Value
O&M Operation and Maintenance costs
PES Primary Energy Supply
RAM Random Access Memory
RES Renewable Energy Source
TB Terabytes
TSO Transmission System Operator

Nomenclature

A_p cross area of the pipe, m^2
bio_cap Maximum allowed biomass consumption in the modelled system, MWh
$CO2\_cap$ Maximum amount of emissions allowed in the system, ton
$CO2\_inten_j$ CO_2 intensity of a certain technology or energy within the system boundaries, ton/MWh
$CO2_{inten_k}$ CO_2 intensity of a certain technology or energy coming in or out of the system boundaries, ton/MWh
$CO2_j$ Costs of CO_2 emissions, €/ton
c_w specific heat capacity of water, 4.187 kJ/(kg*K)
$dies\_dem$ Diesel demand, MWh
$dies\_imp_k$ Price of import of diesel in a specific hour, €/MWh
dis_rate_i Discount rate of the technology i, %
DN Nominal diameter of the pipe, mm
el_dem Electricity demand, MWh
$el\_imp\_exp_k$ Price of import or export of electricity in a specific hour, €/MWh
$fix\_O\&M_i$ Fixed operating and maintenance costs of energy plants, €/MW
$fuel_j$ Fuel cost of specific energy type, €/MWh_{fuel}

gas_dem Gas demand, MWh

$gas\_imp\_exp_k$ Price of import or export of gas in a specific hour, €/MWh

$heat\_level_r$ Heating energy content stored in the energy storage, MWh

$heat\_dem_t$ Heat demand in district heating grid t, MWh

inv_i Total investment in technology i, €

lev_inv_i Levelized cost of investment over the energy plant lifetime, €/MW

$lifetime_i$ Lifetime of the technology i, years

$\dot{m}_{max}$ maximum mass flow of the water transferred through the pipes, kg/s

$petr\_dem$ Gasoline demand, MWh

$petr\_imp_k$ Price of import of gasoline in a specific hour, €/MWh

$q_{v,max}$ maximum volume flow of the water transferred through the pipes, kg/s

t the number of geographically separated DH systems; $number\ of\ DH\ grids = 1,2..t$

$var\_O\&M_j$ Variable operating and maintenance costs of energy plants, €/MWh

v_f flow velocity, m/s

x_i Capacity variables of energy plants, transmission grid and gas grid, MW

x_j Generation capacities of energy plants (8,760 variables for each energy plant, representing the generation in each hour during the one year), MWh

$x_{j,EL}$ Hourly generation of technologies which generate electricity

$x_{j,EL,biomass}$ Hourly generation of technologies which generate electricity and are driven by biomass

$x_{j,EL,gas}$ Hourly generation of technologies which generate electricity and are driven by gas

$x_{j,EL,other}$ Hourly generation of technologies which generate electricity and are driven by other fuel types

$x_{j,heat}$ Hourly generation of technologies which generate heat

$x_{j,heat,gas,t}$ Hourly generation of technologies which generate heat, are driven by gas and operate in the DH system t

$x_{j,heat,biomass,t}$ Hourly generation of technologies which generate heat, are driven by biomass and operate in the DH system t

$x_{j,heat,gas,t}$ Hourly generation of technologies which generate heat, are driven by gas and operate in the DH system t

$x_{j,heat,other,t}$ Hourly generation of technologies which generate heat, are driven by other fuel types and operate in the DH system t

$x_{j,heat,storage\_ch,t}$ Hourly charge of heat to the heat storage operated in the DH system t

$x_{j,heat,storage\_dis,t}$ Hourly discharge of heat from the heat storage operated in the DH system t

x_{j,an_dig} Generation of gas after CO_2 removal in anaerobic digester

x_k Import or export across the system boundaries of different types of energy (8,760 variables per one type of energy, representing the flow in each hour during the one year), MWh

ΔT water temperature difference, K

η_j Efficiency of technology, MWh_{energy}/MWh_{fuel}

ϕ_{max} maximum heat capacity transferred through the pipes, W

ρ_w water density, 1000 kg/m^3

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