In the Heat of the Moment - A modelling exercise of power and heat system interactions in a renewable energy future

BY

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Abstract

The integration intermittent energy sources (IRES) in the electricity system poses challenges related to the variable production of IRES. Integration of the electricity system and the heating system through power-to-heat (P2H) interactions, can help overcome these challenges. This research studies whether and how these linkages could lead to reductions in total system costs and carbon dioxide (CO_2) emissions with large IRES deployment.

In this study, the PowerFys model was expanded in order to model the whole heating system of a country and all its interactions with the electricity system. In the new model, it is possible to model: (1) inter-system interactions such as P2H conversions; (2) combined heat and power (CHP) generation; and (3) seasonal thermal energy storage (STES). Several scenarios were tested for the Netherlands in the years 2030 and 2050. In the scenarios the deployment of heat pumps and connections to district heating (DH) were varied. The influence of electric boilers and STES connected to the district heating were studied as well. The electricity system was assumed to become increasingly dependent on renewable energy sources and was similar for all scenarios of the same year.

Under the assumptions in this study, the scenario with the highest deployment of heat pumps resulted in the lowest system costs in 2030 and 2050. In 2050, this scenarios resulted in savings of little over 2 billion euros annually compared to the 14 billion euros of annual Dutch system costs in the baseline scenario. Additionally, the CO_2 emission reduction was the largest with 22.7 $MtCO_2$/yr compared to 30.8 $MtCO_2$/yr in the baseline. It was found that the flexible dispatch of heat pumps and CHP units resulted in these savings. It was shown that the capacity of both electric boilers and STES can increase system costs of district heating with 1 billion euros per year. However, it is possible that carefully balanced capacities of electric boilers and STES can also reduce the system costs of district heating.

This research showed that next to electricity and heat system integration, additional savings of 8 $MtCO_2$/yr are required to achieve a fully renewable Dutch heating and electricity system in 2050. Integration of IRES can be achieved with the deployment of heat pumps at the lowest system costs and with the highest emission reduction. The innovative method, as presented in this thesis, can also be used for future research on the integration of other energy systems as well as further research on electricity and heat interactions.

Keywords: Power system flexibility, Heat pump, District heating, Power-to-Heat (P2H), Seasonal thermal energy storage (STES), System costs, Carbon dioxide emissions

PREFACE

I combined my thesis research with an internship at Ecofys, from September 2016 until the beginning of February 2017. At the beginning of this process my primary interest was the integration of (intermittent) renewable energy sources in the electricity system and the various opportunities and challenges this would entail. During the course of this thesis I became to appreciate the importance of 'greening' the heating system more and more. I hope that it is visible from this writing that I now believe that both systems are equally important and interesting although heating is often treated with less attention in the literature.

Roughly one year ago, I spent a short vacation in a small village on Sicily. We stayed in a so called 'eco house' which was completely off grid. Electricity was provided by one small solar panel (which was so poorly placed that it was in the shade from noon onwards) and the heating came from a small wood stove. Although we stayed in the south of Italy, the evenings were still cold in early spring and the sun would hide behind Mount Etna already early in the evening. Despite the cosiness of the woodstove and a few candles (the LED lighting strips were everything but cosy), I quickly became to appreciate the instant heating and electricity available to us in the Netherlands. It was on the small scale of this house – or rather cabin – where I first consciously experienced the importance of interactions between heat and power. As we used the shower, fuel for heating the water and electricity for pumping the water were used. As we quickly found out, taking a shower quickly drained the battery. While there still was ample fuel, we could no longer use the shower because the battery was dead. With the changes that lie ahead in both our heating and the electricity system, I believe that we should not forget to appreciate the comfort these systems provide to us.

I hope that you enjoy reading my thesis.

Bas van Zuijlen, Utrecht, February 10th 2017

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List of Abbreviations

Abbreviation	Meaning
BE	Belgium
CCHP	Combined cooling heating and power
CHP	Combined heat and power
COP	Coefficient of performance
CO_2	Carbon dioxide
CCGT/NGCC	Combined cycle gas turbine
DE	Germany
DH	District heating
DHW	Domestic hot water
DK	Denmark
FO&M	Fixed operation and maintenance
GBI	Great Britain and Ireland
HP	Heat pump
IRES	Intermittent renewable energy sources
LT	Low temperature
NG	Natural gas
NL	The Netherlands
OCGT	Open cycle gas turbine
ODH	Open district heating
ORC	Organic Rankine cycle
P2H	Power-to-Heat
PV	Photovoltaics
SH	Space heating
STES	Seasonal thermal energy storage
stTES	Short term thermal energy storage
TPA	Third party access
VO&M	Variable operation and maintenance
WindOn	Onshore wind energy
WindOff	Offshore wind energy

1 Introduction

A global movement to reduce carbon dioxide (CO_2) emissions considerably is aiming to keep average global surface temperature rise well below a 2 degree Celsius increase above pre-industrial levels (UNFCCC 2015). Of the global CO_2 emissions, 25% is emitted by heat and electricity production (IPCC 2014). Clearly, emission reductions in this sector are required. Recently, both the electricity and heating systems experienced new developments which can contribute to the reduction of CO_2 emissions.

In the electricity sector, an increasing share of the production comes from renewable sources. Many of these renewable sources have an intermittent nature. These sources are therefore called intermittent renewable energy sources (IRES). With an increasing share of IRES, the variability of electricity production will increase. This can be problematic for the electricity system. Without appropriate action, high variability may lead to electricity excess and shortage events. Variability of electricity supply can be absorbed by flexibility in the electricity system. Flexibility can generally be improved by adding storage and by increasing flexibility of production and demand (Lund et al. 2015). IRES, is of a smaller influence to the heating sector. Only the smaller solar thermal technologies can be defined as IRES. Other, more constant renewable sources, such as geothermal heat and waste heat are also available to provide heating.

Another recent development is the planning of open district heating (ODH) systems (Söderholm & Wårell 2011). ODH allow producers and users of heat to join or leave the heating system (Municipality of Amsterdam 2015). The price per hour (or any other fixed time step) is set equal costs of heat production by the marginal producer (Li et al. 2015). This new system will create local heating markets similar to the current electricity market (Kamp 2015). Enabling third party access (TPA) will increase the competition, but, especially for smaller grids, possibly also increase the system costs (Söderholm & Wårell 2011). Nonetheless, TPA remains a strong political wish (Kamp 2015; Söderholm & Wårell 2011).

Finally, electricity is increasingly used to produce heat (Fraunhofer 2014). Heat pumps can provide heat at high efficiencies and, if the electricity is from a renewable source, without CO_2 emissions. Heat pumps can be used to heat homes that are not connected to a district heating (DH) system. Electric boilers can, similarly to heat pumps produce heat but at lower efficiencies. However, the investments for electric boilers are also lower.

This last development shows that interactions between the heating and electricity systems are increasing. Conversions where electricity is converted to heat are called Power-to-heat (P2H) conversions (Ehrlich et al. 2015; Böttger et al. 2015; Sowa et al. 2014). P2H conversions may provide flexibility to the electricity system (Lund et al. 2015). Conversions to other energy carriers are also possible. However, due to the low costs and high efficiencies, it is likely that P2H is the option with the highest economic feasibility (Deuchler 2013). Together, these three developments allow for interesting future possibilities for both the heating and electricity system.

The value of interactions between the heating and electricity system were studied and acknowledged before. Several studies modelled some of the possible interactions. Thermal energy storage is found to be a good option to provide flexibility to the power system (Li & Zheng 2016). Also the smart dispatch of a combined cooling heating and power[1] (CCHP) unit is found to reduce

[1] A unit able to produce heat, electricity as well as cooling.

curtailment and lower operational costs (Li et al. 2016). A complete energy system was modelled by Gill et al. (2011) finding that reduction in wind energy curtailment is possible trough linking the electricity and heating system. Liu et al. (2016) focusses more on methodology and present a model that is also used to optimise an integrated heat and electricity energy system. However, in these two studies, only small islanded energy systems were modelled. Large energy system cannot be viewed as several islanded systems but rather as several interconnected systems. Since these interconnections may provide new possibilities, but also new problems, this thesis will focus on large interconnected energy systems. Additionally, it is studied what the optimal configuration of the heating system will be.

1.1 Research question

The research question following from the problem introduced above is:

How can power and heat system be integrated to reduce CO_2 emissions and costs of both systems?

To answer this research question, the following sub-questions are posed:

1. What will the future power and heat system look like?
2. How will the future heat and power system interact?
3. How much can these interactions reduce the costs and CO_2 emissions for both systems?

1.2 Scope

This study focuses on the Netherlands as a case study. The Netherlands is a good case study for several reasons. First, the Dutch government is aiming to increase the share of renewable energy supply considerably, targeting for a fully renewable energy system in 2050 (SER 2013). Secondly, renewable heating is still a considerable challenge in the Netherlands according the Dutch minister of Economic Affairs (Kamp 2015). Finally, countries surrounding the Netherlands are undergoing similar developments potentially interacting with the Netherlands. The neighbouring countries which are expected to develop strong interconnections with the Netherlands were also modelled. These countries are Denmark (DK), Germany (DE), Belgium (BE) and Great Britain and Ireland (GBI)[2].

The heating system was only modelled for the Netherlands. Heat is generally transported by pumping a hot medium (often water) from the heat source to the heat demand. Both within buildings and in DH networks, heat is transported this way. The transport of a hot medium is limited by speed and heat losses. Increasingly large amounts of energy are required to pump water at higher speeds and heat losses will increase with the distance over which the medium is transported. Therefore, no significant heat exchanges between the Netherlands and other countries were expected.

Contrarily, the transport of electricity is limited by speed and losses only to a small extent. Transport of electricity between countries is already taking place and is expected to increase towards the future. Since the transport of electricity is an important aspect in the electricity system, the electricity systems of the abovementioned countries were modelled next to the Dutch electricity system.

[2] I.e. Great Britain and Ireland are modelled as if they are one country.

1.3 Outline

The next section will introduce the crucial concepts considering heat and electricity interactions. Section 3 discusses the methodology and model that were used for this research. Thereafter, section 4 gives an overview of the input data. The results of the model are presented in section 5 and subjected to a sensitivity analysis described in section 6. Finally, the report finishes with a discussion of the results and a conclusion answering the research questions in sections 7 and 8, respectively.

2 HEAT AND ELECTRICITY INTERACTION CONCEPTS

A distinction can be made between direct interactions and indirect interactions. Direct interactions are the various conversions between heat and electricity. Indirect interactions are the consequences which these direct interactions have on the broader heating and electricity system in general. Based on the literature, several of these interactions were identified.

Most interactions between the heat and electricity system are energy conversions from electricity to heat. Since the exergy level of electricity is high and the exergy level of heat is low (depending on the temperature difference with the environment), conversions from electricity to heat can be highly efficient. Similarly, conversions from heat to electricity are less efficient (Blok 2007). Therefore, conversions from heat to electricity are also less common.[3]

2.1 DIRECT INTERACTIONS

One conversion from heat to electricity that is employed more often over the last few years is the Organic Rankine Cycle (ORC) (CE Delft 2011). With an ORC, relatively high temperature waste heat (±300°C) can be converted to electricity at reasonable efficiencies (Wang et al. 2013). However, this thesis only considers low temperature heating and therefore ORC falls outside the scope.

The most applied technologies for conversion from electricity to heat are electric boilers and heat pumps (Fraunhofer 2014). An electric boiler can heat water with electrical heat elements. The conversion efficiency is close to 100%. The initial investment of an electric boiler is generally low. A heat pump does not convert electricity into heat, but rather uses electricity to transport heat from a low temperature to a high temperature region. The investment for a heat pump is high, but the efficiency, expressed as coefficient of performance (COP), can be five times higher as an electric boiler (Fraunhofer 2014). When the temperature difference which the heat pump needs to overcome decreases, the COP can even increase further.

Another direct interaction between heat and electricity is the combined generation of heat and power (CHP). In a CHP plant the heat that is normally wasted in thermal power plants is utilised. Since CHP plants are currently a heat source for district heating grids (CE Delft 2009), they run in a heat driven mode. This means that the heat demand determines the level of the generation. The generated electricity is exported without considering the electricity demand. Therefore, from an electricity perspective, CHP plants are often seen as electric capacity that must deliver to the grid. An ideal dispatch of CHP plants can lead to an optimal situation for both the electricity and the heating system.

2.2 INDIRECT INTERACTIONS

Since the heat and electricity system can interact, one can be used to the advantage of the other. During electricity excess events, electricity is relatively cheap[4] and often produced from renewable sources. With cheap seasonal thermal energy storage (STES) and the capacity to convert electricity excess to heat, electricity excess events can be absorbed. The potential of STES in combination

[3] Thermal power plants are an exception, the temperature of heat used in thermal power plants is high and hence the exergy level is higher as well.

[4] Prices may even turn negative due to subsidies for renewable electricity production (Fraunhofer 2014). At those points in time, renewable generators still have an incentive to produce while other generators only have the incentive to minimise their generation.

with P2H conversions is also acknowledged by the Dutch minister of Economic Affairs (Kamp 2015).

Heat pumps can also be used to provide flexibility across the energy systems. Heat that is produced by a heat pump can be stored in the thermal mass of a building which is heated by the heat pump. This way, the heat pump can be dispatched before heat is required but when electricity is (more cheaply) available.

3 METHODOLOGY

In this research, various scenarios were tested with respect to both the amount of CO_2 emissions and the total system costs. These system costs consist of investment costs and operational costs. The operational costs and CO_2 emissions were calculated by means of a unit commitment and dispatch model called PowerFys. This model was extended specifically for this research. The model dispatches various generation units to fulfil the demand while minimising costs. The investment costs were determined from the literature. The flow of the research steps is shown in Figure 1 below.

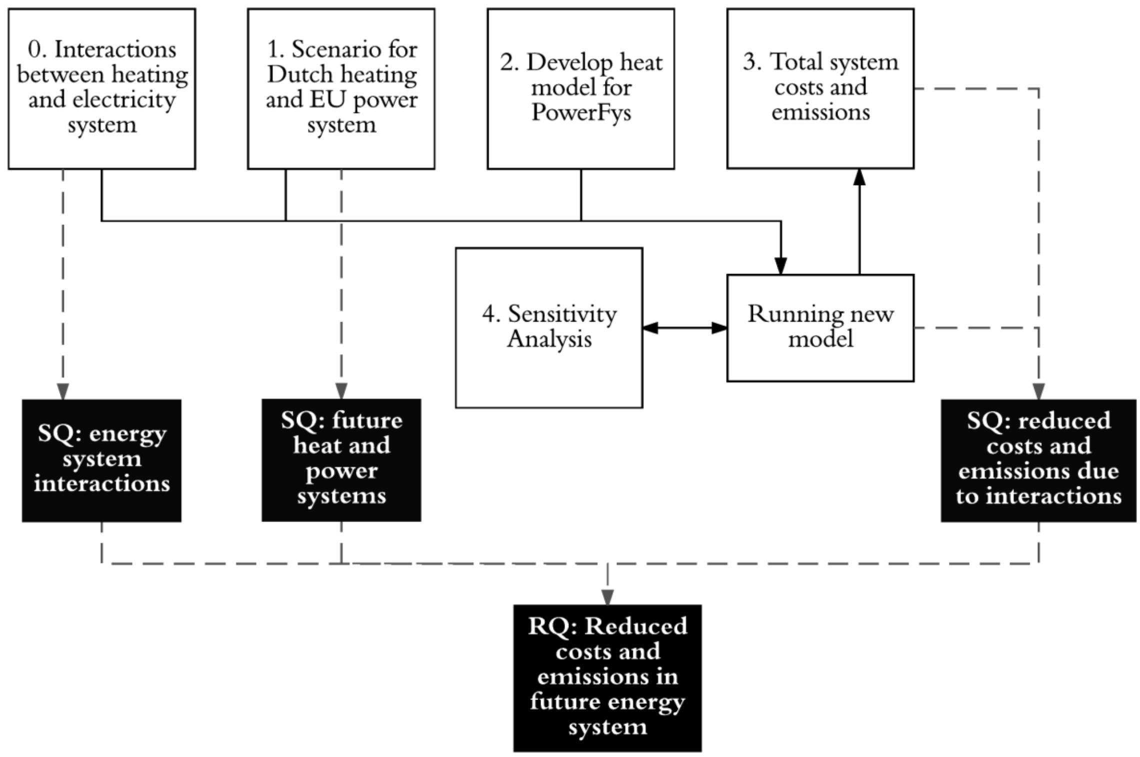

Figure 1: Overview of the research method. White boxes show the steps taken in the research and the black boxes show how the research question (RQ) and the sub-questions (SQ) are answered.

3.1 SCENARIOS

Model input was collected by consulting various scenario studies. As the aim of this research is to show how the heat and electricity system can interact with large amounts of renewable energy sources, scenarios with a high penetration of these sources were chosen. Data was collected for both the years 2030 and 2050 to capture the development over time. A complete overview of the data used is given in section 4. Data was selected based on two guidelines: (1) the future scenarios should be realistic, (2) deployment of renewables will speed up towards 2050 while fossil sources will be used considerably less.

3.2 POWERFYS MODEL

The existing PowerFys model simulates the electricity system and is based on the model described by Abrell & Kunz (2015). The optimisation in PowerFys minimises costs in a 'rolling planning' procedure. In this procedure, costs are minimised in a day ahead market every day and in an intraday market for every hour of the day. The dispatch in the day ahead and intraday market consider all relative parameters for the next 36 hours.

The requirements for reserves are determined in the day ahead market. Reserves are modelled as available capacity which is not used, i.e. a power plant with a maximum capacity of 700 MW and a minimum capacity of 200 MW can provide 200 MW upwards reserve and 300MW downward reserve when generating 500 MW, see Figure 2. The secondary and tertiary reserve markets are modelled in PowerFys. Depending on the input specifications, power plants and storage units can contribute to these markets. Sudden power plant outages or unexpected changes in demand are not modelled. Therefore, reserves are not used in the PowerFys model. The reserve markets are still modelled since it results in more realistic market behaviour.

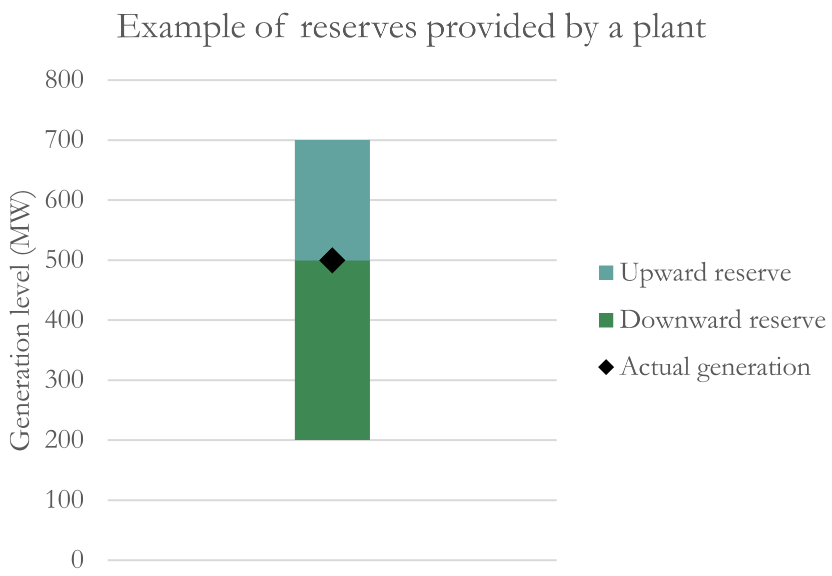

Figure 2. Example of the reserves available at a power plant. This power plant is generating at 500 MW and has a maximum capacity of 700 MW and a minimum capacity of 200 MW. Therefore, the power plant can provide an upward reserve of 200 MW and a downward reserve of 300 MW.

Once the day ahead market dispatch is completed, the intraday market again minimises costs for each of the 24 hours in the day. In this dispatch, PowerFys again considers the next 36 hours from the respective hours. As new information arises for the hours in the intraday market, the dispatch as decided in the day ahead market may be changed.

The production by IRES influence the changes in dispatch considerably. Since IRES sources are weather dependent, their future hourly production is uncertain. This effect is modelled by a simulation of imperfect 36 hour forecast of produced electricity for each hour in the year[5].

The functioning of the PowerFys model is structurally different from the real-world power market(s). In the modelled countries, individual actors are trying to optimise their profits by dispatching their power plants. In the PowerFys model, the decision of dispatch is made by one optimisation algorithm. However, if it is assumed that the real-world power system functions as a perfect market, both outcomes will be the same.

[5] I.e. a forecast for hours 1-36 is available in the first hour and a similar but different forecast for the hours 2-37 available in the second hour etc. The closer the forecasted hour is to the hour which is modelled, the more reliable this forecast is.

3.2.1 INTEGRATED ENERGY MODEL

A first crude heat extension was already developed for PowerFys (Ecofys 2016a). However, in this setup, the heat system was implemented slightly different compared to the electricity system. The model was generalised in the current research, the modelled energy carriers can now be defined in the model input. Therefore, in future research, interactions with other energy systems can also be modelled with the new PowerFys model. Despite the changes in the model, data collected during the earlier project was also used in the further development of the model for the current research.

The explanations of the PowerFys model from this part onwards describe the changes to the original model that were added for this study. In this and the following sections, the same notation is used as is used by Abrell & Kunz (2015). A nomenclature is shown in Table 1 below.

Table 1. Nomenclature for the equations. This nomenclature is based on Abrell & Kunz (2015) and extended for this research.

Name	Explanation	Name	Explanation
	Indices		
Ψ[6]	Mapping from generation units, renewable sources and storages to nodes	$Off_{p,t}$ $On_{p,t}$	Minimum offline and online times for generation unit p at time t
Υ[7]	Mapping from node to country	Res, res	Set of reserve markets
CN, cn	Set of countries	T, t	Set of time steps
J, j P, p	Set of storages and generation units	W, w	Set of renewable sources
N, n	Set of nodes in network[8]	E, e[9]	Set of energy carriers
	Parameters		
$\eta_{p,t,e}$ $\eta_{j,t,e}$	(pump)efficiency of generation unit p or storage j at time t for energy carrier e (-)	$dr^{+}_{cn,res,t}$ $dr^{-}_{cn,res,t}$	Positive and negative reserve requirements at country cn for reserve market res at time t (MWh)
$\overline{s_{w,t,e}}$	Expected renewable supply from renewable source w at time t for energy carrier e (MWh)	$gmax_{p,e}$ $gmin_{p,e}$	Maximum and minimum generation of generation unit p for energy carrier e (MW)
mc_{curt}	Cost per unit of curtailment (€/MWh)	$lmax_{j,e}$	Maximum storage level of storage j for energy carrier e (MWh)

[6] I.e. $\forall p\ \Psi(p) = n$ if and only if unit p is located at node n, analogous for all renewable sources w and storages j.

[7] I.e. $\forall n\ \Upsilon(n) = cn$ if and only if node n is within country cn.

[8] In the paper by Abrell and Kunz (2015) all physical electricity lines are included in the model. This is not the case in the PowerFys model.

[9] In some formulas bot e and ee are used, ee is also an index of $E$and is used whenever it is necessary to describe two energy carriers

Name	Explanation	Name	Explanation
$mc_{p,t,e}$	Variable cost of generation unit p at time t for energy carrier e (€/MWh)	ton_p $toff_p$	Required online and offline times of generation unit p (h)
$d_{n,t,e}$	Demand at node n at time t for energy carrier e (MWh)	$vmax_{j,e}$ $wmax_{j,e}$	Maximum storage release and pumping of storage j for energy carrier e (MWh)
mc_{infes}	Cost per unit of demand not met by supply (€/MWh)	$elf_{p,t,e,ee}$	Energy loss factor for generation unit p at time t for energy carriers e and ee (-)
$elfmax_{p,e}$	Maximum energy output considering the energy loss factor for generation unit p and energy carrier e (MW)	$eter_{p,ee,e}$	Energy-to-energy ratio for generation unit p between energy carriers ee and e (-)
$\eta cross_{p,e}$	Amount of energy carrier e needed by generation unit p for conversion to another energy carrier (-)		
		Variables	
$CR_{w,t,e}$	Curtailment of renewable source w at time t for energy carrier e (MWh)	$S_{w,t,e}$	Supply of renewable source w at time t for energy carrier e (MWh)
$CS_{p,t}$ $CD_{p,t}$	Start-up and shutdown costs for generation unit p at time t (€)	$TR_{cn,ccn,t,e}$	Commercial transfer between country c and cc at time t for energy carrier e (MWh)
$G_{p,t,e}$	Generation of generation unit p at time t for energy carrier e (MWh)	$U_{p,t}$	Operation status of generation unit p (on or off) at time t (-)
$R^{+}_{p,res,t,e}$ $R^{-}_{p,res,t,e}$	Provided upward and downward reserve by generation unit p at time t for energy carrier e (MWh)	$V_{j,t,e}$ $W_{j,t,e}$	Releasing and loading of storage j at time t for energy carrier e (MWh)
$R^{H+}_{j,t,e}$ $R^{H-}_{j,t,e}$	Provided upward and downward reserve by storage j at time t for energy carrier e (MWh)	$INF_{cn,t,e}$	Amount of infeasible load at country cn, time t and for energy carrier e (€/MWh)
$DE_{n,t,e}$	Demand for energy carrier e at node n and time t for conversion to another energy carrier (MWh)		

The constraints (i.e. code) of the original model (Abrell & Kunz 2015) were adjusted to fit the purpose of this research. A dimension with energy carriers was added to all constraints concerning the outputs of production and storage units. For this study the energy carriers in the model were heat and electricity. Additionally, since heat pumps were modelled as well, the efficiency of production units depends on the time of dispatch[10]. Therefore, the variable costs of power plants are also time dependent.

The adjusted objective function is shown in Formula I below. Note that both the start-up and shutdown cost variables do not have an energy dimension since these are independent of the energy carrier. The generation, however, does have an energy carrier dimension.

The PowerFys model also includes an 'infeasibility variable'. Whenever the electricity supply is lower than the demand, the infeasibility variable fills the gap. This ensures that the model runs without errors. However, since the usage of the infeasibility variable would mean a blackout in the electricity system, high costs associated with the variable. Consequently, the optimisation of the model will try to avoid using the infeasibility variable.

Formula I. Objective function in the day ahead model.

$$\text{minimise:} \quad \sum_{p,t,e}\left(mc_{p,t,e} \times G_{p,t,e} + CS_{p,t} + CD_{p,t}\right) + \sum_{j,t,e}\left(mc_{j,t,e} \times V_{j,t,e}\right) + \sum_{w,t,e}\left(mc_{curt} \times CR_{w,t,e}\right) + \sum_{cn,t,e}\left(mc_{infes} \times INF_{cn,t,e}\right)$$

All constraints that were originally developed for the electricity system can now be used for all energy carriers introduced in the model input. However, not all constraints will always be relevant for all energy carriers. An example is the contribution to the reserves market. This is relevant for the electricity system, but not for heat systems. Therefore, the reserve requirements for heat were set to zero in the model input.

3.2.2 Energy conversion technologies

In this section, a systematic overview of energy conversion technologies in both the heat and electricity system is given. In this overview, technologies are classified based on their similarities and fundamental differences relevant for the modelling. Based on the similarities and differences, the technologies are modelled in similar or different ways. The adjustments of and additions to the original model are shown here as well.

Various technologies can produce heat and electricity and multiple sources of energy are used by these technologies. These technologies can be divided based on the extent to which they can control their output:

- Controllable technologies: the production is based on the amount of input and the amount of input can be controlled. The production may be limited by technical boundaries such as ramping rates or minimum load capacities. Examples of controllable technologies are coal or gas-fired power plants, but also individual household gas boilers.
- Non-controllable technologies are technologies where the production of the output is not controllable because it relies on the uncontrollable input. For example, the amount of wind

[10] Whenever the ambient temperature of a heat pump is higher, the COP of the heat pump will also be higher. The efficiency changes over time because the ambient temperature changes over time.

or sunshine are non-controllable since they depend on the weather. Curtailment of energy generated by these non-controllable technologies is of course always an option. Here, the option of curtailment is not captured by the term controllable.

- Partly controllable technologies also rely on non-controllable input. However, to produce output some choices can be made. An example is waste heat from datacentres. The heat is at a low temperature and requires upgrading by a heat pump before it can be fed into a DH grid. The amount of waste heat available at the datacentres is non-controllable since it is both dependent on the weather and the datacentre activity. The heat pump on the other hand is fully controllable which gives some control over the produced heat.

Finally, technologies might use multiple inputs or have multiple outputs. An example of multiple inputs are low temperature waste heat and electricity. If these are both used as an input for the heat pump, the output is useful heat at a higher temperature.

An example of an energy conversion with multiple outputs is a CHP plant which produces both heat and electricity. An overview of the possible energy conversions based on their controllability and amount of inputs and outputs are shown in Table 2. In this study, no technologies are relying on specific conversion categories where the cells are empty. However, these are not by definition impossible energy conversion categories. Only the cells with the '*' sign indicate an impossible combination since a conversion with only one input is either controllable or not.

Table 2. Categorisation of structurally different energy conversion technologies based on controllability and number of outputs and inputs. Cells with similar colours indicate types of technologies which can be modelled in the same manner.

in => out	Controllable	Partly controllable	Non-controllable
1 => 1	- Gas turbine	*	- Wind energy - Solar energy
1 => 2	- Gas CHP	*	- Concentrated solar CHP
2 => 1	- Biomass co-firing	- Datacentre waste heat	
2 => 2	- Biomass co-firing CHP		

3.2.2.1 MODELLING THE CONTROLLABILITY OF UNITS

Controllable units are defined in the model with a certain maximum capacity and a set of constraints based on technology specific parameters (e.g. efficiency, ramping rates etc.). In the model, the optimisation results in the dispatch of each unit considering the applicable constraints.

Non-controllable conversion technologies are modelled with a fixed production profile over the year. A share of this production profile can be curtailed in the model. The model generally only curtails if no other option is available because curtailment has high opportunity costs

Partly controllable units are modelled similar to controllable units. The difference is that while the maximum capacity for controllable units is constant throughout the year, partly controllable units have a maximum capacity that fluctuates over the year. The maximum output of partly controllable units depends on the amount of input. This input cannot be controlled and therefore, this captures both the non-controllable and controllable part of the unit.

3.2.2.2 MODELLING SINGLE AND MULTIPLE INPUTS AND OUTPUTS

Non-controllable sources with multiple outputs can be modelled as multiple separate production profiles one for each output. The amount of inputs is not relevant for non-controllable sources since only the output profiles are used in the model.

It is assumed that if a unit uses multiple inputs, the share of inputs remains constant. The conversion with multiple inputs can be modelled like the controllable conversion with only one input. The mixture of the two fuels is then defined in the model input.

A distinction between technologies which have one or multiple outputs for both the controllable and partly controllable technologies exists. The case of a CHP is discussed here as an example. In this example, it is shown that generation units with one output (e.g. a power plant) and generation units with multiple outputs (e.g. a CHP) can be modelled by the same set of constraints.

CHPs can have various combinations of electricity and useful heat output which are limited by the feasible operation range (Li et al. 2016). Generally, the operation range of a CHP unit has the shape of the graph presented in Figure 3 below. The shape of the operation range is specific for each CHP; however, it can be expected that for an operation range of a different technology, the restrictions are similar. In reality, the lines in the graph are not perfectly straight, but for modelling purposes it is often assumed that they can be described by linear inequalities (Cosijns et al. 2006; Sadeghian & Ardehali 2016). Logically, the amount of fuel increases whenever more electricity and/or more heat is produced. The fuel input is at a maximum along the top right constraint and at a minimum along the bottom left constraint.

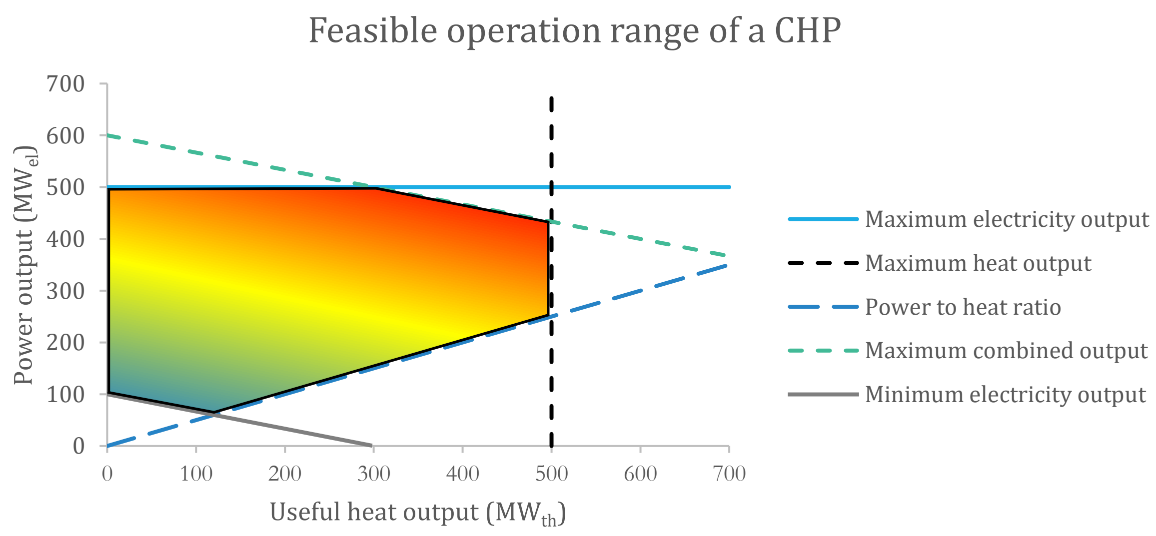

Figure 3. Feasible operation range of an extraction-condensing CHP (Adapted from Cosijns et al. (2006)). Similar graphs of feasible operation ranges are given by Danish Energy Agency (Energinet.dk 2012), Sadeghian & Ardehali (2016) and Haghrah et al. (2016). The amount of fuel needed to produce a certain output increases with the intensity of the redness of the operation range. The lines, along which the same amount of fuel is used, are parallel to the maximum combined output and the minimum electricity output.

The constraint of maximum combined output is determined by the power-loss-factor (Urošević et al. 2013). Since the new PowerFys model was designed to model multiple energy carriers this factor was called the energy-loss-factor (elf) here to be more general. Similarly, the power-to-heat-ratio was more generally called energy-to-energy-ratio ($eter$).

By setting the parameters right, CHPs, power plants and heat plants can all be modelled by the same set of linear inequalities. Only the constraint of maximum combined output is not used for single output plants, the other constraints can still be used. When the parameter of maximum heat generation is set to zero, the operation range only differs along the electricity axis. Therefore, a plant with a maximum heat output of 0 will behave as an electricity plant. On the other hand, when both the minimum and maximum electricity output parameters are set to zero, the plant behaves as a heat only plant. The constraints that were added to the model are Formula II-Formula IV.

Formula II. Maximum heat and electricity output.

$$\forall p,t,e: \qquad U_{p,t} \times gmax_{p,e} \geq G_{p,t,e} + \sum_{res}\left(R^{+}_{p,res,t,e}\right)$$

Formula III. Minimum energy output. For modelling the CHP, this constraint is only used with electricity. Where $\boldsymbol{elf_{p,t,e,ee}}$ stands for energy loss factor of unit $\boldsymbol{p}$ for energy carrier $\boldsymbol{e}$ to energy carrier $\boldsymbol{ee}$ at time step $\boldsymbol{t}$.

$$\begin{aligned}\forall p,t,e: \quad & G_{p,t,e} - \sum_{res}\left(R^{-}_{p,res,t,e}\right) \\ & + \sum_{ee\neq e}\left(\left(G_{p,t,ee} - \sum_{res}\left(R^{-}_{p,res,t,ee}\right)\right) \times elf_{p,t,e,ee}\right) \\ & \geq U_{p,t} \times gmin_{p,e}\end{aligned}$$

Formula IV. Maximum combined energy output. This equation in only used for units with multiple outputs. $\boldsymbol{elfmax_{p,e}}$ describes the starting point of the maximum combined energy output constraint. In the case of Figure 3 this would be 600 MW_{el}.

$$\begin{aligned}\forall p,t,e: \quad & U_{p} \times elfmax_{p,e} \\ & \geq G_{p,t,e} + \sum_{res}\left(R^{+}_{p,res,t,e}\right) \\ & + \sum_{ee\neq e}\left(\left(G_{p,t,ee} + \sum_{res}\left(R^{+}_{p,res,t,ee}\right)\right) \times elf_{p,t,e,ee}\right)\end{aligned}$$

Formula V. Energy-to-energy-ratio. Where $\boldsymbol{eter_{p,ee,e}}$ stands for energy-to-energy-ratio. In the case of a CHP energy carrier $\boldsymbol{e}$ must be electricity but in other cases $\boldsymbol{e}$ could be another energy carrier.

$$\begin{aligned}\forall p,t,e: \quad & G_{p,t,e} - \sum_{res}\left(R^{-}_{p,res,t,e}\right) \\ & \geq \sum_{ee\neq e}\left(\left(G_{p,t,ee} + \sum_{res}\left(R^{+}_{p,res,t,ee}\right)\right) \times eter_{p,ee,e}\right)\end{aligned}$$

Finally, electricity may be used to produce heat, or – more generally – energy carriers may be used to produce other energy carriers. Whenever one of the modelled energy carriers is used as an input for a conversion technology, this should have an effect on the generation of the first energy carrier.

Therefore, the amount of energy carrier used as an input to generate another energy carrier, is added to the demand for the first energy carrier. Consequently, an increased amount of this energy carrier needs to be produced, immediately affecting the dispatch and thereby operational costs and CO_2 emissions. The adjusted formulas are Formula V and Formula VI.

Formula VI. Market clearing equation. The variable $\boldsymbol{DE_{n,t,e}}$ describes the amount of energy carrier $\boldsymbol{e}$ required for conversion to other energy carriers and is defined in Formula VII.

$$\forall cn,t,e: \quad \sum_{p\in\Psi(\Upsilon(cn))}\left(G_{p,t,e}\right)+\sum_{ccn\neq cn}\left(TR_{ccn,cn,t,e}-TR_{cn,ccn,t,e}\right) + \sum_{j\in\Psi(\Upsilon(cn))}\left(V_{j,t,e}-W_{j,t,e}\right)+\sum_{w\in\Psi(\Upsilon(cn))}\left(S_{w,t,e}\right)+INF_{cn,t,e} = \sum_{n\in\Upsilon(cn)}\left(d_{n,t,e}+DE_{n,t,e}\right)$$

Formula VII. Definition of demand for energy carrier e for conversion to other energy carriers. This equation only sums the generation of units which have energy carrier $\boldsymbol{e}$ as an input to produce energy carrier $\boldsymbol{ee}$. Where $\boldsymbol{\eta cross_{p,e}}$ is the cross efficiency, describing the amount of energy carrier $\boldsymbol{e}$ used to produce one unit of energy carrier $\boldsymbol{ee}$.

$$\forall n,t,e: \quad DE_{n,t,e}=\sum_{\substack{ee\neq e,\\ p\in\Psi(\mathrm{n})}}\left(G_{p,t,ee}\times \eta cross_{p,e}\right)$$

3.2.3 Infrastructure

A setup of the model is shown in Figure 4 below. The model simulated the electricity and heating system in five geographical regions, the Netherlands and four neighbouring countries. The regions of all countries except for the Netherlands are represented by one node. The Netherlands was split into three nodes (NL1, NL2, and NL3). Each of the systems, connected to these seven nodes, has its own supply and storage options and demand profile for electricity. The systems within the Netherlands also have supply, storage and demand defined for heat. The arrows between the nodes represent the transmission capacities between the systems.

Heat sources can only fulfil heat demand of a system to which they are connected. The different nodes within the Netherlands were defined to keep different heating systems separate. Therefore, no transport capacity is defined between the heating systems. In the reality, there will be more separate heating systems than were modelled. However, it is assumed that these various heating systems are similar and can be aggregated into one large heating system in the model. For example, all households with heat pumps are aggregated in one system. The Dutch nodes in the model should therefore not be viewed as geographical regions. One node in the model can comprise similar heating systems from different parts of the Netherlands.

For electricity, an unlimited transport capacity between the nodes within the Netherlands is assumed[11]. This assumption mimics the copper plate assumption.[12]

[11] These transport capacities are actually not unlimited, but several times larger compared to the peak demand and therefore effectively not a limiting factor.
[12] This assumption implies that within one region (a country in this instance) there is unlimited transport capacity between all generators and consumers. The physical restraints of power lines within that region are therefore not

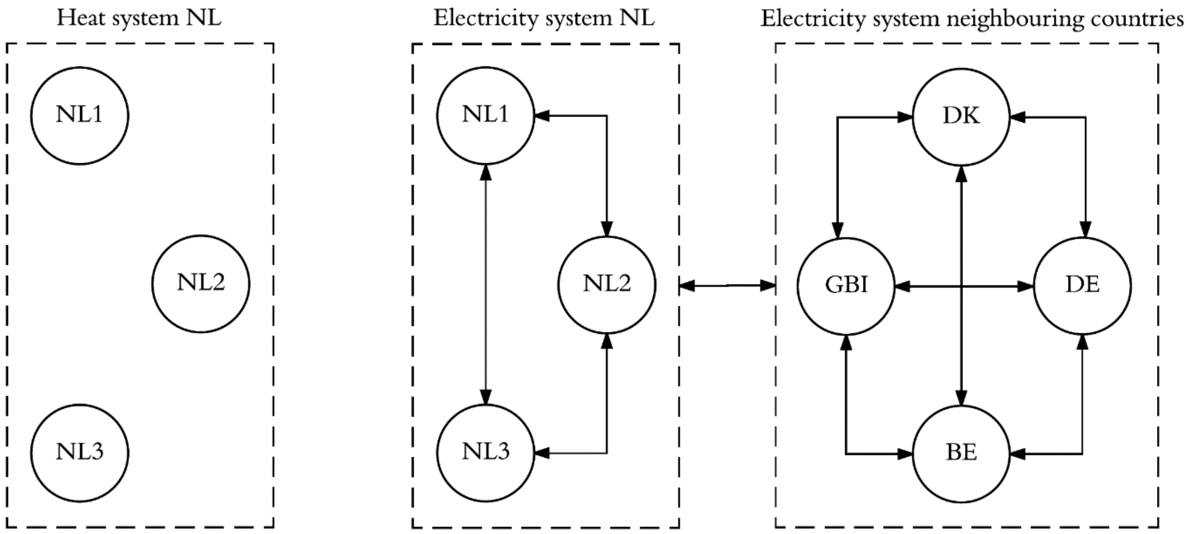

Figure 4. Setup of the model. The nodes in the heat system correspond to the nodes with the same name in the electricity system.

3.2.4 Modelling flexibility in the heat system

A vital part of the model is the flexibility in the heat system. This flexibility can be acquired through smart dispatch of the heat pump and (long-term) thermal storage. Flexibility of heat pumps can be achieved through postponing or frontloading the heat production of a heat pump. When heating is frontloaded, the heat is stored in the thermal mass of the building. When heating is postponed, heat is consumed from the thermal mass of the building rather than the heat pump. Flexibility of thermal storage can be achieved through charging or discharging the thermal storage faster or slower than originally anticipated. In this chapter, it is explained how this flexibility was modelled in the new PowerFys model.

3.2.4.1 Heat pump flexibility

The smart dispatch of heat pumps has already been modelled in PowerFys before (Papaefthymiou et al. 2012). For this study, the same approach is used. However, the input of this study is less refined. The approach by Papaefthymiou et al. (2012) assumes that a temperature range ΔT of 2 degrees Celsius[13] is possible in households. In this study the considered buildings are households and utility buildings. It is assumed here that the required comfort levels in utility buildings is the same as in households. Therefore, the temperature range of 2 degrees Celsius is assumed here as well.

The flexibility is modelled by means of a virtual heat storage. A virtual storage is a storage which only exists within the model. Within the model the heat pump is not dispatched in a smart way. However, in combination with the virtual storage, this behaviour can be mimicked. The size of the virtual storage is then described by the formula below:

regarded. If only one node would have been used to represent the Netherlands, the copper plate assumption would also hold for this node.

[13] I.e. 1 degree Celsius above or below the preferred temperature.

Formula VIII. Definition of the storage size. Where $\boldsymbol{C_{tot}}$ is the total thermal capacity of buildings heated with a heat pump.

$$Stor\ [MWh] = C_{tot}\left[{}^{MWh}/_{K}\right] \times \Delta T\ [K]$$

It should be noted that heat losses are neglected in this approach. Heating a building consistently above the preferred temperature level may lead to higher heat losses and a higher heat demand. However, since this flexibility is specifically used for heat pumps, and heat pumps are often implemented in well insulated houses, the heat losses in well insulated houses are limited and neglecting them will not result in large inaccuracies.

3.2.4.2 Flexibility of thermal storage

Thermal storage may need to be used to store heat seasonally. Optimisation of STES dispatch would require perfect foresight over the whole year. PowerFys, however, optimises over a period of 36 hours and is therefore not able to optimise STES. In order to circumvent this problem, several changes were made to the model input.

The exogenously defined heat demand was changed for the DH system within the scenarios with STES scenarios. The peaks and valleys in the original heat demand are perfectly shaved and filled. Whenever the heat demand including STES is lower compared to the original, it is implicitly assumed that STES is discharging and vice versa[14]. An example of this procedure is depicted in the top graph in Figure 5. The results of this method used as model input are described in section 4.1.3.

Based in the discharge profile that was constructed, the storage level of the seasonal storage could be determined. After all, if the seasonal storage is discharging, the level will drop and vice versa. This is the predicted seasonal storage level in the second graph in Figure 5. However, to allow flexibility in the system, the modelled storage level may differ.

The modelled discharge of the STES (not shown in Figure 5) is the predicted discharge profile of the STES plus the discharge of virtual storage. This virtual storage is, similar as with the heat pump flexibility, a storage unit defined in the model which does not exist in the modelled scenario. Whenever the virtual storage is discharged, this mimics the real-life option of discharging the STES faster (or charging slower) than the predicted rate. The size of the virtual storage is the range on which the actual charge/discharge of the STES may differ from the predicted discharge profile. The virtual storage is half full at the beginning of the model run. Whenever the virtual storage level is more or less than half full this means that the modelled STES level is the same amount above or below the predicted STES level, respectively.

[14] Note that negative discharge means that the STES is charging

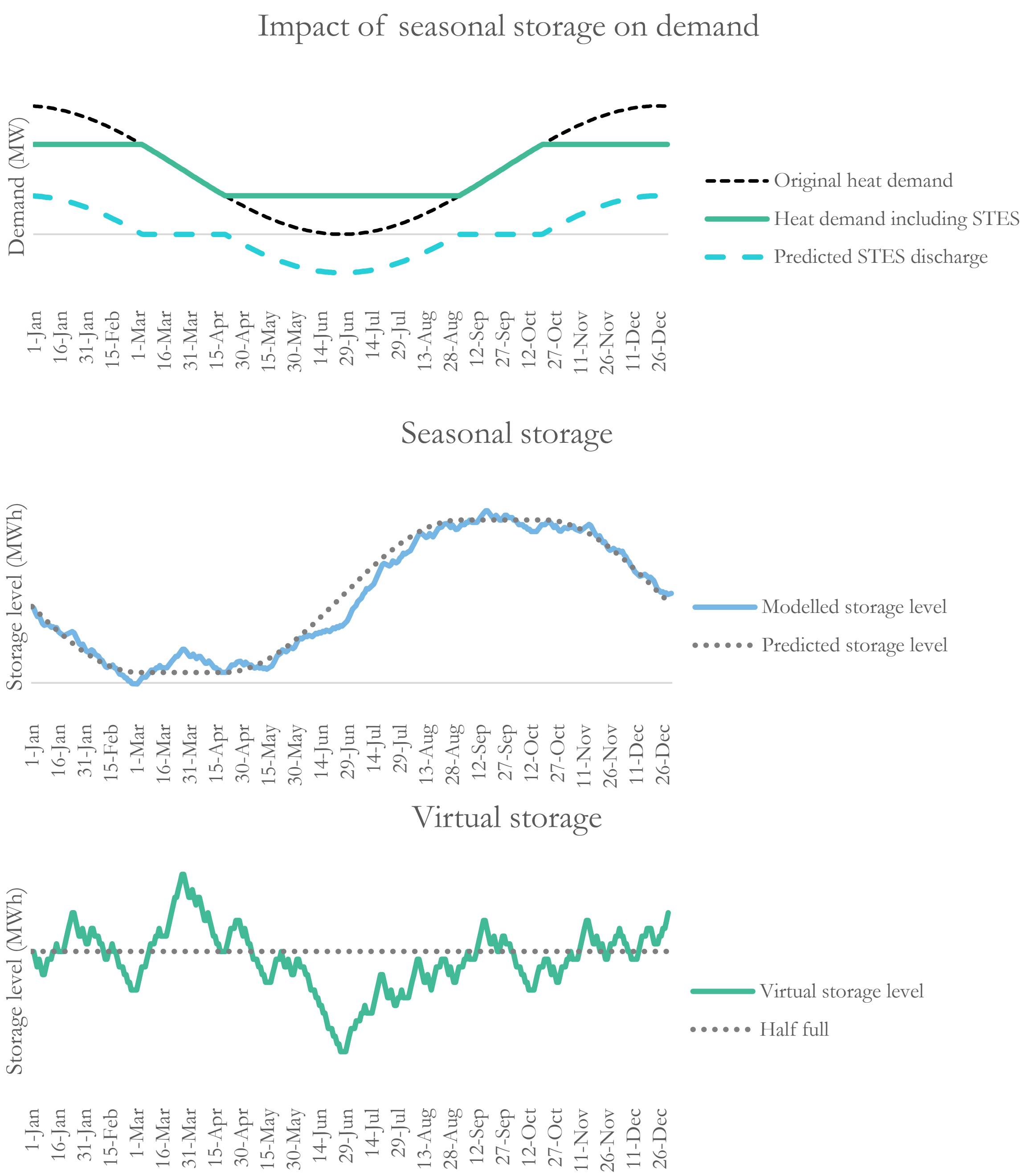

Figure 5. Example used as explanation of behaviour of the virtual storage over the year. The distance between the middle level of the virtual storage and the level of the virtual storage is equal to the difference between the modelled seasonal storage level and the predicted seasonal storage level. The actual profiles are much more refined; however, this example shows the method more clearly.

3.3 System costs and emissions

The model described above calculates variable operational and maintenance costs (VO&M)[15] and start-up and shutdown costs. Additionally, it calculates the CO_2 emissions which are emitted while the demand is supplied. However, to compare the scenarios on systems costs, not only the VO&M and start-up and shutdown costs need to be considered.

[15] In the current PowerFys model maintenance costs are not included. However, to keep the terminology coherent with other literature, it was chosen here to use the term VO&M.

The system costs also include fixed operation and maintenance costs (FO&M), generation unit investment costs[16] and infrastructure investment costs. The total system costs are calculated in a separate cost model. This cost model uses the output of the PowerFys model as an input.

The investment costs that were used in the cost model are based on a literature review and converted to yearly values by multiplying them with an annuity factor. The formula for the annuity factor is shown in Formula IX. Because various factors of the investment may have different lifetimes (e.g. a nuclear power plant has a longer lifetime than a gas-fired power plant), annuity factors were calculated for each factor of the investment costs.

Formula IX. Annuity factor. Where $\boldsymbol{L}$ is the lifetime of the generation unit and $\boldsymbol{r}$ is the discount rate.

$$\alpha = \frac{r}{1-(1+r)^{-L}}$$

Formula X. System costs

$$C_{system} = \sum_{unit} \left(\alpha \times C_{inv} + C_{FO\&M} + C_{VO\&M} + C_{start/shutdown}\right) + \sum_{infra} (\alpha \times C_{inv})$$

One social discount rate is used for all investment costs because this research studies overall system costs. In the cost model, a social discount rate of 4.5% is used. This discount rate is equal to the current Dutch government discount rate for social cost benefit analyses (Dutch Government 2015). The standard social discount rate by the Dutch government is 3%. However, for physical public investments[17], where the project cannot be adjusted to actual usage, a higher discount rate of 4.5% is used.

With this methodology, the investment costs of generation units and infrastructure are spread out evenly across the whole lifetime. Therefore, the investment costs of generation units that are already installed now and still in operation in 2030 (or even 2050) still attribute to the overall system costs. It is assumed that all infrastructure and generation units are replaced (by either a similar or different technology) at the end of their lifetime. Therefore, costs of early depreciation, i.e. replacing the unit or infrastructure before the end of its lifetime, is not considered here.

For power plants and renewable sources, the assumptions by Brouwer et al. (2015) and VGB (2011) are used. For heat and CHP plants as well as the seasonal thermal energy storage, a report from the Danish Energy Agency (Energinet.dk 2012) was used. Based on the outcome of the model run, for each technology, the maximum used capacity was taken as the actual installed capacity. Consequently, only capacity which is actually used is paid for. For electricity infrastructure, assumptions by Ecofys (2016c) are used. For the district heating assumptions, the cost estimations of Ecofys (2016a) and Pöyry (2009) are used.

For some technologies, cost figures were presented in multiple reports. Wherever there was overlap between the reports, the cost figures were similar in both reports. This indicates that the used cost figures are reliable. An overview of all cost assumptions is given in appendix 10.

[16] Generation unit investments costs are all investment costs required for units which supply heat and/or electricity. Investment costs for heat pumps and gas boilers installed at households and utility buildings are therefore also considered here.
[17] Energy plants and infrastructure are explicitly mentioned as examples of these kind of investments.

The CO_2 emission factors are taken from the IPCC (2006) and shown in Table 3. Biomass is reported to have emissions in the IPCC report. However, it is assumed that these emissions are again taken up by newly grown biomass after usage resulting in a carbon neutral fuel (Hamelinck 2004).

Table 3. Emission factors in the model.

Fuel	Emission factor ($kgCO_2/MWh_{fuel}$)
Biomass	0
Lignite	364
Coal	341
Gas	202
Oil	279

4 INPUT DATA

The aim of this research is to determine the potential of electricity and heat interactions in a renewable energy future. Scenarios were developed for the years 2030 and 2050. The scenarios should be viewed as an indication of what the electricity and heat system might look like in these years and not as exact predictions of the systems. The basis of the scenarios is that climate policy will gain serious momentum and the considered countries all have a nearly climate neutral energy system by 2050.

The electricity price, calculated by the PowerFys model, is based on the fuel and carbon prices. The fuel and carbon prices are based on the input values used by Fraunhofer (2011) and Brouwer et al. (2015). The gas, coal and biomass prices and the CO_2 emission prices are assumed to go up towards 2050. The price for lignite and nuclear fuel are assumed to remain the same. An overview of the values is shown in Table 4.

Table 4. Fuel and carbon prices. The first four fuel prices and the price of CO_2 emission rights are based on Fraunhofer (2011) in line with the other scenario assumptions. No price for biomass was given by the Fraunhofer report, therefore, the biomass price is based on Brouwer et al. (2015).

	Price 2030 (€/MWh)	Price 2050 (€/MWh)
Gas	30.8	31.8
Hard coal	15.4	18.7
Lignite	3.8	3.8
Nuclear	3.7	3.7
Biomass	28.8	32.4
CO_2 price[18]	35.0	80.0

4.1 THE DUTCH HEATING SYSTEM

To study the impact of heat pumps, district heating, seasonal heat storage and P2H conversions 5 scenarios in which the heating system differs are developed. All these scenarios are further refined for the years 2030 and 2050, resulting in a total of 10 scenarios. First, a distinction is made between a dominant heat pump scenario and a dominant district heating scenario (HP and DH, respectively). In the DH scenarios, the options of seasonal thermal energy storage (STES) and electric boiler (P2H) connected to the district heating are added separately and together.

Furthermore, baseline scenarios for both 2030 and 2050 are constructed. In these scenarios, the heat sources are kept constant from 2015 onwards. However, the electricity system is assumed to become increasingly renewable as in the other scenarios. The resulting scenarios and their main properties are shown in Table 5.

Table 5. Overview of the various heat scenario and their properties

#	Scenario name	Year	Dominant heat source	STES	P2H
1	2030-HP	2030	Heat pump	-	-
2	2050-HP	2050	Heat pump	-	-
3	2030-DH	2030	District heating	-	-

[18] The CO_2 price is given in €/tCO_2.

#	Scenario name	Year	Dominant heat source	STES	P2H
4	2050-DH	2050	District heating	-	-
5	2030-DH-STES	2030	District heating	✓	-
6	2050-DH-STES	2050	District heating	✓	-
7	2030-DH-P2H	2030	District heating	-	✓
8	2050-DH-P2H	2050	District heating	-	✓
9	2030-DH-STES-P2H	2030	District heating	✓	✓
10	2050-DH-STES-P2H	2050	District heating	✓	✓
11	2030-BASE	2030	Gas boiler	-	-
12	2050-BASE	2050	Gas boiler	-	-

4.1.1 Demand

Only the heat demand of households and utility buildings[19] is considered in this study. This heat demand is assumed to consist solely of space heating (SH) and domestic hot water (DHW). To determine the total annual demand in 2030 and 2050 it is assumed that the demands of households and utility buildings, as given by Agentschap NL (2013), decreases at the same rate as is predicted for the heat demand excluding industry by Greenpeace & EREC (2013). This decrease comes down to -21% in 2030 and -47% in 2050 compared to 2010. The resulting heat demands can be found in Table 6, along with other estimates found in literature. The heat demand profile used by Ecofys (2016a) was then scaled to match to annual heat demand. The demand profile of all households and utility buildings for the first 250 hours in the year are shown in Figure 6.

Table 6. Current and future Dutch final heat demand in PJ. The terminologies of the consulted reports differ. It is assumed that utility and services are the same group of heat consumers and that households and utility only use heat at a temperature below 100°C (T<100).

2006	2010	2030	2050	Source	Share of heat
-	1,150	950	750	(Greenpeace & EREC 2013)	Total
-	760	600	480	(Greenpeace & EREC 2013)	Excluding industry
1,093	-	-	-	(ECN 2009)	Total
628	-	-	-	(ECN 2009)	Only T<100
486	-	-	-	(ECN 2009)	Only households and services
-	388	-	-	(Agentschap NL 2013)	Only households
-	258	-	-	(Agentschap NL 2013)	Only utility
-	1,324	-	-	(Agentschap NL 2013)	Total
		306	**245**		**Used in this study households**
		204	**163**		**Used in this study utility**

[19] Utility buildings are: offices, stores, education buildings, hospitals and nursing homes (Agentschap NL 2013).

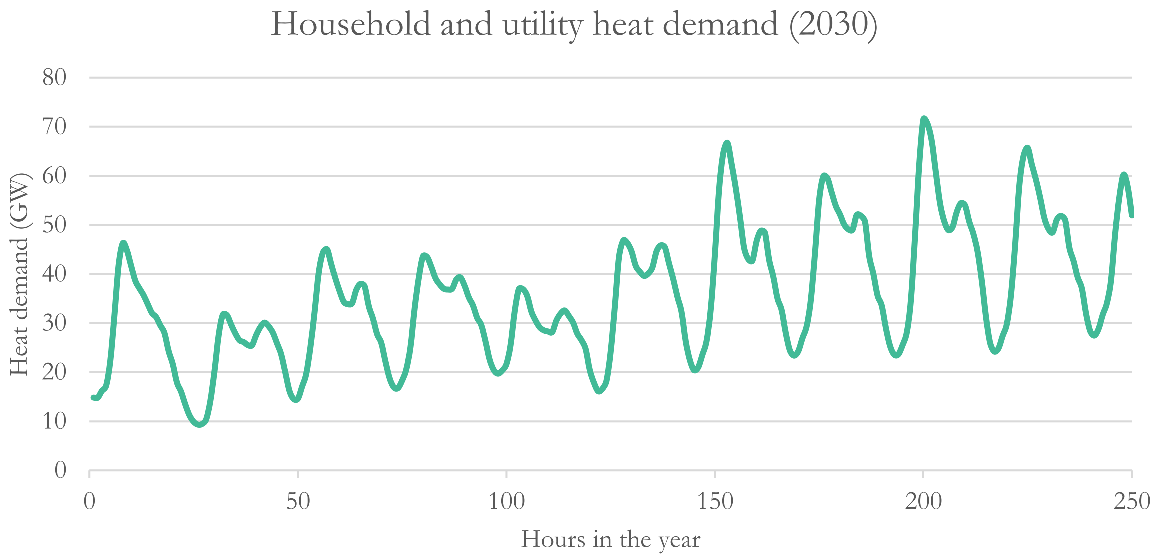

Figure 6. The first 250 hours of heat demand profile in the year (winter).

4.1.2 Supply

The supply of the heat to the end-users is assumed to be fulfilled by one of three sources: high efficiency domestic gas boilers, district heating or heat pumps. The district heating, in its turn, is supplied by various sources of heat. Currently, almost all households and utilities are heated by a domestic gas boiler and a small share is heated by district heating. However, in a sustainable energy future, the amount of domestic gas boilers will rapidly reduce and a larger share of the heat demand will be fulfilled by heat pumps and district heating. Additionally, the heat supply of the district heating will also change towards more sustainable sources. The shares of households and utility buildings heated by the various heat sources are based on the 'Urgency' and 'Technology adaptation' scenario by Ecofys (2016b) and are shown in Figure 7.

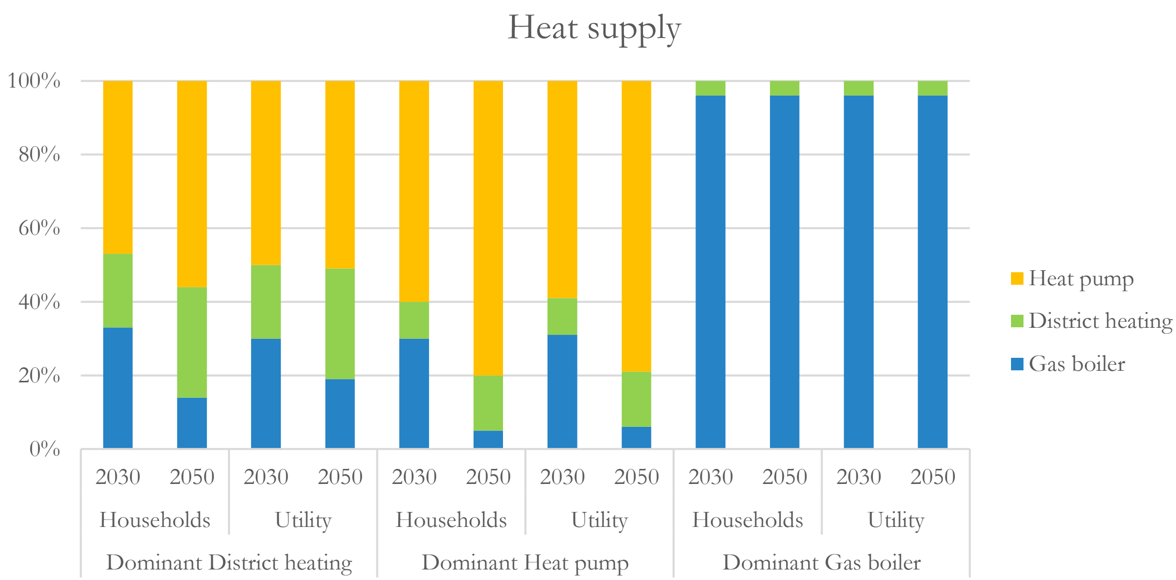

Figure 7. Share of heat demand filled by heat source, based on Ecofys (2016b)**.** The dominant district heating scenario is the 'Urgency scenario', the dominant heat pump scenario is the 'Technology Adaptation scenario'. The different types of heat pumps in the original Ecofys report are aggregated for this study.

4.1.2.1 District heating

The emissions, flexibility and costs of the DH system depend on the sources that provide the heat for the DH and the transport of heat in the network. It is assumed that the heat transported by the DH suffers from losses of 15% (Ecofys 2016a). The sources supplying the heat are discussed below.

Currently, a considerable share of heat supplied to DH is generated by CHP units (CE Delft 2009). The amount of CHP units in the scenarios is based on the developments in the electricity system (see section 4.2). The share of CHP units in gas-fired generation is assumed to increase towards 2050. It is assumed that the CHP plants have a thermal output equal to the electric output.

Sources of waste heat were connected to the DH network. Some of these waste heat sources are at a low temperature and need to be upgraded by a heat pump. Waste heat sources at higher temperatures are directly connected to the district heating grid. Examples are the waste heat from data centres and supermarkets at around 35°C (Roossien & Elswijk 2014) and waste heat from industry at 100°C, respectively. In reality, the available waste heat is of course more differentiated. Due to a lack of data it is assumed that the available waste heat is split fifty-fifty between supermarkets and industry. The total potential of waste heat which can be utilised in the Netherlands is estimated at 57 PJ annually (CE Delft 2011). Waste heat sources are mainly limited by their distance to the district heating (CE Delft 2011). Therefore, it is assumed that the share of waste heat can be utilised is higher when DH is deployed among more household and utility buildings. After all, the waste heat potential cannot be unlocked without a district heating network in the vicinity. In the DH scenarios, the utilised share of the waste heat potential is 25% and 33% in 2030 and 2050 respectively. In the HP scenarios, the utilised share is 13% and 17% respectively. No waste heat is utilised in the baseline scenarios. The potential calculated by CE Delft (2011) does not consider the economic feasibility of using these waste heat sources. Additionally, the amount of available waste heat may decrease due to improvements in energy efficiency in e.g. industrial processes.

Deep geothermal heat can supply a large share of the district heating in 2030 and 2050. Based in the low estimation of geothermal heat availability by the PBL (2011), it is assumed that 10 PJ and 25 PJ of geothermal heat are available per year in 2030 and 2050 respectively. Similar to the argumentation above, the geothermal heat should be obtained close to a DH network. Therefore, it was assumed that the potential in 2050 will only be 20 PJ. Since the model needs (heat) production capacities as input, these figures are converted to installed capacities under the assumption that the geothermal heat plants will provide heat at full capacity throughout the year. For the district heating scenarios, this is 4110 MW in 2030 and 8219 MW in 2050.

Finally, the resulting heat demand will be fulfilled by district heating boilers fired by either gas, biomass or electricity. Furthermore, electricity boilers are assumed to supply to district heating in the appropriate scenarios. These boilers are assumed to have the same capacity as the peak capacity of the district heating network. Thereby, these boilers can provide significant flexibility for the electricity system.

4.1.2.2 Heat pumps

The heat pumps in both 2030 and 2050 are assumed to be air-water heat pumps. Since these heat pumps extract heat from the air, the COP of the heat pumps is strongly dependent on the outside air temperature. The COP of a heat pump is assumed to respond to outside air temperature as shown in Figure 8 below in 2030 (Ecofys 2013). Whenever a heat pump has a lower or higher maximum COP, this profile is scaled down or up accordingly. In 2050 the maximum COP for household heat pumps is assumed to be 7, based on historical improvements in COP described by Eschmann (2012). During cold periods a built-in backup resistance heating unit is assumed to take over and provide heat at 100% efficiency (Ecofys 2014). Heat pumps are often only installed in combination with a low temperature (LT) heating system and good insulation. Therefore, the heat pump only bridges a relatively small temperature difference resulting in a higher COP. Other effects of LT heating and better insulation are not considered in this study. The installed capacity of heat pumps is assumed to be the same as the peak demand that needs to be fulfilled by the heat pumps.

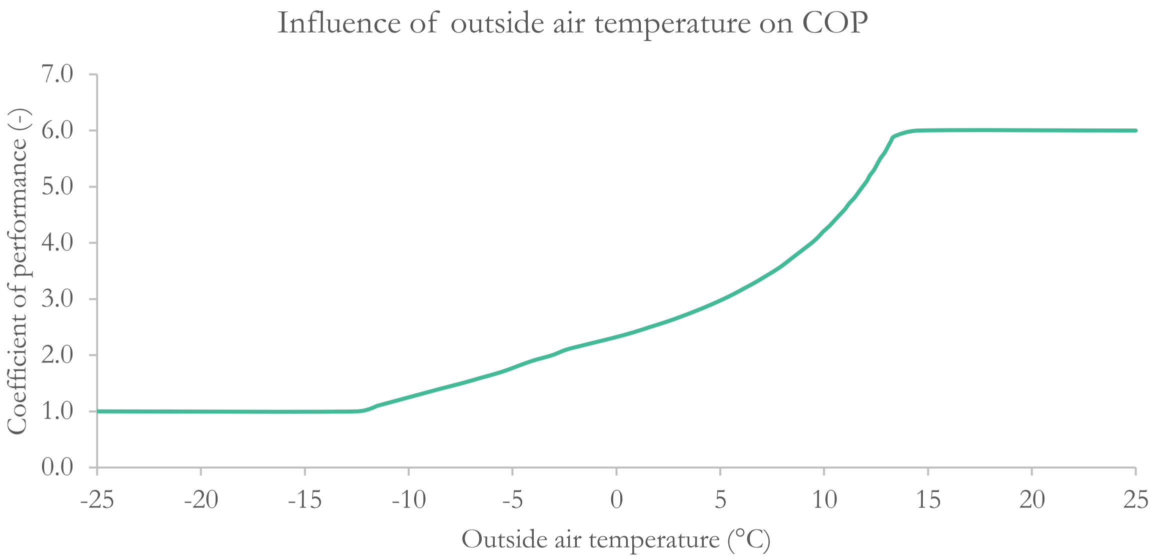

Figure 8. COP vs. temperature of a heat pump with a maximum COP of 6 (Ecofys 2013)**.** For less or more efficient heat pumps the same graph will be scaled down or up to the maximum COP.

4.1.2.3 Domestic gas boilers

For the years 2030 and 2050 it is assumed that all installed boilers are highly efficient condensing boilers. The economic lifetime of a domestic gas boiler is 20 years (Melorose et al. 2014), consequently it can be assumed that the inefficient boilers installed today will be replaced by 2030. The efficiency of the boilers is assumed to be 91% (LHV) for SH and DHW combined (Cockroft & Kelly 2006). The capacity of gas boilers is set equal to the peak capacity which they need to fulfil.

4.1.2.4 Overall supply of heat

The complete installed capacity in the Netherlands for all scenarios based on the method described above is shown in Figure 9. The data can also be found in appendix 10.5. In this figure the generation capacities and peak demand are shown for the three separate heating systems combined (heat pumps, gas condensing boilers, district heating).

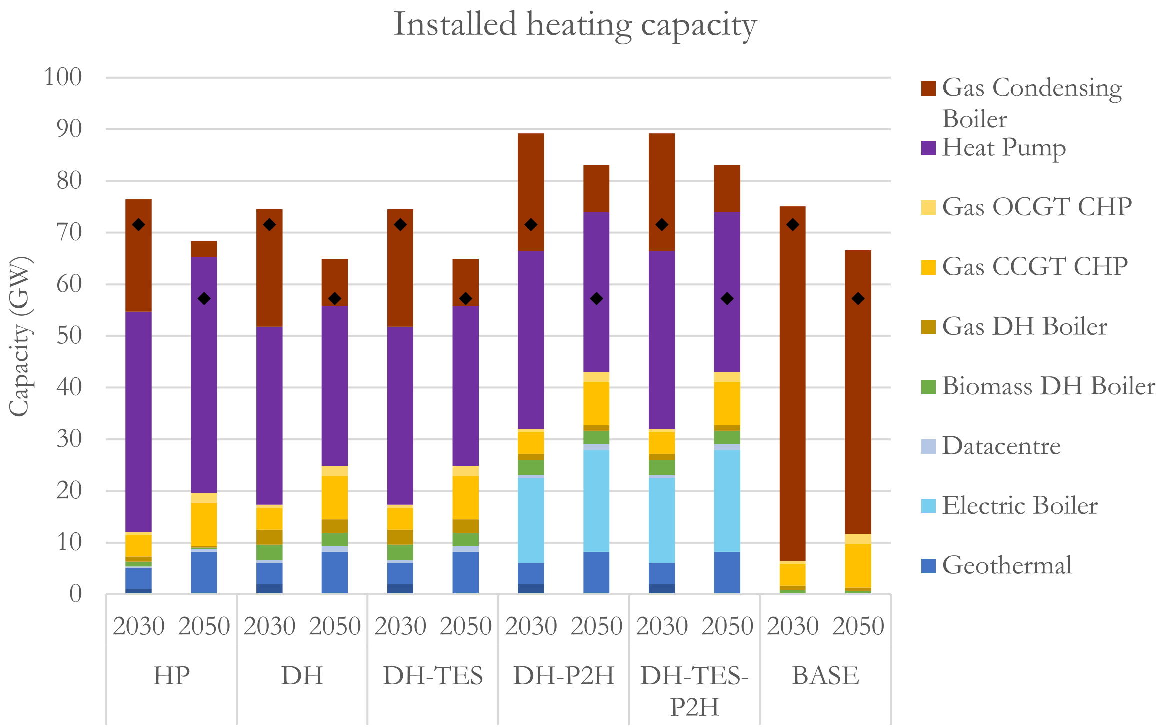

Figure 9. Installed heat capacity in the Netherlands for all scenarios.

4.1.3 Seasonal storage

The large advantage of heat over electricity is that it is simply and cheaply stored. Therefore, heat storage plays an important role in the research. Generally, heat can be stored in three forms: (1) chemical; (2) latent; and (3) sensible (Pinel et al. 2011). In this study sensible heat storage is chosen because this technology is well demonstrated and already widely used (Pinel et al. 2011).

The size of the STES was assumed to be 2.5 TWh in 2030 and 3.0 TWh in 2050, 7.7% of the total heating demand in the district heating system. This would mean roughly 595 water pits of 60,000m^3 in 2030 and 714 of these pits in 2050. Such a water pit was built in 2010 in Denmark (Energinet.dk 2012). The deployment of these water pits would be enormous towards 2030 and 2050. But the fact that such a water pit is already built, shows that the technology is ready.

The predicted charge/discharge profile of the STES was assumed to be perfect. I.e. the heating demand for scenarios including an STES stays perfectly in between a lower and a higher value. The original heat demand (2030-DH) and the heat demand including STES (2030-DH-STES) are shown in Figure 10. All peaks and valleys in heat demand are ‘shaved’ and ‘filled’ by charging and discharging the STES. The lowest remaining heat demand was chosen at 13% of original peak demand (i.e. without STES) and the highest remaining heat demand was set at 43% of the original peak demand. This results in the fact that the total heat demand increases with 2% relative to the original heat demand (i.e. without STES). This increase in total heat demand accounts for heat losses from the STES.

The perfect profile might be unrealistic since temperature (and therewith heat demand) cannot be perfectly predicted for the whole year. However, knowledge on general daily trends (peaks in heat demand during the morning and evening) and seasonal trends (more heating during winter than summer) can be identified from the heat demand profile (see Figure 6). Accordingly, it is possible that the predicted charge profile can be similar to this perfect charge profile.

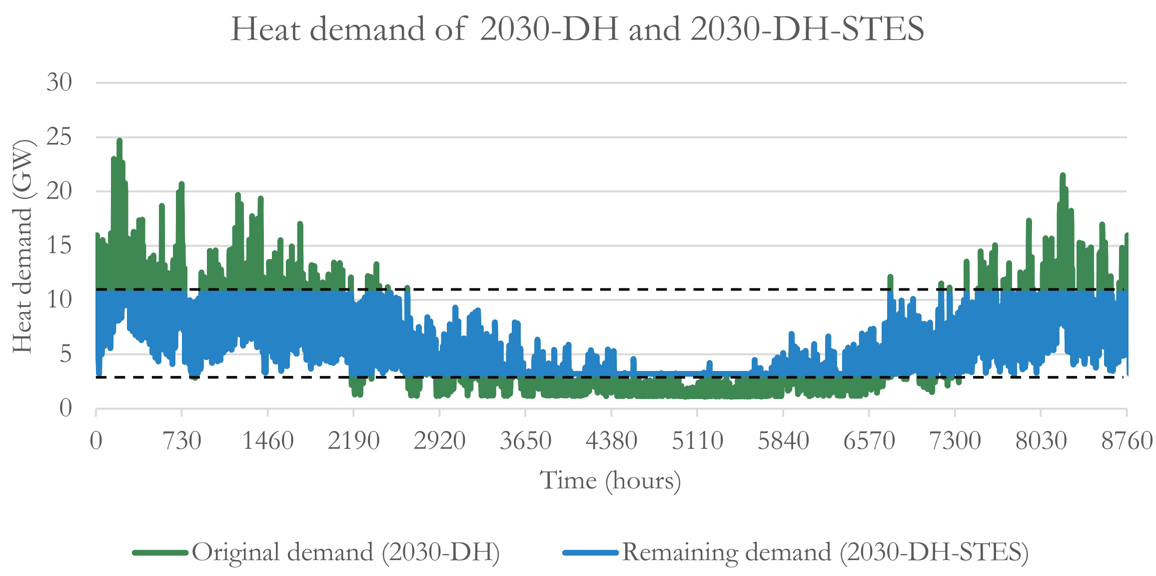

Figure 10. Adjustments to the heat demand in scenarios with a STES. When the original demand is below 13% of the original peak demand, the demand including STES stays at 13% percent and vice versa for the 43% of the original peak demand. This changed demand mimics charging and discharging the STES respectively.

4.2 THE FUTURE ELECTRICITY SYSTEM

The focus of this study is on the Netherlands. However, the neighbouring countries of the Netherlands were also considered. The electricity exchanges between these countries are considerable and therefore have a large impact on the developments in the electricity system. The neighbouring countries that were modelled are Denmark (DK), Germany (DE), Belgium (BE) and Great Britain and Ireland (GBI)[20].

4.2.1 DEMAND

The hourly demand in the Netherlands is based on the demand profile used in a previous Ecofys study (2016a). The load profile is further refined by adding the load profile for electric vehicles (EVs). It is assumed that the charging of the EVs mainly takes place during the night. The aggregated charge profile of EVs is shown in Figure 11 (left graph) and is based on Verzijlbergh (2013). The total amount of EV is assumed to be 3 million in 2030 and 5.5 million in 2050, 42% and 75% (Verzijlbergh 2013) of the (current) Dutch car fleet (CBS 2016b). EVs are assumed not to act as demand response options. The resulting total Dutch electricity demand for the first 250 hours of 2030 is shown in the right graph in Figure 11.

The hourly electricity demand in the neighbouring countries is based on a dataset that was used for an Ecofys project before (Ecofys 2016c). No further refinements were made to these demand profiles. All profiles were scaled to match the total annual electricity demand as assumed in this study.

Multiple studies suggest that the electricity demand will keep increasing towards 2050 (Greenpeace & EREC 2013; Brouwer et al. 2015; McKinsey 2010). The increased electrification of the energy demand will have a larger effect than the efficiency improvements and thus the electricity demand will grow (EC 2012). The demand profile is scaled upwards based on a 0.8% annual increase in

[20] I.e. Great Britain and Ireland are modelled as one node.

electricity demand in order to capture this effect. This 0.8% annual increase is the growth rate assumed by Brouwer et al. (2015) in the Global Union scenario. Similar to growth rates are expected in other studies (McKinsey 2010; Greenpeace & EREC 2013). In the 'Global Union' scenario it is assumed that climate policies develop ideally, aiming to limit global warming to less than 2°C.

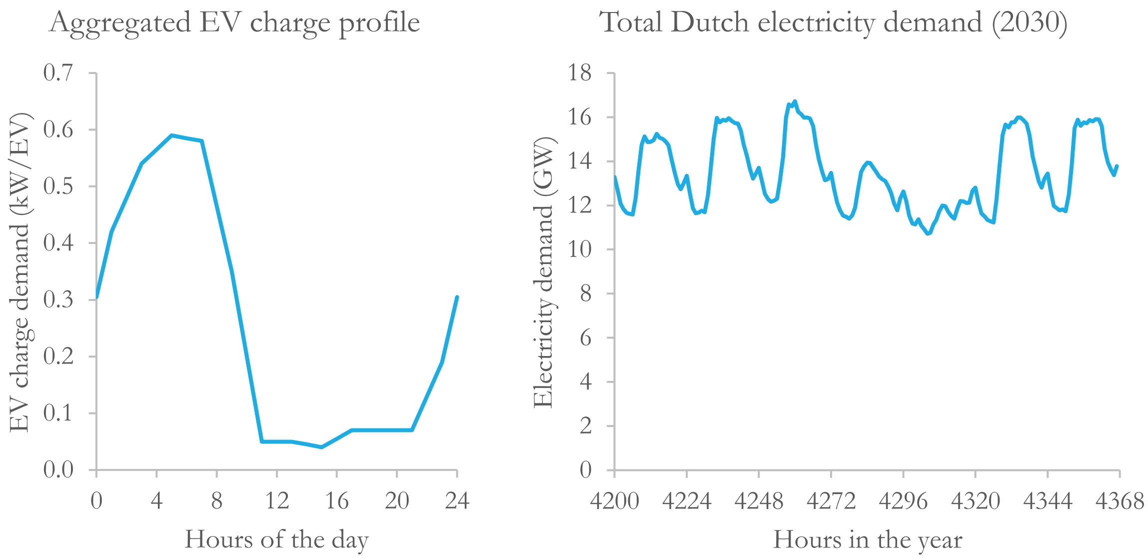

Figure 11. Aggregated charge profile of EVs (Verzijlbergh 2013) during one day and the total Dutch electricity demand for one week starting at hour 4200 (summer).

The total electricity demand for the Netherlands with the highest assumed deployment of heat pumps is estimated at 143 TWh in 2030 and 168 TWh in 2050. However, part of the increased electricity demand will be induced by the heating with heat pumps. Because heat pumps fall within the scope of this research, the electricity demand for heat pumps should be excluded from the exogenous defined electricity demand. As the electricity demand for heat pumps is not included in the demand profile, the shape of the abovementioned profile is still applicable.

The Dutch electricity demand excluding the demand for heat pumps is based on several assumptions: (1) the heat demand in 2030 and 2050; (2) the share of households and utility buildings with a heat pump; and (3) the average seasonal COP. The average seasonal COP is assumed to be 4.0 in 2030 and 4.5 in 2050[21]. These values were assumed based on the average COP over the year weighted according to the heat demand. The electricity demand excluding the demand for heat pumps was set equal among the scenarios. As a consequence, in scenarios with a lower deployment of heat pumps, the total demand is lower.

The values shown in Table 7 for the Netherlands are for the scenarios in which heat pumps are dominant (HP), in which district heating is dominant (DH) and the baseline scenarios (BASE). The peak demands in Table 7 are the exogenous defined demands. Because the exogenous defined demands are equal among all scenarios, the peak demands are also equal among the scenarios. Additional demand from P2H dispatch might increase the actual peak demand in the Netherlands.

[21] Analysis of the dispatch of heat pumps after running the model showed that the seasonal COP of heat pumps was indeed 4.0 in 2030 and 4.7 in 2050.

The annual electricity demand in Table 7 is an estimation which was used to predict how much larger the generation capacity would need to be with a changing deployment of heat pumps.

Table 7. Annual electricity demand for the considered countries. The levels for 2030 and 2050 are based on an annual 0.8% increase in total demand compared to the base level of 2008, taken from Fraunhofer (2011). Note that the peak electricity demand is the exogenously defined peak demand, for the Netherlands this might be higher in the model run due to P2H dispatch.

Country	Annual electricity demand (TWh)		Peak electricity demand (MW)	
	2030	2050	2030	2050
NL (HP)	143	168	18.9	22.3
NL (DH)	139	160	18.9	22.3
NL (BASE)	122	140	18.9	22.3
DK	43	50	7.6	9.0
DE	663	777	102.9	120.7
BE	107	126	17.7	20.7
GBI	471	552	81.0	95.0

4.2.2 Supply

The electricity supply will be fulfilled by both renewable electricity sources and conventional electricity sources. In line with the report by Fraunhofer (2011) the only conventional electricity generation in 2050 will be gas fired. In the years leading to 2050 the other types of conventional capacity, such as nuclear and coal, decrease rapidly in Europe (Fraunhofer 2011).

Non-controllable renewable electricity generation profiles were derived from a previous Ecofys study (2016c). The electricity demand in this study is assumed to be higher compared to the Ecofys study. Therefore, increased generation from renewable sources is also required. The renewable electricity capacities are increased linearly with the electricity demand.

There was one exception to this methodology. The resulting onshore wind energy capacity for the Netherlands would be multiple times the technological potential for onshore wind in the Netherlands (PBL 2011; Hoefnagels et al. 2011). On the other hand, the offshore wind energy capacity would be well below its potential. Hence, in 2050, the onshore wind capacity is held to the 2030 levels, while extra offshore wind capacity is assumed. The increase in offshore capacity is slightly smaller compared to the decrease in onshore capacity, accounting for the fact that offshore wind turbines usually have a higher capacity factor.

The fossil generation capacity was based on recent data on the installed capacity and the percentage change in capacity per fuel over the whole of Europe, as calculated by Fraunhofer (2011). It is assumed that the same percentage change as for the whole of Europe also takes place in the modelled countries, e.g. a 20% increase in gas-fired generation in Europe towards 2030 is assumed to also increase the gas-fired generation in the five modelled countries by 20% compared to the base year. Furthermore, it is assumed that 61% of the gas capacity are combined cycle gas power plant (CCGT). The remaining gas power plants are open cycle gas turbines (OCGT). The data on which this method was based is given in appendix 10.3.

Finally, for each country, the exogenous defined electricity demand and the time series of renewable generation were analysed together to find the amount of electricity that still needs to be generated by fossil generation, the residual load. The previously calculated generation capacities of the fossil generation are scaled to match the maximum residual load. Thereby it is assured that no infeasibilities, i.e. blackouts, occur during the model run. The residual load is, also in 2050, still a considerable share of the demand. When the aim is a fully renewable energy system in 2050, additional efforts such as further energy efficiency, additional renewable generation capacity and/or further flexibility options are required.

For the Netherlands, the CCGT, coal, lignite and nuclear power plants were assumed to have a maximum capacity of 700 MW (Brouwer et al. 2015). The other category was assumed to be waste incineration CHPs of 150 MW each. The OCGT plants were also assumed to have a capacity of 150 MW each. If the total capacity could not be exactly fulfilled by these power plants, one power plant with a slightly higher or lower capacity was assumed. About 60% of the currently installed gas-fired power plants are CHP plants (Frontier Economics 2015). This share of CHP plants within the gas-fired power plants is assumed to remain constant for the years 2030 and 2050.

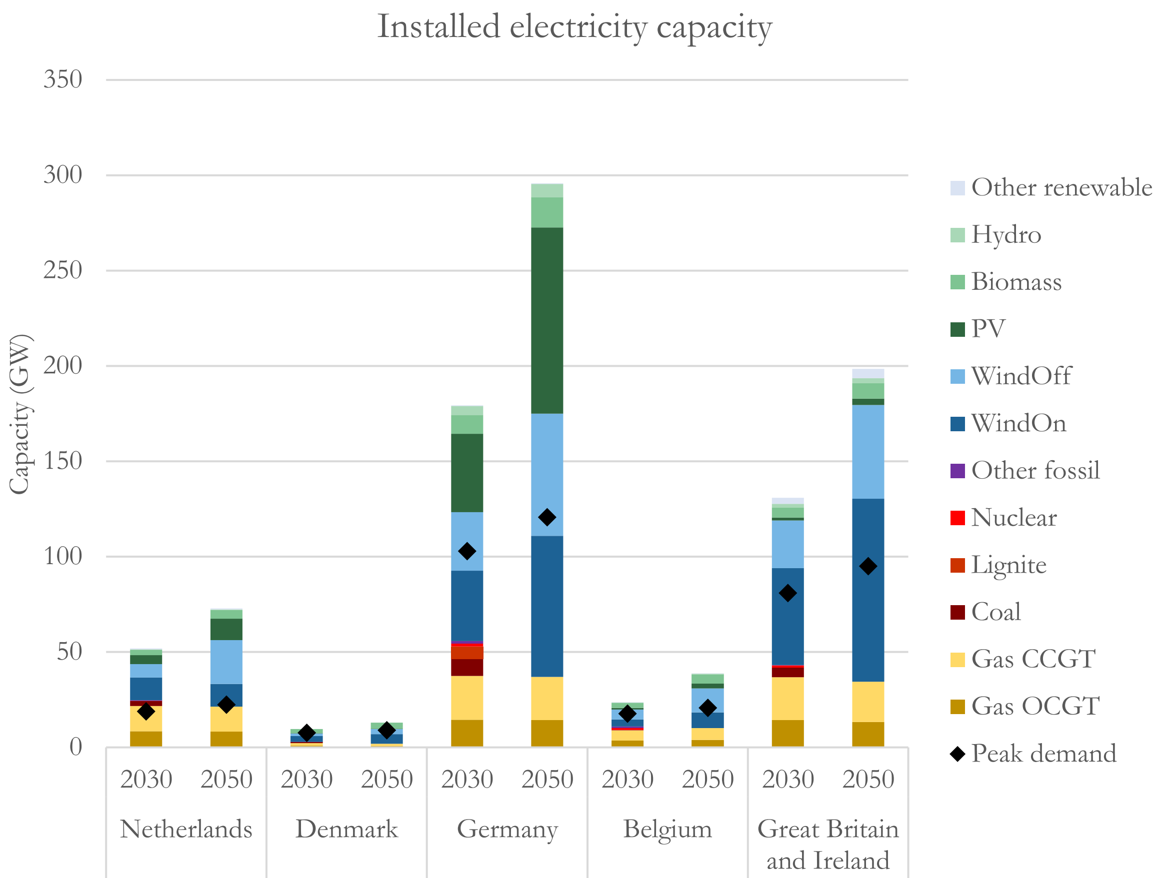

Figure 12. Installed generation capacity and the peak demand assumed for the 2030-HP and 2050-HP scenario. The generation capacity in the Netherlands is marginally smaller for the other DH scenarios. The peak demand is the peak in exogenously defined demand. In the Netherlands, the actual peak can be higher due to the dispatch of heat pumps and/or other P2H options.

The setup of the neighbouring countries was similar to the setup for the Netherlands described above. However, it was more simplistic to keep the calculation time within bounds. The total capacity of each technology was modelled as one large power plant. It would be possible to shut down multiple of these similar power plants but still have a few of them running. Therefore, this aggregated power plant was modelled with a considerably lower minimum generation capacity. Furthermore, a considerable battery storage with twice the size of the maximum hourly load was included in these countries to mimic the flexibility options that will arise in these countries. The resulting installed generation capacities for the five countries in both 2030 and 2050 are shown in Figure 12. The data is also given in appendix 10.4.

Finally, the relevant technical parameters were based on Brouwer et al. (2015), the Danish Energy Agency (Energinet.dk 2012) and VGB (2011). Small improvements in power plant efficiencies are expected to develop from 2030 up to 2050. The parameters are presented in appendix 10.6.

4.2.3 Transmission capacity

The interconnection capacities between the five considered countries are based on the modelling result of scenario A by Fraunhofer (2011). However, as a higher electricity demand is expected, the transmission capacity is also assumed to be higher. The extent to which the demand was assumed higher in this study compared to Fraunhofer is multiplied by the transmission capacity. This was done per transmission connection. The average demand increase between the two countries connected by the transmission connection was multiplied with the capacity predicted by Fraunhofer (2011). The resulting transmission capacities are shown in Table 8. It should be noted here that the expected transmission capacities in 2030 and 2050 differ considerably between various sources (Brouwer et al. 2015; Frontier Economics 2015).

Table 8. Net transmission capacities between the considered countries in 2030 and 2050 (MW). It is assumed that the net transmission capacity is similar in both directions.

From	**NL**	**NL**	**NL**	**NL**	**DK**	**DE**
To	**DK**	**DE**	**BE**	**GBI**	**DE**	**BE**
2030	1,006	4,913	5,276	3,699	1,893	0
2050	5,041	20,079	7,167	12,974	5,604	2,185

5 Results

Based on the results of the PowerFys model and the separate cost model, the overall costs as well as the emissions can be compared between the scenarios. The desirability of the scenarios can be based on the system costs and emissions presented below. The results are mainly presented as a comparison with the baseline results. The absolute results of the baseline scenario are always presented alongside. Furthermore, the absolute values of the results are also presented in the appendixes 10.7-10.9.

5.1 Scenarios in 2030

In the 2030 baseline scenario, the system costs of the Dutch heating system for household and utility buildings and the complete electricity system for the five modelled countries costs 90.2 billion € annually (Figure 13). The largest shares are the costs for generation unit investments and the variable operation and maintenance costs (VO&M). The fixed operation and maintenance costs (FO&M) and infrastructure investments only contribute marginally to the total costs. Start-up and shutdown costs are even less than 1% of total costs. The exact figures can be found in appendix 10.7-10.9. The total system costs for the Netherlands are 15.1 billion € annually[22].

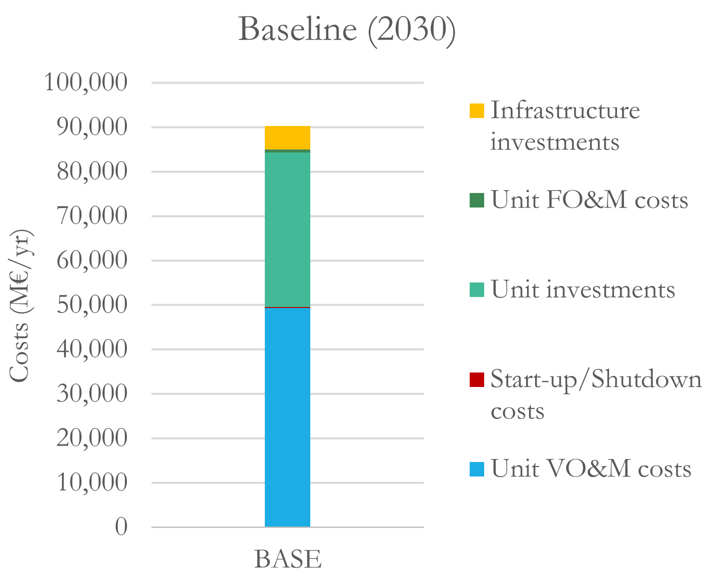

Figure 13. Baseline system costs in 2030.

Compared to the baseline scenario, additional investments in generation units and infrastructure are required in all other scenarios. Ceasing operation of old infrastructure (gas grid) leads to savings, but additional investments in district heating and the electricity grid lead to an overall increase in infrastructure costs. The FO&M costs and start-up and shutdown costs increase. These increases are, however, small for each scenario. The VO&M costs decrease considerably. Nonetheless, the total system costs are all comparable to the baseline scenario. The total system cost changes vary between -102 M€/yr and 338 M€/yr. These costs are less than 1% of the total system costs considered in this research, they also are below 3% of the Dutch system costs. It is important to note here that the changes in costs can only be attributed to changes in the Dutch

[22] This and further results as presented for the Netherlands, are rough estimations of total system costs. All countries are interconnected in the model. Import and export of electricity might have influenced the total system costs per country.

heating systems (district heating, heat pumps and gas boilers) while the total system costs comprise the costs for the electricity system of all five modelled countries and the Dutch heating system combined. Therefore, the impact of the changes in all scenarios is relatively small.

The 2030-HP scenario is the scenario with the lowest system costs. Little additional infrastructure costs and large reductions in the VO&M costs make this scenario the most preferable. The differences between the more expensive DH scenarios are also considerable. The high investment costs for only a STES result in only a small decrease in operational costs, resulting in higher system costs. The P2H installations connected to the district heating lead to higher peak demands on the electricity grid and thus to higher infrastructure costs[23] and overall system costs. However, when STES is combined with P2H, the system costs go down compared to the 2030-DH scenario.

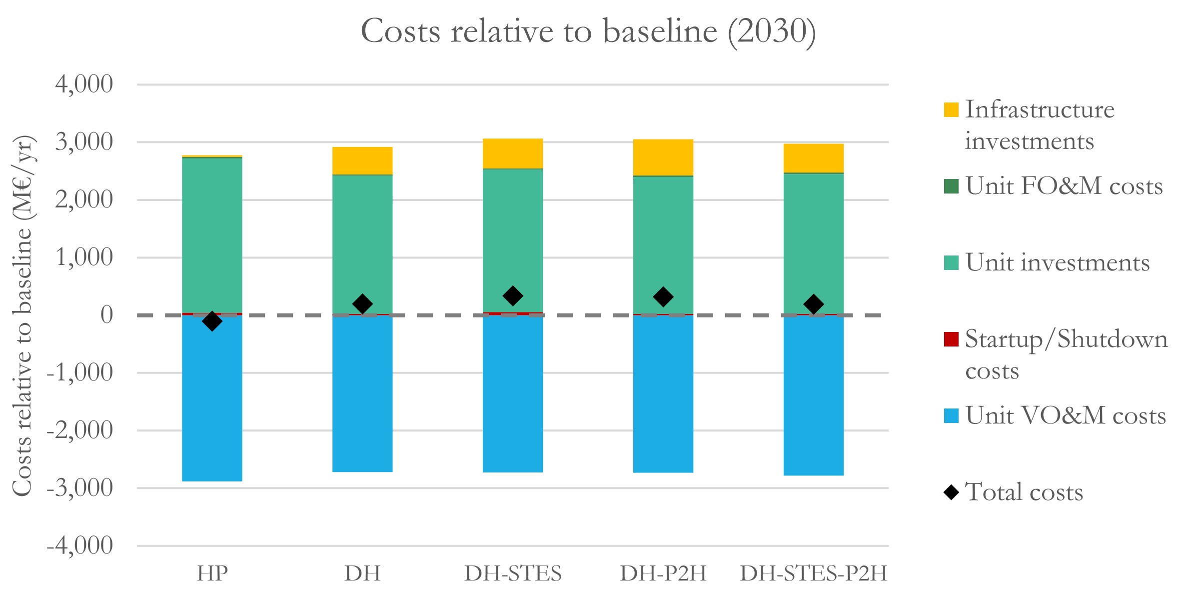

Figure 14. Costs relative to baseline per scenario in 2030. Costs factors below the zero line are a decrease in comparison to the baseline. The black diamonds (total costs) are the combination of all cost factors.

The process of how the usage of electric boilers installed at the district heating results in a higher electricity peak demand is illustrated in Figure 15. The upper two graphs in Figure 15 show that at peak heat demand the P2H plant is used in the 2030-DH-P2H scenario (right), where this is not the case for the 2030-DH scenario (left). The dispatch of the P2H units results in a higher electricity demand in the 2030-DH-P2H scenario. The increase in electricity is best visible in the hours 200-220. However, the electricity demand also increases in hours where the electricity demand was already high in the 2030-DH scenario. Especially when the electricity demand without P2H is already high, an electricity demand increase due to electric boilers leads to higher peaks on the electricity grid.

[23] It is debatable whether the whole electricity grid would need extra investments due to these increased peaks resulting from centralised P2H installations. It might be the case that the electricity can be delivered to the P2H installations with smaller infrastructure investments. Consequently, the total system costs might be lower.

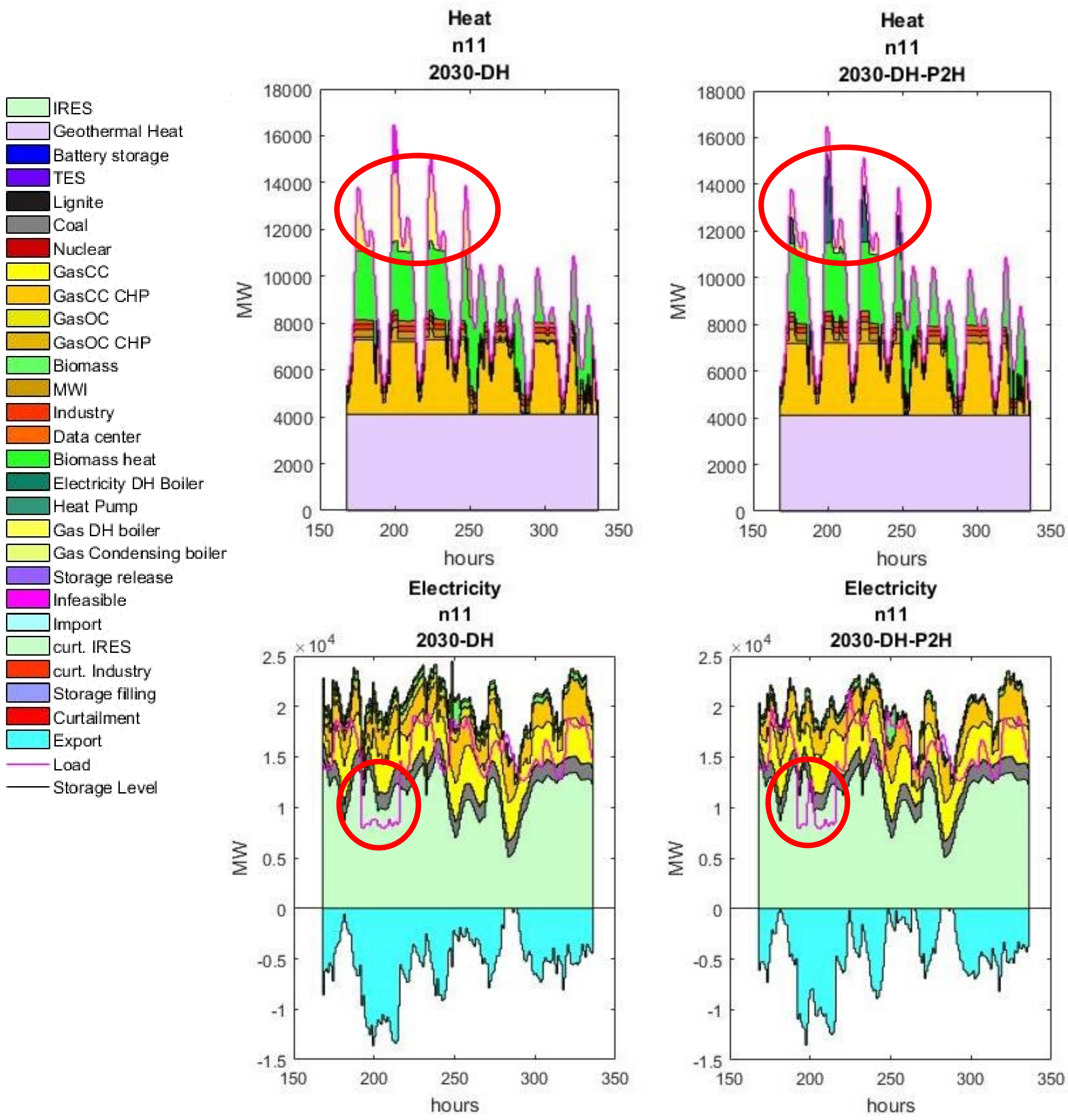

Figure 15. Effect of P2H in winter. The top two graphs show the heat demand for district heating while the lower two graphs show the total Dutch electricity demand. The two graphs on the left are from the 2030-DH scenario while the two graphs on the right are from the 2030-DH-P2H scenario. In the top right graph the peak heat demand (red circle) is supplied by the electric boiler while in the top left corner the peak demand is supplied by a gas peak boiler. The difference in electricity demand can be seen best in the red circles in the lower to graphs.

In Figure 15 it can also be seen that the baseload of the heat demand is fulfilled by geothermal heating. CHP dispatch is adapting flexibly to both the heat and electricity demand as well as the renewable electricity production. Currently, CHPs are the main providers of heat to district heating in the Netherlands. Therefore, the CHPs must provide heat when demanded and consequently also produce electricity. This can also happen at moments with already sufficient electricity production. Therefore, CHP units can be viewed as must run capacity, when only considering the electricity system. However, the way that CHP units are modelled in this thesis no longer require them to be modelled as must-run capacity in the electricity network. Since the heat demand can also be fulfilled by other sources of heat, CHP units are also no longer dispatched as must run capacity. The capacity factor for heat is only at around 8% over the whole year, the capacity factor for electricity is around 50%.

It should be noted here that the capacity factors are determined on the basis of the maximum capacity. However, the CHP units in this model cannot provide their maximum capacity of heat and their maximum capacity of electricity at the same time. Therefore, the capacity factor for CHP units can never be 100% for both heat and electricity.

Curtailment of renewable energy production exists in all scenarios. In the baseline scenario, 641 GWh of renewable electricity production is curtailed. All scenarios have less curtailment than the baseline scenario, see Figure 16. The amount of curtailment reduction is only a small share of renewable electricity, below 1% of the total generation of renewable electricity. In the Netherlands, 2 GWh of curtailment takes place. However, since this is only a small amount, the import and export of renewable electricity between the modelled countries can influence this number considerably.

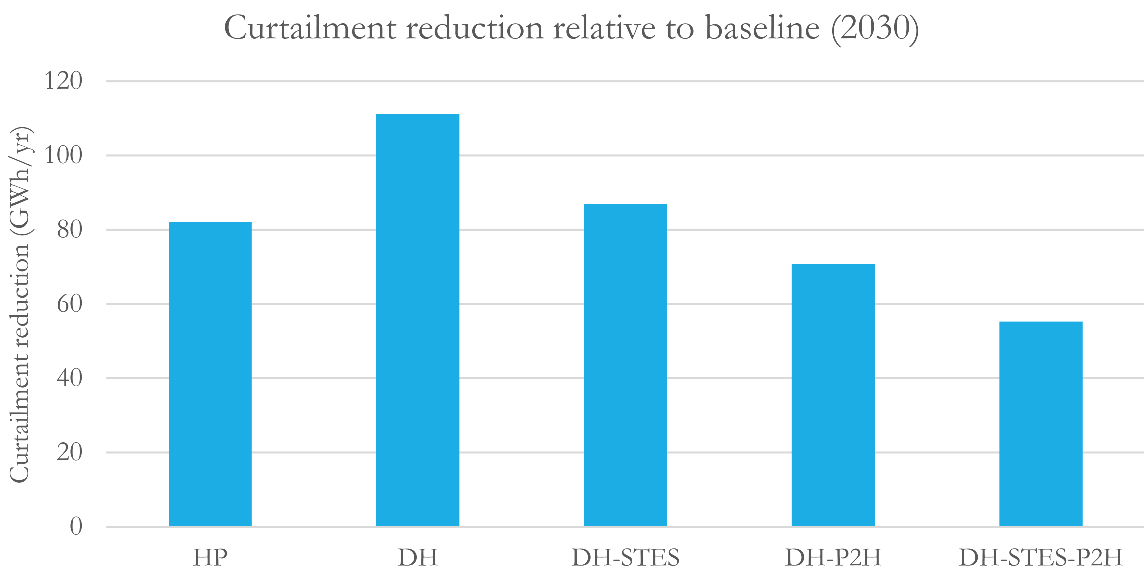

Figure 16. Electricity curtailment reduction in 2030.

The total emissions in the baseline scenario are 347.1 $MtCO_2$/yr, of these, 57.2 $MtCO_2$/yr are emitted in the Dutch heating and electricity system[24]. All scenarios result in considerable emission savings of around 15 $MtCO_2$/yr compared to the baseline scenario (Figure 17). The 2030-DH-STES-P2H scenario results in the highest emission savings, closely followed by the 2030-HP scenario. Both the P2H units and the STES increase the amount of emission savings. Geothermal heat production requires only a small amount of electricity and therefore a small amount of CO_2 emissions. Because valleys in the heat demand do no longer exist with a STES, the geothermal heat can achieve a higher capacity factor.

[24] For comparison, the current Dutch emissions from energy companies and the built environment are 78 $MtCO_2$/yr (CBS 2016a).

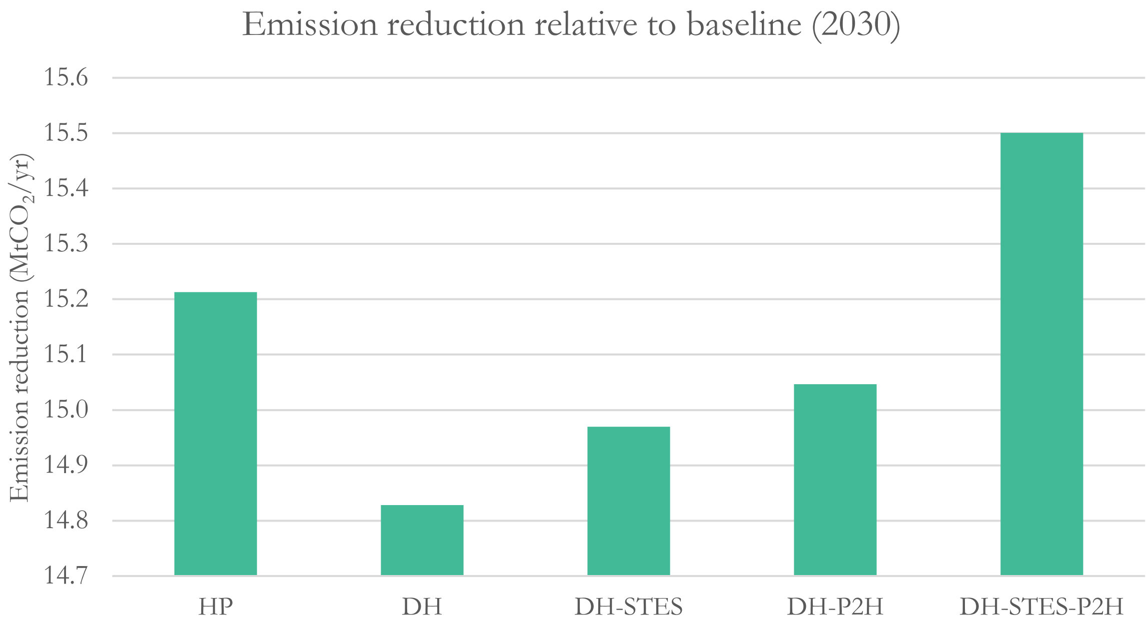

Figure 17. Emission reduction relative to baseline per scenario in 2030.

Although all scenarios reduce CO_2 emissions, all district heating scenarios also result in higher system costs. The difference between costs and emissions can be expressed as abatement costs. The abatement costs for the DH scenarios (these are the only scenarios which have higher costs and lower emissions compared to the baseline) are shown in Table 9. In general, if the CO_2 emission rights were increased from 35 €/tCO_2 with the abatement costs in each scenario, the scenario would have the same system costs as the baseline scenario. However, since increases in the price of emission rights would also change the position of the different technologies in the merit order. Therefore, the dispatch choices made in the model might also change and the actual emission reduction could be different.

Table 9. CO_2 abatement costs for the district heating scenario.

Scenario	Abatement costs (€/tCO_2)
DH	13.65
DH-STES	22.55
DH-P2H	21.30
DH-STES-P2H	12.39

5.2 Scenarios in 2050

The baseline scenario in 2050 has a similar cost breakdown compared to the 2030 baseline scenario. Total system costs have increased to 94.0 billion euro annually. The VO&M costs and the unit investments still constitute the majority of the system costs. Nonetheless, the unit VO&M costs decreased considerably compared to 2030. All other cost factors increase towards 2050. The total system costs within the Netherlands are 14.0 billion € annually.

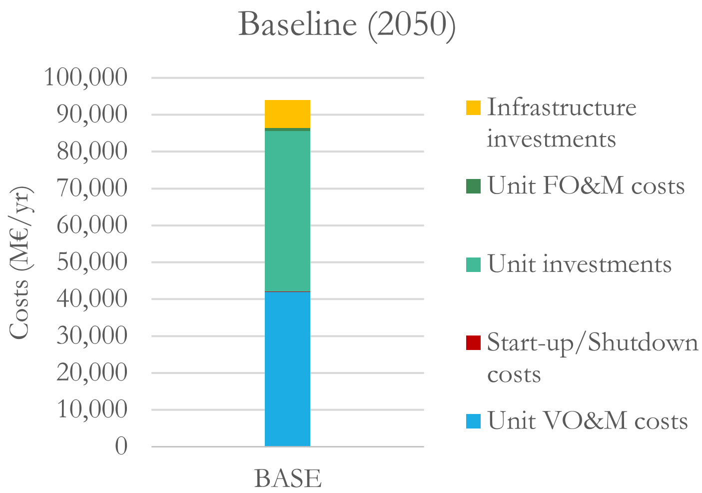

Figure 18. Baseline system costs in 2050.

A different picture arises for the scenarios for year 2050 (Figure 19) compared to the same scenarios for the year 2030. All scenarios result in cost savings compared to the baseline scenario. The savings are mainly achieved through the reduction of VO&M costs. As the number of starts and stops decreased, the start-up/shutdown costs are also smaller compared to the baseline in all scenarios. However, the reduction in start-up and shutdown costs is only a marginal factor. Again, investments and FO&M costs for power plants are higher.

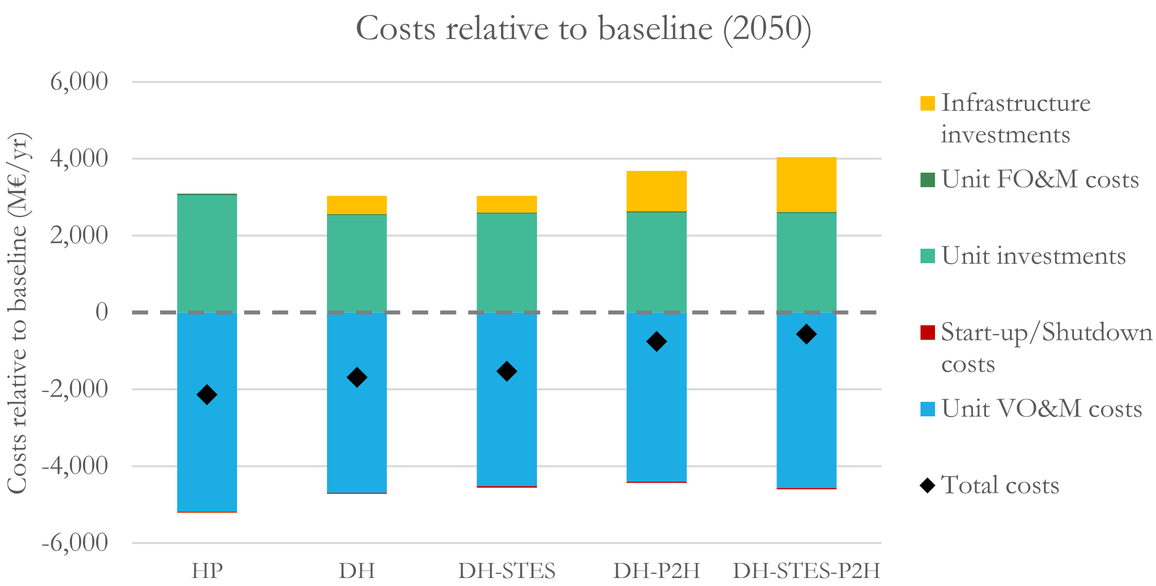

Figure 19. Costs relative to baseline per scenario in 2050.

The reduction in system costs compared to the baseline is the largest in the 2050-HP scenario. More than 2.1 billion €, 15% of the baseline Dutch system costs, is saved annually. Other scenarios also result in cost savings compared to the baseline scenario. The additions of P2H plants and the STES added to the district heating system do only result in additional system costs. Compared to the 2050-DH scenario without these options, it is mainly the cost for infrastructure which increases considerably. The large increases in infrastructure cost are mainly due to the high capacity of P2H plants which can attribute to an increased to an increased peak demand. The increased peak demands for all 2050 scenarios are given in Table 10. The peak demand increases generally due to higher general electricity demand. Since all scenarios except the baseline scenario have a large deployment of heat pumps, the peak demand increases further. However, with the additional P2H option in the district heating scenarios, the peak demand is higher than in the HP scenario.

Table 10. Increased peak demand for all countries[25] compared to 2015 for the 2050 scenarios.

Scenario	Increased peak demand (GW)
HP	112.87
DH	108.96
DH-STES	108.31
DH-P2H	118.73
DH-STES-P2H	124.88
BASE	99.53

In the 2050 baseline scenario, more than 1,200 TWh of renewable electricity is generated. Little over 47.9 TWh of this renewable electricity is curtailed in the baseline scenario. Of this amount, 9.8 TWh is renewable electricity that would have been generated in the Netherlands. Although the 2050-DH-STES-P2H scenario is the scenario with the highest system costs, it achieves the largest amount of curtailment reduction. An amount of 19 TWh of renewable electricity is used rather than discarded. This is 12% of the total annual Dutch electricity demand in 2050. It should be noted that the reduced curtailment may also take place in other countries, but can be attributed to changes in the Dutch system. Other scenarios result in smaller amount of curtailment reduction. The P2H scenario reduces the curtailment with 8 TWh. The extra flexibility of the STES in combination with the P2H does provide a large curtailment reduction potential. Only a STES is not enough to reduce the amount of curtailment. The high share of heat pumps in the 2050-HP scenario results in increased flexibility and therefore a curtailment reduction. However, this is only a little bit more than the 2050-DH scenario. The curtailment reduction in the 2050-DH scenario can also be attributed to the flexible dispatch of heat pumps. However, in this scenario the deployment of heat pumps is low. Therefore, the curtailment reduction is also small compared to other scenarios.

[25] Note that the electricity grid in each country needs to be able to handle the peak demand in that country. Therefore, the presented peak demand is the peak demand of each country summed and not the peak of the combined demand of all modelled countries.

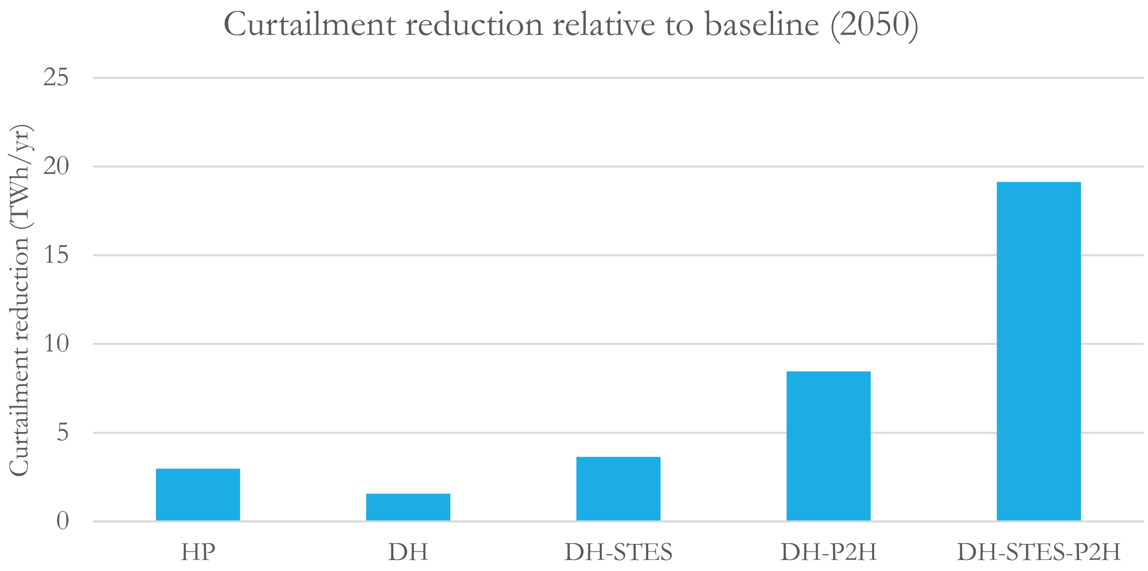

Figure 20. Curtailment reduction relative to baseline.

Figure 21 illustrates how STES and P2H reduce the amount of curtailed renewable electricity. At moments when large amounts of curtailment take place in the general 2050-DH scenario (bottom-left), less curtailment takes place in the 2050-DH-STES-P2H (bottom-right). The reason for the lower amount of curtailment can be found in the upper two graphs. At the points in time when curtailment would occur, more production of heat than the current demand, mainly due to the P2H plant, take place. Consequently, the storage[26] is filled such that the extra amount of (renewable) heat can be used later. As can be seen in the lower right graph, even extra electricity is imported to the Netherlands, lowering the curtailment in other countries.

As can be seen in Figure 22, not only the electric boilers connected to the district heating provide flexibility, the flexibility (virtual storage) of heat pumps is almost constantly filling or releasing. This means that heat pumps are constantly preheating or delaying the heating of buildings to accommodate the electricity system. It is clear that the virtual storage is filled at moments with high renewable electricity generation. Peaks in the heating demand are not always shaved through usage of the storage. The virtual storage in the heat system is mainly used to provide flexibility in the electricity system.

[26] Note that the thermal storage in the graphs is the virtual storage, described in section 3.2.4.2. The filling of the storage does in this case therefore express the extra filling of the STES faster than the predetermined charging profile, or discharging the STES slower than the predetermined discharge profile.

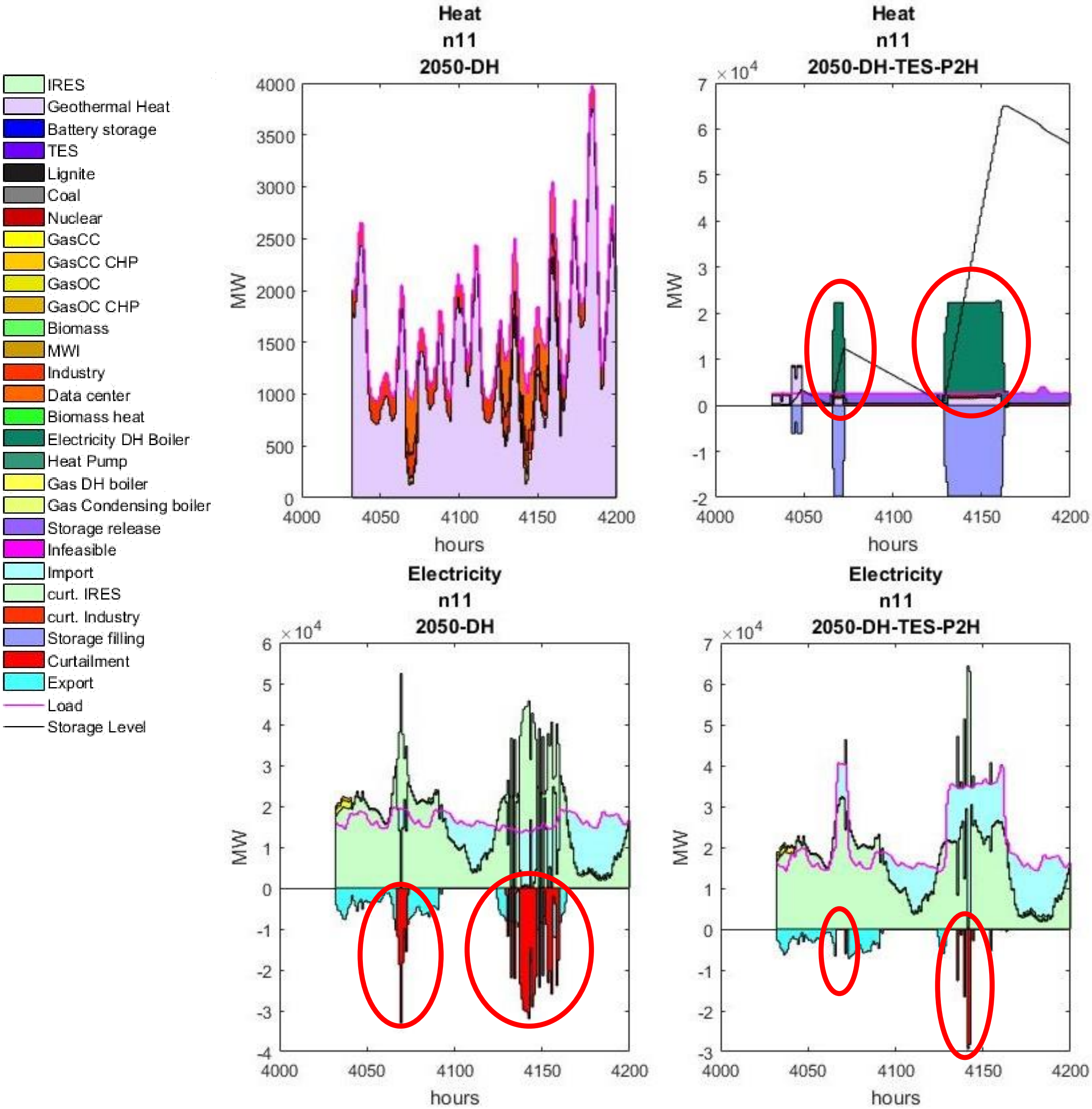

Figure 21. Effect of STES in combination with P2H in summer. The top two graphs show the heat demand for district heating while the lower two graphs show the total Dutch electricity demand. The two graphs on the left are from the 2050-DH scenario while the two graphs on the right are from the 2050-DH-STES-P2H scenario. As explained in section 3.2.4.2 the heat demand is always above a certain level, therefore the heat demand is a flat line in the top right graph. At points in time when curtailment would normally take place (red circles in the lower left graph), this curtailment is reduced (red circles lower right graph) through using the electric boiler and filling the virtual storage (red circles top right graph).

Since the graphs in Figure 21 depict the dispatch in the summer, heat demand is low. Therefore, almost the entire heat demand can be fulfilled by renewable sources: geothermal heat, industry and datacentre waste heat. However, also at moments of higher heat demand, CHPs are only rarely used. The CHP capacity factors for heat are below 1% for all scenarios, the CHP capacity factors for electricity have decreased below 17%. With these low capacity factors it is likely that the CHP units would not be profitable. Therefore, a smaller share of CHP units is more likely.

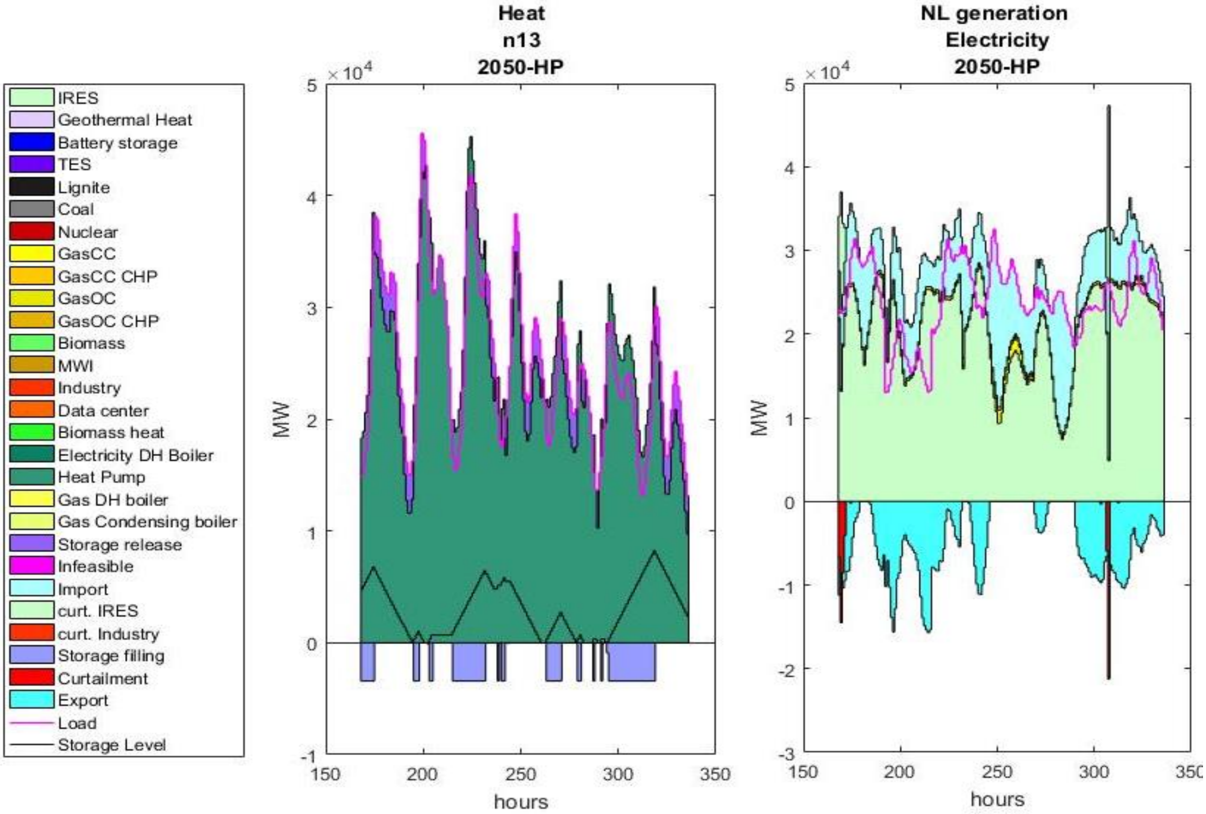

Figure 22. Flexibility from heat pumps. On the left is the heat generation by heat pumps within the Netherlands. On the right, the electricity production in the Netherlands.

The total emissions did go down considerably, also in the baseline scenario. In the baseline scenario, the total emissions are 166.3 $MtCO_2$/yr, of which 30.8 $MtCO_2$/yr in the Netherlands. Despite the fact that a large amount of electricity is no longer being curtailed in the 2050-DH-STES-P2H scenario, the emission saving is larger in the 2050-DH scenario and the 2050-HP scenario. The high efficiency of heat pumps in 2050 explains the large emission reduction in this scenario. Biomass boilers are used as peak capacity. Therefore, the dispatch of biomass boilers is higher in the 2050-DH scenario compared to the other DH scenarios with other option (P2H) or smaller peaks (STES). In the other scenarios, the heat which is not generated by biomass but by geothermal heat and/or electric boilers (P2H). Electric boiler and, to a lesser extent, geothermal heat require electricity as an input. The capacity factor of gas-fired generation is also slightly higher in the scenarios with P2H and/or STES. Since biomass has no (net) CO_2 emissions, the reduction in emissions is larger in the 2050-DH scenario.

It might seem contradictive that increased dispatch of electric boilers and geothermal heat, leading to more gas-fired electricity generation, is chosen over a gas-fired district heating boiler. First of all, the high efficiency of geothermal heat production results in the fact that less gas is needed per unit of heat delivered. Therefore, geothermal heat is clearly the cheaper dispatch option compared to gas-fired district heating boilers. Secondly, the dispatch of the electric boilers is not necessarily directly fuelled by gas-fired electricity generation. Through flexibility of the system, other technologies might be used to provide the required electricity, while later on extra gas-fired generation is needed to provide additional electricity. Thirdly, start-up and shutdown costs may lead to the fact that gas boilers are not used. It can be cheaper to leave a gas-fired power plant on for a short period of time rather than shutting it down and starting it up again a few hours later.

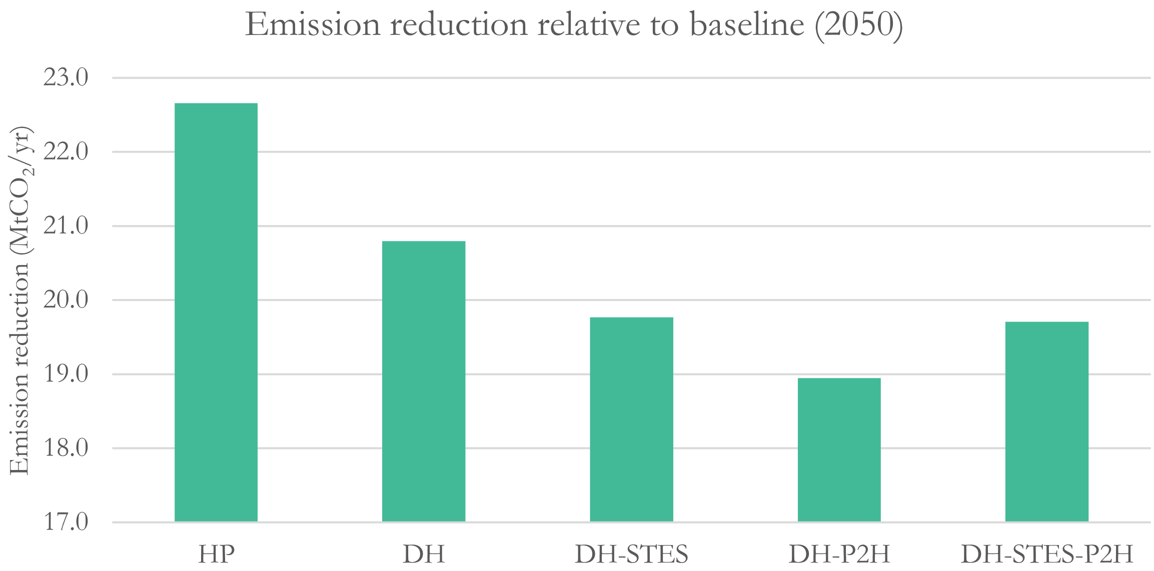

Figure 23. Emission reduction relative to baseline per scenario in 2050.

5.3 DEVELOPMENTS OVER TIME

An overview of all the presented results is given in Table 11. The dominant HP scenarios perform the best on the two main indicators, namely system costs and CO_2 emissions. Also, the basic DH scenario is generally cheaper than the scenarios with STES and/or P2H. On the long run the DH scenario also leads to a higher emission reduction. Nonetheless, around 11 $MtCO_2/yr$[27] for the Dutch emissions for heating and electricity is still a considerable amount. When the aim of the Dutch government remains to be to have a fully renewable electricity system in 2050, additional efforts such as other options for flexibility, additional energy efficiency improvements and/or further deployment of renewable energy production is needed.

Table 11. Overview of results for all scenarios.

	Scenario	System costs (M€/yr)	Emissions reduction ($MtCO_2/yr$)	Curtailment reduction (MWh/yr)
2030	HP	-102	15.21	82
	DH	202	14.83	111
	DH-STES	338	14.97	87
	DH-P2H	321	15.05	71
	DH-STES-P2H	192	15.50	55
2050	HP	-2,133	22.66	2,975
	DH	-1,688	20.79	1,557
	DH-STES	-1,525	19.77	3,642
	DH-P2H	-748	18.95	8,461
	DH-STES-P2H	-561	19.71	19,130

[27] i.e. 31 $MtCO_2/yr$ in the baseline minus the total system emissions reduction of around 20 $MtCO_2/yr$ for the varying scenarios.

In 2030 the DH-STES-P2H scenario, the system costs are lower compared to the DH scenario. It might be that the smaller capacities of the STES and the P2H units in 2030 are closer to the optimal situation compared to the STES and P2H capacities assumed in 2050. This touches upon the decreasing marginal returns as described by Deuchler (2013): "The first installed conversion units have a large effect, while the complete reduction of excess (electricity, red.) will call for unreasonably large conversion capacities." Clearly, a large curtailment reduction is achieved by the seasonal storage with electric boilers. In the 2050 scenarios, the curtailment reduction for the DH-STES-P2H scenario is more than six times as large compared to the curtailment reduction for the HP scenario. Therefore, it is probable that while reducing the size of the STES and electric boilers may still result in a large curtailment reduction, while generation unit and infrastructure costs go down considerably. This effect is further analysed in the sensitivity analysis.

More generally, it also becomes clear that pursuing increased flexibility of the system in order to reduce the curtailment of renewable electricity will clearly lead to higher system costs. Reducing curtailment may decrease system costs to some extent, but the optimum does not lie at the complete reduction of curtailment. Therefore, the flexibility of the system should be chosen carefully.

As could be seen in Figure 15 CHP units prove to provide considerable flexibility for both the electricity and the heating system in 2030. However, when renewable deployment increases further, the capacity factors of CHP units go down, even when considering the previously explained fact that the capacity factors for CHPs can never be 100%. Therefore, CHP units can provide considerably less flexibility in 2050. With these low capacity factors, owners of CHP units can, under current market conditions, likely not earn enough profits to maintain all CHP units.

6 Sensitivity analysis

The final outcomes are the result of many different factors. These factors have different impacts on the final outcome. The sensitivity analysis gives insight into what the effects of changes in the important factors would have on the end result.

6.1 Discount rate

The discount rate is highly influential on the outcome of the results. As argued in section 3.2.4, the discount rate was chosen at 4.5% for this research. However, if a different discount rate would have been used, the results would differ considerably. The system costs relative to the baseline scenario decrease with a lower discount rate and vice versa. The system costs relative to the baseline range between -632 M€/yr and +486 M€/yr for the 2030-HP scenario if the discount rate is changed with ±50%. As can be seen in Figure 24, the ranking between most of the tested scenarios would not change when the discount rate is varied between 6.75% (+50%) or 2.25% (-50%). In the case where the ranking would change between scenarios with a different discount rate, the differences between the scenarios are marginal.

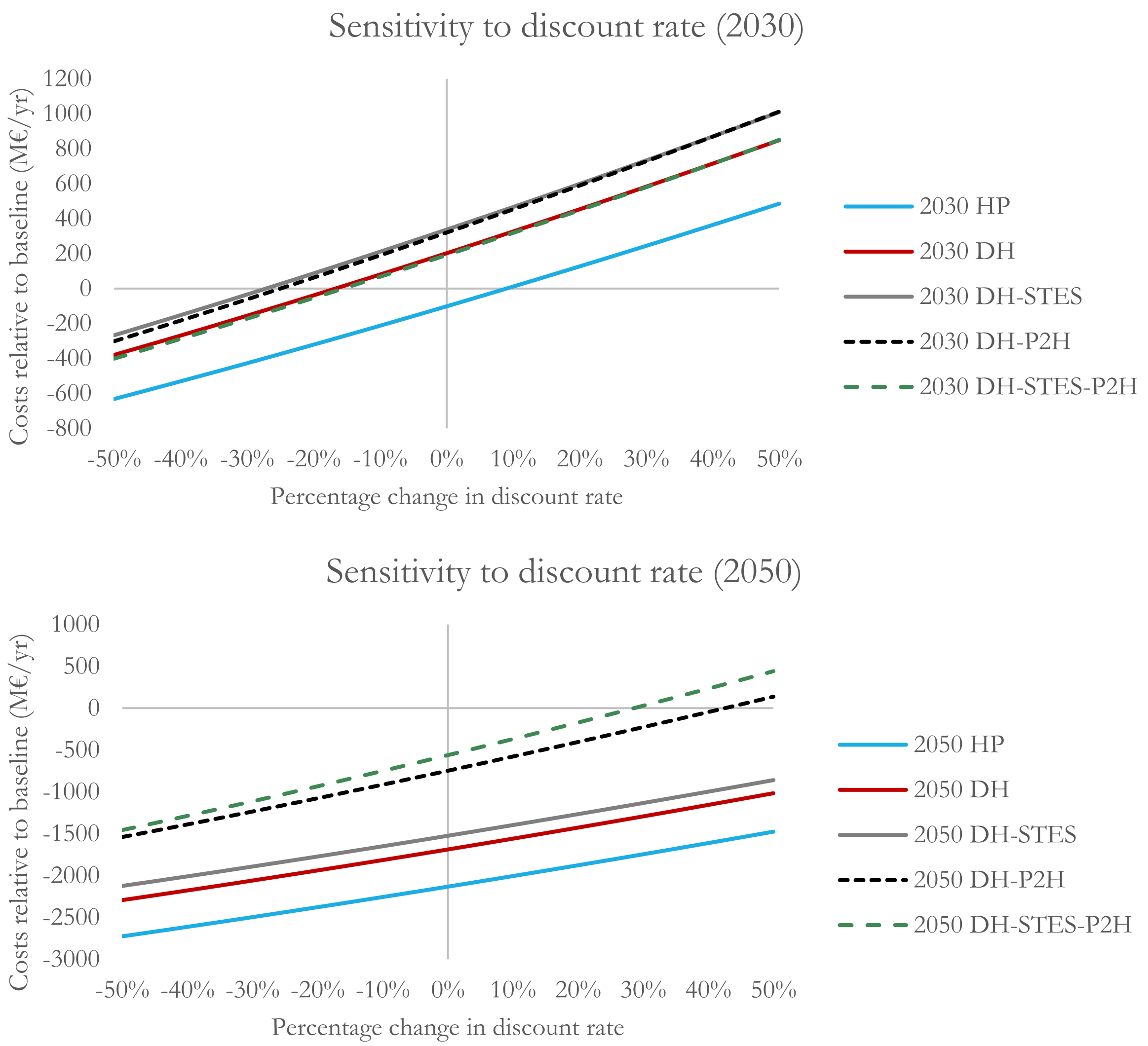

Figure 24. System costs (2030 and 2050) of all scenarios and their sensitivity to a percentage change in discount rate.

The scenarios with a dominant heat pump deployment result in the lowest system costs independent of the changes in discount rate. However, the system costs of the 2030-HP scenario are higher than the baseline scenario when the discount rate is increased with 10% or more.

Since the discount rate only influences the investment costs and all scenarios require more investments than the baseline scenario, an increasing discount rate results in higher relative system costs for all scenarios. All scenarios also result in lower operational costs than the baseline scenario but these costs do not respond to changes in the discount rate. Especially the scenarios with the additional P2H units installed in the district heating system are more sensitive to change in the discount rate due to the high investment costs in infrastructure in these scenarios.

6.2 Installed P2H and STES capacity

As indicated in section 5, the addition of P2H and or STES to district heating did result in lower system costs in the year 2030, but in higher system costs in 2050. The capacity of the P2H units and the STES might be of importance here. Four new scenarios, based on the 2050-DH-STES-P2H scenario were considered to identify possible improvements:

a) .5P2H: In this scenario, the P2H capacity is reduced to 50% of the original capacity of 19.7 MW. This change likely reduces the peaks on the electricity grid, but the amount of reduced curtailment probably decreases as well.

b) .25STES: In this scenario, the storage capacity of the STES is reduced to only 25% of the original capacity of 3.0 TWh. Since the storage capacity probably suffers from decreasing marginal returns, this change will make the STES overall more feasible considering the smaller investment costs. Therefore, this can possibly also lead to a decrease in total system costs.

c) stTES: Next to just reducing the size of the STES, this scenario only has a short term thermal energy storage (stTES). The exogenous defined heat demand is not changed in the model and the virtual storage is now the actual storage in the model. The size of this short-term storage is 0.7 TWh.

d) .5P2H-.25STES: This scenario combines the changes made to the first two scenarios mentioned in this list. The P2H capacity is reduced to 50% and the STES capacity is reduced to 25%.

Only the stTES scenario leads to a small system cost increase (+22 M€/yr) compared to the original 2050-DH-STES-P2H scenario (see Figure 25). Apparently, a STES which can adapt to seasonal and daily fluctuations in heat demand is of more value than the stTES despite the higher investment costs for the STES.

Just a smaller STES results in slightly reduced system costs compared to the original 2050-DH-STES-P2H scenario. In the .25STES scenario the system costs are 14 M€/yr lower compared to the original scenario. This indicates that the originally assumed capacity of the STES was too large and 25% of this capacity is closer to the optimal situation. Nonetheless, the scenario would still result in higher system costs than the 2050-DH scenario. Consequently, in the optimal situation the STES capacity should be changed even further or the STES cannot be implemented in a cost-effective manner.

The decrease of the P2H capacity reduces the overall system costs. As expected, the infrastructure costs and generation unit investment costs decreased and the operational costs increased for the .5P2H scenario. Nonetheless, the large reduction in infrastructure costs results in a mayor reduction in total system costs (-505 M€/yr).

The largest system cost reductions are found in the last scenario used in the sensitivity analysis. Reducing both the P2H capacity and the STES capacity resulted in a system cost reduction of 547 M€/yr. Almost the entire reduction can be attributed to the decreased infrastructure investment costs. Nonetheless, the system costs are still higher than the system costs in the 2050-DH scenario. Two possibilities can explain this difference: either new proposed capacities of P2H and STES for district heating is still far from the optimal situation, or P2H and STES cannot be implemented in a cost-effective manner. Further research in the combination of P2H and STES is needed to answer the question whether and how STES and P2H can be combined optimally. For the 2030 scenarios, it was shown that STES and P2H can be implemented in a manner where system costs go down. Therefore, it is likely that this could also be the case in 2050.

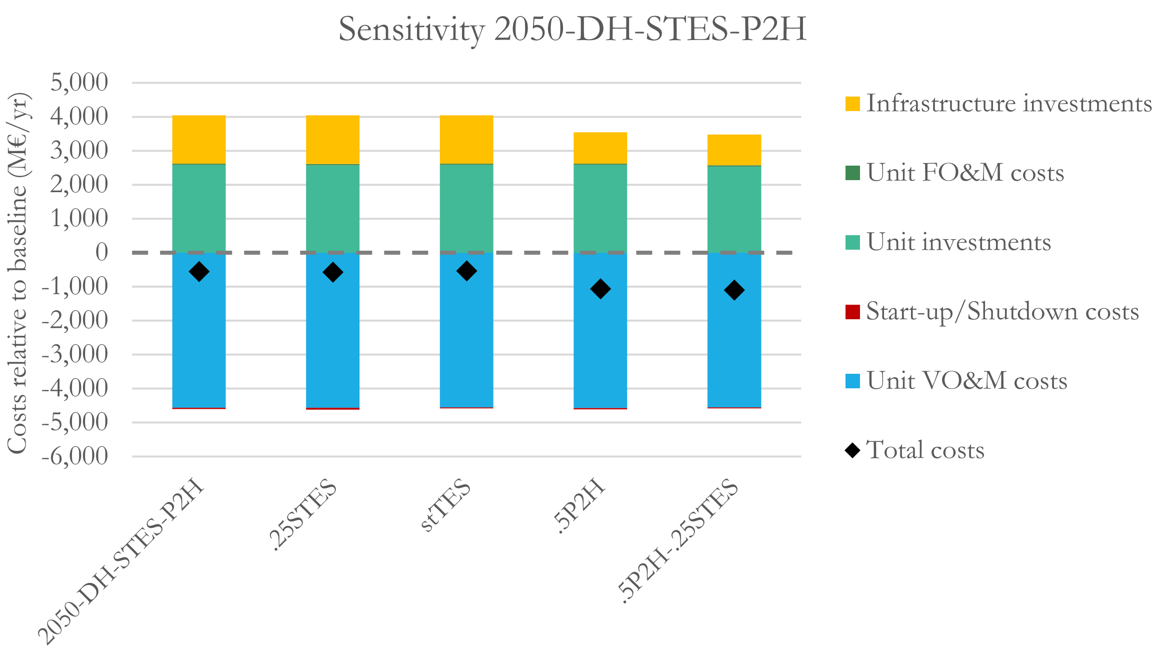

Figure 25. Sensitivity of system costs for the 2050-DH-STES-P2H scenario.

The resulting curtailment reduction of these scenarios clearly shows the importance of the electric boilers in the amount of curtailment reduction (Figure 26). In the two scenarios where the capacity of the electric boilers is halved, the curtailment reduction decreases with 25% to 15 TWh. In the other scenarios where the capacity of the storage is changed, the curtailment reduction roughly remains at the same level as the original 2050-DH-STES-P2H scenario.

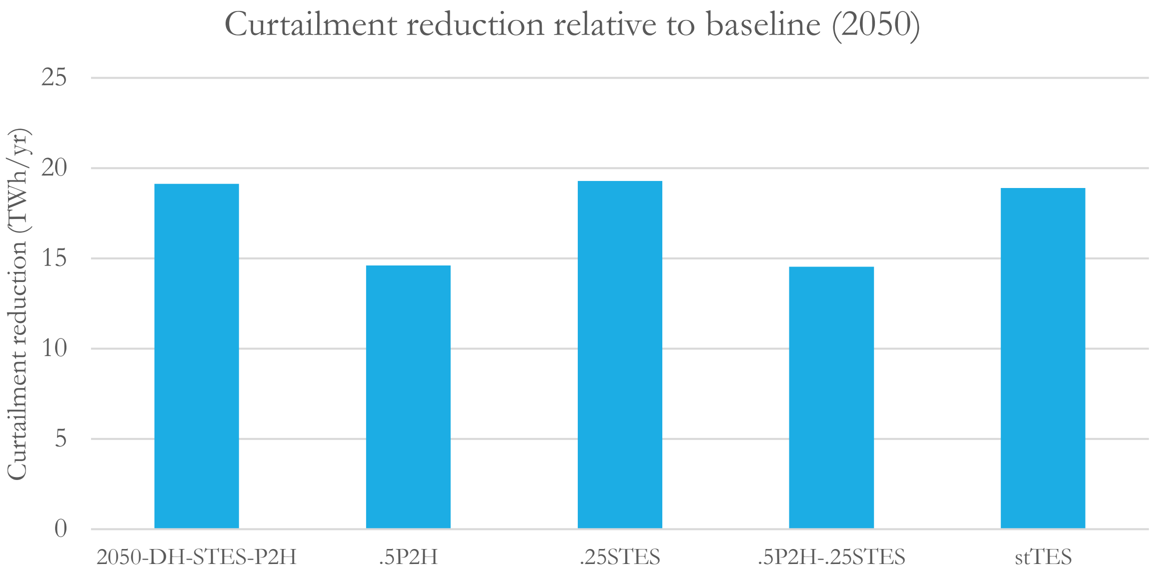

Figure 26. Sensitivity of curtailment for the 2050-DH-STES-P2H scenario.

The capacities of both the STES and the electric boilers seems to be of importance for the amount of emission reduction. The emission reduction becomes smaller both when the STES capacity and the electric boiler capacity is reduced. However, when they are both reduced (.5P2H-.25STES), only a minor decrease in emission reduction takes place. Nonetheless, the emission reduction in the .5P2H-.25STES scenario is still smaller than in the original 2050-DH-STES-P2H scenario.

The additional emission saving in the original scenario compared to the .5P2H-.25STES scenario are achieved at an additional carbon abatement costs of 2806 €/tCO_2 on top of the carbon price of 80€/tCO_2. Clearly, this high abatement costs is not desirable and the costs savings in the .5P2H-.25STES scenario could better be used for other projects reducing carbon emissions.

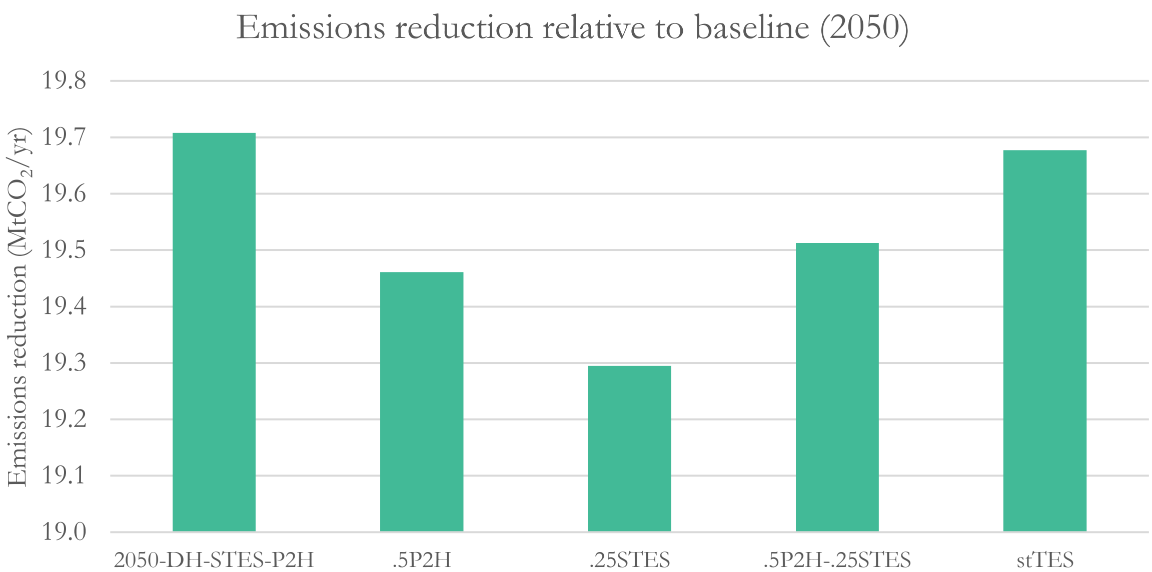

Figure 27. Sensitivity of CO_2 emissions for the 2050-DH-STES-P2H scenario.

7 Discussion

First, the limitations of the research and their impact on the final results will be discussed in this section. Secondly, the results will be compared to the results of similar studies to determine the reliability of these values. Finally, suggestions for future research and policy implications are discussed.

7.1 Limitations

First of all, in PowerFys the variable operation and maintenance (VO&M) costs are only made up of fuel costs and emission costs. In reality, a small share of the VO&M costs is also spent on other factors such as maintenance, cleaning etc. The VO&M apart from fuel and emission costs are around 3 €/MWh for large power plants (Energinet.dk 2012). Because the addition of these 3 €/MWh would likely not change the merit order, the dispatch of power plants would also remain the same as in the current model. Therefore, when the additional VO&M costs would be considered, the only difference would be that the total system costs would be slightly higher. However, as in all scenarios the operational costs were lower than in the baseline scenario, this would also mean that costs reduce further in all scenarios.

Additionally, the units in PowerFys convert fuel with fixed efficiencies to either heat or electricity. In reality, power plants have different efficiencies at different capacities (e.g. a higher efficiency when dispatched at full capacity compared to the efficiency when only dispatched at half capacity) (Brouwer et al. 2015). The efficiencies of all generation units in PowerFys are average efficiencies and therefore the deviation can be expected to be small. It should be noted that the efficiency of heat pumps does changes dependent on the outside air temperature and not on the generation level. The impact on the results is likely very limited. In the modelled results the units are dispatched at various levels between the minimum and maximum load. Therefore, the average of the variable efficiencies are likely to converge towards the average efficiency in the model.

The system costs where all calculated as annual costs. This method has the advantage that investments with different lifetimes can be added together fairly. Some older investments were depreciated before the end of their lifetime. An example is the gas infrastructure with a lifetime of 40 years. Only about 30% of the buildings are connected to the gas network in all scenario in 2030. The costs of early depreciation are not taken into account in the calculation of the system costs. Since the least changes occur in the baseline scenario, there is no need to depreciate investments before the end of the economic lifetime.

As a general approach, the cost factors were all calculated as if technologies and infrastructure were only replaced after their economic lifetime. Additionally, the cost of the heating system within households and utility buildings was not considered. Both these facts may have led to underestimations of the costs of the deployment of heat pumps. In general, the costs of low temperature (LT) heating within households is of higher cost than that of higher temperature heating. The costs for LT heating increase with the size of the house. A rough estimate is that a LT heating system would cost 2500 €/household[28]. With an assumed 50 year lifetime (Ecofys 2013) for the low temperature heating this might add roughly 1 billion euros in annual costs in the 2050-HP scenario with 80% heat pumps. Furthermore, LT heating systems are often combined with high insulation. However, costs for insulation were not considered in this study. The total

[28] No cost figures could be determined from literature or reports. https://www.vloerenverwarming.nl/vloerverwarming-prijzen/

heat demand was assumed to go down due to better insulation independent of the scenario. Therefore, the costs of insulation will not change the ranking of

The method to determine the installed electricity and heat capacities which can be dispatched is only determined on literature and whenever appropriate, data is extrapolated. However, this simplifies the complex market decisions to invest in certain types of power and heat plants with certain capacities. Therefore, the assumed installed capacities might be unrealistically far from the optimal installed capacities. The aim of this study was not to show exactly how the future energy system would evolve, but how interactions between the heat and electricity system may reduce systems costs in a sustainable energy future. Therefore, the method to determine installed capacities of all types of plants from literature was deemed sufficient.

The installed heating capacities were also not changed between similar scenarios with or without STES. Since the storage considerably reduces the peak demand and at the same time increases the lower heat demand over the year. Therefore, the STES scenarios could have fulfilled the same total heat demand with less heat plants. Only capacity that was not utilised in the model over the entire year was not considered in the cost calculations. It might be that some capacity was only used for a short period within the year. Although this dispatch might result in the lowest operational costs, the system costs might have been lower when storage was used. Therefore, a more careful balancing of installed heating capacity and storage capacity might result in further cost reductions for the STES scenarios. For example, gas-fired DH boilers and biomass DH boilers have a capacity factor of 0.03% and 0.05% in the 2050-DH-STES scenario respectively. When these boilers would not have been installed, this would lead to a reduction in investment costs of 176 M€ annually, likely at a marginal increase in operational costs.

7.2 Other literature

The author is not aware of studies in which varying heating systems are tested in combination with a 70% renewable penetration in the electricity system in 2050. However, several smaller or partly overlapping factors were studied by other researchers before. In this section, the results of this study are compared to the results of these researchers.

Several technologies to reduce curtailment were tested in the study by Deuchler (2013). None of these technologies was found to be profitable. In this research, profitability was not studied specifically, however, a reduction in total system costs was found for all scenarios in 2050. Ideally, this reduction in total system costs will also result in profitable business cases for conversion technologies. This difference with the study by Deuchler can be explained by at least two factors. First, in this study, the electricity dispatch was optimised with the dispatch of heat technologies, while Deuchler started with a fixed amount of curtailment which could be avoided. Secondly, Deuchler focussed on the year 2020 with a 40% renewable penetration compared to 70% in this study. Because there is more intermittent generation capacity in this study, there also is more potential for P2H conversion to reduce system costs. has more inter that Furthermore, Deuchler (2013) also finds that the total reduction of curtailment should not be pursued. Reducing marginal returns of curtailment reduction make that the last unit of curtailment reduction can only be achieved at extremely high costs.

Gill et al. (2011) only study the effect of district heating networks with electric boilers and heat storage on the integration of wind energy. Different from the co-optimisation of heat and electricity in this study, Gill et al. (2011) study fixed dispatch strategies for wind energy[29]. It is concluded, similar to the results of this thesis, that heat storage and electric boilers can reduce the level of renewable energy curtailment. However, the additional achieved curtailment reduction quickly decrease when additional capacity of electric boilers and heat storage are installed.

Li et al. (2016) develop an optimal dispatch strategy for an integrated energy system with a combined cooling heating and power (CCHP) plant. An installed electric boiler and seasonal thermal energy storage result in an increase wind energy utilisation rate (i.e. reduced wind energy curtailment) of roughly 4%-points while reducing operational costs. CHP plants in this research are similar to a CCHP plant. Although the specific impact of CHP plants was not studied in this research, the general impact of power and heat system integration also resulted in lower operational costs and reduced curtailment. However, infrastructure and unit investment costs are not discussed in the article by Li et al. (2016). In this research, the investment costs were found to be important aspects of the total system costs and thus the desirability of technologies.

7.3 Further research and policy implications

The method of this research and the expanded PowerFys model in general are of great value. Individual modelling of the heating and electricity system will likely lead to suboptimal results since interactions have been shown to influence the results. In this study, only the heating and electricity systems were modelled. However, other energy (consuming) systems such as the natural gas system may provide different interactions. Interactions such as Power-to-Gas (P2G) or more general Power-to-X (P2X) may have as a side effect that interactions between the electricity and heating system will actually be used less than is modelled here.

With the expanded PowerFys model, these interactions can now also be modelled. It is strongly suggested that further research focusses on how the interactions between several energy systems relate to each other. Nonetheless, P2H is still a likely source of flexibility for the electricity system due to the high consumption of heat, the extent to which the load can be shifted in time and the high conversion efficiency.

One effect that might influence the results considerably was not modelled in this study. During a number of consecutive extremely cold days, a system with a high share of district heating may be more favourable. During extreme colds, the heating demand is large, while the COP of heat pumps is 1, similar to electricity boilers. Therefore, the high heating demand also has a large effect on the electricity system. The high electricity demand peaks in the 2050-DH-P2H-STES scenario indicates that this might result in high system costs. Although during normal years the heat pump scenarios may result in lower system costs, this can be reversed in years with extreme cold events. The difference is mainly attributed to infrastructure, generation unit investment and fixed costs. Infrastructure investments need to be made for several years. Therefore, the (possible) occurrence of one extreme cold event during all these years would increase infrastructure costs considerably for the entire span of years.

The ideal configuration of electric boilers and seasonal thermal energy storage can be subject to further research. Both are subject to decreasing marginal returns. Additionally, the added value of seasonal thermal energy storage and electric boilers interact with each other. In an optimal

[29] E.g. one example of such a dispatch strategy is: first, all wind energy goes to heat demand, then to heat storage and finally the wind energy is used to fulfil electricity demand.

configuration, it is possible that a scenario with district heating can be competitive with a heat pump dominant scenario.

Based on the results of this study it can be concluded that curtailment reduction does not necessarily lead to a reduction in either costs or emissions. Therefore, it is recommended that curtailment reduction is not a policy goal per se but rather a by-product of policy aimed at minimising system costs and carbon dioxide emissions.

Policy on infrastructure will be crucial in the transition of the heating and electricity system. The baseline scenarios with a high share of gas boilers resulted in the highest system costs in 2050. Additionally, gas infrastructure has an economic lifetime of 40 years. Because the almost complete abolishment of gas boilers lead to total system costs reductions, it is recommended that no new investments in gas infrastructure are made.

8 CONCLUSION

As the supply of renewable energy becomes increasingly important, problems with matching demand and supply can arise. Additionally, the electricity and the heating system are becoming increasingly interconnected. In this study it was researched how these interconnections can be used to reduce overall system costs and emissions in a renewable energy future.

In order to find an answer to the research question, the PowerFys model was expanded to co-optimise both the heating and the electricity system. With this innovative method, the lowest operational costs for the combined heat and electricity system can be found. Next to the operational costs, the investment costs in infrastructure and generation units were considered as well. The influence on the heating and electricity system of power-to-heat (P2H), seasonal thermal energy storage (STES) and combined heat and power (CHP) generation, were studied. The results are based on 12 scenarios that were developed. The scenarios differed in share of building heated by district heating, heat pumps and gas boilers. Additionally, in the scenarios with the highest share of buildings (30%) connected to the district heating the influence of electric boilers and STES were studied. The Netherlands was studied as a case study in this research. To account for imports and exports of electricity, the electricity systems of Denmark, Germany, Belgium, Great Britain and Ireland were modelled as well.

In future energy systems, the amount of fossil fuels used for heat and electricity generation will be largely reduced. In this study, natural gas is the only fossil fuel that is used to complement the generation from renewable sources in 2050. In a fully renewable energy future, additional renewable generation capacity, additional flexibility and/or larger energy savings are required to bring the Dutch system emissions from 8.1 $MtCO_2$/yr to 0.

Under the assumptions of this study, interactions between the heating and electricity system will be used in various ways. Electric boilers will mainly be used to fill peaks in heating demand or convert surplus electricity when it would otherwise have been curtailed. When a P2H link (e.g. a heat pump or an electric boiler) exists, the flexibility in the heating system is used to accommodate renewable sources in the electricity system. The curtailment reduction can be increased through installing a STES. Also CHP units are shown to provide considerable flexibility in the year 2030. The capacity factor of CHP units is below 1% for heat and below 17% for electricity in 2050 due to other cheaper (renewable) heat sources. Therefore, CHP units can only provide a small amount of flexibility.

The lowest system costs for both 2030 and 2050 are achieved when 80% of buildings is heated by heat pumps. A high share of heating from heat pumps results in a cost reduction of approximately 2.13 billion euros annually compared to 14.0 billion euros annually for the Dutch heating and electricity system in the baseline scenario. Additionally, the heat pumps would also result in the lowest emissions in 2050. The reduction in emissions is 22.7 $MtCO_2$/yr compared to the total Dutch emissions of 30.8 $MtCO_2$/yr in the baseline. The curtailment reduction is not the largest for the dominant heat pump scenarios but the high efficiency of heat pumps still results in lower costs. In the dominant district heating scenario with up to 30% of the buildings connected to the district heating, total system cost savings are lower with 1.68 billion €/yr. In 2050, the deployment of STES or P2H (electric boilers) in the district heating result in system costs savings of only 1.53 and 0.75 billion €/yr respectively. When both the STES and P2H are connected to the district heating, the savings compared to the baseline decrease even further to only 0.56 billion €/yr. The decreasing system cost savings are mainly due to higher peak electricity demand as a result of electric boiler dispatch. Next to system costs, the emission reductions also decrease in the district heating scenario due to the higher deployment of geothermal heat and electric boilers replacing biomass heat. However, it was shown in the sensitivity scenario that half the capacity of the electric boilers and a quarter of the STES capacity results in system cost reductions of 1.11 billion €/yr compared to the baseline without a significant change in CO_2 emissions.

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10 Appendixes

10.1 Cost assumptions 2030

Plants

	Economic lifetime (yr)	Inv. costs (€/MW)	Inv. storage (€/MWh)	Fixed O&M (€/MW/yr)	Fixed O&M storage (€/MWh)	O&M costs (€/MWh)	alpha	Source
Nuclear	40	3,000,000	0	73,000	0.00	0.00	**0.082**	(Brouwer et al. 2015)
Lignite	35	1,382,400	0	25,000	0.00	2.20	**0.086**	(Brouwer et al. 2015)
Coal	35	1,382,400	0	25,000	0.00	2.20	**0.086**	(Brouwer et al. 2015)
NGCC	25	672,280	0	15,000	0.00	1.20	**0.094**	(Brouwer et al. 2015)
NGCC CHP	25	672,280	0	15,000	0.00	1.20	**0.094**	(Brouwer et al. 2015)
NGOC	25	370,000	0	0	0.00	3.40	**0.094**	(Brouwer et al. 2015)
NGOC CHP	25	672,280	0	0	0.00	3.40	**0.094**	(Brouwer et al. 2015)
Biomass	30	2,500,000	0	62,500	0.00	3.90	**0.089**	(VGB 2011)
Battery	15	0	136,000,000	51,000	5.30	0.00	**0.117**	(Energinet.dk 2012)
Waste CHP	20	8,500,000	0	16,500	0.00	23.00	**0.102**	(Energinet.dk 2012)
Biomass DH Boiler	20	800,000	0	0	0.00	5.40	**0.102**	(Energinet.dk 2012)
Gas DH Boiler	35	100,000	0	3,700	0.00	0.00	**0.086**	(Energinet.dk 2012)
Gas Condensing Boiler	20	36,000	0	0	0.00	0.00	**0.102**	(Energinet.dk 2012)
Datacentre	20	580,000	0	3,650	0.00	0.00	**0.102**	(Energinet.dk 2012)
Heat Pump House	20	580,000	0	3,650	0.00	0.00	**0.102**	(Energinet.dk 2012)
Geothermal	25	1,600,000	0	34,000	0.00	0.00	**0.094**	(Energinet.dk 2012)
Electricity Boiler	20	60,000	0	1,100	0.00	0.50	**0.102**	(Energinet.dk 2012)
ATES	20	0	500	0	3.50	0.00	**0.102**	(Energinet.dk 2012)
WindOn	25	1,181,292	0	17,287	0.00	0.00	**0.094**	(Brouwer et al. 2015)
WindOff	25	2,112,000	0	52,214	0.00	0.00	**0.094**	(Brouwer et al. 2015)
PV	30	1,170,000	0	18,556	0.00	0.00	**0.089**	(Brouwer et al. 2015)
Water	55	1,800,000	0	18,000	0.00	0.00	**0.081**	(VGB 2011)

Infrastructure

	Economic lifetime (yr)	Investment				alpha	
			HV grid < 3 GW (€/kW)	HV grid 3-10 GW (€/kW)	HV grid 10-100 GW (€/kW)		
HV grid expansion (€/kW)	40	=>	10	50	500	0.043	(Ecofys 2016c)
MV grid expansion (€/kW)	40	600				0.043	(Ecofys 2016c)
LV grid expansion (€/con.)	40	700				0.043	(Ecofys 2016c)
			DH < 15% (€/connection)	DH 15%-29% (€/connection)	DH>29% (€/connection)		
DH grid (€/connection)	30	=>	4,142	7010	7,743	0.051	(Ecofys 2016a)
Smart charging EV (€/EV)	10	20				0.117	(Ecofys 2016c)
Flexible HP (€/HP)	10	20				0.117	(Ecofys 2016c)
Gas grid (€/connection)	40	3,051				0.043	(Ecofys 2015)

10.2 Cost assumptions 2050

Plants

	Economic lifetime (yr)	Inv. costs (€/MW)	Inv. storage (€/MWh)	Fixed O&M (€/MW/yr)	Fixed O&M storage (€/MWh)	O&M costs (€/MWh)	alpha	Source
Nuclear	50	3,000,000	0	73,000	0.00	0.00	**0.082**	(Brouwer et al. 2015)
Lignite	35	1,274,020	0	25,000	0.00	2.20	**0.086**	(Brouwer et al. 2015)
Coal	35	1,274,020	0	25,000	0.00	2.20	**0.086**	(Brouwer et al. 2015)
NGCC	25	645,658	0	15,000	0.00	1.20	**0.094**	(Brouwer et al. 2015)
NGCC CHP	25	645,658	0	15,000	0.00	1.20	**0.094**	(Brouwer et al. 2015)
NGOC	25	370,000	0	0	0.00	3.40	**0.094**	(Brouwer et al. 2015)
NGOC CHP	25	645,658	0	0	0.00	3.40	**0.094**	(Brouwer et al. 2015)
Biomass	30	2,500,000	0	62,500	0.00	3.90	**0.089**	(VGB 2011)
Battery	15	0	136,000,000	51,000	5.30	0.00	**0.117**	(Energinet.dk 2012)
Waste CHP	20	8,500,000	0	0	0.00	23.00	**0.102**	(Energinet.dk 2012)
Biomass DH Boiler	20	800,000	0	0	0.00	5.40	**0.102**	(Energinet.dk 2012)
Gas DH Boiler	35	100,000	0	3,700	0.00	0.00	**0.086**	(Energinet.dk 2012)
Gas Condensing Boiler	20	36,000	0	0	0.00	0.00	**0.102**	(Energinet.dk 2012)
Datacentre	20	530,000	0	3,650	0.00	0.00	**0.102**	(Energinet.dk 2012)
Heat Pump House	20	530,000	0	3,650	0.00	0.00	**0.102**	(Energinet.dk 2012)
Geothermal	25	1,600,000	0	34,000	0.00	0.00	**0.094**	(Energinet.dk 2012)
Electricity Boiler	20	60,000	0	1,100	0.00	0.50	**0.102**	(Energinet.dk 2012)
ATES	20	0.0	429	0	3.00	0.00	**0.102**	(Energinet.dk 2012)
WindOn	25	1,134,513	0	16,603	0.00	0.00	**0.094**	(Brouwer et al. 2015)
WindOff	25	1,351,680	0	36,842	0.00	0.00	**0.094**	(Brouwer et al. 2015)
PV	30	658,125	0	16,396	0.00	0.00	**0.089**	(Brouwer et al. 2015)
Water	55	1,800,000	0	18,000	0.00	0.00	**0.081**	(VGB 2011)

Infrastructure

	Economic lifetime (yr)	Investment				alpha	
			HV grid < 3 GW (€/kW)	HV grid 3-10 GW (€/kW)	HV grid 10-100 GW (€/kW)		
HV grid expansion (€/kW)	40	=>	10	50	500	0.043	(Ecofys 2016c)
MV grid expansion (€/kW)	40	600				0.043	(Ecofys 2016c)
LV grid expansion (€/con.)	40	700				0.043	(Ecofys 2016c)
			DH < 15% (€/connection)	DH 15%-29% (€/connection)	DH>29% (€/connection)		
DH grid (€/hh)	30	=>	3,469	5871	6,485	0.051	(Ecofys 2016a)
Smart charging EV (€/EV)	10	20				0.117	(Ecofys 2016c)
Flexible HP (€/HP)	10	20				0.117	(Ecofys 2016c)
Gas grid (€/hh)	40	3,051				0.043	(Ecofys 2015)

10.3 Basis for installed conventional capacity

Installed non-renewable generation capacity (GW), various sources.
*No data could be obtained for Ireland. Therefore, the capacities in Ireland are assumed to have the same shares as GB, but is scaled to final electricity consumption in the two countries (Eurostat 2016).

Country	Other	Gas	Coal	Lignite	Nuclear	Year	Source
NL	1.0	16.0	8.0	0.0	0.5	2015	(ECN 2015)
DK	0.4	2.2	2.2	0.0	0.0	2015	(Energinet.dk 2016)
DE	4.2	28.3	28.6	21.1	10.8	2015	(Fraunhofer 2016)
BE	2.6	5.9	0.5	0.0	5.9	2013	(May 2014)
GBI	0.8	32.9	19.5	0.0	10.2	2014	(Ofgem 2014)
GB	*0.7*	*30.5*	*18.1*	*0.0*	*9.5*	*2014*	(Ofgem 2014)
Ireland	*0.1*	*2.4*	*1.4*	*0.0*	*0.8*	*	*

Installed non-renewable capacity in Europe over the years in scenario A by Fraunhofer (2011) **in GW.**
*The data for the years 2013-2015 was acquired by linear interpolation between 2008 and 2020. These years are used as base years from which the percentage change is calculated.

Year	Other	Gas	Coal	Lignite	Nuclear
2008	74	180	123	56	135
*2013**	*55*	*175*	*95*	*42*	*122*
*2014**	*52*	*175*	*89*	*40*	*119*
*2015**	*48*	*174*	*83*	*37*	*116*
2020	29	169	55	23	103
2030	15	226	26	11	17
2040	6	198	0	0	0
2050	0	160	0	0	0

10.4 Installed electricity generating capacities in 2030 and 2050 for HP scenarios

(GW)	Year	Gas OCGT	Gas CCGT	Coal	Lignite	Nuclear	Other fossil	Wind Onshore	Wind Offshore	PV	Biomass	Hydro	Other renewables	Total
Netherlands HP scenarios	2030	8.5	13.3	2.6	0.0	0.1	0.3	11.9	7.0	4.8	2.9	0.2	0.4	**52.0**
	2050	8.3	13.0	0.0	0.0	0.0	0.0	11.9	22.9	11.3	4.6	0.3	0.6	**72.9**
Netherlands DH scenarios	2030	8.2	12.9	2.5	0.0	0.1	0.3	11.5	6.8	4.7	2.8	0.2	0.4	**50.4**
	2050	8.0	12.5	0.0	0.0	0.0	0.0	11.9	21.7	10.8	4.4	0.3	0.6	**70.2**
Netherlands BASE scenarios	2030	7.2	11.3	2.2	0.0	0.1	0.3	10.1	5.9	4.1	2.4	0.2	0.3	**44.1**
	2050	7.3	11.5	0.0	0.0	0.0	0.0	11.9	19.2	9.9	4.1	0.3	0.5	**64.7**
Denmark	2030	0.9	1.4	0.6	0.0	0.0	0.1	2.9	1.4	0.1	2.2	0.0	0.0	**9.6**
	2050	0.8	1.2	0.0	0.0	0.0	0.0	5.0	2.6	0.3	3.1	0.0	0.0	**13.0**
Germany	2030	14.5	22.8	9.0	6.4	1.6	1.3	36.9	30.6	41.1	9.8	4.8	0.3	**179.1**
	2050	14.4	22.6	0.0	0.0	0.0	0.0	74.0	64.0	97.7	16.0	6.8	0.4	**295.9**
Belgium	2030	3.5	5.5	0.2	0.0	1.0	0.8	3.6	5.3	0.9	2.6	0.2	0.1	**23.7**
	2050	3.9	6.2	0.0	0.0	0.0	0.0	8.3	12.6	2.4	4.9	0.4	0.2	**38.9**
Great Britain and Ireland	2030	14.3	22.5	4.9	0.0	1.3	0.2	50.7	25.0	1.5	5.3	2.0	3.2	**130.9**
	2050	13.4	21.0	0.0	0.0	0.0	0.0	95.9	49.3	3.3	8.1	2.6	4.9	**198.5**

10.5 Installed heat generating capacities for all scenarios

(GW)	Year	Heat Pump	Industry	Datacentre	Geothermal	Electric Boiler	Biomass DH Boiler	Gas DH Boiler	Gas CCGT CHP	Gas OCGT CHP	Gas Condensing Boiler	Total	Peak demand	Heat storage charge/discharge
HP	2030	42.6	0.1	0.3	4.1	0.0	1.0	1.0	4.2	0.6	21.7	**76.5**	71.5	N/A
	2050	45.6	0.2	0.5	8.2	0.0	0.3	0.3	8.4	2.0	3.1	**68.4**	57.2	N/A
DH	2030	34.5	0.2	0.5	4.1	0.0	3.0	3.0	4.2	0.6	22.7	**74.6**	71.5	N/A
	2050	30.9	0.5	1.1	8.2	0.0	2.6	2.6	8.4	2.0	9.2	**65.0**	57.2	N/A
DH-STES	2030	34.5	0.2	0.5	4.1	0.0	3.0	3.0	4.2	0.6	22.7	**74.6**	71.5	16.4
	2050	30.9	0.5	1.1	8.2	0.0	2.6	2.6	8.4	2.0	9.2	**65.0**	57.2	19.7
DH-P2H	2030	34.5	0.2	0.5	4.1	16.5	3.0	1.2	4.2	0.6	22.7	**89.3**	71.5	N/A
	2050	30.9	0.5	1.1	8.2	19.7	2.6	1.0	8.4	2.0	9.2	**83.1**	57.2	N/A
DH-STES-P2H	2030	34.5	0.2	0.5	4.1	16.5	3.0	1.2	4.2	0.6	22.7	**89.3**	71.5	16.4
	2050	30.9	0.5	1.1	8.2	19.7	2.6	1.0	8.4	2.0	9.2	**83.1**	57.2	19.7
BASE	2030	0.0	0.0	0.0	0.0	0.0	0.8	0.8	4.2	0.6	68.7	**75.1**	71.5	N/A
	2050	0.0	0.0	0.0	0.0	0.0	0.7	0.7	8.4	2.0	54.9	**66.7**	57.2	N/A

10.6 TECHNOLOGY SPECIFIC PARAMETERS

2030													
Main fuel	Technology	Average efficiency	Average efficiency[1]	Cross efficiency[2]	Cross efficiency[2]	Minimum generation[3]	Minimum generation[3]	Minimum on time	Start-up costs[4]	Ramping up[3]	Ramping down[3]	Energy to Energy ratio[5]	ELF starting point[3]
		Elec	Heat	Elec	Heat	Elec	Heat					Elec	Elec
Nuclear	Nuclear	0.33	(-)	(-)	(-)	0.500	(-)	36.00	115.00	0.05	0.05	(-)	(-)
Nuclear	Nuclear_Agg	0.33	(-)	(-)	(-)	0.001	(-)	(-)	115.00	0.05	0.05	(-)	(-)
Lignite	Lignite	0.34	(-)	(-)	(-)	0.400	(-)	10.00	50.00	0.03	0.05	(-)	(-)
Lignite	Lignite_Agg	0.34	(-)	(-)	(-)	0.001	(-)	(-)	50.00	0.03	0.05	(-)	(-)
Coal	Coal	0.50	(-)	(-)	(-)	0.400	(-)	6.00	56.00	0.04	0.05	(-)	(-)
Coal	Coal_Agg	0.50	(-)	(-)	(-)	0.001	(-)	(-)	56.00	0.04	0.05	(-)	(-)
Gas	Gas_CCGT	0.61	(-)	(-)	(-)	0.330	(-)	2.00	25.00	0.04	0.07	(-)	(-)
Gas	Gas_CCGT_CHP	0.61	1.30	(-)	(-)	0.100	(-)	2.00	25.00	0.04	0.07	0.70	1.00
Gas	Gas_OCGT	0.39	(-)	(-)	(-)	0.200	(-)	2.00	50.00	0.04	0.05	(-)	(-)
Gas	Gas_OCGT_CHP	0.39	1.30	(-)	(-)	0.200	(-)	2.00	50.00	0.04	0.05	0.70	1.00
Gas	Gas_CCGT_Agg	0.61	(-)	(-)	(-)	0.001	(-)	(-)	25.00	0.04	0.07	(-)	(-)
Gas	Gas_OCGT_Agg	0.39	(-)	(-)	(-)	0.001	(-)	(-)	50.00	0.15	0.15	(-)	(-)
Biomass	Biomass	0.40	(-)	(-)	(-)	0.200	(-)	(-)	(-)	0.13	0.13	(-)	(-)
Biomass	Biomass_Agg	0.40	(-)	(-)	(-)	0.001	(-)	(-)	(-)	0.13	0.13	(-)	(-)
None	Battery	0.85	(-)	(-)	(-)	(-)	(-)	(-)	(-)	0.50	0.50	(-)	(-)
Waste	Waste_CHP	0.26	1.61	(-)	(-)	0.200	(-)	(-)	50.00	0.05	0.05	0.70	1.00
Waste	Waste_CHP_Agg	0.26	(-)	(-)	(-)	0.010	(-)	(-)	50.00	0.05	0.05	(-)	(-)
Biomass	Biomass_DH_Boiler	(-)	0.95	(-)	(-)	(-)	(-)	(-)	(-)	1.00	1.00	(-)	(-)
Gas	Gas_DH_Boiler	(-)	0.95	(-)	(-)	(-)	(-)	(-)	(-)	1.00	1.00	(-)	(-)
Gas	Gas_Condensing_Boiler	(-)	0.91	(-)	(-)	(-)	(-)	(-)	(-)	1.00	1.00	(-)	(-)
None	Data_Centre	(-)	(-)	0.33	(-)	(-)	(-)	(-)	(-)	1.00	1.00	(-)	(-)
None	Heat_Pump_House	(-)	(-)	0.17	(-)	(-)	(-)	(-)	(-)	1.00	1.00	(-)	(-)
None	Geothermal	(-)	(-)	0.15	(-)	(-)	(-)	(-)	(-)	1.00	1.00	(-)	(-)
None	Electricity_Boiler	(-)	(-)	1.05	(-)	(-)	(-)	(-)	(-)	1.00	1.00	(-)	(-)
None	ATES	(-)	0.99	(-)	(-)	(-)	(-)	(-)	(-)	1.00	1.00	(-)	(-)

2050													
Main fuel	Technology	Average efficiency	Average efficiency[1]	Cross efficiency[2]	Cross efficiency[2]	Minimum generation[3]	Minimum generation[3]	Minimum on time	Start-up costs[4]	Ramping up[3]	Ramping down[3]	Energy to Energy ratio[5]	ELF starting point[3]
		Elec	Heat	Elec	Heat	Elec	Heat					Elec	Elec
Gas	Gas_CCGT	0.62	(-)	(-)	(-)	0.33	(-)	2.00	25.00	0.04	0.07	(-)	(-)
Gas	Gas_CCGT_CHP	0.62	1.30	(-)	(-)	0.10	(-)	2.00	25.00	0.04	0.07	0.70	1.00
Gas	Gas_OCGT	0.42	(-)	(-)	(-)	0.20	(-)	2.00	50.00	0.04	0.05	(-)	(-)
Gas	Gas_OCGT_CHP	0.42	1.30	(-)	(-)	0.20	(-)	2.00	50.00	0.04	0.05	0.70	1.00
Gas	Gas_CCGT_Agg	0.62	(-)	(-)	(-)	0.001	(-)	(-)	25.00	0.04	0.07	(-)	(-)
Gas	Gas_OCGT_Agg	0.42	(-)	(-)	(-)	0.001	(-)	(-)	50.00	0.15	0.15	(-)	(-)
Biomass	Biomass	0.40	(-)	(-)	(-)	0.20	(-)	(-)	(-)	0.13	0.13	(-)	(-)
Biomass	Biomass_Agg	0.40	(-)	(-)	(-)	0.001	(-)	(-)	(-)	0.13	0.13	(-)	(-)
None	Battery	0.85	(-)	(-)	(-)	(-)	(-)	(-)	(-)	0.50	0.50	(-)	(-)
Biomass	Biomass_DH_Boiler	(-)	1.01	(-)	(-)	(-)	(-)	(-)	(-)	1.00	1.00	(-)	(-)
Gas	Gas_DH_Boiler	(-)	1.01	(-)	(-)	(-)	(-)	(-)	(-)	1.00	1.00	(-)	(-)
Gas	Gas_Condensing_Boiler	(-)	0.91	(-)	(-)	(-)	(-)	(-)	(-)	1.00	1.00	(-)	(-)
None	Heat_Pump_House	(-)	(-)	0.14	(-)	(-)	(-)	(-)	(-)	1.00	1.00	(-)	(-)
None	Data_Centre	(-)	(-)	0.29	(-)	(-)	(-)	(-)	(-)	1.00	1.00	(-)	(-)
None	Geothermal	(-)	(-)	0.15	(-)	(-)	(-)	(-)	(-)	1.00	1.00	(-)	(-)
None	Electricity_Boiler	(-)	(-)	1.05	(-)	(-)	(-)	(-)	(-)	1.00	1.00	(-)	(-)
None	ATES	(-)	0.99	(-)	(-)	(-)	(-)	(-)	(-)	1.00	1.00	(-)	(-)

1 The heat efficiency for CHP units is above 1 since the fuel input for generation is both counted for the electricity production and for the heat production. The overall efficiency of a CHP is then the weighted average of the heat and electricity efficiency.

2 Cross efficiency is, other than the normal efficiency, defined as the units of energy carrier needed to produce a unit of another energy carrier.

3 As a percentage of the maximum generation. The maximum generation is defined per generation unit individually.

4 In euro per MW of maximum generation.

5 As described in section 3.2.2 the energy-to-energy-ratio is defined for electricity.

10.7 MODEL RESULTS HEAT PRODUCTION

	HP		DH		DH-STES		DH-P2H		DH-STES-P2H		BASE	
	2030	2050	2030	2050	2030	2050	2030	2050	2030	2050	2030	2050
Capacity factors												
NGCC CHP	0.4%	1.5%	7.3%	0.8%	5.5%	1.5%	7.6%	0.6%	5.8%	2.4%	9.8%	5.6%
NGOC CHP	0.9%	0.1%	7.2%	0.2%	6.6%	0.1%	5.1%	0.2%	4.7%	0.0%	6.0%	1.2%
MWI	4.6%	0.0%	32.7%	0.0%	37.1%	0.0%	32.7%	0.0%	38.2%	0.0%	94.7%	0.0%
Biomass heat	1.2%	0.1%	11.2%	6.2%	6.4%	0.1%	11.3%	4.8%	7.7%	0.0%	17.9%	66.5%
Gas DH boiler	0.1%	0.0%	0.9%	0.6%	0.1%	0.0%	1.5%	0.5%	0.0%	0.0%	0.3%	5.4%
Gas Condensing boiler	22.6%	22.6%	22.6%	22.6%	22.6%	22.6%	22.6%	22.6%	22.6%	22.6%	22.6%	22.6%
Datacentre	1.1%	8.6%	10.9%	12.0%	11.0%	7.9%	14.4%	4.9%	14.4%	2.7%	0.0%	0.0%
Heat Pump	22.6%	22.8%	22.6%	22.8%	22.6%	22.8%	22.6%	22.8%	22.6%	22.8%	0.0%	0.0%
Geothermal Heat	41.4%	23.8%	65.3%	47.5%	73.1%	49.1%	65.3%	37.3%	73.3%	25.5%	0.0%	0.0%
Industry Waste Heat	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	89.7%	100.0%	95.7%	0.0%	0.0%
Electricity DH Boiler	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	5.7%	0.0%	10.3%	0.0%	0.0%
Production (TWh)												
NGCC CHP	0.09	0.09	2.29	0.44	1.56	0.09	2.41	0.33	1.58	0.01	2.58	0.91
NGOC CHP	0.05	0.00	0.38	0.03	0.34	0.00	0.27	0.03	0.25	0.00	0.31	0.16
MWI	0.13	0.00	0.91	0.00	1.04	0.00	0.91	0.00	1.07	0.00	2.31	0.00
Biomass heat	0.10	0.00	2.88	1.41	1.66	0.01	2.93	1.11	1.63	0.00	1.29	3.83
Gas DH boiler	0.01	0.00	0.24	0.13	0.02	0.01	0.16	0.05	0.00	0.00	0.02	0.31
Gas Condensing boiler	43.06	6.12	45.04	18.13	45.05	18.12	45.07	18.13	45.04	18.13	135.97	108.78
Datacentre	0.02	0.31	0.39	0.89	0.39	0.64	0.40	0.33	0.39	0.20	0.00	0.00
Heat Pump	84.45	90.32	68.29	61.31	68.30	61.28	68.34	61.27	68.30	61.30	0.00	0.00
Geothermal Heat	14.91	17.16	23.49	34.22	26.30	35.31	23.50	26.85	26.39	18.35	0.00	0.00
Industry Waste Heat	0.99	1.98	1.98	1.98	1.98	3.96	1.98	3.55	1.98	3.79	0.00	0.00
Electricity DH Boiler	0.00	0.00	0.00	0.00	0.00	0.00	0.05	6.84	0.01	17.73	0.00	0.00

10.8 Model results electricity production

	HP		DH		DH-STES		DH-P2H		DH-STES-P2H		BASE	
	2030	2050	2030	2050	2030	2050	2030	2050	2030	2050	2030	2050
Capacity factors												
IRES	34.7%	34.8%	34.7%	34.9%	34.7%	34.8%	34.7%	35.0%	34.7%	35.3%	34.7%	34.7%
Nuclear	99.1%	0.0%	99.0%	0.0%	98.9%	0.0%	99.0%	0.0%	99.0%	0.0%	99.1%	0.0%
Lignite	99.7%	0.0%	99.6%	0.0%	99.5%	0.0%	99.7%	0.0%	99.7%	0.0%	99.8%	0.0%
Coal	32.6%	0.0%	32.6%	0.0%	32.2%	0.0%	32.3%	0.0%	32.1%	0.0%	31.0%	0.0%
NGCC	74.2%	44.2%	74.1%	44.0%	74.2%	44.3%	74.4%	44.4%	74.3%	44.4%	73.3%	44.1%
NGCC CHP	51.3%	17.6%	52.7%	17.4%	53.6%	17.2%	52.5%	18.5%	52.7%	17.6%	50.0%	18.3%
NGOC	1.7%	0.6%	1.4%	0.5%	1.6%	0.6%	1.4%	0.6%	1.4%	0.6%	1.1%	0.5%
NGOC CHP	16.9%	3.1%	19.0%	0.8%	20.0%	3.0%	7.8%	1.5%	7.7%	3.5%	6.7%	1.6%
Biomass	14.0%	10.2%	14.0%	10.3%	13.8%	10.2%	13.9%	9.8%	14.1%	10.0%	12.2%	9.2%
MWI	99.8%	0.0%	99.4%	0.0%	99.2%	0.0%	99.4%	0.0%	99.3%	0.0%	99.3%	0.0%
Production (TWh)												
IRES	635.93	1,217.65	634.08	1,215.96	633.97	1,213.15	634.16	1,217.96	634.03	1228.63	626.03	1,198.60
Nuclear	46.81	0.00	46.78	0.00	46.75	0.00	46.81	0.00	46.79	0.00	46.85	0.00
Lignite	82.32	0.00	82.29	0.00	82.18	0.00	82.32	0.00	82.31	0.00	82.39	0.00
Coal	66.11	0.00	66.17	0.00	65.42	0.00	65.58	0.00	65.16	0.00	63.09	0.00
NGCC	513.17	417.82	512.66	416.31	513.35	419.14	514.50	420.25	514.38	419.58	508.68	417.66
NGCC CHP	18.88	12.97	19.38	12.84	19.71	12.66	19.33	13.38	19.39	12.69	18.39	13.25
NGOC	7.28	3.93	6.26	3.18	7.06	3.72	6.03	4.01	6.23	3.53	4.58	3.10
NGOC CHP	0.62	0.11	0.70	0.12	0.74	0.10	0.29	0.17	0.28	0.12	0.25	0.15
Biomass	27.84	32.88	27.88	32.96	27.47	32.62	27.54	31.23	28.01	31.88	23.81	28.94
MWI	32.66	0.00	32.45	0.00	32.39	0.00	32.46	0.00	32.43	0.00	31.88	0.00

10.9 Costs, emissions and curtailment

Costs

	HP		DH		DH-STES		DH-P2H		DH-STES-P2H		BASE	
(M€/yr)	2030	2050	2030	2050	2030	2050	2030	2050	2030	2050	2030	2050
Unit VO&M costs	46,491	36,785	46,653	37,280	46,644	37,451	46,638	37,569	46,587	37,405	49,370	41,972
Start-up/Shutdown costs	179	219	153	217	190	206	153	214	154	208	133	247
Unit investments	37,517	46,425	37,244	45,902	37,311	45,943	37,225	45,972	37,272	45,959	34,845	43,378
Unit FO&M costs	666	930	663	923	663	924	663	924	663	925	637	887
Infrastructure investments	5,221	7,540	5,665	8,022	5,704	7,983	5,816	8,606	5,692	8,973	5,190	7,548
System costs	104,483	109,339	104,625	109,526	104,771	109,716	104,703	110,370	104,613	110,480	103,646	110,353 +

Emissions and curtailment

	HP		DH		DH-STES		DH-P2H		DH-STES-P2H		BASE	
	2030	2050	2030	2050	2030	2050	2030	2050	2030	2050	2030	2050
$MtCO_2$/yr	331.8	143.6	332.2	145.5	332.1	146.5	332.0	147.4	331.6	146.6	347.1	166.3
Curtailment electricity (GWh)	559	44,946	529	46,365	554	44,280	570	39,461	585	28,792	641	47,922
Curtailment heat (GWh)	0	0	0	0	0	0	0	410	0	165	0	0

Costs (detailed) (M€/yr)	HP		DH		DH-STES		DH-P2H		DH-STES-P2H		BASE	
	2030	2050	2030	2050	2030	2050	2030	2050	2030	2050	2030	2050
Costs calculated by PowerFys												
VO&M	46,491	36,785	46,653	37,280	46,644	37,451	46,638	37,569	46,587	37,405	49,370	41,972
Start-up/Shutdown	179	219	153	217	190	206	153	214	154	208	133	247
Costs calculated in Excel												
Total investment costs	**37,517**	**46,425**	**37,244**	**45,902**	**37,311**	**45,943**	**37,225**	**45,972**	**37,272**	**45,959**	**34,845**	**43,378**
Total fixed O&M	**666**	**930**	**663**	**923**	**663**	**924**	**663**	**924**	**663**	**925**	**637**	**887**
Infrastructure	**5,221**	**7,540**	**5,665**	**8,022**	**5,704**	**7,983**	**5,816**	**8,606**	**5,692**	**8,973**	**5,190**	**7,548**
HV grid expansion	2,008	3,067	1,942	2,961	1,960	2,943	2,011	3,226	1,954	3,393	1,628	2,704
MV grid expansion	2,409	3,680	2,330	3,553	2,352	3,532	2,413	3,871	2,345	4,072	1,954	3,245
LV grid expansion	68	167	54	117	54	117	54	117	54	117	0	0
DH grid	240	511	813	1,129	813	1,129	813	1,129	813	1,129	96	81
Gas grid	473	82	507	236	507	236	507	236	507	236	1,504	1,504
Smart charging EV	8	14	8	14	8	14	8	14	8	14	8	14
Flexible HP	14	19	11	13	11	13	11	13	11	13	0	0