MSc Thesis Energy Science

Modeling Local Energy Systems in PLEXOS – Coupling Electricity and Heat Demand in Search for Improved Flexibility

Maarten Sosef

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Author	Maarten Sosef Student number: 3508943 maartensosef@gmail.com Graaf Adolftraat 40 3585 VV Utrecht, the Netherlands
Date	August 11 2017
Place	Utrecht, The Netherlands
Utrecht University	Heidelberglaan 8, Bestuursgebouw 3584 CS Utrecht, the Netherlands
DNV GL	Utrechtseweg 310, Building B50 Energy Business Park - Arnhems Buiten 6812 AR Arnhem, the Netherlands

Utrecht University Supervisors

Daily Supervisor:	ir. William Zappa
Main Supervisor:	dr. ir. Machteld van den Broek
Second Reader:	dr. Wilfried van Sark

DNV GL Supervisors

Daily Supervisor:	Pieter van der Wijk
Second Supervisor:	Wim van de Veen

Universiteit Utrecht
Faculty of Geosciences

DNV·GL

Preface and Acknowledgements

I conducted this thesis during an internship at DNV GL Arnhem from September 2016 to August 2017. I arrived at DNV GL after a meticulous search for a graduation internship and have enjoyed expanding my knowledge there. The choice to use PLEXOS as a research method directly results from this opportunity. The majority of the thesis has been spent working part-time making 24 hour workweeks. To discuss progress, (bi)-weekly meetings were held with my supervisors Pieter van der Wijk and Wim van der Veen at DN VGL, and every three to four weeks with William Zappa at Utrecht University. At critical moments, their supervision combined with insightful guidance from Machteld van der Broek secured my progression into the next phase of research.

The path towards this thesis's completion has often been rougher than predicted and I often found myself in less than favorable personal circumstances. Conducting this final assignment before graduating in a field I feel passionate about has been an insightful challenge both as a student and as a person. I would like to express my gratitude for the understanding and assistance that I received from my supervisors when, more than once, my mind seemed preoccupied with a disorganized fog. Although it required more time and energy than expected, I feel I arrived at a final station. Ready to soon start another journey in the vast landscape of Energy Science.

Abstract

Integrating large capacities of intermittent renewable energy sources (iRES) poses significant challenges in the path towards decarbonization. Increased flexibility of the power system is often coined as a solution to the integration problem but remains an ambiguous concept that is often only sought after in the electricity sector. This thesis follows a more holistic view towards this problem and explores the potential of coupling the electricity sector with the heating sector in local energy systems for increased flexibility. A PLEXOS model has been developed to assess the potential benefits of electricity-heat coupling for decarbonization.

The PLEXOS model includes one dense urban neighborhood with residential electricity and heating demand profiles for the year 2016 and four technological heating scenario's. The performance of each scenario is assessed using indicators for energy consumption, CO_2 emissions, flexibility (measured as self-consumption and peak flow and demand), and costs (investment and operation). These scenarios include a reference scenario with condensing gas boilers, a centralized heating scenario with CHP powered district heating, an electrification scenario using heat pumps, and an advanced gas heating scenario using mCHP's. Variations in PV capacity ranging from current penetration levels to a share of 25% and 50% of households serve to establish the baseline flexibility in each scenario. Further variations with thermal storage on a district level combined with a large-scale heat pump, electric battery storage, flexible feed-in tariffs and flexible electricity pricing are explored to assess their effects.

The results show reductions in emissions and signs of increased flexibility in all alternative scenarios. While electrification and mCHP's increase self-consumption the most, the peak electrical flow a least triples in these simulations. Adding electrical energy storage to each scenario further improves self-consumption, and the effect of flexible electricity prices only reduces costs in scenarios equipped with a heat pump. The potential benefits of electricity-heat coupling on a local level noteworthy but remain modest.

Contents

1. Introduction

In the pursuit towards a decarbonized power system, PV and wind power are expected to become two of the most prevalent sources of renewable energy in the coming decades now their investment costs are increasingly competitive with fossil energy sources. While the penetration of these intermittent renewable energy sources (iRES) increases, the unpredictability of their generation becomes more of challenge for their integration into power systems. Traditional measures for flexibility will be unable to maintain reliable operation above an iRES share of roughly 20% in overall electricity consumption. Curtailment of iRES is then needed during low demand periods to prevent grid outage and congestion (European Commission, 2015).

Increasing flexibility in these systems is often touted as a solution to the integration problem. However, in the absence of a single and concise definition of the concept of flexibility, its precise meaning often needs to be derived from the context of its application. In general, flexibility relates to the extent to which a power system can maintain reliable operation under rapid changes in supply or demand. Traditionally it is provided by reserves with varying ramping rates that either provide additional power generation and/or reducing the system load, or by reducing power generation and/or increasing system load (ECOFYS, 2014). New sources of flexibility are essential to solving the integration problem in pursuit of decarbonization.

Different opportunities and solutions are identified and developed to increase flexibility and allow a higher integration of iRES. Many of these remain close to the origin of the integration problem and focus on the power sector for increased flexibility. A perspective that is gaining popularity suggests that the majority of the required flexibility can actually be offered by the inherent capabilities of the energy system itself. It acknowledges that electricity is only part of the total energy demand, and shows that valuable integration opportunities can be found in other energy sectors (Lund, Lindgren, Mikkola, & Salpakari, 2015). The importance of taking such a holistic, whole-energy system perspective when planning for decarbonization is gaining recognition and signifies that a true decarbonized energy system not only features a decarbonized electricity sector, but a decarbonized heating, cooling and transport sector too (Mancarella, Andersson, Peças-Lopes, & Bell, 2016).

Research has shown that merging the individual energy sectors, allowing multiple energy sources to interact with each other, offers significant opportunities for the integration of large amounts of iRES and is economically feasible (Capuder & Mancarella, 2014; Mathiesen et al., 2015). The EnergyPLAN model has been used to show that a combination of combined heat and power (CHP) plants, heat pumps and power to gas technologies can couple the electricity, heating and transport sectors on a national scale and result in energy savings and increased flexibility (Mathiesen et al., 2015). The concept of multi-energy systems (MES) aims to identify how individual sectors can be merged using (distributed) multi-generation technologies and how their collective performance can be improved (Mancarella et al., 2016). In this respect, different combinations of boilers, CHPs, thermal storage and/or electrical heat pumps have been studied for their operation on a district scale. Compared with traditional flexibility options, flexible and combined operation of these technologies offers significant benefits in terms of cost, primary energy demand and emissions (Capuder & Mancarella, 2014).

Simultaneously, the importance of the municipal level is increasingly recognized in realizing integrated energy approaches (Mirakyan & De Guio, 2013). Considering that cities were responsible for 30% to 40% of global anthropogenic GHG emissions in 2004 (Satterthwaite, Satterthwaite, Haughton, Budds, & Dodman, 2008) local dimensions can have a key role in addressing the challenges towards decarbonization and are highlighted for their potential to implement solutions (Pasimeni et al., 2014). However, most research related to coupling electricity and heating is limited to the impacts of heat pumps on system planning and the integration of district heating systems, often in combination with thermal storage (Heinen, Burke, & O'Malley, 2016).

While different combinations of coupling technologies have been assessed in terms of costs and emission reductions on a district level, the interactions between the technologies itself and the extent to which they can offer flexibility on a local scale remain unclear. The effects of and interactions between different types of (distributed) electricity-heat coupling technologies in a local (city) energy system and their benefits for decarbonization are not adequately assessed.

The size, complexity and dynamics of energy systems impede intuitive predictions as only one incorrect decision, e.g. an undersized transmission line capacity, can have significant negative consequences (Mancarella et al., 2016). Hence, models are widely used and developed to make informed choices about innovations in the energy system. Even though such assessment tools for energy planning and operation are readily available, the holistic approach outlined above is seldom incorporated.

The integrated energy modelling tool PLEXOS[1] is currently used for research using power system modeling at Utrecht University. However, the focus of this research lies on the power sector, omitting the potential benefits from coupling other energy sectors. [although, gas is available and heat on large scale with CHP plants]. Understanding how PLEXOS can be used to research coupling of the electricity and heating sectors on a local scale and if it is a suitable model for future research on this topic is part of this research.

While the importance of local energy planning is increasing, the potential benefits of coupling the electricity and heating sectors remain uncertain. Therefore, this research aims to develop a PLEXOS model that can capture interactions of a local energy system that has characteristics of a MES. Specifically, MES interactions that result from coupling the electricity and heating sector and their effects on flexibility as iRES integration will be a focus in this research. The research questions are:

Main research question:

- *What are the potential benefits of electricity-heat coupling in local energy systems?*

Sub research questions:

- *What type of local interactions are possible between the electricity and heating sector?*
- *How can local electricity-heat sector coupling be modeled in PLEXOS?*
- *How do different coupling portfolios perform technically and economically?*
- *To what extent can electricity-heat coupling increase flexibility and aid decarbonization through increased iRES integration?*

In this research, we seek to answer these questions by focusing on a densely-populated city neighborhood from Utrecht as a research case. PLEXOS is used to represent the research case as a local energy system to study the coupling of electricity- and heat demand. Residential electricity and heating demand profiles are created to be representative for the year 2016. The used residential electricity and heating demand profiles and energy conversion technology portfolios allow simulations for a full year at hourly resolution and enables PLEXOS to fulfill current energy consumption levels under different technological scenarios.

[1] PLEXOS integrated energy model. Developed by Energy Exemplar (https://energyexemplar.com/software/plexos-desktop-edition/).

2. Method

The primary objective of this research is to assess the potential benefits of coupling the electricity and heating demand in local energy systems and its contribution to decarbonization by constructing a model in PLEXOS. This requires the construction of a local energy system in PLEXOS, and technology portfolios capable of electricity-heat coupling. Based on this, the method of this research consists of 7 parts as shown in Figure 1:

1. Create electricity and heating demand profiles for neighborhood
2. Define energy conversion technology scenarios
3. Collect techno-economic parameters for relevant technology portfolios
4. Construct the neighborhood model in PLEXOS
5. Define indicators for overall system performance and flexibility
6. Analyze simulation results
7. Perform sensitivity analysis

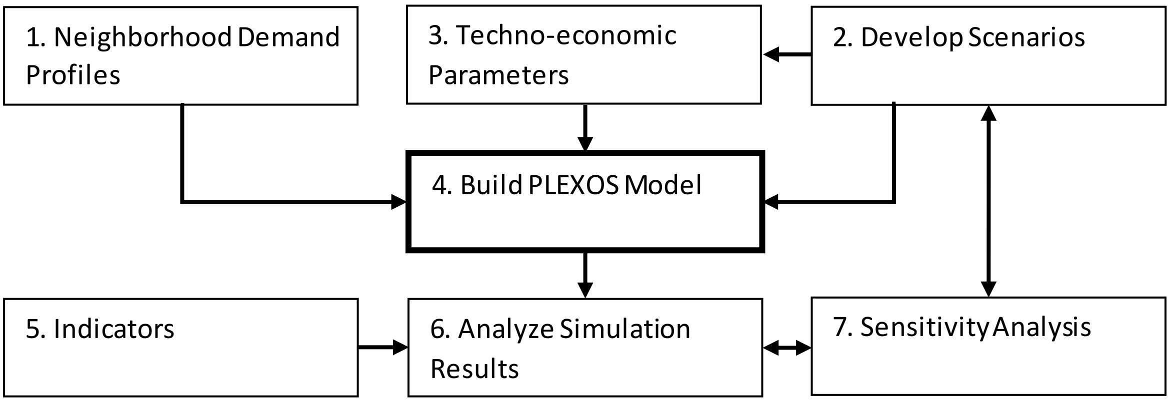

Figure 1 - Method Outline

The PLEXOS model lies at the core of the method and offers a flexible tool to research different heating scenarios. The model matches the hourly demand for electricity and heating of a Dutch residential neighborhood with the dispatch of energy technologies. Techno-economic parameters for heat and electricity generation and conversion technologies including gas boilers, district heating, heat pumps, micro CHP, and electrical and thermal storage, are used. Then, four heating scenarios are developed, reflecting possible future developments in the heating sector. With these inputs, the PLEXOS model runs simulations in which it matches dispatch with the demand for heat and electricity in every hour of the simulation year. A select number of parameters from the simulation results are used as indicators to quantify the performance of the local energy system in terms of fuel consumption, emissions, costs and flexibility. A flexible electricity price is added to the simulations as a means to assess the sensitivity of the results

2.1. Energy Demand Profiles

Table 1 are used to construct the demand profiles for PLEXOS and to determine the technology capacities Section 2.3. *Wilhelminapark en omstreken* is a densely populated residential neighborhood in Utrecht. Compared to the Utrecht average for the year 2016, the annual electricity and gas consumption of 2576 kWh and 985 m^3 per household lies 8% and 6% higher respectively. The household composition (single, no kids, kids) lies within 1% of the average neighborhood in Utrecht.

The above average consumption can likely be attributed to the assumption that their insulation is below average due to the relatively old building stock.

Table 1 – CBS Neighborhood Statistics for 2016 (CBS, n.d.)

	Wilhelminapark en omstreken
Number of residents	2625
Number of households	1320
Average residents per household	2,0
Population density [residents / km^2]	5344
PV capacity (2014) [MW][a]	0.082
Share of District Heating (2015)	38%
Residential Electricity Consumption [GWh/yr]	3,4
Residential Gas Consumption [10^6 m^3/yr]	1,3

[a]Total PV capacity in Utrecht of 9 MWp allocated to individual neighborhoods based on their share of total residential electricity consumption (Gemeente Utrecht, 2015).

The neighborhood in our PLEXOS model requires demand profiles that specify its electricity and heating demand for every hour of the year. This is important as demand is affected by time of day, the day of the week and by the seasons. Furthermore, the profile differs per consumer so it is important to make a clear distinction between consumer types. In our research, we focus on residential consumers only.

The demand profiles of our neighborhood are based on two parts, hourly residential energy demand measurements and annual energy consumption statics from the research case neighborhood (Table 1). This allows us to construct neighborhood profiles that reflect real-world consumption patterns for our research case. The outline in Figure 2 shows the steps in this process.

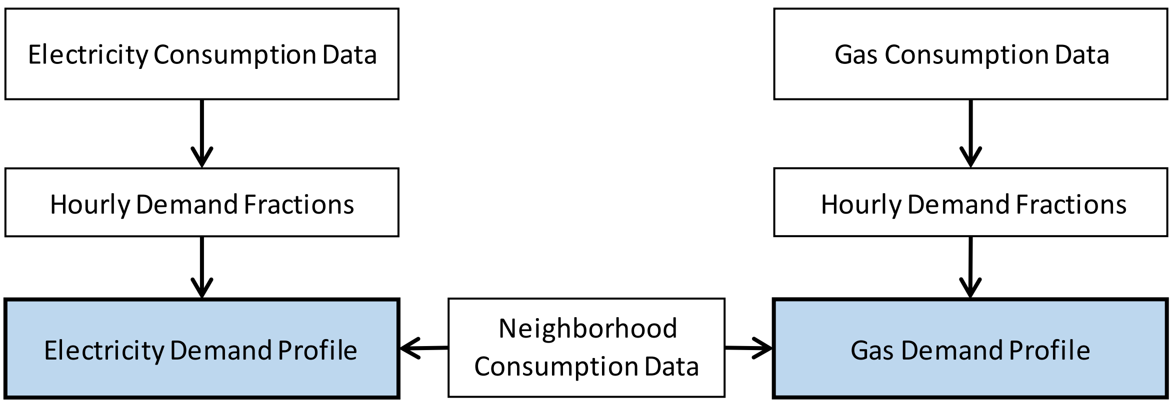

Figure 2 - Outline of demand profile construction

Following the approach outlined above, we start with extracting residential hourly demand fractions (f_h) from electricity and gas consumption data (Liander, 2017)[2] using Equation 1a and 1b, where d_h is

[2] The residential electricity and gas consumption measurements are from Liander (Liander, 2017). The electricity consumption measurements are available for the year 2008 for consumers with at most a 3x25 Ampere connection, which is typical for households. The gas consumption measurements are available for the year 2009 for consumers with an annual

the reported consumption in MWh during hour h and D is the total annual consumption of the measurements. The subscripts e and g refer to electricity and heat respectively. Gas consumption is used as a proxy for the heating demand as in the Netherlands heating is almost exclusively supplied using natural gas.

$$f_{e,h} = {d_{e,h}}/{D_e} \qquad \text{Eq. 1a}$$

$$f_{g,h} = {d_{g,h}}/{D_g} \qquad \text{Eq. 1b}$$

Hourly demand fractions: f_h
Hourly consumption: d_h
Annual consumption: D

We use the hourly demand fractions from Equation 1a and 1b to create electrical- and heating demand profiles for our neighborhood by multiplying the hourly fractions with the annual electricity and heat consumption of the neighborhood as in Equation 2a and 2b. The resulting neighborhood demand profile with annual demand values in MW can be imported into PLEXOS. The neighborhood demand profile for our model is based on the data in Table 1.**Error! Reference source not found.**

$$dp_{e,h} = f_{e,h} * D_{e,N} \qquad \text{Eq. 2a}$$

$$dp_{th,h} = f_{g,h} * D_{g,N} \qquad \text{Eq. 2b}$$

Demand profile: dp_h
Hourly demand fractions: f_h
Annual consumption from research case neighborhood: D_N

The group size from which the measurements are taken should be large enough, as a profile from a single consumer does not account for the temporal differences in demand in larger groups that smooth the profile. The group sizes of our consumption data are in the thousands, which is enough to ensure a smoothed profile (DNV GL, 2017a). The created demand profiles used in the simulations are presented in Figure 3 to Figure 6 below.

consumption up to 5000 m^3 of natural gas and are temperature corrected based on an average temperature profile of the 20 years prior to the measurements[2]. Both the electricity and gas measurements are based on a group of 10000 consumers.

Neighborhood Electricity Demand Profile

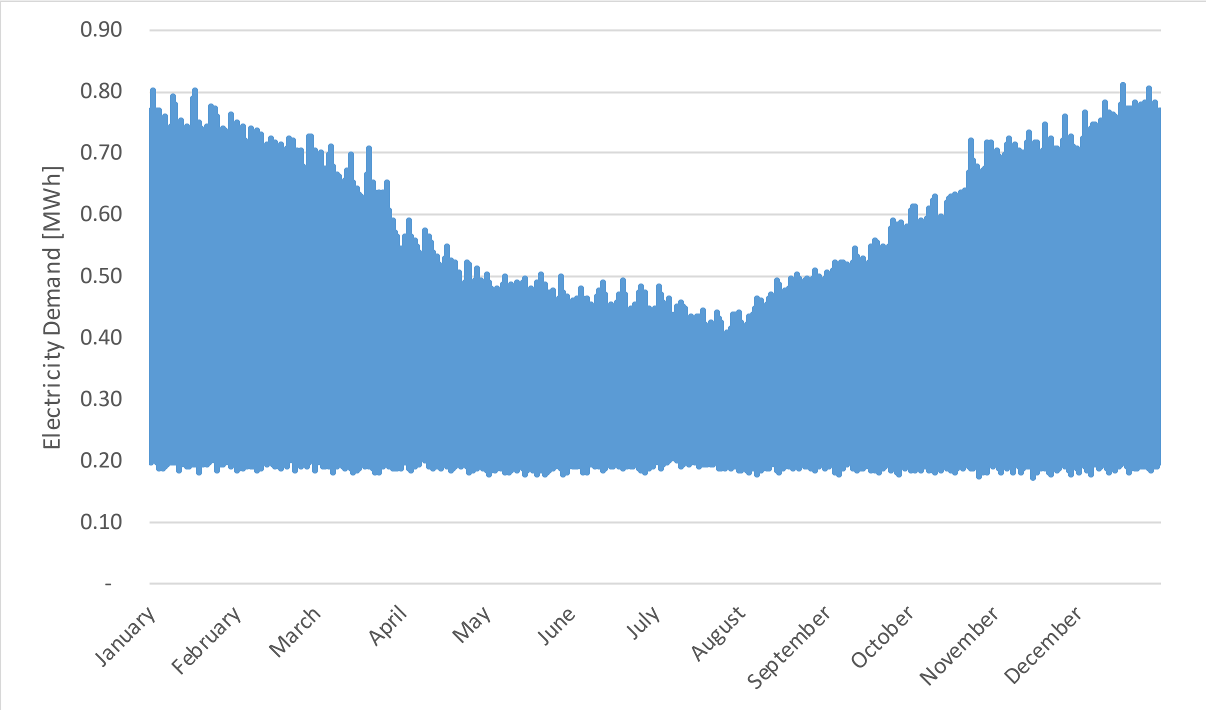

Figure 3 - Hourly electricity demand profile for the PLEXOS neighborhood for the full simulation year.

Detailed Neighborhood Electricity Demand Profile

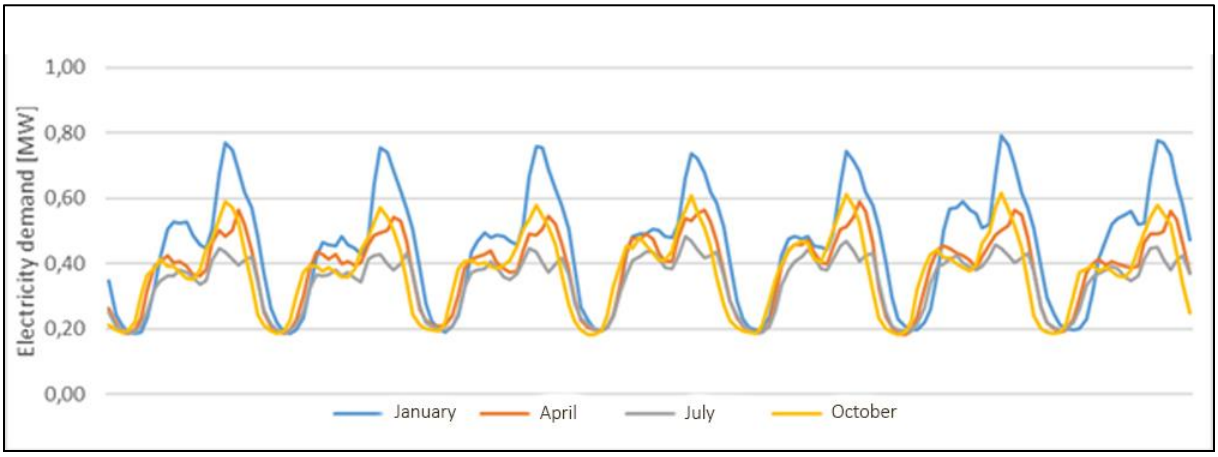

Figure 4 - Hourly electricity demand profile for the PLEXOS neighborhood. Series 1 to 4 stand forr the first week of January, April, July and October. Showing seasonal differences in demand.

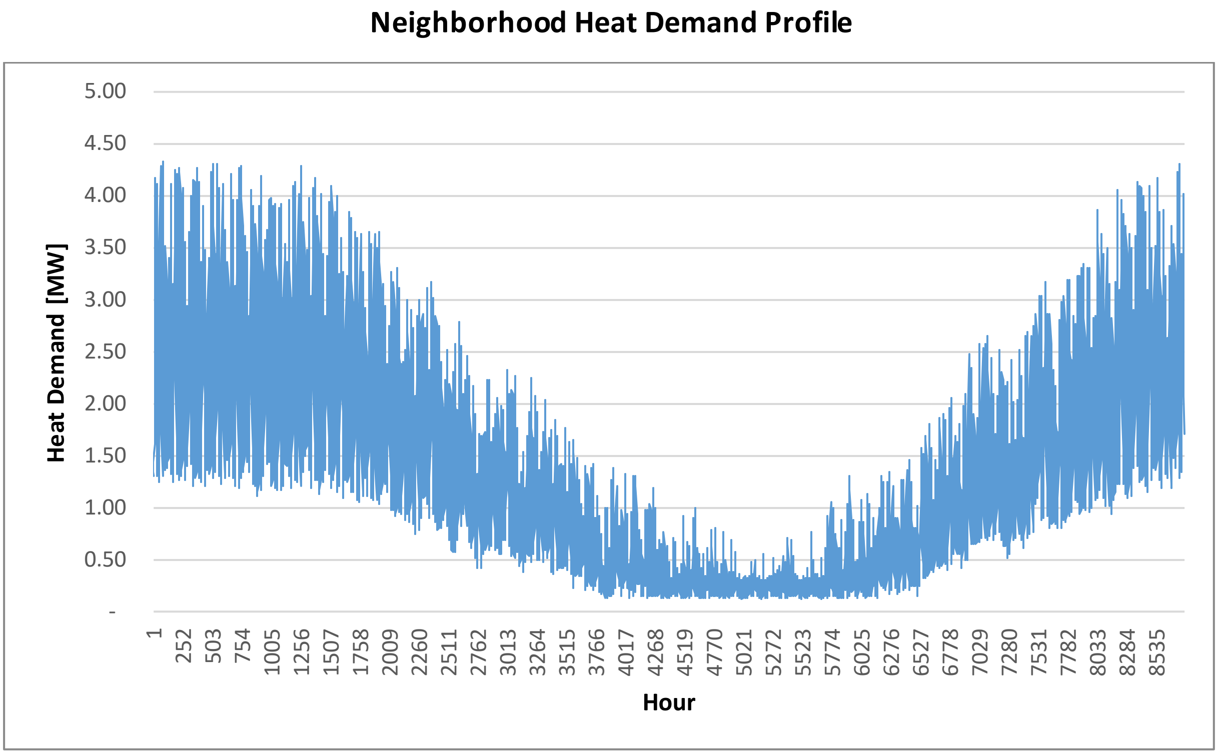

Figure 5 - Hourly heat demand profile for the PLEXOS neighborhood for the full simulation year.

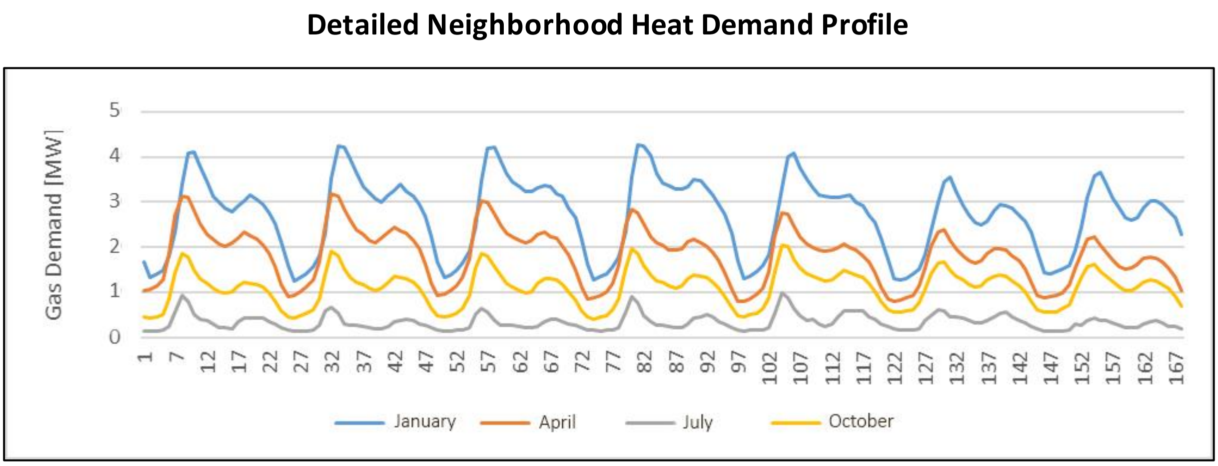

Figure 6 - Hourly heat demand profile for the PLEXOS neighborhood. Series 1 to 4 stand for the first week of January, April, July and October for the first week of January, April, July and October. Showing seasonal differences in demand.

2.2. Define scenarios

Due to uncertainty in the future developments of the heating sector, we model several scenarios to look at how different developments in the heating sector could influence the prospects for heat-electricity sector coupling. Each of these scenarios represents an extreme situation in which one heating technology is applied to all the households in the neighborhood. The following scenarios and core developments are used:

- a **reference** scenario, assuming business as usual where condensing gas boilers remain the dominant heating technology. Coupling between electricity and heat is not present.
- a **district heating** scenario with a high reliance on centralized heating using CHP-powered district heating and neighborhood-level thermal energy storage. Coupling between electricity and heat, exists in the CHP plant in the form of gas, to electricity and heat, and when combined with thermals storage and a heat pump in the form of electricity to heat.
- an **electrification** scenario with a high reliance on electrical heating using residential heat pumps. Coupling between electricity and heat in the form of electricity to heat.
- a **micro-CHP** scenario with a high reliance on advanced gas heating using micro CHPs. Coupling between electricity and heat take place in the form of gas to electricity and heat.

Table 2 shows the scenarios and the technologies shares used in the PLEXOS model.

Table 2 – Simulation Scenarios

Scenario	Core Development	Main Heating Technology	Heating Technology Shares			
			Gas Boiler	DH	HP	mCHP
(REF) Reference	Business as usual	Condensing gas boilers	100%	0%	0%	0%
(DH) District Heating	Centralized heating	CHP driven district heating network	0%	100%	0%	0%
(ELEC) Electrification	Electrical heating	Residential heat pumps	0%	0%	100%	0%
(mCHP) Micro CHP	Advanced gas heating	Residential micro CHP	0%	0%	0%	100%

Certain variations on these scenarios are selected to simulate promising combinations or likely developments in PV penetration levels[3], thermal energy storage (TES), electrical energy storage (EES), feed-in tariffs and energy pricing. The following variations can be added to the base scenarios from Table 2:

- Current PV Penetration: Current PV penetration from the research case is used to determine total PV capacity (see Table 1).
- Medium PV Penetration: 25% of households are equipped with a PV system.
- High PV Penetration: 50% of households are equipped with a PV system.
- TES Heat Pump (TES HP): A district scale heat pump is connected to the TES in the district heating network.

[3] PV penetration levels are calculated as the % of households equipped with a PV system.

- Electrical Energy Storage (EES): 10% of the households are equipped with electrical battery storage (total storage capacity: 924 kWh).
- Flexible Feed-in Tariff (FFIT): A flexible- instead of a flat feed-in tariff is used to sell excess residential PV and mCHP electricity generation back to the grid. The tariff is based on hourly spot prices. See section 2.3.2 for more information.
- Flexible Electricity Price (FEP): Hourly- instead of a flat electricity prices are used based on APX spot prices. See section 2.3.2 for more information.

The variations in PV penetration levels serve to establish the baseline flexibility under the different heating technologies for each scenario. For simulations #1-3, #4-6, #9-11 and #14-16, variations with the current, medium and high PV penetration levels are simulated for each base scenario.

These base line simulations are further expanded upon in simulations #7, #12 and #17 featuring an appropriate form of storage combined with a flexible feed-in tariff (FFIT) to simulate a more dynamic incentive for utilizing storage. In the DH scenario thermal energy storage is provided by TES and in the ELEC and mCHP scenario electrical energy storage is provided by household batteries (EES) to allow for shifting in demand and generation. As a sensitivity analysis, the storage simulations are further expanded upon with flexible electricity pricing (FEP) in simulation #8, #13 and #18 to further incentivize dynamic storage.

Combining the base scenarios with different variations results in 18 different simulations. These are shown in Table 3. The storage and sensitivity simulations are all simulated in PLEXOS with a MT plan in addition to the ST plan. See Section 2.4 for more information.

Table 3 - Simulations and selected scenario variations:

Simulation	Scenario	Baseline			Storage			Sensitivity
		Low PV	Medium PV	High PV	TES + HP	*EES*	Flex Feed-In Tariff (FFIT)	Flex Energy Price (FEP)
#1	REF	x						
#2	REF		x					
#3	REF			x				
#4	DH	x						
#5	DH		x					
#6	DH			x				
#7	DH			x	x		x	
#8	DH			x	x		x	x
#9	ELEC	x						
#10	ELEC		x					
#11	ELEC			x				
#12	ELEC			x		*x*	x	
#13	ELEC			x		*x*	x	x
#14	mCHP	x						
#15	mCHP		x					
#16	mCHP			x				
#17	mCHP			x		*x*	x	
#18	mCHP			x		*x*	x	x

2.3. Techno-economic parameters for generation and conversion technologies

2.3.1. Main Technologies

To model the energy generation and conversion technologies described in 2.1, we need data about their techno-economic characteristics. For generators, these data include the fuel type, maximum capacity and efficiency. The investment and maintenance costs are also needed to calculate the total costs of each scenario.

Table 4 shows an overview of the modeled technologies and their techno-economic parameters that will be used to construct the PLEXOS model.

Table 4 - Techno-economic parameters for generation and storage technologies

Heating Technologies

Delivered Energy	Technology	System Level	Fuel	Unit capacity	Total capacity in PLEXOS	Efficiency (LHV) [%] / COP range	Unit Price [2015 €]	Unit Price [€/KW_{th}] [2015 €]
Heat	Condensing Gas Boiler	Consumer	Gas	34.15 kW_{th}[a]	1320 kW_{th}	94.5%[a]	€1,000[b]	29.28
	District Heating	Neighbor-hood	Gas	n/a	1320 kW_{th}	86.1%[c]	€3,600[d]	-
Heat-Electricity	District Heating heat pump	Neighbor-hood	Electric	500 kW_{th}	500 kW_{th}	1.16 - 5.26[e]	€800,000[f]	1,600.00
	mCHP	Consumer	Gas	24.9 kW_{th}, 1 kW_e[k]	1320 kW_{th}, 53kW_e	96.0%[k]	€9,500[k]	366.80
	Air Source Heat Pump	Consumer	Electric	9.25 kW_{th}[d]	1320 kW_{th}	1.16 - 5.26[e]	€5,400[g]	583.78

iRES Technologies

Sector	Technology	Level	Unit capacity [kW]	Unit Price [2015 €]	Unit Price [€/kW] [2015 €]
Electricity	PV	Consumer	3[h]	€4,050[h]	1,350.00

Storage Technologies

Sector	Technology	Level	Max charge/discharge [kW]	Unit capacity [kWh]	Efficiency	Unit Price [2015 €]	Unit Price [€/KWh] [2015 €]
Heat	Thermal Energy Storage	Neighbor-hood	3966[i]	353,000[i]	87.0%[i]	€1,260,000[f]	3.57
Electricity	Electrical Storage	Consumer	5[j]	13.5[j]	90.0%[j]	€6,300[j]	466.67

a, Average of Remeha Calenta 28c and 40c and *Seisoensgebonden energieefficientie ruimteverwarming* used for efficiency (Remeha, 2017a)
b, Unit price based on 2017 internet prices
c (Heat delivered to dwelling + commercial in Utrecht city network) / Heat produced for Utrecht city network (incl. 15% distribution loss): $\frac{1200\ TJ+1900\ TJ}{3600 TJ} = 86.1\%$ (Niessink & Rösler, 2015).
d, Average from (Cooper, Hammond, McManus, & Rogers, 2014).
e, Winter and summer COP (Hepbasli & Kalinci, 2009).
f, (DNV GL, 2017a)
g, (Homeadvisor, 2017).
h, Average system size for households in the Netherlands (Gasunie & DNV GL, 2014).
i, Ecovat M. Stated efficiency is the seasonal efficiency, see section 2.4 for PLEXOS implementation. (Ecovat, 2015).
j, Tesla Powerwall II. Stated efficiency is the round-trip efficiency (Tesla, 2017).
k, Remeha Evita (Remeha, 2017b).

2.3.2. Price and Emissions of Electricity and Gas, and electrical feed-in tariffs

Both the electricity and gas in the national grid are modelled as fuels with a fixed CO_2 production rate. For electricity the emissions factor of 146.1 kg CO_2/GJ is used, representing grey electricity produced from the average grid mix in the Netherlands in 2015 (CO2 Emissiefactoren, 2015)[4]. For natural gas the Dutch emission factor of Dutch natural gas combustion of 56.8 kg CO_2/GJ is used (Heslinga & Harmelen, 2006).

Table 5 shows the electricity and gas price components used to set prices in the PLEXOS model.

Table 5 - Electricity and gas price components based on reported consumer prices for 2015, except the flex component which is based on 2015 APX spot prices.

		Electricity Price [€/kWh]		Gas Price [€/m3]
		Fixed price	Flexible price	Fixed price
	Fixed Component	0.150	0.150	0.340
Feed-In Tariffs	Flexible Component *(average)*	-	*(0.078)*	-
	Flat Component	0.078	-	0.330
	Total *(Average)*	**0.228**	***(0.228)***	**0.670**

The electricity price is build up from a fixed component, and either a flexible- or flat component depending if flexible electricity prices are simulated or not. The average Dutch electricity price per kWh in 2015/2016 was €0.22, consisting of €0.12 taxes, €0.035 BTW, and around €0.06 for the production of electricity itself (Energiesite, 2017). Based on this the fixed component in our electricity price consists of €0.12/kWh taxes and €0.030/kWh BTW[5]. Depending on the choice for a fixed or flexible electricity price in the simulation the remainder of the electricity price consists of a flexible or flat component.

The flexible component consists of the 2015 APX spot price. The flat component of the fixed electricity price is determined by calculating the weighted average of the cost of electricity using the hourly APX spot prices and the hourly electricity demand of the PLEXOS neighborhood. In this way, the average cost of both the fixed and flexible electricity price are equal and close to the reported residential consumer prices. The green shade in Table 5 indicates the feed-in tariffs for electricity that can be used in our model. The flexible feed-in tariff consists of the flexible component (thus 2015 APX spot prices) and the flat feed-in tariff consists of the flat component.

The gas price is fixed in all the simulations and is based on reported residential gas prices per m^3 for 2014/2015, consisting of €0.34 taxes and €0.33 for the gas itself.

The flexible profiles for feed-in tariff and electricity pricing are presented in Figure 7 and Figure 8 below.

[4] Reported 0.526 kg CO_2/kWh for the average Dutch grey electricity mix in 2015.

[5] €0.030 is used instead of €0.035 to make the total price closer to the reported residential consumer prices.

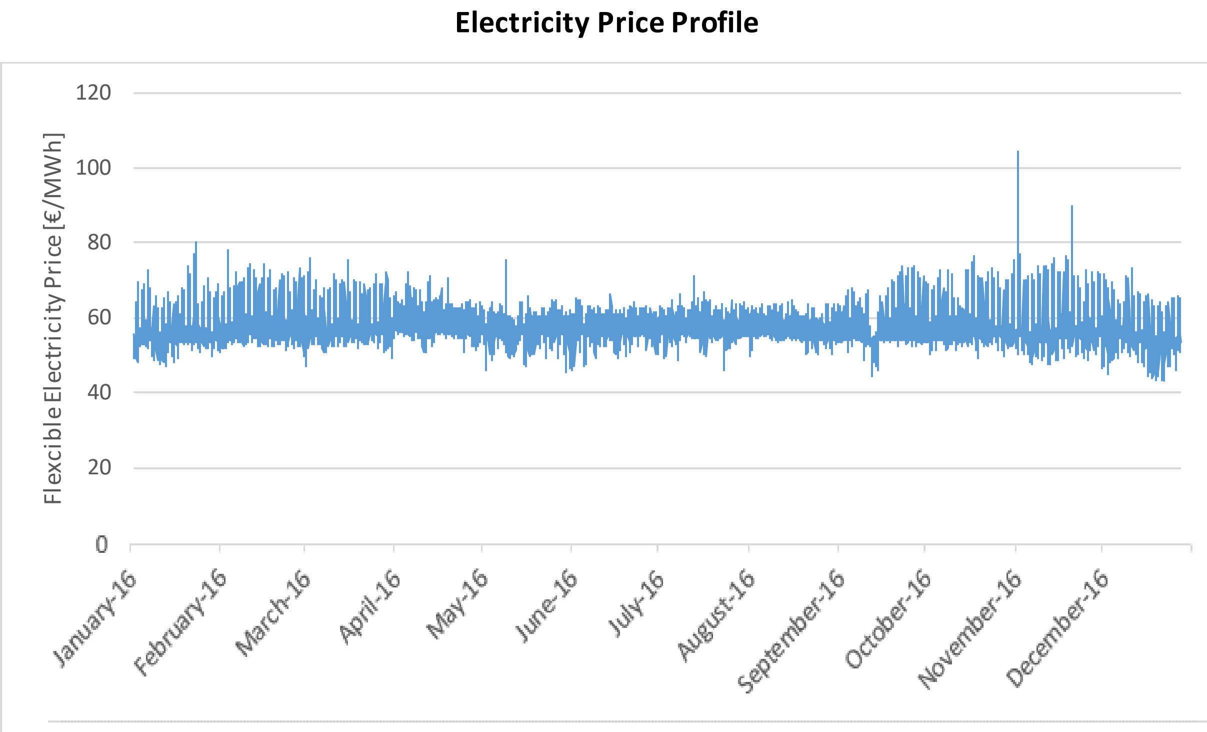

Figure 7 - Flexible Electricity Price profile used in the model.

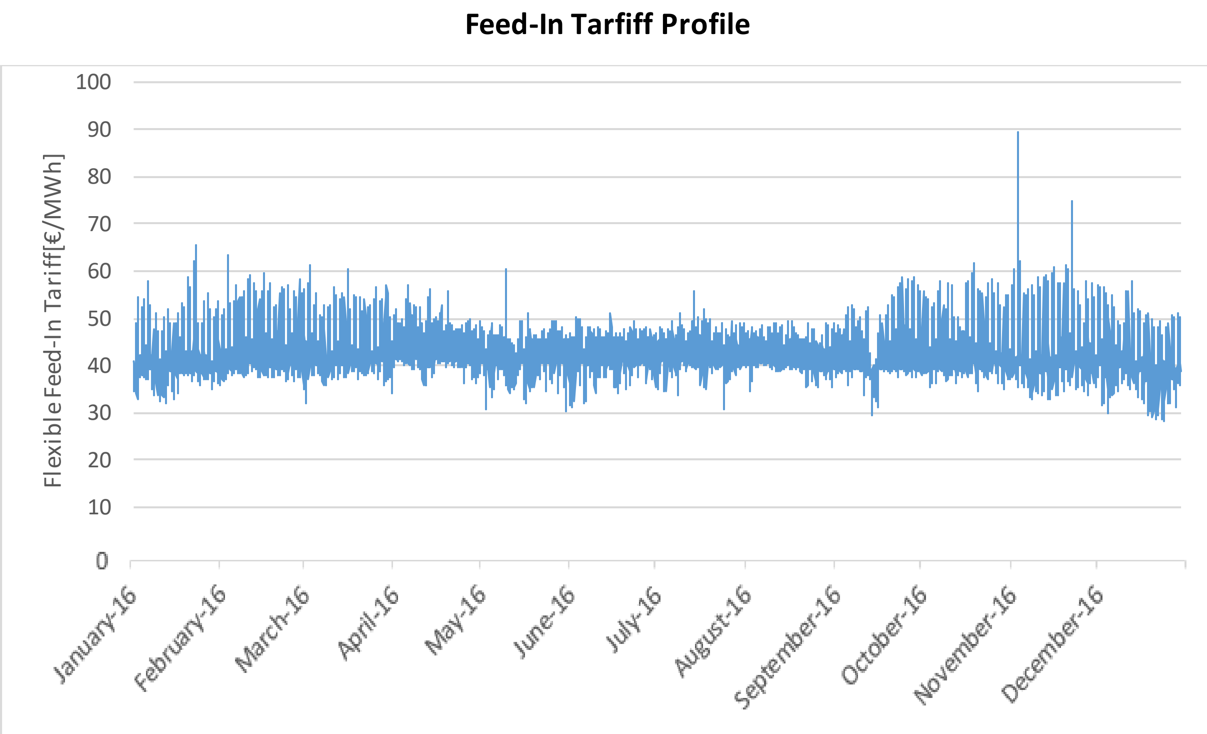

Figure 8 - Flexible feed-in tariff used in the model for local PV and mCHP generation.

2.3.3. PV generation profile

The PV generation in our model is determined by a PV generation profile based on the average PV generation for the Netherlands and gives hourly generation values (DNV GL, 2017b). This profile is converted to a profile that gives the relative output compared to the maximum on a scale from 0% to 100%. In this way, the profile (Figure 9) can be used as a rating factor in PLEXOS with any desirable capacity for PV generators.

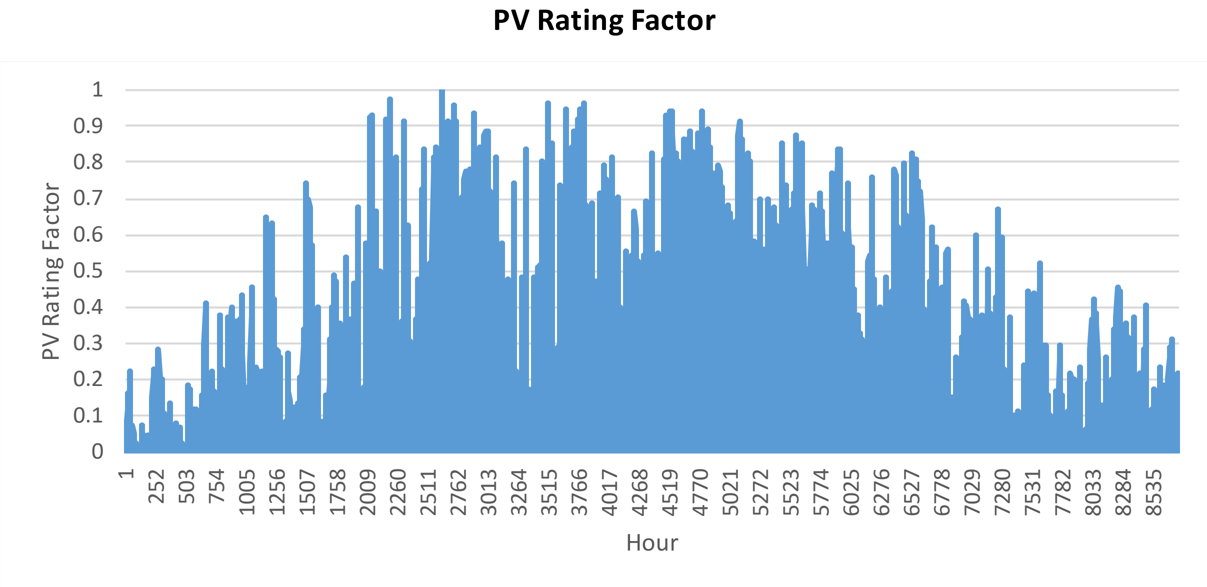

Figure 9 - PV rating profile used in the PLEXOS model.

2.3.4. Heat Pump COP profile

This profile in Figure 10 is based on daily temperatures for the year 2016 ranging from a COP of 2 to 5 and is inverted on a scale of -1 to 0 to be used as generation participation factor in PLEXOS (see appendix 7.4). In this way, the COP profile determines how many units of electricity the heat pump needs to consume to produce one unit of heat.

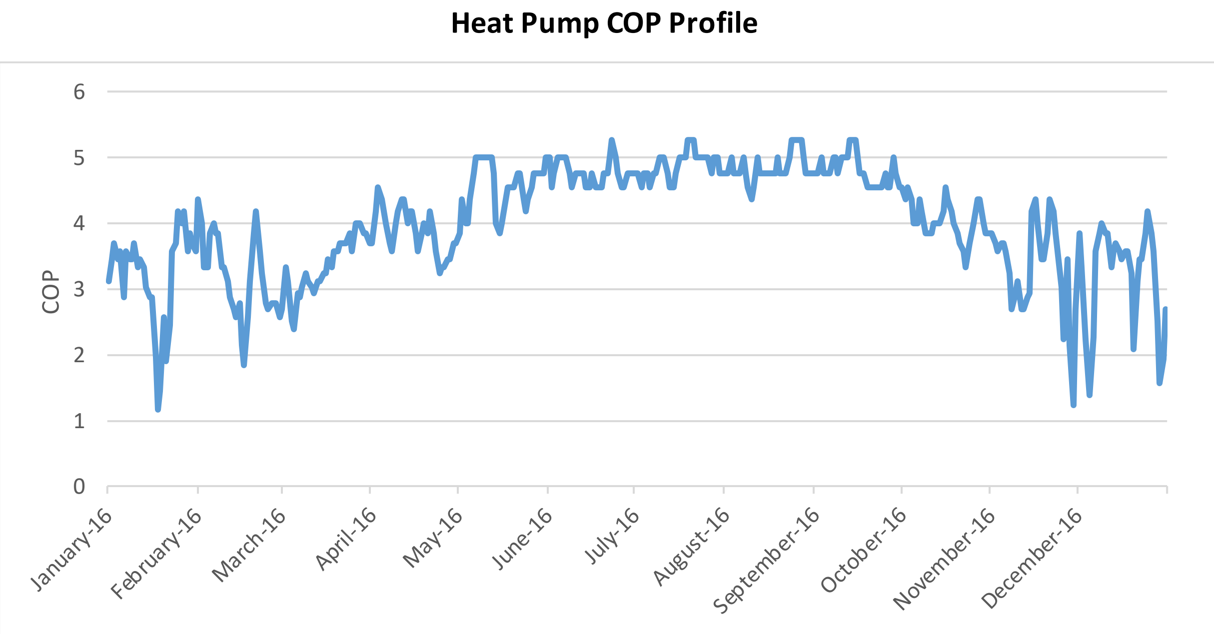

Figure 10 - Heat Pump COP profile based on average daily temperatures (see appendix 7.4 for more details).

2.4. Build PLEXOS model

Each object in our model has certain properties assigned to it based on the techno-economic properties defined in section 2.3. Figure 11 outlines the main components of the PLEXOS model with all the possible scenario variations from section 2.2.

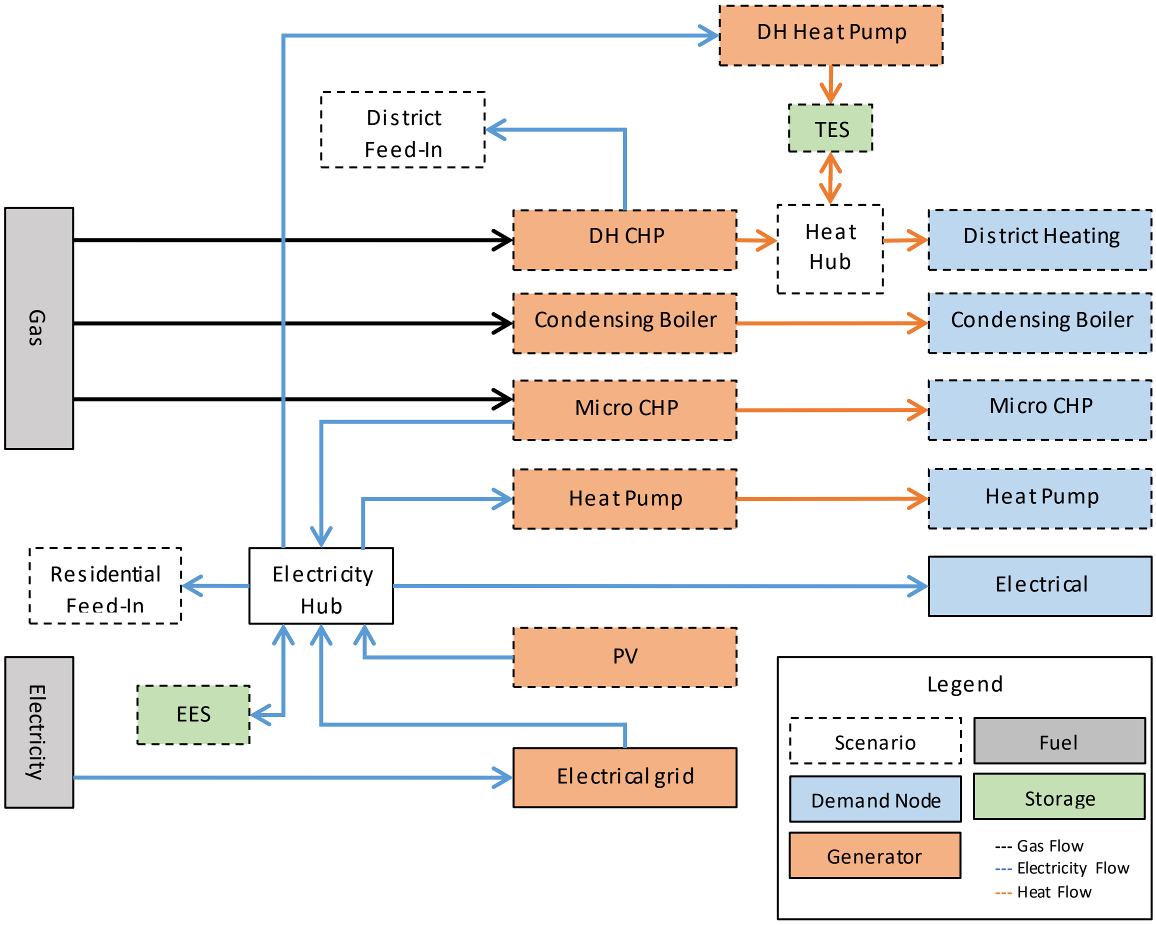

Figure 11 - PLEXOS Model Outline

At its core, the PLEXOS model is based on energy demand profiles and a portfolio of generators defined by various techno-economic parameters which are dispatched in order to meet demand. The electricity and heating demand profiles describe the electrical or heating load in MW for each hour of the simulation year. In our model, the loads are assigned to a *Node* object to create demand nodes (shaded blue in Figure 11).

The load in the demand nodes need to be fulfilled with generation by dispatchable *Generators* (shaded Orange in Figure 11). The *Max Capacity* and *Heat Rate* property of a *Generator* are used to define the generators. Most generator consume a *Fuel* (shaded gray in Figure 11), defined with a certain production of CO_2 emissions, to produce energy. The district heating CHP (DH CHP), condensing boiler and micro CHP consume gas as a fuel. The electrical grid, heat pump and district heating heat pump (DH heat pump) generators all consume electricity, but only the electrical grid generator is connected to electricity (fuel). The other generators have an indirect connection to electricity (fuel) through the electricity hub.

Together with the heat hub, the electricity hub serves a particular purpose. These ‘virtual’ hubs combine electricity and heat generation from multiple sources to balance them with (possibly multiple) sources of demand. This is particularly important for our results regarding electricity as in this way electricity generation from local sources (mCHP and PV generators) is balanced with the demand from the electrical demand node, the electricity consumption from the heat pumps and the electrical storage. For instance, without the electricity hub, electricity generated by the PV generator could not be used by the heat pumps to generate heat. The remaining electrical demand is generated by the electrical grid generator and excess generation from PV and mCHP generators is feed-back to the grid in the residential feed-in node for the selected feed-in tariff. The heat hub combines heat from multiple heat sources in the district heating network and delivers this to the district heating demand node. This is needed for simulation number 7 and 8 where the optional district heating heat pump (DH heat pump) and TES are added. The electricity generated in the DH CHP is sold in the district feed-in node for the feed-in tariff selected for the simulation

The way in which the fuels, generators and demand nodes are connected varies per technology. The condensing gas boiler generator is directly connected to its corresponding heating demand node and consumes gas, making it the most straightforward connection. The DH CHP generator consumes gas and delivers its produced energy to the heat hub from where it is delivered to the district heating demand node. The micro CHP generator consumes gas and is delivers its generated heat to the micro CHP demand node and its electricity to the electricity hub.

The heat pump generator consumes electricity and takes this off from the electricity hub. Depending on the current COP (see section 2.3.4) the amount of electricity offtake per unit of heat varies. The generated heat is then delivered to the heat pump demand node. The same concept is applied to the DH heat pump generator which delivers its heat to the TES. The PV generator has an assigned generation profile determines the hourly PV generation and delivers this to the electricity hub. The electrical grid consumes electricity and delivers this to the electricity hub. The electrical storage (ES) and thermal energy storage (TES) are connected to the electricity- and heat hub respectively. Based on the simulations scenario and settings they are dispatched based on the demand, availability of energy and their prices. Using an MT schedule in combination with the ST schedule the TES can be used as seasonal storage. The MT Schedule uses longer time period to decompose medium-term constraints and objectives which can be passed on to the full chronological simulation in the ST Schedule The ST Schedule simulates unit commitment and economic dispatch based on mixed-integer programming. The settings used in the model can be found in appendix 7.2.

It is important to note that PLEXOS is not designed to model heat in this way as it does not differentiate between electrical and thermal energy using this method and that exploring the usability of PLEXOS for this research is part of the research objectives. With a strict separation of heat and electrical flows in our model (represented by orange and blue lines respectively in Figure 11), we ensure they are not mixed up in the simulation results. In this way, PLEXOS treats the heat demand as if it would be a parallel electricity system with properly adjusted parameters and conversion factors.

PLEXOS uses a Unit Commitment and Economic Dispatch algorithm using Mixed Integer Programming to minimize a cost function subjected to operational constraints. PLEXOS gives co-optimized solutions by solving these objective function through simultaneous calculation of the optimal solution for unit commitment and economic dispatch (Energy Exemplar, n.d.). The objective function and main constraints for our model are:

Minimize {total system costs} = Total Cost of Electricity Generation + Total Cost of Heat Generation - - (Feed-In Profits + Penalty Costs for Insufficient Generation)

Subject to {system constraints}:

- Electricity Balance (Electricity Hub): (Electrical Grid Generation + PV Generation + mCHP Generation + EES Generation) = (Residential + District Feed-In + Residential Electricity Demand + Residential Heat Pump Demand + DH Heat Pump Demand)
- Heat Balance (Heat Hub): (DH CHP Generation + TES Generation) = (District Heating Demand)
- Heat Balance (Residential) = (Residential Heat Generation + DH CHP Generation + TES Generation) = (Residential Heat Demand)

Other constraints:

- Generator and storage constraints: max capacity, max load.

2.5. Indicator definitions

Several indicators are defined to assess the results of the simulations and to determine the performance of the scenarios and their variations in relation to the main and sub research questions. The following indicators are chosen:

Energy Consumption and Generation Indicators

- Annual electricity and gas consumption [TJ/y]
  The annual consumption of grid electricity and gas by the generators serves as a comprehensible indication for the total energy need to satisfy electrical and heating demand in the different simulations. It is a direct output from the following PLEXOS simulation results in TJ/y: Total Annual Gas Offtake [TJ/y], and Total Annual Electricity Offtake [TJ/y]. The contribution of individual generators towards the total consumption is included.

- Annual local energy generation [GWh/y]
  The annual energy generation of the different generators gives an overview of the different sources of electricity and heat and is used in to determine the self-consumption share. Depending on the simulation it is a combination of direct outputs from the following PLEXOS simulations results: (electrical) generation in [GWh/y] from the PV, mCHP, and Electrical Grid generators, and the (thermal) generation in [GWh/y], from the Heat Pump, Micro CHP, Condensing Boiler, DH CHP, and DH Heat Pump generators.

CO_2 Emissions Indicators

- Annual CO_2 Emissions [t CO_2/y]
  The CO_2 emissions per fuel offtake and per generator give a quick overview of the origin of the CO_2 emissions. They can easily be combined to five the total annual emissions. It is a direct output from the following PLEXOS simulations results: Emissions from Electricity offtake [t CO_2/y], Emissions from gas offtake [t CO_2/y] and Emissions from generator fuel offtake [t CO_2/y].

- Reduced Grid Emissions from Feed-In [t CO_2/y]
  Feed-in from of excessive local electricity generation reduces the need for generation elsewhere in the grid. Therefore, it is assumed that for every GJ of electricity that is feed-back to the grid the grid emissions are reduced. The Reduced Grid Emissions from Feed-In [t CO_2/y] is calculated using

the following direct PLEXOS simulation results: Feed-In [GWh/y] and the Emission Production Rate of Electricity (fuel) [CO_2/GJ].

Flexibility Indicators

- Self-Consumption [GWh /y], [%]
  The self-consumption of locally generated electricity by PV and mCHP gives insight into the extent to which different technology combinations are able to utilize local electricity production. It is calculated from the following direct PLEXOS simulation results: PV Generation [GWh/y], mCHP (electricity) Generation [GWh/y], and Residential Feed-In [GWh/y]. Self-consumption is used both as an actual value [GWh/y] and as a share [%].

- Peak Demand (electrical) [MW]
  The peak demand of electricity is used to give insight into the distribution infrastructure (i.e. cables and transformer capacity) e needs that would be required in the different simulations. It is based on the maximum hourly value of sum of: the hourly Residential Electricity Demand [MW], Residential Heat Pump Demand [MW] and the District Heat Pump Demand [MW].

- Peak Flow (electrical) [MW]
  The peak flow of electricity is the maximum hourly flow of electricity in the Electricity Hub. This flow is a result of either the maximum absolute value of the electrical generation from PV and mCHP or the grid import due to demand. It reflects the infrastructural needs of the simulation as electrical lines must be able to accommodate the highest flow, whether it is caused by demand or supply. It is the maximum value of the following direct PLEXOS simulation result: Flow (Electricity Hub) [MW].

- Peak Flow to Peak Demand (electrical) Ratio [n/a]
  The ratio between the Peak flow and Demand gives insight into the cause for the maximum flow. It is calculated using the values for the Peak Demand [MW] and Peak Flow [MW] indicators.

Costs Indicators

- Total Annual Costs [1000€/y]
  The total costs are broken down into the investment and operation costs, allowing for a quick comparison of these cost aspects between the different simulations. The total investment costs are calculated based on the number of installed generators and their unit price and then divided over their lifetime to calculate the annual investment costs [1000€/y] (see appendix 7.8 for scenario investment cost calculations). The operation costs are based on the following direct PLEXOS simulation results: Annual Gas Offtake Costs [1000€/y] and Annual Electricity Offtake Costs [1000€/y]. The costs for installation and maintenance of the heating and storage technologies, and external infrastructural costs for the electrical grid, heating network or district CHP are not taken into account.

- Feed-In Revenue [1000€/y]

The revenue from feed-in to the grid is split divided over whole neighborhood and can be seen as a reduction in total costs. It is based on the following direct PLEXOS simulation result: Annual Feed-In Price Paid [1000€/y].

3. Results

Using the indicators defined in section 2.5 the various simulation results can be interpreted. In this way, the advantages and disadvantages of the technological scenarios in fulfilling the electrical and heating demand of our model neighborhood becomes clear.

The results are presented in the following order; First the simulations results are compared using the Energy Consumption and Generation Indicators, then on the CO2 emissions indicators, then on the Flexibility Indicators and then on the Costs Indicators. After that some more detailed results are presented on seasonal and hourly interactions. Note that the abbreviations for scenarios names from Table 3 are used in the description.

3.1. Indicator Results

3.1.1. Energy Consumption

Figure 12 shows the results of the annual energy consumptions in TJ per year for each simulation. Together, the electricity consumption from the electrical grid for non-heating and heating purposes (HP and TES HP), electricity self-consumption (from PV and/or mCHP) and gas consumption make up the total energy consumption for each simulation.

The differences between the efficiency of the various gas fueled heating technologies becomes apparent from the different levels of gas consumption in the REF, DH and mCHP simulations. Compared to the REF simulations, the DH baseline simulations result in a 29% lower gas consumption while the mCHP simulations results in a 23% higher gas consumption.

Only simulation #7 and #8 feature a combination of gas fueled heating with electrical heating, allowing PLEXOS to prioritize electrical heating when conditions are favorable. Compared to the REF simulations, heating by the TES HP in these simulations results in gas consumption levels that are 35% and 41% lower respectively. In turn, this results in increased consumption of electricity by the TES HP of 10% and 17% respectively compared to the baseline simulations. The flexible electricity price in #8 is advantageous for the TES HP, allowing it to generate more cost-effective heat.

The electricity consumption from the grid shows an expected reduction in the REF baseline simulations (low, medium and high PV) as PV capacities increase. The same pattern is visible in the DH, ELEC and mCHP baseline simulations with further reductions in the TES+HP, EES, and FEP simulations respectively. The remainder of the non-heating electricity demand is fulfilled through self-consumption of PV and/or mCHP. In appendix 7.6 the seasonal differences between PV supply and electricity demand are presented, explaining why the increase in self-consumption is not linear with the increase in PV capacity.

Without gas fueled heating, the ELEC baseline simulations have a 101% increase in total electricity consumption compared to the other scenarios. Electrical energy storage and flexible electricity prices in the ELEC EES and ELEC FEP simulations increase total electricity consumptions with an extra 0.6 TJ/y, resulting in a 110% increase. In section 7.5 the hourly electricity consumption of the residential HP is shown, revealing large, temperature dependent peaks.

The mCHP scenario has the lowest electricity offtake from the grid due to its combined generation of heat and electricity. In simulation 18 electrical grid offtake is only 1.4 GWh/y compared to 7.9 GWh/y in simulation 3 of the Reference scenario. The gas consumption is the highest of all scenarios however.

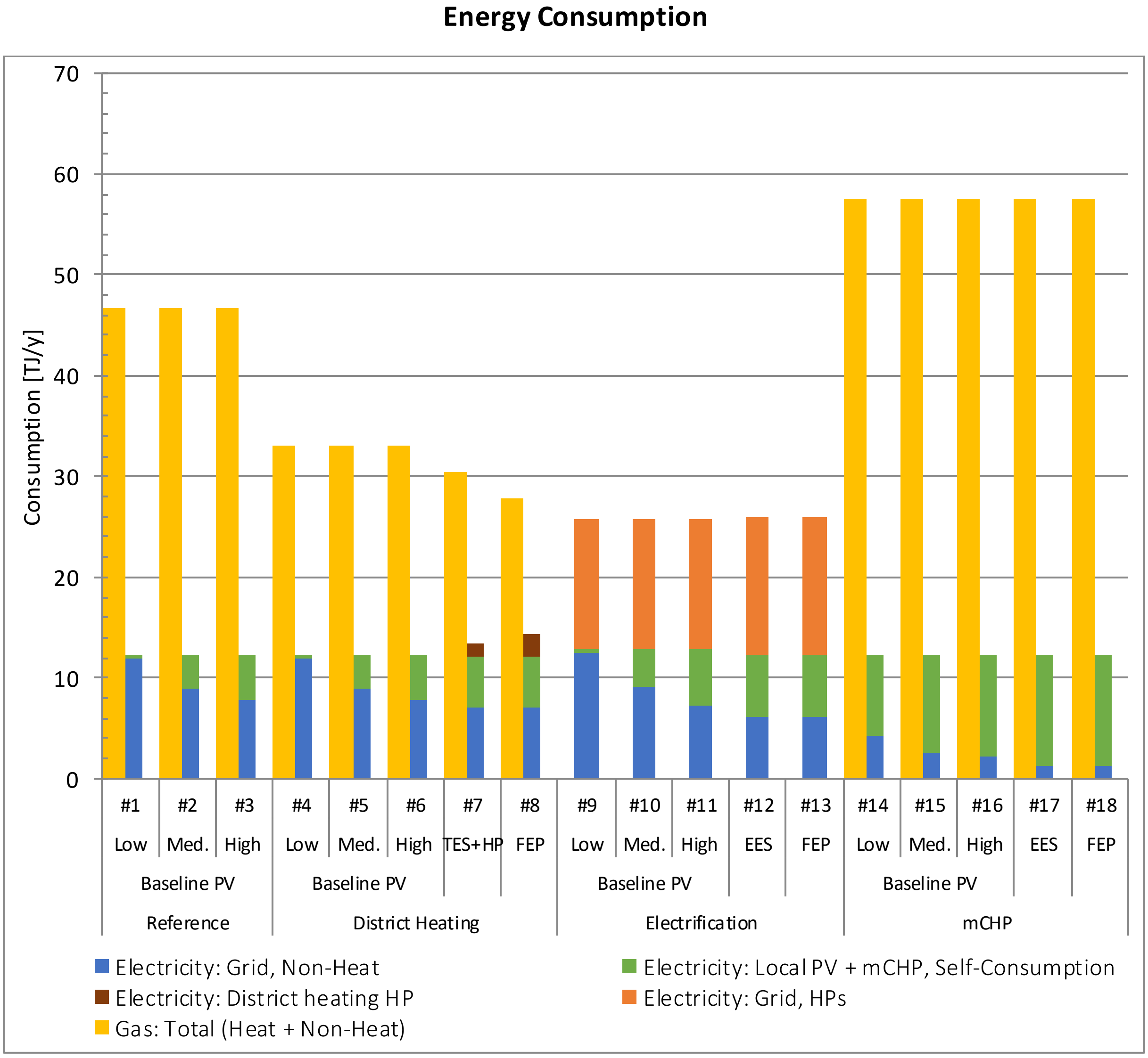

Figure 12 – Annual electrical grid and gas offtake for each simulation (#1-18). Note that self-consumption includes both PV and mCHP generation.

3.1.2. CO_2 Emissions Indicators

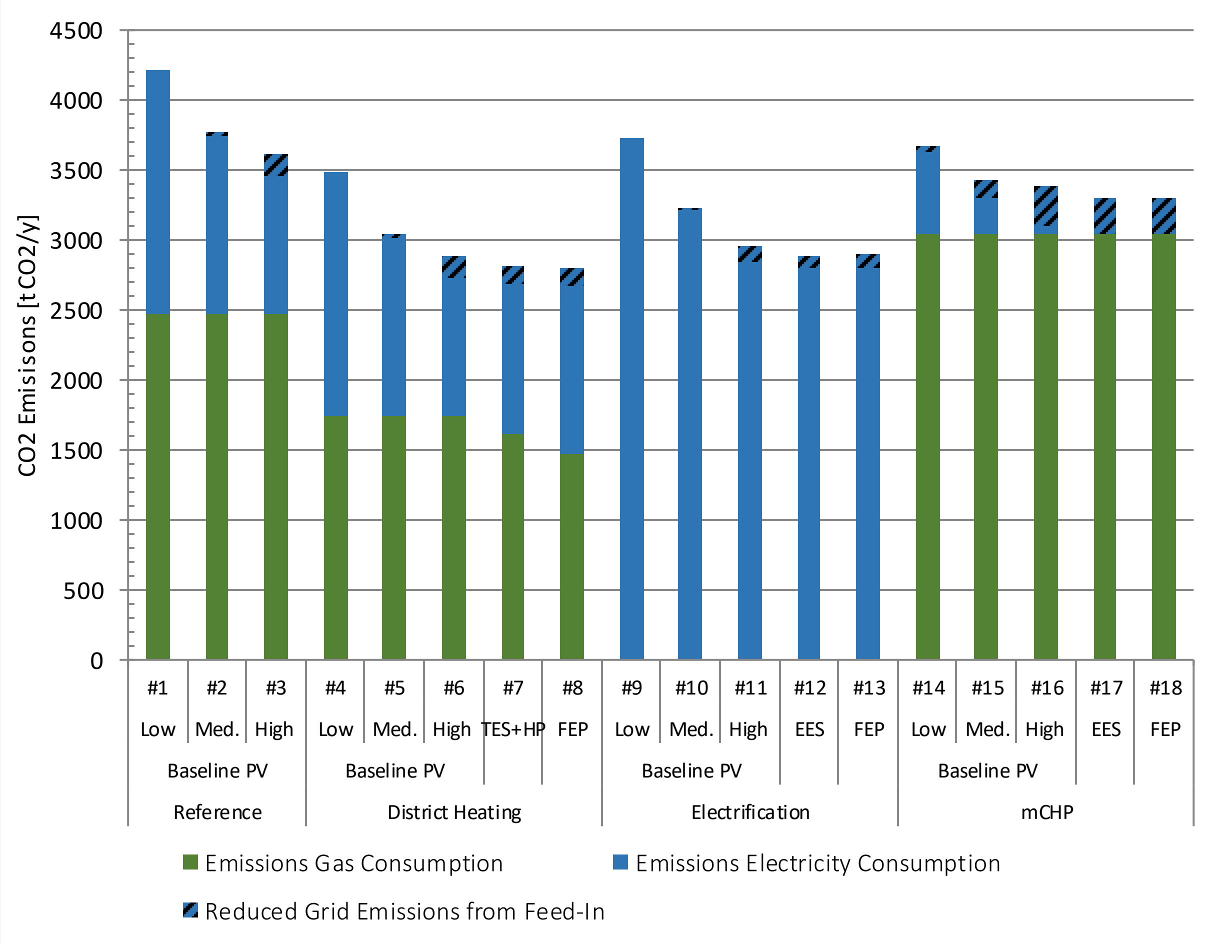

Figure 13 shows the results for the annual CO_2 emissions in tons of CO_2 per year for each simulation, broken down by fuel source. The reduction in grid emissions due to feed-in are included.

The distinct levels of gas consumption in the REF, DH baseline and mCHP simulations results in a 29% reduction in the DH baseline simulations and a 23% increase in the mCHP simulations. In the DH TES + HP (#7) and DH FEP (#8) simulations the emissions from gas consumption further reduce due to electrical heating. The reduction is largely offset due to the increased emissions from electricity consumption, resulting in the same emissions total for both scenarios.

The reduced electricity consumption due to increasing PV generation in the baseline simulations directly reduces CO_2 emissions. The reduction in emissions from electricity consumption in the medium and high PV simulations for REF and DH are 25% and 34% respectively, compared to the low PV simulations. Feed-in further decreases (grid) emissions for these simulations to a total reduction in electricity consumption emissions of 27% and 43% respectively.

Fully electric heating in the ELEC simulations results in total emissions levels that lie 5% above those of the DH simulations. In the mCHP simulations emissions stay relatively high due to the gas consumption levels. Emissions from electricity consumption can effectively become negative due to the high reduction in grid emissions. The biggest reduction in total emissions in the ELEC and mCHP scenarios take place in simulations #12 and #17 with a 31% and 29% reduction respectively.

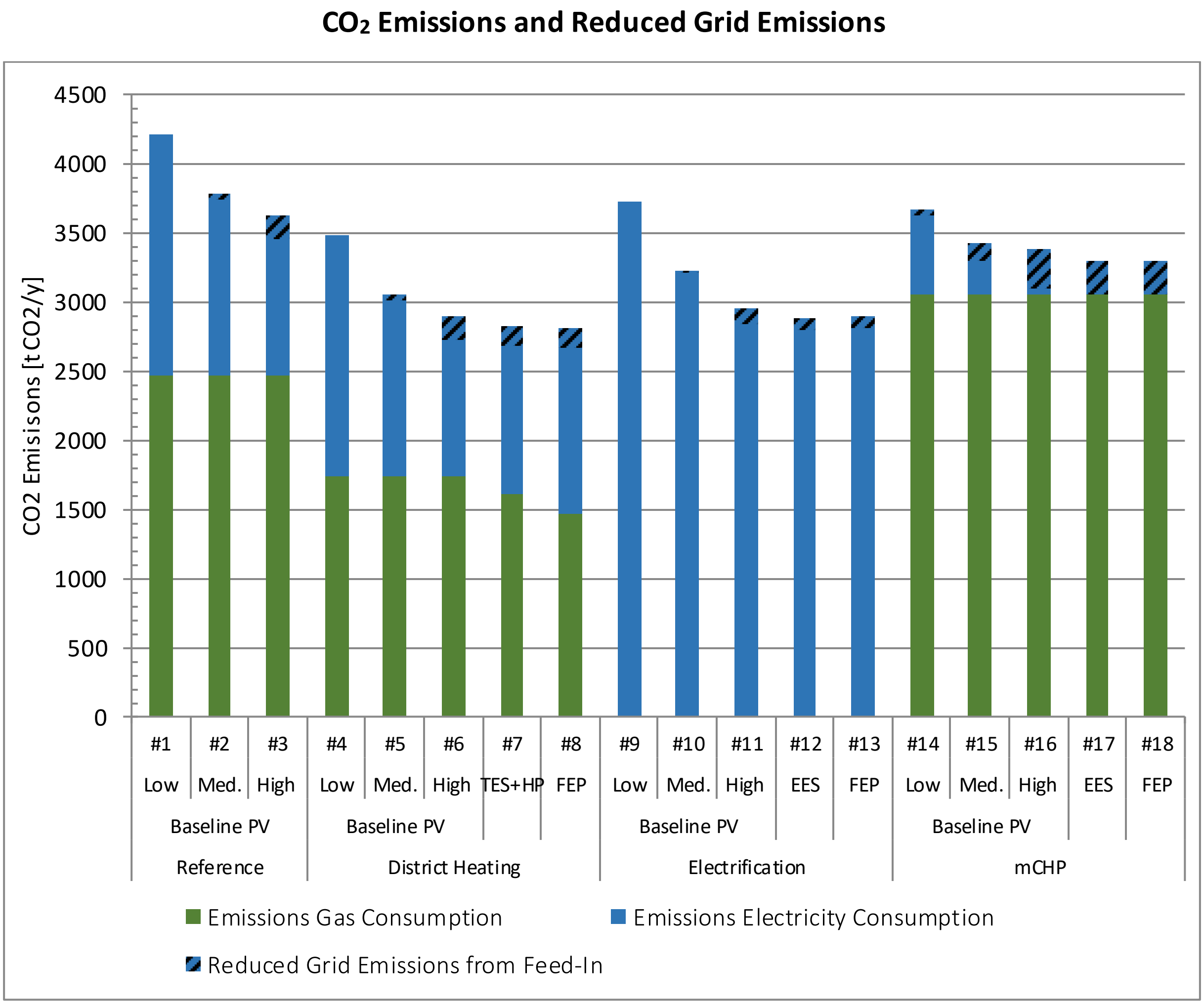

Figure 13 – Annual CO_2 emissions for each scenario broken down by fuel offtake. Reductions in grid emissions due to electrical feed-in are subtracted from the total results.

3.1.3. Local Generation, Self-Consumption and Peak flow and Demand

Figure 14 shows the locally generated electricity from PV and mCHP in GWh per year, the amount that is self-consumed and the self-consumption share for each simulation on the second y-axis. In the REF, DH and ELEC simulations, local generation is determined solely by the amount of PV capacity (low, medium or high) showing a similar patterns along the scenarios. In the mCHP simulations, local generation is raised due to added mCHP generation. Self-consumption values and shares are equal in the REF and DH baseline simulations as there are no coupling interactions possible.

As local generation increases throughout the baseline simulations the shares of self-consumption decrease. As PV capacity increases the mismatch between supply and demand becomes amplified. These seasonal and daily differences between PV generation and the demand for electricity and heating explained in section 7.6.

Both in the DH TES + HP and DH FEP as well as the ELEC simulations, the addition of heat pumps enables higher shares self-consumption. The effect however is relatively small due to the mismatch of heat demand and PV generation between the winter and summer.

In the mCHP scenario this seasonal mismatch is reduced, as more electricity is produced in winter months. The amount of hours in which electricity is self-consumed roughly doubles as can be seen in the self-consumption duration curve in Figure 22 in section 7.6. *Figure 27* clearly shows the significant increase in self-consumption during winter months in the mCHP scenario compared to e.g. the electrification scenario in Figure 25 (see section 7.6.1)

Electrical heating in ELEC raises the self-consumption share by 10% (absolute) and 15% (absolute) respectively over the REF and DH baseline scenarios. With this, the ELEC scenario achieves the highest level of self-consumption with a share of 67% in ELEC High PV and 73% in ELEC EES and FEP.

The effect of electrical storage in the EES and FEP simulations is relatively small, increasing the self-consumption share from 67% to 73% in the ELEC simulations and from 58% to 64% in the mCHP simulations. Furthermore, flexible energy prices do not influence self-consumption at all as can be seen in the FEP simulations.

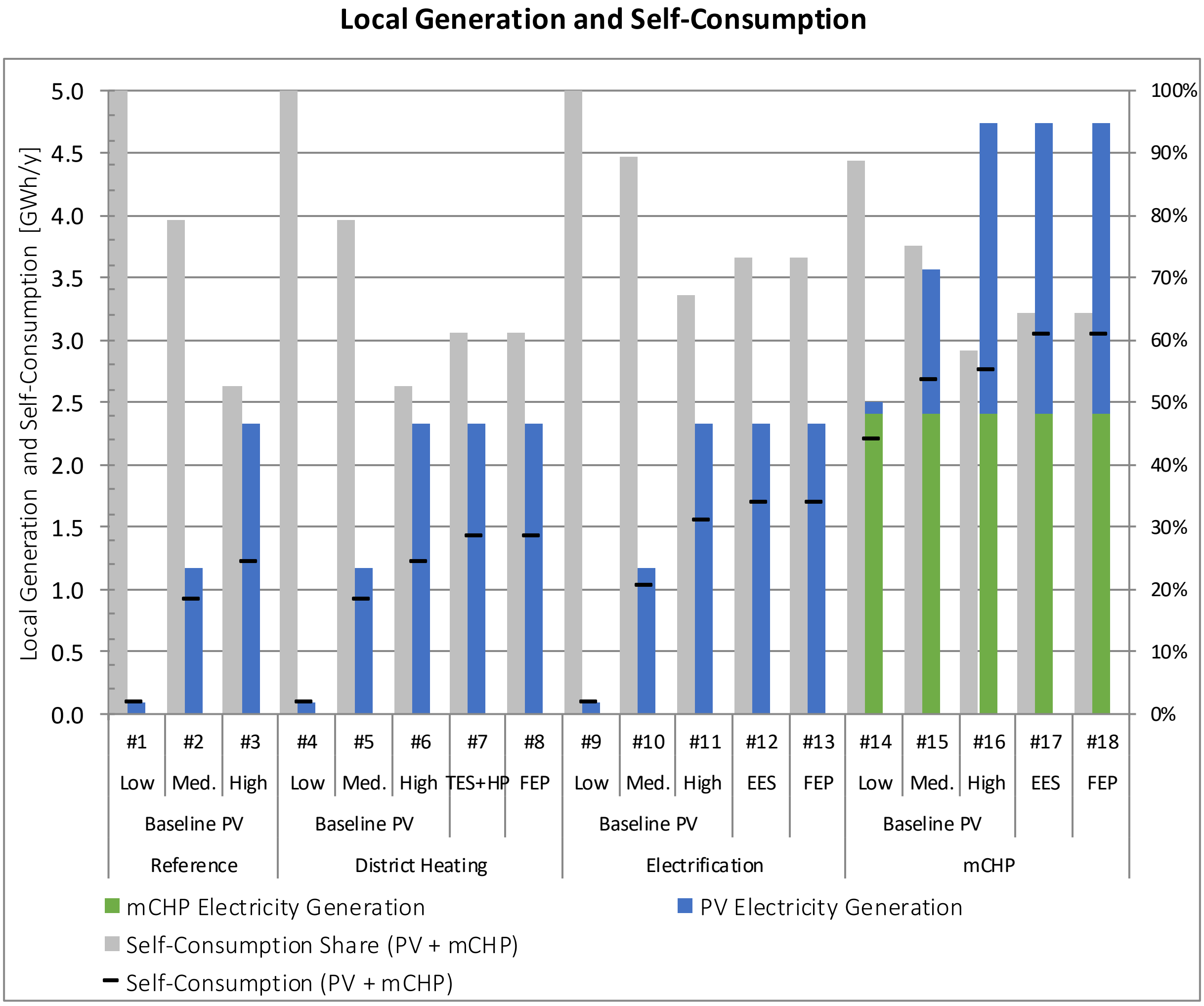

Figure 14 - PV and mCHP generation, and Self-Consumption. The self-consumption share is displayed on the x-axis under the simulation number.

Figure 15 presents the results for the electrical peak flow and electrical peak demand in each simulation. Because the REF, DH baseline and mCHP simulations have no electrical heating their peak demand remains equal. As PV capacities increase throughout the baseline simulations, so does the peak flow as more electricity is fed in to the grid. The ELEC simulations are an exception to this as here the peak flow is dominated by the combined demand for electrical heating and non-heating purposes. In the REF and DH simulations the increase in PV capacities increases the peak flow with 1.2 MW to a maximum of 2 MW. In the mCHP simulations, the extra electricity generation from the mCHP further increases peak flow.

Interestingly, in the mCHP EES and FEP simulation, as well as in the ELEC FEP simulation, the peak flow increases further without the addition of extra PV capacities. Here, electrical energy storage is responsible for the increase in peak flow. This effect is not seen in the DH scenario with TES.

The combined effects of increased local electricity generation and dynamic battery charging and discharging in the mCHP FEP simulation leads to the highest ratio between peak flow and peak demand of 3.3. Thus, flow is dominated not by demand but by other energy flows

Overall the peak flow increases with increasing PV capacities, to a maximum of 2.4 times the peak demand in the REF and DH High PV simulations. In the mCHP scenario this effect is increased to the highest ratios of all simulations, 2.8 in the High PV simulation and 3.3 in the EES and FEP simulations. In the ELEC scenario electrical heating demand dominates peak flow and the ratio does not change, except when flexible energy prices are used and the peak flow increases with 0.5 MW to the highest flow of 4.4 MW. In the mCHP scenario only electrical energy storage increases peak flow further.

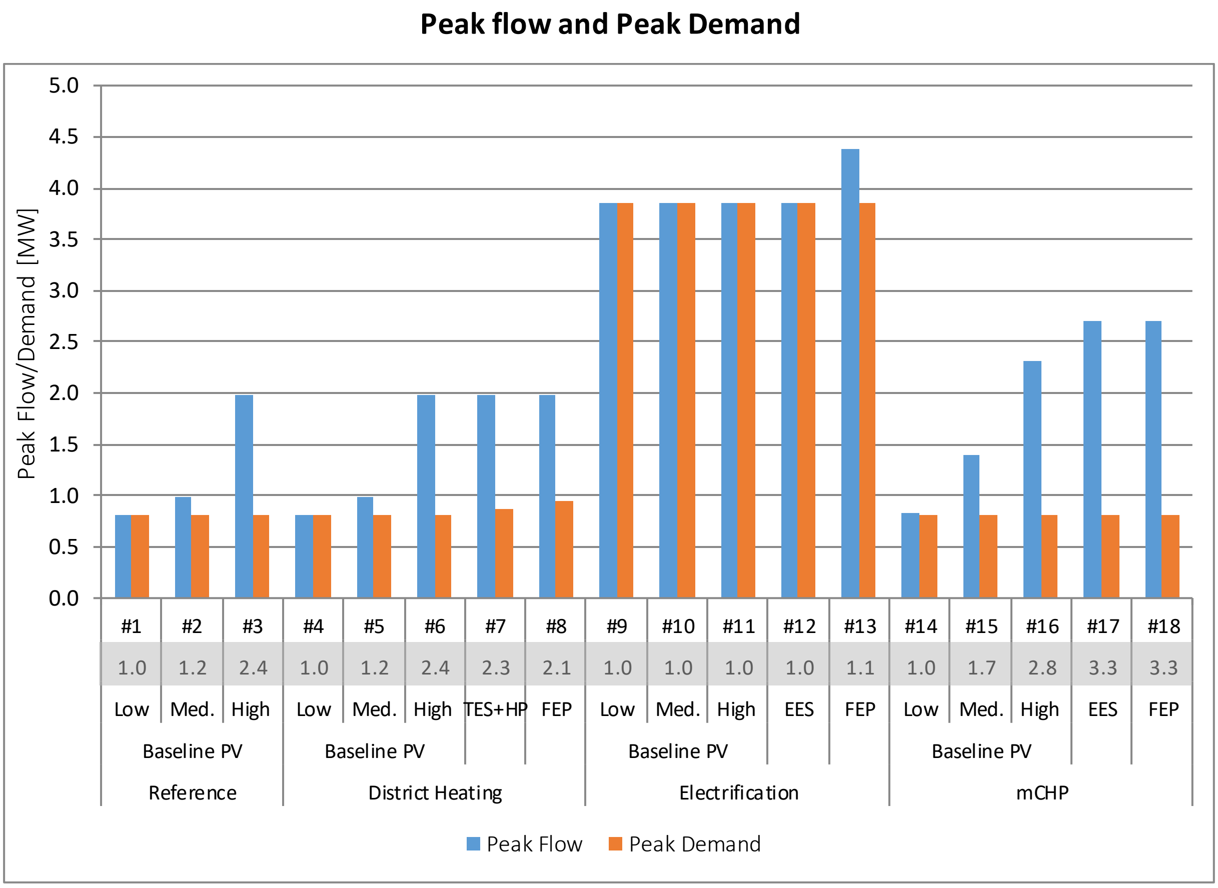

Figure 15 - Peak flow and demand results for each simulation. The ratio between Peak flow and peak demand is displayed in the shaded area beneath the simulation # on the x-axis.

3.1.4. Costs

Figure 16 shows the total annual costs for each simulation, with investment costs spread assuming a 20-year lifetime for the heating technologies and PV systems. Appendix 7.8 shows the costs in a graph per type.

The REF scenario has the lowest annual investment costs for heating in the baseline simulations of DH, ELEC and mCHP these increase with €172,000 €288,000 and €561,000 respectively. The highest heating related investment costs incur in mCHP EES/FEP (#17/18) at €669,000, an increase of 913% compared to the REF High PV simulation.

In line with the energy consumption results the REF, DH baseline and mCHP baseline simulations have a distinct gas cost level. Electricity cost increase significantly when electrical heating is applied, increasing the total costs above the REF levels. In the ELEC scenario, electricity costs take up most of the annual costs although flexible electricity prices show the most benefit here. Only heat pumps seem to allow households to benefit from flexible pricing as simulation 8 and 13 show a reduction is costs whereas the electrical storage in the mCHP scenario (simulation 18) shows no changes. Noting that the total electricity demand is equal in all the electrification scenarios the decrease in cost can be attributed to shifts in electricity offtake from the grid from periods with higher prices to periods with lower prices.

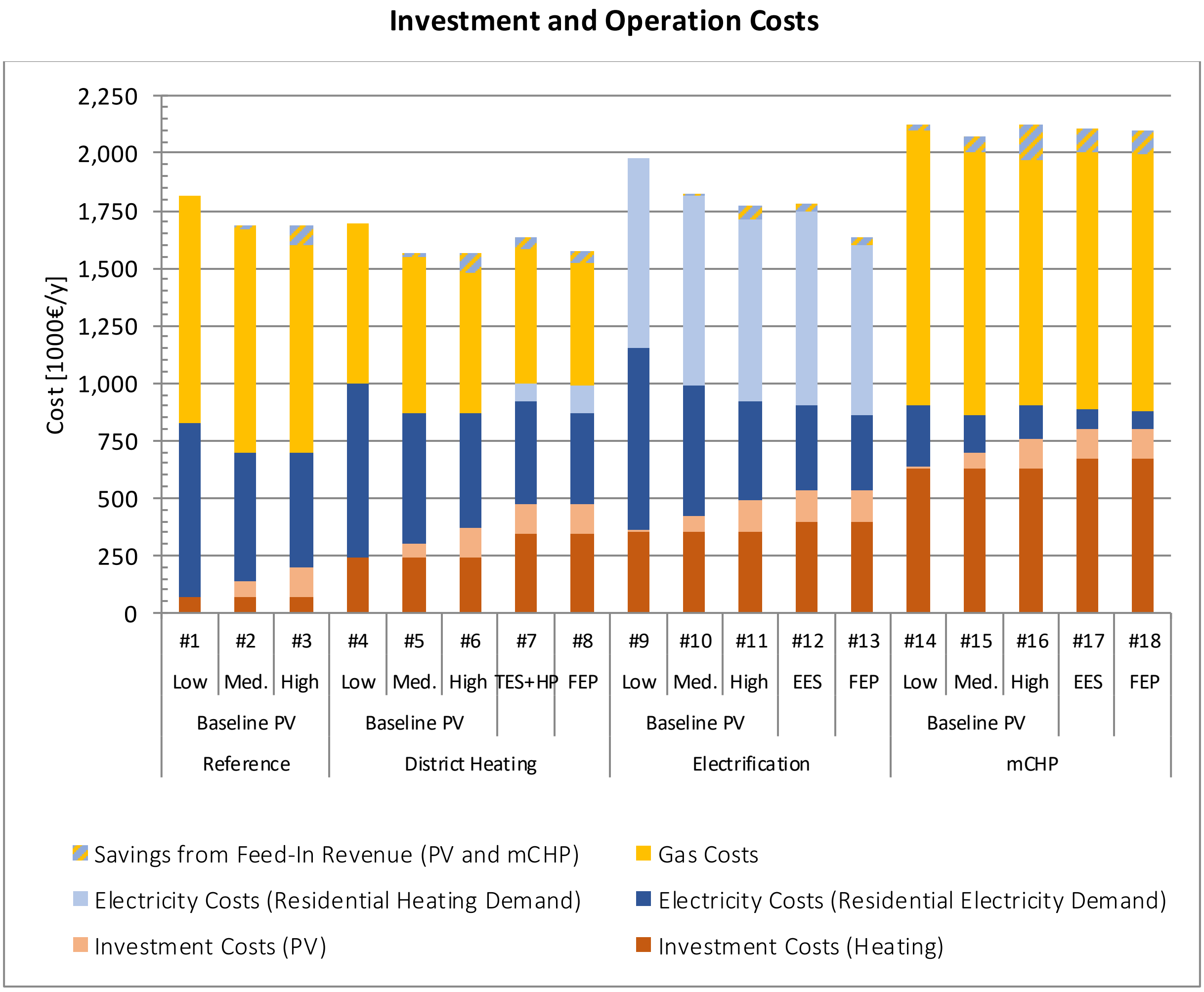

Figure 16 – Investment and operation costs results for each scenario. Savings from feed-in revenue are subtracted from the total results. Investment costs for storage and DH HP are included in the heating investment costs.

The biggest difference in costs can be seen between simulation 8 and 14, 546,000€ per year. The DH scenario has the lowest cost in general whereas mCHP has the highest. This is mainly due to the significantly higher investment costs for mCHP, as well as high gas costs. Whereas, in the DH scenario the investment costs are relatively modest and the gas cost

Overall the DH simulations are the least expensive but difference is not very big compared to the REF simulations. The ELEC simulations are slightly more expensive and have high costs incurred with electrical heating. The mCHP simulations are the most expensive due to the highest investment and gas consumption cost. Electricity cost are practically zero with feed-in profit in the mCHP High PC, EES and FEP simulations (#16, #17 and #18).

4. Discussion

Using PLEXOS to model electricity and heating interactions in a local energy system commenced as an exploration of its suitability and has proven capable of delivering results. As a modelling driven research, the system boundaries, input parameters and assumptions determining them have a direct influence on the results. Despite the careful approach that is taken to formulate these in the presented method, simplifications had to be made or potentially influential factors dad to be omitted considering their required time investment. A sensitivity analysis testing the impact of uncertainty in the input parameters is perhaps one of the most regrettable omissions that had to be made in this research as some techno-economic parameter have profound effects on the simulation outcomes. The demand profiles for heat and electricity are among the biggest influencers on the end results, dictating the dispatchment of the various generators in the model. Acquiring demand profiles that are representative for current real-world situations in the research case has been a challenge. Converting gas consumption to heat demand without further adjustment or exploration of applied heating technologies diffuses the applicability of the result to the research case. However, looking at the variations in actual gas consumption between different neighborhoods in the research case reveals big differences, indicating that the acquired demand level should fall well within the range of realism.

Uncertainty in the conversion efficiencies of the various heat generators can have a more meaningful effect on the simulation results. Especially in the case of heat pumps, where the coefficient of performance is directly dependent on the difference between in- and outside temperatures. Using daily instead of hourly COP values discards intra daily fluctuations that can be of significant importance considering the daily peaks in heating demand and fluctuations in the electricity price. In this research, the use of daily average values as a basis for the COP range is a rough and impromptu approach to modeling heat pump efficiency and a point of improvement for future research.

Considering the chosen indicators, no clear “winner” arises amidst the results of the different technological scenarios. District heating results in the lowest emissions and shows promise to increase self-consumption when coupled with thermal energy storage and a district heat pump. Increasing the capacity of the district heat pump could further improve flexibility as the heat pump often operates at maximum capacity and seems to be successful in taking advantage of flexible electricity pricing. Electrification of heating supply offers similar benefits to in terms of emission reduction, especially in simulations with high PV capacities, and shows increased self-consumption. Although flexible energy prices do not notably affect emissions and self-consumption it does succeed in lowering the costs. Equipping the neighborhood with mCHP’s significantly decreases electricity consumption from the grid. The increased amount of self-consumption due to the year-round generation of local electricity together with extra feed-in revenue manages to effectively reduce electricity costs to zero (or less). However, the increased consumption of gas results in the lowest emission reductions, and together with the highest investment costs it makes the mCHP scenario the most expensive of all.

As future price developments are not considered for the various technologies the economic prospects of mCHP’s may improve, especially when combined with reduced gas costs due to insulation. However, where reduced heating demand looks promising combined with electrified heating, the benefits for combined generation of electricity and heat may be restricted as electrical output decreases. Considering the option of using biomass fueled mCHP’s can drastically change the perspective of mCHP heating. As practically all the emissions in the mCHP simulations are a result of gas consumption, switching from gas to a bio fuel could significantly reduce emissions and is worthy of pursuit in future research. It must be noted that large scale adoption of biomass fueled heating creates new challenges as they are not expected to be able to substitute the current fossil fuel demand (Mathiesen et al., 2015).

The differences in infrastructural requirements between a fully electrified, district heating connected or mCHP powered neighborhood are vast. Whereas the current infrastructure can be assumed to suffice for the use mCHP's, electrification but also district heating, are expected to require extra investment in expanded heating networks or grid capacities. A two to four-fold increase in peak electrical demand and/or flow as shown in the high PV simulations and electrification scenario results is likely to overshoot the limits of current local grid capacities. However, transmission limits have not been applied in this model making it uncertain if local battery storage could be utilized to reduce these peaks. Testing this assumption in future modeling exercises could provide more insights on this.

Considering none of the scenarios shows benefits on all the indicators, future reductions in energy demand, especially the demand for heating, is expected to have considerable effects on the simulation results. In terms of operation costs and emissions the electrification and mCHP scenario can be expected to show considerable improvements with reduced heating demands. Incorporating future prospects for reduced residential energy demand, e.g. as a result of insulation, are therefore another suggestion for further modeling exercises on this topic.

In a scenario of well insulated households, expanding the model to enable households as small thermal (but humanly comfortable) storages can unlock a potentially large source of flexibility, especially in the electrification and mCHP scenario's. In those cases, peaks in heat demand could be reduced by shifting demand by a few hours, or sudden peaks in local generation could be stored as both electricity and heat, which can be beneficial from an infrastructural point of view.

The daily and seasonal dynamics in PV generation lead to considerable excess generation during the summer months. The mismatch between seasonal PV generation and heating demand offers little opportunity to improve this with electric heating. Seasonal thermal storage may provide some relief when provided with heat pumps. Batteries can be more relevant for the mismatch between hourly PV generation and non-heating electricity demand, but these dynamics have not been assessed in detail in this study.

The coupling between the electricity and heating sector is identified as a potentially big and important source of flexibility for the power system, and even a necessity in the path towards 100% renewable energy systems (Mathiesen et al., 2015). In the current research setup, the potential of coupling on a local level shows benefits in terms of improved self-consumption and emission reduction but important obstacles remain in pursuit of integrating large amounts of iRES. None of the scenarios can reduce feed-in from excess generation during summer months due to the big seasonal mismatch. Stretching the assumed maximum PV penetration of 50% towards 100% of the households is likely to result in lower shares of self-consumption, and much higher peak flows due to grid feed-in. Concentrating on the local scale for coupling the electricity and heat sector might only bring us so far, and perhaps a combination of for example mCHP's and a district heating network with thermal storage and a large-scale heat pump will be more ideal.

Recently, increased attention has been given in the media and local (municipal) politics to so called gasless neighborhoods. These neighborhoods rely on heat pumps to electrify heating supply and are often presented as an important step I achieving urban decarbonization ambitions. Although electrification reduces emissions in assessments confined to municipal borders, the increase in local electricity demand relocates emissions to the national grid. Therefore, achieving decarbonization in this way relies on decarbonizing the electricity generation. From a more practical point of view, and more interesting to DSO's, the implications of electrified heating on local energy infrastructures raise questions. Depending on the capacity limits of the electricity lines on neighborhood level, a four-fold increase in peak demand could implicate costly investments. Although it opens the way for decarbonization in a way that gas fueled heating does not, the prospect of electrified heating do not show immediate benefits in the results of this study.

5. Conclusion

In this study, we have modelled four alternative technological scenarios that couple the electricity and heating sector in an urban neighborhood to investigate their potential benefits in relation to decarbonization. Keeping energy demands equal in all simulations revealed the consequences of adopting different technologies on energy consumption, CO_2 emissions, flexibility and costs. While none of the scenario's proved to be a clear-cut choice for future endeavors, each scenario showed different advantages and drawbacks.

Regarding energy consumption we found that mCHP's increase gas consumption by at least 20% compared to condensing gas boilers, and district heating reduces gas consumption by roughly 30%. Eliminating gas consumption through electrified heating avoids local emissions but results in double the amount of electricity consumption. Emission wise the biggest reduction is achieved with district heating, with electrification showing comparable reductions with the opportunity for further reductions through decarbonizing electricity generation. The dominance of gas induced emissions from mCHP's points towards reduced heat demand for further improvements. In terms of costs DH shows a slight reduction overall and except for the electrification scenario with flexible electricity pricing and battery storage the costs increase with electrification and mCHP's. The mCHP scenario practically reduces electricity costs to zero due to increased local generation and self-consumption. A reduction in heating demand seems especially beneficial for the performance in the electrification and mCHP scenario. However, the intended benefits of coupling electricity with heating demand are likely to diminish as the potential for flexibility is expected to fall with lower heating and electricity demand.

Flexibility is improved where a coupling between electricity and heat is present and the addition of storage further increases it. Although, in terms of self-consumption share the effects are relatively modest. Seasonal differences between heating demand and PV generation seem a critical inhibiting factor for high self-consumption. Using mCHP's as a residential heating source reduces this seasonal mismatch. Therefore, the effects of adding wind as another source of iRES on the seasonal mismatch between iRES generation and heating demand may yield interesting results in further research.

Furthermore, PLEXOS showed to be a useful model for local electricity-heat sector coupling by modelling heat as a separate network in parallel to the electricity system.

6. Bibliography

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7. Appendix

7.1. Indicator results

Table 6 - Indicator results

Scenario	Variation	Total Gas Offtake [TJ/y]	Total Electricity Grid Offtake [TJ/y]	Self-Consumption [GWh/y]	Self-Consumption [%]	Total CO2 Emissions fuel offtake [t CO2/y]	Reduced Grid Emissions from Feed-In [t CO2/y]	Total Costs [1000€/y]
Reference		46.7	11.9	0.1	100%	4,210	-	1,815
	Medium PV	46.7	8.9	0.9	79%	3,740	35	1,688
	High PV	46.7	7.8	1.2	52%	3,456	162	1,685
District Heating		48.8	11.9	0.1	100%	4,318	-	2,029
	Medium PV	48.8	8.9	0.9	79%	3,847	35	1,901
	High PV	48.8	7.8	1.2	52%	3,563	162	1,900
	High PV + TES HP + Flex FI	45.2	8.2	1.4	61%	3,461	132	1,840
	High PV + TES HP + Flex FI + Flex EP	41.1	9.1	1.4	61%	3,377	132	1,753
Electrification		-	25.5	0.1	100%	3,726	-	1,977
	Medium PV	-	22.1	1.0	89%	3,211	18	1,823
	High PV	-	20.2	1.6	67%	2,841	112	1,770
	High PV + ES + Flex FI	-	19.7	1.7	73%	2,793	91	1,782
	High PV + ES + Flex FI + Flex EP	-	19.8	1.7	73%	2,803	91	1,638
mCHP		57.6	4.3	2.2	89%	3,630	41	2,122
	Medium PV	57.6	2.6	2.7	75%	3,296	129	2,076
	High PV	57.6	2.3	2.8	58%	3,094	287	2,124
	High PV + ES + Flex FI	57.6	1.4	3.0	64%	3,000	246	2,107
	High PV + ES + Flex FI + Flex EP	57.6	1.4	3.0	64%	3,001	246	2,096

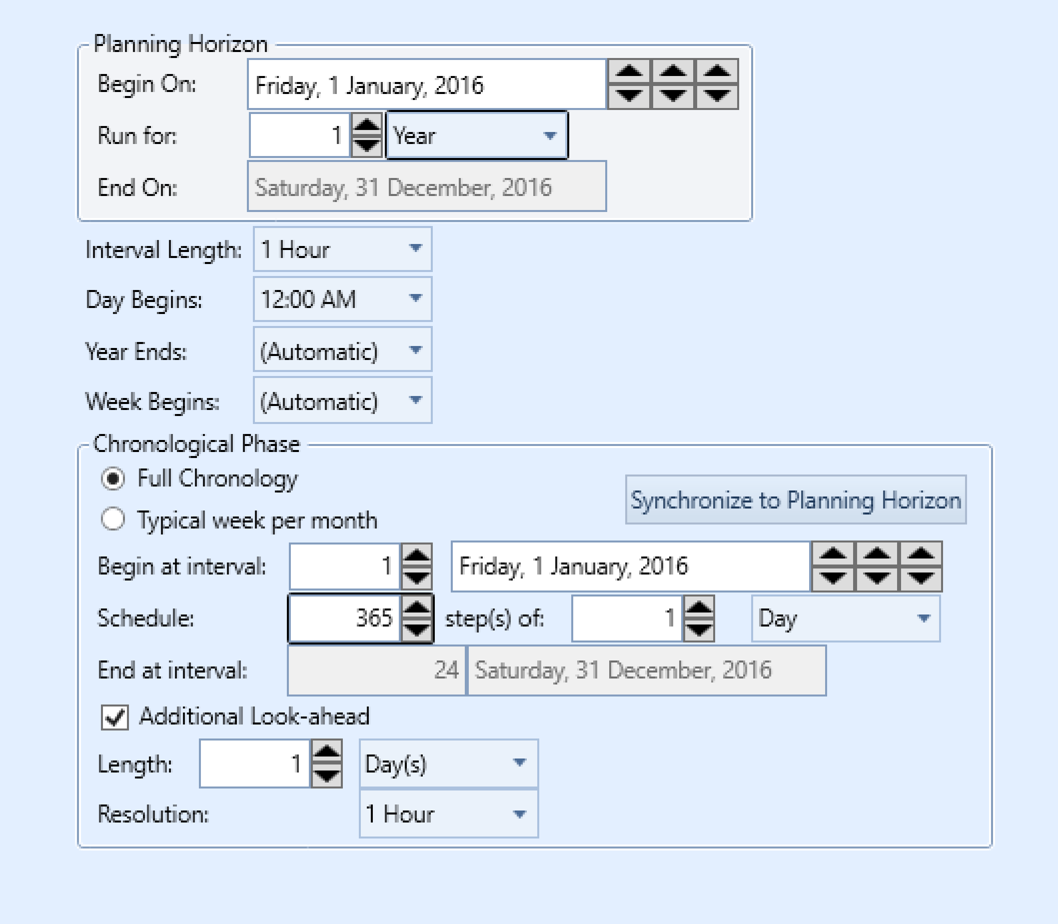
Scenario	Reference			District Heating				
	Baseline Simulations			Baseline Simulations				
Simulation #	1	2, Medium PV	3, High PV	4	5, Medium PV	6, High PV	7, High PV + TES HP + Flex FI	8, High PV + TES HP + Flex FI + Flex EP
Total Gas Offtake [TJ/y]	46.7	46.7	46.7	33.0	33.0	33.0	30.5	27.8
Total Electricity Grid Offtake [TJ/y]	11.9	8.9	7.8	11.9	8.9	7.8	8.2	9.1
PV Electricity Generation [GWh/y]	0.1	1.2	2.3	0.1	1.2	2.3	2.3	2.3
mCHP Electricity Generation [GWh/y]	-	-	-	-	-	-	-	-
PV + mCHP Feed-in [GWh/y]	-	0.2	1.1	-	0.2	1.1	0.9	0.9
Self-Consumption [GWh/y]	0.1	0.9	1.2	0.1	0.9	1.2	1.4	1.4
Self-Consumption [%]	100%	79%	52%	100%	79%	52%	61%	61%
ES Generation [GWh/y]	-	-	-	-	-	-	-	-
TES Generation [GWh/y]	-	-	-	-	-	-	3.9	3.5
Peak Flow [MW]	0.8	1.0	2.0	0.8	1.0	2.0	2.0	2.0
Peak Demand [MW]	0.8	0.8	0.8	0.8	0.8	0.8	0.9	1.0
Ratio Peak Flow to Peak Demand	1.00	1.22	2.44	1.00	1.22	2.44	2.26	2.08
CO2 Emissions Gas offtake [t CO2/y]	2,473	2,473	2,473	1,745	1,710	1,583	1,484	1,337
CO2 Emissions Electricity Offtake [t CO2/y]	1,737	1,302	1,145	1,737	1,302	1,145	1,204	1,336
Total CO2 Emissions [t CO2/y]	4,210	3,775	3,618	3,482	3,012	2,728	2687	2, 674
Feed-in Grid Emission Reduction [t CO2/y]	-	35	162	-	35	162	132	132
Net Emissions [t CO2/y]	4,210	3,740	3,456	3,482	2,976	2,566	2,555	2,542
Investment Cost/year [1000€/y]	72	134	200	243	304	371	371	371
Electricity cost [1000€/y]	754	565	497	754	565	497	520	514
Gas Cost [1000€/y]	989	989	989	698	698	698	642	587
Total Costs [1000€/y]	1,815	1,688	1,685	1,695	1,567	1,566	1,533	1,472
Feed-in profit (PV + mCHP) [1000 €/y]	-	19	87	-	19	87	52	52

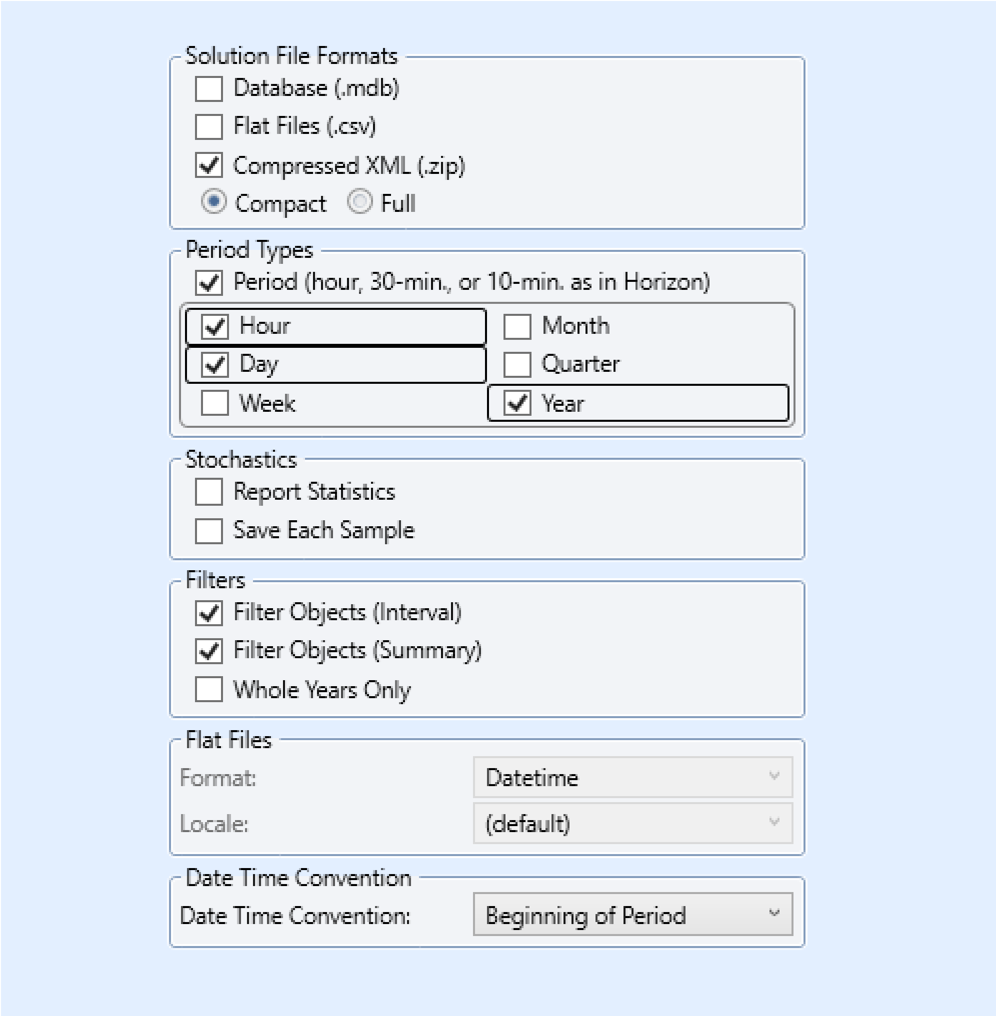
Table 7 - Simulation Results

Scenario	Electrification					mCHP				
	Baseline Simulations					Baseline Simulations				
Simulation #	9	10, Medium PV	11, High PV	12, High PV + ES + Flex FI	13, High PV + ES + Flex FI + Flex EP	14	15, Medium PV	16, High PV	17, High PV + ES + Flex FI	18, High PV + ES + Flex FI + Flex EP
Total Gas Offtake [TJ/y]	-	-	-	-	-	57.6	57.6	57.6	57.6	57.6
Total Electricity Grid Offtake [TJ/y]	25.5	22.1	20.2	19.7	19.8	4.3	2.6	2.3	1.4	1.4
PV Electricity Generation [GWh/y]	0.1	1.2	2.3	2.3	2.3	0.1	1.2	2.3	2.3	2.3
mCHP Electricity Generation [GWh/y]	-	-	-	-	-	2.4	2.4	2.4	2.4	2.4
PV + mCHP Feed-in [GWh/y]	-	0.1	0.8	0.6	0.6	0.3	0.9	2.0	1.7	1.7
Self-Consumption [GWh/y]	0.1	1.0	1.6	1.7	1.7	2.2	2.7	2.8	3.0	3.0
Self-Consumption [%]	100%	89%	67%	73%	73%	89%	75%	58%	64%	64%
Electrical Storage (EES) Generation [GWh/y]	-	-	-	0.2	0.4	-	-	-	0.4	0.4
Thermal Storage (TES) Generation [GWh/y]	-	-	-	-	-	-	-	-	-	-
Peak Flow [MW]	3.9	3.9	3.9	3.9	4.4	0.8	1.4	2.3	2.7	2.7
Peak Demand [MW]	3.9	3.9	3.9	3.9	3.9	0.8	0.8	0.8	0.8	0.8
Ratio Peak Flow to Peak Demand	1.00	1.00	1.00	1.00	1.14	1.01	1.71	2.84	3.34	3.34
CO2 Emissions Gas offtake [t CO2/y]	-	-	-	-	-	3,048	3,048	3,048	3,048	3,048
CO2 Emissions Electricity Offtake [t CO2/y]	3,726	3,229	2,953	2,885	2,894	623	378	333	199	199
Total CO2 Emissions [t CO2/y]	3,726	3,229	2,953	2,885	2,894	3,671	3,425	3,381	3,246	3,247
Feed-in Grid Emission Reduction [t CO2/y]	-	18	112	91	91	41	129	287	246	246
Net Emissions [t CO2/y]	3,726	3,211	2,841	2,793	2,803	3,630	3,296	3,094	3,000	3,001
Investment Cost [1000€/y]	360	421	488	529	529	633	694	761	802	802
Electricity Offtake Cost [1000€/y]	1,618	1,402	1,282	1,252	1,108	271	164	145	86	75
Gas Offtake Cost [1000€/y]	-	-	-	-	-	1,218	1,218	1,218	1,218	1,218
Total Costs [1000€/y]	1,977	1,823	1,770	1,782	1,638	2,122	2,076	2,124	2,107	2,096
Feed-in profit (PV + mCHP) [1000 €/y]		10	60	38	38	22	69	154	100	100

Table 8 - Simulation Results

7.2. PLEXOS Simulation Settings




Solution File Formats
Database (.mdb)
Flat Files (.csv)
Compressed XML (.zip)
Compact
Full
Period Types
Period (hour, 30-min., or 10-min. as in Horizon)
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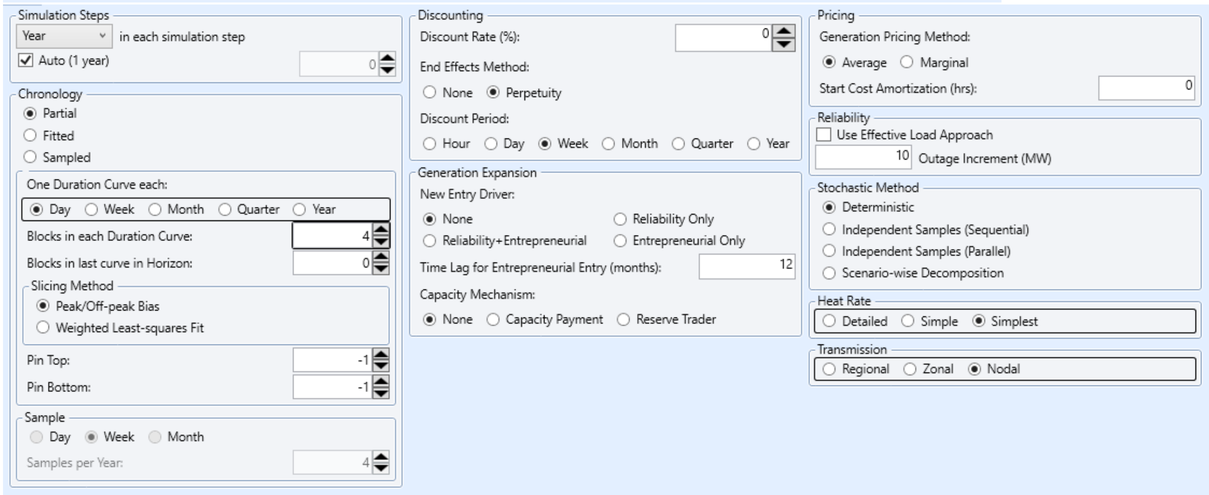
Month
Day
Quarter
Week
Year
Stochastics
Report Statistics
Save Each Sample
Filters
Filter Objects (Interval)
Filter Objects (Summary)
Whole Years Only
Flat Files
Format:
Datetime
Locale:
(default)
Date Time Convention
Date Time Convention:
Beginning of Period


Simulation Steps
Year
in each simulation step
Auto (1 year)
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Chronology
Partial
Fitted
Sampled
One Duration Curve each:
Day
Week
Month
Quarter
Year
Blocks in each Duration Curve:
4
Blocks in last curve in Horizon:
0
Slicing Method
Peak/Off-peak Bias
Weighted Least-squares Fit
Pin Top:
-1
Pin Bottom:
-1
Sample
Day
Week
Month
Samples per Year:
4
Discounting
Discount Rate (%):
0
End Effects Method:
None
Perpetuity
Discount Period:
Hour
Day
Week
Month
Quarter
Year
Generation Expansion
New Entry Driver:
None
Reliability Only
Reliability+Entrepreneurial
Entrepreneurial Only
Time Lag for Entrepreneurial Entry (months):
12
Capacity Mechanism:
None
Capacity Payment
Reserve Trader
Pricing
Generation Pricing Method:
Average
Marginal
Start Cost Amortization (hrs):
0
Reliability
Use Effective Load Approach
10
Outage Increment (MW)
Stochastic Method
Deterministic
Independent Samples (Sequential)
Independent Samples (Parallel)
Scenario-wise Decomposition
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Detailed
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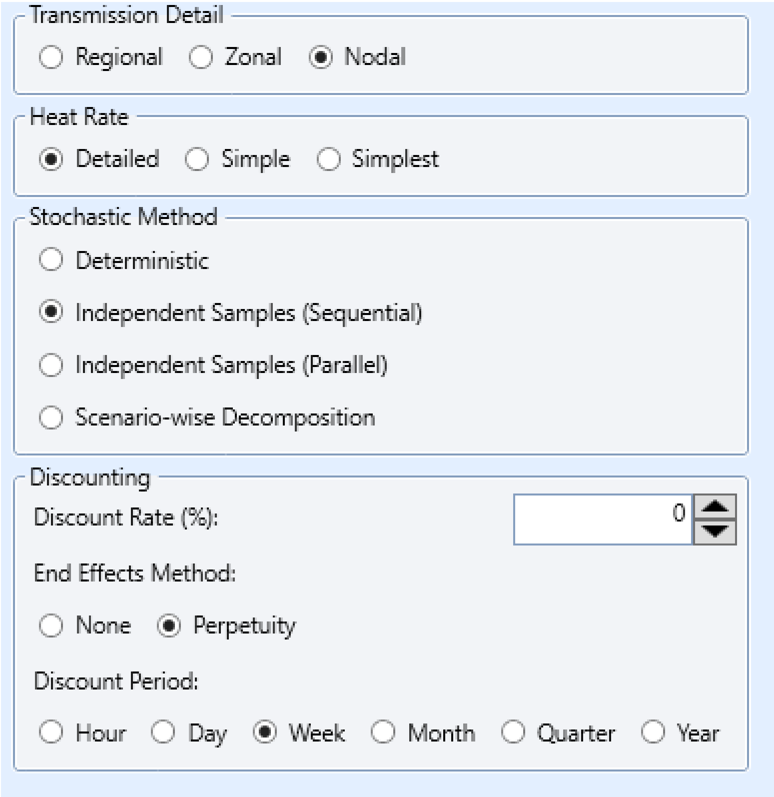
Simplest
Transmission
Regional
Zonal
Nodal


Transmission Detail
Regional
Zonal
Nodal
Heat Rate
Detailed
Simple
Simplest
Stochastic Method
Deterministic
Independent Samples (Sequential)
Independent Samples (Parallel)
Scenario-wise Decomposition
Discounting
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End Effects Method:
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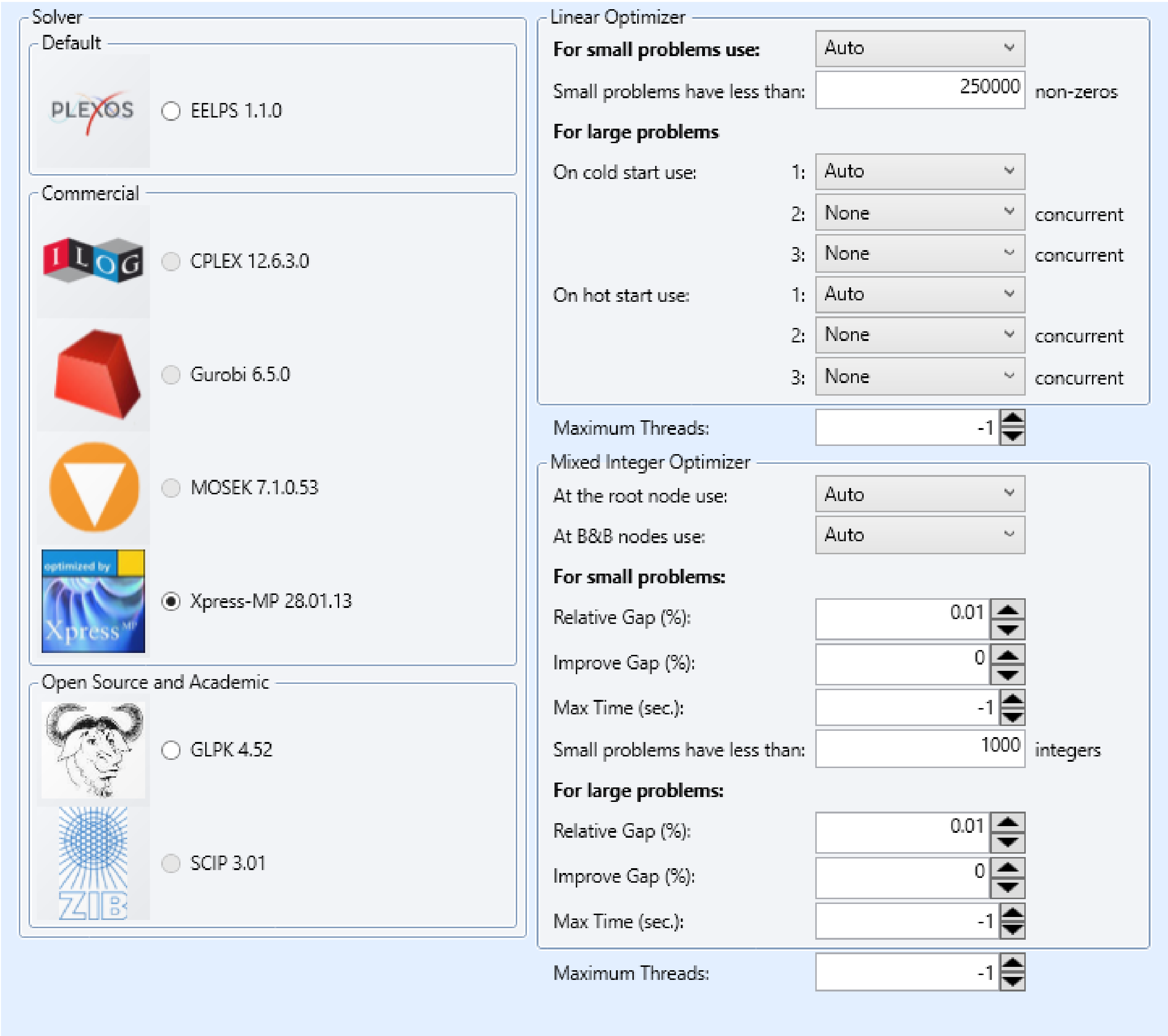
Perpetuity
Discount Period:
Hour
Day
Week
Month
Quarter
Year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EELPS 1.1.0
Commercial
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Gurobi 6.5.0
MOSEK 7.1.0.53
Xpress-MP 28.01.13
Open Source and Academic
GLPK 4.52
SCIP 3.01
Linear Optimizer
For small problems use: Auto
Small problems have less than: 250000 non-zeros
For large problems
On cold start use: 1: Auto
2: None concurrent
3: None concurrent
On hot start use: 1: Auto
2: None concurrent
3: None concurrent
Maximum Threads: -1
Mixed Integer Optimizer
At the root node use: Auto
At B&B nodes use: Auto
For small problems:
Relative Gap (%): 0.01
Improve Gap (%): 0
Max Time (sec.): -1
Small problems have less than: 1000 integers
For large problems:
Relative Gap (%): 0.01
Improve Gap (%): 0
Max Time (sec.): -1
Maximum Threads: -1

7.3. Demand Profile Data

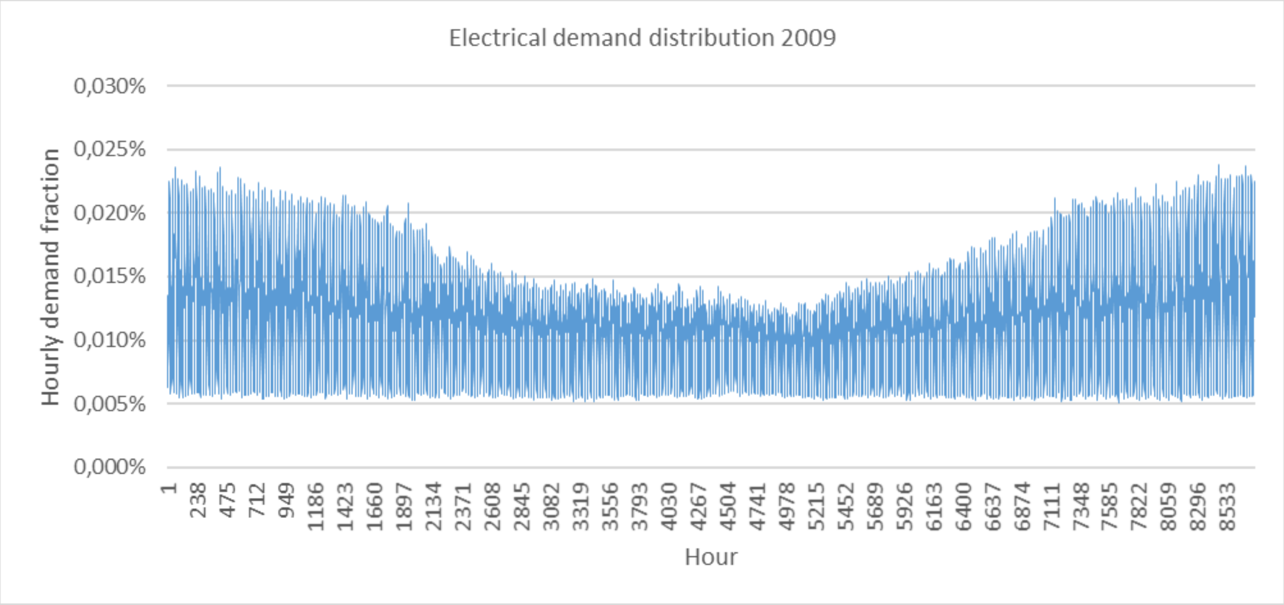
Liander open data website, demand profiles

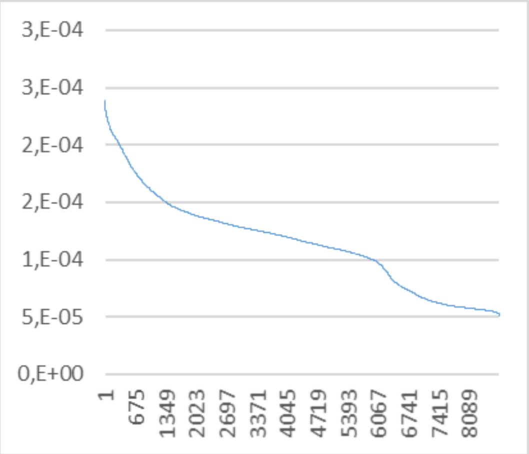
Expected electricity (2009) and gas (2008) consumption profiles for a group of 10.000 consumers based on earlier measurements or allocation data. The consumption is normalized (temperature corrected based on average temperature profile of the last 20 years prior).

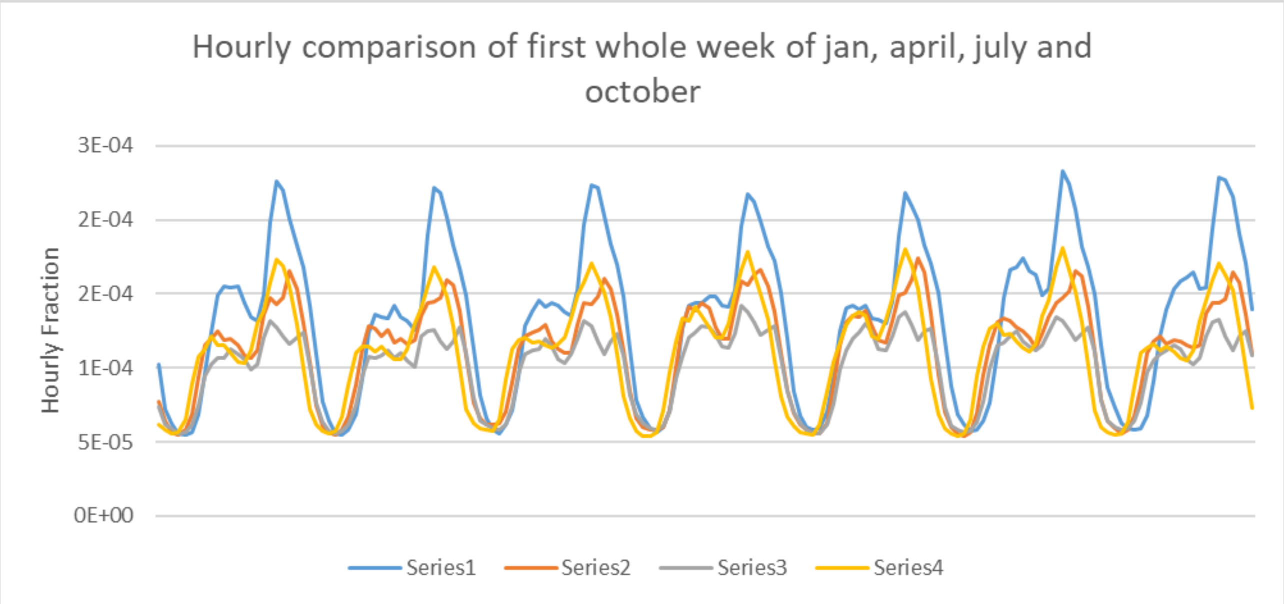
The electricity data includes consumers with a <= 3x25 Ampere connection with single and double tariff (ratio between these is not known). The gas data includes consumers with an annual consumption of <5000m^3 (35,17 MJ/m^3) with a connection of <= G6 and is temperature corrected. The hour fraction is given as the share of the consumption in a certain hour of the annual consumption.

Both the electricity and gas consumption distribution is presented in a graph over the whole year to show seasonal variations, as a load/demand duration curve and as a graph that compares the first whole weeks of January, April, July and October to compare daily variations throughout the year (starting at Monday 00:00).

Electrical Hourly Fractions:

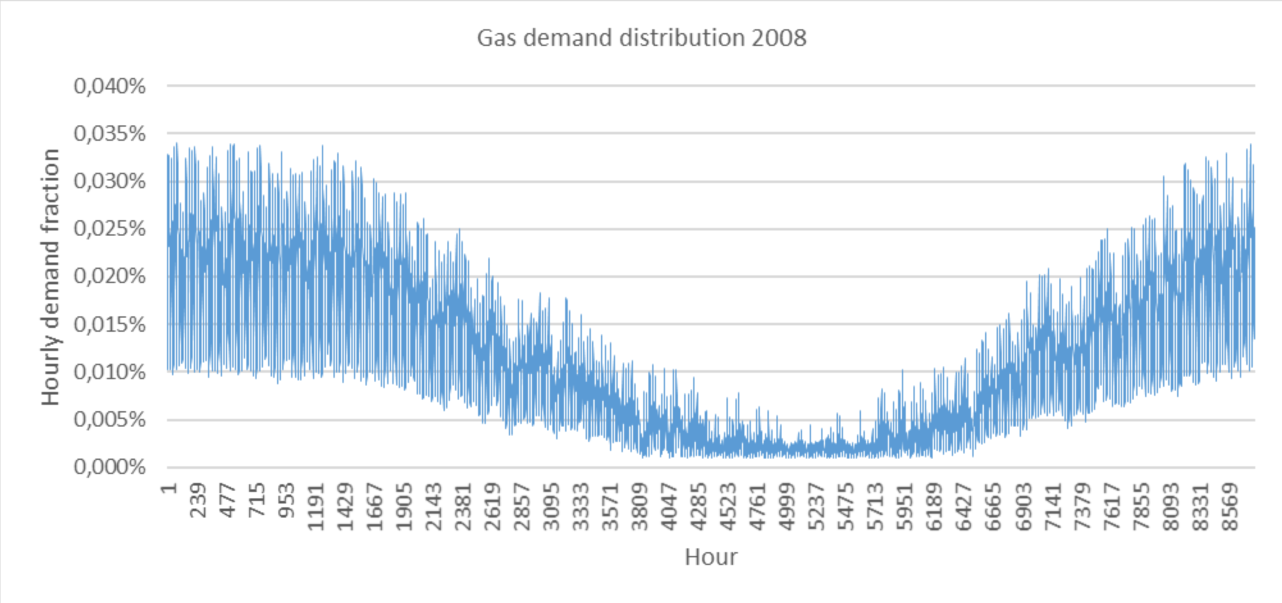


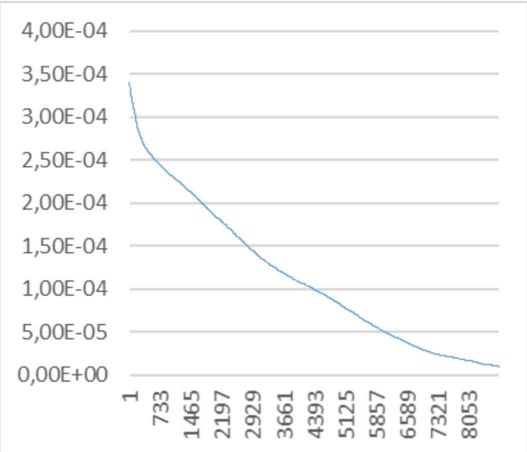


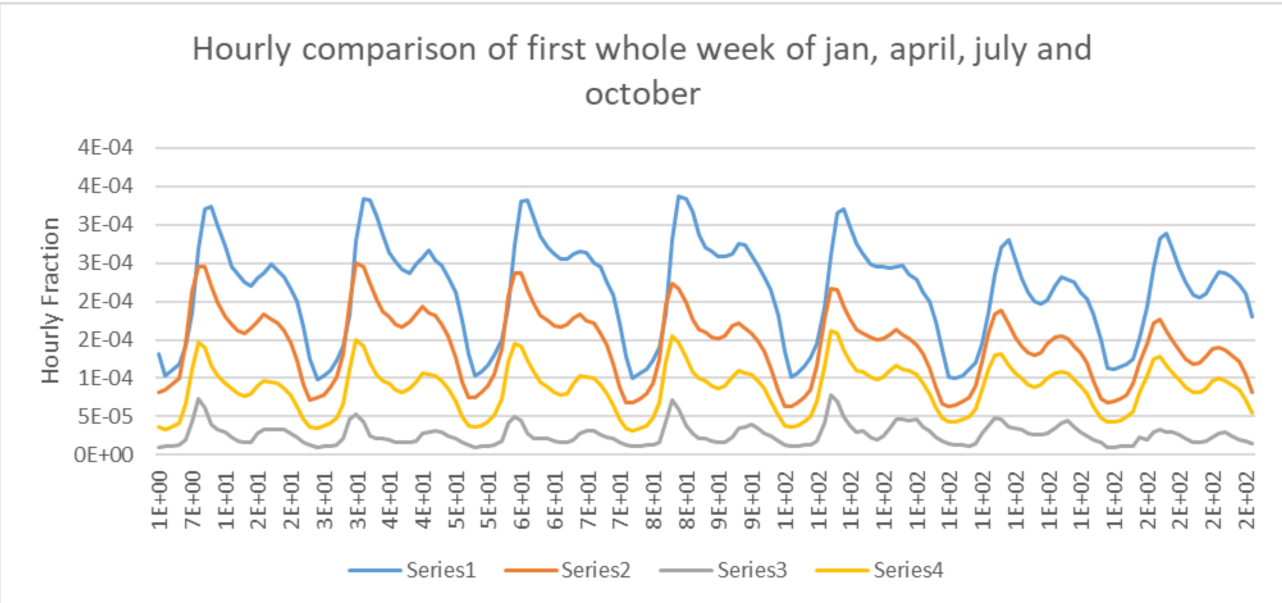


Remarks on graphs: only seasonal variation in peak demand, minimum demand stays at the same level throughout the year. Higher morning peak in weekend days in winter.

Gas Hourly Fractions:







Remarks on graphs: big seasonal variation following outside temperature, clearly visible in the comparison of weeks. Note: lower demand in weekend days (not expected?).

7.4. Heat Pump Generation Participation Factor and KNMI Temperature Data

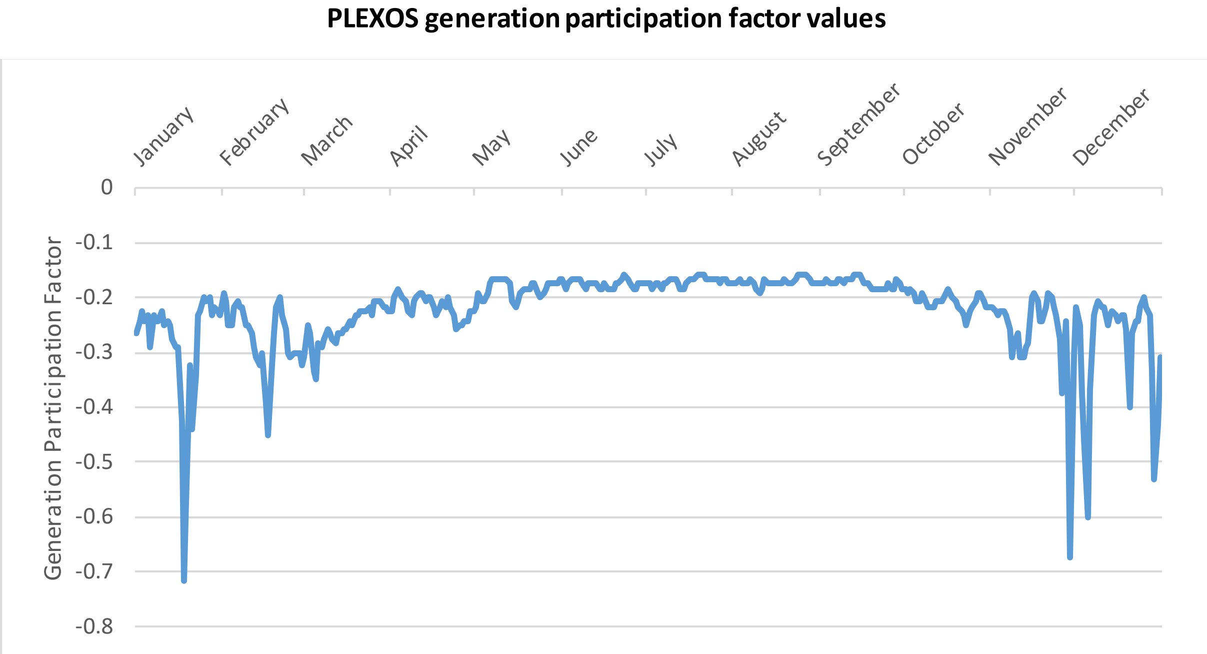


Figure 17 – PLEXOS generation participation factor used to model daily heat pump COP values (based on KNMI daily temperature data 2016).

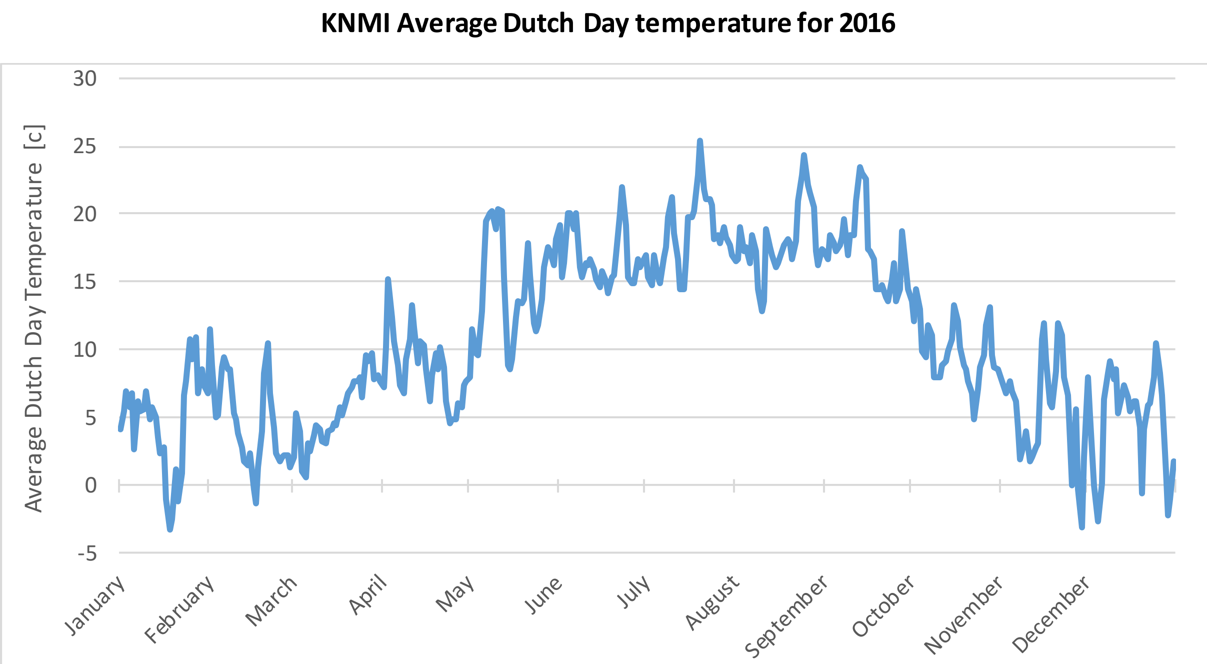


Figure 18 - KNMI Average Dutch Day temperature for 2016, used to determine Heat Pump COP and Generation participation factor in PLEXOS.

7.5. Hourly HP Electricity Consumption

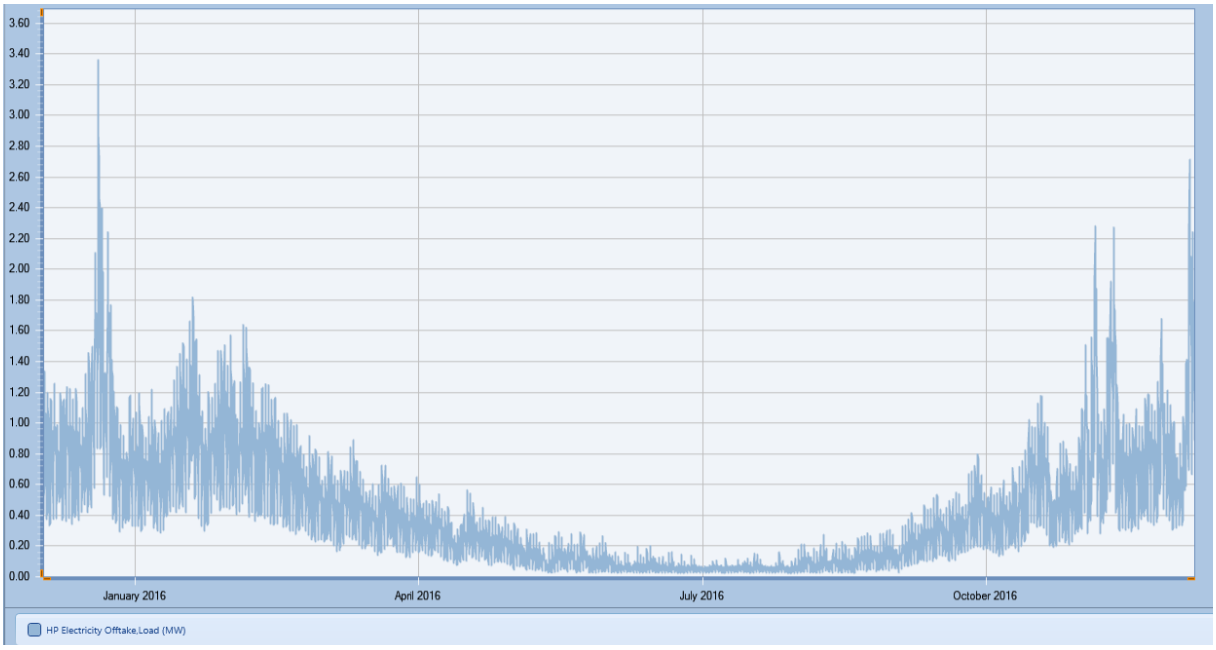


Figure 19 - Hourly electricity consumption of residential heat pumps shows that the temperature dependence of heat pump efficiency can have big consequences for peak demands.

7.6. Seasonal and Hourly dynamics of Local Generation and Electricity Demand

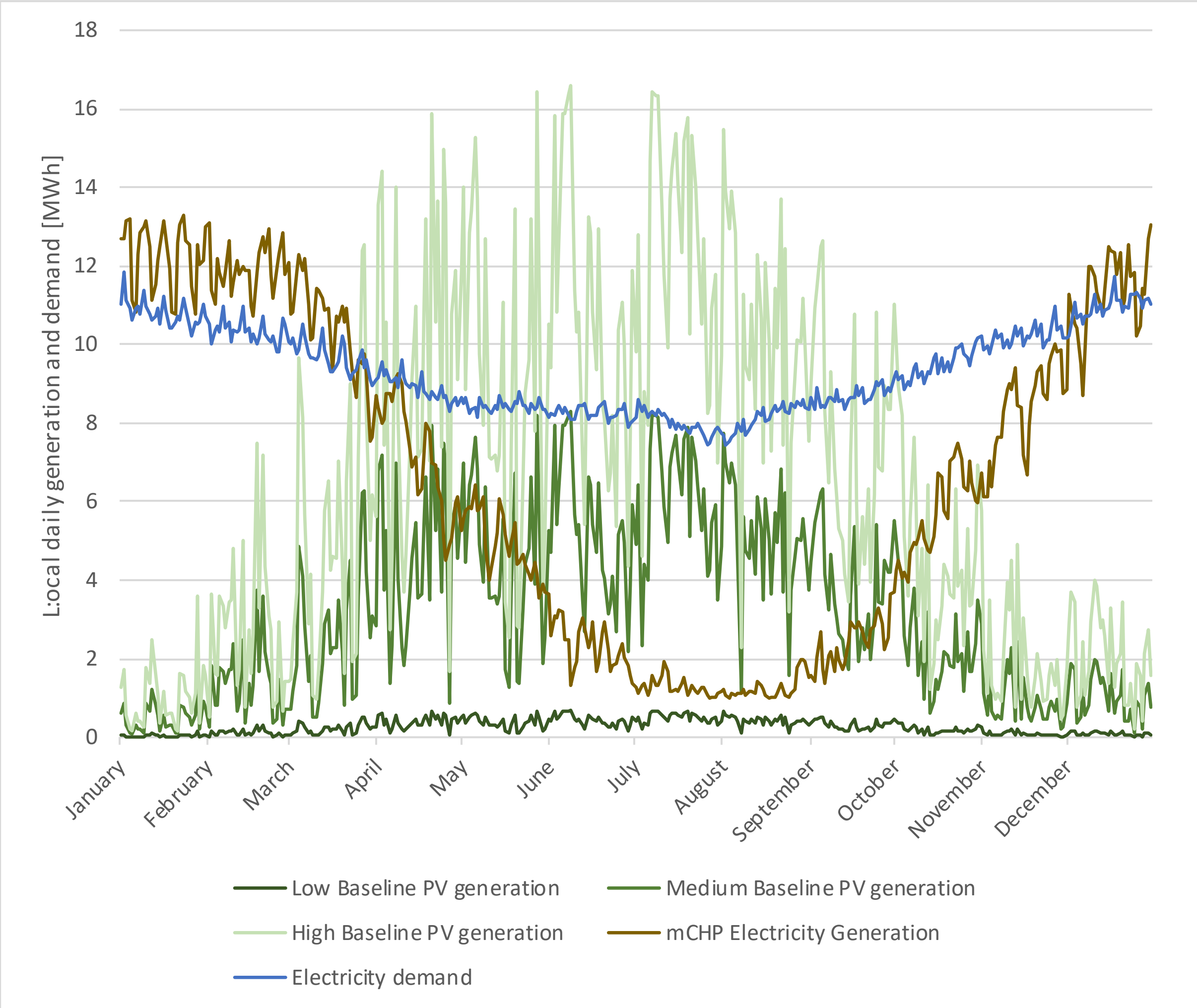


Figure 20- Daily PV and mCHP generation, and electricity demand [MWh]. Seasonal mismatches between PV generation and electricity demand, but also with between heating demand (indicated by the mCHP electricity generation) are clear.

7.6.1. Self-consumption duration curve

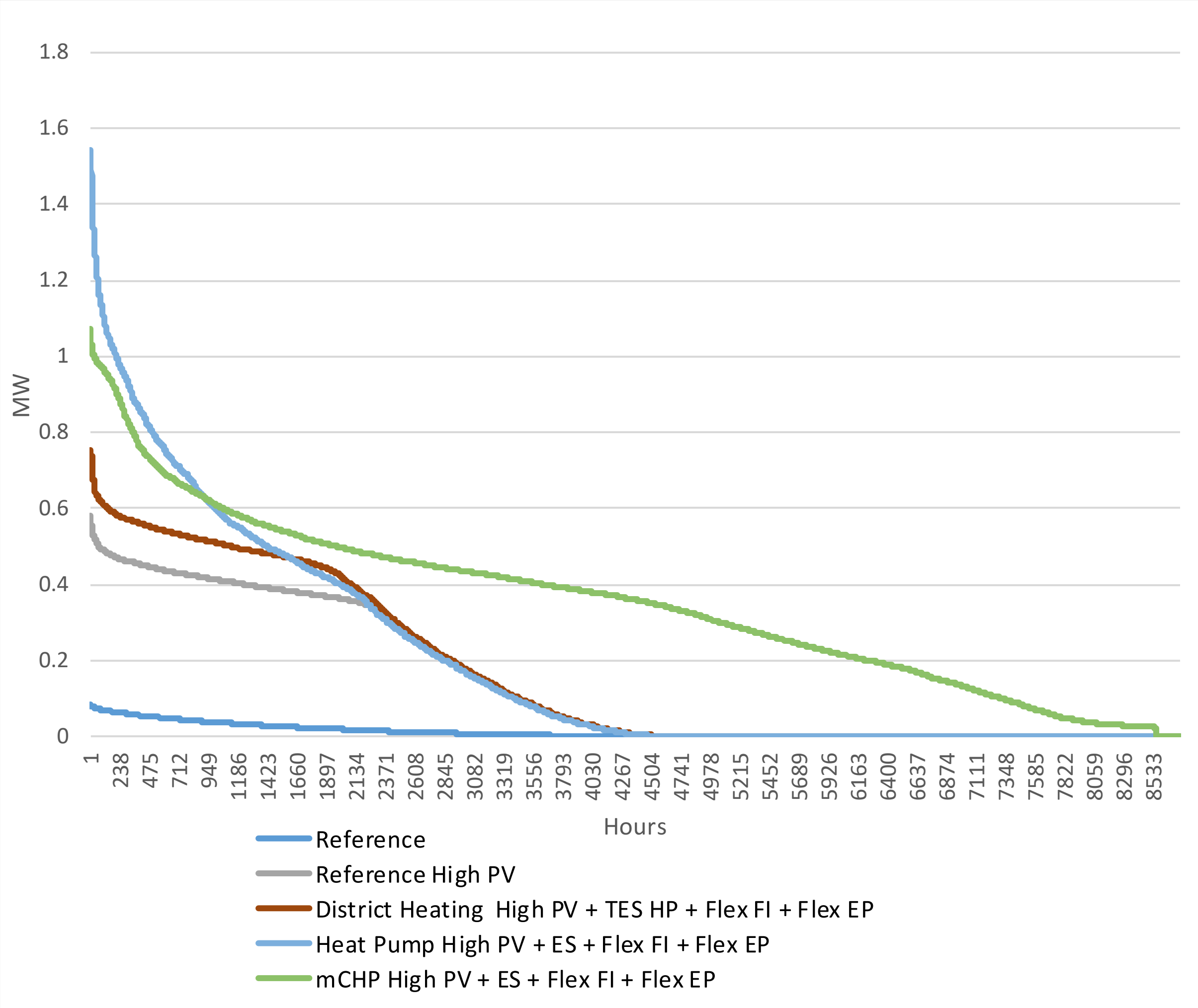


Figure 21 - Self-Consumption duration curve for the simulations with the highest self-consumption from each scenario. Reference (low PV) is added for comparison.

7.7. Individual Scenario Results for Self-Consumption

Reference scenario

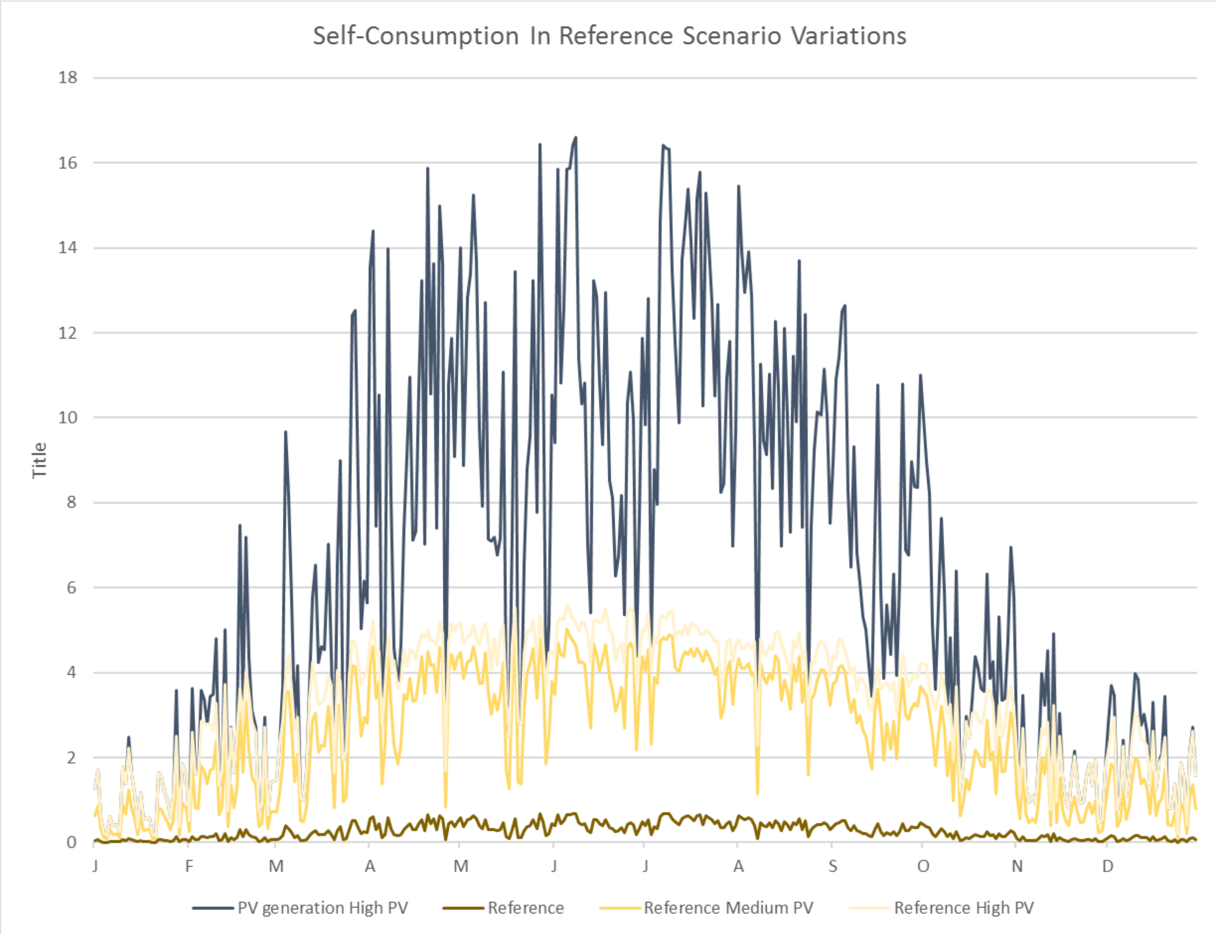


Figure 22 - High PV generation output compared to the self-consumption under reference scenario simulations in MWh/d.

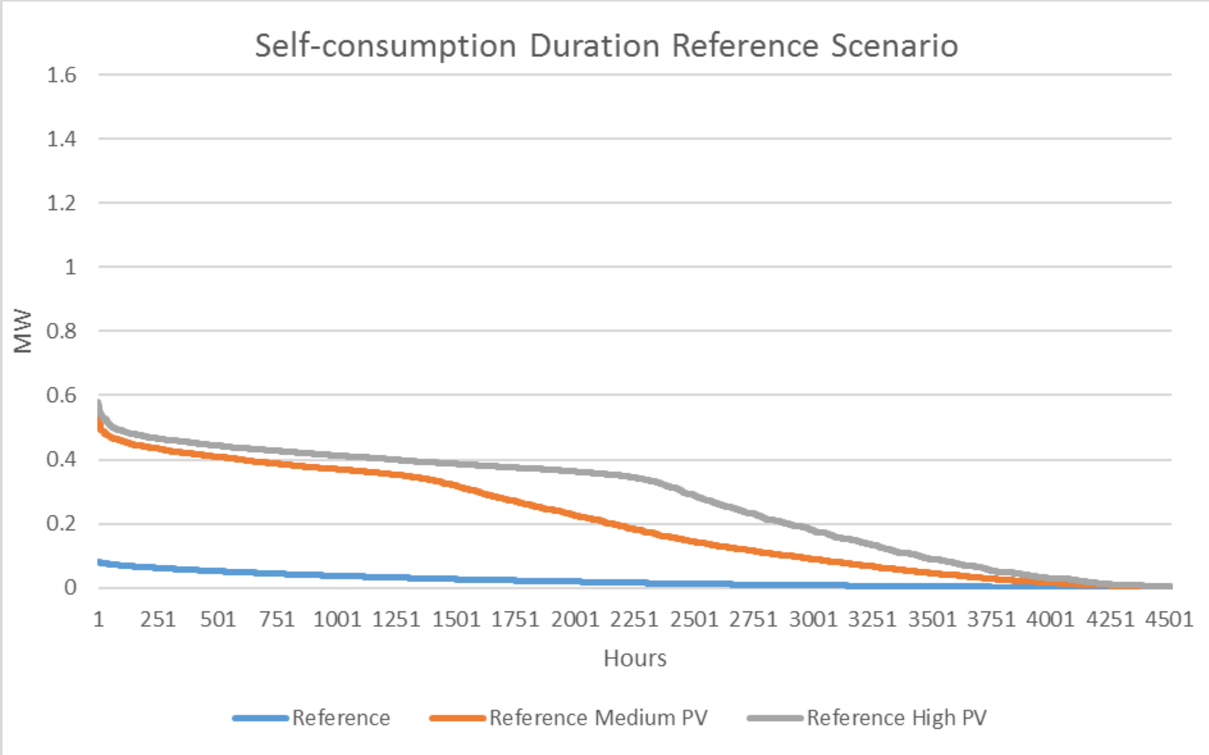


Figure 23 - Self-consumption duration curve under reference scenario simulations.

District Heating Scenario

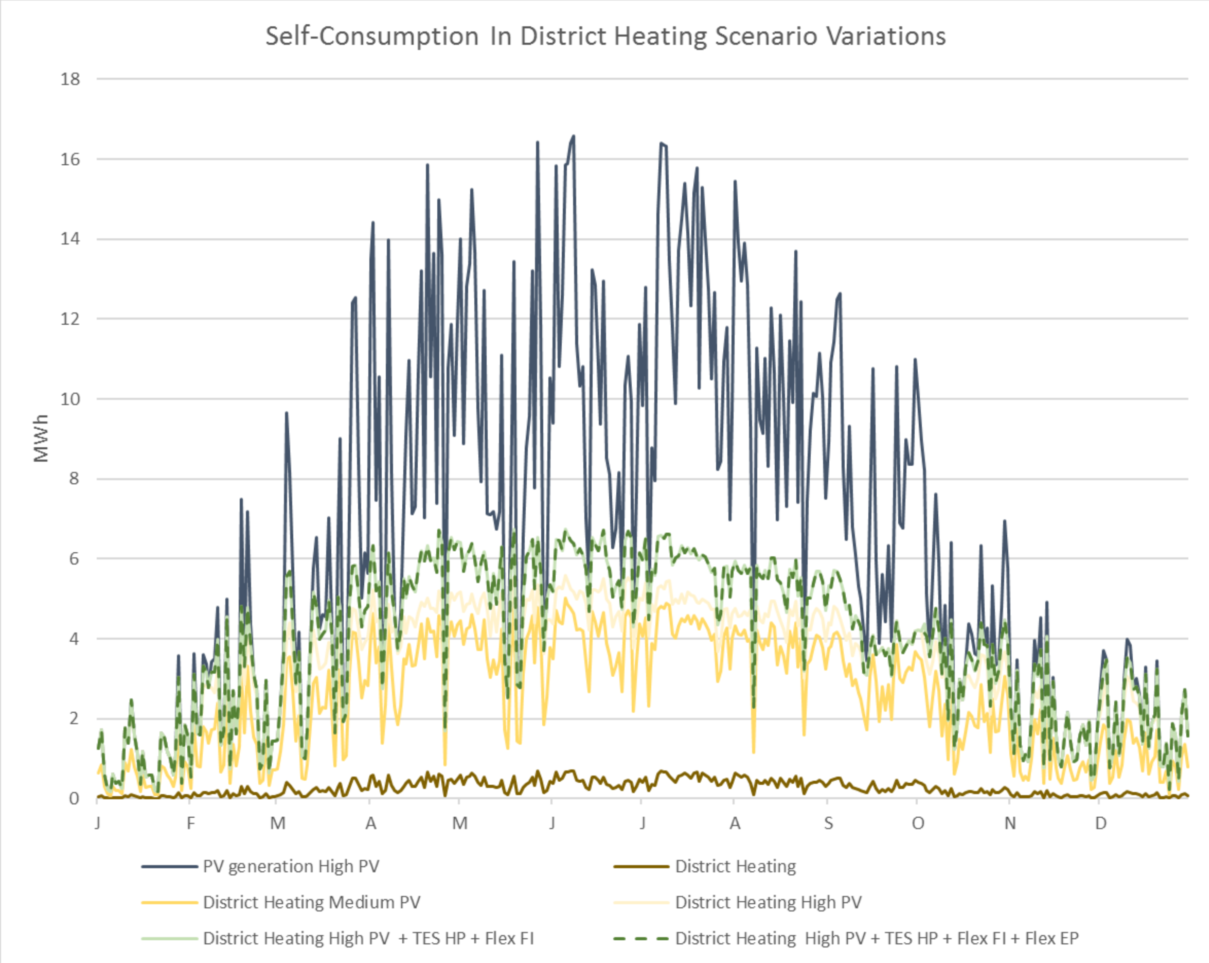


Figure 24 - High PV generation output compared to the self-consumption under district heating baseline and variation simulations in MWh/d.

Electrification Scenario

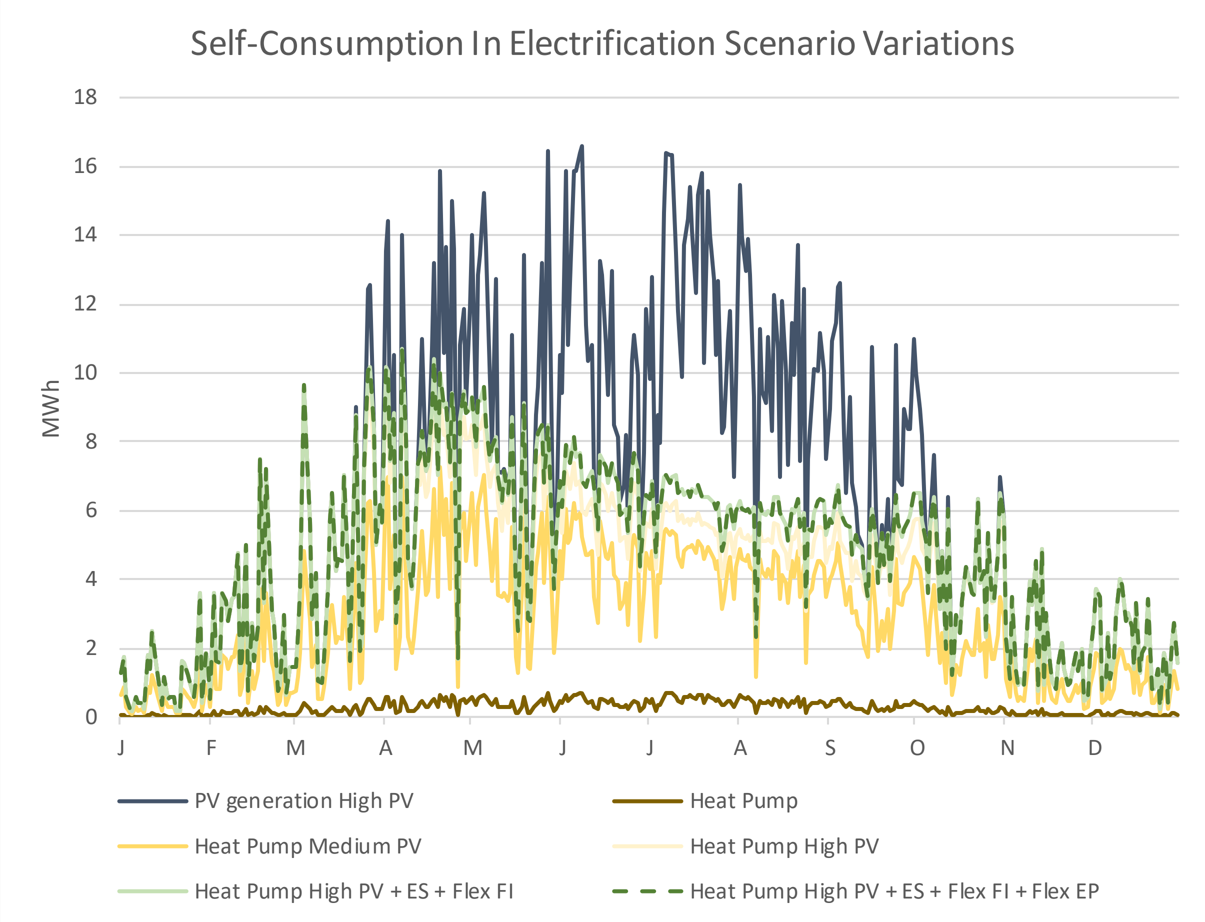


Figure 25 - High PV generation output compared to the self-consumption under electrification baseline and variation simulations in MWh/d.

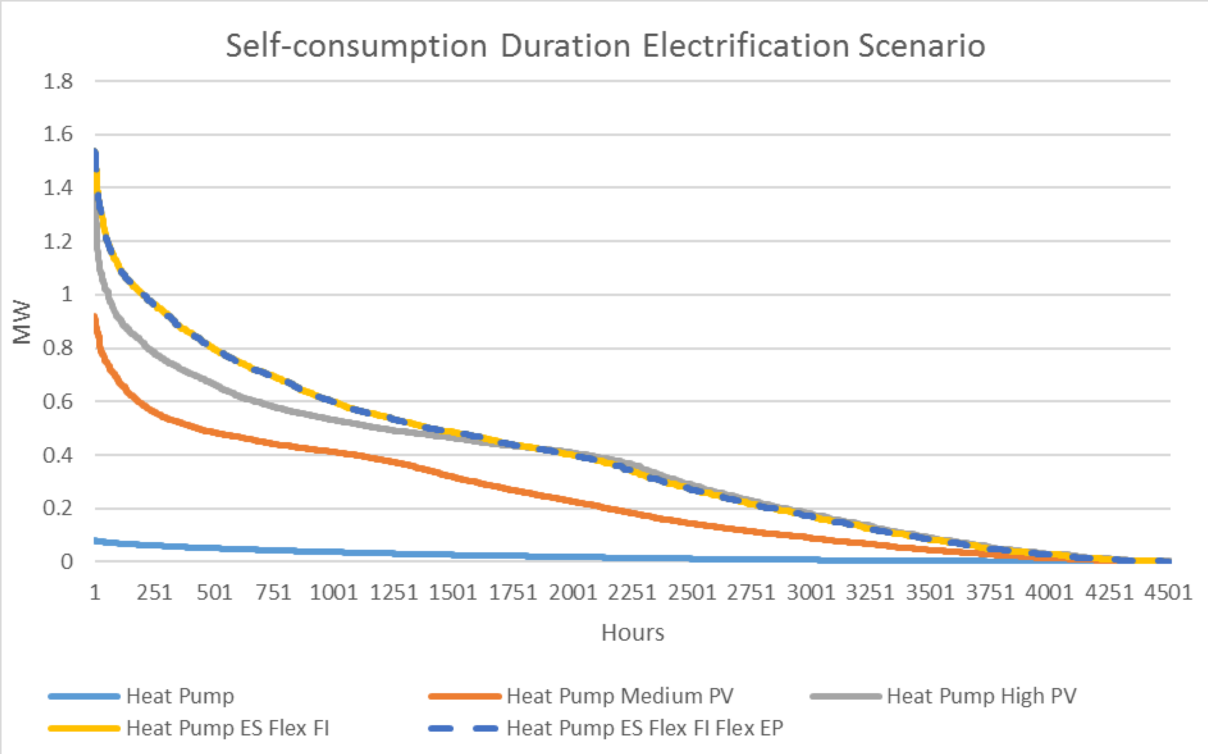


Figure 26 - Self-consumption duration curve under electrification scenario simulations.

mCHP Scenario

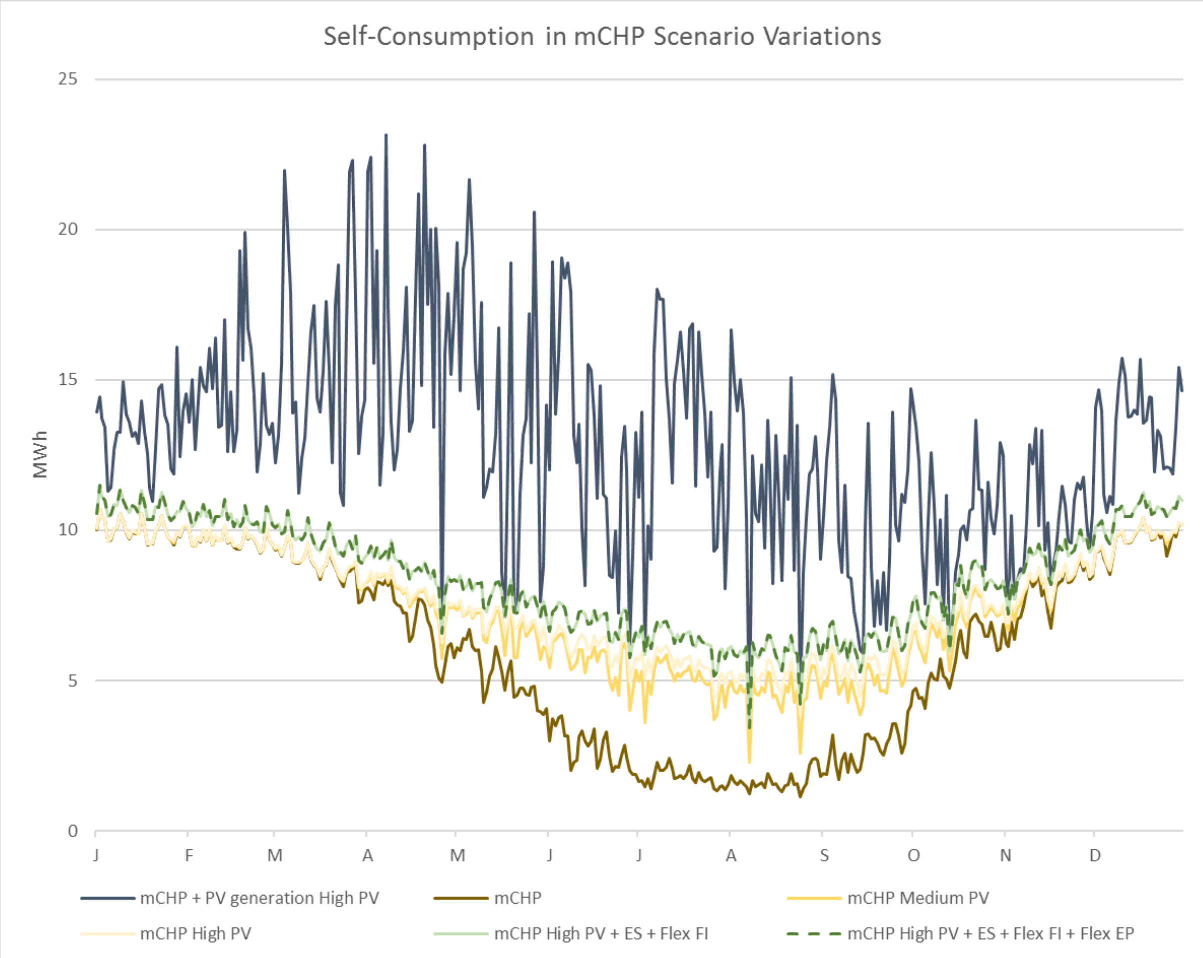


Figure 27 - High PV generation output compared to the self-consumption under mCHP baseline and variation simulations in MWh/d.

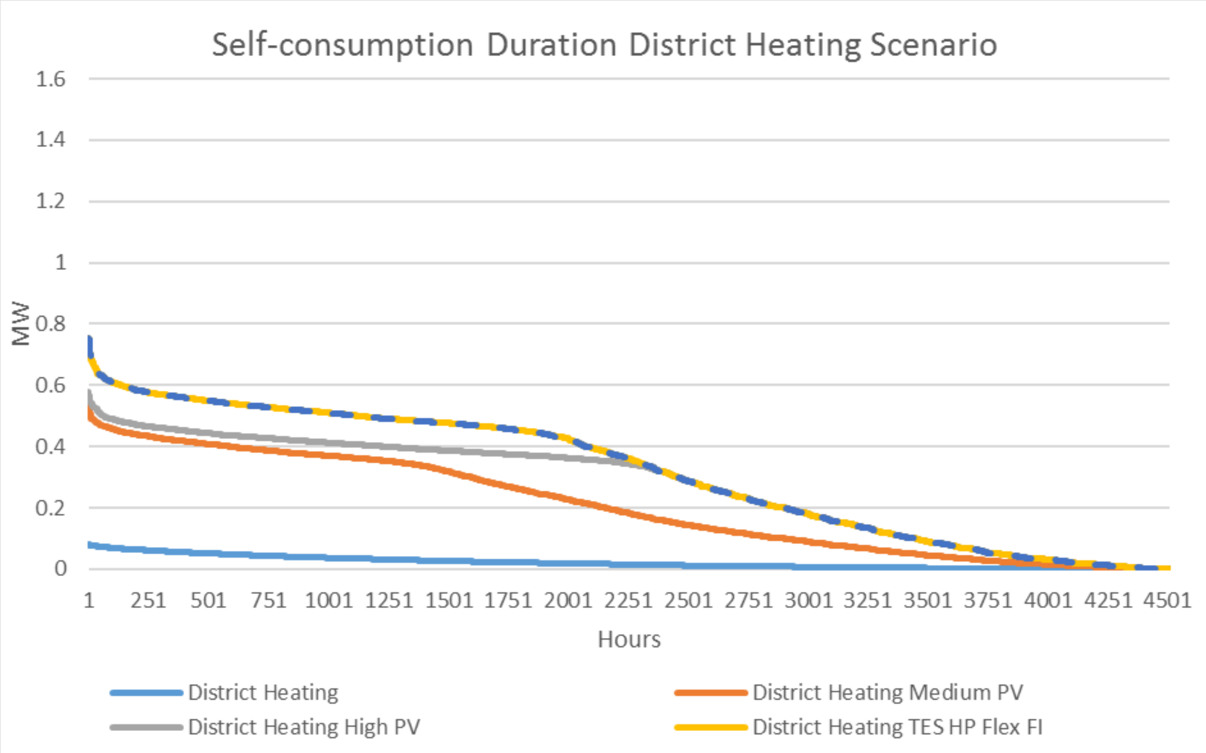


Figure 28 - Self-consumption duration curve under district heating scenario simulations.

7.8. Investment Costs

Table 9 - Total investment cost breakdown for each scenario [1000€].

Scenario	**Reference**			**District Heating**				
Variation	**Baseline Simulations**			**Baseline Simulations**			**Storage**	**FEP**
Simulation #	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**
Main Heating Technology [1000€]	€1.320	€1.337	€1.320	€4.752	€4.752	€4.752	€4.752	€4.752
PV [1000€]	€111	€1.337	€2.673	€111	€1.337	€2.673	€2.673	€2.673
ES [1000€]								
TES [1000€]							€1.260	€1.260
DH HP [1000€]							€800	€800
Total [1000€]	**€1.431**	**€2.673**	**€3.993**	**€4.863**	**€6.089**	**€7.425**	**€9.485**	**€9.485**

Scenario	**Electrification**					**mCHP**				
Variation	**Baseline Simulations**			**Storage**	**FEP**	**Baseline Simulations**			**Storage**	**FEP**
Simulation #	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**
Main Heating Technology [1000€]	€7.080	€7.080	€7.080	€7.080	€7.080	€12.540	€12.540	€12.540	€12.540	€12.540
PV [1000€]	€111	€1.337	€2.673	€2.673	€2.673	€111	€1.337	€2.673	€2.673	€2.673
ES [1000€]				€832	€832				€832	€832
TES [1000€]										
DH HP [1000€]										
Total [1000€]	**€7.191**	**€8.417**	**€9.753**	**€10.585**	**€10.585**	**€12.651**	**€13.877**	**€15.213**	**€16.045**	**€16.045**

7.9. Annual Costs Breakdown

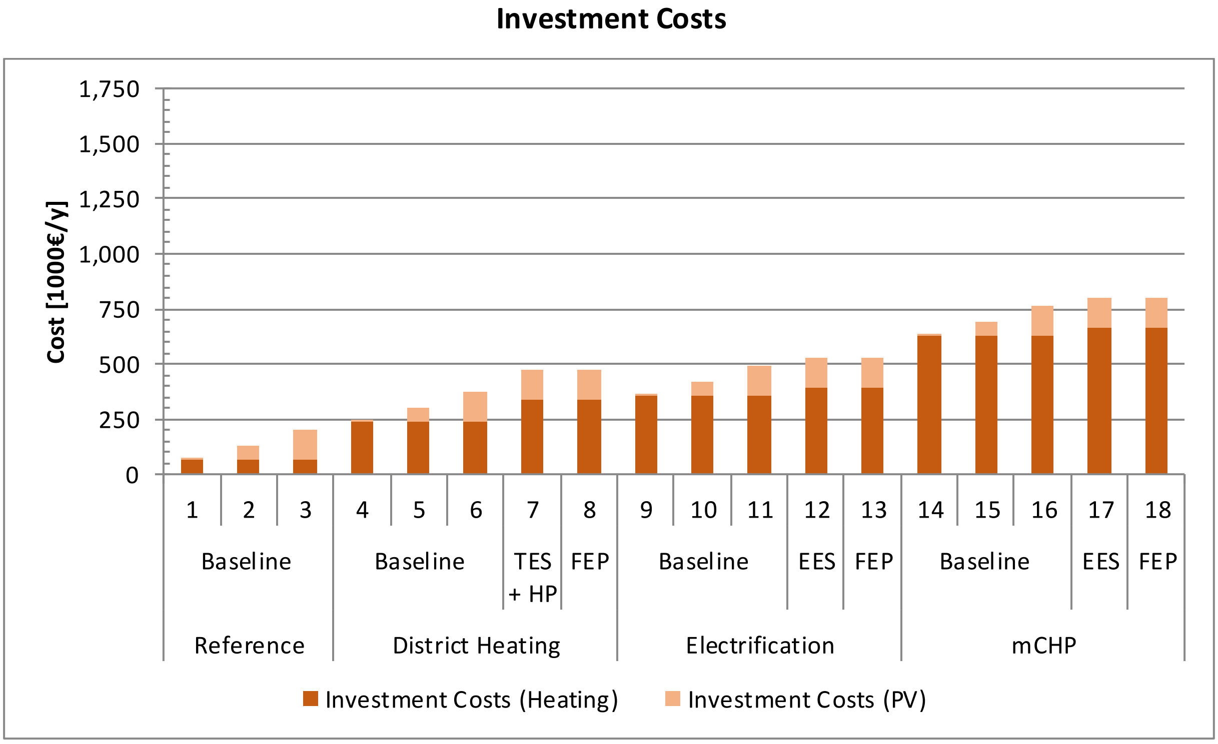


Figure 29 - Total annual investment costs for heating (including storage) technologies and PV

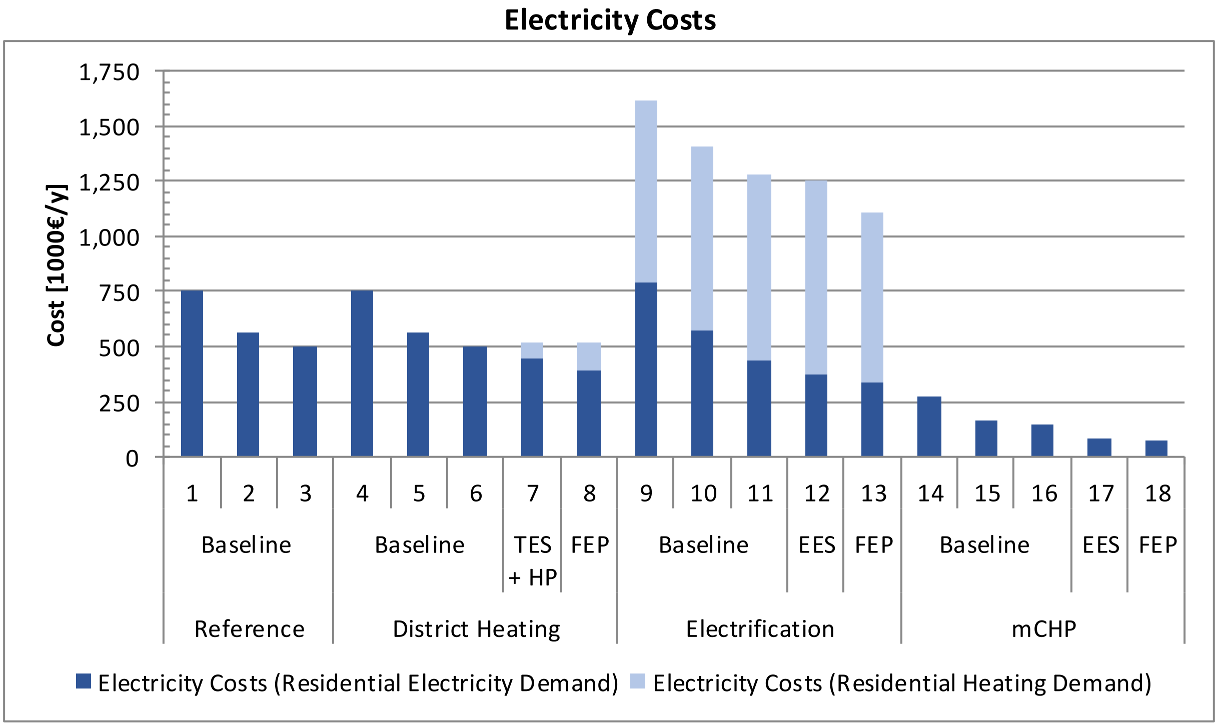


Figure 30 - Total annual electricity costs from residential heating and non-heating demand

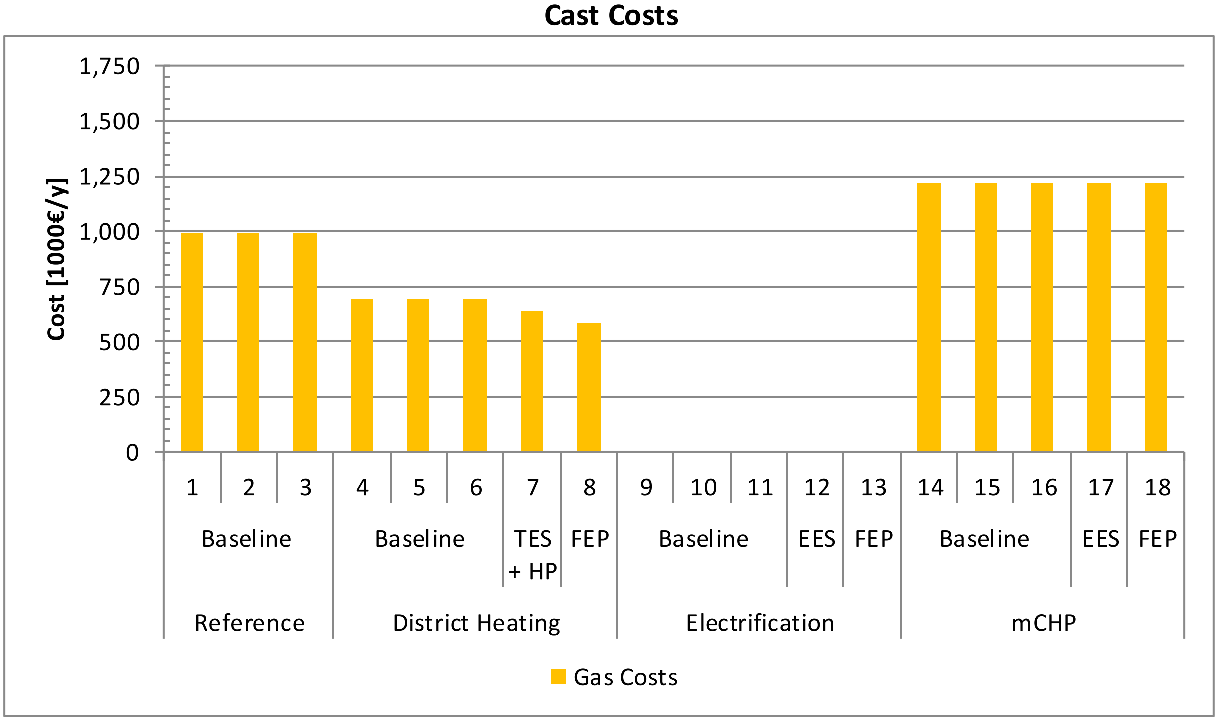


Figure 31 - Total annual gas costs from residential heating

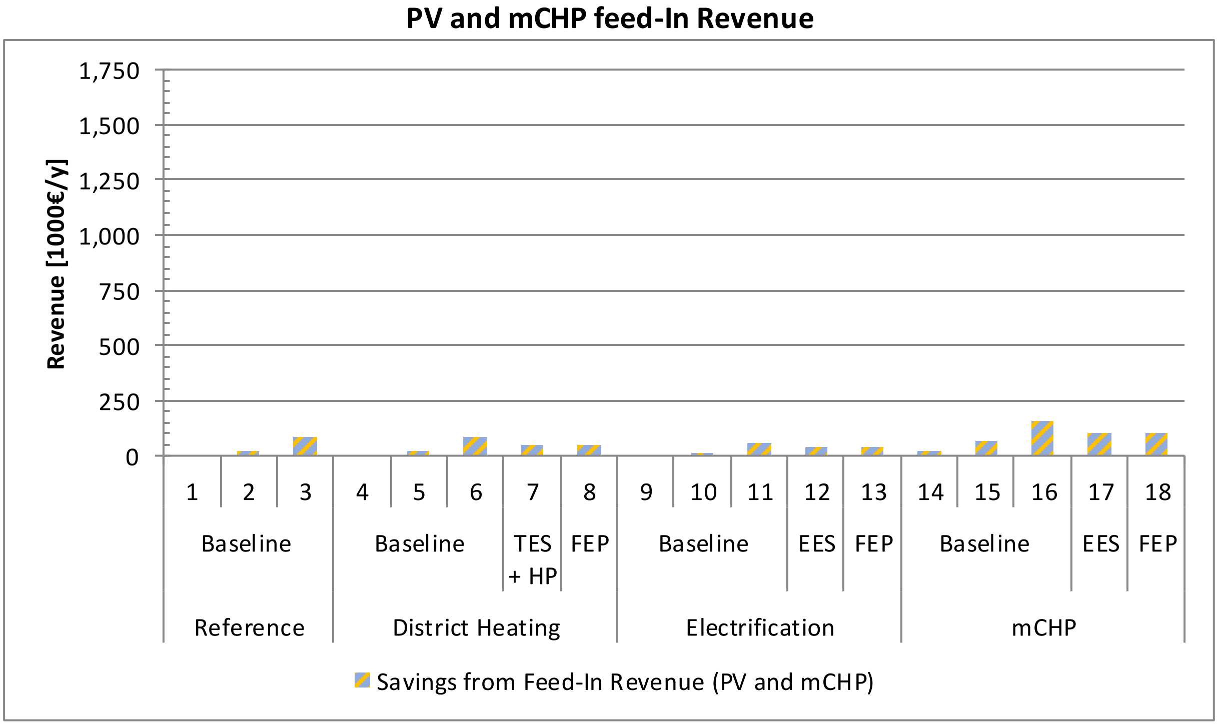


Figure 32 - Total annual revenue from PV and mCHP feed-in