Université catholique de Louvain

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Economic, environmental and social analysis of decentralized power production and storage in Belgium

Can Belgium count on decentralized photovoltaic power production and storage to achieve its emission reduction targets?

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Contents

Chapter 1

Introduction

In August 2017 I participated in a massive civil disobedience action aiming the Garzweiler lignite coal mine and the Neurath power station (4300 MW) in the Rhine-Ruhr region in Germany. Its symbolic goal was to stop as long as possible the industry's activity and thereby denounce its impact on global warming. In the end, together with 6,000 activists, the Neurath power station's output was forcibly reduced by 37% during nine hours [1]. With this sole action we thus theoretically prevented the emission of 14.3 kt of $CO_{2,eq}$[1]. This is 80 times what I personally emitted in my 24-year existence[2] and it had 400 times more impact than if I had been vegan for those entire 24 years[3]. Most of all, it helped me understand the importance of choosing the right target, especially in the context of global warming mitigation.

Figure 1.1: Image from the Neurath Power Station being approached by activists from Ende Gelände in August 2017. Image taken from Ref. [1].

[1]The computation is as follows: $4300[MW] \times 9[h] \times 0.37 \times 1[tCO_2/MWh] = 14.3\ ktCO_2$
[2]European average carbon footprint: 7.1 $tCO_2/year$ [2].
[3]A vegan diet produces 2.9 $kgCO_2/day$ while a meat-rich diet (100 g_{meat}/day) produces 7.2 $kgCO_2/day$ [14].

Except lowering greenhouse gas (GHG) emissions and like so mitigating the effects of global warming as stated above, blocking or even closing fossil fuel plants can be motivated by two more facts. First, fossil fuels (like coal) are extracted from finite sources. At a certain moment in time there will be none left, or at least, none as easily accessible as now. If mankind wishes to maintain infinitely the level of comfort it has gained with the combustion of fossil fuels, an equally infinite source of energy is necessary. Secondly, on a shorter term, geopolitics may accelerate the inaccessibility to fossil fuels for some countries. Take Iran for example, they are the world's fourth-largest and second-largest reserve holder of oil and natural gas (data taken from EIA). The US economic sanctions adopted recently prevents it from exporting those resources to some other countries. This puts countries like Belgium, heavily dependent on import, in delicate situations. But if Belgium could exploit sources like the sun or wind, it would resolve both the issue of long term availability – sun and wind will be there for at least 5 billion years – and security of supply – there is wind in Belgium and believe it or not, some sunlight.

The evolution from fossil fuel to renewable fuel is also an evolution from centralized to decentralized generation and from steady to intermittent output. The outcome of this evolution is described by economic and social theorist Jeremy Rifkin as follows [15]:

> *In the 21st century, hundreds of millions-and eventually billions-of human beings will transform their buildings into power plants to harvest renewable energies on site, store those energies in the form of hydrogen and share electricity, peer-to-peer, across local, regional, national and continental inter-grids that act much like the Internet.*

The aspect of storing and networking are central in his vision. Storage offers the mini-power plants independence and works as a buffer for the intermittent output. The "energy internet" allows a flow of electricity from locations with high renewable output to low-output locations. Simply put, Rifkin tels us how an entire fossil fueled power grid could be replaced by a 100% renewable power delivery.

In contrast, energy expert Jean-Marc Jancovici tells the following [16]:

> *The "rifkenian" dream is a solution for the very-very-rich and for an unlimited world, not for a limited world.*

In short, he says Rifkin's solution demands extremely high financial investments which cannot be delivered by a society running on renewables only. Additionally, producing the adequate technology and extracting the needed resources may turn the net ecological balance negative. By pointing out that one needs high revenues to afford such technology he also raises the question of equal access to electricity. In brief, what Jancovici does is criticize Rifkin through the economic, ecologic and societal criteria. Those were the three criteria first adopted by René Passet in *l'Économique et le vivant* to describe a *sustainable* solution.

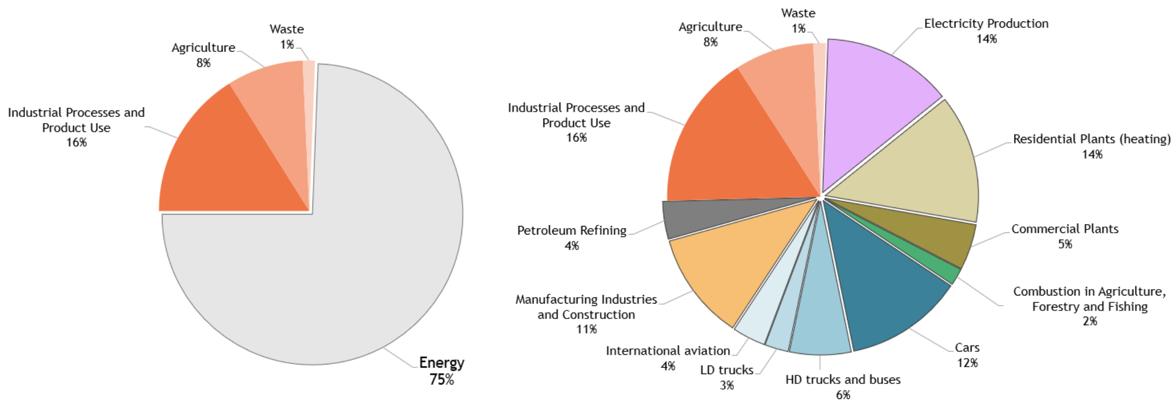
The goal of this research is to use those criteria in combination with numbers (*"numbers, not adjectives"* – David MacKay) to evaluate the potential of decentralized power production and storage (DPPS) in Belgium. We want to understand whether households, industries, schools, hospitals and others can afford such systems, if enabling those systems will help Belgium reduce its net GHG emissions and what the effect will be on other stakeholders in the electricity market.

A Context

Before giving any clues on the actual content of this research it is necessary to detail the above mentioned subjects slightly more. In five stops we travel from GHG emissions to electricity storage, passing by a solar prosumer and its relation with the power grid. At the end we are left with a complete picture of this research's context.

STOP 1 : Greenhouse Gas Emissions

The main motivation of this work lies in the mitigation of global warming. As demonstrated in the first part of the introduction, if we want an action to be efficient it is important to choose the target carefully. Clearly identifying the sources of GHG is an important first step to locate the target.



(a) *(b)*

Figure 1.2: The definition of each sector is referenced in Appendix A.1. Data taken from Ref. [2].

Belgium's emission-map (Figure 1.2) shows the GHG emissions per sector. On Figure 1.2(a) we observe the importance of energy. Indeed, since the industrial revolution, a majority of man-made GHGs originate from the burning of fossil fuels to produce heat and motion. Energy and GHG emissions are so closely related that countries' total emissions are sometimes compared in terms of emission intensity, i.e. the mass of $CO_{2,eq}$ emitted per unit of energy generated. Emission intensity can also be expressed per USD of Gross Domestic Product (GDP) using the countries' energy intensity as conversion factor. The latter indicates how much a country can increase its GDP by using one unit of energy, in other words, how clean a country's production process is. Back to Belgium, Table 1.1 shows its average score in terms of emission intensity (per GDP) in the European Union. Note that Belgium's production process is twice as dirty as Europe's cleanest, Sweden. There is thus still some way to go.

Having clarified the relation between energy and GHG emissions, we can now take a closer look at the origins of these emissions. Figure 1.2(b) shows the relative importance per sector of activity. The three main sectors are transport[4] (shades of blue on the pie-chart), heat generation[5] (sand) and electricity production[6] (pink).

Even though the ultimate goal of this work is to find a way of *sustainably* decreasing GHG emissions in Belgium, it would not be this short if it had addressed the mitigation possibilities in all of the three above mentioned sectors. From the introduction we know it is the sector of *electricity generation* on which this research focuses. This choice was made for two reasons. One, according to a report published in 2013 by the Belgian government [21], the power production sector has the biggest emission reduction potential. This is in accordance with an earlier, independent publication from 2010 where it is shown for several scenarios that the power sector is an important emission reduction source in the EU-28 countries [22]. And secondly, Belgium is one of the leading countries worldwide regarding solar power per capita (4th worldwide, from IEA data). In this position it can play an important role in showing the path to solarizing countries and help develop a novel and robust energy supply system.

Rank	*Country*	$kgCO_2/\$$
1.	Sweden	0.084
2.	Denmark	0.114
...		
11.	Belgium	0.186
...		
13.	Germany	0.191
...		
28.	Estonia	0.851
Averages		
	EU-28	0.185
	World	0.491

Table 1.1: Data taken from Ref. [6].

STOP 2 : Prosumers and self-sufficiency

The basis of this novel energy supply system is the *prosumer*, as stated by Jeremy Rifkin. The word 'prosumer' is composed of the words 'producer' and 'consumer'. A prosumer is defined here as a physical or moral person successively consuming electricity from a power grid and reselling surplus electricity originating from its own production capacity to the power grid. Note that in both cases no economic profit can be made of this activity (or else they are considered as

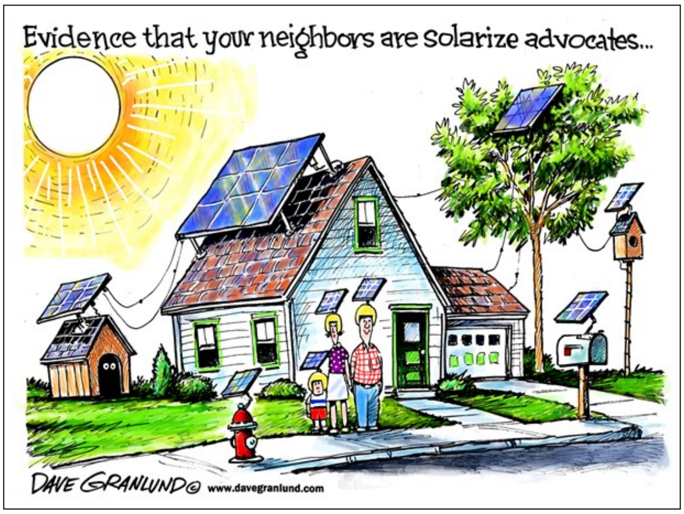
[4]The main fuel used is petroleum in form of diesel (80%) and gasoline (15%). Electricity in transport represents 1%, biofuels a bit more than 3%. [17]

[5]The most frequently used energy source is natural gas (55%), followed by heating oil (30%) and electricity (8%). The rest is mainly divided in wood and coal [17]. Thermal solar power accounted for 0.26 TWh of energy in 2015 [18], which is negligible compared to the 30 TWh of natural gas used by households [17].

[6]The figures on the pie charts date back to 2015 when the 560 MW Langerlo coal-fired power plant was still in use. Its shutdown in 2016 meant Belgium was the seventh European country to entirely quit coal and represented an estimated reduction of GHG emissions of 1% [19]. This left a gap in the electricity generation sector which was filled by more import and gas [20].

producers only). In the case of a moral person, the electricity production activity should not be its main (or only) economic activity.

As a consequence centralized, big-scale electricity production is partly being replaced by tiny decentralized solar power plants; And this evolution is ongoing. The International Energy Agency (IEA) showed in a recent report [23] that solar power is the fastest-growing source of energy and that this growth will be sustained in the following years. During the last decade in Belgium, APERe [24] observed a positive evolution in the amount of solar power installations in three of the five[7] main energy consuming sectors. Indeed, more residential, commercial and industrial electricity consumers are installing solar facilities on their own lands and roofs.



STOP 3 : Power grid and grid policies

The power grid is, in most cases, composed of four actors: the electricity provider (e.g. Engie Electrabel, EDF Luminus,...), the transmission system operator (Elia is the only operator in Belgium), the distribution network operator (DNO, e.g. ORES, Sibelga, Eandis,...) and the electricity consumer or client. The first produces electricity, the second operates the transmission through high voltage lines in the entire region or country while the third ensures the distribution at local scale to the client. The generic term for the companies in the electricity market is *electric utility*. All the actors usually function in a regulatory framework with policies depending strongly on the region or country in which they reside.

As stated above, prosumers make a heavy use of the power grid. It assumes a double role for them: provide electricity when the available solar power is not sufficient and take over any surplus

[7]Residential, Commercial, Industrial, Transport and Fishing, Agriculture and Forestry [9].

power production, sometimes in exchange for financial compensation. In this context it is mostly the relation between client and utilities who is concerned and less the inter-utilities relation). The policies controlling this relation have an important impact on the economic viability of decentralized power production systems [25–33]. The policy-maker responsible for the electricity market can decide to soften or harden the economic environment for prosumers and by such encourage or discourage decentralization. Until today, most policy-makers worldwide have build a beneficial regulatory environment for prosumers [34]. Largely two types of policies exist today:

- *Net-metering* (NM): The prosumer can consume part of the electricity produced and the net surplus is automatically fed into the distribution network (power grid). The electricity meter provided by the distributor deducts the electricity injected to the grid automatically and this is taken into account in the final invoice from the energy supplier. This solution is used in several countries, among which Belgium, Greece, the Netherlands, the US (43 of 50 states) and Australia [35].
- *Feed-in tariff* (FIT): A contract between the electricity distributor and the prosumer allowing the latter to sell its surplus energy at a fixed price. The price sometimes depends on the size of the installation. A majority of European countries apply this policy (Denmark, Austria, Bulgaria, Croatia, France, Germany, Italy, Luxembourg, Portugal and Romania). In some European countries the retail price is fixed at zero (Slovakia, Spain, Norway, Slovenia), encouraging self-consumption [35].

The policy problem

But some of these policies have endured criticism from electric utilities. Especially NM has initiated a debate between solar advocates (homeowners) and utilities [36, 37]. The argument of the latter is that due to NM a financial gap is created by prosumers, which is put on the back of the other electricity consumers. In a report from the Edison Electric Institute the following statement is given [38]:

> *Lost revenues from distributed energy resources (DER) are being recovered from non-DER customers in order to encourage distributed generation implementation. This type of lost revenue recovery drives up the prices of those non-participating customers and creates the environment for ongoing loss of additional customers as the system cost is transferred to a smaller and smaller base of remaining customers.*

To address this issue policy-makers will decide to switch from NM to FIT or to stay with NM but add certain conditions. Switching to FIT is more complex while prosumers need to install a second electricity meter to record the outgoing power. That is why implementing a conditioned NM is often preferred. Two regularly used NM 'add-ons' are taxes, in the form of fixed or proportional tariffs (e.g. the prosumer tax in Flanders, see Ref. [88]), and limits on energy transfers. The latter consists in forcing the prosumer to self-consume a fixed percentage of its produced electricity before being allowed any kind of compensation. Germany for example set this self-consumption limit at 30% for small installations [39], meaning the prosumer may feed in a maximum of 70% of the installed power. Wallonia recently decided to give financial compensation to commercial and industrial prosumers (in the form of green certificates) if and only if 60% of the production is self-consumed[8].

STOP 4 : Energy storage

The act of storing energy is simply defined as the capturing of energy at one time for use at a later time. The idea of storing energy seems very complex and innovative, but it is present everywhere around us. Food is energy from the sun stored in a chemical form. An alpine lake at 2000 meters high can be seen as a storage of solar energy[9] in the form of gravitational potential energy. The batteries in mobile phones transform electric energy into chemical energy for storage.

Going back a bit, we remember prosumers discharged electricity from the power grid at certain moments and charged it again with surplus solar power at other moments. In a certain way, the power grid can be regarded as an infinite source of storage. In a NM system, this infinite storage is almost entirely free. In general, it seemingly offers a reliable and low-cost solution to prosumers but due to the issues lifted previously, it may rapidly change. By installing an electricity storage system at home, the prosumer could become entirely self-sufficient and proclaim its independence from the grid. The question is, is the investment in a home storage system cheaper than using the grid? Or is it more interesting to have both at hand?

A prosumer can choose to invest in a storage system capable of overcoming the unavailability of solar power at night but it would not be sufficient to bridge the gap during consecutive cloudy days (which often happens in the winter). To overcome the day-night variability, *daily* or *short-term* storage systems are used. To bridge the seasonal gap, *seasonal* or *long-term* storage

[8]For more information, see CWAPE website: `https://www.cwape.be/?dir=3&news=376`.

[9]The evaporation, displacement and precipitation of water, i.e. the water cycle, is fueled by solar energy.

systems are preferred. Both have typical characteristics making them more fit for a certain application. More details on those characteristics will be given in Chapter 2.

NOTE : Sustainability

More and more frequently a (technological) solution is measured in terms of its sustainability. As stated by the Brundtland Report [40],

> *A sustainable development meets the needs of the present without compromising the ability of future generations to meet their own needs.*

Relating the sustainability criteria to the definition above, we conclude that a sustainable development promotes economic growth while maintaining environmental protection and social equality. To encompass the needs of the future generation, DPPS should be evaluated in terms of the three sustainability criteria – and even more so if the idea is to implement it at large scale. Of course, entirely evaluating each criteria would take an incredible amount of time and resources which we don't have at hand. For this reason a more precise formulation of the objectives is given in the following section.

B Content

B.1 Research Scope and Literature Review

As said above, the point of departure are the three sustainability criteria, but to avoid an unnecessary extensive research, additional choices were made to narrow down the scope.

Least-cost analysis

Supported by the fact that in the domain of DPPS consumer behavior is mainly motivated by financial benefit and less importantly by environmental aspects [35, 41], it is important to put the finance related questions on the foreground.

A least-cost analysis consists in *finding which system configuration offers the lowest cost to the owner in a chosen, constrained environment.* The scientific literature shows the existence of a myriad of methods to achieve this goal. In the domain of DPPS, the heuristic approach[10] is mostly used (e.g. Refs. [26, 27, 29, 30, 42, 43]). A more thorough analysis consists of using linear optimization techniques (e.g. Refs. [31, 32, 44, 45]). It allows a fast overlook of thousands of possibilities and the increase in complexity is marginal compared to the gain in accuracy. More advanced research manages to include unexpected externalities (e.g. meteorological factors influencing solar power production) through stochastic and dynamic optimization (e.g. Refs. [46, 47]). Here, the choice fell on *linear programming* (LP) while it offers a satisfying compromise between precision and simplicity.

Societal impact

Optimizing a system for one stakeholder does not mean the remaining stakeholders, and more generally the society, will profit from it. The problems between prosumers and utilities (Section A) illustrate this. Other examples of societal impacts a DPPS system can have are GHG emissions

[10] In the heuristic approach, a small amount of relatively distinct scenarios are constructed and tested in a simple model. The outcomes are compared on the basis of certain economic criteria allowing to simply find the least-cost scenario.

(societal cost of carbon), rise of electricity billing prices for all clients (e.g. the Turteltaks in Flanders[11]), impact on the viability of gas-fired power plants (e.g. merit order effect), etc.

In this report, we restrict the analysis to *the computation of the financial gap created by prosumers and the impact on net GHG emissions.* The latter is presented in the following section. Regarding the first, it involves a simplified analysis of the costs and benefits for electric utilities and the potential rise in electricity billing prices for customers. Research on the utilities' costs and benefits was lead by the Californian authorities in 2013 [37], assessing the impact of net-metering on the local electric utility. In Belgium, only one source was found mentioning DPPS's impact on the grid. It did so by modeling power flows between the prosumer and the power grid without assessing the resulting financial gains or losses for the electric utility [29].

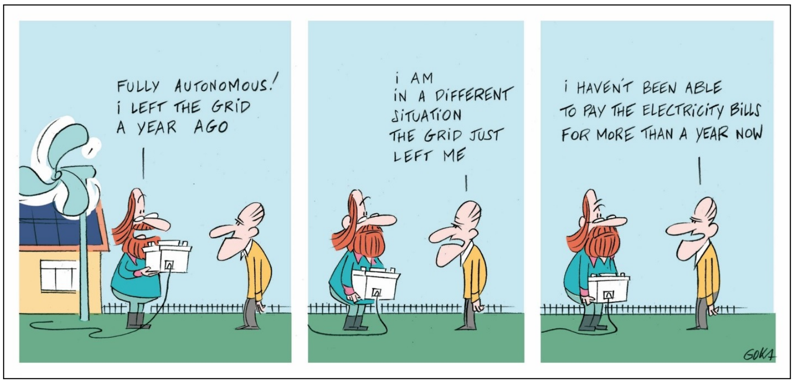


Figure 1.3: Cartoon by Oliver Goka, taken from presentation of D. Ernst at AIM study day on electricity storage (2016).

Environmental impact

To assess the environmental impact we will take the European 2030-targets as reference [48]. The goal will be to *evaluate whether DPPS-systems can help to achieve the 2030 targets or, in contrary, enhance net GHG emissions.*

Scientific literature regularly uses *life cycle assessments* to evaluate the environmental benefit or impact of a certain technology or system (e.g. Refs. [30, 31, 49–51]). It reveals the amount of GHG emitted on all stages of a product's life, offering an extensive estimation based on physical units. Another approach consists of comparing the energy delivered by a source or system with the energy required to exploit this source or system (e.g. Refs. [26, 52]). This is expressed in the form of a ratio named Energy Return On Invested (EROI). Even though this measure is important for all the reasons cited in Ref. [53], in this report we prefer to express environmental impact in terms of mass of equivalent $CO_{2,eq}$ allowing an easier comparison with the European

[11] For more information, see `http://www.standaard.be/cnt/dmf20160429_02264957`

emission reduction targets (ERT).

Location

When evaluating the financial cost and benefits for DPPS system-owners, location is crucial. The amount of case-specific research in the literature ascertains this statement. The type of grid policies, the capital cost of the system components, the price of grid electricity and the shape of load profiles all depend, up to a certain degree, on the country or region where the evaluation is done. Besides, the effectiveness of a solar power system depends on the solar exposure (i.e. the irradiance) at the chosen location.

In this report the case of Belgium will be analyzed. As stated above, the actual situation regarding PV power and grid policies make this case unique in the world but still general enough to be transposable to other countries.

B.2 Objective

To summarize the above mentioned objectives, this research aims at analyzing DPPS-systems by...

- ...finding what mix of power grid dependency, solar power and storage capacity offers the lowest total cost to an electricity consumer;
- ...computing how much a big-scale implementation of this mix will impact the benefits of the electric utilities;
- ...evaluating whether the big-scale deployment of this mix will help achieve the European emission reduction targets by 2030.

To comply with the conclusions from the literature review on DPPS found in Ref. [54], the objective is to keep things simple but to allow a certain degree of comparability. Eight different types of load profiles and two types of storage systems are thus compared. To achieve the different objectives, a model-based approach and LP optimization techniques are used.

B.3 Method

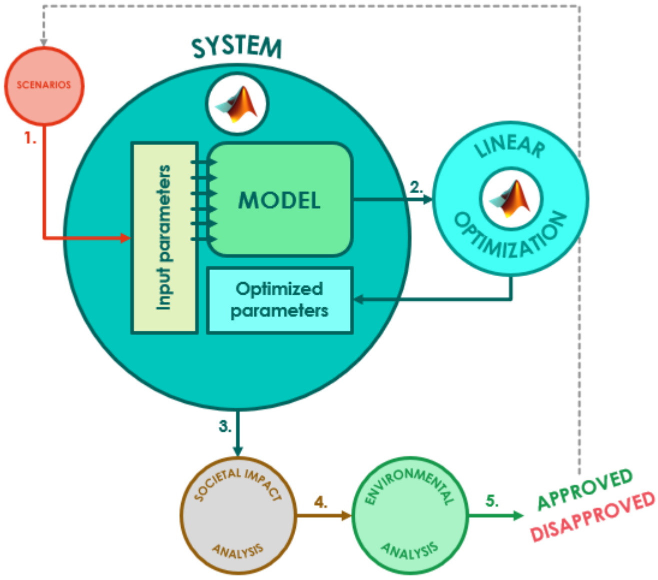


Figure 1.4: Input parameters depend on the scenario. Examples of input parameters are: load profiles, type of grid policy, capital costs of the devices, etc. Optimized parameters or decision variables are the outcome of the LP optimization. Total solar power capacity is an example of a decision variable.

The analysis is conducted in several steps. First (1.) a scenario is build-up based on observations and assumptions. This scenario is then translated into a set of input parameters which are fed into the model. The economic analysis happens in the second step (2.) through a linear optimization algorithm (`linprog`, more information at `matlaburllinprog`). The outcome is a set of optimized parameters which complete the description of the financially optimized system. Third (3.), the societal impact of the system is analyzed. Next (4.), the net environmental impact of the system is computed. Once all the steps finished (5.), the proposed scenario is discussed as a function of the outcome. If the scenario does not seem feasible it is adapted or entirely changed and the analysis is repeated.

Model

The model is set-up in MATLAB® and can be found in Appendix B. Central is the load profile, which has to be met at all times. The two sources of energy are the electricity from the power grid and solar power transformed in electrical energy by photovoltaic (PV) panels. Additionally, energy consumption can be delayed at a later time through the use of energy storage systems. Note that only the energy from the solar power system can be stored. The grey, crossed arrow (Figure 1.5) signifies the storage system cannot be used to do price arbitrage with the power grid. Finally, all capital costs are absorbed over a period of 20 years.

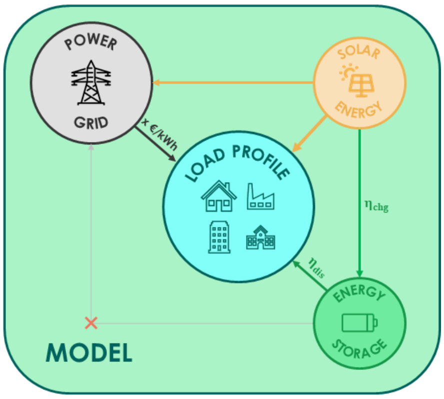


Figure 1.5

The **power grid** is modeled as an infinite source of energy. It is supposed stable at all times[12]. To make this assumption realistic, the energy transfers to and from the grid are limited. Finally, the electricity from the grid is set at a fixed price per kWh.

Realistic irradiation data and PV characteristics are used to obtain hourly **solar power** data. The PV panel is described by its lifetime, capital cost, efficiency and performance ratio[13]. A limit can be set on the total solar power capacity to simulate available rooftop-area for example.

In theory, an infinite number of **electricity storage** technologies can be used in the same system. Each storage technology has its own fluxes coming from the PV system and going to the load. So, if two storage systems are set-up they may charge and discharge simultaneously, albeit the power balances are respected. Each storage technology is described through a set of nine parameters: charging and discharging losses, self-discharge rate, depth of discharge, cycle lifetime, shelf lifetime, maximum and minimum storage capacity, capital cost and energy retention.

B.4 Build-up

This report is build-up in four chapters. Chapter 1 and Chapter 4 respectively introduce and conclude the report. Chapter 2 retraces the construction of the model and elaborates the mathematical formulation of the linear optimization program. It does so in four steps, starting from a basic model to the end result presented above (Figure 1.5). In Chapter 3 the analysis framework is set up and the analysis is performed following the diagram of Figure 1.4. The results are presented in the same chapter. The final words of this report will be dedicated to a general discussion of the results and a final conclusion.

[12] Power demanded by the consumer is always met by the power grid, without any failures.

[13] Measure of the quality of a PV plant, independent of its location. It takes into account energy losses due to thermal losses and conduction losses [55].

B.5 Symbols and Units

Symbols

Symbol	*Description*	*Unit*	*Subscript*	*Description*
P	Total power	$[kW]$	L	Load (consumption)
$P(t)$	Power at time t	$[kW]$	PV	Solar Power
E	Total energy	$[kWh]$	$PV, self$	Self-consumed PV
$E(t)$	Energy at time t	$[kWh]$	$PV, spil$	Spilled PV
p	Proportion or ratio	$[/]$	$PV, grid$	PV transfered to grid
C	Total cost or cost coefficient	$[EUR/kWh]$	G	Grid
c	Capital cost	$[EUR/kWh]$	S	Storage
A	Surface	$[m^2]$	B	Battery
η	Efficiency	$[\%]$	$H2$	Hydrogen storage
			tot	Total
			max	Maximum

Units

Unit	*Description*
kW	Watts (W) are used to measure power. Power is a measure of energy consumed per unit of time. Many electric appliances use this denomination. A normal light bulb for example will consume 40 W or in other words, it will consume 40 units of energy per unit of time (per definition, 1 W = 1 Joule per second). When you set a high wattage on a microwave oven, the item will heat *faster* because more energy is delivered per unit of time. Remember: 1000 W = 1 kW (just like g and kg). $1kW$ can be compared to the maximum setting of a microwave or the power rating of a dishwasher.
kWh	Watt-hours (Wh) are used to measure energy. In fact, it measures the amount of energy consumed by a device switched on without interruption during an entire hour. Take the light bulb as example again, a 40 W lamp left on for one hour will consume $40\ W \times 1\ h = 40\ Wh$. A microwave oven heating at $1kW$ for 1 minute consumes $1000\ W \times 1\ ' \times \frac{1\ h}{60\ '} = 17\ Wh$. $1kWh$ can be compared to the energy consumed by a light bulb switched on an entire day (24 hours) or a dishwasher used for one hour. An average household in Belgium pays around 28 cents for one kWh.
$kgCO_2$	The mass of emitted GHG is measured in kilograms (kg) of $CO_{2,eq}$ *equivalents*. This last word is very important. What it says is that not only the global warming effects of $CO_{2,eq}$ is taken into account, but also of other gases like CH_4 (methane) or N_2O (nitrous oxide) are considered. The 100-year *global warming potential* (GWP) of each gas is measured and converted to a mass of $CO_{2,eq}$. All those masses are added up and we get a total mass measured in $kgCO_2$. Note that the societal cost of one kg of $CO_{2,eq}$[14] is almost 4 cents.

[14] The societal cost of carbon is the cost paid by society for the warming of the climate (More information on `https://www.carbonbrief.org/qa-social-cost-carbon`).

Chapter 2

Model Construction

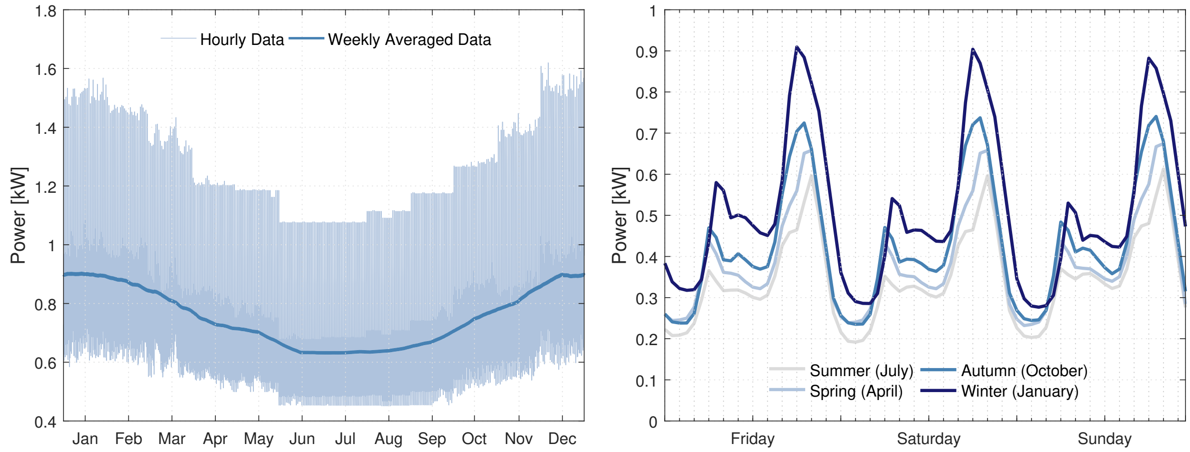
From 0 to 100 % self-sufficiency.

The first big step towards the final objective is the development of the model described in Figure 1.5. Usually a model is presented in its finished form and no information is given on the development steps. Motivated by the fact that a lot of knowledge can be gained from the elaboration process, it will be presented in this chapter. Furthermore, at each step of the process, a small analysis is performed to justify the passage from one step to the other.

Starting from the electricity consumption data of an average household, the model is incrementally build-up to finally obtain an entirely self-sufficient system based on solar power production and storage. In short, step A presents the input data: load profile and solar irradiance. At step B we add solar power capacity, which meets a percentage of the load. At the next step (C), a connection is made with the power grid and in the last step (D) electricity storage systems are added.

A Input Data

A.1 Load Profile



(a) Hourly load of a single-family household. *(b) Detail of the hourly load data.*

Figure 2.1: Theoretical data from the Office of Energy Efficiency & Renewable Energy [3].

Precise electricity consumption data of Belgian households (or other type of buildings) are hard to obtain due to a combination of monitoring, data access/ownership and cost issues. For this reason, an American data base of hundreds of theoretical[1] load curves are used in this chapter as well as in Chapter 3. The load profile of an average household living in the city of Bellingham (Washington State) was chosen given that its climatic and demographic characteristics approaches those of Brussels [56, 57]. Note that US households consume on average more electricity than European (and thus Belgian) households [17, 58]. As a result, the chosen load profiles had to be normalized to the Belgian average, i.e. 3,600 kWh approximately [59]. The resulting profile is shown in Figure 2.1.

As appears in Figure 2.1(b), load data is time-dependent. Typically, daily and seasonal variations are observed. On daily basis, two peaks appear for household-type electricity consumption. The first occurs in the morning (around 7AM) when people wake-up and start using electric appliances (lights, kitchen appliances, etc.). Note that the *morning peak* is lower during week-ends. The *evening peak* (between 6PM and 8PM) is higher than the morning peak while more energy intensive appliances are used (electric cookers, microwave ovens, television, computer, etc.). On a seasonal time-scale, the load is usually lower during summer and spring than during winter and autumn. The longer days lower the use of lights and the hot weather possibly changes

[1]Meaning load profiles are reconstructed theoretically from averages.

cooking habits (cold dishes may be preferred). The graph shows morning peaks happen slightly later in the winter-time. This is simply explained by the adoption of daylight saving time during this period. Other factors influencing load data are climate type, socioeconomic and sociodemographic factors, rural/urban location and building type [60]. Those aspects will have an importance in Chapter 3.

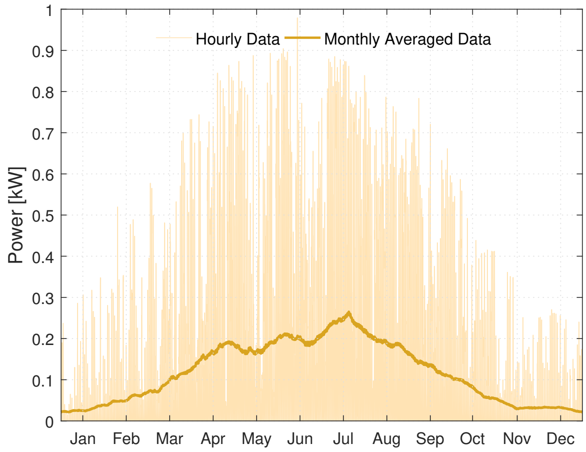
Note: Precision of load profiles

In Refs. [33, 61] load profiles with different time-steps are compared. It is concluded that the bigger the time-step, the more the power consumption is smoothened out and the more self-consumption is overestimated, leading to an incorrect calculation of the total costs. Also, theoretical load curves are in fact averages of hundreds of different profiles resulting in a supplementary smoothening of peak power moments. We conclude that there is a *high probability of obtaining underestimated results* with the hourly and theoretical load profiles chosen here. Note that at least four sources in the scientific literature were found using the same load data [62–65].

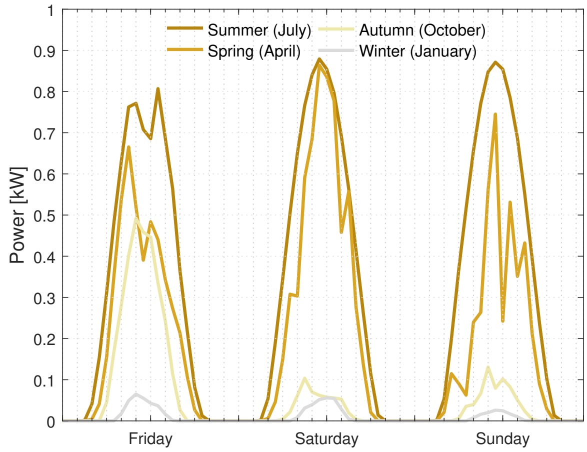
A.2 Irradiance

The global solar irradiance data on Figure 2.2(a) was measured in 2013 on a flat surface in Uccle at the Royal Meteorological Institute of Belgium (RMI). In Figure 2.2(b) the same data is plotted for three weekdays, similar to Figure 2.1(b). As expected, an important temporal variation for solar irradiance is observed. On a 24-hour basis, the usual curve is in the form of a bell (see Sunday in the summer). But depending on local meteorological factors (cloudiness, etc.), this form may show many fluctuations (see Sunday in the spring). On a seasonal basis, solar irradiance is much lower during winter and autumn months than during spring and summer. This is explained by the trajectory of the Earth around the sun which puts the Earth further away from the sun during those months.

Not shown on either graph is the inter-annual variation of solar irradiance. This variability imports here while the systems will be evaluated over a period of 20 years. The RMI observed the inter-annual variation in total solar irradiance reached a maximum of 15% compared to the average of 996.8 $\mathrm{kW\,m^{-2}}$ between 1981 and 2016 [66]. Precisely predicting the energy supplied by the sun in the next two decades is close to impossible [67]. The outcome depends on a vast number of factors, some unpredictable (e.g. the eruption of a volcano) and others hard to evaluate (e.g. the solar cycle) [68]. The data should be supplemented by complex forecasting models for more precise results [69].



(a) Plot of the entire year.



(b) Detail of the hourly irradiance data. Same days as in Figure 2.1(b).

Figure 2.2: Hourly irradiance observed at Royal Meteorological Institution of Belgium in Uccle during the year 2013.

The available data indicates a total yearly irradiance of 1037 kW/m^2 in 2013, which is 4% higher from average. The RMI indicates the sunshine duration in 2013 is statistically considered as *normal*, but no information is given on solar irradiance [66]. In this report we use this data without alterations and suppose it repeats itself in exactly the same way for the entire considered period (20 years). This assumption, as explained above, is hard to evaluate.

B Solar Power

B.1 PV Characteristics

From irradiance to power

PV panels are devices used to convert the energy from solar irradiance to electric energy. A second device, generally called *inverter*, transforms this electric energy from direct current (DC) to alternating current (AC), which is how most appliances in households are powered. A PV panel is described by the type of chemistry used, which partly defines how well solar irradiance is converted to electric energy. A second parameter influencing this conversion is the inclination of the panel relative to the incoming solar rays. In this report all the panels are supposed to be installed on a horizontal surface. Finally, the performance ratio (PR) of a panel incorporates the conduction losses in the wiring system and the losses in the inverter.

In this report we use *monocrystalline panels* with an efficiency of 15%, a lifetime of 25 years, installed *horizontally* and with a performance ratio of 84% (average for Belgium installations [70]). The actual electricity output per square meter per hour, $H(t)$, is then formulated as in equation 2.1.

$$H(t) = \eta_{PV} \cdot PR \cdot I(t) \tag{2.1}$$

The hourly power production depends on the area covered by PV panels, A_{PV}:

$$P_{PV}(t) = A_{PV} \cdot H(t) \tag{2.2}$$

The nominal capacity of the solar power system (expressed in kW_{peak}) is then found by using the yield of the system, γ_{PV}. The latter is specific to the solar panel technology and indicates how much kW_p can be installed on 1 m^2. The average yield of Brussels' PV capacity is 0.136 kW_p/m^2 [7].

$$P_{PV} = \gamma_{PV} A_{PV} \tag{2.3}$$

Cost coefficient

Throughout this report we will compute the results over a *period of 20 years.* This means capital costs need to be absorbed over this period to compare them with annual costs (e.g. the price paid for electricity from the grid). Secondly, the investment in a technology (i.e. paying the capital cost) enables the use of this technology for a fixed amount of time, the *lifetime*. If the lifetime exceeds the 20-year period, the remaining value should be subtracted from the initial investment to correctly represent the used value. Finally, capital costs of a technology evolve over the years. In the next 10 years the capital cost of solar panels for example is forecast to decrease by almost 60% [71].

Taking all those characteristics into account, we define the cost coefficient as the investment minus the remaining value .

$$C_{PV} = C_{PV,INV} - C_{PV,REM} \tag{2.4}$$

The investment coefficient is defined as the capital cost (c_{PV}) decreasing yearly by a factor d_{PV}.

$$C_{PV,INV} = \sum_k \frac{c_{PV}}{(1 + d_{PV})^{r(k)}} \tag{2.5}$$

Vector r takes all the reinvestment years. If for example the PV lifetime is 5 years and the period under consideration y is 20 years, then the reinvestment vector r is $[0, 5, 10, 15]$, excluding year 20 since there is no need to reinvest in the last year of the considered period.

The remaining value is formulated in equation 2.6. The proportion of remaining lifetime $pLT_{PV,rem}$ is found by dividing the remaining lifetime with the invested lifetime (equation 2.7).

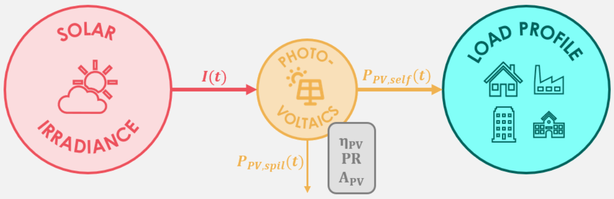
$$C_{PV,REM} = pLT_{PV,REM} \cdot \frac{c_{PV}}{(1 + d_{PV})^y} \tag{2.6}$$

$$pLT_{PV,REM} = \frac{LT_{PV,REM}}{LT_{PV}} = \frac{r(end) + LT_{PV} - y}{LT_{PV}} \tag{2.7}$$

B.2 Model characteristics

Power balances

A power balance describes the relation between power fluxes present at a same time t. A set of power balances defines the behavior of the model. To build a set, the existing power fluxes and their interactions need to be identified.



In the case of a load profile $L(t)$ met by solar power only, the fluxes all start from or arrive at the solar power system (panel+inverter). The first flux is the irradiance coming in at time t, $I(t)$. The PV system then converts it to useful solar power, $P_{PV}(t)$. One part is immediately consumed, $P_{PV,self}(t)$ and the rest (if there is one) is simply spilled energy at this stage of the model, $P_{PV,spil}(t)$. So, if $P_{PV}(t) \leq L(t)$ then $P_L(t) = P_{PV}(t)$ and if $P_{PV}(t) > L(t)$ then $P_L(t) = P_{PV}(t) - P_{PV,spil}(t)$. See equation 2.8 for the general formulation. Equation 2.9 expresses the power balance equation of the PV system.

$$P_L(t) = P_{PV,self}(t) \tag{2.8}$$

$$P_{PV}(t) = P_{PV,self}(t) + P_{PV,spil}(t) \tag{2.9}$$

Constraints

In a realistic model, power flows are constrained for many different reasons. In this case, the total solar power production is constrained by the maximum area available for PV panels.

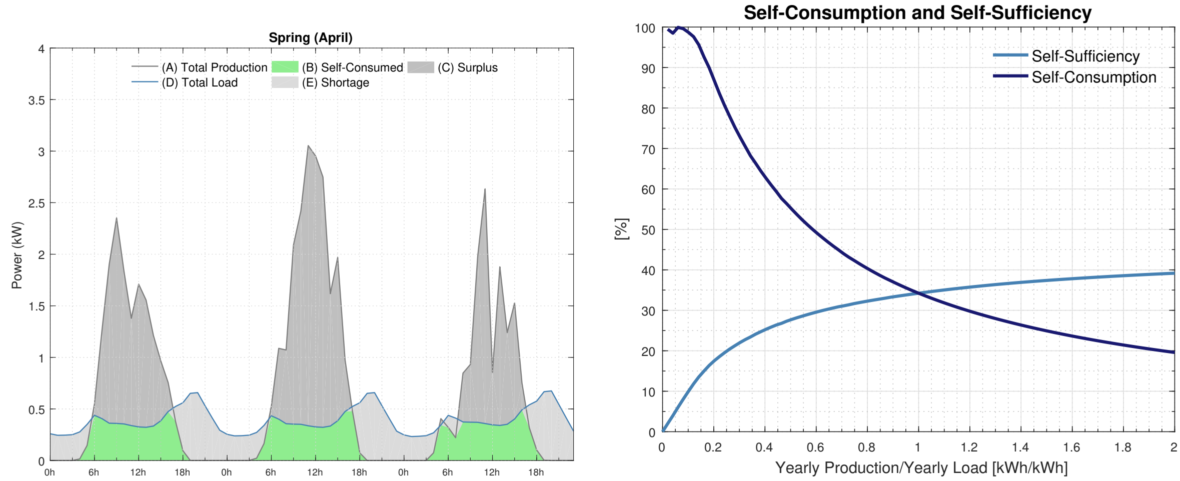
$$A_{PV} \leq A_{PV,max} \tag{2.10}$$

Cost function

The cost function communicates the relative value of the power flows. It tells the LP-algorithm which parameters to minimize or maximize and by how much relative to each other. In this case, the only endured cost is the installation of the PV panels.

$$C_{tot} = C_{PV} \cdot A_{PV} \tag{2.11}$$

Insight: self-consumption and self-sufficiency



(a) Power flows for three April days.

(b) SC and SS in terms of installed PV capacity. PV capacity is expressed as the ratio of annual PV capacity output to annual load.

Figure 2.3

Suppose now our single-family households has an installation of $A_{PV} = 28\ m^2$ ($P_{PV} = 3.8\ kW_p$). This capacity allows the household to produce exactly what it consumes yearly ($E_{PV} = E_L = 3665\ kWh$). Using the cost coefficient computation, the total cost of the 3.8 kW_p installation (including solar inverter and installation costs) amounts to almost 8,500 EUR.

We plot the resulting power flows for three days in April (Figure 2.3(a)). We use the plot to graphically define (and differentiate) the self-consumption (SC) and self-sufficiency (SS) ratios.

$$SC = \frac{\mathbf{B}}{\mathbf{B} + \mathbf{C}} = \frac{B}{A} \tag{2.12}$$

$$SS = \frac{\mathbf{B}}{\mathbf{B} + \mathbf{E}} = \frac{B}{D} \tag{2.13}$$

Note that the letters A, B, C, D and E represent integrals.

Using the energy fluxes defined previously, we find a general definition for SC and SS.

$$SC = \frac{E_{PV,self}}{E_{PV,self} + E_{PV,spil}} = \frac{E_{PV,self}}{E_{PV}} \tag{2.14}$$

$$SS = \frac{E_{PV,self}}{E_L} \tag{2.15}$$

We compute SC and SS over an entire year for PV capacities ranging between 0 and 7.6 kW_p (see Figure 2.3(b)). With a PV capacity of 3.8 kW_p, $SS = SC = 34.2\%$. We observe a quick rise of SS for PV capacities between 0 and 1 kW_p (0 and 0.25 kWh/kWh). For low PV capacities, the production peaks are mostly below the $L(t)$-line, meaning all solar power output can immediately be self-consumed.

In Ref. [29], the case of a Belgian household with quarter hourly load and irradiation data is analyzed. For a PV installation of 0.76 kWh/kWh, an SS of 30% is found. This is very close to the 31.6% obtained with this model. The result is slightly overestimated as expected, but less than predicted.

B.3 Summary and Conclusion

Power balances $P_{PV}(t) = P_{PV,self}(t) + P_{PV,spil}(t)$

$P_L(t) = P_{PV,self}(t)$

Constraint $A_{PV} \leq A_{PV,max}$

Cost function $C_{tot}E_L = C_{PV}A_{PV}$

Discussion

The main observation is that the SS-curve seems to slowly reach an asymptote at around 40%-50% for big PV installations (Figure 2.3(b)). In the meantime the self-consumption of solar power is low, meaning a high percentage of the production is spilled.

In practice, a household will never reach 100% self-sufficiency with solar panels only. There is a need for a second source of energy (e.g. the power grid), a storage system or a radical change in the household's consumption behavior to achieve this. Further on we analyze the combination of the first two solutions.

C The Power Grid

The power grid supplies electric energy to consumers instantly and almost faultlessly. The mix of sources used to generate power is specific to each country. In Belgium, power is mainly extracted from natural gas, nuclear energy and renewable sources [17]. It is then transported through high voltage lines and distributed through low voltage lines to all the connected consumers. Producing, transporting and distributing electricity has a cost. So if one plans to consume energy from the power grid, a financial compensation in the form of a yearly electricity bill is expected in exchange.

C.1 One-way Connection

Suppose the household introduced previously decides to connect itself to the grid in order to meet the yet unmatched load. As a first step, we suppose the power grid is *one-way*, meaning all the surplus energy is still curtailed on-site.

Power balances

The load is now matched by the self-consumed PV *and* the input from the grid, $P_G(t)$.

$$P_{PV}(t) = P_{PV,self}(t) + P_{PV,spil}(t) \tag{2.16}$$

$$P_L(t) = P_{PV,self}(t) + P_G(t) \tag{2.17}$$

Constraints

DNOs limit the power supply from the grid at every time to avoid exuberant consumption and facilitate the maintenance of the grid.

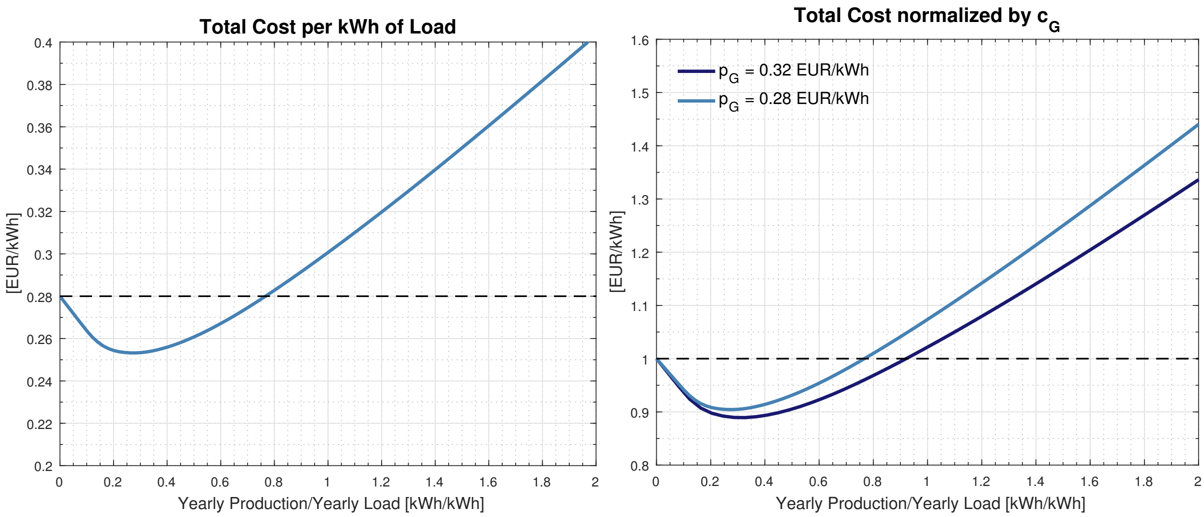
$$P_G(t) \leq P_{G,max} \tag{2.18}$$

Cost function

Consuming kilowatt-hours from the grid entails a certain cost, c_G. This is added to the cost coefficient of the PV installation.

$$C_{tot} = C_{PV} \cdot A_{PV} + c_G \cdot E_G \tag{2.19}$$

The total cost is computed for increasing PV capacities and plotted in Figure 2.4(a). The least-cost solution is now graphically visible. The household can reduce its yearly electricity bill by ca. 9% if it invests in a 1 kW_p PV installation (3 to 4 panels of 2 m^2 each). In the case of a one-way power grid, producing exactly the total amount consumed entails an *increase* of yearly electricity expenses of 7%. Finally, to reach grid-parity the household should invest in a 3 kW_p installation (0.75 kWh/kWh). This result corresponds to the results from Ref. [29] where grid-parity for a typical Belgian household is reached at 0.76 kWh/kWh.



(a) The black dotted line shows the price of electricity (billing price) in Belgium. It was around 0.28 EUR/kWh in 2017[17]. For the modeled household, this corresponds to a yearly electricity bill of around 1,000 EUR.

(b) At 0 production, the total cost is equal to the grid price, i.e. the normalized total cost is 1. When the graph is below 1, the corresponding PV capacity offers a cost reduction compared to the grid-only situation. Above 1, it is cheaper to stay on the grid.

Figure 2.4: Levelized cost of electricity (per kWh of load) as a function of total PV capacity.

Insight: Electricity billing price

The electricity billing price can be divided in three almost equal parts: the actual cost of electricity and its generation (e.g. cost of the combustion fuels, maintenance cost of the power plants, etc.), the transport and distribution costs (e.g. maintenance of the power lines, grid-balancing, etc.) and the taxes and levies (e.g. VAT, contributions, etc.) [72, 73]. The exact amount billed to the consumer depends on the type of consumer (e.g. households pay a higher price per kWh of load than hospitals) and on the country/region in which he resides. In function of changes in one or more of the above mentioned categories the billing price can vary from one year to the other. For instance, the increase of renewable penetration in the last decade has resulted in a net increase of the prices due to a rise in electricity and distribution costs [35].

Figure 2.4(b) shows what happens with the financial benefit on PV-owner side with rising billing prices. Observe installing solar panels is more beneficial in the case of higher electricity billing prices (dark blue curve). The grid-parity is now obtained with an installation of 3.4 kW_p, almost reaching the $E_L = E_{PV}$ limit.

Discussion

In the case of a one-way grid-connection, a Belgian households can only make marginal gains with installations below 3 kW_p. This gain increases when the billing price of electricity rises.

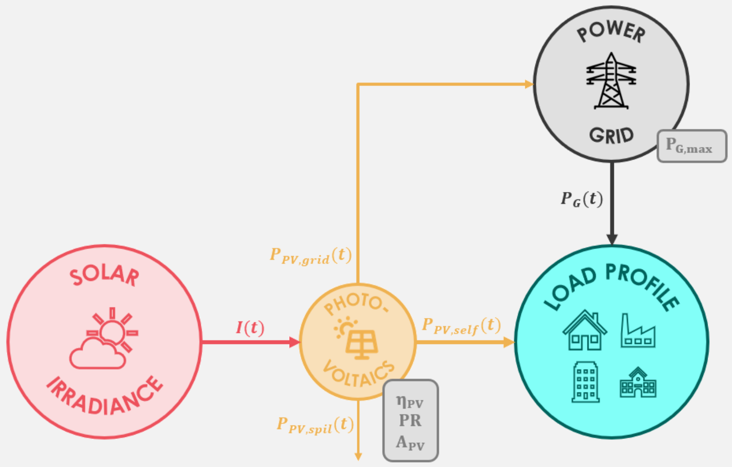
The gain is marginal because, as explained in the previous section, the load profile does not sufficiently coincide with the available solar power, meaning self-consumption is relatively low for bigger installation. Recall, a low self-consumption means only a small percentage of the PV production is useful to the owner. For bigger installations, the actual value of the investment is thus low.

The correlation between available solar power and power consumption is called *capacity value*. Sunny countries with high irradiance levels usually have high capacity values. Take Spain for example, people use air-conditioning systems during hot days to cool their homes. Electricity consumption then coincides with high irradiance. Investing in solar panels is more beneficial in those countries [74]. There is no need for external financial aid to make PV production in households profitable [35]. In countries like Belgium on the contrary, policy-makers need to create a favorable environment to encourage the development of PV. Different compensation systems exist and are in use today. More detail in the following sections.

C.2 Two-way Connection: Net-Metering (NM)

In a net-metering system the surplus production of solar power is automatically fed into the distribution network. The electricity meter provided by the DNO automatically deducts the amount of electricity injected to the grid (i.e. turns backwards) and this is taken into account in the final invoice from the energy supplier [35]. Amongst the countries using it are Belgium, Greece, the Netherlands, 43 US states and Australia. Note that in most of those countries it is only used for residential-size installations [35].

Power balances



Solar power can now be self-consumed, spilled *and* fed into the grid.

$$P_{PV}(t) = P_{PV,self}(t) + P_{PV,spil}(t) + P_{PV,grid} \tag{2.20}$$

$$P_L(t) = P_{PV,self}(t) + P_G(t) \tag{2.21}$$

Constraints

Two supplementary constraints are necessary. The first restricts the injection of electricity to the grid to avoid voltage rises (see equation 2.22). This voltage rise is not modeled in this report so we take the same value as in equation 2.18. The second prevents the electricity meter from turning backwards into negative figures (equation 2.23).

$$P_{PV,grid}(t) \leq P_{G,max} \tag{2.22}$$

$$E_{PV,grid} \leq E_G \tag{2.23}$$

Cost function

A backwards turning meter is as if there is a financial compensation for exported electricity equal to the amount paid for imported power, c_G.

$$C_{tot} = C_{PV} \cdot A_{PV} + c_G \cdot E_G - c_G \cdot E_{PV,grid} \tag{2.24}$$

Figure 2.5 shows the positive effect of NM on the owner's financial benefits. A solar power capacity of 3.8 kW_p is found to be the least-cost solution. The yearly electricity bill is cut by almost two-thirds (57%) in this case. The payback period is approximately 8 years, which is within the margins given by Test Achats in 2018[2].

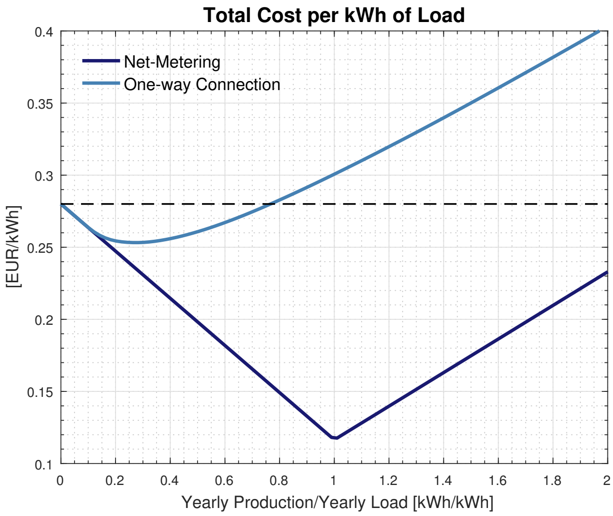


Figure 2.5: Levelized cost of electricity as a function of annual PV output on annual load.

As a consequence, the household pays a lower amount of money to the electric utilities *and* the net energy exchanges with the grid have increased. 4,820 kWh of electricity is now yearly exchanged with the grid (half consumed, half injected) compared to 3,665 kWh before (entirely consumed). This is in basic terms the reason behind the financial gap defined in the introduction. This matter will be developed more thoroughly in Chapter 3.

C.3 Two-way Connection: Feed-in Tariff (FIT)

Another grid policy often used is in the form of a contract between DNO and prosumer, allowing the prosumer to sell its surplus energy at a fixed price. This price is lower than electricity billing price. As a result, the advantage gained by households in a FIT system is less than in a NM system. The system is especially adopted by countries with higher PV penetration levels to lessen the DNO's financial losses.

It is the most used policy worldwide[3]. In Europe there is Denmark, Austria, Bulgaria, Croatia, France, Germany, Italy, Luxembourg, Portugal and Romania. In some countries surplus electricity can be injected on the grid but without any financial compensation (e.g. Slovakia, Spain, Norway and Slovenia) [35].

[2] More information at `https://www.test-achats.be/maison-energie/energie-renouvelable/dossier/panneaux-photovoltaiques-toujours-interessant/prix-et-rentabilite`

[3] More information at `https://www.greentechmedia.com/articles/read/feed-in-tariffs-a-tool-for-us-economic-equality`

Power balances

Same as in the NM system. See Chapter 2, Section C.2.

Constraints

One cannot make net financial benefits by reselling surplus electricity, otherwise he is considered as an energy producer and not a consumer.

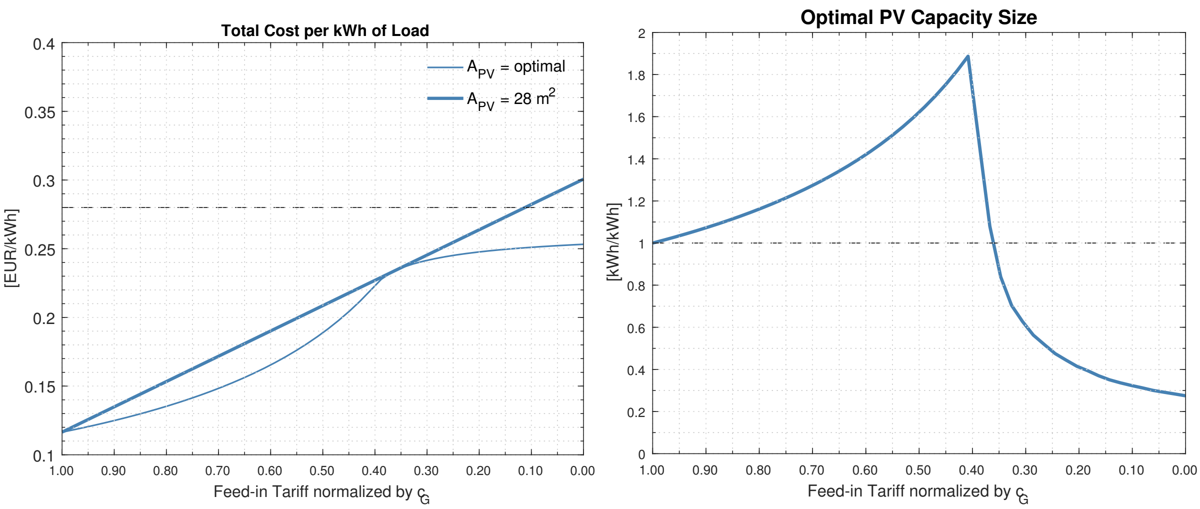
$$c_{FIT} \cdot E_{PV,grid} \leq c_G \cdot E_G \tag{2.25}$$

Cost function

The financial compensation for exported electricity is lowered from c_G to c_{FIT}.

$$C_{tot} = C_{PV} \cdot A_{PV} + c_G \cdot E_G - c_{FIT} \cdot E_{PV,grid} \tag{2.26}$$

Similar to previous analyses, the total cost is found for different feed-in tariffs in the case of a household with a solar power capacity of 3.8 kW_p (see thick blue line on Figure 2.6(a)). As expected, the optimum is found for a tariff equal to the electricity billing price, i.e. a NM system. Tariffs below 0.03 EUR per kWh injected (0.10 on the x-axis) make the cost balance turn negative for this household.



(a) The slim line represents the total cost for the optimal PV-sizes (see Figure 2.6(b)). The thick line is for a PV size of 28 m^2.

(b) Optimal PV size as a function of FIT.

Figure 2.6: The tariff is normalized by the electricity billing price, $c_G = 0.28$ EUR/kWh.

In Figure 2.6(b), the LP algorithm is used to find the optimal PV capacity for different feed-in tariffs. The related total cost is showed by the thin blue line on Figure 2.6(a). Observe

FIT between 0.28 EUR/kWh (1.00) and 0.11 EUR/kWh (0.40) make the over-sizing of the household's PV capacity more interesting. This over-sizing increases the value gained by reselling electricity but is constrained by equation 2.25. A maximum is reached when the increase of PV-capacity becomes more costly than the financial benefit it procures. This happens for a FIT of 0.11 EUR/kWh (0.40). After that, the optimal capacity quickly decreases to attenuate the overall costs. The lower the FIT, the less steep the decreasing curve becomes. This is because self-consumption is high at low PV capacities (see Figure 2.3(b)), so the exchanges with the grid are then limited and FIT have a lesser effect. Note that for an FIT of 0.10 EUR/kWh (0.35), the optimal solution is the same as for the NM system (3.8 kW_p).

C.4 Additional Grid Policies

Additional grid policies can be used in parallel to a NM or FIT scheme in order to limit exchanges with the grid or to increase the benefits for households.

Green Certificates (GC)

A GC-system is a way of encouraging investment in solar panels. It is a compensation based on total energy production rather than installed capacity. How the produced energy is used (e.g. self-consumed, fed into the grid, ...) does not import here. It can be used in parallel with FIT or NM policies. In Belgium, a complex GC system is used for commercial-size installations[4].

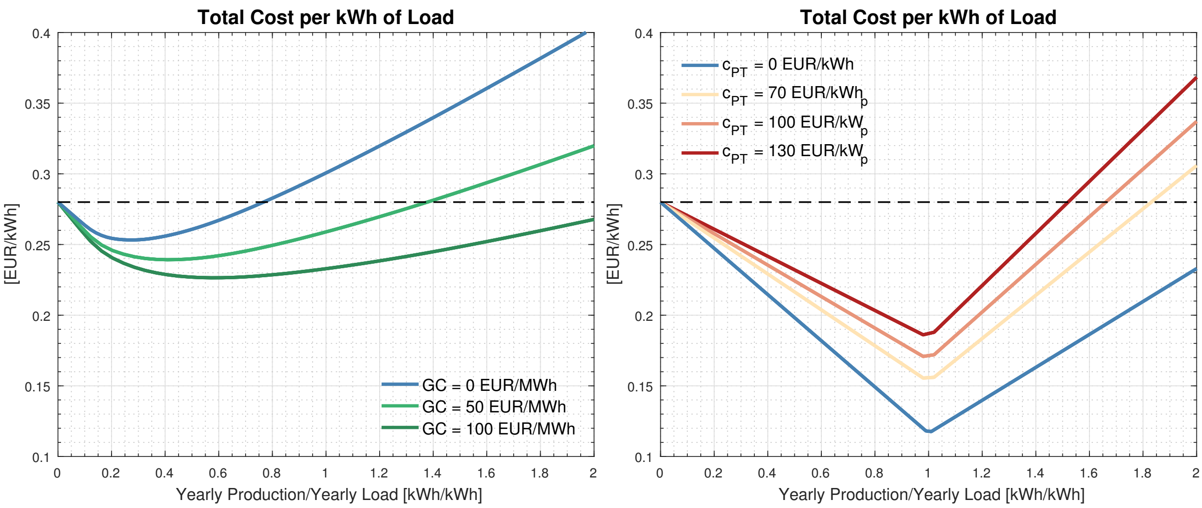
Compared to the previous model formulation, the only difference lays in the cost coefficient of the PV infrastructure (see equations 2.27 and 2.28). Recall the cost coefficient C_{PV} is expressed in EUR/m^2 and H in kWh/m^2. Note also GC are usually granted for a fixed amount of time (e.g. 10 years in Wallonia). GC should thus be normalized to the period considered (y).

$$C_{PV} = C_{PV,INV} - C_{PV,REM} - C_{PV,GC} \tag{2.27}$$

$$C_{PV,GC} = c_{GC} \cdot H \cdot \frac{y_{GC}}{y} \tag{2.28}$$

The outcome is illustrated in Figure 2.7(a) in the case of a one-way connection grid. The least-cost solution is found for higher PV capacities and the net benefit per kWh of load increases with higher PV capacities.

[4] More information at `https://www.vreg.be/en/support-system-green-certificates` (Flanders), `https://www.cwape.be/?dir=6.1.05` (Wallonia) and `https://www.brugel.brussels/nl_BE/actualites/mechanisme-van-de-groenestroomcertificaten-35` (Brussels)



(a) Green Certificates over 10 years. The average in Belgium is around 65 EUR/MWh for 10 years.

(b) Prosumer Tax based on capacity over 10 years. The average in Flanders is around 90EUR/kW_p for 10 years.

Figure 2.7: Levelized cost of electricity (per kWh of load) as a function of total PV capacity.

Prosumer Tax (PT)

Prosumer tariffs are usually introduced as yearly taxes based on installed capacity. They are used in several countries to tax a prosumer for its use of the grid. The Flemish region in Belgium introduced a capacity-based version in 2015 and Wallonia will soon follow [87, 88].

Regarding model formulation, only the cost coefficient of PV changes (see equation 2.29). A prosumer can be taxed yearly on its installed capacity (e.g. Flanders, equation 2.30) but also on its annual energy output (cf. GC, equation 2.31).

$$C_{PV} = C_{PV,INV} - C_{PV,REM} + C_{PV,PT} \tag{2.29}$$

$$C_{PV,PT} = c_{PT,cap} \cdot \frac{y_{PT}}{y} \tag{2.30}$$

$$C_{PV,PT} = c_{PT,out} \cdot H \cdot \frac{y_{PT}}{y} \tag{2.31}$$

The outcomes are plotted in Figure 2.7(b) in the case of an NM-system and a tax on installed capacity. Prosumer taxes do not displace the least-cost solution but lower the total financial benefit. The yearly discount of the owner's electricity bill goes from almost 60% (blue curve) to a bit more than 30% (fire-red curve). In payback period terms, it goes from 8 to 13 years.

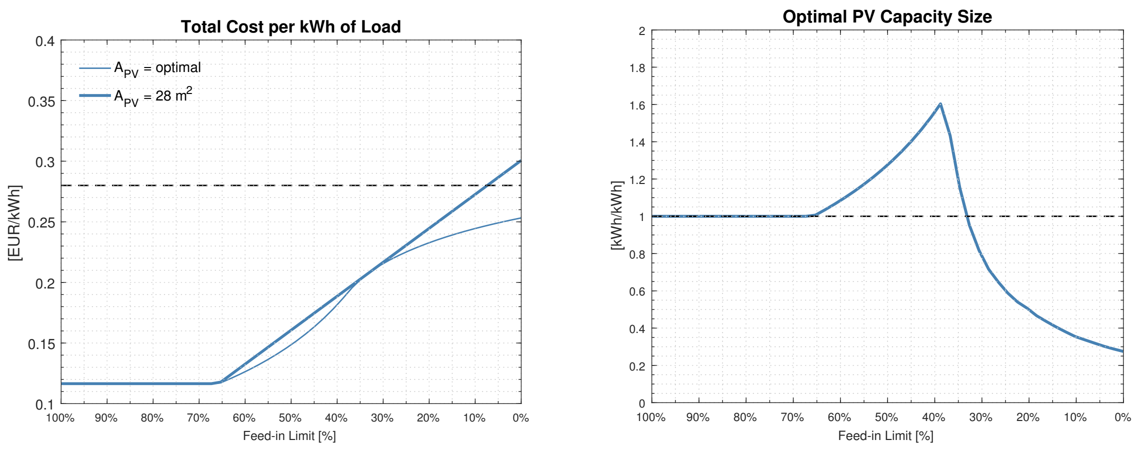
Feed-in Limit (FiL)

FIT and PT policies reduce the financial gap created by PV-owners but do not *physically* reduce the prosumer's interactions with the grid. That is why in some countries a feed-in limit is used to prevent households of exporting too much to the grid. In Wallonia for example, buildings with industrial-size PV installations should at least keep 60% of their yearly production on-site before receiving GC [89]. The constraint can be added in two ways: as a percentage of the nominal capacity at every time t (e.g. Refs. [75–77]) or on the total yearly energy flows (e.g. Wallonia):

$$P_{PV,grid}(t) \leq FIL \cdot P_{PV} \tag{2.32}$$

$$E_{PV,grid} \leq FIL \cdot E_{PV} \tag{2.33}$$

Once again the example of the modeled household with a 3.8 kW_p PV capacity is taken. The solutions are found in the case of a NM-scheme with a Wallonia-type FIL policy. Figure 2.8(a) (thick line) shows the evolution of the household's financial benefit as a function of increasing feed-in limits. Until $FIL = 65\%$ nothing changes since for this PV capacity size 2410 kWh is exported and 3665 kWh is produced, so an export-to-production ratio of 65%. After this point, every increase in FIL reduces the yearly amount of electricity exported to the grid.



(a) The slim line represents the total cost for the optimal PV sizes (see Figure 2.8(b)). The thick line is for a PV size of 28 m^2.

(b) Optimal solar power capacity in function of FIL.

Figure 2.8

Figure 2.8(b) is similar to Figure 2.6(b). It shows the benefit of increasing the PV capacity at specific FIL to temper the losses endured. Of course, this increase is first limited by the constraint equation 2.23. Then it reaches a maximum (at $FIL = 40\%$) and sharply decreases to reach the one-way connection optimum.

C.5 Summary and Conclusion

Power balances

$$P_{PV}(t) = P_{PV,self}(t) + P_{PV,spil}(t) + P_{PV,grid}$$
$$P_L(t) = P_{PV,self}(t) + P_G(t)$$

Constraints

General constraints: $P_G(t), P_{PV,grid}(t) \leq P_{G,max}$

Net-metering: $E_{PV,grid} \leq E_G$

Feed-in tariff $c_{FIT}E_{PV,grid} \leq c_G E_G$

Feed-in limit
$$P_{PV,grid}(t) \leq FIL \cdot P_{PV}$$
$$E_{PV,grid} \leq FIL \cdot E_{PV}$$

Cost function $C_{tot} \cdot E_L = C'_{PV} \cdot A_{PV} + c_G \cdot E_G - c'_{PV,grid} \cdot E_{PV,grid}$

With c'_{EG} and C'_{PV} depending on the type of grid policy applied.

Discussion

In the introduction was stated that decentralized power production and the policy framework in which it resides can impact the sustainability of the grid. In this section we saw how certain policies can emphasize the issues caused by prosumers (e.g. NM and GC) and others can moderate those issues (e.g. PT, FIL and FIT). The trend observed is that a policy benefiting the prosumer causes damage to the electric utilities and the other way round. A continued balance has to be found between these two stakeholders.

Now what if the prosumer has access to an unlimited storage capacity? Figure 2.9 shows it could then decrease its dependency form the grid and even, with enough solar power capacity, go entirely off-grid. The owner would then be less burdened by changing billing prices and the grid less burdened by incoming power. This is analyzed in the following section.

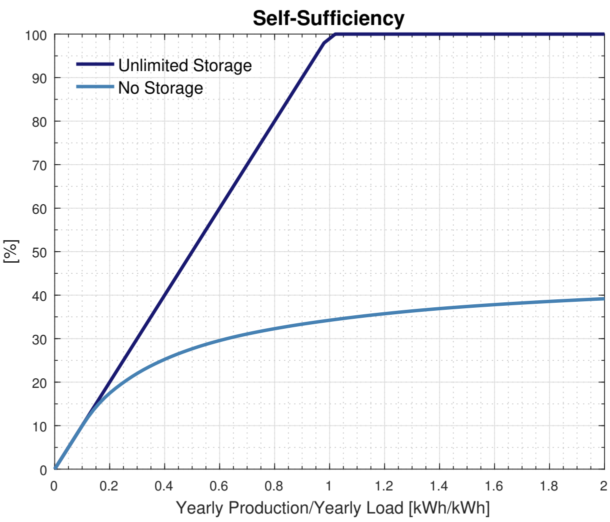


Figure 2.9

D Electricity Storage

D.1 Storage Characteristics

This section deals with the idea of electricity storage. The previous section was concluded by showing the potential increase in self-sufficiency with unlimited storage. In reality, storage is not unlimited.

Storing electricity is done by converting electrical energy into a specific type of *storable energy* which is then converted back to electricity when needed. This storable energy can be mechanical (e.g. flywheels, compressed air, pumped hydroelectric storage), chemical (e.g. batteries, hydrogen storage, power to gas) or even electromagnetic (e.g. superconductors). Each technology has its own set of characteristics. Some can store energy for a long time without losing any of it, others can store energy very rapidly, still others are small and can easily be put in automobiles. In this model, we assume a technology is defined by a set of *9 characteristics*: total capacity, power-to-energy ratio, charging and discharging losses, self-discharge rate, depth of discharge, shelf and cycle lifetime and remaining capacity factor (or energy retention) as proposed in Ref. [44].

Power and capacity

The storage system's behavior is modeled by the power balance formulated in equation 2.34. $P_{S,chg}(t)$ is the flow of power going in the storage system, referring to the *charging* of the system. $P_{S,dis}(t)$ is the power flow out of the battery, i.e. the *discharging*. And $E_{S,soc}(t)$ is the energy accumulated (*stored*) in the system at time t, i.e. the state of charge.

$$E_{S,soc}(t+1) = E_{S,soc}(t) + P_{S,chg}(t) \cdot t + P_{S,dis}(t) \cdot t \tag{2.34}$$

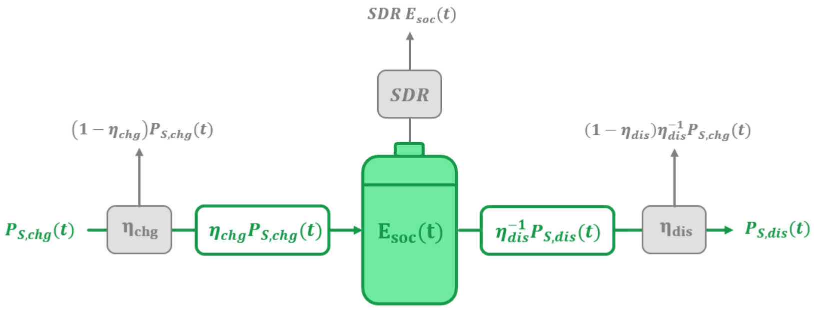
The first characteristic of the storage system is its total capacity, K_S, expressed in kWh. It defines the maximum amount of energy the storage system can hold in one moment t. The state of charge of the storage system is thus limited by its capacity (equation 2.35).

$$E_{S,soc}(t) \leq K_S \tag{2.35}$$

A second characteristic is the speed at which the system charges or discharges. This is defined by the power-to-energy ratio or PER. The PER is in fact a measure of time describing how fast a storage system can (dis)charge itself entirely. As an illustration, batteries used in electric vehicles have a PER of around 2 to 3 hours. The charging and discharging power is thus constrained (equation 2.36).

$$0 \leq P_{S,chg}(t), P_{S,dis}(t) \leq \frac{K_S}{PER} \tag{2.36}$$

Losses



Reversible losses occur when the storage system is in use, but also when it is at rest. Think of a fully charged cellphone left unused for a long time, its energy content will have slightly lowered after a few months (by around 2% per month usually [78]). This reversible loss is defined by a single parameter called self-discharge rate (SDR). The use-related losses are characterized by charging and discharging efficiencies (η_{chg} and η_{dis}) which together form the round-trip efficiency. As a result, the power balance has to be adapted (equation 2.37).

$$E_{S,soc}(t+1) = (1 - SDR)E_{S,soc}(t) + \eta_{chg}P_{S,chg}(t) \cdot t + \frac{1}{eta_{dis}}P_{S,dis}(t) \cdot t \tag{2.37}$$

Finally, the remaining capacity factor (RC) is an *irreversible* loss of capacity due to ageing [78]. It causes the usable capacity to decrease with time. The lifetime of a system is generally based on this parameter. In the Tesla Powerwall's warranty for example, the RC is fixed at 70%. By calculating the time it takes for the storage system to reach this irreversible loss of capacity, a lifetime of 10 years is found [79].

Lifetime

In the same way losses occur when the storage system is in use and when it is not, the lifetime of a system can be measured as a function of its use or its 'age'. The first, called cycle lifetime

(CLT, $LT_{S,cy}$) is defined as a maximum amount of equivalent full cycles a system can bear (see definition equation 2.38). The word 'time' (in cycle lifetime) is misleading while it is measured in cycles, not time. The second, called shelf lifetime (SLT, LT_S) is a measure of how long a storage system can be used independent of the way it is used.

$$FCE = \frac{\eta_{chg} E_{S,chg}}{\max(E_{S,soc}(t))} = \frac{\eta_{chg} E_{S,chg}}{K_S} \tag{2.38}$$

In the case of battery storage, the depth of discharge (DOD) can influence lifetime. DOD indicates which proportion of the total capacity can maximally be discharged from the system. A DOD of 80% means the state of charge of the system should, at all times, be at least 20% (equation 2.39). The cycle lifetime depends on the DOD. When DOD is high (close to 100%), the lifetime is low and vice-versa [80, 81].

$$E_{S,soc}(t) \leq (1 - DOD) \cdot K_S \tag{2.39}$$

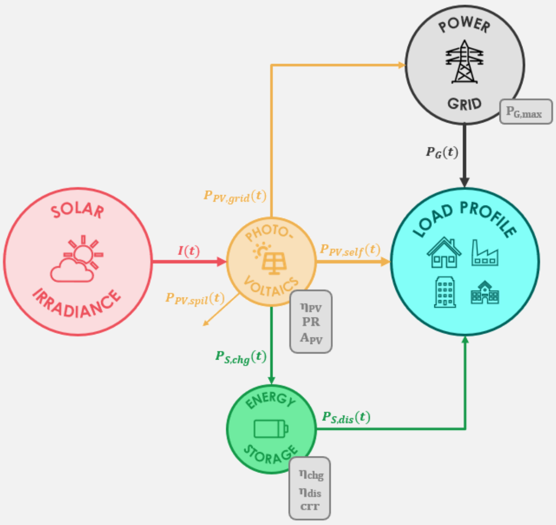
Cost coefficient

While the lifetime of storage can be apprehended in two different ways, the cost coefficient can also be computed in two ways: using shelf lifetime, C_S, or using cycle lifetime, $C_{S,cy}$. C_S is computed in the exact same way as the PV cost coefficient (section B.1). $C_{S,cy}$ is slightly different, but the general principle is identical. The main difference lays in how the reinvestment vector r is found. We refer to Appendix A.2 for a detail on its computation.

In the rest of this report we will use C_S to describe the cost of storage. This is usually the way utilities sell their products (e.g. Tesla Powerwall [79]).

D.2 One Storage System

Power balances



The addition of the storage system entails a supplementary energy balance equation (equation 2.42). Also, the load can now be met by self-consumption, grid power *and* energy discharged from the storage system (equation 2.41). Finally, the PV power balance is also adapted (equation 2.40). Note that the storage system can not store power from the grid.

$$P_{PV}(t) = P_{PV,self}(t) + P_{PV,spil}(t) + P_{PV,grid}(t) + P_{S,chg}(t) \tag{2.40}$$

$$P_L(t) = P_{PV,self}(t) + P_G(t) + P_{S,dis}(t) \tag{2.41}$$

$$E_{S,soc}(t+1) = (1 - SDR)E_{S,soc}(t) + \eta_{chg} P_{S,chg}(t) \cdot t - \frac{1}{\eta_{dis}} P_{S,dis}(t) \cdot t \tag{2.42}$$

Constraints

From the previous section we have the following two constraints.

$$0 \leq E_{S,soc}(t) \leq K_S \tag{2.43}$$

$$0 \leq P_{S,chg}(t), P_{S,dis}(t) \leq PER \cdot K_S \tag{2.44}$$

Cost function

The cost coefficient of the storage system is added to the equation.

$$C_{tot} = C'_{PV} \cdot A_{PV} + c_G \cdot E_G - c'_{PV,grid} \cdot E_{PV,grid} + C_S \cdot K_S \tag{2.45}$$

Self-consumption and self-sufficiency

Self-consumption and self-sufficiency have to be redefined. This is done similarly as in Section B.2. The colors in equations 2.46 and 2.47 match the legend in Figure 2.10. We also plot the self-sufficiency as a function of increasing storage capacities and for different PV plant sizes (Figure 2.11(a)).

$$SC = \frac{E_{PV,self} + E_{S,dis}}{E_{PV,self} + E_{S,chg} + E_{PV,grid} + E_{PV,spil}} = \frac{E_{PV,self} + E_{S,dis}}{E_{PV}} \tag{2.46}$$

$$SS = \frac{E_{PV,self} + E_{S,dis}}{E_{PV,self} + E_{S,dis} + E_{G}} = \frac{E_{PV,self} + E_{S,dis}}{E_{L}} \tag{2.47}$$

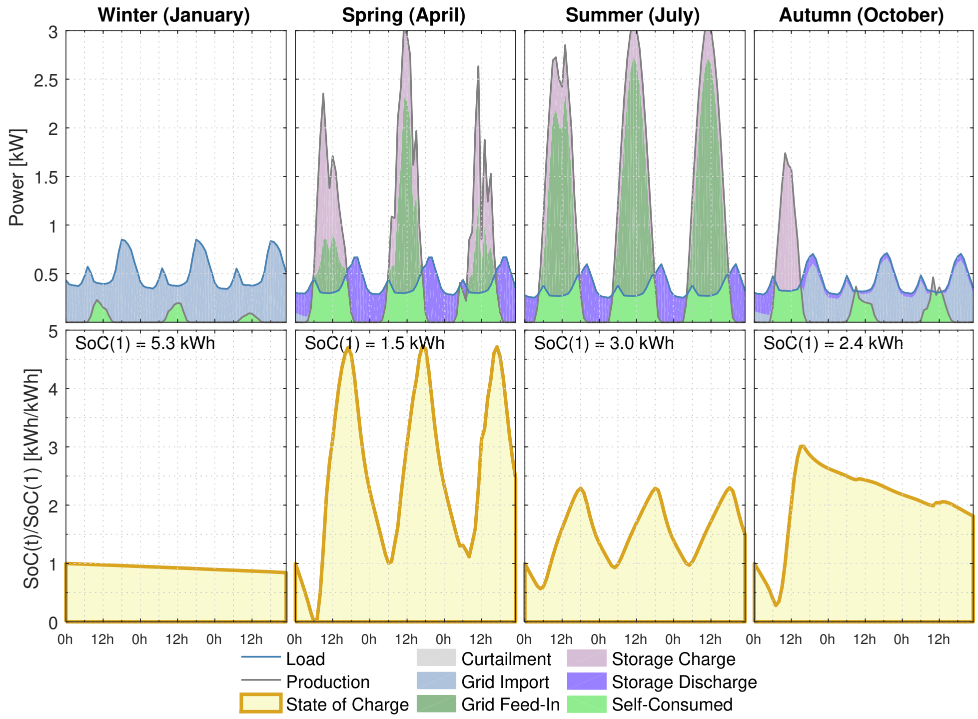
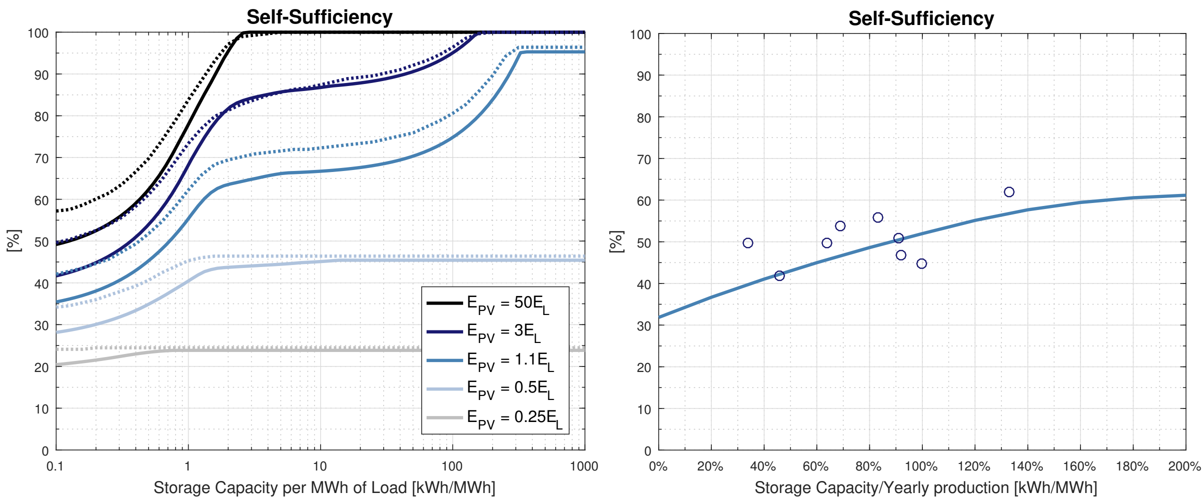


Figure 2.10: Power fluxes in the case of a PV capacity of $A_{PV} = 28m^2$ and a lithium-ion battery of 14kWh (4 kWh/MWh) for three typical days in each season.

The first and foremost observation confirms what Figure 2.9 hinted: storage systems increase self-sufficiency. The dotted lines on the graph show results from a similar research conducted on typical German households [75]. The irradiation and load data are thus different. The results match relatively well for high storage capacities but at almost zero storage capacity, the self-sufficiency of ref. [75] is 5 to 10 points higher than for this model. This is simply explained by the difference in input datas.

Ref. [82] is used to compare results at low storage capacities (Figure 2.11(b)). Note that the storage characteristics are more or less different for each dot. Nonetheless it can be concluded that the outcome of this model matches relatively well with the existing scientific literature.

A closer look is taken at the shape of the $E_{PV} = 1.1E_L$ (30 m^2 or 4 kW_p) curve, Figure 2.11(a). With a storage capacity of ca. 7 kWh (corresponds to 2 kWh/MWh on the graph) the curve reaches a first *plateau*. Right after that, the curve flattens out meaning increasing storage capacities have a lesser effect on self-sufficiency. Figure 2.10 shows the power flows in this situation. Note that during spring and summer months power is charged during the day and discharged at night. This is called daily storage. During autumn and winter months, the low PV production prevents the storage system of doing the same. A much higher storage capacity is needed to accumulate the surplus energy produced during the sunny seasons and discharge it during the cloudy winter and autumn months. The latter is called seasonal or long term storage. Back to Figure 2.11(a), when the storage capacity reaches ca. 350 kWh (100 kWh/MWh), the curve rises quickly again, showing the seasonal storage has begun. Finally, we observe SS is capped at 95%. This is surprising at first sight given that there is enough solar power production to reach 100% SS. It is simply explained by the storage characteristics. The (dis)charging losses prevent the household to go off-grid entirely. To reach this target, the solar power capacity should be even more oversized. More exactly, to $E_PV = 1.22E_L$ (34 m^2 or 4.6 kW_p). The more the household oversizes its PV capacity, the less storage capacity is needed (see Appendix A.3).



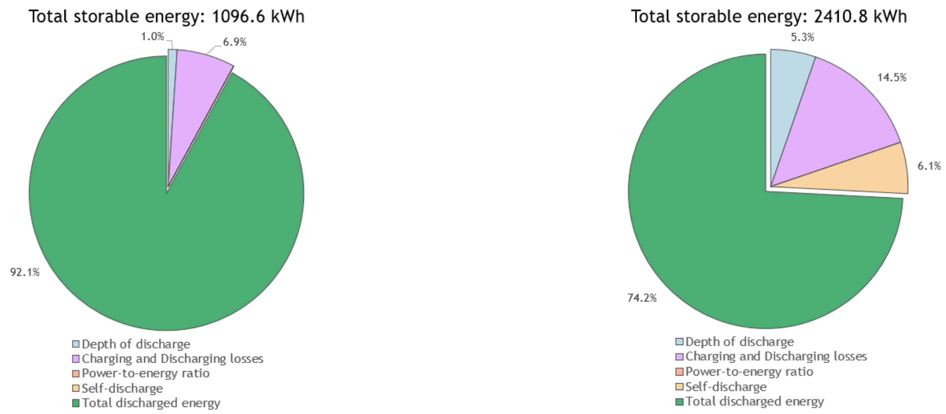
(a) Solutions found with same storage characteristics as in Ref. [75] (dotted lines). X-axis on logarithmic scale.

(b) Circles indicate results from multiple sources (taken from Ref. [82]). Solution for $E_{PV} = 1E_L$.

Figure 2.11: Self-sufficiency as a function of increasing storage capacities.

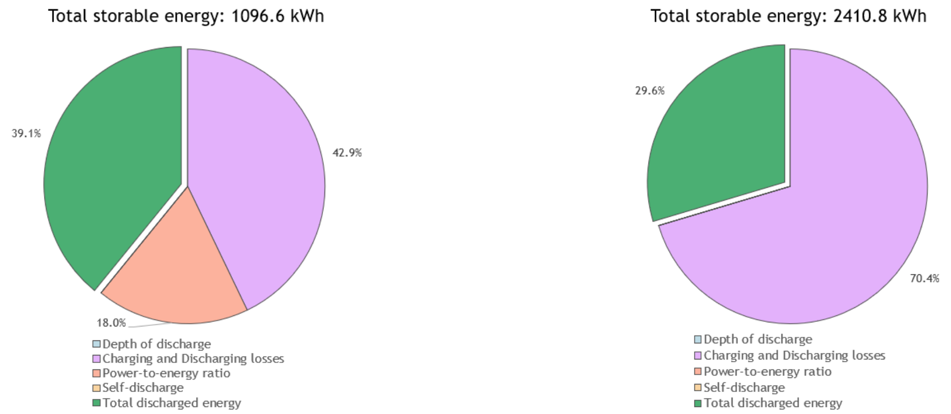
Insight: Choice of technology

The graphs above were found with characteristics typical to lithium-ion (Li-ion) batteries. Previously it was stated that different storage technologies are used for different applications. In the case of stationary storage of PV power, two applications are identified: day-to-day or short term storage and seasonal or long term storage. The question raised here is what sort of characteristics should be used for what application. To find an answer, the losses and the system's total cost of two different storage technologies are compared. Li-ion batteries for short term storage and electrolyzer + fuel cell hydrogen storage for the seasonal gap. For each technology we take a storage capacity of 10 kWh representing daily storage and allowing an SS of ca. 65% without losses. Seasonal storage is done with a 1282 kWh[5] storage system, allowing an SS of 100% without losses.



(a) 10 kWh *(b) 1280 kWh*

Figure 2.12: Litium-ion battery storage losses. Characteristics see Appendix A.5.



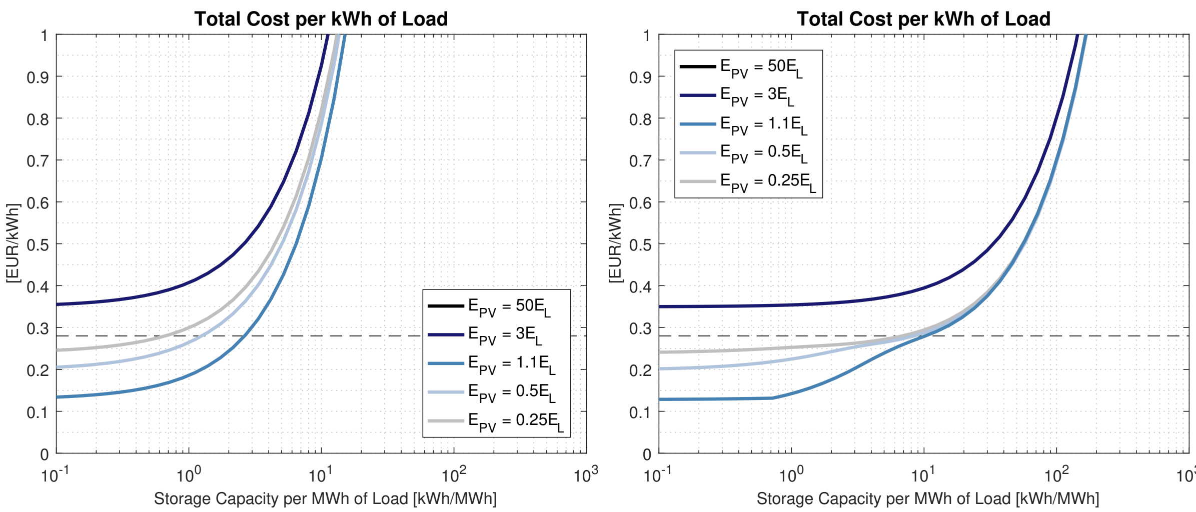
(a) 10 kWh *(b) 1280 kWh*

Figure 2.13: Hydrogen storage losses. Characteristics see Appendix A.6.

[5]The calculus to find this value is specified in Appendix A.3.

Looking at the losses first, the pie-charts in Figures 2.12 and 2.13 illustrate the relative importance of each characteristic for daily and seasonal storage. In general, we see losses are proportionally more important for big storage capacities than for low capacities. Per technology, the increase in losses from daily to seasonal for Li-ion batteries (18 points) is almost two times higher than for hydrogen storage (9.5 points). The losses due to SDR (2% per month) and the limited DOD (90%) increase importantly for Li-ion storage. The low PER typical to hydrogen storage prevents it from storing all the available energy on a daily basis. At low capacity, the power is low, so the chargeable energy at time t is limited. Note this effect disappears when the size of the storage system (and thus its power) rises.

Figure 2.14 shows the cost per kWh of load for the entire system. Due to the high capital cost of storage (independent of the technology), the cost quickly rises when reaching high capacities. The difference between both systems is small for low storage capacities (daily storage) but hydrogen clearly takes over for high storage capacities (seasonal storage). The system with a 1280 kWh battery comes at 20 EUR/kWh while the system with a same sized hydrogen storage facility reaches 2.8 EUR/kWh. Note hydrogen is stored in a vessel or storage tank. Charging and discharging hydrogen from small vessels is technically complicated so hydrogen storage systems below 10 kWh are hard to come by [52].



(a) Li-ion battery. Cost for 10 kWh and $E_{PV} = 1.1E_L$ is 0.29 EUR/kWh. Cost for 1280 kWh and $E_{PV} = 1.1E_L$ is ca. 20 EUR/kWh.

(b) Hydrogen storage. Cost for 10 kWh and $E_{PV} = 1.1E_L$ is 0.20 EUR/kWh. Cost for 1280 kWh and $E_{PV} = 1.1E_L$ is around 1.8 EUR/kWh.

Figure 2.14: Black striped line represents on-grid situation.

Using a single storage technology to reach high values of self-sufficiency entails or a high total cost or important losses. A hybrid system could combine the advantages of both system as proposed in Ref. [84]. The following section deepens this question.

D.3 Multiple Storage Systems

Model-wise, the changes are not fundamental. The power balances are similar, with the exception that the storage energy balance is multiplied by the number of storage systems, i.e. there is one balance equation per storage system. The formulas for self-sufficiency and self-consumption rates do not change

Power balances

The power balances are generalized for multiple storage systems by using index j. n_S is the total amount of storage systems. Note that multiple storage systems can be charged and discharged simultaneously.

$$P_{PV}(t) = P_{PV,self}(t) + P_{PV,spil}(t) + P_{PV,grid}(t) + \sum_{j=1}^{n_S} P_{S,chg}(j,t) \tag{2.48}$$

$$P_L(t) = P_{PV,self}(t) + P_G(t) \sum_{j=1}^{n_S} P_{S,dis}(j,t) \tag{2.49}$$

$\forall j = 1 \ldots n_S,$

$$E_{S,soc}(j,t+1) = (1-SDR)E_{S,soc}(j,t) + \eta_{chg,j} P_{S,chg}(j,t) \cdot t - \frac{1}{\eta_{dis,j}} P_{S,dis}(j,t) \cdot t \tag{2.50}$$

Constraints

$$0 \leq E_{S,soc}(j,t) \leq K_S(j) \tag{2.51}$$

$$0 \leq P_{S,chg}(j,t), P_{S,dis}(j,t) \leq PER(j) \cdot K_S(j) \tag{2.52}$$

Cost function

$$C_{tot} = C_{PV} \cdot A_{PV} + c_G \cdot E_G - c_{GP} \cdot E_{PV,grid} + \sum_{j=1}^{n_S} C_S(j) \cdot K_S(j) \tag{2.53}$$

Insight: Optimal storage technology-mix

At the end of the previous section the idea of combining two different storage technologies was hinted. The question pending is at what proportions should they be combined for optimal performance?

The optimal solution for different degrees of self-sufficiency is found with the LP algorithm. Figure 2.15 shows the solutions for $E_{PV} = 2.4E_L$, which is the minimum PV size needed to potentially obtain a 100% hydrogen storage solution. The optimal Li-ion storage capacity is capped at around 9.7 kWh (2.65 kWh/MWh). An SS of 100% is optimally reached with a Li-ion battery of 9.7 kWh and a hydrogen storage system of almost 1,500 kWh or 40 kg of H_2 (conversion made using LHV). If the gas is stored at 30 bar, the tank has an approximate volume[6] of 13.6 m^3, potentially corresponding to a 2.5 m by 2.5 m area with a height of 2.1 m.

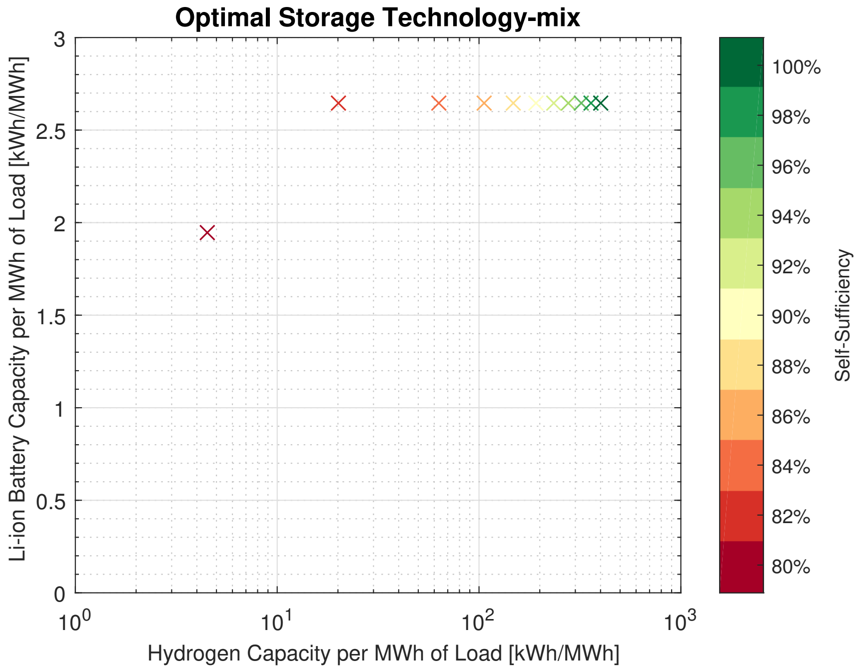


Figure 2.15: The cost for $SS = 80\%$ is 0.42 EUR/kWh; $SS = 90\%$ is 1.3 EUR/kWh; $SS = 100\%$ is 2.3 EUR/kWh.

[6]Using the density reached by Mahytec hydrogen tanks. More information at `http://www.mahytec.com/en/our-solutions/`.

Chapter 3

Analysis

Can Belgium count on decentralized photovoltaic power production and storage to reach its emission reduction targets?

The objectives of this analysis are stated in Chapter 1. In short, the goal is to evaluate the environmental, economic and societal value of decentralized photovoltaic production and storage. More precisely, an assessment of the benefit of investing in a daily and/or seasonal storage system is completed. This is followed by a modeling of the resulting cost endured by electric utilities. Finally, the net GHG emissions per year are computed and compared with the 2030 targets set by Belgium.

The first section of this chapter can be regarded as the problem statement. Belgium's actual case is summarized and described using numbers and some assumptions. In the second stage of this analysis, the question 'What if we add daily storage systems?' is presented. The same is done in the third section with a combination of daily and seasonal storage. Finally, the off-grid situation is analyzed.

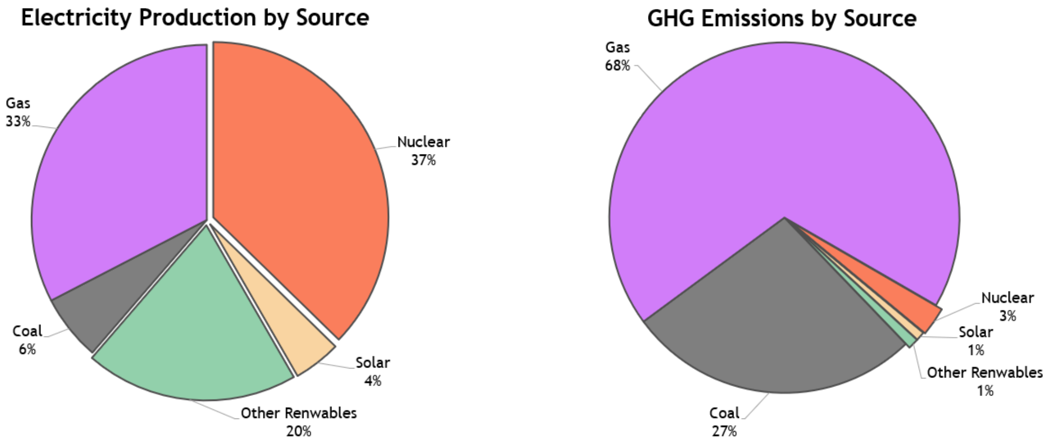
A The Case of Belgium

The case description starts with a numeric expression of the Belgian emission reduction targets (ERT). Second, the existing solar power capacity and the regulatory framework in Belgium is described and modeled to fit in the analysis. Then, a simple evaluation of the potential development of solar power is conducted. This helps understand whether using solar power to achieve the ERT is feasible. Finally, based on [37], a definition of the net cost endured by the electric utility is presented.

A.1 Emission Reduction Target

By 2030 a cut in GHG emissions equivalent to 20% relative to the emission-total in 2015 is demanded by the European Commission [2, 48, 85]. Across all sectors, this represents a reduction from 125 $MTCO_2$ per year to 100 $MTCO_2$ per year. Suppose this reduction target is equally transposed to all sectors[1] identified in Figure 1.2, the power production sector should thus by 2030 decrease its 'own' emissions by 20%.

Figure 3.1(a) shows the mix of energy sources used in 2015 to produce 70 TWh of electricity. Figure 3.1(b) shows how the emissions in the power sector are distributed. The entire power generation sector emitted more or less 15 $MTCO_2$ that year [2], mostly from the combustion of natural gas. Using those figures, the ERT for the power sector in Belgium is set at **3 MTCO₂**. For the sake of comparison, shutting down the 560 MW Langerlo coal-fired power plant in April 2016 amounted, in theory, to a decrease of 1 $MTCO_2$ approximately[2].



(a) Total production: ***70 TWh****. Note that the last coal-fired power plant was closed in April 2016. Other renewables: 8% biopower, 6% wind, 0.4% hydropower. Data from Ref. [17].*

(b) Total emissions: $\boldsymbol{15\ MtCO_{2,eq}}$. *Resulting emission intensity* 0.22 $kgCO_2/kWh$. *See Appendix A.4 for the values of emission intensities.*

Figure 3.1

[1]This assumption is somewhat biased because some sectors may have a higher potential to decrease GHG emissions than others [86]. The target should be seen here as a reference point more than an actual goal.

[2]Estimation done by taking as a capacity factor 50% and efficiency 40% and assuming, of course, the capacity is replaced by a $CO_{2,eq}$-neutral energy source.

A.2 Solar Power

Categorization and load profiles

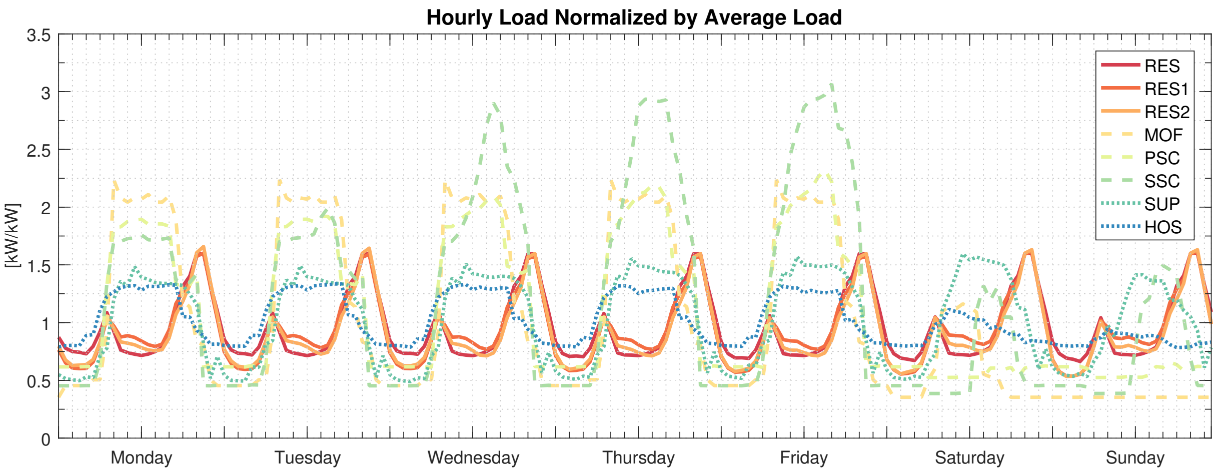


Figure 3.2: R: red-orange full lines; C: yellow-green striped lines; I: green-blue dotted lines.

Solar installations are divided into three size-categories: residential (R, $< 10\ kW_p$), commercial (C, between 10 and 250 kW_p) and industrial installations (I, $> 250\ kW_p$). To multiply the possibilities of interacting with the model and its outcomes, the categories are multiplied into several subcategories. This will allow to obtain a more complete analysis and a better targeting of the solutions. 3 subcategories are added to the residential category, 3 to the commercial and 2 to the industrial category. Each subcategory represents a type of building (see Table 3.1) and is characterized by an adequate, theoretical load profile[3] (see Figure 3.2, [3]). The total, average and peak load are presented in Table 3.1. Each building type has a fixed maximal available area for solar panels.

Name [Unit]	*Residential*			*Commercial*			*Industrial*	
	RES	RES1	RES2	MOF	PSC	SSC	SUP	HOS
Building type	Small HH[1]	Average HH	Big HH	Medium Office	Primary School	Secondary School	Super-market	Hospital
$A_{PV,max}$ $[m^2]$	45	60	75	1,000	1,500	2,000	4,000	5,000
E_L $[MWh]$	2.665	3.665	4.665	153.3	236.4	341.2	2,036	2,974
$\overline{E_L}$ $[kW]$	0.304	0.418	0.533	17.5	27.0	38.9	322	340
$E_{L,pk}$ $[kW/kW]^2$	2.15	2.25	2.33	2.24	2.78	3.37	1.27	1.39

Table 3.1: [1]HH = Household. [2]Peak load normalize by averaged load.

[3]Note that the load profiles originate from Bellingham,WA (USA) but have been normalized to the Belgian averages. See Appendix A.7 for more details.

Regulatory framework

The regulatory framework in Belgium is complex due to the differences between regions. Brussels, Flanders and Wallonia have different laws for different type of consumers. Nonetheless, similarities exist across the regions and those will be exploited to draw a general form of the Belgian regulatory framework. Table 3.2 summarizes the situation. The different hypotheses and similarities with the existing framework are detailed in six points below.

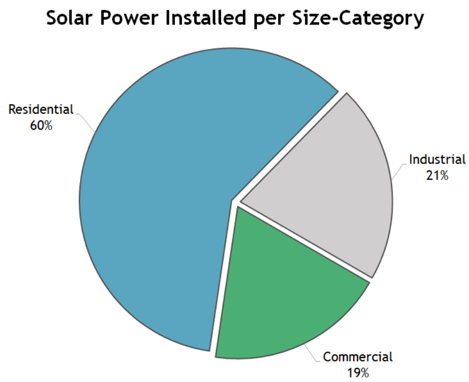
Name [Unit]	*Residential*			*Commercial*			*Industrial*		*Source*
	RES	RES1	RES2	MOF	PSC	SSC	SUP	HOS	
c_G $[EUR/kWh]$[1]		0.3			0.21		0.148	0.121	[17]
Grid policy		NM			FIT		FIT		[59, 88]
Tariff $[EUR/kWh]$		/			0.0		0.0		
PV policy		PT			GC		GC		[59, 88]
Tariff $[EUR/kW_p]$		95.6			72.2		57.2		[59, 88]
Duration $[years]$		10			10		10		
FIL		100%			40%		40%		[89]

Table 3.2

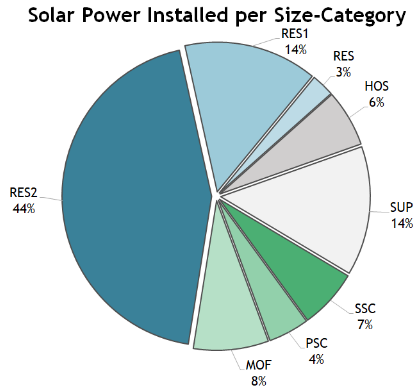
- c_G is the billing price of electricity. It is different depending on total load consumed. It is forecast to rise by approximately 0.75% per year [35]. This means that in 20 years (considered period), the price will go from 0.28 to 0.32 EUR/kWh for residential consumers. The average over 20 years is taken: 0.30 EUR/kWh. The same is done for all load profiles.
- NM for residential-size installations is effectively in use in all three regions. In Brussels though, it is limited for installations with a capacity lower or equal to 5 kW_p. Here NM is for all installations below or equal to 10 kW_p.
- Commercial and industrial installations are modeled to be in a FIT-scheme with zero compensation. They are in reality compensated for electricity injected on the grid, but through a GC system.
- PT is in use in Flanders since 2015 and Wallonia has decided to implement it in the coming years [87]. PT is supposed to be in use everywhere from year one.
- GC are effectively in use in all three regions for installations above 10 kW_p. The given value is an average of the three regional tariffs.

- The FIL imposed on big installations is only in use in Wallonia. In Ref. [29] this policy is considered to be beneficial for the management of the Belgian power grid, so it could be only a matter of time before it is used in the entire country.

Existing infrastructure



(a) Data from Ref. [24].



(b) Using vaues from Table 3.4.

Figure 3.3

As stated in the introduction, Belgium is one of the leading PV-countries worldwide. Its penetration level of 4.6% in 2015 was the sixth highest in the world [23]. Per capita, Belgium placed fourth behind Germany, Japan and Italy. The total solar energy production in 2015 amounted to 3.2 TWh. According to [24], this was produced by a total of roughly 460,000 installations or 28 km^2 of PV-area. The aggregated installed capacity per size-category is given in Figure 3.3(a). In Ref. [24] it is also added that 98% of all installations in Belgium are residential.

The task now is to, as precisely as possible, attribute a total number of installations for each subcategory. This is done by combining the information given above with the data in Table 3.2. The total installed PV capacity per building type is found through a first iteration of the model described in Section C.5. The solar irradiance data presented in Section **??** is used for this purpose. The spatial variability is neglected for simplicity. The outcome is presented in Table 3.3.

Note that the residential category has enough surface available to reach the optimum $E_{PV} = E_L$. For the commercial category, the optimal is found with an undersized PV capacity (see Chapter 2, Section C.4 to understand why), resulting in low SS and high SC figures. The industrial-size installations are both constrained by the building's available surface. Without constraint, the optimal surface for SUP is $5,395$ m^2 and for HOS, $6,020$ m^2. Table 3.3 also shows the net cost benefit each PV installation offers to the building owner. This benefit is positive in all cases. The proportional reduction of the yearly electricity bill is around 30% for R, 25% for C and 15% for I.

Symbol [Unit]	*Residential*			*Commercial*			*Industrial*	
	RES	RES1	RES2	MOF	PSC	SSC	SUP	HOS
A_{PV} $[m^2]$	20.39	28.05	36.07	791.3	1,072	1,839.4	4,000	5,000
E_{PV} $[MWh]$	2.67	3.67	4.67	103.41	140.09	240.37	522.71	653.39
$E_{PV,self}$ $[MWh]$	0.85	1.25	1.54	65.04	84.90	144.22	507.54	627.24
$E_{PV,grid}$ $[MWh]$	1.82	2.41	3.13	38.37	55.19	96.15	15.18	26.15
$E_{PV,spil}$ $[MWh]$	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
E_G $[MWh]$	1.82	2.41	3.13	88.30	151.50	197.00	1,528.75	2,346.8
SS [%]	31.8	34.2	32.9	42.4	35.9	42.2	24.9	21.1
SC [%]	31.8	34.2	32.9	62.9	60.6	60.0	97.1	96.0
C_- $[EUR/MWh]$	78.0	84.0	90.0	52.0	45.0	55.0	24.0	15.0

Table 3.3: mean(C_-) = 49.7

The amount of installations per subcategory can now be chosen. Based on installed PV capacity per building, on the data from Figure 3.3(a) and assuming residential-type installations are more prominent in big households than in small ones the value in Table 3.4 are found. Figure 3.3(b) graphically shows the outcome.

Symbol [Unit]	*Residential*			*Commercial*			*Industrial*		*Total*
	RES	RES1	RES2	MOF	PSC	SSC	SUP	HOS	
Installations $[\times 10^3]$	29.5	125.0	300.0	2.5	1.0	0.85	0.85	0.3	460.0
$E_{PV,tot}$ $[TWh]$	1.94 (61%)			0.60 (19%)			0.64 (20%)		3.18
$E_{PV,self,tot}$ $[TWh]$	0.64			0.37			0.62		1.63
$E_{PV,grid,tot}$ $[TWh]$	1.30			0.23			0.02		1.55
SC_{avg} [%]	33.0			61.7			96.9		51

Table 3.4: [1]Average power-yield of 7.35 m^2/kW_p [7]

Development potential

The solar power potential in Belgium is not entirely exploited. Several estimations of the total usable rooftop area in Belgium exist (e.g. Refs. [4, 35, 90, 91]). The most recent estimations are above 200 km^2. Here, an estimation of **210** km^2, based on a formula proposed in Ref. [4], is used. The same source indicates approximately 50% of this area represents residential dwellings, 30% are commercial-size and 20% industrial-size buildings. Based on those assumptions the potential of rooftop solar power can be found in terms of the PV penetration percentage. More information on the computation method is found in Appendix A.8.

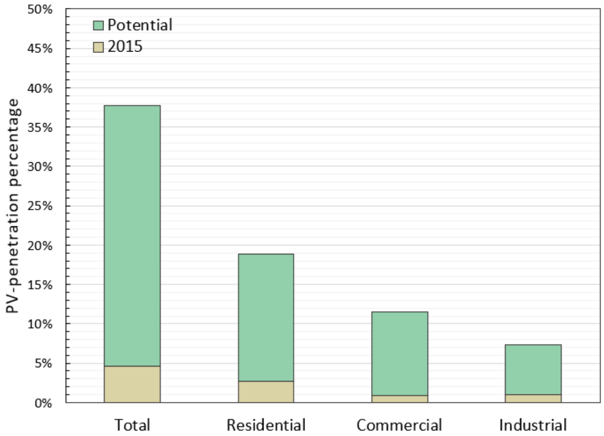


Figure 3.4: Potential Solar Rooftop power production. Computation based on [4].

Following our assumptions, decentralized PV could technically increase the Solar PV integration by 33 points (23 TWh) in Belgium (see Figure 3.4). The highest potential lies in residential dwellings.

A.3 Achieve ERT with Solar Power

Replacing a portion of the power output from natural gas plants by a less emitting source, say solar power, one could reduce yearly GHG emissions. This assumption is only based on the fact that, one source having a lower emission intensity than the other (Table 2), its yearly energy output will result in a lower total GHG emission output. Based on this, the total yearly output to be replaced (E_r) is:

$$E_r = \frac{ERT}{0.046 - 0.46} = \frac{-3MTCO_2}{-0.414kgCO_2/kWh} = 7.2\ TWh$$

The resulting PV-penetration would then be ca. 15%, an increase of more or less 9 points. This is way inside the technical potential computed above. The total installed capacity in Belgium would then amount to 10.9 GW_p. In Elia's 2030 decentralized scenario, the estimated capacity is around 18 GW_p [92], so the assumed increase in PV capacity is plausible. To find the number of installations per subcategory in this future scenario a simple rule of three is used (Table 3.5).

Symbol [Unit]	*Residential*			*Commercial*			*Industrial*		*Total*
	RES	RES1	RES2	MOF	PSC	SSC	SUP	HOS	
Installations[1] [$\times 10^3$]	96.3	408.1	979.3	8.2	3.3	2.8	2.8	1.0	1,501.6
$E_{PV,tot}$ [TWh]		6.32			1.97		2.10		10.38
$E_{PV,self,tot}$ [TWh]		2.10			1.21		2.02		5.33
$E_{PV,grid,tot}$ [TWh]		4.22			0.76		0.08		5.05

Table 3.5: [1]Rule of three with 2015-scenario to attain ERT of +7.2kWh

But, is it realistic to replace gas by a source as incontrollable as solar power? The latter's minute-by-minute availability does not match a gas-fired plant's output, so a mere replacement of total capacity output will automatically cause energy abundance at some points in time and shortages at other points. So, if storage is not available, there is still a need for a controllable source of power to 'even-out' or balance the output ultimately. The question is to know whether there is enough balancing capacity available and, if not, how much solar energy has to be *curtailed*.

Using load and electricity generation data provided by Elia [20], we can, bearing some assumptions, estimate the effects on the grid's power balance. We assume the total load is provided by the mix of power sources presented in Figure 3.1(a), supplemented with import. We suppose the nuclear and coal output cannot be altered, but the rest of the power supply can be shut down instantly to balance out any expected or unexpected power failures. This means wind energy is curtailed before solar energy. With those assumptions, 0.57 TWh of solar energy is yearly curtailed. This seems to be slightly overestimated compared to the scenarios in Ref. [92]. More details on the computation can be found at Appendix A.9. Taking into account the curtailment of solar energy and supposing this curtailed energy is compensated by NG, the amount of GHG emissions that can maximally be reduced if 7.2 TWh of PV is added becomes

$$\begin{aligned} ERT' &= E_r \cdot EI_{PV} - (E_r - E_{cur}) \cdot EI_{NG} \\ &= 7.200 \cdot 0.046 - (7.200 - 0.570) \cdot 0.460 \\ &= -2.72\ MTCO_2 \end{aligned}$$

A.4 Utility Net Cost (UNC)

Decentralized power has the ability to reduce the consumer's electricity bill in a beneficial regulatory framework (Chapter 2). As already explained, this financial benefit creates a gap in the electric utility's yearly budget. This *financial gap* is defined as the difference between the total bill reduction (BIR) on consumer side and the total avoided costs (AC) on utility side. To compute the *net cost* of decentralized PV production, the PV integration cost (PVI) is added (see Figure 3.5). A detail on how PVI is computed is found in Appendix A.10.

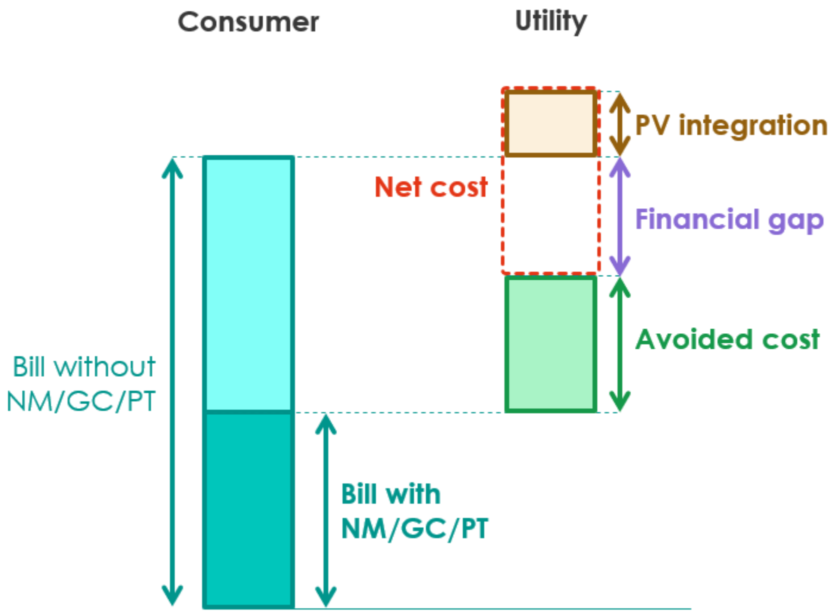


Figure 3.5: SOURCE

Negative		**Positive**	
Definition	*Formula*	*Definition*	*Formula*
Bill reduction	$(E_L - E_G) \cdot c_G$	Electricity generation	$(E_L - E_G) \cdot c_{G,elec}$
PV integration	$E_{PV,tot} \cdot c_{PVI}$	$CO_{2,eq}$ emissions	$(E_{PV,tot} - E_{cur}) \cdot c_{CO_2}$
		Capacity credit	$p_{cc} \cdot c_{CHP}$
		Prosumer tax	$E_{PV} \cdot c_{PT}$
		Green certificates	$E_{PV} \cdot (c_{GC,pen} - c_{GC})$

Table 3.6

Different sources of AC exist. The most trivial one is the reduction of electricity consumption from the power grid due to self-consumption of PV power. A reduced consumption means reduced generation costs. Recall from Chapter 2, Section C.1 that approximately one third of the billing price is used to reimburse the cost of producing electricity.

A second source is the reduction of GHG emissions. In Europe, for every ton of $CO_{2,eq}$ emitted, 15 EUR has to be paid[4]. So for every ton of $CO_{2,eq}$ not emitted, 15 EUR is gained by the utility.

Another positive effect for the electric utility is the reduction of total capacity enabled by PV power. If the production of PV power coincides with the grid's peak load, it can be used to replace existing capacity. This 'replacement value' is more commonly measured in terms of *capacity credit* (p_{CC}).

As stated earlier in this report, the net cost for the electric utility is in NM-schemes always negative (non-beneficial). To somewhat moderate the losses, different taxation methods are used. One of them is the so called *prosumer tax*, introduced in Belgium (Flanders) in 2015 to reduce the financial bubble created by PV over-compensation[5]. It directly aims at lowering the PV-owner's bill reduction.

For bigger installations, a compensation system based on green certificates is still in use. Simply put, a PV-owner receives 1 GC per MWh of solar power. This certificate is bought by electricity suppliers in order to reach an imposed green electricity quota. A quota of 7% means the electricity supplier has to provide 7 GCs for every 100 MWh delivered to its customers. If it fails to do so, a penalty of 100 EUR pr GC has to be paid. The difference between the price of penalty and the fixed price at which the supplier buys the GCs is also considered as an avoided cost.

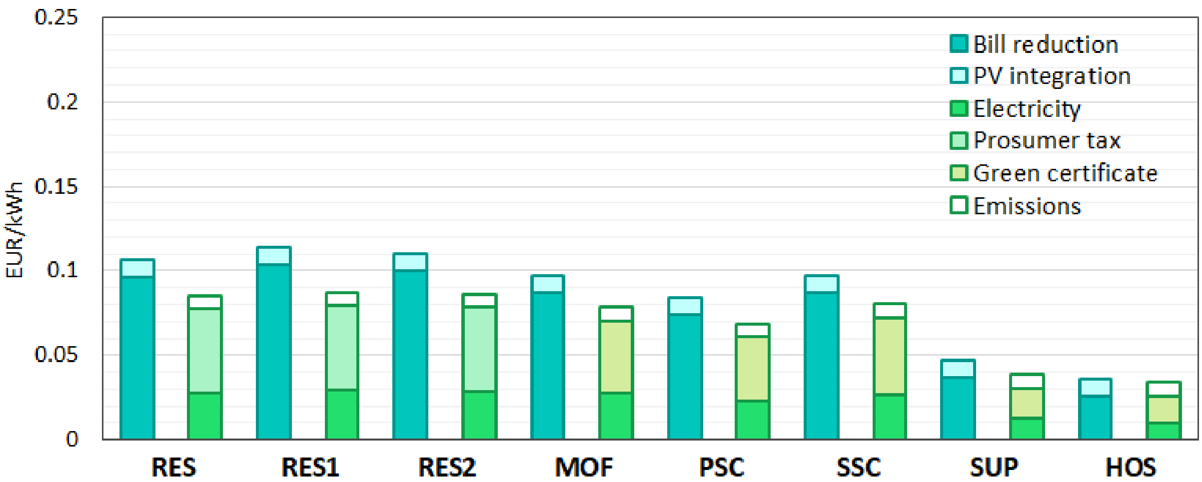


Figure 3.6

[4]Europe's Emission Trading System regulates the overall emissions by putting a price on every ton of $CO_{2,eq}$ emitted. More information at `https://ec.europa.eu/clima/policies/ets_en`. The evolution of the price can be found at `https://www.eex.com/en/market-data/environmental-markets/spot-market/european-emission-allowances#!/2018/06/07`

[5]More information at `http://deredactie.be/cm/vrtnieuws/opinieblog/opinie/1.2478097`

Table 3.6 groups all the different cost parameters in negative or positive effects on utility-size. In Figure 3.6 the results are illustrated for the eight different load profiles. The left columns group all the negative effects, the right column the positive effects. Note that the total UNC is usually carried over to all the electricity consumers in the market. Levelizing the total UNC to 82 TWh (total load in Belgium in 2015, [17]), the potential rise in the electricity billing price is **3.10 EUR/MWh**.

Suppose now this rise is reported to each subcategory by using a weight according to its electricity billing price (values in Table 3.2). The outcome is written in Table 3.7. c_{G+} is the rise in electricity bill per category. $C_{-} - c_{G+}$ describes the remaining cost benefit for PV-owners. The economic balance remains positive for all PV owners.

Symbol [Unit]	*Residential*			*Commercial*			*Industrial*	
	RES	RES1	RES2	MOF	PSC	SSC	SUP	HOS
w		1.33			0.93		0.66	0.54
c_{G+} $[EUR/MWh]$		4.12			2.88		2.05	1.67
$C_{-} - c_{G+}$	73.9	79.9	85.9	49.2	42.2	52.2	22.0	13.3

Table 3.7

A.5 Conclusion

Summary of the model input

Symbol	*Unit*	*Residential*			*Commercial*		*Industrial*			*Source*
		RES	RES1	RES2	MOF	PSC	SSC	SUP	HOS	
Building type	[/]	Small HH*	Average HH	Big HH	Medium Office	Primary School	Secondary School	Super-market	Hospital	
Total Load	$[MWh]$	2.665	3.665	4.665	153.3	236.4	341.2	2,036	2,974	
Installations	$[\times 10^3]$	96.3	408.1	979.3	8.2	3.3	2.8	2.8	1.0	1,501.6
$A_{PV,max}$	$[m^2]$	45	60	75	1,000	1,850	3000	4000	5000	
eta_{PV}	[%]					15				
PR	[%]					84				
LT_{PV}	[years]					25				
c_{PV}	$[EUR/kW_p]$	2541	2420	2299	1936	"	1815	1694	1573	
d_{PV}	$[\%/year]$					5				
c_{PT}	$[EUR/kW_p]$		95.6				0.00			
y_{PT}	$[years]$		10				0			
c_{GC}	$[EUR/kW_p]$		0.00			72.2		57.2		
y_{GC}	$[years]$		0				10			
c_G	$[EUR/kWh]$		0.280			0.190		0.137	0.112	
c_EG	$[EUR/kWh]$		0.280			0.187		0.135	0.111	
$P_{G,max}$	$[kW]$		9.2		75		250	1000		
FIL	[%]		100				40			

*Table 3.8: *HH = Household.*

Summary of the results

- PV installations procure an average cost benefit of almost 50 EUR/kWh to owners. The NM system offers households the biggest advantage, even though they are subjected to a prosumer tax;
- The ERT can not be reached with PV only due to curtailment. A maximum reduction of 2.71 $MTCO_2$ is possible.
- The installation of PV induces a net cost on utility side which could be reflected in a 3.10 EUR/MWh rise in electricity billing prices.

Discussion

The answer to the question, should Belgium count on decentralized PV power production only to reach the ERT, depends on the relative importance of the criteria.

This solution is economically viable for PV-owners. The regulatory framework in Belgium creates a beneficial environment for prosumers, even with prosumer taxes. The yearly reduction of price paid for electricity is 30% for R, 25% for C and 15% for I.

Other electricity consumers on the market see their bill rise without enjoying the beneficial effects of a PV system. Households more specifically observe a rise of 1.5% on their bill. This is 15 $EUR/year$ for an average household (RES1). Supposing this rise is not reported to the households suffering from any form of energy poverty (approx. 21% in Belgium, [93]) , a rise of 1.9% is inflicted on the remaining households.

Finally, with an installed capacity of 10.9 GW_p, 5.5% of the total PV production is curtailed resulting in insufficient emission reductions. The capacity should be around 11.9 GW_p (with a curtailment of 7.7%) to be able to reach the target. The resulting rise in electricity bill would be 3.90 EUR/MWh on average. Supposing precarious households are exempted of any rise, the remaining, non PV-owners, see a rise in electricity billing price of 2.3% or 24 $EUR/year$ for an average household.

The issues of PV power are the curtailment and the utility net cost. Both rise with increasing PV capacity. In the coming years, the ERT could be importantly stepped up to mitigate even more the effects of global warming. In that case, the negative effects of decentralized PV will be emphasized. As a result, policy-makers could harden the environment for prosumers to reduce the losses endured by the utilities, putting at risk the economic viability of the PV systems. Storage systems could in theory temper curtailment by increasing self-consumption, meaning ERT can be reached with lower PV capacities. The question is whether the effect on the utility net cost will be positive or negative.

B What if we add daily storage systems?

B.1 Model Input

In Chapter 2, Section D.2 it was concluded batteries' characteristics are best adapted for day-to-day storage. To comply as much as possible with the reality, two different battery technologies are used, differentiating small scale (S) and large scale (L) systems. The reference for S is the Tesla Powerwall 2 and for the L the Samsung SDI, Module ER-MO90. The latter is used for storage systems up to 6 MWh [94]. The battery-packs have an in-build inverter. The inverter losses are comprised in the charging and discharging efficiencies. The capital cost (c_S) includes installation costs.

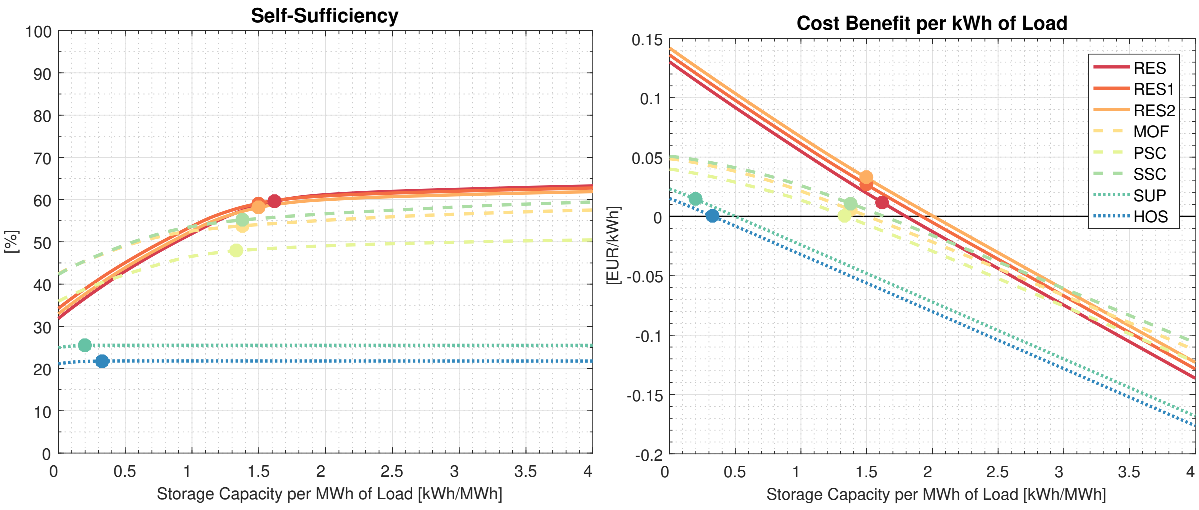
		Scale			
Category	*Symbol*	S	L	*Unit*	*Sources*
Type	/	NMC^1	LMO^2	[/]	[94, 95]
Power	PER	0.35	0.5	$[kW/kWh]$	[94, 95]
Losses	η_{chg}	90	"	[%]	[94, 95]
	η_{dis}	90	"	[%]	[94, 95]
	SDR	2	"	[%/month]	[94, 95]
Lifetime	DOD	90	80	[%]	[94, 95]
	$LT_{S,cy}$	$3{,}200^3$	6,000	[cycles]	[79, 94]
	LT_S	10	"	[years]	[79, 94]
	RC	70	80	[%]	[79, 94]
Cost	c_S	500	450	$[EUR/kWh]$	[96, 97]
	d_S	3.5	"	$[\%/year]$	[97]
Emissions	LCA	0.26^4	"	$[kgCO_2/kWh_{dis}]$	[98]

Table 3.9: $^1LiNiMnCoO_2$. $^2LiMn_2O_4$. ^{3}Assuming the battery pack will have 70% of its original capacity by the end of its warranty and the degradation in its capacity will be linear. This gives an average of 11.81 kilowatt-hours per cycle and 37,800 kilowatt-hours divided by that amount gives 3,200 cycles [8]. ^{4}The value of the LMO-type battery was taken for both.

B.2 Model Output

System-owner level: self-sufficiency and cost

As in Chapter 2 the self-sufficiency and total system cost are plotted for battery storage capacities ranging from 0 to 4 kWh/MWh (Figure 3.7).



(a)

(b) Cost benefit compared to usual grid consumption (without PV and storage).

Figure 3.7: Characteristics of Li-ion battery.

Industrial-size installations have a low interest in storing electricity. Recall, SUP and HOS have very high SC rates (Table 3.3). This means almost no energy is left over for storage. Taking storage losses into account, the overall increase in SC (and thus SS) is negligible. Due to the small available area, the resulting self-sufficiency is low (below 25%) even with storage systems.

Self-sufficiency of R and C reach an almost horizontal asymptote indicating the capacity needed for daily storage. The cost benefit decreases (almost) linearly for every kWh of storage capacity added. Self-sufficiency of MOF, PSC and SSC is relatively high at low storage capacity due to the load profiles' important capacity credit. Storage has a lesser effect on self-sufficiency for C due to the undersized PV system.

Naturally the question of how Figures 3.7(a) and 3.7(b) can be related comes up. In other words, what does it cost to increase self-sufficiency by 1% with storage systems? Figure 3.8 shows the total cost of the system per kWh of energy discharged from the storage system. The lower this cost, the higher the storage's cost effectiveness. The dots on the figure represent the minimum value for each building type. The results are similarly plotted on Figure 3.7. SUP and

HOS pay a relative high price for 1 kWh discharged energy, consolidating the observation above. C and R all reach a minimum at more or less 1.5 kWh/MWh.

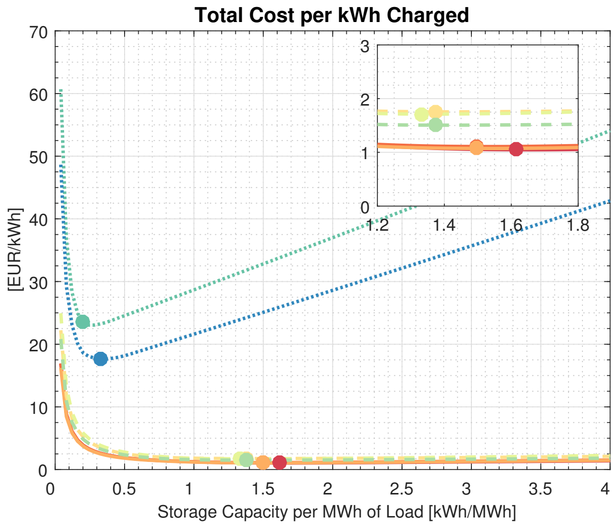


Figure 3.8: The dots indicate minimum values.

The solutions, indicated by the dots, are financially beneficial to all type of owners 3.7(b). This is not surprising. The cost of Li-ion batteries is predicted to decrease rapidly in the coming years and meanwhile electricity billing prices increase year by year.

Summing those results (supposing HOS and SUP have zero storage capacity) for all installations, a total amount of discharged energy equal to 1.95 TWh is found. Adding to this 5.33 TWh immediately self-consumed (Table 3.5), the overall self-consumption of the PV park rises by almost 20 points (from 51% to 70%). The average cost benefit for the system-owners is almost 22 EUR per MWh consumed.

Symbol [Unit]	*Residential*			*Commercial*			*Industrial*		*Total*
	RES	RES1	RES2	MOF	PSC	SSC	SUP	HOS	
C_{-} $[EUR/MWh]$	11.9	27.2	32.8	5.9	0.4	11.1	24.0	15	$(21.9)^1$
${KS_{opt}}^2$ $[kWh]$	4.3	5.5	7.0	210	315	470	0	0	13.6×10^6
$E_{PV,dis,tot}$ $[TWh]$	1.60			0.35			0		1.95
SC_{avg} [%]	58.5			79.2			96.9		70.1

Table 3.10: ^{1}Average value ^{2}Optimal capacity per installation; total is summed over all installations.

Utility level: UNC

The solution described above has an impact on its surroundings. The next step of this analysis is to assess this impact. Just like the previous section, the total bill reduction, PV integration costs and avoided costs are computed. The outcome for every building type is illustrated in Figure 3.9. Comparing with Figure 3.6 an evident increase of the negative effects relative to the positive effects is observed, in other words, an increase of the net costs. This corresponds to the conclusions from Ref. [83]: "*Higher prosumage shares (self-consumption) lead to increasing system costs*". The only positive effect of higher SC, is a 15%-reduction of PV integration costs compared to the previous case.

The independence from the grid gained through the storage system increases the bill reduction drastically while the only increase in avoided costs comes from the lowered net electricity generation on utility side, the decrease of net emissions and the appearance of capacity replacement. The latter effect is caused by the discharge of energy at peak load, resulting in a 130 MW capacity replacement. Also PV integration costs have slightly decreased due to the fewer interactions with the power grid (see Appendix A.10 for more details).

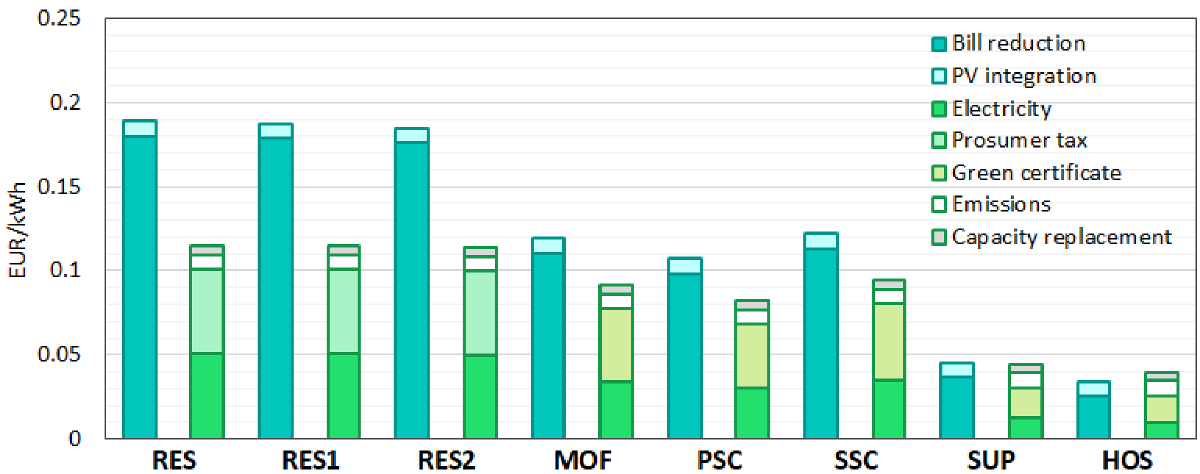


Figure 3.9: text

The potential rise of electricity bill for all consumers was around 3.10 EUR/MWh for the zero-storage case. This new solution more than doubles the rise to **6.35 EUR/MWh** on average for all consumers. Suppose now this rise is reported to each subcategory by using a weight according to its electricity billing price (values in Table 3.2, result in Table 3.11). $C_{-} - c_{G+}$ describes the remaining cost benefit. The economic balance remains positive for R, SSC and I. For MOF, the system reaches grid parity and for PSC the system is not interesting economically.

Symbol [Unit]	*Residential*			*Commercial*			*Industrial*	
	RES	RES1	RES2	MOF	PSC	SSC	SUP	HOS
w		1.33			0.93		0.66	0.54
c_{G+} $[EUR/MWh]$		8.45			5.91		4.19	3.43
$C_- - c_{G+}$	3.45	18.75	24.35	0.00	-5.51	5.60	19.81	11.57

Table 3.11

National level: GHG emissions

Simply put: more storage means less curtailment and thus less GHG emissions. The solution above cuts the assumed curtailment by more than half, from 0.57 TWh to 0.26 TWh. As a result, the total reduction in emissions increases from 2.72 to **2.86 $\mathbf{MTCO_2}$**, almost reaching the 3 $MTCO_2$ target.

B.3 Conclusion

Summary of the results

- Installing small scale storage lowers the financial gains for all building types;
- The optimal storage capacity in terms of total cost per kWh of discharged energy is around 1.5 kWh/MWh for all but industrial installations. The latter have no interest in storing electricity due to high self-consumption figures;
- The effect of a nation-wide distribution of the above mentioned solution on the net utility cost is negative. As a result, the electricity billing price increases from 3.10 EUR/MWh to 6.35 EUR/MWh;
- Reporting this increase on PV-owners pushes the financial balance on the negative side for PSC-type load profiles.
- A second effect of big scale distribution is the lowering of net GHG emissions. Adding 13.6 GWh of daily storage allows a reduction of 0.14 $MTCO_2$ compared to the initial scenario, reaching 95% of the ERT.

Discussion

Adding decentralized small scale storage to the existing PV infrastructure has positive and negative effects.

First of all, the owner's financial benefits decrease as expected. But, installing the storage systems with the highest cost effectiveness (i.e. the lowest cost per kWh of discharged energy) is still viable for all building types. As a result, a total decentralized capacity of 13.6 GWh is installed. Average self-consumption increases from 51% to 70%.

To the question, will utilities benefit from decentralized storage systems installed by building owners, the answer is no. Decentralized small scale storage systems actually double the cost for utilities due to the higher increase in bill reduction compared to avoided costs. In a similar fashion to the previous section, the total rise in electricity billing price for remaining and non-precarious households is computed. The result is a 3.8% increase meaning an average households will pay an extra 40 EUR per year. At this rate, households struggling to pay electricity bills will soon fall under the energy poverty line, compromising the sustainability of this solution.

Hospitals without PV infrastructure see their electricity bill rise by 3%. An extra 10,000 EUR per year has to be spent on electricity. Knowing almost one out of three general hospitals in Belgium had a negative current income in 2016 [99], this extra cost, even though relatively small, may cause financial damage.

The positive effect of increased storage is the lowering of solar energy curtailment from 5.5% to 2.5% resulting in an emission reduction reaching 95% of the ERT. But storage does not come at a zero-emission cost. Li-ion batteries for example use materials like iron, copper, nickel and cobalt which are mostly extracted in Asian or African countries (the Democratic Republic of Congo is known for cobalt mining). Mining in those countries have important environmental and human impacts [100, 101]. Including the battery's life-cycle emissions, taken from Ref. [98], result in an extra emission due to the storage systems of 0.52 $MTCO_2$. The net reduction in emissions is now 2.32 $MTCO_2$, which is *lower than in the PV-only case*, i.e. 2.71 $MTCO_2$.

Could utilities benefit from investing themselves in decentralized storage systems? If the investment is not done by building owners, the net utility cost would simply be lowered to the PV-only level while maintaining the reduction in GHG emissions. A total investment of approx. 13 billion EUR is necessary to install 13.6 GWh of decentralized storage capacity, taking into account economies of scale. The total avoided cost for the electric utility over the entire 20 year period amounts to approx. 5 billion EUR or 40% of the investment. If the electric utilities aim to 'gain' as much as they invest, a total storage capacity of approx. 5.4 GWh should be installed. Supposing the remaining storage capacity (8.2 GWh) is installed by the building owners, then the net utility cost is lowered to 5.05 EUR/MWh.

On the first sight, the answer to the question, should Belgium count on daily storage to *sustainably* reach the ERT, would be yes. Daily storage is affordable and lowers the need for curtailment by half closing the gap with the ERT. Looking slightly deeper into the effects of large scale decentralized storage, the answer is not so positive anymore. Socio-economically, the net utility costs increase even when utilities themselves invest in storage systems. Environmentally the net GHG emissions increase due to the battery's life-cycle emissions. The question remaining is whether increasing self-consumption even more with a long term storage technology could have a positive economic, environmental and/or social impact.

C And seasonal storage systems?

C.1 Model Input

The next step of this analysis is the addition of a seasonal storage system to the above described system (with daily storage).

Regarding the type of seasonal storage, the choice fell on hydrogen fuel cell storage. It is made up of three different devices : the electrolyzer, the storage vessel and the fuel cell. The first transforms electric energy into hydrogen through electrolysis. The hydrogen gas is then compressed and stored in a tank and finally consumed by the fuel cell to produce electricity at the right moment. Each device converts one form of energy into another with a certain efficiency.

In this analysis an alkaline electrolyzer combined with a 30 *bar* hydrogen tank and a PME fuel cell are used. The corresponding characteristics are given below.

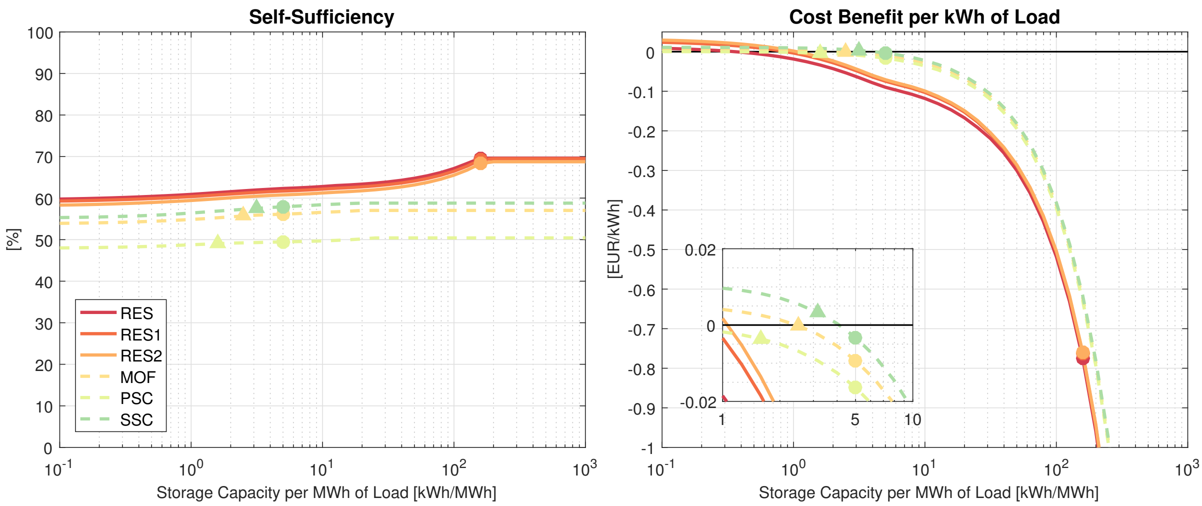
		Scale			
Category	*Symbol*	S	L	*Unit*	*Sources*
Power	PER	0.08	"	$[kW/kWh]$	[52]
Losses	η_{chg}	70	"	[%]	[52]
	η_{sto}	89	"	[%]	[52]
	η_{dis}	47	"	[%]	[52]
	SDR	0.01	"	[%/month]	[102]
Lifetime	CLT	1500	"	[cycles]	[52]
	SLT	20	"	[years]	[52]
Cost	$c_{S,1}$	90	80	$[EUR/kWh]$	[103]
Emissions[1]	LCA_{chg}	0.003	"	$[kgCO_2/kWh_{dis}]$	[104]
	LCA_{sto}	0.010	"	$[kgCO_2/kWh_{dis}]$	[104]
	LCA_{dis}	0.026	"	$[kgCO_2/kWh_{dis}]$	[105]

Table 3.12: RC and DOD are specific to battery storage systems. For hydrogen storage they are both put at 100%. [1] *Values converted from specified sources using LHV of* H_2.

C.2 Model Output

System-owner level: self-sufficiency and cost

Once again the outcome of the model is presented by showing the self-sufficiency and net financial benefit per kWh of load (Figure 3.10). The values for SUP and HOS were not plotted in compliance with the conclusions from the previous section. Similar to the daily storage, an increase of self-sufficiency and a decrease of net financial benefit with increasing storage capacity is observed. The difference is a relative low increase of self-sufficiency and a relative high decrease of cost benefit. The latter is explained by the size of the storage system rather than its capital cost. Regarding self-sufficiency, the increase is low due to the high losses of the system. As seen in Chapter 2, the PV capacity should be over-sized to reach higher self-sufficiency rates.



(a)

(b) Cost benefit compared to usual grid consumption (without PV and storage).

Figure 3.10: Characteristics of hydrogen storage.

Similarly to the previous section, the total cost per kWh of energy charged is plot (Figure 3.11). The result is zero seasonal storage capacity for R and small storage capacities for C (see triangles Figure 3.11). This scenario is almost exactly equal to the previously analyzed scenario, so its result would not be of much interest. For this reason, this section will rather emphasize on the effects of SC maximization with the initially installed PV infrastructure. The solutions for maximum SC are indicated by the colored dots. The exact values and the corresponding self-consumption and cost benefits are given in Table 3.13. Notice self-consumption is not at 100% even though all the PV production that is not immediately self-consumed is charged in the storage system. But due to storage losses, only a portion of this charge gets out, impacting the overall self-consumption.

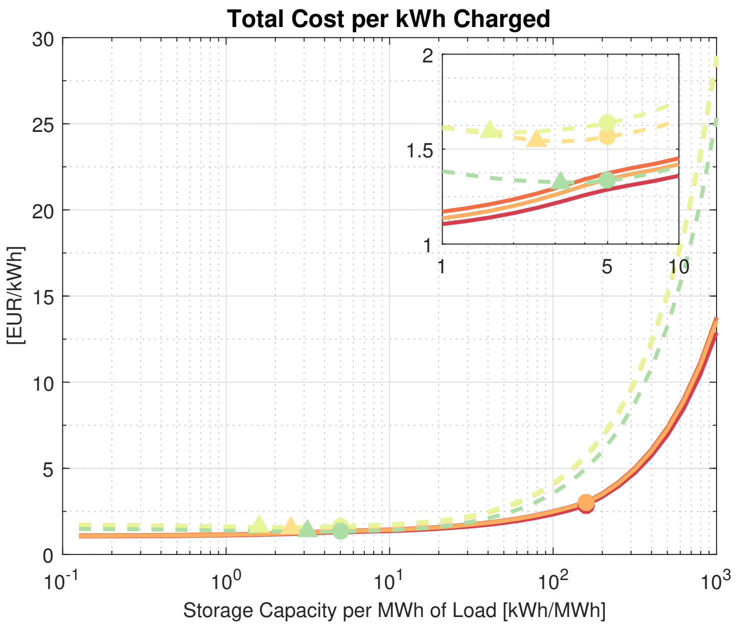


Figure 3.11: Triangles indicate the minimum value. Dots indicate the value procuring maximum self-consumption.

As expected, this solution is not affordable for R. It pays approximately 7 cents more for each kWh than in the grid-only scenario. C need a relative smaller storage capacity than R to maximize SC. This is due to the undersized PV capacity. The resulting cost benefit is only slightly lower than in the previous scenario. I remains unchanged.

The total discharged energy rises by almost 1 TWh (from 1.95 TWh with daily storage only to 2.89 TWh). In other words, seasonal storage has half the effect on total discharge daily storage has. Consequently, self-consumption rises by 10 points compared to the previous case.

Symbol [Unit]	*Residential*			*Commercial*			*Industrial*		*Total*
	RES	RES1	RES2	MOF	PSC	SSC	SUP	HOS	
SS_{max} [%]	69.6	69.2	68.3	56.1	49.5	57.9	25.5	21.8	45.3
C_{-} [EUR/MWh]	-770	-762	-759	-9.3	-16.4	-3.3	24.0	15.0	(16.0)[1]
$KS_{opt}{}^{2}$ [kWh]	420	580	740	770	1180	1710	0	0	1.0×10^{9}
$E_{PV,dis,tot}$ [TWh]	2.19			0.65			0		2.89
SC_{avg} [%]	67.9			94.4			96.9		80.0

Table 3.13: [1] Average value [2] Optimal capacity per installation; total is summed over all installations.

Utility level: UNC

Figure 3.12 shows seasonal storage simply reinforces the evolutions observed with short term storage. The net utility cost is bigger. Only the capacity replacement does not increase, it stagnates at 130 MW. The cost of integrating PV power is now at 7.35 EUR/MWh, an almost 30% decrease compared to the PV-only case (10.25 EUR/MWh).

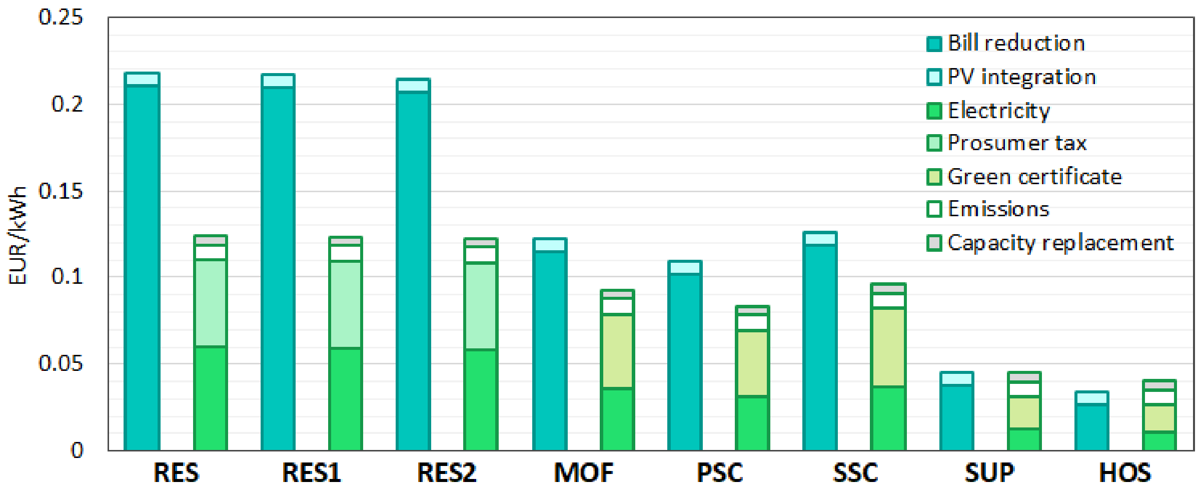


Figure 3.12

The potential rise of electricity bill for all consumers in this new case is **7.90 EUR/MWh**, only slightly higher than the previous case. While PV-owners are already heavily penalized by their own capacity (see Table 3.13), this value does not make an important difference on their overall electricity bill (see Table 3.14). For the remaining electricity consumers, the increase is relatively important. R are penalized by a rise of 5.4% relative to the grid-only situation, C and I of approximately 4%.

Symbol [Unit]	*Residential*			*Commercial*			*Industrial*	
	RES	RES1	RES2	MOF	PSC	SSC	SUP	HOS
w		1.33			0.93		0.66	0.54
c_{G+} $[EUR/MWh]$		10.51			7.35		5.21	4.27
$C_{-} - c_{G+}$	-780.5	-772.5	-769.5	-16.65	-23.75	-10.65	18.80	10.73

Table 3.14

National level: GHG emissions

Maximizing self-sufficiency has a positive effect on GHG emissions. Indeed, high self-sufficiency means less curtailment so less emissions. In this case, curtailment drops to 9 MWh (0.015% of the PV-only value). This is the sole effect of the industrial installations. While this is negligible, it can confidently be stated that the ERT is reached with a total reduction of **3.0 $\mathbf{MTCO_2}$**.

C.3 Conclusion

Summary of the results

- To maximize self-sufficiency (which is limited due to the available PV-capacity), the commercial-type buildings should, in addition to the daily storage of ca. 1.5 kWh/MWh, install a storage capacity of approximately 5 kWh/MWh and residential-type buildings, 150 kWh/MWh.
- Installing long term storage (with hydrogen fuel cell storage characteristics and price) has no financial interest for the considered buildings.
- The effect of a nation-wide distribution of the above mentioned solution on the net utility cost is less negative than the effect of daily storage only. The cost increases from 6.35 EUR/MWh (daily storage solution) to 7.90 EUR/MWh;
- Maximizing SC with hydrogen storage permits to reach the ERT of 3 $MTCO_2$.

Discussion

To the question, should Belgium count on decentralized short and long term storage to sustainably reach the ERT, the answer is the same as in the previous section. Indeed, adding long term storage and maximizing self-consumption mostly emphasizes the effects of short term storage.

First, hydrogen storage is not an entirely mature technology, especially at household-level. Its cost is not forecast to decrease in the following years. As a result, maximizing self-consumption in households or commercial buildings is not interesting financially.

The only beneficial effect of maximizing SC for electric utilities is a decrease of PV integration costs. For the rest, the increase in bill reduction results in a negative cost balance on utility side for all buildings except hospitals. But this positive effect is not sufficient to overcome the financial losses in the other subcategories.

Maximizing SC is the only way of really achieving the ERT. But taking into account the life-cycle emissions of the storage systems, the net reduction in emissions drops to 2.45 $MTCO_2$ (0.52 $MTCO_2$ from batteries, 0.03 $MTCO_2$ from hydrogen storage).

To conclude, the ERT is reached, but it comes at a heavy cost for the system owners and the utilities. Also, even without PV injection on the grid the utilities' cost balance remains negative. The only remaining option to reduce net costs and simultaneously reach ERT targets may be the maximization of SS by oversizing the PV capacity or in other words, go off-grid (see Appendix A.11).

Chapter 4

Conclusion

A Summary

The objective of this research consisted in evaluating the potential of decentralized solar power production in Belgium. To maximize the possibilities, the evaluation was done in eight different types of buildings and using both day-to-day and seasonal storage. Three parameters were evaluated: total cost of the system, net GHG emissions and resulting cost of electric utilities.

In a first step, linear optimization was used to find the least-cost solution for each type of building in an environment closely imitating Belgium's case. It was found all buildings reach a minimum overall cost by investing in photovoltaic panels and using the power grid as back-up. Storage systems do not appear in this optimal solution. Industrial type buildings cannot exploit the full potential of decentralized solar power due to the restricted available surface. Commercial buildings in Belgium are better off with an undersized solar power system. Residential buildings can fully exploit the net-metering system with a solar power capacity matching their yearly load, even when subjected to prosumer taxes.

The eight different models were then aggregated and scaled to match the 2030 emission reduction targets set by Belgium after the Paris Agreements. In the first instance, a total solar power capacity of almost 11 GW_p was deemed sufficient to reach the target, i.e. reduce yearly emissions by 3 million tons of $CO_{2,eq}$ equivalent.

Using the scaled models though, a curtailment of 5.5% of the produced solar power is found. This reduces the overall reduction to 2.7 million tons of $CO_{2,eq}$, a gap of 10% with the emission reduction target. The nationwide scaling of decentralized production also triggers a rise of electricity billing prices. This is an indirect effect of the prosumers paying a lower price for an increased utilization of the grid. The rise amounts to 3.10 EUR/MWh on average for all electricity consumers in Belgium. Households which are not on a social tariff pay the highest price with an increase of almost 2%.

The question whether storage systems could bring something to the table was next. The previous analysis already indicated storage systems are not part of the optimal solution but this conclusion was only based on the building owners' point of view.
First, Li-ion batteries were used for small scale storage. The systems were optimally sized by using a measure of the total cost per energy unit discharged. Minimum values are found for storage capacities of 1.5 kWh per MWh of load in the case of residential and commercial buildings. Investing in such systems reduces the net financial benefit but not sufficiently to turn into negatives. Decentralized solar power production in combination with daily storage is thus financially interesting for households and commercial-type buildings. Industrial buildings have no interest in storing while the undersized solar power capacity does not provide sufficient energy surplus for storage, i.e. self-consumption is high.

Scaling the new models to the emission reduction targets, a total storage capacity of 13.6 GWh is installed in the entire country. This reduces curtailment to 2.5% and GHG emissions by 0.14 million tons of $CO_{2,eq}$, closing the gap with the emission reduction target to only 5%. The price to pay for this is a doubling of the increase in electricity billing price, from 3.10 EUR/MWh to 6.35 EUR/MWh on average. Households not benefiting from social tariffs now pay an extra 40 EUR per year (3.8%) on their electricity bill.

Finally, seasonal storage is added in the mix to maximize self-consumption of solar power. A combination of electrolyzer, hydrogen tank and fuel cell is used for this purpose. The resulting cost is economically viable for none of the building types. On a positive note, the emission reduction target of 3 million tons of $CO_{2,eq}$ is reached, but the average rise in electricity billing price reaches 7.90 EUR/MWh for all electricity consumers. Even when zero solar power is injected on the grid, utilities pay an important price to back-up prosumers when nor solar power nor discharged energy from their storage system is available to them.

B Conclusion

To the question, should Belgium count on decentralized production and storage to achieve its emission reduction targets, the answer is partially yes.

Simply increasing solar power capacity to bridge the losses due to curtailment and as such reach the emission reduction targets is, relatively, the least expensive solution, both for system owners as electric utilities. An extra 10% of solar power capacity would be needed bringing the rise of electricity billing price for households to 2.3%.

When system owners decide to install daily storage systems in the form of Li-ion batteries, the emission reduction target can be reached with an increase in solar power capacity of only 5%. But the increased self-consumption leads to an even bigger net cost for electric utilities, even when the latter decide to invest in storage systems themselves. Also, when taking into account life-cycle emissions of Li-ion batteries, this solution is even worse than if only solar power is installed.

Maximizing self-consumption with seasonal storage simply emphasizes the tendencies observed with day-to-day storage.

As a conclusion, we state decentralized solar power is a good path to follow for reduction in GHG emissions in the next twenty years if the policymakers take the financial gap created by PV owners into account. Day-to-day and seasonal storage are effective in reducing and even removing solar power curtailment and by such reducing net GHG emissions. But, as of today, the systems' capital costs are still too high for building owners and electric utilities to gain any economic profit from it, even when taking into account the forecast decrease in costs for the next 20 years.

C Discussion

The first issue that may compromise the validity of the results is the 'simplicity' of the input data. About load profiles specifically, it was stated in Chapter 2 that hourly and theoretical load curves smooth out high power peaks leading to overestimated outcomes. But comparison with existing scientific literature showed this overestimation was relatively low. Also, when computing results on a scale as big as a nation, it is not abnormal to smooth out high load peaks. Indeed, when aggregating many load profiles, non-coincident peaks and valleys in the load profiles of individual customers tend to offset one other. This dampening effect results in a flatter overall load profile [106]. Still, it is hard to imagine one could realistically model a nationwide PV market with only eight different load profiles. An analysis using empirical data is necessary to lift this uncertainty.

The extrapolation of a single solar irradiation curve to all type of buildings on the entire PV market brings up the question of spatial variability. Indeed, having exactly the same irradiance at all hours on a territory of 30,000 km^2 is not realistic. Different parts of the country have different weather conditions at the same time, especially in a one hour time span. So, when aggregating irradiance over an entire country the overall curve is usually rather smooth (cf. aggregated load profiles). This is demonstrated for Réunion in Ref. [107]. As a result, the total curtailed energy may be overestimated. Because peak load happens during dark hours, this does not alter the values for capacity replacement.

Also the annual variability of irradiation data and load data are neglected in this analysis. The data is supposed to repeat itself in the exact same manner for the entire considered period (20 years). Concerning load data this assumption is not far off. For irradiation data, as stated before, it is hard to predict. Forecasting models and stochastic optimization should be used to include predictable and unpredictable climatic externalities influencing solar irradiance.

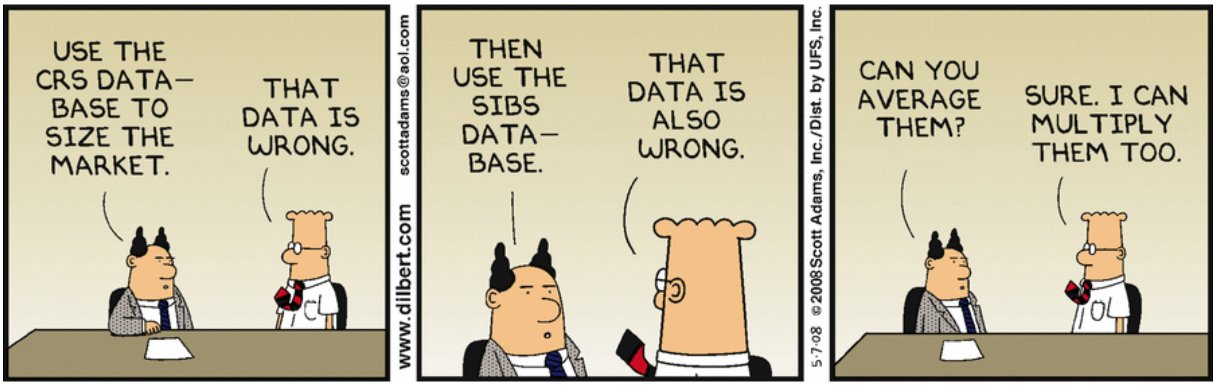


Figure 4.1: Taken from `http://dilbert.com/strip/2008-05-07`

In general, the exact value of the results is not what matters most in this report. More precise data and a more complex model should be used if the goal is to come up with accurate results. This report rather focuses on how some general solutions compare on average in the light of different criteria. A more comprehensive approach would have been to use ranges of values and probability distributions to identify average and extreme values more accurately.

D Possible Improvements

Some ideas have already been brought up in the section above. First, including predictable and unpredictable factors into the optimization program would offer more robust solutions. Secondly, robustness could also be improved if a broader range of values is used for each parameter (including load and irradiance data), paired with probability distributions. Third, it could be interesting to evaluate the effects of technology modeling precision (e.g. use accurate ageing effects of battery storage technologies). Fourth, adding grid-related losses and simulating voltage rises due to over-injection of PV in one location would offer a better idea of the advantages or disadvantages of decentralized storage. In this model everything is included in a single PV integration cost.

E Future Research

A multitude of possibilities lie ahead to build on this research. First, one could add a second type of decentralized energy production and storage, namely thermal energy. Only small changes to the model are needed to include a second type of production technology. Secondly, it could be interesting to optimize on the EROI rather than on costs. This could lead to, for example, an analysis comparing the energy-effectiveness of a grid-tied system and an off-grid system in households. Third, centralized storage should be compared with decentralized storage solutions in terms of cost, GHG emissions, net utility cost and energetic losses. Also, a research focusing on grid policies could help regulators find a way to encourage investment in renewable energies and storage without making huge financial losses. It could also be interesting to evaluate new types of grid structures like micro-grids or community production and storage with virtual net-metering through the three sustainability criteria.

F Acknowledgments

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Appendices

Appendix A

A.1 Definition of sectors

Electricity Production	Sum of emissions from public electricity generation, i.e. whose primary goal is to supply the public. Autoproducers are consequently not included.
Residential Plants (heating)	All emissions from fuel combustion in households
Commercial Plants	Emission from fuel combustion in commercial and institutional buildings.
Combustion in Agriculture, Forestry and Fishing	Emissions from fuel combustion in agriculture, forestry, or domestic inland, coastal and deep-sea fishing. This includes traction vehicles, pump fuel use, grain drying, horticultural greenhouses and other agriculture, forestry or fishing related fuel use. Highway agricultural transportation is excluded.
Petroleum Refining	All combustion activities supporting the refining of petroleum products.
Manufacturing Industries and Construction	Emissions from combustion of fuels in industry including combustion for the generation of electricity and heat.
Cars	Automobiles designated primarily for transport of persons and having a capacity of 12 persons or fewer.
Light Duty (LD) Trucks	Vehicles with a gross vehicle weight of 3900 kg or less designated primarily for transportation of light-weight cargo or which are equipped with special features such as four-wheel drive for off-road operation.
Heavy Duty (HD) Trucks and Buses	Any vehicle rated at more than 3900 kg gross vehicle weight or designed to carry more than 12 persons at a time.

Table 1: Information from Ref. [9].

A.2 Storage cost coefficient computation

We define the reinvestment factor as follows.

$$r_f = \frac{FCE \cdot puc}{LT_{S,cy}} = \frac{\eta_{chg} E_{S,chg} \cdot puc}{K_S} \frac{1}{LT_{S,cy}} \tag{1}$$

$r_f < 1$means the cycle lifetime has not been reached during the period under consideration (PUC, y). $r_f > 1$ means the cycle lifetime has been exceeded during the PUC. The total amount of years the storage system is usable in those conditions is then:

$$LT_{S,cy}(years) = \frac{y}{r_f} \tag{2}$$

The reinvestment vector then becomes

$$r = [0, 1, 2, ...] \cdot LT_{S,cy}(years) \tag{3}$$

Remembering $r(end) \leq y$, so if $LT_{S,cy}(years) = 12$, $r = [0, 12]$ (not $r = [0, 12, 24]$ for example).

We can now compute the first part of the storage coefficient:

$$C_{S,cy,INV} = \sum_{k=1} \frac{c_S}{(1+d)^{r(k)}} \tag{4}$$

The negative part of the coefficient, i.e. the remaining value after the PUC, can be computed as follows.

$$prem_{cy} = \frac{LT_{S,cy,REM}(years)}{LT_{S,cy}(years)} = \frac{r(end) + LT_{S,cy}(years) - puc}{LT_{S,cy}(years)} \tag{5}$$

The second part of the storage coefficient then becomes

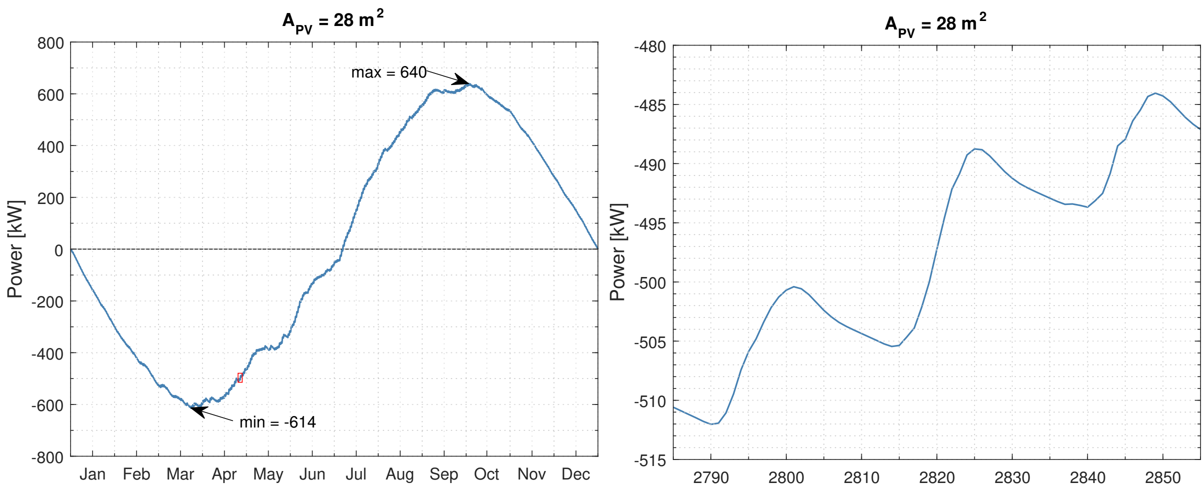
$$C_{S,cy,REM} = \sum_{k=1} \frac{prem_{cy} c_S}{(1+d)^{r(k)}} \tag{6}$$

A.3 100% self-sufficiency storage capacity

We use the cumulative sum of the hourly difference between production and load. If at consecutive hours the production is higher than the load, there is energy available for storage. When, during the following hours, load overpasses production, the previously stored energy is used to 'fill the gap'. As such, the graph of the cumulative sum will help us identify at what moment there is more energy available for storage and at what moments there is a higher demand for stored energy.

$$Y(\tau) = \sum_{t=1}^{\tau}(E_{PV}(t) - E_L(t)) \tag{7}$$

$$K_{S,max} = \max(Y) - \min(Y) \tag{8}$$



(a) Seasonal variation. $K_{S,max} = 640 - (-614) = 1254kWh$. *Red rectangle is detail showed on the right figure.*

(b) Daily variation (3 april days). Detail from left figure.

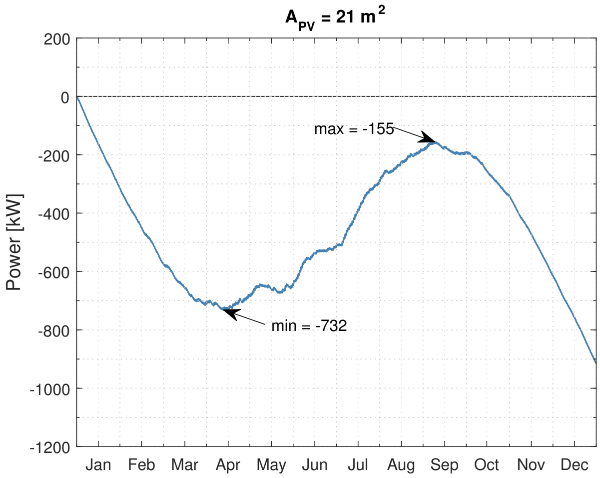
Now if ones total yearly production exceeds its yearly load, some changes need to be made. Indeed, the $Y(\tau)$-curve is vertically stretched (see Figure 3(a)), meaning there is more energy available for storage than there is needed. The equation 7 does not stand anymore, we need to normalize it by adding a balancing term.

$$Y(\tau) = \sum_{t=1}^{\tau}(E_{PV}(t) - E_L(t)) - (\sum_{t=1}^{T} E_{PV}(t) - \sum_{t=1}^{T} E_L(t)) \tag{9}$$

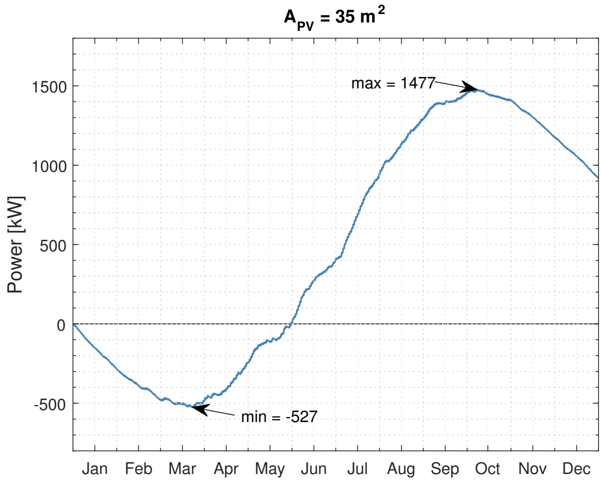
If the total yearly production is lower than the total yearly load (Figure 3(b)), we cannot reach 100% self-sufficiency. We can still compute the maximum amount of useful storage in those cases.

The formula becomes:

$$Y(\tau) = \sum_{t=1}^{\tau}(E_{PV}(t) - E_L(t)) - \max(0, \sum_{t=1}^{T} E_{PV}(t) - \sum_{t=1}^{T} E_L(t)) \tag{10}$$



(a) $K_{S,max} = 1477 - (-527) - (4574 - 3665) = 1095kWh$.



(b) $K_{S,max} = -155 - (-732) = 577kWh$

A.4 Emission intensity per source

Power source	*i*	*EI*
Nuclear	NU	0.016
Natural Gas	NG	0.460
Coal	CP	1.001
Solar	PV	0.046
Wind	WI	0.012
Hydropower	WA	0.004
Biopower	BI	0.018
Import	IM[1]	0.100

Table 2: EI expressed in $kgCO_2/kWh$. Data from Ref. [10]. [1] Import is supposed to be a mix of mostly nuclear and a lesser amount of gas and coal.

A.5 Lithium-ion storage characteristics

Category	*Symbol*	*Value*	*Unit*	*Sources*
Type	/	NMC^1	[/]	
Power	PER	0.35	$[kW/kWh]$	[95]
Losses	η_{chg}	90	[%]	[95]
	η_{dis}	90	[%]	[95]
	SDR	2	[%/month]	[95]
Lifetime	DOD	90	[%]	[95]
	$LT_{S,cy}$	3,200[2]	[cycles]	[79]
	LT_S	10	[years]	[79]
	RC	70	[%]	[79]
Cost[3]	$c_{S,1}$	500	$[EUR/kWh]$	[96]
	d_S	3.5	$[\%/year]$	[97]

Table 3: [1]*$LiNiMnCoO_2$.* [2]*Assuming the battery pack will have 75% of its original capacity by the end of its warranty and the degradation in its capacity will be linear. This gives an average of 11.81 kilowatt-hours per cycle and 37,800 kilowatt-hours divided by that amount gives 3,200 cycles [8].* [3]*All installation costs included.*

A.6 Hydrogen storage characteristics

Category	*Symbol*	*Value*	*Unit*	*Sources*
Type	/	Alkaline electrolyzer	[/]	
	/	30 *bar* storage tank	[/]	
	/	PEM Fuel cell	[/]	
Power	PER	0.08	$[kW/kWh]$	[52]
Losses	η_{chg}	63	[%]	[52]
	η_{dis}	47	[%]	[52]
	SDR	0.02	[%/month]	[102]
Lifetime[1]	$LT_{S,cy}$	1,500[2]	[cycles]	[52]
	LT_S	20	[years]	[52]
Cost[3]	$c_{S,1}$	90	$[EUR/kWh]$	[103]
	d_S	0	$[\%/year]$	[97]

Table 4: [1]*RC and DOD are specific to battery storage systems. For hydrogen storage they are both put at 100%.*

A.7 Normalization of load curves

Name [Unit]	*Residential*			*Commercial*			*Industrial*	
	RES	RES1	RES2	MOF	PSC	SSC	SUP	HOS
Total surface $[m^2]$								
Source	95	195	295	5,000	6,900	10,000	12,500	22,500
BEL avg	/	120	/	4,000	6,500	7,000	10,200[1]	21,000
Choice[3]	130	180	230	2,600	6,700	8,500	7,000	24,000
Load $[MWh/m^2]$								
Source	0.043	0.040	0.036	0.140	0.114	0.228	0.163	0.388
BEL avg	0.030	0.030	0.030	0.065	0.035	0.040	0.292[1]	0.122
Load $[MWh]$								
Normalized	2.665	3.665	4.665	153.3	236.4	341.2	2,036	2,974

Table 5: Belgium averages taken from Refs. [11, 12] (Wallonia) and [13] (Flanders). [1]HH = Household. [2] Average for hyper-markets. [3]In the case of residential-type buildings the choice to take higher-than-average surfaces was made supposing PV-owners statistically have higher incomes and thus a, supposedly, a bigger propriety. In the case of commercial and industrial buildings, the same choice was made in general except for MOF and SUP. For the latter, while the Belgium average is taken for a hypermarket and SUP is actually a supermarket, we slightly decrease the surface. In the case of MOF, the Belgium is average is taken for all office-sizes and not only medium offices. For this reason we slightly lower the surface.

More information on the building characteristics of the base (RES1), high (RES2) and low (RES) load model can be found at `https://openei.org/doe-opendata/dataset/eadfbd10-67a2-4f64-a394-3176c7b686c1/resource/cd6704ba-3f53-4632-8d08-c9597842fde3/download/buildingcharacteristicsforresidentialhourlyloaddata.pdf`. Note that the building characteristics are listed in the "Marine" column, which is the climate corresponding to Bellingham (USA) and Belgium. For commercial and industrial type buildings (MOF, PSC, SSC, SUP and HOS), information can be found at `https://www.energy.gov/eere/buildings/existing-commercial-reference-buildings-constructed-or-after-1980`.

A.8 Solar power potential

The BIPV (Building Integrated Photovoltaics) rooftop potential is described in m^2/cap in Ref. [4]. The following values are given:

Building type	*Potential*
Residential	9.0
Agriculture	3.0
Commercial	2.5
Industrial	2.5
Other	1.0
Total	18 m^2/cap

To comply with the categorization in this report, we suppose agricultural buildings are integrated into the commercial category. The 'other' buildings are distributed equally into the commercial and industrial category. Obtaining a 9 m^2/cap potential for residential buildings, 5.5 m^2/cap for commercial and 3.5 m^2/cap for industrial.

We now take the irradiation data to translate the rooftop-area potential into an energetic potential. The total potential then becomes:

$$E_{PV,pot} = 18 \cdot \sum_t H_t = 2340\ kWh/cap$$

With 11.3 million inhabitants, Belgium has a total potential of 26.4 TWh. Supposing the total energy production is 70 TWh, this corresponds to a PV-penetration level of 37.7%.

A.9 Solar power curtailment

Suppose $P_{base}(t)$ is the power constantly produced at all times t. It is entirely composed of coal and nuclear power. $P_{PV,grid,tot}(t)$ is the total solar power injected on the grid at all times t and $P_{PV,self,tot}(t)$ is the total self-consumed solar power at all times t. $P_{L,tot}(t)$ is the Belgium's total load at all times t. $P_{base}(t)$ and $P_{L,tot}(t)$ are taken from Elia [20].

Supposing all sources except nuclear, coal and solar can be used for balancing, supposing nuclear and coal have no planned or unplanned outages and supposing solar energy is curtailed after wind energy, the curtailed power at all times t is computed as follows.

$$\forall t,\ \texttt{if}\ P_{PV,grid,tot}(t) + P_{PV,self,tot}(t) + P_{base}(t) > TL(t)$$

$$\texttt{then}\ P_{cur}(t) = TL(t) - (P_{PV,grid,tot}(t) + P_{PV,self,tot}(t) + P_{base}(t))$$

$$\texttt{else}\ P_{cur}(t) = 0$$

The total curtailed energy over a year is thus,

$$E_{cur} = \sum_t P_{cur}(t)$$

A.10 Cost of PV integration

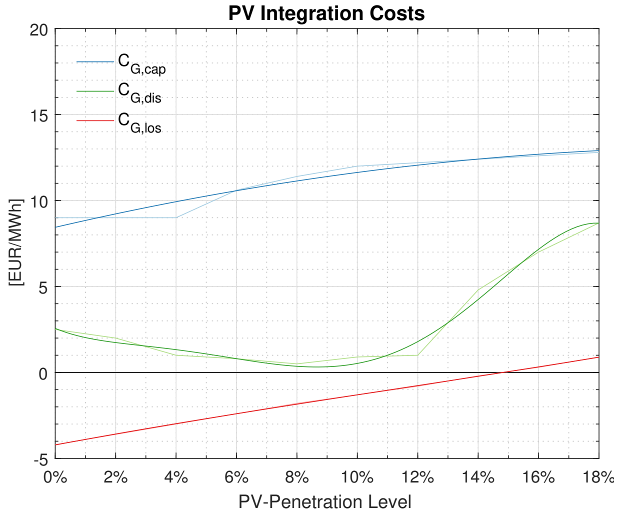


Figure 4: Fitted using polyfit in Matlab. Original data from Ref. [5].

The induced integration costs appear in different areas. They are usually expressed per unit of energy and vary as a function of the solar penetration-percentage. We use [5] to compute integration costs in three well-defined areas explained below. The different costs as a function of the PV-penetration percentage are plotted in Figure 4.

- The additional **system capacity cost**, $C_{G,cap}$. This cost relates to the capacity credit of PV. The latter reflects how well (or bad) a PV plant replaces the existing electricity generators at peak demands. In Belgium, the capacity credit of PV is low, while peak demand occurs in the evening when the sun (and PV production) is low. In the mean time, PV production is responsible for the decrease of the total amount of electricity asked to existing generators. Both factors make that existing generators need to stay open (to secure a constant electricity supply at peak demands), but with a reduced yearly amount of working hours, i.e. a reduced capacity factor. The latter means the capacity cost MWh increases while the cost stays the same, but the amount of energy (MWh) is lower. This is clearly the case with the residual NG plants in the new scenario.
- The additional **distribution network expenses**, $C_{G,dis}$. Increase PV penetration may trigger distribution network problems such as over-voltages due to voltage rise effects, thermal overloading and reverse power flows. In that case, distribution networks need to be reinforced entailing a cost. But the impacts of PV deployment can also be positive (benefits) to the system. For example, PV may release some capacity of the network allowing load growth without necessarily incurring network investment.

- The cost of **electricity losses** contributed by PV, $C_{G,los}$. Other benefits PV may bring to distribution networks is the reduction of traffic, and as such reduce network losses. This cost is thus often expressed in negative terms, meaning it is a benefit.

Each cost can be related to one of the power flows identified earlier in this report. The system capacity costs is directly applied to the power supplied from the grid, $P_{G,tot}(t)$. The two remaining costs are induced by the PV power fed into the power grid, $P_{PV,grid,tot}(t)$. The formula for the total cost of integration is thus known.

$$C_{G,int}E_{PV,tot} = C_{G,cap}E_{G,tot} + (C_{G,dis} + C_{G,los})E_{PV,grid,tot} \tag{11}$$

A.11 Bonus: What if households go off-grid?

The technologies used to go off-grid are the exact same as the ones used in the rest of the analysis. As the title of this section tells, only RES, RES1 and RES2 are going off the grid. The other buildings can not go off-grid due to the insufficient available surface.

Symbol [Unit]	*Residential*			*Commercial*			*Industrial*		*Total*
	RES	RES1	RES2	MOF	PSC	SSC	SUP	HOS	
C_{-} $[EUR/MWh]$	-2,090	-2,270	-2,365	52.0	45.0	55.0	24.0	15.0	(-806)
A_{PV} $[m^2]$	45	60	75	791	1,072	1,839	4,000	5,000	133×10^6
$K_{S,B}$ $[kWh]$	7.18	9.47	12.86	0	0	0	0	0	17.15×10^6
$K_{S,H2}$ $[kWh]$	1160	1676	2237	0	0	0	0	0	3.0×10^9
$E_{PV,tot}$ $[TWh]$		13.4			1.97		2.10		17.43
$E_{PV,self,tot}$ $[TWh]$		2.12			1.21		2.02		5.35
$E_{PV,grid,tot}$ $[TWh]$		0			0.76		0.08		0.84
$E_{PV,spil,tot}$ $[TWh]$		1.91			0		0		1.91
$E_{S,dis,tot}$ $[TWh]$		3.95			0		0		3.95

Table 6

The outcome of the model is summarized in Table 6. As expected, the total cost for residents is extremely high. Per MWh consumed, the household pays approx. 2,500 EUR, and this during 20 years. This is a 9,000% increase in the household's electricity expenses compared to the on-grid situation (and without PV and storage).

Regarding the PV-production, due to the over-sizing of the PV capacity in households the total area covered with PV rises from ca. 80 km^2 to ca. 133 km^2. In terms of capacity, 18 GW_p is reached. This is just like Elia's decentralized scenario in Ref. [92]. Also, it remains under the potential development computed in Section A.2, so in theory, an acceptable solution. This over-sizing also results in an increase of PV penetration from 15% to 25%. Note that almost 2 TWh has to be curtailed in situ (i.e. spilled), meaning the actual penetration level is around 22%.

The size of the storage systems per household are in the range of what is expected (and accepted) [47]. But sum the capacities over the entire country and it becomes quite another story. The total Li-ion storage capacity needed is 17 GWh and the total hydrogen storage capacity is 3,000 GWh. Those systems yearly discharge respectively 2 TWh and 1.95 TWh. Knowing the Coo-Trois-Ponts pumped-storage hydroelectric power station (water reservoir of around 8,450,000

m^3) yearly discharges 1 TWh of electric energy, it can be concluded that the need in storage capacity is extremely high.

But the most interesting analysis here is the effect of this system on its surroundings. Figure 5 shows the negative and positive effects on the UNC per load type. RES, RES1 and RES2 are supposed off-grid so they create nor negative[1] nor positive effects. For on-grid buildings, the positive effects are more important than the negative effects. Thanks to the investment of the household sector, 1,300 MW of peak capacity is replaced by decentralized PV production and storage. This corresponds nearly to the total TGV (gas-fired power plant) capacity in Belgium: 1,680 MW.

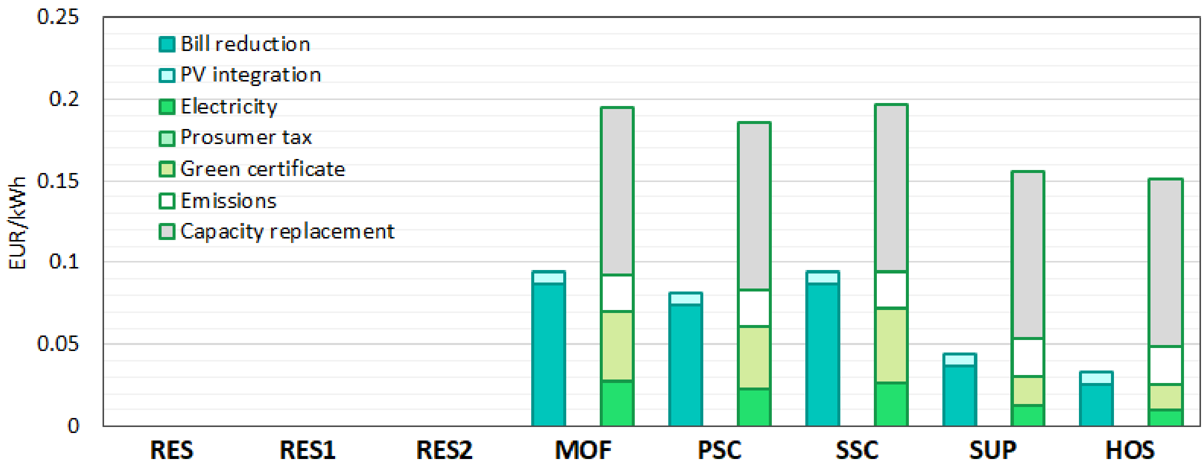


Figure 5

The net utility cost has become a net utility benefit. The total investment of the off-grid households has allowed a *reduction* of the electricity bill for other consumers of **−21 EUR/MWh**. Relative to the initial situation (3.10 EUR/MWh rise in electricity bill), the gain is 25.6 EUR/MWh.

In total, utilities are left with a gain of 40 billion EUR for the entire 20 year period. So what if this gain is used to compensate households for their investment? The utilities' gain amounts to only 15% of the total investment of the household sector (256 billion EUR).

Finally, the total reduction in emissions is **6.33 $\mathbf{MTCO_2}$**. This is more than two times the ERT. Taking into account the LCA of the Li-ion batteries (0.53 $MTCO_2$) and the hydrogen storage systems (0.08 $MTCO_2$), the net reduction is **5.72 $\mathbf{MTCO_2}$**.

[1]This assumption is a bit optimistic. Actually decoupling almost 1.5 million households of the grid most certainly has a cost.

Appendix B Matlab model

The following model has been implementend in MATLAB. It is build up as a function taking as input a serie of demand-, production-, storage- and grid-related parameters (explained later). Its output is the solution of the Linear Programming (LP) function `linprog`.

Contents

1 Model Basics : Input and Output

The function identity is written as follows:

```
function [X,Coeff_KS,Coeff_PV] = model_M_2Gb(...
    MaxIt,y,T,...
    D_t,H_t,...
    LT_PV,A_max,A_min,c_PV,c_PT,y_PT,c_GC,y_GC,d_PV,...
    n_S,eta_chg,eta_dis,SDR,DOD,LT_S,c_S,K_Smax,K_Smin,PER,RC,d_S,...
    c_G,c_EG,G_max,EG_max,SS,FIL,SSbin,NM,NB)
```

1.1 Input

intlinprog options
- `MaxIt` (1x1, []): max. number of iterations done by `linprog` (default value: 80);

general
- `y` (1x1, [years]): period under consideration (general value: 20);
- `T` (1x1, []): length of input data (general value: 8760);

data
- `D_t` (1x `T`, [kWh]): vector containg electricity demand data;
- `H_t` (1x `T`, [kWh/m^2]): vector containg global radiation data;

production
- `LT_PV` (1x1, [year]): lifetime of production unit;
- `A_max/A_min` (1x1, [unit]): maximum and minimum installable production units;
- `c_PV` (1x1, [EUR/kWh]): cost of production unit (installation included);
- `c_PT` (1x1, [EUR/kWh/yr]): prosumer tax;
- `y_PT` (1x1, [year]): duration of prosumer tax;
- `c_GC` (1x1, [EUR/kWh/yr]): green certificates;
- `y_GC` (1x1, [year]): duration of green certificates;
- `d_PV` (1x1, [%/year]): forecast yearly cost decrease;

storage
- `n_S` (1x1, []): number of available storage systems;
- `eta_chg/eta_dis` (1x `n_S`, [kW]): (dis)charging losses;
- `SDR` (1x `n_S`, [%]): charge retention rate (use-independent losses);
- `DOD` (1x `n_S`, [%]): depth of discharge (storage capacity PERcentage present at all time);
- `LT_S` (1x `n_S`, [year]): shelf lifetime (use-independent);
- `c_S` (1x `n_S`, [EUR/kWh]): cost of storage system (installation included);
- `K_Smax` (1x `n_S`, [kWh]): max. storage capacity;
- `K_Smin` (1x `n_S`, [kWh]): min. storage capacity;
- `PER` (1x `n_S`, [kW/kWh]): Power-to-Energy ratio;
- `RC` (1x `n_S`, [%]): Remaning capacity percentage;
- `d_S` (1x1, [%/year]): forecast yearly cost decrease;

grid
- `c_G` (1x1, [EUR/kWh]): electricity price (from grid);
- `c_EG` (1x1, [EUR/kWh]): electricity injection price (to grid);
- `G_max/EG_max` (1x1, [kW]): max. grid capacity (in and out);
- `SS` (1x1, [%]): imposed self-sufficiency;
- `FIL` (1x1, [%]): feed-in limit;
- `SSbin` (1x1, [binary]): binary variable enabling(1)/disabling(0) self-sufficiency constraint
- `NM` (1x1, [binary]): binary variable enabling(1)/disabling(0) net-metering;
- `NB` (1x1, [binary]): binary variable enabling(1)/disabling(0) net-billing;

1.2 Output

- `X` (1x(`n_S`+1+ `n_S*T`)): vector containing the solution of the objective function optimization;
- `Coeff_PV/Coeff_KS` (1x1, [EUR/kWh]: cost coefficient calculated on basis of cost, lifetime and period under consideration;

2 Model Basics: Cost Coefficients

In this model cost coefficients are used in order to include as much different parameters as possible in the optimization. Using only the investment cost (`c_PV` and `c_S`) is not sufficient while they don't take into account the overall lifetime of the installed systems.
All cost coefficients are made up of a positive and a negative part. The positive part entails all the related costs (investment, maintenance, ...). The negative part is best explained through an **example**: considering the period under consideration (puc, `y`) is *20 years* and the lifetime of a production unit is *15 years*. So if a production unit for the complete *puc* is needed a double investment is needed: first at year 0, then at year 15. This is the positive part of the coefficient. The problem is that at year 20, there remains a production unit that could last 10 more years. Thus the negative part of the coefficient is the remaining proportion of the total investment, so 10/15 times the investment cost.
The reinvestment vector `rinv0` is first initialised. It will be used to elect the *reinvestment years*:

```
rinv0 = 0:y-1;
```

2.1 Storage

Prealocation of the coefficient vectors:

```
Coeff_KSneg = zeros(n_S,1);
Coeff_KSpos = zeros(n_S,1);
```

The coefficient is computed for each storage system differently. The index `j` goes from 1 to `n_S`, i.e. the quantitiy of available storage systems.

```
for j = 1:n_S
```

At each iteration the variable LTrem_S is initialised, containing the proportion of remaining lifetime after one period for storage system j.

```
    LTrem_S = 0;
```

Then the reinvestment years are found using rinv0. An example illustrates the computation: if LT_S = 4 years and y = 20. Then *rinv0(1:ceil(y/LT_S))* is a vector of coefficients [0,1,2,3,4] which will be multiplied by LT_S to obtain all the reinvestment years: [0,4,8,12,16].

```
    rinv_S = rinv0(1:ceil(y/LT_S(j)))*LT_S(j);
```

The remaining lifetime after the *puc* is then computed as follows:

```
    if (rinv_S(end)+LT_S(j)-y) > 0
        LTrem_S = (rinv_S(end)+LT_S(j)-y)/LT_S(j);
    end
```

Now the positive part of the coefficient is computed using the investment cost p_S. The vector rinv_S tells how many investments should be made.

```
    for k = 1:length(rinv_S)
        Coeff_KSpos(j,k) = c_S(j)/(RC(j)*(1+d_S(j))^rinv_S(k));
    end
```

Finally, the negative part is computed using LTrem_S

```
    Coeff_KSneg(j) = LTrem_S*c_S(j)/(1+d_S)^y;
end
```

Both coefficients are summed up to obtain the global coefficient for storage systems:

```
Coeff_KS = sum(Coeff_KSpos,2)' - Coeff_KSneg;
```

2.2 Production

The computation for Coeff_PV is similar to Coeff_KS, with one for-loop less because there is only one type of production unit available:

```
LTrem_PV = 0;

rinv_PV = rinv0(1:ceil(y/LT_PV))*LT_PV;

Coeff_PVpos = zeros(1,length(rinv_PV));

for k = 1:length(rinv_PV)
    Coeff_PVpos(k) = c_PV/(1+d_PV)^rinv_PV(k);
end

if (rinv_PV(end)+LT_PV-y) > 0
    LTrem_PV = (rinv_PV(end)+LT_PV-y)/LT_PV;
end
Coeff_PVneg = LTrem_PV*c_PV/(1+d_PV)^y;

Coeff_PV = sum(Coeff_PVpos) - Coeff_PVneg;
```

3 Linear Program: Objective Function

The objective function is here representend as a vector of coefficients `f`. This vector contains all the decision/design variables which whose value will be the outcome of the optimisation process. In order, those variables are:

- `K_S(j)` (`n_S`, [kWh]) : capacity of storage system `j`;
- `A_PV` (1, [m^2]) : PV surface;
- `E_soc(j,t)` (`n_S*T`, [kWh]): state of charge of storage system `j` at each time `t`;
- `P_chg(j,t)` (`n_S*T`, [kWh]): energy charged on storage system `j` between `t` and `t+1`;
- `P_dis(j,t)` (`n_S*T`, [kWh]): energy discharged from storage system `j` between `t` and `t+1`;
- `P_G(t)` (`T`, [kWh]) : proportion of grid input;
- `P_PVgrid(t)` (`T`, [kWh]) : proportion of grid output;
- `P_PVspil(t)` (`T`, [kWh]) : proportion of grid output;
- `P_PVself(t)` (`T`, [kWh]) : proportion of grid output;

The total length F of `f` is then `n_S+1+3*n_S*T+4*T`. The coefficient vector `f` is written hereunder:

```
    f = [...
      Coeff_KS...             K_Sj                    (n_S)
      Coeff_PV...             A_PV                    (1)
      sparse(1,n_S*T)...      E_socj1...E_socjT       (n_S*T)
      sparse(1,n_S*T)...      P_chgj1...P_chgjT       (n_S*T)
      sparse(1,n_S*T)...      P_disj1...P_disjT       (n_S*T)
      c_G*ones(1,T)...        P_Gj1...P_GjT           (T)
      -c_EG*ones(1,T)...      P_PVgridj1...P_PVgridjT (T)
      sparse(1,T)...          P_PVspilj1...P_PVspiljT (T)
      -0.0001*ones(1,T)...    P_PVselfj1...P_PVselfjT (T)(*)
     ];

F = length(f);
```

(*) `P_PVself(t)` has a coefficient of `-0.0001` even though in practice it should not have any influence on the total cost of the solution. In fact, only the storage capacity (`K_S(j)`), the production capacity (`A_PV`) and the interactions with the grid (`P_PVgrid(t)` and `P_G(t)`) impact the total cost. So why do they have a non-zero coefficient? It is done to ensure all locally produced energy coinciding with the local demand is used on the spot and not sold to the grid for profit maximization. By adding a negative non-zero coefficient, `linprog` is asked to maximize this value.

4 Linear Program: Constraints and Matrix Filling

The following vectors are used to fill the `sparse`-matrices. See Sparse Matlab documentation for more information on how to create `sparse`-matrices in Matlab.

```
V         = circshift(reshape((1:n_S*T)',T,[])',[0 T-1]); %shifting (E_soc(j,T+1) = E_soc(j,1))
indS      = reshape(V',1,n_S*T);                          %indices for E_soc(j,t+1)
indK      = reshape(repmat(1:n_S,T,1),1,[]);              %indices for K_S(j)
indJ      = reshape(repmat(1:T,n_S,1)',1,[]);             %indices for sum_j
dodvec    = reshape(repmat(1-DOD(1:n_S),T,1),1,[]);       %vector for DOD(j)
PERvec    = reshape(repmat(PER(1:n_S),T,1),1,[]);         %vector for PER(j)
rvec      = reshape(repmat(SDR(1:n_S),T,1),1,[]);         %vector for SDR(j)
etachgvec = reshape(repmat(eta_chg(1:n_S),T,1),1,[]);     %vector for eta_chg(j)
etadisvec = reshape(repmat(1./eta_dis(1:n_S),T,1),1,[]);  %vector for eta_dis(j)
```

The constraints are divided in production related, storage related and grid related constraints, all combined by the energy balance equation. The constraints can be in the forms:

- $M \cdot x \leq b$;
- $M_{eq} \cdot x = b_{eq}$;
- $x \leq ub$;
- $lb \leq x$;

4.1 Storage related

State of charge limited by storage capacity:
$E_{soc}(j,t) \leq K_S(j)$

```
M_Sjt = speye(n_S*T,3*n_S*T);                              %  E_soc(j,t)
M_KSj = sparse(1:n_S*T,indK,-ones(n_S*T,1),n_S*T,n_S+1); % -K_S(j)

M_SK = horzcat(M_KSj,M_Sjt,sparse(n_S*T,4*T));
b_SK = sparse(n_S*T,1);
```

Min. capacity in storage system limited due to DOD:
$DOD(j) \cdot K_S(j) \leq E_{soc}(j,t)$

```
M_dodj_KSj      = sparse(1:n_S*T,indK,dodvec,n_S*T,n_S+1); % DOD(j)*K_S(j)

M_Sdod          = horzcat(M_dodj_KSj,-M_Sjt,sparse(n_S*T,4*T));
b_Sdod          = sparse(n_S*T,1);
```

Charging limited by Power-to-Energy ratio
$P_{chg}(j,t) \leq PER(j) \cdot K_S(j)$

```
M_PER_KSj      = -sparse(1:n_S*T,indK,PERvec,n_S*T,n_S+1); % -PER(j)*K_S(j)
M_chgjt        =  speye(n_S*T,2*n_S*T);                    %  P_chg(j,t)

M_PERchg = horzcat(M_PER_KSj,sparse(n_S*T,n_S*T),M_chgjt,sparse(n_S*T,4*T));
b_PERchg = sparse(n_S*T,1);
```

Discharging limited by Power-to-Energy ratio
$P_{dis}(j,t) - PER(j) \cdot K_S(j) \leq 0$

```
M_disjt        =  speye(n_S*T,n_S*T); % P_dis(j,t),t)

M_PERdis = horzcat(M_PER_KSj,sparse(n_S*T,2*n_S*T),M_disjt,sparse(n_S*T,4*T));
b_PERdis = sparse(n_S*T,1);
```

Storage System Balance
$E_{soc}(j,t+1) = SDR(j) \cdot E_{soc}(j,t) + \eta_{chg} \cdot P_{chg}(j,t) - P_{dis}(j,t)/\eta_{dis}$

```
Meq_SSjt0 = -sparse(1:n_S*T,1:n_S*T,rvec);                    % -SDR(j)*E_soc(j,t)
Meq_SSjt1 =  sparse(1:n_S*T,indS,ones(1,n_S*T),n_S*T,n_S*T); %  E_soc(j,t+1)

Meq_SSjt   =  Meq_SSjt0 + Meq_SSjt1;                %  E_soc(j,t+1) - E_soc(j,t)
Meq_Schgjt = -sparse(1:n_S*T,1:n_S*T,etachgvec);    % -P_chg(j,t)*eta_chg(j)
Meq_Sdisjt =  sparse(1:n_S*T,1:n_S*T,etadisvec);    %  P_dis(j,t)*1/eta_dis(j)

Meq_Sbal =  horzcat(sparse(n_S*T,n_S+1),Meq_SSjt,Meq_Schgjt,Meq_Sdisjt,sparse(n_S*T,4*T));
beq_Sbal =  sparse(n_S*T,1);
```

Other storage related constraints:

- $0 \leq E_{soc}(j,t)$
- $K_{S,min}(j) \leq K_S(j) \leq K_{S,max}(j)$

(See upper- and lower-bound vectors below)

4.2 Production related

Local Production Balance

$A_{PV} \cdot H(t) = P_{PV,grid}(t) + P_{PV,spil}(t) + P_{PV,self}(t) + \sum_j P_{chg}(j,t)$

```
Meq_APV       =  H_t';                                          %  A_PV*H(t)
Meq_Pchgjt    = -sparse(indJ,1:n_S*T,ones(1,n_S*T),T,2*n_S*T+T); % -sumj(P_chg(j,t))
Meq_PPVgridt  = -EG*speye(T);                                   % -P_PVgrid(t)
Meq_PPVspilt  = -speye(T);                                      % -P_PVspil(t)
Meq_PPVselft  = -speye(T);                                      % -P_PVself(t)

Meq_PVbal = horzcat(sparse(T,n_S),Meq_APV,sparse(T,n_S*T),Meq_Pchgjt,Meq_PPVgridt,...
                Meq_PPVspilt,Meq_PPVselft);
beq_PVbal = sparse(T,1);
```

Other production related constraints:

- $A_{min} \leq A_{PV} \leq A_{max}$
- $0 \leq P_{PV,self}(t), P_{PV,spil}(t), P_{PV,grid}(t)$

(See upper- and lower-bound vectors below)

4.3 Grid related

Grid input limited by grid capacity:
$P_G(t) \leq G_{max}$

```
M_Gt = speye(T,4*T); % P_G(t)

M_Gmax = horzcat(sparse(T,n_S+1+3*n_S*T),M_Gt);
b_Gmax = G_max*ones(T,1);
```

Grid feed-in limited by grid capacity:
$P_{PV,grid}(t) \leq EG_{max}$

```
M_EGt = speye(T,3*T); % P_PVgrid(t)

M_EGmax = horzcat(sparse(T,n_S+1+3*n_S*T+T),M_EGt);
b_EGmax = EG_max*ones(T,1);
```

Grid feed-in limited by production:
$P_{PV,grid}(t) \leq A_{PV} \cdot H(t)$

```
M_EG = horzcat(sparse(T,n_S),-H_t',sparse(T,3*n_S*T+T),M_EGt);
b_EG = sparse(T,1);
```

Total grid feed-in limited by feed-in limit:

$\sum_t P_{PV,grid}(t) \leq FIL\dot{A}_{PV} \cdot sum_t H_t$

```
M_EGFIL = horzcat(sparse(1,n_S),-FIL*sum(H_t),sparse(1,3*n_S*T+T),ones(1,T),sparse(1,2*T));
b_EGFIL = 0;
```

Net-Metering (NM scenario):
$NM \cdot \sum_t P_{PV,grid}(t) \leq NM \cdot \sum_t P_G(t)$

```
M_EGt2 =  NM*ones(1,T); %  NM*sumt(P_PVgrid(t))
M_G    = -NM*ones(1,T); % -NM*sumt(P_G(t))

M_GNM = horzcat(sparse(1,n_S+1+3*n_S*T),M_G,M_EGt2,sparse(1,2*T));
b_GNM = 0;
```

Net-Billing (FiT scenario):
$NB \cdot c_{EG} \cdot \sum_t P_{PV,grid}(t) \leq NB \cdot c_G \cdot \sum_t P_G(t)$

```
M_pEG = NB*c_EG*ones(1,T); %  NB*c_EG*sumt(P_PVgrid(t)
M_pG = -NB*c_G*ones(1,T);  % -NB*c_G*sumt(P_G(t))

M_GNB = horzcat(sparse(1,n_S+1+3*n_S*T),M_pG,M_pEG,sparse(1,2*T));
b_GNB = 0;
```

Imposed self-sufficiency :
$\sum_t P_{PV,self}(t) + \sum_{j,t} P_{dis}(j,t),t) = SS \cdot \sum_t D(t)$

```
Meq_SSPself = ones(1,T);
Meq_SSdis   = ones(1,n_S*T);

Meq_SS = SSbin*horzcat(sparse(1,n_S+1+2*n_S*T),Meq_SSdis,sparse(1,3*T),Meq_SSPself);
beq_SS = SSbin*SS*sum(D_t);
```

Power Balance
$D(t) = P_{PV,self}(t) \cdot H(t) + G(t) + \sum_j P_{dis}(j,t),t)$

```
Meq_Pdisjt  = sparse(indJ,1:n_S*T,ones(1,n_S*T),T,n_S*T); % sumj(P_dis(j,t),t)
Meq_PGt     = G*speye(T,3*T);                              % P_G(t)
Meq_PEselft = speye(T);                                    % P_PVself(t)

Meq_Pbal = horzcat(sparse(T,n_S+1+2*n_S*T),Meq_Pdisjt,Meq_PGt,Meq_PEselft);
beq_Pbal = D_t';
```

Other grid-related constraints:

- $0 \leq P_G(t)$

Finally, we fill the lower- and upper-bound vectors:

```
lb = sparse(1,F);       % non-negativity (|0 <= E_soc(j,t),D(j,t),A(j,t),...|)
lb(n_S+1) = A_min;      % min. production required (in terms of area)
for j = 1:n_S
    lb(j) = K_Smin(j); % min. storage capacity required (in terms of capacity)
end

ub = inf(1,F);
ub(n_S+1) = A_max;      % max. production available (in terms of area)
for j = 1:n_S
    ub(j) = K_Smax(j); % max. storage capacity available (in terms of capacity)
end
```

5 Linear Program: Concatenation of Matrices and Function Call

Finally we concatenate all the matrices and separate them in the overall matrices `M`, `b`, `Meq` and `beq`.

```
M = vertcat(M_SK,M_Sdod,M_Gmax,M_EGmax,M_EG,M_EGFIL,M_GNM,M_GNB,M_PERchg,M_PERdis);
b = vertcat(b_SK,b_Sdod,b_Gmax,b_EGmax,b_EG,b_EGFIL,b_GNM,b_GNB,b_PERchg,b_PERdis);

Meq = vertcat(Meq_Pbal,Meq_PVbal,Meq_Sbal,Meq_SS);
beq = vertcat(beq_Pbal,beq_PVbal,beq_Sbal,beq_SS);
```

Now `linprog` is called. The `interior-point-legacy` algorithm is used with the maximum number of iterations defined by `MaxIt`. For more information on the algorithm, see : Linear Programming Algorithms

```
options = optimoptions('linprog','Algorithm','interior-point-legacy','MaxIteration',MaxIt);
X = linprog(f,M,b,Meq,beq,lb,ub,[],options);
end
```

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