UNIVERSIDAD PONTIFICIA COMILLAS
ESCUELA TÉCNICA SUPERIOR DE INGENIERÍA (ICAI)

Delft University of Technology
Faculty Technology, Policy and Management

OFFICIAL MASTER'S DEGREE IN THE
ELECTRIC POWER INDUSTRY & ENGINEERING
AND POLICY ANALYSIS

Master's Thesis

POLICY AND ECONOMIC IMPACTS OF END USERS TARIFF POLICIES CONSIDERING THE "DEATH SPIRAL":

APPLICATION TO A SPANISH CASE STUDY

Author:	**Yola Riana Effendi**	
Supervisor:	**Prof. Benjamin F. Hobbs**	**(Johns Hopkins University)**
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Summary

Recently, the cost for Renewable Energy Sources (RES) and the other distributed energy resources have become more affordable at the household level, especially photovoltaics (PV) and storage batteries. With this, the possibility of households to become "prosumers" (producers and consumers of energy at the same time) becomes an attractive alternative due to the opportunity to save on the electricity bill costs. The traditional concept where a household can only purchase from the grid becomes outdated; this also triggers the concern of "death spiral." The reinforcing loop where the increase of the prosumers can provoke them to defect from the grid and force the utilities to increase their tariffs in order to cover their network grid and additional policies cost. Where in the past, this kind of condition was unlikely to happen. Due to household consumers are usually the least elastic and ended up carrying the burden of the of the cost because this type of end user will not change their consumption by much, even if prices increase greatly (Alleman, 1999; Ramsey, 1927).

This research is using Vensim software to build and run a model of the Spanish household market based on System Dynamics (SD) methodology. The model is using six different scenarios that tested into four kinds of combinations of policy: no net metering and mixed tariff, no net metering and volumetric tariffs, net metering and volumetric tariffs, and net metering with mixed tariff. On top of that, the possibility of exit charges and network-only regulation charges were also being tested on those four combinations of policy, to see about the potential possibility of the "death spiral" in the Spanish household market. Results indicated that there is less possibility for the "death spiral" happening in Spain's household market. Interestingly, cost recovery aside the concept of net metering leads to less to none of the grid defection, and without net metering, it is encouraging households to defect from the grid. Other results are fixed-network regulation cost can dampen grid disconnection, but at the same time delayed the RES adoption, and exit charges managed to prevent grid defection. Other alternatives are needed to be explored in order to foster RES, efficient market mechanisms need to be designed in order to put in level playing field different technologies at different scales and not incentivizing certain technologies with non-transparent cost shifting among consumers as net-metering does.

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These last few months have been quite a journey for me. The electric power industry is something that is new for me, moreover, I came from the country that applies a monopoly on the electricity sectors. Thus, I learned a lot of new and challenging things during this writing process. I would not have made it without the support of the people around me. First, I need to thank God for helping me pass through this time.

Next, I would like to express my sincere gratitude to my supervisor, Prof. Benjamin F. Hobbs, for patiently and willingly teaching and guiding me through my research, despite his full and busy schedule. He is always available to give input and answer my questions. Secondly, I want to thank Jose Pablo Cháves-Ávila, Ph.D. for being my co-supervisor. Even though there he already oversees so many students he was always there when I needed his assistance related to my research. These two people also motivated me to choose this research topic for my thesis.

Afterward, I also want to thank Comillas' teachers who are sharing an insight on how electric power industries works, as well as TU Delft teachers that educated me on methods and tools for analyzing policies and complex problems. In particular, I also want to thank Dr. Erik Pruyt for introducing me to the System Dynamics world and encouraging me to join the SD conference.

Last but not least, I want to thank my family for their support and letting me go back to school to chase my curiosity. My friends who are always available for discussion and patiently listen to my concerns—Cin Cin Go, Gita Nangoy, and Eva Yuliana. I also want to thank my university friends in the Electric Power Industry and Engineering & Policy Analysis. Especially, Bramka Arga Jafino and Nadia Rayhanna for being there for me when I need advice and for becoming my partner for the conference paper.
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1. Introduction

1.1. Background

The beginning of the electricity power industry came in the 18th century with the invention of lighting and electricity. During the time the demand for this service increased rapidly and became an industry of its own. The electricity power industry itself consists of generation, transmission, distribution, and consumption. Generation functions as the part that creates the electric power; this power is then distributed to the customers at a high voltage through a transmission line. Afterward, this energy is converted into lower voltage through a distribution line/grid in order to reach customers for consumtion (Pérez-Arriaga, et al., 2013).

The reason why the network of electricity power industry is considered a natural monopoly is due to the nature of the infrastructure system, where it performs fundamental socio-economic functions that involve: providing for the fundamental needs of humans as a base of other activities and acts as a facilitator for economics activities (Correljé, 2016). These conditions also lead to market failures due to the huge fixed cost and economics of scale. As it involves public needs, it also creates a network complexity. In order to reach efficient pricing and investments there is a need to have central coordination and dependencies.

Due to the complexity of the electricity power industry, there are many costs involved in creating a complete power industry ecosystem. This cost, as charged to consumers, is usually separated into three segments: volumetric, capacity charges, and fixed charges. As the generation business nowadays has already been liberalized, this paper will be more focused on the cost involved with network cost as this cost is highly regulated by the central government.

Until recently, the way that charges were set to recover electricity network costs generally followed a combination of cost-causality and Ramsey pricing principles (Pérez-Arriaga, et al., 2013). Ramsey (1927) stated the price margin (price minus marginal cost) should be inversely proportional to the elasticity of the demand in order to minimize the social welfare losses from deviations from marginal cost pricing. To minimize this loss means that the most inelastic market should bear a disproportionate burden of the cost because this type of end user will not change their consumption by much even if prices increase greatly (Alleman, 1999; Ramsey, 1927). The most they can do is to reduce their consumption slightly and politically voice their disagreement. e.g., usually when the market is sufficiently competitive the residential end users (the least elastic) will be charged more than the large industrial end users (the most elastic) (Pérez-Arriaga, et al., 2013). In this case, it was also applied for the investment in the electricity business. The government charges the bulk of the cost of their transmission and distribution network to lower-elasticity end users (such as residential consumer, who also take power at a lower voltage), and less to higher-elasticity users (such as industrial users).

However, the low elasticity condition of residential consumers (and thus the rationale for saddling them with network charges) started to change with the vast growth of technology and renewable energy, which led to the decreased price of such technology. Because of the reduced cost in technology, the elasticity of end users market has gradually increased due to the implementation of Distributed Energy Sources (DERs) in the form of PV and batteries. By doing this, end users are not just consumers anymore but becomes “prosumers” because they ended up becoming producers and consumers at the same time. This action is triggered by the economics factor, where at some point the price to invest in renewable is equal to or cheaper than buying energy directly from the grid; this action also leads to a higher possibility for the end users deciding to leave the grid. Consequently, the utilities needed to increase their network charges, which are around 26% according to ACER report (2015), to cover the fixed costs of the grid’s decreasing demand. This action can lead to the “death spiral” for the utility companies, in which higher charges promote more load loss and defections from the grid, leaving fewer and fewer consumers to recover network costs from (Pérez-Arriaga, et al., 2013; MIT Energy Initiative; IIT-Comillas, 2016; Kubli, 2016).

The changing behavior of the end user would significantly impact the allocation tariffs set by the government. This research intends to see the behavior of end user in the electricity market and policies' impact on tariffs and the possible solution needed to face the issue. The alternative policies that will be considered in this thesis are grid exit fee charges (the fee applied when the end user wants to disconnect from the grid completely), net metering, and price differentiation among end user groups (e.g., by customer class, or by charging PV end users a higher price when they use energy from the grid) (Faruqui & Brown, 2014).

1.2. Research objective

The main objective of this thesis is to use system dynamics modeling to answer the following research questions.

- The main question is, "Is there a risk of a 'death spiral' for Spanish household utilities, given future expectations of PV and battery costs?"
- The sub questions are, "What are the impacts of alternative network charging policies?" and, "Does system dynamics able to model the dynamics of the Spanish household utilities market?"

These questions are addressed by (1) developing a system dynamics model of the Spanish residential electricity market, and then (2) applying policies into the system to see the effect on the end user's investment decision on Renewable Energy Sources (RES) (in the form of Solar PV and battery) and to see whether alternative policies help with recovering the initial investment, or if it will actually lead to the "death spiral" condition. The electricity system will be modeled into six different scenarios, which show the possibility of various improvements in a few sectors, such as the decrease of PV and battery storage cost using System Dynamics. Some of the policies are a grid´s exit fee charge, net metering, and different tariff designs.

1.3. Scope of thesis

The thesis is organized as follows. The next chapter (Chapter 2), surveys the literature on the research question (the "death spiral" in electric utilities) and methodology (systems dynamics). Then in Chapter 3, the methodology used in this research is explained. Chapter 4 explains the background of the case study used. Chapter 5 discusses the conceptual model, boundaries, and the detail model and sub model. In Chapter 6 the focus is on the data sources that were used in this research. Chapter 7, mainly concentrates on the model validation process before used in the model for experimental design that is explained in Chapter 8. The concluding chapter (Chapter 9), summarizes the results of the thesis, and in particular, states the answers to the main question and two subquestions given in Chapter 1.1. It also includes a discussion of the limitations of the thesis and summarizes some desirable "next steps" for research.

2. Literature Review

This chapter covers two areas of literature. They are cost recovery focus and SD modeling methodology.

Currently there are already some works covering the utilities' "death spiral" and some of them are using the system dynamics method. Some other research is more focused on the utilities' "death spiral" in relation to the capacity expansions, and others are related to the overall utilities cost.

On the cost recovery focus, Faruqui and Brown (2014) conducted research for the Australian Energy Market Commission. The research focused on the issue of long-marginal cost (LRMC) being used as base price due to the efficiency of end user decisions on the use of electricity and investment, but in the long run, this will not recover the total cost of the regulated services or approved revenue. Thus, a new term for the cost difference between LRMC and the approved revenue called "residual" cost was born. They identified three relevant principles for recovering the residual cost through tariff restructuring: economic efficiency, fairness, and gradualism (Faruqui & Brown, 2014). This concept can be seen in this research simulation, whether in some of the price combinations the cost of regulation will be recovered or not.

Other work related to residual cost recovery is the "utility of the future" paper done by MIT and IIT Comillas (2017), where the concept of costs that need to be included in the tariffs in the scope of residual network and policy cost need to be analyzed in more detail. This is because it usually contains subsidies—such as RES subsidies—transmission, and distribution cost. This kind of cost can influence the customer's decision to defect from the grid, thus inside this paper, there are also recommendations on policy regarding exit charges to prevent defection. These two policies will also be tested in this research.

On the modeling using SD as methodologies, there are a number of papers, one of them in particular is Kubli's (2016). She used TREES (transition of regional energy systems), an SD simulation model, to see the feedback process in the interaction effect of prosumers' diffusion effect and its affect on grid tariff design. She used data from areas in Switzerland areas: Frutigen, Wohlen, Ostermundigen, and the overall supply area by Bern (utility company). In this research, she focused on the grid only, and four tariff designs were being used (electric work grid tariff, flat-rate grid tariff, capacity grid tariff, mixed tariff). The electric work grid tariff is where prosumers pay based on their usage and are given the best incentives for the transition into renewables. Flat-rate grid tariff charges the end users based on their connection point and disregards their usage, giving the worst conversion rate towards renewables. Capacity grid tariff charges end users based on their cumulated peak demand; this model attracts prosumers with storage and only attracts medium conversion into renewables. Mixed tariff is the combination between electric work grid tariff and flat-rate grid tariff, which also has a medium conversion rate into renewables (Kubli, 2016). The research simulation found in this thesis applied some of the tariff models in Kubli's (2016) experiment, which is mixed tariff and electric work grid tariff (volumetric). This research will elaborate on other regulation charges, not only on the grid tariff design.

Similar research has been performed by Meehan (2015), who modeled US rooftop solar systems and the utilities' "death spiral," and used data from Salt River Project in Arizona. He oversaw factors that can result in the "death spiral" in Arizona. However, his study omitted the effect of rooftop solar diffusion on the grid cost and the effect of storage systems in his model. Meehan also used the concept of Word of Mouth (WOM) which this research also applied in order to add a social decision factor that may apply the end user when converting to the RES system. The

WOM effect was often found in the model that represents new technology diffusion (Meehan, 2015; Bass, 1969).

Laws, et al. (2017) researched on the impact of utility rate structures and the adoption rates of residential solar PV and energy systems. He was using data from LA, Boulder, and Sydney, and focused on residential PV systems with and without storage systems. The stock and flow consisted of regular customers, customers with PV, and defectors (off-grid end users). In his works, a utility “death spiral” is highly unlikely due to the fact that it only happens in the scenario combinations of high adoption rates, high utility costs, and favorable financial conditions (Laws, et al., 2017). This conclusion will be used as a comparison in this simulation as it is estimated that the research subject will face the same conditions as the Laws, et al. experiment.

In summary, this research will elaborate on parts that have been mentioned in the literature review. The model will run calculations on the residual cost with some policy combinations that have been mentioned, such as net metering, mixed tariff between volumetric and contracted capacity charge, and pure volumetric, similar to what was done in the Laws, et al. (2017) and Kubli (2016) research. This research will also test the tariff design suggested by “utility of the future” (2017) on charging the customer based on their network and power cost instead of a full chunk of the regulation cost. Additionally, the application of exit charges will be tested in this model. The difference is that this model will be applied to the Spanish household market model and Spanish regulation costs from Comisión Nacional de los Mercados y la Competencia (CNMC). Since this is the first application of SD for the Spanish household market, especially in relation to the “death spiral” and RES system adoption, the experiment results will provide valuable insights for regulator’s considerations when deciding on tariff designs, especially for the household market.

3. Methodology

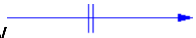
The simulation of the electric system is done using System Dynamics (SD) methodology and Vensim software. The organization of this chapter is as follows: Chapter 3.1 will explain the concept overview of System Dynamics.

3.1. System Dynamics

This method is used to understand the dynamics and structures of a complex system by simulating the system's behavior over time (Forrester, 1961; Sterman, 2000). The concept of SD is to see things as a whole and to understand the interactions inside the system (SDEP-MIT, 1997). The underlying core assumption of SD is that the behavior of the system is determined by the structure of the model/system, including positive and negative feedbacks loop. The system's structure contains policies and information that is necessary for the process of complex problem decision-making (Roberts, 1988). Therefore, there is a need to have structural change, in order to improve undesirable behavior in the system, as well SD-enabled one to identify and test the impact of system changes in a 'virtual laboratory' (Pruyt, 2013).

Causal links and feedback loops

In SD models, links between parameters and variables can represent direct causal relations, thus SD can be used to explore the complex behavior of the interaction between structures to gain insights, in order to transform the structure of the system into more desirable behaviors (Pruyt, 2013).Elements that are linked by two or more causal links that are connected and eventually return to the first element is the definition of the feedback loop (Pruyt, 2013).
There are two different types of feedback loops (Pruyt, 2013):

- It's considered a positive feedback loop, or reinforcing, if the initial increase in one variable leads to the additional increase on that variable over time, i.e. Figure 1. When the number of users converts to PV increased, the number of PV users will also increase. In turn, this will also increase the potential contact between PV users and normal users through the WOM cycle, which can result in the increase of users converting to PV. However, this process cannot be done instantaneously, thus the arrows have a delay sign on them. This arrow  means delay or that there is a time delay to achieve the result.
- It's considered a negative feedback loop, or balancing, if the initial increase in one variable leads to the decreasing of that variable over time, i.e. Figure 1. When the number of normal users increases, the more users can be converted into PV users, the more users converted, the less the normal user would be.

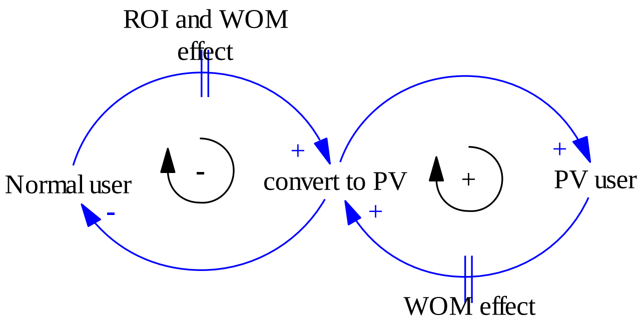


Figure 1 Causal link diagram positive and negative loop

Causal Loop Diagram (CLD)

First, the conceptual model is made in the form of a Causal Loop Diagram (CLD) to identify main feedback loops and sub-systems affecting the system. Afterward, a detailed stock-flow diagram (SFD) is developed to model the system, followed by the formulation of the model equations. The details of CLD can be found in Model Description under main feedback loop chapters.

The model considers four types of end users: the normal end users who purchase electricity from the grid, consumers with PV installations (PV end-users), consumers with PV and batteries (PV and battery end-users), and consumers disconnected from the grid or off-grid end-users. Based on the degree of elasticity of electricity demand, from the most inelastic to the most elastic one, normal users < PV users < PV and battery users < off-grid end-users. The model will also consider the market price of electricity as a baseline for the volumetric tariff for the energy that the end users will bear. The details of the CLD and feedback loop will be explained in Chapter 5.2.

Stock and Flow

SD contains the stock and flow; the stock itself is a state variable. This stock has an initial value and can be affected only through inflows and outflows. This caused the stock to be increasing and decreasing depending of the flow, and it is accumulating over time (Pruyt, 2013). Thus, these stocks are considered as integral equations, as described by Pruyt in Figure 2.

$$x = x_0 + \int_{t_0}^{t} (+ax - bx)\, dt$$

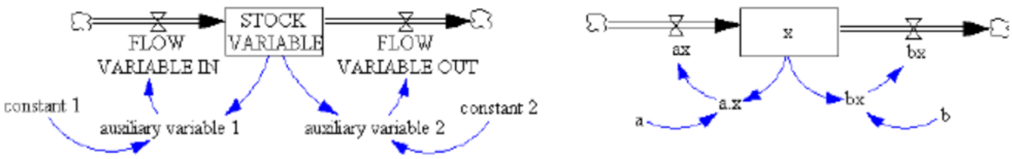


Figure 2 Basic stock and flow diagram (Pruyt, 2013)

A systems dynamics model will be created for the Spanish household market. The stocks will include the four types of end users mentioned in CLD segment, the “death spiral” will be detected if the value of the rates climb very high over time and the stock variables representing consumers connected to the system and their demands shrink—this refers to the orange loop in Figure 5 in Chapter 5.2. Data from the case study will be fed into the model, and several scenarios will be applied to see the changes in the system. From the resulting feedback, the model and policies will be calibrated and tested using sensitivity and uncertainty analysis to see the robustness of the policies and the model itself.

4. Case Study

4.1. Spanish household PV condition

Based on Solargis data—the Global Horizontal Irradiance (GHI), Figure 3—Spain is one of the European countries that has an enormous potential for solar energy due to its location and abundant hours of sunshine (Solargis, 2014).

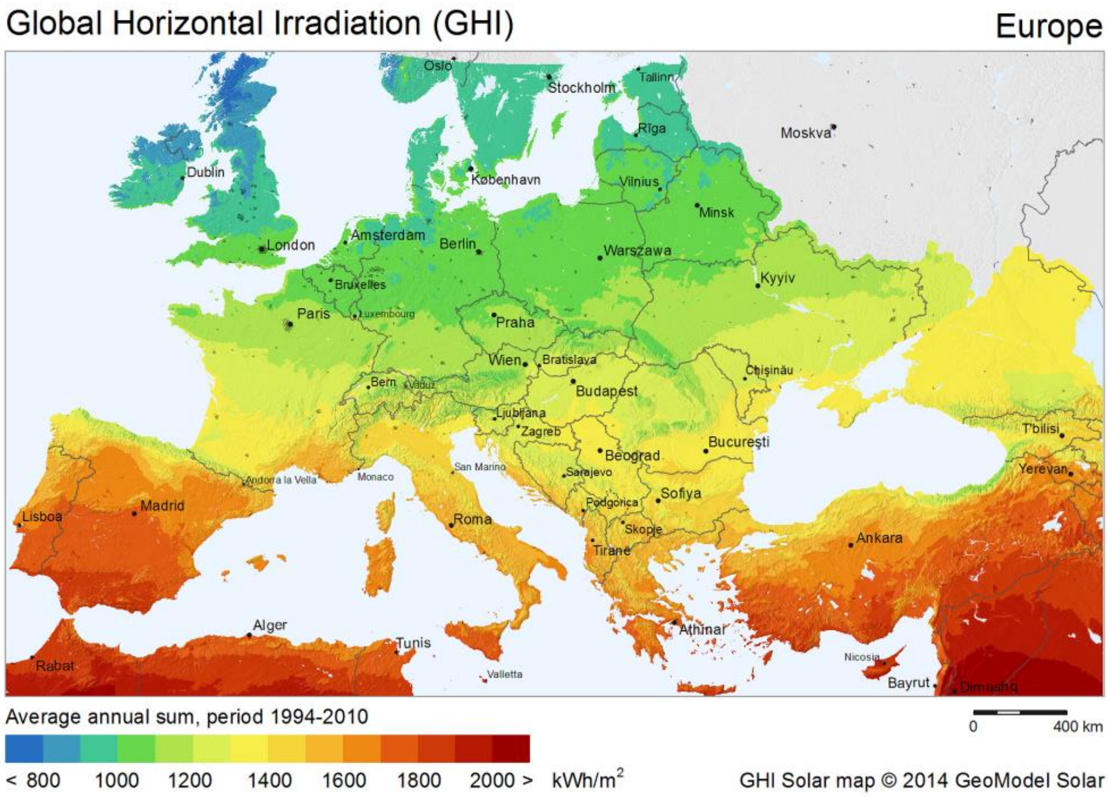


Figure 3 Global Horizontal Irradiation (Solargis, 2014)

GHI itself is the sum of shortwave radiation that can be received from above, horizontally to the ground. This value is considered interesting for PV installation (3TIER, 2017).

In the past, Spain had high Renewable Energy Sources (RES) support under the Royal Decree no. 1578/2008. With this support mechanism the producer was able to choose where they can sell their produced electricity—whether under Feed-in tariff (FiT) mechanism where producers with PV under 20kW were able to sell it at 0.2662 Euro/kWh, or to sell it in the free market to get the market price plus a feed-in premium remuneration. However, in 2012 with Royal Legislative Decree no. 1/2012, this support scheme was suspended (Campoccia, et al., 2014). In 2016 and 2017, the government called for technological neutral renewables auctions and the payment paid to the winners of these auctions considers the market income and additional remuneration based on the auction prices. Regarding the results from the 2016 and 2017 auctions, the winning technology was wind power with an obtained "zero price," meaning that renewables would be installed without any additional remuneration beyond the market price.

In 2015, Spain released a new royal decree, the Royal Decree no. 900/2015, about "sun tax," where systems up to 100kW are not allowed to sell electricity—excess energy that is injected into the grid is not remunerated. For systems above 100kW, they need to register to sell electricity to SPOT market.

Nowadays, Spain is in the middle of implementing smart meters with the target of 100% installation by the end of 2018 (USmartConsumer Project, 2016). Thus, without FiT and net metering benefits, the present condition is not appealing for household end-users to install PV systems on their houses.

In addition to the Spanish regulation, other regulations—with respect to self-generation—are important to analyze as far as their impact on the evolution of the system as different countries and regions are looking for solutions to, on one hand, foster renewable generation, but on the other hand foster economic efficiency of the system.

4.2. Net Energy Metering (NEM)

Although in Spain the concept of NEM for PV users is not implemented, in California they are using this system to incentivize users that are willing to install PV to become prosumers. The way NEM works is by netting the consumption from the grid with their PV production, which they can inject into the grid. In this scheme, residential customers are able to pay the utility based on monthly net consumption or settling it every 12 months. If, by the end of 12-month period, there was excess energy that was injected into the grid, the customer can receive a payment under special utilities tariffs (California Energy Commission & California Public Utilities Commission, 2017).

In this research, there are some experiments which assumed the usage of net metering in Spain's market.

5. Model Description

This chapter will focus on the model boundaries and the scope of variables that are included in the model, which can be found in Chapter 5.1. In Chapter 5.2, the main feedback loops that describe the overview on how the model works will be explained in more detail. Finally, Chapter 5.3 will discuss the detail simulation model, how the dynamic of multilayered behavior of the stock variables of each end user, as well as the logic of different policies implemented in the model. The KPI for comparing policies are the number of users and the changes in electricity price, especially the change in the financial condition of the network.

5.1. Model Boundaries

The Spanish electricity system and renewable energy system are complex sociotechnical systems that involve many interrelated elements. Therefore, not all of the elements related to the system are included to avoid an extreme and complex model that could result in run failures and obscured insights. Thus, the considered elements can be seen in Figure 4. System variables are divided into four categories in the figure.

The first category is the thoroughly modeled endogenous variables. In this category, the system is modeled in detail as these factors directly contribute to the risk of PV-caused "death spiral" on systems in the Spain household.

The second category is the superficially modeled endogenous variables. For this category, the factors are modeled in less detail to prevent an overly extravagant model. These variables are usually aggregated in some way in the model.

The third category is the exogenous variables. This category includes the factors that are out of the scope of the research, or cannot be influenced directly by the stakeholders' behavior in the system (and so are not in a feedback loop with consumers), but have a significant impact on the whole model system. Thus, scenarios of their values have been included and run in the model for each scenario.

The fourth category is the deliberately omitted variables. This category is where the factors have been completely omitted from the model to make sure the model is manageable and insightful.

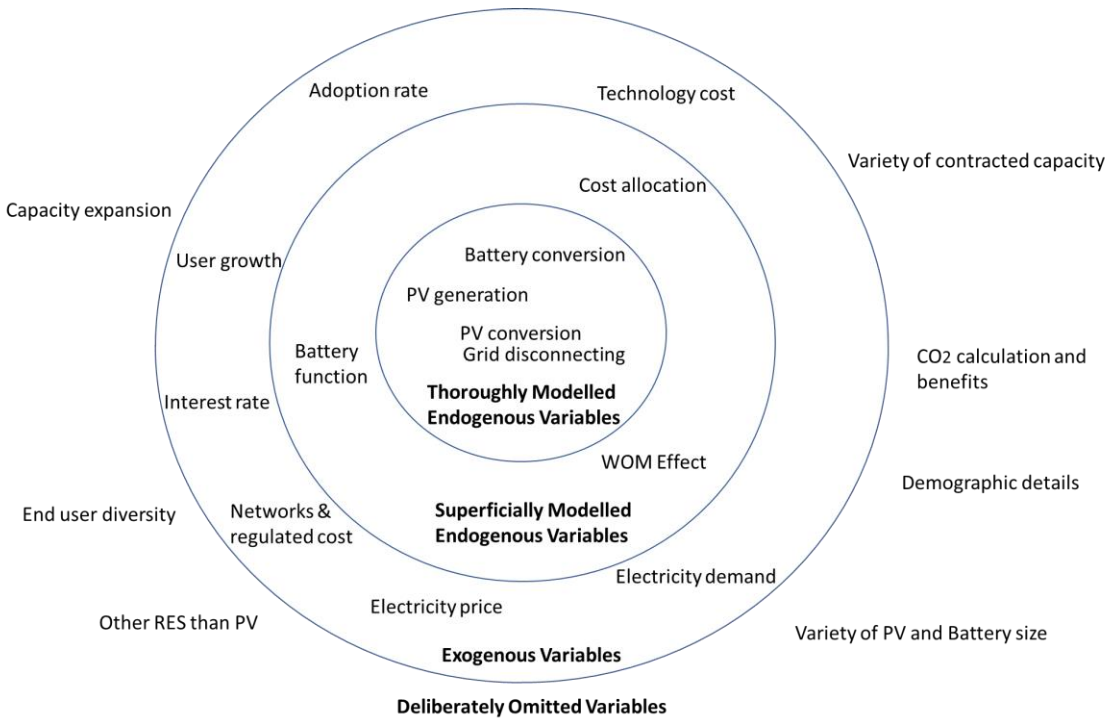


Figure 4 Bull's eye diagram

5.2. Main Feedback Loops

The main purpose of the model is to see the effect of residential solar diffusion in the Spanish market. There are two main considerations of end-user conversion to RES systems: one is based on the Return of Investment (ROI) time, and the other is the WOM (Word of Mouth) factor, which can leverage the amount of users willing to install RES systems. The logic used for PV battery users to disconnect from the grid are based on whether being on the PV battery for a year is sufficient, and whether the PV battery's annual cost is cheaper than paying the network cost. This will be explained in more detail in Chapter 5.3, "The Simulation Model."

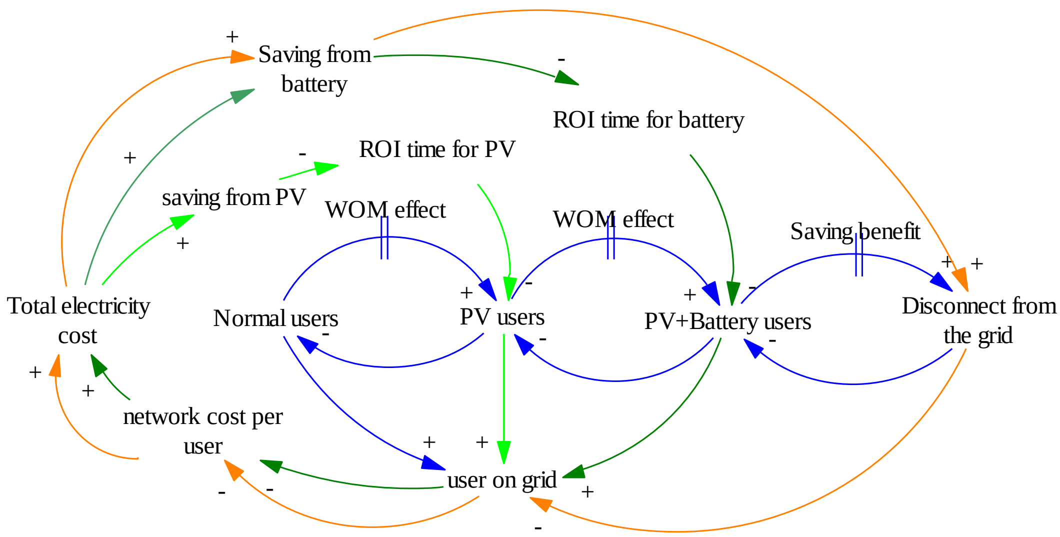


Figure 5 Aggregated feedback loop

There are **three** main feedback loops in the model:

First are the (3 loops) blue negative feedback loops that are showing the conversion from normal users into PV users, PV users to PV and battery users, and then how that eventually leads to disconnecting from the grid.

Secondly, there are the (2 loops) green negative feedback loops that show the economic logic of conversion through saving: the more saving from PV and from the battery, the lesser ROI time needed. Thus, it leads to the increase of PV or PV and Battery installation.

The last one is the orange positive feedback loop, which is related to defection from the grid. The more users that defect from the grid, the fewer users on the grid would be, which will in turn affect the network cost per user. If the user on the grid decreases, the network cost per user will increase, which leads to the increase of total electricity cost. When electricity cost increases, installing PV or PV and batteries would be more attractive from the point of view of savings. Thus, this cycle will lead to the utilities' "death spiral."

5.3. The Simulation Model

The model uses a year as the unit of time and 0.125 years as the time step. The PV system used in this simulation is 4 kW and for the battery 13.5 kW. When calculating the end user's usage there are two differentiations on hour period: "hour period off peak" (5840 hours/year) and "hour period peak" (2920 hours/year) with "the total hour" adding up to 8760 hours, which is equal to one year. This off peak and peak definition comes from the peak and off peak for PV system—9 AM to 4 PM is considered peak and times outside of those hours are considered off peak.

The model is divided into a few segments, starting from the Demand simulation, going to the regulated cost simulation, the User simulation (which is also divided into a few sub-models), and finally the main stock and flow simulation. The description of the model is organized as follows in this chapter:

- 5.3.1. Demand Simulation
- 5.3.2. Regulated Cost Calculation Simulation
- 5.3.3.User Simulation (simulation per one type of user conditions)
  - 5.3.3.1. Non PV Simulation
  - 5.3.3.2. PV Simulation
  - 5.3.3.3. Battery Simulation
- 5.3.4. Main Stock and Flow Simulation

The overview of the entire system can be seen in Appendix B and the code related to this simulation can be found in Appendix C.

5.3.1. Demand Simulation

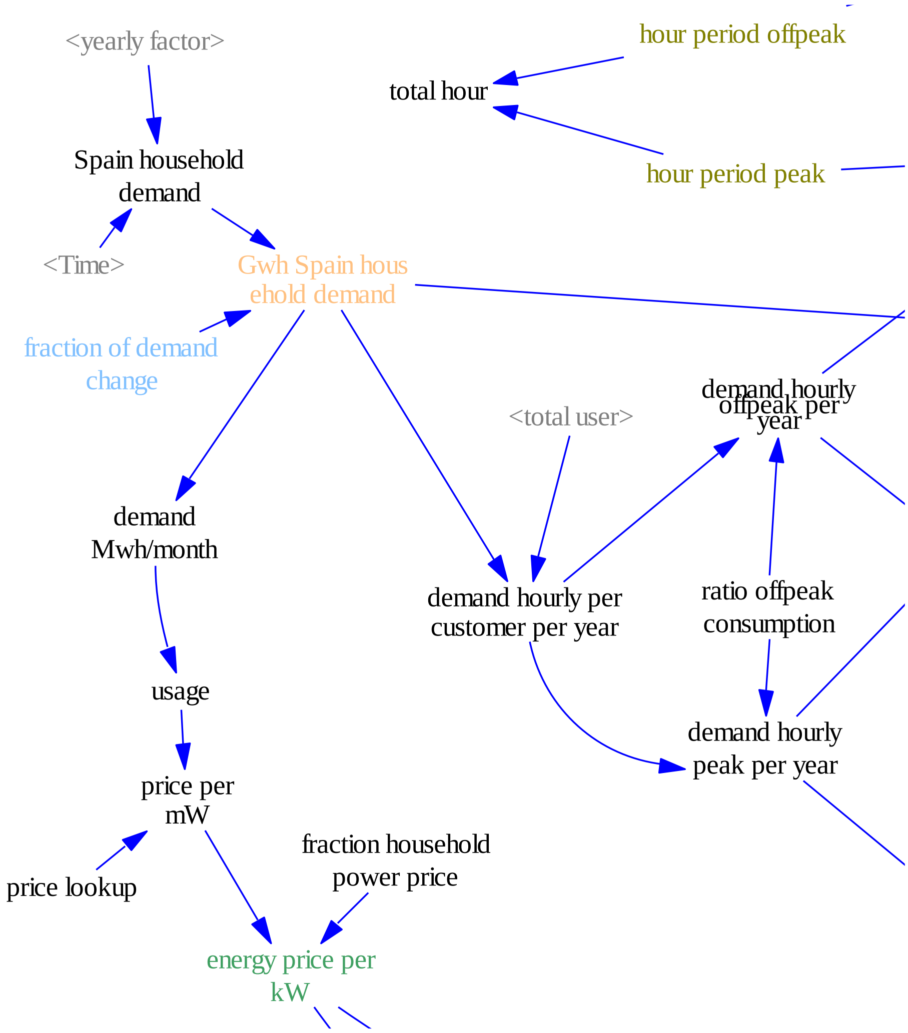


Figure 6 Demand Spain household simulation

In Figure 6, the flows start from “Spain household demand” this data contains total Gigawatt hour of Spanish household electricity usage per year extracted from Eurostat and European Commission’s reference scenario 2016 (for detail check Chapter 6. Data sources). This data used to decide the price for energy per kilowatt hour (“energy price per kWh”) by crossing the reference with REE (Red Electrica de Espana) data.

The variable “fraction of demand change” is used for sensitivity analysis to change the size of demand, in the base case this number is 1, which means the value of “GWh Spain household demand” the same as reference numbers.

*Eq 1. GWh Spain household demand= fraction of demand change*Spain household demand ~ GWh/Year*

That data is converted into “demand MWh/month” to get the price reference for demand usage

*Eq 2. "demand MWh/month"=”usage”= GWh Spain household demand*1000/12 ~ MWh/Month*

“Demand MWh/month” is used to get the monthly energy price that contained in “price per MWh” By using REE data as the cross reference on monthly data. Afterward this “price per MWh” is multiplied by twelve months of the year to get “energy price per kWh.” As, the REE data based on power usage of total Spain electricity, variable “fraction household power price” (35%) is added into “energy price per kWh” equation to get the estimation price for household market price.

Eq 3. price per MWh=price lookup(usage) ~ euro/MWh

*Eq 4. energy price per kWh= price per MWh/1000*12*fraction household power price ~ euro/kWh*

Variable "demand hourly per cust year" is the estimated demand per end user per year in the model, where "Gwh Spain household demand" data is divided with total number of household's data in Spain extracted from INE (Instituto Nacional de Estadistica).

*Eq 5. demand hourly per cust year= (GWh Spain household demand*1e+006)/total user ~ kWh/customer*

This "demand hourly per cust year" is divided into two conditions, offpeak hours demand usage and peak demand usage, the "demand hourly offpeak per year" and "demand hourly peak per year" size are decided through the "ratio offpeak consumption", this data based on the REE data on end user hourly usage behavior (Red Eléctrica de España, 2017).

These data are the input for the PV and non-PV end user electricity usage simulation.

*Eq 6. demand hourly offpeak per year= demand hourly per customer per year*ratio offpeak consumption ~ kWh/customer*

Eq 7. demand hourly peak per year= demand hourly per customer per year(1-ratio offpeak consumption) ~ kWh/customer*

Eq 8. ratio offpeak consumption= 0.643

5.3.2. Regulated Cost Calculation Simulation

Inside the model described in Figure 7, there are cost related with government regulation and ruled through CNMC and every year they released those data. The cost divided mostly into two part contracted capacity cost and volumetric tariffs that attached into electricity tariff in Spain. The contracted capacity consist the amount needed to recover the investment of network system and the volumetric is used to recover the other regulated cost such as RES subsidies.

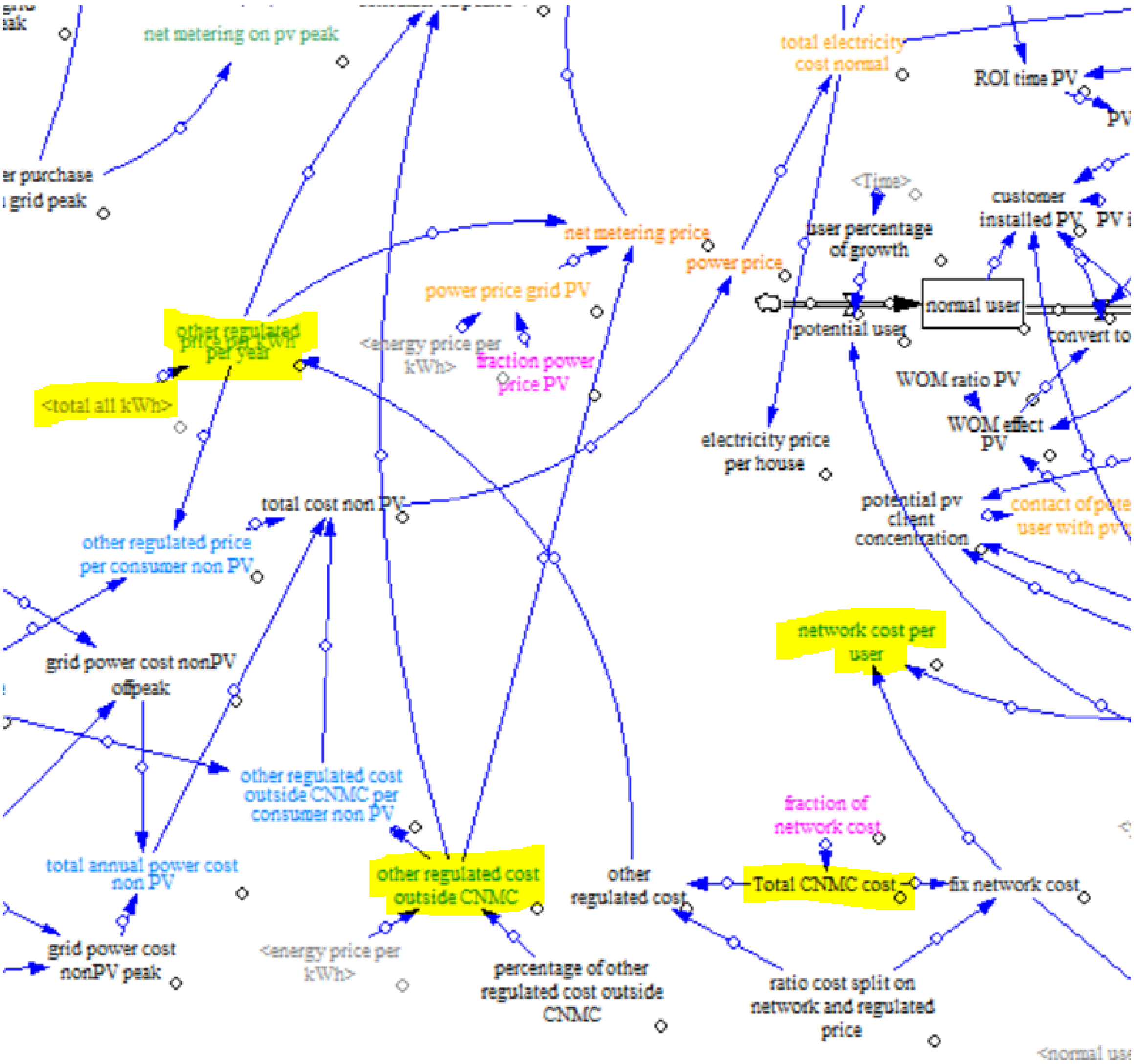


Figure 7 Regulated cost calculation

As the change of yearly cost is not significant, in this simulation the "Total CNMC cost" is based on 2017 CNMC report for 2.0A end user, which is around 6.532 Billion euro. The ratio of the split between the contracted capacity and volumetric capacity is around 60:40. In this model, it is described as "fix network cost" for contracted capacity and "other regulated cost" for volumetric capacity cost.

*Eq 9. fix network cost= ratio cost split on network and regulated price*Total CNMC cost ~ euro/Year*

Eq 10. other regulated cost= Total CNMC cost(1-ratio cost split on network and regulated price) ~ euro/Year*

Aside from that, there are also costs named "capacity payment" and "interruptibility service charge" that is not in CNMC cost breakdown but also charged to the customer. Thus those charges also included in the model as the variable "other regulated cost outside CNMC". From REE extraction of active energy data from 2015 to 2016 the capacity payment and interruptibility service charge is estimated around 18.45% of "energy price per kWh" (Day Ahead and Intraday Market price).

*Eq 11. other regulated cost outside CNMC= percentage of other regulated cost outside CNMC*energy price per kWh ~ euro/kWh*

To distribute the “fix network cost” that are based on contracted capacity, as mentioned in boundaries about the variability of contracted capacity. The assumption that all the end users will have the same contracted capacity is used. Therefore, “network cost per user“ would be the “fix network cost” divided by “total user on grid”. This assumption also applied to PV Battery user while they are still connected to the grid.

Eq 12. network cost per user= fix network cost/total user on grid ~ euro/Year

To distribute the “other regulated cost” which based on volumetric model, “other regulated cost” is divided by the “total all kWh” which is the total kWh electricity demand consumption from the grid per user types; no PV (“normal user”), PV (“pv user”) and Battery users (“pv battery user” and “disconnect from grid”).

Eq 13. other regulated price per kWh per year= other regulated cost/total all kWh ~ euro/kWh

Eq 14. total all kWh= total kWh battery+total kWh PV+total kWh nonPV ~ kWh

Eq 15. total kWh battery= ((pv battery user-saleable battery power))*365 ~ kWh*

*Eq 16. total kWh nonPV= normal user*total power purchase from grid non PV ~ kWh*

*Eq 17. total kWh PV= total net metering power*pv user ~ kWh*

5.3.3. User Simulation

There is a separate submodel for each of the four types of residential customer (non PV, PV, PV+battery, and disconnected PV+battery), each described in a separate subchapter below.

5.3.3.1. Non PV User Simulation

The non PV user simulation is intended to get the total cost per normal end user would have to pay if they consumed based on Spanish household demand which was already explained at demand simulation chapter (Chapter 5.3.1).

From demand simulation chapter, the “demand hourly offpeak per year”[*Eq* 6] and “demand hourly peak per year”[*Eq* 7] are extracted and used for the baseline on yearly non PV user demand.

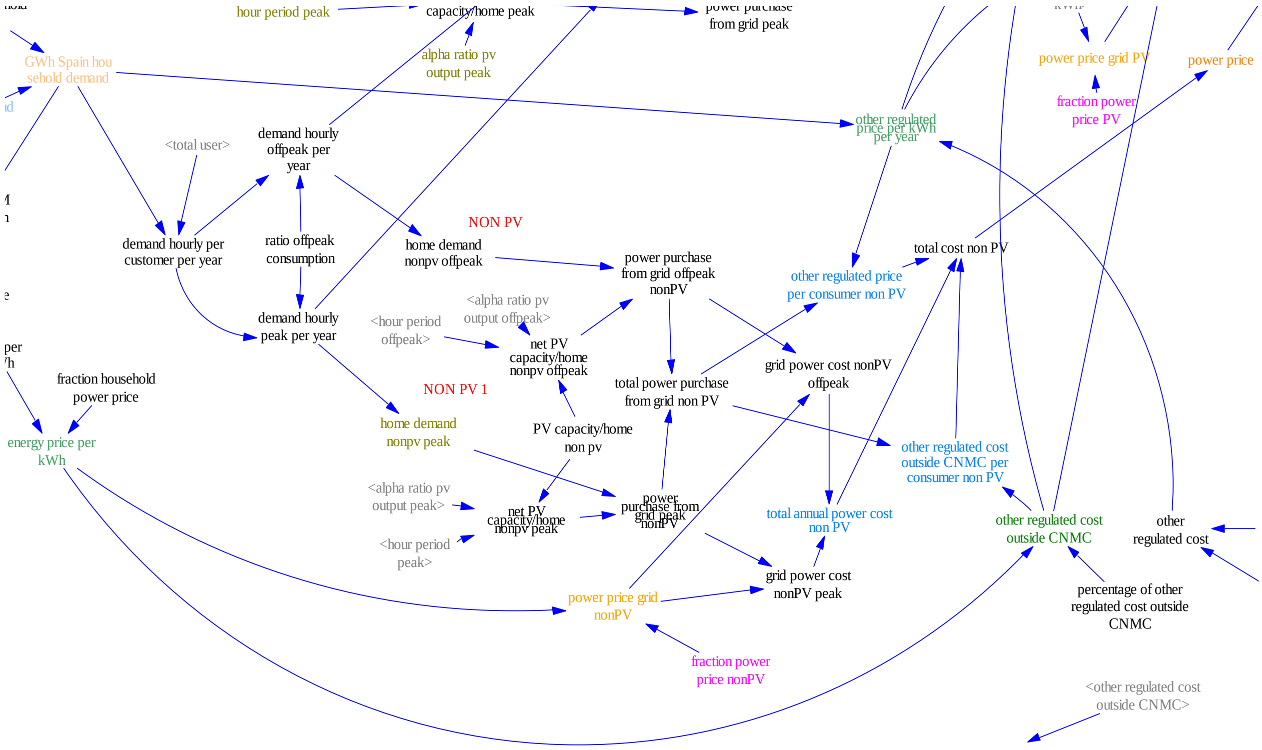


Figure 8 Non PV user simulation

In the case of non PV user, the “alpha ratio pv output offpeak” (0.0256) and “alpha ratio pv output peak” (0.4256) are set based on NREL PV watts calculator on Madrid area (National Renewable Energy Laboratory, 2017). These numbers also have the same values with the “alpha ratio” used in PV user simulation below; the difference between two simulations is in the “PV capacity/home non pv” for Non PV user is 0, meanwhile for the PV user is 4 kW.

The “power purchase from grid offpeak nonPV” are the difference between “home demand nonPV offpeak” and "net PV capacity/home nonpv offpeak", and “power purchase from grid peak nonPV” are the difference between “home demand nonPV peak” and "net PV capacity/home nonpv peak". In this case due to ““PV capacity/home non pv” is 0 then the value of “power purchase from grid” would be purely come from “home demand nonpv peak/offpeak”.

Eq 18. "net PV capacity/home nonpv peak"= alpha ratio pv output peak"PV capacity/home non pv"*hour period peak ~ kWh/customer*

Eq 19. "net PV capacity/home nonpv offpeak"= alpha ratio pv output offpeak"PV capacity/home non pv"*hour period offpeak ~ kWh/customer*

Eq 20. power purchase from grid offpeak nonPV= (home demand nonpv offpeak-"net PV capacity/home nonpv offpeak") ~ kWh/customer

Eq 21. power purchase from grid peak nonPV= (home demand nonpv peak-"net PV capacity/home nonpv peak") ~ kWh/customer

After getting the net power purchase from grid *Eq* 6 and *Eq* 7, each those values are multiplied with each respected regulated costs, “power price grid nonPV”, “other regulated cost outside CNMC”, “other regulated price per kWh per year”. Those numbers then summed up and added with “network cost nonPV” to get the value of “total electricity cost normal” this is the total value that non PV user would pay every year for their electricity usage.

*Eq 22. other regulated price per consumer non PV= total power purchase from grid non PV*other regulated price per kWh per year ~ euro/Year*

*Eq 23. grid power cost nonPV offpeak= power price grid nonPV*power purchase from grid offpeak nonPV ~ euro/customer*

*Eq 24. grid power cost nonPV peak= power price grid nonPV*power purchase from grid peak nonPV ~ euro/customer*

Eq 25. total annual power cost non PV= grid power cost nonPV offpeak+grid power cost nonPV peak ~ euro/customer

*Eq 26. other regulated cost outside CNMC per consumer non PV= other regulated cost outside CNMC*total power purchase from grid non PV ~ euro/customer*

Eq 27. total cost non PV="power price"= other regulated price per consumer non PV+total annual power cost non PV+other regulated cost outside CNMC per consumer non PV ~ euro/Year

Eq 28. total electricity cost normal= power price+network cost nonPV ~ euro/customer

5.3.3.2. PV User Model Simulation

The way this PV user simulation work is actually similar to the non PV simulation. The difference are in the "PV capacity/home non pv" value at 4 kW and the application of "net metering switch" inside the model.

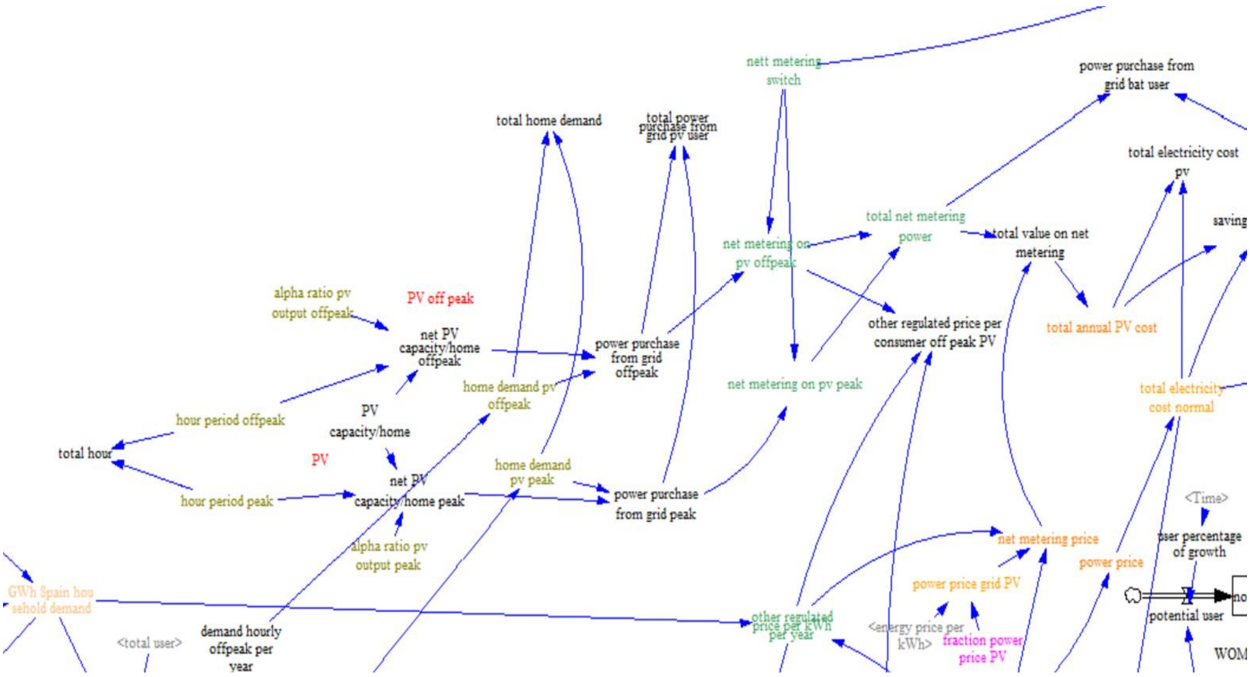


Figure 9 PV user model simulation

As seen in Figure 9, after the amount of power used in PV household is calculated through the variables "power purchase from grid offpeak" and "power purchase from grid peak" (the same concept calculation as Eq 20 and Eq 21, there are variables named "net metering on pv offpeak" and "net metering on pv peak" this value actually contain the same value as "power purchase from grid peak/offpeak" with the difference in connection logic for "net metering switch". These variables basically decide the values used for net metering condition (1=on, 0=off). If the net metering is off then the value of "net metering on pv peak/offpeak" should not be lower than 0, due to the logic in this model if the value is less than 0 mean that the end user is selling the extra energy into the grid. Without the net metering function prosumers cannot sell the extra energy to the grid, thus if the “power purchase from grid peak/offpeak” are less than 0, then “net metering on pv peak/offpeak” will be set as 0.

Eq 29. net metering on pv offpeak= IF THEN ELSE(net metering switch=1,power purchase from grid offpeak,IF THEN ELSE(power purchase from grid offpeak<0, 0 , power purchase from grid offpeak)) ~ kWh/customer

Eq 30. net metering on pv peak= IF THEN ELSE(net metering switch=1,power purchase from grid peak,IF THEN ELSE(power purchase from grid peak<0, 0 , power purchase from grid peak)) ~ kWh/customer

However, if the “net metering switch” is on, it is allowing the end user to sell their extra energy to the grid with the same price as their purchase price from the grid. This assumption based on the US regulation for net metering.

To get the total cost for PV user in form of variable “total value on net metering”, “total net metering power” is multiplied with the “net metering price”, which consist all the regulated and power cost aside from network cost. The network cost will be added in “total annual PV cost” as the total cost of electricity that the PV user need to pay each year.

Eq 31. total net metering power= net metering on pv offpeak+net metering on pv peak ~ kWh/customer

*Eq 32. total value on net metering= (net metering price*total net metering power) ~ euro/customer*

Eq 33. net metering price= other regulated cost outside CNMC+other regulated price per kWh per year+power price grid PV ~ euro/kWh

Eq 34. total annual PV cost= total value on net metering+network cost PV ~ euro/customer

5.3.3.3. Battery User Simulation

In this simulation, the way battery usage is simulated daily charge-discharge cycles. It is mentioned before that the battery usage in this simulation is limited to 13.5 kWh and 4 kW PV system. This configuration system was tested using manual charge and discharge calculation sheet to ensure that the charging and discharging process in the model will not be over the limit. This part of simulation as described in Figure 10 only focus on the total available power from the system, for the possibility of going autonomous will be explained more detail in 5.3.4 Main stock and flow simulation part.

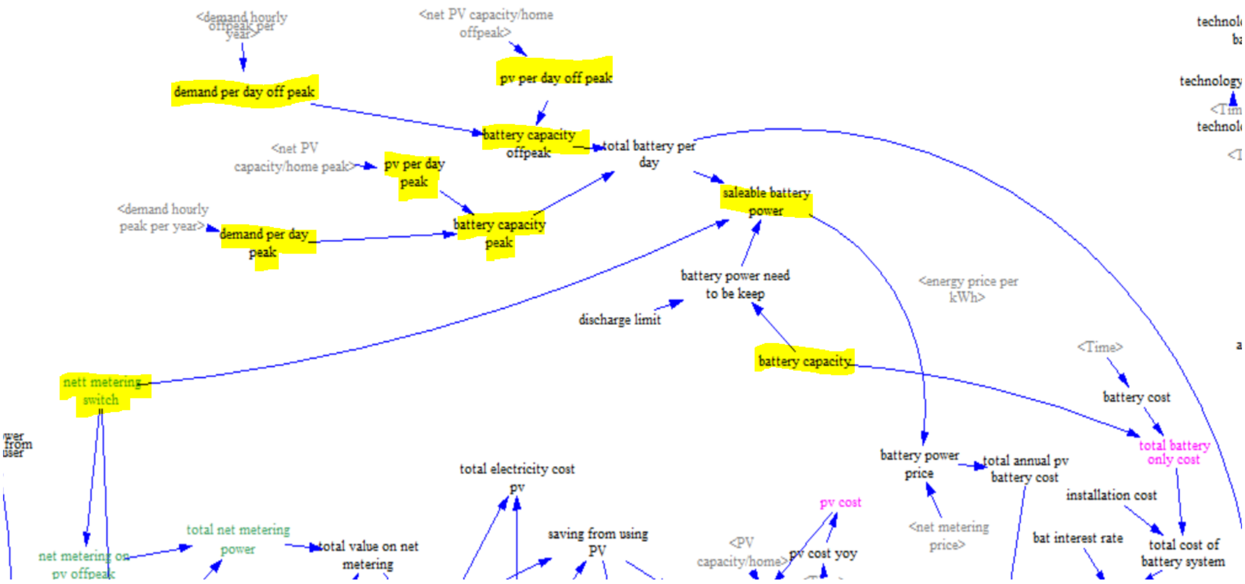


Figure 10 Battery user simulation

The concept of this simulation is similar to non PV and PV users calculation. The differences are on the “demand hourly offpeak per year”, “demand hourly peak per year”, “net PV capacity/home offpeak”, and “net PV capacity/home peak”, all of this values divided by 365 each to get the daily average numbers.

Eq 35. demand per day peak= demand hourly peak per year/365 ~ kWh/customer

Eq 36. demand per day off peak= demand hourly offpeak per year/365 ~ kWh/customer

Eq 37. pv per day peak= "net PV capacity/home peak"/365 ~ kWh/customer

Eq 38. pv per day off peak= "net PV capacity/home offpeak"/365 ~ kWh/customer

To get “battery capacity peak” and “battery capacity offpeak”, “pv per day peak” subtracted with “demand per day peak,” as well “pv per day off peak” subtracted with “demand per day off peak.” The sum of battery capacity per day valued as variable “total battery per day.” If this number is positive, it is mean there is extra battery left over that can be sold to the grid.

Eq 39. battery capacity peak= pv per day peak-demand per day peak ~ kWh/customer

Eq 40. battery capacity offpeak= pv per day off peak-demand per day off peak ~ kWh/customer

Eq 41. total battery per day= (battery capacity offpeak+battery capacity peak) ~ kWh/customer

In this simulation, assuming the battery work really well on discharge capacity ability. Thus, it is only needed to keep around 5% of its capacity, this is set as variable “discharge limit” for the 5% limit, and the final number of “battery capacity” that need to be preserved as “battery power need to be keep”. The difference between the “battery power need to be keep” and “total battery per day” are “saleable battery power,” this is the amount of battery that can be sold to the grid after taking out the minimum limit of battery discharge. All these numbers are still in a daily format. Thus, when calculating the price, those number will need to be multiplied by 365.

*Eq 42. battery power need to be keep= discharge limit*battery capacity ~ kWh*

As seen in the charge there is also a function of net metering at “saleable battery power”, this is to put a limit on how much power can be sold to the grid. If the “net metering switch” is on then the left-over battery after taking out minimum battery discharge can be sell but if net metering switch is off, it is mean that 0 power can be sell into the grid.

Eq 43. saleable battery power= IF THEN ELSE(net metering switch=1,(total battery per day-battery power need to be keep),IF THEN ELSE(total battery per day>0, 0 , (total battery per day-battery power need to be keep))) ~ kWh/customer

5.3.4. Main Stock and Flow Simulation

The main stock and flow model as can be seen in Figure 12. This stock and flow reflect the total population of household customer per each type of end users. As seen in Figure 12 for the detailed stock and flow chart which is build based on the aggregated CLD from Figure 5.

There are four stocks which can flow in a limited way as seen in Figure 11 the simplified version of Figure 12, this model only allows the conversion from “normal user” to “PV user”, from “PV user” to “PV battery user”, and from “PV battery user” to “disconnect from grid”. For example, from “normal user” cannot convert directly into “PV battery user”, and from “disconnect from grid” the end user is assumed sufficient to fulfill their own needs and do not have the will to go back to the grid.

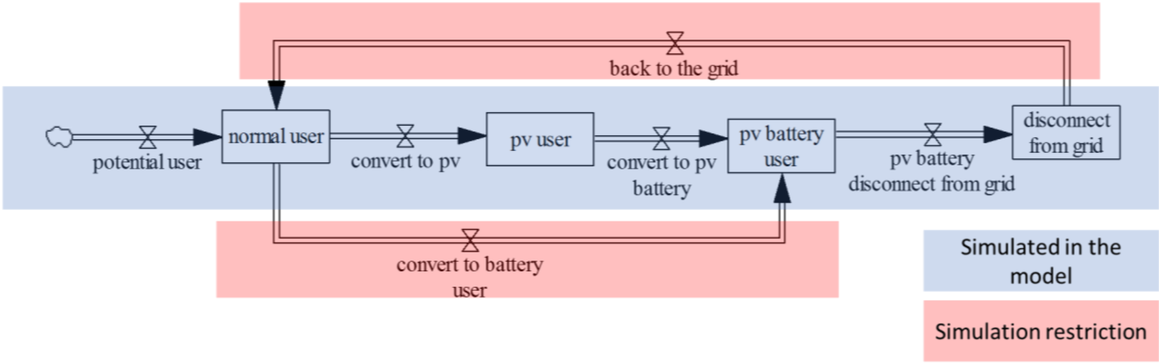


Figure 11 The simplified stock and flow overview

From "normal user" to "PV user" conversion, there are two main considerations for investing decision in PV. One is based on the Return of Investment (ROI) time, and the other is the WOM (Word of Mouth) factor which can leverage the amount of user willing to install PV. The same logic also applied from PV user to PV battery user conversion. The logics used for PV battery user to disconnect from the grid are based on whether they can suffice on PV battery for a year and whether the PV battery annual cost is cheaper than paying the network cost, this will be explained in this model further.

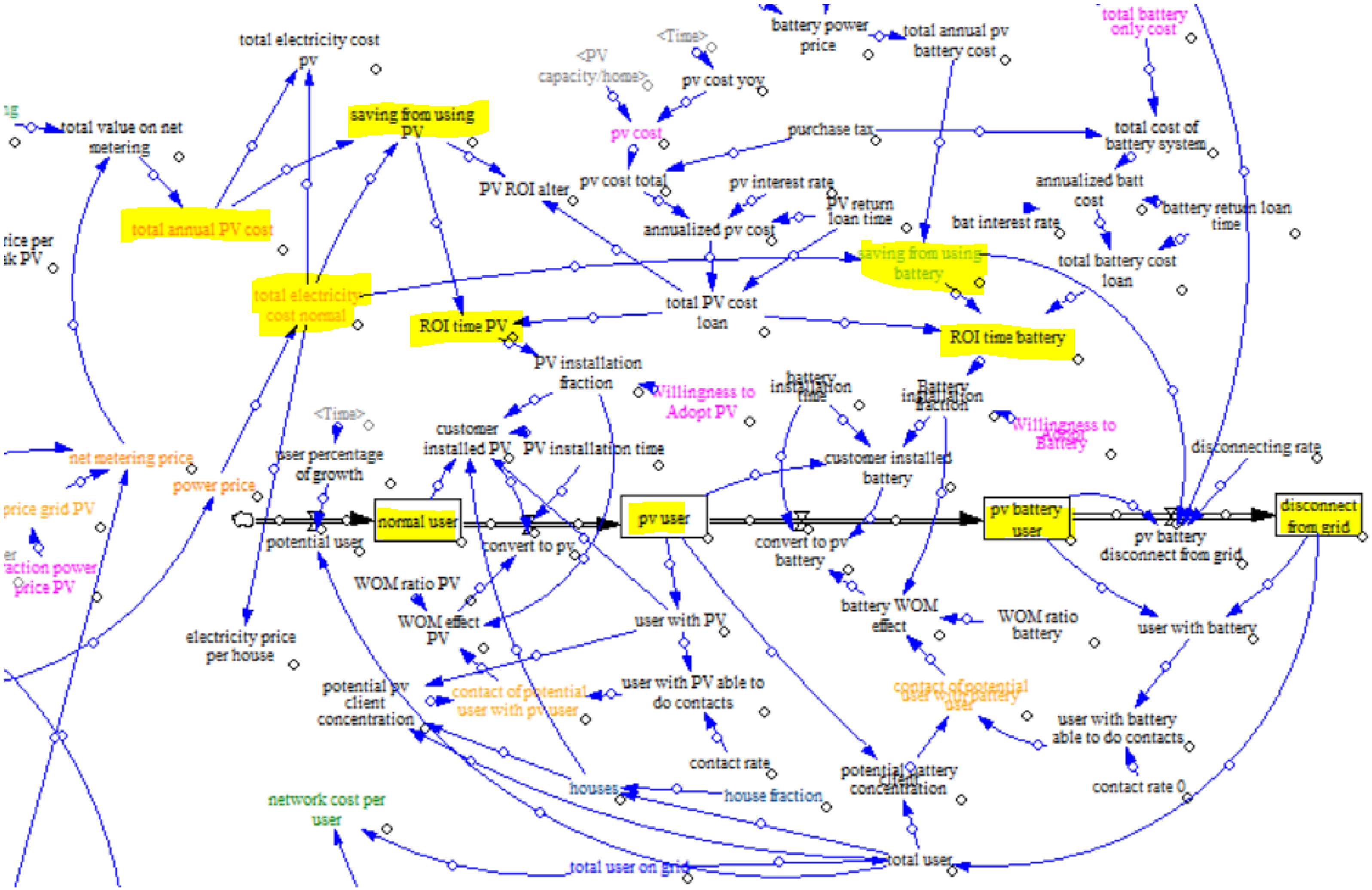


Figure 12 Main stock and flow

The “ROI time PV” factor is the time to take for the end user to recover their money by using the PV, by using the equation of the total cost for PV (“total PV cost loan”) divided by the “saving from using PV.” If the “saving from using PV” lower than 0 then the ROI assumed to be 50 years.

This calculation is using the assumption that the user will take a loan or mortgage for the PV investment. The total cost for PV (“total PV cost loan”) is higher than the original PV cost (“pv cost total”), due to the mortgage assumption (“annualized pv cost”) of a 10 years loan time (“PV return loan time”) from Laws, et al. (2017) and 8% for interest rates (“pv interest rate”).

The total PV cost (“pv cost total”) before mortgage comes from the ETRI Year on Year (YoY) PV price estimation data (“pv cost yoy”), multiplied with the size of PV used ("PV capacity/home") and also multiplied with “technology price”, as variable for scenario to modified the price of “pv cost yoy”. Afterward, this total PV cost is added with 21% “purchase tax” for Spain market resulted in “pv cost total” variable.

*Eq 44. total PV cost loan= PV return loan time*annualized pv cost ~ euro/customer*

*Eq 45. annualized pv cost= ((((1+pv interest rate)^PV return loan time)*pv interest rate)/(((1+pv interest rate)^PV return loan time)-1))*pv cost total ~ euro/Year/customer*

*Eq 46. pv cost total= (1+purchase tax)*pv cost ~ euro/customer*

*Eq 47. pv cost= pv cost yoy*technology price*"PV capacity/home" ~ euro*

The amount of “saving from using PV” comes from the difference between “total annual PV cost”[*Eq* 34] which is the money for PV user have to pay yearly for their electricity usage and “total electricity cost normal”[*Eq* 28] which is the money for non PV user have to pay yearly for electricity usage.

Eq 48. ROI time PV= IF THEN ELSE(saving from using PV>0, (total PV cost loan/saving from using PV), 50) ~ Year

Eq 49. saving from using PV= total electricity cost normal-total annual PV cost ~ euro/customer

This “ROI time PV” is used as input to get “PV installation fraction”, this variable determines how many of the end users install PV in one year based on their willingness to install and the ROI fraction (“ROI time PV”) itself. The chart for cross reference ROI time with PV adoption rate for this simulation based on Meehan (2015) research on calibrated adoption rate for SRP, Arizona customers as seen in Figure 13 and Table 1. Drury, et al. (2010) also shared the same shape of graphical functions on their research for residential PV adoption rate in US market. The reason I used this chart because there is no sufficient data on the historical Spanish PV household market. The lower the time needed for ROI, the more eager an end user will be to install the PV, whereas the higher the ROI span, the less eager the end user will be to install the PV system. When the ROI time is bigger than 30 years, this model assumed nobody wants to install as it deemed not profitable at all, that is why in the “ROI time PV” equation when “saving from using PV” goes minus nobody want to invest in PV. In this model, the “willingness to adopt PV” is set as 1 for base scenario.

Table 1. Table of PV installation fraction (Meehan, 2015)

ROI time (Year)	Instalation fraction (%)
0	100.00%
1	49.50%
2	39.90%
3	32.70%
4	25.30%
5	20.30%
6	14.60%
7	10.00%
8	6.00%
9	4.00%
10	3.00%
11	2.00%
12	1.50%
13	1.30%
14	1.00%
15	0.80%
16	0.70%
17	0.60%
18	0.50%
19	0.40%
20	0.30%
21	0.25%
22	0.20%
23	0.16%
24	0.13%
25-30	0.10%
31-50	0%

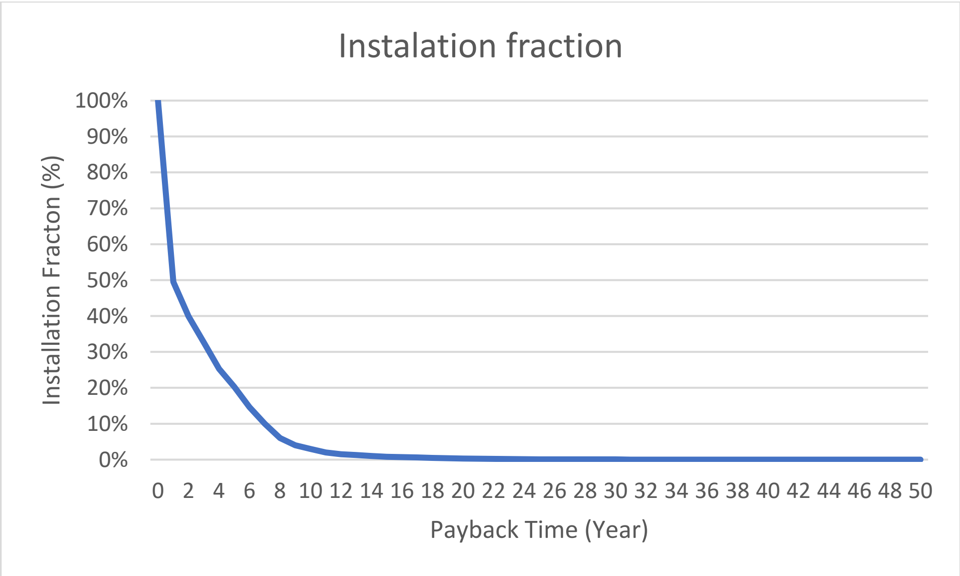


Figure 13 PV installation fraction (Meehan, 2015)

Eq 50. PV installation fraction= WITH LOOKUP (ROI time PV/Willingness to Adopt PV) ~ Dmnl

Eq 51. Willingness to Adopt PV= adoption rate ~ Dmnl

In this model, the estimation time needed to install PV ("PV installation time") is set on 0.5 year and with the assumption that only detached house that can install PV. Thus, the customer that can install PV ("customer installed PV") in this equation is limited with total houses from total household available (30% of the total household in 2014). This percentage estimation comes from IDAE data houses percentage in 2014 around 30% of total household in Spain.

Eq 52. customer installed PV= IF THEN ELSE((user with PV<houses),(normal user*PV installation fraction/PV installation time),0) ~ customer

The second factor of the conversion is the WOM factor, this factor also affects the number of normal end user conversion to PV. Therefore, the total normal user that converting into PV user ("convert to pv") is the sum of the end user installed PV that comes purely from ROI calculation ("customer installed PV") and the end user that comes from the WOM effect divided by the time needed to install the PV.

Eq 53. convert to pv= MAX(customer installed PV+(WOM effect PV/PV installation time),0) ~ customer

The concept of this WOM is on how big is the potential PV users can get in contact with the current PV users, and how big the contact rate per person per year, and in the end how convincing these PV users able to convince the potential PV users to convert. Which shown in this model as "WOM ratio PV." WOM ratio is set at 0.78 percentage point based on research by Bollinger and Gillingham (2012) on WOM effect on PV installation (Bollinger & Gillingham, 2012).

The WOM effect has a limit constraint of the end user who owns detached house is the only one that can be influenced to install PV.

Eq 54. WOM effect PV= IF THEN ELSE(PV installation fraction > 0, MAX(WOM ratio PV*contact of potential user with pv user,0),0) ~ customer/Year

Eq 55. contact of potential user with pv user= potential pv client concentration*user with PV able to do contacts ~ contact/Year

Eq 56. potential pv client concentration= (houses-user with PV)/total user ~ Dmnl

Eq 57. user with PV able to do contacts= user with PV*contact rate ~ contacts/Year

Eq 58. user with PV= pv battery user+pv user+disconnect from grid ~ customer

Eq 59. contact rate= 1 ~ contact/customer/Year

The PV user to PV battery user conversion is also using the same logic with the normal user conversion to PV user [*Eq* 44 until Eq 59]. Where ROI and WOM factor are playing in significant role to convert this user.

In the PV battery to disconnect from grid user, the disconnect from grid user is exempted from paying regulated cost due to the assumption that this user is able to self-suffice themselves and even able to sell an extra energy to the grid. Due to that logic, the PV battery user's defection based on the logic whether they can meet their entire demand over the year on PV and Battery usage only. If they are able to fulfill that condition, and their saving for using PV battery only are larger than paying the network cost they will defect from the grid.

Eq 60. pv battery disconnect from grid= IF THEN ELSE(total battery per day>0,IF THEN ELSE((-total annual pv battery cost<network cost PV),pv battery user/disconnecting rate, 0),0) ~ customer

By using this simulation model, we can see the behavior of Spanish household market on their decision to invest RES system (PV and Battery) and the effect they have on the cost recovery especially on network cost. So far there is no similar model, especially for Spanish household market.

6. Data Sources

The data used in this simulation is summarized in Table 2. In this chapter, some of the details of the data extraction and processing processes are discussed, at least for the data items that have already been explained.

Table 2. Data needed

Customers	**Technology [6.2]**	**Supply of electricity [6.1]**
Population of each type of end user (commercial, residential, etc.)	PV capital cost and output by hour	Power prices
Historical rate of technology adoption (As a function of prices of electricity and technology) [Table 1 on Chapter 5.3.4]	Battery price	Network cost to be recovered
Base electricity demands (no PV) [6.3.]		

The next subchapters will explain the information and data used in the model outside—that has been mentioned in Chapter 5.3—in more detail.

Chapter 6.1 will focus on the supply of electricity cost and cost related to regulation. Chapter 6.2 will cover the source and information for the technology data. And finally, in Chapter 6.3 and 6.4 the customer's data for demand and the population is explained.

6.1. Cost Data

The model using four kinds of cost data: energy price, network cost from Comisión Nacional de los Mercados y la Competencia (CNMC), other regulated cost from CNMC, and other regulated cost which is not included in the CNMC report.

Energy price data on Table 3 comes from REE website's monthly average price "Day Ahead" market component, for the total Spanish energy price combined with the monthly average's final sum of components (Red Eléctrica de España, 2017). This data is then calibrated with Consumption profiles PVPC billing related to 2.0.A tariff (default tariff) to get the estimation of the Spanish household usage price and fraction 0.35 from data calibration (Red Eléctrica de España, 2017).

Table 3. Calibrated Day Ahead market data for model lookup function (Red Eléctrica de España, 2017)

Monthly average price final sum of components (Euro)	**Monthly final energy (MWh)**
58.06	19,799,299
59.52	19,873,850
63.84	20,548,101
61.34	20,776,593
81.7	23,014,493

The assumption for network cost recovery ("fix network cost" as the variable in the model) comes from the contracted capacity of the data extracted from CNMC report that is published each year. Inside the report, only 2.0.A segment data (assumption for the household market) is used and this data consists of contracted capacity cost and additional regulated cost in the form of volumetric tariffs, which is also charged to the customer. This contracted capacity basically represents the network cost that needs to be recovered. Meanwhile, the volumetric tariff consists of various policy aspects such as RES Support, the cost of energy losses, tariff deficit, nuclear moratorium, and others. The split of contracted capacity and volumetric tariff in this model were assumed as 60:40 according to the average split on YoY CNMC data as seen in Table 4 (Comisión Nacional de los Mercados y la Competencia, 2015; Comisión Nacional de los Mercados y la Competencia, 2016; Comisión Nacional de los Mercados y la Competencia, 2017; Comisión Nacional de los Mercados y la Competencia, 2016). Due to the similarity in the total cost each year, for this simulation model data from 2014 is used.

Table 4. CNMC cost from 2014-2017 for segment 2.0A (Comisión Nacional de los Mercados y la Competencia, 2015; Comisión Nacional de los Mercados y la Competencia, 2016; Comisión Nacional de los Mercados y la Competencia, 2017; Comisión Nacional de los Mercados y la Competencia, 2016)

Year	Contracted Capacity (k€)	Volumetric Cost (k€)	Total (K euro)	Contracted Capacity (MW)	Power Consumption (GWh)
2014	3,890,062	2,641,716	6,531,778	102,253	60,002
2015	3,990,836	2,561,104	6,551,940	104,902	58,174
2016	3,968,391	2,558,221	6,526,612	101,922	56,849
2017	3,851,616	2,482,943	6,334,559	104,758	57,003

Aside from CNMC regulation data, there are also cost named capacity payments and interruptibility service charges that are not in the CNMC cost breakdown. But, they are also charged to the customer, thus those charges are included in the model. The source of that data comes from REE extraction of active energy data from 2015 to 2016, the capacity payment and interruptibility service charge being around 18.45% of Day Ahead and Intraday Market price (Red Eléctrica de España, 2017).

6.2. Technology Data

The technology cost data is extracted from the European Union Institute for Energy and Transport report (European Union Institute for Energy and Transport, 2014). This research is using the average price of the CAPEX, low and high, as the price reference.

Based on their research on Solar Photovoltaic (PV) there is an expectation that the solar PV will grow significantly in Europe and the price will also decrease significantly over time. They separated the type of solar systems into several commercial solar PV systems, residential solar PV systems, and solar thermal electricity power plants without thermal storage. The way they estimate the cost of the components is by including these factors in the CAPEX for Solar PV: civil and structural costs, major equipment costs, balance of plant costs, electrical and I&C supply and installation, project indirect costs and interconnection costs (European Union Institute for Energy and Transport, 2014).

Table 5. Residential Solar PV <100 kW estimation cost (European Union Institute for Energy and Transport, 2014)

	CAPEX (€2013/kW)		
Year	Average	Low	High
2014	1500	1150	1850
2020	1100	950	1250
2030	985	850	1120
2040	935	810	1060

As for battery storage, Lithium-ion battery is considered to have better performance, be more efficient, and have better energy density while being durable with low self-discharge rates compared to other battery types. As it is widely used, the capital costs are estimated to decrease around 66% during 2010-2020 and 14% during 2020-2030.

Table 6. Li-ion storage battery estimation cost (Energy storage capability) (European Union Institute for Energy and Transport, 2014)

	CAPEX (€2013/kWe)		
Year	Average	Low	High
2014	490	390	590
2020	165	130	200
2030	140	110	170
2040	137.5	110	165

PV data was extracted from the NREL PV watts calculator on the Madrid area, then manually calculated and separated into the peak and off peak times for PV systems, which is again, 9 AM to 4 PM for peak; outside those hours for off peak.

Table 7. PV peak-offpeak hour and production (National Renewable Energy Laboratory, 2017)

Condition	Produced AC power (W)	Hour
peak	4,971,308.26	2,920
offpeak	598,716.98	5,840

6.3. Residential Demand Data

The data for household demand comes from Eurostat and the European Commission's reference scenario 2016. EU Commission involves national experts from EU countries in order to create modeling for energy, transport, and climate action to enable countries' related policy-makers to analyze those sectors based on the current EU policy framework. (The Directorate-General for Energy, European Commission, 2017). Historical data of overall electricity usage and household usage retrieved from Eurostat can be seen in

Table 8 (Eurostat, European Commision, 2017).

Table 8. Eurostat Spain electricity usage in GWh (Eurostat, European Commision, 2017)

GEO/TIME	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Spain total	246,126	250,785	255,097	239,779	245,393	242,619	239,420	230,951	226,971	232,082
Residential	67,882	68,213	69,438	71,411	75,679	76,107	75,088	71,060	70,710	70,056
% of Resi	27.6%	27.2%	27.2%	29.8%	30.8%	31.4%	31.4%	30.8%	31.2%	30.2%

Based on historical data, the average of residential usage from 2006 to 2015 is 29.7% of the total electricity usage in Spain. Thus, this data is used to adjust EU reference scenario 2016 for Spanish households utilized in this model, due to the EU reference file using overall Spain electricity data as seen in Table 9.

Table 9. Spain household forecast based on EU reference scenario 2016 in GWh (The Directorate-General for Energy, European Commission, 2017)

GEO/TIME	2020	2025	2030	2035	2040
Spain total	246,612	249,290	256,699	263,240	270,277
Residential	73,244	74,039	76,240	78,182	80,272
% of Resi	29.7%	29.7%	29.7%	29.7%	29.7%

6.4. Spain Household Data

The variable of “total user” in the model contains a total household population in Spain. This data comes from INE (Instituto Nacional de Estadistica), which is Spain National Statistics Institute. They have provided this information every two years, with a 15-year projection horizon, through historical series and inter-census household estimation since 2002. The data is also coherent with population projections results (Instituto Nacional de Estadistica, 2016). The data provided by INE can be seen in

Table 10 below, as INE only provides the data until 2031, from 2032 onwards the growth of the household is assumed to be an average 0.25% YoY growth.

Table 10. Spanish household data (Instituto Nacional de Estadistica, 2016)

year	Number of Household	YoY growth
2014	18,252,887	0.46%
2015	18,353,761	0.55%
2016	18,378,691	0.14%
2017	18,449,131	0.38%
2018	18,519,338	0.38%
2019	18,585,275	0.36%
2020	18,647,760	0.34%
2021	18,717,392	0.37%
2022	18,777,767	0.32%
2023	18,837,272	0.32%
2024	18,900,076	0.33%
2025	18,963,395	0.34%
2026	19,023,337	0.32%
2027	19,079,494	0.30%
2028	19,135,054	0.29%
2029	19,190,030	0.29%
2030	19,238,175	0.25%
2031	19,281,354	0.22%
2032	19,323,773	0.22%
2033	19,368,218	0.23%
2034	19,414,701	0.24%
2035	19,463,238	0.25%
2036	19,513,843	0.26%
2037	19,564,579	0.26%
2038	19,617,403	0.27%
2039	19,666,446	0.25%
2040	19,721,512	0.28%

According to the IDE report, there is total of 17,199,630 households, and 5,159,889 are detached houses. Thus, in this simulation model assumes 30% of the total household population consists of detached houses (Instituto para la Diversificación, 2012). The data used in the simulation can be found in Figure 14.

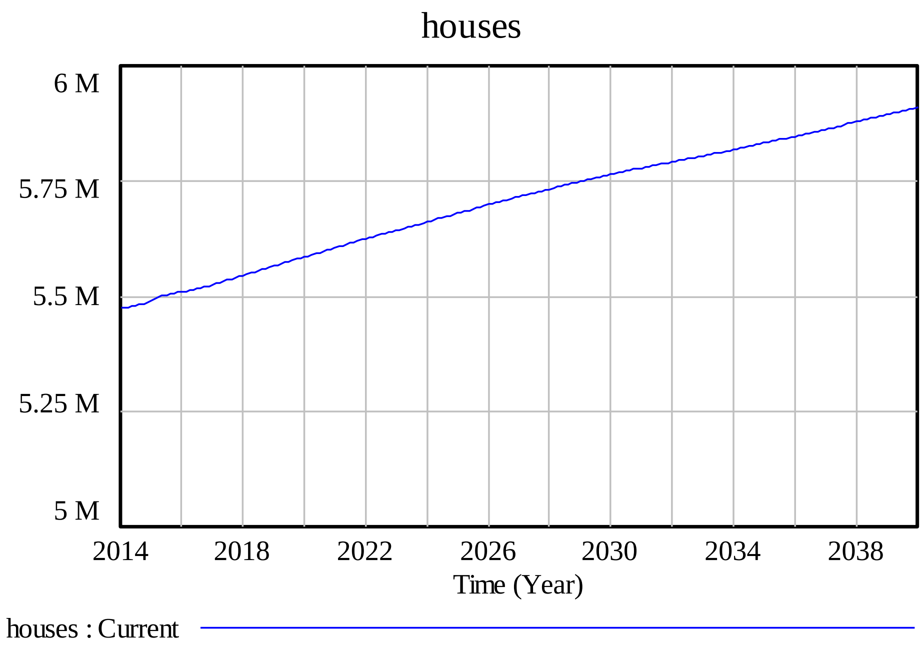


Figure 14 Houses evolution in Spain market

7. Model Validation

This section focuses on the validation process of the SD model included in this research. As it has been mentioned by Sterman (2000), "systems thinking requires understanding that all models are wrong and humility about the limitations of our knowledge" (Sterman, 2002). The reason is that a model is a simplification of reality (Sterman, 2000). Even some modelers stated that it is impossible to validate models in the sense of establishing the truth, but a test can be done to see whether the model is useful (Sterman, 2000).

This model will be tested using the methods below:

A qualitative test, which is done through:

- Boundary adequacy test
- Structure confirmation test
- Parameter confirmation test

A quantitative test done through:

- Extreme conditions test
- Sensitivity analysis

7.1. Boundary Adequacy Test

This test is done to see whether the model appropriately represents real world conditions, and if the exogenous variables should stay exogenous—or if they should be modeled as endogenous variables (Sterman, 2000).

Exogenous variables in this model can be seen in Chapter 5.1; however, some of those variables are explained below:

Network & regulated cost is one of the main important exogenous variables; this number affects the flow of tariffs' distribution and the customer's decision on deciding whether the total investment is worth it or not. The data itself came from the Spanish government and was released per year as we normally cannot know the specific cost of the entire network and regulation split in terms of individual investment break down.

User growth in this model is treated as an exogenous variable, even though the user's stock flow will be affected by the new user growth flow. The user's flow in the model is limited to the one related to household electricity and not justified enough to affect user growth of the entirety of Spanish households, where this number can be affected by GDP, economic growth, and other factors. Thus, the growth used in the model is coming from INE as mentioned in Chapter 6.3.

Electricity price in this model is not modeled in detail as one big sub-model, but rather referenced from REE sources due to similar reasons with user growth. This model focuses only on the household part of Spain's electricity market. Meanwhile electricity price is affected by various factors such as total demand from Spain's market, import and export of energy, power flow, and a number of other factors.

7.2. Structure Confirmation Test

The structure confirmation test was used to check whether the aggregated SD model was in-line and appropriate enough with the physical reality of the real world (Sterman, 2000).

This model was built with the perspective of the real world Spanish electrical system and stakeholders' assumptions. It is elaborates on some input and formatting that has been applied by other researchers in the literature review. It is clear that this model is still lacking compared to real condition, such as being able to deal with a customer's decision for investment. This model is only focused on two points: ROI and the WOM effect. Whereas, in the real world, there are more aspects that can influence the customer's decision. However, the qualitative validation will provide information on whether the behavior in this model can be compared with real world conditions.

7.3. Parameter Confirmation Test

The parameter confirmation test is used to check whether the parameters or variables are acceptable and have a reasonable counterpart in the real world (Sterman, 2000).

The parameter used in this model is mostly based on the literature mentioned in Chapter 2 and historical or real world references, which is described in Chapter 5.3 and Chapter 6.

7.4. Extreme Conditions Test

The extreme conditions test is considered a critical test because it can show whether the model is still giving realistic results when subject to extreme conditions. This test is using scenario 1 for the current condition of Spain's regulations (no net metering and mixed tariffs).

The hypotheses to be tested under the extreme conditions test are:

- If the demand is really low (20% of the original demand), the end user has no interest in investing for RES as the saving from RES is too insignificant to have their investment worth.
- If the demand is really high (200% of the original demand), the number of users disconnecting from the grid will be low, or zero, due to the fact that the demand is higher than the system threshold.

- If the willingness to adopt PV/batteries is really high (5), the end user will still invest even though the demand is really low (20% of the original demand).
- If the willingness to adopt PV/batteries is really high (5), the conversion of the user will be faster and the cost of regulation will be increased.
- If the power price is really low (10% of the original price), the end user will have no interest in investing for RES since the savings from RES will be too little to get a good investment in return.

These hypotheses are tested one by one; the results can be found in Appendix A. There are no structural changes on the model and the results show the model behaving as expected under extreme conditions.

7.5. Sensitivity Analysis

Sensitivity analysis was used to test the robustness of the model conclusion under uncertainty assumption (Sterman, 2000). Some of this test used the Monte Carlo simulation in Vensim with 200 runs under latin hypercube. The variation used in this test is 10%.

The external factors that influenced the model and were being tested: fraction of demand change, willingness to adopt, and price of the technology.

Fraction of demand change around a variation of 10% showing numerically sensitivity affecting the user conversion numbers, but not affecting the original normal user behavior as seen in Figure 15.

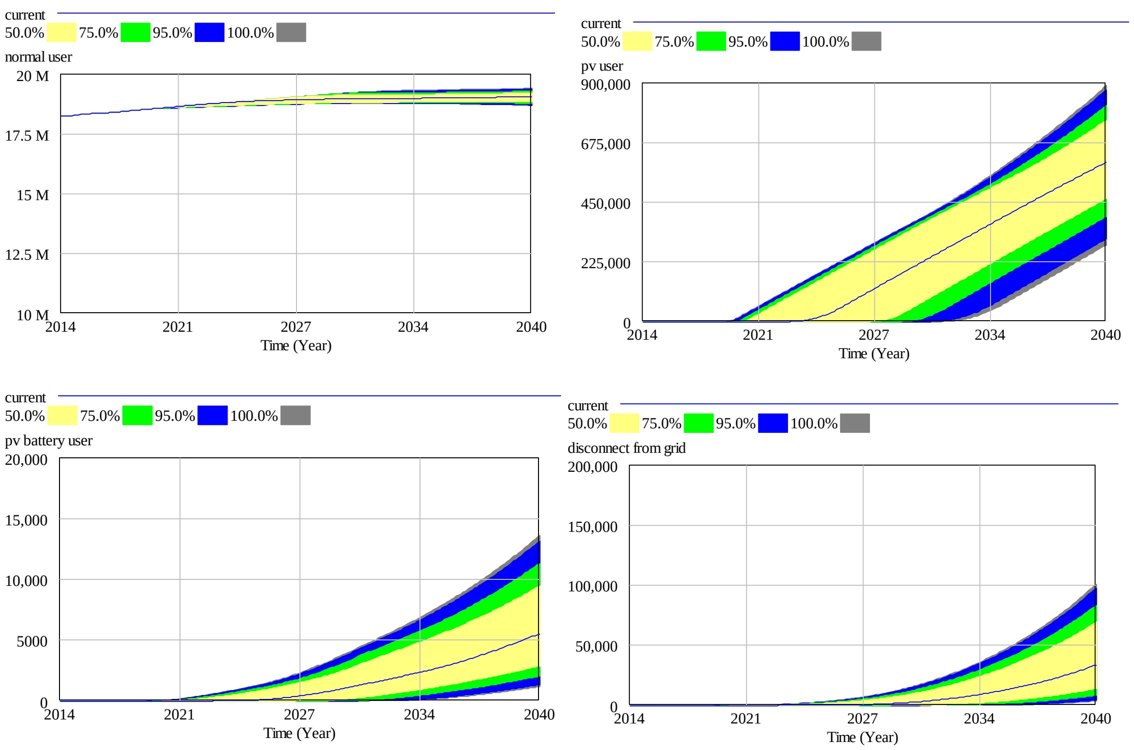


Figure 15 End users conversion evolution

This fraction of demand change, if set really low (20% of the original demand) and really high (200% of the original demand) as per the extreme conditions test, can also show the behavior sensitivity to the end users' conversion behavior as illustrated in Figure 41 and Figure 42 on Appendix A.

For the willingness to adopt PV/batteries, Figure 43 and Figure 44 on Appendix A show the difference between a normal scenario and really high adoption. The one with really high adoption significantly increased in numbers compared to the normal situation; this shows the numerical sensitivity of the model affected by the willingness to adopt PV /batteries value.

For the price of the technology, the sensitivity can be seen in experimental result graphic on Figure 22, where scenario 1 and scenario 4 with 50% price gap impacting the PV installation behavior as expected.

This shows the expected behavior of the model—due to the limited PV and Battery resources, at some demand threshold, the conversion to disconnect from the grid will be zero because the customer needs to keep the grid connection to fulfill their energy need.

8. Experimental Design and Results

This chapter presents the experimental design conducted for the model. There are 6 scenarios which were prepared to be tested on this model and, as mentioned in the model simulation chapter, where only end users with detached houses capable of installing PV—as seen in Figure 14 (max on 2040, 5.909 Million houses)—and the experiment was done using Spanish household market data. The underlying assumption for the “death spiral” in this experiment is using the Laws, et al (2017) definition, when the number of users that disconnect from the grid is larger than the users that are still on the grid anytime during the duration of the simulation time (Laws, et al., 2017).

The experimental design involves varying policies as well as critical assumptions concerning the cost of PV technology and customer adoption rates. The next chapter (Chapter 8.1) shows the scenarios combination which was used to test the policies. In Chapter 8.2-8.5 four different policies are being tested by using the scenario found in Chapter 8.1. Then, in Chapter 8.6 the total system cost for each policy is described. Finally, in Chapter 8.7 the alternative tariff concept is also tested with four previous combinations of policies.

8.1. Technology Cost and Adoption Rate Scenarios

The six scenarios can be seen in Table 11. The scenarios represent different combinations of a few different technology prices and adoption rates. It wasmentioned previously that the technology price numbers come from ETRI report data. In the scenario base case, the ETRI report number is used as it is but in tech1 case, the price of ETRI is multiplied with the value 1-1.5 times the original ETRI price. Thus the decrease in technology price is not as deep as the base case condition.

As for the adoption rate, there are three combinations of adoption speed; base as in 1, mid as in 1.5 faster, and high as in 2 times the base condition. As it is explained in the model simulation, this adoption rate is affecting the variable of “willingness to adopt PV” and “willingness to adopt battery.” These variables influence the view of the end user on how they perceive ROI time investment.

Table 11. Scenario combinations for PV technology costs and adoption rate`s

Scenario	Technology Price	Technology Price Value	Adoption Rate	Adoption Rate Value
1	base case	1 ETRI price	base	1
2	base case	1 ETRI price	mid	1.5
3	base case	1 ETRI price	high	2
4	tech1	1-1.5 ETRI price	base	1
5	tech1	1-1.5 ETRI price	mid	1.5
6	tech1	1-1.5 ETRI price	high	2

8.2. Base Case: Current Spanish Regulation (No Net Metering and Mixed Tariff Policy)

The simulations ran reflect the conditions of Spain's regulations these days, where there is no net metering option and the regulated cost distribution is based on volumetric and contracted capacity. Based on those conditions and scenarios application, from Figure 16 to Figure 19, we can see the evolution of change in normal user, PV user, PV and battery user, and those that disconnect from the grid.

From these graphs' results, the scenario that significantly differs compared with other scenarios is scenario 3, where the willingness for adoption is high and technology price is exactly as ETRI predicts. In particular, scenario 3 shows the greatest impact RES implementation in total on PV and also PV battery customers over time. It shows the fast adoption from PV to battery, followed with disconnecting from grid. This fast adoption rate also explains why there is some kink in Figure 16 to Figure 18. By the year 2035, all the users with detached houses are already implementing PV, thus the flow from previous stock is smaller than the flow to the next stock and it showed through the peak and fall charts. The second position with high implementation of RES is scenario 2 where the willingness for adoption is mid and the technology price is also as ETRI predicts. The third position of the highest RES implementation is scenario 6 where the willingness for adoption is high and technology price is higher than the ETRI prediction. From these graphs it can be seen that the market is sensitive to the price and the willingness for adoption rate.

By comparing results for scenarios that have the same price of technology but different adoption rates, the difference effect for adoption rate from the PV user growth in Figure 17 can be seen. Without additional external variables that can influence end-user adoption behavior (scenario 1), an end user starts to consider investing on PV when the "total PV cost loan" is around 7.737 k Euro, together with 3.872 k Euro for a battery system. Since scenario 4 did not reach that number, there is no PV user in that scenario. However, if the customer adoption rate behavior can be influenced as seen in scenario 6, even with a higher price end user is willing to purchase the PV and battery.

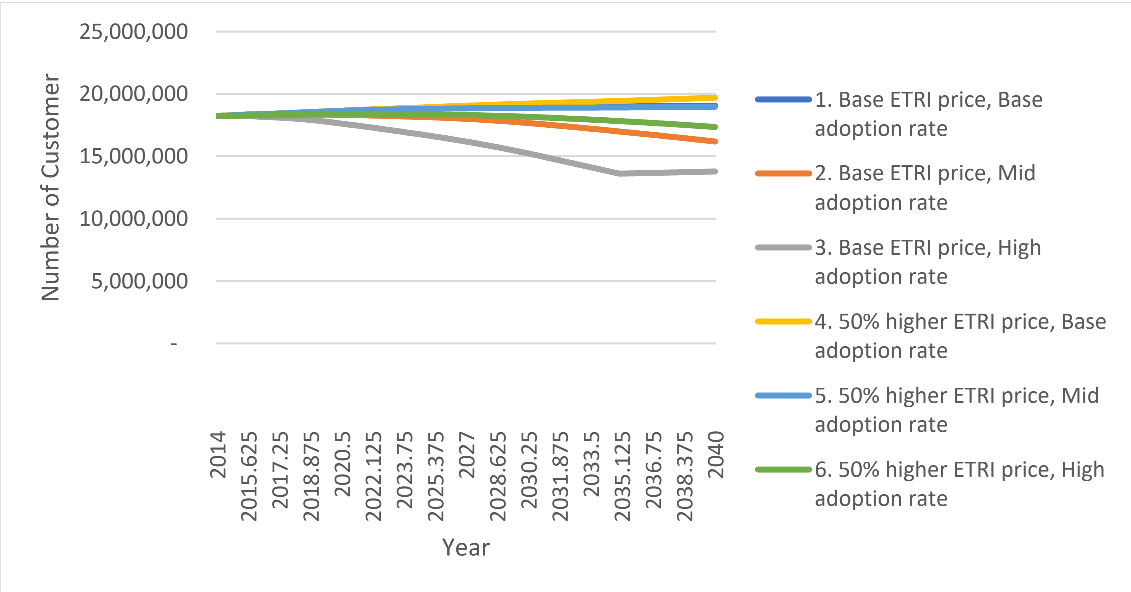


Figure 16 Normal User values over time under policy of no net metering and mixed tariff

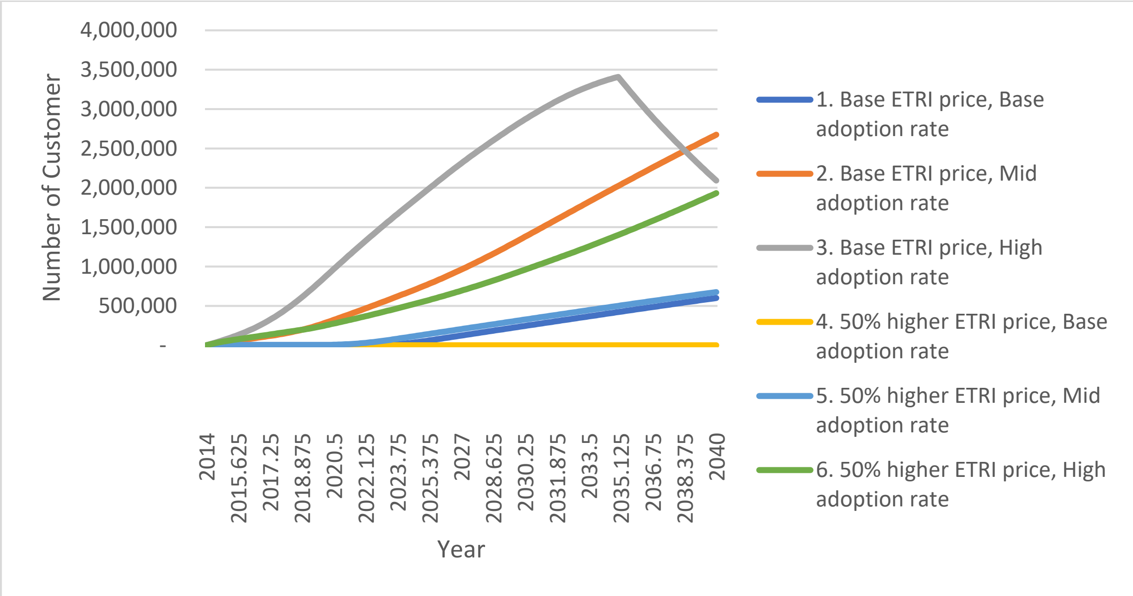


Figure 17 PV user values over time under policy of no net metering and mixed tariff

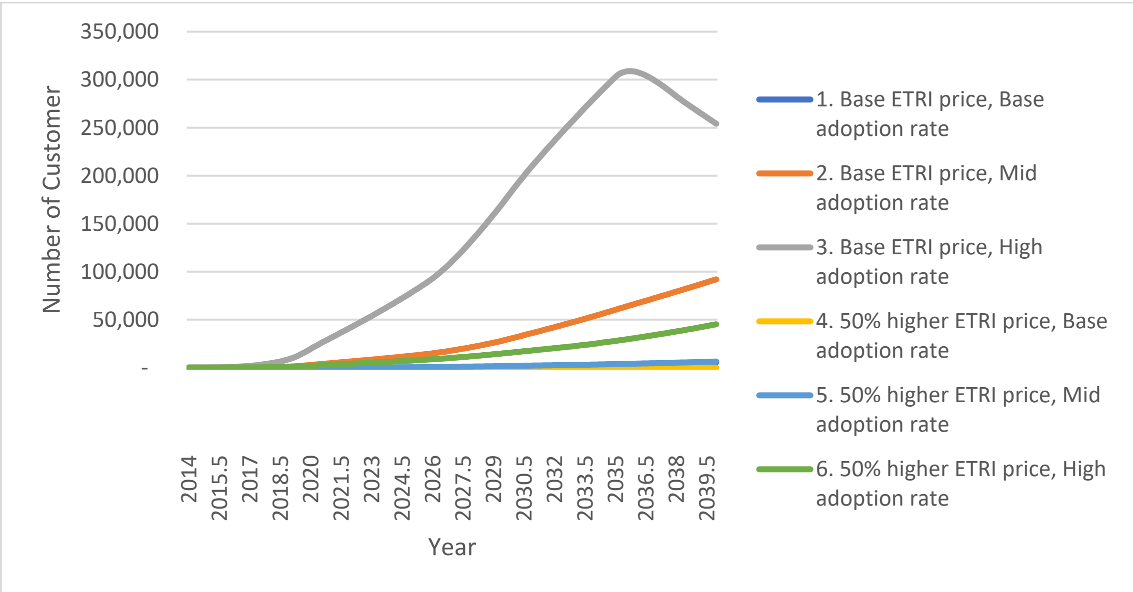


Figure 18 PV battery User values over time under policy of no net metering and mixed tariff

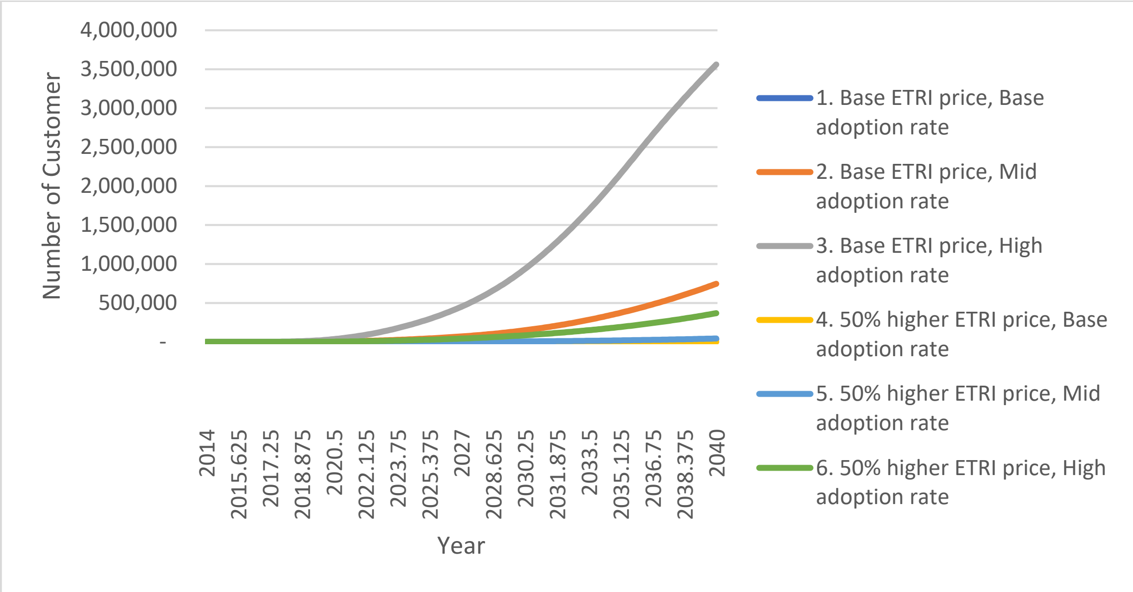


Figure 19 Disconnect from grid values over time under policy of no net metering and mixed tariff

As the current condition in Spain is highly reflected in scenario 1 and 4 (depending only on the market price of the technology) there is no incentive for the end user to install PV that can influence the behavior of adoption rate. Even with the best scenario for RES application scenario 3, the "death spiral" will not happen. In 2040, without the detached house limit of 30% of total household customers (5.9 Million houses). Only 4.318 Million houses decide to disconnect (27% of the total household population in Spain), and with the 30% houses limit, 60.26% of this detached house user (3.56 Million houses) decide to disconnect from the grid.

The network cost evolution at scenario 3 can be seen in Figure 20 with the max cost at 242.9 Euro per year in 2040, only a 13.13% increase compared to 2014. This is the most conservative solution and the safest in terms of regulated cost recovery point of view.

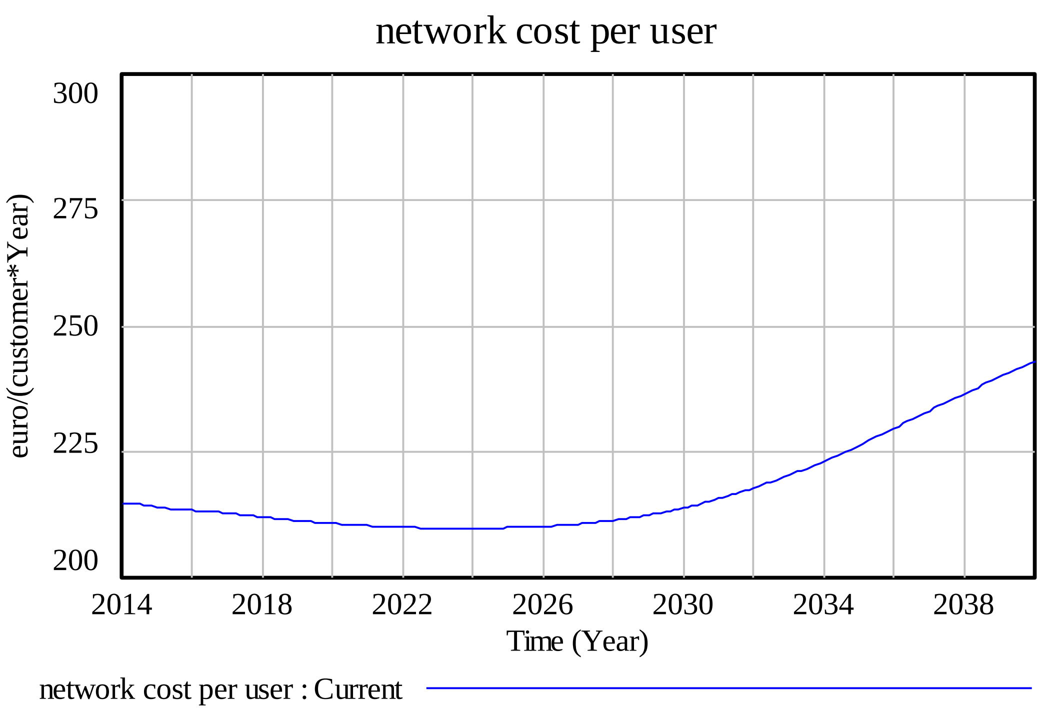


Figure 20 Scenario 3 network cost evolution under policy of no net metering and mixed tariff

8.3. Spanish Case with No Net Metering and Only Volumetric Tariffs Policy

As seen on the picture of the end user's evolution from Figure 21 to Figure 24, this simulation shows the same behavior with the current Spanish condition where there are no net metering and mixed cost. The notable difference in this simulation is that the end user feels more incentivized to apply the RES system—which is in-line with the research conducted by Kubli (2016)—due to the end user feeling incentivized by the savings they can get from reducing their usage since contracted capacity cost is following their usage behavior.

By using the base technology price and base adoption rate (scenario 1), end users are already willing to invest in RES for the "total PV cost loan" around 11.021 k Euro and 8.467 k Euro for batteries, which means they are willing to pay 42% and 118.7% higher than the condition when using volumetric and contracted capacity as the tariff design.

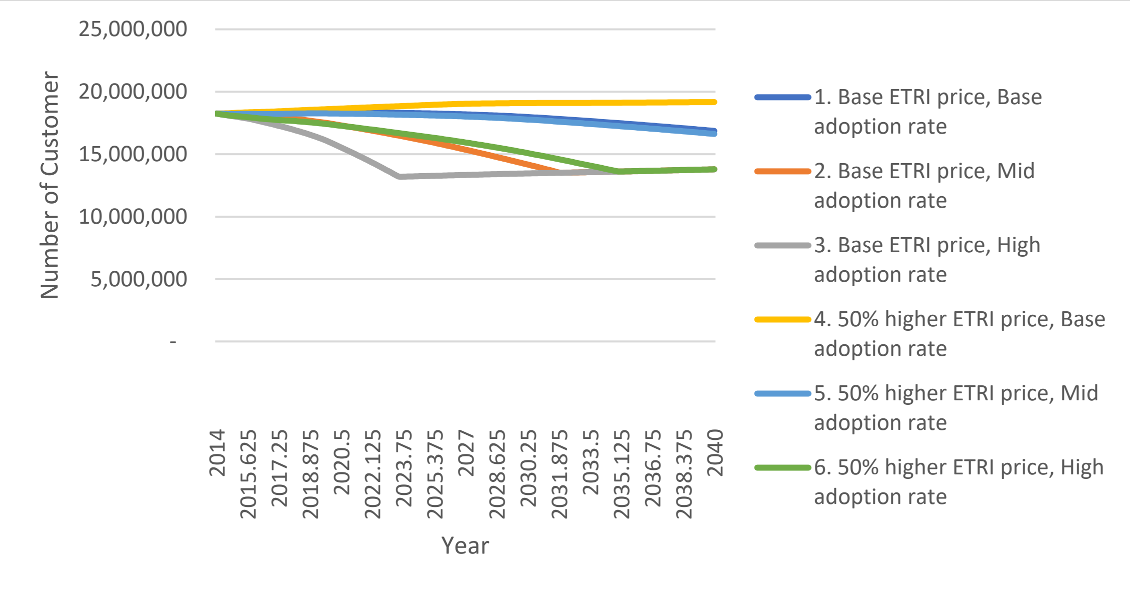


Figure 21 Normal user over time under policy of no net metering and only volumetric cost

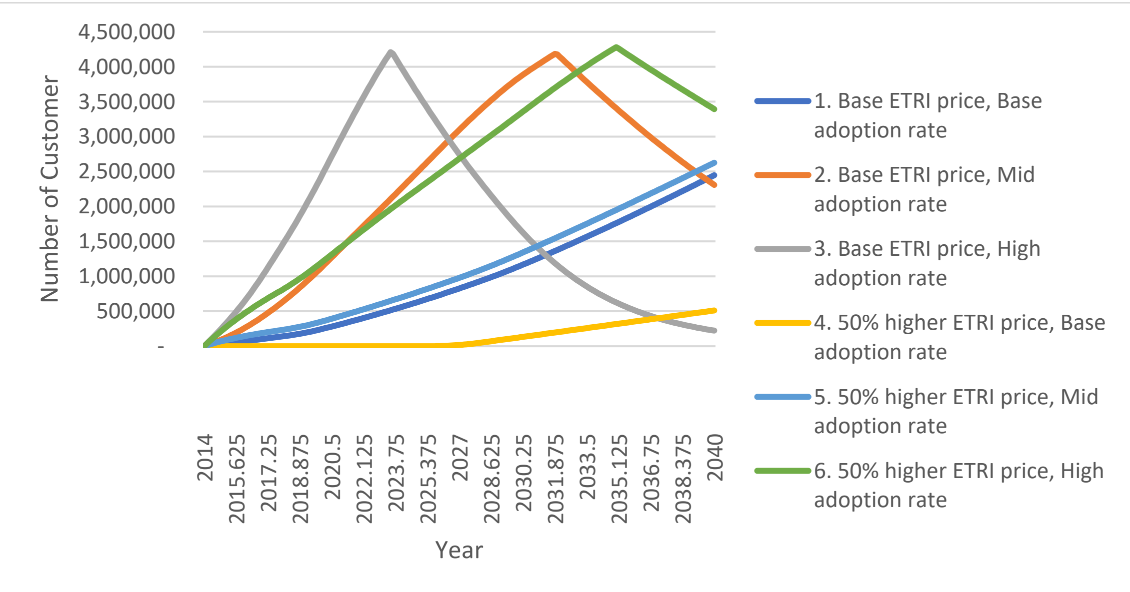


Figure 22 PV user over time under policy of no net metering and only volumetric cost

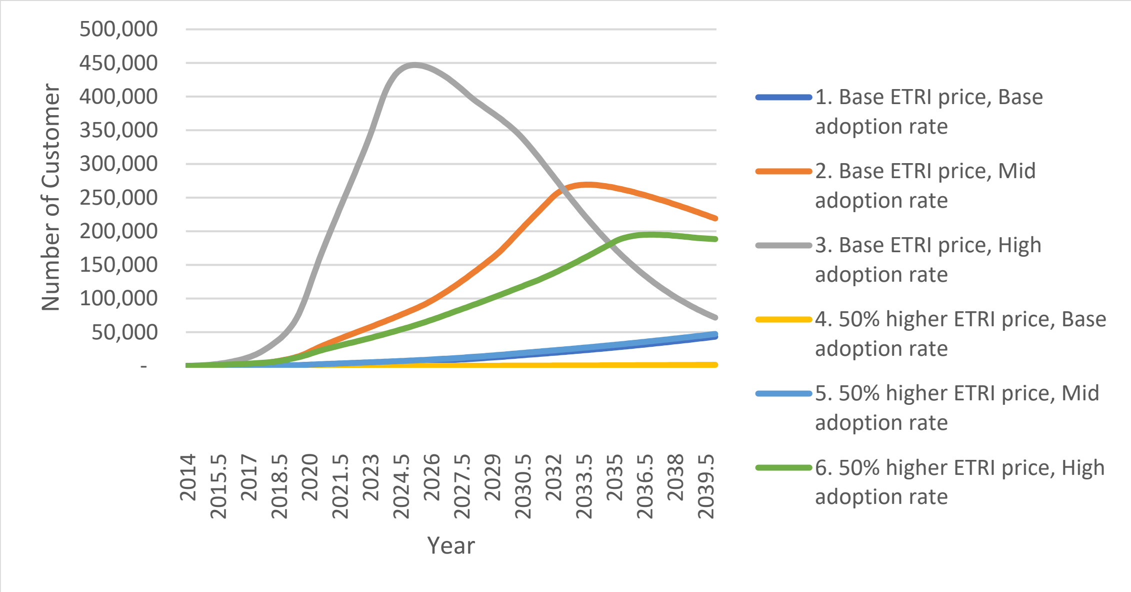


Figure 23 PV battery user over time under policy of no net metering and only volumetric cost

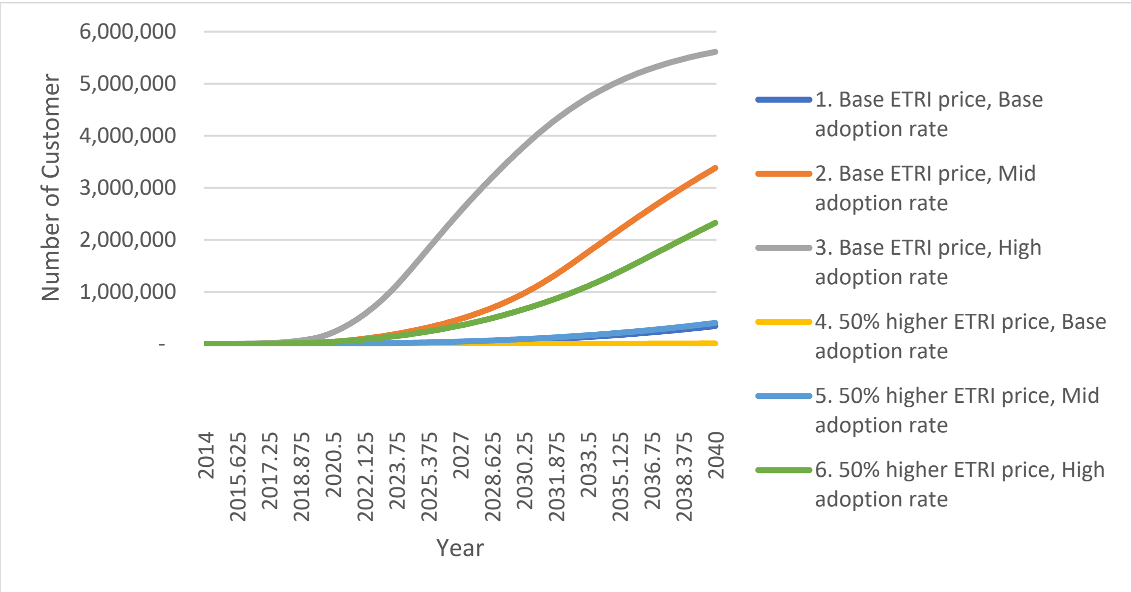


Figure 24 Disconnect from grid over time under policy of no net metering and only volumetric cost

From this experiment with the 30% limit of the houses, only scenario 3 is able to hit the limit of available houses and disconnect from the grid. In this scenario, by 2023-2024 all of the available detached houses have installed PV, which is soon followed by battery installation, and then finally disconnected from the grid. This explains the sharp peak curve in Figure 22 and Figure 23. The "death spiral" does not happen in this simulation due to the 30% detached house limit, the network cost in 2014 for non PV 214.7 euro per year, and PV user 104.9 euro per year and the hike up to 282.01 euro per year for non PV and 139.96 euro per year for PV user in 2040.

If there is no limit on who is able to install RES systems, the "death spiral" will likely happen by mid-2031 when disconnected users are higher in number than grid users. This triggered the increase of network cost from 214.7 for non PV and 104.9 for PV users in 2014 to 105,800 for non PV and 52,510 for PV users as seen in Figure 25. This case only happens in scenario 3 with base ETRI price and high adoption rate; even Scenario 2 (with a base ETRI price and mid-adoption rate) will not trigger the "death spiral."

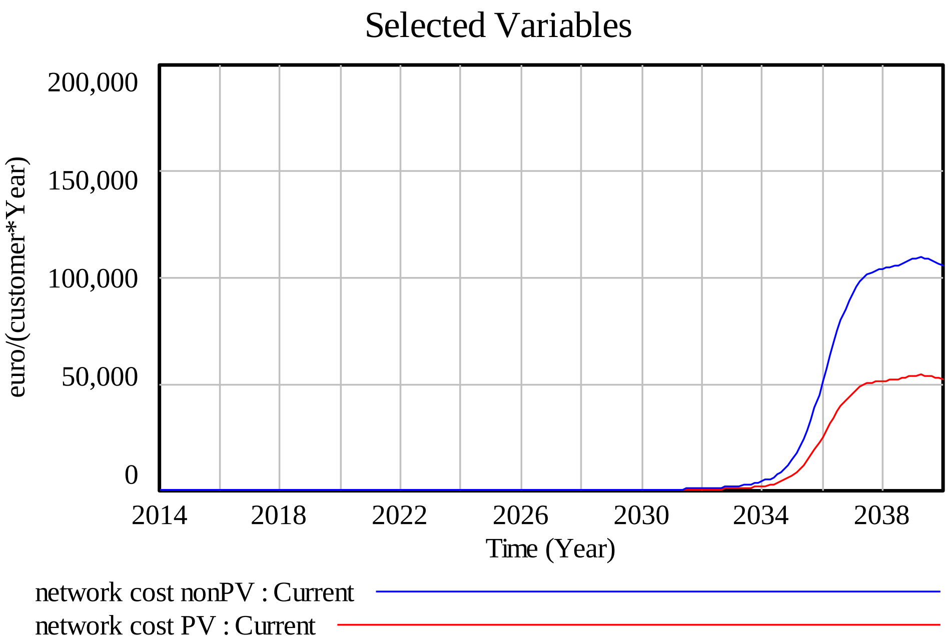


Figure 25 Scenario 3 network evolution no net metering and volumetric cost if there no limit on houses

8.4. Spanish Case with Net Metering and Only Volumetric Tariffs Policy

In this simulation, the regulation applied is similar to US regulation in California, where there is net metering available and cost recovery through volumetric cost.

From Figure 26 to Figure 28 you can see the evolution of the end user. In this evolution, the volumetric cost plus net metering combination manages to persuade the end user to invest in RES due to the attractiveness of "cost saving" and the ability for them to sell the extra energy to the grid.

As seen in Figure 27 and Figure 28, for scenario 1 and scenario 4, even without an incentive on the adoption rate to buy the RES system, the end user is still buying the RES system. In scenario 1, by 2018 all the houses will have installed the PV system and in scenario 4, due to the fact that the price of PV system is 50% higher than scenario 1, the same result is eventually reached in 2022.

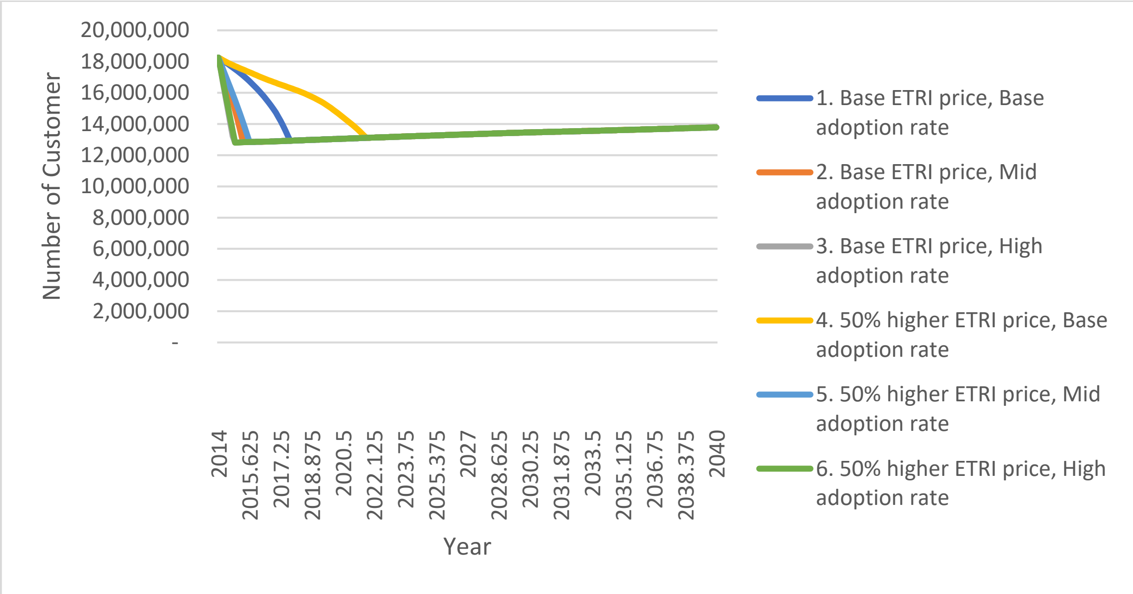


Figure 26 Normal user over time under policy of net metering and only volumetric tariffs

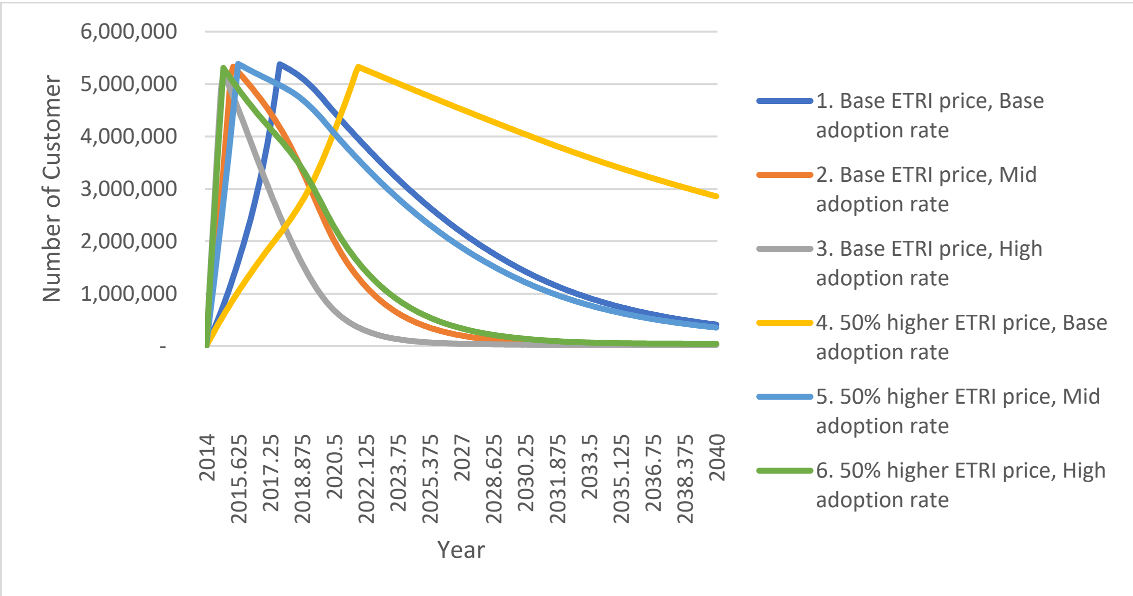


Figure 27 PV user over time under policy of net metering and only volumetric tariffs

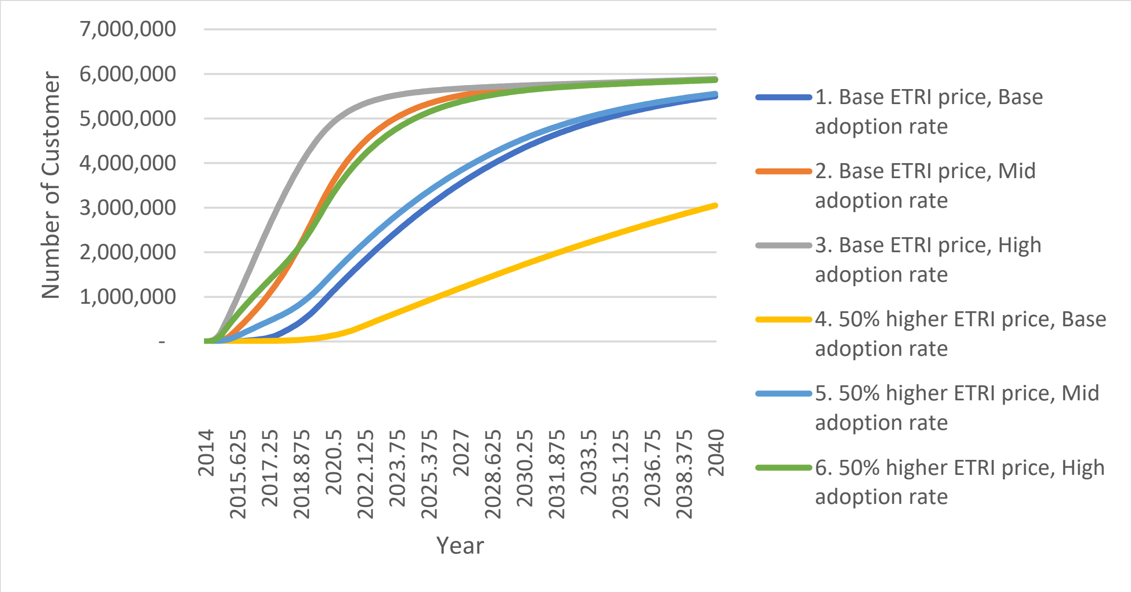


Figure 28 PV battery user over time under policy of net metering and only volumetric tariffs

The interesting part of this simulation is that none of the users in this scenario is willing to disconnect from the grid, even though they are installing the battery and are able to sufficiently meet their consumption needs. The reason is that it is more profitable to stay on the grid and receive money from excess energy sold to the grid. As seen in Figure 29, in scenario 1, for network cost per user per year with the detached house limit activated, the non PV user ended up subsidized the PV owner by paying a higher network cost of 327.9 euro per year (2040), meanwhile PV owner get money around 120.1 euro per year (2040) by selling their excess of energy.

If there is no limit on the detached house, the user still will not detach from the grid and is instantly willing to invest in the RES system due to the benefit mentioned above. The issue is that all of the users will become prosumers with excess energy to sell, which mean the regulation cost cannot be recovered. Thus, this policy should be treated carefully on the implementation. One needs to take consideration the demographics, architecture, and landscape of the area.

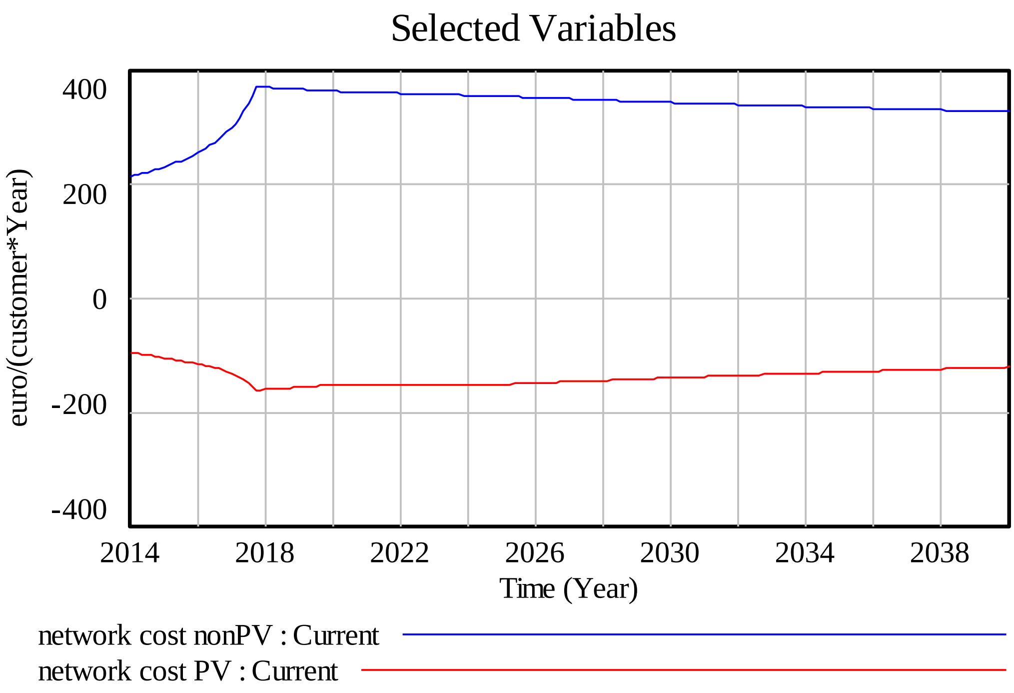


Figure 29 Network cost evolution scenario 1 with net metering and volumetric tariffs

8.5. Spanish Case with Net Metering and Mixed Tariff Policy

In this model, the current condition of Spanish mixed tariff, where they use volumetric and contracted capacity, is combined with net metering to see the effect of net metering in the current Spanish market. When comparing Figure 26, there is a similar behavior in the graphics movement with the difference only in the speed of conversion. From this it can be seen that mixed tariff is not as beneficial as volumetric for the end user, since the RES user still has to pay contracted capacity with the same price as the PV user. Still, the net metering gives enough incentive for the end users to install RES.

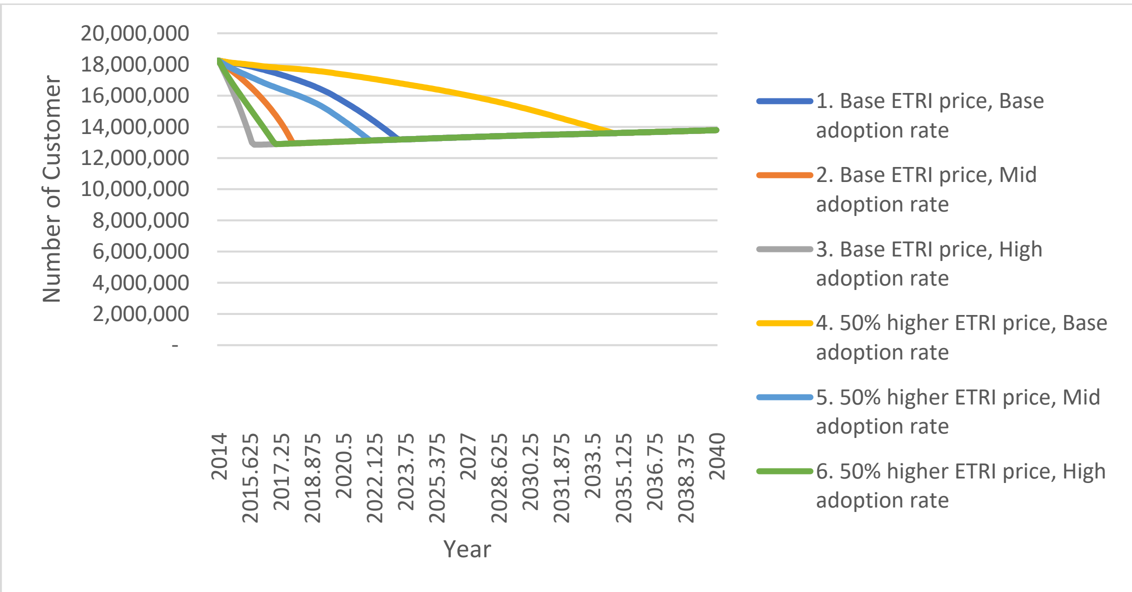


Figure 30 Normal user net metering and mixed tariff

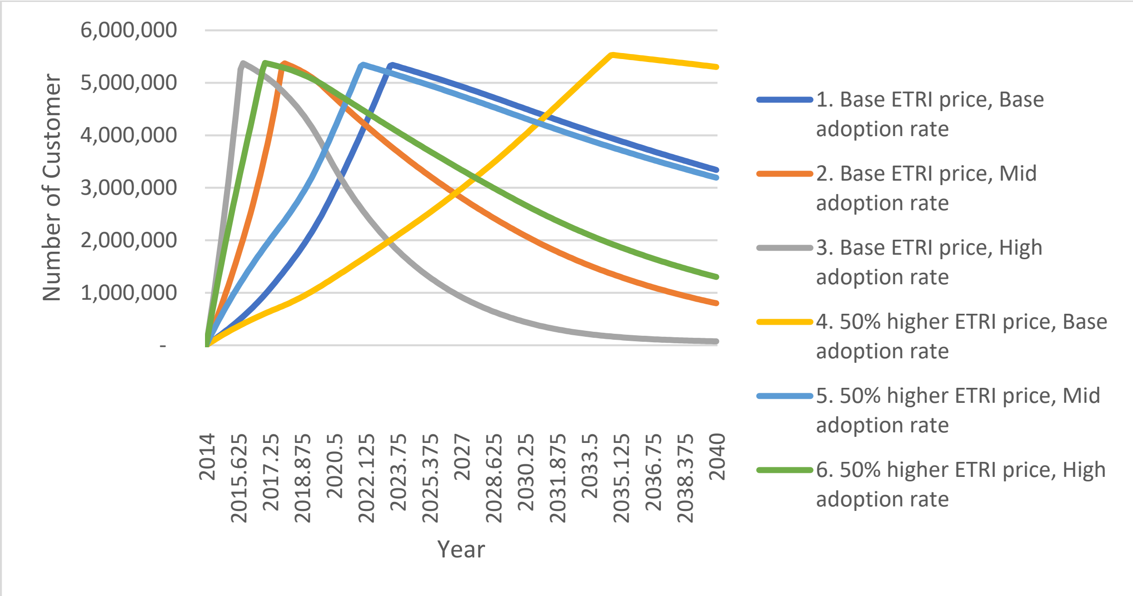


Figure 31 PV user net metering and mixed tariff

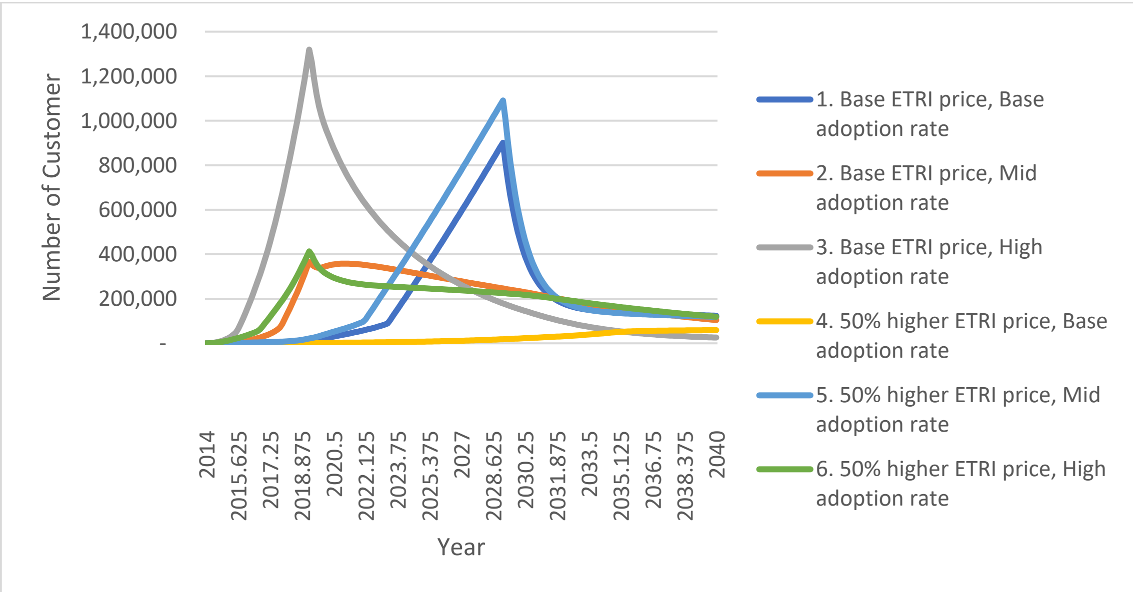


Figure 32 PV battery user net metering and mixed tariff

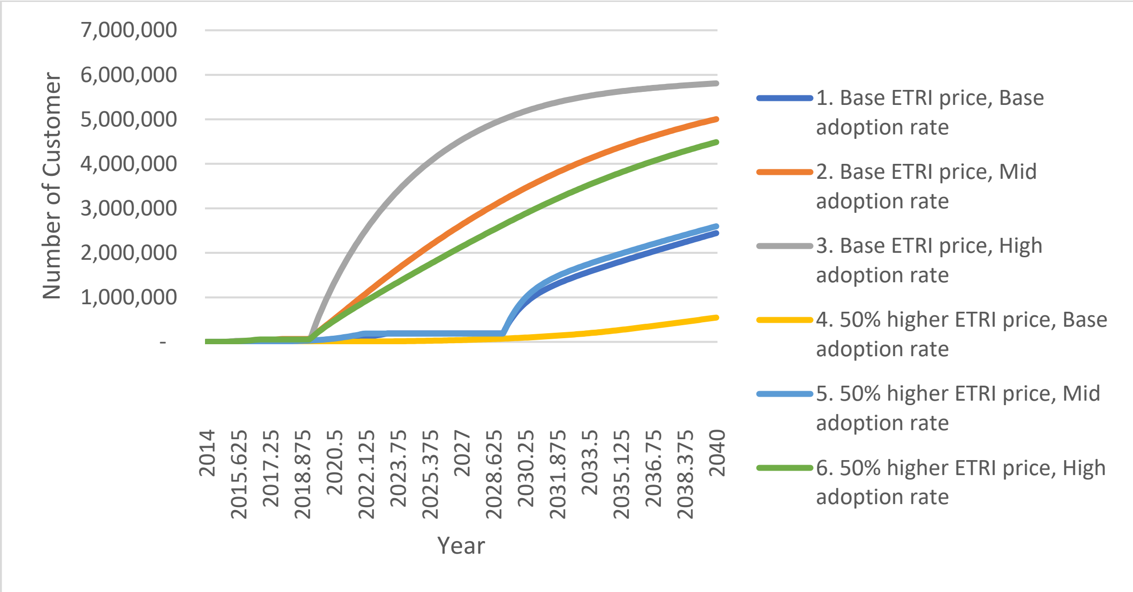


Figure 33 Disconnecting from grid net metering and mixed tariff

The interesting part in this simulation is in scenario 4 where the price really holds an important key for the end user's decision to invest in the PV. From normal users to PV users it took until 2034 for normal users with detached houses to completely convert to PV users, as seen in Figure 30. In the same scenario, the price for the battery is still deemed too expensive for them to invest since they also should consider the RES system as one cost around 20.7 k Euro. Thus, the shape of the conversion into Battery graphic in scenario 4 as seen in Figure 32 is considered flat compared with the other scenarios.

Next, we will consider the best RES installation (scenario 3) where it can hit the maximum limit of houses (all the houses installed PV). The "death spiral" is still not happening; it is managed to hike up the price of volumetric charge in "net metering charge" from 0.123 euro per kWh in 2014 to 0.14 euro per kWh in 2040 and increased network cost from 214.7 euro in 2014 into 257.7 euro in 2040.

There is a point that needs to be noted here. If base scenario 1 without houses limit (all users can install PV) and the net metering regulation is applied, which enable prosumers to sell power to the grid, by 2027 there will be more people selling the power to the grid than buying from the grid. Therefore, the government will not able to recover their investment.

8.6. The Total Cost of the System for Each Experiment

This experiment runs with the 30% limitation of detached house, meaning this is the total value of the system which includes power price and all of the regulation costs (network and other costs) from the grid. It is mean this cost is the cost that regulator receives and omitting end users investment in RES system.

From Figure 34 we can see the most beneficial policies for regulation cost recovery, from the best to the worst:

1. No net metering and mixed tariff
2. No net metering and volumetric tariff
3. Net metering and mixed tariff
4. Net metering and volumetric tariff

A No net metering and mixed tariff is the best option to recover the regulation cost (14.235 B Euro in 2040), the second option is no net metering and volumetric tariff with 13.731 B Euro in 2040. This is because the increase of PV and PV battery users automatically reduces the power purchased from the grid, which results in a loss of income from that reduction. On the third position, the net metering and mixed tariff only recovers 11.517 B Euro in 2040. This is due to the additional income for the prosumers from selling their extra power, which means cross-subsidizing the volumetric part of the tariff and there is also some income loss from end users' defection from the grid. As expected with net metering and volumetric tariff, the total cost gained in 2040 is the lowest out of the four options at 11.181 B Euro. This is due to the decrease of usage of the PV and PV battery user; this user even gained additional money greater than net metering and mixed tariff scheme, due to the addition that comes from the volumetric network cost.

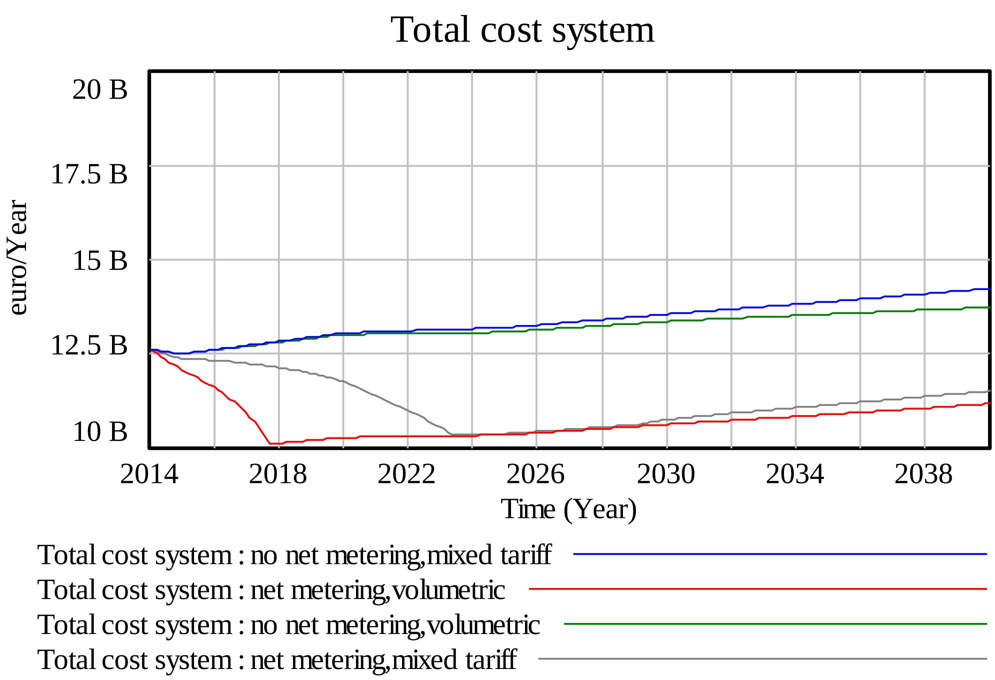


Figure 34 Comparison of system cost receivable from the grid for power and regulation charges

The alternative view on the total cost of the system is not only power and regulation cost but also taking into account the RES investments. It means the cost includes the user that defect from the system, as they still have to pay for the PV and battery cost. As a note the RES investments number here is the annual cost of PV and PV battery system, to ensure the comparability with the other cost in the system.

From Figure 35 we can see the most expensive total system cost, from the highest to the lowest:

1. Net metering and volumetric tariff (17.01 B Euro in 2040)
2. Net metering and mixed tariff (16.36 B Euro in 2040)
3. No net metering and volumetric tariff (15.77 B Euro in 2040)
4. No net metering and mixed tariff (14.68 B Euro in 2040)

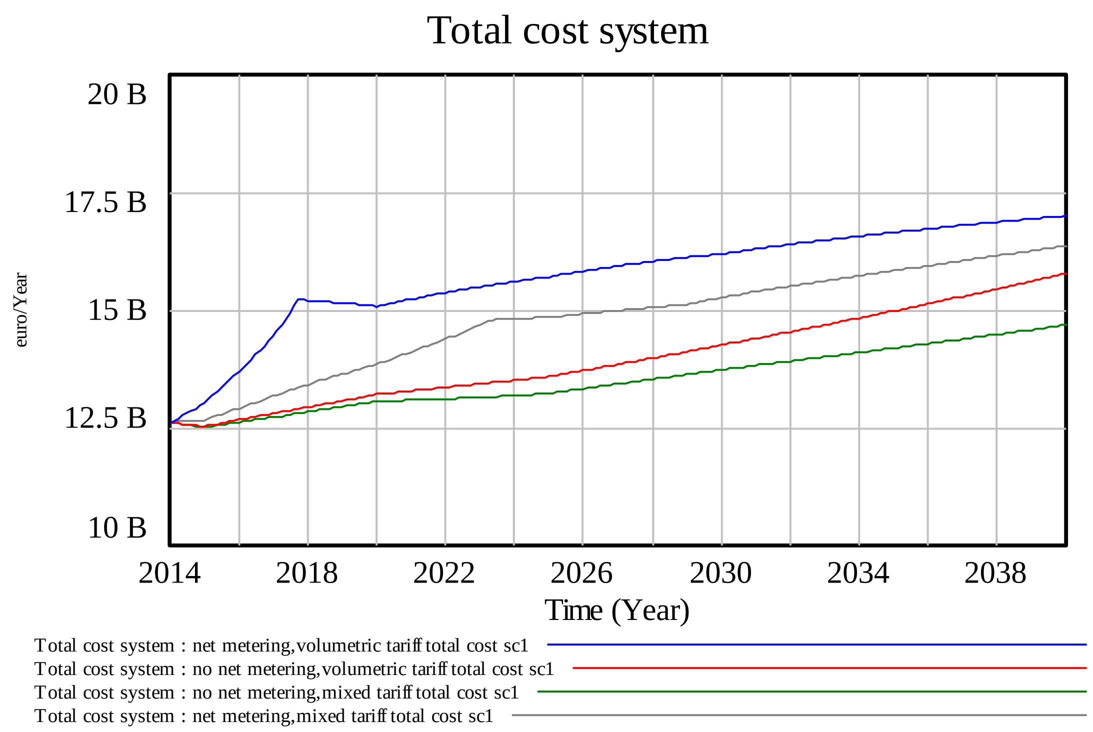


Figure 35 Comparison of system cost from the grid for power, regulation and RES charges

The interesting part is that the result of total system cost has a backward result with the previous analysis on Figure 34. It is because the end user implements RES systems at quite early stage when the price of the technology still high.

8.7. The Case Where CNMC Regulation Cost only Consider the Cost of Network Part

There is a theory from the "Utility of the Future" report (2016) whether we assume customers are only charged for the energy usage, network cost, and omitted from paying other regulation CNMC cost and shift that charge to taxpayers (MIT Energy Initiative; IIT-Comillas, 2016). Thus, the customer can know better the components they paid for their usage of the network and power without getting charged for subsidized costs on their bill. This can help them when deciding on grid defection as this extra charge can affect their point of view when calculating costs and benefits as seen in Figure 36 (MIT Energy Initiative; IIT-Comillas, 2016).

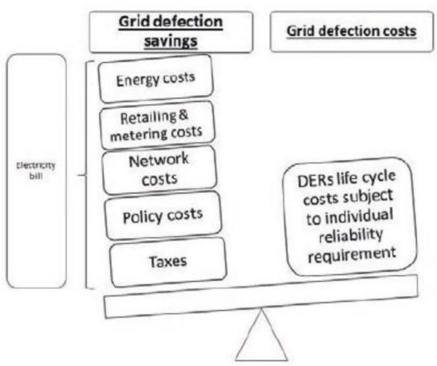


Figure 36 Customer point of view of grid defection (MIT Energy Initiative; IIT-Comillas, 2016)

The same report also mentions the use of exit charges to prevent end-user defection from the grid. In this simulation, that policy will also be tested to see whether it is effective or not in preventing defection.

The simulation was done by using scenario 1 (base ETRI price and base adoption rate) with the detached house limitation applied. The results of the behavior comparison for this experiment can be seen in Figure 37 to Figure 40. In the chart, there is also a comparison with the condition where they got charged for other CNMC regulation costs.

As seen in Figure 37 and Figure 38, when the other CNMC regulation is taken out from the customer's bill it can delay PV adoption. In the case where net metering is on and volumetric tariff is applied by 2018 all of the detached houses would have already installed PV, but with the other CNMC regulation cost taken out, this would happen near the end of 2020. There are only two policies that manage to reach 100% PV installation; both are the ones with the net metering on option.

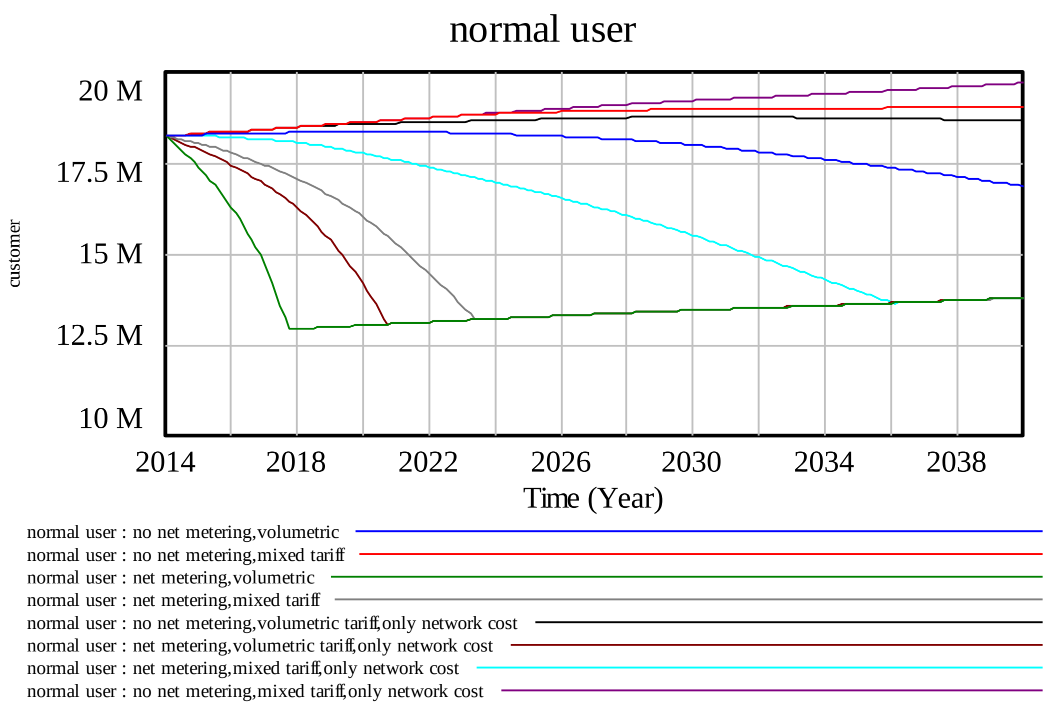


Figure 37 Normal user comparison on each policy for all cost vs other CNMC cost omitted

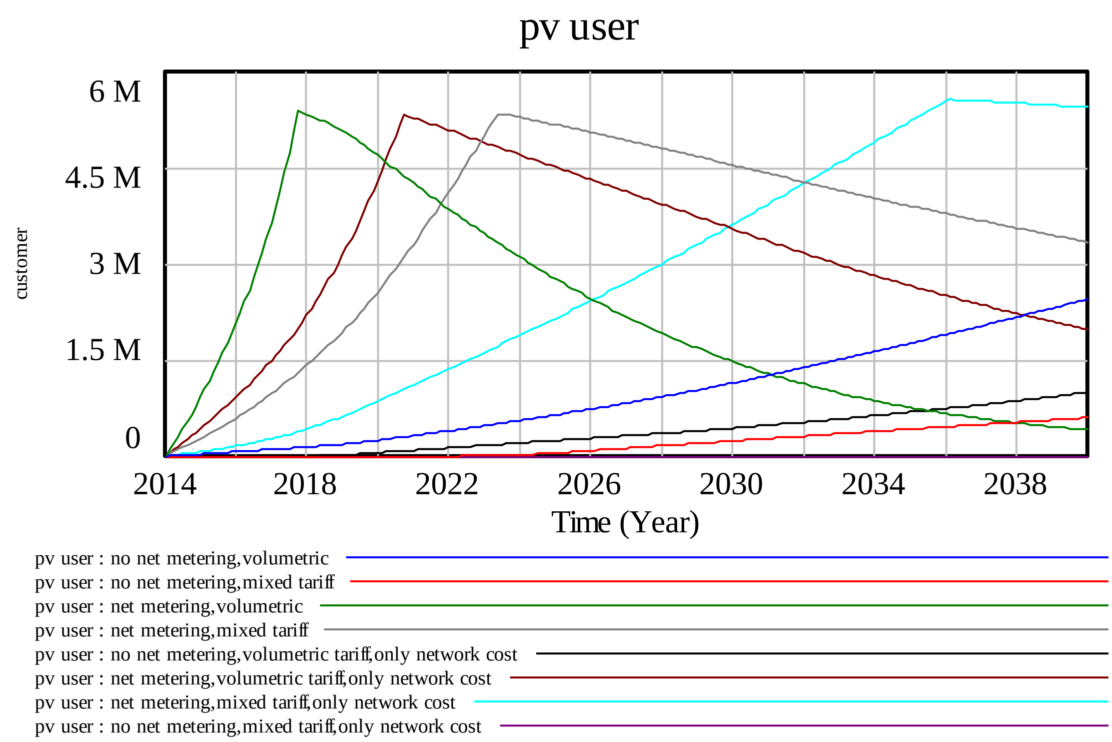


Figure 38 PV user comparison on each policy for all cost vs other CNMC cost omitted

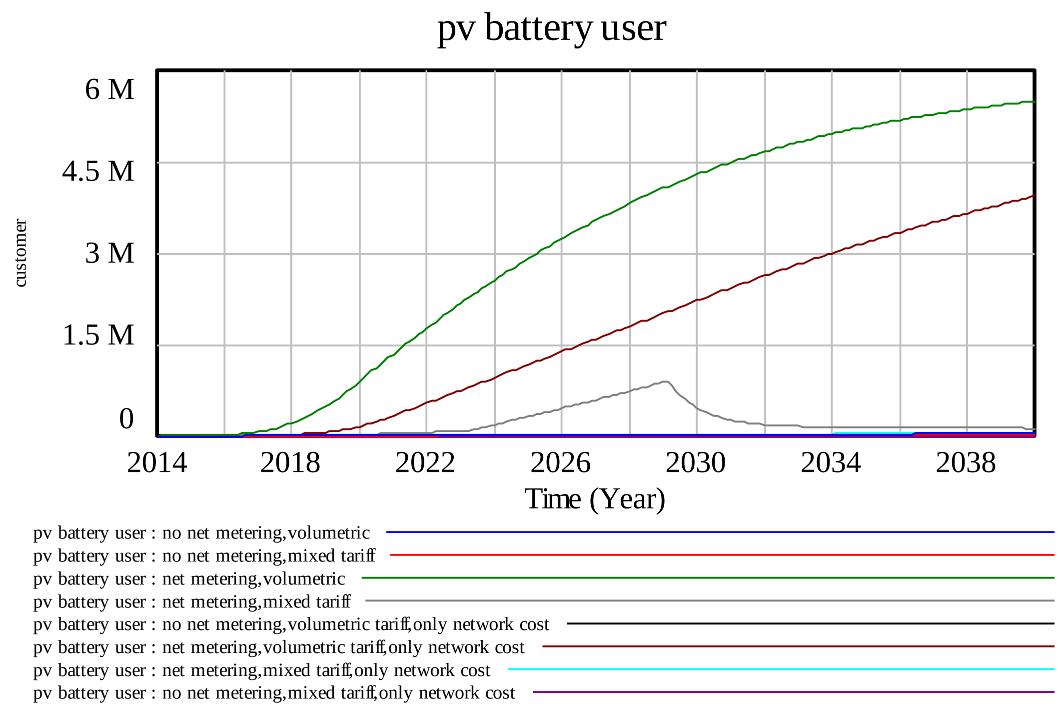


Figure 39 PV battery user comparison on each policy for all cost vs other CNMC cost omitted

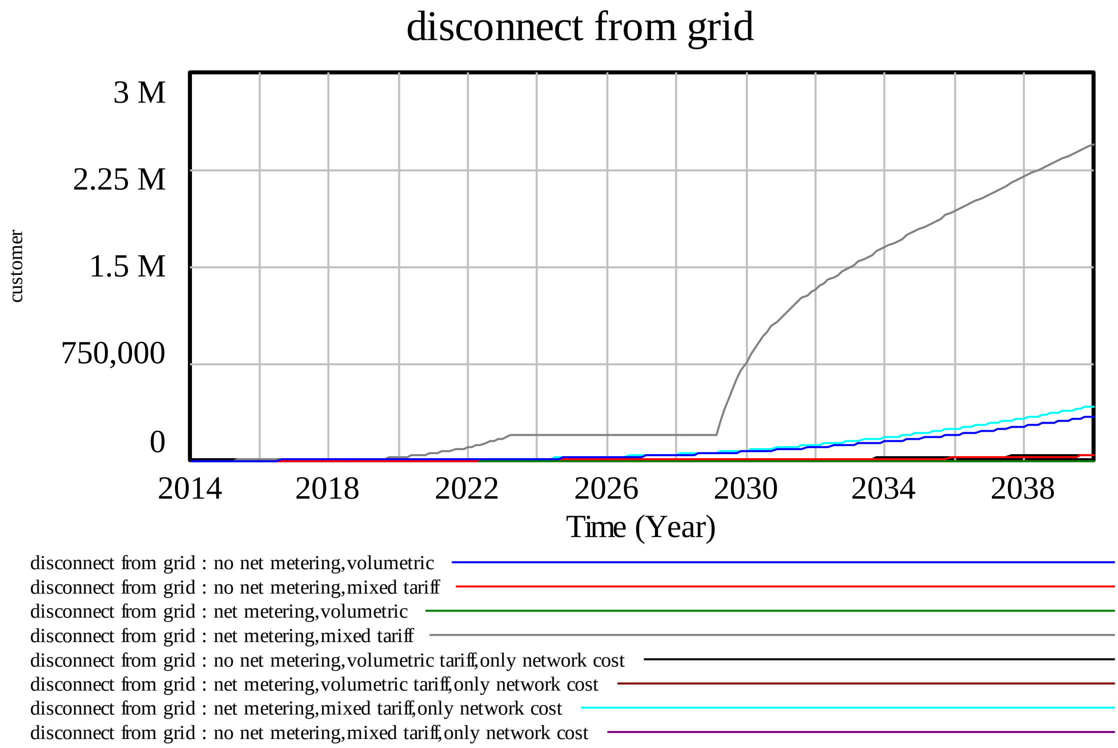


Figure 40 Defected from the grid user comparison on each policy for all cost vs other CNMC cost omitted

The interesting part is when we see the defected users from the grid chart on Figure 40. Only net metering with a mixed tariff has a high disconnection rate, even though on Figure 39 the installation for PV Battery are higher for net metering with volumetric tariff and net metering with volumetric tariff without other CNMC regulation cost. This is because the benefit of selling extra energy to the grid considered as profitable for net metering with volumetric tariff and not so on net metering with mixed tariff. The other part is the distinct size of defectors between the two schemes of net metering with mixed tariff. By removing the CNMC and other regulation costs the defection can be pressed from 2.443 M customers into 419.3 k customers. This shows this regulation can dampen and reduce defectors from the grid.

In all of the models that were applied above, to prevent the disconnection from the grid there is regulation called exit charges that can be implemented. These exit charges consist of current network charges for normal users multiplied with the estimated year of network cost recovery around 40 years. This effectively prevents the user from disconnecting as this in-front charge is too costly to recover from the electricity savings only.

9. Conclusions and Policies Recommendation

The main objective of this research is to answer the main research question of, "Is there a risk of a "death spiral" for Spanish household utilities, given future expectations of PV and battery costs?"

To answer this question, referring to Chapter 7.2 with the current Spanish regulation, it is less likely that the "death spiral" (defined in this thesis as the higher percentage of residential consumers leaving the grid versus the ones that remain connected) will happen in the Spain household utilities market with or without the housing type limitation (as in Spain the majority of consumers live in apartment buildings). With the simulation of no limitation on the capability of the households to install the RES system, only 4.318 million of the total end-users (27% of the total household population in Spain) decided to disconnect with the condition that households have a high willingness to adopt the RES system. To be able to influence households to increase their willingness to install RES systems without significant benefit (i.e. subsidies for the end user's economic benefit) is a challenging thing to do.

Next, we must consider the sub questions of, "What are the impacts of alternative network charging policies?" and, "Does system dynamics able to model the dynamics of the Spanish household utilities market?"

The impact of alternative network charging policies reflects strongly the behavior of the end users and how the regulator wants the focus to be. In summary, what has been done in chapter 8 can be used to understand the impact of alternative network charge policies.

Net metering schemes can push the RES adoption on the household market, but its implementation must be treated carefully since it shifts the cost from consumers to others, and it highly depends on the ratio of users and usage size between the grid user and defectors from the grid. This will not lead to the "death spiral" due to the benefit it has for the RES user is relevant, but with incorrect methods of implementation the regulation cost would not be recovered. In short, this option is quite risky for the regulator. They must pay attention to the demographics, landscape, and architecture of the implemented area.

A no net metering scheme can lead to higher rates of grid defection, but it will not result in the "death spiral" unless it is combined with volumetric tariffs and has a high adoption rate. As seen in Chapter 8.3, even with a medium adoption rate, it will not lead to the spiral.

Fixed charges would be needed to recover residual network costs, which can be seen in the policies with mixed tariff policy.

Based on the results of Chapter 8.6, the most beneficial policies for regulation cost recovery from best to worst are: no net metering and mixed tariff, no net metering and volumetric tariffs, net metering and mixed tariff, and net metering and volumetric tariffs.

Total cost of the system if the RES investment is considered into account would be a backward result from the regulation cost recovery result as seen in Chapter 8.6, from the most expensive system cost to the cheapest are: net metering and volumetric tariffs, net metering and mixed tariff, no net metering and volumetric tariffs, no net metering and mixed tariff.

The application of exit charges in Chapter 8.7 effectively prevented the user from disconnecting, as this in-front charge is too costly to recover from the electricity savings alone.

Removing regulated cost components from the tariffs, as seen in Chapter 8.7, it showed that by omitting these charges can dampen the desire to defect from the grid. But at the same time, it can delay RES adopters. In addition, in order to foster RES, efficient market mechanisms need to be designed in order to put in level playing field different technologies at different scales and not incentivizing certain technologies with non-transparent cost shifting among consumers.

Based on the above explanation, the answer to the question about whether SD is able to simulate the dynamics of Spanish household utilities is, "yes." With this research SD was able to simulate the logical behavior of the Spanish household market. Due to SD ability to simulate the loop interaction between variables over time, with SD the evolution of the users affected by the policies over time can be seen. Thus, it is helpful to have the insight of this behavior to find a better solution to the problem.

9.1. Further Research Suggestion

For further research development, this model can be expanded through:

- Combining and adding more detailed information, such as hourly detailed demand and consumption, demographics information, and more types of customers. Within the research conducted with Vensim software there is a limitation of the software.
- Considering adding effects such as CO_2 emissions as well as variability in PV and battery systems.
- Possibly adding generation and network capacity expansion and other RES alternatives in the research.
- Combining SD with an agent base modeling model. Since each end user has their own autonomy and distinct way of thinking and behavior, adding the agent base modeling into the model will show more specific and detailed behavior of the market.

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Appendix A

This appendix is depicting Chapter 7.4 Extreme condition test results based on model runs in Vensim software.

If the demand really low (20% original demand), end user has no interest in investing for RES due the saving from RES is too little to get their investment worth.

True as seen in Figure 41, only normal user graph that increasing.

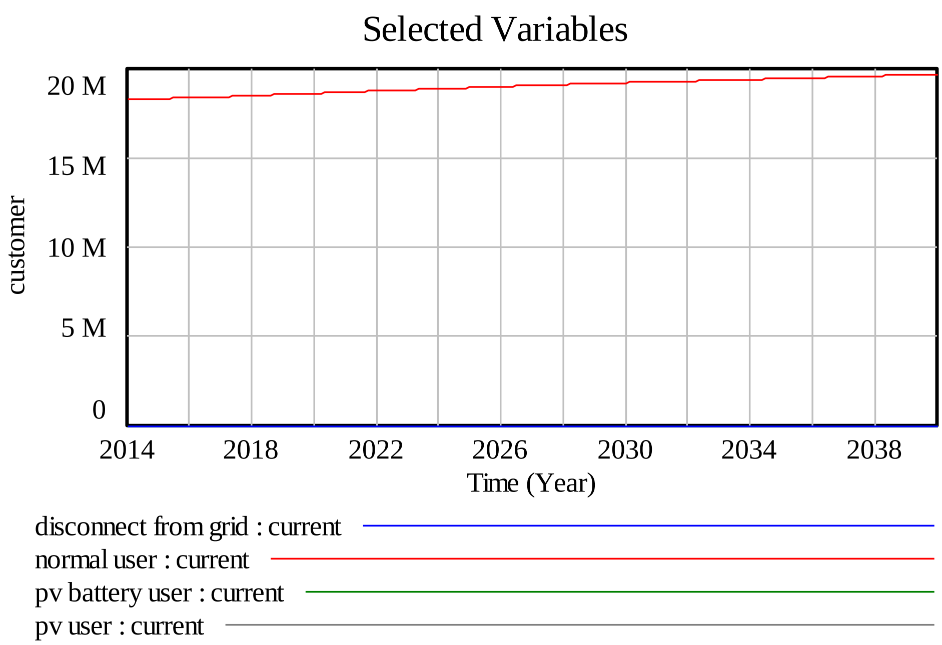

Figure 41 User evolution on demand really low

If the demand really high (200% original demand), the number of user disconnecting from the grid will be low or zero due the demand is higher than system threshold.

True as seen in Figure 42, zero disconnect from grid.

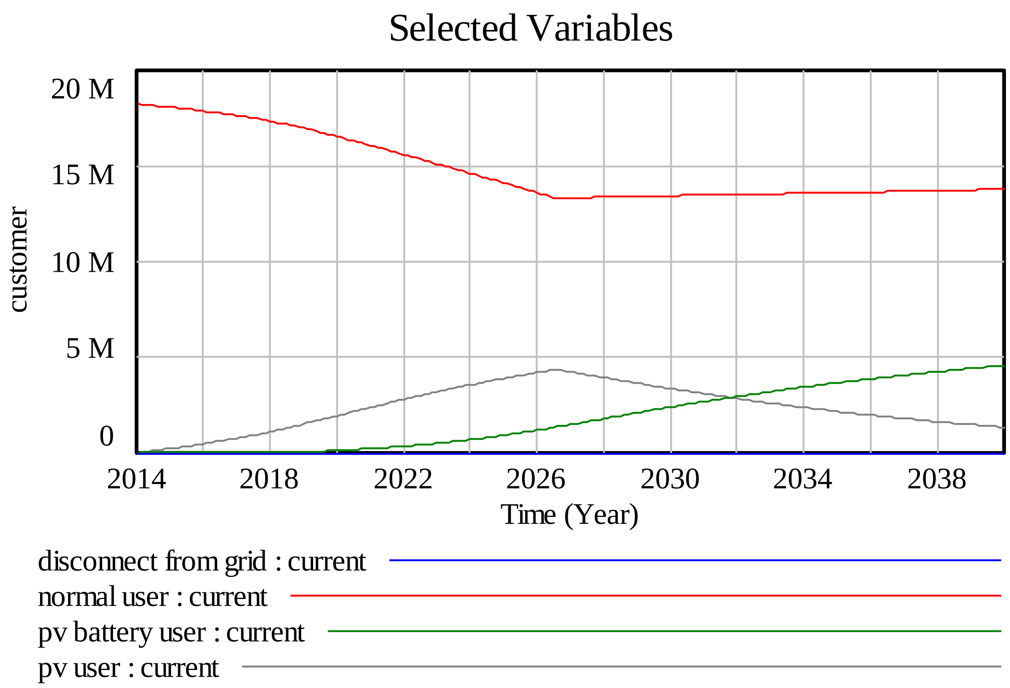

Figure 42 User evolution on demand really high

If the willingness to adopt PV/battery really high (5), end user will still invest even though the demand is really low (20% original demand).

True, as seen in Figure 43

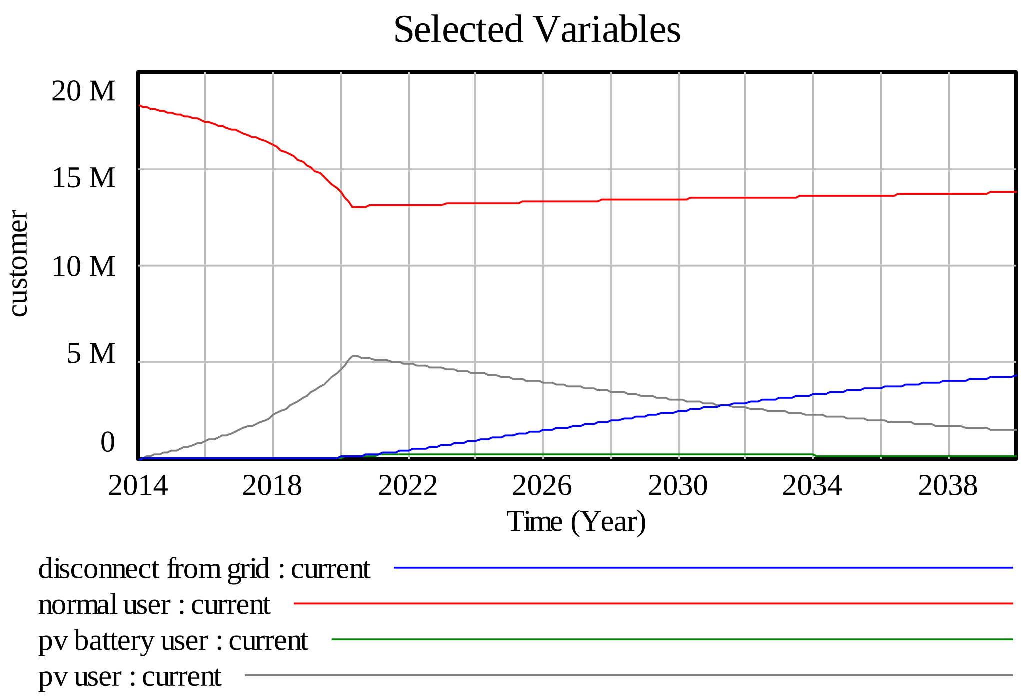

Figure 43 User evolution on high willingness on adoption of technology

If the willingness to adopt PV/battery really high (5), conversion of the user will be faster and the cost of regulation will be increased.

True as seen in Figure 44 and Figure 45, the difference between normal scenario and really high adoption, the one with really high adoption significantly increased in numbers compared the normal situation. Figure 46 shown the increased of network cost.

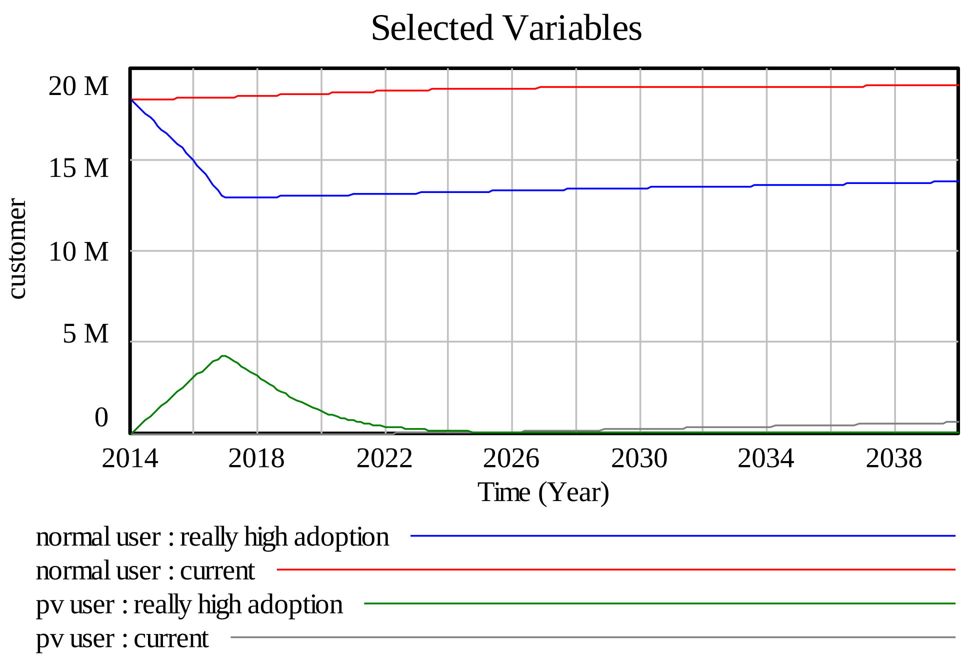

Figure 44 Normal user and PV user normal condition vs really high adoption

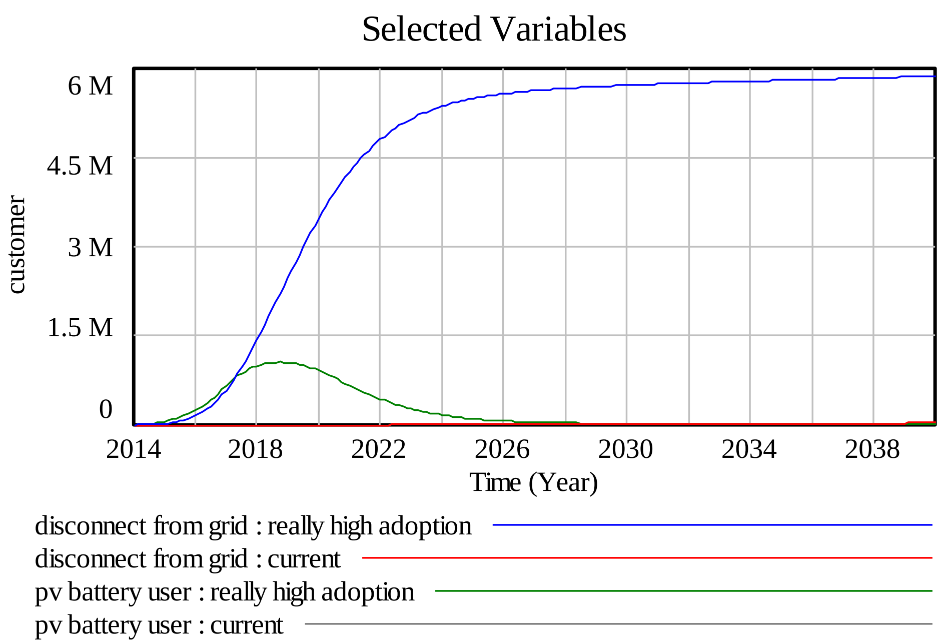

Figure 45 PV battery user and disconnect from grid normal condition vs really high adoption

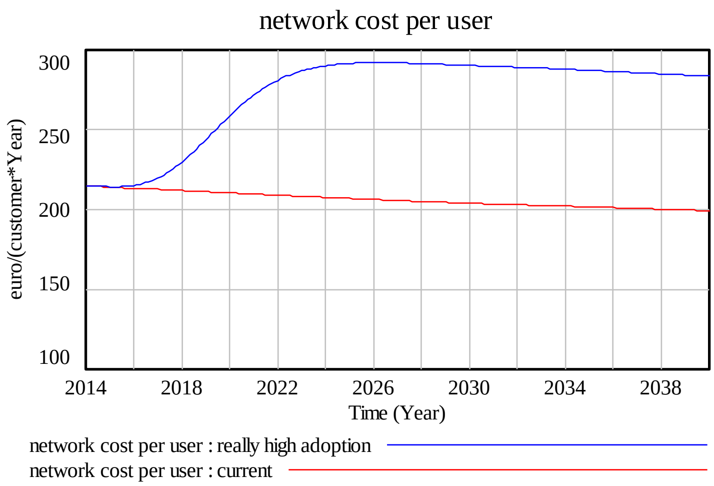

Figure 46 Network cost evolution normal condition vs really high adoption

If the power price is really low (10% original price), end user has no interest in investing for RES due the saving from RES is too little to get their investment worth.

True, as seen in Figure 47. There no changes in the RES evolution due the it is more profitable to use energy from the grid

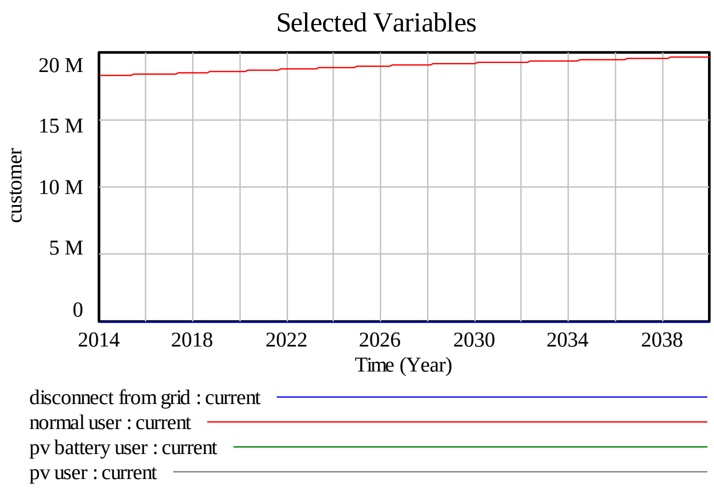

Figure 47 End user evolution on really low power price

Appendix B

This appendix contains the model's overview

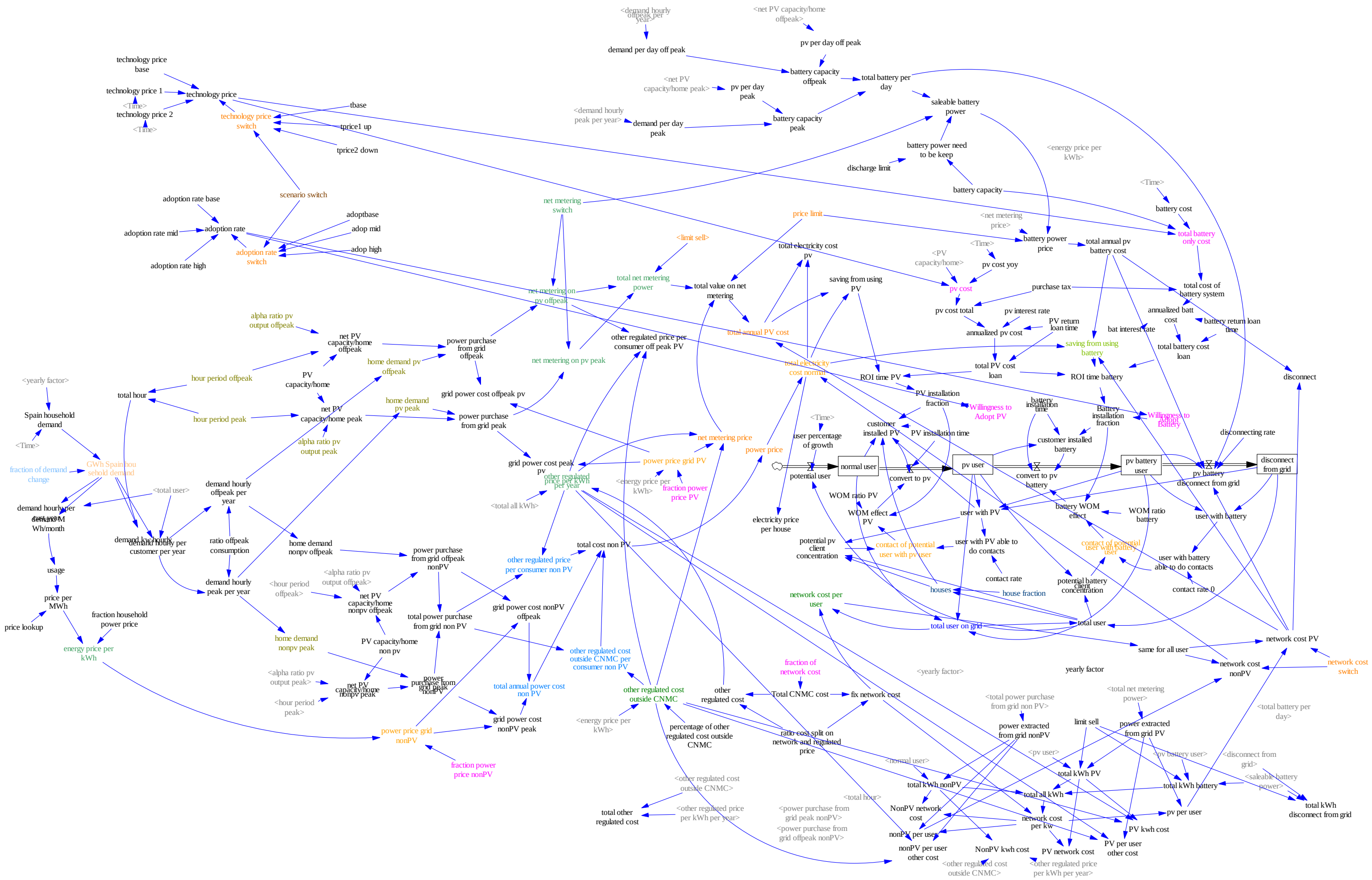

Figure 48 Model's overview

Appendix C

This appendix contains the model's code for the Vensim program

```
MWh=
	1000
	~	Mwh/GWh
	~		|

"demand MWh/month"=
	GWh Spain household demand*MWh/month
	~	Mwh/Month
	~		|

month=
	12
	~	Month/Year
	~		|

total kWh disconnect from grid=
	(disconnect from grid*-saleable battery power)*365*limit sell
	~
	~		|

total annual pv battery cost=
	-battery power price
	~	euro/customer
	~		|

total kWh PV=
	power extracted from grid PV*pv user*limit sell
	~
	~		|

total net metering power=
	IF THEN ELSE( (net metering on pv offpeak+net metering on pv peak)<0, (net metering on pv offpeak\
		+net metering on pv peak)*limit sell , (net metering on pv offpeak+net metering on pv peak\
		) )
```

~ kWh/customer

~ (net metering on pv offpeak+net metering on pv peak)

|

limit sell=

1

~

~ |

price limit=

1

~

~ |

total kWh battery=

(pv battery user*-saleable battery power)*365*limit sell

~ kWh

~ (disconnect from grid*power extracted from grid pvbattery)+(pv battery user*power \
extracted from grid pvbattery)
((disconnect from grid*-saleable battery power)+(pv battery user*-saleable \
battery power))*365

|

net metering on pv offpeak=

IF THEN ELSE(net metering switch=1,power purchase from grid offpeak,IF THEN ELSE(power purchase from grid offpeak\

<0, 0

, power purchase from grid offpeak

))

~ kWh/customer

~ |

disconnect=

IF THEN ELSE(-total annual pv battery cost<network cost PV, 1,0)

~

~ |

other regulated price per kWh per year=

other regulated cost/total all kWh

~ euro/kWh

~ other regulated cost/(GWh Spain household demand*1e+006)

other regulated cost/total all kWh

|

pv cost=

pv cost yoy*technology price*"PV capacity/home"

~ euro

~ |

purchase tax=

0.21

~ Dmnl

~ 21%

|

power extracted from grid nonPV=

total power purchase from grid non PV

~ kWh/customer

~ (MAX(power purchase from grid offpeak nonPV, 0)+MAX(power purchase from \

grid peak nonPV, 0))

|

net metering price=

other regulated cost outside CNMC+other regulated price per kWh per year+power price grid PV

~ euro/kWh

~ |

normal user= INTEG (

potential user-convert to pv,

1.82529e+007)

~ customer

~ 2.58262e+007

18,252,887

1.71996e+007

```
|

demand hourly per cust year=
	(GWh Spain household demand*1e+006)/total user
	~	kWh/hour/customer
	~		|

potential user=
	total user*user percentage of growth
	~	customer
	~		|

user percentage of growth= WITH LOOKUP (
	Time,
		([(2014,0)-(2040,0.006)],(2014,0),(2015,0.00552647),(2016,0.0013583),(2017,0.0038327\

	),(2018,0.00380544),(2019,0.00356044),(2020,0.00336207),(2021,0.00373407),(2022,0.00322561\

	),(2023,0.00316891),(2024,0.00333403),(2025,0.0033502),(2026,0.00316093),(2027,0.00295201\
		),(2028,0.00291203),(2029,0.00287305),(2030,0.00250885),(2031,0.00224444),(2032,0.0022\
		),(2033,0.0023),(2034,0.0024),(2035,0.0025),(2036,0.0026),(2037,0.0026),(2038,0.0027\
		),(2039,0.0025),(2040,0.0028) ))
	~	Dmnl
	~		|

house fraction=
	0.3
	~
	~	30% from total user
	|

houses=
	house fraction*total user
	~
	~		|

demand hourly per customer per year=
	(GWh Spain household demand*1e+006)/total user
```

~ kWh/customer

~ (demand EU*1e+006/total hour)/customer

|

potential pv client concentration=

(houses-user with PV)/total user

~ Dmnl

~ normal user/total user on grid

(houses-user with PV)/total user

|

potential battery client concentration=

pv user/total user

~

~ pv user/total user on grid

|

total user=

disconnect from grid+total user on grid

~ customer

~ |

adop high=

2

~

~ |

adop mid=

1

~

~ |

adoptbase=

0

~

~ |

power extracted from grid PV=

total net metering power

~ kWh/customer

~ MAX(power purchase from grid offpeak, 0)+MAX(power purchase from grid peak, 0)

total net metering power

|

tbase=

0

~

~ |

total other regulated cost=

other regulated cost outside CNMC+other regulated price per kWh per year

~

~ |

tprice2 down=

2

~

~ |

adoption rate switch=

IF THEN ELSE(scenario switch=1 :OR: scenario switch=4 :OR: scenario switch=7, adoptbase\

,

IF THEN ELSE(scenario switch=2 :OR: scenario switch=5 :OR: scenario switch=8, adop mid\

,

IF THEN ELSE(scenario switch=3 :OR: scenario switch=6 :OR: scenario switch=9, adop high\

, 0)))

~

~ |

technology price switch=

IF THEN ELSE(scenario switch=1 :OR: scenario switch=2 :OR: scenario switch=3, tbase,

IF THEN ELSE(scenario switch=4 :OR: scenario switch=5 :OR: scenario switch=6, tprice1 up\

,

IF THEN ELSE(scenario switch=7 :OR: scenario switch=8 :OR: scenario switch=9, tprice2 down\

, 0)))

~ Dmnl

~ |

tprice1 up=

1

~

~ |

PV per user other cost=

(other regulated cost outside CNMC+other regulated price per kWh per year)*power extracted from grid PV

~

~ |

nonPV per user other cost=

(other regulated cost outside CNMC+other regulated price per kWh per year)*power extracted from grid nonPV

~

~ |

same for all user=

network cost per user

~

~ |

PV network cost=

network cost per kw*total kWh PV

~ euro/(customer*Year)

~ |

total kWh nonPV=

normal user*power extracted from grid nonPV

~ kWh

~ |

pv per user=

network cost per kw*power extracted from grid PV

~ euro/(customer*Year)

~ |

NonPV network cost=

total kWh nonPV*network cost per kw

~ euro/Year

~ |

nonPV per user=

network cost per kw*power extracted from grid nonPV

~ euro/(customer*Year)

~ |

total all kWh=

MAX((total kWh battery+total kWh PV+total kWh nonPV),1)

~ kWh

~ |

total battery only cost=

battery cost*technology price*battery capacity

~ euro/customer

~ |

network cost PV=

IF THEN ELSE(network cost switch=0, same for all user, pv per user)

~ euro/(customer*Year)

~ |

network cost nonPV=

IF THEN ELSE(network cost switch=0, same for all user,

nonPV per user)

~ euro/(customer*Year)

~ |

network cost switch=

0

~ Dmnl

~ 0 same for all user, 1 volumetric

|

NonPV kwh cost=

total kWh nonPV*(other regulated price per kWh per year+other regulated cost outside CNMC\

)

~

~ |

network cost per kw=

fix network cost/total all kWh

~ euro/(kWh*Year)

~ |

PV kwh cost=

total kWh PV*(other regulated price per kWh per year+other regulated cost outside CNMC\

)

~

~ |

power price grid nonPV=

energy price per kWh*fraction power price nonPV

~ euro/kWh

~ 0.09

|

fraction power price PV=

1

~

~ |

power price grid PV=

energy price per kWh*fraction power price PV

~

~ 0.15

|

```
grid power cost nonPV offpeak=
	power price grid nonPV*power purchase from grid offpeak nonPV
	~	euro/customer
	~	power price grid 0*power purchase from grid 0
	|

grid power cost offpeak pv=
	power price grid PV*power purchase from grid offpeak
	~
	~	power price grid 1*power purchase from grid offpeak
	|

fraction power price nonPV=
	1
	~
	~		|

saleable battery power=
	IF THEN ELSE(net metering switch=1,(total battery per day-battery power need to be keep\
		),IF THEN ELSE(total battery per day>0, 0 , (total battery per day-battery power need to be keep\
		)
	 ))
	~	kWh/customer
	~	IF THEN ELSE(nett metering switch=1,power purchase from grid offpeak,IF THEN \
		ELSE(power purchase from grid offpeak<0, 0 , power purchase from grid \
		offpeak
		 ))
		IF THEN ELSE(total battery per day>total battery per day,(total battery per \
		day-battery power need to be keep),0)
		IF THEN ELSE(nett metering switch=1 :AND: (total battery per day-battery \
		power need to be keep)>0,(total battery per day-battery power need to be \
		keep),0)
	|

Total CNMC cost=
	6.53178e+009*fraction of network cost
	~	euro/Year
```

~ |

fraction household power price=

0.35

~ Dmnl

~ |

fraction of network cost=

1

~ Dmnl

~ |

energy price per kWh=

price per MWh/1000*12*fraction household power price

~ euro/kWh

~ price per mW/1000

|

pv battery disconnect from grid=

IF THEN ELSE(total battery per day>0,IF THEN ELSE((-total annual pv battery cost<network cost PV\

),pv battery user/disconnecting rate

, 0),0)

~ customer

~ IF THEN ELSE(total battery per day>0,IF THEN ELSE(saving from using battery>0.01,pv \

battery user/disconnecting rate

, 0),0)

|

percentage of other regulated cost outside CNMC=

0.1854

~ Dmnl

~ |

Spain household demand= WITH LOOKUP (

Time/yearly factor,

([(2014,70000)-(2040,90000)],(2014,70710.4),(2015,70055.6),(2020,73243.7),(2025,74039.2\

),(2030,76239.7),(2035,78182.3),(2040,80272.2)))

~ GWh/Year

~ |

other regulated cost outside CNMC=

percentage of other regulated cost outside CNMC*energy price per kWh

~ euro/kWh

~ |

GWh Spain household demand=

fraction of demand change*Spain household demand

~ GWh/Year

~ ([(2014,0)-(2040,200000)],(2014,70707.6),(2015,78145.8),(2016,80503.6),(2017,82835.2)\

,(2018,84985.3),(2019,87015.2),(2020

,88986.4),(2021,90992.9),(2022,93081.9),(2023,95286.2),(2024,97631.6),(2025,100143),(\

2026,102809),(2027,105583),(2028,

108420

),(2029,111319),(2030,114277),(2031,117293),(2032,120361),(2033,123477),(2034,126633)\

,(2035,129806),(2036,132976),(2037

,

136135),(2038,139284),(2039,142424),(2040,145560))

|

adoption rate=

IF THEN ELSE(adoption rate switch=0, adoption rate base,

IF THEN ELSE(adoption rate switch=1, adoption rate mid,

adoption rate high))

~

~ |

adoption rate base=

1

~

~ |

adoption rate high=

2

~

~ |

adoption rate mid=

1.5

~

~ |

technology price=

IF THEN ELSE(technology price switch=0, technology price base,

IF THEN ELSE(technology price switch=1, technology price 1,

technology price 2))

~ Dmnl

~ |

technology price 1= WITH LOOKUP (

Time,

([(2013,0.9)-(2040,2)],(2013.84,1),(2017.74,1.45965),(2040,1.5)))

~

~ |

technology price 2= WITH LOOKUP (

Time,

([(2014,0.4)-(2040,1)],(2014,1),(2018.06,0.778947),(2019.65,0.718421),(2024.97,0.610526\

),(2034.04,0.521053),(2034.04,0.523684),(2035.63,0.515789),(2040,0.5)))

~

~ |

technology price base=

1

~

~ |

scenario switch=

1

~

~ |

total cost of battery system=

(total battery only cost)*(1+purchase tax)

~ euro/customer

~ 10000/2

4000

|

Willingness to Adopt Battery=

adoption rate

~ Dmnl

~ increasing this will increase adoption rate

|

pv cost total=

(1+purchase tax)*pv cost

~ euro/customer

~ 6000

|

Willingness to Adopt PV=

adoption rate

~ Dmnl

~ increasing this will increase adoption rate

|

battery cost= WITH LOOKUP (

Time,

([(2014,0)-(2050,500)],(2014,490),(2020,165),(2030,140),(2040,137.5),(2050,135)))

~ euro/kWh

~ |

battery power price=

IF THEN ELSE((saleable battery power)>0, (net metering price*saleable battery power*\

365*price limit), (net metering price*saleable battery power*365))

~ euro/customer

~ price per kW*total battery power

energy price per kW*power purchase from grid bat user energy price per kW*saleable battery power*365

|

user with PV=

pv battery user+pv user+disconnect from grid

~ customer

~ |

other regulated cost outside CNMC per consumer non PV=

other regulated cost outside CNMC*total power purchase from grid non PV

~ euro/customer

~ |

total annual PV cost=

total value on net metering+network cost PV

~ euro/customer

~ grid power cost+grid power cost 1

|

other regulated price per consumer off peak PV=

(net metering on pv offpeak*other regulated price per kWh per year)+(net metering on pv offpeak\

*other regulated cost outside CNMC)

~ euro/customer

~ |

total value on net metering=

IF THEN ELSE((total net metering power)<0, (net metering price*total net metering power\

*price limit), (net metering price*total net metering power))

~ euro/customer

~ (power price grid 1*total net metering power)+other regulated price per consumer off \

peak PV

(net metering price*total net metering power)+other regulated price per consumer off \

peak PV

(net metering price*total net metering power)

|

total cost non PV=

other regulated price per consumer non PV+total annual power cost non PV+other regulated cost outside CNMC per consumer non PV

~ euro/Year

~ |

pv cost yoy= WITH LOOKUP (

Time,

([(2014,900)-(2040,2000)],(2014,1500),(2020,1100),(2030,985),(2040,935)))

~ euro/kWh

~ |

other regulated cost=

Total CNMC cost*(1-ratio cost split on network and regulated price)

~ euro/Year

~ harga dibagi energy yang dipakai total

|

other regulated price per consumer non PV=

total power purchase from grid non PV*other regulated price per kWh per year

~ euro/Year

~ |

total power purchase from grid non PV=

power purchase from grid offpeak nonPV+power purchase from grid peak nonPV

~ kWh/customer

~ |

fix network cost=

ratio cost split on network and regulated price*Total CNMC cost

~ euro/Year

~ harga dibagi population

|

power price=

total cost non PV

~

~ 100

total annual cost non PV

|

ratio cost split on network and regulated price=

0.6

~ Dmnl

~ |

network cost per user=

fix network cost/total user on grid

~ euro/Year/customer

~ annualized network cost/total user on grid

|

battery capacity peak=

pv per day peak-demand per day peak

~ kWh/customer

~ |

demand per day peak=

demand hourly peak per year/365

~ kWh/customer

~ |

annualized batt cost=

((((1+bat interest rate)^battery return loan time)*bat interest rate)/(((1+bat interest rate\

)^battery return loan time)-1)

)*total cost of battery system

~ euro/Year/customer

~ |

saving from using battery=

(total electricity cost normal-(total annual pv battery cost+network cost PV))

~ euro/customer

~ MAX(total electricity cost normal-total annual PV cost,0)

(total electricity cost normal-total annual pv battery cost)+network cost per user

IF THEN ELSE(total annual pv battery cost>0, (total electricity cost normal-total \
annual pv battery cost), (total electricity cost normal-total annual pv \
battery cost)+network cost nonPV)

IF THEN ELSE(total annual pv battery cost>0, (total electricity cost \
normal-(total annual pv battery cost+network cost PV)), (total electricity \
cost normal-total annual pv battery cost)+network cost nonPV)

|

battery power need to be keep=

discharge limit*battery capacity

~ kWh/customer

~ |

pv per day peak=

"net PV capacity/home peak"/365

~ kWh/customer

~ |

total battery per day=

(battery capacity offpeak+battery capacity peak)

~ kWh/customer

~ |

battery capacity offpeak=

pv per day off peak-demand per day off peak

~ kWh/customer

~ |

discharge limit=

0.05

~ Dmnl

~ |

pv per day off peak=

"net PV capacity/home offpeak"/365

~ kWh/customer

~ |

demand per day off peak=

demand hourly offpeak per year/365

~ kWh/customer

~ |

net metering on pv peak=

IF THEN ELSE(net metering switch=1,power purchase from grid peak,IF THEN ELSE(power purchase from grid peak\

<0, 0 , power purchase from grid peak

))

~ kWh/customer

~ |

power purchase from grid peak=

(home demand pv peak-"net PV capacity/home peak")

~ kWh/customer

~ (home demand-"net PV capacity/home")*hour period

IF THEN ELSE(nett metering switch=1,(home demand pv peak-"net PV \

capacity/home peak"),IF THEN ELSE((home demand pv peak-"net PV \

capacity/home peak")<0, 0 , (home demand pv peak-"net PV capacity/home \

peak")))

|

total battery cost loan=

annualized batt cost*battery return loan time

~ euro/customer

~ |

total PV cost loan=

PV return loan time*annualized pv cost

~ euro/customer

~ |

ROI time battery=

IF THEN ELSE(saving from using battery>0, ((total battery cost loan+total PV cost loan\

)/saving from using battery), 50)

~ Year

~ |

fraction of demand change=

1

~ Dmnl

~ |

net metering switch=

0

~ Dmnl

~ 1 on 0 off

|

ROI time PV=

IF THEN ELSE(saving from using PV>0, (total PV cost loan/saving from using PV), 50)

~ Year

~ |

"net PV capacity/home nonpv peak"=

alpha ratio pv output peak*"PV capacity/home non pv"*hour period peak

~ kWh/customer

~ |

"net PV capacity/home offpeak"=

alpha ratio pv output offpeak*"PV capacity/home"*hour period offpeak

~ hour*kW/(customer*Year)

~ |

"net PV capacity/home nonpv offpeak"=

alpha ratio pv output offpeak*"PV capacity/home non pv"*hour period offpeak

~ kWh/customer

~ |

usage=

"demand MWh/month"

```
	~	Mwh/Month
	~		|

battery capacity=
	13.5
	~	kWh/customer
	~	10
	|

contact of potential user with battery user=
	potential battery client concentration*user with battery able to do contacts
	~	
	~		|

price per MWh=
	price lookup(usage)
	~	euro/Mwh
	~		|

price lookup(
	[(0,0)-(2.30145e+007,90)],(0,0),(1.97993e+007,58.06),(1.98739e+007,59.52),(2.05481e+007\
		,63.84),(2.07766e+007,61.34),(2.30145e+007,81.7))
	~	Dmnl
	~	([(0,0)-(2.30145e+007,90)],(0,0),(1.97993e+007,58.06),(1.98739e+007,59.52),\
		(2.05481e+007,63.84),(2.07766e+007,61.34),(2.30145e+007,81.7) )
	|

battery WOM effect=
	IF THEN ELSE(Battery installation fraction > 0, MAX(WOM ratio battery*contact of potential user with battery user\
		,0),0)
	~	
	~	IF THEN ELSE(PV installation fraction > 0, MAX(pv user*normal user*WOM \
		ratio*contact rate/total user on grid,0),0)
	|

battery installation time=
```

0.4

~ Year

~ |

Battery installation fraction= WITH LOOKUP (

ROI time battery/Willingness to Adopt Battery,

([(0,0)-(50,1)],(0,1),(1,0.495),(2,0.399),(3,0.327),(4,0.253),(5,0.203),(6,0.146),(\

7,0.1),(8,0.06),(9,0.04),(10,0.03),(11,0.02),(12,0.015),(13,0.013),(14,0.01),(15,0.008\

),(16,0.007),(17,0.006),(18,0.005),(19,0.004),(20,0.003),(21,0.0025),(22,0.002),(23\

,0.0016),(24,0.0013),(25,0.001),(26,0.001),(27,0.001),(28,0.001),(29,0.001),(30,0.001\

),(31,0),(32,0),(33,0),(34,0),(35,0),(36,0),(37,0),(38,0),(39,0),(40,0),(41,0),(42,\

0),(43,0),(44,0),(45,0),(46,0),(47,0),(48,0),(49,0),(50,0)))

~ Dmnl

~ 100% if ROI

|

user with battery=

disconnect from grid+pv battery user

~

~ |

user with battery able to do contacts=

user with battery*contact rate 0

~ contacts/Year

~ |

customer installed battery=

(pv user*Battery installation fraction/battery installation time)

~ customer

~ |

WOM ratio battery=

0.0078

~

~ 0.78 percentage points

|

```
contact rate 0=
	1
	~	contact/person/Year
	~		|

user with PV able to do contacts=
	user with PV*contact rate
	~	contacts/Year
	~		|

contact of potential user with pv user=
	potential pv client concentration*user with PV able to do contacts
	~	contact/Year
	~		|

convert to pv=
	MAX( customer installed PV+(WOM effect PV/PV installation time),0)
	~	customer
	~	MAX(normal user/conversion ratio to pv,0)
		normal user/conversion ratio to pv
		MAX(normal user*0,normal user/conversion ratio to pv)
		MAX( ((normal user*PV installation fraction/instalation time)+WOM effect/instalation \
		time),0)
		DELAY1( normal user/conversion ratio to pv , 100)

		MAX( customer installed PV+(WOM effect PV/PV instalation time),0)
	|

contact rate=
	1
	~	contact/customer/Year
	~		|

WOM effect PV=
	IF THEN ELSE(PV installation fraction > 0, MAX(WOM ratio PV*contact of potential user with pv user\
		,0),0)
	~	customer/Year
```

```
	~	IF THEN ELSE(PV installation fraction > 0, MAX(pv user*WOM ratio*contact rate/total \
		user on grid,0),0)
		atau gabungan PV dan normal user aja sebagai faktor pembagi
		IF THEN ELSE(PV installation fraction > 0, MAX(pv user*normal user*WOM ratio*contact \
		rate/total user on grid,0),0)

		penting IF THEN ELSE(PV installation fraction > 0, MAX(pv user*normal user*WOM ratio \
		PV*contact rate/total user on grid,0),0)
		IF THEN ELSE(PV installation fraction > 0, MAX(WOM ratio PV*contact of \
		potential user with pv user,0),0)
	|

customer installed PV=
	IF THEN ELSE((user with PV<houses),(normal user*PV installation fraction/PV installation time\
		),0)
	~	customer
	~	IF THEN ELSE((user with PV<houses),(normal user*PV installation \
		fraction/PV installation time),0)
	|

PV installation fraction= WITH LOOKUP (
	ROI time PV/Willingness to Adopt PV,
		([(0,0)-(50,1)],(0,1),(1,0.495),(2,0.399),(3,0.327),(4,0.253),(5,0.203),(6,0.146),(\
		7,0.1),(8,0.06),(9,0.04),(10,0.03),(11,0.02),(12,0.015),(13,0.013),(14,0.01),(15,0.008\
		),(16,0.007),(17,0.006),(18,0.005),(19,0.004),(20,0.003),(21,0.0025),(22,0.002),(23\
		,0.0016),(24,0.0013),(25,0.001),(26,0.001),(27,0.001),(28,0.001),(29,0.001),(30,0.001\
		),(31,0),(32,0),(33,0),(34,0),(35,0),(36,0),(37,0),(38,0),(39,0),(40,0),(41,0),(42,\
		0),(43,0),(44,0),(45,0),(46,0),(47,0),(48,0),(49,0),(50,0) ))
	~	Dmnl
	~	100% if ROI
	|

saving from using PV=
	total electricity cost normal-total annual PV cost
	~	euro/customer
	~	MAX(total electricity cost normal-total annual PV cost,0)
	|
```

WOM ratio PV=

0.0078

~ customer/contact

~ 0.78 percentage points

|

demand hourly offpeak per year=

demand hourly per customer per year*ratio offpeak consumption

~ kWh/customer

~ |

demand hourly peak per year=

demand hourly per customer per year*(1-ratio offpeak consumption)

~ kWh/customer

~ |

demand kw hourly =

(GWh Spain household demand*1e+006/total hour)

~ kWh/hour/customer

~ |

PV installation time=

0.5

~ Year

~ |

electricity price per house=

total electricity cost normal

~ euro/GWh/Year

~ demand*Time

|

total hour=

hour period peak+hour period offpeak

~ hour/Year

~ |

home demand pv peak=

demand hourly peak per year

~ kWh/customer

~ 2

demand hourly peak*hour period

|

home demand pv offpeak=

demand hourly offpeak per year

~ kWh/customer

~ 0.8

demand hourly offpeak*hour period 1

|

ratio offpeak consumption=

0.643

~ Dmnl

~ |

home demand nonpv offpeak=

demand hourly offpeak per year

~ kWh/customer

~ 2

demand hourly offpeak*hour period 0

|

total electricity cost pv=

total electricity cost normal-total annual PV cost

~ euro/customer

~ total electricity cost normal-total annual PV cost

total annual PV cost+network cost per user

|

grid power cost peak pv=

power price grid PV*power purchase from grid peak

~

~ |

alpha ratio pv output peak=

0.4256

~ Dmnl

~ |

alpha ratio pv output offpeak=

0.0256

~ Dmnl

~ |

power purchase from grid offpeak nonPV=

(home demand nonpv offpeak-"net PV capacity/home nonpv offpeak")

~ kWh/customer

~ (home demand-"net PV capacity/home")*hour period

|

power purchase from grid offpeak=

(home demand pv offpeak-"net PV capacity/home offpeak")

~ kWh/customer

~ (home demand-"net PV capacity/home")*hour period

|

power purchase from grid peak nonPV=

(home demand nonpv peak-"net PV capacity/home nonpv peak")

~ kWh/customer

~ (home demand-"net PV capacity/home")*hour period

|

"net PV capacity/home peak"=

alpha ratio pv output peak*"PV capacity/home"*hour period peak

~ hour*kW/(customer*Year)

~ |

grid power cost nonPV peak=

power price grid nonPV*power purchase from grid peak nonPV

~ euro/customer

~ |

"PV capacity/home non pv"=

0

~ kW/customer

~ |

"PV capacity/home"=

4

~ kW/customer

~ |

hour period peak=

2920

~ hour/Year

~ 3000

|

hour period offpeak=

5840

~ hour/Year

~ 5760

|

total annual power cost non PV=

grid power cost nonPV offpeak+grid power cost nonPV peak

~ euro/customer

~ |

home demand nonpv peak=

demand hourly peak per year

~ kWh/customer

~ 0.8*hour period 1 0

demand hourly peak*hour period 1 0

|

bat interest rate=

0.08

~ Dmnl

~ assumption

|

battery return loan time=

10

~ Year

~ 8

|

total electricity cost normal=

power price+network cost nonPV

~ euro/customer

~ |

annualized pv cost=

((((1+pv interest rate)^PV return loan time)*pv interest rate)/(((1+pv interest rate\

)^PV return loan time)-1)

)*pv cost total

~ euro/Year/customer

~ |

pv interest rate=

0.08

~ Dmnl

~ assumption

|

convert to pv battery=

MAX(customer installed battery+(battery WOM effect/battery installation time),0)

~ customer

~ pv user/conversion ratio to pvbat

MAX(normal user/conversion ratio to pv,0)

normal user/conversion ratio to pv

MAX(normal user*0,normal user/conversion ratio to pv)

```
		DELAY1( normal user/conversion ratio to pv , 100)
	|

pv battery user= INTEG (
	convert to pv battery-pv battery disconnect from grid,
		0)
	~	customer
	~		|

disconnect from grid= INTEG (
	pv battery disconnect from grid,
		0)
	~	customer
	~		|

disconnecting rate=
	1
	~
	~		|

yearly factor=
	1
	~	Year
	~		|

total user on grid=
	normal user+pv battery user+pv user
	~	customer
	~		|

PV return loan time=
	10
	~	Year
	~	25
		5
	|
```

```
pv user= INTEG (
	convert to pv-convert to pv battery,
		0)
	~	customer
	~	147
	|

******************************************************
	.Control
******************************************************~
		Simulation Control Parameters
	|

FINAL TIME  = 2040
	~	Year
	~	The final time for the simulation.
	|

INITIAL TIME  = 2014
	~	Year
	~	The initial time for the simulation.
	|

SAVEPER  =
      TIME STEP
	~	Year [0,?]
	~	The frequency with which output is stored.
	|

TIME STEP  = 0.125
	~	Year [0,?]
	~	The time step for the simulation.
	|
```