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MASTER´S THESIS

ENERGY TECHNOLOGY FOR SUSTAINABLE DEVELOPMENT

DEVELOPMENT OF A METHODOLOGY TO OPTIMIZE THE INTEGRATION OF PHOTOVOLTAIC PLANTS COUPLED WITH ENERGY STORAGE SYSTEMS IN ADVANCED ELECTRICAL GRIDS: TECHNICAL AND ECONOMIC EVALUATION

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RESUMEN

La integración de las tecnologías de energía renovable es un gran componente para alcanzar los serios objetivos medioambientales de diferentes gobiernos e instituciones a nivel mundial. Sin embargo, hay varios desafíos a lo largo de su camino para seguir aumentando en capacidad. La mayor penetración de estas tecnologías surge la necesidad de que proporcionen la misma fiabilidad y servicios que los generadores convencionales han hecho en la red eléctrica. El almacenamiento de energía proporciona una de las soluciones.

La propuesta del trabajo fin de master era desarrollar una metodología que permita modelar y simular sistemas de almacenamiento de energía acoplado a campos fotovoltaicos, para optimizar su integración en las redes eléctricas. La metodología puede modelar cualquier ubicación y cualquier condición que requiera un proyecto de este tipo y calcular su dimensionamiento óptimo. Los parámetros que se puede variar son los siguientes: potencia, ratio DC/AC, ubicación, precios de la electricidad, mecanismos de fijación de precios de tarifas (existentes y propuestos), y finalmente costes de capital.

En este modelo, además, se propuso una nueva configuración para beneficiarse de los excesos fotovoltaicos producidos a partir de un campo fotovoltaico sobredimensionado, mediante la conexión del sistema de baterías a un convertidor DC/DC de relativamente alta potencia.

Se analizó diferentes casos de estudio, con el fin de mostrar como este tipo de sistema puede ayudar a reemplazar los generadores convencionales y asegurar la fiabilidad y calidad de la red eléctrica. Los casos que se estudia son: (i.) almacenamiento de excesos por “clipping”, (ii.) power-shifting, (iii.) regulación primaria y secundaria, y (iv.) acoplamiento de respuesta de demanda mediante vehículos eléctricos.

Key words (in Spanish): Energía, Almacenamiento, Fotovoltaica, Excesos, Desfase de potencia, Regulación primaria, Regulación Secundaria, Respuesta de demanda.

RESUM

La integració de les tecnologies d'energia renovable és un gran component per a aconseguir els seriosos objectius mediambientals de diferents governs i institucions a nivell mundial. No obstant això, hi ha diversos desafiaments al llarg del seu camí per a continuar augmentant en capacitat. La major penetració d'estes tecnologies sorgix la necessitat que proporcionen la mateixa fiabilitat i servicis que els generadors convencionals han fet en la xarxa elèctrica. L'emmagatzemament d'energia proporciona una de les solucions.

La proposta del treball fi de màster era desenrotllar una metodologia que permeta modelar i simular sistemes d'emmagatzemament d'energia acoblat a camps fotovoltaics, per a optimitzar la seua integració en les xarxes elèctriques. La metodologia pot modelar qualsevol ubicació i qualsevol condició que requerisca un projecte d'este tipus i calcular el seu dimensionamiento òptim. Els paràmetres que es pot variar són els següents: potència, ràtio DC/AC, ubicació, preus de l'electricitat, mecanismes de fixació de preus de tarifes (existents i proposats) , i finalment costos de capital.

En este model, a més, es va proposar una nova configuració per a beneficiar-se dels excessos fotovoltaics produïts a partir d'un camp fotovoltaic sobredimensionat, per mitjà de la connexió del sistema de bateries a un convertidor DC/DC de relativament alta potència.

Es va analitzar diferents casos d'estudi, a fi de mostrar com este tipus de sistema pot ajudar a reemplaçar els generadors convencionals i assegurar la fiabilitat i qualitat de la xarxa elèctrica. Els casos que s'estudia són: (i.) emmagatzemament d'excessos per “clipping”, (ii.) power- shifting, (iii.) regulació primària i secundària, i (iv.) adaptament de resposta de demanda per mitjà de vehicles elèctrics.

Key words (in Valencian): Energia, Emmagatzemament, Fotovoltaica, Excessos, Desfasament de potència, Regulació primària, Regulació Secundària, Resposta de demanda.

ABSTRACT

The integration of renewable energy technologies is an important component to achieve the serious environmental objectives of different governments and institutions worldwide. However, there are several challenges along the way to continue increasing in capacity. The greater penetration of these technologies arises the need to provide the same reliability and services that conventional generators have made in the electricity grid. Energy storage provides one of the solutions.

The purpose of the master's project was to develop a methodology that allows modeling and simulating energy storage systems coupled to photovoltaic fields, to optimize their integration in electricity networks. The methodology can model any location and any condition that a project of this type requires and calculate its optimal sizing. The parameters that can be varied are the following: power, DC / AC ratio, location, electricity prices, tariff pricing mechanisms (existing and proposed), and finally capital costs.

In this model, in addition, a new configuration was proposed to benefit from the photovoltaic excesses produced from an oversized photovoltaic field, by connecting the battery system to a DC/DC converter of relatively high power.

Different cases studies were analyzed, in order to show how this type of system can help to replace conventional generators and ensure the reliability and quality of the electrical network. The cases studies were: (i.) Storage of excesses by "clipping", (ii.) Power-shifting, (iii.) Primary and secondary regulation, and (iv.) Demand response coupling by electric vehicles.

Keywords: Energy, Storage, Photovoltaic, Excess, Power-shifting, Primary regulation, Secondary regulation, Demand response.

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NOMENCLATURE

Below shows a list of all nomenclature used throughout the Master´s thesis:

C	constant of integration.
$C_{dc/ac}$	increase in capital costs from over-sizing the battery system.
C_a	annual earnings due to the battery system integration.
C_{batt}	total capacity of the battery chosen.
C_{inv}	investment cost for the battery system integration.
C_0	original battery cost from the initial investment.
$C_{sec,reg}$	additional capacity needed to provide a certain amount of power for reserve/curtailment, during the maximum time required.
C_T	total battery costs, taking into account replacement costs throughout the plant lifetime.
D	daily earnings generated.
C_{deg}	change in battery replacement costs (due to change in degradation rate).
DC/AC	over-sizing ratio (PV power with respect to the maximum inverter AC power).
E	solar excesses produced in that day.
E_{reg}	Earnings (both band and availability) produced during the lifetime of the plant.
$E_{DC/AC}$	solar excesses produced during the whole year (with no limits in battery capacity – since at such large battery sizes all excesses are harnessed, as explained earlier).
E_o	represents the initial capacity of the vehicle battery when connecting to the port.
f_{grid}	grid frequency [Hz] at a given moment.
f_N	rated frequency [Hz] of the grid.
$f_{set-point}$	frequency value [Hz] at which active power regulation starts, for Frequency Response.
$I_{mpp,array}$	MPP current of the array.
$I_{mpp,panel}$	MPP current of the panel.
$I_{sc,array}$	short-circuit current of the array.
$I_{sc,panel}$	short-circuit current of the panel.
L	lifetime of the original batteries.
N	final year.
N_{inv}	number of inverters (to the next whole number).
NPV	Net Present Value.
N_s	number of panels per string.
N_p	number of strings.
p	new power output.

p_0	original power output.
ρ	maximum inverter power, which is assumed constant here for simplicity purposes.
P	energy of the year (equivalent to adding the power every hour of the year).
$P_{batt\_syst,inv}$	total power provided by the battery system, per inverter.
$P_{batt\_syst,SODA}$	power available for clipping and power-shifting services, this value being in the most demanded period, which is during peak period, where discharging of the total battery capacity needs to be performed during 4 hours.
P_{charge}	charging power selected (depending on tariff).
$P_{charge,MAX}$	maximum charging power of that vehicle.
$P_{charging}$	charging power required in order to have a completely charged battery by the time the driver returns to their vehicle (e.g. 08:00).
$P_{discharge,MAX}$	possible discharge power that can be used in order to fully recharge the battery on time with the maximum charging power of that vehicle. Note: Here, discharge power will have a negative value, so the numerator term will always increase or stay the same (in the case of no possible discharge available from that vehicle).
$P_{inv,max}$	maximum AC power that the inverter can operate.
$P_{inv,Tdesign}$	capacity of 1 inverter at the design temperature used.
P_{limit}	power of the inverter being limited to a value lower than the maximum.
P_{plant}	plant capacity.
P_{PV}	PV array power.
$P_{rated,grid}$	total rated power to be injected at the point of interconnection.
$P_{reserve}$	power reserve.
$P_{sec,reg,inv}$	power reserve to be provided per inverter.
$P_{sec,reg}$	power reserve/curtailment to be provided by the plant.
$P_{t_{design}}$	maximum power the inverter can operate at the ambient temperature the project has been designed for.
r_{inf}	inflation rate.
r_{int}	interest rate.
SoC	State of Charge of the battery, the moment the vehicle is connected to the mains when the driver parks their vehicle.
t	year considered.
T	period length.
T_{charge}	time left for the vehicle to charge to 100% SoC.
$t_{left,recharge}$	time left to recharge and pick-up the vehicle, before power request is issued.
t_{max}	maximum time to perform this service (which currently is 15 minutes).
V_{mpp}	MPP voltage of the array.

π_v, π_s and π_p	valley, shoulder and peak price for each period of the time-of-use pricing mechanism.
Π_{batt}	battery cost in a certain year, t.
$\Pi_{batt,0}$	battery cost at the beginning of the project.
$\Delta D_{DC/AC}$	change in daily earnings.
$\Delta E_{DC/AC}$	change in solar excesses produced in that day.
$\Delta p_{DC/AC}$	change in power output (change in production in a certain hour).
$\Pi_{pcs-system}$	associated cost of installing this battery system, with the PCS converters.
π_{batt}	average cost per kWh of batteries, as calculated using various models in the market.
π_{pcs}	average cost per MW of an inverter-charger, as calculated using various models in the market.
ΔC	increase in capital costs due to the increase in battery size as well as battery and DC-DC converter power. This increase in capital costs will be dependent on the power willing to be offered (which has to be a minimum of 5MW, as stated in current regulations), and battery price at the time of purchase (projections made predict a 9% decrease in price per year, from 2017 to 2025).
$\overline{\Pi_{sec,reg}}$	weighted average market price for secondary regulation (power up or down)
$\sum_{m=1}^{48}(\overline{\pi_{sec,reg,m}} \cdot E_{deviated,m})$	is adding for the 48 months (4 years) the product of the energy deviated in each month (whether it´s power up or power down) and the average price for that month (whether it´s power up or power down).
$\sum_{m=1}^{48}(E_{deviated,m})$	is adding for the 48 months (4 years) the energy deviated in each month (whether it´s power up or power down).
$\Pi_{loss,xx:xx}$	economic loss of a certain 15-minute interval.
$\Pi_{loss,total,yearly}$	estimated economic loss during one year.
$\sum_{c=1}^{20}[\Pi_{loss,c} \cdot (1/48)]$	sum of the product of the economic losses of each contingency event that has an economic impact (as studied previously) and the probability of occurrence (1/48).

1. INTRODUCTION

1.1. Background

The increased research and development in renewable energy technologies, as well as the reduction in unitary costs of such power plants has led to an increase in demand for its integration. As time passes by, many countries opt for an increased capacity in these technologies. Even more so, regional and national grid codes are being updated in order to include more requirements that these renewable energy plants now have to meet. This has arisen from the increased penetration that these technologies have in the energy mix of different countries. This increased penetration of such plants leads to a consideration of various new issues that need to be resolved:

- Photovoltaic plants of significant capacity (relative to the total capacity of the energy mix) should be able to control its power output fluctuations (e.g. during cloudy days), which could otherwise affect grid stability.
- These power plants should reduce dependence on its resource, so that it becomes more autonomous with its power injection, similar to conventional power plants. That way, it is better able to satisfy electricity demand in the grid at any moment.
- As renewable capacity increases, it becomes more necessary that these power plants provide similar grid support as is done now by conventional generators (Grid support includes: frequency response, regulating active power injection via power shifting, secondary regulation, voltage control, etc).

The first solution already considered in the industry is the integration of energy storage systems to support these renewable energy plants. However, the problem here is an economic one, since battery costs considerably increase the CAPEX of these plants, and which is very difficult to amortize during the lifetime of the plant.

The methods proposed to solve this problem is to consider firstly the best configuration of such battery coupled – solar photovoltaic plants. The best configuration will be the one with the greatest response rate, greatest control and the one which can provide much better use of the battery energy storage system itself.

A new configuration, using DC-DC converters, will be proposed for such battery-coupled solar photovoltaic installations.

To further increase the optimization of such plants, various PV array sizes will be considered, including over-sizing, to benefit from storing solar excesses, for later use.

Finally, a methodology for the optimization of such plants (considering the proposed and existing system configurations) will be developed, in order to find the optimum battery size for different plant characteristics. In order to provide a novel and insightful methodology, the following input characteristics will be considered: plant size, PV array to inverter load over-sizing ratio (DC/AC ratio), battery capacity, battery degradation model (DoD, C-rate, SoC, equivalent cycles, temperature, etc.), and pricing mechanism (direct access to electricity market, PPA, etc.)

The earnings accrued due to the integration of the battery will be due to the following features:

- Storing solar excesses as a result of over-sizing PV array. These excesses will then be discharged later. This results in an increase in overall grid injection, and depending on the tariff contracted, this stored electricity can be sold at a higher electricity price.
- Charging the whole battery during the night (valley period), to then discharge during peak period. This power-shifting service will cycle the battery once per day, with its associated daily earnings. This is subject to the pricing mechanism contracted as well.
- Participating in the secondary regulation market and providing power reserve and curtailment requests from the grid operator.
- Providing a platform for Demand Response, via electric vehicle recharging, in order to further optimize battery size of the power plant as well as reduce impact on normal operation of power plant when secondary regulation power requests are made from the grid operator. Also, it provides an economic alternative depending on the particular moment of the day for which is more profitable from using (Demand Response or the battery system).

1.2. Motivation and Justification

The motivation to this thesis arose from my evolved passion in renewable energy technologies, understanding the important role it has to play for meeting future energy demands in a sustainable way, whilst also understanding the challenges that these technologies still have, in order to provide a reliable and good quality power supply.

Understanding its limitations allowed me to think of how to resolve one of their continuing problems.

The integration of energy storage systems is the first step to provide a reliable and controllable energy supply. However, the capital costs, and the associated costs related to maintenance and battery replacement due to their relatively short lifetimes presents a great limitation towards its integration.

My motivation was to try and present a solution to help increase its integration, by firstly proposing a new system configuration, new provisions to increase battery use, as well as developing a methodology to optimize battery capacity whilst maximizing profitability.

My motivation towards this thesis started when I decided to embark on a new career direction towards renewable energy technologies. At the beginning of 2015, I started studying a postgraduate diploma on Photovoltaic Power Systems. These studies as well as the professional experience gained during the time made me pursue further this new challenge, whereby I took the decision to concentrate fully my time and effort to start a Master´s degree at the Polytechnic University of Valencia. Besides having graduated with a Physics degree, I wanted to further my knowledge in energy technologies, with a strong interest in development of solar energy and its integration in the electrical grid as well as its participation in the different energy markets.

The Master´s degree allowed me to gain further knowledge in the different fields related to energy technologies. During the last year, I have been working in an international company called Power Electronics, a solar inverter and storage manufacturer. My role has been in providing technical solutions to different proposals customers present and working alongside the research and development team in order to present and develop new solutions, in terms of components and configurations.

My work done in Power Electronics presented a starting point to my thesis topic, being that I work close-hand with photovoltaic plant technology, with an increased interest in the integration of storage solutions.

From there, I decided to embark upon myself a new methodology to optimize the integration of these plants, whilst incorporating new features for further amortization of the battery, such as power-shifting, secondary regulation participation, and coupling with Demand Response via electric vehicle recharging.

1.3. Objectives

The general objective of this thesis is the development of a methodology for the optimization of an energy storage system coupled to a solar photovoltaic array, with a new configuration to harness all solar energy, including excesses, and also integrating additional functionalities to the system in order to further amortize the costs of such a storage system, as well as to provide the grid support that will be required in future legislations for renewable energy generators.

Furthermore, the specific objectives laid out in this thesis are the following:

1. *Develop a technical-economic model for the optimization of photovoltaic systems coupled with battery energy storage systems.*

   Model will propose a battery sizing methodology, which will iterate in steps of 50kWh, in order to find the battery capacity that maximizes the Net Present Value for a given plant size, over-sizing ratio, and location (8760 values of solar data). The model also integrates a degradation algorithm, which based on the type of use of the battery will produce a precise degradation curve, which will then consequently calculate the battery replacement costs required over the lifetime of the plant.

2. *Study the technical and economic viability of battery-coupled photovoltaic plants for different pricing mechanisms (direct market access, PPA contract, and time-of-use tariff contract).*

3. *Study the technical and economic viability of the integration of a battery system when over-sizing the photovoltaic array with respect to the inverter capacity.*

   The initial objective here is to over-size the PV array in order to widen the PV power output curve and produce more overall energy during the early and late hours of the day. However, this also means that the panel costs increase, and during the solar peak hours not all the PV array power can be delivered through the solar inverter. In order to not lose these solar excesses and also amortize further the increase in panel costs, an optimum battery capacity will be installed on the DC side. Different oversizing ratios are considered, to compare at what ratios and how much battery capacity is needed in order for this system to be economically viable.

4. *Develop an algorithm and study the technical and economic viability of the integration of a battery system when over-sizing the photovoltaic array as well as providing power-shifting service.*

   The addition of power-shifting (charging the whole battery during valley period and discharging the whole battery during peak period) allows a greater amortization of the battery chosen. However, charging the battery at night may not allow for the storage of excesses later in the day during the solar peak period. Therefore, an algorithm needs to be developed in order to determine how much of the battery needs to be available in order to cover the excesses during the next day.

5. *Study the technical and economic viability of the use of the plant, including the battery system, for the provision of Primary and Secondary Frequency Response.*

   Firstly, the technical viability of this plant will be determined in order to verify that it meets with new European legislation, regarding frequency response provision required for photovoltaic plants of a certain size and category.

   Also, it will be determined how providing these services at these times will impact on the provision of active energy (i.e. how it will impact real time PV production, charging and discharging mode of solar excesses, as well as the battery cycling for power-shifting and consequent degradation effects).

   Finally, economic results will be produced to see how much more profitable can installing a battery system become if also participating in the secondary regulation market.

6. *Integration of Demand Response via local electric vehicle recharging points, to provide support when secondary regulation power requests are made to the power plant.*

   The novel proposal in Demand Response here is to use local electric vehicle loads to provide the additional power reserve or curtailment needed in order to meet the secondary regulation power being requested, without having to affect the active power injection of the plant (via real time solar production, charging and discharging of solar excesses, as well as the battery cycling for power-shifting). The objective is being able to participate in the secondary regulation market without having to impact on the active power injection earnings, and as a result having an increase in net profits.

1.4. Organization of the thesis

Chapter 1 introduces a background on the thesis, highlighting issues and improvements that still need to be made regarding the technical and economic viability of integrating battery systems into photovoltaic plants. An extensive State of the Art literature review has been carried out to understand what has been researched so far in battery technologies (battery degradation, battery cost projections, comparison of different technologies), research on battery-coupled PV plants along with configurations studied as well as optimization models developed to make these systems more economically viable.

In Chapter 2, a State of the Art is carried out on the different concepts covered in this thesis, such as optimization models developed, research on battery modelling and degradation, development of different pricing mechanisms, evolution of battery technology and its projection of costs for the near future, ancillary support from photovoltaic plants, and demand response.

Chapter 3 explains the model developed. The different pricing mechanisms to be integrated in the model is explained. In the case of direct market access, an extensive analysis of the Spanish electricity market has been carried out in order to determine estimated prices for the future. The battery model is also explained, along with the degradation modelling that has been integrated. The different battery sizing criteria has also been described.

In Chapter 4, the novel system configuration is described, using a battery system via a high power DC/DC converter coupled in parallel to the inverter on the DC side in order to store PV excesses from an oversized array. Also, the different components and features that this novel system is comprised of, is described.

Chapter 5 explains the storage of PV excesses in the model, comparing different DC/AC power ratios, using various PPA prices and battery projection costs. Results are produced to show the viability of the batteries to provide this service alone.

Chapter 6 then incorporates power-shifting with the storage of PV excesses, in order to make the same battery system more profitable. An algorithm is developed to incorporate both services with no clashing of each other.

Chapter 7 studies and compares different solutions for the new requirements from many grid codes in integrating Frequency Response Service with Renewable Energy generators. The technical and economic evaluation is carried out, and results are shown, comparing different possible solutions. This chapter continues furthermore by proposing to offer secondary regulation service with the battery system, in order to further amortize such system. Results are shown, taking into account other considerations as well.

Finally, Chapter 8 aims at using Demand Response as well. The idea is to have connected a set of loads close to the power plant and dispose of them in order to provide secondary regulation power being offered in the market. This becomes a dynamic problem, depending on the load connected and the costs of both requesting Demand Response as well as the degradation cost of using the battery system in the plant instead. A reduction in the plant´s battery system size is proposed, and the technical viability of using Demand Response is analyzed to see if it can meet secondary regulation requirements at different times of the day. The loads used are electric vehicles connected in the town nearby. Here the dynamics of electric vehicles are studied, and different options are investigated (home charging, electric charging station, and work charging).

1.5. Key words and definitions

- AC-coupled system: PV generator (array and inverter) is connected parallel to the BESS on the AC side. They are each connected to the same Point of Interconnection, via their corresponding medium voltage transformers. Here, energy that is stored in this BESS originates either from the grid, or from output power from the inverter that has been limited by the grid operator for grid injection.
- BESS: Battery Energy Storage System.
- DC/AC power ratio: This is the ratio between the array power (DC) and the AC power of the inverter installed. When this ratio is greater than 1, there will be many hours during the year (depending on location), when the PV power produced will exceed the maximum inverter capacity. These are photovoltaic excesses.
- PV excesses: During hours where PV power is greater than inverter load capacity, the difference of these two equates to energy excesses that cannot be converted into AC and injected to the grid.
- DC-DC converter: This converter can alternate between a buck/boost converter, in order to change from charging/discharging mode, respectively. This converter is connected on the DC side, parallel to the photovoltaic inverter.
- DC-coupled system: Current from the PV array is drawn partially to the inverter and to the BESS (via the DC-DC converter). It allows for PV excesses to be stored when inverter is at full load capacity.

- PPA: Power Purchase Agreement is a contract made between a purchaser and a plant developer, for the acquisition of electricity produced by the respective plant. The purchaser buys power from the plant developer at a negotiated rate for a specified term, without taking ownership of the system. The power is not necessarily delivered physically to the purchaser, but as a result this amount of power will be removed from the spot market in terms of supply. (*More in Chapter 3.4.3*)
- Time-of-use tariff: Pricing mechanisms which constitutes three tariffs: peak, shoulder and valley. Each has its own price. This tariff incentivizes the use of power-shifting.
- Direct market access: This pricing mechanisms involves selling the produced PV and stored energy directly through the Spanish wholesale electricity market. This power is only sold if the marginal cost of generation is less than the market price ceased, for each hour.
- SOC: State of Charge.
- DOD: Depth of Discharge.
- FRS: Frequency Response Service.
- C-rate: In battery terms this indicates a charging/discharging power. It can be calculated by dividing the power over the maximum battery capacity.
- Clipping: In an over-sized photovoltaic array, during a certain hour when the PV array power is greater than the inverter maximum power, the Maximum Power Point of the corresponding Power-Voltage curve would have to be deviated until the PV power is equal to the inverter maximum power. As a result, there is a loss of power, which we associate as clipping losses.
- Power-shifting: It involves consuming energy from the grid during low demand period in order to charge the energy storage system, to then later export energy to the grid during high demand period by discharging the same energy storage system.

2. STATE OF THE ART

2.1. Introduction

From the objectives proposed in Chapter 1, the main goal of this thesis is to make the installation of a battery energy storage system more economically viable. There are various ways proposed. One of the ways is to harness excess energy from an over-sized photovoltaic array. A review of different system configurations and array sizing procedures will be studied in order to be well aware of the latest studies carried out and conclusions formulated.

A literature review on the different pricing mechanisms researched is carried out (Chapter 2.2). This is followed with a review on the different optimization methodologies developed for these technologies, so far (Chapter 2.3). Different plant configurations are then compared and contrasted (Chapter 2.4). Then, different battery degradation factors (of Lithium-ion technology mainly) are studied, and a literature review is done as to how much is this quantified in techno-economic models (Chapter 2.5). Then it followed with researching up to now how battery sizing has been carried out in existing plants, and if there has been some optimization involved (Chapter 2.6). Battery cost projections are investigated, in order to establish this as another variable in the methodology, by considering when the plant installation is carried out (Chapter 2.7). Grid support services provided by photovoltaic plants up to now will be studied (Chapter 2.8). Finally, a study on the latest demand response work has been carried out, in order to understand where here can be improved and how it can help support battery coupled – photovoltaic plants.

Therefore, the purpose of this State of the Art is to learn and understand from where I can proceed with my investigation and what challenges are existing in this field of study.

2.2. Pricing mechanisms and electricity markets

In current regulations in many countries, renewable energy generation has priority dispatch. However, this will change in the near future as these sources stabilize themselves in grid parity with other sources. In that case, direct market access of renewable energy generators will be more present in many countries. In the case of UK, they seem to be going for fixed price schemes (PPA o fixed FiT). Research suggests [2, 3] that this is more profitable. However, this largely depends on solar resource and market behaviour. Since the energy market is very volatile this may not be the most profitable solution during the lifetime of the installation, irrespective if risk is considerably lower

During recent efforts in finding better economic solutions to battery-coupled PV plants, not all pricing mechanisms possible have been studied and compared, and plant topologies used were limited and perhaps antiquated to what could be improved. A thorough and extensive study on the different pricing mechanisms available needs to be carried out to identify the most suitable one for a given set of plant and location characteristics where this battery system will be commissioned.

As it suggested in [1], since PV system cost is decreasing and the electricity market is constantly evolving there is marked interest in understanding the performance and economic benefits of adding battery systems to PV generation under different retail tariffs. Here in this paper, three different types of tariffs were analysed in Switzerland and Germany: a dynamic tariff based on the wholesale market (one price per hour for every day of the year), a flat rate (although this increases every year) and time-of-use tariff with two periods.

The two-period tariff offers a more dynamic tariff structure. Still though research into time-of-use tariffs of even more periods has scope to research its benefits yet.

Also, further research is needed in order to demonstrate under what conditions (solar resource, flat rate price, DC-AC power ratio) is better to use one pricing mechanism or another.

As commented in [2] tthe 2015 EU Energy Union Package proposes integrating renewable energy technologies directly into the market. This is different to what UK for example has leaned towards to, shifting from Premium Feed-in Tariffs (FiTs) to something closer to the standard FiT, which consequently has less risk to volatile price changes.

From [2] the Energy Union Package though insists that selling directly in the market or even with PFiTs allows the seller to choose the best time to inject energy into the grid, since high prices indicate a higher demand needed for energy generation. This helps the operation and stability of the grid. Note though, in order to sell at the most demanded hour, EES will be needed.

[6] also found that tariffs indexed to the market price (such as time-of-use tariffs) have similar revenue streams compared to wholesale electricity tariffs. This can be seen in the objective function values for the existing PV system, £482 for the economy 7 tariff and £507 in the case study with wholesale electricity tariff. This represents a 5% increase (not a significant increase) in the objective function when the wholesale tariff was used instead of the economy 7 in the case of the existing PV system. This though depends on the wholesale market prices and its daily distribution. In chapter 3, a detailed analysis of the Spanish wholesale market has been carried out, to determine the viability of using such pricing mechanism.

2.3. PV and battery optimization

A lot of work has been done recently to developing models regarding the techo-economical evaluation of battery-coupled PV plants. However, little research has been shown to compare the economical benefits by using different pricing mechanisms for such systems, such as PPAs. Also, important part that has not been taken into account in previous models and that is of great importance is the projection of battery costs and benefits in the coming years, from 2020 to 2030. A sensitivity analysis based on projected costs should be quantified.

Finally, economic benefits for these battery-coupled PV plants in terms of DC-AC ratio (oversizing ratio) hasn´t been studied in previous literature.

In [1] their battery model is simulated to capture the impact of the mismatch between PV generation and demand on the battery performance. No study has been done though on the impact of PV generation excesses and battery capacity on battery performance and on economic viability. This will be involved in my thesis.

The indicators used in [1] will be relevant however in my model, as well as the following:

- Net Present Value.
- Return On Investment.
- Average Depth of Discharge.

In [14] another model was proposed that also takes into account battery degradation effects, based on variable C-rates. Then the model will determine if the batteries will be used at a certain high-power (high C-rate) operation to capture additional grid revenues, if economical against the cost of degradation effects due to this operation.

The aim of this paper was to maximize profits with the incorporation of a battery system.

In [6] a model was developed to determine battery unit costs required to make a battery-coupled PV system economically viable. The idea was to evaluate the benefit of having coupled battery systems, and how low per kWh should battery costs have to be, comparing FiT and time-varying electricity tariffs. The value of battery unit cost calculated in their model where the software only adopts this type of system is £138/ kWh. This is incredibly low, and for such prices one would have to wait until 2025 where battery costs are projected to drop to that order (*See Chapter 1.2.6*). In this thesis, the optimization model will take into account other tariffs as well to try and determine the most viable method to integrate these systems. One other note to consider in [6] is that their model was used for small-scale systems. The cost per kWh in large-scale utility plants is lower than the residential sector.

Various different models have been designed for the economic optimization of battery-coupled PV plants. However, there are several areas that still need to be addressed:

- most are in reference to residential-scale systems. The scope of this thesis is in utility scale plants, for the integration of generation units in transmission and distribution grids, which will still play a key role in the supply of energy demands of a population.
- not all pricing mechanisms possible have been studied and compared together.
- and plant topologies used up to now were limited and perhaps antiquated to what could be improved.

2.4. Plant configurations

There are several configurations that have been previously used when coupling battery systems to a photovoltaic array. These are the following, as studied in [5]:

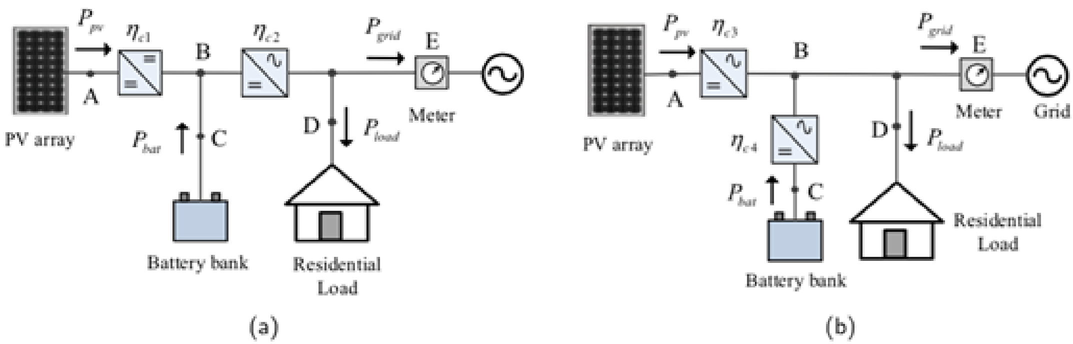


Figure 1: Configurations of PV systems coupled with batteries (a.) DC-coupled, (b.) AC-coupled.

Simulations were carried out in Matlab to investigate the effectiveness of the optimization algorithm designed to manage BESS with the PV array, using the two configurations above. The results are shown in the figure below.

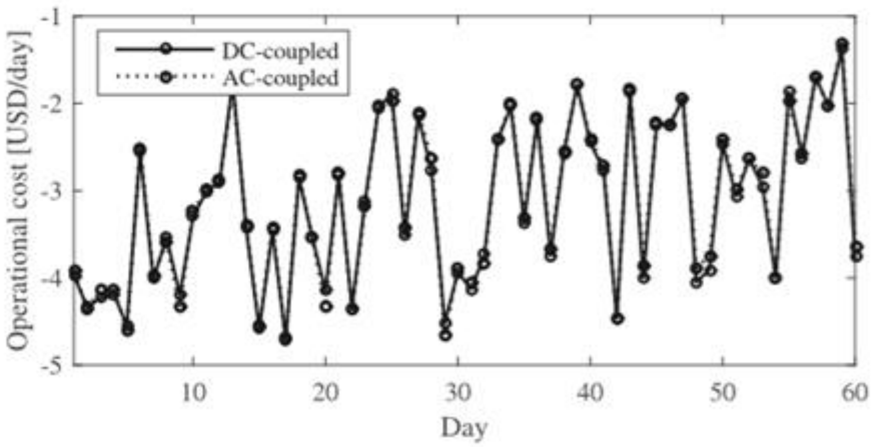


Figure 2: Daily operational cost comparison of AC- and DC-coupled systems.

Results from [5] conclude that differences in the daily costs of the two configurations are small, in fact negligible. This means that the efficiency of each configuration is very similar. This is because it involves two converters, one of which is bidirectional. So, assuming efficiencies of each is the same, and cabling losses are the same, the overall efficiency for the same daily operation would be similar.

However, this does not take into account that there are some advantages of using the AC configuration over the DC configuration. The AC configuration is:

- more flexible in the development stage;
- can be expanded later on without having to interfere with other parts of the configuration. For example, an amplification of battery capacity with a converter can be added independently without affecting the PV array and its inverter.

Even though these systems fully support power shifting services, a new configuration is to be proposed that would fully suit the model to be constructed and also improve the overall efficiency if possible. In other words, we need a model to support an oversized PV array in terms of storing excesses whilst being able to deliver the expected nominal power into the grid. The existing topologies does not fully support this idea. In (a.) & (b.), the battery is located after the inverter, thus any excesses produced by the PV array will be lost.

2.5. Battery degradation

As stated in [10] besides economic developments of PV-BESS system and electricity costs, technological aspects are influencing investment decisions. In particular, battery ageing mechanisms. Over the service life of 20 years the simulated BES needs to be replaced one to three times.

The aim of the model developed in this thesis is to minimize battery replacements and optimize battery use.

In [20] the techno-economic evaulation of distributed EES for power shifting is carried out, comparing with different battery technologies: Li-ion, NaS and a redox battery. However, no degradation was considered. This leads to an inaccurate analysis of the global benefits of such battery system.

It has been studied extensively the different causes of battery degradation, such as mechanical stress, loss of lithium, cathode degradation side reactions as well as the growth of the SEI (Solid Electrolyte Interface) due to electrolyte decomposition at the anode.

One key factor as studied and modelled in [16] is the formation of SEI. [17, 18] also indicate how SEI plays a dominant role on calendaric degradation. SEI formation is described with the following electrochemical reaction:

$$2C_3H_4O_3(l) + 2e^- + 2Li^+ \leftrightarrow (CH_2OCO_2Li)_2(s) + C_2H_4(g) \qquad (1)$$

The liquid electrolyte (ethylene carbonate, $C_3H_4O_3$) is electrochemically reduced to the solid $(CH_2OCO_2Li)_2$, which makes up the SEI (Solid Electrolyte Interface). Also, gaseous ethylene (C_2H_4) is produced. These lithium ions and electrons that are lost originated from the anode. As a result of this, it leads to self-discharge, electrode imbalance, and consequently capacity loss.

From [16] the graph below shows the model for charge and discharge behaviour, in comparison to experimental data. The model seems to represent well the experimental data, for different C-rates.

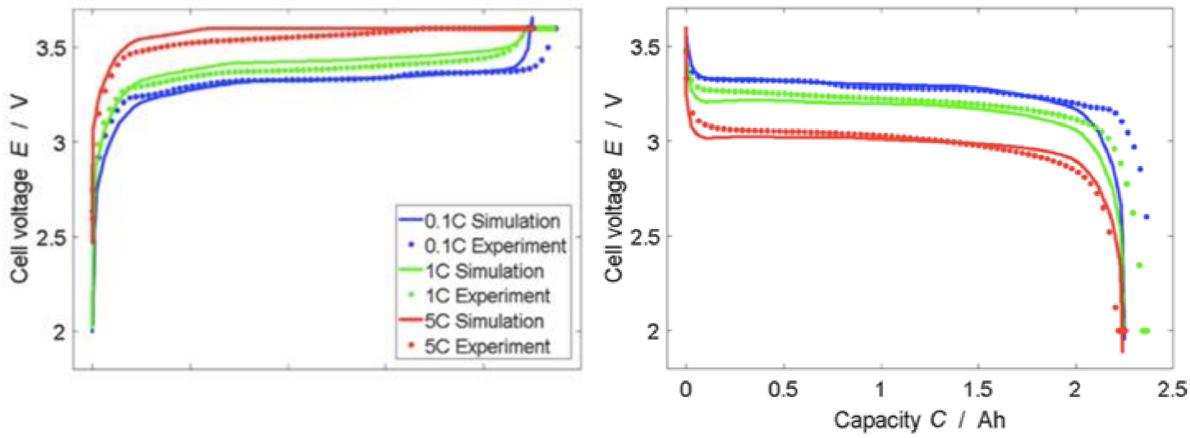


Figure 3: Charge and discharge model, with experimental data, for different C-rates [16].

Also, they modelled experimental data of available capacity for different State Of Charge (SOC) applied. The model showed clearly how with time there was a capacity loss due to its use. However more importantly the model somewhat also supports the relationship that capacity loss depends significantly on the SOC used (*See Figure 4*).

However, a doubt in these results is whether the temperature remained constant for the different sets of data (different SOC). Perhaps this is why there is some discrepancy in the results for 65% SOC. Further work would be needed to confirm this.

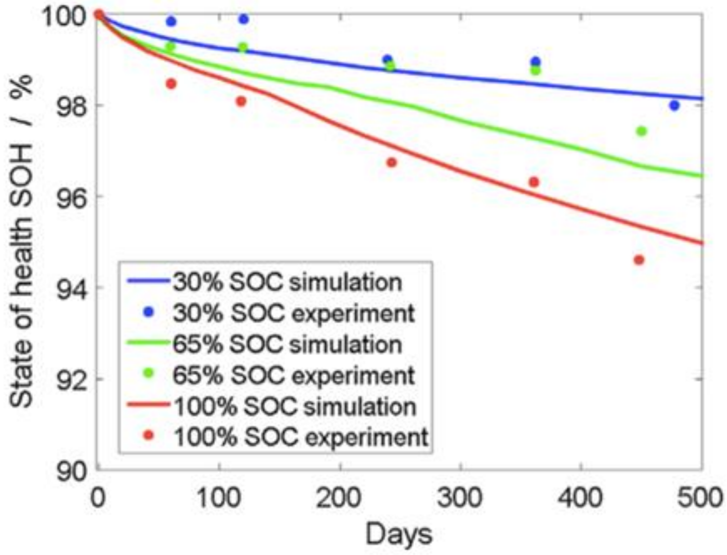


Figure 4: Calendaring ageing of lithium-ion battery cell at 30ºC, where simulations are compared to experimental data previously carried out.

After running the annual simulation in [16], it was found that SEI formation rate was highest at the start of the battery´s life, and from there decreased (*See Figure 5*). This was concluded to be due to the diffusion-limited SEI growth mechanism, which results in faster reaction rates for a fresh cell.

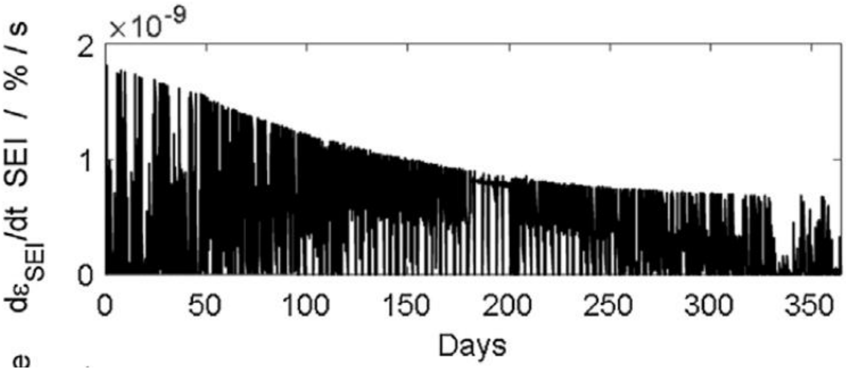


Figure 5: Capacity fade (due to SEI formation) vs time., for a consistent daily battery use.

This also confirms experimental data from [12] where in the first 100 cycles the normalized discharge capacity drops relatively quick, which can also be modelled as a power law relationship (*See Figure 6*).

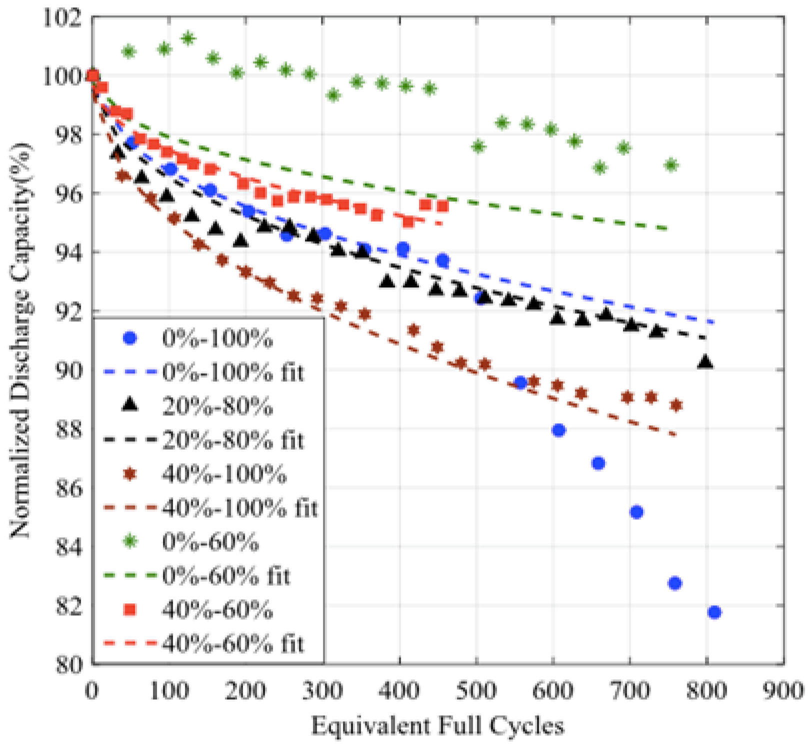


Figure 6: Capacity fade experimental data comparison with power law curve fit.

It was also shown in [16] that SEI formation rate is correlated with the SOC. It is close to zero for a discharged cell (0% SOC) and shows a plateau for a fully-charged cell (100% SOC). The results confirmed that high SOCs are detrimental for battery lifetime. These results are important in the thesis for two main reasons:

1. Power shifting: will charge upto to 100% SOC every day, so SEI formation will accelerate when providing this service. Nevertheless, most battery manufacturers now slightly limit the charge cut-off voltage, since even though it will slightly affect the available capacity of the battery, it will preserve considerably more the lifetime of it. [16] showed that for 1C charge conditions, a cell voltage of 3.4 only has a very small capacity drop from 3.5 V. But with this small change, battery lifetime is increased considerably.

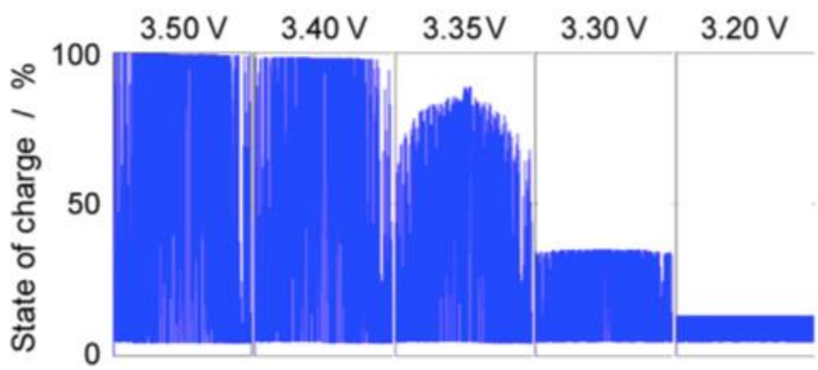


Figure 7: State of charge available for different cut-off voltages of a lithium-ion cell.

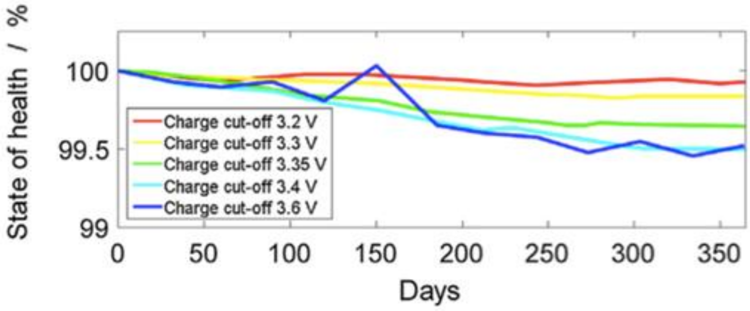


Figure 8: Capacity fade of a Lithium-ion cell for different cell cut-off voltages.

2. Variable PV generation will result in variable battery charging and discharging (for PV excess charging).

In the study in [16] only SEI formation was taken into account in terms of degradation. Even though this is a major factor in the lifetime of the battery, there are other factors to consider as mentioned previously. One important factor is mechanical degradation, where in [19] it comments on how mechanical ageing mechanisms such as particle swelling which can lead to accelerated extended SEI growth following SEI cracking. Therefore, in the model of [16] mechanical ageing cannot be predicted, as well as analyze how it varies with respect to DoD, SOC, discharge power, etc. As a consequence, cell degradation in this model is significantly optimistic.

Other factors that influence Li-ion battery degradation are the following:

1. *C-rate*

Degradation of Lithium-ion batteries is affected by the charging/discharging rates (C-rates). C-rate is the charging/discharging current compared to the current if it charged the whole battery (nominal capacity) in 1 hour.

From [14] Li-ion cells were cycled continuously at specified C-rates. Fig. 1.9 shows the cycle-life degradation of the Li-ion cell at ±0.5C, ±1C, ±2C, and ±3C. It can be seen higher C-rate operations lead to larger decreases in state-of-health (SoH) of the battery under room temperature.

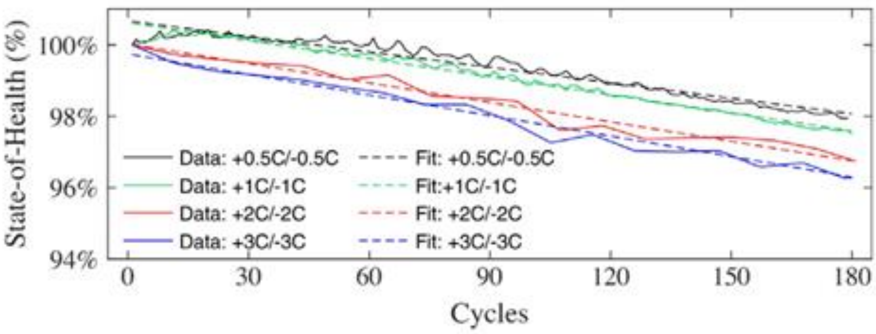


Figure 9: SoH measurements of a Li-ion cell at various C-rates.

This model developed in [14] is an accurate degradation model with respect to C-rate and efficiency. However, there is not a true representation of the variable depth of discharge (partial charges/discharges). It only takes into account a default value of this, and this significantly has an effect on degradation, just like the mean SoC does.

For power shifting and PV excess storing applications, low C-rates are sufficient. The results produced in [12] provides base data to be used in the model developed in this thesis, to produce related battery degradation costs for a 20-year installation.

2. *Partial cycling*

Apart from this paper, there is a lot of research down on cycle life, along with its degradation costs. However, most do not consider partial cycling and DoD. Many research done considers SOC of 100%, which is useful in my model, since daily power shifting is applied. However, for the PV excesses partial cycling will occur in most days.

In [10] it was identified that in most practical applications, batteries undergo charge-discharge cycling only for partial SOC ranges as opposed to the full SOC (0%-100%) range. Hence, it is important to study the effects of partial SOC range cycling on battery life. In [12] this is studied.

Previously it was assumed in a lot of research that discharging of batteries from 100% to 80% was the same as discharging from 40% to 20%. However, from [12] it was confirmed that partial charging-discharging cycles at different initial SOC values have a different impact on the State of Health.

Due to varying daily PV production as well as intermittent fluctuations batteries are prone to irregular SOCs and charge and discharge cycles. This is also the case for my project, where excesses will vary significantly on a daily basis.

To conclude partial cycles account for a more accurate optimization formulation. This will be developed into my model.

3. *Depth Of Discharge*

In [22] they found that the depth of discharge (DOD or ΔSOC) did not affect the cycle life. This was until [12] published their findings, that they do indeed have an effect. Not only SOC has an effect, but also depth-of-discharge, as well as C-rate.

Further work was done in [24] where five DODs (90%, 80%, 50%, 20% and 10%), six temperatures and four discharge rates were studied, showing a power law relationship between capacity fade and energy delivered by the battery during cycling. They interestingly showed that temperature had a bigger effect on the capacity fade, whereas the effect of DoD was more pronounced for high C-rates.

However, more research was needed in terms of the effect of DoD on low C-rates, which is the case for stationary battery applications for power shifting and clipping purposes.

In [18] the influence of cycle depth and mean SOC on cycle aging was studied. They observed a linear relationship between the degradation rate and cycle depth (DoD). Also, they found that for a given cycle depth, degradation was at minimum when the cells cycled at a mean SOC of 50% during a period. These results were also shown in [12].

After significant research during the last 5 years of the effects of DOD, SOC and cycling on battery lifetime, there is still some clear evidence though that temperature and discharge rate have a more dominant effect on the ageing of batteries. All these factors will be taken into account in the model of this thesis.

From such studies, [12] carried out further experimentation to produce a more accurate capacity fade model. This study is useful to identify the DoD with slow degradation rates.

They commented that the primary objective of this study is to find the effects of SOC ranges on battery cycle performance at a constant discharge rate of C/2. This C-rate is a typical value for stationary applications to provide power shifting and clipping services (depending on pricing mechanism, as will be discussed later on). However, if the battery is to provide power output smoothing (due to intermittent PV generation), or frequency response service, these batteries would be required to be used at higher C-rates.

This model based on real data can be used to simulate battery degradation in my optimization model. It takes into account very well the use conditions such as mean SOC and DOD. However, for my general model I need to further extend from [12] here to take into account different C-rates, as well as different environmental conditions.

In my model another thing to consider is at what point a battery is considered to have reached the end of its lifetime. There is no exact value at what point (whether its number of cycles or available capacity) a battery will fail. Number of cycles, as seen from previous research can vary depending on use of battery and environmental conditions. Therefore, as has been used in past research, such as in [26], end of battery life will be considered when it reaches 80% of available initial capacity.

To conclude, developing battery lifetime and performance models is very complex, and in all literature, simplifications to their models have been done. The complexity of the model is due to the following:

- Various use factors, such as SOC, DOD and C-rates have different effects on battery lifetime and performance, which can be difficult to model.
- Environmental conditions, most notably, temperature has an effect on battery lifetime that is important to consider.
- Modelling degradation for the different causes (active material loss, loss of lithium inventory, mechanical stress, SEI layer growth, etc) is very complex since they affect degradation differently and at different periods of the battery´s life. Even then, if modelling various different degradation causes to predict more accurately the lifetime of a battery, the relationships are not maintained when considered during uses, or even more so, when considering different battery technologies.
- Furthermore, the added detail in terms of degradation causes does not necessarily aid in the high level optimal decision-making strategy for power grid participation. It may make using batteries a lot less economically viable. This is perhaps a very important reason why perhaps simpler yet reliable models can be more useful in implementing such systems into the grid.

For the scope of this thesis though the aim is to keep improving the model that can be used for these stationary grid-level applications. My model will take into account use factors (DoD range, Mean SoC, C-rate, efficiency), temperature (using PVSyst data), and the causes of degradation to consider will be SEI formation as well as mechanical stresses. This already in itself is a relatively more complex model which will improve previous work and will help in determining an optimum battery capacity for different sized plants with different characteristics (different DC-AC power ratios, different pricing mechanisms, different solar resource, etc).

2.6. Battery sizing

Battery sizing methodologies is also an area where more research is needed at utility scale, and which in many cases the number of batteries is not the optimum, since it is based on available models from suppliers, whilst adjusting it to the existing plant configuration. This is definitely not an optimum, and proposals to improve this will be investigated and discussed.

Work done in [10] explores the maximum NPV optimization to determine optimal sizing of the different components in a battery coupled-PV installation.

However, even though they apply this max profitability criteria in their research, there are significant differences to what I intend to find out, and I intend to amplify this and compare with other criteria to dimension battery systems. The differences are:

- it does not take into account the excesses produced using the new DC configuration proposed. Therefore, results will be different.
- no time-optimization algorithm is proposed (when to charge or discharge, and how much).
- different pricing mechanisms are not compared.
- This study was based on peak shaving application in an industrial site, not at utility scale, for power shifting or PV excess storage applications.
- Battery degradation effects, thus battery replacements costs over the lifetime of the plant are not taken into account. Furthermore, the optimum battery size does not consider battery replacement costs, as well as what the costs of these batteries will be in the future.

Another criteria was studied for battery sizing, which is also another criteria to form part of my battery sizing analysis. In [11], optimal sizing and economic performance of battery installation was assessed in terms of the minimum packback period. [11] comments that consideration of a battery with an optimal size helps to reduce the payback time of the PV system, even though the up-front costs of such a system may be increased. The results from [11] were that increasing electricity price leads to a larger battery size of optimal dimensioning. This is because increased electricity price leads to more earnings in storing the excess energy from the PV array. As electricity prices increase, the payback time decreases (*See Figure 10 below*). However, if the optimal battery size is greater, it means more capital costs will accrue. This will be further investigated in the model of this thesis. Factors like solar resource and DC-AC ratio may play a deciding role here.

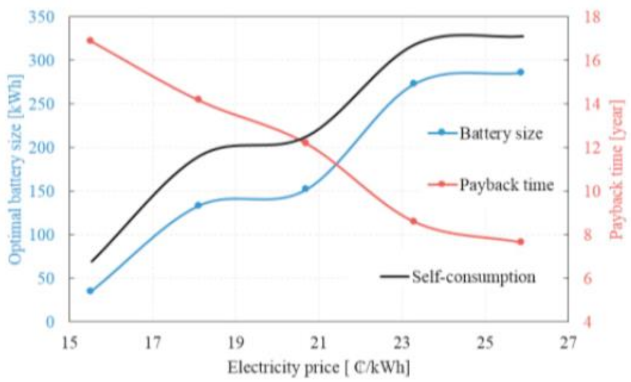


Figure 10: Variation of optimal battery size and payback time with electricity price.

2.7. Battery cost projections

In recent years, solar PV capacity has increased significantly. Furthermore, PV plants have become in grid parity with other sources. Demand for this technology will continue to grow. A good estimate of the global power capacity increase in the next few decades is shown in [9]. Figure 11 below shows the projection from different sources of the growth in PV capacity installed globally. The Greenpeace cases are more pessimistic than the projection made by the International Energy Agency, since Greenpeace is a source who tend to be less optimistic about the actions made by government in order to preserve the environment. They still believe a lot of work is needed in order for many countries to reduce their use of non-renewable resources and reduce greenhouse gas emissions. The study from the International Energy Agency on the other hand invokes different parties in order to make this projection, therefore it is a good reference for how this technology will grow in the next few decades.

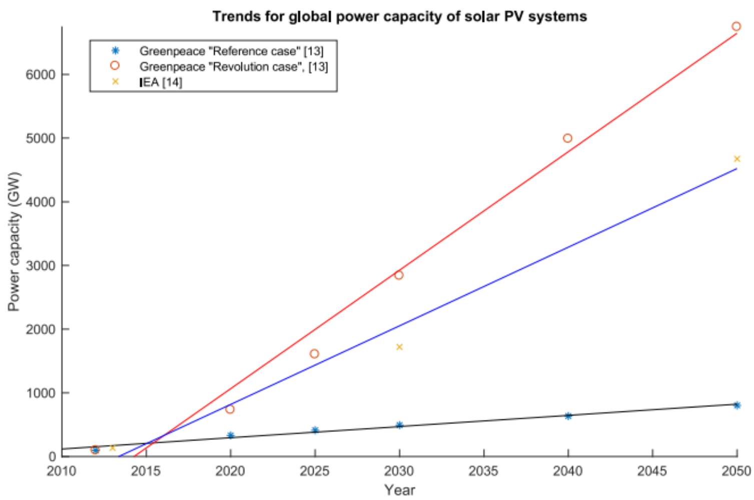


Figure 11: PV global capacity from 2015 to 2050.

As stated in [15] due to the excellent round-trip efficiency, high energy density and high-power density, it is expected that Li-ion batteries will be widely used in renewable hybrid systems. However, the capital costs such as manufacturing and the cost of cobalt in cathodes are the major factors that prevent the wide-scale adoption at present. Therefore, as also stated in [1] and [6], the revenue streams and Return on Investments for these systems applying a certain pricing mechanism will largely depend on the battery installation costs.

In fact, from [15] with the current technology costs and a discount rate at 8%, it is shown that the capital cost for $LiCoO_2$ needs to be reduced to 200 $/kWh to be economically competitive with a dispatchable source such as a biogas power plant by taking into account also the ESS degradation costs.

However, from [6] the cost of battery packs is falling, about 25% reduction for lithium-ion battery between 2009 and 2014 has occurred.

Furthermore, [9] presents the projected costs for ESS. It shows that the costs of ESS could be constant at around 2030, at 350 $/kWh. The storage technology will be matured by then and the costs associated with will be manufacturing and maintenance costs. Figure 12 below shows projected Lithium-ion costs for utility-scale applications from 2010 to 2035.

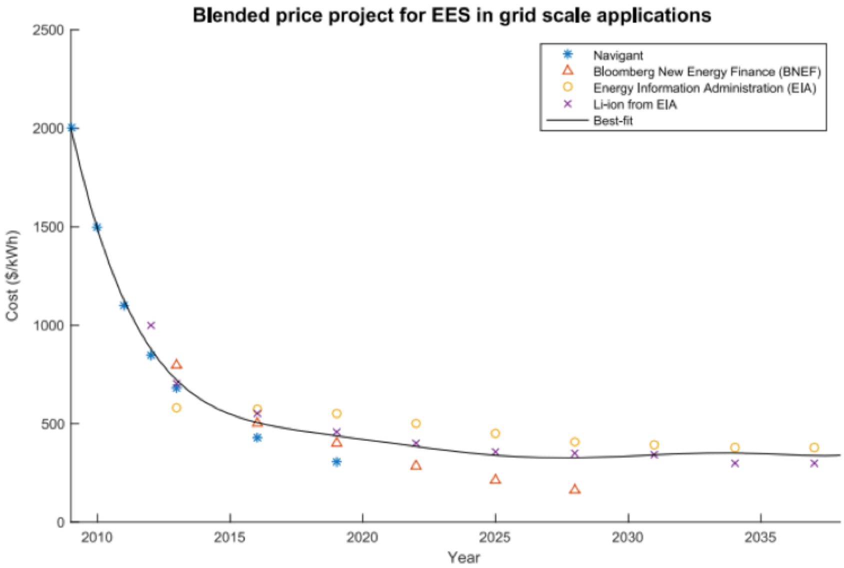


Figure 12: Projected Li-ion costs from 2010 to 2035.

Interestingly also, in [11] a study was carried out to determine the optimal battery size depending on the battery price. Results are shown Figure 13 below. It is revealed that as battery price lowers, the optimal battery size actually increases, meaning that more excesses can be stored (if solar resource permits it), and thus more earnings compared to the originally smaller battery size. Future battery price improvements will have an important contribution to the deployment of such technologies in this application.

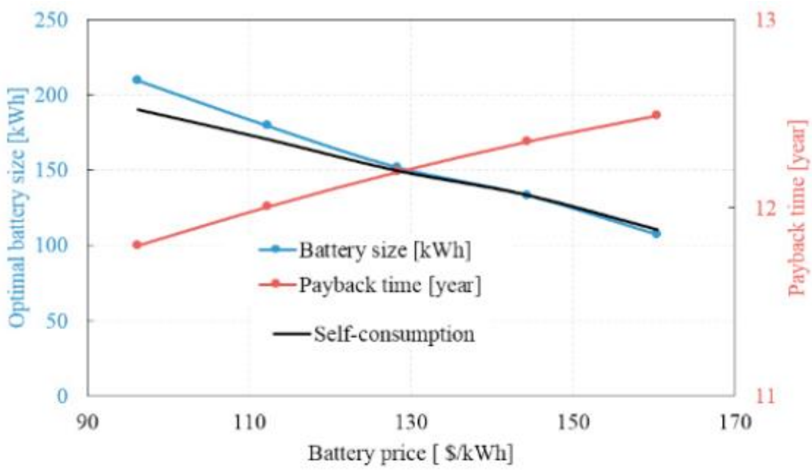


Figure 13: Optimal battery size and payback time vs battery price.

2.8. Grid services

The main issue with further integration of PV plants is its intermittent nature, which can cause serious power fluctuations and voltage instabilities at the output of the plant. Furthermore, as the penetration of these renewable sources increases, there is an increased need that they provide the same regulation services as conventional generators do, such as frequency response service and voltage support.

From [9] "Replacing conventional generators with PV generators will cause a reduction in the damping torque of the system modes. This can largely degrade the system inertia. One of the possible ways to improve the system inertia is to keep the critical generators in use. This is a solution for the short and medium term. However, in the long term, in order to increase PV penetration further, other solutions to inertia response is needed. One upcoming technology is "Synthetic Inertia", using batteries to supply this frequency response during a grid frequency event.

Photovoltaic plants with inverter themselves cannot be used to provide this service due to the resource intermittency, as commented in [9]. Also, in the event of a cloud cover, the PV generator will immediately drop its power output to zero, without any ramp down, which can cause significant grid stability. Here, battery system can play an important part, as well as further amortize its costs if this service can be economically compensated.

In [9] as well the stability problems and control methods of PV generators for secure and reliable operation are the main focus in many research works. The spinning reserve and dispatching strategies for energy storage could play an important part in the stability of future power

system with high PV penetration. Another reason why the development and implementation of ESS in these plants will help in terms of stability problems, especially as PV penetration increases.

[9] PV power curtailment was examined with the use of ESS installed. An economic analysis has been carried out. The results showed that PV output power smoothing will lead to a revenue loss, as compared to the scenario when the PV power is not smoothed. This though was compensated with x improvement on the system stability. Disposing of excess power to meet power fluctuations constraint or utilizing power curtailment are economically superior than employing an ESS with huge power fluctuations permitted. In conclusion, the combined use of ESS and power curtailment is found to be the most economical solution in this paper. However, power reserve was not investigated here. In the thesis, power curtailment and power reserve services will be investigated and incorporated in the novel DC-coupled system proposed, to identify the increase/decrease in economic profitability of such battery system, as well as improve the technical viability of integrating further PV generators into the grid.

The incorporation of power curtailment/reserve service could be interfered with the dynamics of electricity markets. Depending on the pricing mechanisms used, the technical and economic viability will vary. Further research needs to be carried out on this. This will also form part of the thesis.

Also, in this paper the cost to the system from poor power quality, Volt/VAr control etc. due to the high uncertainty and fluctuation from PV power has not been mentioned. This can be quantified not only by how much a generator would get penalized for this, but also the potential benefits it would lose by not being able to provide voltage support or frequency response service in the ancillary markets. Further research needs to be carried out on this. This will also form part of the thesis as well.

2.9. Complementing Demand Response with Battery installation.

Similar work has been done in coupling battery systems with other sources in order to optimize battery use. From [15] minimum operational cost was determined by calculating the optimal point for the SoC to be charged, using the supply of the battery system as well as the other sources connected. The minimum operational cost took into account battery degradation costs as well as costs associated with the other sources (in this case a biomass generator was used). The study concluded that a grid-connected PV-EES system was more useful in energy saving operation. In the case of utility plants, the point is grid injection. However, even though this paper was to do with residential systems remaining connected to the grid had an energy saving benefit, since battery cycling would be done optimally to minimize degradation, the idea can be applied to utility scale plants, in terms of demand response.

A lot of research has been done lately on the integration of Demand Response. [27, 28, 29] show different examples of the use of Demand Response for different applications. The application for this thesis though would involve the electric coupling of this plant with a load base nearby (most likely a town). The proposal is to use electric vehicles for Demand Response. However, the more novel proposal in terms of Demand Response is to provide Frequency Response Service with it, instead of using it for supply of energy demand. Not much research has been done on this. This will be investigated in the thesis, in order to reduce battery costs of the plant whilst still being able to provide the same service and gain the same economic benefits.

2.10. Conclusion

It has been concluded from this literature review that there is great need in improving the optimization of such plants, and in proposing new ways to do this. Even though in the future, battery costs are decreasing each year, and that forecasts predict that that these decreases will be more significant, the time this takes is still long, and measures need to be taken now in order to increase storage integration for supporting the increased capacity of renewable energy plants, whilst replacing the polluting fossil-fuel generating plants.

In the case of many countries, conventional power generation is being overlooked with storage technologies already, which is why as well legislation is changing to make more strict requirements for these new technologies. However, in order to also attract interest from Governments, economically viable options for the integration of battery storage technologies need to be studied and proposed.

The first step will be introducing the methodology developed for the optimization of such systems. This will be continued in the next chapter.

3. GENERAL MODEL AND ITS METHODOLOGY

3.1. Introduction

In this chapter, the general model for the optimization of battery-coupled photovoltaic systems is explained.

The methodology consists in determining the most optimum battery capacity for a given set of input parameters. The optimum battery size is the one that simulates the highest Net Present Value after the lifetime of the plant (20 years to be used).

The input variables used are:

- Location (Hourly temperature and irradiance profile) and altitude of plant.
- Total plant size.
- Inverter capacity and number of inverters connected in parallel.
- Oversizing ratio (DC/AC power ratio).
- Pricing mechanism contracted (direct market access, PPA, and time-of-use tariff).
- Battery use pattern (to determine equivalent cycles per year, average depth of discharge, average daily maximum state of charge, and C-rate).

3.2. Block diagram

The following figure depicts the methodology developed, with a block diagram that shows the different input variables, steps and the different parts, in order to produce the final optimized result.

From the "START" location, the user will have chosen their location, power plant size (*Pac*), solar panel model and solar inverter mode. Also, user can choose the oversizing ratio (*DC/AC ratio*) they wish to implement, otherwise a range of results with varying DC/AC ratios will be produced.

The optimization model then acquires hourly data of temperature (*Tamb*) and irradiance (*Geff*) based on the location selected. The data is obtained using historical data which is then simulated in PVSyst. With PVSyst, MPP voltage (*U*), MPP current (*I*), MPP power (*P*) is calculated. From here, using the inverter efficiency (*Eff_inv*) in every hour, as well as the corresponding losses (*Plant losses*), power at the inverter output and power injected to the grid is calculated.

Depending on the ambient temperature (*Tamb*) and DC voltage (*U*) in that hour, the capacity of the inverter (*Inverter apparent power limit*) will vary. Comparing the MPP power multiplied by the DC/AC ratio selected with the inverter capacity, this will determine the excesses produced in that hour. The *DC/AC ratio* will determine the *PV array costs*, just like the Pac will determine the *inverter costs* of the plant.

The amount of PV excesses will be input into the battery model for further calculations. Inside the battery model, different *battery sizing criteria* will be calculated. Also, different *pricing mechanisms* can be compared. User can choose which one to use. With this input data, the *optimum battery size* (kWh) for storing PV excesses can be calculated. Also calculated are different battery parameters such as *equivalent full cycles, initial SoC, Average DoD, and C-rate*, which will be used to determine the degradation of the battery itself, and thus determine its *lifetime*. With this information, the *plant lifetime replacement costs* will be calculated and integrated into the *capital costs*.

Calculating the *C-rate*, and knowing the *optimal battery size*, the *battery discharge rate* required can be determined. With this value and the *pricing mechanism* selected, the *DC/DC converter costs* can be calculated.

Finally, in the *economic model*, the *earnings* are accumulated from the *total discharges* from all the *PV excesses*, as well as from *power shifting*, in order to then calculate the *NPV* and the *payback time*.

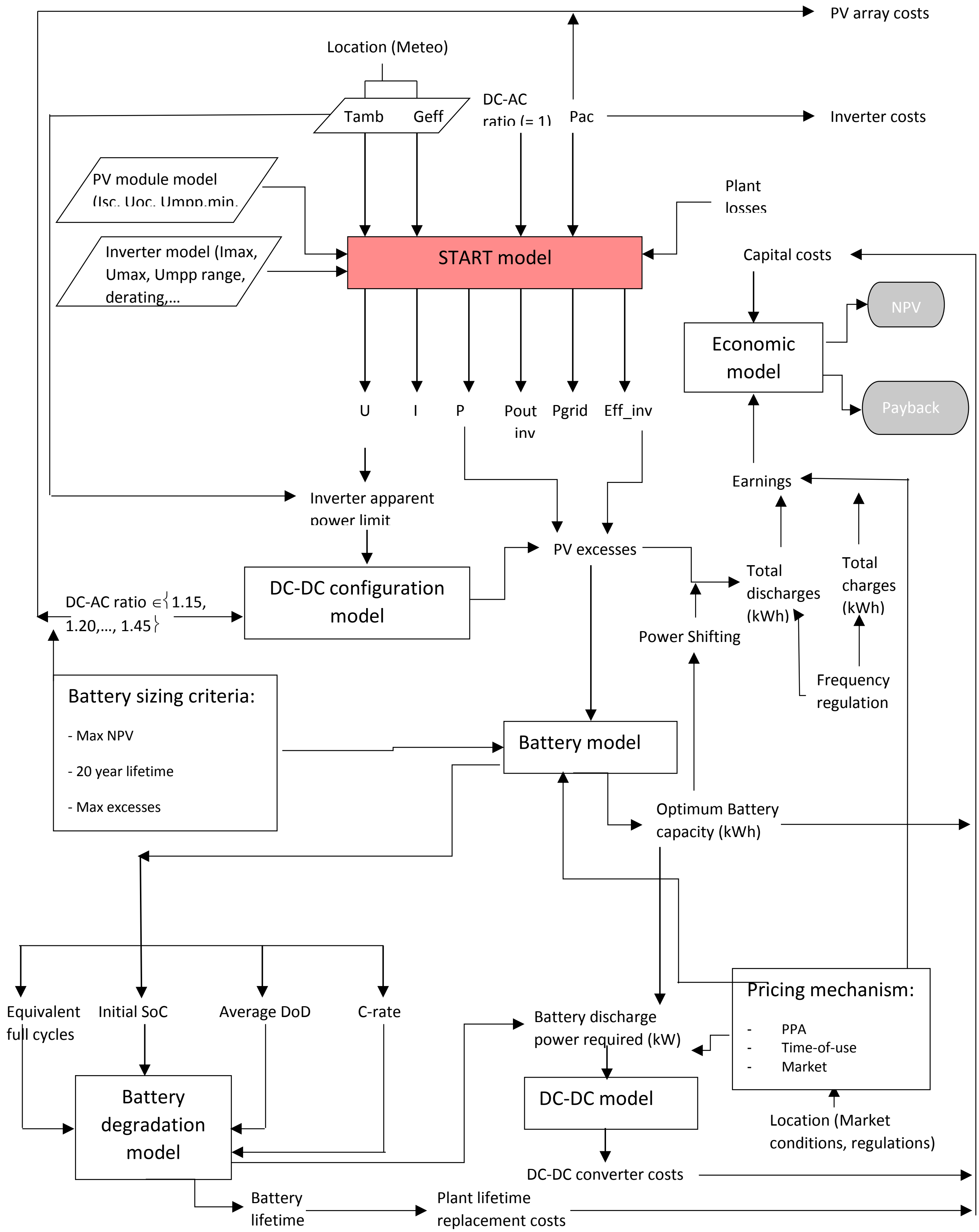


Figure 14: Flow diagram showing the different characteristics and steps of the methodology.

3.3. Calculating optimum battery size

An algorithm has been developed, using Microsoft Excel with Visual Basic for Applications, in order to simulate the Net Present Value of a plant (with its input variable as outlined above) for different battery capacities (50 kWh to 5000 kWh, in 50 kWh intervals).

In the simulation it calculates how much capacity each battery system installed in the plant should be. In other words, how much battery size per PV-inverter coupling. So, if two inverters are considered, it would give you the result as to how much battery size is needed for each of the two inverters. In order to then know the total battery size needed, you would multiply the optimum value obtained from the simulation by the number of inverters needed.

In the simulation, for each 50 kWh increment of battery capacity, the Net Present Value is calculated for a range of DC/AC power ratios. In order to calculate this, the following is needed:

1. *Total battery system cost.*
   This is dependent on the battery capacity being considered in that iteration but is independent of the DC/AC power ratio used.

2. *Battery replacement cost.*
   This is dependent on the battery degradation modelling taken into account. In the background, using the 8760 values initially simulated with PVSyst, the model then analyzes the consequent charge-discharge cycles per day for the battery capacity simulated. Depending on this it will calculate the equivalent cycles per year, Depth of Discharge, as well as the average C-rate performed, and from there the corresponding degradation curve will be applied, with it estimating the lifetime of this battery system. Once we know the lifetime, we can calculate the consequent replacement costs until the end of life of the power plant.

3. *Yearly earnings.*
   The daily earnings from all the services provided by the battery system is quantified (More on the forthcoming chapters regarding the different services). All the different earnings from each day is added together to obtain the yearly earnings.

4. *Interest rate.*
   This value should be fixed to the current market interest rate that banks are offering. This will effectively determine the increase in real return of their money from the bank when that interest rate is applied during the contracted time. By knowing what real returns they would have with the bank, it will allow investors to calculate the opportunity cost in investing capital in this long-term project. Calculating the IRR (Internal Rate of Return) will allow to obtain this opportunity cost. If the Internal Rate of Return is higher than the market interest rate, then there is an opportunity to invest in this project, given the plant characteristics and the optimization proposed.

5. *Inflation rate.*
   Inflation will have an effect on the actual returns that an investment will produce. Therefore, in order to know if a project is deemed to have a significant IRR, inflation also has to be taken into

account. In other words, the IRR needed is higher in order to make this battery storage system economically viable in the integration of such plants.
In the model, the user is allowed to choose a suitable value of inflation to use. One example, as used in the thesis, is the average CPI (Consumer Price Index) during the last 5 years. Even though the CPI will vary considerably during the lifetime of the plant, this will however provide a rough indicator of how much value the money will have after the 20 years considered.

Finally, during each iteration, the following formula is applied in order to calculate the Net Present Value in each case. It calculates the cash flow each year, given the interest and inflation rate, as well as the year since the initial investment, then adds the result of each year together. Then the investment cost is subtracted from this added value (after 20 years).

$$NPV(int, inf, N) = \sum_{t=0}^{N} C_a \frac{(1+r_{inf})^{t-1}}{(1+r_{int})^{t}} - C_{inv} \qquad (2)$$

3.4. Pricing mechanism

In order to determine the most economically favourable returns in the investment of an ESS coupled PV plant, different existing and proposed pricing mechanisms will be used.

In the recent past, the marginal cost of solar PV generators has been considerably higher than conventional generators. This meant that this renewable technology could only compete with fossil fuels if it was subsidized or supported by another financial incentive. In 2010, PPA prices ranged between 120 and 150 €/MWh. Now, in 2017, PPA auctions have been receiving bids below 100 €/MWh (depending on the location and the solar plant size).

Recent auctions in Spain has allocated developers the construction of solar plants, at a total of 3.5 GW capacity. With discount rates also provided by the government to developers, PPA conditions agreed are very competitive with other sources of generation.

In the case of integrating a battery system, these prices rise considerably. As the associated capital costs stand, without any optimization of the plant, it proves very difficult to be economically viable. However, the hypothesis is that with a controlled design and optimization of the plant as well as an appropriate pricing mechanism, taking into account selling of energy as well as grid services, this type of plant can generate benefits, with little or no subsidies.

In Spain, for plants such as CSP (Concentrated Solar Power), due to the high costs, the selling price is based on a premium-added wholesale market price. The selling price has two components: the hourly spot market price, and the premium component. The premium component guarantees the PV developer that sufficient earnings will be made (especially in low price periods), and that way is able to amortize costs during a period set out initially. This type of pricing mechanism is one that will be considered for ESS-coupled PV plants.

The following outlines the three different pricing mechanisms that will be mentioned and considered throughout the thesis:

3.4.1. Direct Market Access

Ideally all producers should bid in the wholesale market at equal conditions. However, this is not the case for all generators. Combined Cycle plants for example usually are given a state subsidy in order to avoid excessive peak prices, at times of high demand.

Also, using 2017 prices alone is too low for ESS-coupled PV plants to be economically viable at this time. Therefore, several things will be developed:

3.4.1.1. Future market price

Even though 2017 spot prices represent an accurate reflection of the demand and electricity supply of the last year, it is a very different situation next year. The electricity market as we know is very volatile, since it depends on a range of factors that deeply and quickly affect both supply and demand. Secondly, it is very difficult to predict demand accurately, which can lead to using reserve capacity, and thus increase electricity price significantly. Also, wind and solar generation can be unpredictable, leading to need disposition of other more expensive sources of energy.

Even more so, to model this plant with 2017 spot prices when the lifetime of this plant is of 20 years is quite truly unrealistic. Therefore, it is proposed to produce 8760 estimated future average hourly prices, which will be based on a projection of supply and demand of the Spanish electrical grid, up to 2050. This projection was initially done by a study elaborated by the company Deloitte, which outlines most notably:

- increase in renewable supply,
- decrease in thermal generation,
- and increase in demand.

Taking this into account, for each year looked at, we will use the current energy mix of the Spanish grid. Using real data from REE (Red Eléctrica Española), a detailed market analysis is provided. Hourly values of generation from all technologies, as well as hourly values of spot prices are compared.

3.4.1.2. Spanish spot market analysis

Using this data, we extrapolate an equation that relates thermal generation with market price, with a 75% regression. Even though it is not entirely precise, it still though provides a suitable base for producing a projected market price.

The reason this regression is not closer to 100% is because the other 30% in most of those hours represents periods of low demand (most typically during the night), where most generation is nuclear power and where thermal generation has no effect on the price. Thermal generation has an effect most notably when the demand exceeds a certain amount of power (base power), which is the moment when thermal generation is traditionally offered in the market and supplied to meet the demand.

The other reason for not having a regression close or equal to 100% is because the marginal cost of thermal generation itself is volatile, due to the variable price of fossil fuels. If for example the price of natural gas rises steeply, other types of generation may be offered instead, which breaks this relationship formulated. If on the other hand, the price of natural gas drops considerably, combined cycle generators will enter the market in more hours of lower market price, thus hindering this relationship as well. The conclusion though is, that the type of generation that most influences the wholesale price in Spain right now is thermal generation. But perhaps just as important, this thermal generation is directly linked to the demand. At a certain demand, if it increases, thermal generation increase is directly proportional, and at this stage price increase is directly proportional too. Figure 15 below demonstrates this relationship between spot price and thermal generation. The years considered were from 2014 to 2016, since during this time the installed capacity in the Spanish electrical system was the same, thus provides a controlled environment for a fair comparison.

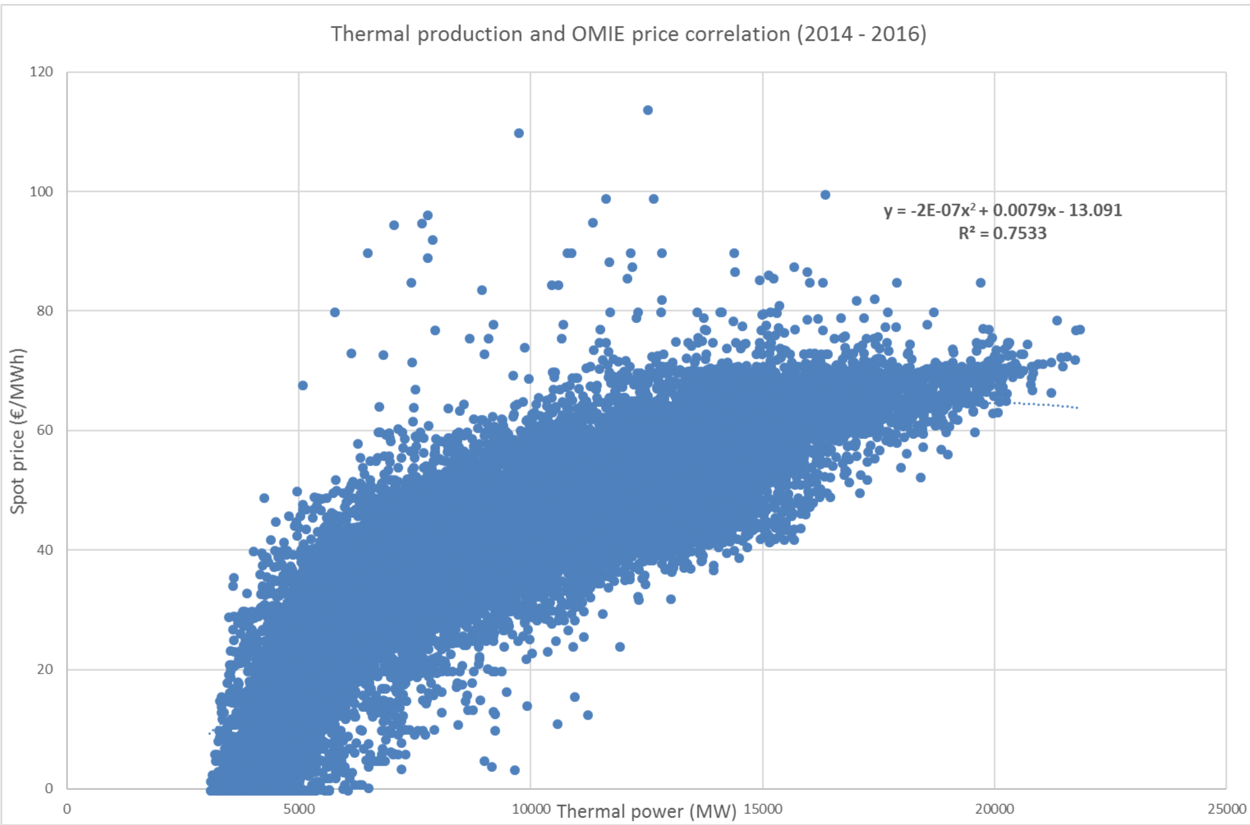


Figure 15: Thermal generation vs spot price, during 2014 – 2016.

Using then this historical market data, we modify it to include the 2030 criteria, which is projected to be:

- an additional 32.5 GW of renewable generation,
- a reduction of 1 GW and 11 GW of natural gas and coal technology respectively. Therefore, a total of 12 GW of thermal generation is reduced. Using the relationship established above in Fig 3.2., If we apply the extrapolated formula to the first hour of the year, as an example, we obtain a new market price. This is repeated for 8760 values.

However, if we then take into account the increase in demand and the replacement of this thermal generation with the increase in renewable capacity, this will evidently increase the price somehow. Using an estimated marginal cost for these renewable technologies, it will raise the market price. Note though, adding renewable capacity in every hour is not realistic, since it depends on the resource itself, for example, if on the 1st January there is not enough solar resource to provide nominal power in certain PV plants of a region, then we cannot simply add this capacity, since it would mean that this amount of MWh in demand will be supplied by the peak power of these plants, which would not be the case. We use the historic data to determine, with the existing PV capacity already, how much PV energy was provided in that hour versus how much it could possibly have provided. This is done by dividing the PV energy in that hour by the peak power of all PV plants installed currently. To now know how much solar energy is provided in 2030, we use this fraction and multiply it by the new 2030 photovoltaic or renewable power.

In terms of demand, we apply a simplistic multiplication factor for each hour, based on the new 2030 demand, in order to know what the new demand each hour is. Then subtracting the existing demand (with the increase in solar energy) from the new demand will give us how much extra thermal generation is needed.

Finally, what will influence the price is the additional thermal generation (using the extrapolated formula) and the additional renewable generation.

Fig 3.3. below shows the OMIE prices of 2014, along with the projected OMIE prices in 2020 and 2030, by taking into account the factors described above.

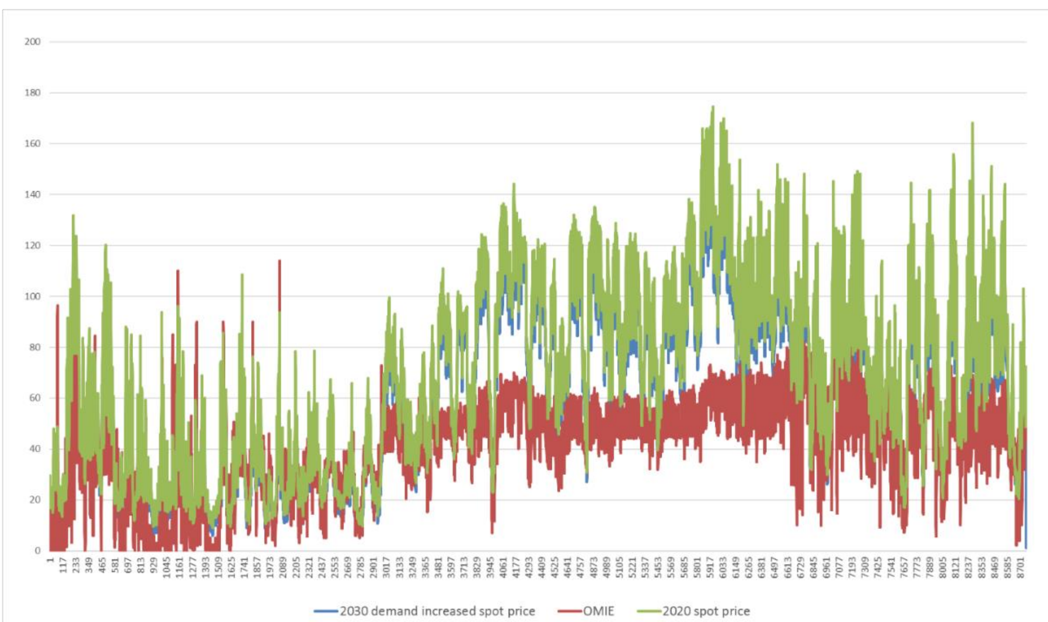


Figure 16: 2014 hourly spot prices, as well as 2020 and 2030 projected hourly spot prices.

The 8760 estimated average hourly values have then been calculated and will be used to model the spot market when user wishes to sell directly to the market.

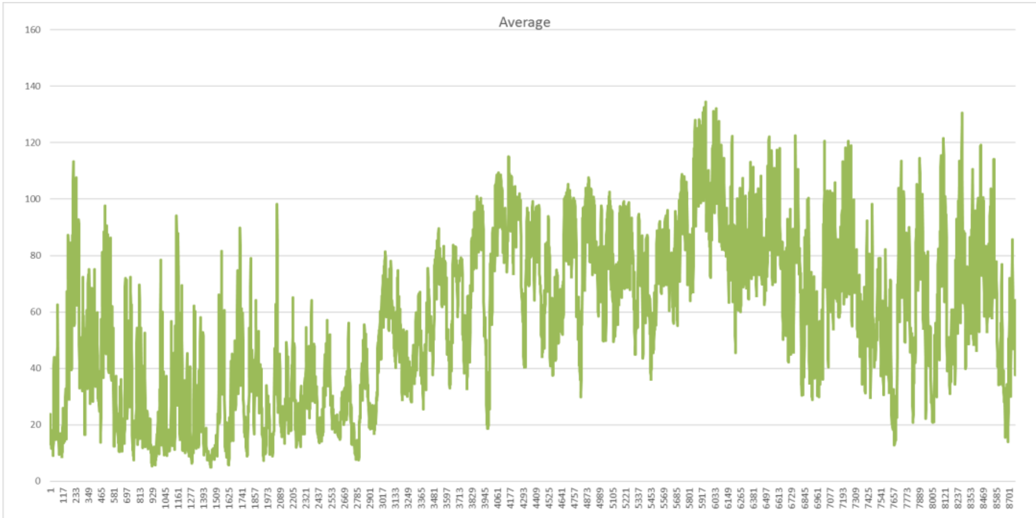


Figure 17: Estimated average hourly values to use in model, when applying direct market access price mechanism.

Having calculated this, due to the volatility of this market, where multiple variables can significantly alter the price and daily distribution, as part of the calculation of the economical returns of such power plants it is important to calculate this based on a worst case, best case and normal case scenario of electricity prices. For this, deviations in each hour with respect to the average historical price is calculated. This followed by calculating the average lower bound and upper bound deviation. Using the 8760 calculated values along with the average lower and upper bound for each hour of the day will help us compare different case scenarios and different possibilities as to the economical returns one can have in such a plant.

Below shows the average of each hour, for these 8760 values, along with error bars that represent how much each hour can deviate with respect to the historical prices registered from the Iberian market (MIBEL).

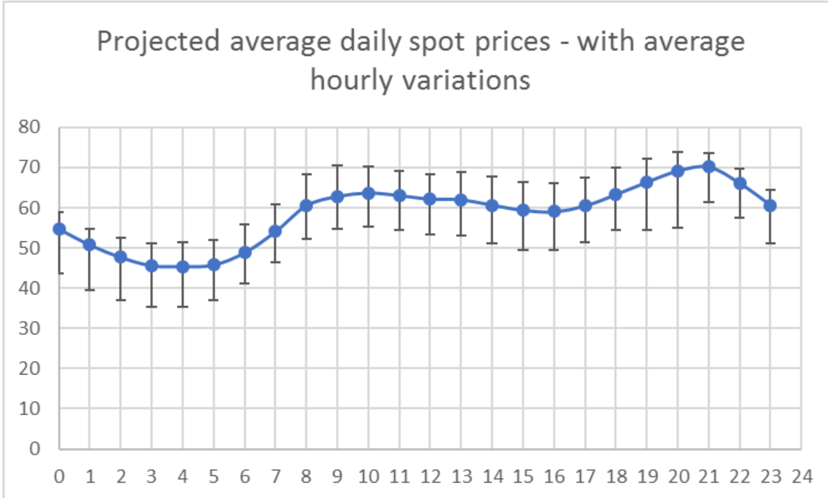


Figure 18: Projected daily spot price curve, with average values for each hour based on 2014 data, as well as 2020 and 2030 projections. Average hourly variations also calculated based on historical variations of each of these hours.

The projected average daily spot curve is compared to the 2017 average hourly spot curve. For every hour, the multiplication factor between the projected price and the average 2017 price is calculated. The average multiplication factor calculated is of 1.152. This factor will be used when applying the direct market access pricing mechanism in the optimization model developed.

3.4.1.3. Premium

Due to the volatile nature of the energy market, and the high battery costs, it is not guaranteed for many hours that the hourly spot price will be such that it will create sufficient returns for the plant developer. Therefore, in Spain, at least, after analyzing market prices and tendencies, a premium will be necessary. This is already a pricing mechanism used in other technologies, such as CSP plants. In our model we will consider the economic returns involved when having a premium component.

3.4.2. Time-of-use

The next pricing mechanism is still linked to market behaviour, but now presents significantly less risk to directly selling in the wholesale market.

Here, based on the historic and the 8760 estimated future average hourly prices, as already discussed previously, a peak, shoulder and valley period will be fixed, each with their own prices. This type of pricing mechanism will allow the producer to sell in a higher priced period, which does not necessarily coincide with PV production. However, since the idea is to dispose of ESS, developers can discharge batteries during these peak hours, and at the same time provide useful grid services.

The main purpose of this pricing mechanism is so that power shifting service can be provided. This involves charging the battery during valley period, to then discharge during peak period.

To combine power shifting and clipping on a daily basis, the following equation has been constructed:

$$D = E \cdot \pi_s + C_{batt} \cdot (\pi_p - \pi_v) \qquad (3)$$

This formula is based on part of the optimization algorithm, in the economical point of view.

From Fig 3.5., it shows the daily curve with average hourly prices used (based on the future analysis explained previously). In the curve, we can see a period of low demand (*valley*), medium demand (*shoulder*) and high demand (*peak*), which corresponds to the different priced periods. This curve will vary depending on the demand of the country, which consequently depends on many factors (climate, temperature, working hours, energy intensity of the country, energy efficiency measures in place, etc). Even though price is directly linked to the demand, the daily price distribution will vary depending on the country, which is mainly dependent on the type of generation installed and available.

Prices can stay fixed during the lifetime or have a condition of being able to vary every year depending on economic changes, such as Consumer Price Index and market interest rates, or changes in electricity prices (such as oil crisis, or water shortage). In this project, the time-of-use tariff periods will remain the same, since we assume dependence on fossil fuels and water for electricity generation will reduce during the years, and we assume inflation rate and interest rate will have on average a value of 2% and 4% respectively.

3.4.3. PPA

This type of pricing mechanism is popular globally for PV plants. However, the aim of analyzing it here is to see at what PPA values can we have economical returns with an ESS-coupled PV plant.

In a PPA, a purchaser or "off-taker" (consumer via wholesaler) buys power from a plant developer at a negotiated rate for a specified term without taking ownership of the system. The plant developer procures, builds, operates, and maintains the system. The PPA conveys the economic benefits, and in some cases the environmental benefits, of solar power to the off-taker regardless of whether the power is physically delivered to serve the off-taker's electric demand.

The steps involved in a Power Purchase Agreement is the following:

1. Part of the procurement process involves a preliminary assessment of PV suitability on a region.
2. From here, a Request for Proposal (RFP) is set up to receive bid from plant developers. Governments, for example, setup capacity auctions for project developers to construct, maintain and decommission these plants. Project developers bid in these auctions in accordance to what they are willing to sell electricity for. Depending on the type of auction, projects are then allocated to developers offering the lowest bids, although other things are taken into account regarding suitability of the developer itself, such as project development experience, financial stability, as well as willingness/contract to provide performance guarantees and a percentage of availability each year. Therefore, normally prior to this auction, for utility-scale plants, plant developers have to go through a registration process in order to be considered and qualify for this auction.

3. Determining a PPA pricing structure is an important step in order to maximize long-term cost savings. It is based on electricity rates in that country, government legislation, as well as existing financial incentives that project developers can benefit from.

The benefits of a PPA are the following:

- No up-front cost: PPAs allow governments/system operators to buy power produced from a solar system without tying up capital in a large up-front investment, since it is paid as kWh of energy is delivered into the grid. The zero-up-front-cost makes PPAs an easier sell to governmental bodies, utility companies and system operators who are concerned about return on investments.
- No need for purchasers (governmental bodies, utility companies or system operators) to dispose of full capital. They pay as they receive the energy produced. All budgetary outlays such as operation and maintenance can be covered within the PPA price, which takes into account all fixed and variable costs.
- Having long term fixed price PPA contracts provides a low risk financial mechanism which when coupled with the low interest rates in the latest years provides a medium to invest in these long-term projects and ensures an amortization period of the plant, compared to the voltage utility electricity rates, which can fluctuate in a daily basis. A PPA provides a guaranteed selling price, which is in accordance to the requirements of the plant (it will be higher than the LCOE costs of that plant).

The main challenges of PPAs is having to enter into a long-term contract, when perhaps in the future electricity rates could significantly alter, and as a result prove more unfavourable for the project developer than if they would have just sold directly into the market. A solution is to provide a scaled PPA contract where there is an increase in price per year, depending on the projection study carried out, and agreed by both parties.

In terms of profitability, this pricing mechanism will only be applicable for just clipping services, since there is no hourly and periodic price discrimination, therefore there is no point in an economical point of view. However, in a technical point of view, the grid may require a plant to limit its power injection and discharge at a later time. Even more so, despite having a fixed price, the grid can benefit from a plant consuming (charging) during valley periods, and generating (discharging) during peak periods, with the result of flattening the demand curve and reducing transmission losses as a result, as explained previously. Depending on regulation, this could nevertheless have economical retributions who provide this power shifting service, irrespective if the pricing mechanism contracted does not provide the incentive.

Despite this low risk, there will be many hours where the wholesale price will be higher than the PPA price. This means that the earnings will be less than what it could have potentially been, if sold directly to the market. Developers would have to mitigate this loss of earnings by contracting a virtual PPA, for example.

3.5. Battery model

This section involves obtaining the optimum battery size for a plant with particular characteristics (AC power, DC-AC power ratio, solar resource, pricing mechanism), whilst also considering degradation of the battery by taking into account the different factors, such as, temperature, C-rate, depth-of-discharge, and initial state-of-charge.

The battery modelling will also review the economic performance of the plant, by producing the NPV (Net Present Value) and ROI (Return on Investment).

This modelling will take into account different criteria, which are the following:

- Criteria 1: Max NPV
- Criteria 2: Max excesses
- Criteria 3: 20-year battery lifetime

The Energy Storage System (ESS) that could be used can be of different technologies. However, the one to be used in the model is Lithium-ion, since in recent projects it has been the choice of battery system chosen for utility scale projects, due to considerable research and development done in this technology as well as the advantages it presents. This is analyzed below.

Below shows a comparison of costs, self-discharge rate and efficiencies for different battery technologies.

Parameter	Lead-acid	Lithium-ion	Sodium-sulphur	Redox-Flow
c_{kWh} [€/kWh]	223	385	455	558
c_{kW} [€/kW]	345	385	680	1,250
d [%/(15 min)]	0.00177	0.00026	0.10417	0
η_{ch}, η_{dis} [%]	90	97	88	88

Figure 19: Battery technology comparison [9].

Analyzing all these characteristics, the most suitable and the one to use as reference during the project is Lithium-ion. Even though Lithium-ion technology still has relatively high costs compared to other technologies, its low self-discharge, high energy density and high charging efficiency (low charging losses), as well as the anticipation that a lot of research on this technology has recently been carried out, and that costs/kWh have dropped considerably in the last few years, this technology is the most adequate for future battery installations for large scale PV plants.

Two things that still have to improve are:

- Cost of these batteries. As technology keeps advancing and demand keeps increasing, prices seem to keep dropping. Future cost projections and economic viabilities of these battery-coupled systems is demonstrated in the thesis.
- Number of cycles and lifetime of these batteries, in terms of technology improvements, but also in terms of daily optimization. The latter is a key focus in the thesis.

This decision being made for my model is also backed by [1], where they state that lithium-ion is the most suitable for battery-coupled PV plants, highlighting its capability for charging/discharging efficiently at high power rates, even with low battery capacities, which also gives rise to be used not only for energy purposes but for power purposes as well, more specifically, for grid services, such as Frequency Response Service (*See Chapter 6 and 7*).

In terms of battery costs, as analysed in the literature review related to battery price projections it has been studied by various prestigious institutions, such as National Renewable Energy Laboratory and Green Technology Media, that with further research and development, as well as with the increase in demand in its different applications, battery prices are going to drop considerably. For the next study, a 9% decrease on battery prices has been applied (as concluded from studies by GTM). The battery price decrease is therefore represented by the following power law relationship:

$$\Pi_{batt} = \Pi_{batt,0} \cdot (0.91)^{(t-2017)} \qquad (4)$$

Below shows the power law relationship for this projected battery price evolution:

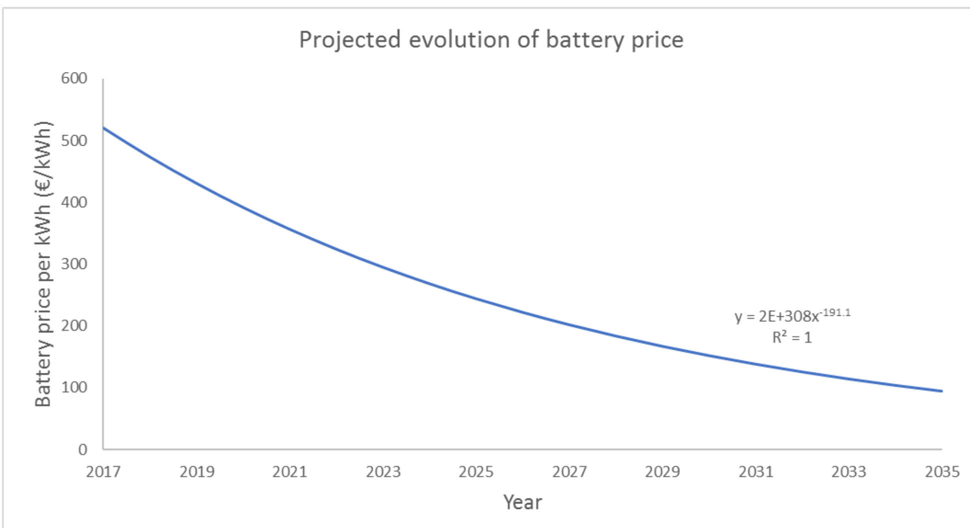


Figure 20: Projected battery price per kWh evolution from 2017 to 2035.

3.5.1. Battery degradation modelling

Before the different criteria is analyzed, it is important to take into account the different factors that affect the lifetime of the batteries themselves. A study of the different factors has been performed, to then produce different degradation curves for different values of these factors. To date, there is no model that incorporates a techno-economic analysis of the optimum battery size, taking into account different DC-AC ratios, power sizes, pricing mechanisms, as well as battery degradation characteristics. This model will be innovative for being a more complete study of the optimum characteristics of such a plant to maximize earnings over its lifetime.

Figure 21 below shows how the model produces the degradation curves for different depths-of-discharge. The curves represent a power law relationship, which is based on experimental results obtained from previous literature [10, 12]. This relationship shows that during the first 500 cycles, degradation is greater due to the diffusion-limited SEI growth mechanism, which results in faster reaction rates for a fresh cell. Moreover, working with a higher average DoD has a greater effect in the lifetime of the battery.

In the model as well, due to previous work [26], it was decided that the life of the battery ends when it reaches 80% of maximum available capacity (capacity fade). From Figure 21, it can be seen how the number of total cycles before the battery´s end of life varies significantly. In the model the total cycles are 9435.2, 4350.0, and 2453.6 for cycling at an average DoD of 50%, 60% and 80%, respectively. The aim then is to optimize the battery use to reduce the DoD as much as possible, in order to extend the battery´s lifetime and reduce the battery replacement costs. The greater the extension of the battery´s lifetime, the less years needed to replace batteries, but also the cheaper the batteries will be in the moment of purchase.

For example:

- non-optimized battery use: lifetime of 7 years.
- Optimized battery use: lifetime of 10 years.
  This means a reduction of 3 years equivalent costs. However, in the 10th year (moment of purchase), due to the 9% cost decrease projection in Lithium-ion technology, the cost of purchase in this year is less than in the 7th year.

(*More details on battery replacement costs in Chapter 3.2.4*).

Note that Figure 21 shows the degradation curves for a C-rate of 0.5C (which is the aim of charge/discharge power) to use for the PV excess storage and power-shifting application proposed in this thesis (*See chapter 4 and 5*).

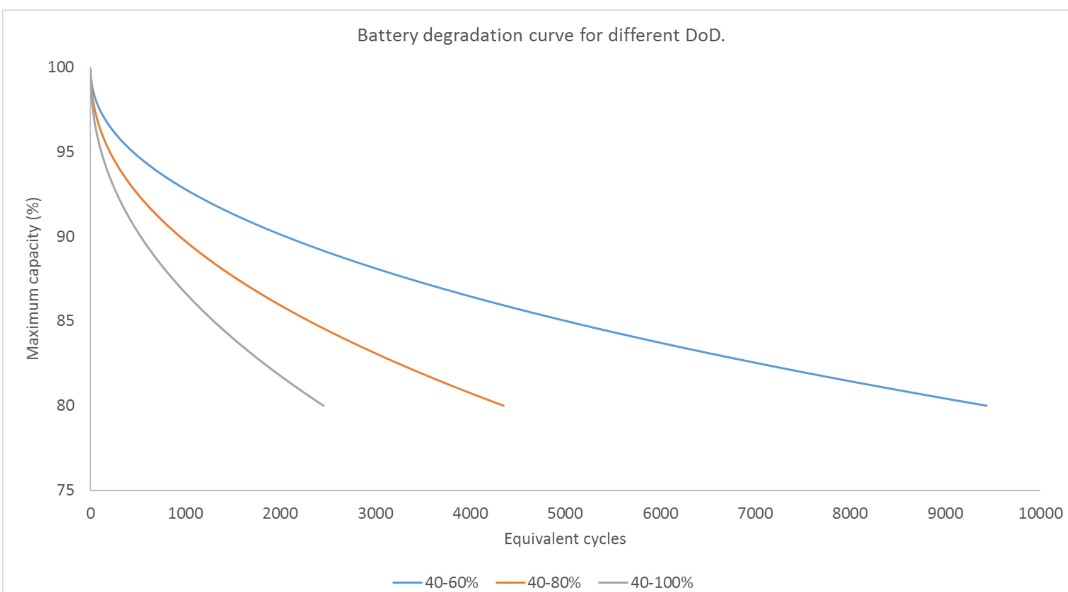


Figure 21: Capacity fade with respect to equivalent cycles, for different average DoD.

Just like the panel degradation reduces the amount of production and therefore solar excesses produced every year, the battery degradation reduces the capacity to store energy. Therefore, when considering every day, the excesses stored and the power shifting cycle carried out, the new battery capacity needs to be taken into account.

The initial simulation produced in the model is of 1 year. One of the variables modelled and calculated is the yearly earnings. When taking into account clipping excesses and power-shifting, the earnings can be expressed as the following:

$$Earnings_{year\ 1} = \left[\sum_{D=1}^{365} MIN\{C_{batt}, Excess_D\}\right] \cdot \pi_{sh} + C_{batt} \cdot (\pi_{pk} - \pi_{val}) \quad (5)$$

The first term is a limitation, where the amount of earnings from the excesses depends on the solar resource, but also on the battery capacity. If the excesses produced are below the maximum battery capacity, then all excesses are stored, and so its corresponding earnings will be accrued. If though, the excesses available in that day are greater than the battery capacity then the maximum excesses stored is equal to the battery capacity. The second term is for power-shifting. The variables π_{pk}, π_{sh}, π_{val} are the peak, shoulder and valley tariff respectively.

However, when taking into account the total earnings during the lifetime of the system, in order to determine its Net Present Value, the earnings each year will vary since the battery capacity reduces due to its degradation. This needs to be taken into account, using the following algorithm which has been implemented in the optimization model.

$$Earnings_{year\ n} = \left[\sum_{D=1}^{365} MIN\left\{C_{batt,n}, Excess_{D,n}\right\}\right] \cdot \pi_{sh} + C_{batt,n} \cdot (\pi_{pk} - \pi_{val}) \quad (6)$$

Therefore, the lifetime earnings are:

$$Earnings_{lifetime} = Earnings_{year\ 1} + Earnings_{year\ 2} + \cdots + Earnings_{year\ N} \quad (7)$$

$$Earnings_{lifetime} = \left[\sum_{D=1}^{365} MIN\left\{C_{batt,1}, Excess_{D,1}\right\}\right] \cdot \pi_{sh} + C_{batt,1} \cdot \left(\pi_{pk} - \pi_{val}\right) + \left[\sum_{D=1}^{365} MIN\left\{C_{batt,2}, Excess_{D,2}\right\}\right] \cdot \pi_{sh} + C_{batt,2} \cdot \left(\pi_{pk} - \pi_{val}\right) + \cdots + \left[\sum_{D=1}^{365} MIN\left\{C_{batt,N}, Excess_{D,N}\right\}\right] \cdot \pi_{sh} + C_{batt,N} \cdot (\pi_{pk} - \pi_{val}) \quad (8)$$

Note how the variables here are:

- Battery capacity, which varies every year due to the annual battery degradation calculated in the model.
- Excesses, which varies every day due to the solar resource simulated, and also varies each year, due to the panel degradation which reduces the production from the PV array.

To show the yearly battery degradation as well as the yearly panel degradation, below shows an example of how the excesses (due to clipping) varies per year.

The orange curve represents the total excesses available for the DC/AC ratio used. The blue curve represents the excesses captured for the battery capacity available and the DC/DC converter maximum power used. This curve shows the actual excesses harnessed in the system. For both curves, we can see a decrease in the excesses produced every year. The orange curve decreases only due to the panel degradation. On the other hand, the blue curve decreases due to panel degradation as well the limitations imposed by the degraded battery in a particular year. It also shows that in year 13, in this example, the battery is replaced by a new one with a capacity equal to the original one. As a result, the excesses produced increased since there is now less limitation compared to the previous year. Also, the difference between the orange and the blue curve is less, in fact they are practically the same. This is due to that with 100% of the original battery capacity, we lose less of the total excesses since the excesses produced after these years are significantly less due to the panel degradation. In this example, for this DC/AC power ratio, the loss of excesses is nearly zero.

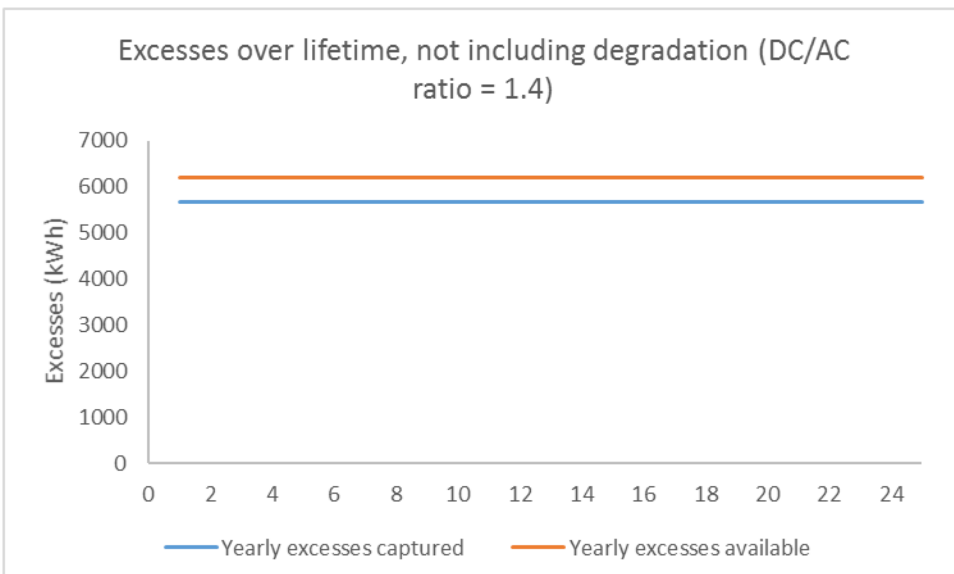


Figure 22: Example of yearly excesses produced, when panel and battery degradation not taken into account

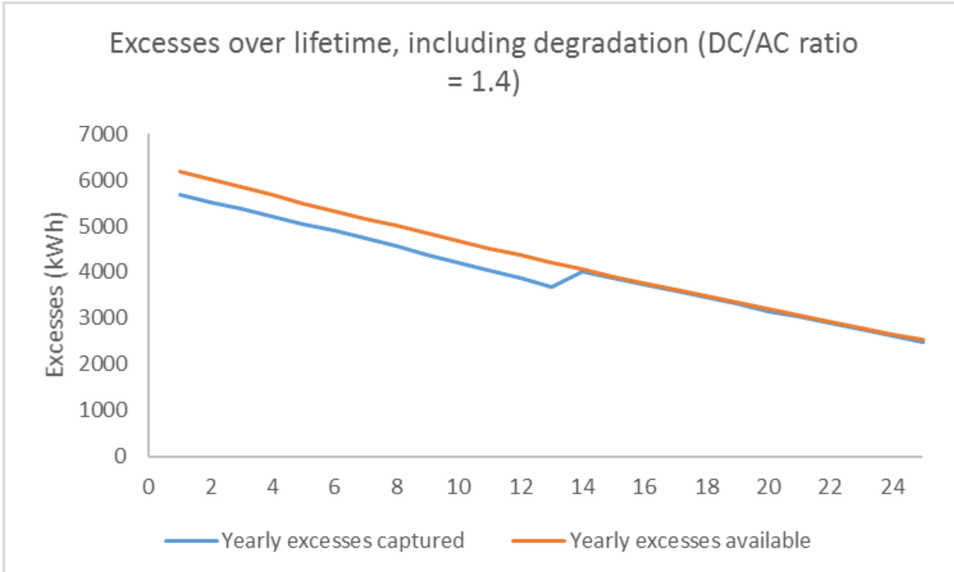


Figure 23: Example of yearly excesses produced, when panel and battery degradation taken into account

3.5.2. Criteria 1: Max excesses

In this criteria, very simply, the battery size chosen is big enough to cover the day with maximum excesses, that way all clipping possible is harnessed, and no solar excesses are lost.

However, even though earnings from clipping are maximum, it is not the most profitable over the lifetime of the plant, since in order to cover all excesses, the battery size needs to increase, which consequently increases the installation costs considerably (how much can vary depending on characteristics of plant and solar resource).

3.5.3. Criteria 2: Max NPV

In this criteria, a model has been developed, using Visual Basic for Applications language. Here it is set out to calculate for different battery sizes (from 50 to 5000 kWh, in 50 kWh intervals) the following:

- Excesses that can be stored.
  Here, it adds up two different components. For days where the excesses are below the battery size, all these days are added up. Secondly, for days where the excesses are above the battery size, the maximum excesses that can be stored is the total capacity of the battery. There here, the battery size is multiplied by the number of these days. Finally, both components are added together, giving the total excesses that can be stored.
  The percentage of total excesses is calculated as well, which provides another indicator to determine the viability of such a system.
- Earnings accrued due to the excesses stored at a certain battery size. The amount of earnings will depend on the excesses stored as well as the price mechanism used.

- NPV, based on the earnings accrued over the 20-year lifetime, capital costs considering a certain battery size, as well as the interest rate and inflation rate used.
- Payback period, taking into account the earnings calculated for a year, the battery costs, as well as the interest rate and inflation rate used.

Using these output results, the max NPV will be found, which will correspond to the optimum battery size, for this criteria.

With these output results also, a graph of NPV and ROI against different battery sizes will be produced, for further analysis into the economical behaviour.

3.5.4. Criteria 3: 20-year battery lifetime

The criteria is based on increasing the size of the battery system in order to increase its lifetime, and thus reduce the replacement costs during the lifetime of the plant.

A model has been developed, by increasing the battery size, the battery characteristics, for example the depth-of-discharge, is updated, such that a new degradation curve applies, and thus the degradation rate reduces. The lifetime of the battery is then determined, which is when the capacity fade of the battery reaches 80%.

Note, external factors (such as temperature), as well as C-rate remains the same, since the application and location of the plant does not change.

The next part of the optimization is more of a fine-tuning optimization, in order to determine finally the real NPV associated with this battery system. The 20-year lifetime criteria is carried out. This involves the following:

1. Inputs:
   - DC/AC ratio: Using this value, the optimum battery size (from max NPV criteria) is extracted from the previous calculations. The reason for this is to basically have a starting point.
   - Battery size factor: The max NPV optimum battery size is multiplied by this battery size factor to obtain a new battery size (a multiple of the original capacity) with the aim of determining the degradation rate and consequently the new estimated lifetime of the battery.
   - Max DoD: Maximum Depth of Discharge possible. It means that cycles are performed taking into account that there will be a reserve of battery capacity that will never be discharged, with the aim of increasing the battery lifetime.
   - Battery capacity.
   - Daily excesses.
2. Outputs:

The following variables are calculated every day during the 365 days of the year.

- Equivalent cycles: It calculated how many cycles are produced per day based on the excess produced (which is generated from the original PVSyst simulation). It uses the following condition to calculate this:

$$
\begin{aligned}
&If\ (Excess)_{day\,'n'} > C_{batt}\ Then\\
&\quad Cycles = 2;\\
&Else\\
&\quad Cycles = \frac{Excess}{C_{batt}} + 1\\
&End\ If
\end{aligned}
$$

If the excesses produced that day is greater than the actual battery capacity, then it means the excesses produced will allow for a whole charge/discharge, as well as the additional daily charge/discharge for power-shifting. If the excesses are less, then the charge/discharge of the excesses will correspond to an equivalent cycle less than 1 (Excess / Battery capacity), as well as the power-shifting cycle.

- Average DoD / SoC: It calculate for all the cycles (between 1 and 2) that occur per day, what is the average DoD that the battery has discharged to.

$$
\begin{aligned}
&If\ (Excess)_{day\,'n'} > C_{batt}\ Then\\
&\quad SoC = \frac{C_{batt} \cdot 2}{C_{batt} \cdot 2} \cdot DoD_{max};\\
&Else\\
&\quad SoC = \frac{C_{batt} + (Excess)_{day\,'n'}}{C_{batt} \cdot 2} \cdot DoD_{max}\\
&End\ If
\end{aligned}
$$

It is clear that for power-shifting cycle, the DoD is the max DoD, which it has been assigned to be 0.8, as a normal value to use for lithium-ion batteries. The average DoD will therefore depend on the excesses produced on that day, as shown above. If the excesses are greater than the battery size, then two whole cycles will be performed, and so the average DoD will be the max DoD, which has been assigned to be 0.8. If the excesses are lower, the consequent value will be calculated, as shown in the algorithm above.

- Accumulated cycles: Cycles carried out each day is added, to accumulate the total cycles performed by the battery system. This value will allow to deduce the capacity fade produced already in this battery. Capacity fade vs equivalent cycles has been modelled. There are various curves of this, since each represent a different final SoC value, and thus degradation would vary (*See Chapter 3.1.2*).
- Discharge capacity: Also known as capacity fade, it determines the capacity at which the battery can still discharge, with respect to the original capacity. As mentioned already, depending on the use of the battery (cycles, SoC, DoD, C-rate), the discharge capacity reduces.

- New battery capacity: This is obtained by multiplying the actual discharge capacity of that day by the original capacity of the battery. In fact, this new battery capacity will be the new value of the variable C_{batt} in the following day, which will be used to calculate the equivalent cycles and the average DoD. Therefore, the algorithms change to perform in the following way:

  Equivalent cycles:

$$
\begin{aligned}
&If\ day = 1\ Then\\
&\quad If\ (Excess)_{day\ 1} > C_{batt,1}\ Then\\
&\qquad Cycles = 2;\\
&\quad Else\\
&\qquad Cycles = \frac{Excess}{C_{batt,1}} + 1\\
&\quad End\ If\\
&ElseIf\ day = n\ Then\\
&\quad If\ (Excess)_{day\ 'n'} > C_{batt,(n-1)}\ Then\\
&\qquad Cycles = 2;\\
&\quad Else\\
&\qquad Cycles = \frac{Excess}{C_{batt,(n-1)}} + 1\\
&\quad End\ If\\
&End\ If
\end{aligned}
$$

  Average DoD:

$$
\begin{aligned}
&If\ day = 1\ Then\\
&\quad If\ (Excess)_{day\ 1} > C_{batt,1}\ Then\\
&\qquad SoC = \frac{C_{batt,1} \cdot 2}{C_{batt,1} \cdot 2} \cdot DoD_{max};\\
&\quad Else\\
&\qquad SoC = \frac{C_{batt,1} + (Excess)_{day\ 1}}{C_{batt,1} \cdot 2} \cdot DoD_{max}\\
&\quad End\ If\\
&ElseIf\ day = n\ Then\\
&\quad If\ (Excess)_{day\ 'n'} > C_{batt,(n-1)}\ Then\\
&\qquad SoC = \frac{C_{batt,(n-1)} \cdot 2}{C_{batt,(n-1)} \cdot 2} \cdot DoD_{max};\\
&\quad Else\\
&\qquad SoC = \frac{C_{batt,(n-1)} + (Excess)_{day\ 'n'}}{C_{batt,(n-1)} \cdot 2} \cdot DoD_{max}\\
&\quad End\ If\\
&End\ If
\end{aligned}
$$

Once these outputs have been generated for the whole year in daily intervals, the accumulated cycles and the discharge capacity after 1 year is transferred to a yearly table. Therefore, year 1 has been completed. Year 2 will follow by carrying out the same simulation again. In other words, the accumulated cycles of Year 1 is multiplied by 2. The discharge capacity is then read from the battery degradation curve (from the battery degradation model), for the accumulated cycles after year 2, using the same C-rate, and using the Final SoC calculated (which is dependent on the original battery size. Ideally this would change since battery capacity reduces due to degradation, but for simplicity purposes we will keep using same final SoC for the rest of the years). The same procedure is done for the rest of the years, until a degradation capacity of 80% is reached. From previous literature (add reference here), this value of discharge capacity is reached at the final stages of the lifetime of current lithium-ion batteries. Once 80% is reached, the year in which this occurs is recorded.

This procedure is done for battery size factors of 1 to 10, which is generated using a macro created in VBA. For each of these battery size factors, along with the expected lifetime generated, the following is also calculated:

- Associated capital costs from the amount of battery size (kWh) needed. The capital costs now also consider the battery replacement costs, which is dependent on the expected lifetime of the battery. The battery replacement costs are calculated with the following equation:

$$C_T = C_0 + C_0 \cdot 0.91^{L} + C_0 \cdot 0.91^{2L} + \cdots + C_0 \cdot 0.91^{(n-1)L} \qquad (9)$$

Where:

- C_T is the total battery costs, taking into account the battery replacement costs throughout the lifetime of the plant.
- C_0 is the original battery cost from the initial investment.
- L is the lifetime of the original batteries.

What this equation actually calculates is assuming the whole battery system lasts for the lifetime calculated, L, what would the cost be in the future to replace this entire system using new projected prices for that year. The factor, 0.91, is a factor determined from studies carried out by GPM, which projects a 9% decrease per year of battery costs from 2017. Thus, 0.91^{L} will give the corresponding factor in the year the battery system is expected to be replaced. The factor (20/L) is the multiplication factor to increase the total capital costs according to the associated replacement costs.

Note:

- the last term of this equation is represented by the term $C_0 \cdot 0.91^{(n-)L}$. This term represents the last investment needed before the end of life of the power plant. In this thesis, this is assumed to be 20 years.
- How many terms in this equation depends on the lifetime of the battery, which in turn depends on the use of the battery (as well as the climatic conditions of the location of the plant). For example, if the lifetime of the battery is 6 years, then there will be 4 investments (Year 0, Year 6, Year 12 and Year 18). However, if the lifetime of the battery is calculated as being 10 years, then there will be only 2 investments (Year 0 and Year 10).

- Ideally the replacement of the battery should be such for the last replacement it should last up to year 20, in order to fully amortize the use of these batteries. Therefore, in this case, nL would equal to 20 (This is the first case looked at). However, this is not always the case. For example, if lifetime of battery for a particular use is 8 years, it means an investment is needed in Year 16. Therefore, these new batteries will only be used for only half of its life (This is the second case looked at).

The equation can be simplified to:

$$C_T = C_0 \cdot (0.91^{0L} + 0.91^{L} + 0.91^{2L} + \cdots + 0.91^{(n-1)L}) \qquad (10)$$

This equation actually represents a geometric series. Therefore, with the following derivation the geometric series can be simplified to the following form:

$$C_T = C_0 + C_0 \cdot 0.91^{L} + C_0 \cdot 0.91^{2L} + \cdots + C_0 \cdot 0.91^{(n-1)L}$$
$$C_T \cdot 0.91^{L} = C_0 + C_0 \cdot 0.91^{L} + C_0 \cdot 0.91^{2L} + \cdots + C_0 \cdot 0.91^{nL}$$
$$C_T - C_T \cdot 0.91^{L} = C_0 - C_0 \cdot 0.91^{nL}$$
$$C_T \cdot (1 - 0.91^{L}) = C_0 \cdot (1 - 0.91^{nL})$$
$$C_T = \frac{C_0 \cdot (1 - 0.91^{nL})}{(1 - 0.91^{L})} \qquad (11)$$

In order to calculate the total capital costs (with replacement costs), there are two cases to consider:

Case 1:

Assuming nL = 20, in other words, installing batteries such that the life of the last replacement ends in Year 20. This would be the case for the following:

- Lifetime: 20, Investment: 1.
- Lifetime: 10, Investment: 2.
- Lifetime: 6.67, Investment: 3.
- Lifetime: 5, Investment 4.
- Lifetime: 4, Investment: 5.

In this assumption, the equation can be reduced to:

$$C_T = \frac{C_0 \cdot (1-0.91^{20})}{(1-0.91^{L})} \qquad (12)$$

This relationship is illustrated in Figure 22 below. The graph shows how total costs vary with the lifetime of the battery (which in turn depends on the use of the battery). Figure 23 shows different curves that represent the different battery sizes. Assuming the cost per kWh remains the same irrespective of battery size, as more battery size is needed the total costs increases proportionally, as seen in Figure 23.

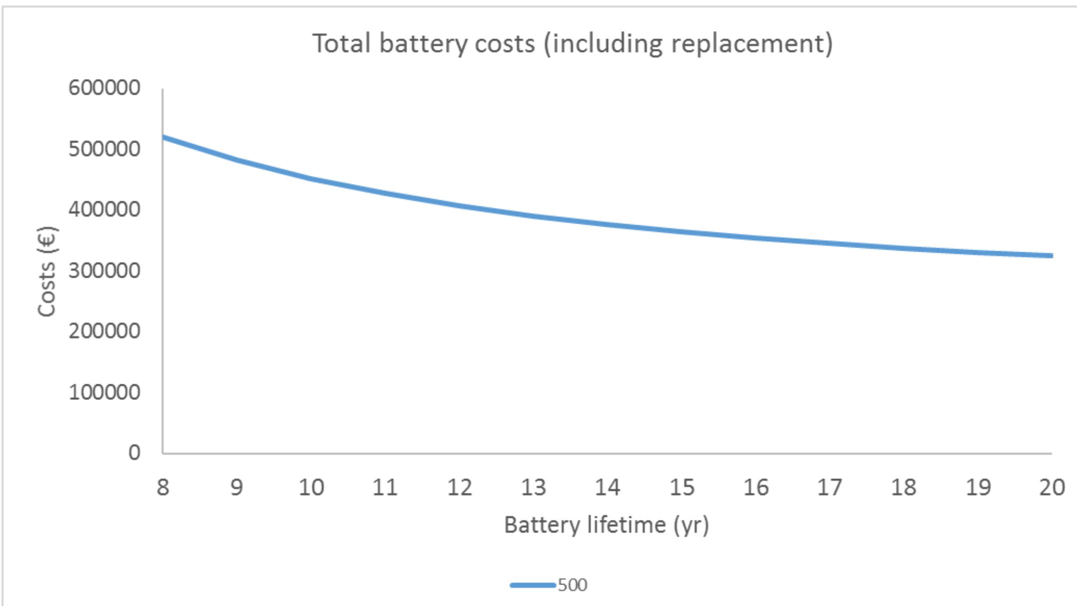


Figure 24: Total battery costs for different battery lifetimes, for battery size of 500 kWh.

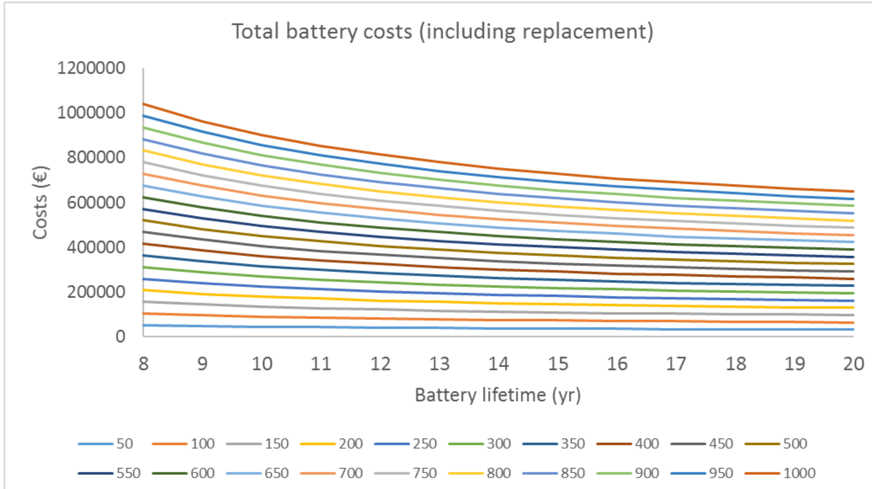


Figure 25: Total costs for different battery lifetime, for different battery sizes (kWh).

<u>Case 2</u>:

In reality, nL can have another value not equal to 20. As explained earlier, an investment may be needed in Year 18, therefore nL would not equal to 20. This is the most likely case. Therefore, equation (5) applies here.

In order to determine the number of investments needed (n-1), the total lifetime of the plant (20 years) is divided by the lifetime of the battery. This value is then rounded to the next whole number. Adding 1 to this value will give you the value of "n". This is then applied to the above equation.

Figure 24 shows the new relationship for Case 2. It can be seen that the relationship still holds. However, there are some dips at Year 10 and Year 20. This is since at these lifetimes, nL equals exactly 20, so total costs work out more cost effective, since the last investment is fully amortized.

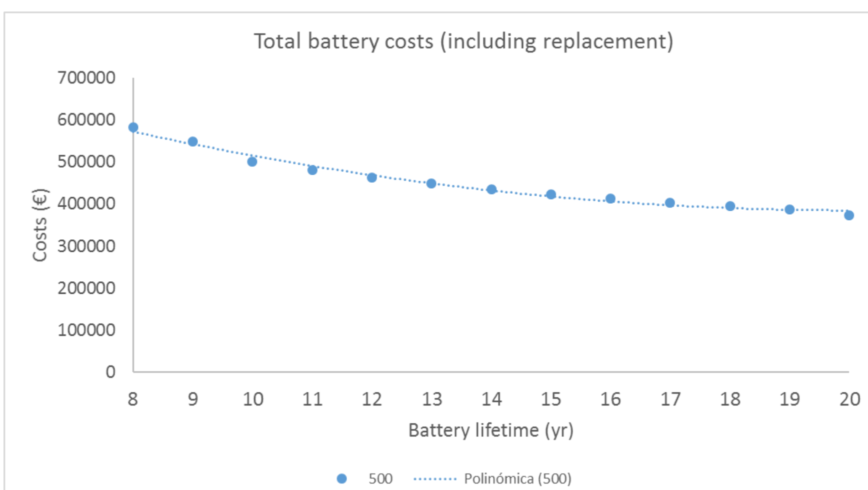


Figure 26: Total costs for different battery lifetime, for 500 kWh battery size, for Case 2 (nL ≠ 20)

- Extra earnings from the solar excesses: As battery size increases, a greater percentage of the excesses (from the same DC/AC ratio) can now be stored. This can be quantified as extra earnings.
- Extra earnings from power-shifting: As battery size increases, a greater amount of energy can be power-shifted, thus more earnings from providing more energy for this service. (This is subject to grid code regulations though).
- Net Present Value: During the NPV generation (using the original macro created in VBA), the battery replacement costs will be considered in the corresponding year of investment (depending on lifetime of battery calculated). Thus, this will have an effect on the NPV after 20 years. Secondly, the new earnings need to also be quantified in the algorithm. These are the extra earnings from more excesses available for storage and the extra earnings from increased power-shifting service.
- ROI: Similarly, the payback time will be calculated, taking into account the extra earnings and the extra costs, during the lifetime of the plant.

3.6. Conclusion

The model developed incorporates a lot of different features that should provide an accurate and optimized solution for the integration of these battery energy storage systems. However, testing the model is now required, in order to observe if results are actually optimum.

What is also needed is to use the battery for new services in order to improve its amortization. This will be studied in forthcoming chapters.

The next thing that is needed though is to study the proposed plant configuration to use as reference in this thesis and analyse how the model (with all its features, as discussed in this chapter) will respond to different plant configurations and components installed.

4. PROPOSED SYSTEM AND CONFIGURATION

4.1. Introduction

After establishing the challenges and objectives of this thesis in Chapter 1, followed by a detailed literature review in Chapter 2, an optimization methodology was proposed in Chapter 3 for the integration of battery energy storage systems. In a technical point of view, having batteries in this plant will allow for a smoother power output as well as providing further services to the grid that were not possible with stand-alone PV generators.

This chapter introduces the proposed design of the system, as well as the different components that it is consisted of.

4.2. Proposed configuration

The following diagram presents a simplified diagram of what is intended to be designed. This configuration will be the one proposed for use in the model developed for this thesis. However other configurations will also be simulated for comparisons with the proposed configuration.

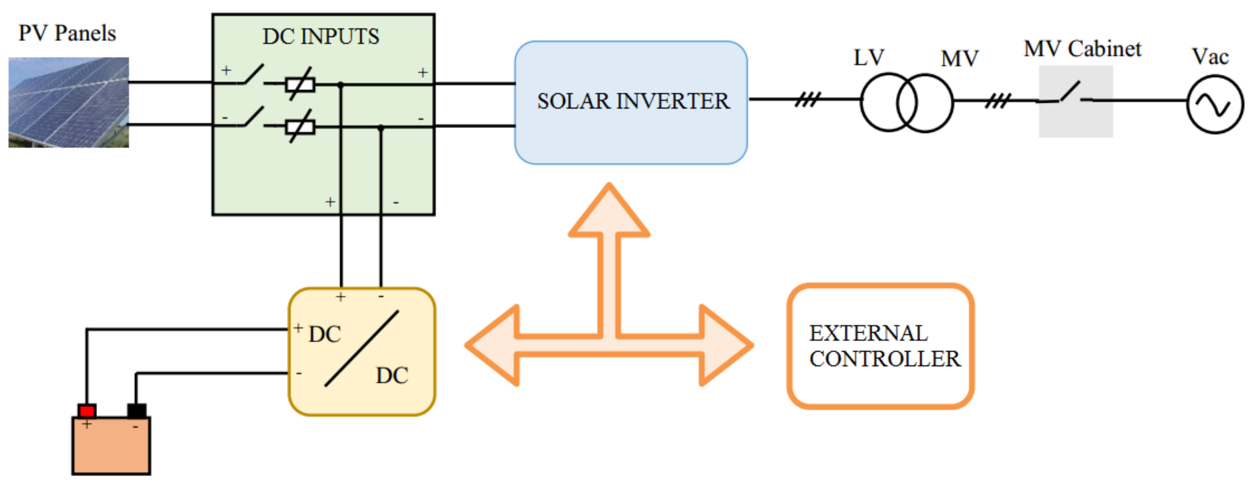


Figure 27: Simplified diagram of proposed configuration

Complete Single Line Diagram of the proposed plant design has been attached in *Appendix I*.

The system comprises of the following components:

PV array: A PV array is the primary energy source in this system. In our model, over-sizing will play a key role in maximizing battery use and increasing power injection, as explained already in Chapter 3.

Solar inverter: A solar inverter is responsible for converting the direct current into alternating current in order to export into the electrical grid. It synchronizes with the voltage and frequency of the grid, with the consequent injection of AC power. The inverter has a maximum capacity, by which if the PV power is greater, the power is deviated from the Maximum Power Point. This is known as clipping.

Battery system: This will allow for the storage of excess energy, or to perform other functionalities such as power-shifting (*More on chapter 3.5 on the battery model developed*).

DC/DC converter: The DC/DC converter can play many roles in this system. Firstly, it is able to charge the excess PV power (when PV power exceeds inverter capacity), via the control of the system. As shown above, the SCADA or Power Plant Controller will receive measurements from the solar inverter (to measure power being delivered), the ESS (to measure the state of charge), and the DC/DC converter (to read the operation mode it is at that moment). If the power delivered from the PV array is greater than the maximum power, and the ESS has sufficient capacity to store this excess energy, the SCADA or Power Plant Controller will send set-points to the DC/DC converter to switch to charging mode at a power rate equal to the excess PV power, so that only the maximum current that the inverter can support will be delivered to the inverter itself for grid injection.

The same thing applies when the PV power received is below the maximum power that the inverter can support, the SCADA or Power Plant Controller will send a set-point to the DC/DC converter to discharge at a certain power rate. Alternatively, it can be programmed during set times, such as during peak selling rate period, to discharge the ESS at a power rate in order to inject all available energy into the grid and maximize earnings. This will be explained further on when incorporating Power Shifting services with this battery-coupled photovoltaic plant.

Transformer: Solar inverters of V1500 technology will allow to connect to AC voltages of between 500 to 700 V, with the correct PV string sizing and consideration of the temperature in the given location. However, a transformer may be needed for the following two reasons:

- Normally generators are required to connect to the electrical grid at much higher voltages. Therefore, this transformer is able to deliver the power produced by the PV array at the interconnection voltage required.
- When connecting transformer-less solar inverters to the grid, transformers coupled to these inverters will provide galvanic isolation needed to prevent DC currents into the grid under fault conditions.

All these components comprise of 1 station. In order for the project developer to increase the power to the total required, more of these stations are connected in parallel on the AC side (*See Appendix II*).

4.3. Plant design

4.3.1. DC/AC power ratio (over-sizing ratio)

The first concept of this proposed system is oversizing the photovoltaic array heavily. The oversizing ratio is also called the DC/AC power ratio.

The DC/AC ratio or power ratio shows the ratio between the installed PV power and the AC power of the inverter.

$$Power\ Ratio_{MAX} = \frac{P_{PV}}{P_{inv,max}} \qquad (13)$$

The purpose of over-sizing a PV array is so that more power can be injected during more hours of the day.

If we look at the simulated example below, Figure 27 shows the power output curve for a clear day, at a DC/AC power ratio of 1. If we apply the same conditions to a PV array oversized to a value of 1.1, the power output during the morning and evening hours increases, thus increasing energy production during the day.

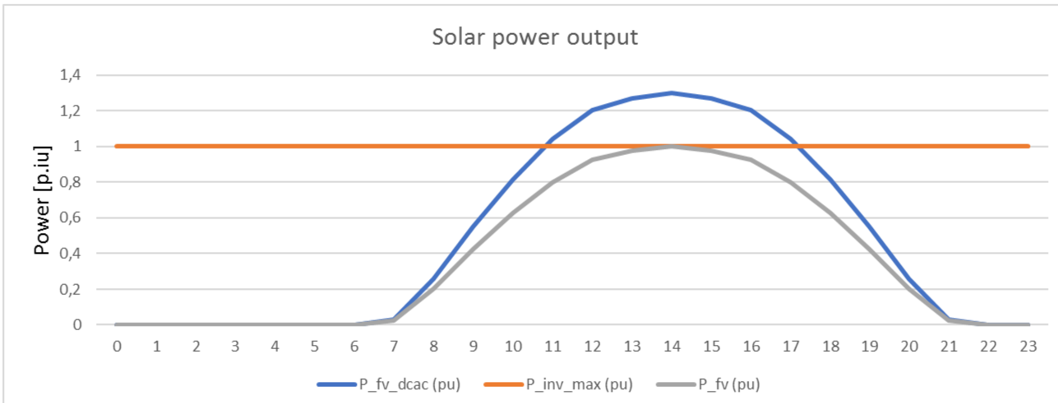


Figure 28: Comparison of solar power output between a normal sized and an oversized array.

However, this also means that during the peak sun hours the inverter will be limited to its maximum and so curtailing of the PV power output would occur. During the last two years, many PV plants have been developed with a small DC/AC power ratio, since even though curtailment occurs during the peak sun hours the daily production benefits overcome the extra amount of capital cost needed for installing extra number of panels, over the lifetime of the plant (*This study is out of scope of the thesis*). However, for larger DC/AC power ratios, these benefits do not compensate the even greater number of panels needed unless there is a way to store these excesses. The proposal of this thesis, is for the first time, to incorporate a DC coupled storage system in order to harness high DC/AC power ratios and store all excesses produced whilst also increasing in energy production during all hours, with the aim of making the extra capital cost for a greater array size and integrating battery system economically optimized.

To follow, it is important to consider that the power output may not entirely follow the irradiance curve. Power output should not be modelled solely on irradiance values but consider that in each moment the temperature varies. From an example of the results of the simulation model, we can see how the array voltage drops during the warmer hours of the day, having some effect on the power output of the PV array.

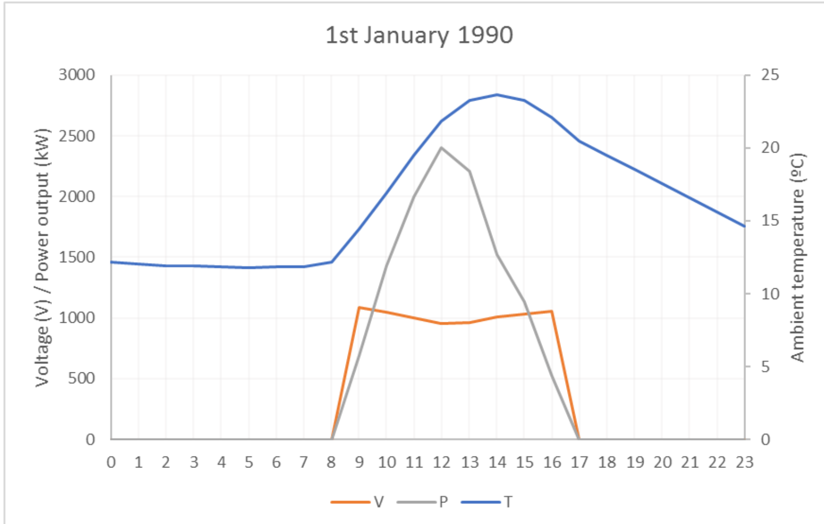


Figure 29: Daily voltage, power and temperature curves simulated for a winter day.

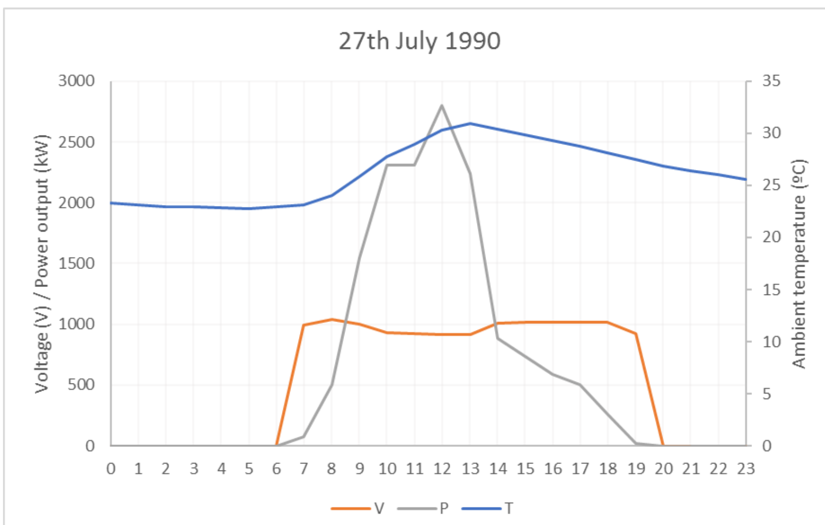


Figure 30: Daily voltage, power and temperature curves simulated for a summer day.

4.3.2. Current limits

In terms of maximum current, the inverter has two related parameters:

4.3.2.1.Maximum DC continuous current & Clipping losses

This is the maximum current that could flow through the inverter on the DC side, taking into account the maximum power of the inverter and the minimum DC voltage for which the inverter can perform MPP (Maximum Power Point) operation.

For example, in the model used FS2800CH15, the maximum AC power of the inverter is 3360 kVA (at 25ºC), whilst the minimum MPP voltage is 913 V. Using P = VI and applying the efficiency of the inverter, the maximum DC current that the inverter can operate and perform MPPT is of 3680 A.

However, this does not mean the inverter cannot support higher currents. If the DC current is higher than this value (as in the case when the array is over-sized), then the inverter would not work at the maximum power point. Instead it deviates by increasing the DC voltage, until the DC power (or current) is the maximum of the inverter.

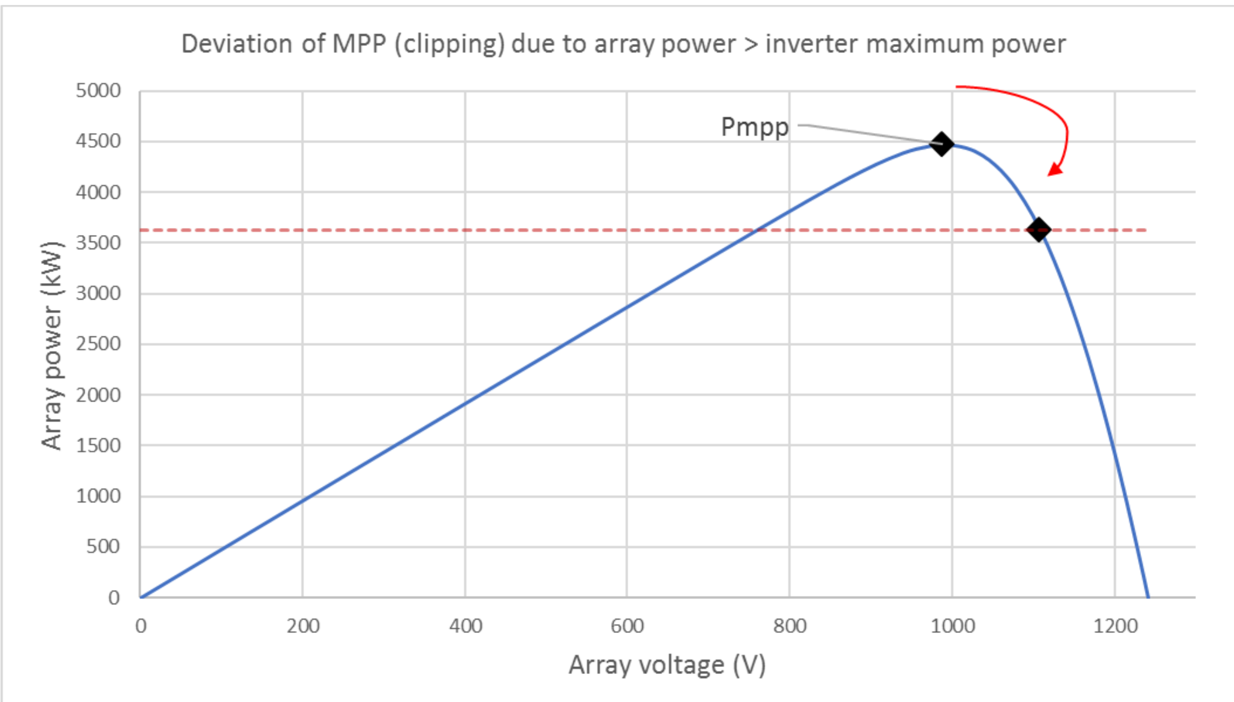


Figure 31: Deviation of MPP when Impp is greater than max DC continuous current

As the DC/AC power ratio of the plant increases, the currents generated during peak solar hours will be higher and for more hours. Therefore, this deviation of the MPP (also known as "clipping") will be carried out. This equates to energy excesses that as a result is lost. However (as discussed already in Chapter 2.3.1), having an over-sized array widens the power output curve and as a result during the day more energy is produced compared to no over-sizing.

In order to avoid losing these excesses (when MPP current is greater than maximum DC continuous current of inverter), it is proposed to integrate a DC-DC converter with battery storage before entering the inverter.

Using such system, the MPP is not deviated. Instead whatever current that cannot be drawn into the inverter, will be charged into the battery via the DC-DC converter. The DC-DC converter will receive a command from the Power Plant Controller, in order to set into charging mode, and to an assigned charging power value. The result is inverter injects as much as it can from the available PV power, and the remaining will be stored into the battery. As mentioned, the Power Plant Controller is responsible for sending the power setpoints to the DC-DC converter. The PPC calculates this from the measurement of the MPP power at that given time, and having a maximum power of the inverter, for the ambient temperature and voltage then.

Below shows a Single Line Diagram of the PV array inputs that reach the DC recombiner unit. The MPP current (MPPT algorithm performed by the inverter itself) drawn from each of these DC inputs will be collected into a DC bus bar. The PPC by then will have sent its power setpoint value to the DC-DC converter which will draw the remaining current that cannot pass through each of the inverter modules.

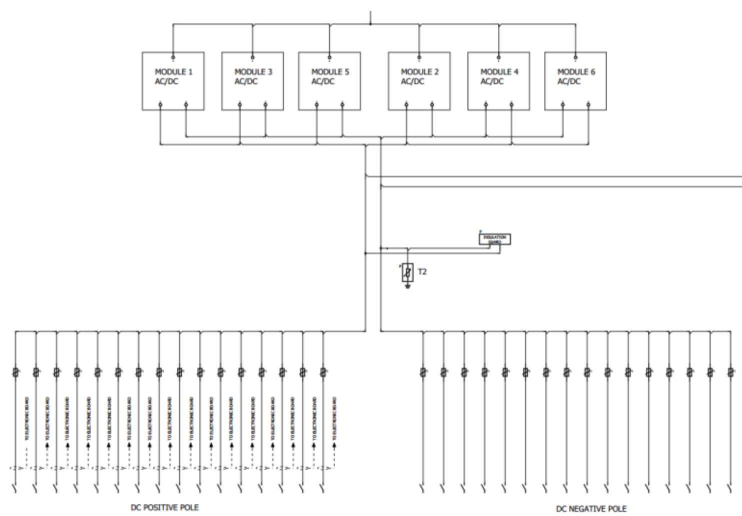


Figure 32: SLD of the DC/DC converter connected at the DC bus between the PV array inputs and the solar inverter

What needs to be determined though is the maximum DC/AC power ratio possible with this inverter model. This is conditioned by the following parameter.

4.3.2.2. Maximum DC short-circuit current

The maximum DC short-circuit current will determine how much over-sizing can be done in the photovoltaic array. The maximum DC/AC power ratio will be such that the consequent array short-circuit current produced from such oversizing will be equal to the maximum DC short—circuit current of the inverter.

If the short-circuit current of the array is greater than the maximum DC short-circuit current of the inverter it can support, then the inverter would be damaged in such an event.

The maximum DC short-circuit current is determined by the maximum current that the DC bus bar can support. The DC bus bar can be found circled in red in the Single Line Diagram drawn below. The DC bus bar collects all the current from the array, thus it needs to be able to support the short-circuit current of the array. Note: the SLD represents 1 inverter only. The reason for 6 blocks (modules) is because this inverter is made up of 6 modules in parallel, each with their own power stage. The modular concept allows uninterrupted service to the power injection when one module fails, with only minimal power loss.

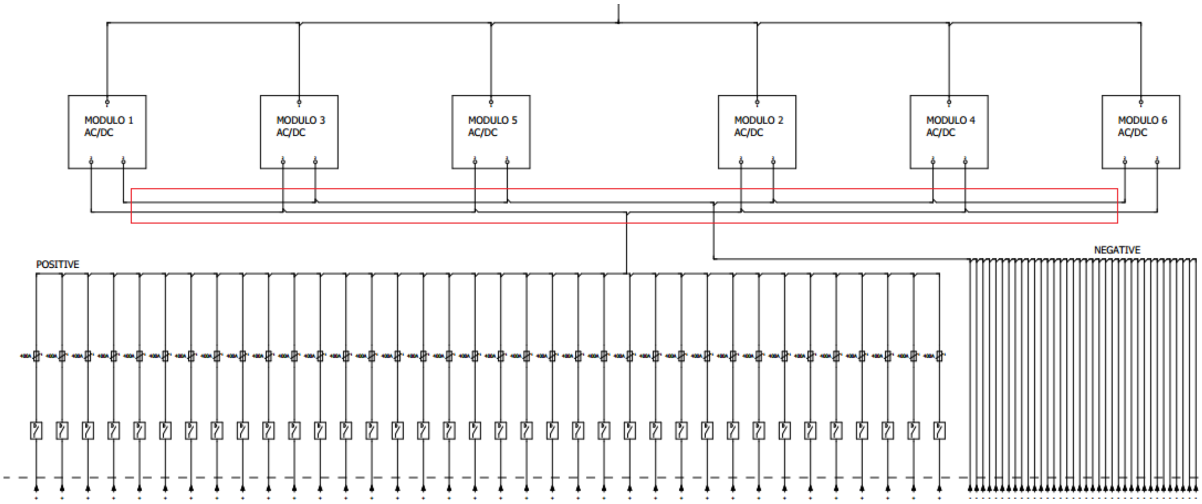


Figure 33: DC bus bar that collects the current from the PV array

The short-circuit current of the array would flow if the short-circuit is created between the two poles of the common DC bus bar, as shown below:

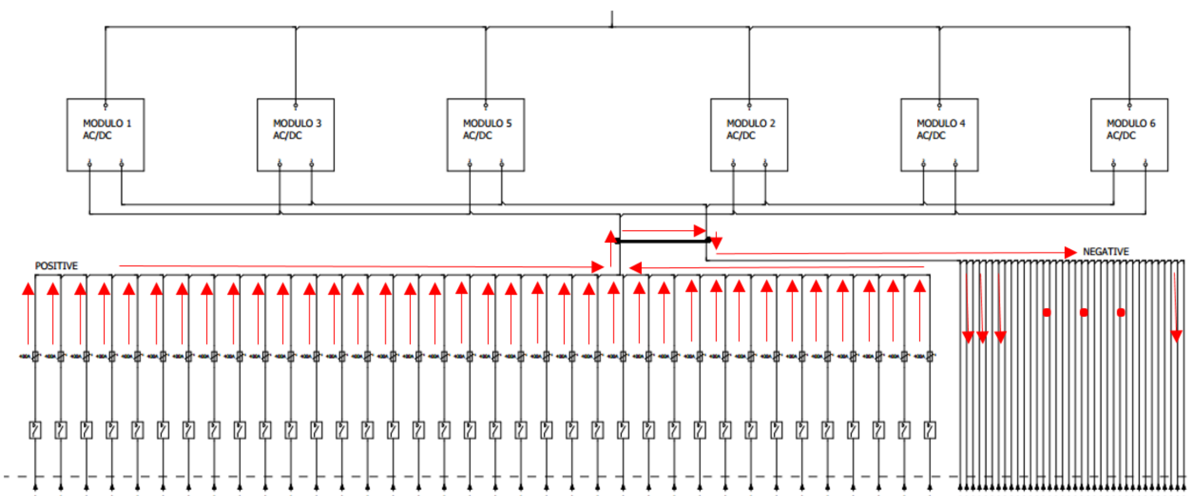


Figure 34: Short-circuit between positive and negative poles (PV array short-circuit current)

During such a short-circuit event, the voltage across the poles is measured to be approximately zero. When this is measured, the inverter stops IGBT switching, opens AC contactor of each module, followed by the DC contactors of the inlets from the array (as shown in the diagram). This leaves the circuit open and eliminating the short-circuit current. Even though the inverter disconnects during such a short-circuit, during the time it takes to measure and respond, the current circulating is the short-circuit current of the array. Therefore, the DC bus bar needs to be able to support such current.

Part of the model developed allows to calculate the maximum DC/AC power ratio. In order to calculate this, the following parameters are needed:

- Maximum inverter power, $P_{inv,max}$.
- Maximum short-circuit current of inverter, $I_{inv,max,sc}$.
- MPP voltage (using STC conditions), V_{mpp}.
- Number of panels per string, N_s.

Knowing the maximum power of the inverter, the MPP voltage and the number of panels per string, for a given DC/AC ratio, the array MPP current can be calculated, using the following equation:

$$I_{mpp,array} = \frac{P_{inv,max} \cdot DC/AC}{V_{mpp} \cdot N_s} \qquad (14)$$

Then the number of strings needed for this DC/AC power ratio is calculated by dividing the array MPP current by the MPP current of one panel (at STC conditions).

$$N_p = \frac{I_{mpp,array}}{I_{mpp,panel}} \qquad (15)$$

This follows with calculating the array short-circuit current, by multiplying the short-circuit current of one panel (at STC conditions) by the number of strings:

$$I_{sc,array} = N_p \cdot I_{sc,panel} \qquad (16)$$

Finally, the short-circuit current of the array calculated is compared to the maximum short-circuit current that the inverter can support at the DC side. If it can be supported, then a greater DC/AC power ratio can be installed. An iteration of this procedure is carried out in order to determine the maximum DC/AC power ratio for the characteristics of the inverter and panel used. See the flowchart below for illustration of this iteration.

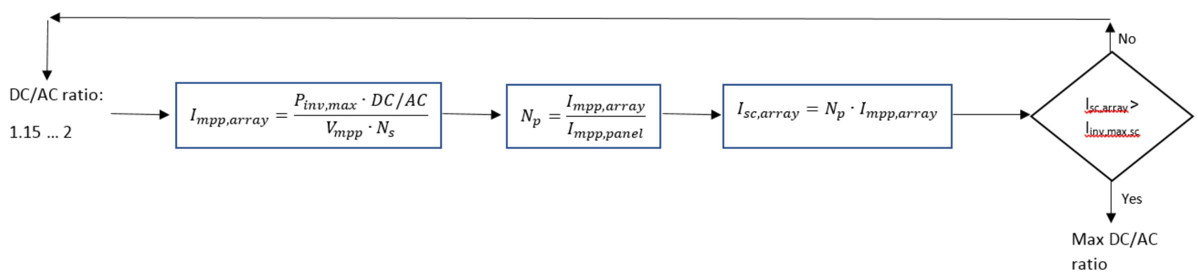


Figure 35: Flowchart to determine the maximum DC/AC power ratio for a given panel characteristics and array configuration.

4.3.3. Inverter power derating

This is the variation of the inverter capacity with respect to the temperature and array voltage.

In the early hours of a very cold day where there are high levels of irradiance, the DC voltage across the DC side of the inverter terminals can exceed the maximum DC voltage that the inverter can sustain to deliver full power. Therefore, the inverter undergoes a power derating in order to withstand these high voltages.

A graph has been constructed, using values generated in the Research and Development Laboratory at Power Electronics for the model FS2800CH15. The aim of this graph is to show how maximum power delivered by the inverter varies in terms of DC voltage, and it is a factor included in the optimization model constructed, as part of this thesis.

The graph below shows that at an ambient temperature of 50 ºC, to deliver full power the DC voltage has to be at most 1315 V, whilst at an ambient temperature of 25 ºC, to deliver full power (120 % rated power) the DC voltage has to be at most 1250 V. There is a power derating as a result. As DC voltage increases, the peak current that can occur in the inverter increases, and so approaches closer to the electrical limit that the hardware can support. If it is operating close to the electrical limit, there needs to be a limit on the current that can be drawn (power derating). In the case of 25ºC, since more current can be drawn in normal operation, the peak current will be higher for a certain DC voltage. Therefore, power derating starts at a lower voltage compared to 50 ºC. This data is available for any temperature between 25ºC and 50ºC, which will be incorporated into the model (*More detail on the model in Chapter 3*), in order to accurately determine how much power can be drawn into the inverter and how much is clipped.

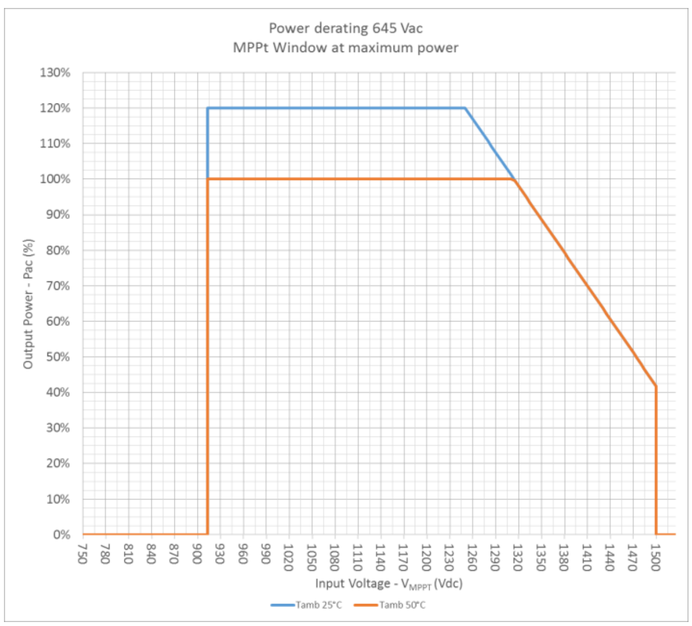


Figure 36: Power derating due to DC voltage

Also Figure 36 below shows how power is derated with respect to ambient temperature.

The maximum power that the inverter can deliver is 3360 kVA, at an ambient temperature of 25 ºC. At this ambient temperature, the refrigeration system of the inverter has sufficient power to maintain the IGBTs below its limiting temperature.

When the ambient temperature increases above 33 ºC, the refrigeration system cannot combat all thermal loads, and therefore cannot maintain the IGBT to a temperature below its limit (120 ºC). Therefore, by applying a power derating the current passing though the IGBT is reduced and thus the heat generated is less, such that at that ambient temperature the temperature of the IGBT remains below its limit. If this derating is not applied at this ambient temperature, then the IGBT runs the risk of having a temperature above its limit, and as a result being damaged.

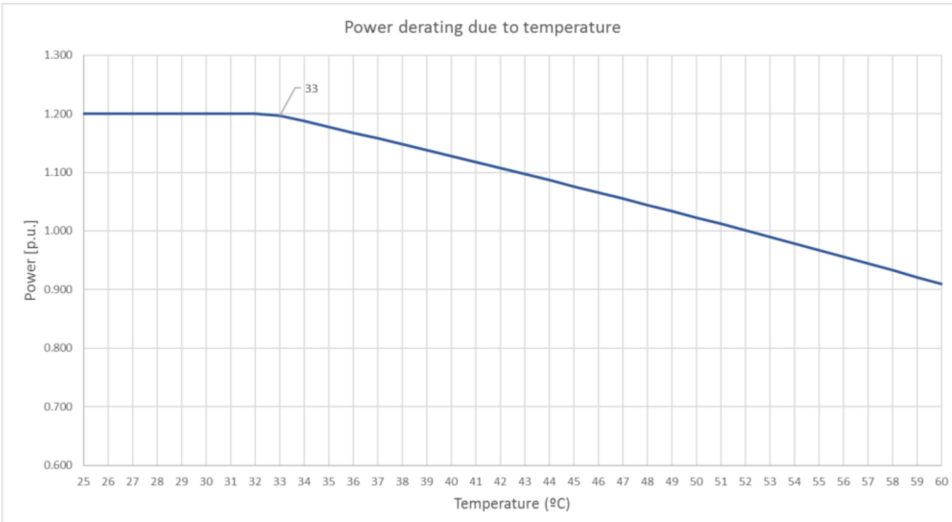


Figure 37: Power derating due to temperature.

4.3.3. Panel degradation

Another important factor to consider is the panel degradation. Over time, the panel reduces in performance. A typical annual degradation rate is 0.5% per year. Below shows how the panel capacity varies over the lifetime of the plant, using this example degradation rate.

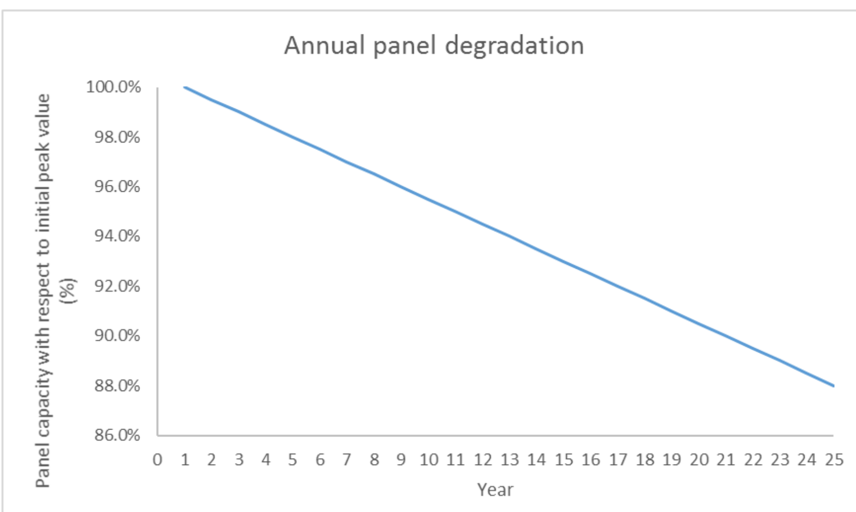


Figure 38: Annual panel capacity reduction for a degradation rate of 0.5%.

In the model, each hourly value of production from the PV array will reduce, depending on the year. This is compared with the inverter capacity in order to determine new hourly excesses. To conclude, the excesses produced (assuming the same irradiance and temperature pattern) will decrease. This is taken into account in order to determine the lifetime earnings from storing “clipping” excesses (*More on case study 1*).

4.4. Conclusion

This chapter has explored and detailed the system configuration proposed, as well as the components to be integrated. The DC-coupled storage system proposes various advantages:

- Global efficiency of this storage system, since it removes the need to pass through a transformer, as in the case of an AC coupled storage solution.
- Can store excesses from the PV array directly, when coupled with an over-sized PV array.

Furthermore, it gives an explanation of how to over-size considerably, and the limitations it has in terms of the current limits. Over-sizing a PV array is something that has already been established in the sector. However, the ratios are very low, and are only integrated in order to widen the power output curve to produce more during the early and late hours of the day. However, this system configuration proposes over-sizing to 40-60% more compared to the inverter capacity, so that energy storage can become more viable. This is only possible with this DC coupled solution.

The next thing is to analyse how the model (Chapter 3) and the proposed system configuration (Chapter 4) will be able to incorporate the different features in order to increase battery integration viability and increase the profitability of a photovoltaic power plant. The proposed configuration and components explained in this chapter will be compared to other existing configurations (such as the traditional AC coupled system). Each of the consequent chapters will be treated case cases of study. Each case of study will consist of incorporating a further functionality in the developed model, describing the methodology of this new incorporation, and showing results to prove its technical and economic viability.

Chapter 5 starts with studying in depth the increase in the PV array size significantly and storing these clipped excesses.

5. CASE OF STUDY 1: CLIPPING POWER EXCESSES

5.1. Introduction

The proposal is to increase daily active power injection using the same capacity, by having an oversized PV array and a DC/DC converter connected in parallel to the inverter, on the DC side.

These excesses, as already discussed, corresponds to a new source of earnings, from having a high DC/AC power ratio. Recent PV constructions has shown great interest in a slight oversizing, in order to amplify production during lower production hours of the day, but as a result excesses during peak hour production are produced and, as a result of the inverter capacity limitation, are lost. (*see Chapter 4.3.1. on DC/AC power ratio*).

The aim now is to store these excesses in an ESS (Energy Storage System), to then discharge them and export them to the grid when the inverter is less saturated and selling rates are more favourable.

In Valencia, for example, the daily peak period falls between 20:00h and 23:00h (*More on chapter on Chapter 3.1. on pricing mechanisms, which outlines analysis done in the thesis on the Spanish electricity market*). This corresponds to a period in which the inverter is less saturated since solar production during these hours is considerably less than during the solar peak hours of the day. This provides the initial medium for this system configuration to be economically viable. However, due to the current battery prices, the next necessary step is to optimize such a system, in order to accrue significant benefits for amortization of these battery costs. This is where the developed model comes into play.

The diagram below shows an example of such excesses.

- The orange line represents the maximum inverter capacity (here it is represented to be constant, but in actual fact it will vary with ambient temperature and DC voltage from the array – *more on this in Chapter 2.3.4. on power derating*).
- The grey curve represents the power output on a day with clear skies, when the array is ordinarily sized ($P_{dc} = P_{ac,inv}$). It can be seen that at peak time (solar midday of the location) the peak PV power is at the inverter maximum capacity.
- The blue curve represents the power output of the over-sized array. It can be seen that for all hours of the day, the power output is higher than with no over-sizing. As a result of this, it has attracted a lot of interest from project developers in the last 24 months. However, during the peak hours of the day, the power output exceeds the inverter capacity, and so there are excesses produced. Despite this, the daily energy production of the over-sized array is greater than with no over-sizing.

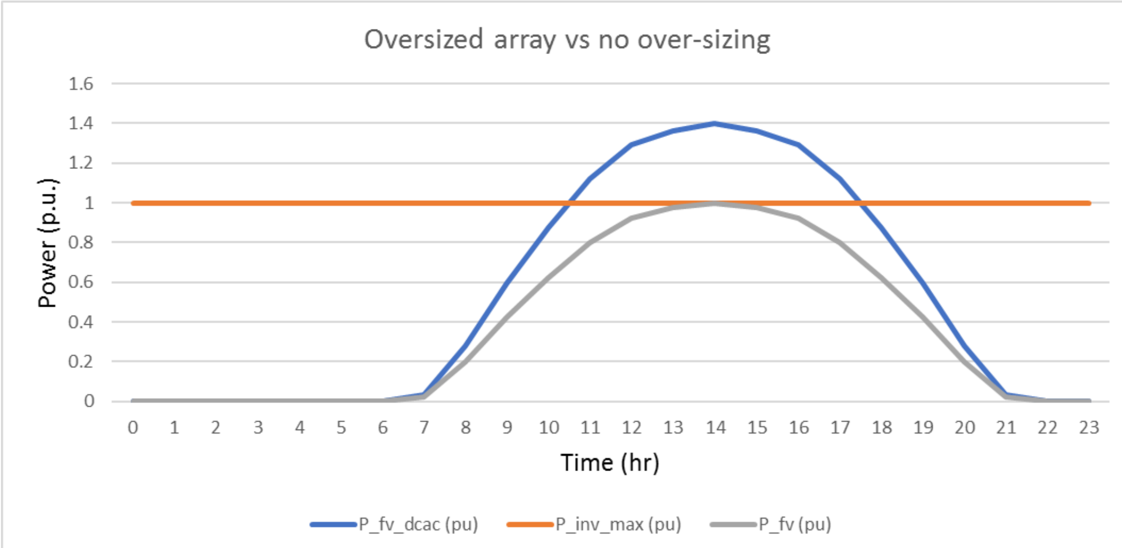


Figure 39: Oversized array vs array with no over-sizing.

5.2. Methodology

5.2.1. Photovoltaic simulation (PVSyst)

A detailed study has been performed with the aim of calculating the economic viability of this system, taking into account various different factors.

PVSyst, as an initial point of reference, has been used to simulate yearly production in the location of Valencia, based on its historic data of temperature and irradiance, as well the panel and inverter models and plant characteristics chosen. At this stage, there is still no over-sizing of the photovoltaic array. In PVSyst no oversizing will be simulated, since the model will then calculate this for the range of DC/AC power values investigated.

The parameters simulated in PVSyst and imported into the model are the following:

- Ambient temperature (*T*)
- Array voltage (*Umpp*)
- Array current (*Impp*)
- Array power (*Pmpp*)
- AC power (*Pinvout*): power at the output of the inverter, considering the efficiency of the inverter in that hour (dependent on load and DC voltage)
- Grid power (*Pgrid*): power injected in the Point of Interconnection, after deducting transformer losses and cabling losses.

From there, the simulated data from PVSyst is imported into the model and processed in order to calculate the excesses for the different DC-AC ratios (over-sizing ratios).

Different DC-AC ratios, between 1.15 and 1.45, in 0.05 intervals have been investigated. A minimum DC/AC power ratio of 1.15 has been used, since it was estimated that below this and the excesses are too small to amortize all battery costs in the lifetime of the plant, even with the optimizations proposed. With the aim to constrict to a range of values and thus have a reasonable collection of data, this minimum value was chosen. A higher value than the maximum DC-AC ratio of 1.45 could have been chosen since from the current limit analysis made many inverters (e.g. Freesun HEC V1500 – FS2800CH15) could support up to a DC/AC power ratio of 1.65 (*See Chapter 2.3.2 for current limit analysis*). However, with the aim of constraining to a reasonable set of values, it was chosen to use from a DC/AC power ratio of 1.15 to 1.45.

5.2.2. Modelling Excesses

The calculation of excesses is based on the following:

1. <u>Original power injected to the grid</u>
   The original power will be based on a DC-AC power ratio of 1 (no over-sizing in PVSyst simulation, as explained earlier). This means that all peak power from the array in principle will be able to be delivered into the grid (excluding total plant losses in between).

2. <u>DC/AC power ratio</u>
   The greater the oversizing ratio, the more excesses there will be, taking into account the original production as well as the inverter efficiency at that particular hour.
   The methodology involves multiplying the original MPP production per hour by each DC/AC ratio, in order to calculate the new production per hour with its corresponding over-sizing and inverter efficiency in each hour. This follows equation (7).

3. <u>Inverter efficiency calculated in a particular hour.</u>
   This value depends on the percentage of output power delivered compared to the nominal power of the inverter.

   Figure 38 below show the measured values for efficiency of the Freesun HEC FS2800CH15 inverter, from Power Electronics, which is the model used in our study. Figure 38 also shows the calculated EU efficiency values for the different DC voltages tested.

   It demonstrates a typical inverter efficiency curve. Since efficiency depends on inverter load, and inverter loads vary throughout the day, there are normalized efficiencies to calculate a single value of efficiency for an inverter model. Such normalized efficiencies are the EU efficiency and the CEC efficiency (USA). The formula in either case is similar, however the frequency given to each partial load is different, since it is based on the solar resource measured in the reference location (CEC – California, EU – Average from various European countries).

   In the case of Valencia, the relevant normalized efficiency is the EU efficiency.

   The EU efficiency value is calculated using the following equation:

$$\varepsilon_{EU} = 0.03\varepsilon_{5\%} + 0.06\varepsilon_{10\%} + 0.13\varepsilon_{20\%} + 0.1\varepsilon_{30\%} + 0.48\varepsilon_{50\%} + 0.2\varepsilon_{100\%} \qquad (17)$$

As part of an extension to the EU efficiency definition (as stated in the European standard EN 50530:2010), the EU efficiency calculation of an inverter weighs different load values at different DC voltage values: at minimum input voltage, rated voltage and 90% of maximum input voltage. The higher the DC voltage (for a fixed AC voltage), the lower the efficiency. This is due to the increased switching losses incurred as a result of the increased modulation performed by the IGBTs. AC voltage also has some effect on efficiency. If the AC voltage increases, the inverter efficiency also increases. This is because the auxiliary loads (control system, ventilation system, etc) have a fixed consumption, and when the AC voltage increases there is more power output. Therefore, the significance of this auxiliary load compared to the total power output is less, and the efficiency of the inverter is increased (considering the same switching losses involved).

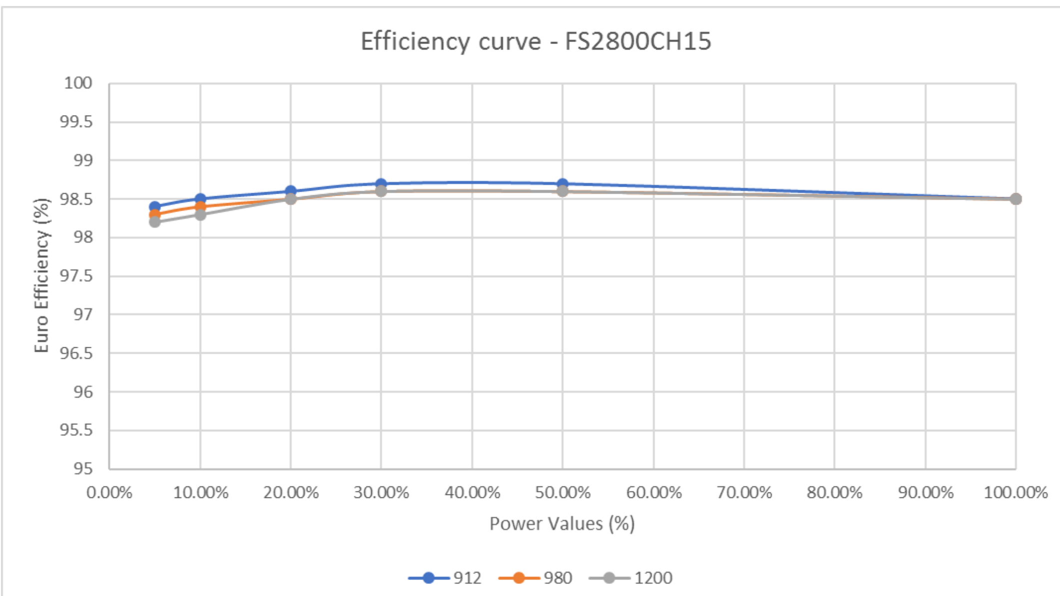


Figure 40: Efficiency curve of inverter model FS2800CH15.

4. Inverter apparent power limit.

The inverter will have a nominal capacity to which it is designed for. However, it is not always the same capacity it has available at a particular moment. This inverter capacity will depend on two main factors:

- Ambient temperature. (*More on Chapter 2.3.4 on Inverter power derating*).
- Array voltage. (*More on Chapter 2.3.4 on Inverter power derating*).
- Altitude.

Below shows a sample day from the simulation, showing the solar production along with the clipping excesses stored (charging of battery between 11:00 and 14:00), and then discharged at a later time when the inverter is less saturated (between 19:00 and 22:00).

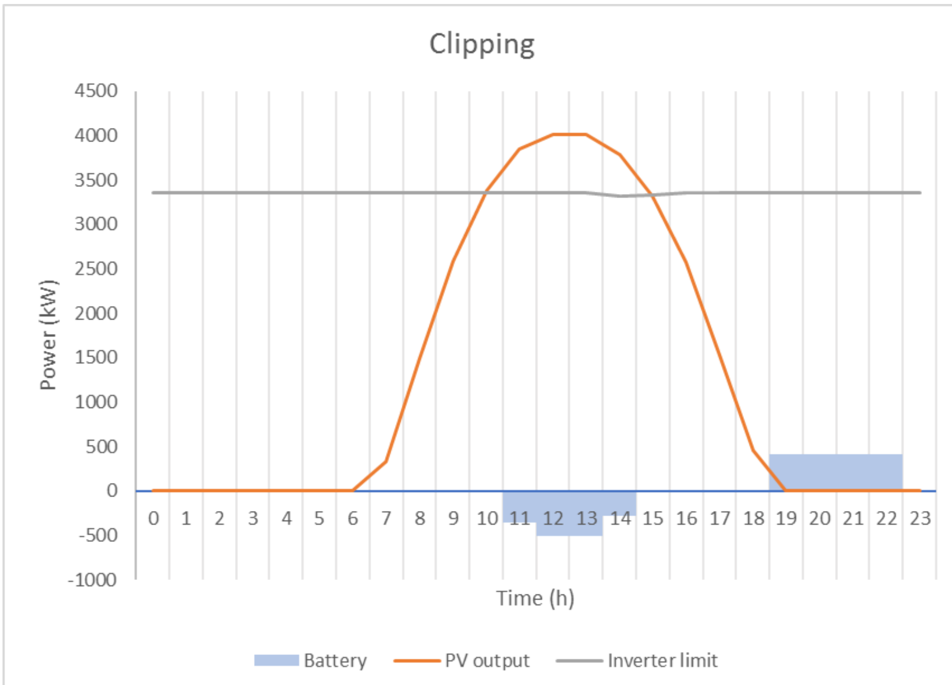


Figure 41: Solar production and clipping excesses for a sample day.

5.2.3. Economical mechanisms

The pricing mechanism used will have a profound effect on the economical profitability earned. It is important to consider and compare various different pricing mechanisms (*More on Chapter 3.1 on pricing mechanisms*), which are:

- Direct spot market access
- Fixed PPA pricing

5.3. Results

5.3.1. Direct market access

Selling PV excesses through the Spanish wholesale market in Spain with the proposed system using the optimization methodology developed is not economically viable. For the current battery prices, an excessive premium (e.g. government subsidy) would be needed on top of the market selling price in order to amortize battery costs in the lifetime of the plant and make a reasonable profit.

Fig 4.5. below shows when applying the Max NPV battery sizing criteria, the results are negative. The results displayed are for a premium of 100€/MWh and for the most favourable DC/AC power ratio considered in this thesis (1.45). The results are given for different years of investment, where battery costs are projected to decrease by 9% per year.

Furthermore, the calculated 1.152 multiplication factor is applied, as a projection towards the average increase in electricity prices in Spain during the lifetime of the plant (*See Chapter 3.1.1*). Even with this multiplication factor the results are negative.

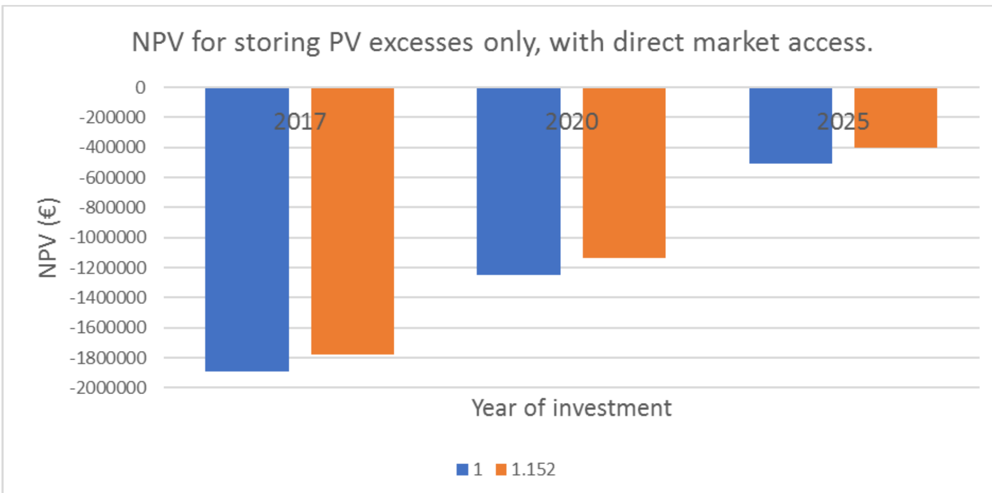


Figure 42: Net Present Value for storing PV excesses only, for different years of investment.

Apart from the negative results, due to the high volatility of the electricity market, accessing the market directly with no premium may present days with little earnings than what was expected. More work is needed to improve such pricing mechanism for such power plants. In chapter 5, power-shifting will be incorporated to analyze if this pricing mechanism can be competitive for such plants.

5.3.2. Fixed PPA

5.3.2.1. Max Excesses criteria

The next important factor which will determine the economic viability of the system is the sizing of the ESS (Energy Storage System). Initially the sizing is determined by how much excesses are produced (which depends on the points described above, most notably the DC/AC power ratio). However, after thorough analysis, covering all the excesses is not necessarily the most optimal, economically. Therefore, several different criteria were proposed, in order to find the optimum battery size for a set of conditions (Location, Pac, DC/AC power ratio, pricing mechanism, battery cost per kWh, etc.). (*More on Chapter 3.2 on battery model methodology*)

5.3.2.2. Max NPV criteria

The PPA price used is of 98 €/MWh, which is a reasonable price offered in the latest capacity auctions for solar systems, in Spain. Using the macro created in the model to calculate NPV values for the battery capacity of 50 to 5000 kWh in 50 kWh intervals, the results are obtained below, for 1 inverter system.

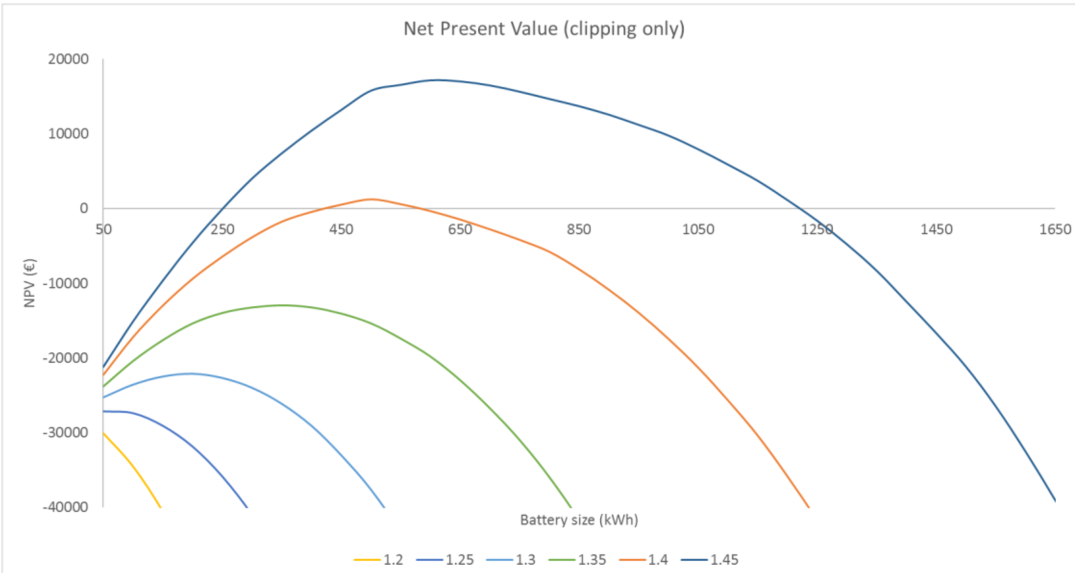


Figure 43: Net Present Value per inverter vs DC/AC power ratio, for different battery sizes.

After generating the optimal battery size for the highest NPV values generated, the NPV values for these lower DC/AC power ratios are negative. Therefore, the results show that installing this battery system for storing solar excesses alone is not economically viable, unless DC/AC ratios are greater than 1.4. Figure 41 shows these results.

For a DC/AC power ratio of 1.4, the NPV after 20 years lifetime is 1199 € per inverter. Therefore, for a 100 MW plant (30 inverters), this would equate to an NPV of 35970 €. For such a large-scale power plant, at this PPA price, these benefits are not that great. Furthermore, the payback time for a DC/AC power ratio of 1.4 is of 19 years. This, for many investors, is too long for a return in investment. Therefore, further services would need to be provided with this DC-coupled battery system in order to amortize further these costs and provide greater benefits.

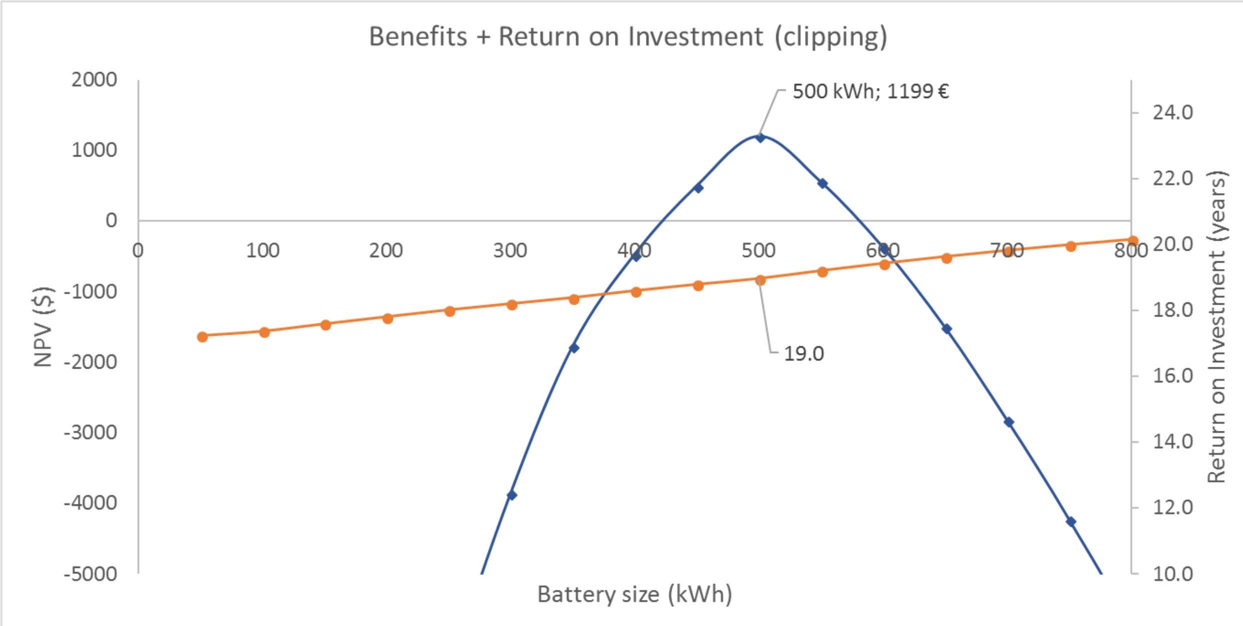


Figure 44: NPV and ROI of optimal battery size for storing excesses at different DC/AC ratios.

Further to this analysis, Fig 4.10 below shows the percentage of excesses stored, with respect to the battery size used. It is observed that for each DC/AC power ratio, the battery size at which 100% of the excesses are stored is significantly higher than the optimal battery size. In principle, this is expected since sizing the battery to cover higher excesses that occur for a limited number of days does not make financial sense. However, having too low percentage of excesses stored raises the question of whether sizing a battery based on maximum NPV is the most effective solution (which is the case for lower DC/AC power ratios between 1.15 and 1.35. For clipping alone, where these batteries are not used for anything else, this is the best criteria to use since it guarantees the highest profitability, even though this is not high enough. The next question is if in 2017, proposing such a system for just storing excesses (albeit a relatively small percentage) is economically viable. Do the benefits outweigh the investment significantly? For high DC/AC ratios yes, but more work is needed to make them more profitable.

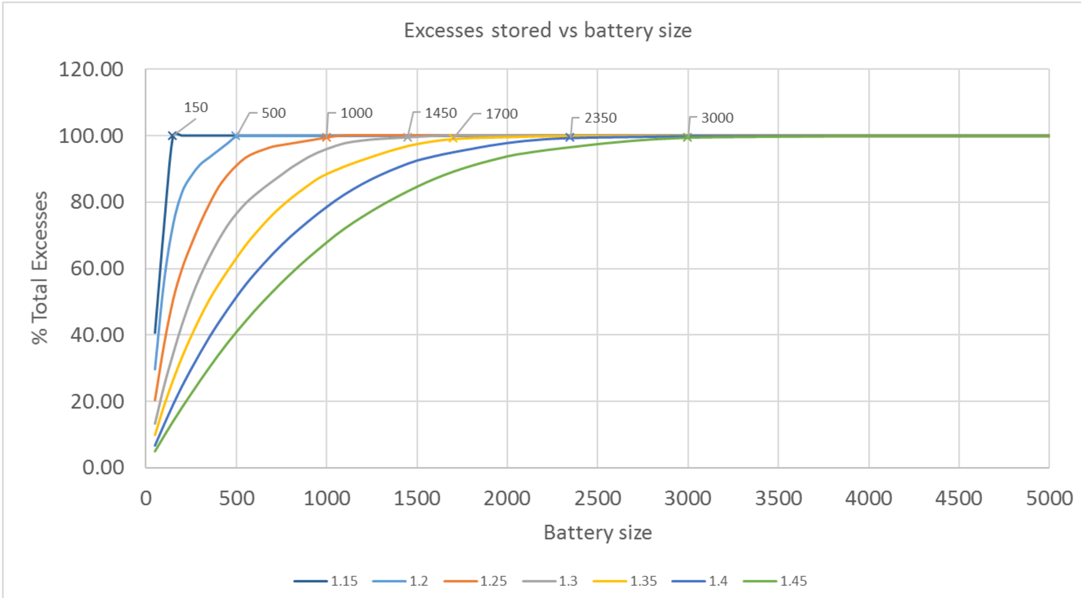


Figure 45: % of excesses stored for different DC/AC power ratios, with respect to the battery size used.

The only two DC/AC ratios with a positive Net Present Value over 20 years are 1.4 and 1.45. However, it can be seen that for the optimal battery size determined (with a DC/DC converter of 500 kW per inverter), the percentage of excesses stored are 12.9 % and 22.2 %, respectively. Figure 44 and 45 below show the monthly excesses in the first year (blue bars are the total excesses available for that DC/AC ratio, and light blue bar are the actual excesses captured, due to the battery size and DC/DC converter maximum power used. The battery size will restrict how much excessed can be stored in a day, which means during a day with high solar production, not all excesses will be captured. The DC/DC converter will restrict how much excess power from the array can be stored in the battery, since this component is the maximum charging power bottle-neck in the system. Since the costs of this component is significantly smaller to the battery, the sizing of this is done so as to not create a bottle-neck in most hours of the year. Note also, the excesses shown take into account already the efficiency of the system, including the round-trip efficiency of the energy storage system (More on Chapter 3 on its calculation).

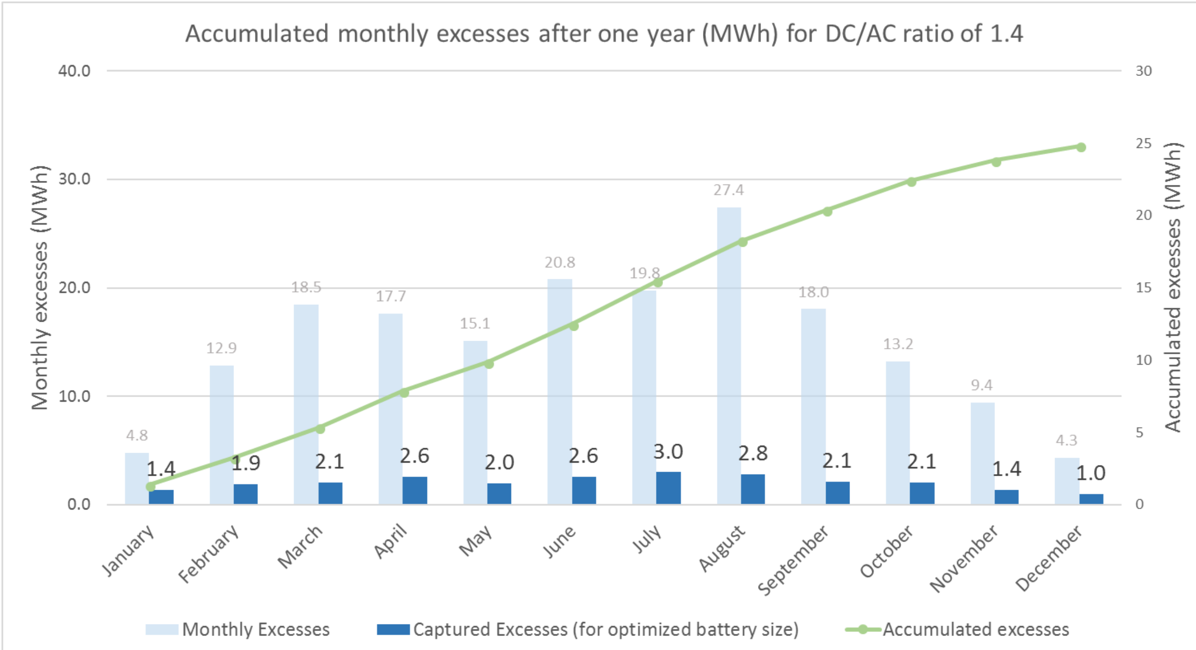


Figure 46: Total excesses and captured excesses stored (for the optimal battery size determined) for a DC/AC power ratio of 1.4.

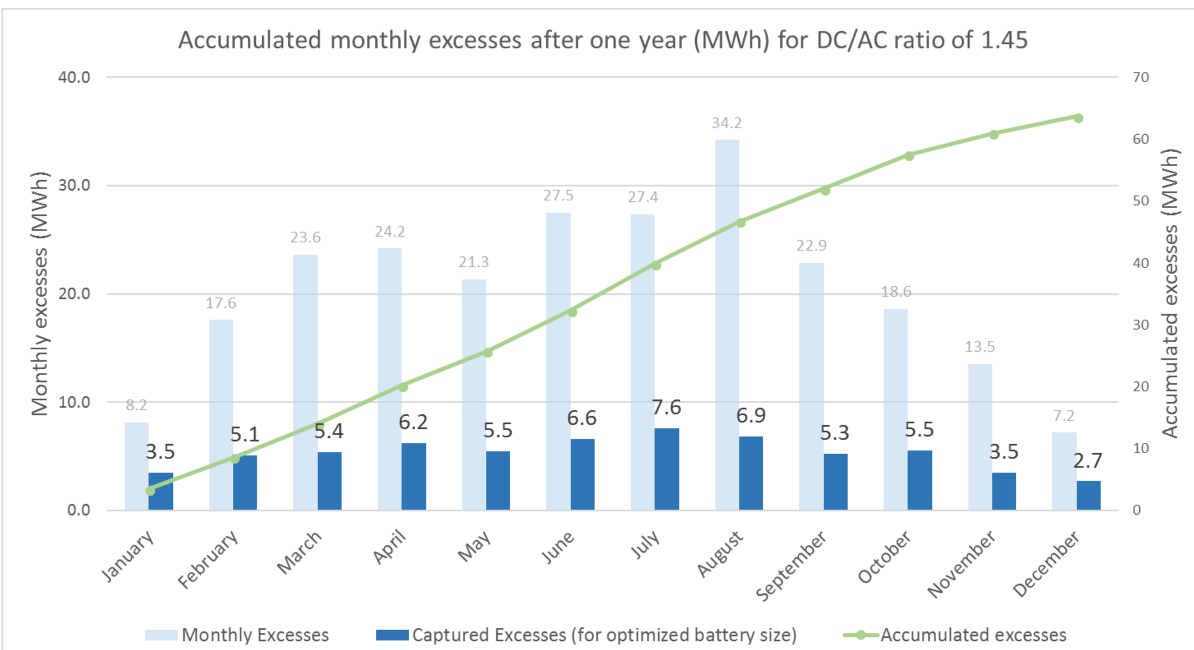


Figure 47: Total excesses and captured excesses stored (for the optimal battery size determined) for a DC/AC power ratio of 1.45.

Further to this, we analyse for the same conditions of the plant, how the Net Present Value would be affected if the plant were commissioned in future years, taking into account the battery price evolution in Chapter 3, using equation (3).

The results show that in 2020, these solar plants can be sized from 1.35 onwards, making possible to install these systems with smaller investments. In 2025, this minimum DC/AC ratio drops to 1.3. Moreover, for a DC/AC ratio of 1.4, the NPV in 2025 is 36264 € per inverter. This corresponds to a (36264 – 1785) x 100 / 1785 = 1932 % increase in benefits, compared to 2017. Therefore, even though with clipping alone, these battery systems are not that profitable right now, for future investments with the reliable projections that have been carried out, the results are significantly more positive. Figure 47 shows the linear increase in profitability as years pass by, and as a result the economically minimum DC/AC power ratio drops more. This relationship though assumes that there are no setbacks or accelerated advancements in battery technologies during these years.

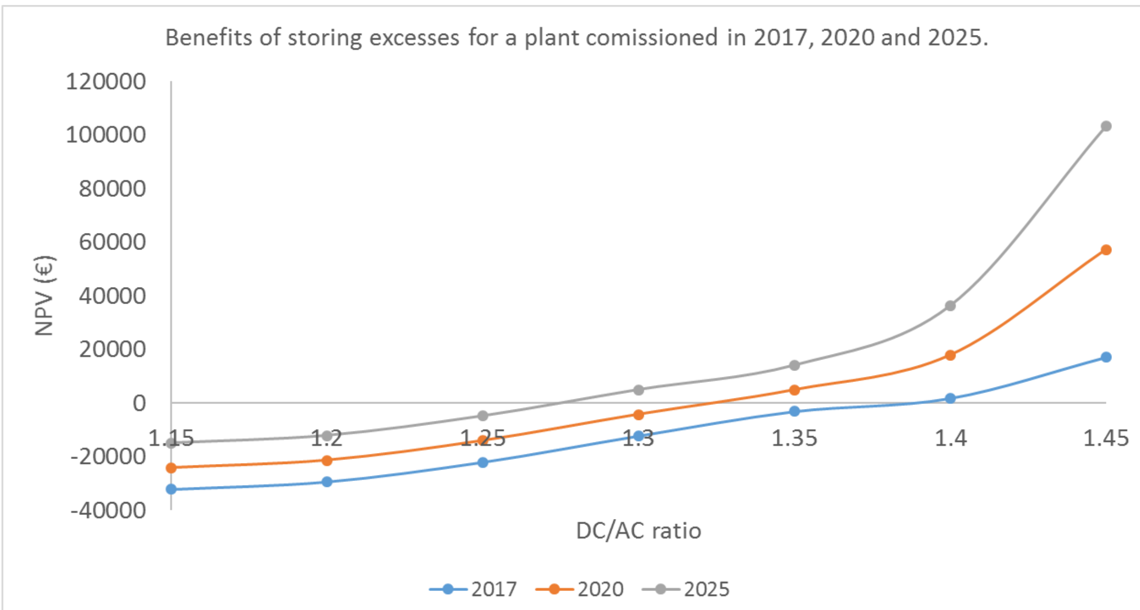


Figure 48: NPV vs DC/AC power ratio, for 2017, 2020 and 2025 investments.

Finally, it should be considered that PPA prices can vary from the 98€/MWh proposed here for the study. Figure 48 below shows the yearly earnings that would consequently be produced by the change in PPA price, applying the same optimal battery size calculated previously. The results are for +/-10% and +/- 20% PPA price variation. The PPA price variation is linear, since for an increase in PPA price, the new earnings will be the same excesses (for the same battery size) multiplied by the new price.

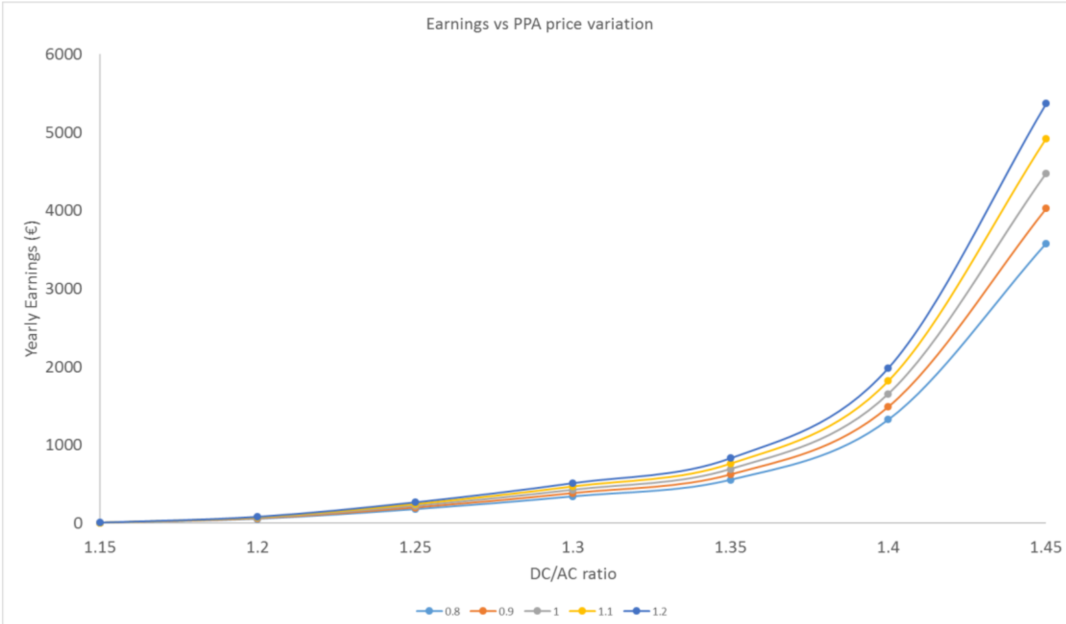


Figure 49: Yearly earnings per inverter vs DC/AC power ratio, for different PPA prices.

5.3.2.2. 20-year criteria

After showing that storing PV excesses can be competitive, a big factor that is left to take into account is the lifetime of the battery. As explained earlier (see Chapter 3.2 on Battery Modelling), a lithium-ion battery system does not tend to last more than 10 years in this typical use (Note: Lithium-ion batteries is the chosen battery technology to be analyzed for this system since it nevertheless presents considerable benefits which make it more competitive right now for utility scale systems. (See Chapter 3.2 on Battery Modelling).

Applying the battery model, the lifetime calculated for the optimal battery size of 500 kWh (for a DC/AC power ratio of 1.4), is over 20 years. Therefore, no additional replacement costs will be needed, since in principle with this model, the use of the battery is relatively low such that it should last throughout the lifetime of the plant. The reason for this high lifetime is because its use is limited to less than 1 cycle per day, the average number of cycles per day being 0.46.

Therefore, the NPV values calculated above is final for only providing storage for the PV excesses produced in an oversized PV array. However, it raises the question whether with clipping storage alone the battery system installed is not fully made use of.

5.2. Conclusion

From the results simulated in Valencia, installing batteries for the provision of storing PV excesses alone is only viable for DC/AC power ratios higher than 1.4.

Nevertheless, this can vary depending on:

1. PPA price agreed. This has a linear effect on the earnings produced, since for example, a greater PPA price means applying a multiplication factor to the original earnings (since the excesses produced are still the same).
   In Valencia, for DC/AC power ratio of 1.4, the minimum PPA price that can be used to invest in these battery systems for storing excesses of this over-sized array is 84 €/MWh.

2. Year of investment (since it is projected that battery prices will decrease 9% per year). By 2025 results show that storing PV excesses alone can be more economically profitable (NPV approximately 2000% more) by 2025.

3. Location (the greater the annual solar output, the greater the excesses produced, for a certain DC/AC power ratio size, thus the greater the earnings by installing a certain battery size). Locations, close to the equator, with a consistently high solar output would benefit more from this type of installation. For other locations, other technical and financial strategies are needed to improve economic viability (which will be discussed later).

Therefore, it can be concluded that integrating energy storage systems in PV plants for storing PV excesses is conditioned by the PPA price, as well as the location, and where profitability will increase as time of investment increases.

Furthermore, larger battery sizes for providing this service is completely unviable currently. However, these battery sizes should still be considered, since the added advantage of increasing capacity is that less of the total excesses produced are lost. In order to consider greater battery sizes at this time (with current battery system prices), the integration of additional services needs to be implemented in order to further amortize these capital costs. With the integration of power-shifting (more detail next chapter), it can be shown that the greater the capacity of storage the more profitable the installation becomes.

6. CASE OF STUDY 2: CLIPPING POWER EXCESSES + POWER SHIFTING

6.1. Introduction

As seen from the previous chapter, providing storage for charging PV excesses in over-sized arrays is only economically viable if the following conditions are met, (which are non-mutually exclusive nonetheless):

- A future reduction in battery prices, as shown from projected results in 2020 and 2025.
- A minimum DC/AC ratio of 1.4 (2017), 1.35 (2020) and 1.3 (2025) to be used so that the excesses produced can amortize the respective cost of the batteries during the lifetime of the plant.

Therefore, this chapter introduces an additional use of this DC-coupled battery system, without hindering the storage of PV excesses. In order to amortize further the battery costs and provide additional services to the grid, what is proposed here is a daily power shifting service. To elaborate, here the whole battery (size conditioned by the optimum and the maximum payback time allowed) is charged during the low demand period (valley period), which is then consequently sold during high demand period (peak period), therefore accruing further daily profits.

Firstly, max NPV criteria will be applied again, to determine what effect this has now on the new optimal size, for the different DC/AC power ratios investigated.

Secondly, as this will obviously have an effect on battery degradation and thus lifetime, since the battery system´s use is greater than with just providing PV excess storage alone, battery replacement costs will be considered, thus contributing to an additional cost during the lifetime of the plant. In principle, on a daily basis this service would only be considered for particular battery size and DC/AC power ratio if the benefits accrued due to extra daily earnings outweigh the increase in battery replacement costs during the lifetime of the plant (*More detail in Chapter 3.2*).

Apart from potential benefits that it can bring to the project developer, there is an incentive for grid operators and regulators too. In terms of grid services, it provides a way to flatten daily demand curves, since:

1. By charging from the grid during valley period, demand during this period increases, thus allows base generators to avoid decreasing in power output or shutting down.
2. By discharging to the grid during peak period, demand during this period decreases, thus helping the grid to provide power to all loads in a more efficient and cost-effective form.

This has significant benefits to the grid operator, and thus to the consumers:

1. By charging during valley period, it helps avoid having to turn off or reduce power from base generators (which have high associated downtime costs). There are cases where in many installations, like nuclear power plants, they are linked with a reversible hydroelectric plant, in order to store energy not demanded during the night and avoiding having to shut down the generators (which have excessive start-up costs). Using batteries instead of reversible hydroelectric power plants represents less equivalent costs (less investment), less environmental impact, and does not depend on a hydraulic resource.

2. By discharging during peak period, the peak demand reduces. This means that it avoids having to turn on a more expensive and polluting generator. If we return to the determination of the market price in the wholesale market, these generators as a result will be left out of the captured offers. Thus, the clearance market price is less.

3. By flattening demand curves, it reduces the need to invest in generators to only be used in certain peak hours during the day, which creates a situation where the cost of these generators is difficult to amortize, but still necessary in order to ensure the security of supply during these hours. By disposing of batteries to discharging energy during these hours, less investment for new conventional generators is needed for connection to the electrical infrastructure. Furthermore, these peak conventional generators (e.g. combined cycle power plants) also represents a more volatile cost, since these generators would depend on natural gas, where prices can fluctuate. As shown in the energy market analysis carried out, demand is directly inter-linked with thermal generation. (*More on Chapter 3.1*).

4. Also, as a result of this reduction in peak demand, the current circulating through the grid is less, in accordance with $P = I^2R$. This means that if we manage to reduce the peak power by a half (current, $P = VI$, halves) the associated power ohmic losses will be 4 times less. This improves the efficiency of transmitting and distributing electricity through the grid. This has two important results:
    a. Grid operators need to spend less on new infrastructure since it needs to support less power flows.
    b. Currently consumers, as regulation stands, are who pay for these losses. If peak demand reduces, the coefficient of losses reduces significantly, thus it will have an economical retribution to consumers.

This is a service which currently is not provided in current Spanish regulation but is one in which could provide significant savings to all players in the energy sector (producers, grid operators, distributors, retailers, consumers, and government agencies).

6.2. Methodology

6.2.1. Description of methodology

6.2.1.1. Time-of-Use tariff

As already described previously, the Time-of-Use tariff proposed (*more detail in Chapter 3.1.2*) involves dividing the day into three periods of different fixed prices, which correspond to different amounts of demand that the grid operator has to meet. Just like already implemented in Spain at a consumer level, this tariff would incentivize plants with regulating capability (both conventional and battery systems) to provide more power in high demand periods and consume surplus power from the grid in low demand periods. This in essence is Power Shifting.

From Chapter 3.1, the following average prices were deduced. From Figure 49 below, the dashed red lines show the variation of the calculated hourly spot price during each of these periods.

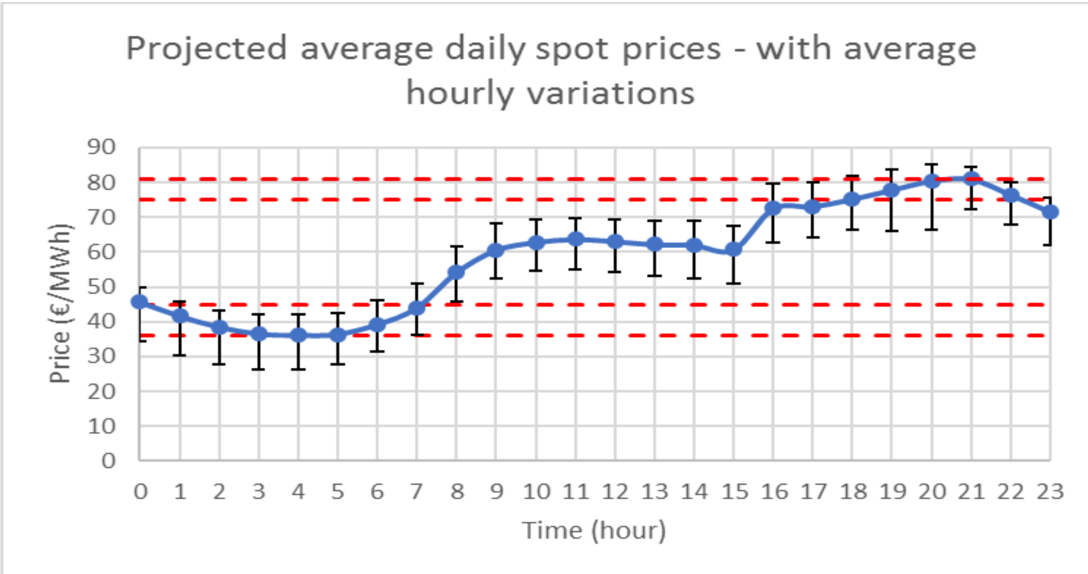


Figure 50: Projected average daily spot prices, with error bars representing the possible variation that could occur, based on average hourly variations from historic data.

From these average hourly prices, the three periods are defined as the following:

- Peak period: From 19:00 to 22:00.
- Shoulder period: From 08:00 to 18:00, and from 23:00 – 00:00.
- Valley period: From 01:00 – 07:00

The methodology to determine the period prices, is by first obtaining the mean value from the hourly values of price associated to one period. Secondly, we add/subtract 20€/MWh to incentivize generation/consumption during peak/valley period, respectively. (Note though, these prices may vary significantly, subject to country regulations). The results are the following:

- Peak period: 98.22 €/MWh
- Shoulder period: 67.78 €/MWh
- Valley period: 18.06 €/MWh.

Then, the optimization methodology is applied to determine the optimum battery size (using Max NPV criteria) for the range from 50 kWh to 5000 kWh, in 50 kWh intervals. The optimization methodology, as explained earlier (*see Chapter 3.1.2*), is governed by the following equation:

$$D = E \cdot \pi_s + C_{batt} \cdot (\pi_p - \pi_v) \qquad (18)$$

Below shows a sample day with the solar output production, as well as the battery charging/discharging cycles.

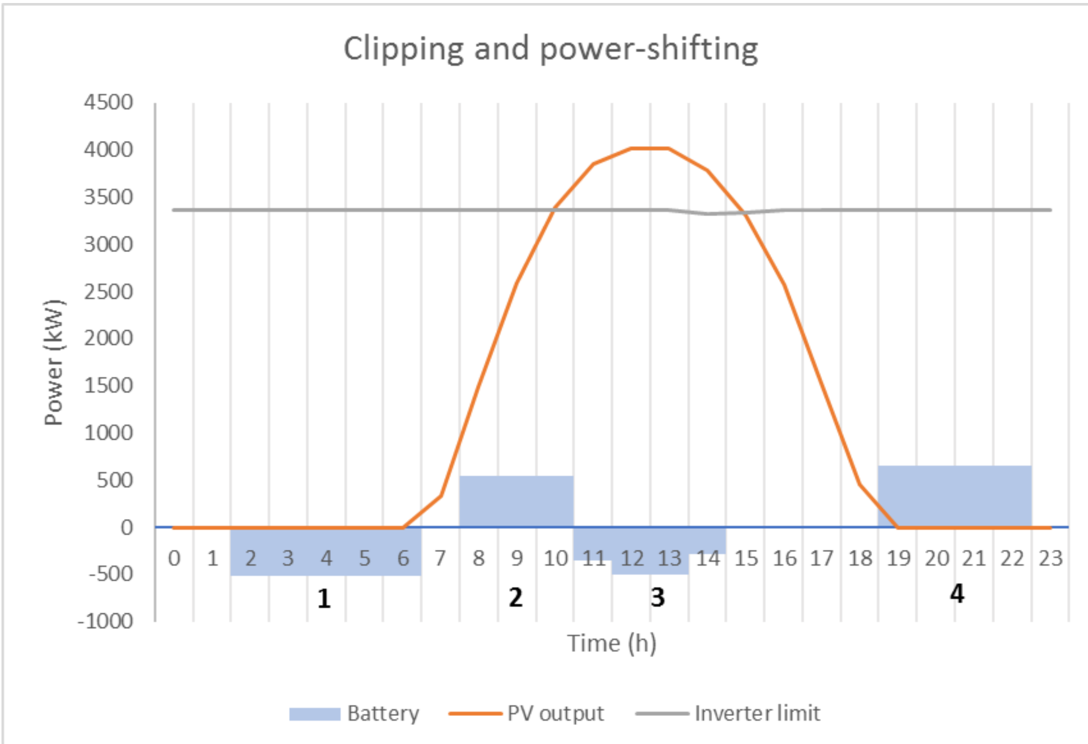


Figure 51: Charging/discharging cycle of DC-coupled battery, with the provision of PV excesses and Power-shifting.

A breakdown of each period is described below:

- Period 1 (Valley period): This period involves charging the whole battery during valley period, in order to have full capacity to sell later (inject later) in the peak period.

- Period 2 (Excess adjustment period): Having the battery fully charged presents the problem that when solar excesses are produced, none of this "free" energy can be stored. The solution the algorithm is that during this period, 3 hours before the solar peak time (8 am to 11 am), the battery is discharged to an amount equivalent to the excesses produced that day. That way, later on, when the excesses are produced in the solar peak time, the whole battery will be charged to 100% SoC again, and then later on in peak period all the capacity can be discharged, selling at the peak price rate. This is equivalent (as expressed in the formula above) as the excesses being sold at the shoulder price, whilst power shifting is applied in the battery on a daily basis. In order to optimize the plant according to this methodology, during the 3 hours prior to the solar peak period, very accurate forecasting tools need to be implemented, so that an accurate amount of capacity is discharged during shoulder period and leaves an amount of capacity available for the forecasted excesses on that day. There will however still be some errors (forecasted production cannot match exactly real production), but the idea is to minimize it as much as possible, otherwise the optimization could not provide as much earnings as simulated here in the model.

- Period 3 (Solar peak period): Here, all excesses produced during these hours are charged in the battery. (*See more details above*).

- Period 4 (Peak period): Here, with the battery approximately at 100% SoC, a complete discharge is produced during this period, in order to maximise returns in the power-shifting service.

6.2.2. Economical mechanisms

Having a fixed PPA does not allow for power-shifting incentives. Also, as already studied earlier, current market trends and historical prices indicate that unless significant premiums/subsidies are introduced, or there is 180° turn on market mechanisms, or there is significant decrease in battery prices, then accessing the market directly is not feasible right now.

By adding power-shifting services, a new optimized pricing mechanism is proposed: Time-of-use tariff. (*More on Chapter 3.1.2*).

Finally, using equation (13), the total daily earnings due to PV excesses and power-shifting service quantified, using the excesses produced each day and the battery capacity chosen, can be calculated. In the economic model, yearly earnings are then calculated, and quantified with total capital costs (inverters, batteries, BOS, etc) to obtain three economic indicators: NPV (Net Present Value), Payback time, and IRR (Internal Rate of Return).

6.3. Results

6.3.1. Pricing mechanisms

When considering power shifting, the two pricing mechanisms that could be favourable are Direct Market Access, and Time-of-use tariff. In this case, fixed PPA schemes present no incentive to provide power-shifting to the grid.

6.3.1.1. Direct Market Access

Figure 51 below shows the NPV calculated for different battery sizes, using 2017 battery costs. The three curves represent the NPV when selling in the wholesale market (*using spot price projections from Chapter 3.1.1*) with no premium, 10€/MWh premium, and 20€/MWh premium. For the current battery prices, even with power-shifting, installing batteries with this pricing mechanism would only be considered if a 20€/MWh premium is added. The maximum NPV is 52587 € / inverter system, for an optimal battery size of 750 kWh.

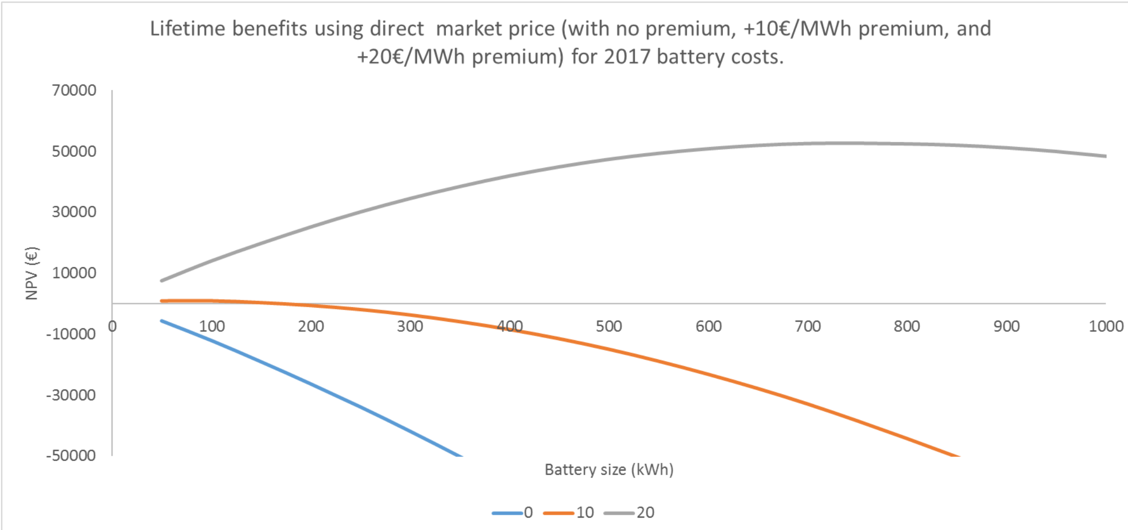


Figure 52: NPV 20 years using direct market access (Spanish wholesale market prices) from 2017

Figure 52 and Figure 53 below shows the same results but for 2020 and 2025 battery costs respectively. For 2020, a premium of 20€/MWh could be seen as excessive since the profits would now be very high as seen in Figure 52. Therefore, in 2020 a 10€/MWh premium is something that can be offered, in order to incentivize the installation of such plants. At this premium, maximum NPV is 58830 € at an optimal battery size of 900 kWh. Finally, in 2025, selling in the market directly is viable, with no financial aid. Results show a profit of 90755 €/inverter system, for an optimal battery size of 1250 kWh per inverter system.

As mentioned already, results are obtained for 1 inverter system of 3630 kVA maximum capacity, and DC/AC power ratio of 1.45. In other words, for a 5 MW solar farm.

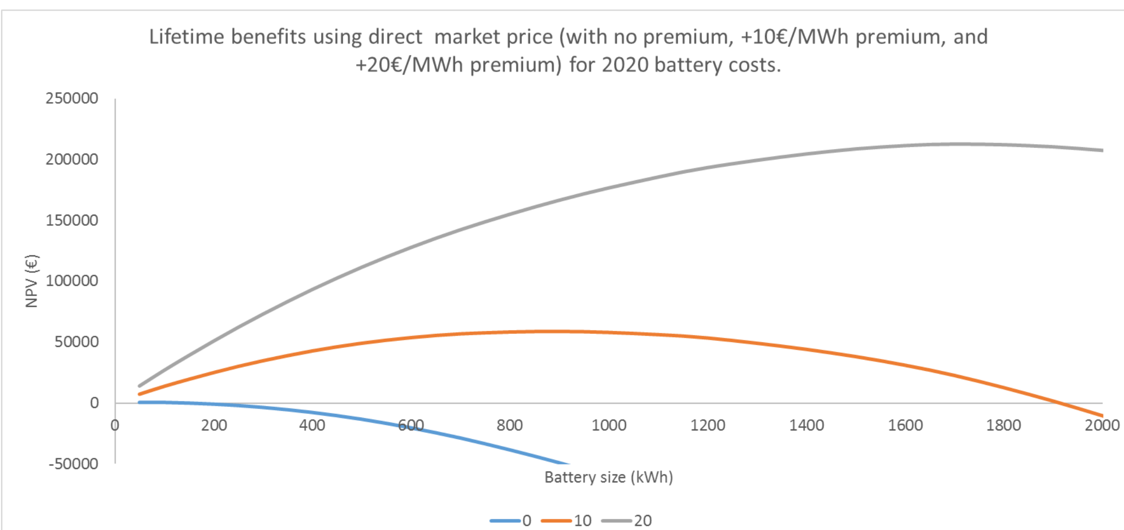


Figure 53: NPV 20 years using direct market access (Spanish wholesale market prices) from 2020

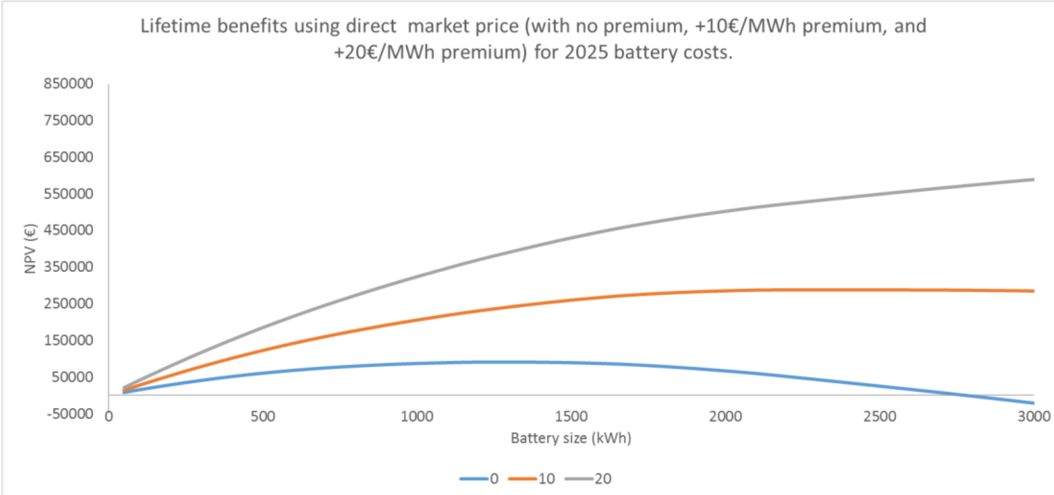


Figure 54: NPV 20 years using direct market access (Spanish wholesale market prices) from 2025

6.3.1.2. Time-of-use tariff

To compare the extra earnings from power-shifting, the battery size used for each DC/AC power ratio are the same ones as generated in the PV excess only methodology used in chapter 4. Below show the yearly earnings from PV excesses compared to the yearly earnings from PV excesses and power shifting. The blue curve shows the increase (in other words, the power shifting earnings) for each DC/AC power ratio. For the period prices used, at a DC/AC power ratio of 1.4, the earnings are 4069 €, which corresponds to:

$$\frac{(4069 - 1657)}{1657} \cdot 100 = 146\%\ increase$$

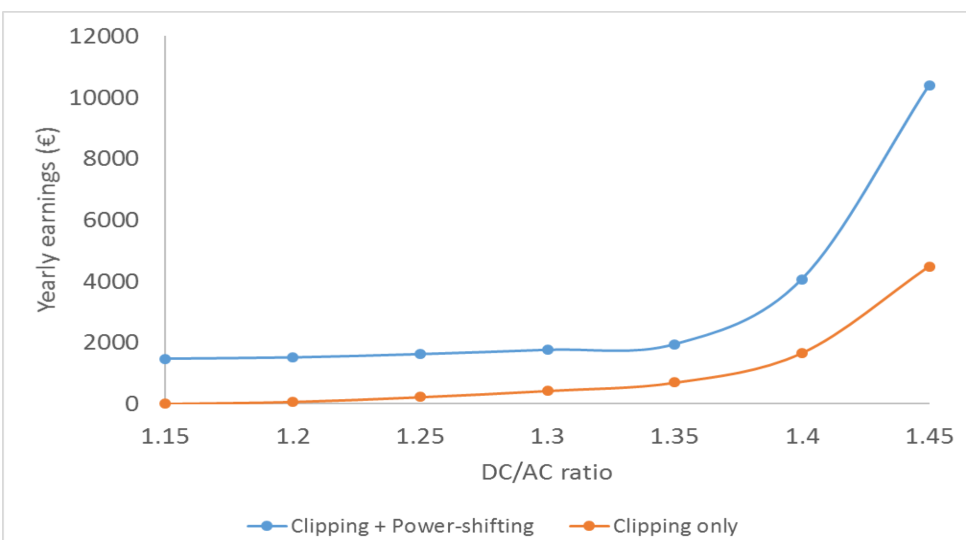


Figure 55: Comparison of yearly earnings with PV excesses + power-shifting vs PV excesses alone.

To conclude, power shifting provides a significant increase in earnings. Then, since the same optimal battery size as with PV excesses alone are maintained, the NPV over 20 years incurred are significantly higher. In fact, with power-shifting, in 2017, all the range of DC/AC power values investigated are economically viable for a plant. This is shown in the results below.

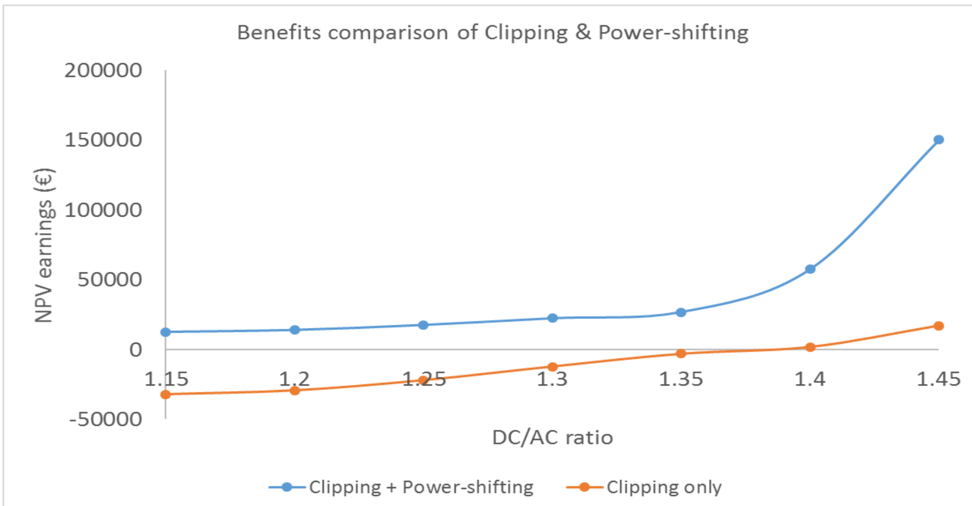


Figure 56: Comparison of NPV with PV excesses + power-shifting vs PV excesses alone.

By generating Net Present Values for different commissioning dates (2017, 2020, 2025), the results are shown below. It presents a significant increase (e.g. for DC/AC power ratio of 1.4, the NPV in 2025 is 92026 €/inverter. This corresponds to a (92026 – 57546) x 100 / 57546 = 60% increase in benefits generated.

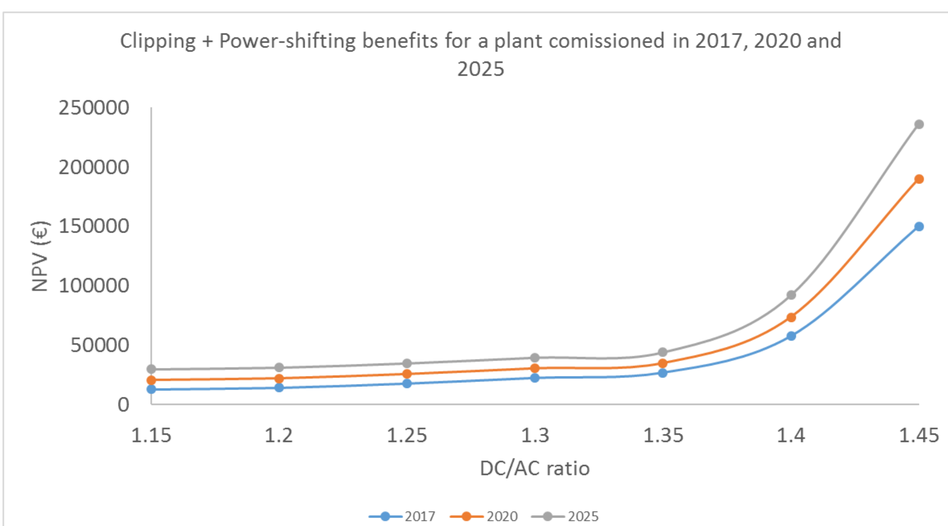


Figure 57: Comparison of NPV in 2017, 2020 and 2025.

The benefits comparison in the different commissioning years can also be visualized in the following way. It is shown clearly that for higher DC/AC power ratios, the benefits are significantly greater (which is why for these proposed systems, DC/AC ratios need to be higher than what has been used so far for solar-only applications). The restricting limit here is the initial capital investment and the short-circuit current limits of the inverter (*see Chapter 2.3.2*).

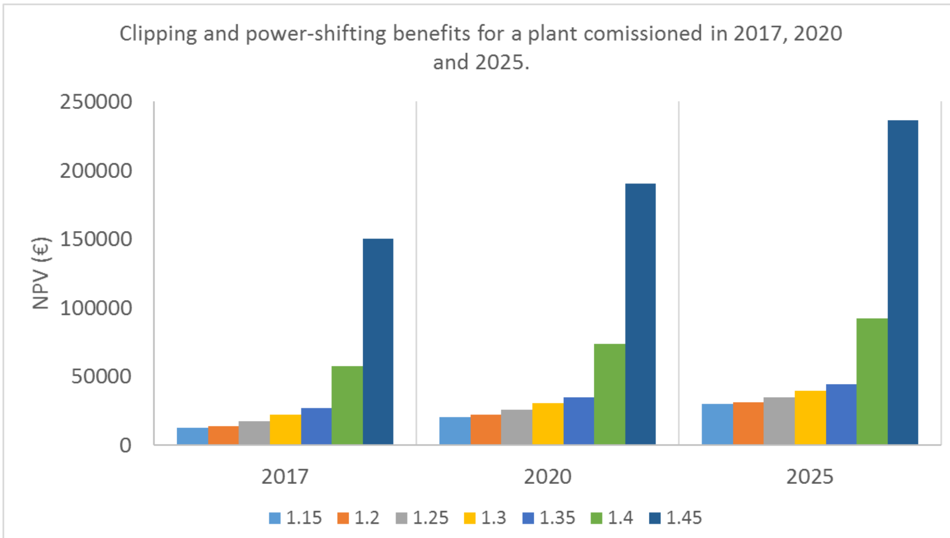


Figure 58: Alternative comparison of NPV in 2017, 2020 and 2025.

In terms of the NPV values generated for all the range of battery sizes simulated (from 50 kWh to 5000 kWh), the results are shown below. The results, with power-shifting, show a positive correlation with increasing battery size. This is contrary to PV excesses storage alone, where a point of inflexion occurs (See results in Chapter 5). This means that even though capital costs increase when having a greater battery capacity, the yearly earnings compensate this, and the NPV after the lifetime of the plant increases quadratically, as shown below.

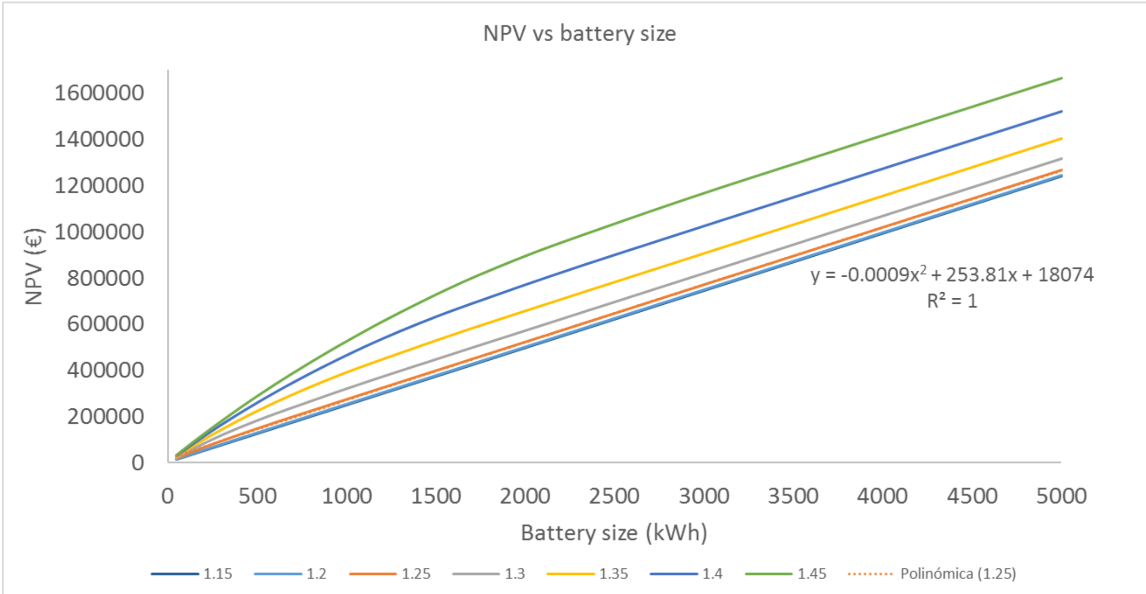


Figure 59: Quadratic relation between NPV and battery size.

It can be observed from the results above that the greater the battery capacity, the benefits increase quadratically.

However, this relationship does not hold for small battery sizes. The main reason is because for smaller battery sizes, clipping (storing PV excesses alone) has a greater proportion of the impact in the benefits accrued, and there are two reasons why a pattern is complex to formulate with clipping alone:

1. It depends on solar excesses, which is difficult to predict and formulate since the production pattern varies hourly and daily each year. Also, this production pattern can vary depending on the location. Therefore, formulating an equation for such low battery sizes, where clipping has a significant impact on earnings, is not really useful.
2. For this small battery size, a lot of excesses are not stored. When increasing the DC/AC power ratios, the amount of excesses lost increases, however the excesses stored in other hours increases. This makes for a complex relationship which is very difficult to formulate.

The graph below shows clearly that at a relatively small battery size of 100 kWh, the increase in benefits accrued for each DC/AC power ratio do not follow a pattern.

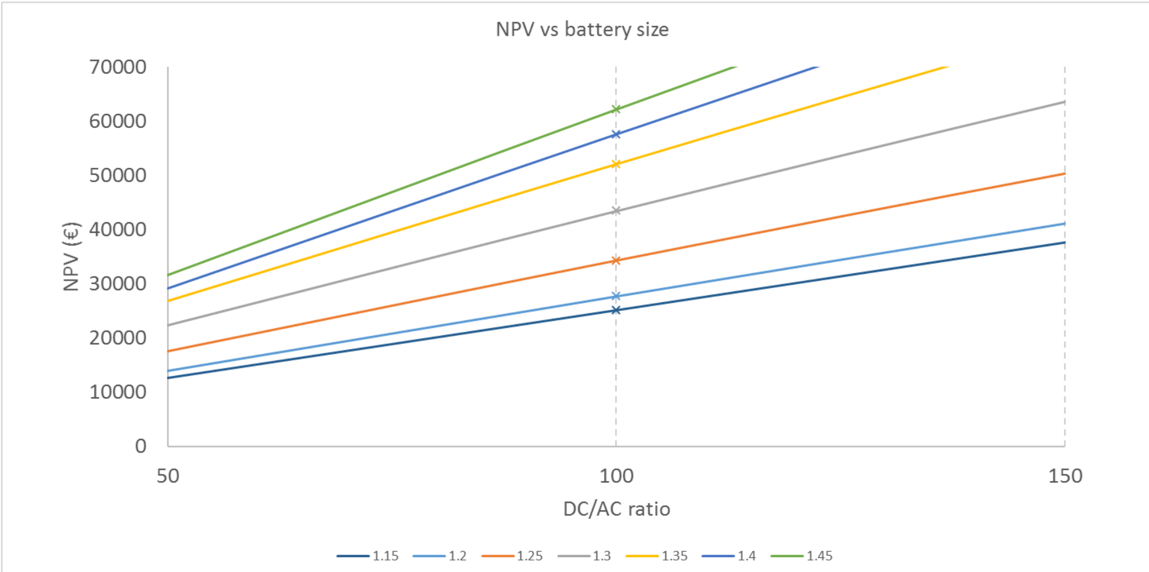


Figure 60: NPV vs DC/AC ratio for 100 kWh battery size per inverter system.

For a larger battery size of 5000 kWh (where maximum benefits occur when using power-shifting), the relationship is more defined. It can be seen that for larger battery sizes the variation of NPV with DC/AC power ratio is the same. In fact, it can be seen below that as DC/AC power ratio increases, the benefits increase quadratically, as demonstrated already in Figure 58.

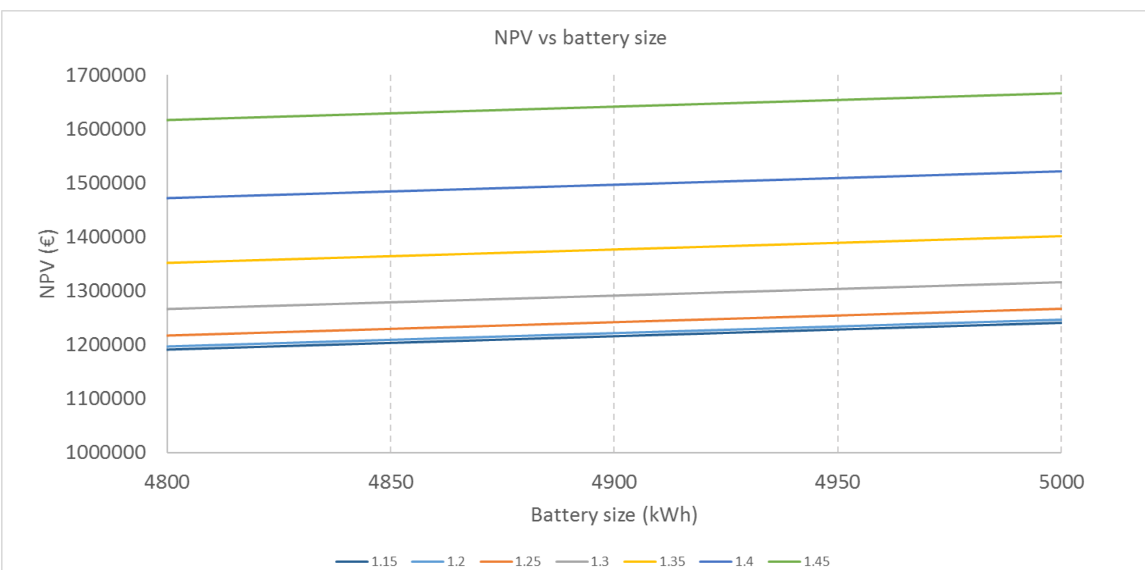


Figure 61: NPV vs DC/AC ratio for 4900 kWh battery size per inverter system.

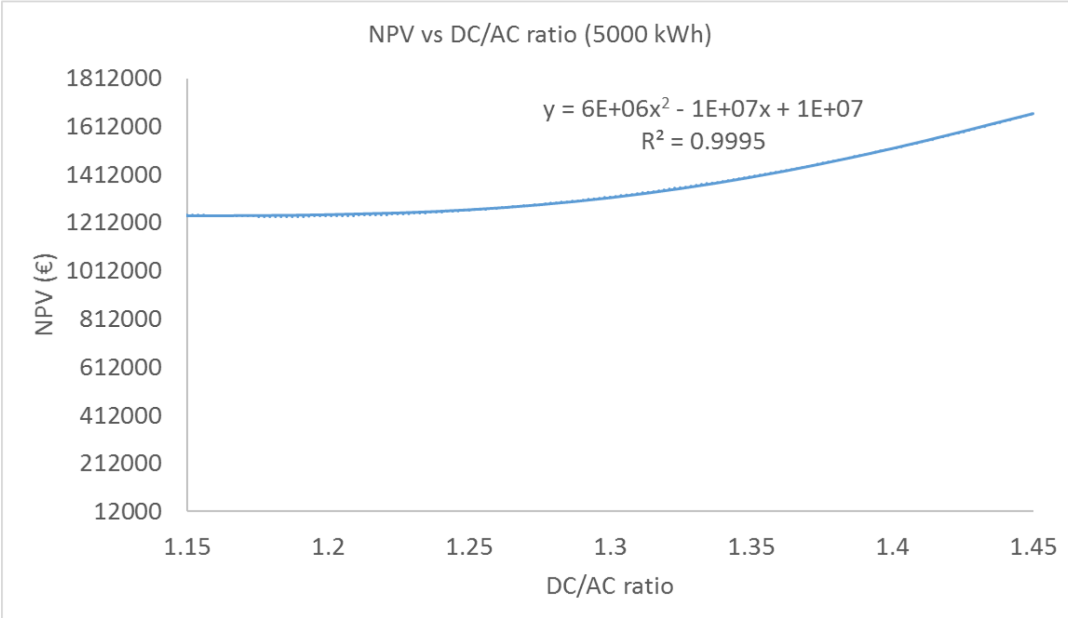


Figure 62: Relationship between NPV and DC/AC power ratio, for relatively large battery sizes.

This quadratic relationship stems from the yearly earnings accrued, which also follows a quadratic relationship. The reason behind this is that at such large battery sizes, no excesses are lost, therefore the increase in excesses, and therefore earnings is directly linked to the increase in DC/AC ratio as shown in the derivation below.

If we return to equation (13) for Clipping and Power-shifting, it can be deduced that as DC/AC power ratio increases the C_{batt} term stays constant, since the battery size has not changed. Therefore, the daily earnings with respect to the DC/AC power ratio is in principle only affected by the amount of excesses produced:

$$\Delta D_{DC/AC} \propto \Delta E_{DC/AC} \cdot \pi_s \qquad (19)$$

We know also that the new power output at a certain hour produced with a certain DC/AC power ratio equates to the following:

$$\begin{aligned} \Delta p_{DC/AC} &= p - p_0 \\ &= (\frac{DC}{AC}) \cdot p_0 - p_0 \\ &= p_0 \cdot [(\frac{DC}{AC}) - 1] \qquad (20) \end{aligned}$$

However, as already taken into account in the model already, the inverter maximum power has to be considered in order to calculate the hourly excesses produced:

$$E_{DC/AC} = \sum_{h=1}^{8760}(p-\rho) \qquad (21)$$

If we convert this sum to represent the total power accumulated in the year, by using integration, we can formulate the following:

$$E_{DC/AC} = \sum_{P=p1}^{P=p8760}(P-\rho) = \int(P-\rho)dP = \frac{P^2}{2} - \rho P + C \qquad (22)$$

Finally, since we know that $P = P_0 \cdot \left({}^{DC}/_{AC}\right)$:

$$E_{DC/AC} = \int(P-\rho)dP = \frac{P_0^2}{2} \cdot \left({}^{DC}/_{AC}\right)^2 - \rho \cdot \frac{P_0}{2} \cdot \left({}^{DC}/_{AC}\right) + C \qquad (23)$$

This derivation proves the relationship we have obtained in Figure 63, since for the same battery size (same capital costs), the NPV is primarily related to the earnings achieved, which in this case for larger battery sizes, is affected by the excesses produced, where the amount of excesses produced is determined by the DC/AC power ratio.

Returning to the optimal battery size when considering also power-shifting, it is clear from Figure 64 that these are not the same optimum values as when storing PV excesses alone. The relationship is, the greater the battery capacity the greater the benefits. However, here only applying a max NPV criteria would be blind-sighted, since there are other factors in place:

- Initial capital investment the project developer disposes of. This is more critical for plant developers who wish to construct relatively smaller plant sizes, with a more limited investment.
- Payback time is directly linked to capital investment. The greater the battery size the longer it will take to payback the capital investment. This value cannot be greater than the lifetime of the plant (this is assuming no battery replacement costs are needed).
- There may be limits imposed as to battery size allowed to connect to the electrical grid, due to stability issues that could arise in the grid from having such a great capacity connected.

Since the regulation restrictions change constantly and can depend as well on the plant characteristics and location, for now, we can say that the greatest battery size to be installed is dependent on the payback time. From here we deduce the following. The graph below shows the payback time variation with battery size, for the different DC/AC ratios. The maximum battery size possible for a plant lifetime of 20 years is 500 kWh, 1400 kWh, 2600 kWh and 4100 kWh, for DC/AC ratio of 1.3, 1.35, 1.4 and 1.45, respectively. This corresponds to an NPV of 182881 €, 502148 €, 924641 €, and 1443148€, per inverter system, respectively.

Regarding the lower DC/AC values analyzed, for current battery prices in 2017, they are not economically viable since payback times are greater than the lifetime of the plant. Therefore, they have been discarded from the results and for the rest of the studies.

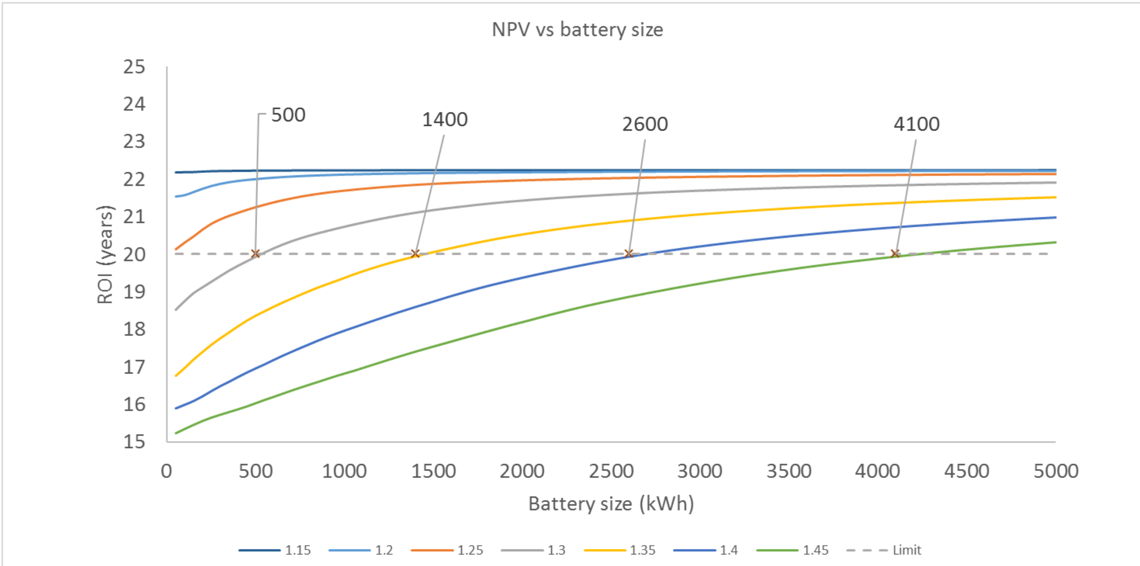


Figure 63: Optimum battery sizes for different DC/AC power ratios, based on maximum ROI to consider (20 years).

This also corresponds to a percentage of excesses used over the total possible of 76.4 %, 96.3 %, 99.7 % and 100 %, respectively. This means that taking into account this maximum payback time criteria (20 years), the percentage of excesses produced from the PV array is a lot higher than when using the Max NPV optimum size (when considering PV excesses alone). To conclude, clipping services is best when combined with power-shifting, applying a maximum payback time criteria.

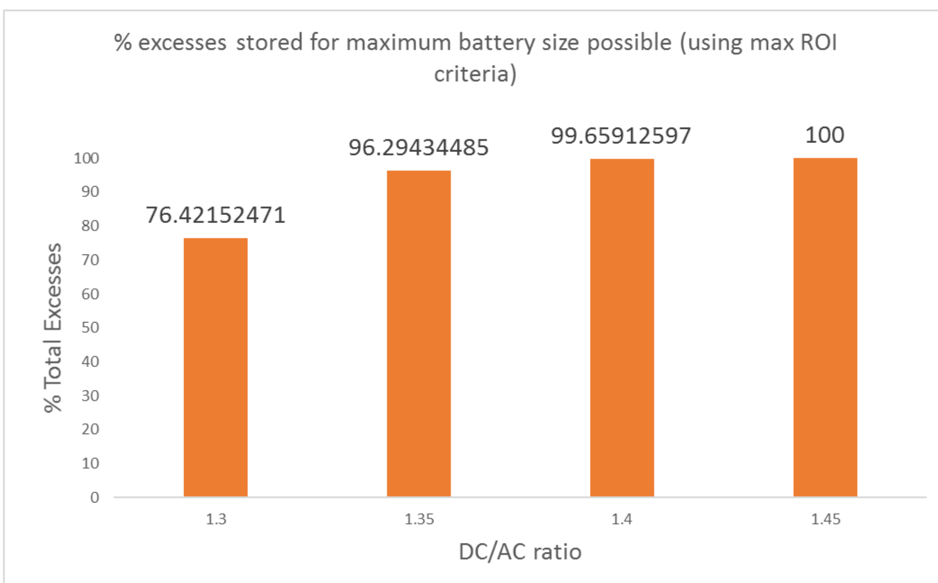


Figure 64: Percentage of excesses stored for maximum battery size possible for each DC/AC power ratio.

6.3.2. Power requirements

These results also take into account the power requirements needed (e.g. size of the DC-DC converters, and the charging/discharging power needed).

For the example used above (DC/AC = 1.4, battery size = 2600 kWh), the maximum charging/discharging power needs to be calculated. Below shows the diagram representing a particular day, with its photovoltaic power output, and also the corresponding battery charge/discharge cycles carried out on that day. The excesses produced, and therefore the power needed will vary per day, depending on the solar production, whereas the power needed for power-shifting will depend on the battery size (energy) and the time of the shortest period. The shortest period because it will indicate the period where it needs the most power from the batteries and DC-DC converter.

In the example used,

Power-shifting:

- Period 1:
  - Energy to charge: 2600 kWh.
  - Time of period: 5 hours
  - Power needed: 529 kW.
- Period 4:
  - Energy to discharge: 2600 kWh.
  - Time of period: 4 hours
  - Power needed: 650 kW.

In terms of excess power needed (period 3), even though this will vary every day, the maximum possible power to charge/discharge would be the smallest of the following:

- P_{inv} x DC/AC = (3360 x 1.4) - 3360 = 1344 kW.
- Charging/Discharging whole battery size in 1 hour: 2600 kW.

In this example, the smallest is the excess power produced when the array feeds nominal power to the inverter, at 25ºC.

Therefore:

Clipping:

- Period 2:
  - Maximum energy to discharge: 2600 kWh.
  - Maximum power to discharge: 1344 kW.
- Period 3:
  - Maximum energy to charge: 2600 kWh.
  - Maximum power to charge: 1344 kW.

Since power needed in clipping is higher than in power-shifting, the power needed in batteries and DC-DC converter is 1344 kW for both charging/discharging.

Taking this power into account, the DC-DC converter cost calculated was 53520 € /inverter system. For the same conditions, but integrating a AC-coupled storage system, the inverter-charger (PCS) costs would instead be: 99111€. The increment in cost is due to several reasons:

- Cost per kW of a AC-coupled inverter-charger is higher than for a DC-DC converter. (40€ vs 72€ from cost analysis done in 2017).
- Extra cabling as well planning and permission costs involved at the site for connecting another system in parallel to the solar plant, on the AC side.
- There are more losses in this system, since the PV power has to go through the:
    - Solar inverter (EU efficiency: 98.5%)
    - MV transformer to elevate voltage from inverter to POI requirements (Efficiency: 99%)
    - MV transformer to step down voltage from POI requirements to battery requirements (Efficiency: 99%).
    - Inverter-charger (EU efficiency: 98.5%)
    - Charging and discharging losses in battery.

  Therefore (without taking into account the losses in the battery itself during charging/discharging):

    - Charging efficiency: 98.5% x 99% x 99% x 98.5% = 95.1%.
    - Discharging efficiency: 98.5% x 99% = 97.52%.
    - Round-trip efficiency: 95.1% x 97.52% = 92.70%.
- In terms of the losses in the DC-coupled system, the PV power has to through:
    - DC-DC converter (EU Efficiency: 99%)
    - Solar inverter (EU efficiency: 98.5%)
    - MV transformer to elevate voltage from inverter to POI requirements (Efficiency: 99%)

  Therefore (without taking into account the losses in the battery itself during charging/discharging):

    - Charging efficiency: 99%.
    - Discharging efficiency: 99% x 98.5% x 99% = 96.54%.
    - Round-trip efficiency: 99% x 96.54% = 95.6%.

Using this efficiency difference, a dividing factor is obtained (92.7% / 95.6% = 97%). This factor is applied to the power produced when using the DC-coupled system, to obtain the power produced when using the AC coupled system. Similarly, this factor is applied to the DC-DC costs, to obtain the AC-coupled inverter-charger costs.

Therefore, when applying cost per kW of each technology, the extra costs (due to cabling, planning and permission), as well as the associated costs due to the difference in efficiencies) the cost differences are the following:

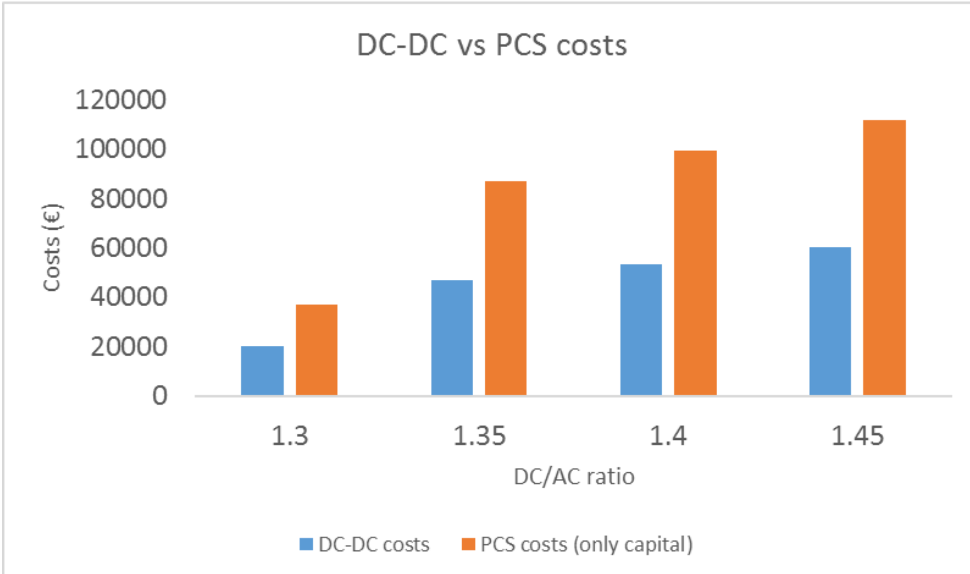


Figure 65: Cost difference between DC-DC converter and AC-coupled inverter-charger.

Moreover, there is an added cost to the AC-coupled inverter-charger. Asides from the power loss due to a lower round-trip efficiency, using the AC-coupled system, the next analysis is to see how the production (from PVSyst simulation) is affected with a lower efficiency, and from here obtain the loss in earnings compared to the DC-coupled system. This will equate to additional losses with the AC-coupled system. Firstly, no excesses can be stored, since there is no DC-DC converter installed on the DC side, and so when PV power produced is greater than the capacity of the inverter, these excesses are lost. The MPPT algorithm implemented within the solar inverter would deviate from the Maximum Power Point, to accept a power equal to its maximum capacity. (*More detail on Chapter 2.3.1*).

Secondly, if we then assume there is no limit by the grid operator in terms of the nominal power injection by the inverters, the only service to be considered with this topology would be power-shifting (buying/selling energy from/to the grid). As a result of this decrease in round-trip efficiency for the AC system, the losses during the daily charging/discharging process are greater. In fact, this can be calculated by modifying the general equation used in the algorithm before, to:

$$D_{DC} = E \cdot \pi_s + C_{batt} \cdot (\pi_p - \pi_v)$$
$$D_{AC} = 0 \cdot \pi_s + (C_{batt} \cdot 0.97) \cdot (\pi_p - \pi_v)$$
$$\therefore D_{AC} > D_{DC}$$

Taking this into account for 365 days of the year that power-shifting is supposedly provided, during the lifetime of the plant (20 years) the final costs comparison of both topologies is shown below. Overwhelmingly, over the lifetime of the plant, the DC system would provide significantly more benefits.

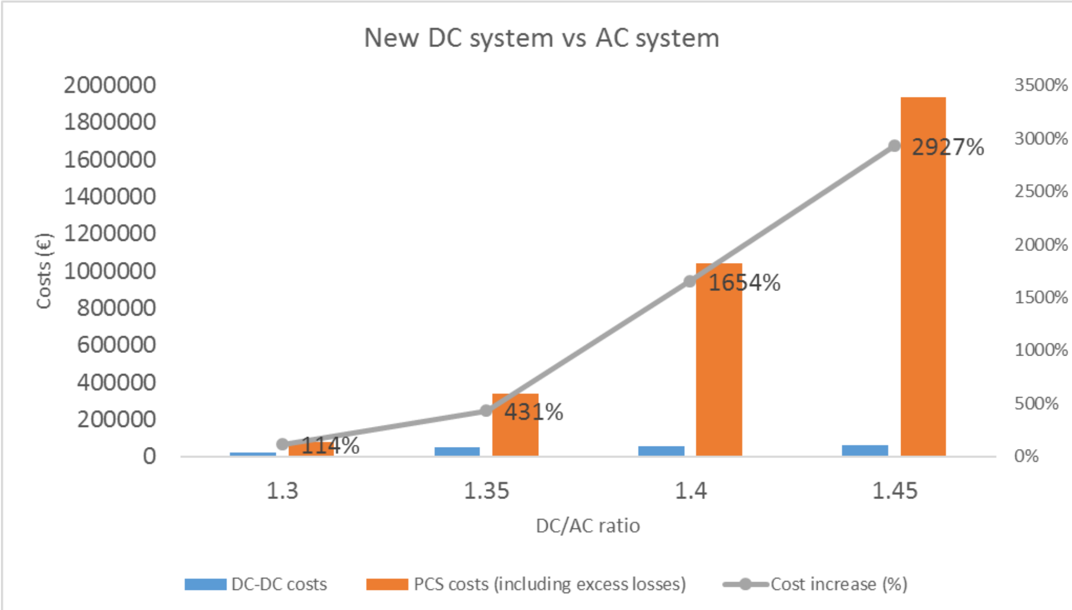


Figure 66: Cost difference between DC-DC converter and AC-coupled inverter-charger (PCS), taking into account capital costs, efficiency costs as well as loss of excess costs.

It is interesting to note that the major cost of the AC-coupled inverter-charger is not the capital costs itself (even though taking into account market price and power loss, it works out to be more expensive), but it is actually the energy losses associated with the lower round-trip efficiency, and the solar excesses that could have been stored with a DC-coupled battery system, which contributes the most. This is shown in Figure 68.

It can be seen that as DC/AC ratio increases, the proportion of the costs associated with energy losses is even higher, since as having a greater oversized array more excesses would be lost. Also the associated battery sizes (as calculated earlier) are higher with higher DC/AC ratio, thus the efficiency difference between both systems has a greater effect on energy losses during power-shifting.

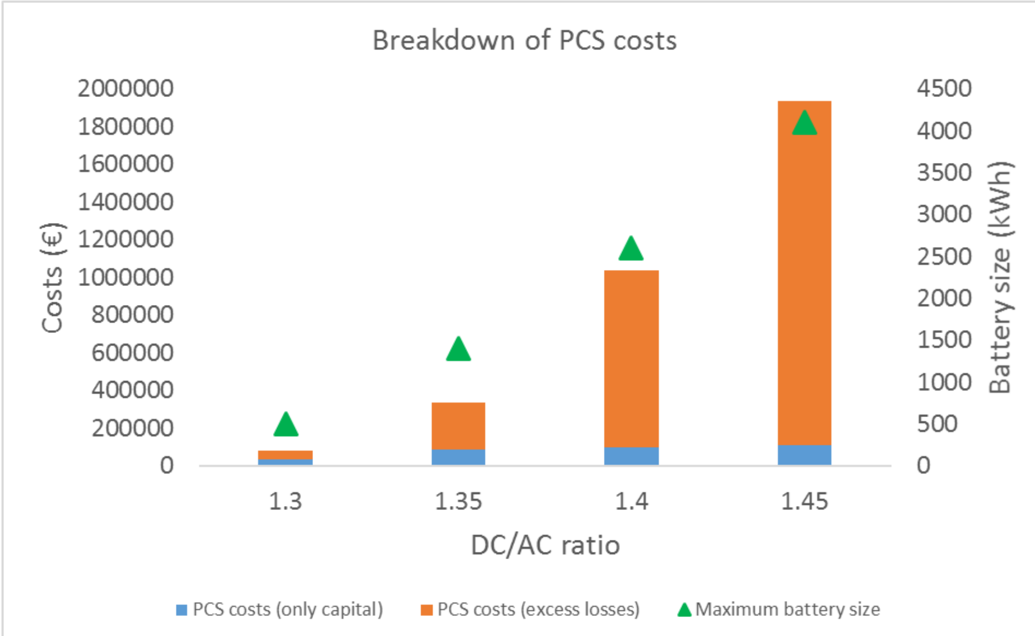


Figure 67: Breakdown of AC-coupled inverter-charger costs as well as maximum battery sizes for different DC/AC power ratios.

6.3.2. Results when considering battery replacements costs

These results present very competitive benefits. However, there is still a cost component which hasn´t been considered, which is the lifetime of these batteries depending on its use, and how this will reflect on battery replacement costs during the lifetime of the plant. (*Methodology used here is explained in detail in Chapter 3.2.4*).

Considering a DC/AC power ratio of 1.4 (since it has been proven so far to be a reliable value for such systems), the NPV generated as well as the battery lifetime for different battery size factors are obtained and illustrated. A first and important point seen is that for the original optimal battery size (100 kWh for DC/AC ratio of 1.4), considering both clipping and power-shifting services provided, the NPV is now negative. This is due to the battery replacement costs now taken into account. Therefore, as already concluded before as well, an increase in battery size is needed in order to raise the NPV. Increasing the battery size increases the NPV for two reasons:

- NPV raises with battery size when power-shifting is considered, as studied before.
- Increasing the battery size for the same conditions in the solar array increases the lifetime of the battery, as shown in the graph, due to a slower degradation. Therefore, the replacement costs reduce, and so the NPV increases further.

Secondly, economic viability of such system occurs for battery size factors of 3 or above, for this DC/AC ratio in Valencia.

Thirdly, as already established, the greater the battery size factor, the greater the NPV. However how much is increased, like already explained, will depend on disposable investment, payback time, as well as grid code requirements.

If we now compare the max ROI optimized battery size (when considering power-shifting), the NPV for this value, 2600 kWh (for DC/AC ratio of 1.4) is now 787563 €. This corresponds to a (787563– 924641) x 100 / 924641 = - 14.8 %. This now represents a 15% decrease in the benefits accumulated over the lifetime of the plant, which is due to the inclusion of replacement costs in the total capital costs. If we keep to this example, using the battery degradation model, having such a battery size for the use of this battery, at the conditions of Valencia and the DC/AC power ratio used, the final SoC calculated is on average a value of 70%. This corresponds to a certain degradation curve. Taking this into account and quantifying the yearly equivalent cycles produced, the lifetime of the battery (conditioned when discharge capacity reaches 80%) is of 15 years. Therefore, the plant needs to replace the batteries in year 15 (at the projected cost of these batteries in such year, taking into account a 9% annual decrease).

Below also shows how NPV (with replacement costs) varies with original NPV (clipping + power-shifting).

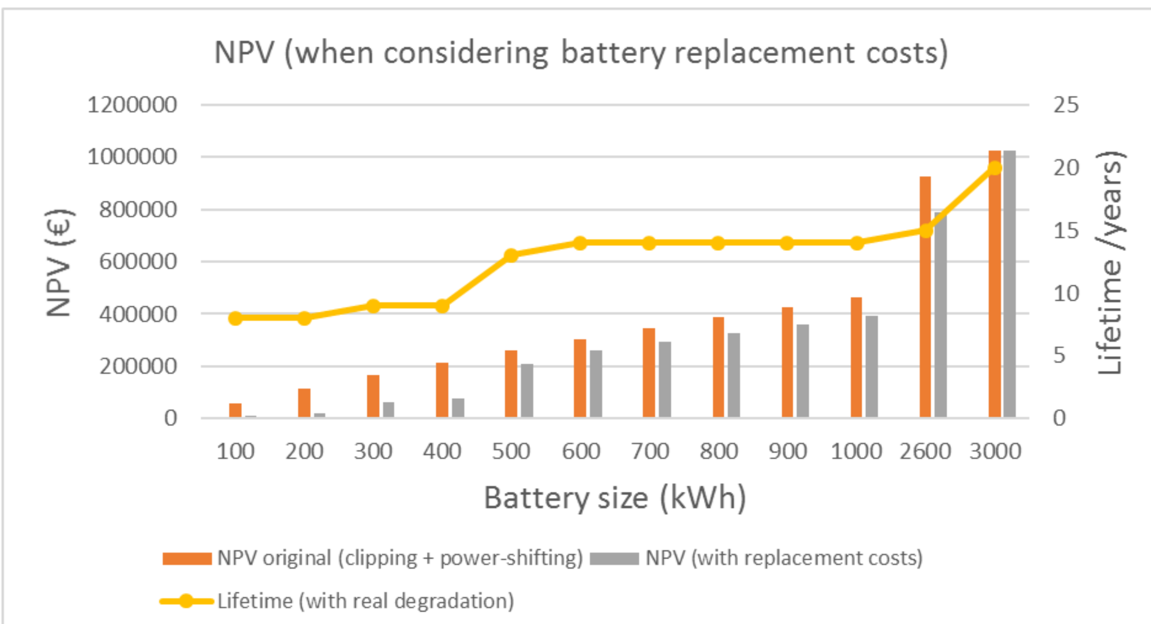


Figure 68: Benefits accrued when considering battery replacement costs, for different battery sizes.

It can also be observed that when applying the battery degradation modelling here, the lifetime is significantly higher with clipping alone. For example, for a DC/AC ratio of 1.4, using the original optimal size of 500 kWh, with clipping alone, the lifetime is over 20 years. However, with clipping and power-shifting services, the lifetime decreases to 8 years. This is because now everyday there is one whole cycle in addition to the cycles produced from the excesses. This increases significantly the use of the battery, which has an effect on the capacity fade. Then as less capacity is available, the average DoD, and the SoC, will increase as a result. More cycles, worse DoD leads to faster degradation, which consequently reduces the lifetime of the battery as being modelled.

6.4. Conclusion

In order to make the proposed DC-coupled battery system more economically viable, power shifting is also provided. With this, a new tariff is proposed (time-of-use tariff).

The greater the battery size, the more profitable. The restricting parameter would therefore be the initial capital investment a plant developer disposes of, or the contract the developer has to construct, or the current regulations imposed. The two last factors are determined by the grid operator /country´s government, in order to maintain the stability of the grid. In other words, having too great power shifting service provided could provide counter-productive results which could cause the grid to become more unstable. (*More on this in Chapter 6*).

Larger battery sizes for clipping alone is completely unviable. However, with the integration of Power-shifting, it shows that the greater the capacity of storage the more profitable the installation becomes. Also, the added advantage of increasing capacity is that less of the excesses produced are lost, and so clipping now becomes better harnessed (only if power-shifting is in place as well as seen with Max NPV optimization for clipping alone). In fact, since for such large battery sizes as studied, practically all excesses are stored, and so project developers have a reliable tool to predict very accurately how much benefits they can earn during the lifetime of the plant, with respect to a DC/AC ratio and plant capacity they wish to use. As has been derived, for a particular battery size (determined by disposable capital investment, required payback time, and country regulation restrictions), the benefits with respect to the DC/AC ratio is quadratic. Also, as shown before, since we are proposing DC-coupled storage systems in between a set of PV strings with an inverter, the benefits earned with respect to power size of the plant is linear. The more plant capacity needed, the more inverter-DC storage-PV array systems connected in parallel, so the earnings are multiplied by the number of inverters installed.

Furthermore, taking into account gives more negative results. However, a model for the first time has been developed to take different battery factors into consideration (DoD, number of cycles, C-rate), in order to produce a degradation curve and apply it the capacity of the battery and calculate its lifetime. Having this calculated lifetime means at a certain time, they have to be replaces. If their lifetime is sooner than the lifetime of the plant then there will be an associated replacement cost (dependent on the battery price at that moment, which has been modelled as a 9% decrease per year). This detailed model provides an accurate cost projection of the battery, during the lifetime of the plant.

Even with this additional cost, providing storage for both PV excesses and power-shifting still generates significant benefits, which makes this system very interesting now, and even more during the forthcoming years when battery technology and price improves.

7. CASE OF STUDY 3: FREQUENCY CONTROL SERVICE

7.1. Introduction

The objective of this chapter is to analyze the possibility of the proposed system in order to regulate active power, for power-frequency control.

To this day, the power-frequency control is structured with the following three levels:

- Primary Regulation: Rapid and local response, traditionally based on the speed controllers of synchronous generator. Its objective consists in stabilizing the frequency perturbations in the grid due to power unbalances.
- Secondary regulation: Slow and zone-specific, in charge of fixing set-points in power generation for the speed controllers in primary regulation.
- Tertiary regulation: Acts globally in the whole electrical system, finding the most optimized distribution of power which guarantees sufficient energy reserves.

In developed countries, where access to electricity is assured, the improvement of electrical systems focuses on quality and efficiency of the service. Since the energy traditionally cannot be stored today on a large scale, the quality and efficiency of the system depend largely on the balance between generation and demand. The mechanisms available to operators of the electrical systems to control this balance, in real time, in Spain, are the Adjustment Services (Servicios de Ajuste). These services have been traditionally supplied by synchronous generators. However, in the new proposed grid code, in accordance with new EU legislation, photovoltaic generators will also have to provide this service at some level.

The increase in renewable energy penetration is adding complexity to the Adjustment Services since due to its fluctuating nature it increases the demand for these services. Below show the net deviations measured by different components, for 2016. Demand shows to have a significant contribution to these deviations, as well as the high penetration of wind capacity that already exists in Spain, as shown in Figure 70 below.

The graph below shows two parts: power reserve (positive) and power curtailment (negative).

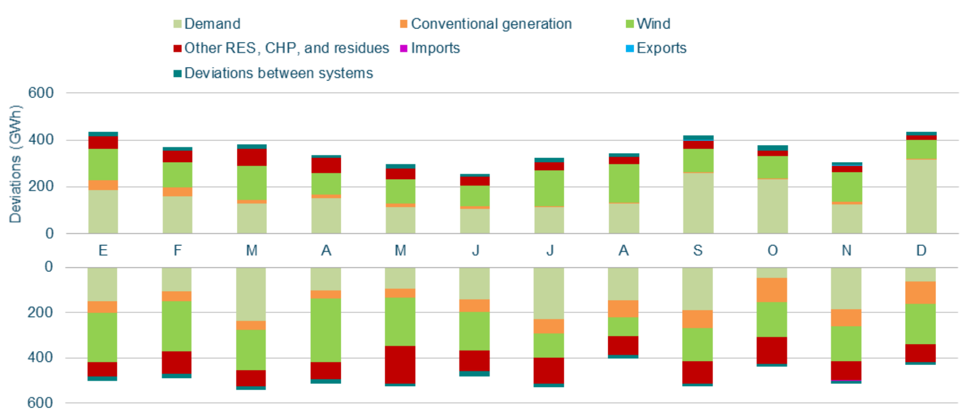


Figure 69: 2016 Monthly energy deviations (increase and decrease), with breakdown of the different contributors.

If renewable penetration (from both wind and solar) continues to increase, the demand for adjustment services will be expected to be higher, due to unbalances between forecast and actual generation.

Red Eléctrica de España, in its role as operator of the Spanish electricity transport system, carries out the necessary activities to guarantee the security and continuity of the electricity supply, as well as the correct coordination of the generating system and the transport network, ensuring that the energy produced by the generators is transported to the distribution networks under the quality conditions required in application of current regulations and at the lowest possible cost to the consumer.

After the result of the daily spot market and the communication of the daily execution of bilateral contracts with physical delivery (e.g. Power Purchase Agreements), and also, during the operation in real time, the system operator can identify situations in which it considers necessary to modify the generation programs to guarantee the quality and security of the electricity supply, and permanently maintain the proper balance between generation and demand.

Since February 11, 2016, non-conventional renewable production, such as wind production, solar production and mini-hydraulic production, among others, as well as Combined Heat and Power and waste facilities, can participate in the markets of system adjustment services of an optional nature, after passing the habilitation tests established for this purpose, in accordance with the applicable regulations.

During 2016, in the markets for adjustment services, a total of 21.4 TWh of electricity was managed, a figure equivalent to 8.6% of the peninsular demand of that year.

7.1.2. Primary Regulation

In order for electricity supply to be delivered under the quality conditions required, the frequency of the voltage waveform needs to be within a set of strict limits. Greater variations of frequency to these limits can cause malfunction or damage to the different equipment that is connected to the power system, thus having a negative economic impact. One example would be on the high magnetizing currents produced in induction motors and transformers as a result of a drop in the grid frequency.

Primary Frequency Regulation is a complementary service of obligatory nature, which is not economically compensated. It is provided by generators coupled to the electrical grid, and its function is to automatically correct the instantaneous unbalances between generation and consumption. It is provided via the variation of power of the generators in an immediate and independent manner. In the case of conventional generators, it is done by actioning the speed regulators of the turbines as a response to the variations of frequency in the electrical grid.

The frequency of the electrical system is strongly linked to the balance between generation and demand of active power. In permanent regime, all the synchronous generators of an electrical network work in synchronism. As long as this synchronism remains, the mechanical torque minus the losses incurred will be equal to the electromagnetic torque. If the load in the system increases, the electromagnetic torque increases, and as a result, for the same power being generated, the generators naturally slow down, thus decreasing the grid frequency. A change in load causes a change between the mechanical and electrical torque, which causes a change in speed.

To comply with the revised Spanish grid code (in accordance with the new European legislation (UE 2016/631)), for large scale PV plants the inverter, just like a conventional generator, must now be able to regulate its power without disconnecting from the system when frequency deviates from its nominal value. The methodology in order to incorporate this into the proposed system is explained below.

7.1.3. Secondary regulation

Secondary regulation is a service of optional nature, where its objective is to maintain the balance between generation and demand, as well as correct frequency deviations with respect to the nominal value established. Its duration can be from 30 seconds to 15 minutes.

This regulation is provided by generators, whose offers in the market have been selected with the competitive mechanisms imposed.

This service is also remunerated, by band availability as well as the use of the energy.

This regulation involves the automatic increase/decrease of power of a generator (AGC: Automatic Generator Control), which has offered a power "band" the day before to the grid operator to dispose of when needed. It thus permits the grid operator to have available capacity reserve in both directions (for the duration established), with the aim of resolving generation-demand unbalances. These unbalances predominantly arise from the demand forecast errors that are obtained, as well as the power flow changes that result from primary frequency response.

On a daily basis, based on forecasts and probability of demand and power outputs, the grid operator calculates an error, which corresponds to possible available power that they need to dispose of, to increase or decrease. This reserve is called a band. The power band corresponds to a margin of variation of power in which secondary regulation can act automatically in both directions.

Since secondary regulation is organized by regions, when there is a generation-demand deviation, the System Operator will send its control signals to the control centre of the region where the power plant is located, which as a result will send new set-points of active power to the Power Plant Controller of the PV plant, in order to change the power output delivered at the Point of Interconnection (POI) and provide this service.

In order to provide this service, the following is needed:

- Generators with fast response rate. Traditionally this has been offered by synchronous generators (using hydroelectric power, natural gas or fuel-oil as the energy source).
- Each generator presents offers of power band for secondary regulation (they offer power [MW] and selling rate [€/MW]) for the next programmed period (day).
- In the case of generators from renewable sources of energy, in Spanish Grid Code, they feature in a category called "Special Regime", which indicate certain distinct criteria to comply, one of which is that they can only provide this service if they offer a minimum of 5 MW increase/decrease of power. This may perhaps change in the new definitive grid code, in accordance with the new European legislation (UE 2016/631).

The economic retribution for this service, as stipulated in the Operation Procedure of the System Operator (P.O. 7.2) is divided into two parts:

- Availability (power band): Generator compensated for putting available some power reserve in the market, the day before.
- Use (energy actually used during grid controller request): Net effective energy used for secondary regulation, on the programmed day.

In order to determine if providing this service has sufficient economic benefits, and makes the whole system even more competitive than determined so far, we need to consider the following:

- How often these contingency events occur.
- How much extra power and energy is needed, and how it will impact total capital costs and lifetime benefits of the plant.
- How can it disrupt normal operation (optimization algorithm).
- What is the economical retribution of providing this service.
- What is the penalization for not providing this service, when contracted the day before.
- How the battery degradation rate is affected.

7.1.4. Tertiary Regulation (REVISAR)

The technical viability of using an ESS-coupled photovoltaic system is similar to that of secondary regulation. However, in an economic point of view, it is less incentivizing since a participant in this market only receives earnings if the System Operator actually acquires their services during a particular day, regardless if their offer has been accepted in the market. This is contrary to secondary regulation where the plant would be compensated anyhow with the power band term every day.

Incorporating tertiary reserve therefore would also mean increasing the battery size and power, which would increase the costs whilst receiving a compensation that is not guaranteed to amortize in a suitable period of time. There are ways that could be studied to participate in the tertiary market without having to increase capital expenditure significantly, but this is out of scope of this thesis.

7.2. Methodology

7.2.1. Primary Regulation

The frequency response functionality allows configuring the active power to be delivered by the plant based on the measured frequency of the grid, in order to stabilize its value in case of deviation.

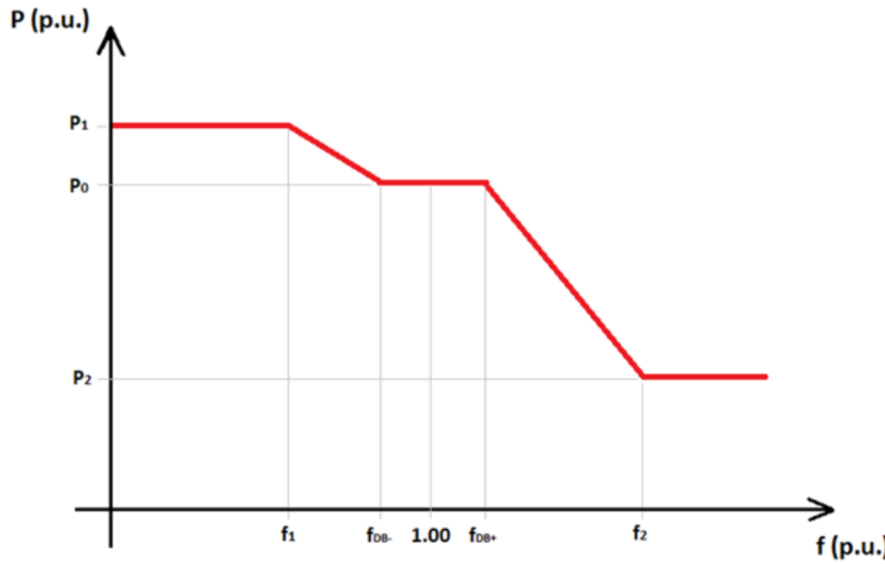


Figure 70: Power-frequency response curve.

Using Figure 71, the parameters to be configured in the solar inverter are: (f_1, P_1), (f_{DB}-, P_0), (f_{DB+}, P_0) and (f_2, P_2), which will vary according to the requirements of the corresponding standards enforced.

This control is activated whenever the frequency is destabilized and falls outside the dead band defined by points (f_{DB-}, P_0) and (f_{DB+}, P_0). The instruction obtained as a result of the control algorithm will be directed to the inverters to reduce their active power delivered in case of over-frequency (if the frequency exceeds the value of f_{DB+}) or to raise it in case of low frequency (if the frequency falls below the value of f_{DB-}).

In the case of low frequency, increasing power output is possible only if the fixed instruction is not already 100%, that is, a reserve power has been established previously. In any case, the availability of this reserve cannot be guaranteed since it depends on the weather conditions at the time it is required. To have a greater guarantee of a reserve during these low frequency events of the network, it is necessary to have an energy storage system to raise the power adequately, independently of the weather conditions at that moment.

In the new grid code that is going to be released in Spain, which is in accordance to the new European regulations (EU 2016/631), it is required from solar photovoltaic plants of Type C (V<110 kV and 5 MW<P<=50 MW) and Type D (V>=110 kV or V<110 kV and 50 MW<P) to provide a power reserve of between 1.5% and 10% of the plant rated power (the rated power is the power that can be injected via the inverters at the peak solar time, thus will not correspond to the peak power produced in the array due to the DC/AC ratio that may be used). However, as the new grid code is currently under study, clear guidance is yet to be given regarding exactly what percentage of rated power always has to be available for primary frequency response. It is clear that for a certain plant, this percentage that could be provided will vary during the day, depending on the solar output at a particular moment. Nevertheless, 10% of the rated plant power will be considered to be sized during this case study.

The methodology to include primary frequency regulation in our model, is as follows:

Firstly, the inverter capacity is verified if it is capable of delivering an extra 10% of power reserve (in other words 110% of apparent power). As shown in the Active Power-Reactive Power curve below of the inverter model HEC FS2800CH15, it can deliver up to 120% apparent power at a temperature of 25 ºC (*see Chapter 2.3.3*) on a permanent basis. At 50 ºC however, this inverter would experience power derating and would only deliver 100% of its rated capacity, thus not being able to over-power the equipment, due to the thermal limits imposed in the IGBT to protect it from reaching its critical temperature. (*see Chapter 2.3.4*).

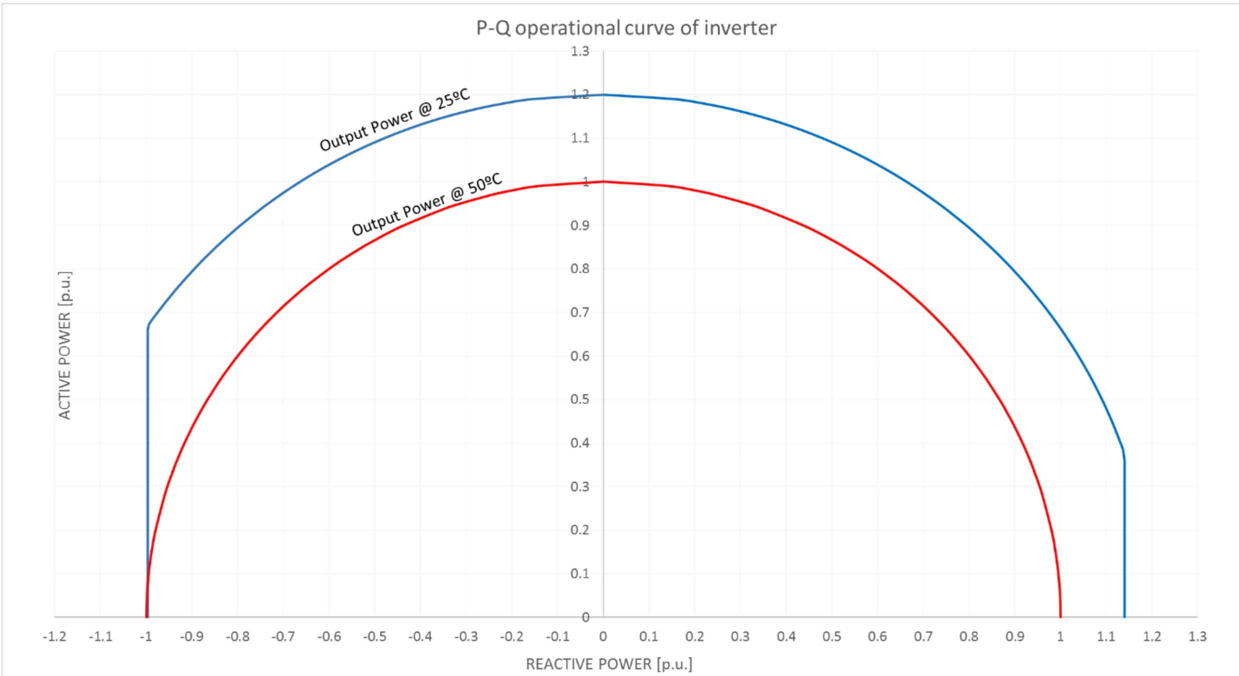


Fig 6.6. PQ operational curve of inverter (HEC Freesun FS2800CH15)

Therefore, in order to know how much over-capacity an inverter can provide; the design temperature of the location needs to be calculated. At temperatures below 50ºC, the inverter is able to deliver more than 100%. Thus, the solution is to size the inverter power for 50ºC, so that at the design temperature (a value less than 50ºC), it would be able to deliver more than 100% rated power. Then the power output would be configured to be limited to a value that would equal to the power required in normal operation. The result though is requiring an increase in inverter power. In other words, it would mean having more available inverter capacity but limited to a percentage of output during normal operation. Then when a grid under-frequency contingency event occurs, this power limit would be removed and a reserve would be available (depending on weather conditions as well).

The steps are the following to size the number of inverters needed, correctly:

1. Identifying the design temperature.

2. Since power derating due to temperature, between 25ºC and 50ºC is linear, the maximum capacity available in the inverter is calculated using the following interpolation:

$$P_{t_{design}} = (P_{25} - P_{50}) \cdot \frac{(T_{design} - T_{50})}{(T_{25} - T_{50})} + P_{50} \qquad (24)$$

P_{50} being 100% and P_{25} being 120%.

3. If $P_{t,design}$ > 110%, then in principle, the design temperature for this plant and the inverter used can provide a 10% power reserve (with weather permitting).

4. Calculate the power limit to be applied in the software of the inverter, in order to deliver rated plant power during normal operation. The power limit to be configured in the inverter for normal operation is calculated in the following way:

$$P_{limit} = \frac{100\%}{P_{t_{design}}} \cdot 100 \qquad (25)$$

5. When there is a frequency change in the grid outside the frequency dead-band configured in the inverter software (value is established in the grid code), where 10% of rated power is required, the inverter power limit is disabled, and all available power from the array is provided. Performing a power response to a frequency already exists in the inverter used. However, delimiting the power limit would have to be developed in the software in order to act quickly and automatically when reaching these frequency threshold values.

6. As mentioned earlier, since we are limiting the power, the number of inverters needed may increase. This is calculated as follows:

$$N_{inv} = \frac{P_{rated,grid}}{P_{inv,T_{design}}} \cdot \frac{100}{P_{limit}} \qquad (26)$$

It follows that, if we are over-sizing the inverters by 10% and limiting the inverter power to be delivered, when there is a contingency event, these limits are disabled, and all power is delivered. However, in order for this power reserve to be delivered, there are two things that need to be met:

- Sufficient inverter capacity to deliver 110% power during a contingency event.
- Extra energy source available in order to increase the power output to 110%.

The former has already been met, by over-sizing the inverter capacity. For the latter however, there are three options that are considered:

1. <u>Auxiliary array</u>:

An extra set of strings is integrated. However, during normal operation they are disconnected from the rest of the array. In the event of an under-frequency in the grid, the PPC or SCADA would send a digital signal to trigger a contactor to connect these extra set of strings. This would provide the extra energy source (weather permitting). The inconvenience of this though is the extra investment in integrating further panels, which would equate to at least 10% more cost of the array. Not only this but considering that this array is not usually used it will be very difficult to amortize it, especially since this frequency response service is not economically compensated. Therefore, spending 10% more in the array is not the best solution and the global economic viability of the system would decrease.

2. AC-coupled battery:

Another alternative is to install a battery system coupled on the AC side with a PCS (inverter-charger) connected in parallel to the solar plant. In this case, no over-sizing of the inverter would be needed, since the extra capacity is provided by the inverter-charger connected in parallel to the solar plant. Also, no extra panels are needed, since the energy source is the battery system installed for this purpose. To provide this 10% of rated capacity (total inverter power), during 15 minutes (as demanded by the grid code), using the same example above, it would require a battery capacity, calculated with the following equation:

$$C_{batt}[kWh] = \frac{10\%}{100\%} \cdot P_{rated,grid}[kW] \cdot \frac{15[mins]}{60[mins]}[hours] \qquad (27)$$

The power reserve (MW) needed would be calculated as:

$$P_{reserve}[MW] = \frac{10\%}{100\%} \cdot P_{rated,grid}[MW] \qquad (28)$$

Then using 2017 battery costs per kWh, the associated costs installing this battery system (along with the inverter-charger) is calculated using the following equation:

$$\Pi_{pcs-system} = \left(C_{batt}[kWh] \cdot \pi_{batt}\left[\frac{€}{kWh}\right]\right) + (P_{reserve}[MW] \cdot \pi_{pcs}\left[\frac{€}{MW}\right] \qquad (29)$$

3. Existing DC-coupled battery:

Finally, the last option will be in line with the novel system proposed in this thesis (over-sized array coupled to a DC-DC converter and solar inverter). Here, the oversizing inverter proposal remains (option 1), but without increasing the array size any further, since this was the biggest cost contributor. When there is a contingency event, the power limit of the inverter would be disabled, and the total available resource will be used to increase the power output at the solar inverter, up to its maximum capacity at that moment. If more power is needed (perhaps on a day with cloud cover, or early hours of the day), the DC-coupled battery (via the DC-DC converter) will provide some of this (depending on the hour of the day, following the established algorithm for clipping and power-shifting already implemented in the model). The DC-coupled battery system here provides an extra power reserve available to further meet the demands imposed by grid operators, without the need to install another system, such as the AC-coupled battery system previously proposed, along with its associated costs, or without the need of installing extra strings of panels.

By choosing option 3, an additional consideration are the costs of having to increase the DC coupled battery capacity (Ah) to provide this Frequency Regulation Service. In other words, a certain amount of capacity will always be reserved to guarantee provision for this service at any time (irrespective of power shifting and clipping use – *see chapters 5 & 6*). As a result, this will increase the costs in implementing this solution. Note however, that since secondary regulation would then be provided with this same system (using the DC coupled batteries and DC-DC converter), a greater DC-DC converter power may not be needed. The capacity designated for secondary regulation can be used here, since Frequency Regulation Service (Primary frequency response) would override secondary regulation, and the grid controller nonetheless would not demand secondary regulation from the plant during that time (i.e. within those 15 minutes it compensates for the contingency event).

However, it is possible the grid may require, after providing this primary regulation, to also immediately supply the contracted secondary regulation to the grid (as was offered in the market the day before). In the case of primary frequency response, this is an obligatory service that new grid codes are requiring (due to the significant change in the generation structure). In the case of secondary regulation, this is not obligatory, but in the point of view of this thesis, is essential to make this proposed system more attractive. Therefore, in the event of a secondary regulation request immediately after the primary frequency response, the battery power will be able to cope (as long as it is sized in accordance to what is offered in the secondary regulation market). However, the battery size (kWh) needs to be greater, since once primary frequency response ends, the battery must still have available the capacity required for secondary regulation.

7.2.2. Secondary Regulation

Similarly, to primary regulation, the DC coupled battery system proposed in this thesis will now be adapted to be able to provide a secondary regulation service as well, by offering additional power in the market on a daily basis, without hindering the power shifting and clipping services it already provides.

Using again Figure 25 as reference to the proposed system:

When $f_{grid} > f_{set\text{-}point}$, the PPC receives this set-point and commands inverter (via Modbus TCP) to reduce the active power to the output configured. The output configured will be dependent on the power variation limits and the power-frequency slope configured. This however results in a power loss due to this curtailment. Even though in the case of secondary regulation it has economic benefits to curtail this power, the power lost cannot be recovered and so there is some potential loss here for not being able to sell it in the spot market, plus the possible deviation penalties incurred due to not delivering the power sold in the spot market the day before. This needs to be carefully managed, and the solution here is using a storage system to store these curtailed losses. Keeping in line with the proposal of this thesis, a DC-coupled solution has up to now proven to be more economically viable, based on the analysis done in this thesis so far. Having this in mind, during primary frequency regulation, after SCADA/PPC receives the measured frequency value from the grid it will communicate this with the inverter. The inverter will then apply the power reserve/curtailment as configured. Also, the idea is to also check the State of Charge of the battery, in order to determine if there is enough remaining battery capacity to store the energy deviated from the power curtailment for the relatively short period of time needed. Using the size of the DC-coupled batteries as has been designed so far would mean that depending on the time of day, there will be periods where the battery will be fully charged and therefore this curtailed energy will not be able to be stored.

Similarly, in the event that the grid operator requests the contracted secondary regulation power, this will need to be provided somehow. When this occurs, the grid controller will send this new set-point to the PPC (Power Plant Controller) via a communication link already set-up. The PPC will then send a Read/Write command to the DC-DC converter (configuring a R/W parameter of the converter, which controls the power output and charging/discharging mode) via Modbus TCP protocol, and from here the DC-DC converter will start performing the charging/discharging depending on whether it is a power curtailment/reserve request.

The initial consideration though is that during any time of the day, the system needs to dispose of enough battery capacity as well as power, in order to provide secondary regulation without affecting active power injection from its normal operation (clipping + power-shifting). There could be periods of the day where not enough battery capacity is available to provide this power reserve for the time requested by the grid operator. Moreover, having to charge/discharge energy during the day for secondary regulation purpose could affect the performance of normal operation and the economic retributions from injecting this active power.

Further to this initial consideration, when the grid controller requests power curtailment/reserve (after an over-frequency/under-frequency event occurs), there are a couple of additional points to consider:

1. Power curtailment/reserve needed must be lower than the maximum charging/discharging rate of the DC-DC converters and of the batteries.
2. Energy curtailed/increased (P_2 x t_2) must be lower than the battery capacity itself. (P_2 is the power requested, and t_2 is the time requested to curtail/increase this power, which is normally of longer duration than that for primary frequency response).

Below shows how the optimization algorithm, used to provide clipping and power-shifting services, using the time-of-use tariff, can be affected in the different periods:

<u>Power curtailment request:</u>

1. Battery initially fully charged. If grid operator requests power curtailment, at the initial stage of this period, none of this curtailed power would be stored. The further along this period the contingency event occurs, the more curtailed power that could be stored, but some may not.
2. The greater the forecasted solar output that day, the more discharged the battery will be at the beginning of this period. Therefore, the more it could store if there is a sudden over-frequency event, and power curtailment is needed.
3. Battery initially fully charged. If grid operator requests power curtailment, at the initial stage of this period, none of this curtailed power would be stored. The further along this period the contingency event occurs, the more curtailed power that could be stored, but some may not. Also, this is the most economically critical time. However, if the grid controller requests for this secondary regulation it cannot be avoided, if already contracted, without having economic penalizations.
4. Battery 0% charged, so all battery available for storing curtailed power.

<u>Power reserve request:</u>

1. Battery initially 100% charged, so can supply power needed if the battery is correctly sized for this service (sized for what it has offered in the secondary regulation market). The further along this period the contingency event occurs, the less charge will be available, therefore the less power reserve available. However, how much this is affected depends on the forecasted solar production that day, since what will be discharged during this period are the equivalent excesses that are predicted to be produced.
2. Battery discharged to a value equal to the forecasted excesses. The greater the forecasted solar production that day, the less energy it has available (the less time it can provide that power requested).
3. Battery 100% charged, so can supply power needed. It would coincide with peak time injection. However, in this particular case, it is when power is being demanded the most. There are two options:
    - If power of battery system is not increased, the power needed for selling in peak time will need be partly sacrificed for this service (it would mean not all energy stored for selling in peak period will be discharged in time before this period ends).
    - Increase power (discharging rate) of battery system (DC-DC converters and batteries) so that it is able to provide this secondary regulation service, as well as continue injecting the same amount of energy during this period for power-shifting service.
4. Battery 0% charged, so cannot provide secondary regulation here.

It is important, in order to avoid penalizations from the secondary regulation market, that if the DC coupled battery system is to provide this service, it must be able at all times to provide the power it has sold in the market the day before. Even though the grid controller may not need to use it the next day, the system needs to be prepared for this power request, and consequently earn the second part of the economic benefits ("availability").

For 5MW minimum power offered (as currently imposed in Spanish legislation):

In the example used in previous chapters (DC/AC ratio of 1.4, P = 3345 kW (1 inverter)), in order to offer the minimum power of 5 MW, the plant must be of a minimum capacity of 25.7 MW. This is calculated by using the following equation:

$$P_{plant,MIN} = \frac{P_{sec,reg,MIN}}{P_{batt,MAX}} \cdot P_0 \qquad (30)$$

With such consideration though, no additional battery sizing is provided. Therefore, this can have a significant impact on the optimization algorithm developed (clipping + power-shifting service), as we can see now. Below shows how in quarterly hourly periods (maximum time grid operator requests this service is 15 minutes), the battery system is affected.

For Figure 72 below, we are considering a DC/AC power ratio of 1.4, with a battery size of 2600 kWh. The maximum power that can be delivered, by considering only normal operation, would be: 2600 kWh / 4 hours = 650 kW. Hence why the maximum it reaches in the graph is at 650 kW. At 5 MW secondary regulation power offered in the market, since the minimum number of inverters for this minimum power value (due to current legislation) would be 8 inverters (as calculated above), each DC-coupled battery system would have to provide 5000/8 = 625 kW of power for secondary regulation. This is power level is possible with the existing batteries for normal operation (650 kW). However, there are cases where secondary regulation cannot be provided, as explained below.

For power up service, using the same battery dimensioning as for clipping and power-shifting services, during 51% of the quarterly hour periods it would not be possible to provide this secondary regulation. This is disregarding changes from charging to discharging mode, which would affect active power injection (normal operation – clipping + power-shifting), as well disregarding reductions in active power injection in a certain quarterly hour period. The point here is that during 51% of the time, secondary regulation cannot be provided since there is not enough energy to charge/discharge the 5 MW minimum power at that time. From the current grid code regulations (P.O. 7.2), this is unacceptable since secondary regulation must be available throughout the entire programmed period it has been offered for.

The similar thing happens for power down service, where during 55% of all quarterly hour periods, secondary regulation cannot be provided. Therefore, it can be concluded that the size of the battery system needs to be increased in order to provide this service, and during the economic analysis these new capital costs will have to be considered.

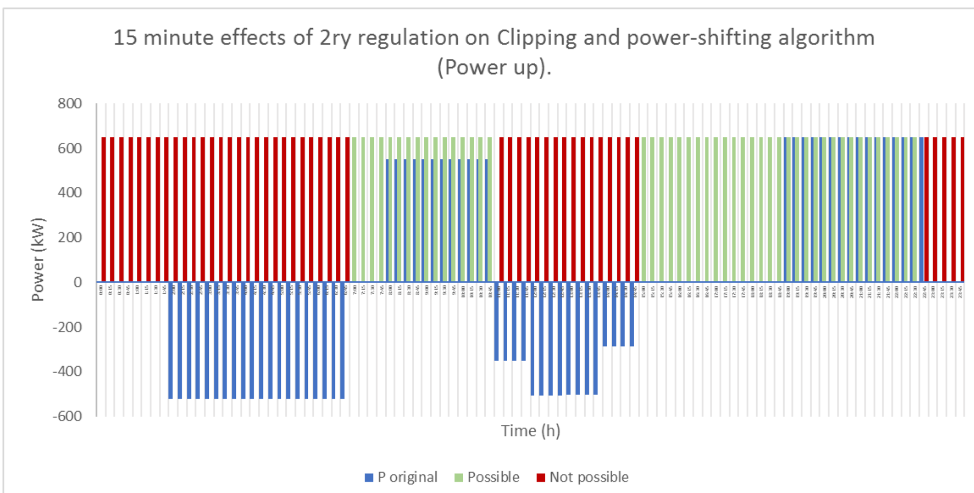


Figure 71: Availability of secondary regulation (power reserve) in each quarterly hour period of the day, for the current battery sizing, at DC/AC ratio of 1.4.

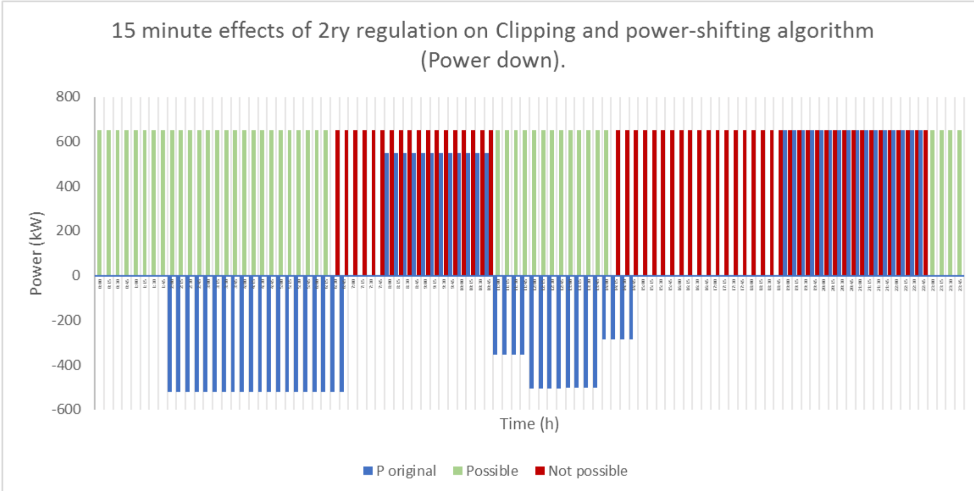


Figure 72: Availability of secondary regulation (power curtailment) in each quarterly hour period of the day, for the current battery sizing, at DC/AC ratio of 1.4.

The provision of secondary regulation service and the consequent increase in battery size and power needed in the system means it would affect the Max NPV method described earlier, since using this method, for the characteristics of the plant (DC/AC ratio, location, etc), the algorithm may generate a smaller optimal battery size, which is not large enough to store all energy curtailments during such requests by the grid controller, even for 100% capacity available from the battery. Therefore, there are two options:

- To add the corresponding increase in battery power and capacity for this service to the NPV optimized battery size already calculated for clipping (100 kWh for DC/AC power ratio of 1.4).
- Use the 20-year lifetime battery criteria (2600 kWh for DC/AC power ratio of 1.4).
- Maintaining same battery size in the DC-coupled system, and adding an AC coupled system (with inverter-charger and ESS).

Option 2 was the most viable choice after concluding this in Chapter 5. Therefore, an additional capacity will be proposed to be added to this battery system, in order to analyze the technical and economic viability of this proposal.

In the example already used, for a DC/AC power ratio of 1.4, a battery size of 2600 kWh is used per inverter, with a maximum charging/discharging power of 650 kW (0.25C) per inverter.

Adding secondary regulation will require both an increase in capacity and power. The additional power per inverter needed will depend on how big the plant is. From Spanish regulations, a minimum of 5 MW needs to be offered for renewable power plant generation. However, this total power can come from the sum of all inverters connected in parallel to each other.

From equation (25), the minimum plant capacity needed can be calculated.

Using the example above, if the minimum plant capacity to provide the minimum of 5 MW of secondary regulation is of 25 MW (8 inverters), the power reserve to be provided per inverter would be calculated with:

$$P_{sec,reg,inv} = \frac{P_{sec,reg}}{N_{inv}} = P_{sec,reg} \cdot \left(\frac{P_{inv,max}}{P_{plant}}\right) \qquad (31)$$

For this example, this results in 5000 kW / 8 = 625 kW.

Thus, the total power provided by the battery system, per inverter can be calculated with:

$$P_{batt\_syst,inv} = P_{batt\_syst,normal} + P_{sec.reg,inv} \quad (32)$$

This would be 650 kW + 625 kW = 1275 kW.

Similarly, the additional capacity needed can be divided between the number of inverters (dependent on plant capacity). Battery capacity needed to provide this power reserve/curtailment is calculated with the following equation:

$$C_{sec,reg} = 2 \cdot P_{sec,reg} \cdot t_{max} \qquad (33)$$

Note how there a multiplication factor of 2 as well in the equation. The reason for this is because there needs to be a capacity available for curtailment (charging), and there is also needs to be a charge equivalent in the battery to dispose for power reserve (discharging).

For the minimum of 5000 kW to be provided, for a maximum duration of 15 minutes, the total energy needed to be supplied/curtailed is 2 x 5000 x (15/60) = 2500 kWh. Using the same example as above (Plant capacity: 25 MW), this would be 312.5 kWh per inverter.

Thus, the total battery capacity per inverter would be calculated by:

$$C_{batt,total} = C_{batt,normal} + C_{sec,reg} \qquad (34)$$

For this example, this would be: 2600 + (156.25 + 156.25) = 2912.5 kWh.

The capacity of 312.5 kWh has been divided into two to emphasize that 156.25 kWh will always be available for 5 MW power curtailment (charging), and another 156.25 kWh will always be available in the battery strictly for 5 MW power reserve (discharging).

Note however, even though increasing battery size allows providing for Frequency Response Service (power change response to a variation of the grid frequency outside the dead-band limits) and Secondary Regulation, without affecting the optimization algorithm for clipping and power-shifting, this is not entirely true.

- In moments when during normal operation the battery is charging (Periods 2 and 4), and suddenly there is an under-frequency event (or power reserve request from the grid operator) the battery needs to revert now to discharging.

In terms of energy, as long as restricting the capacity needed in the new over-sized battery just for this use, there will always be enough to respond to primary and secondary regulation. However, in terms of power, this affects normal operation (clipping + power-shifting algorithm) during that period (maximum of 15 minutes as the worst case). The solution here is, if this occurs, once Secondary Regulation request ends, optimization algorithm reverts to its original operation, therefore reverts to charging for the remainder of that period (period 2 or 4), in order to completely charge the battery before the period ends. This consequently means increasing slightly the power to compensate for the 15-minute contingency event where charging has stopped.

The results below show that for 38% of quarterly periods, normal operation (clipping + power-shifting algorithm) is affected. This is an improvement from before when no additional sizing of the battery system was considered. In the next chapter, further proposals to improving this will be made. For now though, the optimization algorithm (normal operation) needs to adjust itself to complete its charging/discharging period on time, in order to have a minimal effect on the active power injection.

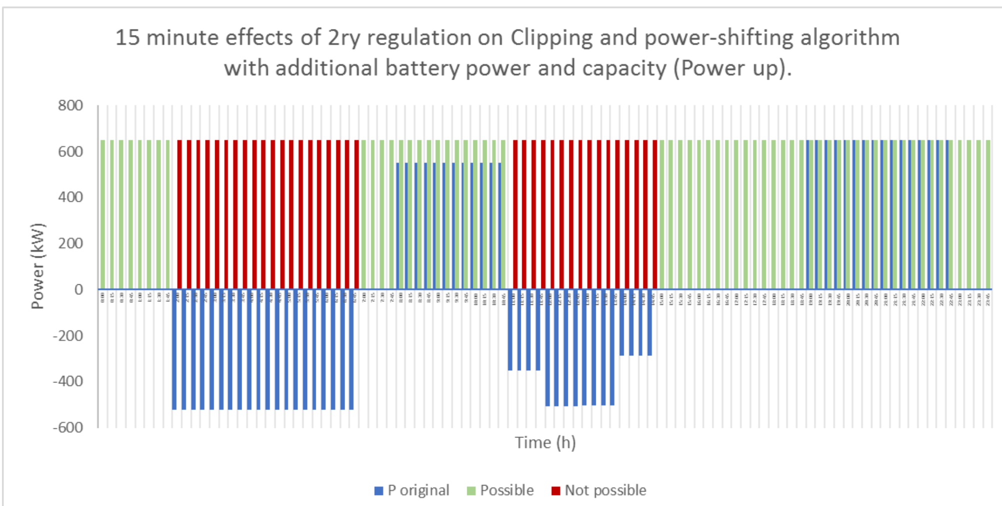


Figure 73: Availability of secondary regulation (power reserve) in each quarterly hour period of the day, for the current battery sizing, at DC/AC ratio of 1.4., by considering additional sizing for this service.

- Similarly, in moments when the battery is in discharging mode (Periods 1 & 3), and suddenly there is an over-frequency event (or power curtailment request from the grid operator), the battery needs to revert now to charging.

  In terms of energy, as long as restricting the capacity needed in the new over-sized battery just for this use, there will always be enough to respond to primary and secondary regulation. However, in terms of power, this affects normal operation (clipping + power-shifting algorithm) during that period (maximum of 15 minutes as the worst case). The solution here is, if this occurs, once Secondary Regulation request ends, optimization algorithm reverts to its original operation, therefore reverts to discharging for the remainder of that period, in order to completely discharge the required amount of the battery before the period ends. This consequently means increasing slightly the power to compensate for the 15-minute contingency event where discharging has stopped.

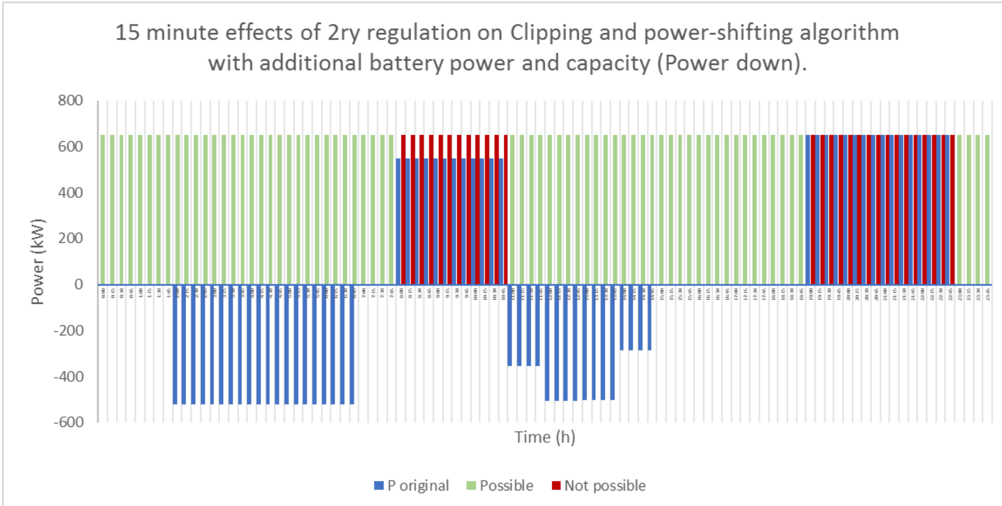


Figure 74: Availability of secondary regulation (power curtailment) in each quarterly hour period of the day, for the current battery sizing, at DC/AC ratio of 1.4., by considering additional sizing for this service.

It can be seen that the main increase here is in power and not battery capacity. Therefore, there are two considerations here:

- During normal operation (clipping + power-shifting), due to having a slightly larger capacity, the depth of discharge will be less, C-rate will also be slightly less. This will have positive effects towards the lifetime of the battery.
- However, during contingency events, the C-rate will be very high, which have a negative impact on the lifetime of the battery.

Overall, this should incur less battery replacement costs. However, depending on the number of contingency events and when they occur, it will require the use of higher C-rates, where its impact may alter the lifetime of the battery in a negative way.

7.3. Results

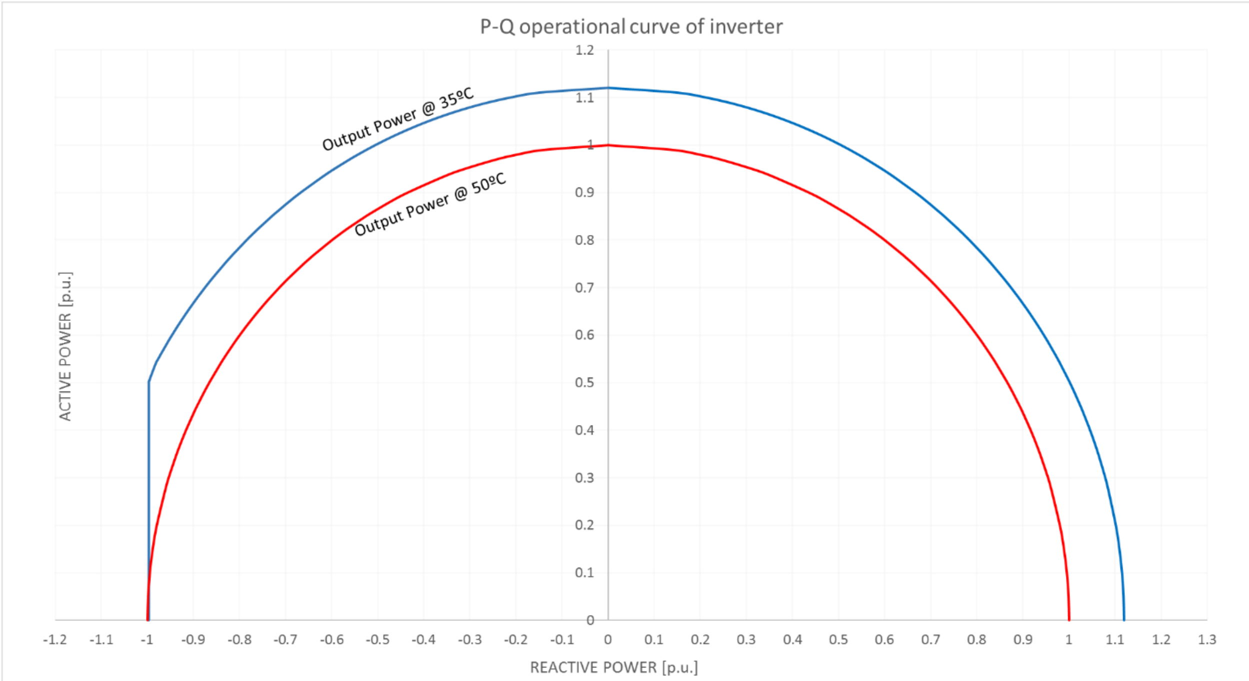
7.3.1. Primary Regulation

The following are the results for Valencia (following each of the steps described in the methodology):

1. Design temperature: 35°C.

2. At this temperature, using equation (19), the maximum power it can deliver is 112 %.

3. This would comply with the 110% required.



4. Thus, the AC power would be limited in the software to: $\frac{100\%}{112\%} \cdot 100 = 89\%$.

5. Then, during a frequency response where 10% of rated power is required, this limit is disabled, and all available power from the array is provided.
6. However, as mentioned earlier, since we are limiting the power, the number of inverters needed may increase.

   For a 50 MW plant (total inverter capacity – rated power at Point Of Interconnection), using the Freesun HEC FS2800CH15 inverters, where the available capacity at 35ºC is 3136 kVA, the number of inverters needed is: $\frac{50000}{3136} = 15.9$ ≈ 16 inverters.

   If the power is now limited to 89%, from equation (21), the number of inverters needed then is:

   $\frac{50000}{3136} \cdot \frac{1}{0.89} = 17.9$ ≈ 18 inverters.

   Therefore, to provide up to 10% power reserve, for the design temperature and the total power of this plant, 2 more inverters are needed.

In terms of the energy source, three options were described in the methodology:

Option 1:

The energy source to provide this 10% power reserve in this case means increasing the array size also. The associated costs for this configuration (for a 50 MW plant) would be approximately 11500000 €.

Option 2:

The power reserve now comes from installing a battery system coupled on the AC side with a PCS (inverter-charger) connected in parallel to the solar plant. To provide this 10% of rated capacity (total inverter power), during 15 minutes (as demanded by the grid code), using the same example above, from equation (22), it would require a battery capacity of: $0.1 \cdot 50000 \cdot \left(\frac{15}{60}\right) = 1250\ kWh$.

Using 2017 battery costs per kWh, (as used in the clipping and power-shifting case studies – *see Chapters 5 & 6*), from equation (24), the associated costs of installing this battery system is:

$$1250[kWh] \cdot 520\left[{}^{€}/_{kWh}\right] + (0.1 \cdot 50000)[kW] \cdot 72\left[{}^{€}/_{kWh}\right] = 1010000€$$

It is clear after comparing options 1 and 2, that an AC-coupled battery system makes the most economic sense.

This follows after a comparison of the oversizing costs (extra inverter costs + oversized array costs) for a photovoltaic plant in Valencia, for different plant capacities (9.4 MW, 18.8 MW, 28.2 MW, 37.6 MW, 47.0 MW, 56.4 MW, 65.9 MW, 75.3 MW, 84.7 MW and 94.1 MW) and DC-AC ratios (1.15, 1.20, 1.25, 1.30, 1.35, 1.40, 1.45). As explained and illustrated in earlier chapters, the cost increase as power capacity increases is linear, as shown in Figure 76 below. Furthermore, the cost increase due to DC/AC power ratio is also linear, since the number of panels needed is directly proportional to the DC/AC power ratio used, thus a linear increase in cost.

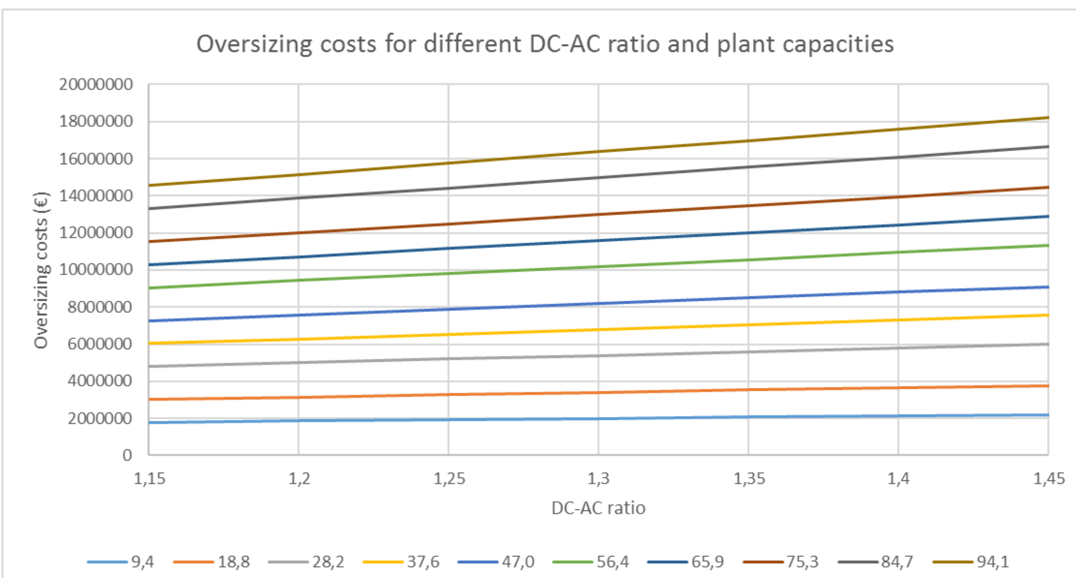


Figure 75: Oversizing costs for FRS provision, taking into different DC/AC power ratios and plant capacities.

The following graph (Figure 77) also shows how for a 9.4 MW plant (3 inverters of FS2800CH15), the costs of a battery system coupled on the AC side is more cost-effective than oversizing inverters and array to meet this 10 % power reserve as defined by the proposed grid code requirements in Spain, in accordance with the new European legislation (UE 2016/631). It can be seen also that as the DC/AC power ratio increases, the cost difference is higher, since there are more solar panel costs incurred. Meanwhile the battery system costs are independent of the DC/AC power ratio since even though more plant power is available, the rated power to be delivered to the grid is unchanged (number of inverters are still the same). It is also important to note that for the case of option 1 (over-sizing array and inverter), the inverter costs represent a small fraction of the total costs here.

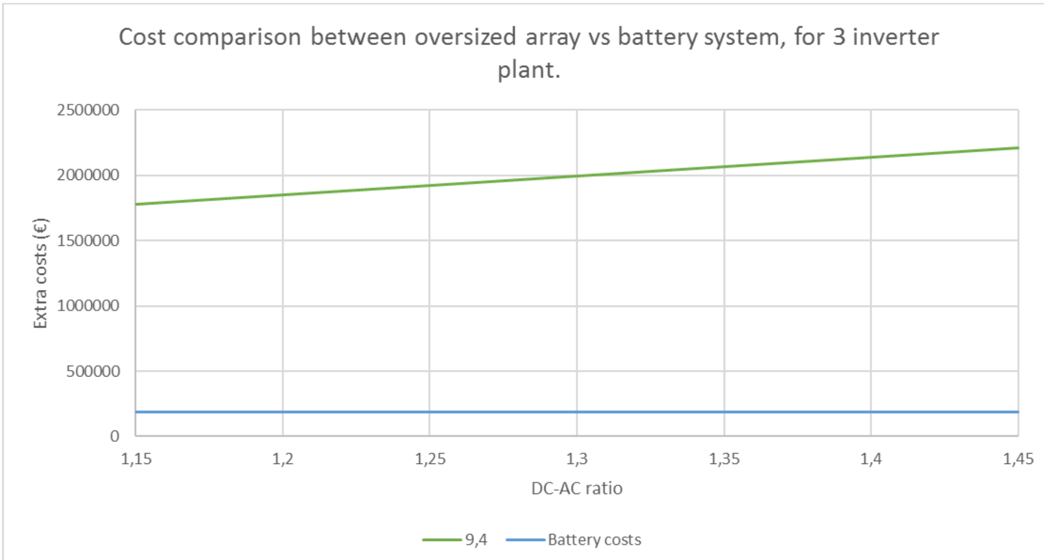


Figure 76: Cost comparison between oversized array (Green curve) vs AC-coupled battery system (Blue line), for a 9 MW plant.

At this point, it can be concluded the following:

The cost of oversizing the number of inverters in option 1 to achieve the 10% reserve is relatively small compared to the alternative of installing batteries on the AC side, for option 2. However, there are two fundamental disadvantages with option 1:

- The results above show that when taking into account the array sizing costs, a battery system is significantly cheaper. Nevertheless, spending approximately 62000€ on a battery system per inverter to provide a non-compensated but obligatory service means that more study has to be carried out in order to find a more economically optimized solution. Having said this, it can also be added that battery prices, as projected by well-respected institutions and companies (NREL, JRC, GTM), are going to continue to drop, thus this system will be even more beneficial in the near future.
- Having an oversized array is not completely reliable. It will not always guarantee a 10% power reserve at all times since it depends on the solar resource at that particular moment. The proposed UE 2016/631 grid code however does facilitate this by providing a reserve range from 1.5% to 10%. Nevertheless, it can be somewhat unreliable for the grid operator. Below shows how much reserve from the oversized inverters can be provided at the different times of the day, with clear skies. It can be seen in Figure 78 below that in Valencia, for the design temperature of 35°C, the power reserve that can be provided with oversized inverters (at 35°C each inverter can give 112% rated power → P_{limit} = 89%) during every hour of a typical day with clear skies. Results show that on a clear day with 10% array oversizing, that 10% power reserve can be provided from 11:00 up to and including 17:00.

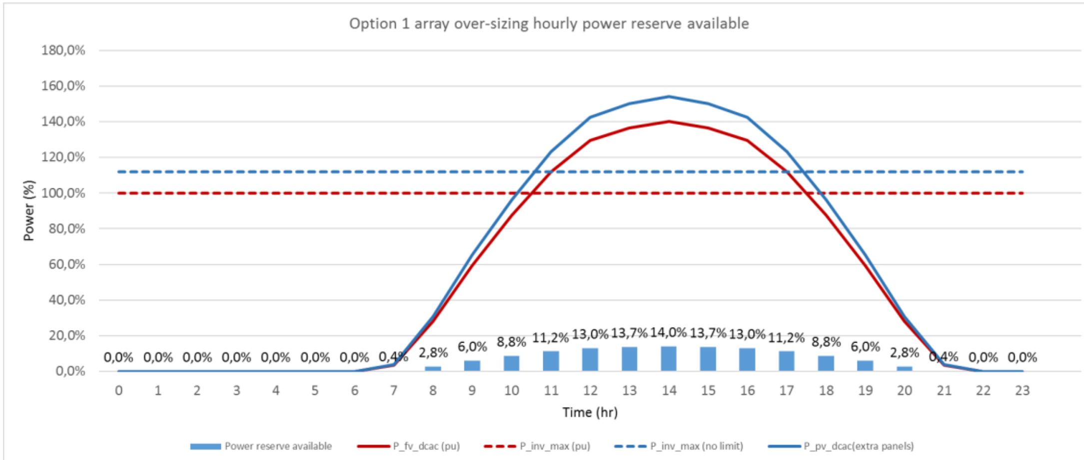


Figure 77: Provision of power reserve on a clear day, with option 1 (auxiliary array + oversized inverter).

Figure 78 above shows the power reserve available for an ideal day with clear skies and nominal irradiance reaching the panels (with no cloud cover). However, in many days there will be cloud cover, and power reserve available will not be the same. Figure 79 shows an example of a cloudy day and the results. This day shows a day with significant fluctuations and generally low power output. As a result, no PV excesses (*see Chapter 4*) are actually produced on this day. Even more so, when an under-frequency event in the grid occurs, the power reserve never reaches the maximum of 10% that could be required. In days like this, there is a deficiency in the power reserve, when using over-sized inverters with extra strings as the energy source. Using extra panels as the energy source presents two significant disadvantages:

- 10% more panels incur significant costs.
- It is completely dependent on the solar resource at that moment.

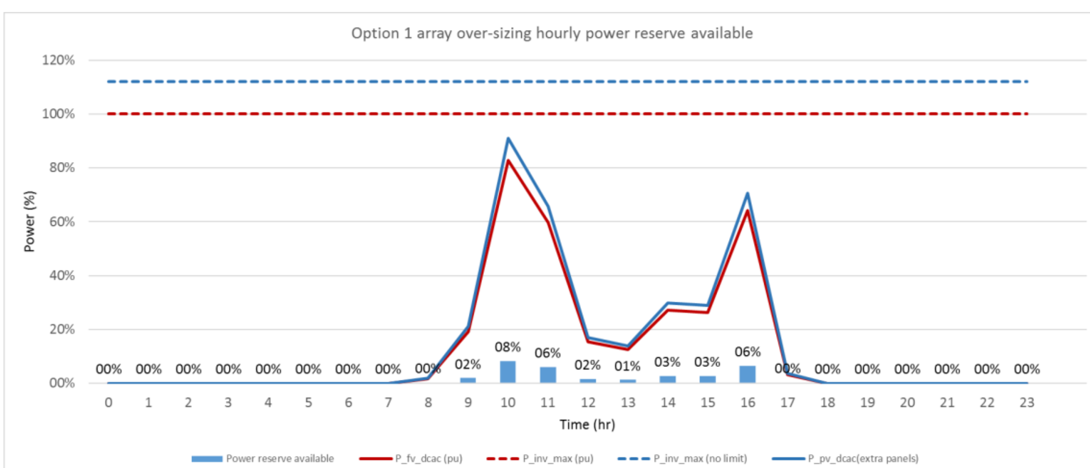


Figure 78: Provision of power reserve on a cloudy day, with option 1 (auxiliary array + oversized inverter).

Therefore, in line with the novel system proposed in this thesis, as well as with the intention of reducing the capital costs of this service, option 3 is studied as well. Here, the oversizing inverter proposal remains, but without increasing the array size, since this was the biggest cost contributor and not completely reliable.

Therefore, when there is a contingency event, the power limit of the inverter is disabled, and so using the total available resource, there will be a variable power reserve. From Figure 80 below, it can be seen that on a clear day, from 11:00 to 17:00, a 12% power reserve is available for the conditions imposed earlier (T_{design} = 35ºC in Valencia). This power reserve is simply obtained from delimiting the inverter so that it has full capacity available. Due to the over-sizing of the inverters, the inverter has more capacity when delimited. In a clear day, the amount of power reserve available depends on the step increase of the inverter capacity, as long as the solar output curve is still above or equal to the new inverter capacity limit. In this option, no further array over-sizing has been added, since here the option is of disposing of the DC-coupled battery system in order to meet the power reserve requested.

Figure 79: Provision of power reserve on a clear day, with option 3 (DC-coupled battery system).

During an under-frequency contingency event, if even more power is needed (perhaps on a day with cloud cover, or hours outside the 11:00 to 17:00 peak time range), the DC-coupled battery system (via the DC-DC converter) will provide some of this (depending on the hour of the day, following the algorithm already implemented for PV excesses and power-shifting).

The figure below shows how the oversized inverter solution with DC-DC support (option 3) is more economical than the AC coupled battery system proposed previously (option 2).

Figure 81 compares the 3 options for a plant capacity of 9.4 MW (3 inverters) and a DC/AC power ratio of 1.4. The results show that option 3 (oversized inverter + DC-DC support) is the most economical.

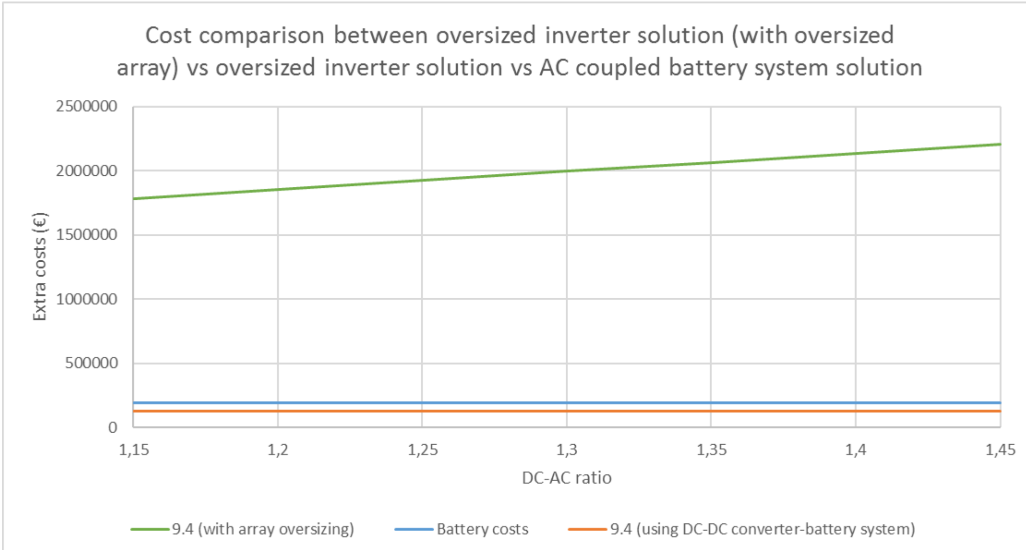


Figure 80: Cost comparison of the 3 options for FRS, for a plant of 9MW capacity and DC/AC power ratio of 1.4.

Furthermore, In Figure 82, only the oversized inverter solution (with DC-DC support) and the AC-coupled battery system solution are compared, since oversizing the PV array has been discarded due to excessive costs that would be incurred, as shown in Figure 81 already.

From the results below, one can see that DC-AC power ratio is not a factor. This is because in both solutions oversizing of panels is not required. What these costs actually depend on is the power size required for primary frequency regulation, which depends on the grid code requirements (10% of plant capacity), and on the plant capacity.

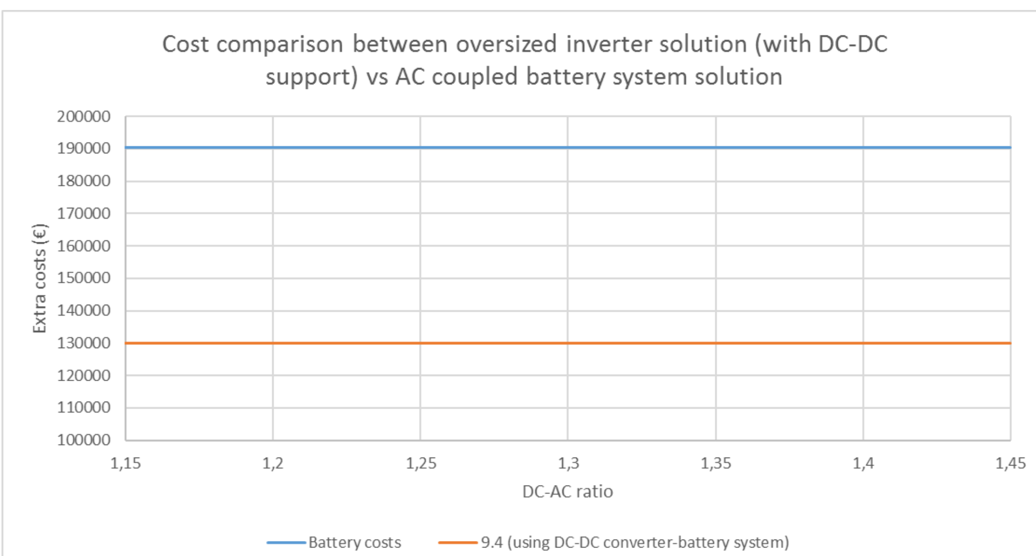


Figure 81: Cost comparison between oversized inverter with DC battery support vs AC-coupled battery system, for a plant of 9MW capacity and DC/AC power ratio of 1.4.

The cost reduction of using the inverter oversizing + DC-DC support solution over the AC-coupled battery system is:

$$\frac{(19000 - 130000)}{190000} \cdot 100 = 31.7\%$$

If the plant capacity increases, this cost reduction also increases. For example, for a 94.1 MW plant (30 inverters), the cost reduction compared to the equivalent AC coupled battery system for that capacity, is 72.7 %.

The next parts show the results when taking into account the extra DC coupled battery costs, due to the increase in battery size (and power in both batteries and DC-DC converter).

It should also be noted that in this comparison, the AC battery system costs include the batteries, as well as the PCS (bidirectional inverter) and the associated transformer on the AC side. Not only this but it is necessary to apply a multiplication factor of 1.1. This takes into account the extra cabling costs from coupling a PCS in parallel to the solar inverter, as well as estimated planning and permission costs to installing this extra equipment.

The results show that the oversized inverter option (with DC-DC support) is still cheaper when taking into account the extra battery size requirements for this frequency response service. Furthermore, cost difference increases as plant capacity increases, linearly.

A line of best fit has been drawn since for the oversized inverter solution the points do not form a straight line. This is because depending on the plant capacity, for the apparent power that this inverter disposes of, in some cases it can be oversized with less inverters than others, thus the cost increase is not exactly linear, when comparing it with an inverter model (Freesun FS2800CH15). Nevertheless, the tendency is clear that the cost increase is linear.

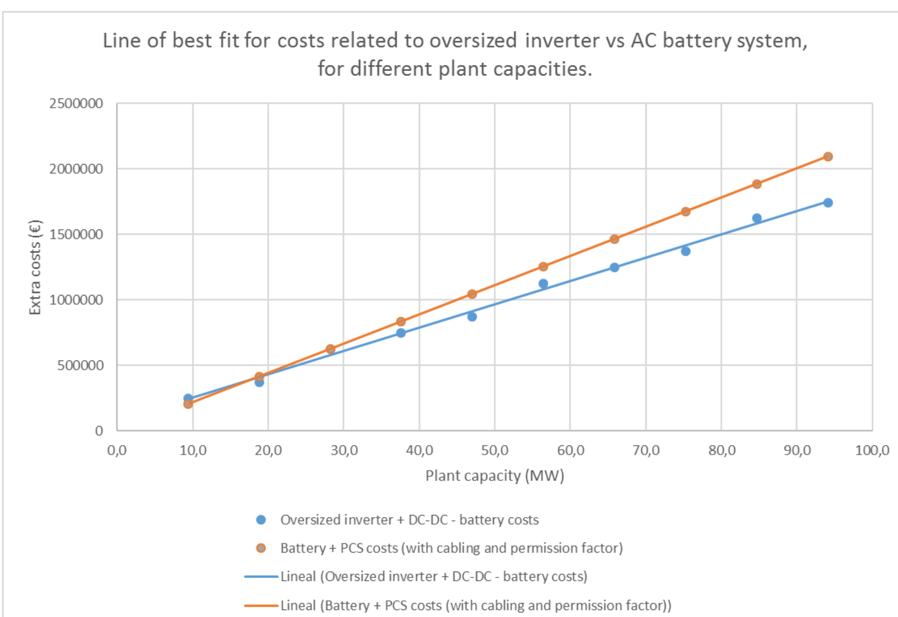


Figure 82: Oversizing costs vs power capacity, to provide FRS.

In terms of sizing (power and energy) of the battery system, for the example used of a DC/AC power ratio of 1.4, we have the following:

Energy:

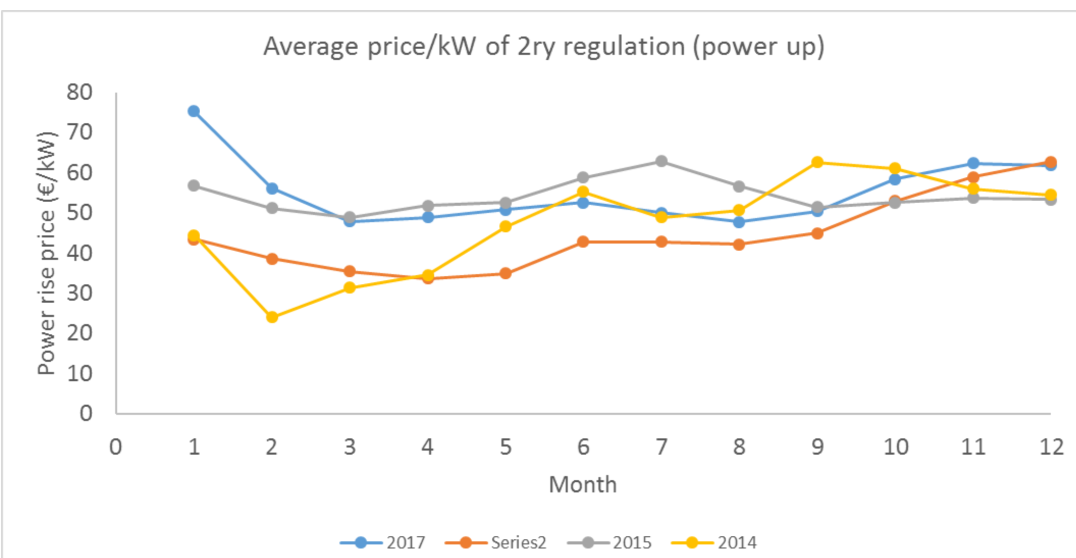
- Clipping + Power-shifting: 2600 kWh (battery size used for DC/AC power ratio of 1.4).
    - Costs already considered (*see Chapter 6*).
- PFR: 2 x P x t = 334.5 x 15/60 = 83.625 kWh x 2 = 167.25 kWh
    - This incurs an extra battery capacity cost of 83.625 x 520 (€/kWh) = 86970 €.
    - The reason for duplicating the battery size is because 83.625 kWh free capacity is needed to be available in the battery when there is a power curtailment, and 83.625 kWh of capacity is needed when power reserve is requested.

Power:

- Clipping + Power-shifting: 2600 kWh /4 hours (time during peak period discharge) = 650 kW.
- Primary Frequency Response: 10% x P_N = 0.1 x 3345 = 334.5 kW.
    - As discussed previously, this extra power will be used from the power reserve available from secondary regulation service. Therefore, no extra costs incurred here.

7.3.2. Secondary Regulation

Below show monthly average prices for secondary regulation provision, from the years 2014 to 2017. The reason these years have been studied is because during this time the installed capacity in terms of renewable energy sources did not change much in Spain. Nevertheless, despite renewable energy capacity not changing, there are significant variations observed, for both power up and power down deviations.



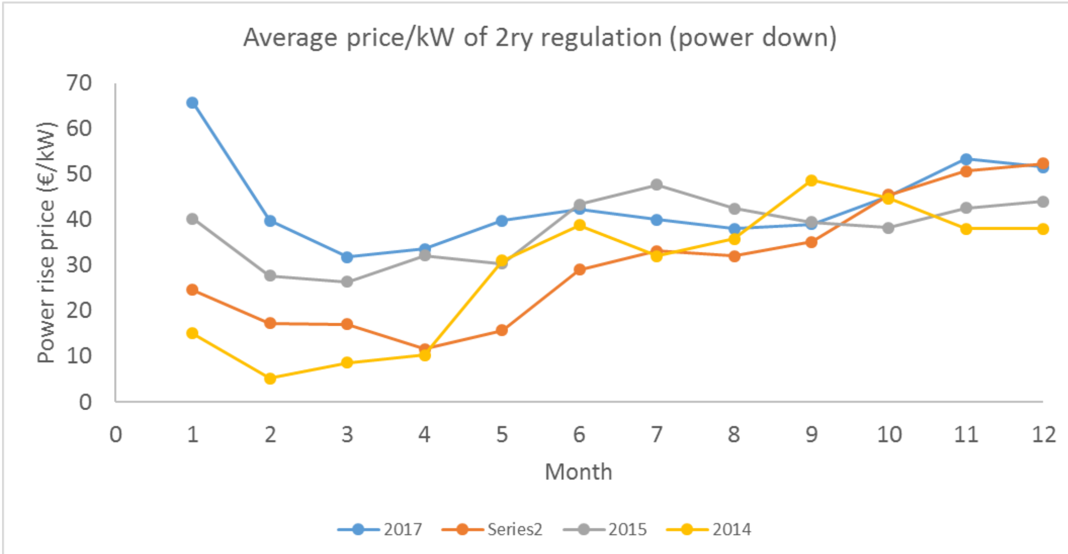


Figure 83: Average monthly price per kW of secondary regulation between 2014 and 2017, for (a.) power up deviation; (b.) power down deviation.

After studying the differences in the different years, it can be concluded that even though there is a fixed installed capacity, there are various factors that affect the market price. These are:

- The variation between the forecast production and the actual production, and in different quantities.
- Demand deviations are independent of the availability of generation.
- For the same energy deviation, market price can vary, depending on the type of generation that offers this service. For example, if a large percentage is offered by combined-cycle generators, this will push up the price. If instead, the wind resource is high, since the marginal cost of this technology is significantly less compared to fossil fuel dependent power stations, the market price will drop. This can be seen in the following graphs. In the results for 2014, it can be seen that the market price for raising power during the months of January to March does not correlate with the high amount of energy being deviated. This is because these months also coincide with a high wind resource. Therefore, many wind farms were able to offer this service at a relatively low marginal cost. During the rest of the months of this year, the price seems to follow the amount of deviated energy, until reaching November-December where the price again drops due to having increased wind energy available during the winter months.

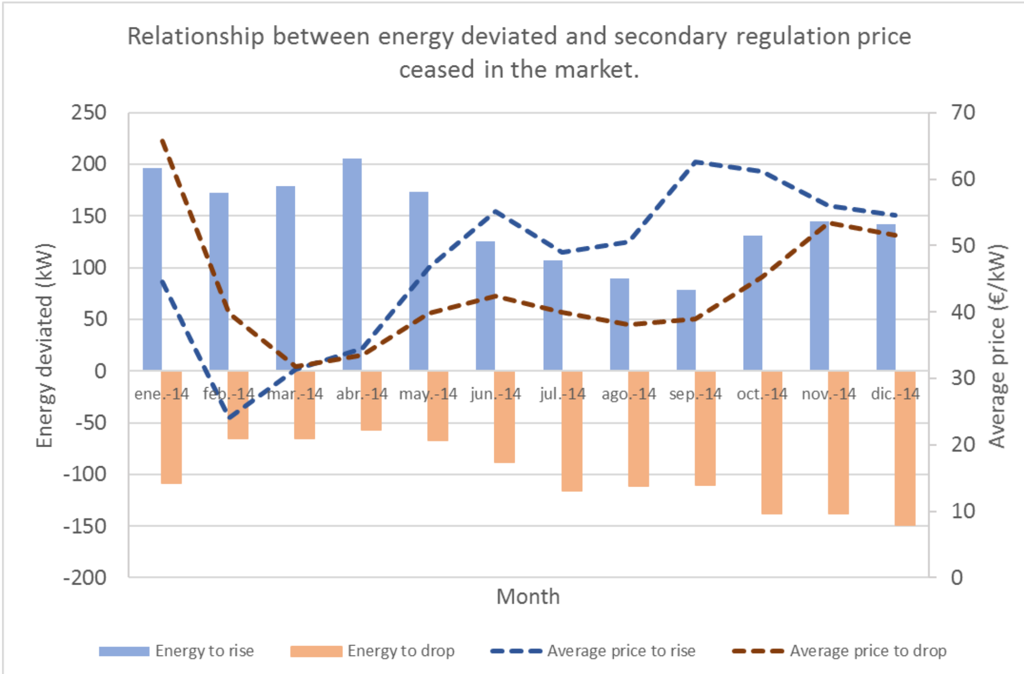


Figure 84. Relationship between energy deviated and secondary regulation price ceased in the market, for 2014.

Similar thing is observed during February-march in 2017. Results are shown in Figure 86.

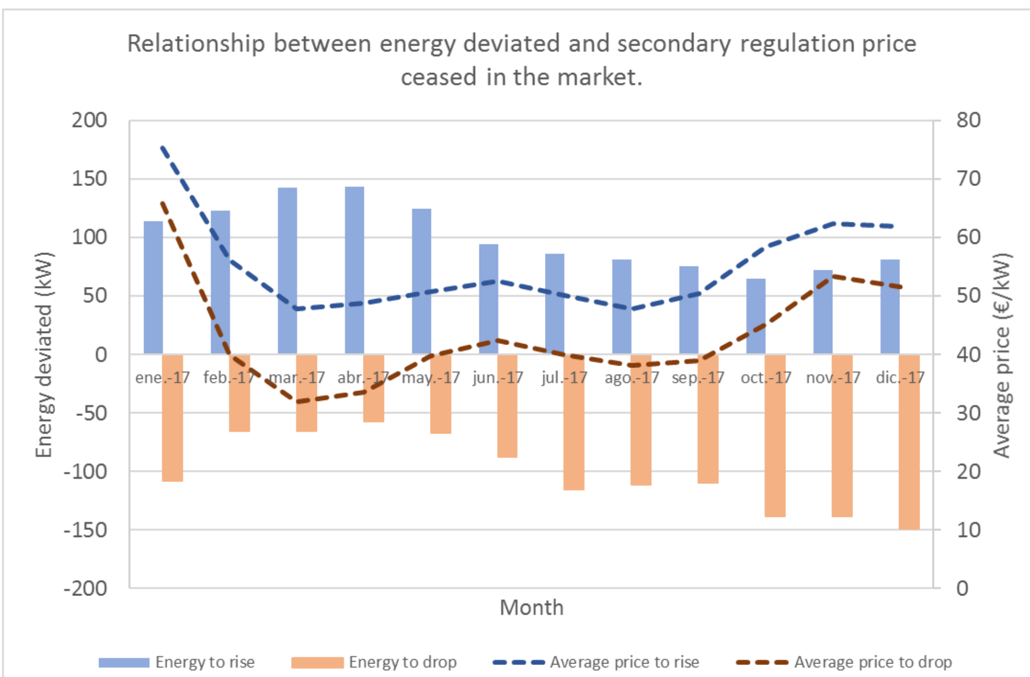


Figure 85: Relationship between energy deviated and secondary regulation price ceased in the market, for 2017.

What can be concluded though is that the price at which secondary regulation is offered is directly related to the amount of energy that needs to be diverted. If we only take this into account, it is being assumed the following:

- no regulatory changes, that could affect a base price offered in the market.
- no market mechanism changes that could affect the cessation of the market price.
- Type of generation offered is the same.

For our model then, whether demand deviates or generation deviates, the secondary regulation price will be directly related to the energy being deviated. This principle will form the weighted average price to be calculated between the years 2014 and 2017 (fixed capacity installed), where the weighted average will depend on the energy deviated and average price during every month of those four years.

$$\overline{\Pi_{sec,reg}} = \frac{\sum_{m=1}^{48}(\overline{\pi_{sec,reg,m}} \cdot E_{deviated,m})}{\sum_{m=1}^{48}(E_{deviated,m})} \qquad (35)$$

Therefore, the base prices to be used in the model are calculated to be the following:

$\overline{\Pi_{sec,reg,UP}}$ = 48.65 €/MWh

$\overline{\Pi_{sec,reg,DOWN}}$ = 32.33 €/MWh.

From the methodology, it has been established already that an additional battery sizing is needed (in both power and capacity) in order to allow for the following:

- To allow for secondary regulation to automate at any time (quarterly period).
- To mitigate the impact it has in normal operation (clipping + power-shifting service).

As shown before, the former has been solved with the increase in battery capacity and power. As for the latter, there is still a percentage of times (38% and 29% for power up and power down respectively) where it has an impact on normal operation, depending on the time of these power requests from the grid operator. Figure 72 and figure 73 shows the quarter-hourly periods that are still affected. Using that initial groundwork, several of these different quarter-hourly periods are investigated further.

<u>Case 1:</u>

At 02:00 it is usually the start of valley period, where the battery begins to charge to full capacity during the duration of 5 hours. If a power reserve request is made during this time, the algorithm will then readjust the power needed (respecting the maximum charging power possible) in order to try and charge the battery to 100% SoC before the end of valley period. The graph below shows, that during these 15 minutes, the energy not charged as a result is represented by the following equation:

$$E_{not_{charged}} = P_{charge,T} \cdot \left(\frac{15}{60}\right) = \frac{C_{batt,normal}}{T} \cdot \left(\frac{15}{60}\right) \qquad (36)$$

$$E_{not_{charged}} = \left(\frac{2600}{5}\right) \cdot \left(\frac{15}{60}\right) = 130\ kWh$$

(Note: this equation can also be used in the cases for energy not discharged). The energy not charged during this quarterly hour period is 130 kWh. This means that the algorithm must adjust in order to additionally charge this 130 kWh, along with the rest of the programmed amount, during the remaining time of this period.

Therefore, the additional power to be provided by the battery system to perform this compensation can calculated using the following equation:

$$\Delta P_{adjust}\left[\frac{kW}{15mins}\right] = \frac{\frac{E_{not_{charged}}}{(^{15}/_{60})}}{T-t\ [mins]} \qquad (37)$$

In this example, the charging power adjustment is of 27.4 kW per quarterly period.

Following from previous conditions proposed (using the minimum power to be offered of 5 MW, for a plant capacity of 25 MW), where maximum power of battery system is 650 kW (for normal operation) + 625 kW (secondary regulation of 5 MW) = 1275 kW, it can be seen that it is well within this limit.

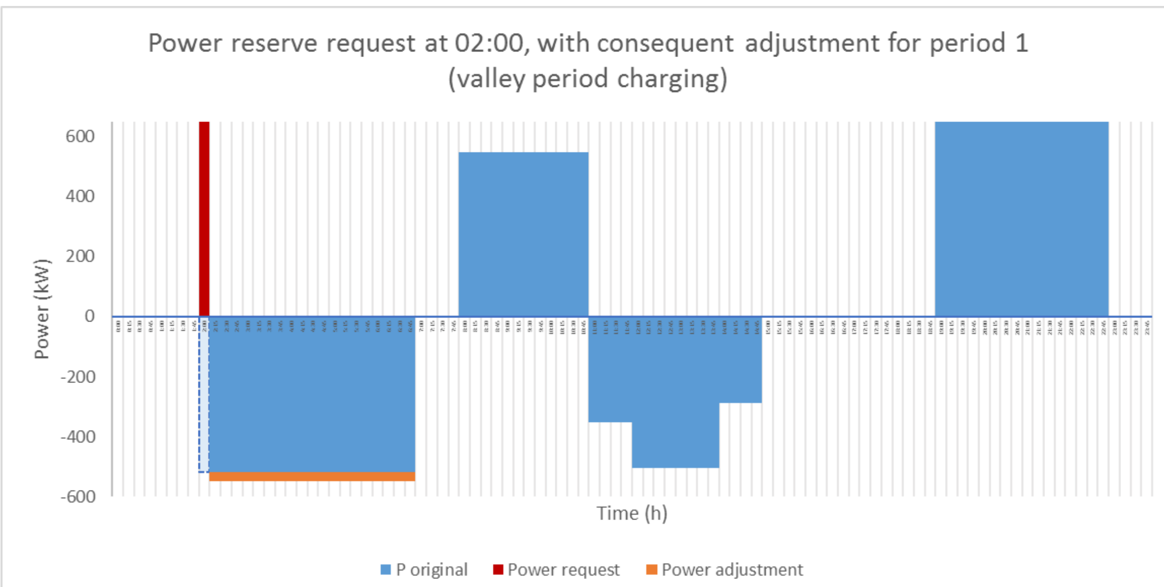


Figure 86: Secondary regulation impact on normal operation - Case 1 results.

<u>Case 2 (limiting case):</u>

On the other hand, if this power request were to be made at 06:30, the battery system will have to work harder in order to provide this compensation before the end of valley period at 07:00. After the power request, this would only give the battery system a further 15 minutes to provide the remaining original energy plus the curtailed energy during the power reserve request. To do this, using equation (32), the required charging power adjustment therefore needs to be 520 kW. If this power is added to the original power (normal operation) of 650 kW, the total charging power needed in that quarterly hour period is 1170 kW. This is still below the 1275 kW limit. The point is, as long as we provide this service with the minimum plant capacity (as calculated), during this period, there will be enough power.

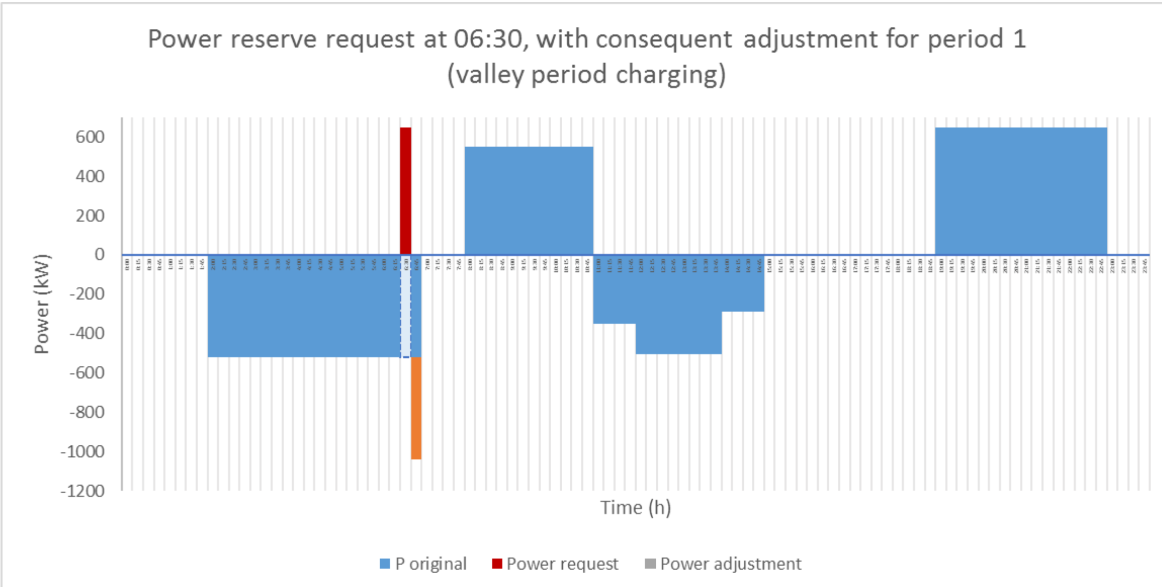


Figure 87: Secondary regulation impact on normal operation - Case 2 results.

<u>Case 3:</u>

At 19:00, it is the start of peak period, where the battery begins to discharge all its capacity during the duration of 4 hours of this period. If a power curtailment request is made during this time, the algorithm will then readjust the power needed (respecting the maximum discharging power possible) in order to try and discharge the battery to 0% SoC (already taking into account max DoD of 80%) before the end of peak period. The energy not discharged during this quarterly hour period is 162.5 kWh. This means that the algorithm must adjust in order to additionally discharge this 162.5 kWh, along with the rest of the programmed amount, during the remaining time of this period.

Therefore, the additional power to be provided by the battery system to perform this compensation can calculated using equation (32). In this example, the discharging power adjustment is of 43.3 kW per quarterly period.

Following from previous conditions proposed (using the minimum power to be offered of 5 MW, for a plant capacity of 25 MW), where maximum power of battery system is 650 kW (normal operation) + 625 kW (secondary regulation for 5 MW) = 1275 kW, it can be seen that it is well within this limit.

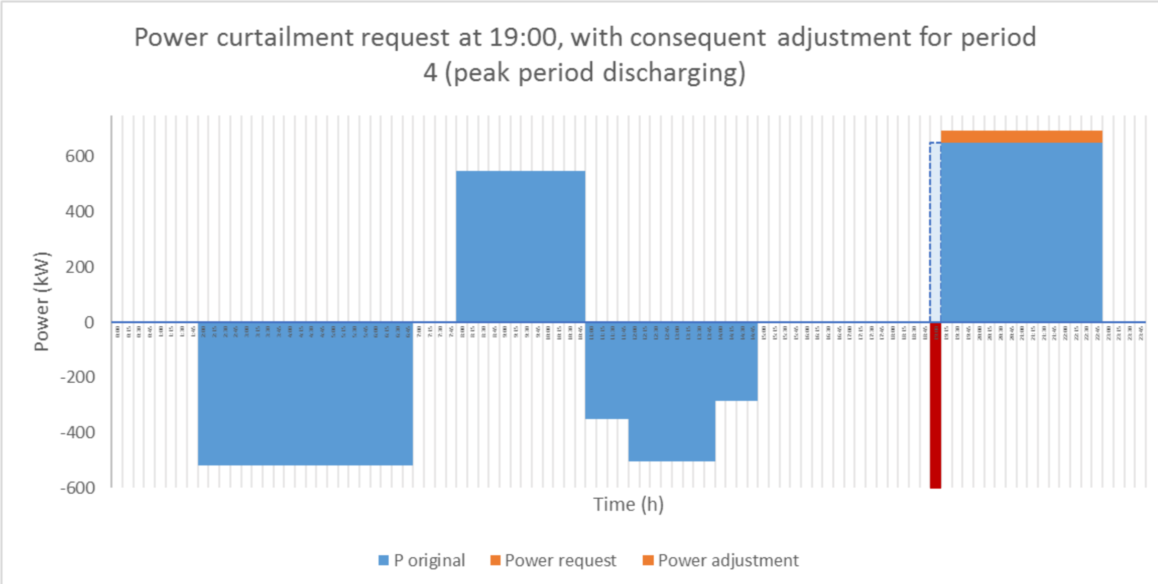


Figure 88: Secondary regulation impact on normal operation - Case 3 results

<u>Case 4 (limiting case):</u>

On the other hand, if this power request were to be made at 22:30, the battery system will have to work harder in order to provide this compensation before the end of peak period at 23:00. After the power curtailment request, this would only give the battery system a further 15 minutes to provide the remaining original energy plus the curtailed energy during the power curtailment request. To do this, using equation (32), the required discharging power adjustment therefore needs to be 650 kW. If this power is added to the original power (normal operation) of 650 kW, the total discharging power needed in that quarterly hour period is 1300 kW. This is slightly above the 1275 kW limit. Therefore, the only way to provide this power is to either slightly increase further the battery power of the system, or another alternative is to dispose of demand response (*more detail in Chapter 8*).

<u>Case 5: Power reserve in peak period.</u>

If instead a power reserve request is made, the extra power sized for secondary regulation (625 kW) is disposed of, along with the 650 kW needed for normal operation in order to discharge the whole battery during this period. The total power needed is the maximum power available, as has been sized.

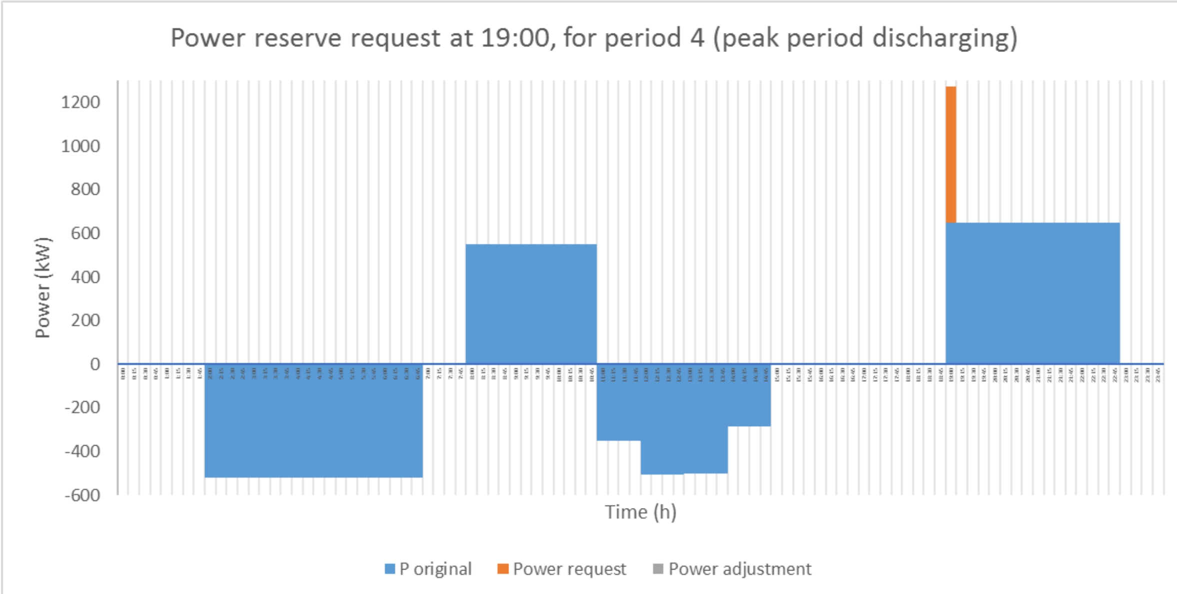


Figure 89: Secondary regulation impact on normal operation - Case 5 results

<u>Case 6: Power curtailment in period 2 (with high solar production).</u>

At 12:00 on this same day (an example of a day with high solar output), the charging power required due to the forecasted excesses, is of 506 kW. If power curtailment request is made (625 kW), the total power required is 1131 kW, which is below the limit. Also, since there is no change in battery mode, there is no effect on the performance of the normal operation algorithm. The only condition to be met is that the total power is below the maximum power possible.

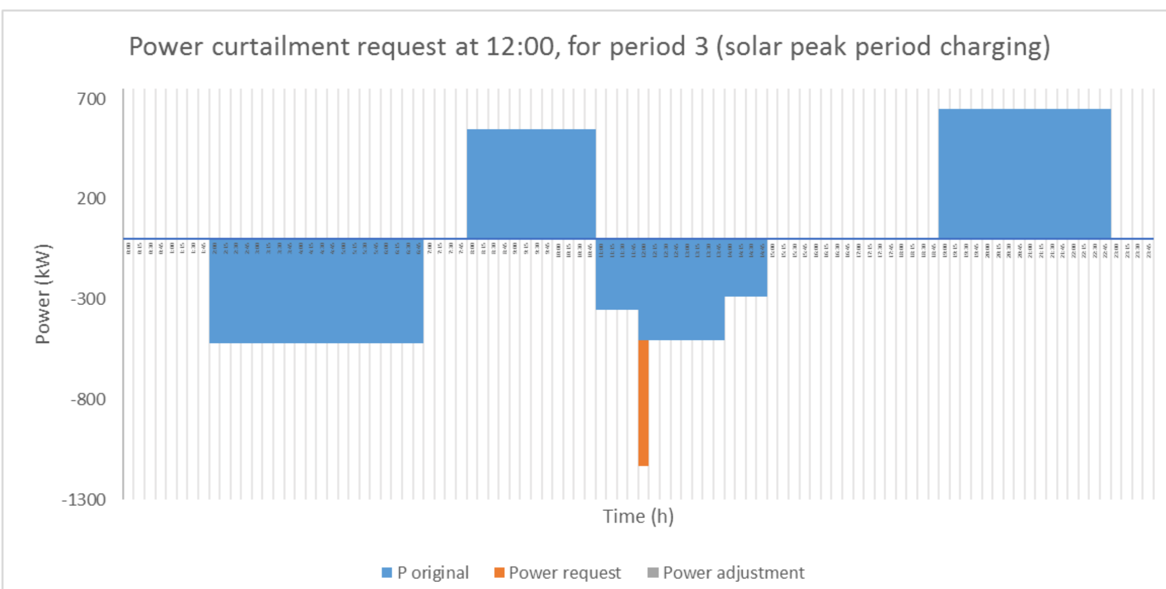


Figure 90: Secondary regulation impact on normal operation - Case 6 results

Case 7: Power reserve in period 2 (with high solar production).

In this event, when battery discharge is required during excess producing period (period 3), then the excesses produced during this 15-minute contingency event is lost. There is no way of retrieving this free energy. The amount of energy lost depends on the excess produced during those 15 minutes. The economic loss would be the product of the excess loss and the peak period price.

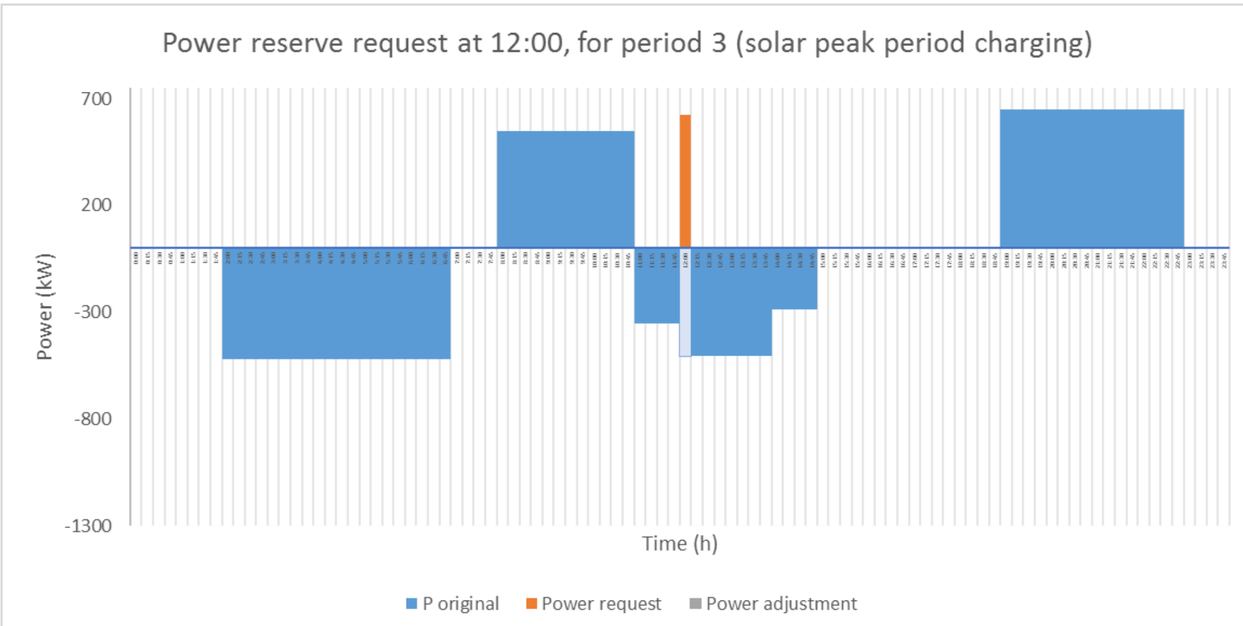


Figure 91: Secondary regulation impact on normal operation - Case 7 results

Case 8: 10:45.

On the other hand, if this power curtailment request were to be made at 10:45, the battery system does not have time to compensate the necessary discharge required during this period, since this period ends at 11:00. Therefore, this will mean not all excesses produced in period 3 will be able to be charged, and so there is a loss of free energy. The amount lost depends on the solar irradiance during that day, since the higher this is, the more excesses will be produced and so more will be discharged during period 2. Figure 93 shows a sample day of a power curtailment request made at this time.

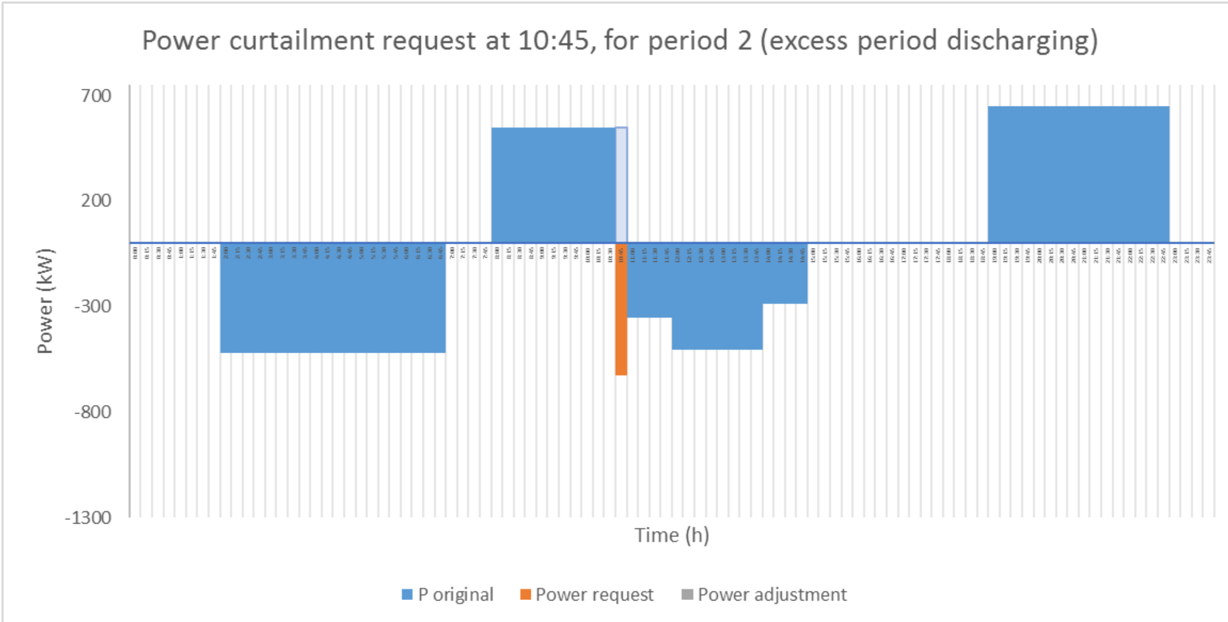


Figure 92: Secondary regulation impact on normal operation - Case 8 results

<u>Case 9: 22:45</u>

Similar to Case 8, the energy lost during these 15 minutes cannot be recovered, since it occurs in the last 15 minutes of this period. Therefore, the optimization algorithm does not have time after the power request to compensate in terms of battery power (even though there is sufficient battery power). Figure 94 shows this.

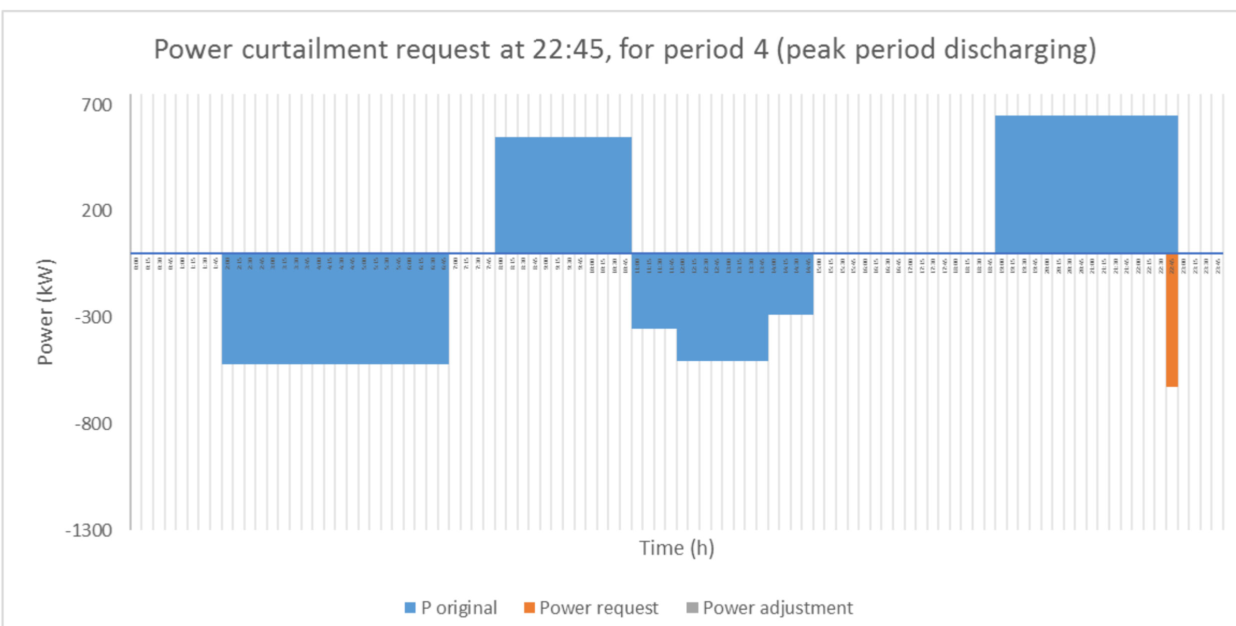


Figure 93: Secondary regulation impact on normal operation - Case 9 results

7.3.2.1. *Economic losses during such limiting events, and mitigation measures proposed*

Power request can be made without affecting economic returns in normal operation in all hours except:

- Power up: 06:45, 11:00, 11:15, 11:30, 11:45; 12:00, 12:15, 12:30, 12:45, 13:00, 13:15, 13:30, 13:45, 14:00, 14:15, 14:30, and 14:45.
- Power down: 10:45, 22:30 and 22:45.

For these quarterly-hourly periods another solution needs to be proposed.

The energy loss implications for each of these affected quarter-hourly periods are:

1. <u>06:45</u>

   Energy loss:

   $$E_{loss} = \frac{C_{batt}}{T} \cdot \left(\frac{15}{60}\right) \qquad (38)$$

   Economic loss:

   $$\Pi_{loss,06:45} = E_{loss}\left[\left(\pi_{pk} - \pi_{val}\right) - \left(\pi_{pk} - \pi_{sh}\right)\right]$$
   $$\Pi_{loss,06:45} = E_{loss}\left[\left(\pi_{sh} - \pi_{val}\right)\right] \qquad (39)$$

   If a contingency event occurs at this time, not all the battery will then be able to be charged. The battery will be charged up to ($C_{batt} - E_{loss}$). This would bring economic losses, corresponding to the product of the energy loss and the price difference between peak and valley period. In order to compensate this, in period 2 (excess discharging), less is discharged. More specifically, an amount equal to E_{loss} is not discharged during this period, so that when excesses are produced in period 3, the whole battery will now be charged for peak period (assuming forecasted excesses match actual excesses).
   This means that the economic loss will be a factor of ($\pi_{sh} - \pi_{val}$) instead of ($\pi_{pk} - \pi_{val}$). There is one condition though, the amount of excesses forecasted to be produced that day needs to be greater than E_{loss}, in order for the battery to fully charge before peak period and have a mitigated economic loss.

2. <u>11:00, 11:15, 11:30, 11:45; 12:00, 12:15, 12:30, 12:45, 13:00, 13:15, 13:30, 13:45, 14:00, 14:15, 14:30, and 14:45.</u>

   During any of these quarter-hourly periods, the effect is the same, the excesses produced by the PV array during those 15 minutes are lost.

   In order to mitigate this economic loss, during detection of such an event, after excess period ends, the algorithm will recover this energy lost (and as a result fully charge the battery) by importing energy from the grid (in this case, it would be at shoulder price). The idea here is so that full capacity is available for peak period, even though part of it has been bought in shoulder period. The original economic loss in such an event therefore is:

$$\Pi_{excess,loss} = P_{excess} \cdot \left(\frac{15}{60}\right) \cdot \pi_{pk} \qquad (40)$$

The mitigated economic loss therefore is:

$$\Pi_{excess,loss,mit} = P_{excess} \cdot \left(\frac{15}{60}\right) \cdot \pi_{pk} - P_{excess} \cdot \left(\frac{15}{60}\right) \cdot \left(\pi_{pk} - \pi_{sh}\right) = P_{excess} \cdot \left(\frac{15}{60}\right) \cdot \pi_{sh} \qquad (41)$$

Moreover, during this time, when excesses are produced, the inverter is at full capacity. Therefore, the plant cannot actually meet this power request, unless there is an extra power reserve coupled on the AC side to the plant, such as an AC coupled battery system.

3. 10:45.
If power down request occurs at this time, then not all the required energy will be discharged. At the end of period 3 (solar peak period), the battery will be fully charged and prepared for peak period. However, by not discharging the correct amount during period 2 (solar discharging period), the following things have occurred:

Not discharging this amount results in an economic loss equal to the product of this energy by the shoulder period price. The idea in this period, as explained previously, is to discharge an amount equal to the forecasted excesses so that an economical profit is made using the difference between shoulder and valley period, then using the free energy charged to fully charge the battery and sell at peak price.

$$\Pi_{loss,10:45} = \frac{E_{excess,day'n'}}{T_{period2}} \cdot \left(\frac{15}{60}\right) \cdot \pi_{sh} \qquad (42)$$

4. 22:30.
As explained earlier, the total discharging power needed in that quarterly hour period is 1300 kW. This is slightly above the 1275 kW limit. If no modifications to the hardware are made (e.g. increase in battery power or disposal of demand response), then during this period, there will be an economic loss of the following amount:

$$\Pi_{loss,22:30} = (2 \cdot P_{discharge} - P_{discharge,max}) \cdot \left(\frac{15}{60}\right) \cdot \pi_{pk} \qquad (43)$$

Note though that this loss is variable, and in most cases, there won´t be any. In this example, for a minimum power request of 5 MW and having 8 inverter system, the extra supply of inverter power needed is 5000/8 = 625 kW. Therefore, the total power per inverter is 1275 kW. However, if a slightly greater battery power is installed, there would not be a loss anymore.

5. 22:45.
If a contingency event occurs at this time, there is no time after that to inject the energy lost during the previous 15 minutes, in order to sell at peak price, since this period ends at 23:00. The economic loss as a result is the following:

$$\Pi_{loss,22:45} = (P_{discharge}) \cdot \left(\frac{15}{60}\right) \cdot \pi_{pk} \quad (44)$$

The power requests can vary in frequency and hour during each day. There may be days where both power up and down requested are made several times, and there may be days where no power request is requested from the grid operator to a particular power plant. It depends on the generation-demand unbalances, power flows and system operator strategy at the time.

For the purpose of this study, it will be assumed that one power up and power down service is requested per day. This means that during the whole year, there will be a total of 365 x 2 = 730 requests from the system operator.

It will also be assumed that the probability that it occurs in a certain quarter-hourly period is equal during any time of the day. (This is not entirely accurate, since e.g. at times of the day of higher demand, the deviation may be higher).

Each of the 9 limiting cases discussed earlier has a probability of occurrence of 1/48. Therefore, the estimated economic loss during the year can be calculated by the following equation:

$$\Pi_{loss,total,yearly} = \sum_{c=1}^{20}\left[\Pi_{loss,c} \cdot \left({}^{1}/_{48}\right)\right] \cdot 730 \quad (45)$$

Since every of the impacting contingency events has different economic impact, the equation can be elaborated to the following:

$$\Pi_{loss,total,yearly} = \left[\Pi_{loss,06:45} \cdot \left(\frac{1}{48}\right) + \Pi_{loss,10:45} \cdot \left(\frac{1}{48}\right) + \Pi_{loss,22:30} \cdot \left(\frac{1}{48}\right) + \Pi_{loss,22:45} \cdot \left(\frac{1}{48}\right)\right] \cdot 730 + \sum_{q=11:00}^{14:45} \Pi_{loss,q} \cdot \left(\frac{1}{48}\right)$$

$$= \left[\frac{C_{batt}}{T_{period1}} \cdot \left(\frac{15}{60}\right)\left[(\pi_{sh} - \pi_{val})\right] + \frac{E_{excess,day'n'}}{T_{period2}} \cdot \left(\frac{15}{60}\right) \cdot \pi_{sh} + \left(2 \cdot \frac{C_{batt}}{T_{period4}} - P_{discharge,max}\right) \cdot \left(\frac{15}{60}\right) \cdot \pi_{pk} + \left(\frac{C_{batt}}{T_{period4}}\right) \cdot \left(\frac{15}{60}\right) \cdot \pi_{pk}\right] \cdot \left[\frac{730}{48}\right] + \sum_{q=11:00}^{14:45} P_{excess} \cdot \left(\frac{15}{60}\right) \cdot \pi_{sh} \cdot \left(\frac{1}{48}\right)$$

$$= \left[\frac{15}{60}\right] \cdot \left[\pi_{pk} \cdot \left(\frac{3}{4} \cdot C_{batt} - P_{discharge,max}\right) + \pi_{sh} \cdot \left(\frac{C_{batt}}{5} + \frac{\overline{E_{excess,day'n'}}}{3}\right) - \pi_{val} \cdot \left(\frac{C_{batt}}{5}\right)\right] \cdot \left[\frac{730}{48}\right] + \sum_{q=11:00}^{14:45} P_{excess} \cdot \left(\frac{15}{60}\right) \cdot \pi_{sh} \cdot \left(\frac{1}{48}\right)$$

$$= \left[\frac{15}{60}\right] \cdot \left[\pi_{pk} \cdot \left(\frac{3}{4} \cdot C_{batt} - P_{discharge,max}\right) + \pi_{sh} \cdot \left(\frac{C_{batt}}{5} + \frac{\overline{E_{excess,day'n'}}}{3} + \overline{P_{excess}} \cdot 16\right) - \pi_{val} \cdot \left(\frac{C_{batt}}{5}\right)\right] \cdot \left[\frac{730}{48}\right] \qquad (46)$$

For the example used above (DC/AC ratio = 1.4, C_{batt} = 2600 kWh, $P_{discharge,max}$ = 1275 kW, for an average clear day):

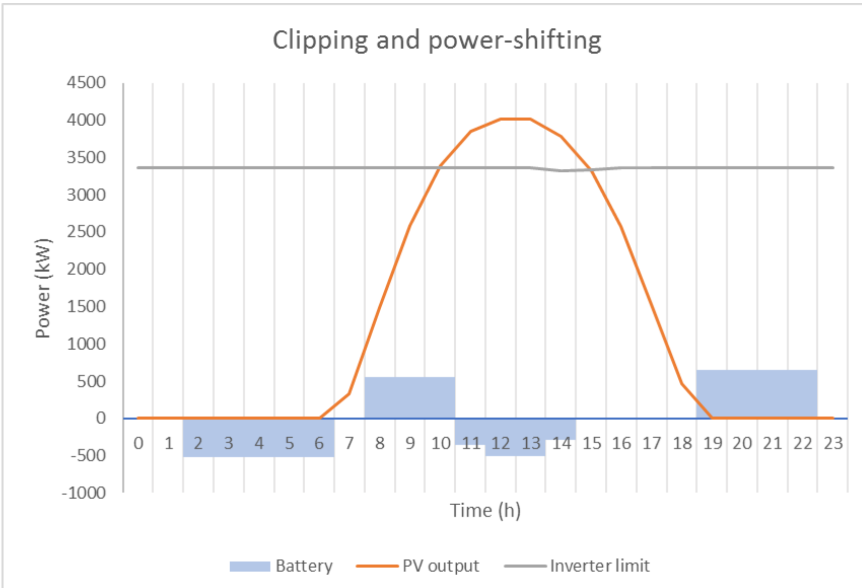


Figure 94: Charge/Discharge cycles for a clear day, with DC/AC ratio of 1.4, and 2600 kWh capacity per inverter.

For these conditions, the annual estimated economic loss is 1394 €. Below show how these losses vary with DC/AC power ratio and with the secondary regulation power offered. It can be seen that this loss does not change much with the secondary regulation power offered. This is because, as commented previously, the loss is independent of this power offered. The only time where it was dependent was for a DC/AC power ratio of 1.4 and 1.45 at a minimum power of 5 MW, where during a 22:30 contingency event, the total power to compensate the loss at this time is not enough to recover all losses. However, when the power offered is greater, then each battery system will have enough.

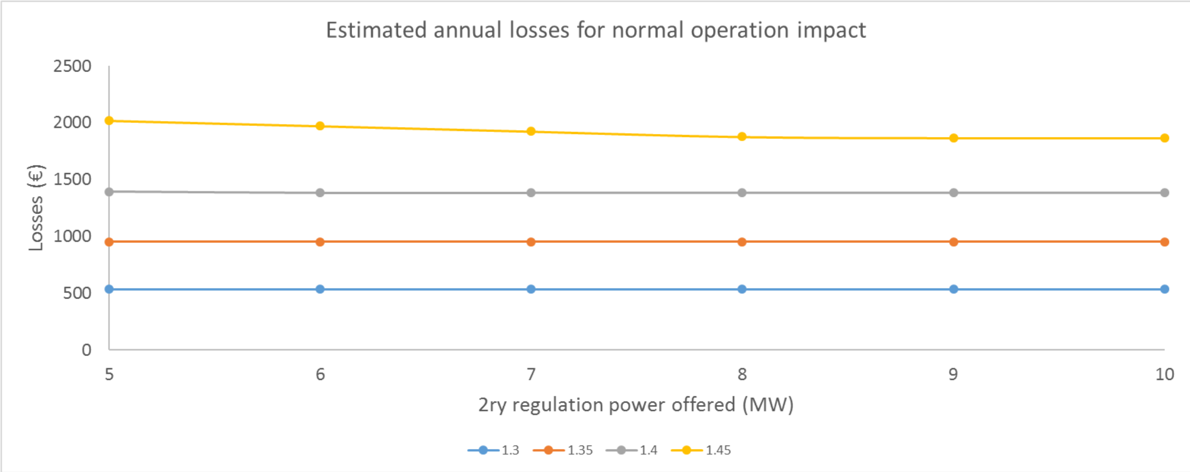


Figure 95: Annual losses estimation on normal operation earnings when incorporating secondary regulation, based on estimated contingency event criteria described above.

The earnings and losses for varying secondary regulation power offered is shown below. The losses shown are for the DC/AC power ratio of 1.4, but compared to the earnings produced, the losses are relatively similar.

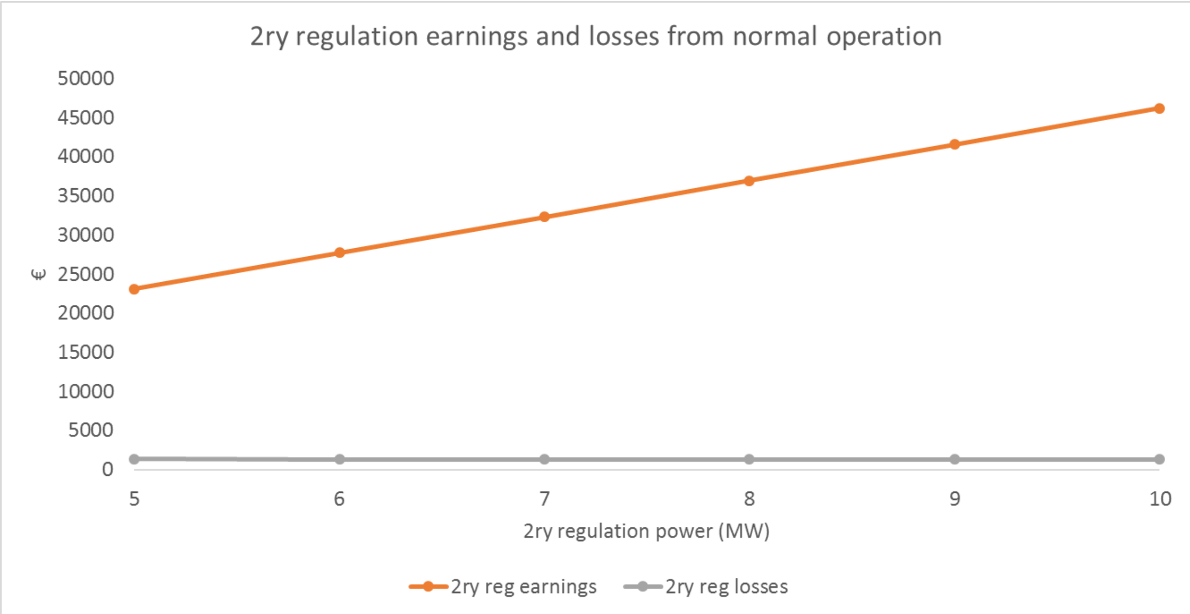


Figure 96: Secondary regulation earnings and resulting estimated normal operation losses.

The profitability of the ESS-coupled PV plant when adding secondary regulation is shown below, for the example used previously.

It can be seen that as more secondary regulation power is offered, even though power size increase by 1 MW, the amount of capacity needed is not that much (since it is only for 15 minutes worth). Therefore, in this case, the capital costs do not have so much effect as in other services offered. The main consideration here though is the extra charging/discharging power needed from the batteries and DC/DC converters as well as the higher C-rates that batteries are used for which ultimately degrades the batteries faster. Meanwhile, the compensation received by offering this service (two components: availability and use) proves to make a profit, with an increase in Net Present Value compared to the previous study of just providing active power excess injection (clipping) and power-shifting service. The increase is significant as shown below, and this increase will rise as battery prices drop during the forthcoming years.

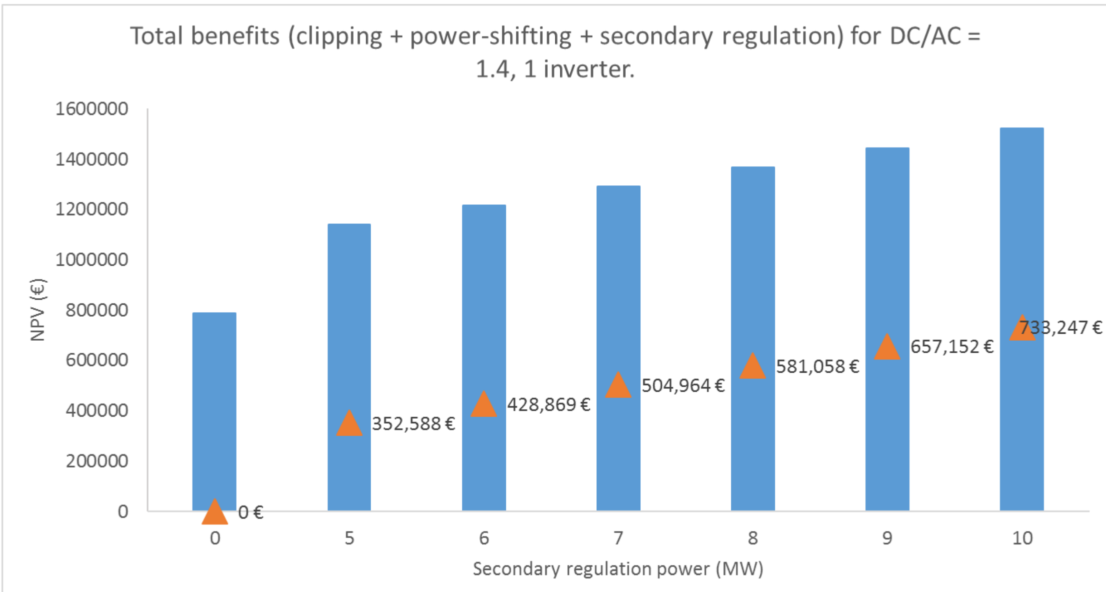


Figure 97: Total benefits with PV excesses, power-shifting and secondary regulation (5 MW), for DC/AC power ratio and 2600 kWh battery capacity, per inverter.

7.4. Conclusion

In this chapter, firstly Primary Frequency Response to fulfill new grid code requirements in Spain has been presented for storage coupled PV power plants. In particular, power reserve/curtailment has been studied, along with its integration with the proposed system and optimization model. The study shows promising results for its integration, in both a technical and economical point of view.

In this primary control, there is no compensation. However, as more renewable capacity is added to existing grids, and grid codes are updated to include more strict controls for renewable energy technologies, this frequency response service becomes obligatory for PV plants.

A comparison of three different options to integrate this service was analyzed. The best option is indeed continuing with our proposed design, over-sizing the inverters, limiting its power output, so that in the event of a drop-in frequency in the grid this power limit is deactivated to provide an extra power reserve. The inverter would have sufficient capacity to provide this, and with sufficient solar resource at that time, the array would provide the energy required. However, in the case of having a lack of PV power to reach the power set-points, the controller would use the DC-coupled battery to fulfill these requirements, which improves the technical performance in comparison with PV plants that are not equipped with storage systems, as well as offering the most economically optimized solution.

The following figure shows the original algorithm (Clipping PV excesses and power-shifting) being performed, with the occurrence of PFR (Primary Frequency Response) at any time of the day. Note PFR here indicates only how power output would vary in any given time, with respect to the normal operation of the plant.

In a grid over-frequency event (above 50.1 Hz in Spanish regulation), PFR would activate and provide a power curtailment between 1.5% and 10% as agreed with the grid operator. The impact of this service with normal operation (Clipping PV excesses and power-shifting) depends on the time of day. For example, during period 3 (solar peak period), when the solar excesses are being stored into the battery, providing a power curtailment for Primary Frequency Response here would cause no impact, since it would mean that more power to be supplied in order to store energy into the batteries. As a result, the only condition here is that the batteries and the DC-DC converter has sufficient charging power to provide all these services.

However, if a power curtailment is required during peak period, when energy from the battery is being discharged, as a result the battery has to revert to charging mode in order to curtail power and provide this frequency response service. This means that during the duration of the contingency event, active power injection would be lost. This, as shown in the secondary regulation considerations, has economic implications.

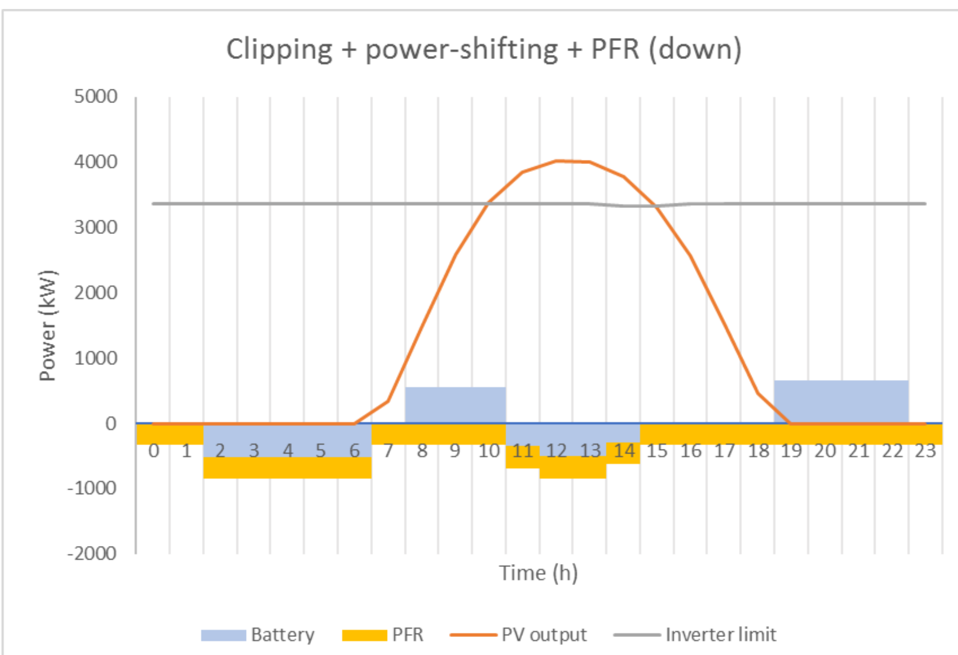


Figure 98: Extra power for power curtailment, during any hour of the day.

In a grid under-frequency event (below 49.9 Hz in Spanish regulation), Primary Frequency Response would activate and provide a power reserve between 1.5% and 10% as agreed with grid operator. The impact of this service with normal operation (PV excesses and power-shifting) depends on the time of day. For example, during period 4 (peak period) when energy from the battery is being discharged, providing a power reserve for Primary Frequency Response here has no impact, since it would mean that more discharging power would be applied to meet this increase in power and match the power reserve requested. The only condition is that the batteries and the DC-DC converter has sufficient discharging power to provide all these services.

If instead power reserve is required during period 3 (solar peak period) when battery is being charged due to the solar excesses produced, then as a result the battery has to revert to discharging mode in order to provide the power reserve requested and provide this frequency response service. This means that during the duration of the contingency event, these free solar excesses to be charged would be lost, and so this would result in a battery capacity with an SoC of less than 100% for peak period discharging. This means there would be a loss in active power injection in peak period. The amount lost is dependent on the solar conditions on that day (The greater the irradiance, the more losses during the maximum contingency event of 15 minutes). This, as shown in the secondary regulation considerations, has economic implications.

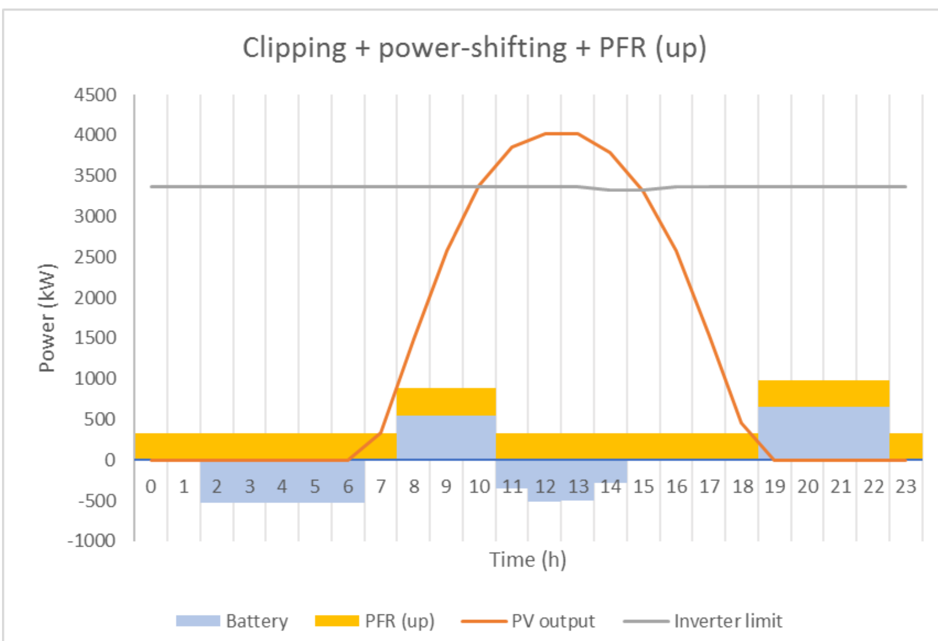


Figure 99: Extra power for power reserve, during any hour of the day.

Overall, Primary Frequency Response is becoming a mandatory service to be provided now with photovoltaic generators. Thus, even though there will be some economic implications using this system, as analyzed above, modifying the original design proposal of the ESS-coupled PV plant by oversizing inverters and increasing slightly the battery capacity of the DC-coupled storage system permits to carry out this service, and complying with new grid code requirements, in accordance with the new European legislation (UE 2016/631).

In the second part of this case study, adding secondary regulation service to the operation of these batteries allows to further amortize the battery system costs and increase significantly the benefits accrued in the plant overall.

However, how much these secondary regulation earnings will be depends on:

- Secondary regulation market price ceased (the lower the captured price the less economically viable it is to install further battery size and power). The market price, as established earlier, can vary depending on how much energy is deviated, and what technologies offer in the market in a particular day.
- The number of power requests made.
- When power requests are made, if there are losses if any (depending on which 15-minute interval it is requested).
    - If power requests are made frequently during moments where charging/discharging power is at a maximum, then the C-rate used is higher. This increases degradation on the battery system. If instead power requests are made during moments where total power required is significantly less (e.g. at 00:00 when no active power injection is carried out), degradation effects are less.
    - If power requests are made frequently during the limiting cases, then there will be significantly more normal operation losses than it has been estimated.

In terms of normal operation losses, all limiting cases have been analyzed and quantified. The estimated annual losses have been calculated, and even though the earnings from providing this service overcomes these losses, this difference can vary significantly depending on the frequency of power requests, what percentage of this frequency occurs in these limiting moments, and what the secondary regulation market price is. Some losses can be mitigated, which will be discussed further in the next chapter.

It was also shown that the greater the power offered in secondary regulation, the greater the benefits (for a certain average market price and estimated contingency events per year). Of course, it would require a greater investment, which is the limiting case at the end.

Moreover, as shown in the results, when a power reserve request is made during excess producing period the inverter is at full capacity. This means that the plant cannot inject any further power and so it cannot actually meet this power request, unless there is an extra power reserve coupled on the AC side to the plant.

The following chapter will study how Demand Response can aid in mitigating the impact of the normal operation of the plant, during primary and secondary regulation requests, as well as allowing to optimize further the battery size needed.

8. CASE OF STUDY 4: DEMAND RESPONSE WITH ELECTRIC VEHICLES

8.1. Introduction

The aim of introducing Demand Response in this ESS-coupled PV plant is to try and reduce the battery size and power required for the services already provided (PV excesses + power shifting + secondary regulation), so that even that as a result of using a smaller battery size there are more occurrences where power reserve from the plant cannot be provided, it can use the support of Demand Response from a nearby consumer.

The advantages of integrating this system are:

- Less battery size required, thus a significant reduction in capital costs.
- Allows providing secondary regulation power requests during the 15-minute intervals that would have affected normal operation (*See Chapter 7*).

The disadvantages of integrating this system are:

- Economic compensation for consumers who are requested to reduce their load during this service.
- Battery degradation could be higher since normal operation is carried out with a smaller battery size, thus greater C-rates and higher depths of discharge. This can lead to greater battery replacement costs during the lifetime of the plant. However, this depends finally on the extent of the Demand Response use.

In this chapter, the loads to be considered are the following:

1. Electric Vehicle (night-time): During night-time when electric vehicles are left charging and connected to the distribution grid, the sum of all these electric vehicles can support the nearby power plant during these hours for Demand Response.
2. Electric Vehicle (day-time): This will involve more specifically an electric vehicle charging station where cars come and go on an hourly basis (approximately, considering the charging time is of 1 hour). Consumers can opt for charging during 35 mins (peak price) or, 1 hour (base price). The greater time they permit charging, there are two advantages:
    - o The less power required from the charging station.
    - o The more time the charging station disposes of this vehicle battery, which can be used to support the power plant for secondary regulation service.

   Vehicle owners need to be aware that for longer charging times, batteries may be used for ancillary services. This means that there will be more cycling in their batteries, and therefore if this is done during the long term and the battery will suffer more degradation compared to not providing this service. Therefore, two things will need to established for the vehicle owner:

   - During the initialization of the charging process, they will dispose of several different tariffs:
       - o Charge 30 mins
       - o Charge 30 mins (grid support)
       - o Charge 1 hour

- Charge 1 hour (grid support)

The idea is that vehicle owners will choose whether they want to provide Demand Response (grid support) during the charging time they have opted for. As a result of choosing this tariff, they will be economically compensated with two terms:

- Availability: Choosing Demand Response has a cheaper tariff (€/kWh) compared to not choosing this service. This is similar as when conventional vehicle drivers choose Petrol Unleaded 95 vs Petrol Unleaded 98. A greater amount of people choose Unleaded 95 for its more economical price, but there is still a significant amount of people that choose Unleaded 98 for better quality fuel and better conservation of engine. This would be similar here: A greater percentage of drivers will choose charging service (with grid support) for a more economical solution, whereas other drivers opt for the more expensive tariff but conserving their battery slightly more.
- Use: During the charging time, if one secondary regulation request is made, which at that given moment due to technical and/or economic criteria Demand Response is requested, the contracted electric vehicle (the one where the driver has opted for grid support) will provide this service. As a result, there is an additional compensation for the driver. If during the charging time no power request is made, no cycling in their battery has performed, but the tariff that still stands is the one with grid support (which is more economical).

3. Electric Vehicle (day-time at company): Contract the Demand Response services from a company. The idea here is that during working hours, employees leave their vehicles parked and connected to the mains, in the company´s parking space. Therefore, when a Demand Response is requested during 09:00 to 19:00, all vehicles uniformly will regulate its power to provide this service. This will undoubtedly during the long term affect the lifetime of the batteries of the employees. Therefore, the incentive for them would be that they always dispose of full capacity, free of charge, since the employer will pay their electricity bill of their installation, without charging employees of course. However, this also would mean that all compensation received from providing Demand Response will be for the employer. This is a win-win situation.

The idea in this town is to combine all these three options, so that on a daily basis, the ESS-coupled PV plant can be supported with:

- 09:00 – 19:00h: Parking lot in company.
- 19:00 – 09:00h: Night time charging at home.
- During any hour: Electric vehicle charging station.

Combining these three options will hopefully allow a provision of Demand Response in a great percentage of the year. However, this will need to be studied and quantified in order to determine if it compensates economically paying these users whilst reducing capital costs.

Also, in order to integrate this, the following needs to be considered:

- For starters, a considerable percentage of this nearby town needs to own an electric vehicle, which at current prices in the market is not viable for most people. This would be the case unless vehicle subsidies are offered for people to buy these vehicles.
- Electrical infrastructure will need to be installed to support additional electric vehicle loads.
- Electric charging infrastructure will need to be installed, not only in terms of a charging station, but also, with more complexity, the provision of charging ports for vehicles parked at home, as well as the parking lot at the company. Charging time is currently limited by the capacity of the grid connection. A normal household outlet delivers 3 kW with a 230 V supply.
    - An idea already established is feeding consumers with a 3-phase supply, fused at 16-25 A allowing for a theoretical capacity of around 11-17 kW. This would be the case for electric charging stations. At home, charging rates will most likely remain slower than electric charging stations connected to a 3-phase supply.

The main moments where Demand Response should be available is for the 15-minute intervals when secondary regulation power requests have an impact on normal operation. These are the following:

- Power up: 06:45, 11:00, 11:15, 11:30, 11:45; 12:00, 12:15, 12:30, 12:45, 13:00, 13:15, 13:30, 13:45, 14:00, 14:15, 14:30, and 14:45.
- Power down: 10:45, 22:30 and 22:45.

By combining all options, the following results will be investigated and obtained:

- Technical viability of always providing Demand Response during the hours that secondary regulation impacts normal operation of the plant. That way no normal operation losses are produced. In order to reduce this loss to zero though, it must be guaranteed that a minimum number of cars (from the three options: home, station and work) for maximum power service is available.
- Economic viability for power plant from reducing battery size costs vs paying these consumers (from the three options) for providing this service as well as the extra battery degradation costs.

8.2. Methodology

The following outline the conditions to consider in the batteries:

- Batteries have a maximum charging rate. For the Tesla Model S (example used), this corresponds to a maximum of 22 kW for home use (slow charging), and 145 kW (rapid charging) for faster charging time in electric charging stations, if vehicle owner disposes of Tesla Supercharger, for connection to a 480 V three phase supply, and a higher amperage charger.
- Batteries cannot accept charge at greater than their maximum charge rate (usually "2C" or "3C"), giving a recharge time of 20 to 30 minutes to 80% SoC. Charging/discharging power requested from vehicles would increase when less cars are connected to the grid at a particular moment. Increase in

this power is acceptable until it corresponds to 3C (maximum for lithium ion technology before degradation costs outweigh compensation costs of providing this service).
    - With the Tesla Supercharger, this is still lower than the maximum C-rate (145/85 = 1.7).
- Slower charging usually is recommended for the remaining 20% to charge, in order to increase lifetime of the battery.

8.2.1. Load 1: Charging at home

Electric vehicle starts charging at a minimum rate (since it disposes of 8-10 hours of charging time before owner needs the car). In fact, it would calculate charging rate by the following:

$$P_{charging} = \frac{(1-SoC)\cdot C_{batt}}{T_{charge}} \qquad (47)$$

What this equation represents is that from the SoC measured of the battery, the controller will calculate the charge required for full capacity, from $(1 - SoC) \cdot C_{batt}$. It will also calculate the time left for the vehicle to charge completely, from the moment the vehicle is parked, to the programmed time the vehicle is to be disposed of again.

Charging power is currently limited by the capacity of the grid connection. A normal household outlet delivers 3 kW with a 230 V single phase supply. This can be increased up to 23 kW, by coupling a greater fuse of 100 A. This still corresponds to a relatively slow charging time, compared to what electric charging stations can offer by being connected a three-phase supply at a higher voltage. Nevertheless, due to the duration of the night, and to avoid further infrastructure costs, this single phase domestic supply is enough for vehicles recharging at home.

This controller would be a home appliance installed close to the vehicle and the mains supply. It would require the following:

- Measurement:
    - Vehicle battery SoC (battery voltage)
    - Time vehicle is parked.
    - Power request (reserve/curtailment, duration) from instructions received by plant controller.
- Calculating:
    - Time for recharge.
    - Charging power (to charge full battery during the night – subject to modifications when power requests are made during this period).
- References to be programmed in the controller (even with user access):
    - Battery size.
    - Maximum charging power.
    - Maximum discharging power.
    - Time to dispose of vehicle.
    - Max DoD.
- Modes/commands:

- Charging mode (using calculated charging power, which will be modified after a power request is made).
- V2G mode charge (increases charging power, though considering its limit)
- V2G mode reduced charge (decreases charging power).
- V2G mode discharge (switched from charging to discharging for greater provision of power reserve).

If a 5MW power request is made for a worst case of 15 minutes, it would require 5000 x 15/60 = 1250 kWh. This amount of energy requested would mean disposing of a battery size equal to 15 fully charged Tesla Model S vehicles (1250 kWh / 85 kWh = 14.7 = 15 vehicles), or alternatively, disposing of 30 Tesla Model S vehicles with an SoC of 50%, and so on.

Also, the maximum energy that can be charged/discharged depends on the maximum power of the batteries (which at the same time depends on the maximum power rate with the connection to the mains, which at home can be a maximum of 22 kW). This corresponds to an energy of 22 x (15/60) = 5.5 kWh that will be charged/discharged from the battery (which is relatively small compared to the size of the vehicle battery). Therefore, in order to provide the 5 MW minimum secondary regulation power, it would require a total of 228 vehicles (for a charging power of 22 kW). This in the future, for a small town with the right infrastructure and investment, is possible.

Figure 101 below show how 228 vehicles, with a random amount of initial capacity, supplies the power needed to meet the 5 MW secondary regulation service. As explained above, maximum power (22 kW in the case of domestic connection) is provided from most vehicles to meet the 5 MW power request (reserve or curtailment).

Figure 102 follows showing the initial capacity of each vehicle (blue) as well as the consequent energy charged/discharged from each vehicle to support the 5 MW power request.

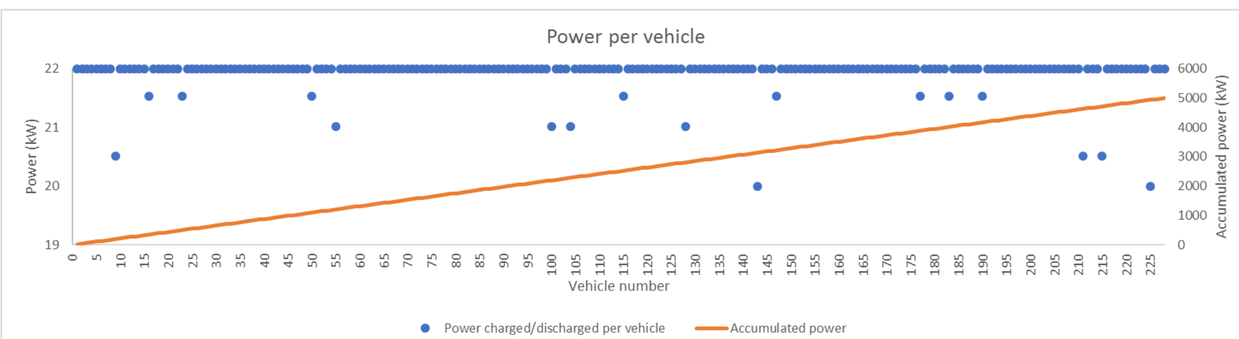


Figure 100: Power charged/discharged per vehicle, and accumulated power, for 228 vehicles.

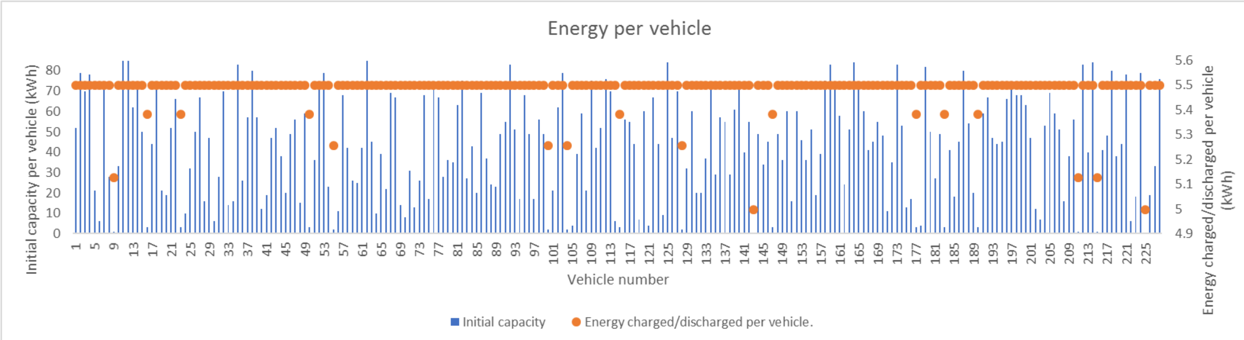


Figure 101: Initial capacity and energy charged/discharged for each vehicle, in a random event with 228 vehicles available.

However, if in the case 228 vehicles are not available, then for the 5MW power request, Demand Response would contribute to less, whilst any remaining power needed would have to be covered by the plant or from the electric charging station (which during the nocturnal hours will provide a minimum service).

Figure 103 and Figure 104 below shows the demand response in terms of power and energy when only 114 vehicles are connected. As a result, all vehicles provide their maximum power, but as can be seen from Figure 103, it is not enough to provide the secondary regulation power reserve requested for. It only provides 2500 kW, 50% of the secondary regulation power needed, which corresponds to 50% of the minimum vehicles needed (228 vehicles).

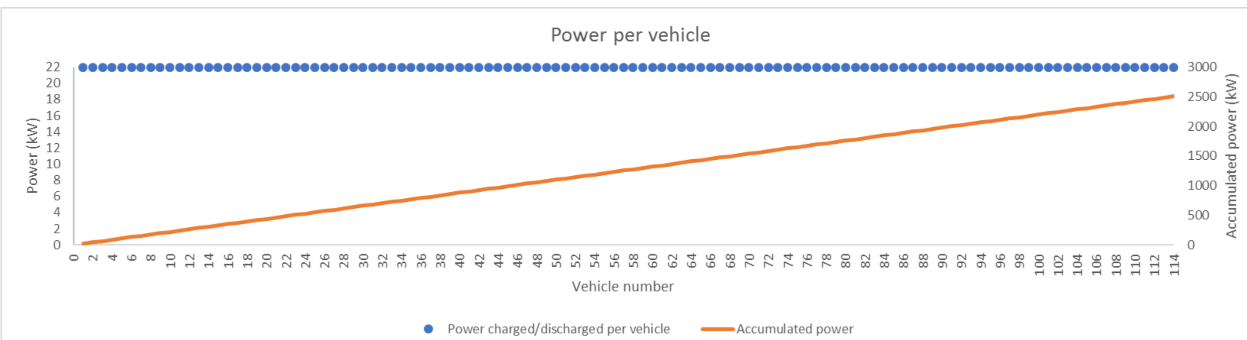


Figure 102: Power charged/discharged per vehicle, and accumulated power, for 114 vehicles.

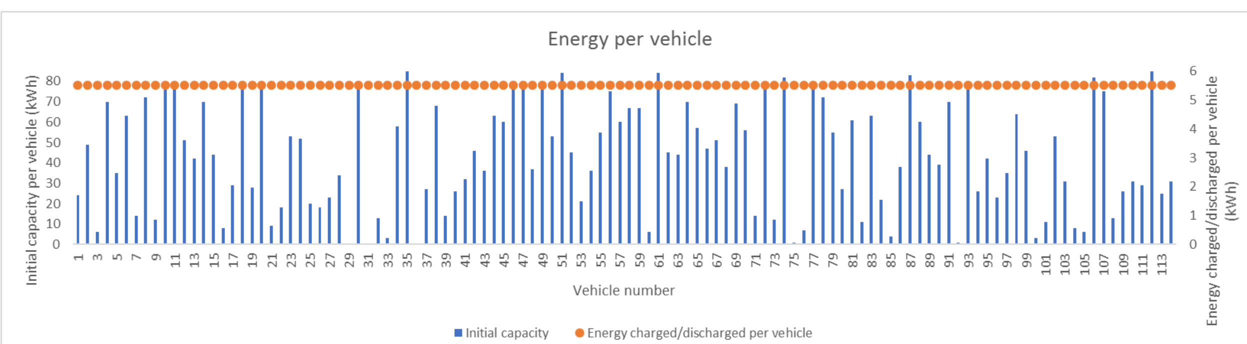


Figure 103: Initial capacity and energy charged/discharged for each vehicle, in a random event with 114 vehicles available.

For further detail, three different scenarios are considered:

- Scenario 1: Electric vehicles charging, when power reserve request is made. Limit from 10 kW to 0 kW.
- Scenario 2: Electric vehicles charging, when power reserve request is made. Limit from 10 kW charging to 22 kW discharging.
- Scenario 3: EVs charging and power curtailment requested –> from 10 kW charging to 22 kW charging.

8.2.3. Load 2: electric charging station

The second option consists of constructing an electric charging station. In a conventional petrol/diesel station, with 6 ports that takes on average 10 minutes for refueling, each hour there will be an average of 6 x 6 = 36 vehicles refueling. In order to facilitate the same number of customers:

- For 1-hour charging, this would require 36 ports instead of 6.
- For 30-minute charging, this would require 18 ports.

Therefore, in order to meet the same number of customers whilst taking into account the most restrictive option (1-hour charging), 36 ports will be used. This should meet the same number of customers as in a 6-port petrol station with the same average waiting time due to the greater number of ports that it disposes of. The user will be able to select from fast service (30 minutes – 145 kW charging power), to normal service (1 hour – 85 kW charging power). Note: In both options, this is significantly more power than in a domestic connection. Vehicle batteries though tend to be able to support up to 90 kW, therefore 1-hour charging is an option for most vehicles. However, for 145 kW charging, it would require an additional high amperage charger.

Since for this proposal we are using 36 ports, that would be:

- In the best case, an available battery power of (36 x 145 kW) = 5220 kW.
    - This would be if all vehicles disposed of 145 kW charging/discharging power.
    - This would correspond to disposing of 145 x (15/60) = 36.25 kWh per vehicle. (This would be 43% of the total capacity of an 85 kWh battery). The consequences to this, as discussed later on, is that once the power request ends (15 minutes max), there may not be enough time for many vehicles to charge all the capacity requested before the scheduled pick-up time. This would create problems for many drivers.
    - Also, this takes into account in the case of a power reserve, a reduction of their charging power from their maximum to 0 kW. In the necessary case, batteries would also discharge to supply the total power reserve request.
- Taking into account all possible combinations in the electric station (0 x 30 min charging, 1 x 1 hour charging → 36 x 30 min charging vs 0 x 1 hour charging), there are 704 possible combinations in total. For each combination, the power is calculated for the following three scenarios:
    - Power curtailment (increase in charging)
    - Power reserve (decrease charging up to 0 kW).
    - Power reserve (decrease charging up to 0 kW and dispose of discharging up to vehicle maximum).

Scenario 1

For scenario 1 (power curtailment), for vehicles charging at 145 kW, there is no further increment of charging power available. For vehicles charging at 85 kW, there is only a further 5 kW charging power, if any. Therefore, a secondary regulation power curtailment request cannot be met with the vehicles in the electric charging station.

Scenario 2

For scenario 2 (power reserve – from initial charging power to 0 kW charging), on average (taking into account that each combination has an equal probability to occur (more study is needed on daily use patterns of a vehicle charging/petrol station in a location to account for more accurate probabilities – *out of scope of this thesis),* the average secondary regulation power reserve that can be provided by the electric charging station is 2820 kW. This means that on average the 5 MW power request would not be met. Therefore, considering this average case, there are two options. Either the rest of the power is supplied by the plant (as the methodology described in Chapter 7), or what is proposed in scenario 3.

Scenario 3

A number of vehicles (depending on number of vehicles connected) will switch to discharging mode and reduce in their initial capacity. However, the question is raised whether the vehicles that provide discharging power will then have enough time before pick-up to charge the battery to the level requested by the driver. Therefore, a methodology has been developed in order to determine which vehicles will be selected for such service, and how much power they each have to provide (respecting their limits).

Taking into account these three scenarios, a model has been developed to show the operation of the following algorithm that has been developed (*More details below*) to show the technical feasibility of providing secondary regulation power reserve request through the electric power station.

In the algorithm, the following inputs are introduced:

- In the 36 available ports, whether it will be occupied by a vehicle or not (1 or 0). For the first set of results, it will be assumed that all ports are occupied.
- For each vehicle, it will have its own initial capacity. This is controlled by a random number generator between 0 and 85, where it assumes that all vehicles connected have a maximum capacity of 85 kWh. This in the future will be greater as battery technology in electric vehicles advances.
- For each vehicle, a tariff will be selected (fast charge – 35 minutes, or normal charge – 1 hour). This will be generated as well at random, choosing between 145 kW and 85 kW, respectively. (Note: in the model it is assumed that the tariff opted for corresponds to the maximum charging power that the vehicle disposes of.)

Then the following will be calculated:

- Time remaining for full recharge. This will be calculated with the following equation:

$$t_{left,recharge} = \frac{(85 - E_o)}{P_{charge}} \qquad (48)$$

- Available reduction in charging power. In principle the total reduction in charging power to meet this secondary regulation power reserve request is determined by adding the charging power of all vehicles connected. However, it has been implemented in the model that if the time remaining for pick-up is less than 15 minutes, then this vehicle will not provide any of this service, so that it is guaranteed a full recharge before the driver returns. Therefore, the available reduction in charging power is the total charging power of the vehicles, subtracting the vehicles that have less than 15 minutes before driver returns for its scheduled pick-up.

$$\Delta P_{charging,total} = \sum_{1}^{36} \Delta P_{charging}\{if\ t_{left,recharge,n} > 0.25\} \quad (49)$$

- Total power remaining. This is the power remaining in order to meet the 5 MW power request. In other words, this is 5000 kW – Total power available (without discharge).

$$P_{remain} = P_{sec,reg} - \Delta P_{charging,total} \quad (50)$$

- Available discharge power. This is discharge power that each vehicle can supply such that after 15 minutes of power request duration, they could charge their vehicle to full capacity (assumed to be 85 kWh) at their maximum charging power, before pick-up. In order to calculate this, the following derivation is used to obtain the equation to calculate this:
  1. The maximum charging power will be able to recharge to full battery for time remaining, starting at an initial capacity, so long as a prior discharging power is used. In other words:

$$P_{charge,MAX} = \frac{(85-E_o)-0.25\cdot P_{discharge,MAX}}{t_{left,recharge}-0.25} \quad (51)$$

  2. Rearranging the equation, the possible discharge power is:

$$P_{discharge,MAX} = 4\left[P_{charge,MAX}\cdot\left(t_{left.recharge} - 0.25\right) + E_o - 85\right] \quad (52)$$

  3. In the case that the time remaining before pick-up is less than 15 minutes (0.25 h), then the discharge power it can provide is 0 kW. Otherwise, it will not charge to the final capacity paid for.
  4. The equation above can also be modified to take into account any final capacity the driver wishes for. It was assumed earlier that all vehicles will charge to 85 kWh (full battery capacity), irrespective of their initial capacity. However, the driver does not necessarily have to charge the whole battery. Also, in the future, battery sizes in vehicles will increase. Therefore, final battery size will be another variable in this equation. Results will be shown later when considering the 85 kWh assumption, and the varying final capacities.

$$P_{discharge,MAX} = 4\left[P_{charge,MAX} \cdot \left(t_{left.recharge} - 0.25\right) + E_o - E_f\right]\right] \qquad (53)$$

5. Finally, the requested discharge power from each vehicle is calculated. This is calculated by taking into account the proportion the available discharge power of the vehicle has compared to the total discharge power available from all vehicles connected at a given moment in time. This proportion is then multiplied by the actual power needed. This can be expressed by the following equation:

$$P_{discharge,final} = \frac{P_{discharge,MAX}}{\sum_1^{36} P_{discharge,MAX}} \cdot (P_{sec,reg} - \Delta P_{charging,total}) \qquad (54)$$

8.2.4. Load 3: Charging at work

This option is very similar to option 1, except it differentiates in three things:

- The time at which it applies. This is important when considering the limiting cases described in chapter 7. For example, originally if a power reserve request is made to the power plant anytime between 11:00 and 15:00, the excesses produced during the request are lost. Moreover, during this time, when excesses are produced, the inverter is at full capacity. Therefore, the plant cannot actually meet this power request, unless there is an extra power reserve coupled on the AC side to the plant. Therefore, this time of the day is the most important time for Demand Response to act, which is where Option 3 plays an important role.

- In the case of many of the vehicles parked, the majority will already be fully or nearly charged. This would be due to either some cars already being charged during the night (option 1) if driver has connection to this at home, or also the likelihood of a fully charged battery is due as well to the fact that during the week, a typical use of the vehicle after work is minimum, usually kept to the route from the workplace to their house. Therefore, the amount of discharge that has occurred for this distance is relatively small. Therefore, taking this into account, it can be assumed that during 09:00 to 19:00, the plant will dispose of full discharge capacity. Note though that charging power (power curtailment) is not possible here since the batteries are already fully charged. Even if a power reserve request is made prior to a power curtailment request, the amount of charge that is available will depend on the time between these two power requests. If the time between them is short, then it may be possible to deliver some of this power curtailment. However, it is most likely that this will not be possible.

- The company would dispose of standard 85 kW chargers as opposed to the maximum 22 kW charging at 230 V single-phase supply with 100 A fuse at home. This allows for greater supply of discharging and charging power from the vehicle.

8.3. Results

8.3.1 Load 1: Charging at home

8.3.1.1. Scenario 1: Electric vehicles charging, when power reserve request is made. Limit from 10 kW to 0 kW.

It is assumed that the normal charging rate of electric vehicles during the night is on average a value of 10 kW. This means that it will take 8.5 hours to charge a battery of 85 kWh capacity from 0 to 100% SoC.

When a secondary regulation power reserve request is made, in a generation point of view, this would mean increasing power output. In a consumption point of view, this would mean instead decreasing power input. Therefore, as a result, these electric vehicles would reduce their consumption. The amount they reduce depends on the number of vehicles connected.

For a large number of vehicles (greater than 228 vehicles, as explained above), the power requested from each vehicle would be less than the 22 kW calculated above. This would mean that it is possible that the vehicles simply have to reduce their charging power in order to contribute to this power request. No energy is therefore discharged. However, a further period of time has to be added to the charging time needed to reach at the capacity level paid for.

In the example below, there are 700 vehicles connected at night. This means on average each vehicle would have to supply 5000/700 = 7.14 kW reduction in charging power. In other words, ΔP = -7.14 kW. Therefore, if all vehicles initially are charging at 10 Kw, during these 15 minutes of power reserve request, they would reduce their charging power down to 2.86 kW.

Fig 8.5. below shows the change in charging power per vehicle, having a maximum change in charging power of 10 kW (to reduce down to 0 kW), assuming the pre-demand response charging rate was at 10 kW.

This graph shows how the algorithm changes the charging power of each individual vehicle based on each initial capacity. The average change in charging power of all vehicles is 7.132 kW. This is a -0.15% difference to the average power of each vehicle needed (from 5000/700 vehicles). After repeating the simulation five times (using randomly generated capacities for each vehicle), this difference is -0.15%, -0.09%, -0.12%, -0.12%, and -0.17%. This shows the algorithm works effectively in the distribution of charging power reduction for each vehicle based on its initial capacity.

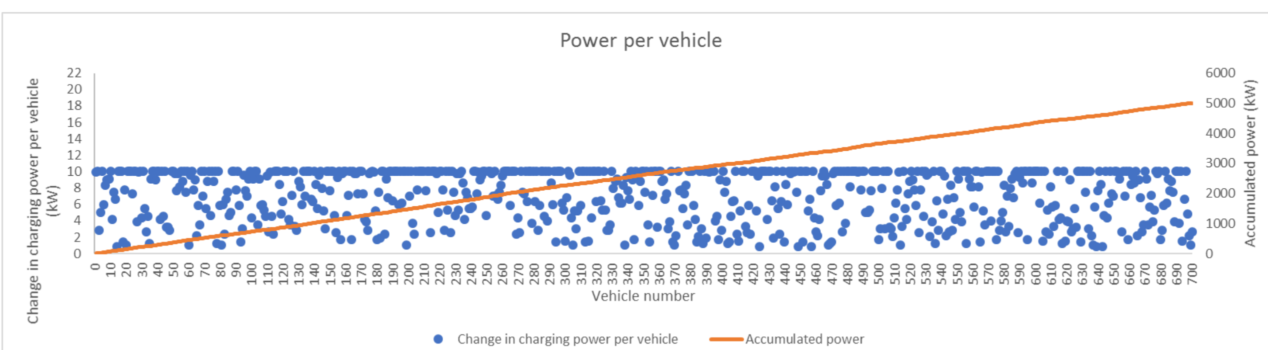


Figure 104: Change in charging power per vehicle, in a random event with 700 vehicles available.

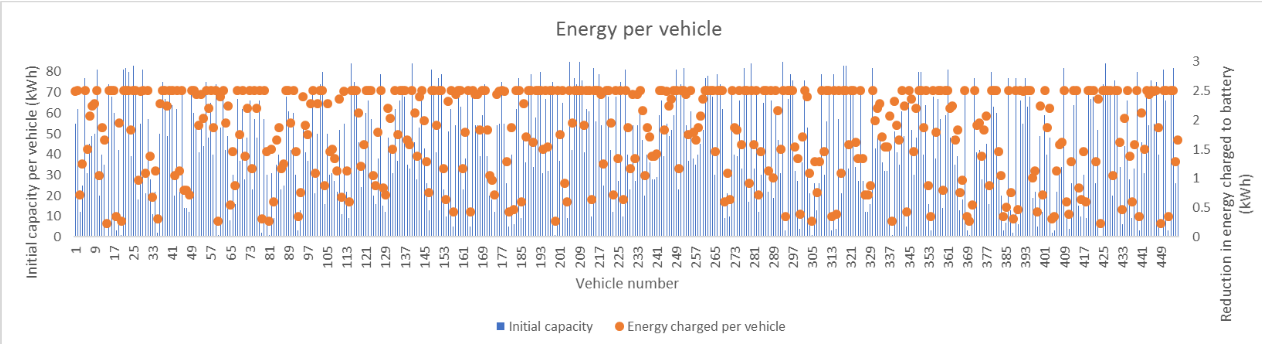


Figure 105: Initial capacity per vehicle and energy charged per vehicle, in a random event with 700 vehicles available.

8.3.1.2. Scenario 2: Electric vehicles charging, when power reserve request is made. Limit from 10 kW charging to 22 kW discharging.

This scenario represents one where significantly less vehicles are connected. Therefore the 10 kW change in charging power would not be enough to supply the secondary regulation power reserve requested for. Therefore, the vehicle would change from charging mode to discharging mode as a result. The advantage of this compared to what was shown in Figure 101 and 102 is that the available power is 22 kW plus the 10 kW change in charging power, which contributes to the power reserve request. Therefore, the maximum power change is 32 kW per vehicle as a result. This means that the new minimum number of vehicles needed for this scenario is 157 vehicles, compared to Figure 101, where 228 vehicles are needed.

Fig 107 below shows the response of 228 vehicles for this scenario.

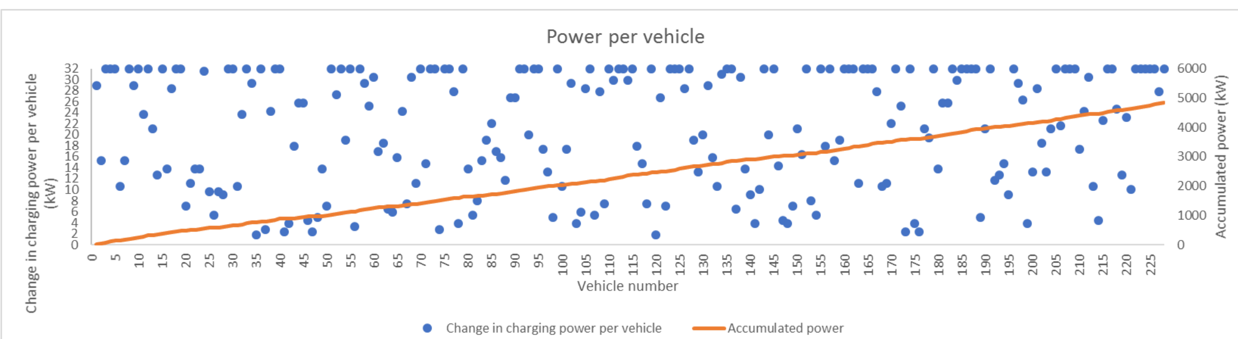


Figure 106: Total disposable power per vehicle, in a random event with 228 vehicles available, for a power reserve request.

Fig 108 shows how in the secondary vertical axis, it represents the loss of energy during the 15 minutes of power request, which includes the reduction in energy charged from 10 to 0 kW charging power, to the energy discharged from discharging power at a rate of 32 kW, during this period.

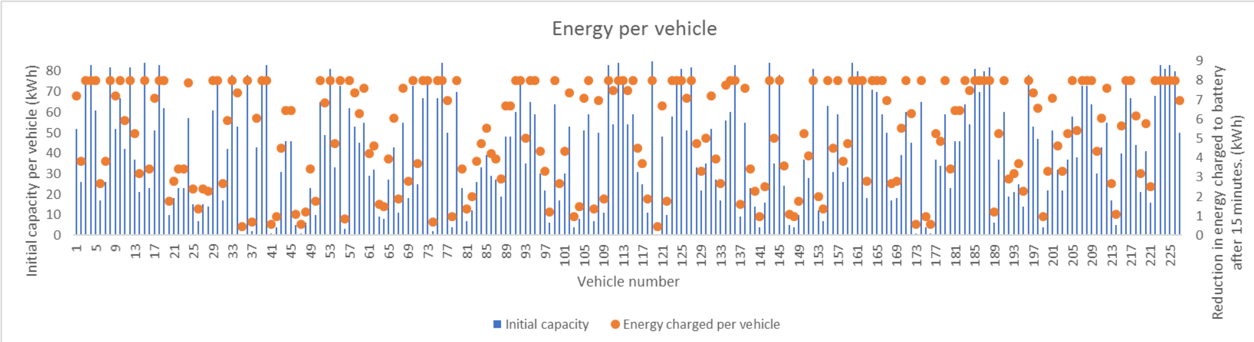


Figure 107: Initial capacity per vehicle and energy charged per vehicle, in a random event with 228 vehicles available.

8.3.1.3. *Scenario 3: EVs charging and power curtailment requested –> from 10 kW charge to 22 kW charge*

When a power curtailment request is made, the way these electric vehicles can provide this power request is instead now by increasing the charging power. If the normal charging power, as established earlier, is 10 kW, and the maximum possible power for domestic connection is 22 kW, then it means that the maximum increase in charging power is 12 kW. Therefore, this will be the limit imposed in this new simulation. For this limit, a minimum of 417 vehicles are needed to provide 5 MW power curtailment.

Below shows an example with 500 vehicles connected, and how a 5 MW power curtailment request is met, without needing all vehicles to charge at maximum power.

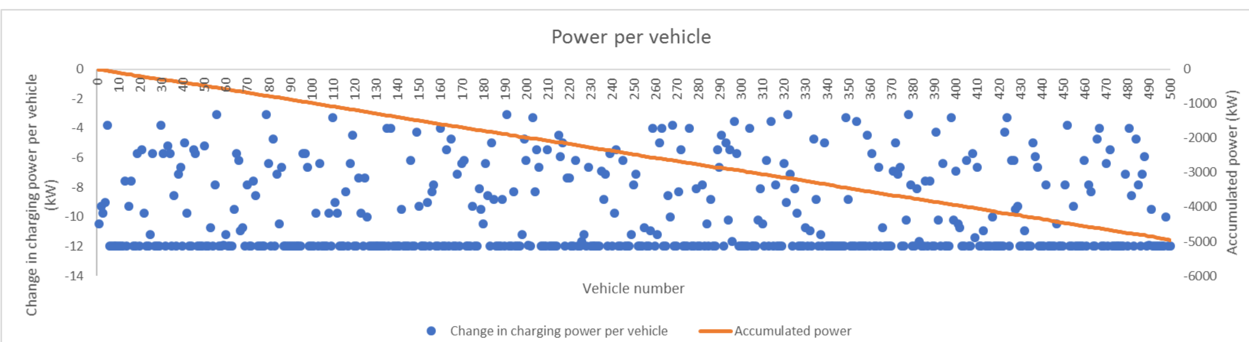


Figure 108: Additional charging power per vehicle needed, in a random event with 500 vehicles available, for a power curtailment request.

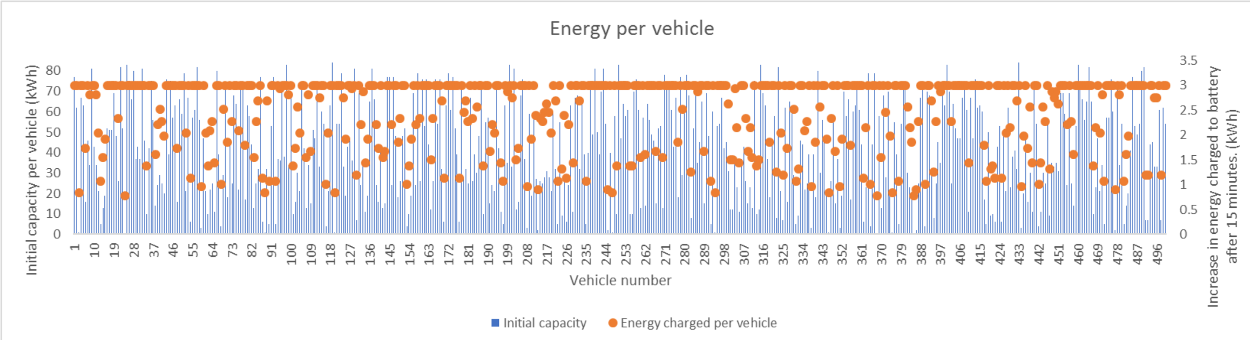


Figure 109: Initial capacity per vehicle and energy charged per vehicle, in a random event with 500 vehicles available.

The procedure proposed would be that at the moment of a power request, the SoC of each vehicle would be measured and fed to the Electric Vehicle Controller. The EVC would then either accept the request or reject the request but offering a new possible power value. The Power Plant Controller would then accept, send new power set-points to each DC-DC converter in the plant and the remaining power needed to meet the secondary regulation power request would have to be obtained from the DC coupled storage system.

As seen from the results of the different scenarios, how much power Electric Vehicle loads can provide depends on:

- Type of power request (if it´s power reserve: up to 32 kW per vehicle, while if it´s a power curtailment: up to 12 kW).
- Number of vehicles connected at that given moment.

8.3.2. Load 2: electric charging station

Results are shown below for two different cases, with randomly varying initial capacity, final capacity paid for and charging tariff requested.

8.3.2.1. Case 1: Power reserve request met.

Available reduction in charging power: 2895 kW.

Discharge power required: 2105 kW.

Available discharge power: 2250 kW. This is the sum of the maximum discharging power that each vehicle can deliver in order to have sufficient time after this power request to charge its battery to the capacity requested for at its maximum charging power before the scheduled pick-up time.

Since the available discharge power is greater than the required, only the required is provided. The required power from each vehicle is calculated as described in the methodology.

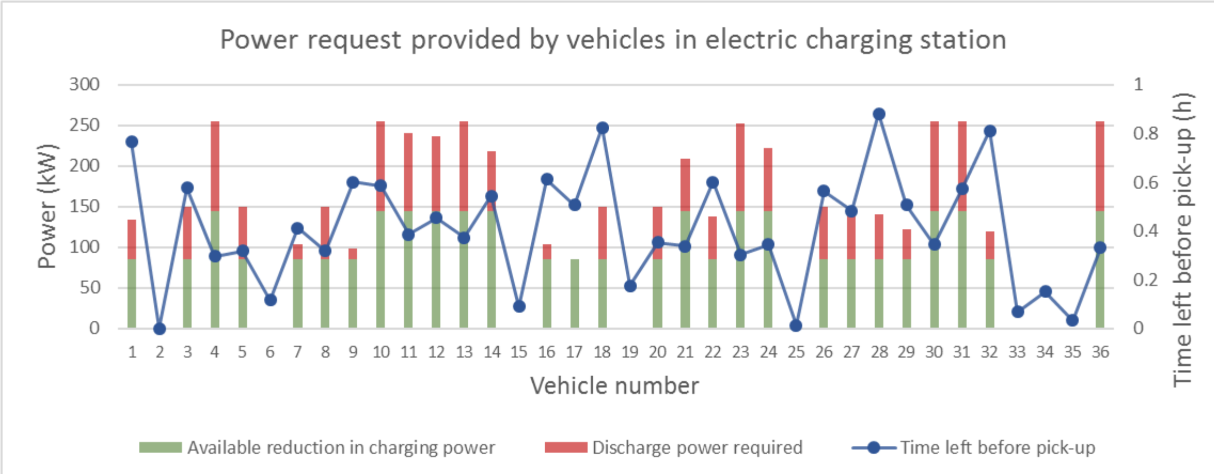


Figure 110: Discharge power provided by each vehicle, based on initial capacity and time before pick-up (Case 1).

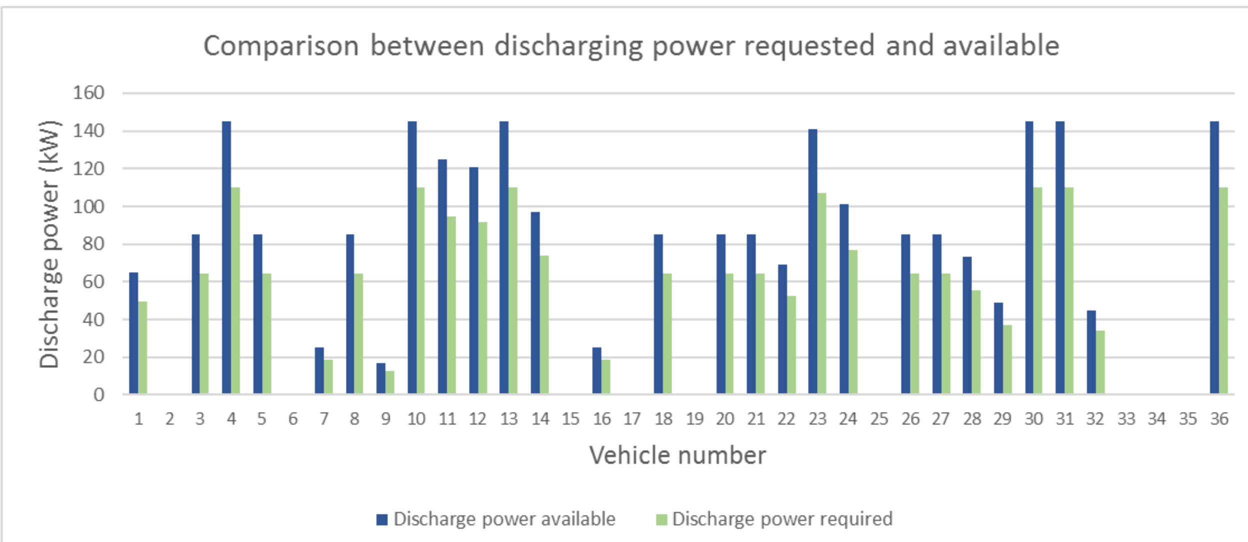


Figure 111: Comparison between discharge power requested and available from each vehicle (Case 1).

8.3.2.2. Case 2: Power reserve request not met.

Available reduction in charging power: 2895 kW.

Discharge power required: 2105 kW.

Available discharge power: 2250 kW.

Since the available discharge power is less than the required, not all the power request can be met with the electric charging station at this given moment.

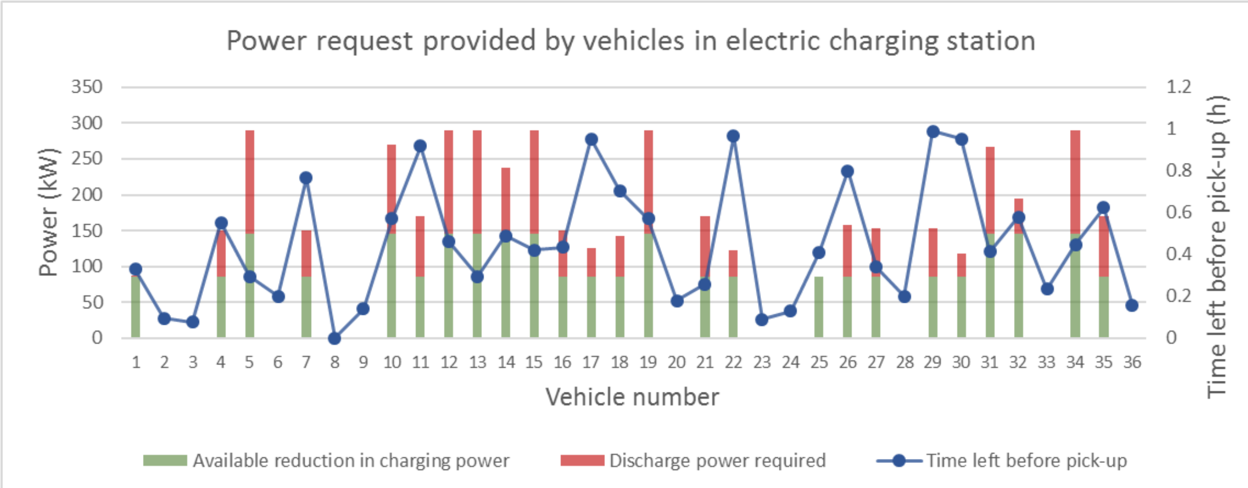


Figure 112: Discharge power provided by each vehicle, based on initial capacity and time before pick-up (Case 2).

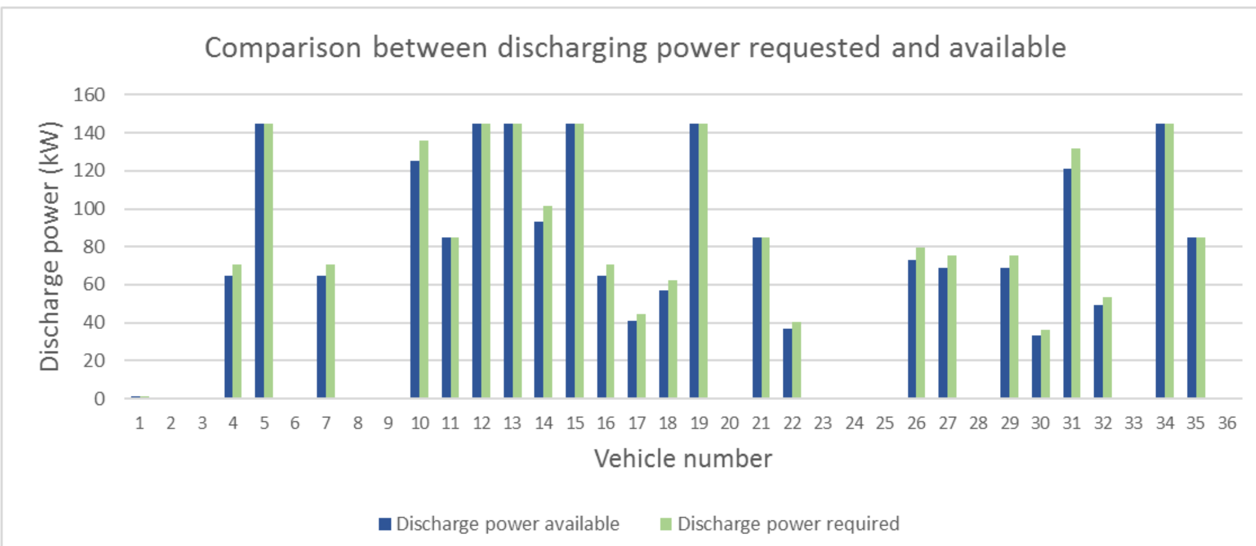


Figure 113: Comparison between discharge power requested and available from each vehicle (Case 2).

Using the random number generator (to randomly generate initial capacity, final capacity and charging tariff for each of the 36 available ports), for 100 simulations carried out, only 21 simulations were like Case 1, where the 5 MW power request was met. The other 79% did not meet the power request. Therefore, in order to avoid not meeting power request requirements but still depending only on Demand Response, the following options are still considered:

- Can dispose of power available from vehicles connected at home and at company parking site.
- Rethink the dimensioning of the electric vehicle station if the capital investment allows it.

- If still not enough power, then use of the DC coupled energy storage would be required in order to meet power request that was offered the day before in the secondary regulation market.

8.3.3. Load 3: Charging at work

Only the following scenario can be considered which is: Electric vehicles charging when power reserve request is made. Limit from 0 kW discharging to 85 kW discharging.

As described in the methodology, all vehicles are fully charged and there are 100 vehicles parked in the workplace and connected to the electrical grid, with charging infrastructure that can support up to 85 kW charging/discharging power.

For 100 vehicles connected, in order to supply the 5 MW power reserve request, (especially during the hours of 11:00 to 15:00 which as described in chapter 7, it is the time when excesses are lost and when no further power reserve can be provided from the plant, since the inverter is at full capacity during this solar peak time), the amount of discharging power per vehicle needed is 5000 kW / 100 = 50 kW. This can be met in terms of both:

- Power (limit of charging infrastructure is 85 kW).
- Energy (since batteries are fully charged and energy needed to be discharged is 50 Kw x (15/60) = 12.5 kWh. Since the battery capacity of each vehicle is assumed to be 85 kWh, it is more than enough to meet this power request.

This raises the next question to how many cars as a minimum is required in order to provide power reserve request during this time. This would be 5000 kW / 85 kW = 59 vehicles.

8.3.4. Economical costs of Demand Response

The costs of Demand Response are difficult to know since it is a relatively new concept in electricity markets and in Spain right now this does not exist. The closest thing that exists in Spain is Interruption Service, provided by large consumers, where the grid operator instructs them to reduce consumption when needed.

Similarly, to secondary regulation, there would be two components: Availability and Use.

Following from the methodology from Chapter 7, the economic losses can be calculated from equation (41).

In this case, the only component that is relevant is the economic loss when it occurs at 10:45, $\Pi_{loss,10:45}$, since it has been calculated that there is a 79% chance it won´t be met at this time.

$$\Pi_{loss,total,yearly} = \frac{\overline{E_{excess,day'n'}}}{T_{period2}} \cdot \left(\frac{15}{60}\right) \cdot \pi_{sh} \cdot \left(\frac{1}{48}\right) \cdot (0.79)$$

The factor (1/48) has been included, since it is assumed that any 15-minute time interval has the same probability of occurrence. Also, the term 0.79 has been included to represent the probability that this power request cannot be met with Demand Response.

This is the only time where normal operation of the plant is affected since nor the storage system of the plant or Demand Response (with a 79% probability) will not be able to meet it. Nevertheless, if it did occur, since it already affects normal operation it makes sense to use the original battery size for normal operation (PV excess storage + power-shifting). To go on further, having Demand Response that can cover most power request cases, it may be useful to not increase the battery size for secondary regulation provision, or at least reduce the battery size for moments when the electric vehicles are not enough to provide the power request. During the hours of 08:00 – 09:00 and 19:00 – 20:00, significantly less cars will be connected to the grid. If a power request is made during these two hours, perhaps not all the 5 MW can be met. Therefore, to use a conservative value, half of the new battery size calculated in Chapter 7 will still be proposed to be available. This value of battery size can be more fine-adjusted with a detailed study of the use patterns in the town in terms of electric vehicle charging.

Therefore, extra earnings from incorporating Demand Response via electric vehicles can be represented by the following equation:

$$Earnings_{DR} = \Pi_{loss,total,yearly,without\_DR} - \frac{\overline{E_{excess,day'n'}}}{T_{period2}} \cdot \left(\frac{15}{60}\right) \cdot \pi_{sh} \cdot \left(\frac{1}{48}\right) \cdot (0.79) + \left({}^{C_{sec,reg}}/_{2}\right) \quad (55)$$

The losses due to Demand Response payments can be calculated with the following equation:

$$Losses_{DR} = P_{sec,reg} \cdot \left(\frac{15}{60}\right) \cdot 720 \cdot \pi_{DR} \quad (56)$$

The results are the following:

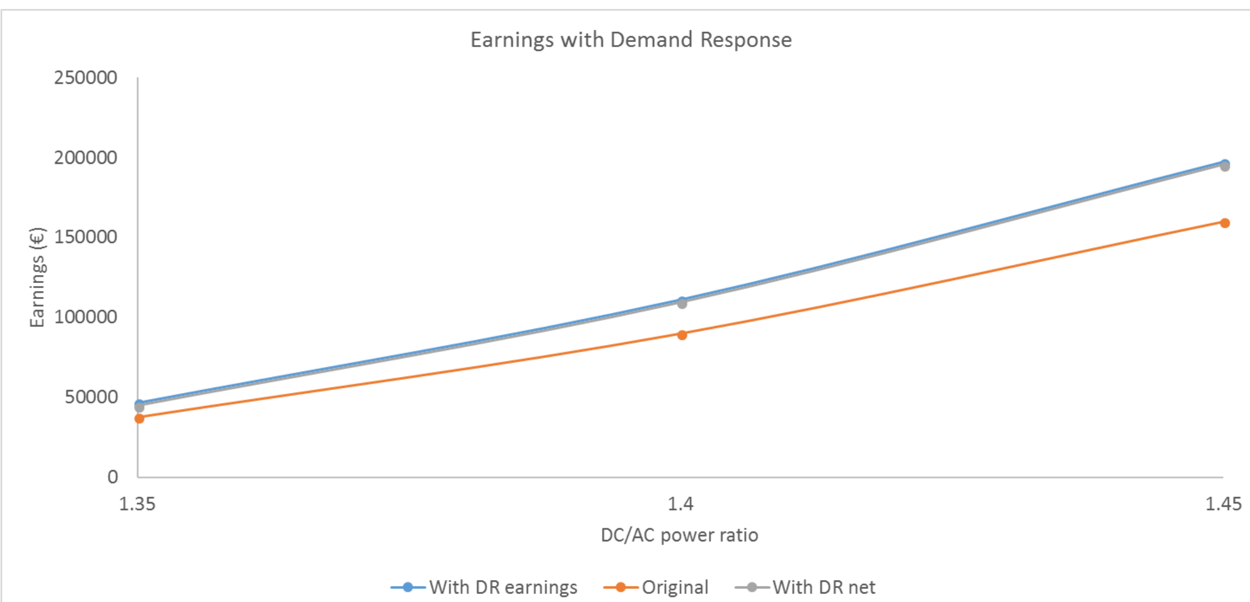


Figure 114: Comparison between earnings with Demand Response vs without Demand Response.

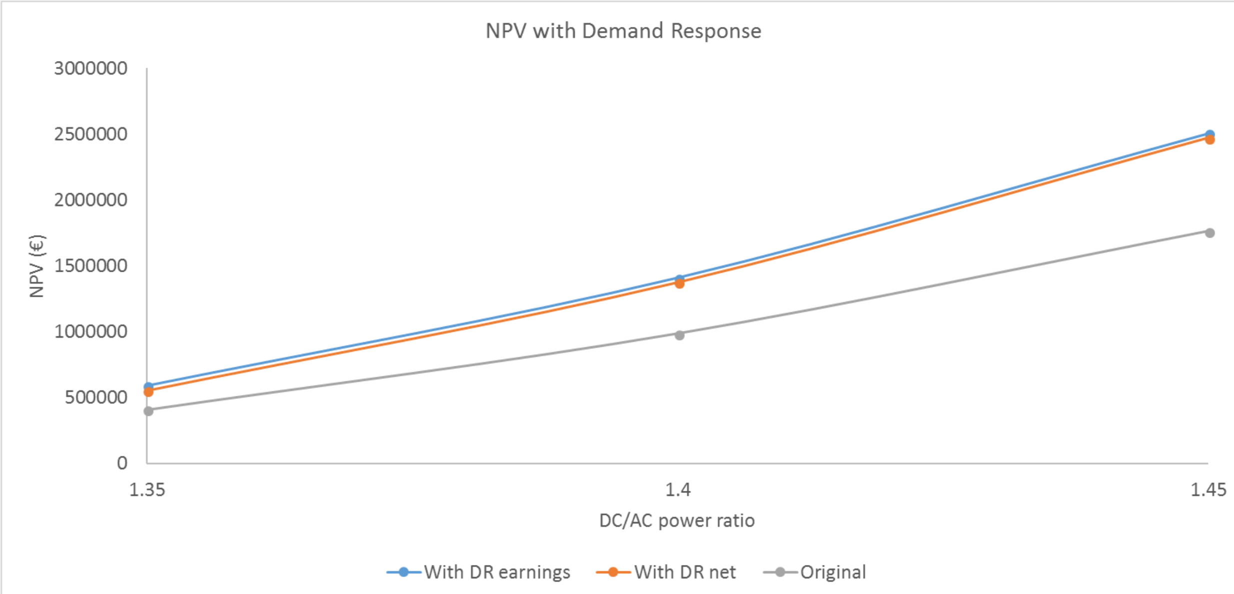


Figure 115: Comparison between NPV with Demand Response vs without Demand Response.

The losses due to Demand Response payments is is greater than the losses calculated for the economic impact that the limiting cases has on normal operation of the plant. However, since the additional battery size needed is significantly less than without Demand Response (half the battery size has been used as a conservative value), then the earnings outweigh these demand response payments. Note though: the original size for normal operation (for PV excesses and power-shifting) has not been changed, since this was already the optimum for normal operation, as calculated in Chapter 6.

8.4. Conclusion

The technical viability was investigated in order to determine that during the normal operation impact hours, Demand Response will always cover these power requests. The following conclusions were formed:

- In order to reduce this loss to 0, it must be guaranteed that minimum number of cars (from the three options: home, station and work) for maximum power service is available.
- The combination of the three load options (Home charging, electric charging station, workplace charging) can support during the limiting cases presented in chapter 7. These occurred at the following times:
    - Power reserve request: 06:45, 11:00, 11:15, 11:30, 11:45; 12:00, 12:15, 12:30, 12:45, 13:00, 13:15, 13:30, 13:45, 14:00, 14:15, 14:30, and 14:45.
    - Power curtailment request: 10:45, 22:30 and 22:45.

  Very importantly was being able to cover a power reserve request from 11:00 to 15:00, since during this time the DC coupled plant cannot provide any further power reserve, and PV excesses would be lost. During this time the main option that will supply this power reserve request is load

3 (workplace). It is calculated that 59 vehicles are needed to provide this service and avoid any penalization from the grid operator to the plant.

For 06:45 power reserve request, this will have to be provided by load 1 (Home charging). As calculated in option 1 results earlier, 156 vehicles connected at home are needed, in order to provide this power reserve request.

For 10:45 power curtailment request, load 1 will be very limited since at this time most cars will not be connected at home. Load 3 as shown earlier cannot be used since batteries will be at full capacity. It will therefore depend on the vehicles at the electric charging station at that time. From earlier results, there is a 21 % chance that a total of 5000 kW can be provided from the station. Therefore, if a power request occurs at this time, there is a 79% chance that it cannot be met with Demand Response from the electric vehicles. Thus, there will be some impact in terms of normal operation of the ESS-coupled PV plant. This though will ultimately depend on the daily charging pattern of this electric charging vehicle station, as well as the probability that a power request at this time occurs (which depends on demand and renewable energy generation deviations at this time).

For 22:30 and 22:45, between load 1 and load 2, there should be enough charging power available from electric vehicles. At this time most vehicles of this pilot town are connected to the grid, via their house. On top of this, most vehicle batteries will not be fully charged since it is still early in the night. Therefore, there is capacity available still for charging in case of a power curtailment request.

- Energy charged/discharged is minimum since impact is only for 15 minutes. Limiting case would be if it occurs during the last 15 minutes of the night, before driver uses their car again, but nevertheless, the maximum effect it can have on their car is 8 kWh (less than 10%). This is very unlikely though to occur. 1/(total 15 minute intervals during the night).

The economic viability was also investigated. The economic objective was to reduce the battery size needed in the power plant, whilst still providing the same service (not affecting earnings accrued).

However, paying these consumers as well as considering degradation costs from having a smaller battery whilst still having the same use, would have to be considered.

From the results, even though the payment and battery replacement costs increase, having a smaller battery size compensates significantly, and the whole installation is more economically viable, as shown in Figure 106.

9. CONCLUSIONS OF THE THESIS

In this thesis, a detailed optimization model was developed in order to produce favourable results for the integration of energy storage systems into an over-sized photovoltaic array. As explained in chapter 3, the detailed model developed incorporates battery degradation (for calculating lifetime of battery in order to determine battery replacement costs, and also to calculate the reduction in battery capacity per year, to determine how much energy it can store on a daily basis). The battery degradation is calculated based on the use of it, which in turn depends on the different variables used in the model (e.g. battery capacity, what functions are enabled (e.g. power-shifting, frequency regulation, etc.), as well as temperature during every hour). It also takes into account PV panel degradation (reducing the production per year based on the manufacturer´s degradation rate). Also, different pricing mechanisms are integrated in the model, where the user can choose which one is suitable for their project. Finally, detailed inverter features (such as power derating due to temperature, DC voltage, and altitude), can be input in order to produce more accurate results in terms of the excesses produced.

With the model developed, various different sets of results were presented, using the different case studies: clipping excesses alone, adding daily power-shifting, adding frequency regulation, and adding demand response for support on frequency regulation requests.

From the different results in the thesis, the following is concluded:

- It was shown that with the proposed DC coupled system the excesses produced could be harnessed, which would provide an additional revenue that more conventional storage configurations would not be able to provide. Depending on the battery capacity and the DC/DC maximum charging/discharging power, a different percentage of excesses would be captured. Furthermore, within the optimum conditions selected, this percentage of excesses would change due to PV panel degradation as well as battery capacity reduction.
- The optimum for storing clipping excesses was calculated for different DC/AC power ratios. Results showed that as battery costs stand in 2017, using a battery system for just storing clipping excesses would be economically viable for DC/AC power ratios greater than 1.4. Beyond a ratio of 1.45 was not studied since depending on the inverter chosen, short-circuit current limits would apply, due to hardware limitations (mostly the common DC bus bar).
- Using battery cost projections, it was observed that the economic viability improves significantly, where using the energy storage system for clipping excesses alone would be possible for even lower DC/AC ratios than 1.4. A minimum DC/AC ratio of 1.4 (2017), 1.35 (2020) and 1.3 (2025) could be used in Valencia so that the excesses produced can amortize the respective cost of the batteries during the lifetime of the plant.
- Nevertheless, a battery system´s integration is to be used for other services as well, where storing PV excesses is just an extra service which we dispose of due to the proposed configuration. In reality other services such as power-shifting will be incorporated. In the second case study this is integrated, and the results evidently are more positive (even though battery degradation effects and therefore battery replacement costs increase). However, this depends on the pricing mechanism and on the tariffs imposed. With the Time-of-Use tariff proposed and developed, as well as the tariff prices used (based on Spanish spot market analysis and projections), the model produced the best results. In the case of

selling in the market directly, due to the volatile nature of the market and the current range of prices, the benefits are significantly less, and the economic viability would be difficult to achieve, depending on the rest of factors (e.g. location of plant, battery system costs, etc).

- For integration of frequency regulation, it was shown that the best system configuration to provide this in a technical and economical point of view is over-sizing the inverters, limiting its power output, so that in the event of a grid under-frequency event this power limit is deactivated to provide an extra power reserve needed. The inverter would have sufficient capacity to provide this, and with sufficient solar resource at that time the array would provide the energy required. However, in the case of having a lack of PV power to reach the power set-points in a given moment of time, the controller would use the DC-coupled battery to fulfill these requirements, which improves the technical performance in comparison with PV plants that are not equipped with storage systems, as well as offering the most economically optimized solution. This proposed system was compared to increasing the array size, as well as integrating and AC coupled storage solution. Both produced significantly less returns, due to efficiency decrease, as well as the increase in capital costs for installing more panels or an additional energy storage system (along with its inverter, transformer, cabling and planning and permission costs), respectively. This DC-coupled system would already be installed, is more efficient, and without disregarding, produces additional energy due to the clipping excesses.
- In secondary regulation, it was studied that there is an impact on the normal operation of the system, when incorporating frequency regulation (for both primary and secondary), which depends on the time at which it is requested. These limiting cases have been analyzed and quantified. The estimated annual losses have been calculated, and even though the earnings from providing this service overcomes these losses, this difference can vary significantly depending on the frequency of power requests, what percentage of this frequency occurs in these limiting moments, and what the secondary regulation market price is.
- In the case study regarding the coupling of Demand Response, it was shown that with a given minimum number of electric vehicles charging, it could support the PV-ESS system during secondary regulation power requests. Three different load options were studied and combined to make this demand response more feasible for the support of this PV-ESS system.
- A new optimization as done when considering Demand Response, which allowed to slightly reduce the battery size generally. Even though the need to pay demand response consumers as well as the increase of battery replacement costs due to increased battery degradation, having a smaller battery size compensates significantly, since the accrued benefits over the lifetime of the plant increases, as shown in the results.

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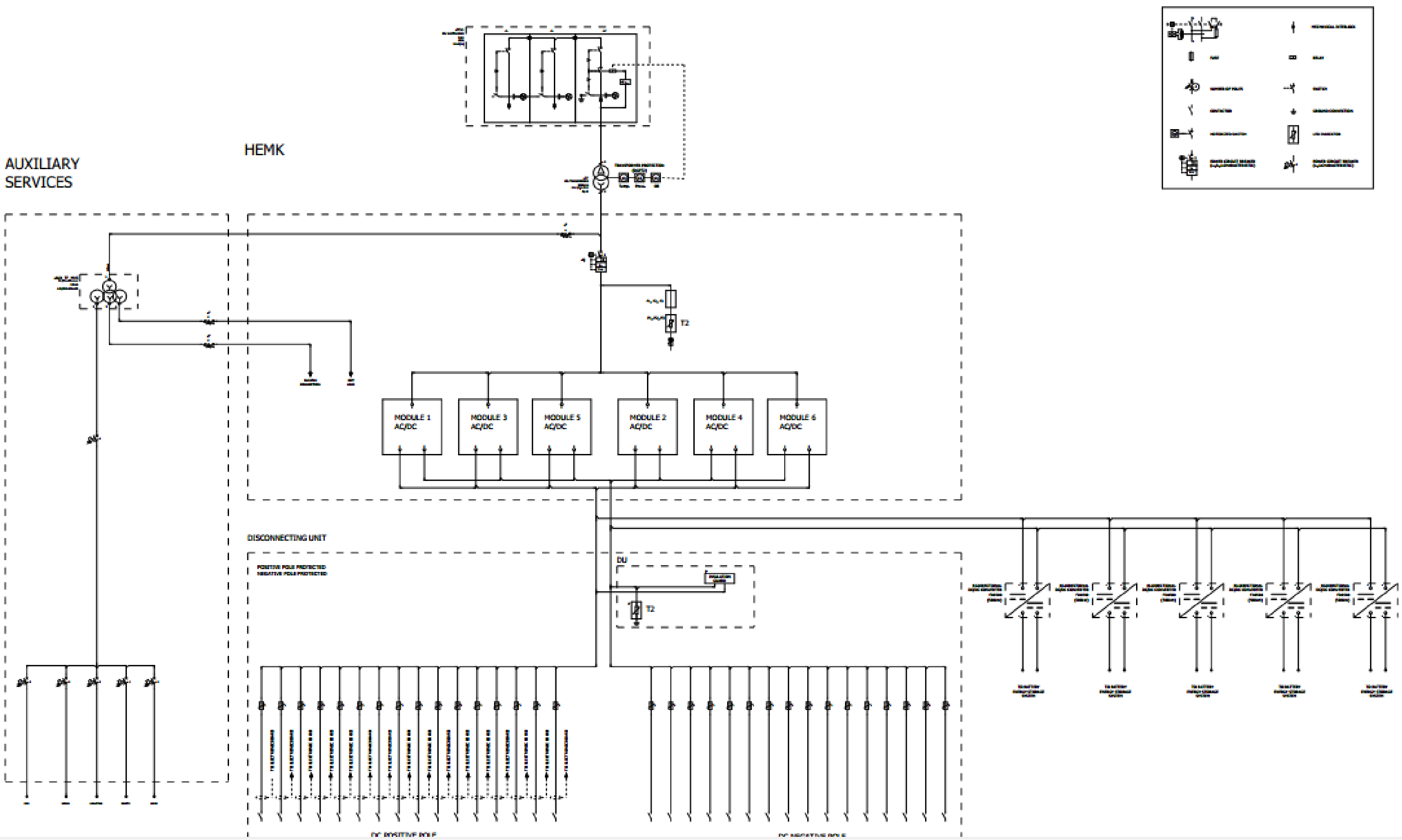
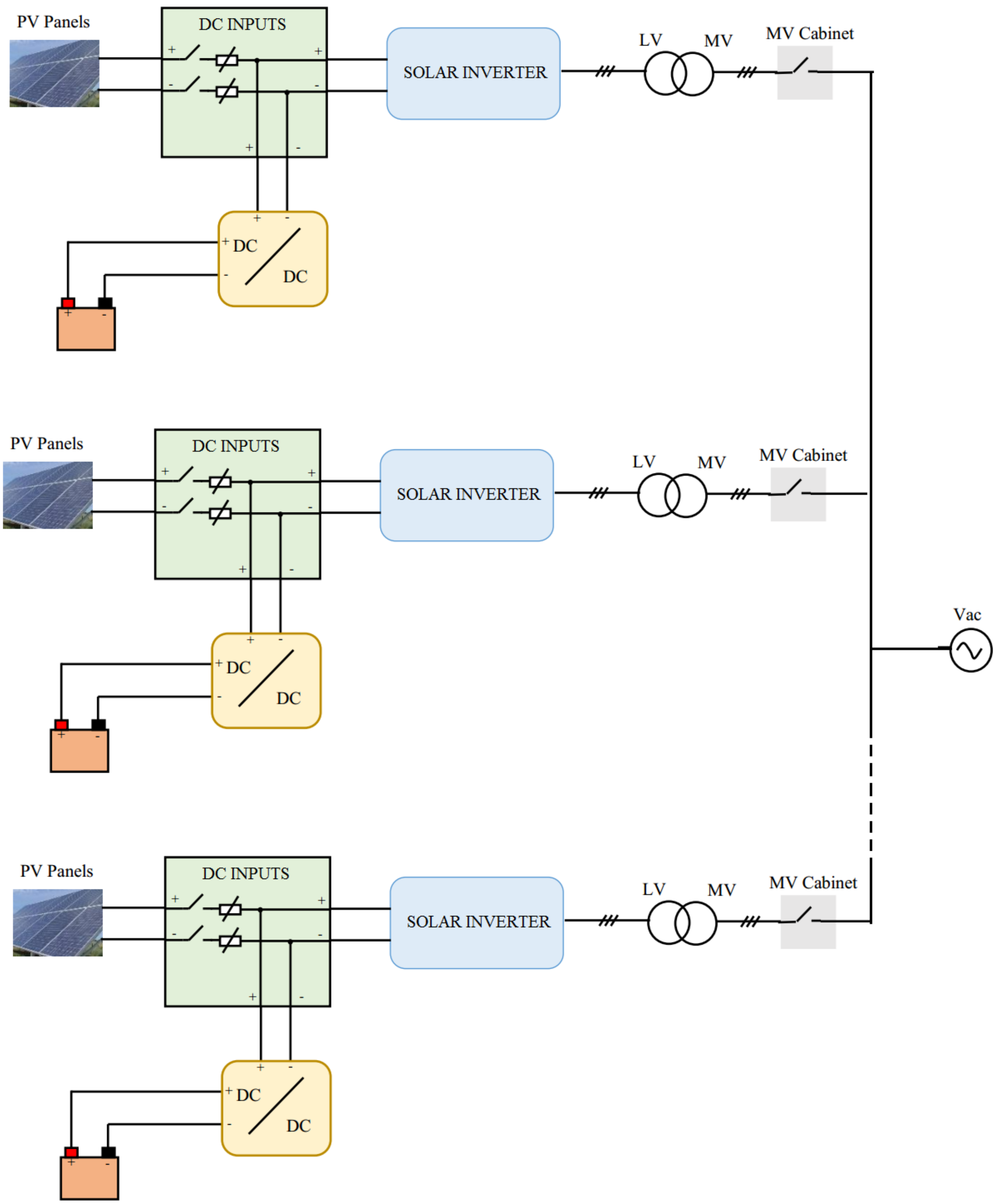
Appendix

Appendix I: SLD of inverter station

Below shows the Single Line Diagram of the inverter station, which includes the DC inputs from the PV array (not taking into account a 1st phase connection box), the inverter, the DC/DC converter connected in parallel at the DC bus, as well as the DC and AC protections, auxiliary transformer, medium voltage transformer and switchgear (in this example it shows a 2L + P feeder configuration).



Appendix II: Parallel connection multiple inverter stations



Appendix III: Solar inverter datasheet

The inverter model used as reference in the case studies is the Freesun FS2800CH15 from Power Electronics. Its technical details are the following:

		Frame 3	Frame 4	Frame 5	Frame 6	Frame 7
	Number of Modules	3	4	5	6	7
	Reference	FS1200CH15	FS1600CH15	FS2000CH15	FS2400CH15	F2800CH15
OUTPUT	AC Output Power (kW) @50°C [1]	1200	1600	2000	2400	2800
	AC Output Power (kW) @25°C [1]	1430	1910	2390	2860	3345
	Max. AC Output current (A)	1285	1710	2140	2570	3000
	Operating Grid Voltage(VAC)	645V ±10%				
	Operating Range, Grid Frequency	50Hz / 60Hz				
	Current Harmonic Distortion (THDi)	<3% per IEEE 519				
	Power Factor (cosine phi) [2]	0.55 leading … 0.3 lagging / Reactive Power injection at night				
	Power Curtailment	0…100% / 0.1% Steps				
INPUT	MPPT window @ full power (VDC) [1]	913V – 1310V				
	Maximum DC voltage	1500				
	Maximum DC continuous current (A)	1600	2140	2675	3210	3745
	Maximum DC Short circuit current(A)	2320	3100	3880	4650	5450
EFFICIENCY & AUX. SUPPLY	Max. Efficiency (η)	98.7%				
	Euroeta (η_{EURO})	98.6%				
	Max. Standby Consumption (P_{night})	< approx. 50W/per module				
	Control Power Supply	400V / 230Vac – 6kVA power supply available for external equipment (optional).				
CABINET	Dimensions [WxDxH] [mm]	3038 x 945 x 2198	3751 x 945 x 2198	4464 x 945 x 2198	5177 x 945 x 2198	5890 x 945 x 2198
	Weight (kg)	2635	3290	3945	4600	5255
	Air Flow	Bottom intake. Exhaust top rear ventilation				
	Type of ventilation	Forced air cooling				
ENVIRON-MENT	Degree of protection	IP54				
	Permissible Ambient Temperature	-35ºC [3] to 60ºC / Active power derating >50ºC				
	Relative Humidity	0% to 100% non-condensing				
	Max. Altitude (above sea level)	2000m / >2000m power derating (Max. 4000m)				
	Noise level [4]	<79dB				
CONTROL INTERFACE	Interface	Graphic Display (inside cabinet) / Optional Freesun App				
	Communication protocol	Modbus TCP/IP				
	Power Plant Controller Communication	Optional				
	Keyed ON/OFF switch	Standard				
	Digital I/O	User configurable				
	Analogue I/O	User configurable				
PROTECTIONS	Ground Fault Protection	Floating PV array: Isolation Monitoring per MPP Grounded PV Array (Positive pole or negative pole): GFDI protection Optional PV Array transfer kit: GFDI and Isolation monitoring device				
	Humidity control	Active Heating				
	General AC Protection & Disconnection	Circuit Breaker				
	General DC Protection & Disconnection	External Disconnecting Unit Cabinet				
	Module AC Protection & Disconnection	AC contactor & fuses				
	Module DC Protection	DC fuses				
	Overvoltage Protection	AC and DC protection (type 2)				
CERTIFI-CATIONS	Safety	IEC 62109				

[1] Values at 1.00·Vac nom and cos Φ =1. Consult Power Electronics for derating curves.

[2] Consult P-Q charts available: $Q(kVAr) = \sqrt{S(kVA)^2 - P(kW)^2}$.

[3] Heating kit option required below -20ºC.

[4] Sound pressure level at a distance of 1m from the rear part.