MÁSTER UNIVERSITARIO EN INGENIERÍA INDUSTRIAL

MASTER THESIS

DYNAMIC HOSTING CAPACITY EVALUATION WITHIN DERMS

Autor: Juan Menéndez-Pidal Hernández-Ros

Director: José Miguel Asensio Bermejo y Carlos Mora Rueda

Co-Director: Lukas Sigrist

Madrid

Declaro, bajo mi responsabilidad, que el Proyecto presentado con el título

Dynamic Hosting Capacity evaluation within DERMS

en la ETS de Ingeniería - ICAI de la Universidad Pontificia Comillas en el

curso académico 2021/22 es de mi autoría, original e inédito y

no ha sido presentado con anterioridad a otros efectos.

El Proyecto no es plagio de otro, ni total ni parcialmente y la información que ha sido

tomada de otros documentos está debidamente referenciada.

Fdo.: Juan Menéndez-Pidal Hernández-Ros Fecha: 22/ 08/ 2022

Autorizada la entrega del proyecto

EL DIRECTOR DEL PROYECTO

Fdo.: Carlos Mora Rueda Fecha: 22/ 08/ 2022

COMILLAS
UNIVERSIDAD PONTIFICIA
ICAI

MÁSTER UNIVERSITARIO EN INGENIERÍA INDUSTRIAL

TRABAJO FIN DE MÁSTER

DYNAMIC HOSTING CAPACITY EVALUATION WITHIN DERMS

Autor: Juan Menéndez-Pidal Hernández-Ros

Director: José Miguel Asensio Bermejo y Carlos Mora Rueda

Co-Director: Lukas Sigrist

Madrid

DYNAMIC HOSTING CAPACITY EVALUATION WITHIN DERMS

Autor: Menéndez-Pidal Hernández-Ros, Juan.
Director: Asensio Bermejo, José Miguel.
Entidad Colaboradora: Minsait

RESUMEN DEL PROYECTO

Introduciendo las incertidumbres de la generación y la demanda en el análisis de la capacidad del sistema y tras realizar un análisis de Monte Carlo ejecutando un OPF con función objetivo la minimización del curtailment, se obtienen distribuciones de curtailment, sobre estas se realiza un análisis de riesgos para aportar información a los inversionistas con el objetivo de incentivar la inversión en DERs, los cuales aportan flexibilidad y robustez a la red local.

Palabras clave: Hosting Capacity, curtailment, DER

1. Introducción

El término Hosting Capacity (HC) se define como la capacidad que tiene un sistema para albergar generación sin que la red alcance un punto de operación crítico. La HC es típicamente utilizada en el ámbito de la integración de generación renovable. Si la generación supera la HC, al menos una variable eléctrica de la red (la tensión, el flujo por una línea, etc.) excede un límite para un determinado tiempo.

Para evitar inversiones a ciegas en reforzar la red, las distribuidoras dieron un primer paso y adoptaron el término de HC, este término fue introducido por primera vez en 2004 por Bollen et al [1]. El primer acercamiento para determinar este valor fue estático. Se tomó el punto de máxima generación y el de mínimo consumo y se simulaban los casos utilizando programas de flujo de cargas hasta que para una determinada capacidad instalada en la red se superaran los límites [2]. Este valor pasaba a ser el HC de dicha red de distribución. Este método ha sido válido hasta que el interés en la inversión en DER se disparó. En efecto, este valor es típicamente muy conservador ya que combina un instante de mínima demanda (típicamente por la noche) con un instante de máxima generación (en caso de generación FV a mediodía).

Para incrementar el HC de la red de distribución se introduce el término Dynamic Hosting Capacity (DHC). Esta nueva metodología es estocástica y considera las incertidumbres asociadas tanto en la producción como en el consumo a la hora de determinar el HC de la red y su relación [3]. Además, con los esquemas de control de los inversores, se puede obtener un incremento del HC reduciendo durante breves periodos de tiempo la potencia inyectada por los DER a la red, esto también es conocido como curtailment.

2. Definición del Proyecto

El proyecto consiste en comenzar con las primeras fases de desarrollo de un módulo integrable en la herramienta Onsait de Minsait. Este recibirá como inputs el tipo de tecnología, la ubicación de esta y la capacidad instalada y devolverá la cantidad de

curtailment que será realizado sobre la instalación en el transcurso de un año y la probabilidad asociada a que este ocurra.
El análisis de riesgo se basa en el Valor Condicional al Riesgo, también conocido como CVaR en inglés. El algoritmo desarrollado considera incertidumbres asociadas a la demanda y a la generación para evaluar la capacidad de la red, el output del algoritmo será una distribución de vertido y tres valores, estos en el proyecto se conocen como Risk Value, Conditional Curtailment at Risk y el Energy Percentage Curtailed.

Lo que estos valores describen es el riesgo que tiene la instalación a sufrir curtailment, la media de curtailment cada vez que este está ocurriendo y el porcentaje de energía no suministrada. Conociendo está información el inversionista tendrá que evaluar qué hacer con su instalación.

3. Descripción del modelo

La estructura de la herramienta se representa en la Ilustración 1. Primero se fijan los grupos a estudiar, estos son los meses, las horas y el número de ejecuciones que se quieren hacer por hora de cada mes. Una vez definidos, para cada simulación de Monte Carlo se toma una muestra aleatoria de demanda para cada nudo del sistema y otra muestra aleatoria de la generación en el nudo que está siendo instalada. Las muestras se tomarán de un banco de datos históricos. Tras ser definidos estos datos, se ejecuta un OPF que tendrá como función objetivo minimizar el curtailment, la salida de cada simulación dará un valor de curtailment. Una vez todos los escenarios se han ejecutado habrá una distribución de curtailment sobre la cual se hará el análisis de riesgos.

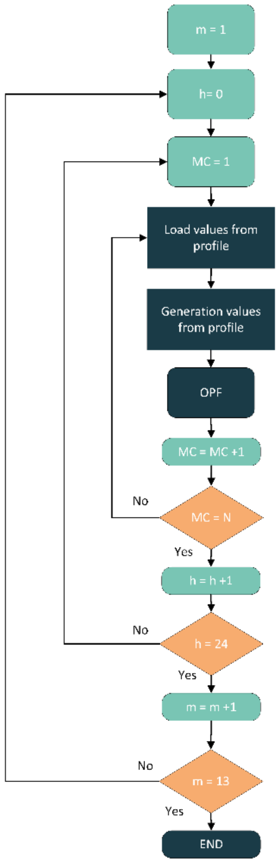

Ilustración 1: Diagrama del modelo

4. Resultados

El algoritmo obtiene a la salida una distribución de curtailment tal y como la que se representa en la Ilustración 2. La figura de la derecha representa la distribución de curtailment mientras que la figura de la izquierda se trata de la distribución resultante al restar la demanda de la generación DER máxima disponible. Únicamente en aquellos casos en los cuales la generación supere a la demanda, podrá darse curtailment.

Tras ejecutar las distintas metodologías, el porcentaje de energía no suministrada obtenido para cada uno se muestra en la Ilustración 3. A la vista de los resultados se observa cómo la metodología tradicional que evalúa el peor de los casos predice que el 97.06% de la energía generada no será suministrada, mientras que el modelo propuesto, en la salida, predice que tan solo el 1,33% de la energía generada no será suministrada, mejorando en un 95,73% los resultados.

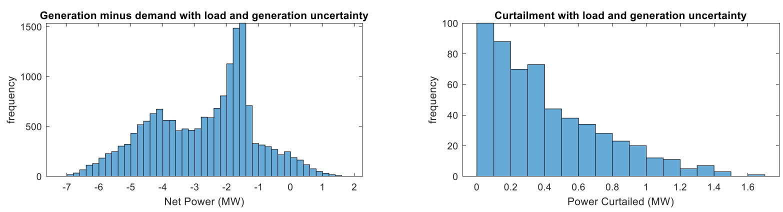

Ilustración 2: Distribuciones generadas por el algoritmo

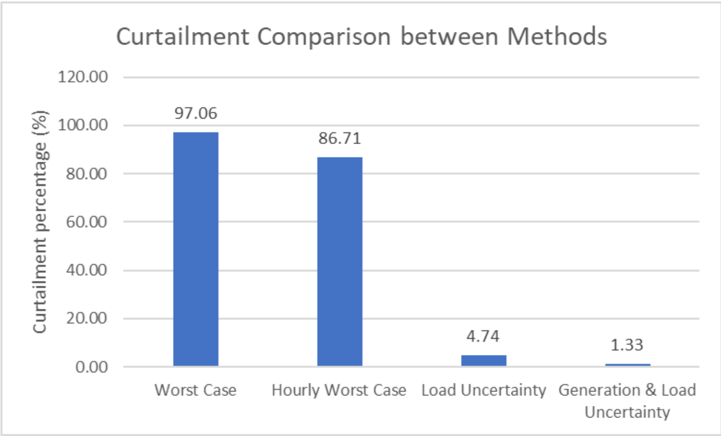

Ilustración 3: Comparación de resultados entre metodologías

5. Conclusiones

Determinar la capacidad del sistema considerando la incertidumbre de la generación y la demanda mejora considerablemente los resultados con respecto al cálculo de la capacidad tomando el peor escenario posible.

Las plantas fotovoltaicas presentan una gran sensibilidad a la potencia instalada, es decir, los rendimientos de la instalación empeoran significativamente si esta está sobredimensionada.

La discriminación horaria del curtailment demuestra que la capacidad del sistema varía con el tiempo, esta herramienta permite al inversionista ajustar el tamaño de la instalación para adaptarse a las horas con los mejores precios.

6. Referencias

[1] S. M. Ismael, S. H. E. Abdel Aleem, A. Y. Abdelaziz, and A. F. Zobaa, “State-of-the-art of hosting capacity in modern power systems with distributed generation,” *Renewable Energy*, vol. 130. Elsevier Ltd, pp. 1002–1020, Jan. 01, 2019. doi: 10.1016/j.renene.2018.07.008.

[2] M. Seidaliseifabad, “Hosting Capacity Assessment of Distribution Systems,” 2020.

[3] M. S. S. Abad, J. Ma, D. Zhang, A. S. Ahmadyar, and H. Marzooghi, “Probabilistic Assessment of Hosting Capacity in Radial Distribution Systems,” *IEEE Transactions on Sustainable Energy*, vol. 9, no. 4, pp. 1935–1947, Oct. 2018, doi: 10.1109/TSTE.2018.2819201.

DYNAMIC HOSTING CAPACITY EVALUATION WITHIN DERMS

Author: Menéndez-Pidal Hernández-Ros, Juan.
Supervisor: Asensio Bermejo, José Miguel.
Collaborating Entity: Minsait

ABSTRACT

Uncertainties associated to Distributed Energy Resources (DER) generation and demand are introduced into Hosting Capacity evaluation by performing a Monte Carlo based OPF analysis with curtailment minimisation as objective function. This approach obtains curtailment distributions, from which risk analysis is performed to provide information for investors with the aim of incentivising investment in DERs. These are beneficial for the grid as they provide flexibility and reliability.

Keywords: Hosting Capacity, curtailment, DER

1. Introduction

The term Hosting Capacity (HC) is defined as the ability of a system to host generation without the grid reaching a critical operating point. HC is typically used in the field of renewable generation integration. If generation exceeds the HC, at least one electrical variable of the grid (voltage, flow through a line, etc.) exceeds a limit for a certain time.

To avoid blind investments in grid reinforcement, distributors took a first step and adopted the term HC, which was first introduced in 2004 by Bollen et al [1]. The first approach to determine this value was static. The point of maximum generation and minimum consumption was taken, and the cases were simulated using load flow programs until for a given installed capacity in the network the limits were exceeded [2]. This value became the HC of that distribution network. This method has been valid until the interest in DER investment exploded. Indeed, this value is typically very conservative as it combines an instant of minimum demand (typically at night) with an instant of maximum generation (in case of midday PV generation).

To increase the HC of the distribution network, the term Dynamic Hosting Capacity (DHC) is introduced. This new methodology is stochastic and considers the associated uncertainties in both production and consumption when determining the HC of the grid and its ratio [3]. In addition, with inverter control schemes, an increase in HC can be obtained by reducing for short periods of time the power injected by DERs into the grid, also known as curtailment.

2. Project Definition

The project consists of starting the first phases of development of a module that can be integrated into Minsait's Onsait tool. This will receive inputs on the type of technology, its location and installed capacity, and will return the amount of energy that will be curtailed on the facility over the course of a year and the probability of this occurring.

The risk analysis is based on Conditional Value at Risk, also known as CVaR. The algorithm developed considers uncertainties associated with demand and generation to assess the capacity of the network, the output of the algorithm will be a curtailment distribution and three values, these are known in the project as Risk Value, Conditional Curtailment at Risk and the Energy Percentage Curtailed.

What these values describe is the risk of the installation to curtailment, the average curtailment each time it is occurring and the percentage of energy not supplied. Knowing this information the investor will have to evaluate what to do with his installation.

3. Model Description

The structure of the tool is shown in Figure 1. First, the groups to be studied are set, these are the months, the hours and the number of executions to be made per hour for each month. Once defined, for each Monte Carlo simulation, a random sample of demand is taken for each node of the system and another random sample of the generation in the node that is being installed. The samples will be taken from a historical databank. After this data has been defined, an OPF is run which will have the objective function of minimising curtailment, the output of each simulation will give a curtailment value. Once all scenarios have been run there will be a curtailment distribution on which the risk analysis will be performed.

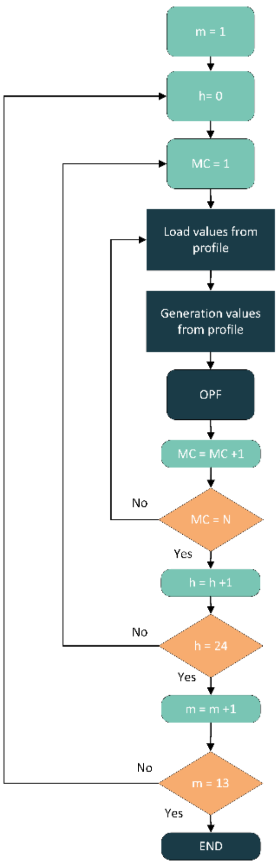

Figure 1: Project model flowchart

4. Results

The algorithm obtains a curtailment distribution at the output as shown in Figure 2. The figure on the right represents the curtailment distribution while the figure on the left is the distribution resulting from subtracting the demand from the maximum available DER generation. Only in those cases where generation exceeds demand, curtailment may occur.

After running the different methodologies, the percentage Energy Percentage Curtailed obtained for each is shown in Figure 3. The results show how the traditional methodology that evaluates the worst case scenario predicts that 97.06% of the generated energy will be curtailed, while the proposed model, in the output, predicts that only 1.33% of the generated energy will be curtailed, improving the results by 95.73%.

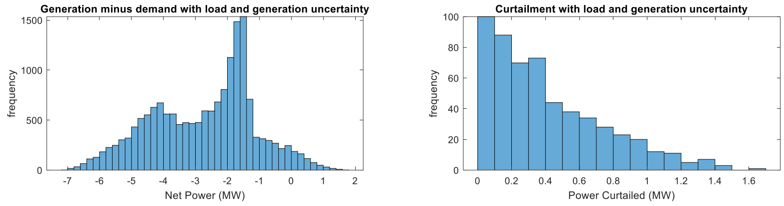

Figure 2: Curtailment Distributions

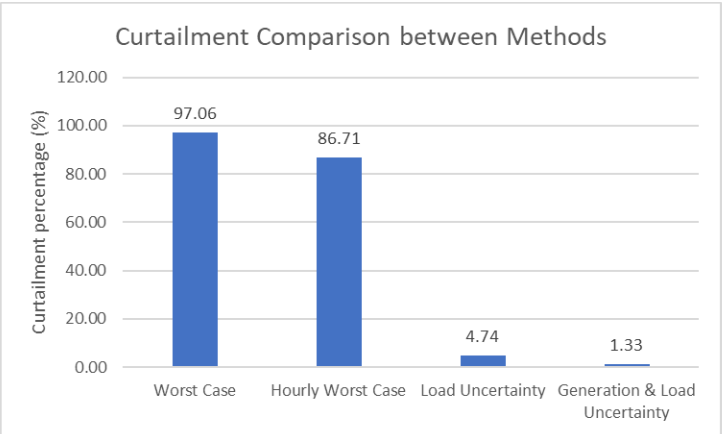

Figure 3: Curtailment comparison between methods

5. Conclusions

Determining the capacity of the system considering the uncertainty of generation and demand considerably improves the results with respect to the calculation of the capacity taking the worst case scenario.

PV plants are highly sensitive to the installed power, meaning that the performance of the plant is significantly worse if the plant is oversized.

The hourly discrimination of curtailment shows that the capacity of the system varies over time, this tool allows the investor to adjust the size of the installation to adapt to the hours with the best prices.

6. References

[1] S. M. Ismael, S. H. E. Abdel Aleem, A. Y. Abdelaziz, and A. F. Zobaa, “State-of-the-art of hosting capacity in modern power systems with distributed generation,” Renewable Energy, vol. 130. Elsevier Ltd, pp. 1002–1020, Jan. 01, 2019. doi: 10.1016/j.renene.2018.07.008.

[2] M. Seidaliseifabad, “Hosting Capacity Assessment of Distribution Systems,” 2020.

[3] M. S. S. Abad, J. Ma, D. Zhang, A. S. Ahmadyar, and H. Marzooghi, “Probabilistic Assessment of Hosting Capacity in Radial Distribution Systems,” IEEE Transactions on Sustainable Energy, vol. 9, no. 4, pp. 1935–1947, Oct. 2018, doi: 10.1109/TSTE.2018.2819201.

Contents Table

Figures index

Table index

1. INTRODUCTION

Hosting Capacity (HC) is defined as the ability of a system to host generation without the grid reaching a critical operating point. HC is typically used in the field of renewable generation integration. HC of a grid is usually determined when at least one electrical variable of the grid (voltage, flow through a line, etc.) exceeds a limit for a certain time.

In recent years, developed countries have set environmental goals aligned with decarbonisation and sustainability. For example, the state of California is aiming for 60% of energy to be produced by renewables by 2030 [4], and Europe has set the goal of increasing energy efficiency while increasing the integration of renewable energy sources [5]. These initiatives have caused investment in Distributed Energy Resources (DER) to grow considerably in recent years. According to [6], Distributed Photovoltaic (DPV) will grow at a rate of 6.1% per year from 2020 to 2050, causing a paradigm shift in the electricity system. The increased penetration of DER can cause problems in the distribution grid such as overvoltages at nodes, overcurrents on lines, reverse flows and problems with power quality due to connected electronic equipment [7].

Traditionally, the power grid worked as follows: power was generated at generation plants and transported to customers (most of whom were located on the distribution network) via the transmission and distribution networks. Distribution system operators (DSOs), when planning investments in the network, had only to take a pattern of demand growth and plan equipment reinforcements. However, the upward trend in DER installation coupled with changes in consumption patterns, complicates the planning of the distribution network using the traditional methodology.

To avoid blind investments in grid reinforcement, DSOs adopted the HC term, which was first introduced in 2004 by Bollen et al, [1]. The first approach to determine HC value was static. Points of maximum generation and minimum consumption were taken, then the cases were simulated using a power flow (PF) until a certain installed capacity exceeded network operational limits. This value became the HC of the distribution network. This method has been valid until the interest in DER investment exploded. Without question, this value is typically very conservative and highly unlikely to correspond with real situations, as it combines an instant of minimum demand (typically at night) with an instant of maximum generation (in case of midday PV generation).

The approach to increase the HC of the distribution grid is named Dynamic Hosting Capacity (DHC). This new methodology is stochastic and considers the associated uncertainties in both production and consumption when determining the HC of the grid. In addition, with inverter control schemes, an increase in HC can be obtained by reducing for short periods of time the power injected by DERs into the grid, this is also known as curtailment. This new methodology increases the HC. Fig 1 shows the evolution of an electrical variable as a function of the connected DER capacity. It compares between the HC of a system without DER control and a system with it, as can be seen, the HC increases with respect to the conventional method when DER control is used.

The project objective is to implement a DHC algorithm that reframes the HC problem and determines the new HC of distribution systems using a DHC approach.

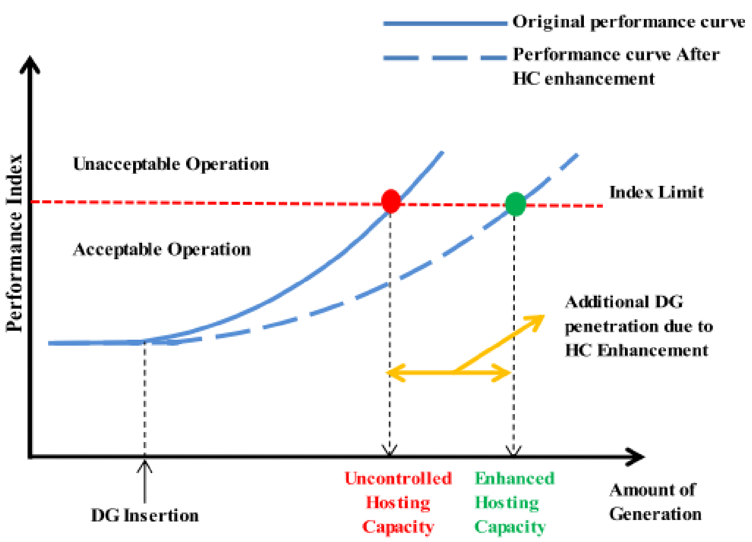

Fig 1: Hosting Capacity: Conventional vs Dynamic Hosting Capacity. Source [2]

1.1 PROJECT MOTIVATION

Distributed generation resources (DER) are becoming increasingly popular and their mass deployment presents new challenges and opportunities for utilities and grid service vendors. These new opportunities have led to the creation of a market for DER Management Systems, or DERMS.

The "worst case scenario" method is too conservative to continue accommodating new DER without the need to invest in network reinforcements in the short term. To avoid investments in reinforcing the distribution network, DSOs are taking an interest in applications that allow the HC of the distribution network to be evaluated automatically using stochastic methods to maximise the HC of the system and incentivise investment in DER simultaneously.

Extending Onesait's DERMS[1] services is one of the main drivers of the project. The creation of an integrable module within this tool that is capable of determining the HC of the system is very attractive to DSOs, therefore, the project aims to lay the foundations for creating such module. The module will aim to incentivise investment in DER and meet the specifications of the DSOs. It will be used by DSOs and will operate by receiving input data from the investor, including the type of technology, the location of it in the distribution grid and the capacity to be installed. Once the investor specifications have been received, the algorithm will be executed. The output will be the percentage of curtailment that the DER is expected to suffer over the course of a year and the risk associated to it.

This project develops a product that satisfies one of the services that this market provides, as previously mentioned, the Dynamic Hosting Capacity evaluation within DERMS is a product that offers DERMS services, which aims to incentivise distributed generation investment. This approach was first mentioned by NREL back in 2019 [8], they propose a PV curtailment risk analysis to settle a contract between the DSO and the DERs owners.

[1] Distributed Energy Resources Management System.

1.2 MARKET OVERVIEW

1.2.1 DERMS SOLUTIONS

According to a market report from Guidehouse Insights [9], four solutions have been identified to offer different services for utilities, these are the following:

- DER analytics for understanding DER characteristics and impacts: These solutions focus on demand and generation forecasting for planning and operational planning, as it is known, DERs can cause serious disruptions due to sudden changes in the meteorological conditions.
- DERMSs for DER and grid management: Products that allows the utility to control and dispatch the DERs in a given location, some examples could be inverter control to manage the generation dispatch or reactive power controls to manage the voltages at the nodes.
- DERMSs for integrated customer solutions: These products are basically optimization tools for DER management of multiple costumers, some examples could be demand charge optimization, energy community memberships or self-generation management.
- Virtual power plants (VPPs) for market interfacing: VPP are used to link the DERs to the wholesale markets, it allows to control the installations and optimises the dispatch to achieve the objective function. These services involve in the creation of local flexibility markets that attempt to solve the local needs, such as congestions and over voltages using only DERs.

1.2.2 MARKET DRIVERS

There are several market drivers that encourage the investment in DERs, this implies that it is has become an interesting investment option, therefore the interest in tools to manage these resources has also increased, the drivers exposed in report [9] are the following:

- Costs reduction for DER installation: With the growth in DER installation, the costs incurred on the installation have declined significantly, therefore it has become an interesting tool for saving costs, especially for industrial and commercial customers which try to cover part of its energy consumption with DERs.

- Regulation reframing for DER adoption: Regulators are starting to propose new distribution level electricity markets which allow DER to participate.
- Government financial support
- Operational benefits and avoided costs: High interest in DERMS services for utilities, which want to gain more visibility of the grid and to be more efficient in real-time management to avoid or postpone reinforcement investments.
- Digitalisation of the grid: With the deployment of smart meters, the DSOs can now receive more data, this allows to develop new solutions to optimize the management of the distribution grid.

1.2.3 MARKET GROWTH

Nowadays, the three regions with more DERMS demand are North America, Europe and Asia Pacific (not China). North America's demand for DERMS services leads the queue and Europe and Asia Pacific are expected to catch up with North America in the following years. Latin America and Middle East are not expected to reach the levels of the three regions from above as they still lack from Smart Grids infrastructure.

From 2021 to 2030 the there is an expected Compound Annual Growth Rate of 21%, the revenues are expected to grow from $332.3 million in 2021, up to $1.8 billion in 2030, this growth takes into account the revenues that come from grid DERMS, grid-edge DERMS and Demand Response Management System (DRMS) services [9]. This expected growth is portrayed in Fig 2, which represents the total growth as well as the growth per region.

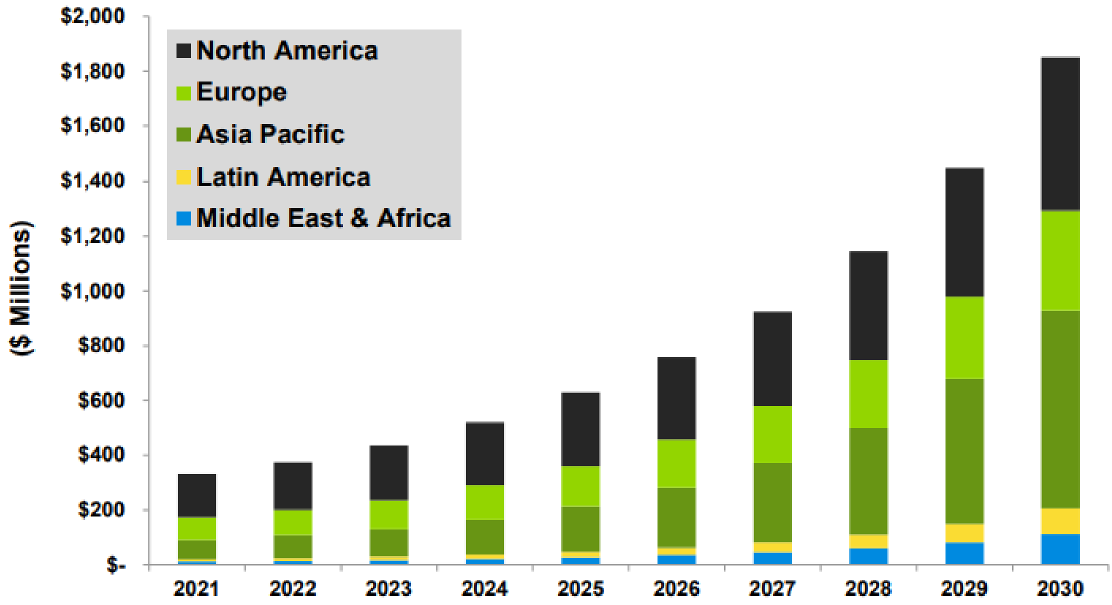

Fig 2: DERMS Revenue by Region. Source: [9]

1.3 OBJECTIVES

The goals that the project aims to achieve are the following:

To demonstrate that considering the uncertainties associated with generation and demand forecasts and using active power control in the inverters of the connected DERs, the Hosting Capacity can be considerably improved with respect to that calculated in the conservative model, worst-case scenario approach.

Start with the first phases of development of a module that can be integrated into the Onesait tool. This will receive as inputs the type of technology, its location and the installed capacity and will return the amount of curtailment that will be carried out on the facility over the course of a year and the probability associated with this occurrence.

Program and test the selected algorithm to study its effectiveness by running simulations. Then, make a comparison between the conventional method and the selected method to evaluate the HC of the network.

1.4 THE PRODUCT

The product developed in this project addresses the problem of Hosting Capacity in a similar way to Opus One Solutions in terms of risk assessment, however, the approach taken is different.

To begin with, this product is being developed for Minsait ACS and is intended to be a module for the Onesait tool, which none of the players in the DERMS market have.

The risk assessment is based on Conditional Value at Risk, but instead of studying distribution network expansion scenarios, it is based on analysing demand and generation scenarios using Monte Carlo analysis. This analysis introduces stochasticity of generation and demand into the OPF. Once all the simulations have been run, curtailment distributions are obtained, which will be studied to assess the risk of curtailment that the DER installation may suffer.

To assess the return on investment, three values are returned, the Risk Value, the Conditional Curtailment at Risk and the Energy Percentage Curtailed. These values are intended to give information to the investor on how his facility will operate for one year. Based on these values, the investor will have to decide whether to continue with the investment, modify the size of his facility or stop the investment altogether.

This project does not include financial performance values because it has been considered that the responsibility of deciding whether to invest or not should lie with the investor. Therefore, this module is limited to providing information for the investor to make an effective economic analysis.

To reinforce the previous point, the structure of the results maintains the temporal data, which allows breaking down the curtailment values into hours or months, so that the investor can study the effects of curtailment on his plant as a function of the price in the hour being studied.

Finally, it should be stressed that this project aims to encourage investment in DERs by providing information to potential investors. At the same time, it serves the DSO by deferring investments in reinforcements and providing less conservative methodologies for assessing system capacity.

1.5 METHODOLOGY

The resolution of the problem will be structured as follows:

1. Study phase
    a. Read scientific articles and understand the state of the art, study the factors that affect and influence the determination of HC.
    b. Study and understand the methodology used in the algorithms, find algorithms that can be useful for solving the problem based on the analysis of the results of the article where they are found.
    c. Set the objectives to be achieved and determine the output data to be studied.
2. Algorithm selection phase
    a. Select an algorithm that performs the conservative analysis.
    b. Select and define an algorithm that performs a stochastic analysis of the problem.
    c. Select and define an algorithm that includes curtailment in the objective function.
3. Implementation phase
    a. Program the algorithms in Matlab using MATPOWER
4. Simulation Phase
    a. First test the conservative algorithm in a simple circuit in which we can analyse the results and know whether or not they are correct. Test the algorithm to be used to solve the problem and check how it works.
    b. Finally, simulate the algorithms on a bigger distribution network and analyse the results.

2. STATE OF THE ART

This chapter will describe the developments to date in the Hosting Capacity environment. First, the criteria that are commonly used to determine HC will be described, then the most common techniques that can be used to increase HC will be discussed. Thirdly, the existing methodologies that are being used to determine HC will be explained. Then, the active control techniques will be described. Finally, the last section of this chapter shows a briefing of a market report, which analyses the existing DERMS products, the players in the market and those who are addressing Hosting Capacity.

2.1 HOSTING CAPACITY CRITERIA

The results obtained from the HC will depend on the criteria previously established. These criteria are the technical limits of the distribution network. As previously mentioned in Chapter 1, the implementation of DER in the distribution network can cause the technical limits of the distribution network to be reached; these limits are used in the algorithms to determine the HC level that the distribution network can accommodate without it reaching critical operating points. The most studied limits according to [2], [10] are: thermal limits, voltage limits, limits associated with the protections and, finally, limits associated to the quality of service. All these criteria can be broken down into different problems. Fig 3 shows a scheme that compiles some of the most common problems that can occur within each of the criteria. In the following, each of the criteria and the problems associated with each of them will be discussed.

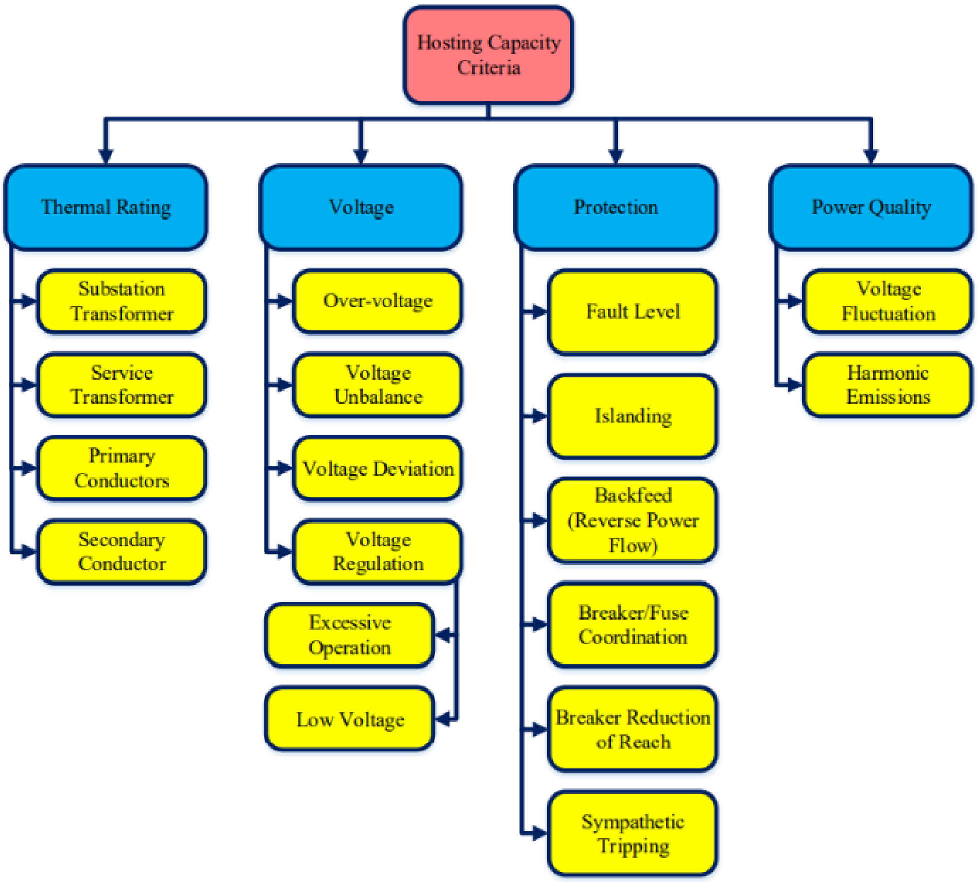

Fig 3: Hosting Capacity Criteria schematics. Source: [2]

Out of all the criteria, the frequency with which they occur is not the same; in most of the studies carried out, over voltages and over currents are the two most frequently reached limits [1], [2], [11].

Thermal Limits

Elements connected to the distribution network, such as line cables or transformers, have a capacity to conduct current, known as thermal capacity or thermal limit. If the thermal capacity is exceeded, the equipment can lose its properties or even suffer irreparable damage. In the case of long-lasting over currents, this can lead to equipment explosions or fires, which is why it is necessary to monitor the system [2], [10].

With the increasing interest in installing DER equipment, the thermal capacity of the equipment may be compromised. However, this does not imply that the installation of DER is always harmful, for example, in high demand situations, connected DER equipment can be beneficial, as it would reduce the load on the lines and the risk of congestion would decrease. By contrast, in a scenario of high generation and low demand, it could happen that generation is higher than consumption at a nodal level, this could lead to reverse power flows. These reverse power flows can be detrimental to the connected equipment such as OLTC control schemes and protections performance.

Voltage Limits

Currently, voltage regulation in distribution networks is done by using on-load tap changer (OLTC) transformers controlled by automatic controllers. Usually, the voltage at the substation busbars is maintained slightly higher than nominal to compensate for the voltage drop along the feeder. The introduction of DER can help the voltage profile, but it also complicates the control scheme. DER installation can cause the following problems [2], [10]:

1. Over voltages: These occur when generation at the node exceeds consumption. Over voltages at a node caused by distributed generation can also cause the voltages at adjacent nodes to approach or even exceed their limits. In [1] it is highlighted that the upper voltage limit is the first limit to be breached in most cases, therefore, as stated in [2], [10], [11] this is the most commonly used criterion when determining the HC.
2. Unbalance: This occurs when both, DER generation and consumption are unbalanced, for instance when the connected DER is single-phase.
3. Voltage variation: This problem is due to the rapid variation in the generation of DERs. Normally, the power injected by the renewable energy equipment into the distribution grid varies faster than the voltage regulation equipment, causing the voltage to be under-regulated and some voltage regulation equipment to over-operate.
4. Voltage Regulation:

a. Over-operation: Uncertainty associated with generation can cause equipment to over-operate.
b. Under voltages: A DER connected at the next node downstream of the voltage regulator can affect its operation, as these devices expect the voltages in the downstream nodes to decrease progressively and not the contrary.

System protections

Under circumstances where DER generation exceeds consumption at the node, reverse power flows can occur in the distribution network. Many protections equipment is not prepared to operate under these circumstances. Some of the situations that can occur under these conditions are the tripping of the protections in when they shouldn't and the non-tripping of the protections in fault situations [1]. The problems of most concern with the penetration of DER are the following:

1. Fault current: Each point in the distribution network has a fault level associated with it; this fault level is the value that the current at given point in the network takes when a fault is taking place. Faults must be cleared quickly, as they pose a risk to the lives of users and to the operation of equipment. It should be added that many grids that have been designed with a maximum fault current, this maximum level can limit the connection of distributed generation. DER equipment contributes to the fault current and makes its calculation more complicated. However, DER connected via power electronics contribute less to the fault current than DER connected directly to the grid.
2. Reverse power flows: These occur when the total distributed generation (DG) exceeds the total demand and the power instead of going from the substation to the nodes, flows from the nodes to the substation. According to [2] there are two factors that limit reverse load flows: these are the rated power of the equipment under these conditions and the automatic control systems. For example, a tapped transformer can present operational problems when it is in a reverse flow scenario, and for it to function correctly, the control system would have to be redesigned. There are three

common failures that can occur when the system is under the influence of reverse flows:

a. Lack of coordination between protection elements.
b. Switch range reduction.
c. Undesired action.

Power Quality

The power quality supplied to customers can be compromised in a scenario with a high presence of DER in the grid. Due to the rapid variation in the power injected and the uncertainty associated with such generation, voltage control equipment may over-operate causing a deterioration in the quality of service. Another problem is related to power electronics equipment connected to the grid, which due to rapid variations in voltages can inject harmonics detrimental to quality. As described in [1], studies on the impact of harmonics on the grid have been carried out and concluded that it is necessary to set a harmonic distortion limit in the HC study, otherwise grid-connected equipment may be damaged.

2.2 HOSTING CAPACITY ENHANCEMENT TECHNIQUES

The techniques to increase the Hosting Capacity try to avoid reaching the limits of the system. In [2], the methods that try to avoid reaching the upper limit of voltages in the nodes are studied, on the other hand, in [1], besides from commenting on the methods to regulate the voltages, it also introduces methods to mitigate harmonics and comments on reinforcements as a method to increase the HC. The last two techniques will not be discussed in the project, the first one because harmonics do not usually cause problems in most cases, the second one because this work aims to find ways to increase the HC without resorting to wire solutions, and therefore, grid reinforcements will not be considered further.

Fig 4 shows the techniques that will be discussed, these are the following: energy storage, On-Load Tap Changer (OLTC) transformer control, active and reactive power control, harmonic mitigation techniques, and finally, grid reinforcements and reconfiguration.

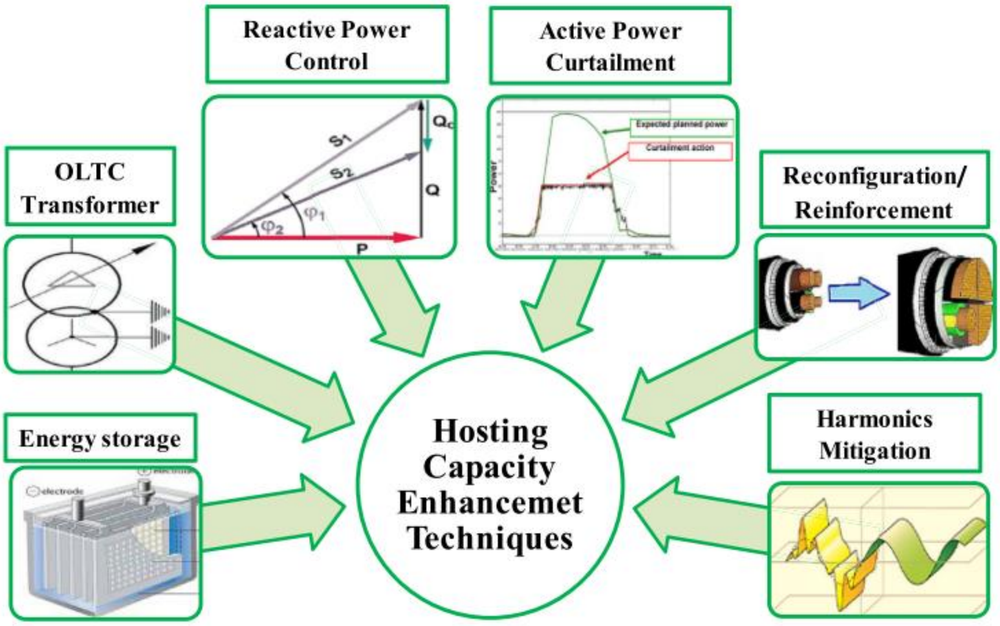

Fig 4: Hosting Capacity Enhancement Methods. Source: [2]

2.2.1 OLTC TRANSFORMER TAP CONTROL

The use of the On-Load Tap Changer (OLTC) is one of the simplest and most common practices used to keep distribution network voltages within the admissible range. An OLTC is defined as an electrical equipment that can adjust the voltage on the secondary winding to solve problems in the feeder [12], its operation is very simple, when the voltages at the feeder nodes are high, the tap is changed so that the voltage on the secondary of the substation transformer decreases, which causes the voltages at the nodes along the feeder to decrease. In the case where the voltages along the feeder are low, the tap will be switched so that the voltage on the secondary increases, causing the other voltages along the feeder to rise [2].

Although the operation is simple, the real challenge lies in designing a good control system capable of taking into account the uncertainties associated with DER generation and demand. In addition, the operation of OLTC is effective in grids in which all nodes have similar characteristics that behave in the same way, however in grids with high DER penetration, nodes may behave in a disparate way, i.e., the needs of each may be opposite, which implies that OLTC in these conditions is not as effective as in the first case described [13].

Fig 5 shows schematically the operation of a tapped transformer, as it can be observed in the upper part of the figure, in the event that the voltage decreases too much along the line, the transformer simply moves the tap position so that the voltage increases at the top of the feeder, and the voltage drop along the line does not exceed the lower limit. In the lower part of Fig 5 the opposite is done; in this case the transformer tap is moved out of position to reduce the voltage and ensure that the upper limit of the network is not reached.

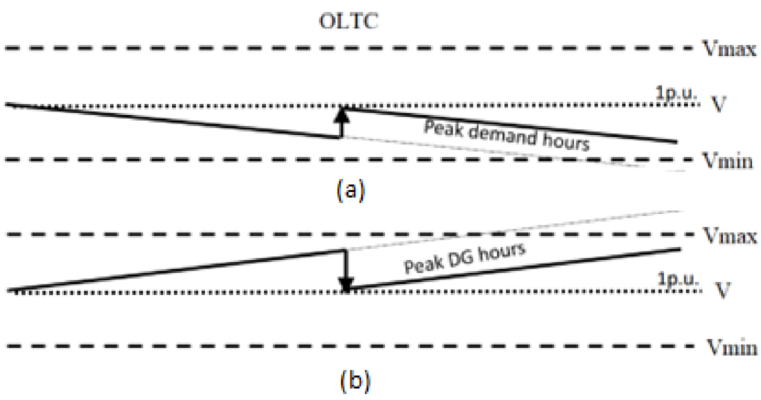

Fig 5: OLTC Control schematic, Source:[14]

2.2.2 REACTIVE POWER CONTROL

Reactive power control is part of the inverter control of grid connected DERs. Reactive power control is widely used in transmission grids, where the X/R ratio is high, whereas in distribution grids the X/R ratio is usually not so favourable and therefore reactive power control methods are not as effective in regulating voltages [2]. Within reactive power control, the two most common strategies are to control reactive power as a function of the voltage at the node with DER (Q(U)) and to control the power factor (PF) as a function of the injected active power (PF(P)) ([2], [15]). The first method causes the inverter to absorb reactive power when the voltage exceeds a certain value. The second method prevents reactive power absorption when the generation is not very high.

2.2.3 Active Power Control

This control is based on reducing the active power injections of the DER equipment until the voltage at the node is within the operating limits. This term is better known as curtailment and is only possible if the DER inverter can be controlled in real time.

Because distribution lines have a low X/R ratio, in other words, the resistance is usually of the same order of magnitude or greater than the reactance, active power control is more effective than reactive power control [2], [10], [12], [16].

With the excellent voltage regulation performance of this control, it would be very easy for the DSO to reduce the injected power to his liking, then the HC would become infinite. However, the DER owner would not benefit from this scenario, since every time his installation undergoes curtailment, his earnings decrease proportionally. A balance needs to be found between both stakeholders. As it has been shown that a few hours per year of curtailment can increase the HC significantly [17].

2.2.4 Energy Storage

The installation of batteries (Battery Energy Storage System, BESS) in the distribution network can increase HC and can delay the DSO's investment in reinforcements. The idea behind the installation of BESS is depicted in Fig 6, which would be to charge them when there is low demand and discharge them when there is high demand.

The main advantage of using BESS as a method to increase HC is that it decouples generation from demand. As far as the BESS equipment is located next to the DER installation it would allow renewable technologies to be manageable. It should be mentioned that for this method to be truly efficient, the batteries need to have an optimised grid deployment and be of the correct size [1].

The major drawback of this method is purely economical, according to [18], in order to install the amount of BESS necessary to exploit the DERs of the network to the maximum, the cost of these must still fall considerably, therefore, this method does provide the benefits that no other technique provides, but at present it is not a viable from the economic point of view.

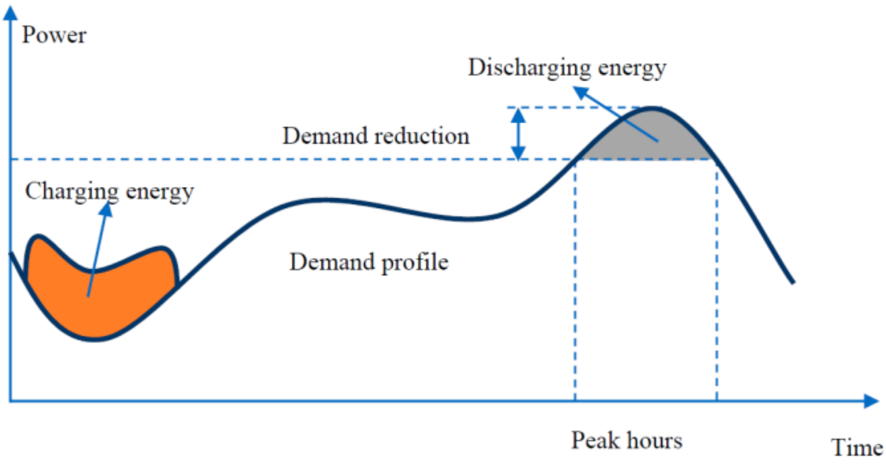

Fig 6: BESS operative cycle, Source: [14]

2.3 EXISTING METHODOLOGIES FOR DETERMINING HOSTING CAPACITY

The system capacity can be broken down into three regions [2]. The three regions are depicted in Fig 7, and are denoted as A, B and C. Fig 7 assesses the probability of an electricity variable reaching its limits as a function of the level of installed capacity. In region A, the probability of exceeding any operational limit is zero for installed capacity levels. Region B comprises those installed capacity values where there is a risk associated with exceeding network limits, the higher the installed capacity, the higher the risk. Finally, region C is where the system limits for the level of installed capacity will always be exceeded. Continuing, there are two points of interest, these are indicated in Fig 7 as HC minimum (Minimum Hosting Capacity) and HC maximum (Maximum Hosting Capacity), the first is the boundary between region A and B, while the second is the boundary between region B and C.

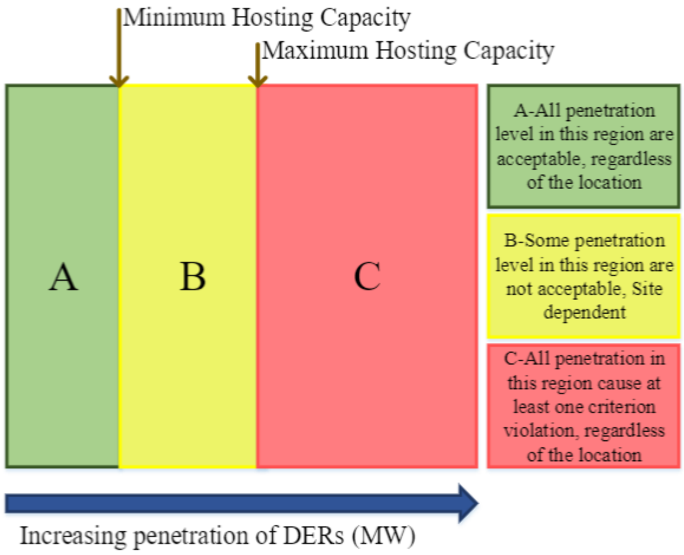

Fig 7: Hosting Capacity Regions, Source: [2]

The traditional method to determine the HC tries to find the value of the minimum HC, as this way of assessing the HC is becoming obsolete, now the region B is the one that takes more interest. The existing mathematical methods for estimating the HC in region B are classified as follows [2], [19]:

1. Optimization problem: Optimization problems tend to converge towards the maximum HC, as the objective function is usually focused on maximising the installed capacity. Three types of optimisation problems are distinguished in [2]:
    a. Robust optimization: Probabilistic distributions of generation and consumption are not needed, only their limits. Decisions are made assuming a worst-case scenario within the previously defined uncertainty interval.
    b. Stochastic Optimization: Uncertainties are modelled as random variables with their probability functions. Scenarios of these variables need to be generated, which are then solved simultaneously.
    c. Distributionally Robust Optimization (DRO): It assumes that probability functions are impossible to achieve, but it does consider generation and consumption predictions as values within a confidence interval.

2. Analytical Method: Analytical methods are deterministic problems and do not consider the uncertainties associated with generation, consumption and location of DER installations.
3. Monte-Carlo: Generates multiple scenarios to model uncertainties and performs a load flow to each scenario to determine the HC.

When estimating the HC of a network, [20] defines 3 variables with uncertainty which are: the location of DER installations, the variation in demand, uncertainty in generation. For computational simplicity, DHC methods do not consider the uncertainty associated with at least one of the variables.

The methodology can be summarised by dividing the mathematical methods into two groups, deterministic and probabilistic. The first group uses those mathematical models to determine the HC that do not consider the uncertainties of the variables, the second group will consider the uncertainties and their results will be probabilistic distributions.

In order to obtain a complete description of the estimation methodology, a mathematical and descriptive analysis will be carried out, first the mathematical model of the network will be presented, followed by a description of the existing deterministic models and then an example of the mathematical approach. Thirdly, a description of the stochastic methods will be given and again an example of the mathematical model will be presented. Finally, active network control techniques will be introduced, explained and one of them will be modelled.

2.3.1 GRID MODELLING

Distribution networks are operated radially [21] due to the simplicity of operation and low investment costs. Therefore, for the purpose of modelling the network, [22] presents the notations from Fig 8, and the following grid modelling example:

$$N = \{0, \dots, n\} \rightarrow number\ of\ buses\ in\ the\ grid$$

$$N^{+} = N \backslash \{0\} \rightarrow buses\ in\ the\ grid\ without\ the\ feeder\ substation\ bus$$

$B \ \rightarrow number\ of\ branches$

$(i,j), i \rightarrow j :\rightarrow branch\ that\ connects\ node\ i\ to\ j$

Branches (i,j) ∈ B

$z_{ij} = r_{ij} + jx_{ij} \ \rightarrow impedance\ branch\ ij$

$y_{ij} = \frac{1}{z_{ij}} = g_{ij} - jb_{ij} \ \rightarrow admittance\ branch\ ij$

$S_{ij,t} = P_{ij,t} + jQ_{ij,t} \ \rightarrow Apparent\ power\ that\ flows\ from\ i\ to\ j$

$I_{ij,t} \ \rightarrow Complex\ current\ that\ flows\ from\ i \rightarrow j$

Nodes i ∈ N

$V_{i,t} \rightarrow Complex\ voltage\ in\ node\ i\ and\ instant\ \ t$

$v_{i,t} = |V_{i,t}|^2$

$s_{i,t} = p_{i,t} + jq_{i,t} \ \rightarrow net\ power\ injected\ in\ node\ i\ and\ instant\ t$

$s_{i,t}^g = p_{i,t}^g + jq_{i,t}^g \ \rightarrow Generated\ power\ in\ node\ i\ and\ instant\ t$

$s_{i,t}^d = p_{i,t}^d + jq_{i,t}^d \ \rightarrow Demanded\ power\ in\ node\ i\ and\ instant\ t$

$z_i = r_i + jq_i \rightarrow Ground\ impedance\ node\ i$

$y_i = \frac{1}{z_i} = g_i - jb_i \rightarrow Ground\ admittance\ node\ i$

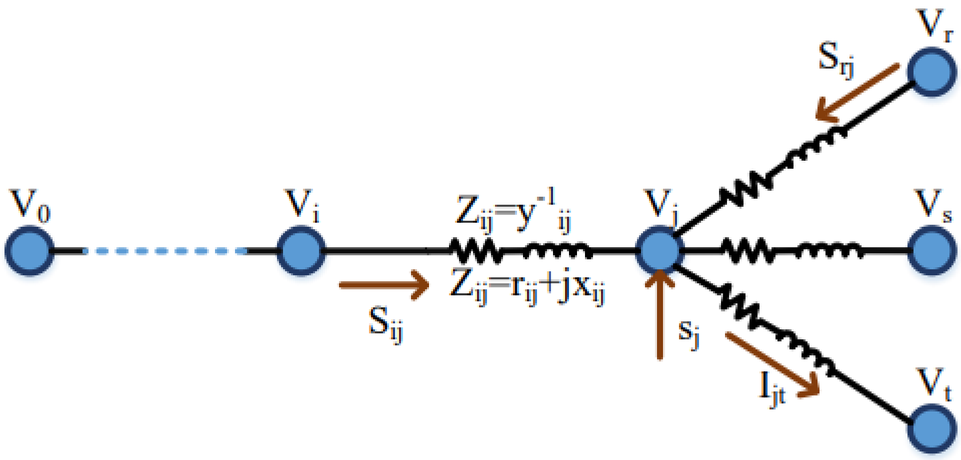

Fig 8: Radial Grid Model Notation. Source: [2]

The line can be modelled using the following formulae, equation (1) is Ohm's law, it relates the voltage drop between nodes i and j is equal to the current flowing on line *i,j* times the impedance of the line.

$$V_{i,t} - V_{j,t} = z_{ij} I_{ij,t} \ \ \forall(i,j) \in B \tag{1}$$

Equation (2) defines the power flow in branch *i,j*.

$$S_{ij,t} = V_{i,t} I^{*}_{ij,t} \ \ \forall(i,j) \in B \tag{2}$$

Equation (3) represents nodal power balance.

$$s_{j,t} = \sum_{k:j\to k} S_{jk,t} - \sum_{i:i\to j} \left(S_{ij,t} - z_{ij}\left|I_{ij,t}\right|^2\right) + y_j^{*}\left|V_{j,t}\right|^2 \ \ \forall j \in N \tag{3}$$

In order to formulate an HC problem, only the boundary conditions remain to be determined, which are the voltages at the nodes (4) and the currents in the lines (5).

$$\underline{v} \le \left|V_{i,t}\right|^2 \le \bar{v} \quad \forall i \in N \tag{4}$$

$$\left|I_{ij,t}\right| \le \overline{I_{ij}} \ \ \forall(i,j) \in B \tag{5}$$

Therefore, the original HC model is an optimization problem in which the objective function is to maximize distributed generation (power injected at the nodes).

$$\begin{gathered} max \sum_{i \in N^+} p_{i,t}^{g} \\ s.t\ (1),(2),(3),(4),(5) \end{gathered} \qquad (6)$$

One of the drawbacks of the original model is that the equations are not linear and may not converge. The solution proposed in multiple studies [2], [3], [12], [19], [20], [22]–[25] relaxes the conditions. The mathematical process followed is identical to the one in [2] and the resulting equations are:

$$l_{ij,t} = \frac{P_{ij,t}^2 + Q_{ij,t}^2}{v_{i,t}} \quad \forall (i,j) \in B \qquad (7)$$

$$p_{j,t} = \sum_{k:j \to k} P_{jk,t} - \sum_{i:i \to j} \left(P_{ij,t} - r_{ij} l_{ij,t}\right) + g_j v_{j,t} \quad \forall j \in N \qquad (8)$$

$$q_{j,t} = \sum_{k:j \to k} Q_{jk,t} - \sum_{i:i \to j} \left(Q_{ij,t} - x_{ij} l_{ij,t}\right) + b_j v_{j,t} \quad \forall j \in N \qquad (9)$$

$$v_{j,t} = v_{i,t} - 2\left(r_{ij} P_{ij,t} + x_{ij,t} Q_{ij,t}\right) + \left(r_{ij}^2 + x_{ij}^2\right) l_{ij,t} \ \forall (i,j) \in B \qquad (10)$$

Equation (7) is the result of a substitution to a term obtained by squaring Ohm's law. Equations (8) and (9) represent the power balance at the nodes, but decoupled into active and reactive power and as a function of the term obtained in (7). Equation (10) is Ohm's law squared and as a function of the active and reactive power through the lines. The relaxed HC model would be:

$$\begin{gathered} max \sum_{i \in N^+} p_{i,t}^{g} \\ s.t\ (4),(5),(7),(8),(9),(10) \end{gathered} \qquad (11)$$

Nevertheless, this model is not convex either, since the equation (7) is quadratic. To solve the model two solutions are proposed, the first is a conic relaxation and the second is to linearise equation (7).

2.3.1.1 Conic Relaxation

The conic relaxation involves modifying (7). First, the terms in the equation are rearranged to obtain (12). This equation closely resembles the elliptic cone expression [24], which is represented in (13).

$$l_{ij,t}v_{i,t} = P_{ij,t}^2 + Q_{ij,t}^2 \quad \forall (i,j) \in B \tag{12}$$

$$Z_1^2 + Z_2^2 \leq z_1 z_2 \tag{13}$$

In order to relax the equation and make the problem convex, (12) is modified to resemble (13), the result is (14). This equation will be introduced into the HC model by substituting equation (7).

$$P_{ij,t}^2 + Q_{ij,t}^2 \leq l_{ij,t}v_{i,t} \quad \forall (i,j) \in B \tag{14}$$

The new HC model with conic relaxation.

$$\begin{gathered} min \sum_{i \in N^+} -p_{i,t}^g \\ s.t\ (4),(5),(8),(9),(10),(14) \end{gathered} \tag{15}$$

2.3.1.2 Linearisation

Linearisation is a method used to simplify the optimisation conditions in order to solve a linear programming problem. These problems are computationally simpler to solve and do not require as much computational power as quadratic or semidefinite programming.

In chapter 2 of [2] two linearisation methods are discussed. The first is to directly eliminate the term $l_{ij,t}$. from the equations. The second method is to approximate the quadratic equation by piece-wise elements, which is represented in Fig 9. The method consists of establishing small intervals to approximate the function with straight lines between the defined intervals. The choice of the number of intervals is another optimisation problem since insufficient points would imply a lousy approximation, while too many intervals would result in higher accuracy, but also in higher computational complexity. Since this method will not be used, the mathematical development will not be explained as this is not the aim of the project.

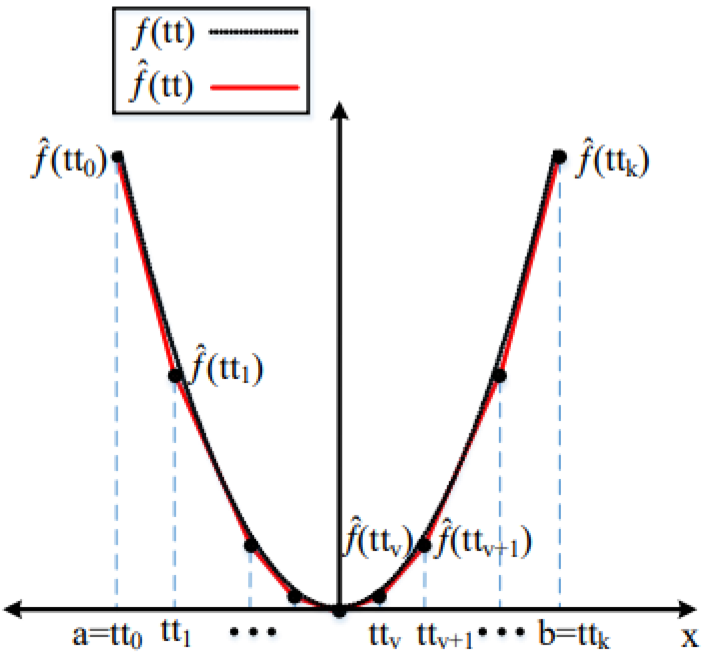

Fig 9: Linear approximation, Source: [22]

Finally, in [26] a linear approximation using the Taylor polynomial is proposed. To carry out the approximation, the equation (7) is taken, to facilitate the understanding of the process, this is represented in (16).

$$l_{ij}(P_{ij}, Q_{ij}, v_i) = \frac{P_{ij}^2 + Q_{ij}^2}{v_i} \qquad \forall(i,j) \in B \tag{16}$$

The first-order Taylor polynomial of equation (16) is made and equation (17) is obtained, where $(P_{ij}^0, Q_{ij}^0, v_i^0)$ are the starting points.

$$\begin{aligned} l_{ij}(P_{ij}, Q_{ij}, v_i) \approx \frac{1}{v_i^0}\left(2P_{ij}^0 P_{ij} + 2Q_{ij}^0 Q_{ij}\right) - \frac{1}{v_i^0}\left(\left(P_{ij}^0\right)^2 + \left(Q_{ij}^0\right)^2\right) \\ - \frac{\left(P_{ij}^0\right)^2 + \left(Q_{ij}^0\right)^2}{\left(v_i^0\right)^2}\left(v_i - v_i^0\right) \end{aligned} \tag{17}$$

Lastly, since the term to the right of the whole is much smaller than the rest of the terms, it is neglected and the linear approximation to the l_{ij} term is (18).

$$\begin{aligned} l_{ij}(P_{ij}, Q_{ij}, v_i) &\approx L_{ij}(P_{ij}, Q_{ij}) \\ &= \frac{1}{v_i^0}\left(2P_{ij}^0 P_{ij} + 2Q_{ij}^0 Q_{ij}\right) - \frac{1}{v_i^0}\left(\left(P_{ij}^0\right)^2 + \left(Q_{ij}^0\right)^2\right) \end{aligned} \tag{18}$$

2.3.2 DETERMINISTIC MODEL

The deterministic model does not consider the uncertainty associated with generation, consumption or the location of DERs in the network, the main advantage of these methods is that they do not require as much computational power as stochastic methods, however, the main disadvantage is the loss of information, which means that the results obtained can be very conservative [25]. Currently, deterministic models with minimum consumption and maximum generation scenarios are used by system operators to determine the HC. They will continue to be used until new models that consider uncertainties proof to be implementable in real systems.

The model generally determines the HC by generating DER installation scenarios. In each of these scenarios the installed DER capacity is increased, and a power flow is solved. So far, this is done by running the worst-case scenario, which is the point of maximum generation and minimum demand. This scenario is highly improbable, since in the case of photovoltaic solar energy the moment of maximum generation is at midday, while the point of minimum demand occurs at night. In the case of wind energy, it is different, as the distribution of wind generation is not as time sensitive as solar. However, what must be emphasised is that the conventional method decouples demand and generation over time, so it is highly unlikely that such circumstances will occur, which implies that the result is conservative, and the system capacity is under-utilised.

A more realistic case would be to take the minimum value of demand in the hours of maximum solar generation. Regardless of the values taken, the load flow is executed for each of the installed DER capacity levels until the limits of at least one electrical variable in the system are exceeded. The HC value will be the last value at which no grid limit was exceeded [22].

There are two mathematical methods to determine the HC deterministically, the optimization problem and the analytical problem.

2.3.2.1 Analytical Problem

The analytical problem is one of the first methods used to determine the HC of a network or node. The method consists of modelling the network with a series of equations including the limits, see [27]. The network is modelled through a Thevenin equivalent seen from the node that has DER generation installed. With this formulation, the total capacity that can be installed into the network is obtained.

The analytical problem is very simple and does not include the network model in detail as an optimization problem does. For example, this method presents difficulties to model other DER installed as well as the currents through the branches. So, the results will not be as accurate as with the second method. However, the great advantage is the simplicity of the model, which allows values to be obtained quickly and easily.

2.3.2.2 Deterministic Optimization Problem

The deterministic optimisation problem to calculate the HC consists of running a power flow or an OPF but changing the objective function. For this to be deterministic, the uncertainties associated with location, generation and consumption will not be considered.

The locations of DER equipment in a deterministic problem are modelled depending on the objective to be achieved. If the capacity of a single node wants to be determined, the connected DER capacity will be increased at predefined intervals until some electrical variable reaches its limit. On the other hand, to determine the HC of the entire system, it is assumed that all nodes have an equal installed DER capacity, and this capacity is increased until one of the system limits is reached.

Generation and consumption can be modelled in many ways. An example of a process of modelling the variables can be explained by using Fig 10. This figure represents an accumulation of daily demand profiles collected over six years. Once this profile has been obtained, if the conservative and traditional demand selection criterion is used, the demand will take the historical minimum value. Another, albeit less conservative, example would be to take the historical minimum value of demand for each hour of the day [19], [28].

The modelling of generation follows the same procedure as demand. Referring to Fig 11, this shows the accumulation of daily profiles of solar irradiance in W/m^2 over the course of a year. The worst case scenario approach would take the maximum irradiance as the parameter to define the power generated by the PV installation, again, a more likely approach would be to take the maximum irradiance for each hour of the day [19], [28].

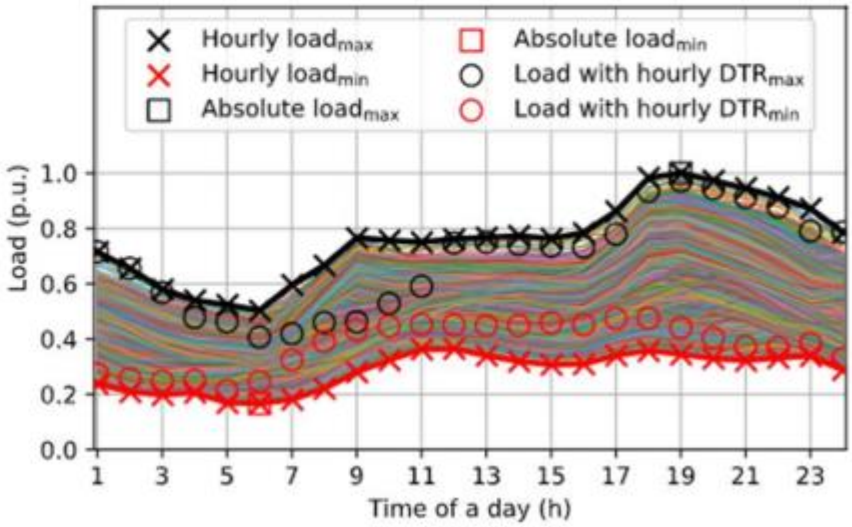

Fig 10: Historical 6-year Demand Profile collected in Scotland. Source [19]

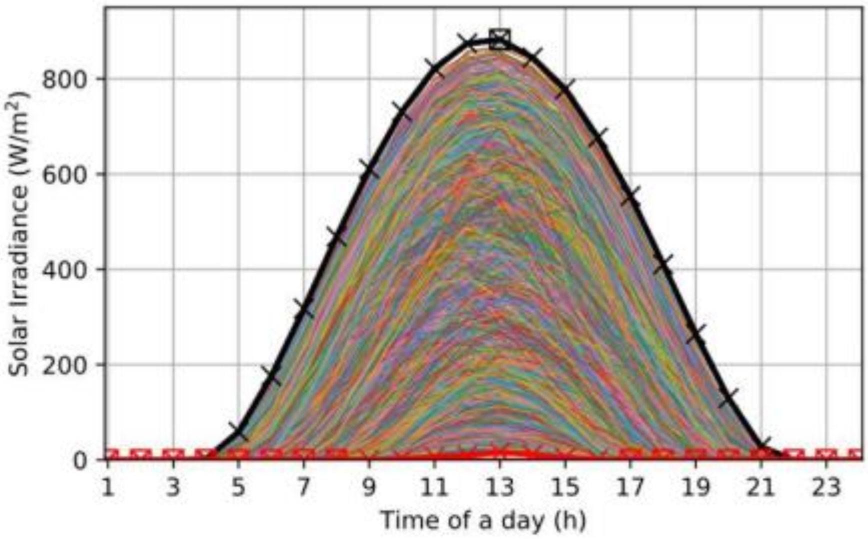

Fig 11: Annual Solar Irradiance variation. Source: [19]

Once the uncertainties have been reduced to certain values, these values are introduced into the optimisation problem. The optimisation problem to determine the HC is nothing more than an OPF whose objective function is to maximise the installed DER capacity. The model used should have relaxed conditions so that the problem is convex and converges faster to a result. The relaxation can be, among others, conic [7], [29] or linear [2].

In the case in which conic relaxation is chosen, the optimisation problem would be as shown in (15).

If instead of using conic relaxation it is decided to linearise, an example of a linearised optimisation model can be the one used in [3], it proposes to solve the optimization problem in two steps, because the term (18) depends on an initial point. The initial point is determined by performing another optimisation problem but eliminating the l_{ij} term. Therefore, being DG is the set of nodes of the distribution network with DER installed and $\mathbb{P}_j$ is the set of lines from the substation to node j:

$$
\begin{gathered}
\max \sum_{i \in DG} p_{i,t}^{g} \\
s.t. \\
P_{ij,t} = \sum_{k:j \to k} P_{jk,t} + p_{j,t}^{d} - p_{j,t}^{g} \quad \forall j \in DG \\
P_{ij,t} = \sum_{k:j \to k} P_{jk,t} + p_{j,t}^{d} \quad \forall j \in \{N \backslash DG\} \\
Q_{ij,t} = \sum_{k:j \to k} Q_{jk,t} + q_{j,t}^{d} - q_{j,t}^{g} \quad \forall j \in DG \\
Q_{ij,t} = \sum_{k:j \to k} Q_{jk,t} + q_{j,t}^{d} \quad \forall j \in \{N \backslash DG\} \\
v_{j,t} = v_{0,t} - \sum_{(l,k) \in \mathbb{P}_j} 2\left(r_{ij} P_{ij,t} + x_{ij,t} Q_{ij,t}\right) \ \forall (i,j) \in B \\
v_{i,t} \leq \bar{v} \ \ \forall i \in N \\
p_{i,t}^{g} \leq \overline{p_{i,t}^{g}} \ \ \forall i \in DG
\end{gathered}
\tag{19}
$$

The term (20), which is a constraint of the optimization problem (19), is intended to limit the voltage variation at the node.

$$
p_{i,t}^{g} \leq \overline{p_{i,t}^{g}} \ \ \forall i \in DG \tag{20}
$$

It is obtained from (21), where $|V_{i,t}|, |V_{i,t}^{NDG}|$ y $\overline{\Delta V}$ are the absolute value of the voltage at node i at instant t with DER connected, the value of the voltage at node i without DER generation and the maximum allowable voltage deviation, respectively. Equation (20) is designed to solve the problem of equation (21). The drawback is that it compares the voltage with and without DER at the same node and at the same instant of time, this is impossible, since a node has or does not have DER. To solve it, [22] introduces $\overline{p_{i,t}^{g}}$, which is the maximum power that a DER can inject in bus i, this depends on $\overline{\Delta V}$, the greater the admissible deviation, the greater the maximum admissible power.

$$|V_{i,t}| - |V_{i,t}^{NDG}| \leq \overline{\Delta V} \tag{21}$$

To determine $p_{i,t}^{g}$, (22) is presented, which is equation (21) but rearranged. Then, (18) is used to linearize the power balance equations and the squared ohm's law, (23)-(27) are the resulting equations.

To determine $p_{i,t}^{g}$, in [22], equation (21) is rearranged into (22). Then (18) is used to linearise the power balance equations and ohm's law squared. The result is the equations (23)-(27).

$$|V_{i,t}| = |V_{i,t}^{NDG}| + \overline{\Delta V} \tag{22}$$

$$P_{ij,t} = \sum_{k:j\to k} P_{jk,t} + p_{j,t}^{d} - p_{j,t}^{g} + r_{ij}L_{ij}(P_{ij,t}, Q_{ij,t}) \quad \forall j \in DG \tag{23}$$

$$P_{ij,t} = \sum_{k:j\to k} P_{jk,t} + p_{j,t}^{d} + r_{ij}L_{ij}(P_{ij,t}, Q_{ij,t}) \quad \forall j \in \{N \backslash DG\} \tag{24}$$

$$Q_{ij,t} = \sum_{k:j\to k} Q_{jk,t} + q_{j,t}^{d} - q_{j,t}^{g} + x_{ij}L_{ij}(P_{ij,t}, Q_{ij,t}) \quad \forall j \in DG \tag{25}$$

$$Q_{ij,t} = \sum_{k:j\to k} Q_{jk,t} + q_{j,t}^{d} + x_{ij}L_{ij}(P_{ij,t}, Q_{ij,t}) \quad \forall j \in \{N \backslash DG\} \tag{26}$$

$$v_{j,t} = v_{0,t} - \sum_{(l,k)\in\mathbb{P}_j} 2\left(r_{ij}P_{ij,t} + x_{ij,t}Q_{ij,t}\right) + \sum_{(l,k)\in\mathbb{P}_j} \left|z_{ij}\right|^2 L_{ij}\left(P_{ij,t}, Q_{ij,t}\right) \quad \forall(i,j) \in B \tag{27}$$

Finally, the following optimization problem returns the value of $p_{i,t}^g$.

$$\begin{gathered} \max p_{i,t}^g \\ st\ (23) - (27) \\ \underline{v} \leq v_{i,t} \leq \bar{v}\ \ \forall i \in N \\ v_{i,t} \leq \overline{V_{i,t}^2} \end{gathered} \tag{28}$$

Once $p_{i,t}^g$ already defined, the second phase of the calculation involves solving the OPF (29) from the starting points defined when solving (19), as shown schematically in Fig 12 and proposed in [22].

$$\begin{gathered} \max \sum_{i\in DG} p_{i,t}^g \\ s.t. \\ P_{ij,t} = \sum_{k:j\to k} P_{jk,t} + p_{j,t}^d - p_{j,t}^g + r_{ij}L_{ij}\left(P_{ij,t}, Q_{ij,t}\right) \quad \forall j \in DG \\ P_{ij,t} = \sum_{k:j\to k} P_{jk,t} + p_{j,t}^d + r_{ij}L_{ij}\left(P_{ij,t}, Q_{ij,t}\right) \quad \forall j \in \{N\backslash DG\} \\ Q_{ij,t} = \sum_{k:j\to k} Q_{jk,t} + q_{j,t}^d - q_{j,t}^g + x_{ij}L_{ij}\left(P_{ij,t}, Q_{ij,t}\right) \quad \forall j \in DG \\ Q_{ij,t} = \sum_{k:j\to k} Q_{jk,t} + q_{j,t}^d + x_{ij}L_{ij}\left(P_{ij,t}, Q_{ij,t}\right) \quad \forall j \in \{N\backslash DG\} \\ (27) \\ v_{i,t} \leq \bar{v}\ \ \forall i \in N \\ p_{i,t}^g \leq \overline{p_{i,t}^g}\ \ \forall i \in DG \end{gathered} \tag{29}$$

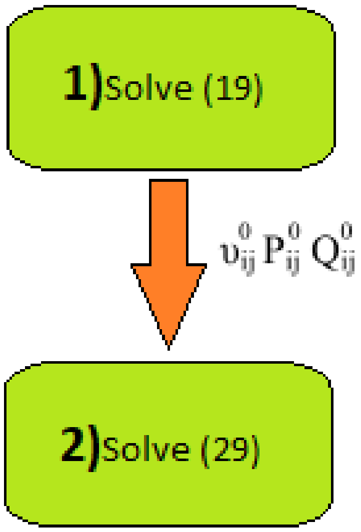

Fig 12: 2-step lineal method. Source: [22]

The methods explained above are an extent review of some of the approaches that have been made in previous works. In the project, the method used will be the OPF from matpower.

2.3.3 STOCHASTIC MODEL

The stochastic method takes uncertainties into account. In the calculation of HC there are several factors that contribute to the uncertainty of HC. According to the Electronic Power Research Institute (EPRI) these factors are the location of DER in the grid, the discontinuous nature of generation due to weather conditions and demand behaviour. Generally, for reasons of computational simplicity, the uncertainties associated with one or two of these factors are usually ignored; the more uncertainty that is considered, the more computing power is required. The result obtained will not be a single value but a distribution and the HC will be determined according to a level of risk that the DSO or the investor is willing to assume [1], [3], [11], [23], [24].

An effective way to perform stochastic modelling is to combine methodologies, one of the most common practices is to combine Monte Carlo analysis with deterministic optimisation models, thus exploiting the virtues of both methodologies. The main reason for this mix is due to the existing computational limitations. A Monte Carlo model considering the uncertainties of location, generation and consumption requires a lot of computational power. Therefore, one of the trends when calculating the HC is to create a series of scenarios using Monte Carlo to model the uncertainty of one or two of the variables, then for each scenario an OPF is performed with the objective of maximising the installed capacity.

For example, the algorithm proposed in [3] focuses mainly on studying the uncertainty associated with the location and installed capacity of DERs. The algorithm is explained in Fig 13 in a schematic way. The method divides the study into three different modules. The objective of each module will be briefly explained:

1. Scenario generation: Generate a series of scenarios following four steps:
    a. First generate DER penetration levels in the network to account for the uncertainty associated with the number of locations that may have DER installations. The penetration level varies between 0% and 100%.
    b. This step is designed to model the uncertainty of the type of DER technology for each penetration level. For example, if the penetration level is 50%, the distribution of technologies installed at the node can be 20% PV and 30% wind, or 40% PV and 10% wind. In short, any combination that adds up to the penetration level. To limit the number of combinations, the N_{TECH} variable is introduced, which will be previously defined to establish the number of combinations to be made.
    c. Third, the model deals with the uncertainty of the location of DERs. Monte Carlo is used to simulate the number of location combinations, N_{scn}, for each combination of N_{TECH} technologies. The positioning combinations of DERs in the network are random.
    d. Finally, the capacity that the DER facilities have for each of the scenarios generated in step C is determined. The capacities are determined based on the load type (residential or industrial) and a probability curve that contains the distribution of DG size.

Module 1 is repeated until the DER penetration level reaches 100%.

2. Time series analysis: In this module, generation and consumption profiles are considered. It is assumed that the generation and consumption profiles have been created from historical data, such as the profiles represented in Fig 10 and Fig 11. From these profiles the normalised value of generation and demand for each time slot is extracted by doing a time series analysis. For each time slot, the OPF is solved for each of the scenarios generated in the first module. This generates a vector of length H for each of the scenarios. The elements of this vector can take two values: 1, indicating that the model has no solution, or 0, indicating that the model does have a solution. This vector is used to determine the scenarios in which an electrical variable reaches its limits. A scenario will cause problems if at least one element of the vector takes the value of 1.
3. Probability curves: The module derives probability curves from the results. The HC can be determined by drawing a density curve and setting a level of risk associated with the trade above the network limits.

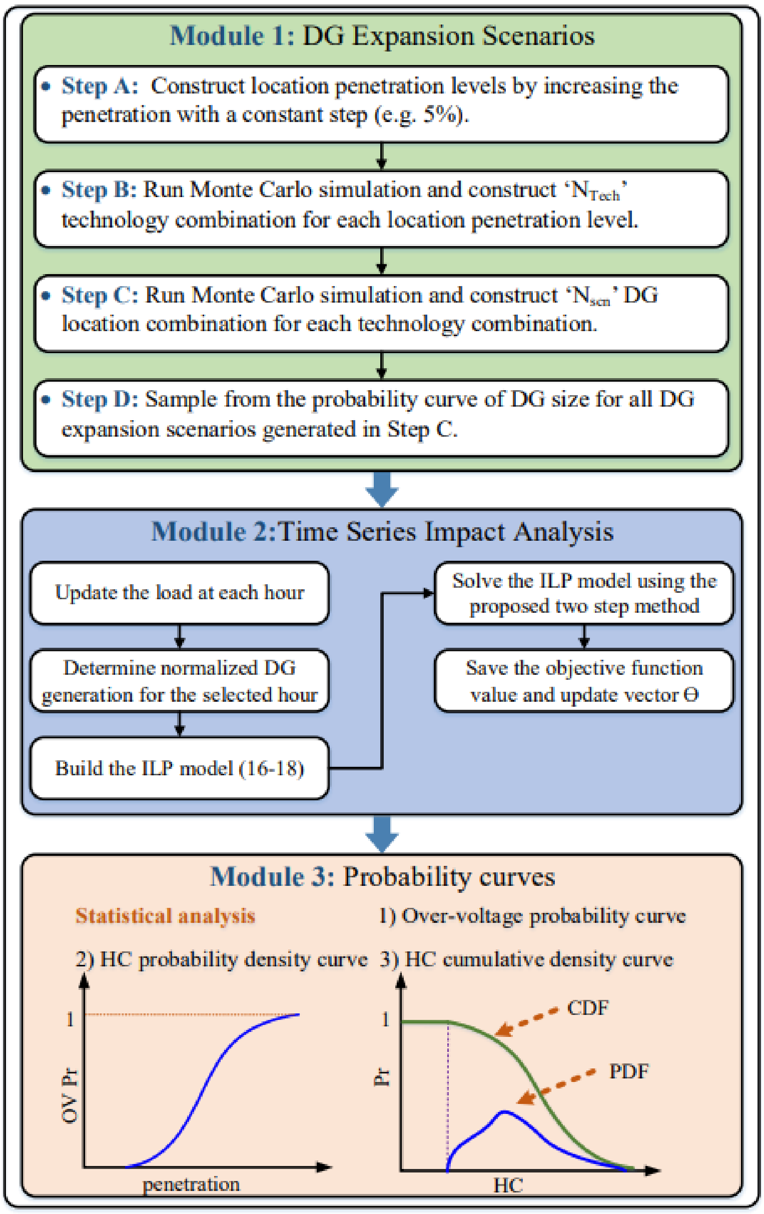

Fig 13: Stochastic approach proposed in [3]

The above algorithm offers one of the possibilities to study the uncertainties, another example is found in [20]. In this case, the proposed algorithm already knows the location of the installed DERs, takes the generated power as the maximum possible and only considers the uncertainty associated to the demand using Monte Carlo. Paper [20] models the demand in the following steps:

1. As demand varies periodically during the year and during the day, it is grouped into homogeneous consumption groups.
2. Six slots per month are defined, which means 72 slots per year.
3. The time slots for each month contain three types of days:
    a. Working day: It has three associated bands.
    b. Saturdays: It has two associated bands.
    c. Sundays and Holidays: It has a single associated band.
4. All bands have an associated probability function.
5. For each time slot, 20 Monte Carlo simulations are performed. Each time slot yields 60 HC values. 20 values are obtained from performing the HC calculation only taking into account the voltage limits, another 20 are obtained from the thermal limits and the last 20 are obtained from the fast variations in the voltages.
6. Once the HC values are obtained, the averages of the three groups are taken and the smallest value is taken to determine the HC for that time slot.

2.3.4 Active Control of the Distribution Network

In a distribution network with high DER penetration, voltages at the nodes are often one of the biggest problems that the DSOs encounter [15], [23]. One of the ways to increase the HC of the network without the need to invest in reinforcements is the asset management in the distribution network. This involves modifying the operating point of the equipment connected to the network so that the network does not go outside its operating limits. The most commonly used techniques to control the grid and simultaneously increase HC are the modification of transformer taps of OLTC at the substation of the feeder, voltage regulators along the feeder and the control of active and reactive power using the inverters of DER installations. Active grid control techniques will be explained below.

2.3.4.1 OLTC Transformer Control

Distribution networks are operated radially and the OLTC is located at the MV/LV substation feeding the feeder. The OLTC allows the transformer tap to be changed while the transformer is under load, this feature enables the system operator to control the voltages at the feeder in real time. The control techniques according to [13], [23] of an OLTC are as follows:

1. Transformer secondary voltage control: This method modifies the OLTC taps to keep the secondary voltage as close as possible to a predefined point.
2. Control of the voltages at the furthest points from the transformer: To carry out this control it is necessary to have measuring equipment installed at the furthest point from the feeder and a telecommunications system to transmit the status of the node to the transformer, the OLTC will change the tap to maintain the voltages at the end of the feeder within acceptable limits. This method would be effective if there were no DER connected, since as the networks are radial, the voltage at the furthest point from the substation will always be the smallest. However, with DER installations this does not need be the case and tap changing can lead to overvoltages at other points in the network.
3. Voltage control at all nodes: OLTC shall modify its taps so that all network node voltages are at acceptable operating points.
4. Temporal control: This method consists of changing the tap in function of time, allowing less conservative values (closer to the lower and upper boundaries) to be adopted in low demand scenarios and more conservative scenarios in high demand scenarios.

2.3.4.2 Inverter Control

Inverter control opens the door to interesting solutions for simultaneously increasing the HC and keeping the system at an acceptable operating point. Due to the power electronics of inverters, active and reactive powers are decoupled from each other and can be operated individually, which enables multiple options and strategies to control grid voltages.

Reactive power control is preferred by DER plant owners as it does not cause them to lose money, however, the most effective controls are active power controls due to the X/R ratio of the distribution networks. An interesting solution is the approach of controls using both techniques to solve the problems that high DER penetration can cause in the network.

2.3.4.2.1 Reactive Power Control Strategies

Reactive power control is based on using the inverter to inject or consume reactive power so that the grid voltages are within acceptable ranges. There are two popular reactive power controls [15], [23]. The first one is based on controlling the reactive power consumed using the Constant Power Factor Mode (CPFM), which is a function of the net active power injected. The second control determines the reactive power that the equipment will consume or inject as a function of the voltage at the node, this is known as Volt-Var Operation Mode (VVOM).

The operation of the VVOM control is shown in Fig 14, which represents the power being injected or consumed on the vertical axis and the voltages on the horizontal axis. As can be seen, when the voltage is below 0.92 p.u., the inverter injects the maximum reactive power. If the voltage is within an acceptable range (0.94-1.06 p.u.) the inverter will not consume or inject reactive power, once the voltage exceeds 1.06 p.u. it will start to consume reactive power, the consumption will increase linearly from zero to the maximum reactive power as a function of the voltage at the node.

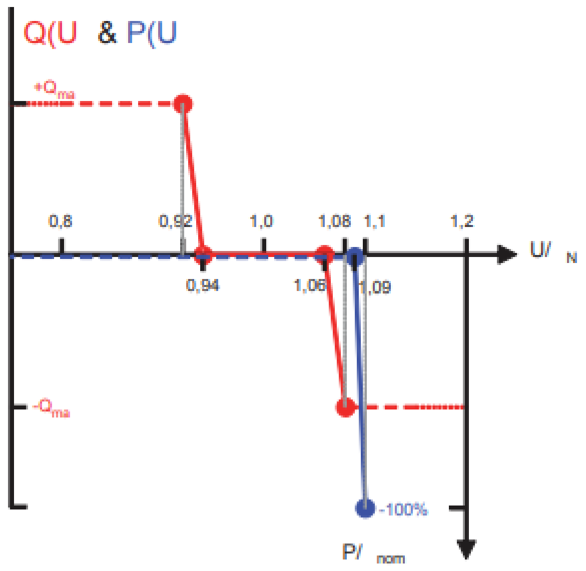

Fig 14: Active and Reactive Power Control in function of node Voltages: [16]

One of the disadvantages of consuming reactive power is that the transmission system operator will charge the distribution network operator for this reactive power.

2.3.4.2.2 Active Power Control Strategies

Inverters also allow to control the active power that can be fed into the grid, active power control in distribution networks tends to be more efficient than reactive power control due to the X/R ratio. Despite being more efficient, the disadvantage is that it reduces the income of the owners of the DER installations proportionally to the power curtailed. This method makes it possible to increase HC. However, the system operator and DER owners must come to an agreement to see how much active power can be curtailed, as too much active power curtailment can cause investors to reconsider investing in DER facilities. The most common control architectures are as follows:

1. Fixed maximum power: This control strategy is presented in [16], on it, the equipment can only inject up to 70% of its nominal power, when the installation is generating more than this, the active power will be curtailed to deliver no more than 70% of the maximum rated power.
2. Volt-Watt Operation Mode (VWOM): This operating mode controls the active power injected as a function of the voltage at the node. The operation of this control scheme is shown in Fig 14, the active power is identified by the blue curve. If the reactive control is ignored, the voltage-dependent active power control is based on starting to curtail active power injections once the voltage exceeds a certain value.
3. Volt-Var-Watt Operation Mode (VVWOM): Combines the VWOM and VVOM control schemes, the operation is shown in Fig 15, the objective of combining these two schemes is to reduce the curtailment (APC in Fig 15). To do this, first the reactive power is controlled until it reaches its maximum, when it is no longer possible to consume more reactive power and the voltage exceeds a certain value, the active power injected will start to be reduced until the voltage returns to within the operating threshold.

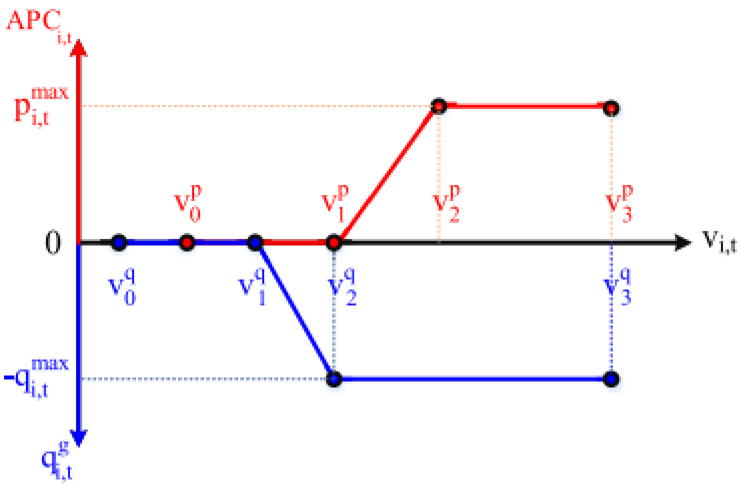

Fig 15: VVWOM Control, Source: [2]

2.4 EXISTING COMMERCIAL PRODUCTS

From the market review, several players are found in the DERMS marketplace, although, out of all of them, the thirteen market leaders according to [9] are the following:

- Minsait ACS
- Schneider Electric – AutoGrid
- Generac Grid Services
- EnergyHub
- GE Digital
- Siemens
- OSI
- Smarter Grid Solutions
- mPrest Systems
- Opus One Solutions
- Oracle Coorporation
- PXiSE Energy Solutions
- Hitachi Energy

After the analysis, out of all the thirteen players, only a few offer Hosting Capacity services, these are Schneider Electric, Opus One Solutions and finally Minsait ACS. Furthermore, companies such as General Electric Digital, OSI and EnergyHub include Hosting Capacity in their portfolios but simply as part of the grid planning services and not as a tool to incentivise DER investment.

2.4.1.1 Schneider Electric AutoGrid

Schneider Electric doesn't have a module within its DERMS services portfolio to assess Hosting Capacity, it briefly mentions that a possible approach is a what if analysis, despite this, their approach is based on real time management of the distribution grid. Concretely they offer a service called Look Ahead Constraint Management [30]. In this tool they present a Hosting Capacity enhancement technique known as DER dynamic operations envelopes.

DER dynamic operations envelopes launches operational limits to the DERs, they can operate within those limits with the certainty that no operational limits will be breached and therefore, active power curtailment will be minimized.

2.4.1.2 Opus One Solutions

Opus One Solutions includes Dynamic Hosting Capacity services within its Integrated Distribution Planning toolbox. Concretely, they introduce this service inside their GridOS platform. According to the executive summary released in November 2017 [31], the approach is based on a risk analysis. This is achieved by executing forecasts for demand and generation based upon historical data. Once the forecasts are complete, an OPF is executed for several scenarios. These scenarios are created from DER expansion options, for each of these scenarios a risk analysis is performed based on Conditonal Value at Risk (CVaR) methods and mean variance portfolio (MVP) curves. The scenario with the best risk return ratio will be carried.

Moreover, GridOS also offers DER performance assessment, returning the values of the locational net benefit analysis and distribution locational marginal pricing. These two values allow the investor to predict the investment performance and study weather to invest or not.

3. MODEL DESIGN

This chapter will describe the model proposed in the project to improve Hosting Capacity. To fulfil the task, an algorithm that introduces the uncertainties associated with generation and consumption has been developed, all the process has been carried out in Matlab and by using Matpower 7.1 package.

The chapter will follow the following structure: first the grid that has been used will be described, once the network is specified, the flowchart that the algorithm will follow will be shown and the most relevant parts of the algorithm will be explained in detail. Finally, there is the data section, where the processes that have been followed to obtain the generation and consumption data and the results that are expected to be obtained in the output once the algorithm has been executed are described.

3.1 MODEL DESIGN

To introduce the uncertainties associated with generation and demand into the model, Monte Carlo has been used. In each of the scenarios created, an OPF will be run with curtailment minimisation as objective function.

Since the historical data contains hourly and monthly information, it is desired to take advantage of this to generate the output data. To achieve this, as shown in Fig 16, three variables are generated, m, h and MC, where:

- m = stands for the month group that will be evaluated, in our case the analysis will be carried out monthly.
- h = stands for the hour group to be evaluated, for example, in [20] a clustering analysis is made to group the hours into homogeneous groups, on this model, the analysis will be carried out in an hourly basis.

- MC = stands for the number of samples that we want to obtain for each hour, this value is up to the user, the higher the value, the higher the computational burden and the longer it will take to run the algorithm.

Therefore, the goal of the algorithm is to get MC samples for every hour and for every month of the year, the number of total runs will be obtained following equation (30). In this case, m will be equal to 12, h will equal 24 and MC will take the value of 60, resulting in 17,280 runs.

$$m \times h \times MC = n° \; of \; runs \qquad (30)$$

For every run the algorithm carries out the following process: firstly, the technology to be installed, the capacity and the location of the plant will be specified. Second, random samples from the input variables are selected, these are load and generation values. These values come from historical data. The objective function of the OPF is active power curtailment minimisation. Moreover, the OPF has a VWOM control which manages the voltages at the nodes by doing active power curtailment. Finally, for every run a curtailment value will be obtained. Once all the runs have been completed, a distribution of curtailment values will be obtained.

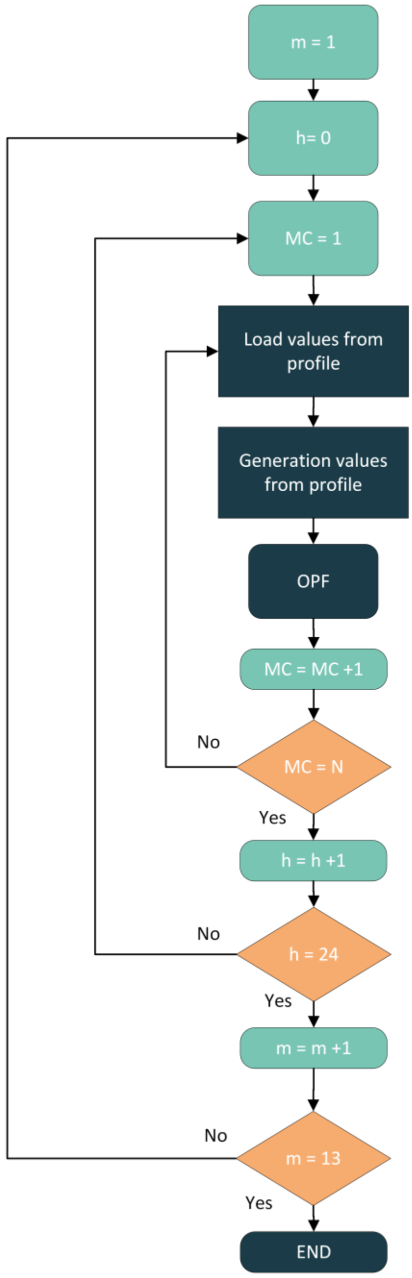

Fig 16: Model Flowchart

3.2 MATPOWER 7.1

Matpower is a MATLAB package composed of M-files for solving power flow and optimal power flow (OPF) problems. It has been designed to be a tool for educators and researchers to implant and test new models that can improve the current state of the grid [32].

It was initially developed by Ray D. Zimmerman, Carlos E. Murillo-Sánchez and Deqiang Gan at Cornell University.

To solve any problem the grid to be simulated must be determined first, this involves introducing nodal data, branch data, generator data and final cost information if an OPF wants to be simulated.

3.2.1 OPTIMAL POWER FLOW

The optimal power flow (OPF) is an optimization problem that aims to minimize the costs of the system. The standard version consists of an objective function that aims to minimize the cost of the generation injections, then there are equality constraints that represent the power balance equations, these are followed by a set of inequality constraints that represent the branch flow limits and the boundaries of the voltage limits defined in the MATPOWER case.

The implemented OPF problem doesn't consider thermal limit constraints and has as objective function active power curtailment minimisation. This is achieved by setting the DER generation costs to zero and the costs from generation coming from the transport grid higher. Therefore, while minimizing the system costs the OPF is prioritising DER generation, which implies that active power curtailment is minimised.

Moreover, curtailment is done in a VWOM manner, as it takes place once the voltages at the nodes surpass the upper voltage threshold.

3.3 GRID SCHEMA AND DESCRIPTION

The network used is presented in the Matpower manual [32], it is a medium voltage distribution network, with a radial configuration and 17 nodes used in the IEEE by Mendoza, Morales, López et al, in [33]. The configuration of the distribution network is shown in Fig 17. The entire study of the method proposed in this project will be carried out on this network.

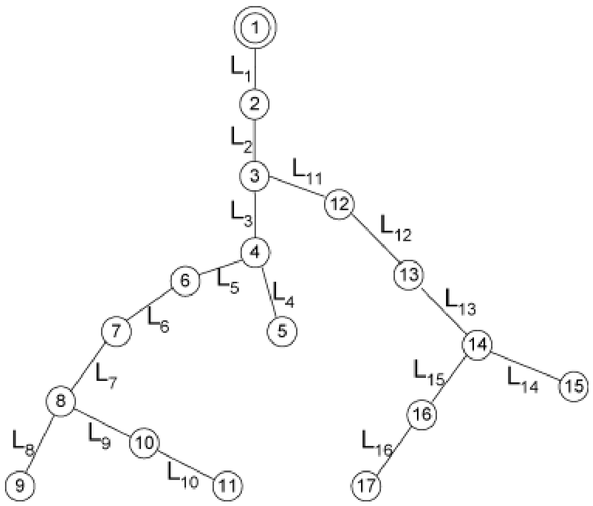

Fig 17: IEEE 17 bus distribution network, Source:[33]

The characteristics of the network are shown in the following tables. Table 1 shows the network's branches resistance and reactance values, the values shown are in per unit (p.u.) values. Nodes characteristics are shown in Table 2, as well as the characteristics of the lines, the values of the voltage limits are also given in p.u.

Branch	r (p.u.)	x (p.u.)	b (p.u.)
1 → 2	0,05	0,05	0
2 → 3	0,11	0,11	0
3 → 4	0,15	0,11	0
4 → 5	0,08	0,11	0

4 → 6	0,11	0,11	0
6 → 7	0,04	0,04	0
7 → 8	0,8	0,11	0
8 → 9	0,075	0,1	0
8 → 10	0,09	0,18	0
10 →11	0,04	0,04	0
3 →12	0,11	0,11	0
12 →13	0,04	0,04	0
13 →14	0,09	0,12	0
14 →15	0,11	0,11	0
14 →16	0,08	0,11	0
16 →17	0,04	0,04	0

Table 1: Branch characteristics

Node	Type	Vmax	Vmin
1	Slack	1,05	0,95
2	PQ	1,1	0,9
3	PQ	1,1	0,9
4	PQ	1,1	0,9
5	PQ	1,1	0,9
6	PQ	1,1	0,9
7	PQ	1,1	0,9
8	PQ	1,1	0,9
9	PV	1,1	0,9
10	PQ	1,1	0,9
11	PQ	1,1	0,9
12	PQ	1,1	0,9
13	PQ	1,1	0,9
14	PQ	1,1	0,9
15	PQ	1,1	0,9
16	PQ	1,1	0,9
17	PQ	1,1	0,9

Table 2: Node characteristics

The base power used to run the OPF is 100 MVA and the base voltage at the nodes is 20 kV.

Without the loss of generality, thermal limits have not been considered in the model, this is because the most restrictive conditions in most cases are the voltage limits at the nodes and not the thermal limits, so with the objective of lowering the computational burden, these limits have not been considered.

As for the voltage limits, those already pre-established in the case given by Matpower have been taken. The value of these limits is not important (as long as they are around 1 p.u.), as the value of the project lies in the improvement of the methodology used to determine the HC of the network. Both the voltage limits and the thermal limits can be easily modified. The stricter they are, the lower the capacity that can be installed in the network will be.

Finally, as can be seen in Table 2, node 9 is defined as the PV node, this implies that the simulations performed will be done with the DER installation connected to the grid at node 9.

3.4 DATA

This subsection describes how the input data will be managed to ensure that the Monte Carlo analysis is carried out correctly and what results are expected to be obtained once the Monte Carlo analysis has been completed.

3.4.1 INPUT DATA

3.4.1.1 Load Data

Starting from thirteen nodal demand profiles provided to Minsait by one of its clients, to generate a demand profile equivalent to six years and a half, from January 1st, 2016, up to July 31st 2022, this path was followed.

After gathering all the demand profiles, reference [34] was consulted to know the average consumption of each month. These values have been gathered and are displayed in Fig 18.

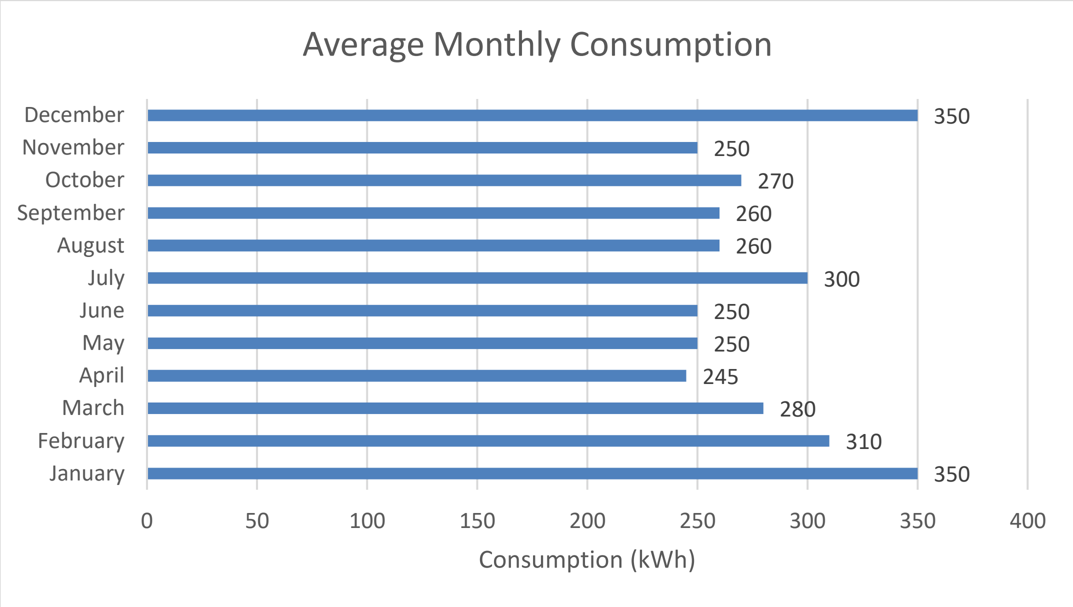

Fig 18: Average Monthly Domestic Consumption

Once the average consumption values are known, a multiplier was created for every month. As the year's mean value is 270 kWh, according to [34], [35], those months with an average consumption of 270 kWh have a multiplier of 1. The multiplier is obtained dividing the average month consumption between the year's mean consumption, each month's respective multiplier is represented in Table 3. Then, each of the profiles is multiplied by a random normal distribution with the multiplier as a mean value and with a standard deviation of 0.2 to reduce significantly the probability of having a negative value. It must be noted that the random normal distributions have a determined number of samples for each month.

Month	Average consumption kWh	Multiplier
January	350	1.30
February	310	1.15
March	280	1.04
April	245	0.91
May	250	0.93

June	250	0.93
July	300	1.11
August	260	0.96
September	260	0.96
October	270	1.00
November	250	0.93
December	350	1.30

Table 3: Monthly Average Consumption and Demand Multipliers

Once this process is completed the resulting distribution will look something like Fig 19. Each node load will have its own distribution.

For each Monte Carlo run, a random sample will be selected, in function of the month and the hour of the day that is under evaluation in that moment.

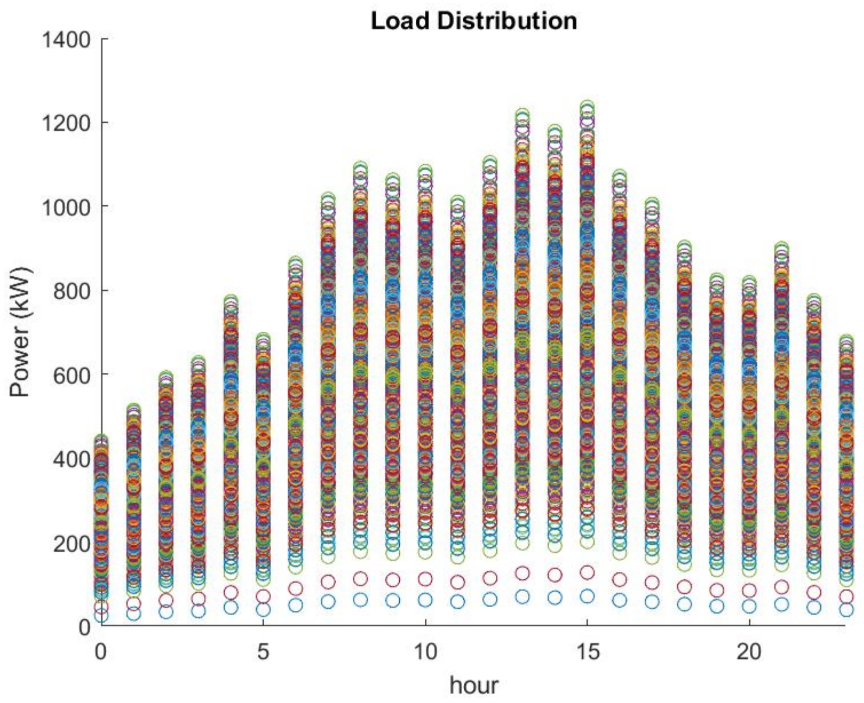

Fig 19: Artificial Historical Demand Profile

3.4.1.2 Generation Data

Meteorological historical measurements from the Military Base of Torrejón de Ardoz, Madrid, have been collected from NASA Power data access viewer web page [36], to estimate how much available generation can be injected into the grid under such circumstances.

To estimate the power that a PV installation will be able to deliver the values of the solar irradiance (in W/m^2), from January 1st, 2016, up to December 31st, 2021, have been downloaded. Once processed, the historical profile obtained is represented in Fig 20.

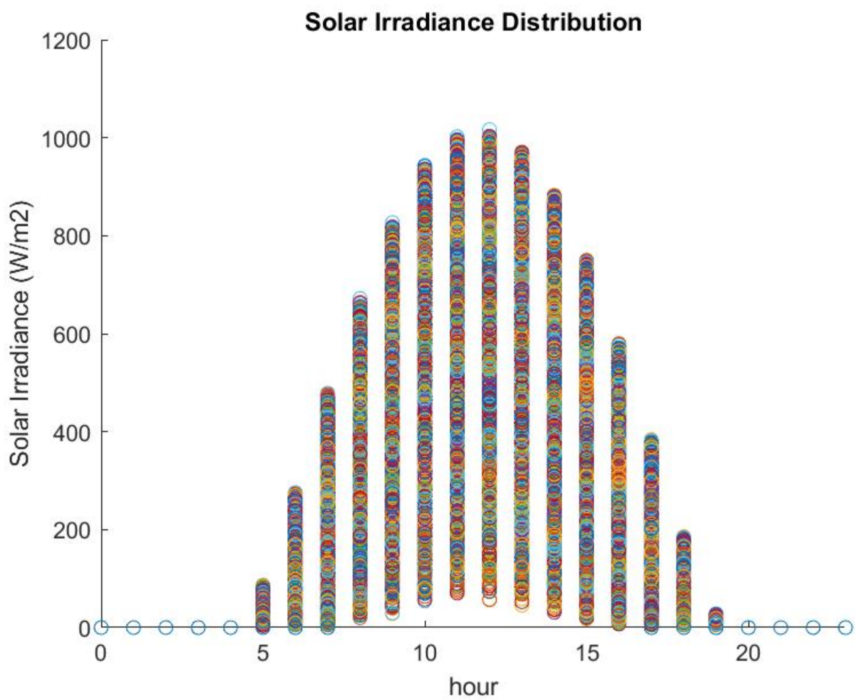

Fig 20: Historical (2016-2022) Irradiance Measurements

Once the historical solar irradiance measurements have been obtained, the PV output power is determined using equation (31), where:

$$P = n \cdot A \cdot r \cdot H \cdot PR \tag{31}$$

- P = Output power (kW)
- n = Number of installed panels

- A = panel area (m^2)
- r = Solar panel yield efficiency (rated maximum power kWp / panel area m^2) (%)
- H = solar irradiance (kW/m^2)
- PR = Performance Ratio (values between 0.7 and 0.9, in the program is set to 0.85)

Therefore, the program must receive from the investor the number of panels to be installed, the area of those and the electrical power of the panel in kWp. Having these values generation will be determined once for every Monte Carlo run sampling the solar irradiance measurements in the same manner as with the demand values, according to the month and the hour under evaluation an irradiance value will be sampled randomly.

The exact same process has been carried out to obtain the historical measurements of the wind speed at 10 meters of height. The historical profile is represented in Fig 21, where each hour of the day has the number of samples corresponding to six years of measurements.

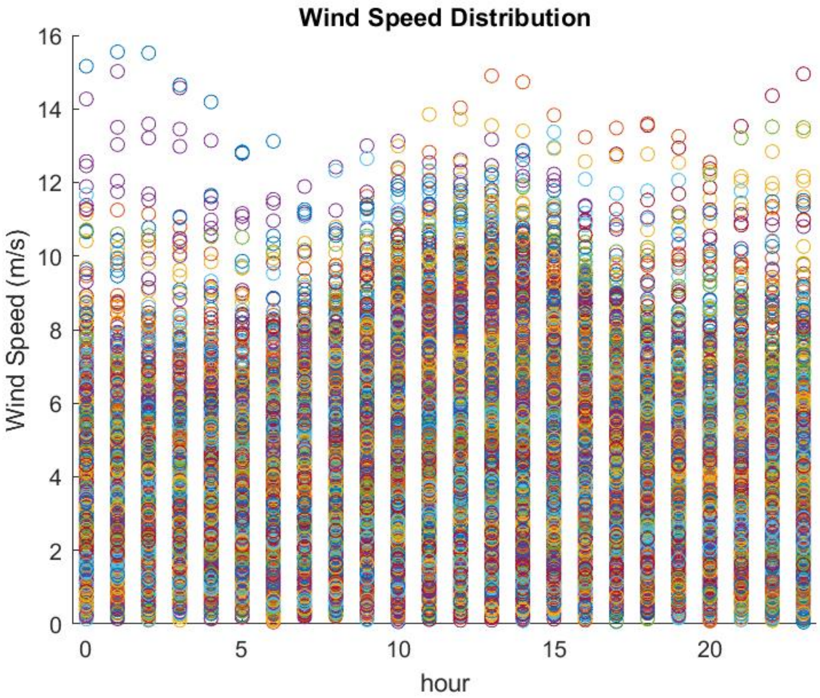

Fig 21: Historical (2016-2022) Measurements of Wind Speed at 10 meters

To calculate the output power delivered by a wind turbine first is necessary to calculate the available wind power, this is done by using equation (32), where:

- ρ = air density, which is 1.225 kg/m^3
- v = wind speed (m/s)
- A = sweep area (m^2)

$$P = \frac{1}{2} \cdot \rho \cdot v^3 \cdot A \tag{32}$$

Knowing the available wind power, by multiplying the wind power by the turbine efficiency, which must not exceed 59.3% due to Betz's law (set to 0.35 to run the simulations) and the number of turbines that are going to be installed, the output power generated by the turbine will be obtained.

The process of simulating the generation is the same as with the PV installation, for every Monte Carlo simulation a wind speed value will be sampled, and the generated power will be the input to the OPF.

The investor must specify the number of turbines that are going to be installed, the area that the blades cover and the turbine's efficiency.

3.4.2 OUTPUT DATA

Once all the input information has been specified by the investors the algorithm will be run. It will simulate the number of times set in equation (30). In each of the Monte Carlo simulations a curtailment value will be obtained, as shown in Fig 22.

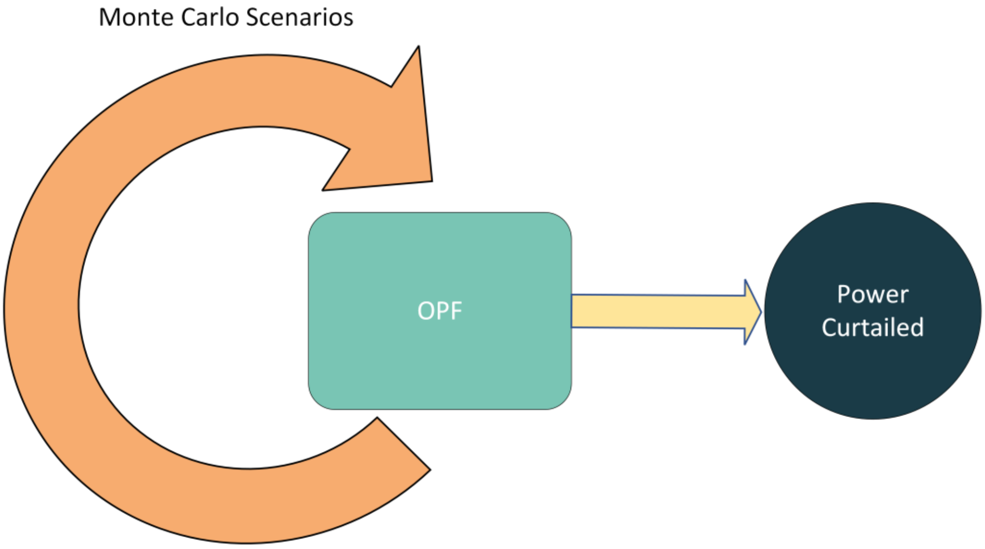

Fig 22: Output data schema

The sum of all curtailment values will form a distribution, as long as curtailment occurs in any scenario, otherwise there will be no distribution and there will be no curtailment risk.

Assuming that there is curtailment after running the simulations, three values will be obtained from the curtailment distribution, the Risk Value, the Conditonal Curtailment at Risk (CCaR) and the Curtailed Energy Percentage.

3.4.2.1 Risk Analysis

The aim is to provide a series of values in the output that study the risk involved in the operation that the investor wishes to carry out.

The conditional value at risk (CVaR) has been chosen as the parameter for measuring investment risk. This parameter is widely used in financial environments, specifically in the evaluation of the risk associated with investments in financial assets, usually portfolios, stocks, indices... However, it can be studied in other areas, as demonstrated in [37], [38]. In summary, the objective of the parameter is to evaluate risk scenarios to see if the losses in the event that these scenarios occur outweigh the gains.

Fig 23 shows a normal distribution where Value at Risk (VaR) and CVaR are identified. VaR returns the losses associated to a confidence level. Though, this risk parameter does not evaluate the tails and ignores the possibility of them occurring [37]. On the other hand, CVaR does analyse the behaviour of losses in the tails, therefore it is more robust than VaR and gives more information to the investor about the behaviour of losses. As can be seen in Fig 23, the VaR returns a value of losses associated with a probability of this situation occurring, whereas, the CVaR is more towards the tail of the distribution, as this is the value of the mean of the area of the distribution that lies in the probability interval 1- α.

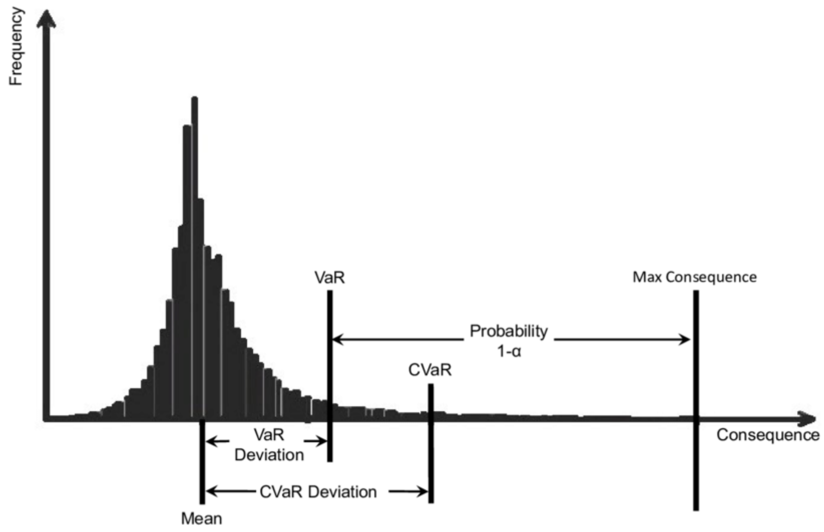

Fig 23: Conditional Value at Risk graphic representation, Source: [37]

Risk Value

Risk value in this project is determined as the percentage of hours that curtailment will occur. This is calculated following equation (33).

$$Risk\ Value = \frac{hours\ curtailed}{total\ simulated\ hours} \times 100 \qquad (33)$$

The aim of this result is to return the value of $1 - \alpha$ from Fig 23, this will give the investor information about how much time of curtailment should be expected. This parameter could be a threshold to decide whether to invest or not.

Conditional Curtailment at Risk

In this project Conditional Value at Risk (CVaR) will be renamed, giving birth to the term Conditional Curtailment at Risk (CCaR). To describe how CCaR is obtained Fig 24 will be used.

As can be seen in the figure, to calculate the CCaR value it is first necessary to know the value of 1-β, which is equal to the $1 - \alpha$ value from Fig 23, the Risk Value described in the previous subsection. Once this value is established, the CCaR is determined by averaging the area shaded in blue in Fig 24.

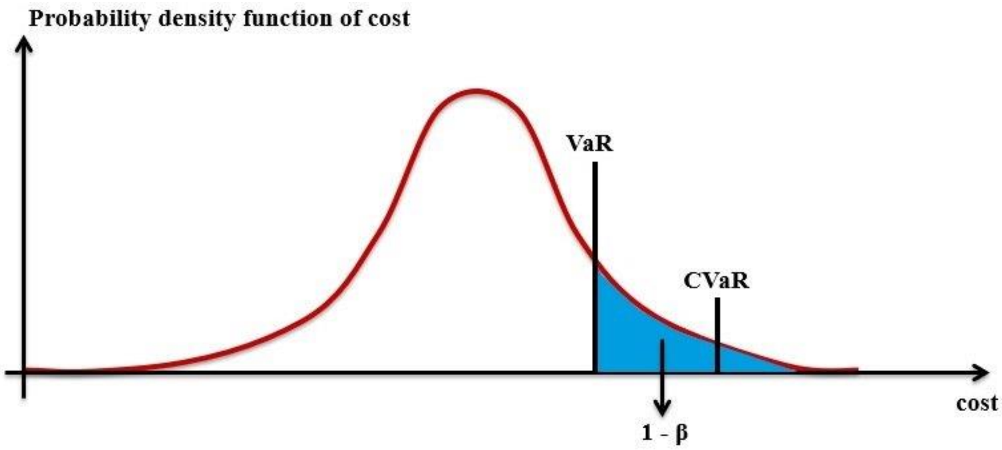

Fig 24: CVaR representation, Source: [38]

In the algorithm presented in the annexes, CCaR is determined by averaging the curtailed energy, i.e. to add up all the curtailed energy and divide by the number of hours in which curtailment has been performed. Equation (34) represents the above mentioned.

$$CCaR = \frac{\sum Energy\ Curtailed}{\sum curtailment\ hours} \qquad (34)$$

Curtailed Energy Percentage

Finally, the percentage of energy that has not been supplied is returned. This value is returned with the aim of enabling the possibility of extrapolating this percentage to the annual production analysis, so that the investor, in addition to knowing the percentage of hours that will be curtailed, will also know the percentage of energy that it has not been able to supply allowing him to carry more detailed investment analysis.

This value is obtained by dividing the total energy curtailed between the total production (35).

$$CEP = \frac{\sum Energy\ curtailed}{\sum Available\ energy} \qquad (35)$$

4. RESULTS ANALYSIS

On this chapter the results obtained from running the algorithm will be discussed. Firstly, the algorithm output of a 6MW PV installation will be analysed. Afterwards, a comparison between four different HC calculation approaches will be made, the energy curtailed, the risk value and the CCaR of these four methods will be discussed. In third place, the results from different installed capacities will be commented, these installed capacities have been simulated for a PV installation, a wind farm and a hybrid installation. Finally, as the curtailment results have been arranged to keep time data (month and hour), they will be broken down into an hourly analysis. The four algorithms to be studied are the following:

- The Worst Case scenario, as mentioned in previous chapters, it selects the meteorological measurement that maximises generation and the minimum load recorded from the entire historical database, then, the OPF is executed. This is the traditional Hosting Capacity evaluation method and the one the project aims to improve.
- The Hourly Worst Case scenario picks the maximum generation at and the minimum loads for each hour, then it executes the OPF.
- The Monte-Carlo based OPF considering only load uncertainty, picks the maximum hourly generation and a random value from the load distribution for each Monte Carlo run. This is also known as DHC with load uncertainty. This is the first of the algorithms proposed in the model, it is based on the algorithm proposed in [20], but the demand values are sampled in an hourly basis.
- Finally, Monte Carlo based OPF considering both, load and generation uncertainty, picks random values for each hour out of the historical database. This is also known as DHC with generation and load uncertainty. This algorithm is the one to become the first approach towards the Onesait DERMS module and is the second algorithm to be proposed in this project.

The last two methods can be considered Dynamic Hosting Capacity approaches, while the first two are deterministic and static methods.

4.1 ALGORITHM OUTPUT

To determine the values of the CCaR, the Risk Value and the Curtailed Energy Percentage, the algorithm generates distributions which are represented in Fig 25 below, it shows the results obtained after simulating a 6 MW PV installation at node 9, for the DHC cases considering demand uncertainties and DHC considering generation and demand uncertainties.

As can be seen, the graphs on the left are virtual curtailment profiles, as the demand has been subtracted from the maximum available DER generation at each instant. All the negative results of this subtraction imply that at the time instant being evaluated, the demand is higher than the generation produced by the installed DER plant. In the event that the subtraction is positive, it will imply that the generation in those moments exceeds the demand, only in these scenarios is when curtailment will occur, although not in all these cases it will be necessary to limit the energy that is being generated.

On the right-hand side of Fig 25 are the curtailment distributions obtained for the two DHC cases mentioned above. The figure positioned on the upper right side represents the curtailment considering only demand uncertainty and the figure positioned on the lower right side shows the curtailment obtained for a simulation considering the uncertainties of demand and generation. With just a glance, the energy not supplied is lower for the second case, since both the number of repetitions of curtailment and the power curtailed are lower. The figure representing curtailment with uncertainty in demand reduces the energy supplied more frequently than for the second case, 300 repetitions of maximum in the first case versus 100 repetitions of maximum in the second, and the evolution of the repetitions in the second is practically always descending, while in the first case there are changes in the frequency trend as curtailment increases.

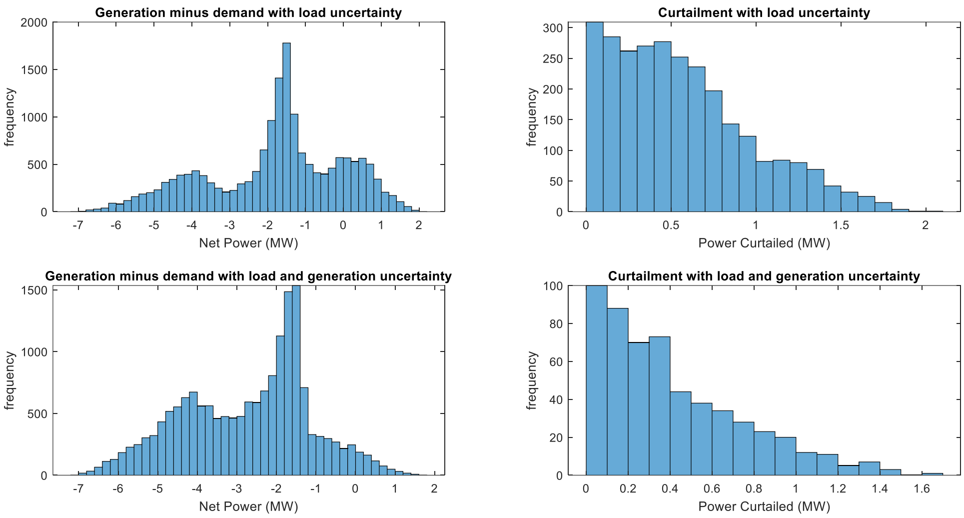

Fig 25: Algorithm Output, comparison between DHC with load uncertainty and DHC with generation and load uncertainty

The equations described in the previous sections are applied to the simulated curtailement distributions to obtain the Risk Value, CCaR and Energy curtailed percentage values. Fig 26 represents the maximum available DER generation minus demand distribution in blue, and the curtailment distribution in red.

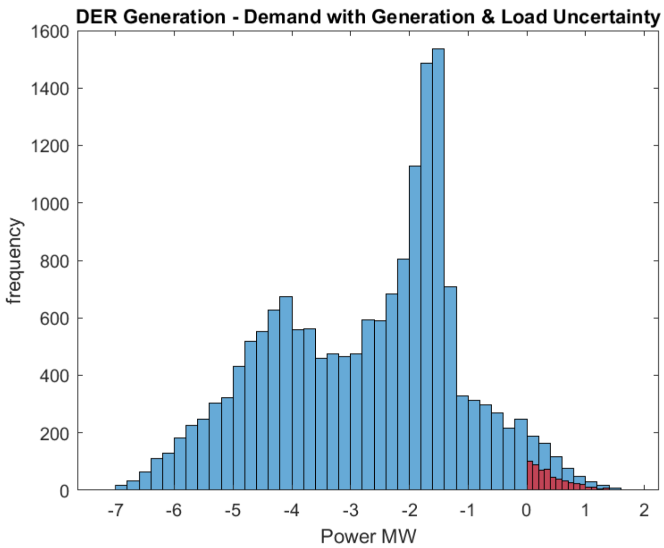

Fig 26: Curtailment distribution analysis

To begin, the curtailment distribution doesn't meet the positive tail of the generation minus demand distribution, this was expected and it basically demonstrates graphically the difference between a Power Flow and an OPF.

The parameters obtained from this distribution analysis are:

- Risk Value = 3.22%
- CCaR = 0.41 MW
- Curtailed Energy Percentage = 1.33%

The Risk Value will be variable, and it will depend on the distribution, the more hours that there is curtailment, the higher the Risk Value. Contrary to the traditional way of carrying out a CVaR based risk analysis, the (1- α) value is set by curtailment output distribution, highlighted in red in Fig 26, and not by the user. Then, the CCaR and the Curtailed Energy Percentage will be determined from the entire curtailment distribution.

4.2 COMPARISON BETWEEN HOSTING CAPACITY CALCULATION METHODS

Four calculation methods have been compared, these are: Worst Case scenario, Hourly Worst Case scenario, DHC with load uncertainty, DHC with generation and load uncertainty.

Having these methods defined, the results out of the simulation will be compared to evaluate if the performance of the proposed algorithm, the results under evaluation will be the Curtailed Energy Percentage, the risk value and the CCaR. All the results have been simulated under the same conditions: a 6 MW PV installation located in node 9 of the grid.

To begin, Fig 27 shows the Curtailed Energy Percentage. As it can be observed, if the 6 MW installation was evaluated using a Worst Case scenario approach, 97.06% of the energy produced will be expected to be curtailed. This result improves if an hourly Worst Case scenario is considered, the improvement is above 10% and results in a 86.71% of the energy expected to be curtailed. Despite this improvement, the result could difficultly encourage the investor to carry on with his project, leaving him with the options of either reconsidering the size of the plant or abandoning the investment. When DHC methodologies are introduced, the results improve significantly, being the expected energy curtailment 4.74% in a DHC considering load uncertainty, and 1.33% if load and generation uncertainty are considered.

These results where expected as the worst case approaches don't take into account seasonality, which means that, in the case of the hourly Worst Case scenario, a generation in July could be compared with a demand from March. Therefore, the results are conservative values which are highly unlikely to occur. On the other hand, DHC methodologies are considering the temporality of the database resulting in more likely scenarios which offer a more realistic forecast.

Summarising, the proposed method is the most effective, the expected energy percentage to be curtailed has a value most encouraging for investors, the downside of this method is the computational burden, as it considers two uncertain variables.

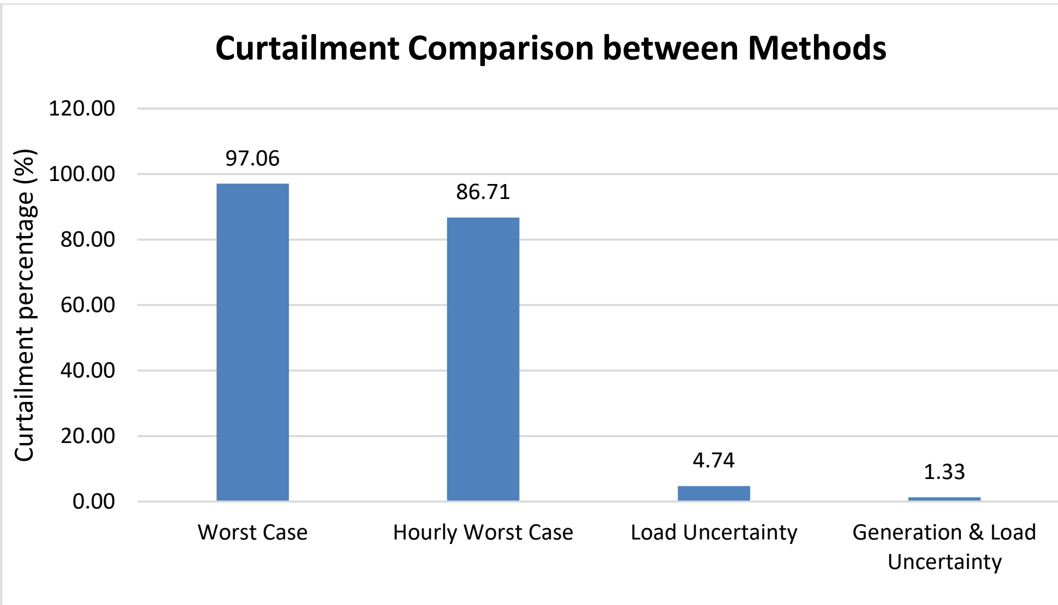

Fig 27: Energy curtailed percentage comparison between methods

Moving on to the Risk Value analysis, as it can be seen in Fig 28, the worst case approaches don't have a value for this indicator, this happens because these methods are deterministic and only return one value as an answer. On the other hand, the DHC approaches return distributions and from these, as shown in Fig 25, the Risk Value is calculated using equation (33).

Looking at Fig 28, DHC considering generation and load uncertainty returns a Risk Value much lower than the Risk Value obtained from the DHC that only considers load uncertainty, 3.22% against 16.14% respectively.

Again, this was expected, as the DHC approach with just load uncertainty takes the maximum hourly generation, where, for example, in winter months, such generation values will be highly unlikely to take place.

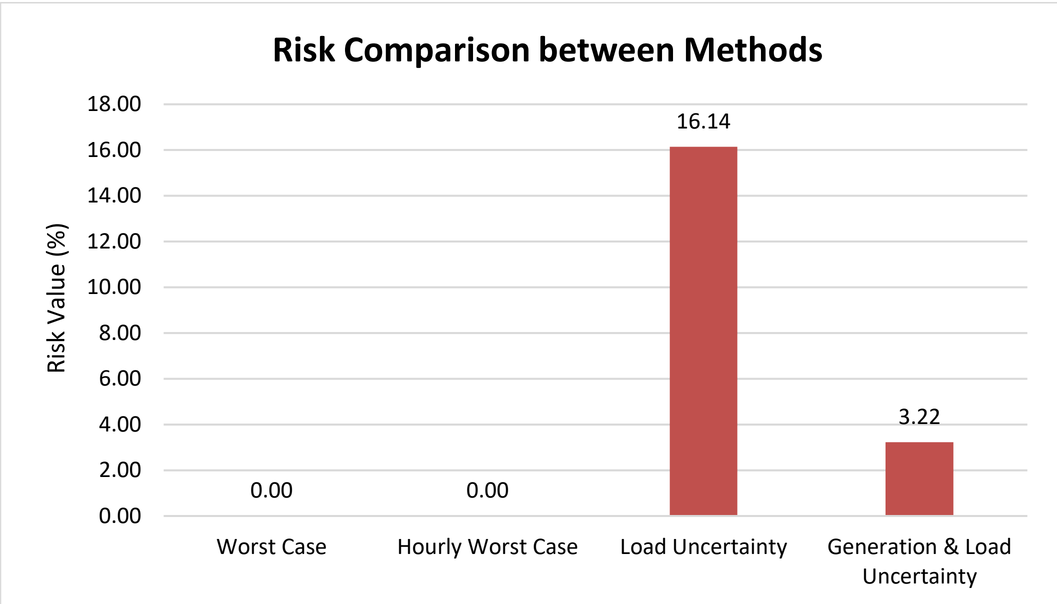

Fig 28: Risk Value comparison between methodologies

With the analysis of the CCaR happens the same thing as with the analysis of the Risk Value, as the worst case approaches are deterministic methods, there is no distribution to obtain the CCaR from.

Fig 29 portraits the CCaR results from the simulation, in this case the values are very similar, still the DHC with load and generation uncertainty outperforms DHC with just load uncertainty, CCaR of 0.41 MW for the former and CCaR of 0.57 MW for the latter.

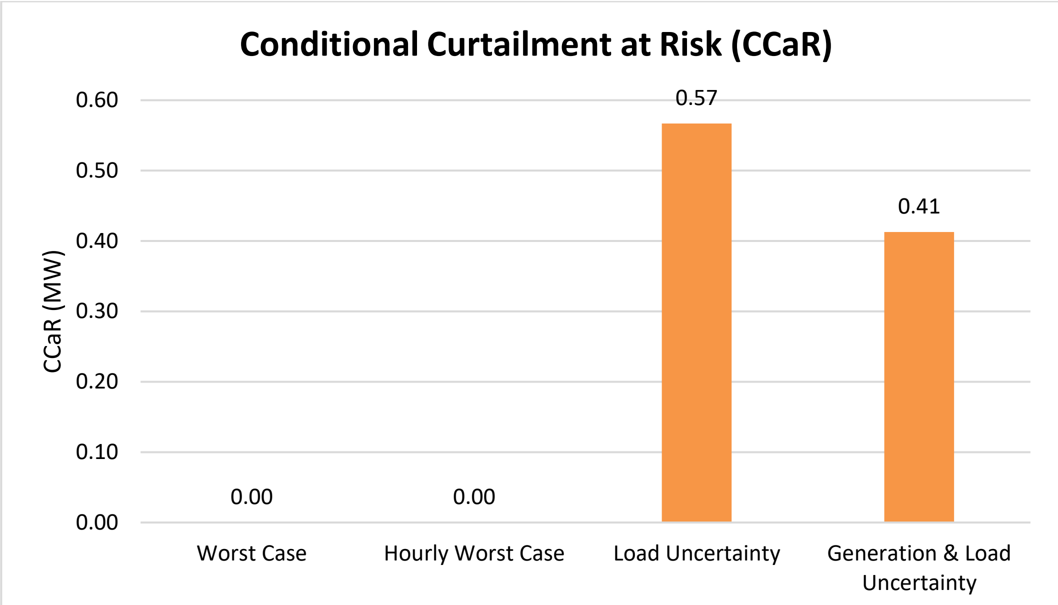

Fig 29: Conditional Curtailment at Risk comparison between methodologies

The CCaR result from Fig 29 jointly with the Risk Value result from Fig 28 states the following:

- DHC with load uncertainty approach has a Risk Value of 16.14% and a CCaR of 0.57 MW. This implies that the investor can estimate that his plant will suffer curtailment for 16.14% of hours and the mean power that will be curtailed during those hours will be 0.57 MW.
- DHC with load and generation uncertainty has a Risk Value of 3.22% and a CCaR of 0.41 MW. This implies that the investor can estimate that his plant will undergo curtailment 3.22% of the time during a year, and the mean curtailed power during that time would be 0.41 MW.

These outputs can be used to develop a flexible contract between the DSO and the investor, the contract could be confectioned so that there is a compromise between the interests of both parties, leaving room for the DSO to operate the plant and not jeopardizing the financial performance of the investment.

4.3 RESULTS EVOLUTION WITH INSTALLED CAPACITY INCREMENTS

This section of the analysis of the results studies how the indicators (Risk Value, CCaR and Curtailed Energy Percentage) vary depending on the installed power and the type of technology being installed when running the DHC with load and generation uncertainty algorithm.

To carry out this analysis, the installed power was increased in steps of 0.5 MW from 2.5 to 7 MW and then two more simulations were carried out, one with an installed power of 8 MW and the other with an installed power of 15 MW. These have been simulated for PV, wind and hybrid installations, which are composed by both PV and wind.

The results are organised in the following way:

- Table 4 gathers the indicators for a PV installation and Fig 30 its curtailment evolution
- Table 5 gathers the indicators for a Wind farm installation and Fig 31 its curtailment evolution
- Table 6 gathers the indicators for a Hybrid installation and Fig 32 its curtailment evolution

PV Installation

Installed Capacity (MW)	Hours Curtailed (%)	CCaR (MW)	Energy Curtailed (MWh)	Energy Percentage Curtailed (%)
2,5	0,00	NaN	0,00	0,00
3	0,00	NaN	0,00	0,00
3,5	0,00	NaN	0,00	0,00
4	0,00	NaN	0,00	0,00
4,5	0,08	0,10	1,34	0,01
5	0,56	0,21	20,38	0,14
5,5	1,51	0,31	81,99	0,52
6	3,22	0,41	229,86	1,33
6,5	5,19	0,56	498,96	2,65

7	7,47	0,69	884,32	4,36
8	11,34	1,00	1.961,05	8,42
15	25,61	3,51	15.530,85	35,49

Table 4: Simulation results for PV installations

The curtailment distribution profiles for a PV plant vary as a function of the installed power, as shown in Fig 30. When observing the evolution of the profiles, the first thing that stands out is that until the installed power does not exceed 4 MW, the curtailment is zero. As the installed power increases, the area enclosed by this distribution increases, which implies that the percentage of energy not supplied will increase, along with the Risk Value and the CCaR. As for the shape of the distribution, the figures show that it is a convex tail, which, as the installed power increases, it flattens out. For the 15 MW plant for example, the frequency with which curtailment is made is very high for very high powers, which indicates, visually, that the installation is oversized and it would be more efficient and profitable to lower the installed power.

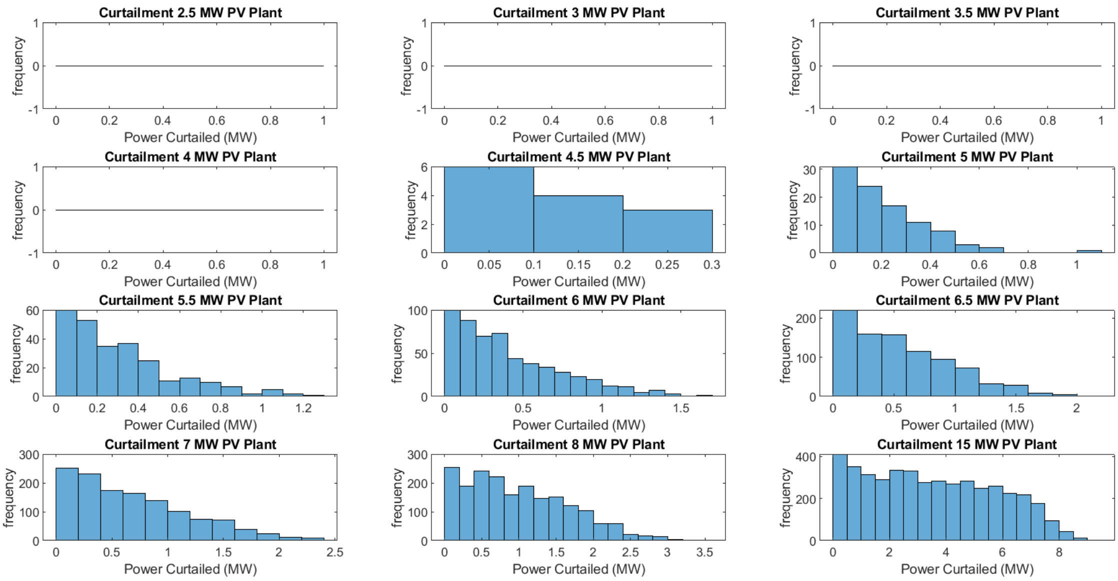

Fig 30: Curtailment evolution for a PV installation

Wind Turbines				
Installed Capacity (MW)	**Hours Curtailed (%)**	**CCaR (MW)**	**Energy Curtailed (MWh)**	**Energy Percentage Curtailed (%)**

2,5	0,25	0,41	17,75	0,41
3	0,28	0,62	29,73	0,58
3,5	0,52	0,77	69,59	1,16
4	0,78	0,77	103,07	1,47
4,5	1,14	0,78	154,19	1,99
5	1,53	0,98	260,76	3,07
5,5	2,30	1,02	404,37	4,26
6	2,93	1,25	633,27	5,96
6,5	3,17	1,41	770,63	6,86
7	3,96	1,46	997,76	8,15
8	4,57	1,80	1.419,57	10,34
15	11,45	3,41	6.745,44	25,98

Table 5: Simulation results for a wind farm installation

The evolution of curtailment of wind turbines as a function of installed power is shown in Fig 31. In this case, there is curtailment with all installed powers, this is due to the fact that the wind distribution, which is represented in Fig 21, is not sensitive to the time of day, therefore, generation peaks and demand valleys are more likely to occur. With regard to the shape of the distributions, it can be seen that they are not so sensitive to changes in shape as the installed power increases; however, in the graphs it can be seen how on some occasions curtailment is practically 100% of the installed power. This is an indicator that the installation is oversized.

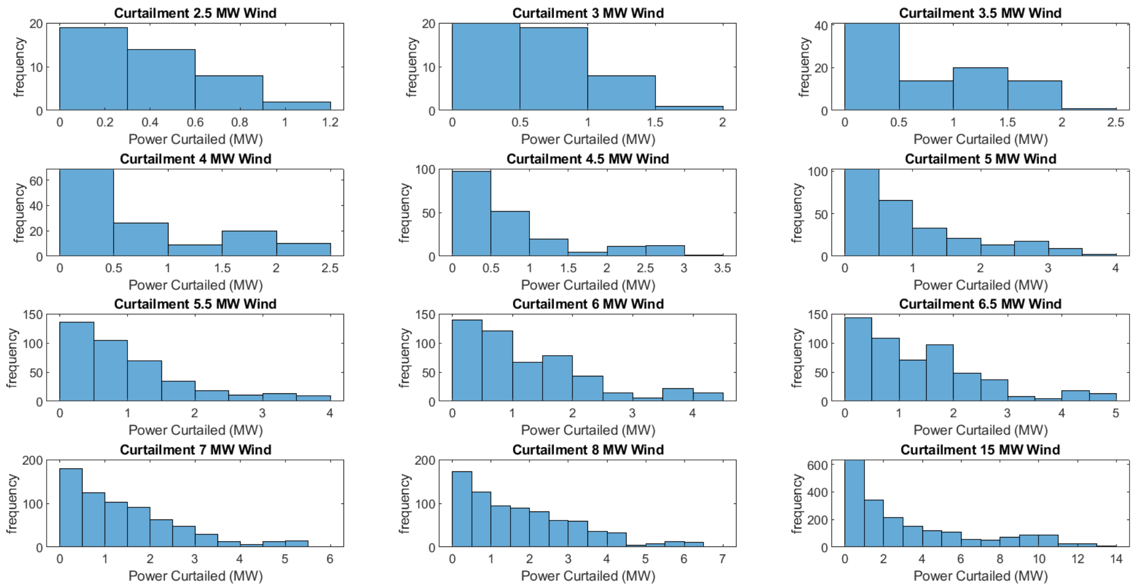

Fig 31: Curtailment evolution for a Wind Farm

Hybrid Installation				
Installed Capacity (MW)	**Hours Curtailed (%)**	**CCaR (MW)**	**Energy Curtailed (MWh)**	**Energy Percentage Curtailed (%)**
2,5	0,00	NaN	0,00	0,00
3	0,00	NaN	0,00	0,00
3,5	0,05	0,15	1,22	0,02
4	0,12	0,22	4,46	0,05
4,5	0,17	0,32	9,41	0,09
5	0,27	0,40	18,74	0,16
5,5	0,49	0,43	36,82	0,29
6	0,82	0,51	72,22	0,52
6,5	1,05	0,66	119,90	0,79
7	1,45	0,69	173,68	1,07
8	2,17	0,87	325,88	1,76
15	18,74	1,74	5.629,35	16,22

Table 6: Simulation results for hybrid installations

Finally, with regard to the distributions of a hybrid installation, which are shown in Fig 32, it is important to highlight the difference between them. This happens because the historical profile of such an installation is the sum of the solar irradiance and wind speed profiles, and therefore, there is a possibility that when sampling randomly the meteorological data, both wind speed and irradiance may be high. However, the frequency with which these situations occur is not very relevant (5 and 5.5 MW profiles).

In order to evaluate only with the curtailment profile whether the size of the installation is acceptable, it would not be very effective to look at the shape of the profile but, as in wind power installations, it would be more suitable to look at the curtailment with respect to the installed power.

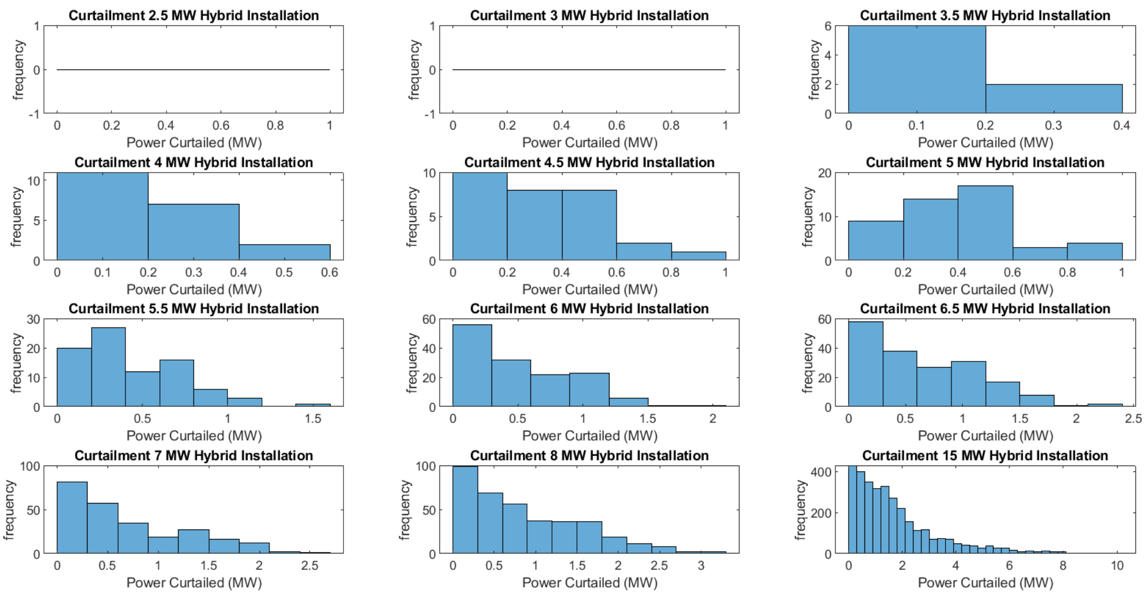

Fig 32: Curtailment evolution for a Hybrid installation

The following graphs evaluate the indicators as a function of installed power.

First, the evolution of Risk Value as a function of installed capacity will be discussed and a comparison will be made between the generation technologies proposed in the project. Fig 33 graphically represents the Risk Value columns of Table 4, Table 5 and Table 6, as expected, the risk increases as the installed power increases. The graph shows how the technology that presents the least risk for lower installed powers is PV. Nevertheless, the increase in Risk Value that this technology suffers when the power exceeds certain thresholds is much more pronounced than with the rest of the technologies. This means that investors must be careful when designing their plants, as the risk of curtailment increases considerably with the power of the plant. On the other hand, wind power plants have a much more linear risk evolution than PV plants. Finally, the best performing technology in terms of risk value is the hybrid technology. It has barely risk until the 15 MW plant is simulated, there is a change in the risk trend from 8 MW to 15 MW, this change in the trend may be due to the presence of photovoltaic installations, as the risk of these installations is very sensitive to the installed power, which can produce the same effect in hybrid installations.

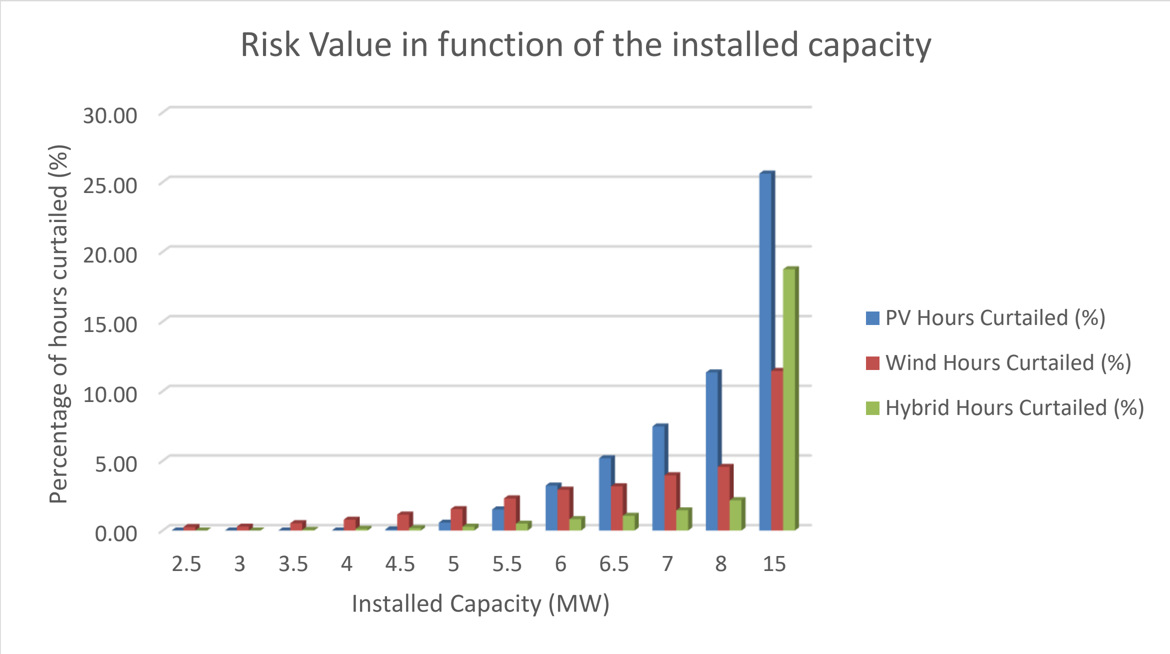

Fig 33: Risk Value in function of the installed power

The study of the evolution of CCaR as a function of installed power is shown in Fig 34. Once again, the value of CCaR increases as installed power increases. As in the case of the Risk Value, the technology that seems to be more sensitive to the installed power is PV. Despite this, it presents the lowest values from 2.5 MW to 7 MW of installed power. This implies that when the photovoltaic installation is undergoing curtailment, on average, the power that is not being supplied will be lower than in the rest of the technologies. Talking about the CCaR of wind installations, these present the highest CCaR values for all installed power except for 15 MW, this implies that although the Risk Value is lower, on average, the power that is not being supplied will be high, for example, for an installed power of 2. 5 MW of wind power, the CCaR value is 0.41 MW, which means that on average, when curtailment occurs, 16.4% of the power that is being generated in the plant at that moment will not be injected. To conclude with the CCaR, the hybrid installation is the one with the lowest sensitivity to the installed power, and its performance at low installed powers is close to the values of the PV installation.

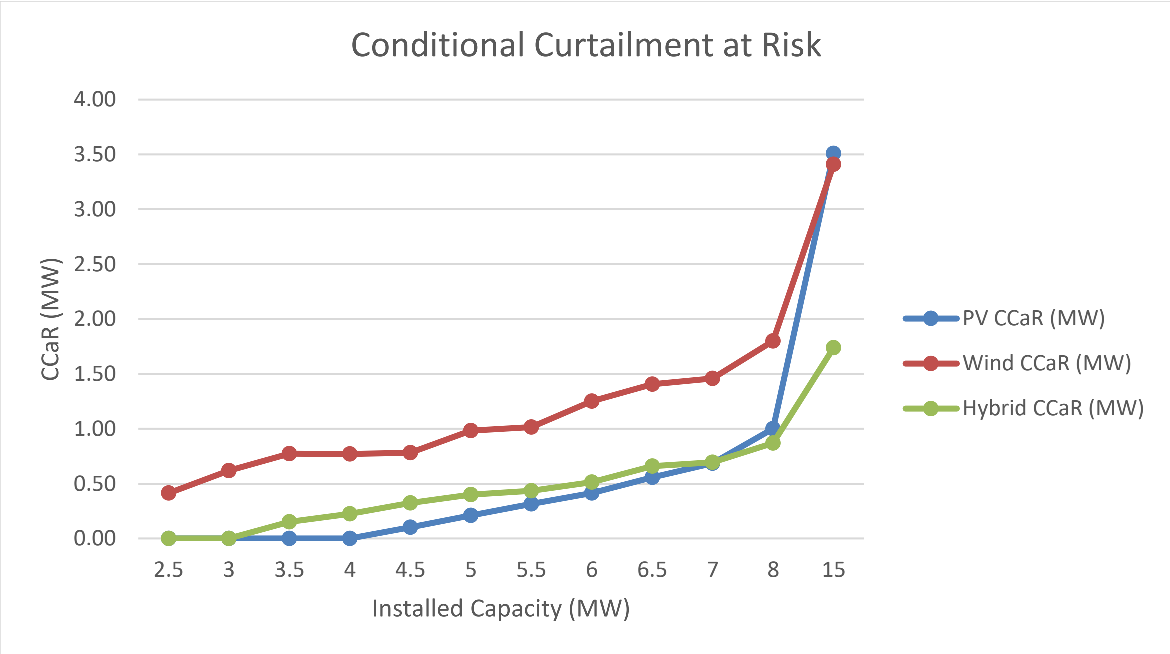

Fig 34: CCaR evolution in function of the installed power

The third and last parameter analysed is the Curtailed Energy Percentage, which is shown in Fig 35. The pattern is very similar to that of the CCaR, with the best performance in the overall calculation being that of the hybrid installation, which shows the least sensitivity to installed power, except at high power levels, where the slope of the hybrid installation is steeper than that of the wind installation. The progression of the indicator in PV installations also shows satisfactory results, again this technology is very sensitive to the installed power, however, up to 7 MW installed, the Curtailed Energy Percentage does not exceed 5%, which implies that with an installation of 7 MW, over the course of a year, the energy not supplied will be less than 5%. The correlation of this indicator with the CCaR in a wind farm is very high, the Curtailed Energy Percentage is the highest in all cases with the exception of 15

MW. In installations of this type, it would be appropriate to install less power, for example, if a threshold of 5% is established, the wind installation would have to be 5.5 MW.

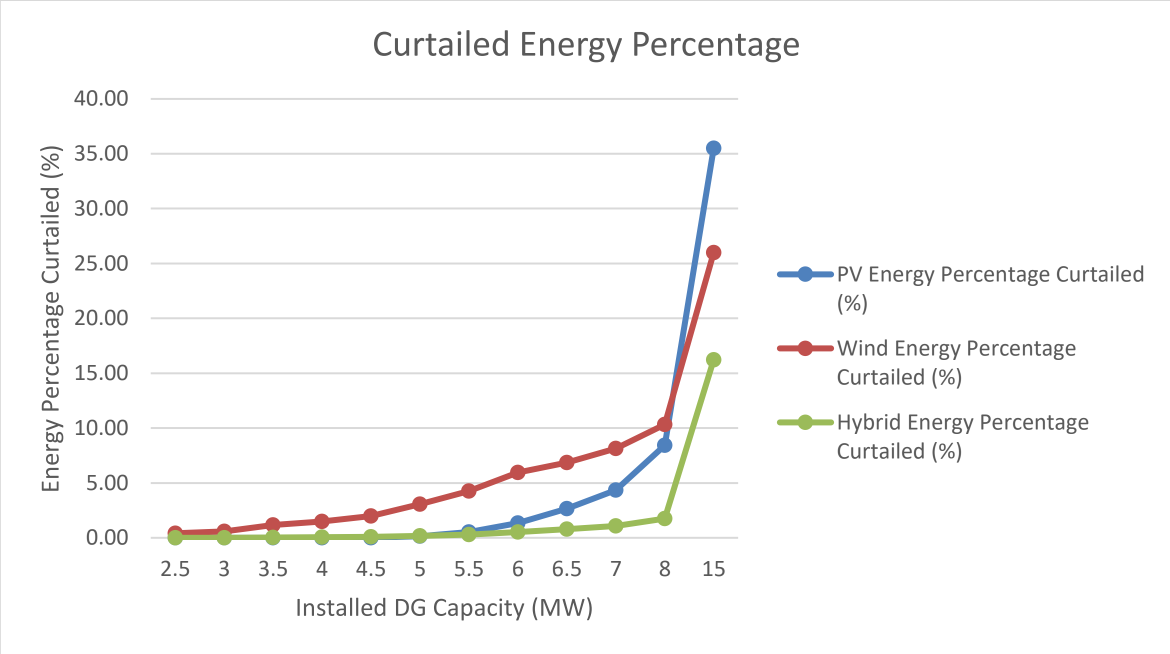

Fig 35: Energy Percentage Curtailed in function of the installed power

In summary, as mentioned above, all three indicators increase with installed power. The points to be drawn from the analysis are as follows:

- For lower plant installed power, based on the indicators alone, the best choice is photovoltaics.
- In the overall calculation, the best choice is a hybrid installation, however, the investment costs would have to be studied to see if it is profitable or not.
- Wind installations in the area where the simulations have been carried out are again, in view of the indicators, the worst choice among the three options presented.

4.4 CURTAILMENT TIME ANALYSIS

One of the strengths of the proposed methodology is that hourly discrimination is retained, this may also be an output of the algorithm which aims to give more information to the investor so that it can assess the investment more accurately.

The need to return these results to the investor arises from the variation in the price of energy over time, since curtailment impact during peak hours is not the same as curtailment impact during flat or off-peak hours.

The analysis is the same as in the previous section, the algorithm will obtain the result of the three indicators, the Risk Value, the CCaR and the Curtailed Energy Percentage, for each hour.

After the simulation of the 6 MW PV plant, the results are shown in Table 7. As it is a photovoltaic plant, it makes sense that the curtailment takes place in the intermediate hours of the day, in this case, from 9:00 to 16:00. The hourly curtailment distributions are shown in Fig 37 and a graphic representation of the parameter's evolution is portrayed in Fig 36.

Hour	Risk Value (%)	CCaR (MW)	Aggregated non-served Energy (MWh)	Energy Percentage Curtailed (%)
0	0	NaN	0	NaN
1	0	NaN	0	NaN
2	0	NaN	0	NaN
3	0	NaN	0	NaN
4	0	NaN	0	NaN
5	0	NaN	0	NaN
6	0	NaN	0	NaN
7	0	NaN	0	NaN
8	0	NaN	0	NaN
9	0.28	0.10	0.20	2.52
10	16.94	0.35	42.32	7.94
11	31.11	0.57	128.17	12.67
12	9.72	0.31	21.83	6.49
13	6.67	0.27	13.16	5.97

14	10.83	0.30	23.10	7.21
15	1.67	0.09	1.06	2.56
16	0.14	0.02	0.02	0.65
17	0	NaN	0	NaN
18	0	NaN	0	NaN
19	0	NaN	0	NaN
20	0	NaN	0	NaN
21	0	NaN	0	NaN
22	0	NaN	0	NaN
23	0	NaN	0	NaN

Table 7: Curtailment hourly análisis of a 6 MW PV Installation

Analysing the values shown in Table 7 and portrayed in Fig 36, which are relative to the hour being analysed, a 6 MW installation is estimated to suffer curtailment approximately eight hours of the day. The hour with the highest risk of curtailment is 11:00, where the Risk Value takes a value of 31.11%, at this hour also coincides with the CCaR and Energy Percentage Curtailed values taking the highest values of the whole day, 0.57 MW and 12.67% respectively. The next most curtailment-prone hours are 10:00 and 14:00.

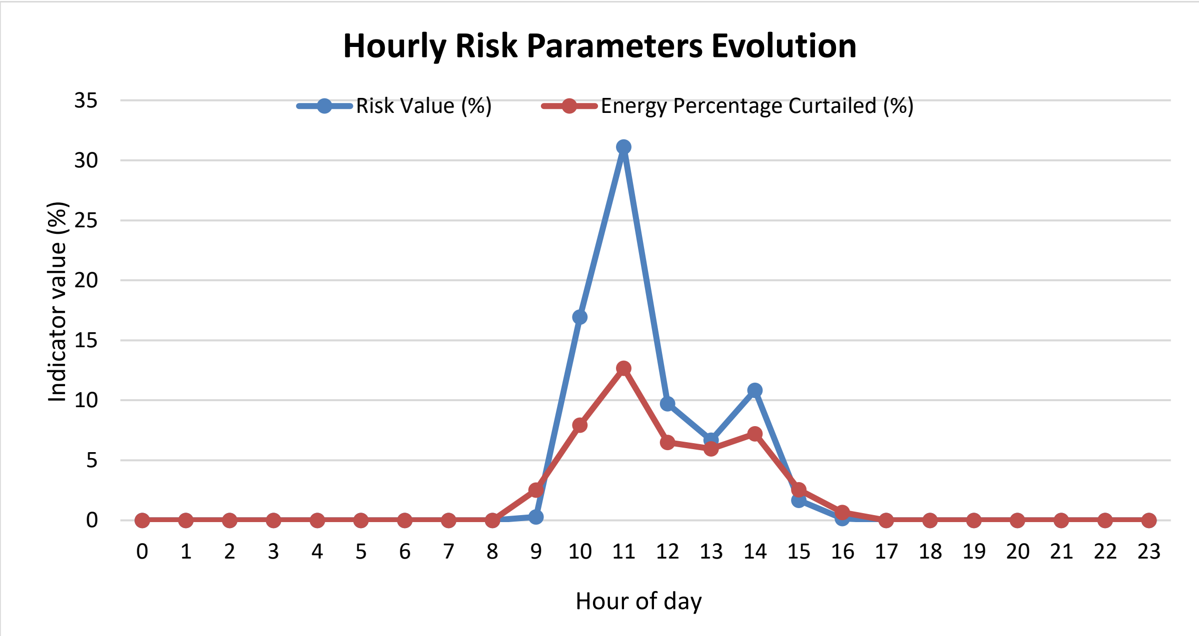

Fig 36: Parameter hourly evolution

Temporal analysis is another tool to facilitate the study of investments in distributed generation in the distribution network, it can simplify the work in the design phases of the DER installation as well as in the economic projections that are made to value an investment.

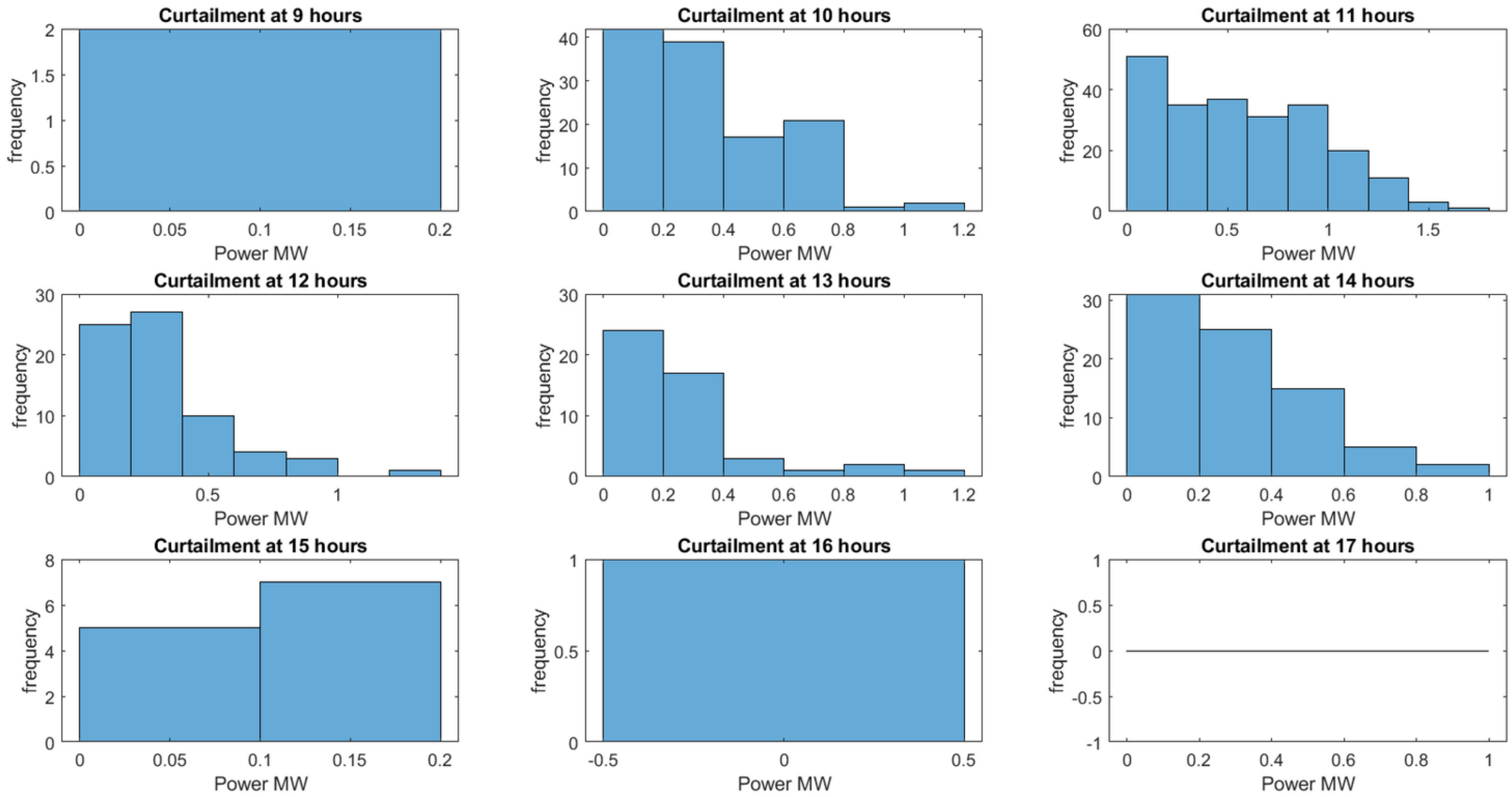

Fig 37: Hourly Curtailment distributions

5. CONCLUSIONS & FUTURE WORKS

5.1 CONCLUSIONS

It has been demonstrated that by including the uncertainties associated with generation and demand in the algorithm, and performing a Monte Carlo based OPF analysis to model them, the Hosting Capacity increases considerably. Concretely, the energy curtailed improved in more than 95% with respect to the Worst Case Scenario when running the DHC algorithm considering generation and demand uncertainties. Therefore, the objective of improving the conservative model has been achieved.

Furthermore, another observation made after comparing the performance of the different methodologies is that the DHC with uncertainty in demand and generation performs better than the DHC with uncertainty in demand; thus, the results obtained with the latter methodology are acceptable, as it improves the results obtained with the Worst Case Approach by 92%.

Although the results are better when considering generation and demand uncertainty. When it comes to make a flexible contract, it would be beneficial to see the results of both DHC methodologies to elaborate it, with the objective of giving more flexibility to the DSO operation by establishing looser contract terms, such as something intermediate between the result considering only demand uncertainty and the result considering demand and generation.

To determine the size of the DER installation, Risk Analysis, CCaR and Curtailed Energy Percentage are the three parameters to analyse. Moreover, there is a possibility to analyse graphically the design of the plant by watching the probability distributions produced by the algorithm.

Regarding the graphic analysis, for photovoltaic installations, one of the indicators of over dimensioning is the analysis of the shape of the curtailment distribution, in the event that the shape of the distribution flattens out, it is an indicator that the installation is over dimensioned. For hybrid and wind turbines, the shape does not tell us as much, as they tend to be always convex. In these two cases looking at the limits of the graph will be more representative. If the curtailment registers are similar to the installed power on some occasions, it is an indicator that the installation may be over-dimensioned.

With regard to the numerical analysis. Photovoltaic plants present a lower risk up to a certain installed capacity. This is due to the sensitivity of the indicators to increases in installed power, which is why it is necessary for them to be correctly designed. In the case of oversizing, the investment will worsen, and the returns will not be as profitable. Hybrid plants show the best results and the best response to power increase, for these installations the risk of oversizing is not as high as in a PV installation, however, the initial investment would have to be assessed to see the profitability. Finally, wind installations are the worst performers in terms of Curtailed Energy Percentage and CCaR.

When making decisions, it is important to look at the three indicators, and not to look only at one of them to assess whether the investment is a good one or not.

Speaking about the hourly breakdown, it gives the possibility to adjust the plant dimension to minimise curtailment when prices are high. Time analysis is significant in time-of-day sensitive DER technologies, it can help in the design of the DER installations and in the economic analysis of the investment.

Finally, after the analysis of the results, it has been concluded that the outputs of the algorithm should be used to develop a flexible contract that satisfies all interested parties. To this end, it is proposed to establish contractual limits that are slightly higher than those obtained after running the algorithm, which give the DSO room for manoeuvre if necessary, and which do not harm the economic performance of the installation. As mentioned, one of the proposals would be to establish the contract conditions at an intermediate point between the results obtained in the DHC simulation with only demand uncertainty and DHC considering generation and demand uncertainties.

5.2 FUTURE WORKS

In view of the project carried out, the following lines of research are proposed, which may lead to possible future works.

To start with, one of the immediate jobs would be to modify the inverter control, right now the control is a VWOM active power control, as it reduces the active power injections to control the voltages at the nodes. A possible improvement would be to introduce a VVWOM control, which combines active and reactive power control, and see how this control would improve the inverter indicators.

The next proposed future work is to consider the evolution of the HC over time. The value of the HC is not static as it varies according to the demand in the network. A valuable contribution would be, using Artificial Intelligence techniques, to include in the algorithm a prediction of the evolution of demand in the coming years. This would provide investors with information on the performance of their installation in the following years. Which could allow them to consider installing more power in the present, even if the indicators are not so favourable, in the knowledge that in the future these indicators will improve. This will also allow the investor to negotiate a flexible contract with the DSO, agreeing to higher curtailment in the present in exchange for lower curtailment in the future, as energy demand increases.

In addition to the above, the study of the evolution of weather conditions over time, using Artificial Intelligence techniques can also be included. Due to climate change, the parameters may evolve, which means that the projections made a priori may deviate from reality and the flexible contracts established between the DSO and the owner of the installation may not be fulfilled.

Another future work is the development of flexible contracts, this would entail a process of studying the regulation in the connection zone, once the regulation has been studied, the flexible contract would aim to establish an agreement between the DSO and the owner of the DER installation, where the operating conditions are agreed. These conditions will be based on the indicators resulting from the algorithm. For example, assuming that the Risk Value takes a value of 10% and the Curtailed Energy Percentage takes a value of 7%, the contract could dictate that such a DER installation can be controlled (can undergo curtailment) by the DSO at zero cost until either the value (in percentage) of non-supplied energy reaches 7%, or the number of hours with curtailment reaches 10%, if these values are exceeded, the owner of the DER installation will have to be compensated. This implies that for the DER installation under review, the cost function will have to be modelled to represent these offsets in the system costs.

The current algorithm is designed for a grid with no DER connected, elaborating a complex cost function that models the flexible contract of each DER installation will be necessary to assess the incursion of future DER technologies into the distribution network. Therefore, the algorithm will help with the creation of new DER flexible contracts by considering the previous flexible contracts.

6. REFERENCES

[1] S. M. Ismael, S. H. E. Abdel Aleem, A. Y. Abdelaziz, and A. F. Zobaa, "State-of-the-art of hosting capacity in modern power systems with distributed generation," *Renewable Energy*, vol. 130. Elsevier Ltd, pp. 1002–1020, Jan. 01, 2019. doi: 10.1016/j.renene.2018.07.008.

[2] M. Seidaliseifabad, "Hosting Capacity Assessment of Distribution Systems," 2020.

[3] M. S. S. Abad, J. Ma, D. Zhang, A. S. Ahmadyar, and H. Marzooghi, "Probabilistic Assessment of Hosting Capacity in Radial Distribution Systems," *IEEE Transactions on Sustainable Energy*, vol. 9, no. 4, pp. 1935–1947, Oct. 2018, doi: 10.1109/TSTE.2018.2819201.

[4] S. Kahrobaee and V. Mehr, "Probabilistic Analysis of PV Curtailment Impact on Distribution Circuit Hosting Capacity," in *Conference Record of the IEEE Photovoltaic Specialists Conference*, Jun. 2020, vol. 2020-June, pp. 2210–2213. doi: 10.1109/PVSC45281.2020.9300440.

[5] W. Niederhuemer and R. Schwalbe, "Increasing PV hosting capacity in LV grids with a probabilistic planning approach," in *Proceedings - 2015 International Symposium on Smart Electric Distribution Systems and Technologies, EDST 2015*, Nov. 2015, pp. 537–540. doi: 10.1109/SEDST.2015.7315266.

[6] M. Emmanuel and Y. Zhang, "Estimating spatial distribution impacts of rooftops solar PV on dynamic hosting capacity evaluation for a real distribution feeder," in *Conference Record of the IEEE Photovoltaic Specialists Conference*, Jun. 2021, pp. 1565–1569. doi: 10.1109/PVSC43889.2021.9518437.

[7] H. Wei, G. Ying, and J. Jiangping, "Dynamic Hosting Capacity Evaluation of DGs in Active Distribution Network," Nanjing, 2020.

[8] K. Horowitz, "Hosting Capacity Analysis for Utilities." [Online]. Available: www.nrel.gov

[9] D. Power and R. Rodriguez Labastida, "Guidehouse Insights Leaderboard: DERMS Vendors Assessment of Strategy and Execution of 13 DERMS for DER and Grid Management Providers," 2022.

[10] Conseil international des grands réseaux électriques. Comité d'études C6. and Impr. Conformes), *Capacity of distribution feeders for hosting DER*. CIGRÉ, 2014.

[11] J. le Baut *et al.*, "Probabilistic evaluation of the hosting capacity in distribution networks," Feb. 2017. doi: 10.1109/ISGTEurope.2016.7856213.

[12] A. Balzhan, A. Aishabibi, N. H.S.V.S Kumar, and M. Bekzhan, *Hosting Capacity Enhancement in Low Voltage Distribution Networks: Challenges and Solutions*. Cochin, India: IEEE, 2020. Accessed: Jun. 15, 2022. [Online]. Available: https://ieeexplore.ieee.org/abstract/document/9070466

[13] C. Long and L. F. Ochoa, "Voltage control of PV-rich LV networks: OLTC-fitted transformer and capacitor banks," *IEEE Transactions on Power Systems*, vol. 31, no. 5, pp. 4016–4025, Sep. 2016, doi: 10.1109/TPWRS.2015.2494627.

[14] C. M. Domingo, "Planning and Operation of Smart Distribution Systems: grid planning under growing shares of DER I/II," Madrid, 2021.

[15] B. Bletterie, S. Kadam, R. Bolgaryn, and A. Zegers, "Voltage Control with PV Inverters in Low Voltage Networks-In Depth Analysis of Different Concepts and Parameterization Criteria," *IEEE Transactions on Power Systems*, vol. 32, no. 1, pp. 177–185, Jan. 2017, doi: 10.1109/TPWRS.2016.2554099.

[16] B. Bletterie, S. Kadam, and J. le Baut, "Increased Hosting Capacity by means of active power curtailment," 2016.

[17] K. Salman, S. Vahid, and I. Andrew, *PV Curtailment Analysis to Improve Utilization of Hosting Capacity in California*. IEEE, 2019. Accessed: Jun. 15, 2022. [Online]. Available: https://ieeexplore.ieee.org/document/8981318

[18] V. Poulios, E. Vrettos, F. Kienzle, E. Kaffe, H. Luternauer, and G. Andersson, *Optimal placement and sizing of battery storage to increase the PV hosting capacity of low voltage grids*. Bonn: IEEE, 2015. Accessed: Jun. 15, 2022. [Online]. Available: https://ieeexplore.ieee.org/document/7388465

[19] M. B. Ndawula *et al.*, *Deterministic and Probabilistic Assessment of Distribution Network Hosting Capacity for Wind-Based Renewable Generation*. IEEE, 2020.

[20] E. Zio, M. Delfanti, L. Giorgi, V. Olivieri, and G. Sansavini, "Monte Carlo simulation-based probabilistic assessment of DG penetration in medium voltage distribution networks," *International Journal of Electrical Power and Energy Systems*, vol. 64, pp. 852–860, 2015, doi: 10.1016/j.ijepes.2014.08.004.

[21] F. M. Echavarren, "Operation and Planning of Future Distribution Networks DSO operational systems: DMS, OMS, NIS. State estimation," 2021.

[22] M. Seydali, S. Abad, G. Verbič, A. Chapman, and J. Ma, "A Linear Method for Determining the Hosting Capacity of Radial Distribution Systems."

[23] M. S. S. Abad and J. Ma, "Photovoltaic Hosting Capacity Sensitivity to Active Distribution Network Management," *IEEE Transactions on Power Systems*, vol. 36, no. 1, pp. 107–117, Jan. 2021, doi: 10.1109/TPWRS.2020.3007997.

[24] A. N. Madavan, N. Dahlin, S. Bose, and L. Tong, "Conditional Value at Risk-Sensitive Solar Hosting Capacity Analysis in Distribution Networks," Apr. 2022, [Online]. Available: http://arxiv.org/abs/2204.09096

[25] M. Asensio, P. Meneses De Quevedo, G. Muñoz-Delgado, and J. Contreras, "Index for alternatives for feeders, and transformers."

[26] M. S. S. Abad, J. Ma, D. Zhang, A. S. Ahmadyar, and H. Marzooghi, “Probabilistic Assessment of Hosting Capacity in Radial Distribution Systems,” *IEEE Transactions on Sustainable Energy*, vol. 9, no. 4, pp. 1935–1947, Oct. 2018, doi: 10.1109/TSTE.2018.2819201.

[27] J. W. MORREN Sjoerd de HAAN and essentnl SWHdeHaan, “C I R E D MAXIMUM PENETRATION LEVEL OF DISTRIBUTED GENERATION WITHOUT VIOLATING VOLTAGE LIMITS.”

[28] “GridOS ® Integrated Distribution Planning Opus One Solutions Energy Corporation,” 2017.

[29] Y. Yao, F. Ding, K. Horowitz, and A. Jain, “Coordinated Inverter Control to Increase Dynamic PV Hosting Capacity: A Real-Time Optimal Power Flow Approach,” *IEEE Systems Journal*, 2021, doi: 10.1109/JSYST.2021.3071998.

[30] Schneider, “Executive summary DER Operation Envelopes for Dynamic Grid Capacity.”

[31] “GridOS ® Integrated Distribution Planning Opus One Solutions Energy Corporation,” 2017.

[32] R. D. Zimmerman and C. E. Murillo-Sánchez, “MATP WER User’s Manual Version 7.1,” 2020.

[33] J. E. Mendoza, D. A. Morales, R. A. Lopez, E. A. Lopez, J. C. Vannier, and C. A. Coello Coello, “Multiobjective location of automatic voltage regulators in a radial distribution network using a micro genetic algorithm,” *IEEE Transactions on Power Systems*, vol. 22, no. 1, pp. 404–412, Feb. 2007, doi: 10.1109/TPWRS.2006.887963.

[34] Red Eléctrica de España, “¿Cómo consumimos electricidad?,” *https://www.ree.es/sites/default/files/interactivos/como_consumimos_electricidad/como-varia-mi-consumo.html*.

[35] Chc Energía, “¿En qué meses se consume más electricidad?,” *https://chcenergia.es/blog/en-que-meses-se-consume-mas-electricidad/#:~:text=Los%20meses%20de%20invierno%20son%20los%20que%20m%C3%A1s,los%20meses%20de%20invierno%20este%20gasto%20se%20dispare.* , Feb. 10, 2021.

[36] NASA, “NASA Power Data Access Viewer,” *https://power.larc.nasa.gov/data-access-viewer/*.

[37] I. Toumazis, C. Kwon, and R. Batta, “Value-at-risk and conditional value-at-risk minimization for hazardous materials routing,” in *International Series in Operations Research and Management Science*, vol. 193, Springer New York LLC, 2013, pp. 127–154. doi: 10.1007/978-1-4614-6794-6_5.

[38] P. Beraldi, A. Violi, M. E. Bruni, and G. Carrozzino, “A probabilistically constrained approach for the energy procurement problem,” *Energies (Basel)*, vol. 10, no. 12, 2017, doi: 10.3390/en10122179.

[39] O. Organización de las Naciones Unidas, “Objetivos de Desarrollo Sostenible,” *https://www.un.org/sustainabledevelopment/es/*, 2015.

[40] Organización de las Naciones Unidas, “Ciudades y Comunidades Sostenibles,” *https://www.un.org/sustainabledevelopment/es/cities/*.

[41] Ministerio para la Transición Ecológica y Reto Demográfico, “Objetivos de reducción de emisiones de gases de efecto invernadero,” *https://www.miteco.gob.es/es/cambio-climatico/temas/mitigacion-politicas-y-medidas/objetivos.aspx#:~:text=2021%20%2D%202030&text=Los%20principales%20objetivos%20de%20dicho,en%20el%20consumo%20de%20energ%C3%ADa.*

ANNEX I MATLAB CODE

This annex has been made to show the code used to get that results described on previous chapters, this annex contains the main code and the functions used, which are: CreateCurtTable, ConditionalCurtailmentatRisk, GenerateLoads, GeneratePVOutput and GenerateWindOutput.

Matlab Main Code

```
First historical data from demand and generation is loaded

load LoadsNudosACEA.mat;
load SolarAndWindData.mat;

%Auxiliary variable to choose the approach
var_aux = 4; % 1 = worst case scenario
% 2 = max gen min load per hour
% 3 = uncertainty loads, max gen
% 4 = uncerainty loads and gen


%Generator variables
%Inputs PV installation
hayPV = 1; %If = 1, then there is PV connected
nPaneles = 12000; %number of panels installed
areaPanel = 2; %m2
potenciaPanel = 0.5; %kWp

%Inputs wind installation
hayWind = 0; %If = 1, then there is wind installation connected
bladeLength = 4; %en m
pturb = 10; %en kW
numofTurbines = 600; %number of turbines installed
pot_inst = pturb*numofTurbines/1000; %in MVAs

%Worst case scenario variables
% Choses the max irradiation registered
IrrMax = max(SolarAndWind.Irrad);
%Calculates the PV generation under such conditions
genPVMax =
(areaPanel*nPaneles*(potenciaPanel/areaPanel)*(IrrMax/1000)*0.85)/1000;
%Choses the max wind speed registered
MaxWind = max(SolarAndWind.WindSpeed);
% Calculates the wind turbines generation
```

```
genWindMax =
numofTurbines*((0.5*1.225*pi*(bladeLength^2)*MaxWind^3)*0.35)/10^6;
%makes shure that the max genration doesn't exceed the rated power
if genWindMax >= pot_inst
    genWindMax = pot_inst;
end

%Curtailment Table is created
hours = 24; %Nº of hour intervals to be studied
months = 12; %Months to be studied
NMCsamples = 60; %Nº of MC samples
%The table will be filled afterwards
TablaCurt = CreateCurtTable(hours,months,NMCsamples);

%These are vectors of zeros to be filled afterwards
vecMaxHourIrr = zeros(hours,1);
vecMaxHourWind = zeros(hours,1);
vecMaxPVGen = zeros(hours,1);
vecMaxWindGen = zeros(hours,1);
vecGenOutput = zeros(hours,1);
vecCurt = zeros(hours,1);
vecGenMax = zeros(hours,1);
hCurt = zeros(hours,1);

%Preparation for the hourly worst case scenario and DHC with just load
%uncertainty
%This for loop gets the maximum generation for each hour of the day
for i_gen = 1:hours
    logicaGen = SolarAndWind.Hour == i_gen-1; %Logic variable to select the
hour
    vecMaxHourIrr(i_gen) = max(SolarAndWind.Irrad(logicaGen));
    vecMaxHourWind(i_gen) = max(SolarAndWind.WindSpeed(logicaGen));
    vecMaxPVGen(i_gen) = (areaPanel*nPaneles*(potenciaPanel/areaPanel)...
        *(vecMaxHourIrr(i_gen)/1000)*0.85)/1000;
    vecMaxWindGen(i_gen) = numofTurbines*((0.5*1.225*pi*(bladeLength^2)...
        *vecMaxHourWind(i_gen)^3)*0.35)/10^6;
    if vecMaxWindGen(i_gen) >= pot_inst
        vecMaxWindGen(i_gen) = pot_inst;
    end
end

% define named indices into bus, gen, branch matrices (from matpower code)
[PQ, PV, REF, NONE, BUS_I, BUS_TYPE, PD, QD, GS, BS, BUS_AREA, VM, ...
    VA, BASE_KV, ZONE, VMAX, VMIN, LAM_P, LAM_Q, MU_VMAX, MU_VMIN] = idx_bus;
 [GEN_BUS, PG, QG, QMAX, QMIN, VG, MBASE, GEN_STATUS, PMAX, PMIN, ...
     MU_PMAX, MU_PMIN, MU_QMAX, MU_QMIN, PC1, PC2, QC1MIN, QC1MAX, ...
     QC2MIN, QC2MAX, RAMP_AGC, RAMP_10, RAMP_30, RAMP_Q, APF] = idx_gen;
[F_BUS, T_BUS, BR_R, BR_X, BR_B, RATE_A, RATE_B, RATE_C, ...
    TAP, SHIFT, BR_STATUS, PF, QF, PT, QT, MU_SF, MU_ST, ...
    ANGMIN, ANGMAX, MU_ANGMIN, MU_ANGMAX] = idx_brch;

%Load the matpower case
CASE = 'case17me';
```

```
mpc = loadcase(CASE);
mpc_aux = mpc; %Auxiliary so that the initial model remains unvaried

count = 1; %counter to fill in the curtailment table
if var_aux == 1
    %Simulates the worst case scenario, taking the minimum loads for each
    %node of the entire grid
            %Active power demand in MW
            mpc_aux.bus(1,PD) = 0.0;
            mpc_aux.bus(2,PD) = min(LoadNudo2.PD)/50/1000; %Load reduction
            mpc_aux.bus(3,PD) = 0.0;
            mpc_aux.bus(4,PD) = min(LoadNudo4.PD)/1000;
            mpc_aux.bus(5,PD) = 0.0;
            mpc_aux.bus(6,PD) = min(LoadNudo6.PD)/1000;
            mpc_aux.bus(7,PD) = min(LoadNudo7.PD)/1000;
            mpc_aux.bus(8,PD) = min(LoadNudo8.PD)/1000;
            mpc_aux.bus(9,PD) = min(LoadNudo9.PD)/1000;
            mpc_aux.bus(10,PD) = min(LoadNudo10.PD)/1000;
            mpc_aux.bus(11,PD) = min(LoadNudo11.PD)/1000;
            mpc_aux.bus(12,PD) = min(LoadNudo12.PD)/1000;
            mpc_aux.bus(13,PD) = min(LoadNudo13.PD)/50/1000; %Load reduction
            mpc_aux.bus(14,PD) = min(LoadNudo14.PD)/1000;
            mpc_aux.bus(15,PD) = min(LoadNudo15.PD)/1000;
            mpc_aux.bus(16,PD) = 0.0;
            mpc_aux.bus(17,PD) = min(LoadNudo17.PD)/1000;
            %Reactive power demand in MVar
            mpc_aux.bus(1,QD) = 0.0;
            mpc_aux.bus(2,QD) = min(LoadNudo2.QD)/50/1000;
            mpc_aux.bus(3,QD) = 0.0;
            mpc_aux.bus(4,QD) = min(LoadNudo4.QD)/1000;
            mpc_aux.bus(5,QD) = 0.0;
            mpc_aux.bus(6,QD) = min(LoadNudo6.QD)/1000;
            mpc_aux.bus(7,QD) = min(LoadNudo7.QD)/1000;
            mpc_aux.bus(8,QD) = min(LoadNudo8.QD)/1000;
            mpc_aux.bus(9,QD) = min(LoadNudo9.QD)/1000;
            mpc_aux.bus(10,QD) = min(LoadNudo10.QD)/1000;
            mpc_aux.bus(11,QD) = min(LoadNudo11.QD)/1000;
            mpc_aux.bus(12,QD) = min(LoadNudo12.QD)/1000;
            mpc_aux.bus(13,QD) = min(LoadNudo13.QD)/50/1000;
            mpc_aux.bus(14,QD) = min(LoadNudo14.QD)/1000;
            mpc_aux.bus(15,QD) = min(LoadNudo15.QD)/1000;
            mpc_aux.bus(16,QD) = 0.0;
            mpc_aux.bus(17,QD) = min(LoadNudo17.QD)/1000;
            %Generation in MW
            if hayPV == 1 && hayWind == 0 %If there is only PV
                mpc_aux.gen(2,GEN_STATUS) = 1;
                mpc_aux.gen(2,PMAX) = genPVMax;
                mpc_aux.gen(2,PG) = genPVMax;
                mpc_aux.gen(2,PMIN) = 0.0;
                mpc_aux.gencost(2,6) = 0.0; %Operation costs = 0
            elseif hayPV == 0 && hayWind == 1 %If there is only wind
                mpc_aux.gen(2,GEN_STATUS) = 1;
                mpc_aux.gen(2,PMAX) = genWindMax;
```

```
                mpc_aux.gen(2,PMAX) = genWindMax;
                mpc_aux.gen(2,PMIN) = 0.0;
                mpc_aux.gencost(2,6) = 0.0; %Operation costs = 0
            elseif hayPV == 1 && hayWind == 1 %Hybrid installation
                mpc_aux.gen(2,GEN_STATUS) = 1;
                mpc_aux.gen(2,PMAX) = genPVMax + genWindMax;
                mpc_aux.gen(2,PG) = genPVMax + genWindMax;
                mpc_aux.gen(2,PMIN) = 0.0;
                mpc_aux.gencost(2,6) = 0.0; %Operation cost = 0
            else
                mpc_aux.gen(2,GEN_STATUS) = 0;
            end
            %Execute the opf
            mpc_out1 = runopf(mpc_aux);
            %Outputs
            pCurt = mpc_out1.gen(2,PMAX)-mpc_out1.gen(2,PG); %Curtailment
            curtPcnt = pCurt/mpc_out1.gen(2,PMAX); %Curtailment percentage
            pGenWorstCase = mpc_out1.gen(2,PG); %Power generated
            vecWorstCase = [pCurt curtPcnt pGenWorstCase];
elseif var_aux == 2
    %Min demand an maximum generation per hour
    %Sample the min demand per hour
    for i2 = 1:hours
        logicaMinDem = LoadNudo9.Hora == i2-1; %logic variable to select the
hour
        %Active power demand in MW
        mpc_aux.bus(1,PD) = 0.0;
        mpc_aux.bus(2,PD) = min(LoadNudo2.PD(logicaMinDem))/50/1000; %Load
reduction
        mpc_aux.bus(3,PD) = 0.0;
        mpc_aux.bus(4,PD) = min(LoadNudo4.PD(logicaMinDem))/1000;
        mpc_aux.bus(5,PD) = 0.0;
        mpc_aux.bus(6,PD) = min(LoadNudo6.PD(logicaMinDem))/1000;
        mpc_aux.bus(7,PD) = min(LoadNudo7.PD(logicaMinDem))/1000;
        mpc_aux.bus(8,PD) = min(LoadNudo8.PD(logicaMinDem))/1000;
        mpc_aux.bus(9,PD) = min(LoadNudo9.PD(logicaMinDem))/1000;
        mpc_aux.bus(10,PD) = min(LoadNudo10.PD(logicaMinDem))/1000;
        mpc_aux.bus(11,PD) = min(LoadNudo11.PD(logicaMinDem))/1000;
        mpc_aux.bus(12,PD) = min(LoadNudo12.PD(logicaMinDem))/1000;
        mpc_aux.bus(13,PD) = min(LoadNudo13.PD(logicaMinDem))/50/1000; %Load
reduction
        mpc_aux.bus(14,PD) = min(LoadNudo14.PD(logicaMinDem))/1000;
        mpc_aux.bus(15,PD) = min(LoadNudo15.PD(logicaMinDem))/1000;
        mpc_aux.bus(16,PD) = 0.0;
        mpc_aux.bus(17,PD) = min(LoadNudo17.PD(logicaMinDem))/1000;
        %Reactive power demand in MVar
        mpc_aux.bus(1,QD) = 0.0;
        mpc_aux.bus(2,QD) = min(LoadNudo2.QD(logicaMinDem))/50/1000;
        mpc_aux.bus(3,QD) = 0.0;
        mpc_aux.bus(4,QD) = min(LoadNudo4.QD(logicaMinDem))/1000;
        mpc_aux.bus(5,QD) = 0.0;
        mpc_aux.bus(6,QD) = min(LoadNudo6.QD(logicaMinDem))/1000;
        mpc_aux.bus(7,QD) = min(LoadNudo7.QD(logicaMinDem))/1000;
```

```
        mpc_aux.bus(8,QD) = min(LoadNudo8.QD(logicaMinDem))/1000;
        mpc_aux.bus(9,QD) = min(LoadNudo9.QD(logicaMinDem))/1000;
        mpc_aux.bus(10,QD) = min(LoadNudo10.QD(logicaMinDem))/1000;
        mpc_aux.bus(11,QD) = min(LoadNudo11.QD(logicaMinDem))/1000;
        mpc_aux.bus(12,QD) = min(LoadNudo12.QD(logicaMinDem))/1000;
        mpc_aux.bus(13,QD) = min(LoadNudo13.QD(logicaMinDem))/50/1000;
        mpc_aux.bus(14,QD) = min(LoadNudo14.QD(logicaMinDem))/1000;
        mpc_aux.bus(15,QD) = min(LoadNudo15.QD(logicaMinDem))/1000;
        mpc_aux.bus(16,QD) = 0.0;
        mpc_aux.bus(17,QD) = min(LoadNudo17.QD(logicaMinDem))/1000;
        %Generation in MW
            if hayPV == 1 && hayWind == 0 %Only PV
                mpc_aux.gen(2,GEN_STATUS) = 1;
                mpc_aux.gen(2,PMAX) = vecMaxPVGen(i2);
                mpc_aux.gen(2,PG) = vecMaxPVGen(i2);
                mpc_aux.gen(2,PMIN) = 0.0;
                mpc_aux.gencost(2,6) = 0.0; %Operation Costs = 0
            elseif hayPV == 0 && hayWind == 1 %Only wind
                mpc_aux.gen(2,GEN_STATUS) = 1;
                mpc_aux.gen(2,PMAX) = vecMaxWindGen(i2);
                mpc_aux.gen(2,PMAX) = vecMaxWindGen(i2);
                mpc_aux.gen(2,PMIN) = 0.0;
                mpc_aux.gencost(2,6) = 0.0; %Operation Costs = 0
            elseif hayPV == 1 && hayWind == 1 %Hybrid installation
                mpc_aux.gen(2,GEN_STATUS) = 1;
                mpc_aux.gen(2,PMAX) = vecMaxPVGen(i2) + vecMaxWindGen(i2);
                mpc_aux.gen(2,PG) = vecMaxPVGen(i2) + vecMaxWindGen(i2);
                mpc_aux.gen(2,PMIN) = 0.0;
                mpc_aux.gencost(2,6) = 0.0; %Operation Costs = 0
            else
                mpc_aux.gen(2,GEN_STATUS) = 0;
            end
            %Run the opf
            mpc_out1 = runopf(mpc_aux);
            %Outputs
            vecGenOutput(i2) = mpc_out1.gen(2,PG); %Generation at hour i2
            vecGenMax(i2) = mpc_out1.gen(2,PMAX); %Max available generation at
hour i2
            %Record which hours have curtailment
            if vecGenMax(i2) > vecGenOutput(i2)
                hCurt(i2) = 1;
            else
                hCurt(i2) = 0;
            end
    end
    %output
    %Max available generation minus actual generation = curtailment
    vecCurt = vecGenMax-vecGenOutput;
    %Energy curtailed
    energyCurt = sum(vecCurt.*hCurt);
    %Total Curtailment
    totalCurt = sum(vecCurt);
    %Curtailment percentage
```

```
    percentCurt = (totalCurt/sum(vecGenMax))*100;
    %Display of the results
    disp('|Curtailment (kW)| |Curtailment (%)|')
    [totalCurt*1e3 percentCurt]
elseif var_aux == 3
    %DHC considering uncertainty in demand and max generation profiles
        for m = 1:months
           for h = 1:hours
              for mc = 1:NMCsamples
                %Logic variable for selecting the hour and month for the
                %generation profiles
                logicaGen = SolarAndWind.Month == m & SolarAndWind.Hour == h-
1;
                %Logic variable for selecting the hour and the month for
                %the demand
                logicHorayMes = LoadNudo10.Hora == h-1 & LoadNudo10.Mes == m;
                %Active power demand in MW
                %The function GenerateLoads is used to sample a random load
                mpc_aux.bus(1,PD) = 0.0;
                mpc_aux.bus(2,PD) =
GenerateLoads(m,logicHorayMes,LoadNudo2.PD)/50; %Load reduction
                mpc_aux.bus(3,PD) = 0.0;
                mpc_aux.bus(4,PD) =
GenerateLoads(m,logicHorayMes,LoadNudo4.PD);
                mpc_aux.bus(5,PD) = 0.0;
                mpc_aux.bus(6,PD) =
GenerateLoads(m,logicHorayMes,LoadNudo6.PD);
                mpc_aux.bus(7,PD) =
GenerateLoads(m,logicHorayMes,LoadNudo7.PD);
                mpc_aux.bus(8,PD) =
GenerateLoads(m,logicHorayMes,LoadNudo8.PD);
                mpc_aux.bus(9,PD) =
GenerateLoads(m,logicHorayMes,LoadNudo9.PD);
                mpc_aux.bus(10,PD) =
GenerateLoads(m,logicHorayMes,LoadNudo10.PD);
                mpc_aux.bus(11,PD) =
GenerateLoads(m,logicHorayMes,LoadNudo11.PD);
                mpc_aux.bus(12,PD) =
GenerateLoads(m,logicHorayMes,LoadNudo12.PD);
                mpc_aux.bus(13,PD) =
GenerateLoads(m,logicHorayMes,LoadNudo13.PD)/50; %Se reduce la carga en este
nudo
                mpc_aux.bus(14,PD) =
GenerateLoads(m,logicHorayMes,LoadNudo14.PD);
                mpc_aux.bus(15,PD) =
GenerateLoads(m,logicHorayMes,LoadNudo15.PD);
                mpc_aux.bus(16,PD) = 0.0;
                mpc_aux.bus(17,PD) =
GenerateLoads(m,logicHorayMes,LoadNudo17.PD);
                %Reactive power demand with random samples
                mpc_aux.bus(1,QD) = 0.0;
                mpc_aux.bus(2,QD) =
GenerateLoads(m,logicHorayMes,LoadNudo2.QD)/50;
```

```
                mpc_aux.bus(3,QD) = 0.0;
                mpc_aux.bus(4,QD) =
GenerateLoads(m,logicHorayMes,LoadNudo4.QD);
                mpc_aux.bus(5,QD) = 0.0;
                mpc_aux.bus(6,QD) =
GenerateLoads(m,logicHorayMes,LoadNudo6.QD);
                mpc_aux.bus(7,QD) =
GenerateLoads(m,logicHorayMes,LoadNudo7.QD);
                mpc_aux.bus(8,QD) =
GenerateLoads(m,logicHorayMes,LoadNudo8.QD);
                mpc_aux.bus(9,QD) =
GenerateLoads(m,logicHorayMes,LoadNudo9.QD);
                mpc_aux.bus(10,QD) =
GenerateLoads(m,logicHorayMes,LoadNudo10.QD);
                mpc_aux.bus(11,QD) =
GenerateLoads(m,logicHorayMes,LoadNudo11.QD);
                mpc_aux.bus(12,QD) =
GenerateLoads(m,logicHorayMes,LoadNudo12.QD);
                mpc_aux.bus(13,QD) =
GenerateLoads(m,logicHorayMes,LoadNudo13.QD)/50;
                mpc_aux.bus(14,QD) =
GenerateLoads(m,logicHorayMes,LoadNudo14.QD);
                mpc_aux.bus(15,QD) =
GenerateLoads(m,logicHorayMes,LoadNudo15.QD);
                mpc_aux.bus(16,QD) = 0.0;
                mpc_aux.bus(17,QD) =
GenerateLoads(m,logicHorayMes,LoadNudo17.QD);
                %Generation, maximum generation for each hour
                if hayPV == 1 && hayWind == 0 %Only PV
                    mpc_aux.gen(2,GEN_STATUS) = 1;
                    mpc_aux.gen(2,PMAX) = vecMaxPVGen(h);
                    mpc_aux.gen(2,PG) = vecMaxPVGen(h);
                    mpc_aux.gen(2,PMIN) = 0.0;
                    mpc_aux.gencost(2,6) = 0.0; %Operation costs = 0
                elseif hayPV == 0 && hayWind == 1 %Only wind
                    mpc_aux.gen(2,GEN_STATUS) = 1;
                    mpc_aux.gen(2,PMAX) = vecMaxWindGen(h);
                    mpc_aux.gen(2,PMAX) = vecMaxWindGen(h);
                    mpc_aux.gen(2,PMIN) = 0.0;
                    mpc_aux.gencost(2,6) = 0.0; %Operation costs = 0
                elseif hayPV == 1 && hayWind == 1%Hybrid installation
                    mpc_aux.gen(2,GEN_STATUS) = 1;
                    mpc_aux.gen(2,PMAX) = vecMaxPVGen(h) + vecMaxWindGen(h);
                    mpc_aux.gen(2,PG) = vecMaxPVGen(h) + vecMaxWindGen(h);
                    mpc_aux.gen(2,PMIN) = 0.0;
                    mpc_aux.gencost(2,6) = 0.0; %Operation costs = 0
                else
                    mpc_aux.gen(2,GEN_STATUS) = 0;
                end
                %Run the opf
                mpc_out1 = runopf(mpc_aux);
                %Snapshot of generation
                pGenPVStat = mpc_out1.gen(2,PG);
```

```
                %Snapshot of max available generation
                pGenPVMaxStat = mpc_out1.gen(2,PMAX);

                %Fill in the curtailment table
                %Sum of the total load
                TablaCurt.PLoad(count) = sum(mpc_out1.bus(:,PD));
                %Max generation minus curtailment
                TablaCurt.Gen_Load(count) = pGenPVMaxStat-
TablaCurt.PLoad(count);
                %Power generated
                TablaCurt.PGen(count) = pGenPVStat;
                %Max available power
                TablaCurt.PMAX(count) = pGenPVMaxStat;
                %Calculates curtailment (Pmax - Pgen)
                TablaCurt.PCurt(count) = pGenPVMaxStat-pGenPVStat;
                %Saves the hour that is being simulated
                TablaCurt.Hora(count) = h-1;
                %Saves the month that is being simulated
                TablaCurt.Mes(count) = m;
                %Actualises the count
                count = count + 1;
              end
           end
        end
        %Outputs
        %Curtailment distribution
        figure;
        histogram(TablaCurt.PCurt(TablaCurt.PCurt >= 0.001))
        title("Total Curtailment")
        xlabel('Power MW')
        ylabel('frequency')

        %Generation minus load representation
        figure;
        histogram(TablaCurt.Gen_Load)
        title("DER Generation minus Demand")
        xlabel('Power MW')
        ylabel('frequency')

        %Returns the parameters, Risk Value, CCaR, Total energy non-served
        %and Energy Percentage Curtailed using the function
        %ConditionalCurtailmentatRisk.
        [riskL, CCaR_L, EnergyMWh_L, EnergyPerct_L] =
ConditionalCurtailmentatRisk(TablaCurt);

elseif var_aux == 4
    for m = 1:months
        for h = 1:hours
            for mc = 1:NMCsamples
                %DHC considering load and generation uncertainty
                %Logic variable for selecting the hour and month for the
                %generation profiles
```

```
                logicaGen = SolarAndWind.Month == m & SolarAndWind.Hour == h-
1;
                %Logic variable for selecting the hour and month for the
                %demand distribution
                logicHorayMes = LoadNudo10.Hora == h-1 & LoadNudo10.Mes == m;
                %Active power demand in MW, sampled randomly
                mpc_aux.bus(1,PD) = 0.0;
                mpc_aux.bus(2,PD) =
GenerateLoads(m,logicHorayMes,LoadNudo2.PD)/50; %Load reduction
                mpc_aux.bus(3,PD) = 0.0;
                mpc_aux.bus(4,PD) =
GenerateLoads(m,logicHorayMes,LoadNudo4.PD);
                mpc_aux.bus(5,PD) = 0.0;
                mpc_aux.bus(6,PD) =
GenerateLoads(m,logicHorayMes,LoadNudo6.PD);
                mpc_aux.bus(7,PD) =
GenerateLoads(m,logicHorayMes,LoadNudo7.PD);
                mpc_aux.bus(8,PD) =
GenerateLoads(m,logicHorayMes,LoadNudo8.PD);
                mpc_aux.bus(9,PD) =
GenerateLoads(m,logicHorayMes,LoadNudo9.PD);
                mpc_aux.bus(10,PD) =
GenerateLoads(m,logicHorayMes,LoadNudo10.PD);
                mpc_aux.bus(11,PD) =
GenerateLoads(m,logicHorayMes,LoadNudo11.PD);
                mpc_aux.bus(12,PD) =
GenerateLoads(m,logicHorayMes,LoadNudo12.PD);
                mpc_aux.bus(13,PD) =
GenerateLoads(m,logicHorayMes,LoadNudo13.PD)/50; %Load reduction
                mpc_aux.bus(14,PD) =
GenerateLoads(m,logicHorayMes,LoadNudo14.PD);
                mpc_aux.bus(15,PD) =
GenerateLoads(m,logicHorayMes,LoadNudo15.PD);
                mpc_aux.bus(16,PD) = 0.0;
                mpc_aux.bus(17,PD) =
GenerateLoads(m,logicHorayMes,LoadNudo17.PD);
                %Reactive power demand in MVar sampled randomly
                mpc_aux.bus(1,QD) = 0.0;
                mpc_aux.bus(2,QD) =
GenerateLoads(m,logicHorayMes,LoadNudo2.QD)/50;
                mpc_aux.bus(3,QD) = 0.0;
                mpc_aux.bus(4,QD) =
GenerateLoads(m,logicHorayMes,LoadNudo4.QD);
                mpc_aux.bus(5,QD) = 0.0;
                mpc_aux.bus(6,QD) =
GenerateLoads(m,logicHorayMes,LoadNudo6.QD);
                mpc_aux.bus(7,QD) =
GenerateLoads(m,logicHorayMes,LoadNudo7.QD);
                mpc_aux.bus(8,QD) =
GenerateLoads(m,logicHorayMes,LoadNudo8.QD);
                mpc_aux.bus(9,QD) =
GenerateLoads(m,logicHorayMes,LoadNudo9.QD);
```

```
                mpc_aux.bus(10,QD) =
GenerateLoads(m,logicHorayMes,LoadNudo10.QD);
                mpc_aux.bus(11,QD) =
GenerateLoads(m,logicHorayMes,LoadNudo11.QD);
                mpc_aux.bus(12,QD) =
GenerateLoads(m,logicHorayMes,LoadNudo12.QD);
                mpc_aux.bus(13,QD) =
GenerateLoads(m,logicHorayMes,LoadNudo13.QD)/50;
                mpc_aux.bus(14,QD) =
GenerateLoads(m,logicHorayMes,LoadNudo14.QD);
                mpc_aux.bus(15,QD) =
GenerateLoads(m,logicHorayMes,LoadNudo15.QD);
                mpc_aux.bus(16,QD) = 0.0;
                mpc_aux.bus(17,QD) =
GenerateLoads(m,logicHorayMes,LoadNudo17.QD);
                %Generation in MW, sampled randomly using the
                %GeneratePVOutput and GenerateWindOutput functions
                if hayPV == 1 && hayWind == 0 %PV installation
                    mpc_aux.gen(2,GEN_STATUS) = 1;
                    mpc_aux.gen(2,PMAX) =
GeneratePVOutput(nPaneles,areaPanel,...
                         potenciaPanel,m,logicaGen,SolarAndWind.Irrad);
                    mpc_aux.gen(2,PG) =
GeneratePVOutput(nPaneles,areaPanel,...
                         potenciaPanel,m,logicaGen,SolarAndWind.Irrad);
                    mpc_aux.gen(2,PMIN) = 0.0;
                    mpc_aux.gencost(2,6) = 0.0; %Operation costs = 0
                elseif hayPV == 0 && hayWind == 1 %Wind installation
                    mpc_aux.gen(2,GEN_STATUS) = 1;
                    mpc_aux.gen(2,PMAX) = GenerateWindOutput(m,bladeLength,...
                        logicaGen,SolarAndWind.WindSpeed,numofTurbines,pot_inst
);
                    mpc_aux.gen(2,PMAX) = GenerateWindOutput(m,bladeLength,...
                        logicaGen,SolarAndWind.WindSpeed,numofTurbines,pot_inst
);
                    mpc_aux.gen(2,PMIN) = 0.0;
                    mpc_aux.gencost(2,6) = 0.0; %Operation costs = 0
                elseif hayPV == 1 && hayWind == 1 %Hybrid installation
                    mpc_aux.gen(2,GEN_STATUS) = 1;
                    mpc_aux.gen(2,PMAX) =
GeneratePVOutput(nPaneles,areaPanel,...
                         potenciaPanel,m,logicaGen,SolarAndWind.Irrad) + ...
                         GenerateWindOutput(m,bladeLength,logicaGen,...
                         SolarAndWind.WindSpeed,numofTurbines,pot_inst);
                    mpc_aux.gen(2,PG) =
GeneratePVOutput(nPaneles,areaPanel,...
                         potenciaPanel,m,logicaGen,SolarAndWind.Irrad) + ...
                         GenerateWindOutput(m,bladeLength,logicaGen,...
                         SolarAndWind.WindSpeed,numofTurbines,pot_inst);
                    mpc_aux.gen(2,PMIN) = 0.0;
                    mpc_aux.gencost(2,6) = 0.0; %Operation costs = 0
                else
                    mpc_aux.gen(2,GEN_STATUS) = 0;
```

```
                end

                %Run the opf
                mpc_out1 = runopf(mpc_aux);

                %Snapshot of actual generation
                pGenPVStat = mpc_out1.gen(2,PG);
                %Snapshot of max available generation
                pGenPVMaxStat = mpc_out1.gen(2,PMAX);

                %Fill in the curtailment table
                %Summatory of the demand in the simulation run
                TablaCurt.PLoad(count) = sum(mpc_out1.bus(:,PD));
                %Max available generation minus actual load
                TablaCurt.Gen_Load(count) = pGenPVMaxStat-
TablaCurt.PLoad(count);
                %Record the generation
                TablaCurt.PGen(count) = pGenPVStat;
                %Record the max available generation
                TablaCurt.PMAX(count) = pGenPVMaxStat;
                %Calculate curtailment in the simulation run
                TablaCurt.PCurt(count) = pGenPVMaxStat-pGenPVStat;
                %Record the hour that is being simulated
                TablaCurt.Hora(count) = h-1;
                %Record the month that is being simulated
                TablaCurt.Mes(count) = m;
                count = count + 1;
            end
        end
    end
%Total curtailment
%Draw curtailment distribution
        n_bins = 30;
        figure;
        histogram(TablaCurt.PCurt(TablaCurt.PCurt >= 0.001),n_bins)
        title("Total Curtailment")
        xlabel('Power MW')
        ylabel('frequency')

        %Draw Max Generation - Load
        figure;
        histogram(TablaCurt.Gen_Load,n_bins)
        title("DER Generation minus Demand")
        xlabel('Power MW')
        ylabel('frequency')

        %Hourly curtailment
        for hc = 0:23
            lh = TablaCurt.Hora == hc & TablaCurt.PCurt >= 0.001;
            figure;
            histogram(TablaCurt.PCurt(lh))
            title("Curtailment en la hora " + hc)
            xlabel('Power MW')
```

```
            ylabel('frequency')
        end
        %Output parameters, Risk Value, CCaR, Energy non-served and Energy
        %Percentage Curtailed
        [riskGyL, CCaR_GyL, EnergyMWh_GyL, EnergyPerct_GyL] =
ConditionalCurtailmentatRisk(TablaCurt);
end
```

Functions

ConditionalCurtailmentatRisk

```
function [hoursCurt, CCaR, EnergyMWh, EnergyPerct] =
ConditionalCurtailmentatRisk(OutputTable)
%This function recieves as input a table that holds all the results from
%the simulation, then it returns the parameters to be analysed by the
%investor.
% hoursCurt = Risk Value --> hours with curtailment/total hours with
% available
% CCaR = Conditional Curtailment at Risk --> mean of all the curtailments
% EnergyMWh = Energy non-served
% EnergyPerct = Energy Percentage Curtailed --> evaluates what percentage
% of the energy generated has been curtailed

%First the hours with curtailment are recorded and saved in the curtailment
%table
horas_tot = length(OutputTable.Run);
for h_cvar = 1:horas_tot
    if OutputTable.PCurt(h_cvar) >= 0.001
        OutputTable.HCurt(h_cvar) = 1;
    else
        OutputTable.HCurt(h_cvar) = 0;
    end
end

horas_curt = sum(OutputTable.HCurt);
hoursCurt = (horas_curt/horas_tot)*100;
EnergyMWh = sum(OutputTable.PCurt.*OutputTable.HCurt);
energia_sumin = sum(OutputTable.PGen);
EnergyPerct = (EnergyMWh/(energia_sumin + EnergyMWh))*100;
logCurt = OutputTable.PCurt >= 0.001;
CCaR = mean(OutputTable.PCurt(logCurt));
end
```

CreateCurtTable

```
function [curtTable] = CreateCurtTable(h,m,MC)
%This function is designed to create a table of zeros to be filled later
%during the MC simulations. The function will create table elements filled
%of zeros. The elements will be columns of m*h*MC rows.
%Inputs
%h --> Number of hours to be studied
```

```
%m --> Number of months to be studied
%MC --> Monte Carlo scenarios to be simulated per month and hour
%Outputs
%The output is the curtailment table, it has the following column elements:
% Hour wich is being simulated
% Month which is being simulated
% PCurt which es the table variable that will store the curtailment values
% obtained from the each simulation run
% PGen variable stores the amount on power that was actually delivered
% PMAX stores the amount of available power
% PLoad stores the total demand in the grid in that MC run
% Gen_Load is variable that aims to store the result of generation minus
% load
% HCurt aims to store the hours where curtailment is happening

mcRuns = h*m*MC;
RunNumber = 1:mcRuns;
curtTable = table(RunNumber','VariableNames',{'Run'});
curtTable.Hora = zeros(mcRuns,1);
curtTable.Mes = zeros(mcRuns,1);
curtTable.PCurt = zeros(mcRuns,1);
curtTable.PGen = zeros(mcRuns,1);
curtTable.PMAX = zeros(mcRuns,1);
curtTable.PLoad = zeros(mcRuns,1);
curtTable.Gen_Load = zeros(mcRuns,1);
curtTable.HCurt = zeros(mcRuns,1);

end
```

GenerateLoads

```
function [Carga] = GenerateLoads(month,logica,data_nudo)
%Generate a random value for P and Q on a bus in function of the month and the
%hour
%The power input is in KW and the output must be in MW in order for
%matpower to converge
%Inputs
% month --> inputs the month that is being simulated
% logica --> Logical variable that gets the samples from the historical
% data table that meet the hour and month specifications
% data_nudo --> Gets the load data from a given node
%Output
% Random load value

%Each month has a certain number of samples
if month == 1
    randVal = randi(217);
elseif month ==2
    randVal = randi(198);
elseif month == 3
    randVal = randi(217);
elseif month == 4
```

```
    randVal = randi(210);
elseif month == 5
    randVal = randi(217);
elseif month == 6
    randVal = randi(210);
elseif month == 7
    randVal = randi(217);
elseif month == 8
    randVal = randi(186);
elseif month == 9
    randVal = randi(180);
elseif month == 10
    randVal = randi(186);
elseif month == 11
    randVal = randi(180);
else
    randVal = randi(186);
end
l = data_nudo(logica);
Carga = l(randVal)/1000; %Returns the load in MW
end
```

GeneratePVOutput

```
function [genPV] =
GeneratePVOutput(n_paneles,areaUnPanel,potenciaUnPanel,logica,dataIrr)
% Out of all the available meteorological data gathered from NASA's
% database, the function samples one random value depending on the hour and
% month that it is on.
%INPUTS
% n_panels --> Number of panels in the installation
% areaUnPanel --> Area of one panel, in m2
% potenciaUnPanel --> maximum power of one panel, in kWp
% logica --> Logical array that aims to sample the data from the solar
% irradiance distribution given the month and the hour that is being
% simulated
% dataIrr --> Solar irradiation historial database
%OUTPUT
%genPV --> maximum available power, in MW

lm = length(dataIrr(logica)); %Gets the length of the vector
randPV = randi(lm); %Generates a random number between 1 and lm
r = potenciaUnPanel/areaUnPanel; % r efficiency ratio of the panel
A = n_paneles*areaUnPanel; % total area of the panels
vIrr = dataIrr(logica); % a vector with just the measurements that meet the
hour and month being simulated
irr = vIrr(randPV)/1000; % random value of solar irradiance, in kW/m2
PR = 0.85; % Performance Ratio, set to 0.85
genPV = (A*r*irr*PR)/1000; %Output power in MW
end
```

GenerateWindOutput

```
function [windGen] =
GenerateWindOutput(month,bladeLength,logica,windSpeed,n_gen,Pbase)
% The function aims to return a random value of the power generated by the
% installation in function of the wind speed recorded, the hour and the
% month that is being simulated

%INPUTS
% month --> Month that is being simulated
% bladeLength --> Length of the aerogenerator blades
% logica --> Logic array that is aimed to filter the historical values to
% get the values of interest
% windSpeed --> Wind Speed historical database
% Number of turbines installed
% Pbase --> Maximum power of the installation

%OUTPUT
% windGen --> Maximum available power

%Generate a random value for the month that is being simulated
if month == 1
    randWind = randi(186);
elseif month ==2
    randWind = randi(170);
elseif month == 3
    randWind = randi(186);
elseif month == 4
    randWind = randi(180);
elseif month == 5
    randWind = randi(186);
elseif month == 6
    randWind = randi(180);
elseif month == 7
    randWind = randi(186);
elseif month == 8
    randWind = randi(186);
elseif month == 9
    randWind = randi(180);
elseif month == 10
    randWind = randi(186);
elseif month == 11
    randWind = randi(180);
else
    randWind = randi(186);
end

eff = 0.35; %Turbine efficiency
A = pi*bladeLength^2; %Area covered by the blades
ro = 1.225; % Air density
vwindSpeed = windSpeed(logica); %Wind speeds that match the hour and month
simulated
```

```
velWind = vwindSpeed(randWind); % Random value of wind speed
windPower = (0.5*ro*A*velWind^3); %Available wind power equation
windGen1 = windPower*eff; %Power generated by 1 turbine
windGen = windGen1*n_gen/(10^6); %Power generated by all the turbines, in MW
%Make sure that the power generated doesn't exceed the rated power of the
%installation
if windGen >= Pbase
    windGen = Pbase;
end
end
```

ANNEX II ALIGNMENT WITH THE SDGS

The Sustainable Development Goals (SDGs) were created in 2015 by the United Nations (UN) and are expected to be met by 2030. They were created to set out a series of targets that all member countries should aim to achieve in order to change the course of development towards one that is cleaner, sustainable and accessible to all human beings, [39]. Fig 38 shows all the SDGs, this project aligns with the following:

- SDG 7: Affordable and Clean Energy
- SDG 8: Decent Work and Economic Growth
- SDG 11: Sustainable Cities and Communities
- SDG 13: Climate Action

Fig 38: UN 17 Sustainable Development Goals

Affordable and Clean Energy

As mentioned in previous sections, DHC consists of introducing the uncertainty associated with generation and demand forecasts to determine the remaining DG installation capacity of the system. This new approach significantly improves HC over the traditional method, which will allow more distributed generation equipment to be connected to the grid.

Consequently, the increase of HC will imply an increase of renewable technologies in the energy portfolio of the region where DHC is applied. The study of this subject is very attractive both for the companies in charge of operating the system and for the investing companies.

The former will be able to postpone the costs associated with strengthening the distribution grid and distribute them in other ways, such as funding research and development, while the latter will be able to exploit their power generation equipment. As for society, it will benefit mainly from increased flexibility in the grid, which goes hand in hand with increased funding for research and development, resulting in lower prices in the electricity market and a substantial improvement in the system infrastructure.

Decent Work and Economic Growth

The efficient operation of distribution networks opens the door to the creation of new industries, new players in the electricity market and new ways of exploiting this business.

Today, the implementation of DHS aims to incentivise distributed generation investment in distribution networks. This investment can be made by companies or by small consumers (prosumers). Both will be able to exploit the generation equipment installed on the distribution network by selling the energy they produce and generate revenue. The appearance of prosumers in the generation business has led to the appearance of another player in the electricity market, called an aggregator, which is responsible for managing the equipment of multiple prosumers, taking a commission for this, to carry out this business new jobs will be generated.

Finally, the incorporation of flexibility into the distribution grid will lead to the creation of local electricity markets where flexibility services can be offered. This will generate new jobs associated with the operation of these local areas, the operation of these local markets and the management of the equipment that provides flexibility.

Sustainable Cities and Communities

More than half of the human population lives in cities, which are the main financial centres. Cities account for 3% of the earth, generate about 60% of the world's GDP, produce more than 60% of resource consumption, consume 60-80% of the world's energy and emit about 70% of CO_2 emissions [40].

Again, by facilitating the installation of renewable energy in cities, it is expected that part of the energy needs can be met in the short term. In the long term, it is expected that with the improvement of technologies that provide system flexibility and the emergence of prosumers, cities will be able to operate as if they were microgrids, requiring less and less support from non-renewable generation plants.

One of the main research avenues being pursued to increase HC is the use of electric vehicles. These, known as Vehicle-to-Grid (V2G), can provide grid support and increase HC by offering flexibility of generation and consumption. However, much work remains to be done to get to this point, as these vehicles are currently unaffordable for most of the population and battery technology cannot meet the needs of the grid without them being damaged. However, HC studies are beginning to assess the contributions that V2G can make to both the system and HC, which means that with time and investment these vehicles will become more accessible to the public and capable of providing flexible services to the grid. Mass adoption of these will lead to a considerable reduction in CO_2 emissions, as transport accounts for a large share of global emissions.

Climate Action

European governments aim to achieve a reduction of at least 55% in carbon dioxide (CO_2) emissions by 2030, with 32% of electricity consumption being covered by renewable energy.

In addition, by 2050, CO_2 emissions are expected to be reduced by 80%, with the main focus on energy savings at the household level and the massive penetration of renewable energies in the electricity system [41].

One of the more short-term objectives of the DHC is to incentivise investment in grid flexibility without the need for distributors or investors themselves to incur grid reinforcement costs. This incentive will result in an increase of renewables in the grid, which are specifically designed to meet the needs of the local grid.

The first step of DHC, which is the one studied in this project, is to use control techniques to reduce power injections for short periods of time in order to increase the capacity of the distribution network to accommodate new DG installations. This approach is limited and at some point in time demand will have to be variable so that grid investments continue to be postponed and HC continues to increase.

With the installation of renewable energies and the paradigm shift in demand, emissions are expected to be reduced, if and only if all parts of the energy system work together.