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# Planning the future expansion of solar installations in a distribution power grid

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# Abstract

## Planning the future expansion of solar installations in a distribution power grid

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This thesis provides a tool to determine the maximum capacity, of a given power grid, when connecting distributed photovoltaic parks including the optimal allocation of the parks taking the power grid configuration into account. This tool is based on a computational model that evaluates the hosting capacity of the given grid through power flow simulations. The tool also integrates a geographic information system that links suitable land areas to nearby substations that can host photovoltaic parks. The mathematical model was tested on different cases in the municipality of Herrljunga, Sweden, where it was determined to be possible to connect 47 photovoltaic parks of 1MWp to the power grid as well as the most appropriate substations to allocate them to without the need for grid reinforcements. Additionally, the concept of grid cost allocation is presented and briefly discussed while analysing the results in relation to national energy targets.

*Keywords: distributed photovoltaic parks, smart allocation, hosting capacity, geographical information systems, grid cost allocation.*

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# Popular Scientific Summary

The transition towards a future with carbon-free societies needs to be driven by strong policies and frameworks that promote renewable energy. This transition goes hand in hand with the development of technology that supports renewable energy generation together with appropriate planning on how to develop this transformation. The performed study provides a novel contribution in the solar park planning and development.

The renewable energy revolution is affordable to all of the public as renewable technologies allow for a wide variety of power plants sizes — from pharaonic buildings such as the hydropower plant in Iguazú, Paraguay to smaller applications e.g. charging mobile phones with photovoltaic technology. In fact, installing photovoltaic modules on the roof-top of residential buildings, offices and industries is gaining more and more popularity thanks to state subsidies and the eagerness of society as a whole to become more sustainable. However, some studies have shown that the uncontrolled development of small-scale renewable power plants could cause disturbances in the power grid (especially in local power grids), such as outages. This is mainly due to current power grid configurations being designed to supply electricity to buildings, lightning, and other electric appliances from a centralised unit rather than locally distributed generators.

This study provides a mathematical model to optimally plan the development of renewable electricity generation in local grids. The model assesses data for a given municipality such as: the power grid configuration, the weather, the electrical consumption, and the land suitable for renewable projects. The tool's output provides the ideal allocation for renewable units in the given municipality in order to take advantage of the power grid configuration and minimize additional investments needed to upgrade the grid.

This tool could be useful for stakeholders such as the municipality board, utility companies, or grid owners to promote the development of renewable energy in their locality and reach local targets related to sustainability.

# Acknowledgments

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I also extend my thanks to Joakim Widén, Alfred Briging and Oskar Lindberg for sharing their novel contribution made in this field.

And last, but certainly not least, I would like to thank my family and friends who have always supported me unconditionally especially to Johnny.

# Nomenclature

| | |
|---|---|
| AC | Alternating Current |
| DER | Distributed Energy Resource |
| DG | Distributed Generation |
| DPV | Distributed Photovoltaic |
| DSO | Distribution System Operator |
| EU | European Union |
| GIS | Geographic Information System |
| HC | Hosting Capacity |
| HV | High Voltage |
| IEA | International Energy Agency |
| LV | Low Voltage |
| MV | Medium Voltage |
| NDA | Non-Disclosure Agreement |
| PV | Photovoltaic |
| RES | Renewable Energy Source |
| SMHI | Sveriges meteorologiska och hydrologiska institut |
| STC | Standard Test Conditions |

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# Chapter 1

# Introduction

*This chapter begins with the motivation behind this thesis in section 1.1, followed by an overview of some previously conducted research that is used in this project in section 1.2. In section 1.3 the purpose and aim of this project is presented and finally, section 1.4 provides a brief summary of the project layout.*

## 1.1. Motivation

Solar photovoltaic technology is becoming more relevant globally and continues to take up a larger share of the energy mix of many nations throughout the world. The photovoltaic sector is expected to undergo a linear growth during the coming 30 years. Currently, the global cumulative photovoltaic capacity is around 500 GW and is expected to reach 4,500 GW by 2050 [1]. In fact, solar photovoltaic is expected to be one of the main drivers behind renewable capacity additions in the coming years, especially in the field of Distributed solar photovoltaic. This is based on the *Renewables 2019* report from the International Energy agency (IEA) [2].

Governmental organizations are also developing policies and frameworks to drive the integration of renewable technologies. For example, the European Union (EU), through the European Commission, has enforced renewable energy development by enacting directive 2018/2001/EU which promotes EU global leadership in renewables with the aim of mitigating greenhouse gas emissions. This directive sets an energy target to supply at least 32% of the energy used by the member states from renewable sources by 2030, and which contains an upwards revision clause in 2023 [3].

On a national level, countries such as Sweden where around 80% of the electricity production is evenly distributed between hydropower and nuclear power, and the rest primarily between wind power and bioenergy [4], have plans to become 100% renewable by 2040 [5][6]. As part of this main goal, the Swedish Energy Agency proposes to increase the national share of electricity from photovoltaic from 5% to 10% by 2040 [7]. Currently the annual production from photovoltaic in 2017 was 0.2% [6]. In fact, there is a yearly budget of SEK 915 million to aid small-scale photovoltaic investments until 2020. In addition to this, any small-scale photovoltaic systems are eligible for the green certificate system, and in the case of microgeneration, a tax reduction system is also in place [8]. All of this support gives small-scale photovoltaic technology projects the green light to be developed on Swedish territory.

Small-scale electricity generation is connected to distribution grids in most cases, i.e. local grids with 0.4 kV and 20 kV[1], rather than transmission grids. Despite the penetration of renewable electricity in local grids helping to reach specified national targets, it can also introduce difficulties by increasing the rate of power disturbances in the grid [9]. One solution to those disturbances is to upgrade the power grid. However, these upgrades require large investments that must be incurred by the owner of the power generation unit in most cases [10]. Several studies point out that finding the optimal site for those power units could be a solution to either eradicating or minimizing these disturbances, to minimize the investment needed to upgrade the grid and help to reach national goals [11][12]. Thus, by knowing these optimal sites, the local power grid owners could run campaigns to promote them. However, in weak local grids[2], it is likely that upgrades would be needed to increase the capacity and be able to handle Distributed Generation [13]. In these cases, changes to the current model to determine which stakeholder (project owner, grid owner, etc.) must pay the

[1] In the case of local grids in Sweden [4]
[2] A weak local grid is a grid with limited capacity, and which is prone to developing problems with power quality.

costs of upgrading the grid are needed to avoid that these costs are detrimental to small-scale DG expansion. Some emerging solutions have been tested in the USA for distributed photovoltaic units [14], however more research and pilot projects need to be done in this field in order to establish a strong framework for solar photovoltaic plant planning scenarios at utility scale.

## 1.2. Previous Research

This project is based on previous research undertaken in solar planning from the Department of Civil and Industrial Engineering, Division of Civil Engineering and Built environment from Uppsala University.

The land suitability analysis of the case study used in this project was developed by Alfred Birging and Oskar Lindberg in their master's thesis called "Solar use planning for efficient expansion of solar parks" in which different photovoltaic sizes were used — 1MWp, 3MWp and 5MWp photovoltaic parks [15].

Additionally, research on maximising photovoltaic electricity injection by smart allocation carried out by David Lingfors, Joakim Widén and Jesper Marklund, was also taken into consideration for developing this thesis [16].

However, the methodology to use the hosting capacity in order to plan the integration of distributed electricity generation was first presented in 2014 in the Final Report Summary - EU-DEEP [17]. Numerous studies have been undertaken afterwards which include different methodologies based on the hosting capacity approach [18].

## 1.3. Novel Contribution

This thesis defines a computational model which could be the basis for local grid owners to identify the power capacity of their power grids. The model could also help with the planning of renewable DG in the near future by figuring out the ideal places to allocate production units – with a focus on distributed photovoltaic units. Additionally, an overview of the latest trends in grid cost allocation is provided in this report to minimise the impact of high initial costs that small-scale power plants must pay at the beginning of a project.

Other models were made previously which are based either on deterministic or stochastic methods which have studied different impacts such as voltage magnitude [19][20], losses [21][22], and harmonic voltage & current [23].

The main questions that this project aims to answer for a given local power grid are:

1. What is the maximum number of photovoltaic systems that can be connected to a specific Medium Voltage (MV) grid before violating the hosting capacity of the grid?
2. What is the optimal location for connecting these photovoltaic systems permitted by the grid reducing the possibility of violating the hosting capacity of the grid, considering the MV grid configuration?
3. What grid cost allocation between stakeholders would resource-efficient promote distributed renewable electricity production?

## 1.4. Thesis Layout

This thesis is composed of seven chapters. A detailed literature review with theoretical background is provided in Chapter 2. The background provides an in-depth overview of relevant past research and it also identifies some knowledge gaps in literature which this project attempts to assess. In Chapter 3, the description of the methodology is provided, explaining the computational model used for this study, the different scenarios which are of interest and the assumptions, limitations and delimitations made. This is followed by a description of the case study in Chapter 4. The results from simulating the different scenarios based on the data from the case study are given in Chapter 5, which are later analysed and discussed in Chapter 6, in order to answer to the research questions. Some suggestions for future work are also provided. Finally, in Chapter 7, the thesis is concluded.

# Chapter 2

# Background

*This chapter is distributed into 9 sections. Sections 2.1 -2.3, 2.5 - 2.8, cover the literature review which contains the following topics: distributed photovoltaic generation, hosting capacity, grid stability, photovoltaic smart allocation, geographic information system, Monte Carlo method and cost grid allocation. Additionally, section 2.4 provides a theoretical background to the power flow theory. The final section (2.9), gives a conclusion of the literature review done in this chapter.*

## 2.1. Distributed Photovoltaic Generation

Power grids have traditionally been designed to have large power plants connected to transmission lines on one end and electrical loads connected to the distribution grid on the other end. This network structure allows electricity to flow in one direction — from generation to consumption [24]. However, the development of new technologies used to produce electricity based on renewable resources have changed the traditional paradigm [25].

Certain renewable resources such as solar irradiation are location-dependent and are unevenly distributed around the globe [26][27]. In fact, many renewable resources follow different patterns and are based on different factors. For example, solar irradiation depends primarily on latitude, the season, the weather, the time of day, and geographical location [28][29].

Solar technologies that produce electricity, i.e. photovoltaic (PV) technologies, have a high allocation potential [25][28]. The development of PV systems in distributed grids has a wide range of size possibilities — from W to MW of power installed — which allows for them to be installed closer to the electrical load [25][29]. All of the power plants connected directly to the distribution network or the customer side of the power meter is by definition called DG [30]. Distributed Photovoltaic (DPV) generation is therefore considered to be decentralized generation and is an antithesis of the traditional centralized network scheme [29], see *Figure 1*.

Among all the different types of renewable sources, solar power is the most appealing for small power plants close to loads due to it being noiseless, generally visually pleasant, carbon footprint free when in operation, and simple to operate & maintain [25][31]. Additionally, the cost-effectiveness of this technology as well as the development of policies and frameworks that motivate the development of renewable electricity production has increased the attractiveness to invest in DPV generation[32][33][34][35].

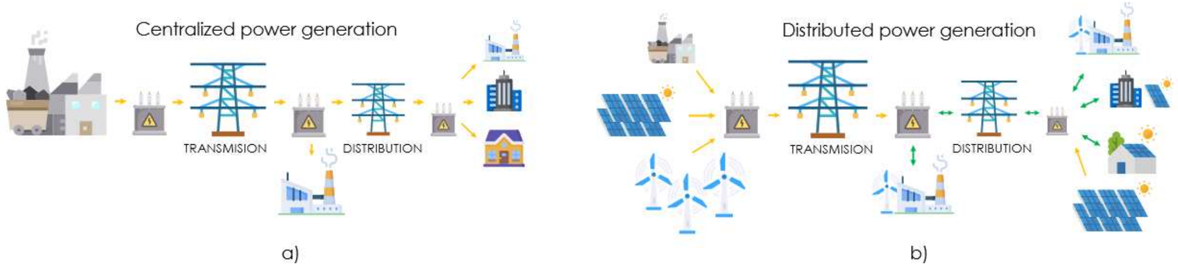



*Figure 1. Power generation configurations. a) Centralized power generation and b) Distributed power generation. Own picture taking open source icons from flaticon.*

## 2.2. Hosting Capacity

The rise of DG penetration into distribution grids allows bi-directionality of power flow within the grid, which gives rise to a number of challenges in order to maintain the power quality of the grid, see Figure 1. Power generation configurations [25][28][9].

The hosting capacity (HC) is the power capacity for producing and consuming electricity in a grid before the grid reaches its performance limit. The performance limit is determined by different risks such as: undervoltage, overvoltage, rapid voltage change, voltage unbalance, harmonics, overcurrent, and power losses [36][18][9].

Studies on grid HC have become necessary in order to understand the impact of introducing renewable electricity production into distribution grids. These studies consider different factors — for both DG units and power grids [9]:

+ Geographical data of the location of the producers, loads and the grid infrastructure (cables, substations, other ancillary, etc.).
+ Disaggregated electricity production and demand over time, i.e. load/generation profiles.
+ Technical information of the electrical equipment (voltage limits, cable length, cable reactance, grid configuration, etc.).

The results of HC calculations have high variability as determined by the input data and the method selected to perform calculations [12]. Uncertainties play an important role in HC calculations due to: the complexity of the network configuration and its dynamics; the large amount of initial data — time series of electric load and generation, location of the DG, characteristics of the components of the grid, etc. — and the intermittency of renewable resources (wind speed, sun irradiation, etc.) [36]. These uncertainties can either be uncertain events (i.e. random) or unknown (i.e. related to the theory of knowledge). Uncertain events as input values refer to the electricity demand and generation that could take a value from a span of known values. The size of the PV system and its location, which is the output of the HC study, are considered as random output parameters which are function of the input variables [18]. The selection of specific parameters and the choice of certain assumptions may be needed, and it can have a significant impact on the results. Sensitivity analysis is also used to evaluate whether additional data and mathematical models are needed [36].

There are three different methods that are primarily used to calculate the PV HC from local grids based on a literature review published in 2020: the deterministic method, stochastic method, and the time series method [18].

*Table 1. The three primarily methods to calculate the HC of a power grid* [18].

| Method | Description |
|---|---|
| Deterministic | • Traditional power system power flow analysis method<br>• Inputs are known fixed values<br>• Unknown input parameters are considered by changing values from a range of possible values.<br>• One value is obtained as the HC result<br>**Advantage**<br>• Fast method and easy to implement. Simple models.<br>• Little input data and those are readily available<br>• It is used by most DSOs<br>• Provides a quick overview of the grid performance<br>**Disadvantages**<br>• Assumes fixed values, thus does not consider the intermittency of solar source.<br>• Results are less accurate due to fixed input values<br>• The HC result is an estimate, i.e., not the true value<br>• The impact is overestimated and the HC understimated |
| Stochastic | • Includes uncertainties such as the consumption, solar irradiation, and the distribution grid data. Probability distribution functions are used to describe uncertainties.<br>• As a result, the HC result is a probability distribution<br>**Advantage**<br>• Used when uncertainties (i.e. solar irradiation) and many scenarios are considered<br>• Realistic overview of the grid performance<br>• Less time consumption when compared to time series<br>**Disadvantage**<br>• Large systems may cause excessive computational complexity<br>• Does not assess time-related grid behaviours<br>• Complexity increases with uncertainties<br>• Evaluation and interpretation of HC values becomes a difficult task |
| Time series | • Can be used for both stochastic and deterministic methods<br>• Several time-based output data<br>• The HC results are very accurate, based on the data accuracy.<br>**Advantage**<br>• Includes the time correlation in the grid, power consumption and production<br>• Considers time-related impacts on the operations of the system<br>• Realistic overview of the grid and results of HC. |

| | |
|---|---|
| | **Disadvantage**<br>• Measurement of grid parameters; requires a lot of data<br>• High number of iterations are needed<br>• Time consuming method |

The methods shown in Table 1 are based on power flow calculations used to obtain the HC values. However, they differ in terms of the data input, the accuracy of the results, the computational time, the consideration of uncertainties and the consideration of the time influence and the models used [18].

Some results from HC studies show that grids with PV systems clustered far from substations are prone to developing low HC and high costs, however, Distributed Energy Resources (DER) systems connected closer to substations or spread out evenly throughout the feeding station have a higher grid capacity limit [37][10]. Additionally, other factors such as the configuration of the grid and the location of electrical loads can also have an impact on the HC results [10].

The improvement of the HC in distribution grids depends on different factors [11][12]:

+ Reinforcement of the power grid. Installation of new equipment or upgrades to existing equipment (substations, cables, reactive power compensators, tap-transformers, smart inverters);
+ Integration of electrical storage systems;
+ Increase of power grid control;
+ Control of DG (transmission line, loads and generation);
+ Smart allocation of DG, see section 2.5.

By knowing this limit, grid owners can get an understanding on how many DG units the existing grid can handle without additional capital investments [38]. Additionally, the studies can provide information on how to plan the expansion of the future changes to the power network in a smarter way [18][39].

## 2.3. Grid Power Quality

The power quality concerns the electrical interactions between the power grid and the electric loads or electric generation connected to it. The power quality is key in understanding the concept of HC as it considers the voltage quality and the current quality [40]. In local power grids with high RES penetration inverters and storage systems can locally enhance the grid quality [41]. Bad power quality in a system can be detrimental for the electrical units connected to the grid. These negative effects can be harmonics, slow or fast voltage variations, voltage dips, voltage swells or interruptions [42].

The Standard EN 50160 is a guideline on voltage characteristics in public distribution grids that is widely used in various European countries. This standard provides a table of the main voltage parameters and their admissible deviation ranges for Low Voltage (LV) (less than 1kV) and MV (between 1 kV and 35 kV) electricity distribution systems in normal operations. This standard mentions that the voltage magnitude variation in LV, MV should be ± 10% for the 95% of the week considering 10 minutes of root mean square (rms) values. Despite there is not a clear value on how much the percentage should be shared between the LV and MV power grid [43].

## 2.4. Power Flow Theory

As shown in section 2.2, studies on HC are based on the behaviour of the entire power system — including grid infrastructure, loads and generation. Power flow calculations provide an understanding of the power grid dynamics under balanced three-phase steady state conditions. Steady state conditions are ruled by the following principles [44]:

+ The generation overcomes the demand and the losses of the system,
+ Bus voltage magnitudes are close to rated values,
+ Generator operation has active and reactive power limits,
+ There are no overloaded transmission lines, nor overloaded transformers.

This method is widely used for existing power systems and also for proposed changes such as including new generation and changes in the transmission lines [44].

These calculations consider four variables for each bus $k$ integrated into the power system: voltage magnitude $V_k$, voltage phase angle $\delta_k$, net active power $P_k$ and reactive power $Q_k$. Power flow computations need at least two of these variables as input data in order to calculate the rest of the variables.

One can identify three different types of buses:

+ *Slack bus*. This bus is considered as the reference bus and there is only one in the entire system. It typically takes a value of 1.0 ∟0° per unit. From power flow computations its active and reactive power are calculated.
+ *Load bus*. $P_k$ and $Q_k$ are input data; from power-flow computations the $V_k$ and the $\delta_k$ of the load buses are calculated.
+ *Voltage controlled bus*. Bus in which $P_k$ and $V_k$ are known; the power flow program computes $\delta_k$ and $Q_k$. A good example of this type of buses is a bus with a tap-changing transformer connected to it.

A bus can be depicted in a single-line diagram as shown in Figure 2. Where on one side there is the power load & power generation, and the transmission lines on the other side.

Generators and loads connected to the bus are considered to be power sources and power sinks, respectively. The net active and reactive power of a bus is composed by the sum of active & reactive generation and active & reactive consumption. The signs are determined as follows for active & reactive power: buses with no generation have negative values for their active power and reactive power takes negative values for inductive loads.

$$P_k = P_{gen,k} - P_{load,k} \quad 2.4.1$$

$$Q_k = Q_{gen,k} - Q_{load,k} \quad 2.4.2$$

Transmission lines are the links between buses and are represented by their equivalent π circuit. Technical features of the transmission lines are given by their admittance $Y_{kn}$ and the corresponding phase angle.

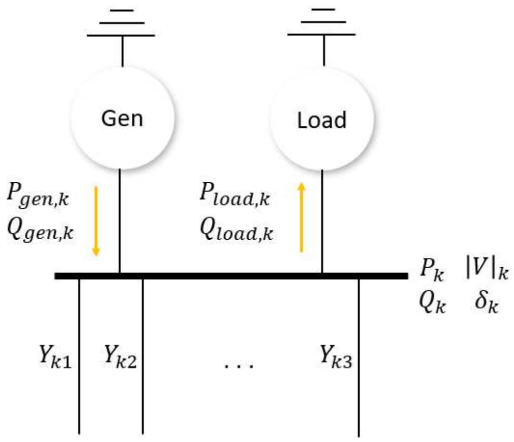



*Figure 2. Scheme of power-flow problem. Single-line diagram of a bus with power generation ($P_{gen,k}$ and $Q_{gen,k}$) and power demand ($P_{load,k}$ and $Q_{load,k}$), with the sum of both reactive and active power ($P_k$ and $Q_k$)and its voltage and phase angle ($|V|_k$ and $\delta_k$) interconnected with the rest of the power grid by transmission lines.*

Power-flow problems use the power flow equations which follow the principles of Kirchhoff's laws. These equations are used in systems with a large number of load buses, as the voltage magnitude and the phase angle are unknown variables. Nevertheless, a slack bus is needed as a reference bus to perform a calculation in which voltage magnitude and phase angle are known [45][46]:

$$P_k = \sum_{n=1}^{N} |Y_{kn} V_k V_n| \cos(\delta_{kn} + \theta_n - \theta_i) \qquad 2.4.3$$

$$Q_k = -\sum_{n=1}^{N} |Y_{kn} V_k V_n| \sin(\delta_{kn} + \theta_n - \theta_i) \qquad 2.4.4$$

*k=1,2 ,...,N*

This leads to a system made up of nonlinear algebraic equations. An effective method used to solve the power-flow problem is Newton-Raphson's method; the unknown voltages can be approached as roots of the mismatch equations.

$$\Delta P_k = P_k - \sum_{n=1}^{N} |Y_{kn} V_k V_n| \cos(\delta_{kn} + \theta_n - \theta_i) \qquad 2.4.5$$

$$\Delta Q_k = Q_k + \sum_{n=1}^{N} |Y_{kn} V_k V_n| \sin(\delta_{kn} + \theta_n - \theta_i) \qquad 2.4.6$$

In this problem, the value for the slack bus is already known, therefore it can be solved by iterating the following steps[44]:

**Start at *ith* iteration**

$$\begin{pmatrix} \frac{\delta(i)}{|V|(i)} \end{pmatrix} \tag{2.4.7}$$

**Step one** Compute:

$$\begin{pmatrix} \Delta P(\delta(i), |V|(i)) \\ \Delta P(\delta(i), |V|(i)) \end{pmatrix} = \begin{pmatrix} P - \ P(\delta(i), |V|(i)) \\ Q - Q(\delta(i), |V|(i)) \end{pmatrix} \tag{2.4.8}$$

**Step two** Calculate Jacobian matrix:

$$J = \begin{pmatrix} \frac{\partial \Delta P}{\partial \delta} & \frac{\partial \Delta P}{\partial |V|} \\ \frac{\partial \Delta Q}{\partial \delta} & \frac{\partial \Delta Q}{\partial |V|} \end{pmatrix} \tag{2.4.9}$$

**Step three** Use Gaussian elimination and back substitution to solve:

$$(J) \begin{pmatrix} \frac{\Delta\delta(i)}{\Delta|V|(i)} \end{pmatrix} = \begin{pmatrix} \Delta P(\delta(i), |V|(i)) \\ \Delta P(\delta(i), |V|(i)) \end{pmatrix} \tag{2.4.10}$$

**Step four** Compute:

$$\begin{pmatrix} \frac{\delta(i+1)}{|V|(i+1)} \end{pmatrix} = \begin{pmatrix} \frac{\delta(i)}{|V|(i)} \end{pmatrix} + \begin{pmatrix} \frac{\Delta\delta(i)}{\Delta|V|(i)} \end{pmatrix} \tag{2.4.11}$$

The computation iteration continue until the mismatch either converges to a solution or a maximum number of iterations ($i_{max}$) is reached. The convergence criteria is more often due to power mismatches $\begin{pmatrix} \Delta P(\delta(i), |V|(i)) \\ \Delta Q(\delta(i), |V|(i)) \end{pmatrix}$ than voltage magnitude and voltage magnitude mismatches $\begin{pmatrix} \frac{\Delta\delta(i)}{\Delta|V|(i)} \end{pmatrix}$ [44].

## 2.5. Photovoltaic Smart Allocation

Previous studies have shown that DG location has an impact on the HC [12]. DG can be located without negatively affecting the power system by developing HC maps which consider low-cost and low-impact locations for DER systems [10][37][14]. In fact DER systems can contribute noticeably by increasing the HC of the power grid [47].

When it comes to defining the decision-making techniques applied to obtain the optimal DG allocation, there is not a consensus on local grids [9]. However, different studies show that all available data must be used to obtain the best results for optimum operation of the power grids, and thereby assess the reliability of the power grid and identify the problematic points [24].

The DER smart allocation naming seems to not have a consensus from the different references reviewed. An article written by Swedish researchers uses this smart allocation naming [16]. However, additional names were found in the sources reviewed such as: optimal PV-DG allocation [29], optimal allocation of renewable energy sources (RES) [48], optimal photovoltaic grid connected systems allocation [49] or PV capacity allocation [50]. Despite the fact that the idea of smart allocation is reflected in the literature, a clear definition is evidently not available. In this report a definition is provided which takes into account the main idea that was discussed in the reviewed literature. As such the PV smart allocation is the optimal placement of DPV systems connected to a known power grid after studying the optimal configuration to reduce the chances of violating the HC of the entire grid system without the need of grid reinforcements.

The study of smart allocation allows power grid owners to foresee the most appropriate way of allocating DG plants based on the configuration of the power grid. This has different benefits to the Distribution System Operator (DSO): planning of grid upgrades that benefits the entire system [47], a faster integration of RES without compromising the power quality of the grid and reducing delays due to unnecessary works on upgrading the grid [11]. However, DSOs have limited authority when deciding the future allocation of new loads and DER plants. In most cases, there exists a compromise between the best RES power production allocation and the costs to ensure the stability of the grid [39]. Finally, it is important to note that smart allocation is directly related to the size of the DPV system.

## 2.6. Geographic Information System

A Geographic Information System (GIS) is a powerful tool capable of capturing, storing, managing, analysing, and presenting many types of geographical data. These geographical data are linked to locations on earth. The main use of GIS is to map out the allocation of physical units or events, to map out quantities or densities, to allocate specific features inside an area, to identify nearby objects, and mapping changes [51].

Strategic energy planning must consider geographical restrictions as well as the available resource which are both location dependent. Therefore, geographical data are key in studying the smart allocation for PV DG [27]. A decision-making model based on GIS with multicriteria allows the optimal location for PV systems to be determined. Some of the advantages for including GIS in solar projects are: to maximise the electricity generation from the PV park based on optimal weather conditions; find the optimal orientation of the solar panels; minimize the losses from power transmission lines by considering suitable sites nearby to the power grid; reduce environmental, social and infrastructural impacts; and exclude non-available land from the area of study [52].

## 2.7. Monte Carlo Method

The Monte Carlo method is a stochastic optimization method which approximates a deterministic quantity by repeatedly using random values [53]. It is considered a stochastic optimization method as it uses a combination of random values from a range of possibilities to obtain the results.

The Monte Carlo strategy in computational algorithms is widely used as an appropriate method for analysing the dynamic uncertainties of a complex system [54]. A power distribution grid is a good example of such a complex system with many degrees of freedom due to the large number of elements that constitute the grid — loads, generators, grid components— which contribute to the power flow fluctuations.

Different studies on HC and optimal DG allocation use the Monte Carlo Method as base of their probabilistic power flow method [36][18][38][55][56]. This type of study consists of simulating random placement of DG systems connected to the power grid in an iterative manner and calculating the HC of the grid. This is followed by a sensitivity analysis from the resulting probability distribution to conclude on the best placement of the RES systems [52][55].

## 2.8. Grid Cost Allocation

The current trend to generate electricity closer to the demand side involves in most cases the connection of distributed electricity generation into the distribution power grid. The designs of current power networks can bear a certain amount of installed capacity of DG before the grid's HC is violated. Before reaching this undesired state, the grid owner needs to upgrade the power grid to ensure a certain level of network power quality. In the majority of cases these system upgrades involve large capital investments as a result of grid reinforcements, new distribution lines and new electrical equipment [57][58][39]. In fact, the rapid growth of DG gives rise to an emerging issue which is how the distributed system costs should be allocated between different stakeholders [47].

The common procedure, followed by most European countries, for requesting a connection point to the power grid, requires the plant developer to send an application to the system operator. If the technical requirements of the electrical system are not adequate to undertake the coupling, then the grid operator proposes the required upgrades/changes needed to move forward with the connection application. However, when it comes to overcoming the grid connection costs there are different approaches based on how the grid costs[3] are allocated between producers, in this example wind power parks, and DSO [59][39], see Figure 3 [60]:

+ *Super-shallow approach.* the grid owner pays for all costs except those related to the inner electrical infrastructure, which also includes the costs of the power substation.
+ *Shallow cost approach*. The RES plant owner pays the costs of the equipment to connect the RES plant to the existing power grid; additionally, the grid owner makes the investment to upgrade the power grid.

[3] Notice that grid connection costs do not include the operation and maintenance grid costs [39]

+ *Mixed Deep-Shallow approach.* This approach covers the shallow cost approach conditions and some of the costs for the reinforcement of the grid which are shared with the grid owner.
+ *Deep cost approach*. In this case, the RES plant owner bears all the costs for the connection to the grid and any other costs associated with grid upgrades.

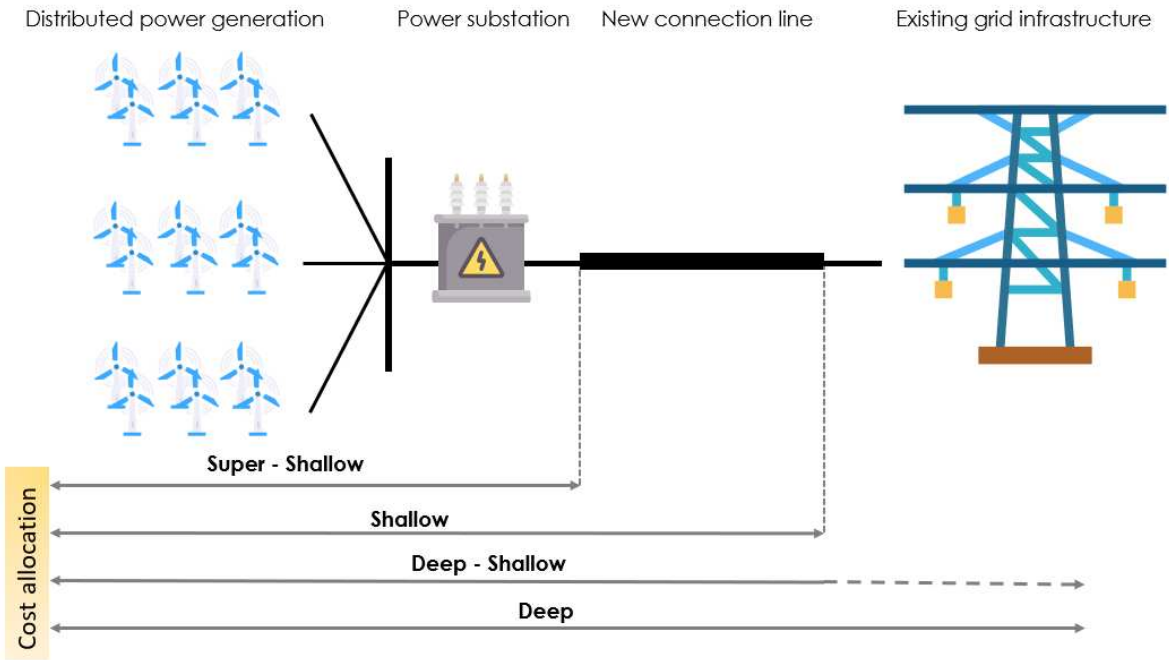



*Figure 3. Cost allocation strategies. Figure based on image from source* [59]

Sweden is currently using a deep cost approach for the transmission network – The RES plant developer pays the grid connection costs, as well any related grid upgrade costs if the production plant is the only beneficiary of the network upgrade. However, this is different for smaller either producers or consumers (16 – 25 A) that want to connect to the grid such as a family house, in the cost to connect to the grid are split by a fix cost and a variable cost based on the distance between the electrical unit and the power grid [61].

However, for the distribution network the charge varies depending on the connection point [59]. In some cases large DPV systems incur associated grid costs, while for small DPV it is the utility company who pays the costs [10].

The cost causation principle can be detrimental for DER projects. DER plants are more susceptible to the increase of initial investment compared to conventional power plants. This could be especially unfair if the cost of the whole grid upgrade is paid by one producer, when the upgrade could also be beneficial to other agents connected to it (Other future producers, consumers, etc.) [14][59].

Therefore, one of the biggest challenges is how to estimate the costs caused by DERs plants in order to allocate costs fairly between different power plant projects. The following list shows some emerging solutions implemented by some US of America utilities, however they are still in an early stage of development. [14][62]:

I. *Group Study/Group Cost Allocation.* Multiple DG project applications are clustered and studied at the same time. The costs calculated for upgrading the grid are prorated and spread across all the projects. The grid connection costs are paid upfront the plant deployment.
II. *Cost-causer post-upgrade cost-sharing allocation*. Based on the deep cost approach, see Figure 3, in which one stakeholder pays the upfront costs for upgrading the grid. However, the main difference is that for each new DG connected to the grid, the original payer gets a reimbursement for each of the new stakeholders connected to the same grid.
III. *Utility prorated cost-sharing allocation*. In this case the utility pays the costs in advance of the grid upgrade once a DG project trigger an upgrade of the grid. Then the utility prorates the costs of the upgrade to reimburse the money from the DG power installed.
IV. *Pre-emptive Upgrade Cost Sharing.* The utility pays for the initial investment, but in contrast to the previous case, the utility pre-determines the locations where the network will be upgraded and sets a marketing campaign. The costs are prorated among the projects connected taking the size into consideration.

All these approaches involve the power plant owners to pay the grid costs, however in case the payment is prorated between the rest of the stakeholders interested in connecting their own power plant to the grid. Therefore, not only one stakeholder must defray all the costs for upgrading the grid.

The advantages and disadvantages between the emerging solutions listed above are shown in Table 2. All of them present advantages on cost allocation equity, however what differentiates them are mainly the disadvantages and how they affect the different stakeholders. For example, for small-scale project, the groups cost allocation solution could present advantages at the start of the project because of reducing the initial investment, however the project could easily suffer delays. On the contrary, pre-emptive upgrade cost-sharing cost allocation might be a better solution for this type of projects although it could be detrimental for grid owners since they could collect a debt.

*Table 2. Emerging solutions for grid cost allocation* [14]

| Method | Advantage | Disadvantage | Examples of usage |
|---|---|---|---|
| Cost-Causer Pays (traditional method) | • Straightforward procedure to connect the DG plant | • Detrimental for small DERs plants<br>• No cost sharing | • Traditional approach |
| Groups Study/Group Cost Allocation. | • Cost allocation equity from the beginning | • Slow interconnection process<br>• Recalculations due to changes in DERs plants applications | • California Independent System Operator<br>• Other USA system operators |
| Cost-causer post-upgrade cost-sharing allocation | • Cost allocation equity | • First project has a high investment impact. Detrimental for small projects<br>• Delays on coupling small power plants | • New York Public Service Commission |
| Utility Prorated Cost Sharing | • Beneficial for DERs power plants, especially small capacity projects | • Risk of not having cost equity due to lack of DERs projects<br>• Delays on coupling small power plants | • HECO (Hawaiian Electric Companies) |
| Pre-emptive Upgrade Cost-Sharing Allocation | • No delays for the first DERs coupled | • Cost recovery risk for consumers | • Pilot run by USA National Grid |

# 2.9. Conclusion of Literature Review

The emerging interest in renewable electricity production in distribution grids has raised different challenges in the power grid itself. Throughout the last decade studies on understanding how DPV affects current power grid design and how this knowledge can be used to develop the grids of the future in a smart and efficient way have become relevant in both the research community and in the development of the energy strategies for different nations.

However, there is still not an answer to many of the problems that have arisen in relation to this topic. A number of knowledge gaps were uncovered in the literature review when it comes to understanding how to implement a fair method for allocating the grid connection costs between the different stakeholders without being detrimental to the PV DG development.

# Chapter 3

# Methodology

*This chapter provides the methodology used in this study. Section 3.1 details a description of the model. This section is followed by the definition of the different tasks considered in section 3.2. Finally, the assumptions, limitations and delimitations are found in section 3.3, section 3.4 and section 3.5, respectively.*

## 3.1. The Computational Model

The study of the PV smart allocation is based on HC calculations for a given power grid. The model developed in this study follows a deterministic approach based on the Monte Carlo method. This consists of randomly placing one or several PV parks into different nodes[4] of the power network based on the available land. For each PV park placement, the model computes the power flow of the power grid and as a result provides information on whether the HC was violated or not. Additionally, this model consists of a time series method which provides reliable and accurate results (see, as a reference, Table 1). One can see in Figure 4 a sketch of the model on a high level showing: the inputs (i.e., power grid data, loads data, land data and DG data; the main mathematical models to calculate the PV power generation, the availability of

[4] A node is understood to be any substation with transformers from MV to LV.

land, the power flow dynamics and the assessment of the HC; and, as output the ideal allocation of the PV parks.

This model considers the variables shown in Table 3 as inputs. Inputs such as solar irradiation and active & reactive power should be a timeseries of the period and resolution, i.e., days, hours, minutes.

*Table 3. Inputs of the computational model for this study*

| Data | Details |
|---|---|
| Power Grid | • Substations/buses: ID, location, transformation voltage<br>• Transmission lines: length, area, admittance, max. admissible current, max. admissible voltage, ID of connection points |
| Loads | • Active and reactive power |
| Land | • Size and location |
| Generators | • Solar irradiation, power factor, optimal PV module tilt, optimal orientation, latitude, size of the PV plant |

This model is run iteratively for a predefined number of iterations. The results are analysed by employing probability distributions from the output of all the simulations. This allows for the identification of nodes which are the best to couple PV systems to for the given power grid.

MATLAB[5] [63], was used to develop the computational model for this study as it can handle large amounts of data and computations. In addition, it is widely used in these types of studies.

[5] Version: Matlab 2018b

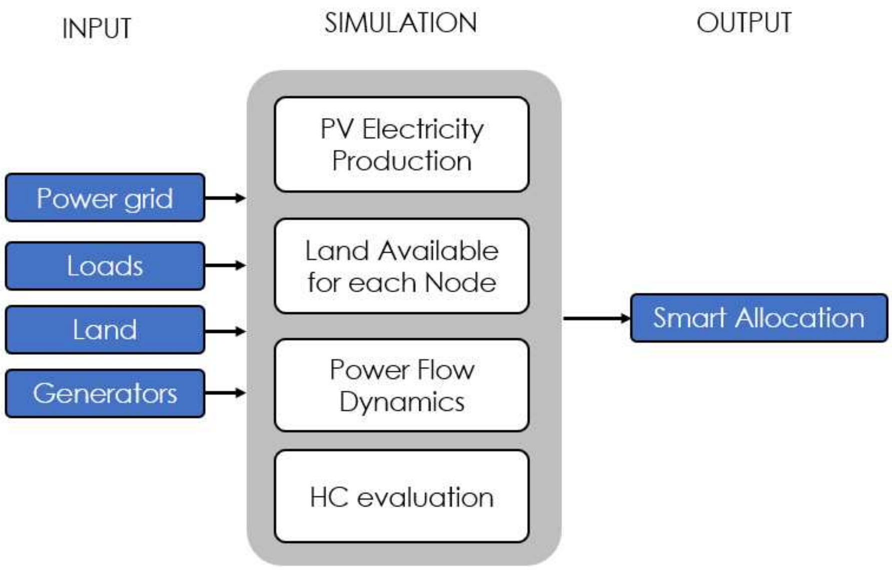



*Figure 4. High level diagram of the model*

### 3.1.1. Solar Electricity Production

The solar electricity production model outputs the electricity that is generated from a PV system considering different input data such as: the solar irradiation, the tilt of the PV modules, the location of the PV system (latitude and longitude), and additional PV system parameters (system efficiency, area of the module, number of modules, etc.). A complete PV model is provided from J.Widén, 2009 [64], the model calculates the radiation components onto the plane of the PV modules.

$$I_T = I_{bT} + I_{dT} + I_{gT} \qquad 3.1.1$$

The incident global radiation on the tilted surface ($I_T$) is composed by three different components. $I_{bT}$ and $I_{dT}$ are the beam and diffuse radiation on the tilted plane respectively. The last factor is defined as the ground-reflected radiation ($I_{gT}$) and it refers to the numerous objects that reflect incident radiation, such as buildings. The albedo values are used for the calculation of this last component.

As the simulation can use different time periods of the year, the model needs to consider solar time as opposed to standard time zones given that most meteorological data are given using this type of time standard [46].

The PV power production by the solar park is calculated using a simple model that considers the surface of the PV module ($A_{pv}$), the number of modules ($N$), the incident global radiation on the tilted surface ($I_T$), the efficiency of the modules ($\eta_{PV}$), and the efficiency of the system ($\eta_{syst}$) which includes the efficiency of the inverters and cables. See equation 3.1.1.

$$P_{pv} = A_{pv} N I_T \eta_{PV} \eta_{syst} \qquad 3.1.2$$

Figure 5 graphically represents the solar electricity production model described above.

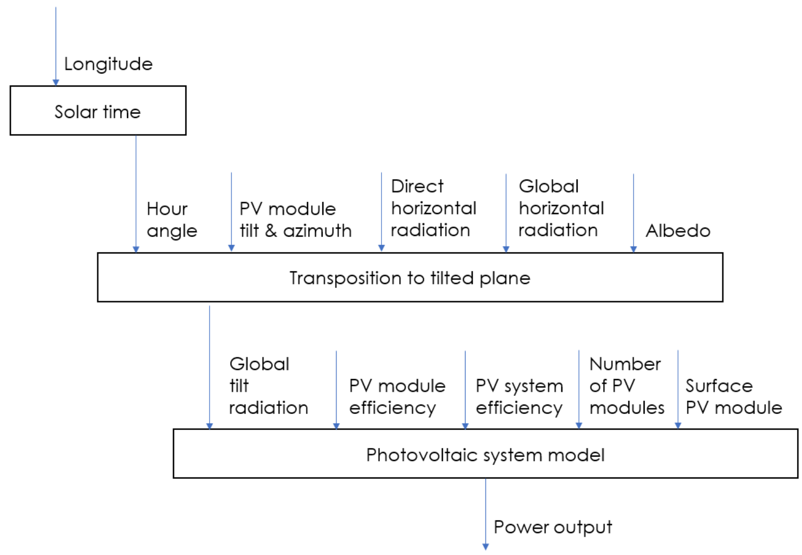



*Figure 5. Solar electricity production model layout. Figure inspired by graph shown in* [64]

All PV system used in the model use the same principle and are described by the data shown in Table 4.

*Table 4. PV system characteristics used in the computational model.* [64]

| Description | Value |
|---|---|
| Longitude [°] | 13.02 |
| Latitude [°] | 58.08 |
| Solar albedo [-] | 0.30 |
| Panel Rated Power, $P_{STC}$* [Wp] | 300 |
| Panel tilt [°] | 40 |
| Panel azimuth [°] | 0 |
| A [m$^2$] | 2 |
| PV module efficiency | 0.17 |
| PV system efficiency [-] | 0.80 |

* $P_{STC}$: Power of Standard Test Conditions (1000 W/m$^2$ , 25 °C, AM 1.5)

### 3.1.2. Hosting Capacity Computation

HC studies involve a high degree of uncertainties as mentioned in section 2.2. For this reason, several constraints are set up in the model to ensure that the simulations converge and provide reliable results.

The HC calculations depend directly on the power flow dynamics of the power grid. The model used in this study runs a power flow analysis every time a new PV park is coupled to a node of the grid. The model considers, as a slack bus, the substation which connects the distribution grid to the transmission grid. The number of iterations were limited to 1000. Once the $V_k$ and the $\delta_k$ for each bus is calculated, then currents are also obtained. Notice that this model does not consider voltage control buses.

The HC in this model is analysed based on the overvoltages and overcurrents detected in the grid. The evaluation of overvoltages is done for each node and the overcurrents for each line of the power grid. The overvoltage limit is determined by the parameters considered to maintain the power quality of the grid, explained in section 2.3 The voltage deviation should be within 10% of the rms voltage at the customer side, based on Standard EN 50160 [43]. To give room for additional deviations in the LV grid (400V), a stricter limit must be set in the MV grid. A Swedish industry standard is 2.5%, however 3% was finally used after discussion with the DSO of the case study [15]. This percentage is called $\%_{MV}$ in this report. The overcurrent limit is based on the maximum current allowed by the transmission lines, defined by their electrical characteristics.

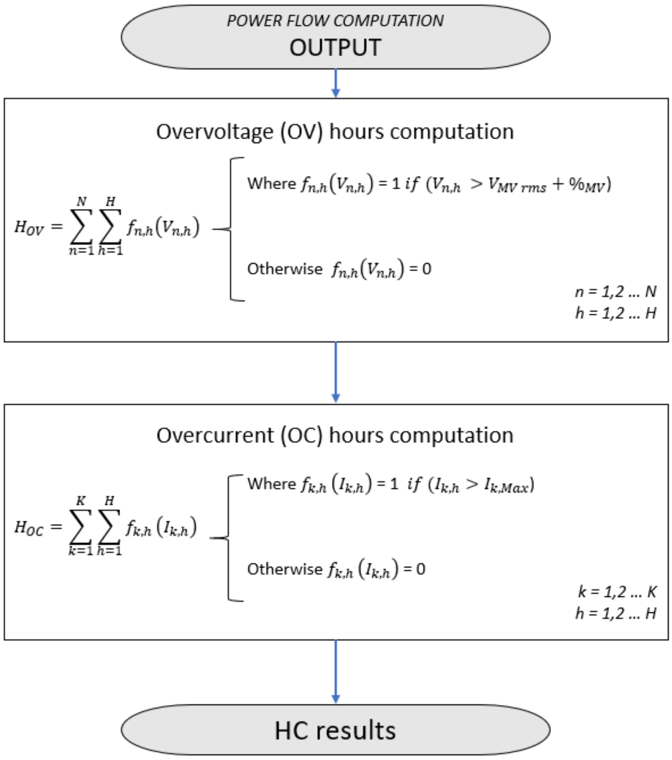



*Figure 6. Flowchart of the HC model used in this computational mode to find hours of overvoltage ($H_{ov}$) and overcurrent ($H_{oc}$). N is the number of nodes of the power grid; H, the number of hours simulated; K the number of cables.*

## 3.1.3. Photovoltaic Park Allocation

In this study the localisation of the PV parks considers the geographical position of the network substations and the available land in the given area of study.

Land surrounding the power grid is evaluated in terms of its suitability for PV parks. To study the suitability of the land, two factors are considered: the land use and the size of the PV park. For the first factor, a land use analysis is conducted to identify whether the land can be used to build a PV park on. A good example of suitable land is land that cannot have any other future purpose, such as waste facilities or landfills. Pastures and strips of land can also be considered suitable for these type of projects. However, this categorization can vary depending on the regulations that are in place [15]. The area of the land is also important when determining whether it is suitable for a given PV park size or not. In this case a standard PV module (1956 x 992 mm) is used to determine an approximate surface area for a certain size of PV park [65] — the area occupied by PV panels determines the PV park power capacity. Lands with equal or higher surface area than that of the surface area of a given PV park size are considered to be suitable land in this study.

The distance between the PV park and the substation is also of interest. As discussed in section 2.2 the closer the PV park is to the substation, the higher the possibility is that the HC limit is enhanced. For this reason, only lands surrounding the substation are target lands to deploy PV parks onto.

Thus, the model considers of available lands close to each substation in the local power grid. Once a piece land is used, it is removed from the list of available land. If the randomly selected node has no-available land nearby, then the model randomly picks another substation until it finds available land sufficiently nearby.

## 3.2. Task Definitions

This thesis aims to study three different cases: (1) the possibility of connecting a PV park to the grid (section 3.2.1) 3.2.3, (2) the maximum HC of a given grid (section 3.2.2), and (3) the grid cost allocation (section 3.2.2).

### 3.2.1. Task 1: Possibility of Connecting a PV Park to the Grid

This task shows what happens when PV parks are placed in a grid without considering the power grid's strengths and weaknesses. This case shows what is commonly happening today's PV park allocation mainly depends on the decision made by the owner of the park. Notice, that this decision can be influenced by the grid costs depending on where the PV park is located. Given this assumption, the aim of this case is to analyse those nodes in the grid which are prone to violating the HC. On the contrary, to identify those nodes which can accept PV systems without deteriorating the quality of the grid.

The simulation consists of placing one PV park at the time, connected to a randomly given node (from a list of available nodes) of a power grid if the HC is not violated, it will continue adding PV parks to random available nodes until the HC of the grid is violated at any point of the grid. When that point is reached, the simulation stops.

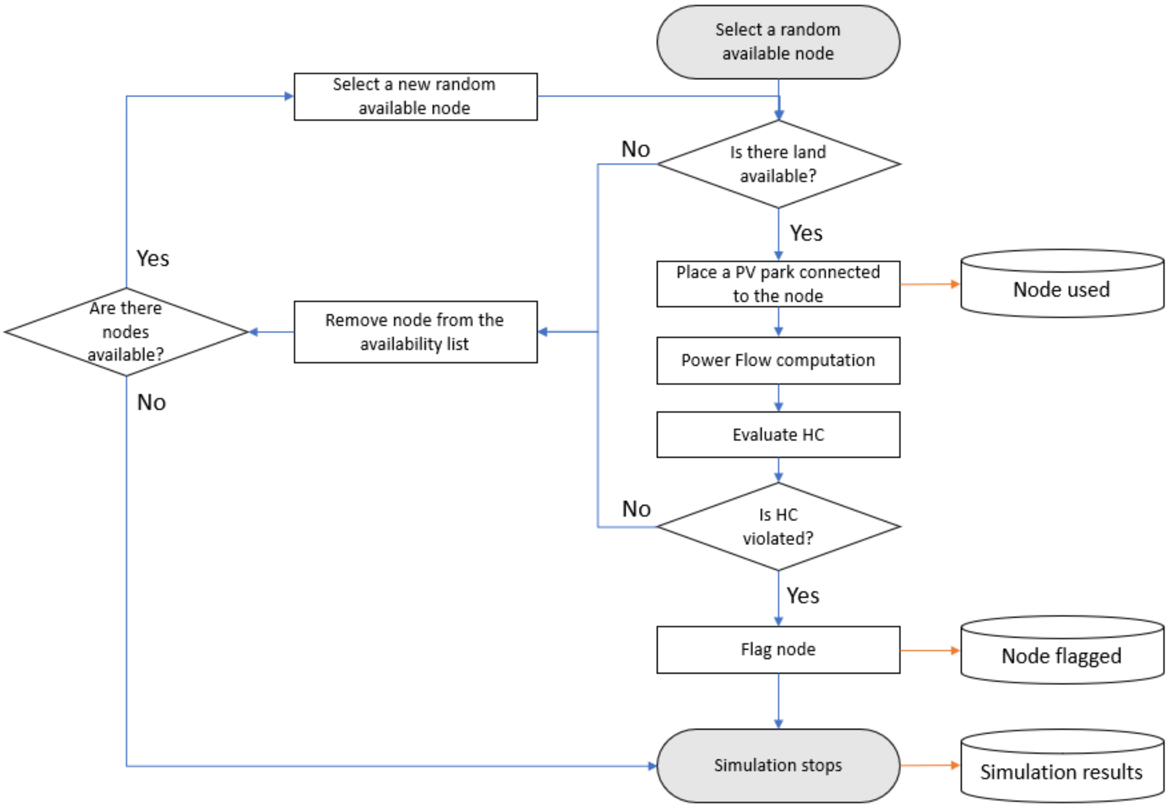



*Figure 7. Flowchart of the task 1 model. This model is run iteratively based on the number of iterations set.*

The model integrates a random function to ensure the randomness of selecting different available nodes in each iteration for this task and the following tasks.

### 3.2.2. Task 2: Maximise the Hosting Capacity of the Entire Grid

In this second task, the aim is to analyse the maximum capacity of a given grid to host a large number of PV parks before the HC is violated. This task evaluates where the best area is to connect the maximum number of PV parks in the current grid before undertaking any type of upgrade.

The simulations will randomly place one PV park at a time. If the HC is violated in any node, then the latest PV system added is removed; the substation used, and the neighbouring affected substations are flagged. A flagged substation will not be used during the rest of the simulation. A new (un-flagged) node is then picked at random, and the process of connecting a PV park is repeated until all nodes in the grid are either used or red flagged, then the simulation stops.

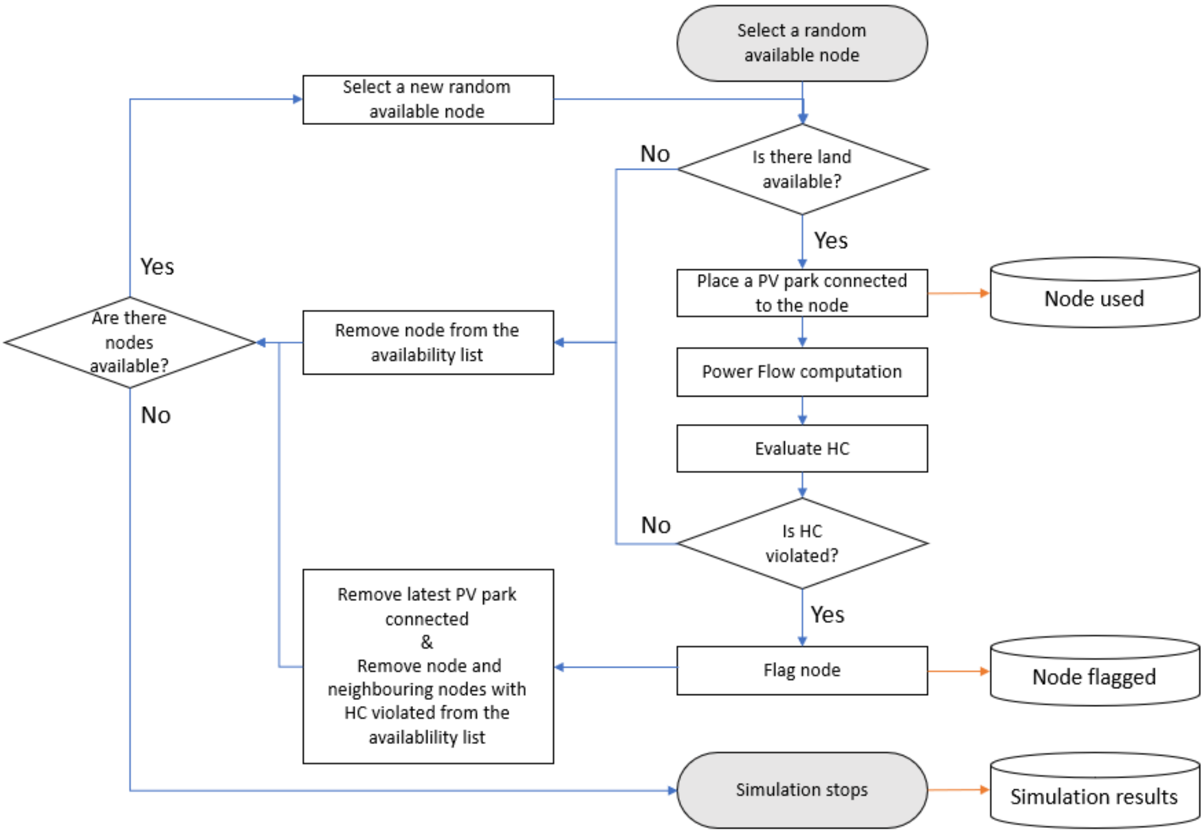



*Figure 8. Flowchart of the task 2 model. This model is run iteratively based on the number of iterations set.*

### 3.2.3. Task 3: Grid Allocation Cost

This final task studies what would happen if there were a fixed number of PV parks randomly placed in the local grid. This number could correspond to a local or EU goal to reach a certain amount of solar based power. This case aims to identify the average number of areas where reinforcement of the grid is needed in order to host all of the parks. This can also provide a guideline to grid owners on where investments need to be made to meet that goal.

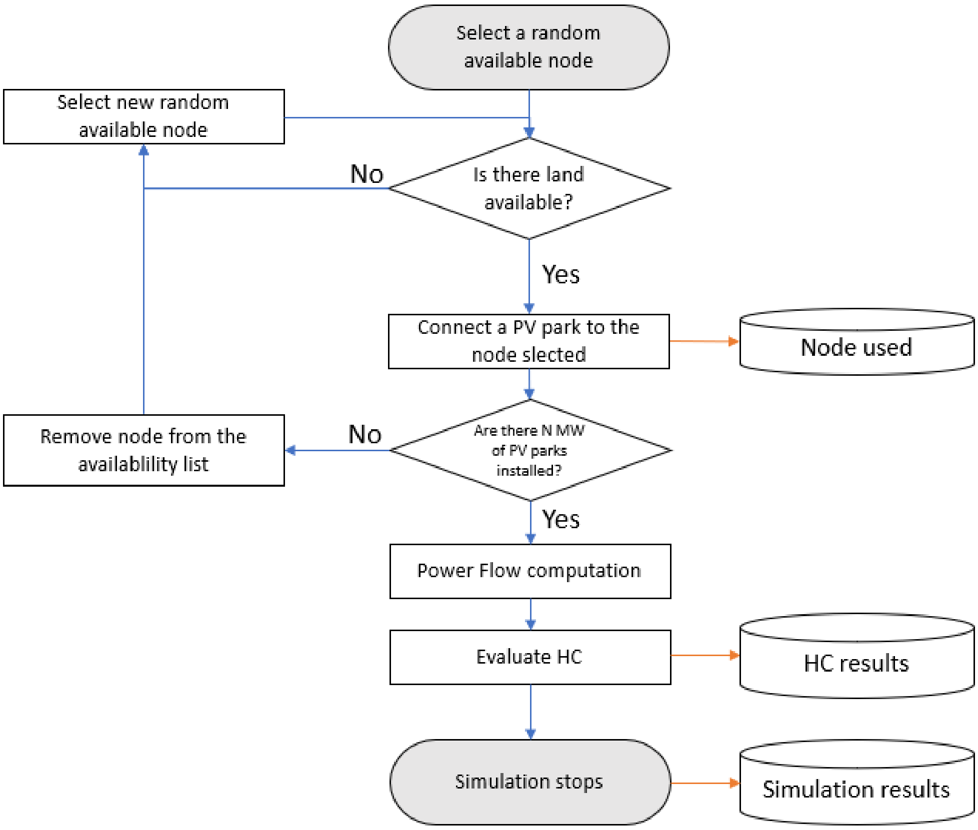



*Figure 9. Flowchart of the task 3 model. This model is run iteratively based on the number of iterations set.*

Considering the data provided by the case study, explained later in chapter 4, the electricity consumption is roughly 75 GWh in 2018, of which 50 GWh electricity consumed in the Herrljunga grid and 25 GWh in the Ljunga-Annelund grid. The equivalent installed PV capacity to reach the 5% to10% goal (mentioned in section 1.1), should be between 4 MWp to 8 MWp, distributed evenly between both grids; 3 - 5 MWp DPV for Herrljuga power grid and from 1 - 3MWp DPV for the Ljung-Annelund grid. These values were calculated considering the PV system data provided in Table 4 and the irradiation data for this area.

This task compared to the previous ones connects randomly a number of PV parks at the same time — each PV park size is the same, 1 MWp. The number varies depending on the grid and the goal established for the simulation, either 5% or 10% goal. For example, for 5% goal there are 4 PV parks connected to Herrljunga grid at the same time in 4 random nodes.

## 3.3. Key Definitions

Due to the large amount of data used in this model, some assumptions were considered.

+ *Number of iterations for each task*. In this study, the number of iterations was chosen to be1000 iterations. This was found to be reasonable based on the literature [66][67].
+ *Overvoltage limit*. The overvoltage limit is selected based on the Standard EN 50160 [43]. The set overvoltage limits are regulated with regards to 10 min average, while the data used for this study is on hourly basis. The overvoltage limit is then set to 3% of the nominal voltage of the grid, based on the discussion with the DSO [15].
+ *Electric cable from PV park to substation.* This cable is not considered in the simulations to simplify the model, as the maximum distance between the land and the substation is short enough and the cable can be dimensioned so to that it will not have a relevant impact on the HC calculation.
+ *Land distance to node.* The maximum distance from the substation to the available land was fixed to 3000 m. This was based on a study undertaken to analyse the correlation between the number of PV parks that the power grid can host and the land availability in the municipality depending on the distance between the land and the substation.

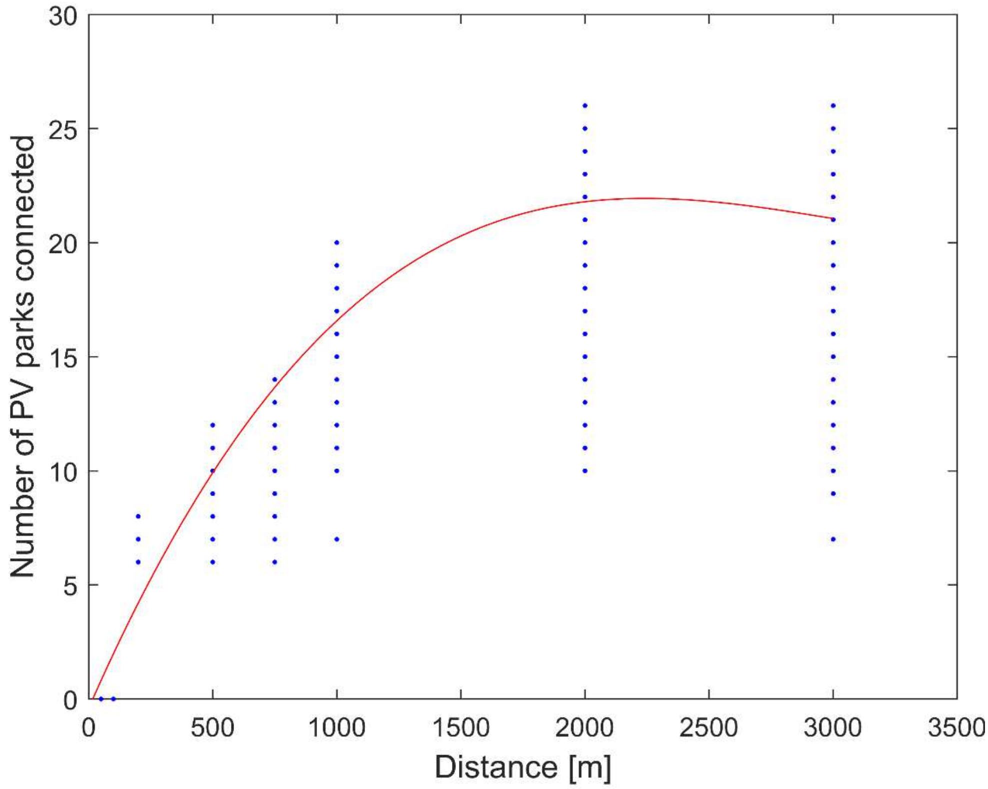



*Figure 10. Correlation between the maximum distance between the available land and the substation vs the number of PV park (1 MWp size) that the power grid can host based on task 2. The blue dots represent the results provided by the given simulation (1000 iterations) for different distances. The red line shows the 3rd degree polynomial curve based on the median results for each distance assessed.*

# 3.4. Limitations

Some limitations were found while designing the model used in this study. They are shortcomings, conditions or influences that cannot be controlled and therefore introduce uncertainties in the model. Those limitations are listed as follows:

+ *Computational time*. Due to the large amount of data and the iterative process used in the power flow calculations the computational time was an issue. In order to reduce the computational time, the following adjustments were made:
    - Flag only affected neighbouring nodes of a node with a PV park that has induced the violation of the HC. Therefore, all the neighbouring nodes that were still available will instantly be removed from the availability list.

- Avoid hours of simulation in which there is no solar irradiation, thus, no power generation.
- Reduce the simulation time to analyse only the maximum solar irradiation week or day of the year. For task 1 and task 3 the simulation is undertaken in week 26 since it is the week with highest values of solar irradiation and low load due to holidays. This week was selected as it could potentially be the week that the DG would cause more disturbances to the grid by injecting large amounts of electricity when compared to the other weeks of the year. For task 2 was chosen data only from the $2^{nd}$ of July which was the day with higher solar irradiation of 2018. This was due to the computational time to simulate task two.

+ *Interaction with other grids*. The study is comprised of only the known distribution grid and omits its interaction with other grids.
+ *Hourly based data.* The data used in the case study is hourly based thus, the analysis of overvoltages and overcurrents is also hourly based. However, based on the Standard EN 50160, this analysis should be done in shorter periods of times (i,e. minutes).
+ *Solar irradiation. The model* considers homogeneous solar irradiation across the studied area, which may be a reasonable assumption on hourly basis.

# 3.5. Delimitations

There are also some delimitations that should be mentioned in order to understand the boundaries set for this study.

+ *HC parameters evaluated.* The reason why overvoltages and overcurrents were selected to determine the HC is mainly due to their popular usage in other HC studies found in literature and due to the the hourly time steps used in this model. Hourly time steps are not accurate enough to study other parameters used for studying HC such as rapid voltage change or harmonics.
+ *PV system characteristics.* To simplify the problem, all PV systems use the same model of PV panel and use the same orientation and tilt of the panel.

+ *PV system placement*. PV systems placed in locations other than on flat land have not been considered in this model, i.e., building rooftops.
+ *Land availability*. The land suitable for PV parks was defined as open land not reserved for any specific purposes, such as agriculture.
+ *Land distance to node*. The distance between suitable land and a node is calculated by tracing a straight line from the closest point of the land perimeter to the nearby power substation. Therefore, the topography between the land and substation is not considered.

Chapter 4

# Case Study

*The model described in Chapter 3 was employed for the local power grid of Herrljunga municipality in Västra Götaland county, Sweden. This chapter presents the location of the power grid, in section 4.1; the configuration of the power grid, in section 4.2., and information on the power grid and geographical data used in the simulation in section 4.3 and section 4.4, respectively.*

## 4.1. Location

Herrljunga municipality is located in the south west of Sweden and has 9 500 inhabitants. The closest big city is Gothenburg (80 km away) [68].

The total area of the municipality is roughly 500 square kilometres [68]. The rural topography is mainly flat dominated by a mixture of fields and forests; the urban areas are characterised by single-family houses.

The annual global solar irradiance in 2018 in this area was, 1 012 kWh/m2, based on data from the solar radiation model STRÅNG [69], developed by the Swedish institutions such as the Swedish Metheorological and Hydrological Institude (SMHI), the Environmental Protection Agency (*Naturvårdsverket*) and the Swedish Radiation Safety Authority (*Strålsäkerhetsmyndigheten*).

## 4.2. Herrljunga and Ljung-Annelund Power Grid

Herrlunga and Ljung-Annelund power grid is owned and operated by Herrljunga Elektriska AB. This company is owned by the municipality and started the electrification of the area back in 1906. Currently this company is in charge to develop and maintain the electrical network which is divided into two grids — one for Herrljunga and, one for Ljung and Annelund urban areas and surroundings. Figure 11 depicts the substations contained in each grid — yellow for Herrljunga and green for Ljung-Annelund. Each local grid is connected to the regional grid through a feeding substation, represented in blue, which are owned by Vattenfall — the regional grid owner. This local grid has two voltage levels, MV at 10.8 kV and LV at 0.4 kV. Currently more than the 82% of the transmission lines are underground lines. Additionally, both grids are interconnected, however, the coupling points are open in the simulations and therefore they can be considered as separate grids.

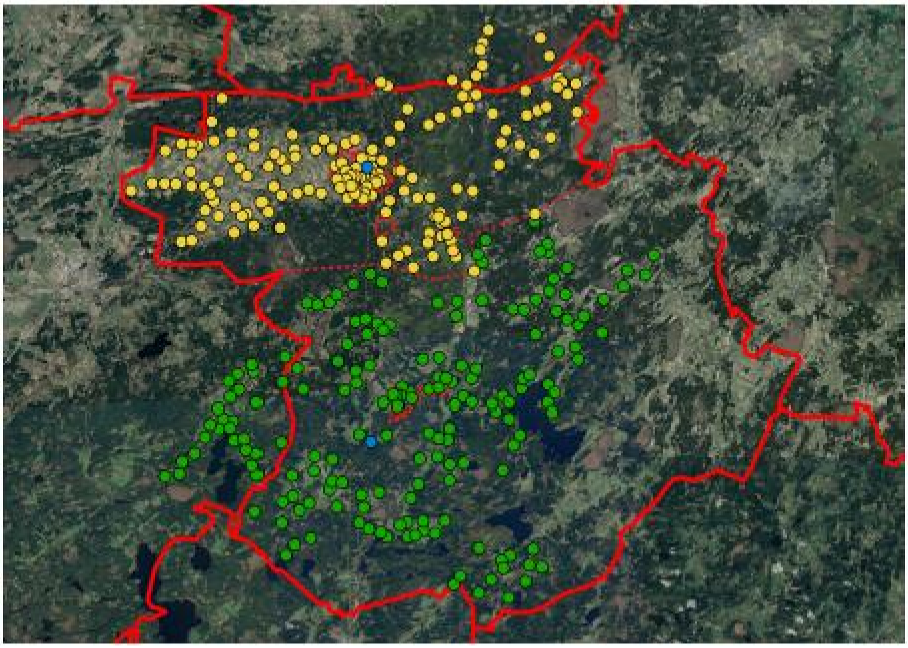


*Figure 11. Herrljunga's municipality satellite view. Red lines set up the bounderies of Herrljunga municipality. The dashedred line separates the two grids. The yellow circles represent the MV substations in the Herrljunga area and the green circles represent the substations in the Ljung-Annelund area. The blue circles are the High Voltage (HV)/ MV substations that feed the local grid. Picture reproduced with the permission from* [15].

# 4.3. Data from Herrljunga Elektriska AB

The data base used in this thesis belongs to Herrljunga Elektriska AB. This data base integrates data related to both power grids described in section 4.2. Among the data provided, there are information on the power substations and the power transmission lines that make up the power grids.

The power substation data include: the names of each substation, geographical location, electrical characteristics, and aggregated values of the load for each substation in hourly timesteps. This load data are only for active power and covers year 2018. A power factor equivalent to 1 is unlikely. For this reason, a power factor of 0.95 was assumed [70].

In addition, the power transmission lines include: the interconnection points of each line, the type of cable, their length, and electric characteristics.

A non-disclosure agreement was signed by both interested parties, the author of this master thesis and Herrljunga Elektriska AB, since the data provided are strictly confidential. Notice that the results, provided in the present report do not reveal sensitive data.

# 4.4. Geographical Data

The geographical data were provided by Herrljunga Elektriska AB, Herrljunga municipality (*Herrljunga Kommun*) and the Swedish National Land Survey (*Lantmäteriet*) and were gathered and analysed in another master [15].

The suitability criteria of the land were based on: available land surface, land use, distance to civil infrastructure ( roads, electricity grids, etc.), and environmental and regulatory factors [15]. This study has taken as reference previous studies on wind power planning which is more evolved than for the PV sector.

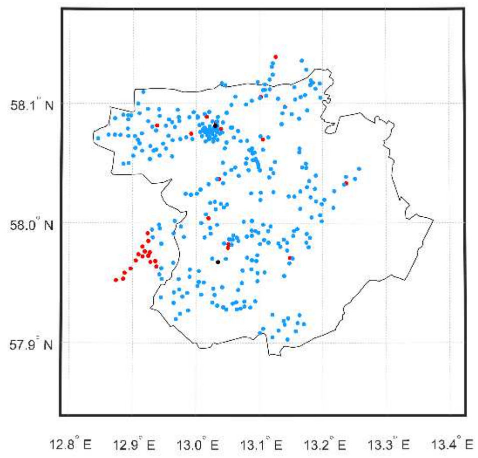
# Chapter 5

# Results

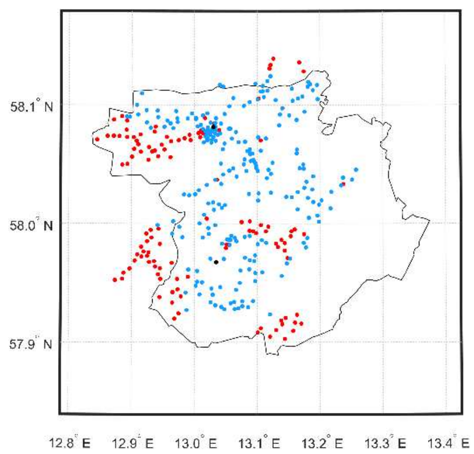
*The computational model described in Chapter 3 was evaluated through the case study explained in Chapter 4. This chapter is divided into the data treatment prerequisites in section 5.1 and the results of tasks 1-3 in sections 5.2.- 5.4 respectively.*

## 5.1. Data Treatment Prerequisites

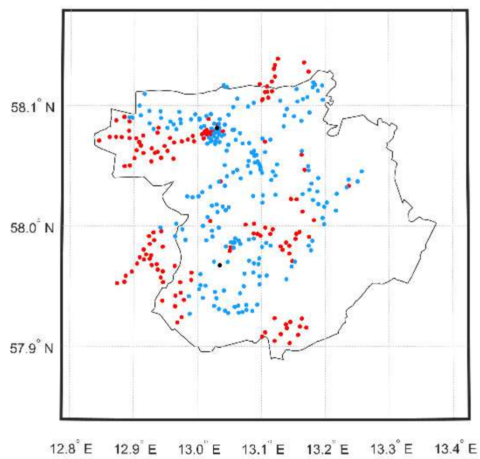
The understanding of the availability of land surrounding each substation is key to place PV parks in the power grid study. In this study, the available lands were selected considering a distance equal to or lower than 3,000 m from the nearest perimeter point of the land to the substation, see Figure 10. Figure 12 illustrates each of the substations — represented by circles —that belong to Herrljunga municipality power grid (a – c) and their land suitability. This figure also shows the boundary of Herrljunga municipality as a black line. The substations that have land available in the surroundings are shown in blue and those with no land available are shown in red. Additionally, the feeding stations are represented as black dots — one for the Herrljunga grid and the other for the Ljung-Annelund grid. This study was carried out for three different PV sizes — 1 MWp, 3 MWp and 5 MWp.




a)




b)




c)

*Figure 12. Nodes with/without one or more suitable lands nearby (blue/red). The black circle is the feeding station. The availability of land depends on the PV park size: 1 MWp (a), 3 MWp (b), and 5MWp (c).*

The total number of nodes with available land for each PV size and grid are shown in Table 5.

*Table 5. Number of substations with land available for Herrljunga and Ljung-Annelund power grids.*

| | Total | 1 MWp PV park | 3 MWp PV park | 5 MWp PV park |
|---|---|---|---|---|
| Herrljunga grid | 173 | 160 | 120 | 120 |
| Ljung-Annelund grid | 185 | 161 | 127 | 107 |

From the maps given in Figure 12 and the data from Table 5 it can be observed that the larger the PV park size is, the lower the number of substations that are available in each grid is. This is because the power capacity of a PV park depends on the area covered by PV panels (see equation 3.1.2).

Additionally, in this chapter the power grids in both urban areas (Herrljunga and Ljung-Annelund) are referred to as Herrljunga municipality power grid.

## 5.2. Results of the Possibility of Connecting a PV Park

The results of this section are based on task 1 explained in section 3.2.1. In this case, three PV park sizes were considered in the set of simulations used to obtain results for task 1. Only one PV park size is used for each simulation, therefore 6 simulations were undertaken (3 for the Herrjunga power grid and 3 for Ljung-Annelund power grid). It should be noted that one simulation has 1,000 iterations in which each iteration provides a single result.

Figure 13 presents the occurrence frequency that the Herrljunga power grid can host a certain number of PV parks connected to it before the HC is violated. The histograms (a – c) represent the occurrence frequency of the number of PV parks that can be connected to the grid before the quality of the grid deteriorates to a level that is no longer acceptable, when considering all the results provided by the 1000 iterations. In addition, a grey vertical line represents the mean of all the results obtained in each simulation. The three different figures are given for each study depending on the PV park's size, the graphs from left to right show the results for connecting 1 MWp PV parks, 3 MWp PV parks and 5 MWp PV parks. Finally, graphs d) – f) provide a cumulative distribution function of the results obtained for each PV park size, respectively.

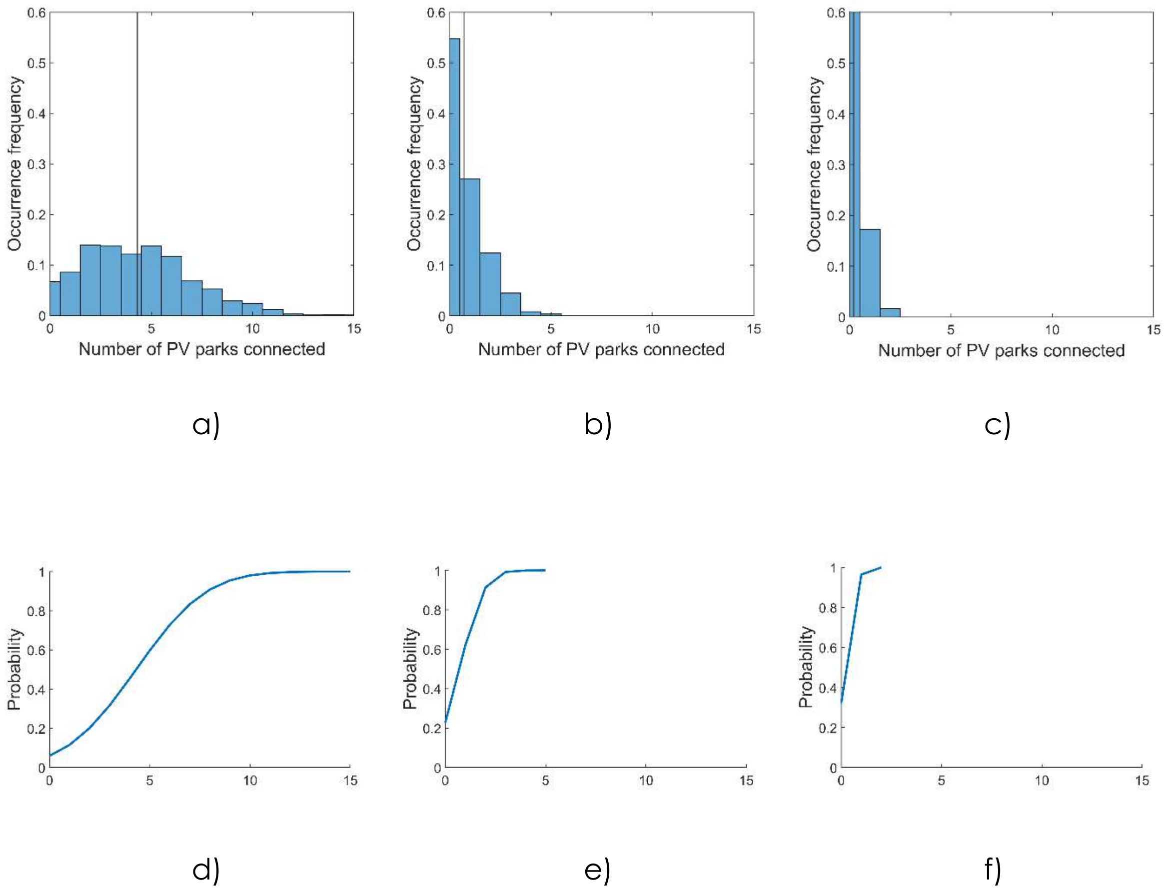



*Figure 13. Histogram of the number of possible PV parks installed in Herrljunga power grid resulting from 1000 iterations of the model based on task 1's assumptions. From left to right there are the results for (a) 1 MWp, (b) 3 MWp and (c) 5 MWp PV parks. The vertical line indicates the mean of PV parks. d – f show the cumulative distribution functions of the results.*

Figure 14 presents the same information as Figure 13, however in this case it is for connecting PV parks to the Ljung-Annelung power grid.

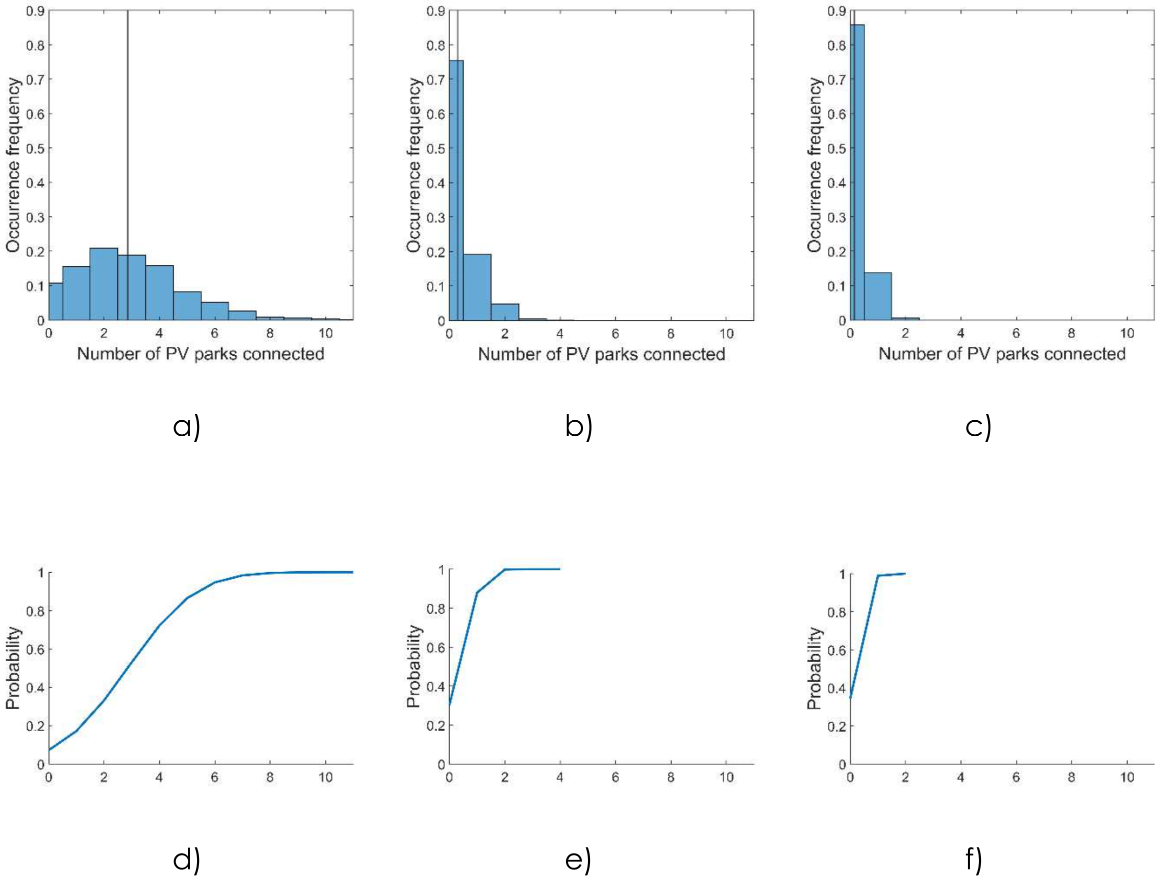



*Figure 14. Histogram of the number of possible PV parks installed in Ljung-Annelund power grid resulting from 1000 iterations of the model based on task 1's assumptions. The vertical line indicates the mean of PV parks. From left to right there are the results for (a) 1 MWp, (b) 3 MWp and (c) 5 MWp PV parks. d – f show the cumulative distribution functions of the results.*

Observing the results provided in Figure 13 and Figure 14 one can see that the power grid could host a higher number of the smallest sized PV parks (1 MWp) compared to larger PV parks units, which also on average, allow more distributed power capacity overall. When it comes to comparing both power grids, the probability that a higher number of parks of the same size can be hosted, was higher in the Herrljunga power grid than in the Ljung-Annelund power grid. In fact, the Ljung-Annelund grid could barely host any 3 MWp or 5 MWp PV parks. This is due to fact that the net electricity consumption in the Herrljunga grid is higher than that of the Ljung-Annelund grid. Therefore, Herrljunga grid has more power capacity to host renewable electricity injection than the Ljung-Annelund network. Nonetheless, in most of the cases the 5 MWp PV parks were detrimental for both grids; it was only in 20% of the simulations that the grid could support this park size.

The results shown in Figure 15 are the spread of the PV parks allowed by the Herrljunga power grid (a) and the Ljung-Annelund power grid (b) provided by each simulation (1MWp, 3MWp and 5MWp PV park size); this is represented by a boxplot. The interquartile range of these box plots is defined by a lower quartile of a 25$^{th}$ percentile and a higher quartile of 75$^{th}$ percentile. The whiskers consider around 99% of the data, any result outside the whisker's limits is considered as an outlier and is represented as a red cross. The boxplot in both grids for the case study of 3 MWp and 5 MWp did not show a complete box. This is due to the little variety in the results and for having either 1 or 0 the median value of the results in each of the simulations.

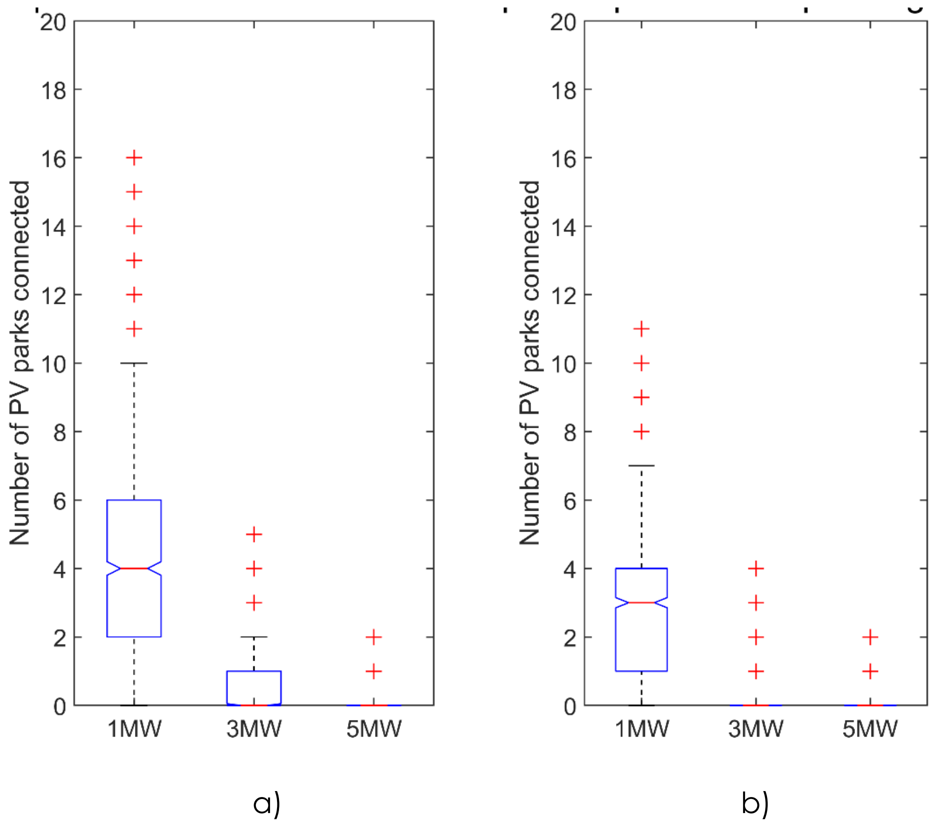
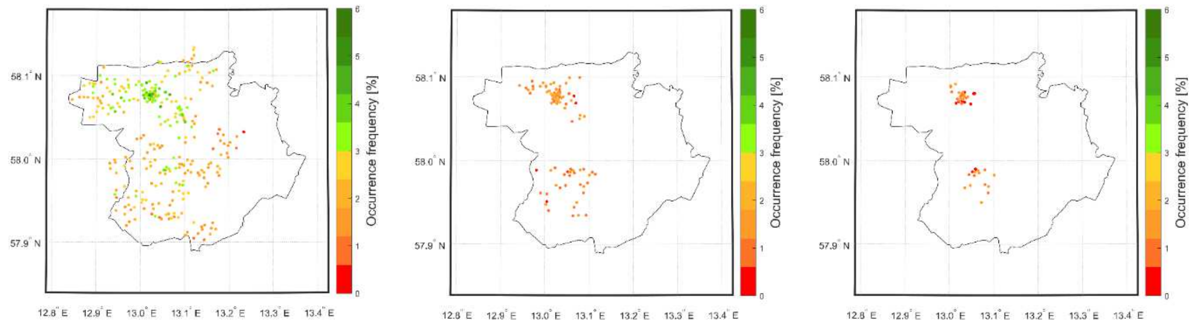



*Figure 15. Spread of the number of PV parks allowed in a) Herrljunga power grid and b) Ljung-Annelund power grid resulting from simulating 1000 iterations using the model based on task 1. The box is limited by 25$^{th}$ and 75$^{th}$ percentiles.*

The spread of the results represented in Figure 15 (a) and (b) also show differences between both power grids when it comes to analysing the possibility of allocating DG randomly in the territory. Looking at this 1 MWp PV park size box plot, while Herrljunga power grid has a span between 2 and 6 PV parks between the 1$^{st}$ and 3$^{rd}$ quantile; in the Ljung-Annelund grid, the span was between 1 and 4 PV parks. The outliers also differed: 16 and 11 were the maximum number of PV parks that could be placed randomly for the two grids, respectively.

The depicted maps, shown in Figure 16, present the probability that a substation — represented by a coloured circle — is used in the simulations for placing a PV park for both the Herrljunga power grid on the left and the Ljung-Annelund power grid on the right. The probability of violating the HC of a given substation, when a PV park is connected to it, is colour coded from red to green, where red represents the highest probability for violating the HC of the grid and the dark green the lowest given the results.




a) b) c)

*Figure 16. Occurrence frequency that a PV park is allowed when connected to each node without violating the HC based on task 1 in Herrljunga municipality power grid. a), b) and c) show the results for 1 MWp PV size, 3 MWp PV size and 5 MWp PV size, respectively. Only substations with available land are depicted.*

It can be seen in Figure 16 that the closer the substations are to the feeding station, the higher the possibility is that the substation can host a PV park. Additionally, it can be observed that there is a relationship in the distance between the substation that can host a PV park to the feeding station and the size of the PV unit. Thus, the study suggests that the larger the PV park size is the smaller the distance between both feeding station and substation needs to be.

## 5.3. Results of Maximising the HC of the Entire Grid

The results of the second task are shown in this section. In this case, the focus of the study was to identify the maximum capacity of each power grid to withstand the highest amount of PV parks possible. To simplify the problem only one PV park size was used — 1 MWp PV park.

Figure 17 provides similar information to that of Figure 13 and Figure 14, however in this case the results for task 2 are shown.

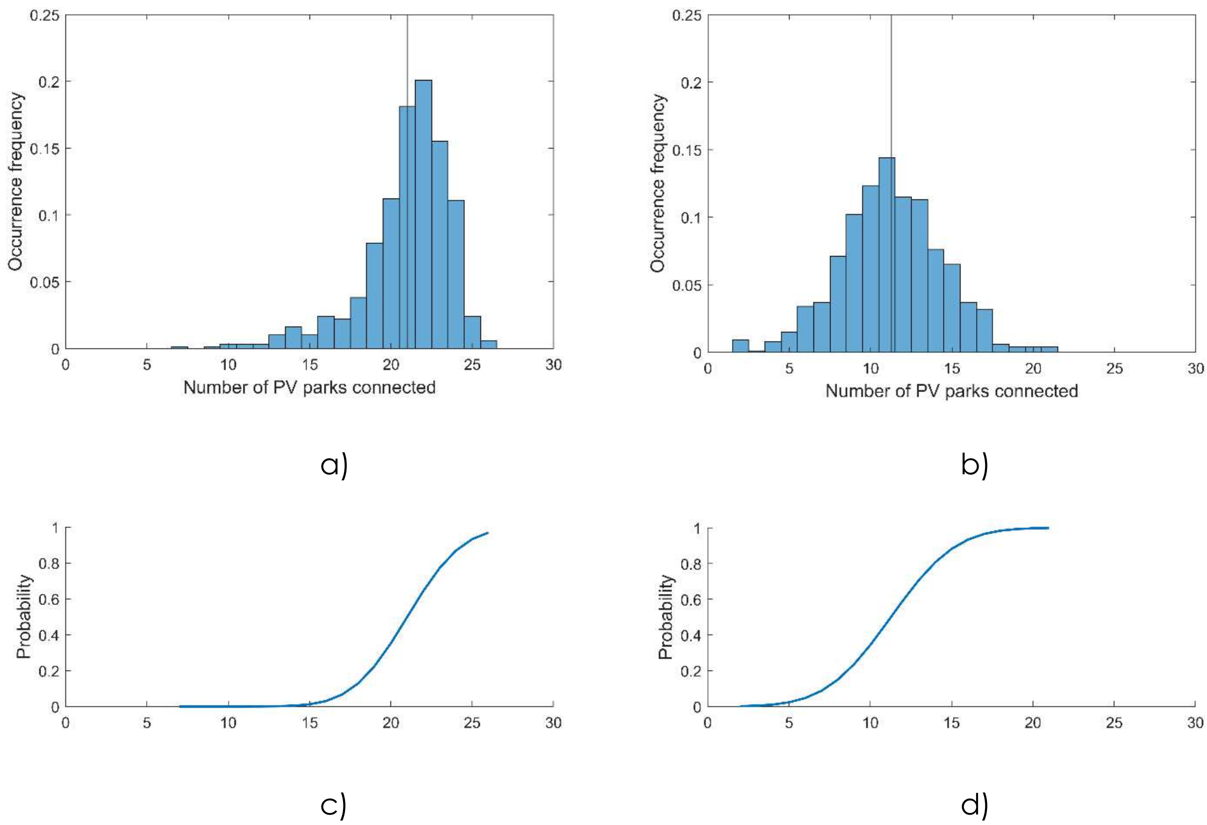
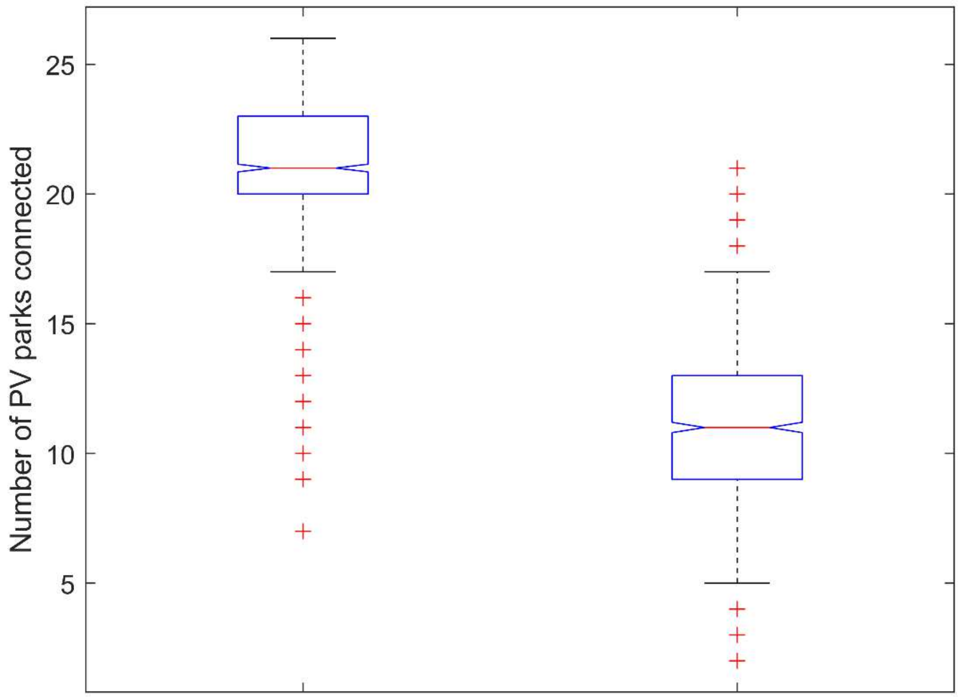



*Figure 17. Histogram of the number of possible 1 MWp PV parks installed in Herrljunga power grid (a) and Ljung-Annelund (b) resulting from 1000 iterations of the model based on task 2's assumptions. The vertical line indicates the mean of PV parks. c) and d) show the cumulative distribution functions of the results, respectively.*

In accordance with the current results shown in Figure 17 it can be observed that the average number of PV parks connected to the grid has increased considerably when compared to the previous task. The cumulative distribution function also differs substantially. While in the Herrljunga power grid low values of PV park units were less likely (< 15 PV parks), there was a high probability that the number of PV parks that the grid could host were between 18 and 24 PV parks. However, for the Ljung-Annelund power grid the histogram is roughly symmetrical which increases the span of possible PV parks that the grid could host.

The spread of the results of 1000 iterations is shown in Figure 18, similar to Figure 15 which a) refers to the results for the Herrljunga power grid and b) the results for the Ljung-Annelund power grid.




a) b)

*Figure 18. Spread of the number of PV parks allowed in Herrljunga power grid (a) and Ljung-Annelund (b) power grid resulting from simulating 1000 iterations the model based on task 2. The box is limited by 25th and 75th percentiles.*

It is clear from the results that the maximum number of PV parks that the Herrljunga power grid and the Ljung-Annelund power grid could host is 26 and 21, respectively. Notice, that for the Herrljunga grid this number was the limit of the whiskers, while in Ljung-Annelund was considered an outlier. Another interesting observation from this figure is the number of outliers found in both box plots (a and b) being from 7 to 26 for the Herrljunga grid and from 1 to 21 to the Ljung-Annelund grid. The wide dispersion of the results suggests the importance of selecting a good node at the start of the simulation. Some substations were prone to violating the HC of the power grid if some of the neighbouring substations hosted a PV park, thus, if those substations were selected at the start of the simulation it could lead to the minimisation of the HC of the entire power grid. The verification of this effect was out of scope of this thesis, however, it could be of interest to study it in future studies.

The maps depicted in Figure 19 showed the same type of information as in Figure 16.

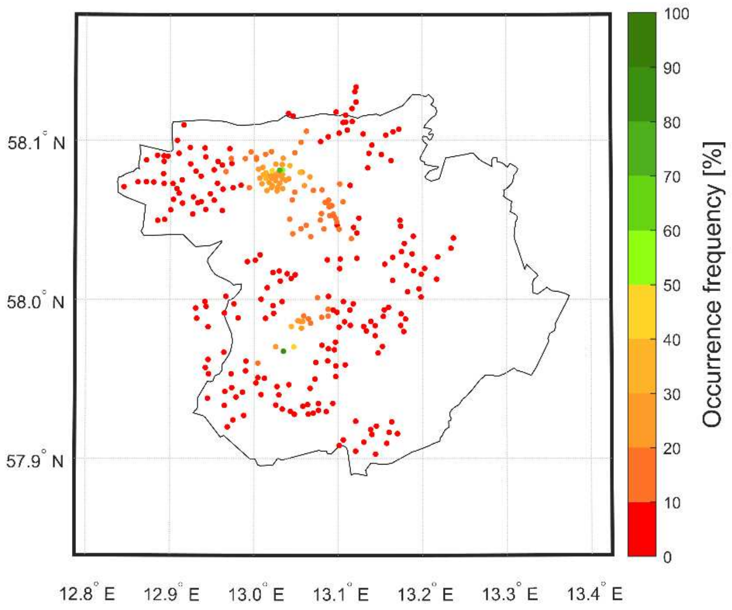



*Figure 19. Occurrence frequency to connect a PV park into a node without violating the HC based on task 2 assumptions for the two power grids.*

Once again it can be seen in Figure 19 that the nodes geographically closer to the feeding station had a higher probability of hosting a PV park, Figure 20, shows clearly this correlation. In addition, the feeding station could host a PV park in all of the iterations. This is because by definition the slack node has a constant voltage.

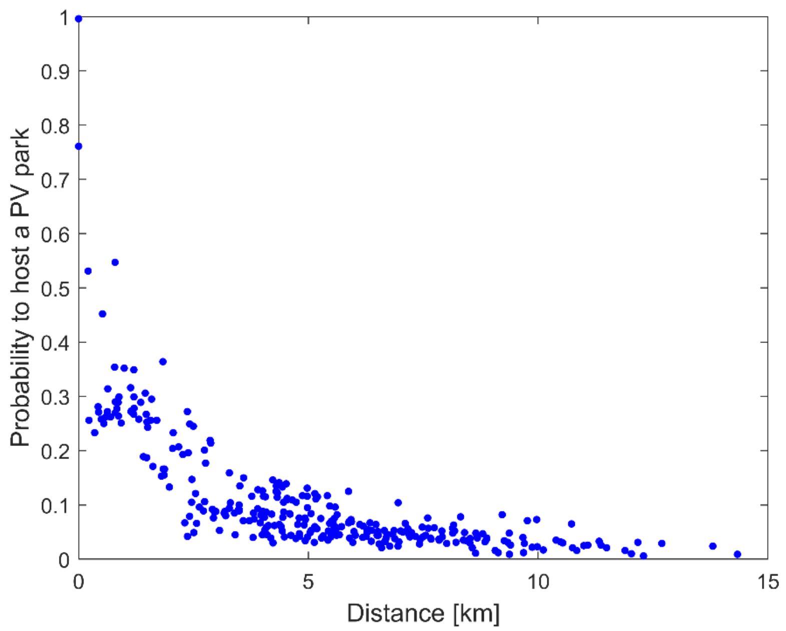



*Figure 20. Probability to host a PV park based on the distance between the host substation and the feeding station. Results taken based on task 2 simulations.*

Different configurations were found for each power grid to connect the maximum number of PV allowed, 6 for Herrljunga and 4 for Ljung-Annelund. The configuration found for connecting the maximum number of PV parks is represented in the maps provided in Figure 21 and Figure 22 for Herrljunga power grid and Ljung-Annelund power grid, respectively. Each map shows: green dots which indicate the substations in which one of the PV parks is installed; grey dots which do not have a PV park installed; and a red dot in each map which indicates the feeding station which also has a PV park connected to it.

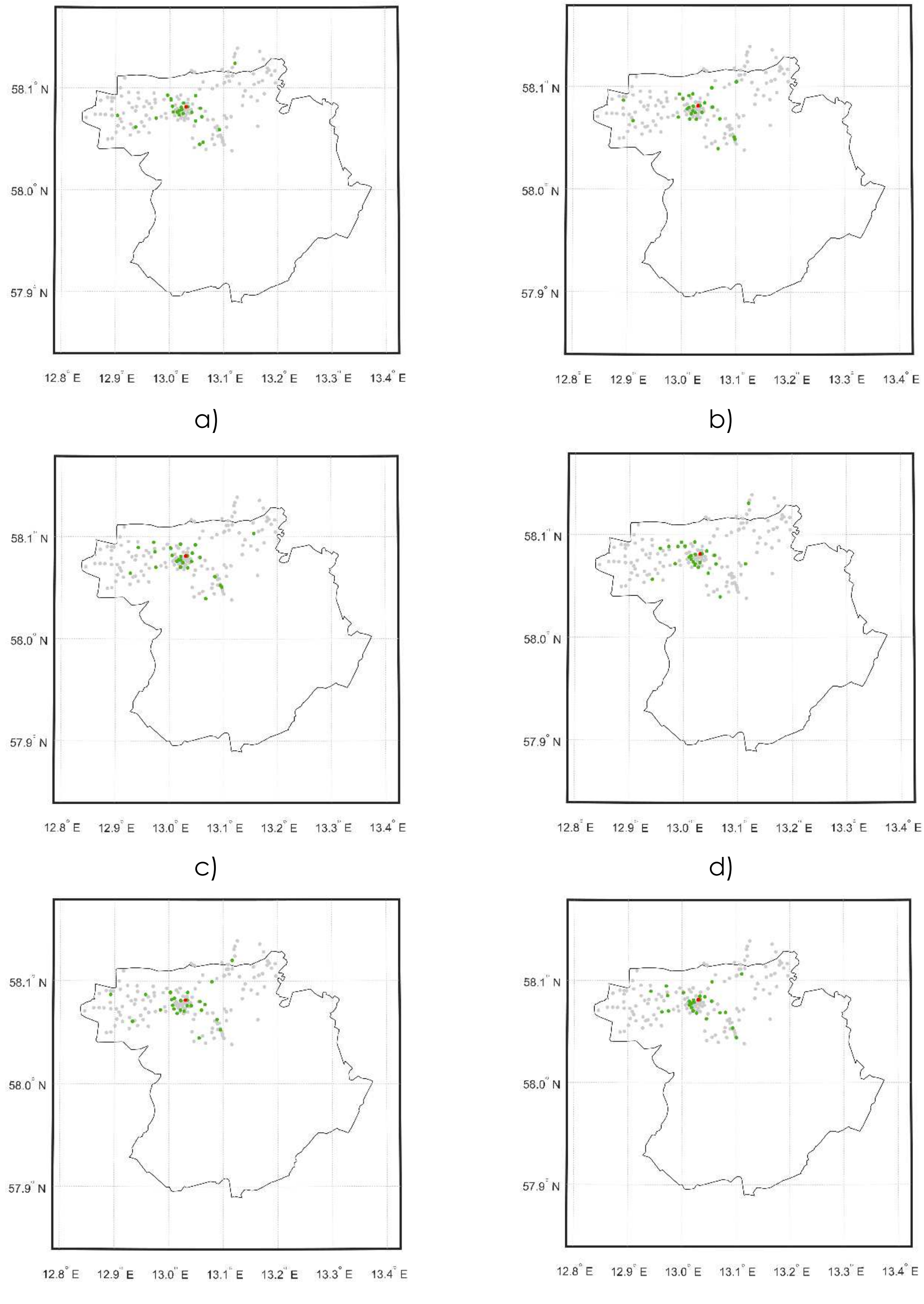



*Figure 21. The optimum park allocation of the maximum number of PV that the grid can host based on the results obtained from 1000 simulation of the model based on task 2 in Herrljunga power grid. Green nodes are substations with a 1 MWp PV park connected to it. Grey nodes are nodes without a PV park. The red node represents the slack node.*

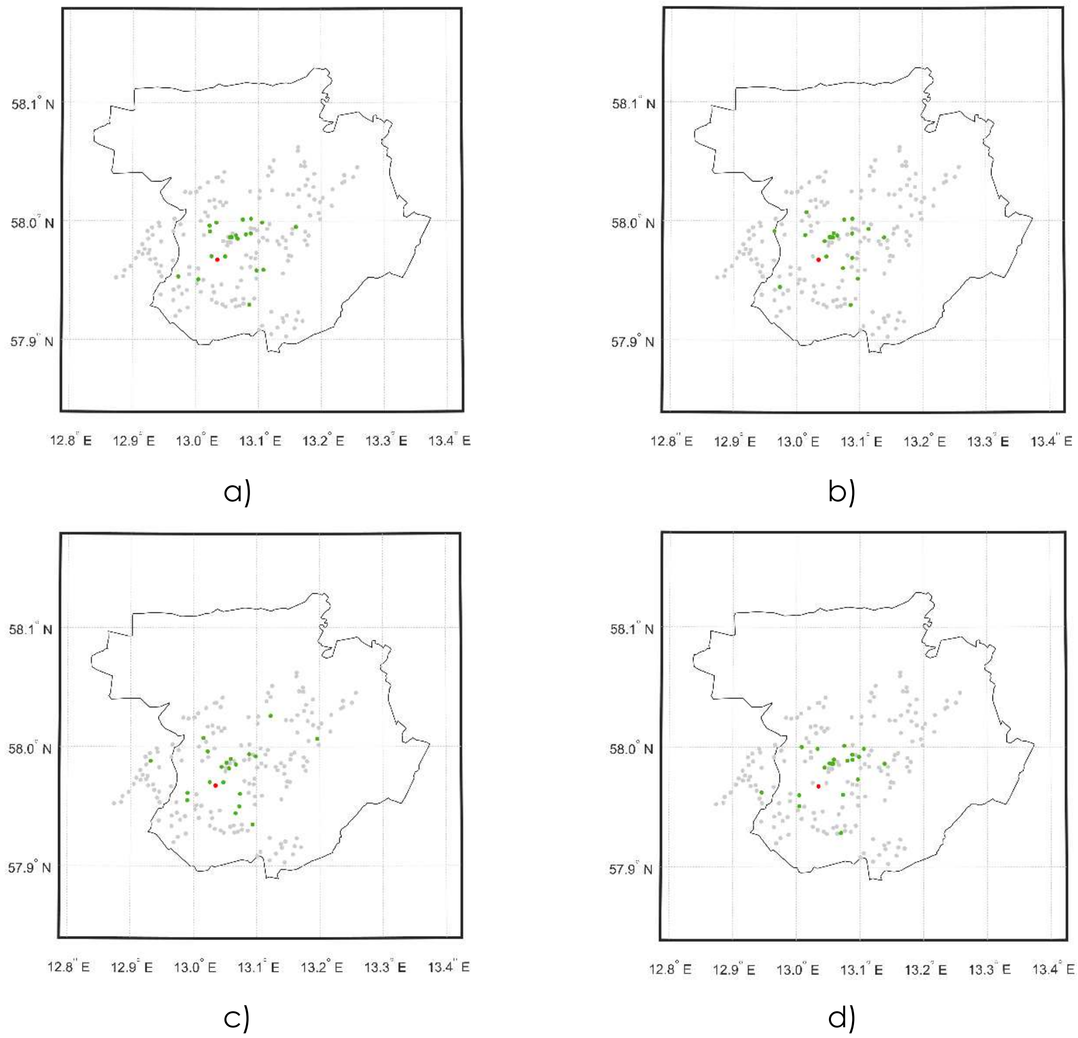



*Figure 22. The optimum park allocation of the maximum number of PV that the grid can host based on the results obtained from 1000 simulation of the model based on task 2 in Ljung-Annelund power grid. Green nodes are substations with a 1 MWp PV park connected to it. Grey nodes are nodes without a PV park. The red node represents the slack node.*

The optimum allocation configurations for connecting the maximum number of PV parks that each grid could host is shown in Figure 21 and Figure 22. Observe that in most of the cases a node was picked in more than one configuration. In addition, one could also notice that those nodes were in general close to the feeding station, however in some cases seldomly there were some nodes far away which were also chosen.

It was also relevant to identify the nodes which were red-flagged during the simulation, these nodes are depicted in Figure 23. Following the colour code: The red indicates a node that was flagged (node unable to host the PV park) more than 95% of the iterations. Orange for 75% - 95%, yellow for 50% - 75%, green for less than 50% and grey those substations that are far from suitable land (> 3000 m), see Figure 10. The blue node indicates the feeding station.

In Herrljunga power grid, there were 6 nodes that were red flagged in all the iterations which correspond to the red nodes situated on the north of the map.

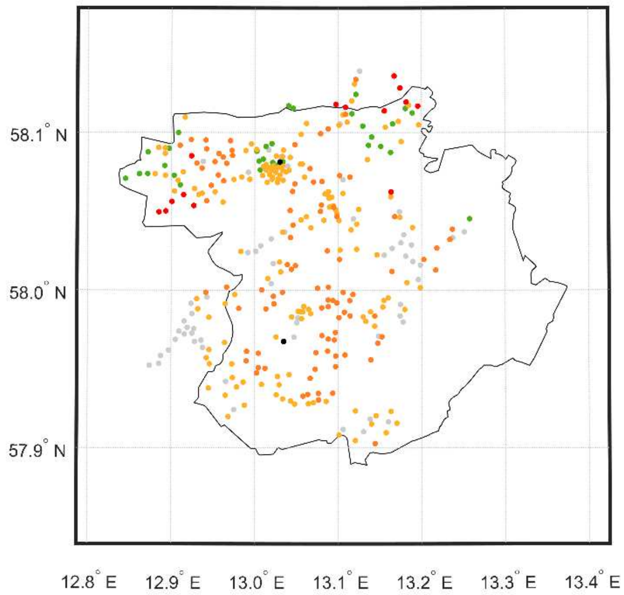


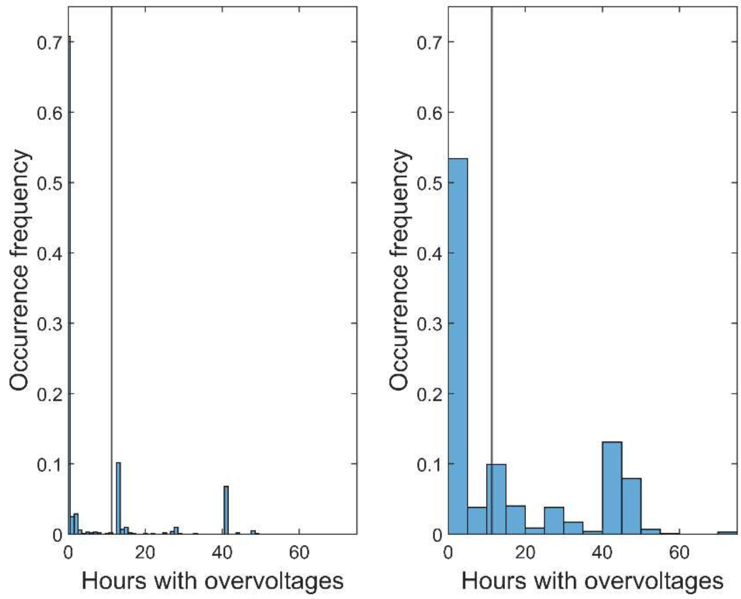

*Figure 23. Flagged nodes in each power grid. Red circles represent nodes that were red-fllaged more than or equal to 95%; orange nodes were red-flagged between the 75% and 95%; yellow nodes between 70% and 50%; green nodes less than 50% and grey nodes have no land availability. Black circles represent the feeding station.*

Unlike the maps that show the optimal allocation of PV parks, Figure 23 shows that some of the nodes close to the feeding station also had a high probability of violating the HC (from 70% to 50%) in most of the cases. These results reinforce the idea of the importance of selecting the initial nodes to host PV parks in the simulation.

# 5.4. Results on Grid Allocation Cost

This shows the results of task 3. The simulation considered the Swedish goal of producing 5% to 10% of annual net electricity demand by 2040 (as mentioned in section 1.1).

Figure 24 and Figure 25 depict the frequency histograms of the number of hours with overvoltages found for all the iterations and for each power grid, respectively. In a), are the results for the goal of producing 5% of the electricity with PV technology and in b) are the results for the goal of producing 10%. The vertical grey line indicates the average number of overvoltages of the simulations.




a) b)

*Figure 24. Histogram blue bars of the number of hours with overvoltages in the Herrljunga power grid resulting from 1000 iterations of the model based on task 3 assumptions. a) shows the values for a goal of 5% and b) values for 10% goal. The vertical line indicates the mean of hours with overvoltages.*

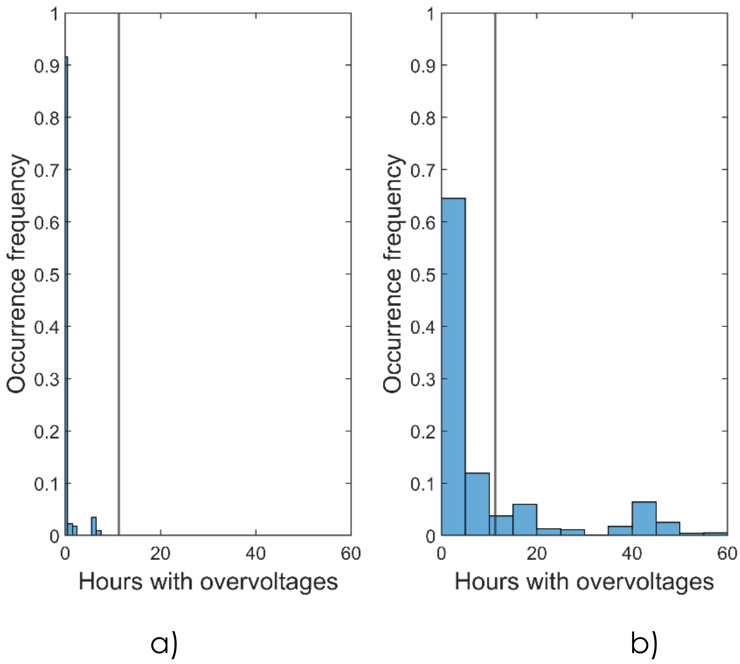
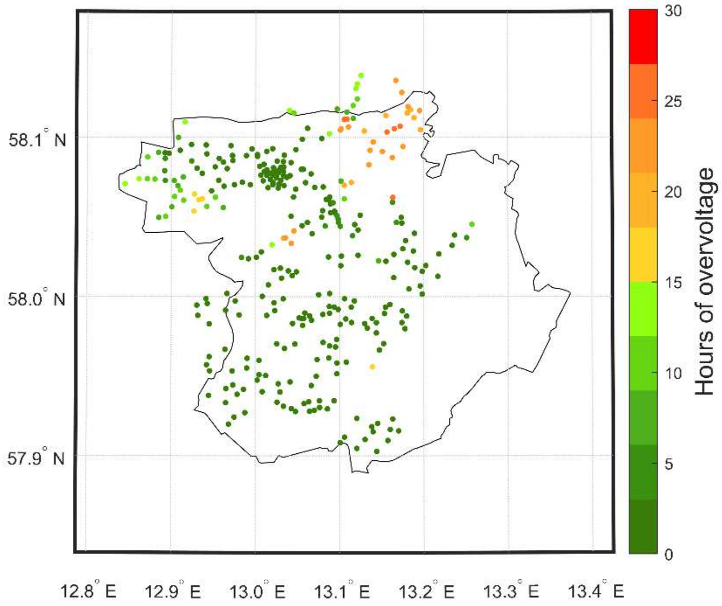



*Figure 25. Histogram blue bars of the number of hours with overvoltages in the Ljung-Annelund power grid resulting from 1000 iterations of the model based on task 3 assumptions. a) shows the values for a goal of 5% and b) values for 10% goal. The vertical line indicates the mean of hours with overvoltages.*

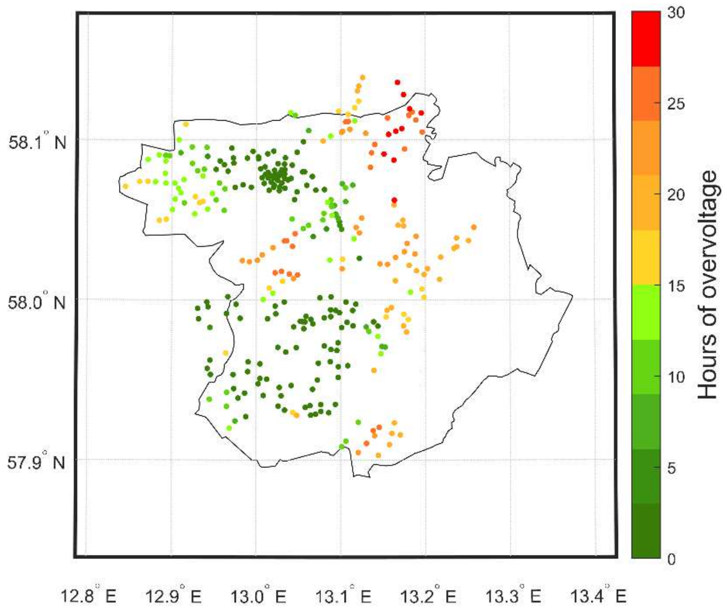
The histograms in Figure 24 and Figure 25 show that 0 hours of overvoltages was the most common result for both the 5% and 10% goals of both grids. One can also deduce that the results of the 10% goal show a higher value of overvoltages than that of the 5% goal due to the higher penetration of PV parks in the grid. However, one can observe outstanding outliers in plot a) of Figure 24 which summed to approximately 20% of the results and were concentrated in overvoltage hours 14 and 41. The overall number of overvoltage hours increased in graph b). One possible explanation to this effect is the order in which substations were selected during the simulation. As seen in the previous results, some substations are prone to decreasing the quality of the grid when a PV park is connected to it, if one or more of these substations were selected at the start of the simulation, that could potentially cause the violation of the power quality of the power grid early in the simulation. Thus, this could lead to high number of overvoltage hours. Regarding the specific number of overvoltage hours shown (14 hours and 41 hours), the results suggest that these substations may be in the same geographical area which as a result affect the behaviour of the grid in a similar way. This could also explain the outliers shown in Figure 25.

The maps presented in Figure 26 represent the average number of hours with overvoltage for each node of the power grid. This is represented using colours from dark green to red. Red represents the higher number of hours with overvoltage in the node and the dark green colour represents the nodes that have no overvoltages. These maps represent the results for Herrljunga municipality power grid, depending on the goal 5% (a) or 10% PV penetration (b).

As far as the overcurrents, the results provided by the simulation show that the grid would not face overcurrents.




a)




b)

*Figure 26. Average overvoltage in each node (circle) of the power grid based on the 2040 goal on supplying electricity with 5% (a) to 10% (b) of PV generation, task 1. Results provide by simulating 1000 times the model based on task 3.*

In this figure, the number of excellent nodes for allocating PV parks — dark green — is clearly higher for 5% goal than for the 10% goal. Nevertheless, this map shows clearly that both grids could easily provide the 10% of the electricity demand from PV.

Additionally, both power grids allow a wide range of configurations to install 8 MWp distributed in Herrljunga power grid and 3 MWp distributed in Ljung-Annelund grid.

Finally, once again the substations closer to the feeding station show higher possibilities to host PV parks than the substations far from it.

### 5.4.1. Sensitivity Analysis

Although 1000 iterations were recommended in the literature review, a sensitivity analysis was performed and showed that less iterations could give similar results, see Figure 27.

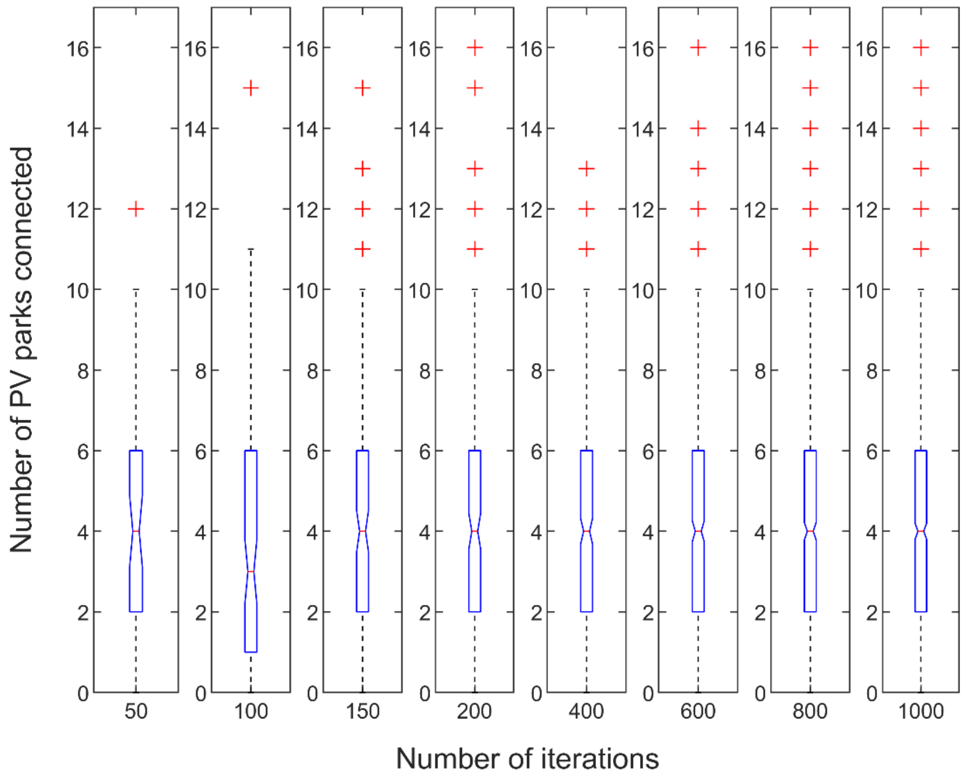



*Figure 27. Box plot of the results obtained by simulating the model (task 1 to the Herrljunga power grid) using a different number of simulations.*

# Chapter 6

# Discussion

*This chapter is divided into three sections: section 6.1, where the capacity of the power grid for PV parks is discussed; section 6.2, where the optimal allocation of the PV parks is discussed; and section 6.3, where the results for task 3 are analysed. In addition, section 6.4 provides a guideline for future work.*

The aim of this chapter is to analyse and discuss the results presented in Chapter 5 based on the case study information given in Chapter 4 to provide an answer to the questions formulated for this project. Additionally, the results are analysed for the specific case study power grid.

One interesting finding before answering the questions mentioned above is the correlation between the availability of nodes depending on the size of the PV park. This was also verified previously by A. Birging and O. Lindberg in their research work [15]. From the maps given in Figure 12 and the data from Table 5 one can observe that for large PV park size the lower chances are to find lands suitable to host the area needed to build those parks. This result may be explained by the fact that the larger the PV park is, the larger the land surface needed to build the park is. It is expected that the access to sufficiently large patches of land suitable for 5 MWp parks are smaller since the municipality is made up mainly by urban areas, forests, and fields.

# 6.1. Maximum Number of PV Parks Installed

In order to identify the installed capacity of PV parks that a local MV grid can host it is important to understand the probability that the HC is violated from n+1 PV parks added. This aspect is reflected in the results provided in section 5.2 and section 5.3.

Based on the results from task 1, the size of the PV park influences the HC of the power grid. Figure 13 and Figure 14 show clearly that the HC was higher for the smaller PV park size (1 MWp) than for larger PV park units (3 MWp or 5 MWp). However, the spread of the number of PV parks that the municipality power grid can host was wider for the smallest PV park size (Figure 15 and Figure 16).

In task 2 the focus was slightly different from task 1. Firstly it focuses only on one PV park size; secondly, it is designed to determine the maximum number of PV parks that can be installed if only the grid owner promotes the areas in which the units should be installed.

The maximum number of 1 MWp PV parks that Herrljunga municipality power grid can host was 47, where 26 PV parks correspond to Herrljunga power grid and 21 PV parks correspond to Ljung-Annelund power grid.

Task 1 and task 2 identify the probability that a park can be connected (for different PV park sizes) without previously planning in which substations they should be coupled to. It can therefore be assumed that the results provided by task 2, show accurately enough the maximum capacity of each grid to host PV parks based on their configurations.

# 6.2. Optimal PV Park Allocation

The most preferable allocation of PV parks was presented in the results in section 5.2 and section 5.3 based on keeping the power quality in the grid studied.

The findings provided in section 5.2, suggest there was a difference from the DG allocation depending on the size of the unit. In this study it is confirmed what was indicated in the literature review; in both grids the nodes which were farther from the feeding station were prone to problems with maintaining the power quality of the grid (see Figure 16 and Figure 20). This effect is pronounced when the size of the PV park increases. Especially for the Ljung-Annelund power grid due to the power capacity of the grid which was lower due to a lower power demand compared to the Herrljunga power grid.

Another interesting observation from the results presented in section 5.3, are the substations that were red-flagged in most of the simulations, see Figure 23. In the case of the Herrljunga power grid there were 6 nodes that were red-flagged in all of the iterations performed. Although this type of node is the antithesis of what is being investigated in this section, it is of interest to recognize them to ensure that no PV park is connected to it as well as understanding how they can influence the neighbouring nodes. It is also interesting to mention that the majority of the neighbouring nodes of the feeding station were prone to violate the power grid HC once a PV park was connected to it or to a neighbouring node (about 50% - 70% of the time). This fact suggests the view on how important the selection of the initial substations in the simulation are and how they influence the power capacity of the entire power grid.

The most interesting finding is found in the results of task 2 which show more precisely the precise allocation of the PV parks in order to make possible the connection of the maximum number of PV parks to without violating the HC of the power grid, see Figure 21 for the combination of PV allocation to nodes of the Herrljunga power grid and Figure 22 the same for the Ljung-Annelund power grid.

Not all the nodes that were selected when maximizing the number of PV parks connected to the grid are close to the feeding station. Unlike what Figure 19 shows, some of the substations selected in Figure 21 and Figure 22 were far from the feeding station. This fact suggests that the power grid has a radial configuration, and each outskirt bus has a certain power capacity to host PV parks. This however was not proven in this study.

# 6.3. Discussion on Grid Cost Allocation

This section focuses on the results in section 525.4 which considers the national Swedish goal of injecting 5 % to 10 % of the annual net electricity demand from PV technology into the grid. This goal was studied locally in Herrljunga municipality for each of the two power grids separately.

The study confirms that the higher the PV penetration the higher the number of hours with overvoltages is. This is presented in Figure 24 and Figure 25 for the hours of overvoltages in Herrljunga, and Ljung-Annelund, respectively. One can deduce from these results that the grid could face some overvolatges depending on where are the PV parks located. Thus, power grid upgrades are recommended to be done to avoid the deterioration of the power quality, some examples of upgrades discussed in section 2.2 are: tap changers in the substations, integrate smart inverters, increase the power grid control or smart allocation of the DG.

Given this results, It can thus be suggested that the best solution for both the grid owner, the PV park owner and the rest of users of the grid should be that the grid owner could promote the best place to allocate those parks in order to take advantage of the strong nodes of the power system; and thus, bear with the new electricity supply. In addition, this solution would help to minimize the costs for upgrading the grid of Herrljunga Elektriska AB.

# 6.4. Future Work

The large amount of data used in this model and high number of iterations result in high computational time of the simulations, up to two days in the worst case. In this study, the simulation was performed on the days of the year in which the highest power generation is expected thus causing the highest power disturbances to the grid. However, it would be of interest to study other periods over the year in which the grid would be prone to have power quality deterioration such as: holidays or weekend days during summer months, when the power generation is higher but there is less consumption than normal.

When it comes to obtaining more realistic results, two additions to the model could be made. The first is to consider different PV parks sizes in the simulation; the second is to increase the simulation period to one year. However, that could lead to higher computational times.

Additionally, the study related to the initial choice of substations in the simulation would be of interest as to how this influences the HC of the power grid. This study would consist of analysing which substations have been initially chosen in each iteration and how they affected the maximum number of PV parks that the power grid could host. This would lead to studying each substation individually in order to calculate the probability that it would allow a larger number of PV parks connected to other substations later in the simulation.

Finally, adding economical calculations into this model would be interesting for determining the costs for reinforcing the grid. This could give information on how to determine which would be the best solution to allocate the costs of the grid upgrade between the stakeholders based on the different local grid configurations, thus, to find new economical solutions that drive the development of renewable DG in local grids.

## Chapter 7

# Conclusion

It is highly likely that the use of PV technology will continue to grow in the coming decades. This growth will be attributable to the development of small-scale power plants connected mainly to distributed grids. Given the susceptibility of these distributed grids to maintain the power quality when power injection is increased throughout the network, this study's purpose was to design a model to evaluate the maximum power capacity of a given power grid based on the ideal allocation of the PV parks. The secondary aim of this study was to investigate and propose possible new solutions for attributing the cost allocation to the stakeholders in the case that the grid needs to be reinforced.

The research has shown that for the given case study at the Herrljunga municipality power grid, the maximum number of PV parks that the power grid could host with a smart allocation of power plants is 47 1 MWp PV parks. The study also shows different configurations to allocate these parks. The results of this study indicate that good PV allocation planning allows the power grid to host a higher amount of PV generation without reinforcing the grid.

The most obvious finding that emerges from this study, is that the closer the substation is to the feeding station the higher the possibility is that it can host a PV unit. Additionally, a correlation was found in the distance between the feeding station and the substation in which a PV unit is connected to.

Another interesting finding suggests that the variability of HC results of the power grid, especially for smaller PV parks sizes, could be influenced by the selection of the initial nodes in the simulation.

The results of investigating the possible upgrades for the Herrljunga municipality power grid suggest that both grids owned by the municipality were designed to host enough PV generation to fulfil the national goal of supplying between 5% to 10% of the electricity demand using PV. This is possible if the power grid owner could promote the use of substations that this study suggests as being the stronger.

# References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