EA006 – GRADUATE PROJECT WORK

RESEARCH ON THE VOLTAGE UNBALANCE CAUSED BY THE INCREASE IN PENETRATION OF PHOTOVOLTAIC SYSTEMS IN ELECTRICAL ENERGY DISTRIBUTION FEEDERS

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EA006 – TRABALHO DE FIM DE CURSO (TFC)

INVESTIGAÇÃO DO DESEQUILÍBRO DE TENSÃO RESULTANTE DO AUMENTO NA PENETRAÇÃO DE SISTEMAS FOTOVOLTAICOS EM ALIMENTADORES DE DISTRIBUIÇÃO DE ENERGIA ELÉTRICA

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PROJECT REPORT

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1 SUMMARY

Due to environmental concerns related to climate change, fiscal incentives from governments around the world, and falling prices of proved and ever-improving technology, the use of renewable energy sources has been rising considerably over the past years. A considerable amount of these sources, among which solar is to be highlighted, is used by grid-connected generators that are installed in electrical distribution systems. Solar photovoltaic generators are characterised for using an intermittent source of energy. Since they do not have any moving parts and therefore no inertia, variations in irradiance levels directly and instantaneously affect output power. Therefore, fluctuations in generated power from PV systems result in unbalancing between consumption and generation.

In such context, this project aims to study the impact of high PV systems penetration in voltage and unbalance levels of electrical distribution feeders, such as percentages of unbalance and rise in pu voltage that can be expected under a certain penetration level of distributed PV generation, feeder sensitivity to photovoltaic penetration, times of the day when maximum unbalance can be expected... among others.

After a literature review that defines power quality issues and the power-flow analysis method, the methodology for the analysis is presented. Two software tools, OpenDSS and MATLAB, have been integrated to program the code that is necessary to run the simulations that will provide the necessary results. The general characteristics of the resulting code are reviewed. Three types of analysis have been implemented:

1. **Snapshot analyses**, which provide the state of the system under certain loading conditions;
2. **Feeder sensitivity to PV penetration analyses**, which calculate the highest unbalance that occurs in the feeder under increasing PV penetration conditions; and
3. **Time-series simulations**, which use time-series solar irradiance and load data drawn from real sources to simulate realistic situations.

These analyses have been performed on two very different feeders: on a smaller, 37-Bus delta-connected distribution feeder from IEEE, and on a bigger, 2998-Bus wye-connected distribution feeder from EPRI.

The results of these simulations and the conclusions regarding the main objectives are then presented.
2  PREFACE

2.1  CONTEXT

The present Final Degree Project – *Trabalho da Conclusão do Curso* in Portuguese– has been written as the final requirement to obtain the Industrial Engineering diploma – *Ingeniero Industrial Superior* in Spanish– from the Escola Tècnica d’Enginyeria Industrial de Barcelona (ETSEIB) at the Universitat Politècnica de Catalunya (UPC) in Barcelona, Spain.

All the work has been developed during three months – September 2014 to November 2014– as an exchange semester at *Universidade Estadual de Campinas* (UNICAMP), specifically in the *Faculdade de Engenharia Elétrica e Computação* (FEEC), located in the city of Campinas, Brazil.

2.2  MOTIVATION

I graduated in Industrial Electronics Engineering in 2012, with a curricula focused on microelectronics, programming, automation and control. After that, I went on to the broader field that is Industrial Engineering, a multidisciplinary programme that aims to provide the tools to deal with problems in fields that include manufacturing, materials technology, electronics, electrical engineering, combustion engines, hydraulics, energy engineering, environment engineering, business and management, and accountancy, to name a few.

It was during my Industrial Engineering degree that I took special interest in electrical engineering, power and energy engineering, and all the challenges that humanity is facing in terms of energy systems sustainability and technology. These were fields on which I had also taken basic courses during my Electronics Engineering degree but were not my specialisation, so I decided to learn more about them during my exchange semester in UNICAMP. I am, like many other people in the world, very concerned about the future of the world’s current energy-intensive economy and its consequences in the near future sustainability. Therefore, dedicating my work to the renewable energy field, specifically solar photovoltaic generation, was a very appealing opportunity.

In addition to the technical motivation, I had a genuine desire to discover the amazing country that is Brazil while learning Portuguese at the same time, a language that I had never before considered learning but has turned out to be one that I really like. For an European like me, South America has been a life-changing experience, a prejudice-shattering continent, a very different world that I have learnt to admire and appreciate, to love.
3 INTRODUCTION

3.1 ACTUAL SITUATION

Due to environmental concerns related to climate change, fiscal incentives from governments around the world, and falling prices (Figure 1) of proved and ever-improving technology, the use of renewable energy sources has been rising considerably over the past years.

Figure 1. Scenarios for PV system price evolution (€/Wp).

A considerable amount of these sources, among which solar and wind are to be highlighted, is used by grid-connected generators that are installed in electrical distribution systems (Figure 2). In the last 13 years, for instance, the total installed power of solar photovoltaic (PV) systems got 93 times bigger (Figure 3), from 1.5 GW in year 2000 to 140.0 GW by the end of 2013. Asia is leading the world market of grid-connected PV installations in 2013 with a 59% of total installed power (with China leading the zone at 11.3 GW), after Europe’s market, traditionally the biggest in the world, has decreased from 22 GW in 2011 to 10.3 GW in 2013. Japan (6.9 GW) and the USA (4.75 GW) are following the way, with Germany (3.3 GW) in fourth position [1], [2].

Figure 2. Share of PV grid-connected and off-grid installations. Source: [1].
In 2013, PV electricity generation represented around 1% of world electricity demand, with Italy, Germany, and Greece having enough capacity to produce 7.8%, 6.2%, and 5.8% of their demand, respectively [2]. For the second consecutive year, PV systems lead the investments in renewable energies [3].

In Brazil, solar energy contribution in comparison to other renewable energy sources is still considerably low, as it can be seen in Table 1. However, the country has a great potential for electricity generation from solar energy and substantial investments are being incentivised by the government in the form of R&D projects of the Agência Nacional de Energia Elétrica (ANEEL). For instance, CPFL Energia will invest R$ 13.8 million in two feeders in the city of Campinas [5].

<table>
<thead>
<tr>
<th>Type</th>
<th>Quantity</th>
<th>Nominal power [kW]</th>
<th>Taxed power [kW]</th>
<th>%</th>
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<tr>
<td>Hydroelectric generating plant</td>
<td>434</td>
<td>265 289</td>
<td>266 495</td>
<td>0.21</td>
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<tr>
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<td>109</td>
<td>2 259 569</td>
<td>2 251 773</td>
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<td>462</td>
<td>4 636 436</td>
<td>4 597 416</td>
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<td>8 946</td>
<td>4 946</td>
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<td>86 720 625</td>
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<td>2</td>
<td>1 990 000</td>
<td>1 990 000</td>
<td>1.57</td>
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Table 1. Operating systems in Brazil, 2014. SHPs = Small Hydroelectric Plants. Source: [4].

With ANEEL’s 482/2012 resolution, barriers to distributed generation connections into low-voltage networks were considerably lowered [6]. This resolution covers installations classified as micro-generation (P ≤ 100 kW) and mini-generation (100 kW < P ≤ 1000 kW), and states that maximum installed distributed generation is limited to the total installed load. In 2013, nearly 80% of installed distributed generation were PV systems. For micro-generation systems of or under 10 kW, connection topology might be mono-, bi- or tri-phasic, and tri-phasic only for systems of more than 10 kW.

Solar photovoltaic generators, like wind turbines, are characterised for using intermittent sources of energy. PV generators, in particular, do not have any moving parts and therefore no inertia, thus variations in irradiance levels directly and instantaneously affect output power.
Fluctuations in generated power from PV systems result in unbalancing between consumption and generation and it is then the substation that supplies the increment of necessary power to feed the loads, resulting in voltage drops (also referred to as under-voltages or brownouts).

Moreover, the utility or the grid-operator has no control over the location in which distributed PV systems will be connected as well as the exact total installed PV power, as each customer is able to decide on its own whether or not to install PV systems and their size (under the mentioned limitations two paragraphs above). This can result in unbalanced net loading (net loading = load power – PV power).

As a consequence, unbalanced net loading across phases and variations in generated power from mono- or bi-phasic PV systems can affect voltage and unbalance levels across the feeder. In such context, this project aims to study the impact of high PV systems penetration in voltage and unbalance levels of electrical distribution feeders.

3.2 OBJECTIVES

3.2.1 MAIN OBJECTIVES

The main objective of the project is to answer, through evidence drawn from simulation of distribution feeders, the following questions regarding the impact of distributed PV generation on an electrical distribution feeder:

1. What are the percentages of unbalance and rise in pu voltage that can be expected under a certain penetration level of distributed PV generation?
2. How sensitive are the unbalance factor and the pu voltage to the change in distributed PV penetration?
3. How does location of the distributed PV generation affect unbalance and pu voltage across the feeder?
4. What is the maximum penetration of distributed PV generation in different locations of the system without surpassing maximum allowed unbalance and/or pu voltage?
5. In what time of the day maximum unbalance can be expected?
6. How might cloud transients affect voltage unbalance?

Since considering several different cases is costly in time and requires more data research, the project aims to cover worst-case scenarios in order to obtain relevant results.

3.2.2 FORMATIVE OBJECTIVES

On a more academic level, the aim of this project is to gain valuable knowledge in the following fields that will serve as a base to both a professional or an academic career in the fields of renewable energy or power engineering:

2. Electrical power systems analysis, modelling and simulation.
3. Use of the OpenDSS software.
4. Electrical power quality issues.
5. Time-series load and irradiation data processing.

3.3 SCOPE AND LIMITATIONS

The scope of the project has included programming the required code, running the defined simulations on the two selected distribution feeders, and interpreting the results of voltage and unbalance levels, as described in 6 METHODOLOGY and 7 SIMULATED CASES.
Because of the rather limited time available, however, many assumptions and considerations have had to be made to be able to present some results, thus significantly limiting the impact of this project and relegating its interest to a mainly self-learning work. These considerations include:

- Power quality issues such as stability, harmonics distortion, and frequency variations are not studied.
- PV inverters and its behaviour have not been modelled.
- Modelling of feeders has not been the object of this study. The two feeders that have been used (see 6.6 DISTRIBUTION FEEDERS for more information) are publicly available models that have been used because of its readiness and availability. They do not represent a typical feeder in any country and do not present optimal characteristics for testing.
- Although it has been necessary to understand the structure of the code for the OpenDSS feeder models that have been used, a detailed review has not been necessary in order to perform the analysis. No modifications have been made to the tested feeder models.
- No energy storage for PV systems (i.e. batteries) has been considered.
- Model of PV loads is just a regular load with negative power rating. No harmonics or voltage regulation has been considered.
- Locations for load-curve and PV-curve data are not even in the same continent. Results are not realistic in that sense, although they do provide a set of data to test and learn from. These particular datasets have been used because they were readily available thanks to the collaboration between UNICAMP and University of Manchester in the field of smart grids.
- The program does not consider different irradiation levels across the feeder.
- All loads in the studied feeders have been considered to have the same behaviour. House occupation, appliance modelling, or different load usage have not been modelled. The same load-shape has been used for all residential loads.
- The load-shapes that have been used correspond to a primary substation located in Central Manchester (UK) that supplies an unknown set of loads. However, in this study it has been used to model the behaviour of residential loads placed in the distribution (secondary) side. There is, therefore, significant mismatch. This data was used because it was
- The simulations are all deterministic, as opposed to probabilistic analyses such as Monte Carlo simulations.
- The effects of high PV penetration on electrical equipment such as voltage regulators or transformers (e.g. tap changes) have not been considered.
- Testing of potential solutions to both unbalance and voltage issues have not been considered.
- Power quality issues have only been considered from an instantaneous point of view, although the severity of these issues is always assessed taking into account the time during which the issue occurs in real power distribution systems.
4 LITERATURE AND KEY CONCEPTS REVIEW

4.1 PHOTOVOLTAIC SYSTEMS AND ENERGY

A solar cell is an electrical device that converts the energy of light directly into electricity by the photovoltaic effect. It is a form of photoelectric cell, defined as a device whose electrical characteristics, such as current, voltage, or resistance, vary when exposed to light. When exposed to sunlight (or other intense light source), the voltage produced by a single solar cell is about 0.6 V, with the current flow being proportional to the light energy (photons).

A PV module is a packaged and connected assembly of solar cells. A solar panel is a set of solar photovoltaic (PV) modules electrically connected and mounted on a supporting structure. A PV array can be composed of PV cells or PV modules, although the latter is more common.

A review of PV systems and its challenges when dealing with partial shading is presented in Annex A.

4.2 THE ELECTRICAL GRID

4.2.1 OVERVIEW

The electric system is the group of elements that operate together in a determined territory to ensure satisfy its customer's electricity demand. It includes the electricity generation elements (combined-cycle plants, hydroelectric plants, etc), the high-voltage electricity transport or transmission lines, transformer substations that change the voltage from one level to another, medium and low voltage distribution lines that bring electricity to the customers, and a control centre from where the system is managed and operated to ensure that generation and consumption are balanced. A schematic representation of a typical electrical grid is shown in Figure 4.

Figure 4. General layout of an electricity grid. Depicted voltages and powers are typical for Germany and other European countries. Source: [7].
Recently, the \textit{smart grid} term has been adopted to refer to the new generation of electrical grid. A \textit{smart grid} is a modernized electrical grid that uses information and communications technology to gather and act on vast amounts of information, such as information about the behaviors of suppliers and consumers, normally via smart metering, to improve the efficiency, reliability, economics, and sustainability of the production and distribution of electricity.

\subsection*{4.2.2 POWER QUALITY}

Power quality is the term adopted to assess the fitness of electric power to consumer devices. High quality electricity means that the power that an electrical device is receiving from the electricity source it is connected to is adequate to its operation requirements. It is worth noting, however, that while "power quality" is a convenient term for many, it is the \textbf{quality of the voltage}—rather than power or electric current— that is actually described by the term.

Electrical power quality can be assessed by measuring a number of parameters:

- \textbf{Continuity of service}: interruptions are undesired and negatively affect power quality.

- \textbf{Frequency}: changes in nominal frequency can affect system performance.

- \textbf{Voltage magnitude}: variations in voltage magnitude are highly undesired, as they can affect the integrity of the equipment that is being supplied with electricity. Undervoltages, overvoltages, \textit{dips/sags}, swells, offsets, \textit{spikes/surges, unbalance}, and flickering, are all possible issues in regards to voltage magnitude.

- \textbf{Transient voltages and currents}: switching on/off of large loads normally causes transient voltages and currents.

- \textbf{Harmonics}: AC power is vulnerable to harmonics introduced by electronic equipment and interference.

Each of these power quality issues has different possible causes and its effects can be both localized or system-wide. In the context of this work, interest has been focused in two phenomena: voltage magnitude changes and voltage unbalance.

\subsubsection*{4.2.2.1 VOLTAGE MAGNITUDE CHANGES}

Although there are many types of issues related to changes in voltage magnitude, only the instantaneous type of fault in voltage magnitude will be considered. In this matter, all voltages across the feeder have to be comprised, at any time, between 1.05 pu and 0.95 pu. That is, maximum deviation from nominal pu voltage in any bus of the system cannot be more than 0.05 pu.

Voltage magnitude changes can have an effect on device integrity, power consumption, and device performance.

\subsubsection*{4.2.2.2 VOLTAGE UNBALANCE}

In a three-phase system, voltage unbalance takes place when the magnitudes of phase or line voltages are different and the phase angles differ from the balanced conditions (120° between each phase), or both [8].

Although there are a number of different definitions that are reviewed in [8], the true definition of the voltage unbalance factor (VUF) is defined as the ratio of the negative sequence voltage component \(V^{(2)}\) to the positive sequence voltage component \(V^{(1)}\). The
percentage voltage unbalance factor (% VUF) is therefore given by (1).

\[ \%VUF = \frac{V^{(2)}}{V^{(1)}} \times 100 \]  \hspace{1cm} (1).

Negative sequence voltage component \( V^{(2)} \) and positive sequence voltage component \( V^{(1)} \) can be calculated with the method of symmetrical components introduced by C. L. Fortescue. Fortescue’s work proves that an unbalanced system of \( n \) related phasors can be resolved into \( n \) systems of balanced phasors called the symmetrical components of the original phasors [9].

In the case of a three-phase system, the three balanced sets of components are (see Figure 5 and Figure 6):

- **Positive-sequence components**: consisting of three phasors equal in magnitude, displaced from each other by 120° in phase, and having the same phase sequence as the original phasors.
- **Negative-sequence components**: consisting of three phasors equal in magnitude displaced from each other by 120° in phase, and having the phase sequence opposite to that of the original phasors.
- **Zero-sequence components**: consisting of three phasors equal in magnitude and with zero phase displacement from each other.

![Figure 5](image1.png)  \hspace{1cm} **Figure 5.** Three sets of balanced phasors which are the symmetrical components of three unbalanced phasors. Source: [9].

![Figure 6](image2.png)  \hspace{1cm} **Figure 6.** Graphical addition of the components shown in Figure 5 to obtain three unbalanced phasors. Source: [9].
From this statement, (2) can be written.

\[ V_a = V_a^{(0)} + V_a^{(1)} + V_a^{(2)} \]
\[ V_b = V_b^{(0)} + V_b^{(1)} + V_b^{(2)} \]
\[ V_c = V_c^{(0)} + V_c^{(1)} + V_c^{(2)} \]  \hspace{1cm} (2).

Expressing \( V_b \) and \( V_c \) as a function of \( V_a \) and the operator \( a = e^{120^\circ} \), after some manipulations one can write (3), which represents an easy and fast way to calculate the sequence components of any of the three-phase magnitudes (it is applicable to both voltages – line to phase and line to line– and currents) when the respective unbalanced components are known (either as a result of running a power flow on the system under study or via real measurement).

\[
\begin{bmatrix}
V_a^{(0)} \\
V_a^{(1)} \\
V_a^{(2)}
\end{bmatrix} = \frac{1}{3} \begin{bmatrix}
1 & 1 & 1 \\
1 & a & a^2 \\
1 & a^2 & a
\end{bmatrix} \begin{bmatrix}
V_a \\
V_b \\
V_c
\end{bmatrix}
\]  \hspace{1cm} (3).

The effects of voltage unbalance are mainly perceptible in three-phase loads, such as induction motors, in which increased losses, overheating, vibration and noise, torque pulsation, and slip can appear [10].

4.3 POWER-FLOW ANALYSIS

4.3.1 DEFINITION

In power engineering, the power-flow study, or load-flow study, is a numerical analysis of the flow of electric power in an interconnected system. It analyses the power systems in normal, steady state operation.

The principal information obtained from a power-flow study is the magnitude and phase angle of the voltage at each bus, as well as the real and reactive power flowing in each line, for given load and generator real power and voltage conditions. Once this information is known, real and reactive power flow on each branch as well as generator reactive power output can be analytically determined. Power flow studies are of great importance in planning and designing the future expansion of power systems as well as in determining the best operation of existing ones [9].

The starting point in obtaining the data that must be furnished to the power-flow algorithm is the single-line diagram of the system. Other essential information includes transformer ratings and impedances, shunt capacitor ratings, and transformer tap settings.

4.3.2 MATHEMATICAL SOLUTION

Four potentially unknown quantities associated with each bus \( i \) are \( P_i \), \( Q_i \), voltage angle \( \delta_i \), and voltage magnitude \( |V_i| \). The so-called power-flow equations shown in (4) relate them all, where \( N \) represents all buses in the system and \( Y_{ik} \) is the \((i,k)\) element of the bus admittance matrix \( Y_{bus} \) that describes the system.

\[
\begin{bmatrix}
P_1 \\
Q_1 \\
P_2 \\
Q_2 \\
\vdots \\
P_N \\
Q_N
\end{bmatrix} = \begin{bmatrix}
Y_{11} & Y_{12} & \cdots & Y_{1N} \\
Y_{21} & Y_{22} & \cdots & Y_{2N} \\
\vdots & \vdots & \ddots & \vdots \\
Y_{N1} & Y_{N2} & \cdots & Y_{NN}
\end{bmatrix} \begin{bmatrix}
V_1 \\
\delta_1 \\
V_2 \\
\delta_2 \\
\vdots \\
V_N
\end{bmatrix}
\]

\hspace{1cm} (4).
\begin{align*}
P_i &= \sum_{k=1}^{N} |Y_{ik}V_iV_k| \cos(\theta_{ik} + \delta_k - \delta_i) \\
Q_i &= -\sum_{k=1}^{N} |Y_{ik}V_iV_k| \sin(\theta_{ik} + \delta_k - \delta_i) \tag{4}.
\end{align*}

Due to the nonlinear nature of this problem, numerical methods are employed to obtain a solution that is within an acceptable tolerance and guarantees algorithm convergence. In general terms, digital solutions of the power-flow problems follow an iterative process by assigning estimated values to the unknown bus voltages and by calculating a new value for each bus voltage from the estimated values and the real and reactive power specified. There are many plausible iterative techniques to accomplish this, such as Newton-Raphson, Gauss-Seidel, and others. Detailed explanations can be found in [9].
5 SOFTWARE TOOLS

The answers to the questions that have been presented in 3.2 OBJECTIVES have been obtained by means of one integrated software script/program that runs on MATLAB but also takes advantages of the circuit modelling and computing capabilities of OpenDSS, an open-source electrical distribution circuit analysis tool, with which MATLAB communicates through a Component Object Model (COM) interface during execution.

Basic information about these two programs is presented below. A more detailed review on how they have been integrated can be found under section 6 METHODOLOGY.

5.1 OPENDSS

OpenDSS (acronym for Open Distribution System Simulator) is an open source electrical power system simulation software developed by a team of power engineers that are members of the Smart Grid Resource Center at the Electrical Power Research Institute (EPRI) based in California, United States.

The following lines are a reproduction from EPRI’s website [12], where the source code and all necessary information and support can be found: "The OpenDSS is a comprehensive electrical power system simulation tool primarily for electric utility power distribution systems. It supports nearly all frequency domain (sinusoidal steady-state) analyses commonly performed on electric utility power distribution systems. In addition, it supports many new types of analyses that are designed to meet future needs related to smart grid, grid modernization, and renewable energy research. The OpenDSS tool has been used since 1997 in support of various research and consulting projects requiring distribution system analysis. Many of the features found in the program were originally intended to support the analysis of distributed generation interconnected to utility distribution systems and that continues to be a common use. Other features support analysis of such things as energy efficiency in power delivery and harmonic current flow. The OpenDSS is designed to be indefinitely expandable so that it can be easily modified to meet future needs."

In the context of this project, OpenDSS has been used to model the test feeders and perform the main power flow calculations. Details about the feeders can be found in 6.6 DISTRIBUTION FEEDERS.

OpenDSS uses its own .dss file extension but it is essentially a non-formatted text file format, so these files can be opened and edited with the most basic of text editors.

Various support PDF documents, programming examples and other help material can be found in the OpenDSS folder once it has been installed, but they are also available at [12].

5.2 MATLAB

MATLAB is a popular proprietary numerical computing environment and fourth-generation programming language. MATLAB allows matrix manipulations, plotting of functions and data, implementation of algorithms, creation of user interfaces, and interfacing with programs written in other languages, including C, C++, Java, Fortran and Python.

Because of its significant user base and on-line support community, high level of abstraction, flexibility, and powerful debugging features, which have all been thoroughly used in this work, it represents one of the most adequate and versatile environments for research and experimentation.
6 METHODOLOGY

6.1 OVERVIEW

The analysis procedure is reduced to the simulation of the connection of a certain amount of distributed PV generation panels (as specified by its $W_p$ peak-power rating) in a particular location of an electrical distribution feeder, and the posterior analysis of the effects on both the voltage and unbalance levels throughout the system.

Although the project has a clear electrical engineering focus, a very high percentage of the work time has been related to software, which is why a significant part of this report is dedicated to the code. The presented MATLAB program allows for multiple types of analysis in order to be able to provide relevant data to attain the project objectives. Even though the program does not have a GUI, it does use some of MATLAB’s configurable dialog boxes and standard input methods to allow basic interaction with the user, who is asked to select between various modes and input a number of parameters that will be used to perform the desired analysis.

![Flowchart of main program](image)

**Figure 7.** Overview of main program represented in a flow chart.
Such features allow the program to be run by executing the main script without the need to change any of its internal parameters to perform all the necessary analysis that fall in the scope of this project. A flow-chart that provides a general view of the analysis process and extraction of results is represented in Figure 7.

As it can be appreciated, on the one hand MATLAB is used to perform soft-computing tasks such as user input management, simulation management and data processing and plotting, while on the other hand OpenDSS is the main tool to compute and feed the raw results into MATLAB.

All the different parts of the main program, as well as the characteristics of the Load and PV curves and their necessary pre-processing steps, are explained with more detail in the following sections. Each section corresponds to a clearly defined section of the MATLAB main code or independent scripts.

6.2 INITIAL CONFIGURATION

The analysis parameters are defined during the initial configuration steps. The user selects the circuit to be analysed and inputs several other information and selections to set-up the desired analysis. A detailed flow-chart of this process is shown in Figure 8.

The key parameters that are hard-coded under the Parameter Definition Section on the main code are presented in Table 2.

As it can be seen in Figure 7, the program takes several user inputs. The definition of each type of input is presented in Table 3.

Once the circuit is selected and the inputs introduced, the MATLAB program only sends subsequent compile and solve commands to the OpenDSS through the COM interface and reads and processes the base results, which includes all the circuit’s loads information, electrical state on all buses, bus locations, and the computation of the unbalance on all 3-phase buses.

It is worth noting that thanks to the fact that system-wide load data is imported at this stage, the program is able to determine which is the worst-case scenario regarding the phase to which the majority of PV power has to be connected according to the MAX_PV_DIST parameter that has been presented in Table 2. This is expressed by means of a 3-element array called pvDist, which contains the pu amount of PV loading that will be distributed between phases ‘a’, ‘b’ and ‘c’. With this array, the total system load, and the PV penetration, the total amount of PV loading that must be connected to each phase can be determined as shown in (5).

\[
\text{pvLoadPerPhase}_{[1x3]} = \text{totalPV}_{[1x1]} \times \text{pvDist}_{[1x3]}
\]  

Finally, it is important to state that if the selected mode is Single Power Flow – Feeder Sensitivity to PV, the pvDist variable is set to be either [1 0 0], [0 1 0] or [0 0 1], depending on the selected phase in which the study will be performed – a, b, or c-, and the pvPenetration value is initially set to PV_PEN_INIT.
### Table 2. Relevant hard-coded parameters defined at the beginning of the main program.

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Default Value</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>PVPF</strong></td>
<td>1.00</td>
<td>PV panel typical operational power factor [13].</td>
</tr>
<tr>
<td><strong>MAX_PARAM</strong></td>
<td>40</td>
<td>The Maximum Parameter value defines the maximum % of system buses that might be considered valid to be included in the sub-group of buses specified by the Location Mode (Table 3).</td>
</tr>
<tr>
<td><strong>MAX_PV_DIST</strong></td>
<td>0.80</td>
<td>The Maximum PV Distribution value defines the per-unit value of total installed PV power that will be connected to the phase that has been determined to represent the worst-case scenario during the initial configuration.</td>
</tr>
<tr>
<td><strong>MAX_PV_PEN_SYS</strong></td>
<td>100.00</td>
<td>The Maximum PV Penetration in System value defines the maximum percentage of total installed PV in system relative to the total system load.</td>
</tr>
<tr>
<td><strong>MAX_PV_PEN_BUS</strong></td>
<td>100.00</td>
<td>The Maximum PV Penetration in Bus value defines the maximum percentage of installed PV relative to the total loading that is connected to the same bus to which a PV load is going to be connected. It has been fixed to 100.00 with the intention to represent a somehow realistic residential PV system, where any house would not connect more PV power than its own installed load power.</td>
</tr>
<tr>
<td><strong>MAX_UNBALANCE</strong></td>
<td>2.00</td>
<td>The Maximum Unbalance value is the threshold value that has been adopted to differentiate between acceptable/unacceptable levels of unbalance. The value of 2% is established by the ANEEL in Brazil [1].</td>
</tr>
<tr>
<td><strong>VPU_DEVIATION</strong></td>
<td>0.05</td>
<td>The PU Voltage Deviation value is the common deviation value (positive and negative) to differentiate between acceptable/unacceptable levels of per-unit voltage.</td>
</tr>
<tr>
<td><strong>AVAILABLE_MODES</strong></td>
<td>-</td>
<td>The Available Location Modes is a list that represents all the possible feeder locations in which the PVs can be connected. These locations represent the relative distance from the PVs to the feeder HV-MV substation and can be ‘close’, ‘far’, ‘medium’, and ‘random distribution’.</td>
</tr>
<tr>
<td><strong>PV_PEN_INIT</strong></td>
<td>0.001</td>
<td>The Initial PV Penetration parameter states the % of PV penetration that will be considered for the first run during the Feeder Sensitivity to PV Penetration analysis (see 6.5.1.2 Feeder Sensitivity to PV Penetration).</td>
</tr>
<tr>
<td><strong>RESIDENTIAL_CLASS</strong></td>
<td>1</td>
<td>OpenDSS load modelling syntax allows the user to define a class property for each load, so that actions can be focused on all elements of the same class without affecting elements from other classes.</td>
</tr>
<tr>
<td><strong>PV_CLASS</strong></td>
<td>10</td>
<td>Since the class property has to be an integer value, ‘1’ and ‘10’ have been adopted for residential and PV loads, respectively. This is a setting that works for the feeders that have been studied. All other classes (2, 3, …), if present, are considered of unknown nature and its management would depend on the simulated circuit.</td>
</tr>
</tbody>
</table>
Figure 8. Flow chart of the initial configuration steps.
VOLTAGE UNBALANCE CAUSED BY PV PENETRATION IN DISTRIBUTION FEEDERS

<table>
<thead>
<tr>
<th>User input</th>
<th>Default Value</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Circuit Master-file</td>
<td>-</td>
<td>The user is prompted to navigate through its hard disk using a standard OS window to select the desired .dss Circuit Master-file to be analysed. Ideally, this master-file will only contain element definitions and not solve or plot commands, which will be issued from the main MATLAB program when needed. The program is built to be capable of analysing virtually any type of feeder that includes location data, no matter the size, cabling or characteristics.</td>
</tr>
<tr>
<td>Circuit Type</td>
<td>Delta</td>
<td>The Circuit Type user input specifies the type of circuit that is being analysed: 3-wire ‘Delta’ or 4-four ‘Wye’.</td>
</tr>
<tr>
<td>Type of Analysis</td>
<td>Single</td>
<td>The Type of Analysis input allows the user to select between a ‘Single Power Flow’ and a ‘Time-series Power Flow’ kind of analysis. These two types of analysis are discussed with more detail under 6.5 TYPES OF ANALYSES.</td>
</tr>
<tr>
<td>Single Power Flow Mode</td>
<td>Snapshot</td>
<td>The Single Power Flow Mode lets the user choose between a ‘Snapshot’ type of solution, which consists of just one power flow with the defined PV penetration, or a ‘Find Maximum PV Penetration’ mode, which lets the user evaluate the sensitivity of the system to the increase of installed distributed PV generation.</td>
</tr>
<tr>
<td>Time-series Mode</td>
<td>Simple</td>
<td>Because the time-series analysis can be a long one, especially for big feeders, two Time-series Modes were defined: ‘Simple’, which only runs a time-series power flow on the circuit with PV and is mainly used for testing, and ‘Compare’, which runs a time-series analysis on the base circuit before doing it on the modified one. As a consequence, the latter allows for an accurate comparison of the relative effect of the PVs on the system.</td>
</tr>
<tr>
<td>PV and Load curves</td>
<td>-</td>
<td>If a ‘Time-series Analysis’ has been selected, the user is prompted to navigate through its hard disk and select the desired files that contain PV and Load time-curves that are necessary for the simulation. More details on these curves can be found in 6.7 TIME-SERIES DATASETS.</td>
</tr>
<tr>
<td>PV Penetration</td>
<td>20%</td>
<td>The PV Penetration value represents the amount of PV that will be installed in the system as a percentage of total system load.</td>
</tr>
<tr>
<td>Location Mode</td>
<td>Close</td>
<td>The Location Mode, the value of which is limited to the AVAILABLE_MODES presented in Table 2, indicates the relative distance from the installed PVs to the feeder HV-MV substation. In mode ‘Close’, for example, all PVs will be connected to buses that are electrically closest to the substation.</td>
</tr>
</tbody>
</table>

Table 3. User inputs that are used to configure the analysis.

6.3 FILTER ELIGIBLE GROUP OF BUSES

Once the characteristics of the analysis have been defined, it is necessary to obtain a group of buses where the PVs will be connected. Such group of buses will be located in the location specified by the user and must have enough base loading to allow for the PVs to be
connected without violating the MAX_PV_PEN_BUS parameter as defined in Table 2. A flow chart of the whole bus filtering process is shown in Figure 9.

![Flow chart of the Bus Filtering process.](image)

The used algorithm is an expansive one, meaning that it will enlarge the candidate bus group until it proves to be big enough to allow for the PVs to be connected. It is easier to understand with an example: if the location mode is selected to be ‘close’, then the algorithm will first consider the \( P\% , P \in (0,100) \) of buses (5% for instance) that are closest to the substation, obtain the connected loads to these buses (and discard the buses with no connected loads), and check if the total loading per phase on these filtered buses is capable of absorbing the pvLoadPerPhase (see 6.2 INITIAL CONFIGURATION for reference) under the
limitations imposed by \texttt{MAX\_PV\_PEN\_BUS}.

If the group of buses is able to bear with the new PV connections, the current group of buses is considered to be valid. If it is not, then \( P \) will be increased by a certain amount and the process will be executed again. If eventually \( P \) exceeds \texttt{MAX\_PARAM} (see Table 2) it means that it is not possible to find a group of buses that complies with all requirements and a warning message is issued. The analysis is then continued with the achieved amount of PV penetration, which appears on all plots.

It is worth noting that in the case of a bus with a 3-phase load (delta load), the program only considers two out of the three phases as loaded, leaving one of them blank. The one that is left blank and therefore will not receive any PV is always the one that will make for a worst-case scenario, that is, the same one that has the highest loading on the system.

### 6.4 CONNECT PV GENERATORS

The PV connection procedure takes place after the bus group where the PVs will be connected has been defined (see 6.3 FILTER ELIGIBLE GROUP OF BUSES). This procedure goes consecutively through all the loads that are connected to the filtered group of buses and, if the determined PV loading on their phase(s) has not been reached, replicates each one of these load as a PQ load with negative active power rating, the \texttt{PVPF} power factor (\( Q=0 \)), and the \texttt{PV\_CLASS} class (see Table 2). From here on, the connected PVs are going to be treated as \textit{PV loads}. An example of an OpenDSS PV load creation line is shown below:

```plaintext
New Load.pv_742a Bus1=742.1.2 Phases=1 Conn=Delta Model=1 kV=4.8 kW=-8.5011 pf=0.95 status=variable class=10
```

A constant \( P + jQ \) load model (\texttt{Model=1} in OpenDSS) has been used, as it represents the operation of PV panels satisfactorily.

The process of creating the PV loads is divided in two parts: first, writing the OpenDSS load creation line to a \texttt{pv\_loads.dss} file that is created during execution, and second, sending the resulting file to the OpenDSS engine in order to update system. A final check is also performed to ensure the PVs have been connected satisfactorily.

A flow chart of the whole PV connection process is shown in Figure 10. The key variable in this process is \texttt{pv\_Remaining\_Load}, which is a three-element array that contains the PV load that remains to be connected in each of the three phases.
6.5 TYPES OF ANALYSES

6.5.1 SINGLE POWER-FLOW ANALYSES

A single power flow analysis consists in running a power flow to obtain the state of the system in one particular situation and analyse the results. As such, it does not account for
load consumption or PV generation variability over time.

In the program, two types of single power flow analyses that are run after connecting the PV loads (see 6.4 CONNECT PV GENERATORS) have been implemented: snapshot, which literally provides a snapshot of the state of the system with current installed loads and PVs according to user configuration (see 6.2 INITIAL CONFIGURATION), and the feeder sensitivity to PV penetration analysis, which connects one PV load in a location of the system as specified by user input and performs snapshot power flow analyses for different and increasing values of the power rating of such PV, keeping track of the maximum unbalance in feeder for each run.

More details about both analyses are given below.

6.5.1.1 SNAPSHOT

The snapshot analysis is the most basic power flow analysis. It runs a power flow with the PVs connected to the feeder, thus providing the necessary data for comparison under fixed loading and PV penetration conditions.

This analysis is mainly related to objectives number 1 and 3, as stated in 3.2 OBJECTIVES, which are to find out about:

1. Expected % of unbalance under certain PV penetration.
2. Effects of PV location on unbalance across feeder.

Since the PVs are connected in the previous PV connection section in the code, the flow chart is as simple as it can be seen in Figure 11.

![Flow chart of the Snapshot analysis.](image)

6.5.1.2 FEEDER SENSITIVITY TO PV PENETRATION

This analysis connects one PV generator in a location of the system as specified by user input and performs snapshot power flow analyses for different and increasing values of the power rating of such PV, keeping track of the maximum unbalance in feeder for each run. The analysis ends when either a determined level of unbalance or a fixed number of runs are reached.

This analysis is mainly related to objectives number 2, 3, and 4, as stated in 3.2 OBJECTIVES, which are to find out about:

1. Sensitivity of the unbalance factor to PV penetration.
2. Effects of PV location on unbalance across feeder.
3. Maximum PV penetration without violating maximum unbalance levels.
The flow chart representing the algorithm that runs this analysis is presented in  

\[ \text{Figure 12. Flow chart of the Feeder Sensitivity to PV Penetration analysis.} \]

6.5.2 **TIME-SERIES POWER FLOW ANALYSIS**

Time-series power flows take into account the variation in time of both the loads and the PV generation systems connected to the feeder, thus providing more realistic results and the possibility to identify critical situations during the day and the year.

Time-series studies require load/demand and PV generation time-series data (also known as load-shapes or load-curves) as inputs. This time-series data are feed into the MATLAB program, which runs the 1440 power flows that correspond to each of the 1440 minutes of the day. An example of such load-curves is shown in Figure 13 and Figure 14. The origin, necessary processing algorithms and characteristics of the load-shapes are discussed with more detail in section 6.7 **TIME-SERIES DATASETS**.

All input curves are normalized. For the load-curves, on the one hand, this means that they have values comprised between 0 and 1. On the other hand, PV-curves values are comprised between 0 and around 2. These values are actually used as a multiplier that modifies the nominal load rating of the corresponding elements for the different simulated times of the day. The total net active power installed on the feeder in minute \( m \), \( TP_m \), can then be expressed as it is shown in (6).
VOLTAGE UNBALANCE CAUSED BY PV PENETRATION IN DISTRIBUTION FEEDERS

\[ TP_m = \sum_{i=1}^{N} k_m P_{i}^L - \sum_{j=1}^{M} v_m P_{j}^{PV} \] (6)

Where \( N \) and \( M \) are the total number of loads and PVs connected to the feeder, respectively, \( k_m \) is the load multiplier value for minute \( m \) (drawn from one of the load-curves shown in Figure 13), \( v_m \) is the PV multiplier value for minute \( m \) (drawn from one of the irradiance-curves shown in Figure 14), and \( P_{i}^L \) and \( P_{j}^{PV} \) are the nominal active power ratings of each different load and PV installed in the feeder, respectively.

A flow-chart representing the time-series power flow algorithm is presented in Figure 15.

![Figure 13. Examples of normalized load curves for weekends and weekdays of different months of 2014. The y-values correspond to \( k_m \). Source: processed from [13].](image)

![Figure 14. Examples of normalized irradiation curves for different days of 2013 and 2014. The y-values correspond to \( v_m \). Source: processed from [15].](image)
Figure 15. Flow chart of the Time-series Power Flow analysis.

6.6 DISTRIBUTION FEEDERS

6.6.1 OVERVIEW

Two different distribution feeders have been used to test the program and present the results. Since the actual modelling of these feeders is out of the scope of this project, the two OpenDSS (.dss) models under consideration have been provided from trusted sources, namely the Institute of Electrical and Electronics Engineers (IEEE) and the Electrical Power Research Institute (EPRI), and are publicly available at [12] and can also be found in the local OpenDSS installation directory.

These models have been used without any alteration of its loads, transformers, lines or any other elements that were present in the original files. In fact, the program has been written with the aim to be flexible enough so that it is able to analyse any circuit with little to
no manual input/work. However, there are two basic considerations that need to be taken into account before analysing any circuit.

First, it is necessary to keep in mind that the MATLAB program is designed to be the control entity of the analysis: all actions that require an OpenDSS computation will be commanded from MATLAB. Consequently, OpenDSS circuit definition files must not contain any actions other than circuit definition lines. In the particular case of the two considered feeders, it has been necessary to comment the Solve command in both master-files. Publicly available OpenDSS models commonly include a two-level OpenDSS file structure: a low-level Circuit Definition file (also called Master-files) and a high-level Run file. Run files, in such cases, will be discarded and Master-files will be the ones that the user must select when prompted to do so.

Second, it is important to state the necessity of Energy Meters. EnergyMeters are one of the most complex OpenDSS objects and although it is not necessary to explain most of their details (the interested reader can find them on the OpenDSS documentation), it is important to note that one EnergyMeter must be installed at the beginning of the feeder. In the context of this project, the connection of an EnergyMeter at the secondary node of the substation is necessary for the OpenDSS to provide the electrical distances of all buses of the feeder to the substation transformer, which is essential information to perform the bus filtering process.

As a final note, XY coordinates are not necessary to perform the analysis proposed in the project as electrical distances are used instead.

6.6.2 37-BUS IEEE TEST FEEDER

This feeder, shown in Figure 16, is an actual feeder located in California. Its main characteristics are presented in Table 4.

<table>
<thead>
<tr>
<th>Characteristic</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Connection type</td>
<td>Three-wire Delta</td>
</tr>
<tr>
<td>Nominal distribution voltage</td>
<td>4.8 kV</td>
</tr>
<tr>
<td>Number of buses</td>
<td>37</td>
</tr>
<tr>
<td>Number of loads</td>
<td>30 loads</td>
</tr>
<tr>
<td>Load classes</td>
<td>Unknown (class = 1), assumed residential</td>
</tr>
<tr>
<td>Total feeder load</td>
<td>2735 kVA</td>
</tr>
<tr>
<td>Load per phase (a / b / c)</td>
<td>810.18 kVA / 712.22 kVA / 1.213.20 kVA</td>
</tr>
<tr>
<td>Voltage at loads</td>
<td>4.8 kV</td>
</tr>
<tr>
<td>Types of loads</td>
<td>Aggregated, spot</td>
</tr>
<tr>
<td>Electrical model of loads</td>
<td>Constant PQ</td>
</tr>
<tr>
<td></td>
<td>Constant current</td>
</tr>
<tr>
<td></td>
<td>Constant impedance</td>
</tr>
<tr>
<td>Loading</td>
<td>Very unbalanced (highest unbalance is ~3.5%)</td>
</tr>
<tr>
<td>Voltage regulator</td>
<td>Substation voltage regulator consisting of two single-phase units connected in open delta.</td>
</tr>
<tr>
<td>Type of lines</td>
<td>All underground</td>
</tr>
</tbody>
</table>

Table 4. Main characteristics of the 37-Bus IEEE Test Feeder.

Although there are very few three-wire delta systems in use, there is a need to test software to assure that it can handle this type of feeder. This feeder also has one 4.8/0.48 kV transformer that feeds one load in node 775. All loads are delta-connected –mostly between two phases, but there are some three-phase loads–, and therefore the PVs that will be connected to this feeder during the simulations will also be delta-connected. This means that the PV load will be shared between the two phases between which it is connected.
All circuit files and documents for this feeder are publicly available for download in [17]. The circuit model has been used ‘as is’ with the exception of the addition of the EnergyMeter and the removal of the Solve command as commented in 6.6.1 OVERVIEW. The OpenDSS circuit model and a detailed description of its characteristics can be found in [16].

![Diagram of the 37-bus IEEE test feeder. Source: [16].](image)

6.6.3 2998-BUS EPRI TEST FEEDER (CKT5)

This feeder, shown in Figure 17, is an anonymized recreation of a real feeder located in an undisclosed location in the United States. Its main characteristics are presented in Table 5.

<table>
<thead>
<tr>
<th>Characteristic</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Connection type</td>
<td>Wye</td>
</tr>
<tr>
<td>Nominal distribution voltage</td>
<td>12.48 kV</td>
</tr>
<tr>
<td>Number of buses</td>
<td>2998</td>
</tr>
<tr>
<td>Number of loads</td>
<td>1379</td>
</tr>
<tr>
<td>Load classes</td>
<td>96% residential (class = 1), 4% unknown but assumed residential (class = 2)</td>
</tr>
<tr>
<td>Total feeder load</td>
<td>7677 kVA</td>
</tr>
<tr>
<td>Load per phase (a / b / c)</td>
<td>2.511,20 kVA / 2.707,20 kVA / 2.458,70 kVA</td>
</tr>
<tr>
<td>Voltage at loads</td>
<td>0.24 kV</td>
</tr>
<tr>
<td>Types of loads</td>
<td>Non-aggregated, spot</td>
</tr>
<tr>
<td>Electrical model of loads</td>
<td>Nominal linear P, quadratic Q (feeder mix)</td>
</tr>
<tr>
<td>Loading</td>
<td>Balanced (highest unbalance is ~0.35%)</td>
</tr>
<tr>
<td>Voltage regulator</td>
<td>None</td>
</tr>
<tr>
<td>Type of lines</td>
<td>-</td>
</tr>
</tbody>
</table>

**Table 5.** Main characteristics of the 2998-Bus EPRI Test Feeder.

---

1 Names and geographical information have been modified so that it is not possible to recognize this feeder.
This feeder is analysed without any modification at all. All circuit files and documents for this feeder are publicly available for download at [18] and found in the OpenDSS installation folder.

Because of the realism and details of this feeder, loads are modelled as single loads, not as aggregated loads as in the case of the 37-BUS IEEE TEST FEEDER. Therefore, PV loads in this feeder are connected parallel to every single load, which means that they are connected in low-voltage, mono-phasic lines and their installed power is quite small (a few kilowatts).

![Diagram of ckt5 circuit with line thickness proportional to power flow. Source: [18].](image)

**Figure 17.** Diagram of ckt5 circuit with line thickness proportional to power flow. Source: [18].

### 6.7 TIME-SERIES DATASETS

#### 6.7.1 OVERVIEW

Time-series datasets for both loads and PVs are necessary to perform the 6.5.2 TIME-SERIES POWER FLOW ANALYSIS. The characteristics of the datasets that have been used in this project and the conditioning processes that have been applied to them are explained in the following sections.

#### 6.7.2 LOAD CURVES

##### 6.7.2.1 OVERVIEW

The load curves that have been used in this project correspond to data from 2014 from the monitored primary substation in Central Manchester (UK) and can be downloaded from the website of *Electricity North West’s (ENW) CLASS Project* [13]. Monitoring began in April 2014, so there is no available data before that month.

Data readings are taken every minute, 24 hours a day, every day since monitoring started. There is one .csv file for every monitored day, with 1440 data points\(^2\). Unfortunately, there is no information available regarding the load classes that this substation feeds.

---

\(^2\) Although the analysed data are 1440 elements long corresponding to the 1440 minutes there are in one day, there is no predefined limit on their length.
The daily raw data files contain several monitored variables such as voltages, currents, active and reactive power, as well as the date and the time of the readings. A filtering and conditioning process has therefore been necessary to be able to feed this data into the program. The conditioning process is separated into three main steps: Processing, Averaging and Normalizing. These steps have been implemented as independent MATLAB scripts, as they have to be used only once.

6.7.2.2 PROCESSING

The Processing step is the first one. Upon pressing the Run command, the user is prompted to select two or more raw data files\(^3\). These files are processed in batch to extract the fields Date, Time, Active Power, and Power Factor readings. During this step, a simple algorithm to correct the values that are 0 is also applied. This step also plots all raw and processed load-curves for manual verification so that faulty load-curves can be detected and dismissed.

A flow-chart of the Processing algorithm can be seen in Figure 18. The resulting data for a day is shown in Figure 18.

---

\(^3\) If only one data file is to be processed, a copy of itself can make up for the second dataset.
Figure 18. Overview of the Load Curve Processing step.
6.7.2.3 AVERAGING

After 6.7.2.2 PROCESSING, the Averaging step is meant to take a group of daily load curves and average their active power $P$ data points for each different minute of the day in order to obtain a representative $P$ curve for such group of days.

To assess the quality of the averaging, i.e., to assess if it is reasonable to consider the averaged curve as representative of the group from which it has been calculated, a $Z$-test is performed for each minute of the day. The results are then represented in an array of $N$ elements, $q_{i,N}$, from which a quality index $Q$ is calculated as shown in (7). The minimum value under which the averaging cannot be considered satisfactory has been set to 0.9, which means that 90% of the $Z$-tests must be positive.

$$Q = \frac{\sum_{i=1}^{N} q_i}{N}$$ (7)

A flow-chart of the Averaging step is shown in Figure 20. The results obtained from this step are plotted in Figure 21. The relevancy of this step is explained in 7.1.2 TIME-SERIES SIMULATIONS.
Figure 20. Overview of the Load Curve Averaging process.

Figure 21. Result from the Load Curve Averaging process.
6.7.2.4 NORMALIZING

The last step in the load curve conditioning process is the Normalizing step. This step is the simplest of them: it is responsible for importing the $P$ readings of a group of datasets, finding the highest value $P_{\text{MAX}}$, dividing all $P$ values by $P_{\text{MAX}}$ and storing the result in a new field called $\text{LoadMult}$, which has values comprised in the range $[0,1]$ and it is therefore suitable to be fed into the program as a modifier of the actual installed power in all loads.

A flow-chart of the Averaging step is shown in Figure 22. The results obtained from this step are plotted in Figure 27. The relevancy of this step is explained in 7.1.2 TIME-SERIES SIMULATIONS.

![Diagram of the Load Curve Normalizing process](image)

**Figure 22.** Overview of the Load Curve Normalizing process.

6.7.3 IRRADIANCE CURVES

6.7.3.1 OVERVIEW

Since the power generation of the PV panels depend on the amount of irradiation they receive, time-series solar irradiance curves are necessary to model the generation of the PV panels throughout the system every moment of the day.

The irradiance curves that have been used in this project correspond to data from various months of 2013 and 2014 measured in the National Renewable Energy Laboratory’s Lowry Range Solar Station (lat.: 39.60701° N, long.: 104.58017° W, elev.: 1860 meters AMSL$^4$) located in the state of Colorado, US, and have been downloaded from its public website [15].

The measured variable that has been chosen to quantify the amount of irradiance is the Global Horizontal Irradiance, measured in W/m$^2$. Available data readings are taken every minute during the time when solar radiance is above 0 (it is therefore not 24-hour long). Data

$^4$ AMSL = Above Mean Sea Level.
is available since January 2008.

Since the data is not 1440 minutes (i.e. 24 hours) long and the measured variable is global irradiance, not PV power generation, a conditioning process has been necessary to be able to feed this data into the program. The conditioning process is separated into two main steps: Processing and Normalizing. These steps have been implemented as independent MATLAB scripts, as they have to be used only once.

6.7.3.2 PROCESSING

The Processing step consists in transforming the raw Global Horizontal Irradiance data that is available from sunrise to sunset, into 1440-minute long datasets that can be fed into the program for the Time-series Analysis. The algorithm is responsible for filling with zeros all the minutes of the day for which there is no Global Horizontal Irradiance data.

An example plot of a raw solar irradiance curve can be seen in Figure 23, while the result of the Processing step is shown in Figure 24.

![Figure 23](Image)

**Figure 23.** Example of data for 18/01/2014 from the NREL. Source: [15].

![Figure 24](Image)

**Figure 24.** Processed data from Figure 23.
6.7.3.3 NORMALIZING

Similarly to the Normalizing step in the case of the load curves explained in 6.7.2.4 NORMALIZING, it is necessary to normalize the irradiation curves to be able to feed the irradiation curves as an actual installed PV power modifier.

It is necessary to remember that the peak power $W_p$ defined for the PV panels corresponds to the power the panel produces under Standard Test Conditions (STC) that are specified in standards such as IEC 61215, IEC 61646 and UL 1703. These STC consider an irradiance of $1000 \text{W/m}^2$, with a spectrum similar to sunlight hitting the earth's surface at latitude $35^\circ \text{N}$ in the summer (air-mass 1.5) and the temperature of the cells being $25 \, ^\circ \text{C}$. Although the effects of temperature have not been considered (defining a more detailed PV model that considers the temperature coefficient would have been necessary, and time has been a significant constraint), it has been considered adequate to normalize all irradiance values in respect to the STC's $1000 \text{W/m}^2$.

For this reason, the Irradiance Normalizing step is responsible for importing the HorizontalIrradiance readings of one or more datasets, dividing all HorizontalIrradiance values by $1000 \text{W/m}^2$ and storing the result in a new field called $\textit{PVMult}$, which has values comprised in the range $[0, \infty]$ (although typically in $[0, 1.5]$) and it is therefore suitable to be fed into the program as a modifier of the actual installed power in all distributed PV generators.

A flow-chart of the Irradiance Normalizing step is shown in Figure 25. The results obtained from this step are plotted in Figure 26.

![Flow-chart of the Normalizing step for solar irradiance curves.](image)

**Figure 25.** Flow-chart of the *Normalizing* step for solar irradiance curves.
Figure 26. Normalized data from Figure 24.
7 SIMULATED CASES

7.1.1 SINGLE POWER-FLOW SIMULATIONS

7.1.1.1 SNAPSHOT SIMULATIONS

A range of snapshot simulations under different PV penetration levels and location modes were performed in the two feeders that have been presented in 6.6 DISTRIBUTION FEEDERS. The characteristics of these simulations are presented in Table 6. It must be noted that the adopted PV Penetration values have been selected so that the three location modes can bear the same amount of penetration without violating the MAX_PV_PEN_BUS parameter (see Table 2).

The simulated cases correspond to a hypothetical situation where both the PV and the loads are running on their nominal installed power (LoadMult = 1, PVMult = 1). It is clear that this case is not very realistic, and simulating situations such as 150% load/50% PV or vice-versa might have seemed more appropriate to simulate different situations during the day. However, since the results of this analysis cannot be extrapolated to any real situation for the reasons explained in 3.3 SCOPE AND LIMITATIONS and time-series simulations already offer realistic situations, further snapshot simulations have been deemed unnecessary.

<table>
<thead>
<tr>
<th>Case</th>
<th>Feeder</th>
<th>PV Penetration [%]</th>
<th>LoadMult</th>
<th>PVMult</th>
<th>Location</th>
<th>Time of execution(^5) [s]</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>IEEE 37-Bus</td>
<td>14</td>
<td>1</td>
<td>1</td>
<td>Close</td>
<td>6,71</td>
</tr>
<tr>
<td>2</td>
<td>IEEE 37-Bus</td>
<td>14</td>
<td>1</td>
<td>1</td>
<td>Middle</td>
<td>6,63</td>
</tr>
<tr>
<td>3</td>
<td>IEEE 37-Bus</td>
<td>14</td>
<td>1</td>
<td>1</td>
<td>Far</td>
<td>7,27</td>
</tr>
<tr>
<td>4</td>
<td>IEEE 37-Bus</td>
<td>12</td>
<td>1</td>
<td>1</td>
<td>Close</td>
<td>16,70</td>
</tr>
<tr>
<td>5</td>
<td>EPRI 2998-Bus</td>
<td>12</td>
<td>1</td>
<td>1</td>
<td>Middle</td>
<td>16,32</td>
</tr>
<tr>
<td>6</td>
<td>EPRI 2998-Bus</td>
<td>12</td>
<td>1</td>
<td>1</td>
<td>Far</td>
<td>17,80</td>
</tr>
</tbody>
</table>

Table 6. Snapshot simulation cases.

7.1.1.2 FEEDER SENSITIVITY TO PV PENETRATION SIMULATIONS

A range of feeder sensitivity to PV penetration simulations were performed under different location modes in the two feeders that have been presented in 6.6 DISTRIBUTION FEEDERS. The characteristics of these simulations are presented in Table 7 below.

Although the program lets the user choose between any of the three phases for this simulation, the number of simulations if all phases for each location mode would be considered would be too much (18 simulations would be necessary) and only the worst-case scenario has been considered. The worst-case scenario occurs when the PVs are connected to the phase that reaches the highest difference of net loading when compared to the heaviest-loaded phase.

Finally, simulation number 7 (see Table 7) has been considered with the intention to show what occurs when PVs are connected to the heaviest loaded phase, thus reducing loading unbalance until PV penetration is high enough to increase unbalance again.

\(^5\) Time of execution depends highly on the hardware on which the program is running, as well as the CPU and memory loadings at the time of execution. Therefore, it is only provided for rough comparison between program modes and feeders. It excludes time used for user input and is the result of one simulation, not an average obtained from several simulations.
7.1.2 TIME-SERIES SIMULATIONS

With the aim to study different realistic situations, several cases have been considered. These cases aim to be representative of the most unfavourable conditions in which the system might operate in different times of the year and are limited to the available data presented in 6.7 TIME-SERIES DATASETS.

On the one hand, residential load demand is dependant on the weather and therefore each season is expected to have different daily load-shapes. On top of that, differences between weekdays and weekends must also be taken into account. Consequently, one load-shape representing a typical weekday demand curve and another load shape representing a typical weekend day demand curve have been considered for four months that are as spaced as possible given the data availability limitations: April, June, August and October of 2014. These load-shapes have been normalized between 0 and 1 according to 6.7.2.4 NORMALIZING considering a group of datasets for the 4 months * 2 load-shapes/month = 8 load-shapes simultaneously, so that relative differences in demand between each period are taken into account. The eight different normalized load shapes are shown in Figure 27.

On the other hand, irradiation data, in addition to being dependant on the season, also varies with the specific cloud conditions of the day. For this reason, for each season two cases have been considered: a typical sunny day (low variability) and a day with transitioning clouds (high variability). Irradiation data has also been normalized according to 6.7.3.3 NORMALIZING. The eight different normalized irradiance shapes are shown in Figure 28.

If all possible cases were to be simulated (4 months with 2 types of load curves and 2 types of irradiation curves), 16 simulations per feeder would be necessary –32 in total–, number that would increase to 96 if the three location modes would have to be considered. After reviewing the resulting load and irradiance shapes, however, it is easily noticed that the differences that actually occur between curves for different months of the year are not so drastic. For the load curves, for instance, the maximum difference is of around 0.15 for both weekdays and weekends, which represents a change of approximately 20%. Weekdays and weekends, in contrast, do present significant differences. Therefore, with the aim to reduce the number of simulations and still obtain relevant results, it was decided to simulate only the worst-case scenarios: only the highest irradiance curves –one smooth, one variable– for the least load-intensive days of the year –weekdays and weekends–. Regarding the location mode, only the two extremes were considered: close and far.

All the different simulated cases are summed up in Table 8. As it can be seen, simulations for the IEEE 37-Bus circuit take around 2 minutes to run –1 minute for the system without PV and another minute for the system with PV–, while the EPRI 2998-Bus system needs as much as 40 minutes, 20 minutes for each case. This represents a 21x increment for a system 81x

<table>
<thead>
<tr>
<th>Case</th>
<th>Feeder</th>
<th>Loaded phase(s)</th>
<th>Bus</th>
<th>Location</th>
<th>Time of execution[^5] [s]</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>IEEE 37-Bus</td>
<td>a-b</td>
<td>701</td>
<td>Close</td>
<td>5,92</td>
</tr>
<tr>
<td>2</td>
<td>IEEE 37-Bus</td>
<td></td>
<td>729</td>
<td>Middle</td>
<td>6,01</td>
</tr>
<tr>
<td>3</td>
<td></td>
<td></td>
<td>738</td>
<td>Far</td>
<td>6,06</td>
</tr>
<tr>
<td>4</td>
<td>EPRI 2998-Bus</td>
<td>c</td>
<td>x-63680-1</td>
<td>Close</td>
<td>64,84</td>
</tr>
<tr>
<td>5</td>
<td>EPRI 2998-Bus</td>
<td></td>
<td>x-28294-1</td>
<td>Middle</td>
<td>41,99</td>
</tr>
<tr>
<td>6</td>
<td></td>
<td></td>
<td>x-74436-1</td>
<td>Far</td>
<td>39,20</td>
</tr>
<tr>
<td>7</td>
<td>IEEE 37-Bus</td>
<td>c-a</td>
<td>701</td>
<td>Close</td>
<td>5,84</td>
</tr>
</tbody>
</table>

[^5]: Time of execution calculated as the most computationally demanding case with highest irradiance curves. Three location modes: close, middle, far. 8 simulations per feeder. Table 7. Feeder Sensitivity to PV Penetration simulation cases.
bigger.

Finally, it must be noted that during each step of the time-series simulations all loads and all PVs will be multiplied by their corresponding multiplier, $LoadMult$ and $PVMult$ respectively. This is very unrealistic, but again time constraints have not allowed for a better simulation.

**Figure 27.** Normalized load data curves ($LoadMult$) for all considered months, weekends and weekdays.

**Figure 28.** Normalized horizontal irradiation curves ($PVMult$).
### Table 8. Time-series simulation cases.

<table>
<thead>
<tr>
<th>Case</th>
<th>Feeder</th>
<th>Load Curve</th>
<th>Irradiance Curve</th>
<th>PV Penetration [%]</th>
<th>PV Location</th>
<th>Time of execution [s]</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>IEEE 37-Bus</td>
<td>Weekdays-06-2014</td>
<td>07-17-2013-smooth</td>
<td>14</td>
<td>Close</td>
<td>127,76</td>
</tr>
<tr>
<td>2</td>
<td>IEEE 37-Bus</td>
<td>Weekdays-06-2014</td>
<td>07-17-2013-smooth</td>
<td>14</td>
<td>Far</td>
<td>130,20</td>
</tr>
<tr>
<td>5</td>
<td>IEEE 37-Bus</td>
<td>Weekends-06-2014</td>
<td>07-17-2013-smooth</td>
<td>14</td>
<td>Close</td>
<td>121,58</td>
</tr>
<tr>
<td>6</td>
<td>IEEE 37-Bus</td>
<td>Weekends-06-2014</td>
<td>07-17-2013-smooth</td>
<td>14</td>
<td>Far</td>
<td>123,34</td>
</tr>
<tr>
<td>9</td>
<td>EPRI 2998-Bus</td>
<td>Weekdays-06-2014</td>
<td>07-17-2013-smooth</td>
<td>12</td>
<td>Close</td>
<td>2479,80</td>
</tr>
<tr>
<td>10</td>
<td>EPRI 2998-Bus</td>
<td>Weekdays-06-2014</td>
<td>07-17-2013-smooth</td>
<td>12</td>
<td>Far</td>
<td>2521,50</td>
</tr>
<tr>
<td>11</td>
<td>EPRI 2998-Bus</td>
<td>Weekdays-06-2014</td>
<td>07-15-2013-variable</td>
<td>12</td>
<td>Close</td>
<td>2682,60</td>
</tr>
<tr>
<td>13</td>
<td>EPRI 2998-Bus</td>
<td>Weekends-06-2014</td>
<td>07-17-2013-smooth</td>
<td>12</td>
<td>Close</td>
<td>2543,30</td>
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<tr>
<td>14</td>
<td>EPRI 2998-Bus</td>
<td>Weekends-06-2014</td>
<td>07-17-2013-smooth</td>
<td>12</td>
<td>Far</td>
<td>2654,90</td>
</tr>
<tr>
<td>16</td>
<td>EPRI 2998-Bus</td>
<td>Weekends-06-2014</td>
<td>07-15-2013-variable</td>
<td>12</td>
<td>Far</td>
<td>2461,50</td>
</tr>
</tbody>
</table>

6 Time of execution depends highly on the hardware on which the program is running, as well as the CPU and memory loadings at the time of execution. Therefore, it is only provided for rough comparison between program modes and feeders. It excludes time used for user input and is the result of one simulation, not an average obtained from several simulations.
8 RESULTS

8.1.1 SINGLE POWER FLOW SIMULATIONS

8.1.1.1 SNAPSHOT SIMULATIONS

The results for the 37-Bus feeder (cases #1, #2, and #3 from Table 6) can be seen in Figure 29, Figure 30, and Figure 31. X-axes represent the feeder’s buses, ordered from closest to furthest electrical distance from substation.

The first fact to be noted is that it is an already unbalanced feeder, with a maximum default unbalance level of around 3.2%, which is already higher than the 2% limit that has been established. Nonetheless, a PV penetration of 14% raises the maximum unbalance from 3.2% to around 4.2% (~30% increment, although increments of up to 43% occur), when PVs are connected close to the feeder’s substation. Very similar results are obtained for the cases of middle and far modes. Unexpectedly, the increase in unbalance is not significantly dependant on the location for the simulated penetration level, as it can be seen on the last plot of each figure. A slightly higher unbalance towards the end of the feeder, however, might be appreciated for the case #3. In a similar fashion, the maximum unbalance change is close to 50% for cases #2 and #3, compared to the 43% for case #1.

As for the voltage changes, the largest increments occur in phase (b), which is the least loaded phase of the feeder and one of the phases holding the PV generators. Voltage increments of up to 2.5% are detected when PVs are connected close to the feeder’s substation, while 3% and 4% increments occur for the middle and far cases, respectively. There is some degree of dependence of the voltage increments to the location of the PV panels. For the close mode, increments are quite homogeneous across the feeder, as voltage changes are propagated from the beginning towards the end. For the middle mode, increments are also homogeneous but slightly higher around the middle of the feeder, where PVs are connected. When in far mode, the highest voltage increments are located towards the end of the feeder. All pu voltages remain inside the [0.95,1.05] limits with 14% PV penetration.

The results for the 2998-Bus feeder (cases #4, #5, and #6 from Table 6) can be seen in Figure 32, Figure 33, and Figure 34, and they are not very different from the 37-Bus results. X-axes represent the feeder’s buses, ordered from closest to furthest electrical distance from substation.

In regards of the unbalance levels, the default feeder unbalance is around 0.3%. Simulations with 12% PV penetration deliver increments of unbalance of up to 1500%, and around 500% for most cases. In fact, maximum unbalance increases to up to 1.1% for the close and middle modes, and to up to 1.2% for the far mode. Higher unbalance changes are concentrated close to the substation for the close mode if compared to middle and far, although some unexpectedly high unbalances occur in a number of nodes in all three cases. These nodes are in its majority on the primary of the small MV-LV transformers that feed the individual house loads (one must remember that PVs are connected to the secondary of the transformers, parallel to the house load). These primaries have a low kVA_{SC} and are therefore significantly affected by the raise in voltage caused by the PVs. Finally, the end of the feeder is more unbalanced for the middle and far modes than for close mode.

Voltage changes offer some interesting results. The largest increments occur in phase (c), where the PVs are connected, and phase (a) suffers from voltage dips that become more
significant towards the end of the feeder, probably because of the effect of mutual impedance. There are some buses that suffer no change at all for one of their phases. For mode close, voltage increments are around 1.5%, while they go up to 2% and 2.5% for modes middle and far, respectively, and always with the highest increments towards the end of the feeder (most distant from substation).
Figure 29. Results for case 1 from Table 6.
VOLTAGE UNBALANCE CAUSED BY PV PENETRATION IN DISTRIBUTION FEEDERS

Figure 30. Results for case 2 from Table 6.
Figure 31. Results for case 3 from Table 6.
Figure 32. Results for case 4 from Table 6.
Figure 33. Results for case 5 from Table 6.
VOLTAGE UNBALANCE CAUSED BY PV PENETRATION IN DISTRIBUTION FEEDERS

Figure 34. Results for case 6 from Table 6.
8.1.1.2 FEEDER SENSITIVITY TO PV PENETRATION SIMULATIONS

The results for the 37-Bus feeder (cases #1, #2, and #3 from Table 7) can be seen in Figure 35, Figure 36, and Figure 37.

As expected, both unbalance and voltage levels rise with PV penetration. Unbalance increases at a rate of approximately 0.083 % of unbalance per % of PV penetration, while voltage does it at a rate of around 0.002 pu / % of PV penetration, although neither of them are pure linear rates – they actually seem to be exponential – and present a degree of irregularity. For the close mode (case #1), a 2% increment of maximum unbalance relative to original maximum unbalance level is reached at 25.59% PV penetration, while voltage limit violation occurs much earlier, at around 16% PV penetration. For the middle mode (case #2), the 2% unbalance increment and the voltage limit violation are reached at 21.93% and 16% PV penetration, respectively. Finally, the same levels are reached within 16.82% and 16% PV penetration for the far mode (case #3).

The results for the 2998-Bus feeder (cases #4, #5, and #6 from Table 7) can be seen in Figure 38, Figure 39, and Figure 40.

Results for the bigger feeder offer some unexpected results, especially for the close mode (case #4). In this mode, the unbalance limit is never achieved: it has an exponential growing trend for PV penetrations of under 6%, but after that value it reached a maximum for ~7% PV penetration and starts decreasing again. Further simulations have been performed in this case and they show a stabilization of the unbalance at around 0.7% for higher penetration levels. For the other modes, middle and far, on the other hand, the limit unbalance level is reached at PV penetration levels of approximately 8% and 7%, respectively. There is voltage limit violation since the very beginning (PV penetrations under 1%) for all three simulations. The voltage issue is caused because in this case the entire PV load is connected to one single bus instead of being spread over a number of houses.

Lastly, Figure 41 shows what happens when PVs are connected to the most-favourable case for the 37-Bus feeder, helping to balance the circuit thus reducing the unbalance level until 21% penetration, where it starts raising again and finally tops the 2% increase at 80% PV penetration.
Figure 35. Results for case 1 from Table 7.

Figure 36. Results for case 2 from Table 7.
Figure 37. Results for case 3 from Table 7.

Figure 38. Results for case 4 from Table 7.
Figure 39. Results for case 5 from Table 7.

Figure 40. Results for case 6 from Table 7.
8.1.2 TIME-SERIES SIMULATIONS

The time-series results for the smaller, IEEE 37-Bus feeder, which correspond to cases #1 to #8 in Table 8, are presented in Figure 42, Figure 43, Figure 44, Figure 45, Figure 46, Figure 47, Figure 48, and Figure 49. The characteristics of the results are shown in Table 9, where some results for the default cases –0% PV penetration– are also presented as reference.

The first fact to be noticed is that weekdays bear higher unbalances than weekends, which could have already been guessed by noticing the higher $LoadMult$ values during weekdays and keeping in mind that the feeder is very unbalanced by default, which is why the unbalance without any PV at all is already high.

For the weekday simulations (cases #1 to #4), on the one hand, maximum unbalances occur mostly around midday (10:00 to 12:00) or even in the previous hours, when the sun starts to shine before people start their working day. The shape of the default maximum unbalance curve –without PV–, however, is not modified. Higher maximum unbalance changes are detected for variable days when compared to smooth days (32% and 39% vs 20% and 30%), although that is mostly caused by the higher $PVMult$ values present in the variable day. Regarding the location of the highest unbalances, the most unbalanced buses are always located at the furthest electrical distance from the substation, and the far mode offers higher unbalances than the close mode (10pp\(^7\) and 7pp\(^8\) differences). There are no voltage limit violations in any of the simulated cases. It is also interesting to see that PVs can actually help reduce the unbalance levels in the system, especially during the evening. Lastly, since PV generators have no inertia, unbalance levels are indeed very dependent on irradiance levels, with the maximum unbalance curves being nearly identical in shape to the irradiation curves.

\(^7\) pp = percentage points.
\(^8\) pp = percentage points.
In the case of the weekend simulations (cases #5 to #8), on the other hand, distributed PVs modify the shape of the maximum unbalance curve, increasing its values for almost all minutes and showing a peak near midday (11:00), instead of having a nearly constant daily unbalance curve. The increments in the unbalance factor are significantly higher (~25pp\(^9\) higher) than in the weekdays, reaching the 58% mark, with slightly higher values for the variable days (#7 and #8) than for the smooth days (#5 and #6). This is due to lighter load curves during the weekend (around 40% lighter). Maximum unbalances occur in the furthest buses for all simulated cases. Regarding the location mode, unbalances are higher in the far mode (#6 and #8) –by 10pp and 2pp– than in close mode (#5 and #7). There are no voltage limit violations in any of the simulated cases, although voltage changes are sometimes positive but other times negative during the day. Again, the maximum unbalance curves are nearly identical in shape to the irradiation curves.

<table>
<thead>
<tr>
<th>Case</th>
<th>Max VUF [%]</th>
<th>Max VUF change [%]</th>
<th>Time(s) of the day when max VUF occurs</th>
<th>Location of highest VUF buses</th>
<th>Violation of voltage limit</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>Default weekdays</td>
<td>3,2</td>
<td>-</td>
<td>12:00</td>
<td>-</td>
<td>No</td>
<td>-</td>
</tr>
<tr>
<td>1</td>
<td>3,6</td>
<td>20</td>
<td>07:00 &amp; 12:00</td>
<td>End of feeder (735 &amp; 740)</td>
<td>No</td>
<td>There’s VUF reduction from 16:00 to 20:00. Unbalance follows solar variability.</td>
</tr>
<tr>
<td>2</td>
<td>4,1</td>
<td>30</td>
<td>12:00</td>
<td>End of feeder (735 &amp; 740)</td>
<td>No</td>
<td>There’s VUF reduction from 16:00 to 20:00. Unbalance follows solar variability.</td>
</tr>
<tr>
<td>3</td>
<td>4,3</td>
<td>32</td>
<td>11:00</td>
<td>End of feeder (735 &amp; 740)</td>
<td>No, but close to limit</td>
<td>VUF reductions happen during early morning and late evening. Unbalance follows solar variability.</td>
</tr>
<tr>
<td>4</td>
<td>4,9</td>
<td>39</td>
<td>10:00 to 11:00</td>
<td>End of feeder (735 &amp; 740)</td>
<td>No, but close to limit</td>
<td>Unbalance follows solar variability.</td>
</tr>
<tr>
<td>Default weekends</td>
<td>1,5</td>
<td>-</td>
<td>10:00 to 20:00</td>
<td>-</td>
<td>No</td>
<td>-</td>
</tr>
<tr>
<td>5</td>
<td>2,7</td>
<td>48</td>
<td>11:00 to 13:00</td>
<td>End of feeder (735 &amp; 740)</td>
<td>No</td>
<td>Voltage changes differ during the day. Unbalance follows solar variability.</td>
</tr>
<tr>
<td>6</td>
<td>3,2</td>
<td>58</td>
<td>11:00 to 13:00</td>
<td>End of feeder (735 &amp; 740)</td>
<td>No</td>
<td>Voltage changes differ during the day. Unbalance follows solar variability.</td>
</tr>
<tr>
<td>7</td>
<td>3,0</td>
<td>50</td>
<td>11:00</td>
<td>End of feeder (735 &amp; 740)</td>
<td>No</td>
<td>Unbalance follows solar variability.</td>
</tr>
<tr>
<td>8</td>
<td>3,6</td>
<td>52</td>
<td>11:00</td>
<td>End of feeder (735 &amp; 740)</td>
<td>No</td>
<td>Unbalance follows solar variability.</td>
</tr>
</tbody>
</table>

Table 9. Key characteristics of the results #1 to #8 from Table 8.

\(^9\) pp = percentage points.
Figure 42. Results for case 1 from Table 8.
Figure 43. Results for case 2 from Table 8.
**Figure 44.** Results for case 3 from Table 8.
**Figure 45.** Results for case 4 from Table 8.
Figure 46. Results for case 5 from Table 8.
Figure 47. Results for case 6 from Table 8.
Figure 48. Results for case 7 from Table 8.
Figure 49. Results for case 8 from Table 8.
The time-series results for the bigger, EPRI 2998-Bus feeder, which correspond to cases #9 to #16 in Table 8, are presented in Figure 50, Figure 51, Figure 52, Figure 53, Figure 54, Figure 55, Figure 56, and Figure 57. The characteristics of the results are shown in Table 10, where some results for the default cases –0% PV penetration– are also presented.

The first fact to be noticed is that, unlike the IEEE feeder, weekdays do not bear significantly higher unbalances than weekends because in this case the feeder is quite balanced by default.

For the weekday simulations (cases #9 to #12), on the one hand, maximum unbalances occur mostly around midday (10:00 to 13:30) and once at 08:00, when the sun starts to shine before people start their working day. The shape of the default maximum unbalance curve – without PV– is significantly modified when adding PVs, as it changes from flat to being almost identical to the irradiation curve. Higher maximum unbalance changes are detected for variable days when compared to smooth days (70% and 75% vs 75% and 80%), although that is mostly caused by the higher PVMult values present in the variable day. The maximum 2% unbalance level is not surpassed in any case. Regarding the location of the highest unbalances, unexpectedly the most unbalanced buses are not always located at the furthest electrical distance from the substation –as it was the case with the IEEE feeder–, but instead they are mainly concentrated on certain nodes around the middle of the feeder, with fewer cases distributed throughout the feeder. The far cases always offer higher unbalances when compared to the close cases, and also present more concentration of unbalanced nodes toward the end of the feeder, although none of them exceed 3% of the time. There are no voltage limit violations in any of the simulated cases.

In the case of the weekend simulations (cases #13 to #16), on the other hand, the highest unbalances occur during the morning, from 08:30 to 14:00 for the smooth cases and from 10:30 to 13:00, with some spikes earlier in the morning, for the variable cases. Since the weekends have a lighter load curve than weekdays (around 40% lighter), unbalance increments are around 5% higher than in weekdays. The highest unbalances are located around the middle of the feeder, although for the far cases furthest nodes also hold highest unbalance a number of times. There are no voltage limit violations in any of the simulated cases, although the voltage is often near the upper 1.05pu limit.
<table>
<thead>
<tr>
<th>Case</th>
<th>Max VUF [%]</th>
<th>Max VUF change [%]</th>
<th>Time(s) of the day when max VUF occurs</th>
<th>Location of highest VUF buses</th>
<th>Violation of voltage limit</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>Default weekdays</td>
<td>0,3</td>
<td>-</td>
<td>All day long</td>
<td>-</td>
<td>No</td>
<td>-</td>
</tr>
<tr>
<td>9</td>
<td>1,1</td>
<td>70</td>
<td>10:00 to 13:30</td>
<td>Relatively close to substation</td>
<td>No</td>
<td>Unbalance follows irradiation curve.</td>
</tr>
<tr>
<td>10</td>
<td>1,2</td>
<td>75</td>
<td>10:00 to 13:30</td>
<td>Middle of system</td>
<td>No</td>
<td>Unbalance follows irradiation curve.</td>
</tr>
<tr>
<td>11</td>
<td>1,3</td>
<td>75</td>
<td>10:30 to 13:00</td>
<td>Relatively close to substation</td>
<td>No</td>
<td>Unbalance follows irradiation curve.</td>
</tr>
<tr>
<td>12</td>
<td>1,4</td>
<td>80</td>
<td>08:00 and 10:30 to 13:30</td>
<td>Close and middle</td>
<td>No</td>
<td>Unbalance follows irradiation curve.</td>
</tr>
<tr>
<td>Default weekends</td>
<td>0,2</td>
<td>-</td>
<td>All day long</td>
<td>-</td>
<td>No</td>
<td>-</td>
</tr>
<tr>
<td>13</td>
<td>1,0</td>
<td>75</td>
<td>08:30 to 14:00</td>
<td>Middle of system</td>
<td>No, but close</td>
<td>Unbalance follows irradiation curve.</td>
</tr>
<tr>
<td>14</td>
<td>1,1</td>
<td>80</td>
<td>08:30 to 14:00</td>
<td>Middle of system, but end nodes also affected</td>
<td>No, but close</td>
<td>Unbalance follows irradiation curve.</td>
</tr>
<tr>
<td>15</td>
<td>1,2</td>
<td>85</td>
<td>08:30 and 10:30 to 13:00</td>
<td>Middle of system</td>
<td>No, but close</td>
<td>Unbalance follows irradiation curve.</td>
</tr>
<tr>
<td>16</td>
<td>1,3</td>
<td>85</td>
<td>08:30 and 10:30 to 13:00</td>
<td>Middle of system, but end nodes also affected</td>
<td>No, but close</td>
<td>Unbalance follows irradiation curve.</td>
</tr>
</tbody>
</table>

Table 10. Key characteristics of the results #9 to #16 from Table 8.
Figure 50. Results for case 9 from Table 8.
Figure 51. Results for case 10 from Table 8.
Figure 52. Results for case 11 from Table 8.
Figure 53. Results for case 12 from Table 8.
Figure 54. Results for case 13 from Table 8.
Figure 55. Results for case 14 from Table 8.
Figure 56. Results for case 15 from Table 8.
Figure 57. Results for case 16 from Table 8.
9 CONCLUSIONS

This project has explained the methodology and presented the results for various power flow simulations involving two very different feeders and a range of distributed PV penetration worst-case scenarios, from which it has been possible to obtain some answers to the proposed questions in 3.2 OBJECTIVES. The obtained results, however, are mixed and depend on the feeder.

In regards to objectives 1 and 2, both unbalance and voltage levels rise with PV penetration as expected, and they do it at a fairly exponential rate but with significant irregularity. During the single-power flow simulations for PVs connected in a group of nodes, it has been found that a relatively low PV penetration (12%~14%) can raise the maximum unbalance by as much as 1500% on a large feeder with low default unbalance, although lower increments (around 45%) are also detected on a smaller, originally more unbalanced feeder. From the more realistic time-series simulations, however, the maximum unbalance changes have been 85% and 60%, respectively. Voltage levels, on the other side, appear to be less sensitive to increments of PV penetration. Rises of up to 4% have been detected, although all pu voltages have remained inside the [0.95,1.05] limits in all single power-flow and time-series simulations.

However, it is quite the opposite when PV is only connected to one node. Unbalance violation has occurred at as little as 16.82% PV penetration for the IEEE feeder and at as little as 7% for the EPRI feeder. Generally, though, voltage limit violation occurs at a lower PV penetration than unbalance violation.

Regarding objectives 3 and 4, in most cases the highest unbalances occur towards the end of the feeder, in the nodes that are electrically furthest away from the substation, which are also the nodes that have a lower short-circuit rating. Snapshot simulations do not present such dependency as clearly, but in the time-series simulations, PVs connected at the end of the feeder cause significantly higher unbalances (up to 10% higher) than in the close cases. During the sensitivity to PV penetration simulations in the IEEE feeder, a 2% increment of maximum unbalance relative to original maximum unbalance level is reached at 25,59%, 21,93% and 16,82% PV penetrations levels for modes close, middle and far, respectively. For the EPRI feeder, unbalance limit is never achieved for the close mode, but 8% and 7% of PV penetration levels are enough on modes middle and far.

In the context of objective 5, for the IEEE feeder, on weekday simulations, maximum unbalances occur mostly around midday (10:00 to 12:00) or even in the previous hours, when the sun starts to shine before people start their working day. The shape of the default maximum unbalance curve –without PV–, however, is not modified. In the case of the weekend, on the other hand, distributed PVs modify the shape of the maximum unbalance curve, increasing its values for almost all minutes and showing a peak near midday (11:00), instead of having a nearly constant daily unbalance curve. The increments in the unbalance factor are significantly higher (~25pp10 higher) than in the weekdays. Voltage is not an issue during time-series simulations.

On the EPRI feeder, for the weekday simulations, on the one hand, maximum unbalances occur mostly around midday (10:00 to 13:30). The shape of the default maximum unbalance curve –without PV– is significantly modified when adding PVs, as it changes from flat to being almost identical to the irradiation curve. Higher maximum unbalance changes are detected for
variable days when compared to smooth days, although that is mostly caused by the higher $PVMult$ values present in the variable day. Voltage is not an issue during time-series simulations. In the case of the weekend simulations, on the other hand, the highest unbalances occur during the morning, from 08:30 to 14:00 for the smooth cases and from 10:30 to 13:00, with some spikes earlier in the morning, for the variable cases. Since the weekends have a lighter load curve than weekdays (around 40% lighter), unbalance increments are around 5% higher than in weekdays.

Finally, regarding objective 6, it must be concluded that the time at which the highest unbalances occur is directly correlated to the higher irradiance periods. Variability in irradiance is translated to variability in unbalance almost instantly.

$^{10}$ pp = percentage points.
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Universidade Estadual de Campinas (UNICAMP)
Faculdade de Engenharia Elétrica e de Computação (FEEC)
Departamento de Sistemas de Energia Elétrica

EA006 – GRADUATE PROJECT WORK
RESEARCH ON THE VOLTAGE UNBALANCE CAUSED BY THE INCREASE IN PENETRATION OF PHOTOVOLTAIC SYSTEMS IN ELECTRICAL ENERGY DISTRIBUTION FEEDERS

EA006 – TRABALHO DE FIM DE CURSO (TFC)
INVESTIGAÇÃO DO DESEQUILÍBRO DE TENSÃO RESULTANTE DO AUMENTO NA PENETRAÇÃO DE SISTEMAS FOTOVOLTAICOS EM ALIMENTADORES DE DISTRIBUIÇÃO DE ENERGIA ELÉTRICA

ANNEX A
RELIEVING OF CLOUD TRANSIENT EFFECTS ON PV SYSTEMS: PV ARRAY CONFIGURATIONS, SYSTEM ARCHITECTURES AND CONVERTER CIRCUIT TOPOLOGIES

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1 MOTIVATION

According to [1], shading of as little as 9% of a solar system connected to a central inverter, can lead to a system-wide decline in power output up to as much as 54%. As a solution option to decrease the effects of cloud transients and therefore partial shading (see Figure 1) in solar photovoltaic (PV) installations, different PV control and circuit techniques can be adopted.

![Figure 1. Array of PV modules under partial shading. Source: [1].](image)

In [1], a complete review of methods for extracting the maximum power of partially shaded PV arrays, which is equivalent to relieving the effects of cloud transients, is presented. The solutions were classified into four main groups:

**Group 1.** This group includes modified maximum power point tracking (MPPT) techniques to automatically detect the global maximum power point (MPP). These techniques can be based on, for example, Fibonacci search, neural networks, and particle swarm optimization;

**Group 2.** The second category includes different array configurations for interconnecting PV modules: series-parallel, total-crosstie, and bridge-link configurations. The configuration can decrease the current that flows through the shaded cell, blocking the operation of bypass diodes. In [21], seven experimental tests were performed to evaluate the difference in the active power generated by PV cell arrays with parallel and series configurations. Figure 2 shows the results of this comparison, where the bars are normalized by the power generated with parallel configuration. Compared with the traditional series-parallel array configuration, total-crosstie and bridge-link configurations can even improve the MPP of the PV system under partial shading;

**Group 3.** The third category includes different PV system architectures. The main architectures are: centralized, series-connected microconverters, parallel-connected microconverters, and microinverters. Except for the central architecture, other architectures are suitable for partial shading conditions;

**Group 4.** The fourth category includes different converter topologies: multilevel converters, voltage injection circuits, generation control circuits, module
integrated converters, and multiple-input converters. The choice of the most suitable converter topology depends on several aspects, the main advantages and disadvantages of which are presented in [1].

**Figure 2.** Comparison of power generation for parallel and series configuration of PV systems. Source: [21].
2 INTRODUCTION

2.1 ELECTRICAL PROPERTIES OF PV ARRAYS

A solar cell is an electrical device that converts the energy of light directly into electricity by the photovoltaic effect. It is a form of photoelectric cell, defined as a device whose electrical characteristics, such as current, voltage, or resistance, vary when exposed to light. A PV module is a packaged and connected assembly of solar cells. A solar panel is a set of solar photovoltaic (PV) modules electrically connected and mounted on a supporting structure. A PV array can be composed of PV cells or PV modules, although the latter is more common.

Figure 3 illustrates typical current–voltage and power–voltage curves for a homogeneous PV array under uniform insolation of all the PV modules. $V_{mpp}$ and $I_{mpp}$ represent the voltage and the current, respectively, at which the PV array operates at the maximum power point (MPP), thus providing the most amount of power. $I_{sc}$ is used to denominate the short-circuit current, and $V_{oc}$ indicates the open-circuit voltage.

![Figure 3](image)

**Figure 3.** Characteristic curves of a PV array. (a) Current-voltage curve and (b) power voltage curve. Source: [22].

When exposed to sunlight (or other intense light source), the voltage produced by a single solar cell is about 0.6 $V_{dc}$, with the current flow (amps) being proportional to the light energy (photons).

From an electrical standpoint, the PV module behaves as a non-ideal voltage source: voltage depends on the generated current. On top of that, the electrical curves depend on temperature and irradiation levels (Figure 4). However, one can notice that the MPP voltage has a small variation within a wide range of the irradiance on a PV module, as well as that the MPP current of a PV module can be considered nearly proportional to the irradiance value.
ANNEX A: RELIEVING OF CLOUD TRANSIENT EFFECTS ON PV SYSTEMS

Figure 4. I-V, P-V, and temperature dependence curves for a 265 Wp MLE module. Source: Mitsubishi Electric.

2.2 BASIC PV ARRAY CONFIGURATIONS

The term PV array configuration pertains to the interconnections of individual PV cells/modules in a larger, multi-cell/module PV array.

The most basic series and parallel array connections for PV panels are shown in Figure 5. In a series connection, each PV panel contributes its part to the total array voltage, which is the sum of all the panel voltages, while the current is equal for all panels. When connecting the panels in parallel, on the other hand, the result is an increase of output current while the voltage difference is the same for all panels.

Figure 5. Series (left) and parallel (right) PV array configurations. Source: [22].

2.3 PARTIAL SHADING EFFECTS ON PV ARRAYS AND BASIC SOLUTIONS

Various factors such as aging, dust, differences in manufacturing, and partial shading result in mismatching and, hence, non-uniform operation conditions. Mismatching in PV systems occurs when PV cells or modules with different operating characteristics are

---

11 Ideal conditions – not considering mismatch of electrical characteristics among PV panels and other external factors.
interconnected, often resulting in loss of power due to modules operating at less-than-nominal values. Partial shading is a frequent phenomenon that occurs when some cells within a module or array are shaded by buildings, birds, passing clouds, or some other object, as illustrated in Figure 1.

Since the short-circuit current of a PV cell is proportional to the insolation level, the partial shading effect is a reduction of the photocurrent for the shaded PV cells while the un-shaded cells continue to operate at a higher photocurrent. Since the string current must be equal through all the series-connected cells, the result is that the shaded cells operate in the reverse bias region to conduct the larger current of the un-shaded cells (Figure 6). The bias voltage $V_{\text{bias}}$ is the reverse voltage at which the shaded cells must operate to support the common string current. Under such conditions, the shaded PV cells (or modules) behave as an unwanted load, which will affect the performance of the array. The high bias voltage may also lead to an avalanche break down. This, in turn, may cause the thermal break down of the cell, creating a so-called hot spot. If untreated, excessive heating can result in cell burn out and create an open circuit in the shaded string.

![Figure 6. Current-voltage curve of a PV cell operating in a reverse bias region. Source: [20].](image)

The change in the I-V curve for PV panels on a series configuration under shading conditions is shown in Figure 9. This phenomenon has been partly addressed by introducing bypass diodes into modules to prevent deterioration of solar cells [22][23], as it is depicted in Figure 10. These diodes are connected parallel to the cells to limit the reverse voltage and, hence, the power loss in the shaded cells. For example, in a module with 36 series cells, one diode may be connected across each set of 18 series cells [20].

If the reverse voltage across the shaded cell increases, the bypass diode restricts the reverse voltage to less than the breakdown voltage of the PV cells. For example, the bypass diode that is shown in Figure 7 begins to conduct when (1) is satisfied, where $V_D$ is the forward voltage drop of the diode.

$$V_2 - \sum_{i=1}^{n} V_i \geq V_D, \quad i \neq 2$$  \hspace{1cm} (8)
Figure 7. By-pass diode across the PV cells when one cell is shaded. Source: [20].

Since the bypass diodes provide an alternate current path, cells of a module no longer carry the same current when partially shaded. Therefore, the power–voltage curve develops multiple maxima, shown in Figure 8.

Figure 8. Power–voltage curve of a PV array under partial shading conditions and forward-activated by-pass diodes. Source: [20].

The situation for parallel configurations is shown in Figure 11, where one can see that the shaded panel will be subject to a certain voltage imposed by its neighboring panels, which is different from its own voltage hence resulting in an unstable situation. The shaded panel(s) will again behave as an unwanted load and will draw current from the array (or from a battery, if the connection would not be through a converter/regulator). Figure 12 shows the implementation of blocking diodes that will serve as a partial solution to the shading problems in parallel configurations.

The cases reviewed above correspond to either series or parallel configurations. For a series-parallel (SP) configuration, the resulting solution is just the sum of the two simpler solutions, which one can see in Figure 13. It follows the scheme below:

- **Series connections** → by-pass diodes in parallel with each panel.
- **Parallel connections** → blocking diodes in series for each series of panels.

By-pass diodes are built-in in most modern panels, whereas blocking diodes must be installed in a case-by-case basis as it depends on the topology of the array. As a side note, typical regulators include blocking diodes to block any current flow from the batteries to the PV array. By-pass and blocking diodes can also be implemented in a cell-level instead of the reviewed module-level.
**INTRODUCTION**

**Figure 9.** Representation of the change in the I-V curve of a PV panel under shading conditions in a PV string. Source: [22].

**Figure 10.** Representation of the by-pass diodes in a PV string. Source: [22].

**Figure 11.** Representation of the partial shading situation for parallel configurations of PV modules. Source: [22].
Figure 12. Representation of the blocking diodes in a parallel PV panel array. Source: [22].

Figure 13. Representation of the by-pass and blocking diodes in a SP PV panel array. Source: [22].
3 MAXIMUM POWER POINT TRACKING TECHNIQUES (MPPTs)

3.1 FUNDAMENTALS

MPPT techniques find the voltage \( V_{mpp} \) and current \( I_{mpp} \) at which the PV array operates at the maximum power point (MPP), represented in Figure 3.

A regulator that incorporates an MPPT algorithm is a fully electronic system that varies the electrical operating point (namely, voltage) of the modules so that the modules are able to deliver maximum available power. Additional power harvested from the modules is then made available as increased battery charge current. MPPT can be used in conjunction with a mechanical tracking system, but the two systems are completely different. In order to the adjust the operating conditions to meet the \((V_{mpp}, I_{mpp})\) values, MPPT converters

However, MPPT techniques may malfunction for non-uniform insolation of the PV array due to irregular and multiple-maxima P-V curves as seen in Figure 8.

It is generally accepted that even the most basic MPPT controller will provide an additional 10-15% of charging capability when compared to standard PWM regulator.
4 PV ARRAY CONFIGURATIONS

4.1 INTRODUCTION

Different PV Array Configurations based on the two previously reviewed basic configurations are reviewed below as part of the solutions that belong to Group 2 (see Error! Reference source not found. Error! Reference source not found.). In [23], measurement results carried out on a 2.2kW plant confirm the interest in modifying array interconnections.

It is important to differentiate the configurations in PV cells (the basic element in PV generation, namely a wafer of silicon with proper connections) from configurations of PV modules (interconnected groups of PV cells forming a larger module, including casing and suitable connections for system integration). Previous research on modifying PV array interconnections of cells in PV modules [23][24] has shown promising simulation results of alternative cell interconnection schemes which reduced from 18% to 7% the amount of power lost in a module of 36 cells due to partial shadowing. Results for module-level solutions will be reviewed in this document.

4.2 SERIES-PARALLEL (SP)

The series-parallel (SP) topology, shown in Figure 14, which consists of a single inverter having a large number of module strings connected in parallel and is the most common topology for PV installations. SP configuration is characterized by having zero interconnection redundancy, which is why it is very sensitive to mismatch losses in the case of partial shading on the PV array [23] (in addition to variations in the nominal electrical properties of the integrating modules, as well as module failure/deterioration).

![Figure 14. Schematic representation of a series-parallel (SP) configuration. Source: [23].](image)

4.3 TOTAL-CROSSTIE (TCT)

The total cross-tied (TCT) configuration, shown on Figure 15, introduces additional connections in between strings of PV modules, so that each module is in series and parallel with another one. The creation of loops in the array increases redundancy in the circuit, which enables PV strings to have different currents values flowing through modules of a same string while respecting voltage constraints.

When a module is shadowed, its operating voltage is very similar to the un-shaded
modules, as it has been showed in Figure 4, but the current it generates decreases proportionally to the percentage of shadow.

![Schematic representation of a total-crosstie (TCT) configuration. Source: [23].](image)

**Figure 15.** Schematic representation of a total-crosstie (TCT) configuration. Source: [23].

### 4.4 BRIDGE-LINK (BL)

Just like the TCT, the BL configuration (shown in Figure 16) introduces additional connections in between strings of PV modules, thus increasing redundancy in the circuit which enables PV strings to have different currents values flowing through modules of a same string while respecting voltage constraints.

In the BL topology half of the interconnections in the TCT topology are removed. The BL arrangement has the advantage of having fewer interconnections, thus reducing cable losses and wiring time of the installation. However, in larger installations the TCT arrangement can be easier to wire because of the simplicity of the pattern.

![Schematic representation of a bridge-link (BP) configuration. Source: [23].](image)

**Figure 16.** Schematic representation of a bridge-link (BP) configuration. Source: [23].

### 4.5 RECONFIGURABLE PV ARRAYS

In [26], an interesting approach called Electrical Array Reconfiguration (EAR) applied on a PV generator of a grid-connected PV system is presented and reviewed.

The reconfiguration strategy is based on the fact that, on one hand, the maximum power point (MPP) voltage has a small variation within a wide range of the irradiance on a PV module, and, on the other hand, that the MPP current of a PV module can be considered nearly proportional to the irradiance value (see P-V and I-V examples of a Mitsubishi MLE PV...
module in Figure 4).

The EAR strategy is implemented by inserting a controllable switching matrix between the PV generator and the central inverter, which enables the generator to perform an irradiance equalization algorithm. The system is shown in Figure 17. The PV modules are arranged in a string of \( m \) series-connected rows of \( n \) parallel-connected PV modules (see Figure 18). The actual schematic for \( m=n=3 \) is shown in Figure 19, although the source paper uses the experimental setup shown in Figure 20, composed by a fixed matrix and an adaptive bank.

In order to maximize the available power at the PV generator’s output, it would be desirable that none of the series-connected rows of parallel-connected PV modules limits the current flowing in the single string. This behaviour can be achieved if the currents, and thus the irradiances, in the different rows are similar. Accordingly, the reconfiguration strategy is based on relocating the PV modules on the rows so that the irradiance equalization is achieved.

\[ \text{Figure 17. System architecture of the EAR experimental setup. Source: [26].} \]
Figure 18. String of series-connected, parallel PV module rows. Source: [26].

Figure 19. EAR switching matrix for \(m=n=3\). Source: [26].

Figure 20. Experimental EAR setup for a total of 10 PV modules. Source: [26].

As a result and in exchange of a substantial increase in complexity and cost, the PV system exhibits a self-capacity for real-time adaptation to the PV generator external operating conditions and improves the energy extraction of the system up to 3% in the experimental tests, which is not very significant.

A potential drawback of the reconfigurable PV array is its performance under severe shading conditions: with a low number of cells in the adaptive bank, it is not practical to compensate for all shaded cells. A large adaptive bank significantly increases installation cost and requires a complicated control algorithm, so applications in smaller systems might be preferable.

4.6 CONCLUSIONS

It should be noticed that, under normal operating conditions, SP, BL, and TCT topologies have equivalent power production. The cable losses due to the additional connectivity can therefore be considered negligible. Consequently, it is worth noting that modifying array interconnections does not affect inverter specifications [23].

Experimental results exposed in [23] have shown beneficial qualities of adding redundancy in array interconnections: additional maximum power output — BL and TCT array topologies increase the maximum power point (MPP) value by 2.3% and 3.8% respectively (although larger variations are expected with harsher environmental conditions) — and they deliver longer power production periods when compared to SP, as well as exhibiting multi-peak shedding.
Although topology modification appears to be a solution to fight against mismatch losses, an evaluation of the supplementary wiring and maintenance of the plant should be addressed to entirely establish the cost-effectiveness of changing traditional array designs. Considering the number of interconnections, the SP configuration has the minimum wiring, while the TCT configuration requires the maximum number of wires. The higher number of interconnections slightly increases the loss of the PV system due to the additional cable loss. However, the simpler pattern of TCT configuration for large PV arrays causes easier wiring process.
5 PV SYSTEM ARCHITECTURES

5.1 INTRODUCTION

The PV system architecture describes how the power electronics converters are connected to configurations of PV modules. An architecture that permits the module-level MPPT can often produce more energy than a string-level or array-level inverter.

Centralized architecture, series-connected microconverters, parallel-connected microconverters, and microinverters are the basic architectures for grid-connected PV systems, as shown in Figure 21, and will be reviewed in this section.

![Figure 21. PV System Architectures. (a) Centralized inverter, (b) Series-connected microconverter, (c) Parallel-connected microconverter, and (d) Microinverter. Source: [20].](image)

5.2 CENTRALIZED INVERTERS

The centralized or plant-oriented (PO) configuration (Figure 21(a)) is one of the most prevailing PV grid-connected system’s architectures for utility-sized solar plants due to its simplicity and low cost per peak kilowatt.

It assumes a single PV generator formed by a prefixed parallel connection of series-connected modules (also referred to as strings), which is linked to the grid through a single central inverter. To avoid any misunderstanding, it should be noted that these so-called strings are represented by single panels in Figure 21(a). The dc power extraction is carried out by the inverter input stage, which is generally driven by a maximum power point tracking (MPPT) algorithm in charge to ensure the PV generator operation at its maximum power point whatever the environmental (irradiance and temperature) conditions are [26].

Given the centralized topology, the MPPT algorithm is incapable of tracking the MPP of individual PV modules individually and it is therefore more vulnerable to loss of power due to shading and mismatching issues. Under shading conditions, by-pass diodes drive the current...
that their associated panels cannot to protect them against hot-spot effects. In doing so, however, they modify the original electrical characteristics curves by adding more maxima, resulting in problems with the MPPT techniques [27].

5.3 SERIES-CONNECTED MICROCONVERTERS

In the series-connected microconverters architecture, shown in Figure 21(b), each individual PV module is connected to a dc-dc converter that is responsible for the MPPT of that particular panel, thus increasing the system performance under shading or electrical mismatching at the expense of increased elements (i.e. cost) if compared to the centralized configuration. The dc-dc converters are then series-connected and fed into a central inverter.

5.4 PARALLEL-CONNECTED MICROCONVERTERS

In the parallel-connected microconverter architecture, shown in Figure 21(c), modules are controlled with individual dc–dc converters that allow for individual MPP tracking and then these converters are parallel-connected to the central inverter. As the series-connected microconverters architecture, this architecture increases the system performance under shading or electrical mismatching at the expense of increased elements (i.e. cost) if compared to the centralized configuration.

5.5 MICROINVERTERS

The microinverter architecture, shown in Figure 21(d), eliminates the central inverter and places a smaller power dc-ac inverter in the back of each and every PV model, thus permitting MPPT for individual modules.

This architecture allows for much more flexibility so it’s possible to set-up smaller systems with high modularity and easy and convenient detailed monitoring, which might be ideal for small, residential generators (e.g. two panels on the roof). Recent insights indicate an increasing market penetration of microinverters due to their natural advantages and falling prices [29].

Using microinverters obviates the requirement of the central dc-ac converter and the high-voltage dc bus, thus resulting in lower size and safer installation of the PV string.

5.6 CONCLUSIONS

Except for the central architecture, all other three architectures enable module-level MPPT and are suitable for partial shading conditions. The aspects of performance and cost are discussed below.

5.6.1 PERFORMANCE

Panel orientation may not be the same for all panels in a given system in order to maximize performance in a yearlong basis, but with a string inverter one will typically need all panels in a string to have the same orientation.

Therefore, one can realize that all the alternatives that have been presented rely on rather module-individualized approaches that allow for more precise regulation. These micro-based architectures, as one could call them, share some common aspects. On one hand, the advantages include higher power generation, longer warranty and increased safety due to lower operating voltages, improved expandability and upgradeability as they get rid of the limitation in capacity of the central inverter, panel-by-panel monitoring, no single point of
failure due to its distributed nature, and presumably better durability of the panels. On the other hand, drawbacks include an increase in investment cost due to higher number of elements, as well as an increase of potential failure points and hence added costs of maintenance [28].

Lastly, using microinverters obviates the requirement of the central dc–ac converter and the high-voltage dc bus, thus resulting in lower size and safer installation of the PV string.

5.6.2 COST

Numbers from 2010 reveal that central inverters averaged at $0.40/Wp (watt-peak), while the price of micro-inverters significantly higher at $0.52/Wp (130% of $0.40/Wp). Higher initial cost per watt-peak does not necessarily mean micro-inverters are ultimately going to cost more. Several other factors have to be taken into account. For example, solar installations with micro-inverters are simpler and less time consuming, which typically cut 15% of the installation costs. Better durability and longer lifespan should also be considered.

Some sources suggest that the key factor seems to be the system size. A central inverter will be more appropriate for larger systems since it takes advantage of the greater size to reduce the cost per kW, whereas microinverters are a better choice for smaller systems that might expand (or not) in the future. According to Figure 22, this size threshold is 6kW.

Ultimately, a complete cost of ownership analysis might be necessary to determine their economic viability in each case, which can only be carried out after detailed examination of capital and maintenance costs, and an understanding of how much energy will be harvested over the lifespan of the system.

![Microinverters vs Central (String) Inverters Cost Analysis](image)

**Figure 22.** Microinverters vs Centralized Inverters cost analysis. Source: [30].
6 CONVERTER CIRCUIT TOPOLOGIES\(^\text{12}\)

6.1 INTRODUCTION

Power converter circuits are of paramount importance in a PV system, since it is the power converter that is responsible for transforming the dc power generated by the PV array to ac or dc power that is suitable for the end user/load.

The circuit topology of the power electronics converters can be modified to further enhance the output power of PV systems under partial shading conditions. Relevant topologies addressing this matter are reviewed below.

6.2 MULTILEVEL CONVERTERS

A four-level diode-clamped converter that is connected to three PV arrays is shown in Figure 23. Each PV array is connected parallel to a capacitor. This architecture allows array-level MPPT by controlling the operating voltage of the corresponding array, but not module-level MPPT. MPPT can be improved by dividing each one of arrays into two identical sub-arrays and connected to the grid using a neutral point-clamped converter or half-bridge converters with an individual MPPT system for each array, under which conditions MPPT is probable to improve but will never be as good as individual MPPT.

Experimental results demonstrate 30% improvement in the output power when a four-level converter is used instead of a conventional inverter. However, a PV system with a multilevel diode-clamped converter is not upgradable, i.e., to increase the number of PV arrays, a multilevel diode-clamped converter with more semiconductor switches is required.

![Figure 23. Four-level diode-clamped converter connected to three PV arrays. Source: [20].](image)

6.3 VOLTAGE INJECTION CIRCUITS

In the voltage injection circuit (VIC) topology, the extracted maximum powers of the PV systems are improved by injecting a bias voltage into the shaded PV strings or modules. Two different approaches are going to be reviewed.

In the first approach, the bias voltage is injected to align the global MPP of the shaded PV

\(^{12}\) Unless otherwise stated, all information in this section comes from [20].
strings with the MPP of the non-shaded PV strings.

This procedure is elaborated for two parallel PV strings, when one of them is 50% shaded, and the modification of the P-V curve is depicted in Figure 24. $V_{\text{max}}^n$ and $V_{\text{max}}^s$ are the operating voltages of the MPP in the normal and shaded PV strings, respectively. Since they are in parallel, their operating voltage has to be the same. As shown in Figure 24(b), the global MPP of the shaded PV string is aligned with the MPP of the non-shaded string by injecting a bias voltage to the shaded PV string. The bias voltage can be provided by connecting the shaded PV string to a capacitor in series, a proposed circuitry is shown in Figure 25. The voltage of the capacitor is controlled by the operation of the series-connected switch.

Experimental results of this approach have shown to improve the extracted power from the PV panel by 20% under a certain partial shading condition. Control can be implemented with an inexpensive microcontroller. This topology can be upgraded as the number of PV strings increases. The main drawback of this topology is that two or more shading levels can occur in the same string and therefore two different bias voltages will be needed to align the MPP, but the capacitor is only able to provide one. Consequently, the maximum power of the PV array cannot be extracted.

![Figure 24](image1.png)

**Figure 24.** Effect of bias voltage on the PV string power-voltage curves. (a) Without bias voltage injection and (b) with bias voltage injection. Source: [20].

![Figure 25](image2.png)

**Figure 25.** Voltage injection-based circuitry to align the MPP of shaded and non-shaded PV modules. Source: [20].

In the second approach, the bias voltages can deactivate shaded PV modules in a string by forward biasing the bypass diodes due to the action of individual dc–dc converters mounted on each PV string, as shown in Figure 26. Each dc–dc converter is fed from the output voltage of the PV system $V_{\text{out}}$ and provides the bias voltage $V_{\text{bias}}^i$ for the $i$th PV string (see by-pass diode operation in Error! Reference source not found. Error! Reference source not found.)
found). The number of PV modules that needs to be deactivated specifies the required bias voltage for each PV string. Therefore, the voltage of each PV module needs to be monitored and compared with other modules’ voltage to extract the number of the shaded modules in each string. A complicated control system is needed to drive the dc-dc converters.

![Diagram](image1.png)

**Figure 26.** Voltage injection-based circuitry to deactivate shaded PV modules. Source: [20].

This topology can improve the energy efficiency of the shaded PV system from 23% to 95%, but noting that the shaded modules are deactivated thus reducing the power capacity of the system. It functions when different strings are under various shading levels. The system can be upgraded, but the number of converters increases the cost.

### 6.4 GENERATION CONTROL CIRCUITS

The generation control circuit (GCC) improves the extracted power of a PV string by controlling the operating voltage of PV modules. Here, two different GCC topologies are discussed [20].

The first topology, named dc–dc converter-based topology, is shown in Figure 27. In this topology, the operating voltage of all PV modules is controlled at a constant value of $V_{out}/m$. $V_{out}$ is the output voltage of the PV string, and $m$ is the number of PV modules in the string. When a module is shaded, its parallel capacitor provides extra current to compensate for the difference between the string current and the current of the shaded PV module. The compensating current facilitates the operation of the shaded PV module at the same voltage as the operating voltage of non-shaded modules.

The dc–dc converter-based topology improves the extracted power from the PV panel, but the individual voltage control of each PV module is not feasible, hence module-level MPPT is not possible. This topology can be upgraded, and accommodate higher number of PV modules. The control system can be simply implemented by an inexpensive microcontroller.

![Diagram](image2.png)

**Figure 27.** Dc-dc converter-based GCC topology. Source: [20].
In the second approach, called multichopper topology (Figure 28), the off-duty ratio\(^{13}\) of the switch associated with the \(i\)th PV module \(D_i\) can be individually controlled to regulate the operating voltage of the \(i\)th PV module.

This is elaborated for a PV string with two PV modules, where the second one is shaded. The current–voltage curves of these PV modules are shown in Figure 29. \(P_{\text{max}}^1\) and \(P_{\text{max}}^2\) are the MPP of the first and second PV modules, respectively. The total output power of this PV string can be adjusted by adjusting the off-duty ratio of the shaded PV module \(D_2\).

The multichopper topology can improve the extracted power from the PV panel by up to 20% under certain partial shading conditions. This circuit topology can be upgraded as the number of PV modules increases. Controller might be complex and costly if system is large.

![Multichopper-based-GCC topology](image)

**Figure 28.** Multichopper-based-GCC topology. Source: [20].

![Effect of changing the off-duty ratio of switches on the extracted power in the multichopper topology](image)

**Figure 29.** Effect of changing the off-duty ratio of switches on the extracted power in the multichopper topology. Source: [20].

### 6.5 MODULE-INTEGRATED CONVERTERS

The module-integrated converters (MICs) conventionally use a series-connected microconverter architecture, shown in Figure 21(b). In this circuit topology, a dc–dc converter is integrated to each PV module that is part of a string, enabling individual MPPT. This circuit topology facilitates the operation of series-connected PV modules at different current levels. Additionally, the decoupled control policy of PV modules significantly increases the PV system robustness and reliability.

\(^{13}\) The percentage of one period in which the switch control signal is inactive (open state).
The dc–dc converter can be a conventional converter (e.g., buck, boost, buck–boost, and Cuk). More recently, modified converter topologies have been presented to achieve a higher efficiency. For example, the circuitry shown in Figure 30 can operate in buck, boost, and pass-through modes. When the PV module is partially shaded, i.e., $I_{pv} < I_{string}$, the converter operates in the buck mode (voltage down, current up to compensate). When the other PV modules work at a lower power level, i.e., $I_{pv} > I_{string}$, the converter operates in the boost mode (voltage up, current down to adjust).

The MIC-based topology can also be implemented as a microinverter architecture, shown in Figure 21(d). Using inverters obviates the requirement of the central dc–ac converter and the high-voltage dc bus, thus resulting in lower size and safer installation of the PV string. However, ACPV introduces filtering, protection, and the electromagnetic interface issues.

The MIC-based topology requires a fast and complicated control system to manage the operation of converters that are installed on the PV modules. This increases the cost and complexity of the PV system. The MIC-based topology can be simply upgraded by adding new PV modules.

![Figure 30](image)

**Figure 30.** MIC-based topology: upgraded from a typical circuitry used in the series-connected microconverter architecture. Source: [20].

### 6.6 MULTIPLE-INPUT CONVERTERS

A multiple-input single-output (MISO) boost converter can be implemented as a first-stage dc–dc converter in microconverter architectures (i.e. one converter per PV module). In a modified PV module, which is shown in Figure 31, the electrical contact is separated in point 1, and the bypass diodes are removed from point 2. The string outputs are connected to the boost converters. The voltages and currents of the strings are measured for the purpose of MPPT. Since bypass diodes are removed from the PV module, the power–voltage curve has only one MPP. Thus, a simple control algorithm, e.g., P&O, can be implemented for MPPT.

For a shaded 120-W PV module, a MISO boost converter increases the output power by 9.6%, compared with a single-input boost converter. This circuit topology can be upgraded for the connection of more PV strings. With a higher number of inputs, the number of semiconductor switches and inductors increases, which, in turn, adds to the system size and cost. The size and cost issues can be reduced by using single-inductor MISO converters.
6.7 CONCLUSIONS

Circuit topologies differ in their implementation, energy efficiency, number of active and passive elements, complexity of control systems, upgradability, and the capability of individual MPPT for each PV module. Particular characteristics have been commented at the end of their respective sections. A summarized review of advantages and disadvantages is presented in Table 1.

<table>
<thead>
<tr>
<th>Type</th>
<th>Key advantages</th>
<th>Potential disadvantages</th>
</tr>
</thead>
</table>
| Multilevel diode-clamped converter | • MPPT for individual PV arrays.  
 • PV system has acceptable energy efficiency under partial shading condition. | • Individual PV modules may not operate at their MPP.  
 • A large PV array requires numerous semiconductor switches, increasing the system complex and cost.  
 • High switching power loss.  
 • PV system is not upgradable. |
| PV system with an auxiliary half-bridge converter | • MPPT for individual PV sub-arrays.  
 • PV system provides better energy efficiency than the multilevel diode-clamped converter.  
 • Lower number of switches and, hence, lower switching loss than the multilevel diode-clamped converter. | • Individual PV modules may not operate at their MPP.  
 • PV system is not upgradable. |
| Neutral point clamped converter | • MPPT for individual PV sub-arrays.  
 • PV system provides better energy efficiency than the multilevel diode-clamped converter. | • Individual PV modules may not operate at their MPP.  
 • PV system is not upgradable.  
 • High switching loss. |
| Voltage injection based topology | Type I  
 • Simple circuitry and control system.  
 • Upgradability. | • Maximum possible power cannot be extracted when two or more PV strings are partially shaded (confined energy efficiency).  
 • More complicated control system than Type I.  
 • Full power capacity of PV system cannot be exploited since the shaded PV modules are deactivated. |
| Type II  
 • Higher energy efficiency than Type I when two or more PV strings are partially shaded.  
 • Upgradability. | | |
| Generation control circuit topology | DC-DC converter  
 • Simple control system.  
 • Upgradability. | • Shaded PV modules may not operate precisely at their MPP (Confined energy efficiency).  
 • Complicated control structure. |
| Multi-chopper | • MPPT for individual PV module.  
 • PV system has acceptable energy efficiency under the partial shading condition.  
 • Upgradability. | | |
| Module-integrated circuit (series-connected micro-converter architecture) | • MPPT for individual PV module.  
 • High energy efficiency.  
 • Upgradability. | • Relatively large number of passive and active components per PV module.  
 • Complicated control structure. |
| Module-integrated circuit (micro-inverter architecture) | • MPPT for individual PV modules.  
 • High energy harvest efficiency.  
 • Smaller size and safer installation than series-connected micro-converter architecture.  
 • System expandability. | • Relatively large number of passive and active components per PV module.  
 • The ac gird technical issues and electromagnetic interface issues need to be considered in the design of integrated inverters.  
 • Complicated control structure. |
| Multiple-input boost converter | • Higher output power than single input boost converters.  
 • Acceptable energy efficiency under partial shading  
 • Upgradability. | • With the higher number of inputs, the number of semiconductor switches and inductors increases which in turn adds to the system size and cost. |
| Multiple-input single-output (MISO) converter with a single inductor | • Lower size and cost compare to conventional MISO.  
 • Upgradability.  
 • Acceptable energy efficiency under partial shading. | • More complex control structure than the multiple-input boost converter. |

Table 1. Converter Circuit Topologies comparison table. Source: [20].
7 CONCLUSIONS

Given the large number of existing MPPT techniques and array and circuit topologies, the PV system operators may face a challenge when choosing the most suitable one for their applications. Keeping this in mind, the main features of different MPPT techniques and circuit topologies should be discussed and compared.

Although this document only anecdotally discusses about the fundamentals of MPPT techniques, one should note that the operator might have to consider factors such as accuracy and tracking speed for critical applications, whereas simplicity and cost (mainly determined by the number and type of the requirement sensors and the complexity of the algorithm) could be a priority in smaller PV systems, in which unitary percentage differences won’t justify the added costs.

In regards of the PV array configuration, discussed in section 1, it seems clear that either the TCT (+3.8% efficiency\textsuperscript{14}) or the BL (+2.3% efficiency\textsuperscript{15}) configurations offer the best cost-performance relationship. Although the SP configuration is the simplest, it is too vulnerable given its non-redundant configuration. The reconfigurable approach, on the other hand, reported a mere 3% efficiency increase when compared to a non-reconfigurable system in exchange of significant complexity. Therefore, the TCT topology seems to be the most efficient for lessening mismatch losses during PV array shading without penalizing the overall efficiency of the plant in non-shaded scenarios. On top of that, it delivers longer power production periods when compared to SP, as well as exhibiting multi-peak shedding. When it comes to the wiring, the added necessary cables in TCT compared to BL are compensated by the easier pattern – that is, shorter wiring time.

As for system architectures, all non-centralized architectures allow for module-level MPPT and are suitable for partial shading conditions. In general, parallel and decentralized architectures offer higher reliability and upgradeability in exchange of a higher cost. As reported before, numbers from 2010 indicate that central inverters averaged at $0.40/Wp (watt-peak), while the price of micro-inverters significantly higher at $0.52/Wp (130% of $0.40/Wp). However, considering that MPPT tracking can improve efficiency by >10-15% and that a decentralized architecture will provide better monitoring, reliability, more safety, and a presumably longer lifespan for the elements of the system, microinverters might just be the wisest option, especially under shading conditions. As reported in [29], their natural advantages and falling prices are helping them take an increasing percentage of PV inverter markets.

Finally, when it comes to converter circuit topologies the choices are so numerous and different that is difficult to pick a clear winner, so it is still a good recommendation to check Table 1 and assess their particular advantages and disadvantages depending on the application. Solutions seem to provide improvements ranging 10-30%, but when it comes to being resilient to partial shading conditions, GCC (multichopper, +30% efficiency) and, more importantly, module-integrated converters in a decentralized architecture seem to be the best candidates. Decentralized MICs are safer, upgradeable, and allow for MPPT at the exchange of presumably slightly higher cost, although the same cost reasoning that was applied to microinverters might as well be applicable to MICs.

\textsuperscript{14} If compared to SP.
\textsuperscript{15} If compared to SP.
8 REFERENCES & BIBLIOGRAPHY


