Modelling and Control of Solar Photovoltaics in Residential Grids

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SYNOPSIS:

As Denmark has a goal to produce all its energy from renewable sources by 2050 therefore they will increase rapidly in the future energy systems. Also in Denmark solar energy is one of the rapidly growing technology of renewable energy. Therefore in the coming years there will be a high penetration level of PV in the system. But this will come with a challenge of power variation and to maintain voltage within limits. So in this project the estimation of maximum amount of PV integration in the system without voltage limits violation, as well as the control of the voltage rise due to high levels of PV is done. The project concludes that if reactive power is provided through PVs it can reduce the voltage rise and meanwhile increase the level of PV integration and hence contribute to the future energy goals.

Copies:	3
Pages, Total:	80
Appendix:	10

By signing this document, each member of the group confirms that all participated in the project work and thereby all members are collectively liable for the content of the report. Furthermore, all group members confirm that the report does not include plagiarism.

Summary

Denmark plans to produce all its energy from renewable sources by 2050 [1]. Because of this plan there will be a rapid increase in the renewable energy sources in the future. As there will be a rise in renewable it is expected that the penetration of PV will also rise rapidly in the system. This will pose a challenge of power variation, which makes it difficult to maintain the voltage in the system without violating the specified limits as per EN 50160 [2]. In this project the estimation of maximum amount of PV that can be added to the system without violating these limits, as well as the control of the voltage rise due to high levels of PV is done.

The 17 bus distribution system was modelled in DigSilent power factory 14.1 for the whole analysis. In Chapter 2 the steady state analysis of the system was performed without PV integration to get the voltages at all the buses in the system. Then PV integration of 50 MW was done at all the 10 kV buses in the system considering the summer and winter cases of minimum and maximum load in Chapter 3 to estimate the amount of PV that can be integrated in each case at each specific bus in the system before the voltage limits are violated. To carry out the analysis with PV generation for every hour of the year the annual PV power output was calculated in Chapter 4 using the irradiance data. Then in Chapter 5 three different scenarios of PV integration were considered with annual PV power output. Finally in Chapter 6 to control the rise in voltage and to increase the amount of PV integration in the system, reactive power was provided from the PVs and for analysis the same cases of summer and winter with maximum and minimum load and also with generation data for one month were considered. It was found that by providing reactive power from the PVs the rise in voltage can be lowered and meanwhile the amount of PV integration can be increased in the system which overall contributes to the future energy goals of Denmark.

Preface

This Master Thesis was conducted at the Department of Energy Technology. It was written by group EPSH4-932 during the period from the 1st of September 2014 to the 27th of May 2015.

This report has been written using LATEX and the modelling in this project has been done using DigSilent power factory 14.1. All the plots in this report are made using the MATLAB software. Some of the figure are made using Microsoft Visio 2007. The reading instructions to this report are that the chapters are further divided in sub parts and references are given inside square brackets for e.g. [2] is the second reference used which are all together given in bibliography to this report. The numbers for figures and tables are given as for e.g. 2.1 which represents the first figure or table of Chapter 2.

Acknowledgement

The author would like to extend his gratitude to his supervisors Dr. Weihao Hu and Dr. Chi Su for their guidance through out this year long thesis project. Their insights helped a lot over the whole period to complete the work related to this project.

The author would also like to thank Nuri Gökmen, Phd student for his help related to work done in Chapter 4 of this report.

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Finally the author would like to extent his gratitude to his parents, especially his mother for always being there to motivate and his grandparents, close relatives and friends especially Marcos Rejas for all his help related with LATEX, MATLAB and for providing good advice whenever needed.

Greetings

Aalborg University, May 27, 2015

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Contents

Nomenclature

Abbreviations

RE	Renewable Energy
PV	Photo Voltaic
kW	Kilowatt
DKK	Danish Krone
kWh	Kilowatt Hour
kV	Kilovolts
WT	Wind Turbine
MW	Mega Watt
TSO	Transmission System Operator
PCU	Power Conditioning Unit
DC	Direct Current
AC	Alternating Current
EN	European Standard
DPL	DigSilent Programming Language
MVAr	MegaVolt Ampere Reactive
V	Volts
p.u.	Per Unit
SA	Solar Altitude
AZ	Azimuth Angle
ZA	Zenith Angle
IA	Incidence Angle
NOCT	Normal Cell Operating Temperature
kWp	Kilowatt Peak
DG	Distributed Generation

List of Symbols

P	Active Power
Q	Reactive Power
|V|	Bus Voltage Magnitude
δ	Angle of Bus Voltage
Z	Impedance
y	Admittance
I	Current
V	Voltage
S_i	Complex Power
$cos\phi$	Power Factor
W/m^2	Watts Per Square Meter
G	Global Horizontal Irradiance
G_d	Diffused Horizontal Irradiance
T_a	Air Temperature
$G_{total-tilted}$	Total Tilted Irradiance
T_c	Cell Temperature
P_{pv}	PV Power Output
β	Tilt Angle
B	Day Angle
E_o	Eccentricity Correction Factor
G_{sc}	Solar Constant
G_{on}	Extraterrestrial Irradiance on Horizontal Surface
m	Relative Optical Air Mass
ϵ	Sky Clearness
F_1	Irradiance Coefficients Circumsolar
F_2	Horizon Brightening Coefficient
n_{pv}	Efficiency of PV Cell
n_{ref}	Reference Solar Cell Efficiency
k_T	Temperature Coefficient
A (m^2)	Area in Square Meters
ΔV	Voltage Variation
R	Resistance
X	Reactance

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Chapter 1

Introduction

1.1 Background and Motivation

Denmark has a plan for 2050 to completely produce its energy through renewable sources [1]. So RE will play a dominant role in the energy systems of the future. In Denmark over the last few years, PV has been one of the fastest growing technologies of renewable energy with rapid increase in the installed capacity as can be seen in the Figure 1.1 and also PV market saw a growth of 300% in 2010-11 [3] and this will for sure contribute to the proposed 2050 plan. On the other hand net metering system has encouraged many Danish consumers to install PV units under which they are allowed to install up to 6 kW of PV for their household to cover their own domestic demand. This system gives them the opportunity to earn approximately 2 DKK / kWh for 10 years for supplying power during the day time and using the grid as storage [3].

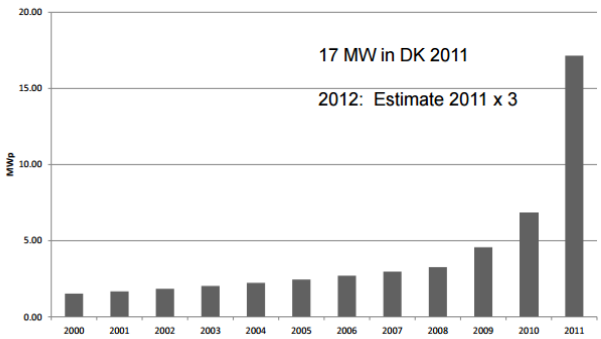

Figure 1.1: Total PV power installed in Denmark (In MWp) [3].

But all of this comes with a challenge as it leads to scenarios of large power variations that are a major challenge for the operation of the local grid as then it may be difficult to manage the voltage within limits and assuring the quality of power.

1.2 Residential Grids

Residential grids are mainly composed of the customers that are the end users in the system which are further connected to the distribution network at 0.4 kV. The voltage is brought to this level from higher voltage networks (20-6 kV) by step down transformers [4].

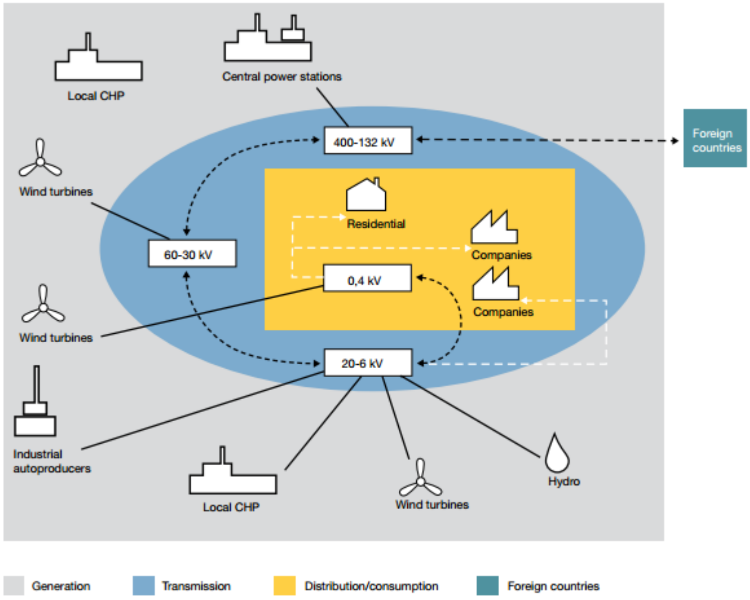

Figure 1.2: The general electrical grid [4].

Figure 1.2 shows the residential grids within the whole distribution network in a general electrical grid whereas the Figure 1.3 shows the load curve for the Danish residential grids.

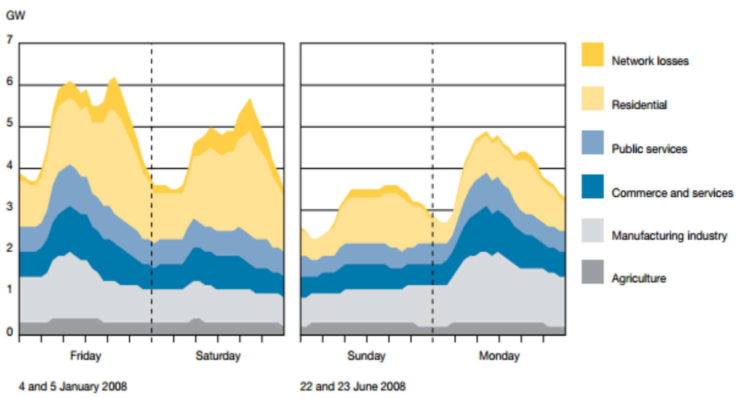

Figure 1.3: Load curve for the residential grids [4].

1.3 Wind Turbines

1.3.1 Current scenario

Denmark is often said to have one of the most sturdy and stable power systems in the world, with many interconnections with neighboring countries. The Danish power system is traditionally made up out of large conventional thermal power plants of which the surplus heat contributes for district heating. Denmark's perspective 2050 goals to produce all of its energy from renewable sources [1] have led to an increase in the number of WTs being installed in the system, both offshore and onshore. The Figure 1.4 shows the increase in installed wind power capacity over the years. In the plans it is outlined that in order to generate up to 30% of the total energy through renewables by 2025, the existing 3000 MW of wind power capacity will need to be increased to 6000 MW. The wind turbines will then fulfill 50% of the total demand in Denmark. In 2050 the wind turbines in offshore wind farms will have enough capacity to fulfill the demands of the Danish residential grids [5].

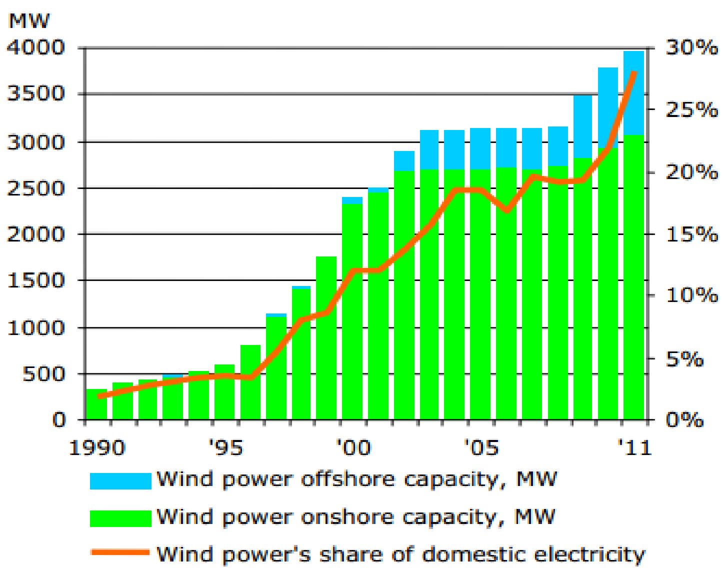

Figure 1.4: Installed wind power capacity over the years [6].

1.3.2 Variable power production

Wind power is a very erratic source of renewable energy as it is hard to predict the wind speeds correctly in advance. Also the main concern in the case of wind power is that it presents a challenge of unreliable supply to the TSO as compared to the existing conventional generators as there can be periods of low and high winds during which the power production can be low or higher than the substantial demand of the system. Therefore a constant supply can not be provided to the system by wind power so it becomes a critical issue for the TSO because for the normal operation of the system the demand needs to be balanced specifically with the amount of generation [7]. The Figure 1.5 shows the power curve of a typical modern WT.

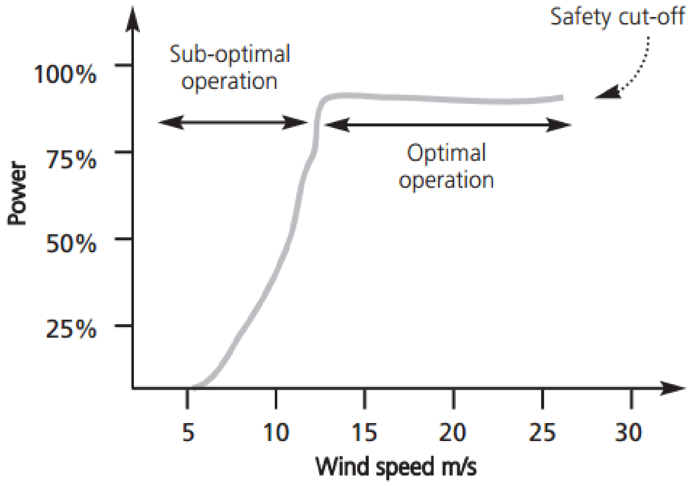

Figure 1.5: Power curve of a typical modern wind turbine [7].

1.3.3 Impacts of wind power on the system

The impact that wind power has on the system is the variation in voltage caused by it and this further influences the amount of wind turbines that can be integrated into the system [8].

1.4 PV Systems

The PV systems can be mainly classified into the following [9]:

1. Grid Connected Systems
2. Standalone Systems

1.4.1 Grid connected PV systems

The grid connected systems as shown in Figure 1.6 are intended to operate in parallel with existing electrical grid. The basic component of these systems is the inverter or the power conditioning unit (PCU). The DC power produced by the PV system is converted into AC power by the inverter as per the voltage and power quality requirements of the grid. Therefore the power which is produced by these systems is delivered to the grid [9].

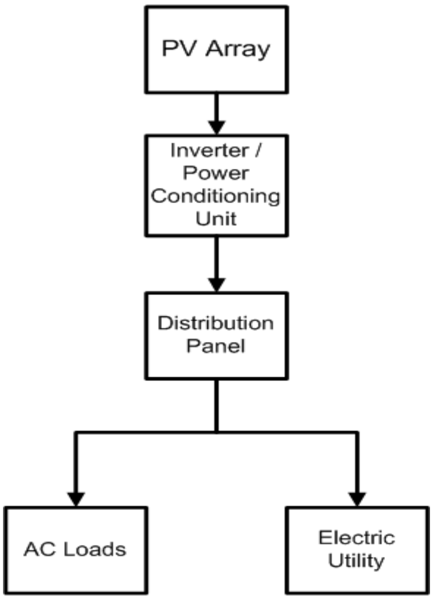

Figure 1.6: Grid connected PV system [9].

Residential grid connected PV system

As solar energy is one of the most rapidly growing form of renewable energy therefore lot of houses have installed PVs which are further connected to the local utility grid as can be seen in Figure 1.7. By this the installed PVs provide the power for the domestic loads of these houses and surplus generation is supplied to the low voltage grid using a net metering system and for which the costumers can earn money for using the grid as storage [10].

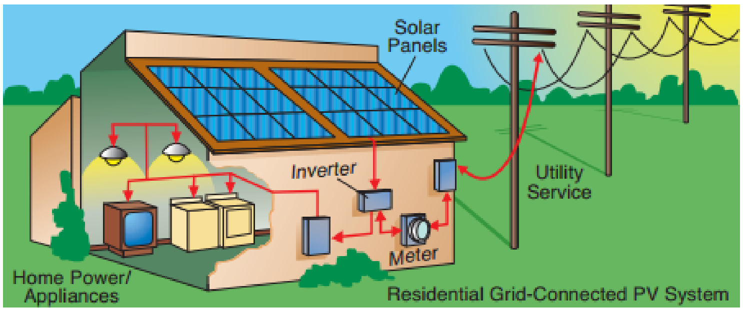

Figure 1.7: Household with a grid connected PV system [11].

Net metering system

In this system the production from the PVs which is not being used for household purposes is fed to the utility grid whereas in case the production from the PVs is less than the household demand there is a possibility to withdraw more power from the grid. So in order to keep a track of exchange of power in this grid connected system a special meter is used that can also run in the opposite direction in order that the surplus production can be transferred to the grid. In this system there is also possibility of having two meters out of which one measures the amount of used power whereas the one accounts for the contribution of costumer to the grid [10].

Also under some rules the customers are charged by the TSO depending on the time of day they use power. The customers under this system are charged higher amount for usage during certain parts of the day when the demand is maximum whereas lower amount is charged for usage during the minimum demand period [10].

1.4.2 PV integration issues in residential grids

The issues regarding the integration of PVs are [12] [13]:

- Rise in voltage levels.
- Overloading of equipment in the network.

Voltage rise

In a system, voltage rise is one of the problems caused when there is a high level of PV penetration because of the reverse power flow as can be seen in Figure 1.8. The maximum sudden variation in voltage that is allowed as per the existing standards EN 50160 is 5% of the nominal voltage [2]. Further this can limit the amount of PV that can be integrated into the system without violating these limits. So in order to decrease the voltage variation and to increase the level of integration reactive power can be injected through the PV systems [14].

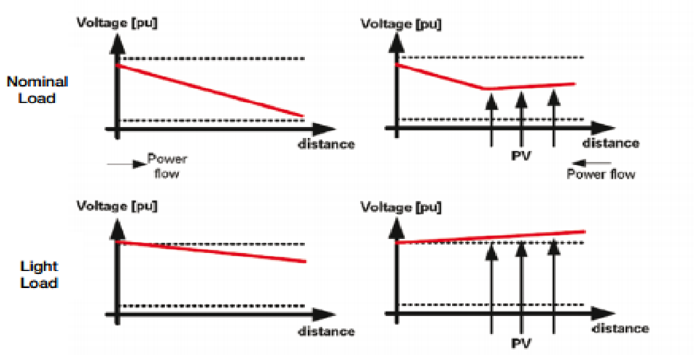

Figure 1.8: Representation of voltage rise due to PV generation [15] [16].

1.5 Problem Statement

As Denmark has a goal for 2050 that it wants to produce all its energy through renewables sources [1] therefore the penetration of renewables will increase in the grids in the coming years. But the proper integration of such renewables sources will be a challenge and cause many issues as discussed before in Sections 1.3.3 and 1.4.2. So in this project a distribution system will be modelled and later controlled with PVs in it to resolve the issues discussed above for a proper integration.

So problem statement can be restated as:

How can the residential grids be operated normally within the specified voltage limits after more PVs are added to it ?

1.6 Project Objectives

To estimate the maximum allowable amount of PV production that can be integrated in a typical LV network under various scenarios and to solve the voltage rise problem caused by high penetration of solar power in LV networks by using reactive power control of PV.

1.7 Project Limitations

- No dynamic simulations have been performed. All the simulations are done in steady state.
- No experimental work was part of this project.

1.8 Report Structure

This report consists of seven main chapters.

- Chapter 1 consists of the introduction to this project.
- Chapter 2 consists of the steady state study of the distribution system. The system has been modelled using DigSilent Power Factory 14.1.
- Chapter 3 consists the study of PV integration into the system. In this chapter the summer and winter cases of PV integration are considered and analyzed.
- Chapter 4 consists of the calculations for the PV output power using the irradiance data provided for one year. The calculated PV output power was used in further analysis in this project.
- Chapter 5 consists of analysis of the system for PV integration using the annual PV power output. Further in this chapter three different scenarios of PV integration are considered.

- Chapter 6 is about the voltage rise problem which is caused due to high levels of PV integration into the system. So reactive power control method has been used to solve this problem in order to increase the level of PV before the voltage limits are violated. Also in this chapter the summer and winter cases are considered.

- Chapter 7 consists the conclusion and future work related to this project.

Chapter 2

Steady State Study

2.1 Load Flow Analysis

It is a steady state analysis which is used to determine the voltages, currents and power (P & Q) flows in a power system under varied load conditions. The representation of the network is always done by a single line diagram. These studies are further used for planning, operation , economic scheduling and power exchange between utilities [17]. The essential parameters in these analysis are the active power **P**, reactive power **Q**, magnitude of bus voltage **|V|** and the angle of bus voltage $\boldsymbol{\delta}$.

2.1.1 Buses in power system

The power system mainly consists of three types of buses which are further explained in Table 2.1.

Bus	**Specified Variables**	**Unknown Variables**
PQ or Load Bus	P, Q	$\lvert V\rvert,\boldsymbol{\delta}$
PV or Voltage controlled bus	P ,$\lvert V\rvert$	Q , $\boldsymbol{\delta}$
Swing or Slack bus	$\lvert V\rvert$, $\boldsymbol{\delta}$	P , Q

Table 2.1: Buses in power system [17].

2.1.2 Bus admittance matrix

Consider a three bus system as shown in Figure 2.1.

The impedances of the lines between the buses 1, 2 and 3 are given by $\boldsymbol{z_{12}}$, $\boldsymbol{z_{22}}$ and $\boldsymbol{z_{31}}$ and the admittances of lines are given by $\boldsymbol{y_{12}}$, $\boldsymbol{y_{22}}$ and $\boldsymbol{y_{31}}$ respectively. The total capacitive susceptances for the buses are given by $\boldsymbol{y_{10}}$, $\boldsymbol{y_{20}}$ and $\boldsymbol{y_{30}}$ [18].

By applying Kirchoff's current law at each bus we get equations 2.1, 2.2 and 2.3 [18]:

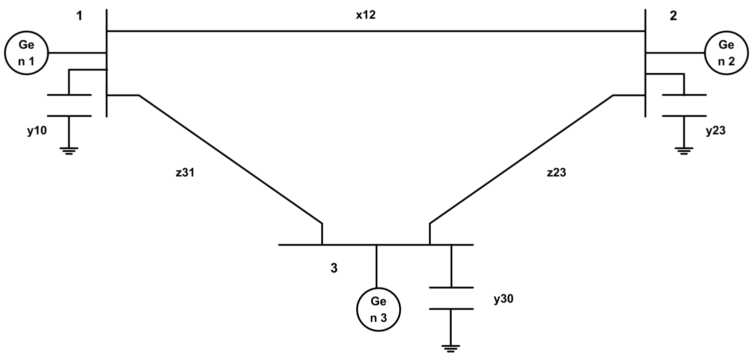

Figure 2.1: Three bus system [18].

$$\boldsymbol{I_1 = V_1 y_{10} + (V_1 - V_2) y_{12} + (V_1 - V_3) y_{13}} \tag{2.1}$$

$$\boldsymbol{I_2 = V_2 y_{20} + (V_2 - V_1) y_{21} + (V_2 - V_3) y_{23}} \tag{2.2}$$

$$\boldsymbol{I_3 = V_3 y_{30} + (V_3 - V_1) y_{31} + (V_3 - V_2) y_{32}} \tag{2.3}$$

The equations 2.1, 2.2 and 2.3 can be written in form of a matrix as given below

$$\begin{bmatrix} \boldsymbol{I_1} \\ \boldsymbol{I_2} \\ \boldsymbol{I_3} \end{bmatrix} = \begin{bmatrix} \boldsymbol{y_{10} + y_{12} + y_{13}} & \boldsymbol{-y_{12}} & \boldsymbol{-y_{13}} \\ \boldsymbol{-y_{12}} & \boldsymbol{y_{20} + y_{12} + y_{23}} & \boldsymbol{-y_{23}} \\ \boldsymbol{-y_{13}} & \boldsymbol{-y_{23}} & \boldsymbol{y_{30} + y_{13} + y_{23}} \end{bmatrix} \begin{bmatrix} \boldsymbol{V_1} \\ \boldsymbol{V_2} \\ \boldsymbol{V_3} \end{bmatrix}$$

$$\begin{bmatrix} \boldsymbol{I_1} \\ \boldsymbol{I_2} \\ \boldsymbol{I_3} \end{bmatrix} = \begin{bmatrix} \boldsymbol{Y_{11}} & \boldsymbol{Y_{12}} & \boldsymbol{Y_{13}} \\ \boldsymbol{Y_{21}} & \boldsymbol{Y_{22}} & \boldsymbol{Y_{23}} \\ \boldsymbol{Y_{31}} & \boldsymbol{Y_{32}} & \boldsymbol{Y_{33}} \end{bmatrix} \begin{bmatrix} \boldsymbol{V_1} \\ \boldsymbol{V_2} \\ \boldsymbol{V_3} \end{bmatrix}$$

where $\begin{bmatrix} \boldsymbol{Y_{11}} & \boldsymbol{Y_{12}} & \boldsymbol{Y_{13}} \\ \boldsymbol{Y_{21}} & \boldsymbol{Y_{22}} & \boldsymbol{Y_{23}} \\ \boldsymbol{Y_{31}} & \boldsymbol{Y_{32}} & \boldsymbol{Y_{33}} \end{bmatrix}$ is the **bus admittance** or $\boldsymbol{Y_{Bus}}$ matrix where the diagonal elements are the self admittances as given by equations 2.4, 2.5 and 2.6 [18]:

$$\boldsymbol{Y_{11} = y_{10} + y_{12} + y_{13}} \tag{2.4}$$

$$\boldsymbol{Y_{22} = y_{20} + y_{12} + y_{23}} \tag{2.5}$$

$$\boldsymbol{Y_{33} = y_{30} + y_{13} + y_{23}} \tag{2.6}$$

whereas all the remaining elements of this matrix are known as the mutual admittances and are given below [18]:

$$\boldsymbol{Y_{12} = Y_{21} = -y_{12}} \tag{2.7}$$

$$\boldsymbol{Y_{13} = Y_{31} = -y_{13}} \tag{2.8}$$

$$\boldsymbol{Y_{23} = Y_{32} = -y_{23}} \tag{2.9}$$

2.1.3 Power flow equations

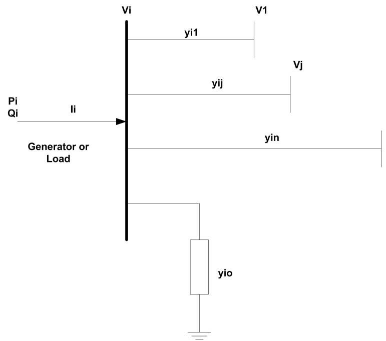

Figure 2.2: [17]

In Figure 2.2, The current injected into the bus i by generators or drawn by loads from the same bus is given by $\boldsymbol{I_i}$ [17].

$$\boldsymbol{I_i = y_{i0}V_i + y_{i1}(V_i - V_1) + y_{i2}(V_i - V_2) + ... + y_{in}(V_i - V_n)} \tag{2.10}$$

$$\boldsymbol{I_i = (y_{i0} + y_{i1} + y_{i2} .... + y_{in})V_i - y_{i1}V_1 - y_{i2}V_2 - ....y_{in}V_n} \tag{2.11}$$

$$\boldsymbol{= V_i \sum_{j=0}^{n} y_{ij} - \sum_{j=1}^{n} y_{ij}V_j} \tag{2.12}$$

$$\boldsymbol{I_i = V_iY_{ii} + \sum_{j=1}^{n} Y_{ij} * V_j} \tag{2.13}$$

$\boldsymbol{S_i}$ is the complex power and is represented by equation 2.14 [17]:

$$\boldsymbol{S_i = P_i + jQ_i = V_iI_i^*} \tag{2.14}$$

$$\boldsymbol{I_i = \frac{P_i - jQ_i}{V_i^*} = V_iY_{ii} + \sum_{j=1}^{n} Y_{ij} * V_j} \tag{2.15}$$

$$\frac{\boldsymbol{P_i - jQ_i}}{\boldsymbol{V_i^*}} = \boldsymbol{V_i Y_{ii}} + \sum_{j=1}^{n} \boldsymbol{Y_{ij} * V_j} \tag{2.16}$$

Finally the active and reactive powers are given by equations 2.17 and 2.18 [17]:

$$\boldsymbol{P_i} = \Re(\boldsymbol{V_i^*}(\boldsymbol{V_i Y_{ii}} + \sum_{j=1}^{n} \boldsymbol{Y_{ij} V_j})) \tag{2.17}$$

$$\boldsymbol{Q_i} = -\Im(\boldsymbol{V_i^*}(\boldsymbol{V_i Y_{ii}} + \sum_{j=1}^{n} \boldsymbol{Y_{ij} V_j})) \tag{2.18}$$

2.1.4 Methods for solving nonlinear algebraic equations

Gauss-Seidel, Newton-Raphson and Quasi-Newton methods are used for solving these equations through iterations [17].

Gauss-Siedel Method

It is also known as the method of successive displacements. Let us consider a function given by equation 2.19 [17]:

$$\boldsymbol{f(x) = 0} \tag{2.19}$$

Now the function in equation 2.19 can be rearranged and written as [17]:

$$\boldsymbol{x = g(x)} \tag{2.20}$$

An iterative equation is formed as given by equation 2.21 if $\boldsymbol{x^{(k)}}$ is taken as an initial estimate of the variable x [17].

$$\boldsymbol{x^{(k+1)} = g(x^{(k)})} \tag{2.21}$$

The solution is attained when the difference of two consecutive iterations is less than the declared accuracy given by equation 2.22, where $\boldsymbol{\varepsilon}$ is the anticipated accuracy [17].

$$|\boldsymbol{x^{(k+1)} - x^{(k)}}| \leq \boldsymbol{\varepsilon} \tag{2.22}$$

Newton-Raphson Method

This method is extensively used for solving the simultaneous non linear algebraic equations. It is based upon the procedure of successive approximation and uses the Taylor series expansion [17].

Let us consider a one dimensional equation whose solution given by [17]:

$$\boldsymbol{f(x) = c} \tag{2.23}$$

Now $\boldsymbol{x^{(0)}}$ is the initial estimate of the solution, and $\boldsymbol{\Delta\ x^{(0)}}$ is the small deviation from the correct solution and it gives [17]:

$$\boldsymbol{f(x^{(0)} + \Delta x^{(0)}) = c} \tag{2.24}$$

The Taylor series expansion is applied on the left hand side of the equation 2.24 which results in equation 2.25 that is given below [17]:

$$\boldsymbol{f(x^{(0)}) + (\frac{df}{dx})^{(0)}\Delta x^{(0)} + \frac{1}{2!}(\frac{d^2f}{dx^2})^{(0)}(\Delta x^{(0)})^2 + ... = c} \tag{2.25}$$

Now if the error $\boldsymbol{\Delta\ x^{(0)}}$ is actually too small the terms with the higher order are neglected which results in equation 2.26 [17]:

$$\boldsymbol{\Delta c^{(0)} \simeq (\frac{df}{dx})^{(0)}\Delta x^{(0)}} \tag{2.26}$$

where

$$\boldsymbol{\Delta c^{(0)} = c - f(x^{(0)})} \tag{2.27}$$

The second approximation is obtained by adding the $\boldsymbol{\Delta x^{(0)}}$ to the initial estimate [17]:

$$\boldsymbol{x^{(1)} = x^{(0)} + \frac{\Delta c^{(0)}}{(\frac{df}{dx})^{(0)}}} \tag{2.28}$$

And now the Newton - Raphson algorithm is obtained by the consecutive use of this method [17]:

$$\boldsymbol{\Delta c^{(k)} = c - f(x^{(k)})} \tag{2.29}$$

$$\boldsymbol{\Delta x^{(k)} = \frac{\Delta c^{(k)}}{(\frac{df}{dx})^{(k)}}} \tag{2.30}$$

$$\boldsymbol{x^{(k+1)} = x^{(k)} + \Delta x^{(k)}} \tag{2.31}$$

The equation 2.30 can be rearranged as below

$$\boldsymbol{\Delta c^{(k)} = j^{(k)}\Delta x^{(k)}} \tag{2.32}$$

where

$$\boldsymbol{j^{(k)} = (\frac{df}{dx})^{(k)}} \tag{2.33}$$

The non linear equation f(x) - c = 0 is approximated by the tangent line on the curve at $\boldsymbol{x}^{(k)}$ as can be seen from the equation 2.32. The intersection of tangent line with the x-axis gives the result $\boldsymbol{x}^{(k+1)}$ [17].

2.2 System Description

2.2.1 Distribution system

The system which is under investigation in this project is a typical Danish distribution system as shown in Figure 2.3. It mainly consists of 17 Buses which are rated at 10, 20, 60 kV respectively. There are two step down transformers between Bus 1-2 (60/20 kV) and Bus 4-5 (20/10 kV). 10 loads are also connected to the different buses in the system and apart from that three wind turbine units are connected at Bus 15, 17 and 18 respectively.

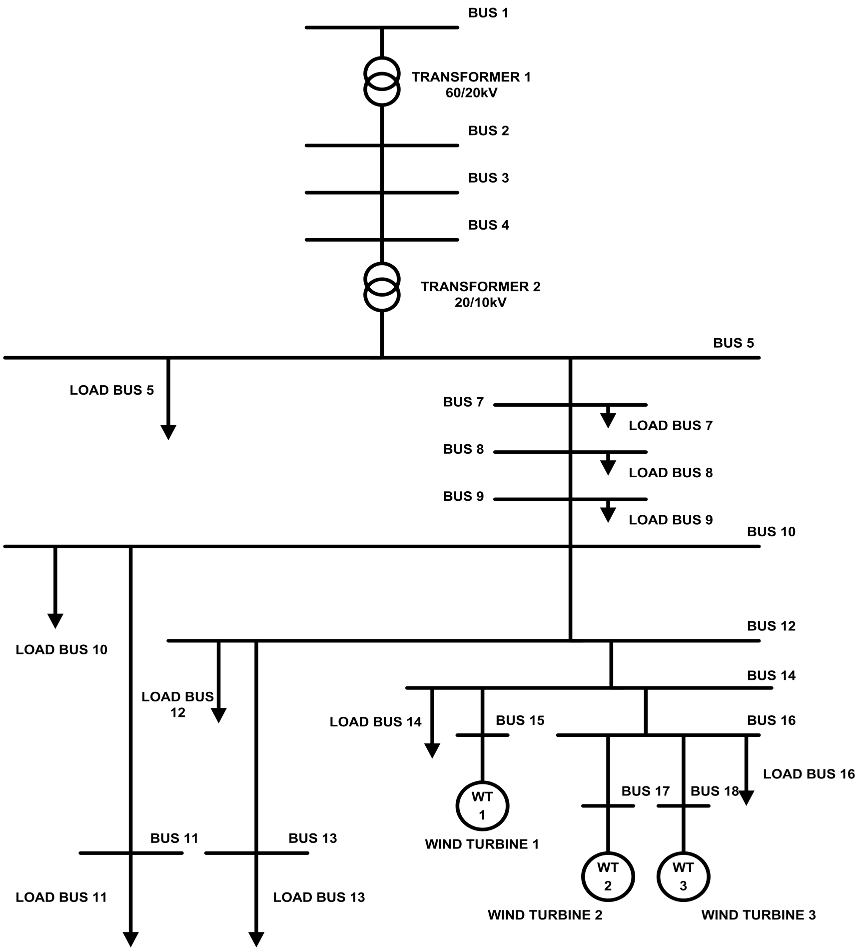

Figure 2.3: Distribution system under investigation [19].

2.2.2 Simulation model

The model of the system as shown in Figure 2.4 was built in DigSilent Power factory 14.1 for further analysis. The data for the network parameters, loads and wind power generation used in the model are given in Tables A.1, A.2 and A.3.

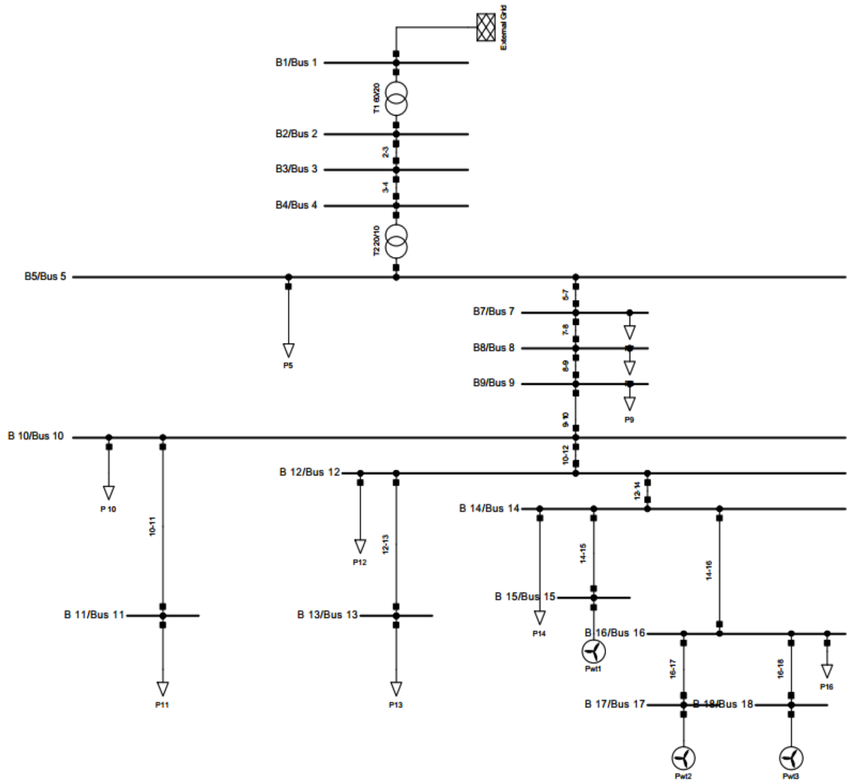

Figure 2.4: System model in DigSilent power factory 14.1

2.3 Load Flow Analysis of the Distribution System

The annual load flow analysis of the distribution system as seen in Figure 2.4 was performed at each hour of the year using the time sweep function of the DPL in DigSilent. For the load flow analysis the provided active power (P) data for all the loads and the wind turbines was used. The reactive power (Q) for all the loads was calculated keeping the power factor ($\boldsymbol{cos\phi}$) to be 0.9 and for the wind turbines the reactive power was considered to be zero. There after for the performed annual load flow analysis the active power for all the 3 wind turbines, active and reactive power for all the 10 loads along with the voltages at all the 17 buses in the system were recorded.

2.3.1 Active power curves (Load)

The active power curves for Load 5 in the distribution system can be seen in Figures 2.5, 2.6 and 2.7. The active power was found to have a maximum value of 7.62 MW and minimum value of 1.67 MW.

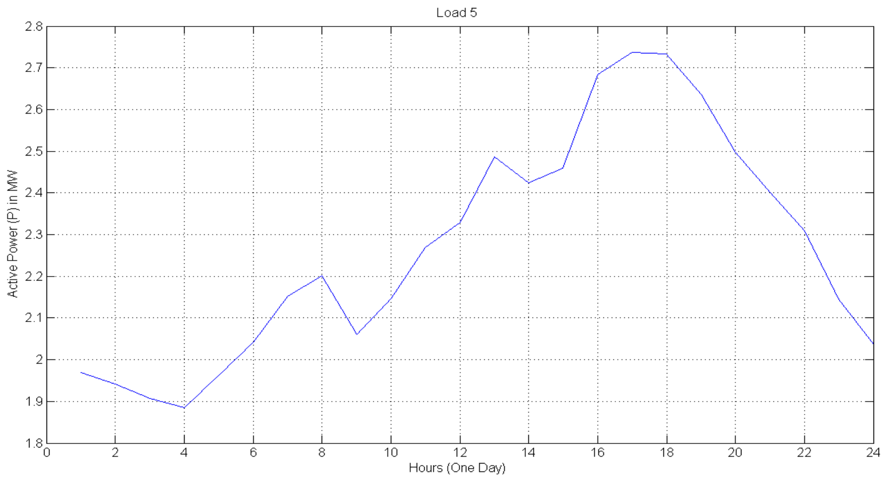

Figure 2.5: Active power curve for one day (Load 5).

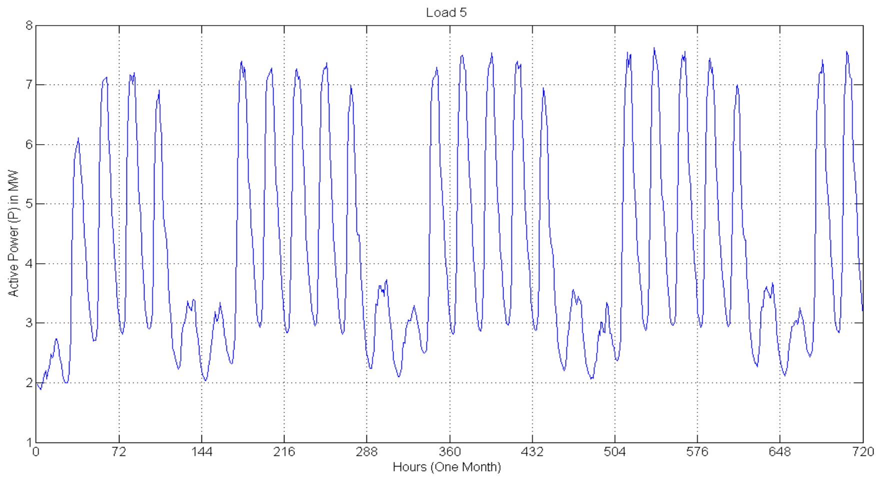

Figure 2.6: Active power curve for one month (Load 5).

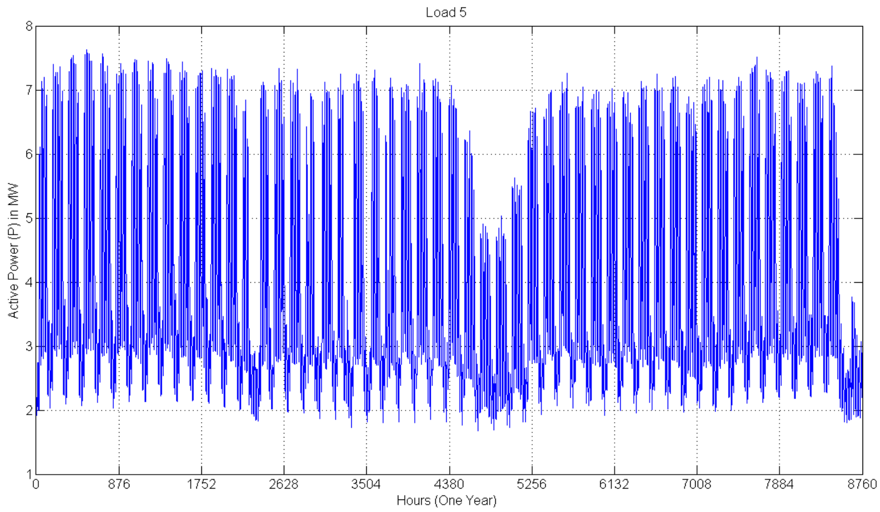

Figure 2.7: Active power curve for one year (Load 5).

2.3.2 Reactive power curves (Load)

The reactive power curves for Load 5 in the distribution system can be seen in Figures 2.8, 2.9 and 2.10. The reactive power was found to have a maximum value of 3.69 MVAr and minimum value of 0.81 MVAr.

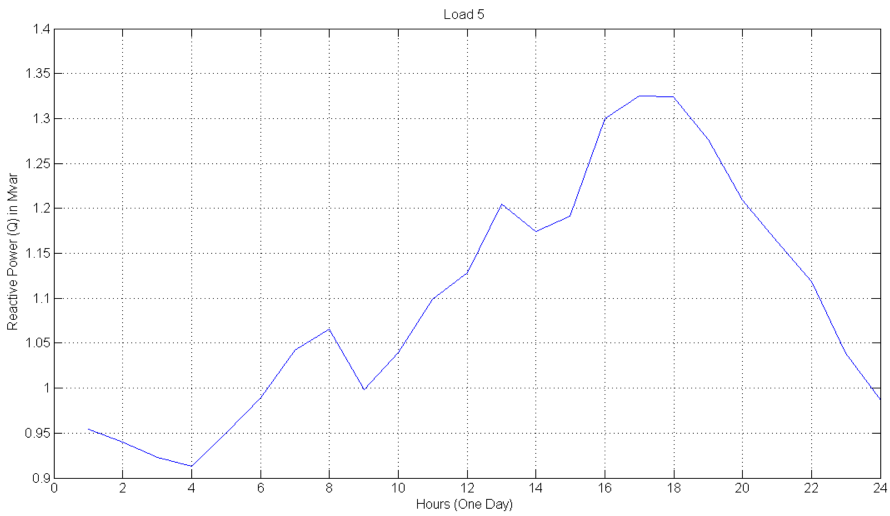

Figure 2.8: Reactive power curve for one day (Load 5).

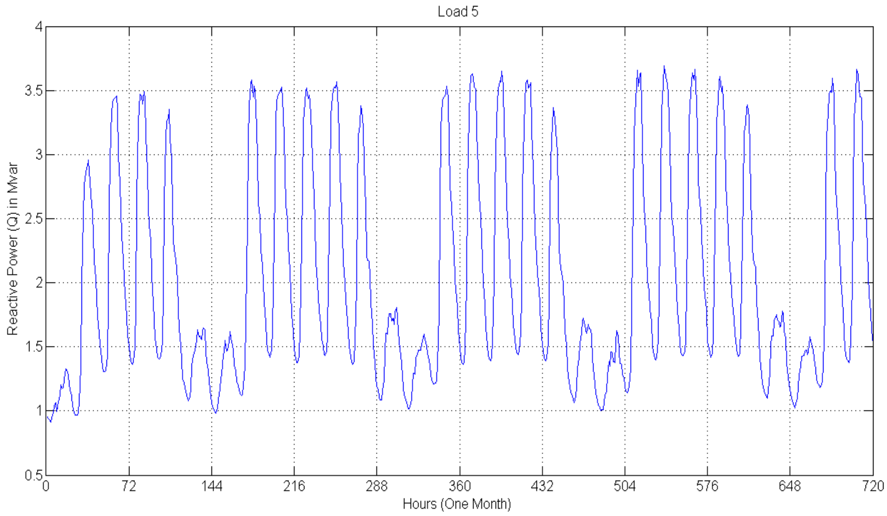

Figure 2.9: Reactive power curve for one month (Load 5).

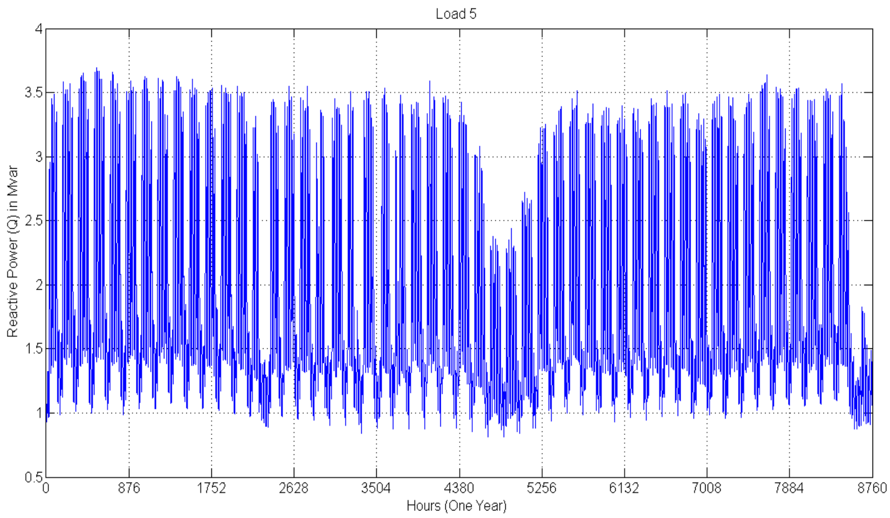

Figure 2.10: Reactive power curve for one year (Load 5).

2.3.3 Active power curves (Wind Turbine)

The active power curves for the wind turbine 1 in the distribution system can be seen in Figures 2.11, 2.12 and 2.13. The active power was found to have a maximum value of 0.17 MW.

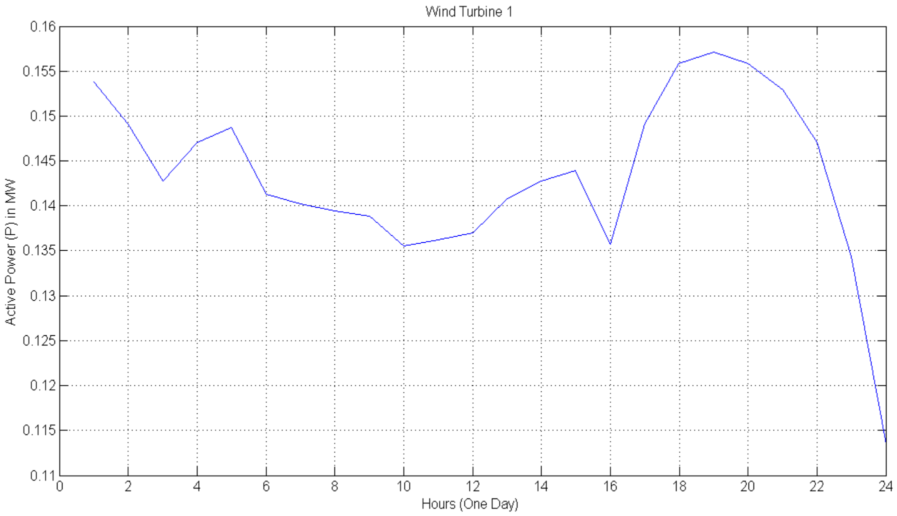

Figure 2.11: Active power curve for one day (Wind Turbine 1).

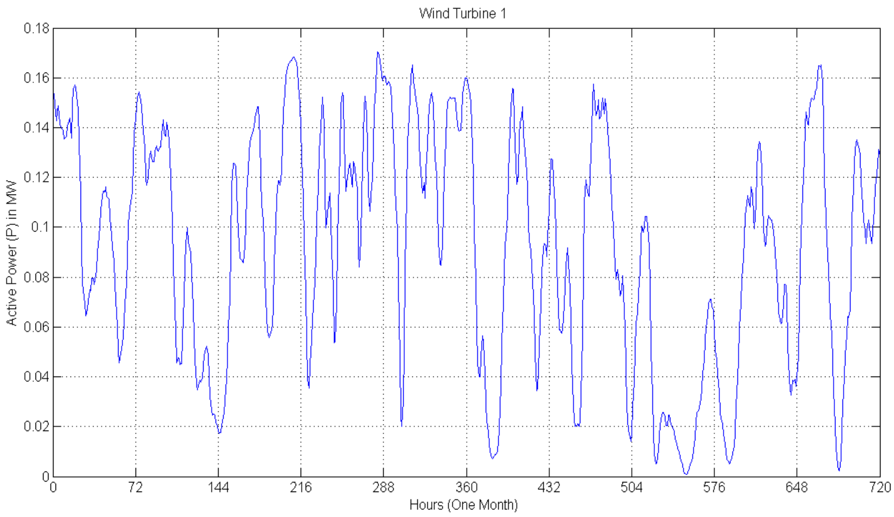

Figure 2.12: Active power curve for one month (Wind Turbine 1).

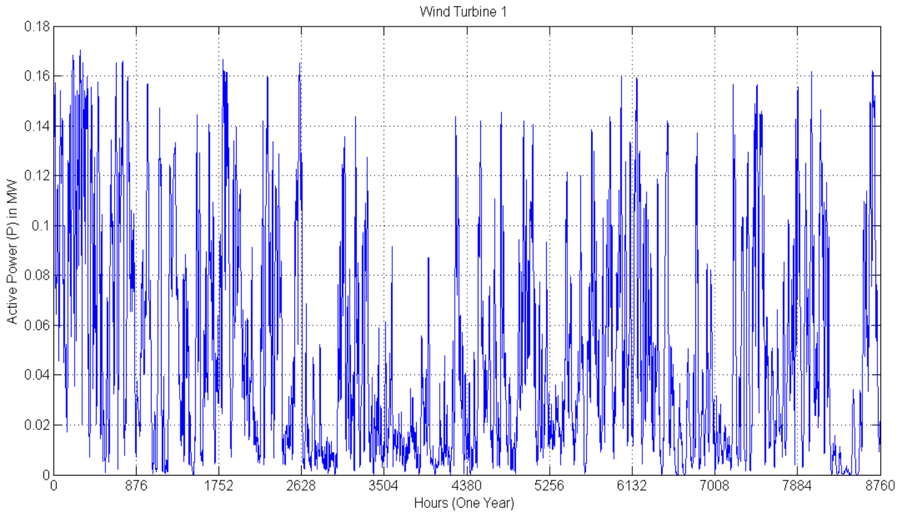

Figure 2.13: Active power curve for one year (Wind Turbine 1).

2.3.4 Voltage curves (Bus)

The voltage curves for Bus 5 in the distribution system can be seen in Figures 2.14, 2.15 and 2.16. The voltage was found to have a maximum value of 0.9969 V (in p.u.) and minimum value of 0.9879 V (in p.u.).

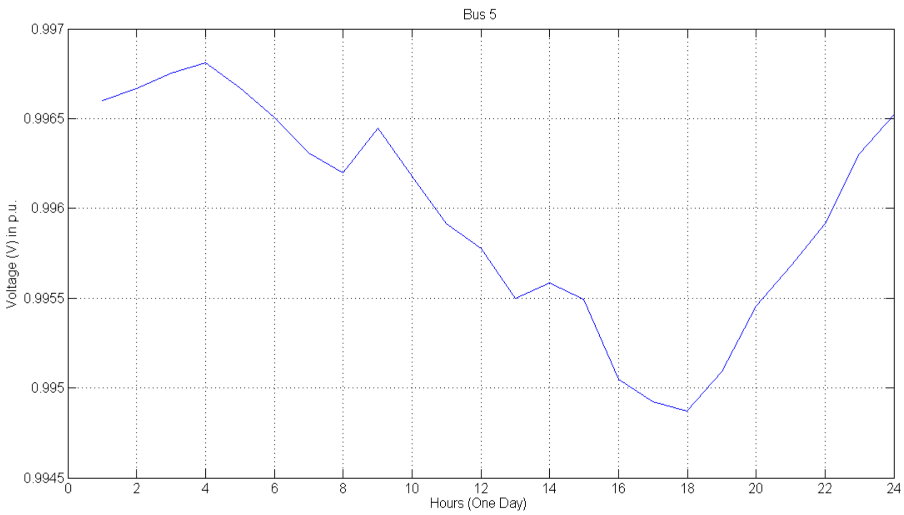

Figure 2.14: Voltage curve for one day (Bus 5).

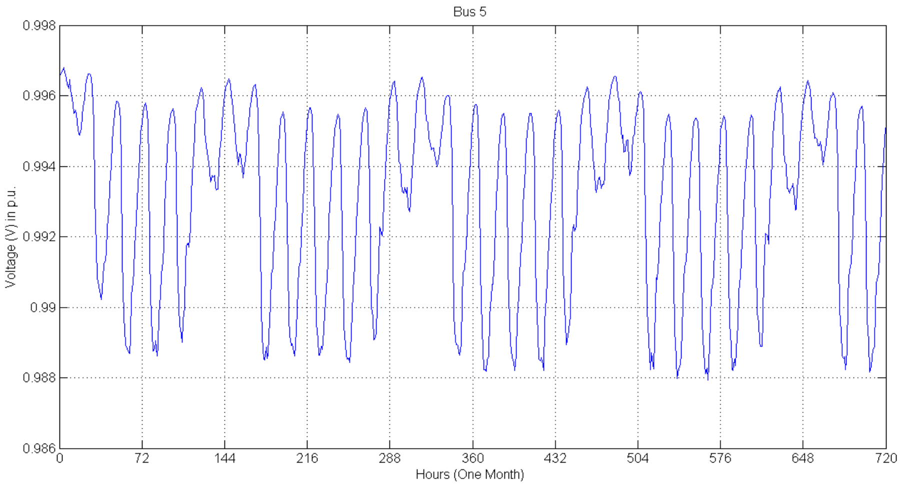

Figure 2.15: Voltage curve for one month (Bus 5).

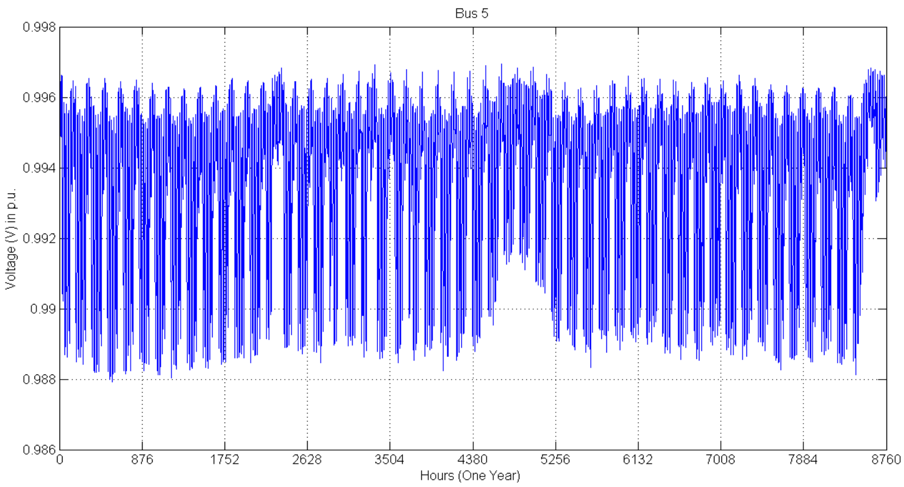

Figure 2.16: Voltage curve for one year (Bus 5).

2.4 Summary

So in this chapter the distribution system was modelled in DigSilent Power Factory 14.1 (Figure 2.4) and the annual load flow analysis of the system was performed using the time sweep function of DPL in DigSilent (DPL Script B.1). The voltages at each hour of the year for all the buses in the system were obtained which are used in further analysis of the system in the later chapters of this project.

Chapter 3

PV Integration into the System

In this chapter the study of PV integration into the system as shown in Figure 2.4 is done in order to estimate the maximum amount of PV generation that can be integrated at each 10 kV bus individually without violating the voltage beyond its limits (5% of nominal) [2]. Further in this chapter the cases of summer and winter hours with maximum and minimum load are taken into consideration and fixed amount of PV generation (50 MW) is integrated individually at each bus with a step of 0.1 MW. Thereafter the load flow simulations are performed for these hours to analyze how the voltage varies at each 10 kV bus due to this PV integration.

3.1 Summer Case

In this case two hours during the month of June with maximum and minimum load are considered. The profile of Load P5 during month of June is shown in Figure 3.1 and the wind power generation during the same month is shown in Figure 3.2:

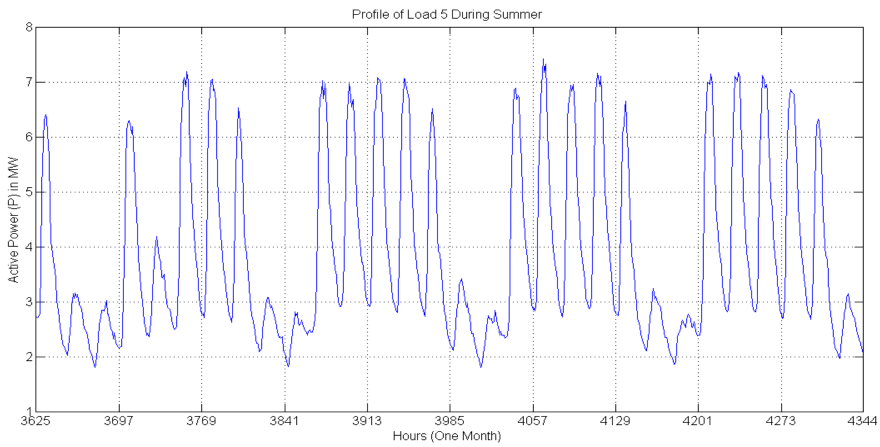

Figure 3.1: Profile of load P5 during June.

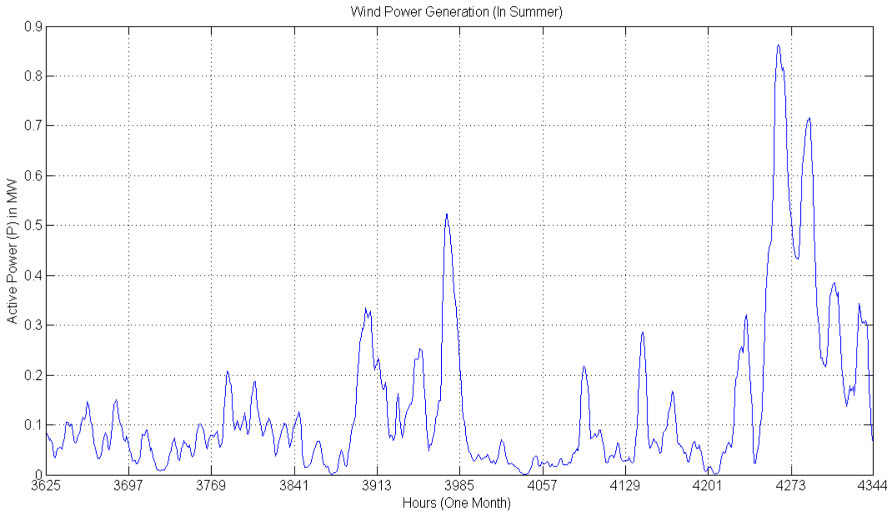

Figure 3.2: Wind power generation during June.

3.1.1 Hour with maximum load

The hour 4067 was found to have the maximum load during the month of June and the active and reactive power data for all the 10 loads during that hour are given in Table 3.1:

Load	Active Power (P) in MW	Reactive Power (Q) in MVar
P5	7.1689	3.4721
P7	1.0618	0.5143
P8	0.3059	0.1482
P9	0.4207	0.2037
P10	0.6891	0.3338
P11	0.1441	0.0698
P12	0.3868	0.1873
P13	0.1844	0.0893
P14	1.3536	0.6556
P16	0.1618	0.0784

Table 3.1: Load data for summer hour with maximum load.

At each 10 kV Bus

So PV generation (50 MW) is integrated individually at each 10 kV bus in this case of maximum load hour during summer. The voltage rise due to PV integration and the PV generation that can be integrated without violating the voltage beyond its limits is analyzed. The voltages at all the 10 kV Buses with PV integration for this case can be seen in Figures 3.3, 3.4, 3.5 and 3.6:

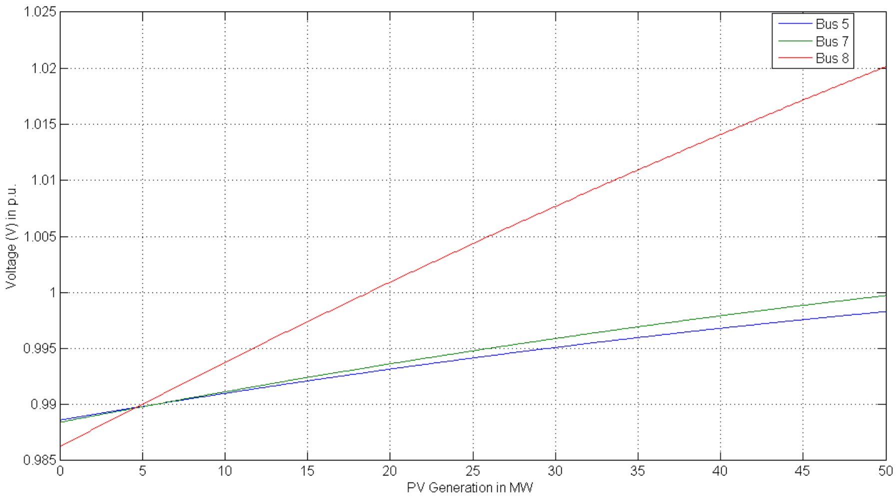

Figure 3.3: Voltage at Bus 5, 7, 8 after PV integration.

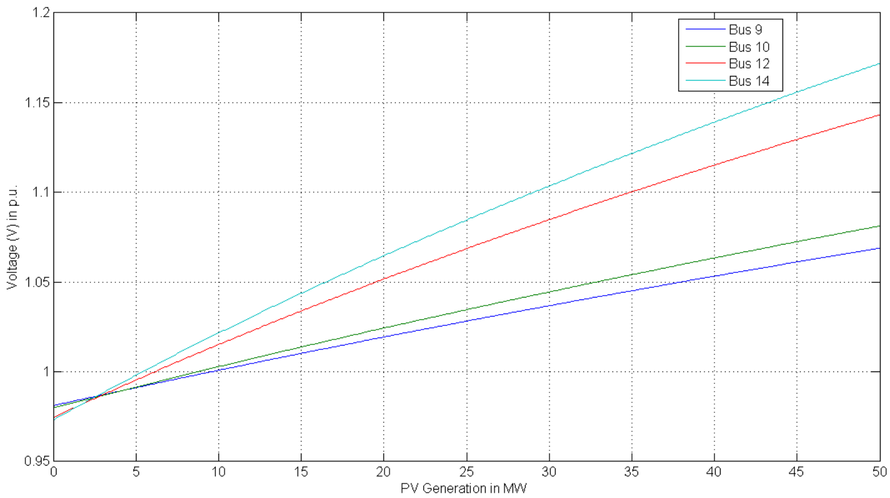

Figure 3.4: Voltage at Bus 9, 10, 12, 14 after PV integration.

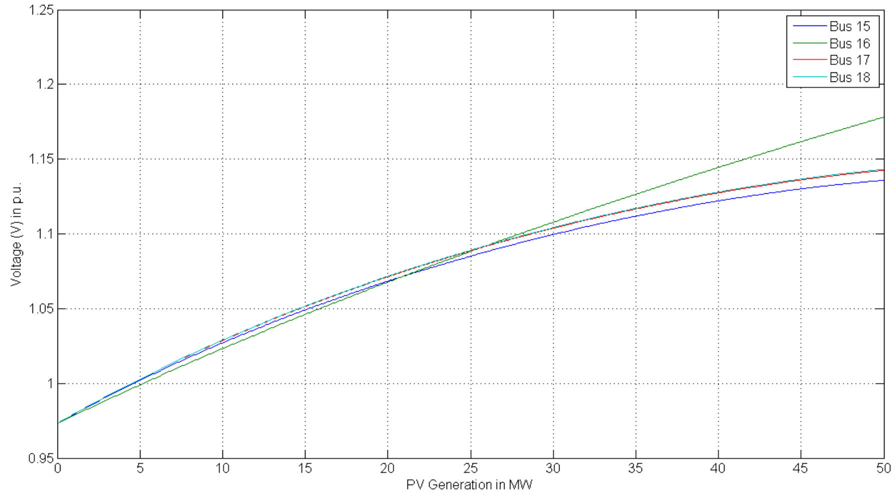

Figure 3.5: Voltage at Bus 15, 16, 17, 18 after PV integration.

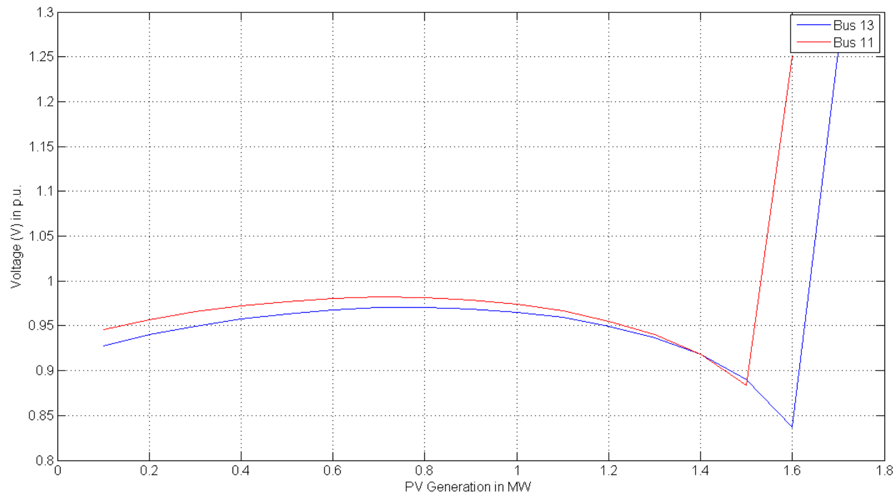

Figure 3.6: Voltage at Bus 11, 13 after PV integration.

The amount of PV generation that can be integrated at each 10 kV bus individually before the voltage violates 1.05 V (in p.u.) at that particular bus for this summer maximum load case are given in Table 3.2:

Bus No.	PV Generation (MW)
5	> 50
7	> 50
8	> 50
9	37.9
10	32.8
11	-
12	19.5
13	-
14	16.5
15	15.2
16	15.8
17	14.6
18	14.6

Table 3.2: Amount of possible PV integration (Summer hour with maximum load).

3.1.2 Hour with minimum load

The hour 4180 was found to have the minimum load during the month of June. The active and reactive power data for all the 10 loads during that hour are given in Table 3.3:

Load	Active Power (P) in MW	Reactive Power (Q) in MVar
P5	1.8553	0.8986
P7	0.2979	0.1443
P8	0.1222	0.0592
P9	0.1813	0.0878
P10	0.2066	0.1001
P11	0.0718	0.0348
P12	0.1473	0.0714
P13	0.0730	0.0354
P14	0.5043	0.2442
P16	0.0504	0.0244

Table 3.3: Load data for summer hour with minimum load.

At each 10 kV Bus

So PV generation (50 MW) is integrated individually at each 10 kV bus in this case of minimum load hour during summer. The voltage rise due to PV integration and the PV generation that can be integrated without violating the voltage beyond its limits is analyzed. The voltages at all the 10 kV Buses with PV integration for this case can be seen in Figures 3.7, 3.8, 3.9 and 3.10:

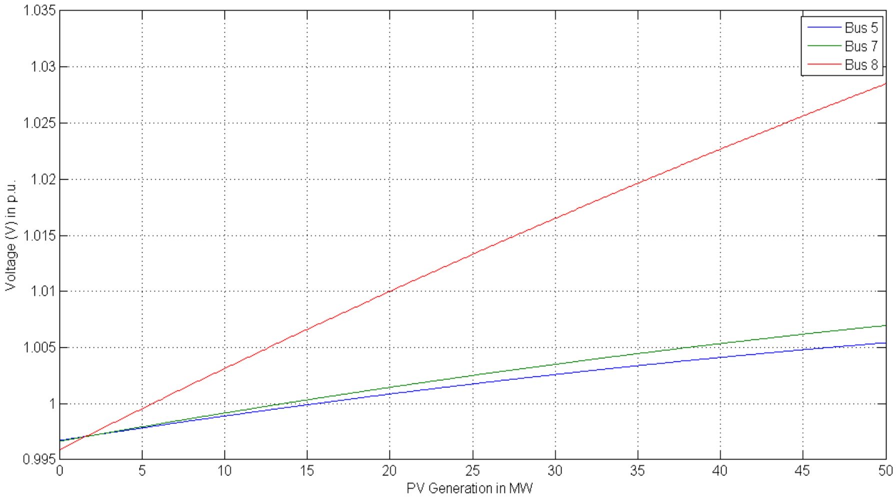

Figure 3.7: Voltage at Bus 5, 7, 8 after PV integration.

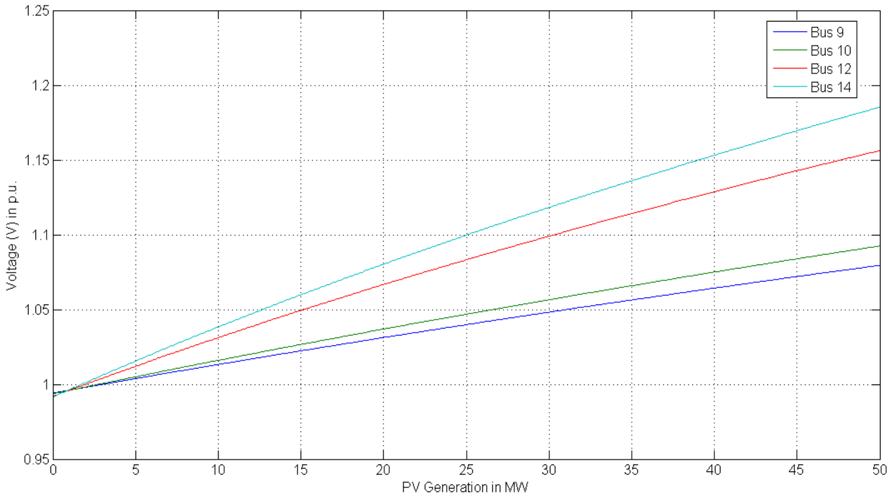

Figure 3.8: Voltage at Bus 9, 10, 12, 14 after PV integration.

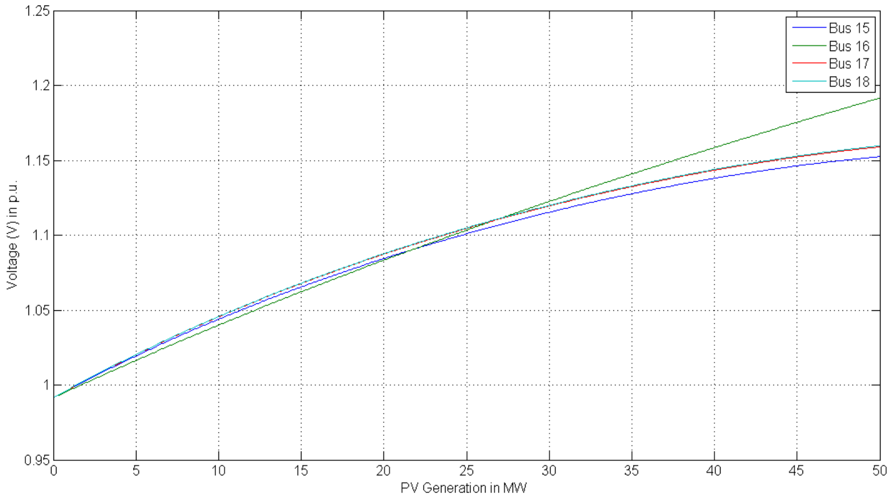

Figure 3.9: Voltage at Bus 15, 16, 17, 18 after PV integration.

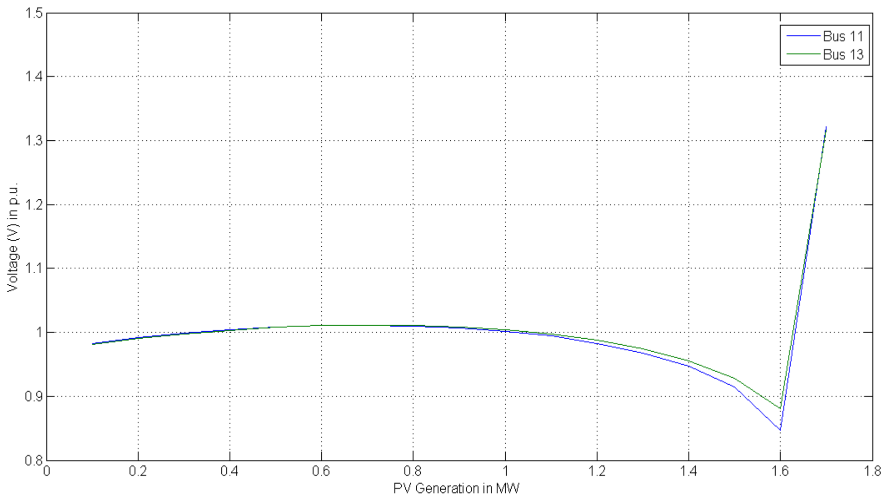

Figure 3.10: Voltage at Bus 11, 13 after PV integration.

The amount of PV generation that can be integrated at each 10 kV bus individually before the voltage violates 1.05 V (in p.u.) at that particular bus for this summer minimum load case are given in Table 3.4:

Bus No.	PV Generation (MW)
5	> 50
7	> 50
8	> 50
9	31.1
10	26.6
11	-
12	15.2
13	-
14	12.7
15	11.3
16	12.2
17	10.9
18	10.9

Table 3.4: Amount of possible PV integration (Summer hour with minimum load).

3.2 Winter Case

In this case two hours during the month of December with maximum and minimum load are considered. The profile of Load P5 during month of December is shown in Figure 3.11 and the wind power generation during the same month is shown in Figure 3.12:

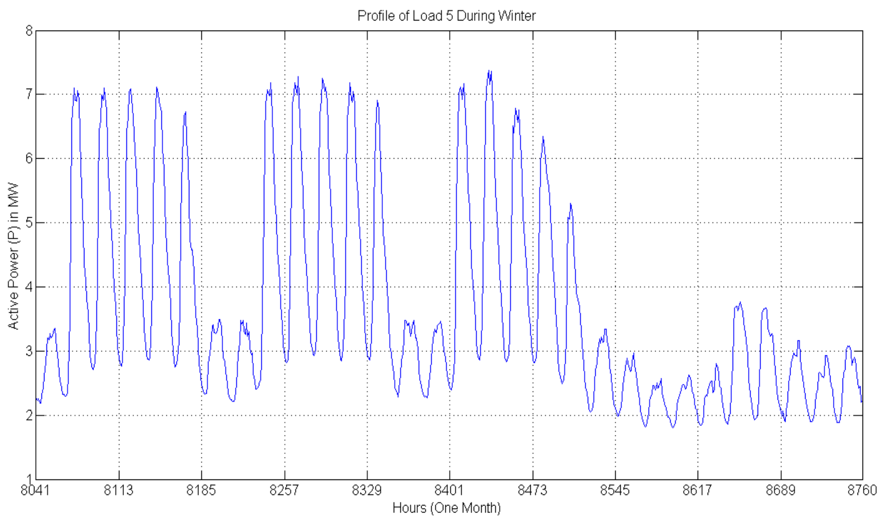

Figure 3.11: Profile of Load P5 during December.

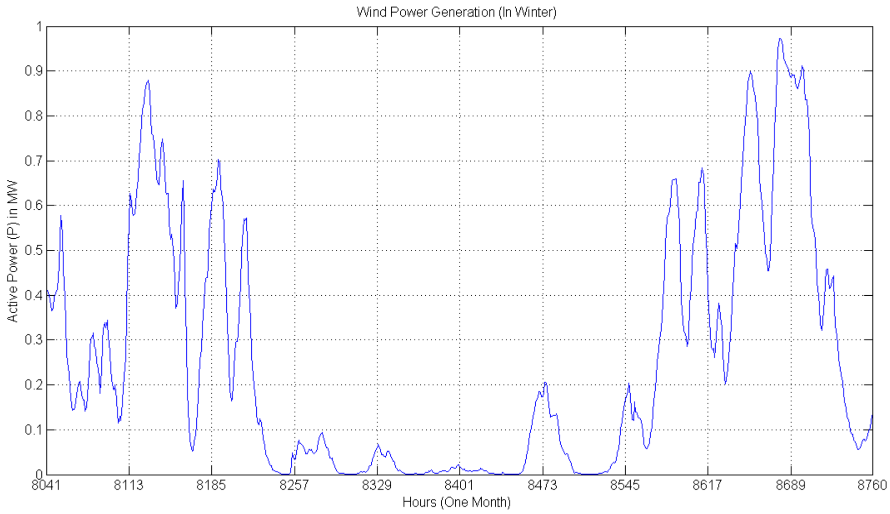

Figure 3.12: Wind power generation during December.

3.2.1 Hour with maximum load

The hour 8436 was found to have the maximum load during the month of December and the active and reactive power data for all the 10 loads during that hour are given in Table 3.5:

Load	Active Power (P) in MW	Reactive Power (Q) in MVar
P5	7.1543	3.4650
P7	1.0880	0.5269
P8	0.3183	0.1541
P9	0.4115	0.1993
P10	0.6622	0.3207
P11	0.1380	0.0669
P12	0.4084	0.1978
P13	0.1823	0.0883
P14	1.4286	0.6919
P16	0.1802	0.0873

Table 3.5: Load data for winter hour with maximum load.

At each 10 kV Bus

So PV generation (50 MW) is integrated individually at each 10 kV bus in this case of maximum load hour during winter. The voltage rise due to PV integration and the PV generation that can be integrated without violating the voltage beyond its limits is analyzed. The voltages at all the 10 kV Buses with PV integration for this case can be seen in Figures 3.13, 3.14, 3.15 and 3.16:

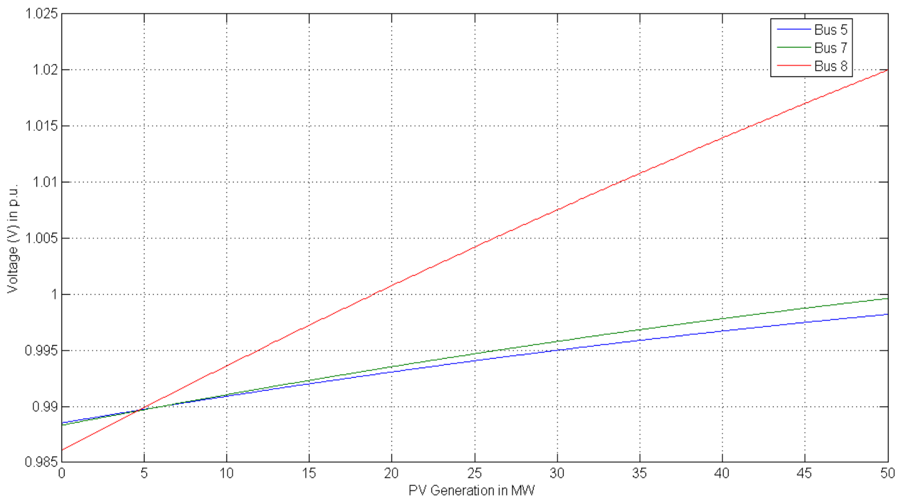

Figure 3.13: Voltage at Bus 5, 7, 8 after PV integration.

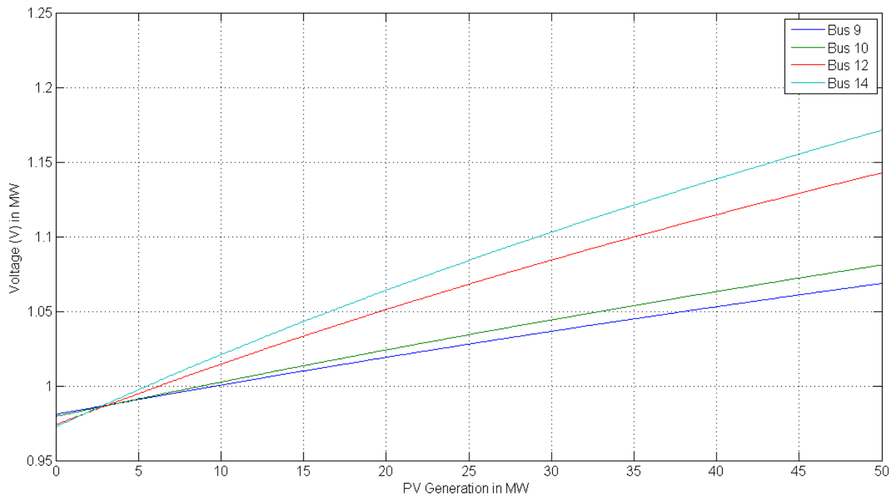

Figure 3.14: Voltage at Bus 9, 10, 12, 14 after PV integration.

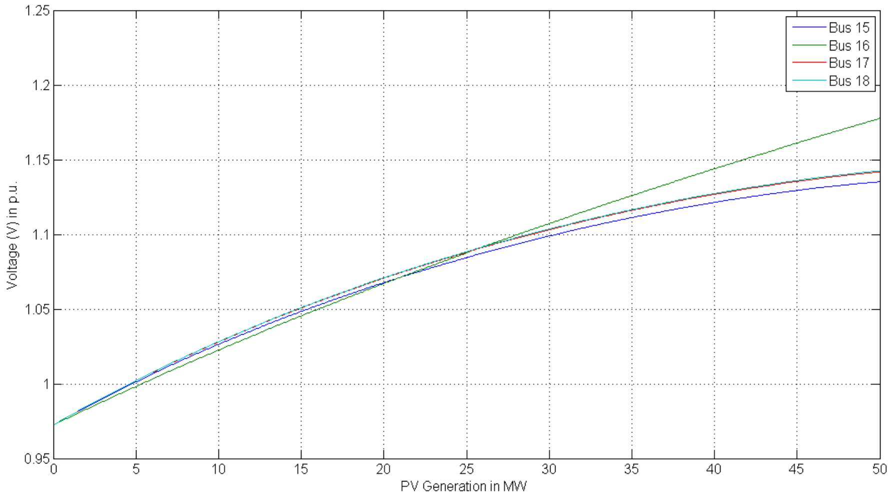

Figure 3.15: Voltage at Bus 15, 16, 17, 18 after PV integration.

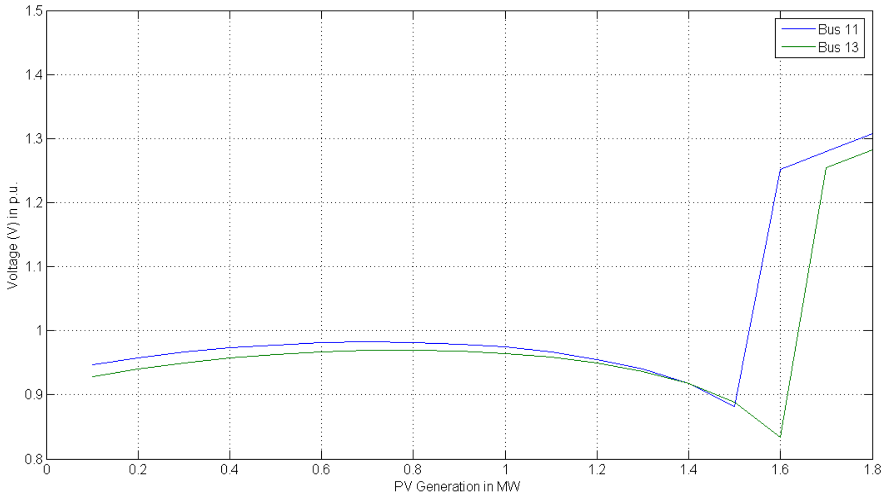

Figure 3.16: Voltage at Bus 11, 13 after PV integration.

The amount of PV generation that can be integrated at each 10 kV bus individually before the voltage violates 1.05 V (in p.u.) at that particular bus for this winter maximum load case are given in Table 3.6:

Bus No.	PV Generation (MW)
5	> 50
7	> 50
8	> 50
9	38.1
10	33
11	-
12	19.7
13	-
14	16.6
15	15.4
16	16
17	14.8
18	14.7

Table 3.6: Amount of possible PV integration (Winter hour with maximum load).

3.2.2 Hour with minimum load

The hour 8572 was found to have the minimum load during the month of December and the active reactive power data for all the 10 loads during that hour are given in Table 3.7:

Load	Active Power (P) in MW	Reactive Power (Q) in MVar
P5	1.8424	0.8923
P7	0.3271	0.1584
P8	0.1266	0.0613
P9	0.1612	0.0781
P10	0.1678	0.0813
P11	0.0567	0.0275
P12	0.1615	0.0782
P13	0.0697	0.0337
P14	0.5607	0.2716
P16	0.0699	0.0338

Table 3.7: Load data for winter hour with minimum load.

At each 10 kV Bus

So PV generation (50 MW) is integrated individually at each 10 kV bus in this case of minimum load hour during winter. The voltage rise due to PV integration and the PV generation that can be integrated without violating the voltage beyond its limits is analyzed. The voltages at all the 10 kV Buses with PV integration for this case can be seen in Figures 3.17, 3.18, 3.19 and 3.20:

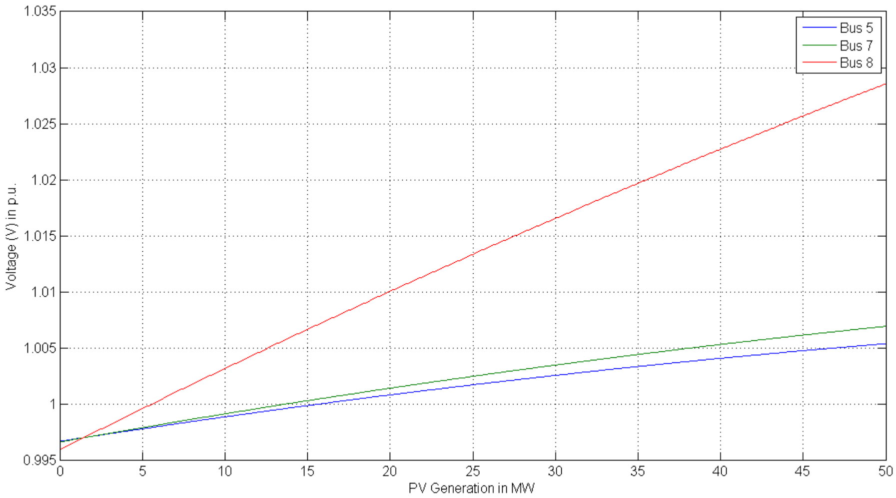

Figure 3.17: Voltage at Bus 5, 7, 8 after PV integration.

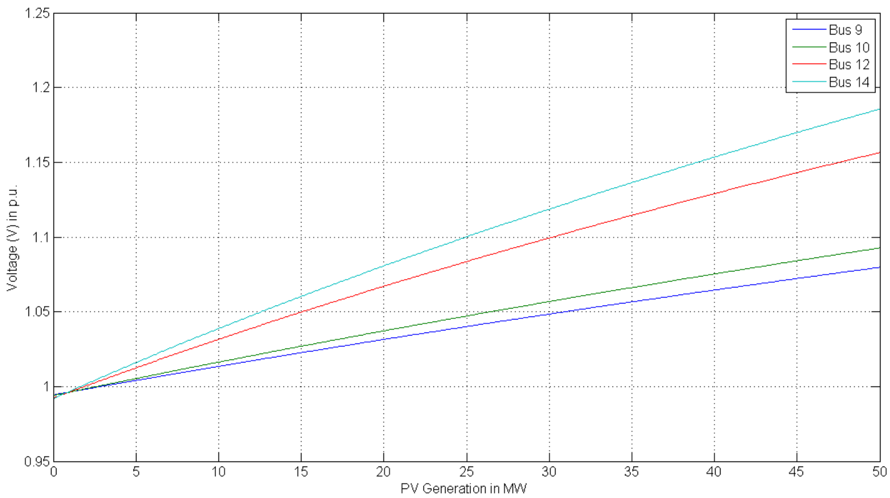

Figure 3.18: Voltage at Bus 9, 10, 12, 14 after PV integration.

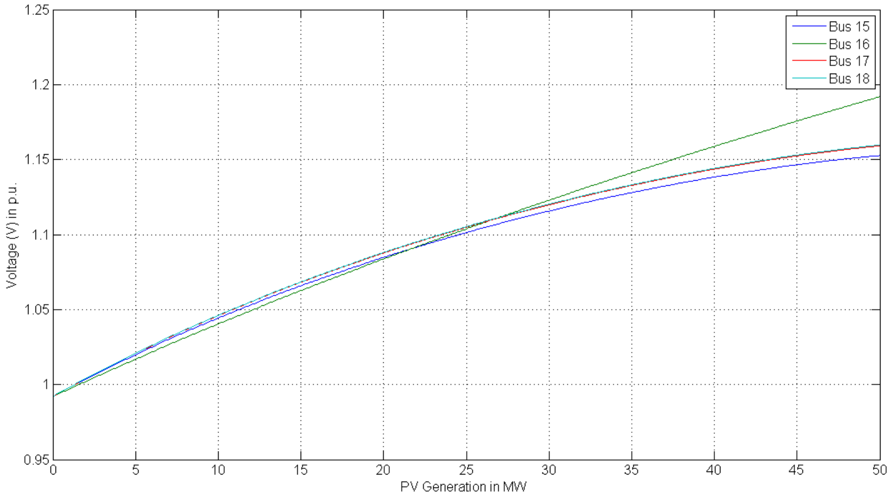

Figure 3.19: Voltage at Bus 15, 16, 17, 18 after PV integration.

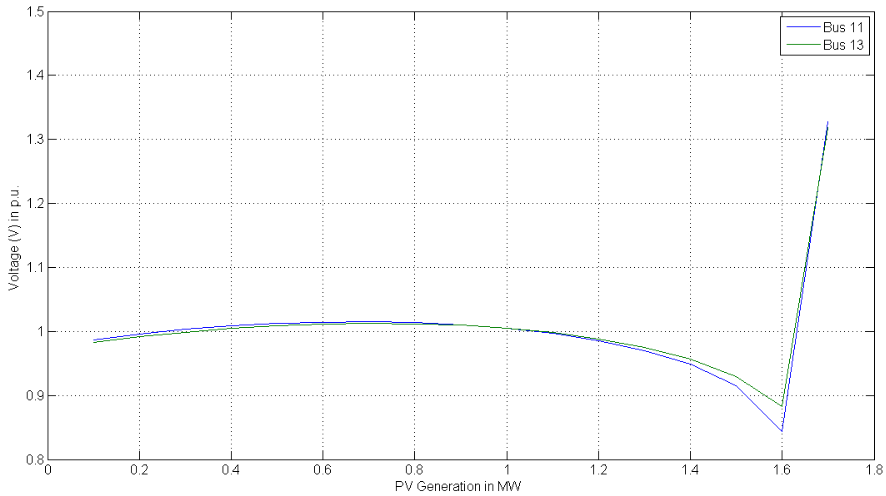

Figure 3.20: Voltage at Bus 11, 13 after PV integration.

The amount of PV generation that can be integrated at each 10 kV bus individually before the voltage violates 1.05 V (in p.u.) at that particular bus for this winter minimum load case are given in Table 3.8:

Bus No.	PV Generation (MW)
5	> 50
7	> 50
8	> 50
9	30.9
10	26.4
11	-
12	15
13	-
14	12.6
15	11.2
16	12.1
17	10.8
18	10.8

Table 3.8: Amount of possible PV integration (Winter hour with minimum load).

3.3 Summary

So in this chapter the amount of PV generation that can be integrated individually at each 10 kV bus in the system for different summer and winter cases without violating the voltage limits has been analyzed. It was seen that when PV is integrated on an individual bus there is a voltage rise with higher amount of PV generation [12] except in the case of Bus 11 and 13 in the system. It was found that for all the four cases especially on Bus 11 and 13 there was a non convergence of the load flow when PV integration on both of them was more than 1.5 or 1.6 MW individually. Finally the amount of PV integration possible for these cases are given in Tables 3.2, 3.4, 3.6 and 3.8.

Chapter 4

Annual PV Power Output Calculation

In this chapter the annual PV output power is calculated using the annual irradiance data provided. Irradiance is the rate at which the radiant energy is incident on a per unit of surface area. The units of Irradiance are watts per square meter ($\boldsymbol{W/m^2}$) [20].

The data includes the global horizontal irradiance ($\boldsymbol{G}$), diffused horizontal irradiance ($\boldsymbol{G_d}$), solar altitude and azimuth angle ($\boldsymbol{SA/AZ}$), air temperature ($\boldsymbol{T_a}$) and the speed of the wind.

The calculations were made in three steps:

1. Calculating the total tilted irradiance ($\boldsymbol{G_{total-tilted}}$) using the Perez irradiance model.

2. Calculating the PV cell temperature ($\boldsymbol{T_c}$).

3. Calculating the output PV power ($\boldsymbol{P_{pv}}$) depending on the area of cell or array.

4.1 Total Tilted Irradiance Calculation

The Perez irradiance model was used for the calculating the total tilted irradiance ($\boldsymbol{G_{total-tilted}}$) for one year from the provided irradiance data. In order to calculate $\boldsymbol{G_{total-tilted}}$ the following calculations were done which are included in this section.

First of all the direct horizontal irradiance ($\boldsymbol{G_b}$) was calculated using the equation 4.1 where ($\boldsymbol{G_b}$) is the solar radiation which comes directly from the sun without getting scattered in the atmosphere and ($\boldsymbol{G_d}$) is diffused horizontal irradiance and is the solar radiation received from the sun whose direction has been changed due to the particles present in the atmosphere [20].

$$\boldsymbol{G_b = G - G_d} \tag{4.1}$$

And $\boldsymbol{G}$ is the total horizontal irradiance which is the sum of both Direct and Diffused horizontal irradiance as can seen in Figure 4.1:

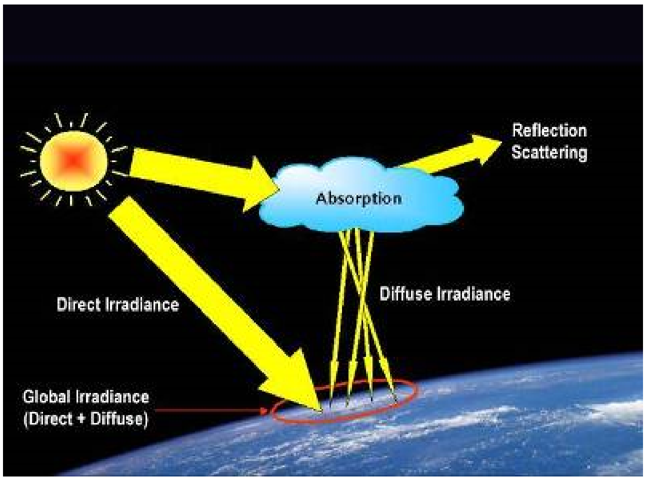

Figure 4.1: Total horizontal irradiance [21].

The zenith ($\boldsymbol{ZA}$) and the incidence angle ($\boldsymbol{IA}$) as can be seen in Figure 4.2 were calculated using the equations 4.2 and 4.3:

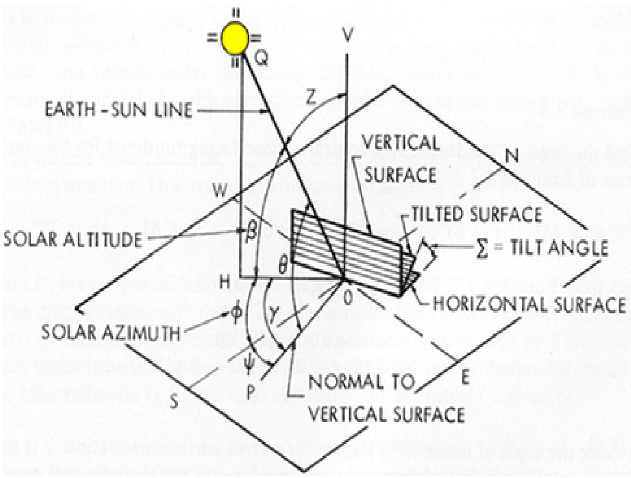

Figure 4.2: Solar angles [22].

Zenith Angle ($\boldsymbol{ZA}$) is the angle between the vertical and the line to the sun ie the incidence angle of the beam radiation on a horizontal surface [20].

$$\boldsymbol{ZA = 90° - SA} \tag{4.2}$$

where ($\boldsymbol{SA}$), solar altitude angle is the angle between the horizontal and the line to the sun and is the complement of the zenith angle (Both are in degrees) [20].

Incidence angle ($\boldsymbol{IA}$) is calculated using equation 4.3 and is the angle between the beam radiation on a surface and the normal to that surface [20].

$$\boldsymbol{IA = acos(cos(ZA).cos(\beta) + sin(ZA).sin(\beta).cos(AZ))} \tag{4.3}$$

where ($\boldsymbol{AZ}$), solar azimuth angle is the angular displacement from south of the projection of beam radiation on the horizontal plane (in degrees) [20] and $\boldsymbol{\beta}$ is the tilt angle and is taken to be $\mathbf{45°}$.

Further ($\boldsymbol{B}$) which is the day angle ($\boldsymbol{radians}$) for each day is calculated using the equation 4.4:

$$\boldsymbol{B = 2\pi(dn - 1)/365} \tag{4.4}$$

where $\boldsymbol{dn}$ is the day number during one year.

The eccentricity correction factor of the earth's orbit ($\boldsymbol{E0}$) using the ($\boldsymbol{B}$) value for each day is then calculated using the equation 4.5:

$$\boldsymbol{E0 = 1 + 0.034cos(B) + 0.001sin(B) + 0.0007cos(2B) + 0.00007sin(2B)} \tag{4.5}$$

Then this ($\boldsymbol{E0}$) is used to calculate the extraterrestrial irradiance on horizontal surface ($\boldsymbol{G_{on}}$) using the equation 4.6:

$$\boldsymbol{G_{on} = G_{sc}.E0} \tag{4.6}$$

where $\boldsymbol{G_{sc}}$, Solar Constant is the amount of the energy received from the sun on a unit surface area in per unit time which is perpendicular to the direction of radiation propagation at a mean distance between the earth and sun outside the atmosphere. The value of $\boldsymbol{G_{sc}} = 1367$ ($\boldsymbol{W/m^2}$) [20].

The relative optical air mass ($\boldsymbol{m}$) is calculated using equation 4.7:

$$\boldsymbol{m = (sin(SA) + 0.15(SA + 3.885)^{-1.253})^{-1}} \tag{4.7}$$

where ($\boldsymbol{SA}$) is in degrees.

Further the sky clearness ($\boldsymbol{\epsilon}$) is calculated using equation 4.8 [23]:

$$\boldsymbol{\epsilon = (Gd + Gb)/(Gd + 1.041Z^3)/(1 + 1.041Z^3)} \tag{4.8}$$

where ($\boldsymbol{Z}$) is the zenith angle ($\boldsymbol{ZA}$) and is in radians.

Based upon the value of $\boldsymbol{\epsilon}$ the irradiance coefficients are obtained from the Table 4.1:

Using these irradiance coefficients circumsolar ($\boldsymbol{F1}$) and horizon brightening coefficients ($\boldsymbol{F2}$) are obtained using the equations 4.9 and 4.10 [24]:

$$\boldsymbol{F1 = F_{11} + F_{12}.Delta + F_{13}.Z} \tag{4.9}$$

ϵ	F_{11}	F_{12}	F_{13}	F_{21}	F_{22}	F_{23}
1	-0.008	0.588	-0.062	-0.060	0.072	-0.022
2	0.130	0.683	-0.151	-0.019	0.066	-0.029
3	0.330	0.487	-0.221	0.055	-0.064	-0.026
4	0.568	0.187	-0.295	0.109	-0.152	-0.014
5	0.873	-0.392	-0.362	0.226	-0.462	0.001
6	1.132	-1.237	-0.412	0.288	-0.823	0.056
7	1.060	-1.600	-0.359	0.264	-1.127	0.131
8	0.678	-0.327	-0.250	0.156	-1.377	0.251

Table 4.1: Irradiance coefficients [24].

$$\boldsymbol{F2 = F_{21} + F_{22}.Delta + F_{23}.Z} \tag{4.10}$$

Further the beam, tilted diffuse and the reflected irradiance are calculated using equations 4.11, 4.12, 4.13, 4.14 and 4.15 [24]:

$$\boldsymbol{G_b(\beta) = G_b.a/b} \tag{4.11}$$

$$\boldsymbol{G_d(\beta) = G_d((1 - F1).(1 + cos(\beta))/2 + F1.a/b + F2.sin(\beta))} \tag{4.12}$$

where

$$\boldsymbol{a = max(0, cos(IA))} \tag{4.13}$$

$$\boldsymbol{b = max(0.087, cos(ZA))} \tag{4.14}$$

$$\boldsymbol{G_r(\beta) = G.pg.((1 - cos(\beta))/2)} \tag{4.15}$$

where $\boldsymbol{\beta} = \boldsymbol{45°}$, the tilt angle and $\boldsymbol{pg} = 0.2$

Finally using equations 4.11, 4.12 and 4.15, $\boldsymbol{G_{total-tilted}}$ is calculated as given by equation 4.16:

$$\boldsymbol{G_{total-tilted} = G_b(\beta) + G_d(\beta) + G_r(\beta)} \tag{4.16}$$

The calculated total tilted irradiance ($\boldsymbol{G_{total-tilted}}$) for one year is shown in the Figure 4.3:

4.2 PV Cell Temperature Calculation

In this section the procedure for calculating the temperature of the PV cell using the calculated total tilted irradiance in Section 4.1 and from the air temperature provided in the data is included.

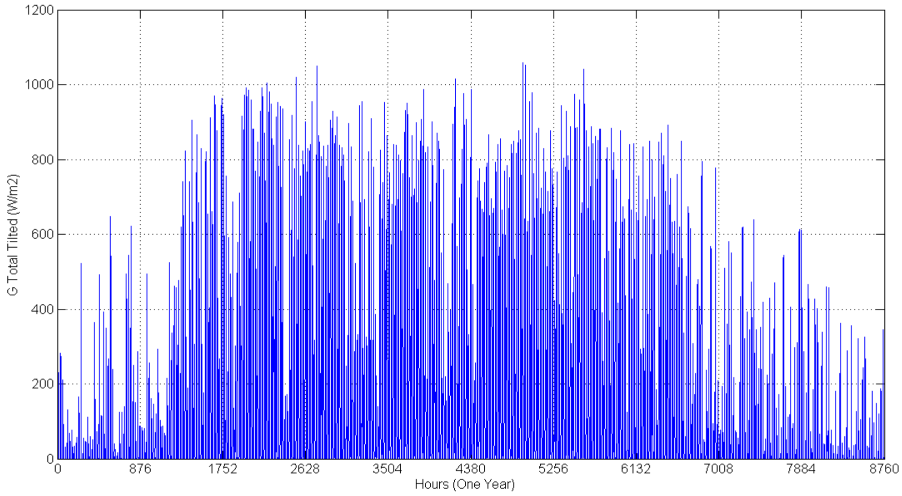

Figure 4.3: Total tilted irradiance for one year ($\boldsymbol{\beta = 45°}$).

The temperature of the PV cell is calculated using the equation 4.17 [25]:

$$\boldsymbol{T_c = T_{air} + \frac{NOCT - 20°C}{800} . G_{total-tilted}} \tag{4.17}$$

where $\boldsymbol{NOCT}$ is the normal operating cell temperature and is taken to be $\boldsymbol{45°C}$ for these calculations.

The Figure 4.4 shows the calculated PV cell temperature for one year.

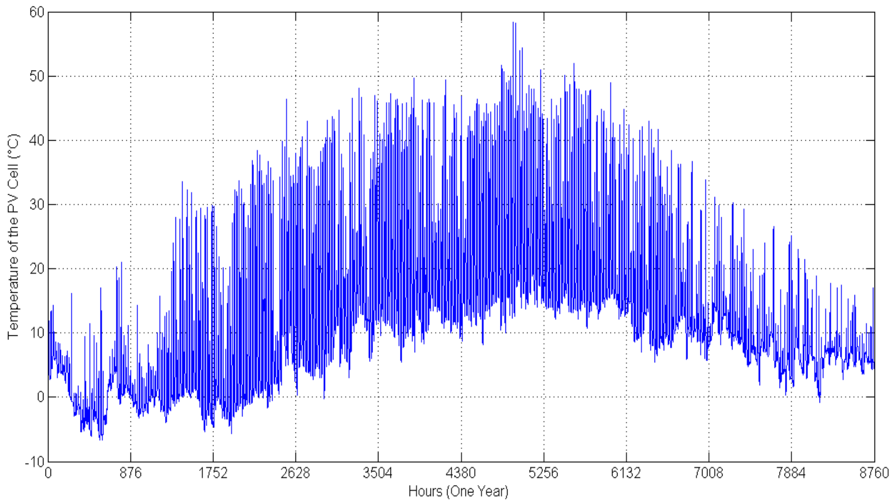

Figure 4.4: Calculated PV cell temperature for one year.

4.3 PV Power Output Calculation

Finally in this section the procedure for calculating the PV output power is included.
The equations 4.18 and 4.19 [26] are used for the calculation.

$$\boldsymbol{\eta_{pv} = \eta_{ref}(1 - k_T(T_c - 25°))} \tag{4.18}$$

where $\boldsymbol{n_{ref}}$ is the reference solar cell efficiency which is 0.15 for silicon PV modules and $\boldsymbol{k_T}$ is 0.004 which is the temperature coefficient.

$$\boldsymbol{P_{pv} = \eta_{pv}.G_{total-tilted}.A} \tag{4.19}$$

where $\boldsymbol{A}$ is the PV module area ($\boldsymbol{m^2}$).

Figure 4.5 shows the calculated PV power production for one year for area A=$\boldsymbol{1m^2}$.

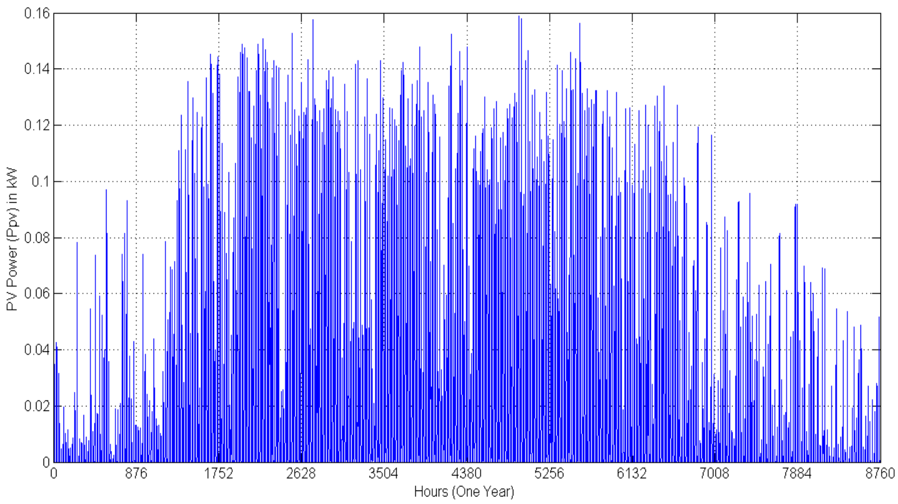

Figure 4.5: PV power production for one year (For A=$\boldsymbol{1m^2}$).

4.4 Summary

So in this chapter the PV power output for one year has been calculated using the irradiance data provided for one year. The calculated data will be used in Chapter 5 for further analysis of the system to estimate maximum PV integration possible with generation data for one year.

Chapter 5

PV Integration (With Annual PV Power Output)

In this chapter three different scenarios of PV integration with generation data for one year are considered and further analysis of the system is done. The minimum and maximum values of voltages at all the 10 kV buses in the system are given in Table 5.1 as obtained from the annual load flow analysis previously done in Chapter 2. It can be seen that the voltage has minimum values at Bus 11 and 13 which are 0.9190 and 0.9079 V (in p.u.) respectively.

Bus No.	**Min. voltage (V) in p.u.**	**Max. voltage (V) in p.u.**
5	0.9879	0.9969
7	0.9877	0.9969
8	0.9855	0.9964
9	0.9800	0.9955
10	0.9786	0.9953
11	0.9190	0.9778
12	0.9727	0.9948
13	0.9079	0.9744
14	0.9711	0.9949
15	0.9711	0.9950
16	0.9711	0.9950
17	0.9711	0.9953
18	0.9711	0.9954

Table 5.1: Voltages at all 10 kV buses (Without PV integration).

5.1 PV Integration (Scenario 1)

In this first scenario the PVs are integrated individually at two buses ie Bus 11 and 13 in order to analyze how the voltage varies at each bus. Then annual load flow analysis of the system is carried out with different amount of PV integration before the voltage at the respective bus violates the limits.

The calculated amount of PV power which is integrated in the system in Section 5.1.1 and 5.1.2 is given in Table 5.2:

S. No.	**Area (m^2)**	**kWp/m^2**	**Peak Output (kWp)**
1	3333	0.15	500
2	6666	0.15	1000
3	10000	0.15	1500
4	11000	0.15	1650

Table 5.2: Calculated PV power output (For scenario 1).

5.1.1 At only Bus 11

With 500 kWp

Figure 5.1 shows the annual voltage at Bus 11 after 500 kWp of PV integration and the minimum and maximum values of voltages are given in Table 5.3:

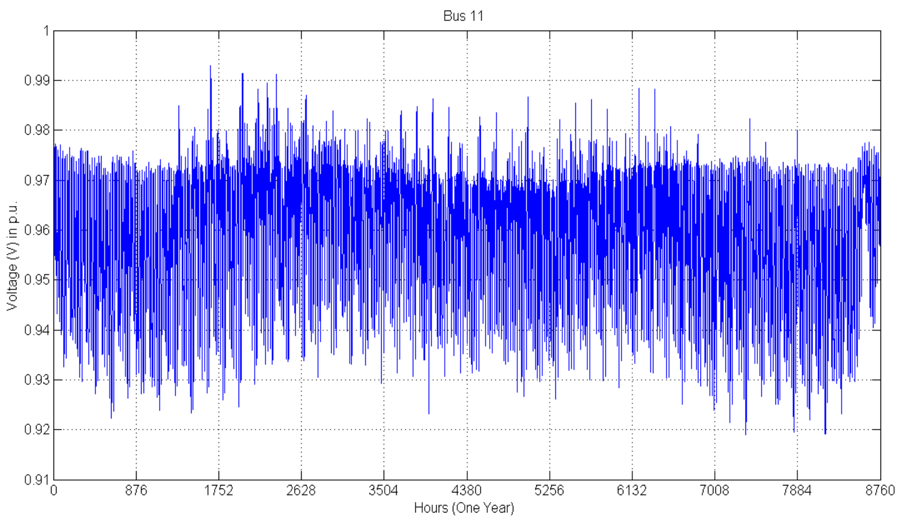

Figure 5.1: Voltage at Bus 11 (With 500 kWp).

Voltage at Bus 11 (in p.u.)	Without PV	With PV (500 kWp)
Minimum Value	0.9190	0.9190
Maximum Value	0.9778	0.9929

Table 5.3: Minimum and Maximum values of voltage at Bus 11.

With 1000 kWp

Figure 5.2 shows the annual voltage at Bus 11 after 1000 kWp of PV integration and the minimum and maximum values of voltages are given in Table 5.4:

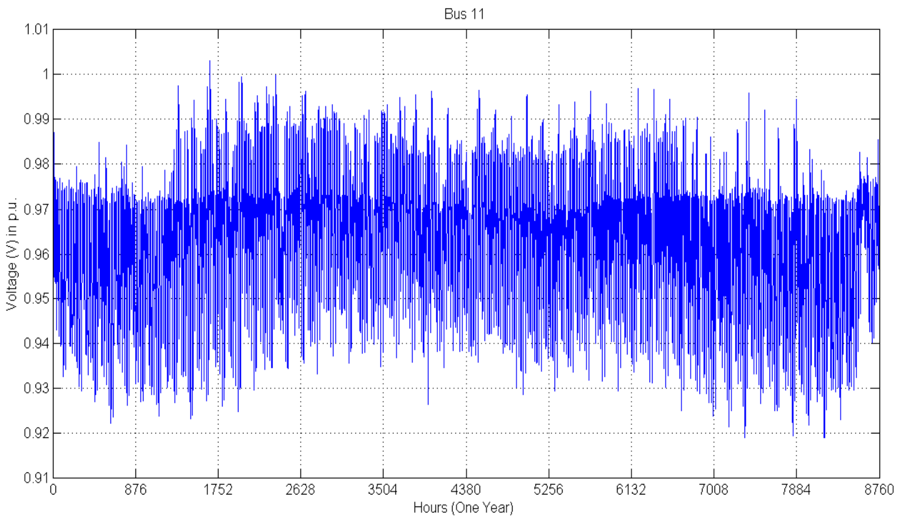

Figure 5.2: Voltage at Bus 11 (With 1000 kWp).

Voltage at Bus 11 (in p.u.)	Without PV	With PV (1000 kWp)
Minimum Value	0.9190	0.9190
Maximum Value	0.9778	1.0030

Table 5.4: Minimum and Maximum values of voltage at Bus 11.

With 1500 kWp

Figure 5.3 shows the annual voltage at Bus 11 after 1500 kWp of PV integration and the minimum and maximum values of voltages are given in Table 5.5:

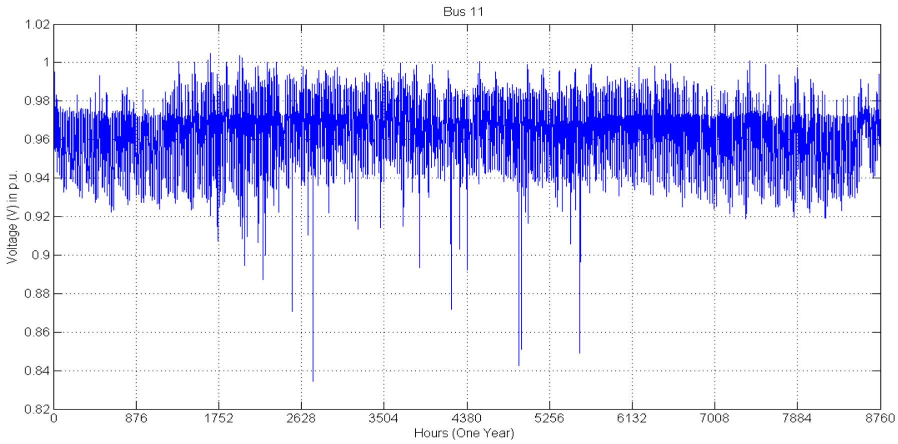

Figure 5.3: Voltage at Bus 11 (With 1500 kWp).

Voltage at Bus 11 (in p.u.)	Without PV	With PV (1500 kWp)
Minimum Value	0.9190	0.8344
Maximum Value	0.9778	1.0049

Table 5.5: Minimum and Maximum values of voltage at Bus 11.

With 1650 kWp

Figure 5.4 shows the annual voltage at Bus 11 after 1650 kWp of PV integration and the minimum and maximum values of voltages are given in Table 5.6:

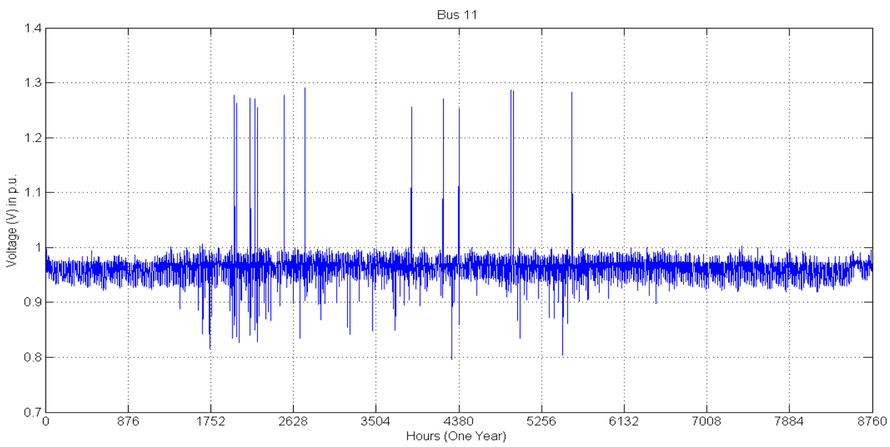

Figure 5.4: Voltage at Bus 11 (With 1650 kWp).

Voltage at Bus 11 (in p.u.)	Without PV	With PV (1650 kWp)
Minimum Value	0.9190	0.7955
Maximum Value	0.9778	1.2906

Table 5.6: Minimum and Maximum values of voltage at Bus 11.

5.1.2 At only Bus 13

With 500 kWp

Figure 5.5 shows the annual voltage at Bus 13 after 500 kWp of PV integration and the minimum and maximum values of voltages are given in Table 5.7:

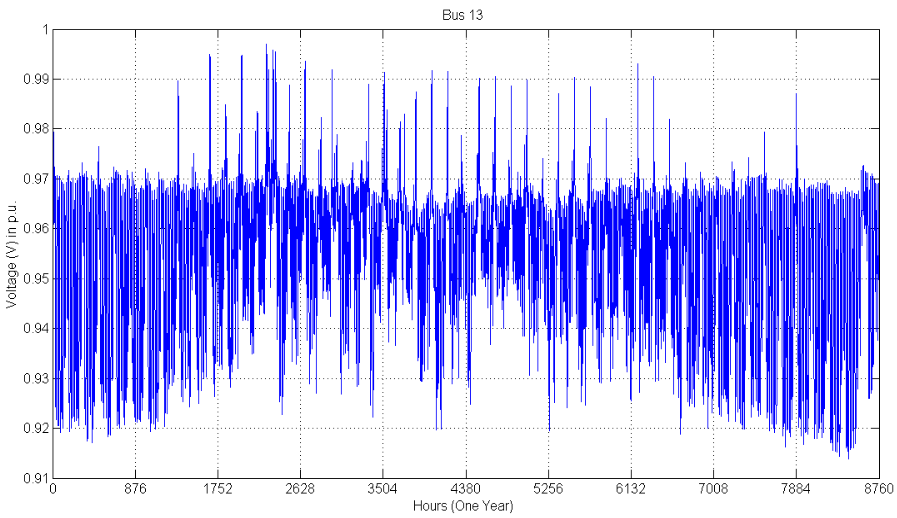

Figure 5.5: Voltage at Bus 13 (With 500 kWp).

Voltage at Bus 13 (in p.u.)	Without PV	With PV (500 kWp)
Minimum Value	0.9079	0.9138
Maximum Value	0.9744	0.9970

Table 5.7: Minimum and Maximum values of voltage at Bus 13.

With 1000 kWp

Figure 5.6 shows the annual voltage at Bus 13 after 1000 kWp of PV integration and the minimum and maximum values of voltages are given in Table 5.8:

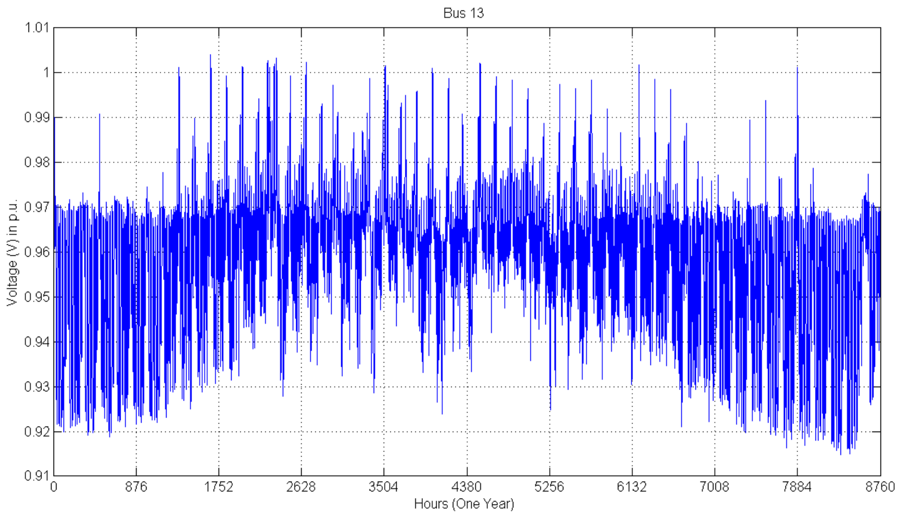

Figure 5.6: Voltage at Bus 13 (With 1000 kWp).

Voltage at Bus 13 (in p.u.)	Without PV	With PV (1000 kWp)
Minimum Value	0.9079	0.9148
Maximum Value	0.9744	1.0041

Table 5.8: Minimum and Maximum values of voltage at Bus 13.

With 1500 kWp

Figure 5.7 shows the annual voltage at Bus 13 after 1500 kWp of PV integration and the minimum and maximum values of voltages are given in Table 5.9:

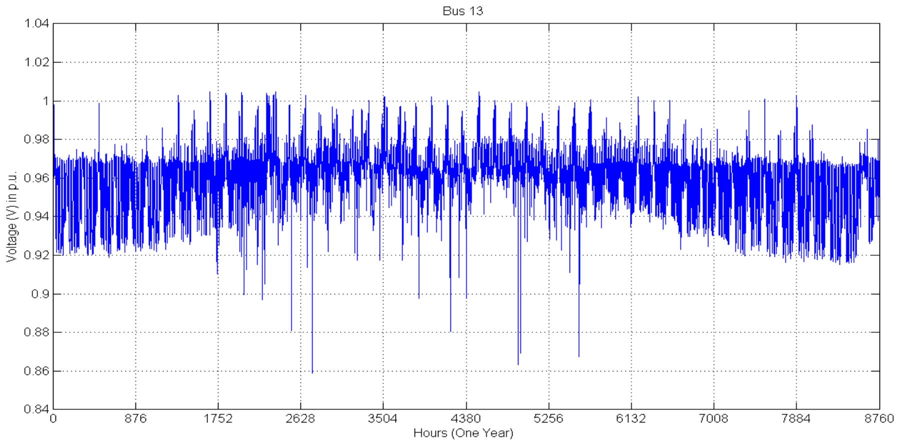

Figure 5.7: Voltage at Bus 13 (With 1500 kWp).

Voltage at Bus 13 (in p.u.)	Without PV	With PV (1500 kWp)
Minimum Value	0.9079	0.8588
Maximum Value	0.9744	1.0048

Table 5.9: Minimum and Maximum values of voltage at Bus 13.

With 1650 kWp

Figure 5.8 shows the annual voltage at Bus 13 after 1650 kWp of PV integration and the minimum and maximum values of voltages are given in Table 5.10:

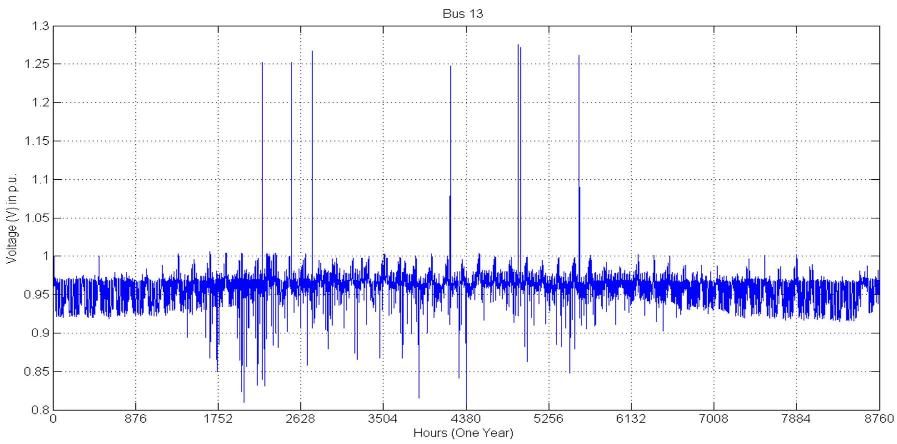

Figure 5.8: Voltage at Bus 13 (With 1650 kWp).

Voltage at Bus 13 (in p.u.)	Without PV	With PV (1650 kWp)
Minimum Value	0.9079	0.8076
Maximum Value	0.9744	1.2754

Table 5.10: Minimum and Maximum values of voltage at Bus 13.

5.2 PV Integration (Scenario 2)

In this second scenario the PVs are integrated simultaneously in equal amount at two buses ie Bus 11 and 13 in order to analyze how the voltage varies at each bus. Then annual load flow analysis of the system is carried out with different amount of PV integration before the voltage at both of the two buses violates the limits.

The calculated amount of PV power which is integrated in the system in Section 5.2.1 is given in Table 5.11:

S. No.	Area (m^2)	kWp/m^2	Peak Output (kWp)
1	6666	0.15	1000
2	13333	0.15	2000
3	20000	0.15	3000
4	23333	0.15	3500

Table 5.11: Calculated PV power output (For scenario 2).

5.2.1 At both Bus 11 and 13

With 1000 kWp

In this case there is equal integration of PV generation i.e. 500 kWp on both Bus 11 and 13.

Figures 5.9 and 5.10 show the annual voltages at Bus 11 and 13 after 500 kWp of PV integration at each bus and the minimum and maximum values of voltages at each bus are given in Tables 5.12 and 5.13:

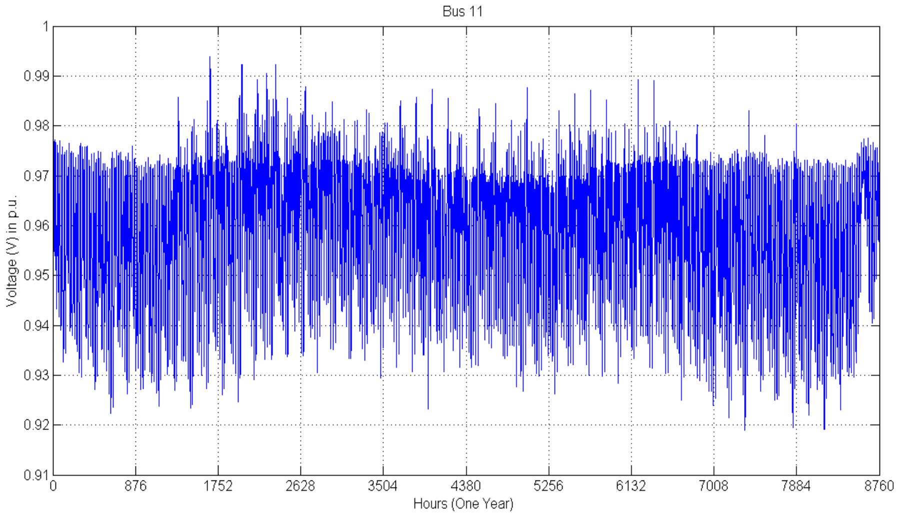

Figure 5.9: Voltage at Bus 11 (With 500 kWp on Bus 11).

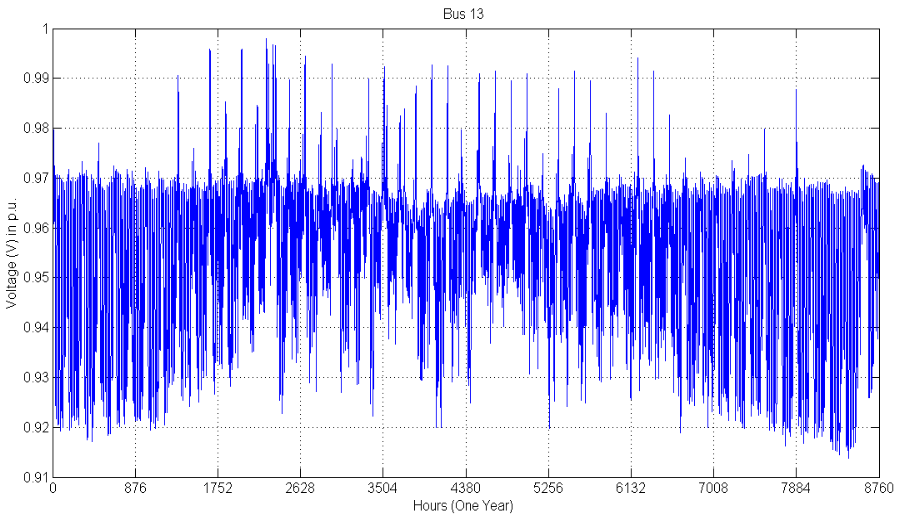

Figure 5.10: Voltage at Bus 13 (With 500 kWp on Bus 13).

Voltage at Bus 11 (in p.u.)	**Without PV**	**With PV (500 kWp on Bus 11)**
Minimum Value	0.9190	0.9190
Maximum Value	0.9778	0.9938

Table 5.12: Minimum and Maximum values of voltage at Bus 11.

Voltage at Bus 13 (in p.u.)	Without PV	With PV (500 kWp on Bus 13)
Minimum Value	0.9079	0.9138
Maximum Value	0.9744	0.9979

Table 5.13: Minimum and Maximum values of voltage at Bus 13.

With 2000 kWp

In this case there is equal integration of PV generation i.e. 1000 kWp on both Bus 11 and 13.

Figures 5.11 and 5.12 show the annual voltages at Bus 11 and 13 after 1000 kWp of PV integration at each bus and the minimum and maximum values of voltages at each bus are given in Tables 5.14 and 5.15:

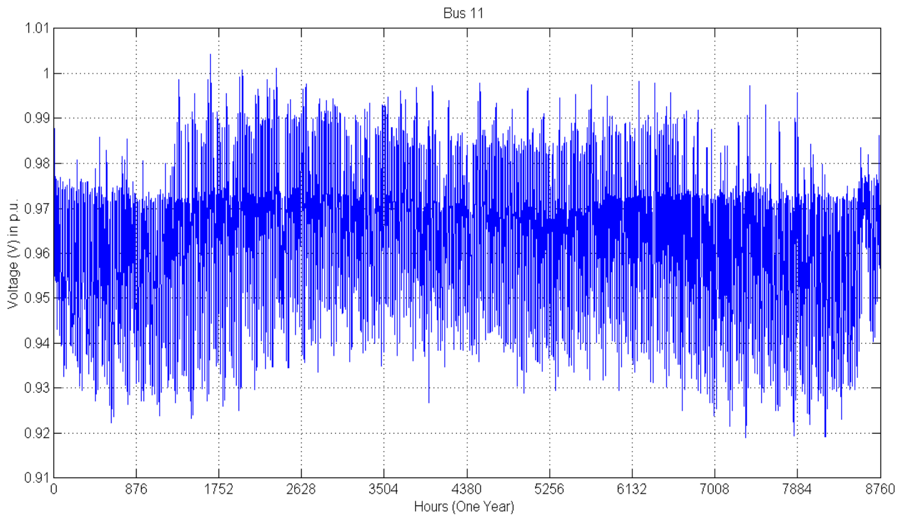

Figure 5.11: Voltage at Bus 11 (With 1000 kWp on Bus 11).

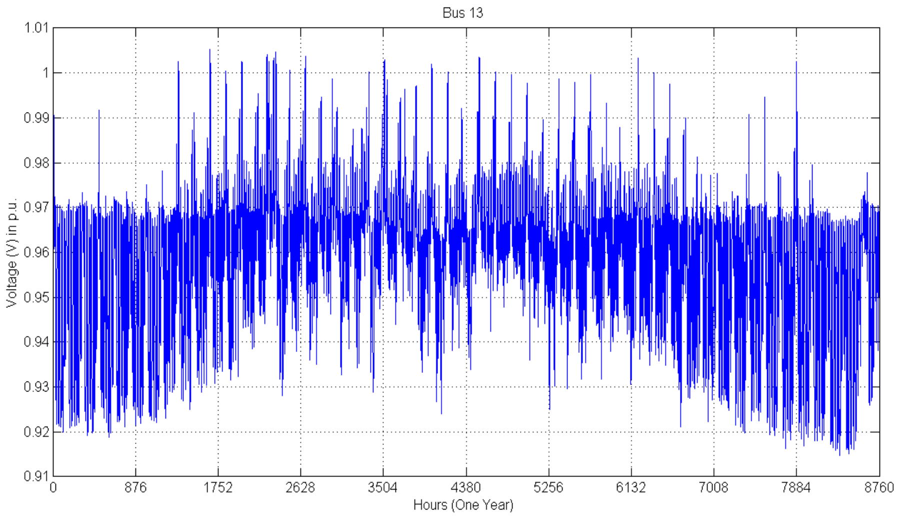

Figure 5.12: Voltage at Bus 13 (With 1000 kWp on Bus 13).

Voltage at Bus 11 (in p.u.)	Without PV	With PV (1000 kWp on Bus 11)
Minimum Value	0.9190	0.9190
Maximum Value	0.9778	1.0042

Table 5.14: Minimum and Maximum values of voltage at Bus 11.

Voltage at Bus 13 (in p.u.)	Without PV	With PV (1000 kWp on Bus 13)
Minimum Value	0.9079	0.9148
Maximum Value	0.9744	1.0053

Table 5.15: Minimum and Maximum values of voltage at Bus 13.

With 3000 kWp

In this case there is equal integration of PV generation i.e. 1500 kWp on both Bus 11 and 13.

Figures 5.13 and 5.14 show the annual voltages at Bus 11 and 13 after 1500 kWp of PV integration at each bus and the minimum and maximum values of voltages at each bus are given in Tables 5.16 and 5.17:

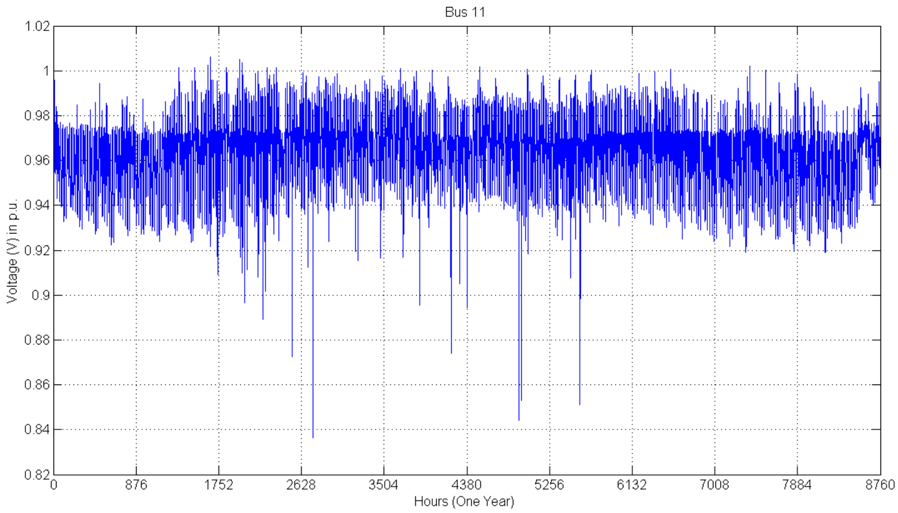

Figure 5.13: Voltage at Bus 11 (With 1500 kWp on Bus 11).

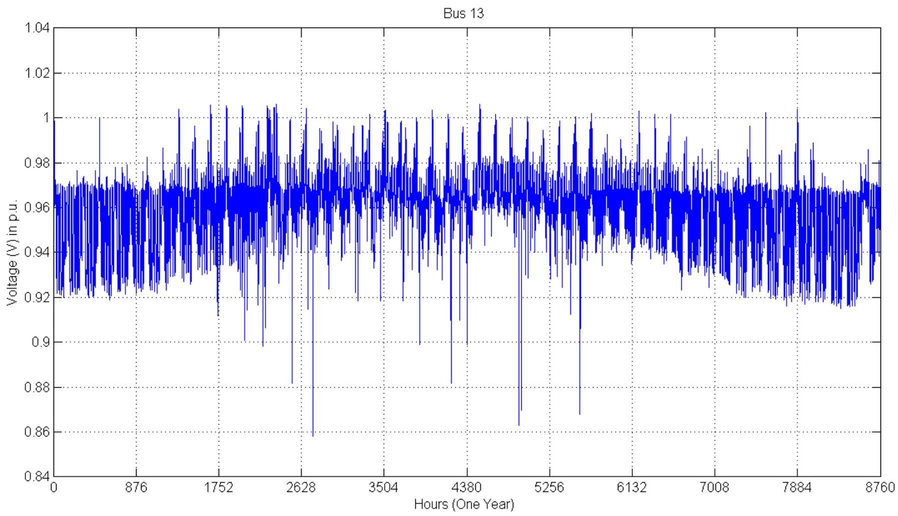

Figure 5.14: Voltage at Bus 13 (With 1500 kWp on Bus 13).

Voltage at Bus 11 (in p.u.)	Without PV	With PV (1500 kWp on Bus 11)
Minimum Value	0.9190	0.8365
Maximum Value	0.9778	1.0060

Table 5.16: Minimum and Maximum values of voltage at Bus 11.

Voltage at Bus 13 (in p.u.)	Without PV	With PV (1500 kWp on Bus 13)
Minimum Value	0.9079	0.8582
Maximum Value	0.9744	1.0061

Table 5.17: Minimum and Maximum values of voltage at Bus 13.

With 3500 kWp

In this case there is equal integration of PV generation i.e. 1750 kWp on both Bus 11 and 13.

Figures 5.15 and 5.16 show the annual voltages at Bus 11 and 13 after 1750 kWp of PV integration at each bus and the minimum and maximum values of voltages at each bus are given in Tables 5.18 and 5.19:

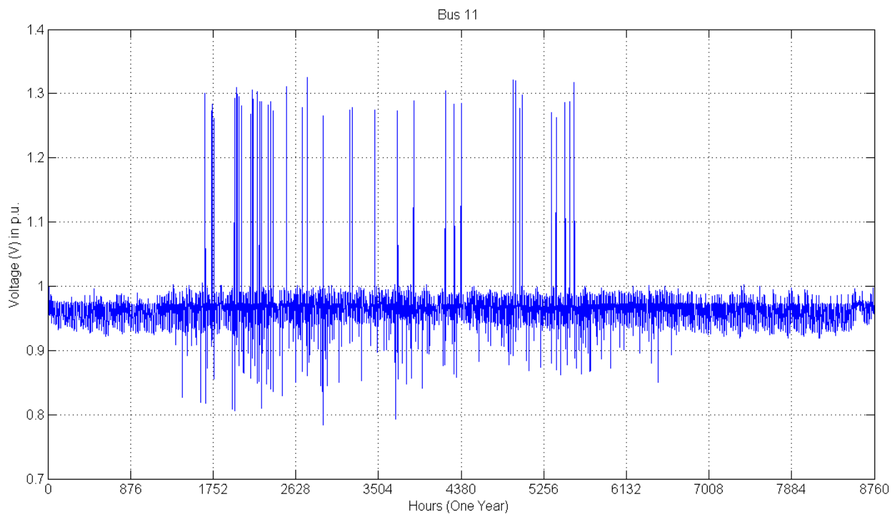

Figure 5.15: Voltage at Bus 11 (With 1750 kWp on Bus 11).

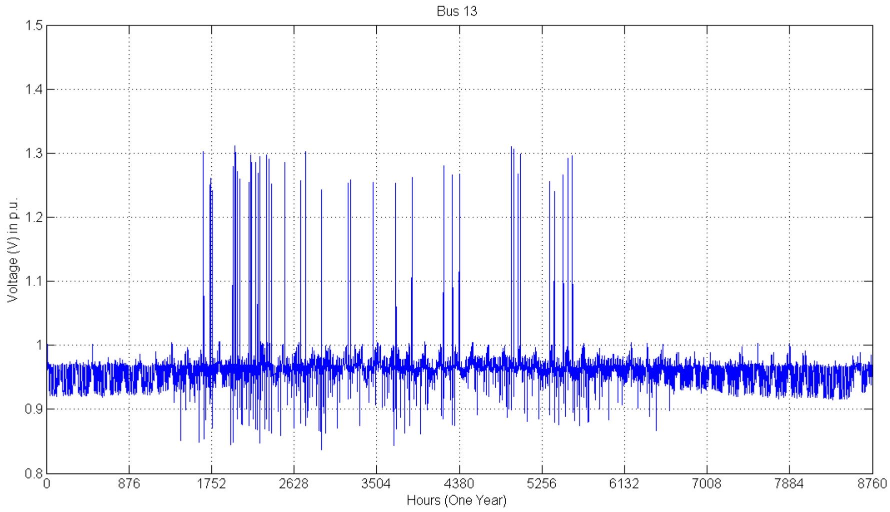

Figure 5.16: Voltage at Bus 13 (With 1750 kWp on Bus 13).

Voltage at Bus 11 (in p.u.)	Without PV	With PV (1750 kWp on Bus 11)
Minimum Value	0.9190	0.7837
Maximum Value	0.9778	1.3258

Table 5.18: Minimum and Maximum values of voltage at Bus 11.

Voltage at Bus 13 (in p.u.)	Without PV	With PV (1750 kWp on Bus 13)
Minimum Value	0.9079	0.8371
Maximum Value	0.9744	1.3118

Table 5.19: Minimum and Maximum values of voltage at Bus 13.

5.3 PV Integration (Scenario 3)

In this third scenario the PVs are integrated at all 10 kV buses in the system in order to analyze how the voltage varies at each of them. Then annual load flow analysis of the system is carried out with different amount of PV integration before the voltages at all 10 kV buses violates the limits.

The calculated amount of PV power which is integrated in the system in Section 5.3.1 is given in Table 5.20:

S. No.	Area (m^2)	kWp/m^2	Peak Output (kWp)
1	43333	0.15	6500
2	86666	0.15	13000
3	133333	0.15	20000
4	153333	0.15	23000

Table 5.20: Calculated PV power output (For scenario 3).

5.3.1 At all 10 kV Buses

With 6500 kWp

In this case around 500 kWp of PV is integrated at each of the thirteen 10 kV buses in order to analyze how the voltage varies at each of them.

The minimum and maximum values of voltages at all of the thirteen 10 kV buses after the annual load flow analysis done with total 6500 kWp of PV integration are given in Table 5.21:

Bus No.	Min. voltage (V) in p.u.	Max. voltage (V) in p.u.
5	0.9882	0.9970
7	0.9880	0.9969
8	0.9857	0.9976
9	0.9804	1.0010
10	0.9790	1.0018
11	0.9190	1.0029
12	0.9732	1.0057
13	0.9142	1.0117
14	0.9716	1.0074
15	0.9716	1.0080
16	0.9716	1.0077
17	0.9716	1.0085
18	0.9716	1.0087

Table 5.21: Voltages at all 10 kV buses (With 6500 kWp).

With 13000 kWp

In this case around 1000 kWp of PV is integrated at each of the thirteen 10 kV buses in order to analyze how the voltage varies at each of them.

The minimum and maximum values of voltages at all of the thirteen 10 kV buses after the annual load flow analysis done with total 13000 kWp of PV integration are given in Table 5.22:

Bus No.	Min. voltage (V) in p.u.	Max. voltage (V) in p.u.
5	0.9882	0.9970
7	0.9880	0.9970
8	0.9858	1.0006
9	0.9806	1.0089
10	0.9793	1.0109
11	0.9190	1.0168
12	0.9736	1.0199
13	0.9149	1.0313
14	0.9721	1.0234
15	0.9721	1.0244
16	0.9721	1.0240
17	0.9721	1.0252
18	0.9721	1.0254

Table 5.22: Voltages at all 10 kV buses (With 13000 $\boldsymbol{kWp}$).

With 20000 $\boldsymbol{kWp}$

In this case around 1500 kWp of PV is integrated at each of the thirteen 10 kV buses in order to analyze how the voltage varies at each of them.

The minimum and maximum values of voltages at all of the thirteen 10 kV buses after the annual load flow analysis done with total 20000 kWp of PV integration are given in Table 5.23:

Bus No.	Min. voltage (V) in p.u.	Max. voltage (V) in p.u.
5	0.9883	0.9972
7	0.9881	0.9975
8	0.9859	1.0024
9	0.9809	1.0158
10	0.9796	1.0190
11	0.9027	1.0186
12	0.9740	1.0331
13	0.9154	1.0323
14	0.9726	1.0384
15	0.9726	1.0399
16	0.9726	1.0393
17	0.9726	1.0408
18	0.9726	1.0409

Table 5.23: Voltages at all 10 kV buses (With 20000 $\boldsymbol{kWp}$).

With 23000 kWp

In this case around 1750 kWp of PV is integrated at each of the thirteen 10 kV buses in order to analyze how the voltage varies at each of them.

The minimum and maximum values of voltages at all of the thirteen 10 kV buses after the annual load flow analysis done with total 23000 kWp of PV integration are given in Table 5.24:

Bus No.	Min. voltage (V) in p.u.	Max. voltage (V) in p.u.
5	0.9883	1.0002
7	0.9881	1.0008
8	0.9860	1.0086
9	0.9810	1.0270
10	0.9797	1.0316
11	0.8295	1.3833
12	0.9742	1.0511
13	0.9156	1.3910
14	0.9728	1.0575
15	0.9728	1.0599
16	0.9728	1.0585
17	0.9728	1.0610
18	0.9728	1.0610

Table 5.24: Voltages at all 10 kV buses (With 23000 kWp).

5.4 Summary

In this chapter three different scenarios of PV integration with annual power generation were analyzed.

Scenario 1

In this scenario PV generation was integrated individually on Bus 11 and then on Bus 13. It was seen with 500, 1000 and 1500 kWp of generation the maximum value of bus voltage remains below 1.05 V (in p.u.) as can be seen in Tables 5.3, 5.4, 5.5, 5.7, 5.8 and 5.9. But at 1650 kWp there was a non convergence of the load flow due to which there was a very big rise in voltage at Bus 11 and 13 during certain hours of the year as can be seen in Tables 5.6 and 5.10. So 1500 kWp is the amount of generation that can be integrated individually on Bus 11 and 13 without violating the voltage limits.

Scenario 2

In this scenario PV generation was integrated in equal amount on Bus 11 and 13. It was seen with 1000, 2000 and 3000 kWp of generation (divided equally on two buses) the maximum values of bus voltages remained below 1.05 V (in p.u.) as can be seen in Tables 5.12, 5.13, 5.14, 5.15, 5.16 and 5.17. But at 3500 kWp there was a non convergence of the load flow due to which there was a very big rise in voltage at Bus 11 and 13 during certain hours of the year as can be seen in Tables 5.18 and 5.19. So 3000 kWp is the amount of generation that can be integrated together on Bus 11 and 13 without violating the voltage limits.

Scenario 3

In this scenario PV generation was integrated in equal amount on all of the 10 kV buses in the system. It was seen with 6500, 13000 and 20000 kWp of generation (divided equally on thirteen buses) the maximum values of bus voltages remained below 1.05 V (in p.u.) as can be seen in Tables 5.21, 5.22 and 5.23. But at 23000 kWp there was a non convergence of the load flow due to which there was a very big rise in voltages at Bus 11 and 13 during certain hours of the year as can be seen in Table 5.24. So 20000 kWp is the amount of generation that can be integrated in total at all of the 10 kV buses in the system without violating the voltage limits.

Chapter 6

Voltage Rise Problem and Control

In this chapter the analysis with PVs providing reactive power in order to control the voltage and meanwhile increasing the amount of possible integration in the system is done. The study of PV integration with PVs providing no reactive power has already been done in Chapter 3.

6.1 Voltage Control in Distribution Systems

In a distribution system, **Δ** V is the variation in voltage which is as per the Figure 6.1 the difference between the voltages at bus 1 and 2 and can be represented by the following equation 6.1 [27]:

$$\boldsymbol{\Delta V} = \frac{\boldsymbol{PR + QX}}{\boldsymbol{V}} \tag{6.1}$$

where P and Q are the active and reactive power outputs from the DG connected to bus 2, X and R are the reactance and resistance of the transmission line between these two buses and V is the nominal voltage of bus 1 as per the Figure 6.1 [27]:

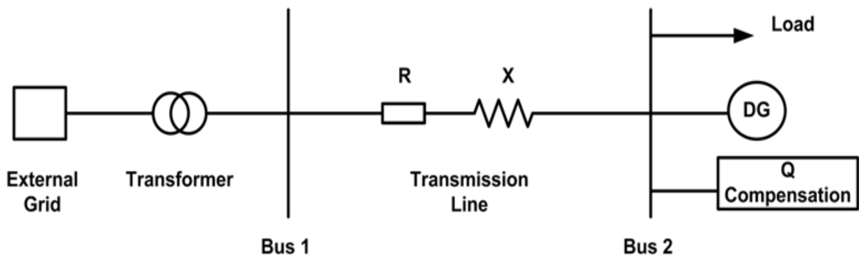

Figure 6.1: DG connected to a simple radial feeder [27].

So the above equation 6.1 can be rewritten as 6.2 and is used for calculating the reactive power for each amount of PV active power generation that is from 0.1 to

50 MW for this analysis. The reactance and resistance data for the lines as given in Table A.1 is used for the calculations.

$$\frac{\boldsymbol{\Delta V.V - PR}}{\boldsymbol{X}} = \boldsymbol{Q} \tag{6.2}$$

The Figure 6.2 shows the Q for 50 MW of PV generation that has been calculated by using equation 6.2.

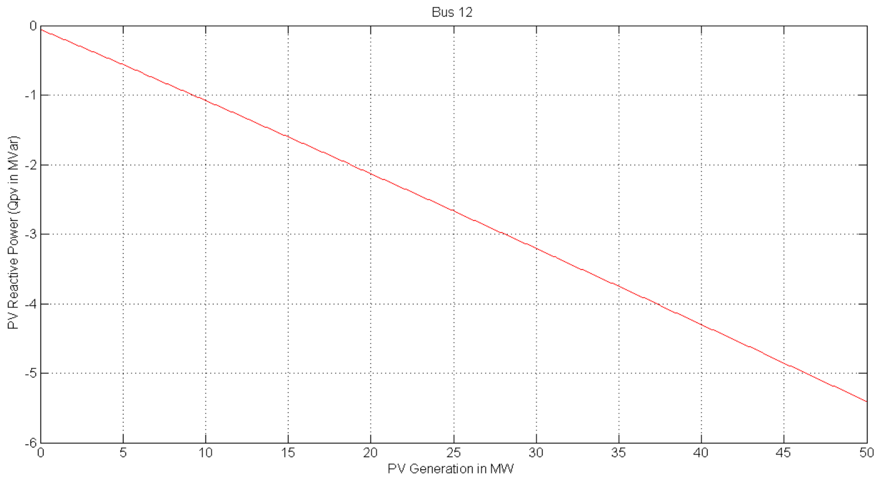

Figure 6.2: Calculated Q for 50 MW of PV generation.

6.2 Summer Case

In this case the same hours with maximum and minimum load during the month of June as in Section 3.1 are considered again and the reactive power is introduced from the PVs for voltage control when they are integrated individually at the 10 kV buses and further the voltage variation is analyzed for both hours.

6.2.1 Hour with maximum load

As the analysis of PV integration at all the 10 kV buses for this case was previously done in Section 3.1.1. Now the PV integration is done with reactive power for voltage control at Bus 10, 12, 14 and 18 and the voltage variation over 50 MW of PV generation can be seen in Figures 6.3, 6.4, 6.5 and 6.6.

At Bus 10

The Figure 6.3 shows the voltage variation over 50 MW of PV integration with and without Q.

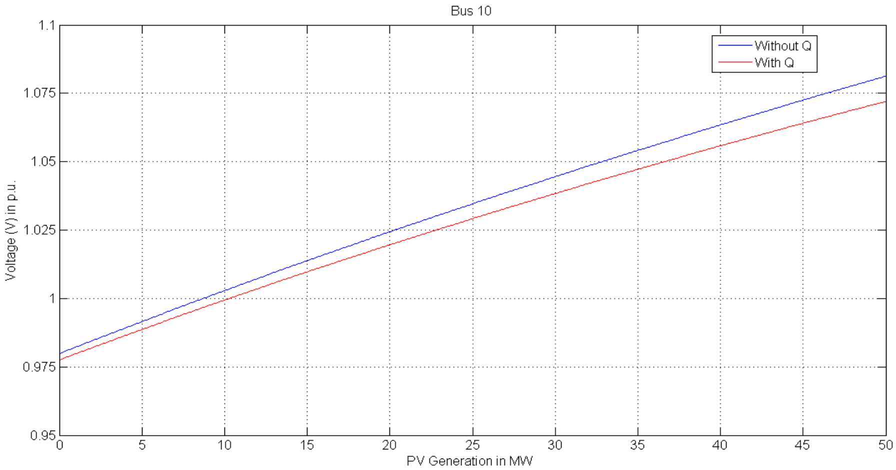

Figure 6.3: Voltage at Bus 10 after PV integration.

At Bus 12

The Figure 6.4 shows the voltage variation over 50 MW of PV integration with and without Q.

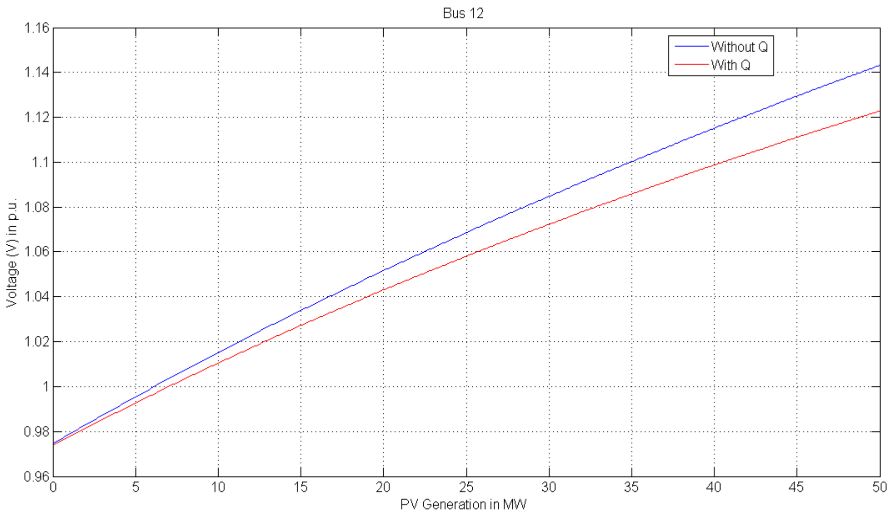

Figure 6.4: Voltage at Bus 12 after PV integration.

At Bus 14

The Figure 6.5 shows the voltage variation over 50 MW of PV integration with and without Q.

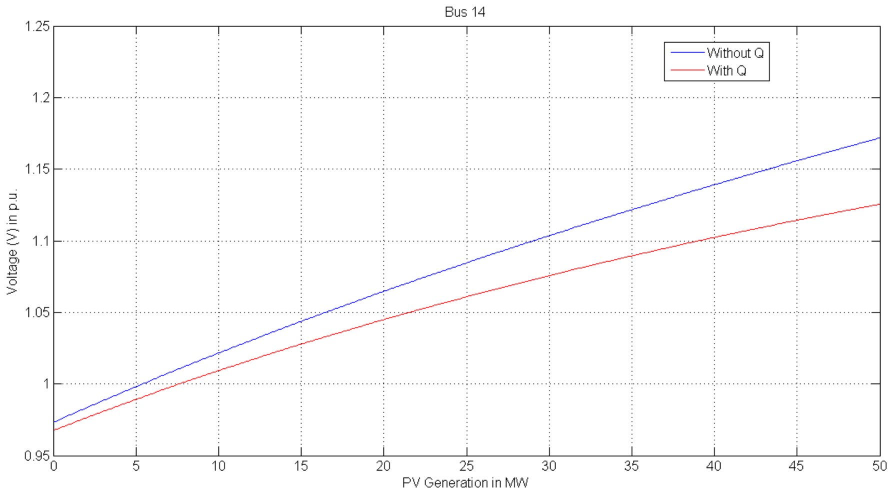

Figure 6.5: Voltage at Bus 14 after PV integration.

At Bus 18

The Figure 6.6 shows the voltage variation over 50 MW of PV integration with and without Q.

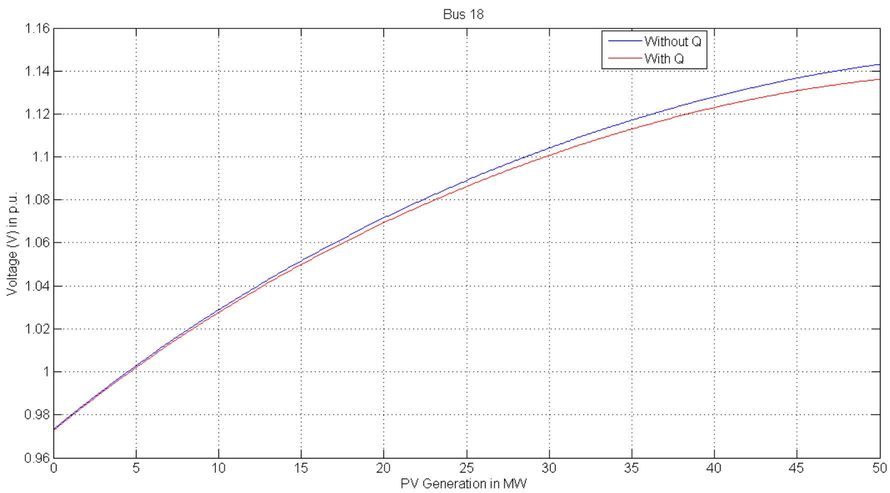

Figure 6.6: Voltage at Bus 18 after PV integration.

The amount of PV generation that can be integrated now at these 10 kV buses individually after using reactive power for voltage control before the voltage violates 1.05 V (in p.u.) at that particular bus for this summer maximum load case are given in Table 6.1:

Bus No.	PV without Q	PV with Q	Increase in PV (MW)
10	32.8	36.6	3.8
12	19.5	22.3	2.8
14	16.5	21.5	5
18	14.6	15	0.4

Table 6.1: Amount of possible PV integration (Summer hour with maximum load).

6.2.2 Hour with minimum load

As the analysis of PV integration at all the 10 kV buses for this case was previously done in Section 3.1.2. Now the PV integration is done with reactive power for voltage control at Bus 10, 12, 14 and 18 and the voltage variation over 50 MW of PV generation can be seen in Figures 6.7, 6.8, 6.9 and 6.10.

At Bus 10

The Figure 6.7 shows the voltage variation over 50 MW of PV integration with and without Q.

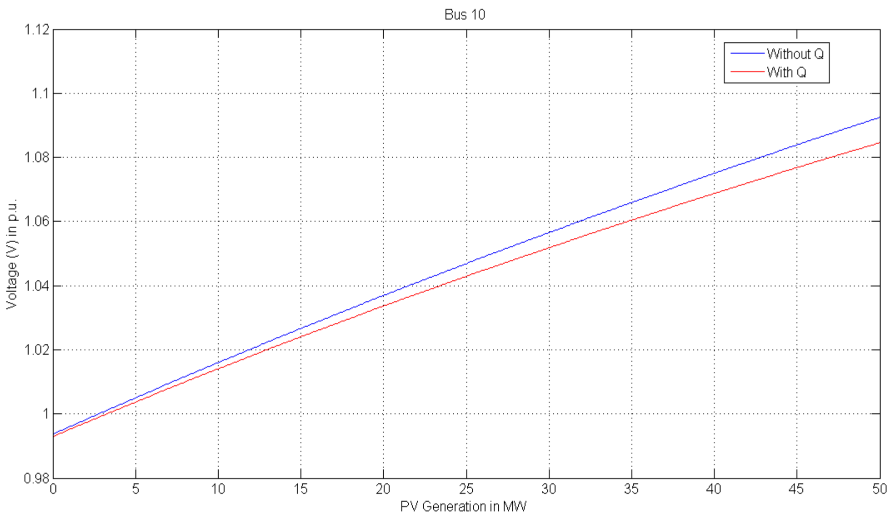

Figure 6.7: Voltage at Bus 10 after PV integration.

At Bus 12

The Figure 6.8 shows the voltage variation over 50 MW of PV integration with and without Q.

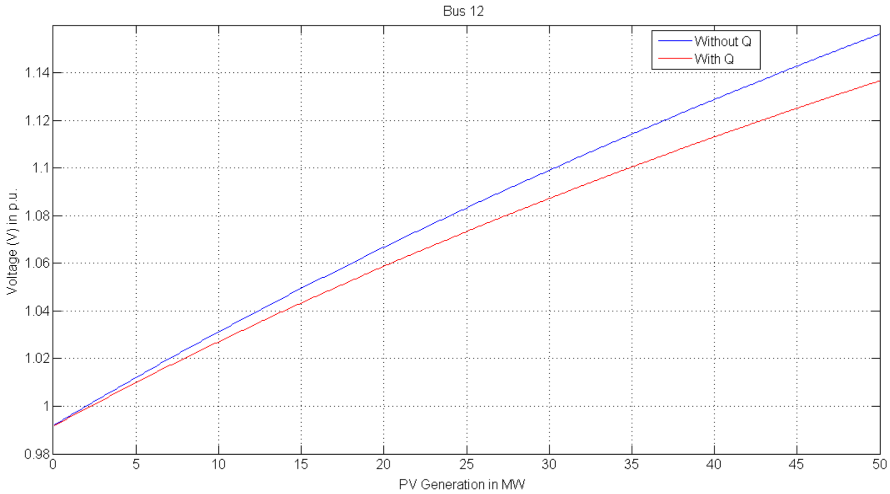

Figure 6.8: Voltage at Bus 12 after PV integration.

At Bus 14

The Figure 6.9 shows the voltage variation over 50 MW of PV integration with and without Q.

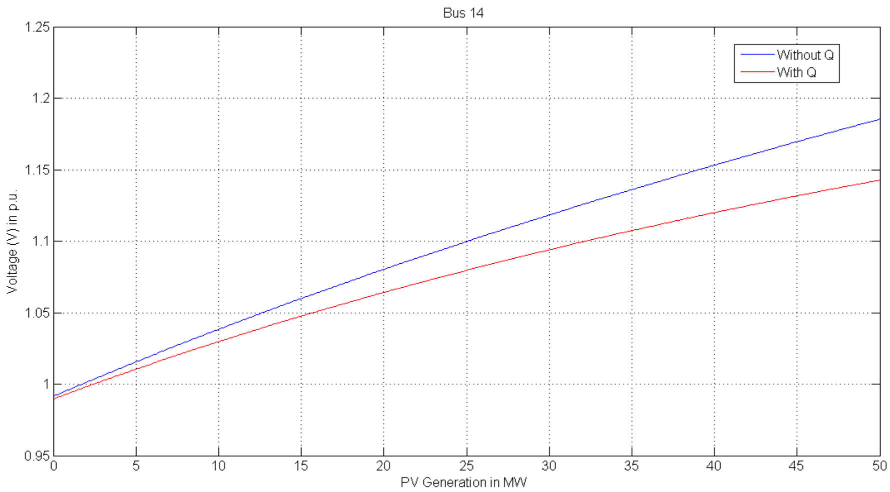

Figure 6.9: Voltage at Bus 14 after PV integration.

At Bus 18

The Figure 6.10 shows the voltage variation over 50 MW of PV integration with and without Q.

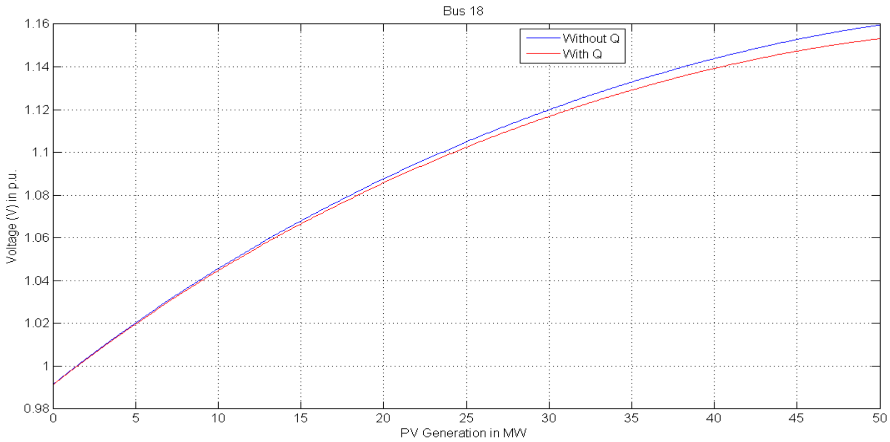

Figure 6.10: Voltage at Bus 18 after PV integration.

The amount of PV generation that can be integrated now at these 10 kV buses individually after using reactive power for voltage control before the voltage violates 1.05 V (in p.u.) at that particular bus for this summer minimum load case are given in Table 6.2:

Bus No.	**PV without Q**	**PV with Q**	**Increase in PV (MW)**
10	26.6	29	2.4
12	15.2	17.1	1.9
14	12.7	15.7	3
18	10.9	11.1	0.2

Table 6.2: Amount of possible PV integration (Summer hour with minimum load).

6.3 Winter Case

In this case the same hours with maximum and minimum load during the month of December as in Section 3.2 are considered again and the reactive power is introduced from the PVs for voltage control when they are integrated individually at the 10 kV buses and further the voltage variation is analyzed for both hours.

6.3.1 Hour with maximum load

As the analysis of PV integration at all the 10 kV buses for this case was previously done in Section 3.2.1. Now the PV integration is done with reactive power for voltage control at Bus 10, 12, 14 and 18 and the voltage variation over 50 MW of PV generation can be seen in Figures 6.11, 6.12, 6.13 and 6.14.

At Bus 10

The Figure 6.11 shows the voltage variation over 50 MW of PV integration with and without Q.

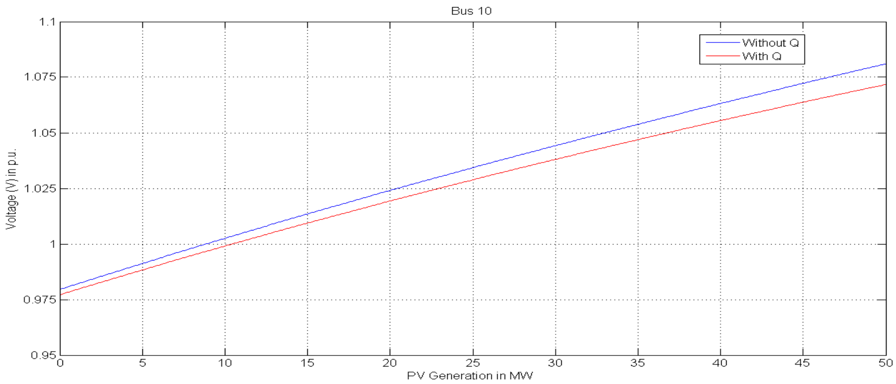

Figure 6.11: Voltage at Bus 10 after PV integration.

At Bus 12

The Figure 6.12 shows the voltage variation over 50 MW of PV integration with and without Q.

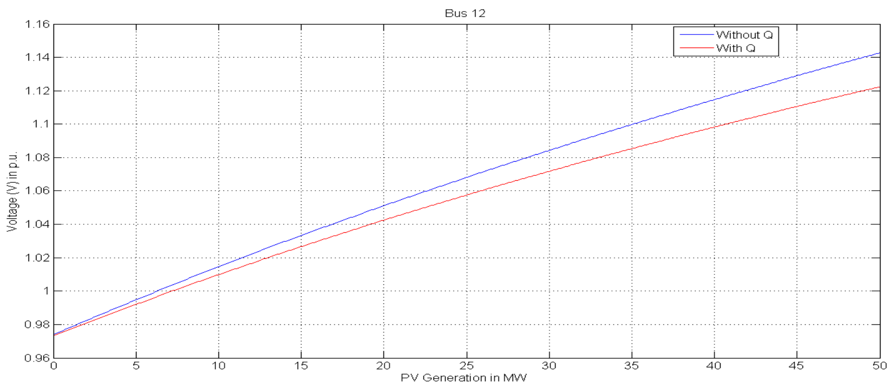

Figure 6.12: Voltage at Bus 12 after PV integration.

At Bus 14

The Figure 6.13 shows the voltage variation over 50 MW of PV integration with and without Q.

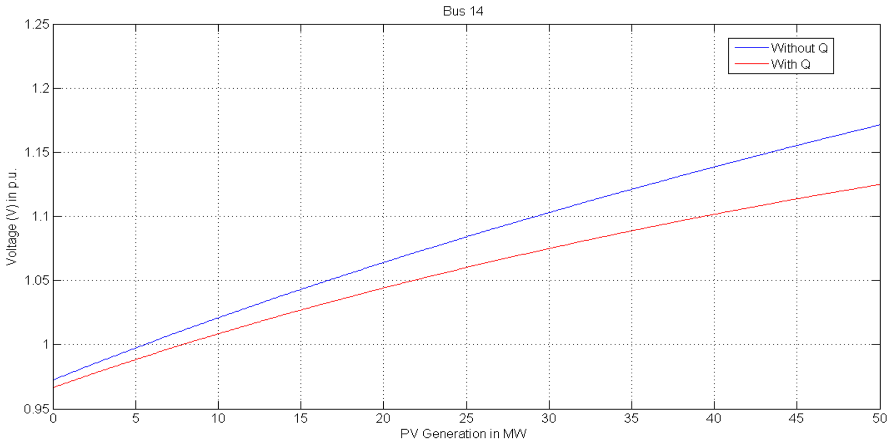

Figure 6.13: Voltage at Bus 14 after PV integration.

At Bus 18

The Figure 6.14 shows the voltage variation over 50 MW of PV integration with and without Q.

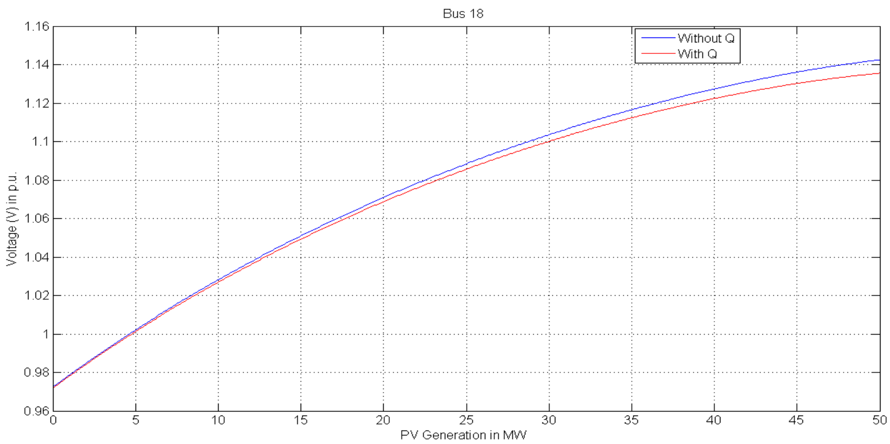

Figure 6.14: Voltage at Bus 18 after PV integration.

The amount of PV generation that can be integrated now at these 10 kV buses individually after using reactive power for voltage control before the voltage violates

1.05 V (in p.u.) at that particular bus for this winter maximum load case are given in Table 6.3:

Bus No.	PV without Q	PV with Q	Increase in PV (MW)
10	33	36.8	3.8
12	19.7	22.4	2.7
14	16.6	21.8	5.2
18	14.7	16.2	1.5

Table 6.3: Amount of possible PV integration (Winter hour with maximum load).

6.3.2 Hour with minimum load

As the analysis of PV integration at all the 10 kV buses for this case was previously done in Section 3.2.2. Now the PV integration is done with reactive power for voltage control at Bus 10, 12, 14 and 18 and the voltage variation over 50 MW of PV generation can be seen in Figures 6.15, 6.16, 6.17 and 6.18.

At Bus 10

The Figure 6.15 shows the voltage variation over 50 MW of PV integration with and without Q.

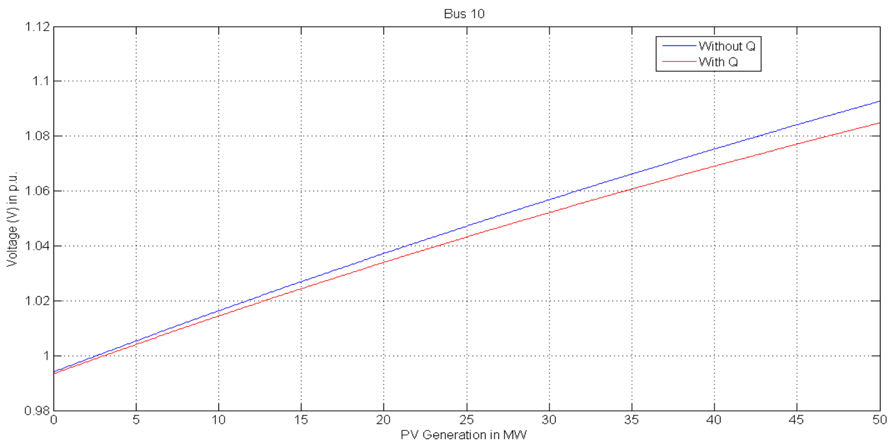

Figure 6.15: Voltage at Bus 10 after PV integration.

At Bus 12

The Figure 6.16 shows the voltage variation over 50 MW of PV integration with and without Q.

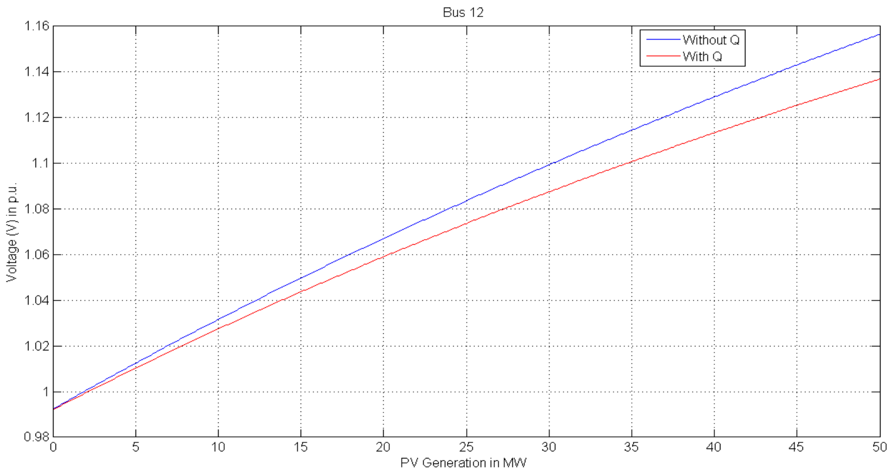

Figure 6.16: Voltage at Bus 12 after PV integration.

At Bus 14

The Figure 6.17 shows the voltage variation over 50 MW of PV integration with and without Q.

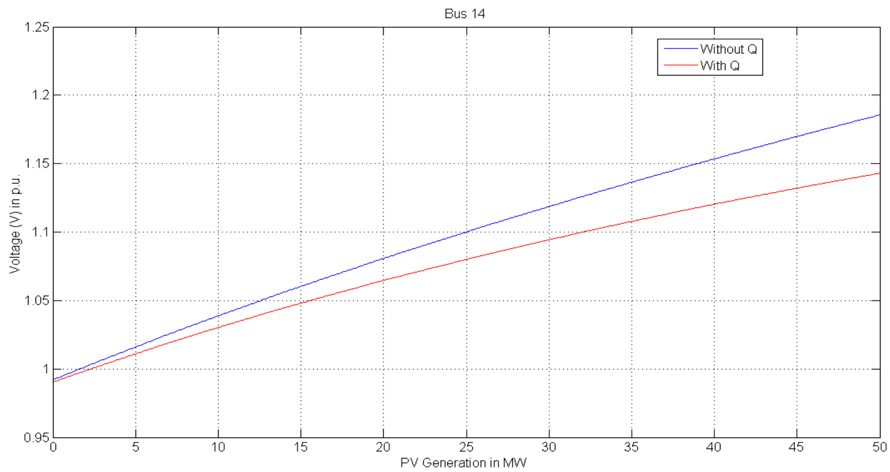

Figure 6.17: Voltage at Bus 14 after PV integration.

At Bus 18

The Figure 6.18 shows the voltage variation over 50 MW of PV integration with and without Q.

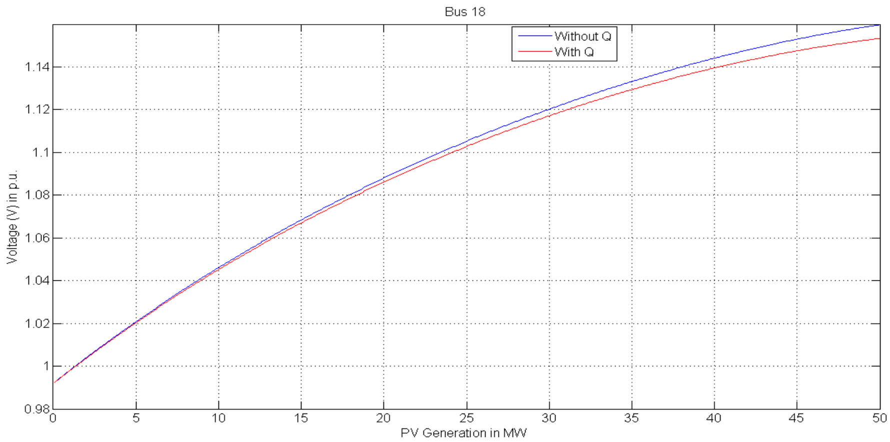

Figure 6.18: Voltage at Bus 18 after PV integration.

The amount of PV generation that can be integrated now at these 10 kV buses individually after using reactive power for voltage control before the voltage violates 1.05 V (in p.u.) at that particular bus for this winter minimum load case are given in Table 6.4:

Bus No.	PV without Q	PV with Q	Increase in PV (MW)
10	26.4	28.8	2.4
12	15	17	2
14	12.6	15.6	3
18	10.8	11	0.2

Table 6.4: Amount of possible PV integration (Winter hour with minimum load).

6.4 With PV Power Output for a Month

In this part PV integration analysis of summer month case with reactive power from PV for voltage control with power output for one month calculated using the irradiance data has been done. The Figure 6.19 shows the reactive power that has been calculated using the equation 6.2 for 4500 kWp of PV generation and is further used in this part of this chapter.

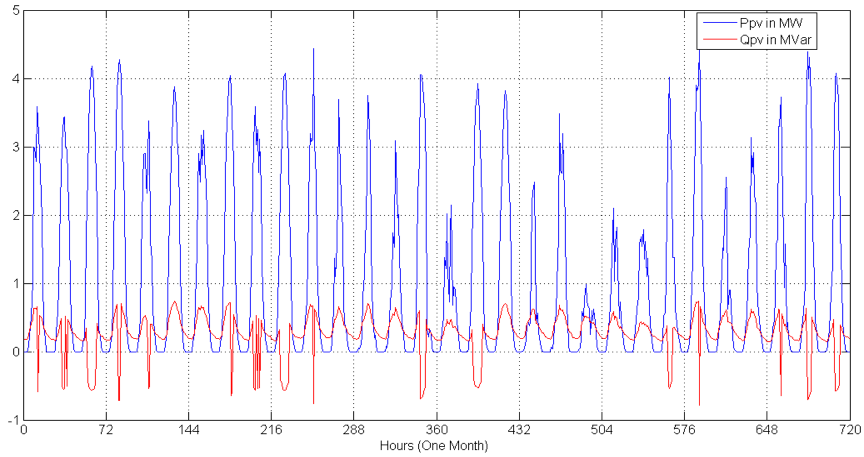

Figure 6.19: Calculated reactive power for one month with 4500 kWp of PV generation.

6.4.1 Summer month case

In this case the analysis with PV integration only on Bus 17 for the summer month of June is done with generation of 4500 and 5000 kWp. Further the reactive power from the PV is calculated and provided by them in order to control the voltage.

With 4500 kWp

The Figure 6.20 shows the voltage at Bus 17 during the month of June with and without Q. The minimum and maximum values of voltage at Bus 17 are given in Table 6.5:

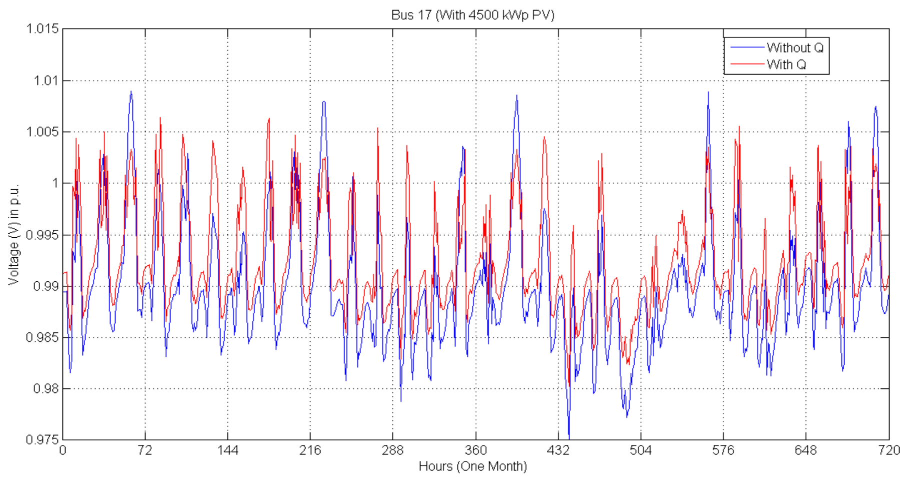

Figure 6.20: Voltage at bus 17 during summer with 4500 kWp generation.

Voltage at Bus 17 (in p.u.)	Without Q	With Q
Minimum Value	0.9751	0.9802
Maximum Value	1.0090	1.0064

Table 6.5: Minimum and Maximum values of voltage at bus 17 (With 4500 kWp).

With 5000 kWp

The Figure 6.21 shows the voltage at Bus 17 during the month of June with and without Q. The minimum and maximum values of voltage at Bus 17 are given in Table 6.6:

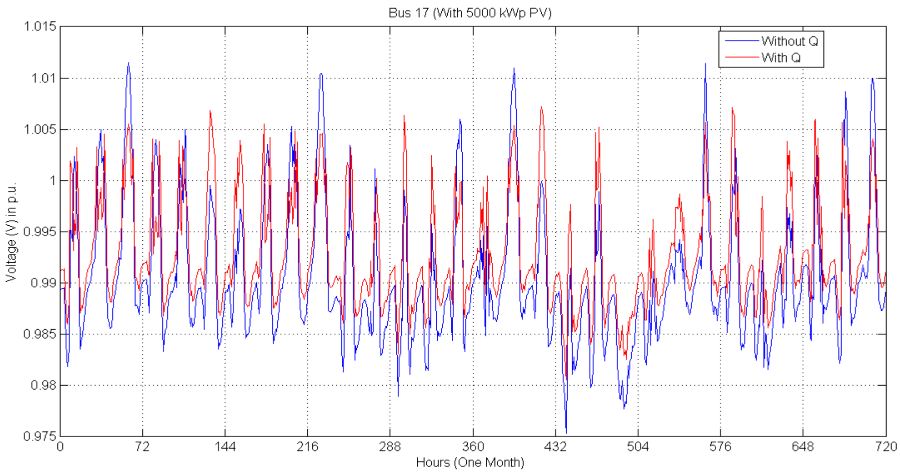

Figure 6.21: Voltage at bus 17 during summer with 5000 kWp generation.

Voltage at Bus 17 (in p.u.)	Without Q	With Q
Minimum Value	0.9754	0.9806
Maximum Value	1.0115	1.0072

Table 6.6: Minimum and Maximum values of voltage at bus 17 (With 5000 kWp).

6.5 Summary

In this chapter the analysis of the system with reactive power from the PVs in order to control the voltage was carried out.

In the first case summer and winter hours with maximum and minimum load were considered for analysis. The simulations were performed for each case when there was a PV integration on Bus 10, 12, 14 and 18. Further by providing an amount of reactive power for each amount of active power of PV generation it was found that the amount of PV that can be integrated on each bus before there was a violation of the specified voltage limits 1.05 V (in p.u.) in each case was increased as can be seen from the Tables 6.1, 6.2, 6.3 and 6.4.

Further in the second case the summer month with PV generation data for each hour of the month was considered. For this case the PV integration was only considered on Bus 17 with 4500 and 5000 kWp. It was found that by providing an amount of reactive power from PVs the maximum value of voltage at Bus 17 was lowered as can be seen from the Tables 6.5 and 6.6.

Chapter 7

Conclusion and Future Work

7.1 Conclusion

The objective of this project was to estimate the maximum possible amount of PV generation under various scenarios without violating the voltage limits as defined per the standard EN 50160 [2]. So in this project the analysis of the modelled distribution system was performed with PV integration considering the scenarios of minimum and maximum load hours during the summer and winter months. The results for these cases are presented in Sections 3.1 and 3.2. It was found that there was a non convergence problem that happened for PV integration on Bus 11 and 13 and due to that the exact amount of integration possible on these two buses has not been given.

Further the PV integration analysis was performed using the annual PV power output. In this analysis three different scenarios were considered and the results for this analysis are discussed in Section 5.4.

As there is a voltage rise problem at high levels of PV as discussed in the Section 1.4.2 therefore in Chapter 6 the control of this voltage was done by providing reactive power through PVs. The cases of summer and winter month with minimum and maximum load were considered again and it was found that when reactive power was provided through PVs the voltage rise was controlled and meanwhile the PV integration level for each case was increased.

So it can be concluded that if there is an increase in the penetration of PVs in the grids the voltage limits can be managed by providing reactive power from the PVs so that the maximum voltage rise is not more than 5% of the nominal voltage [2]. And finally if there is increase of PVs in the system it will increase the level of generation through renewable sources which will contribute to Denmark future goals of 2050 [1].

7.2 Future Work

In this project the analysis was done by performing the steady state simulations. May an analysis with the dynamic simulations can be performed in the future.

Conclusion has been drawn based on all the simulations results obtained during this project. No experimental work was done in order to verify the results obtained from the simulations. So experimental work can be performed in the future to verify these simulation results.

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Appendix A

Simulation Model Data

Line	Resistance, pu	Reactance, pu	Line charging, pu
1-2	0.01250	0.12437	0
2-3	0.01187	0.01826	0.01301
3-4	0.07661	0.10637	0.00121
4-5	0.02530	0.44730	0
5-7	0.00336	0.00158	0
7-8	0.04784	0.02242	0.000085
8-9	0.12184	0.05711	0.00022
9-10	0.03365	0.02264	0
10-11	10.05036	39.79559	0
10-12	0.18194	0.13912	0
12-13	10.00038	39.96883	0
12-14	0.08182	0.02043	0.000115
14-15	0.10000	0.57741	0
14-16	0.01810	0.00453	0
16-17	0.10000	0.57741	0
16-18	0.10183	0.57786	0

Table A.1: Network Parameters [19].

Bus	P_{lmax} , MW	P_{lmin} , MW
5	7.6243	1.6779
7	1.1520	0.2809
8	0.3478	0.1192
9	0.4624	0.1580
10	0.7087	0.1678
11	0.2000	0.0559
12	0.4437	0.1442
13	0.2000	0.0657
14	1.5363	0.4899
16	0.2000	0.0495

Table A.2: Load Data.

Bus	P_{wtmax} , MW	P_{wtmin} , MW
15, 17 & 18	1.0217	0.000092558

Table A.3: Wind power generation Data.

Appendix B

DPL and MATLAB Scripts

B.1 DPL Script

B.1.1 Load Flow Analysis

```
int V,lferr;
double pseti;
object ldf,sumgrid;
ldf=GetCaseObject('ComLdf');
sumgrid=SummaryGrid();
for(V=1;V<=iter;V+=1)
{
L5:plini=P5.Get(V);
L7:plini=P7.Get(V);
L8:plini=P8.Get(V);
L9:plini=P9.Get(V);
L10:plini=P10.Get(V);
L11:plini=P11.Get(V);
L12:plini=P12.Get(V);
L13:plini=P13.Get(V);
L14:plini=P14.Get(V);
L16:plini=P16.Get(V);
pseti=Pwt.Get(V);
Lwt1:pgini=0.5*pseti/3;
Lwt2:pgini=pseti/3;
Lwt3:pgini=1.5*pseti/3;
pseti=Ppv.Get(V);
Lpv1:pgini=pseti;
Lpv2:pgini=pseti;
Lpv3:pgini=pseti;
```

```
Lpv4:pgini=pseti;
Lpv5:pgini=pseti;
Lpv6:pgini=pseti;
Lpv7:pgini=pseti;
Lpv8:pgini=pseti;
Lpv9:pgini=pseti;
Lpv10:pgini=pseti;
Lpv11:pgini=pseti;
Lpv12:pgini=pseti;
Lpv13:pgini=pseti;
L5:qlini=Q5.Get(V);
L7:qlini=Q7.Get(V);
L8:qlini=Q8.Get(V);
L9:qlini=Q9.Get(V);
L10:qlini=Q10.Get(V);
L11:qlini=Q11.Get(V);
L12:qlini=Q12.Get(V);
L13:qlini=Q13.Get(V);
L14:qlini=Q14.Get(V);
L16:qlini=Q16.Get(V);
lferr=ldf.Execute();
if(lferr=1)
{
R5.Set(V,0);
R7.Set(V,0);
R8.Set(V,0);
R9.Set(V,0);
R10.Set(V,0);
R11.Set(V,0);
R12.Set(V,0);
R13.Set(V,0);
R14.Set(V,0);
R16.Set(V,0);
Rwt1.Set(V,0);
Rwt2.Set(V,0);
Rwt3.Set(V,0);
Rpv1.Set(V,0);
Rpv2.Set(V,0);
Rpv3.Set(V,0);
Rpv4.Set(V,0);
Rpv5.Set(V,0);
Rpv6.Set(V,0);
Rpv7.Set(V,0);
```

```
Rpv8.Set(V,0);
Rpv9.Set(V,0);
Rpv10.Set(V,0);
Rpv11.Set(V,0);
Rpv12.Set(V,0);
Rpv13.Set(V,0);
S5.Set(V,0);
S7.Set(V,0);
S8.Set(V,0);
S9.Set(V,0);
S10.Set(V,0);
S11.Set(V,0);
S12.Set(V,0);
S13.Set(V,0);
S14.Set(V,0);
S16.Set(V,0);
}
else
{
R5.Set(V,L5:m:Psum:bus1);
R7.Set(V,L7:m:Psum:bus1);
R8.Set(V,L8:m:Psum:bus1);
R9.Set(V,L9:m:Psum:bus1);
R10.Set(V,L10:m:Psum:bus1);
R11.Set(V,L11:m:Psum:bus1);
R12.Set(V,L12:m:Psum:bus1);
R13.Set(V,L13:m:Psum:bus1);
R14.Set(V,L14:m:Psum:bus1);
R16.Set(V,L16:m:Psum:bus1);
Rwt1.Set(V,Lwt1:m:P:bus1);
Rwt2.Set(V,Lwt2:m:P:bus1);
Rwt3.Set(V,Lwt3:m:P:bus1);
Rpv1.Set(V,Lpv1:m:P:bus1);
Rpv2.Set(V,Lpv2:m:P:bus1);
Rpv3.Set(V,Lpv3:m:P:bus1);
Rpv4.Set(V,Lpv4:m:P:bus1);
Rpv5.Set(V,Lpv5:m:P:bus1);
Rpv6.Set(V,Lpv6:m:P:bus1);
Rpv7.Set(V,Lpv7:m:P:bus1);
Rpv8.Set(V,Lpv8:m:P:bus1);
Rpv9.Set(V,Lpv9:m:P:bus1);
Rpv10.Set(V,Lpv10:m:P:bus1);
Rpv11.Set(V,Lpv11:m:P:bus1);
```

```
Rpv12.Set(V,Lpv12:m:P:bus1);
Rpv13.Set(V,Lpv13:m:P:bus1);
S5.Set(V,L5:m:Qsum:bus1);
S7.Set(V,L7:m:Qsum:bus1);
S8.Set(V,L8:m:Qsum:bus1);
S9.Set(V,L9:m:Qsum:bus1);
S10.Set(V,L10:m:Qsum:bus1);
S11.Set(V,L11:m:Qsum:bus1);
S12.Set(V,L12:m:Qsum:bus1);
S13.Set(V,L13:m:Qsum:bus1);
S14.Set(V,L14:m:Qsum:bus1);
S16.Set(V,L16:m:Qsum:bus1);
V1.Set(V,B1:m:u);
V2.Set(V,B2:m:u);
V3.Set(V,B3:m:u);
V4.Set(V,B4:m:u);
V5.Set(V,B5:m:u);
V7.Set(V,B7:m:u);
V8.Set(V,B8:m:u);
V9.Set(V,B9:m:u);
V10.Set(V,B10:m:u);
V11.Set(V,B11:m:u);
V12.Set(V,B12:m:u);
V13.Set(V,B13:m:u);
V14.Set(V,B14:m:u);
V15.Set(V,B15:m:u);
V16.Set(V,B16:m:u);
V17.Set(V,B17:m:u);
V18.Set(V,B18:m:u);
}
}
```

B.2 MATLAB Scripts

B.2.1 Day Angle Calculation

```
dn = 1:1:365;
B = 2*pi*(dn-1)/365;
B8760 = zeros(1,8760);
for aux = 0:24:8760
for j=1:1:24
B8760(aux+j) = B((aux+24)/24);
end
end
```

B.2.2 Irradiance Coefficients Based Upon Epsilon Value

```
for i=1:length(eps)

if eps(i)>=1 & eps(i)<1.0625
eps(i)=1;

F11(i)=-0.008; F12(i)=0.588; F13(i)=-0.062;
F21(i)=-0.060; F22(i)=0.072; F23(i)=-0.022;

%overcast

elseif eps(i)>=1.065 & eps(i)<1.230
eps(i)=2;

F11(i)=0.130; F12(i)=0.683; F13(i)=-0.151;
F21(i)=-0.019; F22(i)=0.066; F23(i)=-0.029;

elseif eps(i)>=1.230 & eps(i)<1.500
eps(i)=3;

F11(i)=0.330; F12(i)=0.487; F13(i)=-0.221;
F21(i)=0.055; F22(i)=-0.064; F23(i)=-0.026;

elseif eps(i)>=1.500 & eps(i)<1.950
eps(i)=4;

F11(i)=0.568; F12(i)=0.187; F13(i)=-0.295;
F21(i)=0.109; F22(i)=-0.152; F23(i)=-0.014;
```

```
elseif eps(i)>=1.950 & eps(i)<2.800
eps(i)=5;

F11(i)=0.873; F12(i)=-0.392; F13(i)=-0.362;
F21(i)=0.226; F22(i)=-0.462; F23(i)=0.001;

elseif eps(i)>=2.800 & eps(i)<4.500
eps(i)=6;

F11(i)=1.132; F12(i)=-1.237; F13(i)=-0.412;
F21(i)=0.288; F22(i)=-0.823; F23(i)=0.056;

elseif eps(i)>=4.500 & eps(i)<6.200
eps(i)=7;

F11(i)=1.060; F12(i)=-1.600; F13(i)=-0.359;
F21(i)=0.264; F22(i)=-1.127; F23(i)=0.131;

elseif eps(i)>=6.200
eps(i)=8;

F11(i)=0.678; F12(i)=-0.327; F13(i)=-0.25;
F21(i)=0.156; F22(i)=-1.377; F23(i)=0.251;

%clear

else
eps(i)=1;

F11(i)=-0.008; F12(i)=0.588; F13(i)=-0.062;
F21(i)=-0.060; F22(i)=0.072; F23(i)=-0.022;

%in order to get rid of NaN error at zenith 90

end
end
```

B.2.3 Diffused Horizontal Irradiance at Angle β

```
for i=1:length(Gd_beta)
if Gd_beta(i)<0
Gd_beta(i)=0;
```

```
end
end
```

B.2.4 For Qpv Calculation

```
Qpv1 = zeros(length(DV),1);
for i=1:length(DV)
if (DV(i) >= 0)
Qpv1(i) = Qpv(i);
else
Qpv1(i) = abs(Qpv(i));
end
end
```

Appendix C

CD Contents

1. This report in PDF.
2. All the references of this project.
3. The DigSilent model.
4. MATLAB files for Chapter 2, 3, 5 and 6.
5. MATLAB files for Annual PV Output Calculations.
6. MATLAB scripts used in this project.
7. Plots and Figures in this report.