ABSTRACT

WANG, JIYU. Analysis of Voltage Problems for PV Integrated Distribution Feeder. (Under the direction of Dr. Ning Lu).

This research focuses on developing methodologies to simulate and analyze the voltage profile after PV is added in a distribution feeder. A simplified utility distribution feeder model, is used in the study. A set of one-year, 15-min load data, collected from 50 houses from Olympia Peninsula, WA, USA is used to disaggregate load at each node in the feeder. The total load at each node is resolved into load profiles at each house. Air conditioning load is also added to the load profiles. Then these load data are interpolated into one-second data. A set of eight-day, one-second PV output data is used to be solar profile the in this study. Several cases are simulated and voltage profiles for each condition is obtained. The simulation show how daily voltage fluctuation and voltage flicker condition perform in different cases. The contributions of this thesis are four-fold. First, it develops a methodology to disaggregate total residential load from each node to each house at that node. Second, a PV output time delay is set among different zones to fit the condition in realistic. Third, it simulates the different feeder performance when PV is added in different seasons, different weather, different locations, different PV penetration percentage and different types of load. Fourth, two factors, current variation and feeder resistance, are proved to have significant influence to the voltage flicker performance.

Analysis of Voltage Problems for PV Integrated Distribution Feeder

by
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DEDICATION

To my parents and my future family.

To teachers who nourished me with knowledge.

To all the friends who have given me support and courage.

BIOGRAPHY

Jiyu Wang was born in Harbin, Heilongjiang, China. He received his Bachelor of Engineering degree in Electrical Engineering and Automation from China Agricultural University in June 2014. He started to pursue a Master of Science degree in North Carolina State University in August, 2014. His research interests include PV integration study and home energy management system.

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I am immensely grateful to Xiangqi Zhu, who was my mentor and taught me a lot. With her help, I learnt how to set up simulation cases for the PV study. My gratitude also goes to our other group members. I also want to thank all my friends' help and support.

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Chapter 1 Introduction

1.1 Background

In recent years, electricity consumption increases steadily because of the growth of population and the introduction of new electronic devices, as well as the electrification of transportation systems [1]. Traditional power energy generation sources such as coal, oil, and gas are fossil fuel that cannot be relinquished in centuries. In addition, generating power using these resources emits large amounts of CO2 and other greenhouse gas, which is a main cause for global warming. Therefore, it is essentially to replace fossil fuel generation by renewable generation resources such as wind and solar [2]. In this thesis, I focused my study on assessing the impact of integration of solar power on power distribution systems.

In 2014, the global PV capacity had increased 40 GW, which is the largest growth in history. It makes the total global PV capacity comes to 177 GW, and more than 60% of this total capacity are added in the past three years. China generated about 25 billion kWh electricity in 2014, about twice as much compared with the previous year. In Australia, there are about 14% residential households have rooftop PV systems installed, contributed to the 4.1 GW solar power generation. In Germany, the total installed capacity of PV has reached 38.2 GW. In America, the total capacity is 18.3 GW [3].

Many states in the U.S. had passed Renewable Portfolio Standards (RPS) programs for setting their targets [4]. For example, California plans to reach 33% of total generation by 2020. In North Carolina Area, solar power resources are abundant, as shown in Figure 1-1. Recently, Duke Energy, the largest US electric utility as measured by market value and number of customers, has raised its 2020 renewable energy goal 33% to 8GW from the previous target set in 2013 [5]. To meet this goal, Duke Energy is actively engaging its customers regarding new solar installations at both MW and kW levels. Since Jan 2015, North Carolina State University has been working with Clemson University on developing a new planning method for grid planners to evaluate the impact of integrating kW- and MW- PV into the Duke Energy distribution power grids. This thesis is written based on the results obtained in the residential PV integration study, which is a key part of that project.

In general, power generated by residential roof-top PV systems ranges around 1 to 15 kW [6]. Those PV systems will not cause significant grid operation problems at a penetration level lower than 10% based on the results of PV penetration studies conducted by EPRI and other research institutes [7] [8]. However, when most of the houses in a community have roof-top PV systems installed, the PV penetration level of that part of the feeder will be well above 50% or even higher than 100%. Depending on where the community locates on the feeder, the load characteristics, and the settings of voltage regulation (VR) devices, the distribution feeder may experience problems such as overloaded transformers, reverse power flow, over-voltage, flickers, and frequent operation of VR devices. Therefore, the main goal of this thesis to model

a portion of the power system feeder in detail and quantify the impacts when the roof-top PV systems of different installed capacity are installed at different feeder locations [9]. The second goal is to study mitigation methods such as using VR device to adjust the voltage profiles or using load and energy storage to reduce the power fluctuations.

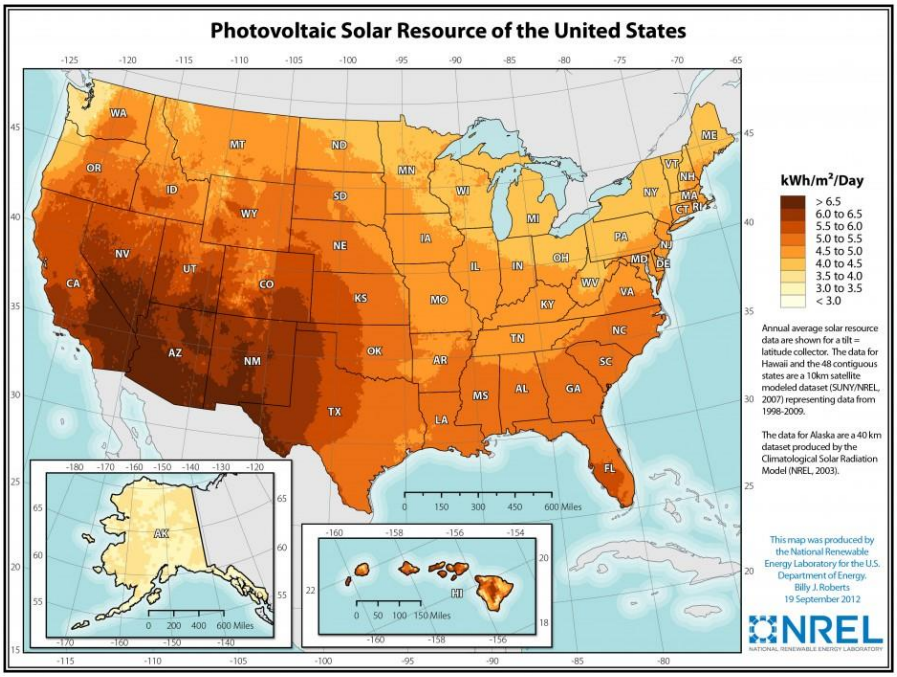


Figure 1-1 Photovoltaic solar resource of the United States [10]

1.2 PV Integration Issues

Although integrating PV into distribution system has many benefits, some issues exist as well. If the PV generation to the local demand at one node reaches a large percentage during a period of time, voltage rise issue will occur [11]. This issue is created by the power generated by PV will decrease the voltage drop on the feeder resistance [12]. When high penetration level of PV is connected to a light load node, there is a possibility that voltage exceed the upper limitation [13].

Secondly, when the PV output power is greater than local demand, the extra power generated by PV will lead to reverse active power flow at feeder and distribution transformer level. This situation will negatively affect the operation of line voltage regulators, especially to the Line Drop Compensation (LDC), [14].

Thirdly, as PV is an intermittent resource, the output power will varies a lot in a short period of time when clouds passing by. Feeder voltage will be significant impacted by this phenomena [14]. Voltage flickers have a higher chance to appear under this condition. This voltage violation problem will lead complaints from customers.

Finally, single phase PV may cause voltage and current unbalance [15]. In a distribution system, mostly the load for three phase is already balanced. However, when the three phase PV capacity is not the same, PV generation for each phase will be different during the time solar irradiation is strong. Then the three phase net load will become unbalance, leads to the voltage and current unbalance for the whole feeder.

1.3 Data Preparation

This subsection discusses the feeder, load, and PV data preparation.

1.3.1 Feeder model

A simplified utility distribution feeder is used in this study. The feeder data we used in this study is in the OPENDSS format. As shown in Figure 1-2, the topology of this feeder has 24 buses in total and 17 out of the 24 buses have residential loads. The power factor of the load at each bus is set at 0.995. There is a capacitor bank at Bus 11 and a voltage regulator at Bus 16. The main feeder voltage of this feeder is 22.87kV. This system is supplied by a substation locates at the beginning of the feeder. It is assumed that the voltage at the substation is constantly equal to 1.033 pu. The peak load of the feeder is 15,300kW in winter. The power factor at the feeder head is assumed to be 1.0. More information of the feeder is shown in Table 1-1, Table 1-2, Table 1-3 and Table 1-4.

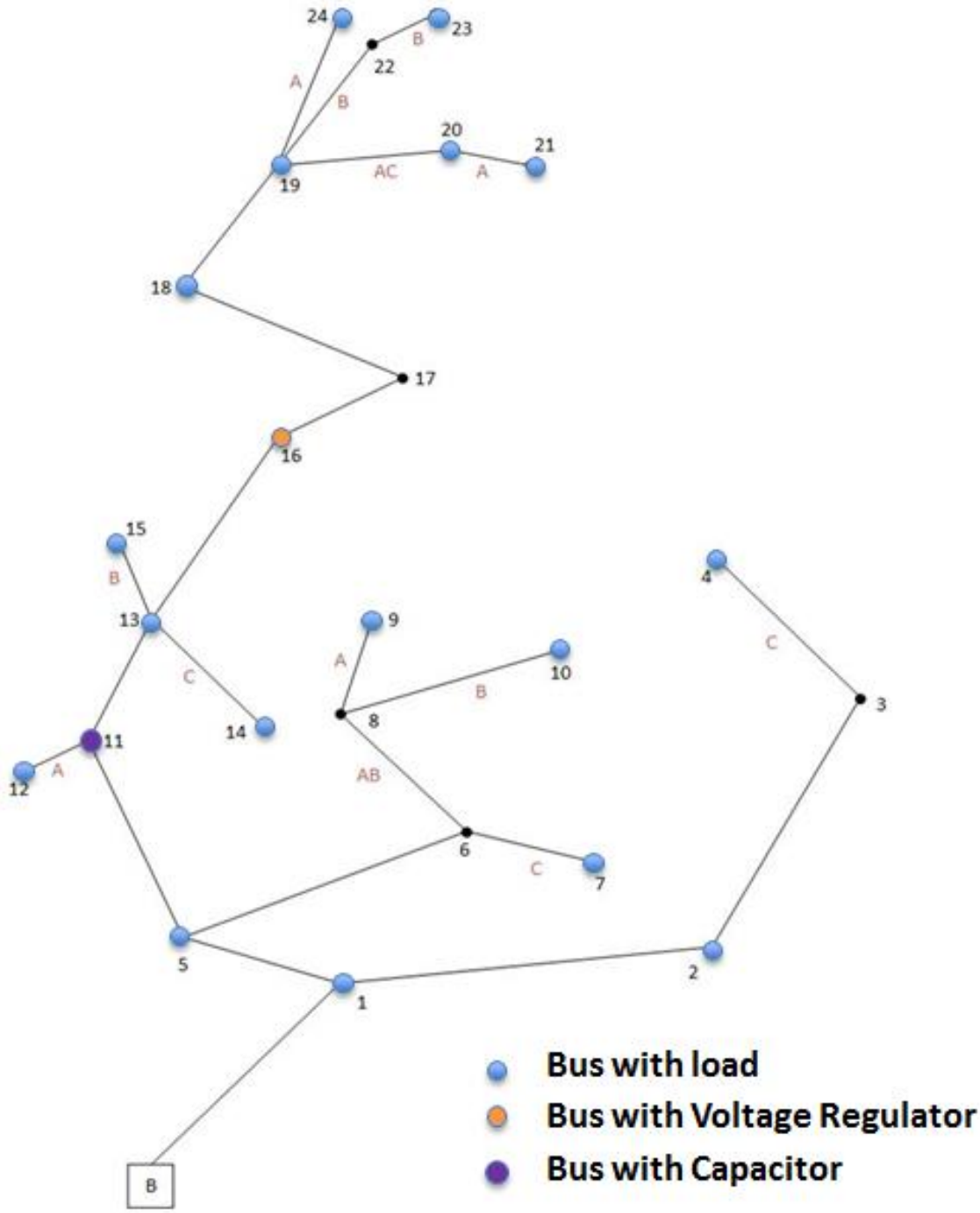


Figure 1-2 Topology of the distribution feeder

Table 1-1 General information of the distribution feeder

Format	OpenDSS
System Voltage	22.87 kV
Feeder Length (Backbone) (mile)	13.35
Number of Regulators	1
Connected Bus	Bus 16
Number of Capacitors	1
Connected kVA	1200
Connected Bus	Bus 11
Substation Voltage	1.033 pu
Substation Power Factor	0.995
Number of buses	24
Number of Loads (Total)	29
Phase A	10
Phase B	9
Phase C	10
Winter Peak Load (kW)	15300

Table 1-2 Branch information of the distribution feeder

Branch #	From	To	Phase	Length (mile)	Impedance (ohm/mile)	Line Type
1	Substation	Bus 1	ABC	1.72	0.214+0.612j	Overhead
2	Bus 1	Bus 2	ABC	1.19	1.017+0.836j	Overhead
3	Bus 2	Bus 3	ABC	1.16	1.017+0.836j	Overhead
4	Bus 3	Bus 4	C	0.04	1.209+1.456j	Overhead
5	Bus 1	Bus 5	ABC	0.88	1.017+0.836j	Overhead
6	Bus 5	Bus 6	ABC	1.04	1.556+0.843j	Overhead
7	Bus 6	Bus 7	C	0.03	1.745+1.469j	Overhead
8	Bus 6	Bus 8	AB	0.41	1.717+1.322j	Overhead
9	Bus 8	Bus 9	A	0.55	1.782+1.421j	Overhead
10	Bus 8	Bus 10	B	1.22	1.209+1.456j	Cable
11	Bus 5	Bus 11	ABC	1.33	1.017+0.836j	Overhead
12	Bus 11	Bus 12	A	0.88	1.209+1.456j	Cable
13	Bus 11	Bus 13	ABC	0.79	1.556+0.843j	Overhead
14	Bus 13	Bus 14	C	0.24	1.209+1.456j	Cable
15	Bus 13	Bus 15	B	0.44	1.745+1.469j	Overhead
16	Bus 13	Bus 16	ABC	1.75	1.556+0.843j	Overhead
17	Bus 16	Bus 17	ABC	2.18	1.556+0.843j	Overhead
18	Bus 17	Bus 18	ABC	1.58	1.556+0.843j	Overhead
19	Bus 18	Bus 19	ABC	2.07	1.490+0.701j	Overhead
20	Bus 19	Bus 20	AC	0.31	1.717+1.322j	Overhead
21	Bus 20	Bus 21	A	0.08	1.782+1.421j	Overhead
22	Bus 19	Bus 22	B	0.88	1.209+1.456j	Cable
23	Bus 22	Bus 23	B	0.37	1.209+1.456j	Cable
24	Bus 19	Bus 24	A	0.8	1.209+1.456j	Cable

Table 1-3 Node information of the distribution feeder

Node #	Phase	Node Type	Power Factor	Other Information
Bus 1	ABC	With load	0.995	N/A
Bus 2	ABC	With load	0.995	N/A
Bus 3	ABC	Without load	0.995	N/A
Bus 4	C	With load	0.995	N/A
Bus 5	ABC	With load	0.995	N/A
Bus 6	ABC	Without load	0.995	N/A
Bus 7	C	With load	0.995	N/A
Bus 8	AB	Without load	0.995	N/A
Bus 9	A	With load	0.995	N/A
Bus 10	B	With load	0.995	N/A
Bus 11	ABC	Without load	0.995	1200 kVAR capacitor connected
Bus 12	A	With load	0.995	N/A
Bus 13	ABC	With load	0.995	N/A
Bus 14	C	With load	0.995	N/A
Bus 15	B	With load	0.995	N/A
Bus 16	ABC	Without load	0.995	Voltage regulator connected
Bus 17	ABC	Without load	0.995	N/A
Bus 18	ABC	With load	0.995	N/A
Bus 19	ABC	With load	0.995	N/A
Bus 20	AC	With load	0.995	N/A
Bus 21	A	With load	0.995	N/A
Bus 22	B	Without load	0.995	N/A
Bus 23	B	With load	0.995	N/A
Bus 24	A	With load	0.995	N/A

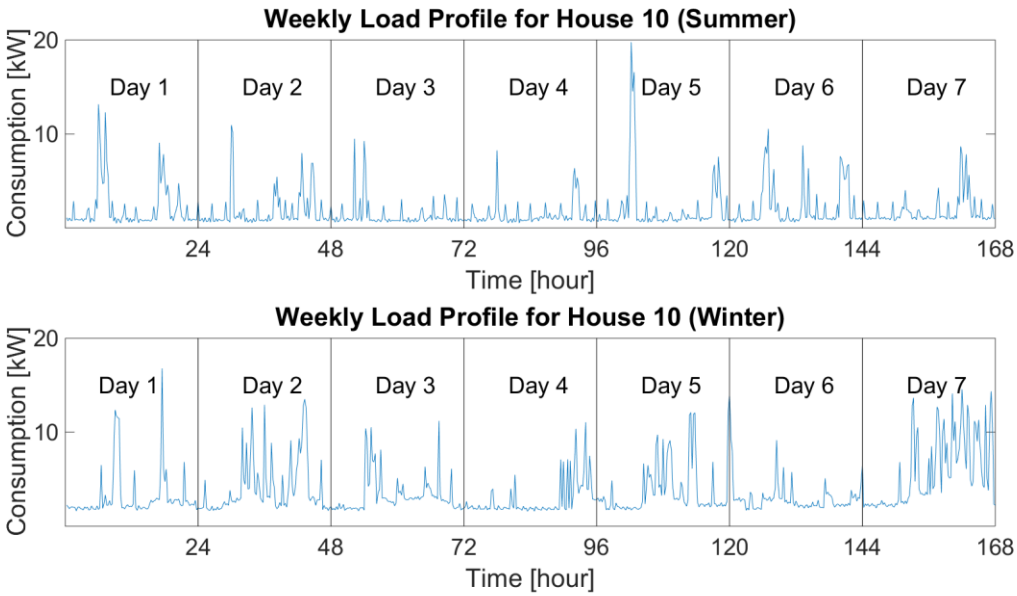
Table 1-4 Load information of the distribution feeder

Load Location	Winter Peak Load (kW)	Winter Reactive Power (kVAR)
Bus1_Aph	32.393	3.142
Bus1_Bph	16.767	1.626
Bus1_Cph	21.827	2.117
Bus2_Aph	734.29	71.226
Bus2_Bph	832.16	80.719
Bus2_Cph	315.97	30.649
Bus4_Cph	601.17	58.313
Bus5_Aph	505.02	48.986
Bus5_Bph	1543.9	149.75
Bus5_Cph	1954.4	189.57
Bus7_Cph	325.02	31.526
Bus9_Aph	630.35	61.143
Bus10_Bph	655.9	63.622
Bus12_Aph	1043.5	101.219
Bus13_Aph	1478.9	143.453
Bus13_Bph	949.57	92.108
Bus13_Cph	313.37	30.396
Bus14_Cph	673.59	65.338
Bus15_Bph	515.42	49.995
Bus18_Aph	89.613	8.692
Bus18_Bph	193.76	18.794
Bus18_Cph	228.21	22.136
Bus19_Aph	477.71	46.337
Bus19_Bph	103.69	10.057
Bus19_Cph	513.34	49.793
Bus20_Cph	130.55	12.663
Bus21_Aph	606.28	58.809
Bus23_Bph	550	53.350
Bus24_Aph	139.65	13.546

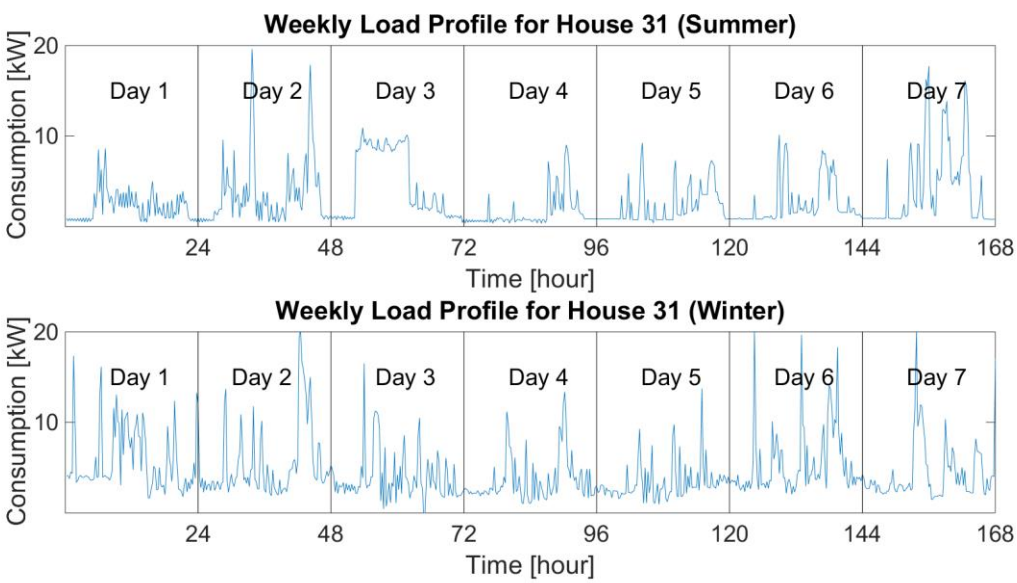
1.3.2 Residential Load Data

In the simulation, a set of one-year, 15-min load data is used to extract the baseload data for the residential houses, so there are 96 data points for a 24-hour period for each house. This data was collected by Pacific Northwest National Laboratory [16] from 50 real residential houses at Olympia Peninsula, WA, USA between April 2006 and Mar 2007. Although load profiles of 50 houses are recorded, not all of them are completed. House 41 and 48 were

excluded from the data set because of too many missing data points and the inconsistency in the recorded data. The load profiles of the remaining 48 houses are used for the study. A few examples of the daily load profiles of the houses are shown in Figure 1-3.



(a)



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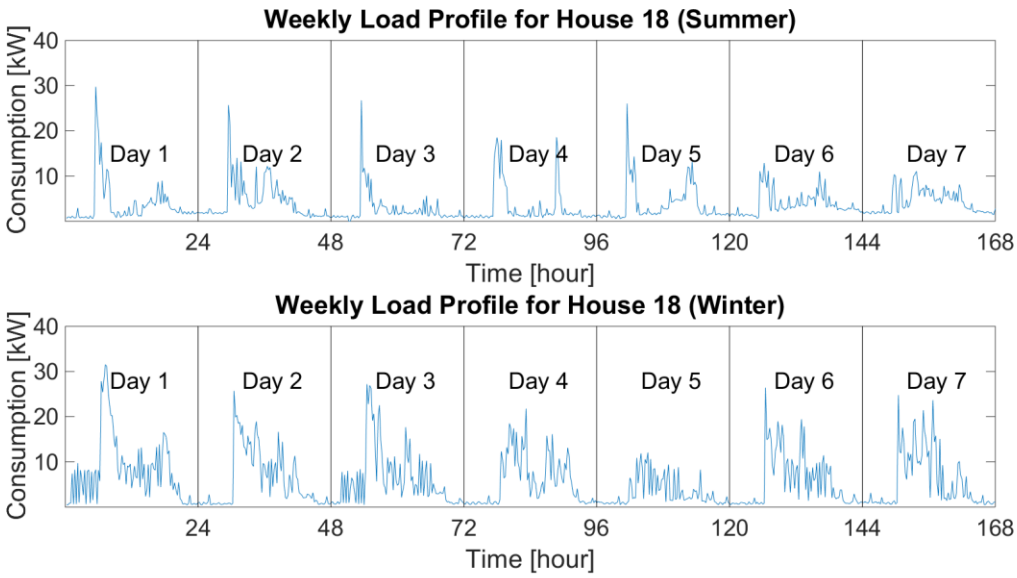

(c)

Figure 1-3 Typical weekly load profiles in Summer/Winter

As shown in Figure 1-3, energy consumptions for different houses vary significantly. Among the 48 houses, house 10 is a house with relatively low electricity consumptions, house 31 is a house with medium electricity consumptions, and house 18 is a house with high electricity consumptions. House 10 has two peaks, a morning peak and an evening peak. This is usually a residential customer who works during the day. House 31 has three peaks. This is usually a house with occupants in all day long. House 18 has a higher load consumption. This is usually a larger house or a house with more occupants.

Because the 48 houses include a broad variety of different daily load patterns, we were able to construct a group of realistic load profiles for a distribution feeder. Because residential solar panels are connected to the grid from each home, it is important to model the point of common coupling down to distribution transformers. The load variations are therefore important to study how the solar variations will influence the grid operation.

Although in a realistic power distribution system, daily load shapes for different houses may vary drastically, at the feeder level, where hundreds or thousands of houses are aggregated together, the load curve is rather smooth. Because the load profiles we received from the utilities are hourly load profiles at the feeder head, we desegregate the load to each end node using the load profiles extracted from the 48 households. Then, when studying the integration of residential rooftop PVs, we can account for the combined impact of load and PV variations on feeder line loadings and voltage profiles.

1.3.3 Solar data

A set of eight-day, second-by-second PV power output data collected by EPRI (see Table 1-5) is used to create the solar power outputs in this study. Typical solar irradiation patterns, such as sunny, partial cloudy, and cloudy, are included in this set of data, as shown in Figure 1-4. In a sunny day, the output of a PV panel is at maximum and is more predictable. Reverse power flow are more likely to happen in a sunny day with light loading conditions. In a partially cloudy day, the power output of a PV panel can vary drastically, causing voltage sags or flickers.

Table 1-5 Solar profile summary

Day Type	# of solar profiles
Sunny	2
Partial Cloudy	3
Cloudy	3
Rainy	0

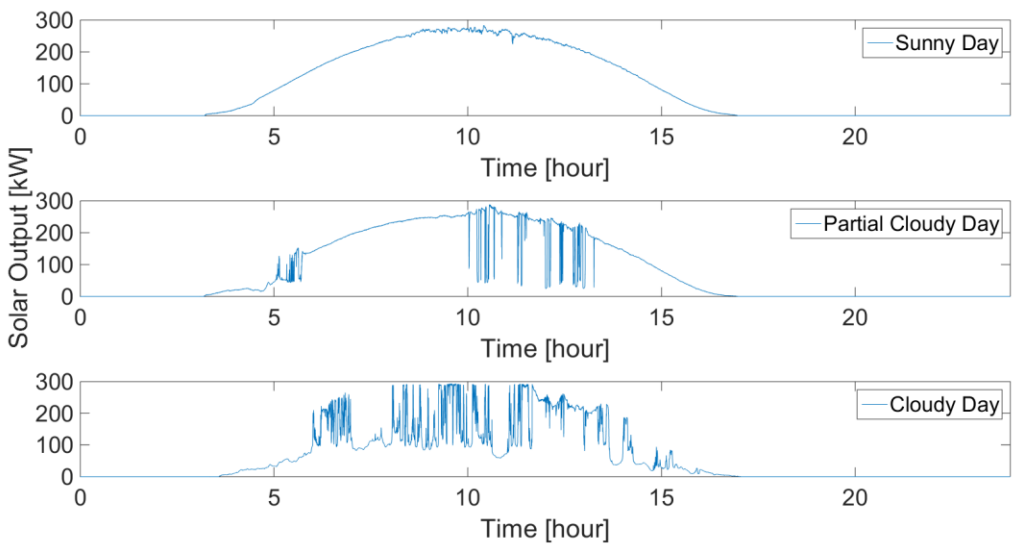

Figure 1-4 PV power outputs in Sunny/Partial-cloudy/Cloudy Day

Because there is no rainy day solar power outputs in the second-by-second solar data set, a 5-minute solar radiation data collected at Raleigh, NC are used to create the rainy day solar power outputs. A 17% efficiency is applied to convert the 5-minute solar irradiation data to the PV output power. In summary, the solar power outputs have four day types (sunny, partial cloudy, cloudy, rainy), as shown in Figure 1-5**.**

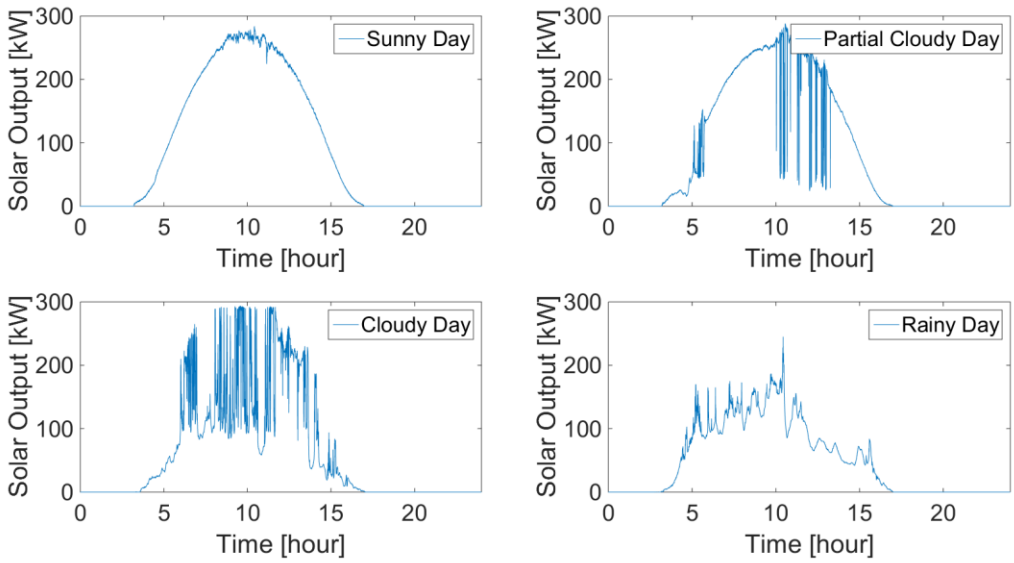

Figure 1-5 PV Output power profile in Sunny/Partial-cloudy/Cloudy/Rainy day

1.3.4 Modeling Air Conditioning Loads

The summer is very mild on Olympic peninsula. Therefore, the air conditioning load is either zero or very low. However, as the location of this feeder is not in Washington state, the air conditioning load may very high in summer. To compensate for the discrepancy, in the study, air conditioning loads are modeled and added back to the load profiles to represent the summer load at this feeder area [17] [18]. The electricity consumption of a residential home after the air conditioning load is added is shown in Figure 1-6.

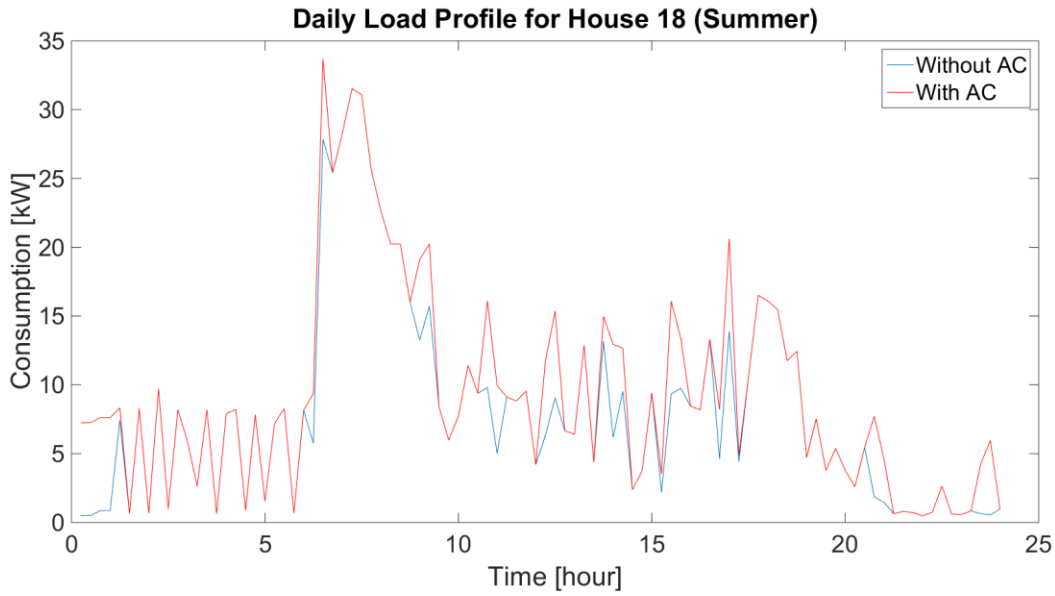

Figure 1-6 Daily load profiles of House 18 (with/without air-conditioning load at Bus 18)

1.3.5 Commercial Load Data

Aside from the residential loads, the residential distribution feeder normally supplies a small portion of commercial loads as well. To model such kind of feeders, we extract the second-by-second load characteristics from a commercial load so that some nodes on the feeder are modeled as commercial loads. The original data set includes second-by-second load profiles from a shopping mall for nine days. Because of the irregular SCADA pulling rate, only 81921 data points are recorded in each day instead of 86400, which is the number of total seconds in one day. An example of the second-by-second commercial load profile is shown in Figure 1-7. The probability density function of the commercial load change is shown in Figure 1-8. As shown in the figure, the commercial load variation on a second by second basis is rather small. However, the load variations on a 10 second basis are greater than 9.8 % of the maximum load.

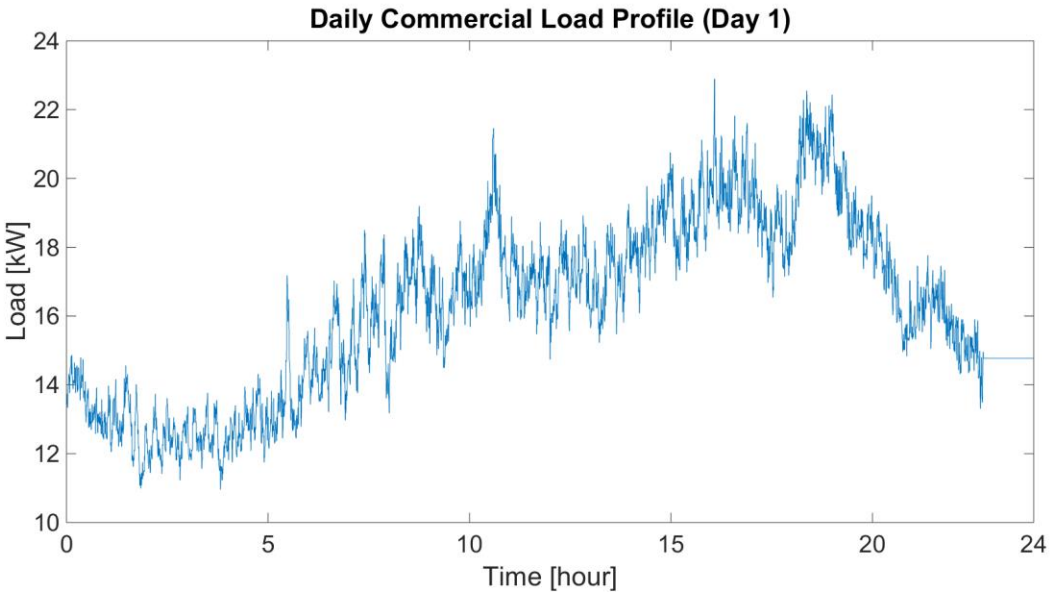

Figure 1-7 Daily Commercial Load Profile

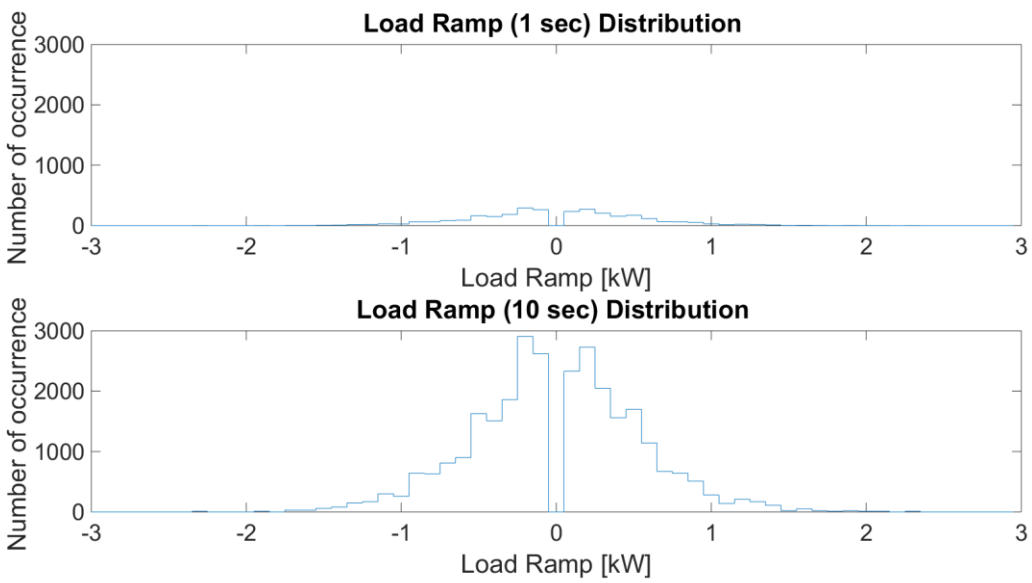

Figure 1-8 Probability Density Function of the commercial load variations (Note that the load ramps between -0.1 to 0.1 are excluded from the plot)

Chapter 2 Simulation Setup

This chapter presents the setup of the feeder network model, PV generation and penetration scenarios, and the distribution system load models. To study the impacts of the PV locations on residential feeders, we divide the feeder into supply zones based on the distance to the substation. To study the impact of PV penetration levels, we model up to 100% penetration assuming each household can have up to10 kW PV panels installed. To study the impact of the solar radiation conditions, we use four kinds of PV profiles: sunny, cloudy, partially cloudy, and rainy days. Because the solar PV is installed at each house, to address the combined impact of load and solar power variations, load profiles are randomly selected from the load profile database to populate each load node. Because the load profile database contains the yearly load profiles form 48 residential homes in Washington State, we adjust the load profile by adding air conditioning load to the original load profiles to reflect the heavier cooling needs in summer at the feeder area. Because the original feeder data set contains only hourly load profiles at the feeder head, a load desegregation method is applied to distribute the load profiles to each load node so that the total number of houses at each node can be determined.

2.1 Feeder Network Model Setup

There are two main considerations to prepare the feeder network model for the solar penetration study. First, the feeders are divided into supply zones based on the distance to the distribution substation so that the influence of the location of the PV installation can be addressed. Second, the voltage regulation devices (a 1200 kVar capacitor at Bus 11 and the voltage regulator at Bus 16) are removed for the base case study to model the net impact of PV penetration. The voltage regulation devices are in operation for the non-base case studies.

2.1.1 Supply Zones

This distribution feeder is divided into four zones based on the distance from the substation, as shown in Figure 2-1. The network parameters of each zone are listed in

Table 2-1**.** Zone 1 represents the beginning of the feeder, Zone 2 and Zone 3 represent the middle of feeder, and Zone 4 represents the end of feeder. Zone 1 has the least amount of loads connected to it. Zone 2 and 3 are at the middle of the feeder with similar amount of loads connected. Zone 4 is at the end of the feeder with the farthest load nodes about 13 miles away from the substation. When studying the penetration of the rooftop PV systems, we connect the same amount of PVs to each zone so that the relationship between the location of the PV site and the location of the substation can be revealed.

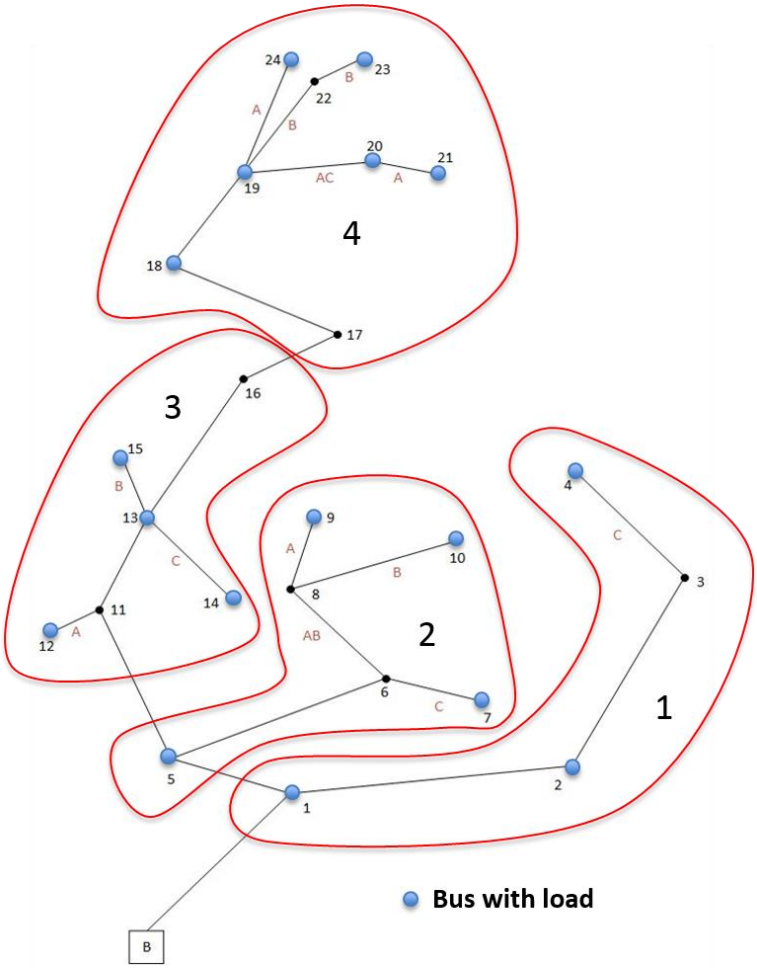

Figure 2-1 Zonal sketch map of the distribution feeder

Table 2-1 Zonal Information

	Zone 1	**Zone 2**	**Zone 3**	**Zone 4**
Minimum Distance to Substation (mile)	1.72	2.6	3.73	10.03
Maximum Distance to Substation (mile)	2.39	5.27	4.96	13.35
# of single phase load	1	3	3	4
# of two phase load	0	0	0	0
# of three phase load	2	1	1	2
# of load nodes	7	6	6	10
Summer peak load (kW)	606.5	1775.7	1424.7	889.9
Winter peak load (kW)	2442.2	5469.7	4784.2	2658.3

2.1.2 Feeder Load Disaggregation

The peak load in winter at each bus in this feeder is given respectively as Table 1-4 shows. However, showing only peak load at each bus is not enough because the simulation needs to find out what will happen in a whole day. Therefore, it is necessary to build the load profiles at every nodes. The following steps are conducted to construct the load curve at each node:

Step 1: The first step is to decide the number of houses at each bus. A general load level of each house is set, then the house load level and bus load level are used to decide the number of houses at each node. In this study, according to the real 50 houses load data we got, one house's load level is set to be 10kW in winter. By using this number, an estimated house number at each node is calculated.

Step 2: The next step is to construct a load pool for the preparation to disaggregate loads. A number of winter load profiles from each home are selected to be a winter load pool. While selecting the load pool, a few days which are not typical need to be excluded. The seasonal load variations and some other facts can be observed when we look at the yearly data profile for each house (Figure 2-2). Energy consumption in winter is larger than summer generally. A low-load period at the beginning of November can be noticed, it is probably because that the residential customer living there took a vacation or going somewhere else and is not at home in those days. These exceptional cases are deleted when the load pool is constructed because these load profiles cannot represent the typical residential load patterns.

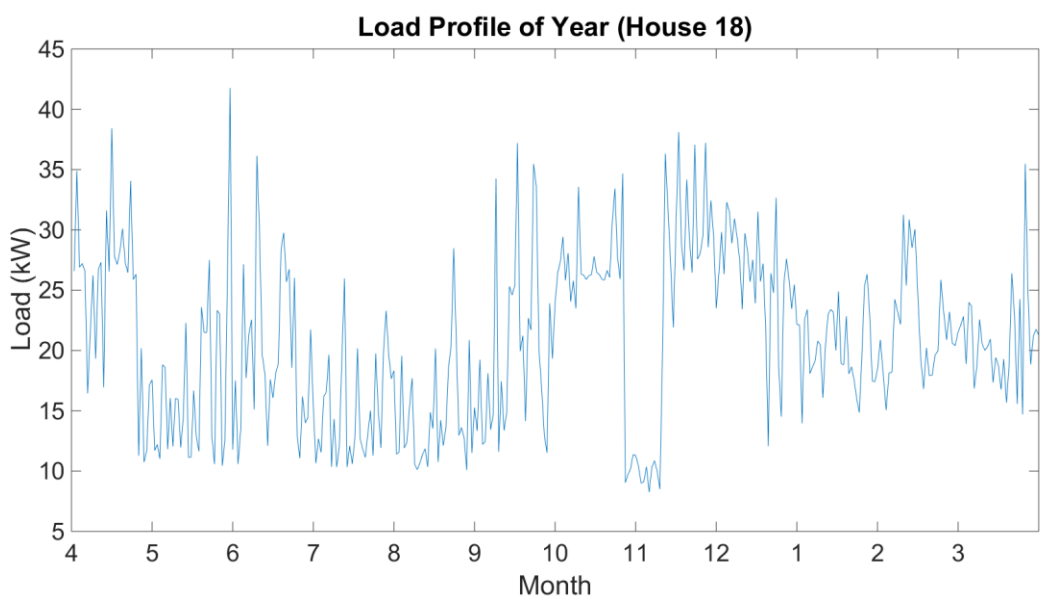

Figure 2-2 One-year load profile of house 18

Step 3: After the load pool is constructed, load profiles are grabbed randomly from the winter load pool and the number of houses of each bus is adjusted according to the load diversity factor. Keep doing this until the total peak load at that bus fit to the original winter peak load which is given by the feeder's data. The detail about the house number at each bus in each zone in winter is given in Table 2-2, Table 2-3, Table 2-4 and Table 2-5. The daily load profile for node is shown in Figure 2-3.

Table 2-2 Load disaggregation in zone 1

Bus#	Winter peak load (kW)	House#	Consumption/House (kW)
Bus1_A	32.4	1	32.4
Bus1_B	16.8	1	16.8
Bus1_C	21.8	1	21.8
Bus2_A	734.3	60	12.2
Bus2_B	832.2	70	11.9
Bus2_C	315.9	24	13.2
Bus4_C	601.2	42	14.3
Total	2554.6	199	12.8

Table 2-3 Load disaggregation in zone 2

Bus#	Winter peak load (kW)	House#	Consumption/House (kW)
Bus5_A	505	48	10.5
Bus5_B	1543.9	160	9.6
Bus5_C	1954.4	195	10.0
Bus7_C	325	33	9.8
Bus9_A	630.4	66	9.6
Bus10_B	655.9	75	8.7
Total	5614.6	577	9.7

Table 2-4 Load disaggregation in zone 3

Bus#	Winter peak load (kW)	House#	Consumption/House (kW)
Bus12_A	1043.5	105	9.9
Bus13_A	1478.9	115	12.9
Bus13_B	949.6	90	10.6
Bus13_C	313.4	30	10.4
Bus14_C	673.6	75	9.0
Bus15_B	515.4	45	11.5
Total	4974.4	460	10.8

Table 2-5 Load disaggregation in zone 4

Bus#	Winter peak load (kW)	House#	Consumption/House (kW)
Bus18_A	89.6	6	14.9
Bus18_B	193.8	14	13.8
Bus18_C	228.2	18	12.7
Bus19_A	477.7	60	8.0
Bus19_B	103.7	12	8.6
Bus19_C	513.3	55	9.3
Bus20_C	130.6	8	16.3
Bus21_A	606.3	60	10.1
Bus23_B	550	48	11.5
Bus24_A	139.7	15	9.3
Total	3032.8	296	10.2

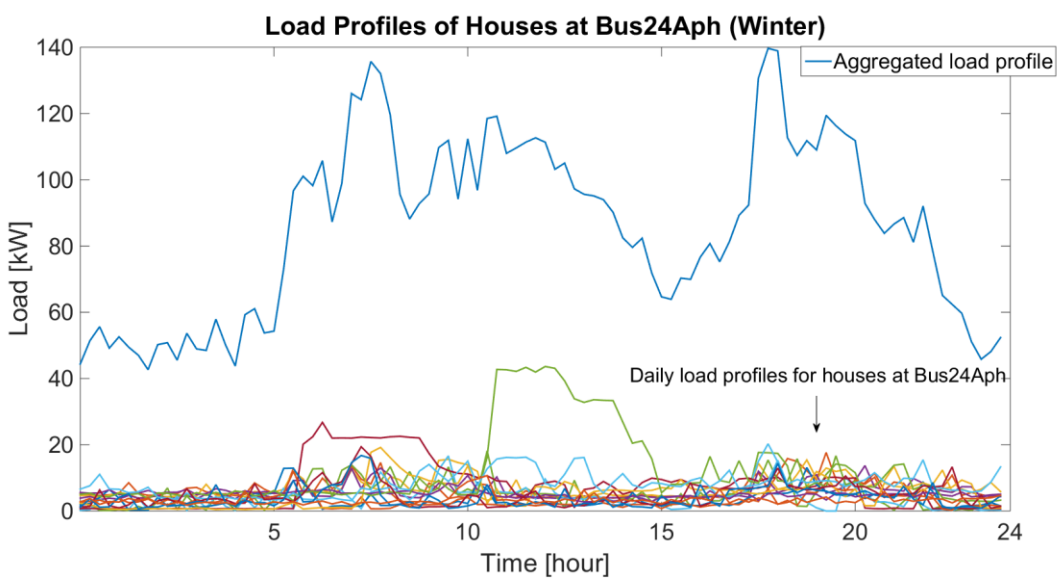

Figure 2-3 Daily load profiles of houses at Bus24 Phase A in winter

The curve for each bus is not the same, but they all have the same trend because many activities for residential customers are in common.

Step 4: After the winter load at each bus is disaggregated, we will know which winter load profiles are used in each bus. Subsequently, the summer load profiles which are corresponding to those winter profiles are selected from summer load pool to be the houses in summer at each bus. In this way, the feeder load in summer is disaggregated too.

Step 5: Since we have already had the load profiles at every bus, the load profile of the substation can be drawn by adding up the bus's profiles together. (See Figure 2-4 and Figure 2-5)

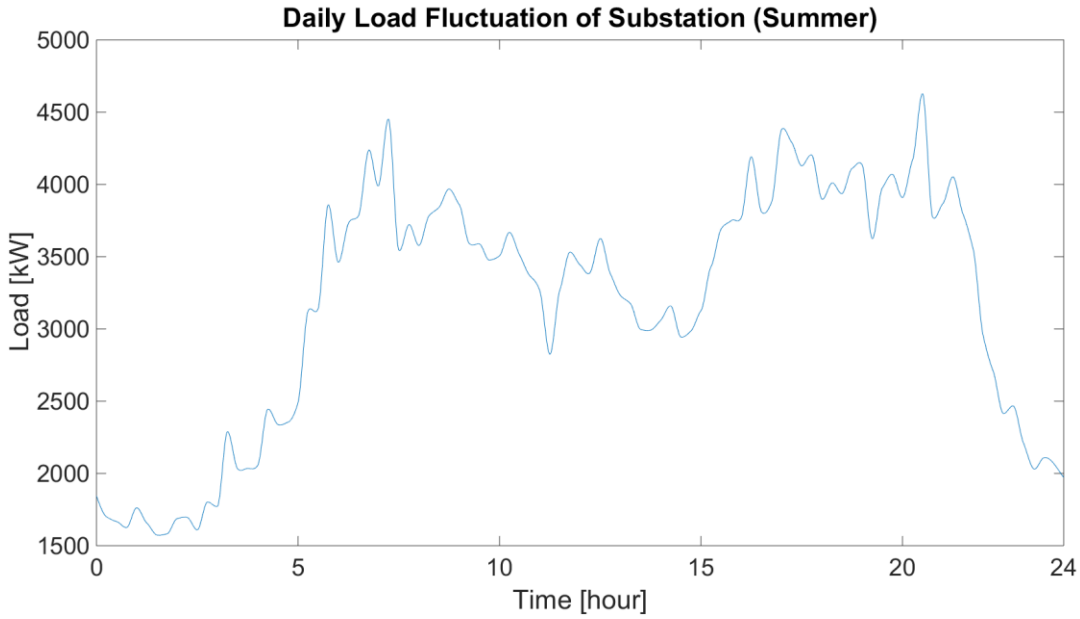

Figure 2-4 Daily load profile for substation in summer

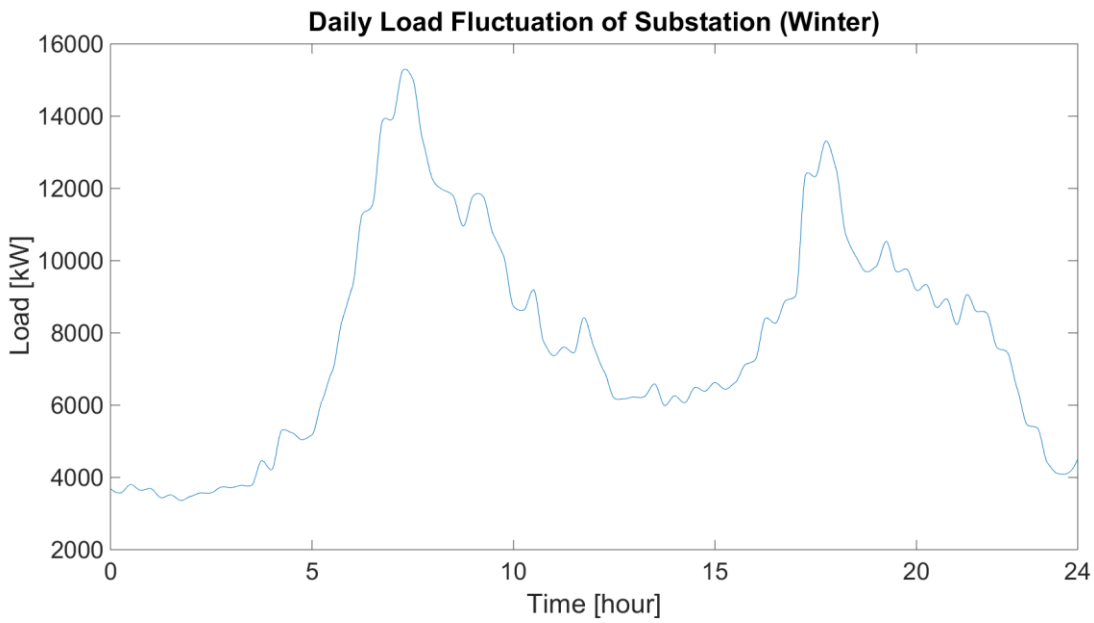

Figure 2-5 Daily load profile for substation in winter

From the above figures, it can be obviously observed that the load profiles between summer and winter are different. The summer curve does not have an apparent peak, rather the load fluctuates during a peak load period. The winter curve has dual-peak, one at beginning of day (morning peak) and the other at end of day (evening peak). The reason for the difference is that in summer, the temperature remains high from noon to evening, so air-conditioning loads are high all over the afternoon. As a result, the load consumption in afternoon does not vary with morning and evening. In winter, temperature in the afternoon hours at the feeder areas are much higher than in the morning or evening so the daytime heating load is significantly lower than nighttime or early morning. In addition, the other loads such as cooking, entertainment, or lighting are significantly higher in the morning and evening hours because of occupants are at home during those hours. Therefore, there are two apparently peaks for the winter's load profile.

2.2 Load Data Interpolation

The original 50 houses' load data we have were measured every 15 minutes, so there are only 96 data points for each house every day. The 15-minute time interval is too long to observe the voltage ramp for voltage flicker studies [19] [20].The voltage flickers result in the flash of the lights, which will seriously impact the customers' comfort. Thus it is significant to get the one second load data to do the simulation in this study.

The interpolation function in MATLAB is used to process the data. The 'pchip' setting is applied in this function to supplement 14 data points between every two 15-minute data points. For representing second-by-second load changes at each bus, 86400 data points are needed. However, because the 15-minute data is the average power consumption in 15 minutes, simply connecting every points together for interpolation will significantly underestimate the actual load variations on second-by-second basis. Therefore, we add a 15-minute 1% load variation time series to each 15-minute load point. The code for implementing the process is:

```
for i=1,1440
    for j=1,60
        P_1sec(j+(i-1)×60) = P_15min(i) + 0.01 P_15min(i) × rand()
    end
end
```

An example of the load profile with 1% load variations added is shown in Figure 2-6**.** A refinement of the process is to use the actual load variation statistics of 1-minute data sets to generate the 1-minute load variations. This work will be conducted in our future efforts.

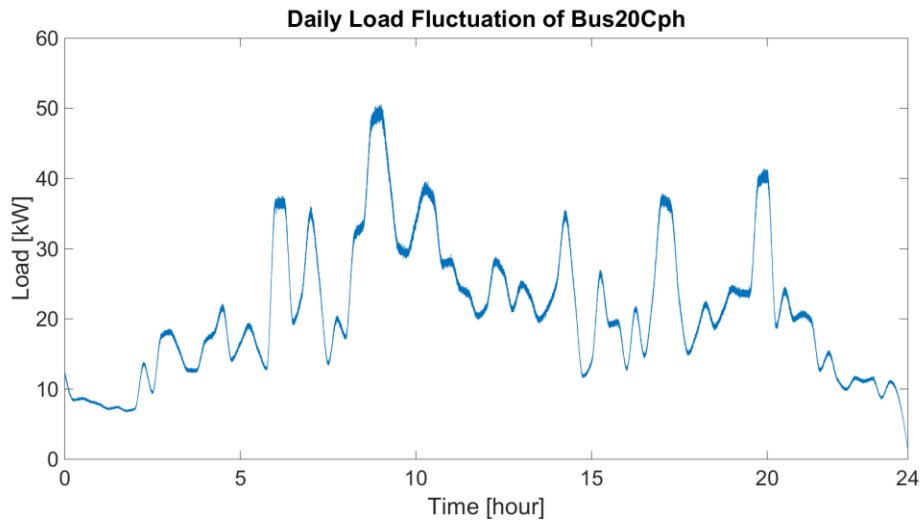

Figure 2-6 A second-by-second daily load profile for Bus 20 Phase C in summer

2.3 PV installation

In this study, the PV is integrated into the feeder in two different ways. The first way is to add the PV by percentage of penetration. The PV penetration is defined as the ratio of the PV installed capacity in percentage of the peak load of the feeder [21].

$$P_{S-\max} = P_{L-\max} \times r \tag{2-1}$$

Where $P_{S-\max}$ is the peak PV output power, $P_{L-\max}$ is the peak load, and r is the PV penetration level.

The one-second solar data we have is scaled to different percentage penetrations, and is added to each bus. This is a traditional way to add PV into the feeder in the study of integrating high penetrations of PV into a distribution grid.

The second way is to add PV according to the number of houses at each bus. A fixed maximum PV is given for each house and the total peak power PV generated at every bus can be calculated:

$$P_{S-\max} = N_i \times P_{Ci} \tag{2-2}$$

Where N_i is number of houses at each node and P_{Ci} is the PV output capacity for each house.

The reason for adding PV per house is that it is a more realistic when residential customers adding PV in their home. It is more likely that residential customers will install PV panels on their rooftops. In America, the rooftop area for each house does not vary a lot, so the number of PV panel people can install on their houses tends to be similar in the same neighborhood. Thus, assuming that the PV added to each house is the same in the same load zone is a reasonable assumption.

To model the cloud impact more flexibly, a time delay representing the moving clouds is added to the PV power output across different locations. In addition, the absolute angels of sun for each zone may vary and need to be taken into account. So a scaling factor between 0.9-1.0 is used to represent the relative variations. For example, a 5-minute time delay is added so that zone 2 is covered by the cloud five minutes later than zone 1, zone 3 is 5 minutes later than zone 2, and zone 4 is five minutes later than zone 3.

In this way the movement of sun during a day is considered into the simulation to make the result more realistic. An example of the PV output curve for four load zones in a 1-hour period is shown in Figure 2-7.

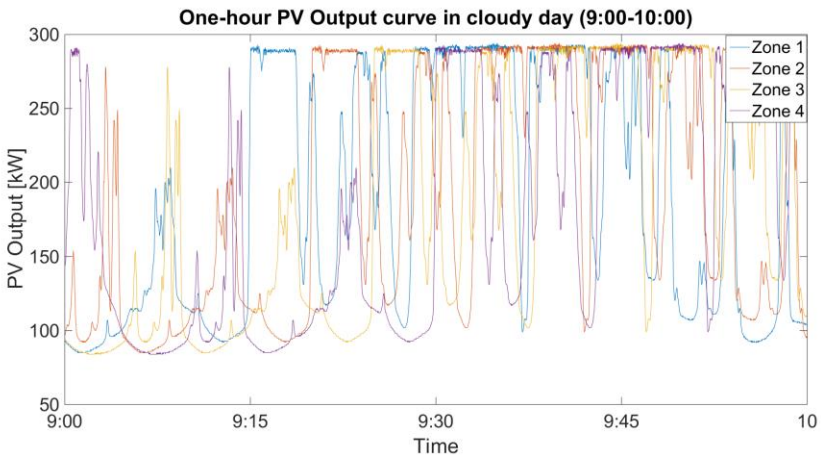

Figure 2-7 PV curve in cloudy day with considering time delay

Chapter 3 Simulation Results

Based on these guidelines, we developed some case studies for investigating the PV impact on distribution feeder. This chapter presents the simulations we had done. The objective is to discover the feeder performance in different types of days, when PV is installed at diverse zones, in different seasons and various PV penetration applied. The comparison and analysis of simulation results will also be shown in this chapter.

3.1 Base Case

For the base case simulation, no PV is added at any nodes. As this feeder does not contain any capacitor or voltage regulators either, we can say that it is a clean circuit. It is consisted of a source which represents the substation, transmission lines, cables and loads. In this case, the main goal is to investigate the voltage-related information when no actions are done on this feeder. By knowing the simulation results of base case, we can assign how the circuit is influenced after different actions are done on it.

As we mentioned above, the voltage at the substation is set to be 1.033 pu constantly. Hence, the voltage for loads which are near to substation will not decrease much. On the other hand, from Table 2-2 it can be observed that the total load at zone 1 is not very large, which means comparing to other zones, the voltage variation of zone 1 will not be influenced that much after actions are implemented to the feeder. Under this situation, what we care more about are the nodes far away from the substation, especially for the nodes at feeder end. This conclusion will be demonstrated in the following part of this thesis. And for this part, we will focus on the voltage of bus at feeder end, which represents the worst condition in the whole feeder.

3.1.1 Voltage Fluctuation

Figure 3-1 shows the daily voltage fluctuation profile of Bus 24 phase A in winter. This node locates at the very end of this feeder. As there are no voltage regulation devices installed, the voltage at the feeder end is pretty low, even comes to about 0.78 pu for its lowest value. For this base case, we do not need to worry about this extremely low voltage because we are only trying to get a base line for voltage profiles and compare them with the cases that PV is installed. This low voltage issue can be solved after voltage regulators are added and we do not have to care about it at this part.

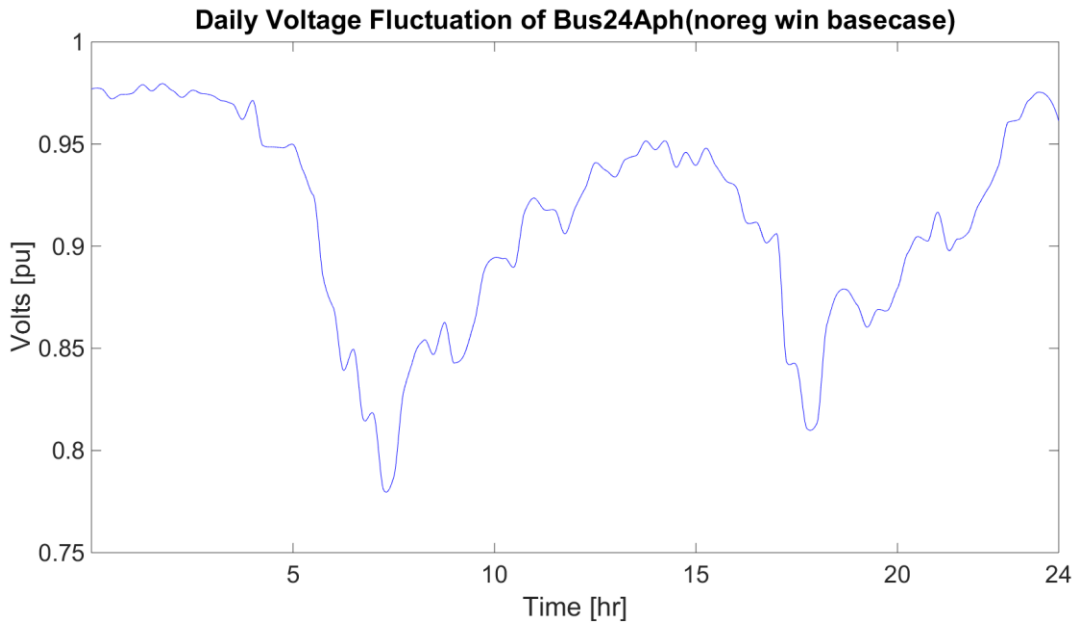

Figure 3-1 Daily voltage fluctuation of Bus24Aph in winter for base case

From the waveform we see that during peak load time the voltage at this node achieves its minimum value. It is because of when the load at a node is heavy, the substation needs to provide a large current to supply that much of load. Since the current is large, the voltage drop on the transmission lines and cables is very big, so the minimum voltage value happens at the peak load time.

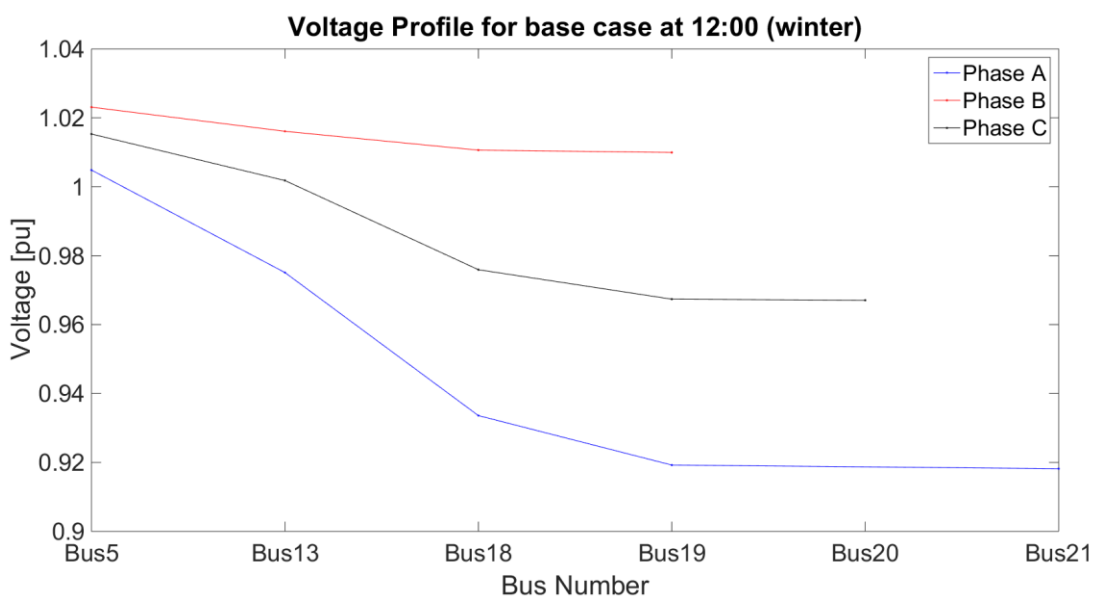

Figure 3-2 Voltage profile along the feeder at 12:00 pm in winter for base case

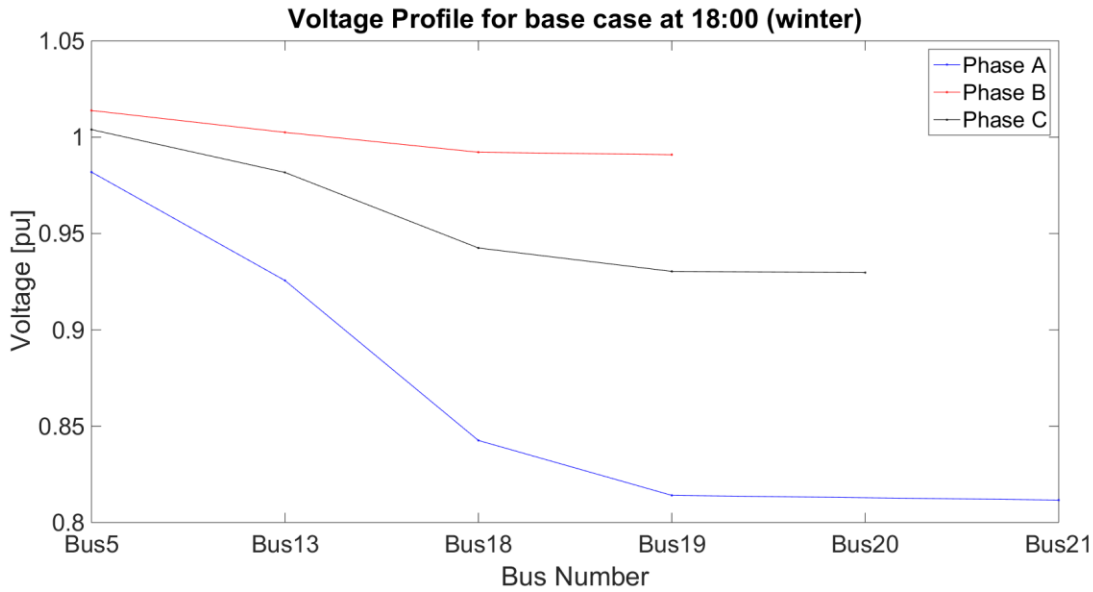

Figure 3-3 Voltage profile along the feeder at 6:00 pm in winter for base case

Figure 3-2 shows the voltage profile along the entire feeder at noon, when substation load is at minimum value during daytime in winter. Figure 3-3 shows the voltage profile along the feeder at 6:00 pm, which is the time substation has one peak load in winter. By comparing these two load profiles, we can find the result demonstrates the conclusion that voltage during peak load time at each bus is smaller than that during light load time.

These figures also show us that the voltage drop from bus 5 to bus 19 is pretty large. And the voltage drop from bus 19 to bus 21, which is an end of feeder, becomes small. There are two reasons to explain this phenomenon. The first reason is as we mentioned in the zonal study part, the total load at zone 4 is smaller than zone 2 and zone3 (see Table 2-3 and Table 2-5), therefore, the current on the transmission line after bus 15 will be much smaller and the voltage drop in zone 4 is smaller than other zones. The second reason is that the length of transmission lines after bus 19 are short. Although the transmission lines before bus 19 are around two miles, however, all the lines and cables after bus 19 are less than 1 mile. This results in the resistance on these lines and cables are small and helps to reduce the voltage drop value. With the combined action of these two reasons, we can observe an obvious voltage drop between bus 5 and bus 19, and a slight voltage drop between bus 19 and bus 21.

3.1.2 Voltage Flicker

Another important power quality issue we care about is voltage flicker. Voltage flicker is a visible change in brightness of a lamp due to rapid fluctuations in the voltage of the power supply. The effects can range from disturbance to epileptic attacks of photosensitive persons. Flicker may also affect sensitive electronic equipment such as television receivers or industrial processes relying on constant electrical power [22]. Hence, the number of voltage flickers determines whether customers are satisfied with the service of utility.

In this study, voltage flickers are monitored in two ways. The first way is to use the flicker meter, which is defined by IEEE recommended practice: International Electrotechnical Commission (IEC) 61000-4-15. In this file, short-term flicker severity, P_{st}, is defined to evaluate the voltage flicker condition [20] [23]. Voltage profile is the input of this meter. After a series of process, it is converted into instantaneous flicker sensation. P_{st} is calculated by performing a statistical classification of instantaneous flicker sensation over a short period of time [24]. The common used P_{st} evaluation time is 10 min, and its values are recorded by the flicker monitor. The P_{st} value will be larger when voltage flickers happen more frequently. In OpenDSS, there is a voltage flicker monitor function. So we can use this monitor to get the P_{st} values at each bus and compare them among different cases.

The second way to see the voltage flicker condition is to calculate the 30-second voltage ramp for a whole day. Then we can use the histogram to count the distribution of voltage ramp values. If the voltage flicker situation is serious, there will be more points distribute in larger voltage ramp value area. We can compare the different distribution shapes to know which case has more chance to suffer voltage flicker condition.

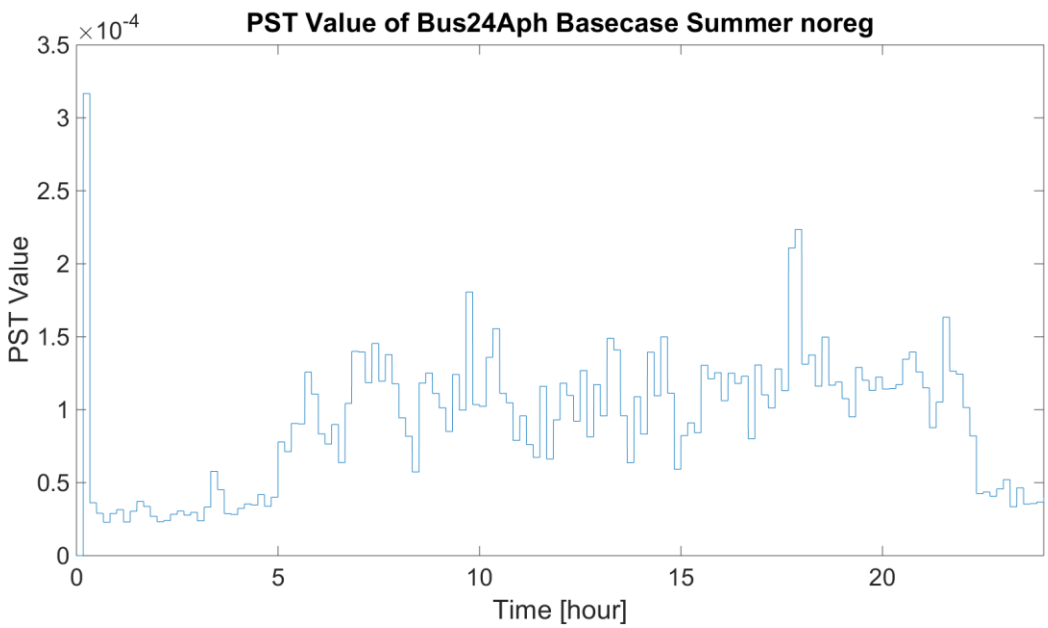

Figure 3-4 Daily P_{st} value of Bus24Aph in summer for base case

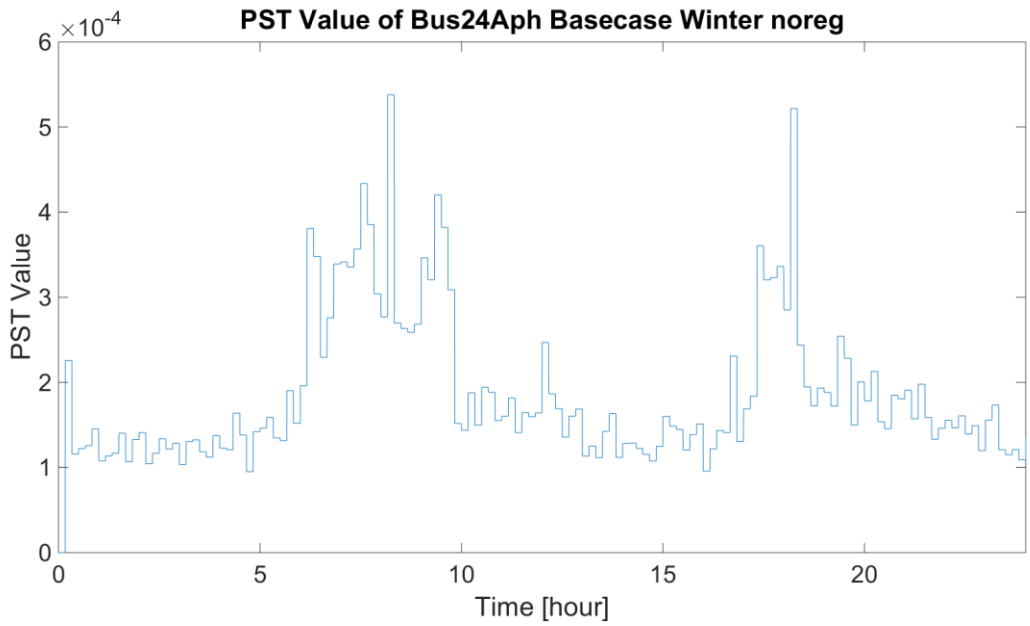

Figure 3-5 Daily P_{st} value of Bus24Aph in winter for base case

Figure 3-4 shows the daily P_{st} value for bus 24 phase A in summer, and Figure 3-5 shows the P_{st} value for this node in winter. From these figures we can see both of them are really small. The reason is in base case there is no tremendous load change. When we look at the shape of this daily P_{st} value fluctuation, it is observed that peak load may lead to a comparatively higher P_{st} value. It can be explained by the fact that higher load level means there is a higher chance for people to change electrical devices' status. The P_{st} values in winter are also larger than that in summer because of the higher load level in winter. In general, these P_{st} values show that voltage flickers will not happen in base case.

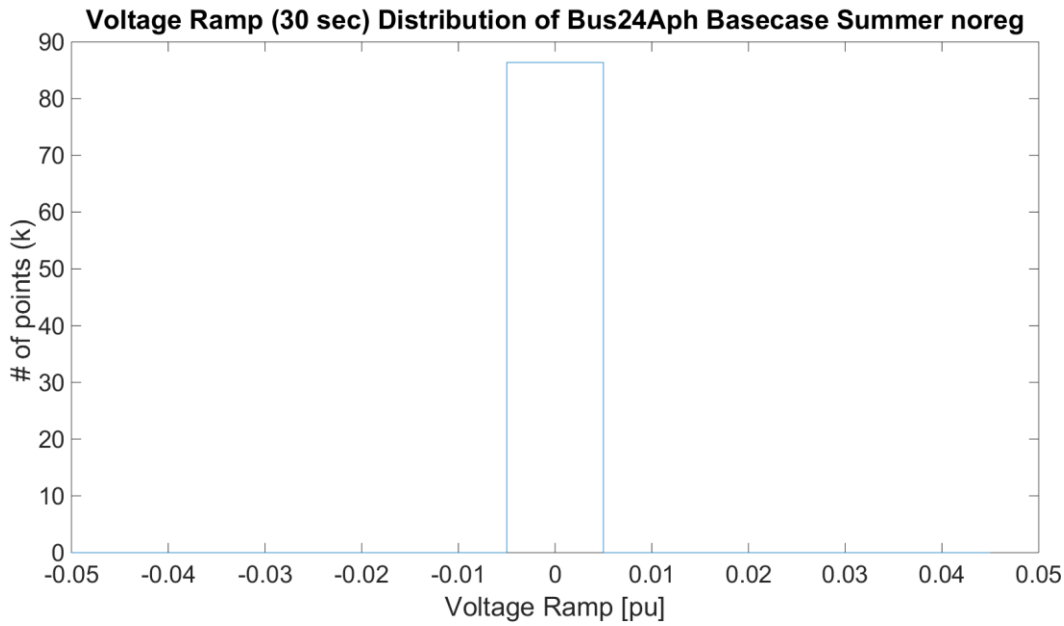

Figure 3-6 Voltage ramp (30-second) distribution of Bus24Aph in summer for base case

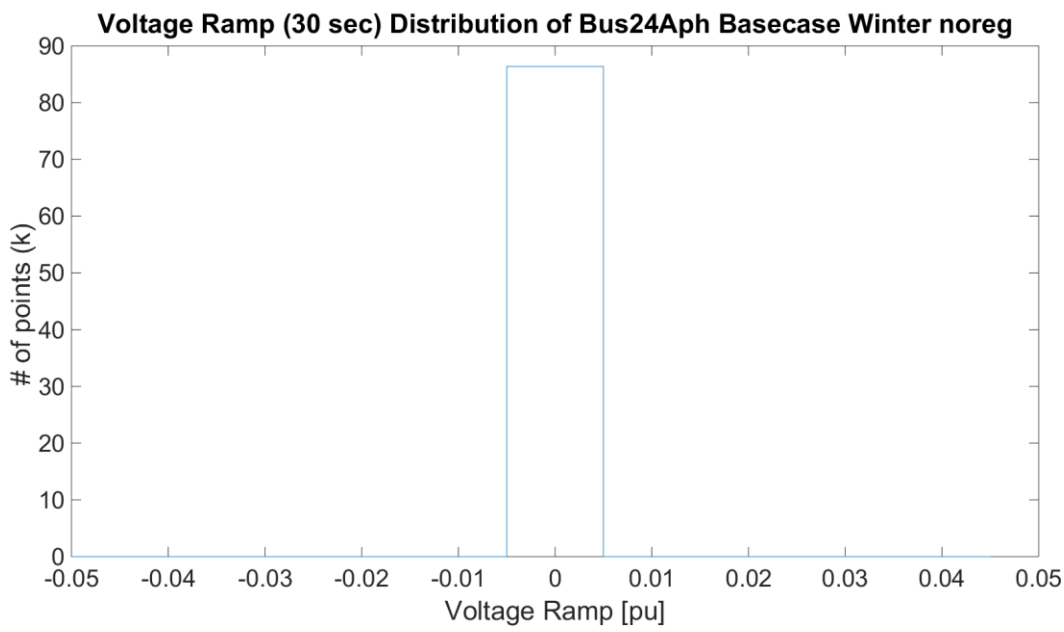

Figure 3-7 Voltage ramp (30-second) distribution of Bus24Aph in winter for base case

Figure 3-6 and Figure 3-7 respectively show the distribution of 30-second voltage ramp. Similar to the daily P_{st} value, we can find that all the values are concentrated around zero. It also proves that the base case will not suffer voltage flicker problem.

3.2 Season Study Case

In this part, we will focus on finding the impact after PV is added at residential houses in different seasons. A summer case and a winter case are simulated. The daily load fluctuation at the substation for these two seasons are shown in Figure 2-4 and Figure 2-5. The winter case has a much higher load than summer. A sunny day PV power output is used in this simulation when PV is installed at all the nodes in the feeder. Note that the PV capacity is set as a certain percentage of the maximum total load. We define the percentage as the PV penetration level. We will compare daily voltage profile and voltage ramp changes at different PV penetration levels for these two seasons.

3.2.1 Voltage Fluctuation

Figure 3-8 shows the daily voltage fluctuation in summer and Figure 3-9 shows the daily voltage fluctuation in winter. The following observations are made:

- After PV is added, the voltage of a load node will increase. This is because when the load is supplied by solar power, the current on the feeder from the substation to the load will be reduced, which leads to a smaller line voltage drop.
- The further the load node is away from the substation, the larger the voltage rise is. This is because the voltage increase at the end node equals to the sum of the voltage increase at each upstream load node. Table 3-1 shows the maximum voltage rise at each node in different conditions.
- The voltage rise after PV is installed are more significant in winter. On a hot summer day, the load peaks at noon which coincide the PV generation peak so the installation of PV at load nodes will not be very significant. But in winter, the peak load happened in morning and early evening, therefore the load is low when PV output is high. As a result, the voltage rise significantly.
- By comparing the voltage waveform among no PV case, 50% penetration PV case and 100% penetration PV case, we can see that when 50% PV is added, the voltage profile looks the best. When there is no PV in the feeder, there is a low voltage problem during daytime. And when the penetration level comes to 100%, there is a high voltage problem.

The above results show that the voltage problem caused by PV is very sensitive to the system loading patterns, the PV installed capacity, and the location of the point of common coupling (PCC).

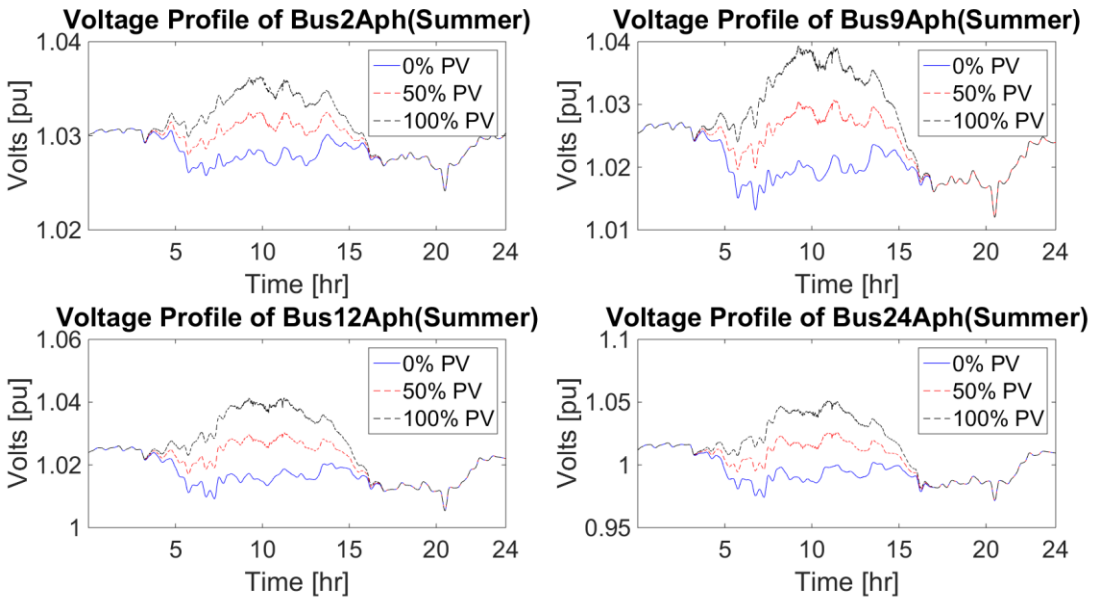

Figure 3-8 Daily voltage profile for nodes in sunny day in summer

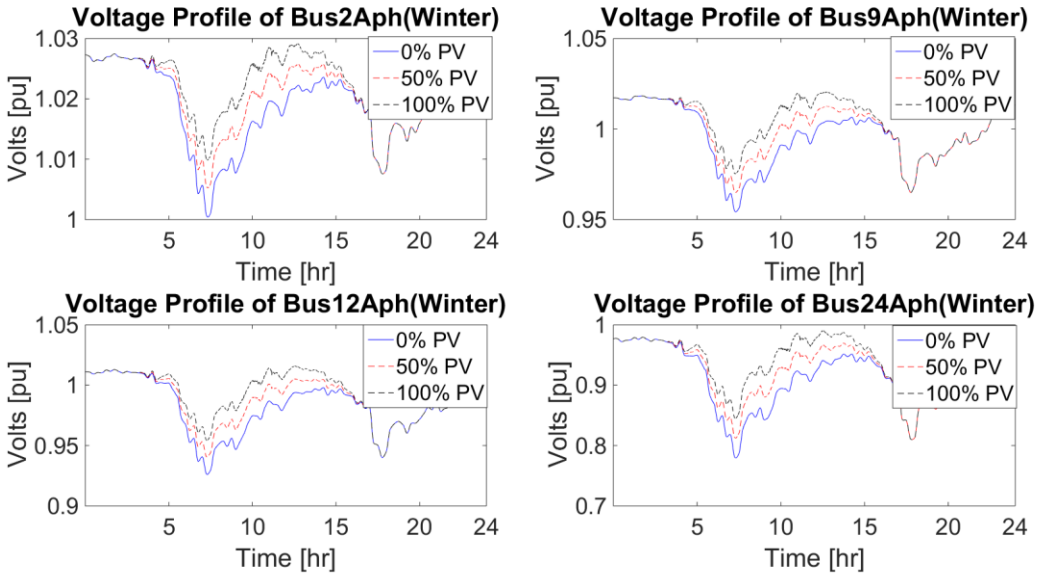

Figure 3-9 Daily voltage profile for nodes in sunny day in winter

Table 3-1 Maximum voltage rise for season case study

	Distance (mile)	Summer max voltage rise (pu)		Winter max voltage rise (pu)	
		50% Penetration	100% Penetration	50% Penetration	100% Penetration
Bus2 Aph	2.91	0.0042	0.0081	0.0056	0.0108
Bus9 Aph	4.6	0.0099	0.0192	0.0126	0.0244
Bus12 Aph	4.61	0.0130	0.0253	0.0169	0.0328
Bus24 Aph	12.9	0.0292	0.0566	0.0388	0.0756

3.2.2 Unbalances among 3-phase Loads

Figure 3-10 and Figure 3-11 respectively show the voltage profile along the entire feeder at noon in summer and winter, when PV power output reaches its maximum value. As we mentioned above that the voltage drop will decrease after PV is installed, the voltages are flatter than when PV is not installed. However, there is a voltage increase after bus 13 for the phase B voltage profile in winter. Three phase net load unbalance may lead to this voltage rise problem. Three phase PV systems could improve this unbalance problem, especially when the PV power output comes to a certain level.

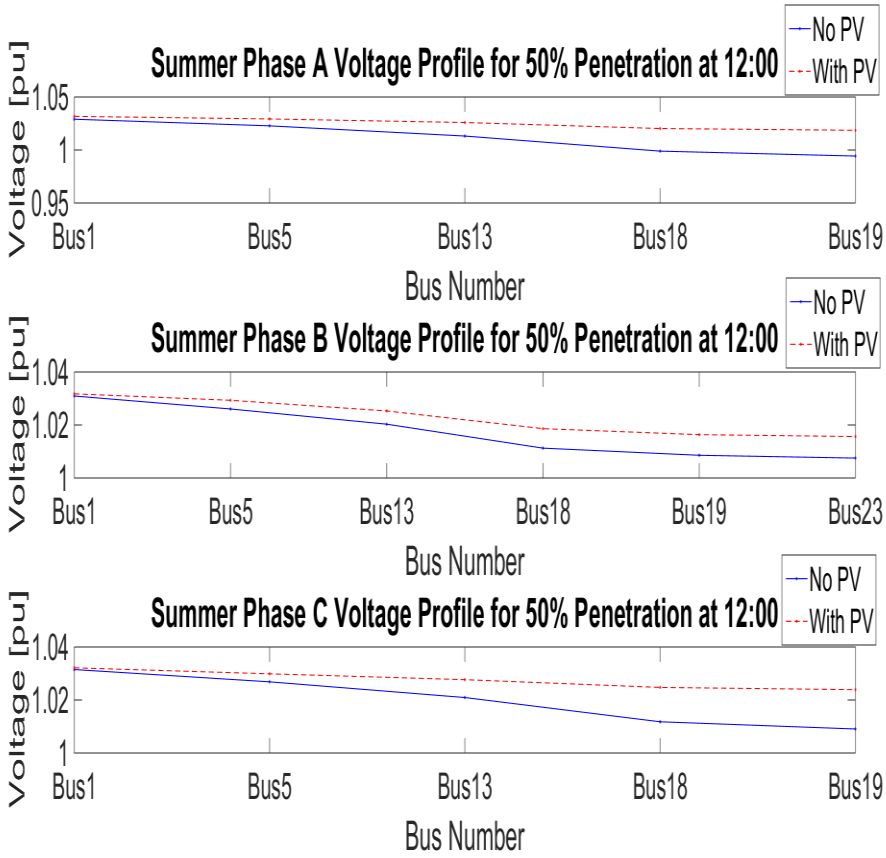

Figure 3-10 Voltage profile along the feeder at 12:00 pm in summer for season case

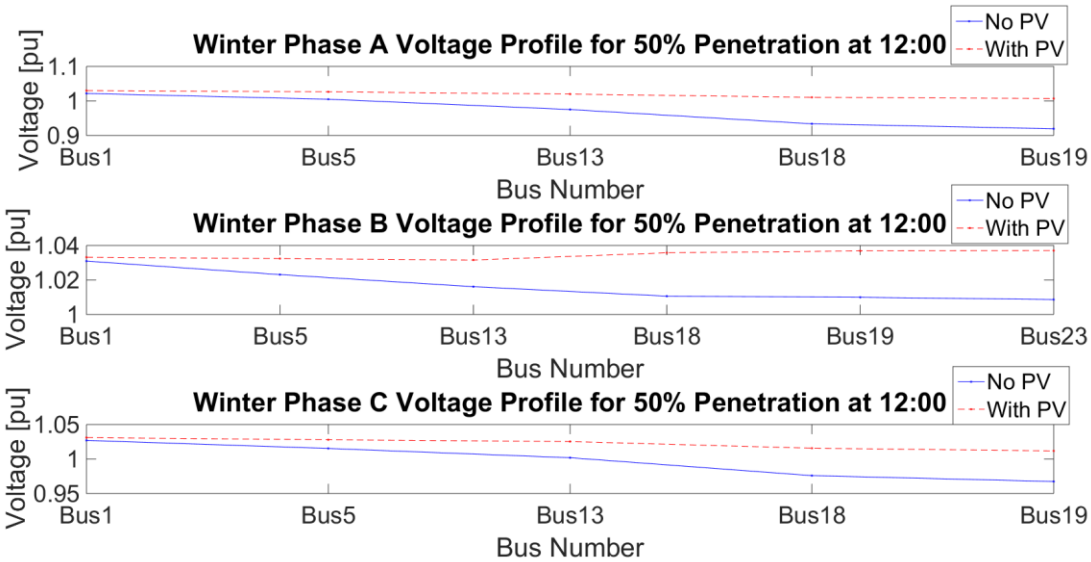

Figure 3-11 Voltage profile along the feeder at 12:00 pm in winter for season case

3.2.3 Voltage Flicker

Figure 3-12 and Figure 3-13 show the flicker severity factor, P_{st}, for bus 24 phase A in summer and winter. The following observations are made:

- P_{st} will increase when PV penetration increases. The value of P_{st} is larger in winter than in summer.
- In a sunny day, PV power does not vary much. Thus, most of these values of P_{st} are smaller than 0.1, which means that voltage flicker is not likely to occur regardless it is in winter or summer.

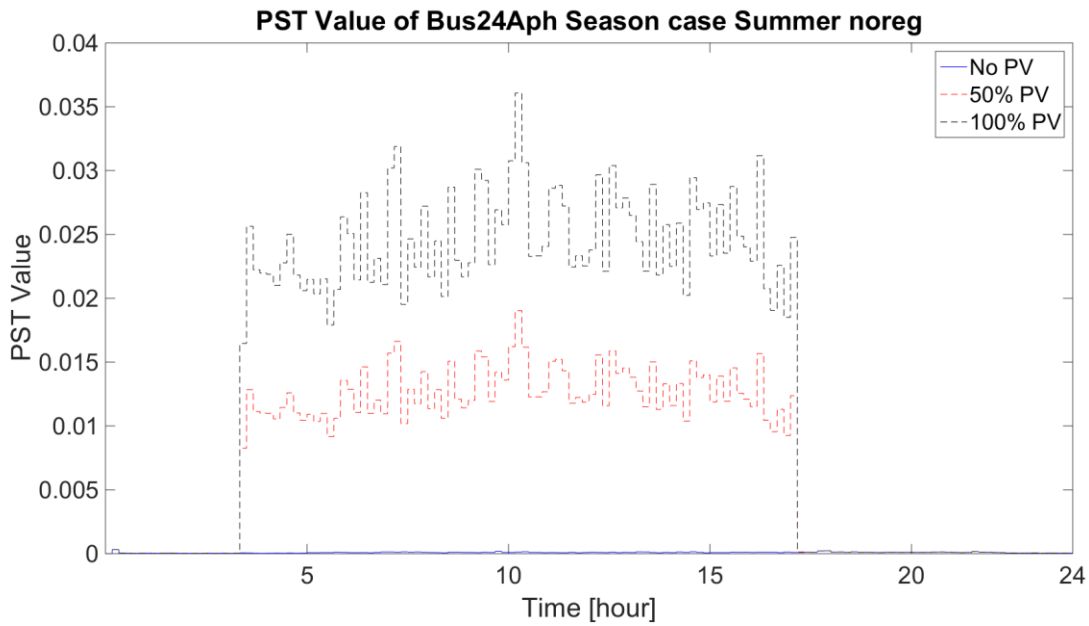

Figure 3-12 Daily P_{st} value of Bus24Aph in summer for season case

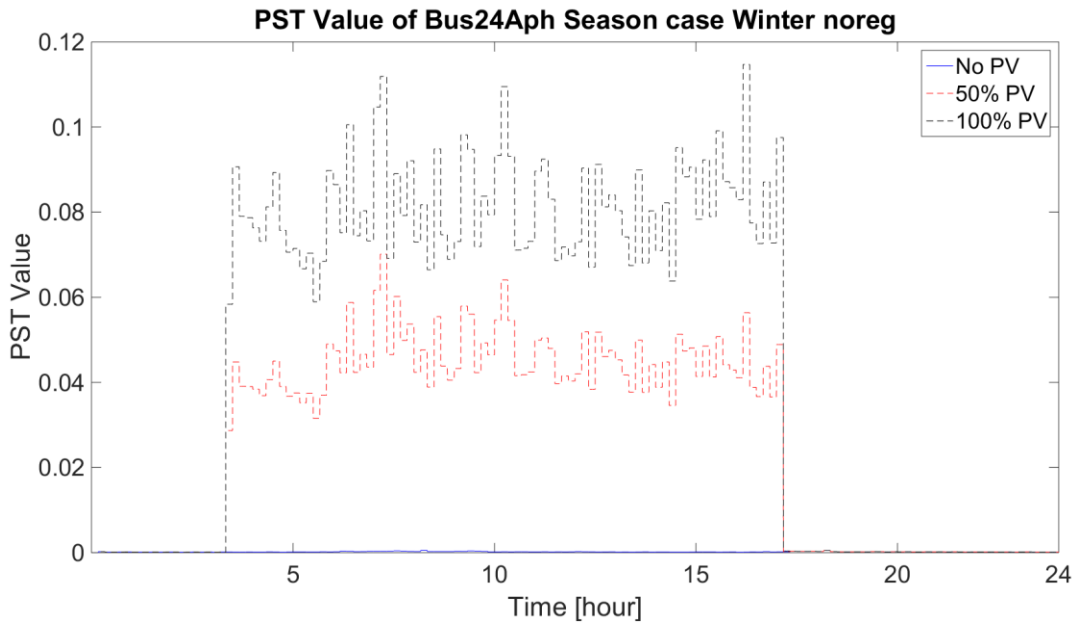

Figure 3-13 Daily P_{st} value of Bus24Aph in winter for season case

Figure 3-14 and Figure 3-15 show the distribution of 30-second interval voltage ramp. In order to look at is more clearly, **all the points centralized around zero are excluded**. Nevertheless, as it is a sunny day, all the voltage ramps still concentrate on very small values. Two nodes are picked up for each season, bus 2 locates at the beginning of feeder and bus 24 locates at the end of feeder. We can see that the voltage ramp for bus 24 distributes more widely than bus 2. So it shows us when PV is added, voltage variation of the feeder end will be influenced more seriously than feeder head. When we observe the same bus for different seasons, it is shown that winter voltage ramp is larger than that in summer. It means that comparing to summer, voltage flickers are more likely to occur on winter. The reason is the same as why P_{st} values are larger in winter. Higher PV penetration also results in a bigger voltage ramp.

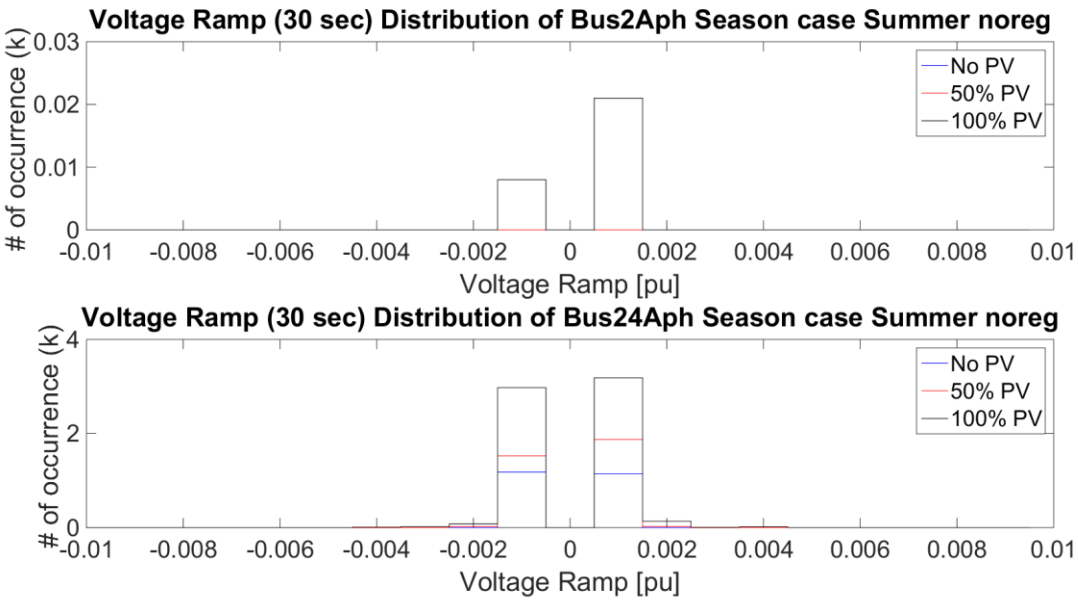

Figure 3-14 Voltage ramp (30-second) distribution of nodes in summer for season case

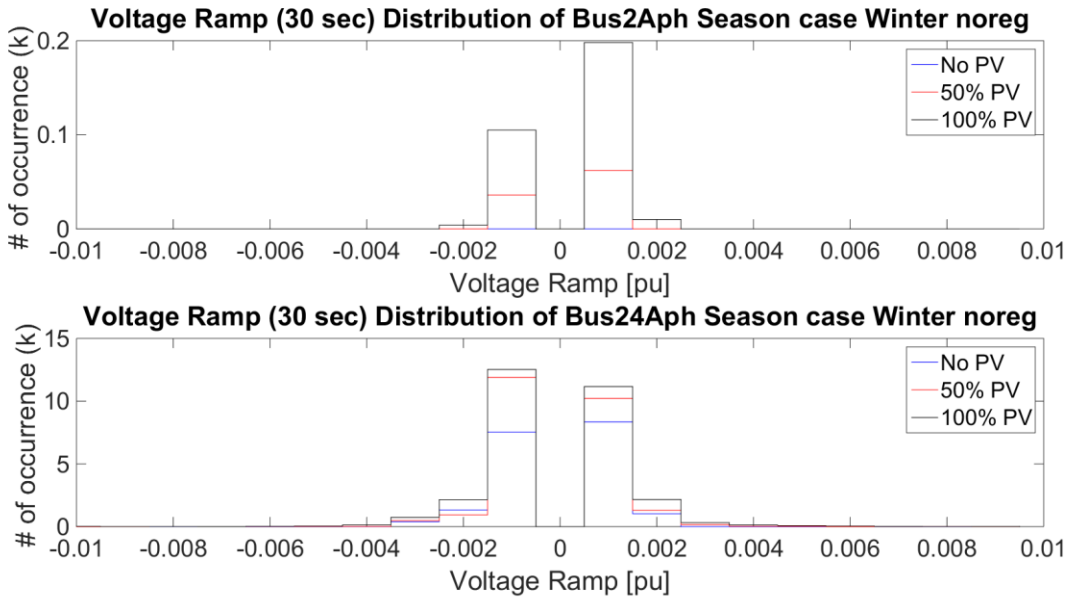

Figure 3-15 Voltage ramp (30-second) distribution of nodes in winter for season case

3.3 Weather day study case

In this part, the main goal is to investigate the different impact of PV between sunny day and cloudy day. The winter case is used to do the simulation with a sunny solar profile and a cloudy solar profile. The PV output profile is shown in Figure 1-5. PV is installed at all the nodes in the feeder. Each house is considered to have a 10 kW PV capacity. As we mentioned in the simulation set up part (Table 2-5), there are 1532 houses in the whole feeder, which means that

the peak PV power output is 4930 kW. The winter peak load for the feeder is 15300 kW (Table 1-1). Hence, this case represents 32% PV penetration. In cloudy day, if a cloud sweeps over this distribution feeder within a short period of time, the PV output variation is much larger than that in sunny day (Figure 3-16). On the other hand, these four zones are miles away from each other, the same solar irradiation cannot be gotten by all the zones at the same time. In order to make the simulation more realistic, we set a time delay among these zones as we mentioned in 2.1. The voltage profile and voltage flicker condition are compared between these two types of days.

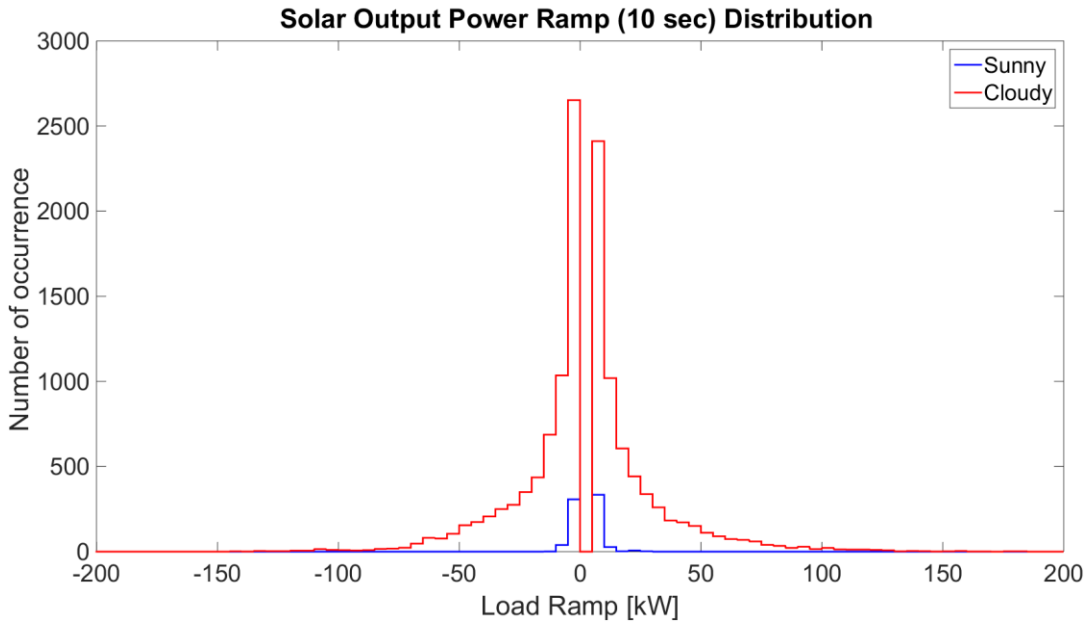

Figure 3-16 Solar output power ramp comparison between sunny day and cloudy day

3.3.1 Voltage Fluctuation

Figure 3-17 and Figure 3-18 show the voltage profile in sunny day and cloudy day. The following observations are made:

- In a sunny day, the voltage profile during day time is still very smooth. In a cloudy day the voltage varies a lot at the time cloud passing by. However, the day is sunny or cloudy will not influence the maximum voltage rise when the penetration percentage is the same, as shown in Table 3-2.
- Similar to the previous case, the farther the nodes are, the more seriously the voltage there is influenced.

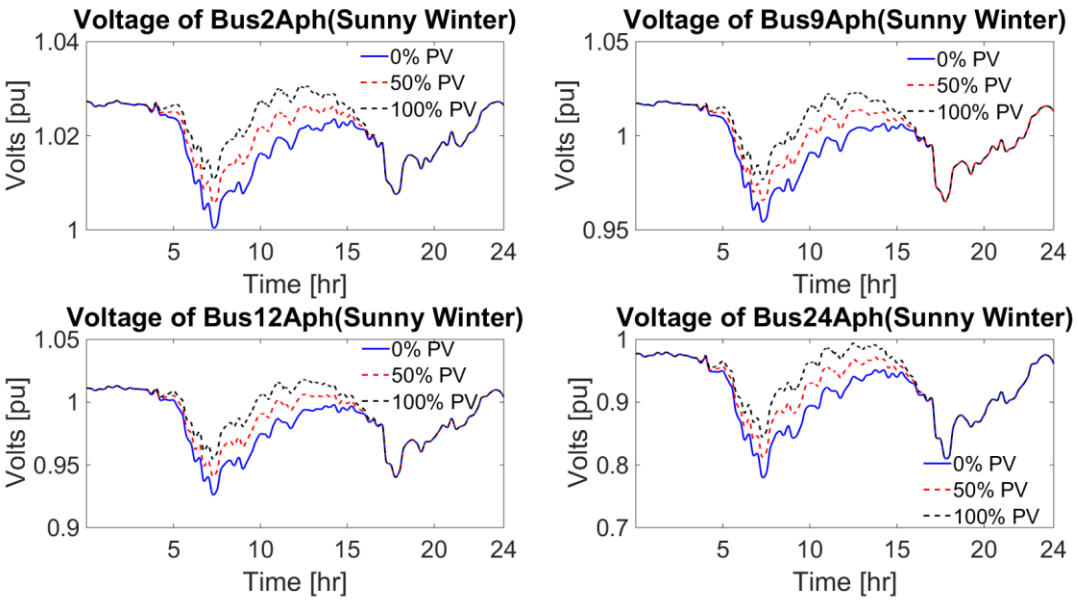

Figure 3-17 Daily voltage profile for nodes in sunny day in winter for weather case

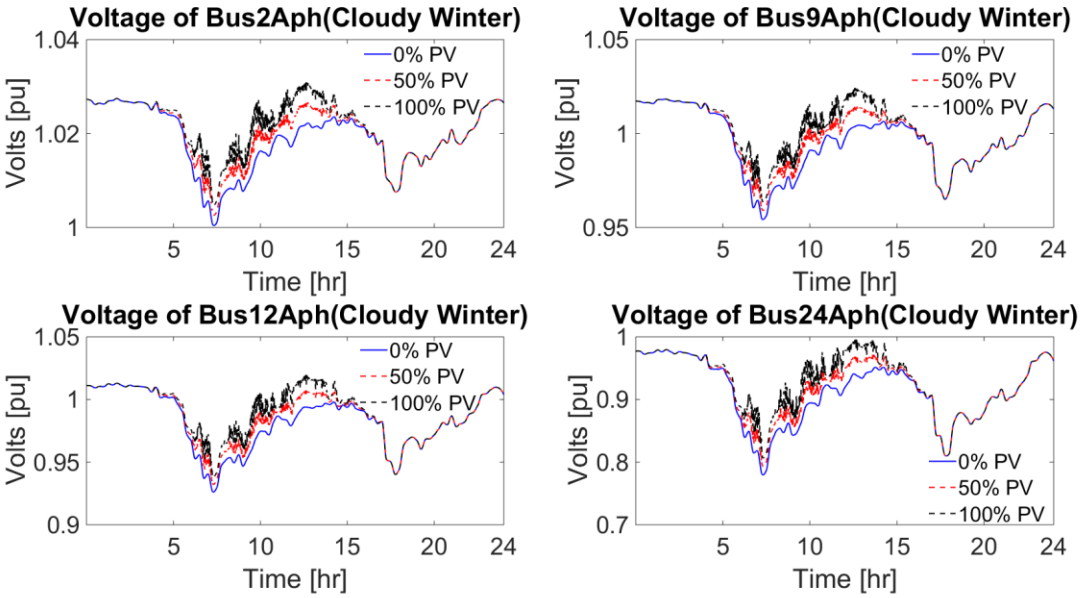

Figure 3-18 Daily voltage profile for nodes in cloudy day in winter for weather case

Table 3-2 Maximum voltage rise for weather case study

	Distance (mile)	Sunny day max voltage rise (pu)		Cloudy day max voltage rise (pu)	
		50% Penetration	100% Penetration	50% Penetration	100% Penetration
Bus2 Aph	2.91	0.0063	0.0123	0.0062	0.0120
Bus9 Aph	4.6	0.0139	0.0270	0.0137	0.0265
Bus12 Aph	4.61	0.0177	0.0344	0.0174	0.0335
Bus24 Aph	12.9	0.0399	0.0776	0.0394	0.0752

Figure 3-19 and Figure 3-20 show the voltage profile along the whole feeder at 12:00 pm in sunny day and cloudy day. Since cloud passing by is a dynamic process, it will not influence the voltage drop trend for one snap shot. So there is no much differences between these two figures.

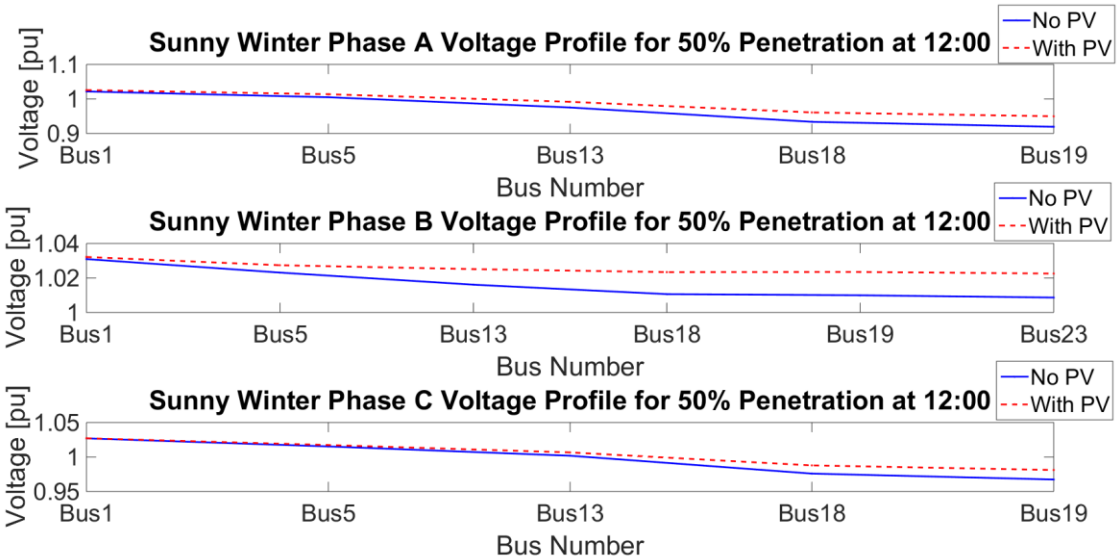

Figure 3-19 Voltage profile along the feeder at 12:00 pm in sunny day for weather case

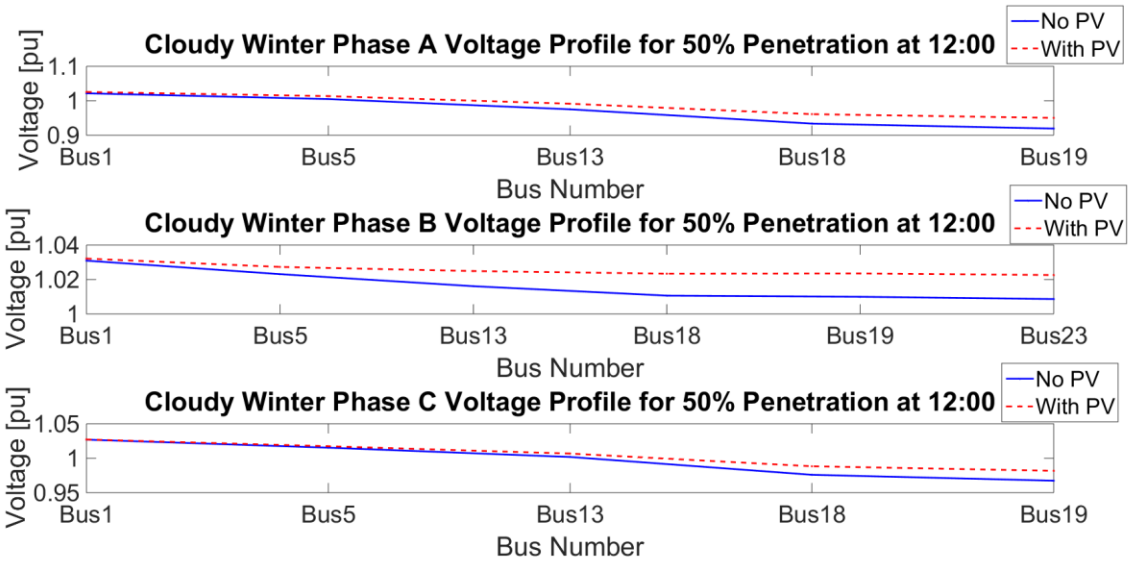

Figure 3-20 Voltage profile along the feeder at 12:00 pm in cloudy day for weather case

3.3.2 Voltage flicker

Figure 3-21 shows the daily P_{st} value fluctuation for Bus 24 phase A. In this case, the P_{st} values in sunny day and cloudy day are almost the same when there is no many clouds passing by. Nevertheless, when clouds start to pass by more frequently from 8:00 am to 1:00 pm, P_{st} values in cloudy day will increase dramatically, which is almost the twice of that in sunny day. A higher PV penetration percentage will also cause larger P_{st} values. Thus, from the view of P_{st} value, voltage flickers are more likely to appear in cloudy days at nodes with high percentage PV installed.

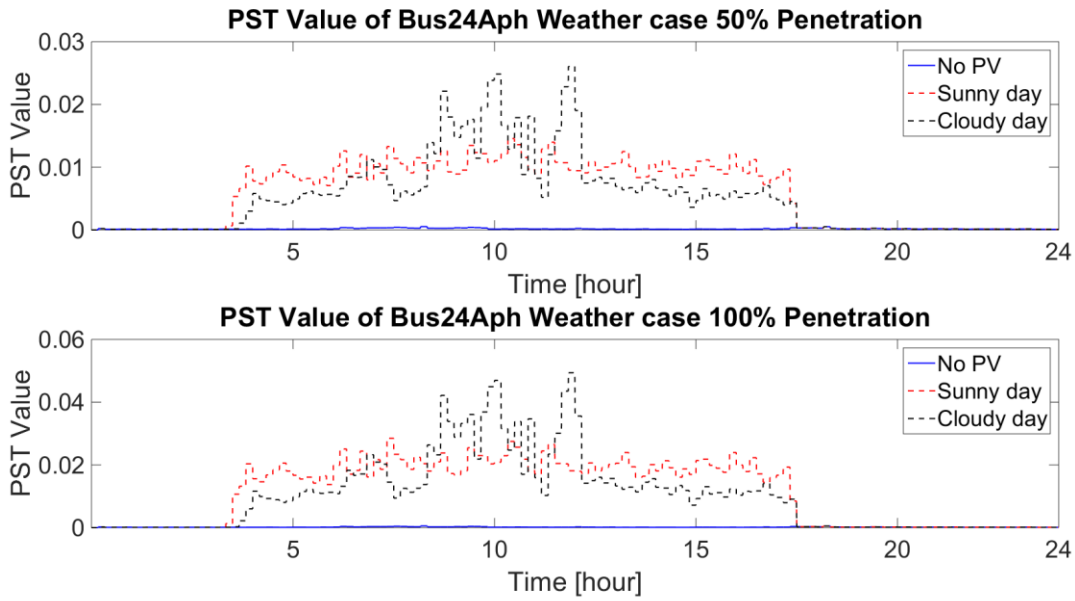

Figure 3-21 Daily P_{st} value of Bus24Aph in winter for weather case

Figure 3-22 shows the 30-second voltage ramp distribution for bus 2 and bus 24. It is obviously shown that in a cloudy day the voltage ramp will distribute more widely, which means the voltage ramp in cloudy day is larger. For no PV case and sunny day case, there is no voltage ramp larger than 0.003 pu at bus 24. However, in cloudy day the largest voltage ramp can come to as much as 0.018 pu, which is easily to cause voltage flickers appear. Then by comparing the distribution result between bus 2 and bus 24, it proves again nodes at feeder end will be influenced more after PV is installed. Therefore, from the view of voltage ramp, voltage flickers are easier to appear in a cloudy day at the nodes locate at feeder end.

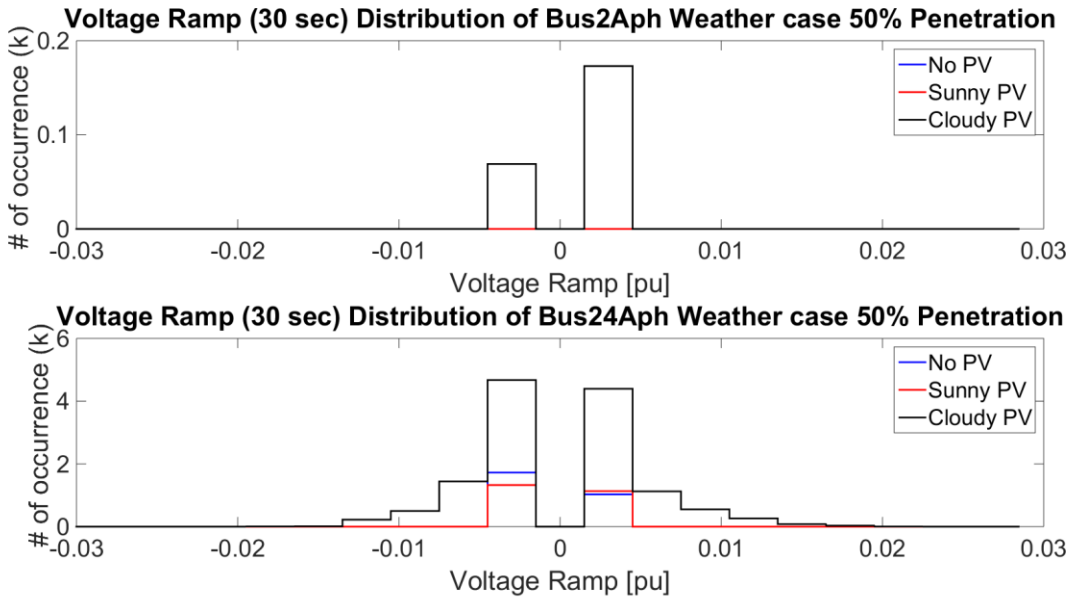

Figure 3-22 Voltage ramp (30-second) distribution of nodes in winter for weather case

3.4 Voltage flicker study

From the above simulation cases, it has shown that node at feeder end has the highest chance to suffer voltage flicker problem. This part will talk about for the feeder end nodes, what factors will influence the chance of occurring voltage flickers and how the voltage profile performs when these factors change.

As we mentioned above, the voltage flicker is caused by a big voltage variation in a short period of time. So it is essential to know what parameters in the feeder leads to voltage variation. If we look into the feeder from the end node, the equivalent circuit can be expressed by Figure 3-23 shows. The voltage variation ΔV for node at feeder end can be calculated by

$$\Delta V = R * \Delta I \tag{3-1}$$

Where R represents the equivalent resistance from substation to the feeder end and ΔI is the current variation at that node.

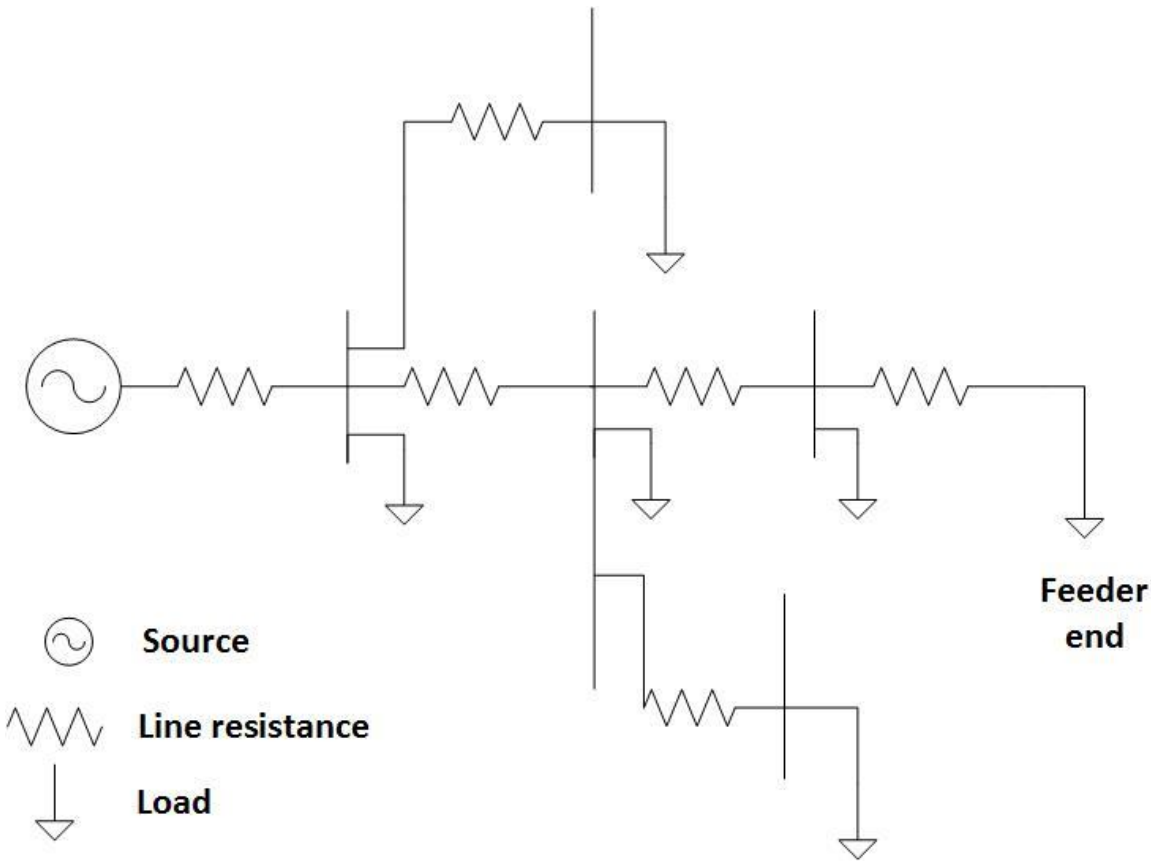

Figure 3-23 Equivalent circuit for distribution feeder

In general, the current variation is determined by the net load change during that period time, and the equivalent resistance is determined by the length and impedance of each transmission line. Two simulation cases are set respectively to find how these two parameters impact the voltage variation, or voltage flickers. The P_{st} value and 10-second voltage variation are be used to judge the condition of voltage flickers in this part.

3.4.1 Current variation

At the feeder end of a distribution system, current variation will not be impacted much by the customer load change of nodes between source and the end node when there is no PV. It is mainly influenced by the load variation at this feeder end node. This is because during a certain period of time, the possibility of the load variation for each node is a normal distribution as Figure 3-24 shows, therefore, the expected value for the total load variation before the end node is zero. It results in the expected current variation is zero as well. However, after PV is added into the feeder, the end node current variation begins to have a relationship with net load change at other nodes. As we know, nodes in a same zone shares the same solar irradiation pattern. In sunny day it does not matter much because the PV output power is pretty stable. Nevertheless, in a cloudy day, when the PV output power increases or decreases quickly during a period of time, all the nodes at the same zone will have the same variation tendency. It causes

a net load variation at all these nodes, along with a current variation along the feeder and voltage variation of the node at feeder end. Under this condition, this case will focus on comparing the voltage variation with different percentage PV penetrations in a cloudy day, which the current variation could be larger than sunny day.

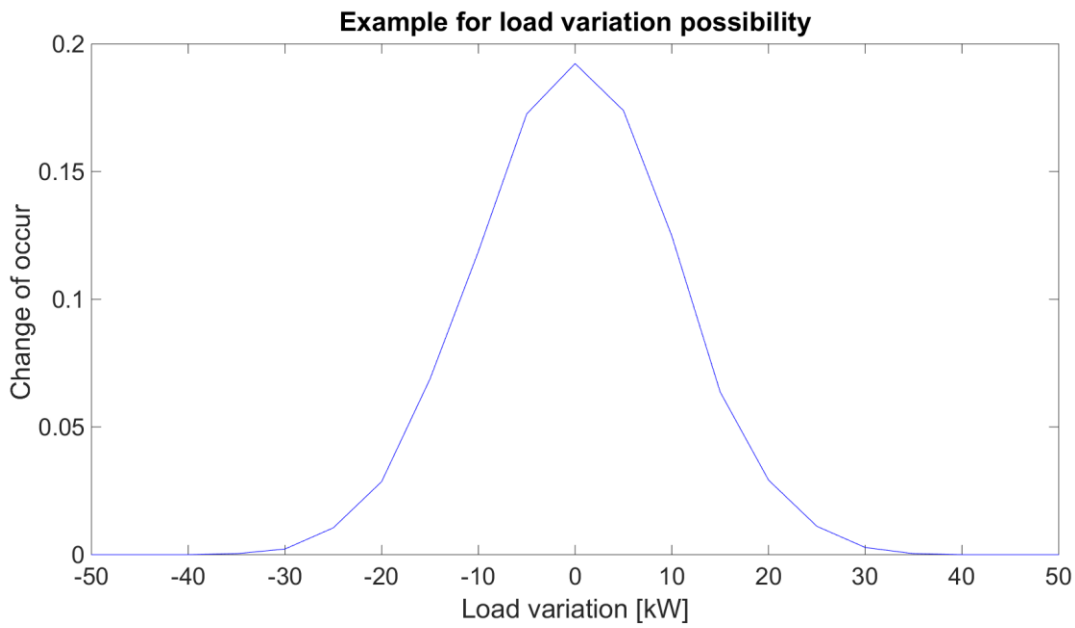

Figure 3-24 Example for load variation possibility

In this simulation, the parameter of transmission lines are set to be constant value. Summer load profiles are considered as light load case, and winter load profiles represent heavy load case. The same PV profiles are added into these two cases. 5 kW PV capacity is installed at each house. As Table 2-5 shows, there are 1532 houses in the whole feeder, which means that 7660kW PV is added. In order to have more comparison, the situation for 2.5 kW PV per house (3830 kW in total) and 7.5 kW PV per house (11490 KW in total) are also simulated.

Figure 3-25 shows the daily P_{st} value for bus 24 phase A with different PV penetration percentage in a sunny summer, a sunny winter, a cloudy summer and a cloudy winter. From this figure it is shown that in sunny day, P_{st} values are more stable during daytime. And in cloudy day, P_{st} values will become extremely higher when clouds passing by. The values keep very small when no PV is added, which proves that the change of customer load will not impact it much.

Table 3-3 shows the maximum P_{st} value during a day of different conditions. The maximum values are nearly zero when there is no PV. When the feeder shares the same solar irradiation profile and the same PV penetration percentage, the maximum P_{st} value and daily pattern are

almost the same no matter it is light load or heavy load case. With the penetration percentage increases, the maximum value of P_{st} will increase with the same multiple growth.

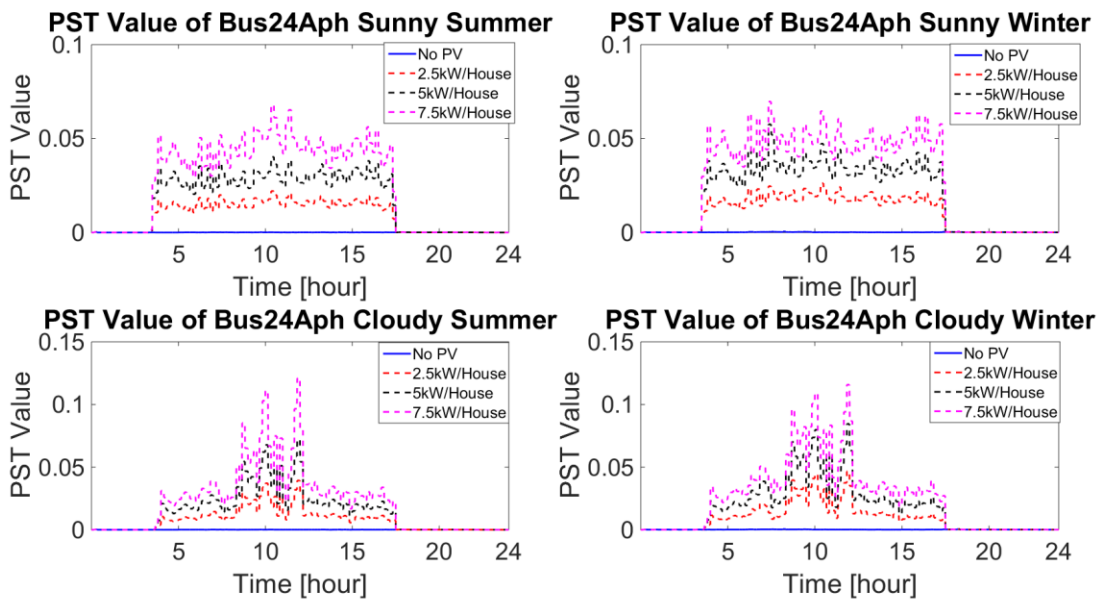

Figure 3-25 Daily P_{st} value of Bus24Aph in winter for flicker study (current variation)

Table 3-3 Maximum P_{st} value for flicker study (current variation)

		Daily Maximum P_{st} value			
		No PV	**2.5kW/house**	**5kW/house**	**7.5kW/house**
Sunny	**Summer**	0.00032	0.022	0.040	0.068
	Winter	0.00054	0.026	0.058	0.069
Cloudy	**Summer**	0.00032	0.039	0.072	0.121
	Winter	0.00054	0.047	0.085	0.116

Figure 3-26 shows the 10-second voltage ramp distribution of bus 24 phase A for different cases. In order to make the figure more intuitive, all the voltage ramp values distributed around zero are eliminated as they will not cause problems. From the distribution histogram it is shown that in sunny day the voltage ramp is pretty small, and in cloudy day the values distribute more widely. Similar to the P_{st} value, light load or heavy load does not impact the voltage ramp distribution. It further proves that customer load change will not have a big impact on leading to voltage flickers.

Table 3-4 shows the maximum voltage ramp for each case. In sunny day with PV installed on customers' rooftop, the biggest voltage ramp is not much large than no PV case, but in cloudy day the increase is obviously. Although in winter it will a little larger than that in summer for

the same penetration level and the same solar irradiation pattern, the difference is very small, almost can be ignored. And the maximum voltage ramp value increases with the same multiple growth of the increase of PV penetration percentage.

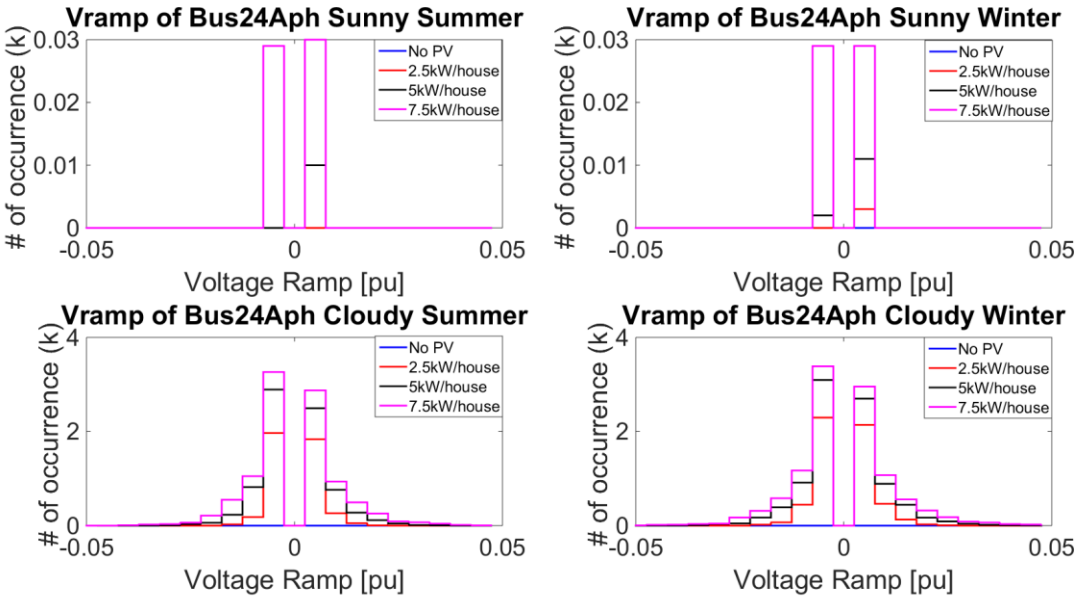

Figure 3-26 Voltage ramp (10-second) distribution of Bus24Aph for flicker study (current variation)

Table 3-4 Maximum voltage ramp value for flicker study (current variation)

		Daily Maximum Voltage Ramp (10 second, absolute value)			
		No PV	**2.5kW/house**	**5kW/house**	**7.5kW/house**
Sunny	**Summer**	0.0003	0.0023	0.0042	0.0069
	Winter	0.0010	0.0027	0.0049	0.0067
Cloudy	**Summer**	0.0003	0.0200	0.0372	0.0559
	Winter	0.0010	0.0252	0.0439	0.0603

From the observations above, customer load change will not impact voltage flicker appearance. Even after PV is added, it still does not impact a lot in sunny day. Only when there are many clouds passing by the voltage flickers will have a higher chance to appear. The higher PV penetration percentage is, the larger P_{st} values and voltage ramps are. Although the possibility of voltage flicker appearing in peak load condition is larger than in light load condition, the difference is not very big.

3.4.2 Feeder resistance

The impedance of the whole feeder is consist of two parts, the first is the impedance of transmission lines and the second is the impedance from the load. Nevertheless, in our simulation the load profile for each node is already fixed, and all the nodes with load are set to be PQ bus. Therefore, the only impedance we can change is the transmission lines' impedance. The way we control it is to increase the length of every line without changing any other line parameters. Three types of feeder are constructed in this part. The first one is the feeder with original line length, the line length in the second feeder is 1.5 times as much as the original one and the line length in the third feeder is 2 times as much as the original one. All these three feeders are simulated with summer and winter load profile, no PV case and 5kW cloudy PV per house case are considered for each season.

Figure 3-27 shows the daily P_{st} value fluctuation for each case. When there is no PV, the P_{st} values are around zero in both summer and winter, and the values do not vary a lot for different line length. In cloudy day the P_{st} values become larger. The longer the transmission lines are, the higher P_{st} values are. Comparing to other two P_{st} patterns in winter, an extremely increase for daily P_{st} value is observed when the line has two times as much as original length.

Table 3-5 shows the maximum P_{st} value for different cases. It is shown that when the feeder with cloudy day PV has original length and 1.5 times length, their maximum P_{st} value are still almost the same. However, when the length of each transmission line extends to two times, the maximum P_{st} value in winter comes to 1.7 times of the value in summer.

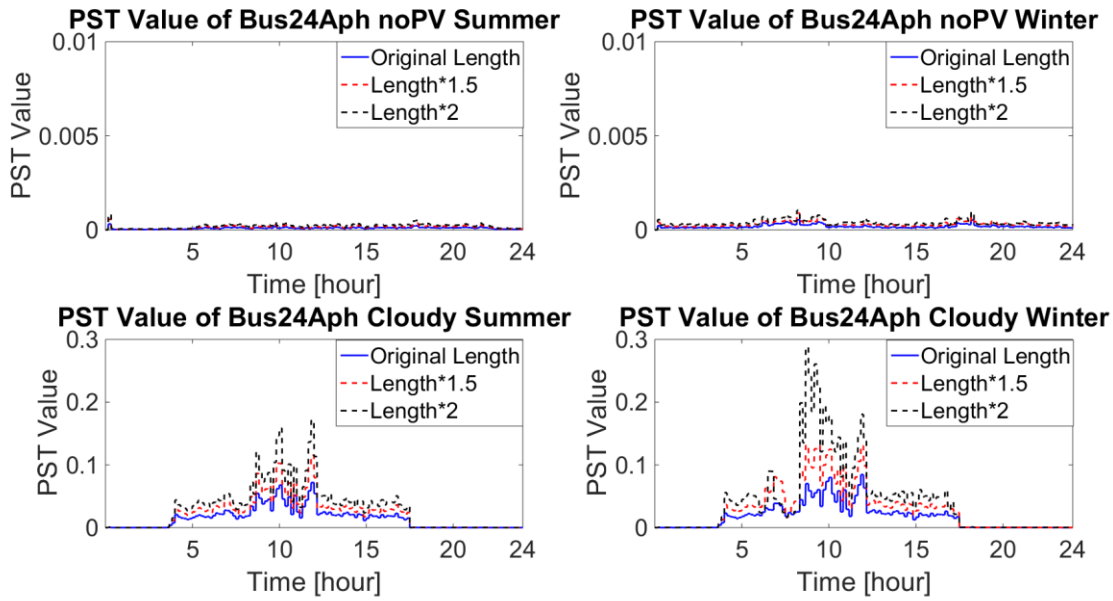

Figure 3-27 Daily P_{st} value of Bus24Aph in winter for flicker study (feeder resistance)

Table 3-5 Maximum P_{st} value for flicker study (feeder resistance)

		Daily Maximum P_{st} value		
		Original Length	**Length*1.5**	**Length*2**
No PV	**Summer**	0.0003	0.0006	0.0008
	Winter	0.0005	0.0009	0.0010
5kW/house Cloudy	**Summer**	0.0719	0.1155	0.1713
	Winter	0.0845	0.1314	0.2874

Figure 3-28 shows the 10-second voltage ramp distribution of bus 24 phase A in different cases, all the occurrence distributed around zero are eliminated. It is shown that when there is no PV, all the voltage ramps are concentrate around zero no matter how long the transmission lines are. And when cloudy PV is added, the feeder length will begin to impact the voltage ramp distribution. The longer the feeder is, the more extensive the voltage ramp distribution is.

Table 3-6 shows the daily maximum voltage ramp value. All the maximum 10-second voltage ramp are nearly zero when no PV is installed. In cloudy day, the maximum value will increase with the extension of feeder length. With the same feeder length, the largest voltage ramp in winter is always larger than that in summer. The difference between summer and winter will increase with the increase of feeder length.

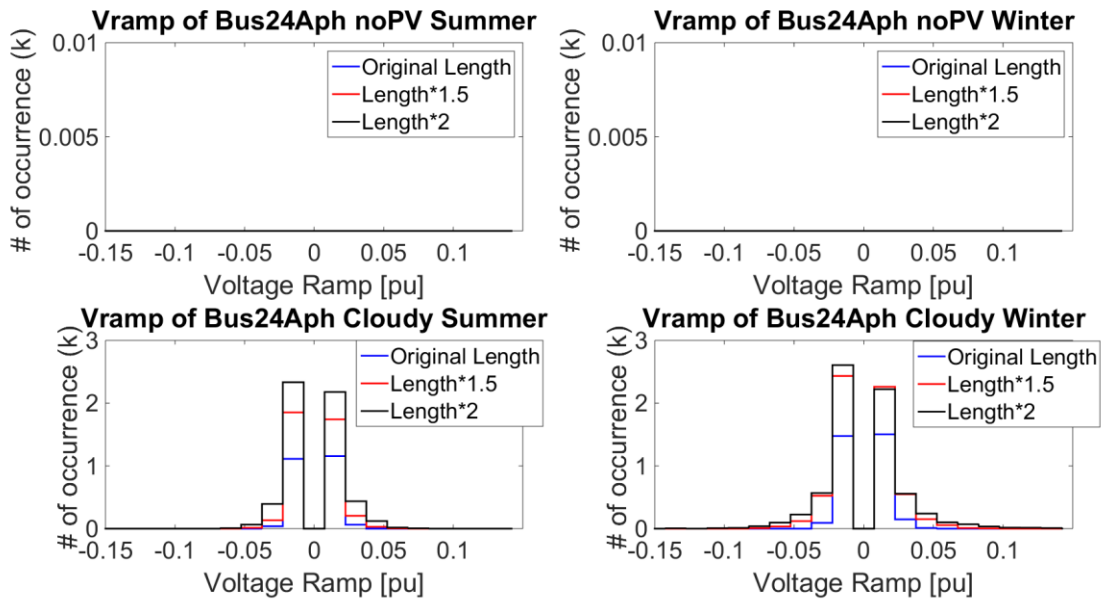

Figure 3-28 Voltage ramp (10-second) distribution of Bus24Aph for flicker study (feeder resistance)

Table 3-6 Maximum voltage ramp value for flicker study (feeder resistance)

		Daily Maximum Voltage Ramp (10 second, absolute value)		
		Original Length	**Length*1.5**	**Length*2**
No PV	**Summer**	0.0003	0.0005	0.0007
	Winter	0.0010	0.0023	0.0025
5kW/house Cloudy	**Summer**	0.0372	0.0553	0.0776
	Winter	0.0439	0.0898	0.1436

From the P_{st} value comparison and 10-second voltage ramp comparison in all the above cases, it can be concluded that feeder impedance will not impact voltage flicker situation when there is no PV in the distribution system. Nonetheless, in cloudy day the voltage flickers are more likely to appear when the line impedance is large. On the other hand, with the same PV penetration percentage, peak load condition is affected more severely by feeder length than light load condition.

3.5 Zonal case

This part presents the different impact when PV is added at different areas in this feeder. In the simulation, PV is successively installed at the four zones which we defined previously. A sunny day case and a cloudy day case are chosen to represent light load and peak load

condition. 5kW PV capacity is added at each house. We will focus on observing the voltage profiles of these cases. In this way we can find the different effect on the voltage profile at each node with the installation of PV in different areas.

Figure 3-29, Figure 3-30, Figure 3-31 and Figure 3-32 show the daily voltage profiles of bus 2 phase A (locates at zone 1), bus 9 phase A (locates at zone 2), bus12 phase A (locates at zone 3) and bus 24 phase A (locates at zone 4) in different cases. Table 3-7 and Table 3-8 show the maximum voltage rise for each case. Following observations are made:

- It is shown that for bus 2 phase A which locates in zone 1, its voltage affect order from strong to weak is PV at zone 3, zone 1, zone 4 and zone 2. Zone 3 has the strongest impact because it has the largest number of houses locate at phase A. Therefore, the solar power generated for phase A will be large and leads the maximum voltage rise to node at zone 1 even they are not nearby. Zone 1 has the second strongest impact because the PV panels are directly installed at Bus2Aph. The reason for zone 4 has a stronger impact than zone 2 is house locates at phase A in zone 4 is more than that in zone 2.
- For bus 9 phase A which is located in zone 2, zone 2 and zone 3 almost have the same impact because of the larger PV power output in zone 3 and the nearer distance in zone 2. The impact for zone 1 is very small as zone 1 is located before zone 2.
- For bus 12 phase A which is located in zone 3, zone 3 has a definitely largest impact since it has most houses at phase A and PV is directly installed there. Zone 4 has the second largest influence because it locates after zone 3. The impact from zone 1 and zone 2 can be almost ignored by comparing with the impact from other two zones.
- For bus 24 phase A which locates at the feeder end and belongs to zone 4, zone 4 has the biggest impact. Although zone 3 is located before zone 4, its impact is still very large as the PV output capacity is the largest. Installing PV at zone 1 and zone 2 do not have much impact to the voltage profile of zone 4.

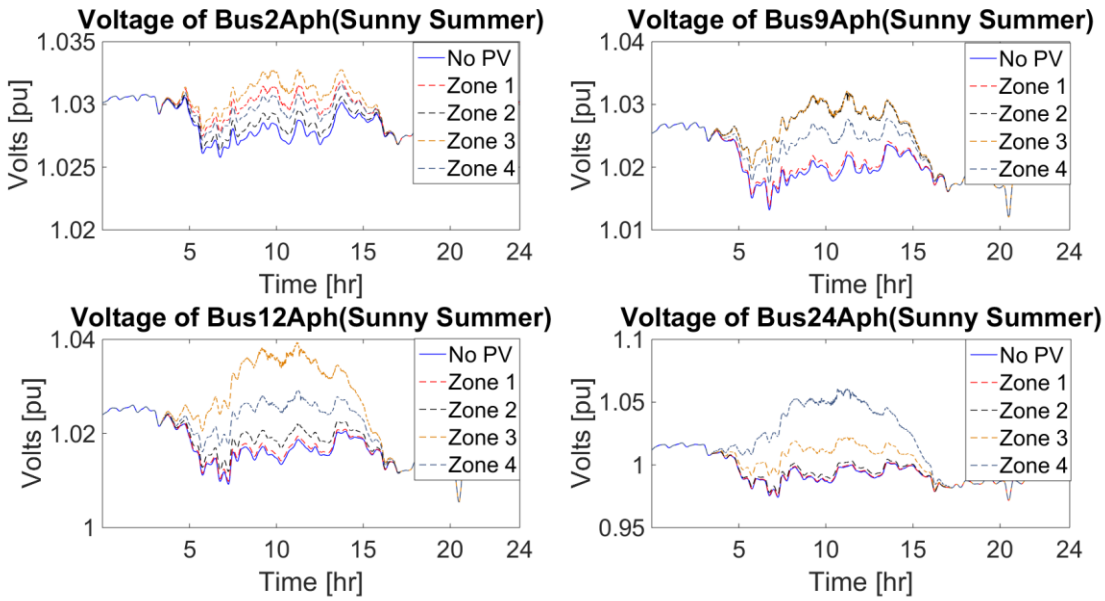

Figure 3-29 Daily voltage profile for nodes in sunny day in summer for zonal case

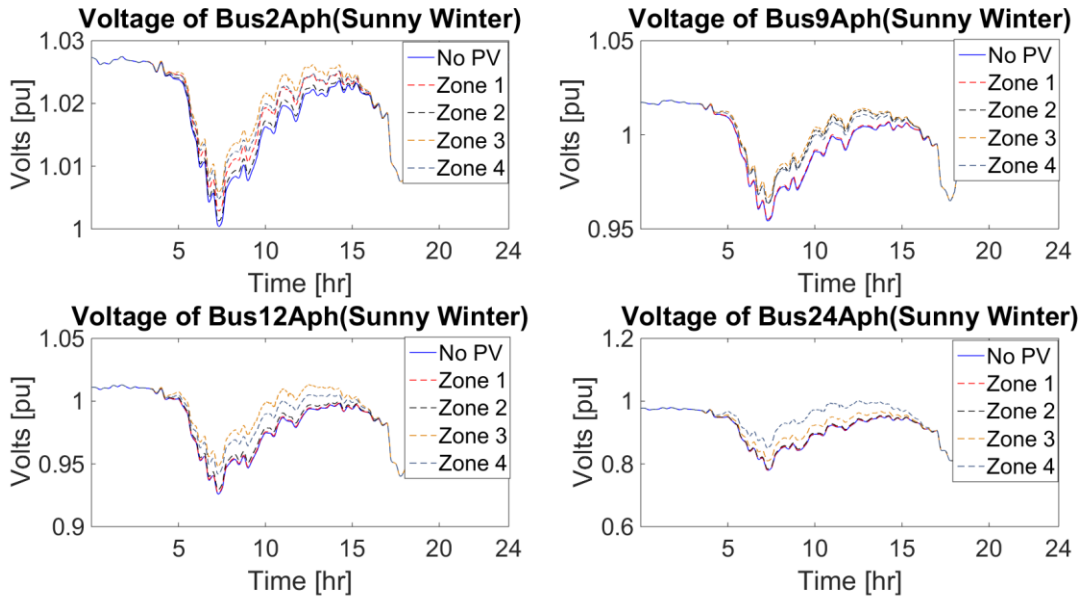

Figure 3-30 Daily voltage profile for nodes in sunny day in winter for zonal case

Table 3-7 Maximum voltage rise in sunny day for zonal study

		Maximum voltage rise after 5kW PV/house added in sunny day			
		Zone 1	**Zone 2**	**Zone 3**	**Zone 4**
Summer	**Bus2Aph (Zone 1)**	0.0031	0.0009	0.0043	0.0023
	Bus9Aph (Zone 2)	0.0008	0.0111	0.0111	0.0062
	Bus12Aph (Zone 3)	0.0008	0.0038	0.0220	0.0113
	Bus24Aph (Zone 4)	0.0008	0.0039	0.0247	0.0647
Winter	**Bus2Aph (Zone 1)**	0.0032	0.0011	0.0063	0.0047
	Bus9Aph (Zone 2)	0.0009	0.0117	0.0145	0.0109
	Bus12Aph (Zone 3)	0.0010	0.0043	0.0270	0.0183
	Bus24Aph (Zone 4)	0.0011	0.0048	0.0337	0.0879

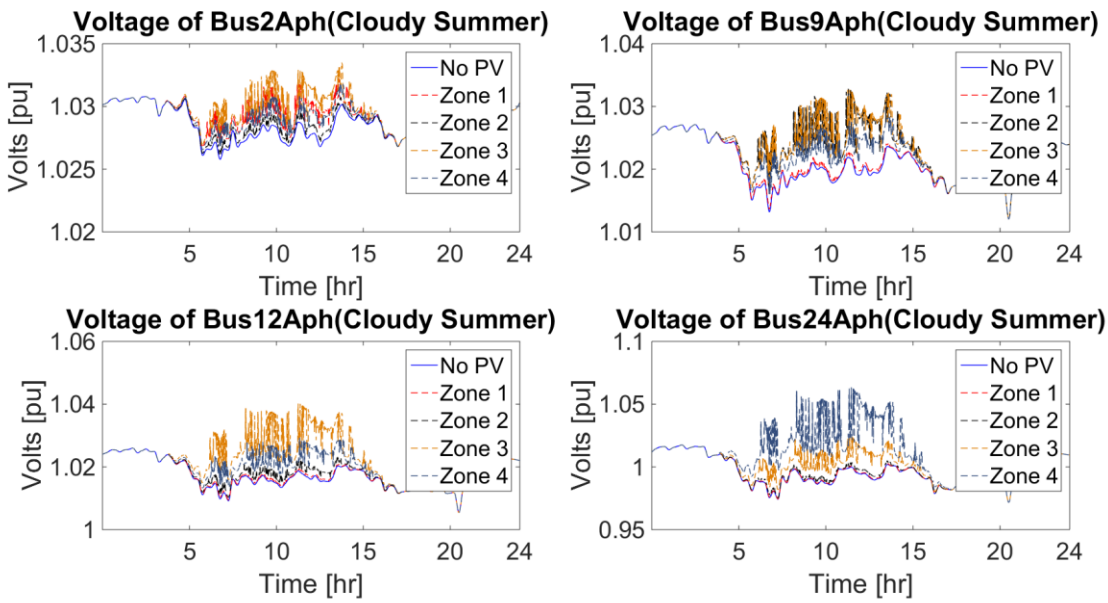

Figure 3-31 Daily voltage profile for nodes in cloudy day in winter for zonal case

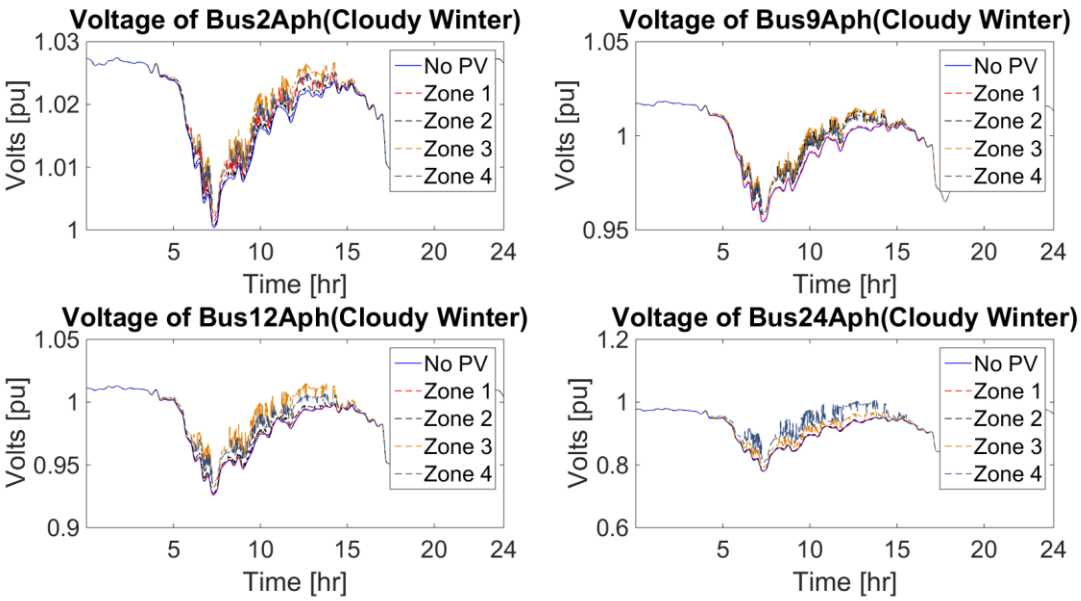

Figure 3-32 Daily voltage profile for nodes in cloudy day in winter for zonal case

Table 3-8 Maximum voltage rise in cloudy day for zonal study

		Maximum voltage rise after 5kW PV/house added in cloudy day			
		Zone 1	**Zone 2**	**Zone 3**	**Zone 4**
Summer	**Bus2Aph (Zone 1)**	0.0031	0.0008	0.0044	0.0023
	Bus9Aph (Zone 2)	0.0008	0.0110	0.0111	0.0063
	Bus12Aph (Zone 3)	0.0008	0.0038	0.0221	0.0114
	Bus24Aph (Zone 4)	0.0008	0.0038	0.0249	0.0660
Winter	**Bus2Aph (Zone 1)**	0.0032	0.0011	0.0064	0.0053
	Bus9Aph (Zone 2)	0.0010	0.0120	0.0149	0.0119
	Bus12Aph (Zone 3)	0.0010	0.0044	0.0276	0.0197
	Bus24Aph (Zone 4)	0.0012	0.0049	0.0344	0.0903

In conclusion, from the observations above, we can find that the PV output capacity and the distance between PV site and nodes are the two most significant factor to quantify the impact to voltage profile. Also, PV will not impact much to nodes after the installation location. In this feeder, if we want to choose one zone to install PV in order to improve voltage profiles for the whole feeder, zone 3 is the best choice.

3.6 Commercial load case

In this part, commercial load condition is simulated to find the different characteristics between distribution systems with residential load and commercial load. All the residential loads at zone 4 are replaced by commercial loads without changing the peak load at each node. In order to

compare the results with the residential load, PV capacity keeps the same. The feeder map for this case is shown in Figure 3-33.

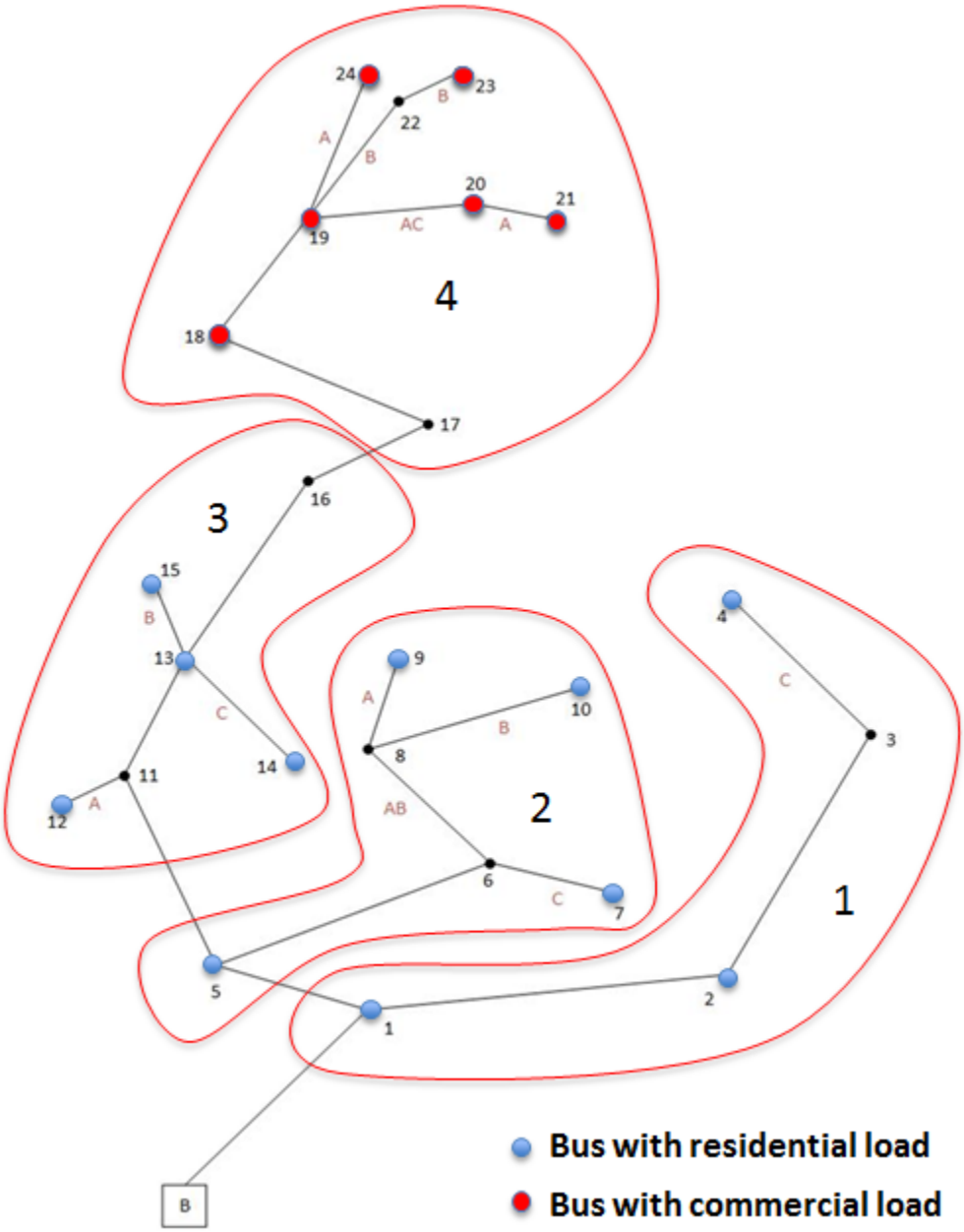

Figure 3-33 Feeder map for commercial load case

The number of commercial buildings are estimated according to the peak load at each node. Based on this number, profiles from the nine-day commercial load profiles are picked out randomly and added together to be the load pattern. After that, the load pattern is scaled to be the load profile at each node. Figure 3-34 shows the load profile at bus 24 phase A.

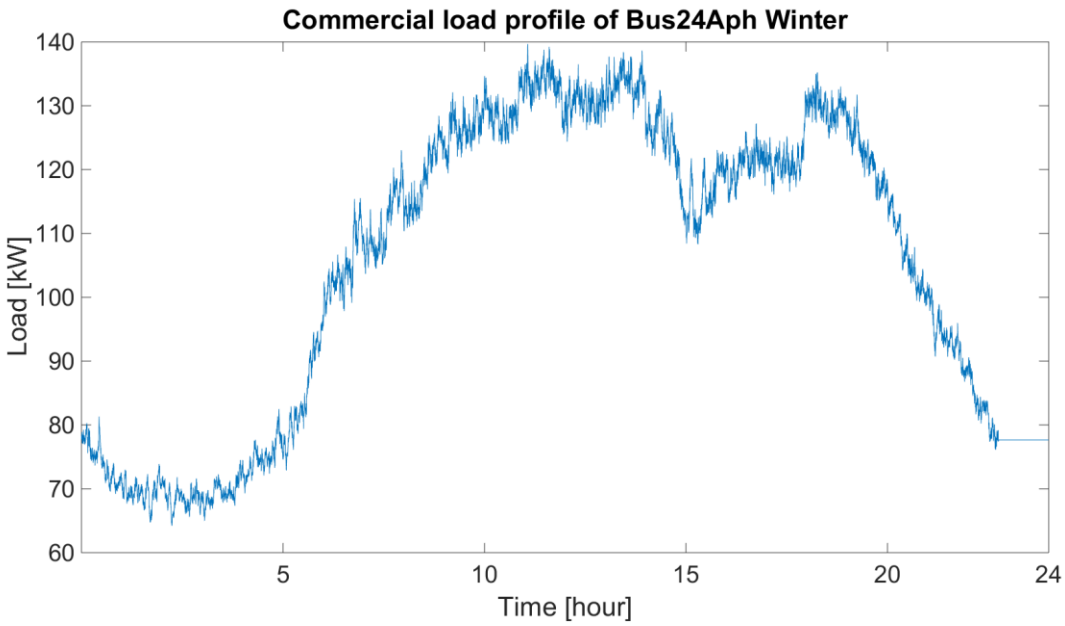

Figure 3-34 Load profile of Bus24Aph in winter for commercial case

3.6.1 Commercial load and residential load

Figure 3-35 and Figure 3-36 show the daily voltage fluctuation in sunny day and cloudy day in winter. These four nodes are all belong to zone 4 and locate at feeder end. The blue line is the voltage profile when zone 4 has residential load and no PV is added. The red line is the voltage profile when zone 4 has residential load with PV. Black line represents zone 4 has commercial load without PV and pink line shows zone 4 with commercial load and PV added. From the comparison, it can be observed that the voltage profile has more short time variations with commercial load. Also, because of the characteristics of commercial load, the voltage profile during daytime is flatter than residential voltage profile.

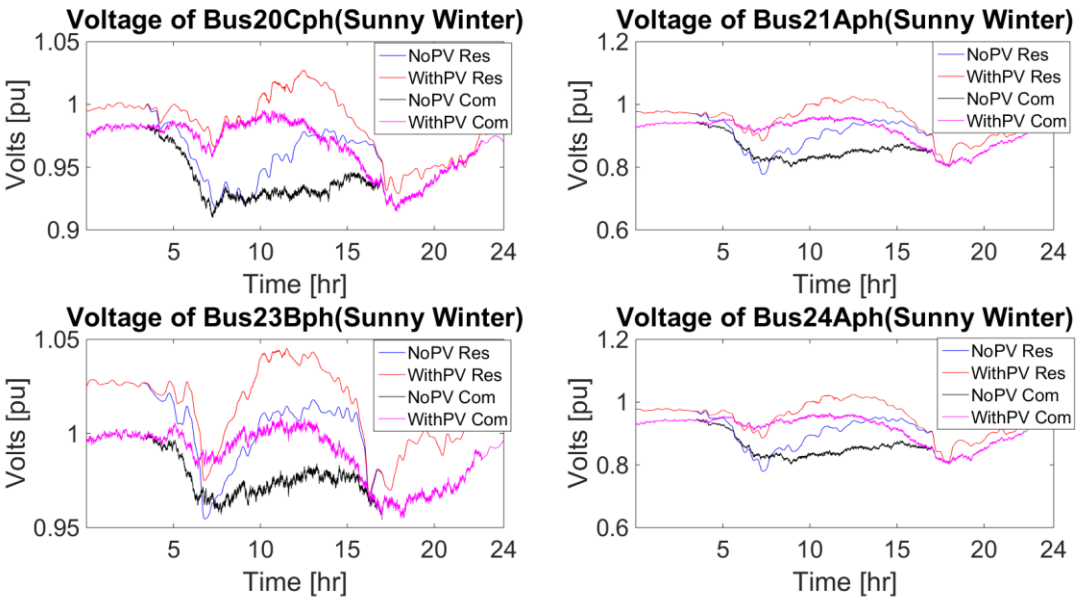

Figure 3-35 Voltage profile in sunny winter for commercial load case

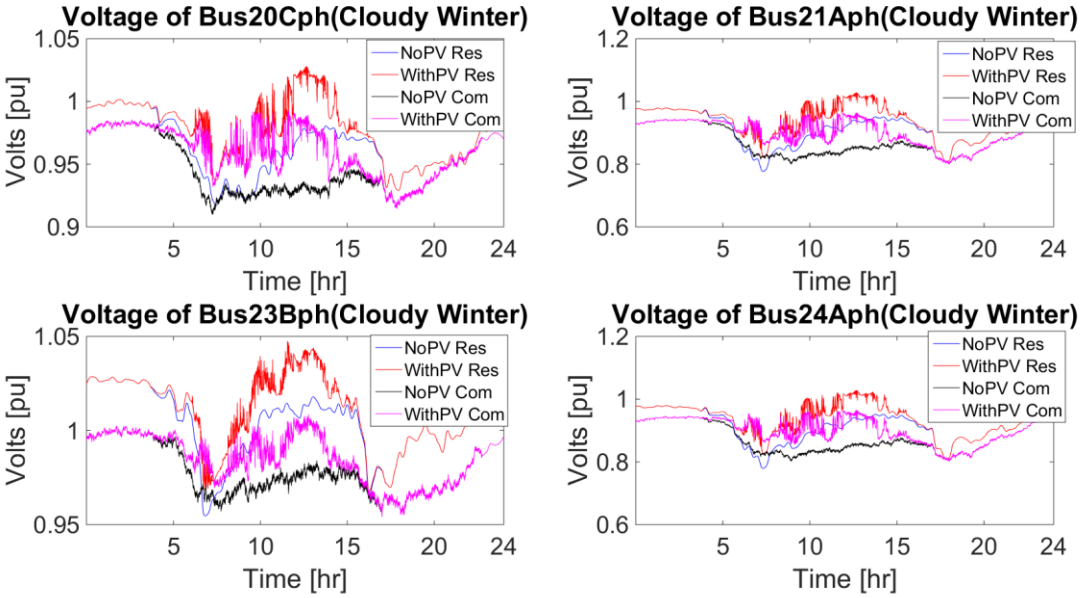

Figure 3-36 Voltage profile in cloudy winter for commercial load case

Figure 3-37 shows the daily P_{st} value comparison between residential load and commercial load. For all of these cases, commercial load condition has a larger daily P_{st} values. Table 3-9 shows maximum daily P_{st} value for each case, and commercial load is always higher than residential load.

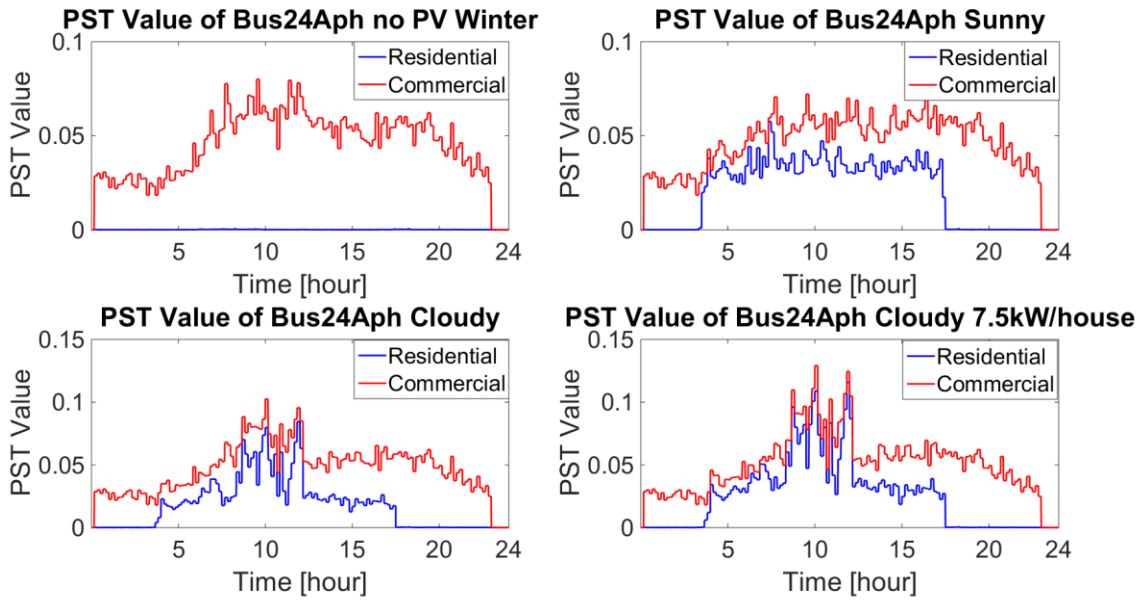

Figure 3-37 Daily P_{st} value comparison between residential load and commercial load

Table 3-9 Maximum P_{st} value for residential load and commercial load

	Daily maximum P_{st} value	
	Residential	**Commercial**
No PV	0.0005	0.0800
Sunny	0.0576	0.0721
Cloudy	0.0845	0.1026

Figure 3-38 and Table 3-10 evaluate the voltage flicker situation from the 10-second voltage ramp aspect. It is shown that commercial load always have a higher voltage ramp than residential load. However, all these voltage ramps are within 5%.

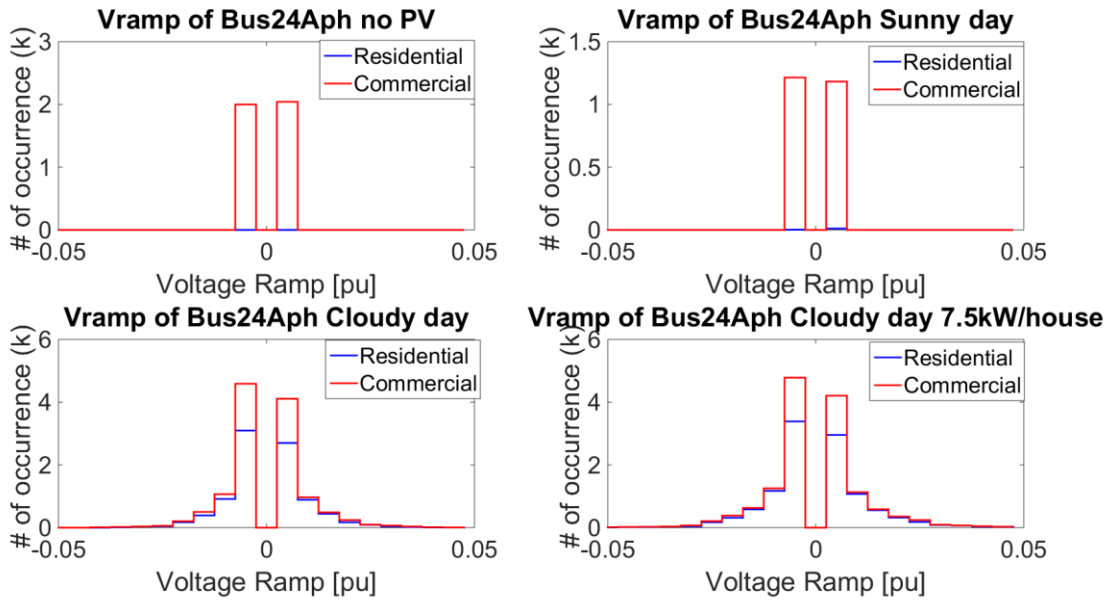

Figure 3-38 Voltage ramp (10-second) distribution comparison between residential load and commercial load

Table 3-10 Maximum voltage ramp (10-second) for residential load and commercial load

	Daily maximum voltage ramp (10 second)	
	Residential	**Commercial**
No PV	0.0010	0.0064
Sunny	0.0049	0.0062
Cloudy	0.0439	0.0509

Therefore, from the point of view for both P_{st} value and voltage ramp, it can be concluded that commercial load is more likely to suffer voltage flickers than residential load in the same environment condition. The reason is the larger load variance for commercial load during daytime.

3.6.2 Distribution transformer

In this case, the loads at zone 4 are still commercial load. The difference is that a distributed transformer is added at Bus24Aph. The parameter for the distribution transformer is shown in Table 3-11. As for all the simulations above the distribution transformers are not added in the feeder, by doing this we can get an estimate voltage drop on the transformer. The feeder map after the transformer is added is shown in Figure 3-39.

Table 3-11 Distribution transformer parameter

	Distribution transformer
KVA	50
HZ	60
HV	22860
LV	240
% Impedance	2.09

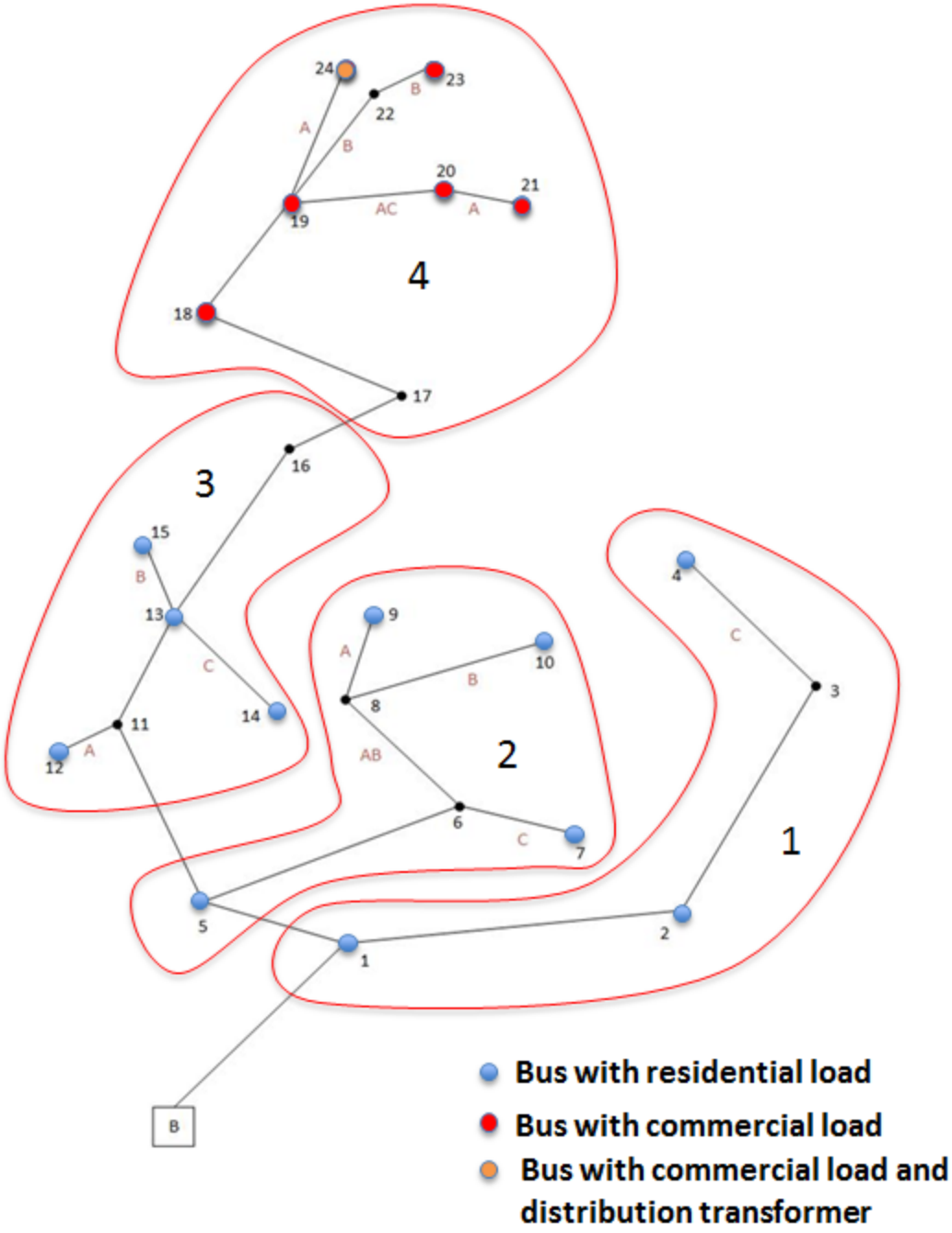

Figure 3-39 Feeder map after distribution transformer added

Figure 3-40 shows the daily voltage fluctuation comparison between with distribution transformer case and without transformer case. From the figure we can get while transformer is added, the voltage profile will decrease because of the voltage drop on transformer. And after PV is added, the voltage drop during daytime is smaller. The reason is PV output power

supplies much of the load, so the current from grid will decrease, which leads to a smaller voltage drop.

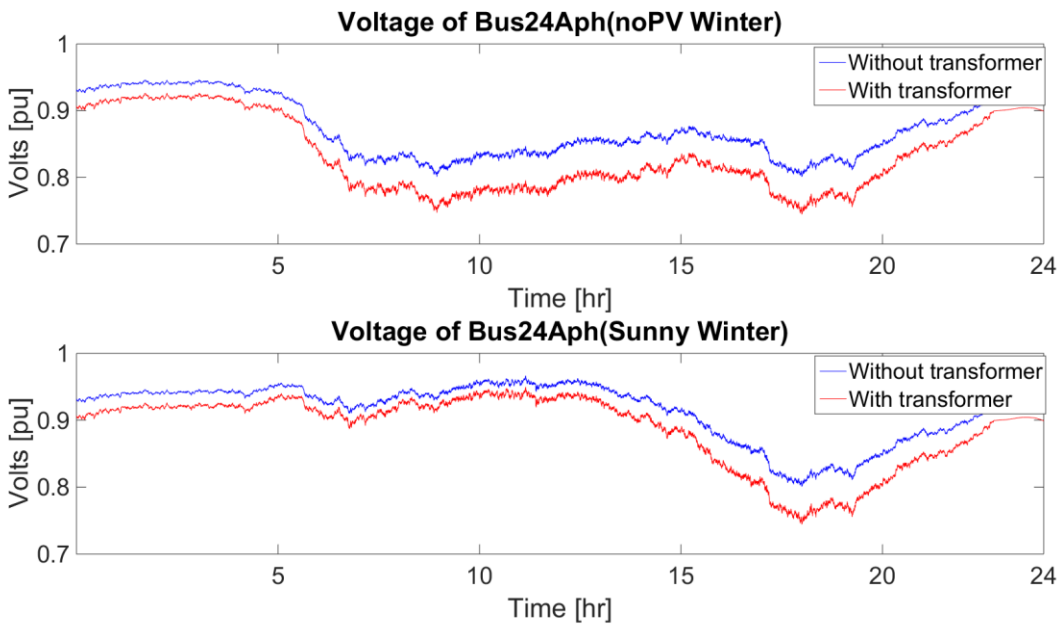

Figure 3-40 Voltage profile comparison between without transformer and with transformer

Table 3-12 shows the maximum and minimum voltage difference between with transformer case and without transformer case. When there is no PV, the voltage drop on the transformer is between 1.95% and 5.73%. The maximum voltage drop happens at peak load time and the minimum voltage drop happens at light load time. After PV is added, the voltage drop range decreased, which is from 1.36% to 5.7%. The maximum drop occurs in the evening, which is the time the sun goes down and the PV output becomes zero. The load at that time is still heavy, so the voltage drop is large. The minimum voltage drop occurs in the morning, the time with light load but large PV output. Hence, integrating PV helps reduce the voltage drop on transformer.

Table 3-12 Voltage difference between with transformer case and without transformer case

		Voltage difference	**Time**
Without PV	**Maximum**	0.0573	11:30 am
	Minimum	0.0195	2:15 am
With PV	**Maximum**	0.0570	6:16 pm
	Minimum	0.0136	8:22 am

Chapter 4 Conclusion and Future Work

In this thesis, a utility distribution feeder is simplified to a feeder with a source, transmission lines and loads. Then, the load data and PV data are processed to fit our simulation requirement. After that, several cases are simulated in OpenDSS and MATLAB. Finally, by using the voltage profiles we get from simulation, daily voltage pattern and voltage flicker condition in different cases are analyzed and evaluated.

The contributions of the thesis are summarized as follows:

- Developed a methodology to disaggregate residential load. By using this method the total load at each node can be resolved to a set of customer houses' load profiles. The sum of these load profiles will still meet the feeder parameter. PV can also be installed according to the number of houses at each node.
- A PV output time delay is set among different zones to simulate the situation that each node will not see the same solar irradiation at the same time because of the long distance.
- Revealed the daily voltage fluctuation and voltage flicker condition in different seasons, different weather conditions, different PV penetration percentages, different PV installation locations and different load types.
- Analyzed two factors which will influence the voltage flicker condition in a distribution feeder, current variation and feeder resistance. Simulations are done to prove the inference.

Our future work will focus on the following directions:

- Develop a reasonable way to interpolate 15-minute load data to 1-second load data.
- Develop a way to create more diversified PV output for each house.
- Do the simulation in another actual feeder without simplified to see if the results are still correct in a large distribution system.
- Monitor the voltage profile at home level, to see what customers will experience in these different environment conditions.

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