# ISLANDING DETECTION USING DATA MINING TECHNIQUES

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**Title**

ISLANDING DETECTION USING DATA MINING TECHNIQUES

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The Supervisory Committee certifies that this ***disquisition*** complies with North Dakota State University's regulations and meets the accepted standards for the degree of

**MASTER OF SCIENCE**

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## ABSTRACT

Connection of the distributed generators (DGs), poses new challenges for operation and management of the distribution system. An important issue is that of islanding, where a part of the system gets disconnected from the DG. This thesis explores the use of several data-mining, and machine learning techniques to detect islanding. Several cases of islanding and non- islanding are simulated with a standard test-case: the IEEE 13 bus test distribution system. Different types of DGs are connected to the system and disturbances are introduced. Several classifiers are tested for their effectiveness in identifying islanded conditions under different scenarios. The simulation results show that the random forest classifier consistently outperforms the other methods for a diverse set of operating conditions, within an acceptable time after the onset of islanding. These results strengthen the case for machine-driven based tools for quick and accurate detection of islanding in microgrids.

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# CHAPTER 1. INTRODUCTION

In order to deliver electric power to the consumers, there are several stages done by the electric utilities. The first stage is the generation. A power is generated in a large central generating stations, to reduce the cost and avoid the environmental issues those stations are located away from the consumer's loads and in non-populated areas. The second stage is transmitting the generated power through overhead transmission lines or underground cables; power transmission also includes some equipment such as transformers, compensation devises and protection devices. The final stage is the distribution stage, it is the interaction between the utility network and the consumer's loads. It is considered as the critical stage since most of the costumer's power interruptions and outages occur at the distribution stage.

Power interruptions can also be a result of adding Distributed Generators (DGs). DGs are other small power generation units that can be added to the distribution grid to serve part of local loads. DGs generate the power from the renewable energy sources, such as photovoltaic (PV) systems, wind turbine, and fuel cells.

Using the renewable energy is a major trend to generate useful energy in form of electric energy. Since it is clean energy and despite the initial cost of renewable energy stations; the running cost will be low, and also less maintenance cost as compared to the cost of the traditional power generation. The widely used renewable energy technology are the PV and wind turbines.

The PV is a system which contains an array of solar cells which convert the solar energy to electric energy. Solar cells are made out of semiconductor materials such as silicon that can produce electricity from the light photons. The performance of the arrays is proportional to the angle of the arrays to the sun light. A better performance can be achieved by keeping the array perpendicular to the sun light. The output of the PV arrays is in form of DC. Inverters are used to convert it from DC to AC in order to interact the DG with the AC utility network. The disadvantages of the PV system are high initial cost and it needs large area to install.

Wind turbines converts the wind energy (mechanical) to electric energy. Several wind turbines are located and grouped together to form a wind farm which interact with the medium voltage network. PV and wind turbines are considered -from the utility network side- as DGs that are part of the new structure of the power systems networks and work in parallel with the utility grid.

As mentioned before; the distributed generators (DGs) have advantages of using the renewable energy which helps in reducing the environmental pollutions that is resulting from the utility generators, reduces the transmission line losses, and improve the power reliability and the voltage profile. On the other hand, considering the fact that many utilities have been using DGs in many countries around the world, problems regarding connecting those DGs to the utility grid have arisen; one of these problems is islanding.

Islanding is the case when a part of the utility grid is electrically isolated from the rest of the network and the distribution line is still energized by the DGs since they are still connected to the load that close to it and to part of the distribution system. The worst scenario happens when there is a utility transformer connected to the line during islanding. The current will suddenly interrupted. This will result a voltage spike and that may cause damage to the transformer as shown in Figure 1.1.

According to the IEEE 1547-2003 standards [1], a maximum time delay of 2 seconds is specified for an unintentional island and all the DGs should stop generating power within that time in order to avoid the issues that may appear with islanding situation.

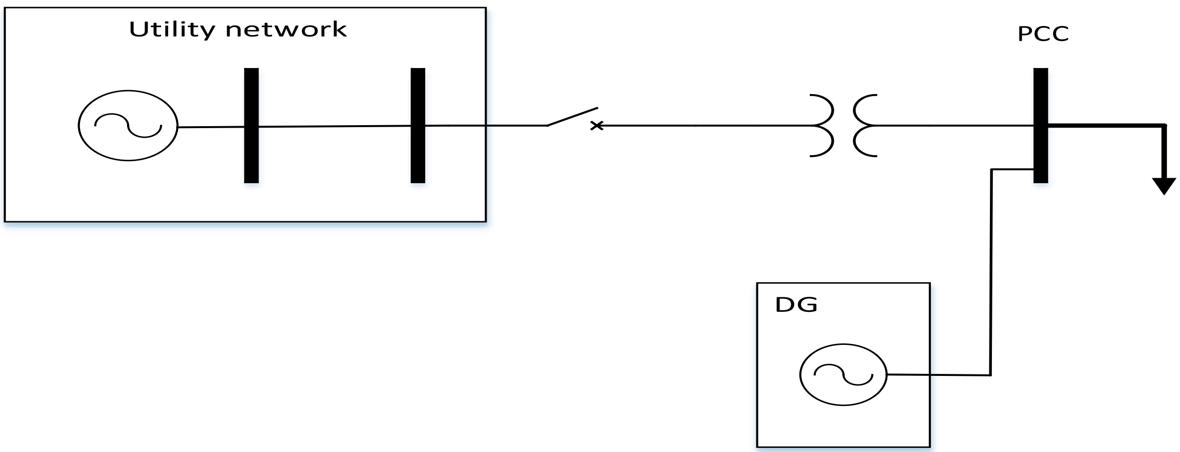


Figure 1.1: Worst islanding scenario

It is important to detect islanding as soon as it occurs for the following reasons:

1. Since the line might be still energized by the DG, it is not safe for the utility line workers who work on the line to fix the problem.
2. In absence of the utility control of the voltage and frequency during the islanding condition, a major damage to the costumers' machines and equipment is possible.
3. Maintaining the same voltage and frequency levels might not occur, and that will cause a damage to the resources equipment during the out of phase closure.

In order to detect islanding in a short time, there are some techniques and methods that have been proposed and discussed in the literature review.

# CHAPTER 2. LITERATURE REVIEW

It is convenient to define some terms that are used in the literature review.

- Inverter is a device that convert direct current (DC) to alternating current (AC). The inverters connected to the DGs are required to synchronize the voltage, frequency and the phase angel of the grid.
- Non detection zone (NDZ) is the range of the load being supplied in the islanded condition, which results in the islanded condition not getting detected by the utility. The goal of islanding detection methodologies is to reduce the NDZ near to zero. NDZ is used as performance index to evaluate whether the detection technique is sufficient or not.
- Point of common coupling (PCC) is the point where the DGs are connected to the utility line. It is important to monitor the voltage, frequency, and the phase at the PCC in order to detect the islanding.

## 2.1. Islanding detection techniques

The main concept of detecting an island lies in monitoring the changes in some parameters from the DG side and the utility side and determining whether the islanding has occurred or not. The techniques that are used to determine the change in those parameters can be divided into two categories; first is communication based techniques and second local techniques which can be further divided into passive and active techniques.

### 2.1.1. Communication based techniques

Communication based techniques depend on a communication between the DGs and the utility network. These techniques are the most reliable techniques and have a zero NDZ. The drawback of these techniques is the high cost of implementation to the utility. The installation of a DG involves a large cost to the owner, and has a breakeven time of more than five years. Installation of communications equipment for control and monitoring involves additional costs which could discourage the use of DGs [2]. Communication based techniques are divided into three techniques as follows:

- **Transmission line signaling technique**

This technique based on using the power lines that are connected between the DG and the utility network to send a continuous small communication signal from the utility network to the DG side. This requires a transmitter device at the utility side and a receiver at the DG side. As soon as the receiver doesn't sense that signal, it will be an indication that islanding has occurred.

Some signal characteristics should be considered to establish this technique such as: the signal should be able to be transmitted through the line very well because the transformer's inductance may filter the high frequency signals. For that reason a low frequency signal should be used. Another characteristic that must be considered is the signal continuity. This means that the signal should propagate all the time during non-islanded normal operation. If this signal is not received due to other reasons, the DG will be falsely disconnected [3].

The advantages of this method are: it doesn't have a NDZ; it detects most if not all the islanding situations; it doesn't get affected by the system's size, the numbers of inverters in the system or type of generators; and one transmitter can cover a large area of the system. On the other hand, there is only one disadvantage of this method and that is the implementation; since it requires a transmitter that is able to send signals to all the DGs in the system and such transmitters are usually expensive.

- **Disconnection signaling technique**

It's also considered as a communication method between the utility and the DGs but this technique depends on sending signals only when the switch is open. The recloser is equipped with small transmitter that sends signal to the DG side as soon as the switch is open, and the power line is not used to transmit the signal in this method. Instead, a different communication channel is used, such as microwave or telephone lines [4].

It also requires a continuity in sending the signals as in the transmission line signaling technique. This method has an advantage of coordinating and controlling the distributed generators, but that requires establishing a phone line between the switch and each DG. And in the case of using microwave we need to make sure that there is a network coverage at both sides to ensure that the signal could be received when the switch is open.

This method has more advantages than detection islanding; it may be useful for coordinating between the DGs and the utility network. For example, a situation of black-start condition, Inverters could help in carrying some of the weak sectors of the network back online and that coordination helps in improving the system reliability.

This method has some disadvantages; if a telephone line is used an additional cost occurs because a telephone lines need to be wired from each distributed generator and the utility. This can be replaced by using a microwave connection but that requires a federal communication commission license and coverage availability at the DGs side. Another drawback of this method is the design complexity, and it might require signal boosters and repeaters if the DGs are far away from the utility side.

- **Using Supervisory Control and Data Acquisition (SCADA)**

The utility power system uses SCADA to sense the network parameters to control the system. Utility network has measuring and sensing equipment all over the system from the high voltage transmission level down to low voltage transmission level at the distribution network side. This is done to cover as much as possible area of the grid in order to control and solve any problem that might appear [4].

The idea here is to extend the use of the SCADA by installing voltage sensors at the inverters on DGs sides; if such sensors are not already installed. If the utility network is disconnected and the sensors detect voltage on the line the voltage sensor sends alarm signals to the utility side and an action to disconnect the DG side should be taken. Furthermore, these voltage sensors could also be used to detect the abnormal voltage on the customer’s side. This will lead to manage the voltage level in order to increase the reliability of the system.

The strength of this method lies in eliminating the islanding and add more controlling to the DG side of the system, that is, if all the instruments are installed properly and all communication links are set correctly.

The drawbacks of this method are if there are many inverters in the system they would be a need to install separate equipment and communication channels to each of the DG’s inverter within the system. Another problem is that this method needs a main utility contribution in the DG installation, and since most of the DG would be set under the substation level the SCADA system doesn’t go into the system under the substation level, which would have more complexity and cost to the utility network.

### 2.1.2. Local techniques

They can be further categorized into passive detection technique and active detection technique.

#### 2.1.2.1. Passive detection technique

This method depends on monitoring and measuring some of the system's parameter at the point of the common coupling (PCC) such parameters are voltage, frequency, power, etc. There are many passive detection techniques; some of these methods are discussed below.

- **Abnormal voltage/frequency detection**

At the DG side the inverters are required to have an abnormal voltage and frequency detection software that will detect the voltage and the frequency at the point of common coupling. If the voltage or frequency is out of determined limits, the inverter stops supplying power to the grid. This is required to protect the costumer's as well as the utility equipment.

In Figure 2.1. The real and reactive power are transmitted from the utility grid are $Pu$ and $Qu$ respectively, and the real power and reactive power generated from the distributed generator are $Pd\ and\ Qd$. And finally the real and reactive power consumed by the load are $Pl\ and\ Ql$.

From that configuration the load active power is:

$$P_l = P_u + P_d \tag{2.1}$$

And the load reactive power is:

$$Q_l = Q_u + Q_d \tag{2.2}$$

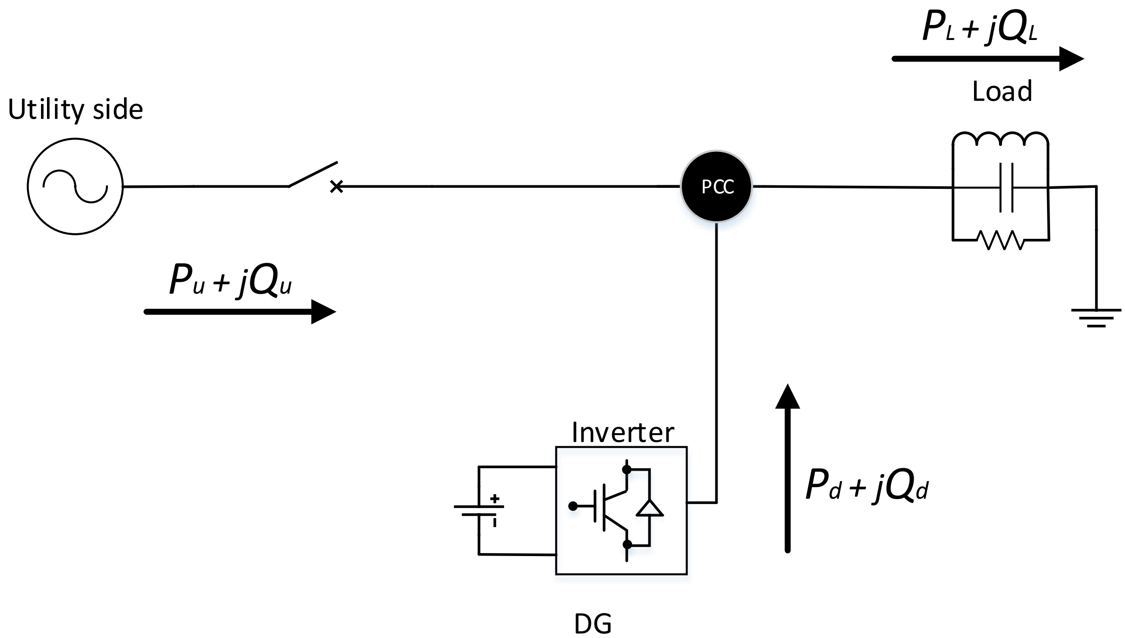


Figure 2.1: Power flow of the utility and DG

If the inverter works with power factor of one; that happens when the output voltage is in the same phase with the output current, then $Q_d = 0$ *and* $Q_l = Q_u$ .

When the islanding occurs the breaker is open, and $P_u = 0$. The voltage at the PCC will change and exceed the limits, the inverter will detect the change in the voltage and hence detect the islanding. Similarly, if $Q_u = 0$ the inverter will start producing reactive power to cover the consumed reactive power at the load, and this will cause a sudden shift in the phase; and lead the control of the inverter to change the frequency of the current and the frequency of the voltage as well at the inverter terminal; the changes in frequency is to get an the output reactive power back to zero ($Q_d = 0$). The abnormal frequency at the inverter will detect that changes in frequency and prevent islanding. The voltage and frequency limits are given in table 2.1. [5].

**Table 2.1: Voltage and frequency limits**

| | Minimum | Maximum |
|---|---|---|
| Voltage | 0.9 p.u | 1.1 p.u |
| Frequency | 59 Hz | 61 Hz |

This method has not only been used for islanding detection, but also for the load equipment protection; if the voltage/frequency exceed some limits. The advantages of this method are the low cost of implementation, and it is used for multiple purposes. On the other hand, this method is considered as insufficient method to detect islanding; because of the large NDZ, and the time of the operation is variable or unexpected.

- **Power factor detection**

It's also called "Voltage phase jump detection". In normal conditions; the inverter's current phase is synchronized with the voltage phase at the PCC by using phase locked loop (PLL) controller which can follow the rising or falling of the of the voltage zero crossings at the PCC. When the utility network's side is disconnected, the output current of the inverter continues to follow the waveform of the PLL since the inverter's current phase depends on the zero crossings of the voltage at the PCC, and between the zero crossings the inverter is working in an open mode [6].

The phase of the output current of the inverter is used to fix the phase for the PLL, and at the PCC; the phase of the voltage will change suddenly to meet the load power factor. These sudden changes could be used to detect islanding by setting a threshold of the power factor at the PCC.

This method has advantages that are easy to implement; since the system already has the PLL all that is needed is to add a phase threshold detection to disconnect the inverter. This method also doesn’t impact the power quality of the inverter and it could be used for several inverters that are connected to the load.

In Power factor detection method; it is hard to set a threshold that can detect islanding from other system instability issues, such as, starting motors causes a transient phase jump that might be understood as islanding and may trip the inverter for the wrong reason.

- **Monitoring the voltage harmonic**

In normal operation condition; utility network produces a rigid voltage with a low distortion voltage at the load, and that will cause the load to draw a low distortion current. When the inverter is connected to the network the harmonic produced by the converters will flow through the grid which has a low impedance. This will produce a small amount of distortion in the voltage at the PCC and remains under detection threshold (typically the THD shouldn’t be more than 5% of its full rated current).

When the island happens, the harmonic in the voltage at PCC will increase because the current harmonic produced by the inverter will no longer flow through the utility. Instead, it will flow into the load which has higher impedance than the utility grid and will cause higher harmonic in the voltage at the PCC. And by setting up a harmonic threshold of the voltage at the PCC the inverter will be able to detect the island and discontinue the operation [7].

One more technique which can produce the harmonic is the voltage response of the transformer if it is located between the PCC and the islanding switch. In this case when the island occurs the secondary coil of the transformer will be excited by the inverter, therefore, the voltage response is highly distorted and that will cause the THD to increase in the voltage at the PCC. It is to be noted that some distortion is produced by the load as well. And this usually produce a third harmonic.

This method has a good promise to be successful in islanding detection and it could be used widely for different systems and configurations. It can also be used in multiple DG inverters within the system. However, this method suffers from implementation difficulties

since we have to pick an accurate threshold that can be used to separate the islanding condition from other system distortions.

The NDZ of the harmonic distortion method is relatively high and it depends on the load characteristics, if the load has a low pass filter characteristics that can filter out the lower order harmonics such as 3rd and 5th order more than the higher order harmonics; it can affect the islanding detection.

#### 2.1.2.2. Active detection technique

This method depends on introducing a small disturbance into the system or at the PCC and measure the change in different parameters. In case of islanding the variation of these parameters will change significantly, whereas in normal operation (where the DG is still connected to the utility network) a small change will be measured which can be neglected. This technique can detect islanding even with a 100% match between the power generated and the power dissipated. It can be divided into different techniques as follows:

- **Reactive power error detection**

The concept of the reactive power error detection in the inverter based DG is to inject a reactive power from the DG side into the PCC and measure the reactive power [8]. When the reactive power is not maintained to the same amount as before plus the injected amount it can be an indication of an island has occurred and an action needs to be taken in order to disconnect the DG side from the rest of the system.

Otherwise, if the total measured reactive power is equal to the total reactive power and the injected reactive power it implies that the system is operating normally and no further action is needed to be taken.

In the synchronous generator based distributed generators injection of reactive power is done by increasing the induced voltage at the DG side in a certain period of time and monitor the change in the voltage as well as the reactive power at the point of common coupling. Islanding is detected if there is an increase in the voltage and no change in reactive power.

This method has some disadvantages such as: it cannot be applied in the case where the DG is operating at power factor of one, also this method is relatively slow because it requires an injection of a small amount of reactive power and monitoring of the system from time to time. The islanding may occur during the time where no reactive power is introduced. On the other hand this method has small NDZ and it can detect the all the islanding conditions [9].

- **Impedance measurement method**

The impedance of the system changes as the islanding occurs. In this scheme a grounded inductor is connected from time to time to the voltage supply, an injected current is produced through the grid and a device is connected to measure the rate of change of the voltage by the rate of change of the current to determine the grid impedance.

$$Z = \frac{dv_{pcc}}{di_{inv}} \tag{2.3}$$

Where $Z$ is the grid impedance, $dv_{pcc}$ is the rate of change of the voltage at the point of common coupling, and $di_{inv}$ is the rate of change of the inverter current. When the utility network is disconnected the measured impedance changes and the islanding can be detected.

This method has an extreme small non detection zone (NDZ) for any load impedance higher than the grid impedance. The drawback of this method is that cannot be applied when multi-inverter is connected in the same island. Also this method might cause certain issues in the system, for example, if the grid has a high impedance a voltage flicker might occur. Also, it might cause system stability issues.

- **Harmonic amplitude jump**

It relies on injection of a current harmonics at a specific frequency into the point of common coupling from the DG side. The difference between this method and the previous one in the passive techniques is that the current harmonic is intentionally injected into the PCC.

If the utility grid is connected, the low impedance utility grid will absorb the harmonic current and no abnormal voltage will appear at the PCC. However, when the islanding occurs the impedance of the main grid will be higher and the harmonic current will flow to the load instead of the grid, and will cause a voltage harmonic at the PCC which can be detected and then disconnect the inverter.

This technique has a wide use and low NDZ, but still needs to set a threshold to determine the islanding. Also, if there is multi inverter injects same current harmonic will falsely trip the inverters since the voltage amplitude increases even with the grid connected (low impedance).

### 2.2. Comparison between the Islanding detection methods

Many islanding detection techniques have been discussed, where they were categorized into communication based techniques and local techniques which can be further divided into passive techniques and active techniques. Each technique has its own advantages and disadvantages. Table 2.2. Summarizes the advantages, disadvantages and situations where these methods are used.

The table and the discussion of the various techniques show that there is no technique which can detect islanding with all the systems and with different types of DGs. Passive methods are the easiest to implement but they suffer from a large NDZ whereas the communication based techniques are the most reliable but they are expensive to the utility network as well as the DGs owner.

Active detection techniques are reliable in order to detect islanding and they have relatively small NDZ. Such techniques however, might cause current ripples and/or voltage flickers in the system. Furthermore, these methods could take a longer time to detect islanding because it depends on the moment of the introduction of the disturbance.

**Table 2.2: Comparison between islanding detection techniques**

| Islanding detection technique | Communication based techniques | Local techniques | |
|---|---|---|---|
| | | Passive | Active |
| **Advantages** | • Zero NDZ<br>• Most reliable method<br>• fast | • Easy to implement<br>• Less cost.<br>• Short detection time | • Accurate<br>• Small NDZ |
| **Disadvantages** | • Expensive<br>• Complexity to implement | • Large NDZ<br>• Needs to set a threshold in order to detect the island | • Slow<br>• Causes instability problems to the system<br>• Addition equipment needs to be installed |
| **Methods** | • Transmission line signaling technique<br>• Disconnection signaling technique<br>• Using Supervisory Control And Data Acquisition (SCADA) | • Abnormal voltage/frequency detection<br>• Power factor detection<br>• Monitoring the voltage harmonic | • Reactive power error detection<br>• Impedance measurement method<br>• Harmonic amplitude jump |

## CHAPTER 3. METHODOLOGY

### 3.1. System under study

A practical IEEE 13-bus system [10] is considered for islanding detection, IEEE 13-bus system shown in Figure 3.1. Is considered as an unbalanced, and heavy loaded medium voltage system which serves different types of load such as commercial and industrial loads. The system is fed by a substation at 115 KV using a 5-MVA 115-KV/4160-V transformer at bus 650. Different types of distributed generators are connected to bus 634, and to the rest of the system using a 500-KVA 4160-V/480-V transformer.

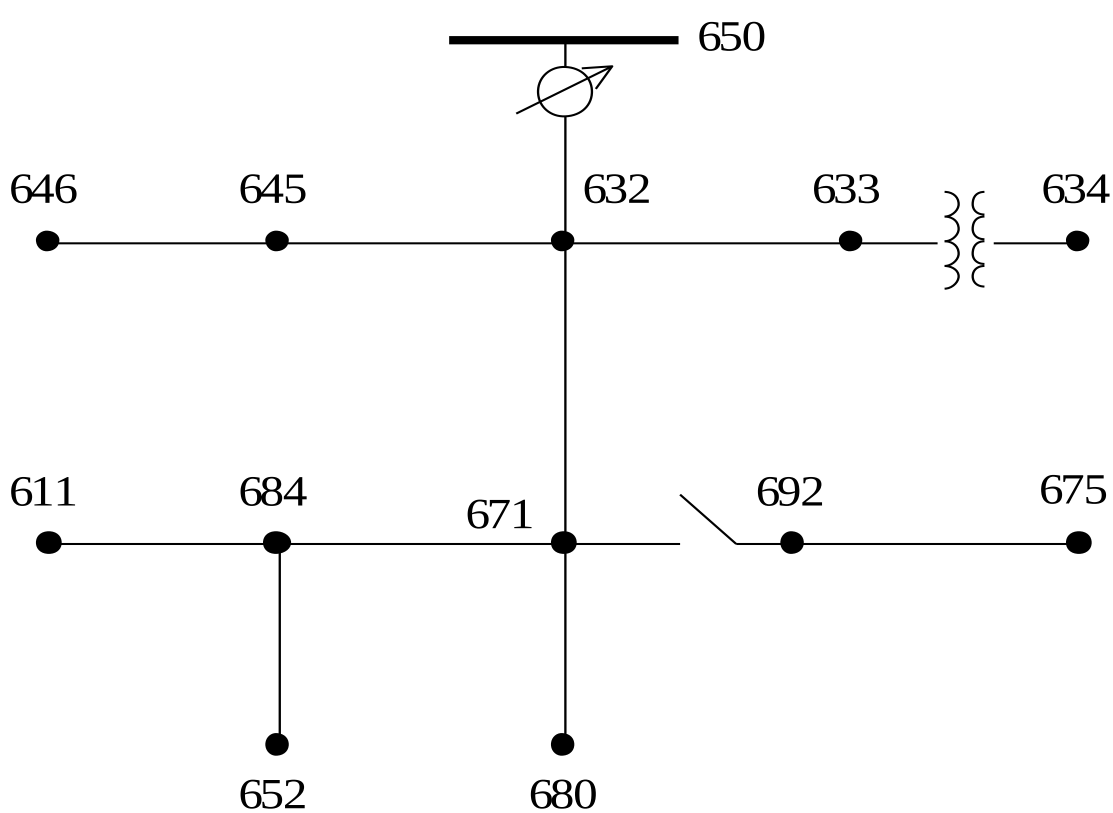


Figure 3.1: IEEE 13-bus system

## 3.2. Distributed Generators

To cover all possible islanding detection scenarios; two different types of distributed generators are connected to the system, one is the inverter- based distributed generators and the other one is synchronous distributed generators.

### 3.2.1. Inverter based distributed generator

The block diagram of an inverter based photovoltaic (PV) distributed generator is shown in Figure 3.2. A three phase IGBT bridge inverter is used to convert the PV's output DC voltage to AC voltage using pulse width modulation (PWM) with a switching frequency of 10 KHz.

The Inverter's output AC voltage, and frequency is synchronized with the utility voltage and frequency. A LC filter is used to eliminate the high switching frequency components from the current, therefore, reduce the current ripple [11].

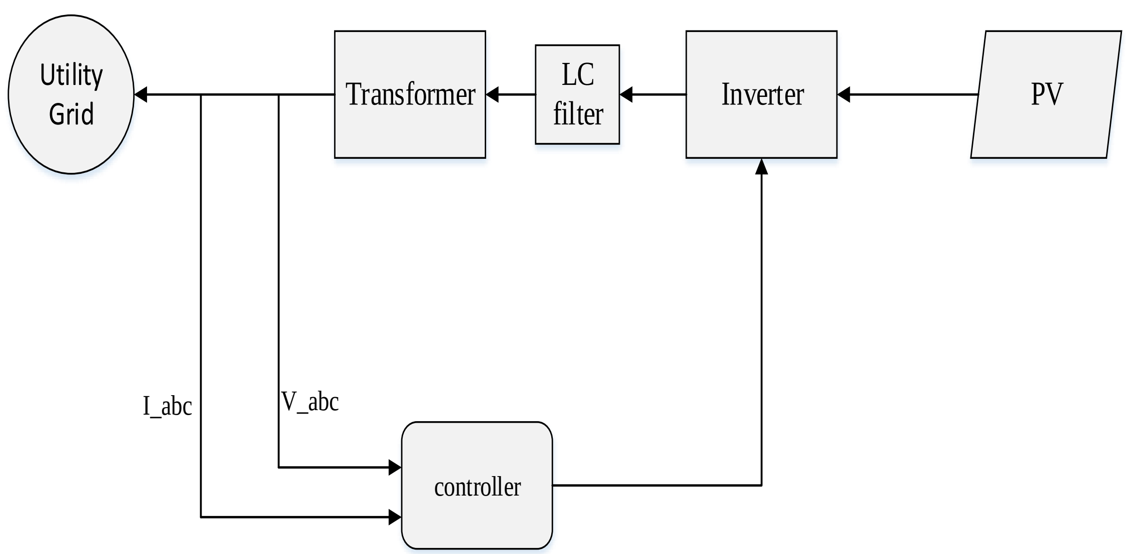


Figure 3.2: Block diagram of the inverter-based distributed generators

Figure 3.3. Shows the system with the LC filter. The design of the LC filter depends on the grid parameters and the switching frequency of the PWM. The ripple current is reduced by adjusting the size of the inductor L, the inverter's bridge switching frequency, and the core loss of the inductor. Typically the ripple current is selected to be within 10% to 20% of the rated current. The inductor is designed using the following equation:

$$L = \frac{V_{dc}}{8 * \Delta I_{Lm} * f_s} \tag{3.1}$$

Where $\Delta I_{Lm}$ is the ripple current percentage, $V_{dc}$ is the input DC voltage of the inverter in Volts, $f_s$ is the PWM switching frequency in Hertz, and $L$ is the filter's inductor value in Henry.

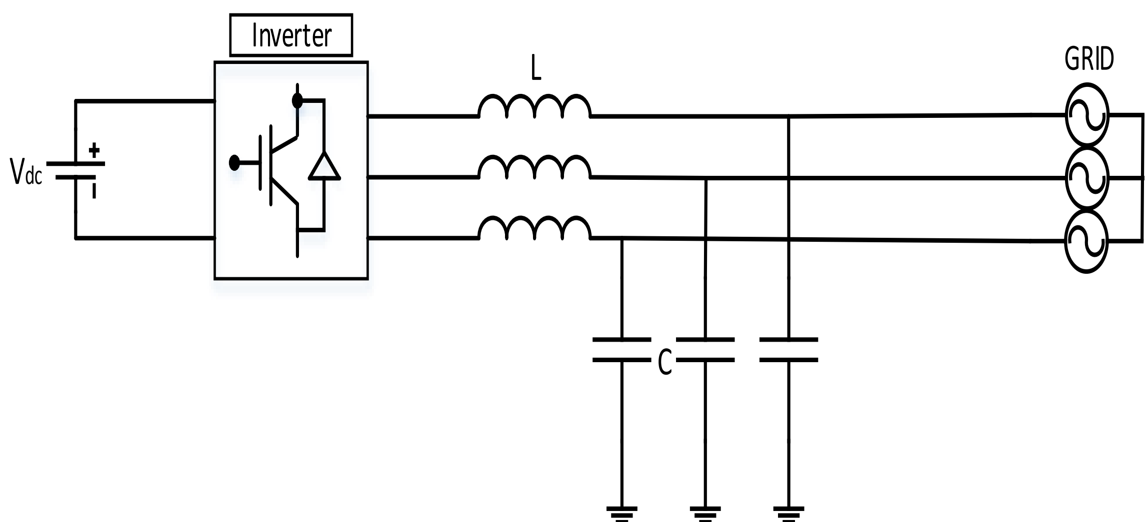


Figure 3.3: The DG with LC filter

The capacitor value depends on reactive power consideration. If the capacitance is too high, the result will be a larger reactive power through the inductor, which will increase the current demand of the inductor and lead to lesser efficiency. The reactive power is selected to be around 15% of the rated power. The following equation shows the calculation the capacitor's value:

$$C = \frac{15\% * P_n}{3 * 2 * 2\pi f_g * V_n^2} \tag{3.2}$$

Where $C$ is the value of the capacitor in Farad, $P_n$ is the nominal power in Watts, $f_g$ is the grid frequency in Hertz, and $V_n$ is nominal voltage in Volts. The grid parameters and the LC filter calculation are shown in table 3.1.

**Table 3.1: Grid parameters and LC filter calculations**

| **Parameter** | **value** |
|---|---|
| Pn | 500 kW |
| Vn | 480 V |
| fg | 60 Hz |
| fs | 10 kHz |
| Δilm | 90 A |
| Vdc | 780 V |
| L | 16.2 mH |
| C | 28.8 mF |

The transformer is selected to step up the inverter's output voltage to 480V. It also isolates the injected DC current and prevents it from flowing in to the grid. A delta star configuration is used in order eliminate the third harmonic which gets circulated in the delta side of the transformer and doesn't enter the grid.

The phase locked loop (PLL) plays a role of synchronizing output frequency and the phase angle of the grid connected DG with the grid frequency and phase angle of the grid voltage. It is used to track one signal to another and keeps the output signal synchronized with the input signal in the frequency and phase.

The current control strategy is shown in Figure 3.4. It uses the Park transformation d-q, also called synchronous reference frame transformation. It transforms the voltage and current a-b-c to d-q frame. The control strategy works as described below:

1. The grid voltage is measured and supplied to the phase locked loop (PLL) to extract the phase angle of the grid.
2. The grid current is measured and fed to the Park transformation a-b-c to d-q to extract the d-q current components $i_d$ and $i_q$.
3. The grid voltage is also measured and transformed to get $v_d$ and $v_q$.
4. A comparison is done between $i_d$ and the $i_d$ reference $i_d^{ref}$ and between $i_q$ and the $i_q$ reference $i_q^{ref}$ .
5. The difference output is fed to proportional integral (PI) controller to eliminate the error between the measured value and the reference value.
6. The following feed forward terms: $v_d - w * l * i_q$ and $v_q + w * l * i_d$ are used to get decoupled control of the system.
7. The controlled outputs $v_d^{ref}$ and $v_q^{ref}$ are divided by $v_{dc}/2$ to get the modulation indices $m_d$ and $m_q$.
8. Modulation indexes $m_d$ and $m_q$ are transformed back to a-b-c frame $m_a$ , $m_b$ and $m_c$ using the same phase angle ϴ and fed to sinusoidal pulse width modulation (SPWM).

9. SPWM generates the switching signals of the inverter.

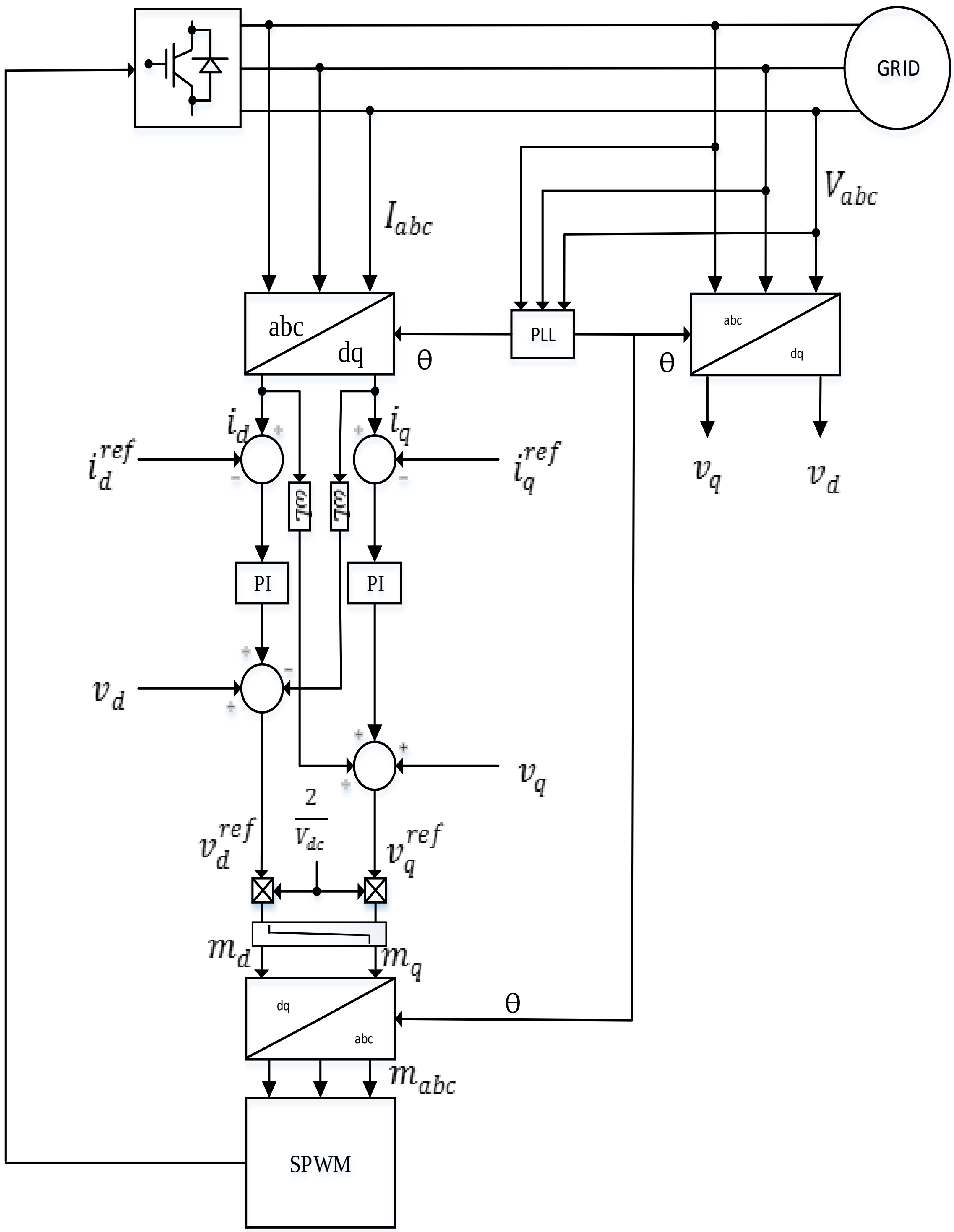


Figure 3.4: Current control structure used to control the inverter-based DG

### 3.2.2. Synchronous based distributed generator

Synchronous generators are rotating energy conversion machines and are able to work in both stand-alone operating source or in parallel with the utility network. When a synchronous generator operates in parallel with the utility network, the output voltage, frequency and the phase angle should be synchronized with the utility grid.

The excitation level of the synchronous generators may be adjusted to achieve the desired operating reactive power; a high level of excitation will make the generator produce reactive power and it appears as capacitive, whereas a low level of excitation will lead to consume reactive power and the unit will appear as inductive with respect to the grid.

The power factor can be adjusted between the leading through unity to lagging, that would benefit in voltage regulation and multipurpose of changing the reactive power to the utility and the customers.

The synchronous generator model used in this work is modeled in [12], and the generator parameters for a rated power of 5 MVA, and output voltage of 15 KV are shown in table 3.2. A step down transformer is used to get the voltage to 480 volts.

The IEEE 1547-2003 standards should be met to connect the synchronous generator to the utility grid because failure in connecting and synchronizing the voltage, frequency and phase angle may cause a voltage and current perturbation on the utility network and in some cases causes damage to the utility equipment as well as the costumer’s equipment. This will also impact the power quality at the consumer’s level.

**Table 3.2: Synchronous generator parameters**

| | |
|---|---|
| Ra | 0.0052 p.u |
| Xd | 2.86 p.u |
| Xd’ | 0.7 p.u |
| Xd” | 0.22 p.u |
| Xq | 2 p.u |
| Xq’ | 0.85 p.u |
| Xq” | 0.2 p.u |
| Td’ | 3.4 p.u |
| Td” | 0.01 p.u |
| Tq” | 0.05 p.u |
| H | 2.9 s |

### 3.3. Features selection and classification

Machine learning is a method of data analysis that mechanizes analytical model building. It uses algorithms that iteratively learn from data, machine learning allows computers to hidden visions without being explicitly programmed where to look. We used machine learning mechanism due to the factors that have made data mining more popular than ever. The factors and reasons of using data mining technique can be summarized as following:

- Growing in the volume and verities of the data.
- The computational processing is cheaper and more powerful.
- Data mining extracts useful information from the data in order to interpret the data.

The motivation of using data mining techniques in the thesis is to use the extracted features data to build a model quickly and analyze bigger and more complex data. In this proposed methodology, we measure the voltage and current at the PCC and we extract four features in order to apply classification techniques to detect the islanding phenomena. The four features are shown in Table 3.3. These features are used as an input to certain classification techniques and a comparison is done to determine which classifier was able to distinguish an islanding from other system disturbances.

**Table 3.3: Selected features to detect islanding**

| | |
|---|---|
| V | Voltage in p.u |
| f | Frequency in Hz |
| dV/dt | Rate of change of voltage |
| df/dt | Rate of change of frequency |

The extracted features are used to train a model to be used as an islanding detection model. This model is then used to test new cases and the precision is measured to test the accuracy of the model. There are different and many types of classifiers and a brief description of well-known classifiers is given below.

### 3.3.1. Nearest Neighbor classifier

This classifier is one of the simplest classification methods; it is useful data mining method that allows using the previous data cases with the known output values to predict the unknown output value of the new data instances [13]. It classifies the input data by comparing the distance between the new instance and the old instances.

It classifies the input data by placing the first instances in the space. Then, it measures the distance of the new instance from the old instances and add the new instance to the closest group. This classifier showed a high percentage of accuracy regarding the Islanding detection and was very close to the Random Forest classifier when the 4 features are used as an input to both classification methods.

### 3.3.2. Bagging classifier

The bagging classifier is an ensemble method that generate individuals for its group by training each classifier on random process. Each classifier's set is created by randomly drawing with replacement [14].

For each data set of size $N$ a training set of size $T$ is sampled with replacement, the training set is same size as in the original data set but some of the data doesn't appear in the training set while some of the data appear more than one time. After that a number of classifiers is made to test the data and the error is then calculated as the average of all the classifiers. In the islanding detection process the number of the data set are N=100.

### 3.3.3. Lazy K start classifier

It is considered as an instance based classifier that uses match function from the training set to classify test set. Misplaced values are averaged by column entropy curves and the global blending parameter is set to 20 [15].

The lazy K star process uses entropic degree, based on probability of converting occurrence into another by randomly selecting between all possible conversions. Using entropy to assess distance has many uses. The number of $k$ nearest neighbor that used in this classifier can be determined using the following equation:

$$k = \sqrt{N} \tag{3.3}$$

Where $N$ is the number of data set (i.e. simulation cases) which $N$=100, And $k =$ 10.

### 3.3.4. Naïve Bayesian classifier

It is a powerful and straightforward classifier. Naïve Bayesian classifier depends on applying Bayes' theorem with independence assumptions between the classification's data [14]. Mathematically Bayes' theorem is:

$$p(c_j|d) = \frac{p(d|c_j) * p(c_j)}{p(d)} \tag{3.4}$$

Where $p(c_j|d)$ is the probability of instance $d$ being in class $c_j$ , $p(d|c_j)$ is probability of generating instance $d$ given class $c_j$, $p(c_j)$ is probability of occurrence of class $c_j$ and $p(d)$ is the probability of instance $d$ occurring.

### 3.3.5. Random Forest classifier

Random forest classifier is an assembly of trees predictors. It takes the input feature vector, classifies it with every tree and the outputs the class label that receives the most votes. All the trees are trained with the same features but with different training group. These groups are generated from the original training group [15].

Random Forest classifier depends on multistage decision making. Each node on the tree is a node of simple decision making. The solution (the last decision) is made by taking the majority votes from all the nodes. The analysis of Random Forest shows that its computational time is:

$$t = c * T * \sqrt{M} * N * \log(N) \quad (3.5)$$

Where $c$ is a constant, $T$ is the number of trees in the ensemble, $M$ is the number of variables and $N$ is the number of samples in the data set.

### 3.4. Proposed methodology

In this thesis a 13-bus distribution system has been simulated using MATLAB/SIMULINK with SimPowerSystems tool box, MATLAB/SIMULINK is a block diagram environment for model-based design and has been used for a wide range of dynamic simulations such as automatic control, digital signal processing as well as electrical power systems design and analysis. The simulated system is shown in Figure 3.5.

Two types of distributed generators are modeled and connected to node 634 in the system, the inverter based DG and the synchronous generator based DG. The inverter based distributed generator with current control is shown in Figure 3.6.

Islanding conditions and different types of disturbances are created in the system, and the voltage, frequency, rate of change of voltage, and rate of change of frequency are extracted from the point of common coupling.

Next, different type of classifications are applied to the extracted features in order to validate the ability of each classifier to detect islanding and the time taken by each classifier to distinguish the islanding condition from non-islanding conditions. The proposed methodology can be summarized in Figure 3.7.

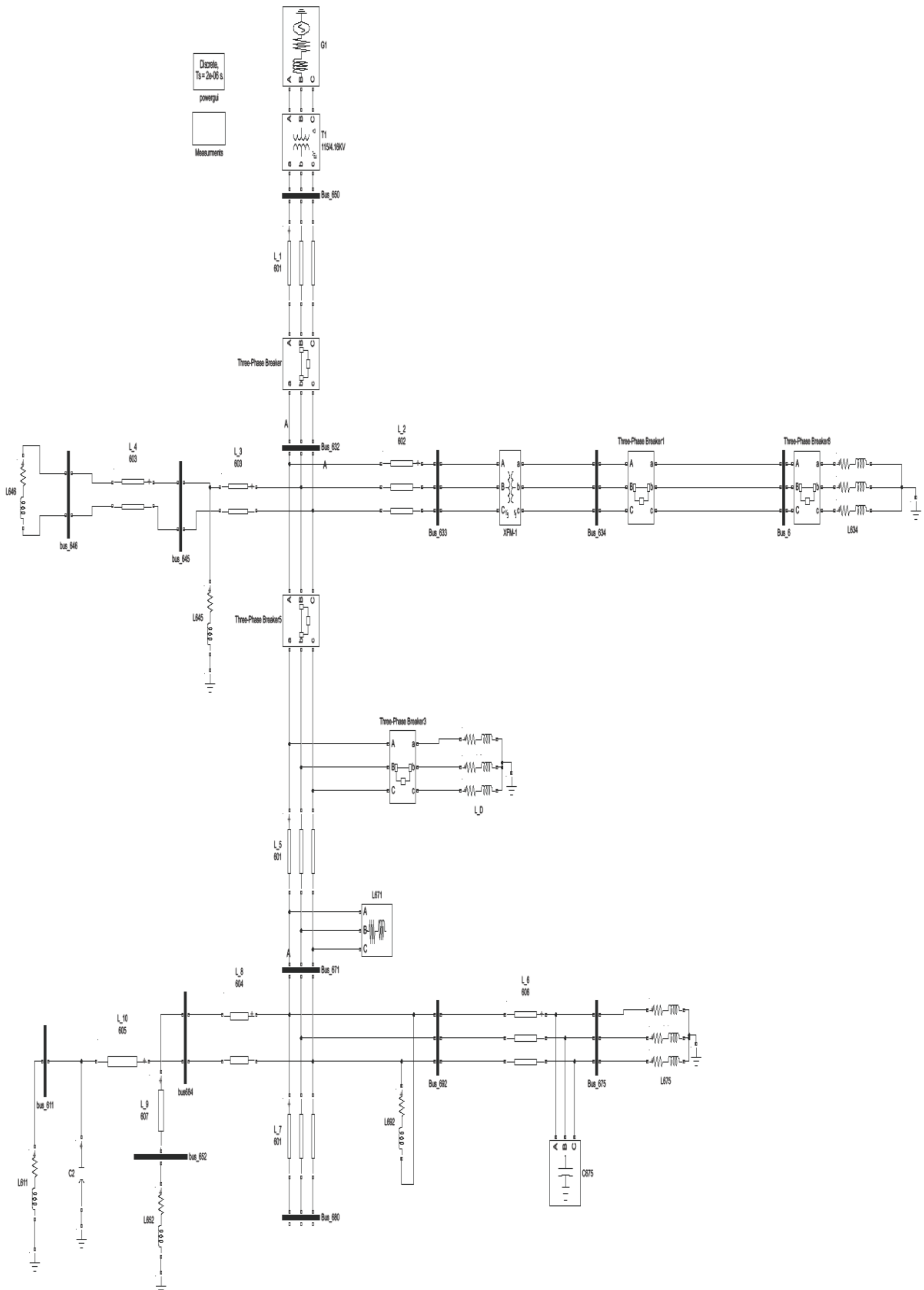

Figure 3.5: Simulated 13-bus system

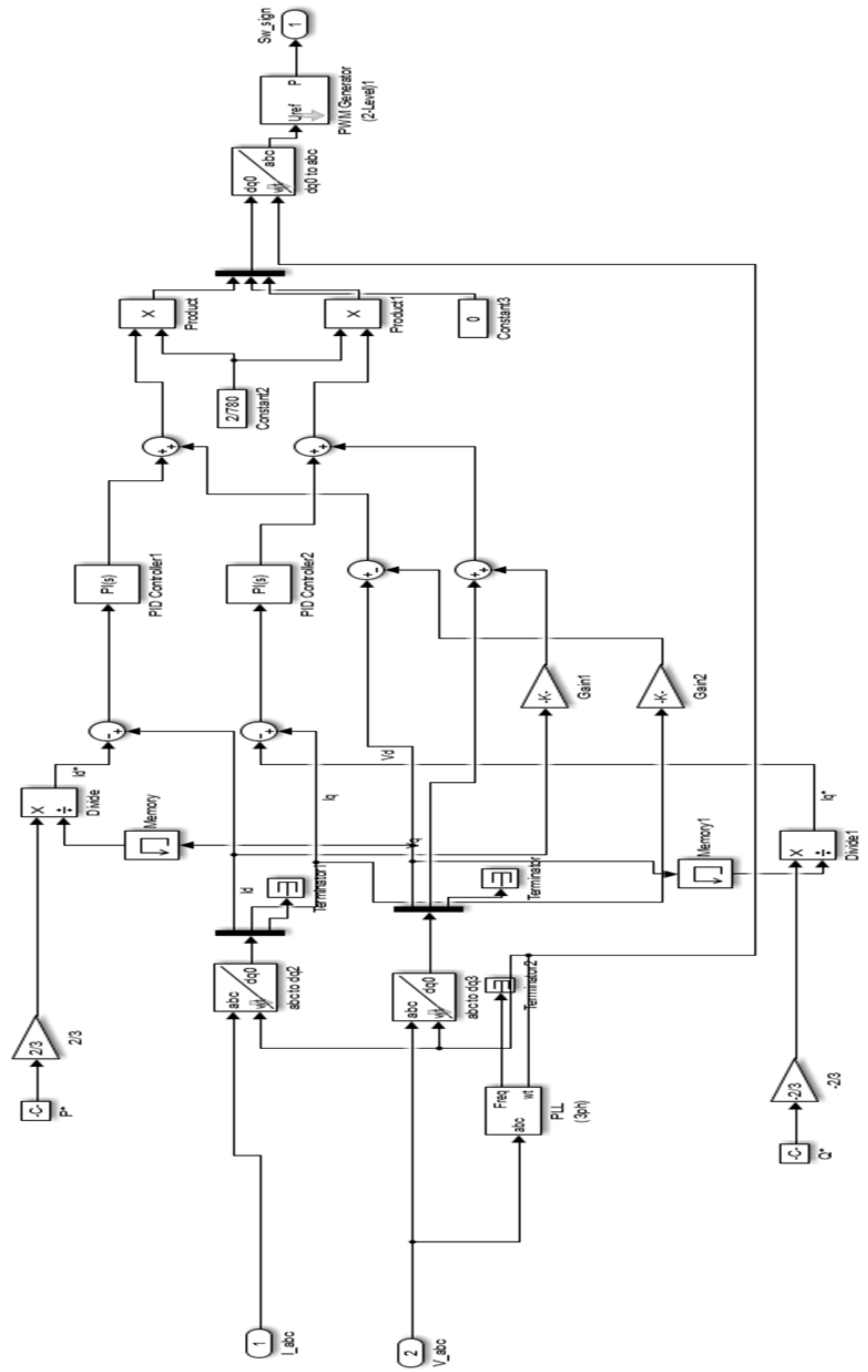


Figure 3.6: Current control scheme

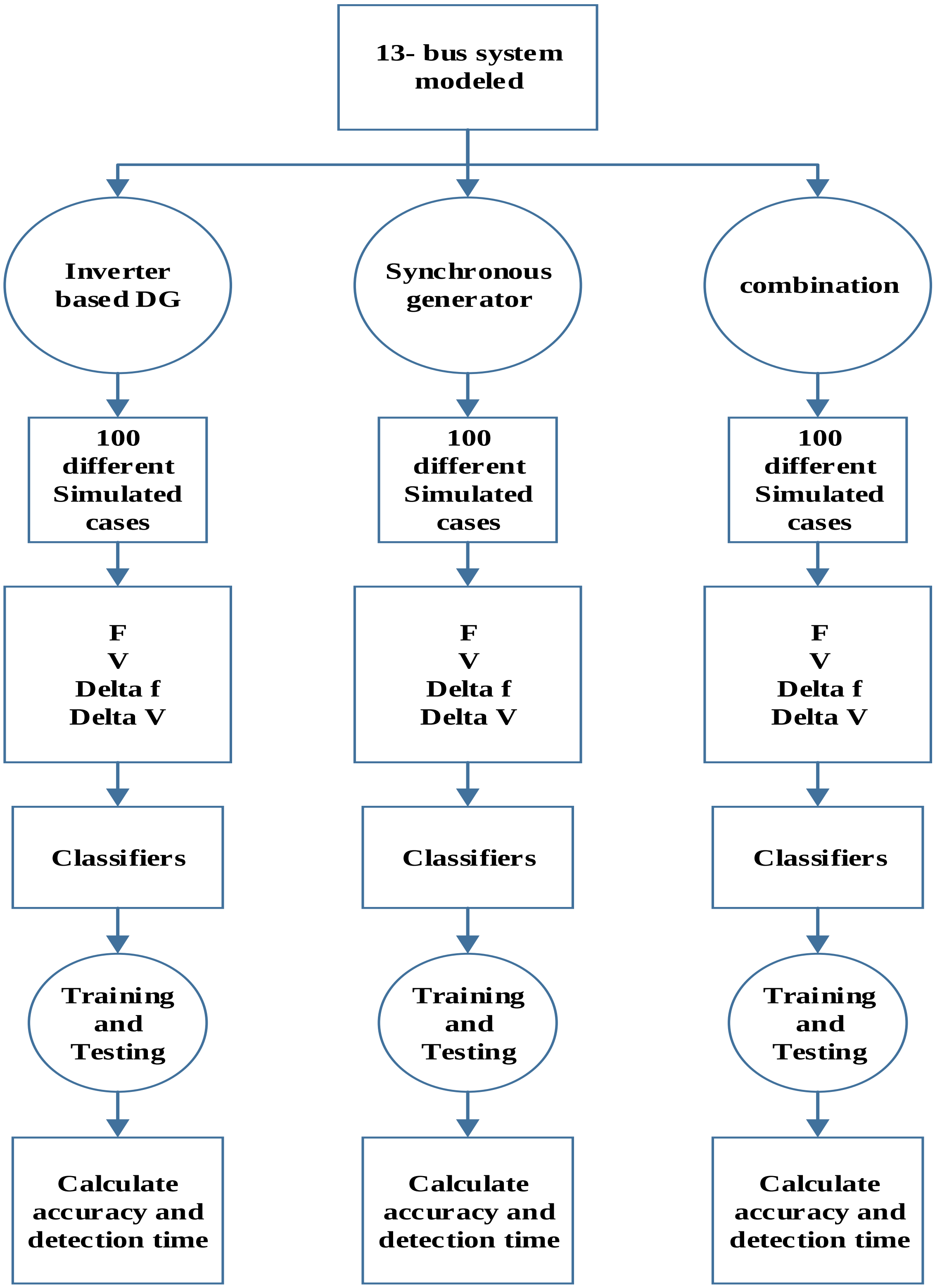


Figure 3.7: Proposed methodology chart

# CHAPTER 4. RESULTS AND DISCUSSION

## 4.1. DG's setting and connection

In order to provide the classifiers with enough information, 100 different simulated cases were performed. The cases included different types of scenarios in order to cover all the islanding and non-islanding conditions.

An IEEE 13-bus system was simulated using MATLAB/SIMULINK with an inverter-based distributed generator connected at node 634. All 4 features have been extracted for single inverter-based DG connected to the system. Two cases were considered to generate the island and they are as follows:

- Disconnect the utility network from a point close to the PCC that will form a small island which includes the DG and the local load.
- Disconnect the system from the substation in the utility network to form a large island which consist multiple DGs and the system loads.

Figure 4.1. Shows the two islanding cases discussed above. For the inverter-based distributed generator the voltage and frequency have to remain within the limits specified by IEEE Std. 1547. If the voltage and frequency exceed the limits the abnormal voltage/frequency islanding detection technique (discussed in chapter 2) will detect the island and trip the DG.

The voltage and frequency deviation is due to the mismatch of active and reactive powers between the DG and the served load. To keep the voltage and the frequency within the limits a small mismatch in the power and reactive power (e.g. 10% power mismatch and 1% reactive power mismatch) is considered in the islanding cases as it is the most challenging islanding conditions to be detected.

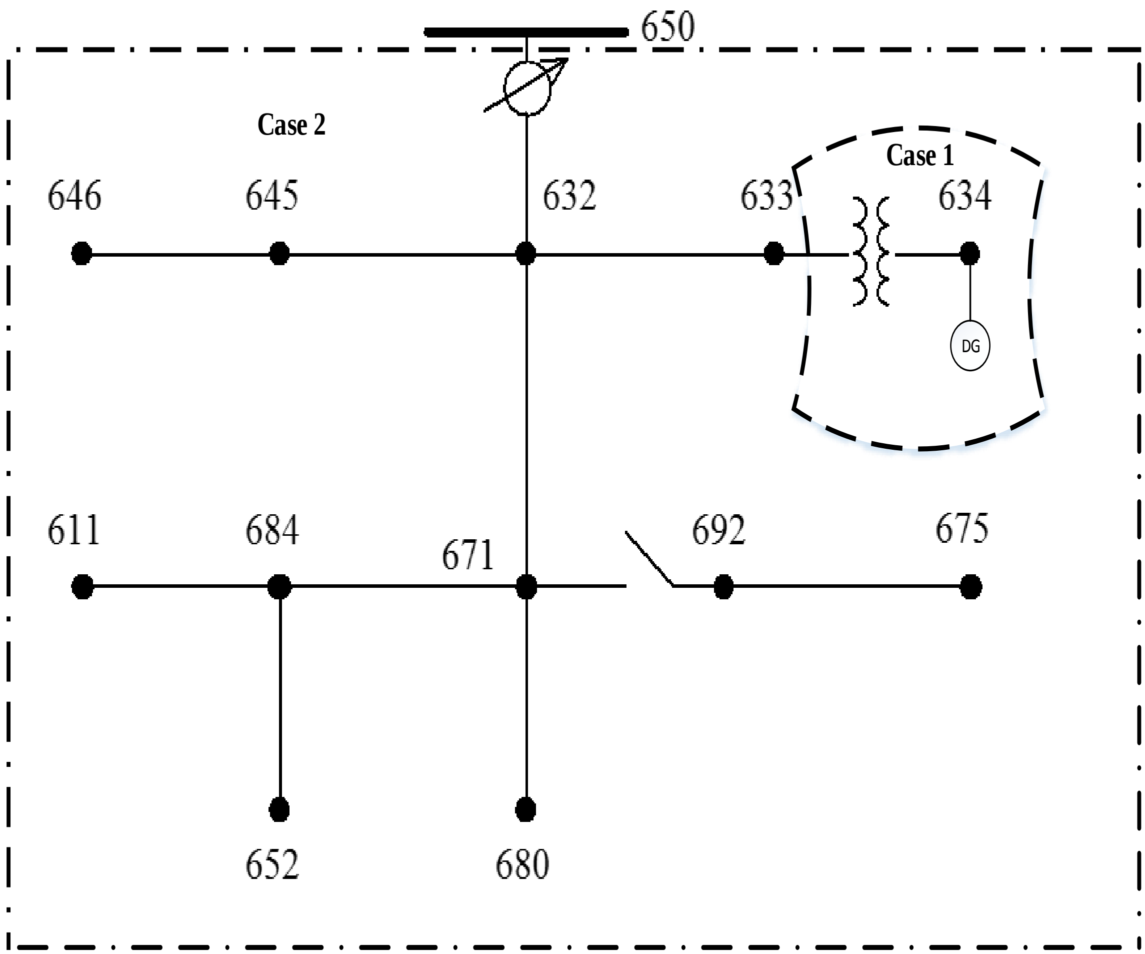


Figure 4.1: Islanding cases

Non islanding conditions considered are: switching loads, capacitors banks switching, and creating some faults on different buses in the system. The islanding and non-islanding conditions are summarized below:

- Islanding conditions: When the utility is disconnected and the power mismatch is between 0 to ±30% and reactive power mismatch is between 0 to ±5% [18].
- Non-Islanding conditions: Switching different types of load, capacitor banks, and faults on different busses within the system.

In order to test the classifier and create a model to detect the islanding condition, the inverter-based DG is substituted with synchronous generator and power and reactive power mismatches of 10% and 1%, respectively, are considered. Moreover a combination system including an inverter-based DG and synchronous generator were connected to bus 634.

Connecting the different types of the distributed generators and a combination of the inverter-based DG with synchronous generator make the model universal with regards to the detection of islanding from other system disturbances.

Using MATLAB/SIMULINK with power system tool box (SimPowerSystem) three system configurations were simulated. Figures 4.2, 4.3, and 4.4. Show the simulated system with inverter-based DG, synchronous generator, and a combination of both DGs, respectively.

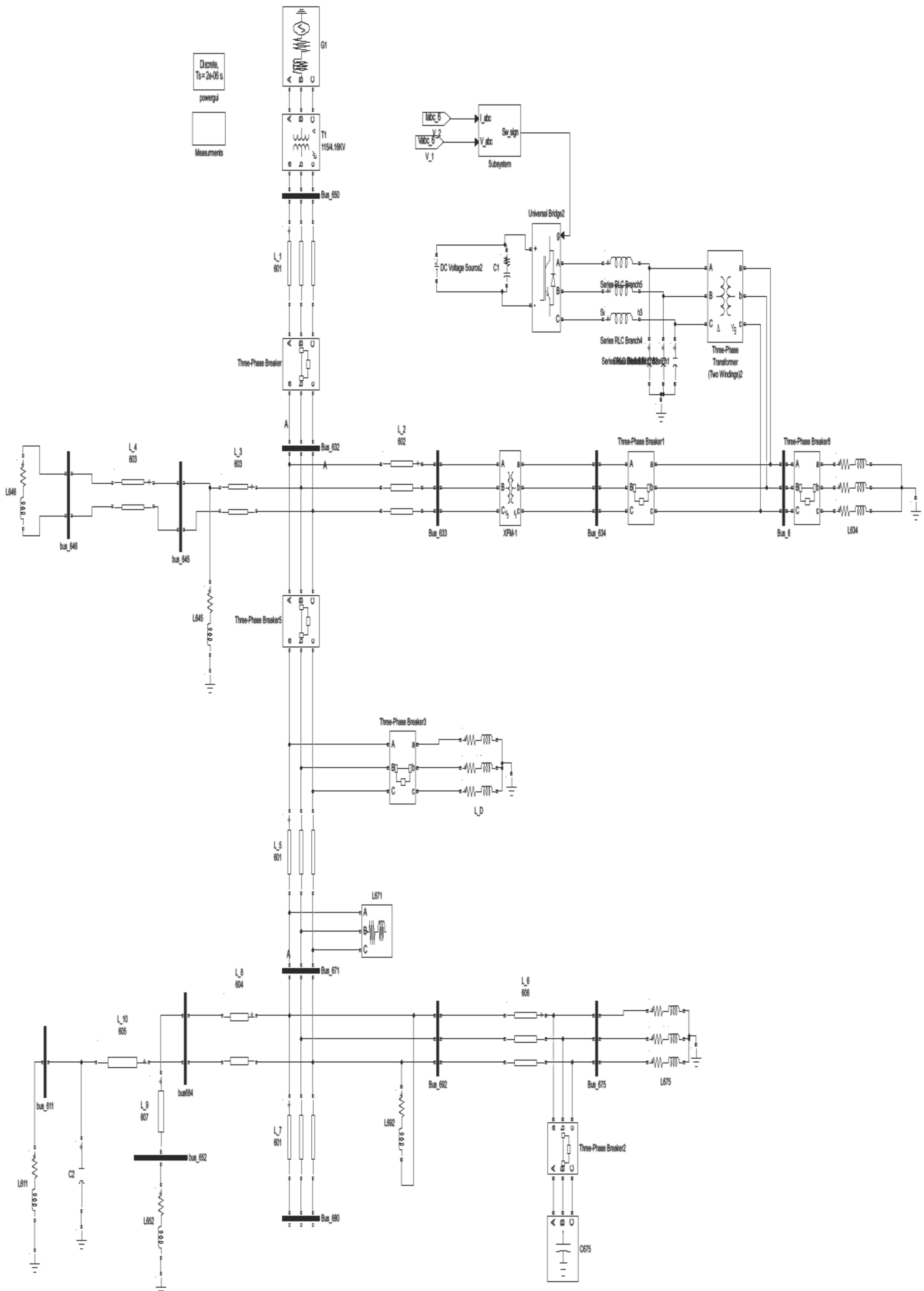


Figure 4.2: Inverter-based DG connected to the system

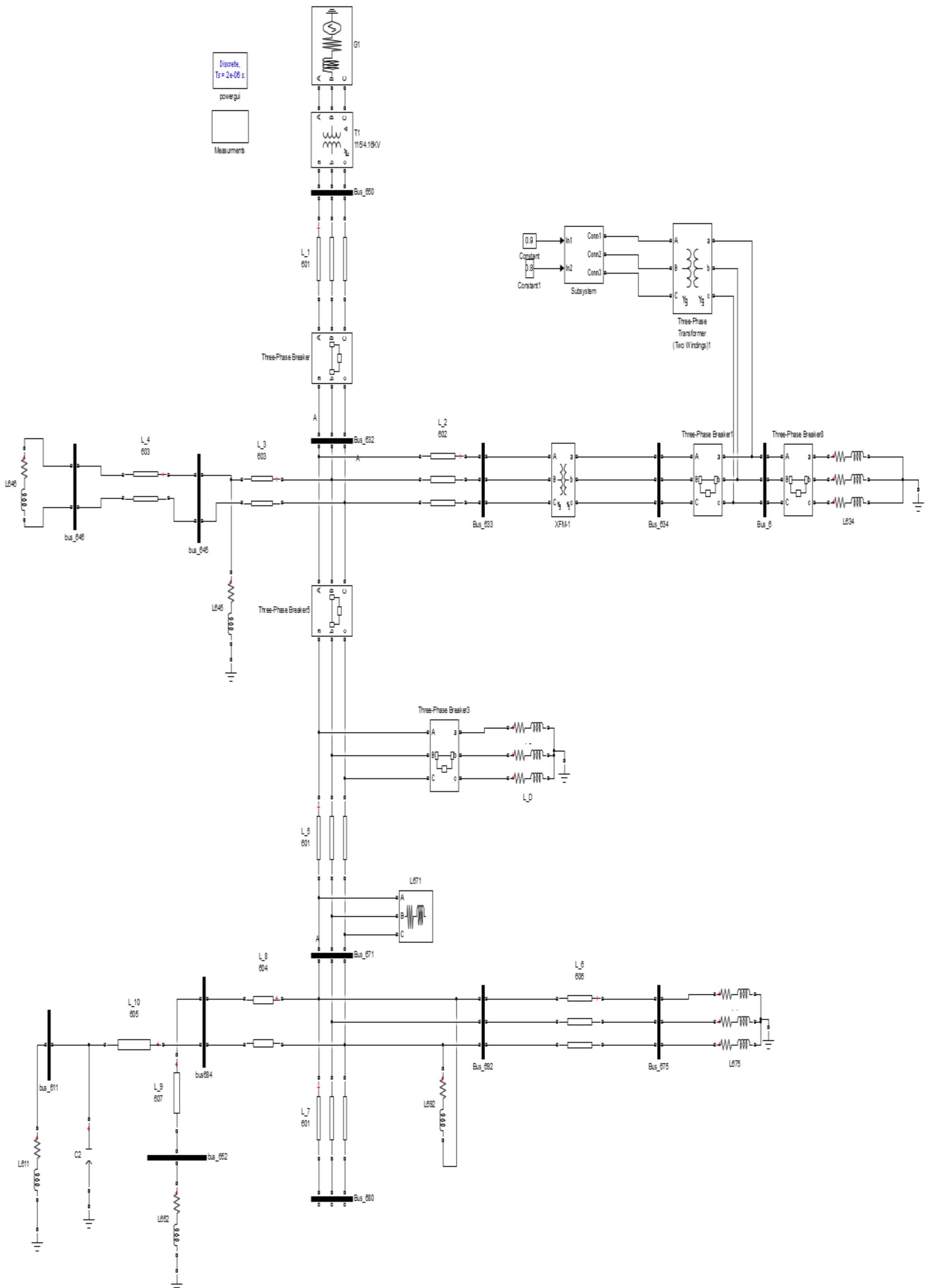

Figure 4.3: Synchronous Generator connected to the system

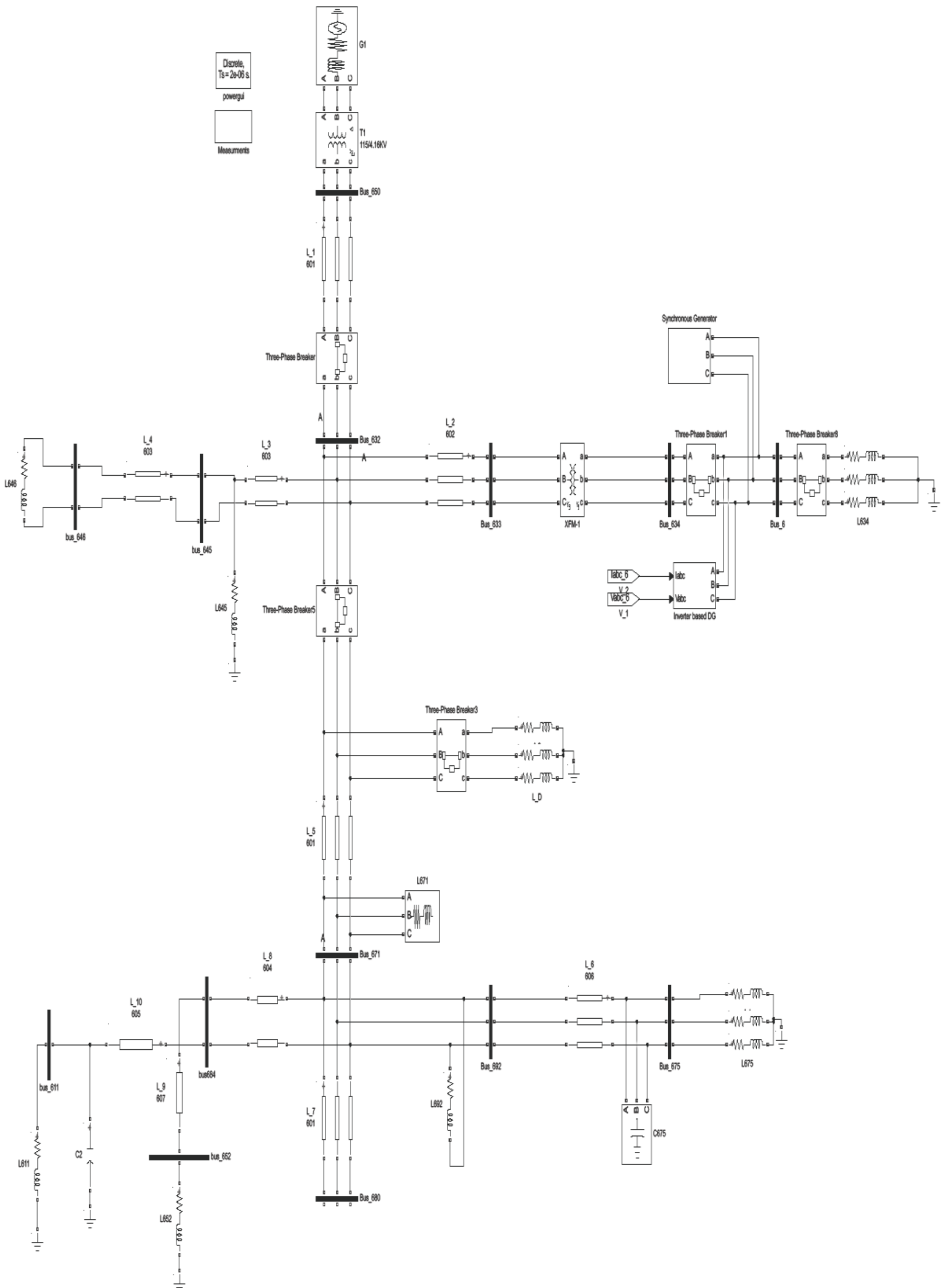


Figure 4.4: Combination of DGs connected to the system

### 4.2. Features extraction

Islanding is detected using 4 features which are: voltage, frequency, rate of change of frequency, and rate of change of voltage. They are extracted from the measured voltage and frequency at the point of common coupling.

Different types of disturbances and islanding conditions are simulated. Figures 4.5. And 4.6. Show the voltage and the frequency responses at the PCC when an inverter-based DG is connected to the utility network. The islanding occurs at t = 1 s.

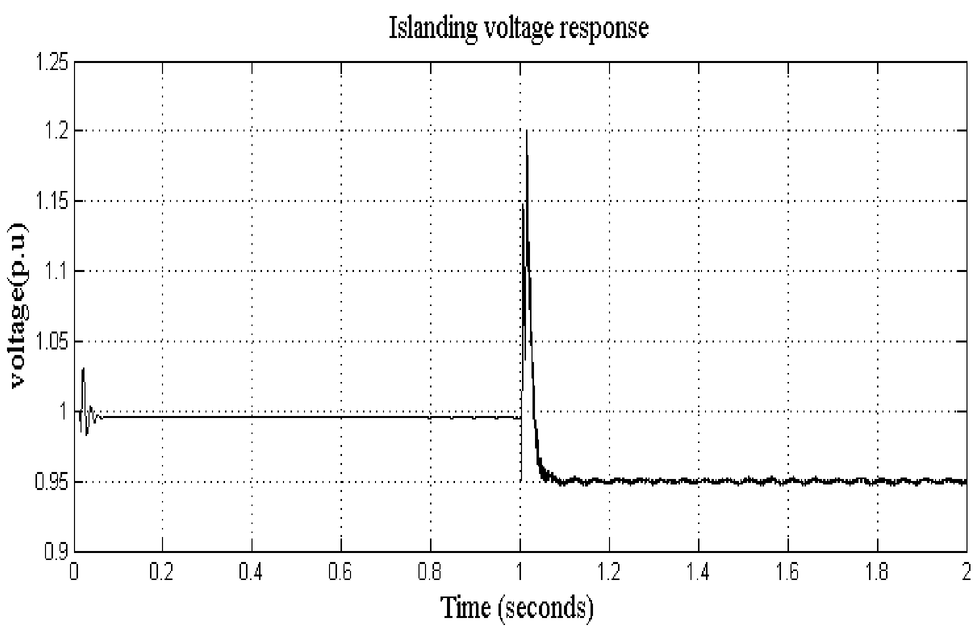


Figure 4.5: Islanding voltage response (Inverter-based DG)

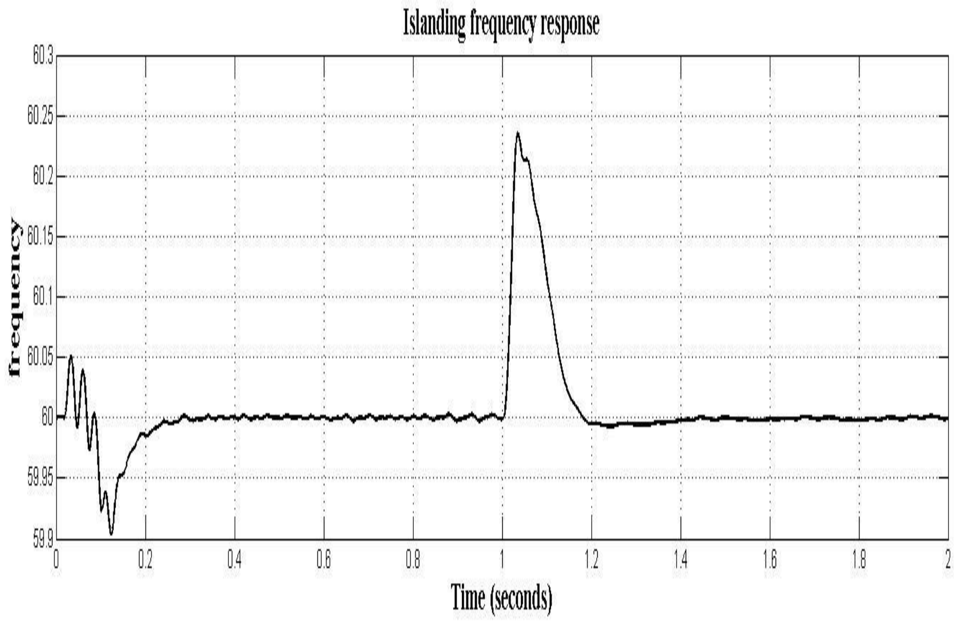


Figure 4.6: Islanding frequency response (Inverter-based DG)

With a small mismatch of the real and reactive powers; the voltage and frequency response remain within the specified standards (IEEE Std. 1547). This means the voltage and frequency lie in the NDZ, and some of the islanding detection techniques such as abnormal voltage/frequency are not able to distinguish whether the islanding has occurred or not.

Similarly, figures 4.7. And 4.8. Show the voltage and frequency when we substitute the inverter-based DG with synchronous generator, and introduce the islanding. Figures 4.9. And 4.10. Show the voltage and the frequency responses when an inverter-based DG and a synchronous generator are connected to node 634 in the system, and islanding is introduced.

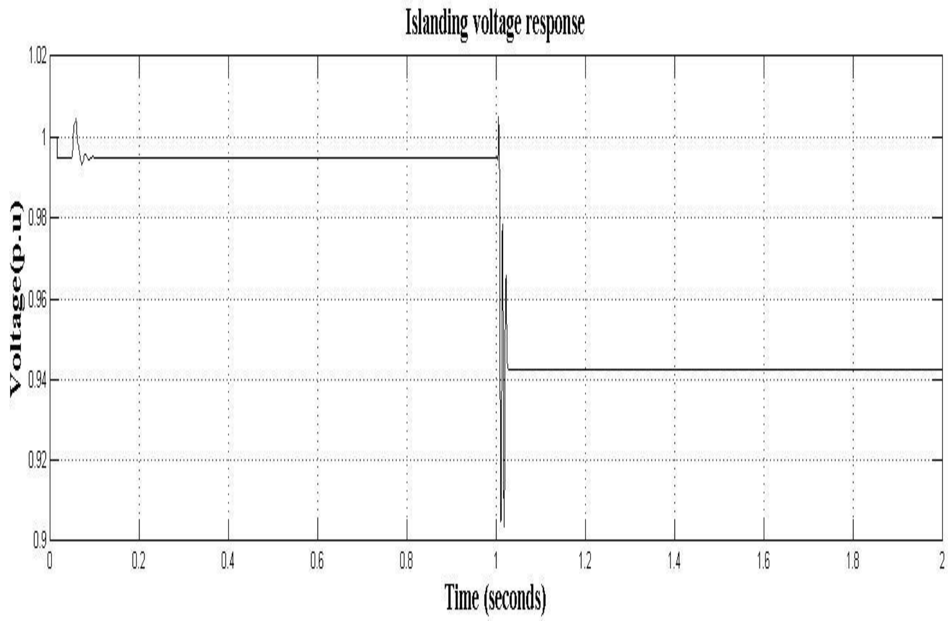


Figure 4.7: Islanding voltage response (Synchronous generator)

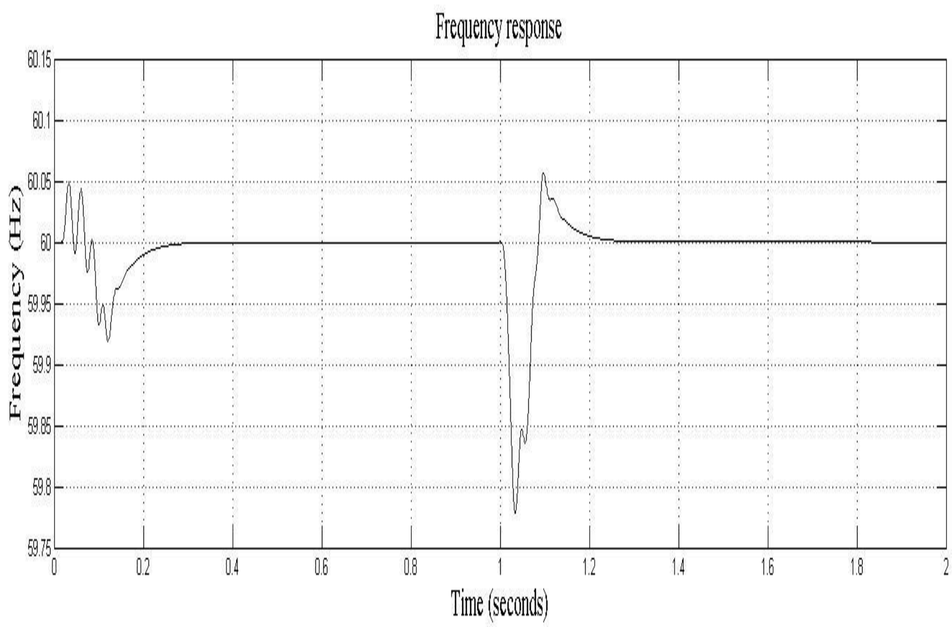


Figure 4.8: Islanding frequency response (Synchronous generator)

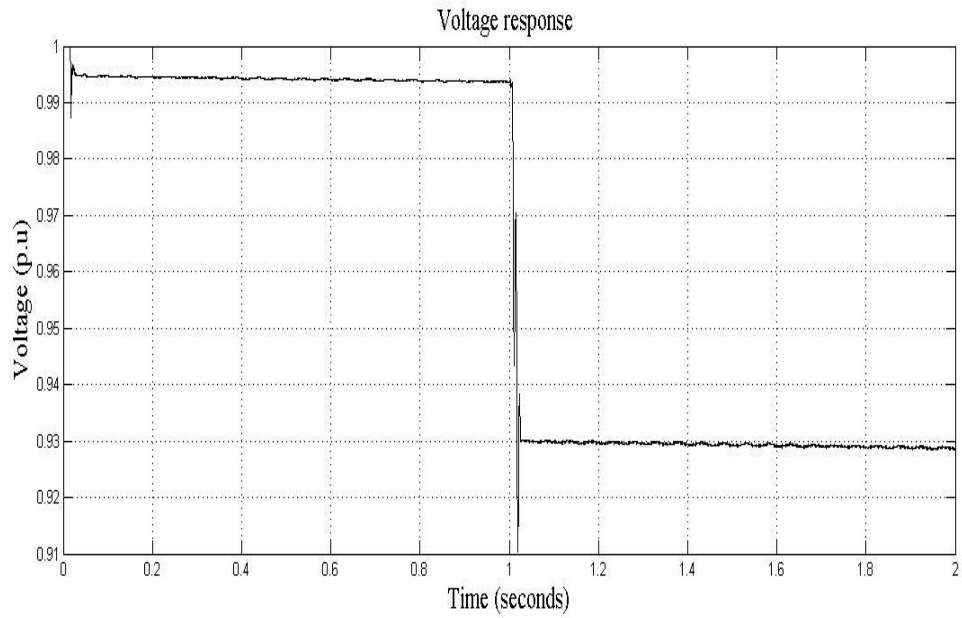


Figure 4.9: Islanding voltage response (combination DGs)

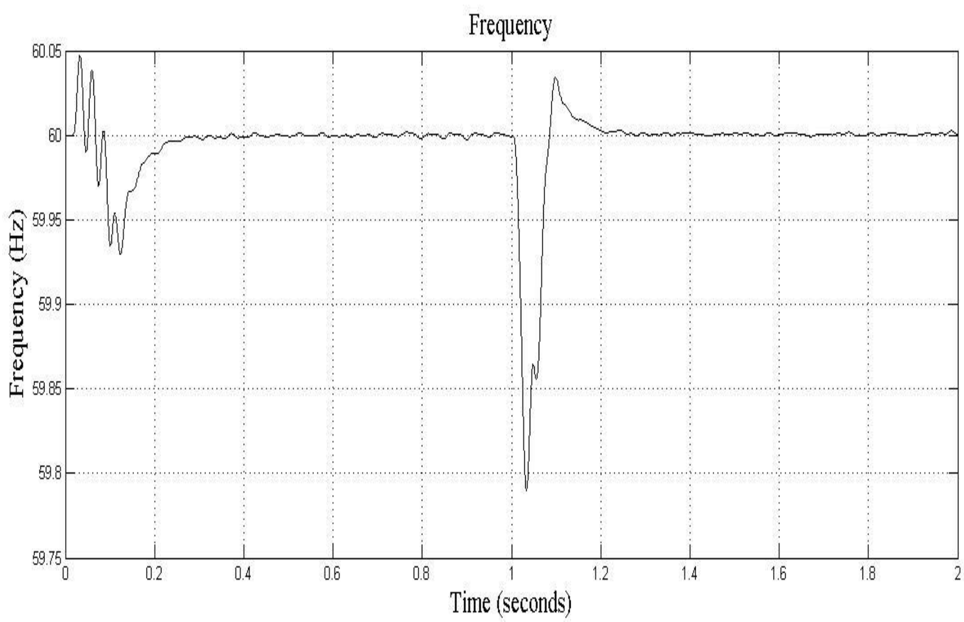


Figure 4.10: Islanding frequency response (combination DGs)

Non-islanding conditions such as switching capacitor bank and switching inductive load are considered, and 100 cases of non-islanding cases are simulated in order to cover as many disturbances that are likely to occur during the normal operation of the system.

The system is simulated and the disturbances are introduced 1 second after starting the simulation. Figures 4.11. And 4.12. Show the voltage and frequency responses of switching a capacitor bank at a certain bus within the system when an inverter-based DG is connected to bus 634. Figures 4.13. And 4.14. Show the PCC voltage and frequency responses of switching the same capacitor bank that are used in the inverter-based DG, but with a synchronous generator in this case. Figures 4.15. And 4.16. Show the voltage and frequency responses for switching the capacitor bank when we used a combination of both synchronous generator and inverter-based DG at bus 634 in the system.

Another example of the voltage and frequency responses of the non-islanding cases are shown in Figures 4.17 - 4.22. Where an inductive load is switched at time =1 s at bus 680 in the system, and different DGs are connected to the bus 634.

A large number of cases were simulated in order to distinguish between islanding and non-islanding situation. We extracted 4 different features to accurately detect islanding, and the features are used to train and test the classifiers model; the accuracy and precision are then calculated.

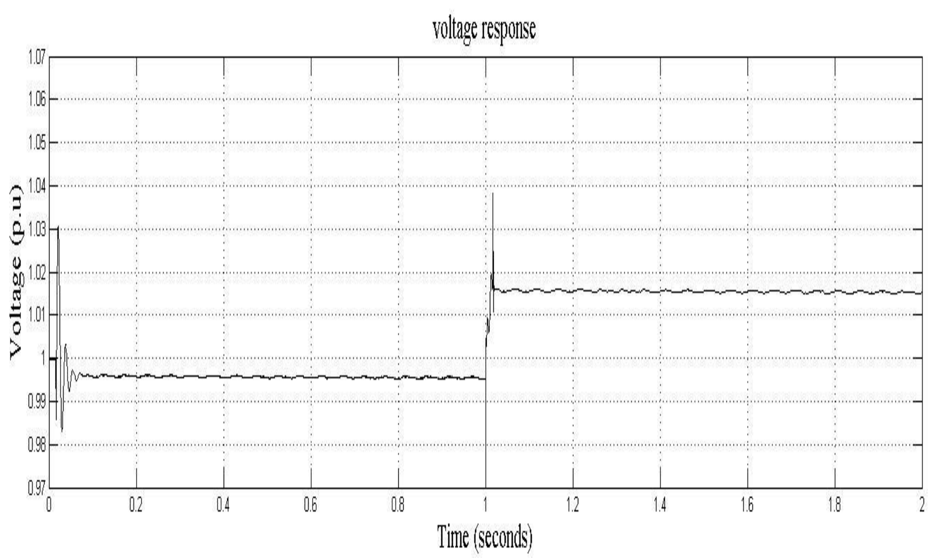


Figure 4.11: Switching capacitor bank voltage response (inverter-based DG)

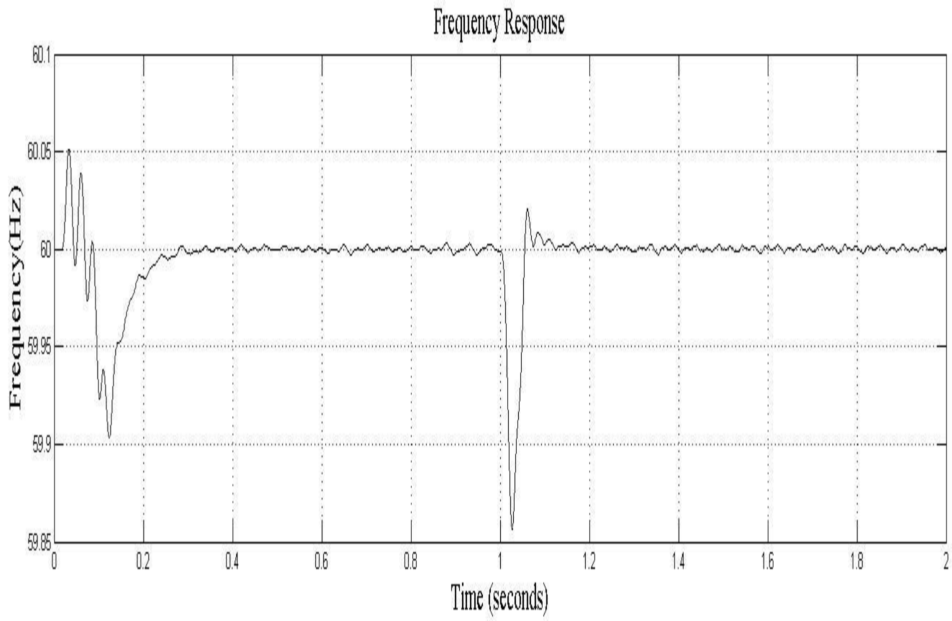


Figure 4.12: Switching capacitor bank frequency response (inverter-based DG)

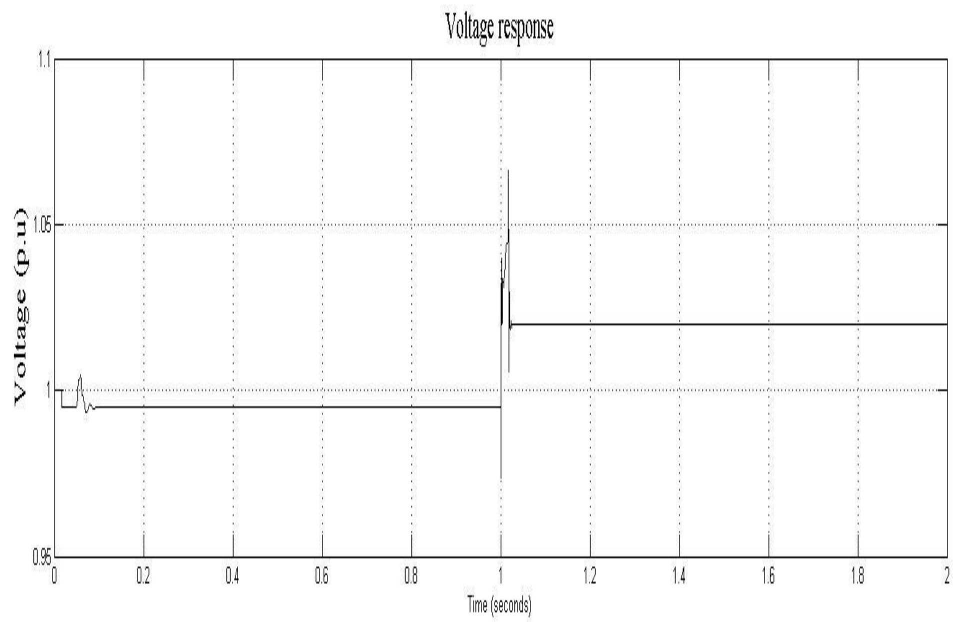


Figure 4.13: Switching capacitor bank voltage response (Synchronous generator)

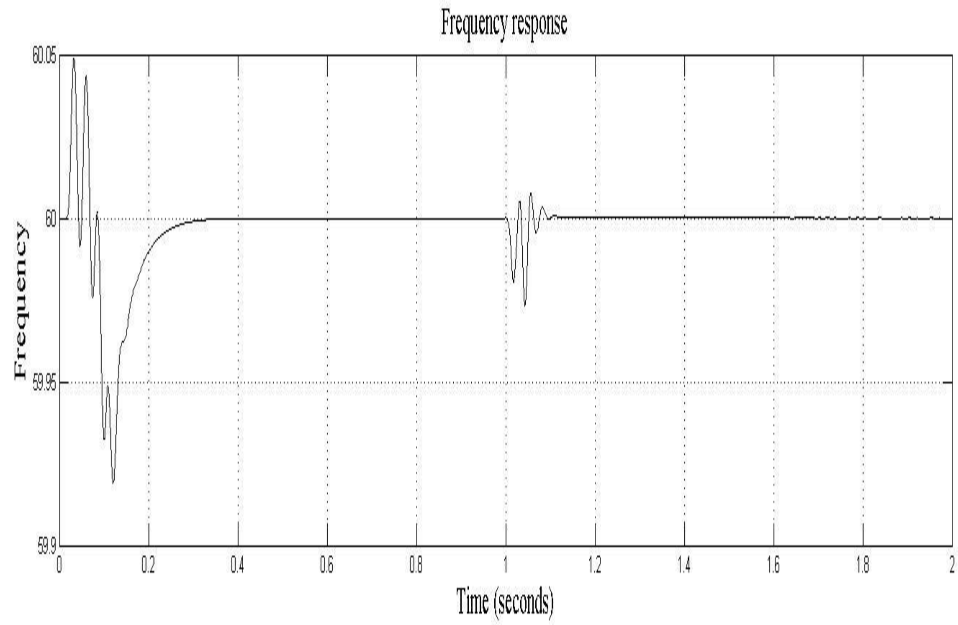


Figure 4.14: Switching capacitor bank frequency response (Synchronous generator)

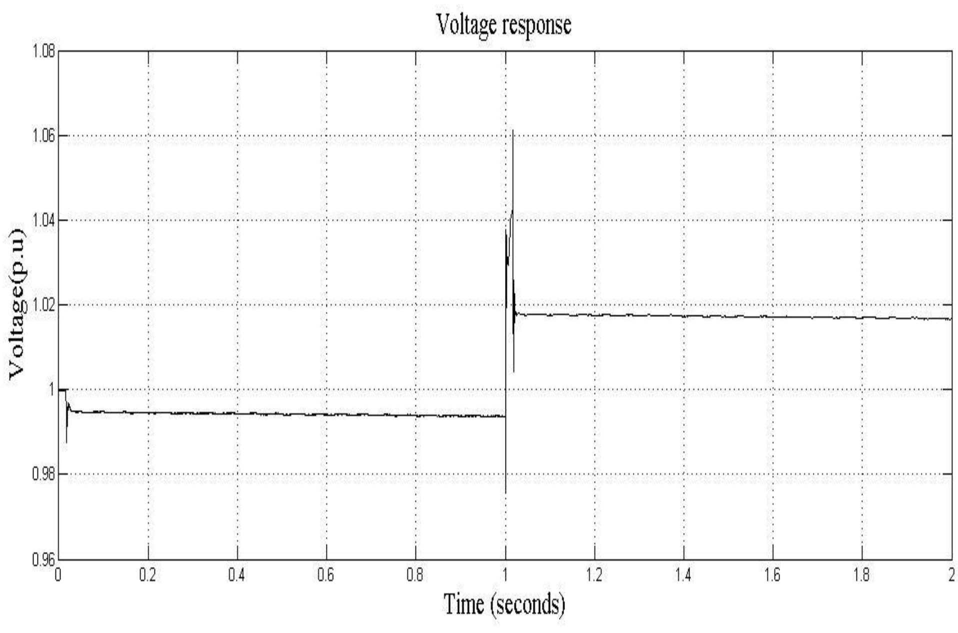


Figure 4.15: Switching capacitor bank voltage response (combination DGs)

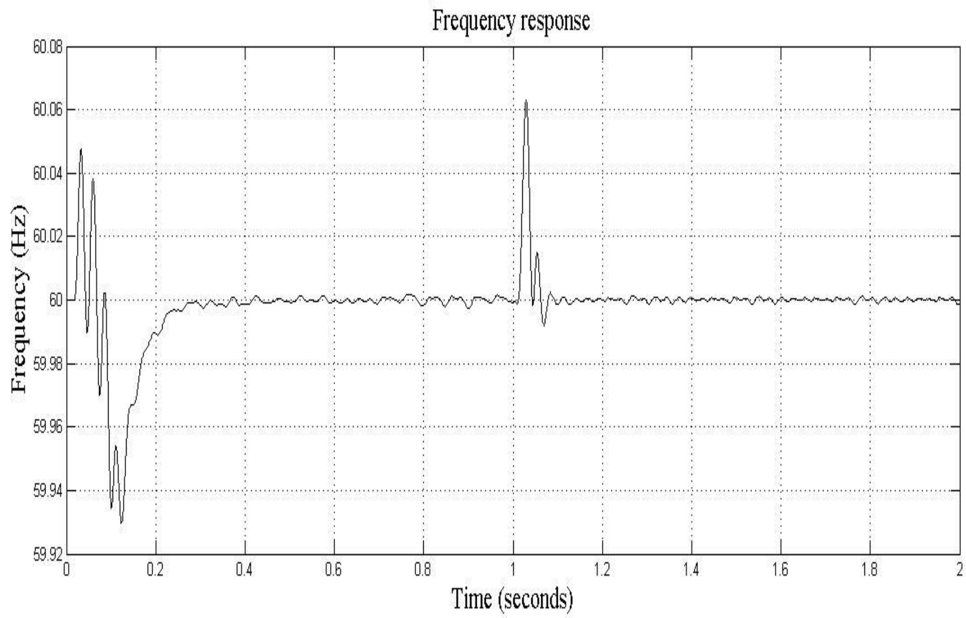


Figure 4.16: Switching capacitor bank frequency response (combination DGs)

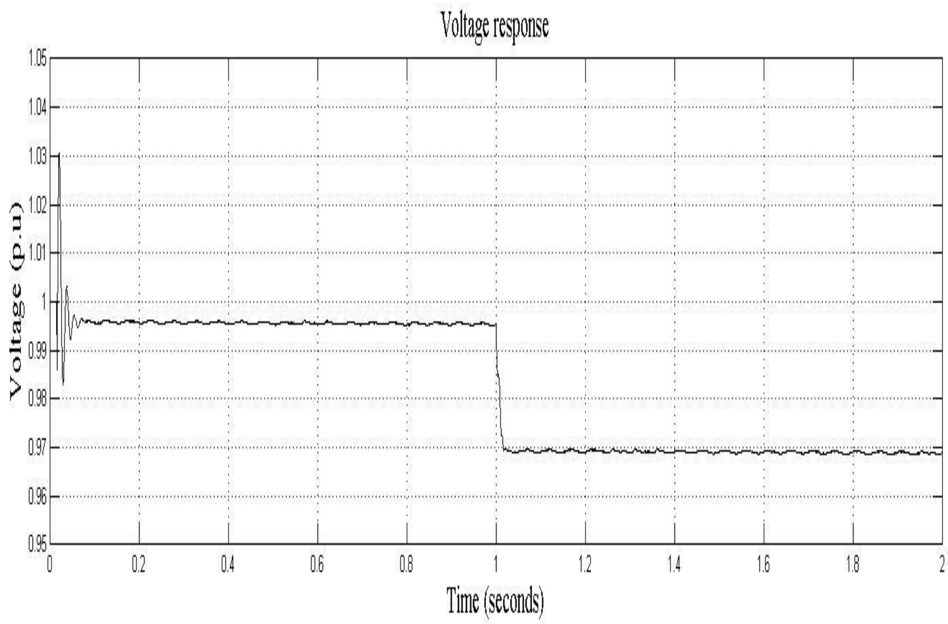


Figure 4.17: Switching inductive load voltage response (inverter-based DG)

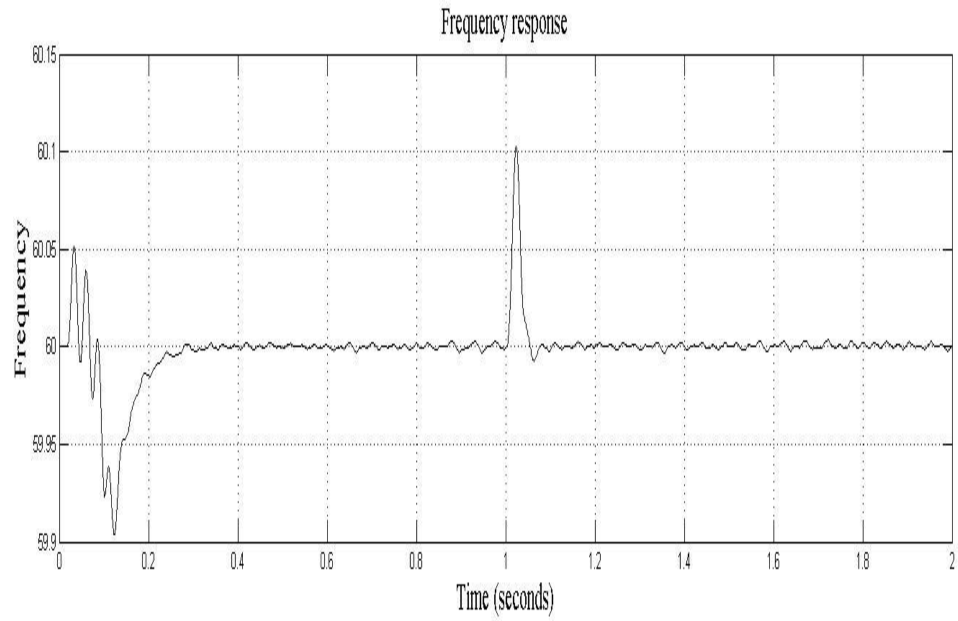


Figure 4.18: Switching inductive load frequency response (inverter-based DG)

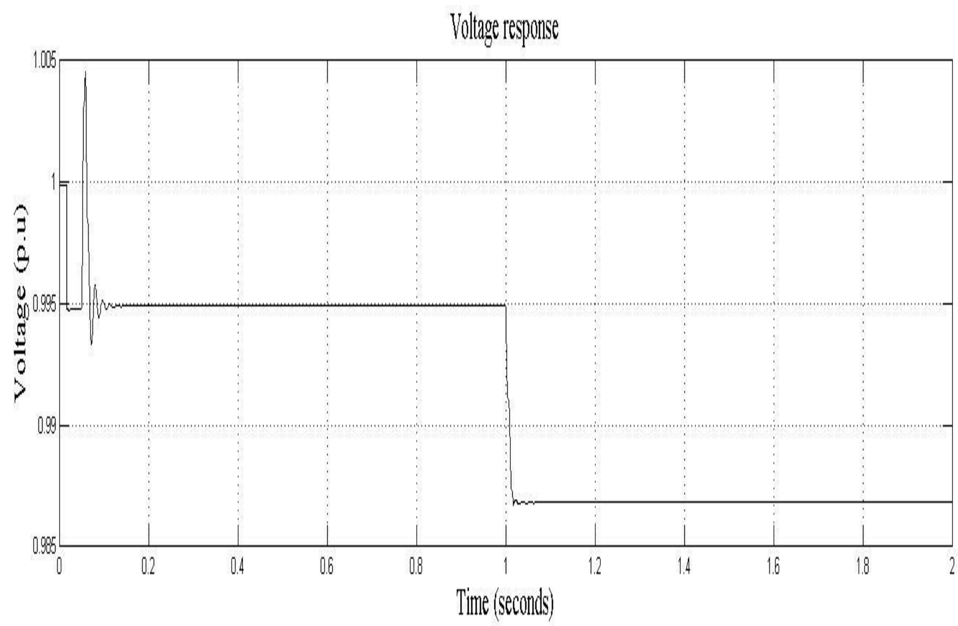


Figure 4.19: Switching inductive load voltage response (Synchronous generator)

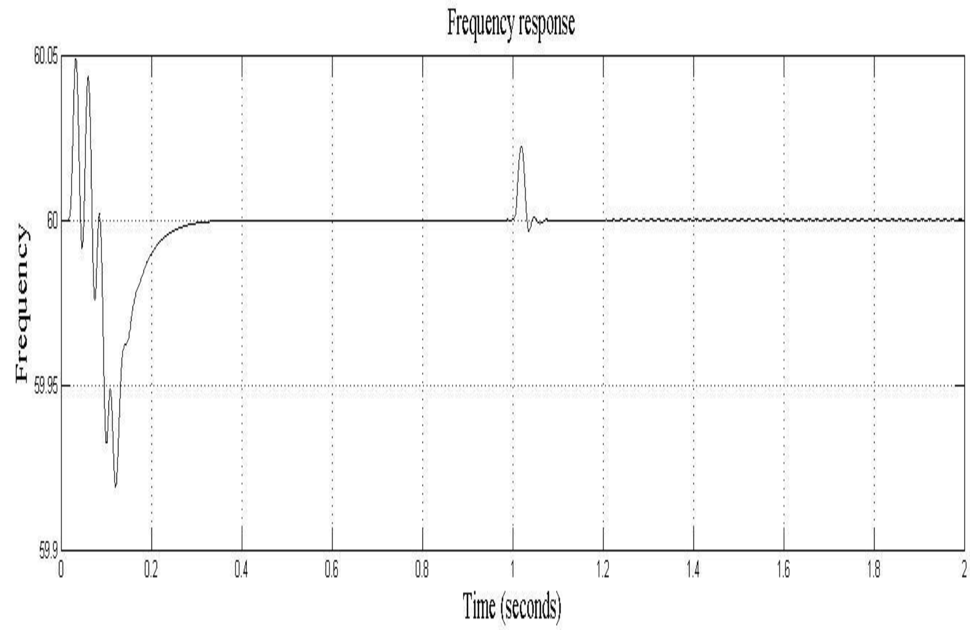


Figure 4.20: Switching inductive frequency response (Synchronous generator)

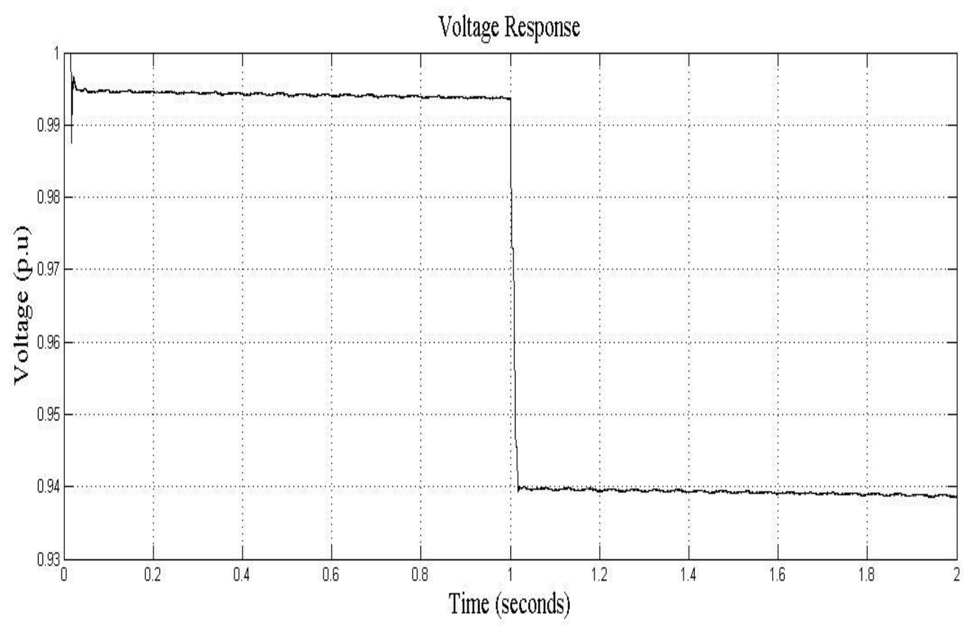


Figure 4.21: .Switching inductive load voltage response (combination DGs)

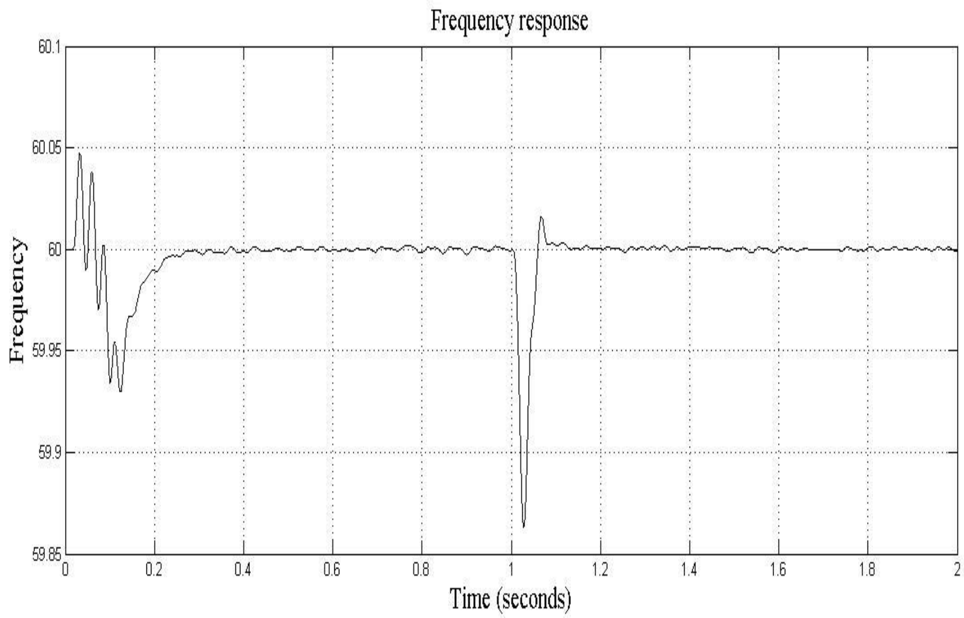


Figure 4.22: Switching inductive load frequency response (combination DGs)

### 4.3. Classification results

The extracted features from the simulation results of a large number of islanding and non-islanding cases are used to train and test different types of classifiers. The machine learning software package WEKA [19] is used to train and test the accuracy of the classifier using three methods: first, the ten cross- validation technique. Second: by splitting the data set into two segments one is used for training and the other one is for testing, and the third method is by spliting the data into four segments one is used for training and the other three are used for testing.

Cross-validation is a technique to asses the accuracy of the classification model. It uses the data set to train the model and then test the proposed model, and assess the model by calculating the accuracy of the results. Fig. 4.23. shows the ten-fold cross validation process, where it breaks the data into ten sets; nine of the datasets are used to train the model and one is used for testing. The process is repeated ten times and the average accuracy of each process is taken.

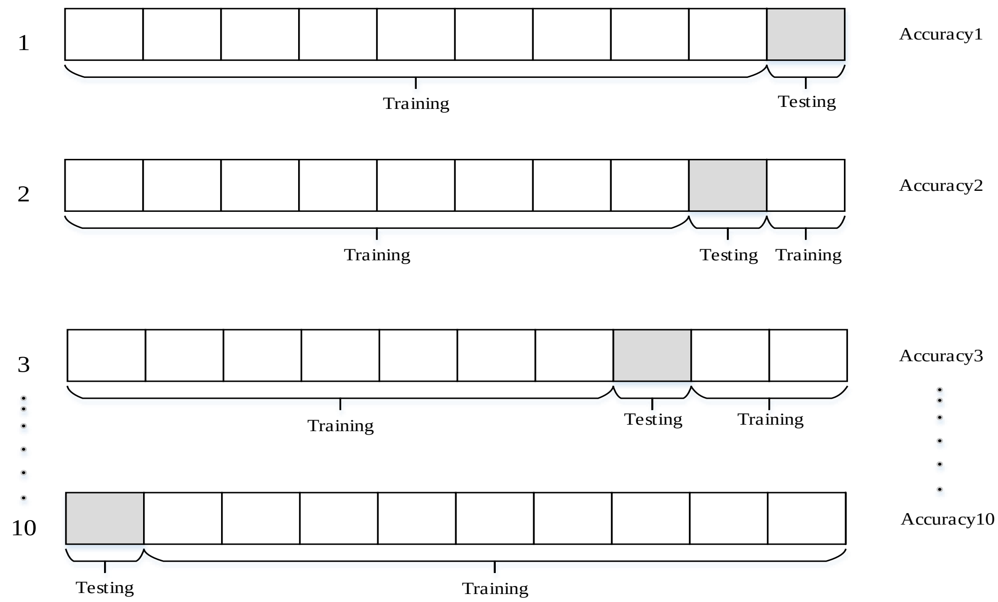


Figure 4.23: Ten-Fold cross validation process

Different types of classifiers are tested to compare the accuracy of each classifier. Table 4.1. Shows the accuracy results of different types of classifiers in order to detect islanding condition using ten-fold cross validation technique. The table shows that the Random Forest (RF) classifier and Nearest neighbor (NN) have an average of 98.3 % and 97.3 % respectively, classification accuracy compared to other classification techniques.

Table 4.2. Shows the accuracy results when we split the data into two datasets. The average accuracy in the table shows that RF and NN are more accurate than the other classifiers with average of 91.33% and 90 % respectively.

**Table 4.1: Accuracy results using 10-fold cross validation of all 4 features**

| classifier | Inverter DG | synchronous DG | combination DGs |
|---|---|---|---|
| NN | 99 % | 99 % | 94 % |
| RF | 99 % | 96 % | 100 % |
| bagging | 99 % | 93 % | 99 % |
| lazy.Kstar | 81 % | 71 % | 84 % |
| bayes.NaiveBayes | 99 % | 97 % | 86 % |

**Table 4.2: Accuracy results using two segment datasets of all 4 features**

| classifier | Inverter DG | synchronous DG | combination DGs |
|---|---|---|---|
| NN | 92 % | 90 % | 88 % |
| RF | 88 % | 90 % | 96 % |
| bagging | 64 % | 86 % | 96 % |
| lazy.Kstar | 64 % | 54 % | 66 % |
| bayes.NaiveBayes | 64 % | 96 % | 84 % |

Table 4.3. Shows the accuracy results when we split the data into four datasets. 25% of the data set is used for training and 75% is used for testing. The average accuracy in the table shows that NN and RF are more accurate than the other classifiers with average of 63.11% and 60.89 % respectively.

**Table 4.3: Accuracy results using four segment datasets of all 4 features**

| classifier | Inverter DG | synchronous DG | combination DGs |
|---|---|---|---|
| NN | 61.33 % | 56.00 % | 72.00 % |
| RF | 58.67 % | 50.67 % | 73.33 % |
| bagging | 36.00 % | 42.67 % | 42.67 % |
| lazy.Kstar | 74.67 % | 24.00 % | 44.00 % |
| bayes.NaiveBayes | 50.33 % | 72.00 % | 60.00 % |

In order to determine whether one or more of the extracted features are needed to improve the accuracy of the trained model, we used the voltage data set, frequency data set, and a combination between the voltage and frequency as inputs to different types of classifiers.

Table 4.4. Shows the accuracy results of using the voltage data set only. The table shows that the lazy.Kstar classifier has an average of 83.67 % Accuracy compared to other classifiers. Table 4.5 shows the accuracy results of different types of classifiers when the frequency data set is only used to train and test the model. The table shows that the Random Forest (RF) is the most accurate with average of 85 %. Table 4.6 is used to illustrate the accuracy of each classifier when we combine both voltage and frequency features. Randome Forest (RF) is also the most accurate classifier when we used the voltage and the frequency features as inputs to the classifier with average accuracy of 84.67 %.

Table 4.7. compares the islanding detection time of each of classifier. Detection time is computed from the moment of islanding or non-islanding occurance (t= 1s) untill the decision is made in terms of simulation time. Following occurance of an event. We select time windows beginning at time t=1s and use information from the time domain simulation as input data to the classifiers. For each window, the classification accuracy is determined. This time window broadened till the desired accuracy level is obtained for each classifier. The islanding detection time corresponds to the time window which yields the maximum accuracy for a given classifier. Random Forest classifier is the fastest in order to detect islanding from other system disturbances.

**Table 4.4: Accuracy results using 10-fold cross validation of voltage data set**

| classifier | Inverter DG | synchronous DG | combination DGs |
|---|---|---|---|
| NN | 81% | 81% | 83% |
| RF | 81% | 81% | 88% |
| bagging | 80% | 81% | 87% |
| lazy.Kstar | 81% | 83% | 87% |
| bayes.NaiveBayes | 77% | 80% | 82% |

**Table 4.5: Accuracy results using 10-fold cross validation of frequency data set**

| classifier | Inverter DG | synchronous DG | combination DGs |
|---|---|---|---|
| NN | 87% | 82% | 83% |
| RF | 87% | 83% | 85% |
| bagging | 81% | 81% | 85% |
| lazy.Kstar | 87% | 71% | 77% |
| bayes.NaiveBayes | 77% | 76% | 77% |

**Table 4.6: Accuracy results using 10-fold cross validation of the f and V**

| classifier | Inverter DG | synchronous DG | combination DGs |
|---|---|---|---|
| NN | 75% | 92% | 85% |
| RF | 75% | 92% | 87% |
| bagging | 78% | 81% | 83% |
| lazy.Kstar | 75% | 92% | 83% |
| bayes.NaiveBayes | 80% | 77% | 76% |

**Table 4.7: Time detection of the classifiers**

| classifier | Inverter DG | synchronous DG | combination DGs |
|---|---|---|---|
| NN | 0.1 s | 0.11 s | 0.1 s |
| RF | 0.1 s | 0.1 s | 0.1 s |
| bagging | 0.1 s | 0.1 s | 0.12 s |

# CHAPTER 5. CONCLUSION AND FUTURE WORK

A robust islanding detection method that works accurately for different types of distributed generators (Inverter-based DG, synchronous generator and a combination of both types of DGs) is introduced. This method is tested by simulating the IEEE 13-bus system using MATLAB/SIMULINK. A large number of islanding and non-islanding condition were simulated, and four different features were extracted from the voltage and the frequency waveforms at the PCC after connecting the DGs to the system.

In order to detect islanding, the extracted features are used to train and test different types of classifiers. The accuracy of each classifier is calculated and the time to reach the accuracy of each classifier is then measured. Random Forest classifier has been found to be the most accurate classifier. Moreover, this classifier has the least time compare to other classifiers.

The trained Random Forest model can be implemented in order to distinguish between the islanding condition and normal system disturbances such as switching capacitor bank or different types of faults within the system.

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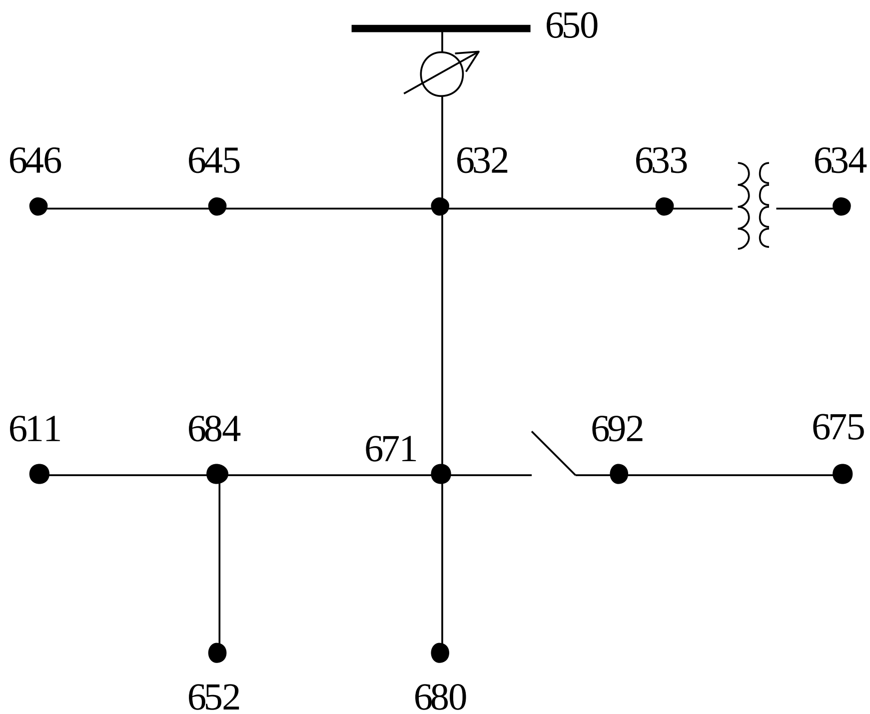
## APPENDIX. IEEE 13 NODE TEST FEEDER DATA



Overhead Line Configuration Data:

| Config. | Phasing | Phase | Neutral | Spacing |
|---|---|---|---|---|
| | | ACSR | ACSR | ID |
| 601 | B A C N | 556,500 26/7 | 4/0 6/1 | 500 |
| 602 | C A B N | 4/0 6/1 | 4/0 6/1 | 500 |
| 603 | C B N | 1/0 | 1/0 | 505 |
| 604 | A C N | 1/0 | 1/0 | 505 |
| 605 | C N | 1/0 | 1/0 | 510 |

Underground Line Configuration Data:

| Config. | Phasing | Cable | Neutral | Space ID |
|---|---|---|---|---|
| 606 | A B C N | 250,000 AA, CN | None | 515 |
| 607 | A N | 1/0 AA, TS | 1/0 Cu | 520 |

Line Segment Data:

| Node A | Node B | Length(ft.) | Config. |
|---|---|---|---|
| 632 | 645 | 500 | 603 |
| 632 | 633 | 500 | 602 |
| 633 | 634 | 0 | XFM-1 |
| 645 | 646 | 300 | 603 |
| 650 | 632 | 2000 | 601 |
| 684 | 652 | 800 | 607 |
| 632 | 671 | 2000 | 601 |
| 671 | 684 | 300 | 604 |
| 671 | 680 | 1000 | 601 |
| 671 | 692 | 0 | Switch |
| 684 | 611 | 300 | 605 |
| 692 | 675 | 500 | 606 |

Transformer Data:

| | kVA | kV-high | kV-low | R - % | X - % |
|---|---|---|---|---|---|
| Substation: | 5,000 | 115 - D | 4.16 Gr. Y | 1 | 8 |
| XFM -1 | 500 | 4.16 – Gr.W | 0.48 – Gr.W | 1.1 | 2 |

Capacitor Data:

| Node | Ph-A | Ph-B | Ph-C |
|---|---|---|---|
| | kVAr | kVAr | kVAr |
| 675 | 200 | 200 | 200 |
| 611 | | | 100 |
| Total | 200 | 200 | 300 |

Regulator Data:

| Regulator ID: | 1 | | |
| --- | --- | --- | --- |
| Line Segment: | 650 - 632 | | |
| Location: | 50 | | |
| Phases: | A - B -C | | |
| Connection: | 3-Ph,LG | | |
| Monitoring Phase: | A-B-C | | |
| Bandwidth: | 2.0 volts | | |
| PT Ratio: | 20 | | |
| Primary CT Rating: | 700 | | |
| Compensator Settings: | Ph-A | Ph-B | Ph-C |
| R - Setting: | 3 | 3 | 3 |
| X - Setting: | 9 | 9 | 9 |
| Volltage Level: | 122 | 122 | 122 |

Spot Load Data:

| Node | Load | Ph-1 | Ph-1 | Ph-2 | Ph-2 | Ph-3 | Ph-3 |
|---|---|---|---|---|---|---|---|
| | Model | kW | kVAr | kW | kVAr | kW | kVAr |
| 634 | Y-PQ | 160 | 110 | 120 | 90 | 120 | 90 |
| 645 | Y-PQ | 0 | 0 | 170 | 125 | 0 | 0 |
| 646 | D-Z | 0 | 0 | 230 | 132 | 0 | 0 |
| 652 | Y-Z | 128 | 86 | 0 | 0 | 0 | 0 |
| 671 | D-PQ | 385 | 220 | 385 | 220 | 385 | 220 |
| 675 | Y-PQ | 485 | 190 | 68 | 60 | 290 | 212 |
| 692 | D-I | 0 | 0 | 0 | 0 | 170 | 151 |
| 611 | Y-I | 0 | 0 | 0 | 0 | 170 | 80 |
| | TOTAL | 1158 | 606 | 973 | 627 | 1135 | 753 |

Distributed Load Data:

| Node A | Node B | Load | Ph-1 | Ph-1 | Ph-2 | Ph-2 | Ph-3 | Ph-3 |
|---|---|---|---|---|---|---|---|---|
| | | Model | kW | kVAr | kW | kVAr | kW | kVAr |
| 632 | 671 | Y-PQ | 17 | 10 | 66 | 38 | 117 | 68 |

### *Configuration 601:*

```
          Z (R +jX) in ohms per mile
 0.3465  1.0179   0.1560  0.5017   0.1580  0.4236
                  0.3375  1.0478   0.1535  0.3849
                                   0.3414  1.0348
         B in micro Siemens per mile
           6.2998   -1.9958   -1.2595
                     5.9597   -0.7417
                               5.6386
```

### *Configuration 602:*

```
          Z (R +jX) in ohms per mile
0.7526  1.1814   0.1580  0.4236   0.1560  0.5017
                 0.7475  1.1983   0.1535  0.3849
                                  0.7436  1.2112
        B in micro Siemens per mile
          5.6990   -1.0817   -1.6905
                    5.1795   -0.6588
                              5.4246
```

***Configuration 603:***

```
          Z (R +jX) in ohms per mile
 0.0000  0.0000   0.0000  0.0000   0.0000  0.0000
                  1.3294  1.3471   0.2066  0.4591
                                   1.3238  1.3569
         B in micro Siemens per mile
           0.0000    0.0000    0.0000
                     4.7097   -0.8999
                               4.6658
```

***Configuration 604:***

```
          Z (R +jX) in ohms per mile
 1.3238  1.3569   0.0000  0.0000   0.2066  0.4591
                  0.0000  0.0000   0.0000  0.0000
                                   1.3294  1.3471
         B in micro Siemens per mile
           4.6658    0.0000   -0.8999
                     0.0000    0.0000
                               4.709
```

***Configuration 605:***

```
          Z (R +jX) in ohms per mile
 0.0000  0.0000   0.0000  0.0000   0.0000  0.0000
                  0.0000  0.0000   0.0000  0.0000
                                   1.3292  1.3475
          B in micro Siemens per mile
            0.0000    0.0000    0.0000
                      0.0000    0.0000
                                4.5193
```

***Configuration 606:***

```
          Z (R +jX) in ohms per mile
0.7982  0.4463   0.3192  0.0328   0.2849 -0.0143
                 0.7891  0.4041   0.3192  0.0328
                                  0.7982  0.4463
         B in micro Siemens per mile
          96.8897    0.0000    0.0000
                    96.8897    0.0000
                              96.8897
```

***Configuration 607:***

```
          Z (R +jX) in ohms per mile
 1.3425  0.5124   0.0000  0.0000   0.0000  0.0000
                  0.0000  0.0000   0.0000  0.0000
                                   0.0000  0.0000
         B in micro Siemens per mile
          88.9912    0.0000    0.0000
                     0.0000    0.0000
                               0.0000
```

# Power-Flow Results

```
- R A D I A L   F L O W   S U M M A R Y - DATE:  6-24-2004 AT 15:33: 2 HOURS ---
SUBSTATION:  IEEE 13;   FEEDER:  IEEE 13
--------------------------------------------------------------------------------
SYSTEM        PHASE              PHASE              PHASE              TOTAL
INPUT -------(A)-------|-------(B)-------|-------(C)-------|------------------
kW   :      1251.398   |      977.332    |     1348.461    |      3577.191
kVAr :       681.570   |      373.418    |      669.784    |      1724.772
kVA  :      1424.968   |     1046.241    |     1505.642    |      3971.289
PF   :        .8782    |        .9341    |        .8956    |        .9008

LOAD  --(A-N)----(A-B)-|--(B-N)----(B-C)-|--(C-N)----(C-A)-|---WYE-----DELTA--
kW   :  785.6    385.0|  424.0    625.7|  692.5    553.4| 1902.1   1564.0
 TOT :      1170.563   |     1049.658    |     1245.907    |      3466.128
                       |                 |                 |
kVAr :  393.0    220.0|  313.0    358.1|  447.9    369.5| 1153.9    947.7
 TOT :       613.019   |      671.117    |      817.450    |      2101.586
                       |                 |                 |
kVA  :  878.4    443.4|  527.0    720.9|  824.8    665.4| 2224.8   1828.7
 TOT :      1321.367   |     1245.865    |     1490.137    |      4053.481
                       |                 |                 |
PF   :  .8943    .8682|  .8045    .8679|  .8397    .8316|  .8550    .8553
 TOT :        .8859    |        .8425    |        .8361    |        .8551

LOSSES ------(A)-------|-------(B)-------|-------(C)-------|------------------
kW   :        39.107   |       -4.697    |       76.653    |       111.063
kVAr :       152.585   |       42.217    |      129.850    |       324.653
kVA  :       157.517   |       42.478    |      150.787    |       343.124

CAPAC --(A-N)----(A-B)-|--(B-N)----(B-C)-|--(C-N)----(C-A)-|---WYE-----DELTA--
R-kVA:  200.0       .0|  200.0       .0|  300.0       .0|  700.0       .0
 TOT :       200.000   |      200.000    |      300.000    |       700.000
                       |                 |                 |
A-kVA:  193.4       .0|  222.7       .0|  285.3       .0|  701.5       .0
 TOT :       193.443   |      222.747    |      285.276    |       701.466
```

p 1

--- **V O L T A G E   P R O F I L E** ---- DATE: 6-24-2004 AT 15:33:12 HOURS ----
SUBSTATION: IEEE 13; FEEDER: IEEE 13

| NODE | A-N MAG | A-N ANGLE | B-N MAG | B-N ANGLE | C-N MAG | C-N ANGLE | mi.to SR |
|---|---|---|---|---|---|---|---|
| 650 | 1.0000 at | .00 | 1.0000 at | -120.00 | 1.0000 at | 120.00 | .000 |
| RG60 | 1.0625 at | .00 | 1.0500 at | -120.00 | 1.0687 at | 120.00 | .000 |
| 632 | 1.0210 at | -2.49 | 1.0420 at | -121.72 | 1.0174 at | 117.83 | .379 |
| 633 | 1.0180 at | -2.56 | 1.0401 at | -121.77 | 1.0148 at | 117.82 | .474 |
| XFXFM1 | .9941 at | -3.23 | 1.0218 at | -122.22 | .9960 at | 117.35 | .474 |
| 634 | .9940 at | -3.23 | 1.0218 at | -122.22 | .9960 at | 117.34 | .474 |
| 645 | | | 1.0329 at | -121.90 | 1.0155 at | 117.86 | .474 |
| 646 | | | 1.0311 at | -121.98 | 1.0134 at | 117.90 | .530 |
| 671 | .9900 at | -5.30 | 1.0529 at | -122.34 | .9778 at | 116.02 | .758 |
| 680 | .9900 at | -5.30 | 1.0529 at | -122.34 | .9778 at | 116.02 | .947 |
| 684 | .9881 at | -5.32 | | | .9758 at | 115.92 | .815 |
| 611 | | | | | .9738 at | 115.78 | .871 |
| 652 | .9825 at | -5.25 | | | | | .966 |
| 692 | .9900 at | -5.31 | 1.0529 at | -122.34 | .9777 at | 116.02 | .852 |
| 675 | .9835 at | -5.56 | 1.0553 at | -122.52 | .9758 at | 116.03 | .947 |

p 1

----------- **VOLTAGE REGULATOR DATA** ---- DATE: 6-24-2004 AT 15:33:16 HOURS --
SUBSTATION: IEEE 13; FEEDER: IEEE 13

| [NODE] | [VREG] | [SEG] | [NODE] | MODEL | OPT | BNDW |
|---|---|---|---|---|---|---|
| 650 | RG60 | 632 | 632 | Phase A & B & C, Wye | RX | 2.00 |

| PHASE | LDCTR | VOLT HOLD | R-VOLT | X-VOLT | PT RATIO | CT RATE | TAP |
|---|---|---|---|---|---|---|---|
| 1 | | 122.000 | 3.000 | 9.000 | 20.00 | 700.00 | 10 |
| 2 | | 122.000 | 3.000 | 9.000 | 20.00 | 700.00 | 8 |
| 3 | | 122.000 | 3.000 | 9.000 | 20.00 | 700.00 | 11 |

```
                                                                         p  1
- R A D I A L  P O W E R  F L O W ---  DATE:  6-24-2004 AT 15:33:27 HOURS ---
SUBSTATION:  IEEE 13;   FEEDER:  IEEE 13
-------------------------------------------------------------------------------
   NODE      VALUE         PHASE A          PHASE B          PHASE C    UNT O/L<
                           (LINE A)         (LINE B)         (LINE C)       60.%
---------------------*--------A-------*-------B-------*-------C-------*--------
NODE: 650       VOLTS:  1.000     .00   1.000 -120.00   1.000  120.00 MAG/ANG
kVll   4.160            NO LOAD OR CAPACITOR REPRESENTED AT SOURCE NODE

TO NODE RG60  <VRG>..:  593.30  -28.58  435.61 -140.91  626.92   93.59 AMP/DG <
<RG60  > LOSS=   .000:    (   .000)        (   .000)        (   .000)    kW
---------------------*--------A-------*-------B-------*-------C-------*--------
NODE: RG60      VOLTS:  1.062     .00   1.050 -120.00   1.069  120.00 MAG/ANG
                  -LD:     .00     .00     .00     .00     .00     .00 kW/kVR
kVll   4.160      CAP:             .00             .00             .00 kVR

FROM NODE 650   <VRG>:  558.40  -28.58  414.87 -140.91  586.60   93.59 AMP/DG <
<RG60  > LOSS=   .000:    (   .000)        (   .000)        (   .000)    kW
TO NODE 632   .......:  558.40  -28.58  414.87 -140.91  586.60   93.59 AMP/DG <
<632   > LOSS= 59.716:    ( 21.517)        ( -3.252)        ( 41.451)    kW
---------------------*--------A-------*-------B-------*-------C-------*--------
NODE: 632       VOLTS:  1.021   -2.49   1.042 -121.72   1.017  117.83 MAG/ANG
                  -LD:     .00     .00     .00     .00     .00     .00 kW/kVR
kVll   4.160      CAP:             .00             .00             .00 kVR

FROM NODE RG60  .....:  558.41  -28.58  414.87 -140.91  586.60   93.59 AMP/DG <
<632   > LOSS= 59.716:    ( 21.517)        ( -3.252)        ( 41.451)    kW
TO NODE 633   .......:   81.33  -37.74   61.12 -159.09   62.70   80.48 AMP/DG
<633   > LOSS=   .808:    (   .354)        (   .148)        (   .306)    kW
TO NODE 645   .......:                  143.02 -142.66   65.21   57.83 AMP/DG <
<645   > LOSS=  2.760:                     (  2.540)        (   .220)    kW
TO NODE 671   .......:  478.29  -27.03  215.12 -134.66  475.50   99.90 AMP/DG <
<671   > LOSS= 35.897:    ( 10.484)        ( -6.169)        ( 31.582)    kW
---------------------*--------A-------*-------B-------*-------C-------*--------
NODE: 633       VOLTS:  1.018   -2.56   1.040 -121.77   1.015  117.82 MAG/ANG
                  -LD:     .00     .00     .00     .00     .00     .00 kW/kVR
kVll   4.160      CAP:             .00             .00             .00 kVR

FROM NODE 632   .....:   81.33  -37.74   61.12 -159.09   62.71   80.47 AMP/DG
<633   > LOSS=   .808:    (   .354)        (   .148)        (   .306)    kW
TO NODE XFXFM1.......:   81.33  -37.74   61.12 -159.09   62.71   80.47 AMP/DG <
<XFXFM1> LOSS=  5.427:    (  2.513)        (  1.420)        (  1.494)    kW
---------------------*--------A-------*-------B-------*-------C-------*--------
NODE: XFXFM1    VOLTS:   .994   -3.23   1.022 -122.22    .996  117.35 MAG/ANG
                  -LD:     .00     .00     .00     .00     .00     .00 kW/kVR
kVll    .480      CAP:             .00             .00             .00 kVR

FROM NODE 633   .....:  704.83  -37.74  529.73 -159.09  543.45   80.47 AMP/DG <
<XFXFM1> LOSS=  5.427:    (  2.513)        (  1.420)        (  1.494)    kW
TO NODE 634   .......:  704.83  -37.74  529.73 -159.09  543.45   80.47 AMP/DG <
<634   > LOSS=   .000:    (   .000)        (   .000)        (   .000)    kW
```

```
                                                                        p  2
- R A D I A L   P O W E R   F L O W --- DATE:  6-24-2004 AT 15:33:27 HOURS ---
SUBSTATION:  IEEE 13;   FEEDER:  IEEE 13
-------------------------------------------------------------------------------
   NODE      VALUE          PHASE A          PHASE B          PHASE C    UNT O/L<
                           (LINE A)         (LINE B)         (LINE C)        60.%
----------------------*--------A-------*-------B-------*-------C-------*--------
NODE: 634        VOLTS:    .994   -3.23   1.022 -122.22    .996  117.34 MAG/ANG
                  Y-LD:  160.00  110.00  120.00   90.00  120.00   90.00 kW/kVR
kVll    .480    Y CAP:              .00              .00              .00 kVR

FROM NODE XFXFM1.....:  704.83  -37.74  529.73 -159.09  543.45   80.47 AMP/DG <
<634    > LOSS=   .000:   (   .000)        (   .000)        (   .000)    kW
----------------------*--------A-------*-------B-------*-------C-------*--------
NODE: 645        VOLTS:                   1.033 -121.90   1.015  117.86 MAG/ANG
                  Y-LD:                  170.00  125.00     .00     .00 kW/kVR
kVll   4.160    Y CAP:                               .00              .00 kVR

FROM NODE 632   .....:                   143.02 -142.66   65.21   57.83 AMP/DG <
<645    > LOSS=  2.760:                    (  2.540)        (   .220)    kW
TO NODE 646   .......:                    65.21 -122.17   65.21   57.83 AMP/DG
<646    > LOSS=   .541:                    (   .271)        (   .270)    kW
----------------------*--------A-------*-------B-------*-------C-------*--------
NODE: 646        VOLTS:                   1.031 -121.98   1.013  117.90 MAG/ANG
                  D-LD:                  240.66  138.12     .00     .00 kW/kVR
kVll   4.160    Y CAP:                               .00              .00 kVR

FROM NODE 645   .....:                    65.21 -122.18   65.21   57.82 AMP/DG
<646    > LOSS=   .541:                    (   .271)        (   .270)    kW
----------------------*--------A-------*-------B-------*-------C-------*--------
NODE: 671        VOLTS:    .990   -5.30   1.053 -122.34    .978  116.02 MAG/ANG
                  D-LD:  385.00  220.00  385.00  220.00  385.00  220.00 kW/kVR
kVll   4.160    Y CAP:              .00              .00              .00 kVR

FROM NODE 632   .....:  470.20  -26.90  186.41 -131.89  420.64  101.66 AMP/DG <
<671    > LOSS= 35.897:   ( 10.484)        ( -6.169)        ( 31.582)    kW
TO NODE 680   .......:     .00     .00     .00     .00     .00     .00 AMP/DG
<680    > LOSS=   .000:   (  -.001)        (   .001)        (   .000)    kW
TO NODE 684   .......:   63.07  -39.12                    71.15  121.62 AMP/DG
<684    > LOSS=   .580:   (   .210)                         (   .370)    kW
TO NODE 692   .......:  229.11  -18.18   69.61  -55.19  178.38  109.39 AMP/DG
<692    > LOSS=   .008:   (   .003)        (  -.001)        (   .006)    kW
----------------------*--------A-------*-------B-------*-------C-------*--------
NODE: 680        VOLTS:    .990   -5.30   1.053 -122.34    .978  116.02 MAG/ANG
                   -LD:     .00     .00     .00     .00     .00     .00 kW/kVR
kVll   4.160      CAP:              .00              .00              .00 kVR

FROM NODE 671   .....:     .00     .00     .00     .00     .00     .00 AMP/DG
<680    > LOSS=   .000:   (  -.001)        (   .001)        (   .000)    kW
```

```
- R A D I A L   P O W E R   F L O W --- DATE:  6-24-2004 AT 15:33:27 HOURS ---
SUBSTATION:  IEEE 13;   FEEDER:  IEEE 13
-------------------------------------------------------------------------------
   NODE      VALUE         PHASE A         PHASE B         PHASE C     UNT O/L<
                           (LINE A)        (LINE B)        (LINE C)         60.%
---------------------*--------A-------*-------B-------*-------C-------*--------
NODE: 684       VOLTS:    .988   -5.32                       .976  115.92 MAG/ANG
                  -LD:     .00     .00                        .00     .00 kW/kVR
kVll   4.160      CAP:             .00                                .00 kVR

FROM NODE 671   .....:   63.07  -39.12                     71.15  121.61 AMP/DG
<684   > LOSS=   .580:    (   .210)                        (   .370)    kW
TO NODE 611   .......:                                     71.15  121.61 AMP/DG
<611   > LOSS=   .382:                                     (   .382)    kW
TO NODE 652   .......:   63.07  -39.12                                   AMP/DG
<652   > LOSS=   .808:    (   .808)                                     kW
---------------------*--------A-------*-------B-------*-------C-------*--------
NODE: 611       VOLTS:                                       .974  115.78 MAG/ANG
                 Y-LD:                                     165.54   77.90 kW/kVR
kVLL   4.160    Y CAP:                                              94.82 kVR

FROM NODE 684   .....:                                     71.15  121.61 AMP/DG
<611   > LOSS=   .382:                                     (   .382)    kW
---------------------*--------A-------*-------B-------*-------C-------*--------
NODE: 652       VOLTS:    .983   -5.25                                   MAG/ANG
                 Y-LD:  123.56   83.02                                   kW/kVR
kVll   4.160    Y CAP:             .00                                   kVR

FROM NODE 684   .....:   63.08  -39.15                                   AMP/DG
<652   > LOSS=   .808:    (   .808)                                     kW
---------------------*--------A-------*-------B-------*-------C-------*--------
NODE: 692       VOLTS:    .990   -5.31   1.053 -122.34     .978  116.02 MAG/ANG
                 D-LD:     .00     .00     .00     .00   168.37  149.55 kW/kVR
kVll   4.160    Y CAP:             .00             .00                .00 kVR

FROM NODE 671   .....:  229.11  -18.18   69.61  -55.19   178.38  109.39 AMP/DG
<692   > LOSS=   .008:    (   .003)       ( -.001)        (   .006)    kW
TO NODE 675   .......:  205.33   -5.15   69.61  -55.19   124.07  111.79 AMP/DG <
<675   > LOSS=  4.136:    (  3.218)       (   .345)       (   .573)    kW
---------------------*--------A-------*-------B-------*-------C-------*--------
NODE: 675       VOLTS:    .983   -5.56   1.055 -122.52     .976  116.03 MAG/ANG
                 Y-LD:  485.00  190.00   68.00   60.00   290.00  212.00 kW/kVR
kVll   4.160    Y CAP:          193.44          222.75             190.45 kVR

FROM NODE 692   .....:  205.33   -5.15   69.59  -55.20   124.07  111.78 AMP/DG <
<675   > LOSS=  4.136:    (  3.218)       (   .345)       (   .573)    kW
```