8-2018

# Efficacy of Smart PV Inverter as a Strategic Mitigator of Network Harmonic Resonance and a Suppressor of Temporary Overvoltage Phenomenon in Distribution Systems

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EFFICACY OF SMART PV INVERTER AS A STRATEGIC MITIGATOR OF NETWORK HARMONIC RESONANCE AND A SUPPRESSOR OF TEMPORARY OVERVOLTAGE PHENOMENON IN DISTRIBUTION SYSTEMS

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A Dissertation
Presented to
the Graduate School of
Clemson University

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In Partial Fulfillment
of the Requirements for the Degree
Doctor of Philosophy
Electrical Engineering

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by
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August 2018

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ABSTRACT

The research work explores the design of Smart PV inverters in terms of modelling and investigates the efficacy of a Smart PV inverter as a strategic mitigator of network harmonic resonance phenomenon and a suppressor of Temporary Overvoltage (TOV) in distribution systems. The new application and the control strategy of Smart PV inverters can also be extended to SmartPark-Plug in Electric Vehicles as the grid becomes smarter.

As the grid is becoming smarter, more challenges are encountered with the integration of PV plants in distribution systems. Smart PV inverters nowadays are equipped with specialized controllers for exchanging reactive power with the grid based on the available capacity of the inverter, after the real power generation. Although present investigators are researching on several applications of Smart PV inverters, none of the research-work in real time and in documentation have addressed the benefits of employing Smart PV inverters to mitigate network resonances. U.S based standard IEEE 519 for power quality describes the network resonance as a major contributor that has an impact on the harmonic levels. This dissertation proposes a new application for the first time in utilizing a Smart PV inverter to act as a virtual detuner in mitigating network resonance. As a part of the Smart PV inverter design, the LCL filter plays a vital role on network harmonic resonance and further has a direct impact on the stability of the controller and rest of the distribution system.

Temporary Overvoltage (TOV) phenomenon is more pronounced especially during unbalanced faults like single line to ground faults (SLGF) in the presence of PV. Such an abnormal incident can damage the customer loads. IEEE 142-“Effective grounding”

technique is employed to design the grounding scheme for synchronous based generators. The utilities have been trying to make a PV system comply with IEEE 142 standard as well. Several utilities are still employing the same grounding schemes even now. The attempt has resulted in diminishing the efficacy of protection schemes. Further, millions of dollars and power has been wasted by the utilities. As a result, the concept of effective grounding for PV system has become a challenge when utilities try to mitigate TOV. With an intention of economical aspects in distribution systems planning, this dissertation also proposes a new application and a novel control scheme for utilizing Smart PV/Smart Park inverters to mitigate TOV in distribution systems for the first time. In other words, this novel application can serve as an effective and supporting schema towards ineffective grounding systems. PSCAD/EMTDC has been used throughout the course of research.

The idea of Smart inverters serving as a virtual detuner in mitigating network harmonic resonance and as a TOV suppressor in distribution systems has been devised based on the basic principle of VAR injection and absorption with a new control strategy respectively. This research would further serve as a pioneering approach for researchers and planning engineers working in distribution systems.

DEDICATION

Specially dedicated to my

Grandparents

Mrs. PADMA SARANGAPANI & Late Mr. M.S.SARANGAPANI

Parents

Mrs. JAYANTHI RANGARAJAN & Mr. S.RANGARAJAN

Maternal Uncle

Mr. SYAM SUNDAR SARANGANPANI

Though my grandfather is no more, his presence and memories will always be there with me. Although he is not there to see me as ‘Dr. S.R. Shriram’ (which was his desire), his blessings and best wishes will always be there for me.

The unlimited love and tremendous support given to me by my parents, grandparents and maternal uncle at every phase of my life has been the only reason for me to reach this point. The sacrifice made by them for me towards every sphere of my life has been the only reason for what I am today. I definitely consider myself to be lucky and blessed in all aspects for being born in such a great family. Finally, I am thankful to God for all that he has given me.

With lots of love,

SHRIRAM SRINIVASARANGAN RANGARAJAN

# ACKNOWLEDGMENTS

I would like to express my heartfelt gratitude to my advisor Dr. Randy Collins for the support he gave me throughout the entire journey of my research and teaching. I learnt a lot from him in all aspects of academic and professional domains. I am definitely proud to have worked with him. The constant encouragement and motivation from him played a major role for me to produce outstanding results in both teaching and research.

I am highly grateful to Dr. Daniel Noneaker (ECE Department Chair at Clemson). He has been constantly encouraging me and had been a great pillar of my strength right from the beginning when I entered Clemson. He is a great motivator and a fantastic human being. I am also thankful to him for kindly agreeing to be on my dissertation committee as well.

A very special thanks to Dr. Johan Enslin and Dr. John Wagner. I am honored to have such experienced Professors in my committee. I am also highly grateful to both of them.

I also wanted to thank Dr. J. Curtiss Fox (Director of Operations at Clemson University Restoration Institute, N. Charleston, SC, USA) for being the source of funding towards research.

I further wanted to thank Dr. Anand Gramopadhye (Dean of the College of Engineering, Computing and Applied Sciences) at Clemson. His encouragement and motivation definitely gave me an extra strength and tremendous recognition at Clemson.

A special thanks to Mr. Mark Sample (SRC Inc., Syracuse, NY, USA), Dr. D.P. Kothari (former Director, Indian Institute of Technology, Delhi, India), Dr. S.P. Sabberwal (former Professor in power systems, Indian Institute of Technology, Delhi, India), Dr. Sekar Viswanathan (Vice President of Vellore Institute of Technology (VIT) University, Vellore, India) and Dr. G. Viswanathan (Chancellor, VIT University, Vellore, India), who had played an instrumental role in my career. I also wanted to thank all my colleagues from VIT University, Vellore, India.

A very special thanks to all my teachers and gurus across the globe who had played a major role in my life and it is only because of their blessings, I have reached this stage.

Finally, I thank all my dear students from VIT University, India and Clemson University, U.S.A for being the backbone of my growth in my career.

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# CHAPTER ONE

# INTRODUCTION

## 1.1 Background

In traditional distribution system, a feeder has been configured in such a way that power flows in a unidirectional manner from substation to the loads. With the effect of Public Utility Regulatory Policies Act in 1978, distributed generators (DG) had started to become a vital segment in distribution systems engineering. Several factors like economic viability and cost-effectiveness, incentives, technical and environmental benefits associated with Photovoltaic based DG's has captured the attention of public utility commissions. Thus the multi-megawatt inverter based distributed PV systems and their interconnection has become an alternative to traditional circuit upgrades and state renewable portfolio standards. As a result distributed photovoltaic (PV) systems have become more common constituting a 'smart grid' environment with advanced capabilities.

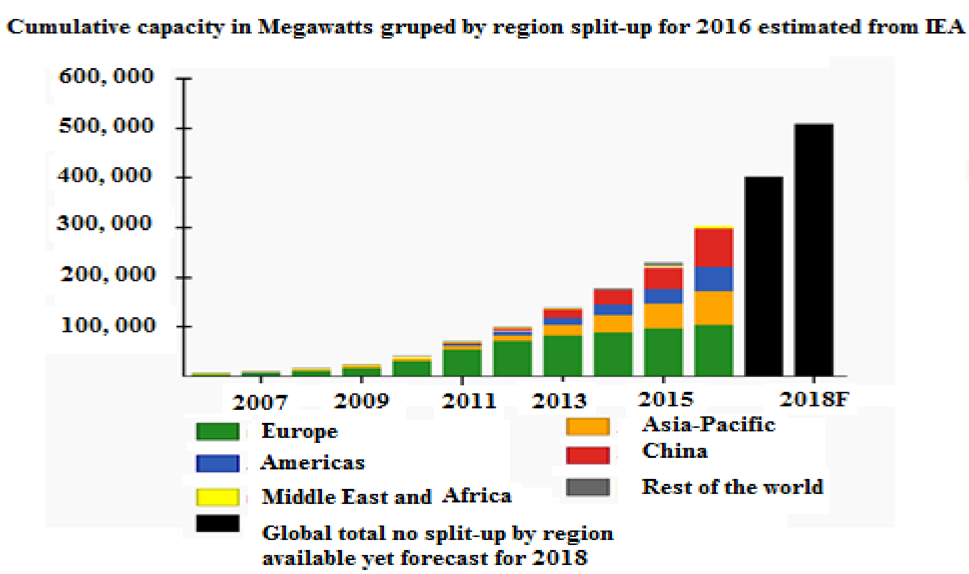



Figure 1.1 Annual solar PV installed capacity by region (MW), world markets [1]:

Figure 1.1 presents a bar graph depicting the annual PV installed capacity by region worldwide [1]. It can be clearly seen that the PV installed capacity has been steadily increasing across the globe in the GW range. With increasing PV penetration levels in distribution systems, more challenges are encountered. Some of the key challenges are associated with the impacts of inverter based distributed generators like PV in distribution systems are outlined. In addition, the main goals and contribution of the dissertation are also presented in this chapter.

## 1.2 Impacts of PV integration - Review

With the high penetration levels of PV systems into the medium-voltage (MV) and low-voltage distribution networks, several benefits are fulfilled by satisfying the additional load demands, hence reducing the transmissions network expansion and losses and so on. As a consequence, PV systems can introduce technical issues such as over-voltages, temporary over-voltages (TOVs) subsequent to ground faults and unintentional islanding incidents, reverse power flows, low fault current contributions, resonance phenomenon and injection of harmonic currents [2–14].

### 1.2.1 Voltage-related impacts

High penetrations of PV can impact circuit voltage in a number of ways. Voltage rise and voltage variations caused by fluctuations in solar PV generation are two of the most prominent and potentially problematic impacts of high penetrations of PV. These effects are particularly pronounced when large amounts of solar PV are connected near the end of long and lightly loaded feeders. Real and reactive power production from the PV system can impact the steady-state circuit voltage, and rise and fall of PV output can result in voltage fluctuations

on the circuit. This, in turn, impacts power quality and voltage control device operation. Potential PV impacts on voltage are discussed below.

With the addition of another power source internal to the distribution circuit, the voltage profile along the circuit may improve when the PV is operating. The voltage rise on a distribution feeder depends on several factors that includes the voltage control equipment such as capacitors and voltage regulating transformers. Figure 1.2 presents an example of voltage profile rise due to PV penetration for a particular time of loading based on research studies. The high voltage at one particular place along the feeder is due to the voltage regulating transformers on the feeder. If reactive power is injected from PV inverter, it also additionally contributes to the voltage rise [15].

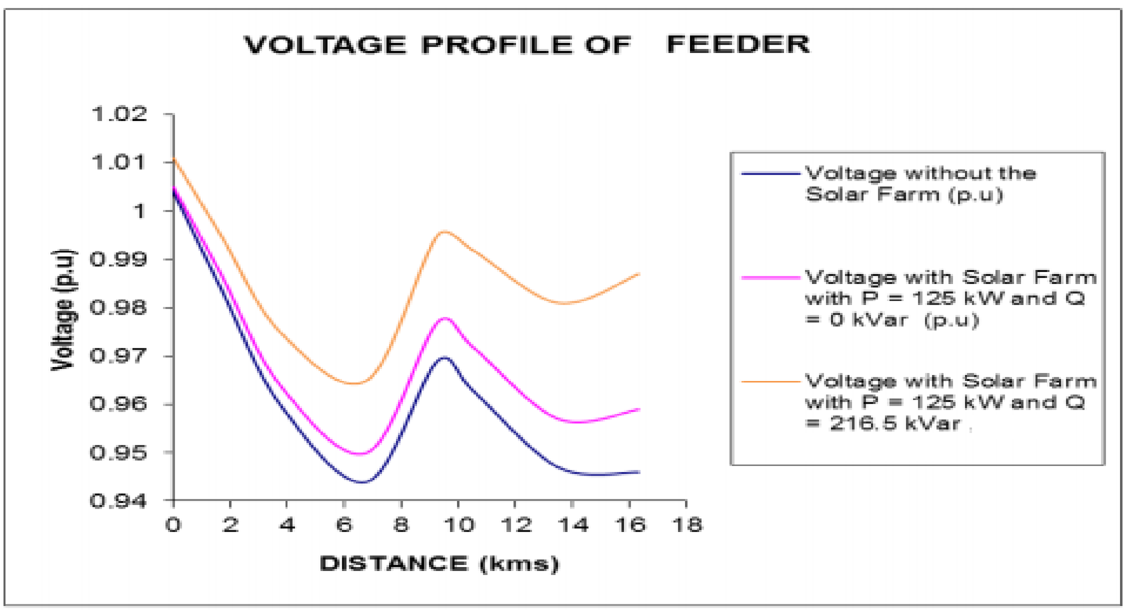



Figure 1.2 Voltage rise due to PV and Voltage regulating transformer on a feeder [15]

During lightly loaded conditions, pockets of high voltage can occur on the distribution circuit, particularly in places of the feeder experiences with cluster of PV connectivity.

During high levels of PV penetrations at the end of a feeder, there can be significant voltage rise that can raise the voltage beyond the ANSI specified range of +5%. Maintaining a voltage limit within the levels of +/-5% is highly important in distribution systems. Failing to comply with the limits the limits can reduce the life of electrical equipment and cause DG (including PV inverters) to trip off-line.

Other forms of over-voltages include resonant over-voltages during islanding incidents. During such an islanding incident, the PV's filter elements (L and C) can interact with the rest of the elements of the distribution systems like the power factor correction capacitors, thereby exciting the resonant modes to cause an increase in voltage. Moreover, interaction of the induction and synchronous generators with feeder capacitor bank can excite ferroresonance and, as such, over-voltages can reach up to 3 per-unit (p.u.). Over-voltages due to lightning strikes, however, are not due to DGs; rather, they are a direct threat to DGs. Thus, care must be taken to protect the DGs against over-voltages caused by lightning strikes.

There is yet another form of overvoltage known as Temporary Overvoltage (TOV). IEEE C62.82.1-2010 defines temporary overvoltage (TOV) as follows:

An oscillatory phase-to-ground or phase-to-phase overvoltage that is at a given location of relatively long duration (seconds, even minutes) and that is undamped or only weakly damped. Temporary overvoltages usually originate from switching operations or faults (e.g., load

rejection, single-phase fault, fault on a high-resistance grounded or ungrounded system) or from nonlinearities (e.g., ferroresonance effects, harmonics), or both. They are characterized by the amplitude, the oscillation frequencies, the total duration, or the decrement.

A number of prior work have studied TOVs caused by inverter-based DGs. Distributed PV systems can also cause TOVs, particularly subsequent to ground faults and unintentional islanding incidents. Further TOVs also arise due to the configurations of isolation transformer associated with PV.

### 1.2.2 Reverse Power Flow

Reverse power flow on a distribution system upstream of a PV system may occur during times of light loading and high PV generation. More than that, if the feeder also has a wind based DG, the reverse power flow can be more during the night considering the fact that most feeders are lightly loaded at night and wind speed is more during the night.

Reverse flow can cause problems for the protection system, as previously noted, and for the voltage regulators. Voltage regulators may be unidirectional and not designed to accommodate reverse flow. If voltage regulators are bidirectional, modifications to the regulator control may still be necessary to accommodate the reverse flow. Impacts depend on factors such as penetration level, aggregated output characteristics, and system characteristics (e.g., amount and type of other generation sources). Most common concerns include increases in cost because of regulation, ramping generation, scheduling generation, and unit commitment, which may degrade balancing authority area performance and wear and tear on regulating units [16].

#### 1.2.2.1 Reverse Power Flow to Adjacent Circuits

Protection concerns, arising from significant reverse power flows, such as exceeding interruption ratings of circuit protection elements and sympathetic tripping of adjacent circuits are two of many ways in which distribution-connected PV or other forms of DG-caused fault current contributions lead to problems on the distribution system.

#### 1.2.2.2 Reverse Power Flow through the Substation Transformer

The system reliability is reduced as a result of outage that can happen due to reverse power flow. Reverse power flows resulting from PV generation could possibly cause reverse power relays at a substation to operate, disconnecting the associated circuit. Islanding refers to the scenario where a part of the utility system, including DGs and local loads, is accidentally or purposefully disconnected from the upstream network, for maintenance purpose, equipment failures, or faults.

The aforementioned operation can impact the DG equipments and customer loads within the islanded zone because of poor power quality. Risks also arise for technicians who work on the lines, as well as for the general public who may be exposed to energized conductors. Modern electronically-coupled DGs generally employ current-controlled voltage-sourced inverters (VSIs). Therefore, islanding can lead to voltage/frequency instabilities, which, in turn, result in inverter shut down by its protection mechanisms. This is commonly referred to as the passive anti-islanding protection. Various protective measures are used to prevent these unintentional islands. PV is often equipped with island detection systems (anti-islanding systems) that can sense the absence of the utility. Many

types of anti-islanding systems exist. TOV's are also experienced during islanding and also during grid connected mode.

Although the requirements for detection of an island are detailed in IEEE 1547 and UL 1741, the specific mechanisms and methods for detecting an island are not there. Thus, anti-islanding schemes for different inverters may vary, and the details of these schemes are often proprietary. Therefore, as penetrations of PV increase, some concern exists because of the potential for interaction among different anti-islanding schemes. Additionally, advanced inverter functionality such as low-voltage ride-through may increase the likelihood of an unintentional island forming, because in those cases low voltage can no longer be used for islanding detection.

If anti-islanding protection is either not available or is insufficient, direct transfer trip (DTT) may be utilized. DTT is often expensive as protection-grade communication channels are typically required, especially if reclosers between the breaker and PV must be included in the scheme. Permissive transfer trip has been proposed as a lower-cost alternative—for example, the loss of a "heartbeat" signal from the substation for approximately 2s would cause the PV to trip.

### 1.2.3 Short Circuit Current Contribution

In the radial distribution systems, protection schemes are based on the principle that power and fault current due to short circuit, flow from the utility energy sources to the loads and were developed without considering the possible impact of the DGs (PV, wind, battery etc.). Therefore, recent high volume of PV systems introduce new sources of fault current that can change the direction of current flow, increase the fault current magnitudes

and, as such, affect the performance for certain types of over-current protection schemes forms the possible solutions. The utilization of local short circuit current limiting capability in the inverter and control architecture and the use of directional over-current blocking and/or special transfer tripping schemes.

### 1.2.4 Resonance Phenomenon and Harmonics

According to IEEE 519 standard, “Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems”, harmonics are defined as: “A sinusoidal component of a periodic wave or quantity having a frequency that is an integral multiple of the fundamental frequency.” These harmonics are generated by interaction of nonlinear loads with power grid, power electronic loads, and rectifiers and inverters in motor drives [17].

Harmonics adversely affect virtually every component in the power system with additional dielectric, thermal, and/or mechanical stresses. Harmonics cause increased losses and equipment loss of life. For example, when magnetic devices, such as motors, transformers, and relay coils, are operated from a distorted voltage source, they experience increased heating due to higher iron and copper losses. Harmonics typically also cause additional audible noise. In motors and generators, severe harmonic distortion can also cause oscillating torques that may excite mechanical resonances. In general, unless specifically designed to accommodate harmonics, magnetic devices should not be operated from voltage sources having more than 5% Total harmonic distortion. Since PV based DG’s are inverters, injection of harmonics into the system could be witnessed.

Although, in general harmonic contribution from every DG units may not be significant to pose a problem, the feeder capacitors utilized to support the voltage of the feeder and capacitors used by customer loads to improve the power factor may tend to resonate with inductive elements of feeder at certain frequencies and produce high network.

Harmonic distortion is a main concern in power quality studies. IEEE 519 standard identifies the network resonance condition as a key factor that impacts the harmonic level. The resonance is defined as an operating condition such that the magnitude of the impedance of the circuit passes through an extremum, that is, maximum or minimum. Series resonance occurs in a series RLC circuit that has equal inductive and capacitive reactances, so that the circuit impedance is low and a small exciting voltage results in a huge current. Similarly, parallel RLC circuit has equal inductive and capacitive reactances, so that circuit impedance is low and a small exciting current develops a large voltage. The resonance phenomenon, or near-resonance condition, is the cause of the most of the harmonic distortion problems in power systems.

The resonance can cause nuisance tripping of sensitive electronic loads and high harmonic currents in feeder capacitor banks. In severe cases, capacitors produce audible noise, and they sometimes bulge. Parallel resonance occurs when the power system presents a parallel combination of power system inductance and PF correction capacitors at the nonlinear load. The product of the harmonic impedance and injection current produces high harmonic voltages. Series resonance occurs when the system inductance and capacitors are in series, or nearly in series, with respect to the nonlinear load point. For parallel resonance, the highest voltage distortion is at the nonlinear load. However, for

series resonance, the highest distortion is at a remote point, perhaps miles away or on an adjacent feeder served by the same substation transformer.

Therefore, it is crucial to analyze such resonance conditions in power system. Resonance phenomenon can be explained using a simple parallel and series circuits. When capacitive reactances of a system at a particular frequency are exactly equal to inductive reactances of the system, parallel and series resonance condition occurs based on the orientation of elements in the systems.

### 1.3 Smart PV Inverters

With the introduction of additional version of IEEE 1547, the series contains the IEEE P1547.8—IEEE Draft Recommended Practice for Establishing Methods and Procedures that Provide Supplemental Support for Implementation Strategies for Expanded Use of IEEE 1547. Earlier PV plants were employed only for the purpose of real power generation. With the introduction of IEEE 1547.8, PV inverters could play a vital role towards the regulation of grid voltage at the point of common coupling (PCC). The PV inverters could perform several ancillary functions with the effective remaining capacity after real power generation. With the efficacy of PV inverter towards ancillary services, Smart inverter has been the name given to PV inverters with specialized controllers to perform additional grid related tasks in distribution systems.

#### 1.3.1 Smart Inverter Functions

The following smart inverter control algorithms as per the Electric Power Research Institute smart inverter functions, could be included in the PV model, particularly to enable mitigation, if required. Some of the major functionality of the smart inverter functions

being used currently or believed to be used in the near future are presented further: Priority setting, PV setting modification, Power factor adjustment, Low-voltage ride-through/high-voltage ride-through,Volt-watt control, Dynamic reactive current support, Intelligent volt-VAR control. The following are descriptions of the smart inverter controls.

#### 1.3.1.1 Priority Setting

During normal operation, the reactive power control is accomplished whenever the real power generation is less than its rated power level so that the real power generation has the higher priority; however, if the utility needs to control the reactive power by reducing the real power generation, an inverter can be programmed to set the reactive power control to a higher priority. This mode can be used for feeders with voltage flicker issues.

#### 1.3.1.2 PV Setting Modification

The maximum power and reactive power capacities can be limited by PV setting modification. This function is designed to let the utility limit the capacities to provide a stable voltage regulation range or provide more reactive power control capability to regulate the line voltage.

#### 1.3.1.3 Power Factor Adjustment

An inverter’s output power factor can be controlled within the limit of the available reactive current. This mode can be used to limit the operating alternating-current (AC) voltage within the allowable levels. Time window and ramp rate can be configured as options. The response time can be programmed with a range of 300 ms to several seconds

with ramp rate option settings. Injecting real power (watts) or reactive power (VARs) will increase the voltage at the point of injection; conversely, absorbing real or reactive power will decrease the voltage. By operating the PV at an absorbing power factor, the PV will absorb more reactive power as the real power output increases. This will help mitigate the increase in voltage with increases in real power injection.

#### 1.3.1.4 Low Voltage Ride Through/High Voltage Ride Through

With conventional grid operations, distribution line faults may cause cascading failures. PV inverters can be used to actively mitigate the transient caused by power line failures and prevent secondary breakdowns. Set points and time durations of at least four different operating modes can be customized and will be reserved for flexible configurations needed for different utility requirements.

#### 1.3.1.5 Volt-Watt Control

When a distribution line has high resistance, the AC voltage can be regulated with the real power. This control can be used to limit the AC voltage magnitude within the normal operating range. Similar to volt-VAR control, described below, the volt-watt curve can be programmed with optional hysteresis and dead band. Distribution line-specific operating conditions can be configured using available modes. The response time can be programmed with a range of 300 ms to several seconds with ramp rate option settings.

#### 1.3.1.6 Dynamic Reactive Current Support

Voltage flicker can be controlled with the fast dynamic response of the inverter. The response time will be as fast as 100 ms. This operation is designed to respond to the

AC voltage fluctuation for the short duration caused by load changes or line disturbances. The dynamic reactive current support curve can be programmed with optional hysteresis and dead band. This mode can be operated in conjunction with the priority setting to regulate AC voltage.

#### 1.3.1.7 Intelligent Volt-VAR Control

The distribution line voltage can be regulated within an inverter's available power capacity. The AC voltage control can be coordinated at the SCADA level with other ancillary control equipment, such as capacitor banks or voltage regulators. The volt-VAR curve can be programmed with optional hysteresis and dead band. Distribution line-specific operating conditions can be configured using available modes. The response time can be programmed to be between 300 ms and several seconds with the ramp rate option setting.

## 1.4 Dissertation Objective and Scope

The overall objective of the dissertation is to examine the major reasons behind the occurrence of resonance phenomenon and Temporary overvoltage phenomenon in distribution systems in the presence of PV. Further, a novel idea of utilizing a smart inverter control forms the crux of the research for mitigating the network harmonic resonance and temporary overvoltage phenomenon.

With the aforementioned control of smart inverters, the concept of VAR control is utilized in designing the new control for the smart inverters. In case of network harmonic resonance, the main feeder capacitor has always been a major contributor towards injection

of harmonics and hence the occurrence of resonance. With conventional PV plant in place, currently industry practices detuning strategy to mitigate network resonances. With a specialized controller based on VAR injection technique from smart inverters, detuning process could effectively be achieved at the point of common coupling (PCC). This effectively utilizes the unused capacity of the PV inverters for VAR injection. With the growing trend of VAR injection from PV inverters, the latest addition will be how differently it could be applied based on specialized design. Hence the idea of utilizing Smart inverter as a detuning component with the ability to perform the role of a capacitor by replacing its functionality to mitigate resonance forms the quintessence of the first part of the research in dissertation.

Further with the ability of smart inverter, the concept of VAR absorption is used to mitigate Temporary overvoltage phenomenon (TOV). In this research a unified controller is designed for smart inverter. Based on the situation, the controller can control the voltage rise due to reverse power flow from conventional PV plant in the distribution system. This control is exerted on all three phases by absorbing VAR during reverse power flow to mitigate over voltage. Further during a Single Line to ground fault and Double Line to ground fault, the voltage levels of one or two phases alone needs to be controlled. This dissertation not only demonstrates a novel idea of utilizing Smart PV/SmartPark -Plug in Electric Vehicle (PEV) inverters to mitigate TOV, it also presents the design of a new control that can automatically differentiate and sense the normal and faulty operation of the grid and perform its controlling action of VAR absorption to mitigate the overvoltage and TOV.

To summarize, the concept of VAR injection and VAR absorption from Smart inverters could be seen in a different dimension in a this dissertation for the first time as a virtual detuner in mitigating network harmonic resonance and an effective strategic mitigator of TOV in distribution systems.

### 1.5 Methodology

To achieve the objectives in this dissertation, the distribution system design and smart inverter design are modeled in detail in the commercial grade software, power systems computer aided design using electromagnetic transients including dc (PSCAD/EMTDC. To witness the novel idea of smart inverter as mitigator of network resonance and TOV phenomenon, IEEE Standard 399-1997 based distribution system is considered with few modifications and the designed smart inverter is interfaced into the system to achieve the necessary goals.

### 1.6 Dissertation Outline

With the first chapter forming the introduction, the rest of the chapters in the dissertation are organized as follows:

The second chapter is a consolidated compendium of PV interconnection standards across the globe in a smart grid. The motivation behind the survey of global PV interconnection standards is to cluster all the possible standards that could serve as useful document for all researchers and engineers and further present the challenges and limitations associated with each PV interconnectivity standard. Further the quick

reference to these standards could effectively be used to improve the safety aspects towards the reliable operation of distribution systems with enhanced PV interconnectivity.

Chapter 3 presents the harmonic resonance repercussions of PV and associated distributed generators on distribution systems. The harmonic resonance and distortion that arises between the PV systems and the rest of the network is investigated thoroughly. Here the PV system is designed based on hysteresis controlled technique compared to commercial PWM control technique to witness the worst case scenarios during harmonic injections from hysteresis controlled PV inverters.

In Chapter 4, interactive impacts of elements of distribution system along with PV is investigated. It is a well-known fact that the filter elements of PV are Land C components that interact with rest of the distribution network that contains L and C elements in the form of distribution line, feeder capacitor banks, loads and so on. This chapter will be highly useful as a reference for distribution system planning engineers and researchers working in the power quality area.

In Chapter 3 and Chapter 4, the PV system is designed based on hysteresis technique to witness the worst case scenarios during harmonic modes and resonant peaks. Chapter 5 presents the comparative impact assessment of hysteresis and PWM controlled PV on network resonances in distribution systems. Two control strategies are designed for PV systems and each controller strategy with the same system has been compared. Normally the filter configuration associated with PV has a definite impact on network resonances. With different control strategies, the filter design is also different. This chapter

examines the comparison to determine the extent to which filter elements and associated control strategy could influence the network resonances modes in distribution systems.

In Chapter 6, a practical North American system with PV and wind (modeled as a harmonic source) are considered. The resonance phenomenon in the system is examined. Further a mitigation strategy of detuning is done on the system's main feeder capacitor bank. This brings out the current methodology in practice in the real time industrial systems for mitigating resonance. With such a practice in place, the methodology in Chapter 7 brings out a new idea of employing smart inverters to mitigate resonance phenomenon in distribution systems thereby forming the crux of the research in dissertation.

In Chapter 7, the efficacy of smart PV inverter as a virtual detuner in mitigating network resonance has been the novel idea that has been proposed for the first time. This would make use of the remaining capacity of the dormant PV inverter as a smart inverter to detune the system for mitigating resonances. This approach witnesses a futuristic vision and a road map for researchers and engineers.

In Chapter 8, neoteric efficacious exertion of smart inverter as a suppressor of Temporary overvoltage (TOV) phenomenon. The smart inverter can be associated with PV plant or SmartPark PEV as well. The novel idea will serve as an effective TOV mitigation strategy in a Smart grid environment. Finally, Chapter 9 concludes the dissertation.

## 1.7 Contributions

The main contributions of this dissertation involves the design and neoteric application of Smart inverters towards the mitigation of network harmonic resonance and Temporary Overvoltage phenomenon (TOV) in distribution systems. With chapter 1 and chapter 9 forming the introduction and conclusion in dissertation respectively, starting from Chapter 2 to Chapter 8, every chapter has become a contribution in form of a conference/journal proceedings.

Considering the fact that a recent detailed survey on global PV interconnection standards hasn't been done, Chapter 2 presents a contribution in the form of 'Consolidated compendium of global PV interconnection standards in a smart grid environment.' The survey written towards global PV interconnection standards can serve as a quick reference for researchers and planning engineers working in several domains associated with PV interconnection in distribution systems.

The modeling and design of distribution systems, PV plant, Smart inverters and other components are modeled using PSCAD/EMTDC.

Chapter 3 brings out a contribution in the form of addressing the impacts of PV and its filter elements using hysteresis control technique to witnesses the overall interaction towards network harmonic resonance phenomenon in distribution systems. This chapter investigates the root cause towards the resonance phenomenon when PV is in place.

Chapter 4 is an extension of Chapter 3 with an aim of further investigating the key element responsible for resonance phenomenon and the concept of detuning is introduced in the presence of PV.

Chapter 5 brings out a contribution by comparing two different control schemes (PWM and hysteresis control) associated with PV and its impact on network harmonic resonance considering the fact that filter elements are different for the same rating of PV using the aforementioned control techniques. So far, such a comparison hasn't been made. All these investigations carried out forms the platform towards the proposal of introducing the smart inverters into the distribution systems.

Chapter 6 considers an exemplary North American system with renewable energy in place. Resonance phenomenon and the current methodology of detuning that in practice is provided as a solution to see the effectiveness of the extent to which the network resonance could be mitigated.

Chapter 7 forms the major crux of the dissertation that proposes a new application of Smart inverter associated with PV (can also be extended to Smart Parks inverters) as a virtual detuner in mitigating network resonances. Although there has been several application of Smart inverters but this application is entirely novel that could be adapted by researchers and planning engineers in future. The contribution involves a new control strategy with Smart PV inverters along with design procedure involved with filter elements and the application of Smart PV inverter as a virtual detuner for the first time in contrast to the current detuning methodology adapted in distribution systems.

In Chapter 7, the resonance mitigation from Smart inverters was devised based on the principle of VAR injection capability of Smart inverters. With the additional capability of Smart inverter to absorb VAR from the grid, a second application towards power quality has been proposed in the dissertation. Chapter 8 provides a contribution towards the same.

For the first time a direct comparison between the current grounding scheme design and the novel schema proposed using Smart PV inverters (also using SmartPark) to mitigate TOV could be seen in the dissertation. The effectiveness of Smart inverter as a suppressor of TOV will further be strengthen the grounding schema in distribution systems.

Overall the dissertation has contributions in several domains like power quality, distribution systems, distributed generation, power electronics and control. The dissertation can serve as a major reference to researchers and planning engineers involved in exploring the various domains of smart grid environment.

# CHAPTER TWO

# CONSOLIDATED COMPENDIUM OF PV INTERCONNECTION STANDARDS AND GUIDELINES ACROSS THE GLOBE IN A SMART GRID

## 2.1 Overview

Photovoltaic energy (PV) is one of the cleanest forms of renewable energy. The popularity of this technology has been widely recognized with the incentives provided by the governments of various countries across the globe. Day by day, the growth rate of PV is steadily increasing. Renewable energy resources like PV are interfaced with power electronic inverters to enable its interconnection to the power system network.

The conventional power system becomes more complex with increasing renewable energy interconnections to constitute a smarter grid. As the decentralized generation achieved by PV plants becomes more prevalent, the grid reliability becomes an important facet. The ramifications associated with the PV interconnection needs an adherence to reliable operation of the grid without any violations.

Safety factor and reliable interconnection of various photovoltaic generators has become a major challenge in the smart grid environment. Standards or guidelines for grid-connected photovoltaic generation systems play a vital role in the PV interconnection. Several organizations and technical committees are constantly involved in research to update and revise such standards on a frequent basis throughout the world. The focus of this chapter is to realize a consolidated compilation of PV interconnection standards

across the globe. This chapter will serve as a reference for improving standards for grid-connected PV systems in a smart grid environment.

## 2.2 Introduction

Since the grid interconnection of PV is increasing rapidly, global installed capacity for PV solar is expected to increase to 489.8 GW by 2020 [18]. PV technology is gaining parity with the incentives provided by the governments of various countries across the globe. The introduction of regulatory policies such as the Feed In Tariff (FIT) program has paved the way for more PV Solar interconnection [19-21]. New strategies are needed to be adopted for facilitating large amount of PV interconnection into the grid in a most efficient and reliable manner. PV interconnection standards are recommended practices and guidelines to ensure compatible and reliable operation of photovoltaic (PV) systems when interfaced with the power system network.

The standards are framed irrespective of the PV types and technologies from various manufacturers across the globe ensuring cost effectiveness with conformance to the established standards. Since the grid is constantly evolving and becoming smarter, the standards for PV interconnection are still in the embryonic stage. This requires a constant revision compared to the widely accepted and established conventional power generation interconnection standards. Although every country and jurisdiction may have its own standards according to its grid code, the overall concept towards PV interconnection has remained more-or-less the same. The International Electrotechnical Commission (IEC) and Institute of Electrical and Electronics Engineers (IEEE) standards are widely being used as

benchmarks to develop several other electric power standards across the globe. International experience with PV interconnection standards are discussed [22-28].

Table 2.1 Major electric power system standards towards PV interconnection

| **Country/Region** | **Standards established** |
|---|---|
| China | GB/Z, GB/T (CEC) |
| Europe | EN (CENELEC committees) |
| Germany | VDE, BDEW |
| USA | IEEE, UL |
| Spain | TC 82 |
| Italy | TC 82 |
| South Africa | NRS |
| Australia, New Zealand | AS, NZS |
| International | IEC committees |
| India | IS (CEA) |

Table 2.1 presents some of the major electric power standards applied towards PV interconnection for various countries and regions. IEEE 1547 has been one of the major standards in the U.S for addressing the interconnection of distributed generation to the utility. Several interconnection rules are adopted based on this. Apart from IEEE 1547, there are other standards and codes that are applicable based on the laws and policies of different states in the U.S. Some of them are: IEEE 929 "Recommended Practice for Utility Interface of Photovoltaic Systems," The National Electrical Code (NEC), the National Electric Safety Code (NESC), National Electrical Manufacturers Association (NEMA), American National Standards Institute (ANSI) and Underwriters Laboratories (UL) standards (including UL Standard 1741). A detailed survey of interconnection rules for distributed generation is presented in [29]. The PV inverter forms the crux of the whole PV system. During the integration process, the power quality is an important factor that needs

to be considered. Voltage, frequency and harmonics are some of the aspects of power quality. These common aspects are considered throughout the world to frame the standards for PV interconnection. Separate standards are established based on the quality of the power injected into grid which includes the flicker, harmonics, DC injection and the operating parameters like voltage and frequency deviation, anti-islanding, low voltage ride through/high voltage ride through (LVRT/HVRT) and reactive power injection. Papers have presented an overview of grid codes for PV interconnection [30]. A suitable comparison of grid codes has been done [31]. Guidelines for PV interconnection are presented in [32]. A comparison of interconnection standards of renewable energy generation is presented in [33]. Coordinating standards development for smart grid integration of DER- smart inverters and micro-grids are presented in [34].

A detailed documentation on PV system codes and standards prepared by NREL for different levels (transmission and distribution) and case studies are presented [35-36]. A survey on PV interconnection rules and issues are presented in [37-39]. Grid integration standards for distributed Solar Photovoltaics (PV) in India have been presented in detail [40]. A comparative study of PV interconnection standards for China is presented in [41-44]. In spite of the aforementioned work, a recent detailed survey for PV interconnection standards from different countries across the globe has not been presented. The objective of this chapter is to present a survey by conglomerating all the possible existing PV interconnection standards across the globe in a single window. This would further be handy in serving as a reference for further exploration of PV interconnection standards in future.

## 2.3 Survey of PV interconnection standards

IEEE and IEC standards are always being adopted as a benchmark to develop other standards universally. Some of them facilitating PV interconnection are as follows:

- IEEE Standard 929-2000-IEEE Recommended Practice for Utility Interface of Photovoltaic (PV) systems up to 10 kW.
- IEEE Standard 1547-2004-IEEE standards for interconnecting distributed resources with electric power systems laid the foundation for: UL 1741, inverters, converters, controllers, interconnection system equipment for use with distributed energy resources.
- CSA 22.2 No. 107.1-01(R2011)-General use power supplies.
- CAN/CSA-C22.2.NO.257-06(R2011)-Interconnecting Inverter based micro-distributed resources to distribution systems.
- CAN/CSA-C22.3.NO.9-08- Interconnection of distributed resources and electric supply systems.
- IEC-TC8 System aspects of electrical energy supply.
- IEC-TC57 power systems management and associated information exchange.
- TC 82- solar photovoltaic energy systems.
- TC 22- power electronic systems and equipment.
- IEC 62109-Safety of power converters for use in photovoltaic power systems- Part 1: General requirements & Part 2: Particular requirements for inverters.
- IEC 62116-Test procedure of islanding prevention measures for utility-

interconnected photovoltaic inverters.

- IEC/TR 61850-90-7-Communication networks and systems for power utility automation- Part 90-7 Object models for power converters in distributed energy resources (DER) systems.

- IEC 62477-Safety requirements for power electronic converter systems and equipment – Part1: general & Part 2: Power electronic converters from 1000 V AC or 1500 V DC upto 35 kV AC.

- IEC 62116-Test procedure of islanding prevention measures for utility-interconnected Photovoltaic inverters.

- IEC 61727-Photovoltaic (PV) systems characteristics of the utility interface.

Considering the fact that the size of PV can be massive and are usually connected as PV farms, it may have a definite impact during the steady- state or dynamic operations. There is a high certainty that over/under voltage problems in low- voltage distribution systems can occur in the high impedance branches of the system. This can be as a result of intermittent nature of PV interconnected into the system and also due to the reverse power flow in smart grid environment.

Further, a frequency regulation in the system is vital due to the mismatch between the load and generation especially with the uncertainty in the output of the PV. Some of the common effects that could be witnessed in a power system after the PV has been integrated may include: Deviation in voltage levels and voltage regulation on the feeder. The effects of connecting PV generators to the grid may include the following:

Voltage fluctuation and voltage regulation problem. Problems associated with voltage unbalance, overloading and sudden shedding of load can lead to a abnormal operation in the system. Although load tap changers (LTCs), line drop compensations, line voltage regulators and capacitor banks are there, any malfunctioning can become problematic.

Apart from voltage regulation which is directly connected with the flow of reactive power, power factor is also associated with that. Current and voltage harmonics, DC current injection, islanding, reverse power flow and several other phenomenon and standards associated are discussed further.

### 2.3.1 Voltage Deviations

A safe operating range of voltage is always recommended for the reliable operation of the grid and the PV system [45]. A deviation or violation of voltage can arise as a result of PV interconnection or during a fault in the power system network. Lower and upper limits of voltages are always specified to ensure that PV system disconnects itself from the system and does not have further detrimental effect on the power system network. Table 2.2 presents the PV interconnection standards across the globe for the voltage limits.

The standards associated with China during voltage deviation include GB/T 19964, Q/GDW 617 and GB/T 29319. For voltage levels ≤10 kV the permissible range is ±7% and for ≥35 kV the permissible range is ±10%.

Table 2.2 PV disconnection based on monitoring of grid voltage

| Country | Standards adopted | Lower limit of voltage | Upper limit of the voltage | Trip time |
|---|---|---|---|---|
| Australia | AS 4777 | 87% | 117% | 2s |
| Europe | EN50438 | 85% | 115% | 1.5s/0.5s |
| Germany | VDE0126-1-1 | 80% | 115% | 0.2s |
| International | IEC 61727 | 50%<br>85% | 135%<br>110% | 0.1s/0.05s<br>2s |
| Italy | DK 5940 | 80% | 120% | 0.2s/0.1s |
| South Korea | PV501 | 50%<br>88% | 120%<br>110% | 0.16s<br>2s |
| Spain | RD 1663/661 | 85% | 110% | 0.5s<br>1.5s/0.5s |
| UK | G83/1-1 | 90% | 115% | 5s |
| USA | UL1741 | 50%<br>88% | 120%<br>110% | 0.16s<br>2s/1s |

### 2.3.2 Frequency Deviations

A constant frequency ensures a reliability of power quality in the grid. When the generated power is less than the consumed power, the frequency will decrease. Conversely, a frequency rise will occur when the generated power is greater than the consumed power. A fluctuation in the frequency can cause misoperation or damage to sensitive loads. There are other aspects of frequency like the subsynchronous resonance (SSR) that can override the natural frequency of the turbine shaft and blades requiring the generators to be tripped.

A PV frequency standard has been established to ensure the stable operation of the grid [46]. For example, the operating frequency in Germany is 50 Hz and the inverter has been designated to operate between 47.5 to 51.5 Hz. The VDE0126-1-1 and BDEW standards clearly state that all the PV inverters should disconnect from the grid whenever

there is a frequency droop. Since Germany has many PV farms installed, sudden disconnection can lead to a considerable instability in the grid. So, the droop function mandates that when the frequency crosses 50.2 Hz, the inverter output could be reduced in steps of 40% per Hz till it reaches 51.5 Hz.

Table 2.3: PV disconnection based on monitoring of grid frequency

| **Country** | **Standards adopted** | **Lower limit of frequency** | **Upper limit of frequency** | **Trip time** |
|---|---|---|---|---|
| Australia | AS 4777 | -5 Hz | +5 Hz | 2s |
| Europe | EN50438 | -3Hz | +1Hz | 0.5s |
| Germany | VDE0126-1-1 | -2.5Hz | +0.2Hz | 0.2s |
| International | IEC 61727 | -1Hz | +1Hz | 0.2s |
| Italy | DK 5940 | -0.3Hz | +0.3Hz | 0.1s |
| South Korea | PV501 | -0.3Hz | +0.3Hz | 2s |
| Spain | RD 1663/661 | -2Hz | +1Hz | 3s/0.2s |
| UK | G83/1-1 | -3Hz | +0.5Hz | 5s |
| USA | UL1741 | -0.7 Hz | +0.5Hz | 0.16s |
| China | Q/GDW 617 GB/T 19964 | 50.2 Hz to 50.5 Hz requires 2 minutes of operation at least > 50.5 Hz requires disconnection from the grid within 0.2s | | |

Once it crosses 51.5 Hz, the shutting down of inverters is required. Table 2.3 presents the PV interconnection standards across the globe with respect to the frequency. Standards for voltage and frequency limits are intended to prevent anti-islanding.

### 2.3.3 Low/High Voltage ride through (LHVRT)

Fault Ride-Through (FRT) is defined as the ability of a grid-tied inverter to stay connected to the power system and withstand momentary deviations of terminal voltage that vary significantly from the nominal voltage without disconnecting from the power system. Since the most likely cause for excessive voltage deviations in a power system is a fault in the system, the term “fault ride-through” is sometimes used in case of a scenarios when a reactive power support is required. It is a well-known fact that the reactive power is directly proportional to the voltage. It is also used in case of cold load pick-up. Cold load pickup is the process of re-energizing a distribution network takes place after a long duration. The load becomes "cold" and draws more current than it would during normal operation. This is due to things like transformers energizing, capacitors charging, motors starting, light bulb filaments heating up, etc. During this time, the grid could experience a deviation in the voltage.

In contrast to reduced terminal voltage, a fault event on power systems with specific characteristics may also cause a momentary rise in voltage Although there exists different classifications of voltage ride through (VRT) like Low-Voltage-Ride-Through (LVRT), Zero-Voltage-Ride-Through (ZVRT), and High-Voltage-Ride-Through (HVRT), it is often appropriate to lump LVRT and ZVRT together as just LVRT because they differ only in the magnitude of voltage drop.

Momentary voltage sag is usually caused when there is a fault due to a short circuit or lightning strike that leads to a flow of high current between phases or to ground. This can cause the inverter to trip and disconnect from the power system network until the

system is stabilized. The disconnection can produce a 'domino effect' by exacerbating the event and causing other inverters to trip. L/HVRT allows inverters to stay connected if such voltage excursions are for very short time durations and the voltage returns to the normal range within a specified time frame. L/HVRT does not require the inverter to stay connected if the fault persists beyond a specified time.

During the event of disturbances/failures in the grid, the inverters compliant with interconnection standards such as IEEE 1547 (USA), UL1741 (USA), VDE 0126-1-1 (Germany) or AS4777 (Australia) are required to disconnect. This was a part and parcel of safety and precautionary aspect to prevent the occurrence of unintentional islanding. Moreover the functionality is based on the frequency. This is mainly due to the unity power factor requirement. Germany has considered the VDE-AR-N 4105 code of practice by enforcing it starting January 2012 that grid tied inverters will have the LVRT capabilities at a low voltage level (LV). Earlier, the BDEW medium voltage (MV) directive, enforced from January 2009, modified the requirements for PV inverters connecting to the MV grid in Germany based on the Transmission Code, 2007 94.

During a fault, the inverters were not supposed to disconnect in the event of a voltage drop to 0% of nominal voltage for a period of 150 milliseconds. If the recovery is not 30% of its nominal value, then the units could be disconnected. The BDEW standard mandates the inverter to stay connected during a fault, causing it to act as a reactive power compensator and aid the dip in the voltage as a requirement from April 1st 2011. PV inverters in Germany now aid the dip in voltage by providing suitable reactive power compensation during a fault.

CAISO's (California independent system operator in USA) interconnection procedures of 2010 95 recommended extending FERC Order 661-A 96 to PV Solar. During a three phase fault or during any abnormal condition of a voltage, FERC 661-A mandates the wind farm to ride through three phase faults. The maximum clearing time the wind generating plant shall be required to withstand for a three-phase fault shall be 9 cycles at 0 p.u. A suitable update and revision on the standard IEEE 1547 and amendment of UL 1741 expects the PV Solar inverter to deal with FRT.

With the revision of IEEE 1547 standard to IEEE 1547.8, PV Solar inverters could possibly inject reactive power in the grid in North America. This would incorporate the capability for FRT. The standards in Australia do not currently mandate the LVRT feature for solar PV inverters. However, the National Electricity Rules 98 in Australia require that the LVRT function be present for wind farms. India currently does not require inverters to have the L/HVRT functionality. In China Q/GDW 617 standard mandates the reactive power support for low voltage ride through.

### 2.3.4 Harmonics

Non-Linear loads are responsible for harmonics that are induced in the system causing a voltage distortion in the supply voltage. Resonances can also lead to performance problems and damage of many types of equipment involved in the power system network. The detailed analysis on resonance phenomenon and a novel approach has been presented in [47-51].

Table 2.4 Harmonic standards towards PV interconnection

| Country | Standard | Description and Specifications |
|---|---|---|
| China | GB/T 19964, Q/GDW 617, GB/T 29319 | Applicable for measurement towards more than $25^{th}$ order of the harmonic. |
| Germany | IEC 61000-3-2 53, 61000-3- 12 54, VDE-AR-N4105 | LV equipment with input current ≤16A (IEC 61000-3-2) and with input current >16A and ≤75A (IEC 61000-3-12). |
| India | IEEE 519 | Adopts in the lines of U.S.A and Australia |
| USA | IEEE 519<br>IEEE 1547 | The voltage distortion limit established by the standard for general systems is 5% THD. In this standard, the Total Demand Distortion (TDD), determined by the ratio of available short circuit current to the demand current is used as the base number to which the limits are applied. The calculation method adopted is based on single-order calculation for orders greater than $35^{th}$ order. |
| Australia | AS4777 | Standard states that the total harmonic distortion (THD) should be less than 5%. |

Table 2.5 Harmonic current distortion limits of PV Systems

| **Standard** | | IEC 61727<br>GB/T 19939<br>GB/Z 19964<br>GB/T 20046<br>CNS 15382<br>AS 4777.2 | IEEE 929<br>IEEE 1547<br>CSA C22.3 No. 9-08<br><br>TPC Technical Guideline<br><br>AS 4777.2<br><br>KEPCO Technical Guideline |
|---|---|---|---|
| **Odd Harmonic** | $3 \leq h \leq 9$ | < 4.0% | < 4.0% |
| | $11 \leq h \leq 15$ | < 2.0% | < 2.0% |
| | $17 \leq h \leq 21$ | < 1.5% | < 1.5% |
| | $23 \leq h \leq 33$ | < 0.6% | < 0.6% |
| | $33 < h$ | - | < 0.3% |
| **Even Harmonic** | $2 \leq h \leq 8$ | < 1.0% | Less than 25% of the odd harmonic limits |
| | $10 \leq h \leq 32$ | < 0.5% | |
| **THD (%) or TDD (%)**<br>h: Harmonic order<br>TDD: Total demand distortion<br>THD: Total harmonic distortion | | < 5% | <5% |

In case of the PV, the inversion stage from DC to AC is responsible for the harmonics to be induced into the grid. While great strides have been made in inverter

technology, a low pass LC filter is normally installed at the inverter output to filter the harmonics. Table 2.4 presents the PV interconnection standards across the globe for the harmonics. The more detailed classification based on the harmonic orders towards distortion limits of PV system are presented in Table 2.5, Table 2.6, Table 2.7 and Table 2.8.

Table 2.6 IEEE STD 519-1992 recommended harmonic limits for PV [50]

| **Harmonics** | **Distortion Limit** |
|---|---|
| $3^{rd}$ to $9^{th}$ | < 4.0% |
| $11^{th}$ -$15^{th}$ | <2.0% |
| $17^{th}$-21st | <1.5% |
| $23^{rd}$ to 33rd | <0.6% |
| Above the 33rd | <0.3% |
| $35^{th}$ or greater | 0.3% |
| Total harmonic distortion | 5.0% |
| Harmonics of even order are limited to 25% of odd values | |

Table 2.7 Harmonic current distortion limits of PV systems (CAN/CSA-C22.2 NO.257-06)

| | | |
|---|---|---|
| Odd Harmonic | $3 \le h \le 9$ | 4.0% |
| | $11 \le h \le 15$ | 2.0% |
| | $17 \le h \le 21$ | 1.5% |
| | $23 \le h \le 33$ | 0.6% |
| | $33 < h$ | 0.33% |
| Even Harmonic | $2 \le h \le 8$ | 1.0% |
| | $10 \le h \le 14$ | 0.5% |
| | $16 \le h \le 20$ | 0.4% |
| | $22 \le h \le 32$ | 0.2% |
| | $34 \le h$ | 0.1% |

Table 2.8 Harmonic current distortion limits of PV systems (EREC G83)

| Odd Harmonic | **Order** | **Percentage %** |
|---|---|---|
| | h=3 | 2.30 |
| | h=5 | 1.14 |
| | h=7 | 0.77 |
| | h=9 | 0.40 |
| | h=11 | 0.33 |
| | h=13 | 0.21 |
| | 15≤h≤39 | 0.15x(15/h) |
| Even Harmonic | h=2 | 1.08 |
| | h=4 | 0.43 |
| | h=6 | 0.30 |
| | 8 ≤ h ≤ 40 | 0.23x(8/h) |
| | | Limits in BS EN 61000-3-2 Class A (equipment input current ≤16 A [per phase) |

### 2.3.5 Anti-Islanding

During an outage, the main grid terminates its role in supplying power to the loads. If distributed generators like PV solar are present, they may supply power to the loads if they remain online. When maintenance had to be performed on the power system network serious safety concerns are present for the utility personnel. The PV Solar Inverter should

detect that the central grid is down or disconnected from the local grid, and terminate its role in supplying to the grid as a distributed generator. This phenomenon is referred to as 'anti-islanding.' Such an island formed is referred to as an 'unintentional island.' IEEE 1547 mandates that the PV Solar Farm should detect the island and should be in a position to stop the energizing process of the island. Some of the key aspects that may be considered are as follows:

a) The aggregate capacity of the PV Solar Farm should be less than one third of the minimum load of the local electric power system (EPS).

b) The PV inverter should be in a position to maintain constant power and power factor.

c) The PV Solar farm should be equipped with a reverse power flow protection sensed between the point of connection and the PCC, which will disconnect or isolate the PV Solar if there is a reverse power flow from the local EPS to the main grid. UL1741 is also embodied with IEEE 1547 standards for this phenomenon.

The islanding operation could be detected by the following two methods: passive and active. Passive techniques are based on measurement of instantaneous voltage, instantaneous frequency, phase deviations, vector surge relay, and detection of voltage and current harmonics at the point of interconnection. Passive techniques rely on distinct patterns or signatures at the point of interconnection to the grid. In the active method, schemes including the voltage shift method, slip mode frequency shift, active frequency drift (AFD), ENS (impedance measurement) and reactive power fluctuation are employed.

The disturbances into the connected circuit are observed in the form of a response. Table 2.9 presents the anti-islanding standards during PV interconnection across the globe in some of the prominent countries.

### 2.3.6 Intentional Islanding

There is yet another phenomenon known as an 'intentional island.' During this phenomenon, the PV Solar Farm is disconnected from the main grid. Intentional islanding of distributed generation (DG) can support local supplies to critical customers in the event of network failure, thus increasing the system reliability. In such a case, the DG interface control is responsible for maintaining both the voltage and frequency on the islanded part of the network within the permissible operating levels. During an event of a grid failure, the PV solar inverter disconnects itself from the grid. The power supply to the loads is done in two ways.

The first way is considered by using the PV solar farm to work in a hybrid inverter mode to charge the batteries that would supply certain loads.

The second mode of operation involves its functionality in a grid-tied mode in synergy with the larger backup system, most likely diesel based generators. All safety features are planned by the utilities to prevent the reverse power flow during the synergy operation with the diesel generator sets. The synergy mode of operation would facilitate in reducing the cost of employing the full diesel generator set. This cooperative interaction mode between the PV Solar and diesel generator would be highly beneficial. Although this phenomenon is not a part of the standards, but the procedure is adopted based on the scenarios. Standard 1547.4 covers this aspect.

Table 2.9 Anti-islanding standards-PV interconnection

| Country | Standard | Description and Specifications |
|---|---|---|
| Germany | VDE 0126-1-1:2013-08 | Standard framed for the automatic disconnection of PV from the main grid. This includes the detection during the under/over voltage, frequency and impedance. The disconnection of PV should happen within 5 seconds when change of one ohm impedance is detected. |
| USA | UL 1741 harmonized with IEEE 1547 | The standard requires the inverter to detect an island condition in order to stop energizing the grid within 2 seconds of the formation of the island. |
| Other European Countries | IEC 62116 | Test procedure for islanding prevention measures. |
| Australia | AS 4777 | Within the prescribed set points of the grid voltage and frequency, the inverter should disconnect itself if the set points are crossed. Reconnection is permitted based on the fact |

| | | |
|---|---|---|
| | | that the grid parameters are within the acceptable range for a minimum time frame of 1 minute after which synchronization process with the grid may be permitted. |
| India | UL 1741/IEEE 1547 | Mandated by MNRE for anti-islanding protection for utility scale projects commissioned under the National Solar Mission (NSM). |
| China | GB/T 19964, Q/GDW 617, GB/T 29319 | GB/T 19964: Shall have the capability of anti-islanding with disconnection time of 2s applicable towards small system.<br><br>Q/GDW617: The protection for anti-islanding is not mandatory. The capability of anti-islanding protection of the medium PV power plant will be determined by the grid dispatch department. This is applicable towards medium and large systems.<br><br>GB/T 29319: PV power station should resort to anti-islanding phenomenon no longer than 2 second for the compliance with the grid protection. |

### 2.3.7 DC Injection

PV inverters can cause a DC bias due to the following mechanisms: imbalance in state impedances of switches, different switching times for switches, and imperfection in implementing the timing of drivers. As a result of which whenever there is a DC injection into the grid, distribution transformers starts drawing current hundred times more than that of a normal rated current leading to saturate of the core, losses and making the equipment lose its efficiency. Apart from that, the grid is also prone to corrosion risks when DC injection becomes prevalent in the grid. Universally majority of the standards across the globe states that the DC injection.

During an automatic disconnection, more than 1A of DC injection is not permitted. If it happens to exceed 1A for some reason, disconnection should happen in 0.2 seconds. USA standard IEEE 1547 mandates that DC injection into the grid should not exceed 0.5% of the rated output at the point of interconnection. AS 4777 is adopted by Australia. The standard mandates the DC output current at AC terminal should not exceed 0.5% of the rated output current. India adopts a standard in line with IEEE 1547 standard. China adopts Q/GDW 617, GB/T 29319 as its standard that mandates the DC component injected into the grid should not exceed 0.5% of the rated output current at the point of interconnection. Further the summary of DC injection is presented in Table 2.10.

Table 2.10 DC injection limitation for PV

| Standard | Limitation of DC injection |
|---|---|
| IEC 61277<br>CNS 15382<br>GB/T 19939 | No more than 1% of rated output current |
| IEEE 1547<br>IEEE 929<br>CSA C22.3 No. 9-08<br>Rule 21<br>TPC Technical Guideline<br>KEPCO Technical Guideline | No more than 0.5% of rated output current. |
| EREC G83 | The limit of dc injection is 0.25% of ac current rating per phase. |
| VDE V0126-1-1 | The power generation system must be isolated within 0.2 s, while the dc current is more than 1 A. |

### 2.3.8 Flicker

Variations in the root mean square (RMS) voltage between 90% and 110% of nominal voltage generated by the solar system produces a phenomenon known as 'flicker.' The phenomenon is evident to the naked eyes with the rapid change of luminance in lighting equipment. The standard framed across the globe has been adopted based on the factor defined as perception of light flicker (Plt). The IEC 61000-3-3 and IEC 61000-3-11 standards are mostly followed globally to curtail flicker. The IEC 61000-3-3 provides the flicker limits for LV equipment (<16A) and IEC 61000-3-11 provides the flicker limits for LV equipment (≤75A). In Germany, IEC 61000-3-3 AND 61000-3-11 are adopted to control the flicker. The standard states that that Plt should not be greater than 1 when observed over an interval of 10 minutes. This is for a shorter duration.

Plt should not be greater than 0.65 when observed over a period of 2 hours of 12 Plt samples when considered over a longer duration. VDE- AR-N4105 standard is also adopted in Germany. U.S also adopts standards in the same line as that of Germany IEC 61000-3-3 AND 61000-3-11.IEEE 1547 is also a part of the standard adopted in U.S for flicker control. Australia adopts AS/NZS 61000.3.3 for equipment rated less than or equal to 16 A per phase and AS/NZS 61000.3.5 for equipment rated greater than 16 A per phase. These adoptions are similar to those of IEC standards. India adopts the same standards as that of Germany and U.S. Q/GDW 617, GB/T 19964, GB/T 29319 are the standards adopted by China to control the flicker.

### 2.3.9 Reactive power injection- Smart PV inverter application

PV Solar farm produce real power during day and are dormant during night and also during the day time when sunlight is not present. The entire capacity of the PV inverter is available during the night time. During the daytime, after the real power injection, the remaining capacity of the inverter is available (based on the insolation from the sun). Every load that is connected to the system has an inherent power factor. The power factor is unity for a resistive load.

Other types of loads like inductive and capacitive loads always operate at a power factor lesser than unity in a lagging and leading modes respectively. This arises due to the phase differences between voltage and current which is created due to the electric and magnetic fields in inductive and capacitive loads. The devices that are inductive in nature include motors and capacitive loads include capacitive banks. Generally, operating at a power factor closer to unity is desired and sometimes mandated. A unity power factor load will behave as a resistive load.

Reactive power is responsible for voltage support in the grid. A unity power factor load does not consume or contribute any reactive power into the grid. Reactive power must balance, but the balancing can be local. For instance, when a motor consumes reactive power, it is not necessary to go all the way back to electric power generators on the transmission grid for the supply. One can simply use a capacitor bank near the location of the motor and it can provide the required reactive power. Industrial customer's loads purchase and install capacitor banks as an additional equipment to run their motors for the reactive power support. But for other small and residential customers, the onus is on the

utility for the reactive power support. PV inverters that have been designed throughout the world have been made to operate at a unity power factor. Considering the fact that the inverters are capable of injecting reactive power, many countries are discussing the possibility of making the inverters to operate at a non-unity power factor (say +/- 0.9). In fact, the power factor of the inverter could vary and be dynamic, unlike fixed capacitors. Thereby, voltage support could be provided by the inverter. Canadian utility systems are trying to utilize this concept based on the revised version of IEEE 1547.8.

Apart from voltage support provided by the PV inverter using specialized controllers, the power factor of loads could be corrected to avoid the penalty. Apart from this, the transmission and distribution line losses could be reduced to a greater extent. The cost benefit analysis witnesses a greater scope. Standard VDE-AR-N 4105 was adopted by Germany and it was the first to mandate the reactive power support to the grid through the PV inverters. U.S. utility is trying to utilize this concept in their grid. However, discussions are going on to implement this.

A recent report 97 mandates this function for all the smart inverters in California. AS4777 standard in Australia has proposed this feature. Indian grid does not support reactive power injection at present from PV Inverters. The detailed analysis on a real time North American feeder presented an example taken from the simulation result of PV Solar with reactive power support during a particular time of day showing a considerable improvement in voltage profile [52]. This specialized functionality of PV Solar inverter for reactive power support witnesses a greater scope in future. This dissertation exploits the utilization of this standard towards the application of Smart PV inverter.

### 2.4 Supporting standards facilitating PV interconnection

There are other standards associated with PV Solar interconnection that also aid in impact assessment with their impacts on the EPS, there are other standards associated with solar system components that are referred to as balance of system that facilitate the integration. Apart from standards for meters, PV modules, data acquisition systems, smart grid interoperability, protections devices and standards for Balance of System (BOS) components like mounting structure, cables, batteries, junction boxes, switch gears, charge controllers are also discussed in this section.

#### 2.4.1 PV solar module technology standards

PV solar modules are classified based on the type of material used. They are crystalline and thin film solar modules. U.S adopts IEC 61215, IEC 61730-I &II, IEC 61701 for using crystalline technology. IEC 61646, IEC 61730-I&II, IEC 61701 are adopted for employing crystalline technology. Part I are the requirements for construction of the module and part II are the requirements for testing and safety qualification. India adopts IEC 61215 (CEA)/IS 14286, IEC 61730 – I & II (CEA), IEC 61701/IS 61701 (MNRE) for using the crystalline technology. IEC 61646 (MNRE), IEC 61730- I &II (CEA), IEC 61701/IS 61701 (MNRE) are adopted for the thin film PV solar modules. Germany adopts IEC 61215, IEC 61730-I &II, IEC 61701 for using crystalline technology and IEC 61646, IEC 61730-I&II, IEC 61701 for thin film technology. Australia adopts IEC 61215, IEC 61730- I &II, AS/NZS 5033 using crystalline type PV. IEC 61646, IEC 61730-

I & II, AS/NZS 5033 (installation and safety requirements of PV array) for thin film technology. Figure 2.1 presents the solar panel of thin film and crystalline type.

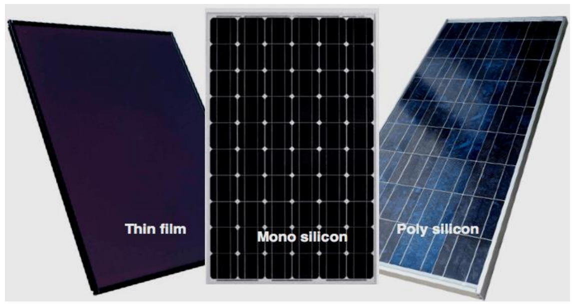



Figure 2.1 Types of PV panels

### 2.4.2 Data acquisition systems

A suitable combination of computer software application and electronic hardware are required for extracting the information about the health of the power system network to which PV solar has been interconnected. The complete status about this PV solar could then be reported to a remote location. Data acquisition system could perform this task. This can be considered to be a subset of the Supervisory Control and Data Acquisition (SCADA) system. With the introduction of digital computers, command signals from the control center were issued to lower or raise the generation levels and opening and closing of the circuit breakers based on suitable monitoring of the system status.

Following a disturbance at generation and transmission level, the ability of the system to withstand such contingences defines the system security. The power system security is an important facet in monitoring, analysis and real time coordination of transmission and generation systems. With the deployment of smart grid, online monitoring systems (OMSs) and information and communication technologies (ICTs)

provide situational awareness and intelligence of power system operation from a local and wide area perspective. As the traditional power system becomes complex, the next generation grid is commonly referred to as a smart grid.

As a part of planning and operation of the grid, during the high penetration of PV solar acquiring the data has become an important aspect. As the penetration becomes more significant, the role of data acquisition systems becomes the need of the hour. In the USA, FERC Order 661-A contains SCADA requirements for wind plants. These are sometimes applied to large-scale PV plants. The further details on SCADA for power system application can be found in IEEE 1547.3 The complete guidelines for SCADA in power system for monitoring, exchange of information and the control of the distributed resources interconnection be found in IEEE 1547 standard.

IEC 61850 is the global standard that has been applied towards communication networks and systems for power utility automation functionalities. Australia adopts AS 4418.1 as a part of a telecommunication systems and a protocol for SCADA systems. CEA in India does not mandate any such protocol using data acquisition systems like SCADA.

### 2.4.3 Communication standards

With respect to the small PV power stations, there are no communication standards, but for medium and large scale PV, there are standards that are adopted. China has adopted GB/T 19964, Q/GDW 617 and GB/T29319. Tracking the irradiance, temperature and the ambient temperature are part of this standard developed. Information about the parameters like voltage, frequency, active power, reactive power, power factor, main transformer and

disconnection status are also yielded. The communication standards for U.S and Germany are based on the negotiations between the grid company and the party that generates power.

### 2.4.4 Interoperability - IEEE 2030 Standard

This standard provides guidelines in understanding and defining smart grid interoperability of the electric power system with end-use applications and loads. Integration of energy technology like PV solar and information and communications technology is necessary to achieve seamless operation for electric generation, delivery, and end-use benefits to permit two way power flow with communication and control. Interconnection and intra-facing frameworks and strategies with design definitions are addressed in this standard, providing guidance in expanding the current knowledge base. This expanded knowledge base is needed as a key element in grid architectural designs and operation to promote a more reliable and flexible electric power system. Interoperability is "ability of two or more systems or components to exchange information and to use the information that has been exchanged." The issues include the interoperation of system components supposedly conforming to a particular standard as well as the interoperation of components across standards. It comprises of the interaction between different domains including the power systems, information technology and communication architecture.

The IEEE Std. 2030–2011 Guide for Smart Grid Interoperability of Energy Technology and Information Technology Operation with the Electric Power System (EPS), and End-Use applications and loads provides alternative approaches and best practices for achieving smart grid interoperability. Though the standard doesn't

exclusively address PV interconnection, it is embedded within this as a part of smart grid. During the interconnection process, the information about the interaction of PV solar interconnection from the renewable energy domain with other different domains like communication systems, information technologies are evident.

#### 2.4.4.1 Traditional Power system

A traditional/conventional power system infrastructure is distinctly made up of a generation, transmission and distribution systems. The flow of electricity in this setting is unidirectional i.e. from the generation systems to the transmission systems and then to the distribution systems that would cater to the needs of a large number of customers. In other words, a traditional power system consists of centralized generation with mainly one-way communication, limited sensing, monitoring and autonomous control.

#### 2.4.4.2 Smart Grid infrastructure

A smart grid can be defined in several ways. It can be referred to as a smart power system, an intelligent grid, the grid of the future, a self- healing grid, etc. A smart grid is the transformation of a traditional power system by incorporating distributed generation including renewable sources of energy like PV Solar and energy storage, intelligent power electronics, intelligent measurements, intelligent communications, computational intelligence, cyber security, visual and data analytics, and intelligent decision-making and control systems. Unlike the traditional power systems, a smart grid allows reverse power flow that could also be referred to as a two-way flow of electricity with two-way communication providing system and customer flexibility. Figure. 2 presents the smart grid

as systems of systems with several domains which include information and communication technology system, computational intelligence, cyber security, visual and data analytics, intelligent communications, intelligent power electronics, environment- renewables and plug-in – electric vehicles, intelligent decision systems and, intelligent measurements.

A smart grid would no longer be defined in terms of *N-1, N-2,* or *N-k* as in a traditional power system, but now in terms *S-1, S-2,* or *S-k* where *'S'* refers to a system of the systems. Currently, there are three additional complementary standards designed to expand upon the base 2030 standard. IEEE P2030.1, Guide for Electric-Sourced Transportation Infrastructure, IEEE P2030.2, Guide for the Interoperability of Energy Storage Systems Integrated with the Electric Power Infrastructure and IEEE P2030.3, Standard for Test Procedures for Electric Energy Storage Equipment and Systems for Electric Power Systems Applications.

The series of IEEE 1547, the IEEE Std. 1547.4 (micro grids) addresses many of the technical integration issues for a mature smart grid, including issues of high penetration of distributed generators like PV Solar and electric storage systems, grid support, and load management. The smart grid interoperability standard is more of a layered approach. As the grid is evolving and expanding, the smart grid interoperability defines the PV interconnection as its interaction with other domains of engineering.

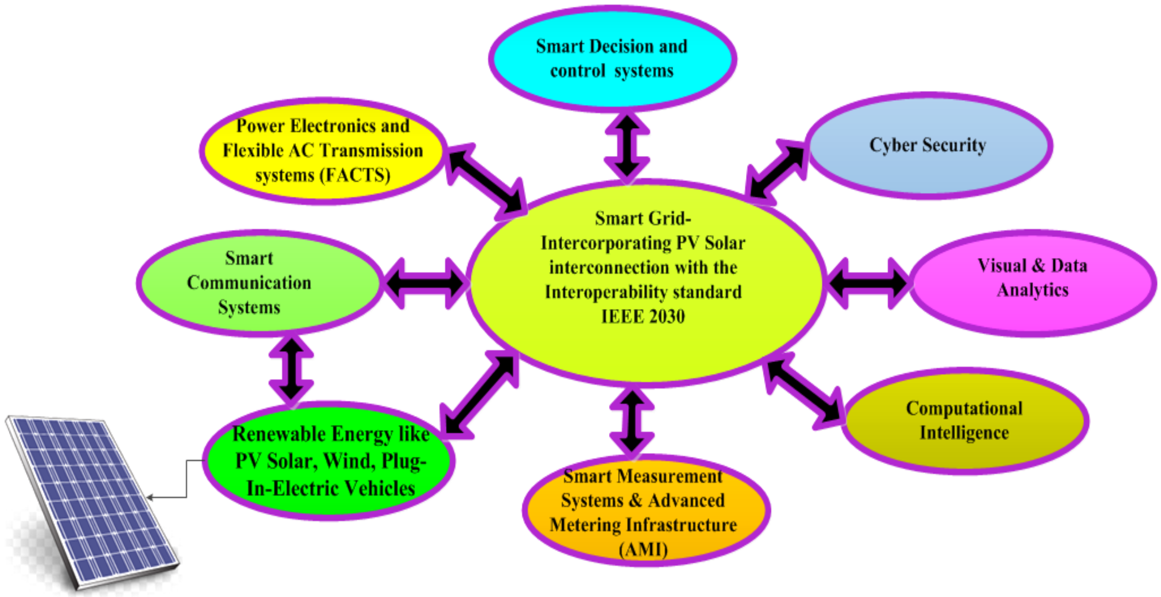



Figure 2.2 PV interconnection in a smart grid environment

### 2.4.5 Protection Devices

During an abnormality, events like voltage fluctuations, frequency deviations, unintentional islanding can happen. To protect from further intensification of the events, protective devices are mandatory and hence their standards associated. Typical protection devices in solar systems consist of surge protective devices, DC and AC isolator switches and an isolation transformer.

### 2.4.6 Surge Protection Devices

PV Solar are subjected to lighting strike and surge at any unexpected instant of time that can lead to electrical/mechanical damages. Irrespective of the distance, even if the lightning strikes a few meters away, it will induce surge voltage in the electrical installation

loops that will cause severe damages. U.S adopts UL 1449. Standards DIN CLC/TS 50539-12 (VDE V 0675-39-12): 2010-09, prEN 50539-11, EN 61643-11 are adopted by Germany. Australia adopted AS/NZS 1768. India adopts relevant International Standards as mandated by CEA and MNRE.

### 2.4.7 Isolator Switch

DC isolator switch is used between DC PV arrays and grid-connect inverters. Positioned adjacent to the inverter a DC switch is required to provide a means of manually isolating the entire PV array during system installation or any subsequent maintenance. AC isolator switches are used with grid-connected solar array. Positioned adjacent to the inverter, a AC switch is required to provide a means of manually isolating the AC supply during system installation or any subsequent maintenance. U.S adopts UL 98 and UL 508. IEC 60364-7-7-12, DIN VDE 0100-712, IEC 60947-3 are standards adopted by Germany. Standards for Australia include AS/NZS 60898/IEC 60947. India adopts IEC 60947-I, II & III/IS 60947-I, II & III (MNRE).

### 2.4.8 Isolation Transformer

As a part of safety reasons, electrical equipments or device are isolated from the main power source as a part of AC reasons while the transformer supplies AC power from the source to the device. Isolation transformers provide galvanic isolation and are used to protect against electric shock, to suppress electrical noise in sensitive devices, or to transfer power between two circuits which must not be connected. The standards associated with PV interconnection for an isolation transformer are as follows. IEC 61558-2-6 is adopted by Germany. India adopts IEC 61727 (CEA). It has also been mandated by some SERC.

### 2.4.9 Balance of System (BOS) components

A solar PV Balance -of – System or BOS refers to the components and equipment that move the DC energy generated by the solar panels. Using a suitable inverter, the DC power is converted into AC power. BOS includes mounting structure, cables, batteries, junction boxes, switch gears, charge controllers. Short descriptions of selective BOS components with their standards are presented in this section. Figure 2.3 presents a pictorial interpretation of BOS trying to play a vital role in balancing between the DC and AC aspects in a power system.

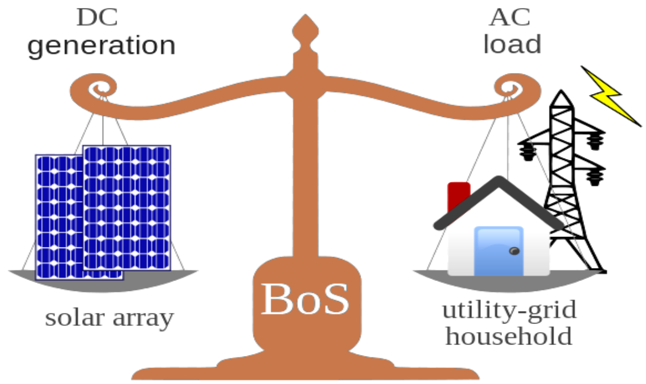



Figure 2.3 Balance of system components, Source: Wikipedia

### 2.4.10 Junction box

A junction box is an enclosure where all PV strings of any PV array are electrically connected and where protection devices can be located, if necessary. It also serves as a protection device when a fault occurs in the DC circuit.

### 2.4.11 Battery

Off grid systems employ batteries more compared to the grid tied systems. The types of batteries used mainly in PV systems are vented (flooded) type and valve regulated type. This regulation is applicable to all batteries made of lead-acid and nickel. The life of a battery could be determined by means of a comprehensive testing procedure. The battery is put through 150 cycles of discharging and charging, assuming that the daily discharge is in the range of 2-20%. The cycles are continued until the battery capacity has decreased to 80% of its rated capacity, which is considered as the end of the useful battery life.

### 2.4.12 Charge controller

There are lots of chances that batteries get overcharged due to high rate of current. Solar charge controllers are basically charge regulators, in other words are referred to as battery regulators. The basic functionality of a solar charge controller is to protect the battery bank from getting overcharge by acting as a current limiter. Solar charge controllers also ensure the life span of the battery. A charge controller is typically integrated with the battery-based inverter. The IEC 62093 standard is the most widely used standard globally, for the testing procedure for all BOS components of PV systems in natural environments.

### 2.4.13 PV module mounting system

Photovoltaic mounting systems are used to fix solar panels on surfaces like roofs, building facades, or the ground. These mounting systems enable retrofitting of solar panels

on roofs or as part of the structure of the building. Table 2.11 presents the standards pertaining to BOS components for PV interconnection.

Table 2.11 BOS component standards for PV interconnection

| BOS component | USA | Germany | Australia | India |
|---|---|---|---|---|
| Junction boxes | IEC 60670, UL 50 | DINEN50548 (VDE 0126-5):2012-02 | AS 1939 | IEC 529-IP54, IP 21 (MNRE) |
| Battery | IEC 61427 | IEC 61427, DINEN 61427 | AS 4086 | IEC 61427, IS 1651, IS 13369 or IS 15549 (MNRE) |
| Charge controller | UL 1741 | IEC 60068-2, IEC 62093/EN 62093:2005 | IEC 62093 | IEC60068-2, IEC 62093 (MNRE) |
| PV module mounting system | UL 2703 | None | AS/NZS 1170.2 | None |
| Cables and connectors | UL62, UL758, EN50521 | VDE0285, VDE 276, EN 50521, VDE-AR-E-2283-4: 2011-10 | AS/NZS 5000.1, AS/NZS 3191, AS/NZS 3000 | IEC 60227/IS 694, IEC 60502/IS 1554-I&II, IEC 60189, EN 50521 (MNRE) |

#### 2.4.14 Cables and connectors

Cables and connectors play a vital role in connecting modules of PV solar farm to the inverter. Though the electrical connections in a system are not noticeable, but they definitely do have an impact in terms of loses at the points of contact. Long-lasting, secure cable connections with low contact resistances are necessary to avoid such losses and accidents.

#### 2.4.15 Renewable energy meter

Renewable energy meters nowadays can be addressed as a smart meter. This is referred to as Advanced Metering Infrastructure (AMI). Advanced metering infrastructure (AMI) is an integrated system of smart meters, communications networks and data management systems that enables two-way communication between utilities and customers. Customer systems include in-home displays, home area networks, energy management systems, and other customer-side-of-the-meter equipment that enable smart grid functions in homes, offices, and factories.

Before the introduction of smart metering, the information about the power flow was available only at the substation level. With more interconnection of renewable energy sources like PV Solar, detailed information about the power flows are possible. By providing data on energy usage to customers (end-users) to help control cost and consumption, sending data to the utility for load factor control, peak-load requirements, and the development of pricing strategies based on consumption information and so on, smart meters play a vital role in the evolving grid. Smart Meters equip customers:

Knowledge about pricing - $/kWh, energy usage, faster outage detection, faster restoration by utility. Demand-response (DR) rates, Tax credits Tariff options Reward programs. Based on these details, the renewable energy penetration could be controlled. The standards associated with the renewable energy meters are listed in Table 2.12. Interconnection of PV solar farm with the BOS components and other elements of the grid are shown in Figure 2.4.

Table 2.12 Renewable energy standards associated with PV interconnection

| | **USA** | **Germany** | **Australia** | **India** |
|---|---|---|---|---|
| **Renewable energy meter standards** | ANSI C12.16,<br><br>ANSI C12.20 | DIN EN 62053-21,<br><br>VDE 0418-3-21:2003-11,<br><br>DIN EN 62053-22,<br><br>VDE 0418-3-22:2003-11, MID | AS/IEC 62052-11,<br><br>AS/IEC 62053-21/22,<br><br>AS 1284.1 | IS 13779,<br><br>IS 14697 (CEA) |

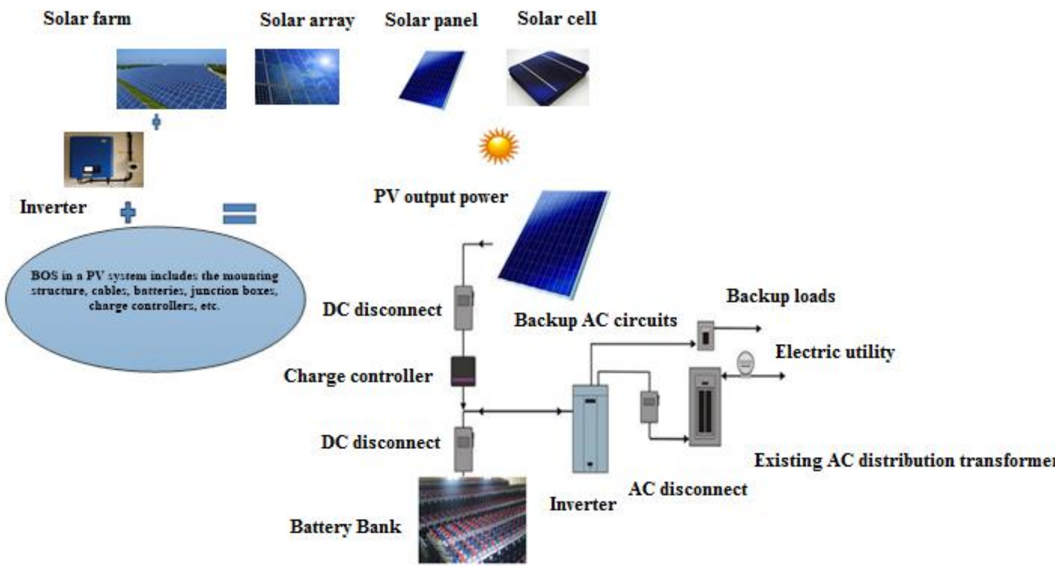



Figure 2.4 Interconnection of PV Solar associated with the BOS components

## 2.5 Standard 1547 towards PV interconnection

The basic foundation for the IEEE 1547 series has been laid by IEEE Std 1547. At present, there are seven additional complementary standards designed to expand upon or support the root standard, five of which are published. All the versions of this standard are applicable towards PV interconnection and have been generalized for any type of distributed generators. The IEEE 1547 series of existing, published standards is as follows:

- IEEE Std. 1547–2003 (reaffirmed 2008), IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems.
- IEEE Std. 1547.1–2005, IEEE Standard Conformance Test Procedures for Equipment Interconnecting Distributed Resources with Electric Power Systems.

- IEEE Std. 1547.2–2008, IEEE Application Guide for IEEE Std 1547, IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems.

- IEEE Std. 1547.3–2007, IEEE Guide for Monitoring, Information Exchange, and Control of Distributed Resources Interconnected with Electric Power Systems.

- IEEE Std. 1547.4–2011, Guide for Design, Operation, and Integration of Distributed Resource Island Systems with Electric Power Systems.

- IEEE Std. 1547.6–2011, Recommended Practice for Interconnecting Distributed Resources with Electric Power Systems Distribution Secondary Network.

- IEEE P1547.7, Guide to conduct Distribution Impact studies for Distributed Resource Interconnection.

- IEEE P1547.8, Recommended Practice for Establishing Methods and Procedures that Provide Supplemental Support/ ancillary services for Implementation Strategies for expanded use of IEEE Std 1547.

This standard is applicable for all the distributed resources. The focus in this chapter would be exclusively towards PV Solar.

### 2.5.1 IEEE Standard 1547-2003

The IEEE Std 1547–2003 is the first in the 1547 series of interconnection standards and provides interconnection technical specifications and requirements as well as

interconnection test specifications and requirements. IEEE Std 1547 has been widely accepted as a benchmark across the globe. Distributed resources include distributed generators (like PV solar, wind, etc), synchronous machines, induction machines and power electronic converters.

A ballot group of 230 members affirmed the IEEE Std 1547 on February 30 2003. Further it was approved by the IEEE Standards Board in June 2003, and was approved as an American National Standard in October 2003. According to the Energy Policy Act of 2005**,** IEEE 1547 standards permitted the interconnection of distributed generators to the grid which was further reaffirmed by a ballot group of 181 members in 2008. Considering the safety aspect, standard UL1741- 'Inverters, converters and interconnection system equipment for use with distributed energy resources' always goes well hand in hand with the IEEE 1547 and IEEE 1547.1 standard. Distribution compatibilities of distributed resources are explained followed which each version of IEEE 1547 is presented in this section.

IEEE 1547 clearly mentions that a distributed resource shall not energize the area of EPS where a fault has occurred. Synchronous generator and inductor generator type distributed generators contribute to the fault current due to the inertia of the dynamic (rotating) nature of the equipment. But the contribution from its side has always been minimal. Inverter based Distributed generators like PV's contribution towards fault current has been nil. Due to this, even when the feeder remains energized, such PV inverters do not detect the fault on the feeder with the infrastructure having overcurrent or distance relaying. After the substation breaker (or line recloser, or lateral fuse) trips or clears, the

DR is more likely to detect the fault using overcurrent or distance relaying if it has sufficient fault current contribution. This is called “sequential tripping” and is commonly accepted to be compliant with IEEE 1547.

Since inverters are in place, the current is not usually a satisfactory means of detecting a fault. The fault detection by the PV inverter based DR’s are purely based on the undervoltage phenomenon. This often will detect the fault even with the substation source still driving the fault current, but may not detect until the feeder is deenergized in some cases. Undervoltage detection of faults is inherently a very non-selective protection approach.

To the DR, an undervoltage caused by a fault on the feeder to which it is connected is often indistinguishable from a fault on the transmission system. Imposition of LVRT requirements inherently places a minimum time on the detection of faults by undervoltage means. The basic requirement of a DR should be in such a way that it should be in a position to detect a fault. Mostly DR’s contribution to the fault current is minimal. Apart from the fault detection, the DR’s contribution towards short circuit current can vary. This may cause the coordination between fuses and circuits breakers in the distribution system.

Automatic circuit reclosers also may be deployed in the distribution circuit to clear faults and quickly restore service on the feeder. Reclosers reenergize the circuit automatically immediately after a trip resulting from a circuit fault. A suitable coordination strategy must be incorporated between the DER unit (PV solar, wind, etc) and the reclosers. The coordination of reclosers with the DR’s is highly essential. A reclosing action into an island poses a risk that the phase sequence might different. During this action, there is a

chance that it might result in inrush current, transient overvoltages that may damage the equipments connected with the utility network posing an inconvenience to the customers. DR's also get affected due to this.

Although there is a common statement that out of phase reclosing doesn't cause any harm to the PV inverters considering the fact the inverters are self-protected still needs a look through. IEEE Standard 1547 makes the vague statement that "The DR shall cease to energize the Area EPS circuit to which it is connected prior to reclosure by the Area EPS." If the feeder reclosing time is less than two seconds, then the allowable island "cease to energize" time for any DR on the feeder is that reclosing time. In other words, the effective island detection time is the lesser of two seconds or the specific feeder reclosing time. However, others interpret this same clause to require that the utility adopt whatever means necessary to accommodate DR that needs two seconds to detect islands. This provision could be done by increasing the reclosing time beyond two seconds or by using an undervoltage-permissive scheme to block reclosing as long as an island is energized.

### 2.5.2 IEEE Standard 1547.1-2005

This Standard facilitates conformance Test Procedures for Equipment Interconnecting Distributed Resources with Electric Power Systems. This clearly provides the testing procedure for the manufactures, utilities or independent testing agencies to corroborate whether the particular system like PV Solar is ready to be interconnected to the electric power system (EPS). A certification after the test procedure verifies the

conformance towards interconnection. Later in 2011 this standard IEEE 1547.1 was reaffirmed.

### 2.5.3 IEEE Standard 1547.2

IEEE Standard 1547.2-2008 addresses the interconnectivity issues exhibited by various forms of distributed resources. Infact, this standard serves as a rule of thumb in terms of technical requirements of IEEE 1547 during the implementation of the interconnectivity.

### 2.5.4 IEEE Standard 1547.3

IEEE Std 1547.3–2007 facilitates the interoperability of one or more distributed resources interconnected with electric power systems which may be a PV solar, wind, fuel cells and so on. It is also compatible with historical approaches to establishing and satisfying monitoring, information exchange, and control. This standard goes along with IEEE 2030 standard Smart grid interoperability as discussed briefly in the earlier sections of this chapter.

### 2.5.5 IEEE Standard 1547.4

IEEE 1547.4-2011 serves as a guide for intentional islands in EPS containing distributed resources. The ultimate motive of this standard is for improved customer reliability, improvement of power quality and serves as a handy standard for the utility for maintenance. Two terms could be defined in the context to understand this standard. Unintentional Islanding occurs when the DG (or group of DG) continues to energize a portion of the power system that has been separated from the rest of the utility. Considering the safety factor that the utility personnel don’t want the electric power system to be

energized during the maintenance, unintentional islanding phenomenon shouldn't take place.

IEEE 1547 requires DG to detect an outage and cease to energize within two seconds. The phenomenon against the formation of unintentional island is known is anti-islanding as discussed in the earlier section of this chapter. But this standard IEEE 1547.4 focuses on intentional islands. The concept could be easily understood from Figure 2.5 which shows a typical distribution substation feeding 5 feeders fed from substation 'SUB XYZ.' DG's like PV, wind and fuel cells are connected at various locations of the laterals and sub-laterals of the feeder. The different colors yellow, green and grey are to indicate that the particular part of the system containing the DG could be isolated from the rest of the system during intentional islanding for utility maintenance, customer reliability and power quality purpose.

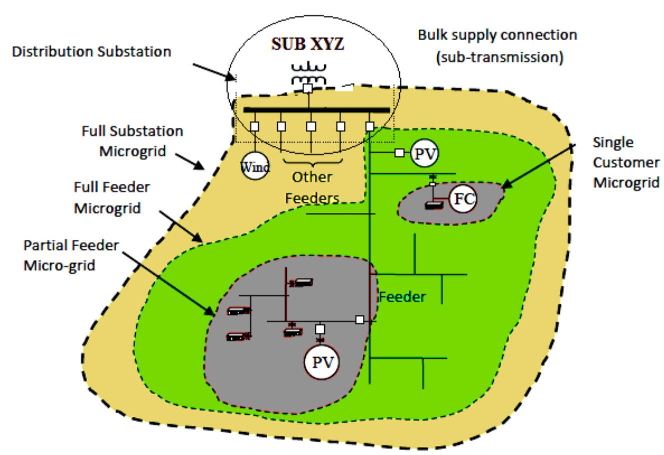



Figure. 2.5 Illustration of islanding operation –IEEE 1547.4

### 2.5.6 IEEE Standard 1547.6

IEEE 1547.6-2011 Recommended Practice For Interconnecting Distributed Resources With Electric Power Systems Distribution Secondary Networks. This standard establishes recommended criteria, requirements and tests, and provides guidance for interconnection of distribution secondary network system types of area electric power systems (Area EPS) with distributed resources (DR) providing electric power generation in local electric power systems (Local EPS). This standard focuses on the technical issues associated with the interconnection of Area EPS distribution secondary networks with a local EPS having DR generation. The standard provides recommendations relevant to the performance, operation, testing, safety considerations, and maintenance of the interconnection. In this standard consideration is given to the needs of the local EPS to be able to provide enhanced service to the DR owner loads as well as to other loads served by the network. Equally, the standard addresses the technical concerns and issues of the Area EPS. Further, this standard identifies communication and control recommendations and provides guidance on considerations that will have to be addressed for such DR interconnections.

### 2.5.7 IEEE Standard 1547.7

This version of IEEE 1547 provides the guidelines for the impact studies of a distributed resource on an EPS or a cluster of distributed resource when interfaced with the power distribution systems. The creation of IEEE Std 1547 "IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems" has led to the increased adoption of DR throughout distribution systems. The guideline clearly brings an

insight towards a methodology to perform such impact studies during the interconnection. Study scope and extent are described as functions of identifiable characteristics of the distributed resource, the area electric power system, and the interconnection. Criteria are described for determining the necessity of impact mitigation.

This facilitates the distributed resource interconnection contractors, operators and regulatory bodies to have the data required, methodology by which the study results are evaluated during the impact studies.

### 2.5.8 IEEE Standard 1547.8- Smart PV inverters

The IEEE P1547.8 recommended practice expands the use of IEEE Std 1547. This P1547.8 document applies to the requirements set forth in IEEE Std 1547 and provides recommended methods that may expand the usefulness and utilization of IEEE Std 1547 through the identification of innovative designs, processes, and operational procedures. The need for P1547.8 is to address industry driven recommendations and NIST Smart Grid standards framework recommendations (e.g., NIST priority action plans). The P1547.8 considerations include voltage ride through; volt-ampere reactive support/reactive power injection; grid support; two-way communications and control; advanced/interactive grid-DR operations; high-penetration/multiple interconnections; interactive inverters; energy storage; plug in electric vehicles; etc.

Voltage ride through and reactive power injection associated with PV Solar interconnection with respect to this standard IEEE 1547.8 are addressed with a suitable comparison with other standards.

#### 2.5.8.1 Voltage ride through

The voltage ride through capability is an important feature that has to be exhibited by the PV inverters. The ability of the PV inverter to remain connected to the system during an event of low voltage ensures the reliability. In a transmission system, during a bulk system fault, creates voltage sag lesser than the operating limit. This depression in voltage also exists for quite a long duration as well as during post-fault. There are also chances that after the post-fault, there might be backswing that causes the voltage to rise. There is a tendency that the voltage deviations propagate from the transmission levels to the distribution levels which in turn results in tripping of the DR connected. Without VRT requirements, and particularly with the present IEEE 1547 “must trip” requirements for voltage deviations, a potentially large amount of DR generation capacity could be tripped simultaneously as a result of a bulk grid event that stresses the grid. This has the potential for aggravating the bulk grid disturbance, and violates a fundamental principle of bulk system planning – generation should not be lost as a result of a grid fault that is within the planning criteria. The voltage sag tends to be less as the distance from the fault at the transmission level increases but the amount of potentially affected DR capacity increases. Just to ensure that the single phase fault is reduced to a greater extent, delta-star transformer connection is always employed bridging the transmission and distribution systems.

For any generation units greater than 20 MW, or generating facilities with a summed capacity less than 75 MW is not considered to be a bulk generation asset according to the criterion of NERC.  So a loss of less than 20 to 75 MW DR capacity is of reasonable

significance according to the criterion of NERC. This is considered to be below the threshold.

Puerto Rico Electric Power Authority (PREPA) has similar requirements of LVRT/HVRT for both solar and wind. For the zero-voltage faults, the PV Solar has to remain connected and should be in a position to ride through this fault upto 600 milliseconds (ms); the no-trip zone is bounded by linear voltage recovery for up to 3 seconds. PREPA sets high-voltage ride-through (HVRT) requirements for maximum high voltage at 140% of nominal for up to 1 second. Fig. 2.6 presents a comparison between LVRT/ZVRT and HVRT requirements for NERC, PREPA, and other island systems such as the HECO and EirGrid. Also, the requirements mandated by IEEE could be witnessed.

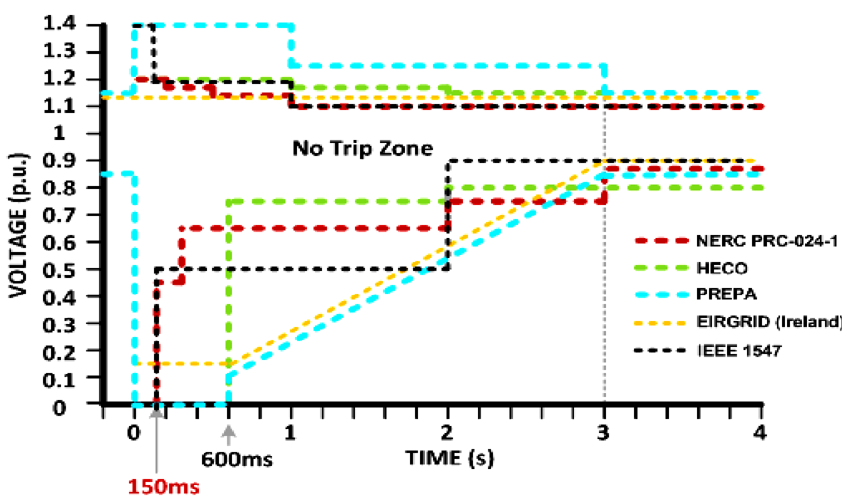



Figure 2.6 Source: Review of PREPA technical documents for interconnecting wind and solar

NERC Protection and Control (PRC) Standard PRC-024-1 requires 150 ms ZVRT. Such ZVRT is a typical requirement for transmission-connected wind power plants (WPP) in the United States also applicable towards PV Solar. The Federal Energy

Regulatory Commission Order 661A also requires 150 ms ZVRT. But recovery time is determined on a site-by-site basis depending on the local grid characteristics and protection schemes. Longer duration of LVRT is essential for weaker systems. HECO system has 600 ms ZVRT requirements. But if we consider the EirGrid, the same 600 ms requirement is applied but at a voltage of 0.15 p.u. So, the standards and requirements are adopted based on the system. The clearing time adopted by IEEE 1547 in United States is also presented in Figure 2.6. Over-voltages normally occur in a system due to sudden loss of loads in the system, unbalanced faults and other conditions. The magnitude varies based on the situations. For HECO or EirGrid, the HVRT is limited between 1.15 to 1.2 p.u. International standards mandate the requirement for HVRT up to 1.3 p.u.

#### 2.5.8.2 VAR Support

Earlier IEEE 1547 did not permit the PV Solar to regulate the grid voltage. With the revised version of IEEE 1547 to IEEE 1547.8, PV Solar inverters could be used to inject and absorb reactive power into the electric power system. It is a well-known fact that PV solar farms produce power during the day and are completely idle in the nights. The full capacity of PV inverter is available during the night and also to a substantial degree during the daytime with the inverter capacity remaining after real power production. Specialized controllers associated with the PV Solar farm has are available from different manufacturers nowadays for reactive power compensation. This is designed to regulate the voltage during the steady state and transient conditions. PV inverter control is also designed for compensating loads that are operating at low power factor. In the Power Factor Correction mode, the PV inverter improves the power factor to a greater extent making it

suitable for industrial applications. The improvement in power factor by this controller benefits the customer without having to pay any penalty if their loads were operating at a power factor lesser than 0.9.

Profile improvements on the feeder are utilities are required to keep voltage at the customers load within a narrow operating range per ANSI C84.1. Primary objective of voltage regulation is to provide each customer connected to the utility with voltage that conforms to the design limitations of the customer's utilization equipment. Injecting power from a DER device into the power system will offset load current thus reducing the voltage drop on the utility.

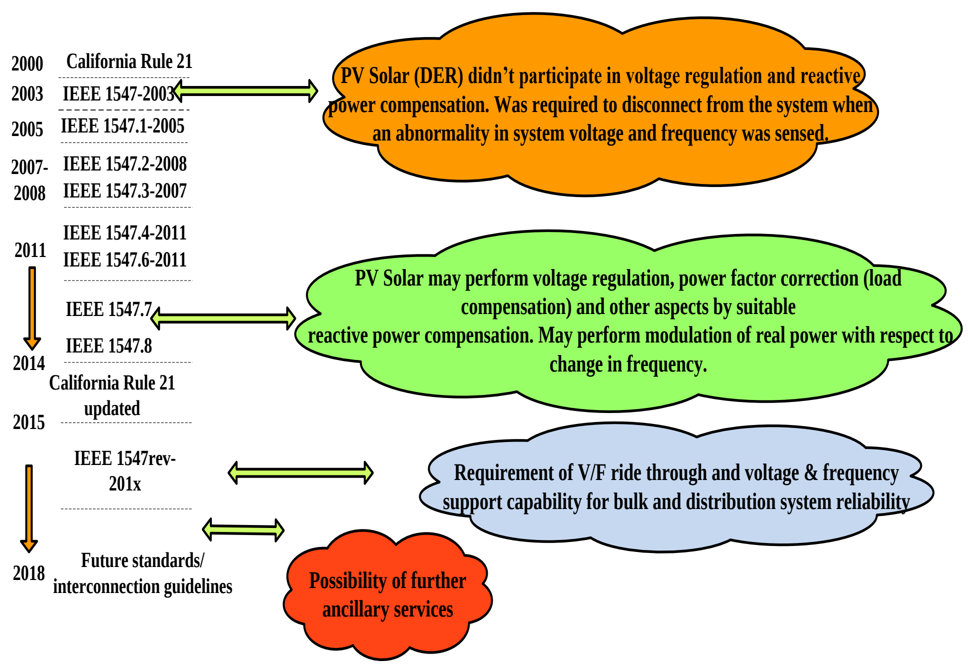



Figure 2.7 Flow of IEEE 1547 Standard

There are two modes of operation. PV solar can either inject or absorb reactive power operating at a leading reactive power (capacitive) into the power system or draw lagging reactive power (inductive) from the power system thus affecting the voltage drop on the utility respectively.  Line loss reduction and cost saving achievement in addition to the benefits from the Feed In Tariff programs are also associated with this standard. Smooth control of voltage regulation could be achieved using PV Solar Plant that would replace the voltage regulators on the feeder if any, which would be an additional benefit in terms of Distribution Systems Feeder Planning and Management.

IEEE 1547/UL 1741 compliant PV inverters typically do not have reactive power capability and operate with a unity power factor. With the standards 1547.8, reactive power and voltage control, a substation level reactive power compensation system will need to be applied for IEEE 1547 inverters. In other words, it PV inverters could act like a Flexible AC Transmission System device – Static Synchronous Compensator (STATCOM). Voltage regulation can be achieved by either regulating the inverter's terminal voltage on the low side of the transformer or by adjusting reactive output according to a droop characteristic.

Voltage regulation system (VRS) with adjustable set point between 95% and 105% of rated POI voltage is the ideal aspect to maintain the grid voltage under limits. The VRS employs an adjustable 0% to 10% reactive droop with accuracy of control within +/-0.5% of set point. Combination of STATCOM or Static VAR compensator along with PV solar inverters is possible in cases where voltage control capability of PV inverters is absent (IEEE 1547 compliance). Another functionality of using PV solar in the inductive and

capacitive mode is that the resonance phenomenon could be eliminated if the inverter had an opportunity to replace the capacitor banks. This again depends on the type of feeder.

With the reactive power injection from PV Solar farm, voltage could be controlled. This in turn could alter the power flow in the line. Installation of new lines for accommodating more renewable sources like PV solar could also be minimized. This application duplicates the feature of a FACTS device. Apart from this, a situation could be imagined with two PV solar farms on a feeder at a suitable distance. When one of the PV solar is generating power, there is a chance that the other PV can stay idle or just generating just at half of its real power capacity. So this PV solar inverter could be used to regulate the voltage. This brings in the possibility of coordination between more than one PV solar on the same feeder. Based on the situation and the standard IEEE1547.8, more ancillary services could be provided by PV inverters in future. Figure 7 presents the flow of different versions of IEEE 1547. The PV inverters associated with this standard are called Smart PV inverter,

### 2.6 Brief Insight - UL 1741 Standard

UL 1741 covers the power conversion and protection equipment for PV solar and other DR products. U.S is taking efforts to adopt IEC 62109. UL was granted rights to develop UL62109-1& IEC 62109-2. Safety of power converters for use in photovoltaic power systems- Part 1: General requirements & Part 2: Particular requirements for inverters. Further it developed International Harmonization Committee (IHC) and published UL62109-1 and UL62109-2 Q1 2015 with an ultimate motive to identify several revisions and to minimize the national differences. UL 62109, Safety of power converters

for use in photovoltaic power systems, was published on July 18th of 2014 and is now the US harmonized version of the international PV power conversion standard IEC 62109. IEC 62109 was born out of UL1741 and was expanded / updated to address cutting edge safety aspects of PV power conversion equipment. IEC 62109 is being adopted around the world and is the basis for harmonized international safety certifications. UL 62109, like UL1741, provides a means to determine that PV inverters and other PV electronics:

- Conform to common industry requirements
- Installation in accordance with US Codes.
- Operated per industry specific required ratings
- Perform safely under rated normal worst case conditions
- Perform safely under foreseeable abnormal operating conditions and failure modes.

UL 1741 and UL 62109 are similar addressing the same types of hazards but 62109 were written to expand upon UL1741 and fill in known gaps. All forms of DG's were covered in 1741 but 62109 boundary has been applied exclusively for PV although it can be applied with other sources as well. IEC 62109-1 was developed over many years, with considerable effort and it was published in April 2010 as a copy of UL 1741. Shortly after EN62109-1 was adopted and published by CENELEC. IEC 62109-2 - specific to inverters (published during June 2011) is being adopted around the world. This addresses the inverter safety functions like PV ground fault protection, power quality THD, DC injection, voltage and frequency control, array and system isolation protection.

The operative modes of inverter can be classified as follows:

- Grid Tied, Utility Interactive

Products that operate in parallel with or back feed power to the utility grid to supply common loads.

- Stand Alone

Products that supply power to loads independent of the utility grid.

- Multimode

Products that can operate in both utility interactive and stand-alone modes in case of utility failure.

### 2.7 Progressive suggestive plan for future towards improvements of grid codes

Although, the majority of requirements among the countries like China, U.S.A and Germany are similar, there are several differences that result from the characteristics of the electric grids. Considering the penetration levels of PV to be more in China, the following could serve to be the future modifications to China's standards, including industry standards set by the grid companies and national standards proposed by designated institutions and implemented by the National Energy Administration, certification bodies, and other relevant parties. The same could be considered by any country across the globe where challenges in smart grid are more with PV penetration levels. Suggestions are presented based on recommendations provided in the documents [37-38] [49-50]:

Based on comparative analysis in this paper, the following is a list of additional considerations for future modifications based on the requirements.

1) Certain impositions could be brought in by the utilities to limit the ramp rates, and curtailing of PV output can help enhance system dispatch capabilities. This can reduce the integration costs caused by reducing the variability and uncertainty of solar generation.

2) Considering the different penetration scenarios (e.g., ≤2%, ≤10%, ≤30%, ≤50%), rules, standards and guidelines should consider specifications based on the PV penetration scenarios.

3) Rules, requirements, and standards could consider the following aspects for distribution and subtransmission integration impact studies: voltage regulation, fault currents, protection coordination (overall circuit protection coordination, potential reverse power flow, coordination with inverters), ground fault overvoltage, and islanding.

4) Considering the standards IEEE 1547.8 towards ancillary services like reactive power level, voltage stability support could be brought in by an an appropriate control method. These range from fixed volt ampere reactive, fixed power factor, closed loop voltage control, to volt/volt ampere reactive droop.

5) If anti-islanding protection conflicts with the low-voltage ride-through requirement; some revisions to these grid codes may be good.

6) The accuracy of a PV plant's output forecast is an important factor to determine a grid connected PV power plant's capacity and its operation and control, but there is no forecast accuracy specification in the current PV standards. A new section could be added to the standards.

7) Rules, requirements, and standards should be revised as newer PV generation technology develops—for example, the active power requirement in the PV standards could be improved according to an advanced power output forecast of a PV plant.
8) Rules, requirements, and standards could consider the development of validated generic dynamic and power flow models of distributed and central-station PV power plants for large-scale simulation studies and to establish relevant integration guidelines. The Western Electricity Coordinating Council's generic PV and wind models provide a good foundation.
9) Most of interconnection standards or guidelines concern DRs with small capacity. For example, IEEE 1547 applies to DR systems with an aggregate capacity of 10 MVA or less at the PCC. IEC 61727, CNS 15382, and GB/T 20046 apply to PV with a capacity of 10 kVA or less. As the PV capacity increases, existing standards or guidelines must be improved. For example, Denmark's Technical Regulation 3.2.2 identifies four categories of PV plants based on the total rated power at the point of connection; these are PV power plants with capacities from 11 to 50 kW (Category A), from 50 to 1.5 MW (Category B), from 1.5 to 25 MW (Category C), and above 25 MW (Category D). Some requirements apply only to categories C and D. For instance, categories C and D systems must be designed to withstand a voltage dip over a specific period. The requirements concerning power quality, control functions, protection functions, and data communication vary among PV categories.

10) Power utilities must pay more attention to the certification and testing of PV inverters. Some safety standards for PV inverters, such as UL 1741, EN 50524, EN 50530, or IEC 62109, have been published to provide a basis for certifying PV grid interconnections.

# CHAPTER THREE

# HARMONIC RESONANCE REPERCUSSIONS OF PV AND ASSOCIATED DISTRIBUTED GENERATORS ON DISTRIBUTION SYSTEMS

## 3.1 Overview

The problems associated with the harmonics needs more attention as more number of distributed generators like PV and wind are integrated into a distribution system. Although the integration presents a lot of benefits, satisfying the needs of local load requirements by reducing the line losses and facilitating congestion management, the problems of power quality that impact the distribution system become a priority.

IEEE 519 describes network resonance as a major contributor impacting harmonic levels. LC and LCL filters on the AC side of PV Solar (PV) inverters that are designed to mitigate higher order harmonics tend to interact with the impedance of the entire network by exciting the harmonic resonance modes. Apart from that, wind based induction generators and induction motors are associated with terminal capacitors for voltage support. The interaction of such capacitive elements of distributed generators with the entire system impedance also impact resonance modes. To witness the impact of DG's, a control scheme for a 1.25 MW PV inverter based on hysteresis control with a simple LC filter is designed. This chapter will serve as a reference for planning engineers and researchers working towards power quality by addressing the impacts of PV with distribution systems.

## 3.2 Introduction

Distributed generators (DG) like PV and wind constitute the wider spectrum in the family of distributed energy resources (DR). Benefits and incentives provided by the US government serve to entice everyone to utilize green energy resources like PV and wind. Thus PV and wind energy resources become a vital member along with other components of distribution systems giving it a visible identity [53].

PV inverters are voltage sources interfaced with a farm of PV solar panels. The recommendation of the utility industry with respect to the harmonic levels in the system is usually less than 5%. Switching techniques such as pulse width modulation and hysteresis control form the crux of such inverters. PWM technique, one of the most commonly used, normally employs a switching frequency between 2- 15 kHz. A suitable filtering is required to smoothen the output during the interfacing of PV inverter. Normally LC and LCL type low- pass filters are installed on the AC side and tend to eliminate the higher frequency components of the current by offering a low impedance path, provided by the capacitor filter. Tuning of the filter elements is very important since it can have a direct impact on the controller of PV Inverter's performance in terms of hampering its stability. Distribution system loads can be of residential and industrial loads include wide range of nonlinear loads like process rectifiers, induction motors, arc furnaces and welders. IEC 61000-3-2, IEC 61000-3-6 and IEEE 519 standards provide suitable guidelines for control of harmonics. For the support of the distribution network, a main feeder capacitor bank also serves as a contributing factor towards resonance.

Small scale induction generator-based wind turbines also contribute to this phenomenon considering the fact that they are equipped with a capacitor for voltage support [54-56]. Apart from that, Doubly- fed induction generators also introduce harmonics into the system. IEEE 519 standard serves as a major guideline for the network resonance conditions that impact the harmonic levels. So analysis of resonance condition in power system is important. The phenomenon happens when the capacitive reactance of the system at a particular frequency are exactly equal to inductive reactance of the system, parallel resonance condition occurs. A similar phenomenon is exhibited in the form of a series resonance at that particular frequency.

Literature suggests that only few investigations have been made with respect to impact of PV Inverters on harmonic resonance issues [57].The resonance phenomenon can also be referred to as a special classification in distribution system stability with high levels of penetrations like PV and wind. Studies based on the interaction of distribution system elements with DG's like wind also has been explored to some extent. With few resonance studies based on PV Inverters, the design of AC filter in the form of LC and LCL elements associated with it, starts playing a role, as a contributor towards resonance.

In case of a transient study in a system, a simple technique involving an introduction of a series damping resistors along with the LC element can play major role in damping the oscillations and also in reducing its peak. With the installations of PV Solar being wide spread at Distribution level in North America, passive damping using the combination of series resistor will be a solution for residential customers. But at the utility side, more comprehensive analysis and exploration into the resonance phenomenon is

required. Studies pertaining to coordination and interaction of PV Solar Inverters with other distributed generators have not been done in detail.

Studies and contributions made in this chapter will serve as a reference for researchers and utility industry personnel to perform more such assessment to ensure safe operation of critical loads and overall reliability of the system. The basic system configuration and parameters are extracted from the benchmark system of the IEEE Std. 399-1997 and with few modifications from [58] to demonstrate the purpose.

### 3.3 PV Controller design

To witness the impact of PV on resonance mode in distribution systems, a controller for 1.25 MW PV is designed. The reason for choosing the hysteresis control switching technique associated with PV in this research is, the inherent nature of variable switching frequency due to which there is a probability of more harmonics that could impact the resonance modes. The simulation model for the controller has been built using PSCAD/EMTDC software [59]. For the analysis purpose, the PV solar panels are lumped together and presented as a dc source that is interfaced with the grid through a 6 pulse VSI. The control circuit associated with PV Inverter is shown in Figure 3.1.

The inverter is controlled in current-control mode, using the hysteresis band control technique. The current injected by inverter into the grid is split into two separately regulated components; active current Ia and reactive current Ir. The reactive current is set to zero, since only current injection is associated with the system. For a 1.25 MW real power to be injected, the total current $\sqrt{Ia^2 + Ir^2}$ is limited to 1503.56A rms) and has been interfaced with a 480V/13.8kV system.

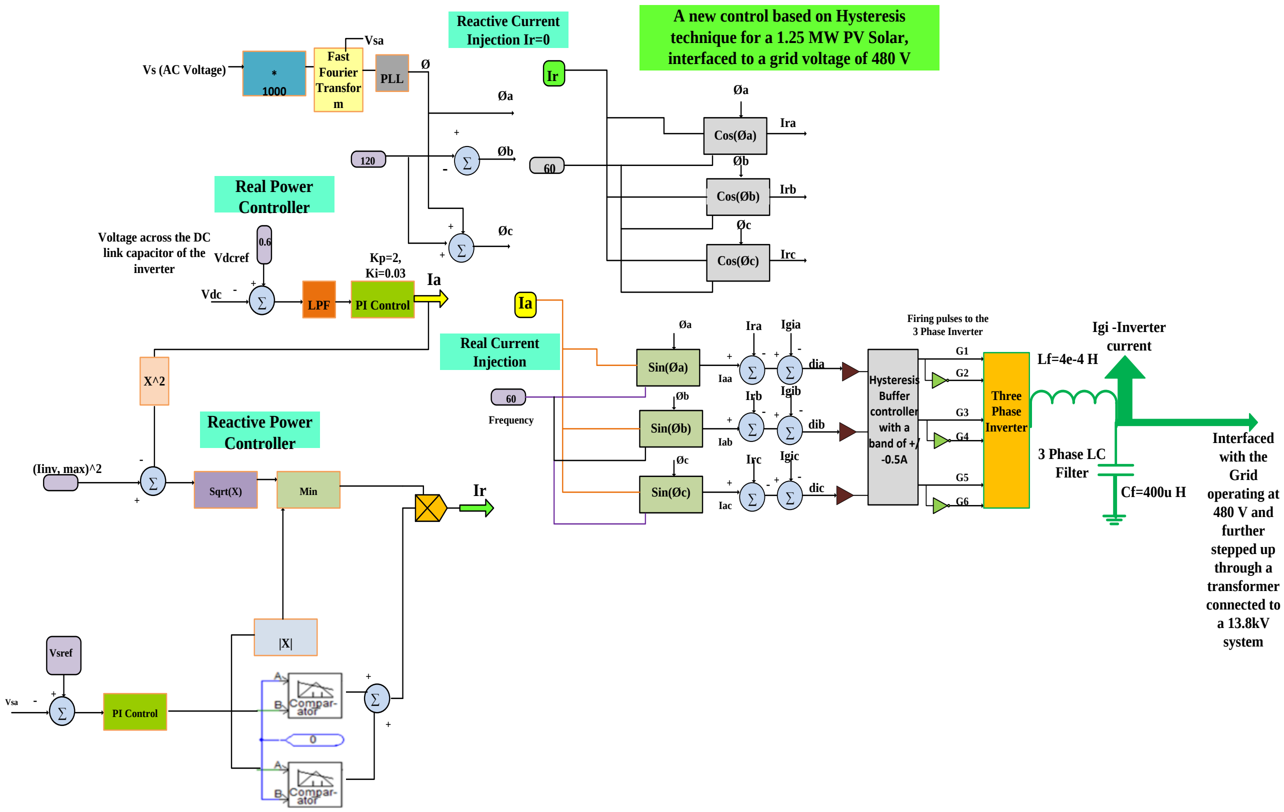



Figure 3.1 Hysteresis controller design incorporated in PSCAD for 1.25 MW PV Solar Inverter

The corresponding PI Control parameters for the active current injection are *Kp* =2, *Ki*=0.03 that are estimated by means of Ziegler-Nichols tuning rules [60] and then refined through simulations. A Phase lock loop (PLL) is used for synchronizing the injected current with the voltage in the Point of Common Coupling (PCC).

Due to the variable switching frequency of the hysteresis control technique associated with the PV Inverter, design of a low-pass filter is essential for connecting the VSC to the grid.

The filter also attenuates the harmonic components of the VSC ac-side voltage, and prevents them from penetrating into the grid. Different configurations could be implemented. However, for its simplicity and economical purpose, the low-pass LC filter is often adopted. The LC values associated with this 1.25 MW PV Solar Inverter are designed to be tuned to a frequency closer to 3rd, 5th and 7th order frequency, with values $L_f$= 4e-4 μH, $C_f$ = 400μF for this control scheme. The goal is to keep the harmonic currents injected by the PV system into the grid at reasonably low levels. Apart from that, inappropriate values of LC filter in the design tend to make the controller lose its stability and impact the resonance mode. So, caution needs to be exercised in the design. A simple SCIG based Wind Turbine Generator rated at 1.25 MW is designed using the PSCAD. The rated current for this WTG is calculated based on 480 V, further connected to a 13.8 kV distribution system through a step up transformer.

To provide the excitation of the windings of the WTG, reactive power is required. This support comes from a capacitor of 0.75 MVAR associated with that. So, a significant interaction from this capacitor with the distribution network also has an impact on resonance modes. So, network operations need to exercise extra caution about the network resonance frequencies. Figure 3.2 presents the model of WTG designed for the study in PSCAD based on the requirements. Figure 3.3 and Figure 3.4 presents the real power of 1.25 MW generated by PV and WTG respectively.

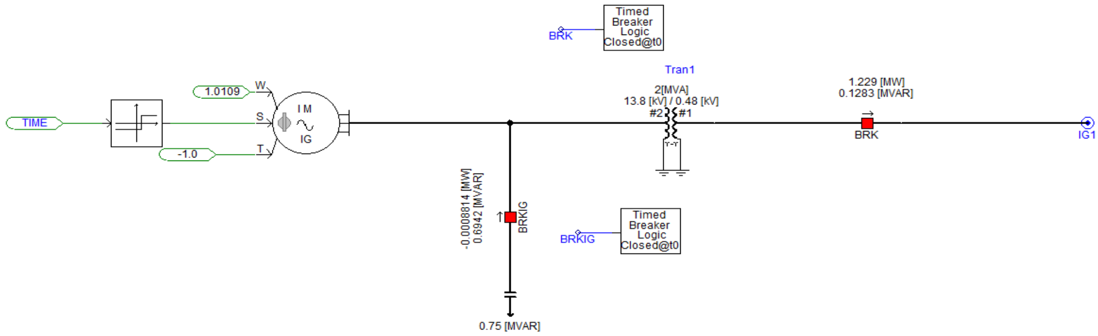



Figure 3.2 Simple SCIG based Wind Turbine Generator (1.25 MW)

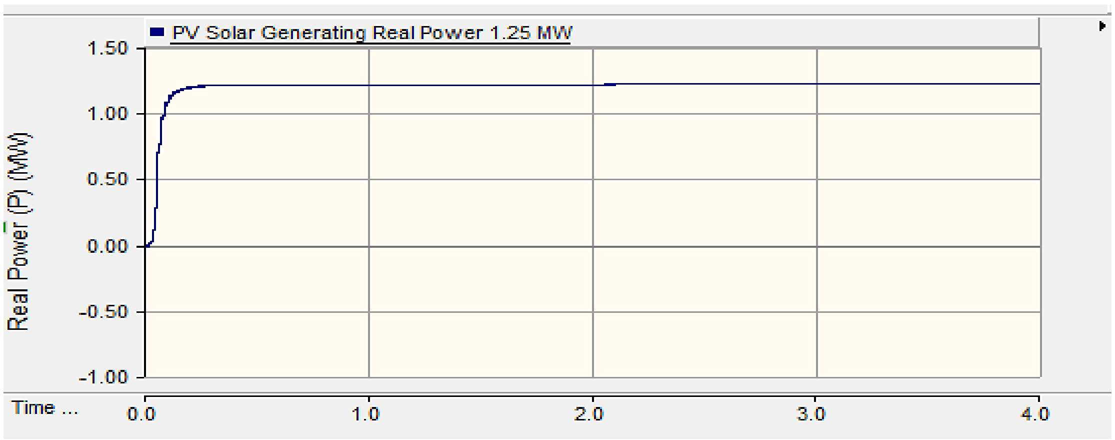



Figure 3.3 Real Power of 1.25 MW from PV Inverter

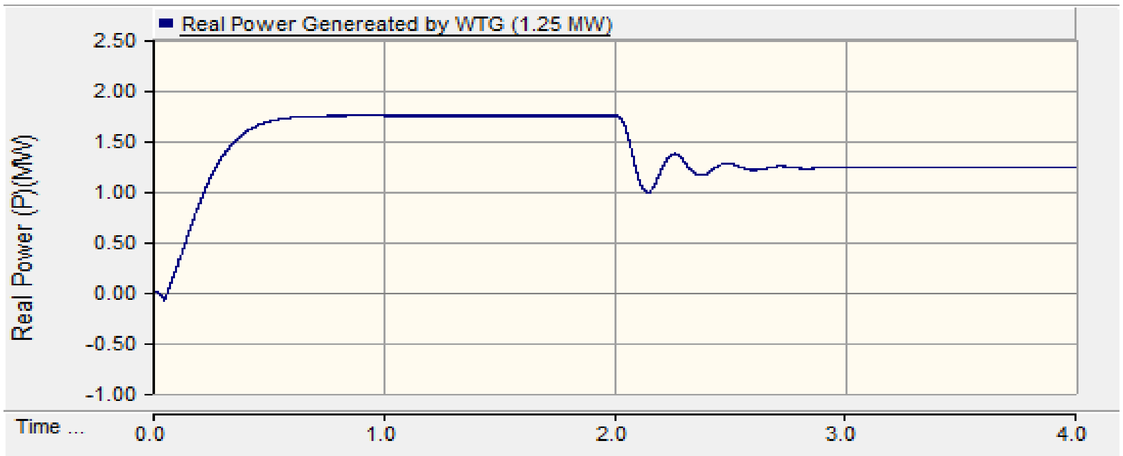



Figure 3.4 Real Power of 1.25 MW from Wind based IG (simple SCIG)

## 3.4 <u>System Description</u>

To demonstrate the coordination of the overall system and resonance phenomenon, IEEE Standard 399-1997 system with few modifications is considered. The complete system along with its data is shown in Figure 3.5 [58]. The study done on this is entirely novel in terms of implementing a new controller for PV and also the interaction with the elements of the distribution system. The system consists of a substation rated at 1000 MVA with X/R ratio of 22. The 69 kV line is stepped down to 13.8 kV through a 15 MVA transformer heading towards the Point of Common Coupling (PCC). This 13.8 kV from PCC feeds three feeders, Feeder 3, Feeder 2 and Feeder 1.

The loads connecting Distribution transformers are stepped down to 480 V and 2.4 KV. The two main buses in the system are DGBus3 and DGBus2. DGBus3 is the location where only PV Solar connectivity would take place in the form of sequential switching operation. The maximum interconnecting capacity that the DGBus3 can take is 2.5 MW. So, there are two sequential operations that are performed in DGBus3. During each operation, a PV Solar of 1.25 MW is turned ON.

The DGBus2 can take a maximum capacity of 5 MW DG's. Similarly during each operation, a DG of 1.25 MW is turned ON at this bus. So this allows 4 sequential switching operation to be performed to the total rated capacity of 5 MW in DGbus2. During the study, DGBus2 can take either Induction Generator based WTG or PV Solar rated at a time. But only one type of DG (either all PV or all WTG) is connected to DGBus2 at a time. The

system is supported by a 1.5 MVAR Feeder Capacitor Bank connected the Point of Common Coupling (PCC).

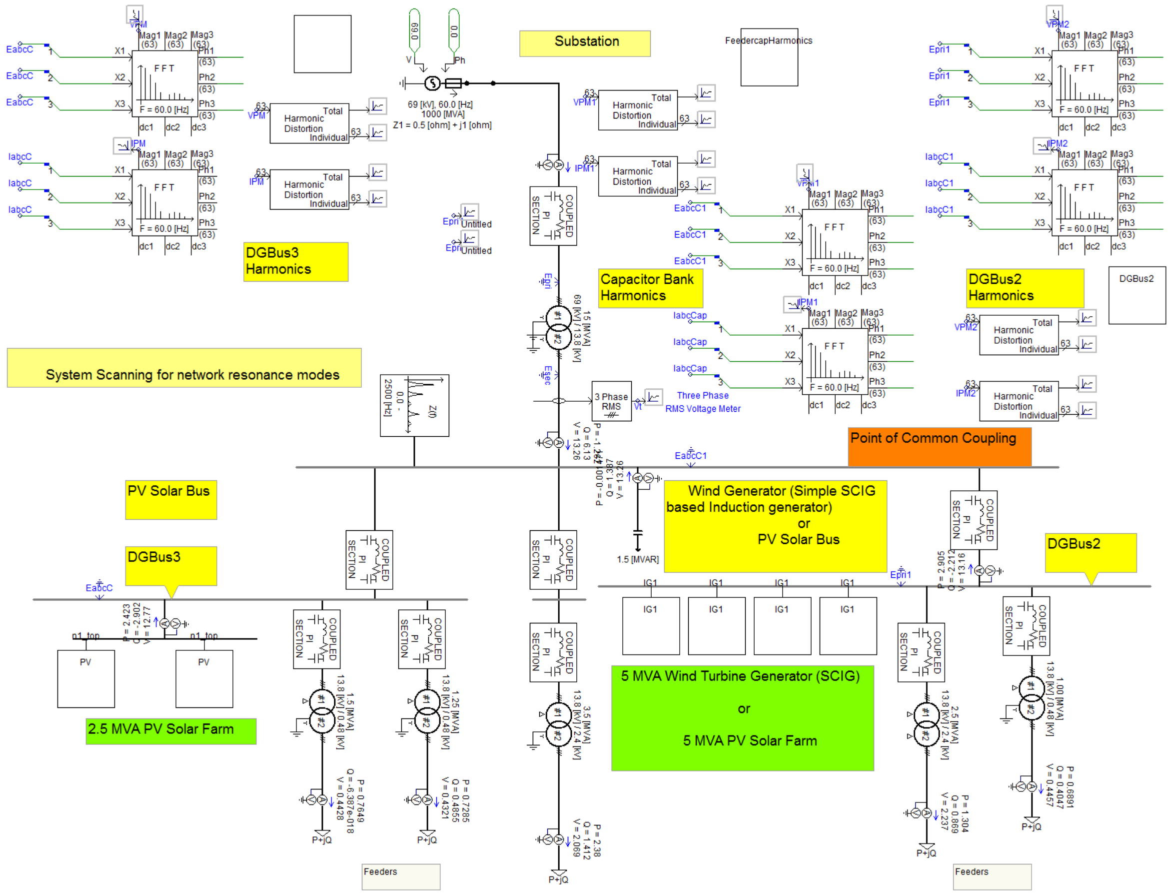



Figure 3.5 Distribution system based on parameters extracted from IEEE Standard 399-1997 [6] [58]

## 3.5 Harmonic limits for distributed generators

The most common harmonic index is the total harmonic distortion (THD) and used to define the effect of harmonics on the voltages of the power system. THD in power system is another term used to quantify the non-sinusoidal property of a waveform. THD is the ratio of RMS value of all the non-fundamental frequency to the RMS value of the fundamental frequency term.

$$\text{THDv} = \frac{\sqrt{\sum_{n=2}^{k} V_n^2}}{V_1} * 100\ (\%) \tag{3.1}$$

$$\text{THDi} = \frac{\sqrt{\sum_{n=2}^{k} I_n^2}}{I_1} * 100\ (\%) \tag{3.2}$$

where $V_n, I_n$ are the RMS voltage and current at harmonic n respectively and k is the maximum harmonic order to be considered, $V_1$, $I_1$ are the fundamental line to neutral RMS voltage and current respectively. Table 3.1 presents the permissible limits of harmonic distortion for distributed generators according to IEEE STD 519-1992 [61-62].

Table 3.1 IEEE STD 519-1992 RECOMMENDED Harmonic Limits for Distributed Generators [12]

| **Harmonics** | **Distortion Limit** |
|---|---|
| 3rd to 9th | < 4.0% |
| 11th -15th | <2.0% |
| 17th-21st | <1.5% |
| 23rd to 33rd | <0.6% |
| Above the 33rd | <0.3% |
| 35th or greater | 0.3% |
| Total harmonic distortion | 5.0% |
| Harmonics of even order are limited to 25% of odd values | |

3.6 Research analysis on resonance modes in the system due to DG penetration

A comprehensive knowledge of network impedances is required for the understanding and analysis of the resonance modes present in the system. For the purpose of frequency scan, the overall system impedance is coupled as viewed from the feeder

capacitor bus. The final impedance equations are frequency dependent. So, a suitable plot can be obtained between impedance and frequency using the Frequency Scan tool.

Normally for any research analysis that is done on a system for resonance, the frequency scanning is done at the Point of Common Coupling, where the feeder capacitor is connected. From Figure 3.5, it can be seen that DGBus3 and DGBus2 are two locations where DG's are turned ON sequentially for the study. The 1.5 MVAR feeder capacitor bank is in place at the PCC.

Figure 3.6 and Figure 3.7 presents the harmonic resonant peaks when DG's are turned on sequentially in the system. When a PV of 1.25 MW is switched ON at DGBus3, it could be seen that the first resonance mode remains the same at 698Hz. There is a small second peak that could be observed due to the interaction of the PV with the rest of the system at 1510 Hz. When a second PV rated at 1.25 MW is switched on DGBus3, the THDi at the feeder capacitor bus is higher than the recommended limits.

Now an Induction generator based WTG rated at 1.25 MW is turned ON at DGBus3 with the existing 2 PV's rated at 2.5 MW overall turned ON at DGbus2. It could be observed that a third resonant mode appears. First peak has shifted to 398 Hz, second peak appearing at 710 Hz and a third one appearing at 1380 Hz. So the THDi at the feeder capacitor is increasing as the number of DG's are penetrated into the system. So the study is done till 4 WTG's are penetrated into the DGbus2 so that the maximum rated penetration of 5 MW is reached.

The same study is repeated by replacing all WTG's by PV's turned ON in a sequential fashion to a total of 5 MW at DGbus2.

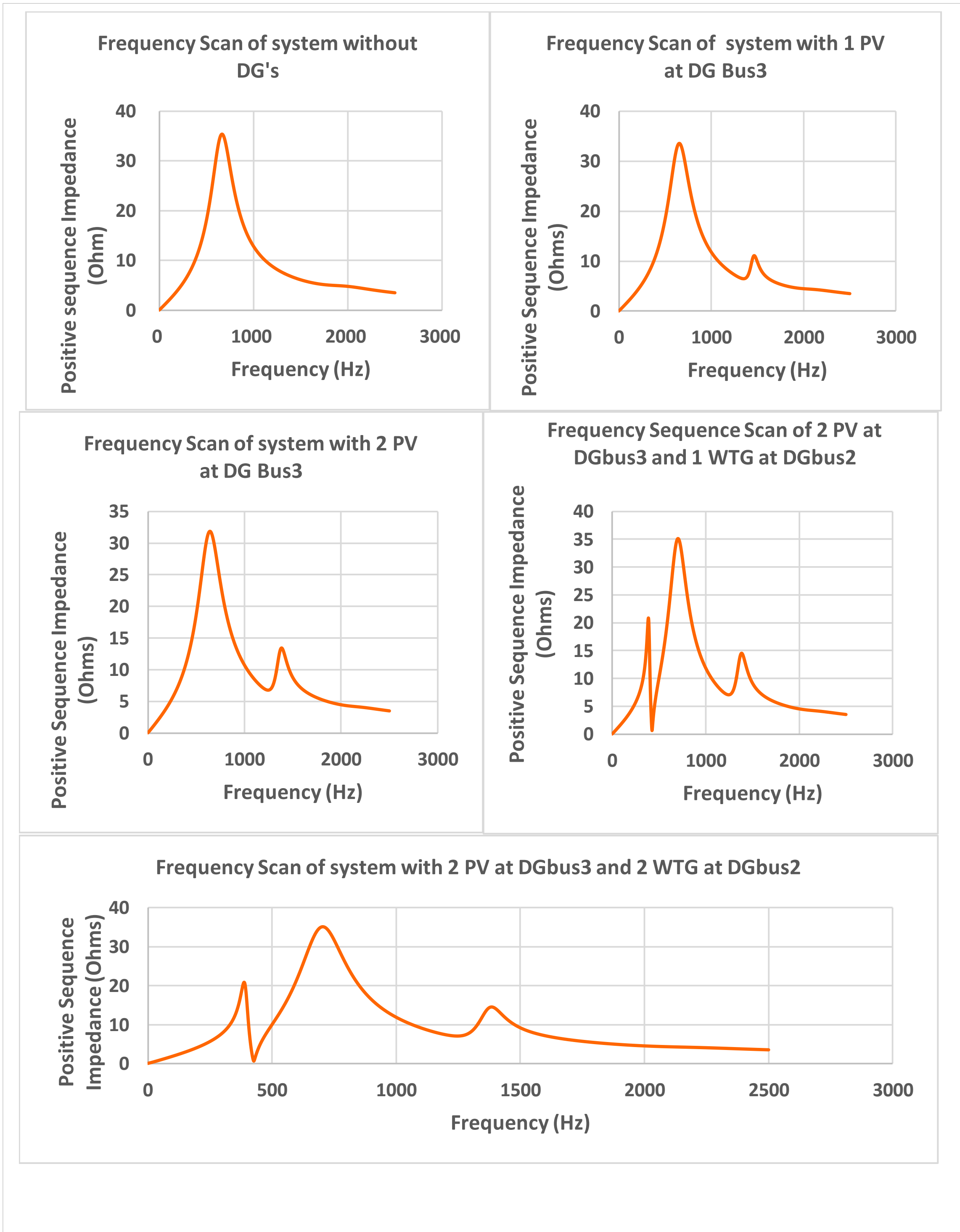
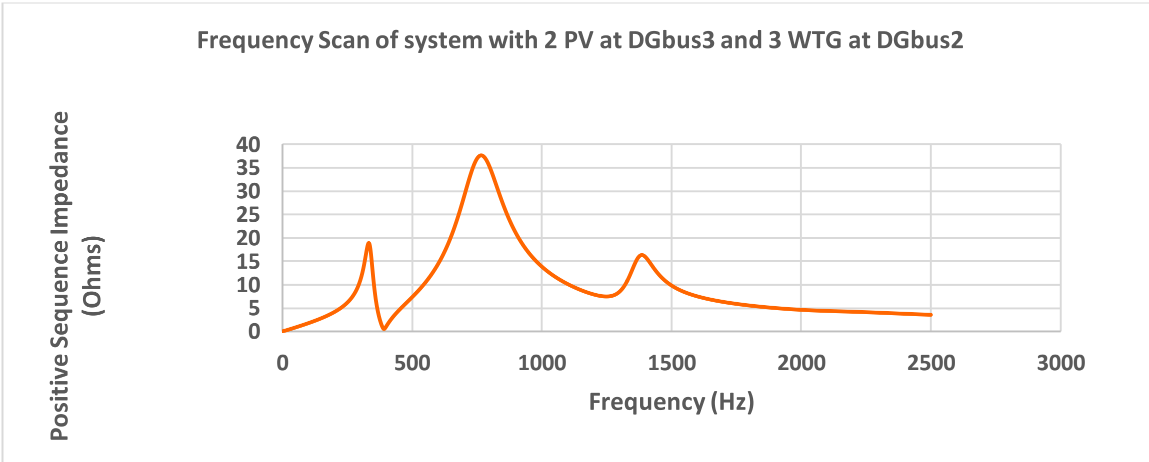
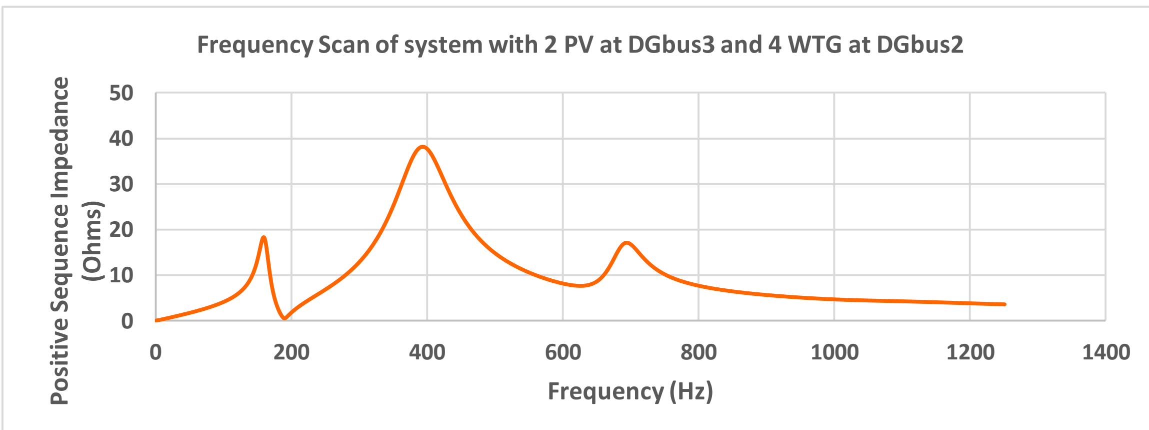



Figure 3.6 Resonance modes during PV Solar and WTG integration during sequential switching



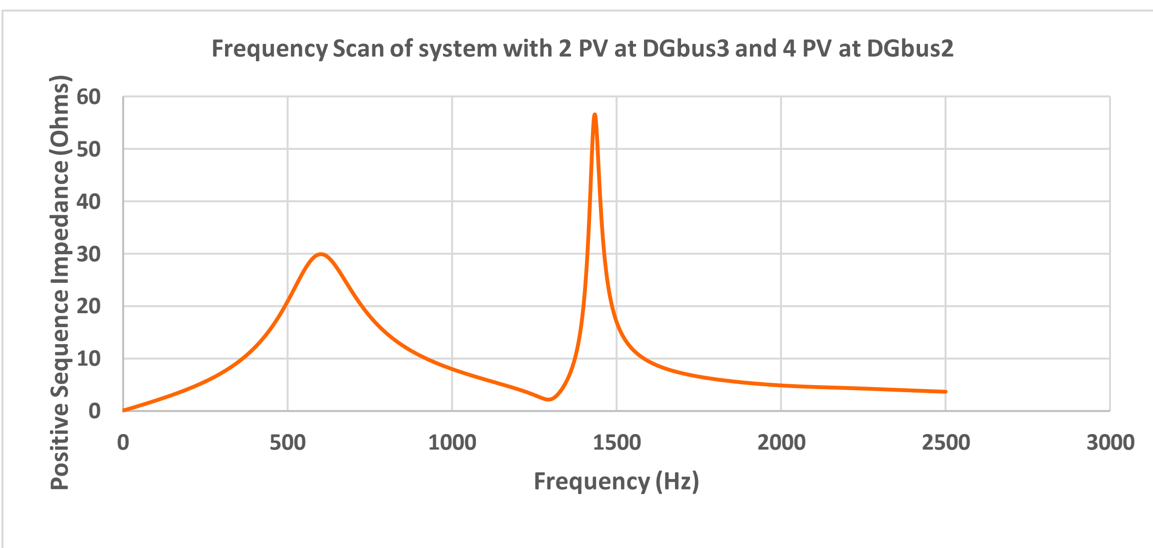




Figure 3.7 Resonance modes during PV Solar and WTG integration during sequential switching

Table 3.2 Results of Total and Individual Harmonic Distortion at Feeder Capacitor Bus (PCC) obtained using PSCAD/EMTDC

| Number of DG units | Feeder Capacitor Bus (PCC) | | Feeder Capacitor Bus (PCC) IHDv % | | | Feeder Capacitor Bus (PCC) IHDi% | | |
|---|---|---|---|---|---|---|---|---|
| | THDv % | THDi % | 3rd | 5th | 7th | 3rd | 5th | 7th |
| NO DG | 0.01 | 0.09 | 0.004 | 0.004 | 0.004 | 0.001 | 0.028 | 0.035 |
| 1 PV at DGbus3 | 0.4 | 0.7 | 0.003 | 0.21 | 0.19 | 0.002 | 1.04 | 1.34 |
| 2 PV at DGbus3 | 0.84 | 9.10 | 0.003 | 0.42 | 0.39 | 0.004 | 2.11 | 2.76 |
| 2 PV at DGbus3+1 WTG at DGbus2 | 0.84 | 9.33 | 0.003 | 0.47 | 0.05 | 0.002 | 2.34 | 0.35 |
| 2 PV at DGbus3+ 2 WTG at DGbus2 | 0.84 | 9.5 | 0.004 | 0.54 | 0.06 | 0.003 | 2.72 | 0.45 |
| 2PV at DGbus3+3 WTG at DGbus2 | 0.932 | 9.97 | 0.004 | 0.667 | 0.09 | 0.006 | 3.317 | 0.626 |
| 2PV at DGbus3+4 WTG at DGbus2 | 1.07 | 10.39 | 0.005 | 0.857 | 0.09 | 0.006 | 4.32 | 0.69 |
| 2PV at DGbus3+1 PV at DGbus2 | 1.22 | 12.54 | 0.0028 | 0.63 | 0.599 | 0.002 | 3.17 | 4.18 |
| 2PV at DGbus3+2 PV at DGbus2 | 1.66 | 18.6 | 0.002 | 0.85 | 0.81 | 0.004 | 4.23 | 5.73 |
| 2PV at DGbus3+3 PV at DGbus2 | 2.04 | 21.4 | 0.002 | 1.06 | 1.03 | 0.014 | 5.27 | 7.28 |
| 2PV at DGbus3+4 PV at DGbus2 | 2.43 | 25.35 | 0.003 | 1.28 | 1.25 | 0.015 | 6.35 | 8.87 |

It could be observed that with 2 PV at DGBus3 (2.5 MW) and 4 WTG's at DGBus2 (5 MW in total), three resonant modes appear are witnessed at 162 Hz, 406 Hz,706 Hz respectively which is closer in alignment with $3^{rd}$, $7^{th}$ and $12^{th}$ respectively.

With the same study repeated for 2 PV at DG Bus 3 (2.5 MW in total), 4 PV's at DGBus2 (5 MW in total), two resonant modes appear at 598 Hz and 1440 Hz corresponding to $10^{th}$ and $24^{th}$ harmonic. The harmonic distortion level at DGBus3 and DGBus2 seems to be acceptable. The feeder capacitor bus/Point of Common Coupling (PCC) is the location where the THDi and IHDi steadily tend to increase, as more number of DG's are penetrated into the system. This clearly depicts that the feeder capacitor interacts with DG and the rest of the system to cause an increase in the harmonic distortion. The harmonic distortion levels are less than 4.0% at DGBus3 and DGBus2. So, the results of those are not presented. All higher values of harmonic distortion in the form of violations at PCC/Feeder Capacitor Bus are shown highlighted in red, in Table 3.2.

This research clearly shows that the Feeder capacitor bus tends to interact more with the installed DG's at PCC, although the DG's contribution towards harmonics are well within the limits at their local buses. It was also noted that same results have been obtained when the WTG based Induction Generators have been replaced by Inductor motor loads in DGBus2. The reason being because of the fact that induction motors and induction generator based WTG's requires the same rating of capacitor for reactive power generation, for excitation purposes. The observations obtained with respect to the violations shown in Table 3.2 clearly showed the interaction of DG's with the main feeder capacitor bank facilitates the importance of such research studies like this in distribution planning. To

eliminate this, the effective solution of adding a reactor in series/parallel with 5%-14% that of the rating of capacitive reactance of the feeder bank capacitor is tested on the system to eliminate the violations. Apart from that, relocating the capacitor bank to some other location is one of the possible solutions in terms planning.

Apart from that, the idea of employing Smart PV Inverters in VAR modes can serve as a virtual de-tuner in eliminating network resonances is a novel solution proposed by the authors for future research.

# CHAPTER FOUR

# INTERACTIVE IMPACTS OF ELEMENTS OF DISTRIBUTION SYSTEMS AND PV ON NETWORK HARMONIC RESONANCE

## 4.1 Overview

As more number of distributed generators like PV are penetrated into the power system network, the interaction of the filter elements associated with PV inverter and rest of the distribution system elements on network resonance needs to be investigated. Although the recent investigation of network resonance is focusing only on distributed generators like PV, the impact from distribution lines coming from substation and underground cables that possesses the line charging capacitances (including the variation in line length), VAR support capacitors for voltage regulation and power factor correction capacitors in the system, inductive loads in the distribution systems needs a detailed investigation on resonance.

The resonance phenomenon can be witnessed in the presence or even without the presence of distributed generators. With the increase in distributed generators, the interaction between them and the elements in the system presents a higher probability of network resonances that needs more attention. Power quality planning require the researchers and engineers to perform such studies to witness the impact of elements in distribution systems. There are limited papers that have done detailed research studies, projecting the impact of elements of distribution systems on network resonances. This chapter brings out a contribution that would serve as a reference for researchers and power system planning engineers to plan on several aspects pertaining to power quality.

## 4.2 Introduction

Distributed generators (DG) such as PV and other power-electronic based generators are capable of injecting harmonics into the power network. The filter elements associated with them tend to interact with the impedances of the system leading to resonance. The resonant modes are highly impacted by the presence of harmonics from power electronic converters or nonlinear loads in the system, whose limits are clearly well defined by the power quality standard IEEE 519-1992. During such a situation, the alignment with any one of the frequencies of the resonant modes, the voltages corresponding to those harmonic frequencies can be amplified resulting in equipment damages or even cause failure of protective relays. Distribution networks require reactive power support.

Such a support or suitable compensation can be provided by shunt capacitors banks that are capable of providing voltage regulation and as well as power factor correction. The inductive nature of distribution lines that also has line charging capacitances and other inductive components like the transformer impedances and loads present in the distribution system can resonate at certain frequencies thereby giving rise to network resonances. The intensity of the resonant peak can be obtained from the frequency scan of network impedance. Based on the network loading conditions and short circuit levels, variations in resonant modes were reported.

The elements tend to interact and cause issues in terms of resonance resulting in a limiting factor towards PV interconnectivity. Assessment after PV interconnection is also important to ensure that the filter elements doesn’t interact with the rest of the system. The

interaction of PV on a small scale has been investigated. It is highly essential that a harmonic analysis is performed as a part of system planning whenever dispersed PV generators are present in the system, since the elements in the distribution system that can interact with PV and other distributed generators. IEEE 519-1992 for PV clearly defines the limits of injection in terms of power quality aspects. Although the impacts of DG's towards are constantly being discussed [63-64], the effects of the elements present in the distribution systems has not been presented in many papers. This chapter brings out a contribution in form of a system study to witness the impact of the elements present in the distribution systems that may contribute to network resonances. This would further serve as a reference for researchers and planning engineers to perform such studies during planning of distribution systems and its interaction with distributed generation.

## 4.3 Study system description

An IEEE Standard 399-1997 based system with few modifications is considered for the study purpose. A substation rated at 1000 MVA with X/R ratio of 22, feeds through a 69 kV line that is stepped down to 13.8 kV through a 15 MVA transformer heading towards the Point of Common Coupling (PCC). This 13.8 kV from PCC feeds three feeders - Feeder 3, Feeder 2 and Feeder 1. The loads connecting Distribution transformers are stepped down to 480 V and 2.4 kV. The two main buses in the system are DGBus3 and DGBus2. DGBus3 is the location where only PV Solar connectivity would take place in the form of sequential switching operation. The maximum interconnecting capacity that the DGBus3 can take is 2.5 MW. So, there are two sequential operations that are performed in DGBus3. During each operation, a PV Solar of 1.25 MW is turned ON.

The DGBus2 can take a maximum capacity of 5 MW DG's. Similarly during each operation, a DG of 1.25 MW is turned ON at this bus. This allows 4 sequential switching operation to be performed to the total rated capacity of 5 MW in DGbus2. During the study, DGBus2 can take either an induction motor or a PV inverter at a time. Either induction motor of 5 MW is turned ON or PV of 5 MW is turned ON at a time for the study. The system is supported by a 1.5 MVAR feeder capacitor bank connected the Point of Common Coupling (PCC). Figure 4.1 presents the complete system that is designed using PSCAD/EMTDC.

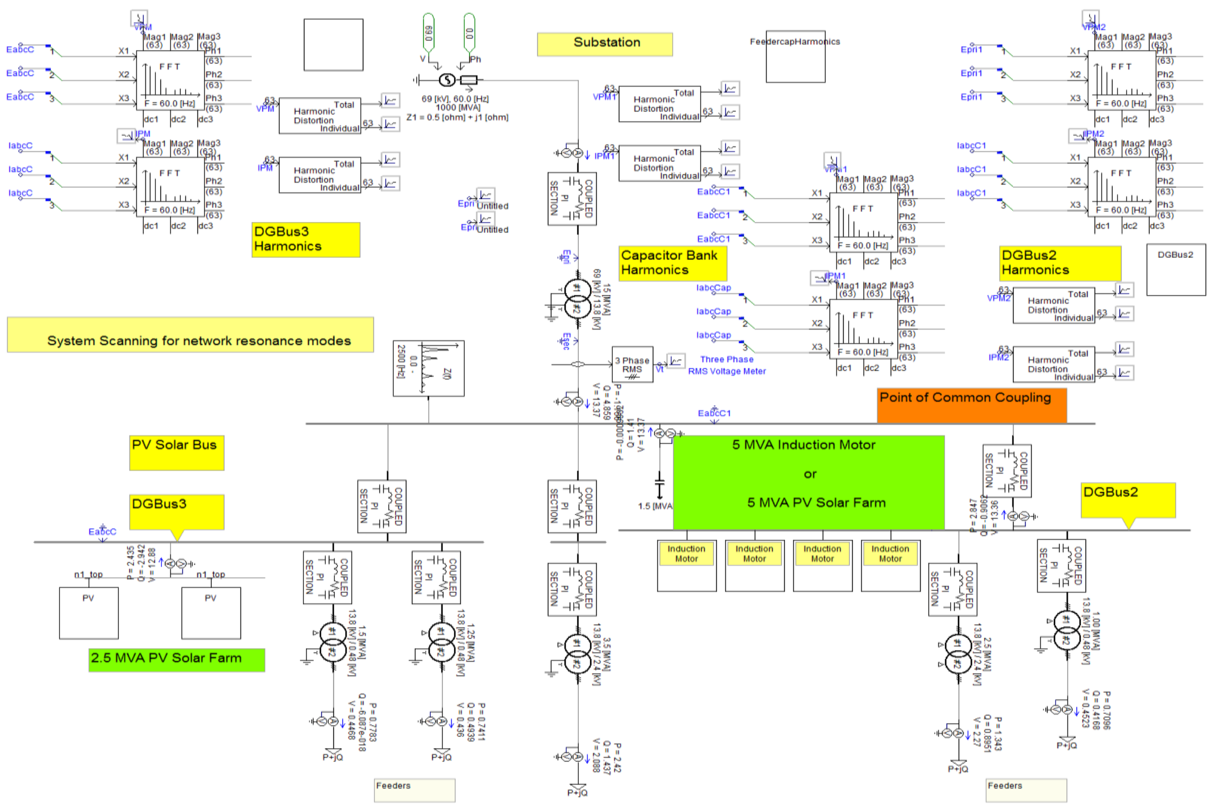



Figure 4.1 Study System designed using PSCAD/EMTDC

### 4.4 Research analysis on resonance modes due to elements in the system

A comprehensive knowledge of network impedances is required for the understanding and analysis of the resonance modes present in the system. For the purpose of a frequency scan, the overall system impedance is coupled as viewed from the feeder capacitor bus. The final impedance equations are frequency dependent. So, a suitable plot can be obtained between impedance and frequency using the frequency scan tool. Normally for any research analysis that is done on a system for resonance, the frequency scanning is done at the Point of Common Coupling (PCC), where the feeder capacitor is connected.

#### 4.4.1 Resonance modes due to increase in the rating of the Feeder Capacitor Bank

The resonant modes for this study is shown in Figure 4.3. At first, the scanning of the system is done with the 1.5 MVAR feeder capacitor bank connected to the system. A resonant peak is observed at 718 Hz. Further, the capacitor's rating is increased to 3 MVAR by turning ON another capacitor of 1.5 MVAR in the form of a sequential operation. It could be seen that the resonant peak appears at 424 Hz, Further the capacitor rating is increased to 4.5 MVAR and 6 MVAR and the corresponding peaks starts to move to a lower frequencies of 334 Hz and 292 Hz respectively. At the same time, it should also be noted that the voltage should be within the limits of +/-5% of a distribution system. It could be observed that 292 Hz peak is trying to align with $5^{th}$ harmonic. So, a suitable caution needs to be exercised in every study when a resonant peak keeps shifting towards

fundamental frequency and tries to align with 3, 5, 7th and other higher order odd harmonics especially that are multiples of 3.

### 4.4.2 Resonance modes due to loading

When induction motors of 5 MW are turned ON at DGbus2, same results were obtained from Chapter 3, due to the fact that terminal capacitor is associated with that. The variation of P-Q load on different feeders has minimal impact on resonance. The corresponding results obtained from PSCAD are shown in Figure 4.2.

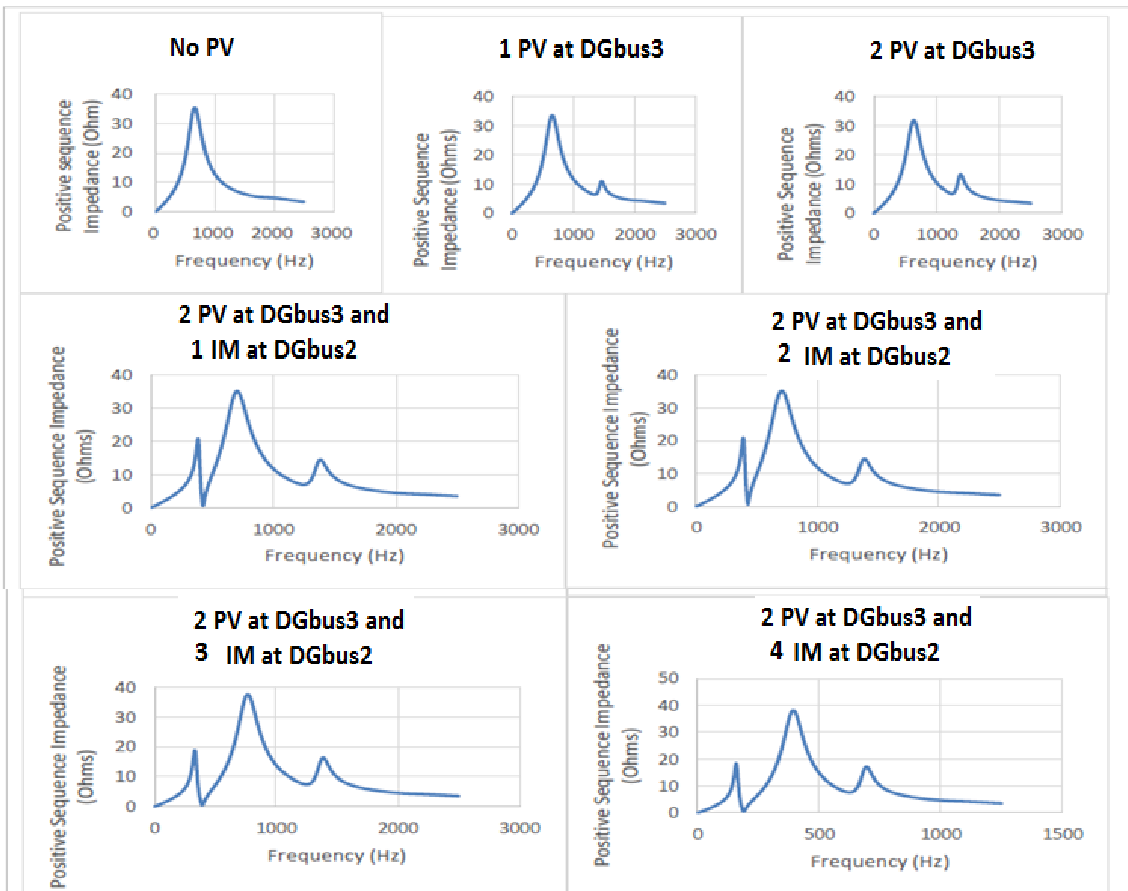



Figure 4.2 Resonance modes during PV and Induction motor load during sequential switching

#### 4.4.3 Resonance modes due to variation in distribution line length

The line that connects the substation and the point of common coupling has a lot of significance with respect to the distance that can impact the resonant modes in the system.

Referring to Figure 4.1, the similar sequence of switching operation is performed for DGBus3 and DGBus2 with 1.5 MVAR feeder capacitor in place. Figure 4.4 presents the results obtained for the sequential operations of PV's and Induction Motors (IM) in place. The maximum switched case of 2 PV at DGBus3 and 4 IM at DGBus2 are considered. The length of the transmission line is varied for the values of 3.05 km, 50 km, 100 km and 150 km. For a 3.05 km the resonant modes appears at 648 Hz and 1440 Hz. As the length of the transmission line is considered to 50 km, a new third peak arises and the resonant modes have peaks at 566 Hz, 1430 Hz and 1770 Hz. For a length that is changed to 100 km, the resonant modes 404 Hz, 1180 Hz and 1460 Hz. When the length of the line is increased to 150 km, the peaks corresponds to 392 Hz, 952 Hz and 1440 Hz.

The same study is repeated with the 2 PV's at DGBus3 and 4 PV's at DGBus2. The results could be witnessed from Figure 4.5. For a length of 3.05 km, the resonant peaks appear at 322 Hz, 808 Hz, and 1420 Hz. For a length of 50 km, resonant peaks appear at 298 Hz, 708 Hz, 1440 Hz, and 1710 Hz. When the length is considered to be 100 km, resonant peaks appear at 284 Hz, 618 Hz, 1200 Hz, and 1408 Hz. A line with a length of 150 km witnesses resonant peaks at 250 Hz, 524 Hz, 1014 Hz and 1420 Hz.

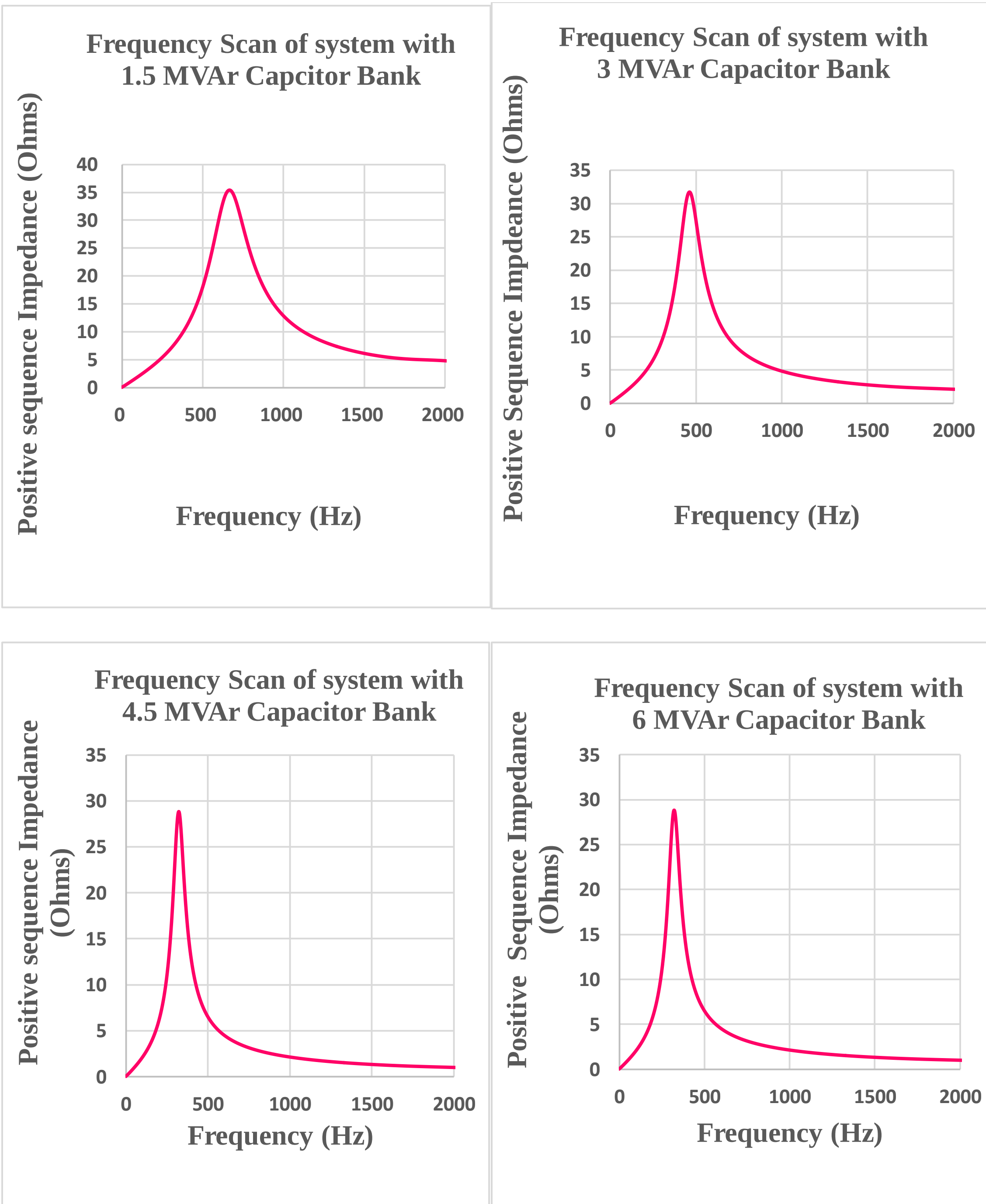



Figure 4.3 Resonant mode variation due to increase in feeder capacitor rating and its interaction with the network

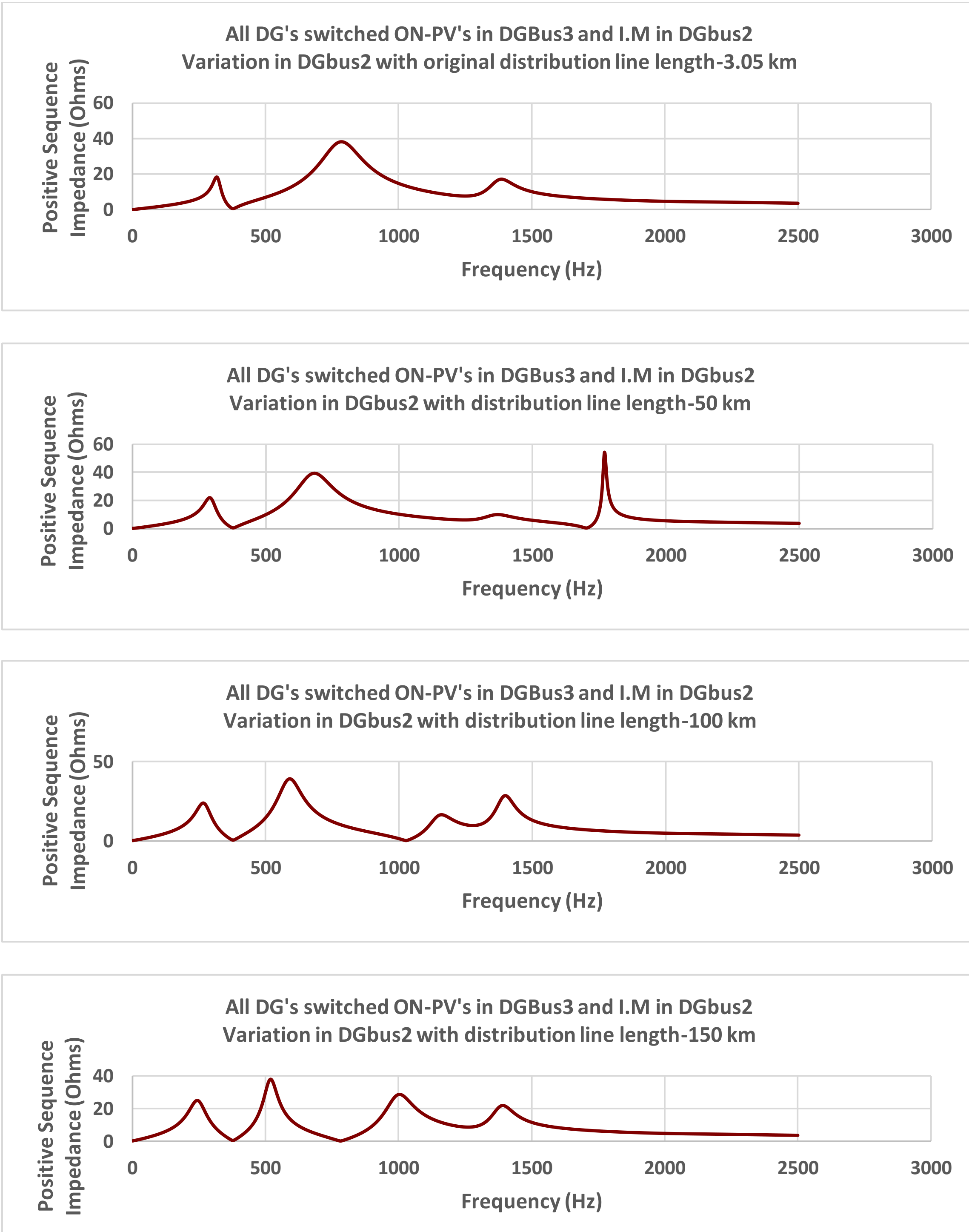



Figure 4.4 Resonance mode due to variation in line length of pi-section model with PV and Induction motor

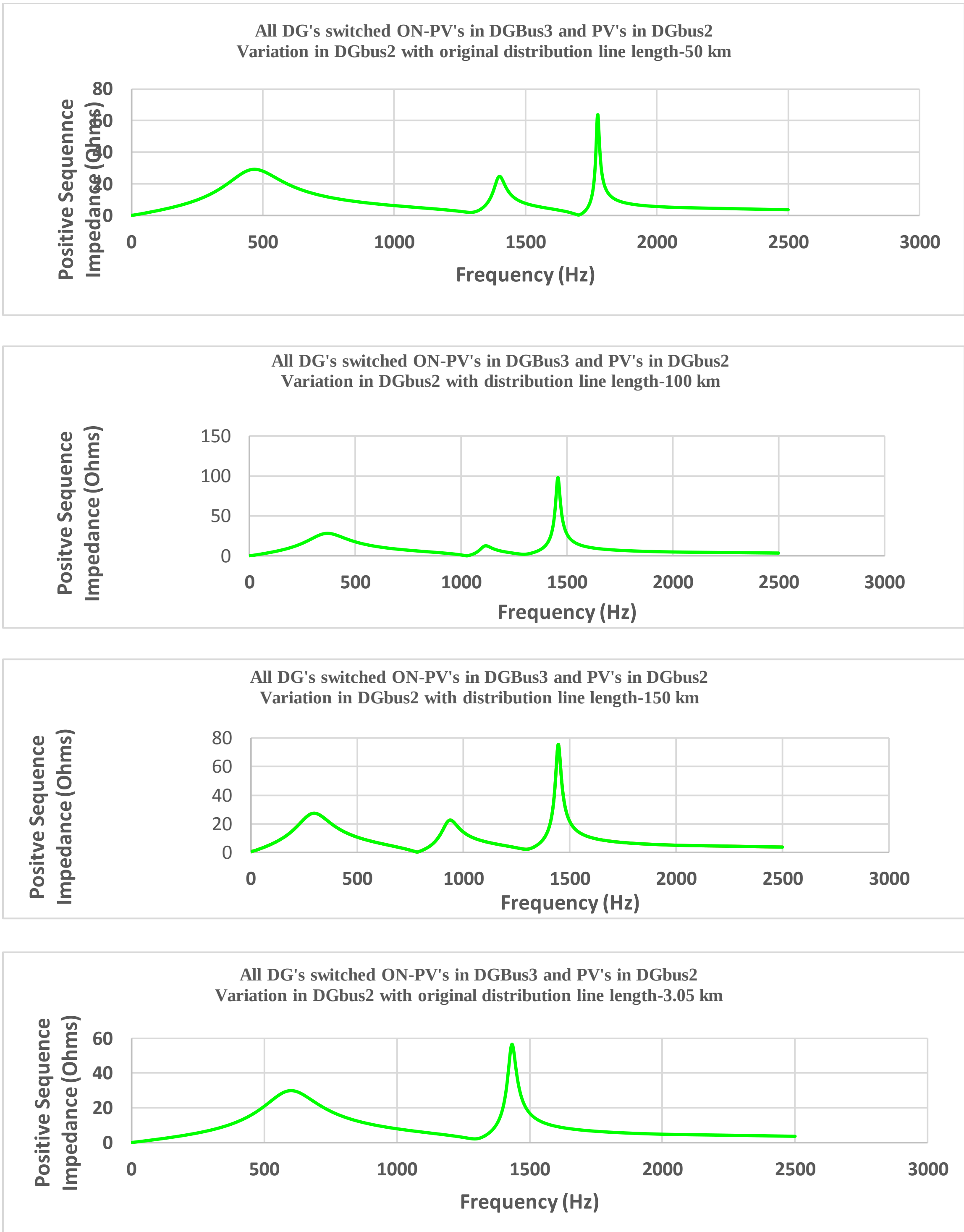



Figure 4.5 Resonance modes due to variation in line length of pi-section model with only PV in place

It is known fact that a line charging capacitance is present on the transmission line (also applicable to sub-transmission as well). In PSCAD/EMTDC, a pi-section model of a line is used for modelling. The line charging capacitance starts to resonate with the rest of the circuit. So, it could be well witnessed from Figure 4.4 and Figure 4.5 that there is an impact in the magnitude and frequency of resonance modes. The length of the cable is directly under the influence of capacitive element of distribution line. As a result of which, as length of the line increases, larger variation in resonant mode frequency is expected and this has been observed with the results shown in Figure 4.4 and Figure 4.5.

## 4.5 Harmonic reduction by detuning

The violations in distortion levels are seen the most at the Feeder Capacitor Bus (PCC) for THDi and IHDi, it increases as more number of DG's/Induction Motors are added into the system at DGBus3 and DGBus2, although it is within the limits at DGBus3 and DGBus2 as seen from Table 4.1, Table 4.2 and Table 4.3.

The changing of a resonance point and making it move far away from the harmonics is referred to as detuning of a system. Adding a reactor to the system is one effective way involved in detuning. One more effective strategy that could be implemented is done by adding a reactor in series with the capacitor, without tuning it to make it act like a filter. Another effective solution that could be associated is by changing the location of the capacitor without any violation in +/-5% of the violation limit in a distribution system. The detuning process of adding a series inductor to the feeder capacitor bank (1.5 MVAR) is experimented with this system.

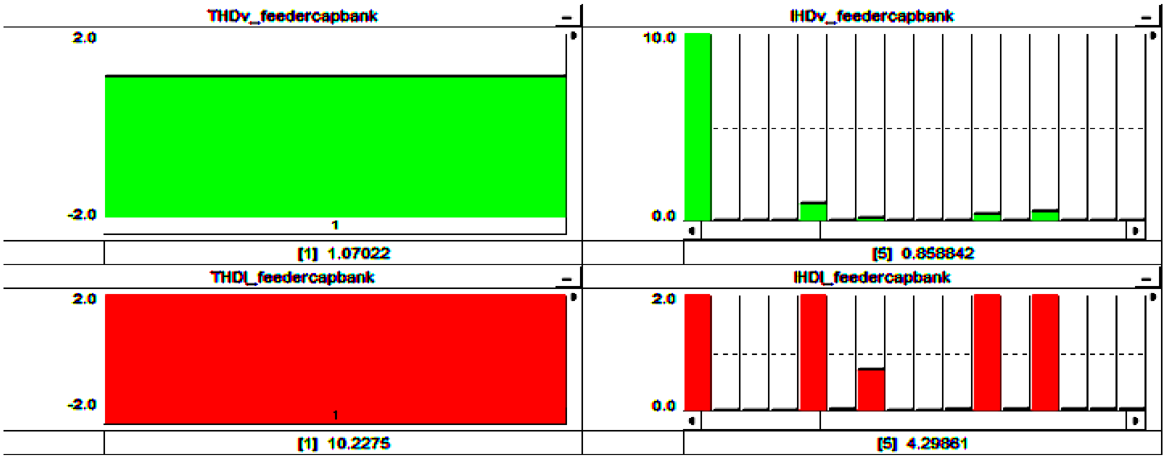



Figure 4.6 Maximum DG penetration case readings from polymeter - Harmonic distortion when DGbus3 has 2 PV's and DGbus2 has 4 IM's- without detuning

Table 4.1 Results of Total Harmonic Distortion of Voltage and Current at DGbus3, DGBus2 and Feeder Capacitor Bus (PCC) using PSCAD/EMTDC

| **Number of DG units+ Induction Motor Load** | **DGBus3** | | **DGBus2** | | **Feeder Capacitor Bus (PCC)** | |
|---|---|---|---|---|---|---|
| | **THDv %** | **THDi %** | **THDv %** | **THDi %** | **THDv %** | **THDi %** |
| **NO DG** | 0.01 | 0 | 0.01 | 0.036 | 0.01 | 0.09 |
| **1 PV at DGbus3** | 0.7 | 3.57 | 0.41 | 0.31 | 0.4 | 0.7 |
| **2 PV at DGbus3** | 1.33 | 3.55 | 0.70 | 0.64 | 0.84 | **9.1** |
| **2 PV at DGbus3+1 IM at DGbus2** | 1.27 | 3.55 | 0.756 | 4.43 | 0.84 | **9.3** |
| **2 PV at DGbus3+ 2 IM at DGbus2** | 1.35 | 3.55 | 0.767 | 5.63 | 0.84 | **9.5** |
| **2PV at DGbus3+3 IM at DGbus2** | 1.43 | 3.55 | 0.909 | 4.83 | 0.932 | **10.0** |
| **2PV at DGbus3+4 IM at DGbus2** | 1.56 | 3.56 | 1.25 | 2.9 | 1.07 | **10.4** |
| **2PV at DGbus3+1 PV at DGbus2** | 1.614 | 3.5 | 1.34 | 2.42 | 1.22 | **12.5** |
| **2PV at DGbus3+2 PV at DGbus2** | 1.97 | 3.55 | 1.91 | 3.05 | 1.66 | **18.6** |
| **2PV at DGbus3+3 PV at DGbus2** | 2.35 | 3.53 | 2.38 | 3.0 | 2.04 | **21.4** |
| **2PV at DGbus3+4 PV at DGbus2** | 2.76 | 3.57 | 2.92 | 3.10 | 2.43 | **25.4** |

Table 4.2 Results of Individual Harmonic Distortion of Voltage (3rd, 5th &7th Harmonic) at DGbus3, DGBus2 and Feeder Capacitor Bus (PCC) using PSCAD/EMTDC

| **Number of DG units +Induction Motor Load** | **DGbus3 IHDv %** | | | **DGBus2 IHDv %** | | | **Feeder Capacitor Bus (PCC) IHDv %** | | |
|---|---|---|---|---|---|---|---|---|---|
| | **3rd** | **5th** | **7th** | **3rd** | **5th** | **7th** | **3rd** | **5th** | **7th** |
| **NO DG** | 0 | 0 | 0 | 0 | 0 | 0 | 0.004 | 0.004 | 0.004 |
| **1 PV at DGbus3** | 0.02 | 0.394 | 0.312 | 0.0038 | 0 | 0.18 | 0.003 | 0.21 | 0.19 |
| **2 PV at DGbus3** | 0.001 | 0.83 | 0.244 | 0.003 | 0.41 | 0.38 | 0.003 | 0.42 | 0.39 |
| **2 PV at DGbus3+1 IM at DGbus2** | 0.001 | 0.83 | 0.244 | 0.004 | 0.50 | 0.239 | 0.003 | 0.47 | 0.05 |
| **2 PV at DGbus3+ 2 IM at DGbus2** | 0.002 | 0.90 | 0.344 | 0.005 | 0.624 | 0.09 | 0.004 | 0.54 | 0.06 |
| **2PV at DGbus3+3 IM at DGbus2** | 0.0016 | 1.00 | 0.368 | 0.006 | 0.82 | 0.061 | 0.004 | 0.667 | 0.09 |
| **2PV at DGbus3+4 IM at DGbus2** | 0.002 | 1.01 | 0.50 | 0.008 | 1.17 | 0.047 | 0.005 | 0.857 | 0.09 |
| **2PV at DGbus3+1 PV at DGbus2** | 0.0017 | 1.01 | 0.80 | 0.0024 | 0.766 | 0.686 | 0.0028 | 0.63 | 0.599 |
| **2PV at DGbus3+2 PV at DGbus2** | 0.001 | 1.23 | 1.07 | 0.002 | 1.12 | 0.988 | 0.002 | 0.85 | 0.81 |
| **2PV at DGbus3+3 PV at DGbus2** | 0.002 | 1.45 | 1.30 | 0.001 | 1.47 | 1.30 | 0.002 | 1.06 | 1.03 |
| **2PV at DGbus3+4 PV at DGbus2** | 0.001 | 1.68 | 1.53 | 0.002 | 1.84 | 1.64 | 0.003 | 1.28 | 1.25 |

Table 4.3 Results of Individual Harmonic Distortion of Current (3rd, 5th &7th Harmonic) at DGbus3, DGBus2 and Feeder Capacitor Bus (PCC) using PSCAD/EMTDC

| Number of DG units+ Induction Motor Load | DGbus3 IHDi % | | | DGBus2 IHDi % | | | Feeder Capacitor Bus (PCC) IHDi % | | |
|---|---|---|---|---|---|---|---|---|---|
| | 3rd | 5th | 7th | 3rd | 5th | 7th | 3rd | 5th | 7th |
| NO DG | 0 | 0 | 0 | 0 | 0.033 | 0.01 | 0.001 | 0.028 | 0.035 |
| 1 PV at DGbus3 | 0.012 | 2.82 | 1.50 | 0 | 0.13 | 0.165 | 0.002 | 1.04 | 1.34 |
| 2 PV at DGbus3 | 0.01 | 2.82 | 1.51 | 0 | 0.31 | 0.32 | 0.004 | 2.11 | 2.76 |
| 2 PV at DGbus3+1 IM at DGbus2 | 0.12 | 2.82 | 1.52 | 0.007 | 0.988 | 3.99 | 0.002 | 2.34 | 0.35 |
| 2 PV at DGbus3+ 2 IM at DGbus2 | 0.013 | 2.81 | 1.518 | 0.026 | 2.82 | 3.94 | 0.003 | 2.72 | 0.45 |
| 2PV at DGbus3+3 IM at DGbus2 | 0.015 | 2.82 | 1.57 | 0.02 | 3.59 | 2.364 | 0.006 | 3.317 | 0.626 |
| 2PV at DGbus3+4 IM at DGbus2 | 0.02 | 2.83 | 1.58 | 0.019 | 2.39 | 0.81 | 0.006 | **4.32** | 0.69 |
| 2PV at DGbus3+1 PV at DGbus2 | 0.001 | 2.83 | 1.54 | 0.007 | 1.62 | 0.7412 | 0.002 | 3.17 | **4.18** |
| 2PV at DGbus3+2 PV at DGbus2 | 0.003 | 2.84 | 1.55 | 0.007 | 2.05 | 0.97 | 0.004 | **4.23** | **5.73** |
| 2PV at DGbus3+3 PV at DGbus2 | 0.005 | 2.85 | 1.56 | 0.006 | 2.31 | 1.13 | 0.014 | **5.27** | **7.28** |
| 2PV at DGbus3+4 PV at DGbus2 | 0.007 | 2.86 | 1.58 | 0.006 | 2.43 | 1.223 | 0.015 | **6.35** | **8.9** |

The values are chosen such that $X_L = x\%.Xc$ connected to a 13.8 kV system. Normally '*x*' takes the values ranging from 2- 14%.

The capacitive reactance $X_c = V^2/Q$ *(ohms)*, *V* is the system voltage rated at 13.8 kV and Q being the reactive power injected into the system which is 1.5 MVAR. Based on this, $X_c$ is found out to be 126.96 Ohms and with this value of $X_c$, $X_L$ value is found out for 7% and 10%. From this, inductance is calculated to be $L$= 23.5 mH for 7% and $L$= 33.694 mH for 10% respectively. To present the effect of detuning to bring down the THDi and IHDi of the feeder capacitor to a value within the limit a detuning is carried out. Figure 4.6 presents case when 2 PV's and 4 IM's are present (maximum penetration). Before detuning the THDi=10.227%, IHDi of 5$^{th}$ harmonic =4.298%.

Now the execution of detuning is done by adding an inductor in series with 1.5 MVAR capacitor. The value is chosen such that $X_L$=7%.$X_{C,}$ L=23.54mH. It could be seen from Figure 4.7 during the case of 2 PV's in DGBus2 and 4 IM's in DGBus3 that THDi value has been reduced to 2.54% and IHDi value of 5$^{th}$ harmonic has been reduced to 2.51%.

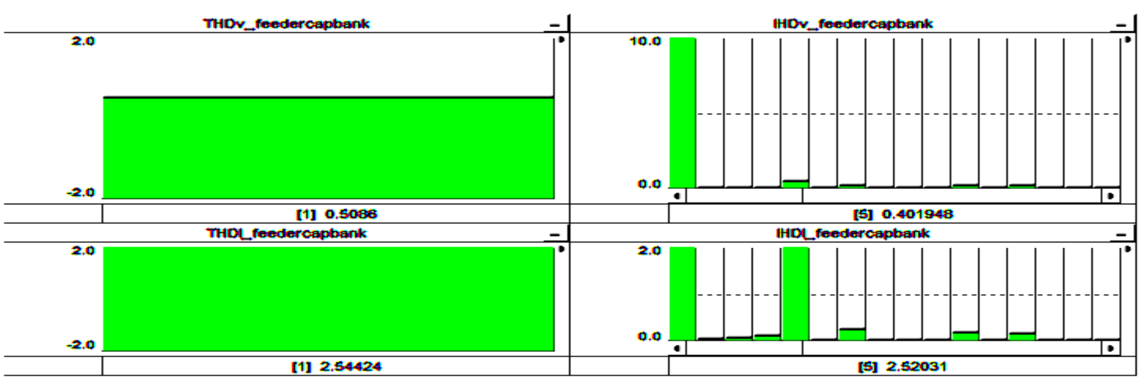



Figure 4.7 Maximum DG penetration case readings from polymeter - Harmonic distortion when DGbus3 has 2 PV's and DGbus2 has 4 IM's- with detuning $X_L$=7%*$X_{C,}$ L = 23.54mH

Similar procedure is carried out for the case of 2 PV in DGbus3 and 4 PV in DGbus2. Without detuning, THDi is 26.82% and IHDi of 5$^{th}$ harmonic is 6.37%, as shown in Figure 4.8.

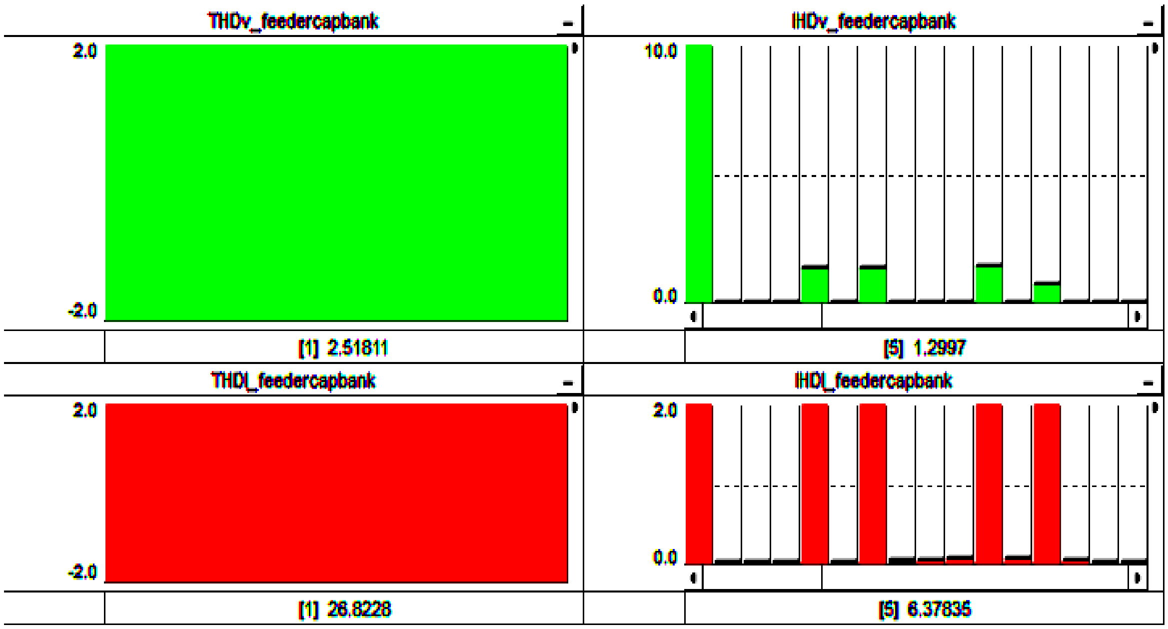



Figure 4.8 Maximum DG penetration Case readings from polymeter-Harmonic distortion when DGbus3 has 2 PV's and DGbus2 has 4 PV's-without detuning

Now the execution of detuning is done by adding an inductor in series with 1.5 MVAR capacitor. The value is chosen such that $X_L$=7%.$X_{C,}$ L=23.54mH. It could be seen from Figure 4.9 during the case of 2 PV's in DGBus2 and 4 PV's in DGBus3. It could be clearly observed that 7% detuning is not sufficient since THDi is 5.44%, IHDi of 5$^{th}$ harmonic=5.01%. So the violation could still be seen slightly.

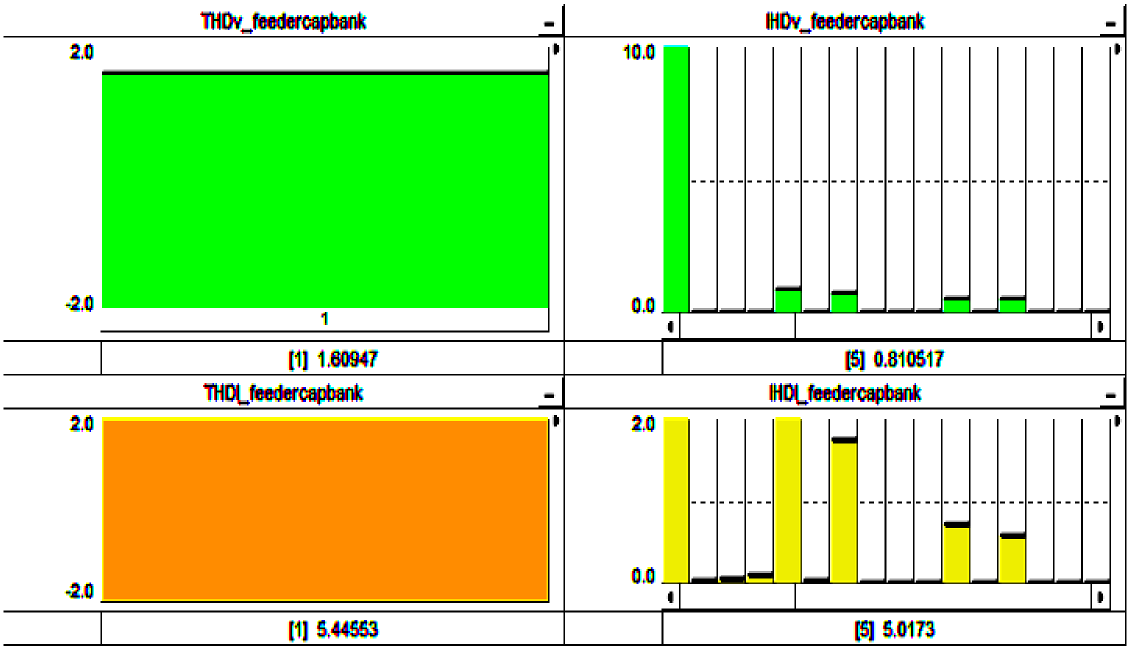



Figure 4.9 Maximum DG penetration Case readings from Polymeter-Harmonic distortion when DGbus3 has 2 PV's and DGbus2 has 4 PV's- with detuning $X_L = 7\%.X_C$, L =23.54mH

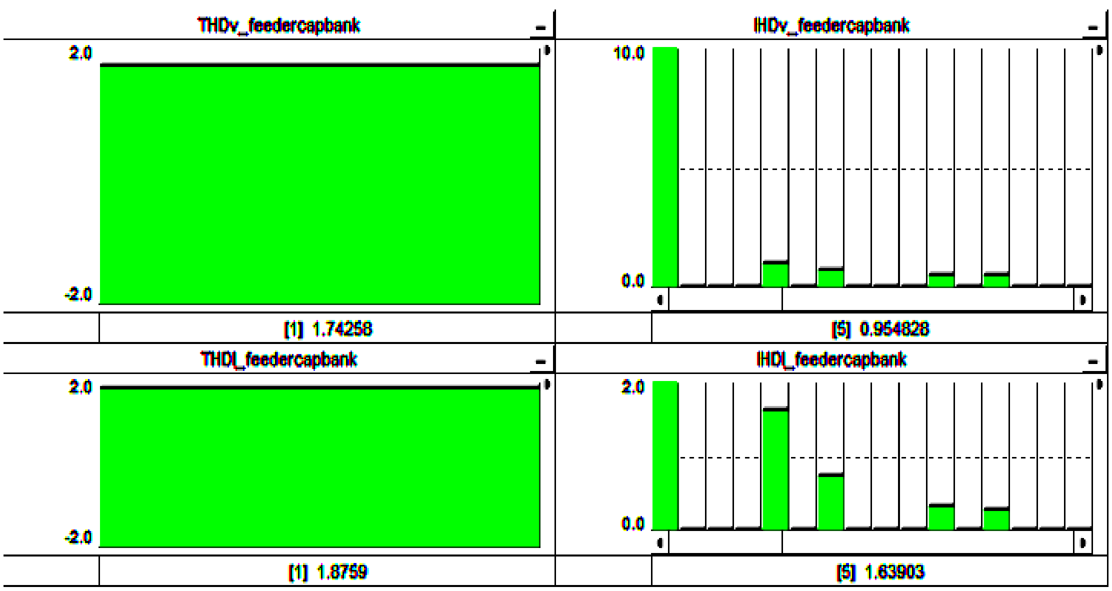



Figure 4.10 Maximum DG penetration Case readings from polymeter-Harmonic distortion when DGbus3 has 2 PV's and DGbus2 has 4 PV's- with detuning $X_L=14\%.X_C$, L = 47.17 mH

To further fix the problem, 14% detuning is carried out by adding 47.17 mH inductor in series. It could be clearly seen that THDi has been reduced to 1.87% and IHDi of $5^{th}$ harmonic to 1.63% as shown in Figure 4.10.

# CHAPTER FIVE
# COMPARATIVE IMPACT ASSESSMENT OF FILTER ELEMENTS ASSOCIATED WITH PWM AND HYSTERESIS CONTROLLED PV ON NETWORK HARMONIC RESONANCE IN DISTRIBUTION SYSTEMS

## 5.1 Overview

PV based distributed generators are inverter based and employ a switching scheme to inject power into the grid. The most common and commercially used technique involves the Pulse Width Modulation (PWM) controlled technique. Although PWM based technique is widely used, it is not affirmative to conclude that hysteresis controlled technique could be dismissed completely. A comparative evaluation and situational needs makes the way for current controlled hysteresis based technique for switching operation associated with PV Inverters.

Although literature suggests that a comparison of these techniques were done only from the perspective of general power electronics, none of the papers in the literature has projected the comparison of these techniques applied to grid connected PV Inverters and especially towards power quality. Although power quality phenomenon not necessarily describe about only about the harmonic injection, IEEE 519-1992 clearly states that the resonance phenomenon is also an important aspect of power quality towards harmonics injected by the PV Inverters into the system.

Considering this fact, a comparative study of PV Inverters using PWM and Hysteresis controlled strategy are employed, to witness the impact of the associated filter element on the AC side of PV Inverters on the network harmonic resonance modes in the system. For the first time, the research work in this chapter brings out a contribution by

addressing a comparative study done for the two control schemes and the impact of its filter element on resonant modes associated with the system.

## 5.2 Introduction

The utilization of Grid-Connected Inverters (GCI) has increased dramatically nowadays, especially PV. In order to ensure that a high quality of sinusoidal output is obtained at the output of the PV Inverter, the switching technique associated for controlling the Inverter output is crucial. Commercially, sinusoidal pulse width modulation technique is employed by several PV inverter manufacturers [65].

The gating pulses to the switches are constructed using a reference sinusoid and compared against a triangular or carrier signal. The switching frequency determines the output current harmonics as well. The higher switching frequency of SPWM technique may satisfy the requirements of IEEE 519 standards, while being subjected to suitable filtering. Normally the current harmonics appears around the frequency of switching and its integral multiples. But in case of hysteresis control, there is a higher probability of harmonics appearing and trying spread wide across the spectrum even at lower harmonics. Though hysteresis control is simple and elegant, there is a chance that its filter size may increase and hence the cost. But utilization of hysteresis control cannot be dismissed completely considering its simplicity in implementation with fast and accurate response. It can still prove to be an effective technique with proper implementation.

The grid that is already injected with harmonics by non-linear loads, it can also subjected to stress when PV Inverter is integrated into the system. It is a well -known fact that inverters also inject harmonics into the grid. A detailed survey on Global PV

Interconnection Standards presented clearly highlights that IEEE Std 929-2000 “IEEE Recommended Practice for Utility Interface of Photovoltaic Systems” ensures reliable operation of PV when connected to the electric utility systems.

Apart from that, IEEE Std 519-1992 limits the harmonic injection into the grid. It also clearly states that the harmonic injection also has a significant impact on the resonant modes. A caution needs to be exercised that the resonant peak corresponding to impedances of the entire system corresponding to different frequencies doesn’t align with $3^{rd}$, $5^{th}$ and $7^{th}$ harmonics. It should also be observed that these peaks doesn’t get closer to the fundamental frequency of the system. The harmonic injection depends upon the filter design associated with the PV Inverters. The filter design again depends upon the switching technique that has been adopted for injecting power into the grid, based on which the spectrum varies.

Though papers in literature have spoken about utilizing PWM and Hysteresis technique for PV Farms towards power quality, none of the papers and research work have compared the PV inverter’s performance utilizing both the switching techniques and its impact on network harmonic resonance. This would further serve as a reference for all researchers and industry personnel to further investigate the different configurations of filter associated with the PV Inverters based on the two techniques in future. Further it will serve as a crucial element in terms of power quality aspects associated with distribution systems planning.

### 5.3 PV Controller techniques

#### 5.3.1 Hysteresis control technique

There are several control techniques for a voltage source converter and the choice of switching technique is highly important especially with PV applications. In case of hysteresis control switching technique (also known as Bang Bang or Tolerance Band control), the current is controlled and kept well within the limits by means of restricting it within a tolerance band with respect to the reference considered. Whenever the current hits the lower limit while falling, a positive voltage is switched to increase the current. Whenever the current hits the upper limit while rising, a negative voltage is switched to decrease the current. The width of the window within which the current is allowed to stay determines the current ripple. This methodology ensures simplicity, high level of robustness and good accuracy. The major drawback associated with this technique is the variation of switching frequency within one load cycle, resulting in a higher switching frequency compared to other techniques. As a result, the average varies with operating conditions, resulting in a high level of stress on the switching devices leading to a difficult situation of designing a filter associated with the Inverter.

A small and a fixed band of +/- 0.5 A (3.24% of inverter output current) is chosen for faster switching action towards the implementation of three hysteresis control blocks. The output of the inverter does not change as long as the errors are within the specified tolerance band. The inverter switches are made to change their states when the error hits the upper or lower limit of the tolerance band that will facilitate the inverter output current to adjust in accordance to bring the error within the limits. Figure 5.1 presents the hysteresis

control logic. The corresponding blocks that are used to implement Hysteresis based controller for PV Inverter in PSCAD/EMTDC are shown in Figure 5.2.

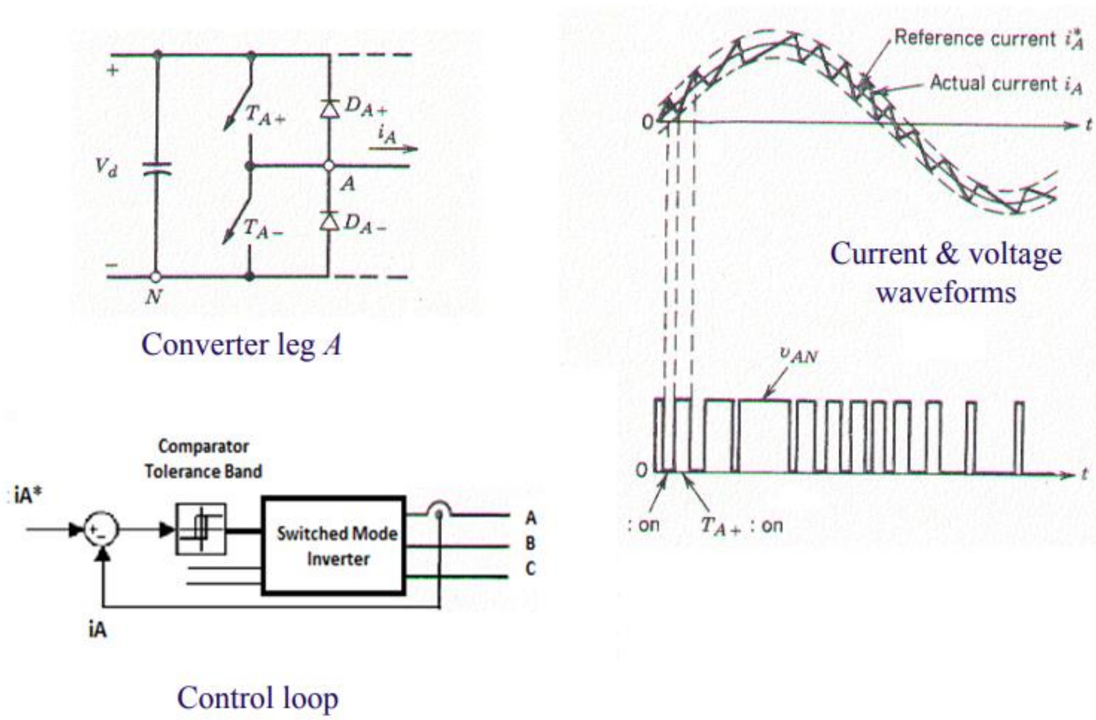



Figure 5.1 Hysteresis control logic [65]

5.3.2 Pulse Width Modulation (PWM)

In case of Pulse Width Modulation (PWM) technique, two control loops are employed. One is the current control loop and other one is the voltage control loop for the DC link voltage. The measured DC link voltage is filtered and then using a suitable voltage as a reference, it is compared with that. The obtained error is fed to a PI controller so that the steady-state error could be reduced. In order to extract the fundamental components, the load and inverter currents are transformed to the rotating *dq0* frame. There is a definite reason to realize the design in *dq0* frame.

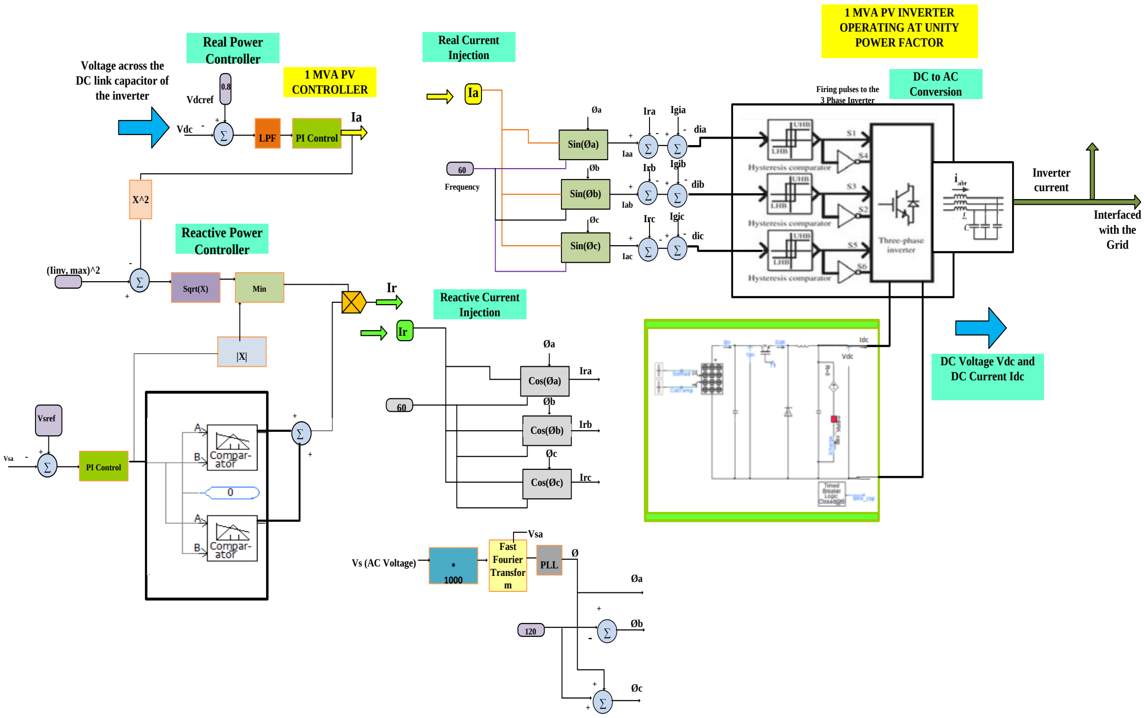



Figure 5.2 Hysteresis controller design in PSCAD/EMTDC for 1.0 MW PV Solar Inverter

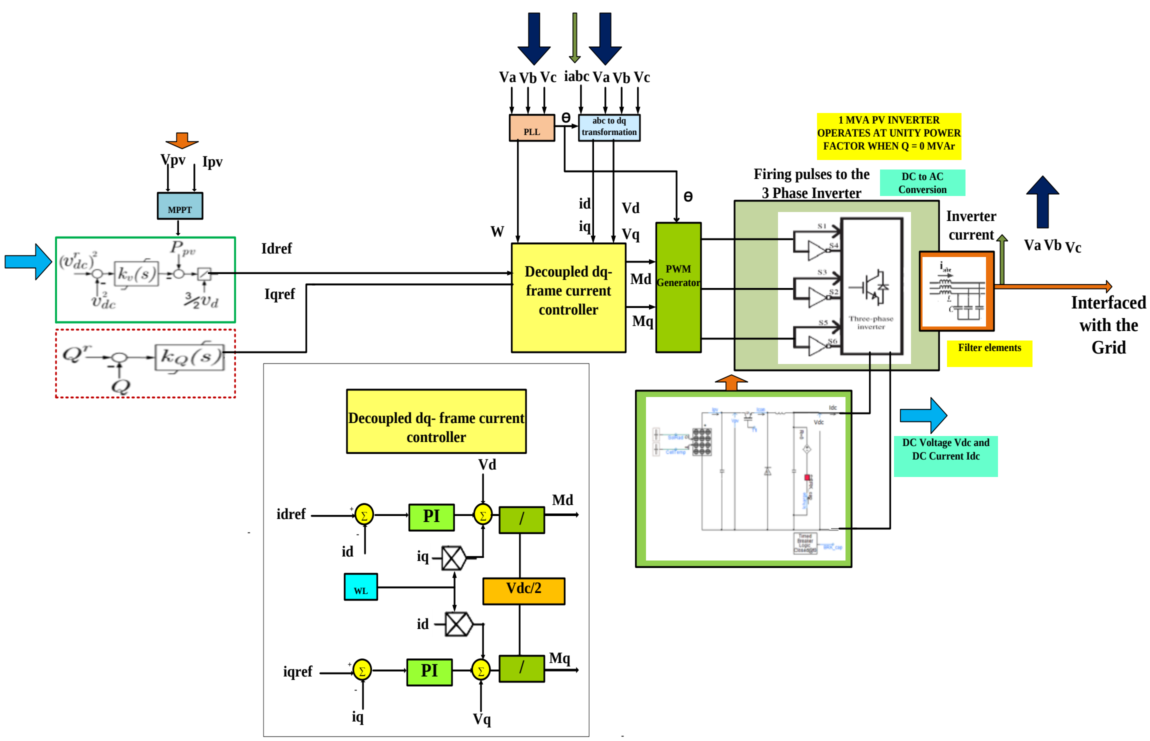



Figure 5.3 PWM based controller designed in PSCAD/EMTDC for 1.0 MW PV Solar Inverter

Considering the fact that the variables involved are sinusoidal functions of time, the optimization involved during compensation in a current-controlled VSC system becomes difficult. Apart from the rejection of disturbance, a large bandwidth is required for a closed-loop control system to ensure that the steady-state errors are infinitesimally small. When variable frequency applications are considered, the controller design is a little complex. By contrast, in *dq* frame the signals and variables are transformed to equivalent DC quantities.

Hence, irrespective of the operating frequency, conventional PI compensators can be utilized for the control. The *dq* frame representation of the two-level VSC can be developed as shown.

$$\mathrm{V_t(t)} = \frac{V_{DC}}{2}.\mathrm{m(t)} \tag{5.1}$$

$$m(t) = (m_d + jm_q).e^{j\theta(t)} \quad \text{and} \tag{5.2}$$

$$V_t(t) = (V_{td} + jV_{tq}).e^{j\theta(t)} \tag{5.3}$$

Substituting (3) and (2) in (1),

$$(V_{td} + jV_{tq}).e^{j\theta(t)} = \frac{V_{DC}}{2}.(m_d + jm_q).e^{j\theta(t)} \tag{5.4}$$

From 4, comparing the real and imaginary terms, we get

$$\mathrm{V_{td}(t)} = \frac{\mathrm{V_{DC}}}{2}.\mathrm{m_d}(t) \tag{5.5}$$

$$\mathrm{V_{tq}(t)} = \frac{\mathrm{V_{DC}}}{2}.\mathrm{m_q}(t) \tag{5.6}$$

Equations (5.5) and (5.6) clearly portray that the that the *d*- axis and *q*-axis components belonging to the AC side terminal voltage of the Voltage source converter are linearly proportional to the corresponding components of the modulating signals $m_d(t)$ and

$m_q(t)$, and the proportionality constant is $V_{DC}/2$. The real power associated with the PV Inverter is given by

$$P_t(t) = \frac{3}{2}\left[V_{td}(t).\,i_d(t) + V_t(t).\,i_q(t)\right] \tag{5.7}$$

From the principle of power balance, the DC input power to the PV Inverter should be equal to the AC power output of the PV Inverter. This could be written as

$$V_{DC}(t).\,I_{DC}(t) = \frac{3}{2}\left[V_{td}(t).\,i_d(t) + V_{tq}(t).\,i_q(t)\right] \tag{5.8}$$

Equations (5.5), (5.6) and (5.7) constitutes the control blocks for VSC in *dq* frame. The detailed controller block that has been used to implement in PSCAD/EMTDC is shown in Figure 5.3. It could be seen that the closed-loop control scheme regulates id and iq based on the reference values of *iqref* and *idref*, by controlling *Vtd (or Vsd) and Vtq (or Vsq).* This in turn (i.e., the output of the compensators) are multiplied by $V_{DC}/2$ for controlling the modulation index in the *dq* frame – *md(t) and mq(t).* These two modulation index are further converted to *ma, mb* and *mc* in the regular *abc* reference frame, thereby providing the gating pulse for the real power injection into the grid.

## 5.4 Comparison of LC filter design of PV inverter using Hysteresis and PWM technique

A 6 pulse two level VSI with IGBT switches are used to model the Inverter system that will facilitate the inversion process when interfaced with the PV module. The DC link capacitor on the DC side of the inverter provides a constant voltage during steady state of operation and during transient operation, it supplies fleeting real power by acting as a mini storage. The DC link voltage is provided from the previous stage, by the PV Module interfaced with this inverter.

The minimum DC link voltage should always be $V_{DC} \geq 1.633*V_{L\text{-}L}$, where $V_{DC}$ represents the dc link voltage and $V_{L\text{-}L}$ represents the line-line voltage. Similarly the DC link capacitor value is calculated as follows: $C_{DC} = \left[\frac{2\times P\times 16.7\times 10^{-3}}{V_{DC}^2\times(1-K^2)}\right]F$,

where $P$ represents the maximum real power that the capacitor can handle, and $K$ represents the ratio between the minimum DC link voltage to the maximum DC link voltage. $16.67*10^{-3}$ represents one cycle time at a power frequency of 60Hz. Harmonics are sinusoidal components of a periodic wave having a frequency that are at multiples of the fundamental.

The current distortion limits at PCC for 6 pulse converters as per IEEE STD 519-1992 are with a limitation of 3rd − 9 th < 4.0 % for odd harmonics, 11th − 15th < 2.0 %, 17th − 21st < 1.5 %, 23rd − 33rd < 0.6 % and above the 33rd < 0.3 %. The key requirements of clause 10 of IEEE Std 519-1992 for Total harmonic current distortion shall be less than 5% of the fundamental frequency current at rated inverter output are the key factors behind the design of LC filter.

The filter elements $L_f$ and $C_f$ for PWM based Inverter are designed based on the following considerations that:

a) The total harmonic distortion (THD) of voltage and current injected into the distribution network should be less than 5%.

b) The value of inductance is chosen such that the ripple of the output current is not more than 10 % to 15%. This is governed by the following equation.

$L_f = \frac{V_{DC}}{8\times\Delta i_{Lmax}\times f_s}$ , where $\Delta i_{Lmax}$ is maximum output ripple current. The value of capacitance should be chosen such that the reactive power consumed is not more than 5% of the rated active power. This is governed by the following equation,

$$C_f = \frac{x_f\times P_{rated}}{3\times2\times pi\times f_s\times V_{ph}\times V_{ph}}$$

where $Prated$ is the rated active power of the PV system, $Vph$ is the voltage across the filter capacitance, $x_f$ denotes the fraction of reactive power consumed by the capacitor. It should be well noted that the resonant frequency of LC filter should ranges between 10 times the line frequency to one half of the PV Inverter's switching frequency. Further damping resistors are chosen such that there is sufficient damping of the resonant peak at the resonant frequency. The lower limit of DC link voltage of VSC is chosen by considering the maximum voltage drop across the filter inductance when the PV inverter injecting its rated reactive power. This relation is governed by the following equation,

$V_{DC} \geq \sqrt{6}\omega I_{rated} L_f + \sqrt{2}\ V_{LL}$, where $Vd$c is minimum DC link voltage level of VSC, Irated (RMS) is the rated current of VSC, $V_{LL}$ (RMS) is line to line voltage at the output of the filter. It should be noted that when PV panel is connected to the input of VSC, $Vd$c becomes equal to $V_{pv}$, although the focus of this chapter is real power injection alone.

## 5.5 System description

The basic system configuration and parameters are extracted from the benchmark system of the IEEE Standard 399-1997 and with few modifications from [6] to demonstrate the purpose of network resonances. The same system is used for comparing the performance of both PWM and Hysteresis based PV inverters. The DGBus3 can take 2

MW PV, with two switching operations of 1 MW PV in sequence and DGBus2 can take 5 MW PV with 1 MW in each switching operation.

Table 5.1 Comparison between PWM and Hysteresis control for PV inverter

| **PV System Parameter** | **Hysteresis Control** | **PWM Control** |
| --- | --- | --- |
| **PV Rating** | 1 MW | 1 MW |
| Research study system | IEEE 399-1997 based | IEEE 399-1997 based |
| **PV Interface transformer**<br>Tr nominal power<br>Tr Voltage ratio<br>Tr leakage reactance | 1.5 MVA<br>Delta/Y<br>0.48 kV/13.2 kV<br>0.075 p.u | 1.5 MVA<br>Delta/Y<br>0.48 kV/13.2 kV<br>0.075 p.u |
| **PV Filter**<br>Filter Inductance, Lf | 0.5 mH | 0.5 mH |
| Filter Capacitance, Cf | 30 mF | 500 uF |
| **Switching frequency** | Variable | 6060 Hz |
| **DC-link Capacitance C** | 5000 µF | 5000 µF |
| **DC-link Inductance L** | 10µH | 10µH |
| **Controller Parameters** | | |

| | | |
|---|---|---|
| Kp<br>Ti | 2<br>0.03 | 2<br>0.01 |
| **Total Harmonic Distortion output of each 1 MW PV Inverter** (%) | **T**HD_V = 0.364%<br>IHD_V3 =0.00127%<br>IHD_V5=0.00077%<br>IHD_V7=0.104% | **T**HD_V=0.116%<br>IHD_V3=0.0017%<br>IHD_V5=0.0165%,<br>IHD_V7= 0.0232% |
| **Individual Harmonic Distortion** ($3^{rd}$, $5^{th}$ and $7^{th}$) | **T**HD_I= 2.662%<br>IHD_I3= 0.0649%<br>IHD_I5=2.60%<br>IHD_I7=0.532% | **T**HD_I=1.224%<br>IHD_I3=0.31078%<br>IHD_I5= 0.4577%<br>IHD_I7=0.3335% |
| **Resonance peaks 2 MW PV at DGBus2 and 5 MW PV at DGBus3** | 138 Hz and 828 Hz<br>(Figure 5.6) | 602 Hz and 1250 Hz<br>(Figure 5.8) |

In the first research study, all 1 MW PV's are based on Hysteresis control and in the second research study, all 1 MW PV are based on PWM control technique. The corresponding PV design with harmonic generation are shown in Table 5.1. The system scanning is done to observe the resonant peaks in the both the cases of the two controllers designed.

Figure 5.4 presents the distribution system designed using PSCAD/EMTDC. Figure 5.5 and Figure 5.7 presents the output generated by 1 MW PV by hysteresis control

and PWM control technique respectively, manifesting the stability and normal functionality of both the controllers.

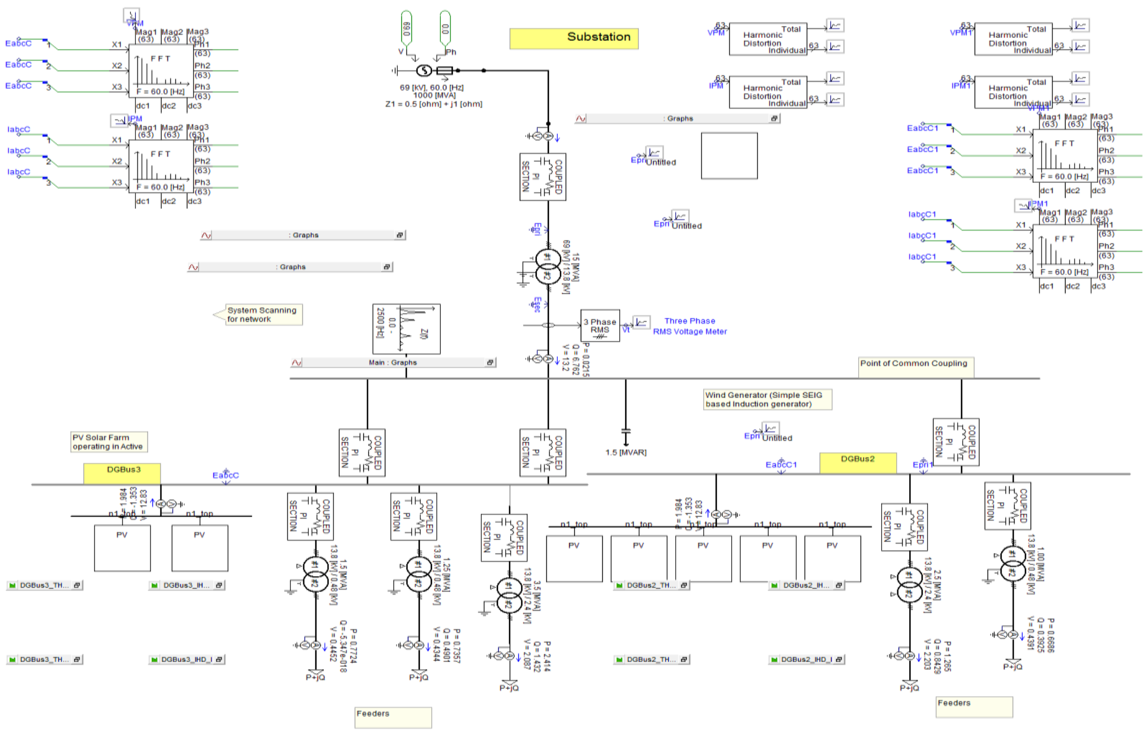



Figure 5.4 System designed using Distribution system based on parameters extracted from IEEE Standard 399-1997 [6].

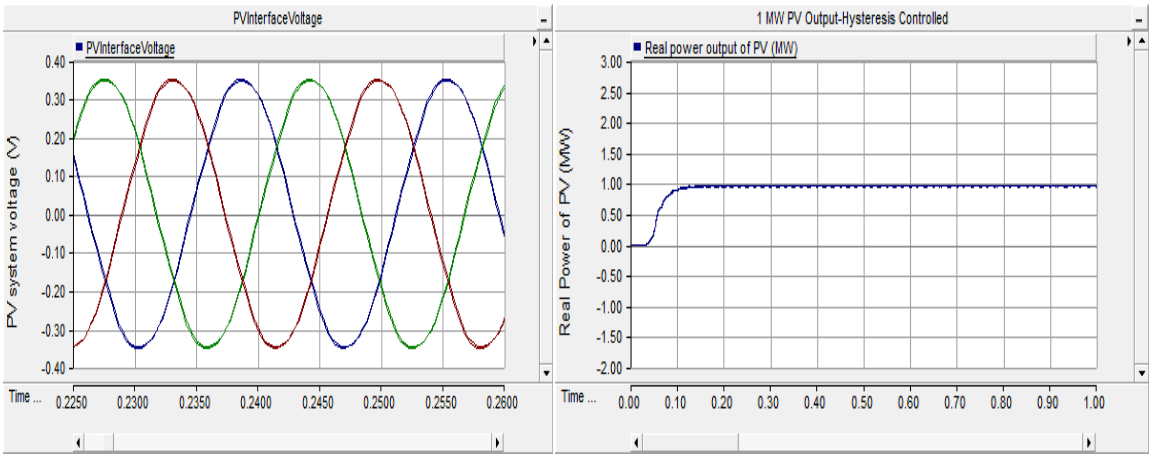



Figure 5.5 PV interface voltage of 480 $V_{L\text{-}Lrms}$ after filtering and 1 MW real power output of PV based on hysteresis control confirms its stability

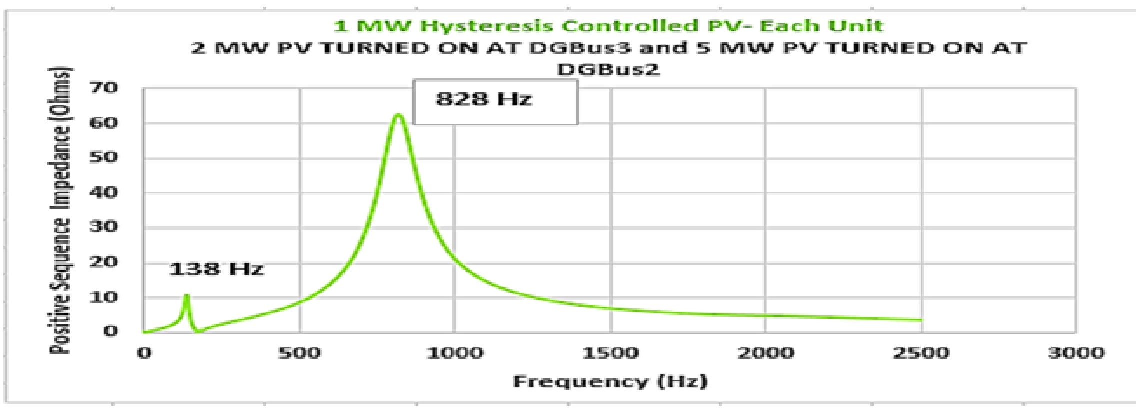



Figure 5.6 Resonant modes for the entire system when 2 MW PV is connected at DGBus3 and 5 MW is connected at DGBus2 using hysteresis based PV

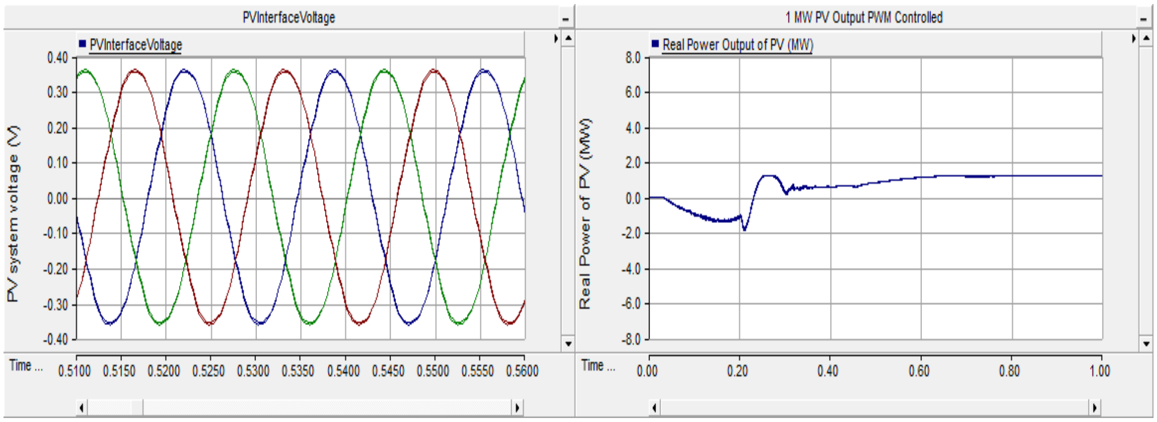



Figure 5.7 PV interface voltage of 480 $V_{L\text{-}Lrms}$ after filtering and 1 MW real power output of PV based on PWM control confirms its stability

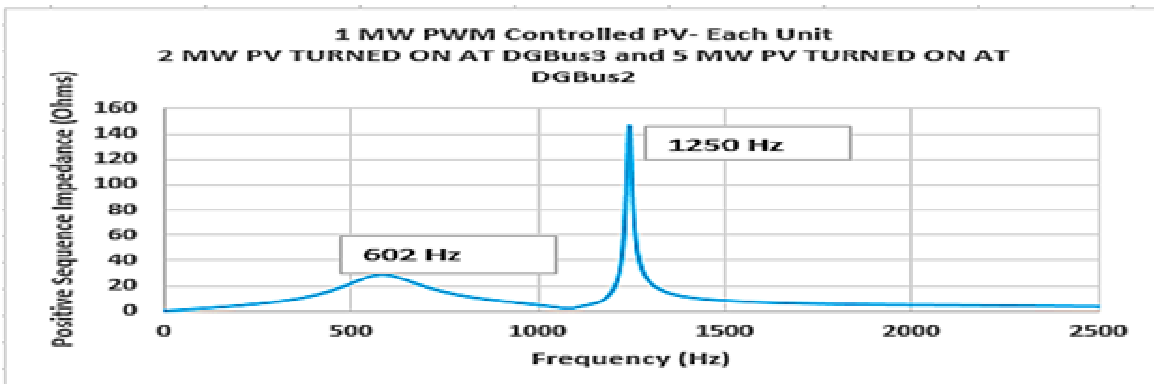



Figure 5.8 Resonant modes for the entire system when 2 MW PV is connected at DGBus3 and 5 MW is connected at DGBus2 using PWM based PV

## 5.6 Discussion

Table I presents the comparison of design between Hysteresis and PWM controlled PV. Hysteresis controlled PV employed a slightly heavier capacitive filter of 30 mF compared to 500 µF as in case of PWM. It was found that this had been the only value of filter when the PV system was providing a stable output. It could also be well witnessed from the resonant peaks from Figure 5.6 that Hysteresis control resonant peaks are getting closer to fundamental frequency compared to resonant peaks in PWM case from Figure 5.8

which are far away of the same rating of 1 MW. This research clearly establishes that filter design (L & C) determines the stability of the controller and also has a significant impact on resonant modes based on the switching technique employed. This further paves the way for investigating the impact of LCL filter design associated with smart PV Inverters that can act as a virtual de-tuner in eliminating network resonances in distribution systems.

# CHAPTER SIX
# DETUNING OF HARMONIC RESONANT MODES IN ACCORDANCE WITH IEEE 519 STANDARD IN AN EXEMPLARY NORTH AMERICAN SYSTEM WITH PV AND WIND

## 6.1 Overview

The increase in penetration levels of distributed generators like PV and Wind in a distribution system makes the IEEE 519 standard to be a vital aspect towards power quality. The network resonance has been described by IEEE 519 as a major contributor towards the harmonic distortion. Non-linear loads such as transformers, machines, silicon-controlled rectifiers (SCRs), solid state devices, power transistors, microprocessors and computers also contribute towards the injection of harmonics into a distribution system. The interaction between all kinds of elements of distribution systems and inverter based distributed generators like PV and Wind impacts the resonance modes to a definite extent. Based on the harmonic levels from the components in the system, the chapter brings out a contribution in the form of a detuning methodology applied to a practical system to eliminate the harmonics. This would further serve as a recommendation for all the utility personnel and researchers. An exemplary North American system has been considered for the study towards detuning process. The phenomenon of resonance and harmonic issues has been inspired from a real situation due to capacitor switching towards power factor correction associated with an induction motor operating as an industrial load. Normally detuning is done on the capacitor banks when non-linear loads are active contributors to harmonics. Nowadays with more renewable penetration, this chapter explores the observation during the interaction of renewables with the rest of the elements and an effective solution in the form of detuning to eliminate it is presented.

## 6.2 Introduction

The capacitor banks in a distribution system are installed as a supporting element towards power factor correction or voltage regulation. The injection of harmonics by such elements can be classified based on distortion levels in voltage and current. The total harmonic and individual harmonic distortion of current associated with the capacitive element is more compared to the voltage distortion.

Resonance phenomenon occurs when capacitive inductance of the system matches with the inductive reactance of the system [66]. Detuned filter reactors are employed in series with these capacitor bank units. Detuning is the process of neutralization based on the requirement. During the presence of high harmonic currents, the voltage waveform becomes distorted with the distorted voltage applied to the terminals of the capacitors. Due to this, the currents that flow through the capacitors can cause a permanent failure to the capacitor at an earlier stage itself by decreasing the lifetime.

An addition of a series reactor causes the impedance to rise with increasing frequency and reduces the harmonic currents through the capacitors. Apart from the non-linear loads, renewable energy resources like PV Inverters are capable of generating harmonics into system. Although manufacturers market their PV Inverter as a pure sine wave generating source, but in reality definite amount of harmonics is injected into the system.

Although the IEEE 519 Standard restricts PV and other renewable energy resources not to inject harmonics less than 5% THD, there are high chances that the percentage can

exceed more than this [67]. In such a situation, detuning becomes the need to enable more penetration of renewables like PV.

The following are the advantages of detuning:

- Harmonic amplification is reduced.
- The reduction in voltage and thermal stress on capacitor banks due to harmonics increase the life span of the component.
- Prevents the tripping of the circuit breakers and blowing of the fuses unwantedly that are employed in the protection system due to high harmonic currents.
- Reduction in the overheating of the elements of systems like the transformers, cables, switchgear, bus bars due to the amplification of harmonics.
- Reduces the impact of resonance phenomenon and prevents the alignment of resonant impedance peak on $3^{rd}$, $5^{th}$ and $7^{th}$ harmonics.
- Achievement of power factor improvement in a harmonic mitigated environment.

Considering the application towards practical distribution systems, there are limited papers that have emphasized a detuning strategy in the presence of renewables, although only the harmonic impacts of DG's with the system have been discussed. This chapter explores the application of detuning as a solution towards interaction of renewables with the rest of the elements to eliminate the harmonics in an exemplary North American distribution system.

## 6.3 System Description

### 6.3.1 Main Feeder

To demonstrate the strategy of detuning, an exemplary North American distribution system is considered. Certain details are modified and made as a practical mock system to maintain the confidentiality of the system information. The feeder is modeled rated at 23.9 KV with 100 MVA source. It is stepped down by a transformer rated at 20 MVA, 23.9 KV/13.2 KV. This 13.2 KV feeder line feeds another transformer that is rated at 3750 KVA, 13.2 KV/480 V. The 3750 KVA transformer is being utilized by an industrial load with an induction motor that is operational and has an approximate rating of 1 MW.

Considering the fact that motor loads run at a low power factor, a capacitor bank of 200 KVAR (fixed) and 950 KVAR (variable) are installed for power factor correction. In other words, their application has been specifically for the customer tests motors under no-load conditions to cancel out the reactive power requirements. During the motor testing that happens sporadically, it takes only 30 minutes and the rate schedule has KVA demand charge.

The 950 KVAR capacitor bank has one 50 KVAR step and nine 100 KVAR steps of switching operation. The 13.2 kV feeder also feeds a Wind Turbine Generator test facility rated at 7.5 MW, which is closer to the industrial load. The 950 KVAR capacitor bank has been tripping due to the appearance of overcurrent when the 7.5 MW WTG is operational leading to the harmonic injection in the system and the phenomenon of resonance. In this study the WTG and industrial load are considered to be at a nearby distance, so the distribution line parameters are not given importance in the study Apart

from that, a 1 MW PV farm is also considered closer to the location of WTG. Moreover, factors were considered to be ideal for providing a solution to the problem. Figure 6.1 presents the system design of the main feeder from PSCAD/EMTDC.

### 6.3.2 Capacitor bank and Induction motor

As already discussed briefly, the industrial load has two capacitor banks: 950 KVAR variable and a 200 KVAR fixed. They use the 950 KVAR capacitor bank for testing of induction motors to cancel out the reactive power requirements.

- Their rate schedule has a KVA demand charge.
- Motor testing happens sporadically and only takes about 30 minutes.
- The 950 KVAR capacitor bank has one 50 KVAR step and nine 100 KVAR steps.
- The 950 KVAR capacitor bank has been tripping on what appears to be overcurrent when the 7.5 MW test bench is operational.

The induction motor is designed to operate at 1 MW approximately, 480V for the study as seen from Figure 6.1. The capacitor bank sequential switching operation design is shown in Figure 6.2.

### 6.3.3 PV Farm

A 1 MW PV Farm is also considered along with WTG during the investigation on resonance modes to see if it has any impact on the considered North American system. Considering the fact that more PV Farms are getting installed in this part of U.S, this would

further serve as a reference if PV filter elements are a contributor towards resonance modes, when such a situation of WTG interaction with industrial load is happening.

The PV System and controller design are shown in Figure 6.3. The best choices of the proportional gain *Kp* and Integral time constant Ti for the current controller are chosen by studying the controller performance for different *Kp* and *Ti* values system using Ziegler Nichols tuning process. These values also ensured that the high level of stability is obtained in the controller design when integrated into the system. The detailed picture of the PV Inverter and controller design employed in the study is shown in Figure 6. 3 and Table 6.1 respectively.

### 6.3.4 Wind Turbine Generator

To emulate the functionality of 7.5 MW WTG under operation, the WTG is modeled as a harmonic current source injector of $5^{th}$, $7^{th}$, $11^{th}$, $13^{th}$ and $17^{th}$ harmonics as shown from Figure 6.4. For a 7.5 MW WTG, modeling is done based on a cluster of 6 WTG's, each operating at 1.25 MW, 480 V and a current rating of 1500 A. Based on this rating of current, the current source is modeled with a permissible percentage of harmonic injection limits times the current rating of WTG for each harmonic injection (multiplied by 6 for an overall rating of 7.5 MW) as shown in Table 6.2.

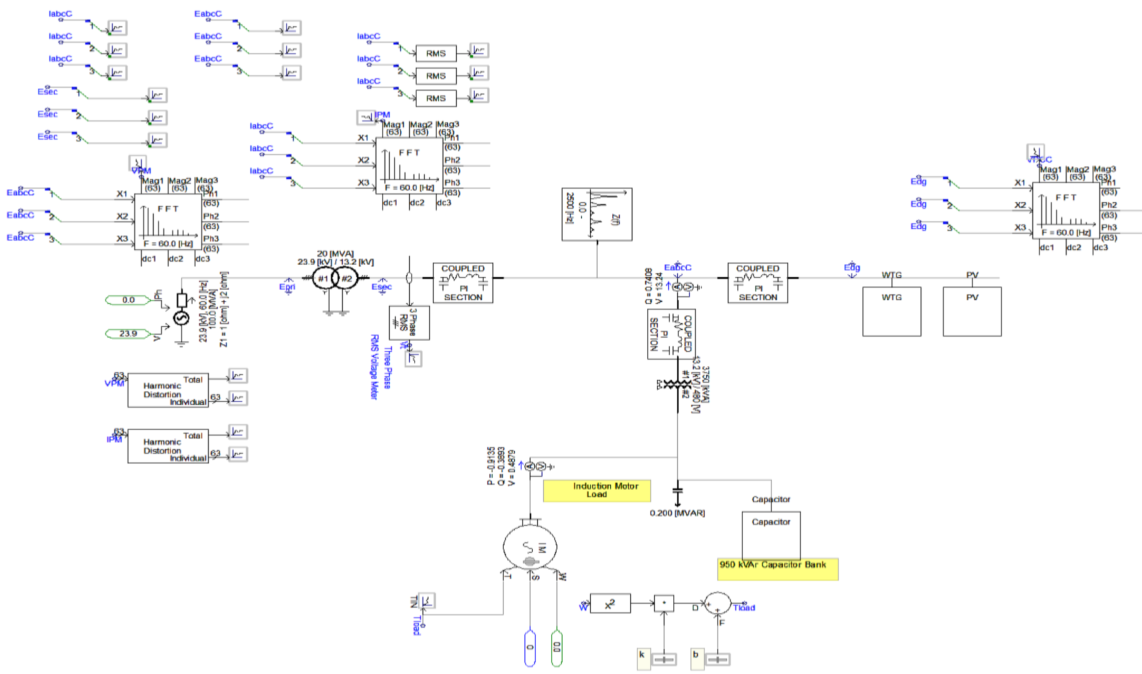


Figure 6.1 North American Distribution system designed in PSCAD/EMTDC for study

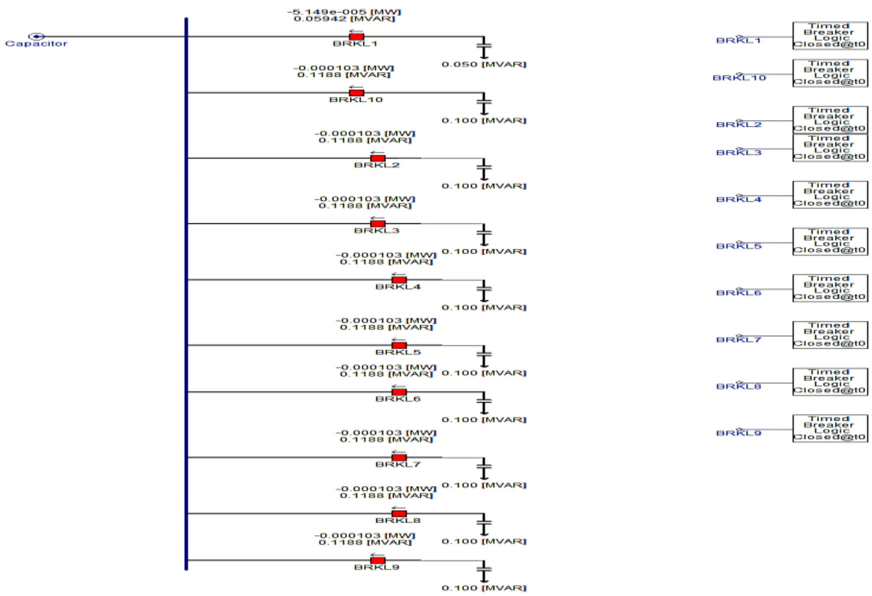


Figure 6.2 Switching of 950 KVAR Capacitor Bank inside the module from Figure 6.1 of main system

Table 6.1 Parameters associated with PV design

| **PV System Parameters** | **Value** | **Comments** |
|---|---|---|
| Filter – L Value | 1 mH | |
| Grid Voltage | 13.2 kV | |
| Tr nominal power | 1.5 MVA | Delta/Y |
| Tr Voltage ratio | 0.48 kV/13.2 kV | |
| Filter – C Value | 500 µF | |
| DC Link Capacitance | 5000 µF | |
| Switching Technique | - | PWM Switching based on *dq* control |
| Controller parameters<br>Kp<br>Ti | 10<br>0.05ms | |
| Output power of PV Inverter | 1 MW | |
| DC Link Inductance | 10 µH | |
| Switching Frequency | 6060 Hz | |

Table 6.2 IEEE STD 519 Harmonic limits for WTG

| Injection of Harmonics from WTG (%) | 5th | 7th | 11th | 13th | 17th |
|---|---|---|---|---|---|
| IEEE-519 limits (%) | 4 | | 2 | | 1.5 |
| Harmonic current magnitude assumed to be injected by 7.5 MW WTG in the study (%) | 1.8 | 0.42 | 0.12 | 0.12 | 0.12 |

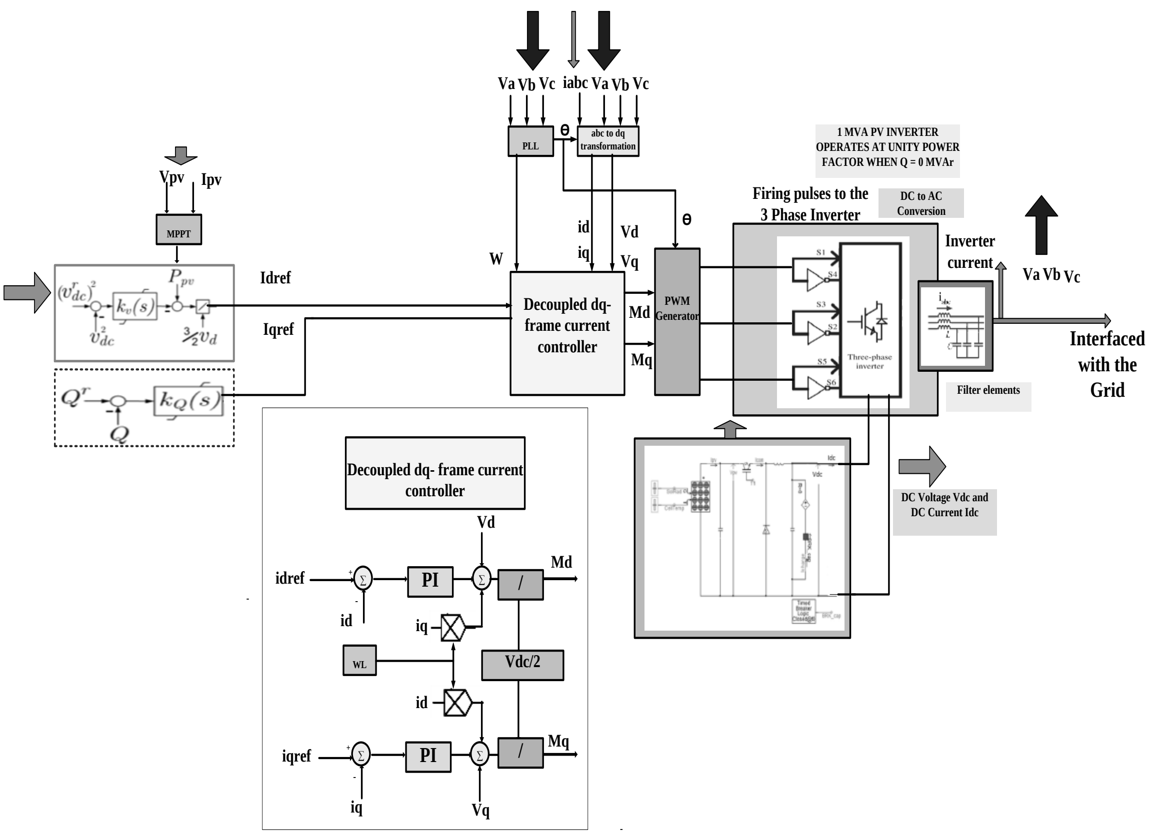



Figure 6.3 Block set of PV Design connected to the system and the PWM based dq control strategy

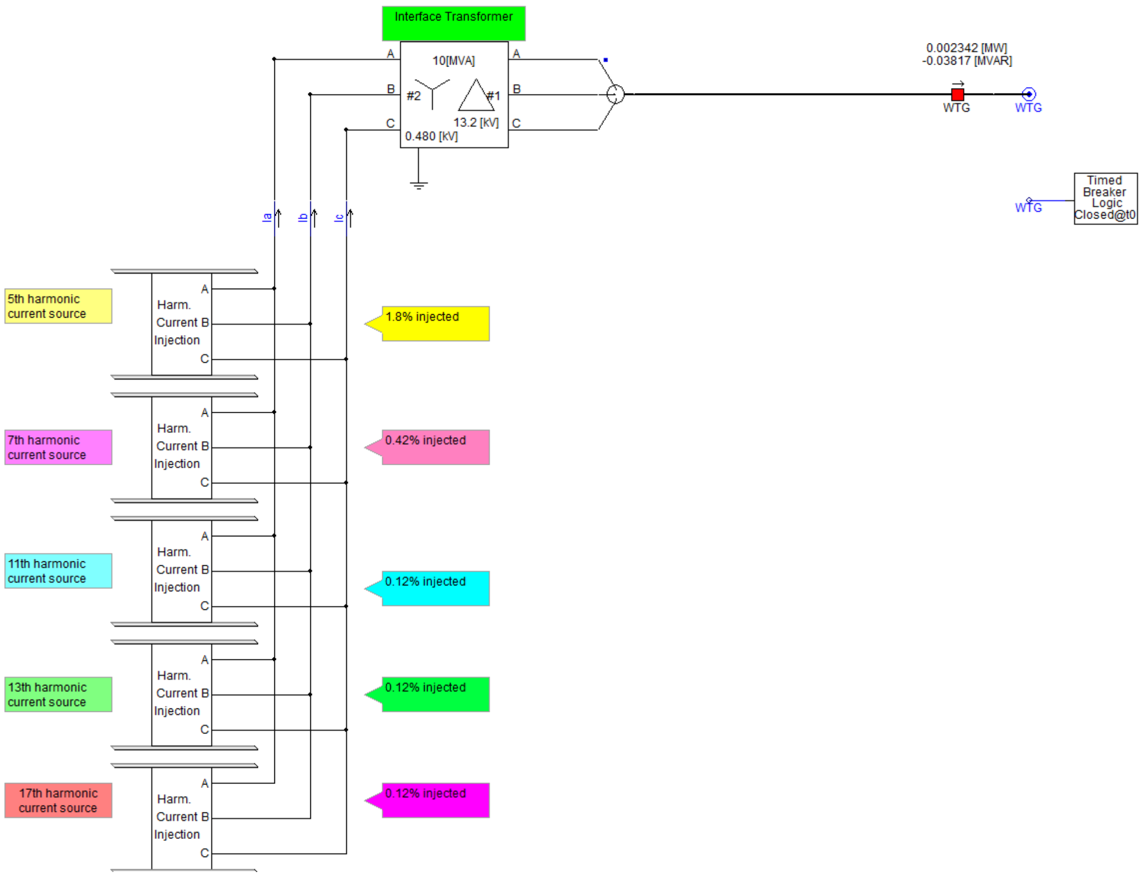



Figure 6.4 Harmonics Injection by 7.5 MW Wind Turbine Generator (WTG) modeled as a current source

## 6.4 Results and discussions before Detuning

### 6.4.1 Interaction of WTG with the induction motor

It can be seen from Figure 6.5 that, when the 7.5 MW WTG is operational during the no load testing of induction motor, the 950 KVAR capacitor towards the power factor correction of induction motor load interacts with the system, causing a violation in total

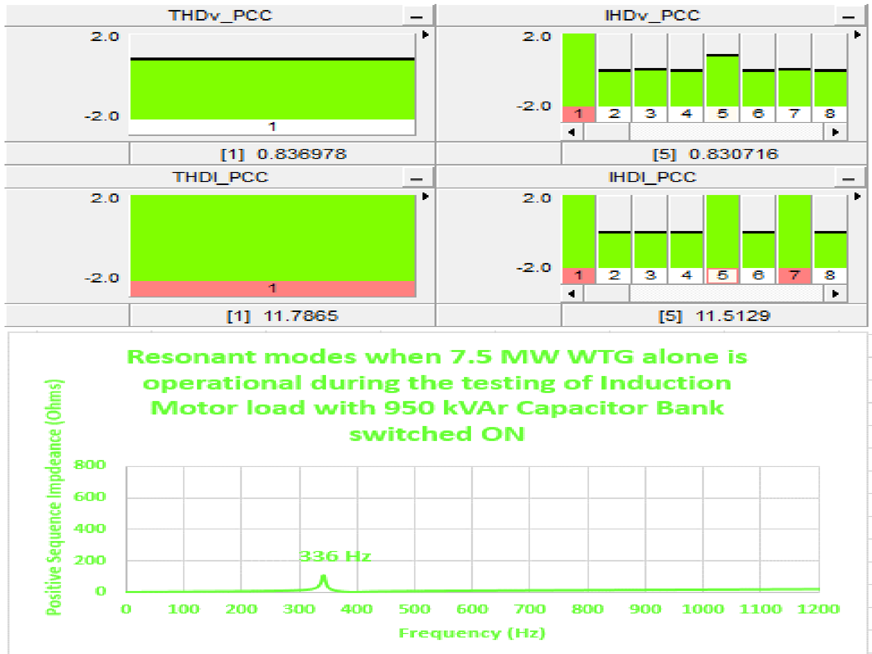



Figure 6.5 Harmonics (top) and resonant mode (bottom) generated in the system when 7.5 MW WTG interacts with the induction motor load and its capacitor bank switching towards power factor correction

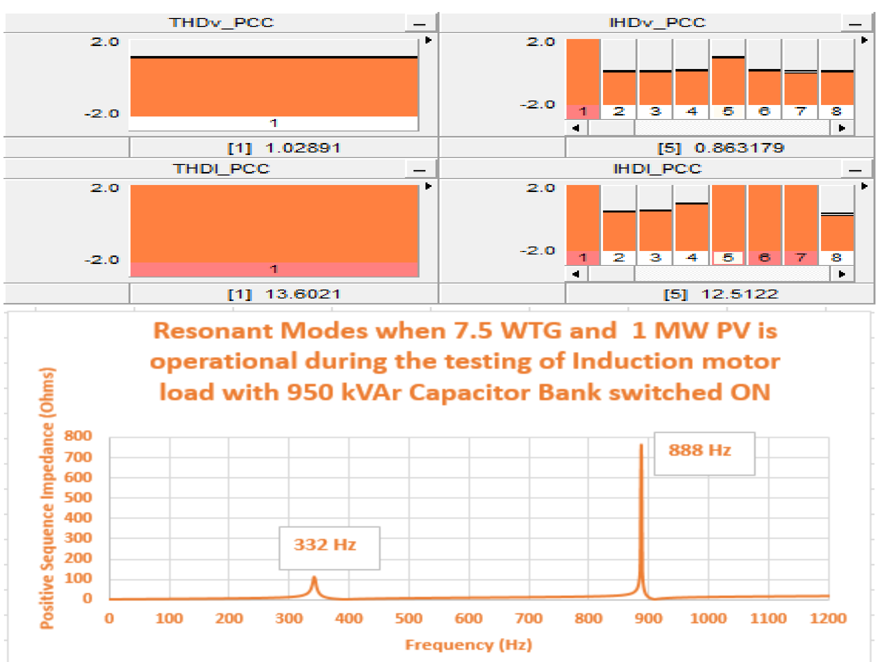



Figure 6. 6 Harmonics (top) and resonant modes (bottom) generated in the system when 7.5 MW WTG interacts with the induction motor load and its capacitor bank switching towards power factor correction and 1 MW PV is operational simultaneously

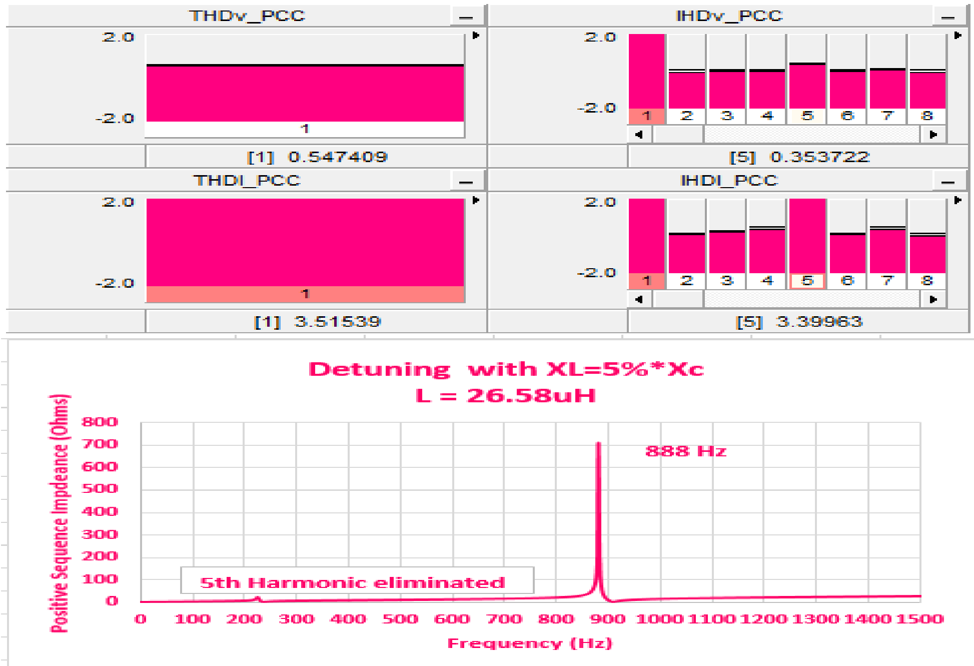



Figure 6.7 Harmonics (top) and resonant mode (bottom) when 5% detuning done in the system

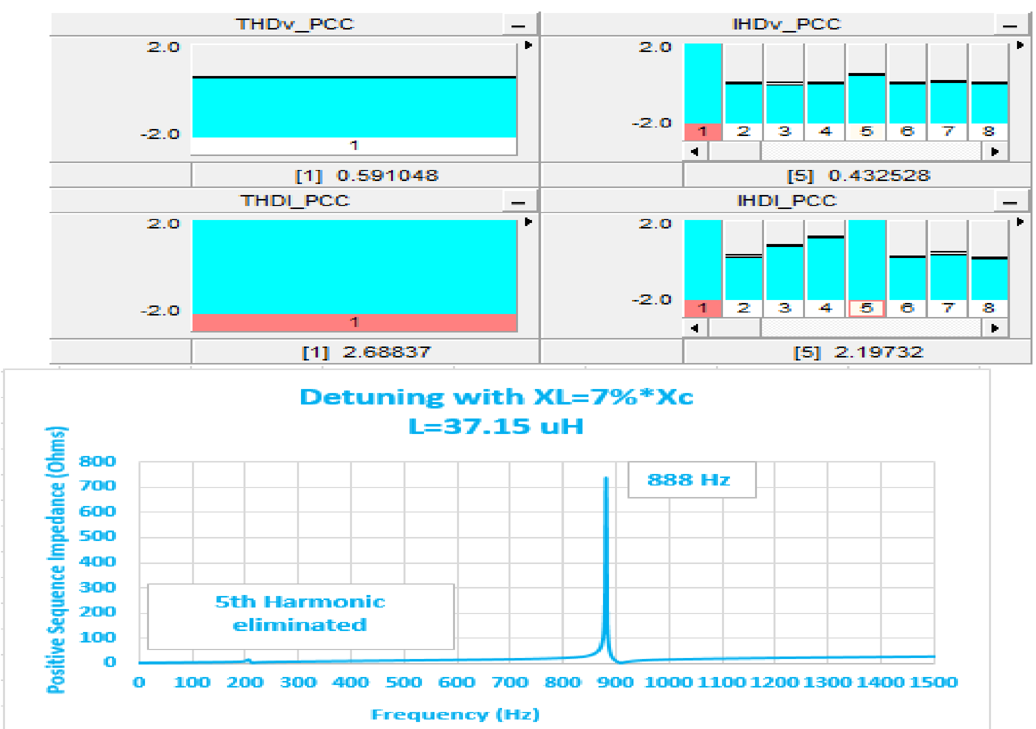



Figure 6.8 Harmonics (top) and resonant mode (bottom) when 7% detuning done in the system

harmonic distortion of current (THDi) at PCC and also individual harmonic distortion (IHDi) of current especially the 5$^{th}$ harmonic. This could also be seen from the resonance mode that is appearing closer to 336 Hz indicating the presence of 5$^{th}$ order harmonics. The THDi and IHDi values are 11.78% and 11.51% respectively.

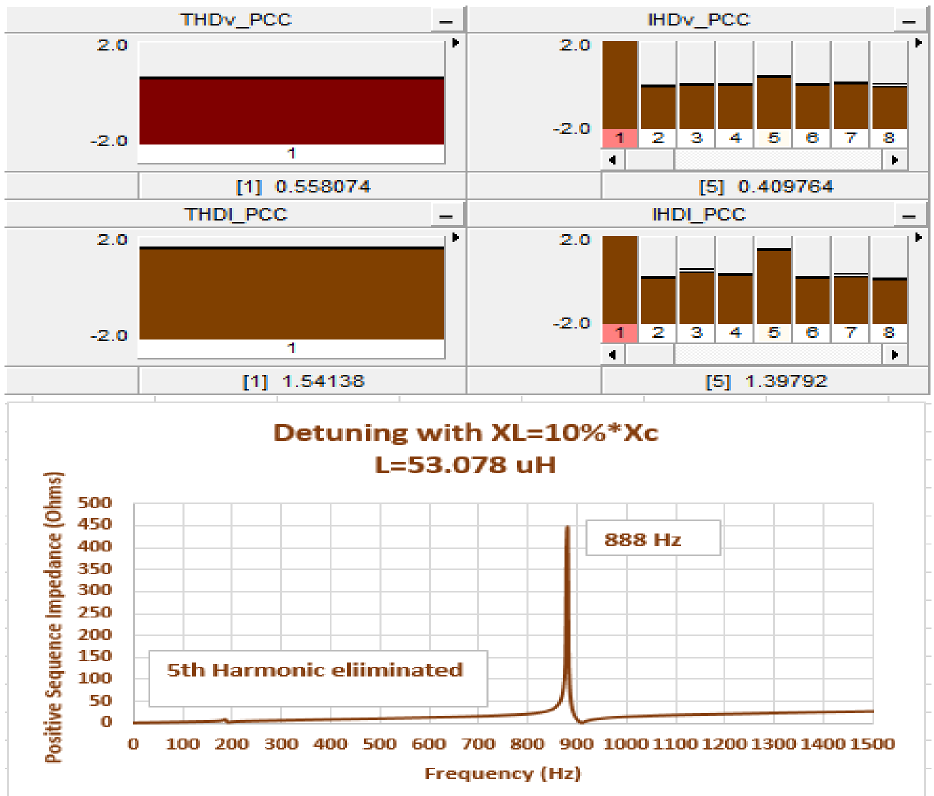



Figure 6.9 Harmonics (top) and resonant mode (bottom) when 10% detuning done in the system

### 6.4.2 PV integration into the system

When 1 MW PV is integrated into such a system, the THDi increases to 13.6% and IHDi of 5$^{th}$ continues to increase to 12.51%. Though the 5$^{th}$ harmonic resonant peak continues to stay closer to 332 Hz, a new peak appears at 888 Hz. This peak doesn't have

that much of significance but the 5th harmonic resonant mode is still existing as seen from Figure 6.6.

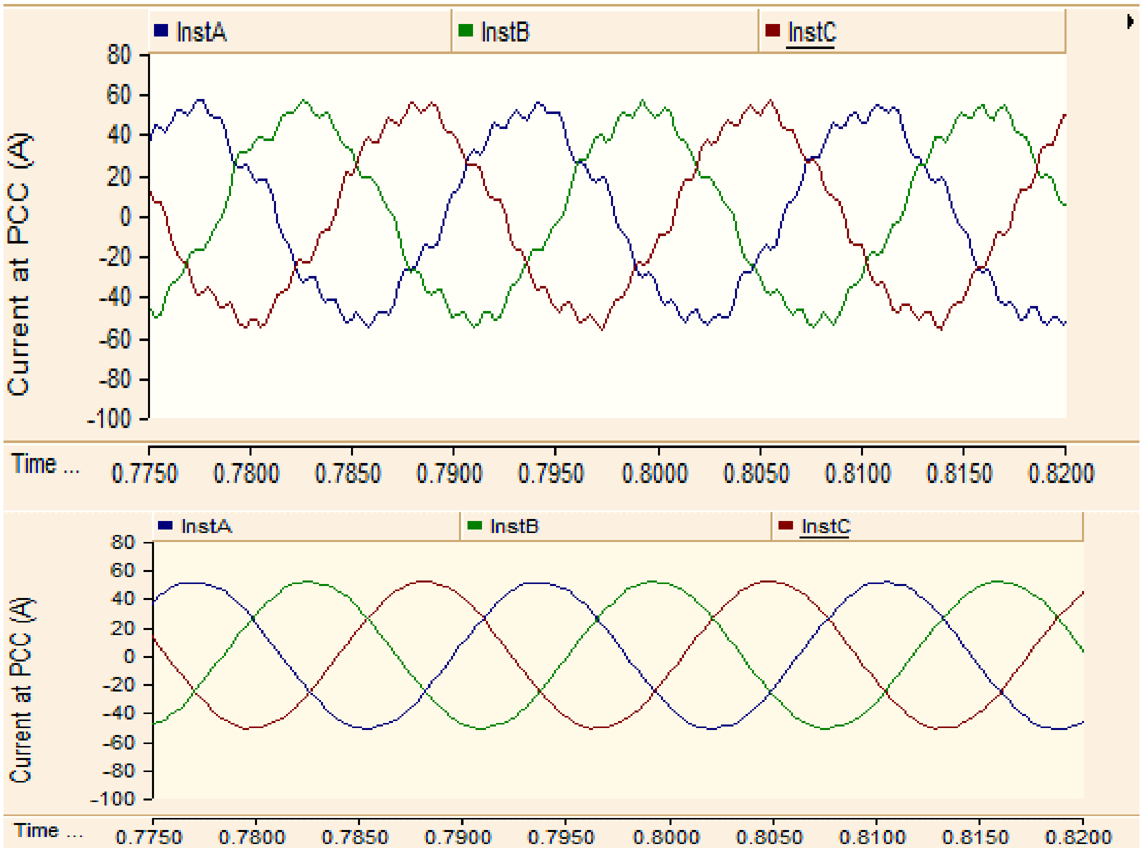



Figure 6.10 Three phase current at Point of Common Coupling without detuning (top) and with detuning (bottom)

## 6.5 After Detuning

Normally the detuning is done by adding an inductor in series with the capacitor bank. The typical values that are used for the detuning process, ranges between 5% to 10% and sometimes even upto 14%. In this chapter, the detuning is done for 5%, 7% and 10%. The violation gets eliminated for 5% detuning strategy. The results of 7% and 10% are also presented. It could be well witnessed from Figure 6.7, Figure 6.8 and Figure 6.9 that

the violation in harmonics has been removed with the specified values of distortion less than 5% according to IEEE 519 and also the resonant peak of the 5$^{th}$ harmonic being eliminated. The corresponding sinusoidal waveform of current at the point of common coupling before and after detuning are shown from Figure 6.10. It could be well witnessed that the waveform is distorted before detuning and after the detuning process, it becomes a pure sine wave, with the 5$^{th}$ order harmonic being eliminated.

# CHAPTER SEVEN

# EFFICACY OF A SMART PV INVERTER AS A VIRTUAL DETUNER FOR MITIGATING NETWORK HARMONIC RESONANCE IN DISTRIBUTION SYSTEMS

## 7.1 Overview

As the grid is becoming smarter, more challenges are encountered with the integration of PV plants in distribution systems. The real power generation varies based on the insolation from the sun. As a result, the fluctuations in voltages are seen as transient adversaries in the system causing the PV inverters to trip. Smart PV inverters nowadays are equipped with specialized controllers for exchanging reactive power with the grid based on the available capacity of the inverter, after the real power generation. With the ability of operation in VAR mode, Smart PV inverters could regulate the voltage based on Volt/VAR control, facilitate the power factor correction of the local loads and provide VAR support to ride through the voltage deviations during faults.

Although the research that are undergoing are pertaining to all the aforesaid applications of Smart PV inverters, none of the research-work in real time and in documentation have addressed the benefits of employing Smart PV inverters to mitigate network resonances. U.S based standard IEEE 519 for power quality describes the network resonance as a major contributor that has an impact on the harmonic levels. This chapter proposes a new idea for the first time in utilizing a Smart PV inverter to act as a virtual detuner in mitigating network resonance, based on the VAR mode control strategy with anti-windup and droop characteristics scheme that are incorporated with the design of Smart PV inverters. In addition to that, the contribution of the research also involves the

design of LCL filter associated with the smart PV inverters that has a direct impact on the stability of the controller. This idea would further serve as a pioneering approach for researchers and planning engineers working in distribution systems as the grid gets more and more smarter.

## 7.2 Nomenclature

| | |
|---|---|
| $V_{DC}$ | DC-side terminal voltage of PV Inverter. |
| $V_{PV}$ | Voltage at the output of PV array. |
| $Ipv$ | Current from the PV array. |
| $V_a, V_b, V_c$ | Voltage on the AC side of PV Inverter. |
| $\Theta$ | Angle generated by PLL/Voltage at the Point of Common Coupling (PCC) |
| $d$ | Subscript denoting d axis component. |
| $q$ | Subscript denoting q axis component. |
| $\omega$ | Angular speed of dq frame. |
| $\omega_0$ | Nominal Angular frequency of the grid. |
| $P$ | Real power injected into the grid. |
| $Q$ | Reactive power injected into the grid. |
| $L_f$ | Inductance of Filter connected on AC side of PV Inverter. |
| $C_f$ | Capacitance of filter connected on AC side of PV Inverter. |
| $M_d$ | Modulating signal in d axis frame. |
| $M_q$ | Modulating signal in q axis frame. |
| $m_a$, $m_b$, $m_c$ | Modulating index corresponding to 3 phases. |
| $V_d$, $V_q$ | Voltages generated in dq frame from abc. |

$I_d$ *and* $I_q$ Currents generated in dq frame from abc.

$I_{dref}$, $I_{qref}$ Reference value of currents in dq frame.

## 7.3 Introduction

The interconnection standards associated with PV includes IEEE 1547, IEC 61850 and UL 1741 to ensure safe and reliable interconnection of PV systems with the utility's distribution grid. A recent detailed survey on global PV interconnection standards presented the consolidated compilation that gives the complete picture of all the possible standards including that of smart PV inverter interconnection [68]. Nowadays, the word 'smart' associated with the grid has several definitions across the globe. In that aspect, this word has become a popular prefix associated with PV inverters, thus christening them as 'Smart PV inverters.' Starting from the basic functionality of PV Inverters, the Direct Current (DC) generated from PV Farms based on the insolation from sun, is converted to Alternating current (AC) thereby delivering electricity to the local grid.

The terminology called 'brownout' is the result of poor quality in the voltage levels, calls for the local tap changing transformers, capacitor banks to regulate the voltage levels to maintain the levels of +/-5% without any violations. Smart PV inverters are power electronic devices that are equipped with specialized functionality in the form of an additional piece of software that controls the actions of the inverter when interfaced with the grid.

The services provided by them are referred to as ancillary services. Earlier, the conventional PV Inverter injected only real power into the grid. With the introduction of IEEE 1547.8, PV inverters were entitled as Smart PV inverters that would permit them

to inject reactive power into the grid, apart from real power generation. Recently, a case study on utilizing Smart PV inverters and its impacts on distribution feeders in California, with increased penetration of PV has been studied [69]. California targets to achieve the goal by extracting half of the energy from renewable resources by 2030. California ISO highlighted the benefit of Smart PV inverters by its agility in providing voltage support to the grid, also considering the fact that absorption of reactive power could take place. In general, the exchange of reactive power between the Smart PV inverter and the grid gives itself a unique entity to play a prominent role in a smart grid environment [70].

In Fresno, PG&E will coordinate the adjustment of smart inverters from Enphase and SolarCity as part of utility's volt/VAR optimization (VVO) pilot, which is automating the control of grid assets like load tap changers, voltage regulators and capacitor banks to drive conservation voltage reduction (CVR) and improve system voltage hosting capacity [71]. The automated settings facilitates the exchange of reactive power. The pilot project involving about 50 homes will ensure PG&E that smart inverters can support voltage and reactive power management. California Rule 21 that governs the interconnection rules and procedures for PV Inverter systems, has already started the installations of the Smart PV inverter starting in 2017 [72]. NERC has identified the ancillary services as essential for expanded integration of renewable resources into the power grid, as stated by California ISO. A 300-MW First Solar photovoltaic plant demonstrated the efficacy of the ancillary services provided by renewable energy plants with smart inverter technology offered more superior services

compared to the conventional PV plants, during August 2016 [73]. California ISO, the U.S .Department of Energy's (DOE), National Renewable Energy Laboratory (NREL) identifies the three main areas of voltage, frequency and ramping capacity as the attributes for the performance of Smart PV inverters that were analyzed by First Solar. Infact, the reactive power control forms the crux of all the identified areas. The initiatives taken by California has been exemplary in terms PV projects [74]. Papers have presented about the Distributed Volt/VAR control by PV inverters [75].

The functional and safety testing with UL in compliance with UL 1741 SA (Supplement A) draft standard was completed by the SMA and it had been the first inverter manufacturer to do so. The functionality of such Smart PV Inverters included inverter functionality required for optimal grid stability.

To achieve that, SMA enhanced the smart-inverter capabilities of its popular Sunny Boy TL-US series of inverters with Secure Power Supply to help maintain voltage, frequency and general grid health. While the new grid support functionality is optional as defined in the UL 1741 SA, it will become mandatory for all new California interactive inverter installations 12 months after the publication of UL 1741 SA [76].

There are very papers in literature that have discussed about resonances in the presence of PV farms [77]. Although the interest in Smart PV inverters are gaining popularity as of today, none of the research work/papers and real time implementations have proposed the idea of VAR based control strategy of Smart PV inverter for mitigating network harmonic resonances in distribution systems.

The changing of a resonance point and making it to move far away from the

violations of harmonic spectrum is referred to as de-tuning of a system. The resonant impedance peak being a function of frequency is not supposed to align on top of the multiples of fundamental frequency, especially odd. Also considering the fact that the first peak in the impedance scan should be far away from the fundamental frequency. As the feeder system capacitors are turned on in a sequential fashion, the net impact of these power factor correction/voltage support capacitors interact with the entire system impedance that include the source impedances of the system, loads and different types of distributed generators like PV. This can tune the system to resonate at a particular frequency. This high impedance path becomes the source of harmonic voltage and harmonic load current. Though the feeder power factor correction capacitor interacts with different elements of the system like loads, DG's, cable/line parameters of the system, the harmful resonance conditions arises between the source and the feeder capacitor banks.

Adding a reactor to the system is the regular approach that is still being followed by utility during the de-tuning process. The effective strategy is implemented by adding a reactor in series/parallel with the capacitor such that $X_L$=5% to 14% of $X_C$, without tuning it to make it act like a filter. Another effective solution is by changing the location of the capacitor without any violation in +/-5% of the voltage limits in a distribution system [78]. This could achieved by moving the capacitor to a location of different short-circuit impedance.

Nowadays, the PV inverters are being referred to as smart inverters presenting their capability of injecting reactive power, when real power is not being generated. So, the

available capacity of PV inverter could be made to operate in VAR mode with a suitable control associated with that. This will become a futuristic effective solution to perform the voltage regulation like a capacitor or reduce the ratings of the installed capacitor banks and would serve to be an effective solution in de-tuning by moving the resonance point away far from the fundamental frequency. The authors have demonstrated the current methodology of detuning with renewables, in a practical system [79].

This chapter proposes a novel approach of utilizing a Smart PV inverter in the VAR mode to act as a detuner, in mitigating network resonance, based on a VAR mode control strategy with anti-wind up and droop characteristics designed for smart PV system. A detuning approach from a Smart inverter is being proposed for the first time in this paper. Smart PV inverters can act like a capacitor and perform the task of the feeder capacitor bank thereby mitigating network resonance. It would also be interesting to witness the design of Smart PV inverter in such a way that harmonics injected into the systems is less than 5%, compared to a capacitor bank that causes violation in total and individual harmonic distortion levels when supporting the feeder. Although inverters also have capability of injected harmonics into the system, the filter and controller associated with it, makes it a more effective as a Smart PV Inverter towards power quality. As a part of the contribution, the LCL filter design is mathematically presented with the new application towards detuning.

This chapter would further serve as a pioneering reference for researchers and engineers working in the utility. The proposed idea will also bring in cost benefits, if the roles of the capacitors were substituted by Smart PV inverters based on the feeder

requirements. The motive behind the proposed idea should not be misunderstood as replacing a capacitor bank by Smart PV inverter. However, it is to make the effective use of the idle PV farms that are installed (when real power is not generated) to act in a smarter way with specialized controllers, in mitigating the network harmonic resonance as a capacitor bank.

The popular and commercial PWM technique is adopted based on *dq* control concept. The major factor in designing this new Smart PV inverter are the filter elements $L_f$ and $C_f$. The filters can impact the resonance modes, inject harmonics and cause the controller to lose its stability when interconnected to a system. So, the controller design also serves to be an important contribution along with the idea/application proposed for the first time to mitigate network resonances with Smart PV systems. To demonstrate the proposed novel idea, the distribution system that is based on parameters extracted from IEEE Standard 399-1997 [80] with few modifications are considered and the novel approach is demonstrated and validated using PSCAD/EMTDC [81-82].

### 7.4 Existing VAR mode applications of Smart PV inverters

With the introduction of IEEE 1547.8 Standard, PV Inverter were permitted to operate at a non-unity power factor by providing an ancillary service as a VAR Compensator for the grid. VAR injection of a Smart PV Inverter associate its services towards the following modes of application. The availability of PV Inverters vary a lot in terms of range, local conditions and capabilities. Issuing an individual command to each PV inverter would involve a lot of information exchange through the communication systems. Managing reactive power generation on their own will be the most feasible way

of management, based on the available capacity of the PV Inverter after real power generation. With a single broadcast of command, large group of Inverters may be switched between the modes. Each mode consists of Volt/VAR pairs that define the linear relationship between the voltage and Q levels of generation. VAR ramp rate limit (%/second) is also part of each mode.

### 7.4.1 Volt-VAR Control

It is a well-known fact that the reactive power is a functionality of the system voltage. In distribution systems, the reactive power support is provided by the feeder capacitors at the Point of Common Coupling (PCC). Also, Load Tap Changers, On Load Tap Changing transformers (OLTC's) are used to alter the range of the voltage. With the introduction of Smart PV Inverters, the capacitors could be replaced by the effective functionality of the PV Inverter operating in VAR mode. The benefit of such an operation extended to investigate on network harmonic resonances is the major contribution towards research in this paper.

### 7.4.2 Low/High Voltage Ride Through

During an event of a fault, the PV Inverter is expected to disconnect from the system thereby stopping itself from injecting real power into the grid. Fault Ride-Through (FRT) is defined as the ability of a grid-tied inverter to stay connected to the power system and withstand momentary deviations of terminal voltage that vary significantly from the nominal voltage without disconnecting from the power system. Since the most likely cause for excessive voltage deviations in a power system is a fault in the system, the term "fault

ride-through" is sometimes used in case of a scenarios when reactive power support is required. The action that the inverter takes during each under voltage or overvoltage region is defined.

Mandatory Operation utilizes the inverter to output power into the system. Momentary Cessation commands that the inverter must stop producing power but be ready to produce power again if the voltage starts to normalize before the inverter is allowed to trip. Although there exists different classifications of voltage ride through (VRT) like Low-Voltage-Ride-Through (LVRT), Zero-Voltage-Ride-Through (ZVRT), and High-Voltage-Ride-Through (HVRT), it is often appropriate to lump LVRT and ZVRT together as just LVRT because they differ only in the magnitude of voltage drop. Standards IEEE 1547.8 and UL1741 mandates PV Inverter to stay connected by providing reactive power support to the system in order to ride through the violations in voltage limits to ensure the reliable operation of the grid.

### 7.4.3 Power Factor control

The voltage at the point of common coupling tends to increase as the real power is fed into the grid from an Inverter. This happens due to the output current flowing through the grid impedance. During a situation of peak hours on a sunny day, the PV Inverter generates more power compared to the power that is being utilized by the loads in distribution systems [83]. An export of power is mandated during such scenarios. During such a situation the voltage in the areas of high penetration of PV tends to increase resulting in the violation of voltage levels and cause the inverter to trip. Absorbing reactive power (operating in an inductive or under-excited state) helps to reduce voltage much the same as

inductive motor loads draw down voltage. If an area has low voltage, inverters can supply reactive power (operating in capacitive or overexcited state) to help raise it, similar to functionality of capacitor banks. PV inverters can control the reactive power in different ways. Setting a power factor, which is the ratio of real power (Watts) to apparent power (Volt-Amperes) forms a methodology to control VAR's. Inverters actually control the phase angle between the output current and grid voltage, creating reactive power whenever the waveforms do not align. The cosine of this phase angle is similar to displacement power factor which does not account for harmonics in the waveforms.

Industrial loads that are inductive in nature tend to operate at a low power factor. As a result, a penalty is incurred whenever the operating power factor is less than 0.85. Rule 21 requires the capability to go down to a power factor of 0.85 for systems greater than 15 kVA and 0.90 for systems 15 kVA or less. The actual setting may be determined during the interconnection process. When a PV inverter is installed closer to a load area, the effective utilization of its control methodology in the form of a Smart PV could be correct the power factor.

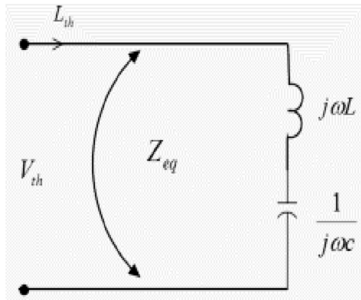
### 7.5 Network resonance phenomenon

IEEE 519 standard identifies the network resonance condition as a key factor that impacts the harmonic level [83]. Therefore, it is crucial to analyze such resonance conditions in power system. When capacitive reactance of a certain system at a particular frequency are exactly equal to inductive reactance of the system, parallel resonance condition occurs. Likewise, if reactance of capacitive element of another system under

consideration, exactly matches the reactance of inductive elements, the system exhibits series resonance at that frequency. Resonance phenomenon can be explained using a simple series and parallel circuits as shown in Figure 7.1. Since the current can be as high as infinity, series resonances results in overcurrent whereas, parallel resonance results in overvoltage. So analyzing the impact of L and C components in a system is really very important.

## 7.6 Controller Design of Smart PV inverters

The Smart PV inverter's (as a virtual detuner) external module that is built in PSCAD is shown in Figure 7.2. A Phase Locked Loop (PLL) produces an output signal that is synchronized in phase and frequency of the input signal. In order to ensure the proper synchronization of the Smart PV inverter with the grid, PLL plays a major role in tracking the voltage angle of the AC system at the PCC (point of common coupling). The Smart PV inverter controller is designed using a dq reference frame. PLL generates an angle, θ based on the input grid voltages. The PLL model given in the PSCAD library is used in the controller design. An *abc to dq* conversion is done to build the controller for Smart PV inverter [84-86].

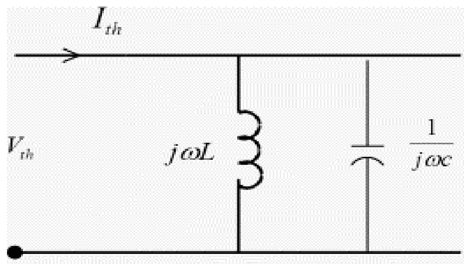



$$j\omega_o L + \frac{1}{j\omega_o c} \cong Z_{eq} \text{ at 60 Hz}$$

$$Z_{eq} = j\left(\omega_r L - \frac{1}{\omega_r c}\right) \cong 0 \text{ at resonance}$$

$$I = V_{th} / Z_{eq} = \infty$$

Series resonance causes overcurrent




$$Z_{eq} = \frac{j\omega L\left(\frac{1}{j\omega c}\right)}{j\omega L + \frac{1}{j\omega c}} = \frac{j\omega L}{1 - \omega^2 Lc}$$

$\boxed{\text{at resonance } 1 - \omega_r^2 Lc \approx 0}$

$$Lc \approx 0$$
$$Z_{eq} = \infty$$
$$V = I_{th} Z_{eq} = \infty$$

Parallel resonance causes overvoltage

Figure 7.1 Series and Parallel resonance phenomenon

Hence, it is modeled in rotating dq reference frame, where d and q represents the direct and quadrature axis components respectively. The abc to dq transformation enables the control system of a three-phase converter system to process DC signals rather than sinusoidal voltage and current signals, in a three-phase system. In a d-q frame the signals and variables are transformed to equivalent DC quantities, allowing the control system to be simple and easy to control. Figure 7.3 presents the PLL and *abc* to *dqo* conversion used towards the design.

A Pulse Width Modulation (PWM) generator uses PLL output θ to convert the modulating signals ($M_d$, $M_q$) in the dq reference frame to the $m_a$, $m_b$ and $m_c$. There modulating signals are compared with the triangular signal with a frequency of 3060 Hz as per the controller design, to generate the gating signals that are required for the turn on the switches of Voltage source converter. Commercial PV inverters employ sinusoidal PWM voltage modulation technique. This has been the main reason to choose this method to design the control required for research. Using Park's transform, the $V_d$ and $V_q$ are found out as shown below in (7.1), where θ represents the voltage angle at the Point of common coupling.

$$\begin{bmatrix} V_d \\ V_q \\ V_0 \end{bmatrix} = \sqrt{\frac{2}{3}} \begin{bmatrix} cos\theta & \cos\left(\theta - \frac{2\pi}{3}\right) & \cos\left(\theta + \frac{2\pi}{3}\right) \\ -sin\theta & -\sin\left(\theta - \frac{2\pi}{3}\right) & -\sin\left(\theta + \frac{2\pi}{3}\right) \\ \frac{\sqrt{2}}{2} & \frac{\sqrt{2}}{2} & \frac{\sqrt{2}}{2} \end{bmatrix} \begin{bmatrix} V_a \\ V_b \\ V_c \end{bmatrix} \tag{7.1}$$

If it is assumed that the three-phase quantities are symmetrical, then the zero sequence component becomes zero, and active and reactive power in the d-q reference frame is given by

$$P = \frac{3}{2}(V_d I_d + V_q I_q) \tag{7.2}$$

$$Q = \frac{3}{2}(V_q I_d - V_d I_q) \tag{7.3}$$

Since the synchronization scheme ensures that the d axis of the dq frame is aligned with the grid voltage reference phasor, that is $V_q = 0$, then P and Q can be controlled by $I_d$ and $I_q$ respectively. The major aim in this research is Q in particular.

Figure 7.4 and Figure 7.5 presents the external loop of the current control unit for the Smart PV controller. The current control unit forms the crux of the Smart PV Inverter controller. $I_d$ and $I_q$ being the direct axis and quadrature axis currents in the dq reference frame are being controlled by two independent control loops. It has two control loops that independently control the direct axis and quadrature axis components of the VSC currents $I_d$ and $I_q$ in the dq reference frame, to generate the direct axis and quadrature axis voltage components ($V_d$, $V_q$) of the VSC terminal voltage. In each control loop, the inverter output current signals, $I_d$ and $I_q$, are taken and fed back to the controller. Then the comparison is made to the reference values of $i_{dref}$ and $i_{qref}$ from the outer loops.

The objective of this research is to demonstrate the novel idea of utilizing Smart PV inverters as a virtual de-tuner in mitigating the network resonances. It should also be noted that the ultimate aim of the research is not to replace the capacitor banks entirely, but to demonstrate the efficacy of dormant PV inverters (when real power is not generated) to perform an operation of reactive power injection like a capacitor in mitigating the network resonances. In the conventional detuning process, an inductor whose reactance is rated between 5% -14% of the capacitive reactance of the main feeder capacitor, is added in series or parallel to mitigate network resonances. As a part of planning, the main feeder capacitor bank is also relocated at times to mitigate network resonances.

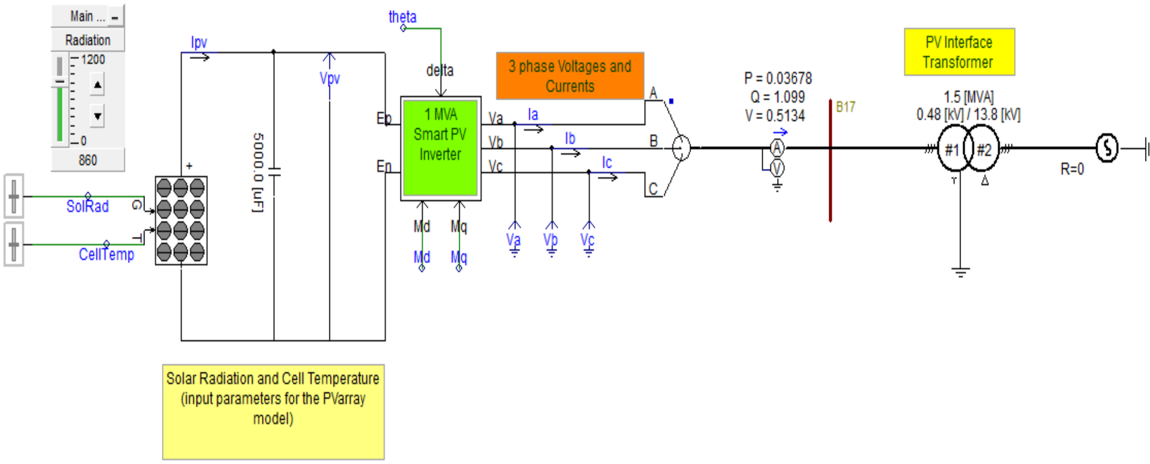



Figure 7.2 Smart PV inverter as a virtual detuner interfaced with a transformer before connecting to the main system

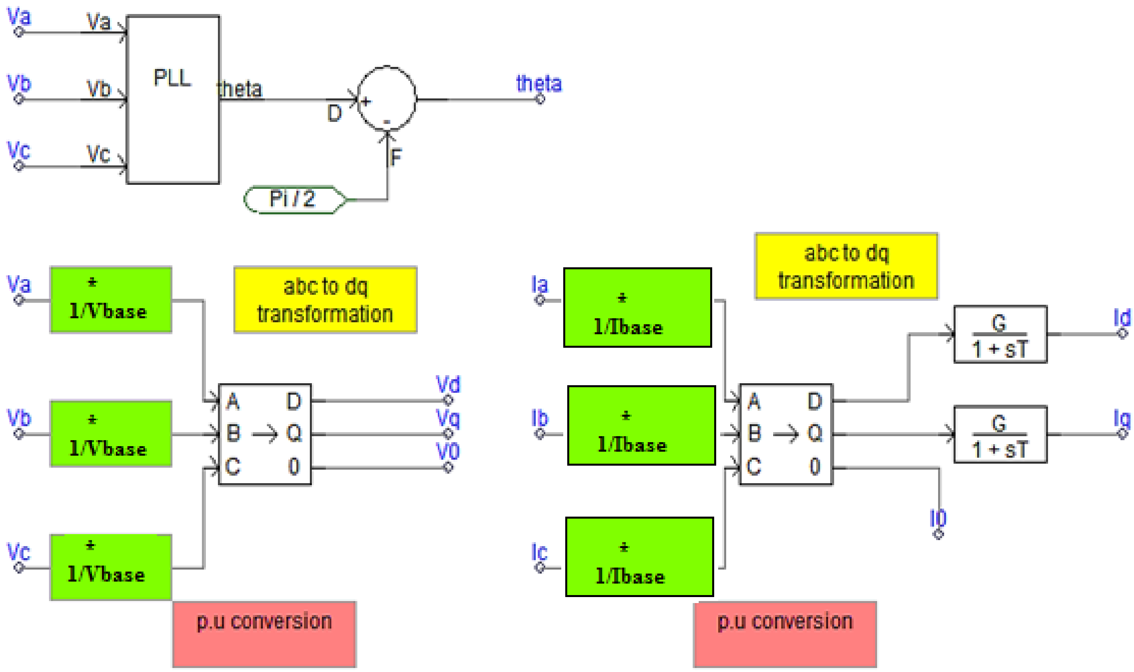



Figure 7.3 Blocks of PLL and abc to dqo conversion in PSCAD/EMTDC

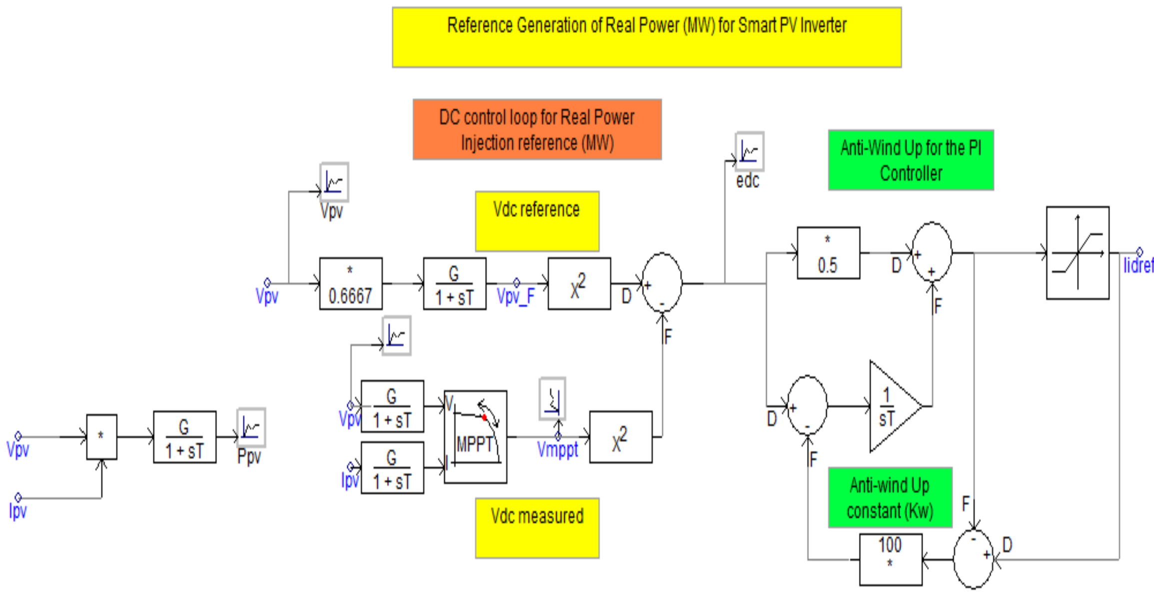



Figure 7.4 External loops of the current controller with anti-wind up feature for PI controller towards real power generation

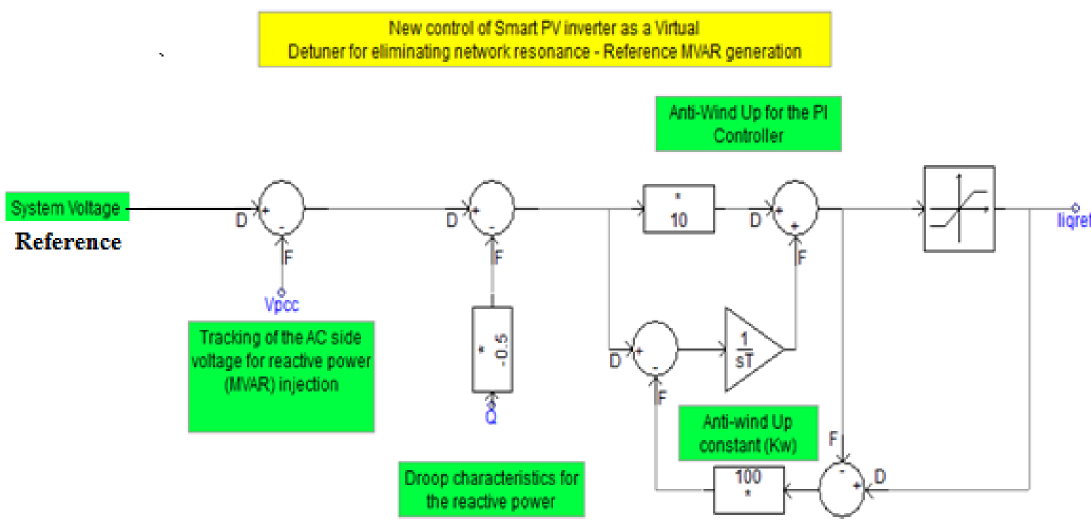



Figure 7.5 External loops of the current controller with anti-wind up feature for PI controller and droop characteristics towards reactive power generation

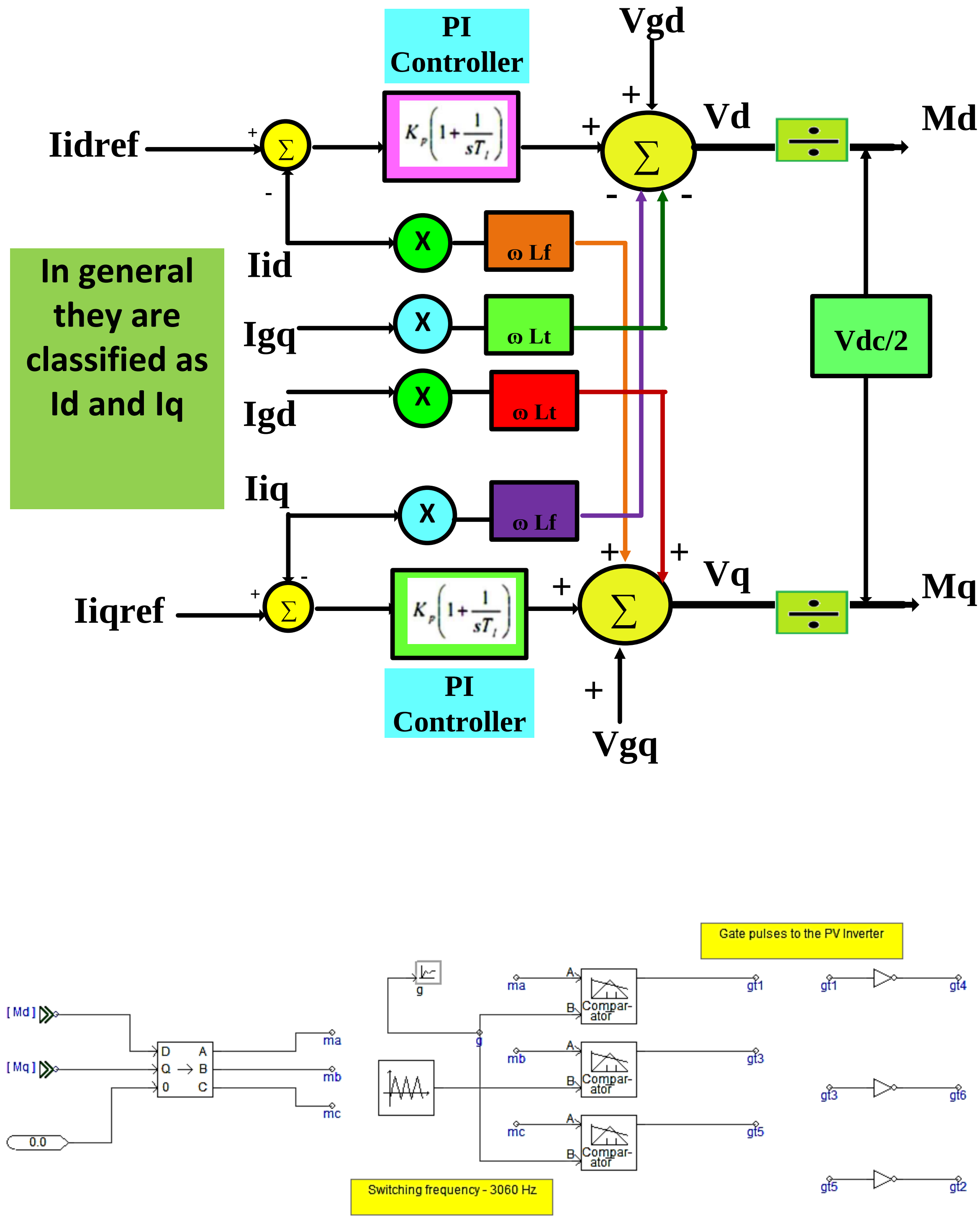



Figure 7.6 Decoupled current control loop and the gating pulse generation to the Smart PV inverter

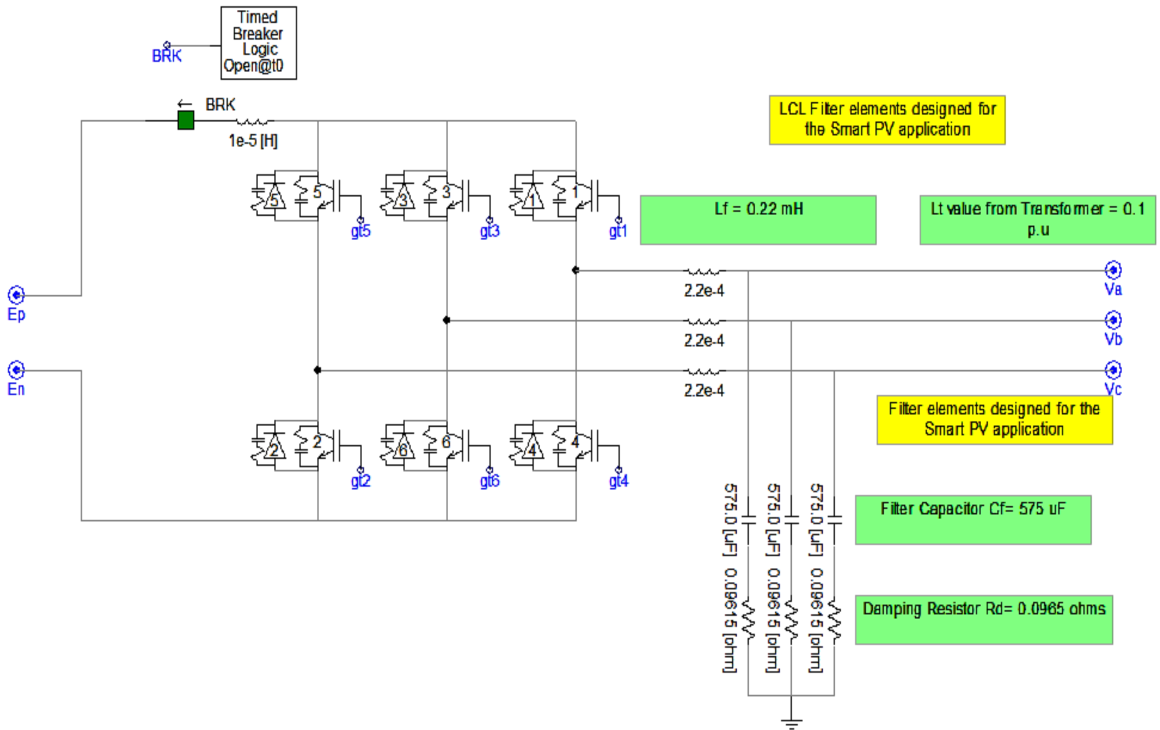



Figure 7.7 LCL filter designed for the Smart PV inverter

The novel idea in this chapter utilizes the dormant PV inverter's capacity to perform the voltage regulation and with the efficient design of filter elements, the impact from it with the entire system on network resonance gets virtually mitigated. As a part of the task from Smart PV inverter as a virtual de-tuner, the voltage regulation needs to be performed. For performing this, the controller for injecting VAR becomes a need of the hour. Although VAR based controllers are common with the advent of Smart PV inverter, the design of filter element is more important since it directly forms the basis of the controller's stability. To incorporate a further contribution to the controller, an anti-wind up scheme has been designed with the PI controller for better response and a droop characteristics associated with the measured reactive power injected from the Voltage source converter is fed back

as a part of the loop as seen from Figure 7.4 and Figure 7.5. The output takes a long time to go to steady-state. The reason is the "windup" of the integrator contained in the PID controller, which keeps integrating the tracking error even if the input is saturating. Anti-windup schemes avoid such a windup effect [87].

During the injection of VAR into the grid by the Smart PV inverter, the regulation is grid voltage is done since the reactive power depends on the voltage. A reference value of line to line rms voltage is compared with the measured AC voltage at the location where PV is interfaced. The error output of the compensator is responsible for the reactive power output in the controller scheme. Considering a discrepancy between the reference value and the natural grid voltage demands a need for large reactive power that needs to be injected and absorbed by the PV system, inclusion of droop mechanism in the controller always plays a very crucial role in the accuracy. The droop mechanism provides a closer to an accurate injection/absorption and as a supporting factor while the grid voltage is being regulated with the reference. So, the extent of voltage regulation will depend on the droop coefficient. This varies based on the design of the PV. Apart from that, droop mechanism is also in terms of multiple paralleled units, when reactive power sharing is happening.

The derivation of LCL passive filter model can be done based on the Kirchhoff's Laws in the stationary reference frame as follows. If $V_i$ is the inverter output voltage and Vg is the grid voltage, their relationship can be expressed as follows with the drop across the LCL under consideration. The output current of the PV inverter $I_i$ can be expressed as a sum of capacitor current $I_c$ and grid current $I_g$. In the voltage oriented reference frame, $\boldsymbol{I_{id}}$ is equal to the active current and $\boldsymbol{I_{iq}}$ is equal to the negative of the reactive power. The active

current is calculated from the control loop that controls DC-link voltage for the dc component. The reactive current is generated by the loop that controls AC output voltage for the q-component. Further equations could be expressed based on the filter elements $L_f$ and $L_t$.

$$I_i - I_c - I_g = 0 \tag{7.4}$$

$$V_i - V_c = L_f \frac{dIi}{dt} \tag{7.5}$$

$$V_c - V_g = L_t \frac{dI_g}{dt} \tag{7.6}$$

$$V_i - V_g + L_t \frac{dI_g}{dt} + L_f \frac{dIi}{dt} \tag{7.7}$$

The transformation of Eq. (7.7) to dq frame is as follows:

$$V_{id} = V_{gd} + L_t \frac{dI_{gd}}{dt} - \omega L_t I_{gq} + L_f \frac{dI_d}{dt} - \omega L_f I_{iq} \tag{7.8}$$

$$V_{iq} = V_{gq} + L_t \frac{dI_{gq}}{dt} + \omega L_t I_{gd} + L_f \frac{dI_q}{dt} + \omega L_f I_{id} \tag{7.9}$$

In the above Eqs. (7.8) & (7.9),

$V_{gd} = |V_{gd}|$ & $V_{gq} = 0$. But $V_{gq}$ is not eliminated from the equation for the purpose of derivation of controller equation. The drop across the LCL filter are treated as an output for the PI controller

$$L_t \frac{dI_{gd}}{dt} + L_f \frac{dI_{id}}{dt} = K_p \left(1 + \frac{1}{sT_1}\right)\left(I_{idref} - I_{id}\right) \tag{7.10}$$

$$L_t \frac{dI_{gq}}{dt} + L_f \frac{dI_{iq}}{dt} = K_p \left(1 + \frac{1}{sT_1}\right)\left(I_{iqref} - I_{iq}\right) \tag{7.11}$$

Substituting above Eqs. (7.10) & (7.11) in Eqs. (7.8) and (7.9)

$$V_{idref} = K_p \left(1 + \frac{1}{sT_1}\right)\left(I_{idref} - I_{id}\right) + V_{gd} - \omega L_t I_{gq} - \omega L_f I_{iq} \tag{7.12}$$

$$V_{iqref} = K_p\left(1+\frac{1}{sT_1}\right)\left(I_{iqref}-I_{iq}\right)+ V_{gq} + \omega L_t I_{gd} - \omega L_f I_{id} \tag{7.13}$$

It could be clearly seen from Figure 6 that the error signals are then fed to the PI controllers. These PI controllers with identical gains, generate output voltage signals in both direct and quadrature axes, which are added/subtracted with respective direct and quadrature axis components of the grid voltage ($V_d$, $V_q$) and coupling elements $\omega L_f$ $Ii_q$, $\omega L_f Ii_d$, $\omega L_t I_{gd}$ and $\omega L_t I_{gq}$ in order to generate inverter terminal voltages ($V_d$, $V_q$) respectively.

The d-axis and q-axis components of the VSC AC side terminal voltages $Vi_{dref}$ and $Vi_{qref}$ ($V_d$ and $V_q$ in general) are linearly proportional to the corresponding components of the modulating signals, with a proportionality constant of $\frac{V_{dc}}{2}$. These inverter terminal voltages are divided by $\frac{V_{dc}}{2}$ in order to generate modulating signals ($M_d$, $M_q$) in the dq reference frame.

$$M_d = \frac{V_d}{\left(\frac{V_{dc}}{2}\right)} \tag{7.14}$$

$$M_q = \frac{V_q}{\left(\frac{V_{dc}}{2}\right)} \tag{7.15}$$

Further the modulating signals in dq frame is converted back back to abc frame and the gating pulse for the smart PV inverter is provided at a switching frequency ($f_{sw}$) of 3060 Hz which is in accordance to the design of the filter parameters. Figure 7.6 present the decoupled current control loop and the gating pulse generation to the Smart PV inverter.

## 7.7 LCL Filter for Smart PV inverter-General design procedure

In a Voltage source inverter (VSI) that is interfaced with the PV farm, the conversion of DC power from PV to AC power causes the harmonics to become more evident due to the switching frequency. As a result, this can become problematic to the associated equipment whose voltage and current levels could be altered beyond the rated value. A suitable filtering becomes the need of the hour on the AC side of PV inverter when the conversion of DC to AC is taking place. When the PV inverter acts as a Smart PV inverter, the design considerations should be carried out perfectly, considering the fact that filter elements designed are the tradeoff between the harmonic injection and the controller's operating range.

The most common filters that are associated with the PV inverters are LC and LCL filters. LC filter is a second order filter whereas LCL filter is a third order filter. LCL filter has better performance compared to LC filter except for the fact that the number of poles and zeros are more with the LCL filter [88-91]. This fact makes the design and controller of the inverter a little complex. The designing aspect of LCL filter associated with the Smart PV inverter is highly important, considering the fact that Smart PV inverter is acting as a virtual de-tuner and shouldn't be a contributor to network resonances. Considering the phenomenon of resonance, a damping resistor is associated with the filter capacitor in series for an efficient design.

In Figure 7.8, Ri represents the internal resistance of the total switching transistors of the PV inverter during ON-state and the internal resistance of the filter inductor $L_f$. $C_f$ presents the filter capacitor for the LCL filter that is connected in series with a damping

resistor $R_d$. $L_t$ represents the inductance of the transformer that interfaces the PV system with the grid [92-93].

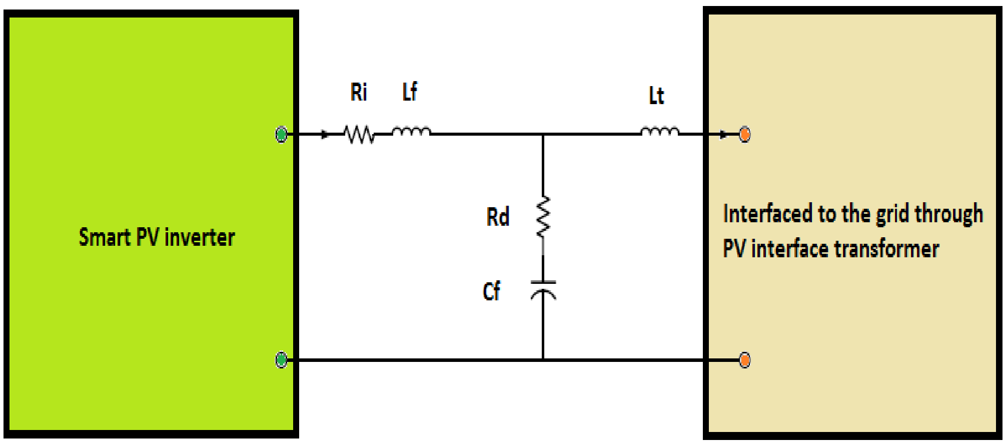



Figure 7.8 Configuration of LCL filter design

The filter parameters are designed based on the several factors such as the harmonics of the output current, the resonant frequency of the LCL filter, voltage drop of the filter inductance and reactive power provided by the filter capacitor. The filter inductance is chosen between the ranges of 0.1 to 0.25 p.u to limit the current ripple. The voltage drop across the inductor is an important aspect in the design and exceeding a value of 0.3 p.u demands for higher value of DC link voltage during the conversion stage from DC to AC.

The PV inverter is also influenced by the amount of the reactive power it generated by the filter capacitor. So, the reactive power exchange is kept below 0.05 p.u of the inverter rated power. This is part and parcel of the design consideration involve with filter

capacitor $C_f$. Considering the fact that the novel idea of this design is to utilize the PV inverter as a virtual de-tuner, the resonance phenomenon should be minimized. The resonance phenomenon between the interaction of $L_f$, $C_f$ and $L_t$ components (LCL filter) are mitigated by utilizing a damping resistor Rd, that is incorporated into the design with series placement along with the filter capacitor $C_f$.. The design implementation is as follows [94].

*a)* The first step is to obtain the inductance of the filter $L_f$,

$$L_f = \left(V_{dc} - V_{grid,peak}\right) \times \frac{D}{2 \times i_{ripple} \times f_{sw}} \tag{7.16}$$

where $V_{dc}$ is the DC-link voltage, $V_{grid,\ peak}$ is the peak value of the AC side voltage, D denotes the modulation index, $i_{ripple}$ is the acceptable value of ripple current whose typical value is 10% of the inverter current peak and $f_{sw}$ is the switching frequency of the PV inverter.

*b)* Following the value of the filter inductor $L_f$, the reactance of the filter is checked between the limits of the base reactance as shown below

$$0.1X_{base} < X_f < 0.25X_{base} \tag{7.17}$$

*c)* The filter capacitor should be designed in such a way that

$$C_f = x \times C_b \tag{7.18}$$

$$C_f \leq \frac{0.05 \times Q_n}{\omega \times Vac_{L-L}^2} \tag{7.19}$$

$$X_c = \frac{1}{C_f} \geq \frac{Vac_{L-L}^2}{0.05 \times Q_n} \tag{7.20}$$

where $'x'$ denotes the percentage of reactive power from the filter capacitor and should not exceed 5% of the inverter capacitor as per the design procedure. $C_f$ is the capacitance of the filter, $\omega$ is the nominal angular frequency, $Q_n$ is the nominal reactive power of the PV inverter and $V_{ac,L-L}$ is the rms value of the line to line voltage on the AC side that connects to the grid through the transformer.

*d)* The resonant frequency is calculated as follows using the values of the calculated values of filter elements in the above steps.

$$f_r = \frac{1}{2\pi}\sqrt{\frac{L_t + L_f}{L_t L_f C_f}} \tag{7.21}$$

*e)* The calculated resonant frequency from the previous state is checked whether it lies within certain limits as shown below

$$10f_0 < f_r < 0.5f_{sw} \tag{7.22}$$

*f)* Considering the well- known fact that L and C components interact and cause resonance, a damping resistor $R_d$ is designed to be connected in series with the series capacitor such that

$$R_d = \frac{1}{3 * \omega * C_f} \tag{7.23}$$

$$where\ \omega = 2\pi f_r \tag{7.24}$$

## 7.8 LCL Filter for Smart PV inverter- Calculations

The crucial element during the design consideration of every Smart PV inverter system is the filter associated with it. The filter elements determines the harmonic injection into the system that arises due the switching frequency of the inverter. Apart from that, the controller that is responsible for the real and reactive power injection from Smart PV inverter needs to be designed in accordance with the LCL filter elements. The reason being the association of filter components as a coupling element in the controller design, determines the stability and performance of the entire PV inverter system. For a 1 MVA two-level-six-pulse IGBT-based voltage source inverters (VSI), a switching frequency of 3060 Hz is considered towards a better harmonic performance. Figure 7.9 presents the block diagram of Smart PV inverter.

The value of the $L_f$ is calculated as follows:

$$L_f = \left(V_{dc} - V_{grid,peak}\right) * \frac{D}{2 * iripple * fsw} \tag{7.25}$$

With D = 0.5, $f_{sw}$=3060 Hz,

$$i_{ripple} = 0.1*I_{rated,peak} \tag{7.26}$$

$$I_{rated,rms} = 1 * \frac{10^6}{\sqrt{3} * 480} = 1202.84\ A \tag{7.27}$$

$$I_{rated,peak} = \sqrt{2} * 1202.84 = 1700.82\ A \tag{7.28}$$

$$i_{ripple} = 17.008\ \mathrm{A} \tag{7.29}$$

$$V_{dc} = 850\ \mathrm{V},\ V_{grid,peak} = (480*1.414)/1.732 = 391.87\ \mathrm{V} \tag{7.30}$$

Substituting values from Eqs. (7.26) - (7.30) in (7.25),

$L_f = 0.22$ mH. (7.31)

The filter capacitor is found out using

$$C_f \leq \frac{0.05 * Q_n}{\omega * Vac_{L-L}^2} \tag{7.32}$$

$Q_n = 1$ MVAR, $V_{acL\text{-}L} = 480$ V, $\omega = 2\pi f$ where f = 60 Hz (7.33)

$C_f \leq 575\ \mu F$. (7.34)

At the same time it should also be ensured that the value of capacitor does not contribute to the steady state and temporary over voltage (TOV). Based on which the value of $C_f$ is decided. In this design the value of Cf is considered to be $575\mu F$. Based on the values of Lf and Cf, the resonant frequency is calculated.

$$f_r = \frac{1}{2\pi}\sqrt{\frac{L_t + L_f}{L_t L_f C_f}} \tag{7.35}$$

The value of the inductance of the transformer Lt is found out based on the reactance. The reactance of the 1.5 MVA, 480 V/13.2 kV transformer is 0.1 p.u. The actual value is calculated based on the base value of reactance,

$$X_b = \frac{480^2}{P_n}\ (\Omega) \tag{7.36}$$

where $P_n = 1$ MW.

$Lt = 61.146$ µH. (7.37)

$f_r = 960\ Hz.$ (7.38)

Now after the calculation of the resonant frequency $f_r$, the resonance frequency is checked whether it is in the valid range of

$10f_0 < f_r < 0.5f_{sw.}$ (7.39)

f0 = 60 Hz and fsw = 3060 Hz. (7.40)

600 Hz < $f_r$= 960 Hz < 1530 Hz. (7.41)

It can be clearly observed that the value of resonant frequency $f_r$ lies in the valid range confirming the design of the filter to be be good. Using the calculated value of the resonant frequency $f_r$, the damping resistor $R_d$ can be calculated as

$$R_d = \frac{1}{3 * \omega * C_f} \quad (7.42)$$

$where\ \omega = 2\pi f_r$

$$R_d = 0.09615\ ohms \quad (7.43)$$

Figure 7.10 presents the output waveforms of 1 MVA Smart PV inverter confirming its stability and THD levels within the limits.

## 7.9 System Description

To demonstrate the novel and pioneering idea of eliminating the resonance, a system based on IEEE Standard 399-1997 system with few modifications are considered. The complete system along with its data are shown in Figure 7.11. The system consists of a substation rated at 1000 MVA with X/R ratio of 22. The 69 KV line is stepped down to 13.8 KV through a 15 MVA transformer heading towards the Point of Common Coupling (PCC). This 13.8 KV from PCC feeds three feeders, Feeder 3, Feeder 2 and Feeder 1. The loads connecting Distribution transformers are stepped down to 480 V and 2.4 KV. The system is supported by a 1.0 MVAR Feeder Capacitor Bank connected the Point of Common Coupling (PCC).

The two main buses in the system are DGBus3 and DGBus2. DGBus3 is the location where normal PV rated at 2.5 MW is connected. The maximum interconnecting capacity that the DGBus3 can take is 2.5 MVA. So, only MW is injected in that bus. The DGBus2 can take a maximum capacity of 5 MVA. So, 2 MW of normal PV (active power injection only) is in place at DGBus2 describes the overall system. Figure 7.11 and Figure. 7.12 presents the complete system with specifications and the system design using PSCAD/EMTDC respectively.

## 7.10 Result discussions on the proposed novel idea

A comprehensive knowledge of network impedances is required for the understanding and analysis of the resonance modes present in the system. For the purpose of frequency scan, the overall system impedance is coupled as viewed from the feeder capacitor bus. The final impedance equations are frequency dependent. So, a suitable plot can be obtained between impedance and frequency using the Frequency Scan tool. Normally for any research analysis that is done on a system for resonance, the frequency scanning is done at the Point of Common Coupling.

### 7.10.1 Resonance Modes due to Feeder Capacitor Bank

Initially the load flow is performed and the system scanning is done with 1 MVAR in place. It could be well witnessed from Figure 7.13 that two resonant peaks appears with the first peak appearing at 704 Hz and the second peak appearing at 1510 Hz. Now the rating of the Feeder Capacitor Bank is increased to 2 MVAR with the sequential switching operation that normally is witnessed in utilities. It could be seen from Figure 7.13 that the first peak happens to appear at 554 Hz, the second resonant peak happens at 1300 Hz and

third at 1410 Hz. With the third sequential switching of Capacitor, a total rating of 3 MVAR feeder capacitor bank being considered, the system scanning is done. It could be well witnessed from Figure 7.13 that the first resonant peak appears at 450 Hz, the second resonant peak happening at 1290 Hz and third at 1380 Hz.

As the rating of capacitor bank is increased, the resonant peak keeps shifting towards the fundamental frequency. A high level of caution needs to be exercised by researcher/planning engineer to ensure that the peak doesn't align with the $3^{rd}$, $5^{th}$, $7^{th}$ harmonics and so on (multiples of 60 Hz fundamental frequency). So the alignment with the odd harmonics needs to checked and also a fact that the peak doesn't get closer to fundamental frequency.

If such a situation happens, then the harmonic injections into the distribution system tend to increase thereby hampering the reliability of the system. It could be well witnessed from Table I that the Total Harmonic Distortion of current (THDi) has severely violated by going beyond 5% of the limits specified by IEEE 519. The violations are marked in red color, as seen from the table. Similar violations could be witnessed for the Individual harmonic distortion of current (IHDi) for the $5^{th}$ and $7^{th}$ harmonic.

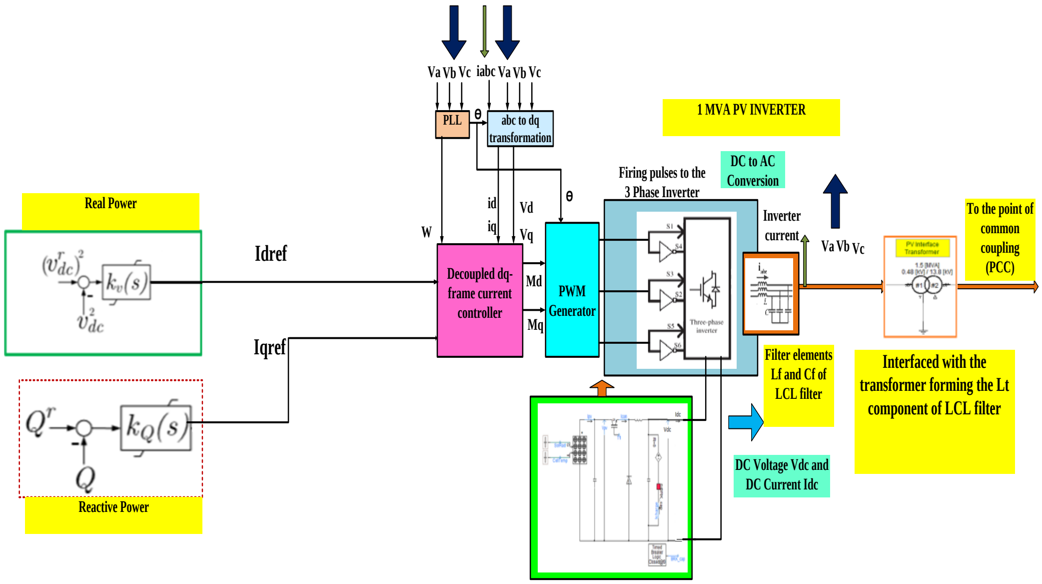



Figure 7.9 Block diagram of Smart PV inverter as a virtual detuner

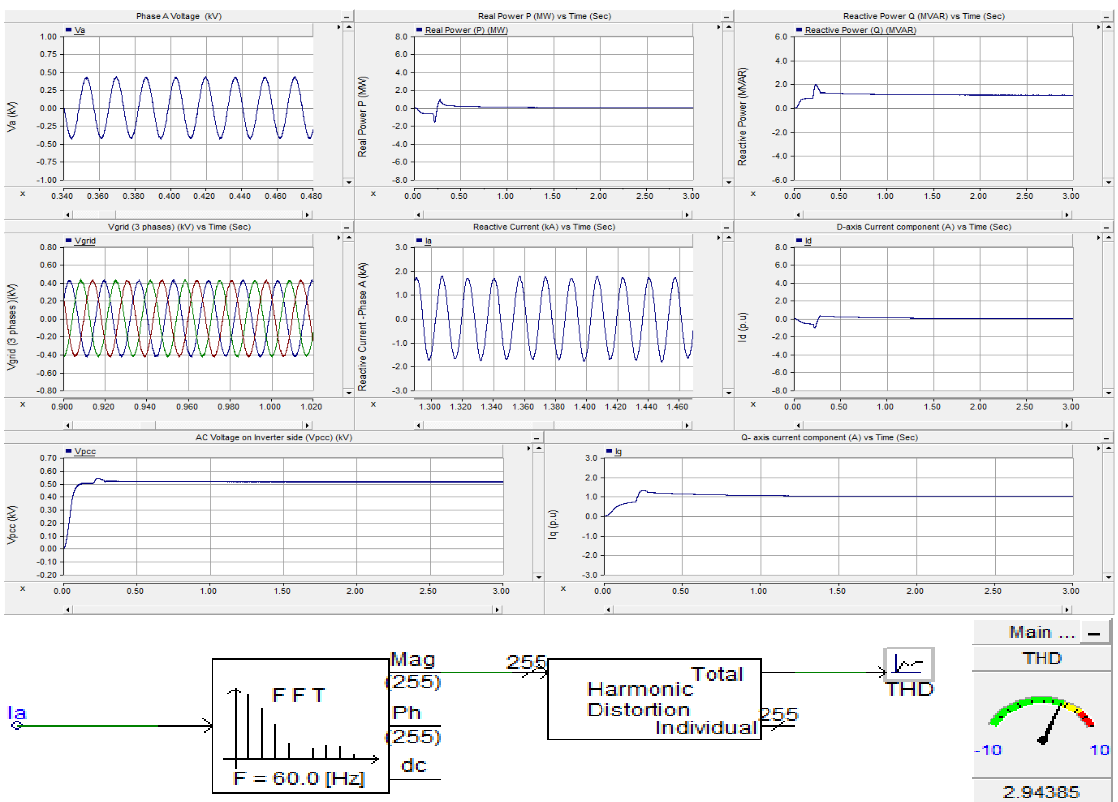



Figure 7.10 Output waveforms of 1 MVAR Smart PV inverter for virtual detuning confirming the stable working and THD limits of the reactive current

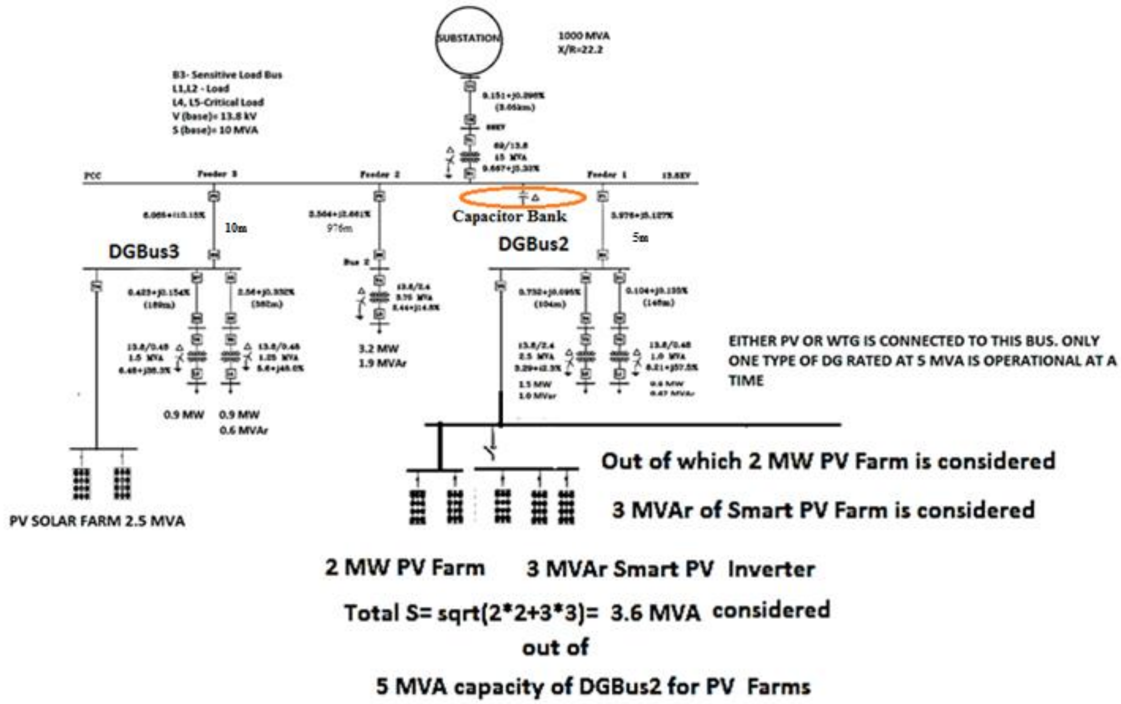



Figure 7.11 Distribution system based on parameters extracted from IEEE Standard 399-1997 and suitable modifications [14]

### 7.10.2 Resonance Modes due to novel strategic application of Smart PV inverters

The feeder Capacitor Bank is removed. In place of that, the newly designed Smart PV Inverters are connected at PCC. Since the resonance has occurred due to the Capacitor Banks, a detuning needs to be done to eliminate it, which is the normal strategy adopted by utility as discussed in the earlier section of this paper. This chapter proposes the Smart PV Inverter as a strategic detuner and is completely a novel and a pioneering application of utilizing PV to eliminate resonance for the first time.

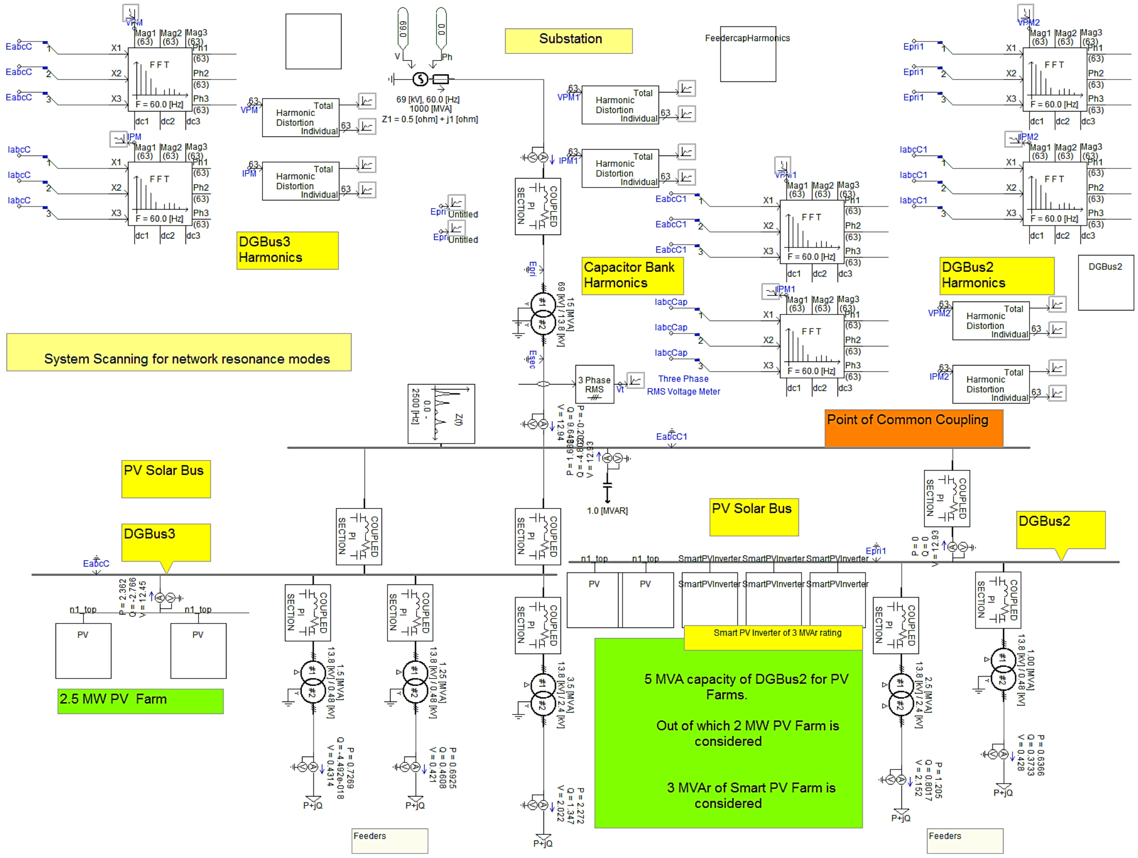



Figure 7.12 System with Smart PV Inverter designed using PSCAD/EMTDC

The other peaks occurring with Smart PV Inverter happens only at 1150 Hz, 1350 Hz, 2040 Hz and 2230 Hz which is getting far away from the fundamental frequency. With 1 MVAR Smart PV Inverter connected to the Point of common coupling (PCC), it could be well witnessed from Figure 7.14 that the first peak appears only at 1150 Hz compared to the first of a capacitor occurring at 704 Hz from Figure 7.13. The other peaks occurring with Smart PV Inverter happens only at 1150 Hz, 1350 Hz, 2040 Hz and 2230 Hz which is getting far away from the fundamental frequency.

With a sequential switching operation of another Smart PV inverter, a rating of 2 MVAR is in place. It could be seen from the resonant peaks that the first peak is occurring

at 1140 Hz and other peaks tend to remain almost the same as that of the 1 MVAR Smart PV inverter. Comparing this to 2 MVAR rating of feeder capacitor bank, 1140 Hz is far away from the fundamental frequency, compared to the peak happening at 554 Hz with the 2 MVAR feeder capacitor bank. Now a third Smart PV inverter of is turned ON with a rating of 3 MVAR in place. Also to note that this DGBus2 has another 2 normal PV injecting real power amounting to overall injection of 3.6 MVA out of the 5 MVA planned capacity. It could be well witnessed that the first peak is occurring at 1120 Hz which is still far away from the fundamental frequency and others peaks happens to be the same, irrespective of increase in the ratings of Smart PV inverter. So, the filter elements associated with PV Inverters doesn't impact the system to cause a violation. Other peaks are far away and are acceptable.

Table 7.1 presents the harmonics injected by Smart PV Inverter. It could be well witnessed that the new control strategy of Smart PV Inverter has infact acted as a detuner by making the resonant peak to occur far away from the fundamental frequency, with little or no changes with other peaks, irrespective of increase in the rating of the Smart PV Inverters. Also, considering the fact that overall system voltage is not violated and are within +/-5% of the distribution system voltage levels based on VAR injection. Also from Table 7.1, it could be seen that the harmonics are eliminated/mitigated eventually if the capacitor bank's functionality were to be substituted by Smart PV Inverter, whenever its capacity for real power injection is not utilized. The pioneering idea has shown that results have been successful with the designed control strategy. In future, more control techniques could be associated.

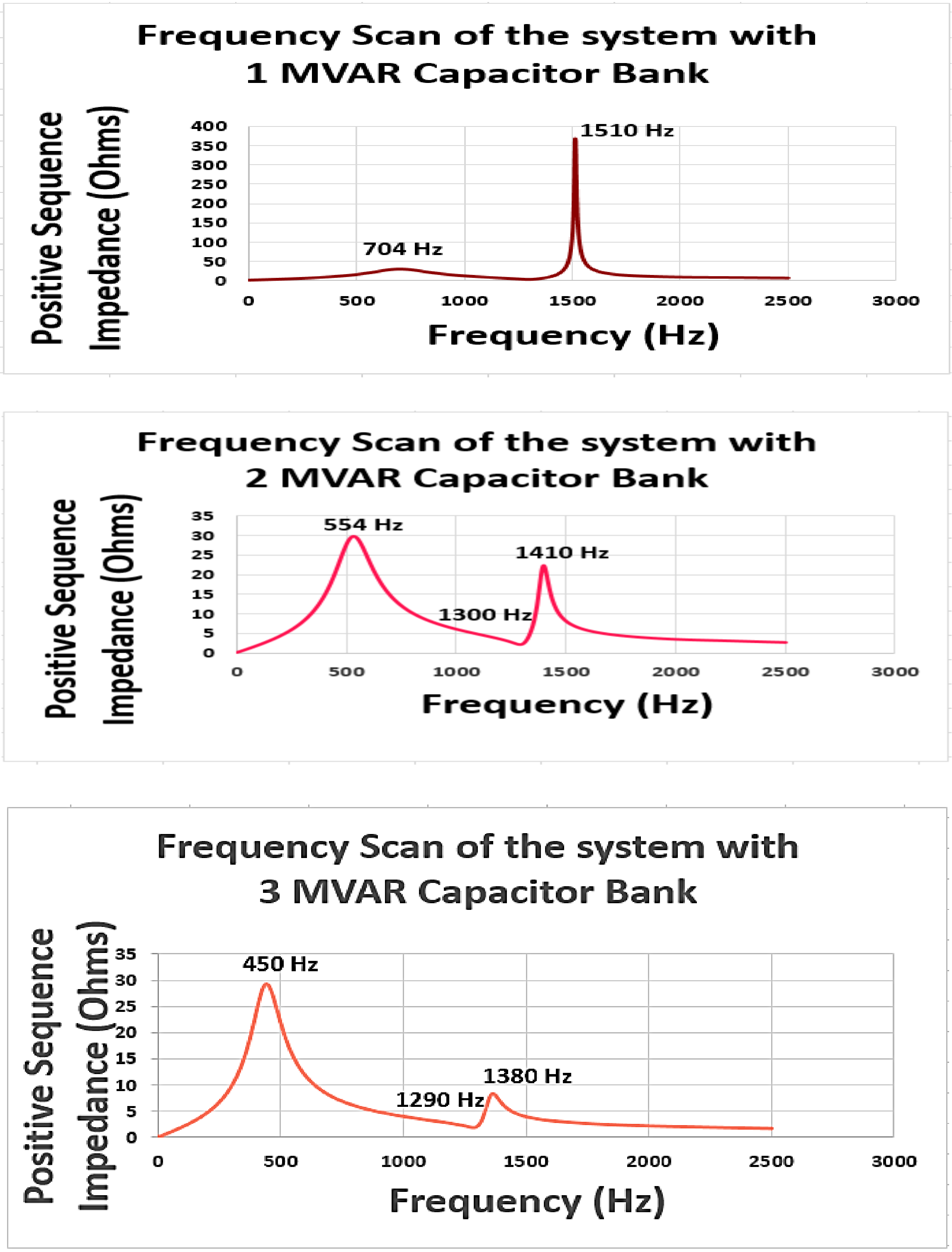



Figure 7.13 Results of resonant peaks obtained for different values of Feeder Bank Capacitor employed at PCC – 1 MVAR, 2 MVAR and 3 MVAR ratings

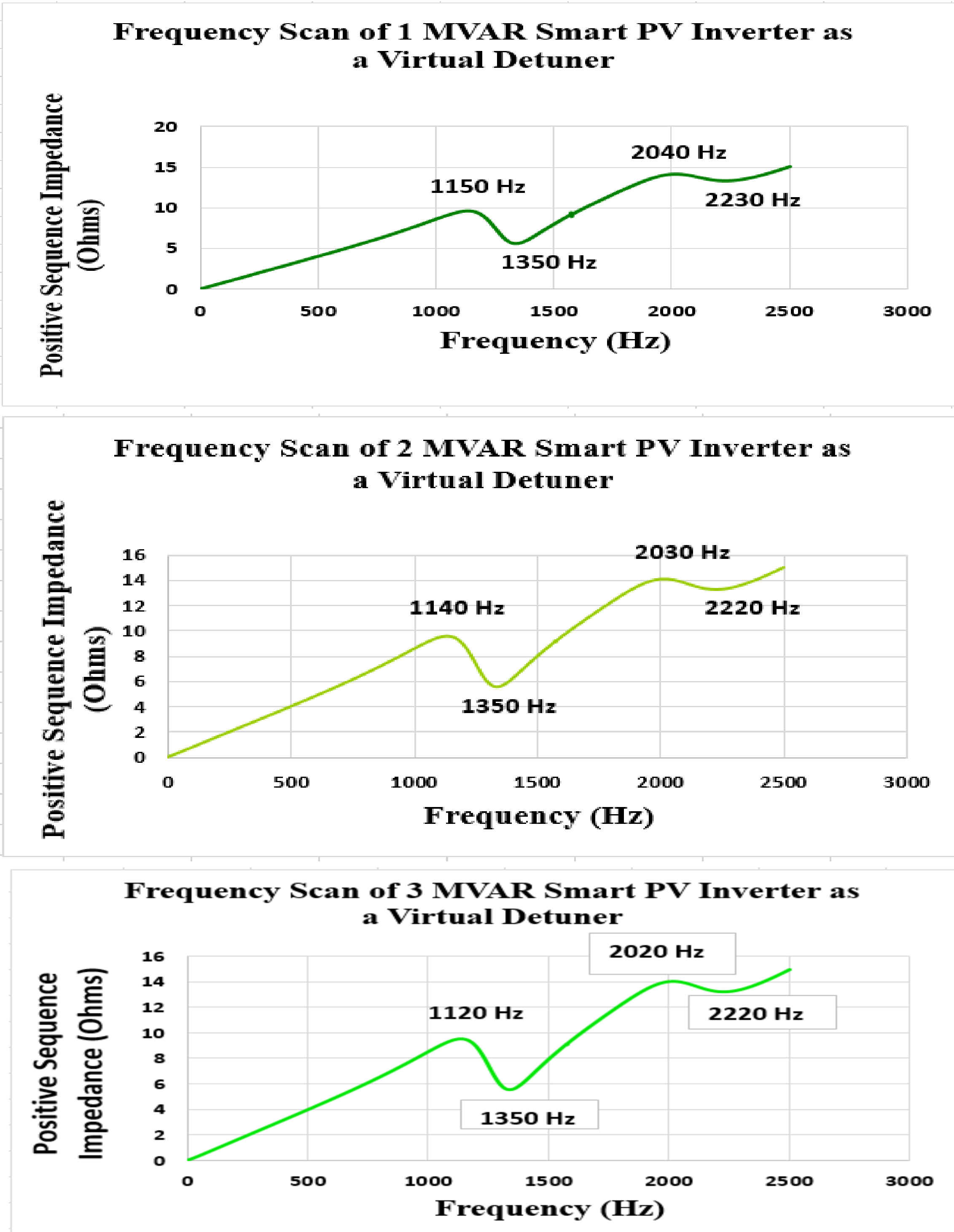



Figure 7.14 Results of resonant peaks obtained for different ratings of Smart PV Inverter employed at PCC – 1 MVAR, 2 MVAR and 3 MVAR rating

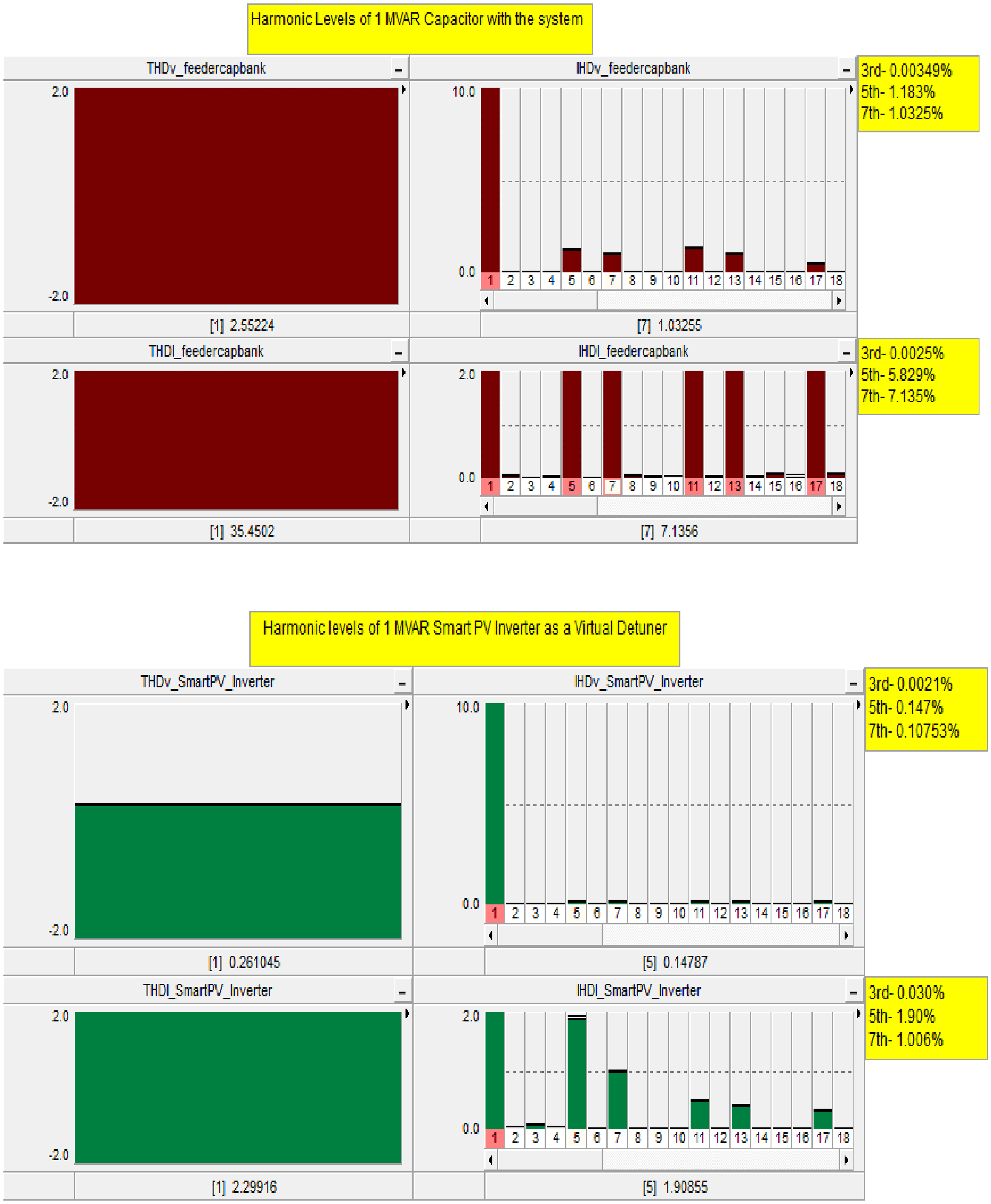



Figure 7.15 Total and Individual Harmonic distortion of Voltage and Current injected by 1 MVAR Feeder Capacitor Bank and 1 MVAR Smart PV Inverter

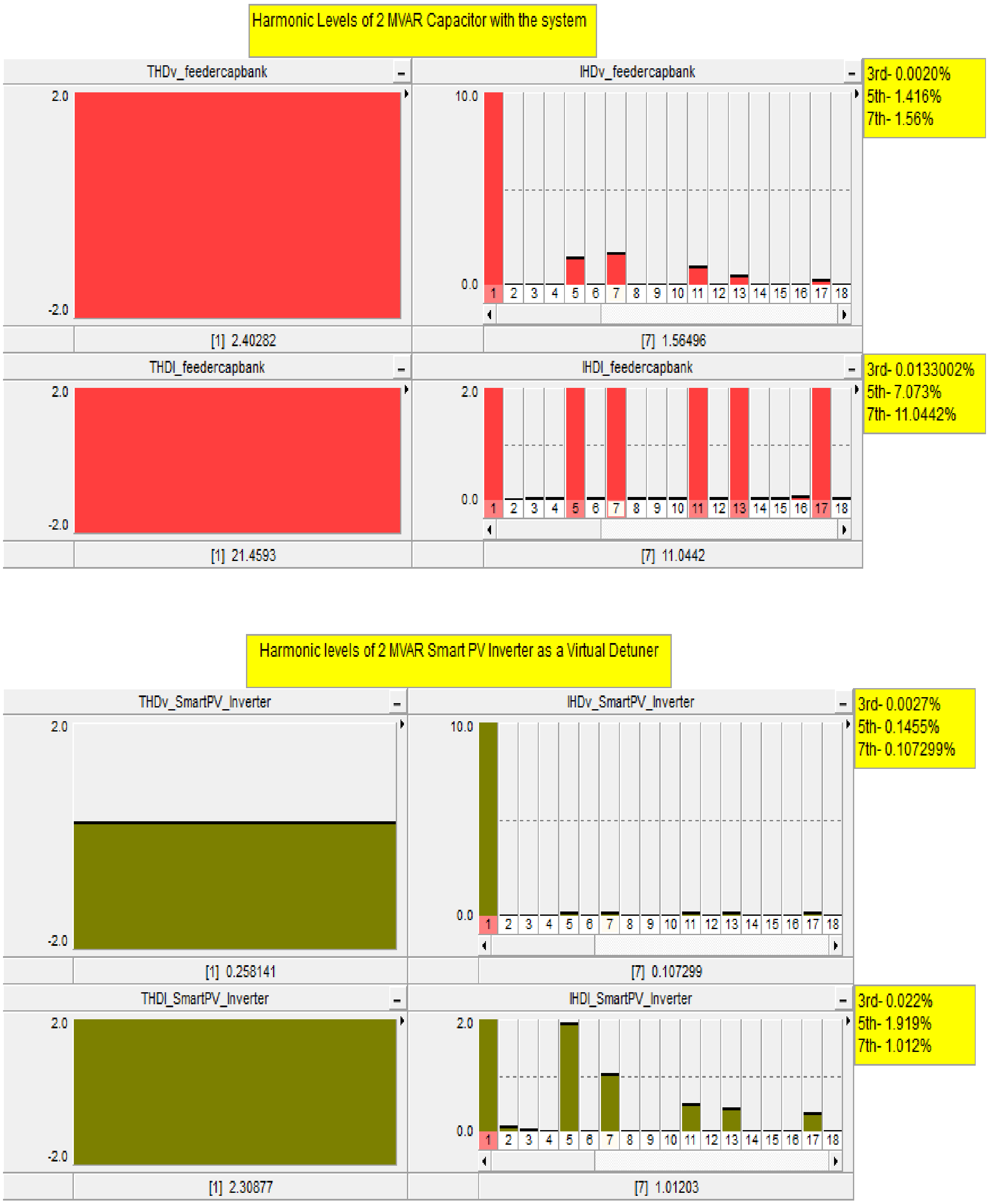



Figure 7.16 Total and Individual Harmonic distortion of Voltage and Current injected by 2 MVAR Feeder Capacitor Bank and 2 MVAR Smart PV Inverter

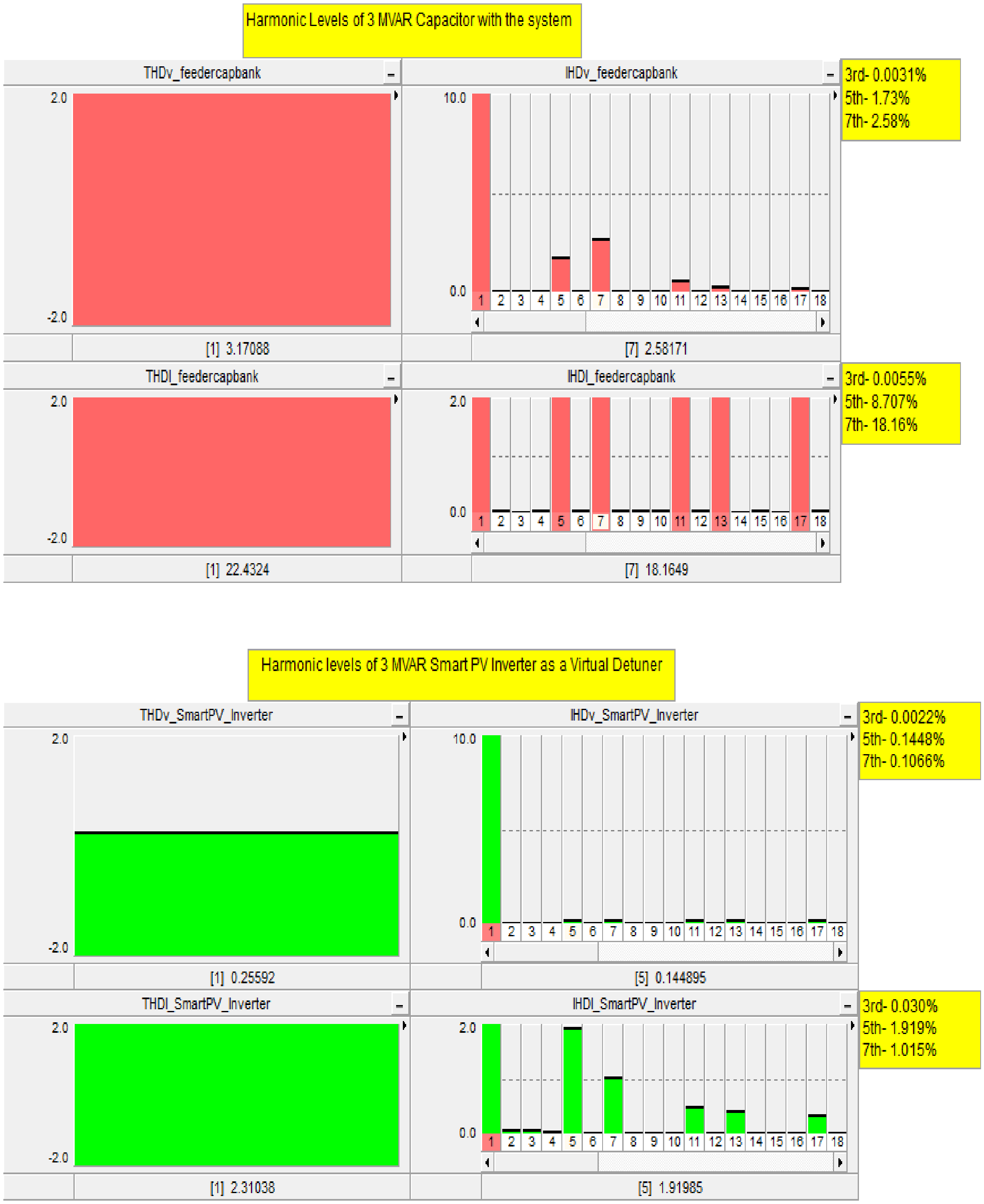



Figure 7.17 Total and Individual Harmonic distortion of Voltage and Current injected by 3 MVAR Feeder Capacitor Bank and 3 MVAR Smart PV Inverter

Figure 7.15, Figure 7.16 and Figure 7.17 presents the Total and Individual Harmonic distortion of voltage and current injected by 1 MVAR, 2 MVAR and 3 MVAR feeder capacitor bank during its interaction with the distribution system and that of 1 MVAR, 2 MVAR and 3 MVAR Smart PV inverter as well. The Smart inverter's parameters are presented in Table 7.2.

Table 7.1
Total and Individual Harmonic Distortion injected by feeder capacitor bank and Smart PV inverter into the grid

| Component Rating (MVAR) | Component Name | Total Harmonic Distortion THDv at PCC (%) | Total Harmonic Distortion THDi at PCC (%) | Individual Harmonic Distortion IHDv at PCC (%) 3rd | Individual Harmonic Distortion IHDv at PCC (%) 5th | Individual Harmonic Distortion IHDv at PCC (%) 7th | Individual Harmonic Distorsion IHDi at PCC (%) 3rd | Individual Harmonic Distorsion IHDi at PCC (%) 5th | Individual Harmonic Distorsion IHDi at PCC (%) 7th |
|---|---|---|---|---|---|---|---|---|---|
| **1 MVAR** | **Feeder capacitor bank** | **2.55** | **35.45** | **0.003** | **1.183** | **1.032** | **0.0025** | **5.82** | **7.135** |
| **2 MVAR** | | **2.40** | **21.45** | **0.002** | **1.416** | **1.56** | **0.013** | **7.07** | **11.04** |
| **3 MVAR** | | **3.17** | **22.43** | **0.003** | **1.73** | **2.58** | **0.0055** | **8.707** | **18.16** |
| **1 MVAR** | **Smart PV inverter as a virtual detuner** | **0.261** | **2.29** | **0.002** | **0.147** | **0.107** | **0.030** | **1.90** | **1.006** |
| **2 MVAR** | | **0.258** | **2.308** | **0.002** | **0.146** | **0.107** | **0.022** | **1.919** | **1.012** |
| **3 MVAR** | | **0.255** | **2.31** | **0.002** | **0.145** | **0.107** | **0.030** | **1.919** | **1.015** |

Table 7.2

Smart PV inverter parameters

| PV System Parameter | Value | Comments |
|---|---|---|
| Grid Inductance | 0.22 mH | |
| Grid Resistance | 1 mΩ | |
| Grid Voltage | 13.8 kV | Delta/Y |
| Tr nominal power | 1.5 MVA | |
| Tr Voltage ratio | 0.48 kV/13.8 kV | |
| Tr leakage reactance | 0.1 pu | |
| Tr ohmic resistance | 0.02 pu | |
| Filter Capacitance, Cf | 575 uF | |
| Switching frequency | 3060 Hz | 51x60 |
| DC-link Capacitance C | 5000 uF | |
| DC-link Inductance L | 10 µH | |
| Controller Parameters | | |
| Kp<br>Ti | 10<br>0.05 | |

# CHAPTER EIGHT

# SMART PV AND SMARTPARK INVERTERS AS SUPPRESSORS OF TEMPORARY OVER-VOLTAGE (TOV) PHENOMENON IN DISTRIBUTION SYSTEMS

## 8.1 Overview

This chapter proposes a new application and a novel control scheme for utilizing Smart PV and Smart Park inverters to mitigate Temporary OverVoltage (TOV) phenomenon in distribution systems. As more number of inverter based distributed generators like PV are connected to a medium and low voltage distribution systems, Temporary Overvoltage (TOV) phenomenon becomes more prevalent during Single Line to Ground Fault (SLGF). Currently, the IEEE 142-"Effective grounding" technique has been the reference for various grounding schemes to prevent TOV. This chapter explores the potential of low-cost and a novel solution for the first time, that utilizes a specialized controller associated with PV/SmartPark inverters (Smart inverters) as a TOV suppressor. The efficacy of the aforementioned novel application has been demonstrated on a simplified bench mark system of the IEEE Standard 399-1997 with few modifications. A 4 MW conventional PV plant is considered along with 10 MVAR Smart inverter connected to the Point of Common Coupling (PCC). During normal operation of the distribution systems, the Smart inverter controller acts in a voltage regulation mode to curtail the voltage rise due to reverse power flow from the 4 MW PV plant. During fault condition, the TOV sensor enables the TOV control to suppress the violated limits of voltages in the healthy phases to an acceptable value.

## 8.2 Introduction

Temporary Overvoltage refers to an oscillatory response that exists for many cycles to seconds. As more number of Distributed Generators (DG's) like PV are integrated into power distribution systems, TOV phenomenon becomes more prevalent. It is a well-known fact that the most common form of TOV arises due to Single Line to Ground fault (SLGF), considering the configurations of the isolation transformers associated with PV and other main transformers [95]. Traditionally with synchronous generators, TOV has been mitigated by utilities using the IEEE 142 "Effective Grounding" technique [96].

The mechanisms associated with inverter based DG's that causes TOV has been classified into six categories: ground potential rise, derived neutral shift, inductive coupling of fault currents, high generation to load ratio, interruption of inductive currents and over-modulation/saturation of load current controls [97]. Among the above mentioned TOV mechanisms, in a three phase system with an ungrounded transformer, a single line to ground fault leading to a neutral voltage displacement or the virtual neutral voltage is considered to be the most common one.

During such a situation, an overvoltage of 1.73 p.u can appear across the other two healthy phases of the three phase system. Further from a pre-fault voltage of 1.05 p.u as per the ANSI voltage regulation limit of +/-5%, TOV can further reach a value as high as 1.82 p.u. During an unintentional islanding incident, the TOV can become more severe when there is a SLGF in the isolated zone. This can damage the customer loads to a great extent.  A high value of 2.3 p.u of TOV has been reported in [98] that has lasted for 5

cycles. In practice, most North American utilities recommend that TOV is limited to a value less than 1.39 p.u [108]. For instance, Hydro One system in Canada has fixed the limit as 1.25 p.u [99].

A number of TOV mitigation strategy has been proposed [100-103]. Recent work on TOV mitigation involved the addition of a half- bridge leg energized by the dc-link of the voltage source inverter (VSI) of the PV system with Y/YG isolation transformer. The neutral point the half bridge leg was connected to the neutral Y of the isolation transformer [104-105]. This may increase the complexity of the hardware and design. More than that, the compatibility of PV inverters with Standards UL 1741 and IEEE 1547 needs to be considered [106-107].

A solid neutral connection in inverters are absent in order to prevent the minute, short duration imbalances in phase switching times that may lead to unwanted neutral current in the output. To prevent the disturbances from causing harmonic distortion to the rest of the system, PV inverter's isolation transformer neutral is configured to stay in a floating mode.

Effective grounding using the inverter's internal transformer neutral connection influences the transformer operation and the output current waveform. Although, PV inverter power electronics on the transformers delta side are not affected. Depending on the site's power quality and impedance, it is possible that an inverter can draw excessive zero sequence currents due to the neutral grounding, which needs an increased value of grounding impedance. Floating Star- delta configuration of the isolation transformer is the

most preferred one by the PV manufacturers. They are further supported with external grounding in the system by the utilities [108-109].

Synchronous generators that are in place are grounded using IEEE 142 "Effective grounding" techniques. Utilities are trying to implement the same grounding scheme for PV inverters as well. In the process, millions of dollars are wasted. Papers have discussed that effective grounding of distributed generation inverters may not mitigate transient and temporary overvoltage [110]. The consequences of more PV integration into the distribution system has started posing a challenge when utilities are trying to mitigate TOV with traditional grounding protection schemes.

Smart inverter capabilities for mitigating over-voltage on distribution systems with high penetrations of PV has been presented in [111-112]. The idea of utilizing the remaining capacity of inverter for reactive power injection injection/absorption forms the crux of such over-voltage mitigation. But the application catered to the mitigation of over-voltage corresponding to all three phases. Similar application of voltage regulation of all three phases has been demonstrated using SmartPark inverters associated with Plug in Electric Vehicles (PEV) can serve as a virtual STATCOM [113].

TOV phenomenon is evident during SLGF. So a specialized controller is required to bring the voltage levels of other two phases when there is a violation. None of the papers and research so far have demonstrated the utilization of Smart PV and Smart Parks inverters as a suppressors of TOV. This chapter presents a novel utilization of a specialized controller designed for the inverters of PV and Smart Park (PEV) to suppress the TOV in distribution systems. This novel TOV mitigation strategy will further serve as an alternate

solution in an ineffective/ungrounded transformer systems that gives rise to TOV during SLGF. PSCAD/EMTDC has been used to manifest the efficacy of Smart PV and Smart Park inverter system.

## 8.3 Mechanisms causing Temporary Overvoltage (TOV)

TOV can be caused by the following mechanisms: Rise in ground potential, neutral voltage displacement, inductive coupling of fault currents, inappropriate ratio between the PV generation and loads in the system, inductive current interruption and over-modulation. Among the aforementioned mechanisms that causes TOV, the most frequent mechanisms of TOV are the neutral voltage displacement that arises due to the line faults in the system and high generation from PV during the time when loading on the feeder becomes less and inductive coupling of fault currents. This chapter provides a strategy to mitigate TOV during a SLGF to demonstrate the novel application of a Smart PV and SmartParks to mitigate it.

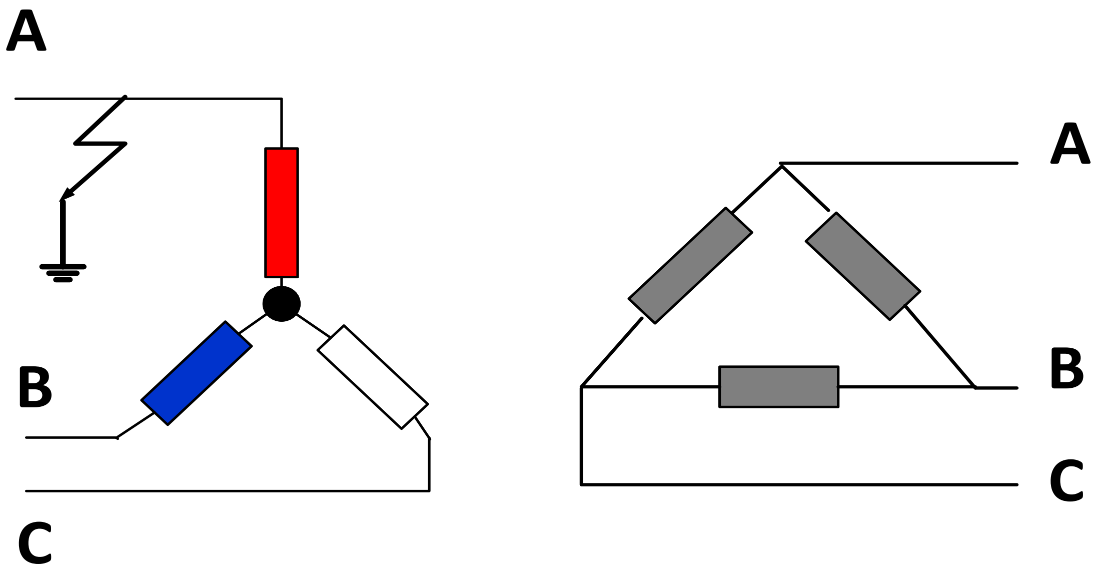
### 8.3.1 Rise in ground potential

As a part of the protection scheme, every system is protected using suitable grounding mechanisms of employing grounding electrodes. The resistance considering the grounding electrode and its reference earth point leads to an increase in voltage between the local grounding point and other distant references of the ground in the system.

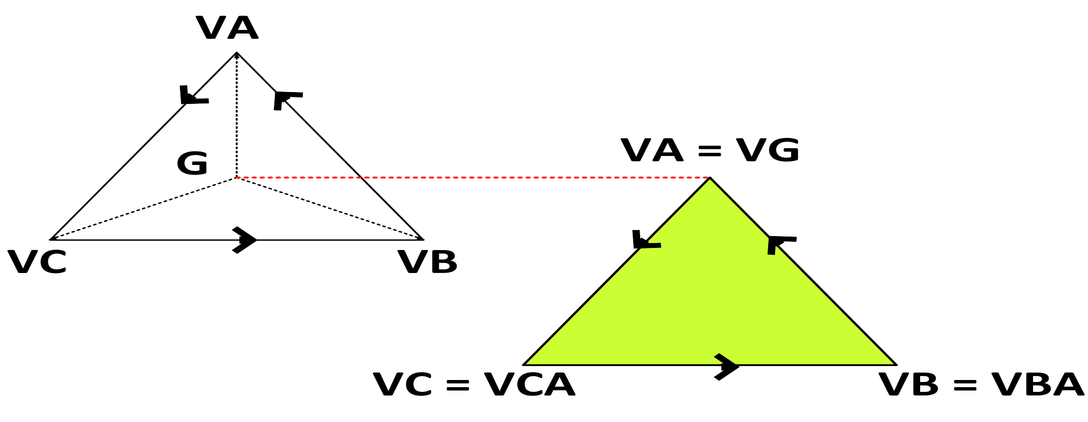
### 8.3.2 Neutral voltage displacement

Irrespective of whether a neutral is connected to ground or not, the neutral voltage in a three-phase is close to zero during a normal operation of a three phase system. When

one phase of the distribution line is faulted to ground (SLGF) with an ungrounded neutral, the voltages of all three phases are not balanced anymore. This leads to a phenomenon known as neutral voltage displacement or virtual neutral voltage or neutral voltage shift. This leads to over-voltage in the other two healthy phases of the system.



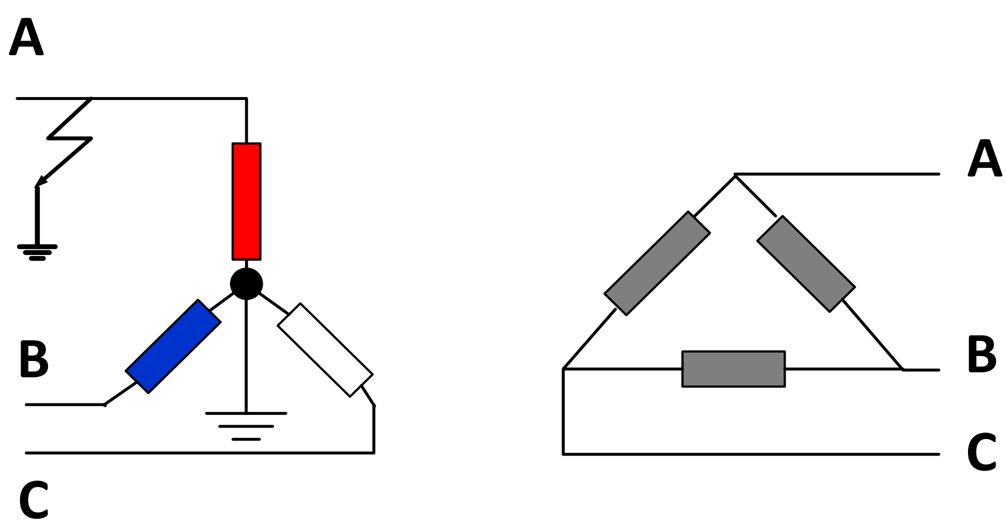

a) Configuration of the circuit



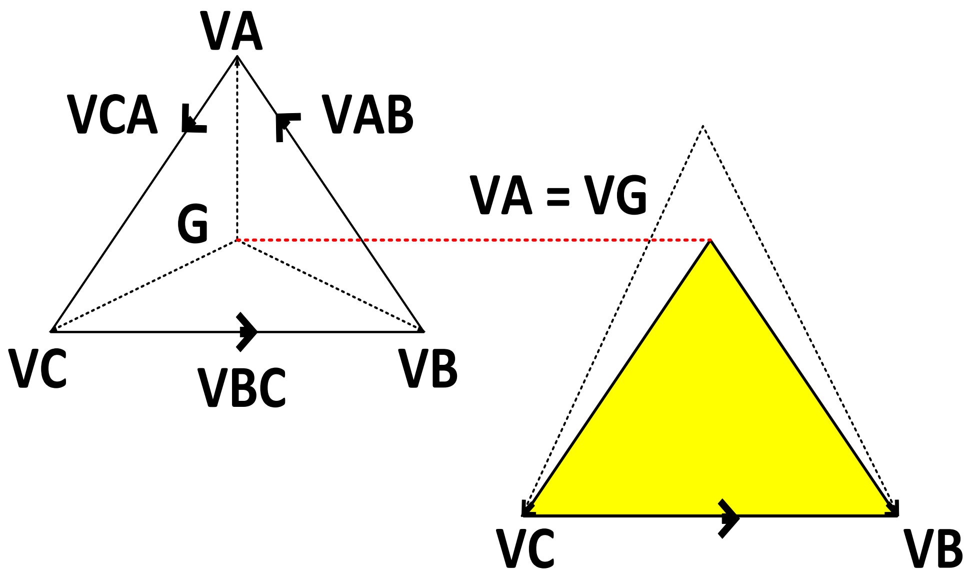

b) Representation of the circuit in vector form

Figure 8.1 Ungrounded transformer during Single Line to Ground Fault (SLGF)

It could be seen from Figure 8.1 that the neutral of the Wye configured primary of the transformer (Wye-Delta) is ungrounded with a SLGF happening on phase A. Figure. 1a presents the circuit diagram and Figure. 1b presents the vector diagram. Before the fault, the three phase system is balanced. Hence the neutral point of the ungrounded Wye connected primary of the transformer has a voltage of $V_G = V_N = 0$. When a SLGF is applied on Phase A, it could be well witnessed from the vector diagram of Figure. 1b that the neutral point $V_G$ is shifted vectorially to the phase A leading to a situation of $V_A=V_G$. As a result of which, the other two phase voltages $V_B$ and $V_C$ has an increase in magnitude equal to that of the line to line voltages. In other words, $V_C=V_{CA}$ and $V_B=V_{BA}$. During such a situation, customer loads connected to phase-to-neutral or phase to ground can be subjected a very high value as much as 1.73 times their rated voltage. Since this conditions exists as long as the fault is cleared, customer loads can be damaged during such an incident.




a) Configuration of the circuit




b) Representation of the circuit in vector form

Figure 8.2 Neutral grounded transformer during Single Line to Ground Fault (SLGF)

As a part of protection scheme, the neutral point is solidly grounded as shown in Figure 8.2. When a fault occurs on Phase A as shown in Figure 8.2a with neutral tied to the ground, its potential change ($V_G$) is not affected. The phase A voltage gets displaced down such that $V_A$=$V_G$ as shown vectorially in Figure 8.2b. In consequence of SLGF, the phase values $V_B$ and $V_C$ tends to remain at a nominal value of voltage as compared to the ungrounded system in Figure 8.1. The "effective grounding" standards in IEEE 142 are primarily designed to mitigate TOV.

8.3.3 <u>Inductive coupling of fault currents</u>

The flow of fault current in the faulted phases or neutral and healthy phases can induce a voltage in healthy phases. Since the contribution of the fault current coming from main generation can be more during SLGF since the breaker of the substation is still ON,

inductive coupling mechanism is more prevalent. Once the faulted section is isolated after opening the substation breaker, TOV might still exist due to other factors like high PV to load generation and so on that may need a common TOV mitigation strategy to cater to the needs of all the possible mechanisms causing TOV.

### 8.3.4 High generation from PV to load ratio

During a fault, the substation main breaker opens to clear it. Hence a significant amount of load becomes separated from the main generation source. This phenomenon is also known as load rejection. As a result, the isolated/islanded section of the load has a chance of still being fed from distributed energy resources like PV. But all current now flows into this isolated segment of the distribution path considering the path that this is the only path for the current to flow through. As a result, the generation from PV can be high compared to the load. As a result, this can lead to temporary rise of voltage in the system until the protection scheme of the PV inverter is made operational.

### 8.3.5 Over-modulation

During load rejection, the PV inverter controls can operate in such a way that current controller can saturate or make it operate at a value of modulation index. As a result, the IGBT switches of the three phase VSI of the PV can be under enormous stress by keeping them turned ON for a longer duration. This can lead to a value of the output voltage of the order of 1.5 to 3 times the nominal peak instantaneous AC output voltage. Most PV inverters are equipped with a protection mechanism to trip to avoid such over voltages occurring in the phases.

## 8.4 Concept of Effective Grounding

As seen from Figure 8.2, instead of grounding the neutral of the transformer, a grounding reactor can provide the similar functionality. So transformer neutral can remain floating with external grounding bank. In case of multiple PV inverters contributing a farm of PV, only one grounding bank at the Point of Common Coupling (PCC) as a part of the protection scheme. The PV inverter doesn't require a neutral to transport the three phase power and is intended to operate as balanced, 3 phase current sources in compliance with UL 1741 Standard.

IEEE 142 (the "Green Book") is a well- established standard that gives a detailed picture of implementing grounding solutions to power systems. This standard is applicable as an effective solution towards "effective grounding" of generators.

It is a well- known fact that the characteristics of generator and PV inverter are different. If we consider generators, they have large reactance due to the huge coiled with magnetic cores. As a result the X/R ratio for a generator is between 30 and 50. This is totally different if we consider PV inverters. The reactance is zero ideally and the X/R ratio can range between 0.02 and 0.05.

According to IEEE 142 standard, the $X_0/X_1 = 3$ for generators, where $X_0$ is the zero sequence impedance of the reactance and $X_1$ is the positive sequence impedance of the generator. This ratio of $X_0/X_1 = 3$ that is applicable for generators cannot be applied directly to PV inverters since X1 is almost close to zero and $X_0/X_1$ in this case doesn't provide a logical application to PV systems. So utility companies do acknowledge that they use an

equation Eq. 8.1, thus avoiding the way to define a positive sequence reactance $X_1$, considering its logical and uncertainty factor associated with PV.

$$X_{0PV} = 0.6 \pm 10\% \text{ p.u.} \tag{8.1}$$

## 8.5 TOV mitigation schemes in practice

According to IEEE green book, IEEE 142 standard defines the "effective grounding" as the ratio of zero sequence impedance to the positive sequence impedance that could be seen from equation Eq. 8.2 and Eq. 8.3.

$$0 < \frac{X_0}{X_1} < 3 \tag{8.2}$$

$$0 < \frac{R_0}{X_1} < 1 \tag{8.3}$$

where

$X_0$: Zero Sequence Reactance

$R_0$: Zero Sequence Resistance

$X_1$: Positive Sequence Reactance

The following above conditions has to be met for a conventional generator to establish effective grounding scheme such that the line to ground short circuit current is limited to 60% of the three phase short circuit value and a permissible overvoltage of less than 1.4 p.u for North American systems. Utilities like Hydro One has a limit of 1.25 p.u for the Overvoltage that the system can withstand during a fault, without causing any damage to the customer loads and other equipment in the system.

There are two effective grounding schemes in general. As already mentioned in the earlier section, a transformer neutral can be used to achieve effective grounding by employing a grounding reactor with a suitable zero sequence reactance $X_0$. In case of a buried neutral associated with a transformer and a delta configuration, externally grounding banks could be connected to the three phases of the line to achieve effective grounding. The grounding banks can be further classified into two configurations. A zig-zag transformer and a Wye (Star)-Delta transformer that can provide a high impedance path for the positive sequence voltages and low impedance path for zero sequence voltages.

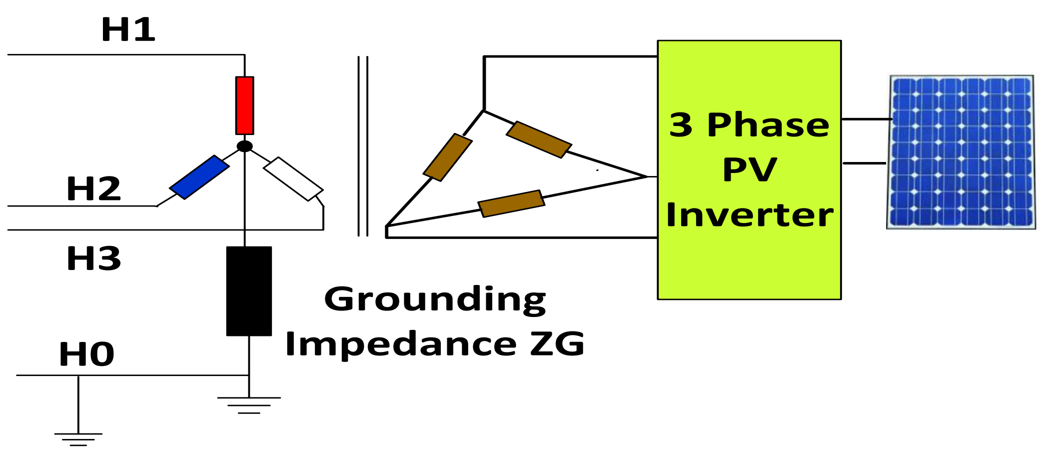
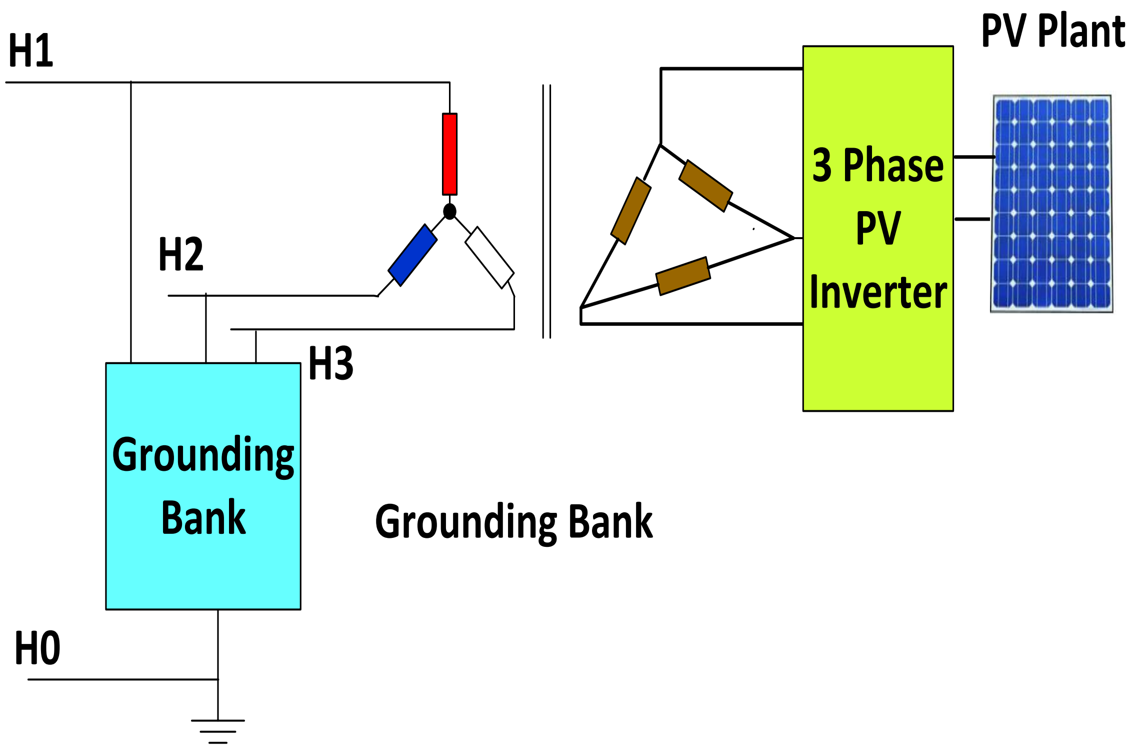
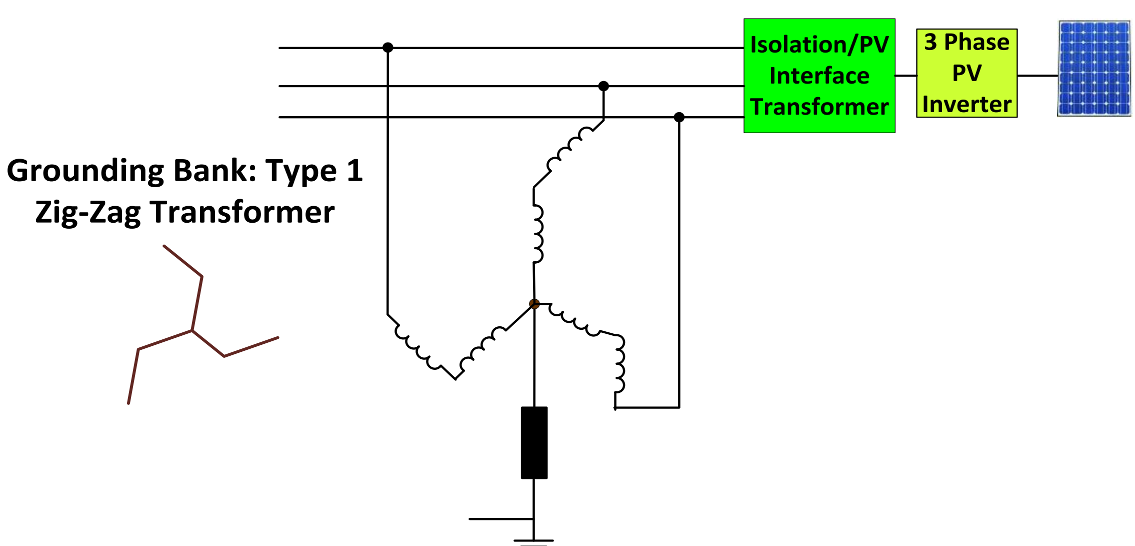


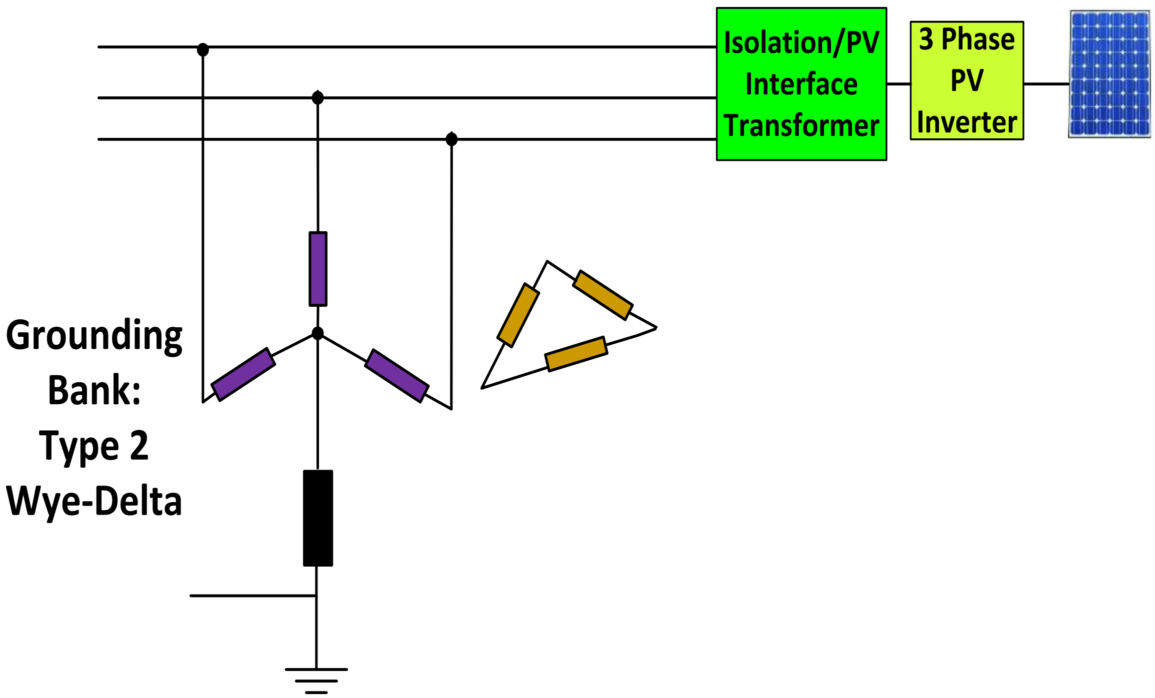

Figure 8.3 Grounding scheme with transformer neutral grounded with grounding impedance $Z_G$




a) Grounding scheme with grounding bank (Type 1 and Type 2)




b) Grounding scheme with grounding bank type 1-Zig-Zag transformer




c) Grounding scheme with grounding bank type 2-Wye-Delta transformer

Figure 8.4 Grounding scheme employing a grounding bank connected to the line for mitigating TOV

Figure 8.3 represents the grounding scheme employing a grounding impedance. Figure 8.4a represents the grounding scheme employed using grounding banks. Figure 8.4b and Figure 8.4c represents the type of grounding banks employed in the form of zig-zag transformer and Wye-Delta transformer respectively.

If the zig zag transformer is considered, the impedance can be designed based on equations Eq. 8.1 as one methodology of grounding scheme for PV and Eq. 8.2 and Eq. 8.3 of the conventional generator as another methodology in the design of grounding scheme

for PV with various preferences from the utility. Based on the real power rating and voltage of the PV inverter, the impedance of zig-zag transformer are decided. The impedance value that can be calculated using Eq. 8.1 is generally less than the design using Eq. 8.2 an Eq. 8.3. As a result, overvoltage phenomenon in design methodology using Eq. 8.1 will be less compared to the design methodology using Eq. 8.2 and Eq. 8.3. But one slight drawback is that the absorption of fault current by the PV inverter can be higher that the feeder protection scheme is more influenced in that case.

Further, there has always been a discussion regarding effective grounding schemes for PV. Certain considerations by the utilities involves the modeling and operational response of inverters during faults, loading and the guidelines of the protection schemes. As of now, the aforementioned effective grounding schemes are adopted based on the guidelines and needs of the utility based on the distribution system design. As the grid is becoming smarter with enhanced PV penetration, it is going to be a while till a common definition and understanding of grounding schemes are in place to mitigate TOV.

The novel idea that is proposed in the further sections of this chapter will involve a mitigation strategy from Smart PV and Smart Park inverters to deal with TOV phenomenon involving PV systems as a more stronger approach towards effective grounding.

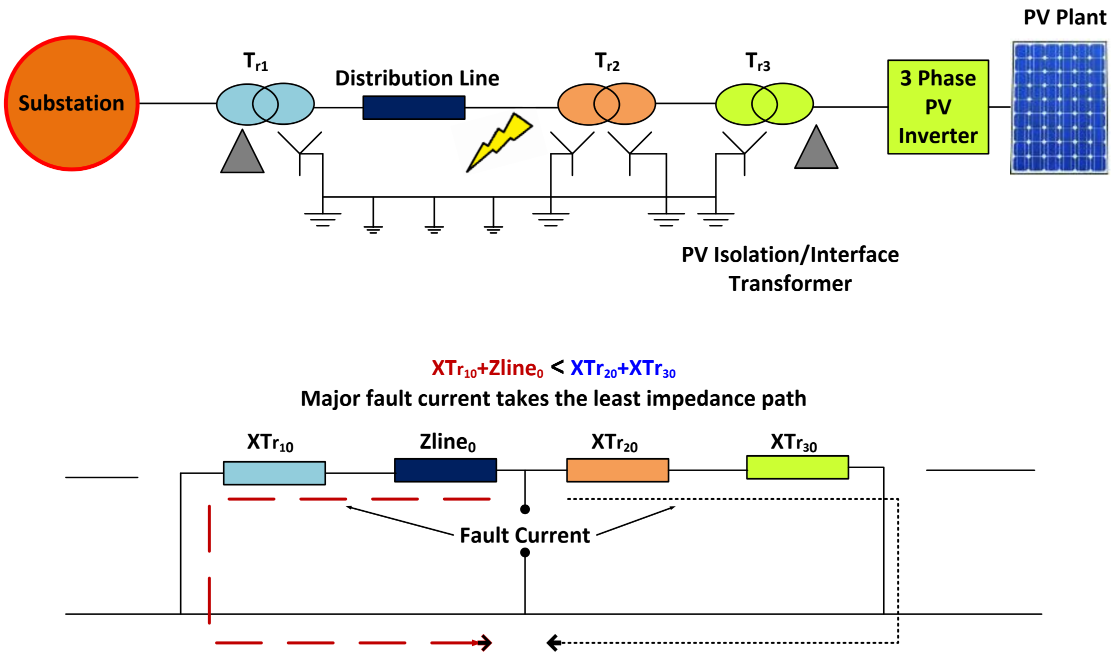



Figure 8.5 Simplified Distribution Feeder with grounding configuration 1 associated with PV (top) and its equivalent zero sequence circuit (bottom)

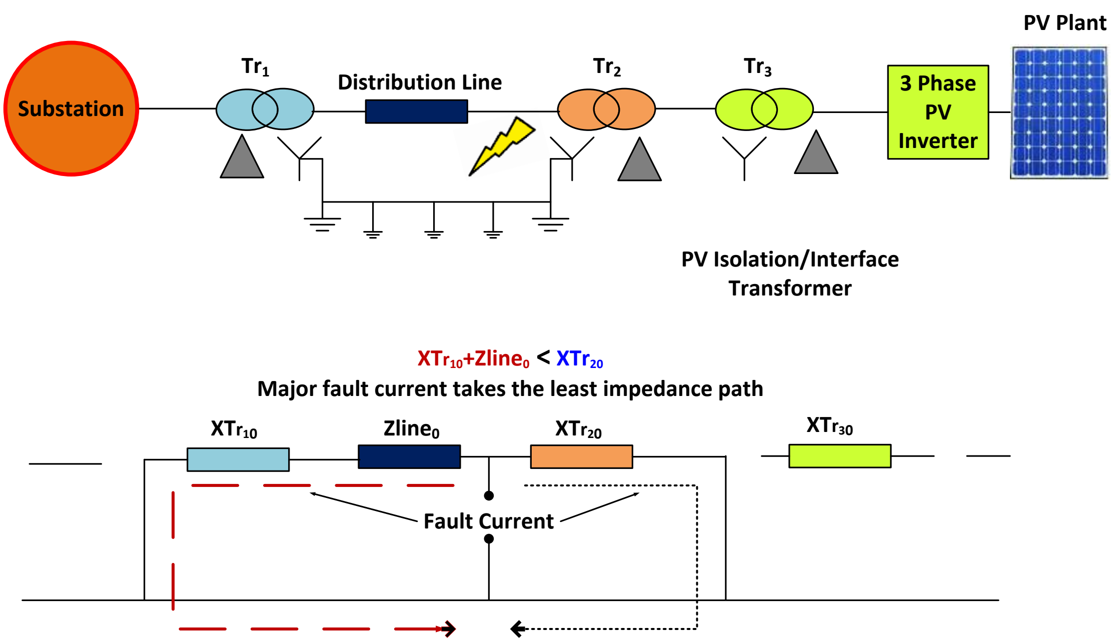



Figure 8.6 Simplified Distribution Feeder with grounding configuration 2 associated with PV (top) and its equivalent zero sequence circuit (bottom)

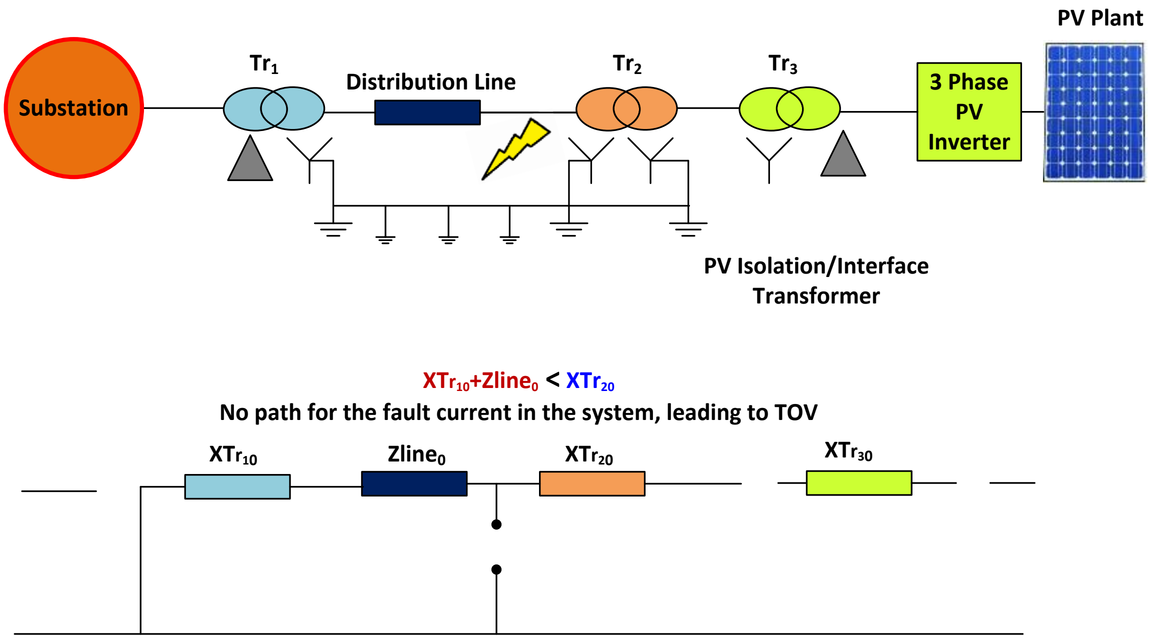



Figure 8.7 Simplified Distribution Feeder with grounding configuration 3 associated with PV (top) and its equivalent zero sequence circuit (bottom)

## 8.6 Influence of Transformer configurations on Temporary Overvoltage

The transformer configurations associated with the distribution system feeder has played a major role during the occurrence of TOV phenomenon [114-115]. During a single line to ground fault, the path for the flow of zero sequence current is determined by the grounding scheme associated with the transformer and the rest of the distribution feeder. This could be well understood by considering a simplified model of a distribution feeder with different transformer configuration during a SLGF and its corresponding zero sequence equivalent circuit model as shown in Figure 8.5, Figure 8.6 and Figure 8.7.

To illustrate it further, Figure 8.5 presents a simplified distribution feeder that is fed from a substation and has a transformer $Tr_1$ Delta-YG. Further a distribution line for carrying the power and after which a transformer $Tr_2$ of the configuration YG-YG is

considered. Further the distribution feeder is fed from the extreme end on the other side with a PV using an isolation transformer $Tr_3$ having a configuration of YG-Delta. When a single line to ground fault (SLGF) occurs on the line connected to transformer $Tr_2$, the fault current flows in both the directions as seen from the zero sequence equivalent circuit of Figure 8.5. Considering the fact that zero circuit impedance (reactance) $XTr_{10}+Zline_0 < XTr_{20}+ XTr_{30,}$ the majority of the current takes the least impedance path, so considering a rough number, if 78% current flows towards the substation side, the remaining 22% flows towards the PV inverter side. This is due to the grounding path provided. In the absence of PV inverter, 100% of the fault current will flow through the substation side. But since PV inverter is present, the 22% reduction in fault current can desensitize the distribution feeder protection coordination. With an effective grounding scheme using a grounding reactor as per the design specifications of Eq. 8.2 and Eq. 8.3, the fault current levels could be brought back to 90%, so the desensitizing is no longer an issue.

The configuration in Figure 8.6 is slightly different. It can be seen that transformer $Tr_3$ is Y-Delta. As a result of which the path for the flow of zero sequence current does not include the $XTr_{30}$ reactance. So, the reactance under consideration includes $XTr_{10}+Zline_0 < XTr_{20.}$ Since flow of fault current is not into the PV inverter's zone keeping it isolated, the desensitizing is no longer an issue and this configuration can be considered as an economical one.

In Figure 8.7, the only difference is the configuration of transformer $Tr_2$ which is YG-YG. When the zero circuit equivalent circuit is considered, it could be well witnessed that there is no path for the fault current to flow on either side of the feeder and is opened

due to the lack of effective grounding pattern associated with all the transformers. As a result, the point of common coupling (PCC) where the PV inverter is connected, experiences a Temporary Overvoltage (TOV). This can be detrimental to customer loads as already discussed.

Effective grounding is relatively a challenging problem with PV industry. Effective grounding may still not mitigate the Temporary Overvoltage issues in a distribution system. This paves the way for exploring into novel mitigation strategies to suppress TOV forms the crux of the research in this chapter.

## 8.7 TOV mitigation using Zig Zag transformer

A system is designed based on the parameters extracted from the bench mark system of IEEE Standard 399-1997 with suitable modifications [116]. It could be seen that that the substation is rated at 100 MVA, 69 kV with a short circuit impedance of 6.1+j24.4 ohms. The transformer steps down the voltage from 69 kV to 13.8 kV and a distribution feeder feeds certain loads rated at 1.5 MW and 2 MVAR, connected at the point of common coupling (PCC). The conventional PV plant rated at 4 MW is connected to the PCC through an isolation transformer 480/13.8 kV, Delta/Star Configuration. Initially the system is simulated without a grounding (Zig zag) transformer. The PV plant is designed based on PWM switching [117]. The pictorial representation and the design using PSCAD are shown in Figure 8.8. Initially the system is tested without the zig zag transformer and then zig zag transformer is has been put into use in the form of effective grounding scheme as shown in Figure 8.8.

Figure 8. 9 presents the output voltage at the point of common coupling (PCC). It could be seen that during a single line to ground fault on phase ‘a’ at $0.80^{th}$ second as seen from Figure 8.8, it leads to Temporary overvoltage peak of 17.89 kV corresponding to a per unit value of 1.59 p.u. This is a huge violation and needs to be brought down to a value less than 1.39 p.u. A zig zag transformer is designed using PSCAD rated at 13.8 kV and based on equations 8.1, 8.2 and 8.3 that could be seen from Figure 8.8.  It could be seen from Figure 8.10 that during a SLGF at $0.80^{th}$ second, the TOV has been mitigated and brought down to a value closer to 1 p.u in the healthy phases b and c (Fact: TOV limit should be less than 1.39 p.u for North American system and varies based on limits set by utility) thereby proving an effective grounding to this system.

Although, the effective grounding is established in this system with zig zag transformer, sometimes TOV has posed a challenge and the concept of effective grounding in the presence of PV has become more challenging. This requires a new strategy to mitigate the TOV phenomenon. Considering the challenge, this chapter further demonstrates the neoteric application of Smart PV and Smart parks for mitigating TOV in the further sections.

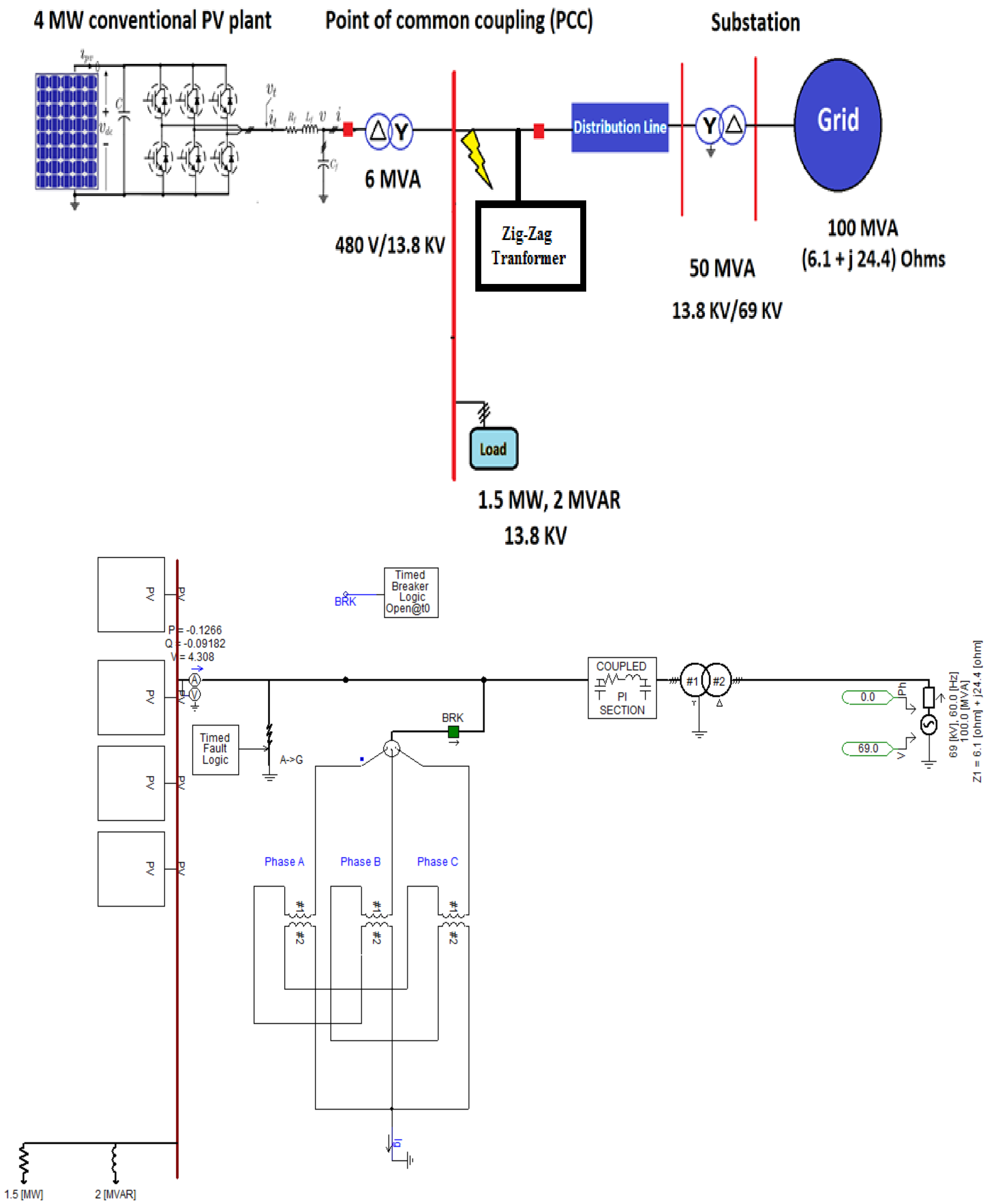



Figure 8.8 System designed based on the parameters on parameters extracted from the bench mark system of IEEE Standard 399-1997 employing grounding bank (zig-zag transformer to mitigate TOV)

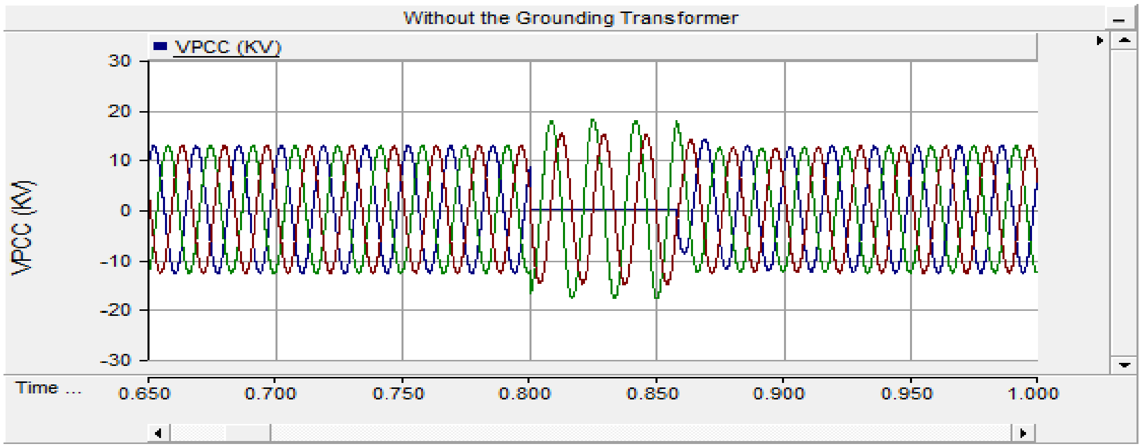



Figure 8.9 Output voltage at PCC during fault without the grounding transformer incorporated into the system designed using parameters extracted from IEEE Standard 399-1997

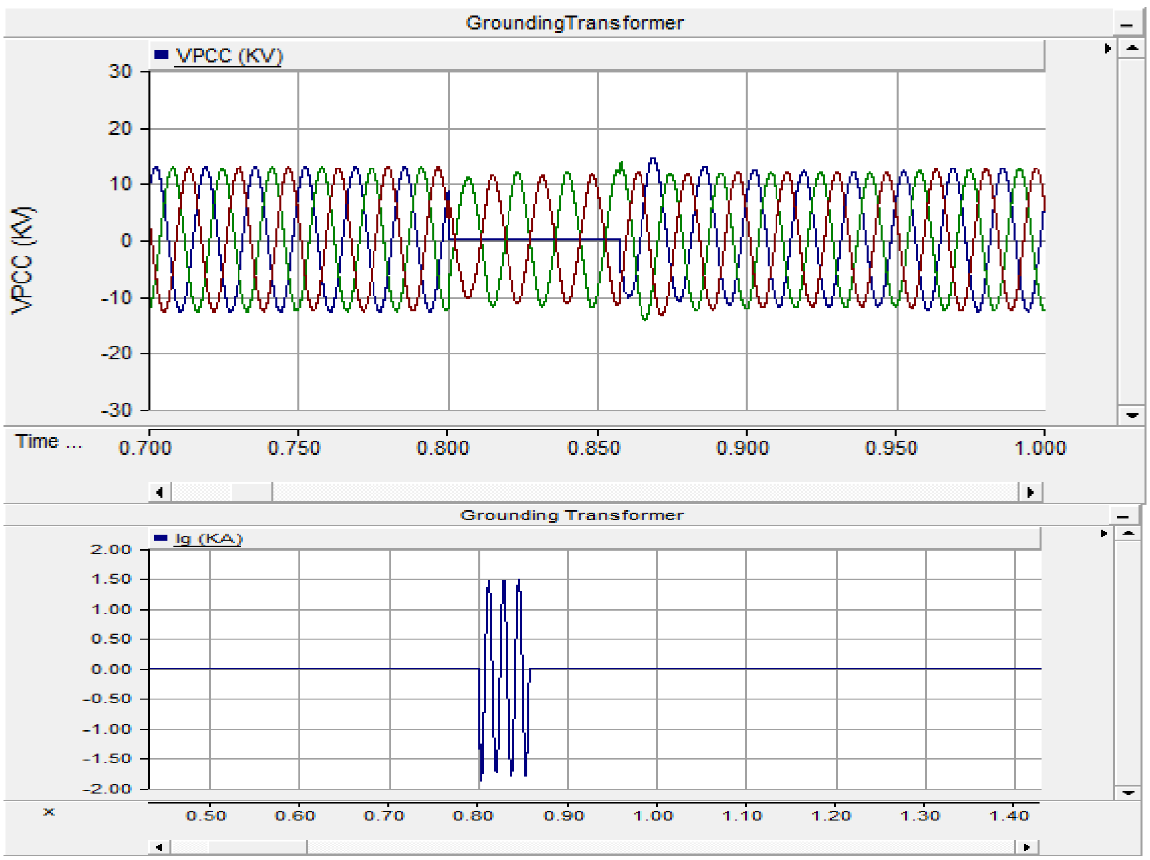



Figure 8.10 Output voltage at PCC and ground current Ig during fault with the grounding transformer incorporated into the system designed using parameters extracted from IEEE Standard 399-1997

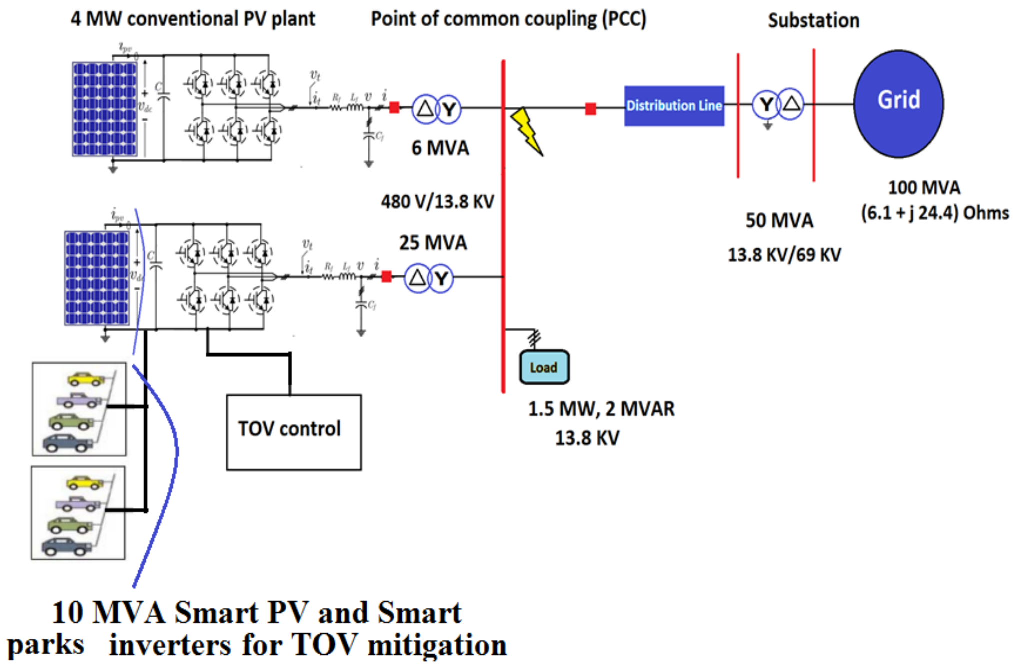



Figure 8.11 System designed based on the parameters on parameters extracted from the bench mark system of IEEE Standard 399-1997 employing Smart PV and Smart parks to mitigate TOV

## 8.8 <u>Neoteric application of Smart PV and SmartParks as a TOV suppressor</u>

As a part of contribution towards a new application, the research work presented in this section manifests a new control strategy associated with inverters referring to them as Smart inverters. Smart inverters are ancillary service providers that could perform various grid related operations apart from real power generation. In this chapter, inverters associated with Plug in Electric Vehicles and PV farms are considered. A specialized controller design enables them to act as a suppressor of Temporary Overvoltage (TOV).

The concept of VAR absorption is the basis behind the design of Smart inverters in this research work. In case of TOV, the overvoltage in two phases needs to be controlled. So a specialized control strategy is needed compared to a usual controller that controls all three phases during VAR absorption. To the system shown in Figure 8.8, the grounding transformer is removed. Instead of that, Smart PV and Smart parks are in place interfaced with inverters through the isolation transformer rated at 480 V/13.8 kV (Delta/Y) and connected to PCC, as shown in Figure 8.11.

The Smart controller associated with Smart PV/Smart Park are classified into two blocks. One is the TOV detection/sensing unit and the other one is the voltage magnitude limiting unit. Whenever there is a SLGF, the TOV sensing/detection unit raises the flag to 'one' and based on which voltage magnitude limiting unit is activated and thereby reduces the TOV phenomenon on the distribution feeder. During normal operation, the TOV sensing/detection unit disables the voltage magnitude limiting unit by setting the flag status to 'zero'. As a result of which the VAR controller is enabled. This controller tries to curtail the voltage rise due to the reverse power flow that happens due to the integration of conventional PV plant in the system. Compared to grounding bank (zig-zag) transformer which can just mitigate TOV, the novel controller application proposed can control TOV as well mitigate the voltage rise due to reverse power flow.

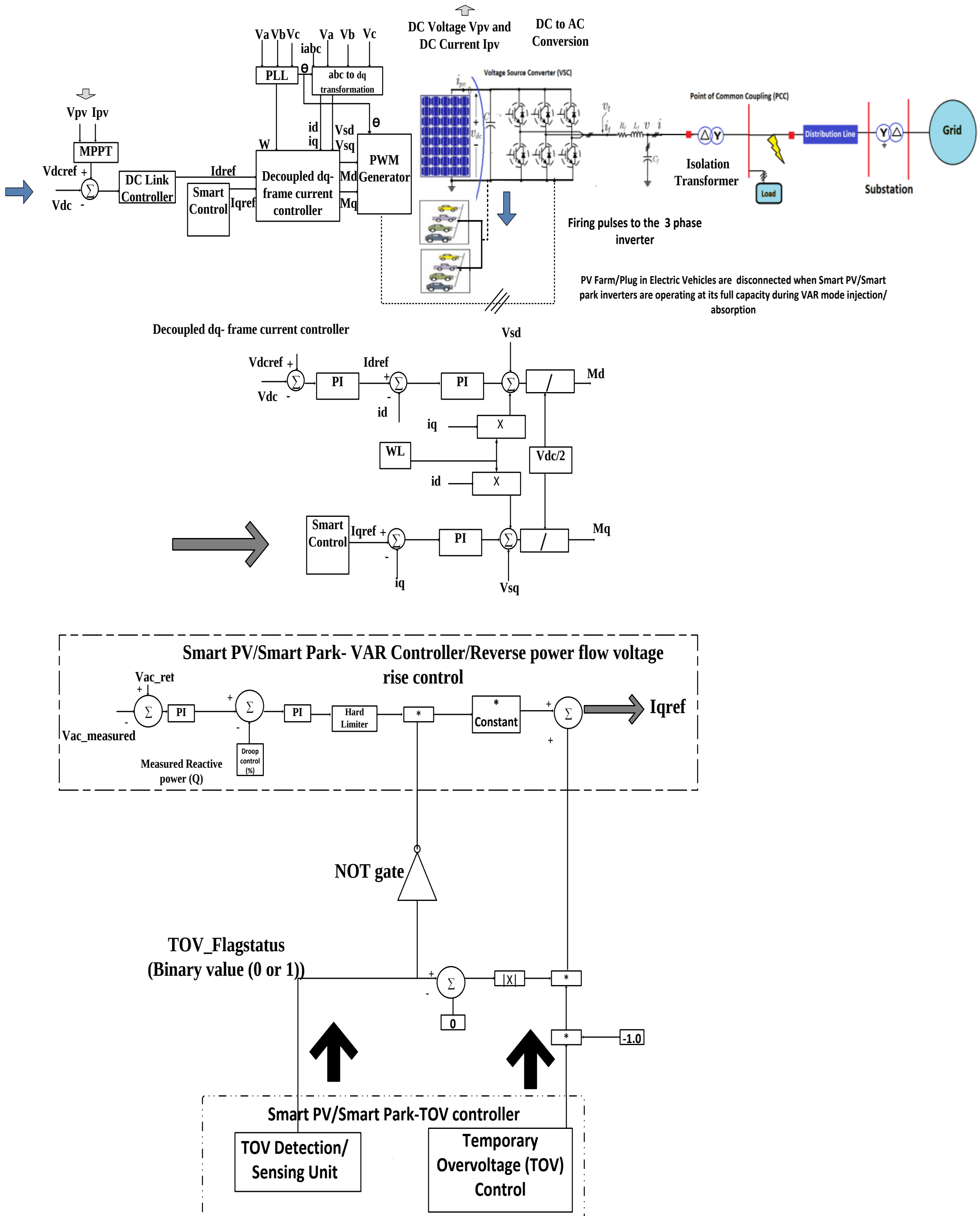



Figure 8.12 TOV controller strategy associated with the PV and Plug in Electric Vehicles Inverter constituting the Smart PV and Smart park system

Table 8.1 Possible digital logic output of Hysteresis buffer with inputs of 3 phases to design the TOV sensing unit

| Phase A | Phase B | Phase C | Output Y |
|---|---|---|---|
| 0 | 0 | 0 | 0 |
| 0 | 0 | 1 | 1 |
| 0 | 1 | 0 | 1 |
| 0 | 1 | 1 | 1 |
| 1 | 0 | 0 | 1 |
| 1 | 0 | 1 | 1 |
| 1 | 1 | 0 | 1 |
| 1 | 1 | 1 | 0 |

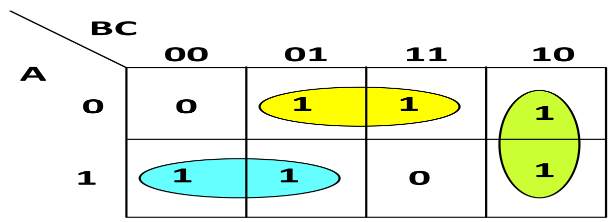



Figure 8.13 Karnaugh Map technique used for the design

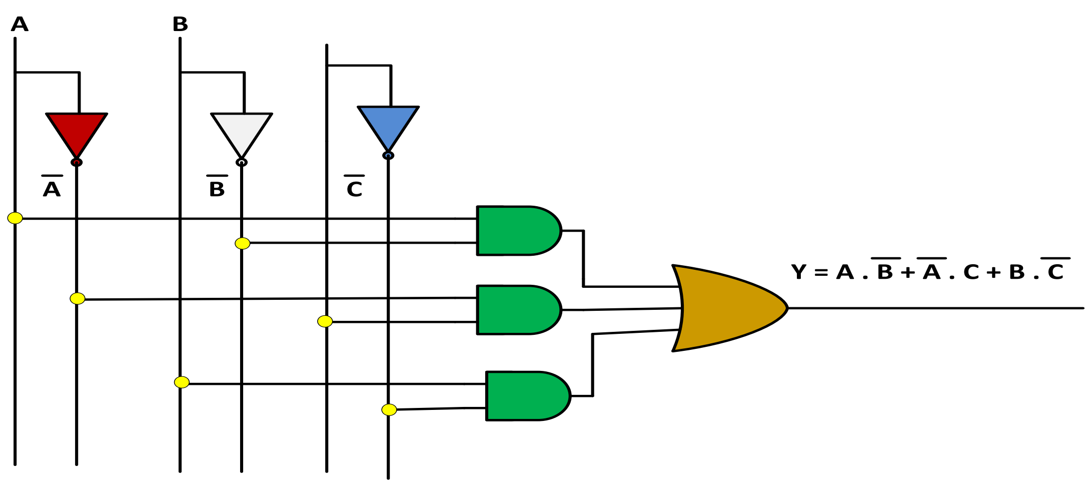



Figure 8.14 Representation of Karnaugh Map in the form of Digital logic gates for TOV sensing unit

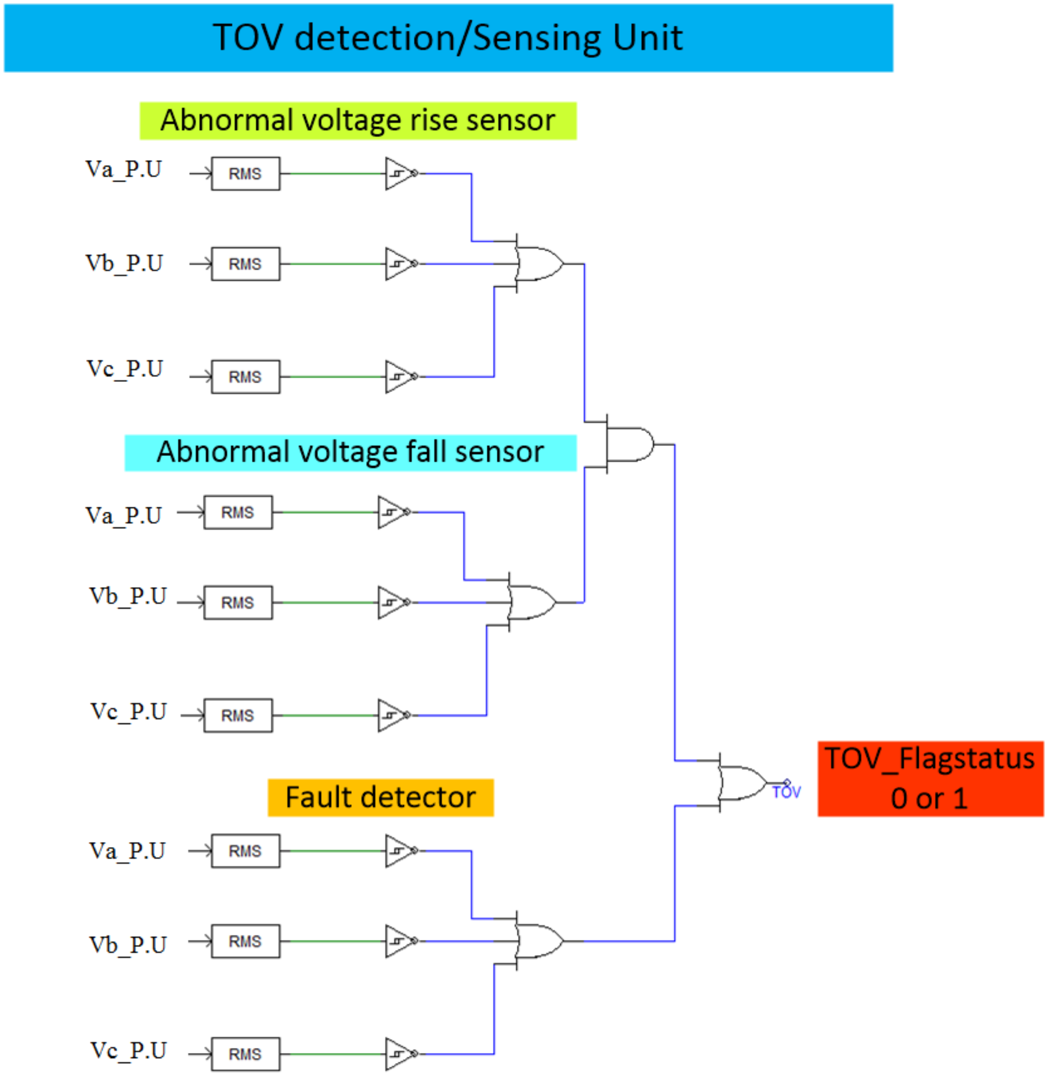



Figure 8.15 TOV sensing/detection unit associated with Smart PV and Smart park system inverters

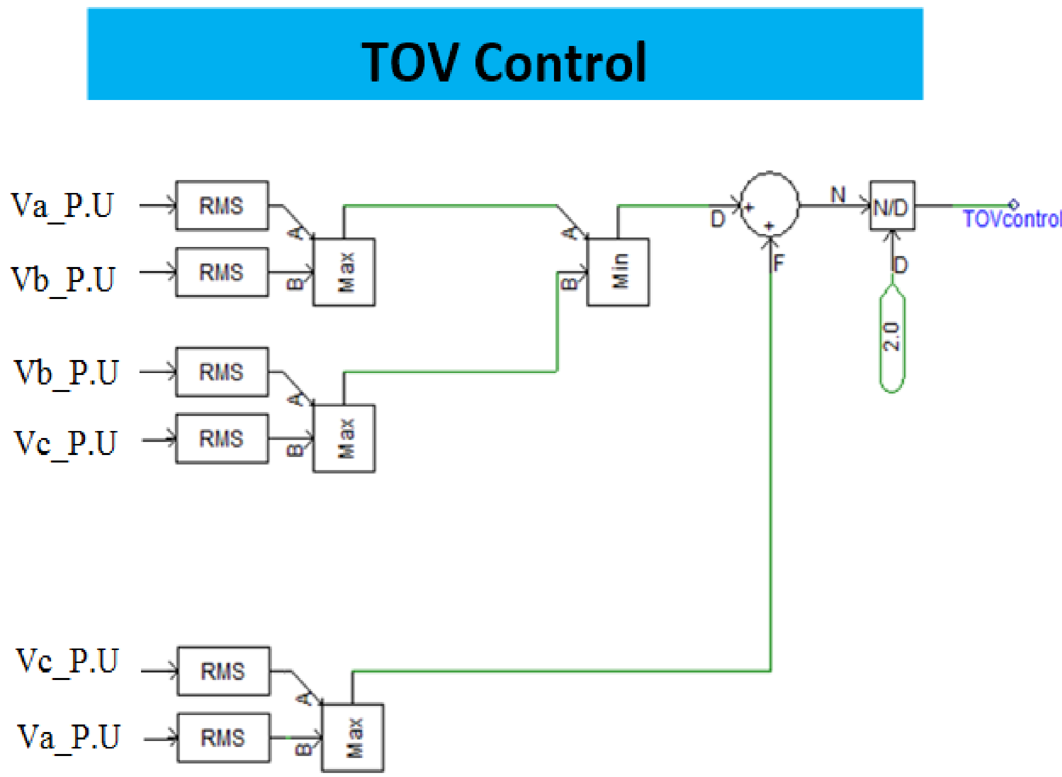



Figure 8.16 TOV controller for the inverter of the Smart PV and Smart park system

Figure 8.15 presents the design of TOV detection/sensing unit corresponding the block in Figure 8.12. Prior to designing the TOV sensing unit, the optimal utilization of logic gates needs to be taken care of to ensure minimal hardware in the design and to avoid propagation delay of the gates. As per the logic, when one of the phases goes high (value 1), the TOV sensing unit should raise the flagstatus to 1. Considering that, a truth table has been devised as shown in Table I. The three phase values are converted into digital signals in the form of 0 and 1 using hysteresis buffer. The three inputs can provide 8 combinations to provide the necessary output. The corresponding Karnaugh Map is drawn as shown in Figure 8.13. The digital logic design corresponding to the Karnaugh Map is drawn, as

shown in Figure 8.14. But the number of gates used in the design are more. Considering the optimal, cost effectiveness and the speed of the design, a simple OR gate is used in the design connecting to the hysteresis buffer as shown in Figure 8.15. Even if one output is 1, the output of the OR gate will be 1.

It could be seen that the TOV detection/sensing unit can be classified into three blocks. The first one on top presents the abnormal voltage rise sensor, the second one presents the abnormal voltage fall sensor and the third block represents the fault detector. A hysteresis buffer and digital logic gates are used to model the TOV detection unit. Since the TOV has to be less than 1.39 p.u, the upper limit for the hysteresis buffer in the abnormal voltage rise sensor is set to 1.39 p.u and the lower limit is set to 1.2 p.u. In case of the hysteresis buffer limit in the abnormal voltage fall sensor, the limits are set between 0.85 p.u and 0.80 p.u. In case of the fault detector buffer, the limits are set between 0.50 p.u and 0.55 p.u. The three phase voltages are measured and given to the buffers of the three blocks. The hysteresis buffers provides a digital logic output ‘0’ or ‘1’. After passing through the connected logic gates, the final output TOV_Flagstatus is either ‘0’ or ‘1’.If the TOV_Flagstatus is 0, the controller behaves in controlling the voltage rise due to reverse power flow due to the flow of power due to the 4 MW conventional PV plant. This control facilitates the penetration of more renewables in the system since the voltage rise in all three phases due to reverse power flow is mitigated.

During an abnormal event in any one of the phases, the TOV_Flagstatus is set to 1 and as a result, the TOV control is enabled. The corresponding TOV control block diagram is shown in Figure 8.16. The logic is purely designed based on the magnitude comparison

and based on which the during a SLGF in one of the phases, the magnitude of the healthy phases are controlled and brought down to a limit less than 1.39 p.u to remove violations.

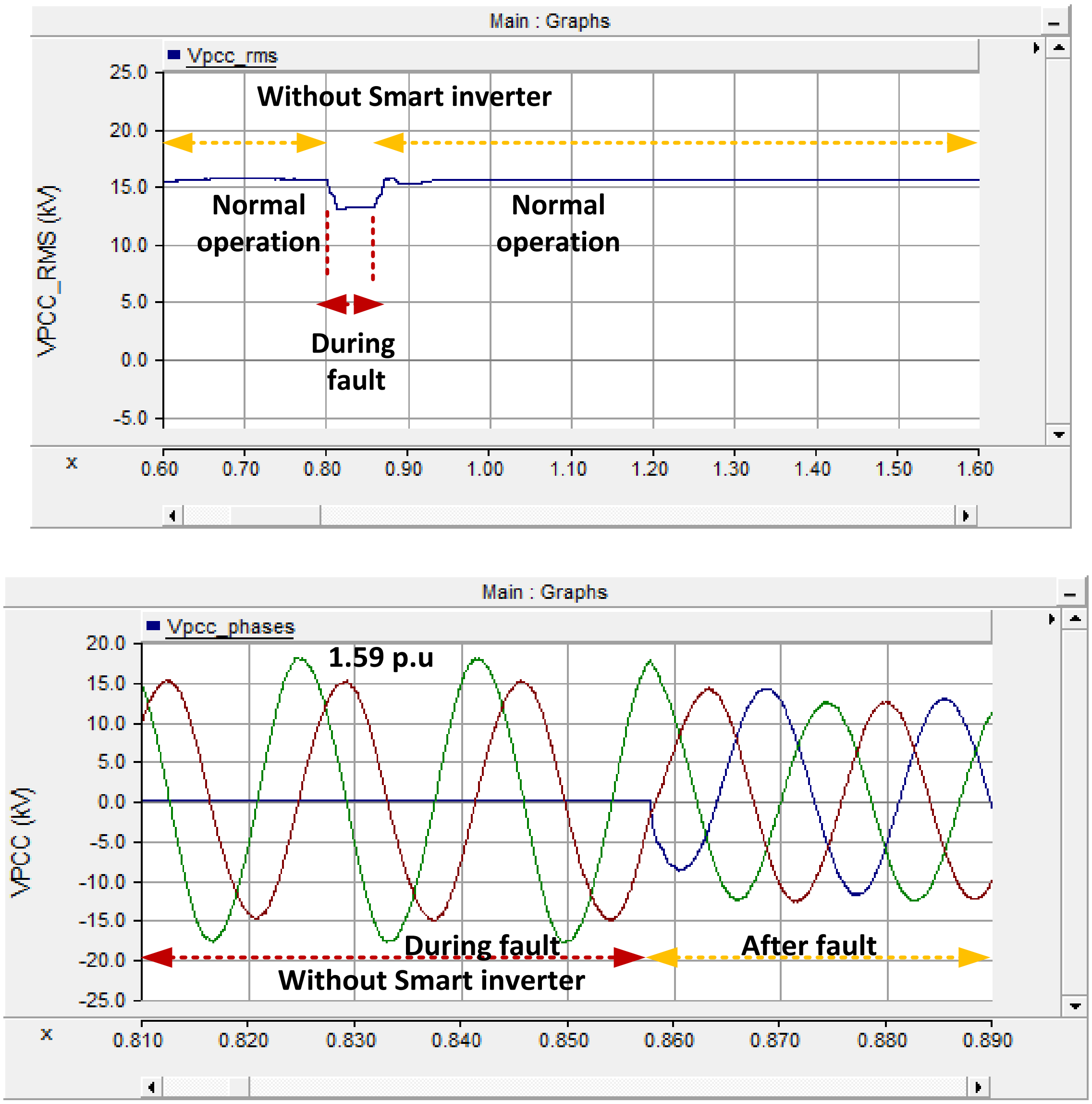



Figure 8.17 Output voltage RMS (top) and Phase voltages (bottom) at PCC during SLGF fault without the Smart inverter

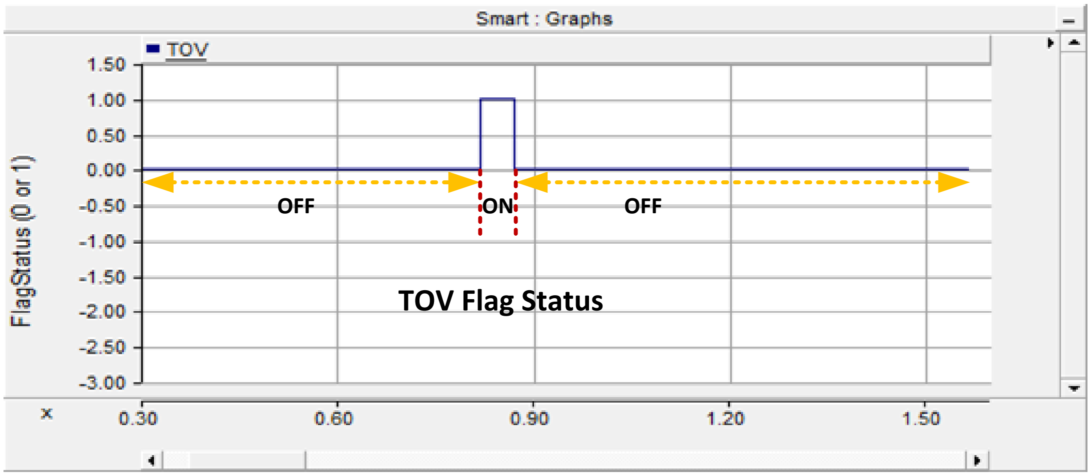



Figure 8.18 Output of TOV detection/sensing unit

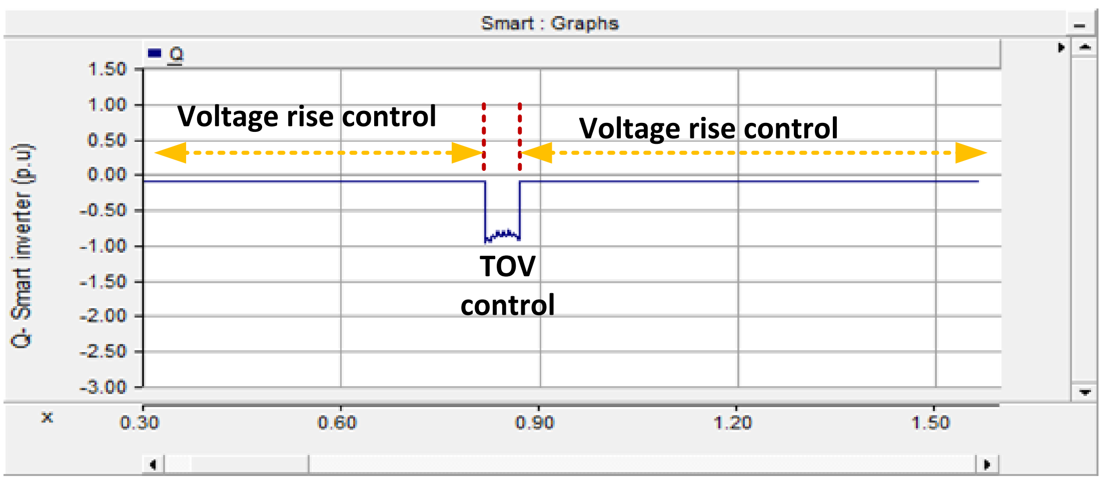



Figure 8.19 Reactive power output of the Smart PV/Smart Park inverter

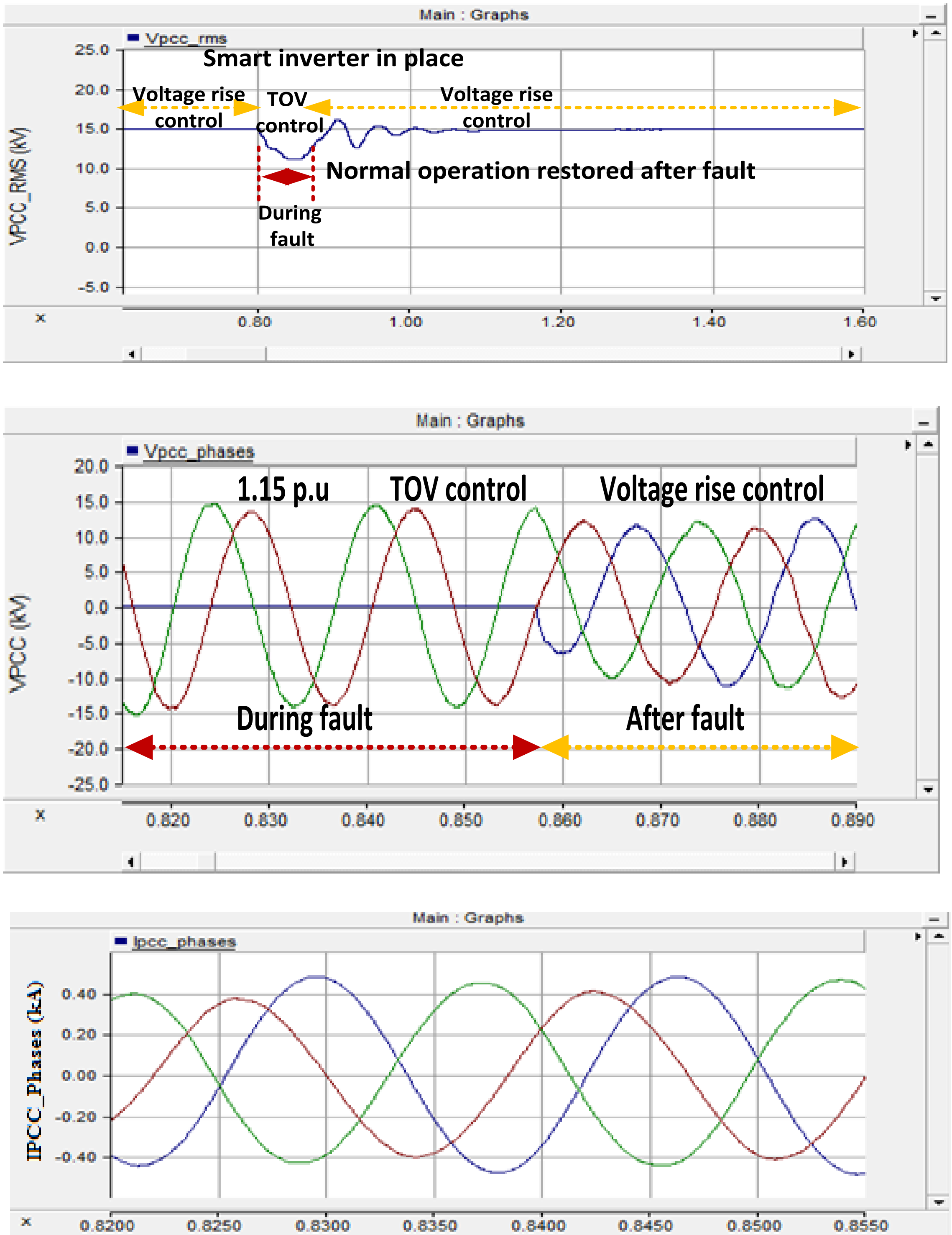



Figure 8.20 Output voltage RMS (top), phase voltages (center) and phase current (bottom) at PCC showing that TOV is reduced effectively by Smart PV/Smart park inverter

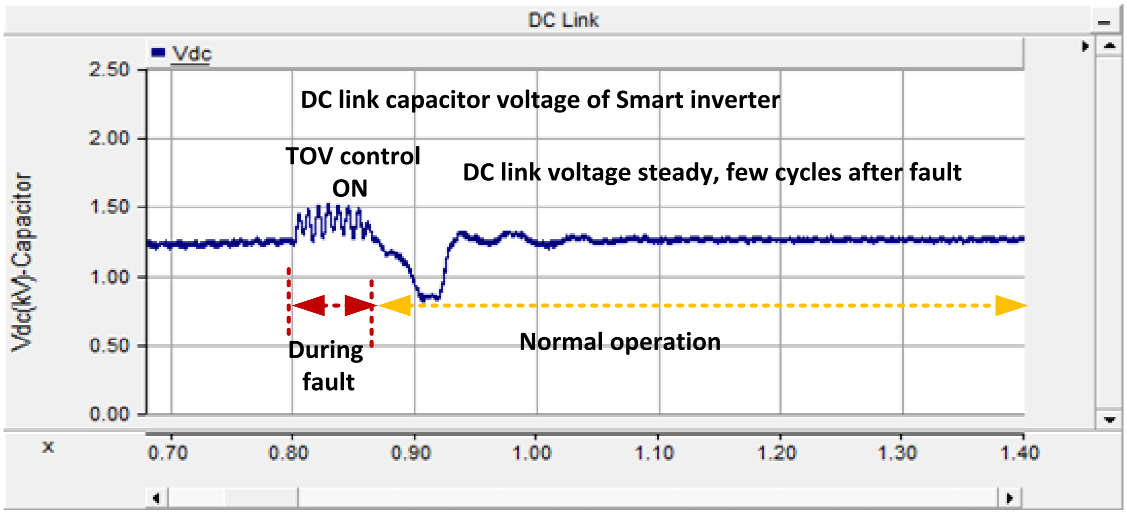



Figure 8.21 DC link voltage across the capacitor of Smart inverter

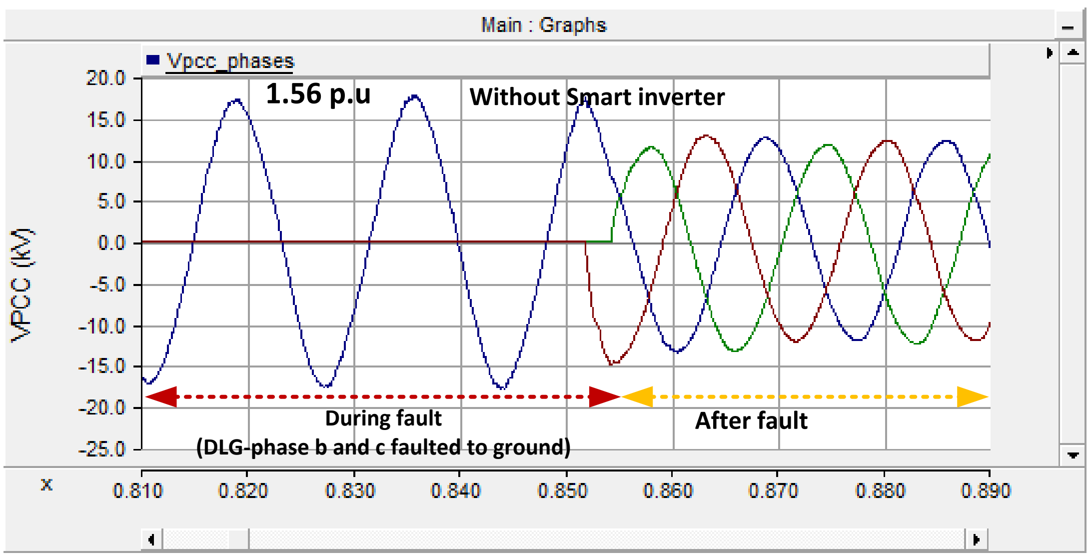



Figure 8.22 Output voltage at PCC showing that TOV is evident during LLG fault without the presence of Smart inverters

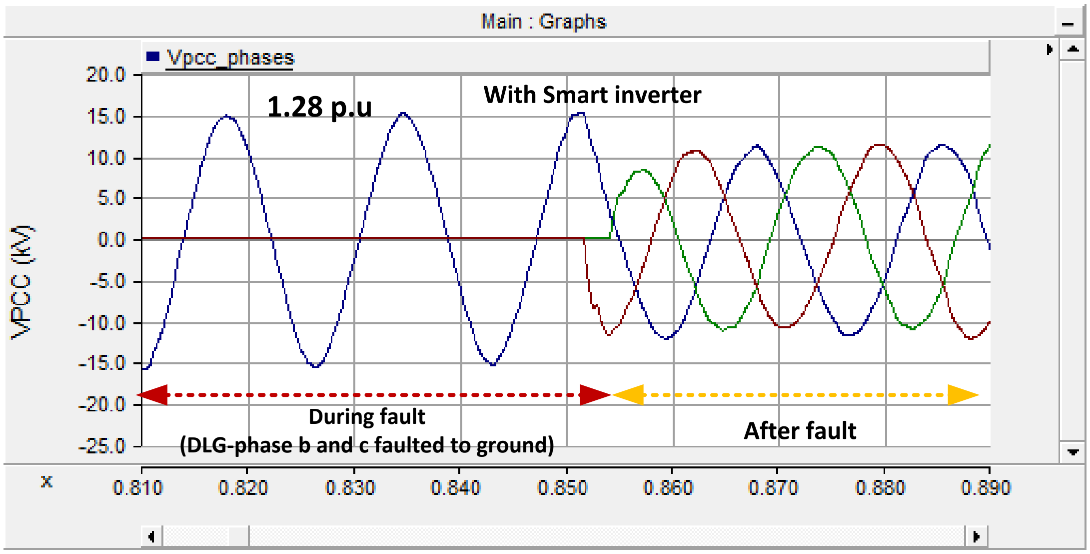



Figure 8.23 Output voltage at PCC showing that TOV is reduced effectively by Smart PV/Smart park inverter during LLG fault (Note: in comparison to Figure 8.22)

This controller is designed for a 480 V North American system and could be adapted to any system universally based on the voltage ratings.

## 8.9 Output of Smart PV/Smart Park TOV Control

The research considers the effective utilization of dormant Smart PV/Smart Park inverters for VAR absorption considering it full available rated capacity. As discussed in the previous section, TOV_Flagstatus determines the mode of operation of the controller. When TOV_Flagstatus is 0, the voltage rise control due to reverse power is enabled. This controller compares the AC system voltage and finally gives the output reference current Iqref to the decoupled current controlled loop of the PWM controller that operates at a switching frequency of 3060 Hz and is designed based on dq reference frame control [118]. During this control mode, all three phase voltages are controlled by reactive power (VAR)

absorption. During a SLGF, TOV_Flagstatus is 1 and as a result of which, the TOV control is enabled and sets the reference Iqref. Based on which the Smart PV/Smart Park inverter absorbs the VAR in the two healthy phases alone where TOV has been witnessed to bring it down to remove the violation. The inverter gate logic plays an important role in the selection of the type of the controller based on the command initiated by the TOV_Flagstatus.

Figure 8.17 presents the output voltage (RMS-top, Phase voltages (bottom) at the point of common coupling during SLGF on phase 'a' when Smart inverter system is not present. It could be seen that the peak in one of the phases is 17.89 KV, corresponding to a value of 1.59 p.u. This can damage the customer loads connected to those healthy phases where TOV is appearing.

Now when Smart inverter system is in place, it could be seen from Figure. 18 that TOV_Flagstatus is '0' till 0.799$^{th}$ second. At 0.80$^{th}$ second there is a SLGF fault on phase 'a' and lasts till 0.855$^{th}$ second. At 0.80$^{th}$ second, the TOV_Flagstatus is automatically set to '1' by the controller. It could be well seen from Figure 8.18 that the TOV_Flagstatus is '0' till 0.799$^{th}$ second. Till this time, the Smart inverter is working as a voltage rise control mode controlling all three phases and absorbing reactive power of 0.1 p.u corresponding to a capacity of 1 MVAR from Smart PV/Smart park inverter system. This ensures that the voltage rise due to reverse power flow from 4 MW conventional PV plant is controlled. Figure 8.19 corresponds to the same with respect to reactive power absorption from Smart inverter during the two modes (voltage rise control and TOV control).

It can be clearly witnessed that the voltage is maintained within the range of 0.95 p.u to 1.05 p.u (+/-5% of the utility limit) during the voltage rise due to reverse power flow from conventional 4 MW PV plant. During the fault at 0.80$^{th}$ second during SLGF, the TOV is the healthy phases are brought down to a value of 1.15 p.u. The corresponding output could be well witnessed from Figure 8.20. Further, it could be seen from Figure 8.21 that during the SLGF fault, the DC link voltage across the capacitor rise just slightly and the Smart inverter controller tries to bring it back to steady state within few cycles after the fault has been cleared.

The research work reveals that a 10 MVAR Smart PV/Smart Park inverter capacity is required to bring down the TOV to 1.15 p.u. As the size of the Smart PV/Smart Park increases, this would still become beneficial to perform the ancillary grid related services. Thus the dormant Smart inverter with this full available capacity performs dual action as a voltage rise controller during normal condition and as a TOV suppressor during SLGF. Further the efficacy of Smart inverter system is also tested for LLG fault. Phase ‘a’ is considered to be healthy and phase ‘b’ & phase ‘c’ are faulty phases in the study. It could be seen from Figure 8.22 presents the output voltage at PCC during LLG fault. It could be seen that the peak value of voltage is 17.57 kV corresponding to a per unit value of 1.56 p.u. When 10 MVAR Smart PV/Smart Park inverter is in place, the TOV is reduced to a peak value of 14.39 kV corresponding to a per unit value of 1.28 p.u, thereby eliminating the violations as shown in Figure 8.23.

## 8.10 General discussion

The research has considered the application of dormant Smart PV/Smart park inverter for mitigating TOV. This can be either in coordination between the Smart PV and Smart park inverters, exclusive operation of Smart PV or Smart park inverter for mitigating TOV. Based on the availability of the inverter capacity the extent of TOV control and other ancillary services could be witnessed. This chapter has considered the full available capacity of the dormant Smart inverters for mitigating TOV. The same controller has also been extended to LLG fault.

# CHAPTER NINE

# CONCLUSIONS AND FUTURE WORK

As the grid becomes smarter, the smart inverters becomes the need of hour for offering several ancillary services in distribution systems. The concluding part of the dissertation has been provided chapter-wise in the further sections.

## 9.1 Consolidated compendium of PV interconnection standards across the globe in a smart grid

As the decentralized generation from PV solar plants has become widespread, the grid reliability calls for the development and constant revision of PV Interconnection standards. While much of the effort is on mitigating local issues such as voltage control and protection coordination, there is also an increasingly urgent need to consider the effect that PV have on bulk power system reliability. Large-scale deployment of PV without adequate voltage and frequency tolerance will negatively affect bulk system reliability and performance by making disturbance recovery more difficult. Suitable development of new standards and revision/updates of existing standards are constantly required. Thus Chapter 2 presented a consolidated compendium of PV interconnection standards and guidelines across the globe in a smart grid.

## 9.2 Harmonic resonance repercussions of PV and associated distributed generators on distribution systems

IEEE 519 standard forms a very important aspect of addressing the power quality issues, as more PV and Wind based distributed generators are penetrated into the system. The research based study like this on every system needs to be performed to have an idea

regarding how the penetration levels of DG's tend to impact the resonance modes and harmonic injection. Thus Chapter 3 also forms an important aspect of distribution systems planning.

## 9.3 Interactive impacts of elements of distribution systems on network harmonic resonance in distribution systems

As a part of distribution systems planning towards power quality, the research study in this chapter presented the impact during the interaction of elements in distribution systems with PV integrated into it. Further, this paves the way for a novel solution of utilizing Smart PV inverters as virtual de-tuner for mitigating network resonances, forms the further investigation of further chapters. Thus Chapter 4 will also further serve as a handy reference to planning engineers and researchers as well.

## 9.4 Comparative impact assessment of filter elements associated with PWM and hysteresis controlled PV on network harmonic resonance in distribution systems

A comparative study of PV Inverters using PWM and hysteresis controlled strategy is employed to witness the impact of the associated filter elements on the AC side of PV Inverters on the network harmonic resonance modes in the system. Chapter 5 brought out a contribution by addressing a comparative study done for the two control schemes and the impact of its filter elements clearly suggests that research studies like this forms the crux of power quality and distribution planning.

### 9.5 Detuning of harmonic resonant modes in accordance with IEEE 519 standard in an exemplary North American distribution system with PV and Wind

As more number of distributed generators like PV and Wind are penetrated into the system, the harmonics injected by them tend to increase, also leading to a phenomenon of resonance. So, an effective detuning methodology should be employed to eliminate the undesired factors that hamper the power quality and hence the reliability of the system. Chapter 6 presented a strategy to detune the system towards reliability and would serve as a reference for all the power quality engineers and researchers. Further this chapter paved the way to utilize Smart PV inverters as a strategic virtual de-tuner in eliminating the network resonance and thus forming a vital element of smart grid formed the base for further investigation in this dissertation.

### 9.6 Efficacy of Smart PV inverter as a virtual detuner for mitigating network harmonic resonance in distribution systems

As the Smart PV Inverters are becoming the hour of the day, it calls for more new ideas and functionalities, to maintain the reliable operation of the grid. This chapter thus proposed a new idea and functionality for the first time in utilizing a Smart PV Inverter to act as a detuner in eliminating network resonances, based on the new controller designed for Smart PV Inverters. It has been well witnessed from the results presented in this paper. This would effectively make use of dormant PV inverters as Smart PV inverters. For a round the clock operation, the detuning can also be done from machine drives whose reserve inverter capacity could be effectively utilized for detuning. Eventually, the Smart PV inverter along with inverter based motor drives could be effectively utilized for

detuning for a 24 hour based operation. This idea would further serve as a pioneering approach for researchers and planning engineers working in distribution systems.

### 9.7 Smart PV and SmarPark inverters as suppressors of Temporary Overvoltage (TOV) phenomenon in distribution systems

The effective utilization of dormant Smart PV/Smart Park inverters (with full available capacity) or with the remaining capacity after real power generation could thus be effectively utilized for voltage rise control due to reverse power flow and TOV phenomenon that arises in the system. In other words, the neoteric application of Smart PV/Smart parks can provide an alternate solution to an ineffective grounding schema in distribution systems when inverter based DG's like PV are in place. The concept of effective grounding for PV system has still been a challenge when utilities try to mitigate TOV. As a result, millions of dollars and power has been wasted by the utilities. This research presented a new application and a novel schema for utilizing Smart PV and Smart Park inverters to mitigate TOV in distribution systems, thus making them as an alternate and strengthening solution towards an ineffective grounding in distribution systems.

### 9.8 Future Work

Future research and investigation associated with Smart inverters can be as follows:

- Coordination between Smart PV inverter, Smart Park inverter and other elements of distribution systems could further be investigated.

- The neoteric efficacious controller strategy for TOV and harmonic resonance mitigation could be implemented and tested in the laboratory environment and field on real North American systems in future.
- The concept of VAR injection/absorption could further be extended to addressing several other ancillary services associated with Smart PV/SmartPark inverters in accordance with IEEE 1547.8.

## 9.9 Publications

### 9.9.1 Refereed Conferences

[1] **Shriram S. Rangarajan, E. Randolph Collins, J. Curtiss Fox, "Harmonic resonance repercussions of PV and associated distributed generators on distribution systems,"** ***2017 IEEE North American Power Symposium (NAPS)*****, Morgantown, WV, U.S.A, 2017**.

**(Student Awards for Best Paper 2017 - IEEE 49th North American Power Symposium (NAPS); Morgantown, WV; September 2017.**
**First Prize, IEEE Website: *http://ewh.ieee.org/soc/pes/sasc/awards.html).***

***Media, Clemson University College of Engineering, Computing and Applied sciences Facebook link:***
***https://m.facebook.com/CES.ClemsonU/posts/1694058497302155***

[2] Shriram S. Rangarajan, E. Randolph Collins, J. Curtiss Fox, D. P. Kothari, "A Survey on Global PV Interconnection Standards", *IEEE Power and Energy Conference at Illinois (PECI)*, February 23-24 2017.

[3] Shriram S. Rangarajan, E. Randolph Collins, J. Curtiss Fox, "Interactive impacts of elements of distribution systems on network harmonic resonances," *6th IEEE International conference on renewable energy research and applications (ICRERA)*, San Diego, CA, U.S.A, 2017.

[4] Shriram S. Rangarajan, E. Randolph Collins, J. Curtiss Fox, "Detuning of harmonic resonant modes in accordance with IEEE 519 Standard in an exemplary North American Distribution System with PV and Wind," *6th IEEE International conference on renewable energy research and applications*, San Diego, CA, U.S.A, 2017.

[5] Shriram S. Rangarajan, E. Randolph Collins, J. Curtiss Fox, "Comparative Impact Assessment of filter elements associated with PWM and Hysteresis controlled PV on network harmonic resonance in distribution systems," *6th IEEE International conference on renewable energy research and applications*, San Diego, CA, U.S.A, 2017.

### 9.9.2 Refereed Journals

[6] Shriram S. Rangarajan, E. Randolph Collins, J. Curtiss Fox, D.P. Kothari, "A consolidated compendium of PV interconnection standards across the globe in a smart grid" –Under Review.

[7] Shriram S. Rangarajan, E. Randolph Collins, J. Curtiss Fox, "Efficacy of Smart PV inverter as a virtual detuner in mitigating network harmonic resonances" Under Review.

[8] Shriram S. Rangarajan, E. Randolph Collins, J. Curtiss Fox, "Smart PV and SmartPark inverters as suppressors of Temporary Overvoltage (TOV) phenomenon in distribution systems"- Under Review.

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# CURRICULUM VITAE

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- Honored during annual ECE award ceremony 2018 by Graduate and Department Chair in the ECE Department, Clemson University, U.S.A for winning the first prize at 49th NAPS 2017, U.S.A for Clemson University.

- Bestowed with a certificate of 'Appreciation Award' for serving as a panel judge during 2017 International conference on renewable energy applications (ICRERA) at San Diego, California, U.S.A.

- Funded by Duke Energy eGrid at Clemson University Restoration Institute, Charleston, SC, U.S.A towards research.

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