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Impact of Inverter Based Resources on System Stability in Low Inertia Power System Network

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Abbreviations

Table 1: List of Abbrevation

BESS	Battery Energy Storage system
HVDC	High Voltage Direct Current
IBG	Inverter Based Generation
IBR	Inverter based Resource
IEEE	Institute of Electrical and Electronic Engineers
PLL	Phase Locked Loop
PSS/E	Power System Simulator for Engineers
PV	Photo Voltaic
PWM	Pulse Width Modulation
RES	Renewable Energy Resource
RoCoF	Rate of Change of Frequency
SC	Synchronous Condenser
STATCOM	Static Compensator
SVC	Static VAR Compensator

Acknowledgement

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Abstract

Inverter-based resources (IBRs), such as solar and wind power are gaining popularity because of their increasing acceptance, environmental benefits and decreasing costs. However, their integration into power systems can lead to significant impacts on system inertia and frequency stability, which are crucial for maintaining the reliability of the power grid. In traditional power systems, the synchronous generators provide inertia, which helps to stabilize the frequency of the system. However, IBRs do not have this inherent inertia, and their integration can result in a decrease in system inertia, leading to frequency instability. This is because IBRs are typically connected to the grid through power electronics, which can introduce additional control and communication delays that affect the system's response to disturbances.

To address this issue, various techniques have been proposed, such as virtual and synthetic inertia, to increase the effective inertia of IBRs. This thesis will cover the modeling of Battery Energy Storage Systems (BESS) and Static Synchronous Condenser (STATCOM) into power systems using PSS/E software to improve the effective inertia of the system and voltage profile respectively, ensuring that the power grid operates with reliability and stability.

1 Introduction

In a power system, inertia is the rotational mass of alternators and their prime movers or turbines which tends to resist the changes in frequency of the power system when a sudden change in load occurs or any other disturbance happens in the system.. This property is attributed to the laws of motion for the rotating masses. With the bulk contribution of renewable energy power like solar and wind with no inertia or very low inertia, power system stability problems need to be dealt with different strategies than before.

Most of the renewable energy resources are interfaced with the power system using power electronic inverters and thus called inverter-based resources (IBRs). The proportion of IBRs in global power networks has grown over the past few decades, and the effects they have during a transient and on the stability of the power system can no longer be disregarded. These results have traditionally been attributed to alternators and turbines in traditional power systems.

1.1 Study Objectives

The objectives of this study are as under:

1. To identify the effects of low inertial systems in power system frequency stability in an IEEE 39 bus network.
2. Steady state and dynamic modeling of renewable inverter-based resource IBR in PSS/E.
3. Modelling, steady state and dynamic simulation of IEEE 39 bus system in PSS/E with and without IBRs.
4. To propose a solution for mitigating the adverse effects of low inertial systems regarding frequency stability in an IEEE 39 bus system with IBRs.

1.2 Methodology

Following methodology has been adopted to carry out and complete this study.

- Steady state modelling of IEEE 39 bus system and inverter-based resources in PSS/E.
- Dynamic modelling of IEEE 39 bus system with and without inverter-based resources in PSS/E.
- Frequency stability analysis of IEEE 39 bus system with and without IBRs in PSS/E.

- Frequency stability analysis of IEEE 39 bus system with Battery Energy storage system and STATCOM added in an IEEE 39 bus system with IBRs in PSS/E.

2 Literature Review

The integration of inverter-based resources into power networks is increasing day by day. The advent of electric vehicles and other inverter-based loads are also increasing. Concerns for grid operators arise as the number of connected inverter-based generation units and loads increases. The situation becomes more interesting when imagining fully inverter-based grids in the future. The grid forming inverters and virtual or synthetic inertial systems also play their role in providing inertial effects and stability to the network. As renewable electricity generation units increase in power systems around the world, researchers are looking into the significance of inertia and redefining it.

For the purpose of controlling a low-inertia system, [1] reviews the literature on inertia in power systems and discusses the difficulties in doing so and the possible solutions. To account for all the different kinds of inertia, a new definition is proposed. The most difficult problem for system operators is the effect of reduced inertia on frequency stability, but the solutions presented in the paper can help mitigate this effect.

2.1 Inertia in Power System

Inertia in power system is explained and challenges and solutions from operator point of view are presented to control a system with low inertia. As soon as there is a change in load on the power system, the stored kinetic energy in the rotating generator-turbine sets must be released instantly to keep the generator-turbine sets spinning at the same frequency. This phenomenon is known as inertia.

For mathematical formulation of inertia, we start with the swing equation for describing the motion of a turbine generator set, given as [2]

$$\frac{d\, J_e.\omega_e}{dt} = T_m - T_e \qquad (1.1)$$

Where T_m and T_e are respectively mechanical and electrical torque on the generator and J_e represents the total moment of inertia of the turbine and generator referred to the electrical frequency ω_e of the system. We can express the above equation in terms of power by simply multiplying ω_e on both side and re-arranging the equation and using the relation $T.\omega = P$.

$$\frac{d\left(\frac{J_e.\omega_e{}^2}{2}\right)}{dt} = P_m - P_e \tag{1.2}$$

The famous swing equation (1.2) for a synchronous machine state that the difference between the electrical and mechanical power of the generator turbine set is equal to the rate of change of kinetic energy.

Inertial constant H is defined as the ratio between the stored rotational kinetic energy and the apparent power S.

$$H = \frac{J_e.\omega_0{}^2}{2\,S} \tag{1.3}$$

Here ω_0 is the base electrical angular speed of the system.

2.2 Role of Inertia in Frequency Stability

Substituting (1.3) in equation (1.1),

$$\frac{2HS}{\omega_0{}^2}.\frac{d\omega_e}{dt} = T_m - T_e \tag{1.4}$$

$$\frac{2H}{\omega_0}.\frac{d\omega_e}{dt} = \frac{T_m - T_e}{\frac{S}{\omega_0}}$$

$$\frac{2H}{\omega_0}.\frac{d\omega_e}{dt} = T_{mpu} - T_{epu}$$

Here $\frac{S}{\omega_0}$ is base Torque T_{base}

$$2H.\frac{d\omega_e/\omega_0}{dt} = T_{mpu} - T_{epu}$$

$$2H.\frac{d\omega_{epu}}{dt} = T_{mpu} - T_{epu} \tag{1.5}$$

Let δ be the rotor angle of the synchronous machine at time instant t when the angular speed is ω_1 and δ_0 be the base rotor angle and ω_0 the base angular speed then we can write the following relation:

$$\delta = \omega_1 t - \omega_0 t + \delta_0 \qquad (1.6)$$

The rate of change of rotor angle would be.

$$\frac{d\delta}{dt} = \omega_1 - \omega_0 = \Delta\omega_e$$

$$\frac{d^2\delta}{dt^2} = \frac{d(\Delta\omega_e)}{dt} = \frac{d(\Delta\omega_{epu})}{\omega_0 . dt} \qquad (1.7)$$

Using (1.5) with (1.6) we get,

$$\frac{2H}{\omega_0} . \frac{d^2\delta}{dt^2} = T_{mpu} - T_{epu}$$

$$2H . \frac{d^2\delta}{dt^2} = \omega_0 . (T_{mpu} - T_{epu})$$

$$2H . \frac{d^2\delta}{dt^2} = P_{mpu} - P_{epu} \qquad (1.8)$$

The factor of damping torque could be included in the eq (1.8) as mentioned in [2]

$$2H . \frac{d^2\delta}{dt^2} = P_{mpu} - P_{epu} - K_D \frac{d\delta}{dt} \qquad (1.9)$$

Here K_D is proportionality constant, between damping torque and speed deviation.

The right-hand side of equation (8) represents the power mismatch, ΔP.

$$2H . \frac{d^2\delta}{dt^2} = \Delta P \qquad (1.10)$$

Inertia's impact on frequency stability is demonstrated by the equation (1.10), as $\frac{d^2\delta}{dt^2}$ is the rate of change of frequency. During a power imbalance, the initial frequency gradient is dependent upon system inertia, and inversely related to it [3].

2.3 Inverter Based Generation and Low Inertial Power Systems

Wind and solar generation are the dominant inverter-based power resources. The integration of these resources into AC power grids is only possible through power electronic inverters. The dynamics of inverter is completely different from the synchronous generators.

When the percentage contribution of inverter-based generation was lower, they were not prominent in the determining the dynamics and response of the power networks, but since in present world their share has increased the power production across the world, the dynamics needs to be re-studied at present time. The understanding of inverter operation is the first step in this path. In this section we will understand the operation and control of power inverters. A comparison with typical synchronous generation system will be done to give insight of low inertial power systems.

Their control algorithm unlike synchronous generators defines the dynamic response of inverters where the dynamics behaviors is governed by the laws of physics applied to it.

2.3.1 Control and Protection Modeling of Inverters

The necessary controls in an IBG can be broken down into three distinct functional levels:

- Inner Control: Inner current, PI control loop, Firing pulse creation (PWM).
- Outer Control: *Id*/*Iq* Current References
- Plant level Control: Frequency and voltage control, or P&Q control at plant level.

Inner Current Control: Controlling the amount of electricity used by motor or power electronics relies on this feedback loop. It modifies the control signals so that the reference current is as close as possible to the desired value.

- PI Control Loop: The PI control loop, short for Proportional-Integral control, is a widely used algorithm in control systems. It uses both proportional and integral actions to minimize the difference between the desired and actual motor currents, thereby improving the performance of the system.
- Creation of Firing Pulses (PWM): Pulse Width Modulation (PWM) is a technique that enables precise control of power delivery to motors and other devices. By generating pulses with varying widths, PWM control regulates the average voltage or current supplied to the system, thereby achieving the desired output.

Id/Iq Current Reference: Current values for both the Id and Iq phases of a motor or power system are controlled by the outer control loop. These parameters are set in accordance with how the system is meant to function. The actual currents are then adjusted by the inner control loop (previously mentioned) to match the desired values.

Frequency and Voltage Control: The stability and dependability of power grids depend on the constant application of voltage and frequency regulation. The frequency and voltage can be kept within safe parameters through plant-level control, which involves monitoring and adjusting power generation or load consumption.

P&Q Control at Plant Level: Both active power (P) and reactive power (Q) play crucial roles in electrical grids. Maintaining the desired power factor, voltage stability, and overall grid operation are the primary goals of P&Q control at the plant level. These control mechanisms regulate and optimize motor and power system operations, ensuring reliable and effective operation.

To fully grasp the dynamics of inverters, it is crucial to have a firm grasp on all of these controls. Control block and signal flows for a PV inverter are depicted in the diagram below [4]. Inverters that connect to the grid use similar dynamics, so it is helpful to understand how the process works.

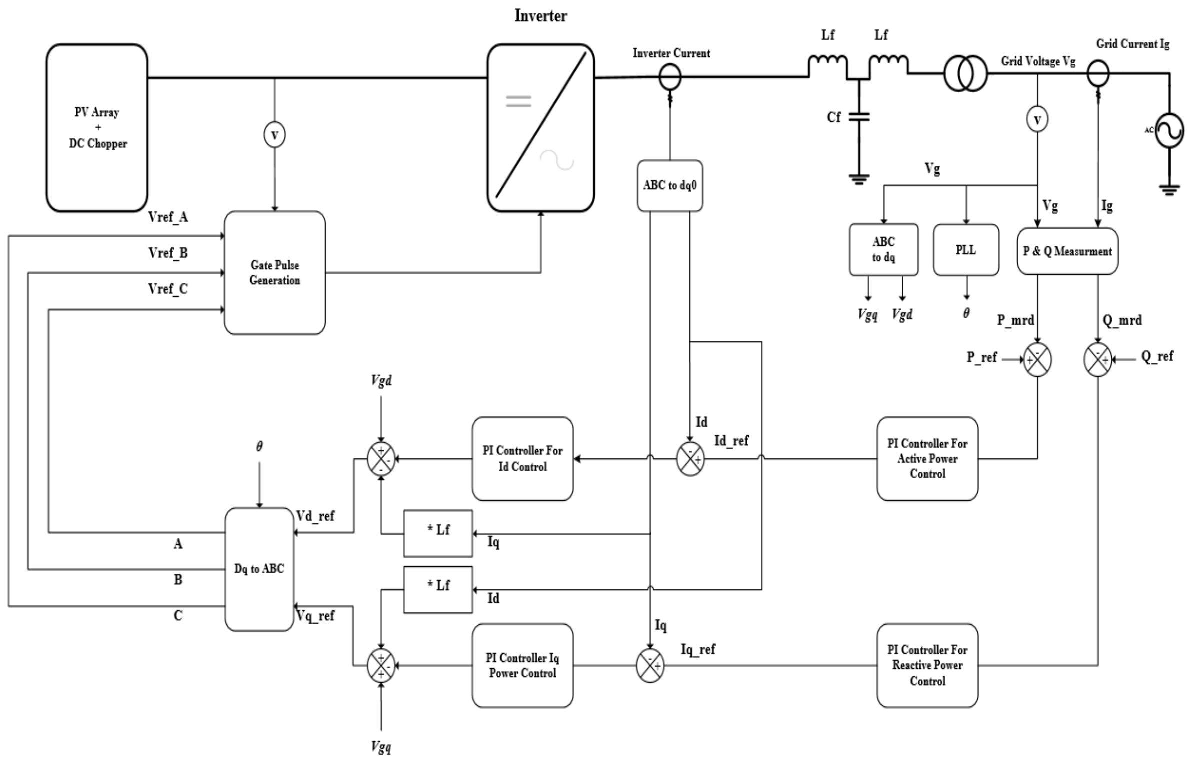


Figure 1:Control diagram of an inverter for IBR generation

2.3.1.1 Mathematical Modeling of IBR as Current Source Inverter

Let **Is** represent the current through the inverter and **Vpv** the voltage across the inverter bus. Using the phasor voltage, **Vpv**, at d-q axis we can separate the current **Is** into its real current (**Id**) and reactive current (**Iq**) components. So, in phasor representation we have we have the current and voltage of inverter as [5].

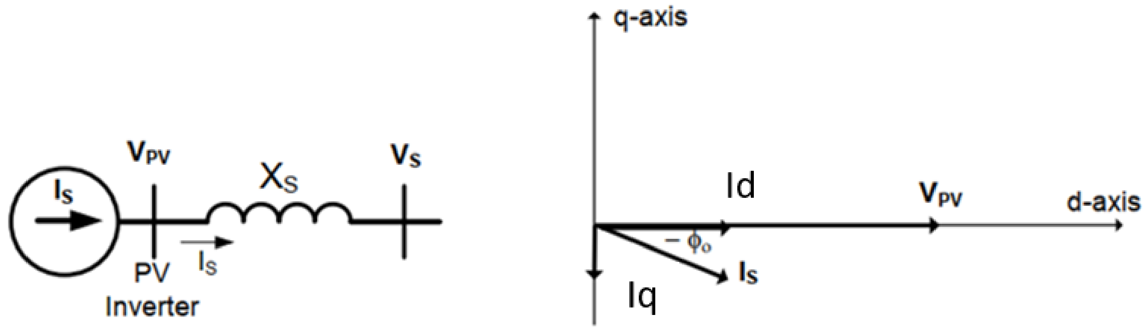


Figure 2:Current source model of an inverter and its phasor diagram

$$\boldsymbol{V_{pv}} = V_{pv}\angle 0° \qquad (2.1)$$

$$\boldsymbol{I_s} = I_s\angle\phi \qquad (2.2)$$

The inverter's apparent power output can be expressed as:

$$\boldsymbol{S_{pv}} = \boldsymbol{V_{pv}} \times \boldsymbol{I_s} = \boldsymbol{P} + \boldsymbol{jQ} \qquad (2.3)$$

$$\boldsymbol{P} = V_{pv}I_s\cos\phi = \boldsymbol{V_{pv}} \times \boldsymbol{I_d} \quad (2.4)$$

$$\boldsymbol{Q} = V_{pv}I_s\sin\phi = \boldsymbol{V_{pv}} \times \boldsymbol{I_q} \quad (2.5)$$

It is possible to regulate the inverter's real power output by manipulating its real current component, **Id**. Reactive power can be regulated by the inverter by manipulating its **Iq**-component of reactive current. The terminal voltage increases as the reactive power output of the inverter increases. Consequently, controlling the reactive current component, **Iq**, can be used to control the terminal voltage and vice versa. Inner level controls of inverters include the implementation of active and reactive power control via **Id** and **Iq** controls. References Ipref and Iqref are calculated by subtracting the set P and Q from the measured P and Q. Vdref and Vqref are produced by subtracting Idref and Iqref from Id and Iq measured at the inverter's output; these are then converted to 3 phase reference voltages via the theta from PLL algorithm, which is essentially the angle of the fundamental frequency component of the voltage in the positive sequence. The PLL is responsible for controlling the frequency and synchronization of inverter voltages with the grid voltages. The reference 3-phase voltages are used to generate firing pulses for the inverter switches to produce the required output.

2.3.1.2 Frequency and Voltage Control at Plant Level

A plant controller supplies the power factor reference for the inverters and, if present, then also the reactive power support equipment at the plant level. When the transmission system operator or a remote operations center issues control command, the power plant controller processes the resulting data to act. The active and reactive power control of the IBG is expected to be used for frequency and voltage management by the utility-scale IBR. This level of plant management also occasionally necessitates collaboration with other controllers operating within the power plant itself, such as an SVC or a STATCOM.

Reactive Power and Voltage Control

At the plant level, reactive power regulation can be split into two distinct types:

- Static or slow control
- Dynamic control

The first modifies the reactive power output in accordance with a selected control mode in response to slow changes in the operating point. When there are significant drops or sags in voltage, the second reference takes precedence and controls the reactive power output. The two controls complement one another and operate on various time scales. Due to coordinated operation of several IBRs and improved voltage management, reactive power regulation at the local and plant levels is different. The output of each inverter's reactive power is synchronized, and the reactive power flow near the point of interconnection is measured as part of plant-level control. Voltage control efficiency is improved through this coordinated use of both internal power plant inverters and external reactive power compensators such as SVC and STATCOM.

These two reactive power control modes are available on the plant level control module:

- Closed loop voltage regulation (V control) at a specific bus, with the possibility of dead band, droop response, and line drop compensation.

• Closed loop reactive power flow regulation (Q control) on user-specified branch, featuring a dead band slider for fine-tuning.

Figure 3 displays the plant-level reactive power control block diagram shown in [6]. This control block diagram can switch between power factor control mode and reactive power control mode with the help of the flag PFPOI_flag. By setting the QPOI_flag for voltage droop control, the reactive power control at the plant level can also maintain a constant voltage at the POI bus. Control at the plant level has a longer reaction time compared to local control. This control at the plant level functions normally if the voltage is not too low.

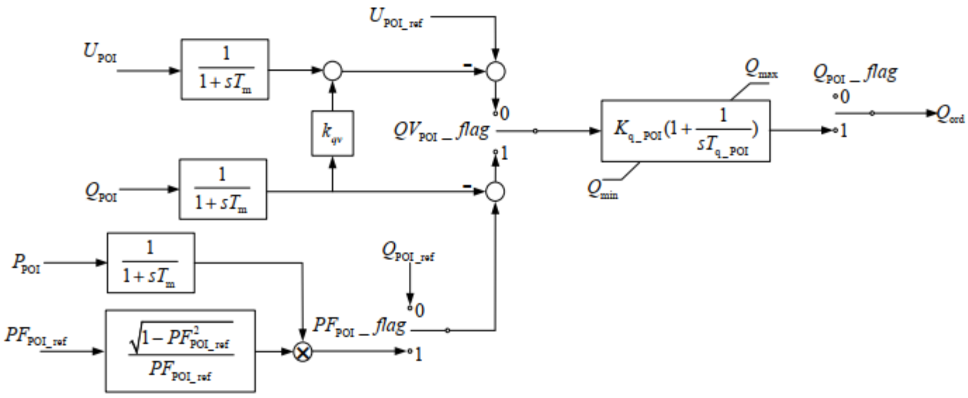


Figure 3:Reactive power control block diagram at the plant level

Power and Frequency Control

Many of the ancillary services that synchronous machines have traditionally provided will become outdated as large conventional units are phased out and IBGs expand. Depending on the nature of the primary source and the availability of storage, IBGs may be able to take part in fewer or more of the depicted services. To take part in inertial and primary control, non-dispatchable IBGs (such as PVs, WTs, etc.) must not operate at their MPPT setpoint and must be given some leeway (reserves) to provide these services. They can also do this with the help of sufficient energy storage. In the absence of such a reserve, the IBG is limited to responding to over frequency transients. Dispatched units, on the other hand, can take part in various services (such as fuel cells, microturbines, etc.). Most grid regulations currently have stringent eligibility restrictions for participation in the ancillary services market and do not mandate that IBGs provide such support.

A power plant controller may be able to actively regulate output [7] such as:

• Constant power output in response to an input signal (Plantpref).

• Governor droop response depending on the frequency deviation, having different features for over and under frequency conditions.

A generic plant level primary frequency control diagram based of Plant_pref or frequency measurement for a plant level inverter is given in the Figure 4 below.

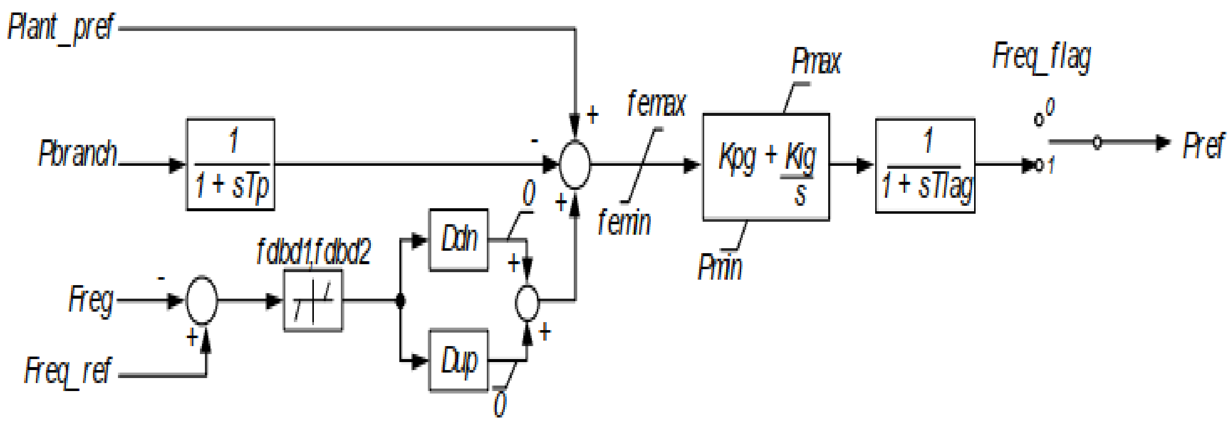


Figure 4:A generic plant level primary frequency control diagram

The control diagram in Figure 4 includes the frequency control's dead band.

2.4 Compensation for Low Inertial in Power System

The replacement of synchronous generators with inverter-based generation clearly posts a challenge to system operation, control, and stability. In this regard, new techniques, equipment, and algorithms have been explored and novelty has been introduced.

In power systems, virtual inertia refers to an artificial or simulated form of inertia that is emulated or mimicked. In traditional power systems, the rotating mass of generators provides inertia, which helps stabilize the grid by resisting changes in frequency during load variations. However, the concept of virtual inertia has emerged as a way to emulate the stabilizing effect of inertia in modern power systems with the increasing integration of renewable energy sources like solar and wind, which typically do not have inherent mechanical inertia. Swing equation (1.9) implementation in power electronic converters or inverters typically requires sophisticated and advanced control techniques to achieve virtual inertia. These control techniques can simulate the behavior of traditional generators by monitoring the grid frequency and adjusting the power output from the renewable energy source or a battery energy storage system (BESS) accordingly. A number of topologies for creating virtual inertia have been explored in [8] and [9]. In general, a virtual inertial system consists of BESS, an inverter, and the control algorithm

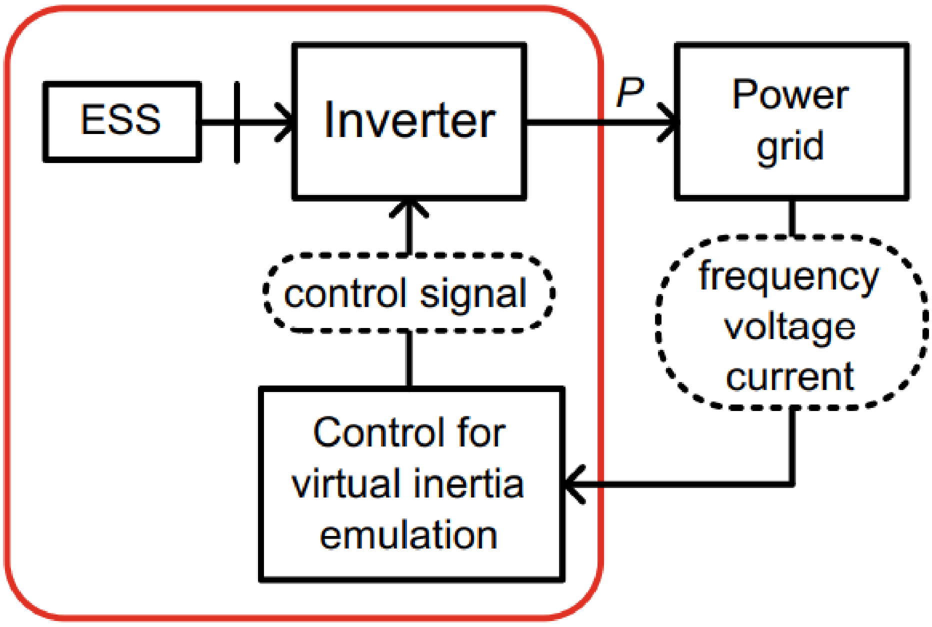


Figure 5:Virtual Inertial Control System

for emulating the inertial response, illustrated in Figure 5.

Based on the control algorithm, a virtual inertial system can belong to one of the following three categories.

- Synchronous machine model based.
- Swing equation based.
- System frequency response based.

In synchronous machine models, both electrical and mechanical system models are used in the control system. The examples of such systems are synchronverters and Virtual Synchronous machine (VSM). Instead of modeling the entire SG, as is done in conventional topology, swing equation-based topology only models the swing equation to simulate virtual inertia. The derivative of the frequency change is measured in order to simulate virtual inertia in a topology based on the frequency-power response. The relation used in this control technique is already discussed above. Some of the above mentioned control techniques have been discussed in [10].

Synthetic inertia in case doubly fed induction generators and droop control based techniques are also used for emulating a virtual inertial response in inverter control techniques discussed in [11] and [12] .

The frequency stability of low inertial power systems may benefit from the use of virtual inertia. [13]. This raises the issue of where precisely in a low inertial power system the virtual inertia should be placed in order to maximize stability [14]. The resilience of virtual inertia is determined not by the total inertia in a power system but by the location of disturbance and the placement of virtual inertia in the grid (as studied in [15]).

A study in [16], the nearly futuristic small power system of Sardinia Island is considered. The frequency response of power systems can be enhanced by using either a synchronous compensator or a battery energy storage system (BESS). For the BESS, the best scenario is to allocate half band of BESS for inertial response. A BESS model is obtained from [17], and the virtual inertia of BESS is mathematically shown. The derivative of frequency is the signal weighted by virtual kinetic energy of BESS which emulates the inertial synchronous response. Increasing the proportion of renewable energy sources in the energy mix in the future reveals that relying solely on virtual inertia implementation is not sufficient and that rapid primary response is required as well.

Another power system is the transmission system of Great Britain. The inertia of this network is expected to decrease by 40% until mid of this decade compared to the inertia at the start of decade [18]. The network has tens and more increasing number (up to 30 by 2028) of decoupled HVDC links with other transmission networks. The frequency control of the British transmission system is discussed in [19], with special attention paid to three main techniques that act over different time scales: synchronous condensers, inertia emulation, and fast frequency response. The author concludes that in the future, frequency control should be evaluated alongside other operability parameters like fault levels and reactive power characteristics, rather than as a discrete function. Therefore, the choice of frequency control solutions should consider the overall system architecture and the range of active control technologies and devices utilized in the system. The challenge of achieving an optimal operational solution for a reliable, robust, and resilient power system lies in the coordination of the various and different techniques.

For a low inertial system with HVDC links, the control techniques for HVDC operation can be altered to provide frequency support due to fast acting nature to power electronic controls. To improve frequency stability in low-inertia power systems, the authors of [20] propose an adaptive control strategy for HVDC links. The proposed control for adaptive HVDC consists of two stages to ensure frequency stability, with the first stage being dispatched when the rate of change of frequency (RoCoF) goes above the specified threshold. After the first HVDC response, the second stage is determined by the frequency response change. Simulations in MATLAB/Simulink validate the proposed adaptive control strategy, demonstrating that it improves upon the frequency response of one-step control and is able to deal with disturbances and inertia of varying magnitudes.

Another study in [21] of the same Great Britain power system, evaluates synchronous condenser as a potential solution to the low inertia of this power system due to increase penetration of non-synchronous resources. The study focuses on impact of synchronous compensation on RoCoF and fault levels. The deployment of a 5 GVA synchronous condenser (SC) can increase the loss limit for a given RoCoF limit, reducing the need for system constraints and potentially lowering costs associated with system security. In addition, the addition of a 5 GVA SC can bring a system condition that was close to breaching the RoCoF limit further within acceptable limits, decreasing RoCoF after a frequency event and giving other services more time to respond.

3 Modeling of Inverter Based Resources

3.1 Modeling Methods

The number of IBRs (Inverter-based resources) like solar and wind power are increasing in the current day world which also shows that they are playing a big part in the power system worldwide. The most important thing is the precise modeling of IBRs as their integration to the grid can cause instability which effects the system performance. RMS and EMT are two common modeling approaches used to investigate and comprehend IBR dynamics. These modeling methods can be used to model the Power Electronics and Control System of IBRs. In this way, the effects of IBRs on the reliability, voltage regulation, and power quality of electrical grids can be simulated.

3.2 RMS Techniques

The IBR is transformed into an RMS power source by the RMS modeling approach, which is a simplified way. Using this model, we can represent the dynamic behavior of the IBRs by using the root-mean-square values of voltage and current. The steady-state behavior of IBRs, as well as the maximum permissible penetration level of IBRs in power systems, can be analyzed through RMS modeling.

3.3 EMT Techniques

On the other hand, EMT modeling is an in-depth approach that considers the IBR's high-frequency components of its dynamic behavior. The transient behavior of the IBR during faults and power system disruptions is noticed by means of time-domain simulations in this approach. To examine how IBRs affect the transient stability of the power system and how they interact with other parts of the system, an EMT model is necessary.

RMS modeling provides a basic approach for steady-state study, while EMT modeling provides a more extensive investigation of transient behavior; both can be used to simulate the behavior of IBRs. We can steady-state behavior of IBRs using RMS modeling while the transient behavior of an IBR can be best studied using EMT modeling (during faults and disturbances in the power system). Characteristics which determine the power quality (like harmonics and flicker) can also be analyzed using EMT modeling. Harmonics are high frequency components The voltage and current waveforms in power systems are distorted by harmonics. This can cause equipment failure and poor power quality. When the power output of IBRs rapidly fluctuates, a phenomenon known as flicker occurs.

In conclusion, only precise modeling of harmonics and flicker can show the effect IBRs have on reliability and efficiency of power grid. Utility and system operators can benefit greatly from RMS and EMT modeling approaches due to the depth of information they provide regarding the dynamic behavior of IBRs. This ensures the safety and efficacy of the grid.Introduction to PSS/E Software

Siemens PTI's Power System Simulator for Engineering (PSS/E) is a powerful program used extensively in the field of power system analysis. Engineers may model and evaluate many aspects of a power system with PSS/E, a comprehensive power system simulation tool. This includes generators, transformers, transmission lines, and protective systems. The software's extensive modeling features allow engineers to assess the efficiency, dependability, and stability of power systems in a variety of contexts.

3.4 Steady-State Parameters of IBR

There has been a rise in the use of inverter-based resources (IBRs) in recent years. However, developing correct IBR models is necessary since incorporating IBRs into power systems can lead to stability and performance difficulties. The steady-state modeling of IBRs in PSS/E is one of the methods which is used for modeling. In order to simulate IBRs in a steady state, it is necessary to transform the IBR into a power source that operates at a constant rate. This technique takes the voltage and current at rest as a representation of the IBR's dynamic behavior. The steady-state modeling approach is ideal for assessing the steady-state behavior of IBRs in power systems and determining the maximum safe penetration level for these devices. To model IBRs' steady-state parameters in PSS/E, the user must specify the IBR's rated power, voltage, and frequency. The user must additionally set the IBR's power factor, as well as its maximum and lowest voltage and frequency. Modeling the behavior of IBRs in power systems relies heavily on these factors.

3.5 Dynamic Parameters of IBR

Addionally, for a more complete analysis of power system behavior, dynamic modeling of IBRs is required in addition to steady-state simulation. Simulation of the IBR's response to transient situations like faults and load fluctuations is at the heart of dynamic modeling. Dynamic aspects of the IBR are incorporated into this modeling strategy. These include response time, voltage regulation, and control system dynamics.

The user must define the IBR's control mode, control system reaction time, and voltage regulation capabilities to model these dynamic parameters in PSS/E. The fault ride-through capabilities of the IBR, as well as its reaction to changes in load and power factor, must be specified by the user. These values are crucial for simulating the IBRs' responses to transient events and other variations in operation. Steps of Modeling of IBR in PSS/E

The following steps can be used to perform steady-state and dynamic modeling of IBRs in PSSE:

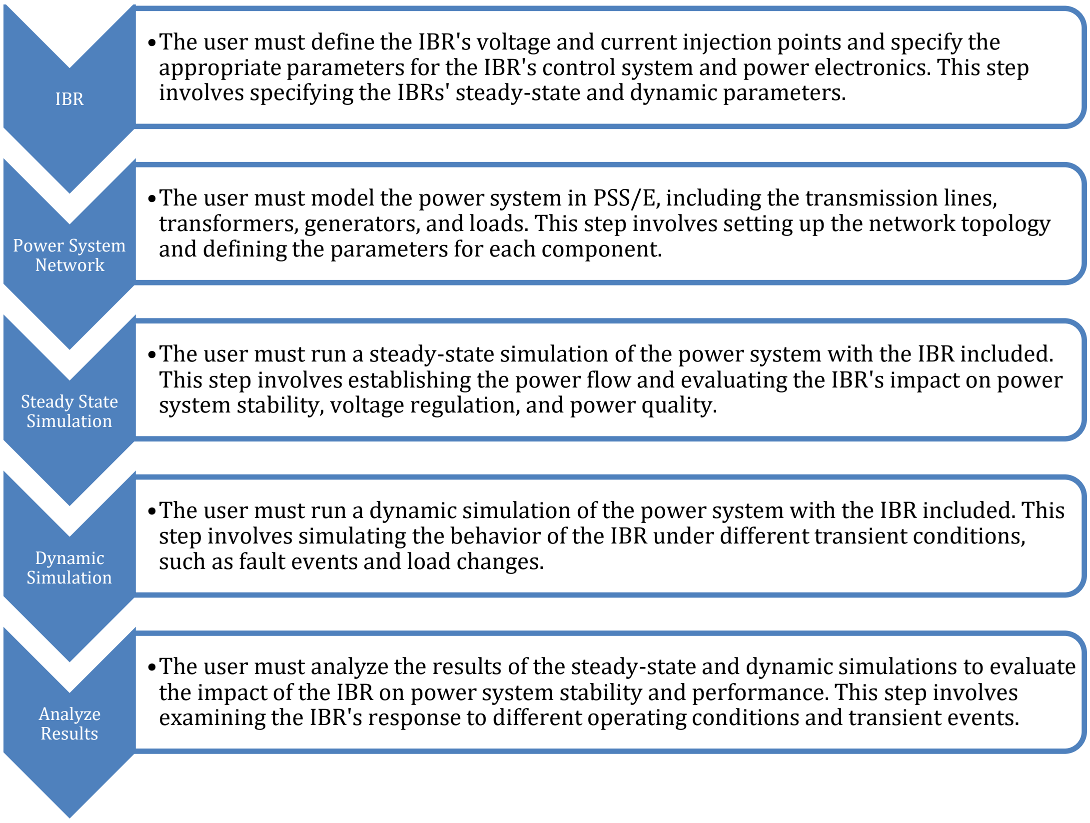


Figure 6:Modeling Steps of IBR

4 Modeling and Simulation of IBR in PSS/E Software

4.1 Steady-state modeling of IEEE 39 bus system in PSS/E

Steady-state modeling of the IEEE 39 bus system and inverter-based resources in PSS/E involves the creation of a power flow model for the system has been done in PSS/E Software. The IEEE 39 bus system is a standard test system widely used in power system analysis. It

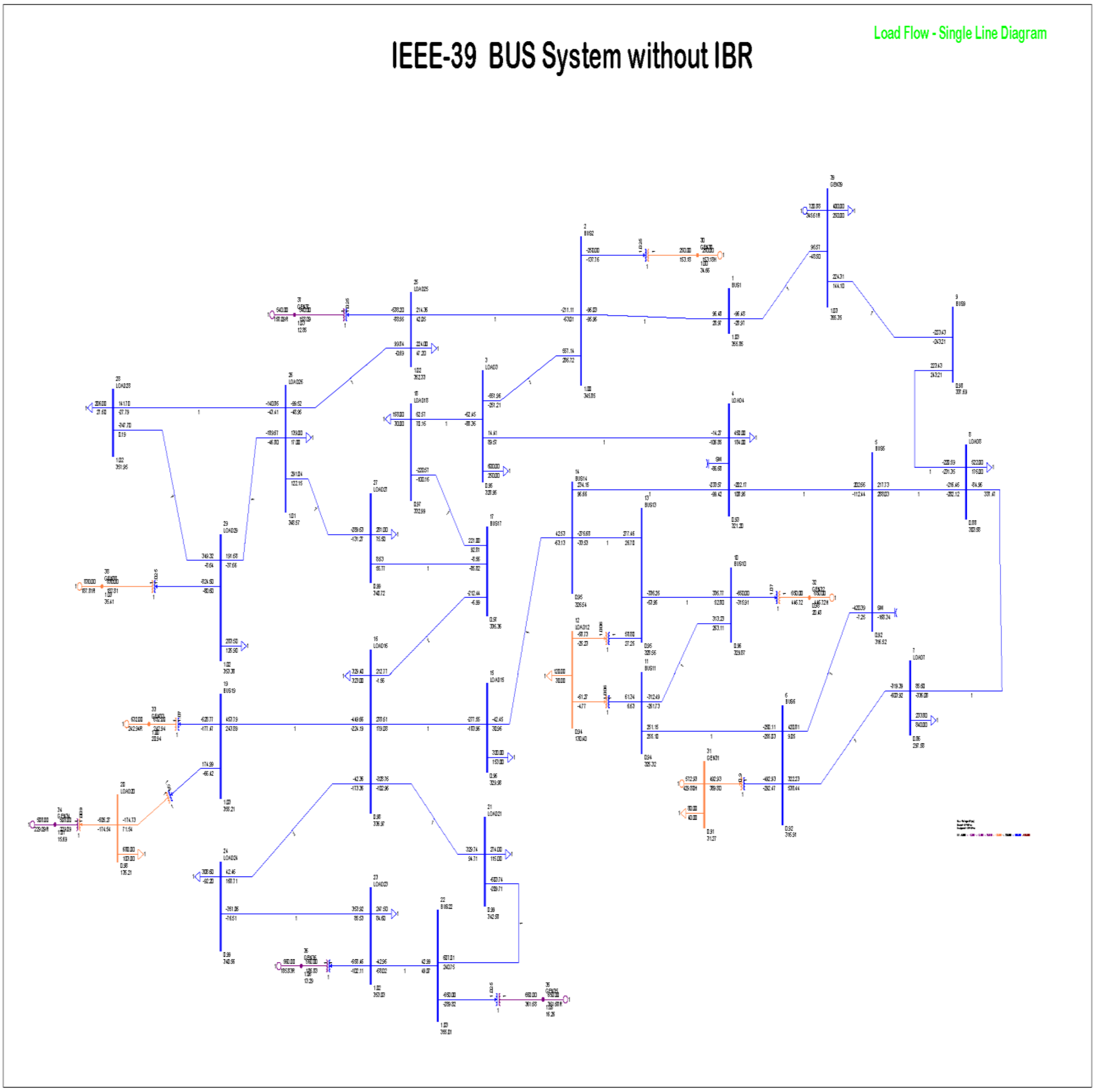


Figure 7:Single Line Diagram without IBR in PSSE

consists of 39 buses, 10 generators, and 46 transmission lines. Inverter-based resources are a type of renewable energy resource that can be connected to the power grid through an inverter.

The following figures describe the single-line diagram of the IEE39 BUS network without and with IBR addition. The high-resolution diagram is attached as (Appendix-A - High Resolution Single Line Diagrams)

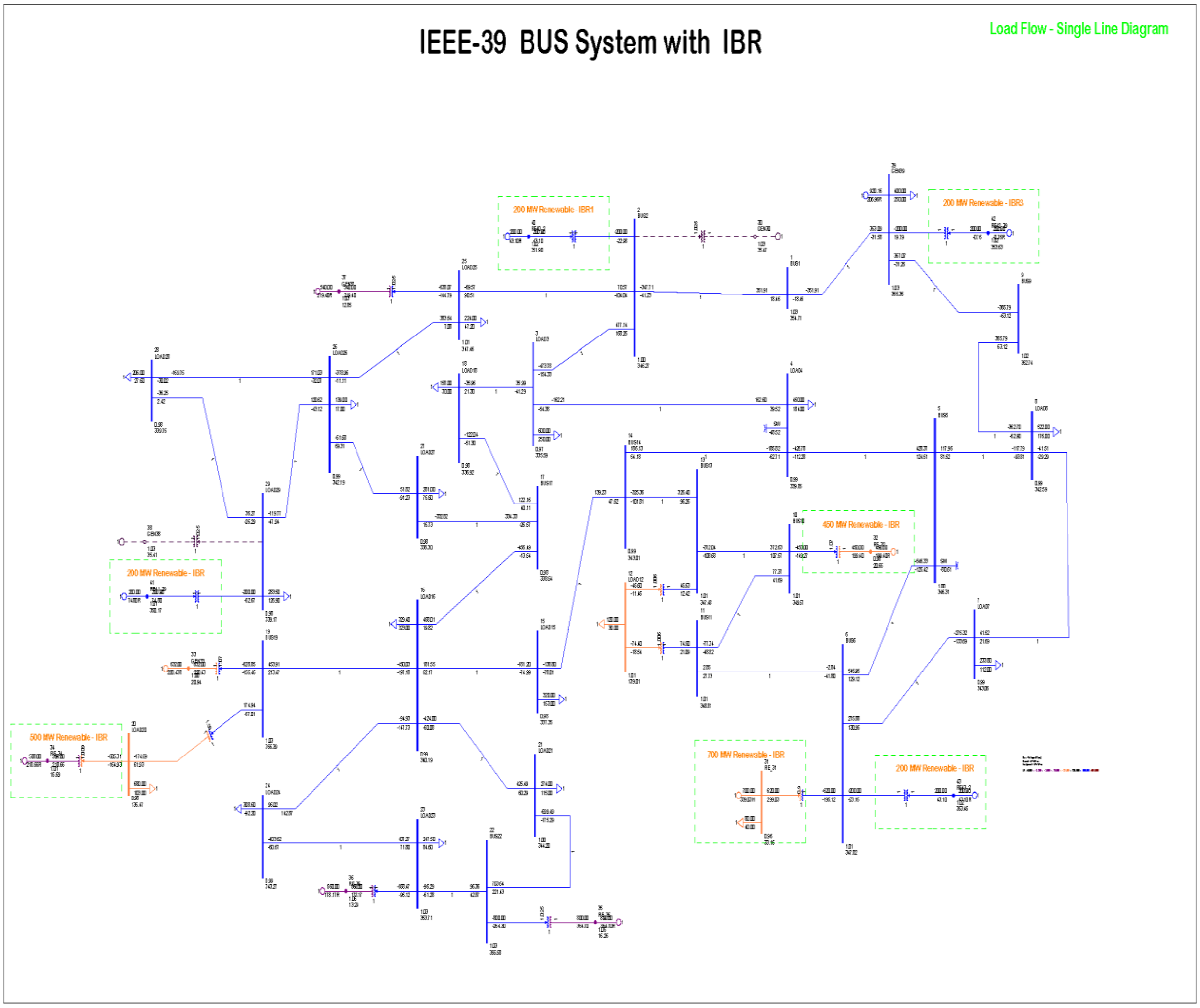


Figure 8:Single Line Diagram IEEE 39 with IBR

The following steps have been implemented to create a steady-state model of the system:

- Create a new PSS/E case and define the system data, including the bus data, branch data, and generator data. This data can be obtained from the IEEE 39 bus system data files.
- Add the inverter-based resources to the model. This can be done by defining new buses for the resources and connecting them to the existing system through inverter models.
- Run a power flow analysis on the model to determine the steady-state operating conditions of the system. This can be done using the PSS/E power flow analysis tool.

4.2 Steady-state modeling of IBR in IEEE 39 BUS

In the next step, the steady state modeling of Inverter based resources has been done. The existing synchronous generation is replaced by the IBR resources. The following generic data is used for the steady-state modeling in PSS/E software:

Table 2: Steady State Data of Generic IBR

Item No.	Descriptions	Value
01	PGen (MW)	200
02	PMax (MW)	200.5
03	PMin (MW)	0.00
04	QMax (Mvar)	96.8644
05	QMin (Mvar)	-96.8644
06	Mbase (MVA)	200
07	X Source (pu)	0.8

In the Modeling of IBR, the maximum size of 700 MW IBR is also added to replace the largest synchronous machine in the IEEE39 Bus Network. The following data is assumed for the largest IBR:

Table 3: Steady State Data of Largest IBR

Item No.	Descriptions	Value
01	PGen (MW)	700
02	PMax (MW)	700
03	PMin (MW)	0.00
04	QMax (Mvar)	339.025
05	QMin (Mvar)	-339.025
06	Mbase (MVA)	700
07	X Source (pu)	0.8

Figure 8 shows the single-line diagram of the IEEE 39 bus network with IBR Generation.

4.2.1 Criteria for Sizing and Settings of IBR in IEEE 39 Bus Network

It is important to highlight that sizing and settings have been done based on the following criteria:

1) Inverter based resource has been deployed where synchronous generation was already installed.
2) The sizing is exactly like synchronous is assumed and replaced with renewable generation.
3) To see the maximum impact of renewable on the system stability and reliability 70 % of generation is replaced by renewable generation.

4.3 Dynamic modeling of IBR in IEEE 39 BUS

For the dynamic modeling following generic dynamic model has been used.

- REGCA1 (Renewable Generator Model)
- REECA1 (Renewable Electrical Converter Model)
- REPCA1 (Power Plant Controller Model)

The detailed parameter of these user-defined models are given below:

Table 4: REGCA1 - PSSE Dynamic Data

Con No	Con Value	Con Descriptions
01	0.0200	**Tg** [Time Constant of converter] (s)
02	10.0000	**Rrpwr** [LVPL ramp rate limit] (pu/s)
03	0.9000	**Brkpt** [LVPL voltage 2] (pu)
04	0.4000	**Zerox** [LVPL voltage 1] (pu)
05	1.2200	**Lvpl1** [LVPL gail] (pu)
06	1.2000	**Volim** [HV Reactive Current Limitation Management] (pu)
07	0.8000	**Lvpnt1** [HV point for LV Active Current Management] (pu)
08	0.4000	**Lvpnt0** [HV point for LV Active Current Management] (pu)
09	-1.3000	**Iolim** [Current limit for HVRCM] (< 0) (pu)
10	0.0200	**Tfltr,** [Voltage filter time constant for LVRCM] (s)
11	0.7000	**Khv** [Overvoltage compensation gain used in HVRCM] (>=0 and < 1)
12	999.0000	**Iqrmax** [Reactive Current Rate of Change Upper Bound] (pu/s)
13	-999.0000	**Iqrmin** [Reactive current rate of change lower bound] (pu/s)

14	1.0000	**Accel,** [Acc. factor for easing the process of calculating voltage and angle] (>0 and <=1)

The above dynamic data of the inverter generator model has been used and all the inverter settings are kept as designed value. Similarly, the following data is used for the electrical converter data:

Table 5: REECA1 – PSSE Dynamic Data

Con No	Con Value	Con Descriptions
01	-99.0000	**Vdip** [Required LV for injecting reactive current] (pu)
02	99.0000	**Vup**) [Required HV to inject a reactive current] (pu)
03	0.0000	**Trv** [Voltage filter time constant] (s)
04	-0.0500	**dbd1** [Dead band LV threshold error] (<=0) (pu)
05	0.0500	**dbd2** [Dead band HV threshold error] (>=0) (pu)
06	0.0000	**Kqv** [Reactive current injection gain] (pu)
07	1.0500	**Iqhl** [Reactive current injection up limit Iqinj] (pu)
08	-1.0500	**Iqll** [Reactive current injection low limit Iqinj] (pu)
09	0.0000	**Vref0** [User defined reference (if 0, initialized by model)] (pu)
10	0.1500	**Iqfrz** [Value at which Iqinj is held following voltage dip] (pu)
11	0.0000	**Thld** [Time that Iqinj is held at Iqfrz following voltage dip] (s) (>=0)
12	0.0000	**Thld2** [IPMAX faulted value time] (s) (>=0)
13	0.0500	**Tp** [Electrical power filtering time constant] (s)
14	0.4000	**QMax** [Reactive power limit] regulator (pu)
15	-0.4000	**QMin** [Reactive power regulator limit] (pu)
16	1.1000	**VMAX** [Voltage control max limit] (pu)
17	0.9000	**VMIN** [Voltage control min limit] (pu)
18	0.0000	**Kqp** [Reactive power regulator proportional gain] (pu)
19	0.1000	**Kqi** [Reactive power regulator integral gain] (pu)
20	0.0000	**Kvp** [Voltage regulator proportional gain] (pu)

Con No	Con Value	Con Descriptions
21	120.0000	**Kvi** [Voltage regulator integral gain] (pu)
22	0.0000	**Vbias** [User-defined bias (normally 0)] (pu)
23	0.0200	**Tiq** [Time constant on delay s4] (s)
24	99.0000	**dPmax** [Max. ramprate for power reference] (pu/s) (>0)
25	-99.0000	**dPmin** [Min. ramprate for power reference] (pu/s) (<0)
26	1.0000	**PMAX** [Power limit max] (pu)
27	0.0000	**PMIN [**Power limit min] (pu)
28	1.7000	**Imax** [Limit for the combined current of the converter] (pu)
29	0.0400	**Tpord [**Power filter time constant] (s)
30	0.2900	**Vq1** [Reactive Power V-I pair, voltage] (pu)
31	1.2500	**Iq1** [Reactive Power V-I pair, current] (pu)
32	1.3300	**Vq2 [**Reactive Power V-I pair, voltage] (pu) (Vq2>Vq1)
33	0.0000	**Iq2** [Reactive Power V-I pair, current] (pu) (Iq2>=Iq1)
34	0.0000	**Vq3** [Reactive Power V-I pair, voltage] (pu) (Vq3>Vq2)
35	0.0000	**Iq3** [Reactive Power V-I pair, current] (pu) (Iq3>=Iq2)
36	0.0000	**Vq4** [Reactive Power V-I pair, voltage] (pu) (Vq4>Vq3)
37	0.0000	**Iq4** [Power V-I pair, current] (pu) (Iq4>=Iq3), Reactive
38	0.0000	**Vp1** [Real Power V-I pair, voltage](pu)
39	1.1500	**Ip1** [Real Power V-I pair, current] (pu)
40	1.1000	**Vp2** [Real Power V-I pair, voltage] (pu) (Vp2>Vp1)
41	1.2400	**Ip2** [Real Power V-I pair, current] (pu) (Ip2>=Ip1)
42	2.0000	**Vp3** [Real Power V-I pair, voltage] (pu) (Vp3>Vp2)
43	1.2400	**Ip3** [Real Power V-I pair, current] (pu) (Ip3>=Ip2)
44	0.0000	**Vp4** [Real Power V-I pair, voltage] (pu) (Vp4>Vp3)
45	0.0000	**Ip4** [Real Power V-I pair, current] (pu) (Ip4>=Ip3)

All these settings are kept as the designed values, and which are generic values and simulated in PSS/E software.

The main part of the IBR is a power plant controller (PPC) dynamic model. The specific control functions implemented in a Power Plant Controller (PPC) for grid following mode will vary depending on the characteristics of the power plant and the regulations and requirements of the grid. However, some common control functions include:

- **Active Power Control:** This function regulates the power plant's output to match the grid's demand for active power while maintaining the power plant's set-point limits.
- **Reactive Power Control:** This control adjusts the power plant's output to provide reactive power support to the grid and maintain grid stability.
- **Frequency Control:** This function ensures that the power plant's output frequency matches the grid frequency, which is typically set at 50 or 60 Hz.
- **Voltage Control:** This control adjusts the power plant's output voltage to match the grid voltage within specified limits.
- **Synchronization Control:** This feature checks that the power plant is in sync with the grid and keeps the phase angle and frequency within specifications.
- **Ramp Rate Control:** This regulation slows down the power plant's output shifts to avoid grid instability caused by rapid shifts.
- **Fault Detection and Diagnostics:** This function detects and diagnoses faults in the power plant and its components and alerts maintenance personnel.
- **Communication and Monitoring:** The PPC allows for remote monitoring and control of the power plant, enabling operators to monitor performance, identify issues, and perform maintenance tasks.

These control functions work together to ensure that the power plant operates safely and efficiently, while meeting the grid's requirements for reliable operation and stability.

Table 6: REPCA1 - PSSE Dynamic PPC Settings

Con No	Con Value	Con Descriptions
01	0.0200	**Tfltr** [Reactive power measurement filter time constant] (s)
02	18.0000	**Kp** [Reactive power PI control proportional gain] (pu)
03	5.0000	**Ki** [Reactive power PI control integral gain] (pu)
04	0.0000	**Tft** [Lead time constant] (s)
05	0.1500	**Tfv** [Lag time constant] (s)

06	-1.0000	**Vfrz [**Voltage below which State s2 is frozen] (pu)
07	0.0000	**Rc** [Line drop compensation resistance] (pu)
08	0.0000	**Xc** [Line drop compensation reactance] (pu)
09	0.0000	**Kc** [Reactive current compensation gain] (pu)
10	999.0000	**emax** [Deadband output upper limit] (pu)
11	-999.0000	**emin** [Deadband output lower limit] (pu)
12	0.0000	**dbd1** [Reactive power control deadband lower threshold] (<=0)
13	0.0000	**dbd2** [Reactive power control deadband upper threshold] (>=0)
14	0.4360	**Qmax** [V/Q control output upper limit] (pu)
15	-0.4360	**Qmin** [V/Q control output lower limit] (pu)
16	0.1000	**Kpg [**Proportional gain for power control] (pu)
17	0.0500	**Kig** [Proportional gain for power control] (pu)
18	0.2500	**Tp** [Real power measurement filter time constant] (s)
19	0.0000	**fdbd1** [Deadband for frequency control, lower threshold] (<=0)
20	0.0000	**fdbd2** [Deadband for frequency control, upper threshold] (>=0)
21	999.0000	**femax** [upper limit for frequency error] (pu)
22	-999.0000	**femin** [lower limit for frequency error lower limit] (pu)
23	999.0000	**Pmax** [power reference upper limit] (pu)
24	-999.0000	**Pmin** [power reference lower limit] (pu)
25	0.1000	**Tg** [Power Controller lag time constant] (s)
26	20.0000	**Ddn** [droop for over-frequency conditions] (pu)
27	0.0000	**Dup** [droop for under-frequency conditions] (pu)

Table 7 REPCA1 - PSSE Dynamic PPC Controls Flags

Icon No	Icon Value	Icon Descriptions
01	0	**Remote bus number or 0 for local voltage control**
02	0	**Monitored branch FROM bus**
03	0	**Monitored branch TO bus**
04	'0'	**Monitored branch ID (enter within single quotes)**
05	1	**VCFlag, droop flag** (0: with droop,1: line drop compensation)
06	1	**RefFlag, flag for V or Q control** (0: Q control, 1: V control)

07	0	**Fflag** 0: disable frequency control, 1: enable

5 Results and Conclusion

5.1 Dynamic Simulation Setting

To perform the dynamic simulation in PSSE following dynamic solutions parameters are fixed to get the convergence of the dynamic solution:

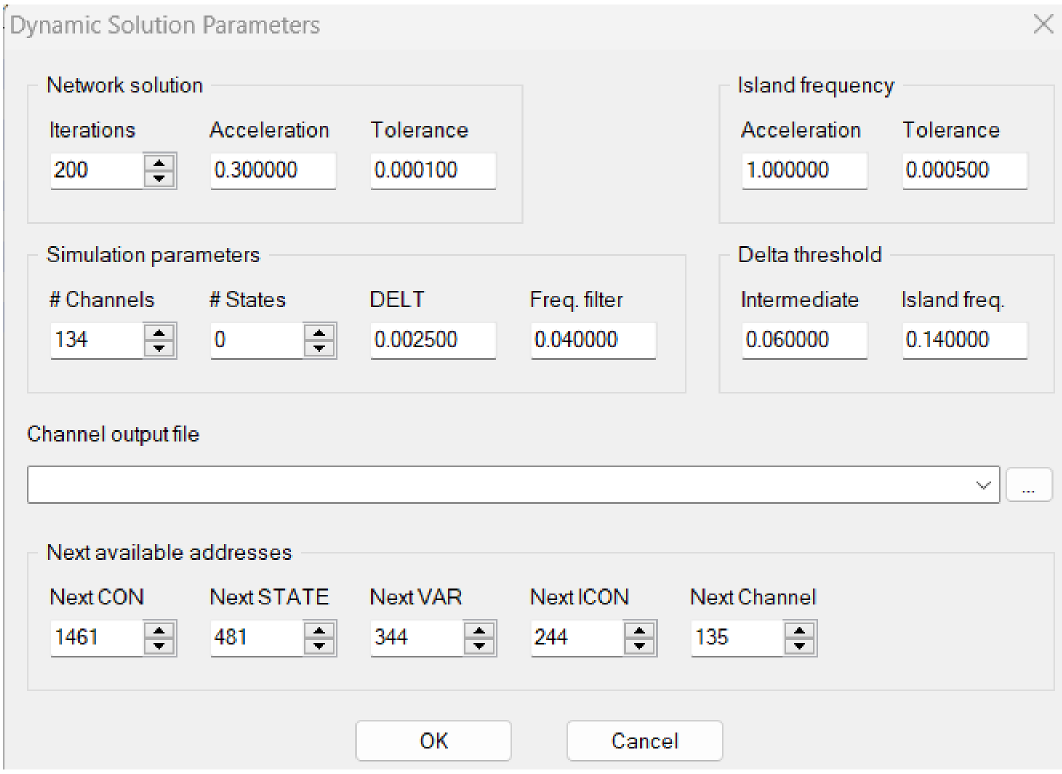
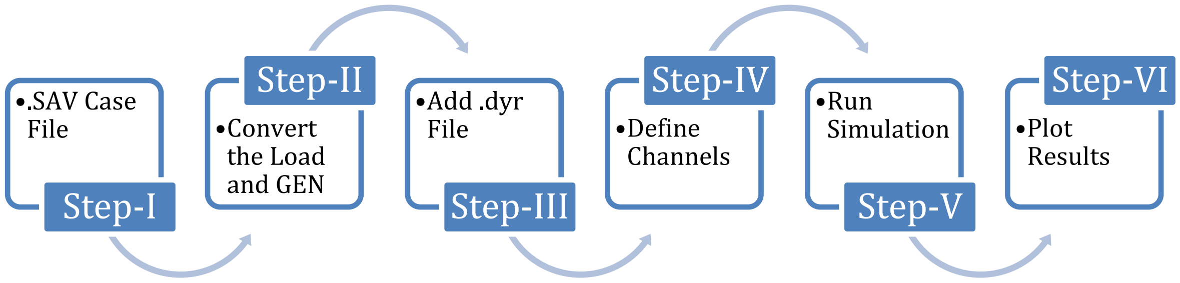


Figure 9:Dynamic Solutions Parameters Settings

5.1.1 Dynamic Simulation Steps

To perform the frequency stability analysis in PSSE the following steps are used:



5.1.2 Study Scenarios and Assumptions

The following scenarios and assumptions have been applied to assess the system's stability and reliability:

Table 8: Study Scenario and Assumptions

Scenario No	Scenario Descriptions	Disturbance Applied
01	IEEE -39 Without IBR	a) 3-Phase Balanced fault at BUS-14 for 5 Cycles (100ms) and then trip 345kV Single Circuit from BUS-14 to 13 b) 3-Phase Balanced fault at BUS-5 for 5 Cycles (100ms) and then trip 345kV Single Circuit from BUS-5 to 6 c) 3-Phase Balanced fault at BUS-16 for 5 Cycles (100ms) and then trip 345kV Single Circuit from BUS-16 to 21
02	IEEE -39 With IBR	a) 3-Phase Balanced fault at BUS-14 for 5 Cycles (100ms) and then trip 345kV Single Circuit from BUS-14 to 13 b) 3-Phase Balanced fault at BUS-5 for 5 Cycles (100ms) and then trip 345kV Single Circuit from BUS-5 to 6 c) 3-Phase Balanced fault at BUS-16 for 5 Cycles (100ms) and the trip 345kV Single Circuit from BUS-16 to 21
03	IEEE -39 With IBR + BESS & STATCOM	a) 3-Phase Balanced fault at BUS-14 for 5 Cycles (100ms) and then trip 345kV Single Circuit from BUS-14 to 13 b) 3-Phase Balanced fault at BUS-5 for 5 Cycles (100ms) and then trip 345kV Single Circuit from BUS-5 to 6 c) 3-Phase Balanced fault at BUS-16 for 5 Cycles (100ms) and then trip 345kV Single Circuit from BUS-16 to 21

5.2 Stability Results without IBRs

After simulating the dynamics of the system, the following system quantities have been monitored:

- Bus Bars Voltages
- System Frequency
- Angle Separations
- P – Accelerations

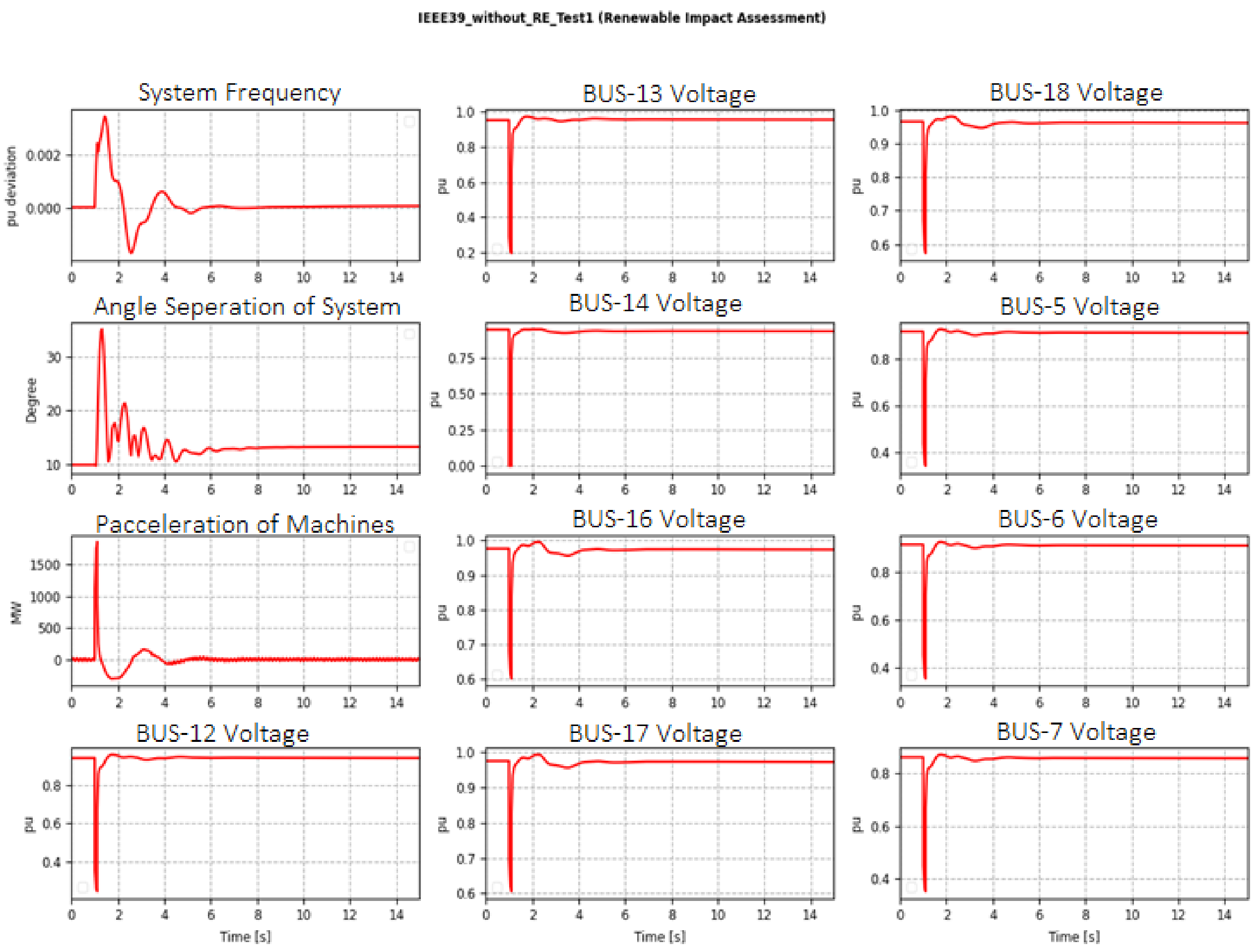


Figure 10:Scenario 1A- Stability Results

It can be noticed from the above plots that even in case of fault system voltages and system frequency is stable because synchronous machine has inertia and provide wide range of frequency and voltage regulation.

Table 9 summarize the finding of the stability results of IEEE39 Bus Network without addition of IBRs.

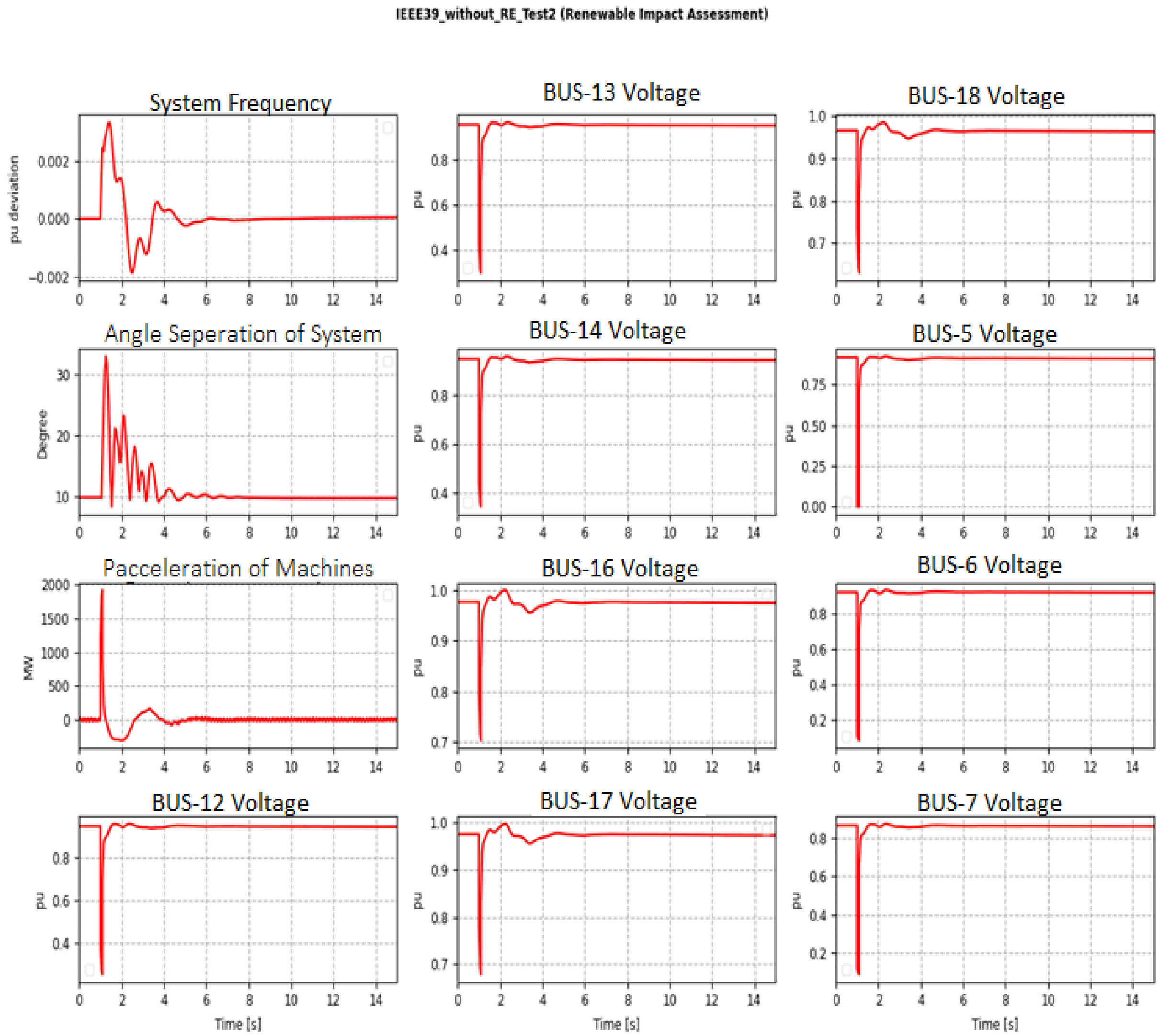


Figure 11:Scenario 1B - Stability Results

Upon examining the above plots in the Scenario 1A,1B, and 1 C, it becomes evident that despite the fault, the system's voltage and frequency remain stable. This is due to the synchronous machine's inherent inertia, which allows for a broad range of frequency and voltage regulation.

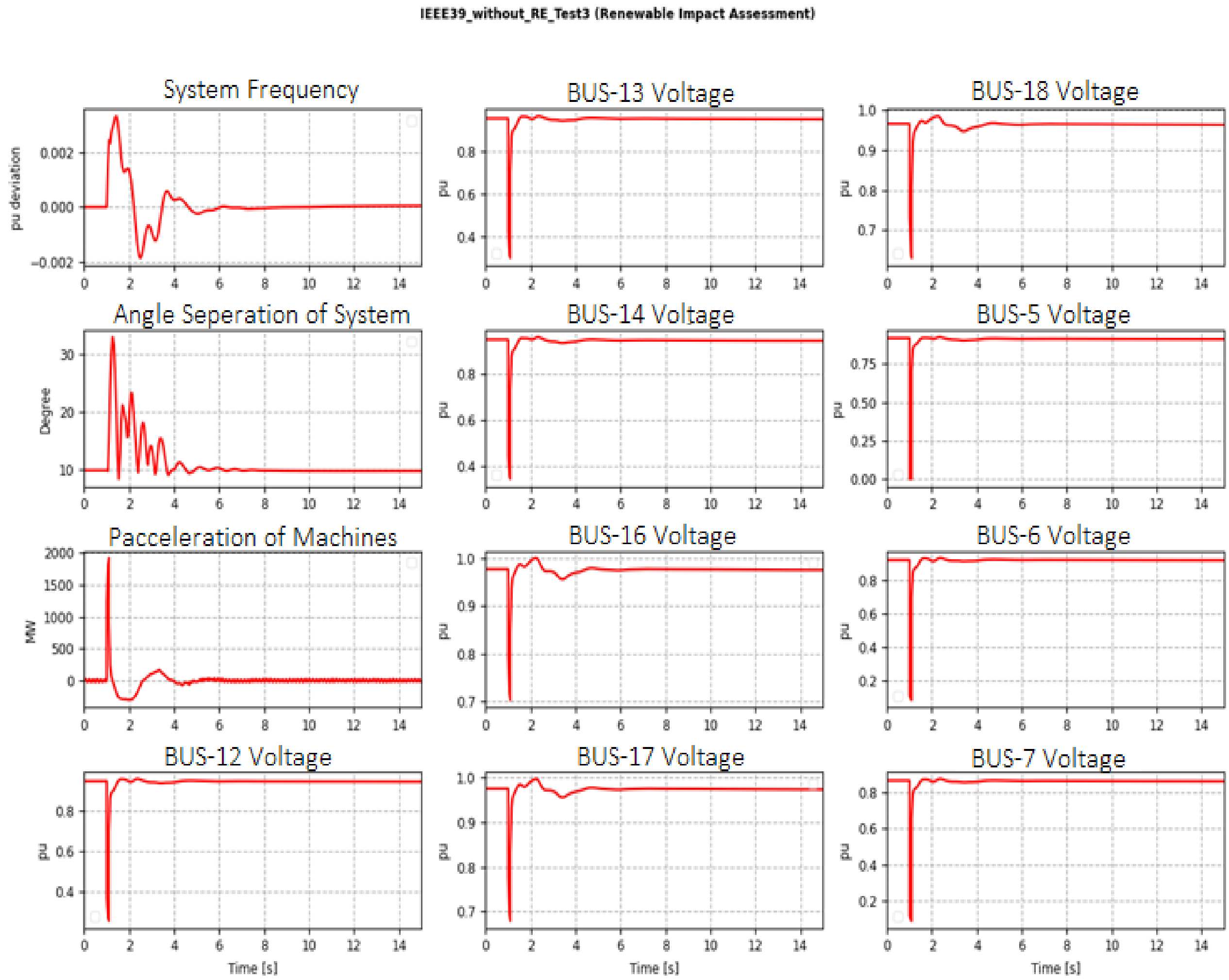


Figure 12:Scenario 1C - Stability Results

Table 9: Stability Results Summary of IEEE-39 without IBRs

Sr.No	Quantity	Assessment	Remarks
01	Bus Bars Voltages	During the stability analysis pre-fault and post fault bus bar voltages are measured and we can see that before fault, (1 second) the voltages are flat and similarly after the fault, (1.1 second) there is not much change in the voltages and voltages values become stable (reached to steady state values) within 5 second.	**Stable & No Oscillation.** **Justification:** Because existing system has synchronous generation and enough dynamic reactive power support from the conventional generation.
02	System Frequency	The deviation in frequency from the nominal value (50Hz) is very less and frequency response against the 3-phase balanced fault is steady.	**Stable & No Oscillation.** **Justification:** Change in frequency from the nominal value is minimum due to enough inertial support from the synchronous machines.
03	Angle Separations	Angle separation is a difference of angle between any two buses. The maximum angular separation is measured, and we see that its less the 35 degree which is acceptable as 35 percent is the stability margin criteria.	**Stable & within limit.** **Justification:** Due to sufficient dynamic reactive power support and inertial power support from conventional generators transmission lines are less congested and resultantly the voltage angle separation is within limit.

04	P - Accelerations	During transient stability analysis of a synchronous machine in power systems, the term "accelerating power" refers to the machine's capability to restore its synchronous speed and stabilize following a disturbance. The graph shows that the machine has enough acceleration to restore the machine speed within limit and no oscillation is observed during and after the fault.	**Stable & No Oscillation.** Enough electrical torque. (Synchronous torque and damping torque of synchronous machines are sufficient to stabilize the system)

5.3 Stability Results with IBRs

The use of intermittent renewable resources may result in voltage fluctuations due to their variable power output. During periods of high production, the voltage may exceed acceptable limits, while during periods of low production, the voltage may fall below acceptable limits.

Similarly, the utilization of IBRs may also impact the frequency of the system. Due to the unpredictable nature of the power output from IBRs, there may be fluctuations in the system's frequency.

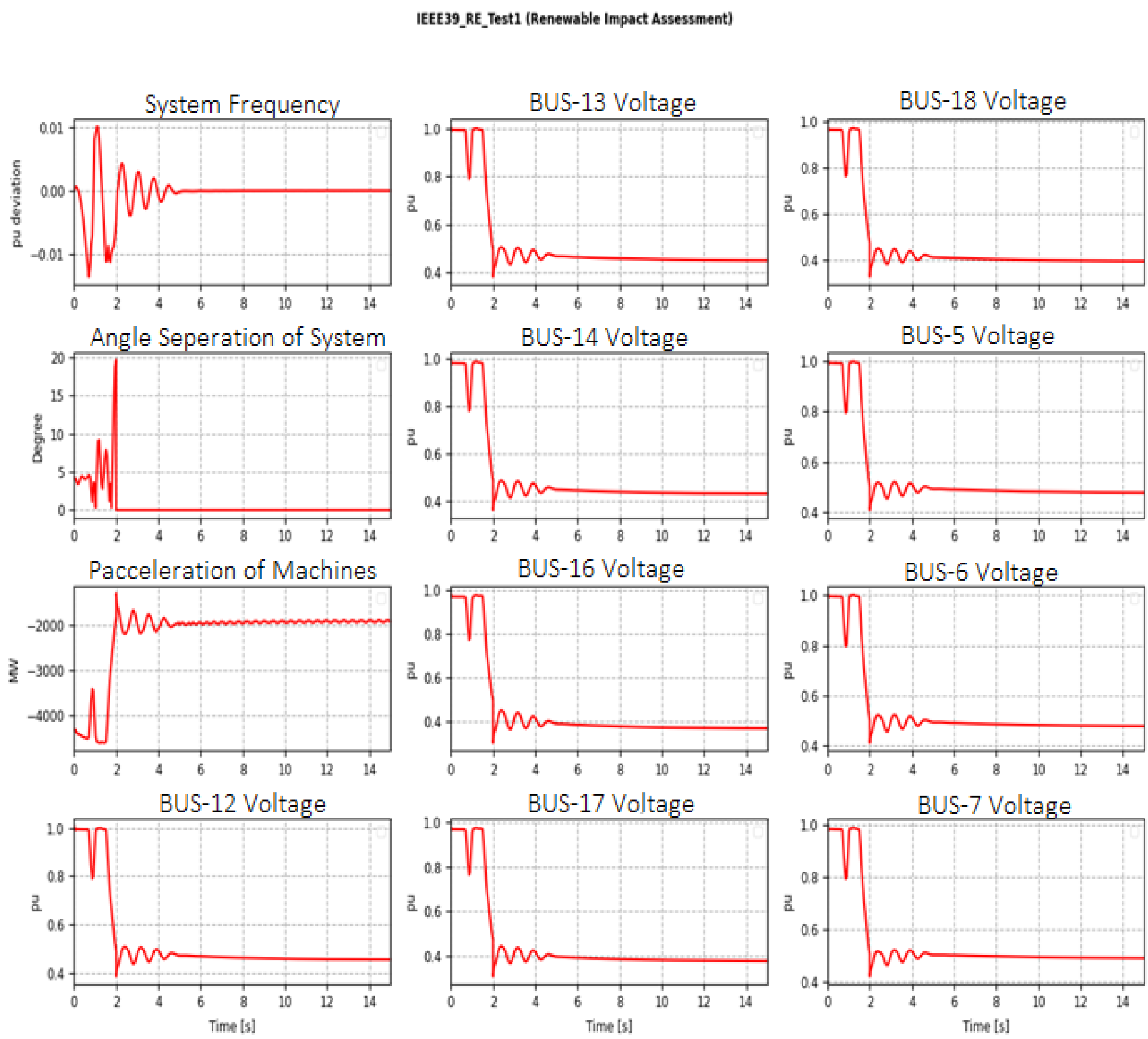


Figure 13:Scenario 2A - Stability Results

After analyzing the plots in the Scenario 2A, we can see that the system's voltage and frequency are not stable even under steady and fault condition.

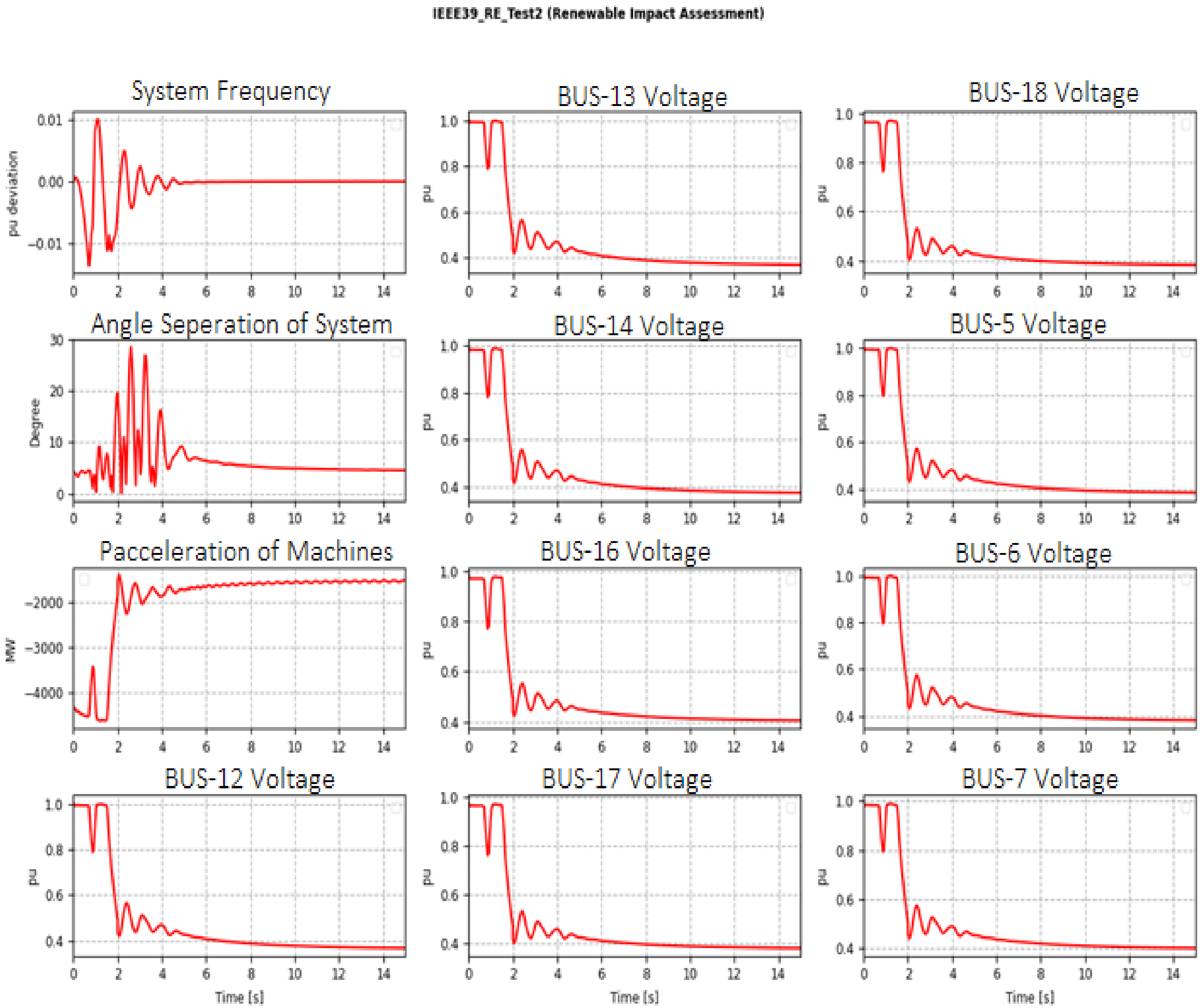


Figure 14:Scenario 2B - Stability Results

Scenario 2B, further strengthens the case of instability is a result because of the over-reliance on renewable energy resources, which has replaced a significant amount of synchronous generation. Inverter-based resources have limited capabilities to provide reactive and frequency support, especially under dynamic conditions. As a result, the responses from these resources become oscillatory.

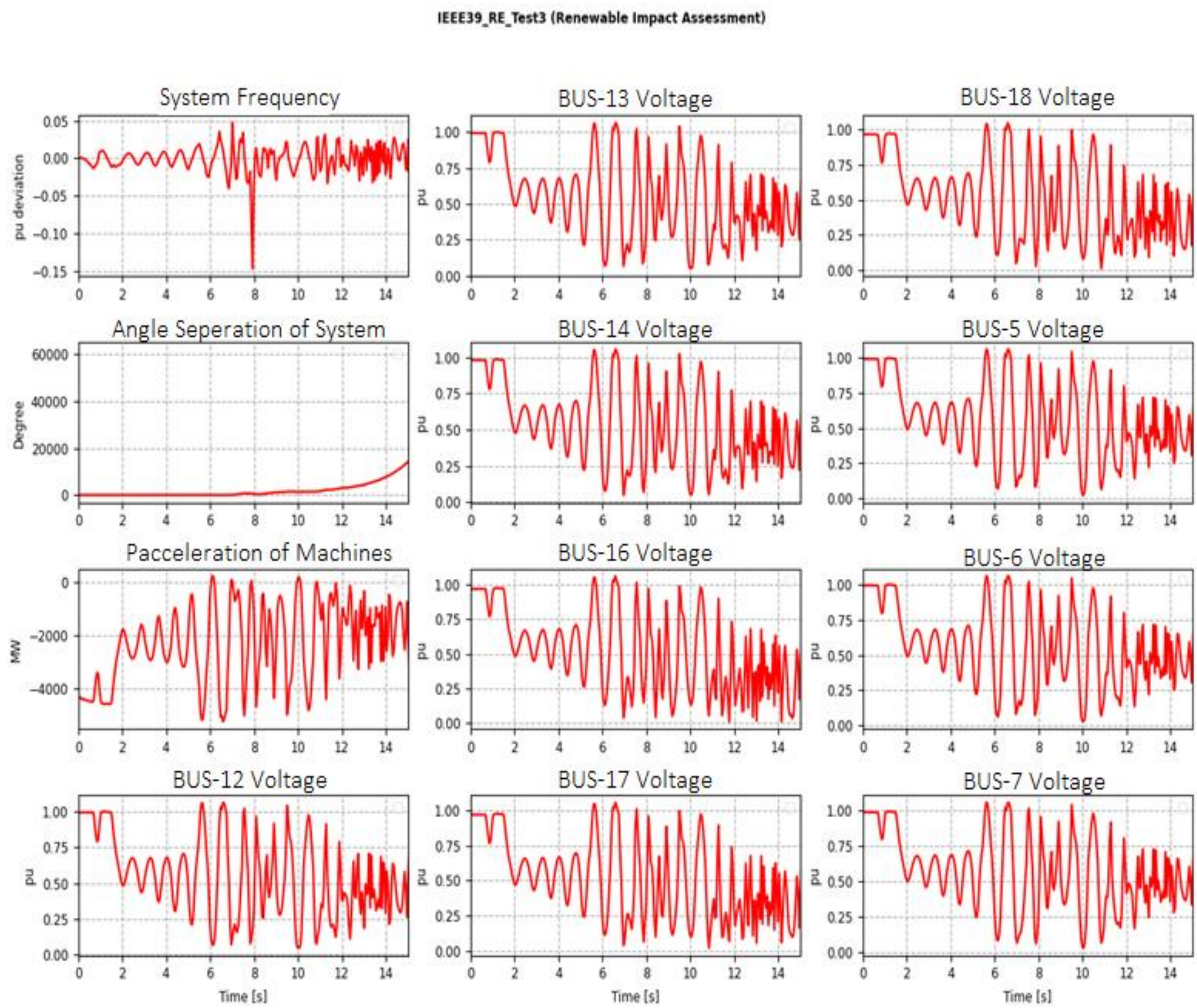


Figure 15:Scenario 2C - Stability Results

From Scenario 2, the voltage and frequency of the power system are unstable, even during both normal and fault conditions. The reason for this instability is the excessive use of renewable energy sources, which have replaced a significant portion of conventional synchronous power generation. Inverter-based resources have limited ability to provide the necessary reactive and frequency support, particularly when the conditions are changing rapidly. Consequently, the responses from these resources become oscillatory, leading to further instability in the system.

Table 10: Stability Results Summary of IEEE-39 with IBRs

Sr.No	Quantity	Assessment	Remarks
01	Bus Bars Voltages	During the stability analysis pre-fault and post fault bus bar voltages are measured and we can see that before fault, (1 second) voltages are almost going below the threshold (not stable). Similarly, after the fault, (1.1 second) there is an oscillatory response in the voltages and voltage stability issue arises which causes instability in the grid system.	**Not Stable & Oscillations.** **Justification:** In the existing system, synchronous generation has been replaced by Inverter based resource which has relatively less capability to supply reactive power to the system under steady state and dynamic state.
02	System Frequency	• The deviation in frequency from the nominal value (50Hz) is very large. • Frequency response against the 3-phase balanced fault is not stable and the response is oscillatory.	**Stable & No Oscillation.** **Justification:** Change in frequency from the nominal value is large due to low inertial support from the inverter-based resources.
03	Angle Separations	Angle separation is the difference of angle between any two buses. The maximum angular separation is measured, and we can see that the angle is more than 35 degree which is not acceptable. Also, machines connected to that bus is out of step which causes the tripping of the load.	**Not Stable & Angular instability** **Justification:** Due to poor/less dynamic reactive power support and inertial power support from inverter-based resources, the transmission lines are heavily congested which results in large voltage angle separation

			which further causes angular stability issue.
04	P - Accelerations	During transient stability analysis of a synchronous machine, the term "accelerating power" refers to the machine's capability to restore its synchronous speed and stabilize following a disturbance. The graph shows that the machine has not enough acceleration to restore the machine speed within limit and oscillation is observed during and after the fault.	**Stable & No Oscillation.** Not enough electrical torque. (Almost zero synchronous torque and damping torque of inverter-based resources which is not sufficient to stabilize the system)

5.4 Modeling of BESS and STATCOM - Solution

5.4.1 Frequency and Voltage Regulation Support

Battery Energy Storage Systems (BESS) technology can help regulate the frequency by discharging or charging its batteries in response to variations in the grid's frequency. When the frequency drops, indicating an electricity shortage, BESS can discharge its stored energy to the grid to help meet the demand. Conversely, when the frequency increases, signaling an oversupply of electricity, BESS can charge its batteries to absorb the excess energy.

BESS typically connects to the grid through power electronics such as inverters that allow the batteries to convert the DC electricity stored in them to AC electricity that can be fed into the grid. The power electronics can also regulate the charging and discharging of the batteries to maintain the desired frequency range. Overall, BESS provides a flexible and reliable solution for frequency regulation in power grid, helping to maintain the stability and resilience of the grid infrastructure.

Similarly, The Static Synchronous Compensator (STATCOM) is a power electronics device used in power grids to provide reactive power support and improve voltage levels. Reactive power is critical for maintaining voltage levels and efficient energy transmission in AC power systems. Reactive power compensation is also necessary to mitigate voltage drops and instability in the power system. STATCOM can quickly inject or absorb reactive power to support the power grid by using power electronics such as capacitors and inverters. It responds quickly to changes in the power flow and system voltage to maintain the desired voltage levels and improve the overall power quality. By providing reactive power compensation, STATCOM can increase the transmission capacity of power lines, improve voltage stability, and reduce the risk of blackouts. In summary, STATCOM is a reliable and efficient technology that can improve the power quality of the grid by mitigating voltage fluctuations, ensuring the power system's reliable operation.

5.4.2 BESS Steady State and Dynamic Data

In the modeling of BESS, 2x100 MW utility scale BESS have been modeled in the middle of load to provide the frequency support to the system in case of frequency disturbances. The following data has been added in the PSSE. dyr file.

```
@!    Electrical Control Model for Utility Scale Battery Energy Storage
44, 'USRMDL', 1, 'REECCU1',102, 0, 5, 45, 7, 6,
                  0, 0, 1, 1, 0,
                  -99, 99, 0.01, -0.05, 0.05, 15, 0.75, -0.75, 1, 0.05,
                  0.75, -0.75, 1.1, 0.9, 0, 1, 0, 1,
                  0.017, 99, -99, 1, -0.667, 1.11,
                  0.017, 0, 0.75, 0.2, 0.75, 0.5,
                  0.75, 1, 0.75, 0.2, 1.11, 0.5, 1.11, 0.75, 1.11, 1,1.11
                  999, 0.8, 0.8, 0.2, // Battery (100 MW)
@!    Plant Controller model
44, 'USRMDL', 1, 'REPCAU1',107, 0, 7, 27, 7, 9,
                  0, 0, 0, 0, 0, 1, 0,
                  0.02, 0, 0.0001, 0.0, 0.05, 0, 0, 0, 0, 0.1, -0.1,
                  0, 0, 0.75, -0.75, 1, 0, 0.25,
                  -0.00083, 0.00083, 99, -99, 1, -0.667, 0.1, 126, 126, // Battery (100 MW)
@!    Renewable Energy Generator/Converter Model
45, 'USRMDL', 1, 'REGCAU1',101, 1, 1, 14, 3, 4,             1,
     0.017 ,10 ,0.1 ,0.05 ,1.22,
     1.2 ,0.2,0.05 ,-1.3 ,0.02 ,0.0 ,99 ,-99,0.7 /  Generic RE Converter model
     //0.02 ,10 ,0.9 ,0.5 ,1.22,
    // 1.2 ,0.8 ,0.4 ,-1.3 ,0.02 ,0.7 ,999 ,-999 ,0.7 /  Generic RE Converter model
@!    Electrical Control Model for Utility Scale Battery Energy Storage
45, 'USRMDL', 1, 'REECCU1',102, 0, 5, 45, 7, 6,
                  0, 0, 1, 1, 0,
                  -99, 99, 0.01, -0.05, 0.05, 15, 0.75, -0.75, 1, 0.05,
                  0.75, -0.75, 1.1, 0.9, 0, 1, 0, 1,
                  0.017, 99, -99, 1, -0.667, 1.11,
                  0.017, 0, 0.75, 0.2, 0.75, 0.5,
                  0.75, 1, 0.75, 0.2, 1.11, 0.5, 1.11, 0.75, 1.11, 1,1.11
                  999, 0.8, 0.8, 0.2, // Battery (100 MW)
@!    Plant Controller model
45, 'USRMDL', 1, 'REPCAU1',107, 0, 7, 27, 7, 9,
                  0, 0, 0, 0, 0, 1, 0,
                  0.02, 0, 0.0001, 0.0, 0.05, 0, 0, 0, 0, 0.1, -0.1,
                  0, 0, 0.75, -0.75, 1, 0, 0.25,
                  -0.00083, 0.00083, 99, -99, 1, -0.667, 0.1, 126, 126, // Battery (100 MW)
```

Figure 16:BESS Data used in PSSE

5.4.3 STATCOM Steady State and Dynamic Data

Similarly, to provide the dynamic reactive power support to the system in case of fault, the STATCOM is proposed. As renewable power plants have narrow band of reactive capability to support the system voltage profile.

The following steady state data has been used in PSSE power flow case.

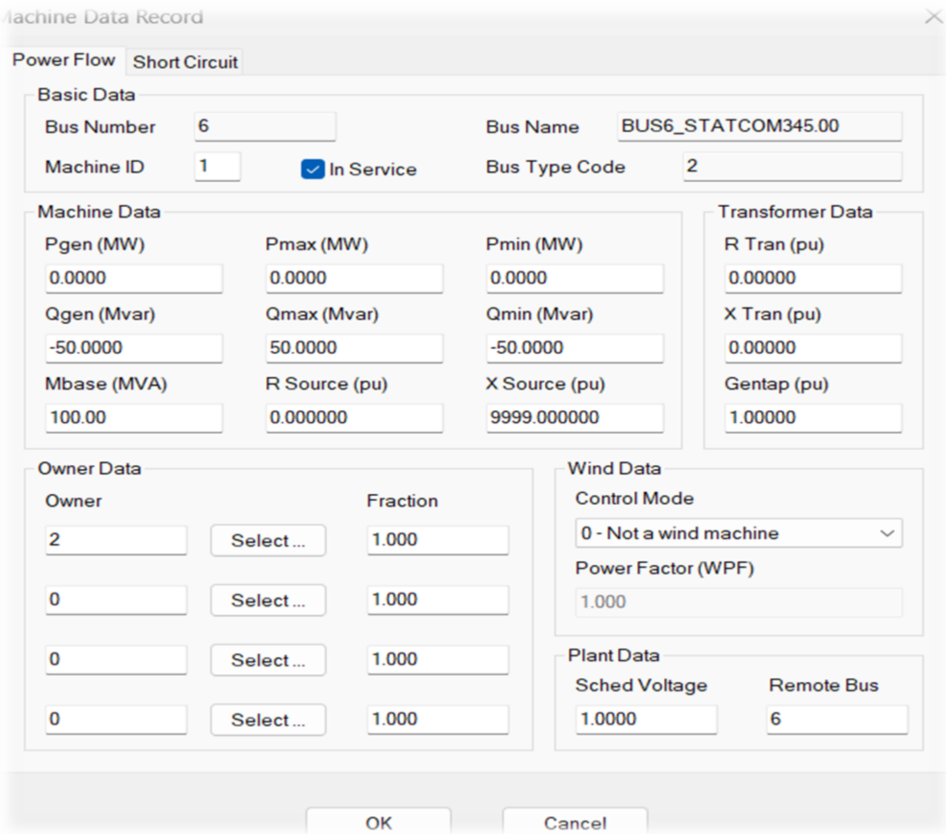
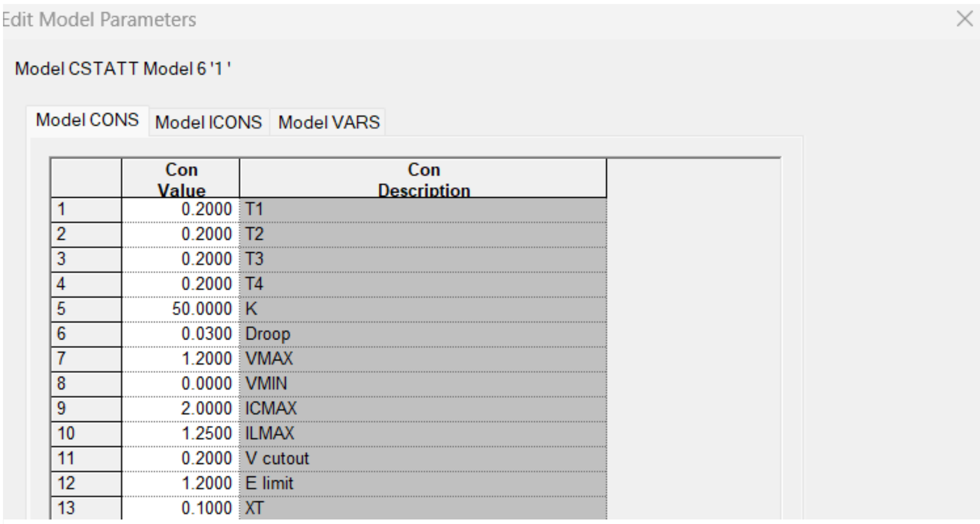


Figure 17:STATCOM Power Flow Data



	Con Value	Con Description
1	0.2000	T1
2	0.2000	T2
3	0.2000	T3
4	0.2000	T4
5	50.0000	K
6	0.0300	Droop
7	1.2000	VMAX
8	0.0000	VMIN
9	2.0000	ICMAX
10	1.2500	ILMAX
11	0.2000	V cutout
12	1.2000	E limit
13	0.1000	XT

Figure 18:Dynamic Data of STATCOM

5.4.4 Transient Stability Results with IBRS & BESS+STATCOM

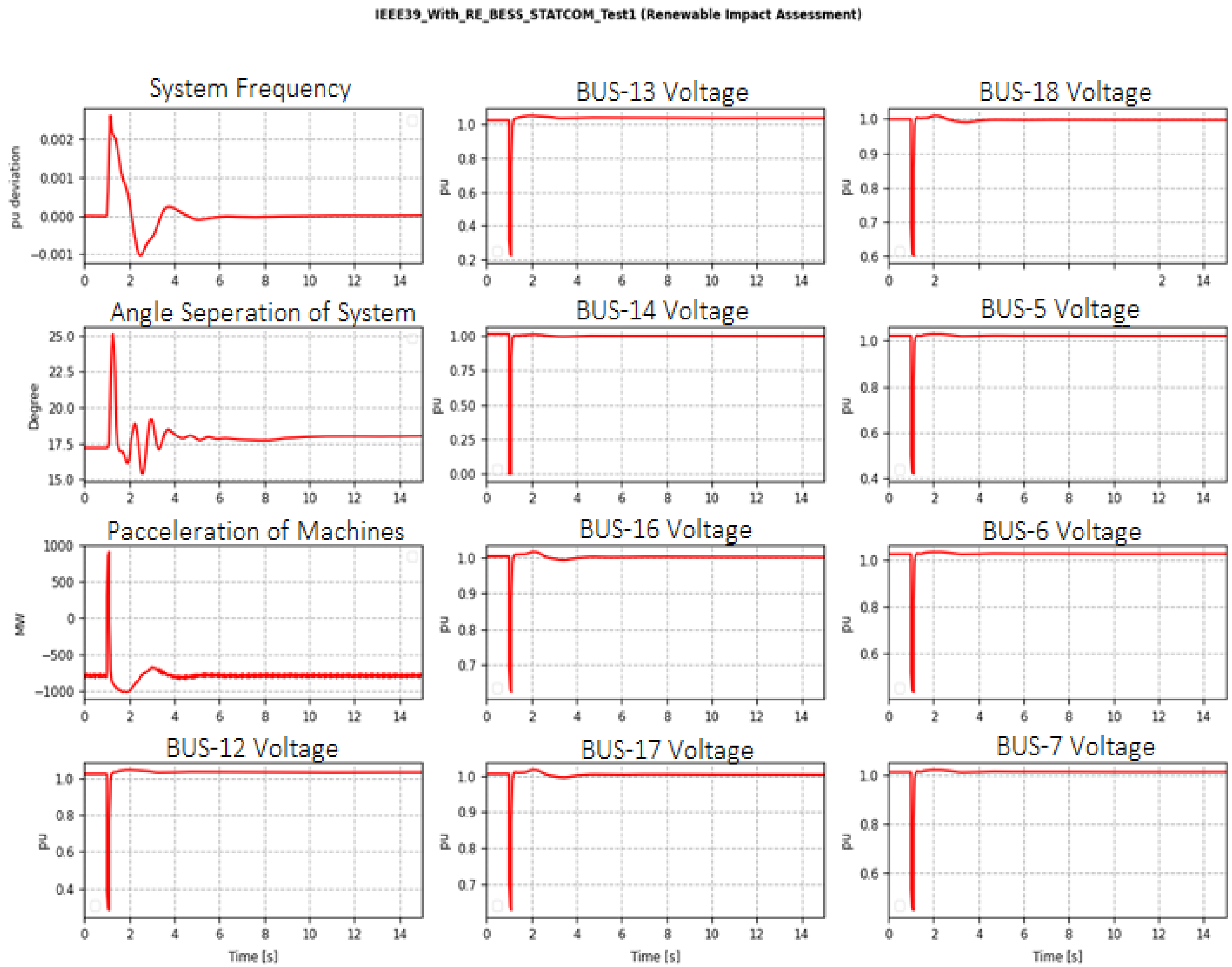


Figure 19:Scenario 3A - Stability Results

It is important to highlight that if we want to add more renewable generation in the power system network, the system inertia gets reduced which will result in system instability. However, from the 3rd scenario results it is proved that if system has dynamic reactive power and frequency support available via STATCOM and BESS respectively then goal of net zero can be achieved under reliable and stable way. Based on the study outcome it can be seen that STATCOM and BESS is critical to improve the effective inertia of the system, and these can help to mitigate instability impacts, ensuring that the power grid operates reliably and stability

IEEE39_With_RE_BESS_STATCOM_Test2 (Renewable Impact Assessment)

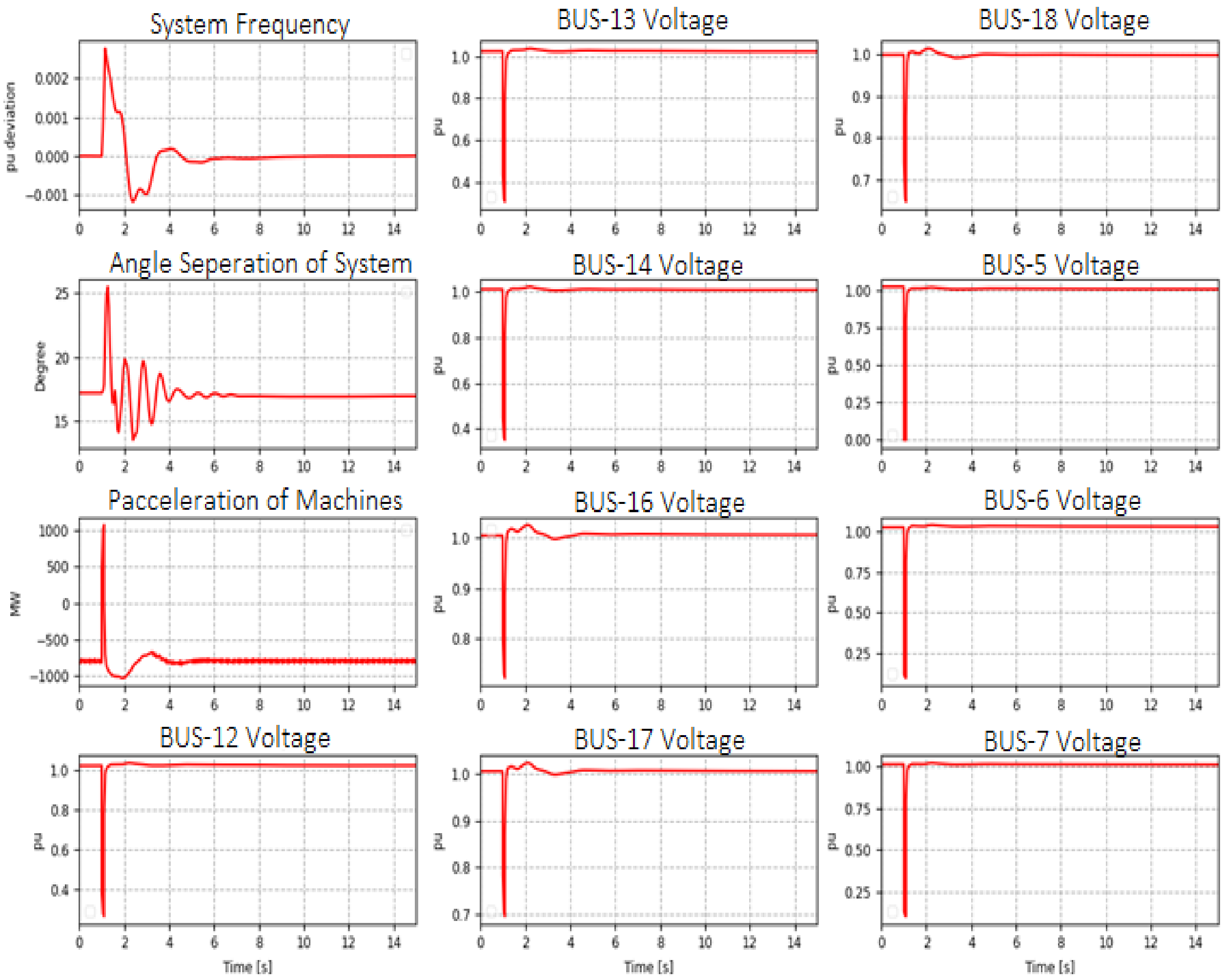


Figure 20:Scenario 3B - Stability Results

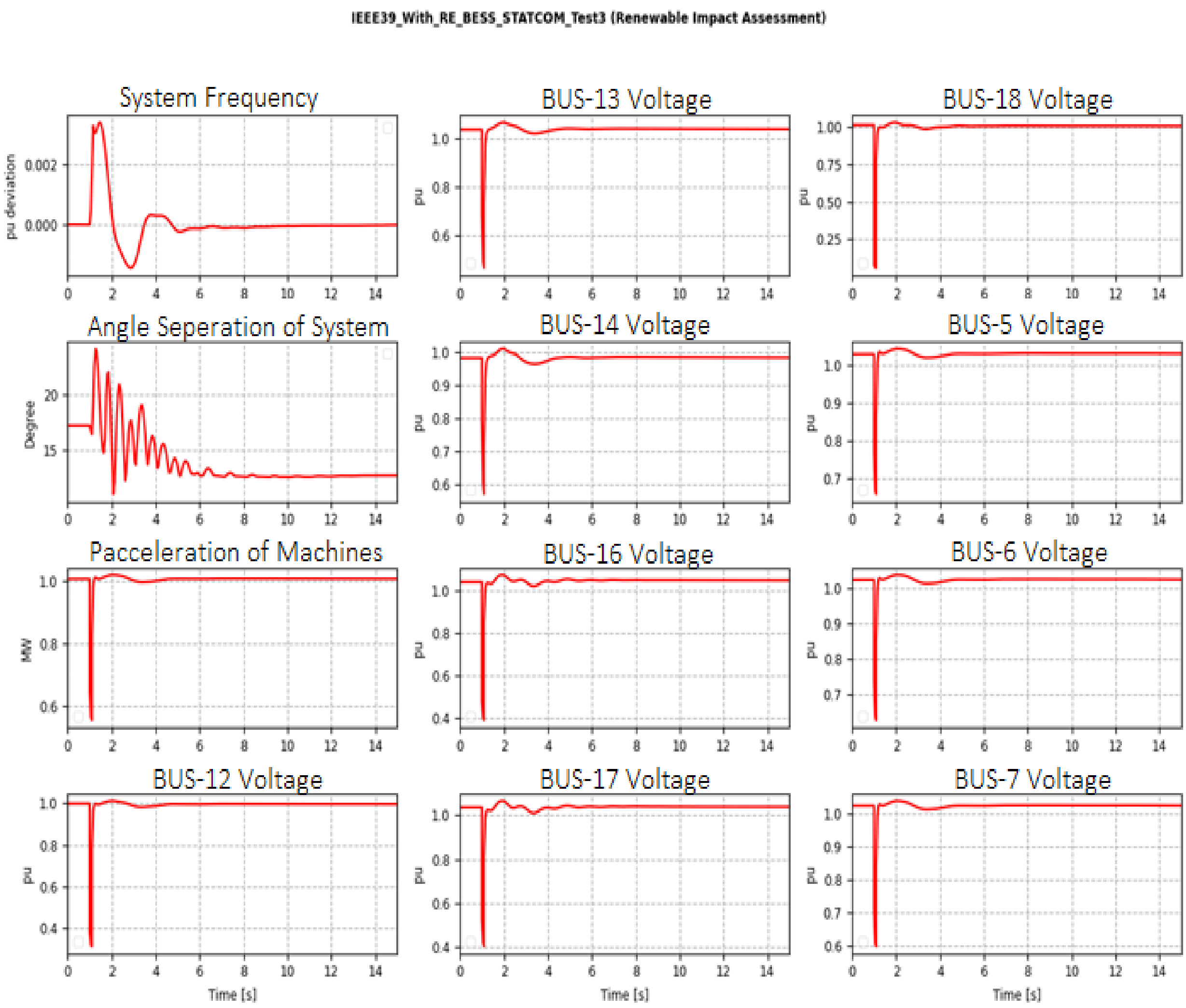


Figure 21:Scenario 3C - Stability Results

Table 11: Stability Results Summary of IEEE-39 with IBRs+BESS & STATCOM

Sr.No	Quantity	Assessment	Remarks
01	Bus Bars Voltages	During the stability analysis pre-fault and post fault bus bar voltages are measured and we can see that before fault, (1 second) the voltages are flat and similarly after the fault (1.1 second) there is not much difference in the voltages. The voltages values become stable (readjust to steady state values) within 5 second.	**Stable & No Oscillation.** **Justification:** The existing system has STATCOM + BESS installed and has enough dynamic reactive

			power support from the conventional generation.
02	System Frequency	The deviation in frequency from the nominal value (50Hz) is very less and frequency response against the 3-phase balanced fault is steady.	**Stable & No Oscillation.** **Justification:** Change in frequency from the nominal value is minimum due to enough inertial support from the BESS.
03	Angle Separations	Angle separation is the difference of angle between any two buses. The maximum angular separation is measured, and we can see that it is less the 35 degree which is acceptable as 35 percent is the stability margin criteria.	**Stable & within limit.** **Justification:** Due to sufficient dynamic reactive power support and inertial power support from STATCOM and BESS respectively, the transmission lines are less congested and resultantly the voltage angle separation is within limit.
04	P - Accelerations	During transient stability analysis of a synchronous machine in power systems, the term "accelerating power" refers to the machine's capability to restore its synchronous speed and stabilize following a disturbance. The graph shows that the machine has enough acceleration to restore the machine speed within limit and no oscillation observed during and after the fault.	**Stable & No Oscillation.** Enough electrical torque. (The damping torque of BESS is sufficient to stabilize the system)

6 Conclusion

Inverter-based resources (IBRs), such as Solar and wind power are gaining popularity because of their increasing acceptance. environmental benefits and decreasing costs. However, their integration into power systems can lead to significant impacts on system inertia and frequency stability, which are crucial for maintaining the reliability of the power grid. In traditional power systems, synchronous generators provide inertia, which helps to stabilize the frequency of the system. However, IBRs do not have this inherent inertia, and their integration can result in a decrease in system inertia, leading to frequency instability.

Based on the study outcome it shows that to address this issue, various techniques have been proposed, such as virtual and synthetic inertia, to increase the effective inertia of IBRs. Incorporating energy storage systems into power systems can also help improve the effective inertia of the system. Similarly, by providing reactive power compensation, STATCOM can increase the transmission capacity of power lines, improve voltage stability, and reduce the risk of blackouts. Overall, BESS and STATCOM both provide a flexible and reliable solution for frequency regulation in power grid, helping to maintain the stability and resilience of the grid infrastructure.

7 Future Work

This thesis covers only the grid following inverter which are relative less capable to provide support to the power system network. Grid-following inverters operate in parallel with the grid and rely on it to regulate voltage and frequency. They are not capable of operating in island mode and are more vulnerable to voltage and frequency fluctuations. However recent technology, which is grid-forming inverters that can regulate the voltage and frequency of the power system independently of the grid conditions. They can maintain stable voltage and frequency even under dynamic conditions and can operate in island mode, which means they can function when the power system is disconnected from the grid.

The future IBRs are the grid forming inverters and industry is exploring this technology as pilot project.

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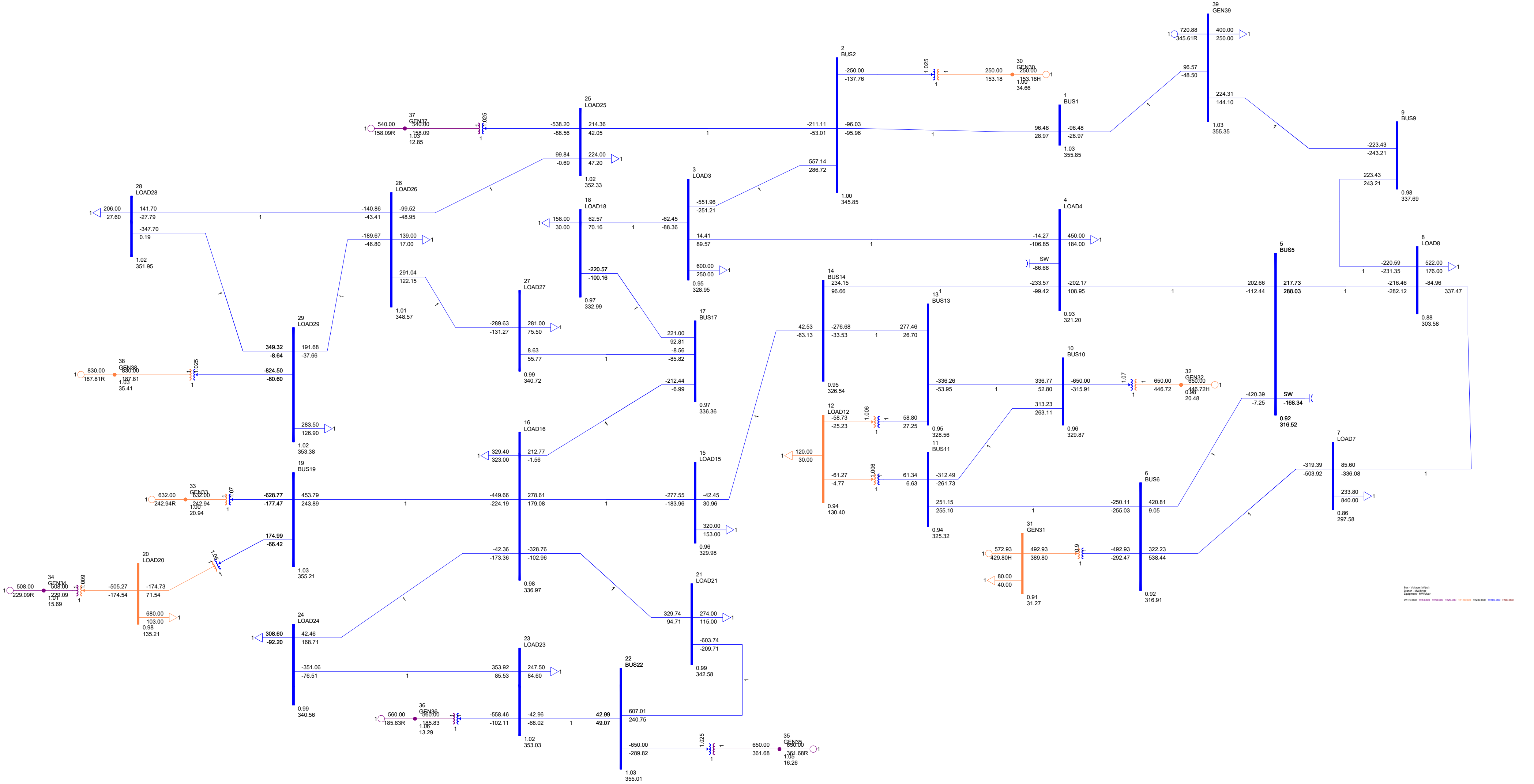
Appendices

Appendix-A - High Resolution Single Line Diagrams

IEEE-39 BUS System without IBR

Load Flow - Single Line Diagram



IEEE-39 BUS System with IBR