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Distributed generation in future distribution systems

Dynamic aspects

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Master of Science in Electric Power Engineering
Submission date: June 2010
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Problem Description

This MSc-work will be a continuation of the project performed in the autumn 2009. The focus of the project was on voltage control, reactive power sharing and loss reduction of a distribution feeder for large variations of load and generation.
Often a cos control approach has been used for distributed generators instead of the voltage control used on large generating units. The voltage control strategy based on voltage set point is sensitive to the tap changing strategy of the distribution transformer but has certain advantages when it comes to loss minimization. The voltage control mode should be studied in this work. The project work mainly addressed steady state analysis and an important extension should be to analyze the dynamic performance and to check control strategies for such a configuration using representative excitation system of the generators.
Transient and small signal stability analysis should be performed for selected cases from the project work.
These items should be addressed:

- Multiple generation units along the feeders
- Multiple loads

The work should consider the robustness of the control strategies for time dependent load and generation.
The simulation tool will be SIMPOW.

Assignment given: 20. January 2010
Supervisor: Olav B Fosso, ELKRAFT

Foreword

This master's thesis was done in cooperation with SINTEF Energi under the project "Distribution 2020". It is a continuation of a specialization project carried out in autumn 2009.

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Atsede G. Endegnanew

Acknowledgement

I would like to express my gratitude to my supervisors, Prof. Olav B. Fosso and Astrid Petterteig, for their guidance with this thesis work.

Special thanks goes to Trond Toftevaag for guiding me every step of the way, for giving me ideas when I was in short of them, for tackling software related problems with me and for giving me feedbacks on the work. I highly appreciate his support and advices.

I would like to thank Lars Lindquist, from SITRI, Sweden, for helping me with SIMPOW related problems.

Last but not least, I would like to thank SINTEF energy research for giving me a chance to work on this project and giving me an office in their building so that I can use full version of SIMPOW software; which was very vital for this work.

Summary

The objective of this thesis work was to study the stability of a distribution network with several distributed generators (DGs) considering different types of regulators in the DGs and loading conditions.

The distribution network under study, Øie – Kvinesdal, is a 57 km long radial feeder. It contains 8 distributed generators; seven synchronous and one induction generator. The largest generator has 10.3 MW rated power and the lowest has 0.25 MW rated power. The first and last generators are located 7.3 km and 45 km away from the 106/22 kV transformer respectively. Four of the synchronous generators are located on the same side branch.

Four cases were studied with three different total active power production levels, two medium and one maximum production levels, and two different network loading conditions, high and low load.

In each case, five different types of disturbances were created to analyse the dynamic response of the distribution network. The disturbances are synchronous generator disconnection, change in load, change in system voltage, short circuit fault, and disconnection of the 22 kV feeder from the HV network. Five different scenarios of synchronous generator disconnections were studied; disconnecting the largest four one by one and disconnecting the smallest three at the same time. Two different scenarios of load changes were studied. The first one is a step change in load either from high load to low load or from low load to high load depending on the initial loading condition of the network. The second type of change in load is disconnection of loads in one area which account to 66% of the total loads in the system. Change in system voltage was created by a 2.5 % step up on the swing bus voltage.

The pre-disturbance linear analysis result showed that controllers connected to the smallest generators have strong relations with the least damped eigenvalues. The case with maximum generation and low loading had very low damped oscillations; as low as 6% damping ratios. Selecting appropriate regulator gain constants plays vital role in the distribution system's small signal stability. There are some eigenvalues with imaginary part as high as 11 Hz. This is due to the low inertia of the distributed generators.

The generators in all cases were able to regain synchronism after disturbances caused by disconnection of synchronous generators, change in load and system voltage. This is because

the distribution network is connected to a strong high voltage network. But not all studied scenarios had terminal voltage and power factor within the allowed range in their post-disturbance steady state. Depending on settings of reactive power and over voltage relays, and how quickly a new set point is calculated for the excitation system controllers, a cascade of faults may occur. This could lead to instability. Relays were not included in this study.

The critical clearing time for the case with maximum production and low load was the shortest because the distribution network had high voltage and the DGs were operating with their rated capacity in the pre-disturbance steady state. The distribution network was not able to reach new steady state, and be able to operate in island mode after disconnection of the feeder from the HV network with the turbine and governor models used.

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1 Introduction

This work is a continuation of the specialization project that was carried out in autumn 2009 [1]. In that work, it was shown that in a distribution network with several distributed generators (DGs), it is possible to achieve voltage control and network loss reduction by coordinating the reactive power production/consumption of the synchronous generators. This thesis work will analyse the dynamic behaviour of the distribution network while the DGs are operating in coordinated reactive power production mode. Selected production and load level cases studied under the specialization project work are also used in this work.

Distributed generators (DG), also referred as dispersed generations, are small source of electric power generation or storage that is not part of a large central power source and is located close to the load [2]. They have production capacities less than 50 – 100 MW and are usually connected to the distribution network. Their production is, usually, intermittent and not correlated with load consumption.

With the integration of more and more distributed generators to the lower level of the power system, the dynamic characteristics of distribution networks change. The DGs are very sensitive to network disturbances due to their low inertia and can cause many technical and operating issues regarding system stability [3].

The distribution network under study, Øie – Kvinesdal, is a 57 km long real feeder located in the southern part of Norway. It contains seven synchronous and one induction generators. The largest generator has 10.3 MW rated power and the lowest has 0.25 MW rated power.

Four cases were studied with three different total active power production levels and two different network loading conditions, high and low load. Transient and small signal stabilities were analysed for each case. Sever transient disturbances were created to investigate the transient stability on the distribution network. Large focus is given to small signal analysis because most of the cases studied were stable after the tested disturbances. All synchronous generators were controlled by either voltage or reactive power controller. Selection of the excitation controller was based on pre-disturbance steady state voltage of terminal buses.

Dynamic simulation program, SIMPOW [4], was used to in this thesis work. Transta dynamic simulation model was used in the software i.e. only the fundamental component in AC systems and the \average value in DC systems are used. Constant mechanical torque model is used for synchronous generators except for analysis of transient disturbance caused by disconnection of the feeder from the high voltage network. Relays were not included in this work.

This report starts by introducing the distribution network and DGs under study. Then it discusses about stability in distribution networks with distributed generators. Chapters 4 to 6 give an overview of synchronous machine excitation systems, their dynamic performance measures and modelling. Chapter 7 describes the method used to selected controller gain constants. Chapter 8 presents the cases studied in this thesis work and type excitation controller used in each case. Chapter 9 and 10 contain pre- disturbance and post-disturbance analysis results, respectively. Discussion of results is presented in Chapter 11. Finally, Chapter 12 summarizes findings of this work and gives a conclusion. Suggestions for possible future works are included in Chapter 13.

2 Network description

This chapter is a summary of Chapter 4 in specialization project [1]. It is included in this thesis report to introduce readers to the network under study or to refresh their memories for those who are familiar with it.

The distribution network studied is a 57 km radial feeder, Øie – Kvinesdal, that is found in the southern part of Norway. It contains eight distributed generators (DGs), several transformers and loads.

Seven of the DGs are synchronous generators and one is induction generator. Generator 2 and Generator 3 have the largest and smallest rated power respectively. Table 2-1 shows the rated power and voltage for each DG in the network.

Table 2-1: Data for distributed generators in the network

Generator code	Name	Rated Voltage (kV)	Rated Power (MW)	Type
GEN 1	Kvinesdal	6.0	1.3	Synchronous
GEN 2	Trælandsfoss	5.25	10.3	Synchronous
GEN 3	Oksefjell	0.4	0.25	Induction
GEN 4	Røylandsfossen 1	0.69	0.42	Synchronous
GEN 5	Røylandsfossen 2	0.69	0.9	Synchronous
GEN 6	Eftestøl	0.23	0.44	Synchronous
GEN 7	Bergesli	0.69	0.7	Synchronous
GEN 8	Hisvatn	6.6	3.5	Synchronous
	Total Production		17.81	

Figure 2-1 shows a single line diagram for Øie-Kvinesdal feeder. It also shows the distance between the 106/22 kV transformer and each distributed generator. The first and last generators are located 7.3 km and 45 km away from the 106/22 kV transformer, respectively. GEN 4, 5, 6 and 7 are connected to the same side branch. GEN 4 and 5 are connected to same bus and are sharing common step up transformer.

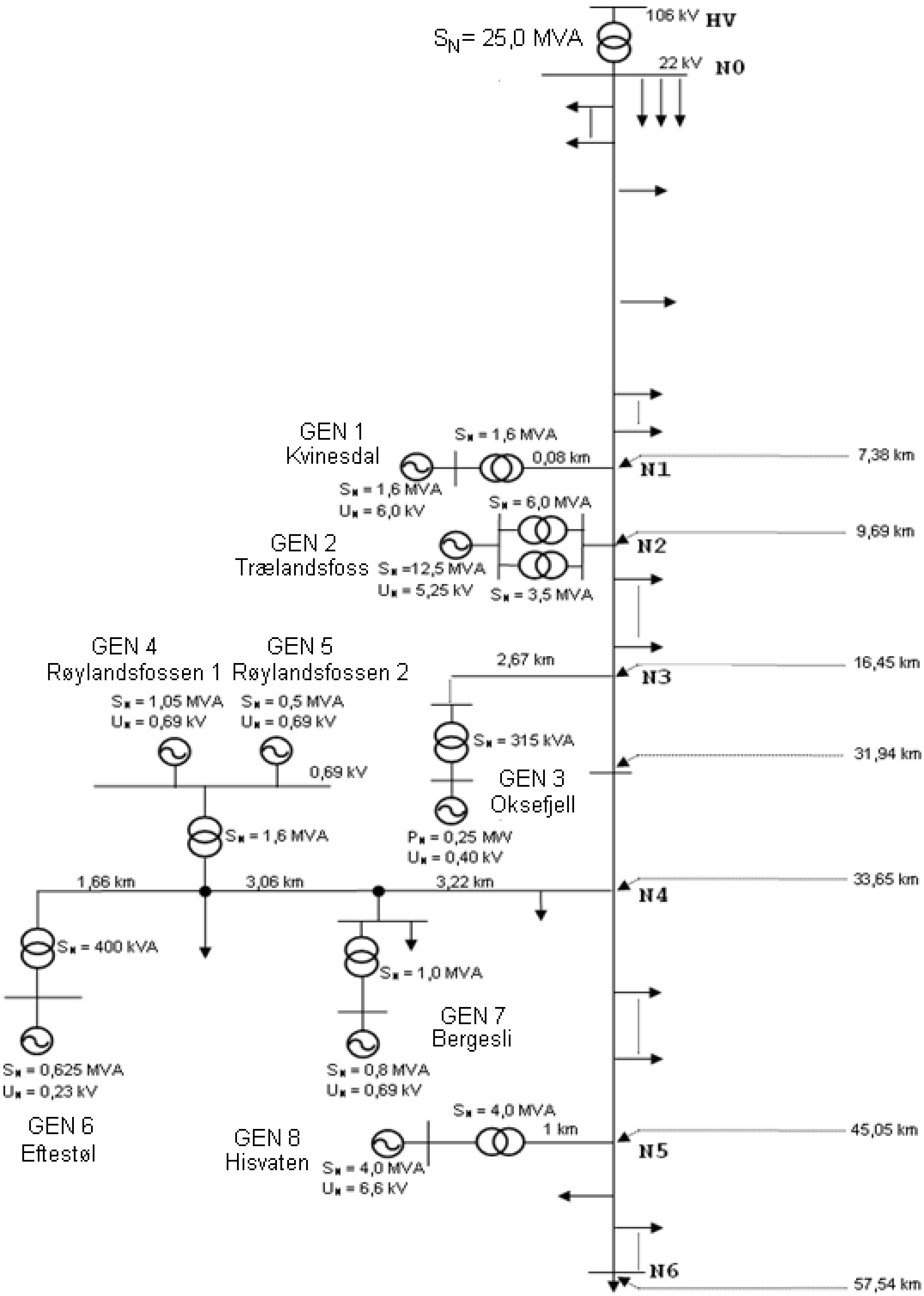


Figure 2-1: Single line diagram of Øie-Kvindesdal feeder

Table 2-2 describes node names that are presented in the single line diagram. These are nodes where the distributed generators are connected to the 22 kV feeder.

Table 2-2: Node description

Nodes	Description
HV	High voltage 106 kV transmission network
N0	Low voltage side of main transformer at Øie (22kV)
N1	Generator 1 connection point to the 22 kV grid
N2	Generator 2 connection point to the 22 kV grid
N3	Generator 3 connection point to the 22 kV grid
N4	Generators 4, 5, 6 and 7 connection point to the 22 kV grid
N5	Generator 8 connection point to the 22 kV grid
N6	Last node on Øie-Kvinesdal network

Most of the distribution network's load is connected at the beginning of the feeder. 66% of the total load is found between N0 transformer and N1. The second largest load concentration is found between N3 and N4 and it is about 16% of the total load. The rest of the load is dispersed in-between the other loads in small amounts.

2.1 Generator modelling

In the power flow computations (optpow), generators are represented as production sources. But in the dynamic simulation of SIMPOW (dynpow), generators have to be modelled in a detailed manner.

The synchronous generators are modelled as Type 2, where they are represented with one field winding, one damper winding in d-axis and one damper winding in q-axis with magnetic saturation [4]. The induction generator is modelled as transient model with out saturation i.e. Type 1A.

Table A- 1 and Table A- 2 in Appendix 1.4 show the parameters used for each distributed generator. The smallest three synchronous generators have same parameters. The generators' data were collected from literature that used similar voltage and power rated generators [5-8].

2.2 Load modelling

There are two load levels considered in this work; high and low loads. Low load level is 15% of the high load level. The combined high load in the distribution feeder is 11 MW and 2.2 MVAr, and the low load is 1.6 MW and 0.32 MVAr.

All loads are modelled with constant power character, i.e. active and reactive voltage exponents of the load are set to zero in the dynamic simulation files (MP=MQ=0). In short circuit fault analysis, loads have to be modelled with constant impedance character; i.e. MP=MQ=2.

3 Stability in distribution systems with DGs

With the integration of more and more distributed generators to the lower level of the power system, distribution networks are no longer be passive. This changes the dynamic behaviour of distribution networks. Due to the low inertia of small rotating machines, these distributed generators are very sensitive to network disturbances and can cause many technical and operating issues regarding the DG stability [3].

The effect of distribution generators on distribution system dynamics strongly depend on technology used and penetration level [9-11]. Technology refers to the type of generators and interfaces used. For example induction or synchronous generator, controlled or uncontrolled power electronic converter and so on. An important factor that determines the penetration level of synchronous generator in distribution networks is type of excitation controller used. In [12] a conclusion was drawn that an excitation system working as a voltage regulator can increase the maximum penetration level of synchronous generators in distribution systems compared with excitation system working as a power factor/reactive power controller. Another factor that limits the number of distribution generators in distribution networks is steady state voltage rise during low demand hours with full production.

The following sections discuss about two main types of synchronous generators and regulators in excitations.

3.1 Voltage supporting and voltage following machines

Synchronous machines in power systems can be categorized into voltage supporting and voltage following machines. These two categories are defined in [13] as follows.

- *Voltage supporting machines* are those machines which would be expected to aid in the regulation of system voltage. Large machines that are connected to transmission systems are under this group. These machines should typically regulate voltage.
- *Voltage following machines* are those machines which would not be expected to aid in the regulation of system voltage, but whose voltage tend to follow the variations of the incoming system voltage. Small synchronous machines that are connected to lower

voltage distribution systems whose incoming voltage is regulated by the utility with load tap changing transformers or other such devices are include in this category. These machines could be selected to regulate reactive power or power factor.

Synchronous machines working as voltage supporting machines, rather than voltage following machines, increase power system voltage stability. But, in distribution systems where there are voltage regulating devices like tap changers, capacitor banks and so on, having voltage supporting machines might create coordination problem with the multiple voltage controlling devices that exist in the network.

3.2 Voltage and power factor/reactive power regulator

A terminal voltage regulator works to keep a generator's terminal voltage constant. When a voltage drop occurs in the network, due to, for instance, increase in load or loss of production unit, the voltage regulator boosts the filed current supplied to the generator in order to keep voltage at the desired value. The increase in field current will increases reactive power output of the generator. Excessive field current causes overheating in rotor windings. When terminal voltage increases, the voltage controller decreases field current which will keep the terminal voltage at reference level but decrease reactive power production. Insufficient reactive droop compensation may cause the generator to become under excited and the voltage regulator circuit may cause potential loss of machine synchronism [14]. To prevent rotor winding overheating and loss of synchronism, over and under excitation limiter are used in excitation system controllers.

In power factor/reactive power controller, the AVR is equipped with a slow, outer-loop control, which uses the error between the desired and measured power factor, reactive power or reactive current signal to raise or lower the AVR's set point in order to maintain the desired unit power factor/reactive output [15].

An excitation system controller can either control voltage or pf/reactive power. Utilizing a controller which holds reactive power (pf) constant would intuitively defeat the purpose of the voltage regulator [13] and vice versa. PF/reactive power controllers prevent excitation systems from providing voltage support during system disturbance. In general, selection of voltage or pf/reactive power controller depends on the size of the generator and the stiffness of the connecting utility bus [3]. An alternative approach is to use reactive power controller when the system voltage is within reasonable limits and voltage controller when system voltage out of limits [13;14]. This is a “hybrid” controller that is a combination of voltage and reactive power controller. It works as reactive power controller during normal system voltage conditions and it switches to a voltage control mode when the system voltage changes and goes out of the limit. This could be easy to implement in digital controllers.

4 Synchronous machine excitation systems

This chapter is written based on Chapter 8 in 'Power system stability and control' [16] and Chapter 2 in 'Power system dynamics and stability' [17]. These books contain detailed explanations about synchronous machine excitation systems. This chapter is a brief summary about synchronous machine excitation systems from the aforementioned books.

The basic function of an excitation system is to provide direct current to a synchronous machine field winding [16]. It also provides voltage and reactive power control along with protective functions that ensure that capability limits are not exceeded.

Power system and synchronous generator characteristics determine the requirements for an excitation system. An excitation system should contribute to effective control of voltage. It should respond rapidly to disturbances and modulate the generator field so as to enhance transient and small signal stability.

In general, an excitation system must satisfy a specified response criterion and provide limiting and protective functions. It should also meet desired operational flexibility, reliability and availability.

An excitation system consists of terminal voltage transducer and load compensator, regulator, exciter, power system stabilizer (PSS), and limiters and protective circuits. Figure 4-1 shows a functional block diagram of a synchronous generator excitation system.

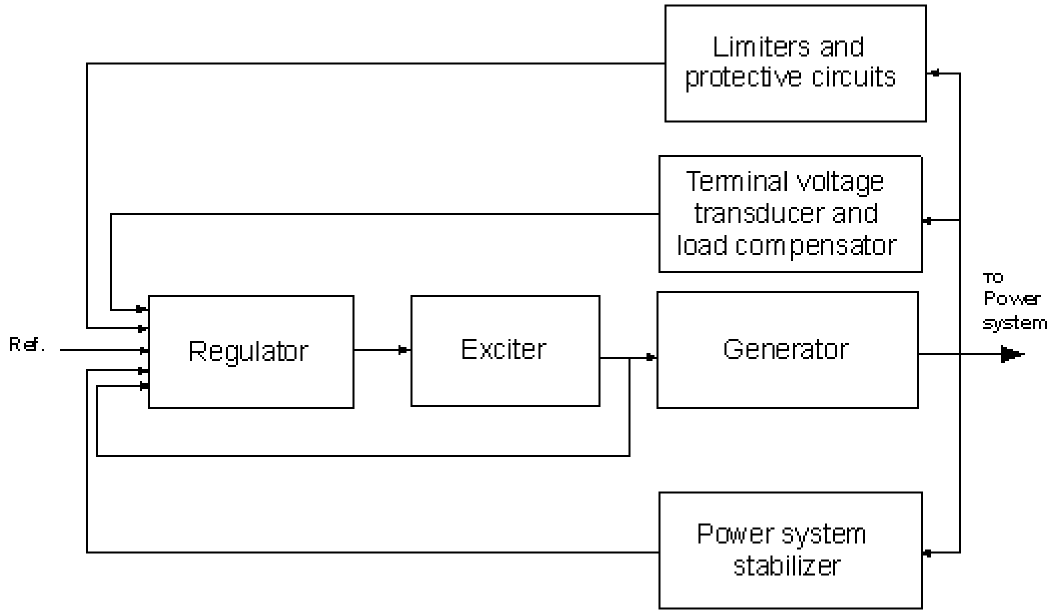


Figure 4-1: Functional block diagram of a synchronous generator excitation system [16]

A terminal voltage transducer senses and rectifies generator terminal voltage. Load compensation is used if it is desired to hold constant voltage at some point electrically remote from the generator terminals. A regulator processes and amplifies input control signals to a level and form appropriate for control of the exciter. An exciter provides dc power to the synchronous machine field winding. A power system stabilizer is used to damp oscillations, and limiters and protective circuits ensure that capability limits of the exciter and synchronous generator are not exceeded.

The following sections describe each component of an excitation system in detail.

4.1 Terminal voltage transducer and load compensator

Load compensation can be used to control voltage at a point either within or external to the generator. In case of block connected transformers (generator + transformer), the voltage control point could be half way into the transformer. If a load compensation element is not added, then the voltage that will be controlled will be the same as the generator terminal voltage. Load compensation element can be defined as follows.

$$V_c = |E_t + (R_c + jX_c)I_t|$$

Where: V_c is the voltage to be regulated

E_t is terminal voltage

I_t is terminal current

If R_c and X_c are positive, then the voltage drop across the compensator is added to the terminal voltage. The compensator regulates the voltage at a point within the generator. This is used to ensure proper sharing of reactive power between generators connected to same bus and are sharing common step-up transformer. Without this, one generator will supply all the reactive power while the other absorbs [17]. If R_c and X_c are negative, then the compensator regulates the voltage beyond the machine terminals. In most cases, the resistance component of the impedance to be compensated is negligible.

The terminal voltage transducer output, V_C, is compared with a reference that represents the desired terminal voltage setting. The deviation is then used as input to the regulator.

4.2 Regulator

An excitation system regulator uses an error between the desired and measured signal to lower or raise exciter's output. The desired signal could be voltage, reactive power or power factor. Automatic voltage regulator (AVR) regulates voltage at a point by controlling the amount of current supplied to the generator field winding by the exciter. If it is desired to control reactive power or power factor, it is possible to add a slow outer loop control that modifies the AVR's set point in order to eliminate the error between desired and measured power factor, reactive power or reactive current signals.

There are two main modes of regulations; DC and AC. DC regulator is used to control generator field voltage while AC regulator is used to control stator terminal voltage. DC regulator, also known as manual control, is a back up when the ac regulator is at fault or need to be disabled. It is also used for testing and start-up. Figure 4-2 illustrates the two regulation modes.

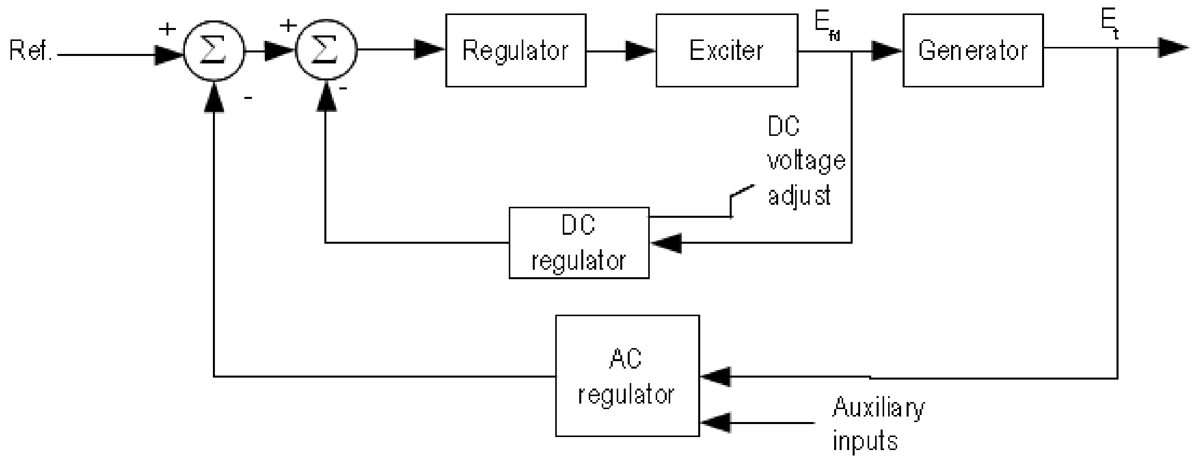


Figure 4-2: AC and DC regulators

4.3 Exciter

Exciters can be classified into three broad categories based on their excitation power source; DC, AC and static exciters. The power rating of an exciter varies from 2.0 - 3.5 kW/MVA [16]. When determining steady state power rating of exciters, margins for temperature variations, component failures, and emergency over heating, etc., should be considered. The voltage rating of an exciter will not normally exceed 1000V; as higher voltage would require additional insulation [17].

In *DC excitation systems*, DC generators are used as sources of excitation power. They provide current to the synchronous machine through slip rings. DC exciters are not used for large generators, which require large excitation currents, due to commutation problems [17]. DC exciters are disappearing and are being replaced by AC exciters as power electronics elements' rating increase and prices decrease.

AC exciters use AC machines as sources of excitation power. The output of the exciters is rectified either by controlled or uncontrolled rectifiers. The rectifiers may be stationary or rotating. Stationary rectifier systems use slip rings. When non-controlled rectifiers are used, the regulator controls the field of the ac exciter, which in turn controls the exciter output voltage. When controlled rectifiers (thyristors) are used, the regulator directly controls the dc output voltage of the exciter. In rotating exciters, an exciter with excitation source "inside out" synchronous machine, i.e. armature winding on rotor and field winding on the stator, is used. It is also known as brushless excitation system. The induced current is rectified by diodes that are also mounted on the rotor and then fed to the excitation winding of the main generator. Figure 4-3 shows a brushless rotating excitation system. Disadvantage of this type of excitation system is that the field current can only be controlled indirectly by controlling the field of the exciter. This will introduce some delays. It is possible to use rotating thyristors but controlling the firing angle will not be easy and the reliability is low.

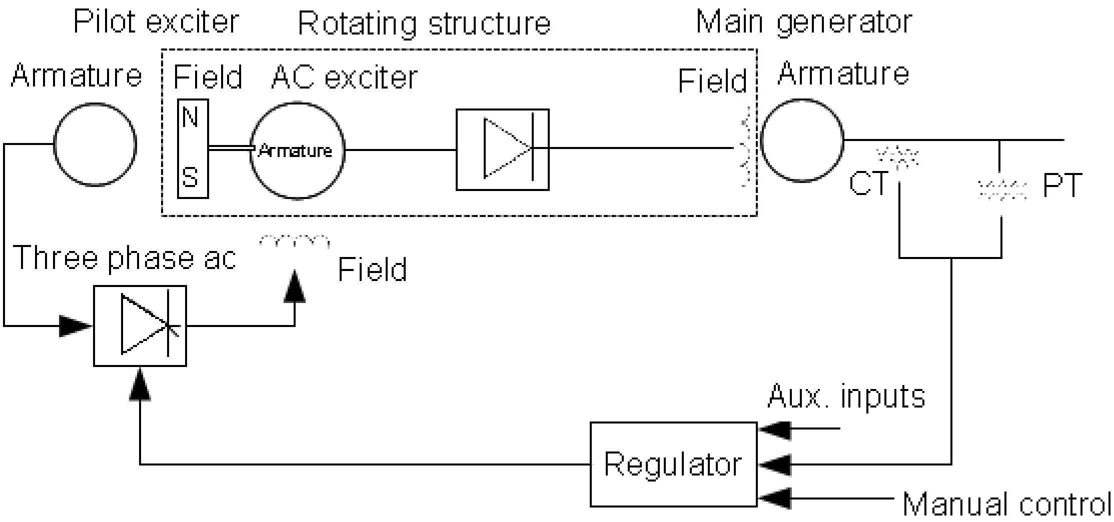


Figure 4-3: Brushless excitation system with PM pilot exciter [16]

In *Static excitation systems*, static rectifiers, controlled or uncontrolled, supply the excitation current directly to the field of the main synchronous generator through slip rings. The excitation power is taken from the generator's terminal or from an auxiliary bus. The main drawback in using this type of static excitation system is use of slip rings. But it is offset by rapid speed with which they react to control signals.

4.4 Limiters and protective circuits

These are circuits that ensure that capability limits of the exciter and synchronous generator are not exceeded.

Under excitation limiter (UEL) prevents reduction of generator excitation to a level where small signal (steady-state) stability limit or stator core end region heating limit is exceeded. UEL prevents generators' loss of synchronism due to high bus voltage. The limiter's performance should be coordinated with the generator loss of excitation protection.

Over excitation limiter (OXL or OEL) protects the generator from overheating due to prolonged field over-current. The function detects high field current and after a time delay ramp down excitation to preset value; if unsuccessful it trips the ac regulator.

Volt-per-Hertz limiter and protection protects the generator and step up transformer from damage due to excessive magnetic flux resulting from low frequency and/or overvoltage.

Field shorting circuits are used under conditions of pole slipping and system short circuits or when the induced current in the generator field winding may be negative. Therefore, a special circuitry is provided to bypass the exciter to allow negative field current to flow. Figure 4-4 shows a field shorting circuit. FDR stands for field discharge resistor.

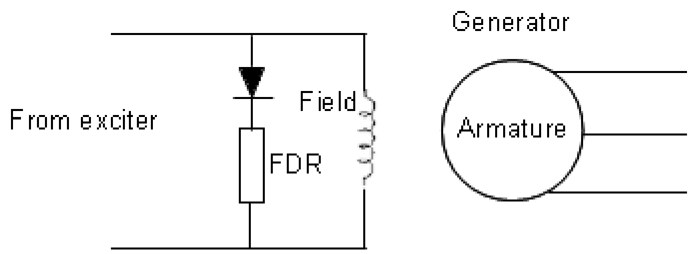


Figure 4-4: Field bypass circuit [16]

4.5 Excitation stabilizers and power system stabilizers

Excitation system comprises of elements with significant time delays and that have poor dynamic performances; particularly dc and ac type excitation systems. Therefore, they need excitation system *excitation system stabilizing circuits*. Static excitation systems do not require stabilization. Series or feedback compensation is used to improve dynamic performance. Derivative feedback is they most commonly used form of compensation and is shown in Figure 4-5.

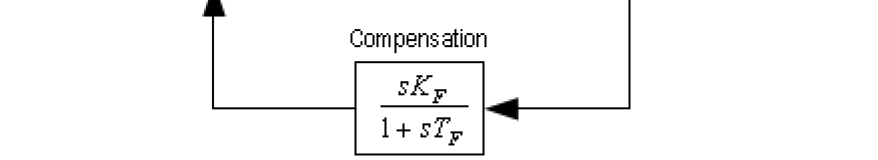


Figure 4-5: Derivative feedback excitation control system stabilization [16]

Power system stabilizer is an element that provides additional input to the regulator to improve the dynamic performance of the power system. It improves power system dynamic performance by damping system oscillations to enhance small-signal stability. Input signals to a power system stabilizer are shaft speed, terminal frequency and power, or a combination of these.

5 Dynamic performance measures

The dynamic performance of an excitation system depends on excitation system, generator and power system characteristics. Large and small signal performances are used in the study of dynamic performance of an excitation system.

5.1 Large signal performance

Large signal performance is the response to signals that are large enough so that nonlinearities are significant [18]. It measures excitation system performance variation in synchronous machine stator voltages, stator currents and field currents. It reflects real power system disturbances. Large signal performance can be evaluated using excitation system ceiling voltage, ceiling current, voltage time response, voltage response time, high initial-response excitation system and excitation system nominal response. References [16] and [18] define these indices as follows.

- *Ceiling current*: The maximum direct current that the excitation system is able to supply from its terminals for a specified time.
- *Ceiling voltage*: The maximum direct voltage that the excitation system is able to supply from its terminals under defined conditions
- *Excitation system voltage time response*: The excitation system output voltage expressed as a function of time under specified conditions.
- *Voltage response time*: The time in seconds for the excitation voltage to attain 95% of the difference between ceiling voltage and rated field voltage under specified conditions.
- *High initial response excitation system*: An excitation system having a voltage response time of 0.1 seconds or less. It represents a high response and fast acting system.
- *Excitation system nominal response*: The rate of increase of the excitation system output voltage determined from the excitation system voltage response curve, divided by the rated field voltage.

5.2 Small signal performance

Small signal performance is the response to signals which are small enough that nonlinearities are insignificant [18]. It measures response of closed loop excitation control system to incremental changes in load, voltage, and synchronous machine rotor speed associated with the initial stages of dynamic instability. It is used to determine and verify excitation system model parameters. Small signal performance can be analysed using time domain transient (step or ramp) response testing, frequency response testing, or by eigenvalue analysis.

Small signal transient response

Small signal transient response test consists of applying a transient, a step or ramp, to the input. It is commonly used to evaluate the performance of closed-loop excitation control systems. The principal characteristics of interest for a small signal transient response are rise time, overshoot, and settling time. Figure 5-1 illustrates these indices for a step response.

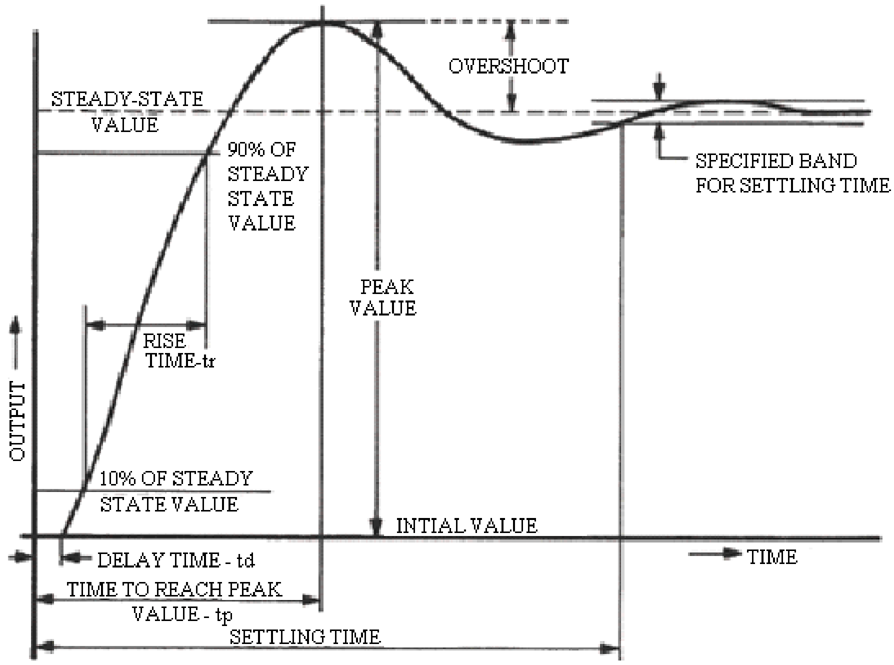


Figure 5-1: Typical small signal transient response of a feedback control system for a step change in input [18]

For an excitation system having small time constants, an acceptable transient response might be considered as one having no more than two overshoots with a maximum overshoot of 5% to 15% [18].

Small signal frequency response

Frequency response testing consists of applying a known driving signal to the input of the element under test and measuring the output with respect to the input. Frequency response measurements can be made with the unit offline or with the unit online and operating near full load with external system conditions as in normal operation.

The principal characteristics of interest for open loop frequency response are the low frequency gain (G), crossover frequency (ω_c), phase margin (ϕ_m), and gain margin (G_m). The parameters of interest for closed loop frequency response are the bandwidth (ω_B), the peak value of the gain characteristic (M_p), and the frequency at which the peak value occurs (ω_m). Gain and phase margins are measures of relative stability. Negative open loop gain and phase margins imply that the system will be unstable with the feedback loop closed. Figure 5-2 and Figure 5-3 illustrate open and closed loop frequency response indices for measurements made with the synchronous machine open-circuited.

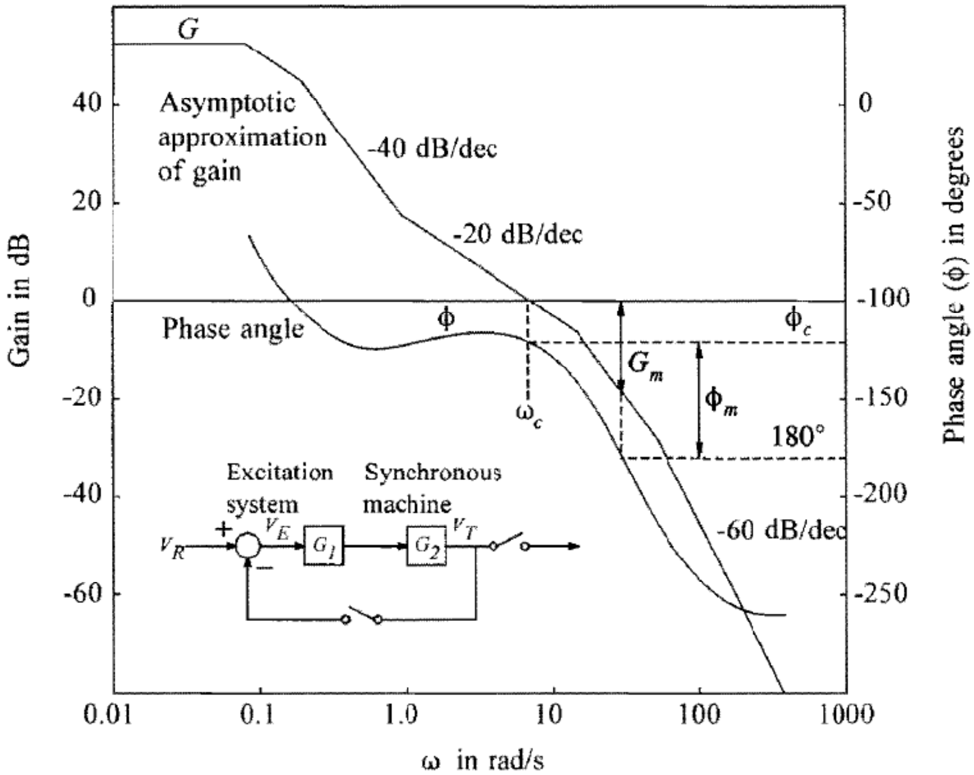


Figure 5-2: Typical open-loop frequency response of an excitation control system with generator open-circuited [18]

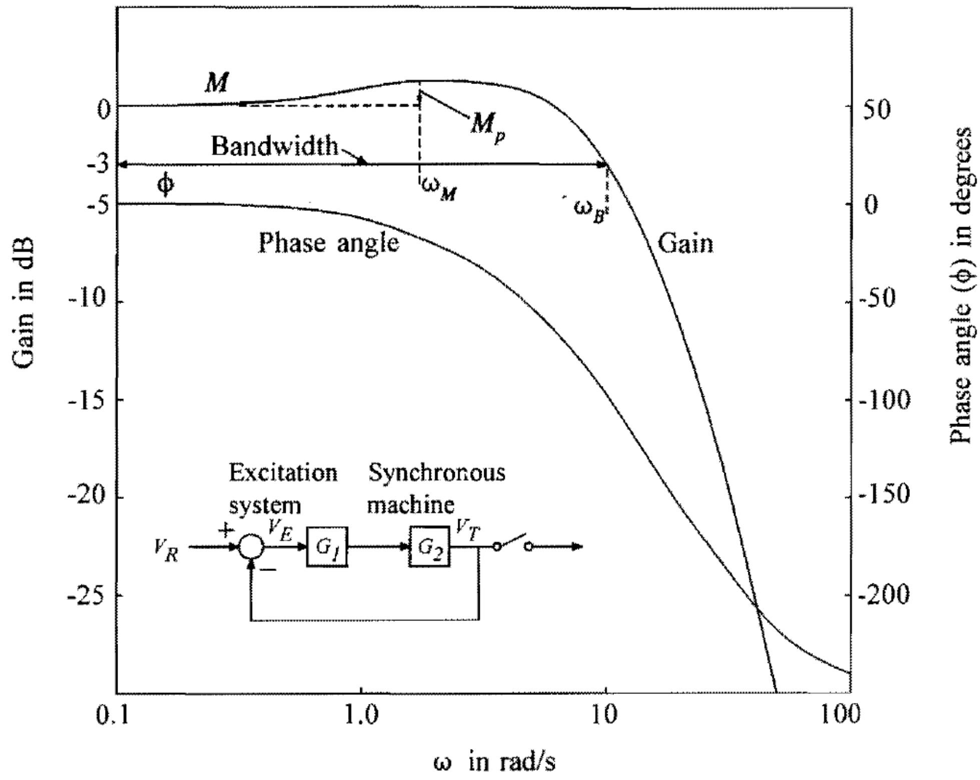


Figure 5-3: Typical closed-loop frequency response with generator open-circuited [18]

A gain margin of 6 dB or more and a phase margin of 40° or more are recommended. A high peak value (M_p) is indicative of an oscillatory system exhibiting large overshoot in its transient response. A peak value between 1.1 dB and 1.6 dB is generally accepted. Bandwidth (ω_B) is important because it is indicative of the rise time T_r or speed of the transient response. In feedback control systems having a step response exhibiting less than 10% overshoot, the product, $T_r * \omega_B$, is between 0.3 and 0.45 [18].

It is not possible to define such generally acceptable ranges of values rise time, settling time, and bandwidth which can be used as a measure of speed and stability of control action. These values are primarily determined by the synchronous machine dynamic characteristics. Their importance is dependent on individual application of each feedback control system.

5.3 Eigenvalue analysis and modes of power system oscillations

A loaded synchronous machine connected to a power system forms a complex multi-loop, multi-variable high order control system. So, time and frequency response analyses described above will not be applicable.

A complex power system can be linearized about an equilibrium point in order to get useful information on the small signal performance of the system. The state-space approach using eigenvalue techniques is an effective method for analysis of such complex systems. When a synchronous machine is connected to a power system, its operating level and the parameters of the external system greatly influence its performance.

Results of linearization of a power system dynamics around an operating point is expressed in state-space form $\dot{\mathbf{X}} = \mathbf{Ax}$, where **x** is *n x 1* vector of state variables, and **A** is an *n x n* matrix of real constant coefficients [19]. The characteristics equation is given by:

$$\det(\mathbf{A} - \lambda\mathbf{I}) = 0$$

Values of λ that satisfy the characteristics equation are called eigenvalues. Eigenvalues can be *real* or *complex*.

Negative *real eigenvalues* represent a decaying non-oscillatory mode while positive *real eigenvalues* represent instability. *Zero eigenvalues* may occur due to lack of uniqueness of absolute rotor angle (no infinite bus) or if all generator torques are assumed to be independent of speed deviations [16].

Complex eigenvalues occur in pairs and each pair represents an oscillatory mode. They are composed of real and imaginary parts; $\lambda_{1,2} = -\sigma \pm j\omega_d$. The real part represents damping while the imaginary part represents damped natural frequency. *Complex eigenvalues* are depicted on a complex plane with real (σ) and imaginary (jω) axes. Eigenvalues that are further on the left side of the vertical (jω) axis represent modes which are more quickly damped than those closer to the jω axis, whereas eigenvalues that are on the right side of the vertical jω axis represent unstable modes and, thus, indicate a system which is unstable.

Damping ratio (ζ) is the rate of decay of the amplitude of an oscillation. It is defined as:

$$\zeta = \frac{-\sigma}{\sqrt{\sigma^2 + \omega_d^2}}$$

The frequency of the oscillation is:

$$f = \frac{\omega_d}{2\pi}$$

Oscillation modes can be divided into different categories based on generating units' interaction with other generating units and control systems. The different oscillation modes are defined in [16] as follows.

- *Local plant modes* are associated with the swinging of units at a generating station with the rest of they power system.
- *Inter machine or inter-plant mode* are associated with oscillations between the rotors of a few generators close to each other. Usually, local plant mode and interplant mode oscillations have frequencies in the range of 0.7 to 2.0 Hz.
- *Inter area modes* are associated with swinging of many machines in one part of the system against other machines in other parts. There are two forms of inter area oscillations in large inter connected systems. The first is a low frequency mode, in the range of 0.1 to 0.3 Hz, involving all generators in the system. The system is divided into two parts with generators in one part swinging against generators in the other part. The second form of inter area oscillation is a high frequency oscillation in the range of 0.4 to 0.7 Hz. It involves subgroups of generators swinging against each other.
- *Control modes* are associated with generating units' excitation system controls and controls of other equipments such as HVDC converters and static var compensators.
- *Torsional modes* are associated with the turbine-generator shaft system rotational components.

6 Modelling of exciters

Models are used for easier understanding of real systems, mathematical formulae and in simulation programs. Excitation system models are used for power system stability studies. In this chapter, excitation control system models used in this thesis work are explained first. Then, each block in the model is discussed relating it to real excitation system elements. The intention behind this chapter is to show how excitation system elements are modelled for power system study.

6.1 Type AC8B and Type II var controllers

The IEEE Type AC8B voltage and Type II var controllers are chosen from IEEE standard models [15] to represent the voltage and reactive power regulators that are used for the distributed generators in Øie – Kvinesdal distribution network.

The AVR in Type AC8B excitation system model represents a brushless excitation system. It consists of PID control, with separate constants for the proportional (K_{PR}), integral (K_{IR}), and derivative (K_{DR}) gains. The values for the constants are chosen for best performance for each particular generator excitation system. The brushless exciter is represented by T_E, K_E, S_E, K_C and K_D. In digital exciters K_C and K_D are set to zero [15]. V_{RMAX} and V_{RMIN} can be a function of terminal voltage. Figure 6-1 shows an AC8B excitation system model.

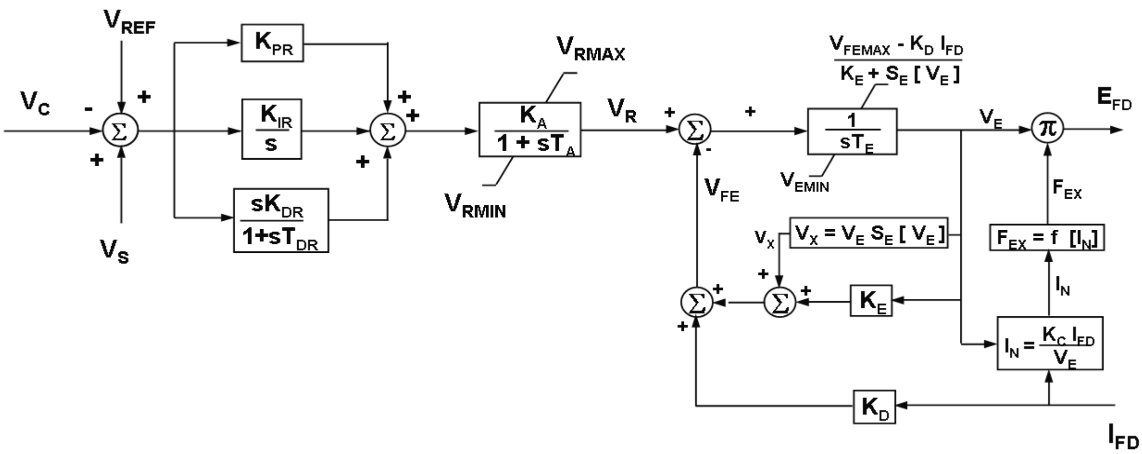


Figure 6-1: Type AC8B excitation system model [15]

The Type II var controller is a summing point type controller. It makes up the outside loop of a two-loop system. The voltage controller makes up the inner loop and the var controller makes up the slow outer loop. The regulator in Type II var controller is PI type. The output signal (V_{VAR}) is used as input to the voltage regulator loop. The integral action is disabled in the over excitation and under excitation cases. Figure 6-2 shows a Type II var controller model.

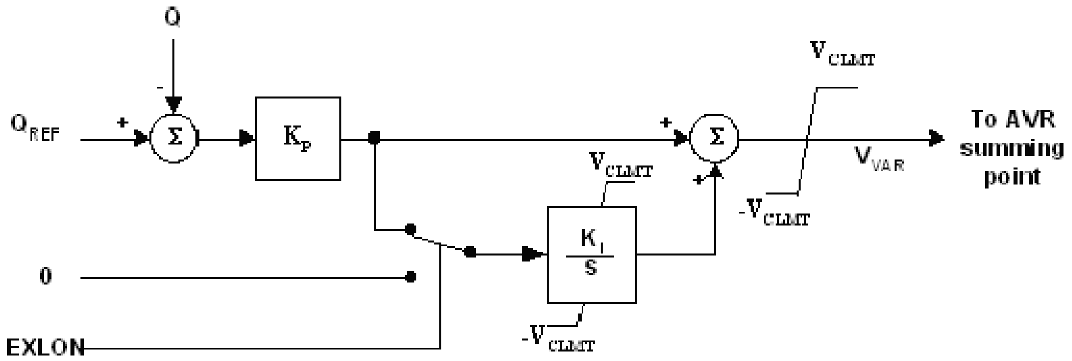


Figure 6-2: Var controller Type II model [15]

Figure A- 1 and Figure A- 2 show voltage and reactive controllers diagrams used to generate DSL (Dynamic Simulation Language) codes that are used in the dynamic simulation analysis. Parameter values used in the controllers are listed in Table A- 3 in Appendix 1.5.

6.2 AC exciters

The IEEE Type AC8B excitation system model includes a brushless AC exciter. A general block diagram for AC exciters is shown in Figure 6-3.

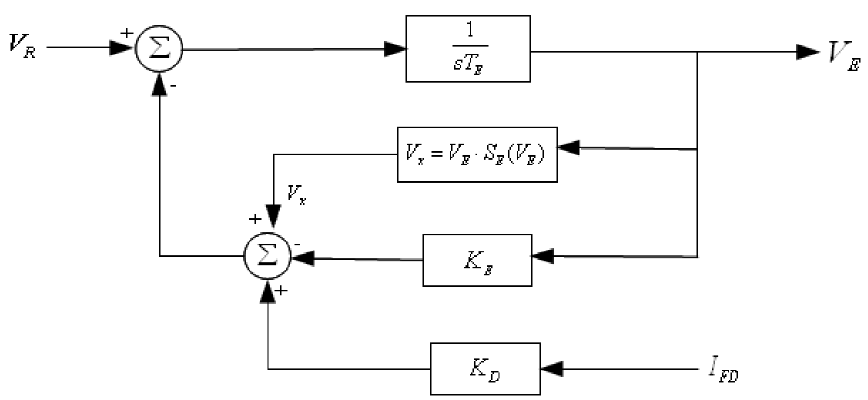


Figure 6-3: Block diagram of an AC exciter [16]

The exciter input is regulator output V_R. The exciter output voltage, V_E, depends on exciter load current, exciter field resistance, and magnetic saturation. I_{FD} represents the exciter load current and $K_D I_{FD}$ stands for armature reaction demagnetizing effect. The constant K_D depends on the ac exciter synchronous and transient reactance [16]. K_E is a function of exciter field resistance and the slope of the air gap line shown in Figure 6-4. The per unit saturation function S_E is calculated using the no load saturation curve and air gap line shown in Figure 6-4.

$$S_E(V_E) = \frac{A - B}{B}$$

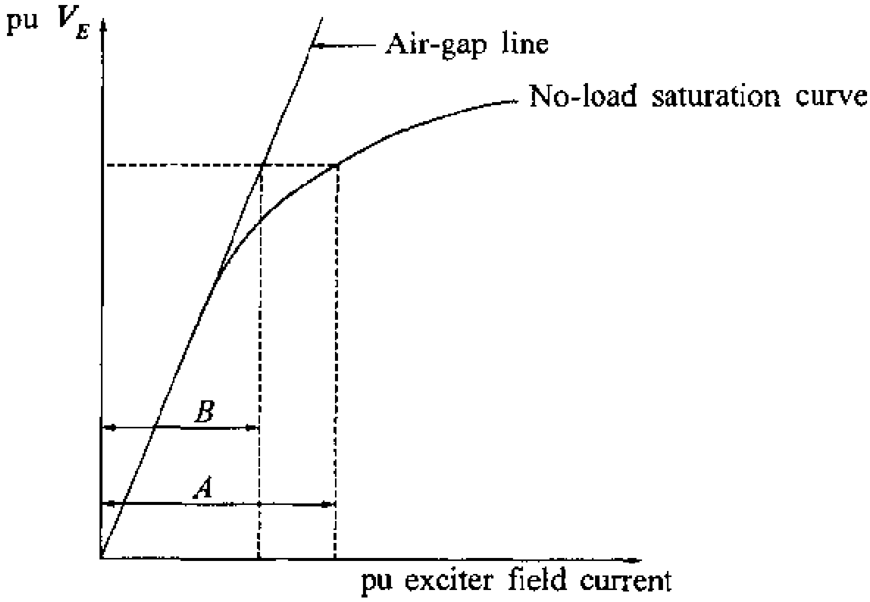
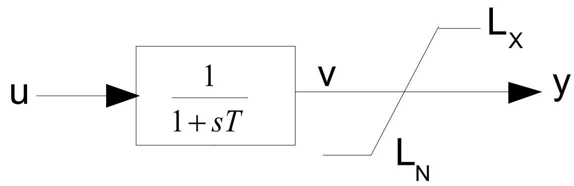


Figure 6-4: AC exciter saturation characteristics [16]

Any convenient functions, i.e. quadratic, linear, or exponential, etc., can be used to approximate the effect of exciter saturation function. For the exciter in type AC8B, linear function was chosen to represent the exciter saturation.

6.3 Windup and non-windup limits

Windup and non-windup limits can be found with integrator blocks, single time constant blocks, and lead lag blocks. In Figure 6-5 and a single time constant block is used to illustrate the difference between the two types of limits.



System equation: $\frac{dv}{dt} = \frac{u-v}{T}$

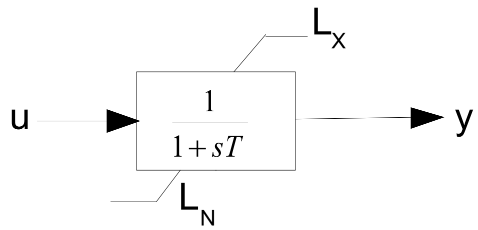
Limiting action:

If $L_N < v < L_X$, then $y = v$

If $L_N \geq v$, then $y = L_X$

If $L_N \leq v$, then $y = L_N$

Figure 6-5: Single time constant block with windup limits [16]



System equation: $f = \frac{u-y}{T}$

If $L_N < y < L_X$, then $\frac{dy}{dt} = f$

Limiting action:

If $y \geq L_X$ and $f > 0$, then set $\frac{dy}{dt}$=0, $y = L_X$

If $y \leq L_N$ and $f < 0$, then set $\frac{dy}{dt}$=0, $y = L_N$

Figure 6-6: Single time constant block with non-windup limits [16]

The difference between windup limit and non windup limit is that, in the first one, the output *y* can not come off a limit until *v* comes within limits and in the later, *y* comes off the limit as soon as the input *u* re-enters the range within limits.

6.4 Amplifiers

An amplifier can be characterized by a gain and a time constant. An amplifier model is shown in Figure 6-7.

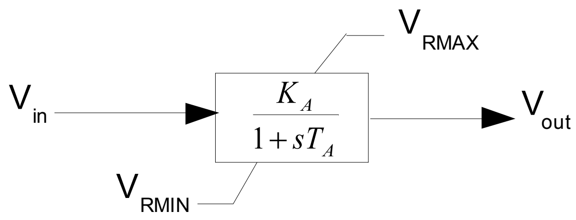


Figure 6-7: An amplifier model

The non-wind up limits V_{RMAX} and V_{RMIN} may depend on generator terminal voltage E_t if the amplifier is getting its power supply from the generator or auxiliary bus voltage.

6.5 Limiters

Standard models do not include limiter such as under excitation limiters, over excitation limiters and V/Hz limiter. These elements do not come into play under normal conditions. The implementation of limiting functions varies depending on manufacturer, the vintage of the equipment, and the requirements specified by utility [16]. Therefore, models of these circuits are established on case basis.

7 PID regulator tuning

The selected voltage controller, Type AC8B, uses proportional, integral and derivative (PID) regulator. To get a good output response the proportional, integral and derivative gain constants should be selected carefully. This process is called PID tuning. An optimally tuned excitation system offers benefits in overall operating performance during transient conditions caused by system faults, disturbances, or motor starting [20].

The proportional gain affects the rate of rise after a change has been initiated into the control loop. The faster the rise time, the faster the response is. Integral gain continuously changes in the direction to reduce the error to zero. It affects the settling time. The derivative block produces an output that depends on the rate of change of error. It affects the percentage of overshoot allowed after the system disturbances [20]. The combined effect of the PID terms will shape the response of the generator excitation system.

Two most commonly utilized PID tuning approaches are pole placement method and pole-zero cancellation method. They are discussed in detail in [21]. But, in this work guidelines recommended by Statnett, FIKS [22], is used to select the PID gain constants.

No load step test has been done on each synchronous DG to find the appropriate proportional, integral and derivative gain constants for the PID regulator in the voltage controller. Voltage overshoot, rise time and settling time for the step change were used to evaluate the performance of the regulator. The expected ranges for these parameters were taken from FIKS [22]. The ranges are:

- Less than 1 second to reach 90% of steady state value for a step response (95% → 100% or 100%→95%) for a generator disconnected from the grid
- Peak overshoot less than 15% of the step
- Settling time less than two seconds to settle within ± 2.5% of steady state value

Each generator was equipped with terminal voltage regulator. At time=1 sec., the reference signal was changed from 1 p.u. to 0.95 p.u. At time= 40 sec., after new steady state has been reached, the reference signal is stepped up from 0.95 p.u. to 1 p.u.. Peak overshoot, rise time and settling time were measured. Figure 7-1 shows the voltage response for GEN 2.

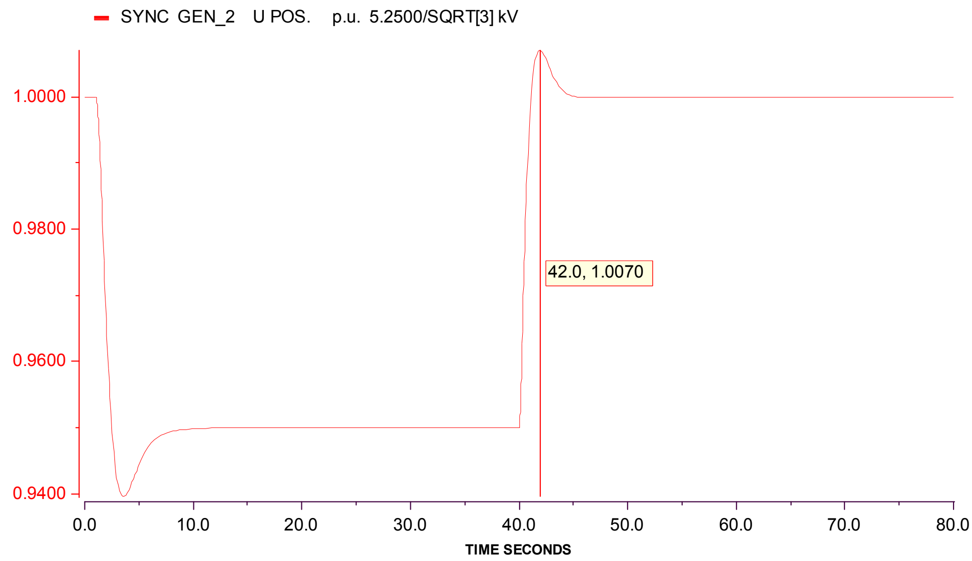


Figure 7-1: Step test voltage response for GEN 2

Rise time for step down test and settling time, for both step-up and step down tests, were not as expected. The time to reach lower pick for the step down test was very long; close to 4 sec. Settling time took more than 2 sec. in both tests. But the overshoot criteria was met for both step up and step down and rise time criteria was satisfied in the step up test. Table 7-1 shows proportional, integral and gain constants of the voltage regulator tuned for each generator.

Table 7-1: Gain constants for the PID regulators in the voltage controller AC8B

Generator code	KP	KI	KD
GEN 1	35	5	10
GEN 2	20	8	10
GEN 4	30	10	10
GEN 5	35	10	10
GEN 6	30	10	10
GEN 7	30	10	10
GEN 8	35	5	10

Sample data given in [15] were used for the gain constants in the reactive controller loop. Both KII and KG were set to 1 for all generators.

8 Test cases description

Four cases with three difference total active power production levels and two different network loading conditions were studied. The different active power production levels are 17 MW, 4.7 MW and 3.25 MW. The first is rated production by all generators and the last two are medium production levels that occur frequently in the distribution network. The two different loading conditions are low load (1.6 MW and 0.32 MVAr) and high load (11 MW and 2.2 Mvar). In all cases, the generators are operating either on the allowed maximum terminal voltage[1] or the allowed minimum power factor[2]. These cases were chosen for dynamic study because the DGs are operating on their margins and the distribution network had the largest loss reduction of the cases studied in the specialization project [1].

For each case, the pre-fault generator terminal voltage and power factor were used as a factor to decide whether to use terminal voltage controller or reactive power controller. If the generator terminal voltage is close to the allowed limit, then voltage control is used even if the power factor is close to its limit. If there is a gap between the generator terminal voltage and the allowed limit, then reactive power regulator is used.

Detailed description of each case is give below.

8.1 Case A

All generators are producing active power at their rated capacity (17 MW) and the network is loaded with low load (1.6 MW and 0.32 MVAr). The net reactive power production from the synchronous DGs is -0.85 MVAr. All generators are consuming maximum allowed reactive power except GEN 2 which is producing 1.55 MVAr. So, all generators except GEN 2 are working on the lower power factor limit i.e. 0.95. Terminal voltage of all generators, except GEN 1 and GEN 7, is very close to the maximum limit. Surplus active power is exported from the feeder as the production is higher than the load demand; while reactive power imported into the feeder. This case was referred as LL_FG_d in [1]. Table 8-1 shows a summary of power productions and generator terminal voltages for Case A.

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[1] The allowed generator terminal voltage range is considered as 0.95 p.u. to 1.05 p.u

[2] The allowed power factor range is considered as 0.9 to 1 when producing reactive power. Otherwise, 0.95 to 1.

Table 8-1: Pre-fault steady state terminal voltage, active and reactive power, and cos Φ for Case A

	Voltage (p.u.)	Active power (MW)	Reactive power (MVAr)	Cos Φ
22 KV side substation Bus	1.007	14.80	-3.51	
GEN 1	1.011	1.30	-0.43	0.95
GEN 2	1.050	10.30	1.55	0.99
GEN 4	1.044	0.42	-0.14	0.95
GEN 5	1.044	0.90	-0.30	0.95
GEN 6	1.051	0.44	-0.15	0.95
GEN 7	1.035	0.70	-0.23	0.95
GEN 8	1.043	3.50	-1.15	0.95

Excitation system controllers used in Case A are automatic voltage controllers in all generators except GEN 1 and GEN 7. These two generators use reactive power regulator. Reference values are measured from the corresponding generator's terminals.

8.2 Case B

This is a case with total production level of 4.7 MW. 80% of the year generation is less than 10 MW and the average during these hours is 4.6 MW [23]. The network is loaded with high load (11 MW and 2.2 MVAr). All of the synchronous generators in the network are producing reactive power to keep network voltage as high as possible. This will keep the network voltage from falling below the lower limit and also reduce network loss compared to producing zero reactive power. Reactive power flow into the feeder is 0.48 MVAr implying that the feeder is supplying its own reactive power demand. This case was referred as HL_G1_a in [1]. Table 8-2 shows summary for Case B.

Table 8-2: Pre-fault steady state terminal voltage, active and reactive power, and cos Φ for Case B

	Voltage (p.u.)	Active power (MW)	Reactive power (MVAr)	Cos Φ
22 KV side substation Bus	1.014	-6.536	0.479	
GEN 1	1.026	0.741	0.359	0.90
GEN 2	1.017	2.100	1.017	0.90
GEN 4	1.030	0.094	0.045	0.90
GEN 5	1.030	0.190	0.092	0.90
GEN 6	1.036	0.105	0.051	0.90
GEN 7	1.028	0.197	0.095	0.90
GEN 8	1.039	1.281	0.620	0.90

Reactive power controller is used in all synchronous generators in Case B as their terminal voltage is below 1.05 p.u. and their power factors are on the minimum allowed value.

8.3 Case C

This case has same total active power production as Case B but differs in network loading and DG reactive power production. The total network load is 1.6 MW and 0.32 MVAr (low load). All generators are consuming reactive power except GEN 2. The net reactive power production of the synchronous generators is zero. There is reactive power generation by the network due to line capacitances. This case was referred as LL_G1_a in [1].

Table 8-3: Pre-fault steady state terminal voltage, active and reactive power, and cos Φ for Case C

	Voltage (p.u.)	Active power (MW)	Reactive power (MVAr)	Cos Φ
22 KV side substation Bus	1.007	2.948	0.286	
GEN 1	1.008	0.741	-0.244	0.95
GEN 2	1.025	2.100	0.800	0.93
GEN 4	1.027	0.094	-0.031	0.95
GEN 5	1.027	0.190	-0.063	0.95
GEN 6	1.030	0.105	-0.035	0.95
GEN 7	1.025	0.197	-0.065	0.95
GEN 8	1.028	1.281	-0.421	0.95

Reactive power controller is used in all synchronous DGs because all except GEN 2 are operating on their lower power factor limit.

8.4 Case D

This case is a low production level of 3.25 MW. 63% of the year the production is less than 7 MW and the average during these hours is 3.3 MW [23]. The network is operating with high load (11 MW and 2.2 MVAr). 3.8 % loss reduction [23] was achieved by producing reactive power from all the synchronous generators compared to running the generators with zero reactive power production. 8 MW and 0.33 MVAr flows into the feeder. Table 8-4 summarizes Case D.

Table 8-4: Pre-fault steady state terminal voltage, active and reactive power, and cos Φ for Case D

	Voltage (p.u.)	Active power (MW)	Reactive power (MVAr)	Cos Φ
22 KV side substation Bus	1.009	-8.038	-0.337	
GEN 1	1.013	0.741	0.359	0.90
GEN 2	0.999	1.100	0.533	0.90
GEN 4	0.999	0.028	0.014	0.90
GEN 5	0.999	0.057	0.028	0.90
GEN 6	1.003	0.041	0.020	0.90
GEN 7	0.996	0.000	0.000	0.01
GEN 8	1.016	1.281	0.620	0.90

All synchronous DGs use reactive power controller to regulate their reactive power generation

.

9 Pre-disturbance small signal stability analysis

Linear analysis was performed on each case before disturbances were applied to the network. Complex eigenvalues were computed. Eigenvalues with small damping ratios and large real parts (closest to the imaginary axis) were studied in detail.

Modal analysis, *participation factor*, *sensitivity* and *data scanning* tools were used to analyse an eigenvalue. *Modal analysis* involves imposing a small perturbation signal, with a frequency of the selected eigenvalue, on for example the mechanical torque of a generator to cause a speed deviation of the machines. The kinetic energy then oscillates between the involved machines [4]. Phasors, that are normalized with the largest rotor outswing, are used to show the oscillating energy between the involved machines. The output of modal analysis is expressed either in terms of kinetic energy magnitude and angle or in terms of phasors diagrams. By studying these outputs, an eigenvalue's oscillation modes can be identified. *Participation factor* is a measure of the relative participation of a state variable in an eigenvalue [16]. By using participation factor tool in SIMPOW, it is possible to list the state variables that contribute most to a selected eigenvalue. It can be used to determine which parameter of a component (e.g. exciters, generators etc) influences that eigenvalue most. There are two types of *sensitivity* analyses; sensitivity overview and sensitivity with respect to data. Sensitivity overview shows how much influence a component has on an eigenvalue. Shifted inverse Arnouldi method is used to compute sensitivity with respected to data. When sensitivity is measured with respect to a parameter, the result is expressed in per unit of the parameter (1/s/pu for the real part and Hz/pu for the imaginary part). It shows how much the damping and the frequency changes when the value of the selected parameter is increased [4]. The difference between participation factors and sensitivity overview is that the first determines which state variables in an exciter, synchronous generator or governor influence the eigenvalue while the later determines which components, for example lines, loads, transformers etc, in the network influence the eigenvalue. So when using sensitivity overview, one should consider components with the possibilities to change settings such as exciters and governors. *Data scanning* shows how an eigenvalue moves on the complex plane for different values of a selected parameter.

A selected eigenvalue must always be improved before other linear analysis tools are used [4].

Chapters 9.1 to 9.4 discuss linear analysis carried out using modal analysis, participation factor, sensitivity and data scanning tools.

9.1 Case A

There are 62 eigenvalues at t=0 and 15 of them are complex conjugate pairs. Table 9-1 lists all the complex conjugate eigenvalue pairs. Eigenvalues with low damping ratios have a high possibility of crossing the imaginary axis for a change in the state variables that are linked to them. These changes can be induced due to disturbances, change in system parameters like regulator gains and so on.

Table 9-1: Complex conjugate pairs of eigenvalues at time=0 for Case A

#	Real part (1/s)	Imaginary part (Hz)	ζ (Damping ratio)
8, 9	-5.79	11.29	8%
10, 11	-3.65	9.38	6%
16, 17	-3.78	8.65	7%
18, 19	-3.92	7.66	8%
22, 23	-5.68	6.08	15%
24, 25	-5.21	5.53	15%
26, 27	-3.15	4.78	10%
30, 31	-22.71	0.72	98%
32, 33	-9.60	0.16	99%
41, 42	-1.11	0.33	48%
43, 44	-1.16	0.27	57%
45, 46	-0.07	0.14	9%
47, 48	-0.36	0.08	57%
49, 50	-0.46	0.07	73%
51, 52	-0.24	0.07	51%

All eigenvalues with real part greater than -1, except # 45, 46, have low oscillating frequencies. This makes their damping ratio high even if they are close to the imaginary axis. On the other hand, eigenvalues with high oscillating frequencies have low damping ratios even if their real parts are small and their locations on the complex plane are far from the imaginary axis. High oscillating frequencies are not common. The typical value of oscillating frequency for large generators connected to high voltage and extremely high voltage networks is around 2 Hz [3]. In this case, there are eigenvalues with imaginary part as high as 11 Hz. This could be due to the low inertia of the distributed generators. This is explained more in the discussion; Chapter 11.

Improvement of eigenvalues has to be done before further linear analysis is carried out. But, the improved eigenvalues are not that much different form the original ones.

Modal analysis, sensitivity and data scanning tools were used to investigate eigenvalues that have damping ratio less than 10%. These tools are very important in finding out to which generator(s) an eigenvalue is connected to, what kind of oscillation mode an eigenvalue represents and what influences it most. The major participations factors in eigenvalues #8, #10, #16, and #18 were found to be state variables related to generators GEN 4, 7, 6 and 5, respectively. The detailed participation factors result is shown in Figure A- 3. The state variables connected to these eigenvalues depend on the generators' parameters and can not be modified.

Detailed analysis carried out on the eigenvalue closest to the imaginary axis, -0.07 1/s + j0.14 Hz (#45), is stated below.

9.1.1 Modal analysis

Modal analysis

The results of the modal analysis, for -0.07 1/s + j0.14 Hz, are shown in Table 9-2. These results are expressed in terms of kinetic energy magnitude and angle; normalized to the largest rotor out swing for a frequency disturbance equal to the selected eigenvalue's frequency. The graphical representation of the oscillations is shown in Figure A- 4 in Appendix 2.

Table 9-2: Mode analysis of Synchronous/Asynchronous Machines for -0.07 1/s + j0.14 Hz

Generator	Kinetic Energy	
	Magnitude	Angle (Deg.)
GEN_1	0.01	-28.7
GEN_2	0.11	108.1
GEN_3	0.58	-64.3
GEN_4	0.07	84.1
GEN_5	0.19	88.9
GEN_6	0.08	87.2
GEN_7	1.00	0.0
GEN_8	0.17	172.4

GEN 1 and GEN 7 has the lowest and the highest kinetic energy response to the eigenvalue frequency. GEN 7 and GEN 8 are oscillating against each other. GEN 4, GEN 5 and GEN 6 are oscillating in the same direction. GEN 2 is oscillating against the induction generator GEN 3.

Participation factors

The reactive power controller in GEN 7 was found to be the largest contributor to eigenvalue #45. Table 9-3 shows the state variables in the reactive power regulator that have the most influence on the eigenvalue.

Table 9-3: Participation factors for -0.072 1/s + j0.135 Hz

State variable	Magnitude	Angle (Deg.)
V13	0.32	-42.4
UF	0.39	65.8
V3	0.21	-69.9
INTER_5	0.16	-69.6

Refer to Figure A- 2 to find the state variables V13, UF, V3 and INTER_5. V13 is output of the integrator, in the PI regulator, of the external reactive power controller loop. UF is exciter output voltage. V3 is output of the integrator, in the PID regulator, of the automatic voltage regulator. INTER_5 is an internal variable created by the DSL code generator (Appendix 1.3). It is related to the output of the derivative block in the PID regulator.

V13, V3 and INTER_5 directly depend on the gain constants KII, KI and KD respectively. The loop gain KG can also influence V13. UF depends on all the constants in the controller. There is no single constant that can be adjusted to modify it.

9.1.2 Sensitivity

Overview

Sensitivity overview shows that GEN 7 has the largest influence on the eigenvalue under study. Figure 9-1 shows the result of the sensitivity overview.

```
*** Sensitivity Overview ***
Eigenvalue: (-0.72135E-01 1/s , 0.13517     Hz)
SYNCGEN_7
Type: G
83.408
*** End of Sensitivity Overview ***
```

Figure 9-1: Sensitivity overview for eigenvalue -0.072 1/s + j0.135 Hz

Sensitivity with respect to data

Sensitivity with respect to data was carried out on gain constants that influence the state variables found under participation factors. Positive real part sensitivities imply that as the parameter value increases the real part of the eigenvalue also increases. This makes it less damped and may lead to instability. Table 9-4 shows sensitivity with respect to KG, KII, KI and KD for the eigenvalue under study.

Table 9-4: Sensitivity with respect to KG, KII, KI and KD for -0.072 1/s + j0.135 Hz

Gain constant	Sensitivity
KG	-0.028 1/s/pu , 0.054 Hz/pu
KII	0.165 1/s/pu , 0.034 Hz/pu
KI	0.016 1/s/pu , 0.001 Hz/pu
KD	-0.012 1/s/pu ,-0.001 Hz/pu

KII has the largest sensitivity per unit on the real part of the eigenvalue; 0.16481 1/s/pu. KG and KD have negative damping sensitivities implying that as the parameters increase the eigenvalue will be more damped and shift to the left on the complex plane. But the eigenvalue's frequency will increase as KG increases and decrease as KD increases because of the different signs of the frequency sensitivity factors. KII and KI have positive sensitivity in both damping and frequency. So, as KII and KI increase the eigenvalue will become less damped with growing oscillation frequency.

9.1.3 Data scanning

The gain constants for KG, KII, KI and KD were varied to see how the eigenvalue moves on the complex plane as the parameters' value change.

KG

Initially KG was equal to 1. Data scanning was performed for KG between 1 and 2 in steps of 0.2. Table 9-5 shows the eigenvalue's location for different values of KG. As KG increase, damping ratio and frequency increase. So the eigenvalue moves to the left and upwards on the complex plane. Figure A- 5, in Appendix 2, shows the eigenvalue movement on the complex plane.

Table 9-5: Change in eigenvalue -0.07452 1/s + j0.135002 Hz for change in KG

KG	Real part (1/s)	Imaginary part (Hz)	ζ (Damping ratio)
1	-0.072	0.135	8%
1.2	-0.079	0.145	9%
1.4	-0.087	0.155	9%
1.6	-0.097	0.164	9%
1.8	-0.107	0.172	10%
2	-0.119	0.180	10%

With increase in KG the magnitude of the oscillations will be more damped but their oscillation frequency increases.

KII

Initially KII was 1. Data scanning was done for an increase from 1 to 2 in steps of 0.2. Table 9-6 shows the eigenvalues for different values of KII. Figure A- 5, in Appendix 2, shows the eigenvalue's movement on the complex plane.

Table 9-6: Change in eigenvalue -0.07452 1/s + j0.135002 Hz for change in KII

KII	Real part (1/s)	Imaginary part (Hz)	ζ (Damping ratio)
1.0	-0.072	0.135	8%
1.2	-0.042	0.142	5%
1.4	-0.016	0.148	2%
1.6	0.006	0.154	-1%
1.8	0.026	0.159	-3%
2.0	0.044	0.164	-4%

As KII increases damping decreases. For the step from 1.4 and 1.6 the eigenvalue's real part changes sign and damping ratio becomes negative. This makes oscillations grow instead of diminishing. Increasing KII more than 1.4 will cause small signal instability.

KI

Initially KI was 10. Data scanning was done for an increase from 10 to 20 in steps of 2. Table 9-7 shows the eigenvalues for different values of KI. Figure A- 5, in Appendix 2, shows the eigenvalue movement on the complex plane.

Table 9-7: Change in eigenvalue -0.07452 1/s + j0.135002 Hz for change in KI

KI	Real part (1/s)	Imaginary part (Hz)	ζ (Damping ratio)
10.0	-0.072	0.135	8%
12.0	-0.041	0.138	5%
14.0	-0.013	0.140	2%
16.0	0.012	0.143	-1%
18.0	0.034	0.146	-4%
20.0	0.055	0.148	-6%

As KI increase damping decreases but frequency increases. Somewhere in between 14 and 16 the eigenvalue will have negative damping meaning that the oscillations will start to grow with increasing frequency. Increasing KI more than 14 will lead to instability.

KD

Initially KD was 10. Since KD was found to have negative sensitivity (Table 9-4), data scanning was done for a decrease from 10 to 1 in steps of 2. Table 9-8 shows eigenvalues for different values of KD. Figure A- 5, in Appendix 2, shows the eigenvalue movement on the complex plane.

Table 9-8: Change in eigenvalue -0.07452 1/s + j0.135002 Hz for change in KD

KD	Real part (1/s)	Imaginary part (Hz)	ζ (Damping ratio)
10.0	-0.072	0.135	8%
8.0	-0.049	0.137	6%
6.0	-0.026	0.139	3%
4.0	-0.002	0.140	0%
2.0	0.022	0.142	-2%
1.0	0.034	0.142	-4%

As KD decreases damping also decreases and for some value between 4 and 6 the real part of the eigenvalue will reverse its sign. Decreasing KD less than 6 will make damping ratio negative and the system will become unstable.

9.2 Case B

There are 66 eigenvalues in total. 16 of them are complex conjugate pairs. Table 9-9 lists all complex conjugate eigenvalue pairs.

Table 9-9: Complex conjugate pairs of eigenvalues for Case B

#	Real part (1/s)	Imaginary part (Hz)	ζ (Damping ratio)
12, 13	-7.35	5.88	20%
14, 15	-6.68	5.22	20%
16, 17	-5.48	4.82	18%
18, 19	-5.84	4.55	20%
20, 21	-7.75	4.49	26%
24, 25	-5.55	3.69	23%
27, 28	-4.52	3.20	22%
30, 31	-3.88	0.65	69%
32, 33	-3.46	0.58	69%
37, 28	-5.31	0.30	94%
41, 42	-2.24	0.35	71%
47, 48	-1.79	0.06	98%
52, 53	-0.49	0.05	82%
56, 57	-0.35	0.05	76%
58, 59	-0.28	0.03	86%
60, 61	-0.29	0.04	76%

Eigenvalue pair #16, #17 has the smallest damping ratio. The largest contributors to this eigenvalue pair was found to be state variables related to GEN 1. These state variables are dependent on the generator's parameters. The modal analysis (participation factor) result is shown in Figure A- 6.

The oscillation frequency for all complex eigenvalues with real part greater than -1 is very low. That is why they have high damping ratios. Eigenvalue pair #58, #59 has the lowest real part magnitude. Detailed study is carried out on this particular pair.

9.2.1 Modal analysis

Modal analysis

Modal analysis results are shown in Table 9-10. The induction generator, GEN 3, has the largest kinetic energy response related to the eigenvalue. All the synchronous generators oscillate in the opposite direction relative to the induction generator. GEN 2, GEN 5, GEN 7 and GEN 8 oscillate together. GEN 4 and GEN 6 oscillate against GEN 3. This is an inter-area oscillation mode where a generator in one part of the system is oscillating against generators in another part of the system.

Table 9-10: Modal analysis for -0.28 1/s + j0.03 Hz

Generator	Kinetic energy	
	Magnitude	Angle (Deg.)
GEN 1	0.03	125.51
GEN 2	0.11	146.01
GEN 3	1.00	0.00
GEN 4	0.22	177.63
GEN 5	0.21	142.96
GEN 6	0.24	170.13
GEN 7	0.19	148.10
GEN 8	0.10	140.95

Participation factor

The largest contributor to eigenvalue -0.28 1/s + j0.03 Hz was found to be the reactive power regulator connected to GEN 6.

Table 9-11: Participation factors for -0.28 1/s + j0.03 Hz

State variable	Magnitude	Angle (Deg.)
V13	0.22	15.78
UF	0.08	-131.42
V3	0.33	33.98
INTER_5	0.04	151.40

Refer to the reactive power controller block diagram in Figure A- 2 in the appendix for the following explanation of the state variables. V13 is output of the integrator of the PI regulator in the var loop. UF is exciter output voltage. V3 is output of the integrator of the PID regulator. INTER_5 is an internal variable created by the DSL code generator. It is related to the derivative block of the PID regulator. V3 and INTER_5 have the highest and lowest magnitudes.

V13, V3 and INTER_5 depend on the gain constants KII, KI and KD respectively. The loop gain constant, KG, also influences V13.

9.2.2 Sensitivity

Sensitivity with respect to data

Sensitivity with respect to gain constants influencing the largest participation factors were computed using *sensitivity with respect to data* tool. Table 9-12 shows the sensitivity per unit of the eigenvalue with respect to each gain constant.

Table 9-12: Sensitivity with respect to KG, KII, KI and KD for -0.28 1/s + j0.03 Hz

Gain constant	Sensitivity			
KG	-0.05	1/s/pu	0.00	Hz/pu
KII	-0.07	1/s/pu	0.00	Hz/pu
KI	-0.01	1/s/pu	0.00	Hz/pu
KD	-0.00	1/s/pu	0.00	Hz/pu

The imaginary part sensitivities are zero and the real part sensitivities are very low for all gain constants studied. All real part sensitivities are negative implying that as the gain constants increase damping increases. The derivative gain constant, KD, has zero influence on the eigenvalue.

9.2.3 Data scanning

Data scanning with respect to KG, KII, KI and KD was computed. But since the eigenvalue have very low sensitivity with respect to these parameters, the changes were insignificant. KII had the largest sensitivity with respect to the selected eigenvalue. Data scanning with respect to KII is shown in Table 9-13.

Table 9-13: Data scanning with respect to KII for -0.28 1/s + j0.03 Hz

KII	Real part (1/s)	Imaginary part (Hz)	ζ (Damping ratio)
1.0	-0.28	0.03	86%
1.5	-0.30	0.03	86%
2.0	-0.30	0.03	86%
2.5	-0.30	0.03	85%
3.0	-0.30	0.03	85%
3.5	-0.30	0.03	85%
4.0	-0.30	0.03	85%
4.5	-0.30	0.03	85%
5.0	-0.30	0.03	85%

It can be observed from the results that change in KII does not have any significant effect on the eigenvalue.

9.3 Case C

There are 68 eigenvalues in total. 18 of them are complex conjugate pairs. List of all complex eigenvalues is shown in Table 9-14.

Table 9-14: Complex conjugate pairs of eigenvalues for Case C

#	Real part (1/s)	Imaginary part (Hz)	ζ (Damping ratio)
14, 15	-6.74	5.90	18%
16, 17	-7.59	5.75	21%
18, 19	-8.77	5.44	25%
21, 22	-6.89	4.94	22%
23, 24	-5.35	4.57	18%
25, 26	-5.93	4.14	22%
28, 29	-4.97	3.42	23%
35, 36	-3.89	0.65	69%
39, 40	-3.18	0.53	69%
44, 45	-1.83	0.34	65%
46, 47	-1.63	0.08	96%
48, 49	-1.69	0.01	100%
50, 51	-0.39	0.12	46%
52, 53	-1.22	0.10	88%
54, 55	-0.42	0.07	69%
57, 58	-0.31	0.04	77%
61, 62	-0.30	0.02	88%
64, 65	-0.52	0.01	98%

There are 7 pairs of eigenvalues with frequency larger than 3 Hz. Eigenvalue pairs #14, #15 and #23, #24 have the smallest damping ratios (18%). Their participation factors (Figure A- 7) show that the major contributors for these eigenvalues are state variables related to GEN 7 and 1, respectively. Eigenvalue # 50 (-0.39 1/s + j0.12 Hz) was chosen for further study.

9.3.1 Modal analysis

Modal analysis

The modal analysis for eigenvalue -0.39 1/s + j0.12 Hz shows that GEN 7 and GEN 1 have the highest and the lowest kinetic energy responses, respectively. The kinetic energy magnitudes of all generators except GEN 3 and GEN 7 are very small.

Table 9-15: Modal analysis for -0.39 1/s + j0.12 Hz

Generator	Kinetic energy	
	Magnitude	Angle (Deg.)
GEN 1	0.007	-99.14
GEN 2	0.037	-17.97
GEN 3	0.126	-129.34
GEN 4	0.093	86.43
GEN 5	0.096	-147.87
GEN 6	0.069	137.13
GEN 7	1.000	0.00
GEN 8	0.034	-44.21

GEN 2, GEN 4, GEN 7 and GEN 8 oscillate in one direction and the rest oscillate in the opposite direction. This eigenvalue represent an inter area oscillation mode where generators are swinging against each other in subgroups.

Participation factor

The largest contributor to the selected eigenvalue was found to be the reactive power regulator connected to GEN 7. Table 9-16 shows the state variables that have the largest influence on -0.39 1/s + j0.12 Hz. KG, KII and KI can be adjusted to change these state variables.

Table 9-16: Participation factors for -0.39 1/s + j0.12 Hz

State variable	Magnitude	Angle (Deg.)
V13	0.54	-91.29
UF	0.73	43.66
V3	0.33	-125.21

9.3.2 Sensitivity

Sensitivity of the selected eigenvalue with respect to KG, KII and KI is presented in Table 9-17. The selected eigenvalue has the largest sensitivity for per unit change of KII of the reactive power controller of GEN 7. Sensitivity with respect to KII is positive implying that for an increase in the parameter, the real part of the eigenvalue will also increase. This will decrease the damping and may lead to instability.

Table 9-17: Sensitivity with respect to KG, KII and KI for -0.38751 1/s + j0.11893 Hz

Parameter	Sensitivity			
KG	-0.02	1/s/pu	0.06	Hz/pu
KII	0.30	1/s/pu	0.04	Hz/pu
KI	0.03	1/s/pu	0.00	Hz/pu

9.3.3 Data scanning

Data scanning with KG did not work. Non-convergence was found for decrease in KG value. Data scanning with respect to KII show that for an increase in KII, both real and imaginary parts of the eigenvalue increase. If KII is increased more than 6, the eignenvalue's real part will become positive. So the oscillations will increase instead of decreasing and dying. This causes small signal instability.

Table 9-18: Data scanning with respect to KII for -0.38751 1/s + j0.11893 Hz

KII	Real part (1/s)	Imaginary part (Hz)	ζ (Damping ratio)
1	-0.39	0.12	46%
2	-0.22	0.16	22%
3	-0.14	0.18	12%
4	-0.08	0.21	6%
5	-0.04	0.22	3%
6	0.00	0.24	0%
7	0.03	0.26	-2%
8	0.06	0.27	-4%

9.4 Case D

There are 66 eigenvalues in total. 19 pairs of them are complex conjugate pairs. Table 9-19 shows all pre-disturbance complex eigenvalues for Case D. Most of the eigenvalues are highly damped. Eigenvalue pair #14,#15 and #16,#17 have the smallest damping ratios; 19% and 16% respectively. Their participation factors result (Figure A- 8) reveals that the major contributors to both eigenvalues are state variables related to GEN 1. Eigenvalue # 56 is chosen to for further analysis.

Table 9-19: Complex eigenvalue pairs for Case D

#	Real part (1/s)	Imaginary part (Hz)	ζ (Damping ratio)
12, 13	-7.30	5.77	20%
14, 15	-6.23	5.08	19%
16, 17	-4.82	4.67	16%
22, 23	-5.27	2.63	30%
24, 25	-4.44	2.62	26%
26, 27	-3.85	2.36	25%
28, 29	-3.45	2.22	24%
30, 31	-6.89	0.65	86%
32, 33	-6.43	0.69	83%
34, 35	-7.01	0.39	94%
36, 37	-3.82	0.64	69%
38, 39	-3.42	0.56	69%
40, 41	-6.01	0.38	93%
43, 44	-2.21	0.35	71%
52, 53	-0.31	0.04	75%
54, 55	-0.28	0.04	75%
56, 57	-0.27	0.03	86%
58, 59	-0.46	0.05	83%
65, 66	-0.72	0.00	100%

9.4.1 Modal Analysis

Modal analysis

GEN 3 and GEN 7 have the highest and lowest kinetic energy responses. The kinetic energy responses of the synchronous generators are very small. All the synchronous generators oscillate against the induction generator, GEN 3. The modal analysis diagram is shown in Figure A- 9. This eigenvalue represent inter-area mode of oscillation.

Table 9-20: Modal analysis for -0.27 1/s + j0.03 Hz in Case D

Generator	Kinetic energy	
	Magnitude	Angle (Deg.)
GEN 1	0.03	124.9
GEN 2	0.09	145.9
GEN 3	1.00	0.0
GEN 4	0.12	175.8
GEN 5	0.11	144.2
GEN 6	0.16	166.6
GEN 7	0.02	153.5
GEN 8	0.11	140.0

Participation factors

The largest contributor to the selected eigenvalue is the reactive power controller of GEN 6. The state variables that have the most influence on the eigenvalue are listed in Table 9-21. These state variables can be changed by changing gain constants KG, KII, KI and KD (refer to **Error! Reference source not found.**).

Table 9-21: Participation factors for -0.26582 1/s + j0.025547Hz

State variable	Magnitude	Angle (Deg.)
V13	0.22	8.5
UF	0.08	-139.7
V3	0.32	29.4
INTER_5	0.03	145.3

9.4.2 Sensitivity

Shifted inverse Arnouldi method is applied for sensitivity computation with respect to KG, KII, KI and KD. The result is presented in Table 9-22. The selected eigenvalue have very low sensitivity to the gain constants. It has zero sensitivity in its frequency for a change in all the gain constants under study. This shows that changing these parameters does not have any influence on the eigenvalue under study.

Table 9-22: Sensitivity with respect to KG, KII, KI and KD for -0.26584 1/s + j0.25548E-01 Hz in Case D

Parameter	Eigenvalue			
KG	-0.05	1/s/pu	0.00	Hz/pu
KII	-0.06	1/s/pu	0.00	Hz/pu
KI	-0.01	1/s/pu	0.00	Hz/pu
KD	0.00	1/s/pu	0.00	Hz/pu

10 Transient stability and post disturbance linear analysis

Five difference types of disturbances were used to analyse the dynamic behaviour of the distribution network. The disturbances are generator disconnection, change in load, change in system voltage, short circuit fault, and disconnection of the feeder from the HV network. Each case is tested for the different types of disturbances.

Five difference scenarios of generator disconnections were studied. These are disconnection of GEN 1, GEN 2, GEN 5, and GEN 8, one generator disconnection at a time, and disconnection the smallest three generators GEN 4, GEN 6 and GEN 7; all at the same time. GEN 2 has the largest rated capacity, 10.3 MW, followed by GEN 8 and GEN 1 which have rated capacities of 3.5 MW and 1.3 MW, respectively. They are large enough to affect the voltage profile of the distribution network. GEN 5 has rated capacity of 0.9 MW. It is connected to same bus as GEN 4 and shares common step up transformer. GEN 4, GEN 6 and GEN 7 have rated capacities of 0.42 MW, 0.44 MW and 0.7 MW, respectively. Even though their production capacities are very small, since are connected to the same side branch, their disconnection might create a disturbance. Disconnection of these three generators at the same time due to fault might be highly unlikely in real case. But, it is done this way to maximize the disturbance in the network.

Two different scenarios of load changes were studied. The first one is a step change in load. This is studied to see how the network would behave for change in loads. The change could be from high load to low load or from low load to high load depending on the initial loading condition of the network. For cases A and C, since their pre-disturbance loading conditions were low load, the step change would be from low load to high load. For cases B and D, the step change in load was from high load to low load. In reality, this change would take place over some time; especially in distribution networks where the loads are fairly predictable and usually with no industrial loads. But, in this study the change was swift. This was done to maximize the disturbance. The second type of change in load is disconnection of loads between the 106/22 KV substation transformer and the first generator (GEN 1). These loads make up 66% of the loads in the system [1].

Table 10-1 summarizes the different scenarios in generator disconnection and change in load disturbances.

Table 10-1: Different scenarios in generator disconnection and change in load disturbances

<table>
<tr><th colspan="2">Type transient of disturbance</th><th>Remark</th></tr>
<tr><td rowspan="5">Generator disconnection</td><td>GEN 1</td><td>The second largest DG in the distribution network</td></tr>
<tr><td>GEN 2</td><td>The largest DG in the distribution network</td></tr>
<tr><td>GEN 8</td><td>The second largest DG and is located at the end of the feeder</td></tr>
<tr><td>GEN 5</td><td>Shares common bus and step up transformer with GEN 4</td></tr>
<tr><td>GEN 4, GEN 6 & GEN 7</td><td>The smallest generators in the distribution network and are located on the same side branch close to each other</td></tr>
<tr><td rowspan="2">Change in load</td><td>Step Change</td><td>Step change from low load to high load (increase by over 600%) or from high load to low load (decrease by 85%)</td></tr>
<tr><td>Disconnection of 66% of loads</td><td>These loads are located between the beginning of the feeder and GEN 1</td></tr>
</table>

Change in system voltage is created by 2.5 % step up on the swing bus voltage. In the real systems, change in system voltage is caused by tap change in substation transformer. Depending on the setting of the transformer, 2.5 % step could be equivalent to one tap change.

A three phase to ground fault was created on GEN 1's connection point to the 22 KV grid (N1). Refer to Figure 2-1 to see where N1 is located. Critical clearing times for each case were analysed.

The line connecting the feeder with the low voltage side of the 106/22 KV transformer was disconnected to check if the generators would be able to maintain synchronism and operate as an island network after the fault.

All disturbances took place at time=1 second. The generators in all cases were able to regain synchronism after disturbances caused by disconnection of synchronous generators, change in load and system voltage. But not all studied scenarios had terminal voltage and power factor within the allowed range in their post-disturbance steady state. Disconnection of the feeder from the HV network caused instability in all studied cases.

This chapter is divided into three parts. The first part describes the new steady state after disturbances caused by disconnection of generators, change in load and system voltage. The second part discusses short circuit fault and disconnection of the feeder form the HV network. The last part discusses post-disturbance linear analysis for selected stable cases.

10.1 Disconnection of generators, change in load and change in system voltage

In this section voltage and reactive powers in the post disturbance steady state values are compared with per-disturbance steady state values for each case. Figure A- 10 to Figure A- 41, in Appendix 3.2, show terminal voltage and reactive power after generator disconnection, change in load and system voltage for each synchronous generator in the distribution network. In the diagrams it is easier to see and compare the pre-disturbance and post-disturbance voltage and reactive power values.

10.1.1 Reactive power and voltage

10.1.1.1 *Case A*

The pre-disturbance terminal voltage, active power, reactive power and power factor for each generator in Case A is given in Table 8-1 in Chapter 8. GEN 1 and GEN 7 are equipped with reactive power controllers and the rest of the synchronous generators are equipped with voltage regulators. So, voltage change after the disturbances occurs only on GEN 1 and GEN 7. There will be reactive power production/consumption change on the rest of the synchronous generators. Voltage and reactive power consumption change on the induction generator's terminal, GEN 3, was not studied.

Generator disconnection

GEN 1 was consuming reactive power before its disconnection. So, its terminal voltage increases in the new steady state. Reactive power production by GEN 2 and reactive power import into the feeder is decreased due to less demand.

GEN 2 was producing reactive power before it got disconnected. After the disturbance, its terminal voltage decreases significantly (from 1.05 p.u. to 1.01 p.u.). Even though the only generator that was producing reactive power got disconnected, there is less reactive power flowing into the feeder in the new steady state. This is because GEN 2 was producing 10.3 MW. So, its disconnection causes less loading on the lines. Thus, less loss and reactive power demands. Reactive power consumption by GEN 8 has decreased. This implies that voltage at the end of the feeder has decreased.

GEN 8 was consuming reactive power prior to its disconnection. Terminal voltages of GEN 4, GEN 5, GEN 6 and GEN 7 have large oscillations (with peaks close to 1.08 p.u.) before the new steady state is reached. The reactive power consumptions of generators 4, 5 and 6 have increased and their new power factors are below 0.95. Reactive power relays might disconnect these generators depending on the relays' settings.

Since GEN 4 and GEN 5 are connected to same bus, disconnection of GEN 5 (which was consuming 0.3 MVAr) will lower the bus voltage. So GEN 4 will consume more reactive to keep the voltage same as the pre-disturbance level. The new power factor for GEN 4 is less than 0.95.

GEN 4, GEN 6 and GEN 7 were consuming 0.12 MVAr, 0.15 MVAr and 0.23 MVAr respectively. After the disturbance terminal voltages of GEN 6 and GEN 7 has increased. But terminal voltage at GEN 4 remained constant because GEN 5 has voltage controller. Since all three generators were consuming reactive power, before their disconnection feeder voltage increased. GEN 8's reactive consumption has increased and its new power factor is less than 0.95.

Change in load

The effect of disconnection of loads in the first part of the feeder does not have a significant effect on the generators' terminal voltage and reactive power production/ consumption. Step change in the load (from low load to high load) increases demand by more than 600%. So, feeder voltage drops. Reactive power production by GEN 2 has increased and consumption by GEN 8 has decreased.

Change in system voltage

Step increase on the swing bus voltage causes the terminal voltages of all generators to rise before the controller brings it down to the initial point. But the reactive power controlled generators (GEN 1 and GEN 7) have higher voltage in the new steady state. Reactive power import into the feeder and reactive power generation by GEN 2 has decreased. The new power factors for GEN 4 and 6 are less than 0.95.

10.1.1.2 *Case B*

All synchronous generators are producing their maximum allowed reactive power and are equipped with reactive power controllers.

Generator disconnection

After disconnection of GEN 1, terminal voltage on all generators decreases slightly. Reactive power flow out of the network decreases.

Voltage decreases on all generator terminals and at 22 KV side substation bus after disconnection of GEN 2. Reactive power was flowing out of the feeder before the fault. After the fault, it started flowing into the feeder.

GEN 8 was producing reactive power before the fault. After the fault, voltage at GEN 8 drops significantly (from 1.03 p.u. to 0.97 p.u.) and voltage at the other generators dropped as well. Reactive power was flowing out of the feeder before the fault. After the fault, it started flowing into the feeder. There is no significant change on the 22 KV side substation bus voltage.

After the disconnection of GEN 5, voltage drops significantly on GEN 4, GEN 5, GEN 6 and GEN 7.

The GEN 4, GEN 6 and GEN 7 were producing Q so when they got disconnected their terminal voltages dropped. No significant change on the other generators.

Change in load

Disconnection of loads at the beginning of the feeder causes voltage to go up on all the feeders except GEN 5. Right after the fault, GEN 4 and GEN 5 have different terminal voltage curves even though they are connected to the same bus. But after a couple of seconds time their terminal voltage reaches to the same value of 1.06 p.u.. Reactive power flowing out of the network increases. Step down in load, from high load to low load, causes voltage to go up, more than 1.05 p.u., on all synchronous generators. GEN 4, GEN 5, GEN 6, GEN 7 and GEN 8 have new steady state terminal voltage 1.1 and more. There are large oscillations in both Q and V curve of GEN 4, GEN 6 and GEN 7 during the transient period. Reactive power flow out of the feeder has increased. Depending on over voltage relays settings this generators might get disconnected from the feeder which will create a new disturbances.

Change in system voltage

Increase in system voltage causes voltage on every generator to increases above 1.05 p.u.. Voltage relays might trip and cause disconnection of the generators unless set values for the reactive power controllers are not applied quickly.

10.1.1.3 ***Case C***

All generators are consuming their maximum allowed reactive power in the pre-disturbance steady state. The reactive power generation by the network (due to capacitance) plays a major role in voltage on generators' terminals and reactive power flow in/out of the feeder.

Generator disconnection

GEN 1 was consuming reactive power before it got disconnected. Its terminal voltage increased after the disturbance. This is a low load case so there is a reactive power generation by the network. Reactive power flow out of the network increased because of less demand.

Terminal voltage drops on all synchronous generators after GEN 2 got disconnected. Voltage increased at substation bus. Reactive power was flowing out of the network but now it is reversed.

GEN 8 was consuming reactive power. Voltage didn't change much on all generators. Reactive power flowing out of the network has increased.

There is no significant change for disconnection of GEN 5, GEN 4, GEN 6, GEN 7, and GEN 8.

Change in load

For step load change, from low load to high load, all synchronous generators' terminal voltages goes down to 0.95 p.u. Due to increase in load, the reactive power starts to flow into the feeder.

Change in system voltage

Chang in system voltage causes the voltage on all generators to go up to their upper limit, 1.05 p.u.

10.1.1.4 *Case D*

In this case all generators are producing their allowed maximum power and the network is loaded with high load.

Generator disconnection

Disconnection of GEN 1, GEN 2 and GEN 8 cause terminal voltage of all synchronous generators to go down but the final level is still within the allowed limits. Reactive power flow into the network increases in each case compared to before the disturbance

Disconnection of GEN 4, 5, 6 and 7 induces no significant change in voltage and reactive power. This is because their pre-disturbance production levels were very small.

Change in load

Both scenarios of load change cause terminal voltage on generators to go up. This is because the network is loaded with high load and both scenarios lead to reducing in load. The reactive power flowing into the feeder decreases and even starts to flow out for the step load change from high load to low load. This is because with low load the network reactive production is greater than its demand.

Change in system voltage

Chang in system voltage causes the voltage on all generators to go up slightly but not above their limits.

10.1.2 Active power flow at 22 kV side of the substation

All generators are modelled with constant torque turbine model. So, the active power production remains constant after all disturbances. Table 10-2shows active power flowing in or out of the feeder for the different cases and disturbances studied. In cases A and C, the DGs active power production is more than the load demand and loss in the network. In cases B and D, active power flows into the network because of more demand than production. In all four cases, generator(s) disconnection causes change equivalent to the production of the disconnected generator(s). Step load change from high load to low load (cases A and C) increases demand in the feeder. So, less active power flows out of the network (Case A) or the power flow reverses and it starts to flow into the network (Case C). There reverse is true for load change from high load to low load. Disconnection of loads always creates less demand in the feeder. The change network loss in the feeder (due to higher voltage and change in reactive power flow) induced by step increase in the swing bus is reflected on the power flowing in/out of the feeder.

Table 10-2: Active power, in MW, flowing in/out of the feeder for different cases and disturbances. Positive value is flow into the feeder. Negative value is flow out of the feeder.

		Active power at the beginning of the feeder (N0) in (MW)			
Type of disturbance		Case A	Case B	Case C	Case D
	Pre-disturbance value	14.802	-6.536	2.948	-8.038
Generator disconnection	GEN 1	13.600	-7.291	2.218	-8.800
	GEN 2	5.242	-8.688	0.880	-9.176
	GEN 8	11.916	-7.867	1.717	-9.401
	GEN 5	14.087	-6.729	2.767	-8.097
	GEN 4, GEN 6 & GEN 7	13.542	-6.940	2.569	-8.109
Change in load	Step Change	5.977	2.897	-6.527	0.242
	Disconnection of loads in the first part of the network	15.844	0.870	4.033	-0.588
Change in system voltage	Tapping up substation transformer by 2.5%	14.780	-6.808	2.948	-8.033

10.2 Short circuit fault and disconnection of the HV network

During short circuit fault the rotor accelerates and increases rotor angle. If this rotor angle increases beyond critical angle then instability occurs. The time it takes to reach the critical angle is called critical clearing time. The fault must be removed before the critical clearing time, for the rotor to stop accelerating and return back to synchronous speed.

A three phase to ground short circuit fault with zero impedance was created on a bus, N1, close to GEN 1. The critical clearing times for Case A, B, C and D are 71ms, 154ms, 159ms and 132ms respectively. Case A has very short critical clearing time compared to the other cases. This is because in pre-disturbance steady state of Case A, all generators are producing active power at their rated capacity and the network voltage was high.

Before disconnecting the feeder from the high voltage network, turbine and governor models have to be included in the dynamic simulation files. This is because the fault will create imbalance between load and turbine torque. In all other cases, no turbine model was given. So, SIMPOW by default set the turbine as a constant torque model. The rating of the turbine will be similar to the rating of the generator it is driving. Every generator was connected to turbine, HYTUR, and governor, HYGOV, which were taken from SIMPOW standard models. Tripping a line connecting the beginning feeder with the 106/22 KV transformer led to instability; in all four studied test cases. Generators GEN 4 and 7 went out of phase in Case A and generators GEN 2 and GEN 7 went out of phase in Case B and C respectively. Generators GEN 1, 2, 7 and 8 went out of phase in Case D.

10.3 Post-disturbance Linear and time domain analysis

This section analyses post disturbance linear and time domain analysis for selected cases. *Modal analysis* is used to study eigenvalues with high frequencies. As it was explained in the introduction of Chapter 9, *Modal analysis* is imposing a small perturbation signal, with a frequency of the selected eigenvalue, to cause a speed deviation between the generators. The amount of kinetic energy that oscillates between the involved machines is then expressed as phasors that are normalised on the largest rotor outswing energy. Phasor diagrams are used to illustrate the modes of the eigenvalues and time simulations are used to illustrate generators oscillation during transient periods.

10.3.1 Disconnection of GEN 2 in Case A

There are 11 complex conjugate pairs of eigenvalues at time=20 sec. after the disconnection of GEN 2 in Case A. They are presented in Table 10-3. Their number is decreased by 4 compared to the pre-disturbance linear analysis (Table 9-1). There are six eigenvalues with high frequencies.

Table 10-3: List of complex eigenvalues at time=20sec. after disconnection of GEN 2 in Case A

#	Real part (1/s)	Imaginary part (Hz)	ζ (Damping ratio)
8, 9	-6.96	10.80	10%
10, 11	-3.68	9.23	6%
16, 17	-4.37	8.31	8%
18, 19	-4.49	7.25	10%
21, 22	-5.06	5.50	14%
23, 24	-3.92	5.15	12%
36, 37	-1.09	0.32	47%
38, 39	-1.22	0.27	58%
40, 41	-0.07	0.14	8%
42, 43	-0.44	0.09	60%
44, 45	-0.35	0.07	63%

Modal analysis

Modal analysis is computed for eigenvalue # 8, 10, 16, 18, 21 and 23. These are eigenvalues with high frequencies and low damping ratios. Such high eigenvalue frequencies are not common. Figure 10-1 shows modal analysis phasor diagram for the six eigenvalues with high frequencies after disconnection of GEN 2 in Case A. For eigenvalue # 8, GEN 4 and GEN 5 are oscillating against each other. The other generators have zero kinetic energy response. This is inter-machine (plant) oscillation mode where generators close to each other are oscillating against each other. For eigenvalue #10, GEN 7 has the largest kinetic energy response and it is oscillating against all the generators in the distribution network. This is an inter-area mode of oscillation. GEN 6 oscillates against GEN 4 and GEN 5 in eigenvalue # 16. This is also a inter-machine (plant) mode of oscillation. For eigenvalue #18, generators 4, 5, 6 and 7 oscillate in the same direction while GEN 1 and 8 oscillate in the opposite direction. This is and inter-area mode of oscillation where generators on the same branch are oscillating against generators on the beginning and end of the feeder. For eigenvalue # 21, GEN 1 has the largest rotor outswing and is oscillating against GEN 5 and GEN 8. It is an inter-area mode of oscillation where a generator in the beginning of the feeder oscillating against generators in the middle and end of the feeder. All synchronous generators are oscillating in the same direction for eigenvalue # 23.

The induction generator, GEN 3, has zero kinetic energy response for all eigenvalues with large frequency. This is because GEN 3 has high inertia constant. So, all eigenvalues with high frequencies are related to only the synchronous generators that have small inertia constants. It is explained more in the discussion; Chapter 11.

The modal analysis values in terms of their kinetic energy magnitude and angle is presented in Table A- 4 in Appendix 3.1.

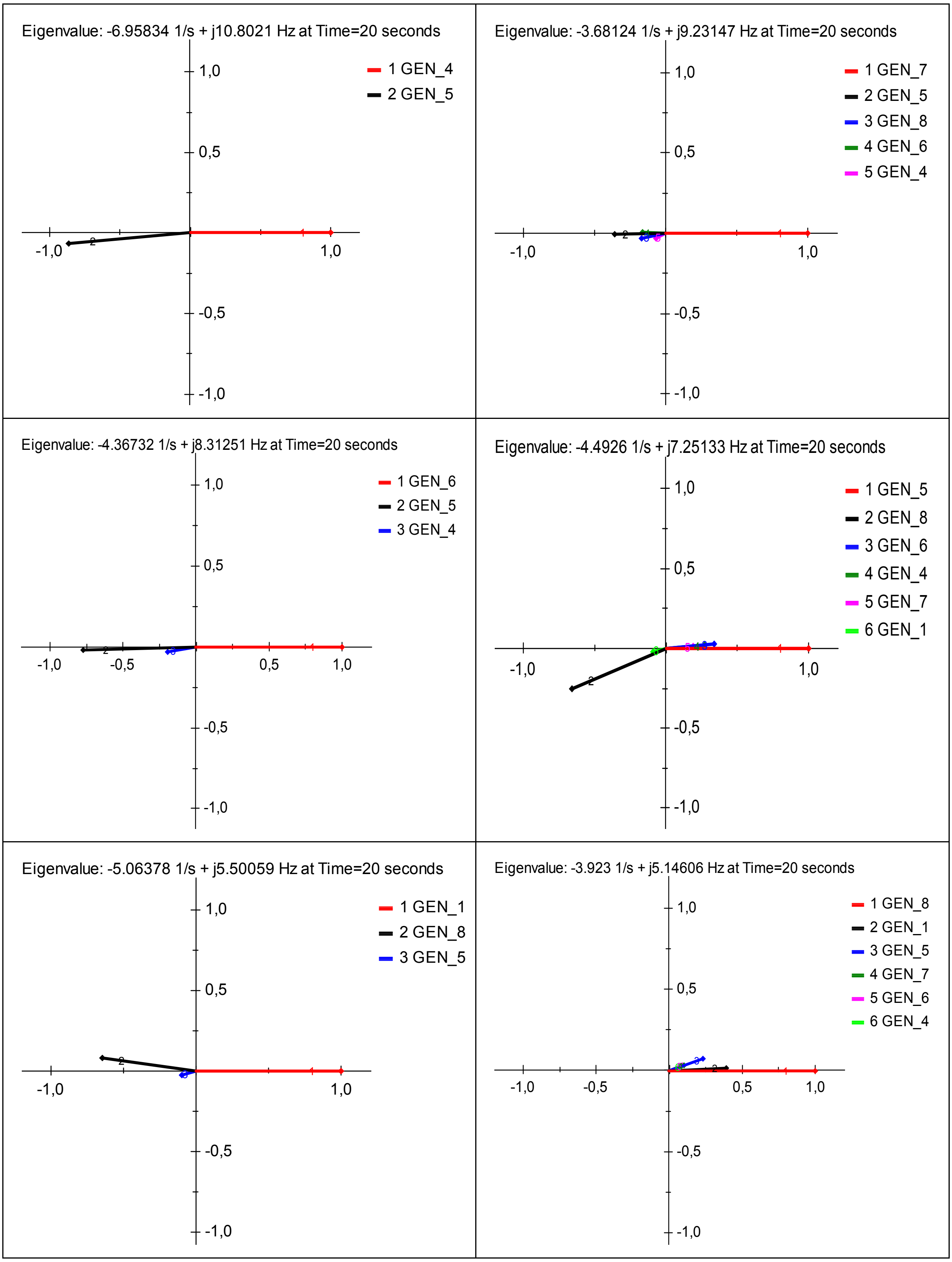
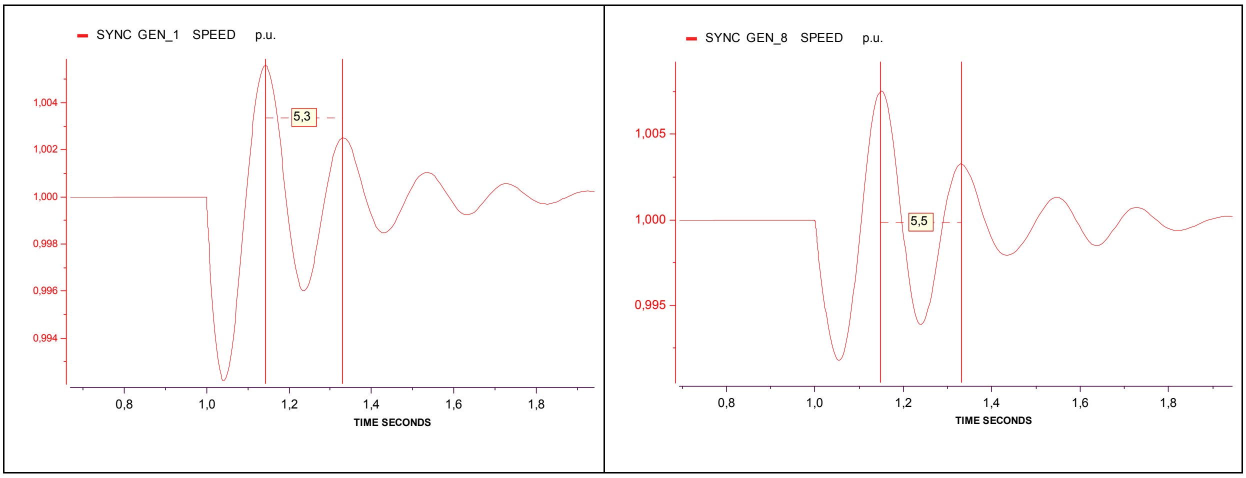


Figure 10-1: Modal analysis graph for eigenvalues with large frequencies after disconnection of GEN 2 in Case A

Time domain analysis

The speed curves for GEN 1 and GEN 8 are shown in Figure 10-2. The frequencies of the oscillations during the transient period are 5.3 and 5.5 Hz for GEN 1 and GEN 8, respectively. Eigenvalue # 21 (-5.06 1/s + j5.5 Hz) and # 23 (-3.92 + j5.15 Hz) have the closest frequencies to the oscillations in GEN 8 and GEN1, respectively.



(a) (b)

Figure 10-2: Speed curves for (a) GEN 1 and (b) GEN 8 after the disconnection of GEN 2 in Case A

Figure 10-3 shows oscillations dominated by more than one eigenvalues. If two eigenvalues were dominating an oscillation and if one has high damping ratio and the other has a very small damping ratio, then it might be possible to see the effect of the eigenvalue with the small damping ratio as the eigenvalue with large damping will die out first. But, in this case all the eigenvalues with high frequencies have close damping ratios (Table 10-2). So it makes it hard to say which eigenvalues are involved.

Speed curve for GEN 4 is shown in Figure 10-3 (a) and Figure 10-3 (b). The frequency of the oscillation is not constant. The frequency between the first and the second peak is 7.3 Hz and the frequency between the second and the third peak is 9 Hz. In the speed curves for GEN 6 and GEN 7 (Figure 10-3 (c) and Figure 10-3 (d)), it is possible to see that the curves are dominated by more than one eigenvalues without calculating the oscillation frequencies. The amplitude of the second peaks is less than the amplitude of the third peak. This implies that the oscillations are damped with more than one eigenvalues with different damping ratios.

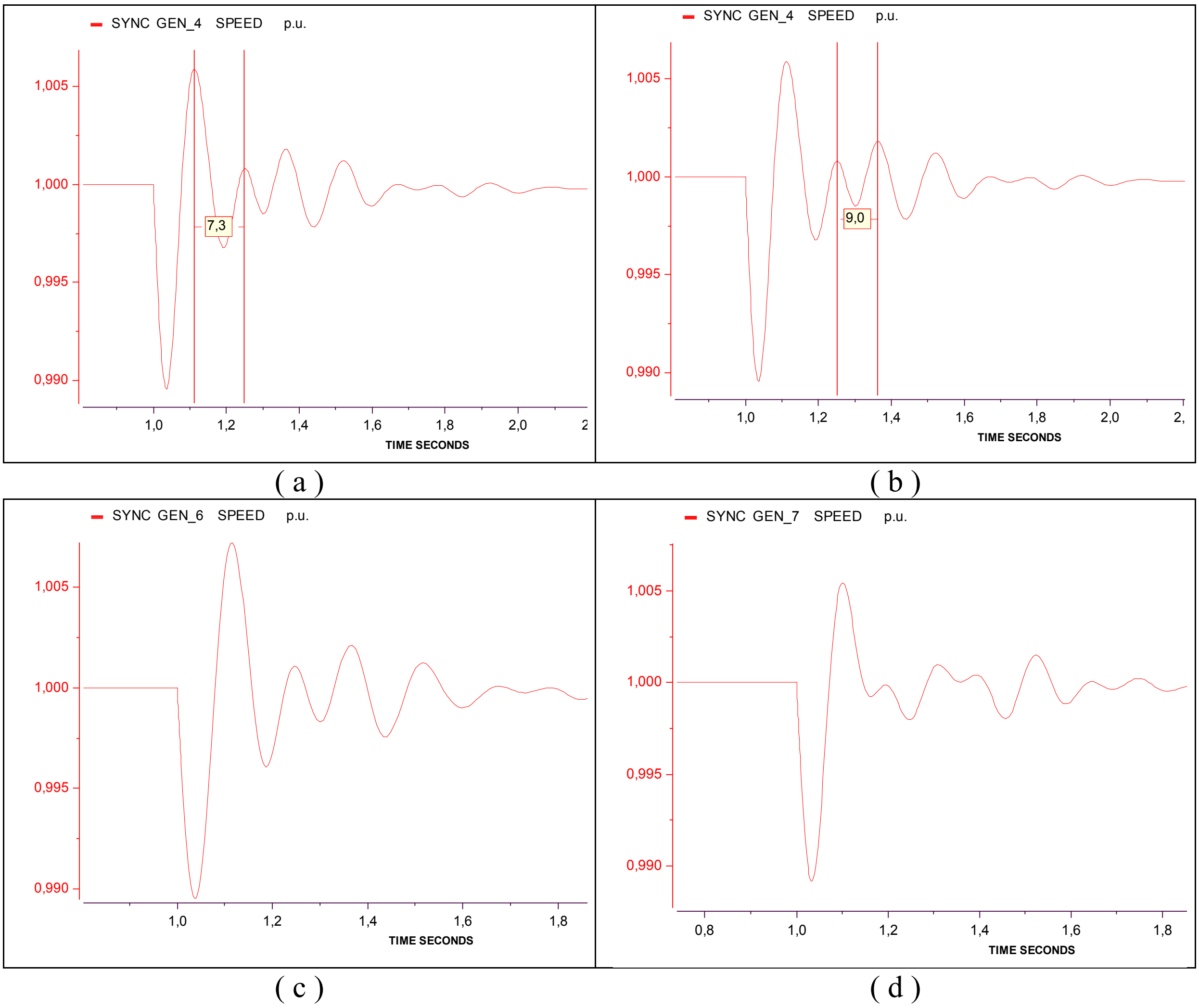


Figure 10-3: Speed curves for (a) GEN 4, (b) GEN 4, (c) GEN 6 and (d) GEN 7 after the disconnection of GEN 2 in Case A

10.3.2 Disconnection of GEN 8 in Case A

The eigenvalues have changed their position on the complex plane compared to the pre-disturbance eigenvalues (Table 9-1). Eigenvalues with large frequencies are reduced by one and they are six now after the disconnection of GEN 8. This implies that one of the eigenvalues was strongly related to the disconnected generator.

Table 10-4: List of complex eigenvalues at time=20sec. after disconnection of GEN 8 in Case A

#	Real part (1/s)	Imaginary part (Hz)	ζ (Damping ratio)
8, 9	-5.10	11.37	7%
10, 11	-3.64	9.41	6%
12, 13	-3.51	8.76	6%
18, 19	-3.18	7.47	7%
21, 22	-5.31	5.71	15%
23, 24	-3.65	5.17	11%
28, 29	-9.62	0.18	99%
36, 37	-1.12	0.33	48%
38, 39	-0.11	0.13	14%
40, 41	-0.37	0.11	47%
42, 43	-0.39	0.07	68%
44, 45	-0.21	0.06	45%

Modal analysis

Modal analysis was carried out on eigenvalue #8, #10, #12, #18, #21, and #23. These eigenvalues are of interest because of their high frequencies. Figure 10-4 shows the modal analysis graph for all six eigenvalues. GEN 4 and GEN 5 are the most dominating masses connected with eigenvalue #8. They have almost equal magnitude of kinetic energy oscillations (1 and 0.967 respectively) and are oscillating against each other. There rest of the generators have insignificant kinetic energies. This is an inter-machine (plant) oscillation mode. The modal analysis for eigenvalue #10 shows that GEN 7 has the largest rotor outswing for a perturbation with the eigenvalue's frequency and is oscillating against all the other synchronous generators on the same side branch. This is an inter-machine (plant) oscillation mode. GEN 6 has the largest kinetic energy oscillation connected to eigenvalue #12's frequency. It is oscillating against mainly GEN 5 and GEN 4 which have kinetic energy magnitude of 0.82 and 0.22, respectively. This eigenvalue represent an inter-machine (plant) oscillation mode. GEN 2 is the most dominant mass related to eigenvalue #18, #21, and #23. In eigenvalue #18, it is oscillating against all the other generators but mainly against GEN 5. In eigenvalue #21, it is oscillating against GEN 1 and in eigenvalue #23 it is oscillating in the same direction with all the other generators.

The modal analysis values in terms of their kinetic energy magnitude and angle is presented in Table A- 5 in Appendix 3.1.

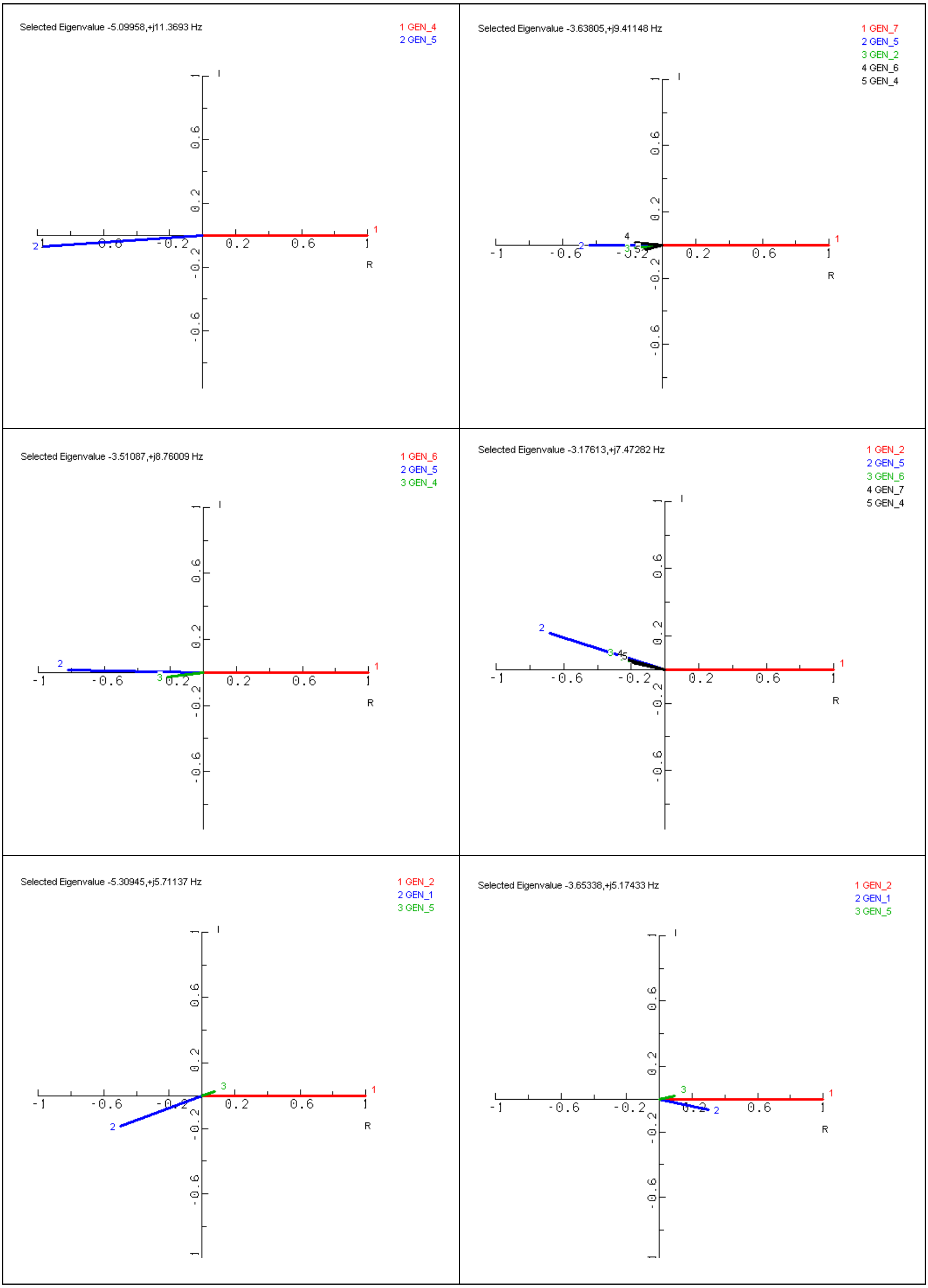


Figure 10-4: Modal analysis graph for eigenvalues with large frequencies after disconnection of GEN 8 in Case A

Time domain analysis

When GEN 8 gets disconnected at time=1sec. a disturbance occurs in the network. Figure 10-5 shows the speed curve for GEN 5 after this disturbance. The oscillations die out very quickly after about 1 second. The oscillating frequency is calculated to be around 7.6 Hz. An eigenvalue with similar oscillation frequency is -3.18 1/s ± j7.47 (# 18). The visibility of this eigenvalue is very high in the speed curve for GEN 5.

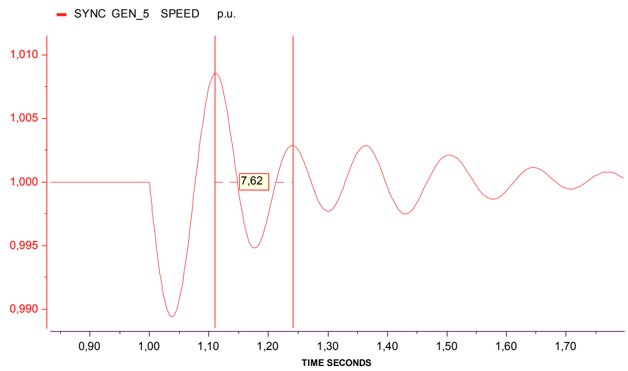


Figure 10-5: Frequency of oscillation for GEN 5 speed curve after disconnection of GEN 8 in Case A

Figure 10-6 shows GEN 2 speed curve. On the same curve there is more than one frequency. The frequency between the first and the second pick is different from the frequency between the second and the third pick. This is because more than one eigenvalues are influencing the oscillations. It is not possible to single out one eigenvalue that is dominating the oscillation because it is a combination of different eigenvalues that is influencing the shape of the oscillation. In the modal analysis (Figure 10-4), it was explained that GEN 2 is strongly related to three different eigenvalues.

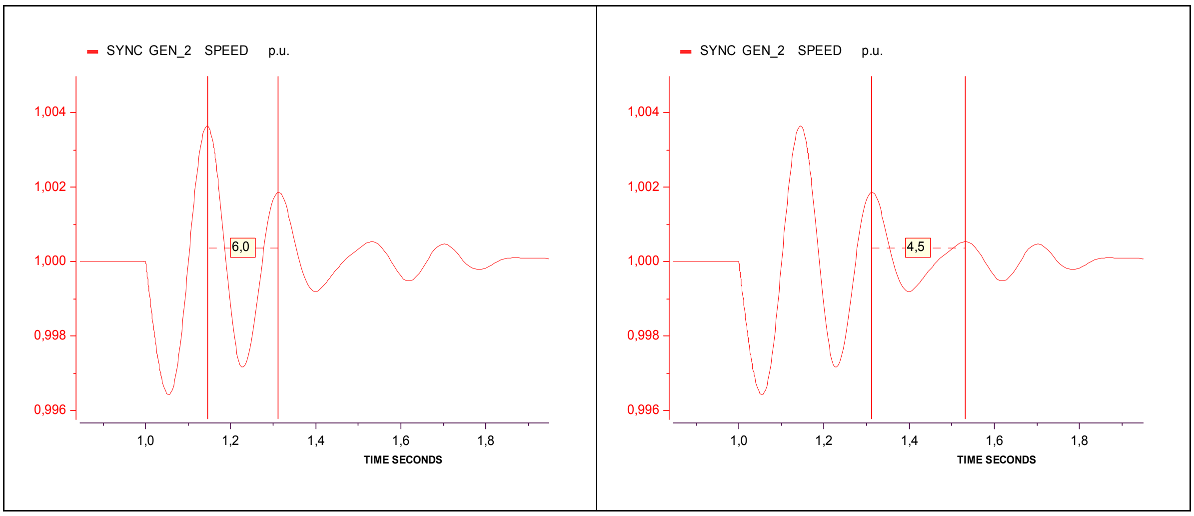


Figure 10-6: Oscillating frequencies for GEN 2 speed curve after disconnection of GEN 8 in Case A

11 Discussion

In the pre-disturbance small signal stability analysis, all four cases are stable. All cases have eigenvalues larger than 3 Hz; as high as 11 Hz. From [3;16;19], it is understood that local oscillation modes have the highest oscillation frequency of all the different modes of oscillation and their frequency is generally in the range of 0.5 – 2 Hz [16;19]. So, these high frequency eigenvalues are not common. There are seven conjugate pairs of eigenvalues with high frequencies in the pre-disturbance steady state (See Table 9-1) and there are seven synchronous generators modelled in the simulation files. When one synchronous generator gets disconnected (See Table 10-3), their number decrease by one and they become six. The induction generator, which has an inertia constant of 6.3 MWs/MVA, has zero kinetic energy oscillation, in modal analysis, for all eigenvalue with high frequencies. Linear analysis done on these eigenvalues (Chapter 9) showed that all of them are highly influenced by state variables related to the synchronous generators. This implies that all eigenvalues with high frequency are related to the synchronous generators. The main reason for having such high frequencies is the low inertia constant value (H=0.35MWs/MVA) of all synchronous generators. But, this might not the only factor as oscillation frequency depend on machine and system parameters and loading conditions [19].

All eigenvalues with large frequencies have small damping ratios in all cases. Case A has the least damped oscillation; 6% (See Table 9-1). Linear analysis done on eigenvalues with the smallest real part magnitude, in all cases, showed that reactive power controllers in GEN 6 and GEN 7 have the largest influence on these eigenvalues. In Case A, increasing the integral gain constants in the reactive power loop (KII) or in the voltage regulator (KI), of GEN 7's reactive power controller led to instability (See Table 9-6 and Table 9-7). Decreasing the derivative gain constant (KD) also caused to small signal instability (See Table 9-8). In Case C, increasing KII of GEN 7's reactive power controller led to instability (See Table 9-18). In cases B and D, even though the gain constants in the reactive power controller of GEN 6 have the most influence on the eigenvalues studied, the sensitivities of the eigenvalues to the gain constants in the reactive power controller of GEN 6 were too low to cause any stability problem.

In the dynamic analysis, it was found that the distribution network is stable for transient disturbances caused by generator disconnections, change in load and change in system voltage for all four cases studied (Chapter 10.1). This is because the network is connected to a strong high voltage grid that was regulating the power balance. Case A had low power factor and over voltage problems on few generators for increase in system voltage and some generator disconnection scenarios. Case B had high terminal voltage on all synchronous generators for step down in load and change in system voltage. Case C and D had both power factor and terminal voltage within the normal range. The generators in Case A and B might get disconnected by relays because of over voltage and high reactive power import problems. Relays were not included in this study.

Case A has the shortest critical clearing time for a three phase to ground short circuit fault on bus N1. This is because all generators are operating with their rated capacity and pre-disturbance system voltage was high.

The synchronous generators were not able to regain synchronism after disconnection of the feeder from the HV network caused by loss of a line between the beginning of the feeder and 106/ 22 kV transformer. This is because of the DGs parameters; especially the low inertia constants. Governor and turbine models were included for these particular simulations so that the mechanical torque can be adjusted to balance the electrical load. The maximum load in the system is less than the combined production capacity of the DGs and the ratings of the turbines is the same as the ratings of the generators they are connected to. So, technically the distribution system has not shortage of power to supply the load and operate on its own; isolated from the high voltage network.

12 Conclusion

In this thesis, small signal and transient stability analysis were used to study the dynamic behaviour of a distribution network with eight DGs. The excitation control system selection for the DGs was based on pre-disturbance generator terminal voltage and power factor.

Results of the linear analysis showed that the studied distribution network has no small signal stability problem. However, in Cases A and C, further investigations on eigenvalues very close to the imaginary axis revealed that change in excitation system controller settings will lead to small signal instability. In cases B and D, even though the studied eigenvalues were strongly related to the reactive power controller in GEN 6, the eigenvalues had small sensitivities towards the controller's gain constants. This shows that selecting appropriate gain constants for the controllers plays an important role in the distribution system's stability; especially in cases A and C.

Transient stability analysis was done by creating five different type of disturbance in the distribution network. It was shown that the synchronous generators in the distribution network regain synchronism after disturbances caused by disconnection of generator(s), rapid change in system load, loss of load, that is equivalent to 66% of all loads in the system, and rise in system voltage by 2.5%. But, not all post-disturbance steady state generator terminal voltages and power factors were within the normal range. Depending on time delay settings of over voltage and reactive power import relays, and how quickly a new set point for the excitation system controllers can be calculated and activated, generators with high voltage or low power factor might get disconnected. This will cause cascade of faults that could lead to instability. Relays were not included in this study.

Other kinds of disturbance that were studied are short circuit fault close to GEN 1 and disconnection of the distribution network from the high voltage network. The critical clearing time for Case A was the shortest because the distribution network had high voltage and the DGs were operating at their rated capacity in the pre-disturbance steady state. The distribution network was not able to reach new steady state, and be able to operate in island mode after disconnection of the feeder from the HV network with the turbine and governor models used.

The case with rated power generation by all DGs in the network while the network loading is low (Case A) is the most sensitive of all the cases studied. It is close to its stability limit both before and after disturbances. Cases with most frequently occurring production levels (Case B, C and D) have proved to be stable and within limits for the cases studied except for disconnection of the feeder from the HV network. The inertia value used for the synchronous generators, in this work, was very low. Higher inertia machines will stretch the stability limit of the network.

In the previous work, it was shown that coordinating reactive power production of DGs in the distribution network helps in voltage control and reduction of network losses compared to running the generator with zero reactive power production. This work has shown that the distribution network is stable in such configurations as long as it is connected to the high voltage network.

After new steady state is reached, new set points for the regulators can be calculated taking reactive power coordination into account. Coordinating the reactive power production of the generators will free up some capacity, so more power can be produced or more generators can be connected without having to reinforce the existing network.

13 Future work

This thesis work studied small signal and transient stability of Øie – Kvinesdal distribution network with eight DGs. An extension work would be:

- To study other types of instabilities like load driven voltage instability. A study should be made to check how much load the system can handle before it collapses.
- To include turbine, governors, relays, limiters and protective elements in the synchronous machine models; so that the power system can have a more complete model. Then, distribution system isolated from the high voltage network should be studied.
- To test different generator parameters (especially inertia) to see how stability limits can be improved.
- To study interaction of the excitation system controller with other types of controller in the system, for example with tap changing transformer.

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Appendix 1: Software used

SIMPOW is highly integrated software for simulation of power systems. It has lots of features, but only three were used in this work; Optpow, Dynpow and DSL.

Optpow computes initial power flow calculations for normal symmetrical steady state operating conditions in a power system for given loads, productions and control of the system. The solution of a power flow calculation comprises the positive sequence phasors of the node voltages and the control variables. Together they form a set of state variables from which all other quantities can be calculated.

The dynamic system model is built up from the model of the network, stored from a previous OPTPOW-function, and the dynamic models of the system elements given in the DYNPOW input file. In the DYNPOW input file, detailed data for synchronous and induction machine, regulators, turbines, stabilizers and protection elements, etc are given.

DSL stands for Dynamic Simulation Language. It is a is a formal language conceived as a powerful tool for either definition of component types to be referenced in power system simulations (Optpow/Dynpow) or for complete specification of independent dynamic simulations. Users can define and implement their own model of a system element using DSL. HiDraw is a graphical program that is used to draw models and generate DSL code.

Type AC8B voltage controller and Type II var controller models drawn with HiDraw are shown in Figure A- 1 and Figure A- 2. The DSL code generated for each type of controller is found in Appendix 1.1 and Appendix 1.2.

The code generated by HiDraw had problems with saturation feed back loop variables, non-wind up limits, and some other variables that were not defined by the program. The user has to go through the code and carefully re-arrange statements that missed their sequence and add variables that the program failed to define. I have put my name next to the corrected lines in the DSL code as a comment.

Appendix 1.1: IEEE Type AC8B voltage controller and Type II reactive power controllers

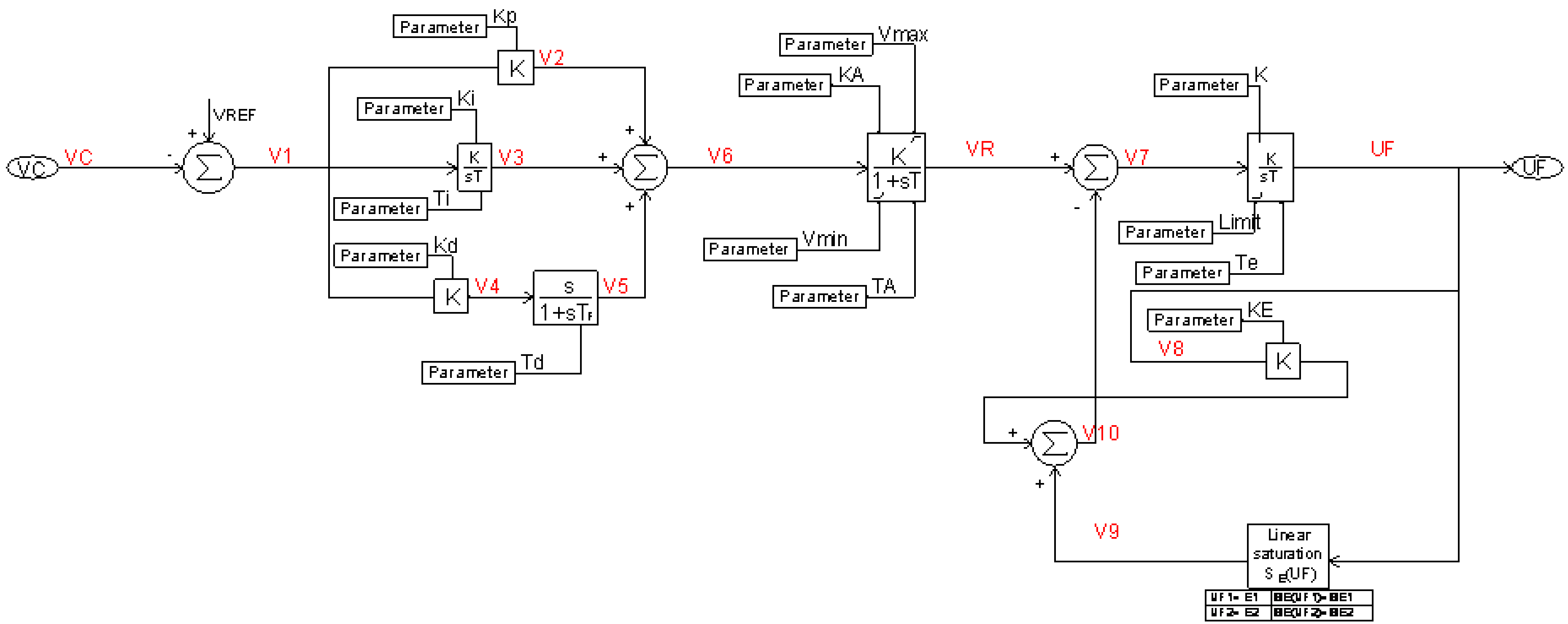

Figure A- 1: Type AC8B voltage controller

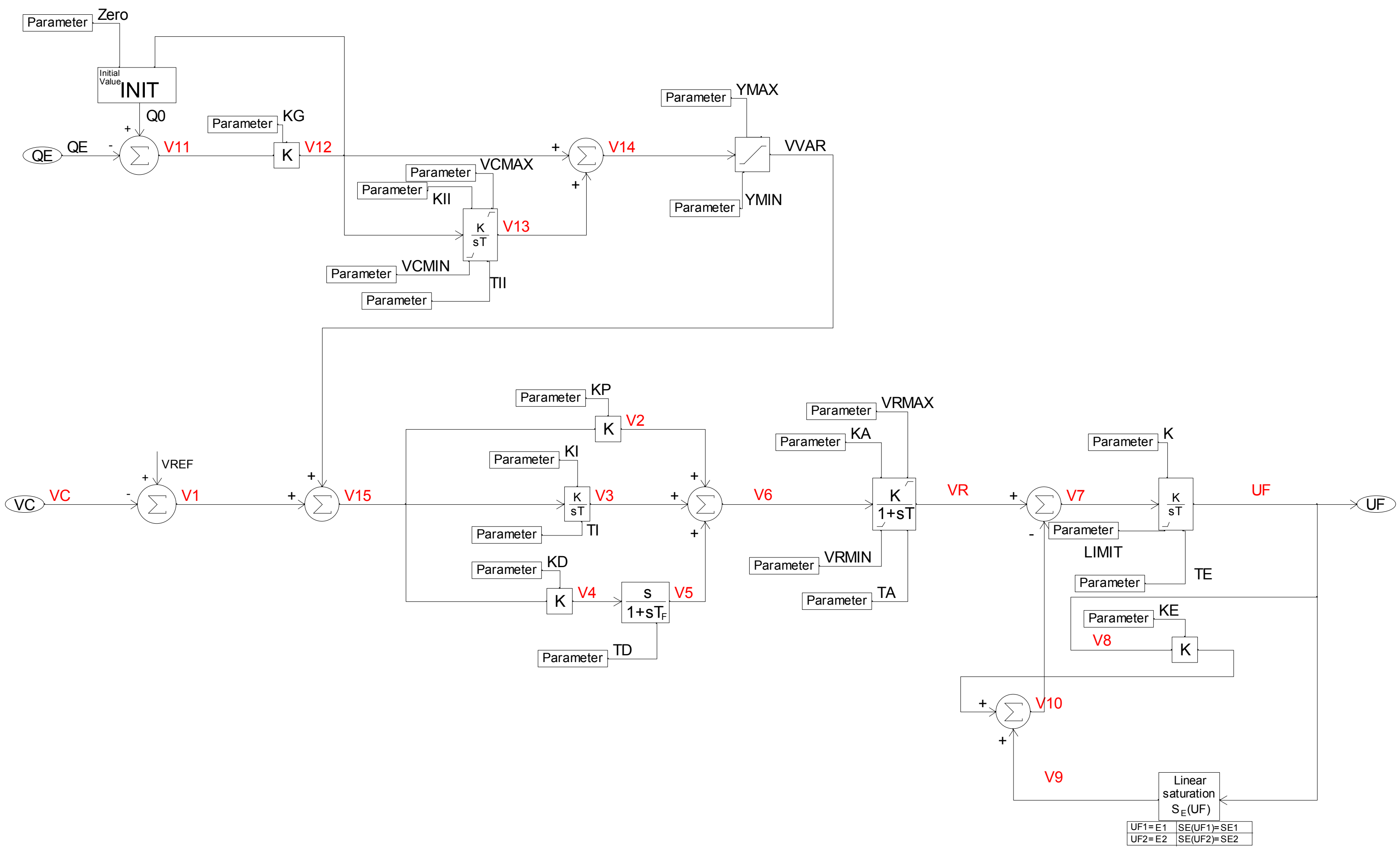

Figure A- 2: Type II reactive power controller with Type AC8B voltage controller

Appendix 1.2: DSL code for AC8B voltage controller

```
!! *--------   DSL Code Generator, Simpow   ----------------------
!! *
!! *           Name       : AC8B
!! *           Explanation: Voltage controller model
!! *
!! *           DSL Code Generator, release 1.3, 2005-02-10.
!! *           Copyright STRI AB, Sweden.
!! *------------------------------------------------------------
!! Department : Electrical power engineering NTNU
!! Designed by: Atsede Gualu
!! Checked by :
!! Approved by:
!! Date       :
!! *------------------------------------------------------------

PROCESS AC8B(E1,SE1,E2,SE2,
& VC,TA,Td,KE,
& Te,Limit,K,Vmin,
& Vmax,KA,Kd,Ti,
& Ki,Kp,UF,UF0)
EXTERNAL E1,SE1,E2,SE2
EXTERNAL VC,TA,Td,KE
EXTERNAL Te,Limit,K,Vmin
EXTERNAL Vmax,KA,Kd,Ti
EXTERNAL Ki,Kp,UF0
!! End of external declarations.
REAL     E1,SE1,E2,SE2
REAL     V9,INTER_1/*/,INTER_2/*/
REAL     INTER_3/*/,VC,TA,Td
REAL     KE,Te,Limit,K
REAL     Vmin,Vmax,KA,Kd
REAL     Ti,Ki,Kp,REF/*/
REAL     V1,UF0,V3,V4
REAL     V2,V5,INTER_4
REAL     INTER_5,V6,VR,UF
REAL     V8,V10,V7
INTEGER  CHECK_OF_LIMITS
!! End of real and integer declarations.
STATE    V9,V3,INTER_5
STATE    VR,UF,CHECK_OF_LIMITS/0/
!! End of state declarations.
   IF (START) THEN
      IF (START00) THEN
!! Control of linear saturation parameters.
```

```
         IF (E1.LT/0.001/.0) STOP'Saturation parameter E1 is less than zero.'
         IF (E2.LT/0.001/.0) STOP'Saturation parameter E2 is less than zero.'
         IF (SE1.LT/0.001/.0) STOP'Saturation parameter SE1 is less than zero.'
         IF (SE2.LT/0.001/.0) STOP'Saturation parameter SE2 is less than zero.'
         IF (E1.GE/0.001/.E2) STOP'Saturation parameter E1 is greater than',
&         ' or equal to E2.'
         IF (SE1.GE/0.001/.SE2.AND.SE1.NE.0) STOP'Saturation parameter SE1',
&         ' not equal to zero and is greater than or equal to SE2.'
      ENDIF
!! End of control of saturation parameters.
!! Calculation of linear saturation variables INTER_1,
!! INTER_2, and INTER_3.
      INTER_1=(SE2-SE1)/(E2-E1)
      INTER_2=SE2-INTER_1*E2
      IF (INTER_1.EQ.0) THEN
         INTER_3=E2
      ELSE
         INTER_3=E2-SE2/INTER_1
      ENDIF
      IF (INTER_3.LT.0) THEN
         STOP'Errors in given saturation parameters.',
&         ' The linear saturation curve lies in',
&         ' the left half plane.'
      ENDIF
   ENDIF
!! End of parameter setting and initiations of AC8B.

!! Here starts the dynamic part of process AC8B.
!! A signal subtracted to the reference, Reference.
   V1=REF-VC
!! An integrator with integral time Ti and integral constant Ki.
   V3: Ti*.D/DT.V3=Ki*V1
!! Multiplication of two signals.
   V4=Kd*V1
!! Multiplication of two signals.
   V2=Kp*V1
!! Filtered deriving function s/(1+sTd).
   INTER_4=V4/Td
   INTER_5: INTER_5=INTER_4-Td*.D/DT.INTER_5
   V5=INTER_4-INTER_5
!! Summation of three signals.
   V6=V2+V3+V5
!! A first-order filter of non-wind-up type, KA/(1+sTA).
   IF (VR.GE.Vmax.AND.
&     (V6*KA-Vmax).GE.0.AND..NOT.START) THEN
      VR=Vmax
      PRINT-I'VR is at maximum limit.'
   ELSEIF (VR.LE.Vmin.AND.
```

```
&         (V6*KA-Vmin).LE.0.AND..NOT.START) THEN
      VR=Vmin
      PRINT-I'VR is at minimum limit.'
   ELSE
      IF (START00) THEN
         VR=KA*V6
      ELSE
         VR: VR=KA*V6-TA*.D/DT.VR
      ENDIF
      PRINT'VR is within limits.'
   ENDIF
!! Multiplication of two signals.               !Atsede
   V8=KE*UF
!! Summation of two signals.
   V10=V8+V9
!! Summation of two signals.
   V7=VR-V10

!! An integrator of non-wind-up type with only a lower limit
!! and integral time Te and integral constant K.
   IF (UF.LE.Limit.AND.
&      V7.LT.0.AND..NOT.START) THEN
      UF=Limit
      PRINT-I'UF is at minimum limit.'
   ELSE
      UF: Te*.D/DT.UF=K*V7
      PRINT'UF is within limits.'
   ENDIF
!!
!!
!! Linear saturation.
   IF (INTER_1.EQ.0.OR.((UF.LE.INTER_3).AND.(UF.GE.-INTER_3))) THEN
      V9=0
   ELSEIF (UF.LE.-INTER_3) THEN
      V9=(-INTER_1*UF+INTER_2)*UF
   ELSE
      V9=(INTER_1*UF+INTER_2)*UF
   ENDIF
!! Initial control of some of the block diagrams.
   IF (START) THEN
!! Checks start conditions by setting REF.
      REF: UF=UF0
!! A check of the filtered deriving function s/(1+sTd).
      IF (Td.LE.0) THEN
         STOP'Time constant Td in block s/(1+sTF) less or equal zero!'
      ENDIF
!! A check of the first-order filter of non-wind-up type, KA/(1+sTA).
      IF (Vmax.LE.Vmin) THEN
```

```
          STOP'The upper limit is lower than the lower limit.'
       ENDIF
    ENDIF
!! End of initial control of some of the block diagrams.
!! Control of block diagram outputs within given limits.
    IF (.NOT.START.AND.CHECK_OF_LIMITS.EQ.0) THEN
!! A first-order filter of non-wind-up type, KA/(1+sTA). This is a start-up check.
       IF (VR.GE.Vmax.AND.
&           (V6*KA-VR).GT.0) THEN
          STOP'VR is at maximum limit.'
       ELSEIF (VR.LE.Vmin.AND.
&           (V6*KA-VR).LT.0) THEN
          STOP'VR is at minimum limit.'
       ENDIF
!! An integrator of non-wind-up type with only a lower limit
!! and integral time Te integral constant K. This is a start-up check.
       IF (UF.LE.Limit.AND.
&           V7.LT.0.OR.UF.LT.Limit) THEN
          STOP'UF is at minimum limit.'
       ENDIF
       CHECK_OF_LIMITS=1
    ENDIF
!! End of control of block diagram outputs within given limits.
END
!! End of AC8B.                :-)
```

Appendix 1.3: DSL code for Type AC8B voltage controller with Type II var controller

```
!! *--------   DSL Code Generator, Simpow   ----------------------
!! *
!! *           Name       : AC8B_VAR
!! *           Explanation: AC8B exciter with Var controller Type II
!! *
!! *           DSL Code Generator, release 1.3, 2005-02-10.
!! *           Copyright STRI AB, Sweden.
!! *-----------------------------------------------------------------
!! Department : IME
!! Designed by: Atsede Gualu
!! Checked by :
!! Approved by:
!! Date       : 17 MAR 2010
!! *-----------------------------------------------------------------

PROCESS AC8B_VAR(E1,SE1,E2,SE2,
& VC,Zero,TII,YMIN,
& YMAX,VCMIN,VCMAX,KII,
& KG,QE,TA,TD,
& KE,TE,LIMIT,K,
& VRMIN,VRMAX,KA,KD,
& TI,KI,KP,UF,
& UF0)
EXTERNAL E1,SE1,E2,SE2
EXTERNAL VC,Zero,TII,YMIN
EXTERNAL YMAX,VCMIN,VCMAX,KII
EXTERNAL KG,QE,TA,TD
EXTERNAL KE,TE,LIMIT,K
EXTERNAL VRMIN,VRMAX,KA,KD
EXTERNAL TI,KI,KP,UF0
!! End of external declarations.
REAL     E1,SE1,E2,SE2
REAL     V9,INTER_1/*/,INTER_2/*/
REAL     INTER_3/*/,VC,Zero,TII
REAL     YMIN,YMAX,VCMIN,VCMAX
REAL     KII,KG,QE,TA
REAL     TD,KE,TE,LIMIT
REAL     K,VRMIN,VRMAX,KA
REAL     KD,TI,KI,KP
REAL     REF/*/,V1,UF0,V13
REAL     VR,UF,V8,V10
REAL     V7,V3,Q0/*/,V11
REAL     V12,V14,VVAR,V15
REAL     V4,V2,V5,INTER_4
REAL     INTER_5,V6
INTEGER  CHECK_OF_LIMITS
```

```
!! End of real and integer declarations.
STATE    V9,V13,VR,UF
STATE    V3,INTER_5,CHECK_OF_LIMITS/0/
!! End of state declarations.
   IF (START) THEN
      IF (START00) THEN
!! Control of linear saturation parameters.
         IF (E1.LT/0.001/.0) STOP'Saturation parameter E1 is less than zero.'
         IF (E2.LT/0.001/.0) STOP'Saturation parameter E2 is less than zero.'
         IF (SE1.LT/0.001/.0) STOP'Saturation parameter SE1 is less than zero.'
         IF (SE2.LT/0.001/.0) STOP'Saturation parameter SE2 is less than zero.'
         IF (E1.GE/0.001/.E2) STOP'Saturation parameter E1 is greater than',
&         ' or equal to E2.'
         IF (SE1.GE/0.001/.SE2.AND.SE1.NE.0) STOP'Saturation parameter SE1',
&         ' not equal to zero and is greater than or equal to SE2.'
      ENDIF
!! End of control of saturation parameters.
!! Calculation of linear saturation variables INTER_1,
!! INTER_2, and INTER_3.
      INTER_1=(SE2-SE1)/(E2-E1)
      INTER_2=SE2-INTER_1*E2
      IF (INTER_1.EQ.0) THEN
         INTER_3=E2
      ELSE
         INTER_3=E2-SE2/INTER_1
      ENDIF
      IF (INTER_3.LT.0) THEN
         STOP'Errors in given saturation parameters.',
&         ' The linear saturation curve lies in',
&         ' the left half plane.'
      ENDIF
   ENDIF
!! End of parameter setting and initiations of AC8B_VAR.

!! Here starts the dynamic part of process AC8B_VAR.
!! A signal subtracted to the reference, Reference.
   V1=REF-VC

!! A signal subtracted to the reference Q0, General reference.        !CODE INSERTED (Atsede)
   V11=Q0-QE
!! Multiplication of two signals.
   V12=KG*V11

!! A non-wind-up integrator with integral time TII and
!! integral constant KII.
   IF (V13.GE.VCMAX.AND.V12.GE.0.AND..NOT.START) THEN
      V13=VCMAX
      PRINT-I'V13 is at maximum limit!'
```

```
   ELSEIF (V13.LE.VCMIN.AND.V12.LT.0.AND..NOT.START) THEN
      V13=VCMIN
      PRINT-I'V13 is at minimum limit!'
   ELSE
      V13: TII*.D/DT.V13=KII*V12
      PRINT'V13 is within limits.'
   ENDIF

!! Summation of two signals.                  !! CODE INSERTED (Atsede)
   V14=V12+V13
!! Limiter, YMIN <= VVAR <= YMAX.
!! Checking the limits of the Limit function.
   IF (YMAX.LT.YMIN) THEN
      STOP'The upper limit is lower than the lower limit.'
   ENDIF
   IF (V14.GE.YMAX.AND..NOT.START) THEN
      VVAR=YMAX
      PRINT-I'VVAR is at maximum limit.'
   ELSEIF (V14.LE.YMIN.AND..NOT.START) THEN
      VVAR=YMIN
      PRINT-I'VVAR is at minimum limit.'
   ELSE
      VVAR=V14
      PRINT'VVAR is within limits.'
   ENDIF

!! Summation of two signals.
   V15=-VVAR+V1
!! Multiplication of two signals.
   V4=KD*V15
!! Multiplication of two signals.
   V2=KP*V15
!! An integrator with integral time TI and integral constant KI.   !! CODE INSERTED(Atsede)
   V3: TI*.D/DT.V3=KI*V15
!! Filtered deriving function s/(1+sTD).
   INTER_4=V4/TD
   INTER_5: INTER_5=INTER_4-TD*.D/DT.INTER_5
   V5=INTER_4-INTER_5
!! Summation of three signals.
   V6=V2+V3+V5
!! A first-order filter of non-wind-up type, KA/(1+sTA).
   IF (VR.GE.VRMAX.AND.
&     (V6*KA-VRMAX).GE.0.AND..NOT.START) THEN
      VR=VRMAX
      PRINT-I'VR is at maximum limit.'
   ELSEIF (VR.LE.VRMIN.AND.
&         (V6*KA-VRMIN).LE.0.AND..NOT.START) THEN
      VR=VRMIN
```

```
      PRINT-I'VR is at minimum limit.'
   ELSE
      IF (START00) THEN
         VR=KA*V6
      ELSE
         VR: VR=KA*V6-TA*.D/DT.VR
      ENDIF
      PRINT'VR is within limits.'
   ENDIF
!!
!! Multiplication of two signals.            !! CODE INSERTED(Atsede)
   V8=KE*UF
!! Summation of two signals.
   V10=V8+V9
!! Summation of two signals.
   V7=VR-V10

!! An integrator of non-wind-up type with only a lower limit
!! and integral time TE and integral constant K.
   IF (UF.LE.LIMIT.AND.
&      V7.LT.0.AND..NOT.START) THEN
      UF=LIMIT
      PRINT-I'UF is at minimum limit.'
   ELSE
      UF: TE*.D/DT.UF=K*V7
      PRINT'UF is within limits.'
   ENDIF

!! CODE REMOVED (Atsede)

!!  CODE REMOVED (Atsede)
!!
!!  CODE REMOVED (Atsede)
!! Linear saturation.
   IF (INTER_1.EQ.0.OR.((UF.LE.INTER_3).AND.(UF.GE.-INTER_3))) THEN
      V9=0
   ELSEIF (UF.LE.-INTER_3) THEN
      V9=(-INTER_1*UF+INTER_2)*UF
   ELSE
      V9=(INTER_1*UF+INTER_2)*UF
   ENDIF
!! Initial control of some of the block diagrams.
   IF (START) THEN
!! Checks start conditions by setting REF.
      REF: UF=UF0
!! A check of the first-order filter of non-wind-up type, KA/(1+sTA).
      IF (VRMAX.LE.VRMIN) THEN
         STOP'The upper limit is lower than the lower limit.'
```

```
      ENDIF
!! Checks start conditions by setting Q0.
      Q0: V12=Zero
!! A check of the filtered deriving function s/(1+sTD).
      IF (TD.LE.0) THEN
         STOP'Time constant TD in block s/(1+sTF) less or equal zero!'
      ENDIF
   ENDIF
!! End of initial control of some of the block diagrams.
!! Control of block diagram outputs within given limits.
   IF (.NOT.START.AND.CHECK_OF_LIMITS.EQ.0) THEN
!! An integrator of non-wind-up type with integral time TII and
!! integral constant KII. This is a start-up check.
      IF (V13.GE.VCMAX.AND.                          !!VCMIN ➔VCMAX (Atsede)
&         V12.GT.0.OR.
&         V13.GT.VCMAX) THEN                         !!VCMIN ➔VCMAX (Atsede)
         STOP'V13 is at maximum limit.'
      ELSEIF (V13.LE.VCMIN.AND.                      !!VCMAX ➔VCMIN (Atsede)
&             V12.LT.0.OR.
&             V13.LT.VCMIN) THEN                     !!VCMAX ➔VCMIN (Atsede)
         STOP'V13 is at minimum limit.'
      ENDIF
!! A first-order filter of non-wind-up type, KA/(1+sTA). This is a start-up check.
      IF (VR.GE.VRMAX.AND.
&         (V6*KA-VR).GT.0) THEN
         STOP'VR is at maximum limit.'
      ELSEIF (VR.LE.VRMIN.AND.
&         (V6*KA-VR).LT.0) THEN
         STOP'VR is at minimum limit.'
      ENDIF
!! An integrator of non-wind-up type with only a lower limit
!! and integral time TE integral constant K. This is a start-up check.
      IF (UF.LE.LIMIT.AND.
&         V7.LT.0.OR.UF.LT.LIMIT) THEN
         STOP'UF is at minimum limit.'
      ENDIF
      IF (V14.GE.YMAX) THEN
         PRINT-I'VVAR is at maximum limit.'
      ELSEIF (V14.LE.YMIN) THEN
         PRINT-I'VVAR is at minimum limit.'
      ENDIF
      CHECK_OF_LIMITS=1
   ENDIF
!! End of control of block diagram outputs within given limits.
END
!! End of AC8B_VAR.                :-)
```

Appendix 1.4: Parameter data for distributed generators in Øie – Kvinesdal distribution network

Table A- 1: Synchronous generators parameters

Description	Parameter	GEN 1	GEN 2	GEN 4	GEN 5	GEN 6	GEN 7	GEN 8
Rated apparent power MVA	SN	1.6	12.5	0.5	1.05	0.625	0.8	4
Rated voltage kV	UN	6	5.25	0.69	0.69	0.23	0.69	6.6
Inertia constant MWs/MVA	H	0.3504	0.3504	0.3506	0.3506	0.3506	0.3506	0.266
Damping constant p.u. torque/p.u. speed	D	1	1	1	1	1	1	1
Direct-axis synchronous reactance p.u	XD	1.192	1.79	2.656	2.656	2.656	2.656	1.334
Quadrature-axis synchronous reactance p.u	XQ	0.687	1.0092	2.52	2.52	2.52	2.52	0.837
Direct-axis transient reactance p.u	XDP	0.185	0.33	0.136	0.136	0.136	0.136	0.335
Direct-axis subtransient reactance p.u	XDB	0.162	0.206	0.105	0.105	0.105	0.105	0.273
Quadrature-axis subtransient reactance p.u.	XQB	0.162	0.2397	0.105	0.105	0.105	0.105	0.3
Stator leakage reactance p.u.	XA	0.143	0.2	0.1	0.1	0.1	0.1	0.153
Stator resistance	RA	0.0047	0.004	0.00219	0.00219	0.00219	0.00219	0.00219
Direct-axis transient open-circuit time constant	TD0P	3.712	6.288	3.3997	3.3997	3.3997	3.3997	2.72
Direct-axis subtransient open-circuit time constant	TD0B	0.0371	0.03	0.0371	0.0371	0.0371	0.0371	0.023
Quadrature-axis subtransient open-circuit time constant	TQ0B	0.0185	0.182	0.0285	0.0285	0.0285	0.0285	0.048
Direct-axis air-gap flux at which the saturation factor SE1D is given	V1D	1	1	1	1	1	1	1
Direct-axis air-gap flux at which the saturation factor SE2D is given	V2D	1.2	1.2	1.2	1.2	1.2	1.2	1.2
Saturation factor at the direct-axis air-gap flux V1D	SE1D	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Saturation factor at the direct-axis air-gap flux V2D	SE2D	0.3	0.3	0.3	0.3	0.3	0.3	0.3

Table A- 2: Induction generator parameter

Description	Parameter	GEN 3
Rated apparent power in MVA	SN	0.35
Rated voltage in kV	UN	0.4
Inertia constant in MWs/MVA	H	6.3
Stator resistance in p.u.	R1	0.00619
Stator leakage reactance in p.u.	X1S	0.135952
Rotor leakage reactance in p.u.	X2S	0.112143
Magnetizing reactance in p.u.	XM	3.904762
Magnetizing resistance in p.u.	RM	0.088095

Appendix 1.5: Voltage and reactive power controllers' data

Table A- 3: Automatic voltage controller and reactive power controller parameters

Description	Parameter		
Voltage value at point 1	E1	[pu]	6.5
Saturation curve value at point 1	SE1	[pu]	0.3
Voltage value at point 2	E2	[pu]	9
Saturation curve value at point 2	SE2	[pu]	3
Initial value for the initialization block	Zero	[pu]	0
PI regulator integral time constant	TII	[s]	1
Minimum output of the reactive power regulator	YMIN	[pu]	-2
Maximum output of the reactive power regulator	YMAX	[pu]	2
Minimum output of the integral block in the PI regulator	VCMIN	[pu]	-2
Maximum output of the integral block in the PI regulator	VCMAX	[pu]	2
PI integral gain	KII	[pu]	1
Reactive controller loop gain	KG	[pu]	1
Regulator amplifier time constant	TA	[s]	0
PID derivative time constant	TD	[s]	0.1
Exciter constant	KE	[pu]	1
Exciter time constant	TE	[s]	1.2
Minimum exciter output	LIMIT	[pu]	0
Constant	K		1
Minimum regulator output	VRMIN	[pu]	0
Maximum regulator output	VRMAX	[pu]	35
Regulator gain	KA	[pu]	1
PID regulator integral time constant	TI	[s]	1

Appendix 2: Pre-disturbance linear analysis

```
Eigenvalue no     8: -5.7881     1/s   11.288     Hz

      Magnitude    Angle (degrees)

 SYNC GEN_4
   0.403252        -5.69749      Teta
   0.403183        -3.47523      Speed
   0.870159E-02     43.6303      Field winding  flux
   0.348317E-01     104.308      Damper winding flux   D-axis
   0.930303E-03    -152.260      Damper winding flux   Q-axis

Eigenvalue no    10: -3.6540     1/s   9.3760     Hz

      Magnitude    Angle (degrees)

 SYNC GEN_7
   0.454181        -3.51872      Teta
   0.453967        -1.88743      Speed
   0.925684E-02     49.1679      Field winding  flux
   0.309959E-01     104.460      Damper winding flux   D-axis
   0.314823E-03    -143.164      Damper winding flux   Q-axis

Eigenvalue no    16: -3.7800     1/s   8.6504     Hz

      Magnitude    Angle (degrees)

 SYNC GEN_6
   0.382262        -4.57002      Teta
   0.382342        -1.69402      Speed
   0.764954E-02     48.6058      Field winding  flux
   0.232398E-01     102.557      Damper winding flux   D-axis
   0.169246E-02    -130.480      Damper winding flux   Q-axis

Eigenvalue no    18: -3.9169     1/s   7.6639     Hz

      Magnitude    Angle (degrees)

 SYNC GEN_5
   0.248039        -10.1000      Teta
   0.247898        -6.47761      Speed
   0.514411E-02     43.9959      Field winding  flux
   0.134549E-01     95.0752      Damper winding flux   D-axis
   0.924477E-03    -116.811      Damper winding flux   Q-axis
```

Figure A- 3: Participation factors for eigenvalues -5.8 1/s + j11.9 Hz, -3.7 1/s + j9.4 Hz, -3.8 1/s + j8.7 Hz, and -3.9 1/s + j7.7 Hz in Case A

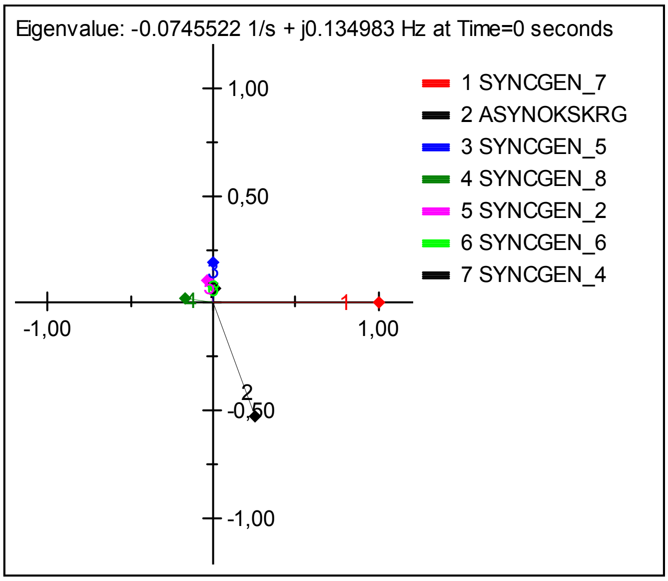

Figure A- 4: Mode analysis of Synchronous/Asynchronous Machines for -5.8 1/s + j11.9 Hz

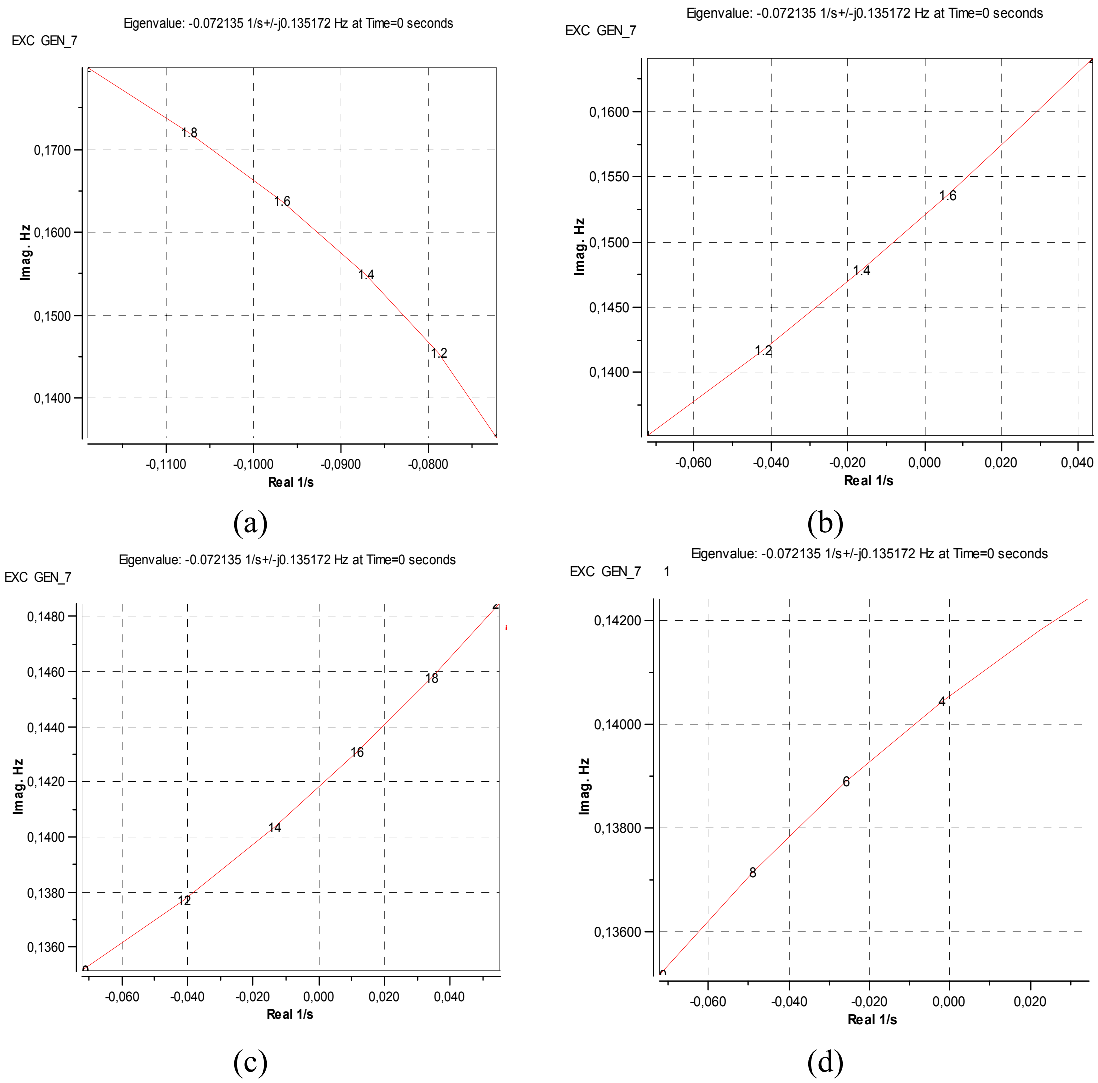

Figure A- 5: Data scanning graph for change in (a) KG (b) KII (c) KI and (d) KD for -0.072 1/s + j0.135Hz

```
Eigenvalue no    16: -5.4844     1/s   4.8242     Hz


      Magnitude    Angle (degrees)

 SYNC GEN_1
   0.371730        -1.02562      Teta
   0.375572         2.87756      Speed
   0.191359E-02     38.6300      Field winding  flux
   0.295398E-02     161.088      Damper winding flux   D-axis
   0.931858E-01    -117.703      Damper winding flux   Q-axis
```

Figure A- 6: Participation factors for eigenvalue -5.48 1/s + j4.8242 Hz in Case B

```
Eigenvalue no    14: -6.7394     1/s   5.9014     Hz


      Magnitude    Angle (degrees)

 SYNC GEN_7
   0.335195         1.49162      Teta
   0.337528         9.82107      Speed
   0.134585E-01     54.4425      Field winding  flux
   0.265508E-01     99.3395      Damper winding flux   D-axis
   0.363007E-01    -102.874      Damper winding flux   Q-axis
Eigenvalue no    23: -5.3473     1/s  -4.5708     Hz


      Magnitude    Angle (degrees)

 SYNC GEN_1
   0.408717        -2.78293      Teta
   0.414176        -7.31678      Speed
   0.400046E-02    -31.5920      Field winding  flux
   0.576720E-02    -159.429      Damper winding flux   D-axis
   0.107014         115.112      Damper winding flux   Q-axis
```

Figure A- 7: Participation factors for eigenvalues -6.74 1/s + j5.90 Hz and -5.35 1/s + j-4.57 Hz in Case C

```
 Eigenvalue no    16: -6.2276     1/s   5.0803     Hz


      Magnitude    Angle (degrees)

 SYNC GEN_1
   0.265552       -0.481009E-01  Teta
   0.268760         3.77507      Speed
   0.135010E-02     35.5252      Field winding  flux
   0.239738E-02     159.243      Damper winding flux   D-axis
   0.792059E-01    -116.689      Damper winding flux   Q-axis

Eigenvalue no    18: -4.8211     1/s   4.6737     Hz


      Magnitude    Angle (degrees)

 SYNC GEN_1
   0.254016         11.2330      Teta
   0.256536         15.0660      Speed
   0.129246E-02     51.4242      Field winding  flux
   0.181498E-02     172.592      Damper winding flux   D-axis
   0.581387E-01    -106.162      Damper winding flux   Q-axis
```

Figure A- 8: Participation factors for eigenvalues -6.23 1/s + j5.08 Hz and -4.82 1/s + j4.67 Hz in Case D

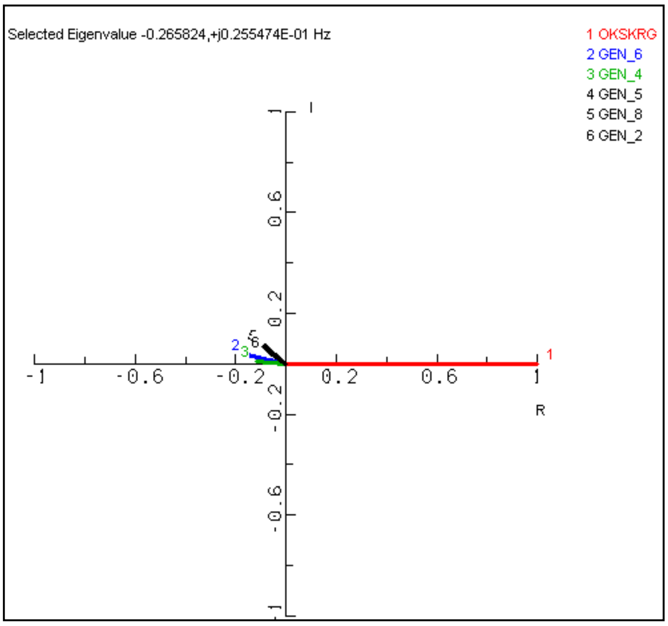

Figure A- 9: Modal analysis diagram for -0.26582 1/s + j0.25547E-01 Hz Case D

Appendix 3: Post-disturbance linear and time domain analysis

Appendix 3.1: Modal analysis kinetic energy for eigenvalues with high frequencies

Table A- 4: Modal analysis kinetic energy for eigenvalues with high frequencies after disconnection of GEN 2 in Case A

Eigenvalue	-6.9583 + j10.802		-3.6812 + j9.2315		-4.3673 + j8.3125		-4.4926 + j7.2513		-5.0638 + j5.5006		-3.9230 + j5.1461	
Generator	Magnitude	Angle	Magnitude	Angle	Magnitude	Angle	Magnitude	Angle	Magnitude	Angle	Magnitude	Angle
GEN 1	0.002	-159.6	0.016	-163.6	0.003	133.3	0.093	-168.7	1.000	0.0	0.394	2.4
GEN 2	0.000	-149.0	0.000	-16.1	0.000	-98.1	0.000	-125.9	0.000	0.0	0.000	-15.7
GEN 3	0.001	172.2	0.005	-172.1	0.001	151.9	0.014	-156.2	0.005	17.4	0.027	-132.7
GEN 4	1.000	0.0	0.073	-154.7	0.196	-171.3	0.268	3.8	0.031	-165.5	0.075	18.6
GEN 5	0.869	-175.8	0.357	-178.7	0.775	-178.6	1.000	0.0	0.099	-165.9	0.243	17.5
GEN 6	0.024	162.9	0.160	178.8	1.000	0.0	0.341	4.9	0.040	-165.4	0.097	18.4
GEN 7	0.057	148.3	1.000	0.0	0.040	-28.7	0.189	3.7	0.044	-167.1	0.104	18.5
GEN 8	0.037	179.6	0.168	-170.2	0.042	163.7	0.706	-159.0	0.649	172.8	1.000	0.0

Table A- 5: Modal analysis kinetic energy for eigenvalues with high frequencies after disconnection of GEN 8 in Case A

Eigenvalue	-5.0996 + j11.369		-3.6380 + j9.4115		-3.5109 + j8.7601		-3.1761 + j7.4728		-5.3094 + j5.7114		-3.6534 + j5.1743	
Generator	Magnitude	Angle	Magnitude	Angle	Magnitude	Angle	Magnitude	Angle	Magnitude	Angle	Magnitude	Angle
GEN 1	0.00	-20.6	0.01	-165.5	0.00	25.4	0.04	-26.7	0.53	-159.4	0.30	-12.5
GEN 2	0.03	137.2	0.17	-173.9	0.04	59.4	1.00	0.0	1.00	0.0	1.00	0.0
GEN 3	0.00	150.5	0.00	-164.9	0.00	78.4	0.01	2.8	0.01	-151.7	0.02	-138.6
GEN 4	1.00	0.0	0.11	-166.0	0.22	-172.9	0.20	167.7	0.03	16.4	0.03	13.7
GEN 5	0.97	-176.0	0.44	-179.7	0.82	179.0	0.72	162.7	0.08	16.0	0.10	12.7
GEN 6	0.03	156.8	0.16	175.2	1.00	0.0	0.28	166.6	0.03	16.6	0.04	13.4
GEN 7	0.05	151.1	1.00	0.0	0.03	-118.9	0.22	165.6	0.04	14.3	0.05	12.6
GEN 8	0.00	79.9	0.00	46.2	0.00	-85.0	0.00	-103.7	0.00	0.0	0.00	170.3

Appendix 3.2: Terminal voltage and reactive power for all synchronous DGs after each scenario in disconnection of generator, change in load and system voltage

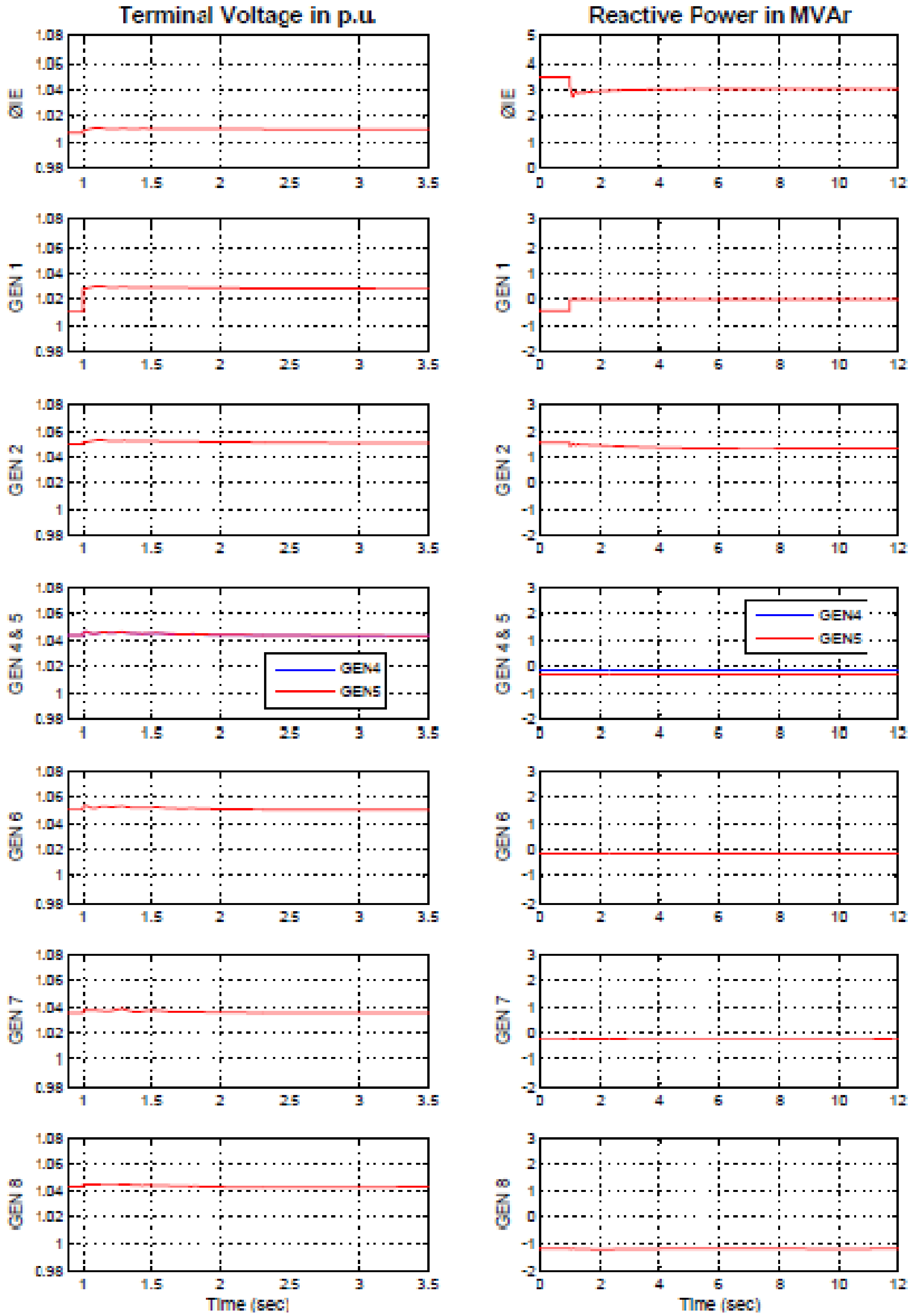

Figure A- 10: Disconnection of GEN 1 in Case A

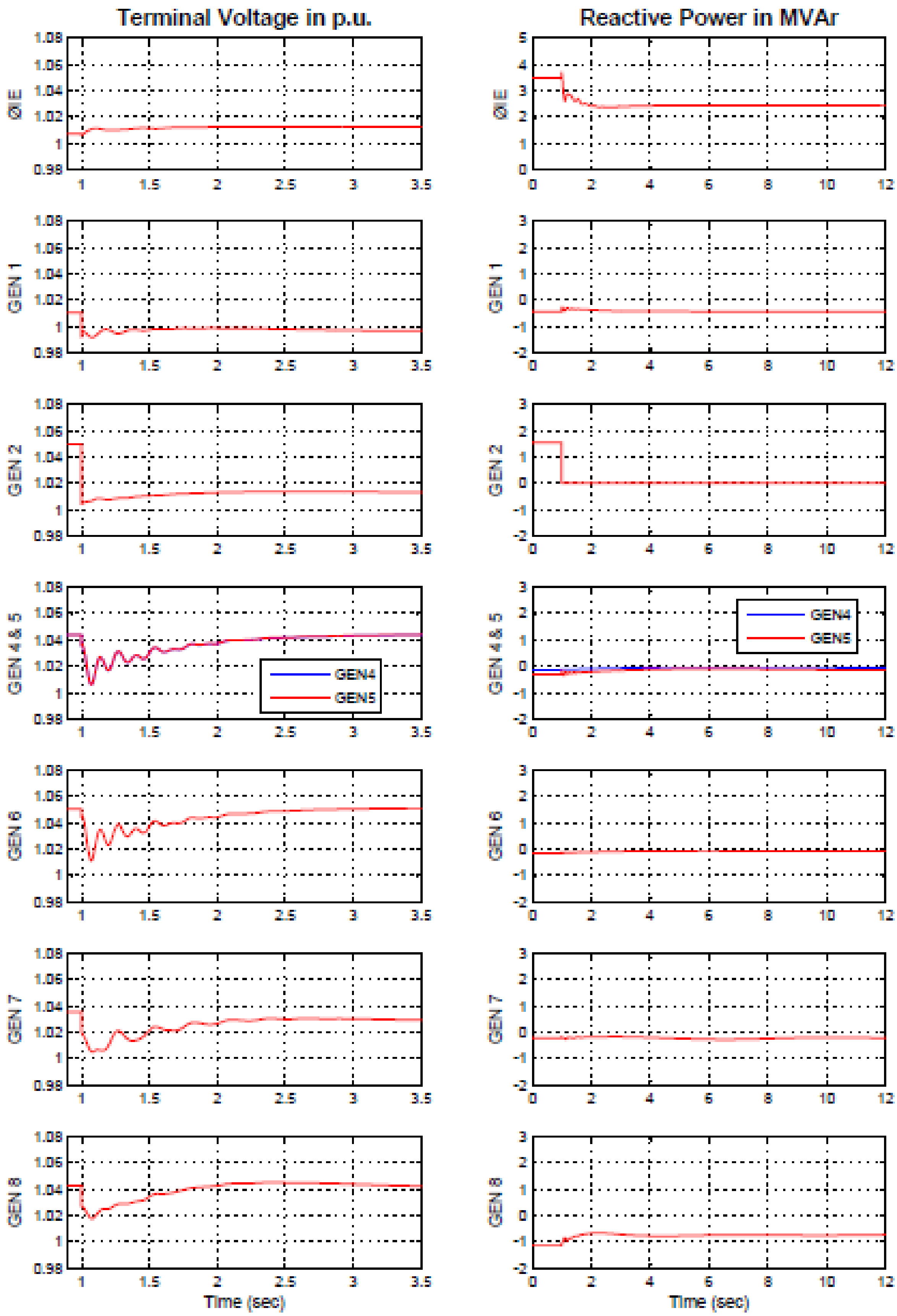

Figure A- 11: Disconnection of GEN 2 in Case A

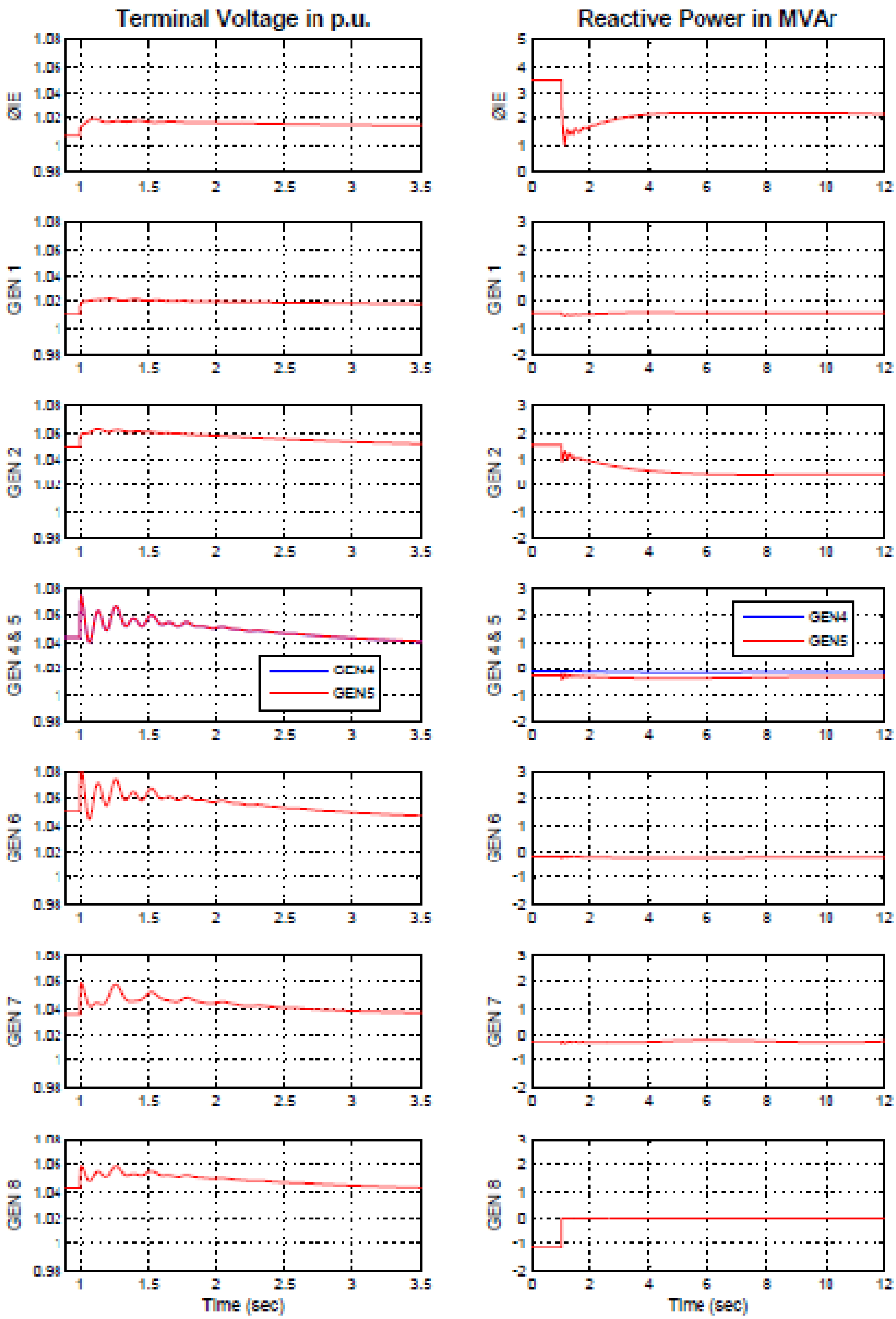

Figure A- 12: Disconnection of GEN 8 in Case A

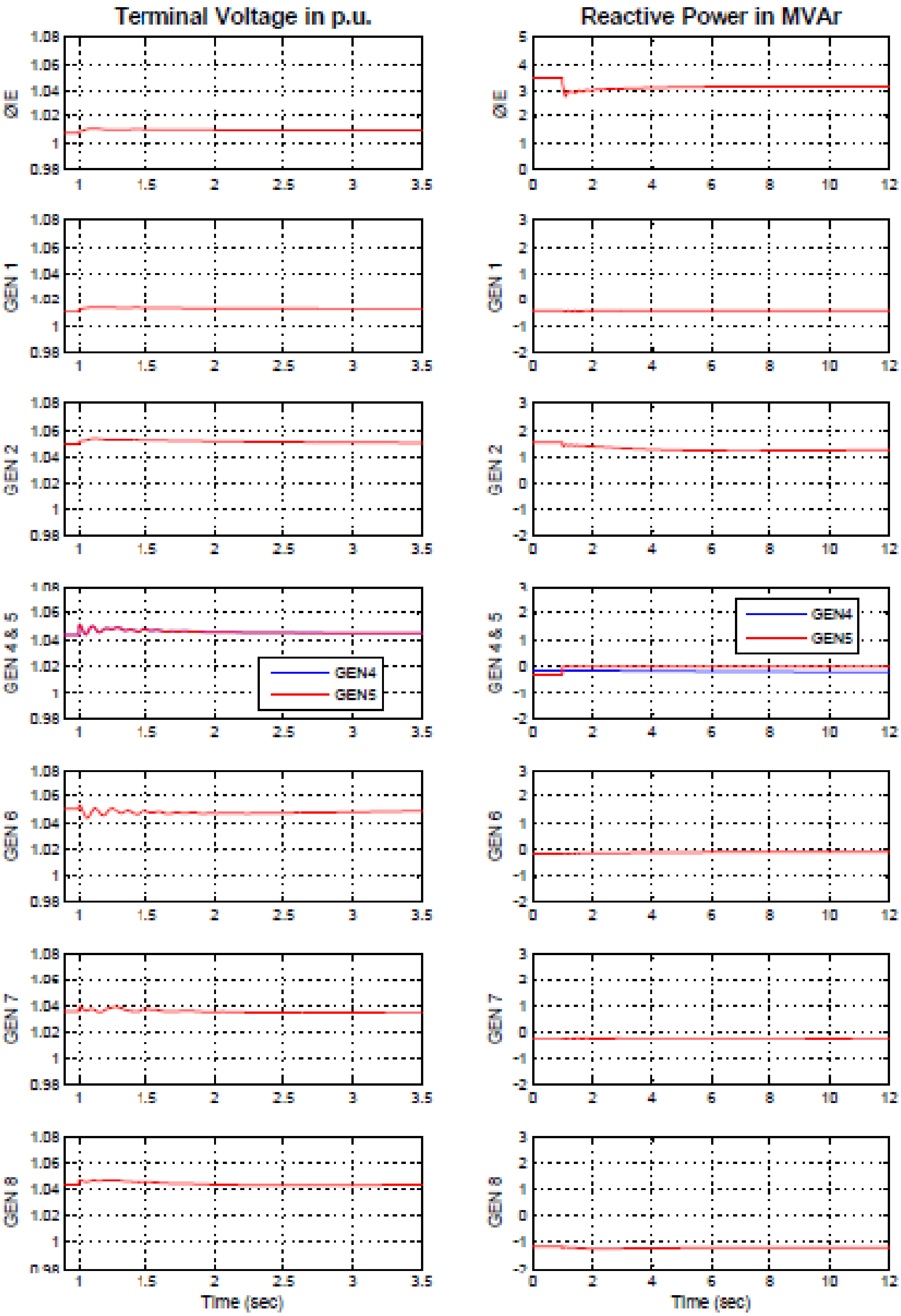

Figure A- 13: Disconnection of GEN 5 in Case A

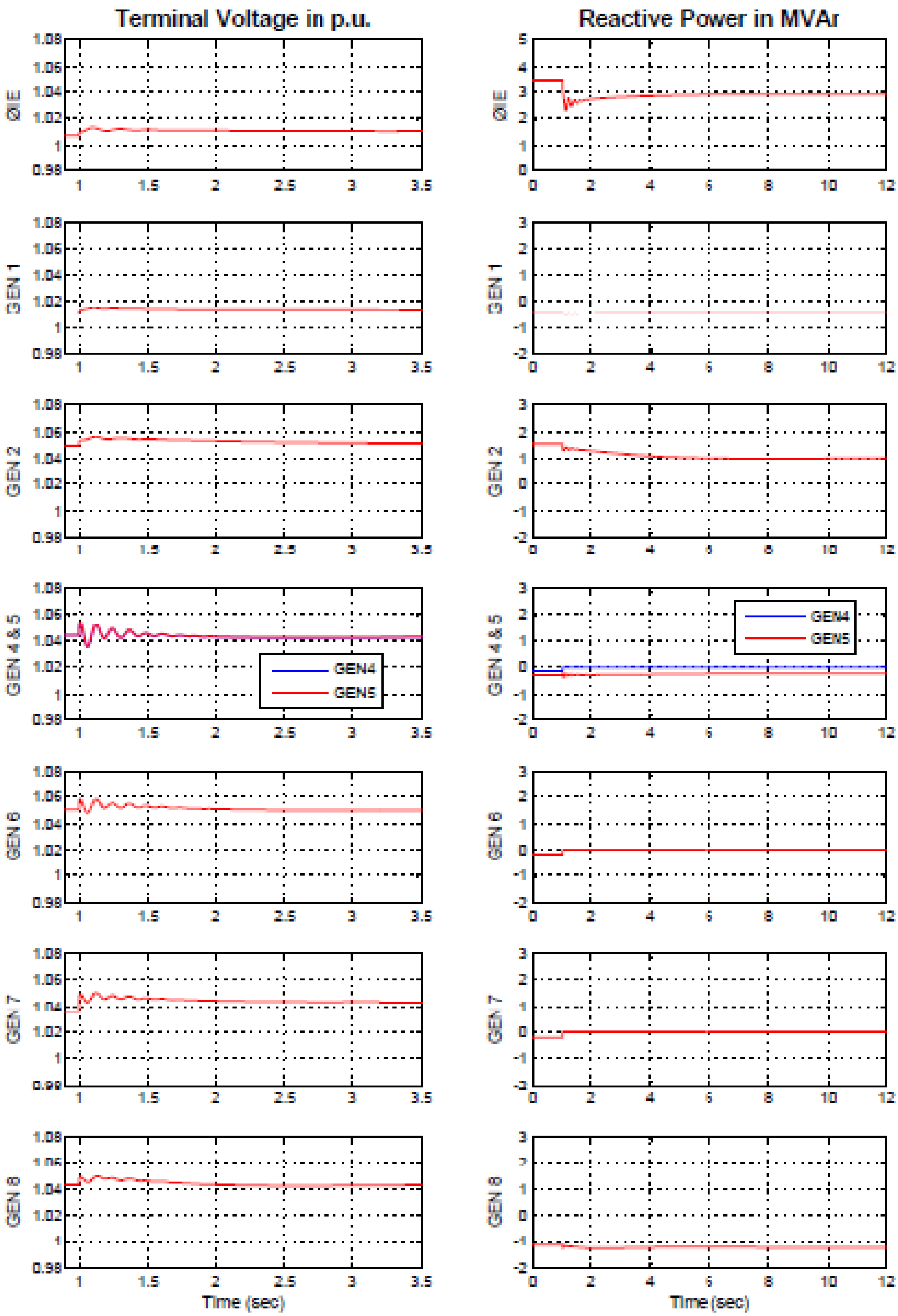

Figure A- 14: Disconnection of GEN 4, GEN 6 and GEN 7 in Case A

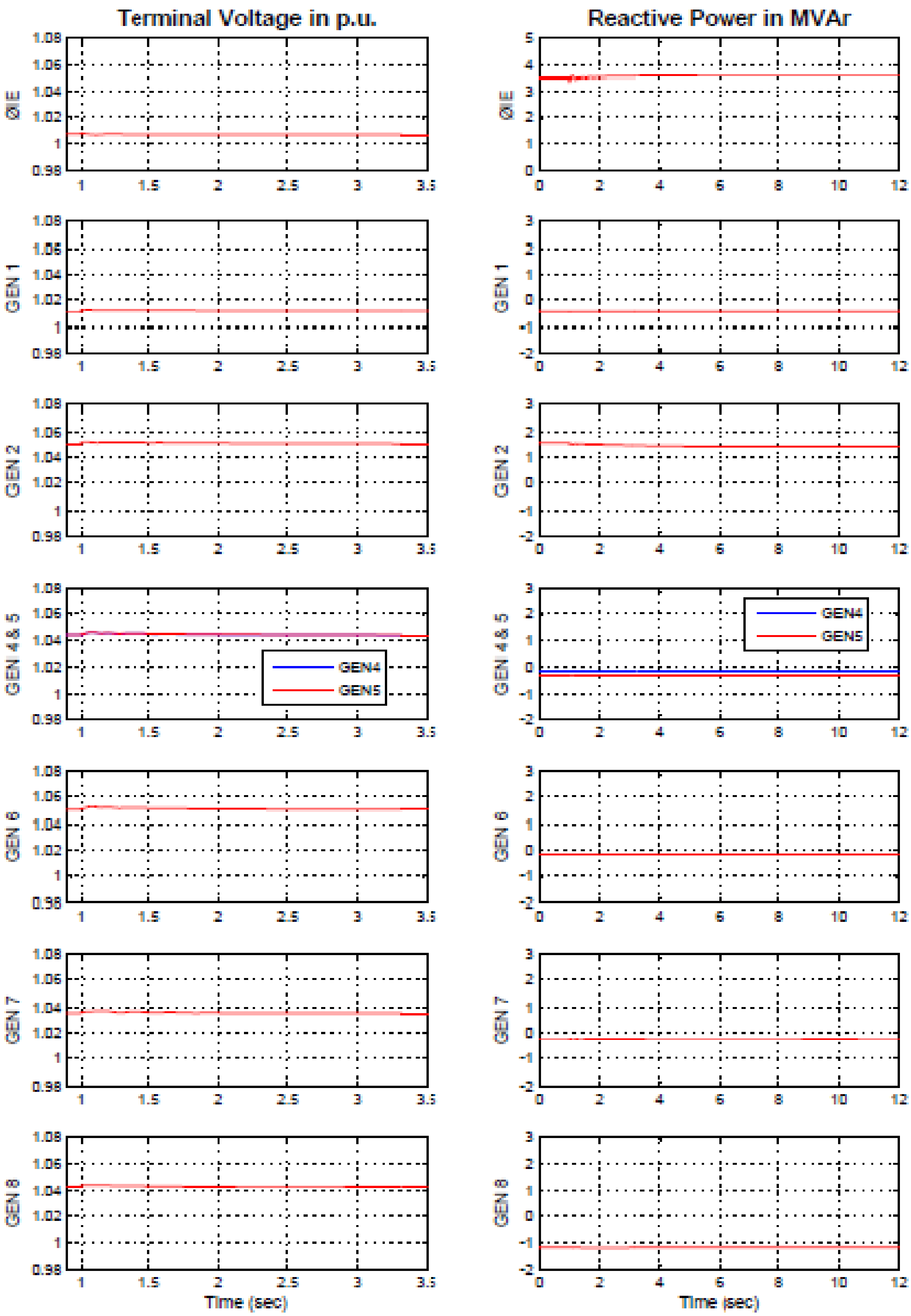

Figure A- 15: Disconnection of loads in Case A

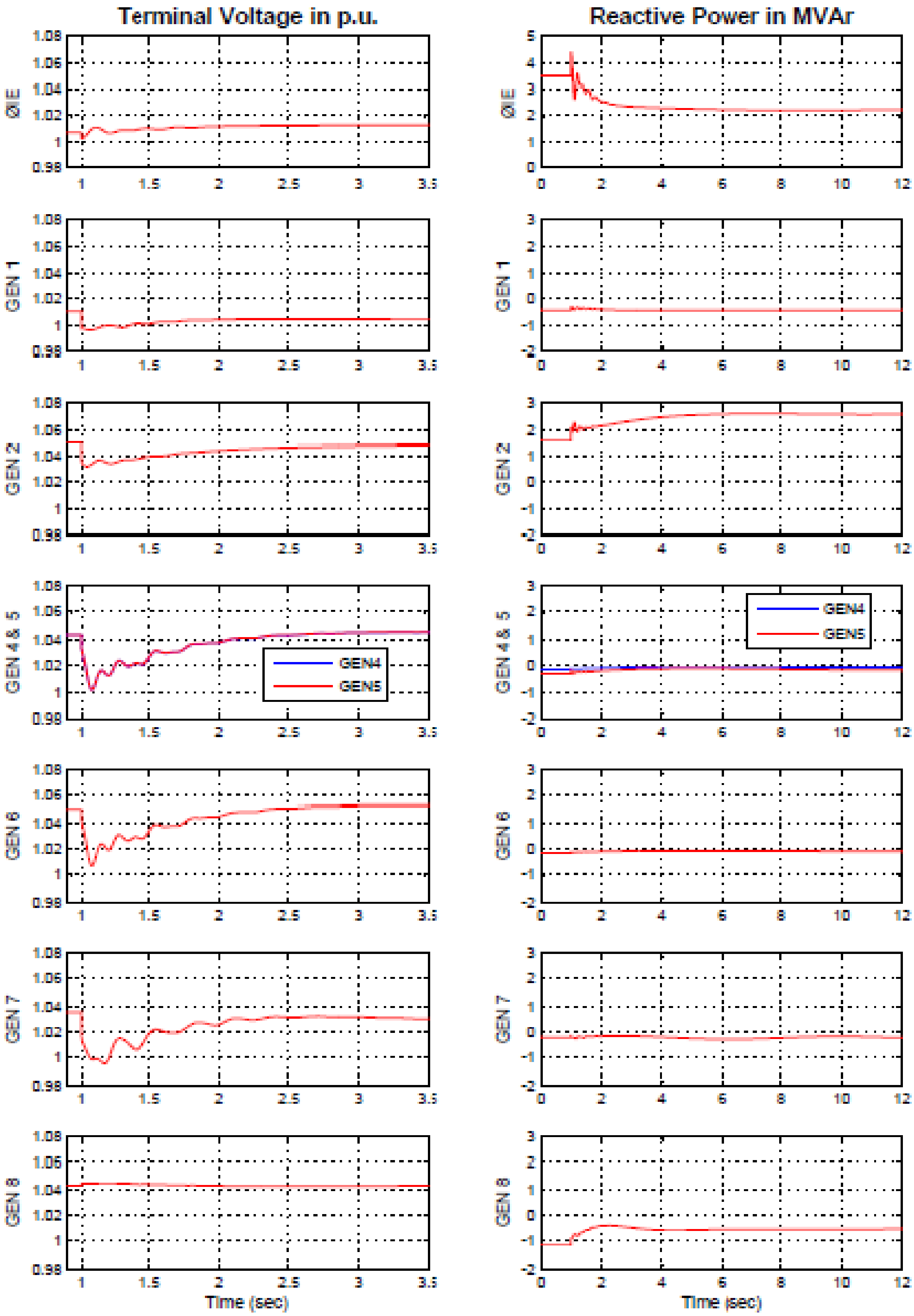

Figure A- 16: Step change in load from low load to high load in Case A

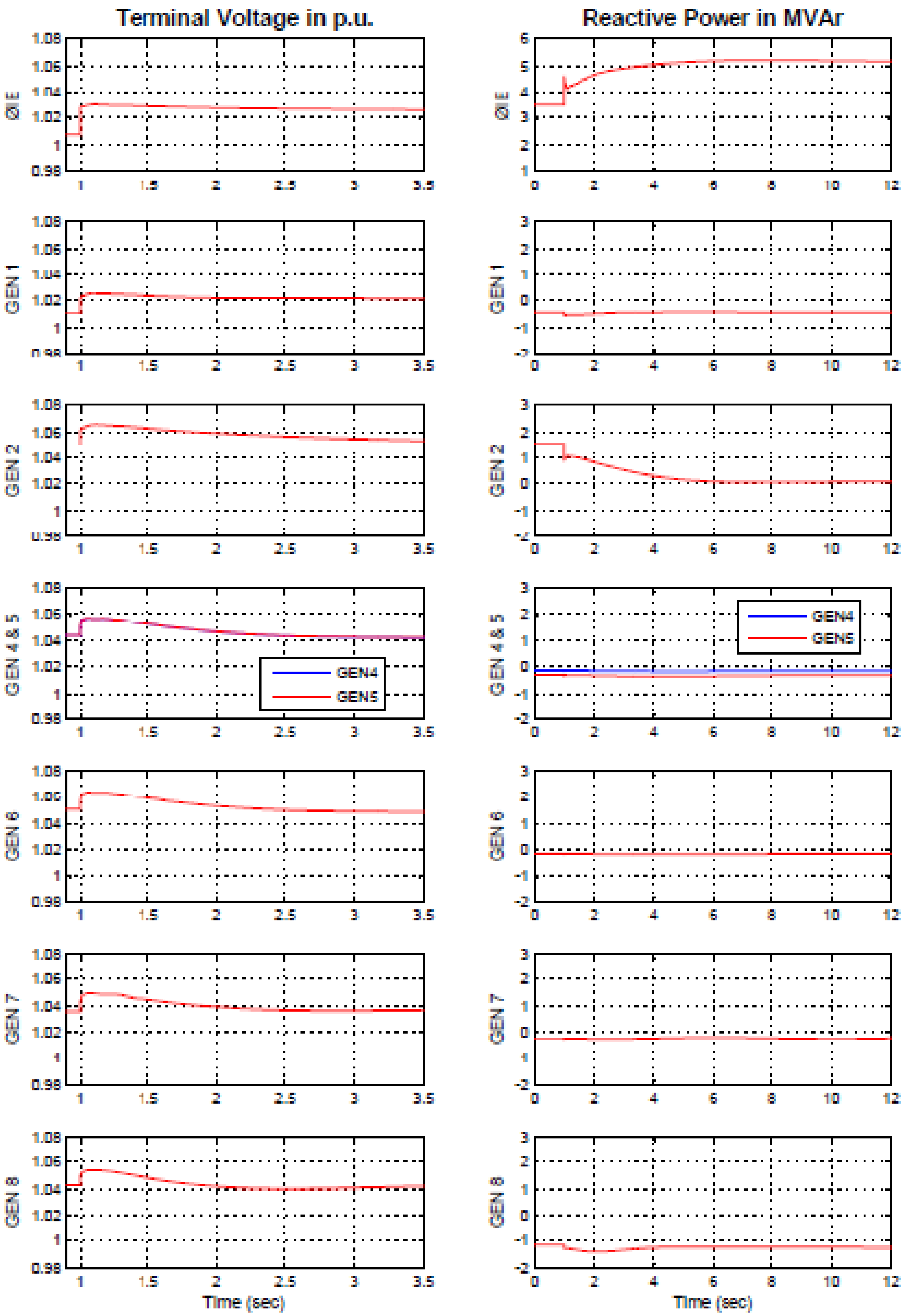

Figure A- 17: Step change in system voltage in Case A

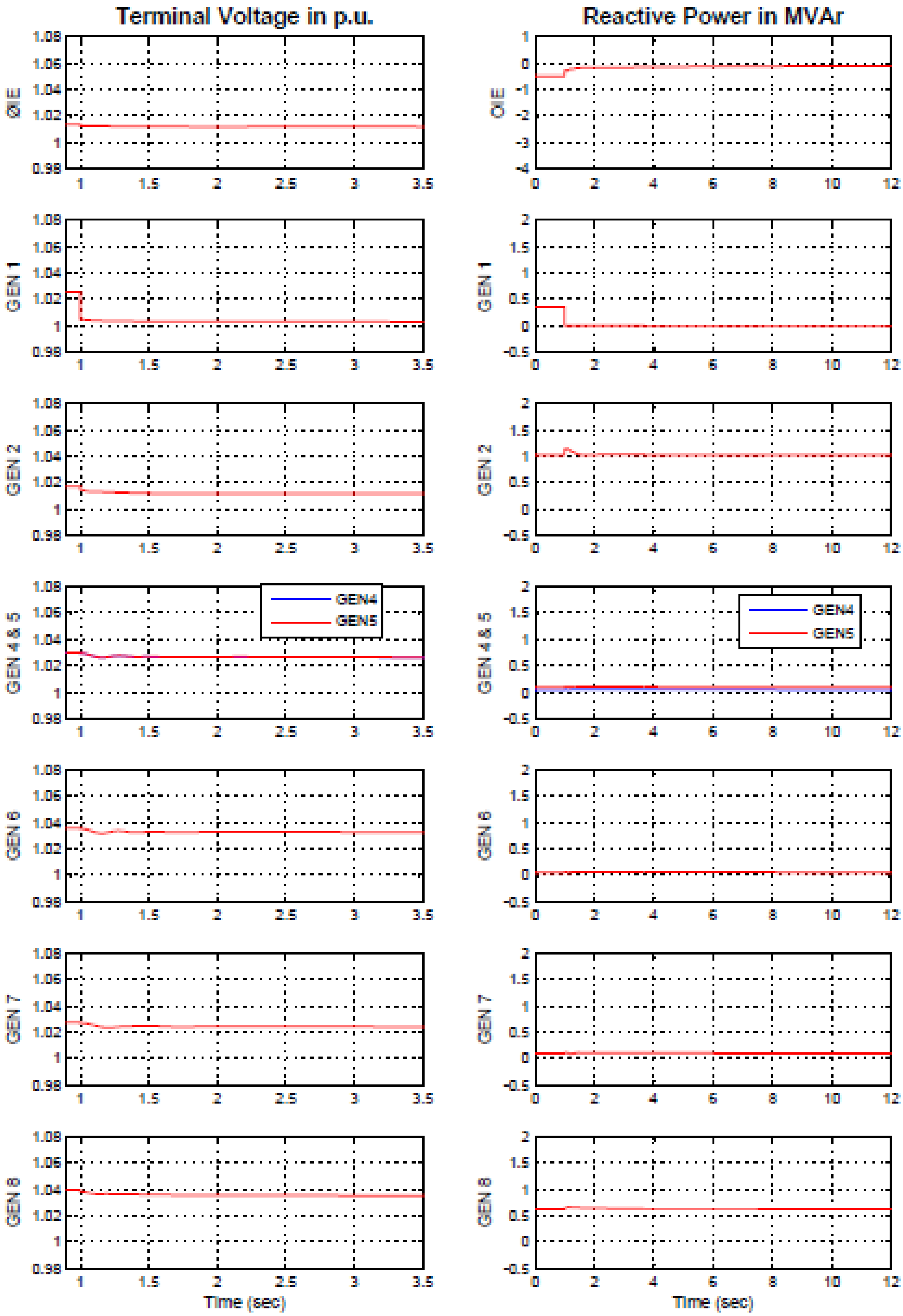

Figure A- 18: Disconnection of GEN 1 in Case B

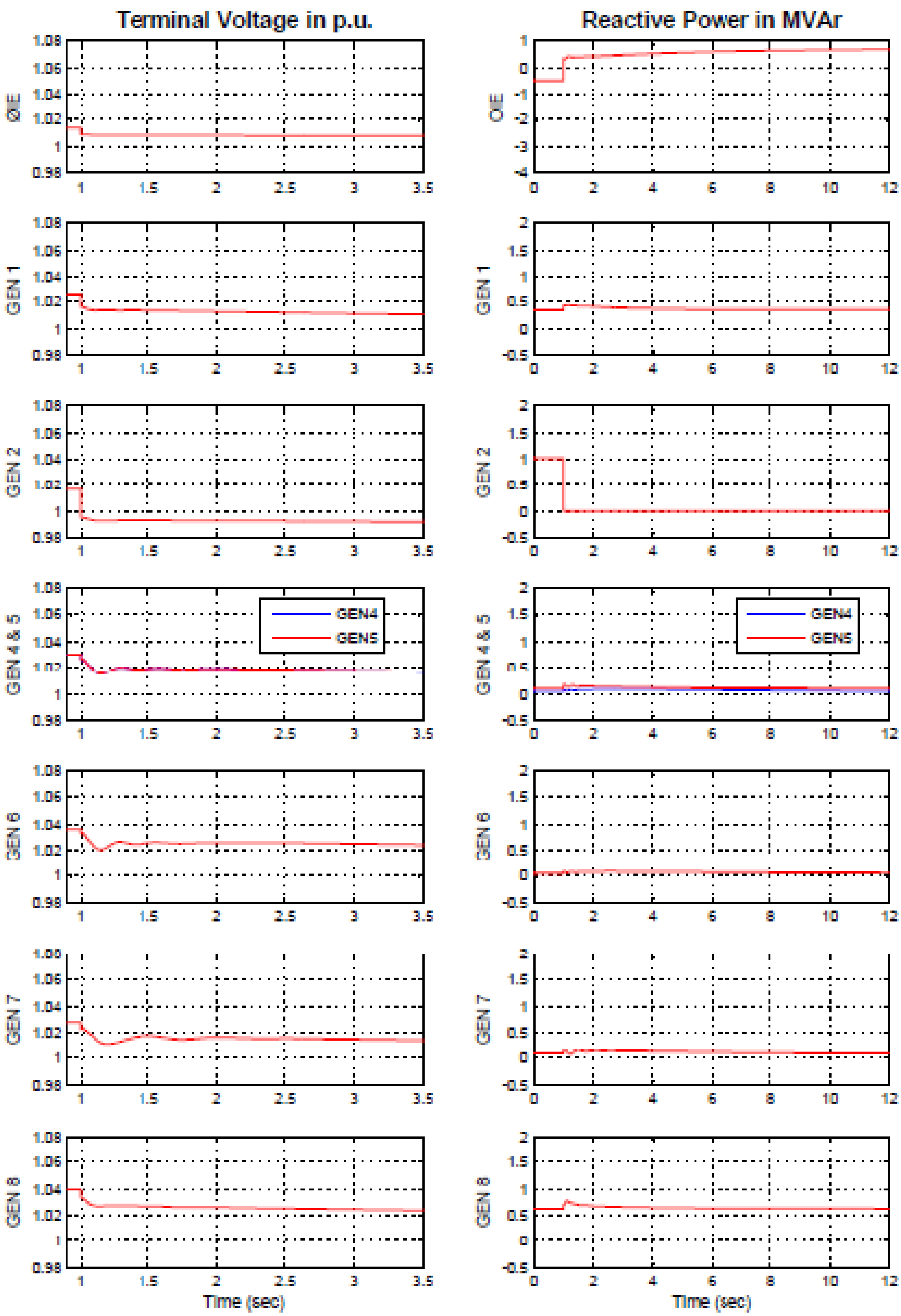

Figure A- 19: Disconnection of GEN 2 in Case B

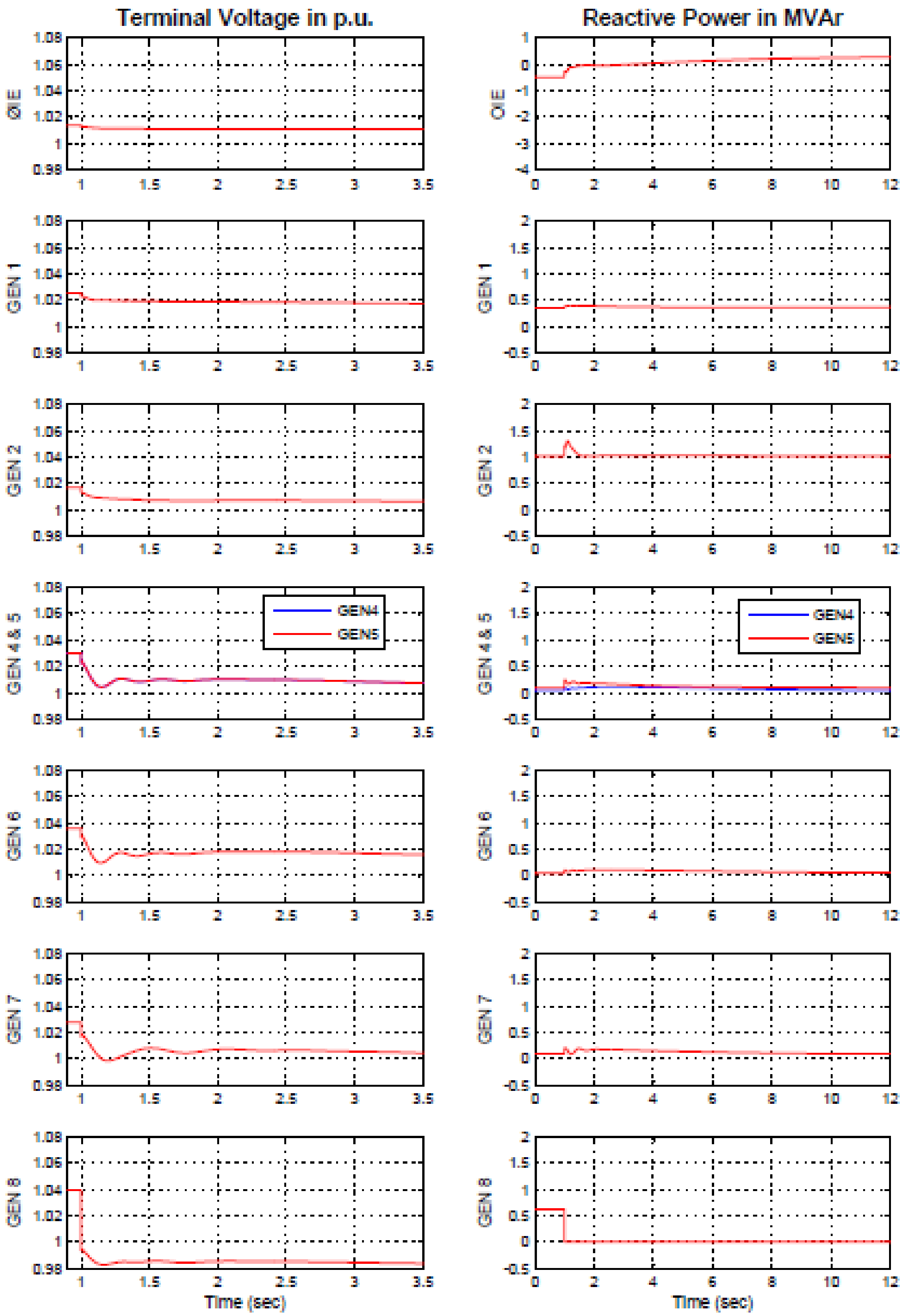

Figure A- 20: Disconnection of GEN 8 in Case B

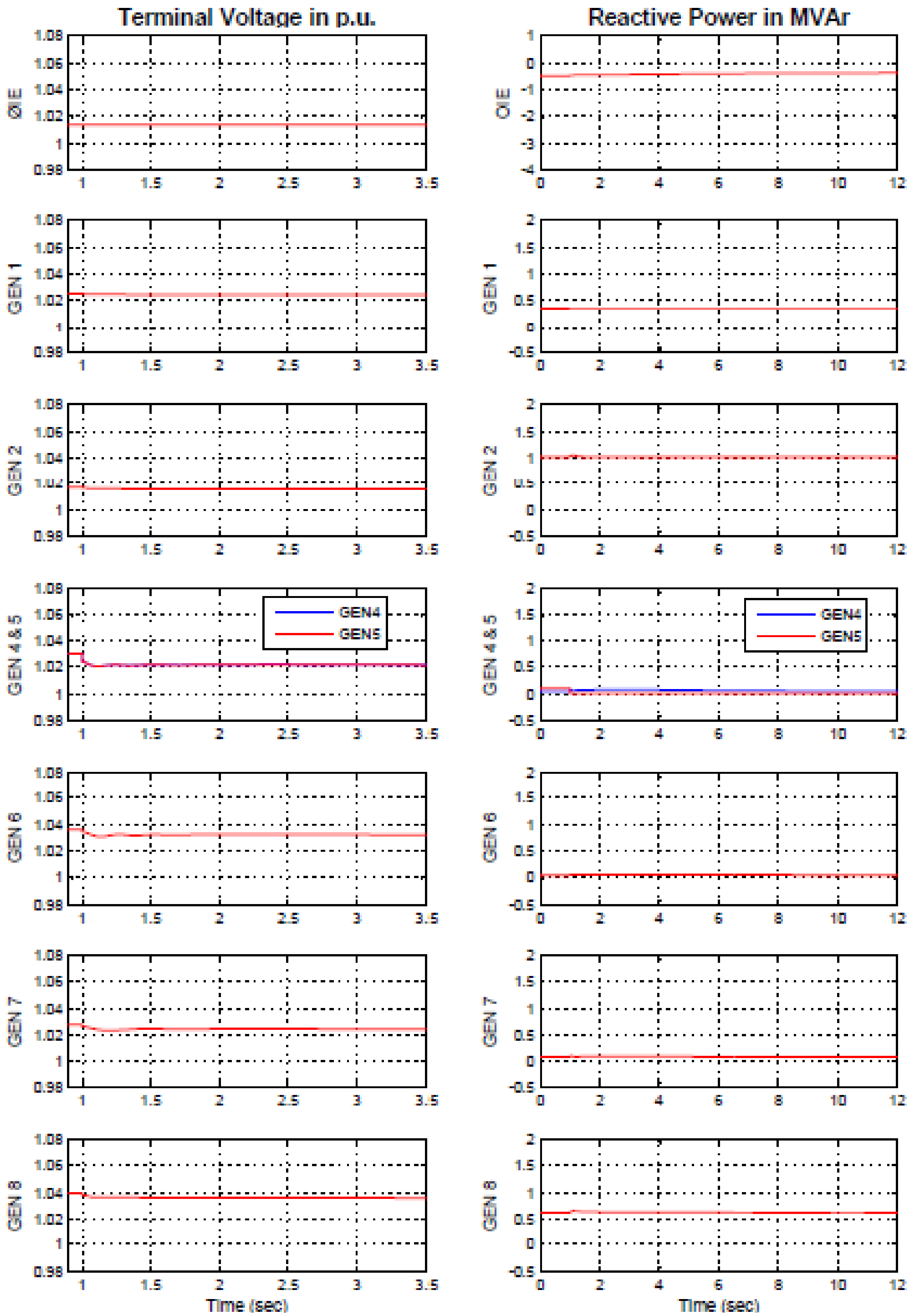

Figure A- 21: Disconnection of GEN 5 in Case B

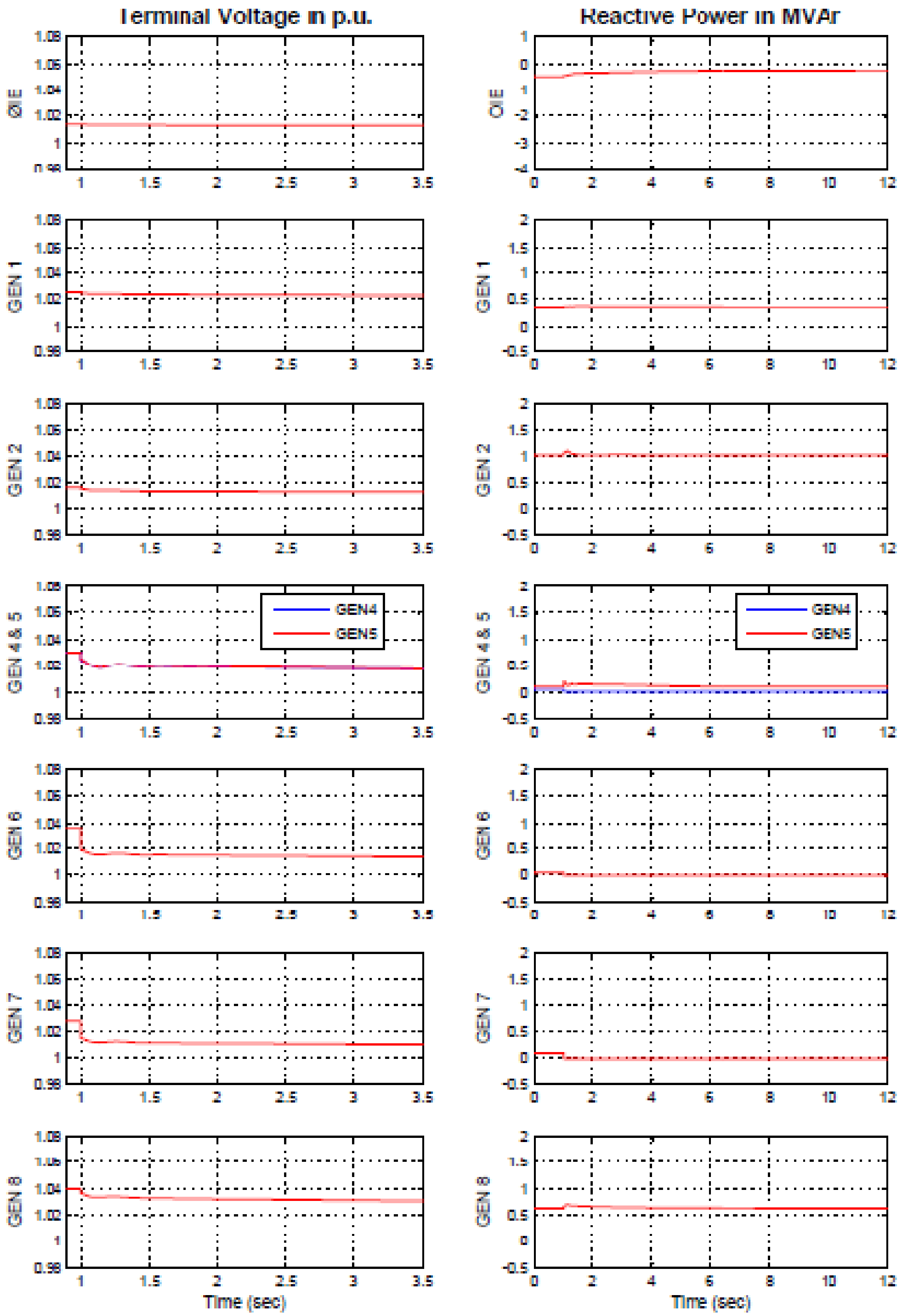

Figure A- 22: Disconnection of GEN 4, GEN 6 and GEN 7 in Case B

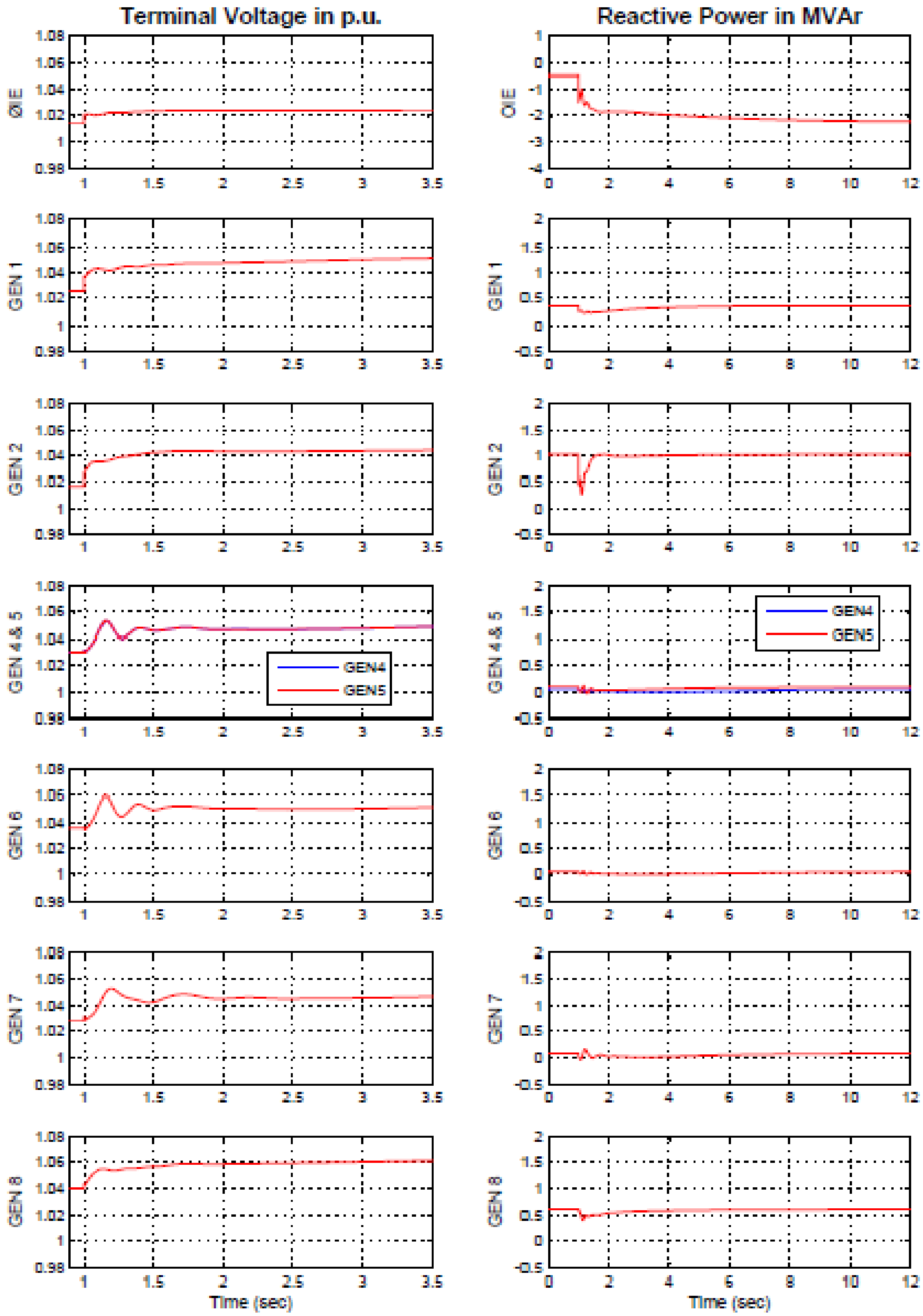

Figure A- 23: Disconnection of loads in Case B

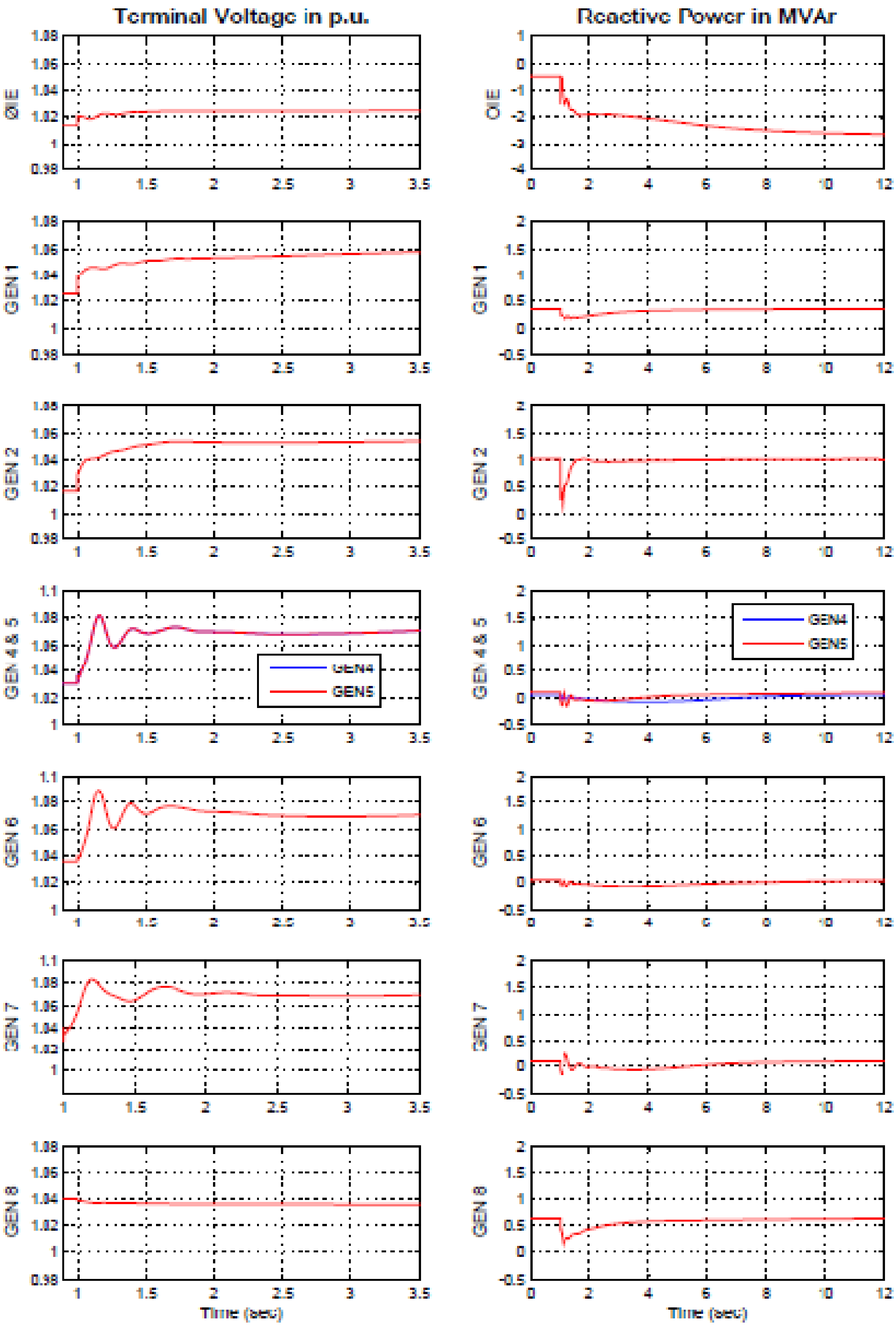

Figure A- 24: Step change in load from high load to low load in Case B

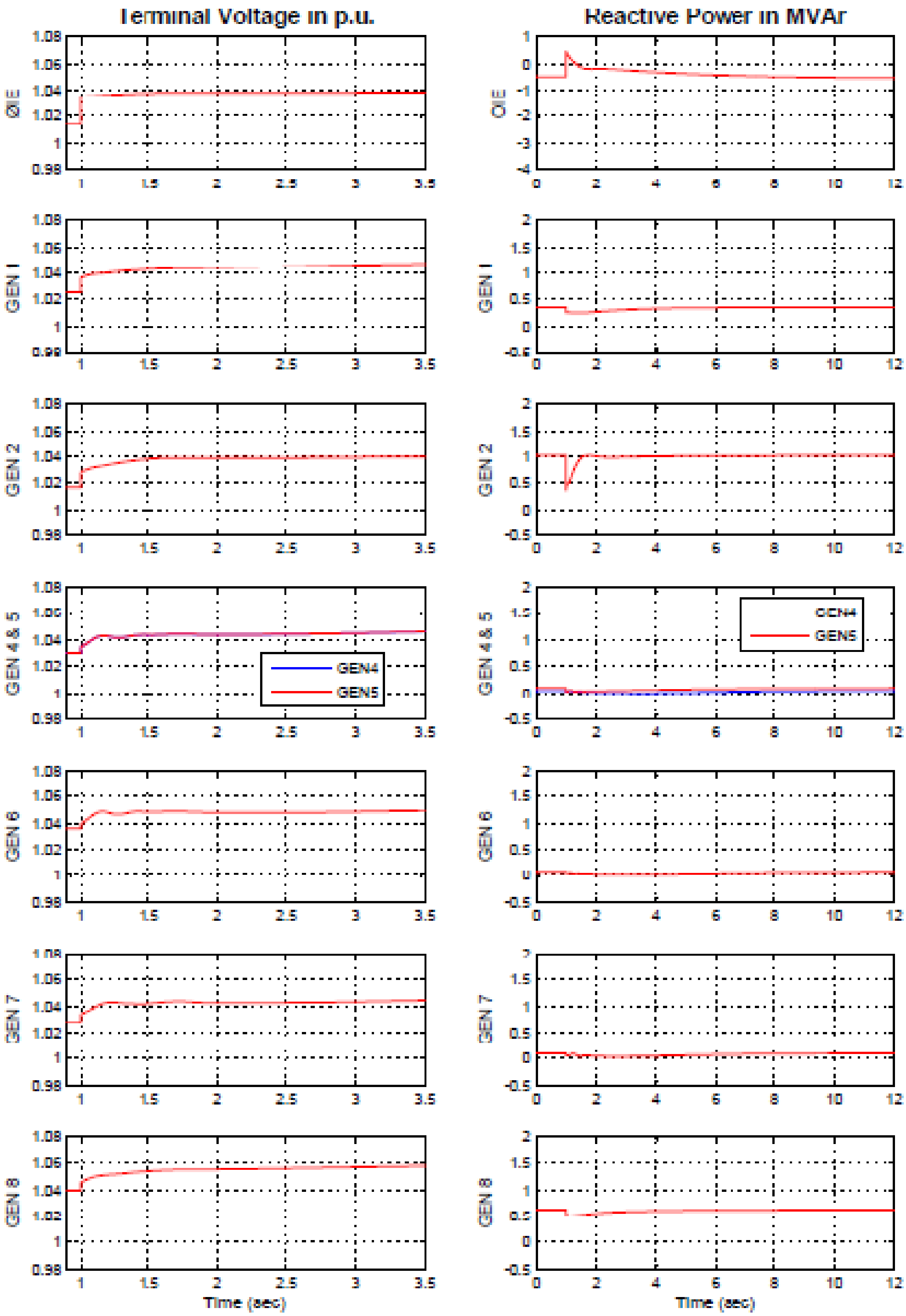

Figure A- 25: Step change in system voltage in Case B

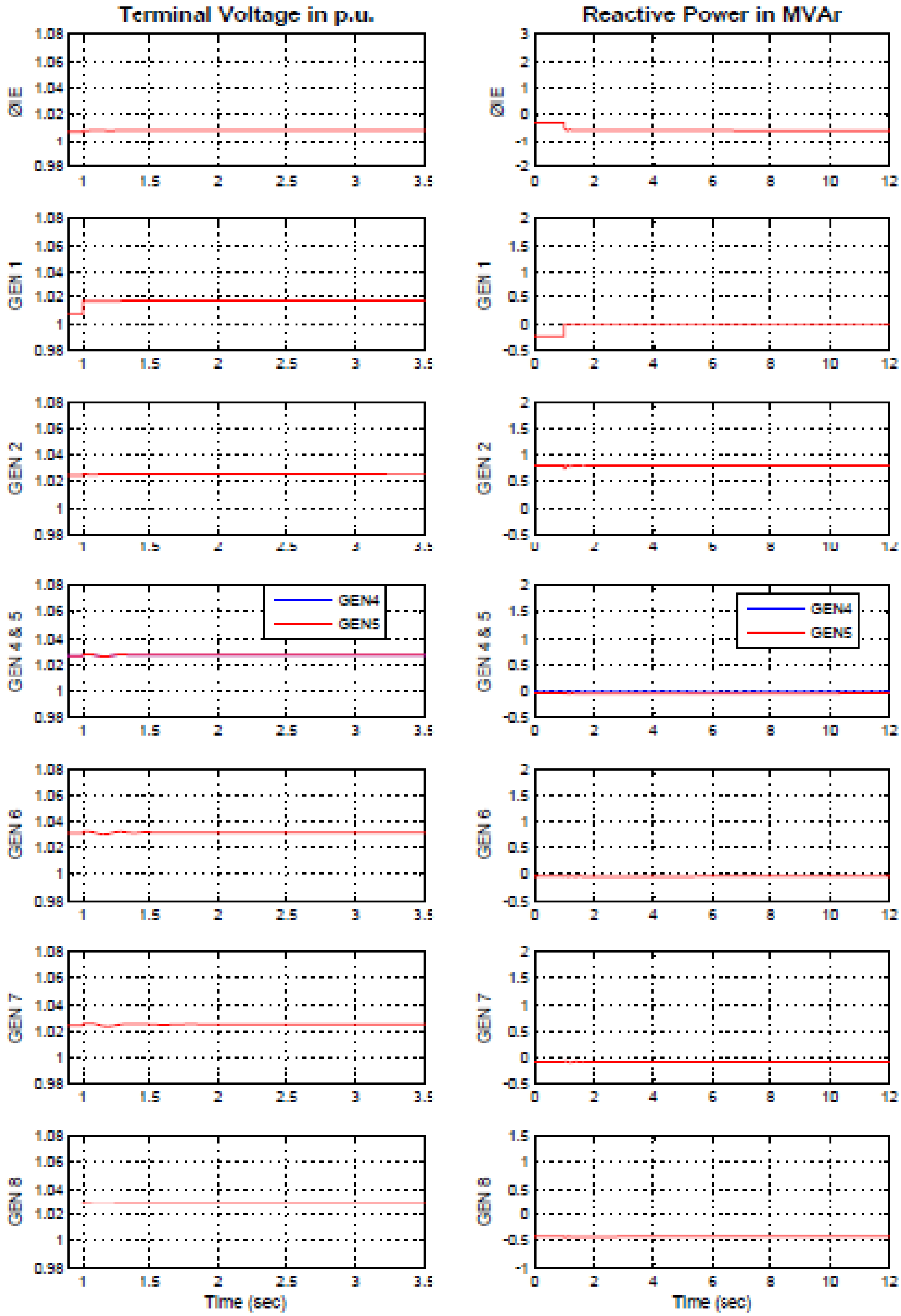

Figure A- 26: Disconnection of GEN 1 in Case C

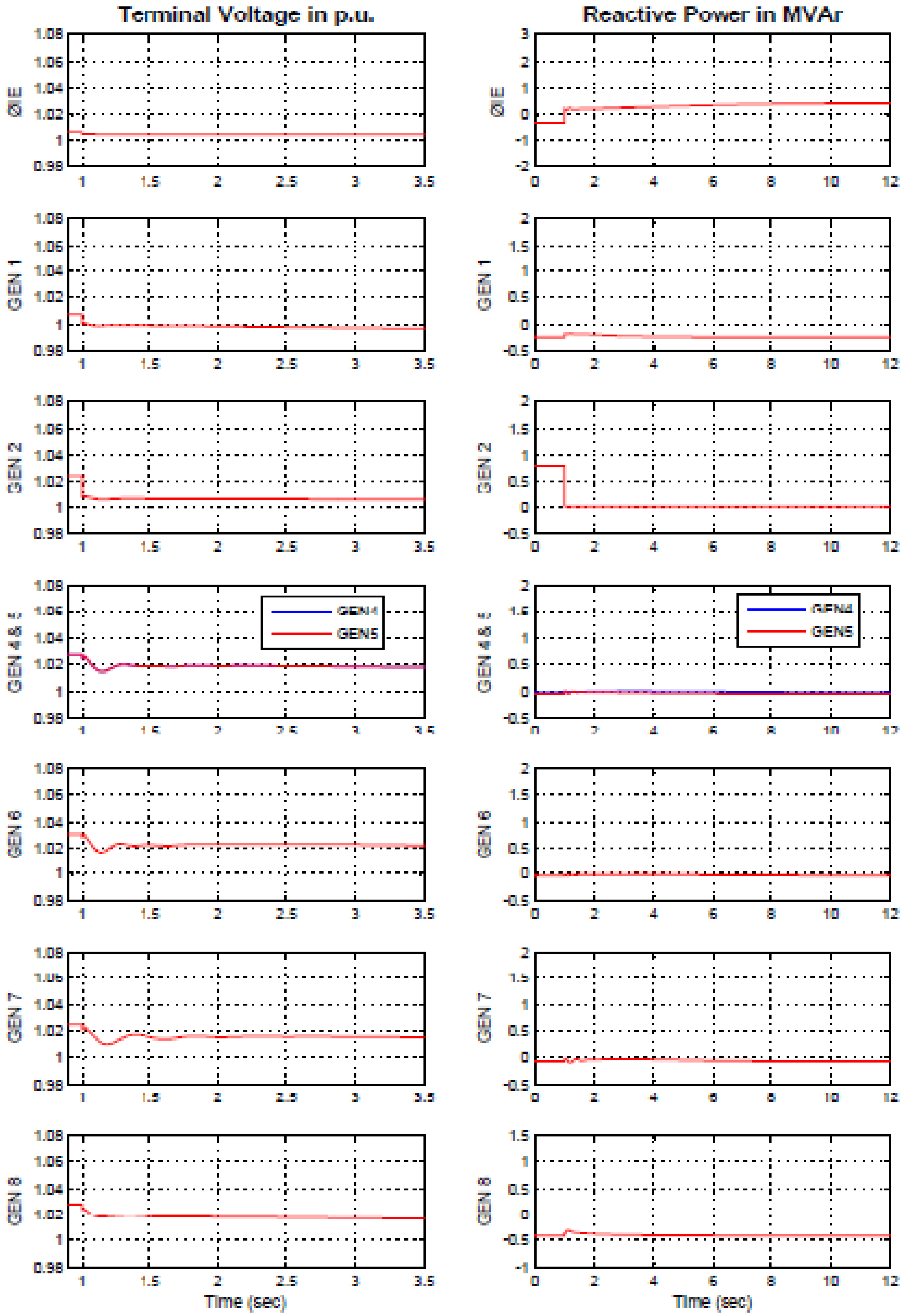

Figure A- 27: Disconnection of GEN 2 in Case C

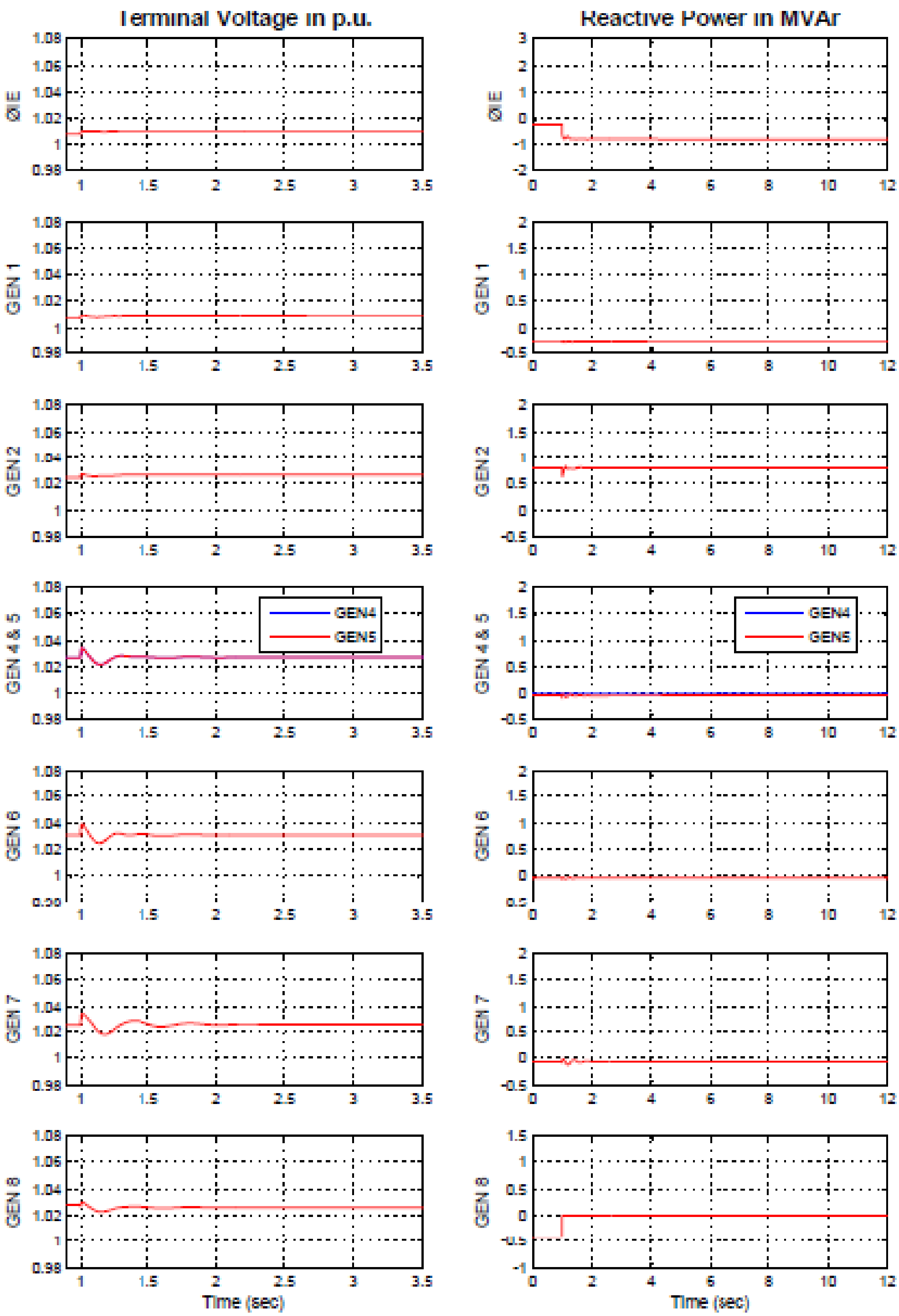

Figure A- 28: Disconnection of GEN 8 in Case C

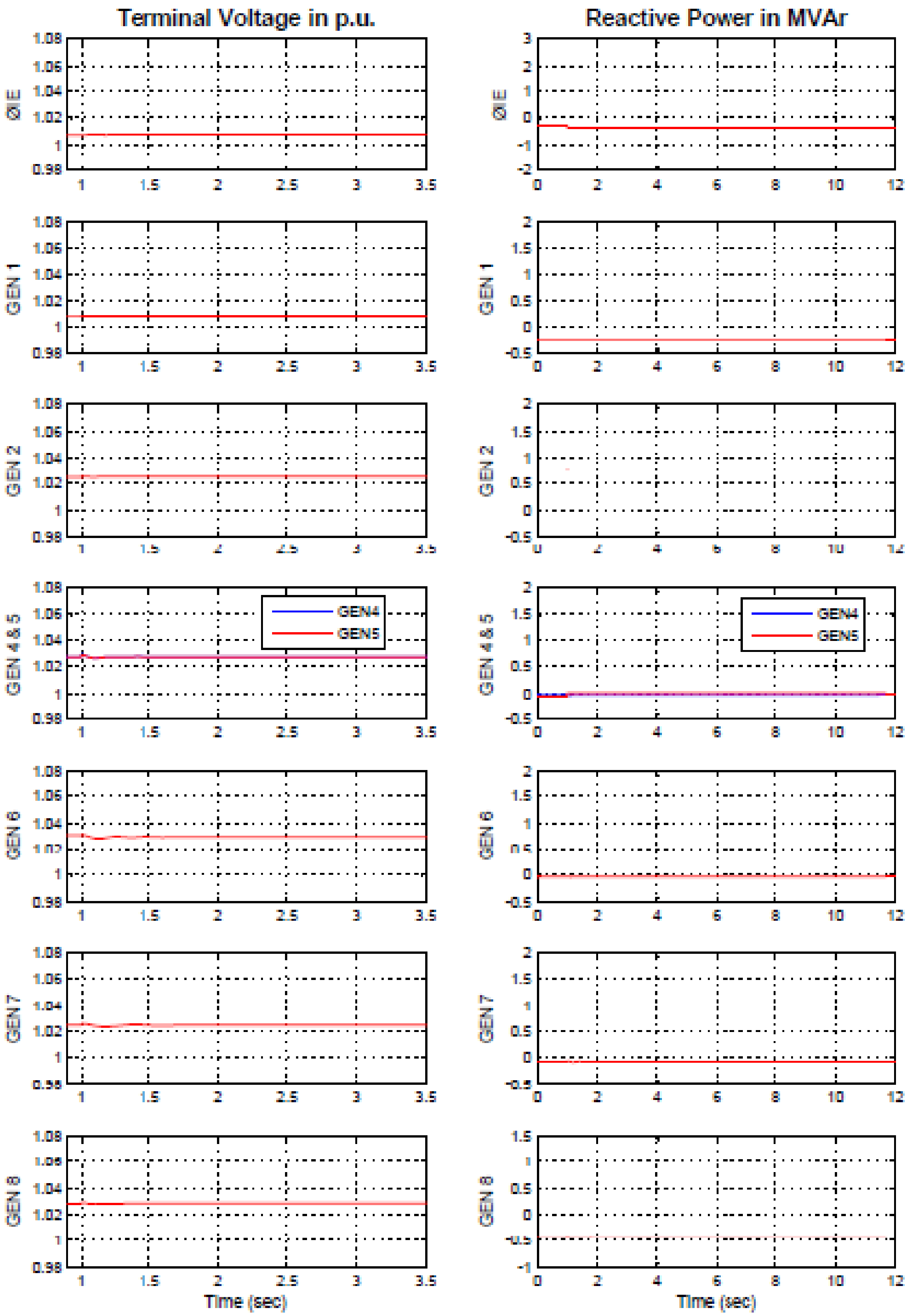

Figure A- 29: Disconnection of GEN 5 in Case C

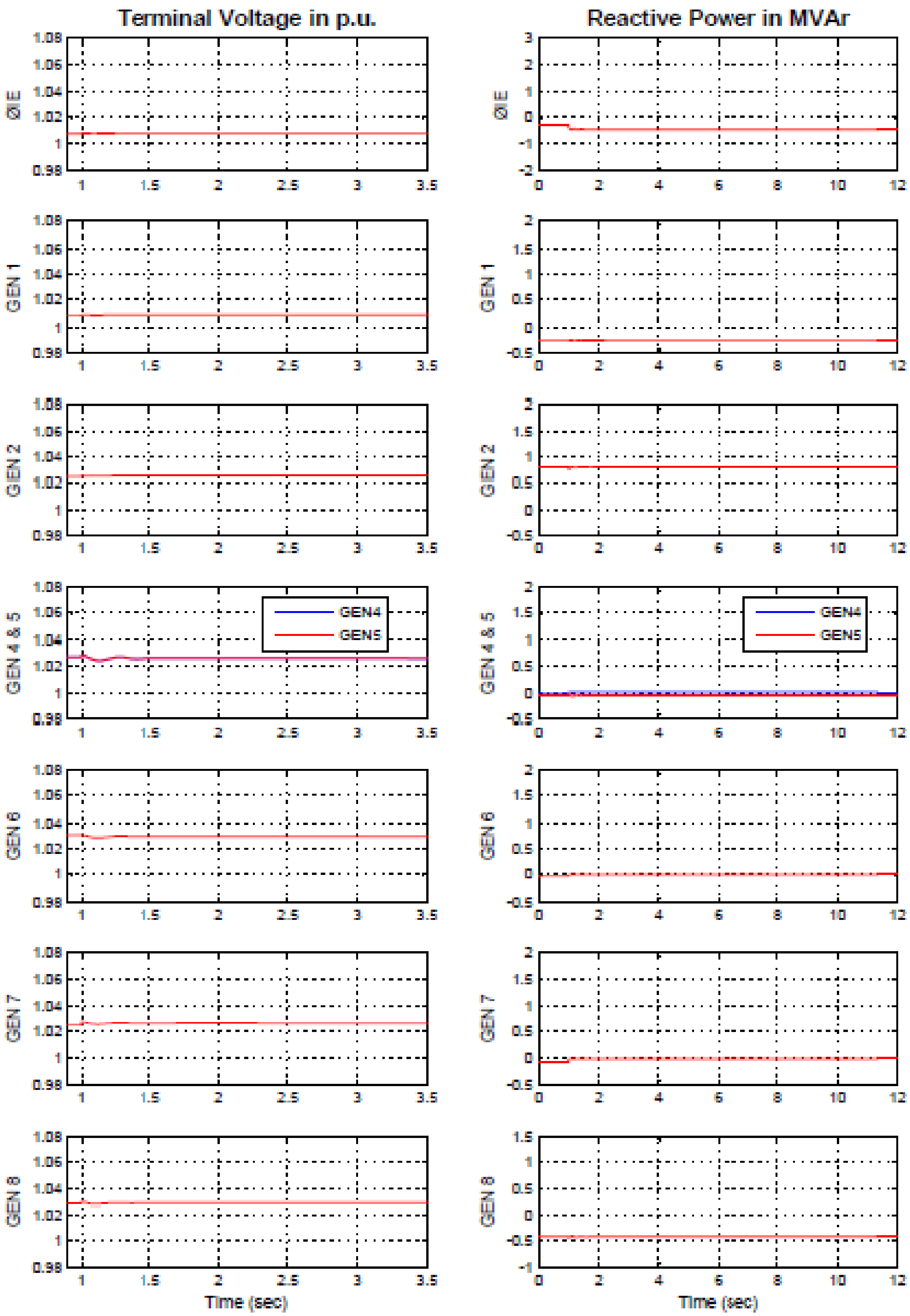

Figure A- 30: Disconnection of GEN 4, GEN 6 and GEN 7 in Case C

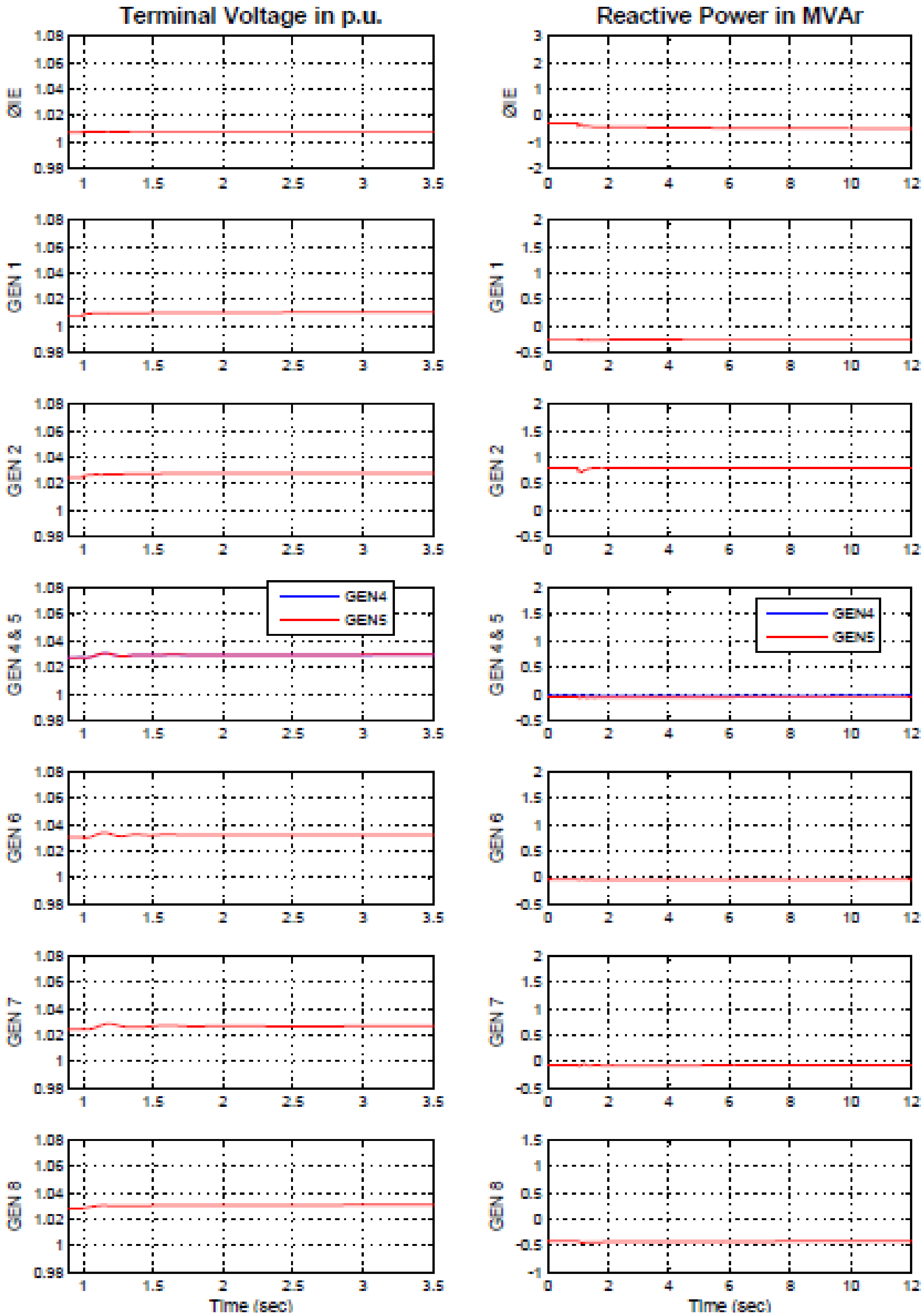

Figure A- 31: Disconnection of loads in Case C

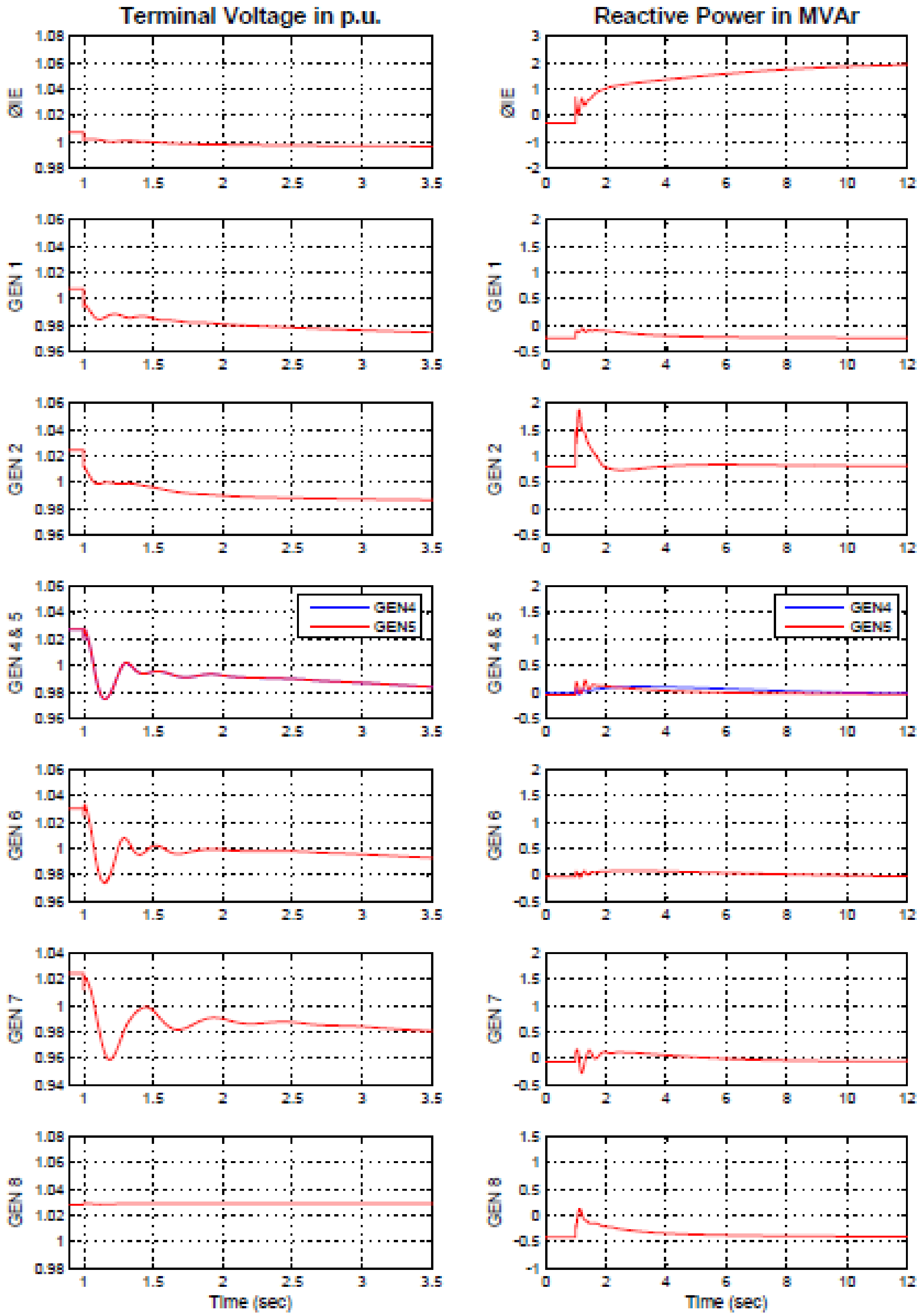

Figure A- 32: Step in load from low load to high load in Case C

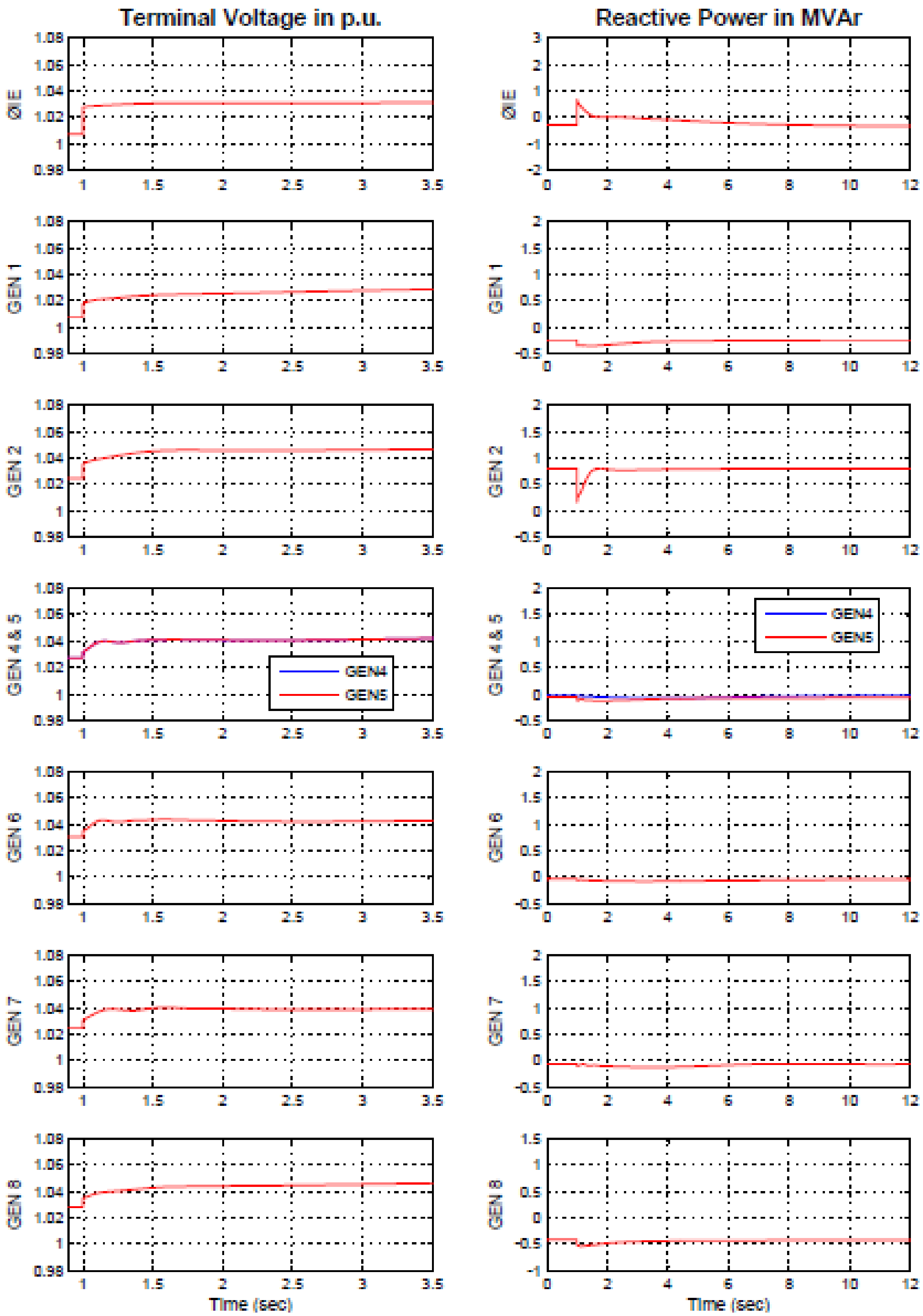

Figure A- 33: Change in system voltage in Case C

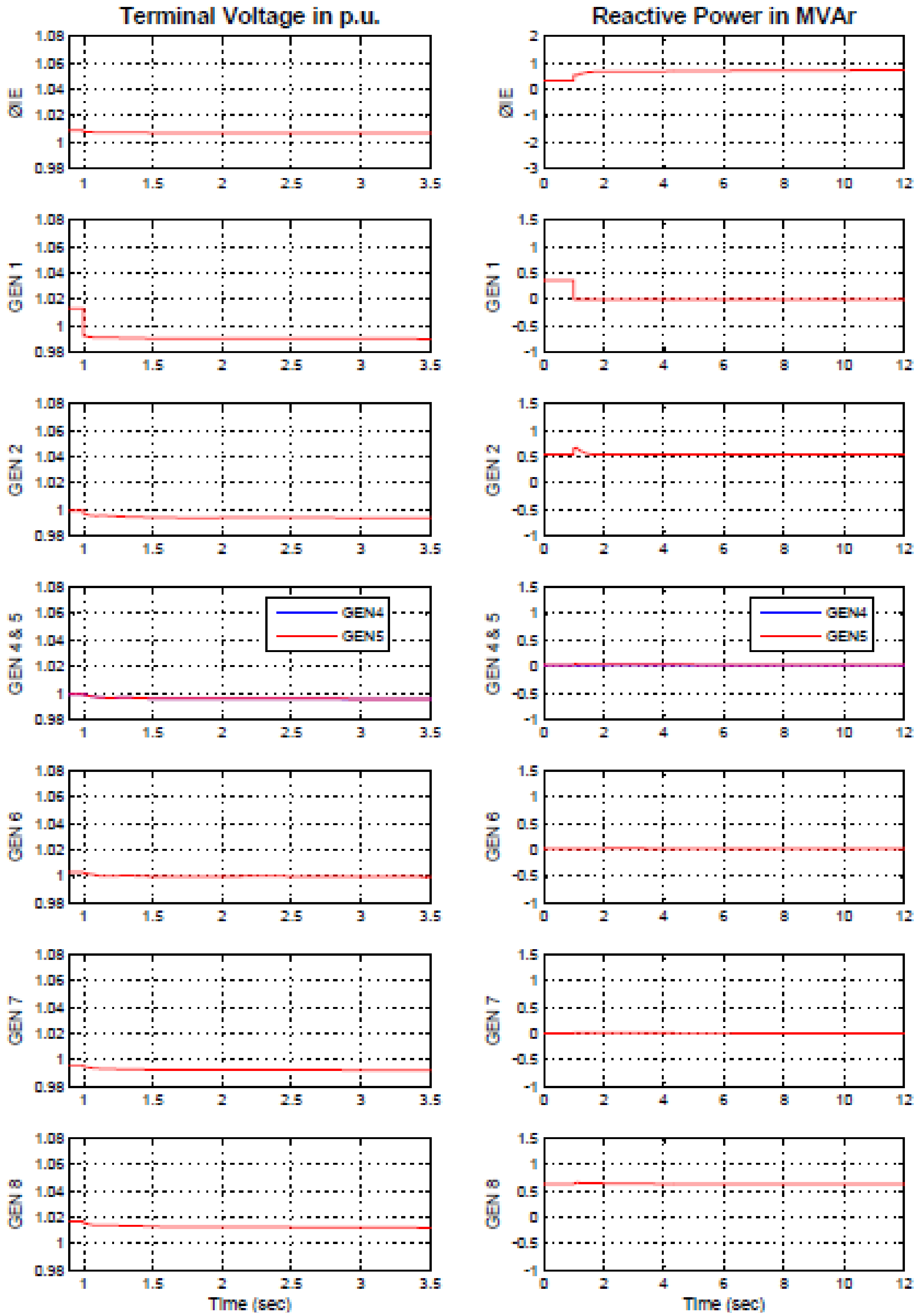

Figure A- 34: Disconnection of GEN 1 in Case D

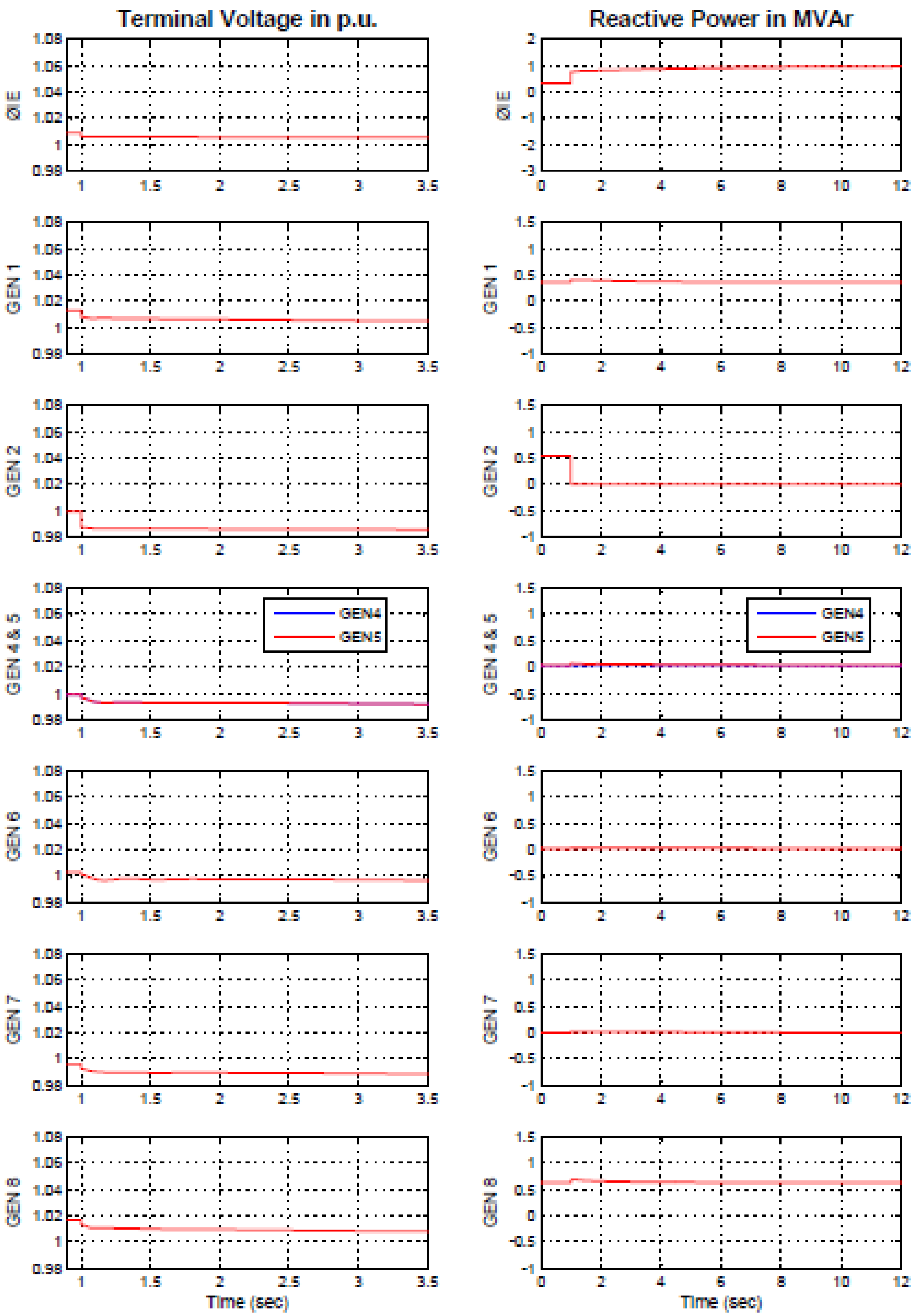

Figure A- 35: Disconnection of GEN 2 in Case D

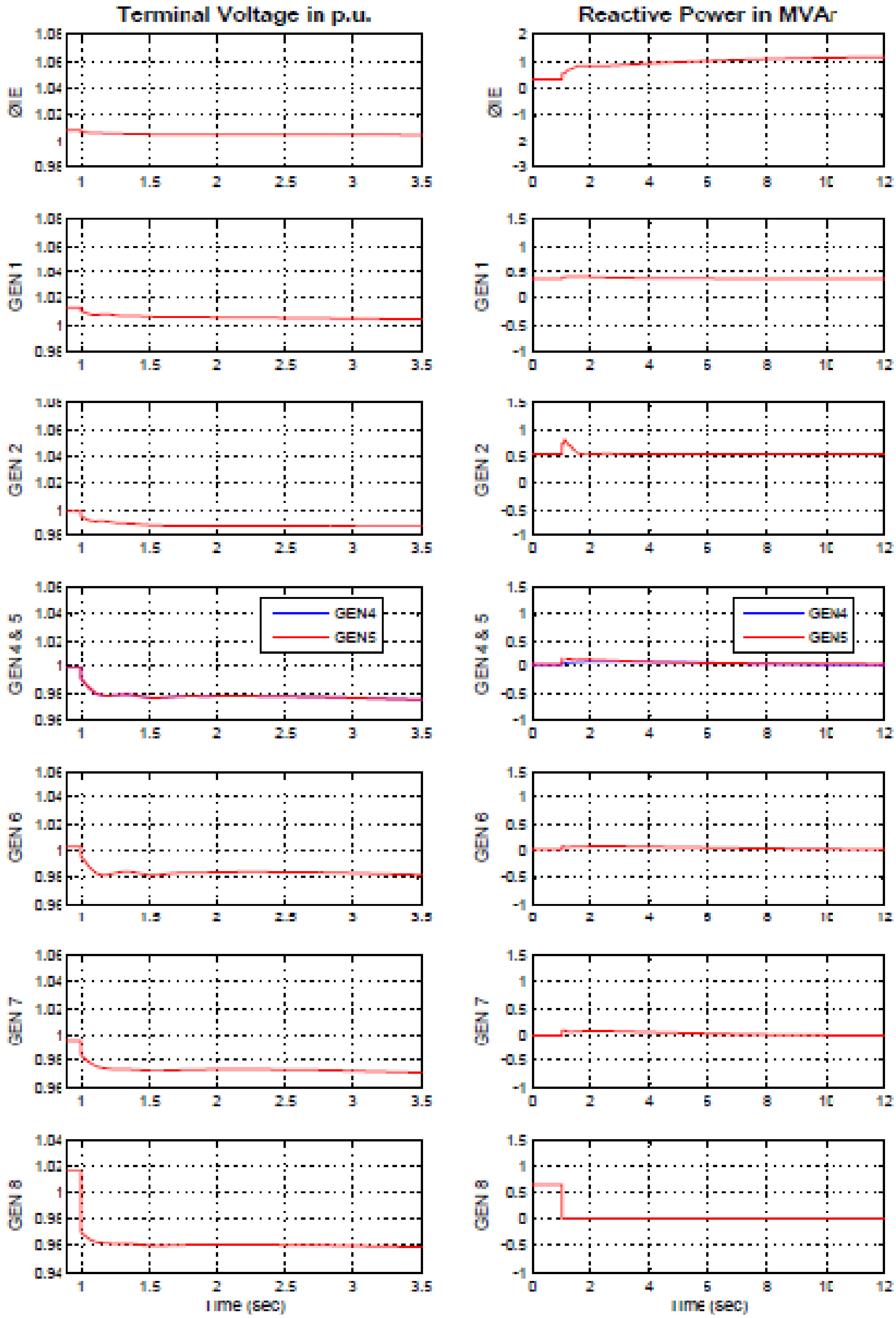

Figure A- 36: Disconnection of GEN 8 in Case D

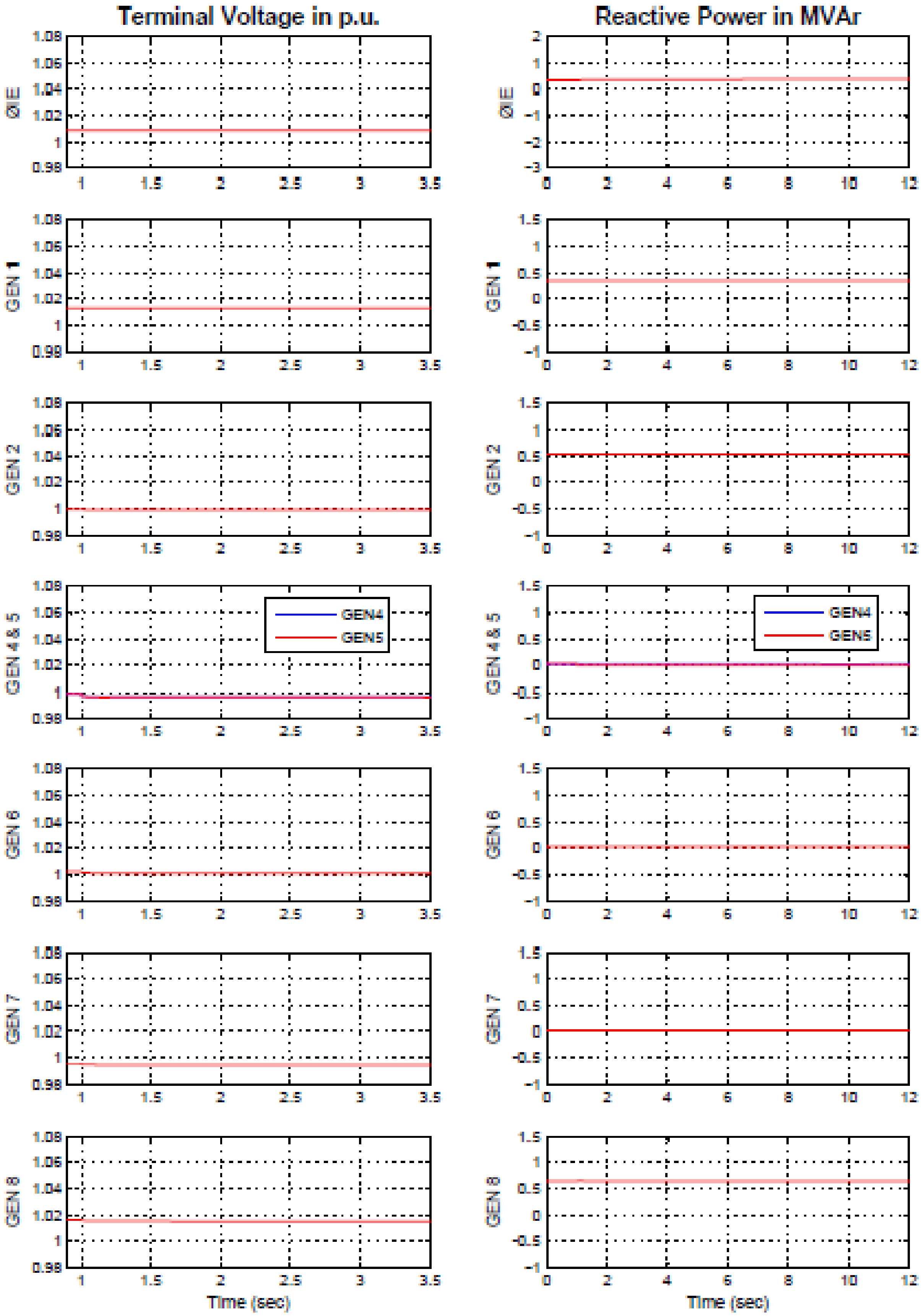

Figure A- 37: Disconnection of GEN 5 in Case D

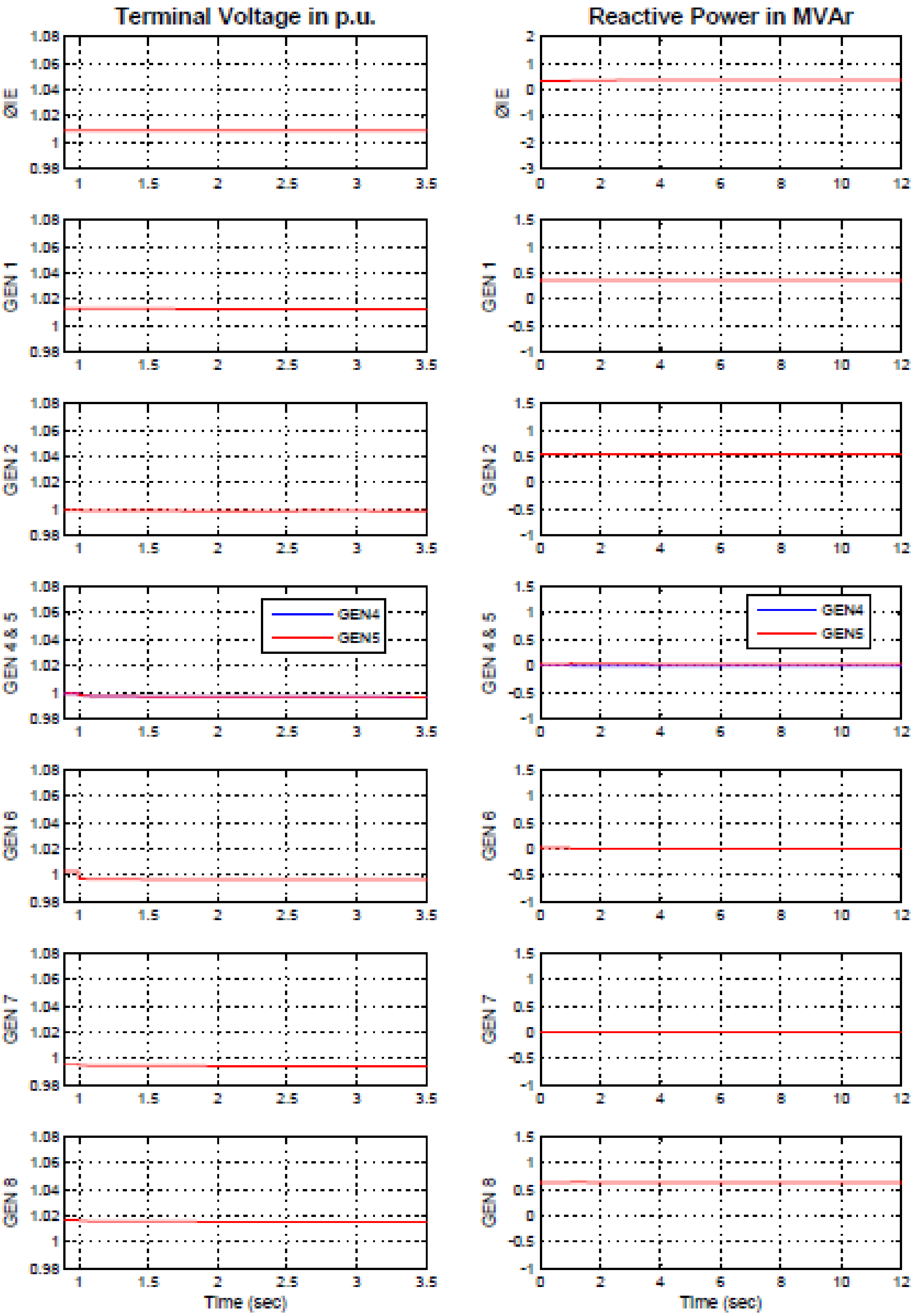

Figure A- 38: Disconnection of GEN 4, GEN 6 and GEN 7 in Case D

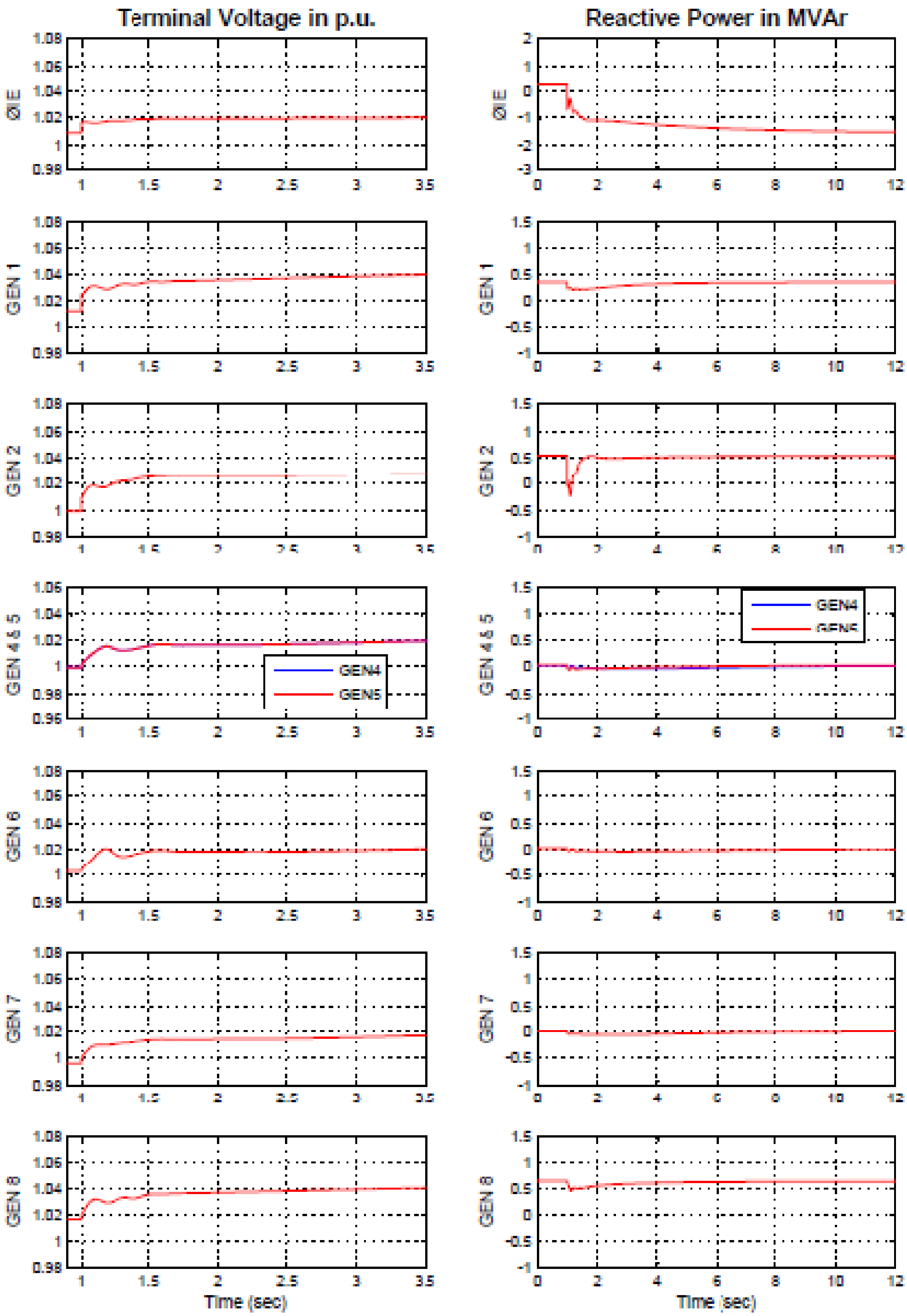

Figure A- 39: Disconnection of loads in Case D

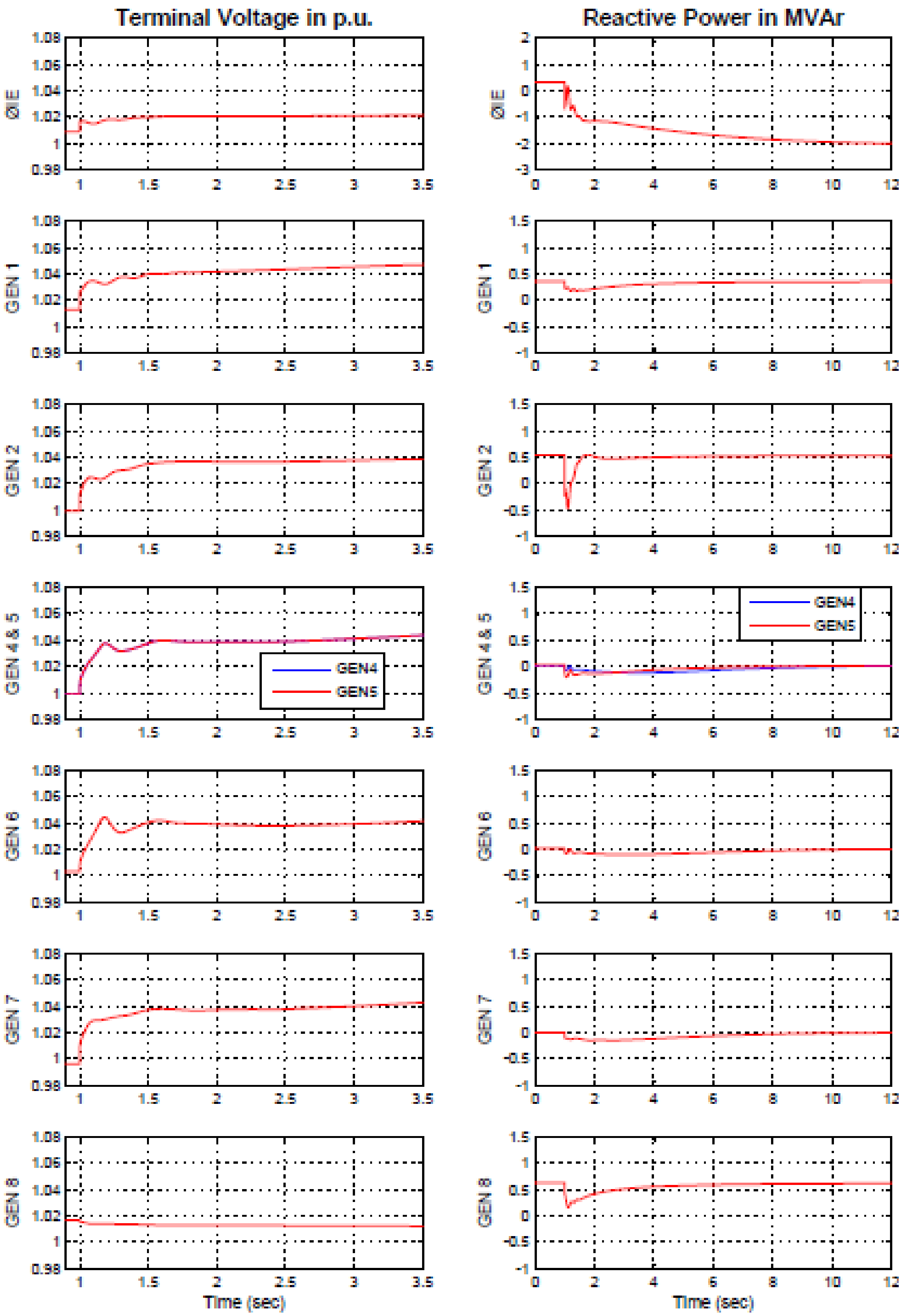

Figure A- 40: Step change in load from high load to low load in Case D

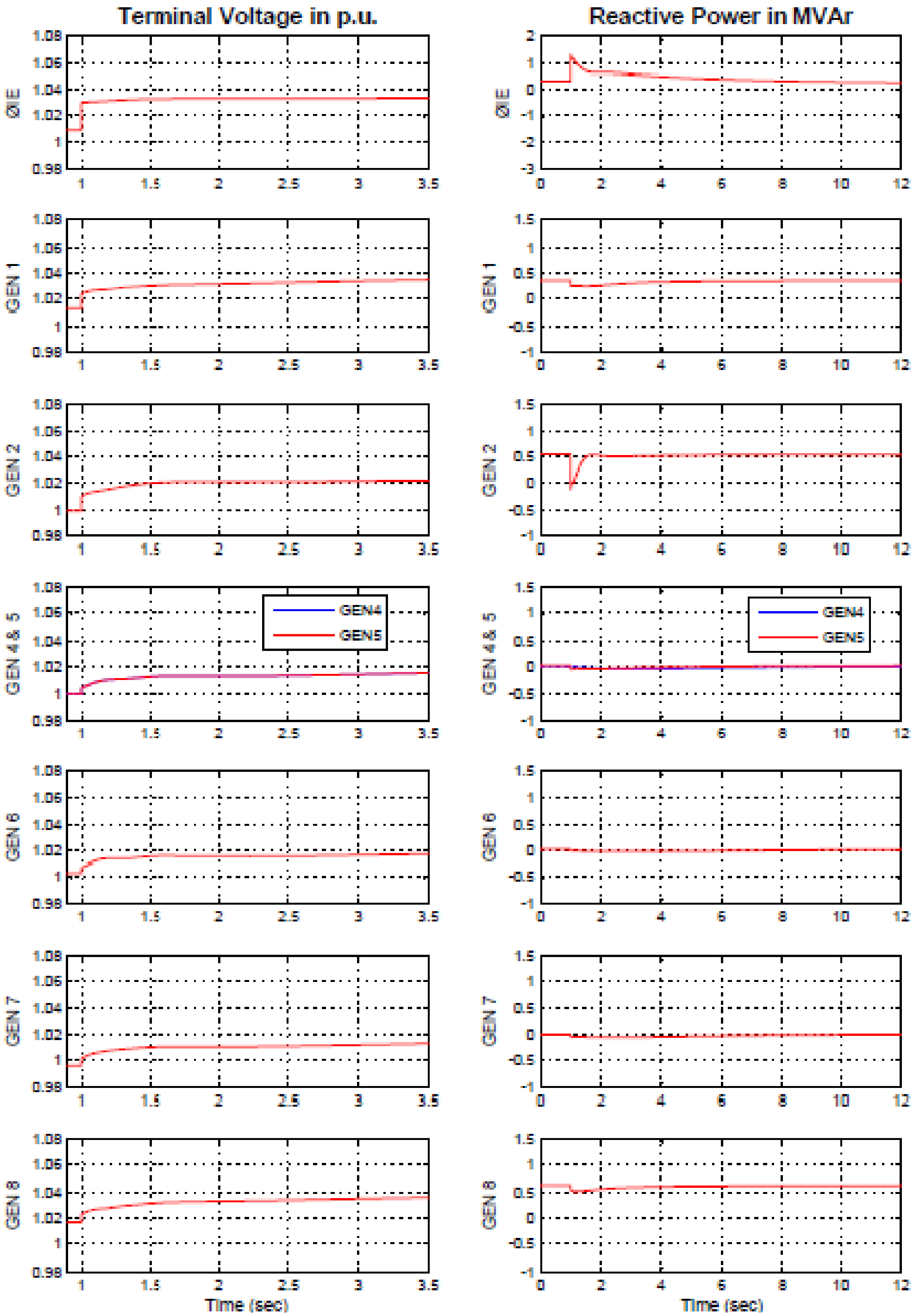

Figure A- 41: step test in system voltage in Case D