



A comparison of inertia estimation in power networks hosting significant renewable energy

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ABSTRACT

In an ever-changing world of power generation, the increased use of renewable generation can pose significant problems for power quality, particularly by affecting a system's sensitivity to frequency deviations. Mechanical inertia is inherently available in a system utilising mechanical generation, this added benefit ensures frequency stability. However, in a system with increased renewable penetration, the amount of mechanical inertia might be insufficient, and knowing how much inertia is available for stability should be investigated. While various methods exist in the literature to estimate inertia, how accurate these methods are for estimating inertia in a system with significant renewable penetration was investigated.

Evaluating available inertia enables power system operators to implement stability measures. These measures may include emulating inertia through static generation sources, utilising reserve capacity during contingencies, or deploying flywheels to provide additional mechanical inertia. In this study several inertia estimation methods from literature have been explored, including the swing equation with consecutive measurements, the swing equation applied to data windows, fifth-order polynomial fitting of frequency curves post-disturbance, electromechanical swing analysis using only active power measurements, and the R-V-RV method.

To compare these methods, synthetic data were generated through computer simulations using three IEEE standard test systems: the 2-Zone, 9-Bus, and 14-Bus systems (converted to 50 Hz nominal frequency). Four disturbance events were instigated on each system: generation loss, a 3-phase fault, load decrease, and load increase. The generated data allowed for a comparative analysis of different inertia estimation methods.

Findings from this work suggest that inertia estimation is highly sensitive to various variables, where improper data selection (hyperparameters) can lead to inaccuracies. Further findings suggest that no one method should be used for all cases, but rather, matching the system type and available event type data to its proposed method can deliver more accurate results. The estimated inertia constant at a given moment reflects the instability a system experienced at that moment. By plotting multiple estimation constants over a period throughout an event, a better picture is seen of the system's sensitivity to change in frequency during a sudden mismatch between generation and loading. From plotting the system stability of a real-life measured system over time, it became clear when exactly a sudden change in generation or loading was present and enabled estimation of the available inertia.

System events were analysed using this approach, enabling an evaluation of system stability under different generation mixes, specifically comparing scenarios with high PV penetration to those where a single synchronous generator supplied the load. The results indicate that stability varies across different measurement locations and is largely influenced by the type of generation electrically closest to the measurement point.

A relationship between higher PV penetration, relative to synchronous generation, and increased system instability was observed by plotting the estimated inertia over time under varying PV contribution levels.

A lack of available inertia in a system to its required inertia may cause frequency runaways. Tracking inertia in a system is useful for grid operators to know when to deploy additional measures for improving the frequency response. This study found that estimating inertia can be done with accuracy, by plotting the stability index of a system over time.

Keywords: Inertia, ROCOF, frequency, renewable generation, swing equation, frequency stability

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LIST OF ABBREVIATIONS AND ACRONYMS

PV – Photovoltaic
ROCOF – Rate of Change of Frequency
RES – Renewable energy source
FES – Flywheel energy storage
BES – Battery energy source
BESF – Battery energy storage facility
BESS – Battery energy storage system
VSG – Virtual synchronous generator
AC – Alternating Current
DC – Direct Current
NIPS – National Interconnected Power Systems
FFR – Fast frequency response
PFR – Primary frequency response
UFLS – Under frequency load shedding
RPP – Renewable power plan
TS – Transmission system
DS – Distribution system
SG – Synchronous generator
IPP – Independent power producer
SAPP – Southern African Power Pool
PoC – Point of Connection
PPA – Power purchase agreement
ERCOT - Electric Reliability Council of Texas
PMU – Phasor measurement device
NEM – National Electricity Market

LIST OF SYMBOLS

H	- Inertia constant.
J	- Moment of inertia of the generator's rotating mass.
ω	- Angular velocity of the rotating mass.
ω_n	- Nominal angular velocity
δ_0	-Rotor angle at steady state
S_{rated}	-Rated apparent power output of the generator.
$\Delta\omega_{g,i}$	-The deviation of rotor speed,
D_i	-The damping factor.
$H_{sg,i}$	-The inertia constant of generator i.
$\Delta P_{m,i} - \Delta P_{e,i}$	-The mismatch between mechanical and electrical power.
ΔP	- Change in Power
$\frac{d(\frac{\Delta f}{f_0})}{dt}$	-Rate of change of frequency
$\Delta P_m(t)$	- Change in mechanical power
$\Delta P_e(t)$	- Change in electrical power
df/dt	- Rate of frequency change
H_{sys}	-Total system inertia constant
H_{SE}	-Represents the average inertia constant of the power system
S_B	-Power rating of the generator
P_m	-Mechanical power
P_e	-Electrical power
f_0	-System's frequency
f_m	-Frequency of the mechanical generator
E_{kin}	-Kinetic energy
P_n	-Nominal electrical power
f_n	-Nominal frequency of the grid
$f_i(t^+)$	-Frequency sampled after the disturbance
$f_i(t^-)$	-Frequency sampled before the disturbance
f_d	-Electromechanical oscillation frequency in Hz
σ	-Attenuation factor
$h_1(f(t))$	-Frequency dynamics behaviour of the load

$h_z(V(t))$ -Voltage dynamics behaviour of the load
 ΔP_{dist} -Change in power noted during the disturbance.

CHAPTER 1 – INTRODUCTION

The reason why and how this research was done is presented in this chapter.

1.1 Why the estimation of power system inertia is important

Modern power systems have become increasingly penetrated by renewable energy. This can lead to a constraint in network dynamic stability as frequency all over the grid needs to be stabilised by different and independent sources of generation.

Electricity generated from renewable sources such as wind and photovoltaic (PV) connects to distribution networks making use of solid-state interfaces. Unlike conventional synchronous generators, these inverter-based resources do not inherently provide mechanical inertia. Instead, their response to frequency disturbances depends on their control strategy.

The extent to which inverter or a wind turbine, making use of a solid state technology, can emulate inertia is limited due to the need to produce as much active power as possible. Although solar PV and Wind turbine inverters can be set up to emulate inertia, the extent to which they can is limited, as the installed capacity is needed to produce as much active power as possible. It is possible to extend the period for emulating synthetic inertia by using battery storage.

Modern wind turbines and PV systems can contribute to frequency support through fast frequency response (FFR). Battery energy storage systems (BESS) can also provide rapid active power injection during frequency deviations and are increasingly deployed as a mitigation measure for reduced system inertia. Such technologies are already in operation in regions with high renewable penetration, including Australia. A more detailed discussion of inverter-based response mechanisms and evolving control technologies is presented in Chapter 2.

System inertia is necessary to contain frequency deviations resulting from sudden changes in loading and available generation. Accurately estimating available inertia is useful for power system operators when planning frequency control measures.

A synchronous generator with a large mass rotating at synchronous (or near-synchronous) speed stores inertia by the fundamental laws of physics such as described by Newton. A solid-state generator (i.e. grid-connected inverter) can at best, emulate inertia.

Grid-forming PV systems offer a solution to the reduced inertia associated with high penetration of inverter-based generation. Unlike conventional grid-following PV systems, which rely on an existing grid voltage and frequency reference, grid-forming inverters are capable of actively establishing and regulating system voltage and frequency.

Using control strategies such as virtual synchronous machine (VSM), grid-forming PV can emulate the behaviour of synchronous generators. This enables a fast active power response to disturbances, effectively providing synthetic inertia, reducing ROCOF, and improving system stability, particularly in low-inertia or islanded systems.

To estimate inertia in a power system where such non-rotating generation sources are embedded, requires an alternative approach to the traditional mathematical basis developed for a rotating

mass. This research dissertation critically evaluates known literature on the estimation of power system inertia.

A solution to estimate how much inertia is available from a power system hosting significant renewable generation is derived from the research results reported in this document. Extensive modelling is done from first principles, and this model is then verified by computer simulation of standardised network configurations such as the IEEE 9 and 14-bus systems.

Validation of the proposed solution concludes the research by making use of field data within a controlled experimental environment. A real-life micro-grid that hosts renewable and diesel generation made the latter possible.

1.1.1 New sources of generation cause a transformation in traditional power system concepts.

Synchronous generators dominated since the inception of power systems. Their rotational mass inherently contained abrupt changes in loading, a principle described by Newton's first law on how inertia resists sudden changes in motion.

Tesla won the war on currents, resulting in the use of AC power for distribution. AC power systems require a stable reference frequency. Inertia from physical sources of rotating masses inherently stabilises frequency fluctuations.

Each source of inertia contributes to the total system inertia, as contributed by the size of the machine [1].

Solid-state inverters as used by renewable energy generators lack mechanical rotating masses. Renewable sources can offer support during a frequency deviation, but an effective response to system-wide frequency deviations is a concern.

The South African grid serves as the reference for this research. The dominance of the coal-fired generation mix is increasingly being offset. Renewables, during 2023, are already accounting for approximately 16% of the national generation with solid-state sources being a significant portion [2]. Renewable penetration will only accelerate in the near future.

1.1.2 Principles of frequency control

Since the oil crisis of 1970, the integration of renewable energy has gained momentum. The infrastructure of a modern grid increasingly consists of static inverters converting renewable energy from DC sources to AC power.

1.2 How renewable energy can contribute to system inertia

The mismatch of demand and generation continuously fluctuates during the day. Grid frequency changes and dynamic system stability directly relates. For example, a frequency deviation exceeding 1.5 Hz (3% at 50 Hz) is already considered a significant risk to equipment and infrastructure, highlighting the sensitivity of frequency regulation [3].

Traditional mechanical generation sources by principle of operation to some extent automatically mitigate grid frequency deviations. Inverters at the power levels applicable here, are grid following, meaning if any frequency deviations take place, the inverters may not self-correct, but rather may inadvertently exacerbate frequency instability.

Replacing rotating generators with static inverters requires a new understanding of alternative mechanisms available for frequency stabilisation. Innovative solutions are needed to maintain grid stability in the face of this evolving energy landscape.

Power system operators have been implementing requirements for large renewable energy plants. On wind farms, a P_{delta} reserve 3% of the current production as some form of “spinning reserve” in the event of system frequency falling. Reduction of active power generation is needed when the frequency exceeds the upper threshold of 50.5 Hz, further discussed in section [3]

1.3 Estimating inertia in a grid with different types of generators

The inertia H of a mechanical generator can be estimated from the kinetic energy within its spinning mass as shown by (1-1) below [4].

$$H_i = \frac{J\omega^2}{2S_{\text{rated}}} \quad (1-1)$$

Where:

- H_i represents the inertia constant, measured in seconds (s).
- J is the moment of inertia of the generator's rotating mass, measured in kilogram square meters ($\text{kg} \cdot \text{m}^2$).
- ω Denotes the angular velocity of the rotating mass, measured in radians per second (rad/s).
- S_{rated} Signifies the rated apparent power output of the generator. Measured in volt-amperes (VA).

It is no longer possible to fully explain inertia using (1-1) when renewable energy generation contributes significantly. Fundamental to these new methodologies is the swing equation.

The swing equation describes power system dynamics by the balance between mechanical power and electrical power in a synchronous generator as shown in (1-2) below [5], [6].

$$2H_{sg,i} \frac{d\Delta\omega_{g,i}}{dt} = \Delta P_{m,i} - \Delta P_{e,i} - D_i \Delta\omega_{g,i} \quad (1-2)$$

With:

- $\Delta\omega_{g,i}$ The change in rotor speed,
- D_i The damping factor.
- $H_{sg,i}$ The inertia constant.
- $\Delta P_{m,i} - \Delta P_{e,i}$ The mismatch between mechanical and electrical power.

Equation (1-2) above describes the dynamic response of a generator's rotating mass to sudden changes in electrical power. When different types of generation exist, quantifying inertia requires an alternative methodology.

Initially, inertia serves as the primary response mechanism to restore stability following load-generation imbalances. How successful the resources of inertia are deployed, is evident in the frequency profile of a power system.

The estimation of the inertia available within a power system requires analysis of the frequency and power profile of a power system where events of significant mismatch between loading and generation occur.

1.4 Objectives of this research

Inertia as a commodity in power system management requires quantification. Mathematical solutions on how to calculate (estimate) the extent of inertia from field data exist. How well they perform in a distribution grid where generation is also obtained from static renewable generators, needs to be researched.

The best-performing solutions are identified from scientific and engineering literature, considering the requirements to apply them in real-life cases. It requires consideration of factors such as complexity, accuracy, and suitability when using real-life field data.

A selected number of methods are then tested by using computer simulation data from the IEEE 9- and 14-bus systems. From the results obtained, the best-performing method was tested using field data from a microgrid that hosts both rotating and renewable generation. This microgrid allowed a direct correlation of known system events to measured field data, supporting the reliability of conclusions obtained from the data analysis.

The best-performing method that allows online implementation, is then proposed as a practical solution to estimate the inertia constant of a real-life power system from measured data, in near real-time. A specific configuration within a power system relates to the inertia constant applicable and can change when the configuration is changed. This is why an online method will be useful to power system operators.

The above is a sequential approach to research methodology. It realises a systematic and rigorous analysis towards a robust understanding of the dynamics relating to inertia within power systems hosting renewable energy.

1.5 Scope of Study

This study focuses on the estimation of system inertia using both simulated and measured data. The analysis is performed on standard IEEE test systems (2-zone, 9-bus, and 14-bus systems), as well as a real mini-grid operating under islanded conditions. The scope is limited to larger, MW-scale systems, where the impact of generation sources on system inertia is more pronounced. Rooftop PV, typically connected at low-voltage level, is therefore not considered to have a significant contribution within the context of this study.

The modelling approach is limited to the initial system response following a disturbance, typically within the first few seconds, where inertia is the dominant factor. A classical synchronous machine model is used in DIGSILENT PowerFactory, and higher-order control dynamics such as governor and excitation systems are excluded.

Several inertia estimation methods are evaluated and compared across different disturbance events, including generation loss, load variation, and fault conditions. Measured field data is also used to assess system behaviour under varying levels of PV penetration.

The study does not aim to model controller behaviour in detail, but rather to isolate and evaluate the inertial response of the system. As such, the results should be interpreted within the context of inertia, evident in the frequency profile after a disturbance.

1.6 Structure of dissertation

The dissertation comprises of 8 chapters. First, an introduction to the research focus and goals was provided in Chapter 1. This is followed by theoretical principles on the dynamics of power system inertia.

A literature review of methodologies to estimate inertia then extensively explores various solutions. Specific methodologies for further evaluation and analysis are selected.

A computer simulation using DIgSILENT Powerfactory is then done in Chapter 4 by modelling reference IEEE 9- and 14-bus distribution networks hosting static and rotating generation. This allowed verification of the theoretical principles on which the methods identified by the literature study, are based. The estimation methods were implemented in MATLAB®.

Chapter 5 further analyses the results presented by the methodologies from chapter 4 in a statistical manner.

Chapter 6 further verifies the method of choice by modelling the micro-grid in DIgSILENT Powerfactory as a prediction of results when the preferred solution is applied to field data in Chapter 7.

Chapter 7 not only validates the performance of the methodology that estimates a real-life inertia constant, but it also demonstrates that this solution allows a near real-time implementation. By tracking the inertia constant, the value of accurate knowledge of system inertia can be exploited by power system operators.

Finally, the concluding chapter encapsulates the key findings of the study and suggests focus areas for future research endeavours.

1.7 Conclusion

The value of knowledge on, and the availability of inertia, in a power system hosting renewable generation sources, were motivated.

From the rationale of why the research reported in this dissertation was done, this chapter describes how the dissertation is structured and what the reader can expect from the research reported.

CHAPTER 2 - LITERATURE STUDY ON FREQUENCY CONTROL

Scientific literature on how frequency control in an AC power system relates to system inertia within a distribution network hosting significant renewable energy sources is analysed in this chapter.

2.1 Introduction

Lower levels of available inertia in an AC power system can constrain measures to contain frequency instability [7] [8], to the extent that overall system stability can become a concern. Research highlights the necessity for further investigation into how less system inertia affects frequency response. Potential mitigation strategies need to consider the limited contribution to system inertia from renewable energy sources.

A general definition for power system stability is found in [9]: “Power system stability is the ability of an electric power system to regain a state of operating equilibrium after being subjected to a physical disturbance, with most system variables bounded so that practically the entire system remains intact.”

The reliable quantification of system inertia remains an ongoing challenge for transmission and distribution system operators [10]. In traditional power systems, this information could be readily inferred from the inertia constants of various synchronous machines and related network topology parameters. As the number of static generation units increases, the complexity of knowing system inertia well enough, becomes more evident [11].

Static generators, due to their inherent non-linear principle of operation, emulate an AC waveform that does not have a clear causal relation between power production and system frequency [12]. The significance of an inertia constant diminishes if the response of a generating unit is not determined by the physical property of a rotating mass but is now controlled by power electronics and signal processing.

2.2 Frequency stability

Frequency stability can be described by how well the power system resists a change in frequency, following a mismatch between generation and demand. Maintaining the dynamic aspects of system stability requires the ability to control frequency. When frequency remains in a stable state, i.e. the ability of the system to remain at a steady frequency following a disturbance, then that power system where frequency is stable, can be considered a “stable power system”.

For the grid frequency to remain within acceptable limits, the balance between power supply and demand needs to be managed. The principles of controlling frequency can be derived from the concept presented in Figure 2-1 below.

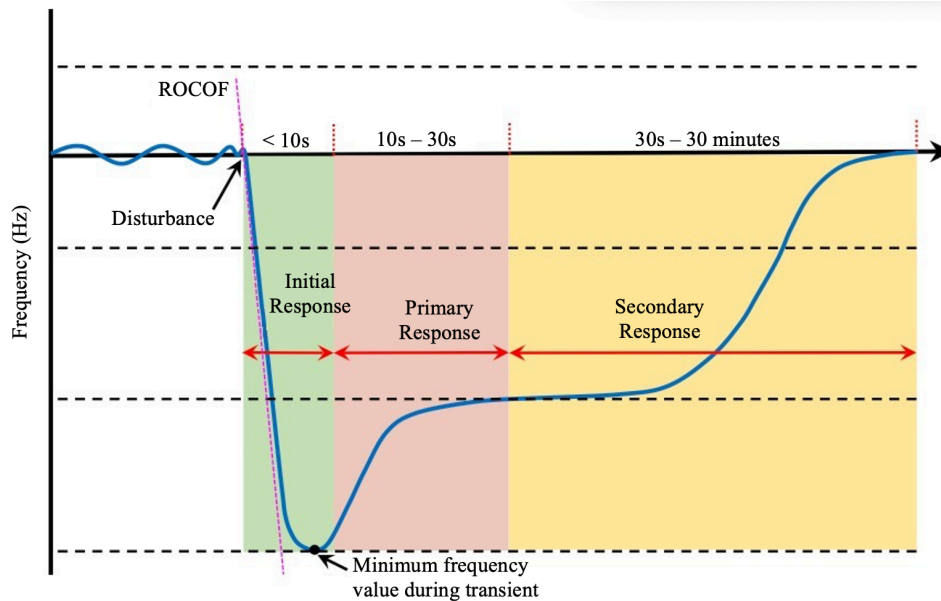


Figure 2-1: Frequency response with different timescales in a power system [13]

An important parameter that quantifies the variation in frequency, is the Rate of Change of Frequency (ROCOF), depicted by the blue line in Figure 2-1 above. When a mismatch between generation and loading takes place, three distinct response stages follow. Using the case of system demand that suddenly has increased to the extent that ROCOF initiated the system response, the operational concepts are explained below:

- An **initial** response is provided by the stored inertia, i.e. in the rotating mass of synchronous generators.
- A **primary** response is initiated by the system controller, which increases the mechanical power input to the prime mover, for example, by adjusting steam flow in a steam-driven synchronous generator or fuel flow in a fossil-fuelled generator. This action is regulated by the governor, which controls shaft speed in response to frequency deviations.
- A **secondary** response takes place when adding additional sources of generation, some as emergency measures such as gas turbines and pumped storage (hydro).

This study focuses on the **initial** system response following a disturbance, where the inherent inertia of synchronous generators plays a dominant role. The generator size, rotational speed, rotor mass, and electromagnetic coupling between the stator and rotor all influence the inertial response. This initial behaviour is illustrated in Figure 2-1.

Inertia would be most prevalent directly after a mismatch between generation and loading, inertia estimation should be analysed in the first 10 seconds after a change in generation or loading, during the initial phase.

Figure 2-1 visualised the traditional view of containing ROCOF where most of the generation is provided by generators with rotating mass. When replaced by static generators, the complexity of inverter frequency response when a high number of inverters are located all over the grid, and not under a centralised control, needs to be accounted for.

As the energy landscape evolves with increasing integration of non-rotating renewable energy sources such as wind and solar, frequency control is challenged by the lack of sufficient system inertia. Frequency control is now more complicated.

Firstly, without sufficient inertia, the grid's ability to absorb and dampen sudden changes in power in a stable manner becomes limited. The potential for more frequent and severe frequency excursions can lead to voltage and dynamic instability to the extent that system blackouts can occur.

Secondly, **primary** frequency response may become less effective in systems due to greater resulting change in frequency. The response when relying on a static generator, must be sufficient to prevent frequency deviations from escalating.

To address the above challenges, grid operators need to explore alternative frequency control strategies. Fast-acting resources such as battery energy storage systems (BESS) and advanced power electronics can supply and absorb large quantities of energy but normally only for a limited and relatively short period of time.

Such a solid-state secondary response mechanism has the advantage of being fast and can potentially be an effective mitigation solution to counteract frequency deviations. This will help to maintain grid stability in the absence of traditional mechanical sources of inertia.

Planning for the initial inertia response, considering renewable generation is important. Ensuring that inverters reserve a margin in generation to be available at all times, can have economic consequences. Less energy is being sold. Despite the latter, the literature indicates this to be highly effective in regulating system frequency [9], [14].

One advantage of using inverters in frequency control measures is their ability to provide fast frequency response due to smaller droop settings. This is attributed to the use of electronic components to realise fast response times, as opposed to mechanical systems [15].

Droop settings within a local context of grid-connected inverters allows the sharing of active power output between inverters, without the need for central control. System frequency support relies on active power whilst reactive power can be used for additional voltage support.

2.2.1 Additional factors impacting frequency stability

In addition to the control mechanisms discussed above, system frequency stability is affected by a range of physical and operational factors. These include, but are not limited to, the factors summarised in Table 2-1 [1]. These factors influence the magnitude of the frequency deviation following a disturbance, as well as the ability of the system to arrest and stabilise the frequency response.

The different mechanisms each has their own respective time period following a disturbance, for which frequency response is mitigated. Of importance to inertia studies, the response following the first 10 s after which a deviation in frequency has taken place, is investigated.

Next, the context and application of ROCOF are discussed.

Table 2-1: Factors affecting frequency control [3].

Factor	Impact On Grid Stability	Dominant Time Period
Generator inertia	Dampens frequency deviations	Initial (0–10 s)
Load inertia and damping	Additional damping of frequency deviations	Initial (0–10 s) (can extend into early primary)
Size of system	Inverse relation between system size and frequency sensitivity	Initial And Primary (0–30 s) (sets overall sensitivity throughout)
Under-frequency limits	Lower settings provide more response time for overall response	Primary ($\approx 10\text{--}30$ s) (protection/limits affect available response time)
Frequency response speed	Faster response time will result in a lower frequency deviation	Primary ($\approx 10\text{--}30$ s) (frequency arrest depends on response speed)

2.3 Rate of Change of Frequency (ROCOF)

AC power systems aim for a fixed fundamental system frequency, 50 Hz or 60 Hz. Changes do occur and technical standard such as [3] state changes within 3% of the reference frequency is should not result in disconnection. It does however matter how fast such a change occurs.

A ROCOF of 1.5 Hz/s falls within acceptable limits as defined in the grid code [3] and represents a realistic system response following a disturbance. The higher value of 2.5 Hz/s is included as an extreme case to illustrate the effect of a faster rate of frequency change.

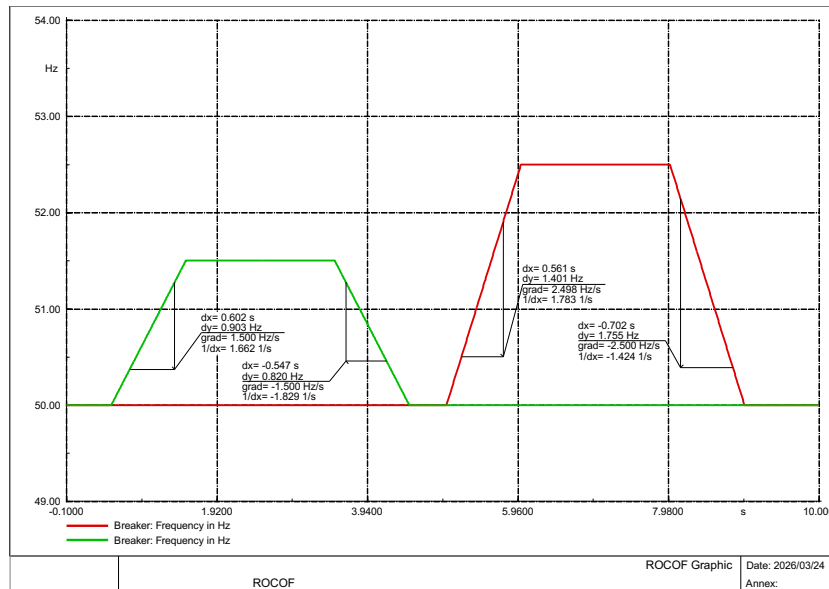


Figure 2-2: Illustration of frequency response showing ROCOF values of 1.5 Hz/s and 2.5 Hz/s

Rate of Change of Frequency (ROCOF) qualifies and quantifies the rate at which the grid frequency changes [16]. Smaller ROCOF values indicate a frequency-stable system and why ROCOF can be regarded as an indication of frequency stability.

ROCOF is pertinent during transient events such as abrupt changes in demand or generation. The ROCOF value reflects the rate by which the frequency changes.

An abrupt change in system frequency where the difference between the steady-state frequency value before and after the event is relatively small, can result in a large ROCOF value whilst a slow change to steady-state frequencies of a larger difference will result in a smaller ROCOF value. The larger ROCOF value, if unaddressed, may escalate into instability and potentially lead to cascading failures within the power system whilst the lower ROCOF value, albeit a larger difference in steady-state frequency, can be regarded as a “more” stable power system.

To track ROCOF in a real-world power system, disturbance events need to occur. ROCOF data is needed to estimate the available inertia as will be seen later in this dissertation. The occurrence of system contingencies can be regarded as “useful” to frequency control measures as it produces useful data.

2.4 Technical standards on frequency control

The frequency control requirements for the interconnected Southern African grid are first discussed as this serves as the context for the field data used in this dissertation. Secondly, related international standards on frequency control are presented.

2.4.1 Frequency control in Southern Africa – the role of renewable energy

Most of the power systems within Southern Africa are interconnected as shown in Figure 2-3 below. They contribute to a Southern African Power Pool (SAPP) that enables an energy trading opportunity that was operationalised by SAPP.

The SAPP energy exchange platform is in Harare and allows generators to sell energy to bidders at prices based on expected generation levels during day, week and month-ahead scenarios.

Most of the generation pool consist of coal, but different power generation units are connected to a grid as can be seen in Figure 2-4.

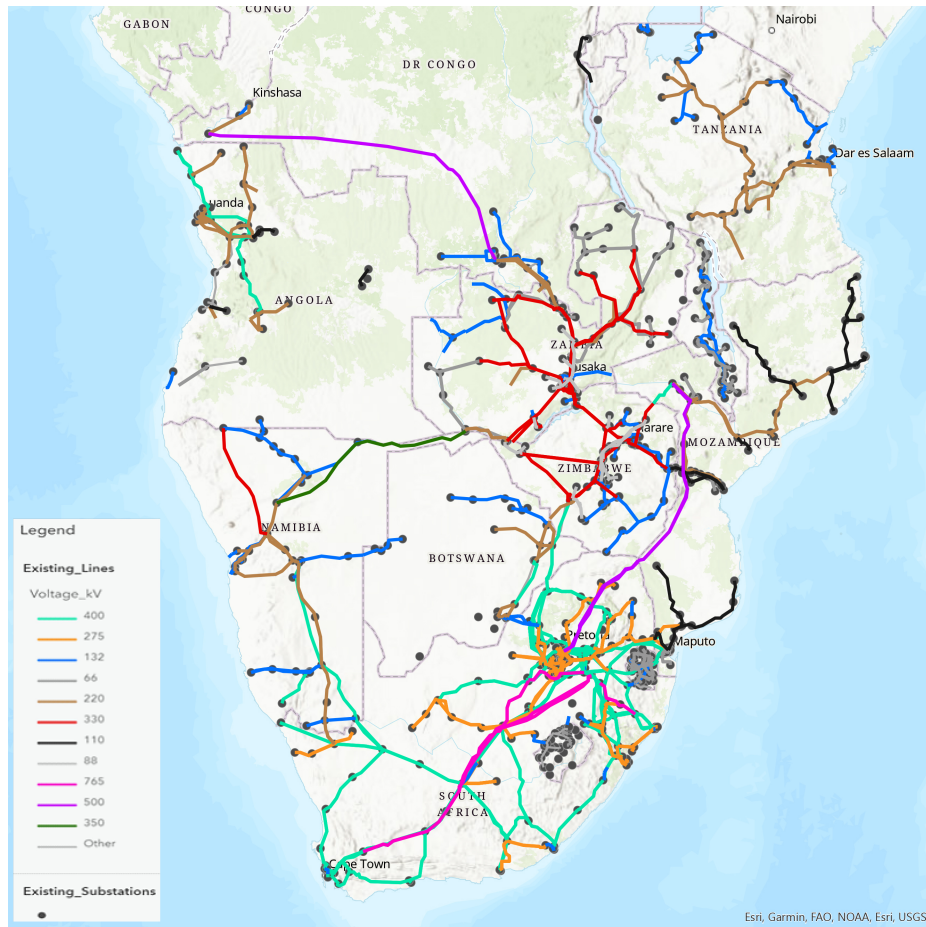


Figure 2-3: The interconnected Southern African grid

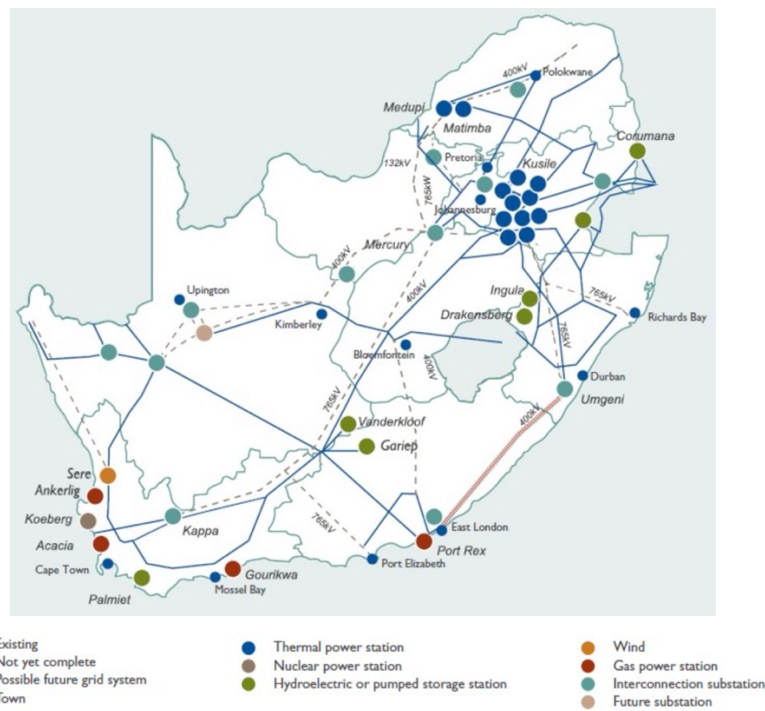


Figure 2-4: Distribution of generation types of generation in South Africa as of 2023

Below in Figure 2-5 a visual representation can be seen of non-renewables (colours in the orange scheme) vs renewables (colours in the green scheme) of generation connected to the Southern Africa grid. [17]

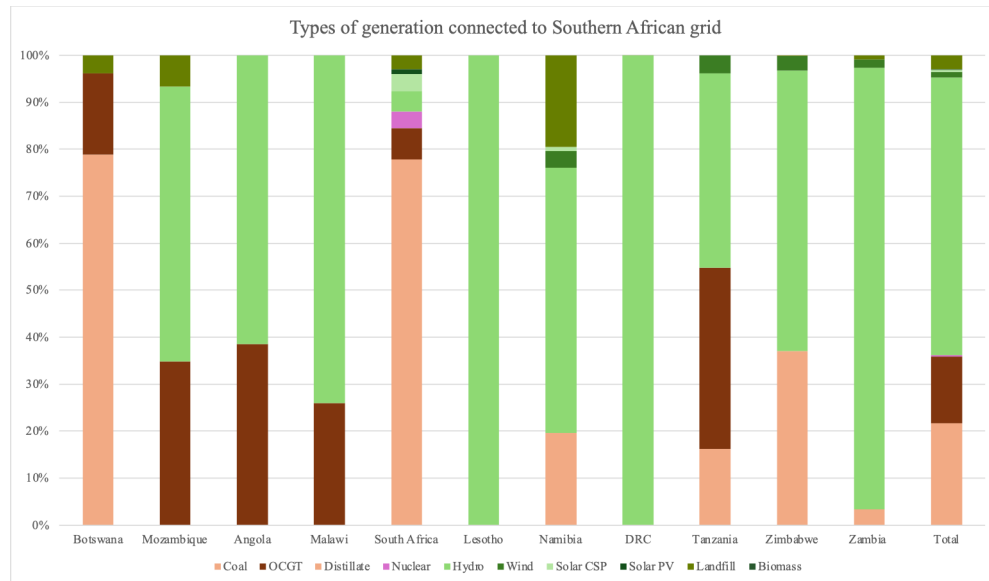


Figure 2-5: Generation units connected to the Southern African grid

An interconnected system needs to maintain a stable frequency and within the normal and unexpected technical reasons why a mismatch between generation and demand can occur, is to some extent further complicated by the economic factors when selling and buying electricity.

In response to the above, the allowable frequency deviation with the SAPP network is set as $\pm 2\%$ from the 50 Hz system frequency. The rate at which the frequency change should remain is ± 1.5 Hz/s.

The requirements on how a Renewable Power Producer (RPP) contribute to frequency and voltage support, are described by the SAGC [3]. A network incident that causes a deviation in frequency can relate to a variation in voltage. Ohms law dictates that voltage magnitude will be a consequence of a sudden change in loading (current).

Rules set for National Interconnected Power Systems (NIPS) on the allowable frequency deviation is specified to the system frequency of 50 Hz[3]

- “When the grid frequency is higher than 51.5Hz for longer than 4 seconds the RPP shall be disconnected from the grid “
- “When the frequency on the NIPS is less than 47.0 Hz for longer than 200ms, the RPP may be disconnected”
- “The RPP shall remain connected to the NIPS during ROCOF of values up to and including 1.5 Hz/s, provided the network frequency is still within the minimum operating range”

Compliance with the above aims at stability within the interconnected grid that hosts renewable energy sources. A RPP should be engineered to detect frequency deviations of ± 10 mHz. The bounds within which the system frequency needs to be kept are presented in Figure 2-6 below.

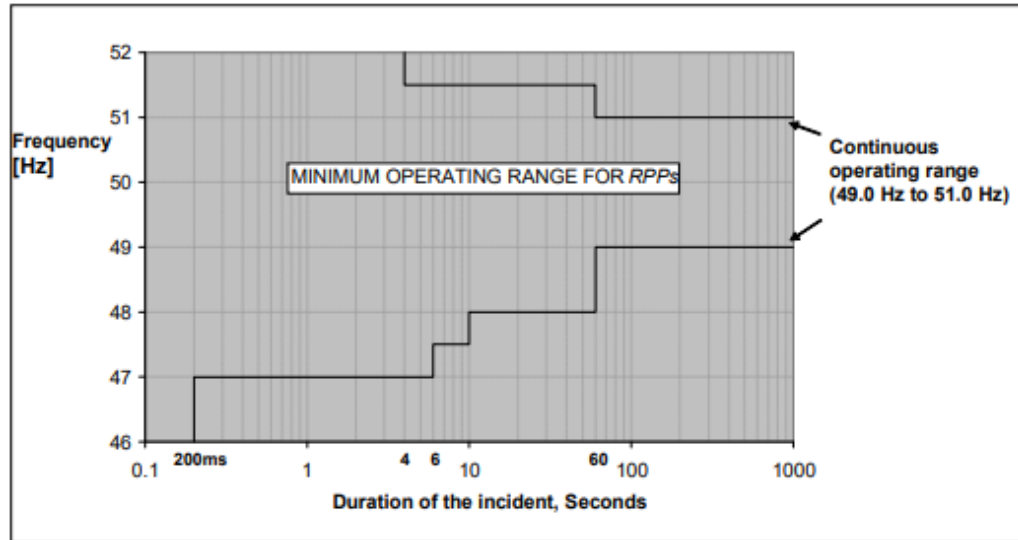


Figure 2-6: Requirements on frequency deviation [3]

Following a frequency disturbance that caused disconnection of an RPP in South Africa, they can reconnect to the national grid within 60 seconds. The requirements for reconnection are:

- The voltage at the POC is within -15% to 10% of the nominal voltage
- Frequency is within 49 Hz to 50.2 Hz.

For Category C renewable power plants (20 MVA or higher), additional measures are necessary to ensure grid stability.

Renewable power plants (RPPs), excluding photovoltaic (PV) installations, must be designed to maintain a minimum active power reserve equal to at least 3% of the available active power. This reserve, referred to as P_{Δ} represents the portion of active power that is intentionally withheld from the maximum available output to provide operating reserve for frequency stabilisation

Power frequency response

- Renewable power plants must be capable of responding to frequency deviations in order to support grid frequency stability.
- When the system frequency rises above 50.5 Hz, the RPP is required to reduce its active power output according to the frequency power characteristic shown in Figure 2-8.
- If the system frequency exceeds 51.5 Hz for a duration longer than 4 seconds, the plant must disconnect from the system to protect its equipment.

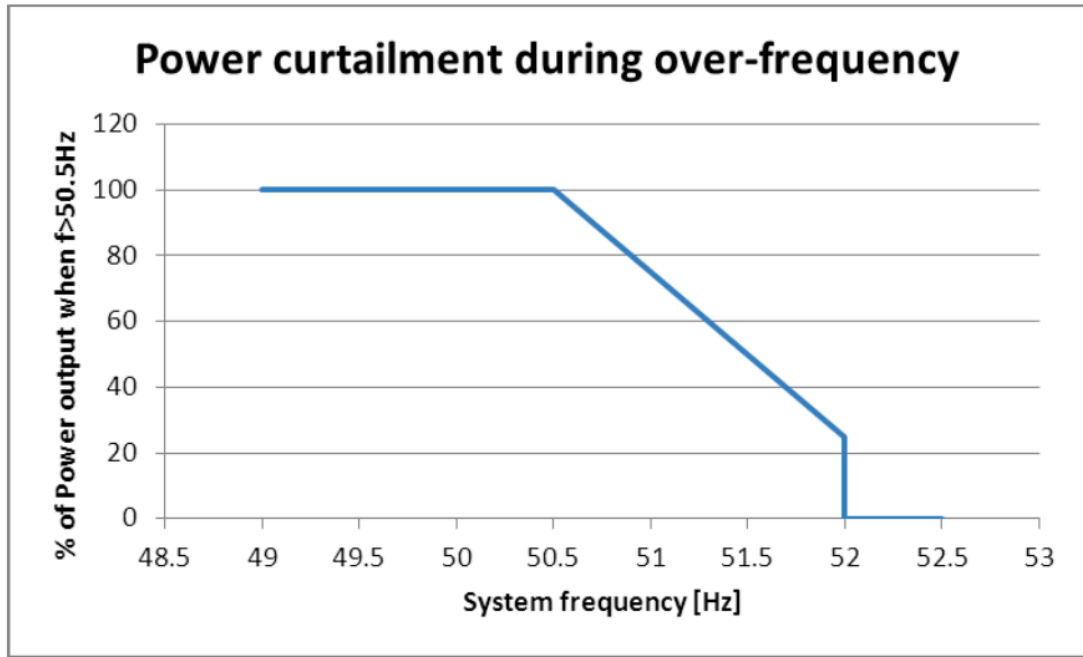


Figure 2-7: Power curtailment during frequency deviations (Figure 6 of the SAGC [3])

Besides the frequency curtailment requirement for a RPP, the BESF Grid Connection Code [18] specifies an additional response capability, shown in Figure 6, whereby the battery facility may be required to import power from the grid during high-frequency events.

For Category B BESF plants, this requirement applies only in the over-frequency range. When the system frequency exceeds $f_5 = 50.50$ Hz, the BESF must respond according to a 4% droop by reducing discharge active power. If the frequency continues to increase above $f_6 = 51.50$ Hz, the BESF shall transition into charging mode and absorb power from the grid, up to $f_{\max} = 52$ Hz unless protection disconnects the BESF.

For Category C BESF plants, response is required during both an under- and over frequency event. During low-frequency conditions, when the system frequency falls below $f_2 = 49.50$ Hz, the BESF must respond according to a 10% droop, by reducing demand if it is charging and transitioning to discharging mode in support of the grid frequency.

If the frequency decreases further below $f_1 = 47.50$ Hz, the plant shall remain connected at least until $f_{\min} = 47$ Hz, unless disconnected by protection. During high-frequency conditions, the Category C BESF responds in the same manner as Category B, with required response above $f_5 = 50.50$ Hz and transition to charging above $f_6 = 51.50$ Hz.

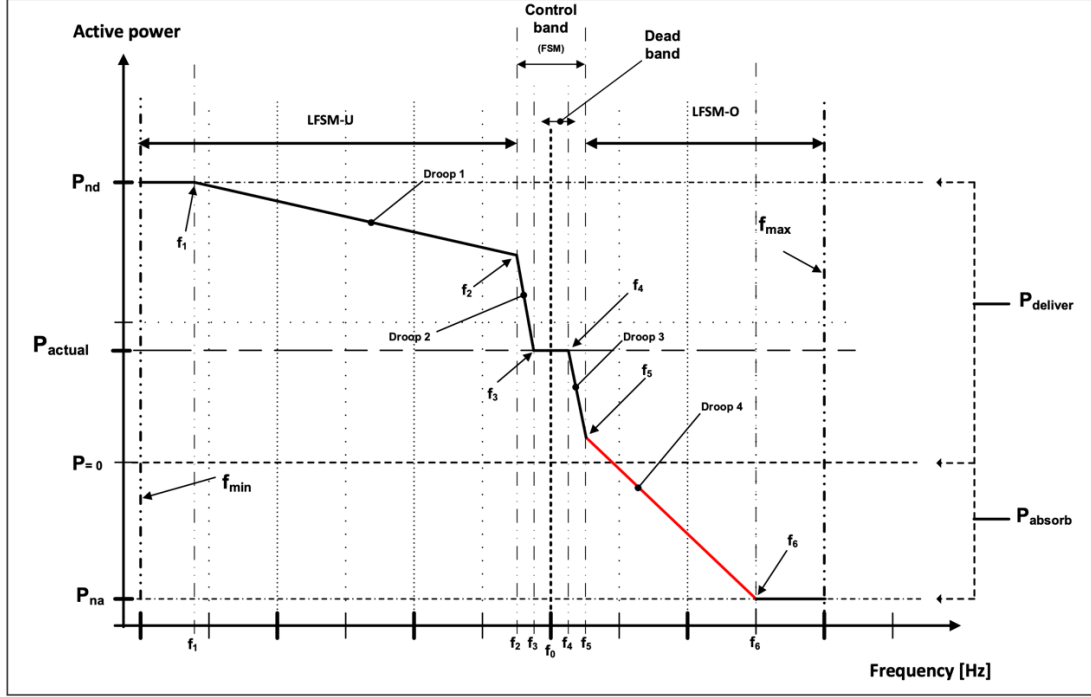


Figure 2-8: Power curtailment during frequency deviations (Figure 6 of the SAGC [18])

2.5 Theoretical principle of inertia in rotating generators

Inertia (J) contributes to kinetic energy (E_{kin}) in a rotating generator by the relation in (2-1) below [4].

$$E_{kin} = \frac{1}{2} J (2\pi f_m)^2 \quad (2-1)$$

Where:

- E_{kin} is kinetic energy in Joules
- J is the moment of inertia of the generator's rotating mass, measured in kilogram square meters ($\text{kg} \cdot \text{m}^2$).
- f_m is the frequency of the mechanical generator in Hz

Equation (2-1) can be rewritten as (2-2) below: [4]

$$E_{kin} = \frac{1}{2} J (\omega_m)^2 \quad (2-2)$$

Where $\omega_m = 2\pi f_m$.

Equation (2-2) relates kinetic energy E_{kin} to the inertia constant (H_i) resulting from a rotating mass within a generator with rated apparent power S_{rated} as shown in (2-3) below [4].

$$H_i = \frac{J\omega^2}{2S_{rated}} \quad (2-3)$$

where:

- H_i represents the inertia constant, measured in seconds (s).
- J is the moment of inertia of the generator's rotating mass, measured in kilogram square meters (kg·m²).
- ω denotes the angular velocity of the rotating mass, measured in radians per second (rad/s).
- S_{rated} signifies the rated apparent power output of the generator measured in volt-amperes (VA).

The traditional sources of generation units supplied inertia with typical inertia constant as listed below in Table 2-2 [13].

The sophistication and advances in power electronics as used in static interfaces between sources of renewable energy and the AC grid, can be used to emulate inertia. From the principle of operation, they do not have rotating masses, but by solutions such as flywheels or synchronous condensers, a predictable amount of inertia can be made available.

In some grids such as the National Electricity Market (or the NEM) located in Australia batteries can be used to support frequency events [19].

Real life examples include the Hornsdale Power Reserve supplied by Elon Musk's Tesla, a groundbreaking battery storage project in South Australia. Initially launched in 2017 with a 100 MW/129 MWh capacity, it was expanded in 2020 to 150 MW/194 MWh. This facility has significantly enhanced grid stability and reduced energy costs by providing rapid frequency control services and synthetic inertia. The project highlights the potential of renewable energy in grid stabilisation [20].

Table 2-2 Inertia constants of different types of power plants [13].

<i>Generation type</i>	<i>Inertia constant (s)</i>
<i>Hydro</i>	1.75 – 4.75
<i>Nuclear</i>	4
<i>Thermal</i>	2 - 10

The swing equation states the relation between inertia obtained from the mechanical properties of a synchronous generator and the generated electrical power output. Once a disturbance occurs, the rotor speed does not change instantaneously due to the inertia within the rotor. By “resisting” the imbalance between generation and load, it helps to maintain system stability for a period as determined by the mass of the rotor.

The above phenomenon is mathematically described as the swing equation in (2-4) [5], [6] below.

$$2H_{sg,i} \frac{d\Delta\omega_{g,i}}{dt} = \Delta P_{m,i} - \Delta P_{e,i} - D_i \Delta\omega_{g,i} \quad (2-4)$$

With:

- $\Delta\omega_{g,i}$ the deviation of rotor speed,
- D_i the damping factor,
- $H_{sg,i}$ the inertia constant,
- $\Delta P_{m,i} - \Delta P_{e,i}$ the mismatch between mechanical and electrical power.

Static sources that emulate inertia do that by a nonlinear principle of operation. They need to be understood and employed as the future distribution grid will increasingly rely on their contribution in supporting frequency.

Unlike “natural” kinetic energy from rotating masses, “synthetic/emulated” inertia could rely on the ability of a control system to correctly detect a fault and only then deploy the “emulated” inertia. Harmonic currents and voltages can be an unforeseen and additional consequence due to the operation of the inverters, even at switching frequencies [21].

A list of potential additional resources to initial frequency response systems are listed below in Table 2-3 below [22].

Table 2-3 Examples of frequency response systems [22].

Technology	Power Range (MW)	Power Ratings (MWh)	Response Time	Discharge Time
<i>Flywheel (Converter)</i>	0.1~400	Up to 5	<= 4 ms	Up to 15 min
<i>Lithium Batteries</i>	Up to 50 or more	Up to 20	Few to 40 ms	Minutes to hours
<i>Flow-Batteries</i>	~3, 50 possible	Up to 60	Few to 40 ms	Seconds to hours
<i>Advanced Lead-Acid Batteries</i>	Up to 40	Up to 40	Few to 40 ms	Seconds to hours
<i>Super-Capacitors High Voltage</i>	Up to 50	Up to 28	10 – 20 ms	Milliseconds to hours

Flywheel energy storage can make use of a rotor at a very high speed. Kinetic energy withdrawn will lower the speed but the static interface to the grid can determine the frequency of the energy that needs to be injected or absorbed from the grid. Significant centrifugal forces could be a design challenge at very high speed [6].

In Germany, the requirement to retain 10% of the generated power output in a synchronous generator seems to be an attractive alternative solution to provide frequency support from

renewable power plants. The synchronous generator runs synchronised to the grid [21] and it is possible to further adjust its inertia constant by adding an additional flywheel. It can inject and absorb energy.

When comparing battery energy storage system (BESS) solution for frequency support, to Flywheel energy storage (FES) solutions. The following has been found: A Li-Ion BESS can offer up to 5000 full-depth discharge cycles compared to FES solutions where 200,000 full depth discharge cycles are possible [23].

Batteries can be effective to mitigate the intermittent availability of photovoltaic (PV) or wind generation. They can at the same time serve the frequency support needed for grid frequency stability [22].

Battery storage has been implemented in the industry: A hybrid project combining 540 MW of solar power and a 225 MW/1,140 MWh battery storage system has begun operations in Kenhardt, Northern Cape South Africa. Covering 879 hectares and stretching 10 km from north to south, the construction started in July 2022, incorporating nearly one million PV modules. The generated power will be sold to Eskom, South Africa's state-owned utility, through a 20-year power purchase agreement (PPA) [24].

Super-capacitors could potentially outlast all similar storage solutions and seems to have the potential to support implementation as large-scale virtual synchronous generators (VSG's) [25]. Inverters can charge and discharge the super-capacitors in a controlled manner to mitigate frequency events, but at the same time, support voltage control measures.

2.5.1.1 Real-life solutions to frequency control in networks with significant diverse sources of generation

A notable attempt to address the lack of "natural" inertia in a distribution grid is by the ERCOT grid in Texas USA.

ERCOT employed a series of responses to low levels of inertia. ERCOT make use of under-frequency load-shedding as first response to frequency events. Consumer loading is regarded as a resource to frequency response. Under-frequency detectors can disconnect certain industries once a lower frequency threshold is detected [1].

Fast frequency response (FFR) is an ability of solid-state inverters to change energy output very fast. Potential resources for FFR includes [1]:

- Adjusting loading

Controlled reduction of loading has been used by ERCOT for more than a decade [1]. Using FFR in combination with mechanical relays, up to 100% of targeted loads can be dropped in less than half a second. It is also much less costly to drop non-critical loads occasionally rather than providing primary frequency response from conventional generators.

The application of frequency response measures at loads, has enabled ERCOT to increase renewable energy penetration in their grid up to 58%.

- Extracting wind kinetic energy

Wind turbines (nowadays) inject energy making use of a solid-state interface to the grid. But rotating blades stores some kinetic energy and holds promise as a potential means of injecting real power into a renewable grid when necessary. This response typically occurs within the first few seconds after a disturbance and can contribute to reducing ROCOF.

When kinetic energy is depleted, other mechanisms can provide frequency response. Wind turbines need time to regain speed, during which those other energy sources must fill the gap.

- Dispatch of inverter-based sources and incentives to primary frequency response

Levels of power production at inverter-based sources of generations can be required to be at less than the maximum instantaneous level available at any moment. When needed, the additional potential can be released nearly immediately.

Plant owners receive incentives to uphold or improve response rates within their own power plants.

Typically, fast frequency response parameters with acceptable droop settings fall within the range of 3-5%, with a deadband not exceeding ± 36 mHz. These parameters are widely adopted as acceptable standards [22].

Summarising the solutions used in the ERCOT grid, by grid operators to address the effects of declining Inertia available for frequency response [1] are listed in Table 2-4 below.

Table 2-4: Solutions employed by ERCOT, Texas, USA.

<i>Maintaining inertia</i>	<i>Synchronous condensers</i>
<i>Providing more response time</i>	Synchronous generators at renewable energy plants
	Reduce loading by under frequency load shedding UFLS
<i>Faster Frequency response</i>	Extracting kinetic energy from wind
	Incentivise inverter-based resources

2.6 Unpredictable active power generation at a PV plant and frequency control

Frequency control measures from a national point of view require a predictable balance between the available sources of generation and loading. Field data of generation over a period of 2 days at a PV farm is presented in Figure 2-9 below.

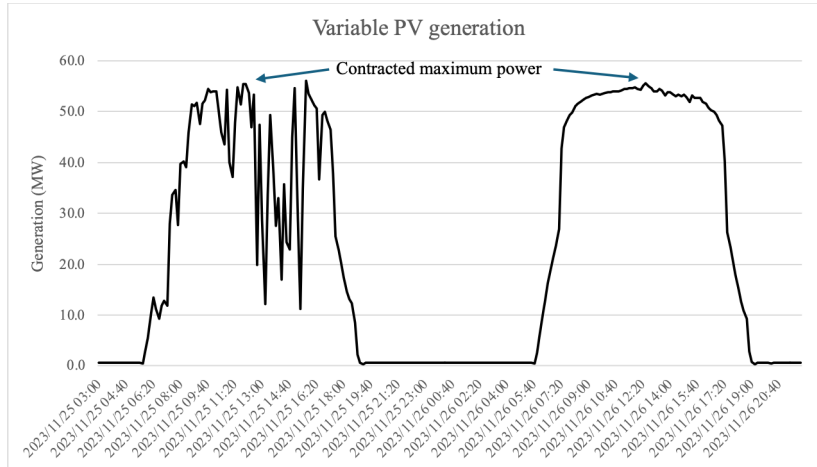


Figure 2-9: A real-world example on PV production variability

From Figure 2-9 the variability in generation between two consecutive days is significantly different. Frequency instability can result due to a sudden mismatch between loading and generation. Field data of PV generation was recorded over two consecutive days in accordance with IEC 61000-4-30, using 10-minute active power measurements.

Generation in Figure 2-9 changes by up to 80% within seconds. The instantaneous change in generation could challenge the traditional frequency response mechanisms in a power system. It is not always the consequence of i.e. cloud cover, but on a normal sunny day, sudden changes in solar irradiation occurs. The root-cause is unknown, but it seems from unverified literature that tropospheric conditions can contribute.

The speed of wind across the blades of a wind turbine can change significantly (“gusts”) causing a variation in torque on the shaft, resulting in a modulation of the power output. Similar to a PV farm, the wind farm will aim to inject as much power as possible all the time, but the level of the power output relies on the availability of the primary energy source.

Figure 2-10 shows how the production at a wind farm can significantly change during a short period. [26]

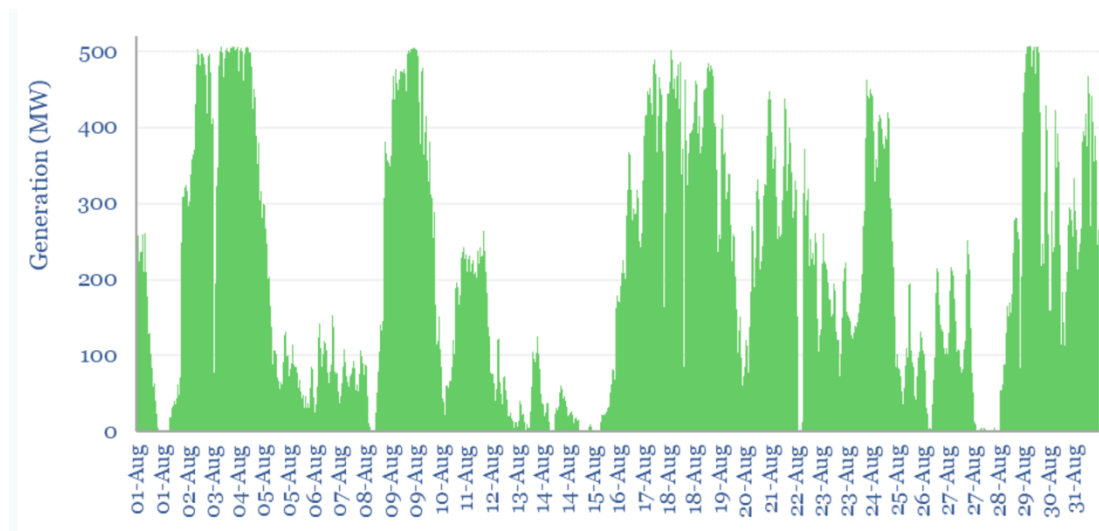


Figure 2-10: Daily output variation of a Wind farm [26]

A RPP will normally not participate in energy dispatch strategies and will generate as much power as possible. Nationally, the grid operator needs reliable prediction data on energy availability and if a significant source of generation is as unpredictable as noted in Figure 2-9, frequency control measures can be compromised.

The importance of having frequency within a predictable range of variation was researched by the impact that a changing frequency has on domestic loads. Chinyemba [27] estimated the effects of varying frequency beyond the grid specifications of 49 Hz and 51 Hz.

A range of domestic loads were tested at different frequencies (45-55 Hz) and voltages (220-240 V) to validate the immunity against frequency and voltage instability. The real part of domestic loading has a linear relation to power consumption. Non-linear interfaces used in energy-efficiency measures i.e. speed control of compressors in refrigeration equipment, the energy consumption does not change when frequency or voltage change. Direct-online compressors withdraw more current when voltage is decreased to maintain a constant power output.

The majority of low-voltage end-user equipment was not affected by a variation of $\pm 10\%$ in frequency, whilst direct-online motors used in appliances were unaffected within $\pm 6\%$ of the nominal frequency.

2.7 The quantification of inertia

The measurement of inertia in an AC power system is not done directly similar to the measurement of a single physical quantity such as voltage. It is estimated but needs to be done with sufficient certainty as the result directly affect how effective frequency control measures will be.

Different methods have been proposed such as mathematical modelling, data-driven analysis and empirical observations [13] [4] [28]. The parameter of interest to the power system operator, is the “inertia constant”. It quantifies how much inertia is “available” and by knowing a “number”, the frequency control measures can be planned. Chapter 3 analyse the different solutions to estimate the inertia constant.

The resistance to frequency change during load-generation mismatches is observable by the ROCOF profile. By measuring the change in frequency (ROCOF) with a sufficient resolution, the inertia constant can be calculated using the swing equation presented by equation (2-5) below.

$$H = \frac{E_k \times 10^6}{S_B} = \frac{\text{Joules}}{\text{Watt}} = \frac{\text{Joules}}{\frac{\text{Joules}}{s}} = s \quad (2-5)$$

The inertia constant (H) of a specific rotating generator is derived from the kinetic energy (E_k in Joules) resulting from the rotating mass (determined by speed and weight) as a ratio to the rated power (S_B apparent power rating in VA) of the generation unit.

Inertia constant (H) has a unit of seconds (s). It signifies a duration of seconds before the generator begins to lose inertia. The higher the rotating mass of the generator, the higher the inertia.

2.8 Summary

The assessment of frequency can be used to track grid stability. In the Southern African grid that interconnects power systems all over the Southern Africa Power Pool (SAPP), the aim is to maintain a frequency at 50 Hz. Deviations below 49 Hz and above 51 Hz can necessitate load shedding as a control measure to regain an acceptable balance between generation and demand.

Grid operators track frequency variations by the rate of change in frequency (ROCOF). A ROCOF exceeding 1.5 Hz/s is generally regarded as an event with the potential to impact frequency stability [3]. Analysis of ROCOF allows the estimating of how much inertia is available.

Due to the large-scale integration of renewable sources of generation, less mechanical inertia is available. A necessity arises on researching inertia estimation methodologies, and how the availability of inertia can be measured or estimated. Different approaches exist and the extent to which they can perform well when a significant contribution to the overall generation is by static generators, are next evaluated.

CHAPTER 3 - LITERATURE REVIEW OF INERTIA ESTIMATION METHODOLOGIES

This chapter analyses methodologies that can be used to estimate inertia in power systems. The goal is to better understand their principles to identify the best solution when comparing their relative performance by computer simulation and field data.

3.1 Introduction

Various methodologies have been proposed in literature to estimate inertia and to identify significant changes in the available inertia. These methodologies aim at a better understanding of the dynamic behaviour of power systems, particularly in the context of grid stability as relating to the variation in available inertia and therefore, the ability of a system to resist change in frequency.

By the tracking of frequency stability, information on system inertia can be derived and used to assess system dynamic stability. Power quality instrumentation is well-suited to produce the field data required. Frequency is a standard PQ parameter when measurements are obtained by the application of IEC 61000-4-30 [29] measuring standard.

A system disturbance allows comparison of a new system state to the prior steady-state condition. Measured data, acquired during a system contingency such as when a significant change in generation occurs, allows estimating the inertia constant of the power system by using the swing equation (3-1) below [28].

$$2H \frac{df(t)}{dt} = \Delta P_m(t) - \Delta P_e(t) = \Delta P(t) \quad (3-1)$$

Where:

- H : Synchronous generator inertia constant, in seconds (s).
- f : frequency at synchronous generator terminals, in Hz.
- $\Delta P_m(t)$: Change in mechanical power, W
- $\Delta P_e(t)$: Change in electrical power, W

An electrical power transient event is of a much shorter duration compared to the corresponding event in the mechanical system. The latter will have a much longer duration, resulting from the availability of mechanical inertia.

Mechanical power can be assumed to not change significantly during the relatively short duration of an electrical power transient, resulting in the assumption that $\Delta P_m(t) \approx 0$.

Methods to estimate inertia using the swing equation in (3-1), are different due to the way change in frequency is interpreted. Rate of change of frequency (ROCOF) can be directly calculated from how fast frequency changes, whereafter the system inertia can be derived.

Calculating the inertia constant H from $(H_i = \frac{J\omega^2}{2S_{rated}})$ ¹ relies on the mechanical properties of a rotating mass and does not account for non-rotating sources of generation. This research specifically deals with distribution power systems hosting solar photovoltaic (PV) and recent wind generators that make use of static non-rotating interfaces between the energy source (irradiation, wind) and the distribution grid.

A wind generator does have some rotating mechanical mass, but the contribution to system inertia is affected by first the solid-state conversion to DC, and then by an inverter to a regulated AC voltage waveform. Generation in recent power systems, increasingly relies on a hybrid generation mix.

Estimating inertia in modern distribution systems requires an indirect approach, as the swing equation does not account for the impact of non-rotating sources on available inertia or its role in system stability.

The fundamental principle of estimating inertia still applies in an AC power system. Analysis of the frequency profile can reflect how the “new” renewable power system can contain a sudden frequency change.

A renewable distribution system, by principle of operation, is prone to a sudden mismatch between generation and loading, as shown in Figure 2-9 and Figure 2-10 earlier.

Requirements, and methods to estimate inertia in renewable distribution systems, are next considered.

3.2 Comparison of different methods to estimate inertia

Different methods require different levels of data availability. Simplicity and complexity are normally orthogonal concepts in assessing power system stability.

In renewable distribution systems, system stability is not influenced by inertia alone, but also by the availability of fast support from sources such as battery energy storage systems (BESS), spare generation capacity, or other reserve mechanisms. However, inertia remains an important parameter, as it governs the initial system response immediately following a disturbance and gives an indication of how rapidly frequency may change.

User requirements of a solution to estimate inertia in a renewable distribution system will typically be the following:

- To be implemented in a distribution system hosting significant renewable energy.
- Easy to implement on real-world field data with limited knowledge of system configuration.
- To be implemented on any size distribution power system.
- Use measurements taken anywhere in the distribution system.
- Minimal data processing.

¹ Discussed in equation (2-3)

The following methods were considered when taking the above requirements into account [13], [4] and [28]:

1. Swing equation using consecutive measurement values.
2. Data windows
3. 5th order polynomial
4. Electromechanical Oscillations
5. R, V, RV method

A discussion of each of the above methods is presented next.

3.3 Method 1: Swing equation using consecutive measurements [30].

According to [30], equation (3-2) only applies directly after a system disturbance. Other factors such as controls and load response will affect the dynamic response of the power system after time $t = 10$ s, resulting in the estimation of inertia no longer quantifying the inherent availability of inertia.

This study [30] lists the following factors affecting inertia estimation:

- Precise data on the size of load loss
- Online plant inertias (for estimation of residual contribution)
- Identification of event start time ($t = t_0$)
- Accuracy of frequency measurement
- Method of ROCOF calculation
- Location of measurement point relative to in-feed loss

For an identical event, a measurement taken from a weakly interconnected area with low inertia will result in a significantly higher ROCOF, resulting in a lower estimated inertia, compared to a measurement taken in an area with higher inertia. This study also notes an improvement in inertia estimation accuracy when a greater number of measurement points in the system are used. An improvement in estimation error of between 0.5% and 3.5% is observed when using 7 PMUs compared to only 3 PMUs. A general accuracy of below 25% is reported for this method of inertia estimation.

The rate of change in frequency, and power, can be determined using two consecutive measurements taken just before the disturbance (t^-) was detected and just after the disturbance (t^+) has taken place. Consecutive measurements of frequency cannot be realised at a resolution better than 20 ms in a 50 Hz system [31].

From equation (3-1):

$$H = \frac{\frac{\Delta P_e}{P_n}}{\frac{2}{fn} \frac{df_i}{dt}} \quad (3-2)$$

Where:

- ΔP_e : Change in electrical power in W.
- P_n : nominal electrical power in W.
- f_n : nominal grid frequency in Hz.

The instantaneous ROCOF can be estimated from two consecutive measured values of frequency as shown below in (3-3).

$$\frac{df_i}{dt} = \frac{f_i(t^+) - f_i(t^-)}{t_i^+ - t_i^-} \quad (3-3)$$

Frequency $f_i(t^+)$ is the frequency directly after the disturbance and $f_i(t^-)$ the frequency sampled directly before the disturbance.

Using results from (3-3), equation (3-2) can be applied as all values are now known. The measurement uncertainty in the derived value for H can be affected when consecutive measurements of power and frequency are taken at a sampling rate of less than 50 Hz [30].

3.3.1 System inertia

Different generators that are connected to a network of interest, collectively contribute to the overall system inertia:

$$H_{SE} = \sum_{i=1}^N o_i H_i \quad (3-4)$$

Where o_i is a binary variable, being 1 if the generator is connected and 0 if the generator is not connected [30].

3.4 Method 2: Using data windows to estimate inertia [32], [33].

Using the swing equation and averages from a data window during a transient event, inertia can be estimated when using equation (3-5) below.

$$H = \frac{P_e(t_0^+) - P_e(t_0^-)}{2 \left[\left(\frac{df(t_0^+)}{dt} \right) - \left(\frac{df(t_0^-)}{dt} \right) \right]} \quad (3-5)$$

Time t_0^- is the time instance when the system was still in a steady state and t_0^+ indicate after the start of the transient event of interest. The inertia constant H at $t = t_0$ is derived from (3-5) [32].

Field measurements of active power and frequency are readily available. ROCOF and the change in active power can be derived to apply the above principle.

Data windows must be chosen according to the sampling rate, as varying the data window size and sampling rate greatly impacts the accuracy of the estimation method.

A feasibility study on quantifying system stability as related to inertia was done by [32]. This was realised by the assessment of inertia (H) over time. Using data windows and consecutive calculation of H when disturbances occur, are used to track the change in H . This allows an estimation of how system stability is affected by the availability of inertia.

As an example, Figure 3-1 presents the change in inertia over time when method 2 was discussed in [33]. The significant variation in inertia can be interpreted as the result of insufficient stability in this system.

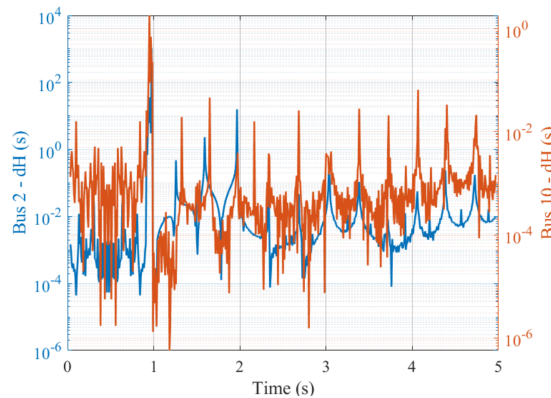


Figure 3-1 Inertia variation dH vs time, Method 2 [32]

Figure 3-2 below demonstrates which data windows are suitable when a sufficiently significant transient has occurred. The goal is to identify data sections where the system is in a relatively stable state of operation just before and just after the transient event [33].

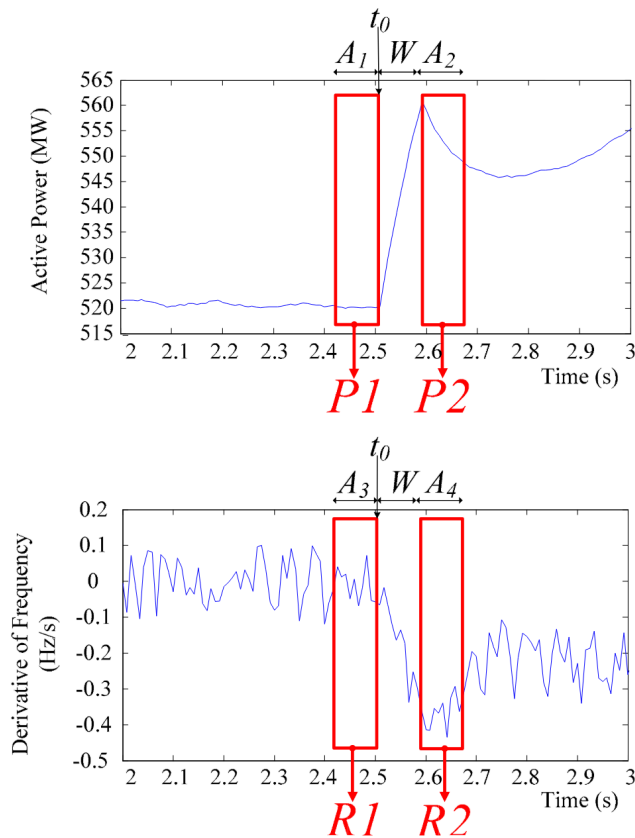


Figure 3-2: Sampling windows to minimise noise when estimating inertia [33]

The width of the windows is indicated as A_1 , A_2 , A_3 , A_4 and t_0 the time when the disturbance starts with W the duration of the disturbance. P_1 and P_2 (in p.u.) is the average active power in the data

windows before and after the disturbance. Similarly, R_1 and R_2 (in Hz/s) represents the average ROCOF of the data windows before and after the disturbance.

Equations (3-6) below mathematically describe the above parameters.

$$\begin{aligned} P_1 &= \frac{\sum_{i=(t_0-A_1)}^{t_0} p(i)}{A_1} & P_2 &= \frac{\sum_{i=(t_0+W)}^{(t_0+W+A_2)} p(i)}{A_2} \\ R_1 &= \frac{\sum_{i=(t_0-A_3)}^{t_0} df dt(i)}{A_3} & R_2 &= \frac{\sum_{i=t_0+W}^{(t_0+W+A_4)} df dt(i)}{A_4} \end{aligned} \quad (3-6)$$

Inertia can now be estimated from (3-7) below:

$$H = \frac{1}{2} \frac{P_1 - P_2}{R_2 - R_1} \quad (3-7)$$

The system inertia follows from the relative contribution of each generation unit, using equation (3-8) below:

$$H_{SE} = \frac{\sum_{i=1}^N S_{ni} H_i}{S_{total}} \quad (3-8)$$

In this context, H_i denote the inertia in seconds, S_{ni} the rated apparent power of the i^{th} generator and S_{total} , the total system apparent power. The total number of generators is N .

An estimation error of 5% was reported for this method.

3.5 Method 3: Application of a 5th order polynomial [30], [34], [35], [36].

An alternative method employs the fitting of a 5th order polynomial to the oscillations in the frequency profile. This supports the approximation of the inertia constant at generators that supports frequency stability, outlined in [34].

Equation(3-9) can be derived from the swing equation (3-1):

$$M = 2H = \frac{-\Delta P}{\left. \frac{d\left(\frac{\Delta f}{f_0}\right)}{dt} \right|_{t=0.0}} \quad (3-9)$$

Where:

- ΔP is the change in active power.
- $\frac{d\left(\frac{\Delta f}{f_0}\right)}{dt}$ is the ROCOF.

Analysis is needed of the oscillatory component, produced between at least two synchronised generators. From the derivative of the frequency change at t_0 , this method calculates ROCOF during the instance of the disturbance.

The oscillatory behaviour observed in the frequency profile aligns closely with the polynomial shape, allowing ROCOF calculation at t_0 . The Fifth-order polynomial curve fitting is demonstrated below in Figure 3-3.

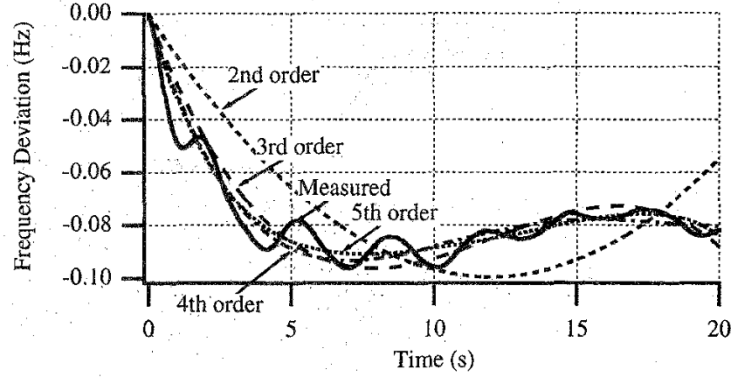


Figure 3-3: Polynomial fit to the frequency deviation profile [37].

A 5th order polynomial approximation is deemed adequate in [34]. Other attempts to estimate inertia using other orders have been investigated [30], [35] and [36] confirming that a 5th order polynomial is sufficient.

When applying the 5th order polynomial to an incremental change in frequency, a polynomial approximation in the form below can be used [34]:

$$\frac{\Delta f}{f_o} = A_5 t^5 + A_4 t^4 + A_3 t^3 + A_2 t^2 + A_1 t \quad (3-10)$$

ROCOF is then approximated as the coefficient of the first order term (A_1), also interpreted as the solution of the derivative of frequency at timestamp $t = 0$ (at time of disturbance).

From the above equations (3-9) and (3-10), the inertia constant can be estimated:

$$M = 2H = -\frac{\Delta P}{A_1} \quad (3-11)$$

Recall from

Figure 2-1 that inertia is the initial response to a frequency change and that inertial response takes place within the first 10 s, followed by a primary response from generators that takes up to 30 s. The fitting of the polynomial makes use of up to 20 s of data [38], [39]. Results obtained by this method can include frequency changes contributed by system components other than purely system inertia.

On-line Power system inertia estimation [30] reported an error of up to 2.6% for inertia estimation in the 9-bus system. For a single-machine test system, an error of below 2% was recorded. A real-world scenario was also used for inertia estimation, where a generation loss of 200 MW resulted in an observed frequency change of -0.125 Hz/s.

3.6 Method 4: Electromechanical oscillations [40]

By considering electromechanical oscillations, the impact of measurement noise when using frequency data, can be reduced [40]. This method relies solely on active power measurements.

Synchronised active power measurements on a tie-line between two inter oscillating areas in a power system is used [40]. An important advantage of this method is that it only requires active power measurements, making it viable for events without advanced measurement devices.

When a sudden mismatch between generation and loading occurs, the active power on the tie-line may oscillate due to the changing contribution of generating units in each area to contain frequency. Analysis of the exponentially decaying electromechanical oscillations is reflected in the active power measurements.

A mathematical relationship exists between the oscillation frequency and the inertia constant as described by the Laplace transform of the swing equation in (3-12) below [4]:

$$2Hs^2 + Ds + \omega_n P_{e0} \cot \delta_0 = \Delta P_m s \quad (3-12)$$

Where

- s : Laplace operator.
- D : Damping factor.
- ω_n : is the angular velocity (rad/s).
- P_{e0} : Electrical power before the disturbance, (W).
- δ_0 : rotor angle before the disturbance (rad).
- ΔP_m : approximated equal to zero during inertial response

The quadratic roots of the characteristic equation (3-12) contains the system's eigenvalues [40].

The real part of the eigenvalues is shown in (3-14) below. It is known as the attenuation coefficient of the electromechanical oscillation whilst the imaginary part (3-15) reveals the electromechanical oscillation frequency [41].

$$s_{1,2} = -\frac{D}{4H} \pm j \frac{\sqrt{D^2 - 8H\omega_n P_{e0} \cot \delta_0}}{4H} \quad (3-13)$$

$$2\pi f_d = \frac{\sqrt{D^2 - 8H\omega_n P_{e0} \cot \delta_0}}{4H} \quad (3-14)$$

$$\sigma = \frac{D}{4H} \quad (3-15)$$

Where:

- f_d : is the electromechanical oscillation frequency in Hz
- σ : is the attenuation factor

From using (3-14) and (3-15), the values of the inertia constant H and the damping factor D can be determined. Needed was the frequency of the electromechanical oscillations f_d and attenuation coefficient σ .

The highest recorded error for this method was 15.2%. Although this error may appear high, it should be noted that inertia estimation and frequency deviation are strongly dependent on the type of mismatch between generation and loading. A small change in load may not result in a significant frequency deviation, whereas a larger disturbance in the same system, with the same mechanical generators and unchanged inertia, will result in a higher inertia estimation.

3.7 Method 5: R, V and RV method [8], [42]

The change in power upon a system disturbance (the sudden mismatch between generation and loading) is influenced by primary frequency control measures (i.e. governor settings at generators) and loading that are affected by changes in frequency and voltage.

To make use of frequency and/or voltage variations in estimating inertia, the R approach, V approach, and a combination; the RV approach have been proposed. The R approach makes use of only frequency dynamics, the V approach only voltage dynamics and the RV approach both frequency and voltage dynamics, [4], [38].

Node voltages can significantly fluctuate during a system disturbance, resulting in similar fluctuation in load currents consumed at linear loads. The estimation of current done during the latter scenario, will be inaccurate [8].

Variations of this method are possible. Power variations can be approximated as relating to frequency variations (R approach). Alternatively, the V approach considers how voltage variations result in power variations (voltage dependency of loads). These two approaches can be employed separately to estimate power system inertia, however each of them does not fully accommodate the system dynamics on its own.

When simultaneously considering both voltage and frequency variations [8], the net change in power following a disturbance is defined in (3-16) below.

$$\Delta P(t) = h_1(f(t)) + h_2(V(t)) - \Delta P_{dist} \quad (3-16)$$

Where

- $h_1(f(t))$: the frequency dynamic behaviour of the load.
- $h_2(V(t))$: Voltage dynamic behaviour of the load.
- ΔP_{dist} : change in active power during the disturbance.

The R method is defined in (3-17), focusing on the frequency dynamic behaviour of the load.

$$H_{est} = \frac{h_1(f(t_{sr})) - \Delta P_{dist}}{\frac{2df(t_{sr})}{dt}} = \frac{R(t_{sr})\Delta f(t_{sr}) - \Delta P_{dist}}{\frac{2df(t_{sr})}{dt}} \quad (3-17)$$

- t_{sr} : first local extremum (maximum or minimum).
- $R(t_{sr})$: average moving window of frequency measurement at t_{sr} (Hz/s)
- ΔP_{dist} : change in power during disturbance, (W).

The V method is shown in (3-18), focusing on the voltage dynamic behaviour of the load.

$$H_{est} = \frac{h_2(V(t_{sv})) - \Delta P_{dist}}{\frac{2df(t_{sv})}{dt}} = \frac{-\Delta P_{LV}(t_{sv}) - \Delta P_{dist}}{\frac{2df(t_{sv})}{dt}} \quad (3-18)$$

- t_{sv} : first local extremum (maximum or minimum).
- $\Delta P_{LV}(t_{sv})$: total load demand at t_{sv} (W)
- ΔP_{dist} : change in power during disturbance, (W).

By combining (3-17) and (3-18), the RV method follows in (3-19) below.

$$H_{est} = \frac{h1(f(t_s)) + h2(V(t_s)) - \Delta P_{dist}}{2\left(df \frac{t_s}{dt}\right)} = \frac{(T_s)\Delta f(t_s) - \Delta P_{LV}(t_s) - \Delta P_{dist}}{2\left(df \frac{t_s}{dt}\right)} \quad (3-19)$$

Where t_s is the time when the algorithm is applied at the first local extremum following a disturbance.

Further expansion of this method is proposed in [8].

A mean error of 12.8% was recorded for the V-method, 7.98% for the R-method, and a lower error of 5.5% for the RV method, indicating that combining the methods results in a more accurate inertia estimation.

3.8 Factors that can affect the accurate estimation of inertia in systems where renewable generation exists.

The following factors [38] are important when estimating the availability of inertia in a system with renewable energy sources:

- Correct identification of event start time.
- Accurate frequency measurement when voltage harmonics can affect the detection of zero crosses of fundamental frequency waveform.
- Method to calculate ROCOF.
- Location in the distribution system where measurements are obtained. It is possible that local sources of reactive power can cause phase angle jumps causing incorrect estimation of system frequency.
- A sufficient sampling rate of voltage, active power and frequency.
- Overall measurement uncertainty.

Identifying the start time of an event is critical when estimating inertia. It is needed for the accurate analysis of the system's response to support an improved estimation of the availability of inertia.

The length of the analysis window [28] also needs to be considered to exclude measurement noise brought about by the system still in a transient state.

Accurate frequency measurements are needed to derive ROCOF with sufficient accuracy, impacting the confidence by which inertia is estimated. ROCOF is sensitive to noise and transient events and why the resolution in frequency measurement needs to be as high as possible.

The location of recording devices relative to the geographical location of a system disturbance, will affect frequency measurements [4], [28]. Measurements should to be taken as near as possible to generators, multiple measurements taken in a system will also increase the accuracy of inertia estimation. Transformers between the point of measurement and the point where the disturbance occurs, introduce phase-shift (shifting the absolute point in time of zero crosses) in voltage waveforms, skewing frequency measurements.

It is important to consider measurement uncertainty when inertia is estimated [43].

3.9 Summary

Five methods were discussed for estimating inertia. The first method utilised the swing equation, using consecutive measurements of active power, frequency, and ROCOF. The measurements taken before, during, and after a disturbance event.

Method 2 uses data windows, taken over a pre-determined window width, based on measurements of active power and ROCOF. The data window average values are then applied to the swing equation.

Method 3 fits a 5th order polynomial curve to the frequency profile after a disturbance event. The 4th method examines electromechanical oscillations of the active power profile, by matching the oscillations in the active power profile with oscillation characteristics, from this establishing two constants, D and H with H estimating the Inertia constant.

Lastly, the R/V/RV method analysed the generation and load contribution to inertia in a power system.

Considering the methods presented in this chapter, each method is an approximation method, with various parameters affecting the accuracy of each method.

Below in Table 3-1, a comparison of the advantages and disadvantages of each method as listed, and further comparison will be done in experimental analyses.

Table 3-1 Comparison and considerations of inertia estimation methods

<i>Method</i>	<i>Comment</i>	<i>Pro's & Con's</i>	<i>Meets Criteria?</i>
<i>Swing equation using consecutive measurements</i>	Heavily dependent on sampling frequency, may pose problem if measuring equipment differs on sampling frequency.	+ Easy to implement - Limited to short term frequency change - Dependency on exact moment of disturbance - Work well when SGs dominant generation source - Depend on sampling frequency (below 0.02 s)	To be evaluated using simulations.
<i>Data Windows</i>	Will work for renewable energy systems as frequency measurements of the system is evaluated. Can be used when renewable generation is significant	+Simple +Extending transient step +More robust w.r.t. location of fault +Performance not affected by extent of renewable generators -Optimal size of window (depends on data sampling rate)	To be evaluated using simulations.
<i>5th order polynomial</i>	Needs 2 synchronous generators to excite oscillation in frequency profile.	+ Low computational burden + Can be used to estimate onset of event. - Depend on exact moment of disturbance.	Requires a system with more than one mechanical generator.
<i>Electromechanical oscillations</i>	Require 2 synchronous generators to excite oscillation	+ only uses active power measurement - high computational burden.	Requires a system with more than one mechanical generator.
<i>R, V and RV approach</i>	Considers primary response Requires lots of knowledge of the primary response and load topology of the network	+ Considers the load response in the system as well. - Requires additional knowledge of the entire system, including all generation and load sources.	Primary response is also considered when using this method, not inertial response alone.

CHAPTER 4: PERFORMANCE EVALUATION OF METHODS TO ESTIMATE INERTIA BY NETWORK SIMULATION.

4.1 Introduction

Various studies have compared inertia estimation methods, as discussed in 3.2, but information on how they perform when using real-life measured data is lacking. Most of them, although seemingly different, rely on the principles of the swing equations.

Some methods merely differ in how the rate of change of frequency (ROCOF) is calculated, while others examine the dynamic oscillation between generators to estimate the inertia constant.

As verification of the theoretical principles applied by different methods, this chapter critically compares their performance making use of results obtained from computer simulations, using standard IEEE systems. Requirements for their application using field data is lastly considered.

4.2 Requirements of test events

To assess the stability of a power system, as related to the availability of inertia, an instantaneous change (disturbance) to the steady state operating conditions is required (e.g., when loading or generation suddenly changes). The consequence of this disturbance is then analysed by the application of a specific inertia estimation method.

Three different types of system disturbances are considered:

- Significant change in generation, without a change in loading.
- Significant change in loading, without a change in generation.
- A fault current causes some part of the power system to be lost, resulting in a loss of generation and/or loading when protection isolates part of the network.

Continuous tracking of frequency and ROCOF needs to be done, retaining measurements before, during and after the system disturbance. Data samples need to be spaced at least one fundamental frequency cycle apart, such as 20 ms in a 50 Hz power system [31].

Frequency, or a change in frequency, is not known within the period of a single cycle at the power system frequency.

DIgSILENT PowerFactory was chosen as a simulation platform. Using a time-domain RMS simulation, it computes Root Mean Square (RMS) values of voltages and currents over time. This type of simulation allows analysis of the system's dynamic phenomena under transient conditions.

Simulation results of power, frequency and ROCOF are exported as comma separated values (*.csv files) to MATLAB™ for further analysis.

4.3 Test system configurations

This study employs three IEEE standardised configurations as benchmarks for evaluating power system inertia under varying conditions: the 2-Zone, the 9-Bus, and the 14-Bus systems. These systems are considered a reliable reference framework for power system analysis.

All synchronous generators in the 2-Zone, IEEE 9-Bus, and IEEE 14-Bus studies were represented using the standard synchronous machine model in DIgSILENT PowerFactory without additional control blocks (i.e., no AVR and no governor). This modelling choice was made deliberately because the research objective is the estimation of system inertia from the initial electromechanical frequency response following active-power imbalances.

Swing-equation dynamics dominate the first-seconds behaviour used for inertia estimation, whereas excitation and turbine-governor dynamics primarily affect voltage/reactive power behaviour and slower active-power recovery dynamics, respectively. The generator model captures the essential coupling between rotor acceleration and power imbalance, while intentionally excluding control actions that could mask the direct inertial response.

PV generation was represented using a PV model incorporating frequency and voltage tripping protection in line with the South African Grid Code (SAGC).

For load frequency dependency, an active-power frequency sensitivity of ($K_p = 1.2$) was selected as a representative load damping value to account for load frequency relief, while reactive-power frequency dependency was neglected ($K_q = 0$).

Results can be directly compared between different methods and to models.

The simulation execution times were limited to less than 10 s, as primary and secondary responses are usually deployed by control systems after 10 s following a system frequency event. Data resolution was set at 20 ms (as is recommended in literature for a 50 Hz power system) [31].

- 2-Zone System:

The 2-Zone system is a simplified network model, comprising of two primary zones with interconnecting transmission lines. Each side of the interconnecting transmission lines consists of 2 generation sources and a load. This system provides a baseline for understanding how small-scale networks respond to disturbances. Its simplicity makes it an ideal starting point for analysing inertia variations due to localised disturbances.

- 9-Bus System:

The 9-Bus system is widely used in power system studies for its ability to represent interconnected network behaviour with minimal complexity. It is composed of nine buses that includes generation and load nodes. This allows for an exploration of how mid-sized networks, with generators running at full load, maintain stability under different events.

- 14-Bus System:

Is larger and more complex, incorporating multiple generation sources, loads, and interconnections, allowing a closer approximation of real-world power systems where interaction between elements is dynamic. This makes it valuable for assessing inertia under diverse operational and contingency conditions. The system includes five generators operating below full capacity, enabling analysis of their behaviour in response to demand changes.

Different events (disturbances) were simulated in each IEEE test system. Active power, frequency and ROCOF of generation units were captured for comparing the different methods.

- Four different network events were considered as controlled experiments.

They were distinctly chosen to simulate a mismatch between generation and loading, or possible power system events that could lead to the loss of generation sources, or loading.

Power imbalance disturbances (Generation loss, Load loss, And Load addition) were selected to examine how sudden active-power mismatches between generation and demand affect system frequency behaviour and overall stability. In addition, single-phase and three-phase faults were investigated to assess whether inertia could be reliably estimated from fault-driven network disturbances. A summary of the considered events is provided below.

- Generation loss: Generation units are disconnected one at a time to establish how generator size affects the accuracy of different inertia estimation solutions.
- Earth fault: A line-to-earth fault, applied for 150 ms before being cleared, at each bus is sequentially simulated to assess how the distance between the location of a disturbance and the measuring point affects the accuracy of each method.
- Loading:
 - Loss: Loading is decreased instantaneously by 50%.
 - Increase: Loading is increased instantaneously by 50%.

It is needed to introduce a significantly large change in generation or loading to induce a sufficient system response that could be monitored. Smaller load and generation changes could be expected to be within the inertia response of rotating generators.

The following methods (discussed in section 3.2) were applied to simulated data:

- **Method 1:** Swing equation using consecutive measurement values.
- **Method 2:** Data windows.
- **Method 3:** 5th order polynomial.

Table 4-1 sets the scope of this chapter by summarising the test systems and events. Each row specifies the simulated conditions for a specific test system.

The error calculated from the results of each method and system are indicated in %, with a positive error indicating an overestimation, and a negative error indicating an underestimation.

Four different network events allow simulation of a mismatch between generation and loading, or possible power system events that could lead to isolation or disconnection of generation sources within a power system.

Table 4-1: Initial summary table: Test systems and disturbance events

2-Zone system	Generation loss	Loss of a single generation unit.
	Earth fault	A line to earth fault at each bus is sequentially.
	Load loss	Loading is decreased instantaneously by 50%.
	Load increase	Loading is increased instantaneously by 50%.
9 Bus System	Generation loss	Loss of a single generation unit.
	Earth fault	A line to earth fault at each bus is sequentially.
	Load loss	Loading is decreased instantaneously by 50%.
	Load increase	Loading is increased instantaneously by 50%.
14 Bus System	Generation loss	Loss of a single generation unit.
	Earth fault	A line to earth fault at each bus is sequentially.
	Load loss	Loading is decreased instantaneously by 50%.
	Load increase	Loading is increased instantaneously by 50%.

4.3.1 2-Zone system:

The 4-machine, 2-Zone system is a standardised test configuration frequently used as a reference model for simulating and analysing dynamic stability in power systems. As shown in Figure 4-1, this configuration is particularly valuable for studying inter-area oscillations between distinct zones of generation, where ROCOF responses can be observed when a system disturbance is deliberately introduced under controlled conditions.

This system setup allows for estimating system inertia, which is crucial in understanding the system's dynamic behaviour under disturbances. In this study, photovoltaic (PV) generation was introduced by replacing synchronous generator G2 with static grid-connected inverters, simulating a renewable energy source (that lacks rotating inertia). This modification reflects the growing interest in evaluating power system stability with renewable sources integrated into distribution systems.

The PV model used adheres to typical PV behaviour, with protection behaviour adhering to the grid code requirements [3].

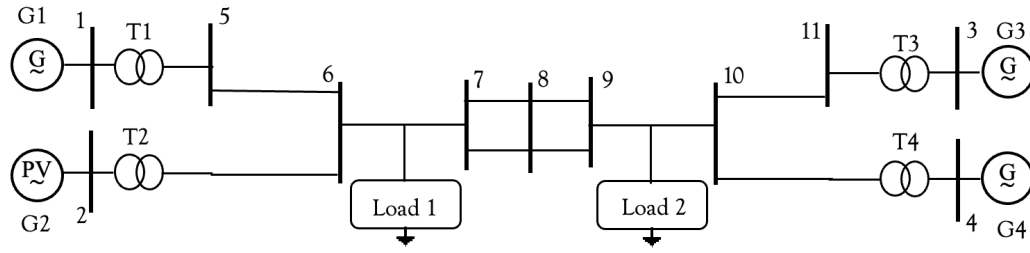


Figure 4-1: Four machine 2-Zone system

The inertia of the system in Figure 4-1 can be estimated as described in [40] and [44], using (3-8).

This system is modelled using DIgSILENT Powerfactory, Frequency, ROCOF, generation and load data are extracted to test the different inertia estimating methods. MATLAB is used for method testing, with algorithms developed for each approach, and the inertia constant is estimated through the processing of simulation data by each method's algorithm.

The specifications for the 4-machine, 2-Zone system are listed Table 4-2 below. Additional detailed parameters can be found in Appendix A, aligning with values from literature sources [45].

System characteristics are as specified in the reference literature [45], except for synchronous generator 2, which was replaced by a PV generation source (Adhering to the SAGC) to simulate the absence of rotating inertia.

Table 4-2: Multimachine 2-Zone system parameters

	G1	PV2	G3	G4
Apparent power (MVA)	900		900	900
Active Power (MW)	700	700	719	700
Rated Voltage (kV)	20	20	20	20
Inertia Constant H (s)	6.5	PV	6.175	6.175
	T1	T2	T3	T4
Rated Apparent Power (MVA)	900	700	900	900
Rated Voltage (kV)	20/230	20/230	20/230	20/230
	L1	L2		
Load Power (MW)	967	1.767		
Reactive Power (MVar)	100			

Observe that a 2-Zone reference power system can exist, or approximated, in the real world when significant generation in an area is related to another area also having significant generation but interconnected by a transmission system. Distribution networks be local or remote. The sources of renewable energy will typically be hosted at distribution level.

The loadflow results for the 2-Zone system at T_0 is shown below in Figure 4-2.

The complete set of simulation results plotted from DIgSILENT Powerfactory can be seen in Appendix B.

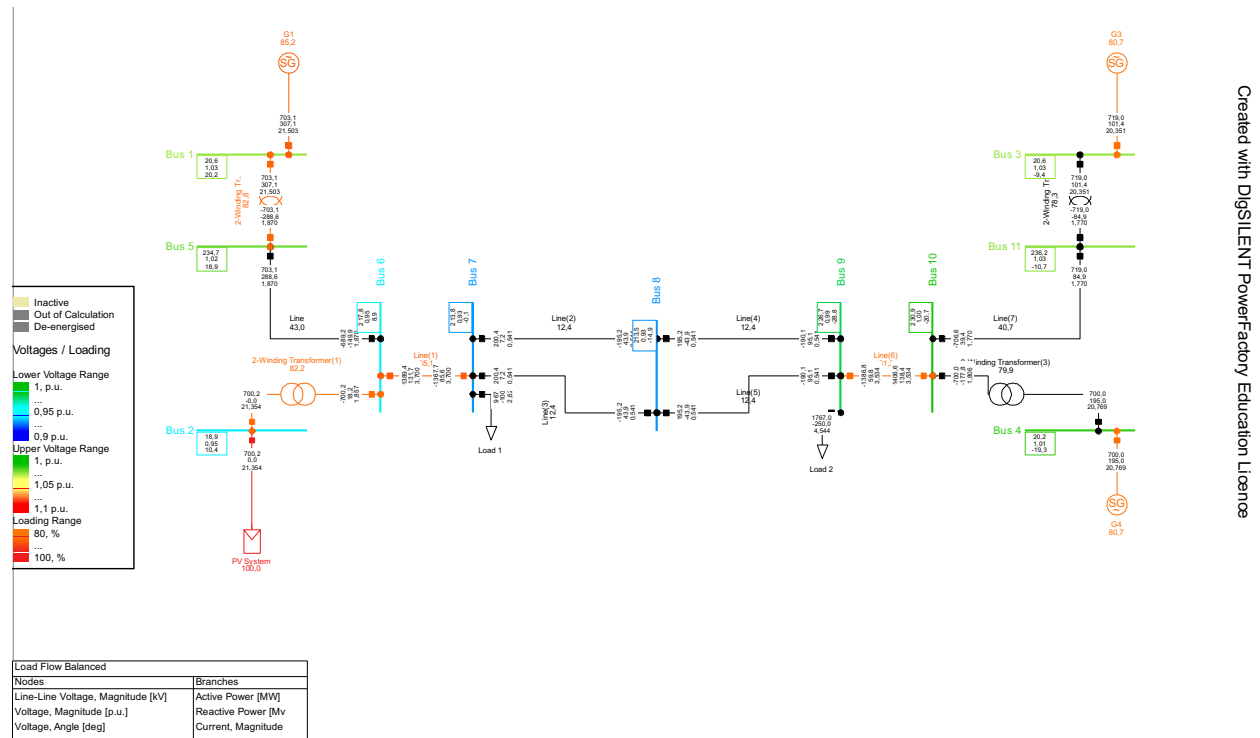


Figure 4-2: 2-Zone loadflow at T_0

Each method was applied in the same manner for each system and each event, resulting in a set of results that can be directly compared.

To illustrate the performance of each method, system inertia for each system was calculated from first principles and then compared using histograms.

Additional analysis of results, and an interpretation as relating to each event, are presented in Chapter 5 Introduction.

4.3.1.1 Loss of generation (gen-loss event)

Inertia was estimated by disconnecting each of the four generators (G1, G2, G3, and G4), one at a time. The results are presented in Figure 4-3 below.

True inertia constants were calculated from preset values of the generators. It is shown as H_{Target} in grey-blue and indicated by arrows. It is not visible for each event, as the estimated value can obscure the target value when larger than the target value. Estimated values are shown in shades of blue emphasised by a border.

Observe that different inertia target values are shown for system inertia. This is done due to the loss of a certain unit having a specific inertia value, whereafter only the remaining generators are contributing to system inertia.

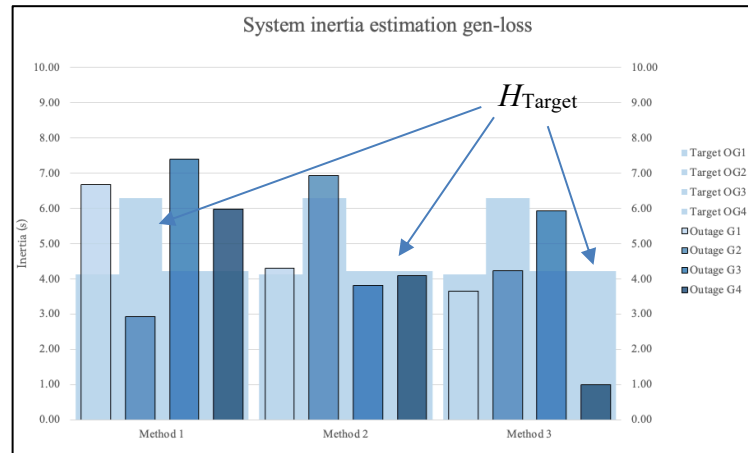


Figure 4-3: Results for 2-Zone system inertia estimations using gen-loss Event

The deviation of the estimated value from the inertia target value is listed in Table 4-3 below. Note a negative error indicates underestimation, with a positive indicating an overestimation.

Table 4-3: 2-Zone system inertia estimations using gen-loss events (error percentages)

Events	H_{Target} (s)	Error(%)		
		Method 1	Method 2	Method 3
Outage G1	3.09	62%	5%	-12%
Outage G2	4.72	-29%	10%	-50%
Outage G3	3.17	79%	-10%	41%
Outage G4	3.17	45%	-3%	-79%

The results of the gen-loss event in Figure 4-3 highlight the performance of each method in estimating system inertia:

- Method 1 overestimates and underestimates inertia
- Method 2 has an error of below 10 %
- Method 3 overestimates and underestimates inertia

4.3.1.2 Earth fault event

An earth fault in a power system can cause generation units to disconnect, resulting in a mismatch between generation and load. Results from earth fault events are shown in Figure 4-4 below. ($H_{Target} = 5.48$ is the same for all events and methods).

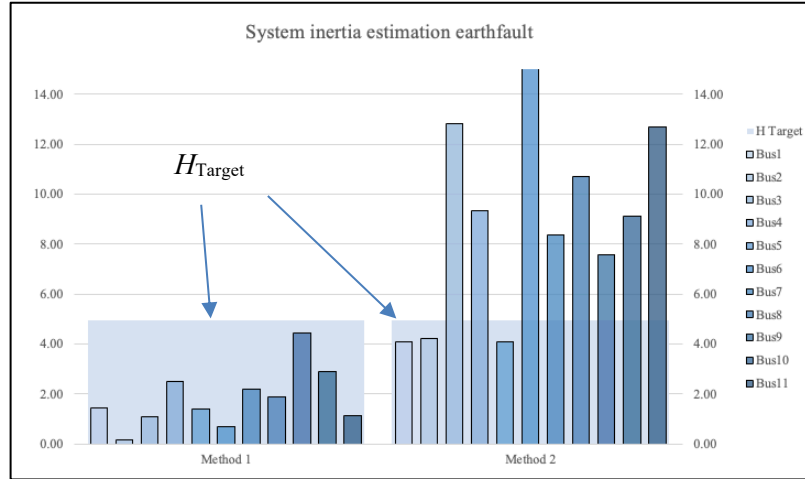


Figure 4-4: Results for 2-Zone system inertia estimations using earth fault events

The deviation of the estimated value from the inertia target value is listed in Table 4-4 below.

Table 4-4: 2-Zone system inertia estimations using earth fault events (error percentages)

<i>Error(%)</i>	<i>Method 1</i>	<i>Method 2</i>
<i>Bus1</i>	-71%	-17%
<i>Bus2</i>	-97%	-14%
<i>Bus3</i>	-78%	160%
<i>Bus4</i>	-49%	89%
<i>Bus5</i>	-72%	-17%
<i>Bus6</i>	-86%	361%
<i>Bus7</i>	-56%	70%
<i>Bus8</i>	-62%	117%
<i>Bus9</i>	-10%	54%
<i>Bus10</i>	-41%	85%
<i>Bus11</i>	-77%	157%

True inertia constants were calculated from preset values of the generators and is shown as H_{Target} in grey-blue (without a border) in Figure 4-4, while the estimated values are displayed in shades of blue with a border.

- Method 3 failed to produce useful results and therefore not shown. The frequency response following an earth fault, did not exhibit significant oscillations, preventing the fitting of a 5th order polynomial to the frequency data.
- Method 1 consistently underestimated system inertia (compared to target values).
- Method 2 could not accurately estimate inertia, and under and overestimates inertia.

4.3.1.3 Load loss

The 2-Zone system includes multiple loads. Half (50%) of the load in a zone is instantaneously reduced, whereafter the load is reduced simultaneously in both zones. The loading in each zone is the same.

The results for each load loss event are plotted below in Figure 4-5. The target inertia ($H_{\text{Target}} = 5.48$ is the same for all events and methods) represents the actual inertia calculated from preset inertia values using equation (3-7).

Estimated values are displayed in shades of blue with a border.

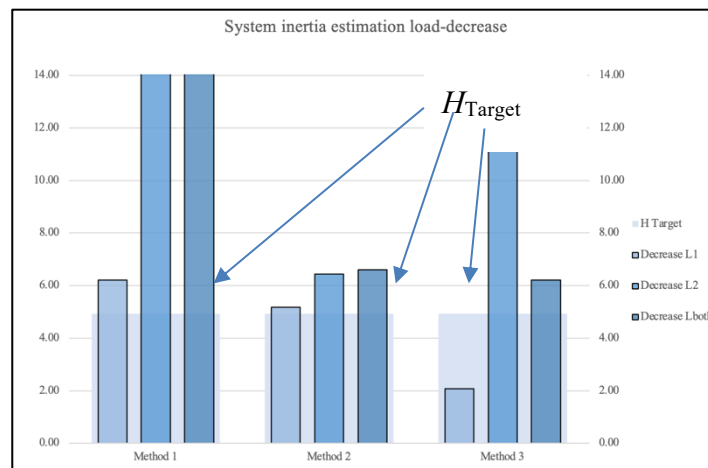


Figure 4-5: Results for 2-Zone system inertia estimations using load loss events

The deviation of the estimated value from the inertia target value is listed in Table 4-5 below.

Table 4-5: 2-Zone system inertia estimations using load loss events (error percentages)

Error (%)	Method 1	Method 2	Method 3
Decrease L1	26%	5%	-58%
Decrease L2	202%	30%	290%
Deacrease L_both	507%	34%	26%

- Method 1 overestimates inertia, when a load loss occurs simultaneously in both zones, inertia is severely overestimated.
- Method 2 over-estimates inertia for a load loss at L2 and when both loads are lost.
- Method 3 only performs better when a load loss event occurs simultaneously in both zones. In real life that is unlikely, concluding that also this method is unreliable.

4.3.1.4 Load increase event

In this event, a 50% increase in load simulates a change in demand, using the 2-Zone system. Results are presented in Figure 4-6 below.

Inertia target ($H_{\text{Target}} = 5.48$ is the same for all events and methods) is represented in grey-blue as indicated.

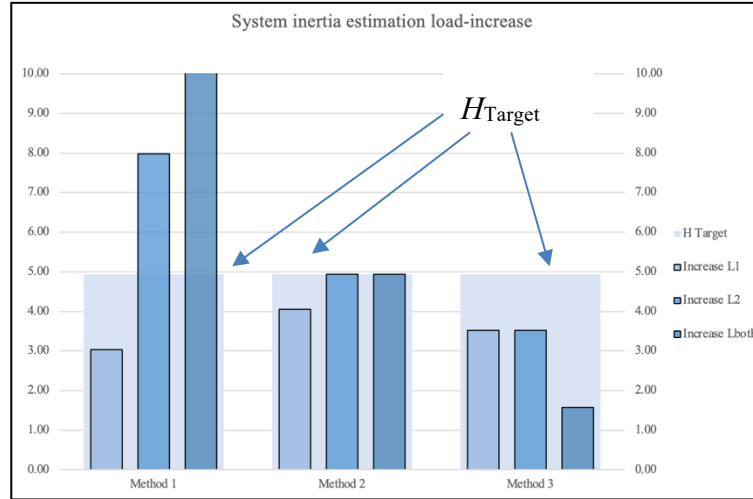


Figure 4-6: Results for 2-Zone system inertia estimation using load increase events

The deviation of the estimated value from the inertia target value is listed in Table 4-6 below.

Table 4-6: 2-Zone system inertia estimations using load increase events (error percentages)

Error (%)	Method 1	Method 2	Method 3
Increase L1	-38%	-18%	-29%
Increase L2	62%	0%	-29%
Increase L_both	171%	0%	-68%

- Method 1 over and underestimates inertia significantly.
- Method 2 performs better than method 1, estimating on average an error less than 10%.
- Method 3 is inadequate and underestimates inertia significantly.

4.3.2 9-Bus system:

The 9-Bus IEEE system is a widely recognised benchmark system in power system research, offering a simplified representation of a small-scale power grid. It is a system with moderate complexity, yet sufficient diverse network elements such as generators, loads and transformers. Previous studies done on inertia estimation using the 9-Bus system can be seen in [30] and [28].

The 9-Bus system was introduced for the purpose of power systems control and stability [5] studies. It consists of a small transmission system of 9 busses, 3 generators, 3 transformers and 6 lines as seen below in Figure 4-7.

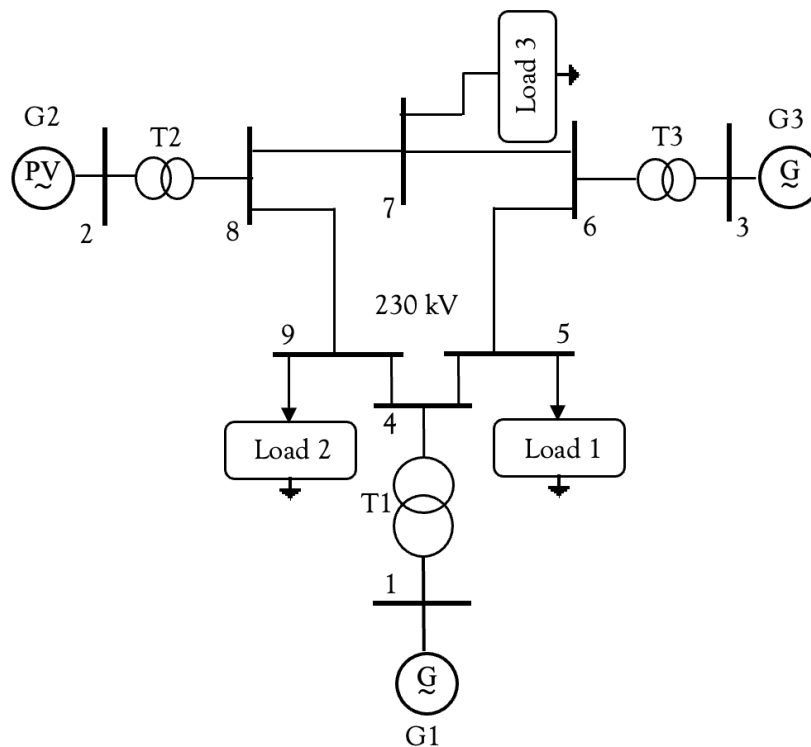


Figure 4-7: 9-Bus system

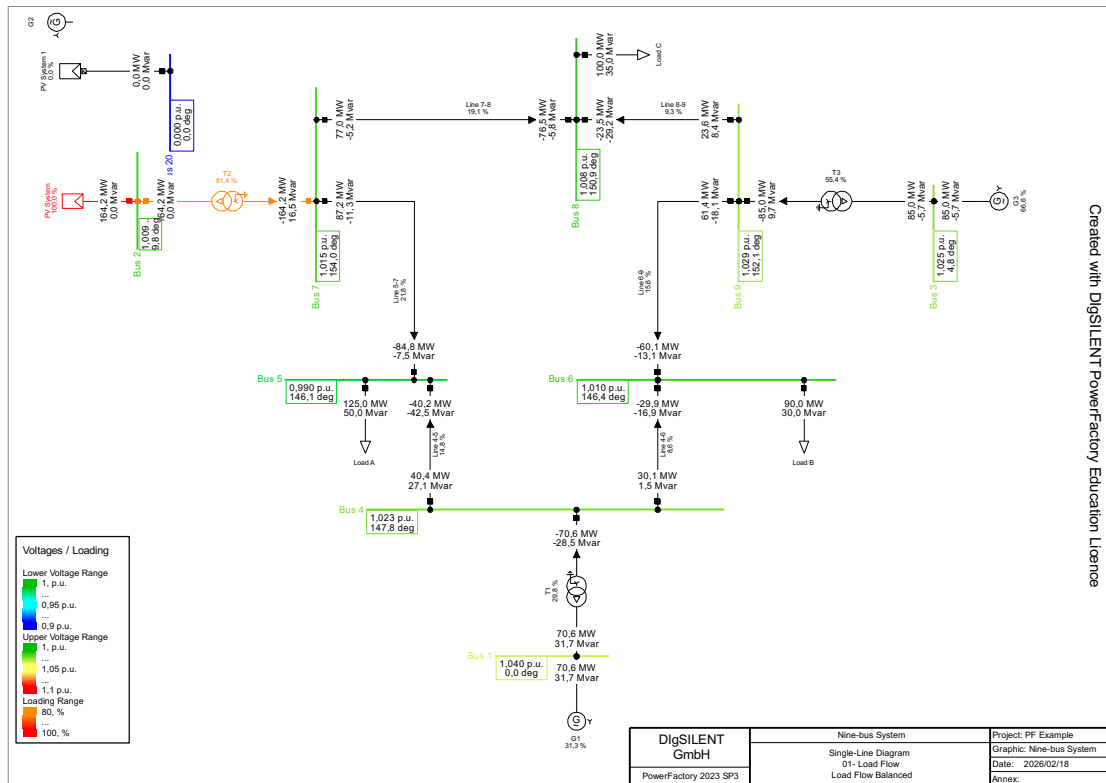


Figure 4-8: 9 Bus system loadflow at T_0

Table 4-7: 9-Bus system specifications.

	<i>G1</i>	<i>PV2</i>	<i>G3</i>
<i>Rated Power (MVA)</i>	247.5		128
<i>Active Power (MW)</i>	71.64	163	85
<i>Nominal Voltage (kV)</i>	16.5	18	13.8
<i>Inertia constant H (s)</i>	9.5515	PV	2.7665
	T1	T2	T3
<i>Rated Power (MVA)</i>	250	200	150
<i>Rated Voltage (kV)</i>	230	230	230
	L1	L2	L3
<i>Active Power (MW)</i>	125	90	100
<i>Reactive Power (MVar)</i>	50	30	35

Different events were simulated as listed in Table 4-1 above.

4.3.2.1 Loss of generation

System inertia is estimated for the 9-Bus system by disconnecting each of the three generators (G1, PV, and G3) individually to observe the impact on system inertia.

True inertia constants were again calculated from preset inertia values at each generator and shown H_{Target} in grey-blue and indicated by arrows. It may not be visible for each event, as the estimated value can obscure the target value when larger than the target value. Estimated values are shown in shades of blue emphasised by a border.

Observe that different inertia target values are shown for system inertia used for the different events. This is done due to the loss of a certain unit having a specific inertia value, whereafter only the remaining generators are contributing to system inertia.

The results for the loss of generation events are shown in Figure 4-9, comparing methods 1, 2, and 3. The inertia target (H_{Target}) is represented in grey-blue as indicated.

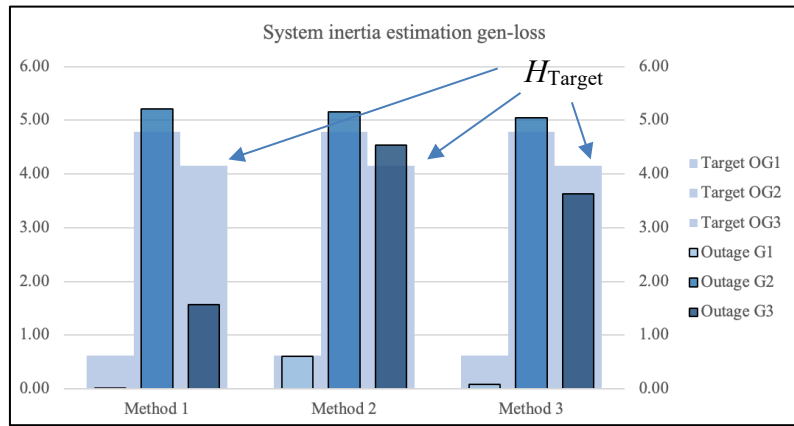


Figure 4-9: Results for 9-Bus system inertia estimations using gen-loss events

The deviation of the estimated value from the inertia target value is listed in Table 4-8 below.

Table 4-8: for 9-Bus system inertia estimations using gen-loss events (error percentages)

		<i>Error (%)</i>		
<i>Events</i>	H_{Target} (s)	Method 1	Method 2	Method 3
<i>Outage G1</i>	0.62	99%	-4%	-87%
<i>Outage G2</i>	4.78	9%	8%	6%
<i>Outage G3</i>	4.16	62%	9%	-12%

- Method 1 performs reasonably only during the loss of PV.
- Method 2 performs relatively well during all 3 events, with an overall error estimation less than 10%.
- Method 3 performs relatively well.
- All methods perform below with a low error below 10% when PV is dropped.

Additional results can be found in Appendix C.

4.3.3 Earth fault events

An earth fault event was simulated on each of the 9 buses. Earth faults were applied sequentially to each bus, creating controlled disturbances during the estimation of inertia.

The results are presented in Figure 4-10. Actual system inertia ($H_{\text{Target}} = 4.78$ is the same for all events and methods) is represented in grey-blue as indicated. The estimated values from method 3 are displayed in shades of blue with borders.

Method 3 did not produce any useful results due to insufficient frequency exceedance.

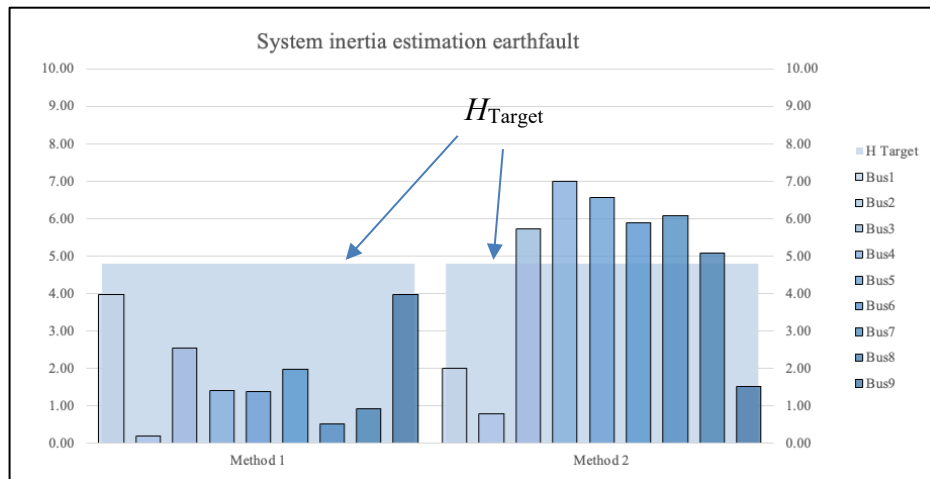


Figure 4-10: Results for 9-Bus system inertia estimations using earth fault events

The deviation of the estimated value from the inertia target value is listed in Table 4-9 below.

Table 4-9: 9-Bus system inertia estimations using earth fault events (error percentages)

Error (%)	Method 1	Method 2
Bus1	-17%	-58%
Bus2	-96%	-83%
Bus3	-47%	20%
Bus4	-71%	46%
Bus5	-71%	37%
Bus6	-58%	23%
Bus7	-89%	27%
Bus8	-81%	6%
Bus9	-17%	-68%

- Method 1 underestimates the target value during all events. A probable cause is limited data points and sensitivity to the choice of consecutive data points used for analysis.
- Method 2 overestimates inertia at most buses during the earth fault events. The location where the fault occurred seems to correlate to overestimation in inertia, the estimation is most accurate when the fault occurred further from a generation source.

The absence of specific guidelines for data selection, aside from a general suggestion to use the nominal frequency, may contribute to inaccuracies.

4.3.3.1 Load loss events in the 9-Bus system

The load loss event was realised by a 50% reduction and not a complete disconnection. This instantaneous change in load is needed to test the methods for inertia estimation.

Results are plotted in Figure 4-11 below. The target for inertia ($H_{\text{Target}} = 4.78$ is the same for all events and methods) is represented in grey-blue as indicated. Estimated values from each method are displayed in darker shades of blue with borders.

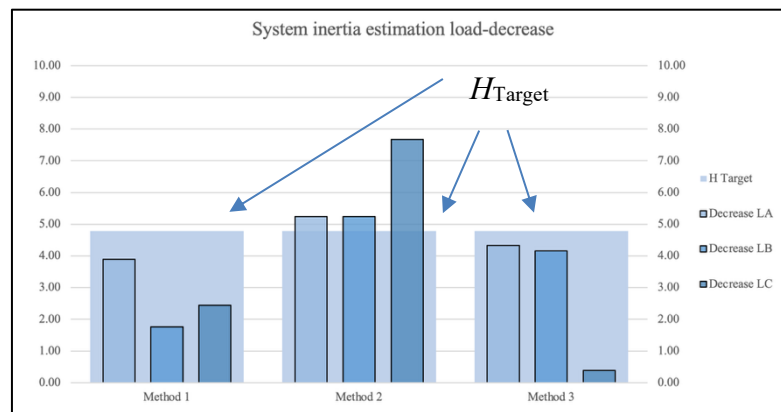


Figure 4-11: Results for 9-Bus system inertia using load loss events

The deviation of the estimated value from the inertia target value is listed in Table 4-10 below.

Table 4-10: 9-Bus system inertia using load loss events (error percentages)

Error (%)	Method 1	Method 2	Method 3
Decrease LA	-18%	9%	-9%
Decrease LB	-63%	9%	-13%
Decrease LC	-49%	60%	-92%

- Method 1 significantly underestimates inertia during all load loss events.
- Method 2 performs better than method 1, but the estimation error is significant when losing L_C of 100 MW
- Method 3 underestimates on L_C , but with significantly higher error.

4.3.4 Additional loading event

A 50% increase in loading was applied to observe its impact on overall system inertia estimation. This sudden increase in demand allows for a comparable assessment of how each method estimates inertia.

In Figure 4-12, the target system inertia ($H_{\text{Target}} = 4.78$ is the same for all events and methods) is represented in grey-blue as indicated. Estimated values from each method are displayed in darker shades of blue with borders.

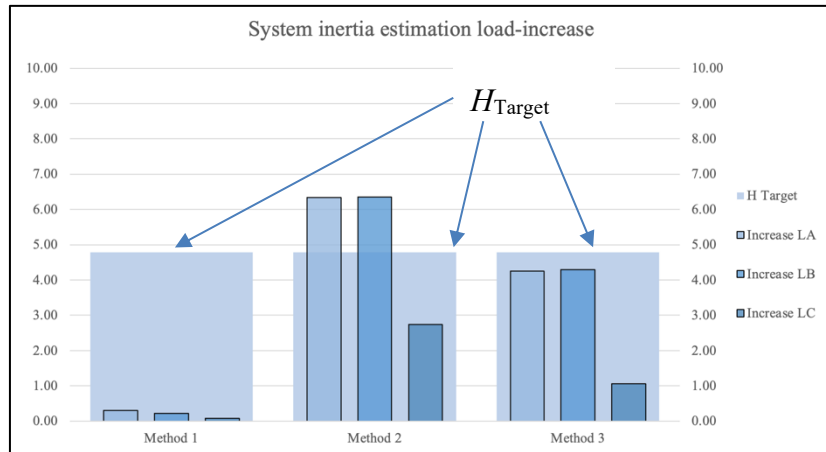


Figure 4-12: Results for 9-Bus system inertia estimation using load increase events

The deviation of the estimated value from the inertia target value is listed in Table 4-11 below.

Table 4-11: 9-Bus system inertia estimations using load increase events (error percentages)

Error (%)	Method 1	Method 2	Method 3
Increase LA	-93%	33%	-11%
Increase LB	-95%	33%	-10%
Increase LC	-98%	-43%	-78%

- Method 1 significantly underestimates inertia during all 3 loading events.
- Method 2 provides better result than method 1, albeit still high error.
- Method 3 is the most accurate, but a significant underestimation on losing L_C .

4.3.5 14-Bus system:

The IEEE 14-Bus system shown below in Figure 4-13 hosts high and medium voltage systems. It is a simplified model of a transmission system in the Midwest United States.

This system consists of five generators and 3 transformers, with 11 load nodes. This system has been used for estimating inertia, reported in [43].

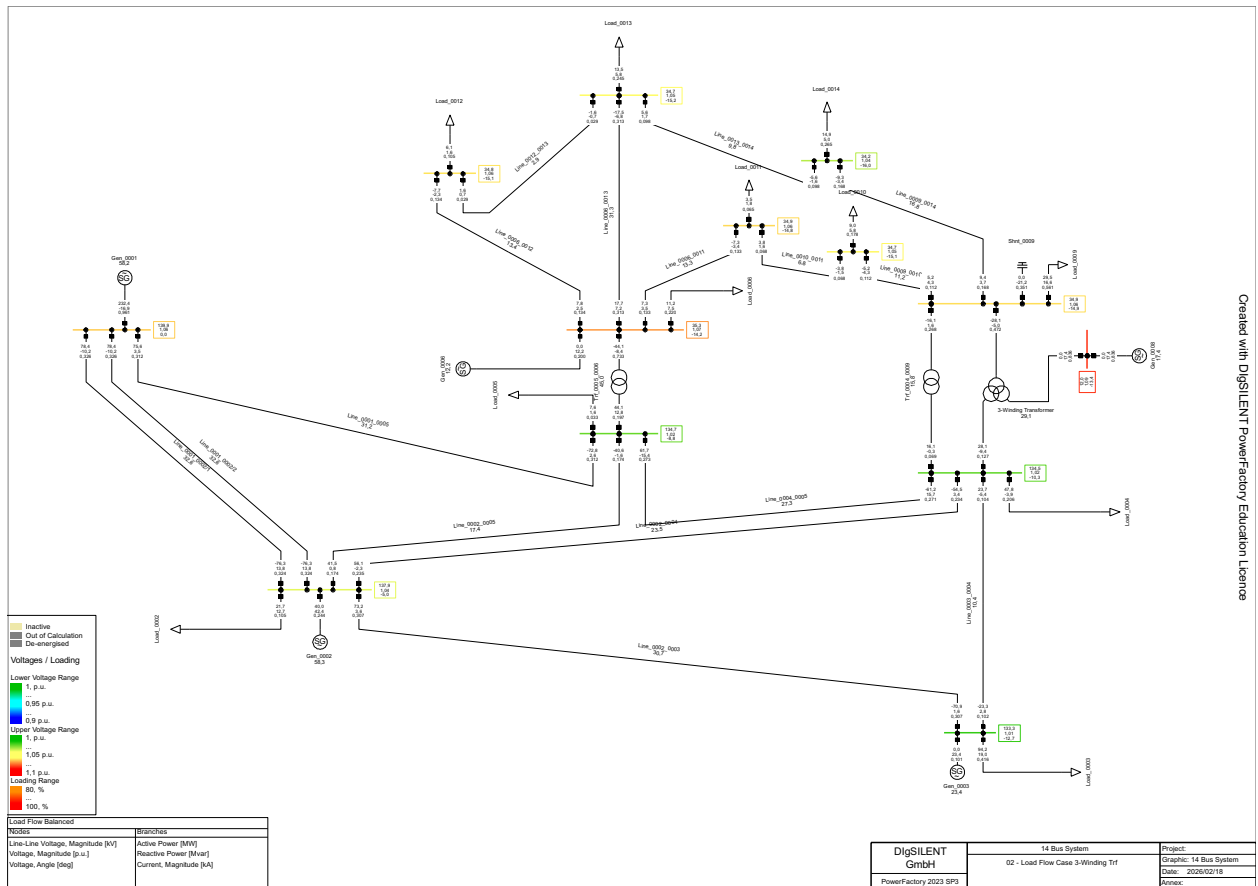


Figure 4-14: 14 Bus system loadflow at T_0

Complete specifications for the 14-Bus system are listed in [43] and Appendix A. Only the aspects relevant to this study, are listed in Table 4-12 below.

Table 4-12: 14-Bus system parameters.

	<i>L2</i>	<i>L3</i>	<i>L4</i>	<i>L5</i>	<i>L6</i>	<i>L9</i>	<i>L10</i>	<i>L11</i>	<i>L12</i>	<i>L13</i>	<i>L14</i>
Active power (MW)	21.7	94.2	47.8	7.6	11.2	29.5	9.0	3.5	6.1	13.5	14.9
Reactive Power (MVar)	12.7	19	-3.9	1.6	7.5	16.6	5.8	1.8	1.6	5.8	5.0
	G1	G2	G3	G6	G8						
Active Power (MW)	232.4	40	0	0	0						

	<i>L2</i>	<i>L3</i>	<i>L4</i>	<i>L5</i>	<i>L6</i>	<i>L9</i>	<i>L10</i>	<i>L11</i>	<i>L12</i>	<i>L13</i>	<i>L14</i>
Reactive Power (MVar)	16.89	42.4	23.39	12.24	17.36						
Inertia Constant (s)	10	10	10	10	10						
	T4-7	T4-9	T5-6	T7-8	T7-9						
Voltage (kV)	132/1	132/33	132/33	11/1	33/1						
Rated Apparent Power (MVA)	100	100	100	100	100						

The 14-Bus system has five generators, with the first two supporting the load, while the remaining three are used as synchronous condensers and sources of inertia.

Each generator is disconnected individually to determine its impact on overall inertia. Observe that different inertia target values apply for system inertia as contributed by remaining generators when one generator is disconnected.

In Figure 4-15 below, target inertia (H_{Target}) is represented in light grey-blue (indicated), while the estimated values are shown in darker shades of blue with a black border.

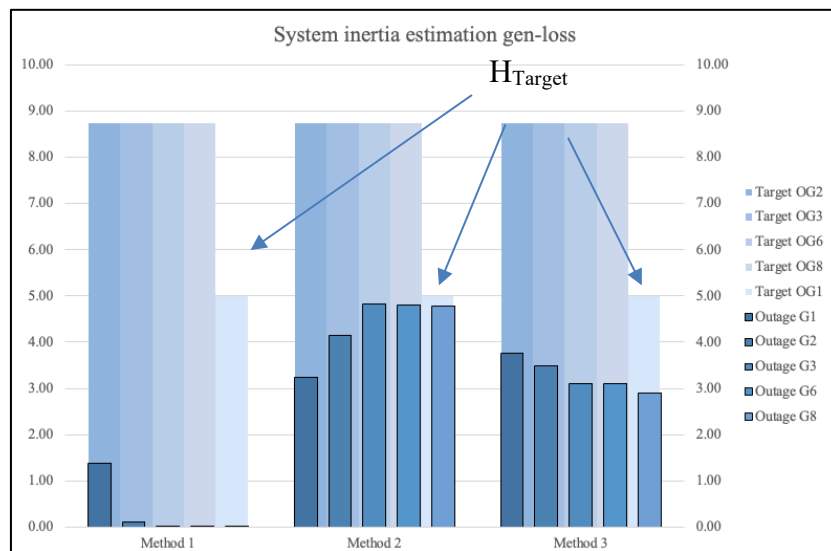


Figure 4-15: Results for 14-Bus system inertia estimations using gen-loss events

The deviation of the estimated value from the inertia target value is listed in Table 4-3 below.

Table 4-13: 14-Bus system inertia estimations using gen-loss events (error percentages)

Event	H_{Target} (s)	Error (%)		
		Method 1	Method 2	Method 3
Outage G1	5	-73%	-35%	-25%
Outage G2	8.75	-99%	-52%	-60%
Outage G3	8.75	-99%	-45%	-64%
Outage G6	8.75	-100%	-45%	-65%
Outage G8	8.75	-100%	-45%	-67%

- Method 1 consistently underestimates system inertia during all generator outage events.
- Method 2 provides improved estimations of inertia. The error remains similar for all events.
- Method 3 underestimates inertia more than method 2.

4.3.5.1 Earth fault event

During the earth fault events for the 14-Bus system, faults are applied sequentially at each of the 14 buses to observe their respective impact on system inertia estimation. Results are presented in Figure 4-16 below. The target for inertia ($H_{\text{Target}} = 10$) is the same for all events and methods) is represented in grey-blue as indicated. Estimated values from each method are displayed in darker shades of blue with borders.

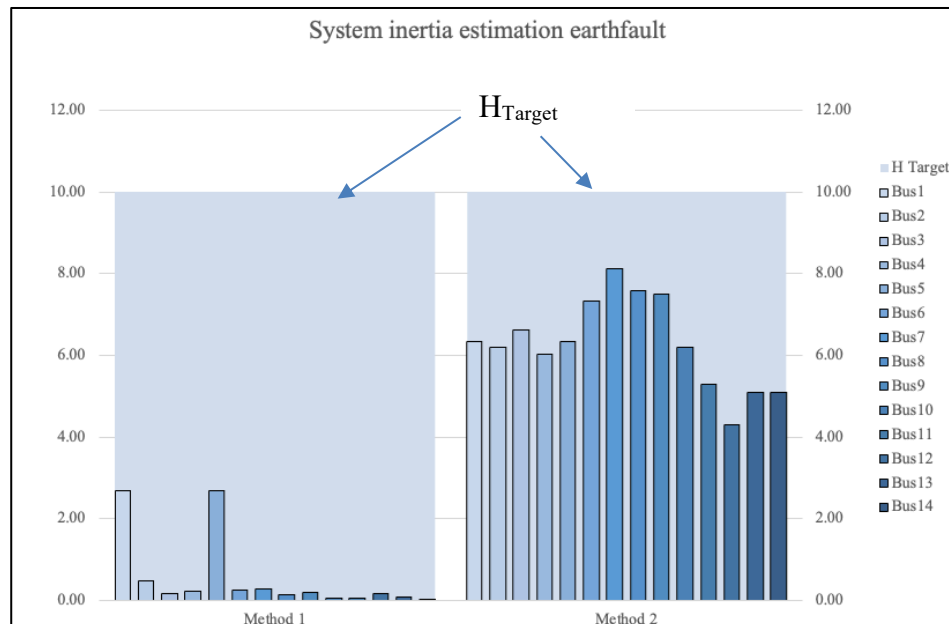


Figure 4-16: Results for 14-Bus system estimations using earth fault events

The deviation of the estimated value from the inertia target value is listed in Table 4-14 below.

Table 4-14: 14-Bus system estimations using earth fault events (error percentages)

Error (%)	Method 1	Method 2
Bus1	-73%	-37%
Bus2	-95%	-38%
Bus3	-98%	-34%
Bus4	-98%	-40%
Bus5	-73%	-37%
Bus6	-98%	-27%
Bus7	-97%	-19%
Bus8	-99%	-24%
Bus9	-98%	-25%
Bus10	-99%	-38%
Bus11	-99%	-47%
Bus12	-98%	-57%
Bus13	-99%	-49%
Bus14	-100%	-49%

The actual inertia constant for the system is shown as H_{Target} in light blue, while the estimated values for each method are displayed in progressively darker shades of blue.

- Method 3 did not produce any useful results.
- Method 1 consistently underestimates the target inertia value at all busses. This may be due to limited data points and the method's sensitivity to the resolution of data point intervals.
- Method 2 performs the best, but with significant high error, suggesting that earth fault disturbances may be a poor choice of event for inertia estimation.

Data collected at generators yield the most accurate results.

4.3.5.2 Load loss event

In a load loss event for the 14-Bus system, the total system load is reduced instantaneously by 50%, allowing for an assessment of each method's accuracy in estimating system inertia under changing demand.

In the graph, the target inertia ($H_{\text{Target}}=10$ is the same for all events and methods) is represented in light blue (indicated), while the estimated values for each method are shown in progressively darker shades of blue with black borders.

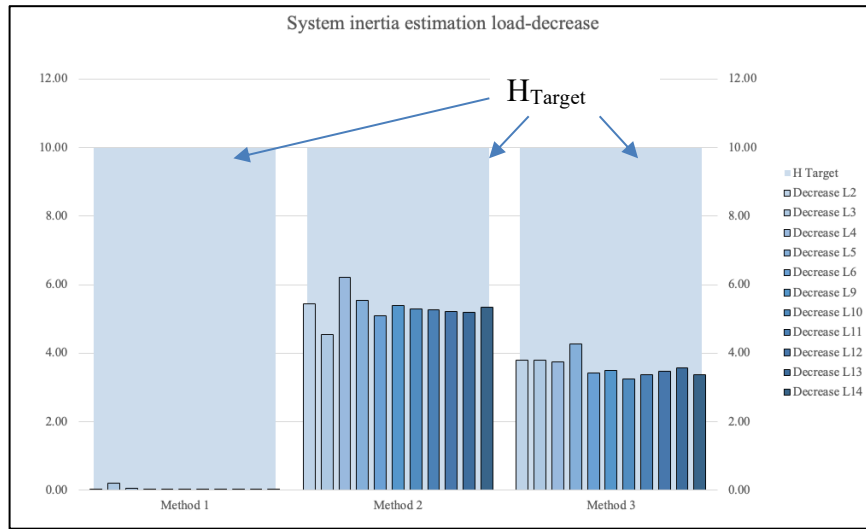


Figure 4-17: Results for 14-Bus system inertia estimations using load loss events

The deviation of the estimated value from the inertia target value is listed in Table 4-15 below.

Table 4-15: 14-Bus system inertia estimations using load loss events (error percentages)

Error (%)	Method 1	Method 2	Method 3
Drop L2	-100%	-45%	-62%
Drop L3	-98%	-55%	-62%
Drop L4	-99%	-38%	-62%
Drop L5	-100%	-45%	-57%
Drop L6	-100%	-49%	-66%
Drop L9	-100%	-46%	-65%
Drop L10	-100%	-47%	-67%
Drop L11	-100%	-47%	-66%
Drop L12	-100%	-48%	-65%
Drop L13	-100%	-48%	-64%
Drop L14	-100%	-46%	-66%

- Method 1 is inadequate because it completely underestimates inertia.
- Method 2 performs better but the error remains large. Reduction in the load by only 50% may suggest Method 2 has higher estimation accuracy as the estimation is consistently around 50% of the available inertia.
- Method 3 produces larger errors than method 2.

4.3.5.3 Load increase events

Each load is sequentially increased by 50%. Results are presented in Figure 4-18 below.

The inertia estimation results are shown in shades of blue with a dark border. The actual inertia constant calculated using (3-7) from the various generation sources in the 14-Bus system is shown.

In the graph, the target inertia ($H_{\text{Target}} = 10$ is the same for all events and methods) is represented in light blue (indicated), while the estimated values for each method are shown in progressively darker shades of blue with black borders.

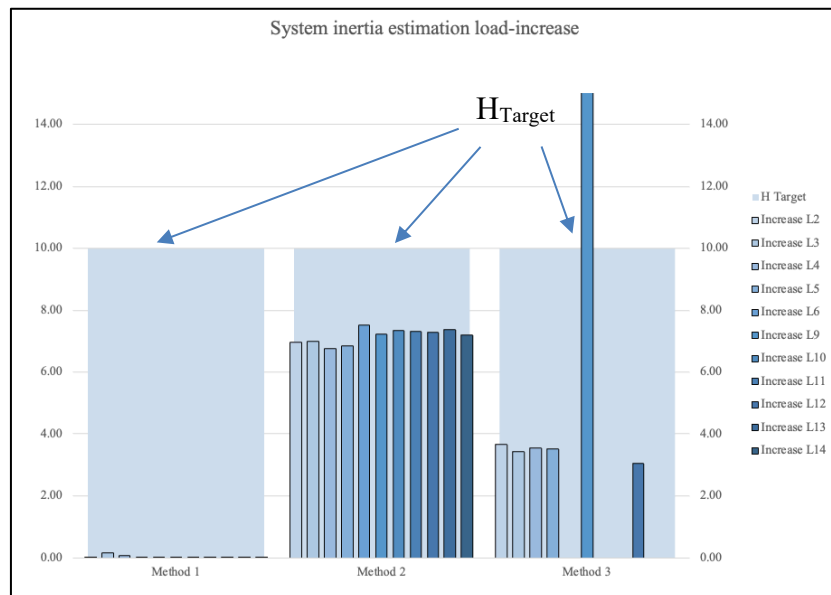


Figure 4-18: Results for 14-Bus system estimations using load increase events

The deviation of the estimated value from the inertia target value is listed in Table 4-16 below.

Table 4-16: 14-Bus system estimations using load increase events (error percentages)

Error (%)	Method 1	Method 2	Method 3
Increase L2	-100%	-30%	-63%
Increase L3	-98%	-30%	-66%
Increase L4	-99%	-32%	-65%
Increase L5	-100%	-32%	-65%

<i>Error (%)</i>	<i>Method 1</i>	<i>Method 2</i>	<i>Method 3</i>
<i>Increase L6</i>	-100%	-25%	-100%
<i>Increase L9</i>	-100%	-28%	115%
<i>Increase L10</i>	-100%	-27%	-100%
<i>Increase L11</i>	-100%	-27%	-100%
<i>Increase L12</i>	-100%	-27%	-69%
<i>Increase L13</i>	-100%	-26%	-100%
<i>Increase L14</i>	-100%	-28%	-100%

- Method 1 is inadequate and completely underestimates inertia.
- Method 2 performs the best, but not without error. Increase in the load by only 50% may suggest Method 2 has higher estimation accuracy as the estimation is consistently around 50% of the available inertia
- Method 3 over- and underestimates inertia. Method 3 seems sensitive to where the loading increases.

4.4 Conclusion

In this chapter, three methods for inertia constant estimation were evaluated using PowerFactory simulations within three reference IEEE power system configurations: the 2-Zone system, the 9-Bus system, and the 14-Bus system.

Each was subjected to four scenarios: loss of generation, earth fault, load demand decrease, and load demand increase. The changes in inertia were known (inertia target values) before using the different methods to estimate what inertia should be.

This allowed comparing performance between the different methods in estimating inertia, and how the type and location of the event within the test network, affect the performance of a specific method.

The performance of the 3 methods used to estimate inertia are compared using the same events for each, respectively in Table 4-17 (2-Zone system), Table 4-18 (9-Bus system) and Table 4-19 below.

Table 4-17: Summary of inertia estimation method results for the 2-Zone system

2-Zone System			
Event	Method 1	Method 2	Method 3
Generation loss	Over- and underestimates. Inconsistent.	Average error below 10%	Over- and underestimates. Inconsistent.
Earth fault	Consistently underestimates.	Over- and underestimates. Inconsistent.	Method fails for small disturbance fitting.
Load loss	Underestimates unless both loads change. Highly variable.	Provides closer estimates with variability. Lacks sensitivity to load size changes.	Inconsistent. Regardless of load loss magnitude.
Load increase	Over- and underestimates. Inconsistent.	Average error below 10%	underestimates

Table 4-18: Summary of inertia estimation method results for the 9-Bus system

9-Bus System			
Events	Method 1	Method 2	Method 3
Generation loss	Variable. Accurate for loss of PV	Average error below 10%	Moderate performance.
Earth fault	Consistently underestimates. Sensitive to data point selection.	Accurate and consistent. Robust across fault locations. Average error below 10%	Method fails for small disturbance
Load loss	Underestimates across all scenarios.	Low error, except for loss of L3	Variable Mostly underestimates
Load increase	Underestimates. Unreliable for increase in load	Closest to target. Slightly overestimates. Consistent accuracy.	Accurate estimation for increase in L1 and L2.

Table 4-19: Summary of inertia estimation method results for the-Bus system

14-Bus System			
Events	Method 1	Method 2	Method 3
Generation loss	Consistently underestimates across all outages. Unreliable.	Closer to target. Consistent but slightly underestimates.	Tends to underestimate more than Method 2. Fails for largest generator (G1).
Earth fault	Consistently undershoots. Sensitive to data point selection.	Accurate and precise. Robust across fault locations.	Not applicable due to insufficient data oscillations.
Load loss	Consistently underestimates. Significantly below target.	Closer to target but only estimates half of the total inertia.	Like Method 2. Estimates roughly half the target value.
Load increase	Consistently underestimates. Values near zero.	Closer to target. Consistent but slightly below target.	Highly variable.

From the above comparative performance, it is concluded that method 2 holds the most potential for a useful prediction of inertia in distribution systems hosting renewable energy sources.

Using the 14- bus system a consistent error of 50% for the load loss and load increase scenarios were captured. This could be due to only a 50% change in loading, as well as the generators not being under full load. Inertia is an indication of a mechanical generators resistance to change in frequency when a change in loading or generation has occurred in a system.

To better understand the results obtained in Chapter 4, a detailed analysis on the results obtained by computer simulation, is then presented in the next chapter as the goal is to apply the best performing method on field data.

What constitutes a best performing will be derived from considering accuracy.

CHAPTER 5: DETAIL ANALYSIS OF SIMULATION RESULTS

5.1 Introduction

This chapter presents a comprehensive analysis of the simulation results obtained from inertia estimation methods. Results obtained in Chapter 4, were interpreted from a qualitative point of view and now, in Chapter 5, a quantitative analysis is presented.

Three different methods to estimate inertia were tested by computer simulation:

- Method 1: Swing equation using consecutive measurement values.
- Method 2: Data windows
- Method 3: 5th order polynomial

The inertia constant for each IEEE reference system (true value within the simulation model) was:

- 2-Zone system: 4 generation units with a total system inertia of 5.48 s.
- 9-Bus system: 3 generation units with a total system inertia of 4.78 s.
- 14-Bus system: 5 generation units with a total system inertia of 10.00 s.

Events were defined to cause a sufficient disturbance that allowed comparing the performance of the above methods:

- Loss of generation: Generation units were disconnected one at a time to establish how generator size affects accuracy when estimating inertia.
- Earth fault: A line-to-earth fault event at each bus was (sequentially) simulated to assess how the distance between the location of a disturbance and the measuring point, affects accuracy.
- Load loss: Loading was decreased instantaneously by 50% to establish how load size affects accuracy.
- Load increase: Loading was increased instantaneously by 50% to assess how load size affects accuracy.

Next, simulation results are subjected to a statistical analysis. The goal is to identify the factors that will help engineers choose what method will work best for what disturbance event, in estimating inertia in distribution systems hosting renewable energy.

5.2 Statistical methodology

A statistical analysis of simulation results allows for an objective evaluation of how the 3 methods perform during different events that affect the availability of inertia. It will be useful to have the knowledge of which method performs the best in terms of accuracy when estimating inertia.

As the true value in inertia was known during the simulations, it was possible to compare inertia constants produced by each method, against the true value (as already discussed in chapter 4).

The ideal method for predicting a change in inertia availability is a method that will be insensitive to the event type and system configuration, producing results that are sufficiently accurate during all these contingencies. From the analysis presented below, it will be shown that unfortunately, no one method exists that can be applied to all configurations and events.

5.2.1 Consideration of accuracy as applicable to the estimation of system inertia

Accuracy, as considered in this chapter, is the difference between the estimated inertia constant and the true value in the reference power system (referred to as the “target inertia constant”).

When considering the same event at each reference power system, the error for a specific method cannot be directly compared, as each reference power system has a different inertia constant. Expressing the error as a percentage is needed, as shown in (5-1) below.

$$\text{Normalised accuracy} = \frac{\frac{1}{n} \sum_{i=1}^n (H_{Estimated_i} - H_{Target})}{H_{Target}} * 100 \quad (5-1)$$

When the number from (5-1) increases, accuracy decreases and a number closer to 0 indicates higher accuracy. Positive errors indicate an estimation higher than the actual inertia constant, and likewise a negative error indicates a lower estimation, compared to the actual inertia constant.

Refer to Figure 5-1 for conceptual clarification, Although the absolute deviations from the target value are of similar magnitude in both cases, the targets differ in size. As a result, the same absolute deviation represents a smaller percentage error for the larger inertia constant (left), leading to a tighter grouping relative to the target.

In contrast, for the smaller inertia constant (right), the same absolute deviation results in a larger percentage error, giving the appearance of a wider spread and reduced accuracy. The green markers (average indicated by a blue square) therefore represent improved normalised accuracy compared to the red markers (average indicated by a red square).

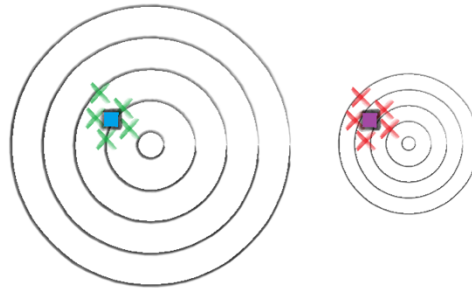


Figure 5-1: Normalised accuracy

An evaluation of accuracy is done using the structure below:

- *System configuration is variable*: The accuracy obtained from a specific method, and a specific event, is compared across all 3 reference power systems. The goal is to establish the change in accuracy of a specific method and event as a function of system configuration.
- *Disturbance event is variable*: A specific method is applied in a reference power system, but the event type is changed. The goal is to establish the suitability of a specific method in a specific system configuration for a specified event.

If the accuracy from a specific method is configuration or event-sensitive, guidelines can be derived from the above results on when to use what method.

5.3 Analysis of accuracy

Errors were calculated considering different methods applied to different disturbance events and in different system configurations.

5.3.1 Errors from method 1

Using (5-1) the normalised accuracy (error) was determined for the inertia predicted by method 1. This was done on a per-system and per-event-type basis as listed in Table 5-1 below.

Table 5-1: Errors obtained from method 1

<i>Event type</i>	<i>2-Zone system</i>	<i>9-Bus system</i>	<i>14-Bus system</i>	<i>Average</i>
<i>Gen loss</i>	39%	-51%	-94%	-35%
<i>Earth fault</i>	-63%	-61%	-95%	-73%
<i>Load loss</i>	245%	-44%	-100%	34%
<i>Load increase</i>	-96%	-96%	-100%	-97%
<i>Average</i>	31%	-63%	-97%	-43%

From Table 5-1:

- The error is large for all methods, systems and events.
- 2-Zone type configuration performs the best with method 1.
- Load loss events has the lowest error for method 1.

5.3.2 Errors from method 2

The errors resulting from applying method 2 are listed in Table 5-2 below.

Table 5-2: Errors obtained by method 2

<i>Event type</i>	<i>2-Zone system</i>	<i>9-Bus system</i>	<i>14-Bus system</i>	<i>Average</i>
Gen loss	0%	4%	-45%	-13%
Earth fault	95%	-6%	-37%	17%
Load loss	23%	26%	-47%	1%
Load increase	-6%	7%	-28%	-9%
Average	28%	8%	-39%	-1%

From Table 5-2:

- Method 2 has an average error of lower than 10%.
- Method 2 over and underestimates, however when using a lot of data, a low error can be expected for estimating inertia.

5.3.3 Errors from method 3

The errors resulting from applying method 3 are listed in Table 5-3 below.

Table 5-3: Errors obtained by method 3

<i>Event type</i>	<i>2-Zone system</i>	<i>9-Bus system</i>	<i>14-Bus system</i>	<i>Average</i>
Gen loss	-25%	-31%	-56%	-37%
Earth fault	-	-	-	-
Load loss	86%	-38%	-64%	-5%
Load increase	-42%	-33%	-65%	-47%
Average	5%	-26%	-46%	-26%

From Table 5-3:

- The error is large for all methods, systems and events, method 3 achieved an average error lower than 50%, however over and underestimated as well.
- Best results are where generators are running at full capacity (9-Bus system).
- Method 3 can't be used for earth faults as the method occasionally fails to estimate a value.
- It can be noted that in load loss and increase estimations, the error is approximately 50%, this could be due to the load only being varied by 50%.

5.4 Comparison of results

Figure 5-2 compares accuracy by showing the errors obtained from applying different methods to different events in the three system configurations.

The average error of each method across events is shown in a back layer in light blue, Figure 5-2, Figure 5-3 and Figure 5-4 below. Each methods average error for a disturbance has been plotted in shades of blue with a black border.

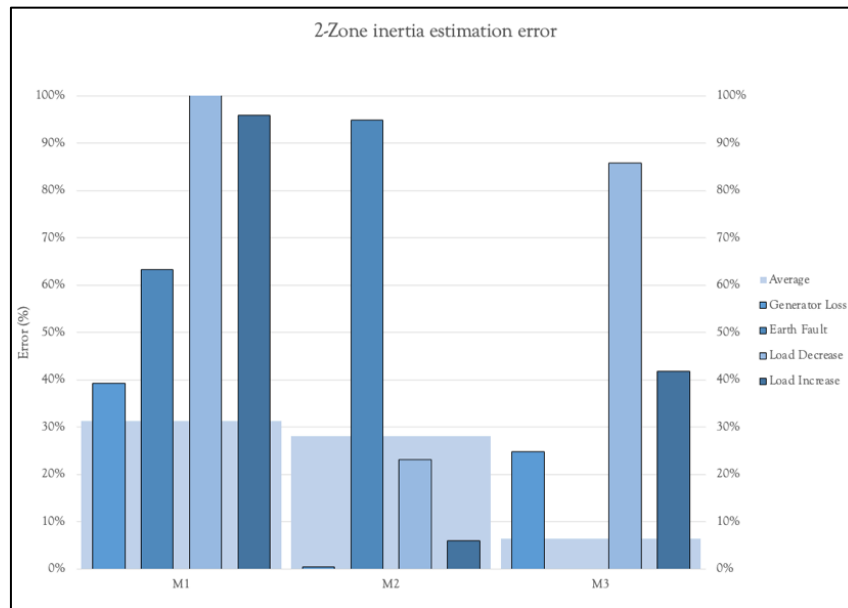


Figure 5-2: 2-Zone system accuracy (depicted as error percentage) method comparison

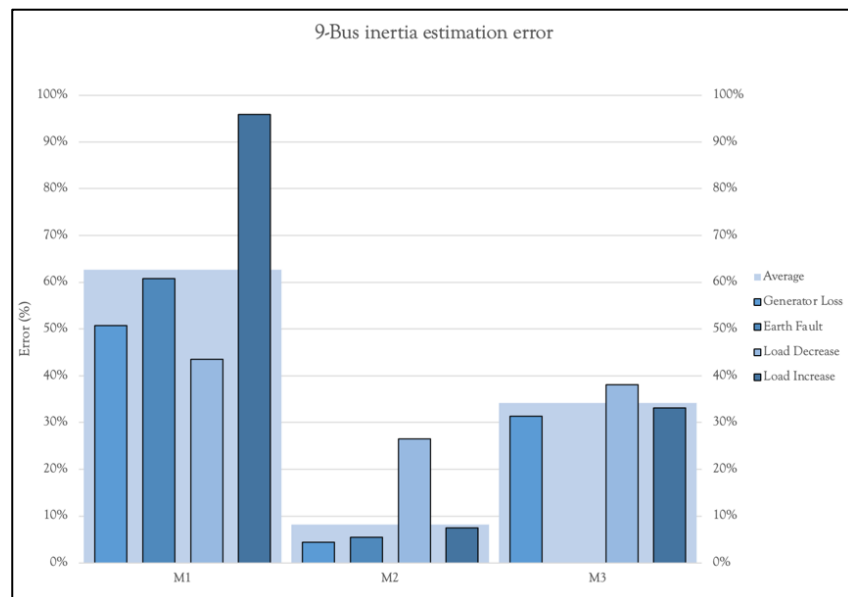


Figure 5-3: 9-Bus system accuracy (depicted as error percentage) method comparison

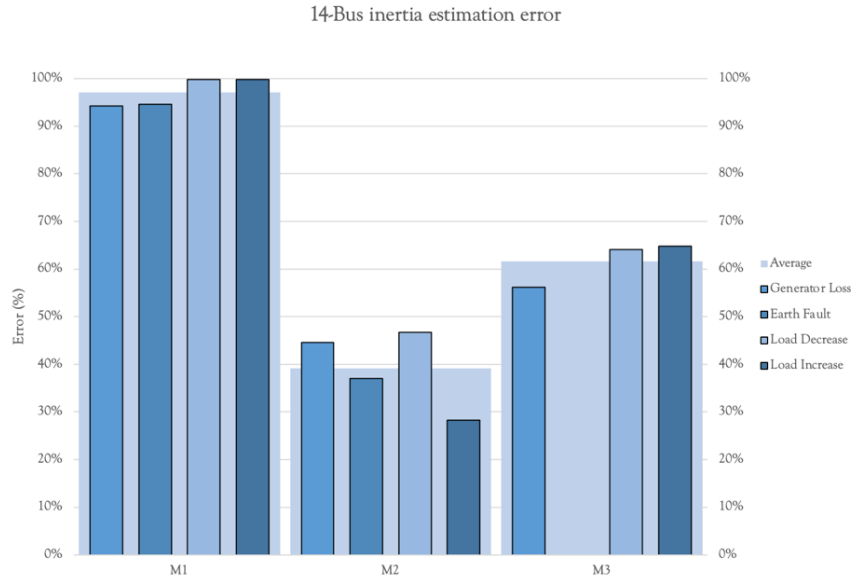


Figure 5-4: 14-Bus system accuracy (depicted as error percentage) method comparison

From Figure 5-2 to Figure 5-4, it can be noted method 2 and 3 shows relative accurate estimations. The average estimation error for method was shown as less than 10%, with an overall average of 1% estimation error.

Estimating inertia is greatly affected by the data used in the estimation. The event that took place will need to be of great magnitude in order to stimulate a great inertia response from the generators in the system. With only this large event one will be able to estimate inertia with good accuracy.

In the 14 bus system, a general error of 50% was observed in the load loss and load increase events. The respective load in the system only changed by 50%, and the generators not running at full capacity could be the reason for the low estimation accuracy.

From the results presented in Chapter 4, and the analysis thereof in Chapter 5, a conclusion is presented next.

5.5 Conclusion

The results obtained in Chapter 4 were compared to determine which method is most suitable for inertia estimation. Each method was evaluated across the different simulated systems and disturbance cases, as presented in Chapter 4. The results are summarised in Table 5-4, here the method with the lowest percentage error is listed along with the corresponding error for each case.

Table 5-4: Average accuracy per method as a function of event type and system configuration.

<i>Event Type</i>	<i>2-Zone type system</i>	<i>9-Bus type (generators at full capacity)</i>	<i>14-Bus type (generators not at full capacity)</i>
<i>Gen loss</i>	Method 2 (0% error)	Method 2 (4% error)	Method 2 (45% error)
<i>Earth fault</i>	Method 1 (63% error)	Method 2 (6% error)	Method 2 (37% error)
<i>Load loss</i>	Method 2 (23% error)	Method 2 (26% error)	Method 2 (47% error)
<i>Load increase</i>	Method 2 (6% error)	Method 2 (7% error)	Method 2 (28% error)

From Table 5-4, it is evident that method 2 provides the most consistent performance across most system configurations and disturbance events. However, its accuracy decreases in larger systems, particularly where generators are not operating at full capacity. This indicates that while Method 2 is generally suitable for inertia estimation, its applicability is dependent on system conditions and the type of disturbance considered.

From the results future research could include how a change in loading affect the accuracy in inertia estimation, as function of the size of the change in loading.

Further research is needed to determine acceptable accuracy thresholds for inertia estimation. Additionally, more studies are required to establish guidelines on data selection, including optimal window width and the choice of consecutive measurements.

CHAPTER 6 ONLINE ASSESSMENT ESTIMATION OF INERTIA VERIFICATION.

6.1 Introduction

As validation of the results, method 2 was implemented in a real-world scenario, the results are presented below in this chapter.

Initially, IEEE reference power system configurations were used to better understand how the different methods performed against each other. By using DIGSILENT PowerFactory, a real-world power system was first modelled to identify how field data should be collected.

Due to national loadshedding in South Africa, significant disturbance events occurred regularly, resulting in the distribution grid of the North-Wes University to part of the national grid, resulting in an islanded condition when the national grid is disconnected.

Integrated photovoltaic (PV) generation complimented the stand-by diesel generation when islanded, and when not, supplemented the grid energy when the diesel generator was not in use. The loading of the diesel generator was not high enough to utilise the nameplate rating, but such a scenario is what occurs in the IEEE 14-Bus system.

From the findings Section 5.5, method 2 is the most suitable approach for a distribution system when rotating generators are not fully loaded.

6.2 Developing a simulation model

During normal operating conditions, the national grid supplies most of the loading (peak demand of 194 kVA), complemented by rooftop PV (up to 50 kVA).

When the national grid is lost, the university distribution grid becomes islanded. The diesel generator (800 kVA) becomes the primary resource, energising the distribution network within 30 s. The grid-connected PV inverters (no batteries) contribute as much energy as possible during the prevailing conditions of irradiation at any time.

6.2.1 Estimate generator mechanical inertia from first principles.

Mechanical inertia in a rotating generator relies on the moment of inertia resulting from the physical mass of the rotor rotating at a specific (i.e. synchronous) speed and its power rating.

Inertia calculation follows from first principles using (6-1) below.

$$H = \frac{J\omega^2}{2S_{rated}} \quad (6-1)$$

Where:

- H represents the inertia constant, measured in seconds (s).

- J is the moment of inertia of the generator's rotating mass, measured in kilogram square meters ($\text{kg}\cdot\text{m}^2$).
- ω denotes the angular velocity of the rotating mass, measured in radians per second (rad/s).
- S_{rated} signifies the rated apparent power output of the generator. measured in volt-amperes (VA).

Nameplate ratings for the three-phase synchronous generator [46] are listed in Figure 6-1 below.

Table 6-1: Diesel generator nameplate data.

<i>Electrical properties</i>	<i>Quantity</i>	<i>Unit</i>
J	Approx 13,12	kgm^2
ω	100π	rad/s
S_B	800	kVA

Using the values in Figure 6-1 in (6-1), result in the calculation below:

$$H = \frac{(13.12)(100\pi)^2}{2(800\,000)} = 0.809 \text{ s}$$

The remaining system data are listed below in Table 6-2.

Table 6-2: Grid parameters.

SYSTEM VARIABLE	POWER (kVA)		Voltage (V)
GENERATOR	800		400
SOLAR	50		400
TRANSFORMER 1	1600		11000/ 400
TRANSFORMER 2	315		11000/ 400
TRANSFORMER 3	315		11000/ 400
TRANSFORMER 4	800		11000/ 400
TRANSFORMER 5	1000		11000/ 400
LOADS	Power (kVA)	Power factor	
LABORATORY	4.10	0.91	400
WORKSHOP	36.00	0.98	400

SYSTEM VARIABLE	POWER (kVA)		Voltage (V)
ENGINEERING COMPLEX	124.16	0.91	400
ADMINISTRATION BLOCK	65.21	0.94	400

The system configuration is shown in Figure 6-1 below.

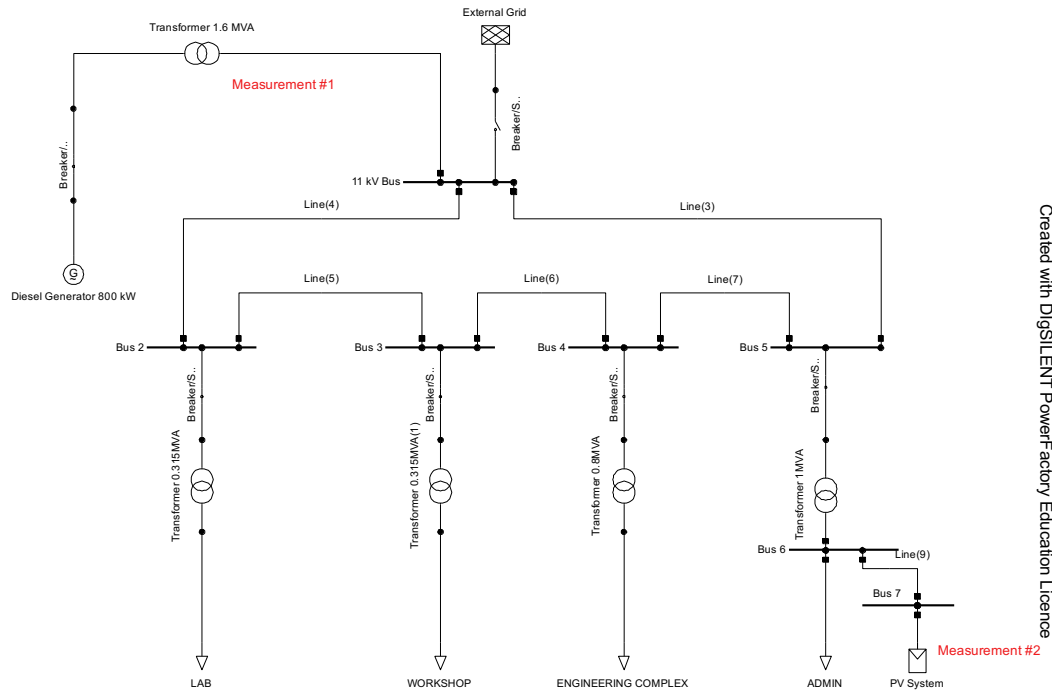


Figure 6-1: The single-line diagram of the simulated system.

6.3 Verifying the network model

The DIgSILENT PowerFactory model was tested against the reference loading values listed in Table 6-2. Simulation results are listed below in Table 6-3 and Table 6-4

Synchronised measurements were taken at the points where the diesel generator, and where the PV generation feeds into the distribution network (see Figure 6-1).

These measurement locations were specifically chosen as the sources of generation, and their impact on inertia estimation are to be investigated. Additional measurement locations could be at the various load connections to the system.

Results for the PV Point of Connection (PoC) are listed in Table 6-3 below.

Table 6-3: Simulation and measured results at PV PoC

<i>Variable</i>	<i>Measured</i>	<i>Simulation</i>	<i>Deviation</i>
<i>Voltage (V)</i>	400.02	400.00	0.0%
<i>Current (A)</i>	93.97	94.96	1.0%
<i>Active Power (kW)</i>	64.74	65.00	0.4%
<i>Reactive Power (kvar)</i>	3.54	3.56	0.5%
<i>Apparent Power (kVA)</i>	65.11	65.10	0.1%

The Generator POC simulation values are compared to the measured values in Table 6-4 below.

Table 6-4: Simulation and measured results at generator POC

<i>Value</i>	<i>Measured</i>	<i>Simulation</i>	<i>Deviation</i>
<i>Voltage (kV)</i>	11.01	11.00	0.0%
<i>Current (A)</i>	10.51	11.00	4.4%
<i>Active Power (kW)</i>	153.16	154.82	0.6%
<i>Reactive Power (kvar)</i>	180.05	174.85	0.3%
<i>Apparent Power (kVA)</i>	200.25	213.29	0.6%

This simulation emulates the islanding process when the utility grid disconnects as shown in Figure 6-2 below. First, the generator starts after 30 seconds, followed by the PV inverters and the load after another 15 seconds (more or less). The simulated RMS power can be seen in Figure 6-2 below.

Replicating the measured system response in DIgSILENT PowerFactory proved difficult due to the presence of generator controllers in the real system. The measured data already includes the effects of these controllers, such as governor and excitation responses, which are not straightforward to model. The available controller models in PowerFactory require accurate parameterisation and tuning, and introducing them without well-defined parameters may introduce unnecessary uncertainty and reduce the reliability of the results.

This study therefore focuses on the initial system response, typically within the first few seconds after a disturbance, where inertia is the dominant factor. During this period, system behaviour is mainly governed by the stored kinetic energy in the rotating masses, as described by the swing equation. The classical synchronous machine model, available from the DIgSILENT PowerFactory library was used. The model enables configuration regarding the inertia constant of the mechanical generator.

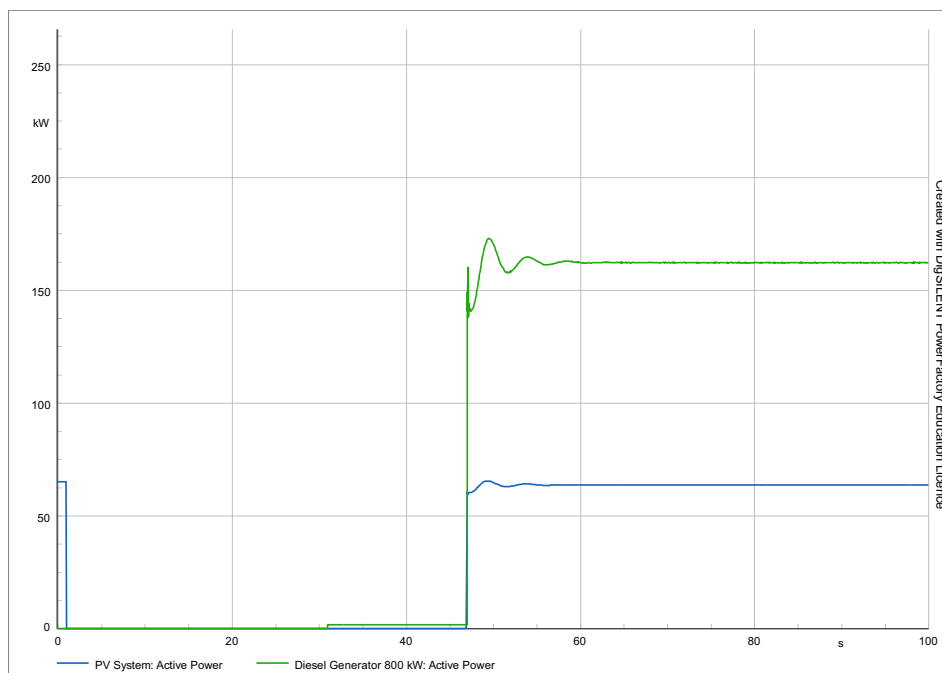


Figure 6-2: Active Power, power system islanding and diesel generator startup.

Rate of change of frequency (ROCOF) can be derived from the frequency swings observed in Figure 6-3 below.

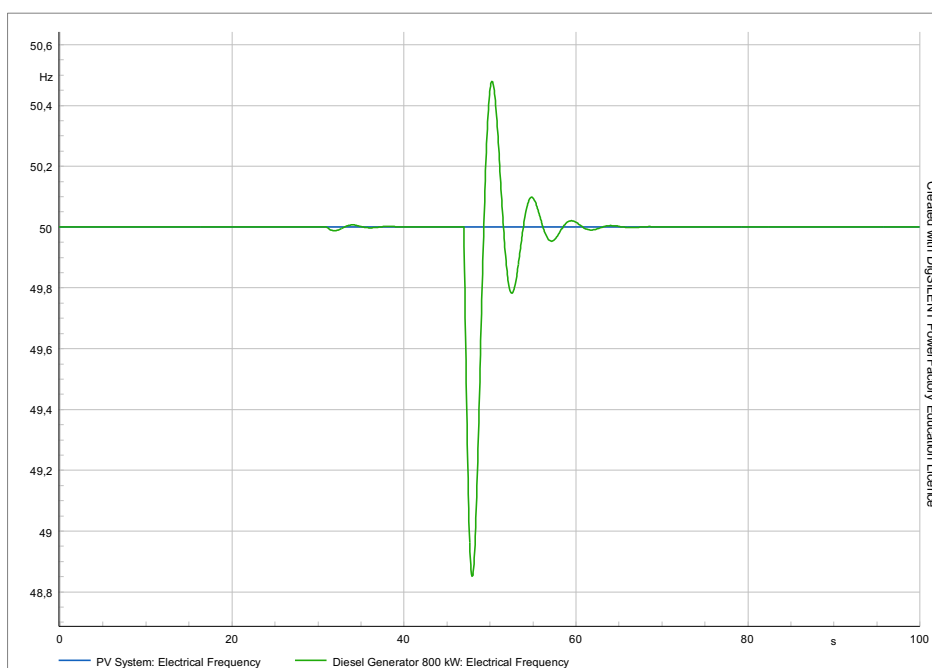


Figure 6-3: Frequency from power system islanding and diesel generator startup.

Figure 6-4 below is obtained by calculating the ROCOF from Figure 6-3 above.

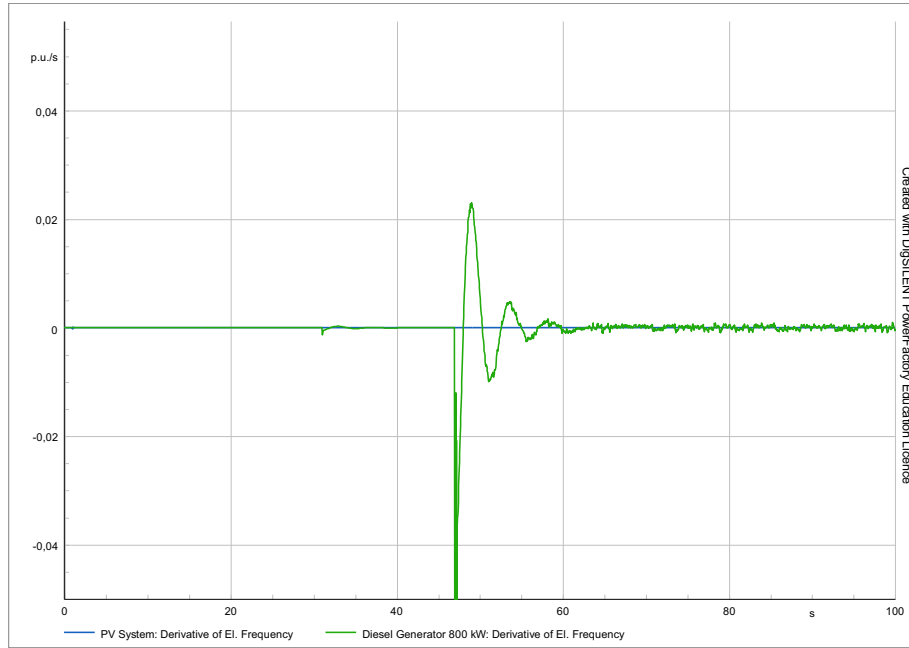


Figure 6-4: ROCOF from power system islanding and diesel generator startup.

Next, the change in inertia is estimated.

6.4 Estimation of inertia by method 2

From the measured data, the system disturbance was defined to occur at $t_0 = 47$ s (the instantaneous loading of the generator and PV). The principles of method 2 was described by (3-7) and tested on reference IEEE power systems, in section 4.3.

Frequency and active power were tracked by DigSILENT PowerFactory reporting the values every 10 ms and using a data window of 1 s to include sufficient datapoints before and after the system disturbance.

Applying method 2, the inertia constant was estimated as 0.48 s.

Table 6-5: Inertia estimation using method 2.

	<i>Load increase (kW)</i>	<i>Inertia Estimation (s) (method 2)</i>	<i>Inertia (s) (from nameplate)</i>
<i>Value</i>	193.87	0.48	0.81

Similar to section 5.3.2, the inertia estimation when using data where; a sudden change in loading took place in a system where the generator is partially loaded. From section 5.5, this resulted in an error of approximately 50 %.

Literature [32], suggests that the performance of method 2 improves when continuously tracking inertia over time, how much is not reported.

6.5 Plotting inertia vs time using method 2

The ratio of the incremental change in loading and frequency at the generator, (dP/dHz) is shown in Figure 6-5 below. A moving window of 1 s was applied to the whole dataset (grid disconnects, the generator starts, load is added, PV inverters connect).

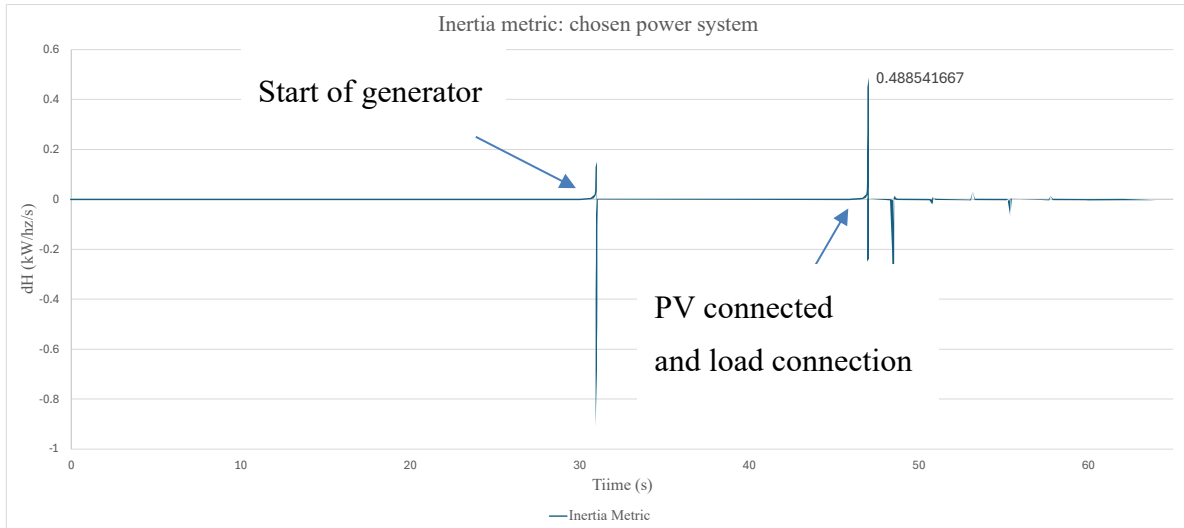


Figure 6-5: Inertia tracking over time in the test network.

These results were obtained using simulation data. It should be noted that real measured data may contain measurement noise; however, the simulation provides an indication of the expected behaviour when analysing real-life system disturbances.

When the generator starts at 31 s (Figure 6-5), a momentary change in inertia occurs as the generator rotor speeds up to be regulated at the nominal value of 50 Hz. The control system used to regulate rotor speed, the mass of the rotor and the characteristics of the diesel engine, all contribute to this event.

When the load is connected at 47 s, another sudden change in the estimated inertia is observed, resulting in an estimated value of 0.48 s. The relatively high error of 41% may be attributed to the disturbance not being sufficiently large to fully excite the system inertia. As a result, only a partial inertial response is captured in the data.

Observe that the generator was not loaded to full capacity when serving a load of approximately 200 kVA, The nameplate rating is 800 kVA. About 50 kW from the PV system is instantaneously added, once the load is energised. It was discussed in Chapter 5 that Method 2 does cause errors in estimating inertia in systems where the generators are not loaded to capacity, resulting in a much lower value for inertia.

6.6 Conclusion

The inertia constant for the mechanical diesel generator, calculated from nameplate values, was found to be 0.81 s. When testing method 2 using a DIgSILENT PowerFactory simulation of the real-world test network, it was underestimated by about 40% as 0.48 s.

This was done using simulated data for active power and frequency at the point where the generator and the utility grid feed into the university distribution network (the real-world test network).

The underestimation of inertia when using method 2, aligns with the results discussed in section 5.3.2, which was obtained by testing method 2 within IEEE reference power networks.

Although method 2 did not estimate inertia accurately, when subjecting it to a moving window of active power and frequency data, it did identify the events where the equilibrium between loading and generation was sufficiently disturbed ($dP/dHz \neq 0$).

By applying Method 2 with averaging data windows and plotting the estimated inertia over time, grid operators can monitor system stability. As a result, stability can be assessed continuously rather than from a single disturbance event.

CHAPTER 7 FIELD APPLICATION OF ONLINE INERTIA ESTIMATION

7.1 Introduction

In Chapter 5, the different methods to estimate inertia were studied making use of IEEE reference networks. Chapter 6 applied a specific method (Method 2) to a simulation of the real-world distribution grid. This network as discussed in Chapter 6, is at the North-West University where rotating and renewable generation are embedded to mitigate the loss of the utility infeed.

Chapter 7 now examines use measured field data, obtained coherently at different points within this real-world network, to test Method 2 under real-world conditions.

7.2 Field data

A basic diagram of the distribution network serving the university campus is illustrated in Figure 7-1.

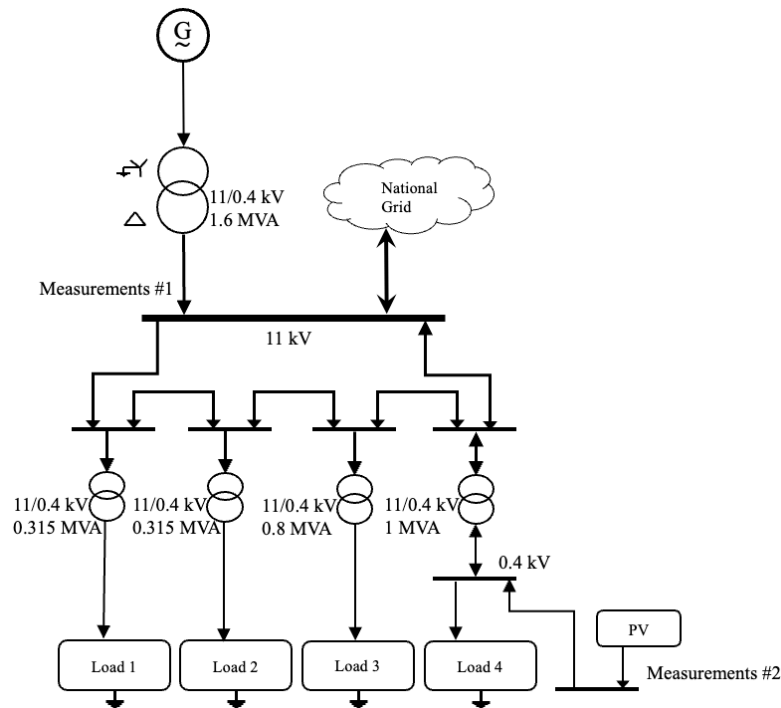


Figure 7-1: Schematic of the university network used for inertia estimation

Two instruments, synchronised by GPS, were needed and located as indicated in Figure 7-1. They were configured to retain 200 ms values of active power and frequency.

As these instruments are certified power quality instruments, they collect voltage and current waveforms for 10 cycles of the fundamental frequency (nominally at 20 ms, resulting in a 200 ms block of data) and then use the harmonic phasors to calculate a host of parameters, amongst them, active power and frequency of the fundamental harmonic component.

The events taking place on a regular basis in this system allows for useful data to estimate inertia in a system with renewable energy. This system was simulated and similar events was simulated

in the model. Measurements were taken at the point when generation connects in the system, similar to what was shown in Chapter 6.

During load shedding, when the national grid is disconnected, the diesel generator energises the network and the grid-connected rooftop photovoltaic (PV) system supply energy as available during the day. End-users are connected at 400 V and supplied by a ring-feed configuration of 11 kV, 50 Hz.

Within this local network, a 50 kW grid-connected rooftop photovoltaic (PV without batteries) system supplements the energy drawn from the national grid. When the connection to the national grid is disconnected, a 400 V, 800 kVA diesel back-up generator starts after about 30 s.

With the maximum loading in the network about 200 kVA, the PV source can supply up to 25% during instances of peak solar irradiation. It will re-connect to the local network once the diesel generator starts to supply the local loads.

It has been shown by [38] that the most significant frequency deviation is recorded nearest to the event, resulting in the largest magnitude estimate of Rate of change of frequency (ROCOF) [38], [39].

7.2.1 Contingency to be used

In South Africa, national frequency control involves scheduled disconnections of various network segments to balance load with available generation. These disconnections vary by region and typically occur in approximately 2-hour intervals. During these events, the campus network operates as an islanded distribution network.

When the national grid connection is lost, the entire distribution network experiences a power outage. Within a minute, the generator begins supplying energy, followed by the PV inverters synchronising within a few seconds. The amount of PV energy available is contingent on daily solar irradiation.

A weather table documenting the cloud coverage of each day can be seen below in Table 7-1. Once the national grid is restored, the diesel generator synchronises with the grid before disconnecting, ensuring a seamless transition from diesel generation to the national grid. The PV disconnects and re-connects once the generator supplies active power.

The previously described sequence of events leads to substantial variations in available inertia, allowing for thorough and comparative assessments of stability quantification based on inertia availability within the distribution grid.

This experiment examines four different states of system inertia within the distribution system.

- Only the national grid: The national grid is the only energy source, but with variable levels of traditional inertia and without any local embedded generation.
- Daytime with PV: The national grid is complemented by PV during the daytime.
- Islanded state: Only diesel generation during night-time.
- Daytime with diesel and PV: Diesel generation is supported by PV generation during the daytime.

All network states were known and correlated with the field data used to study the tracking of system inertia.

The Historic data for Potchefstroom from the 18th of October to the 1st of November was taken from weatherapi.com [47].

Table 7-1: Historic cloud coverage for Potchefstroom 2023

Date	Cloud coverage	Event no
28 October 2023	Cloud coverage at 15:00	
29 October 2023	Cloud coverage at 15:00	Event 1 Generator with no PV
30 October 2023	Cloud coverage at 12:00	
31 October 2023	Full cloud coverage	Event 2 Generator with low irradiance (low PV)
01 November 2023	Clear skies from 09:00	Event 3 Generator with high irradiance (high PV)

7.2.2 Field data: Instrumentation

At each measurement point, voltage and current were recorded using a Vectograph 3, that is a power quality instrument certified to meet the IEC 61000-4-30, Class A, edition 3 standards. The instrument's sampling rate of 500,000 Sa/s captured waveform data in 10/12 cycle blocks. The manufacturer claims an accuracy of 0.1 % within the measurement range of 10 % to 100 % of the rated value. The reporting rate of the device is 200 ms. Key computed metrics included frequency, rate of change of frequency (ROCOF), and active power, with measurements synchronised across different points and a time-stamping precision within ± 100 ns.

7.3 Data analysis

Synchronous measurements were taken at the points where the inverters connect to the local 400 V bus and at the 11 kV bus where the generation feeds into the 11 kV ring via an 11/0.4 kV transformer. Figure 7-1 further illustrates that the national grid connects at 11 kV.

The measured data from each measuring point was plotted, the frequency, ROCOF and Active power is shown for each event. Applying the chosen inertia estimation method to measured data can be seen in the following graphic for each event.

7.3.1 Event 1: Grid loss, generator only with no PV infeed.

Frequency, ROCOF and Active power were measured at measuring point 1 and 2. The plots using raw data of 29 October 2023, with minimal PV (after 18:00) is shown in Figure 7-2, Figure 7-3, Figure 7-4 and Figure 7-5 below.

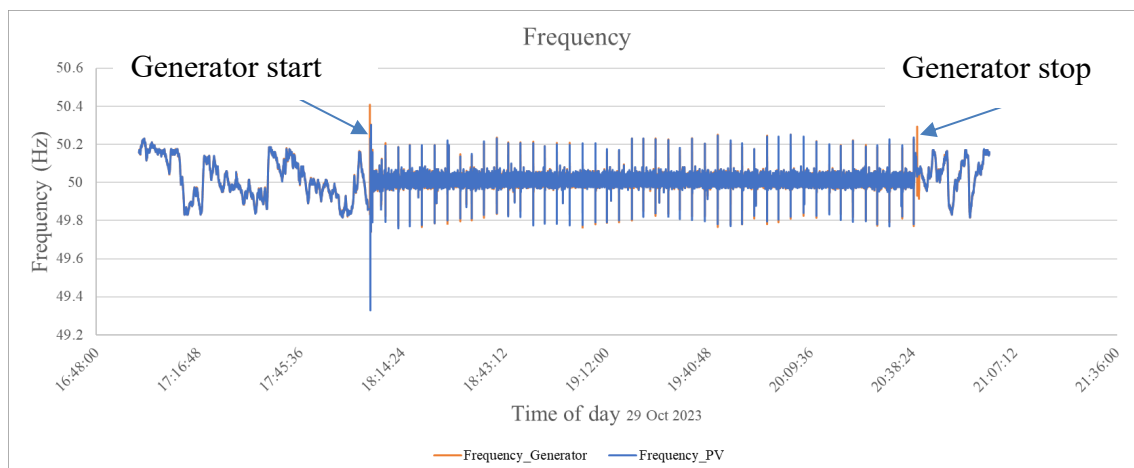


Figure 7-2: Frequency at measuring points 1 and 2

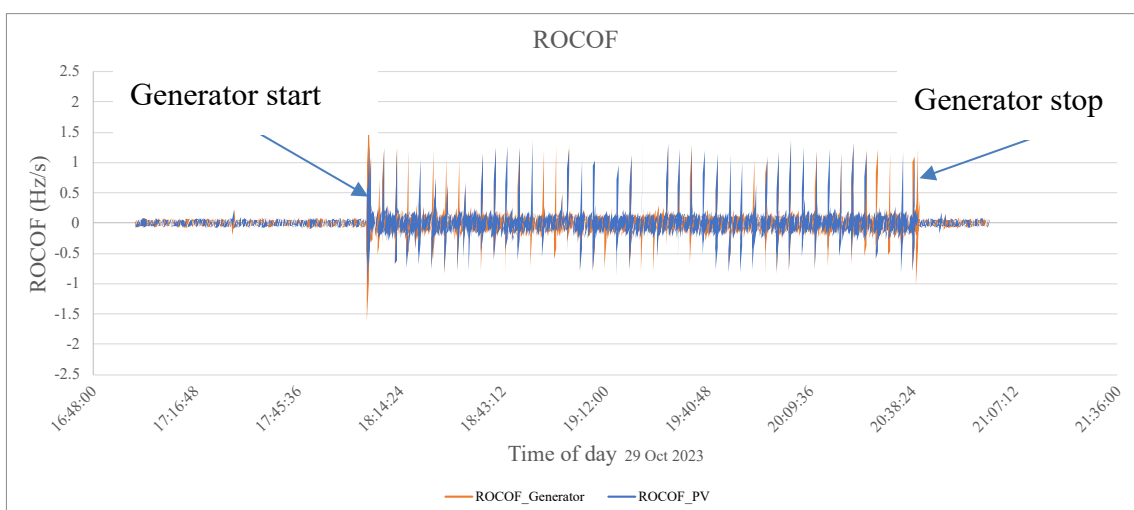


Figure 7-3: ROCOF at measuring points 1 and 2

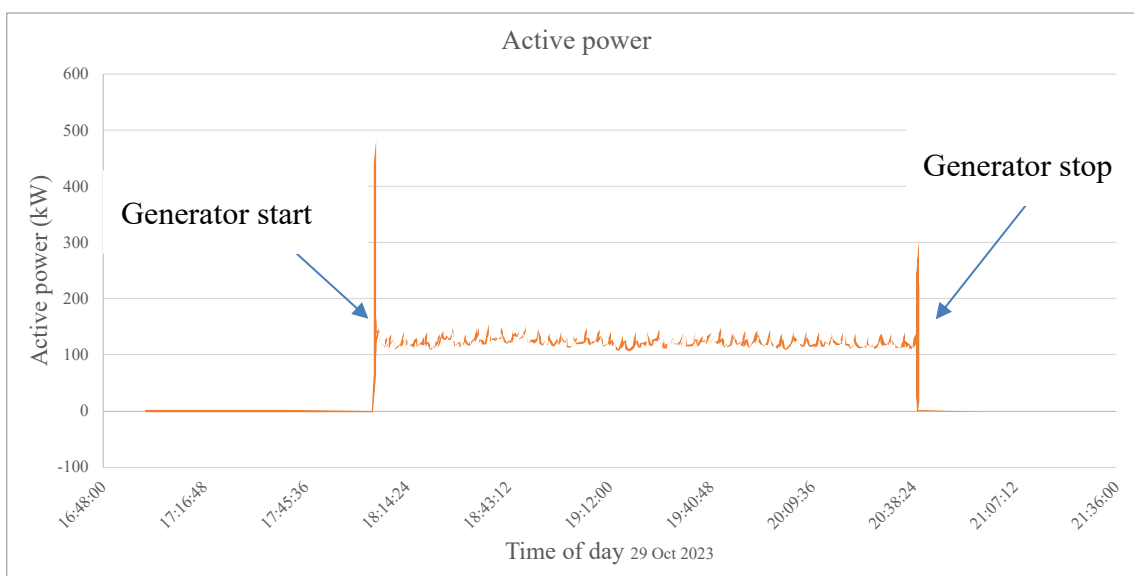


Figure 7-4: Active power at measuring point 1 (Generator PoC)

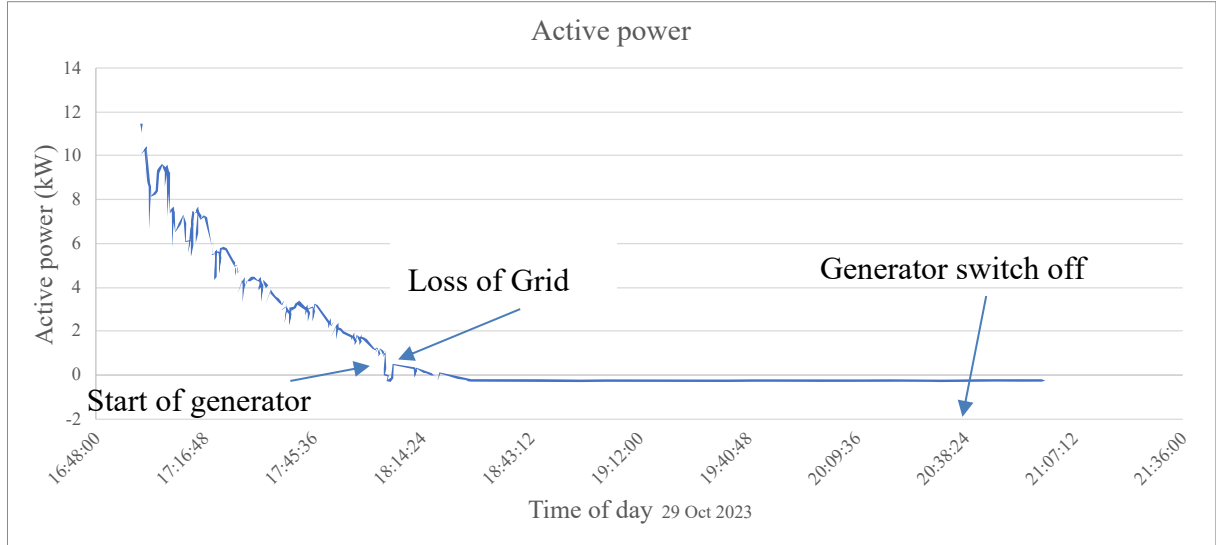


Figure 7-5: Active power at measuring point 2 (PV PoC)

Note the frequency profile in Figure 7-2, there is a visible change in behaviour when the diesel generator is the source in the islanded network. No observation of instability can be made looking at the active power plot alone.

Applying method 2 onto the datasets shown in Figure 7-3, Figure 7-2 and Figure 7-3 above, making use of a 1 s moving window, a significant change is observed in the system state at near 18:00, with several mismatches between loading and generation during the period 18:00 to 20:00. Notably a significant change in load was not present as this is after office hours.

Figure 7-6 below shows how the ratio of active power to ROCOF can be considered as an inertia stability metric. This stability index can be used to estimate of both the available inertia with the first peak at 0.844 s when the generator is running, close to the calculated 0.809 s (error of 4.3%). This highlights the importance of data selection and identifying hyperparameter threshold).

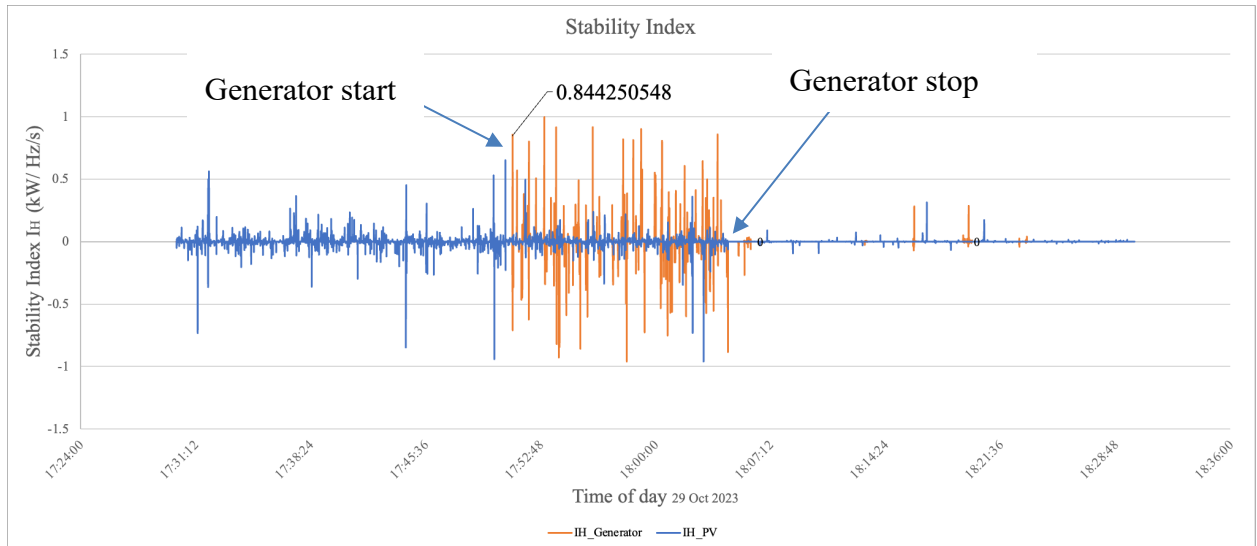


Figure 7-6: A stability metric to assess how inertia affects system stability when no PV is connected

From Figure 7-6 it can be concluded that the generator has less ability to contain frequency during sudden load changes compared to the condition when the university network is connected to the utility grid. Observe that the above results exclude the contribution of the solar PV system. The measured data from the generators' PoC plotted as the stability index, has a standard deviation of 0.0201. This event cannot be directly compared with data measured during daytime, as the load is significantly lower after office hours.

7.3.2 Event 2: Grid loss, generator with PV infeed during period of low irradiation

The 31st of October was a notable cloudy day, variation in PV is notable from 09:00 onwards. At first no notable difference can be seen in the frequency and ROCOF profile of the measured data.

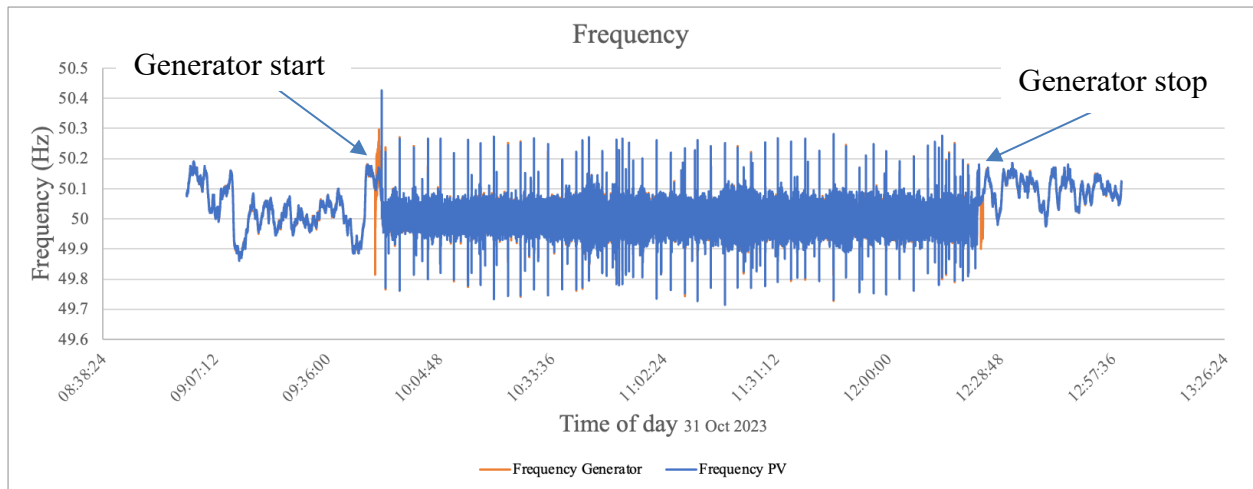


Figure 7-7: Frequency at measuring points 1 and 2

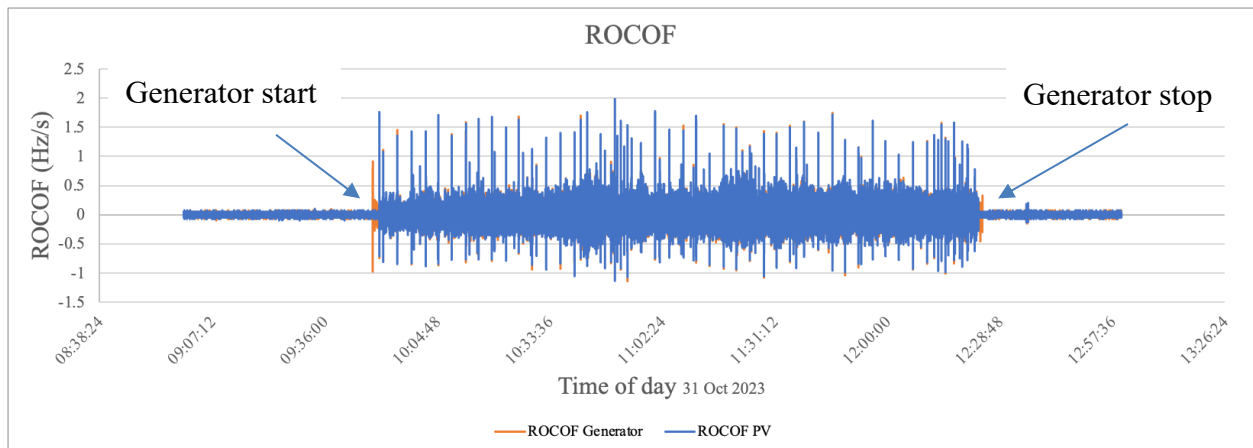


Figure 7-8: ROCOF at measuring points 1 and 2

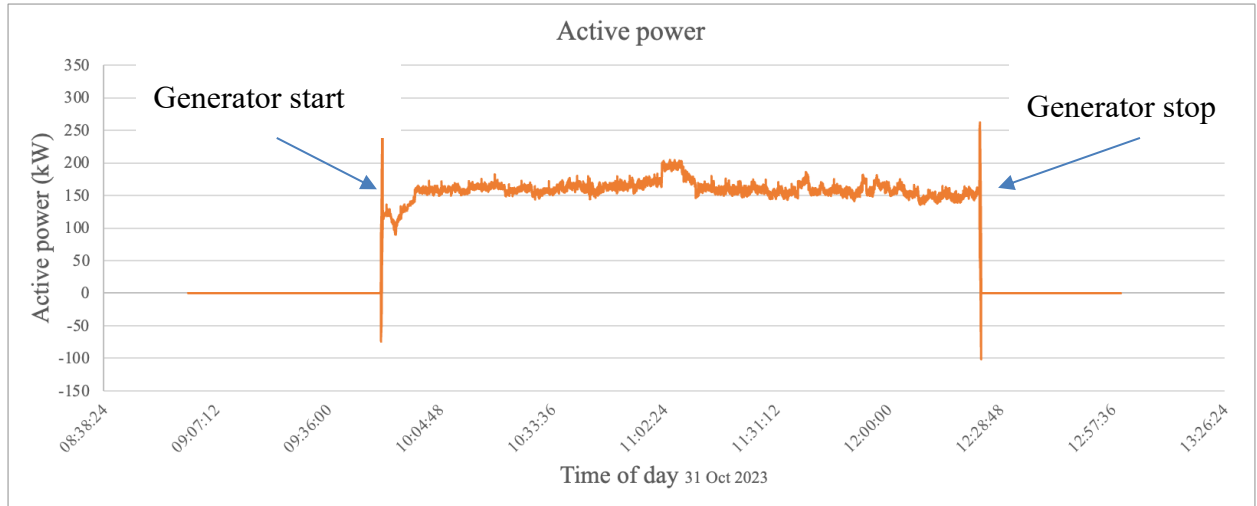


Figure 7-9: Active power at measuring point 1 (Generator PoC)

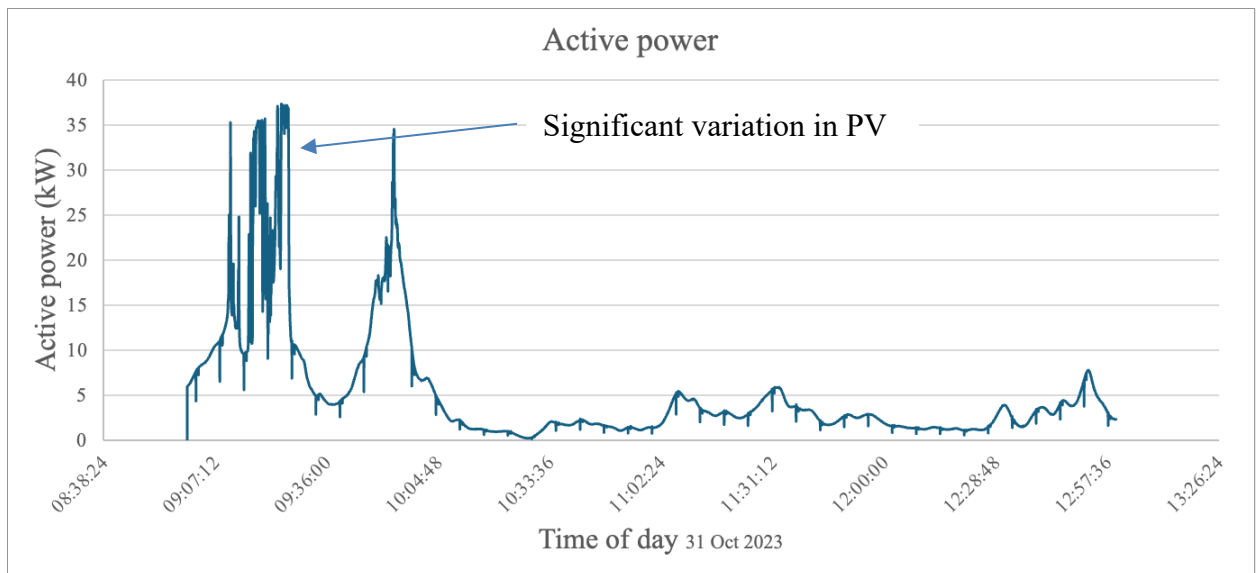


Figure 7-10: Active power at measuring point 2 (PV PoC)

Note the frequency profile in Figure 7-7, there is a visible change in behaviour when the diesel generator is the source in the islanded network. No observation of instability can be made looking at the active power plot alone.

Applying method 2 onto the datasets shown in Figure 7-8, Figure 7-9 and Figure 7-10 above, making use of a 1 s moving window, a significant change is observed in the system state at near 10:00, the significant variation in PV around 09:00 can be visibly seen, however as the power delivery from the inverters decrease, a lower overall stability index can be observed from the PV.

This reduction should not be interpreted as a direct reduction in physical inertia of the PV plant, but rather as a reflection of the changed system operating condition.

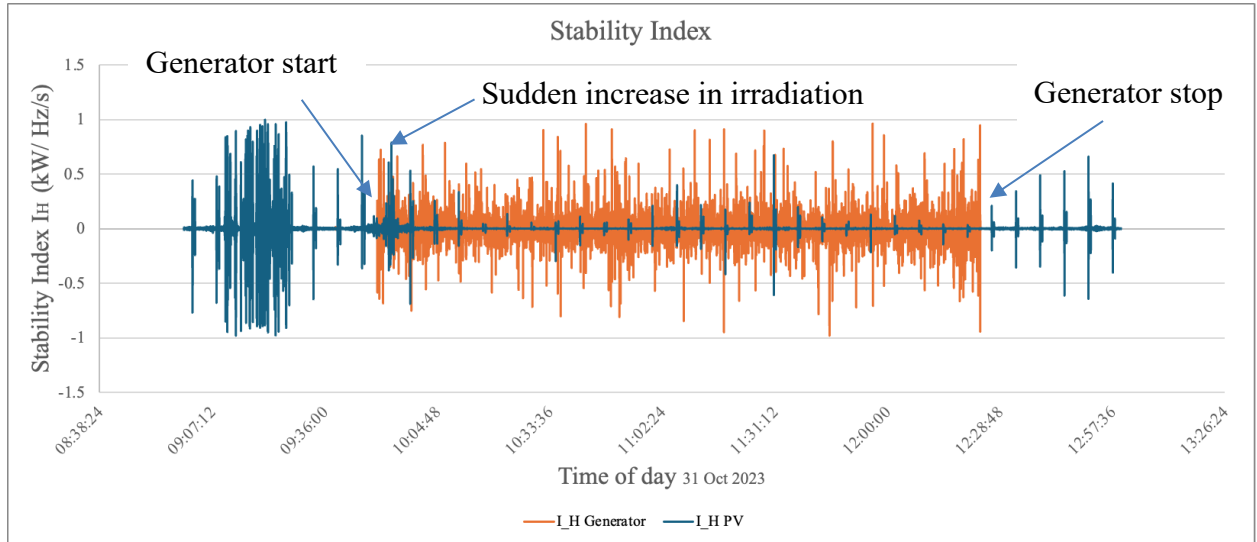


Figure 7-11: A stability metric to assess how the change of inertia affects system stability

From Figure 7-11 it can be concluded that the generator has less ability to contain frequency during load changes compared to the condition when the university network is connected to the utility grid. Observe that with less PV the stability index significantly decreased in comparison with PV infeed during high irradiance shown in Figure 7-16. The measured data from the generators PoC plotted as the stability index, has a standard deviation of 0.0582.

7.3.3 Event 3: Grid loss, generator with PV infeed during period of high irradiation

The 1st of November was a relatively sunny day, supplying measured PV data with high irradiation. At first no notable difference can be seen in the frequency and ROCOF profile of the measured data.

Note the frequency profile in Figure 7-12, there is a visible change in behaviour when the diesel generator is the source in the islanded network. No observation of instability can be made looking at the active power plot alone.

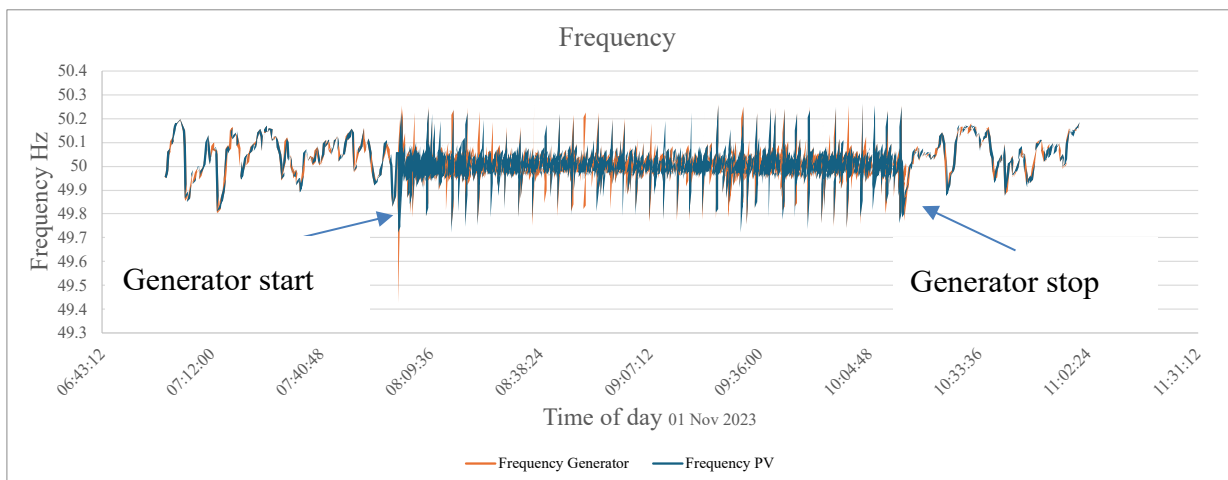


Figure 7-12: Frequency at measuring points 1 and 2

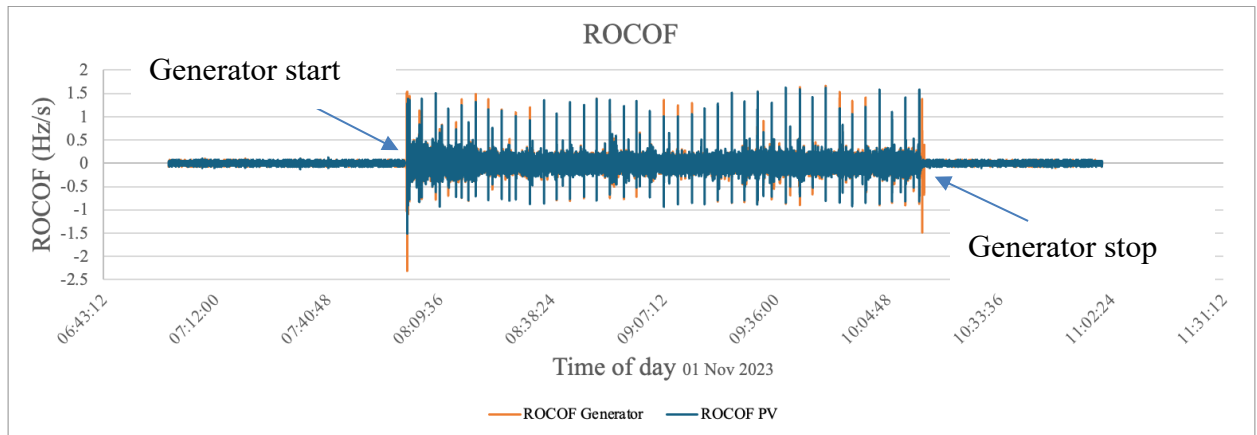


Figure 7-13: ROCOF at measuring points 1 and 2

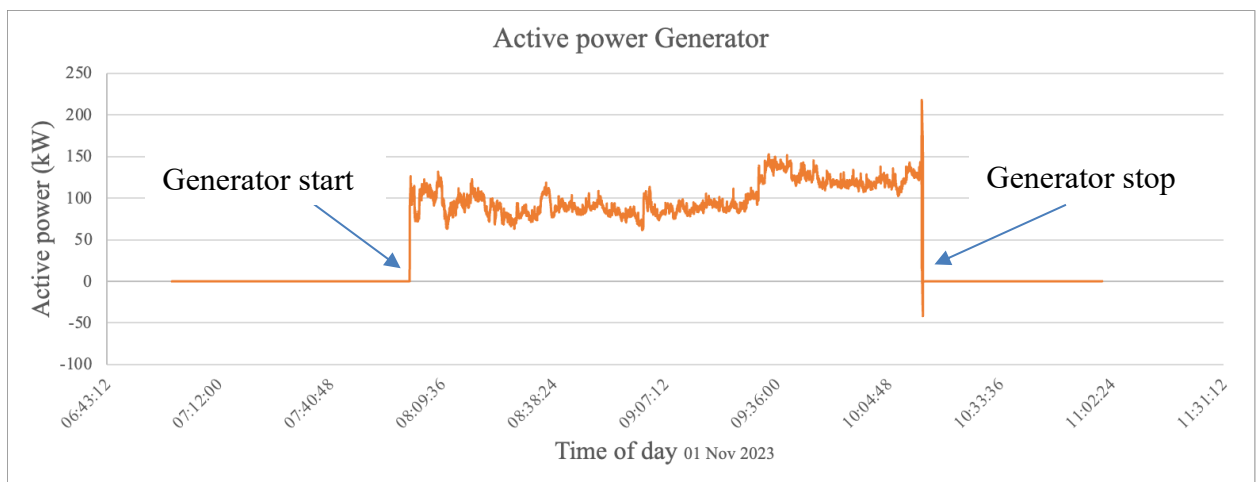


Figure 7-14: Active power at measuring point 1 (Generator PoC)

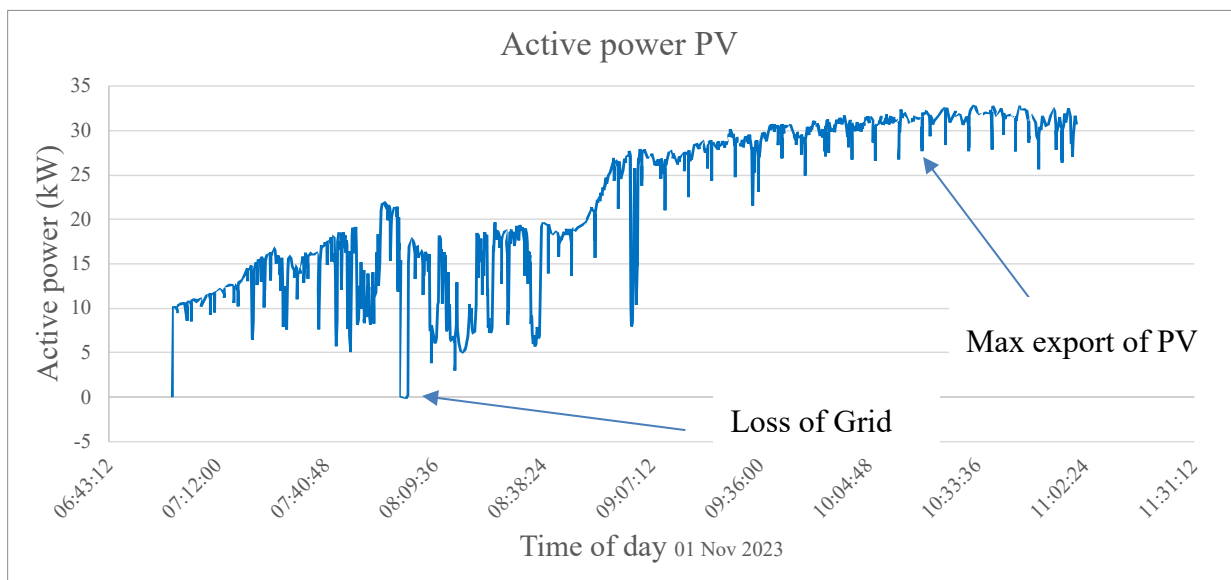


Figure 7-15: Active power at measuring point 2 (PV PoC)

Applying method 2 onto the datasets shown in Figure 7-13, Figure 7-14 and Figure 7-15 above, making use of a 1 s moving window, a significant change is observed in the system state at near 08:00.

Figure 7-16 below shows how the ratio of active power to ROCOF, and can be considered as an inertia stability metric. it is also noted how the renewables are also contributing to instability, especially around 07:40 when there is a visible variation in active power supply from the inverters.

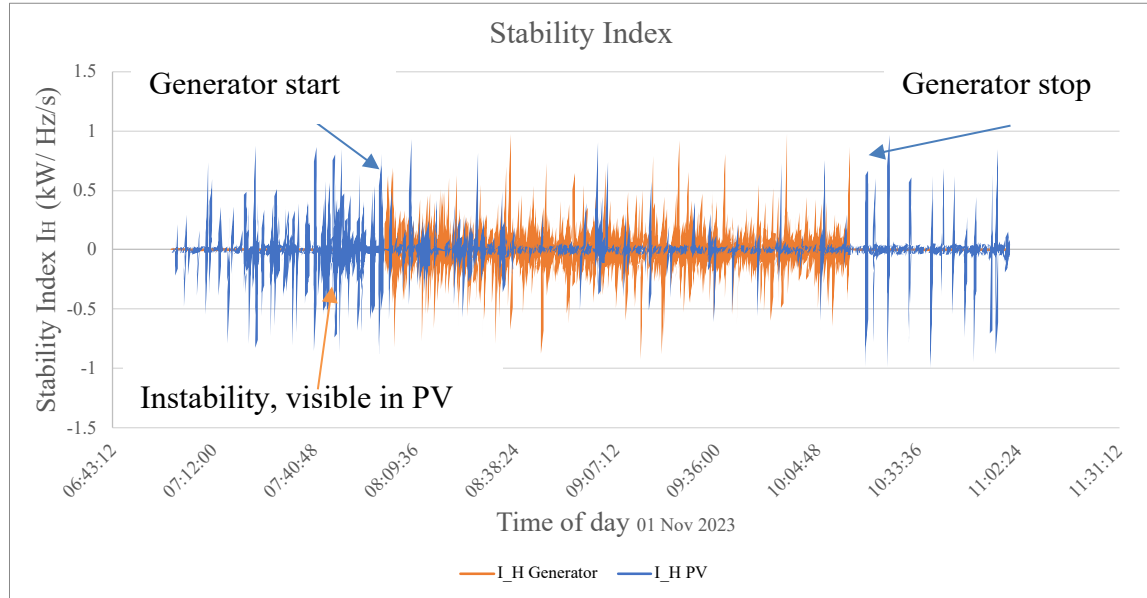


Figure 7-16: A stability metric to assess how inertia affects system stability when PV is connected

From Figure 7-16 it can be concluded that the generator has less ability to contain frequency during sudden load changes compared to the condition when the university network is connected to the utility grid. Observe the added instability from variation in the PV power output. The measured data from the generators PoC plotted as the stability index, has a standard deviation of 0.0697.

7.4 Conclusion

The stability index, a ratio between the ROCOF and active power of a system, can be plotted over time, from this an inertia constant can be estimated by observing the peaks present on this plot.

Shifting the focus to system stability index rather than absolute inertia values provides a more practical approach for grid operators. The results showed that the instability metric varied across different scenarios, with lower PV generation correlating to a lower stability index (increased stability in the system), while high irradiation led to greater stability variations due to PV fluctuations.

Figure 7-11 shows that the stability index during working hours exhibits greater variance in frequency, indicating more frequent and sudden mismatches between generation and loading. In contrast, Figure 7-6 taken after hours, shows less variation in the stability index, implying fewer sudden mismatches between loading and generation, meaning less inertia is constantly required from the generator to counteract the sudden mismatches.

The standard deviation of each event’s stability index was taken and listed in Table 7-2. It can be noted that the deviation during high irradiation days is larger than the deviation during lower irradiation days, showcasing that PV does indeed decrease the stability of a system.

Noted these measurements were taken on 2 consecutive days, during a work week, meaning load variability should be at a minimum.

Table 7-2: Stability metric deviation of each event.

<i>Generator PoC data</i>	<i>Event 1: Grid loss, generator only with no PV infeed.</i>	<i>Event 2: Grid loss, generator with PV infeed during period of high irradiation</i>	<i>Event 3: Grid loss, generator with PV infeed during period of low irradiation</i>
<i>Loading scenario</i>	Less load compared to during office hours.	Equal load to event 3	Equal load compared to event 2
<i>Standard Deviation of stability index</i>	0.0201	0.0697	0.0582

- Figure 7-11, event 2: Lower PV generation corresponded to a more stable inertia index.
- Figure 7-16, event 3: Higher PV penetration increased fluctuations in stability.

By plotting method 2’s estimations as a stability index over time, one can limit the method’s sensitivity to the chosen data window. It is also useful as power system managers can monitor a system’s stability, especially in a system with ever-increasing renewable penetration.

The inertia stability index can easily be implemented in real-time, enabling grid operators to quickly get an idea of the system stability in terms of power supply and load demand.

Plotting method 2 over time resulted in interesting findings, written up in the AMPS 2024 conference paper, and can be seen in Appendix D.

CHAPTER 8 CONCLUSION

Below, a conclusion to this study on inertia estimation is written.

8.1 Introduction

Inertia from mechanical generation sources was a hidden, but crucial aid in frequency stability.

With the increasing use of renewable static generation, the added benefit of mechanical inertia becomes less sufficient, as renewable sources can at best emulate inertia for frequency response. For this reason, knowing the available inertia at any given moment is crucial for grid operators to mitigate instability – avoiding frequency runaways, and thus, total system blackout.

This work presents an overview on the results obtained in comparing inertia estimation methods during significant changes in system state. The work also investigated the contribution (or lack of contribution) to system stability by renewable power sources.

8.2 Advancements on inertia estimation

Three inertia estimation methods were implemented in MATLAB® and tested using simulated data from DigSILENT PowerFactory, using three IEEE benchmark systems:

- 2-Zone System: Two primary zones with interconnecting transmission lines and four generators (one replaced with rooftop photovoltaic (PV) to assess renewable penetration effects).
- 9-Bus System: Three generators running at full capacity, supplying three loads, with one smaller generator substituted for PV.
- 14-Bus System: A more complex system with additional generators, allowing for inertia estimation in scenarios where generators do not operate at full capacity.

The following four event types were simulated on each of these IEEE systems:

- Loss of generation
- Earth-fault
- Decrease in load
- Increase in load

After generating event data from these simulation models and applying the proposed methods for estimating inertia, the results were analysed to determine the best performing method.

However, estimating the inertia constant from simulations did not deliver accurate enough results, acceptable accuracy margins could not be defined for inertia estimation as estimated values often achieved an error of at least 50%.

This was troubling as these methods rendered themselves ineffective of being useful to estimate inertia with enough accuracy to determine whether PV influenced the availability of inertia or lack thereof for stability purposes.

Nonetheless, from the simulation estimation results, Table 8-1 below summarises the average error for the best scoring method per system and event.

Table 8-1: Method accuracy as a function of both event types and system configurations.

<i>Event Type</i>	<i>2-Zone type system</i>	<i>9-Bus type (generators at full capacity)</i>	<i>14-Bus type (generators not at full capacity)</i>
<i>Gen loss</i>	Method 2 (0% error)	Method 2 (4% error)	Method 2 (45% error)
<i>Earth fault</i>	Method 1 (63% error)	Method 2 (6% error)	Method 2 (37% error)
<i>Load loss</i>	Method 2 (23% error)	Method 2 (26% error)	Method 2 (47% error)

<i>Load increase</i>	Method 2 (6% error)	Method 2 (7% error)	Method 2 (28% error)
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Fortunately, a proposed idea was investigated to attempt in mitigating the effects of hyperparameter selection for a system with generators not running at full capacity the method was plotted over time using data windows of a width greater than the reporting rate of the measurement equipment used (data windows of 1 s was utilised for the Vecto III with reporting rate of 200 ms). This approach resulted in much more accurate results, enough to enable investigations into the effects of renewable sources on power system inertia.

8.2.1 *Validating findings on measured data*

The final step involved applying the best-performing method (method 2) to real-world data from a system with renewable penetration. The mechanical inertia of the system's diesel generator was calculated (6-1) to be 0.809 s, serving as a benchmark for validation. A simulation using system nameplate data replicated real-world conditions, including islanding the system, generator reconnection, and PV and load integration.

Applying method 2 to the measured data yielded an estimated inertia value of 0.844 s (4.3 % error).

Additionally, the study highlighted the utility of plotting inertia over time as a tracking tool for grid stability, rather than focusing solely on absolute inertia values.

Sets of data with significant renewable penetration was compared to assess the effects of renewables on the availability of inertia in a power system. The results showed that:

- Higher PV penetration increased fluctuations in stability due to its variability.
- Lower PV generation corresponded to a more stable inertia index.

From this it became clear that the stability index given for a certain measuring point does not show the stability index of the system but rather the stability at that location in the network. Additional research should investigate how stability, due to inertia, changes at different locations within a network.

8.3 Limitations

This work did not apply an extensive method investigation. Methods are ever increasing in literature and over the course of this study 2 additional methods were identified. These methods were not considered as they were not yet known at the time of method identification for comparison.

Measuring at a more diverse set of electrical locations in the system could be beneficial, as later it was found that stability drastically changes due to the generation closest to that measuring point. Research on how stability changes in a system due to location should be investigated.

8.4 Future work:

Future research should enhance inertia estimation accuracy and applicability by exploring:

- The impact of change in load on inertia estimation accuracy.
- Establishing acceptable accuracy thresholds for real-world implementation.
- The influence of measurement location on inertia estimation.
- The data at load connection points should also be measured and compared for stability as was done for the generation data at each measurement point.
- Determining acceptable hyperparameter thresholds, including optimal window widths and consecutive measurement choices, to improve estimation robustness.

This dissertation has explored the challenge of determining effective inertia estimation methods in systems with significant renewable penetration. Despite initial challenges with low accuracy estimations, the research identified suitable methods for various systems and data types. By implementing a dynamic approach and analysing data over time, the study achieved a significant improvement in accuracy, reducing the estimation error to less than 5%, compared to a 50% error using static methods. This highlights the critical need for additional guidance in selecting appropriate data and defining optimal sampling rates for accurate inertia estimation.

The conclusion is that no single event with a small sampling of data, applied to a method can universally guarantee accurate inertia estimation. Plotting estimation outcomes over time reduces the reliance on subjective data selection before and after a disturbance, removing the dependence on choosing the correct data window width, and improving overall inertia estimation accuracy.

8.5 Research publication

A peer-reviewed paper was presented at an IEEE conference, IEEE Applied Measurements for Power Systems 2024, [AMPS2024](#). The paper was doubly peer-reviewed before acceptance, presented at Caserta in September 2024, and is included in the IEEE Xplore conference proceedings at [ieeeXplore](#). A copy is attached in Appendix B.

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Appendix A Test system parameters

4 system 2 zone system, used to study fundamental nature of interarea oscillations (Power systems stability and control KUNDUR) p835

Table A. 1: Generator parameters

Generator Parameters						
S	900 MVA	V	20	kV		
X_d	1.8 (p.u.)	X_q	1.7 (p.u.)	X_l	0.2 (p.u)	
X'_d	0.3 (p.u.)	X'_q	0.55 (p.u.)	R_a	0.0025 (p.u)	
X''_d	0.25 (p.u.)	X''_q	0.25 (p.u.)	A_{Sat}	0.015 (p.u)	
T'_{d0}	8.0	T'_{q0}	0.4	B_{Sat}	9.6 (p.u)	
T''_{d0}	0.03	T''_{q0}	0.05	Ψ_{T1}	0.9 (p.u)	
H	6.5 (s)	For G1		H	6.175 (s)	for G3 and G4

Table A. 2: Generators dispatch and voltage setpoints

Generator loaded as follows	P (MW)	Q (Mvar)	U
$G1$	700	185	$1.03\angle 20.2^\circ$
$PV2$	700	± 231	1.01
$G3$	719	176	$1.03\angle -6.8^\circ$
$G4$	700	202	$1.01\angle -17^\circ$

Table A. 3: Transformer parameters

Transformers		
Z	0+j0.15	pu
S	900	MVA
HV	230	kV
LV	20	kV

Table A. 4: Line parameters

Lines		
V	230	kV
S	100	MVA
r	0.0001	pu/km
x_L	0.001	pu/km
b_c	0.00175	pu/km

Table A. 5: Load demand

Load	P (MW)	Q_L (Mvar)	Q_c (Mvar)	Dynamic/ Static split	Frequency dependancy
Load 1	967	100	200	60/40	k_P 1.2 k_Q 0.0
Load 2	1.767	100	300	60/40	k_P 1.2 k_Q 0.0

9 Bus System Specifications

Table A. 6: Load demand

Load	P [MW]	Q [Mvar]	Dynamic/ Static split	Frequency dependency
Load 1	125	50	60/40	k_P 1.2 k_Q 0.0
Load 2	90	30	60/40	k_P 1.2 k_Q 0.0
Load 3	100	35	60/40	k_P 1.2 k_Q 0.0

Table A. 7: Generator parameters (based on 100 MVA)

Quantity	G1	PV2	G3
Nominal apparent power [MVA]	247.5	192	128.0
Nominal voltage [kV]	16.5	18.0	13.8
Nominal power factor	1.00	± 0.95	0.85
Type	Hydro	PV	Steam
Nominal speed [rpm]	150		3600
x_d [p.u.]	0.1460		1.3125
x'_d [p.u.]	0.0608		0.1813
x_q [p.u.]	0.0969		1.2578
x'_q [p.u.]	0.0969		0.2500
x_l (leakage) [p.u.]	0.0336		0.0742
τ'_{d0} [s]	8.960		5.890
τ'_{q0} [s]	0.000		0.600
Inertia Constant H (Rated to Pgn) [s]	9.5515		2.7665

Table A. 8: Generator dispatch and voltage setpoints

Generator	Bus	P [MW]	u [p.u.]
G1	Bus 1	N/A	1.040
PV2	Bus 2	163.0	1.025
G3	Bus 3	85	1.025

Table A. 9: Line Parameters Based on 100 MVA

From	To	r [p.u.]	x [p.u.]	b/2 [p.u.]
Bus 4	Bus 5	0.0100	0.0850	0.0880
Bus 4	Bus 6	0.0170	0.0920	0.0790
Bus 5	Bus 7	0.0320	0.1610	0.1530
Bus 6	Bus 9	0.0390	0.1700	0.1790
Bus 7	Bus 8	0.0085	0.0720	0.0745
Bus 8	Bus 9	0.0119	0.1008	0.1045

Table A. 10: Line Parameters

Line	From	To	R [Ω]	X [Ω]	B [μ S]
Line 4-5	Bus 4	Bus 5	5.29	37.46	277.14
Line 4-6	Bus 4	Bus 6	8.99	40.54	248.81
Line 5-7	Bus 5	Bus 7	16.93	70.95	481.85
Line 6-9	Bus 6	Bus 9	20.63	74.91	563.73
Line 7-8	Bus 7	Bus 8	4.50	31.73	234.62
Line 8-9	Bus 8	Bus 9	6.30	44.42	329.10

Table A. 11:Transformer Parameters Based on 100 MVA

Transformer	From	To	Ur HV [kV]	Ur LV [kV]	x1 [p.u.]
T1	Bus 1	Bus 4	230	16.5	0.0576
T2	Bus 2	Bus 7	230	18.0	0.0625
T3	Bus 3	Bus 9	230	13.8	0.0586

Table A. 12: Transformer Parameters

Transformer	From	To	Rated Power [MVA]	Ur HV [kV]	Ur LV [kV]	x1 [p.u.]
T1	Bus 1	Bus 4	250	230	16.5	0.1440
T2	Bus 2	Bus 7	200	230	18.0	0.1250
T3	Bus 3	Bus 9	150	230	13.8	0.0879

14 Bus System Specifications

Table A. 13: Load demand

Load	Bus	P [MW]	Q [Mvar]	Frequency dependency
Load_0002	Bus_0002	21.7	12.7	k _P 1.2 k _Q 0.0
Load_0003	Bus_0003	94.2	19.0	k _P 1.2 k _Q 0.0
Load_0004	Bus_0004	47.8	-3.9	k _P 1.2 k _Q 0.0
Load_0005	Bus_0005	7.6	1.6	k _P 1.2 k _Q 0.0
Load_0006	Bus_0006	11.2	7.5	k _P 1.2 k _Q 0.0
Load_0009	Bus_0009	29.5	16.6	k _P 1.2 k _Q 0.0
Load_0010	Bus_0010	9.0	5.8	k _P 1.2 k _Q 0.0
Load_0011	Bus_0011	3.5	1.8	k _P 1.2 k _Q 0.0
Load_0012	Bus_0012	6.1	1.6	k _P 1.2 k _Q 0.0
Load_0013	Bus_0013	13.5	5.8	k _P 1.2 k _Q 0.0
Load_0014	Bus_0014	14.9	5.0	k _P 1.2 k _Q 0.0

Table A. 14: Generator dispatch

Generator	Bus	P [MW]	Q [Mvar]
Gen_0001	Bus_0001	N.A.	N.A.
Gen_0002	Bus_0002	40.0	N.A.
Gen_0003	Bus_0003	0.0	N.A.
Gen_0006	Bus_0006	0.0	N.A.
Gen_0008	Bus_0008	0.0	N.A.

Table A. 15: Data of Lines Based on 100 MVA

From Bus	To Bus	r [p.u.]	x [p.u.]	$q_{c/2}$ [p.u.]	b [p.u.]
1	2	0.01938	0.05917	0.0264	0.0528
1	5	0.05403	0.22304	0.0246	0.0492
2	3	0.04699	0.19797	0.0219	0.0438
2	4	0.05811	0.17632	0.0187	0.0374
2	5	0.05695	0.17388	0.0170	0.0340
3	4	0.06701	0.17103	0.0173	0.0346
4	5	0.01335	0.04211	0.0064	0.0128
6	11	0.09498	0.19890	0.0000	0.0000
6	12	0.12291	0.25581	0.0000	0.0000
6	13	0.06615	0.13027	0.0000	0.0000
9	10	0.03181	0.08450	0.0000	0.0000
9	14	0.12711	0.27038	0.0000	0.0000
10	11	0.08205	0.19207	0.0000	0.0000
12	13	0.22092	0.19988	0.0000	0.0000
13	14	0.17093	0.34802	0.0000	0.0000

Table A. 16: Generator Controller Settings

Generator	Bus Type	Voltage [p.u.]	Minimum capability [MVA]	Maximum capability [MVA]
Gen_0001	Slack	1.060	0	232.4
Gen_0002	PV	1.045	-40	50.0
Gen_0003	PV	1.010	0.0	40.0
Gen_0006	PV	1.070	-6.0	24.0
Gen_0008	PV	1.090	-6.0	24.0

Line_0012_0013	12	13	33.0	2.405819	2.176693	0.0000
Line_0013_0014	13	14	33.0	1.861428	3.789938	0.0000

Table A. 17: Transformer parameters based on 100 MVA

Transformer	From Bus	To Bus	Ur HV [kV]	Ur LV [kV]	r [p.u.]	X [p.u.]	Transformer final turns ratio
Trf_0004_0007	4	7	132.0	1.0	0.0	0.20912	0.978
Trf_0004_0009	4	9	132.0	33.0	0.0	0.55618	0.969
Trf_0005_0006	5	6	132.0	33.0	0.0	0.25202	0.932
Trf_0007_0008	7	8	11.0	1.0	0.0	0.17615	0.000
Trf_0007_0009	7	9	33.0	1.0	0.0	0.11001	0.000

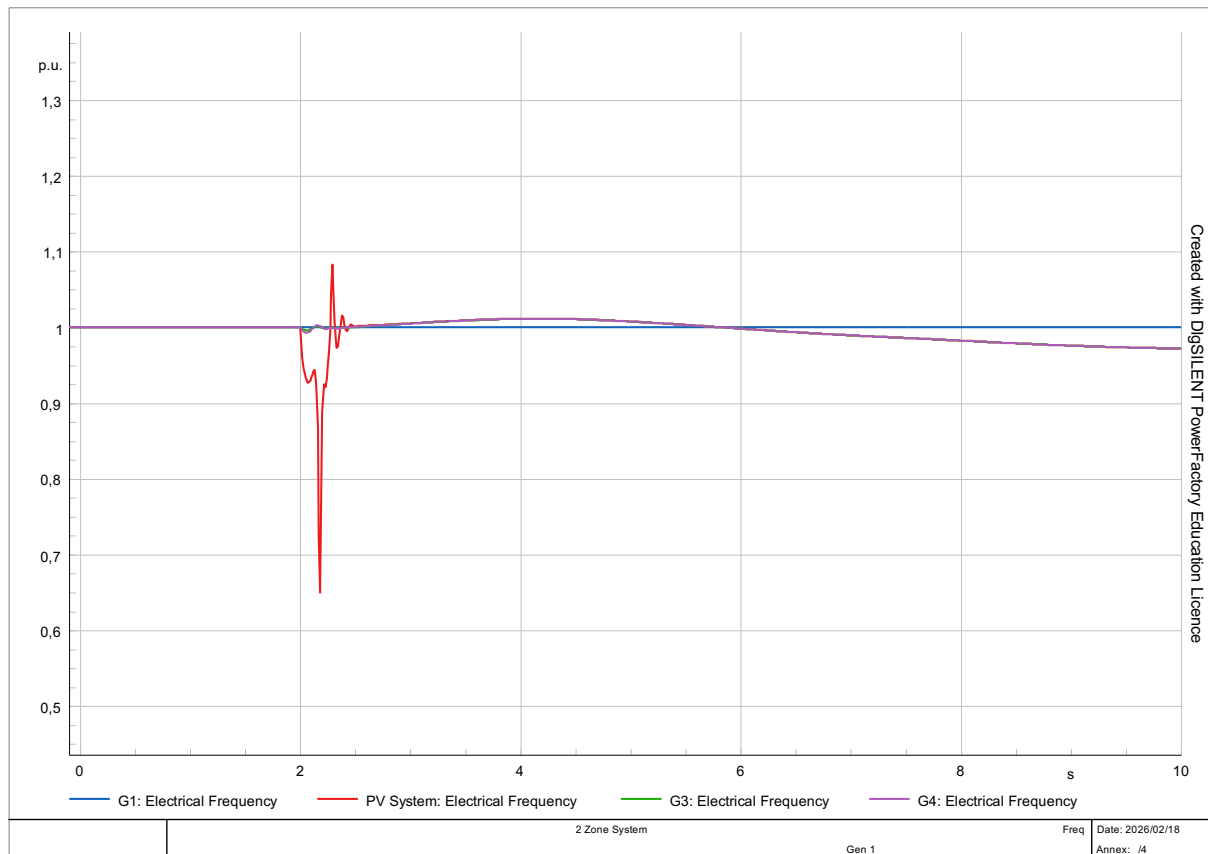
Appendix B Systems case results

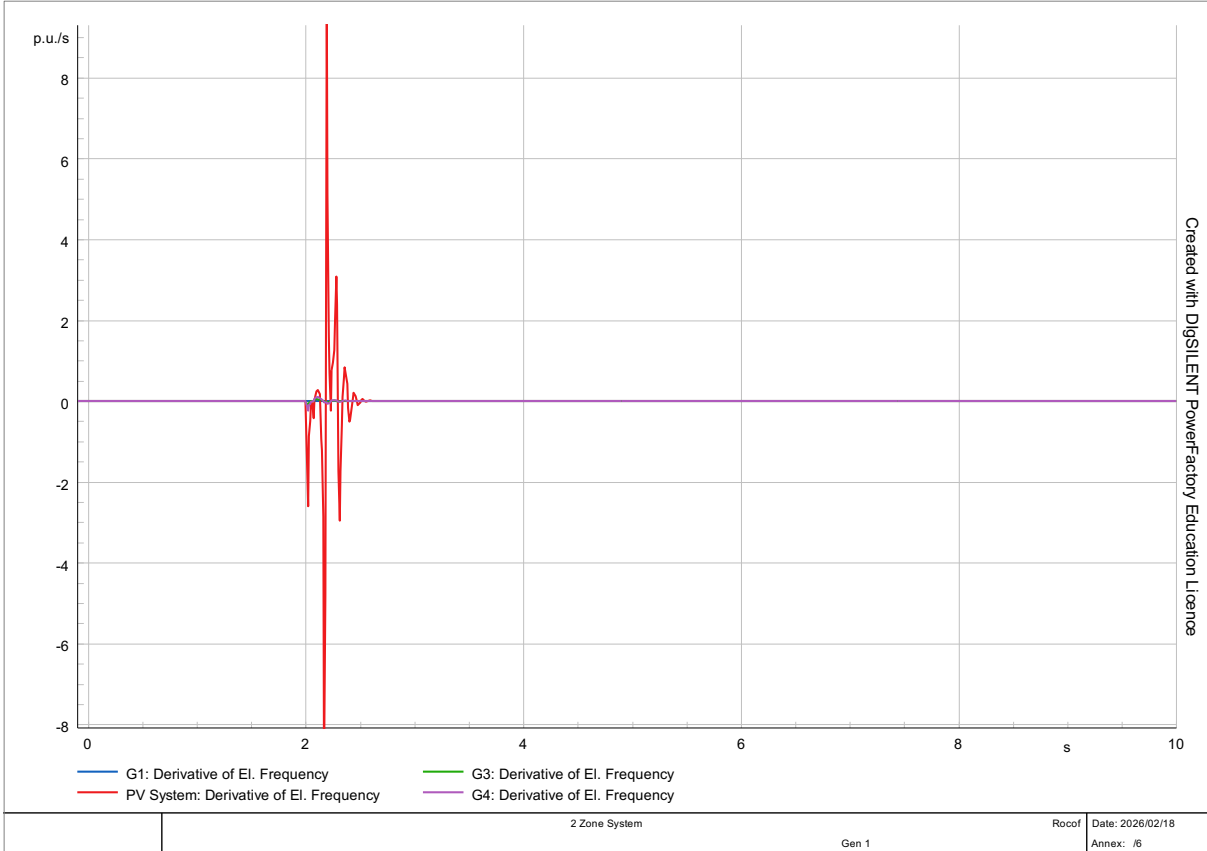
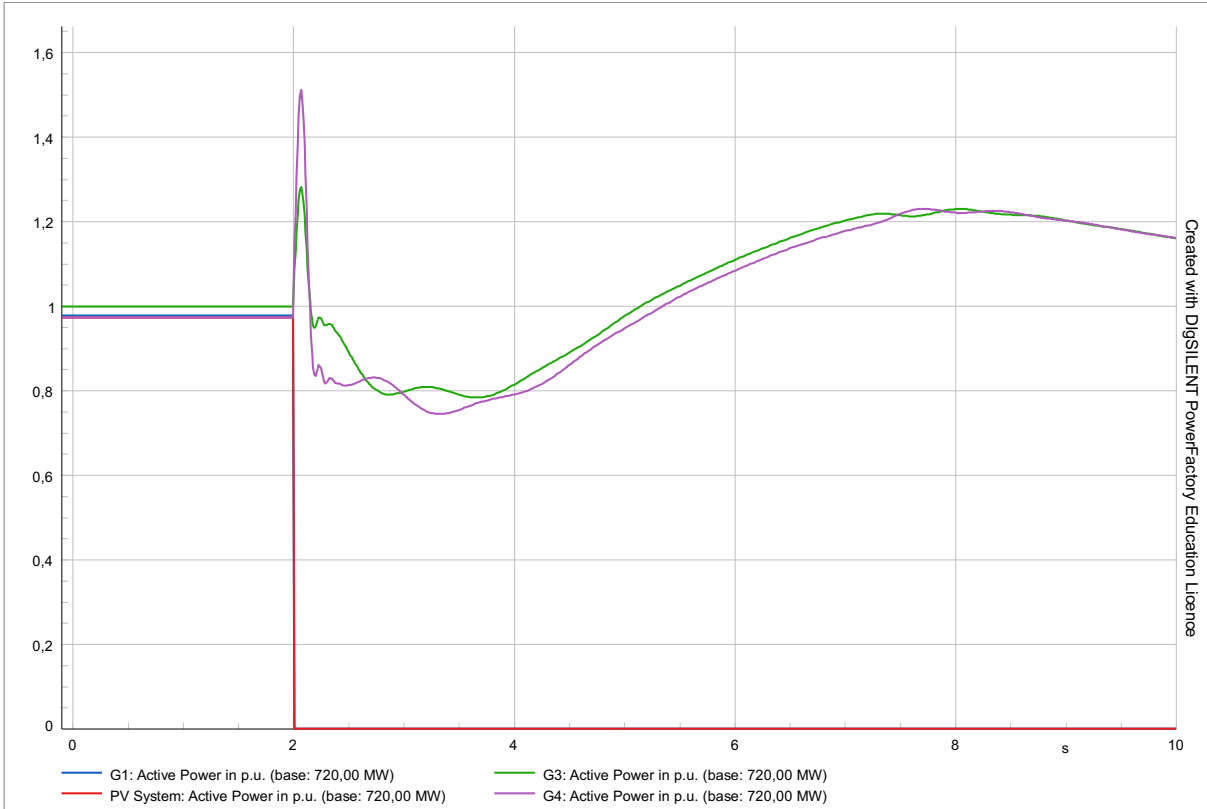
Shown below the graphic extracts of the simulations

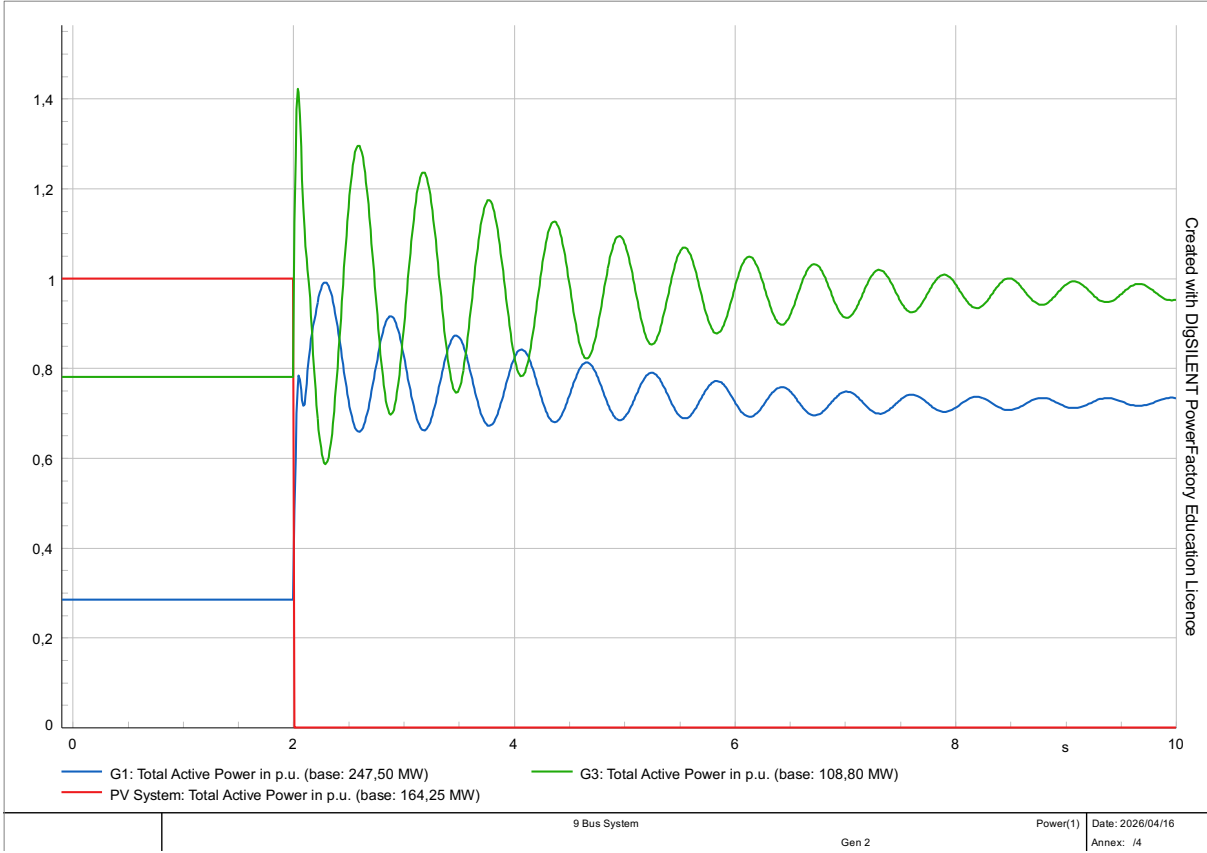
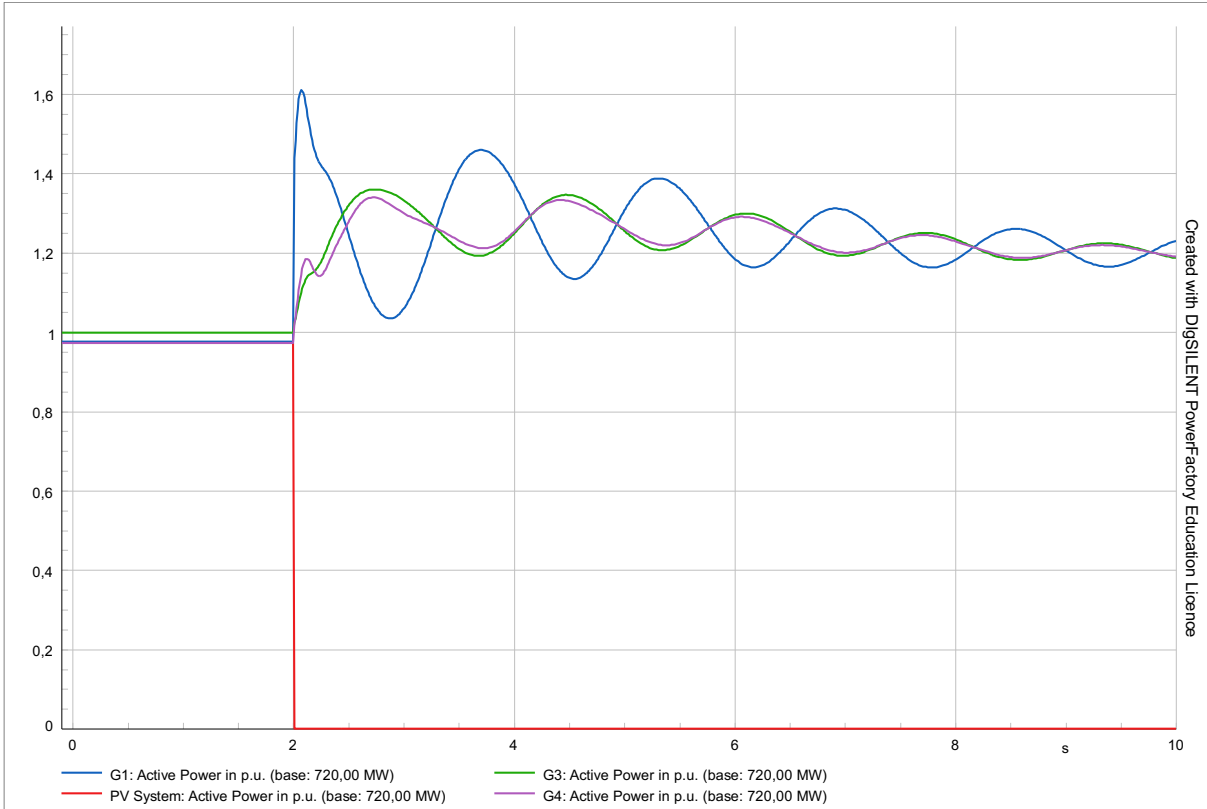
- Active power (p.u.)
- Electrical Frequency (p.u.)
- Derivative of EI Frequency / ROCOF (p.u./s)

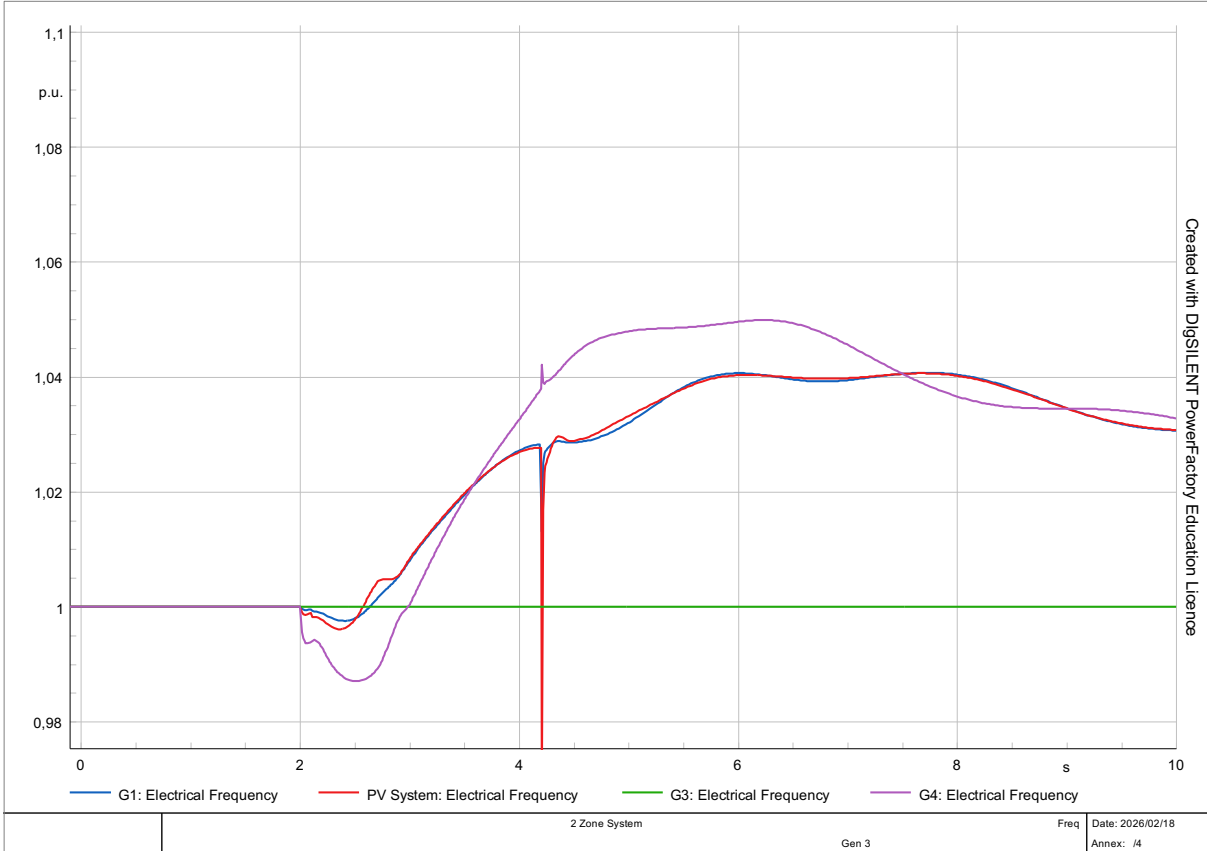
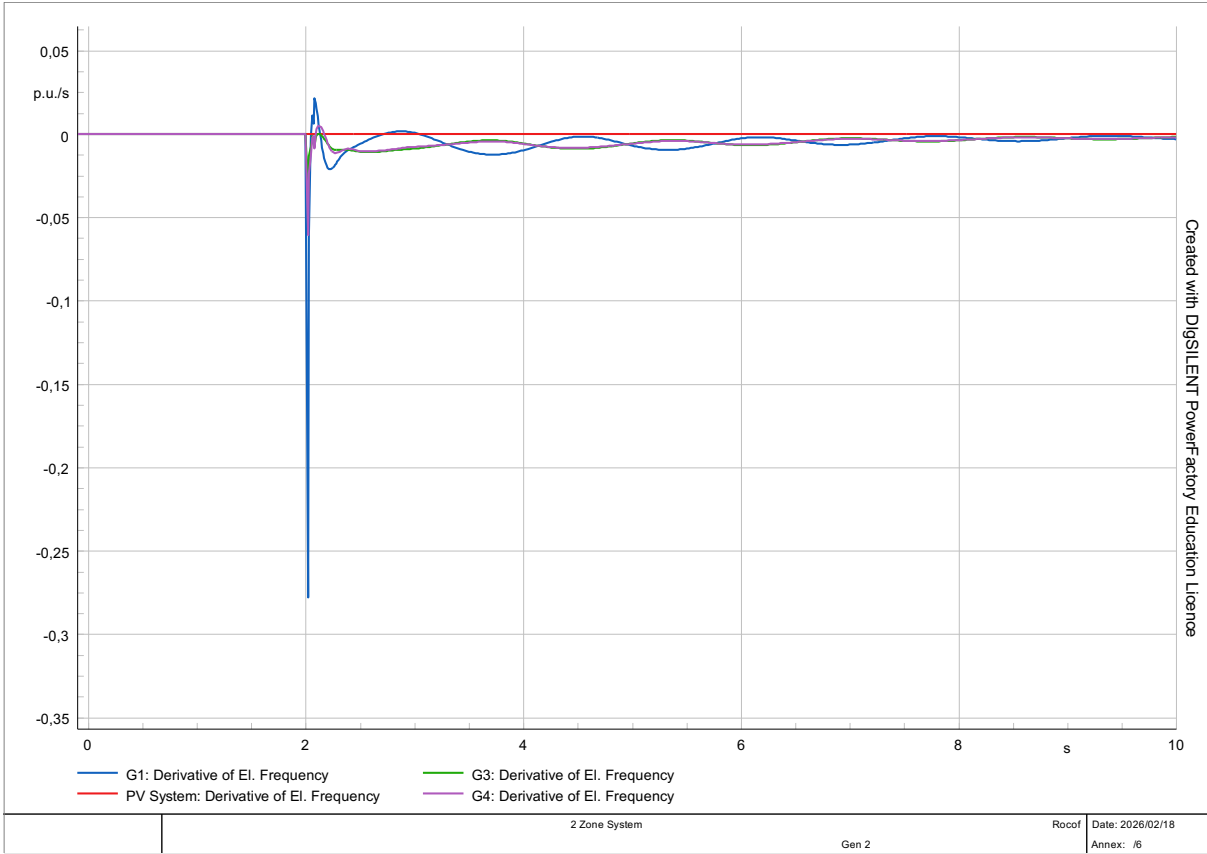
2-Zone System

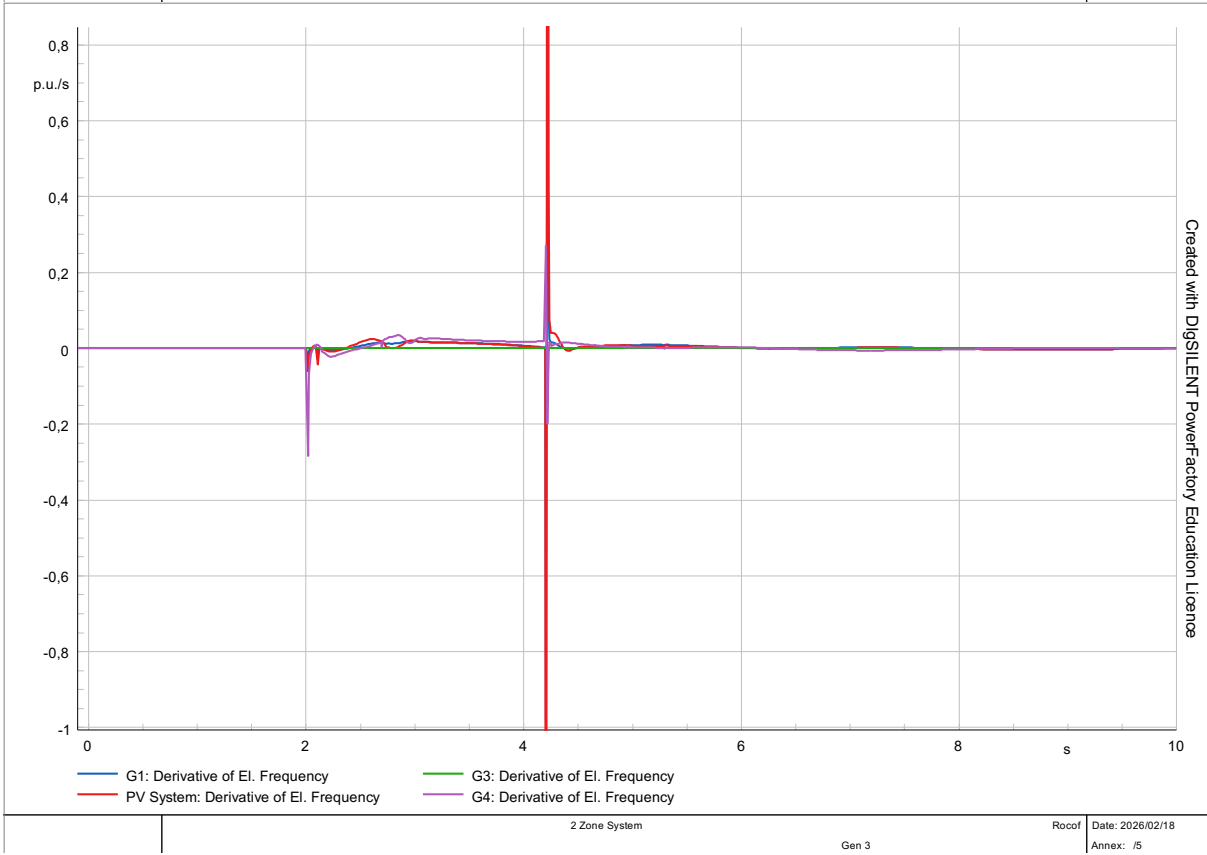
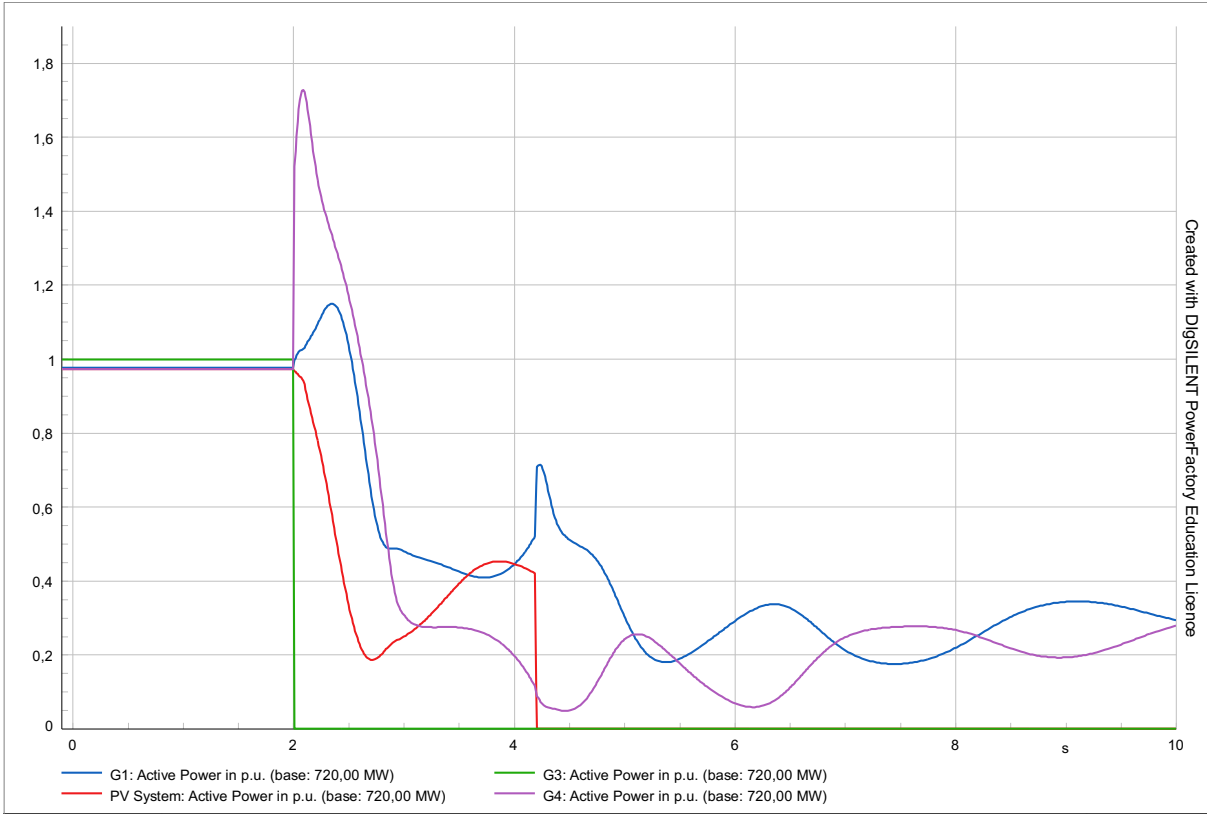
Case: Gen Loss

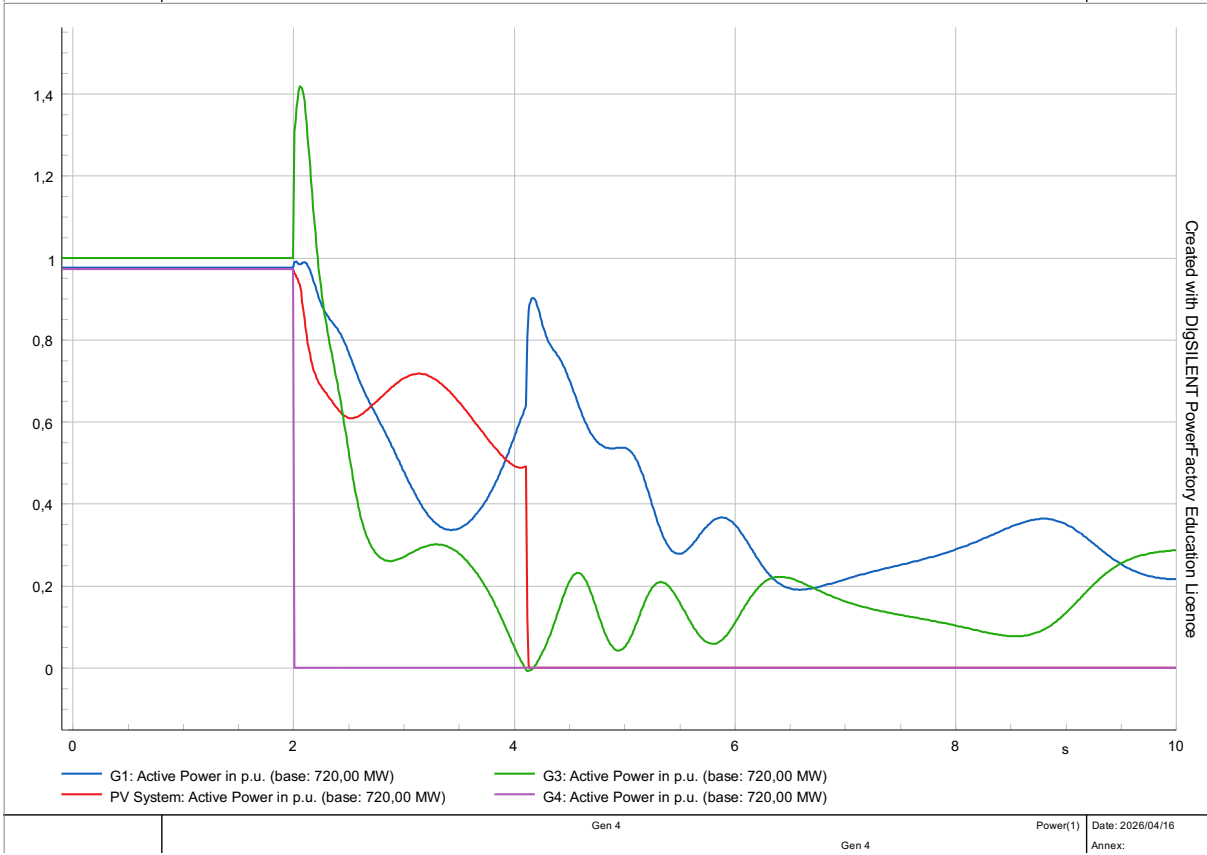
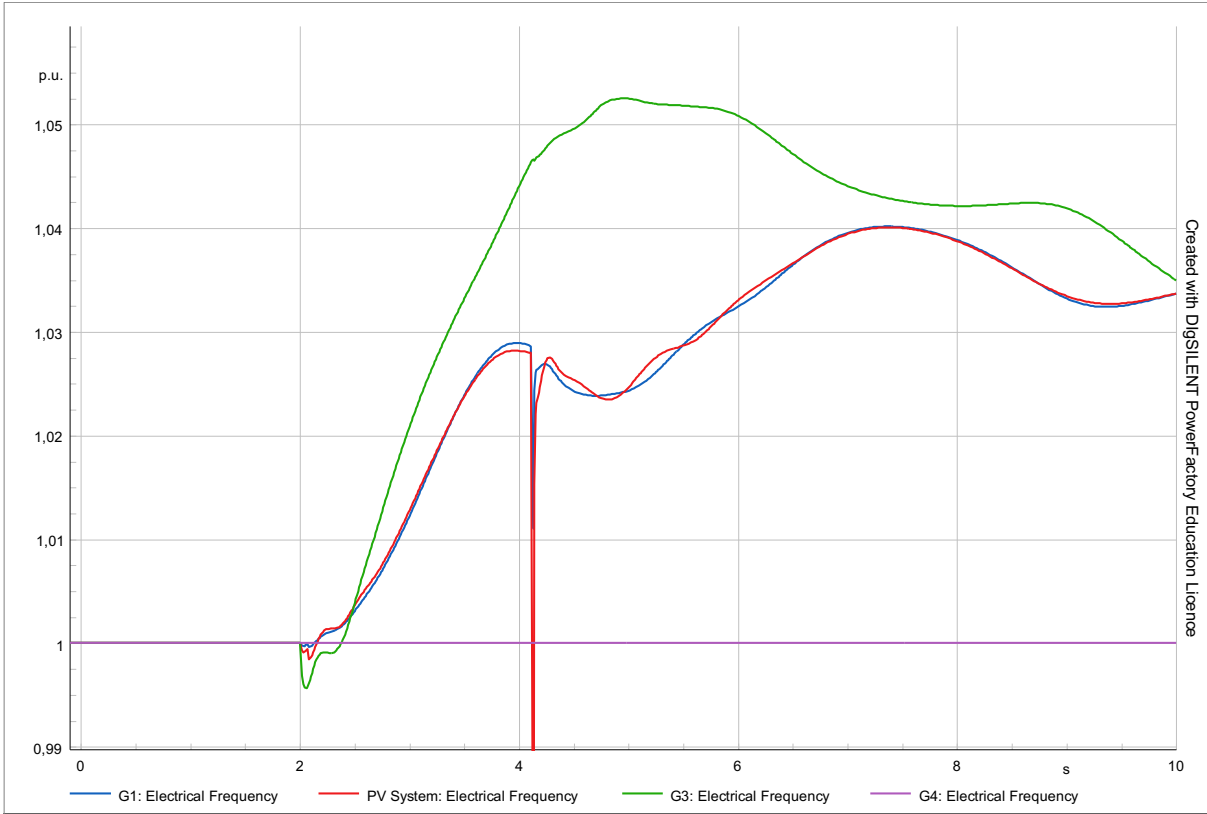


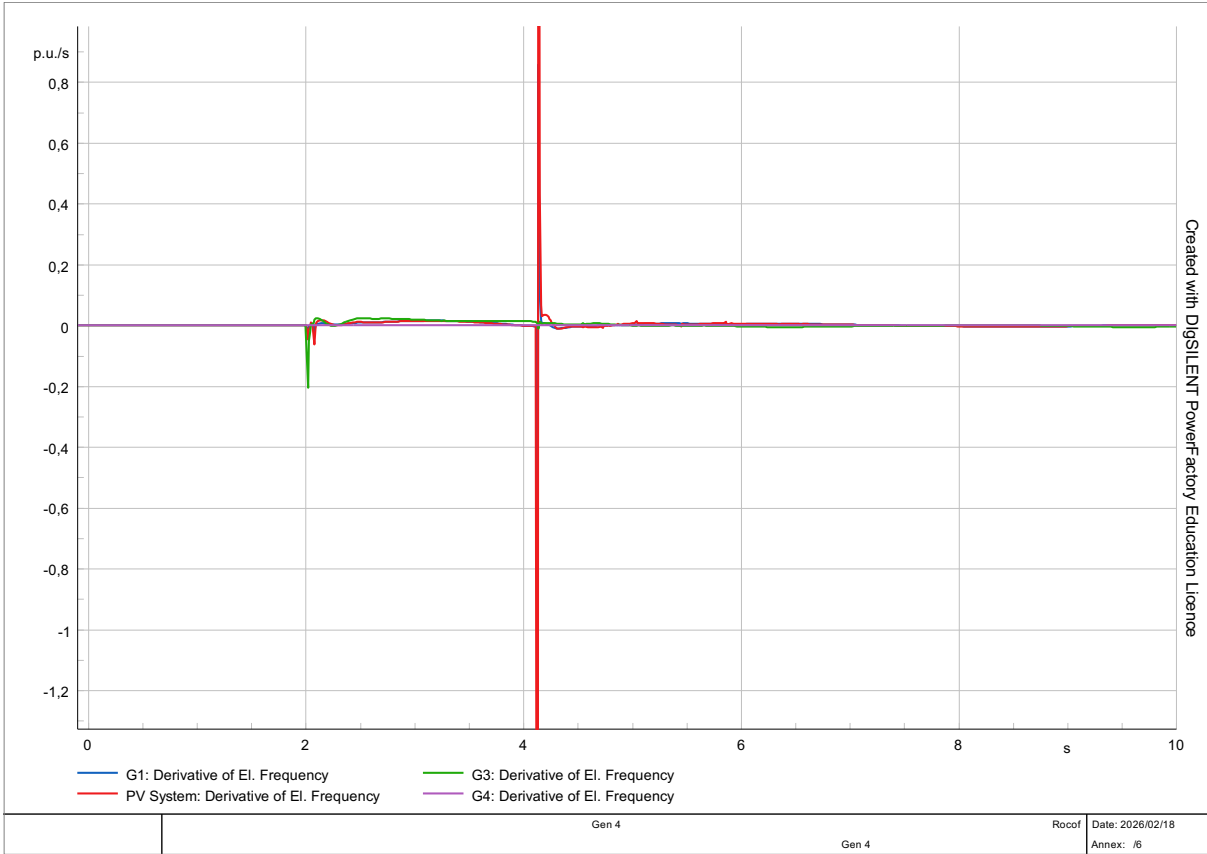




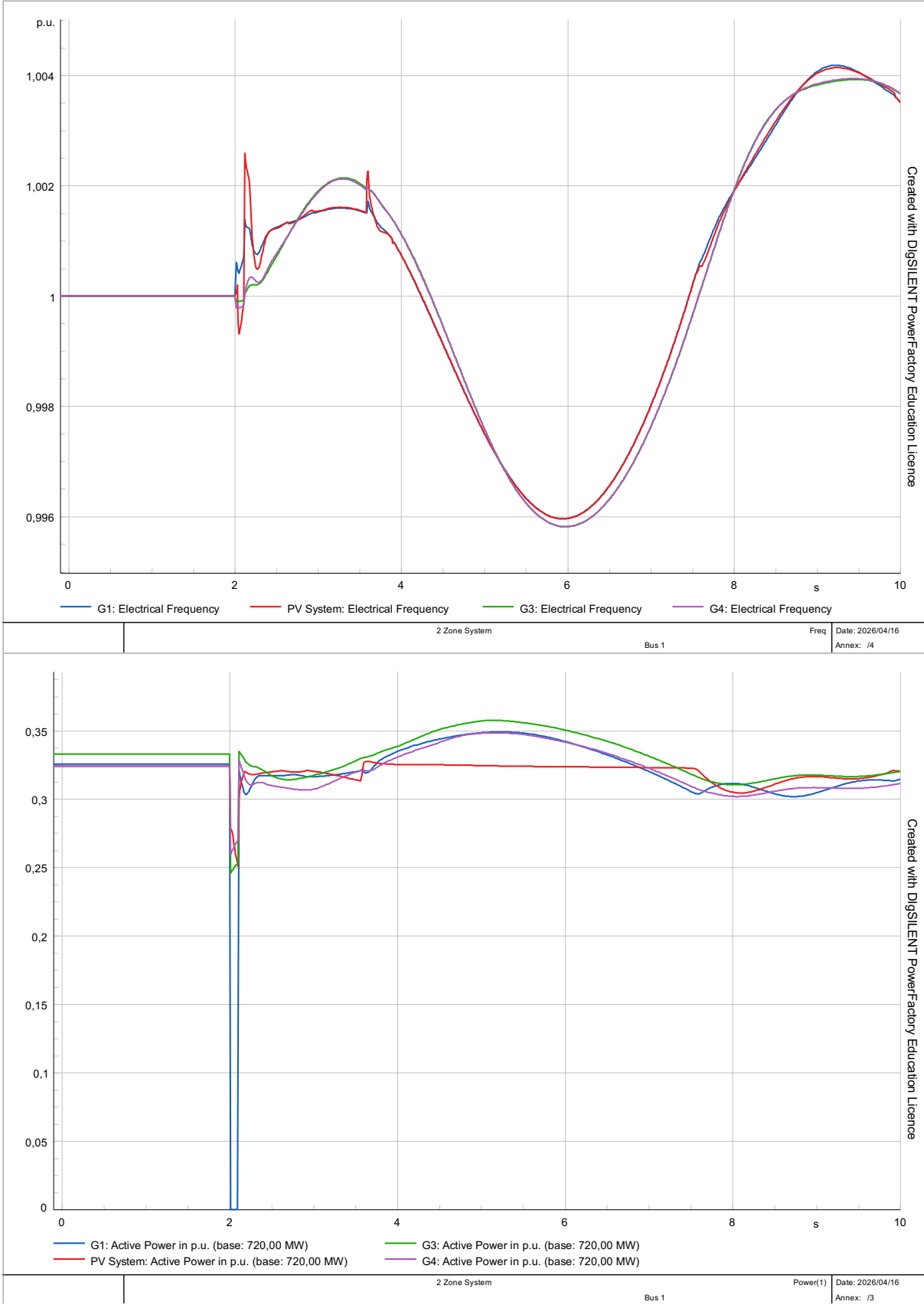


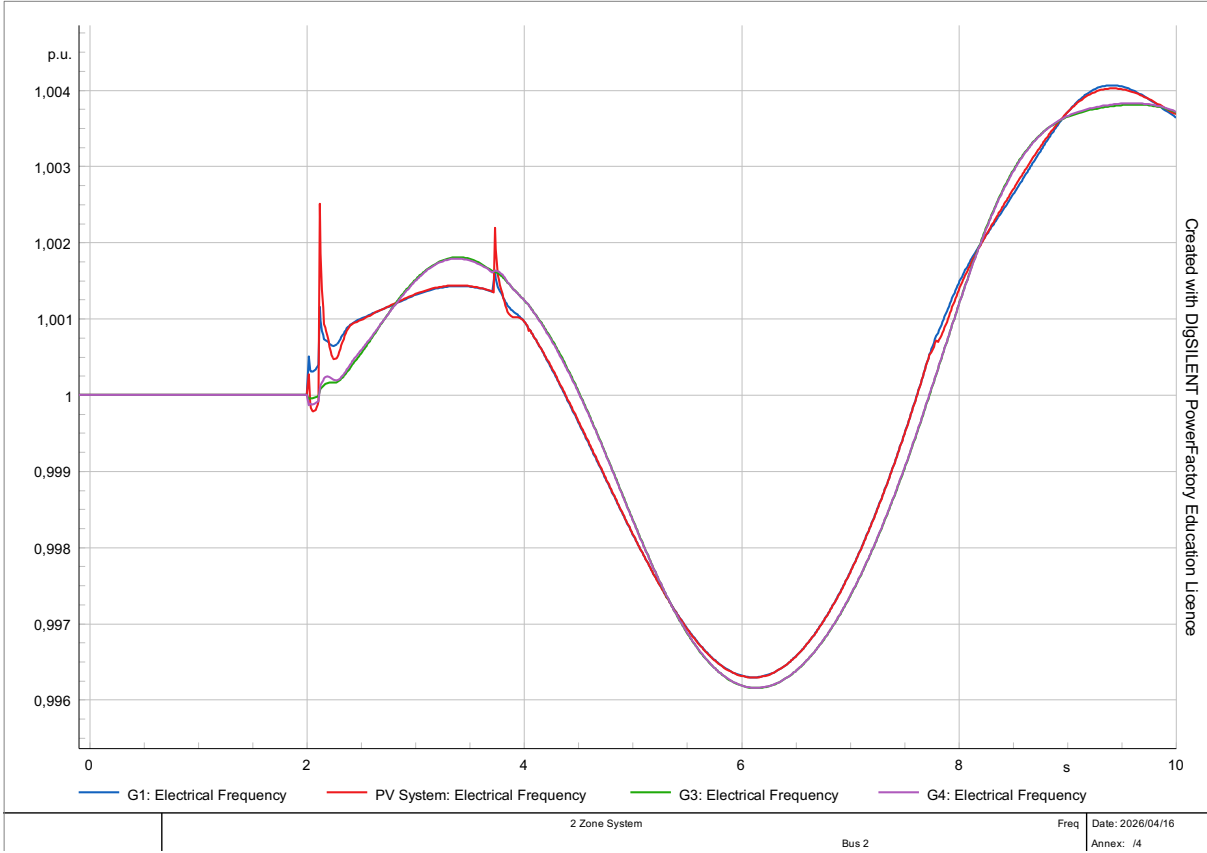
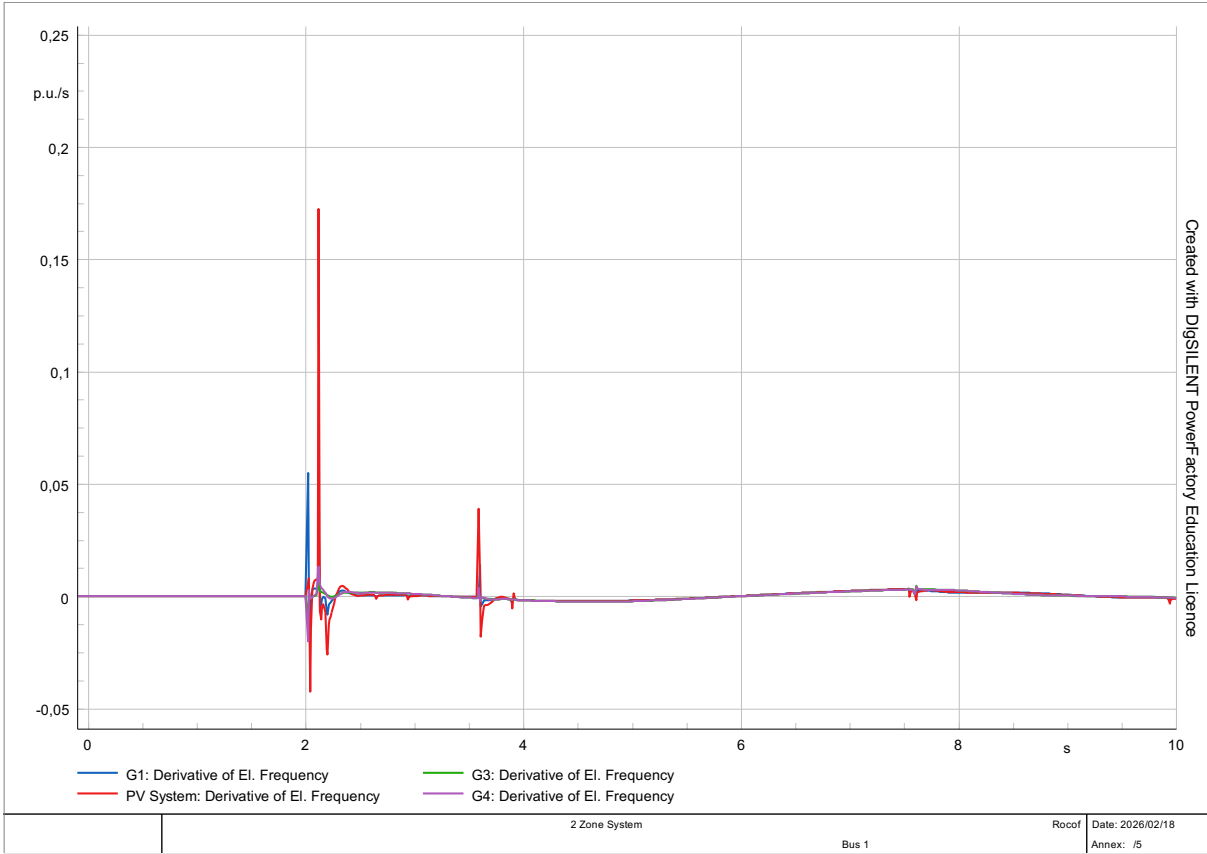


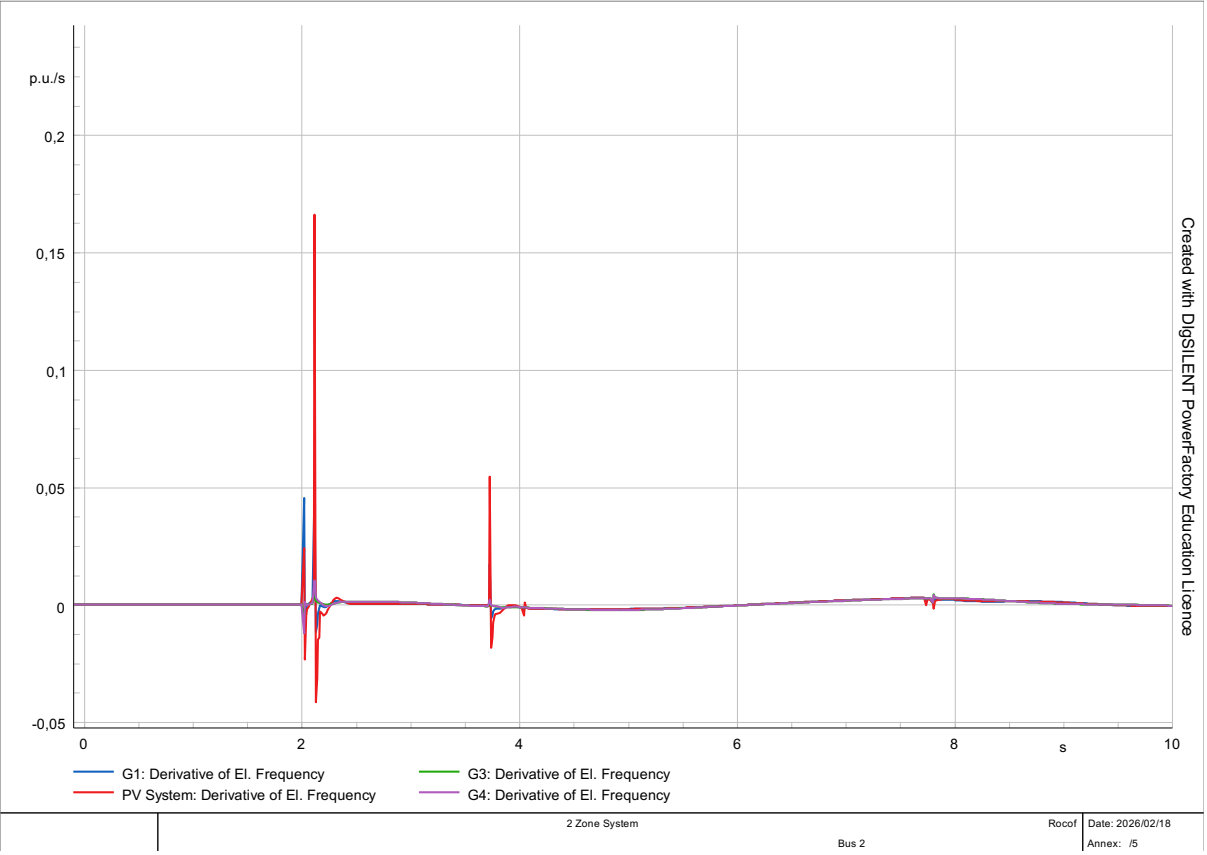
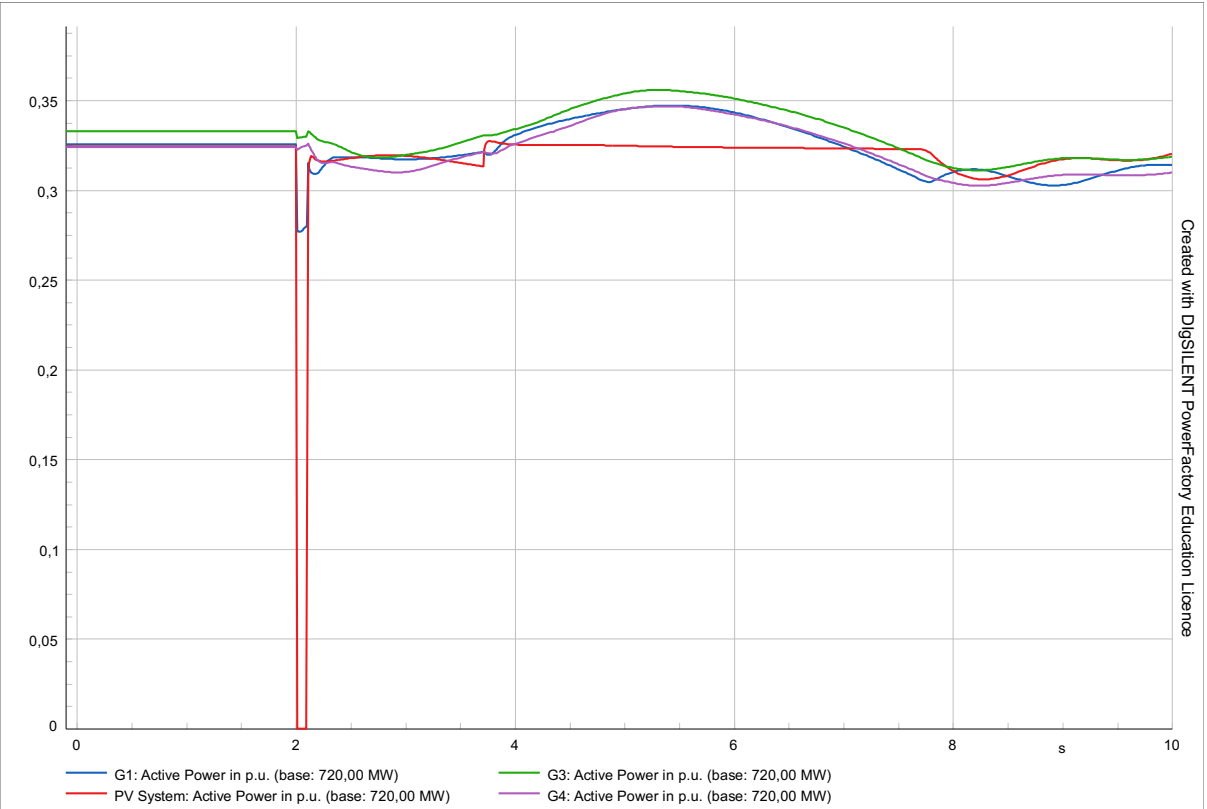


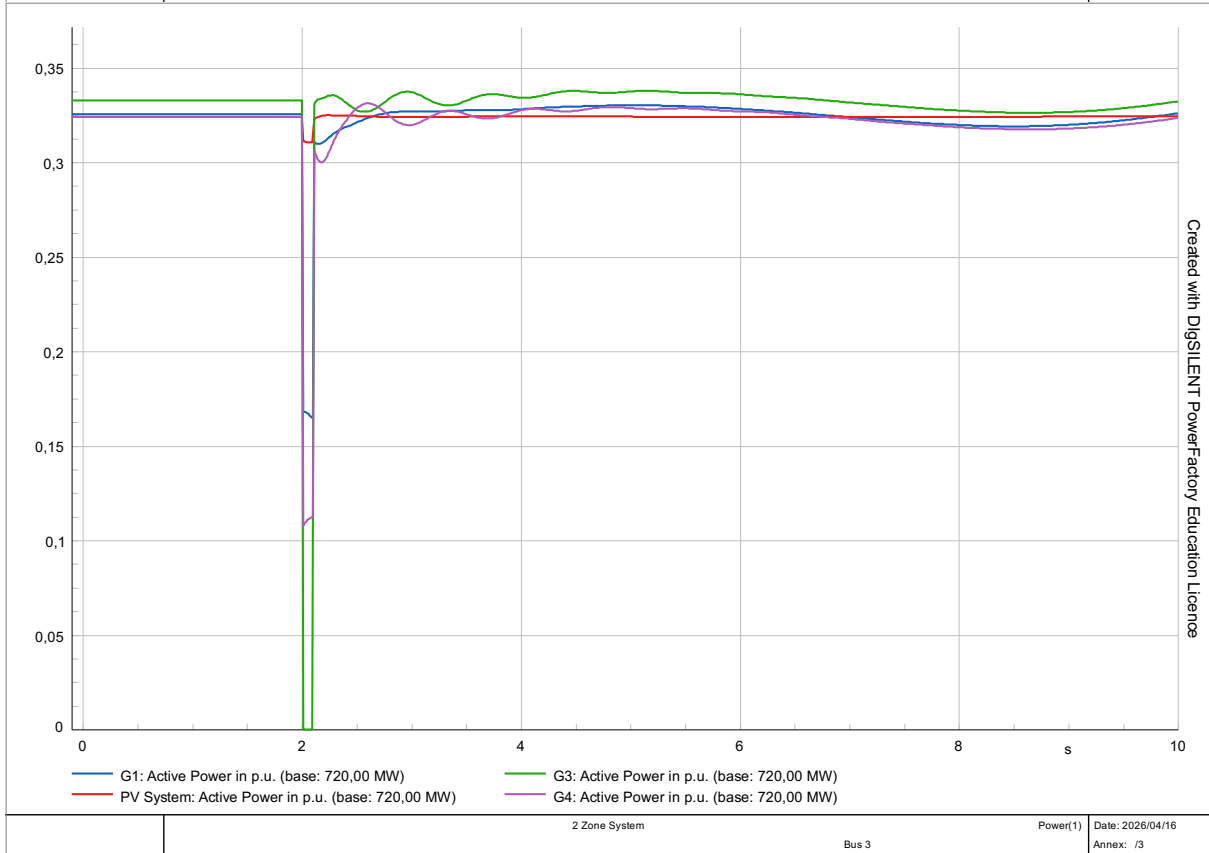
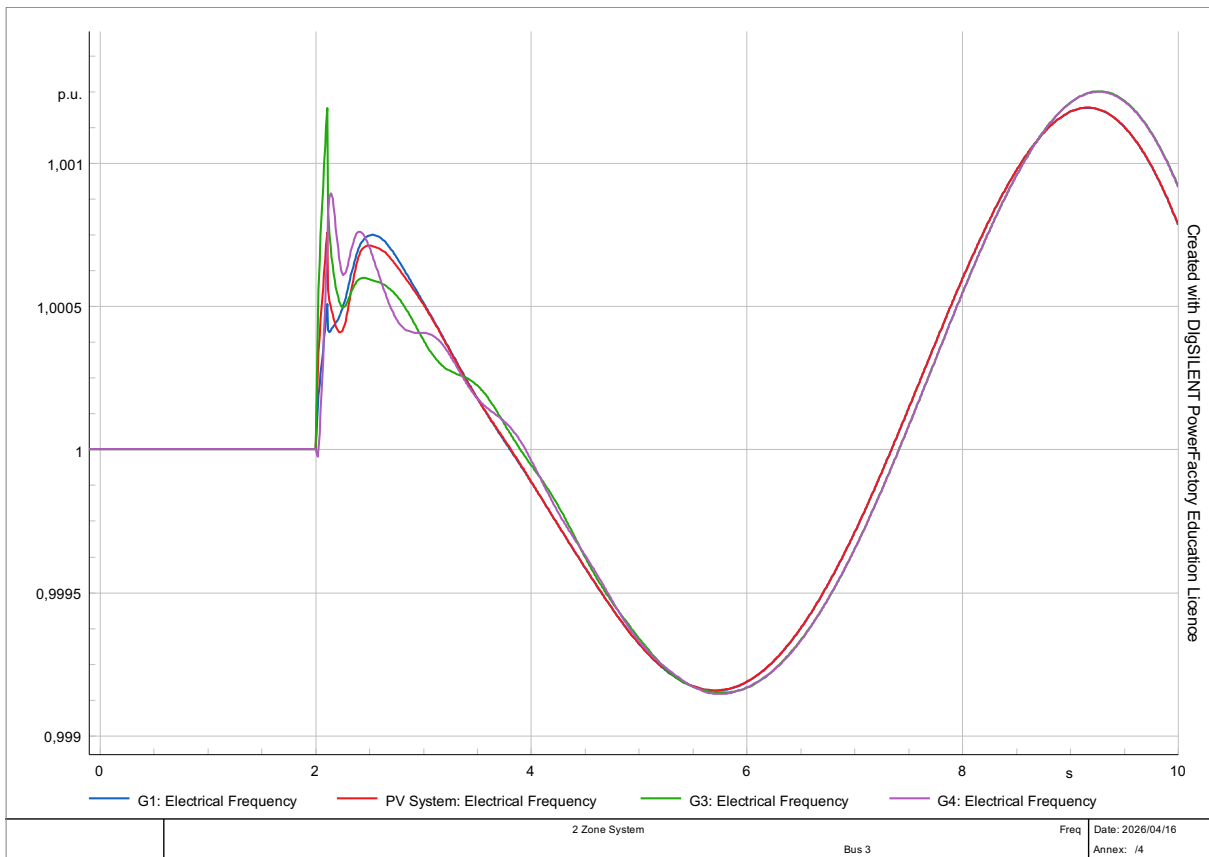


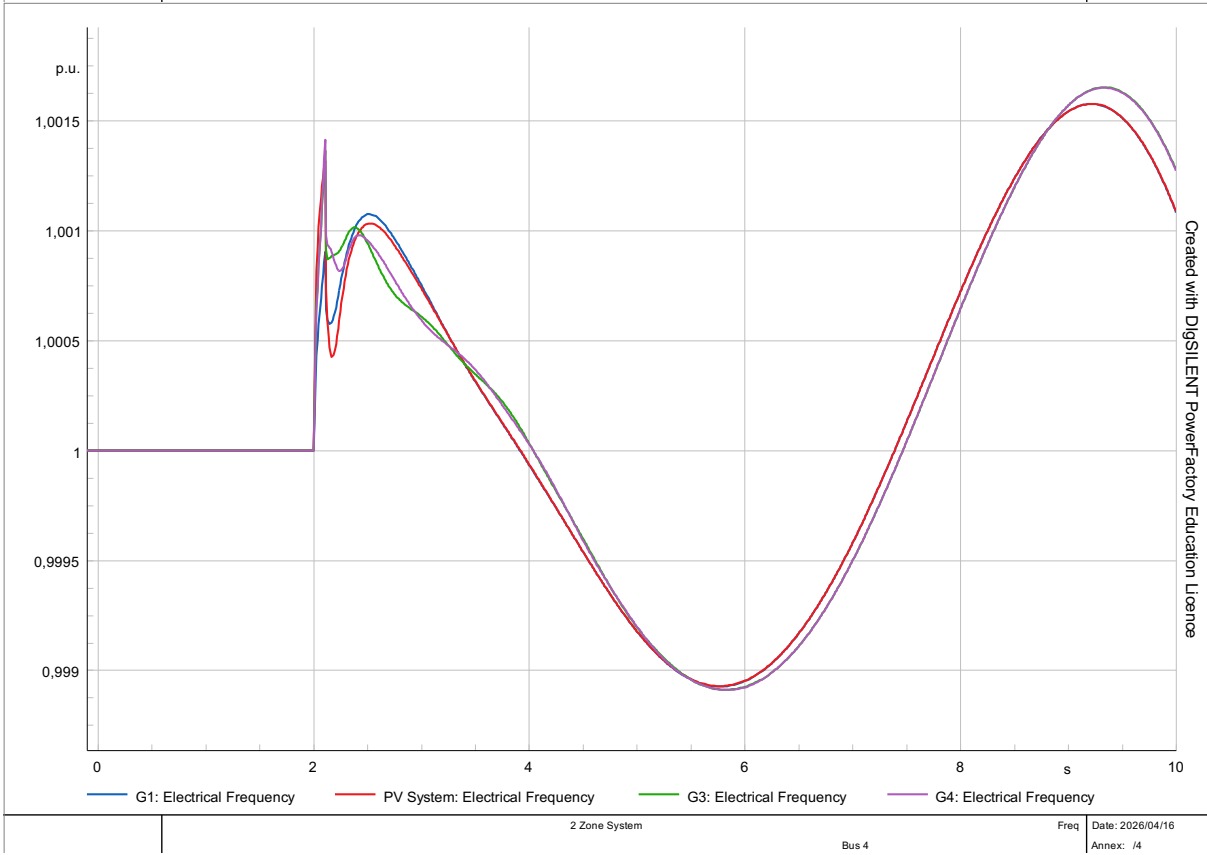
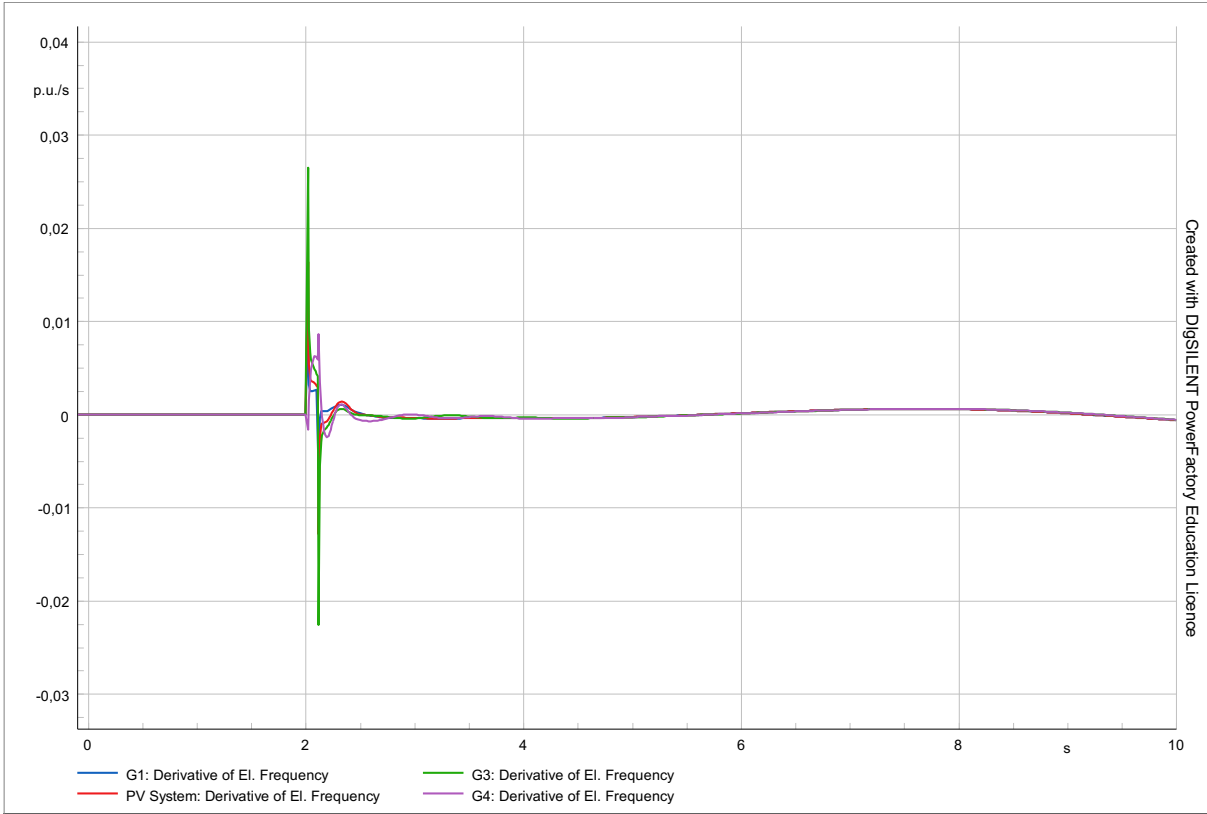
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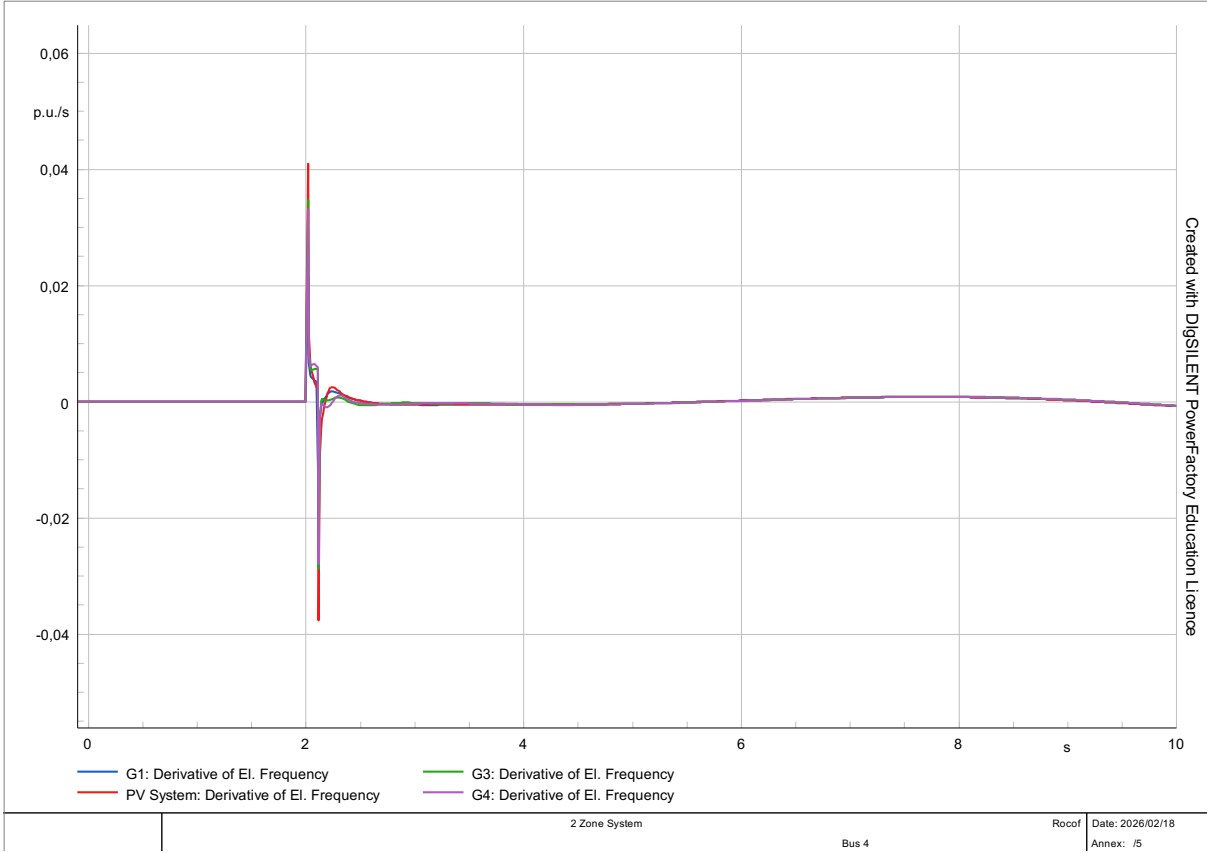
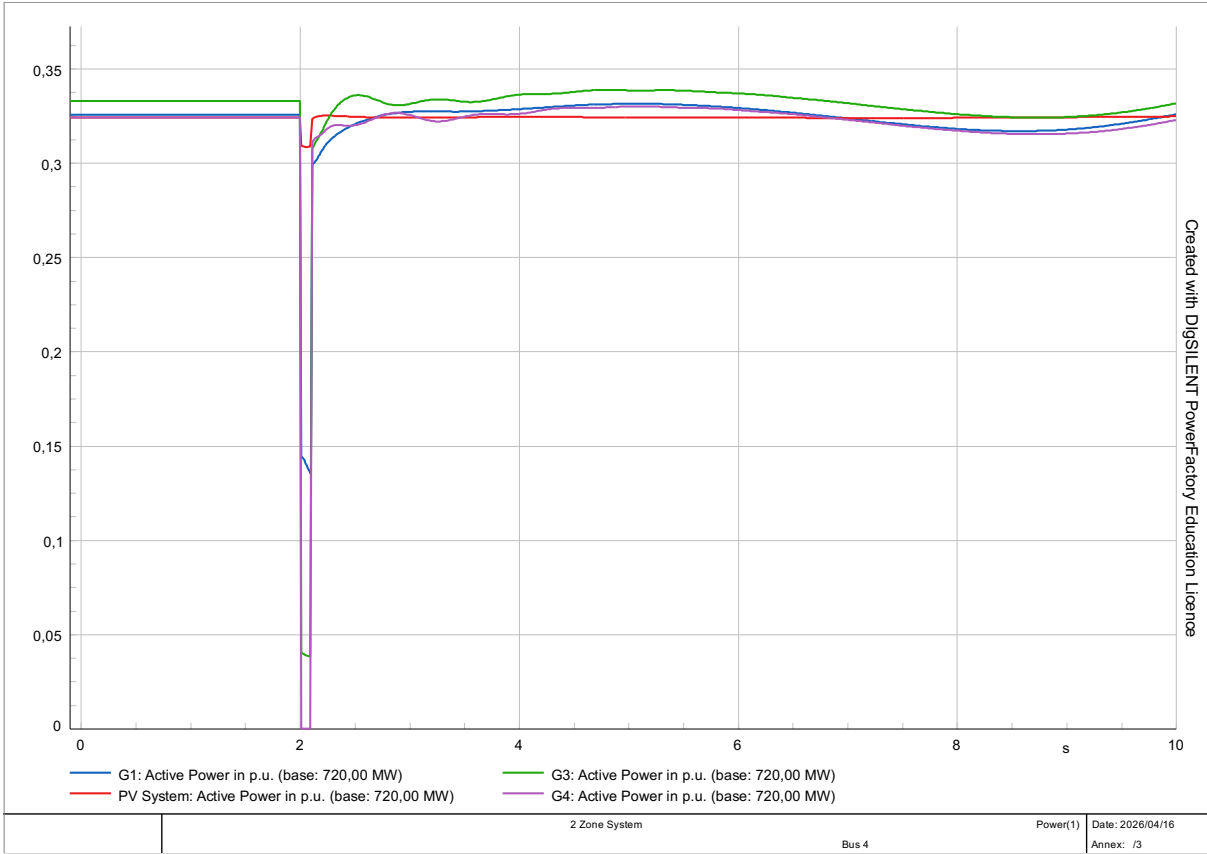


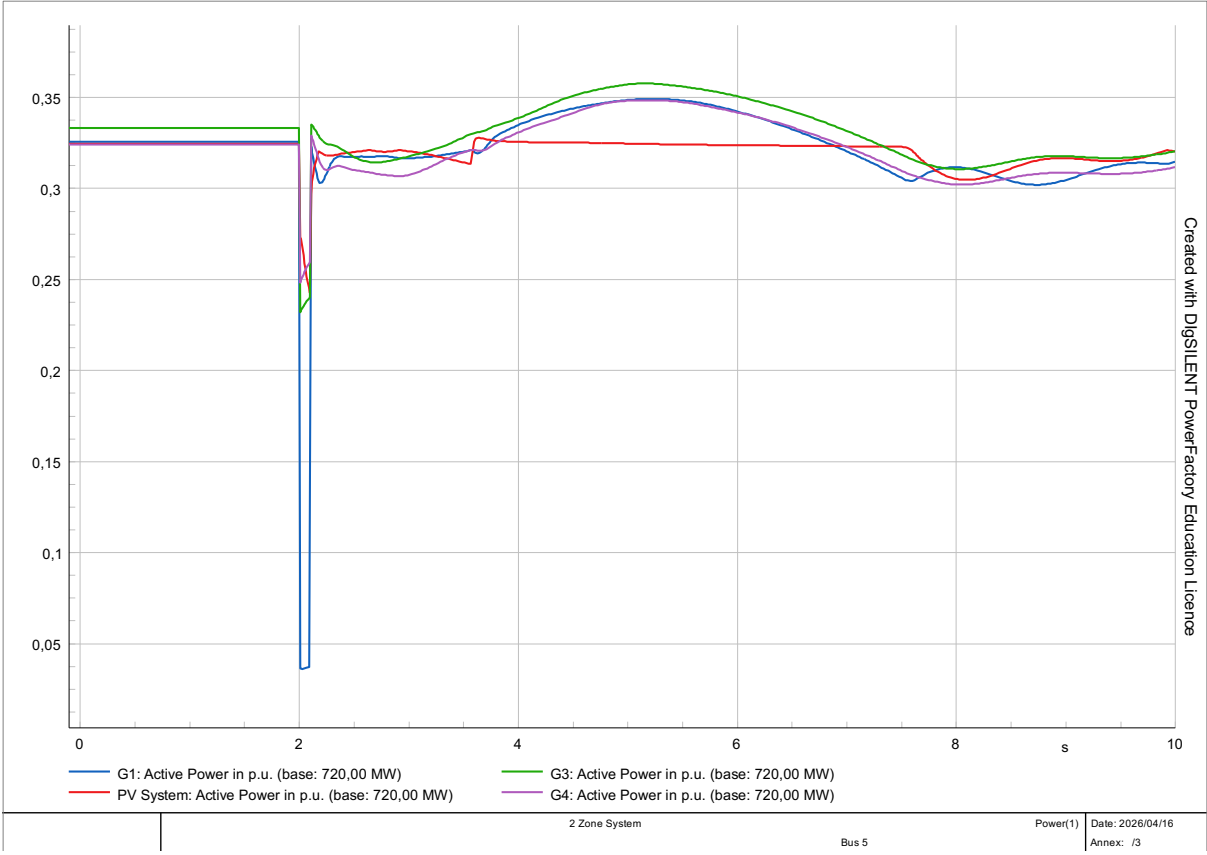
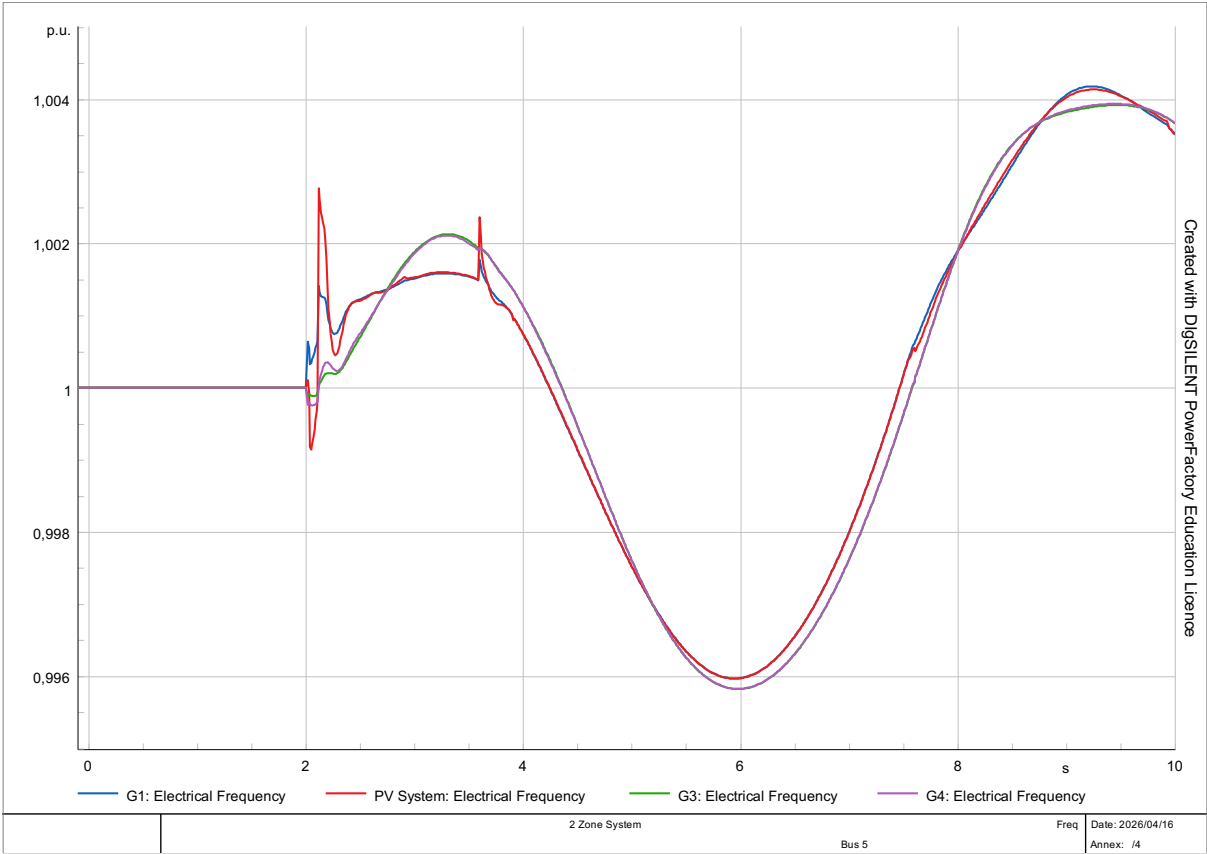


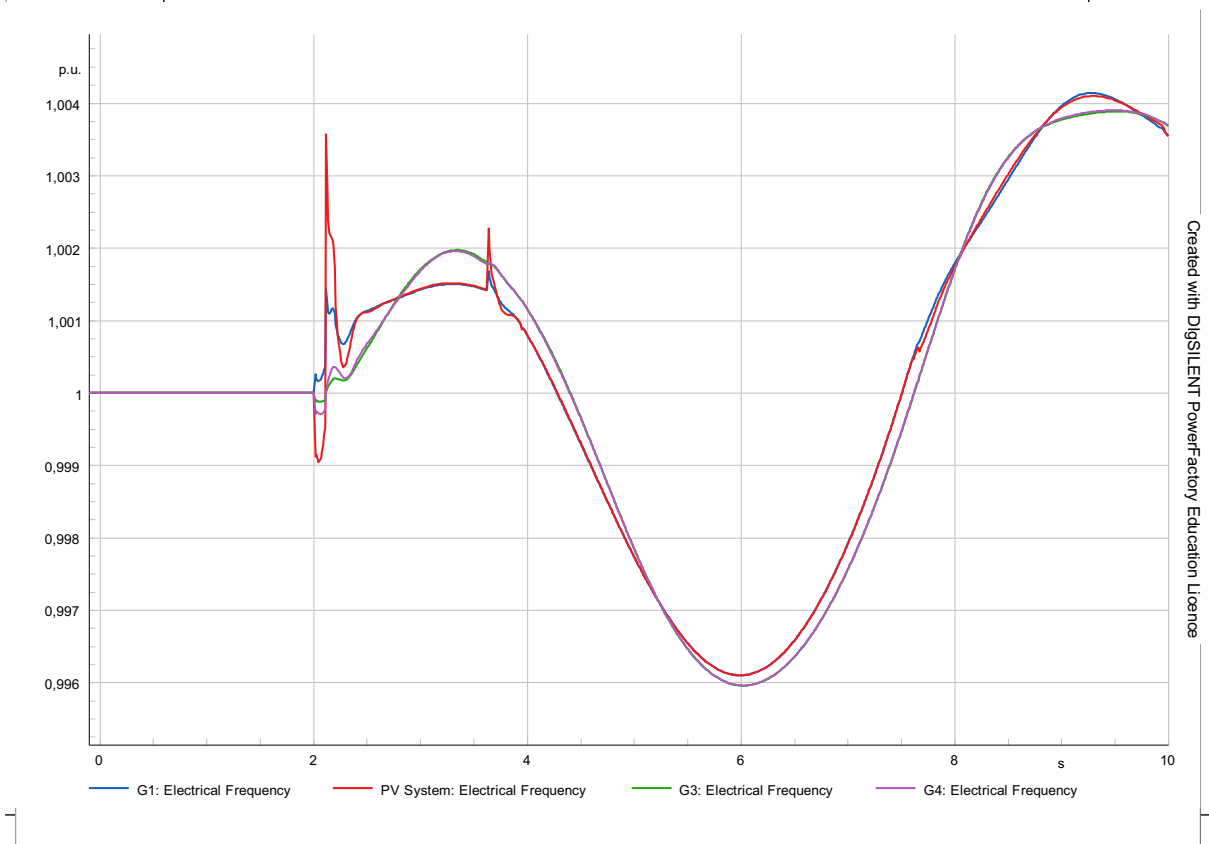
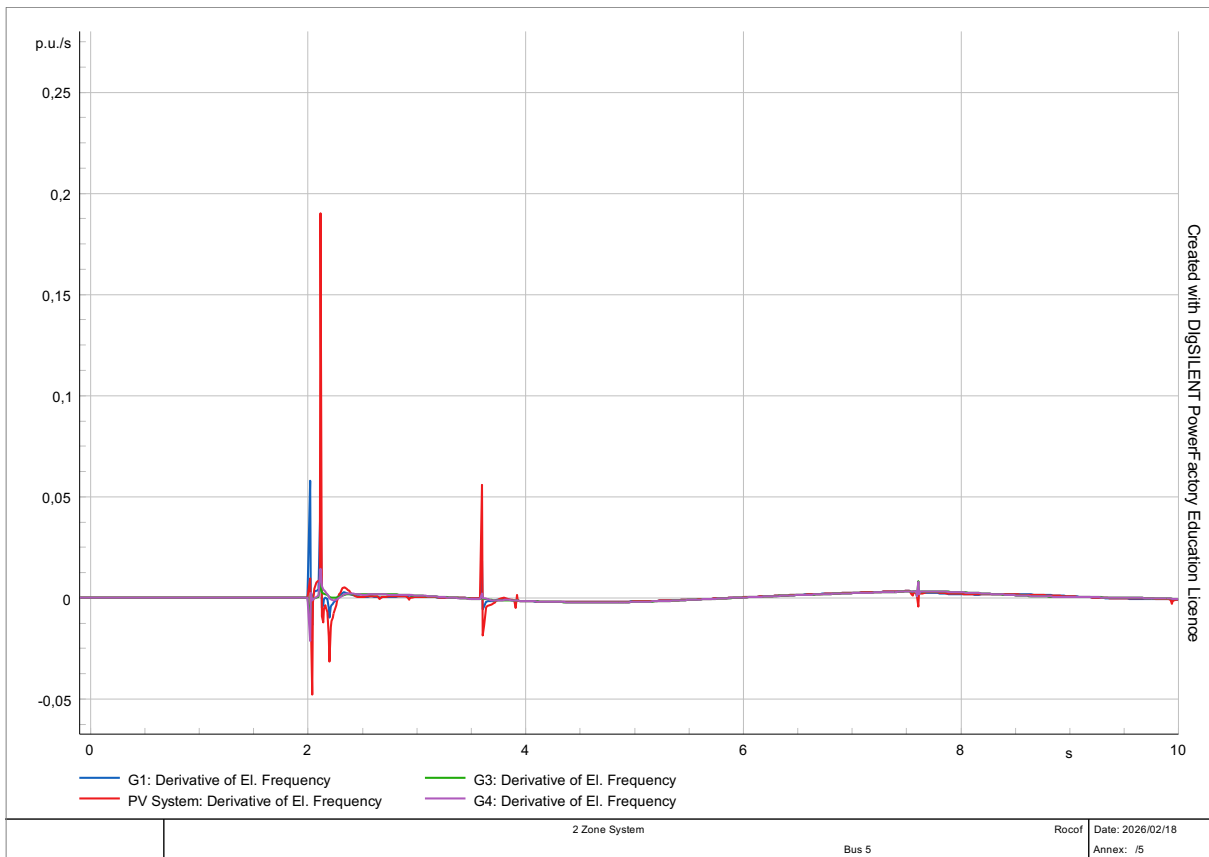


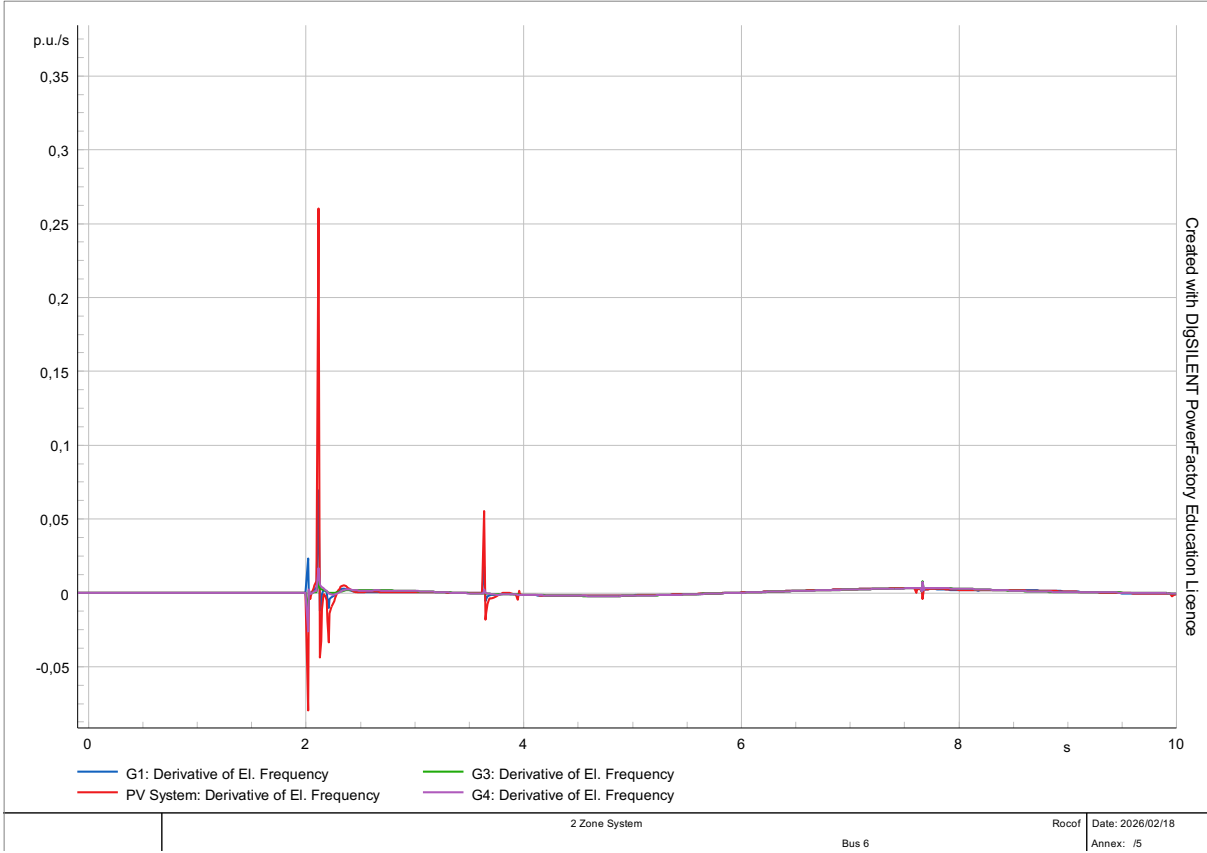
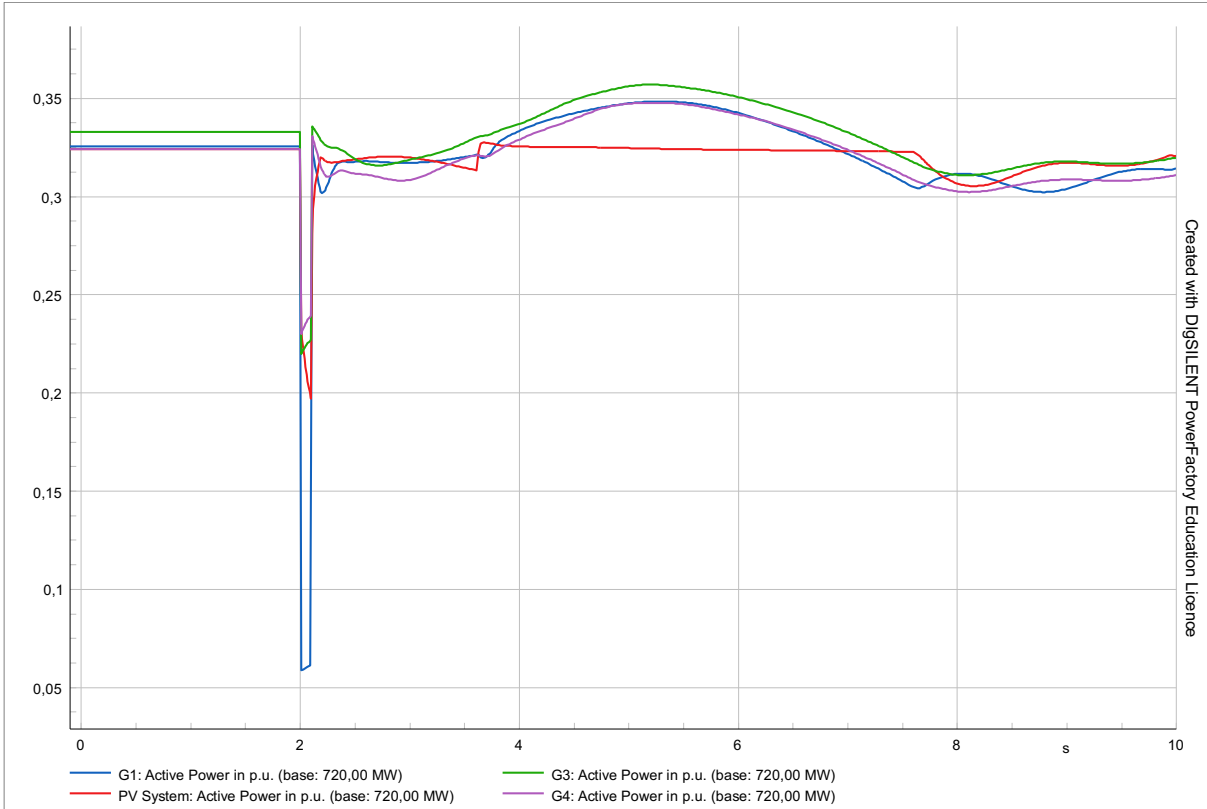


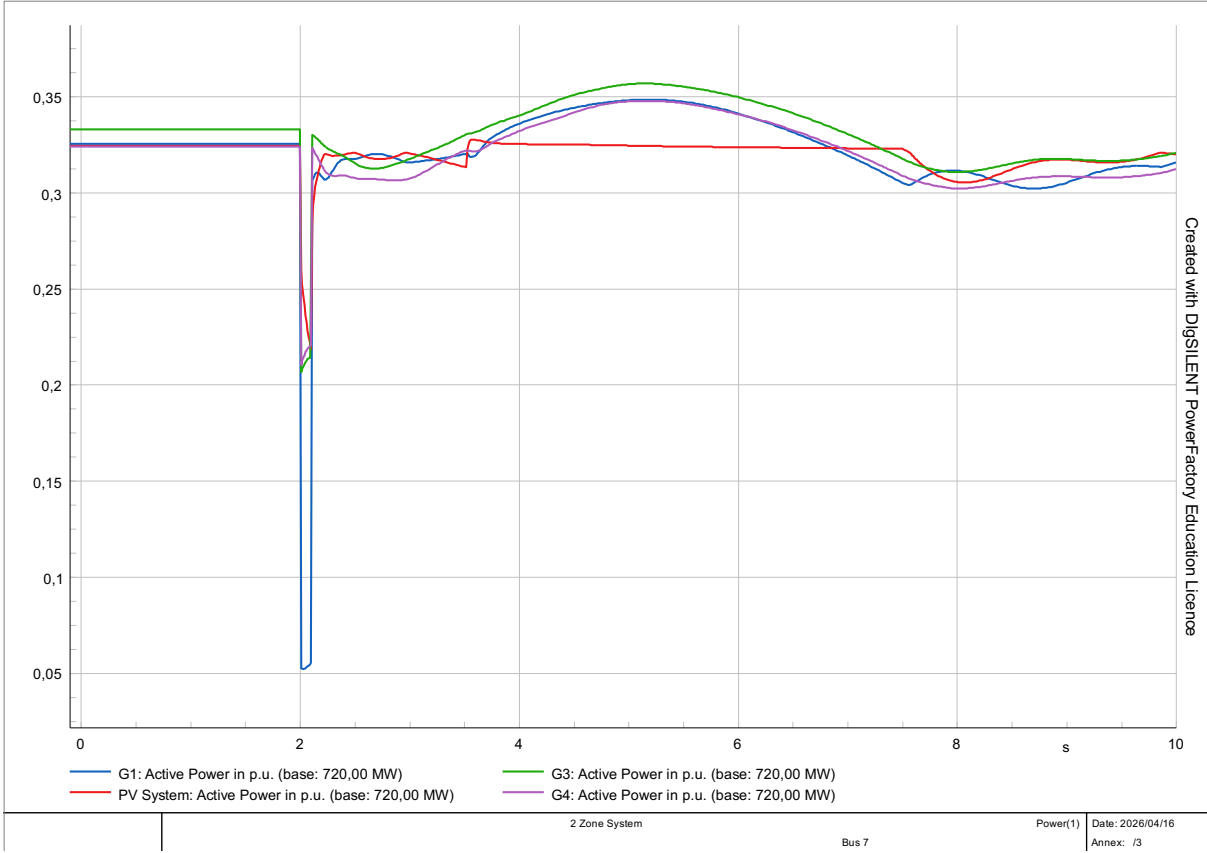
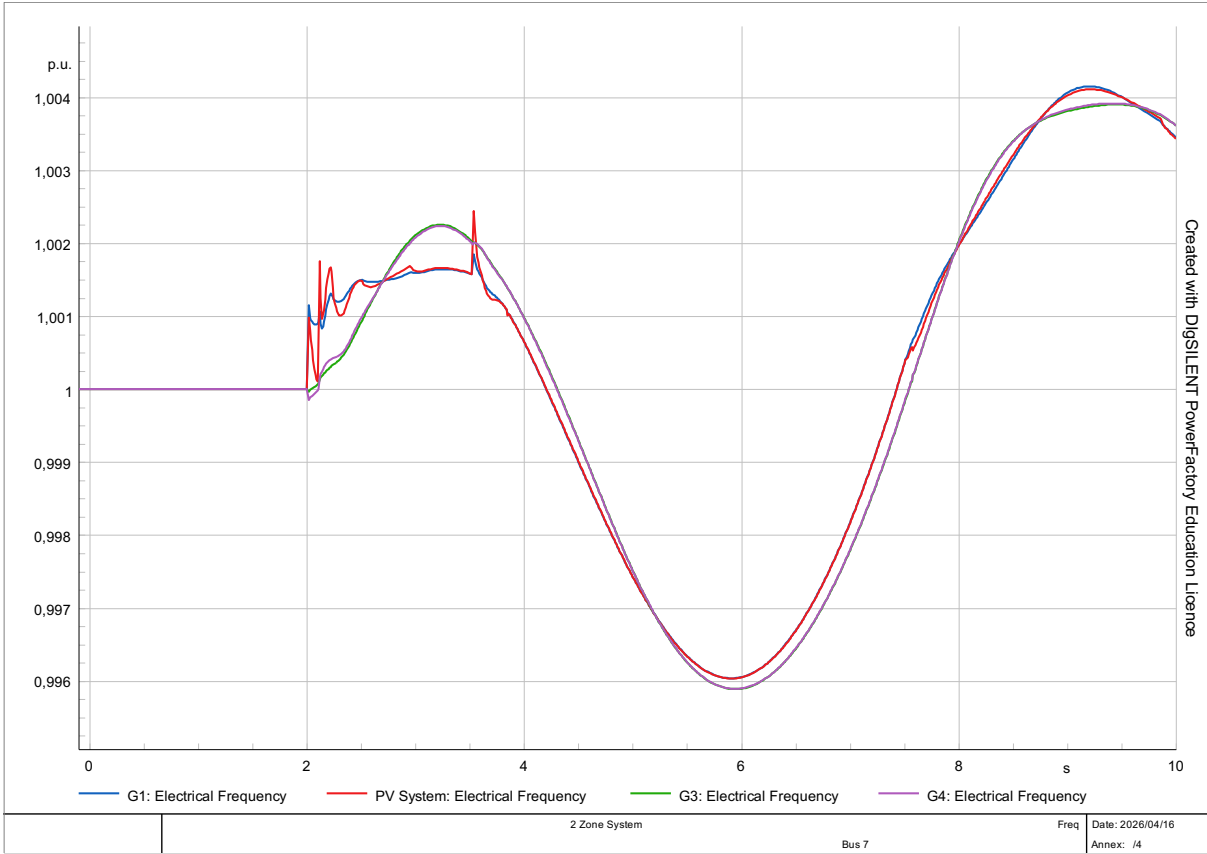


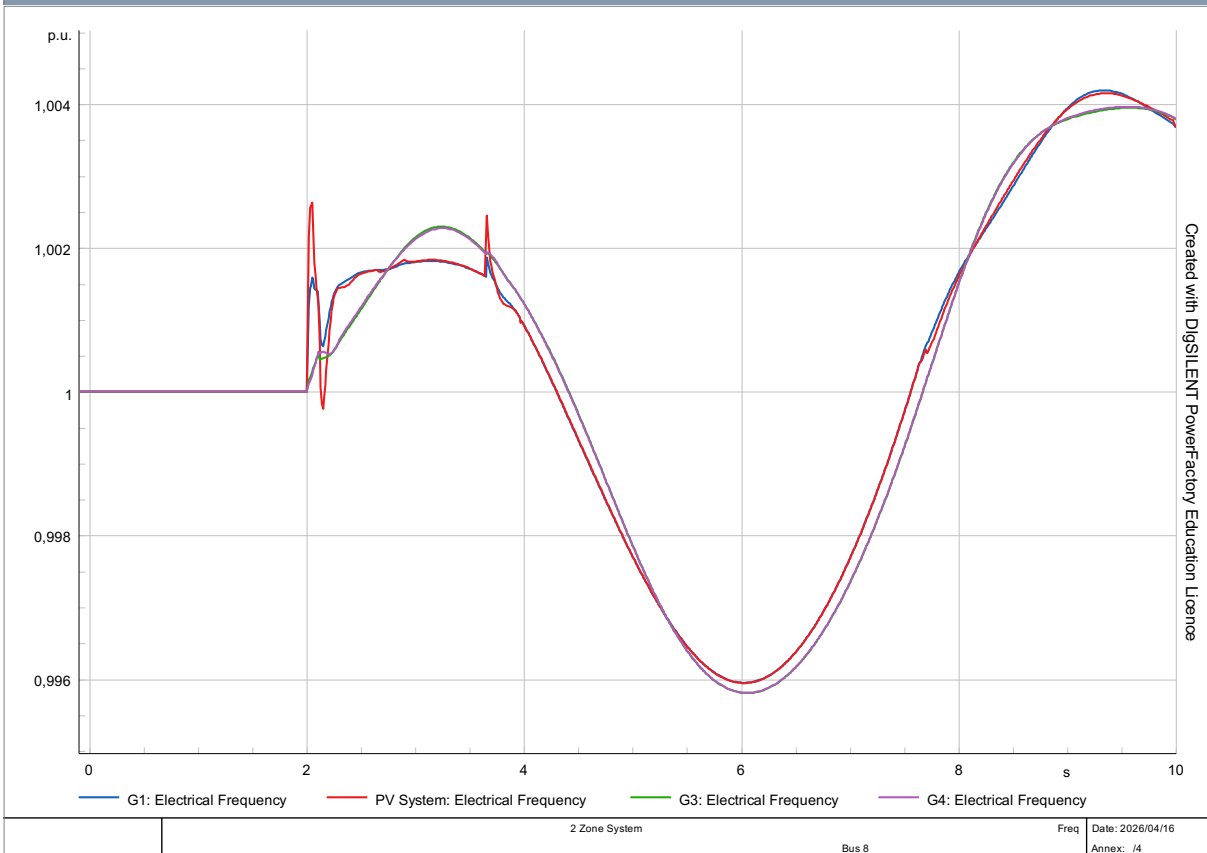
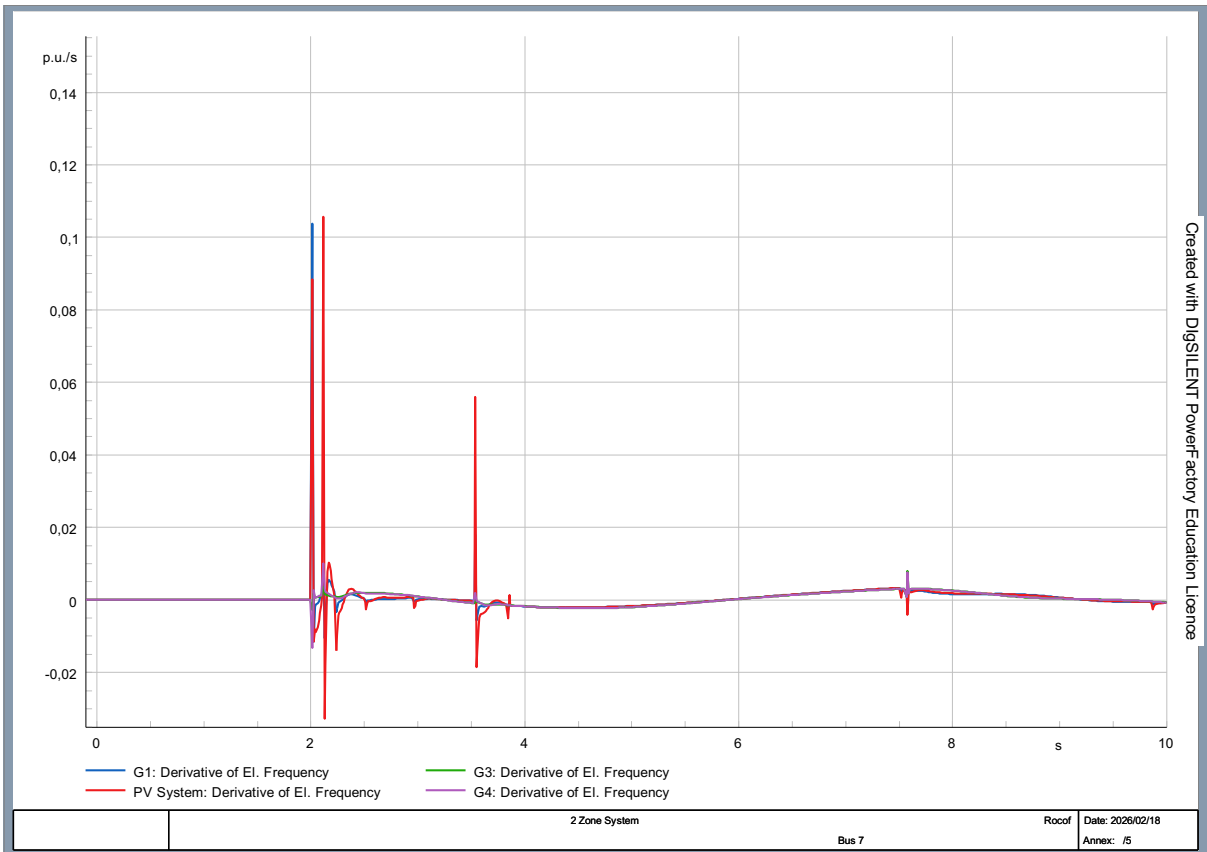


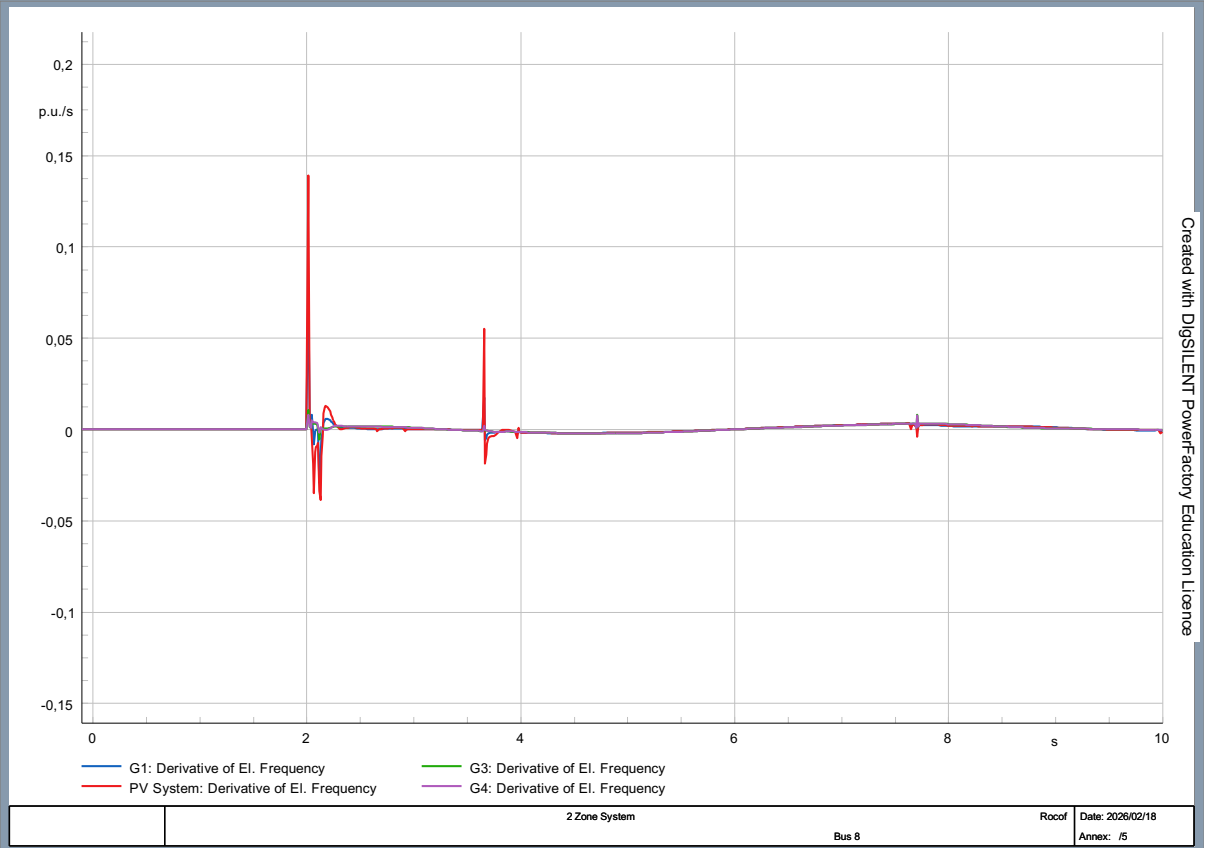
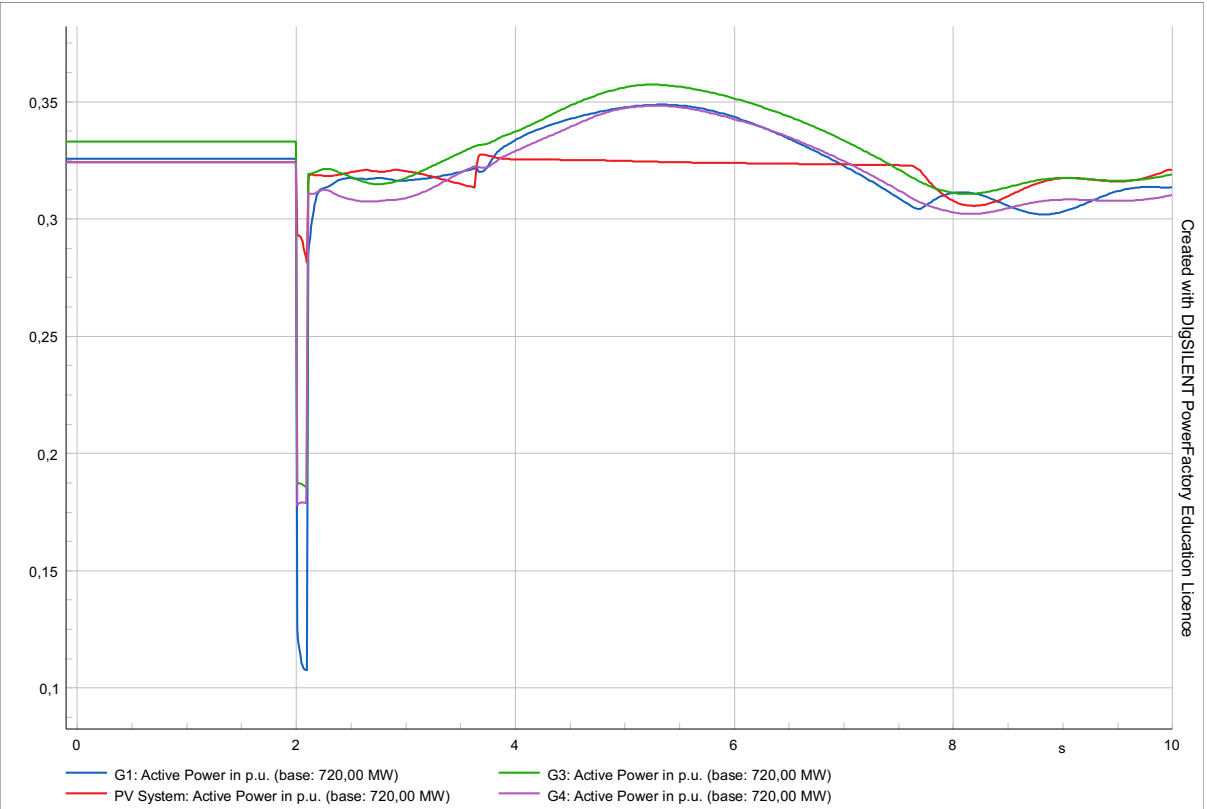


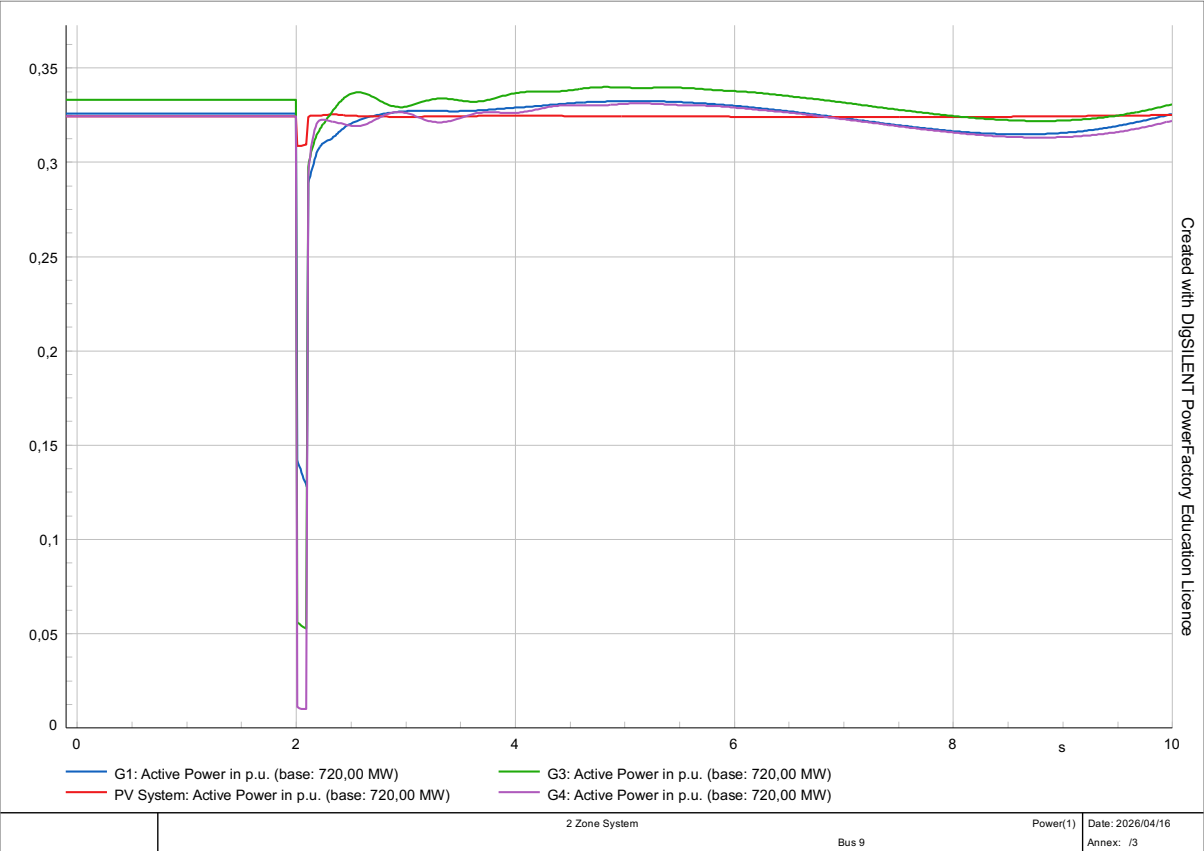
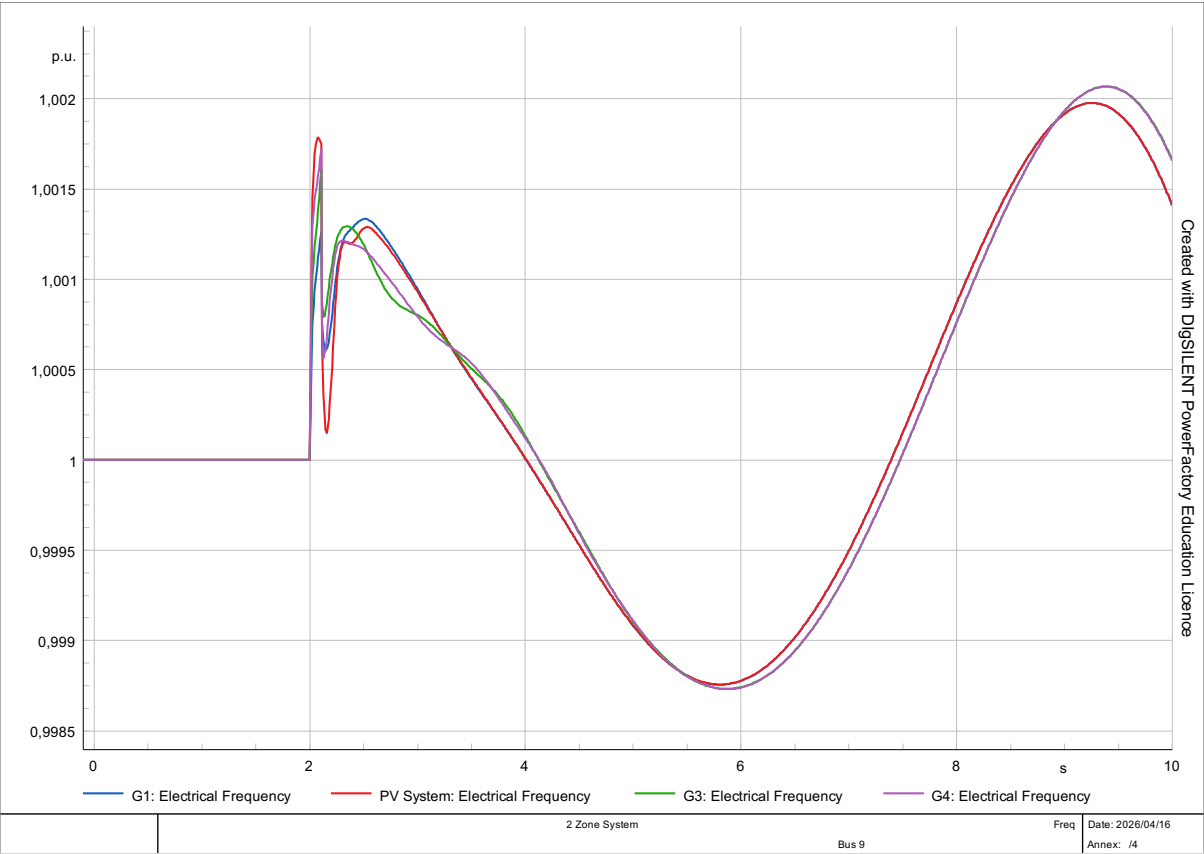


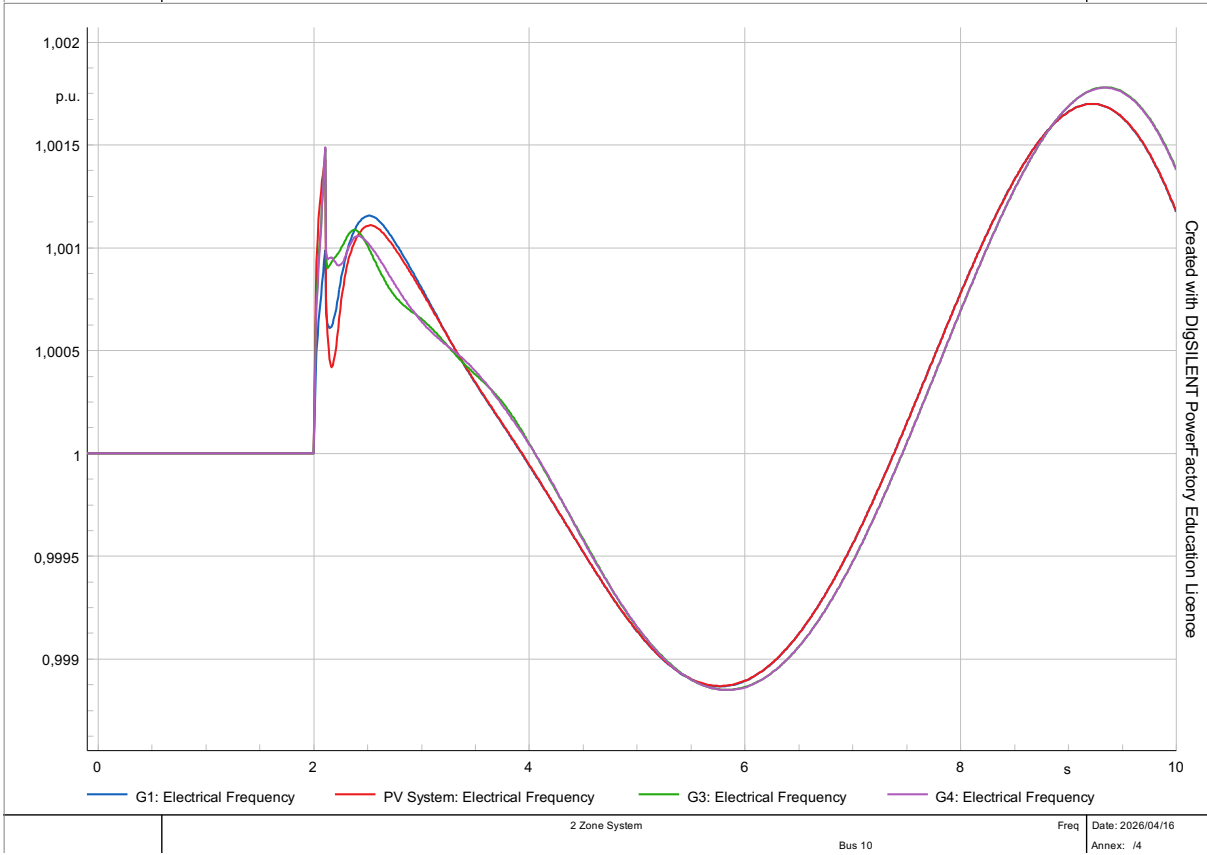
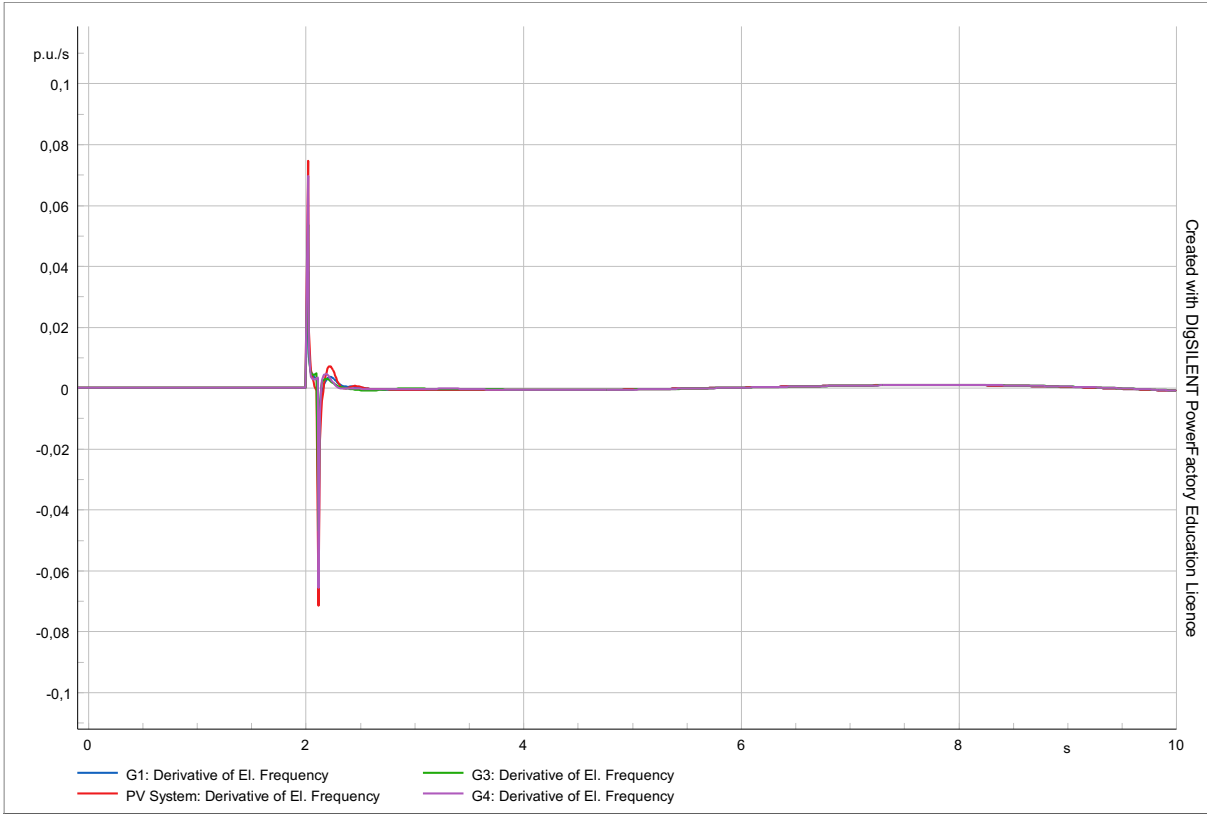


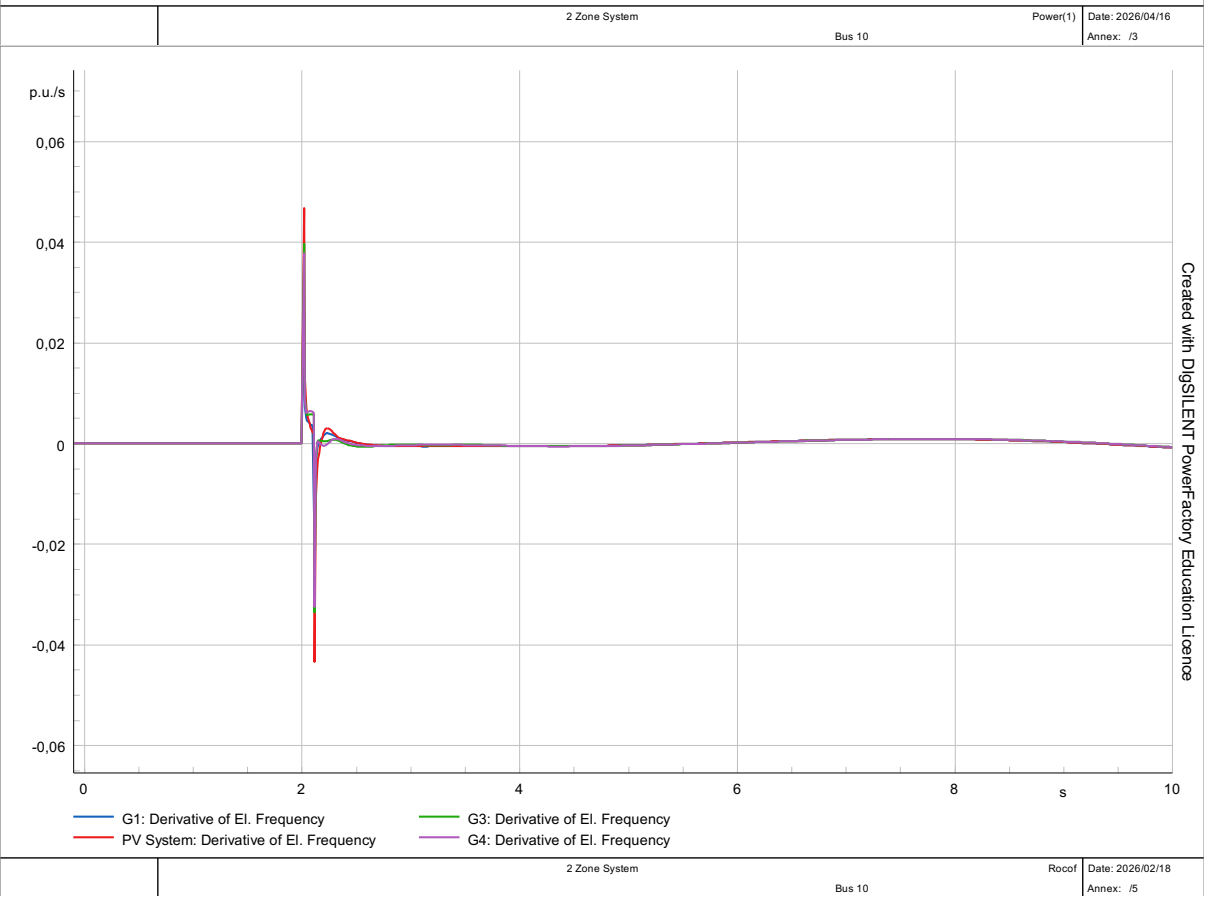
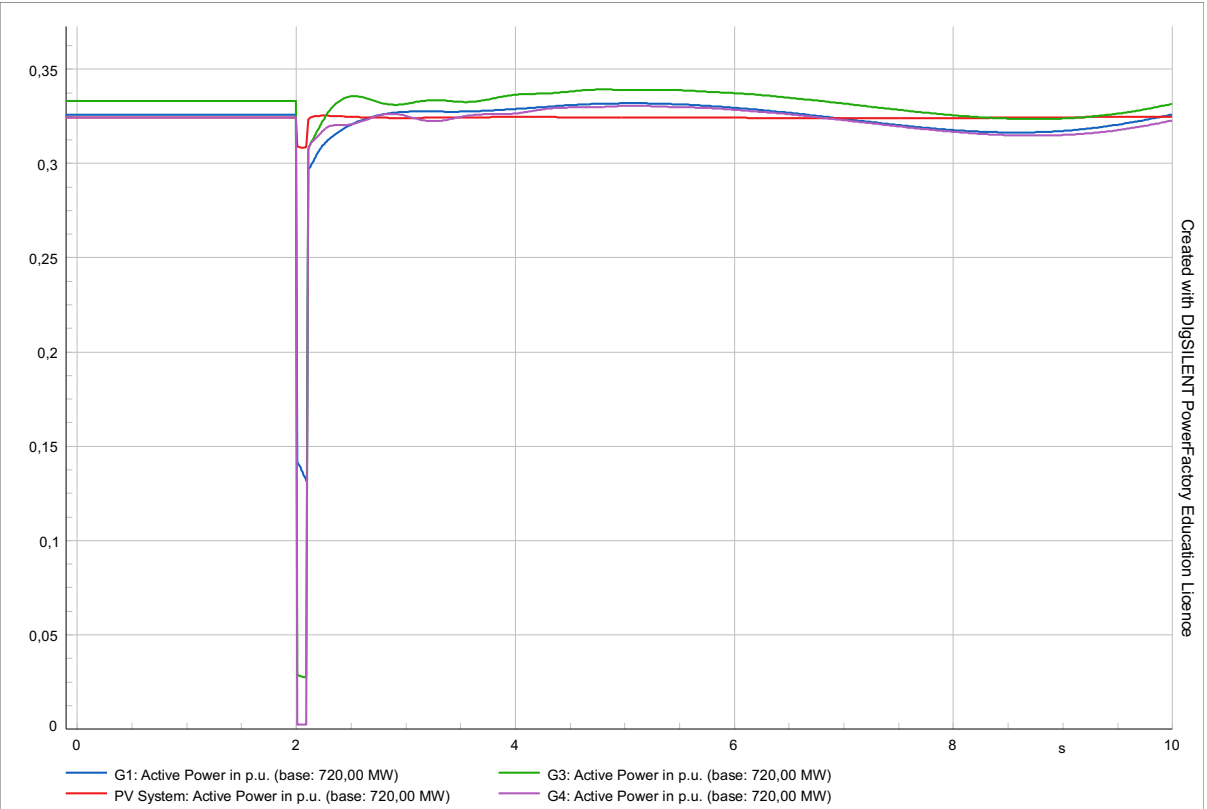


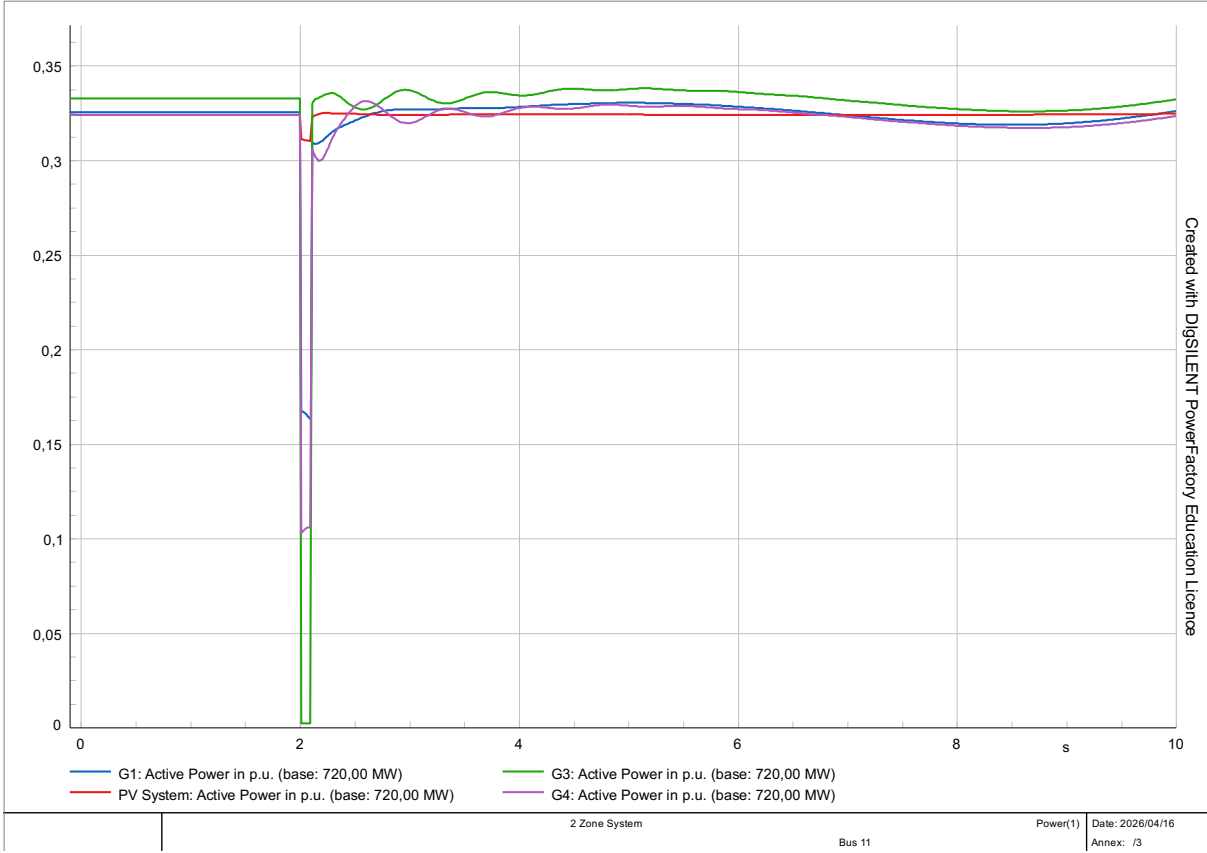
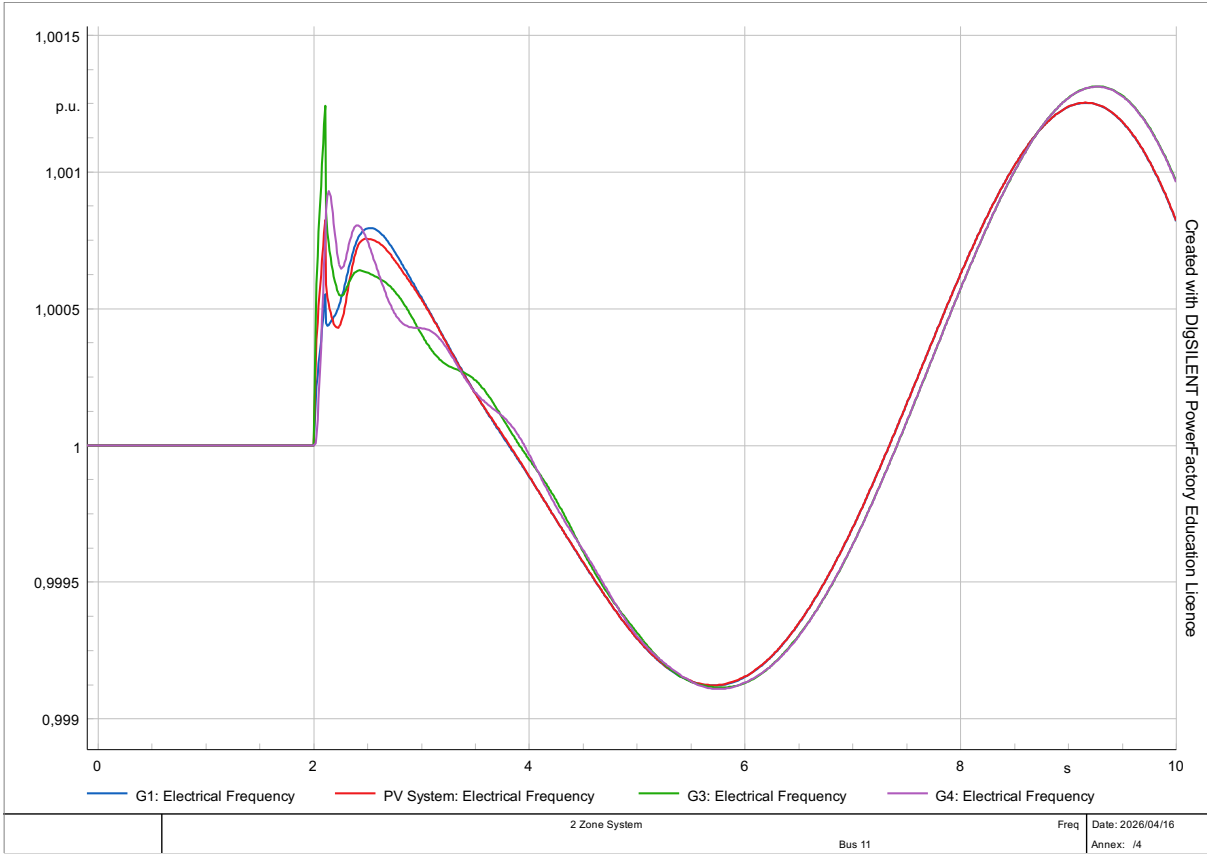


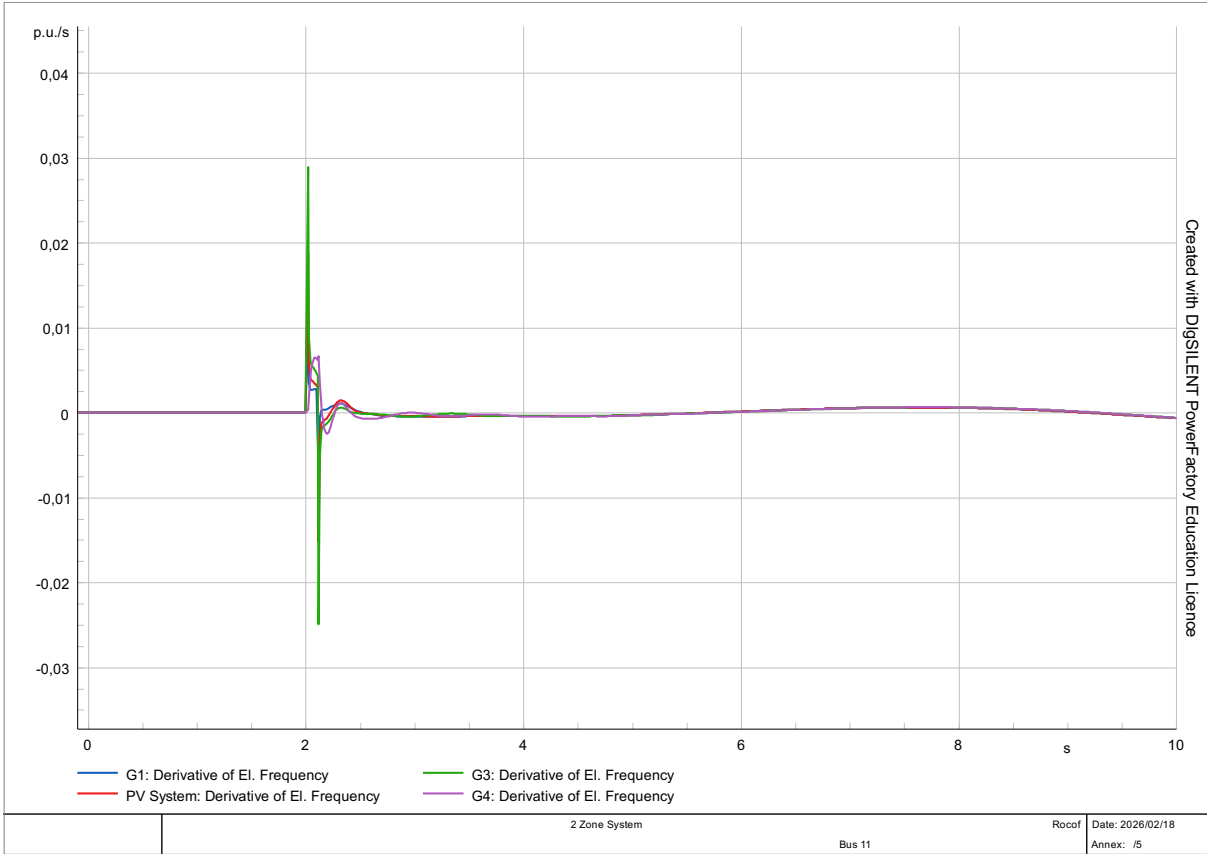




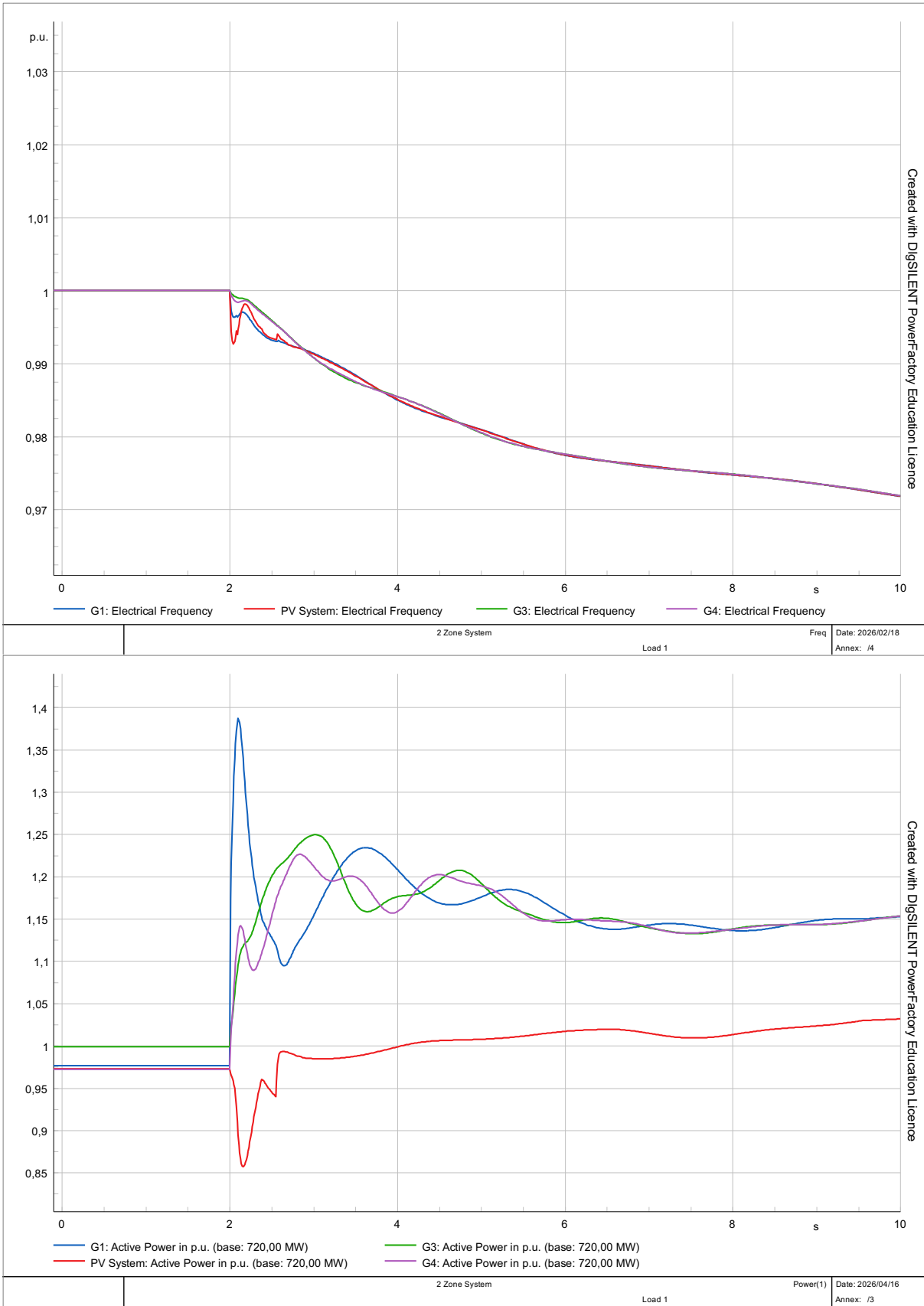


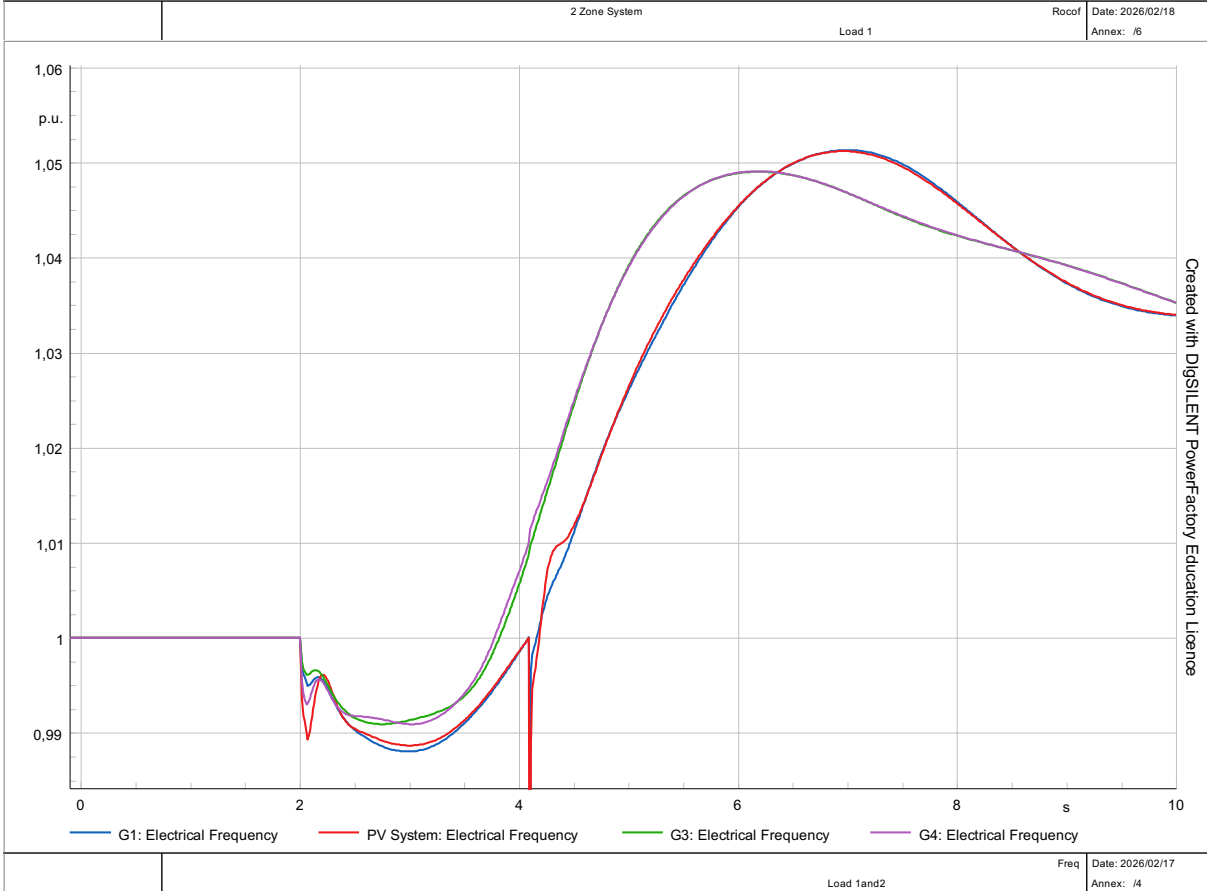
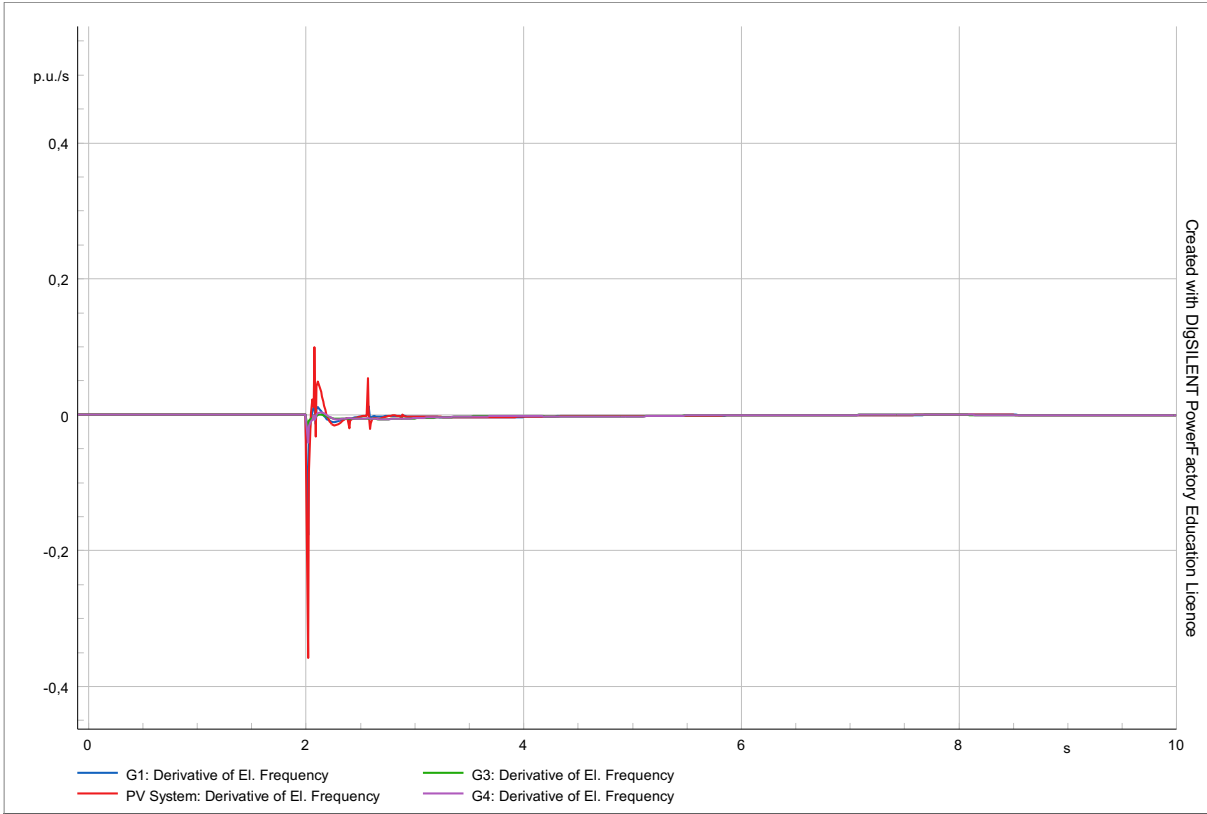


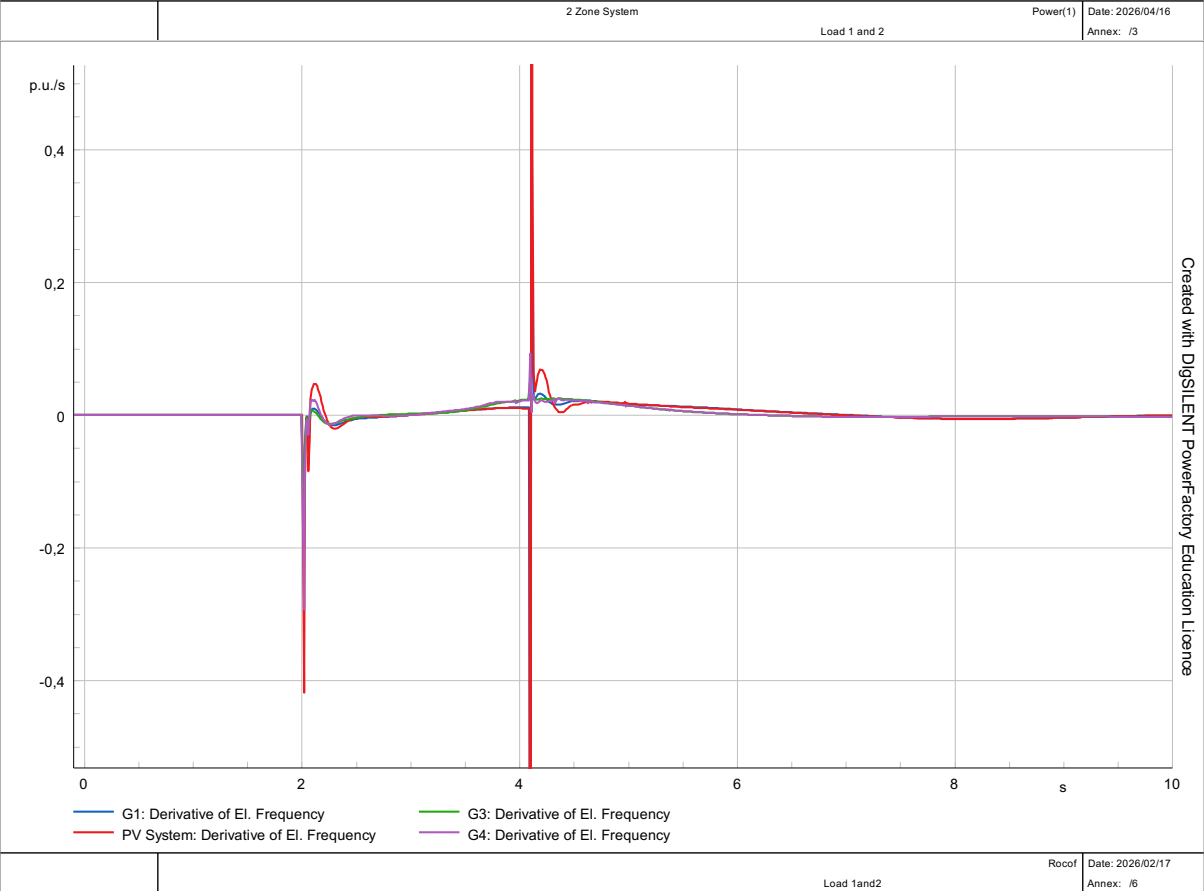
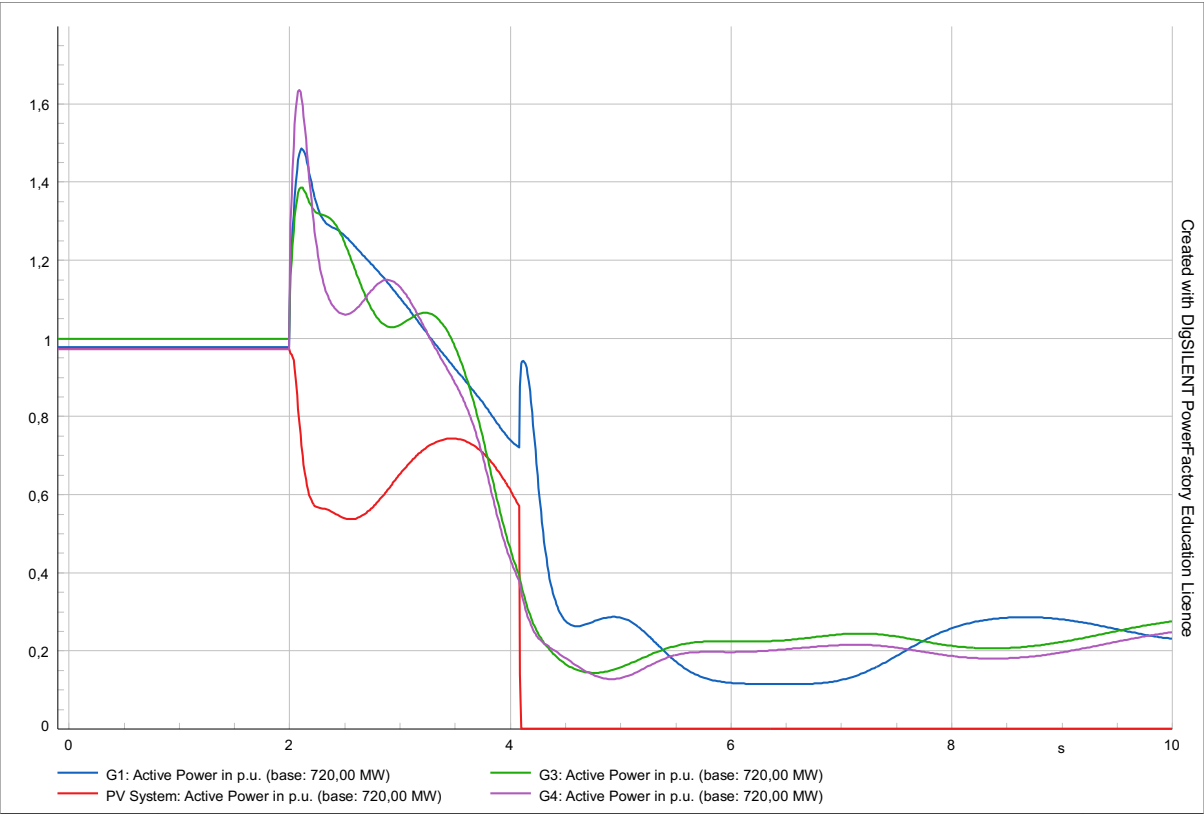


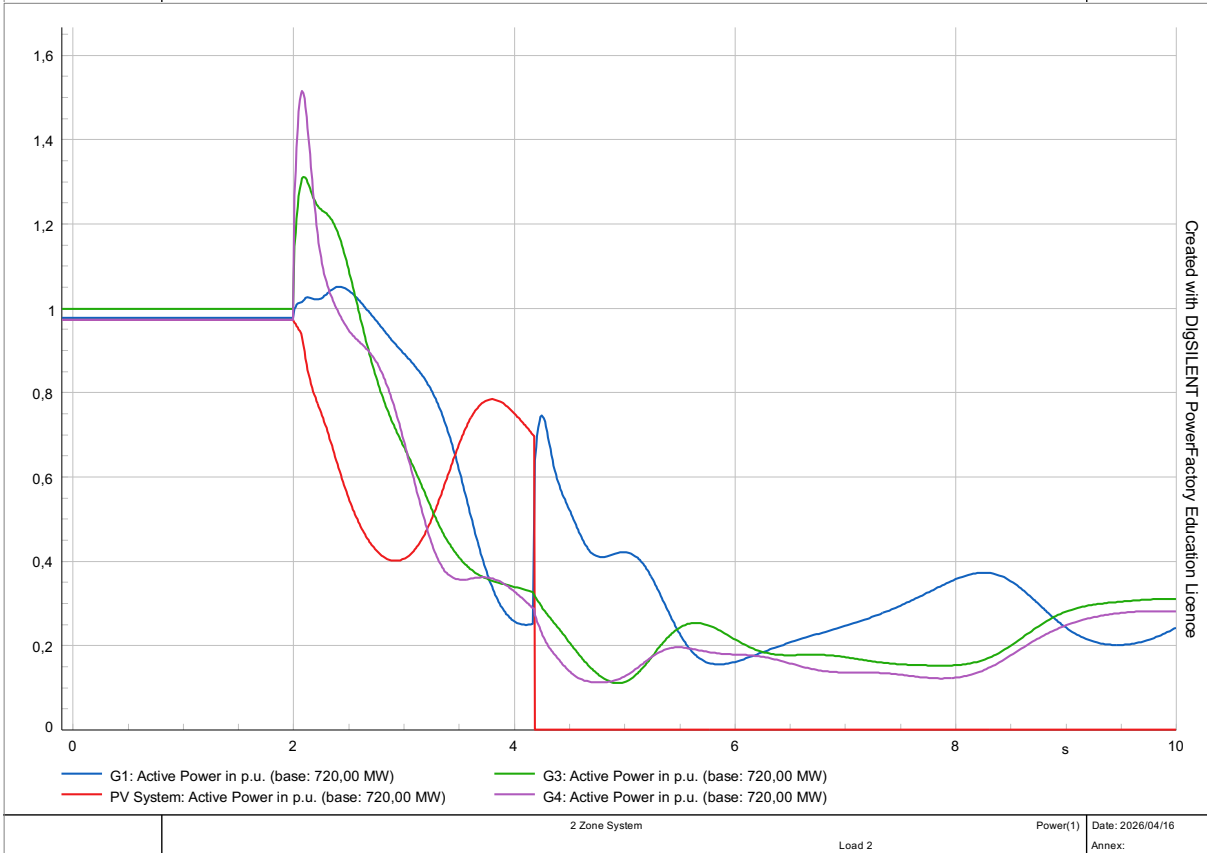
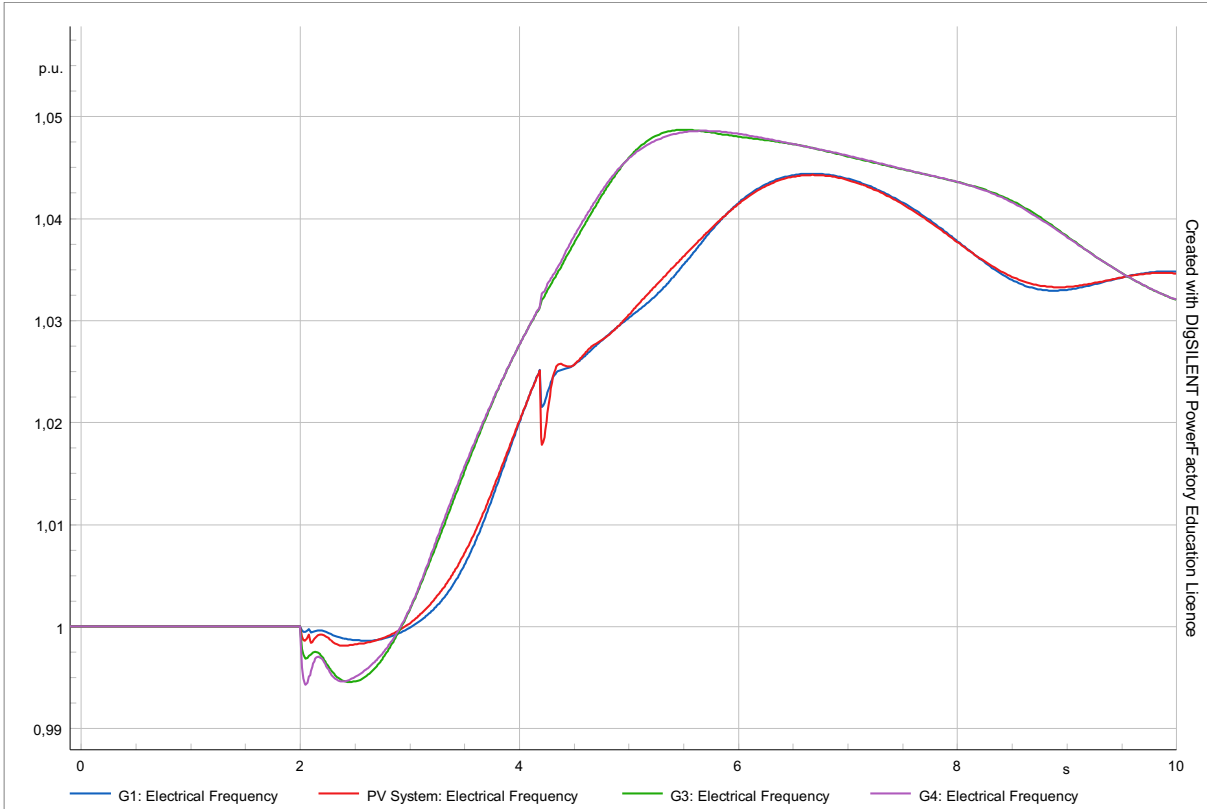


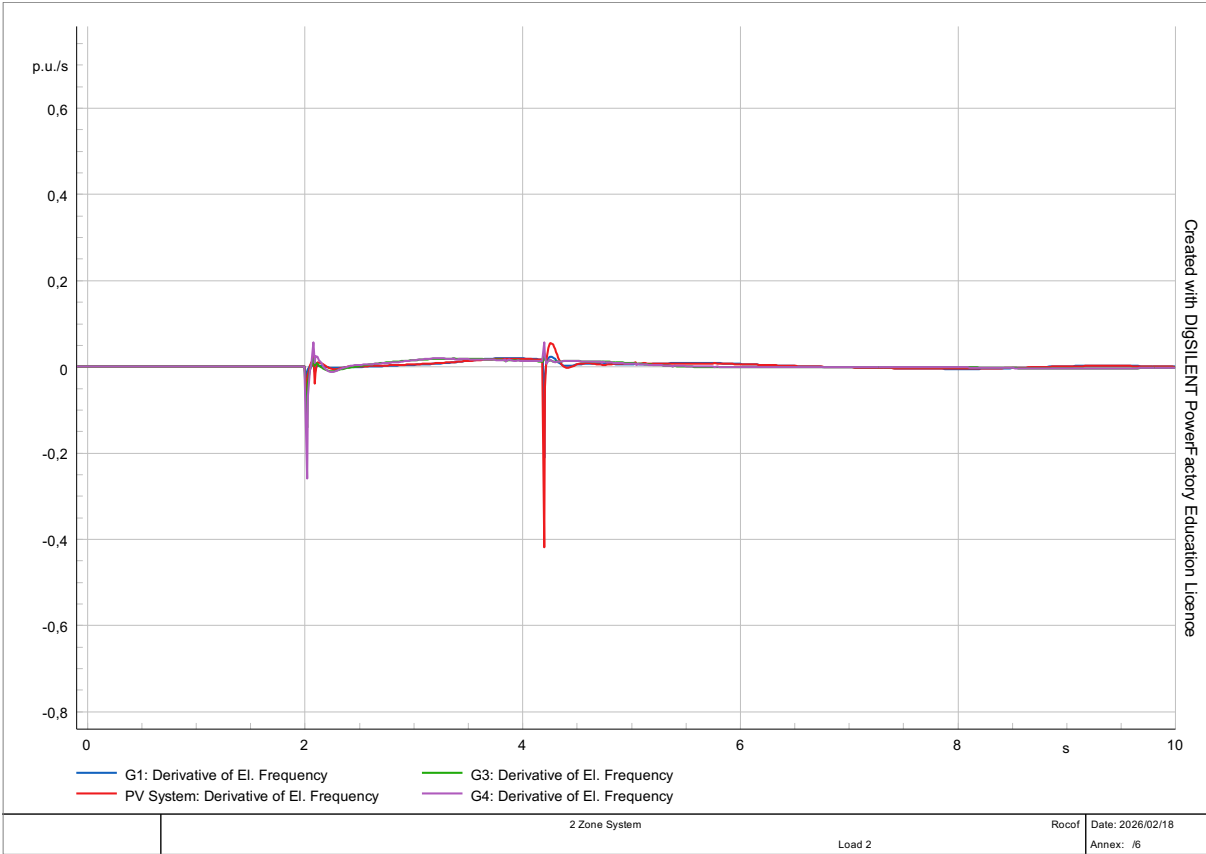
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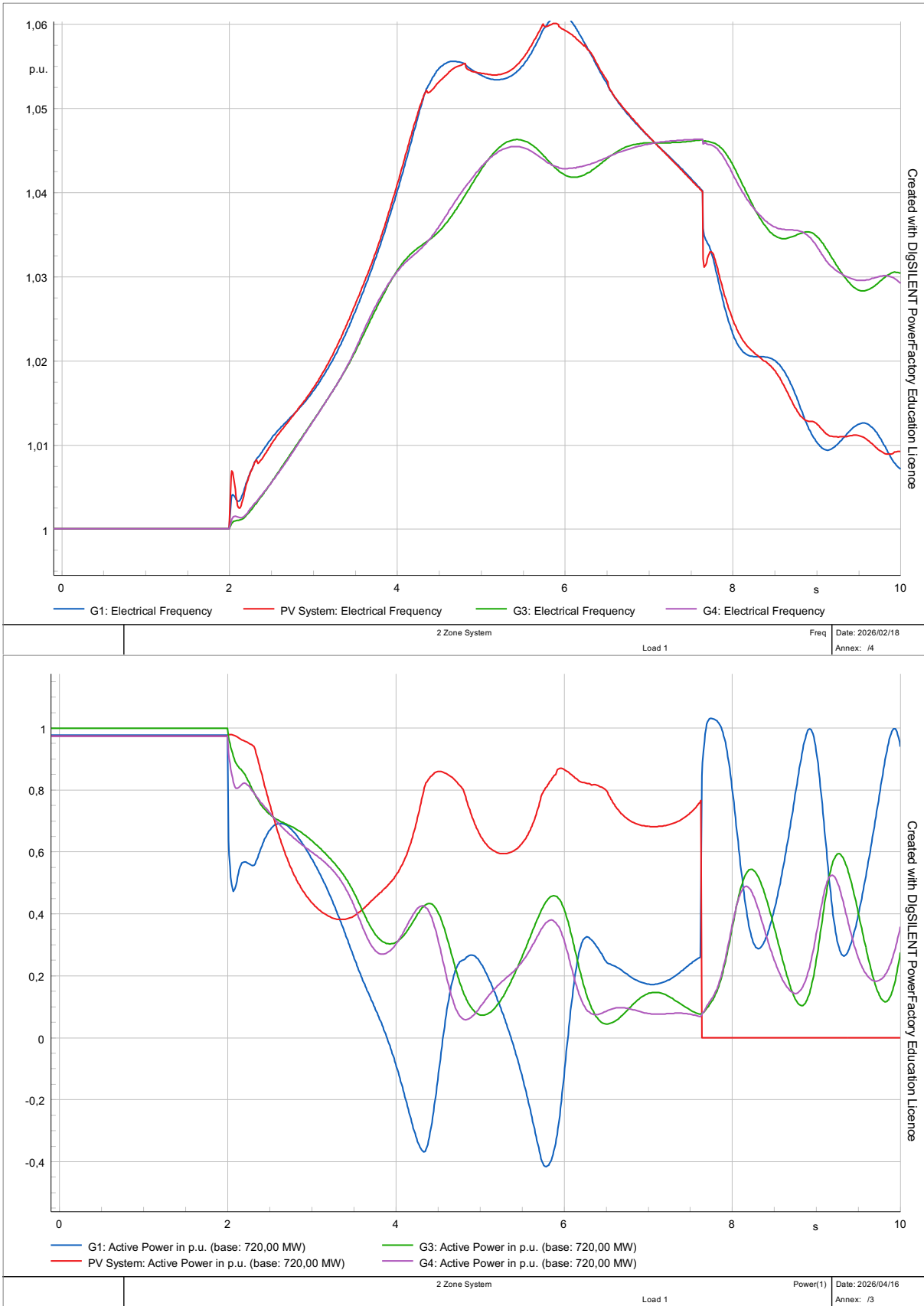


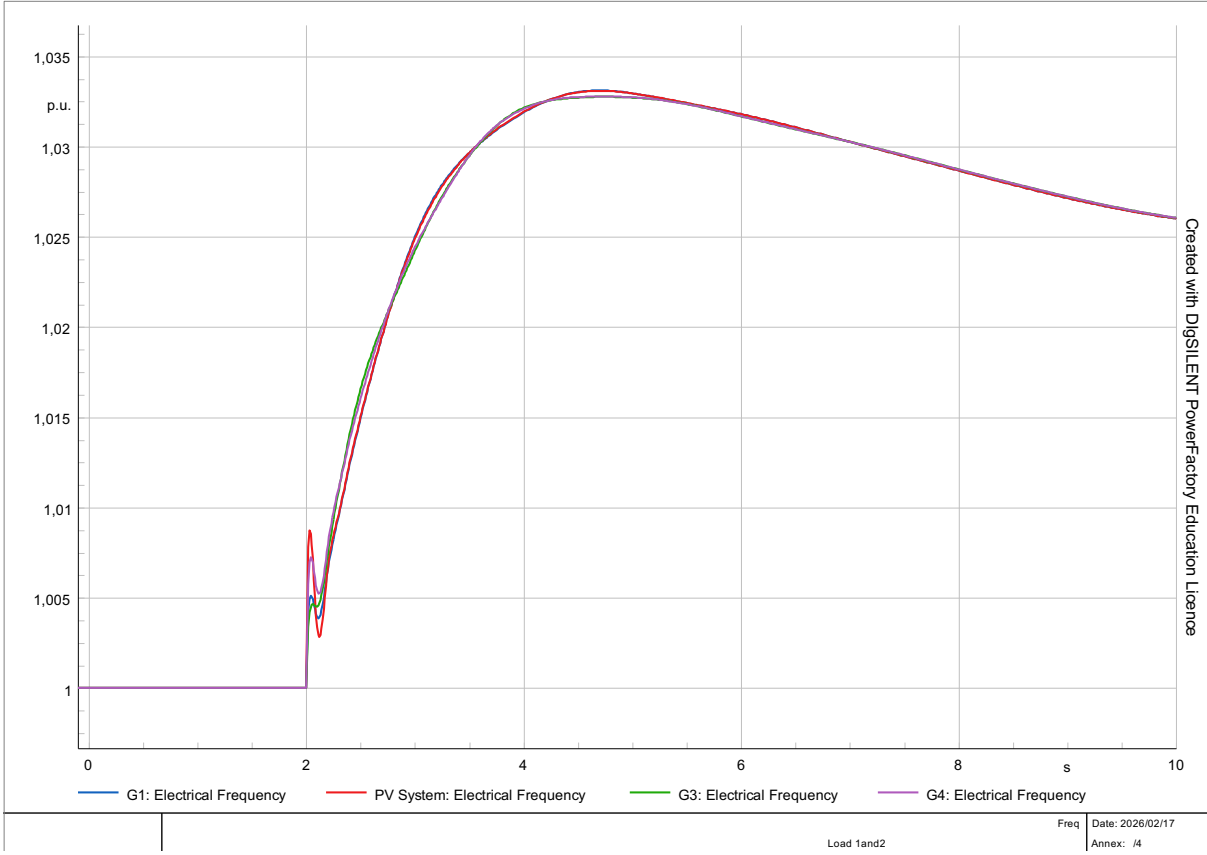
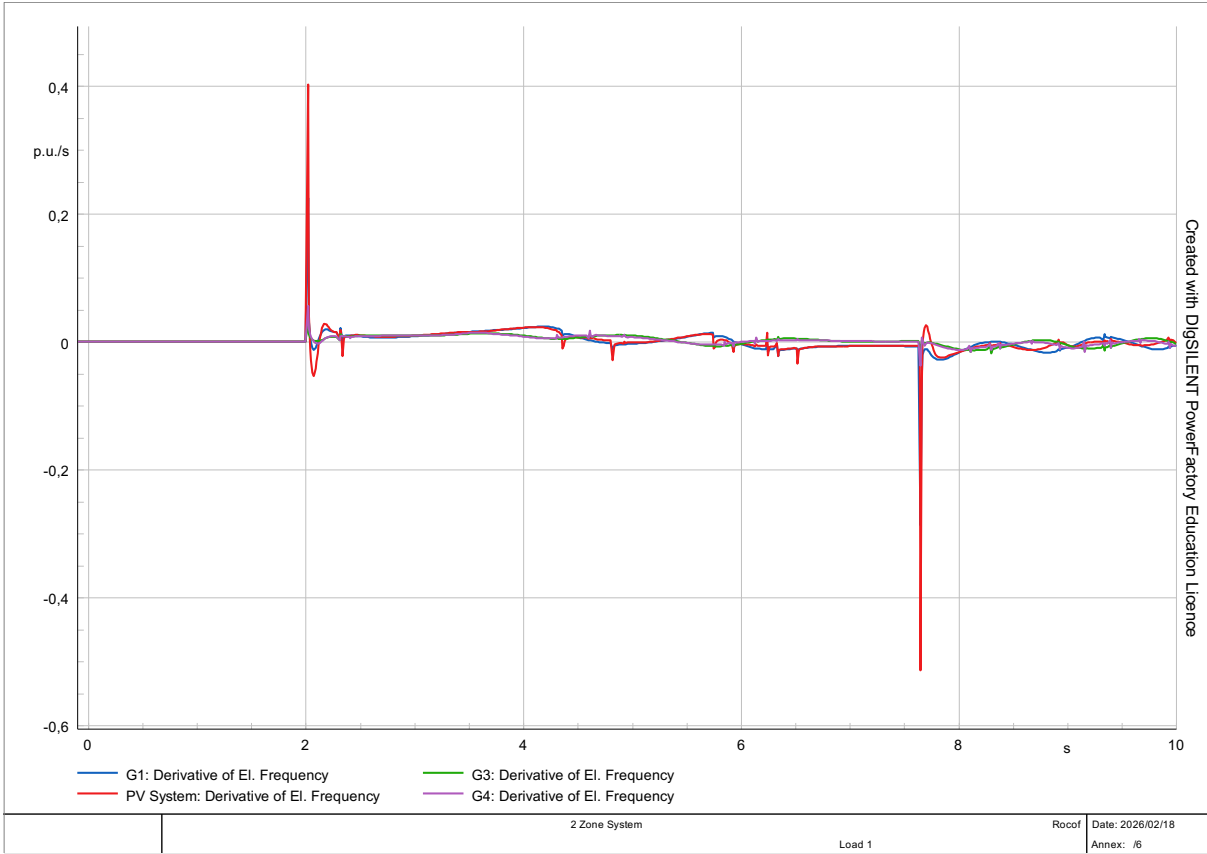


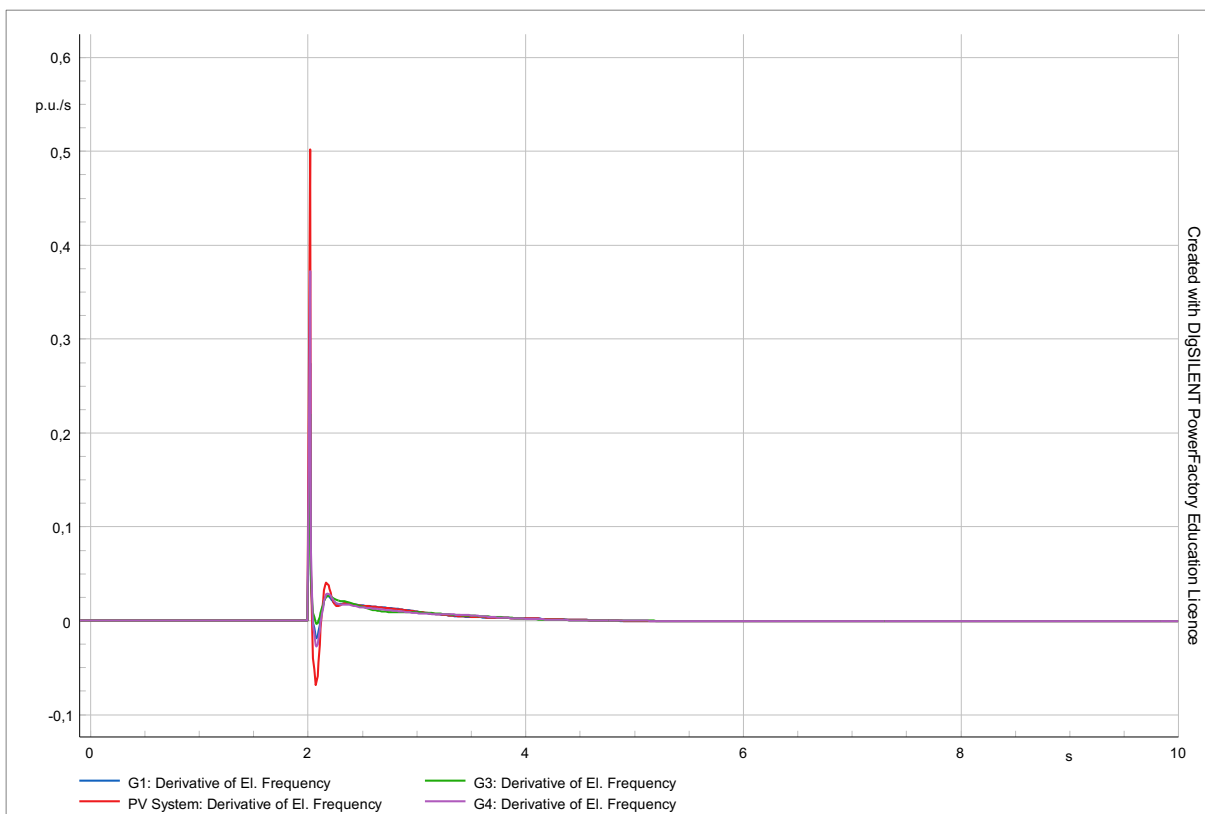
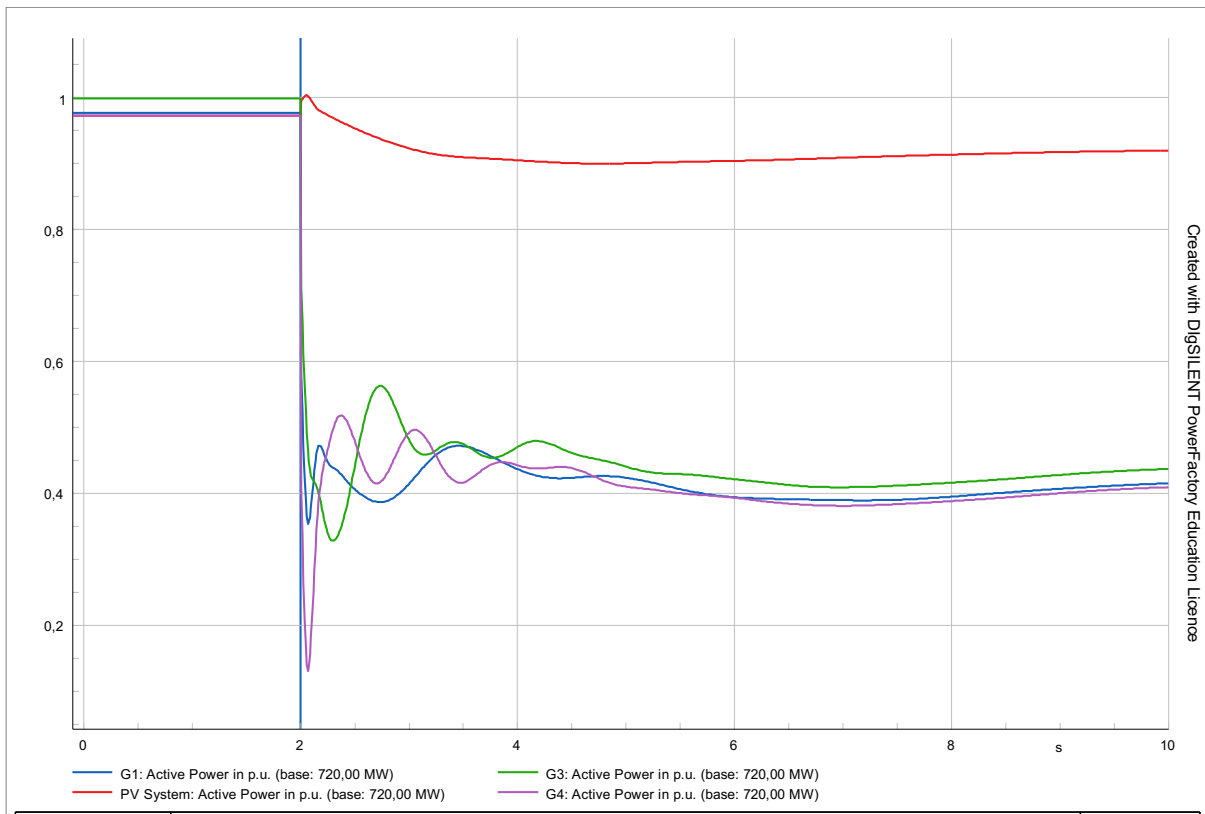




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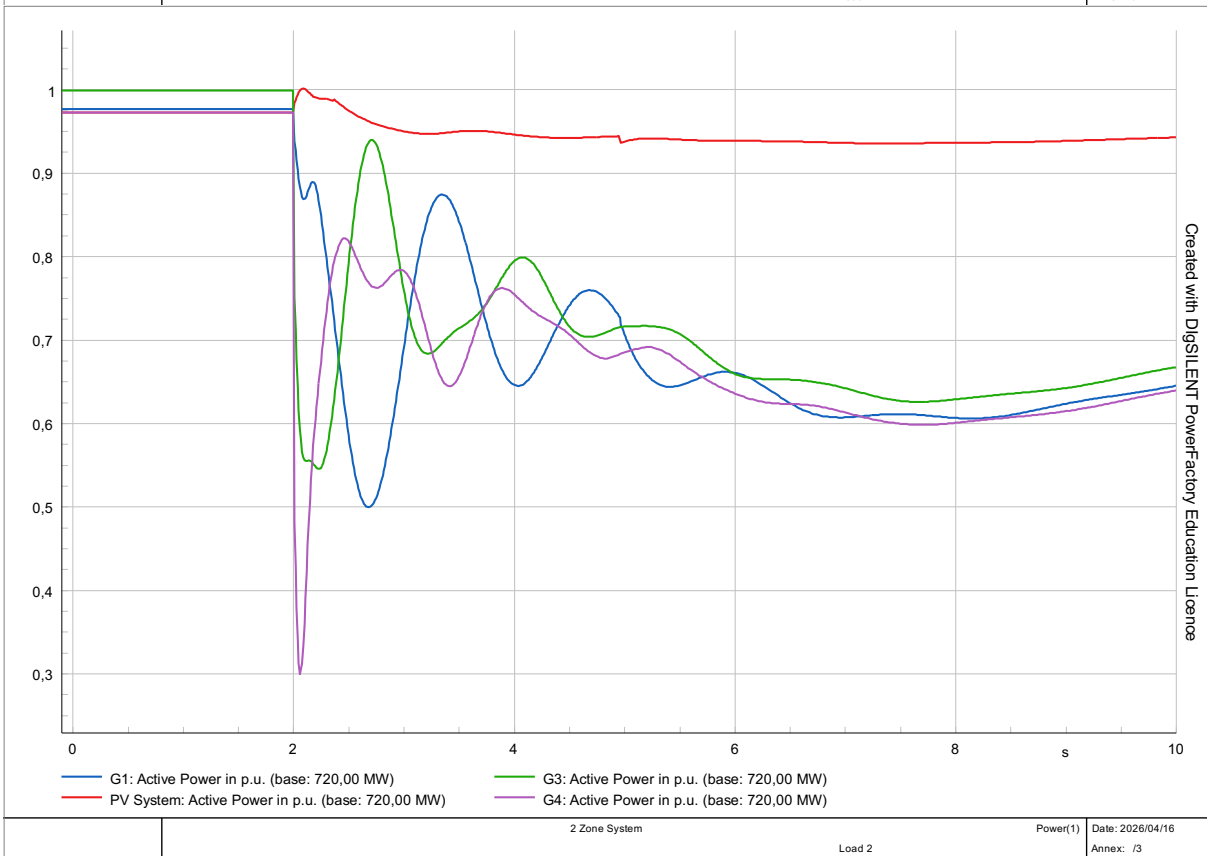
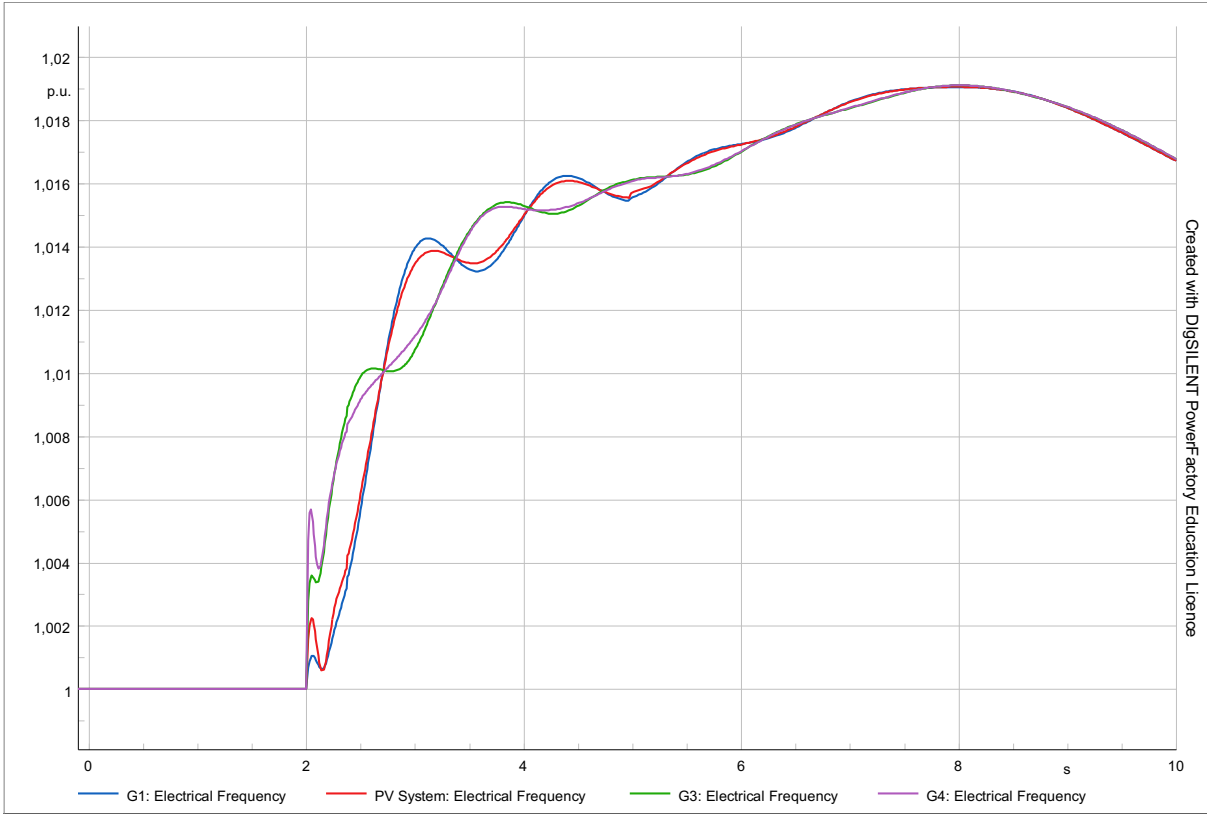


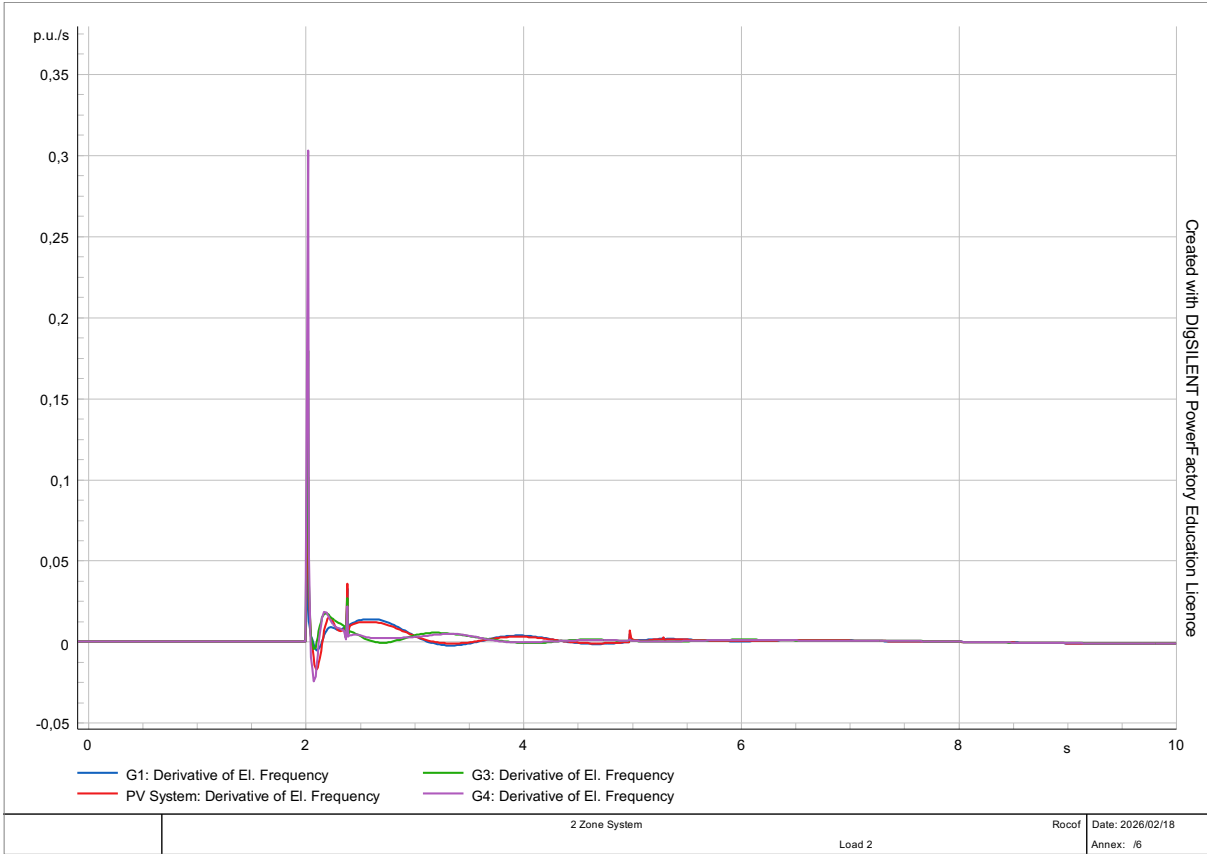




Load 1and2

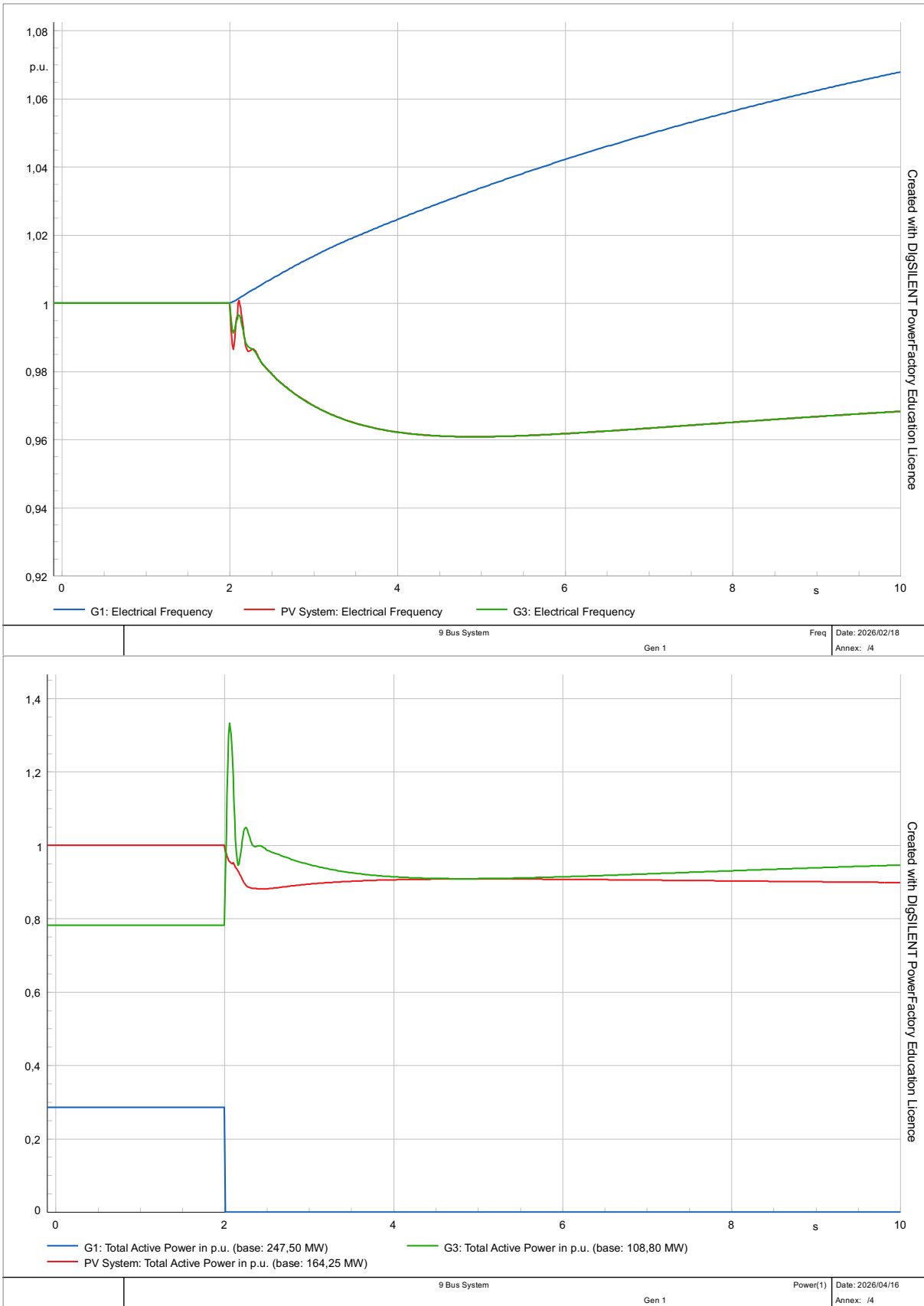
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Annex: j6

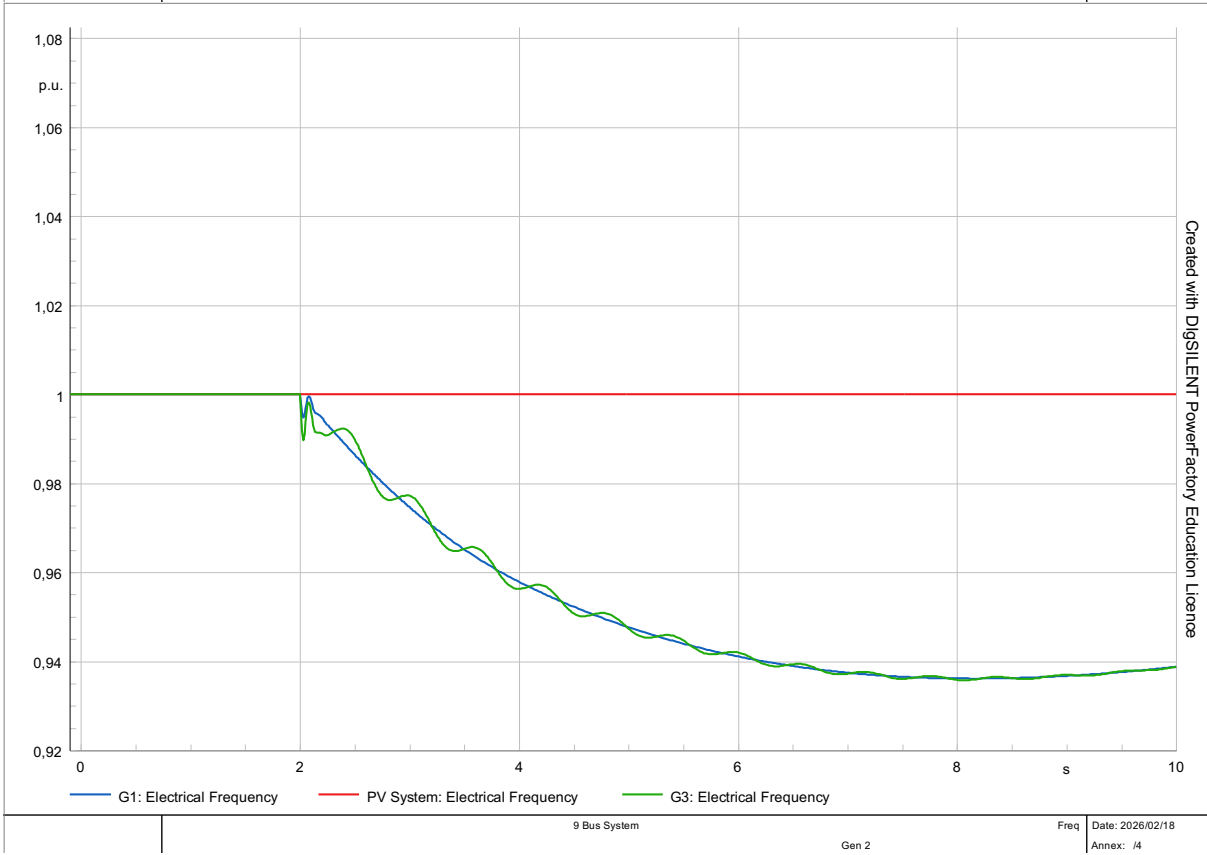
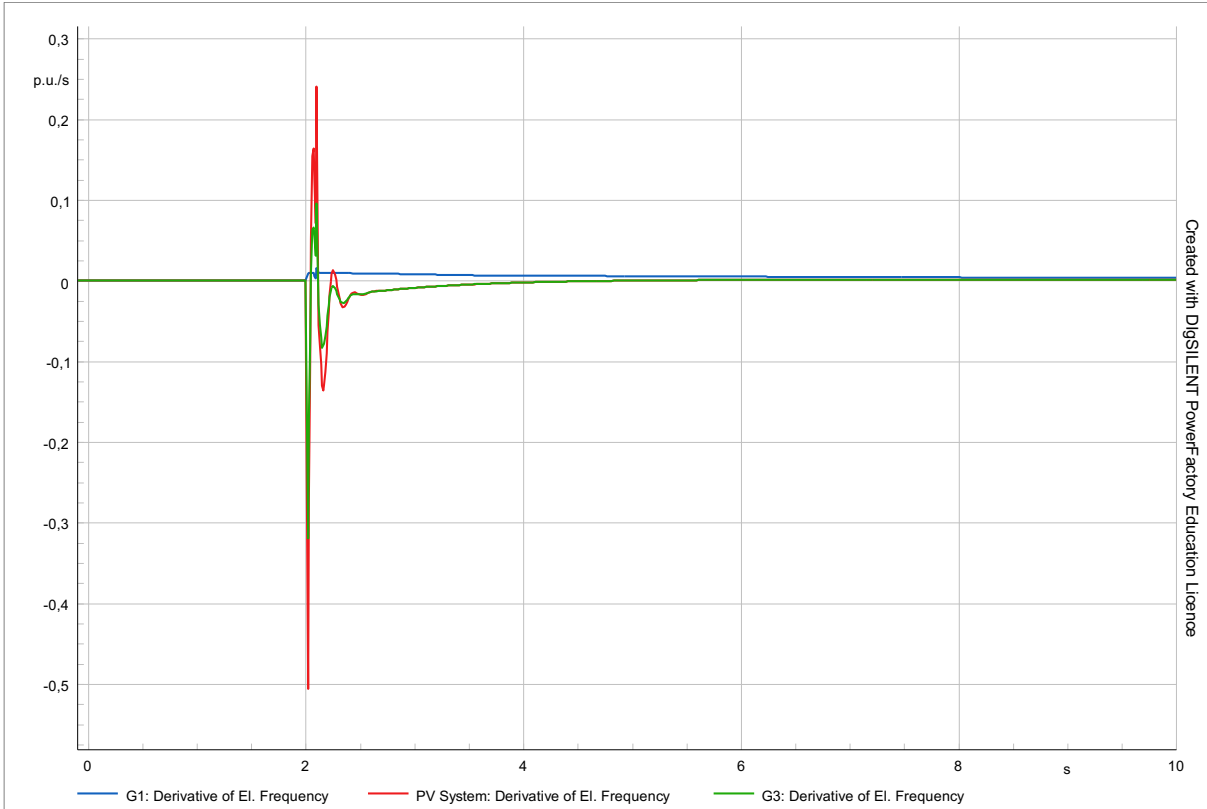


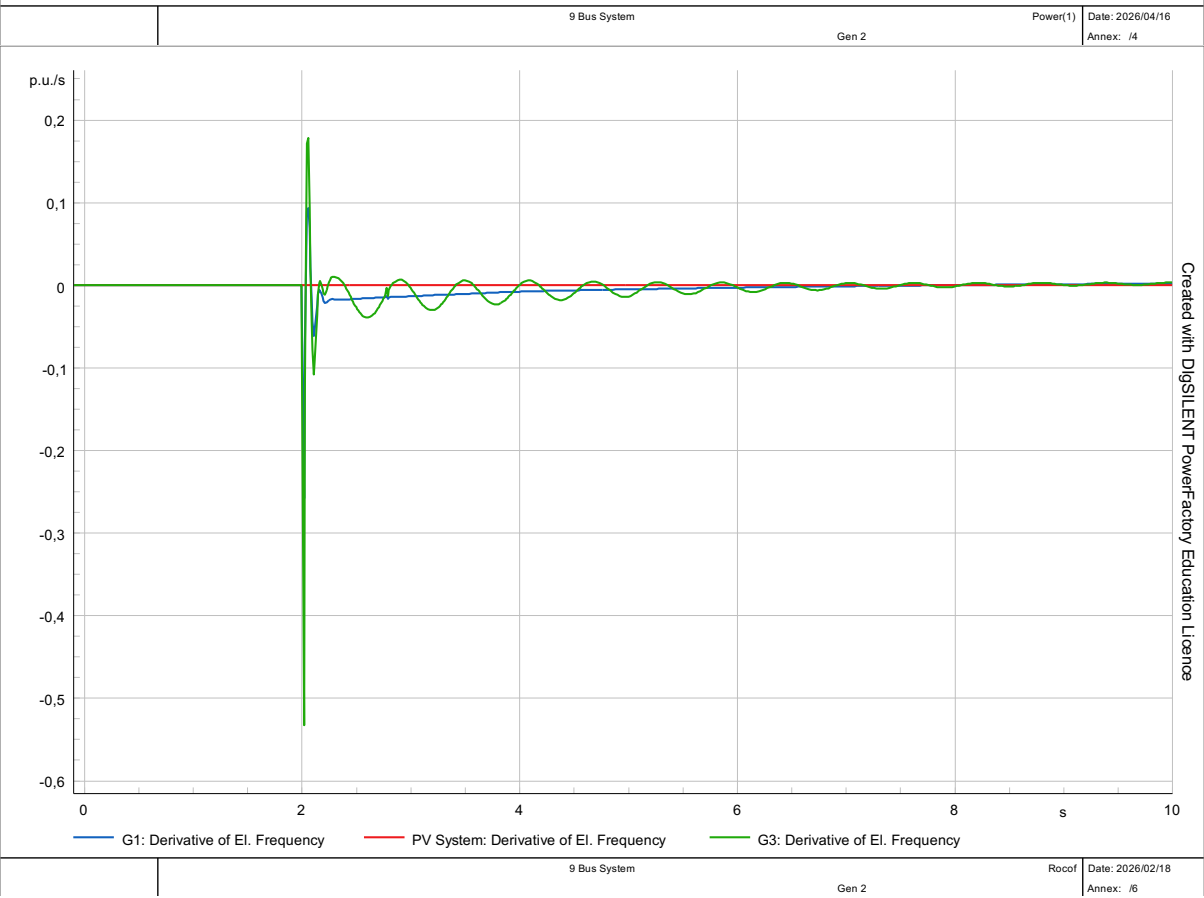
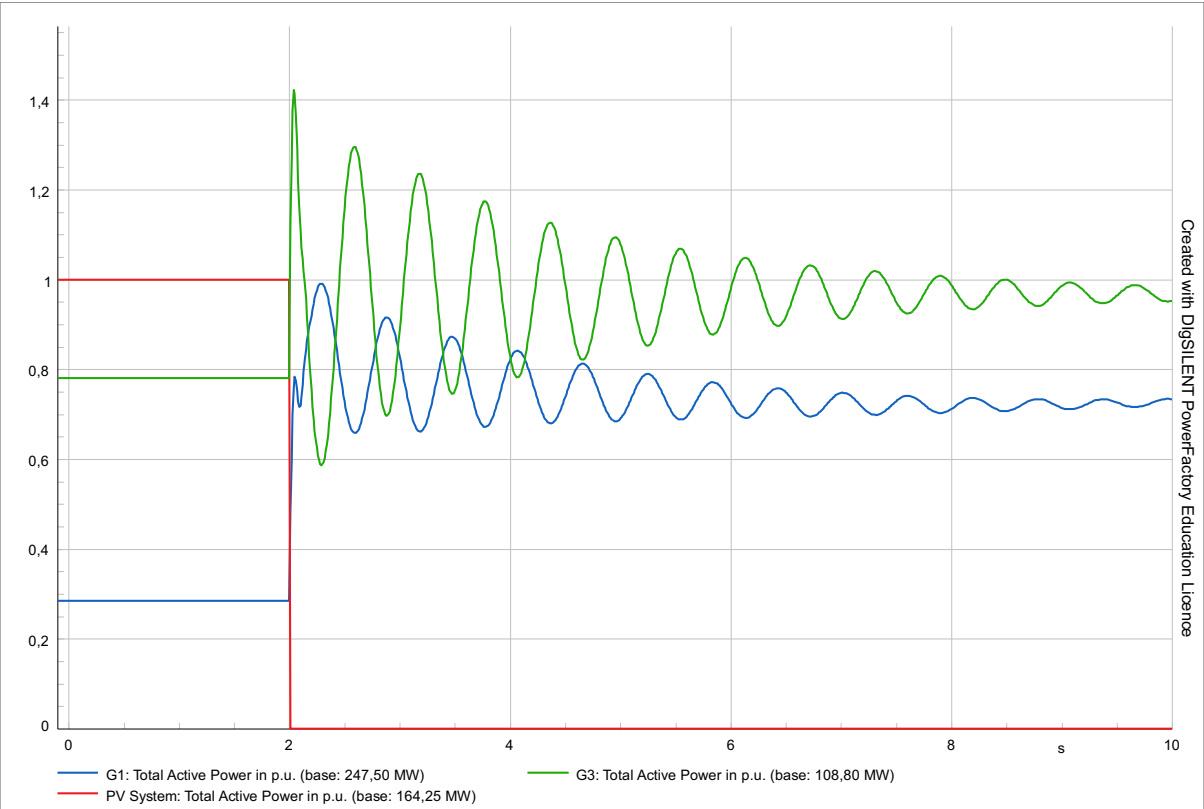


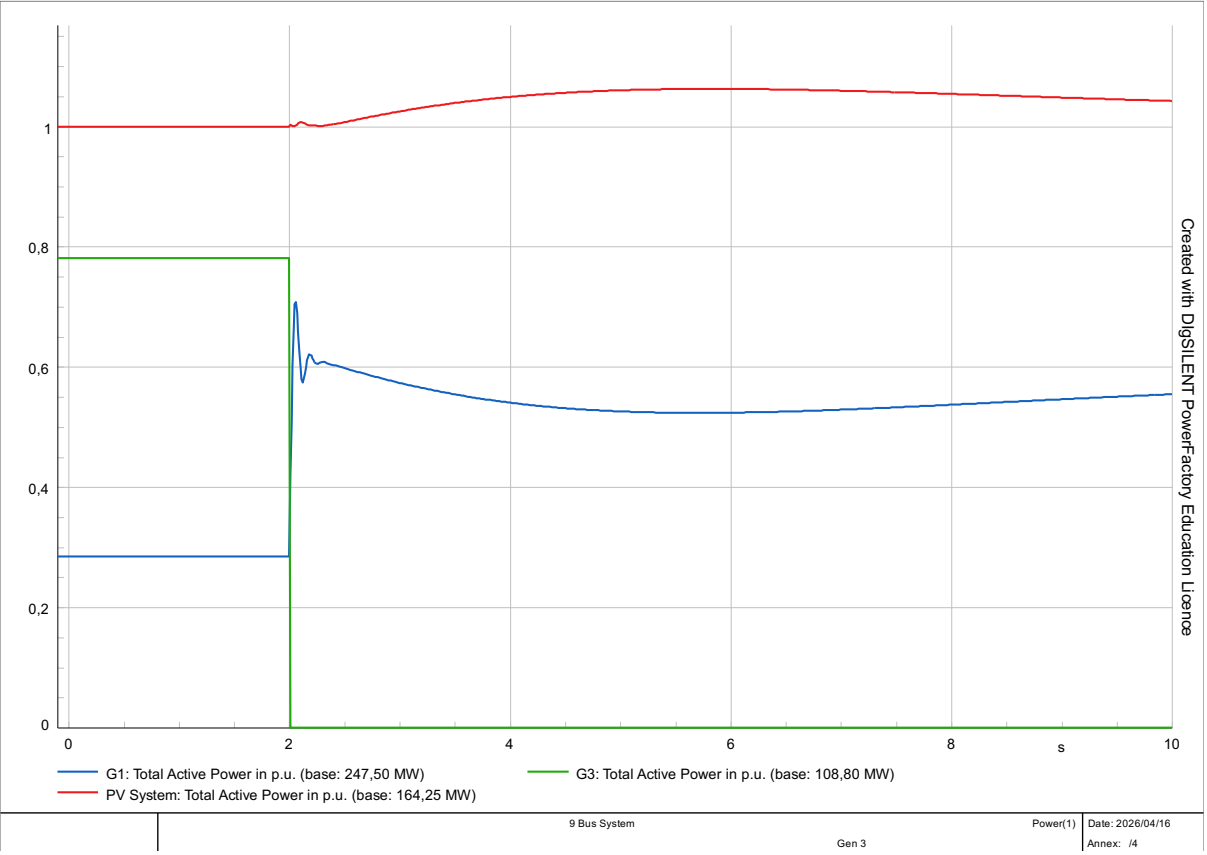
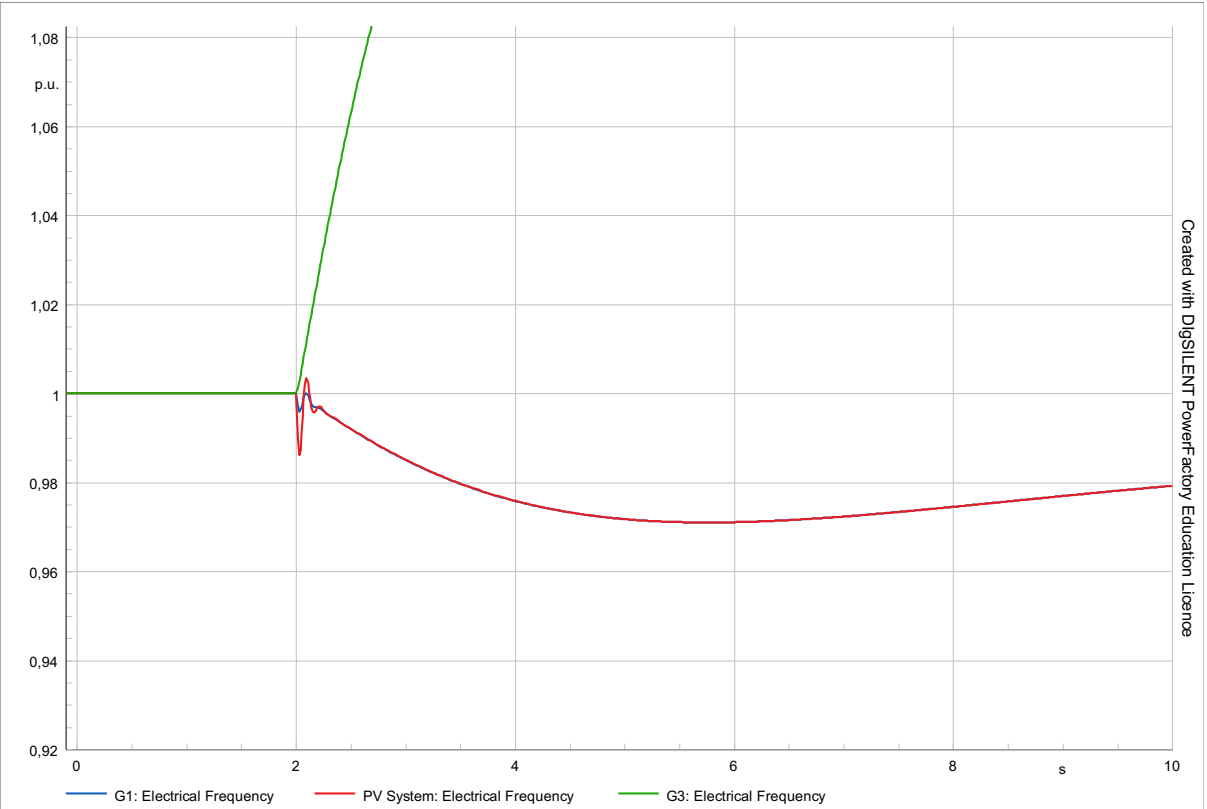
9 Bus System

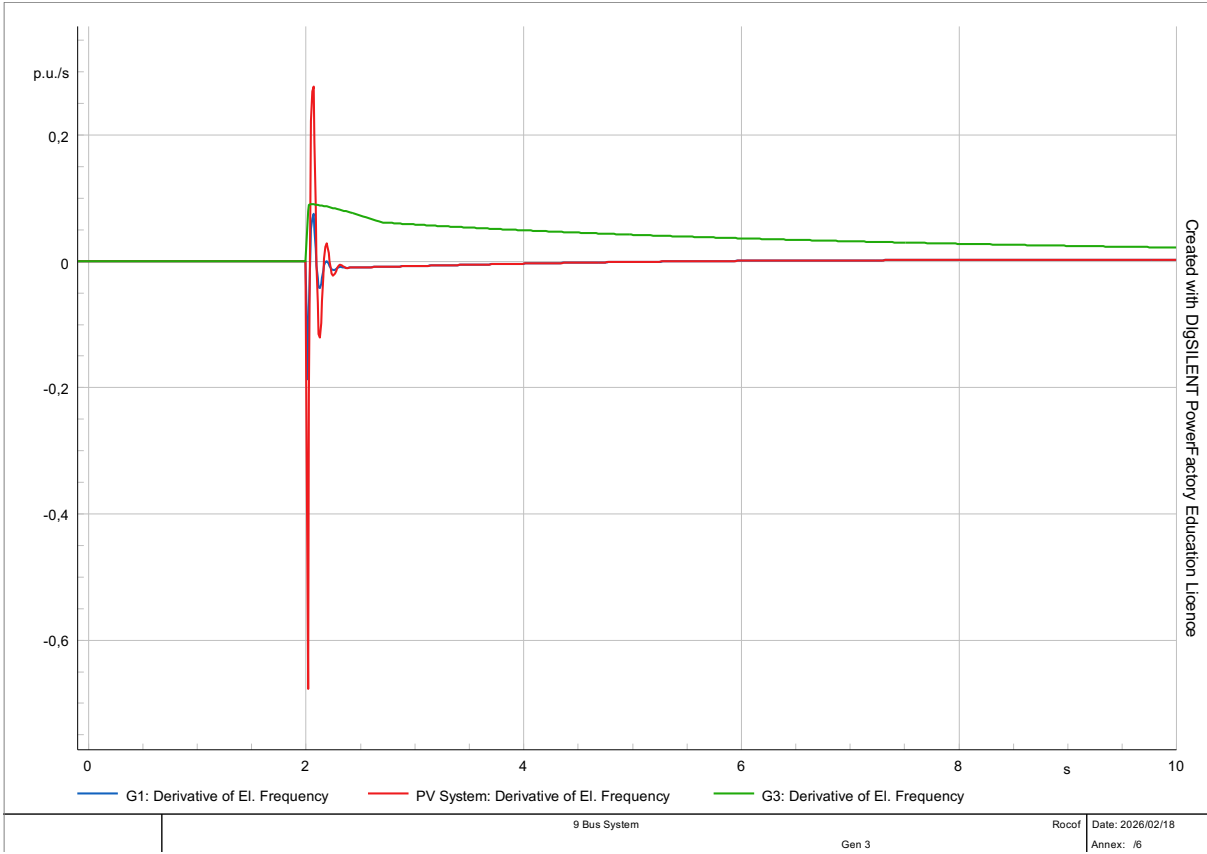
Case: Gen Loss



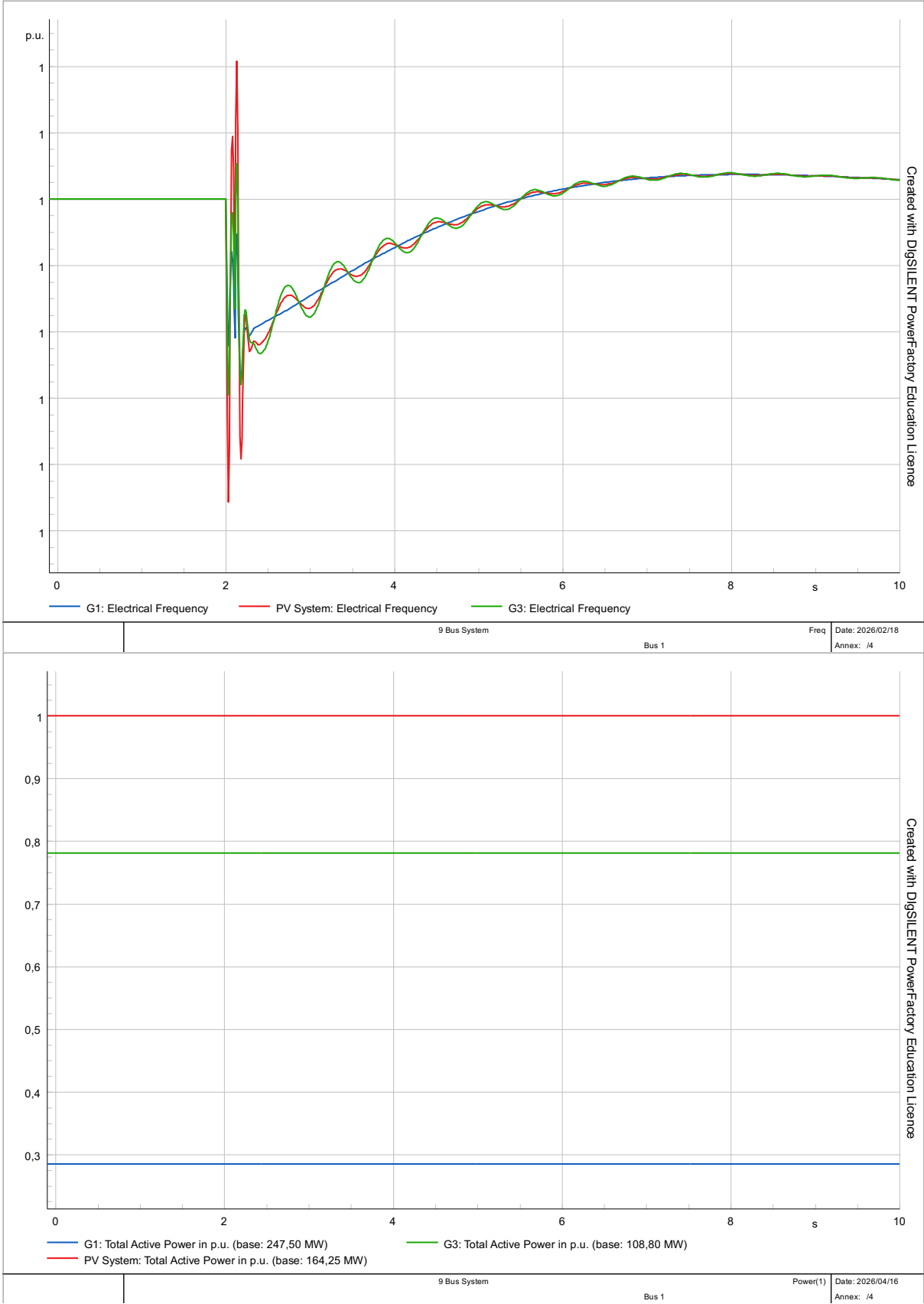


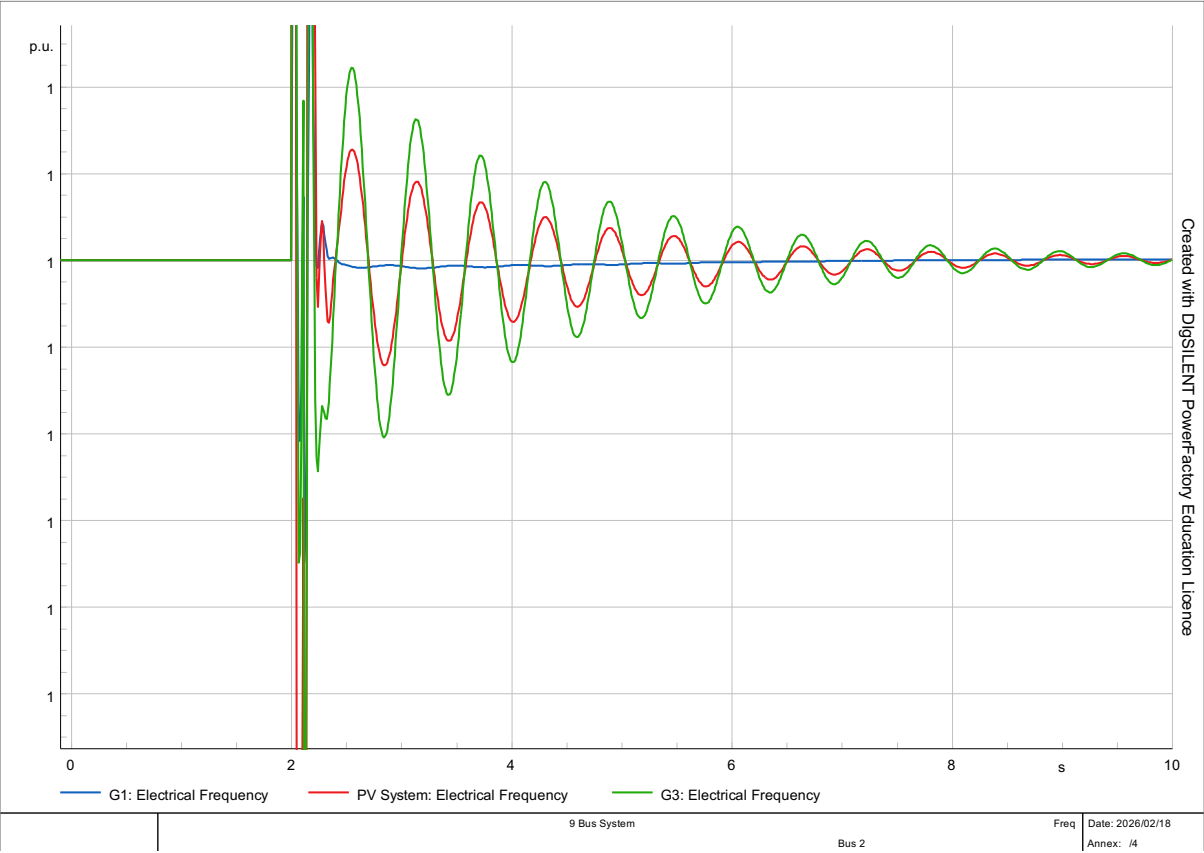
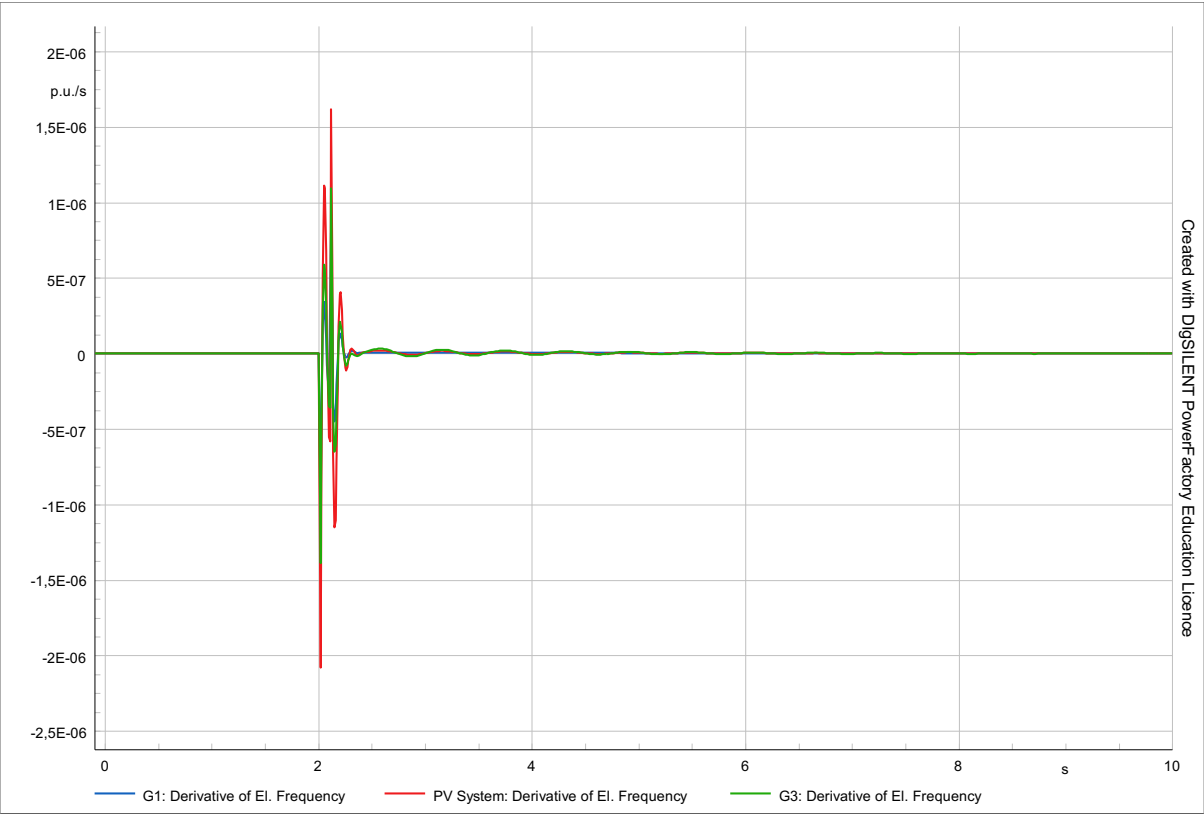


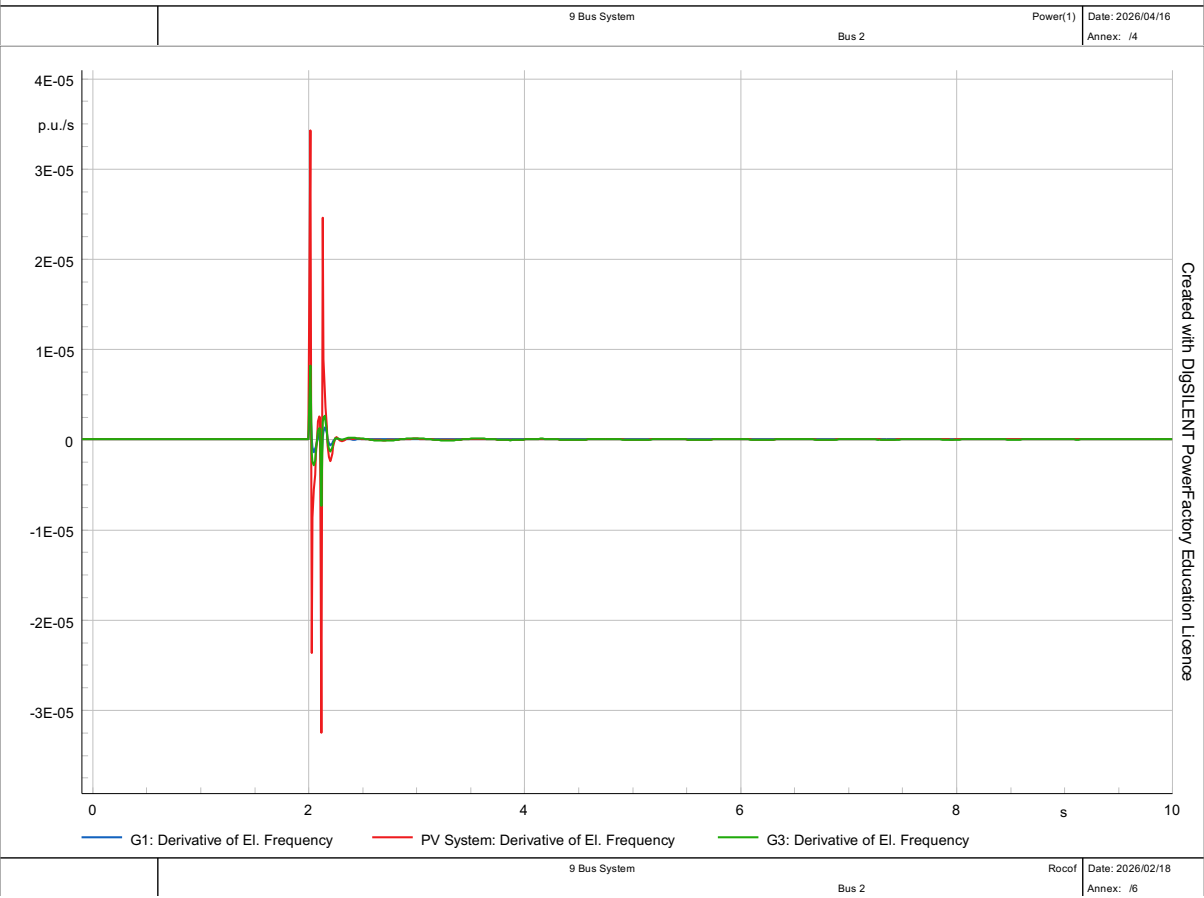
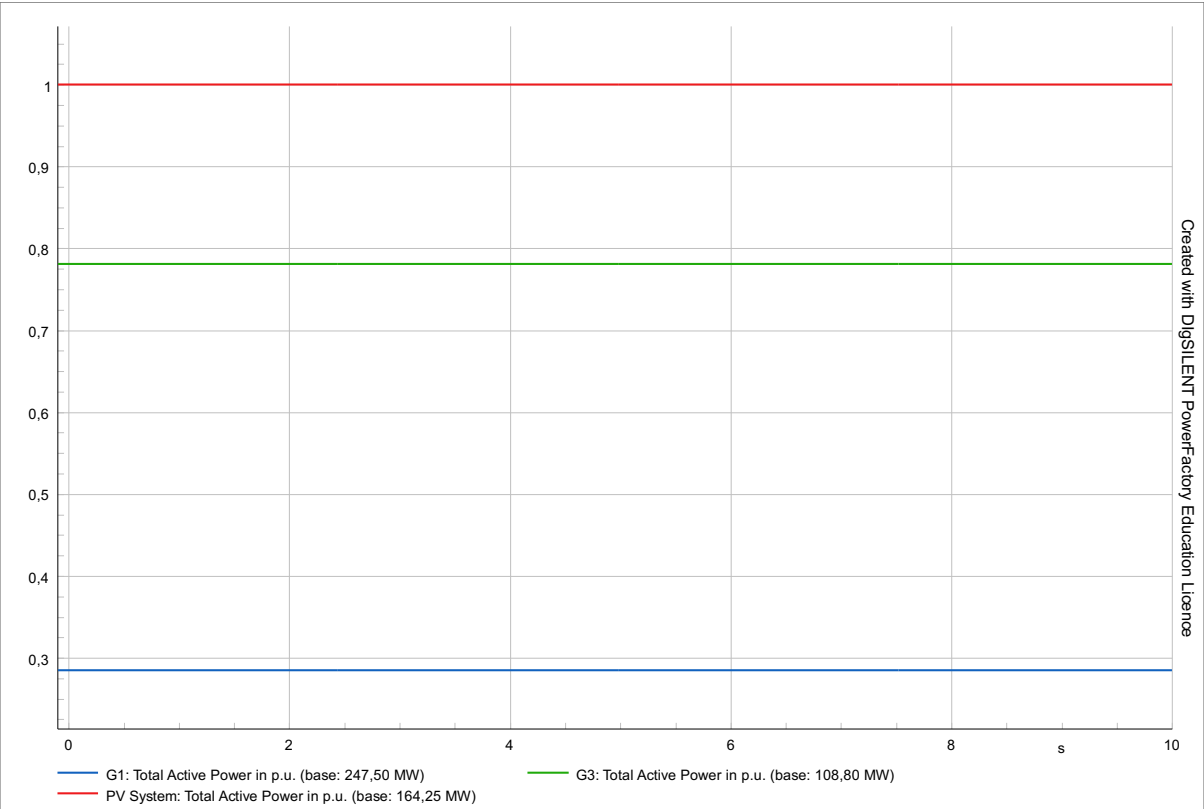


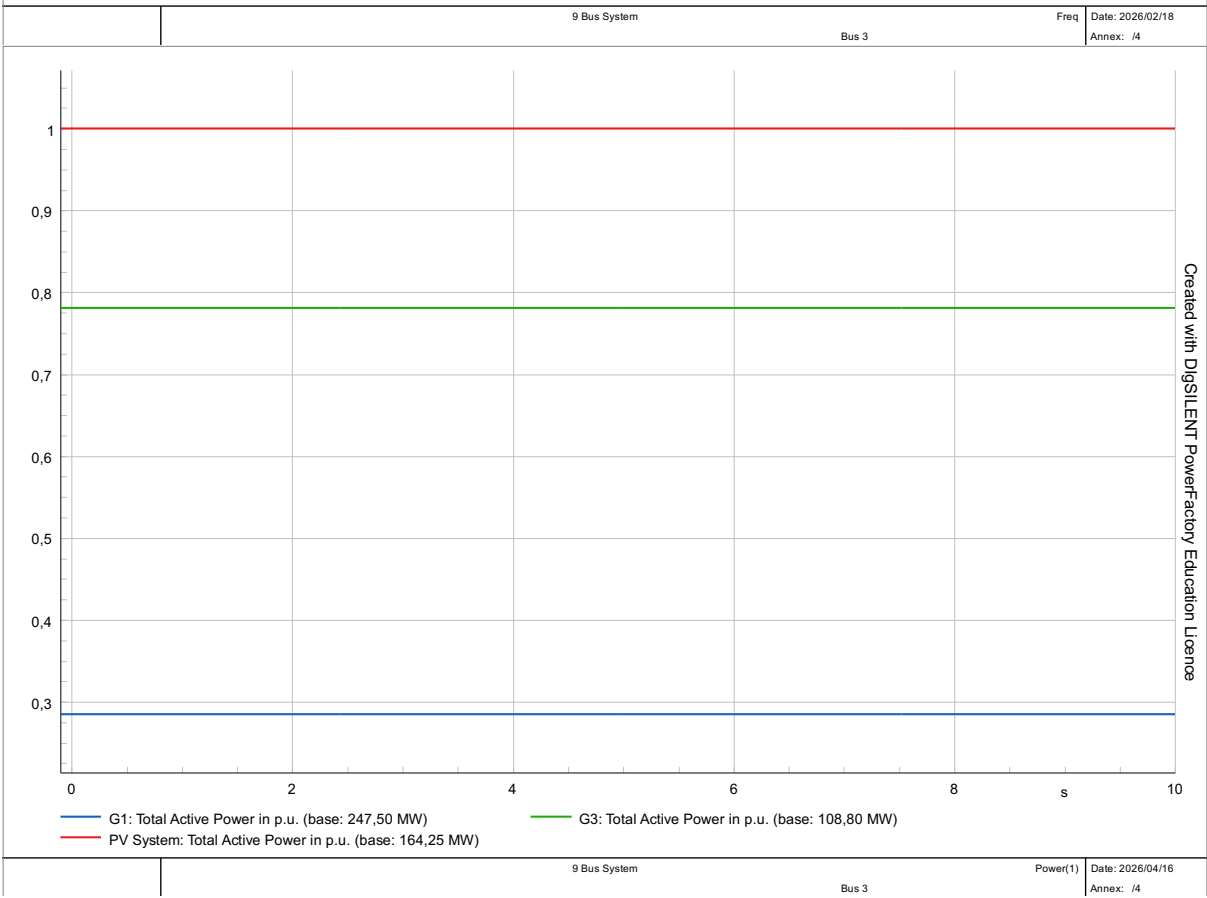
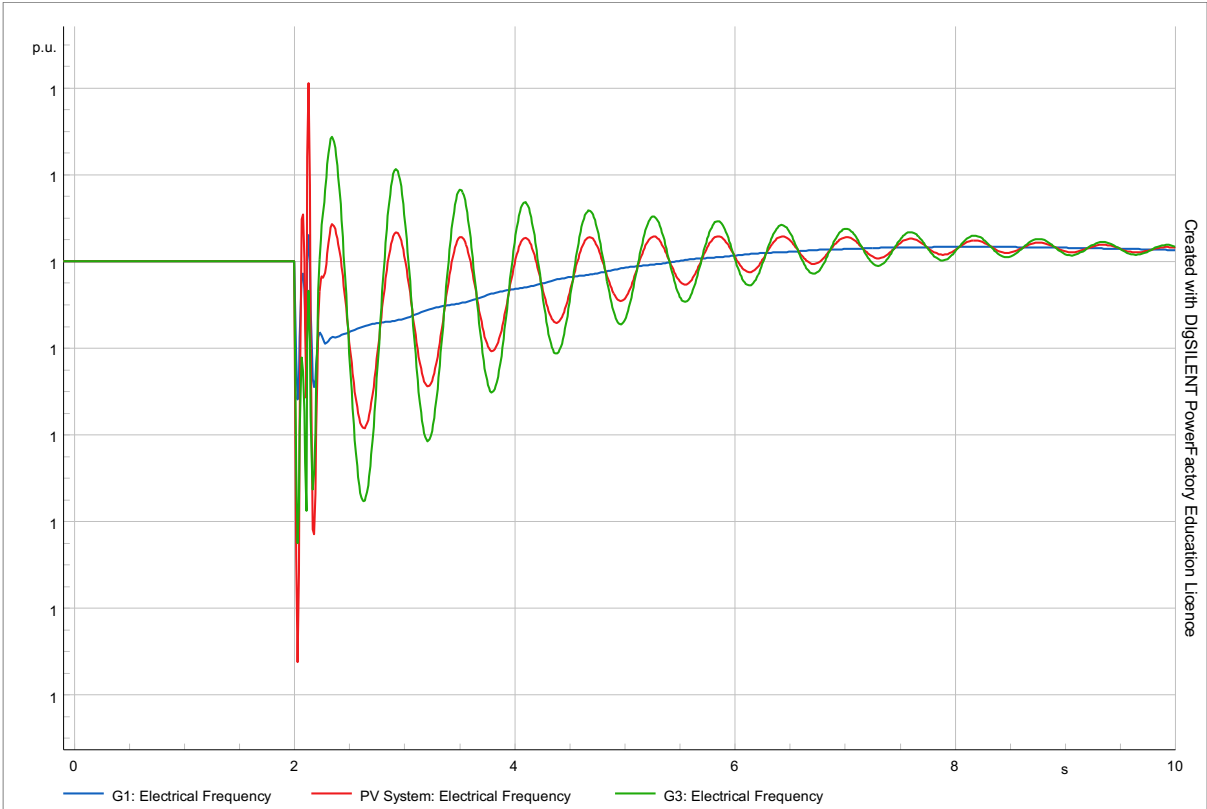


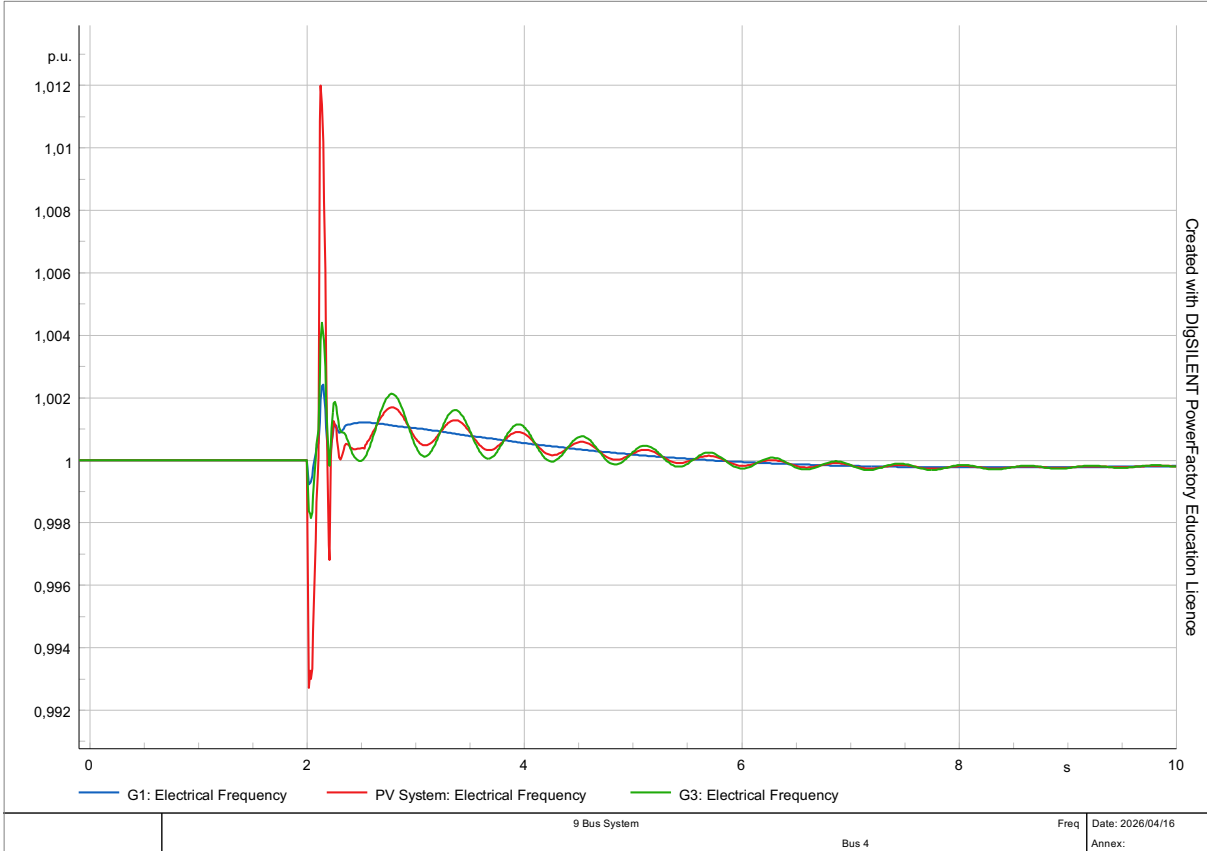
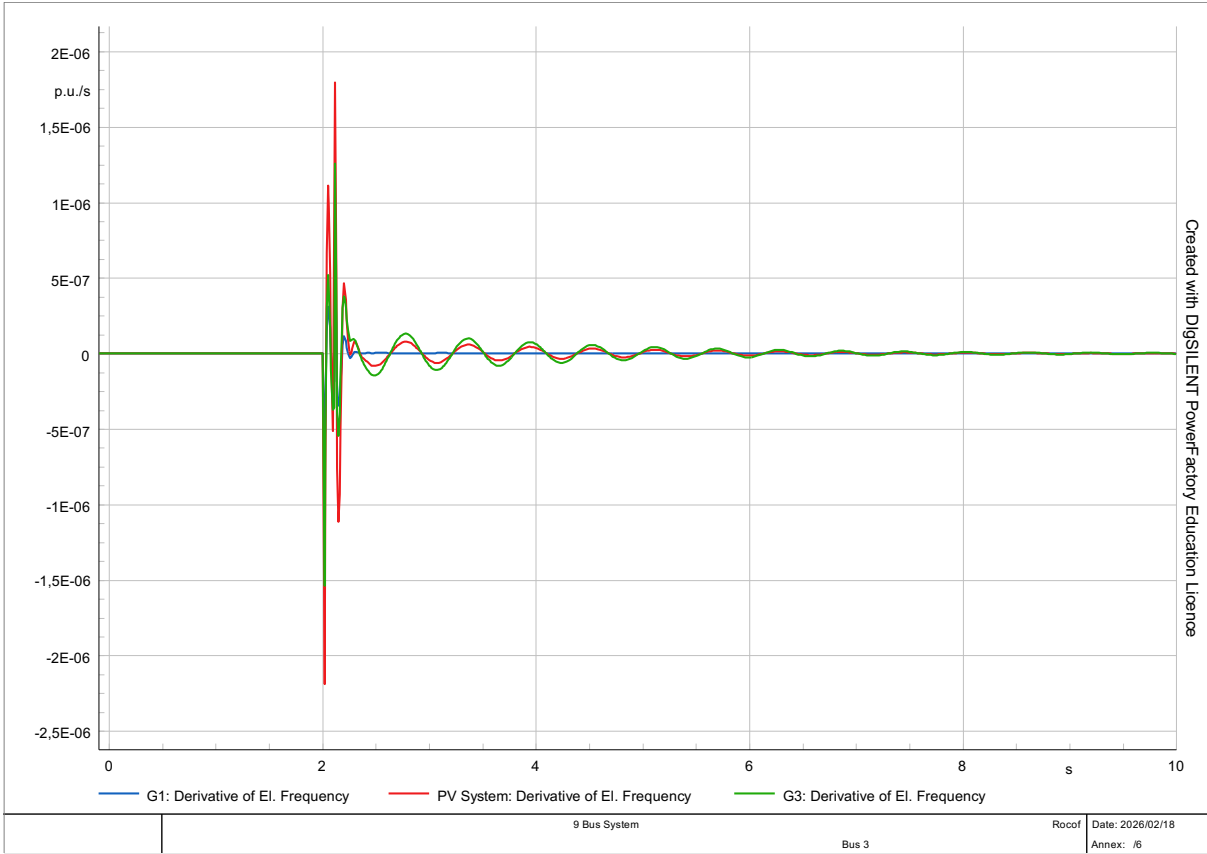
Case: Earth Fault

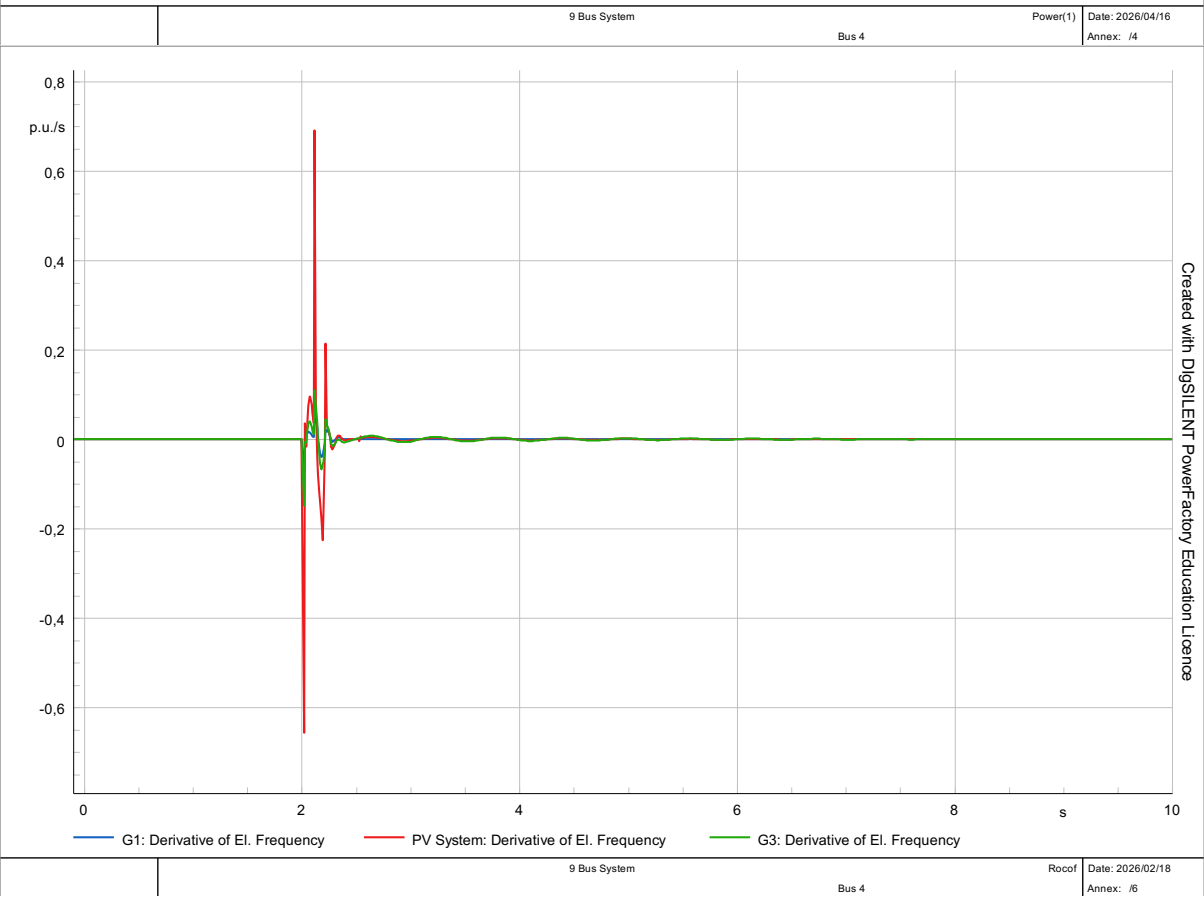
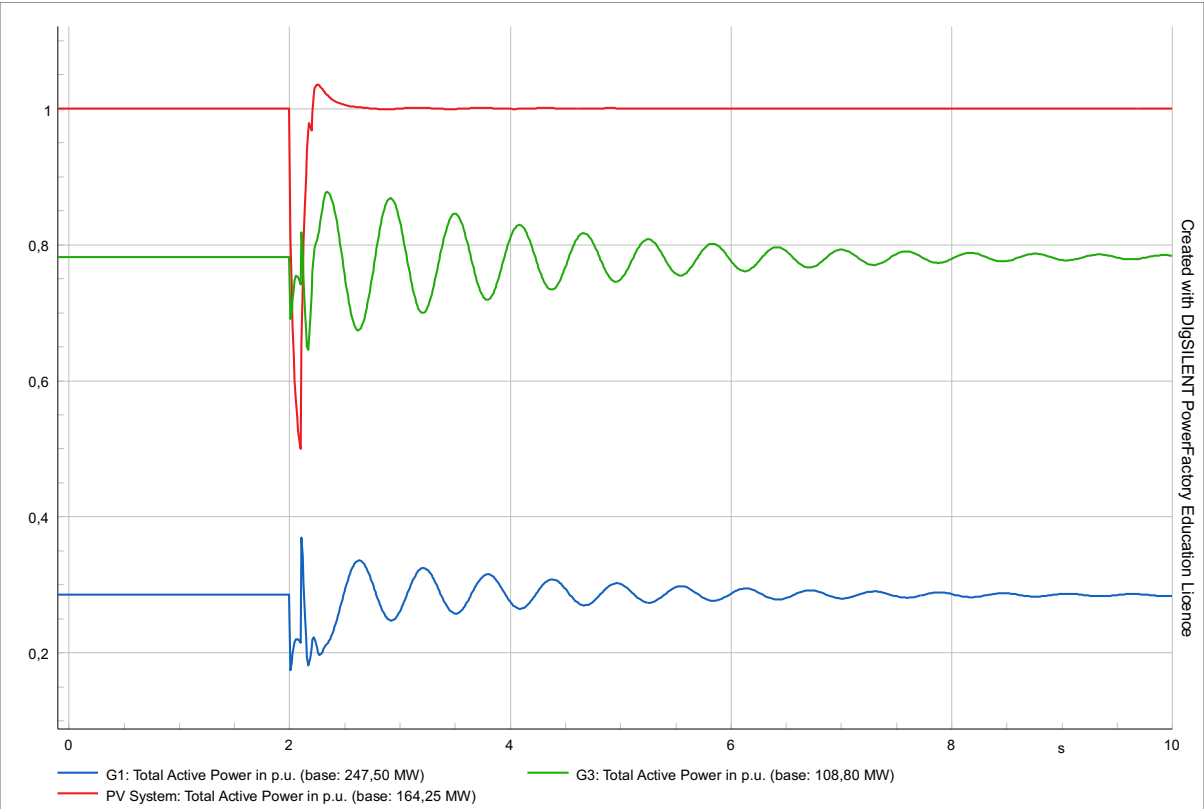


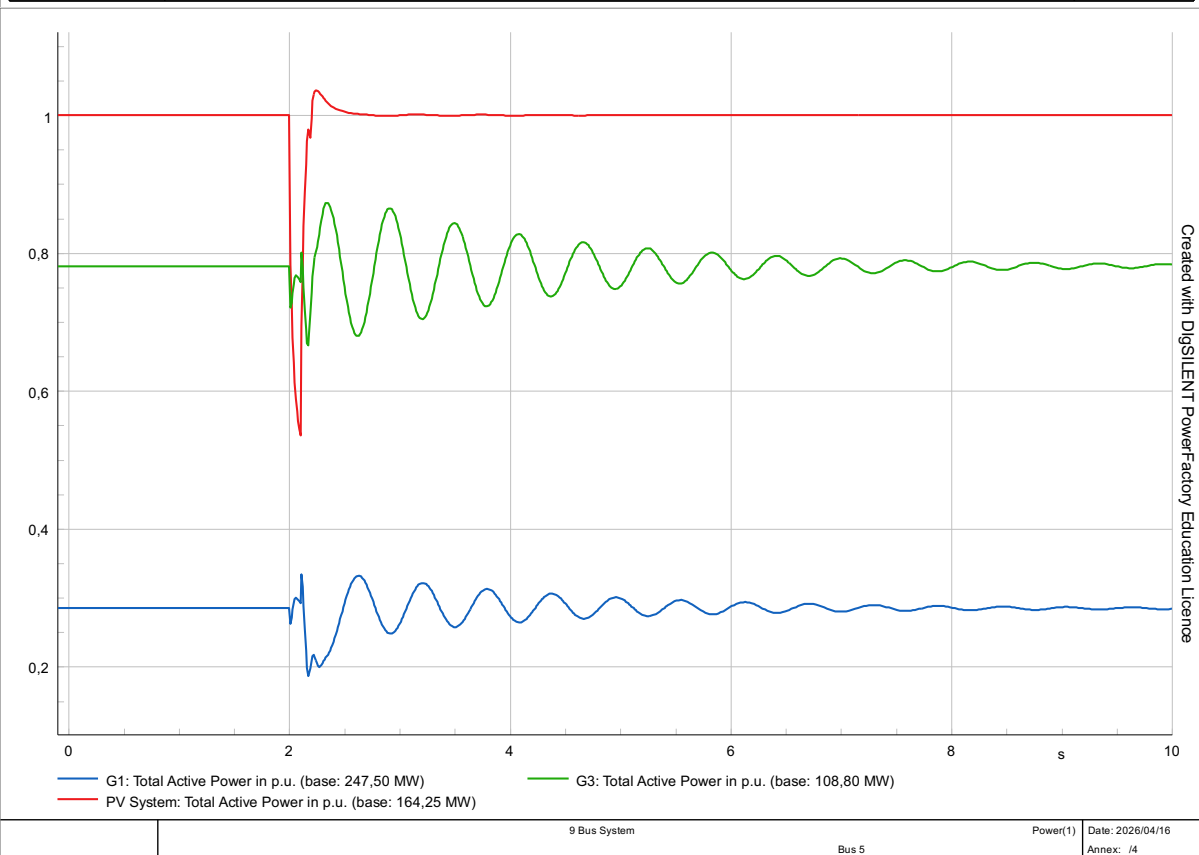
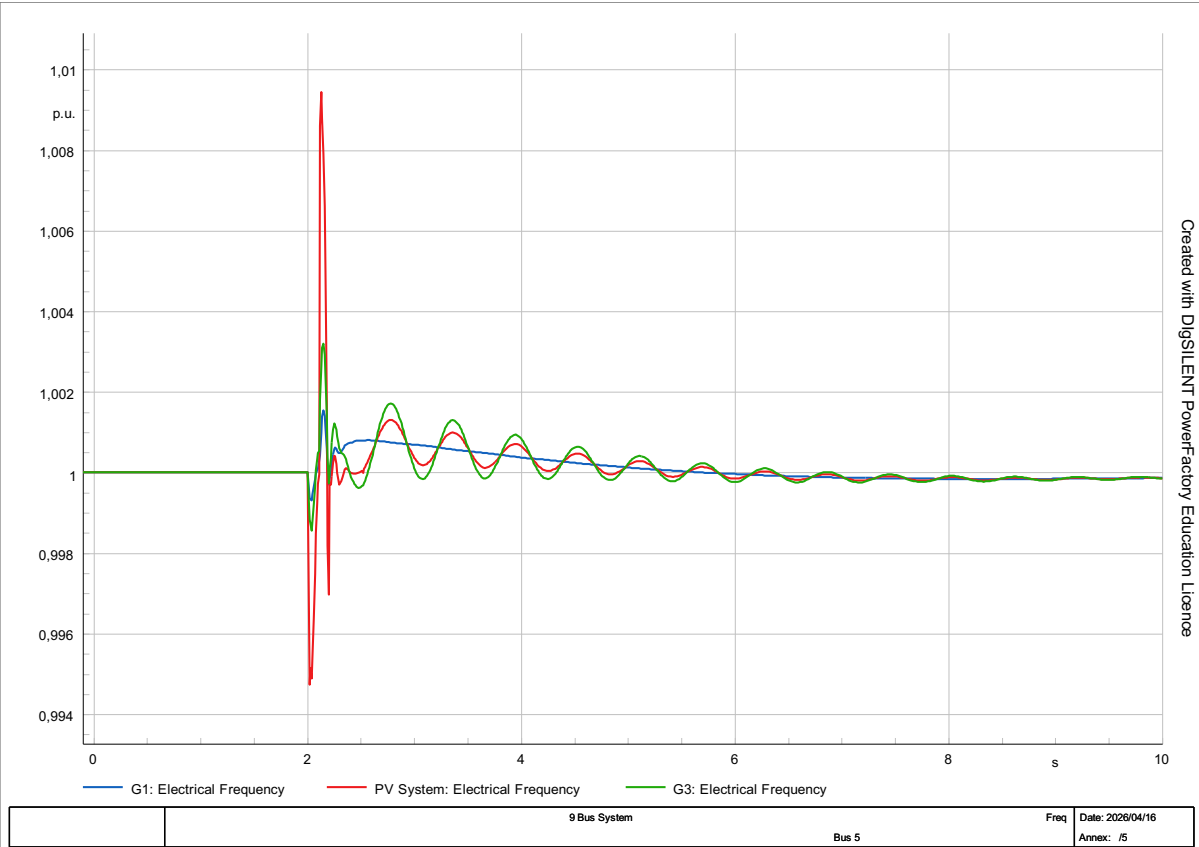


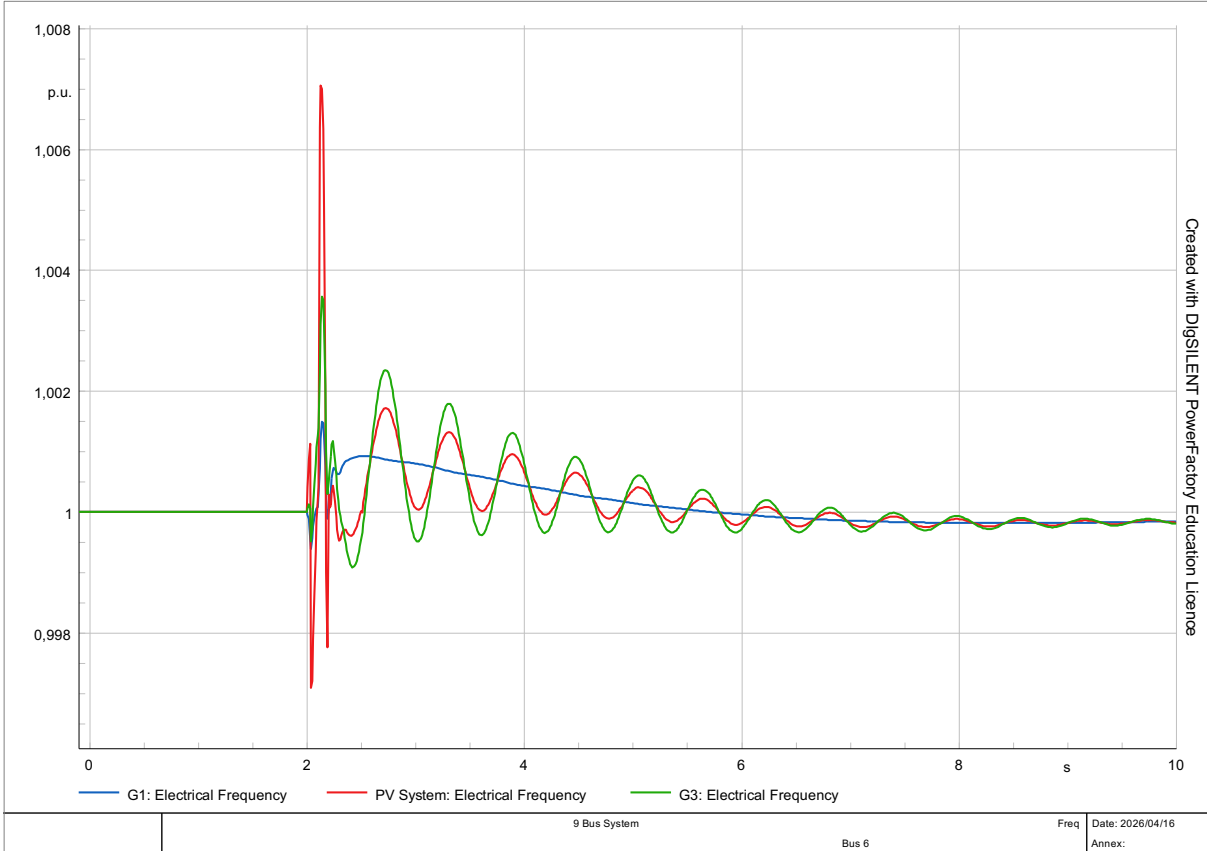
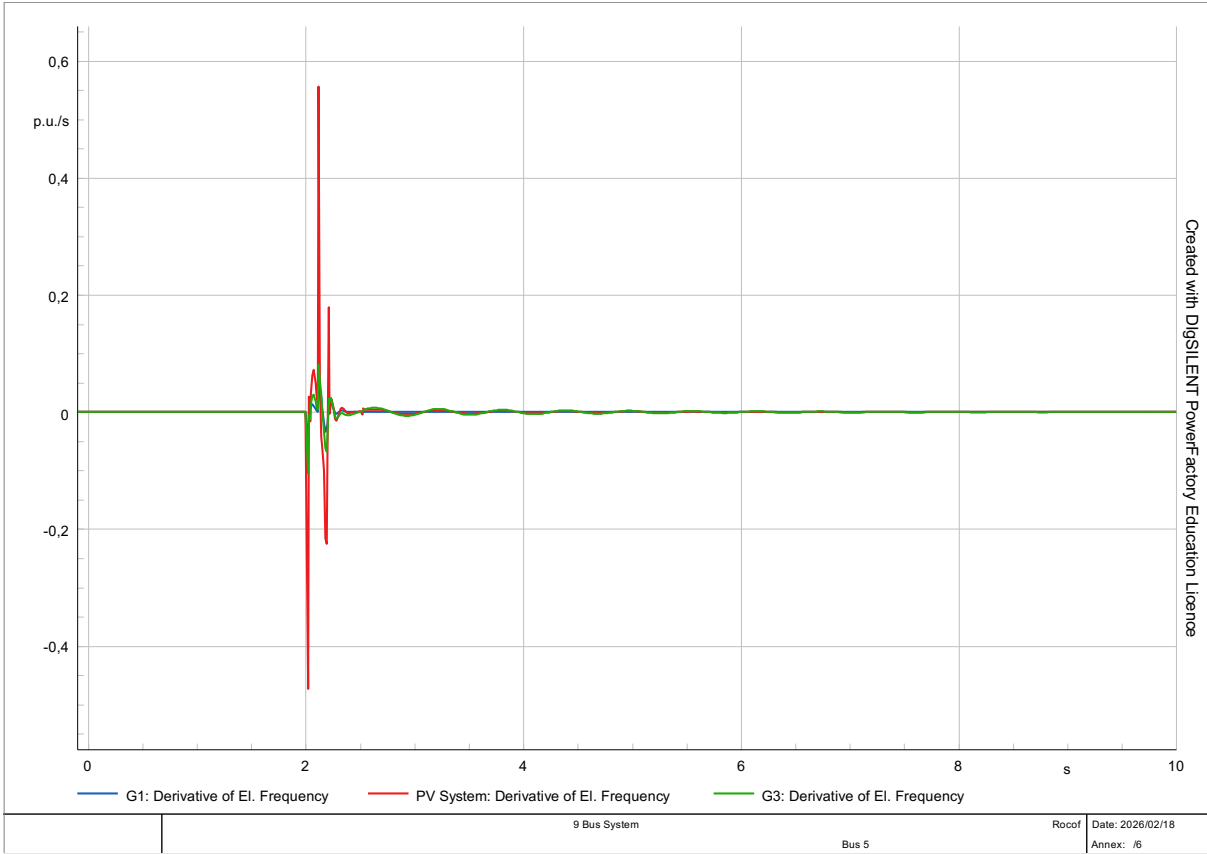


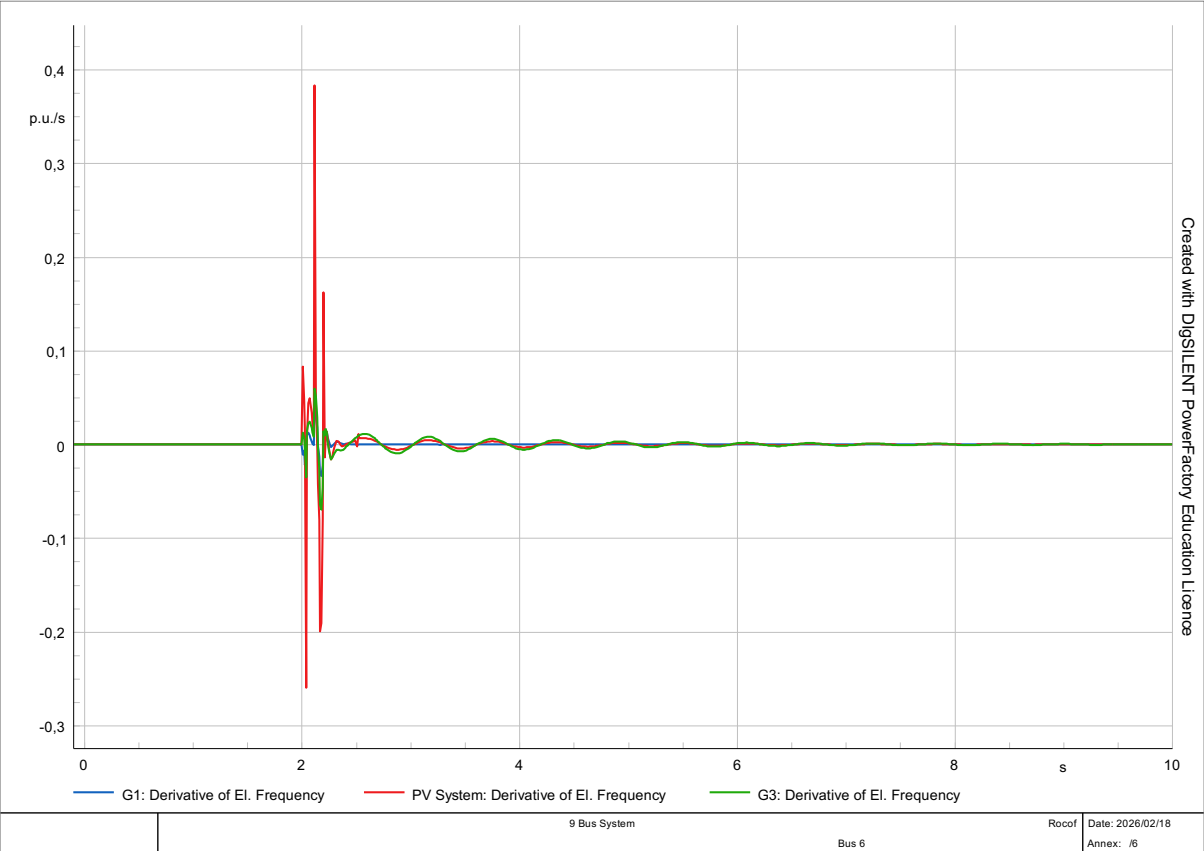
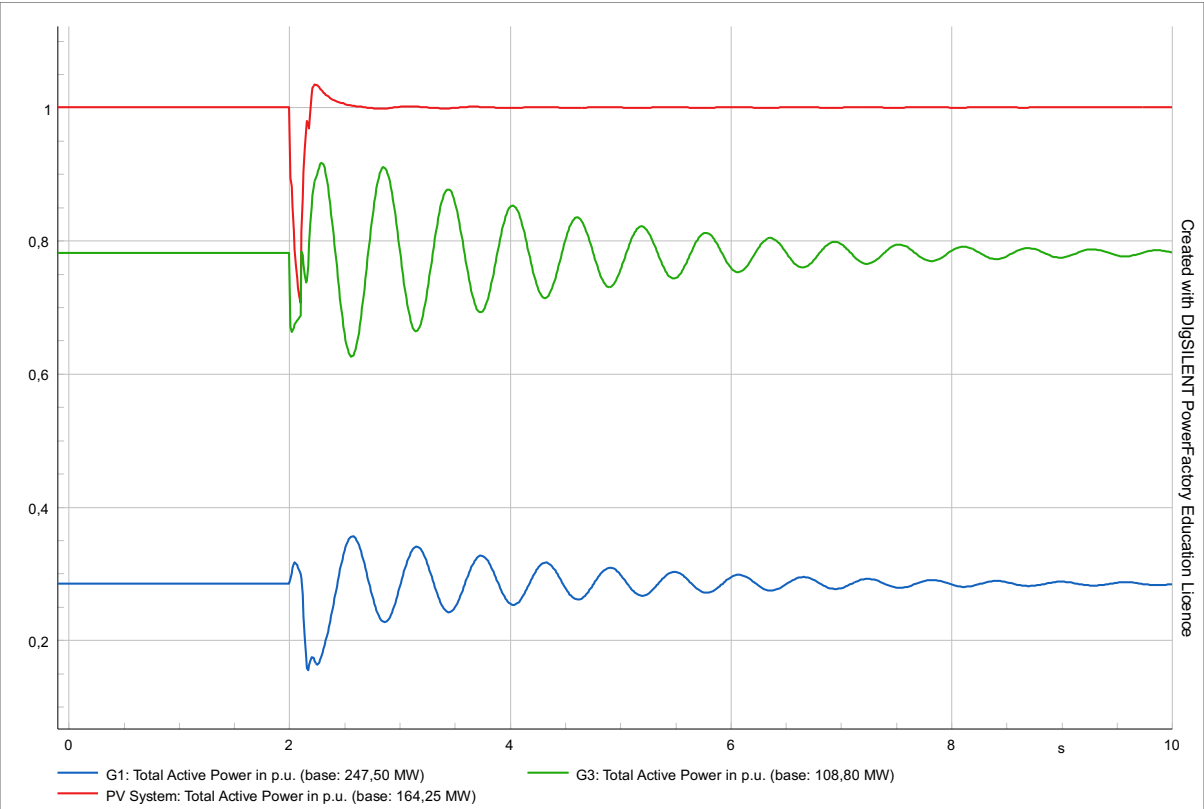


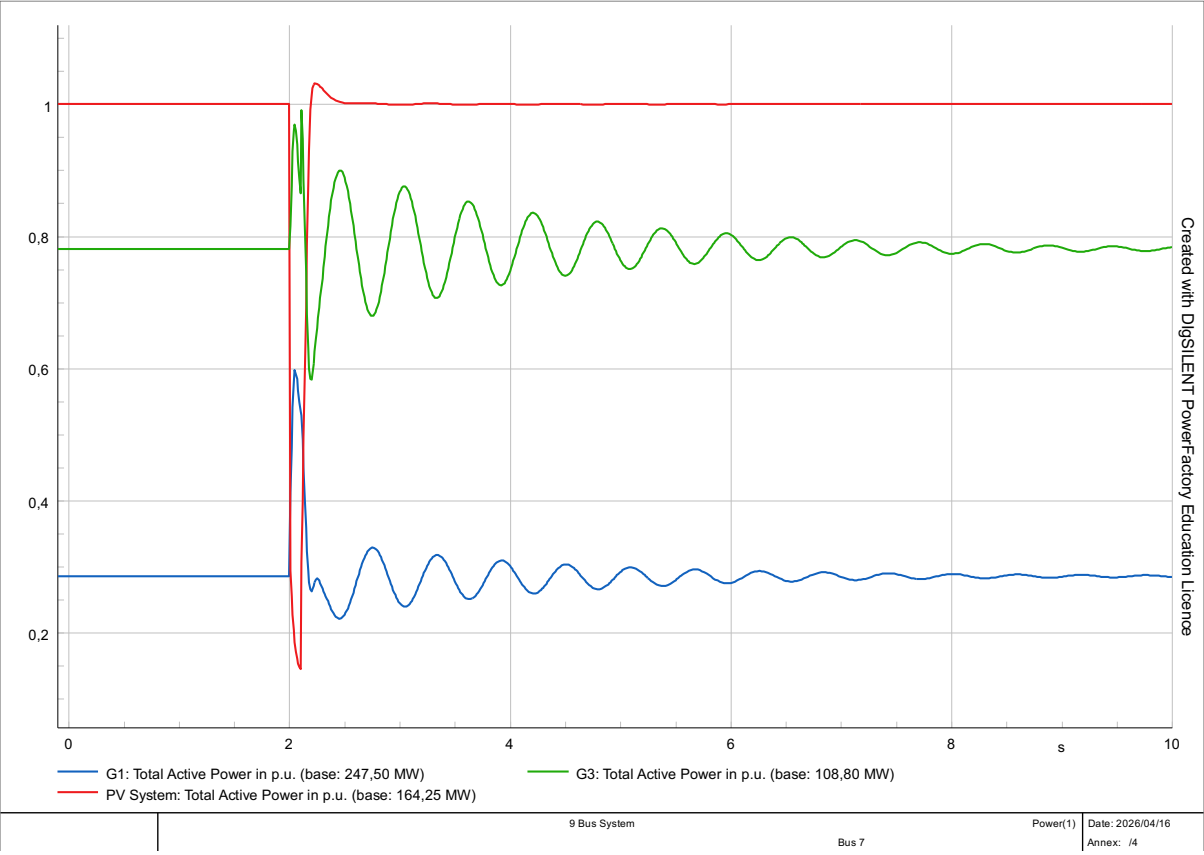
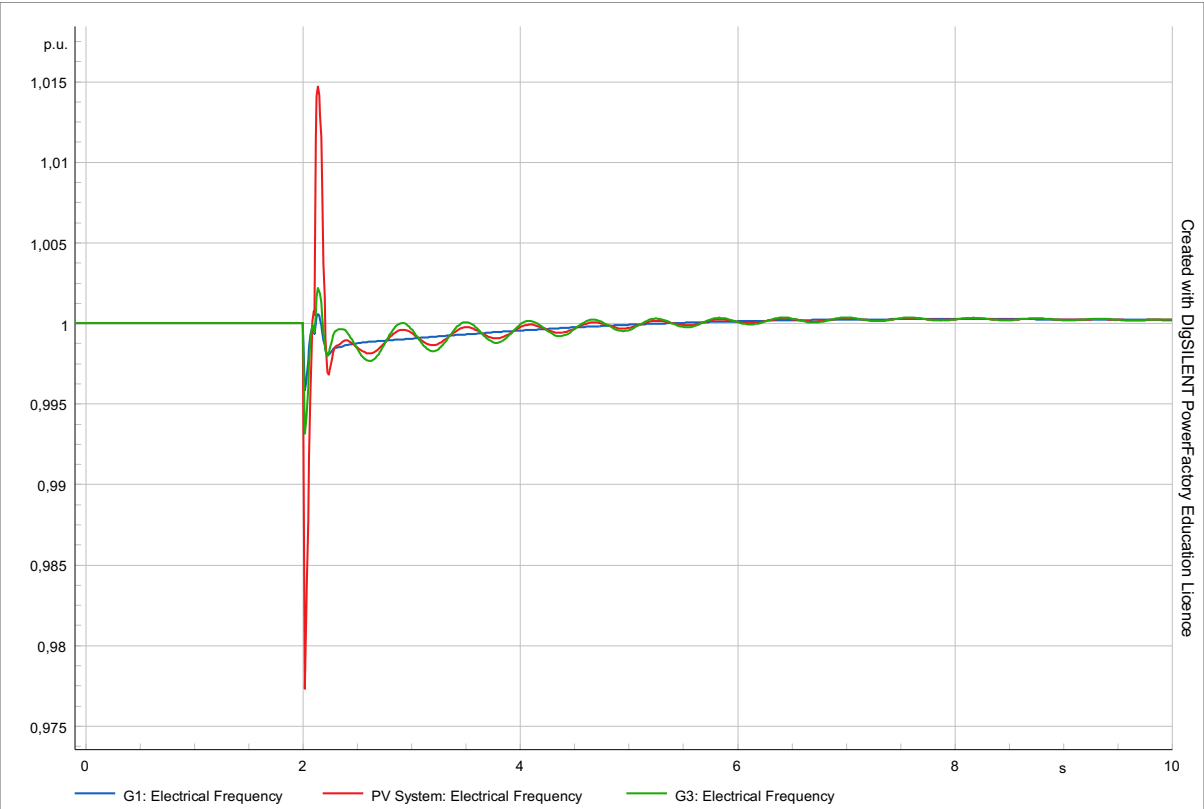


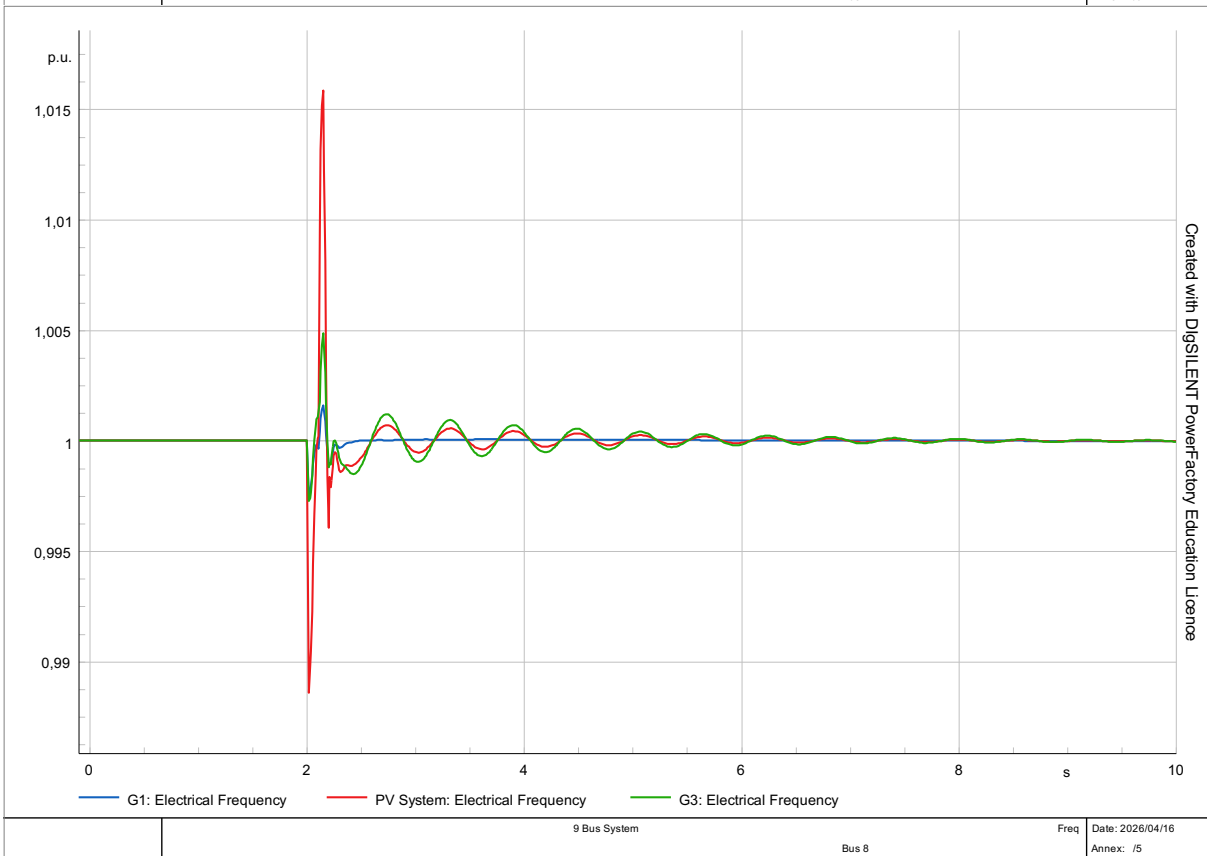
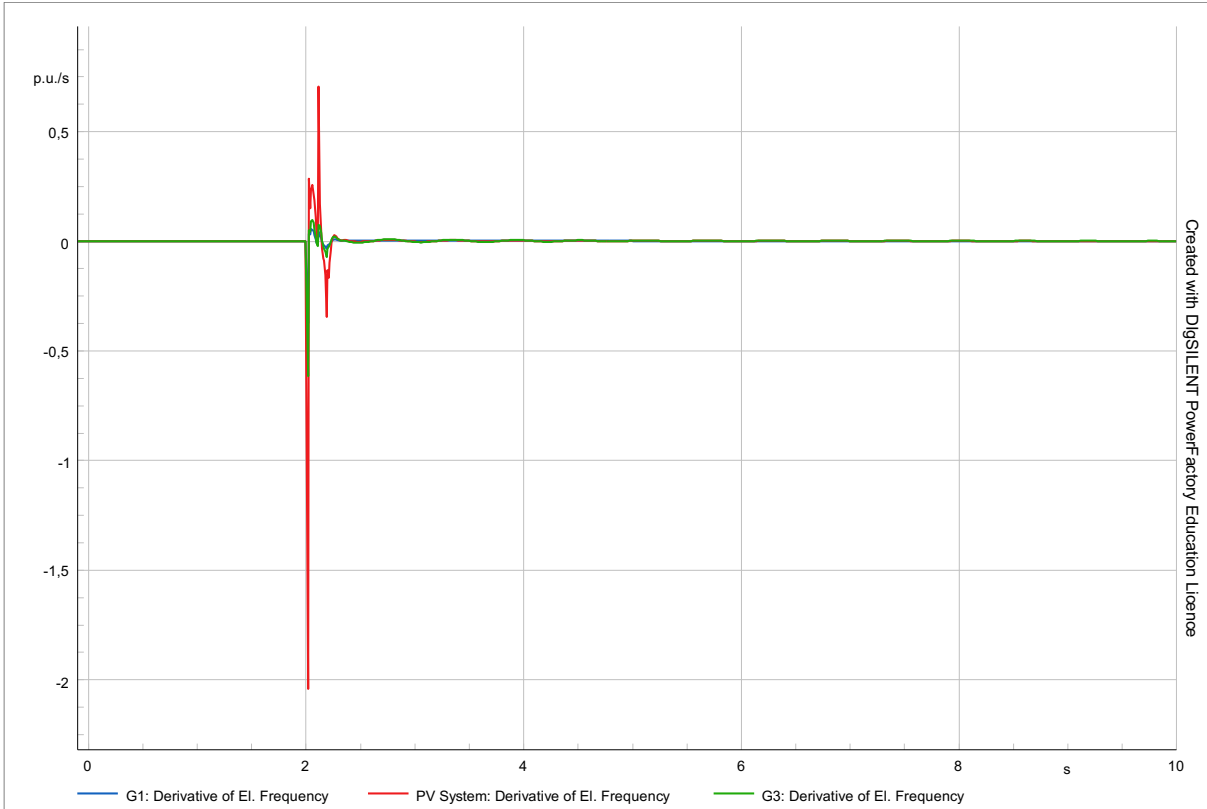


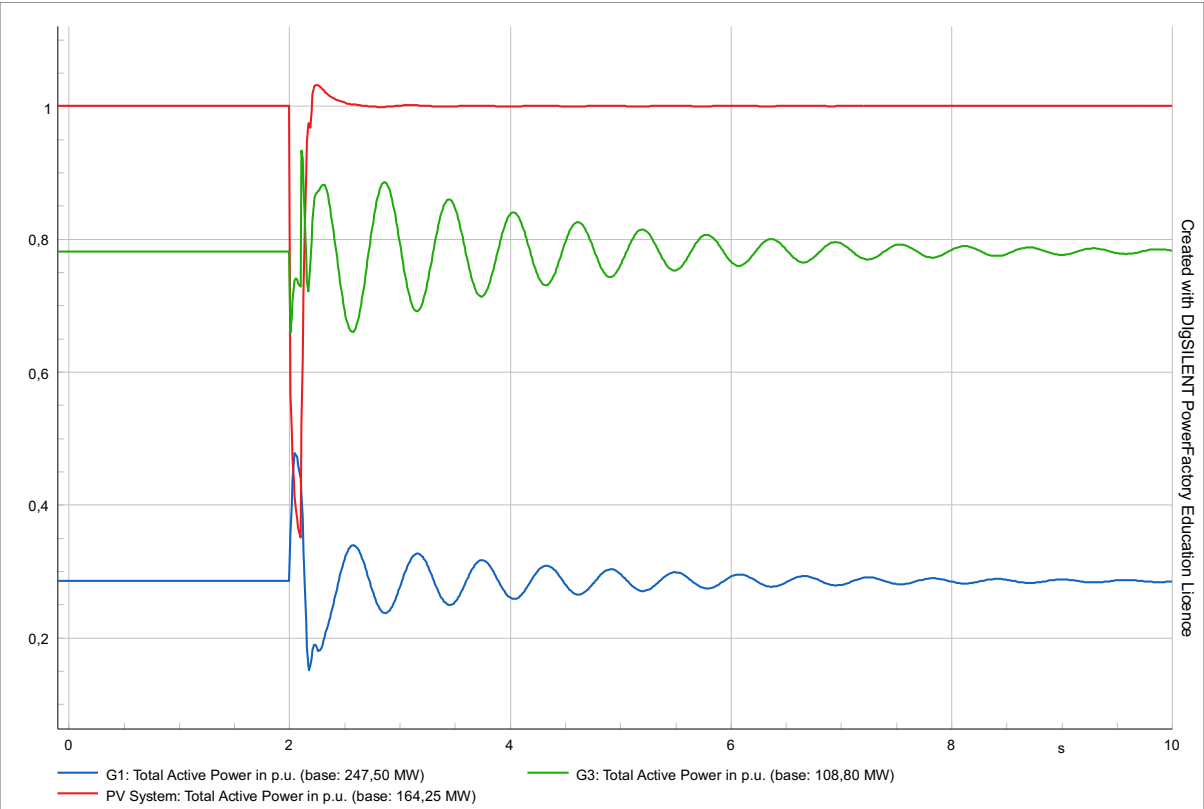




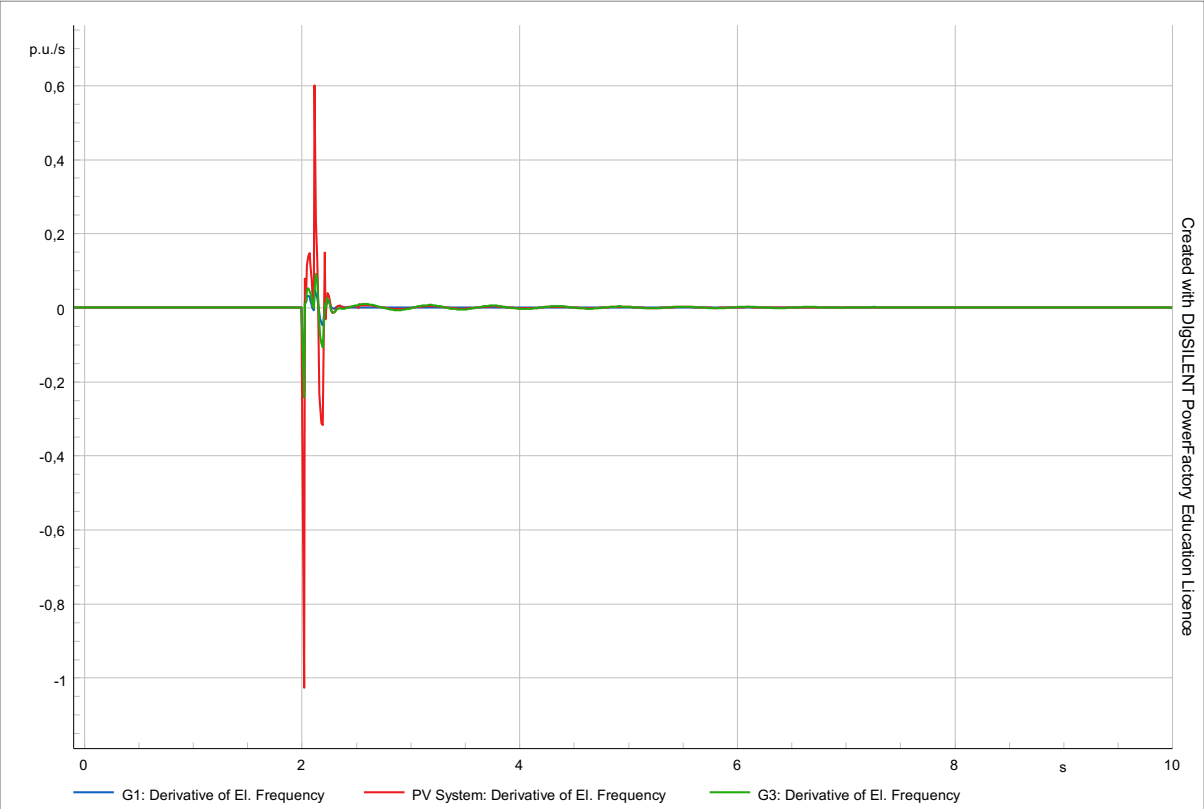




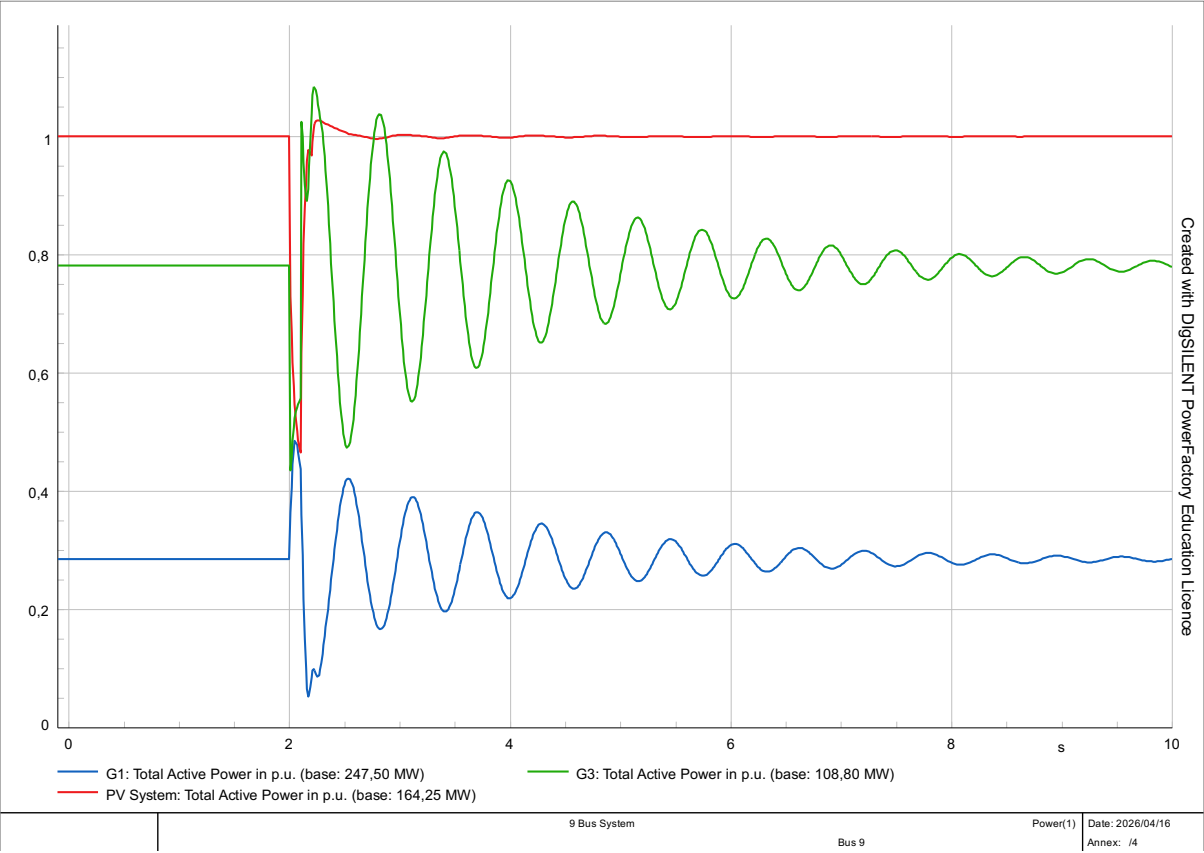
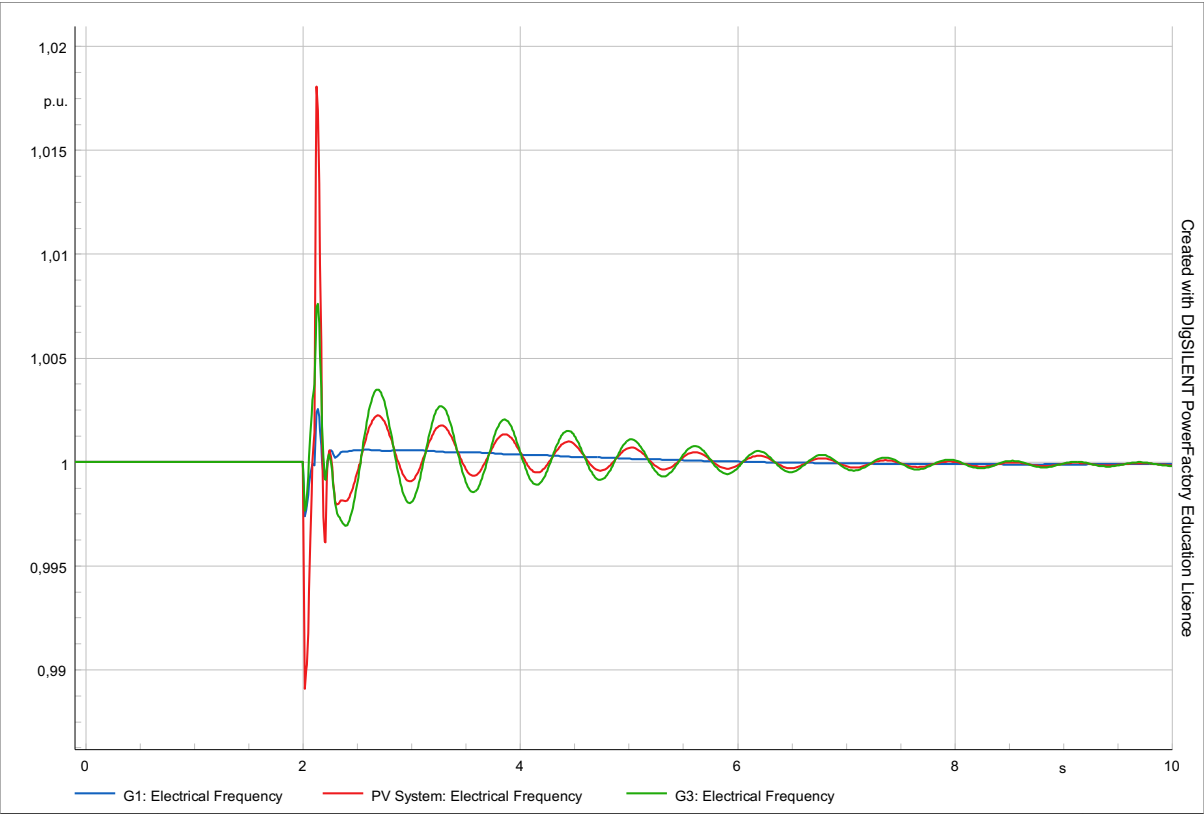


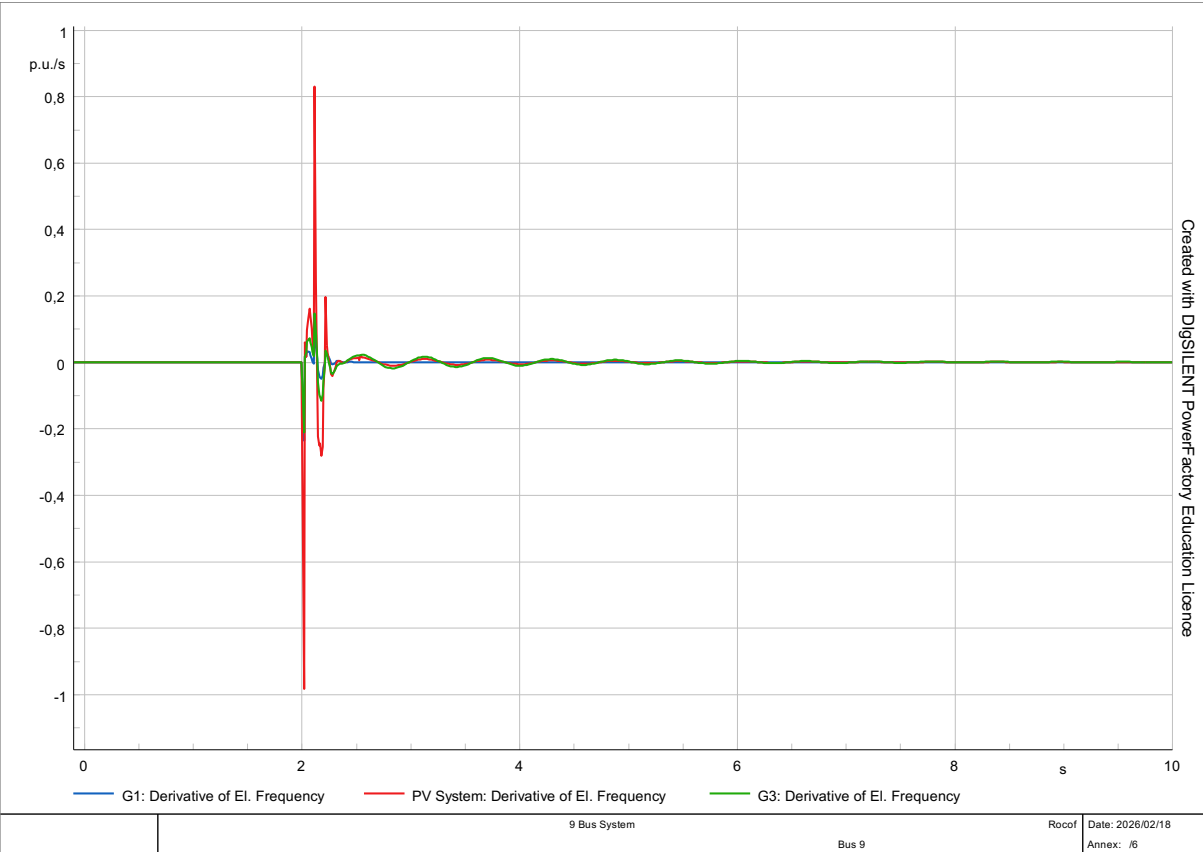


9 Bus System Bus 8 Power(1) Date: 2026/04/16 Annex: /4

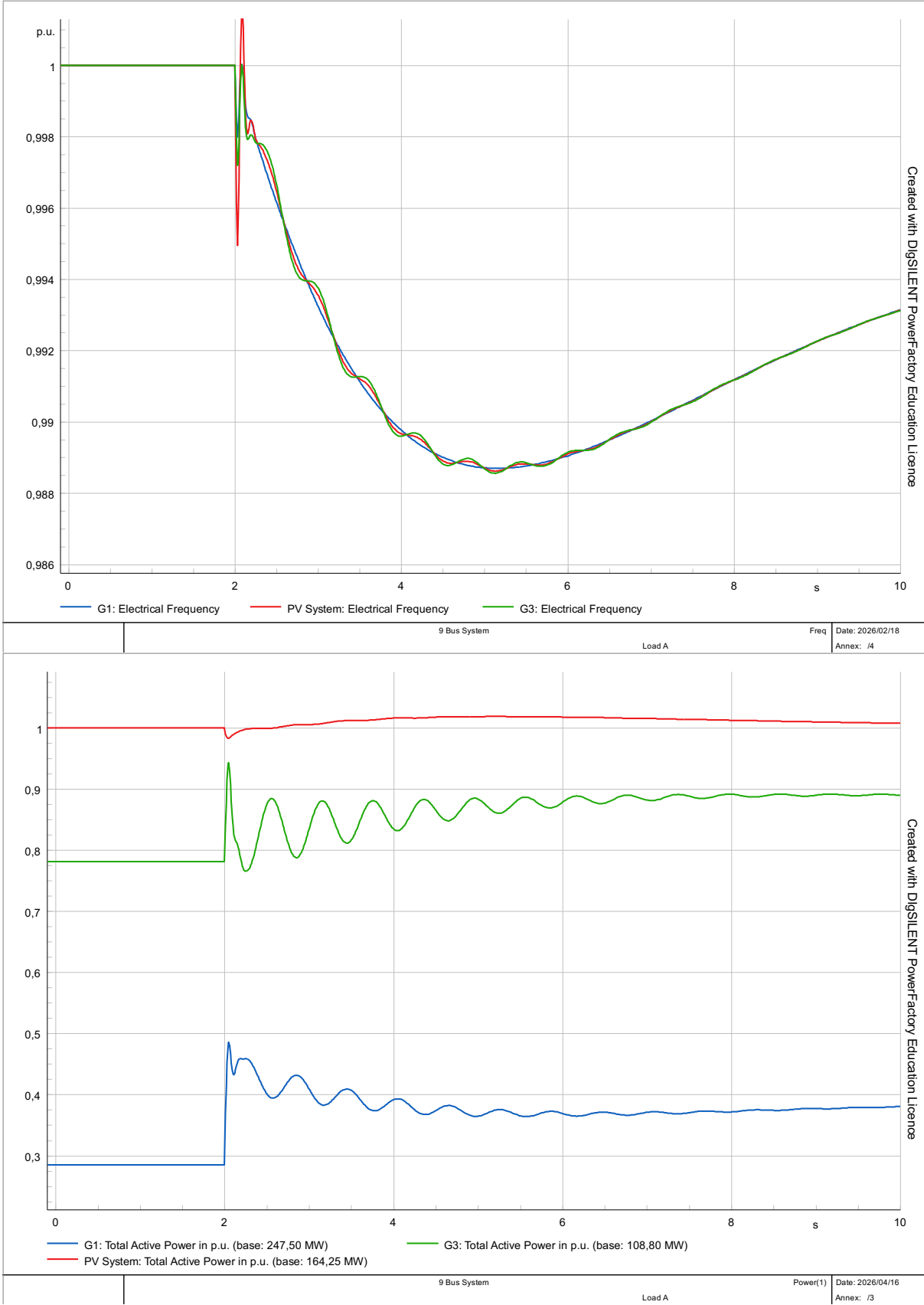


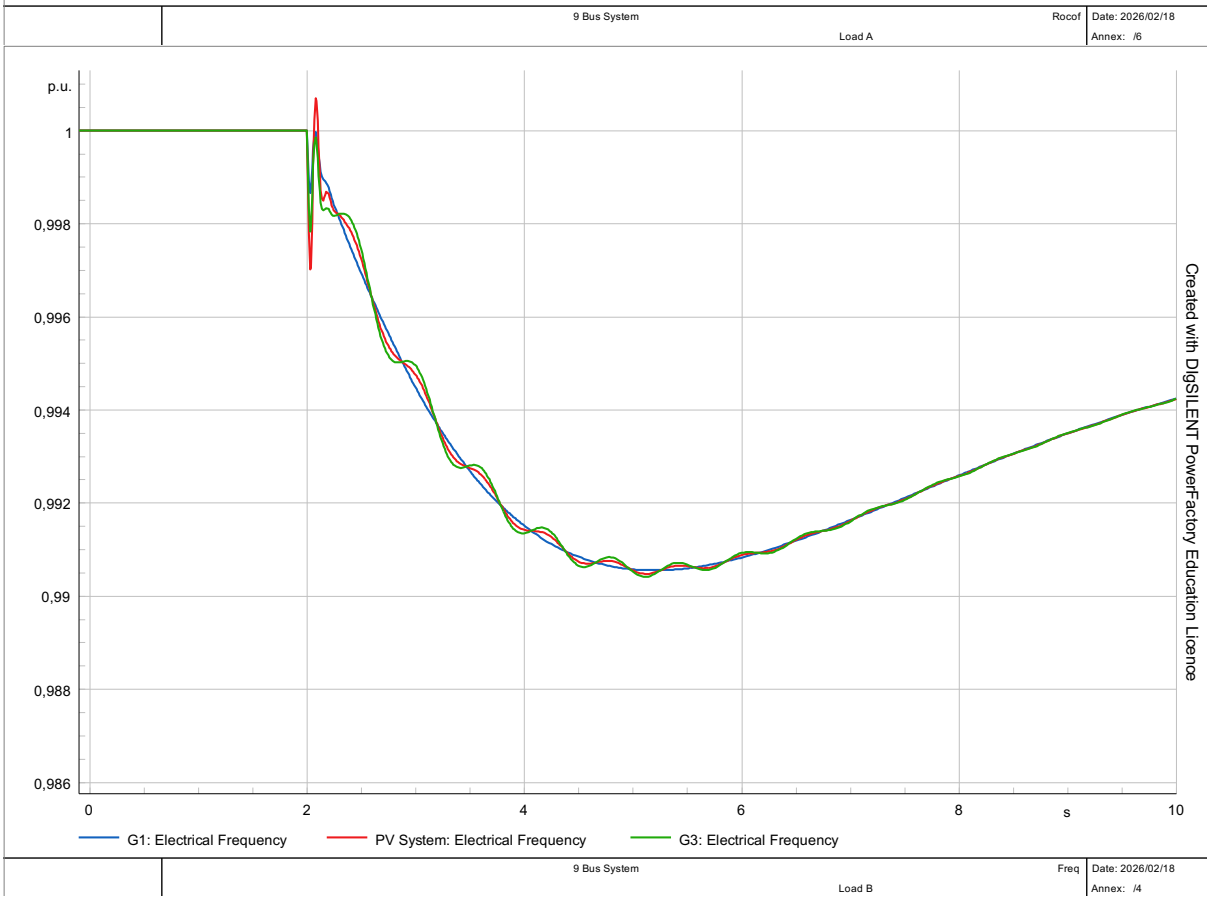
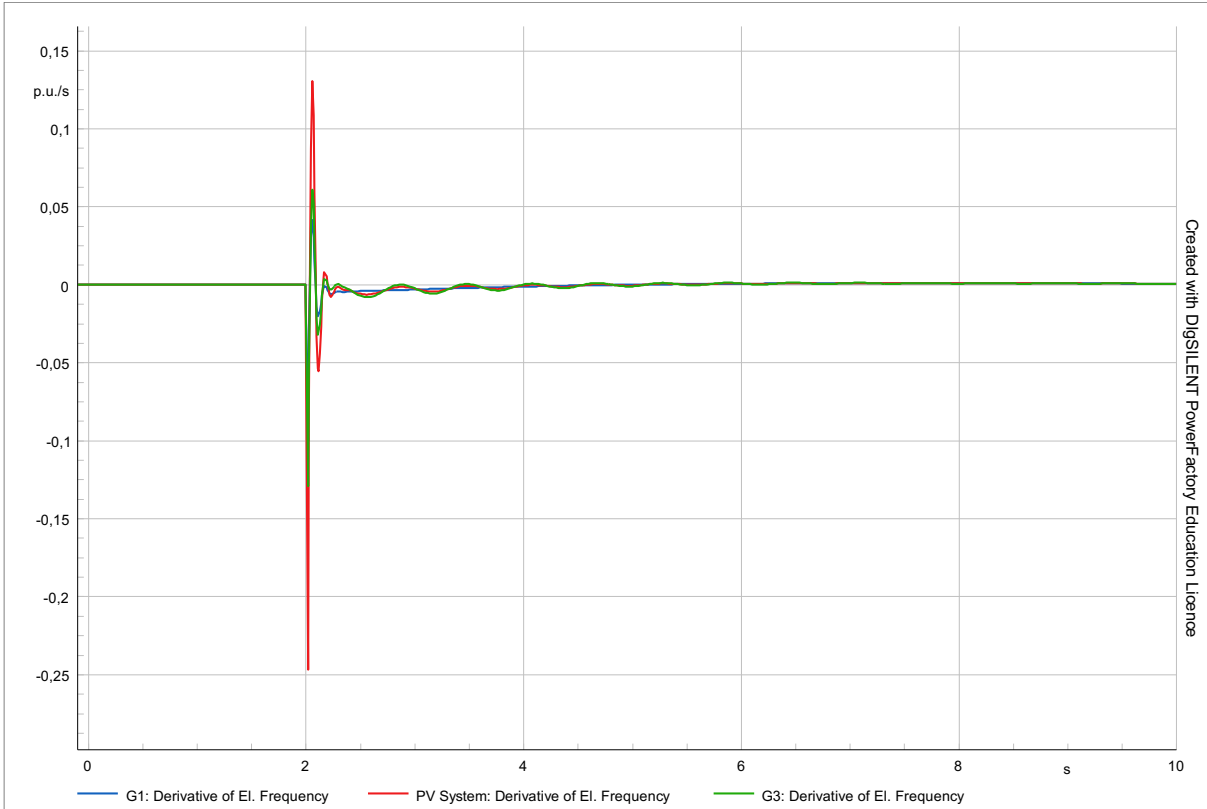
9 Bus System Bus 8 Rocof Date: 2026/02/18 Annex: /6

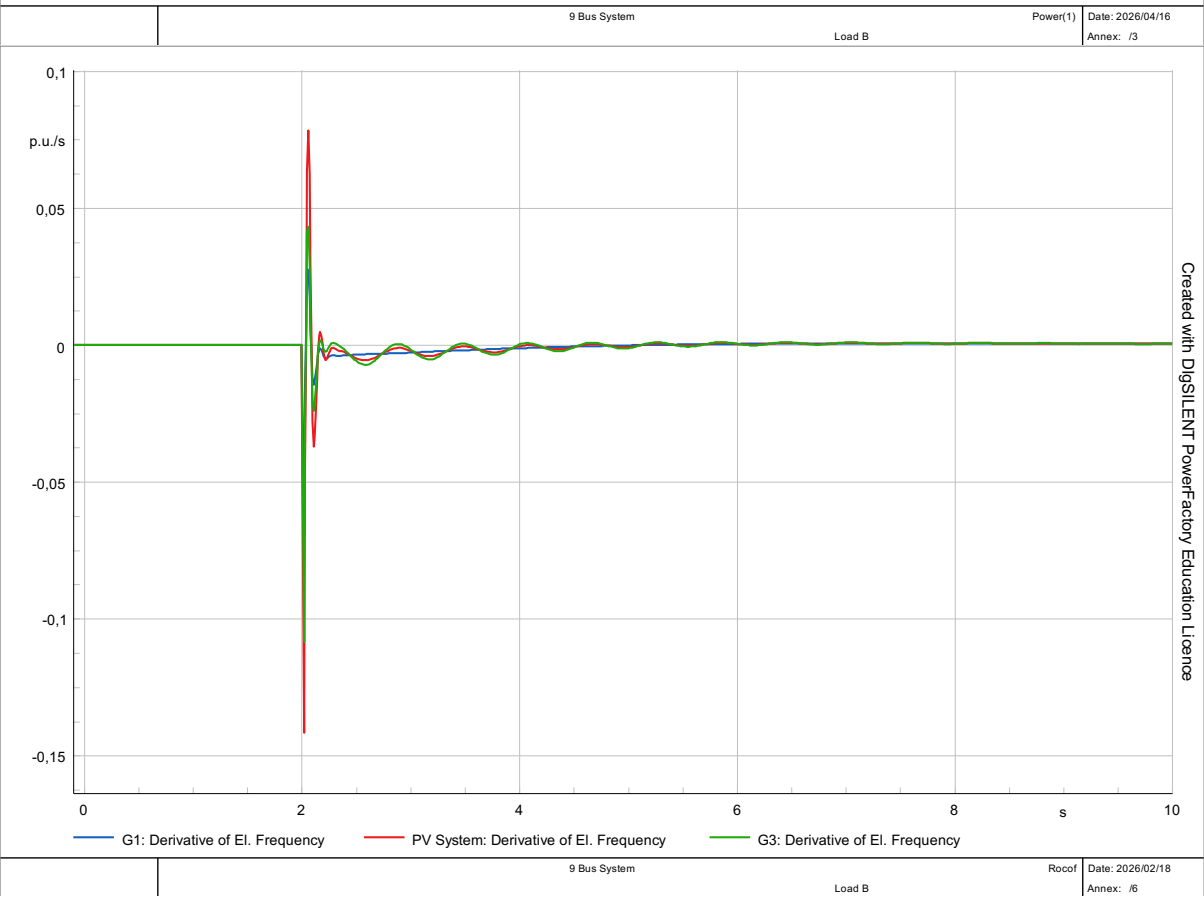
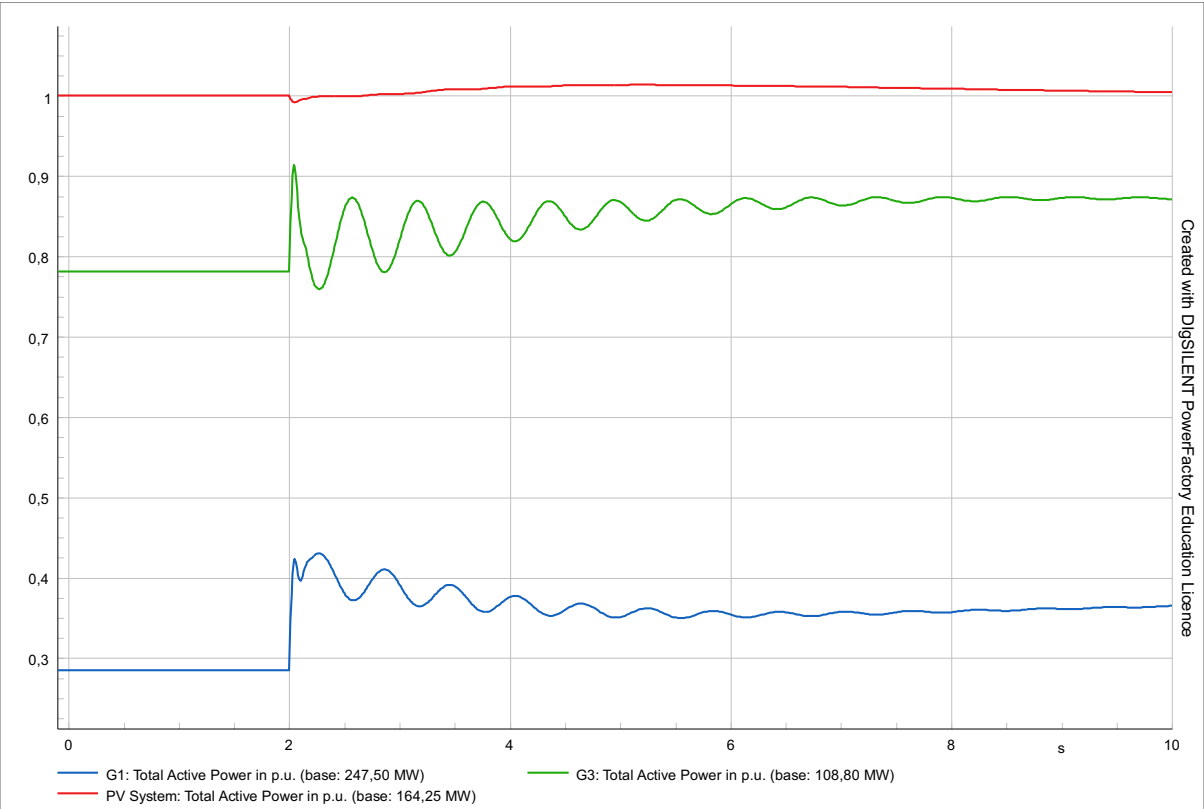


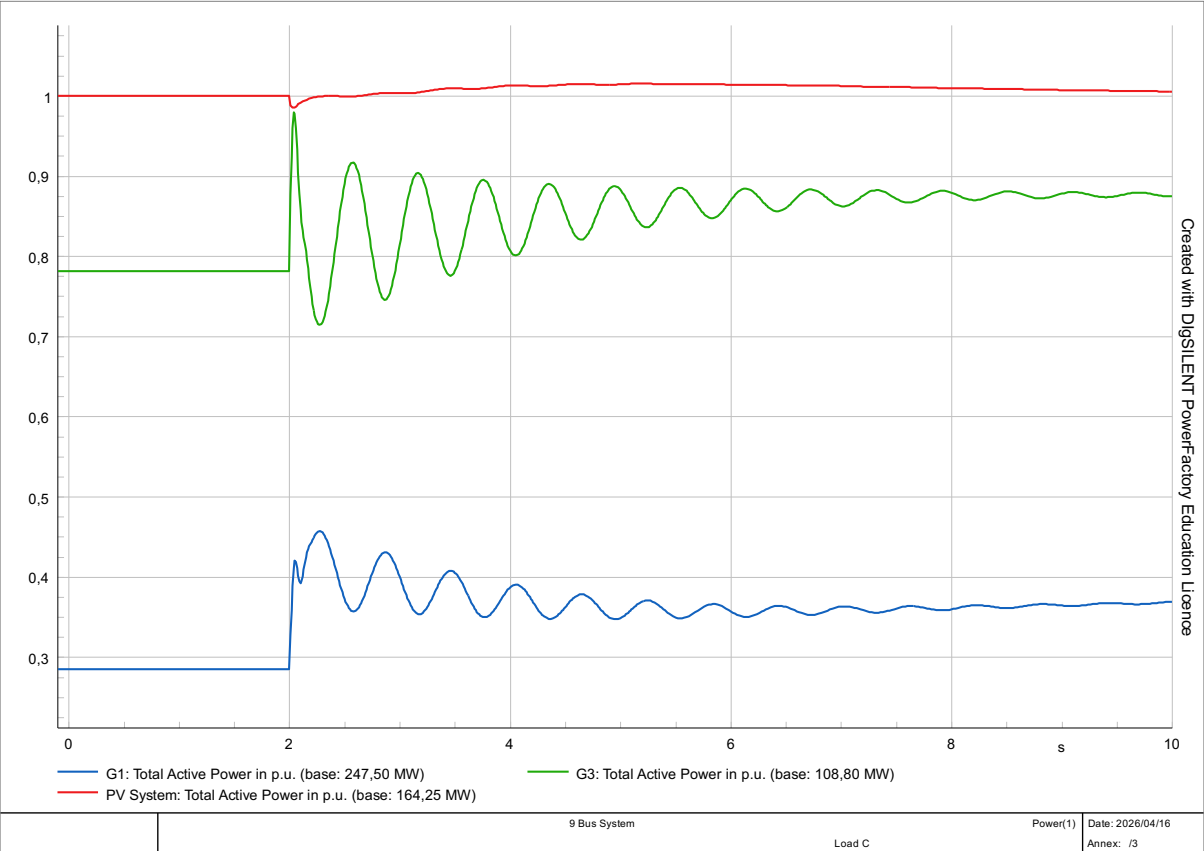
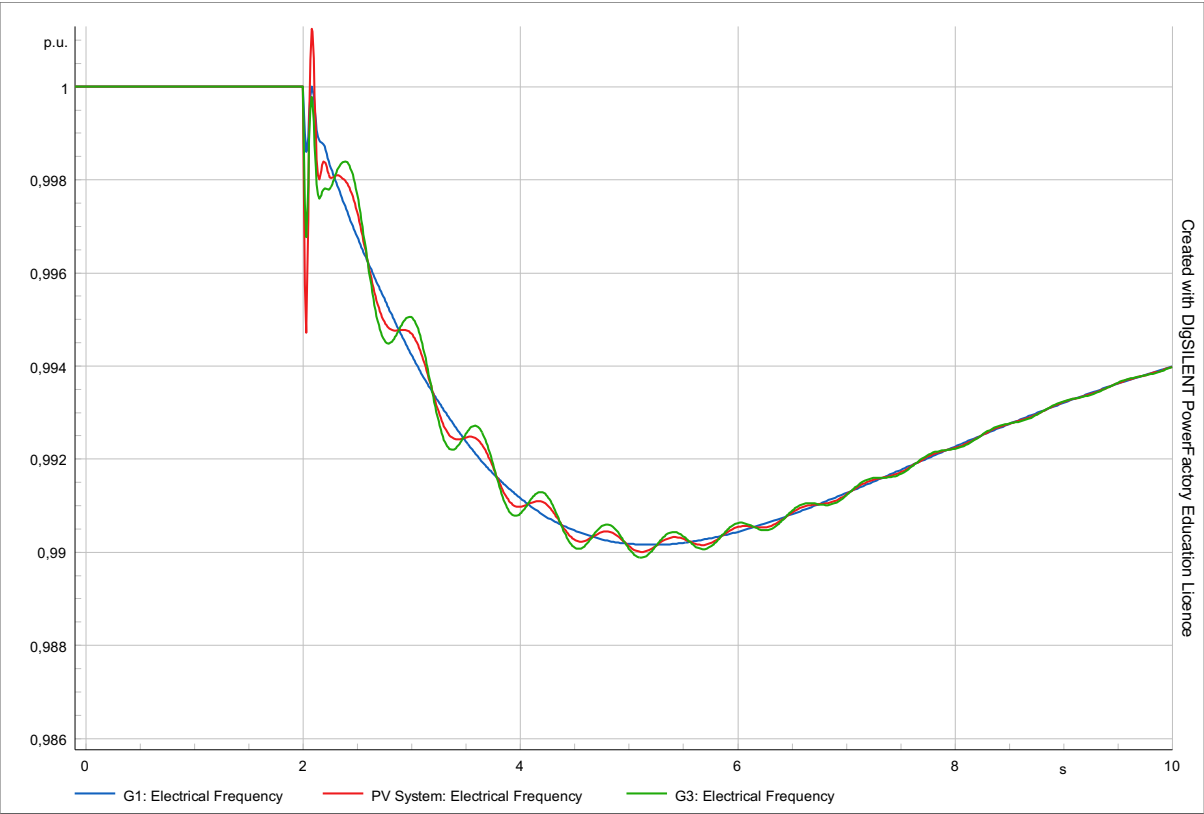


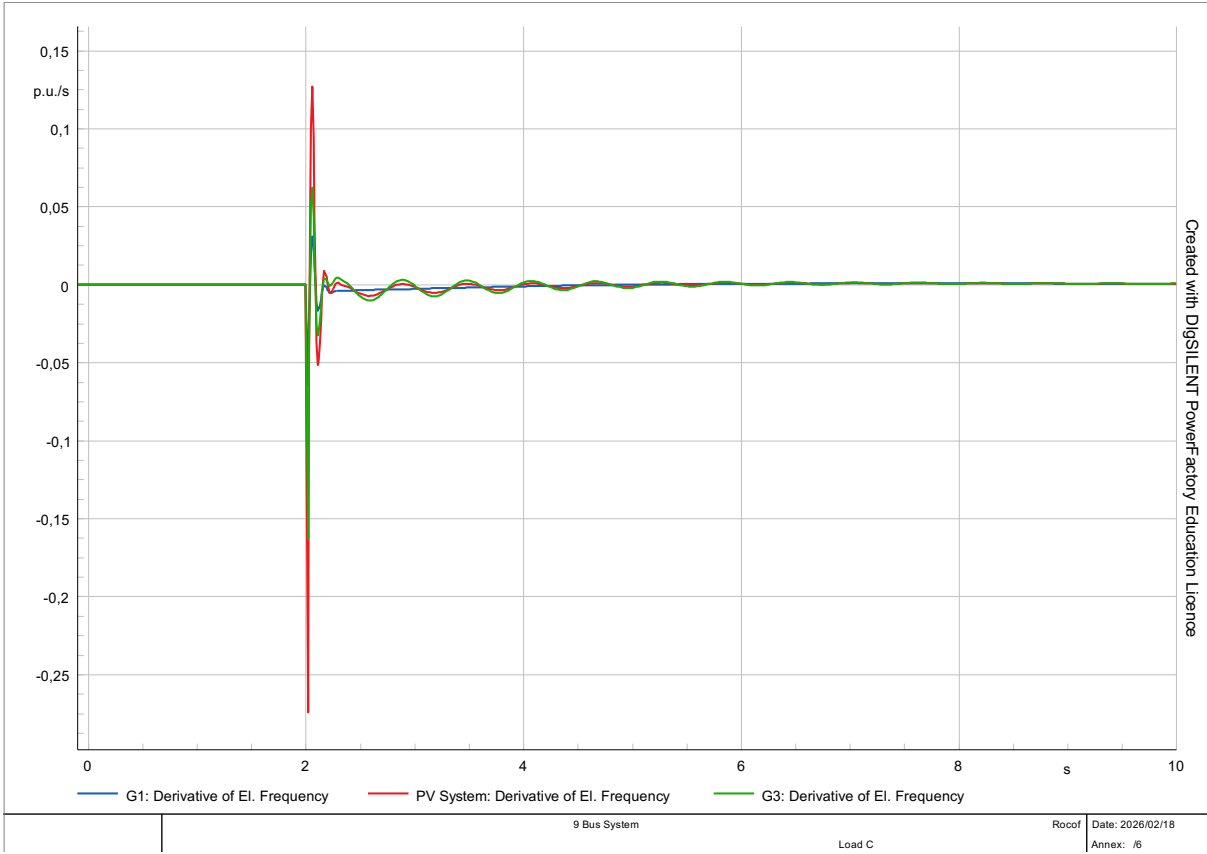
Case: Load Increase



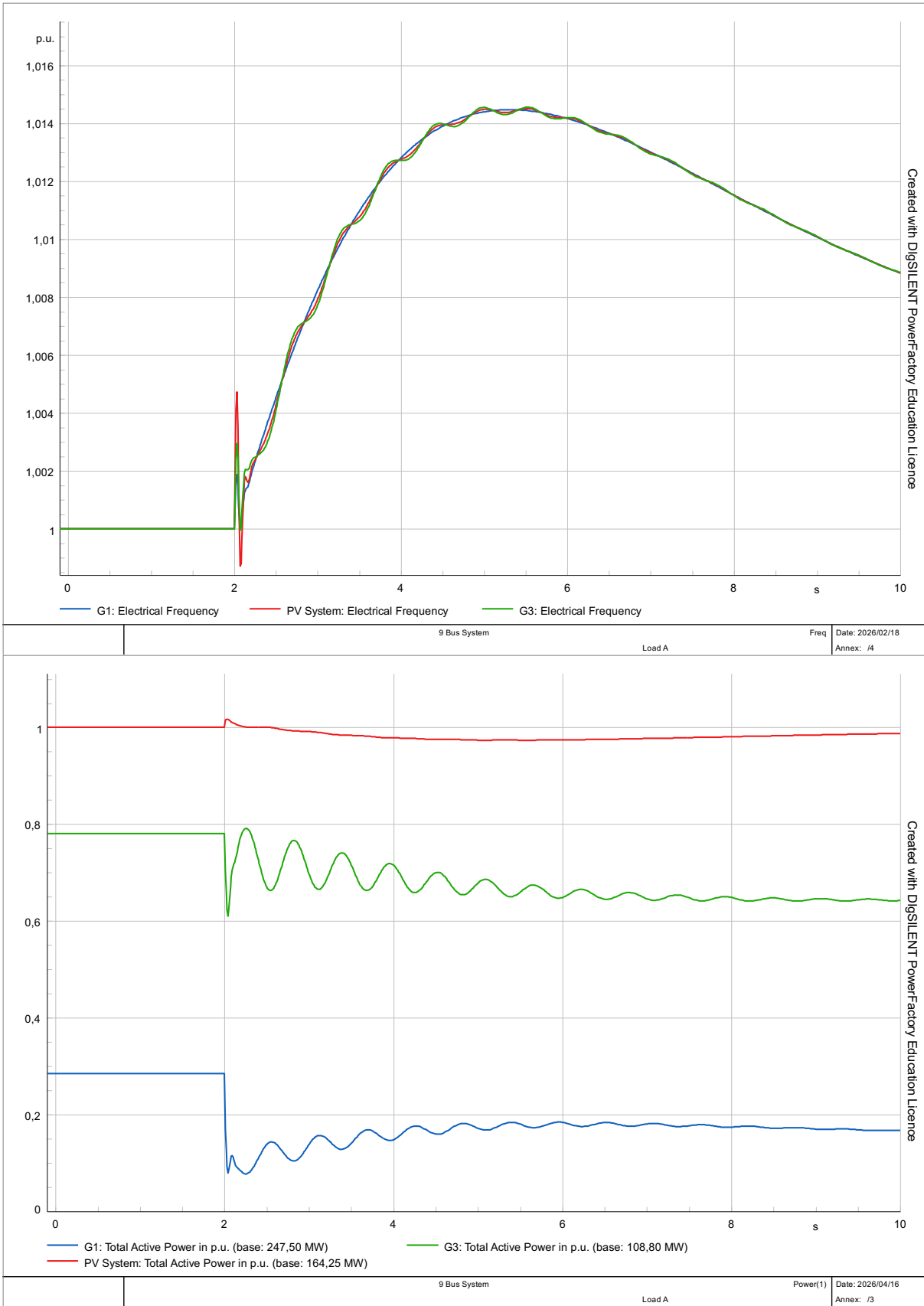


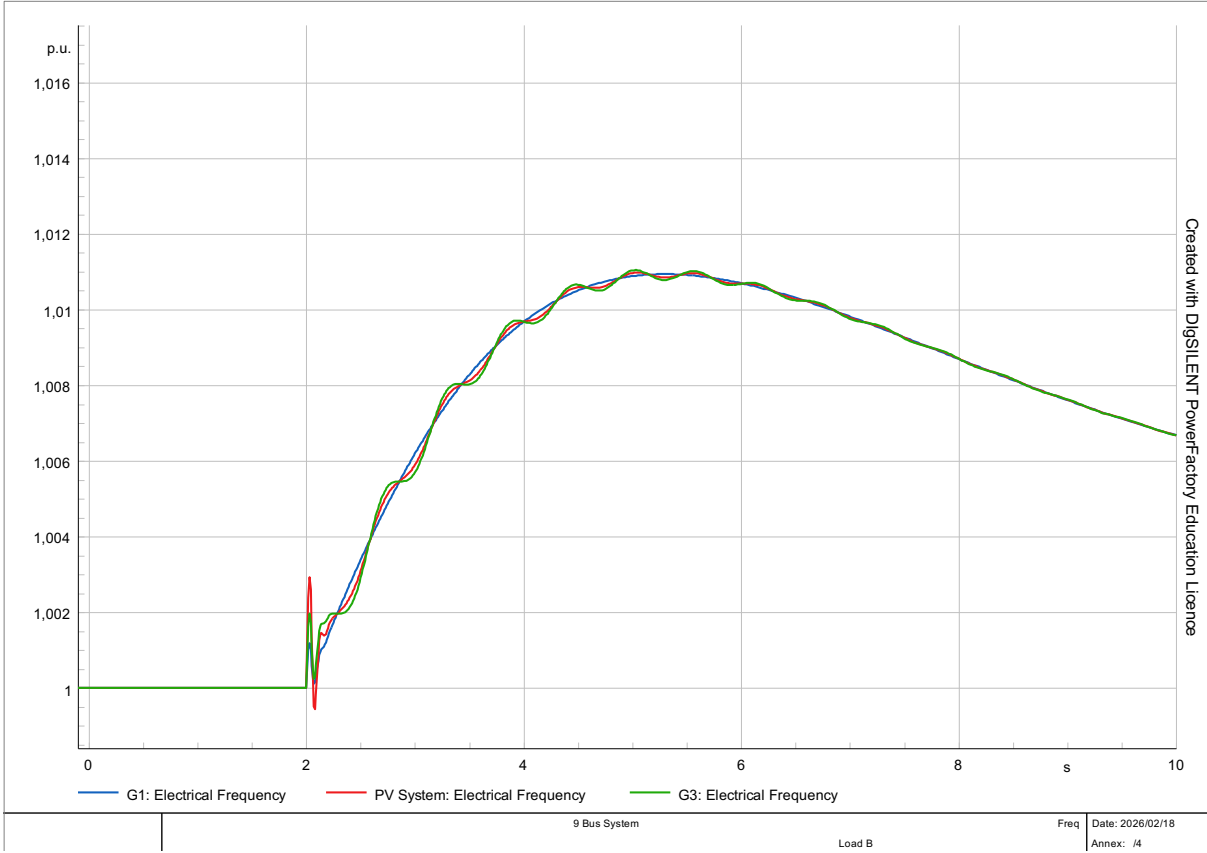
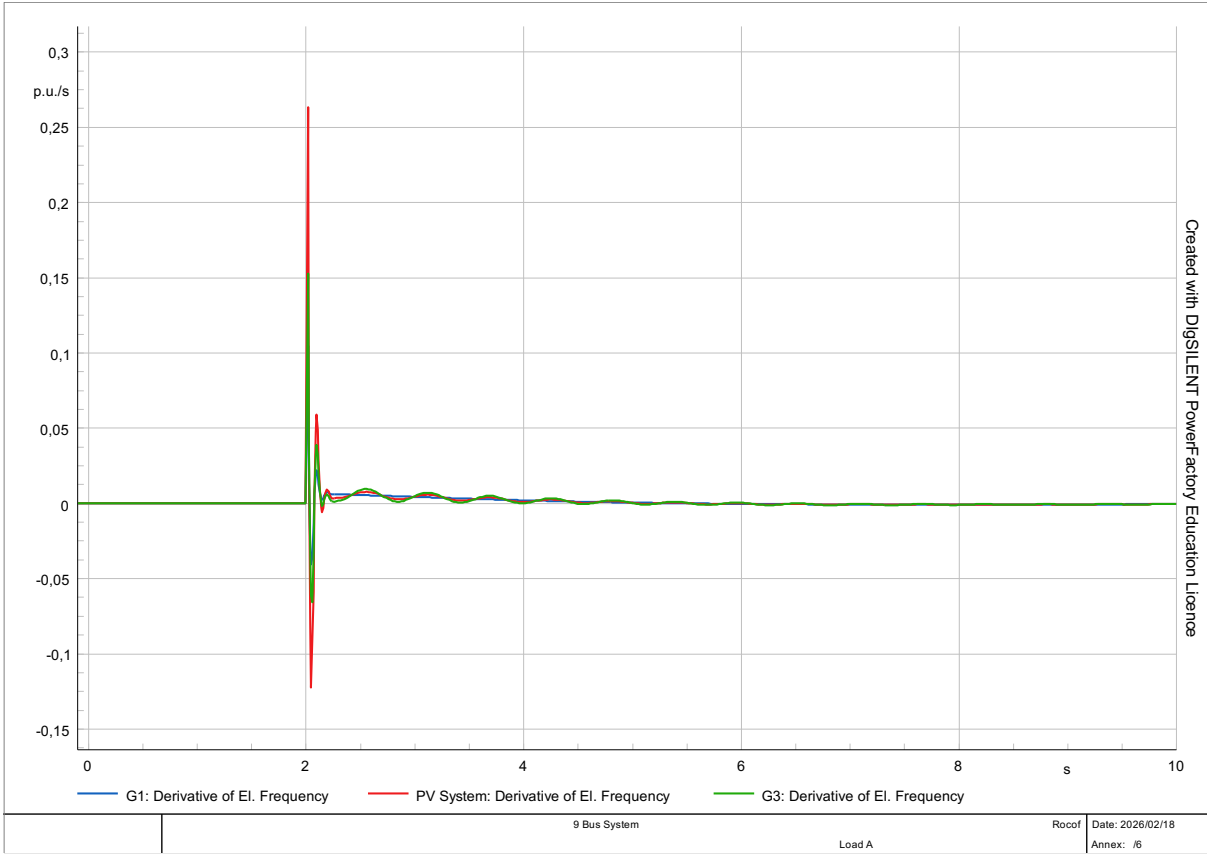


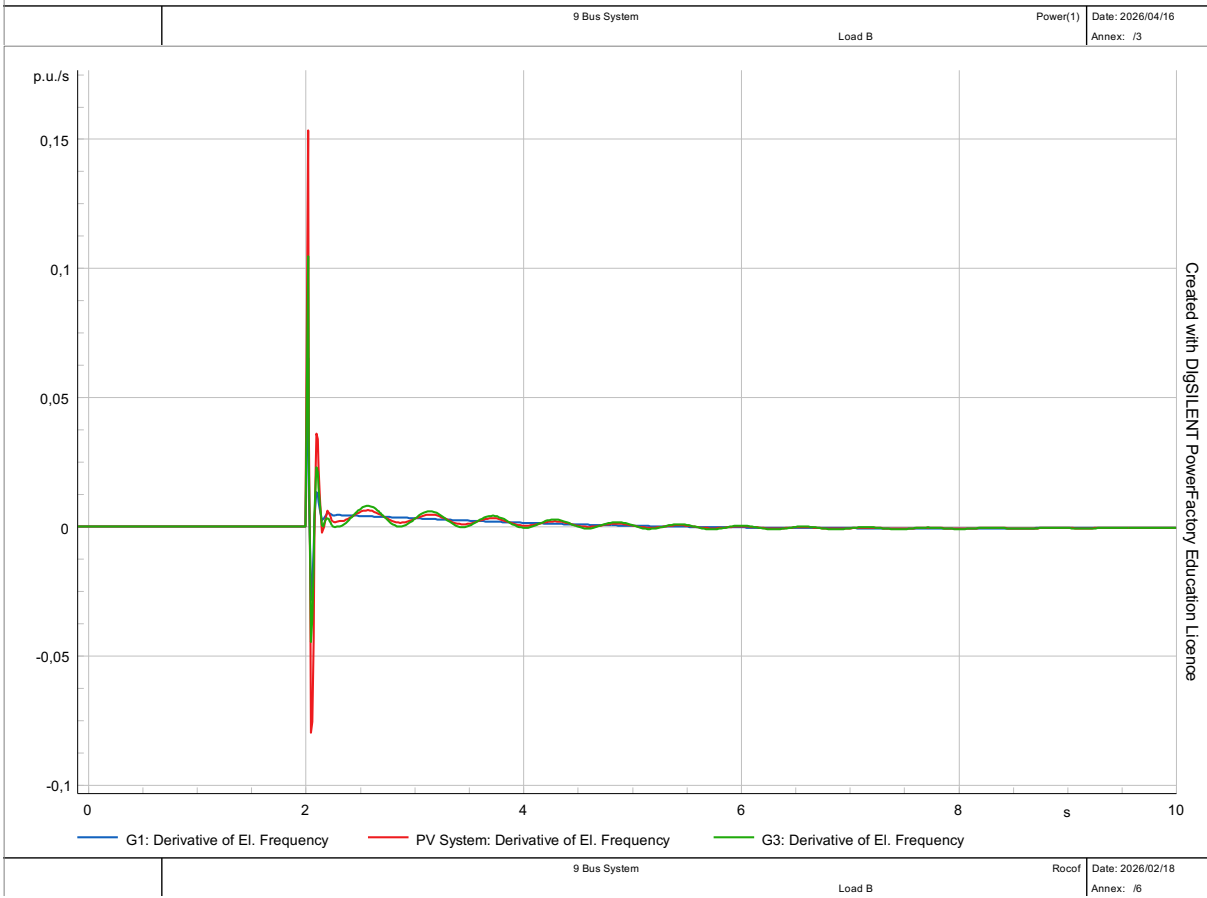
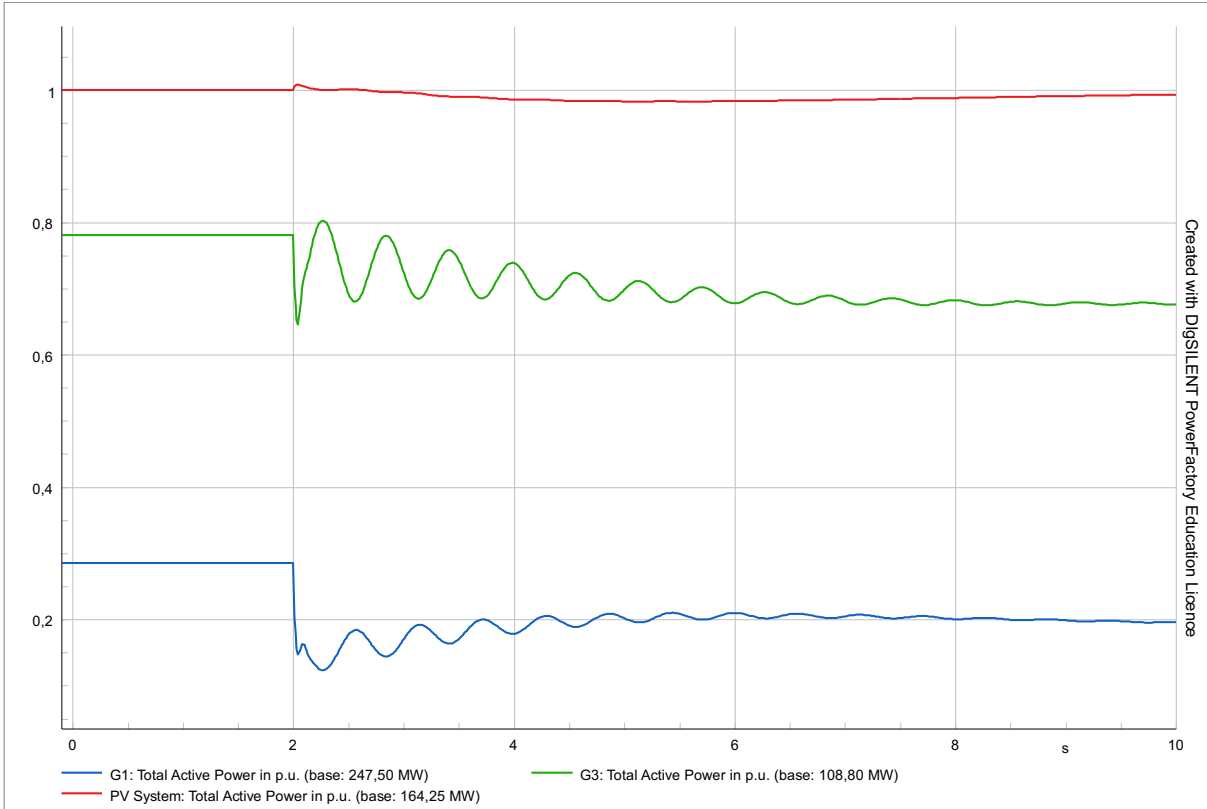


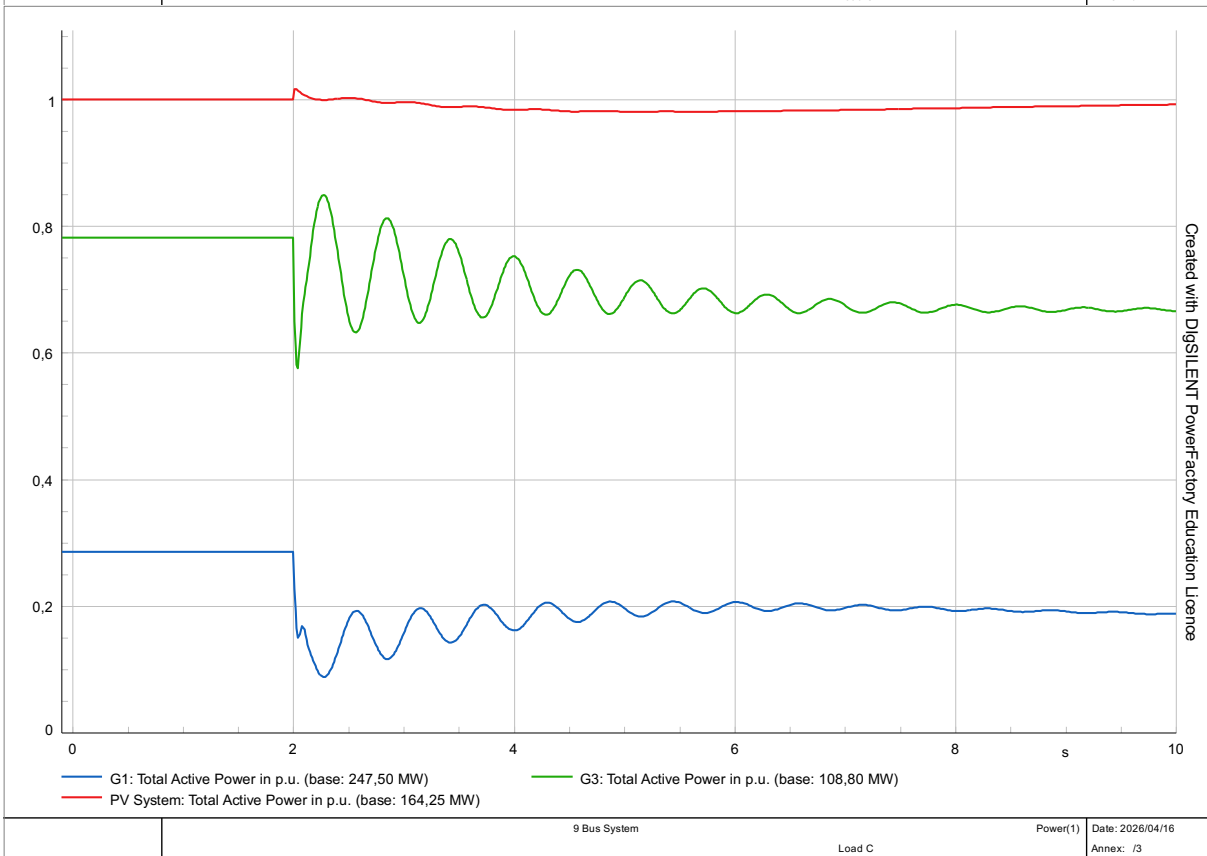
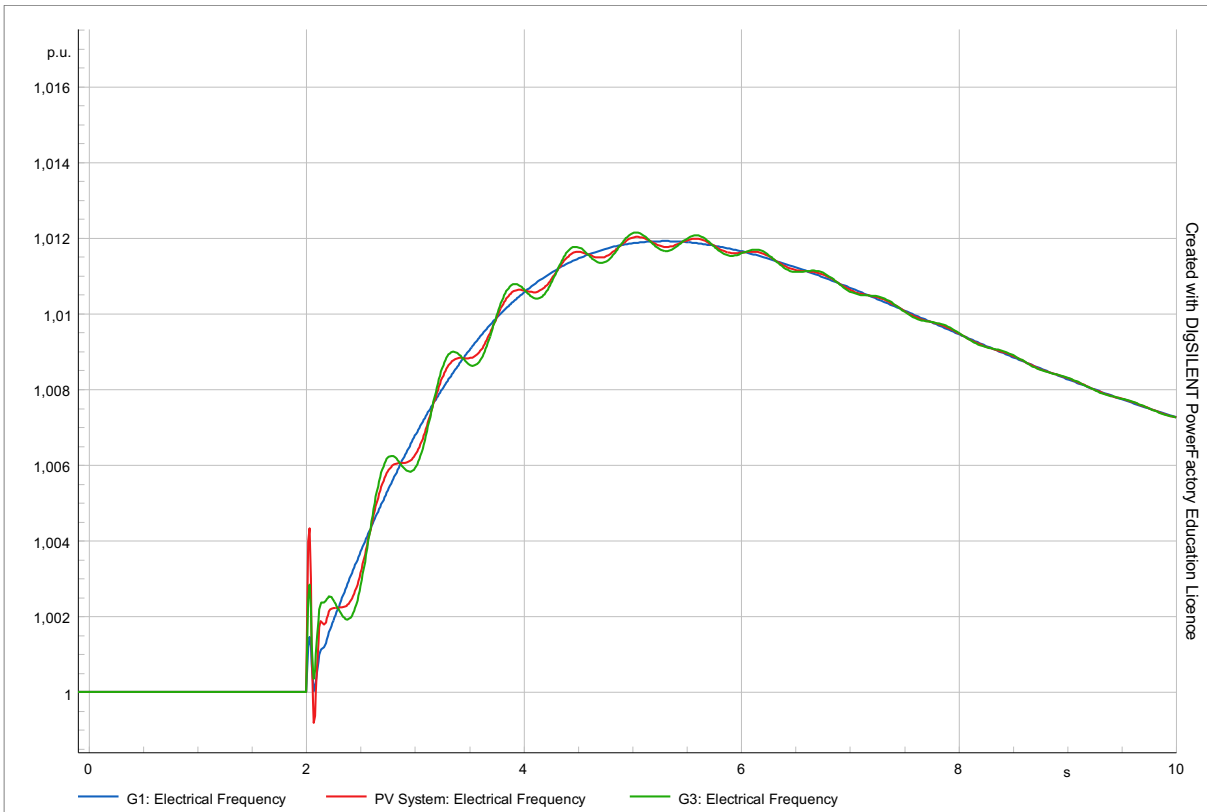


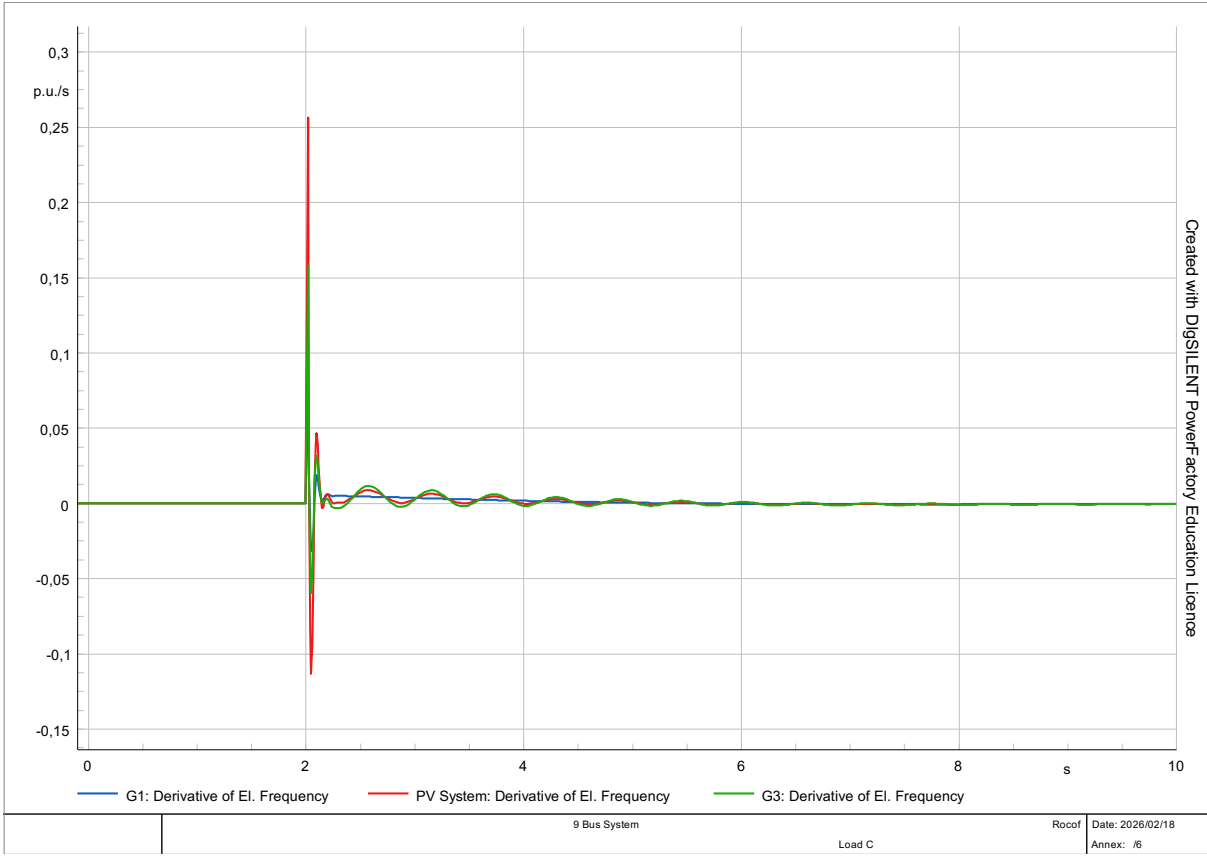
Case: Load Decrease





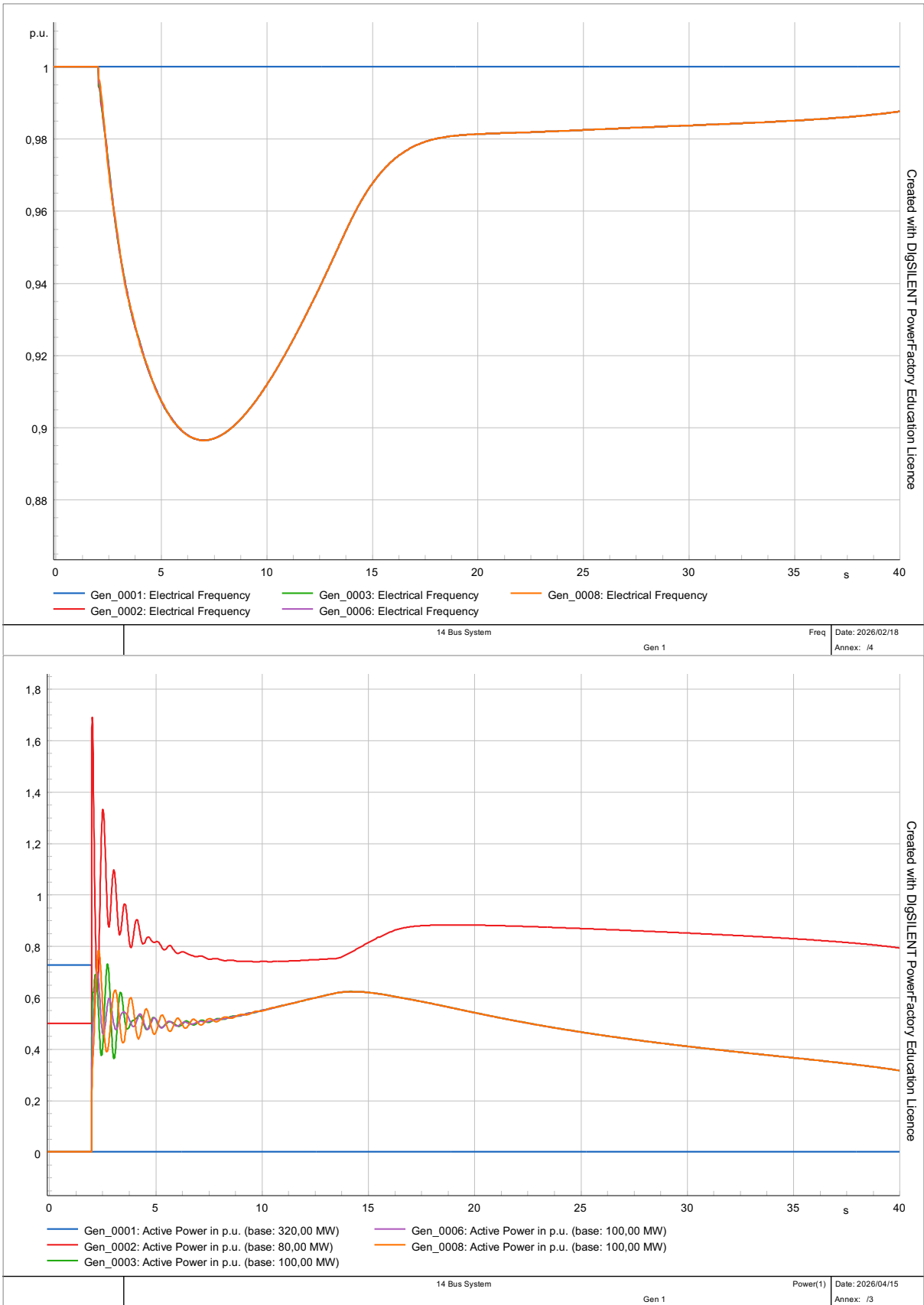


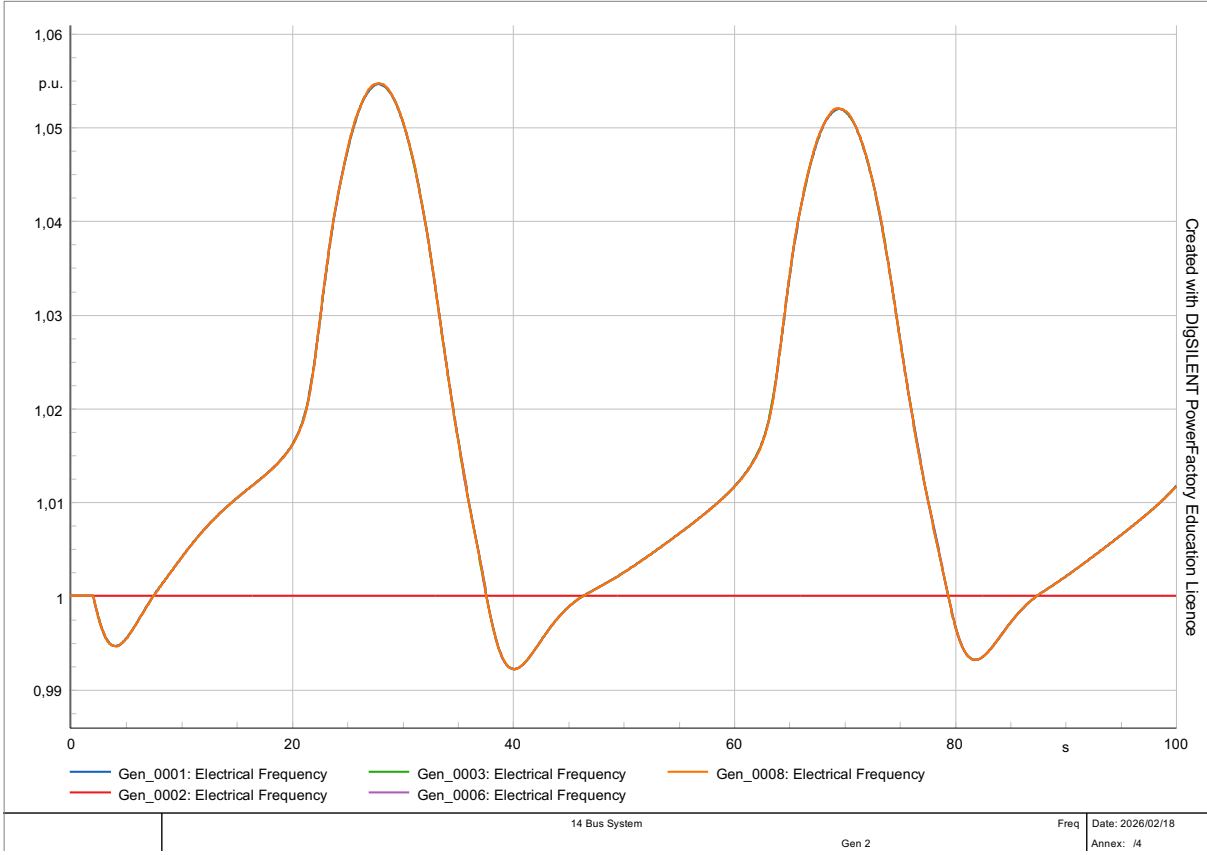
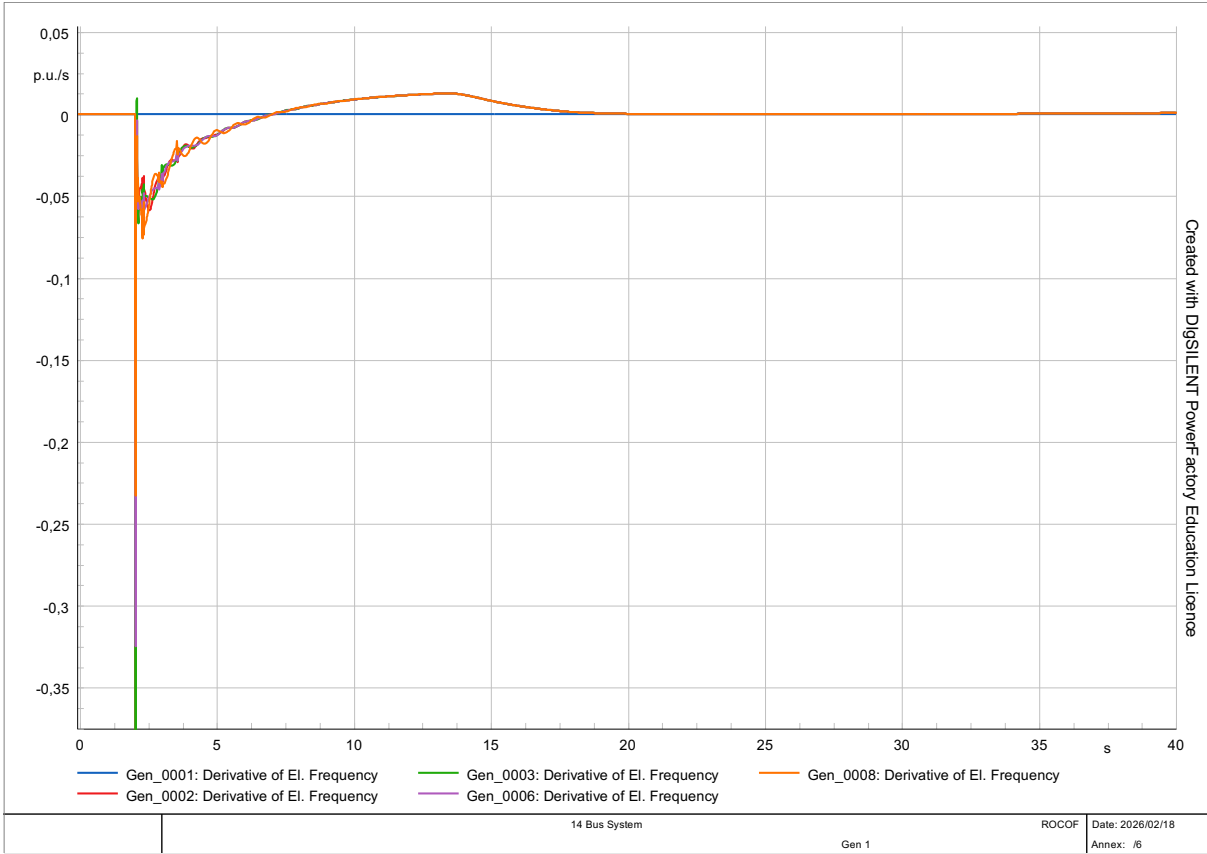


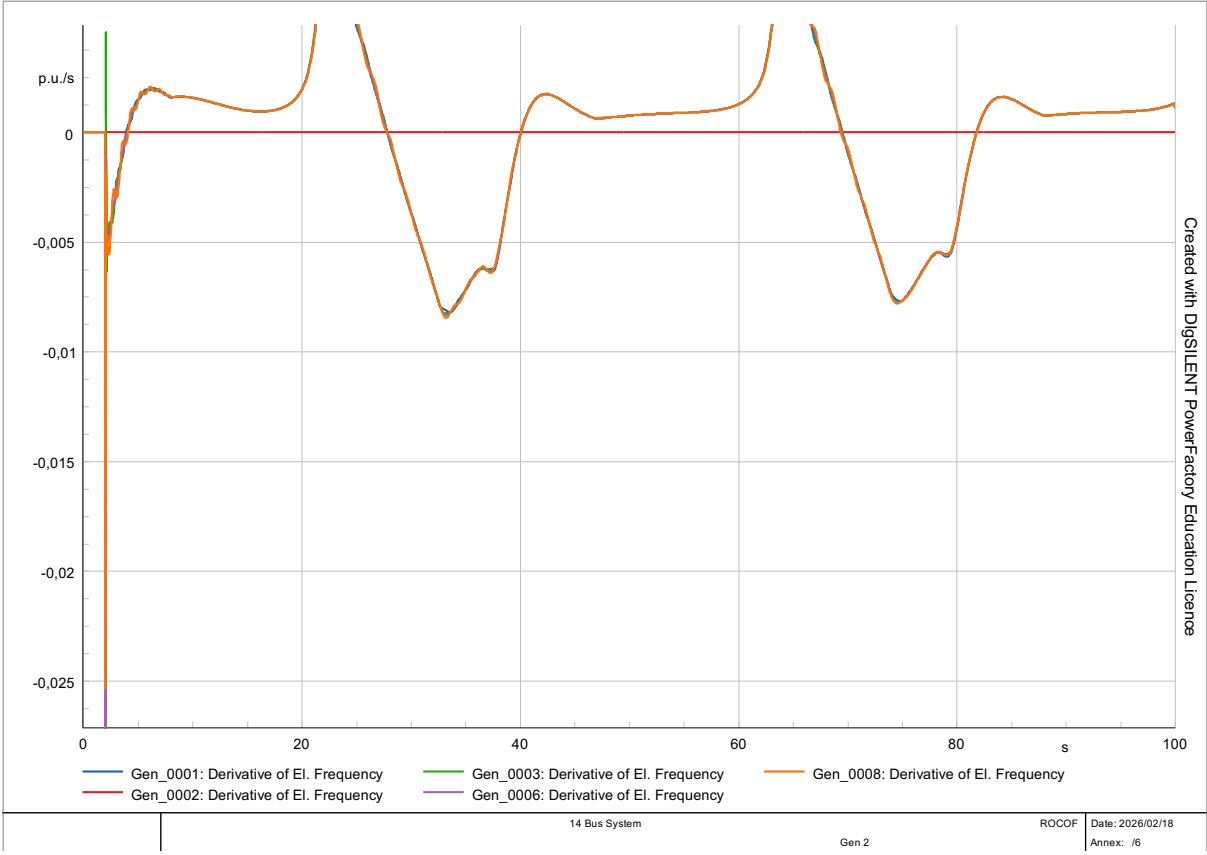
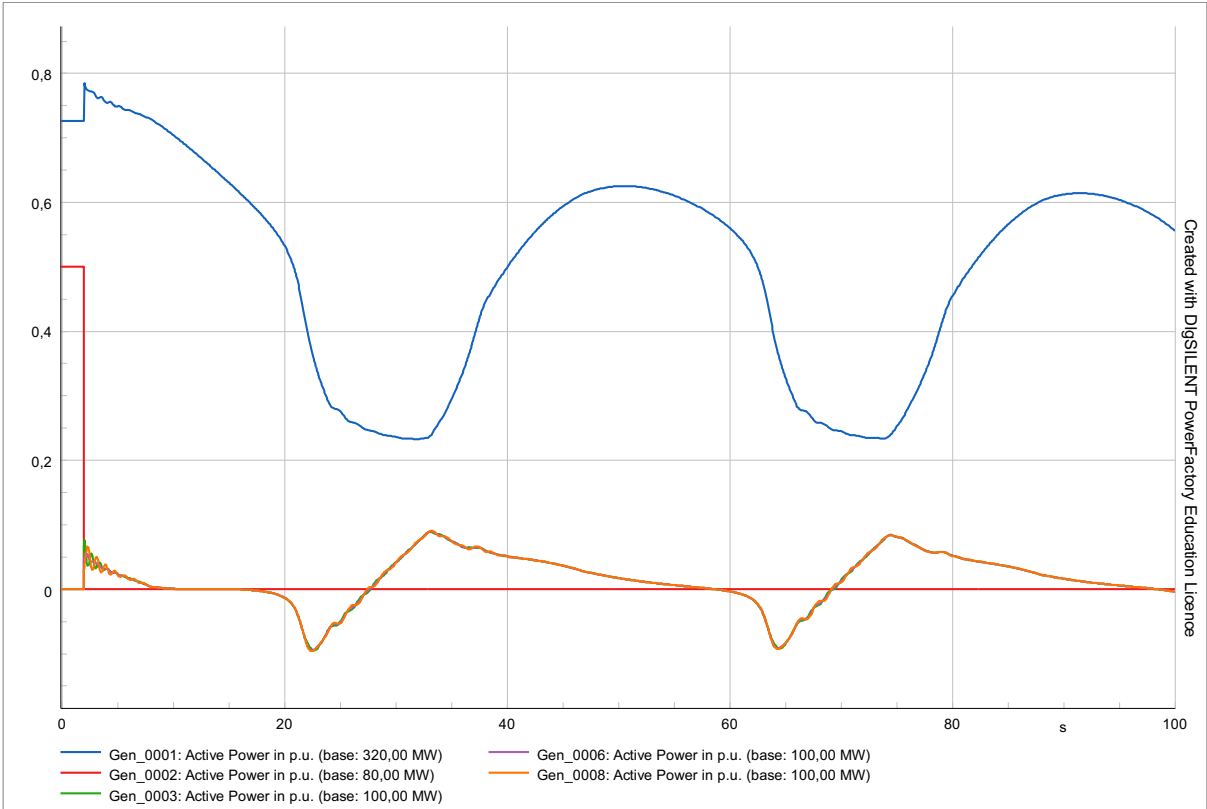


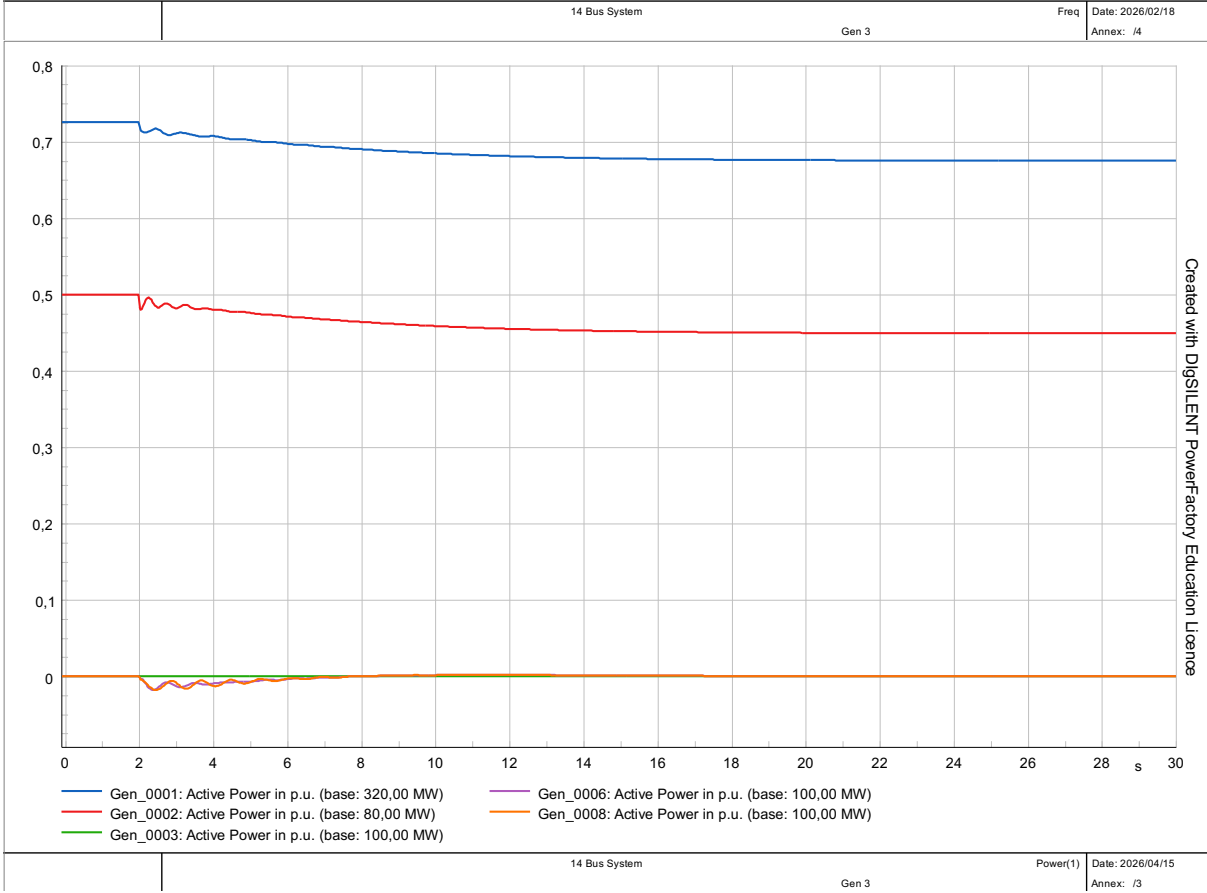
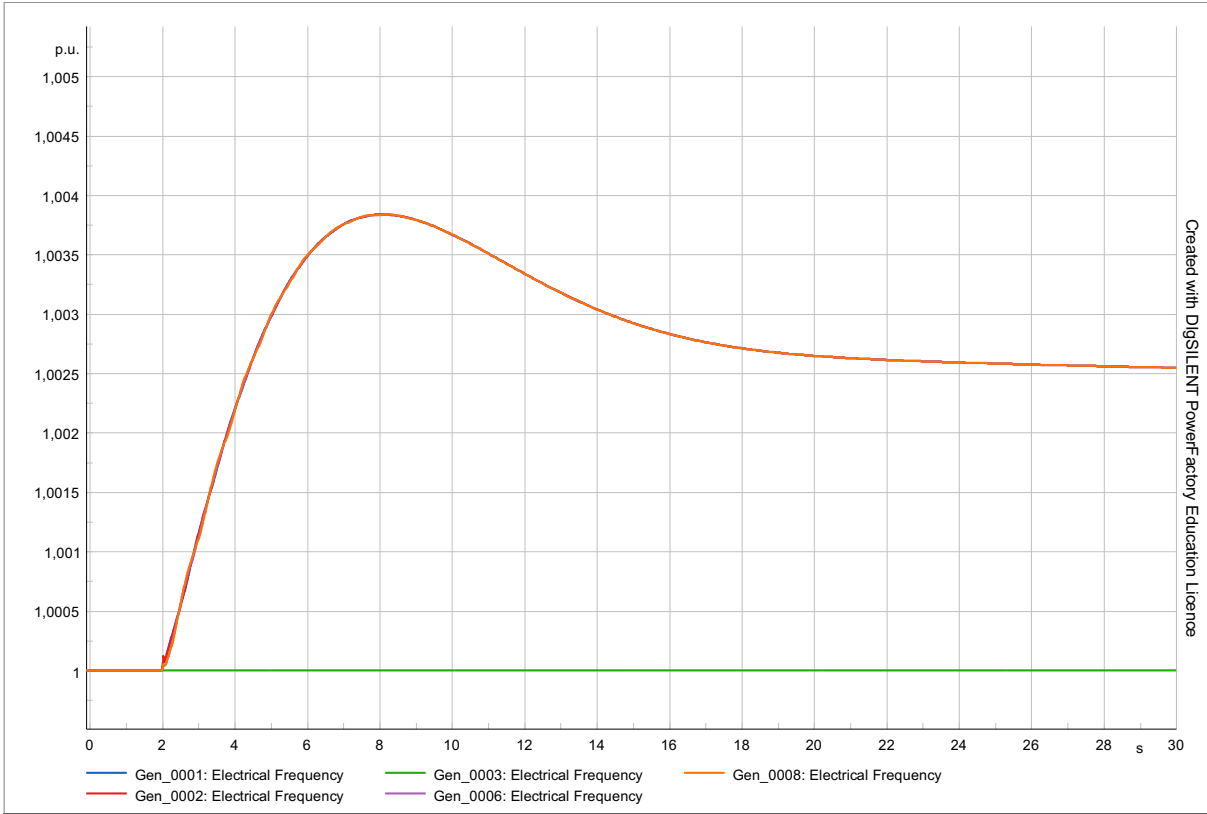
14 Bus System

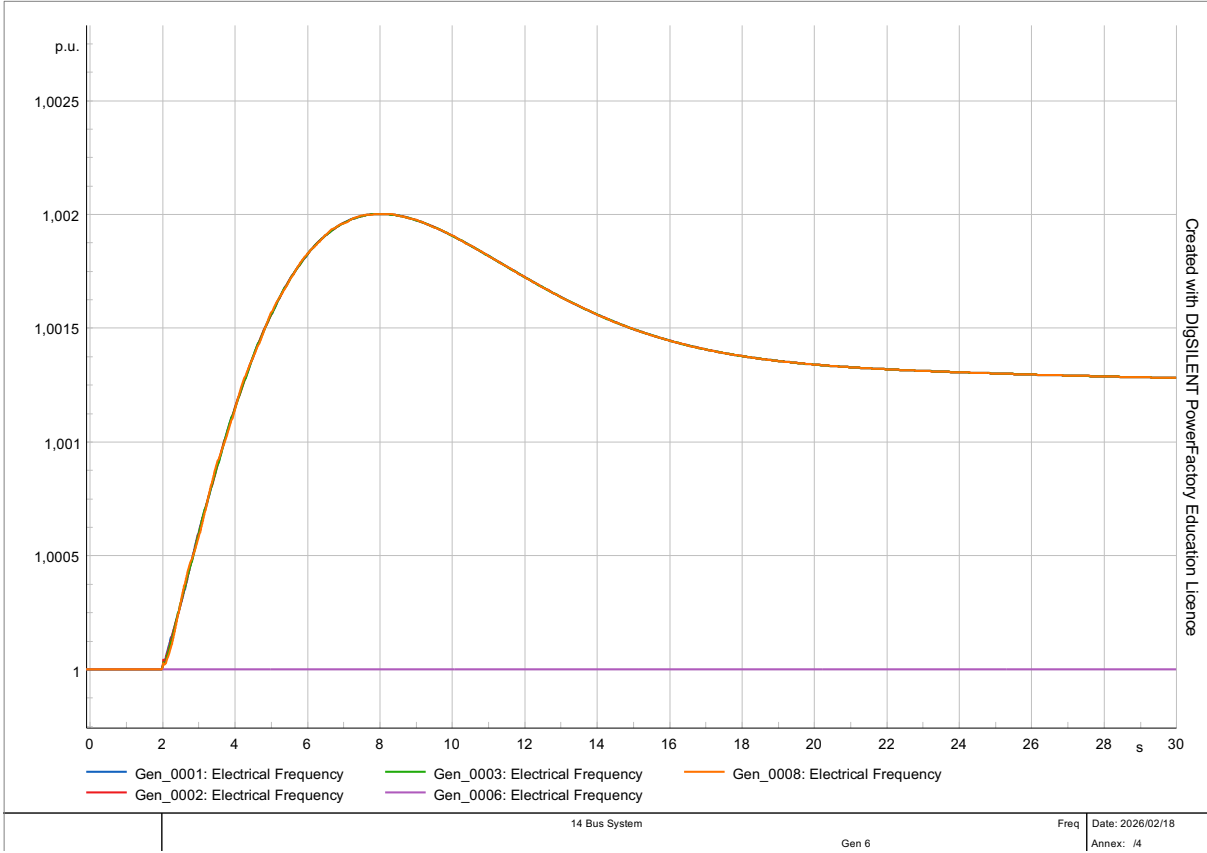
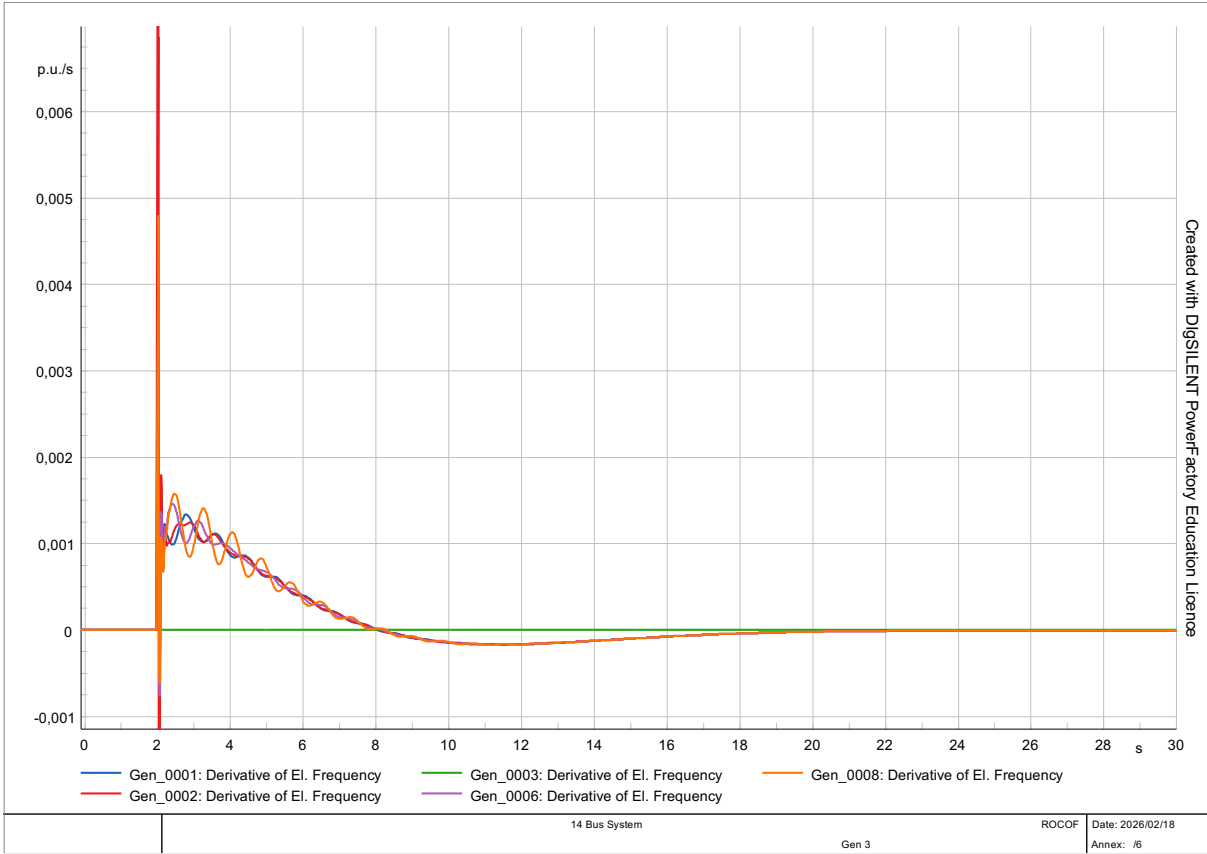
Case: Gen Loss

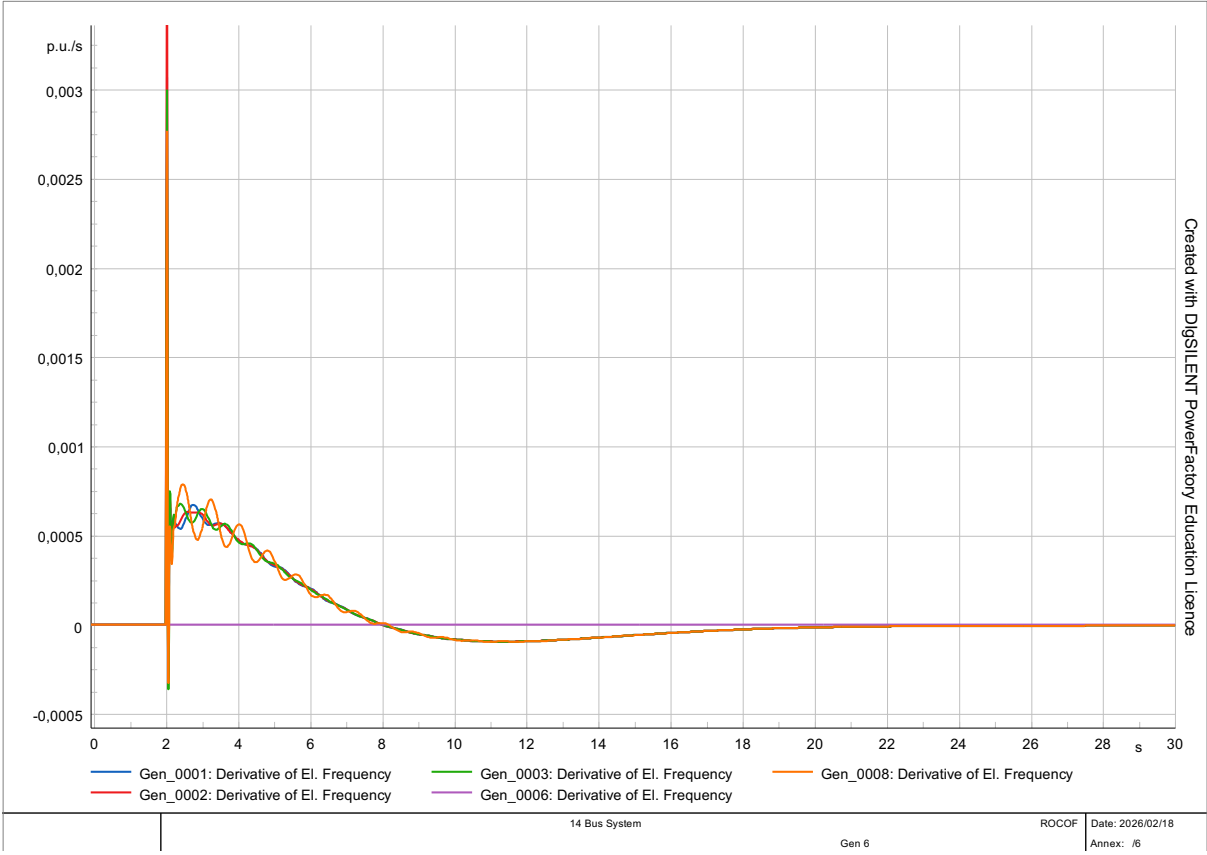
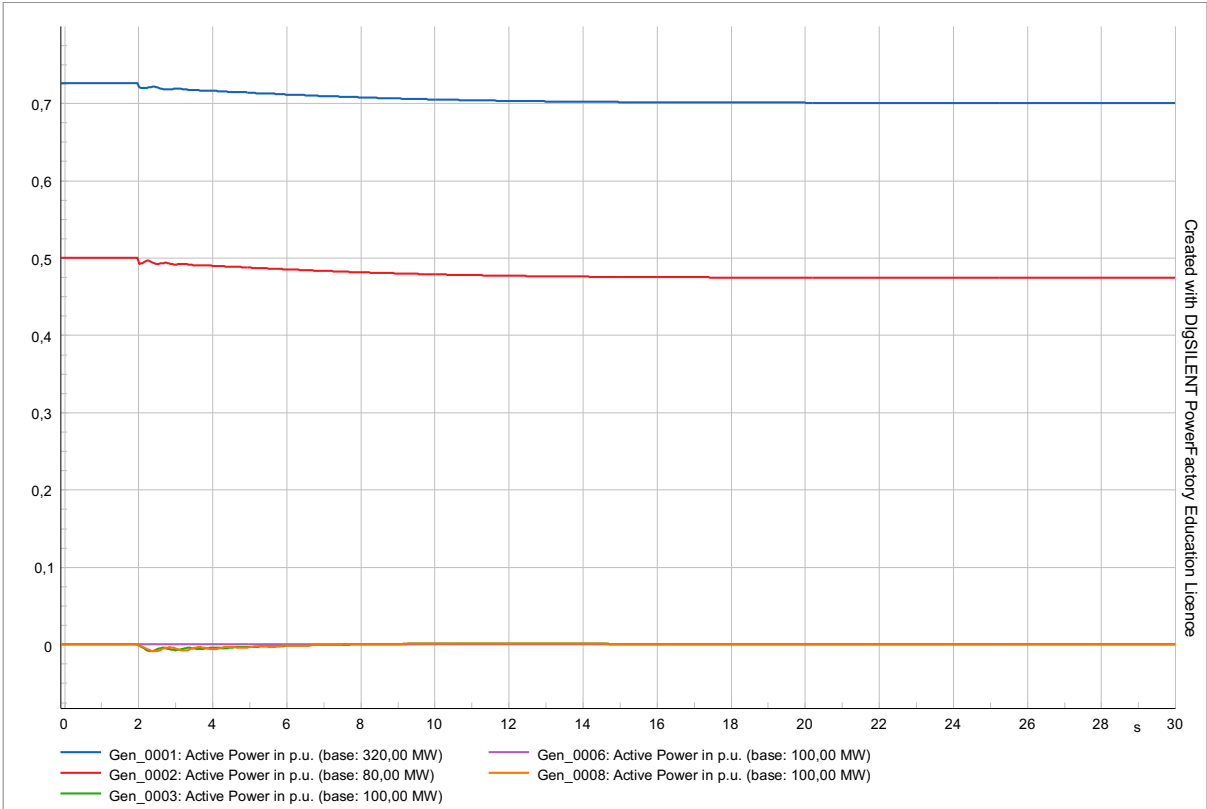


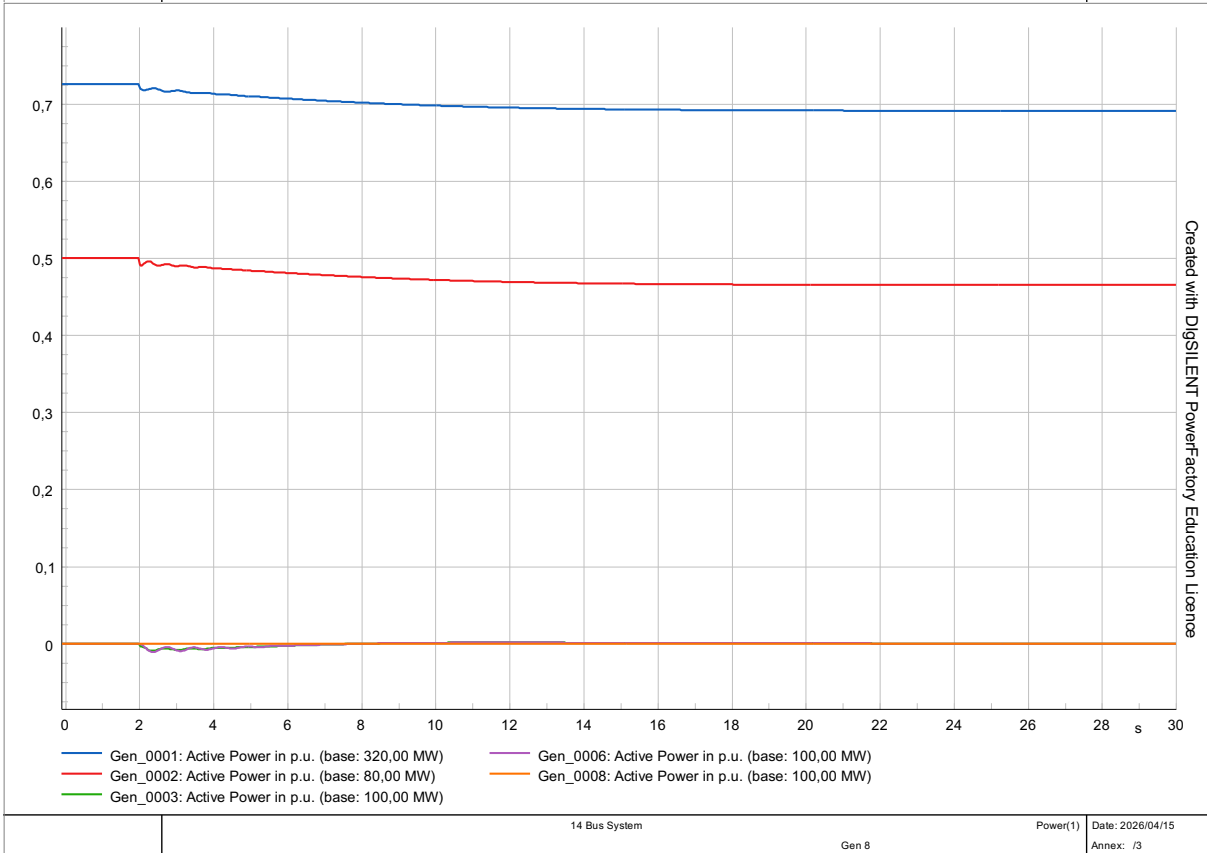
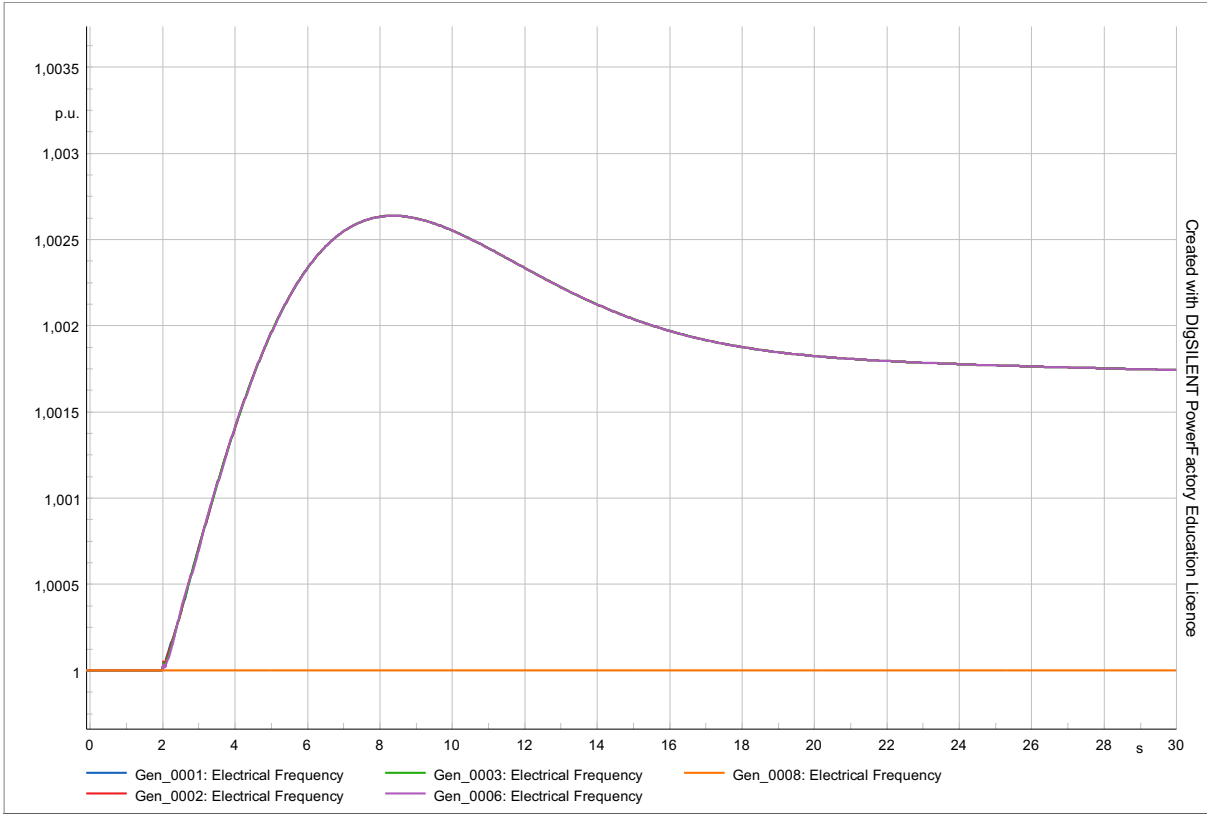


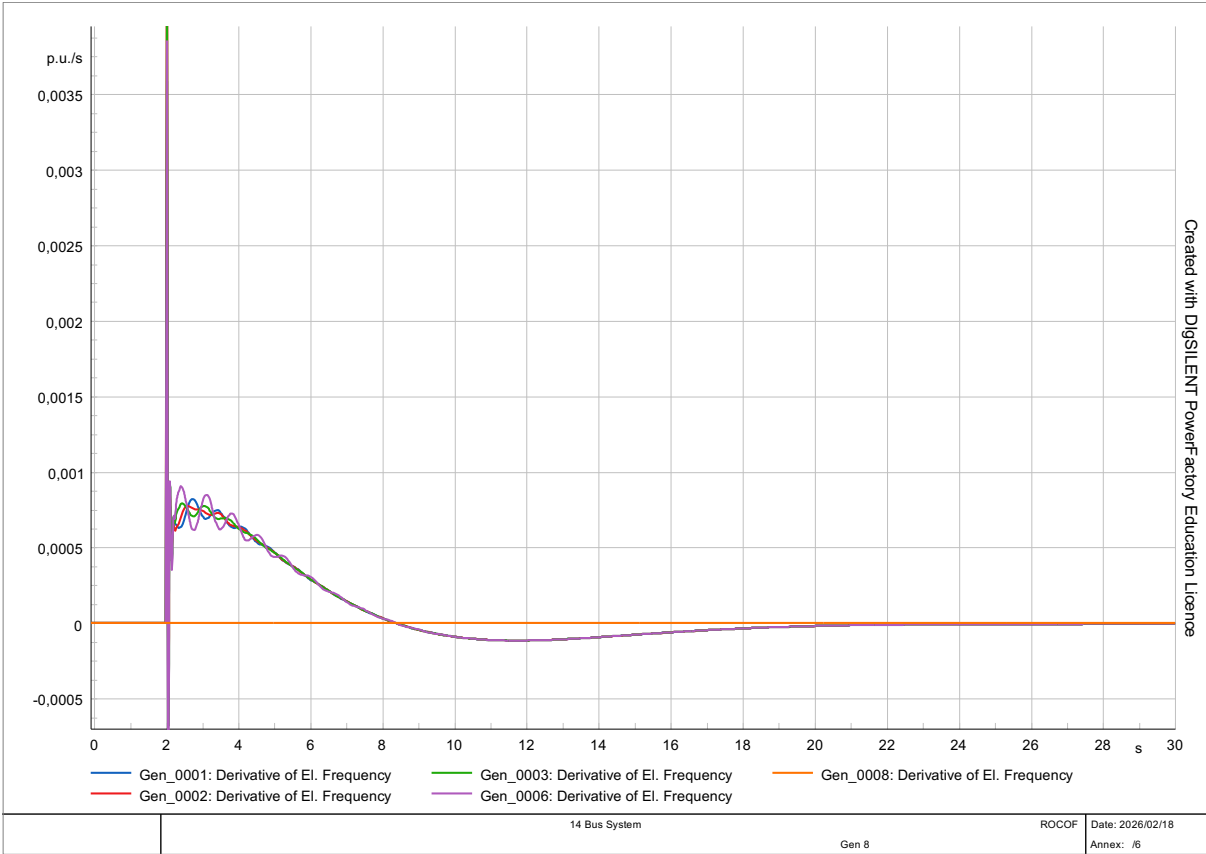




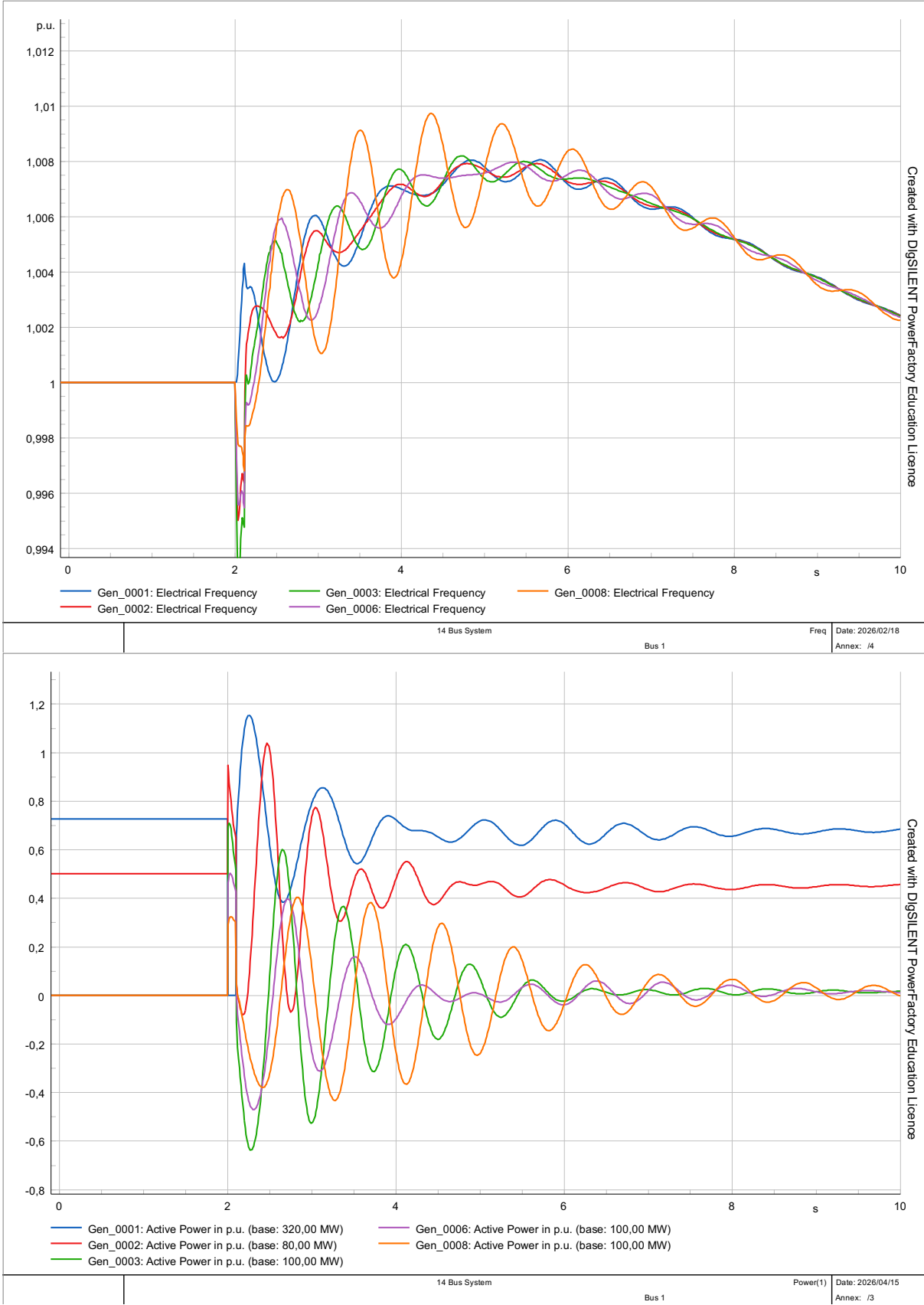


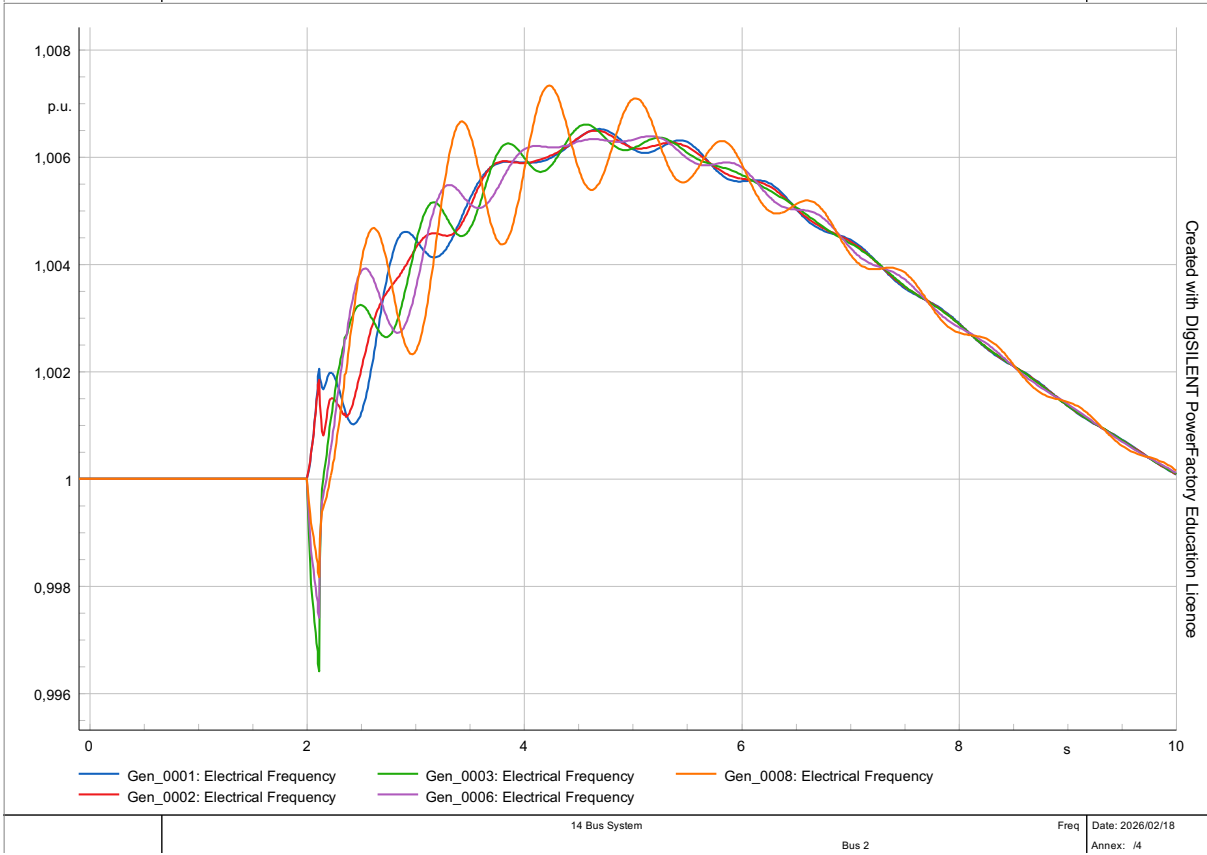
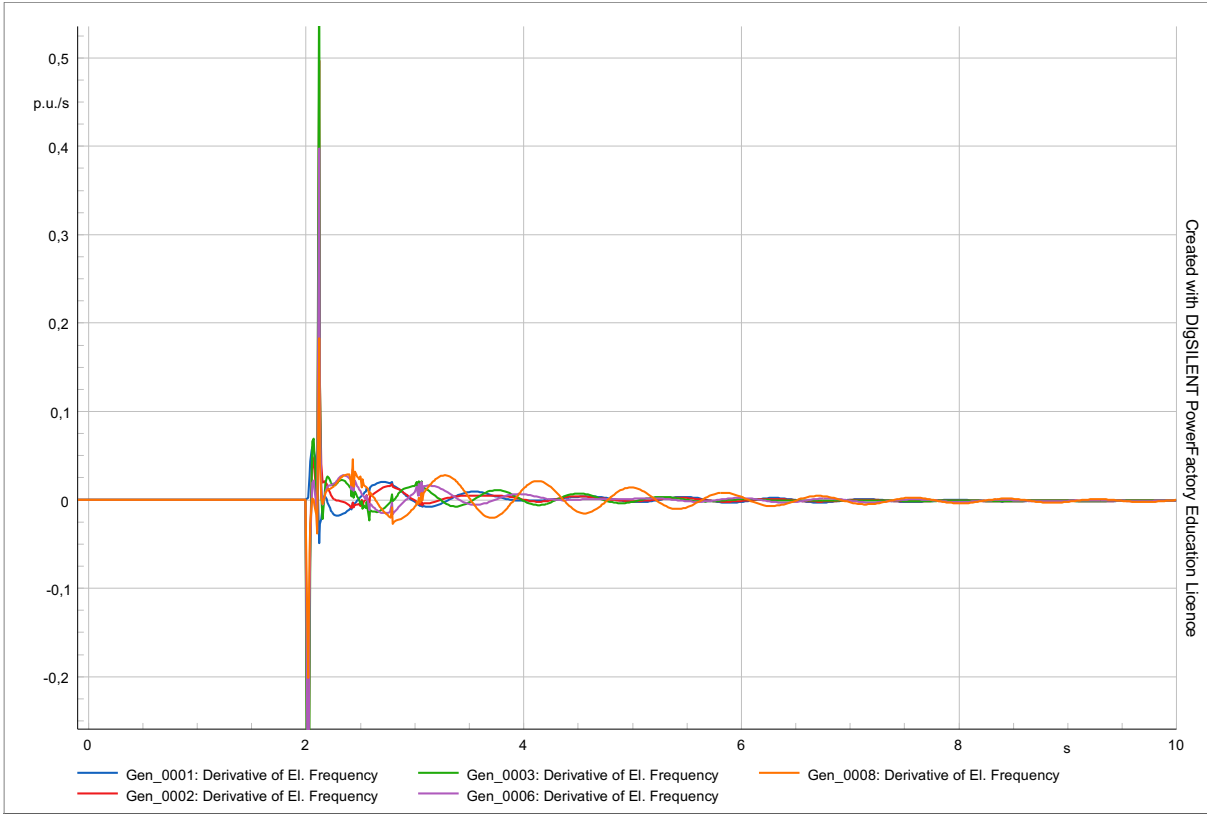


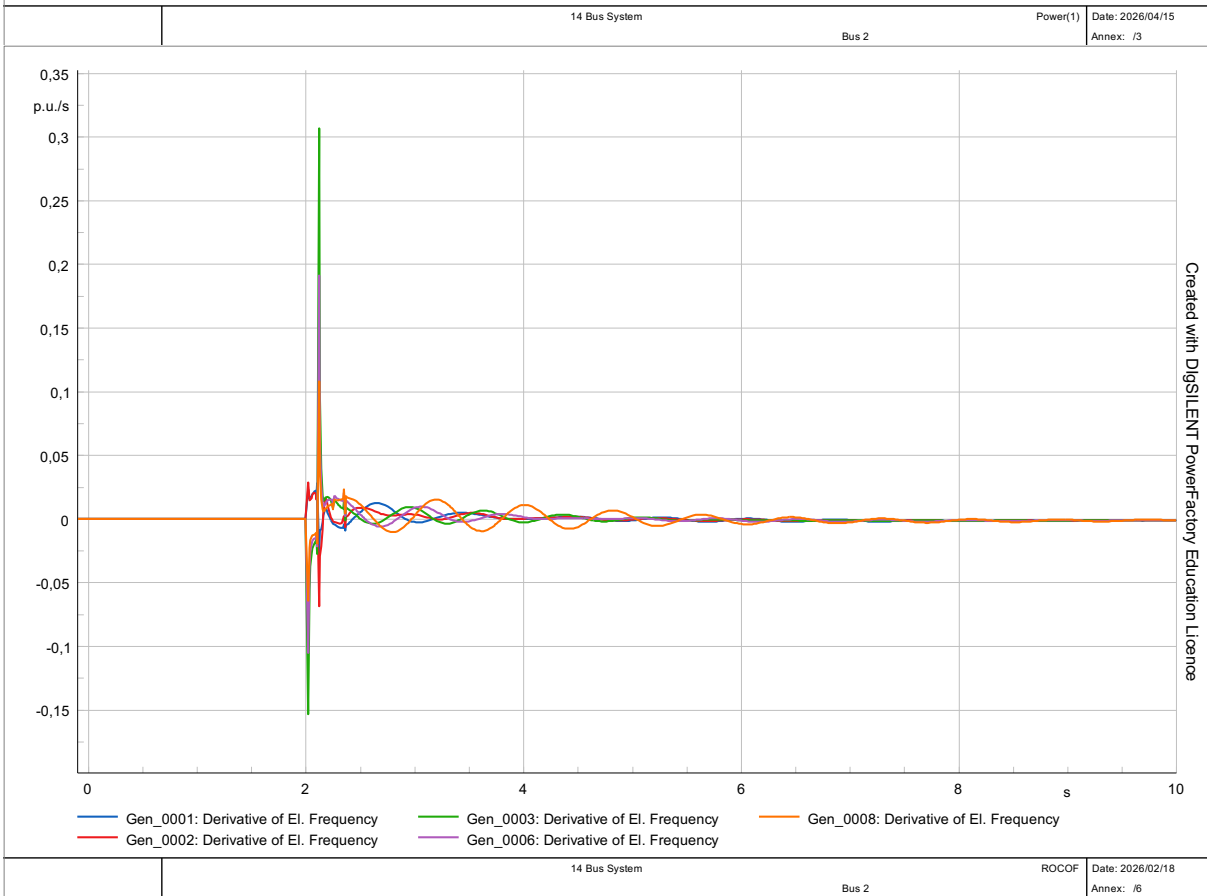
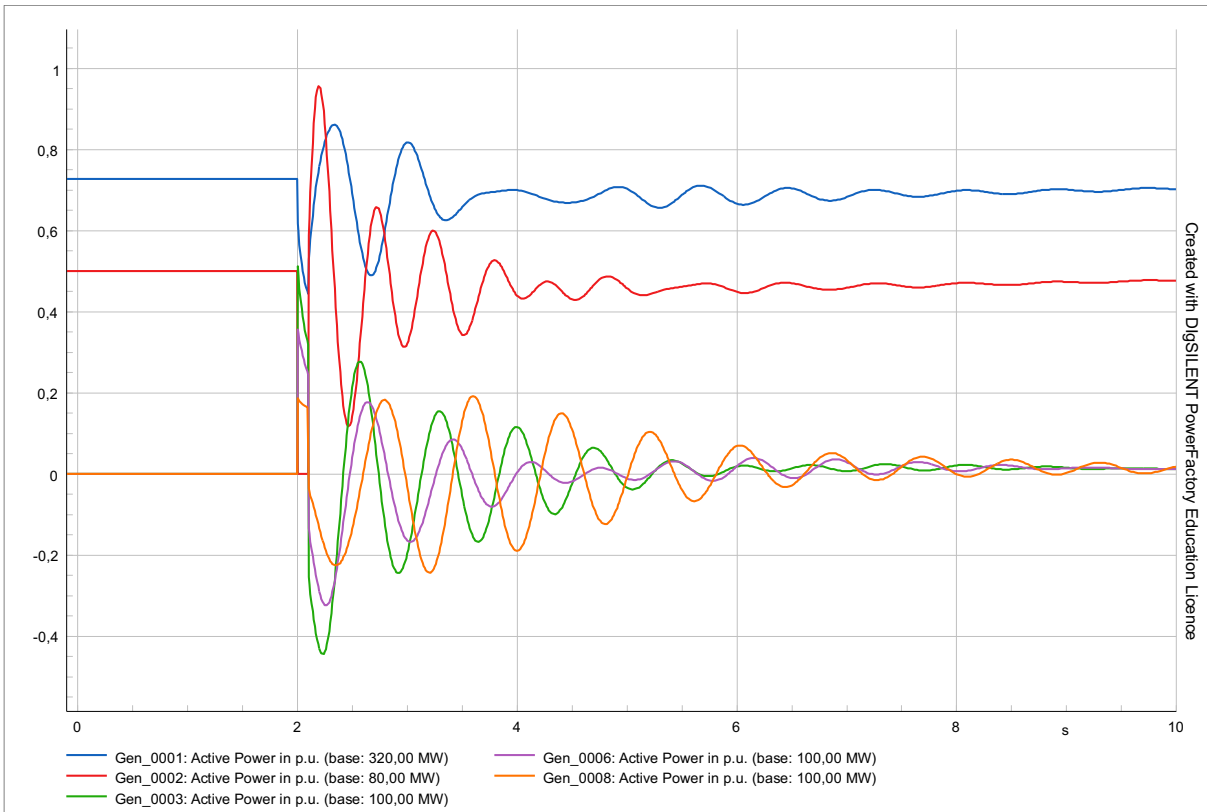


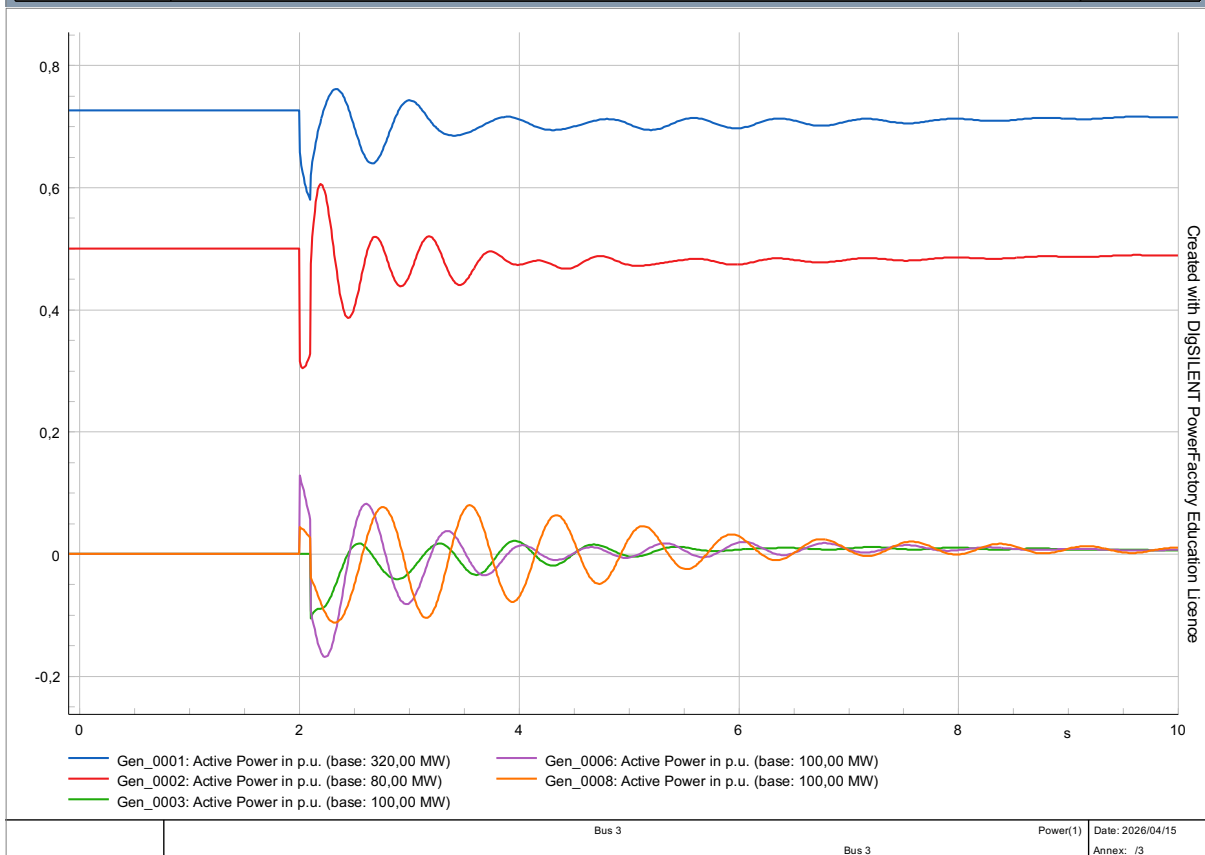
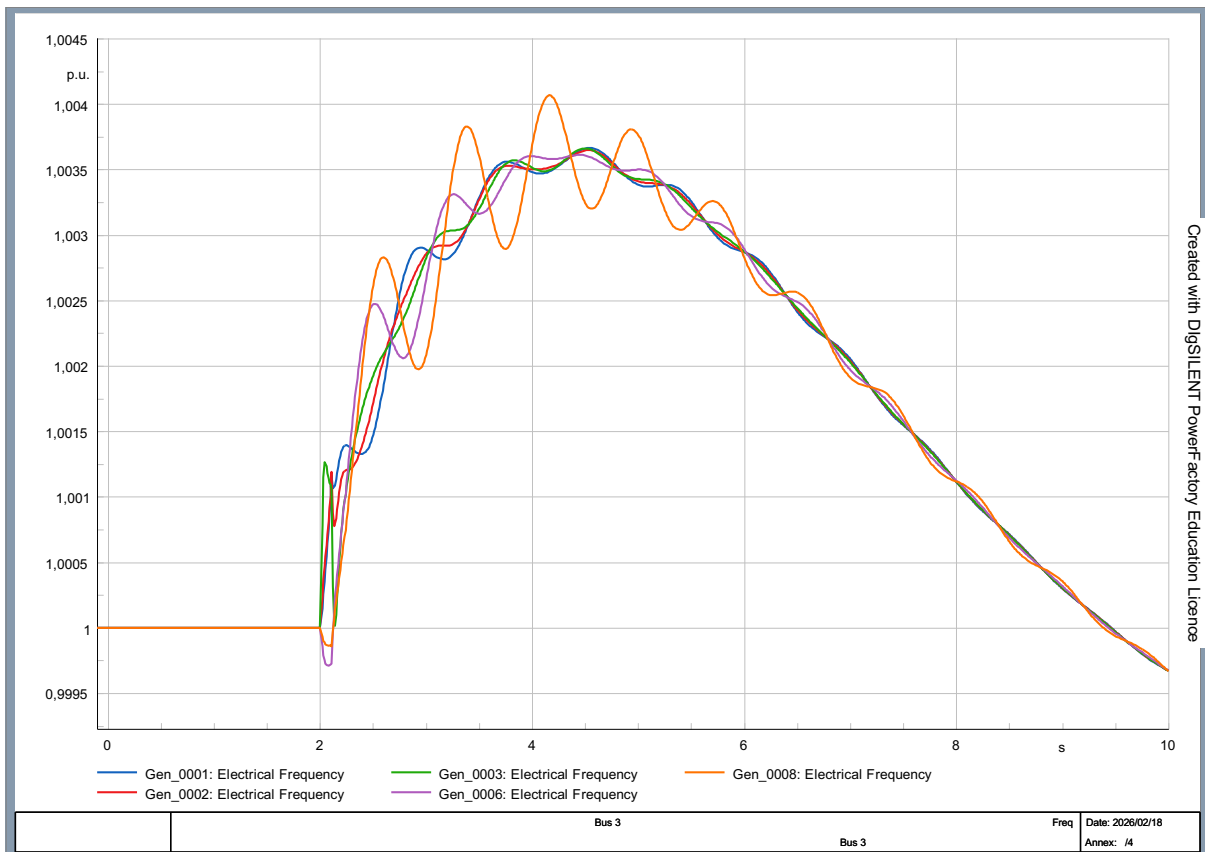


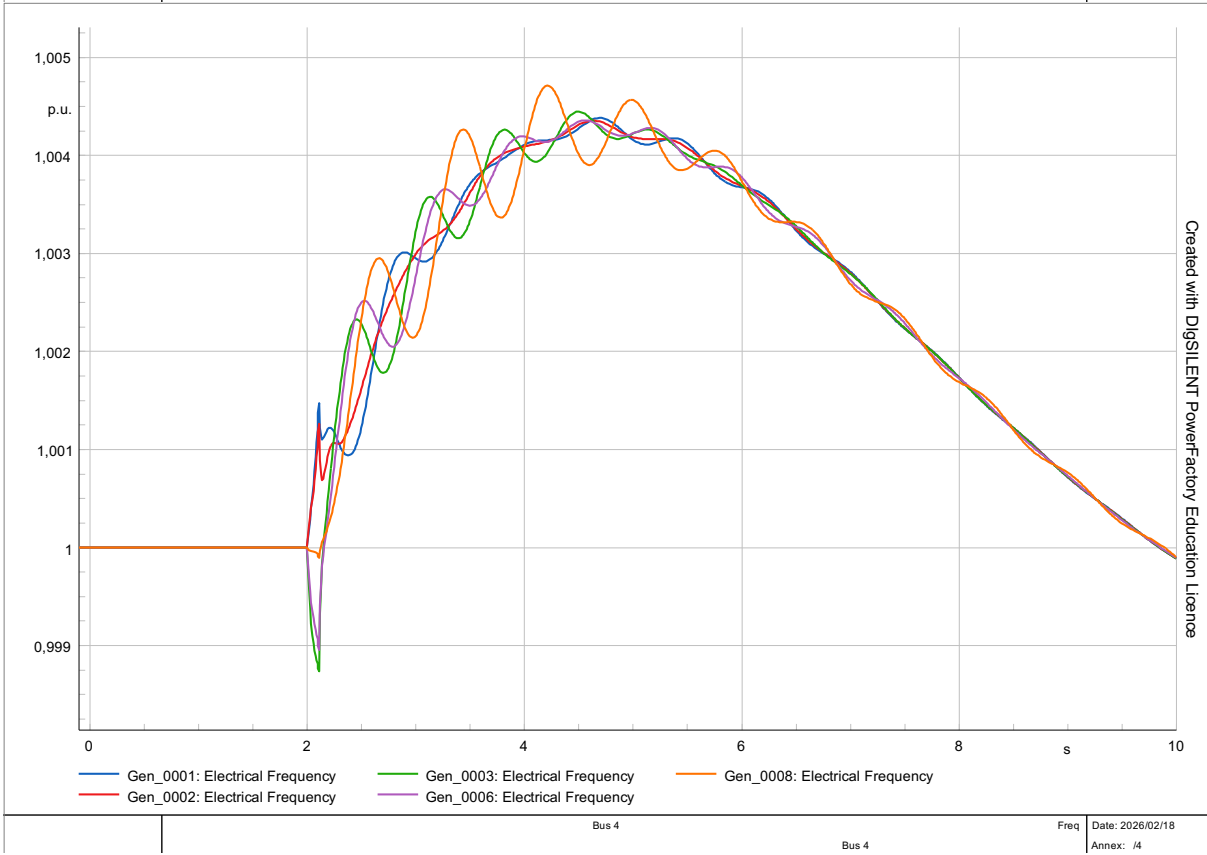
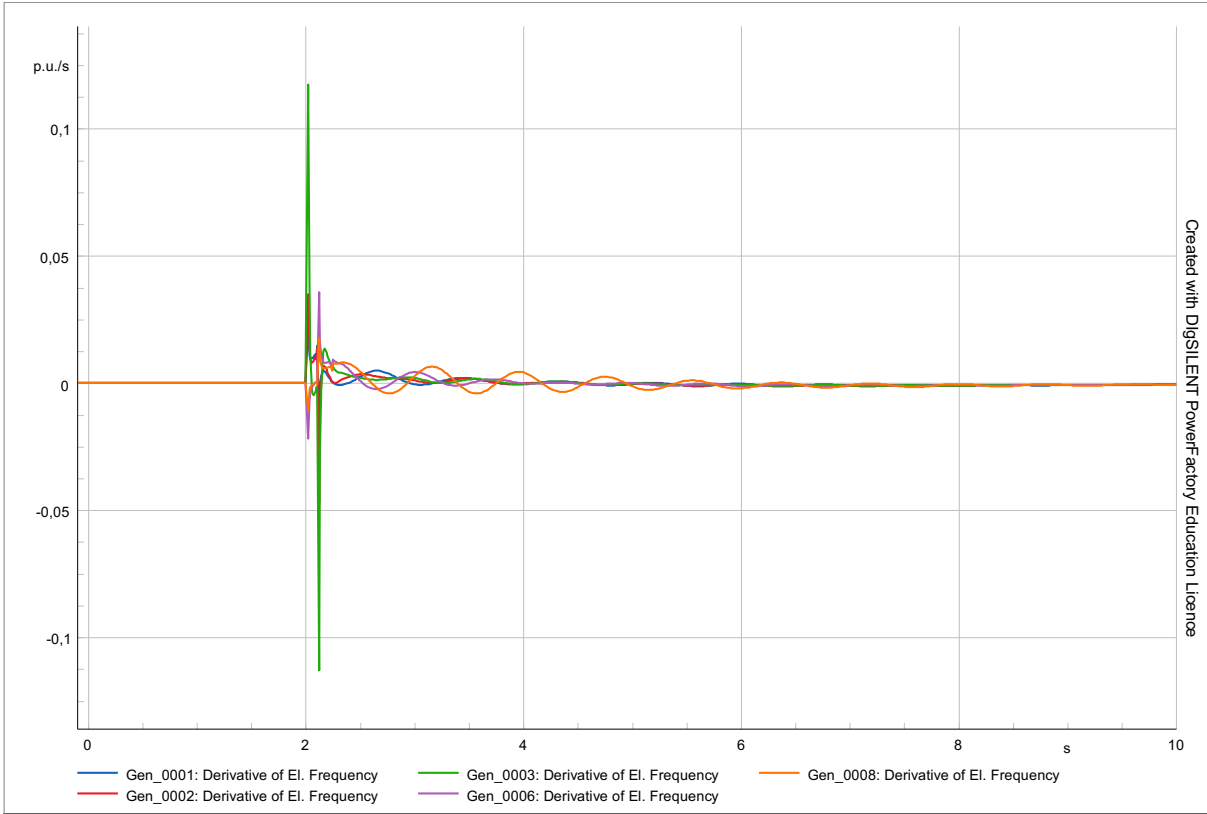
Case: Earth Fault

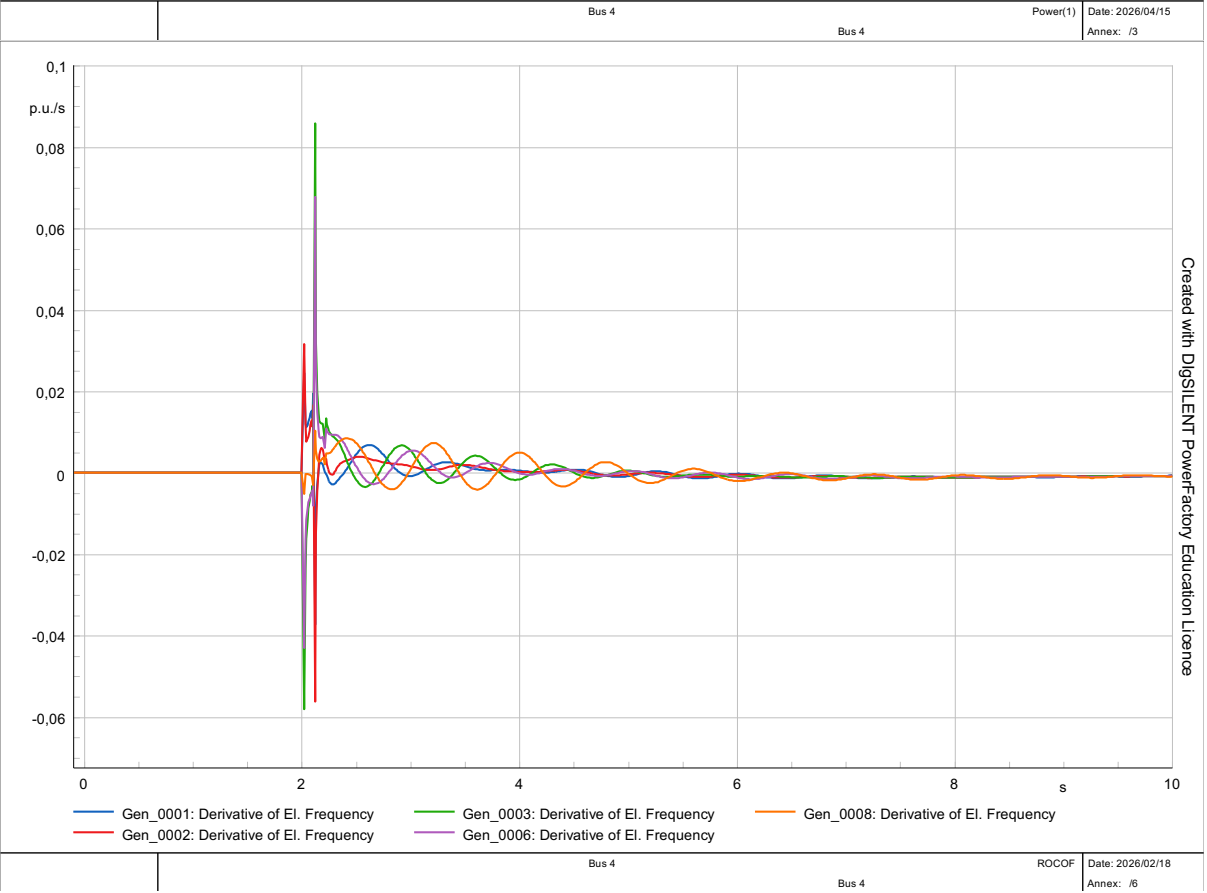
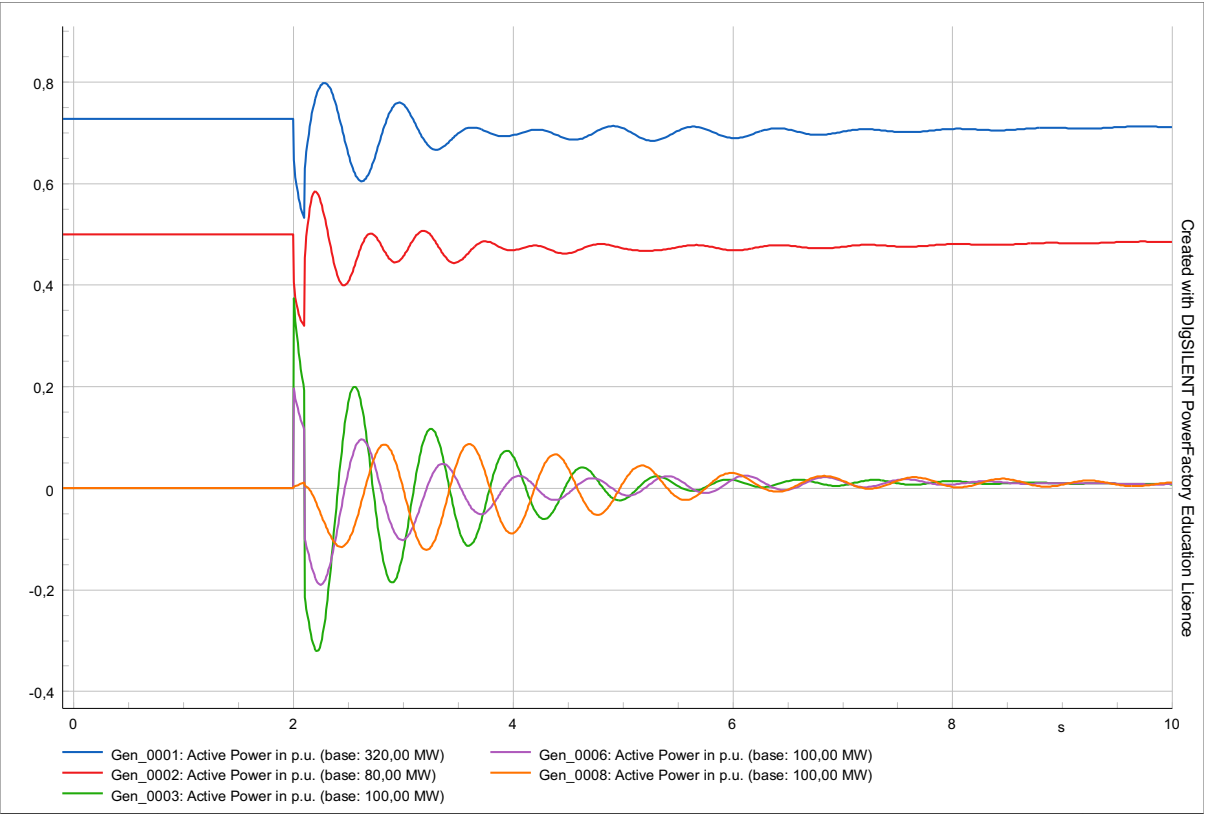


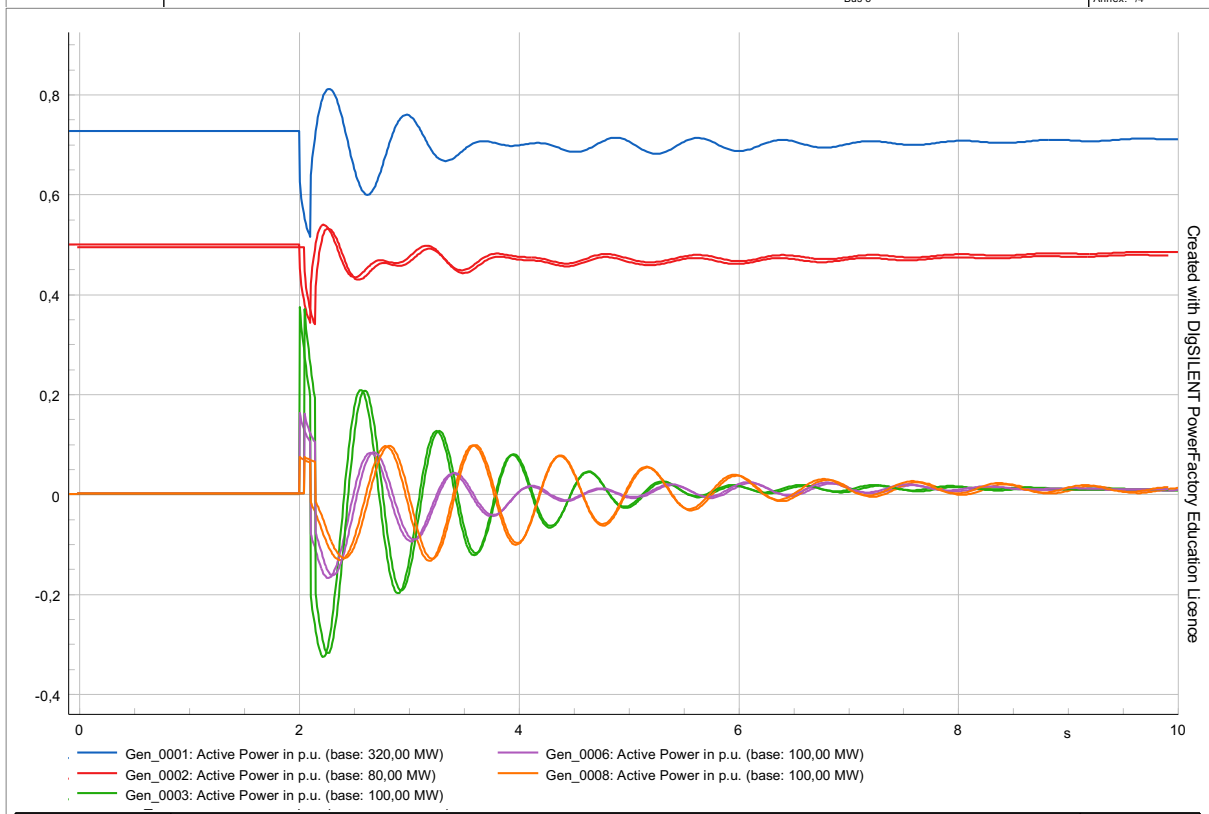
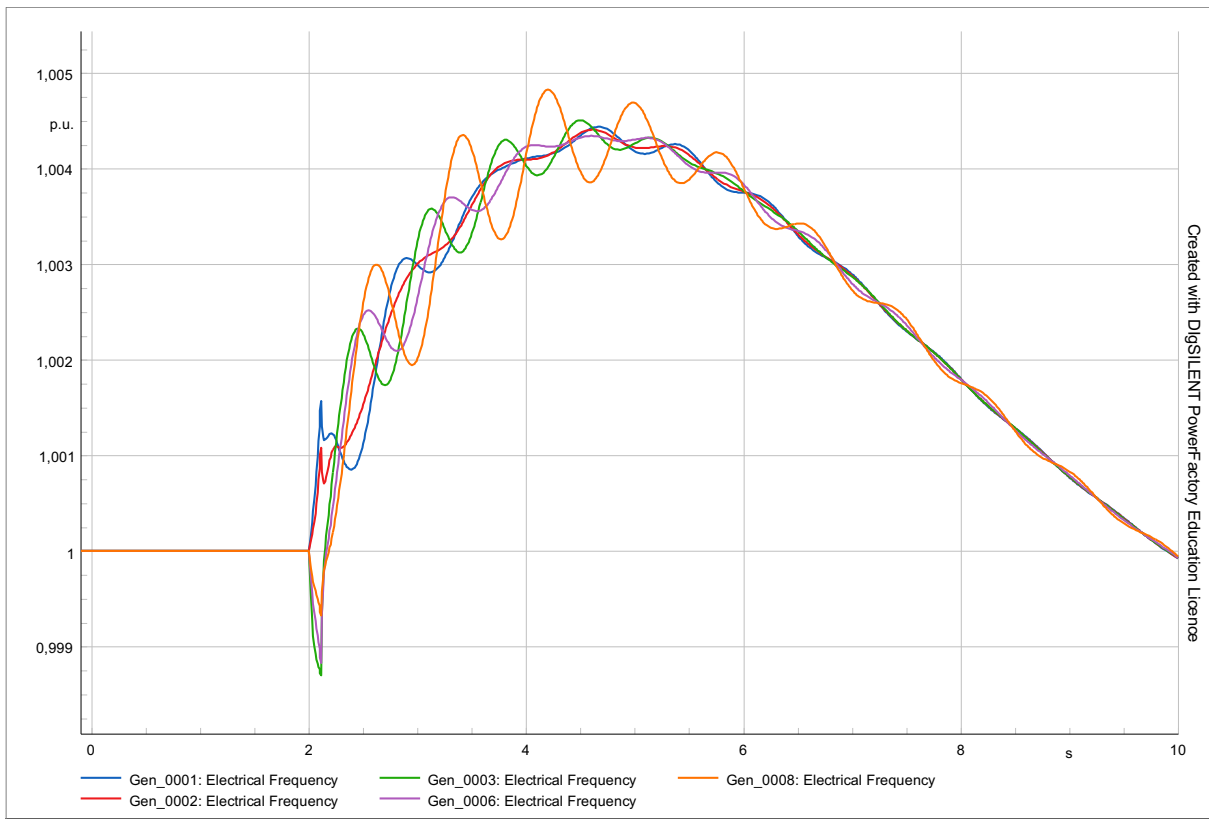


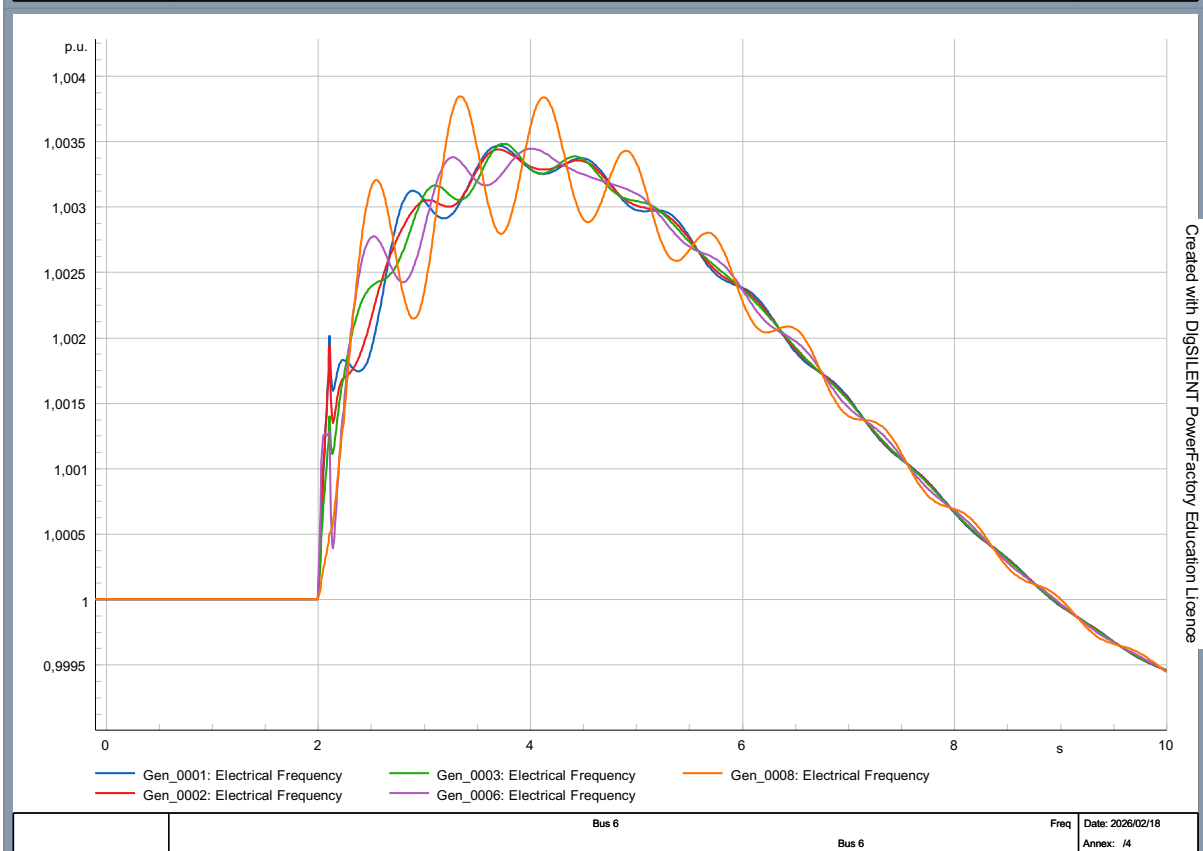
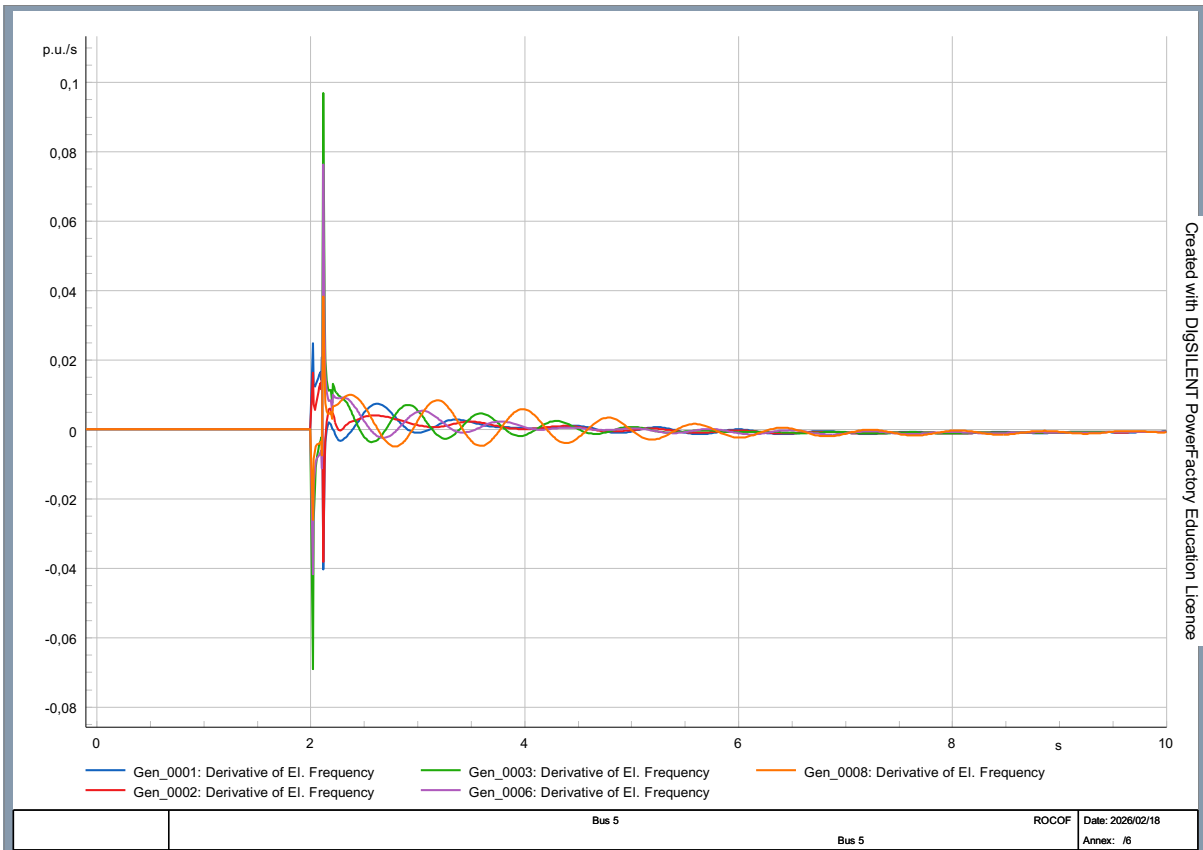


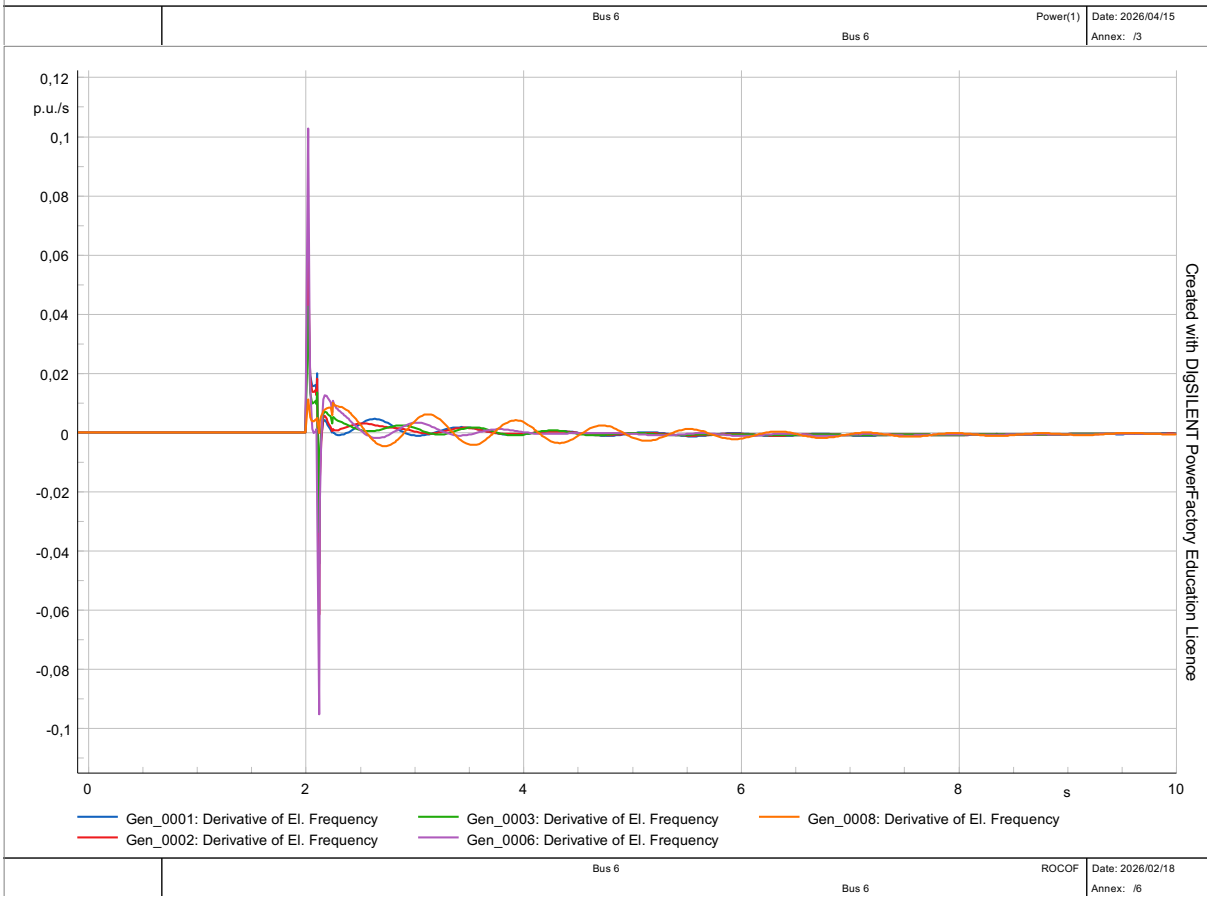
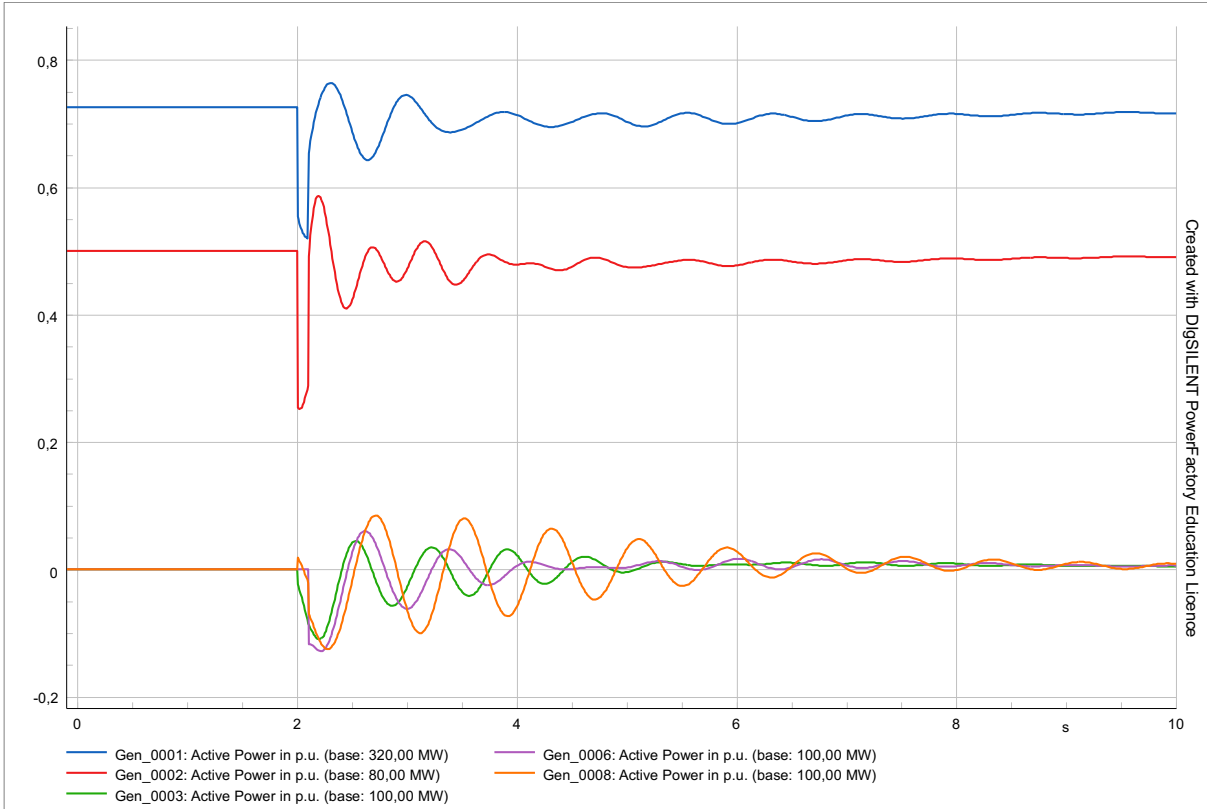


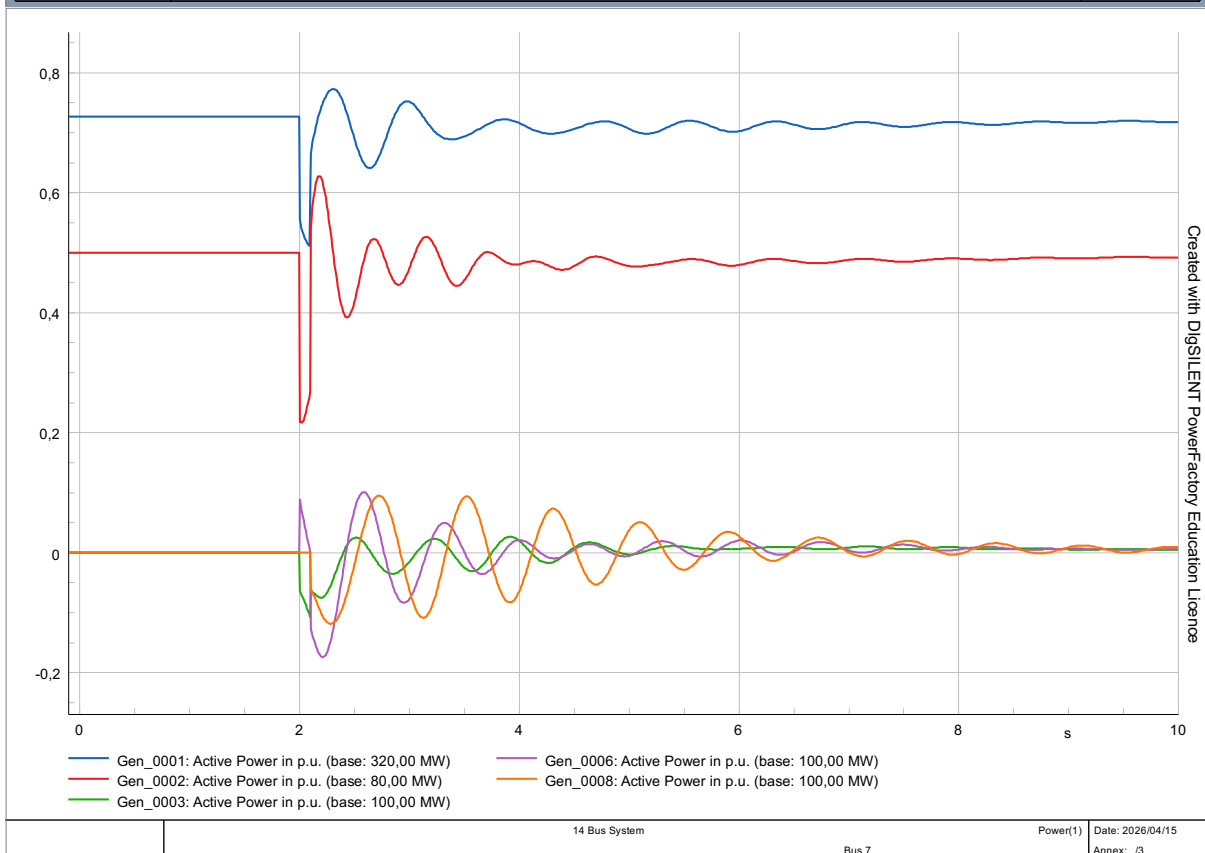
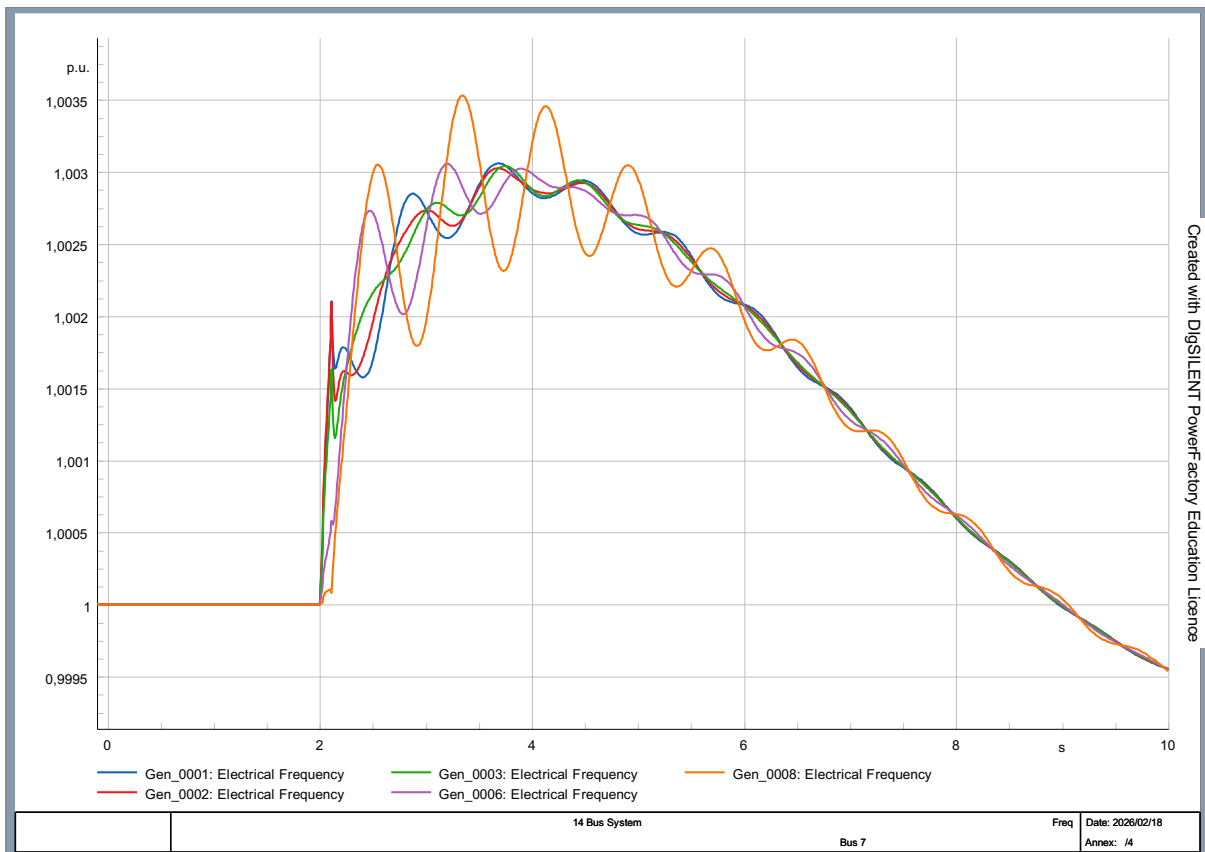


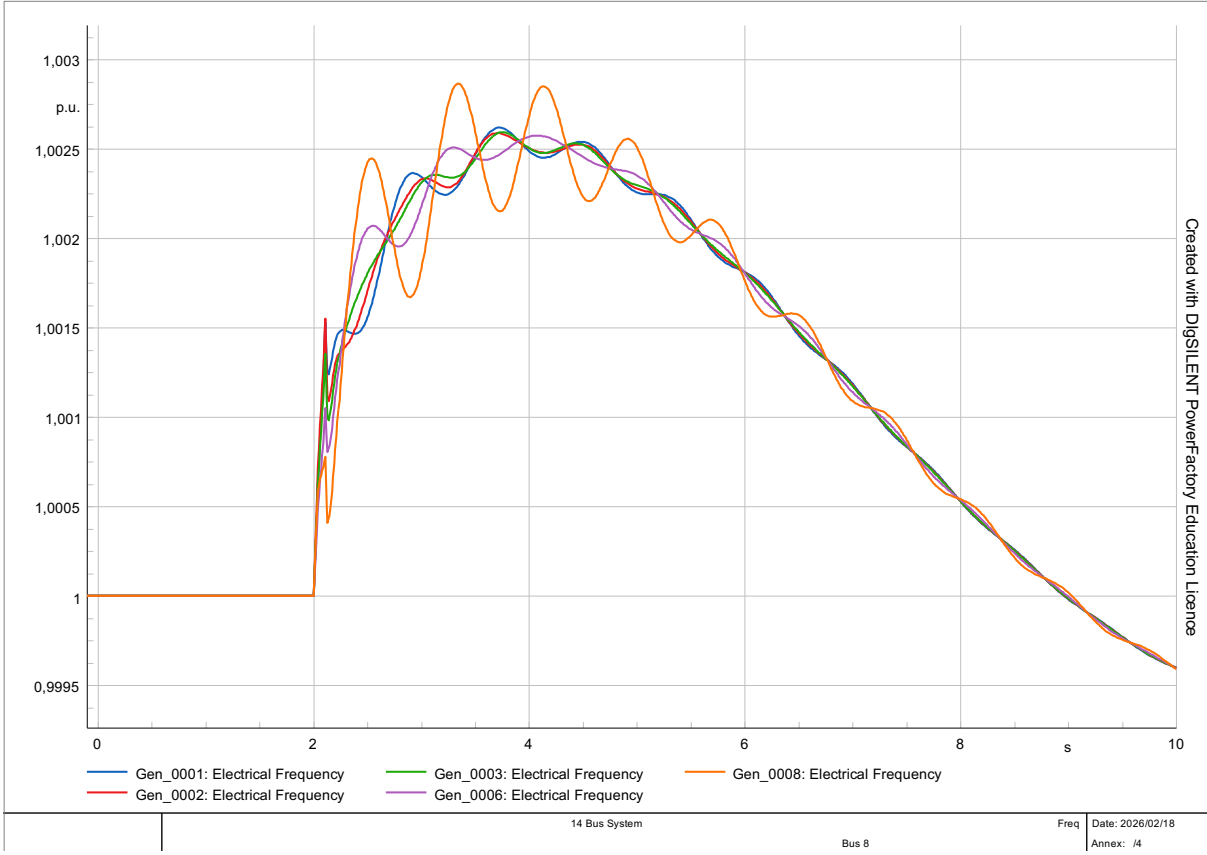
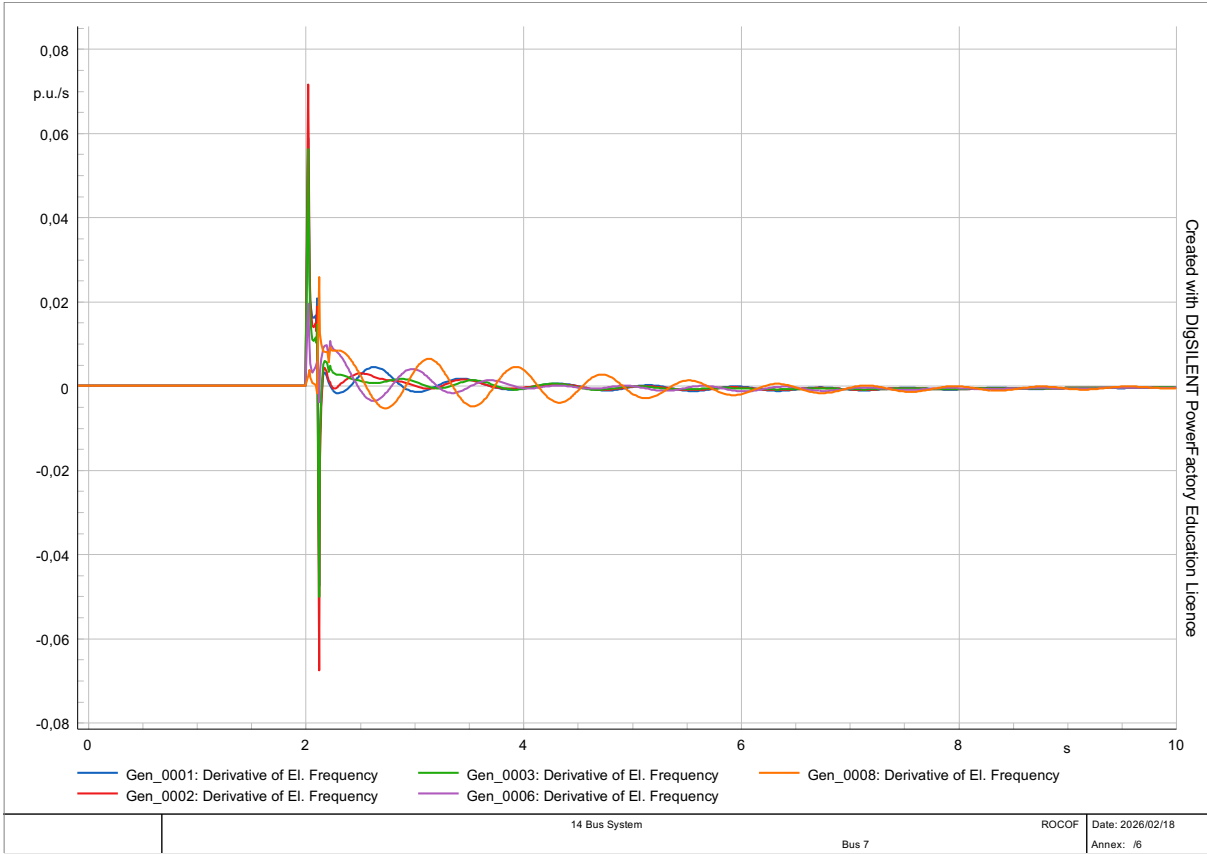


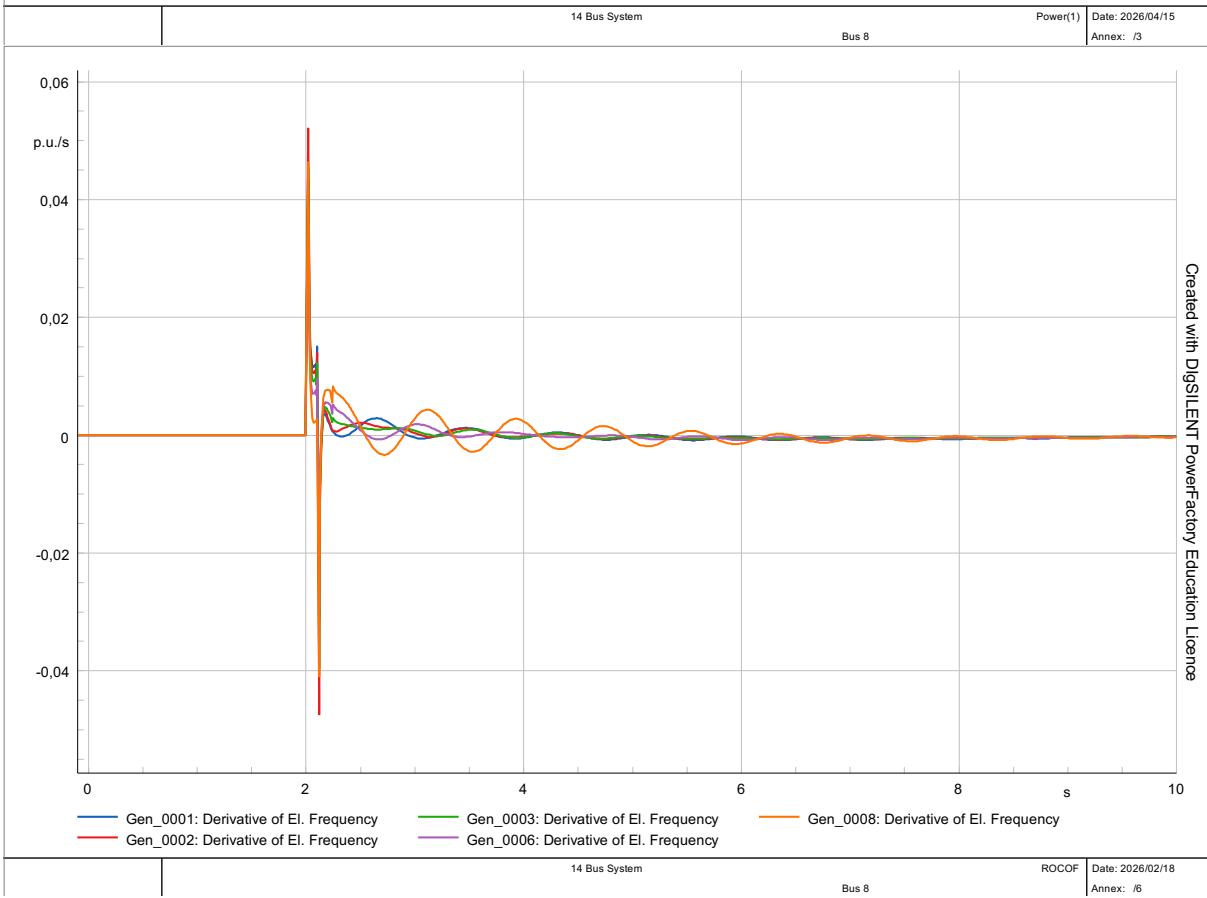
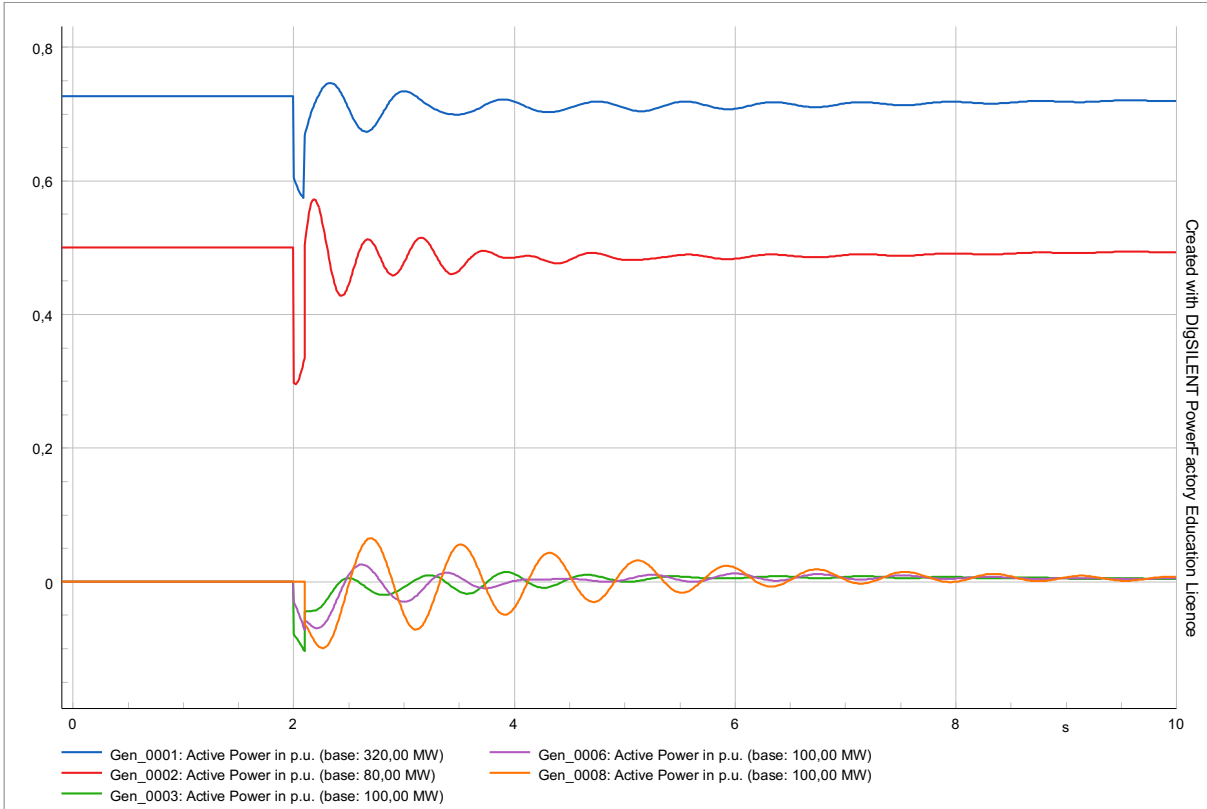


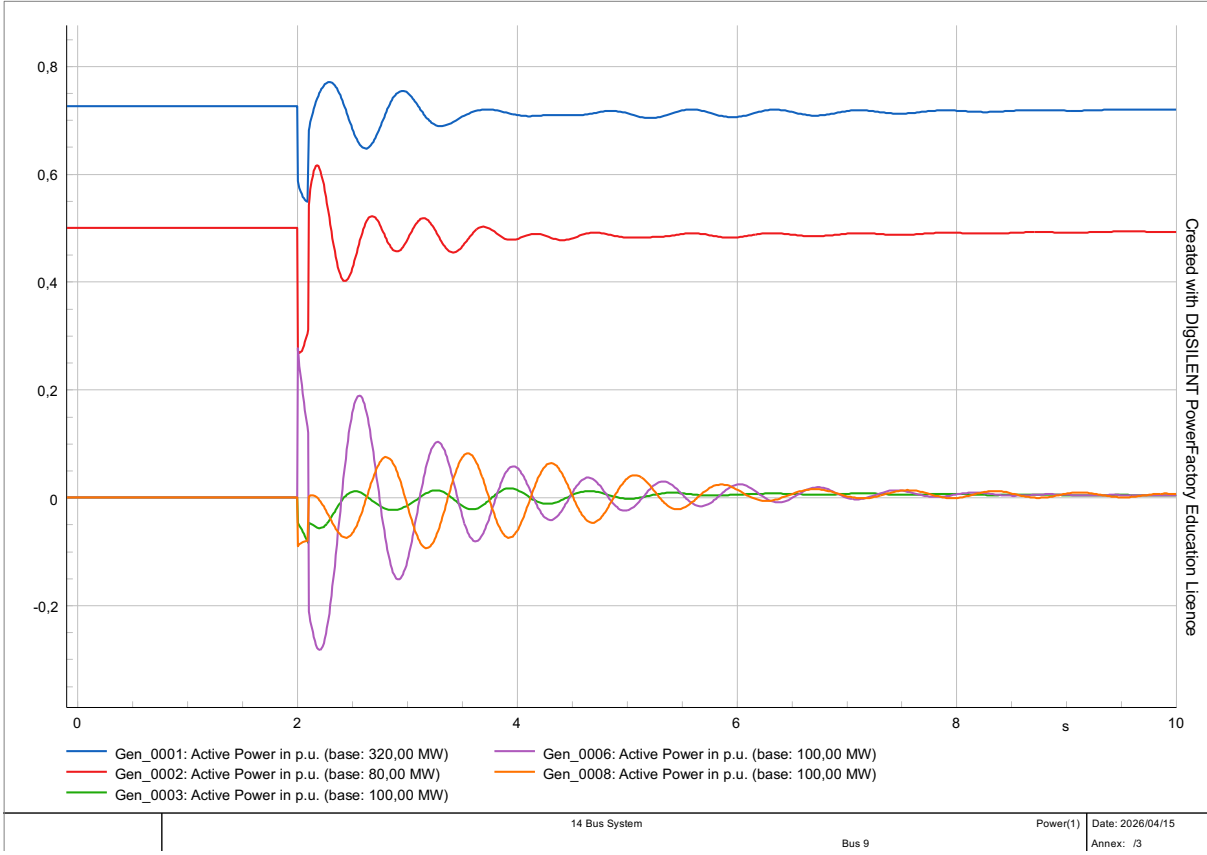
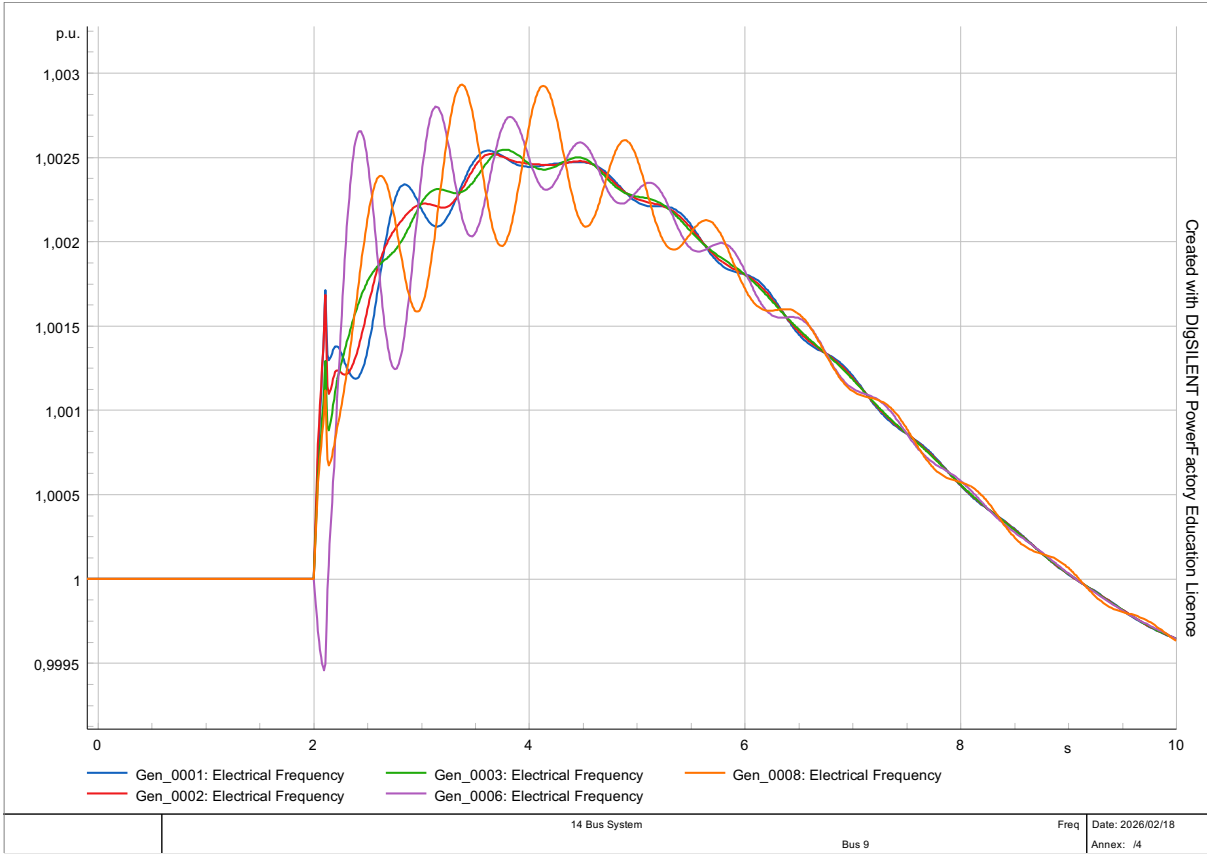


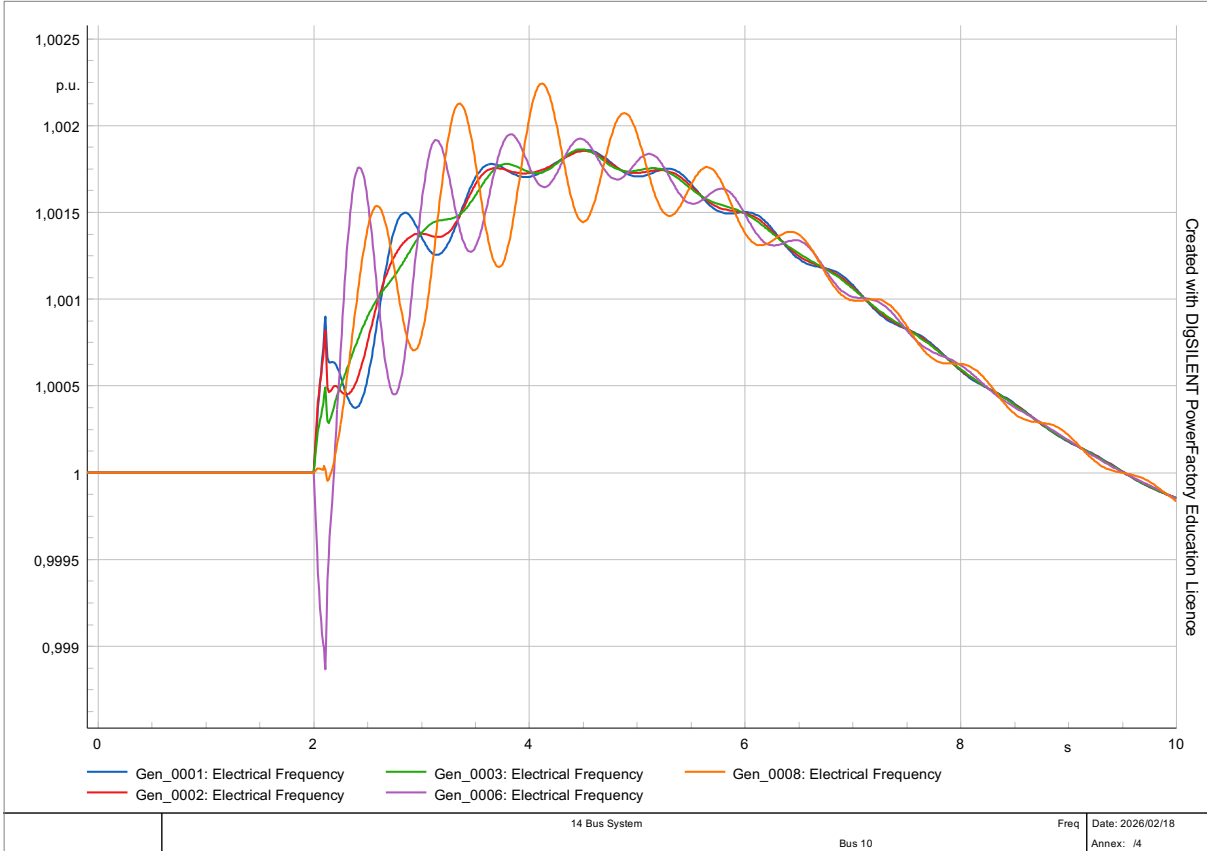
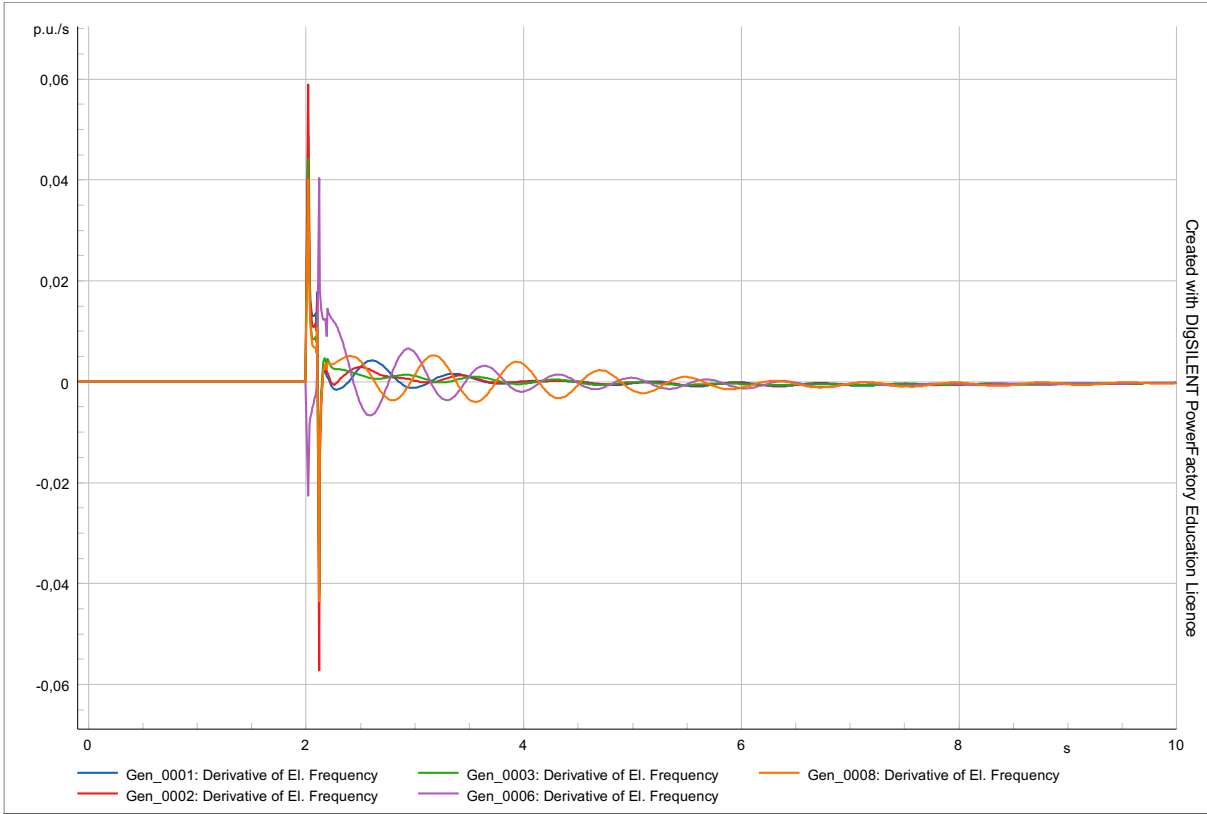


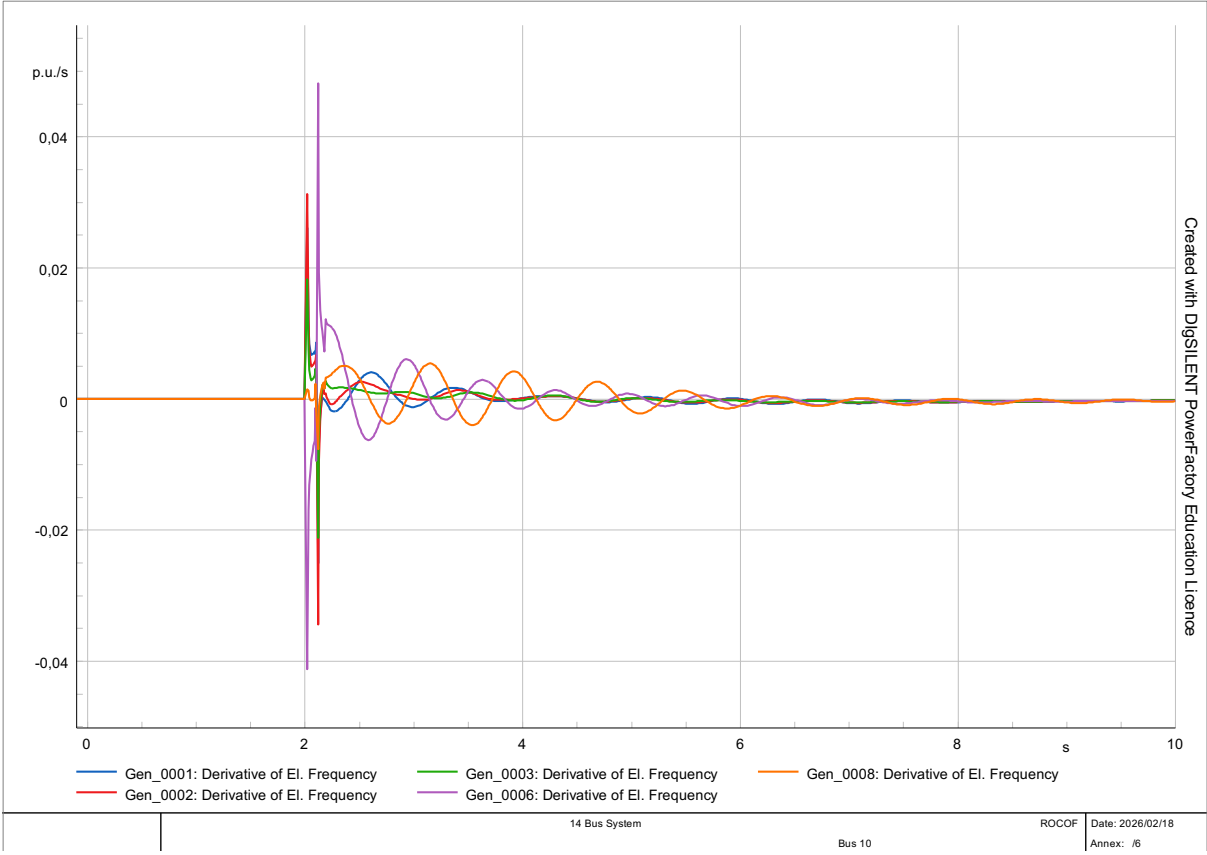
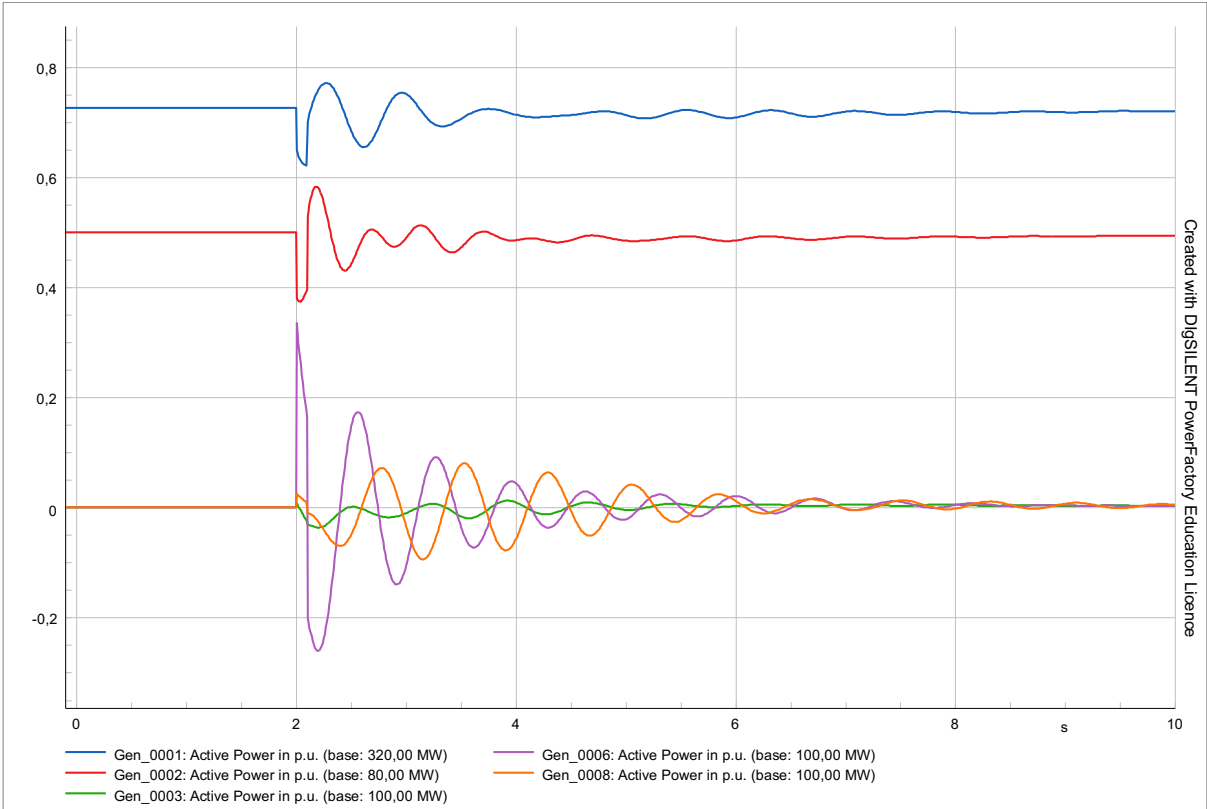


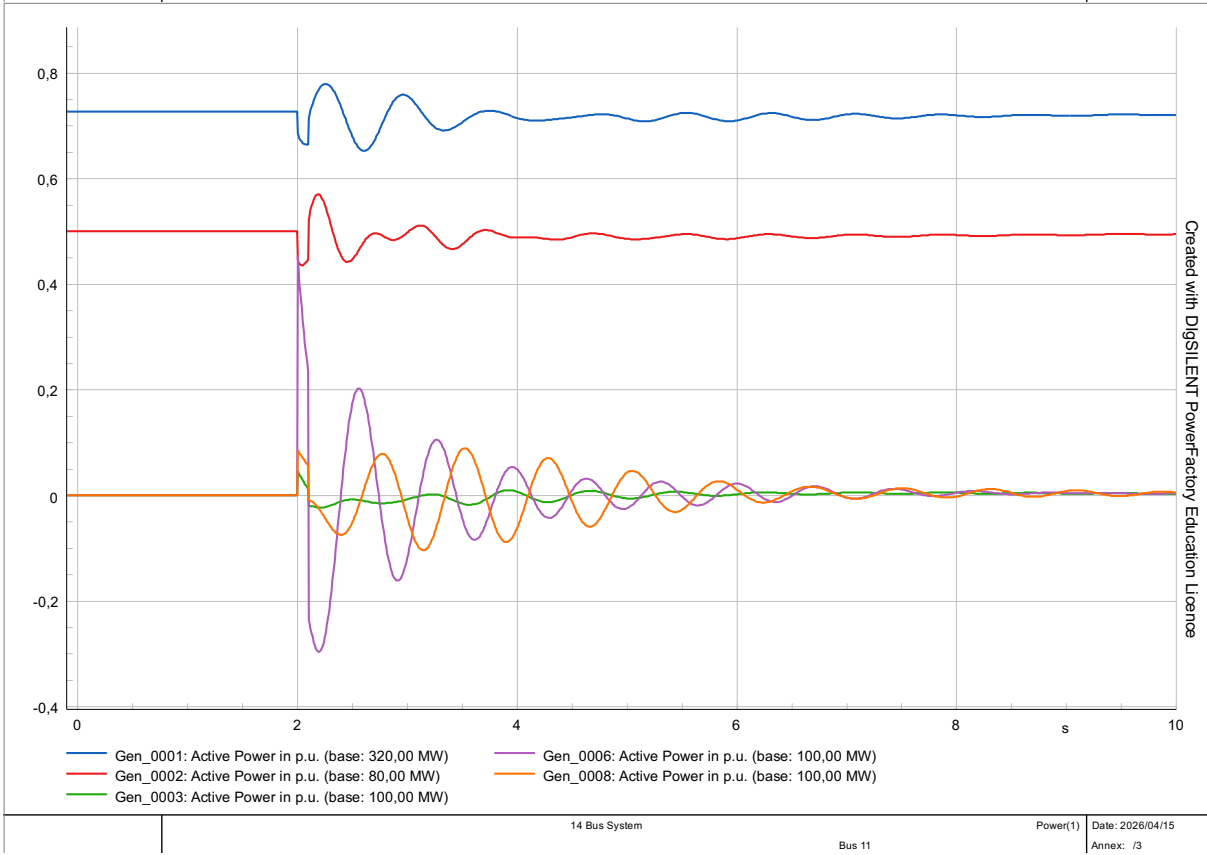
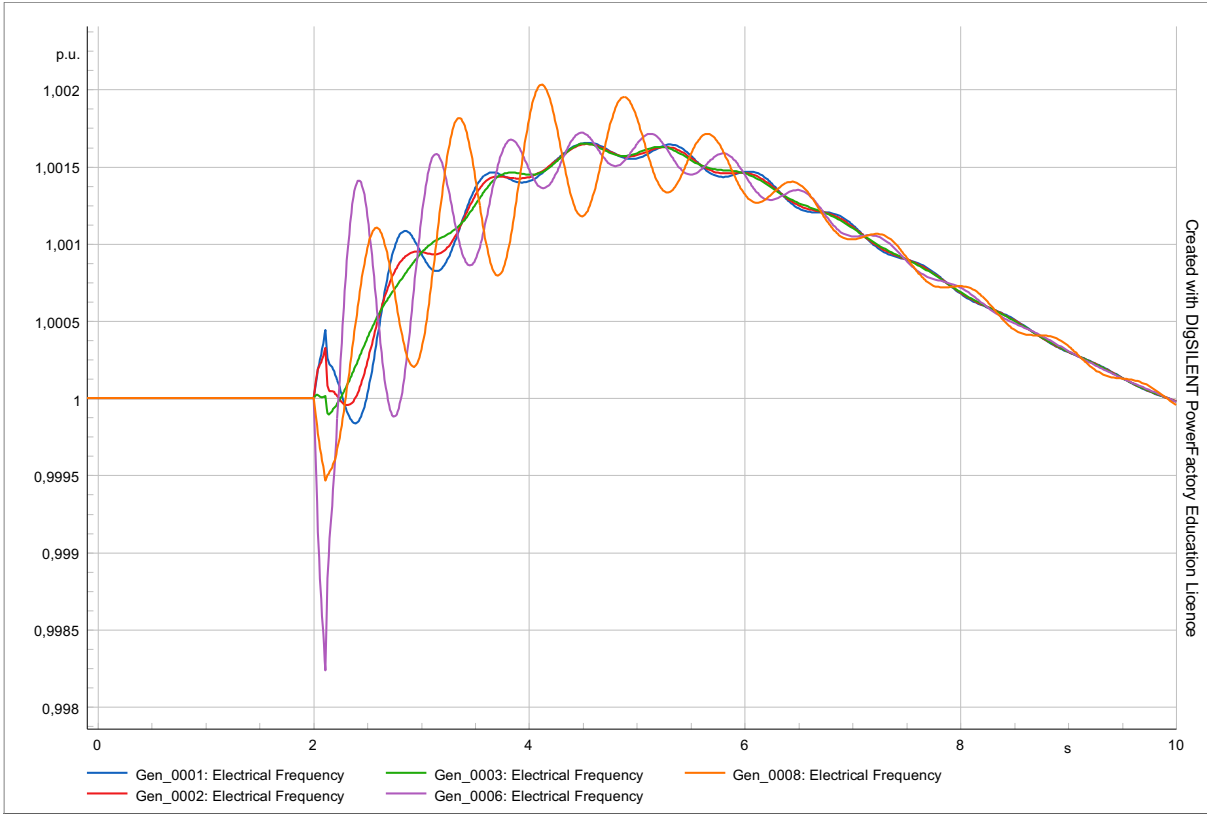


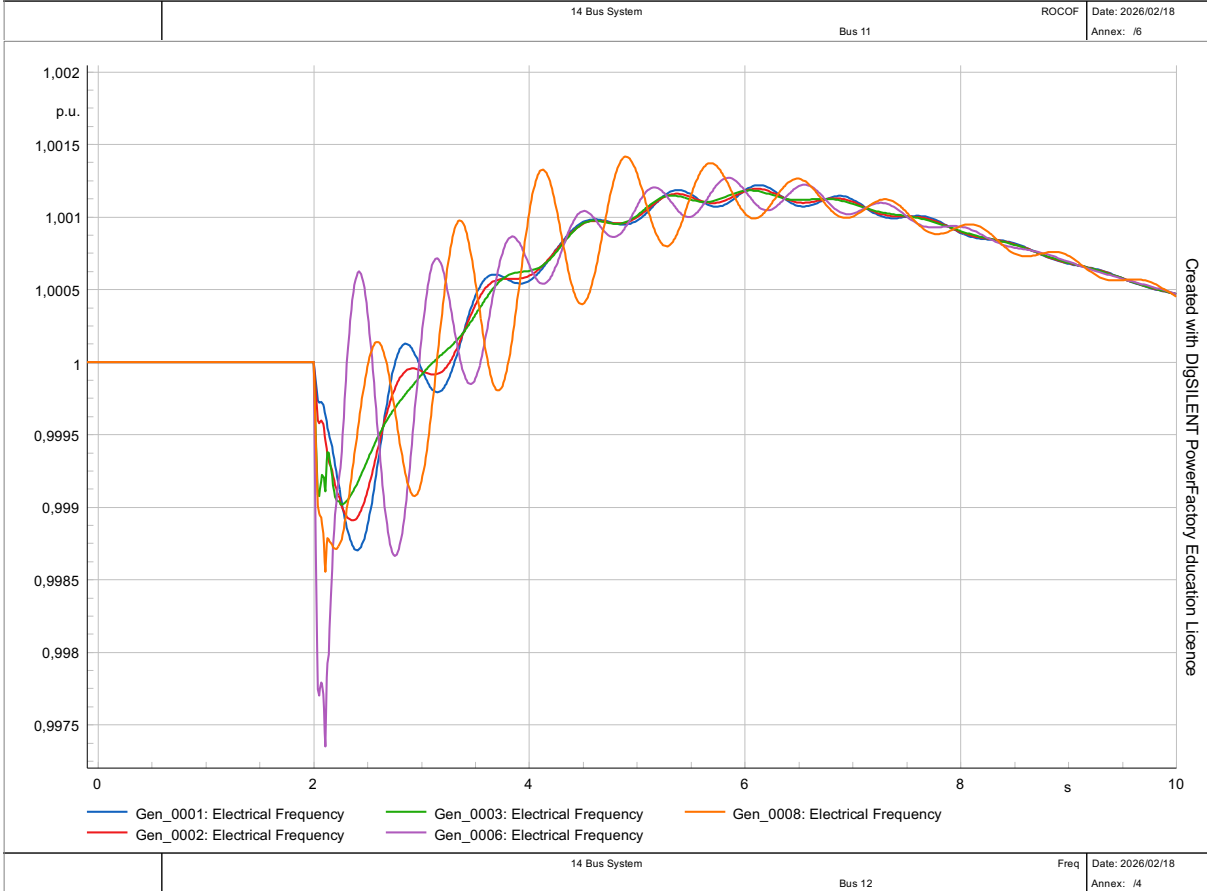
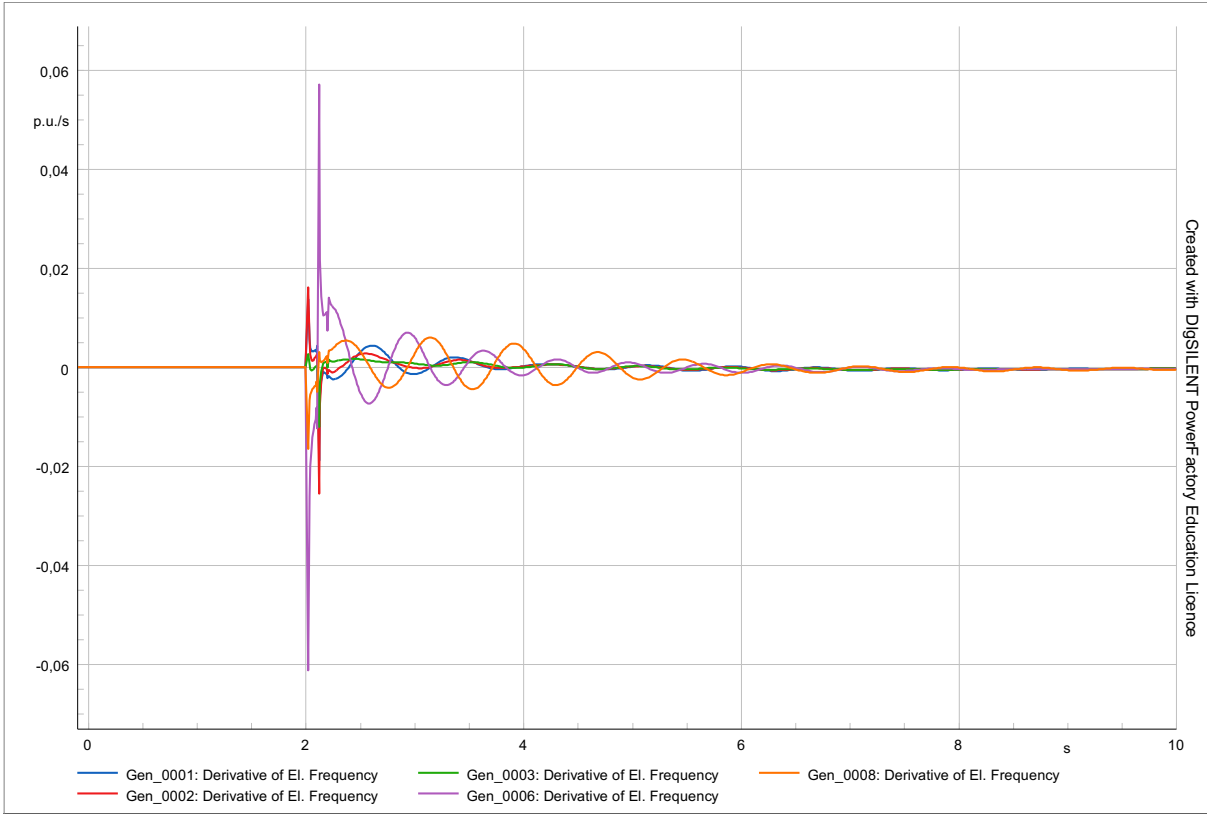


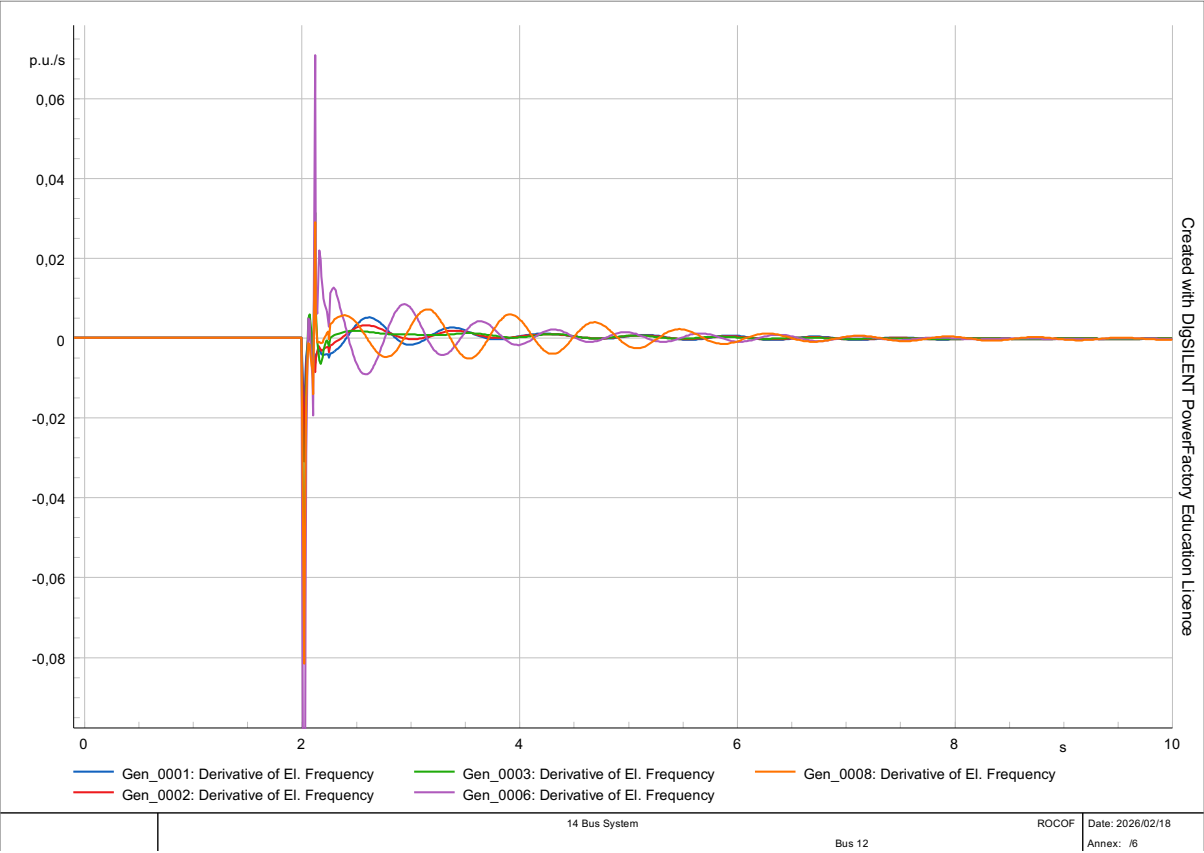
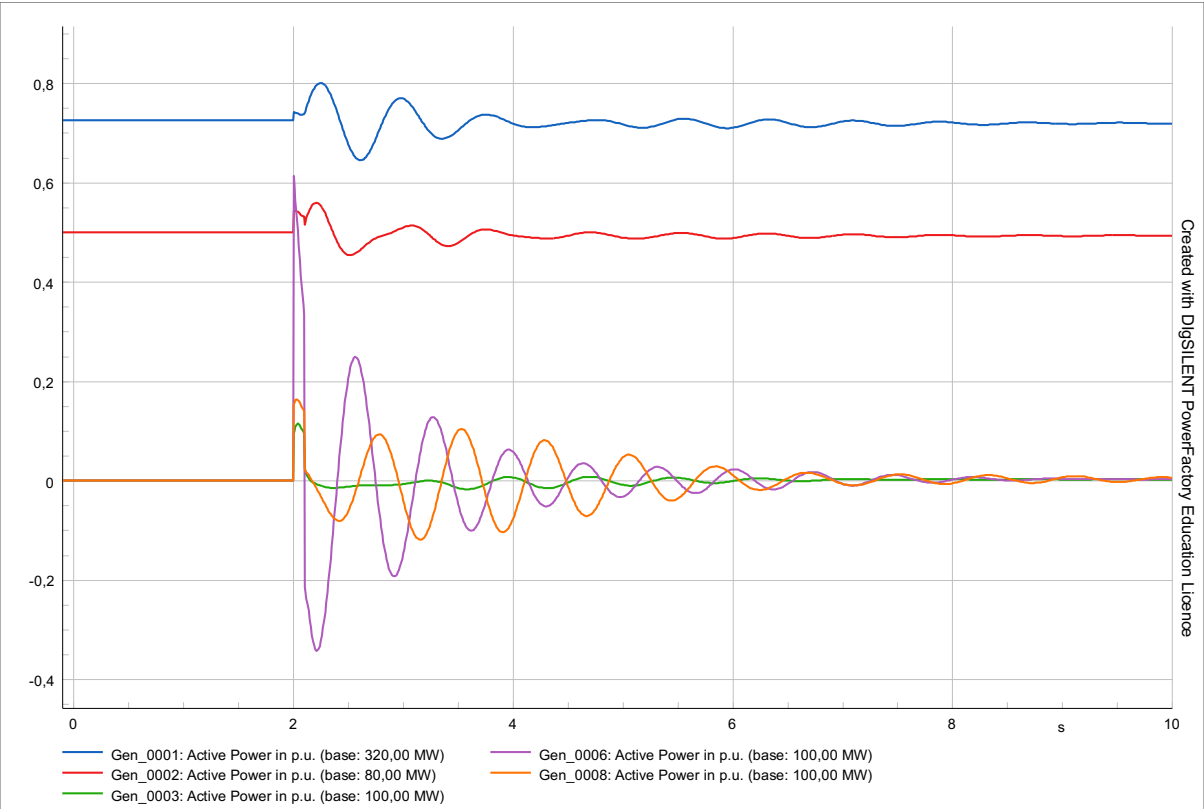


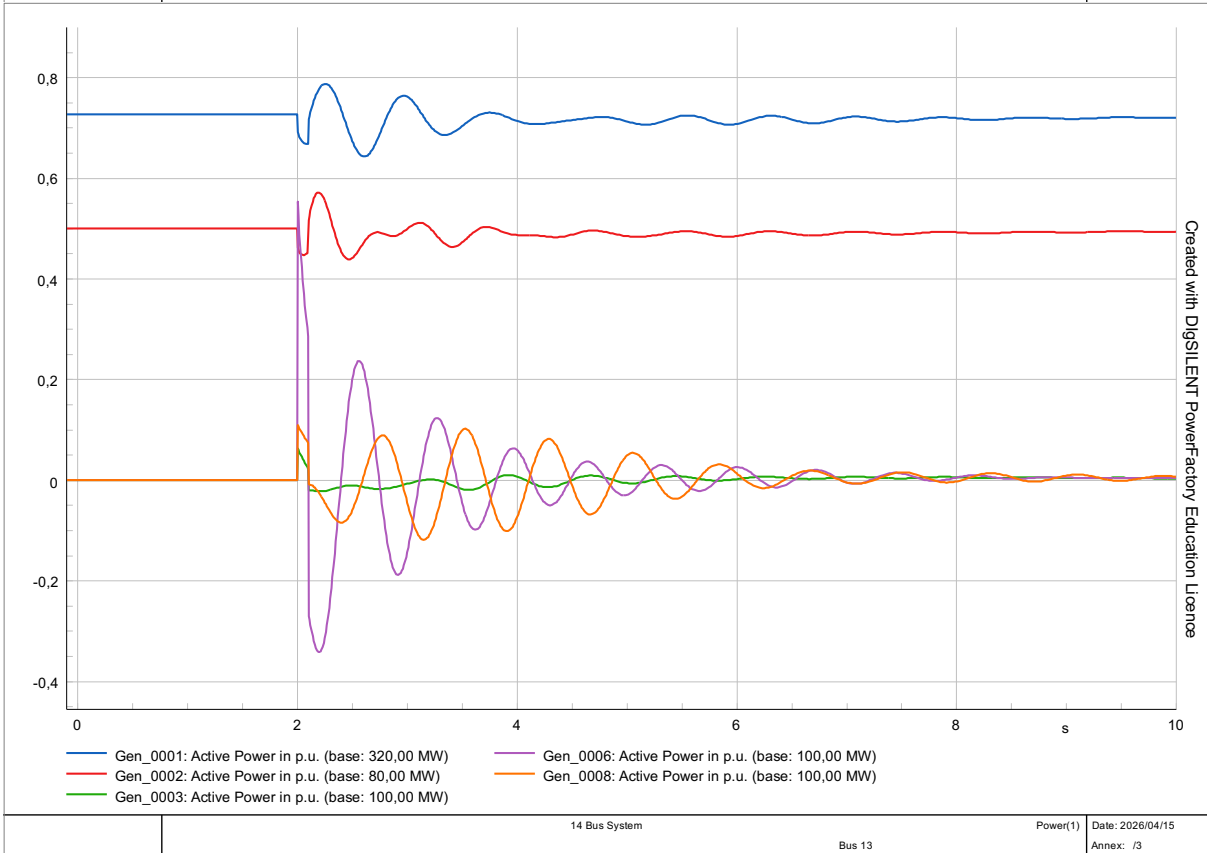
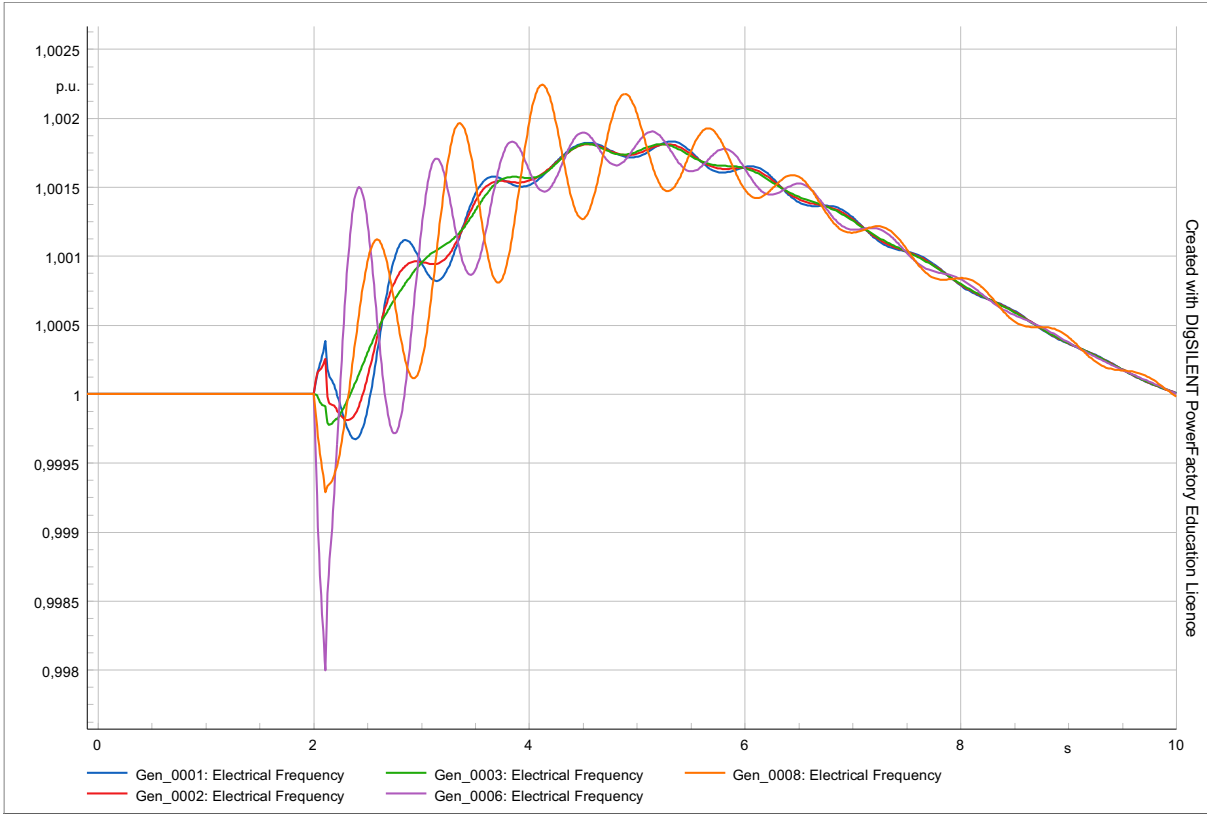


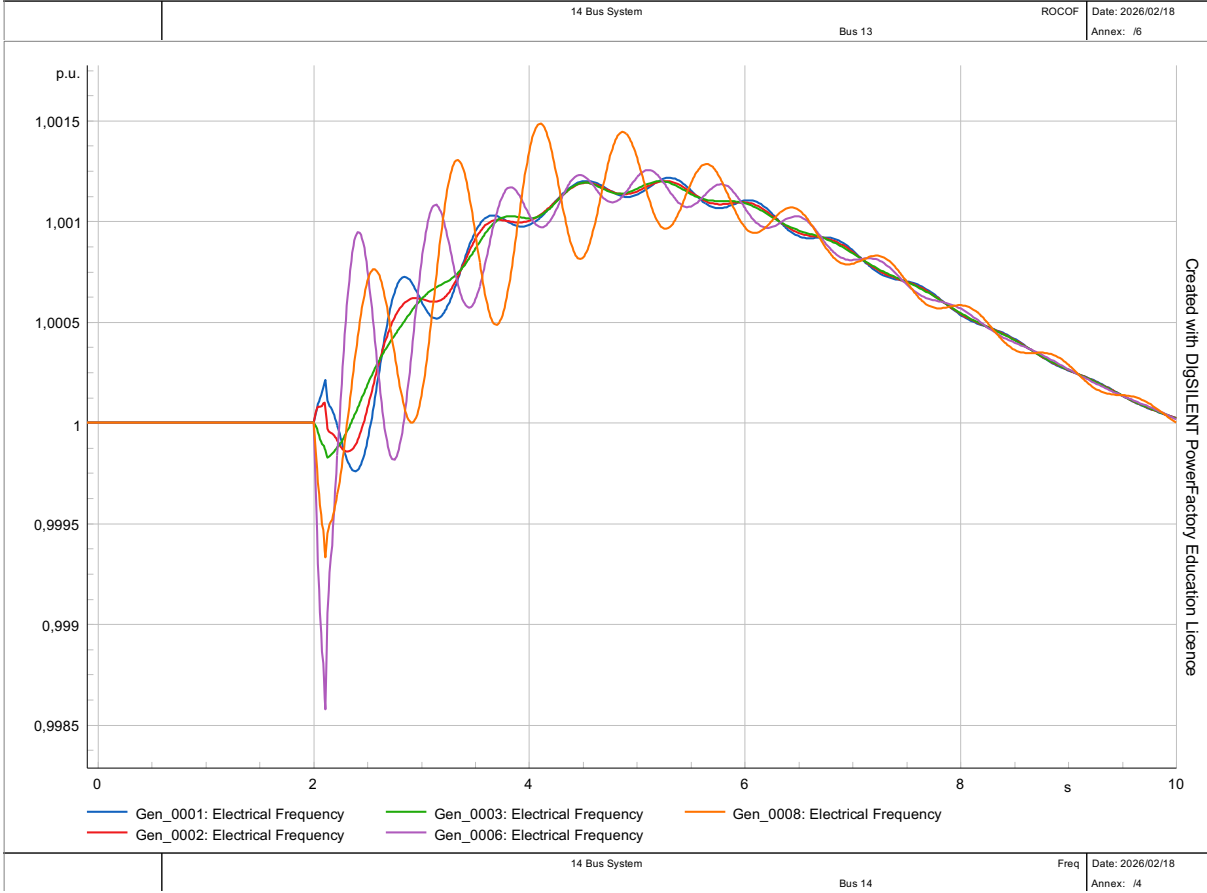
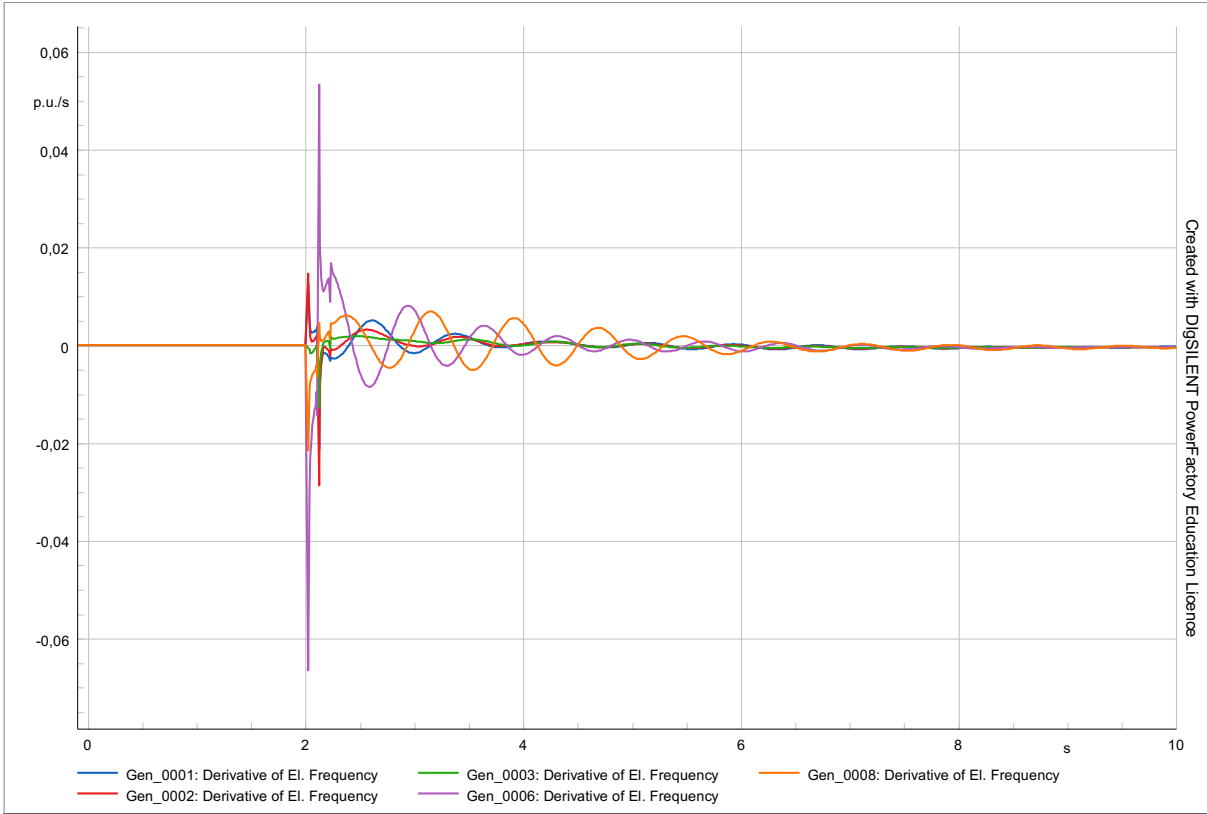


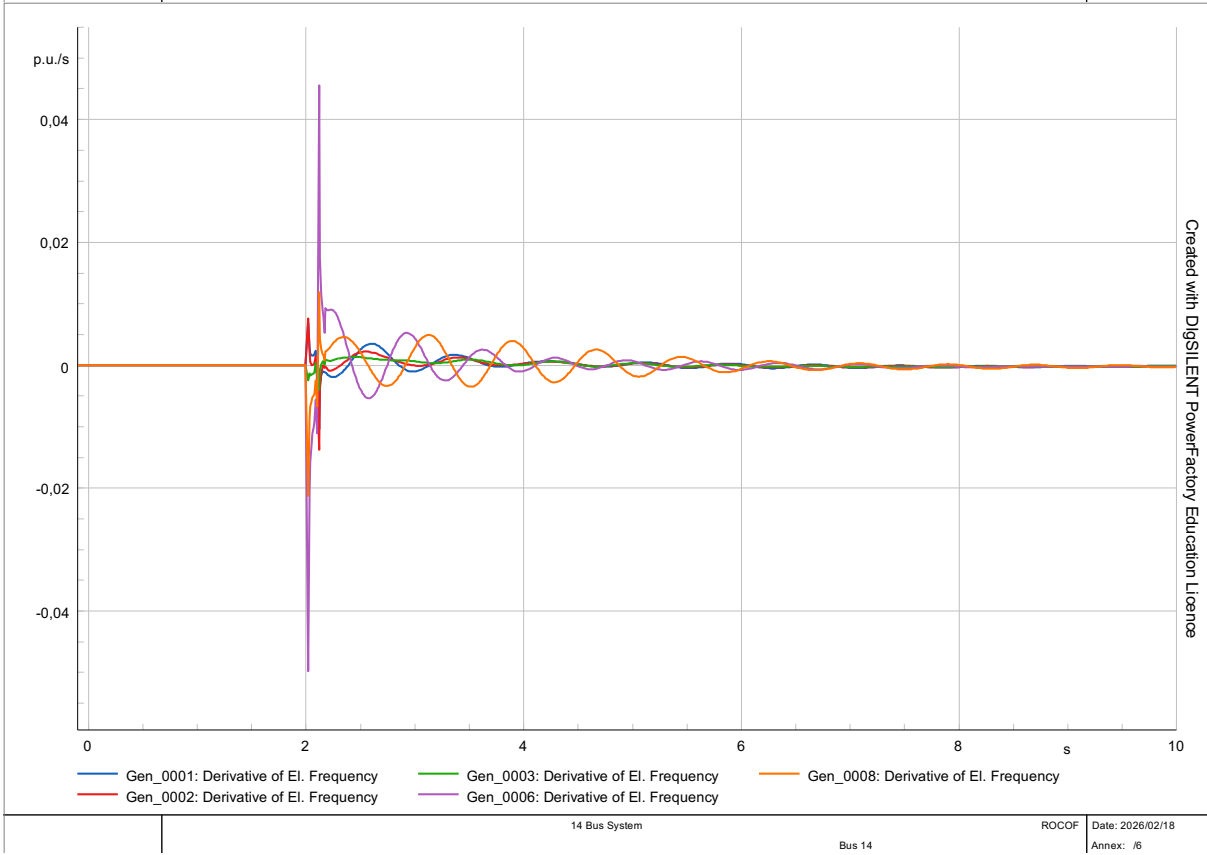
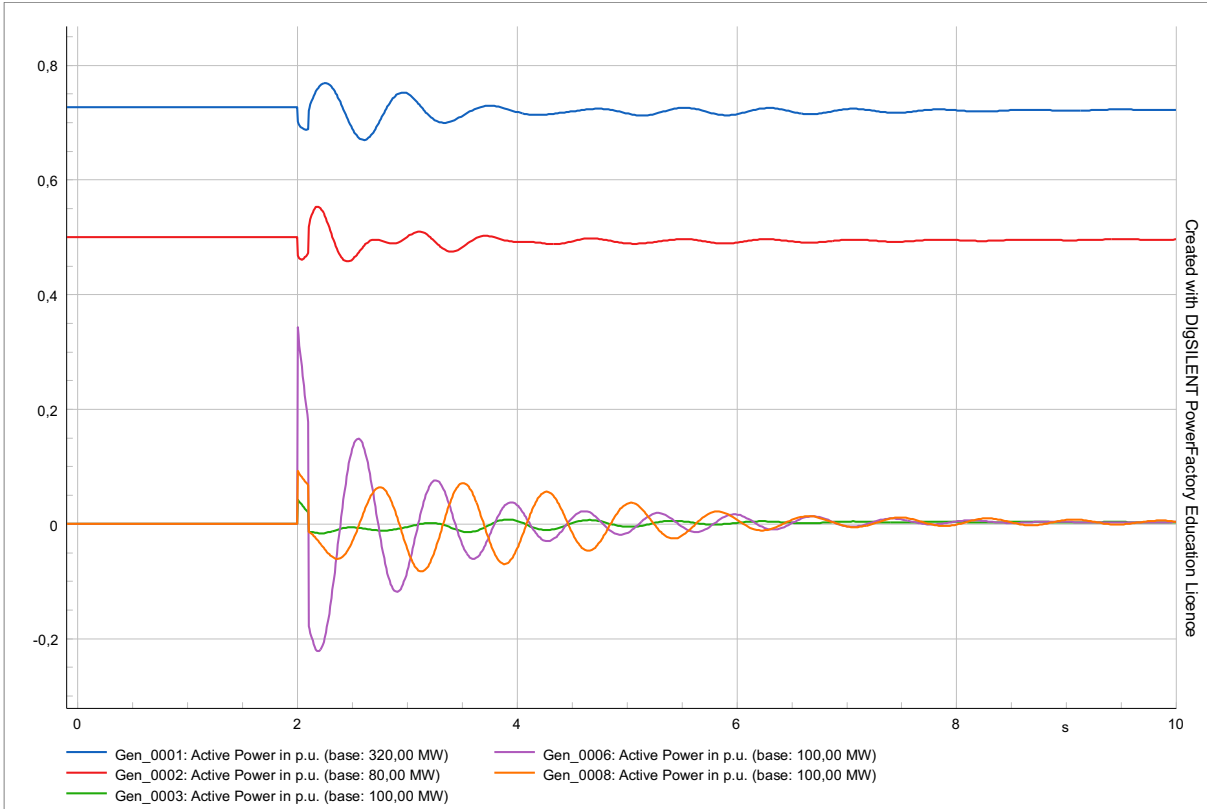




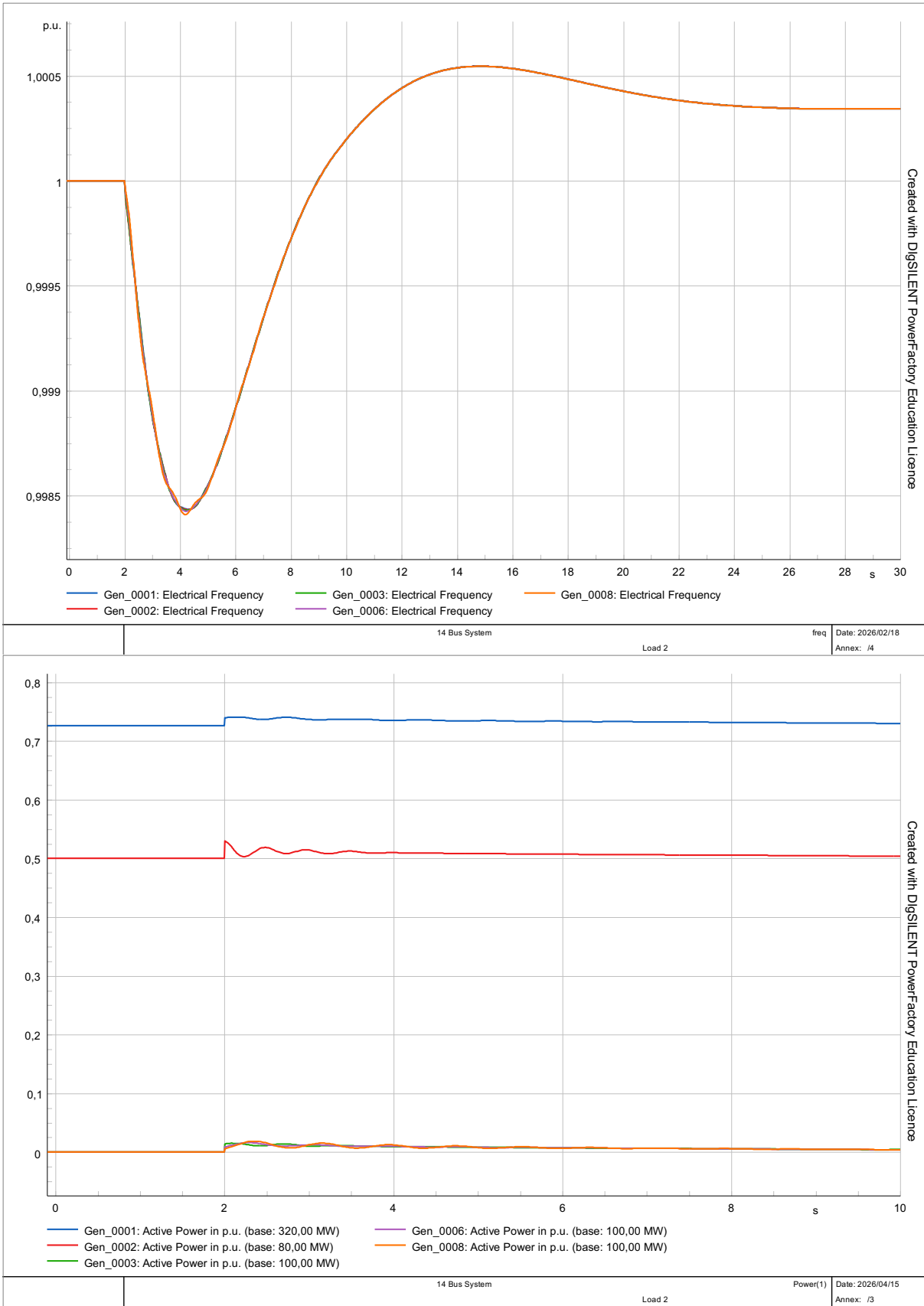


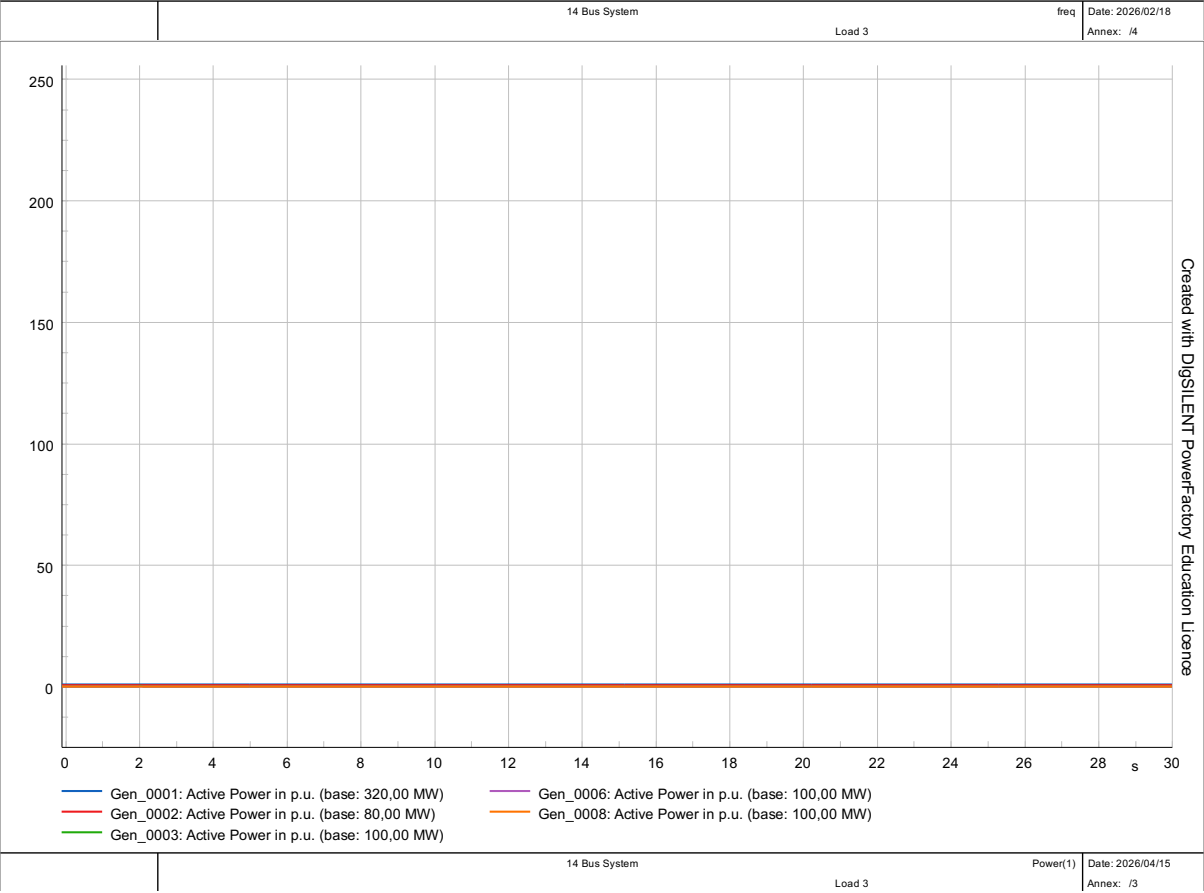
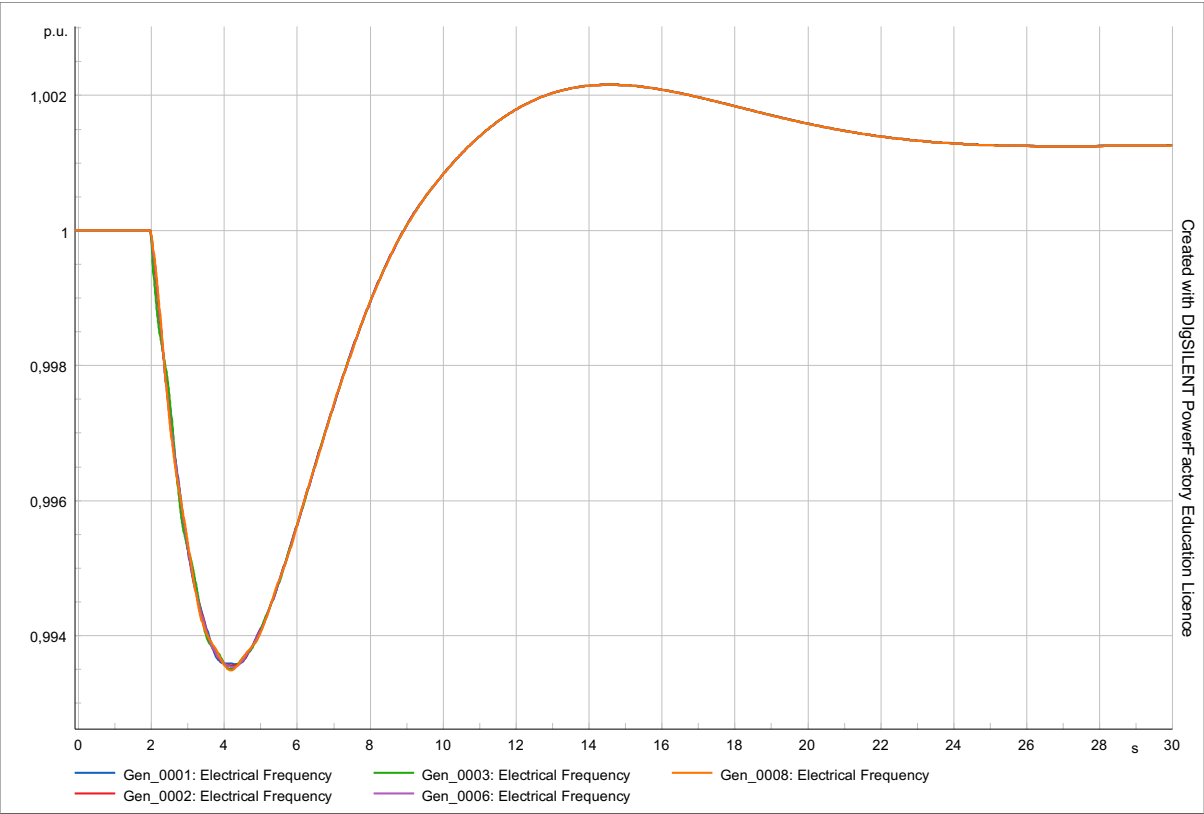


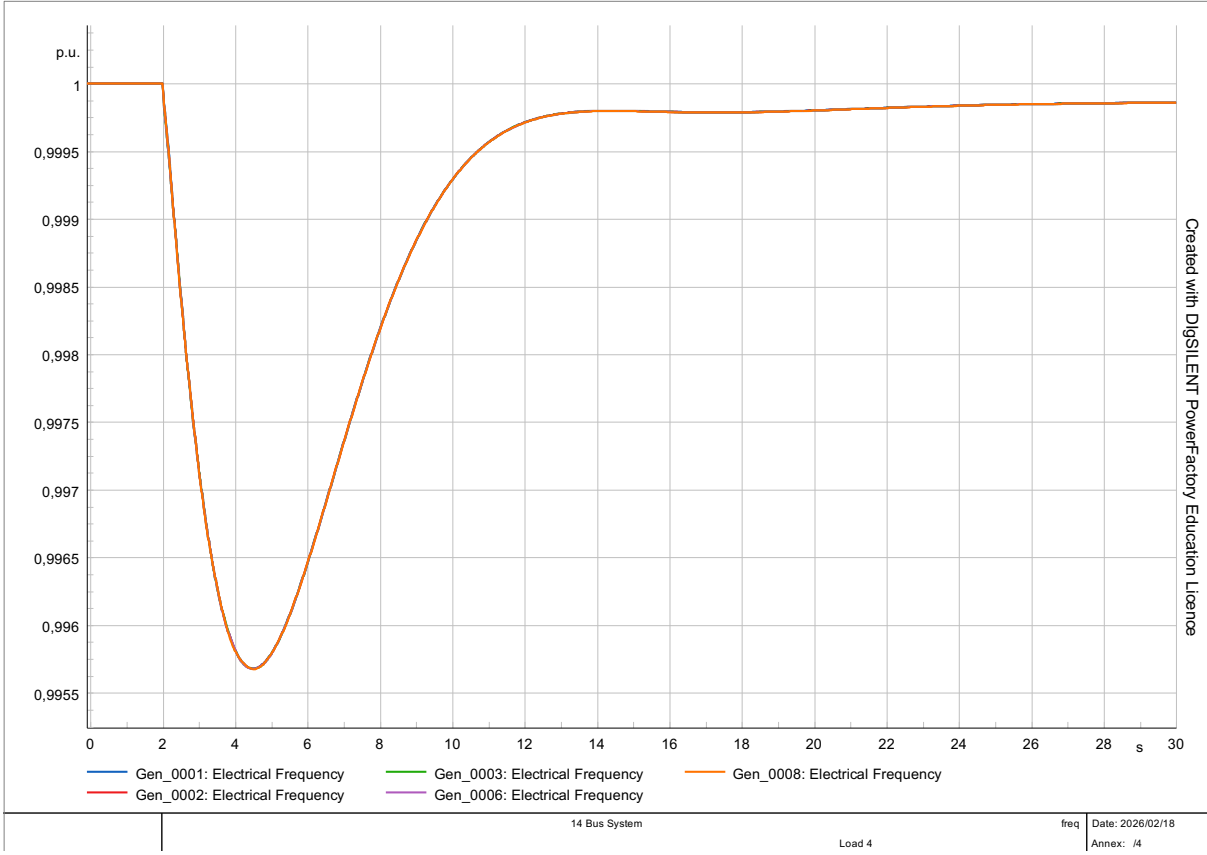
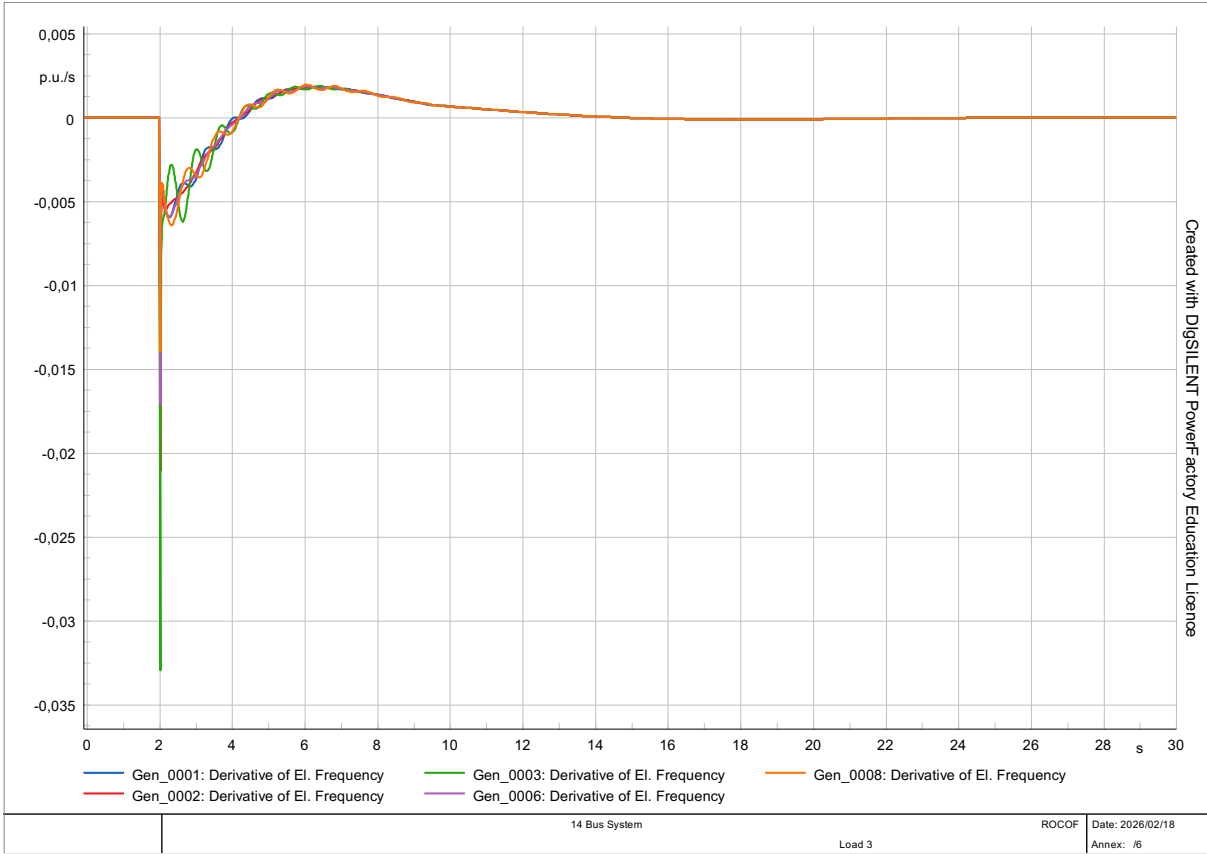


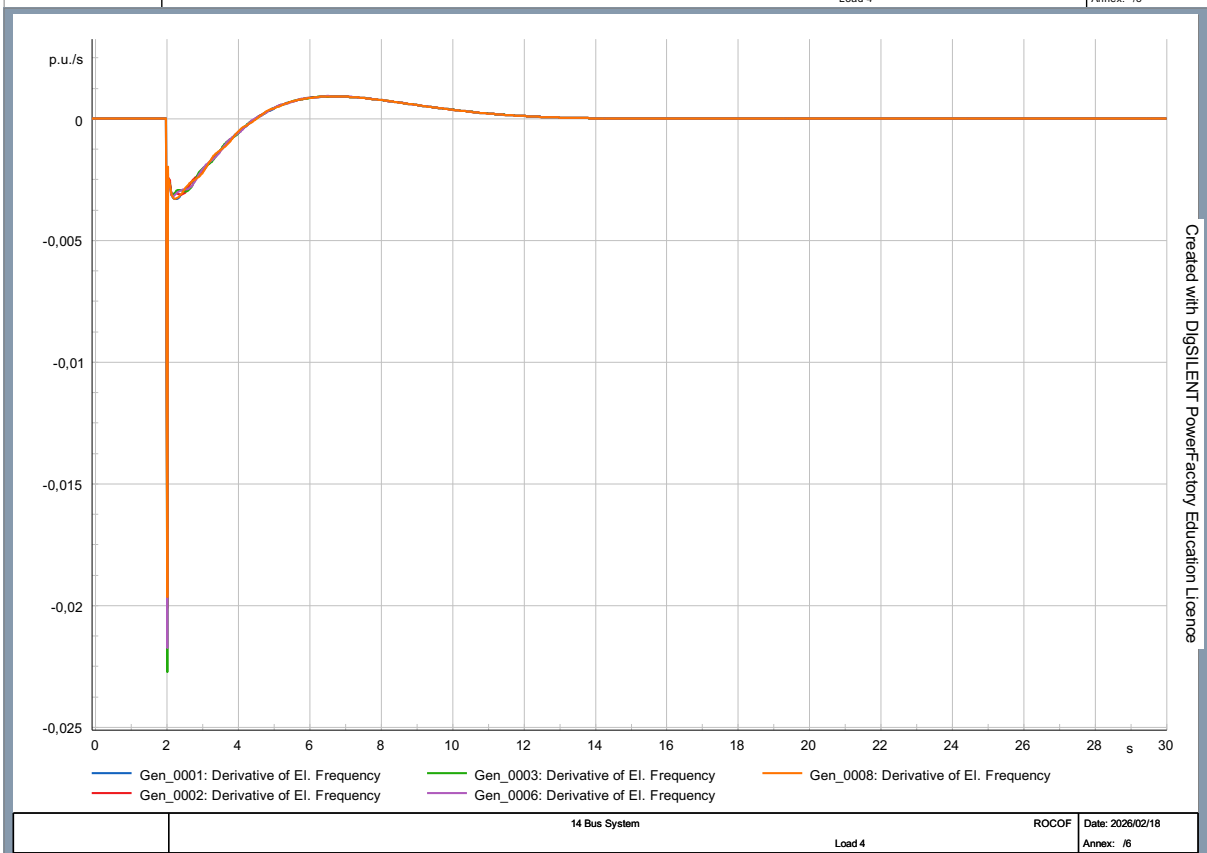
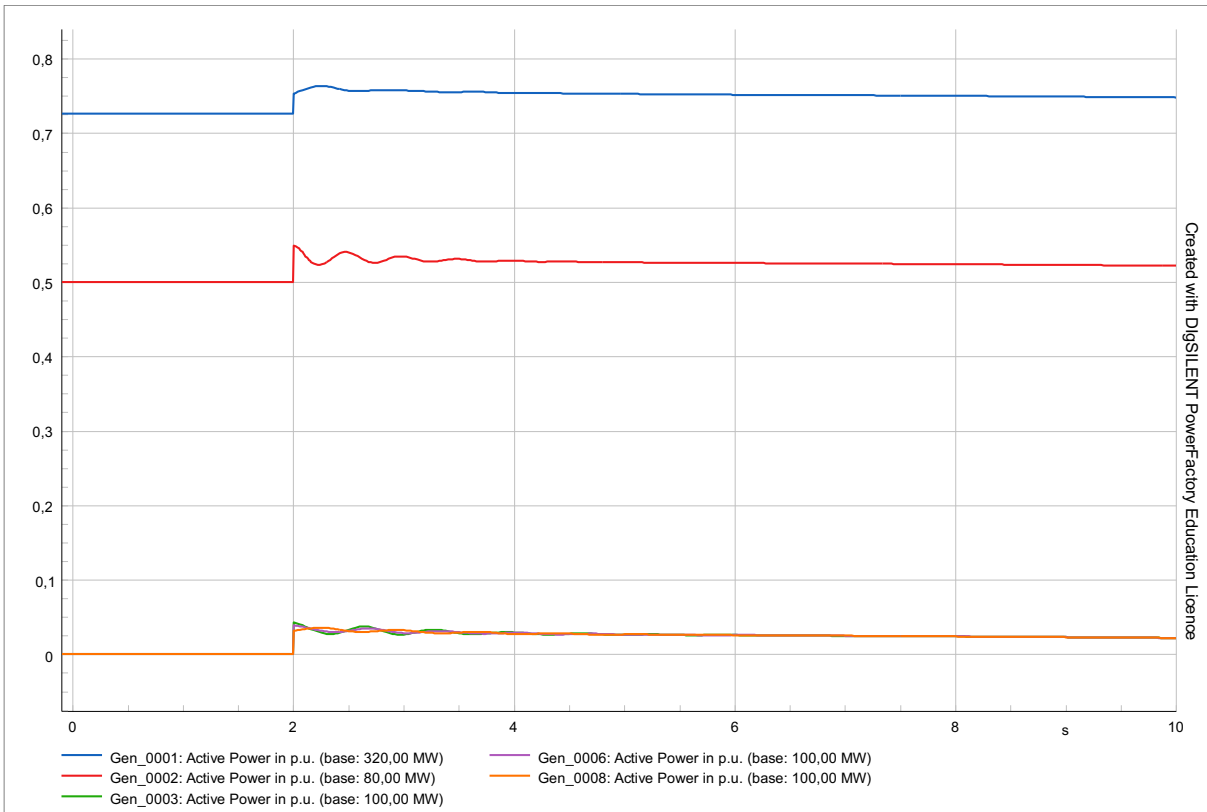


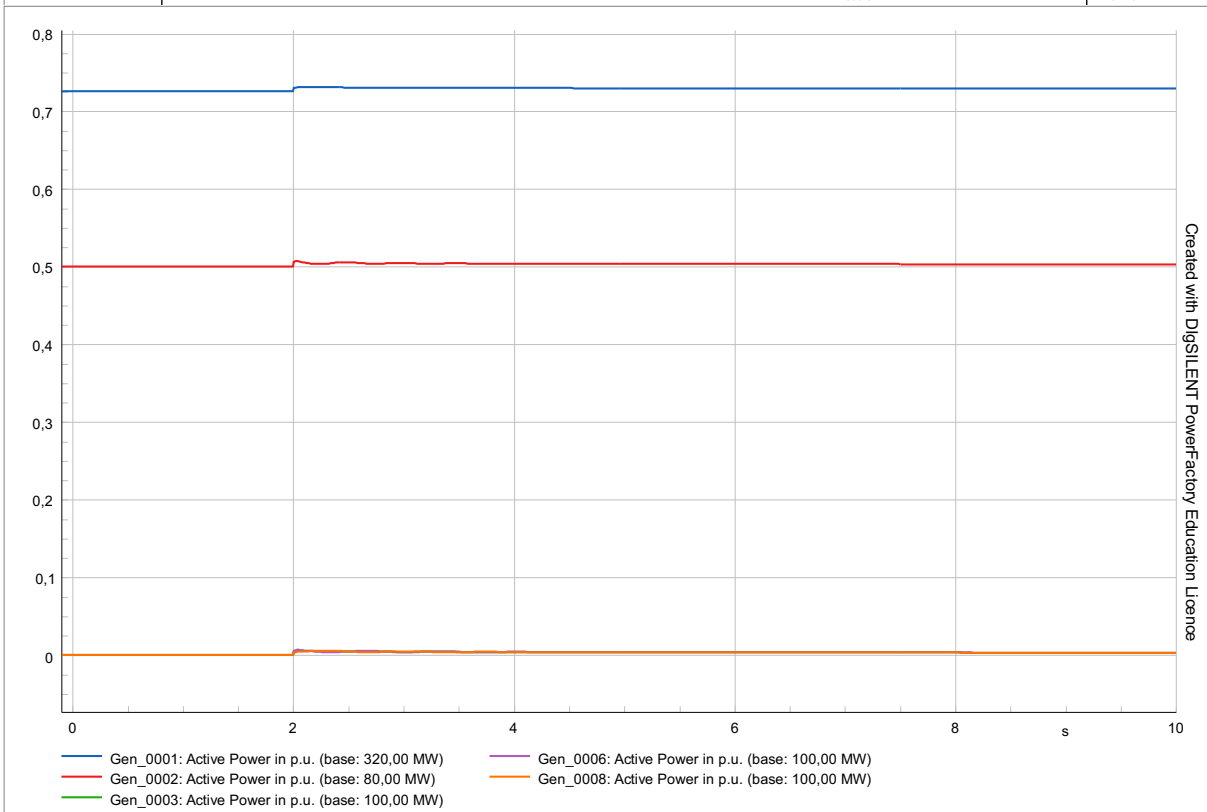
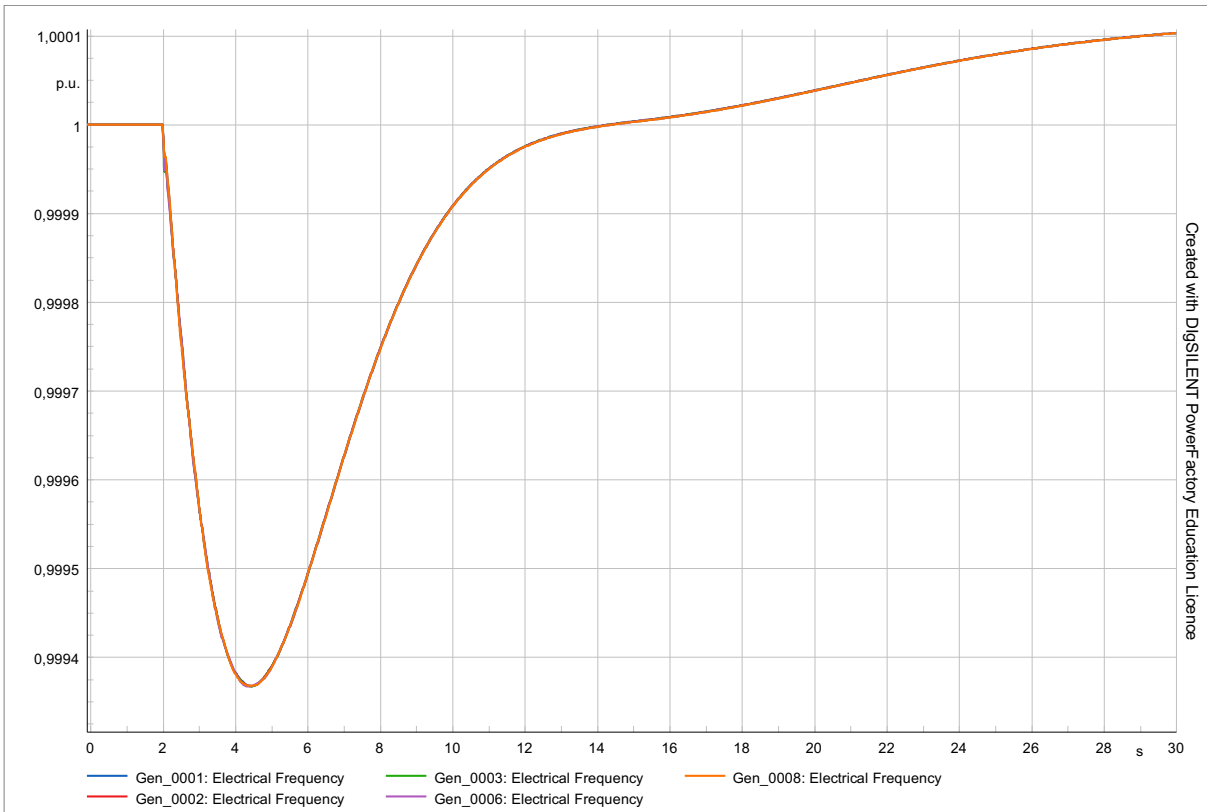
Case: Load Increase

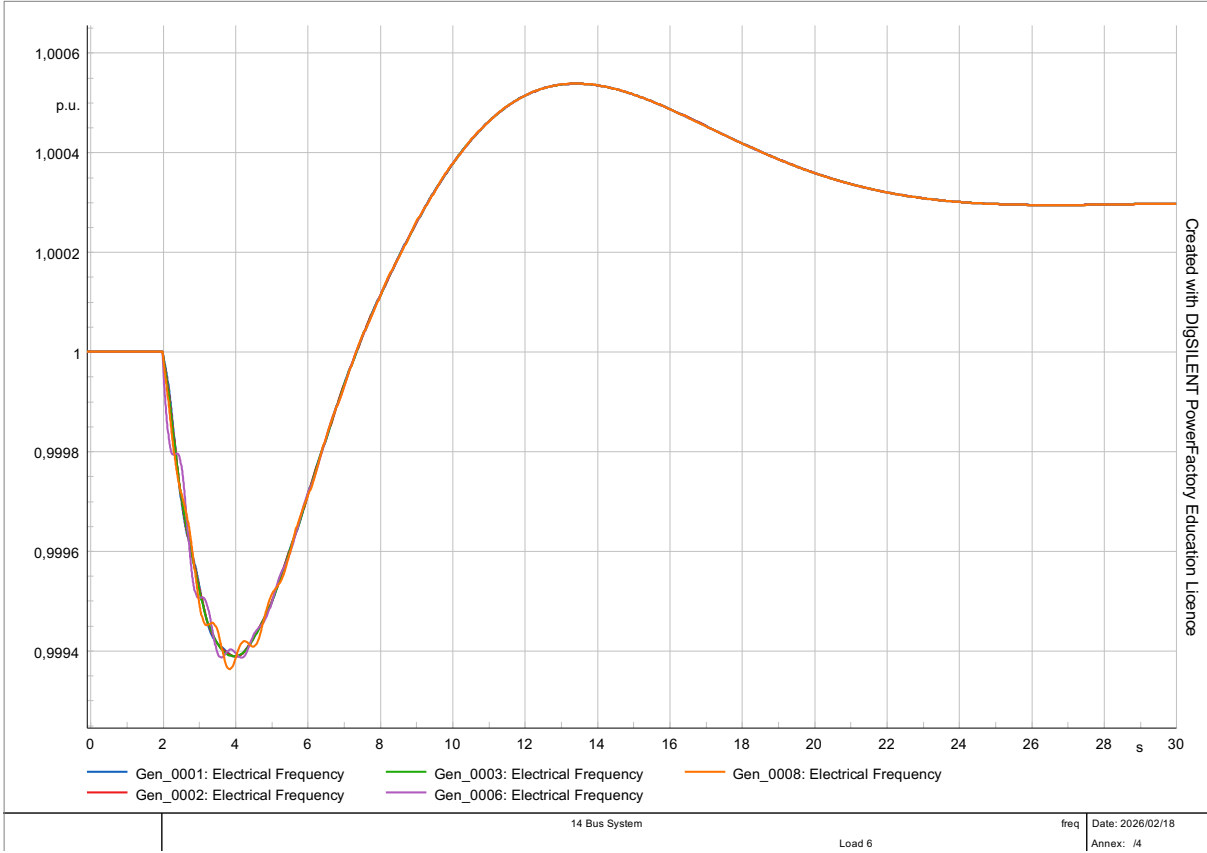
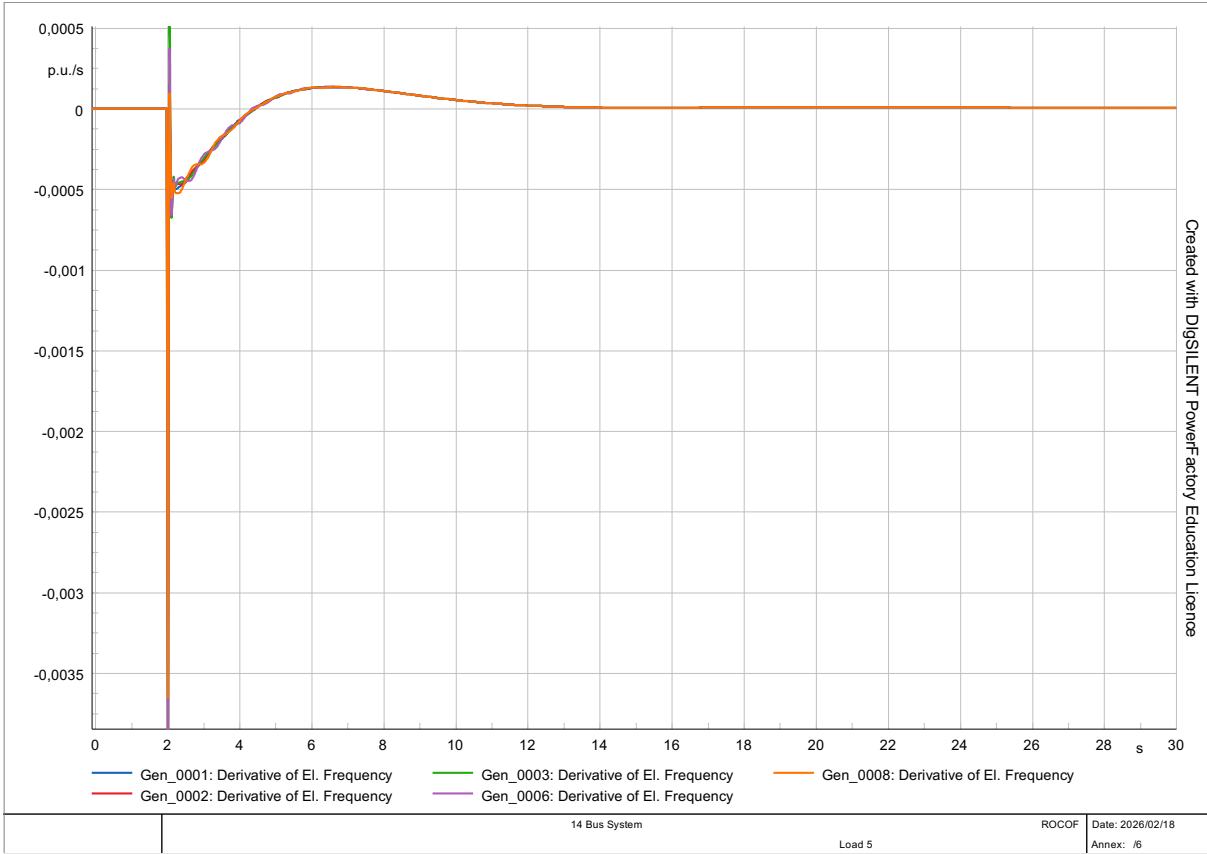


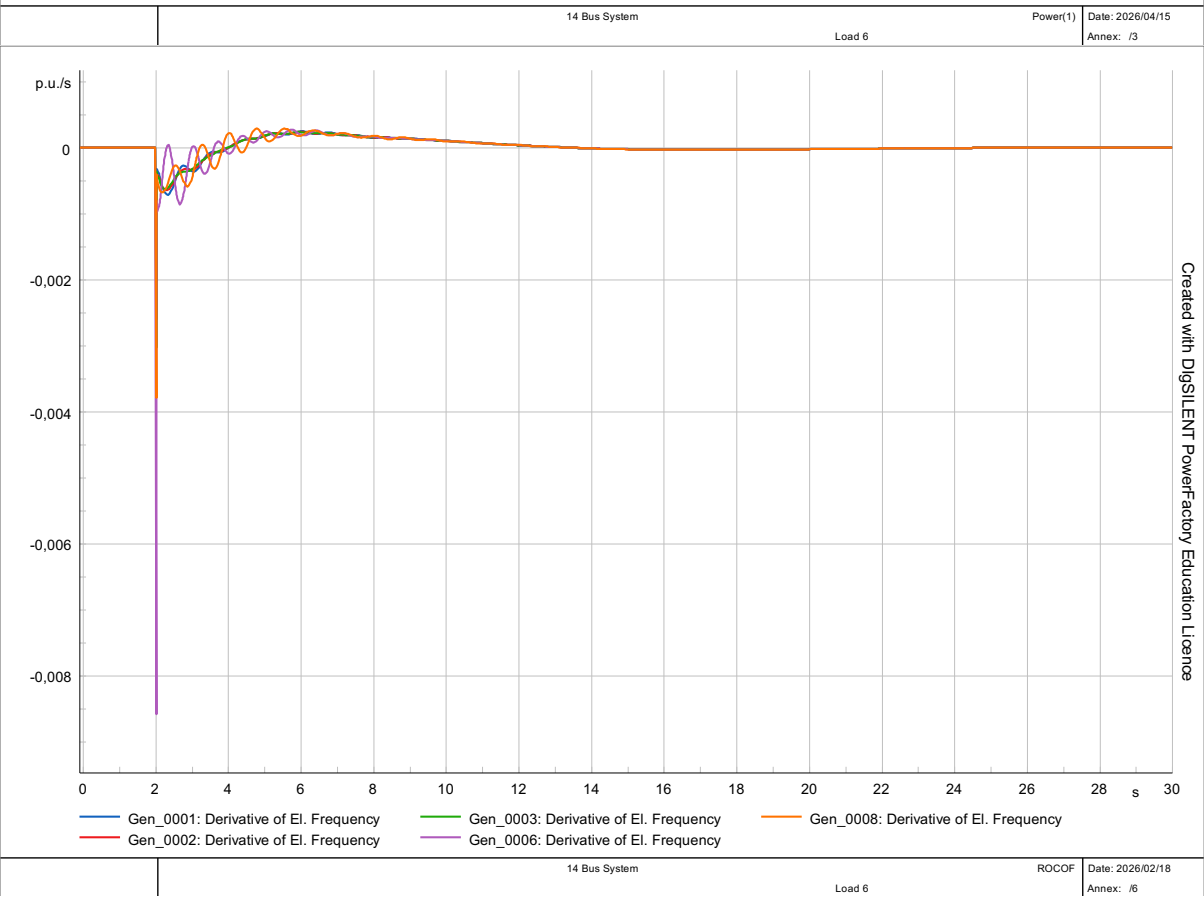
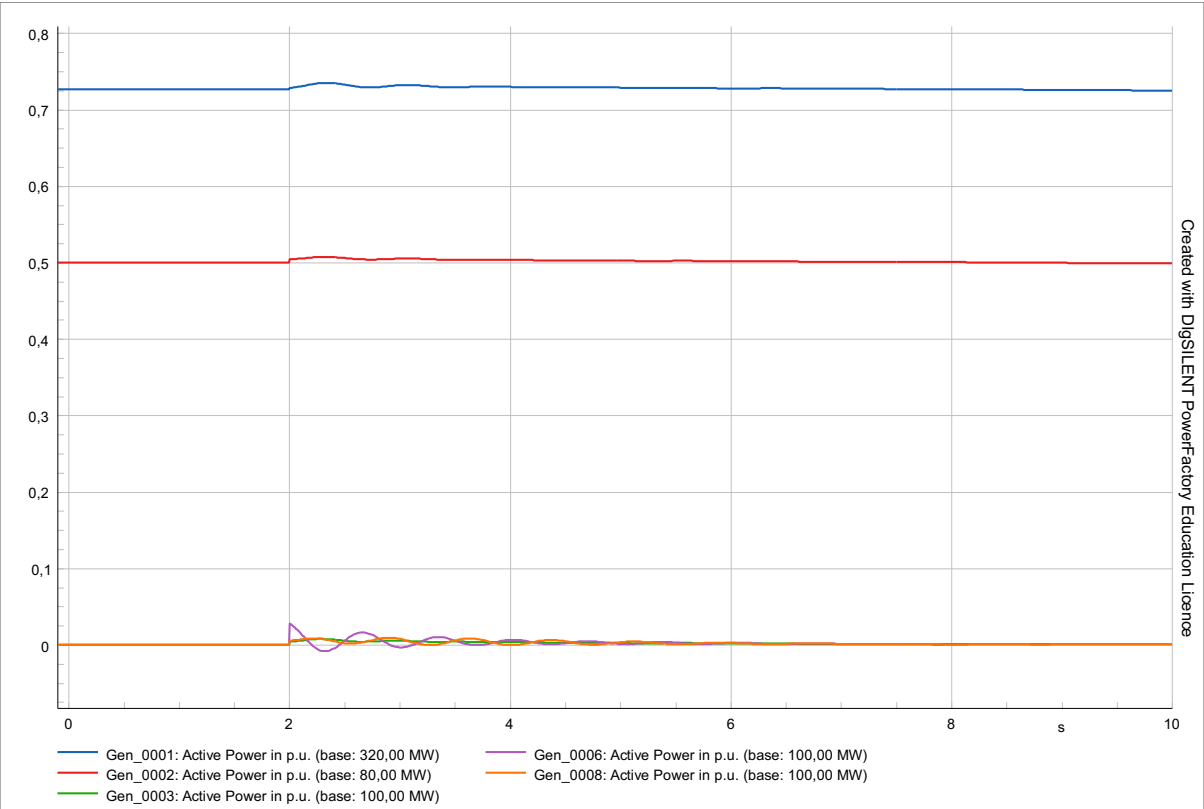


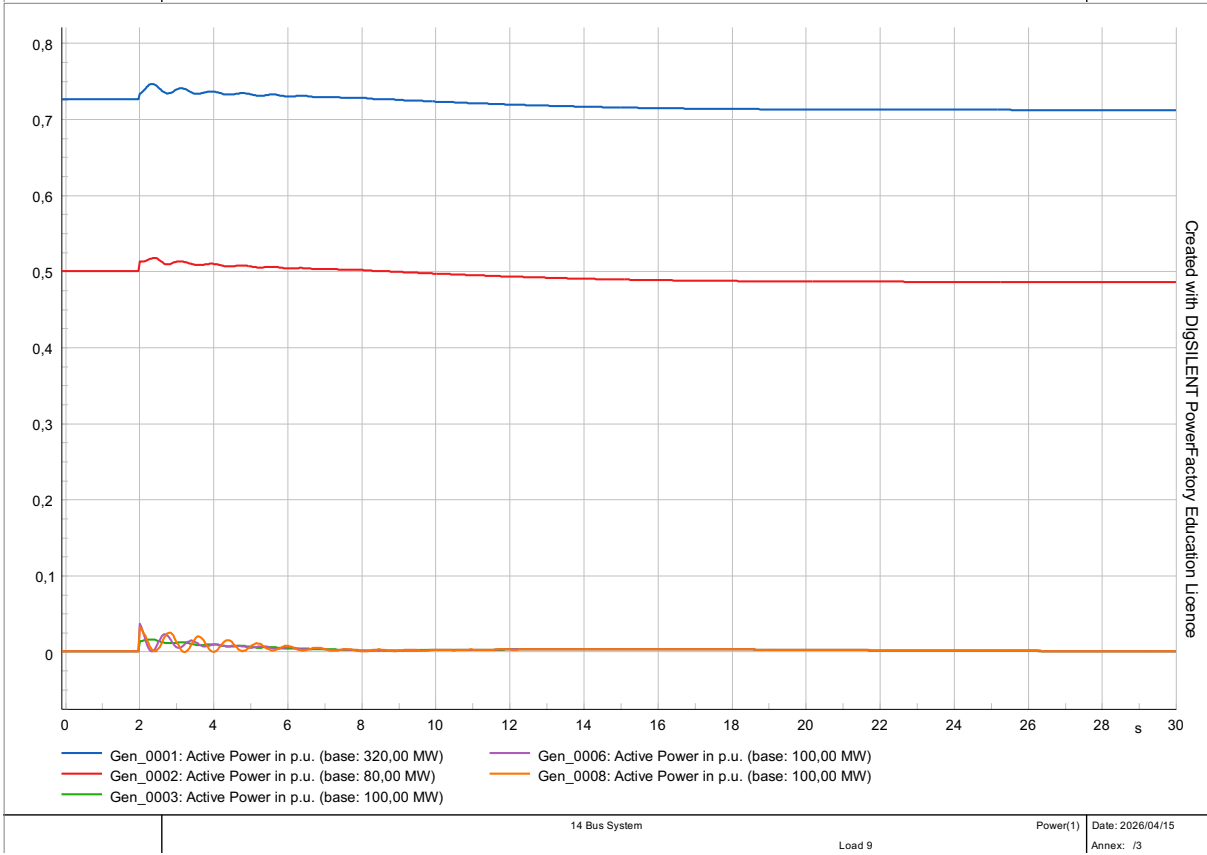
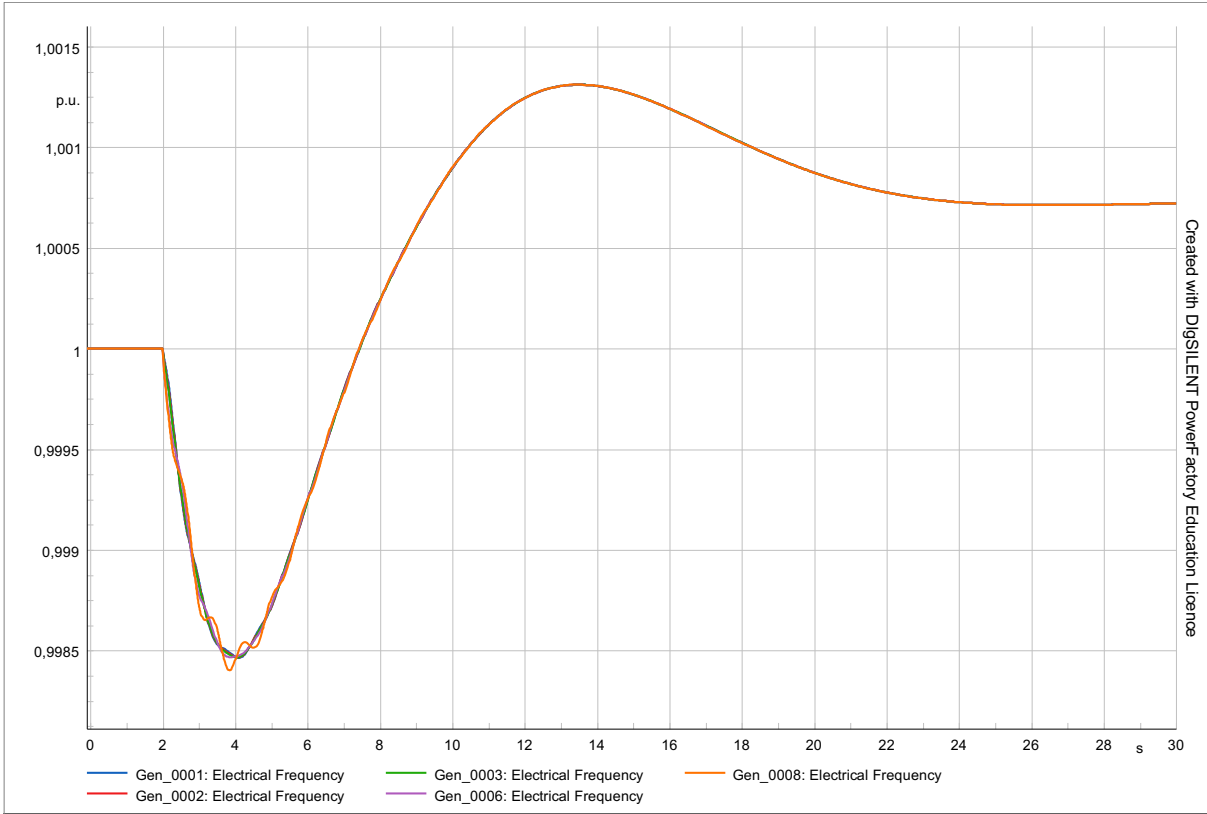


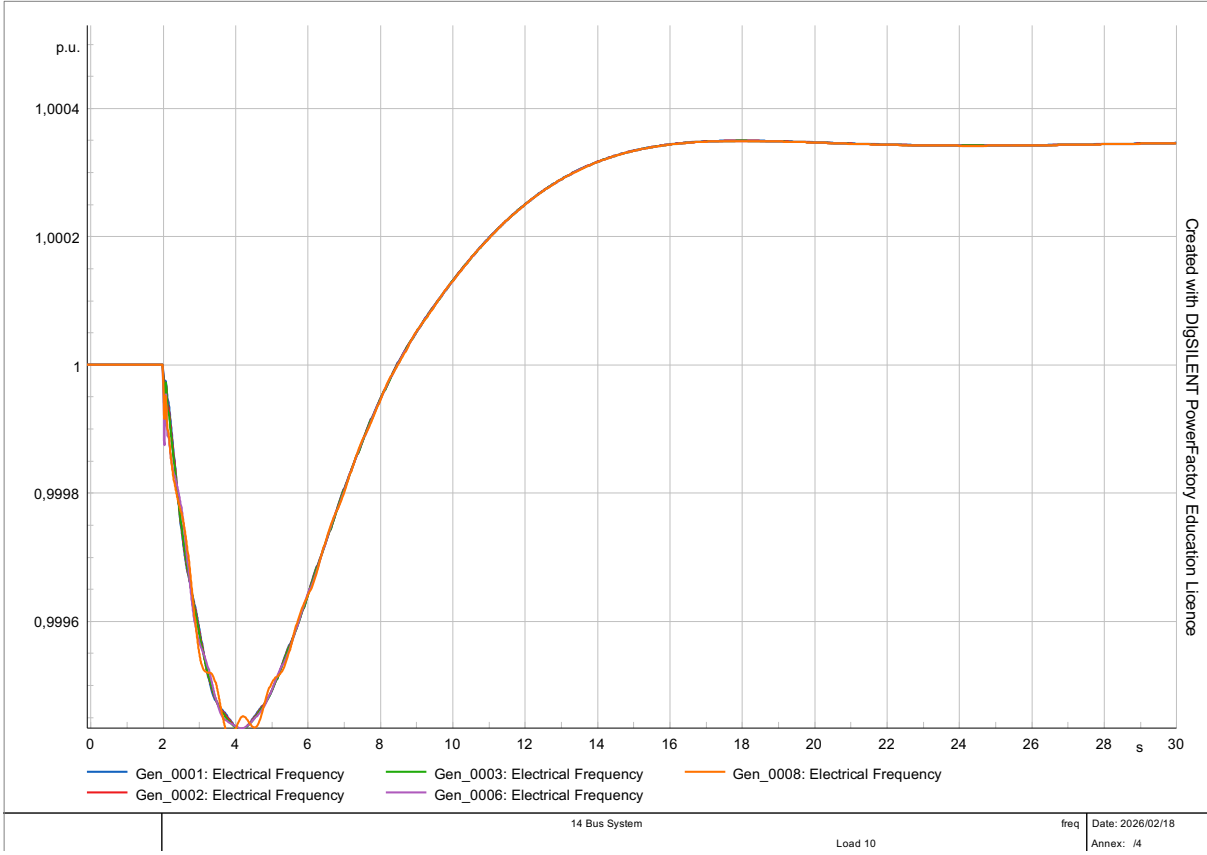
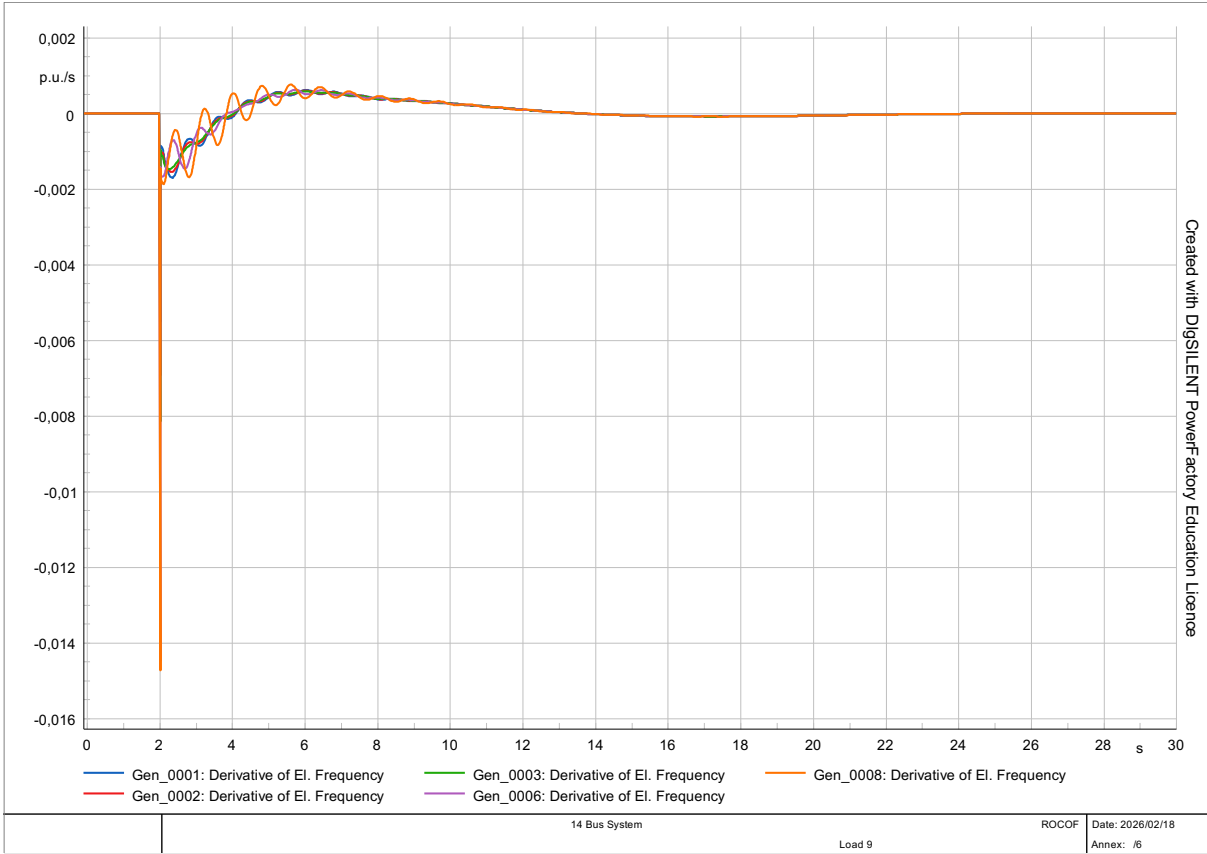


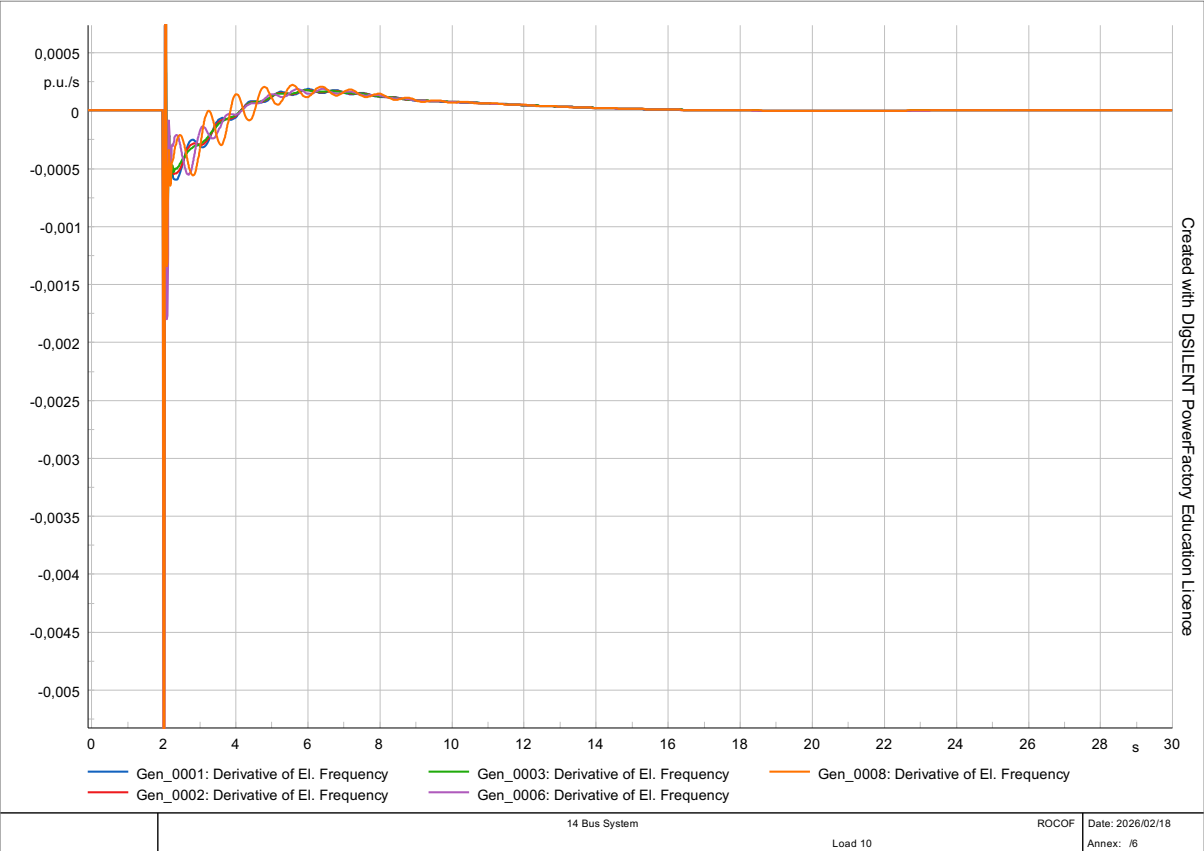
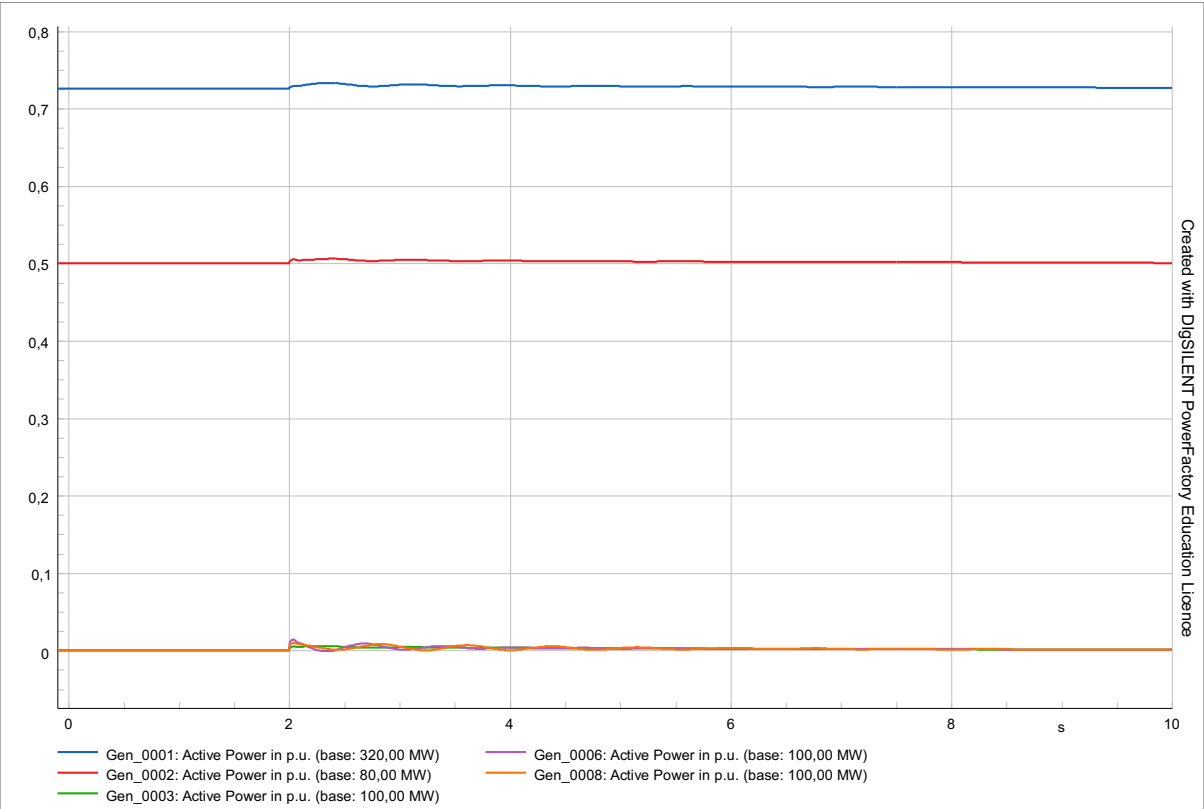


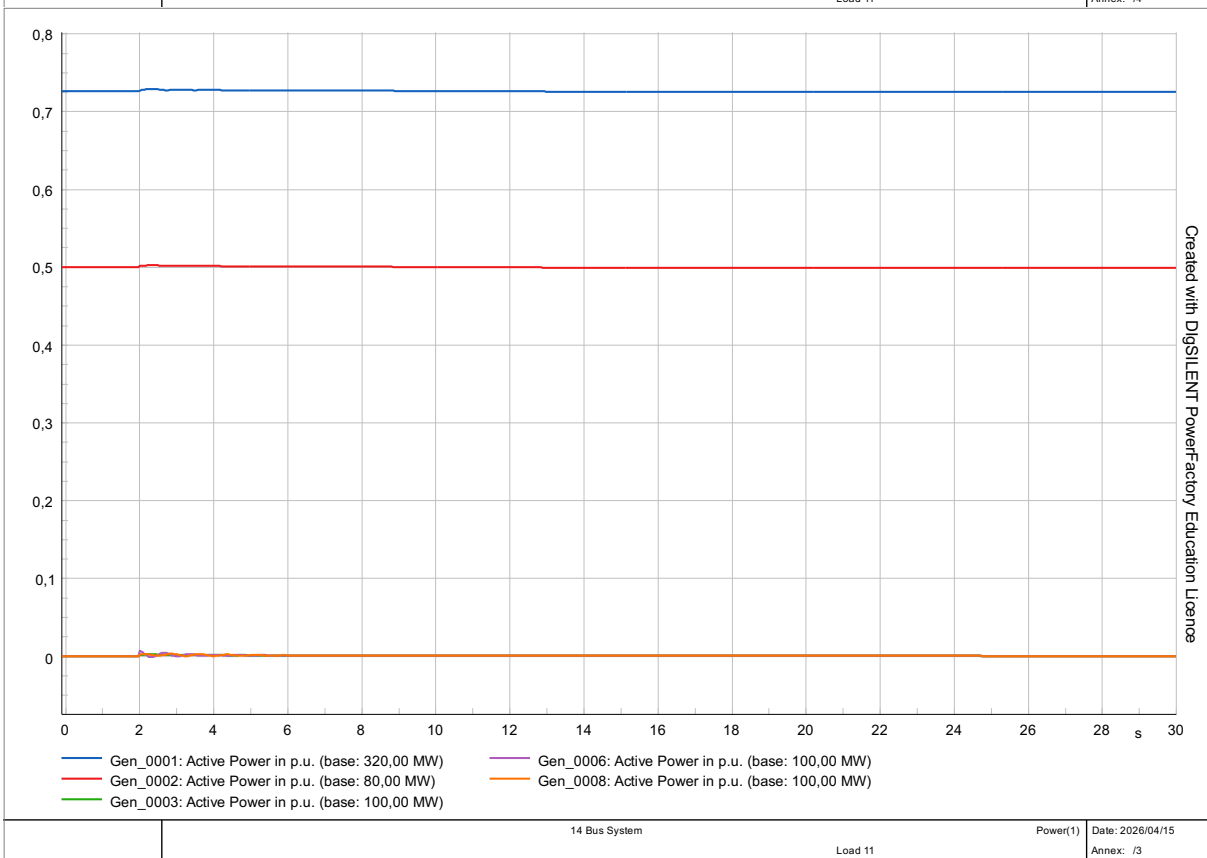
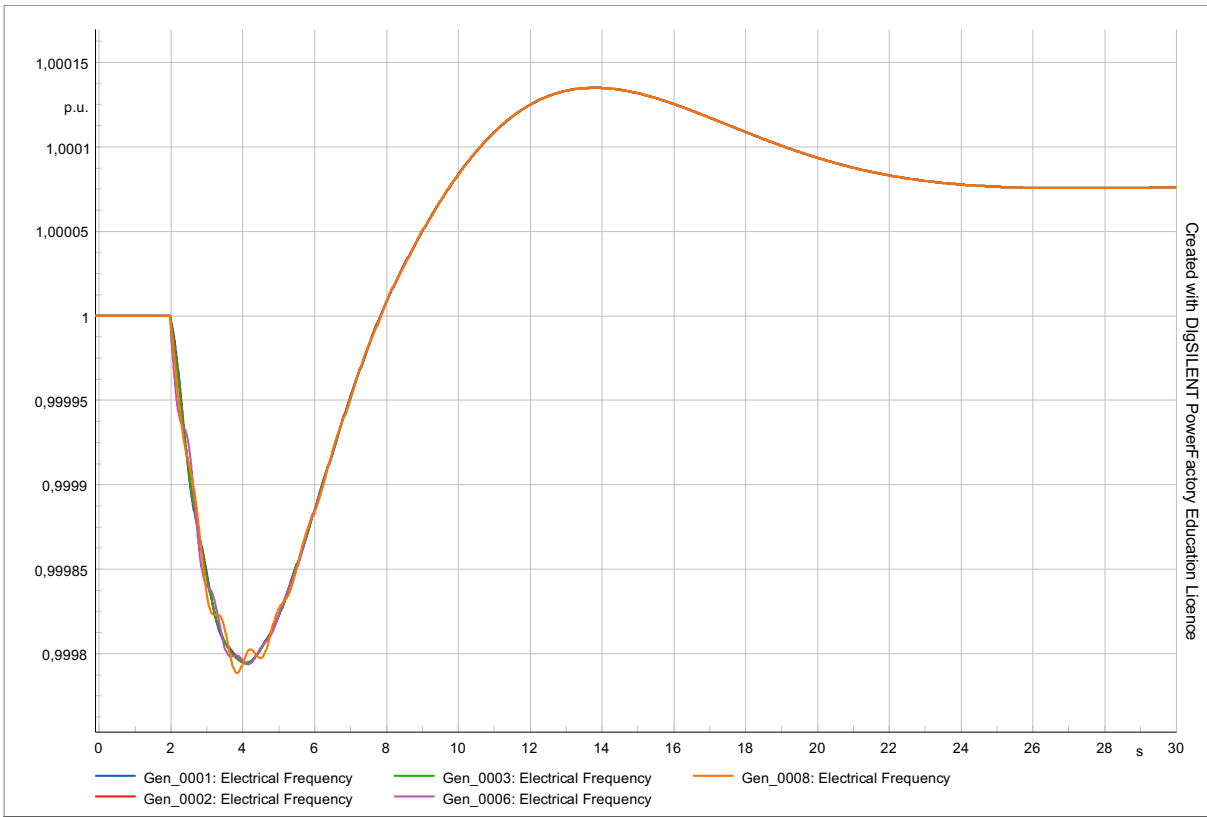


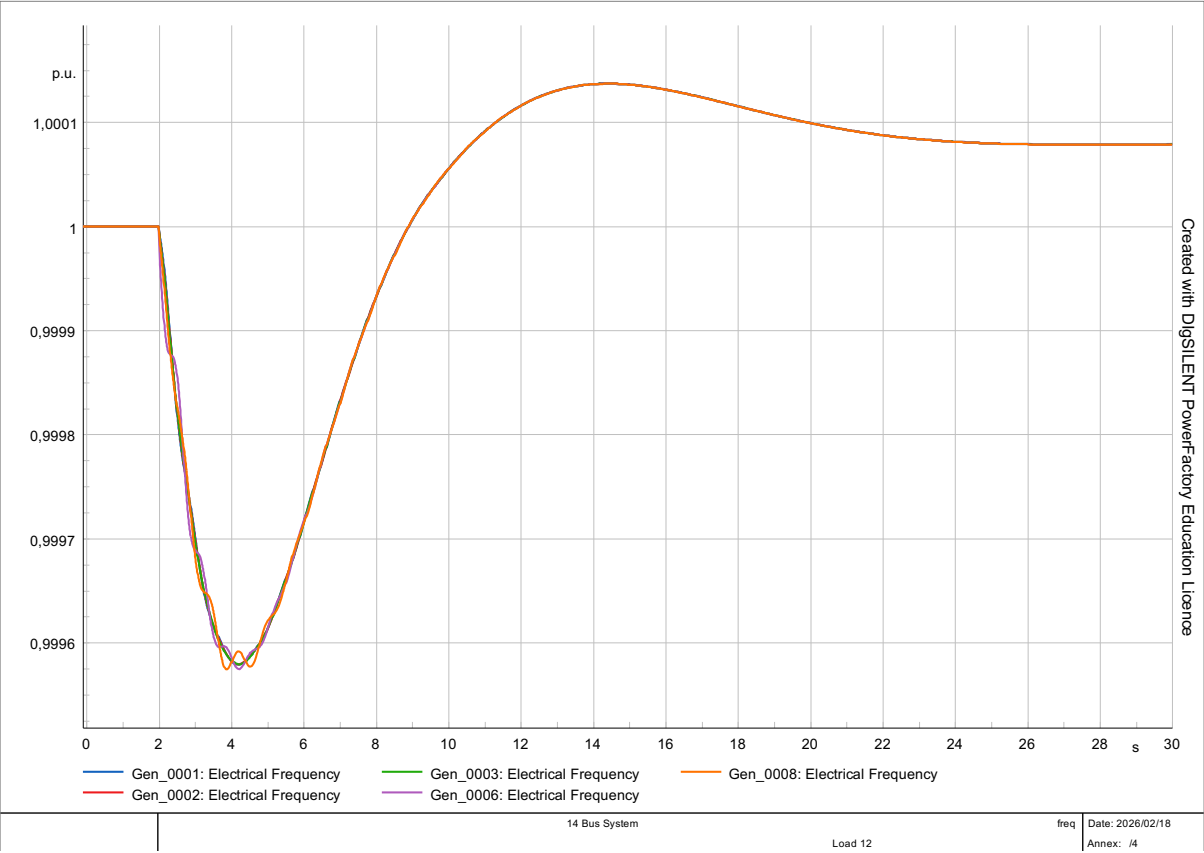
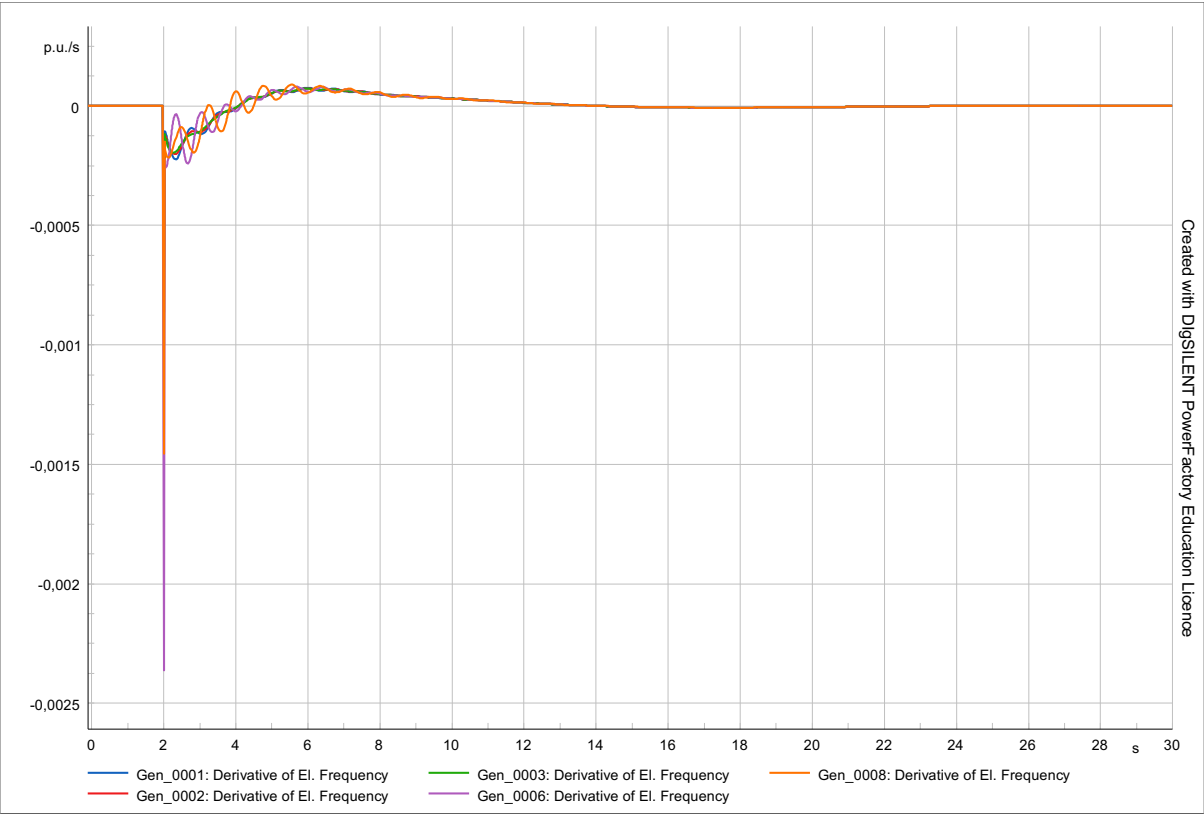


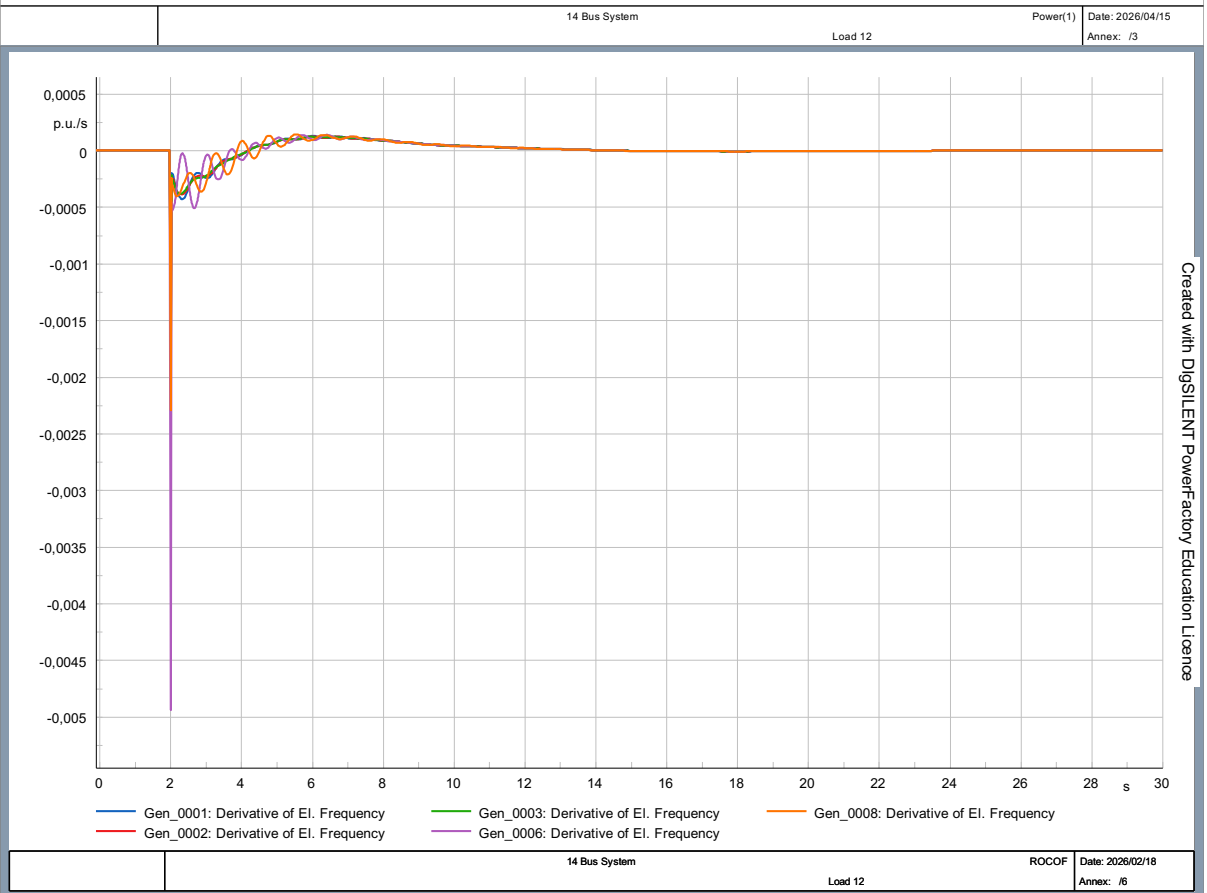
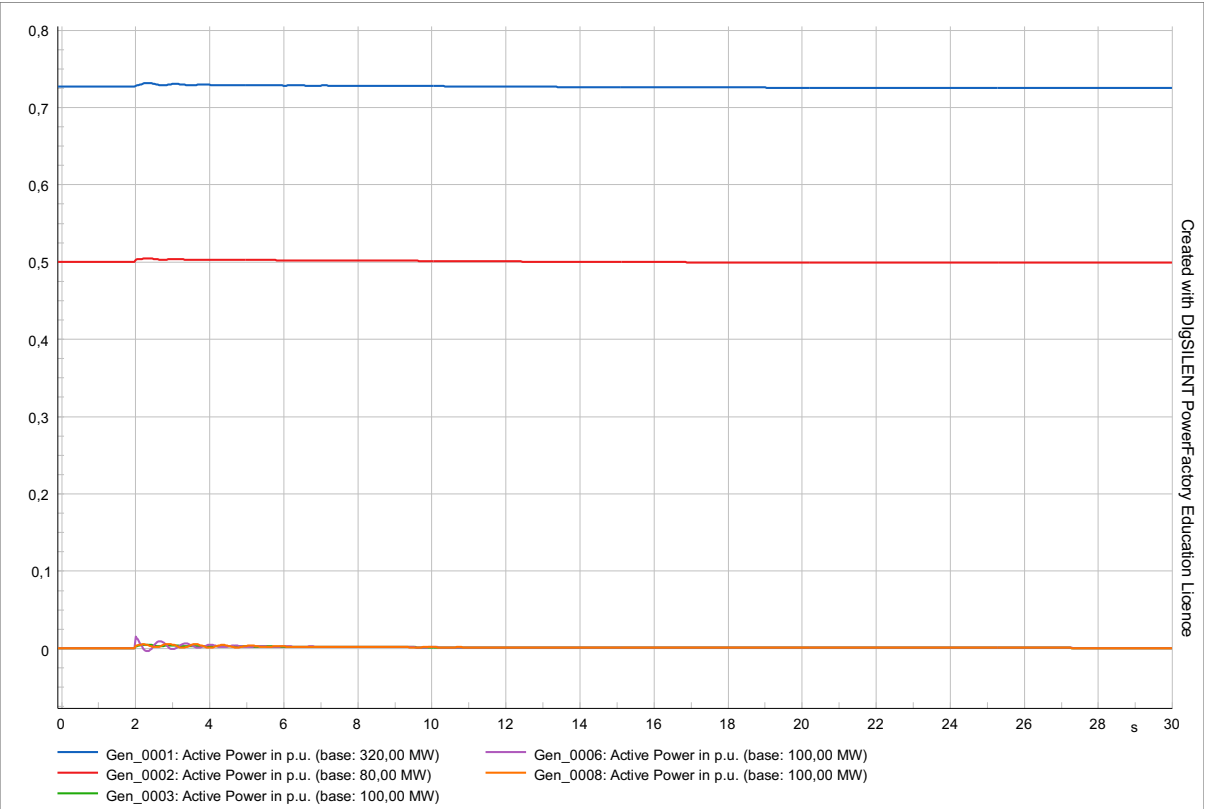


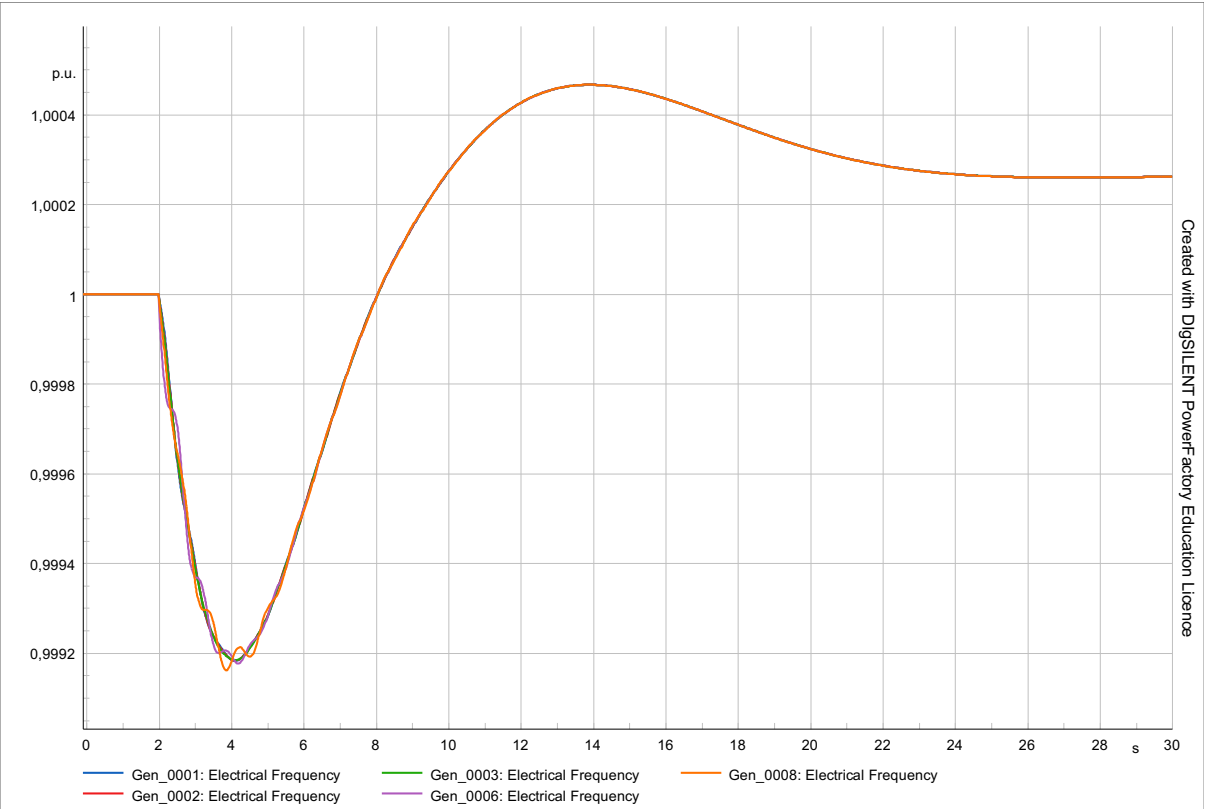






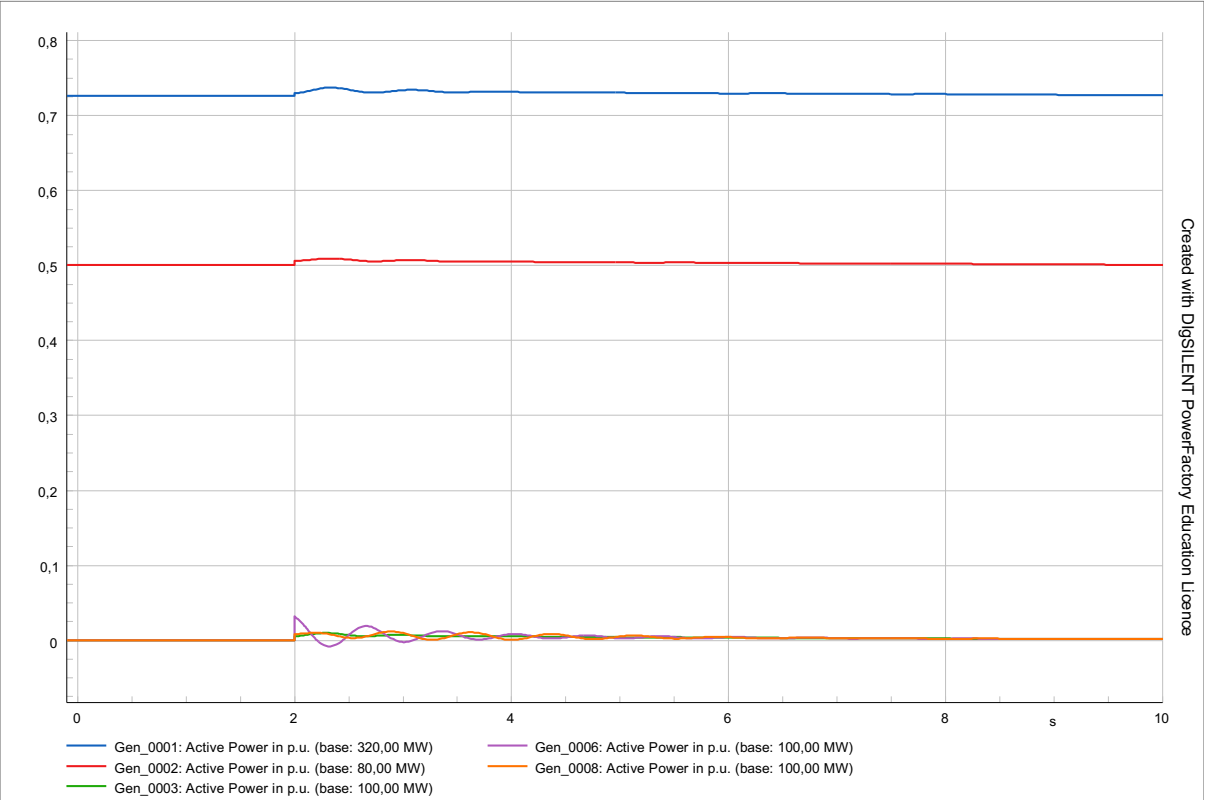






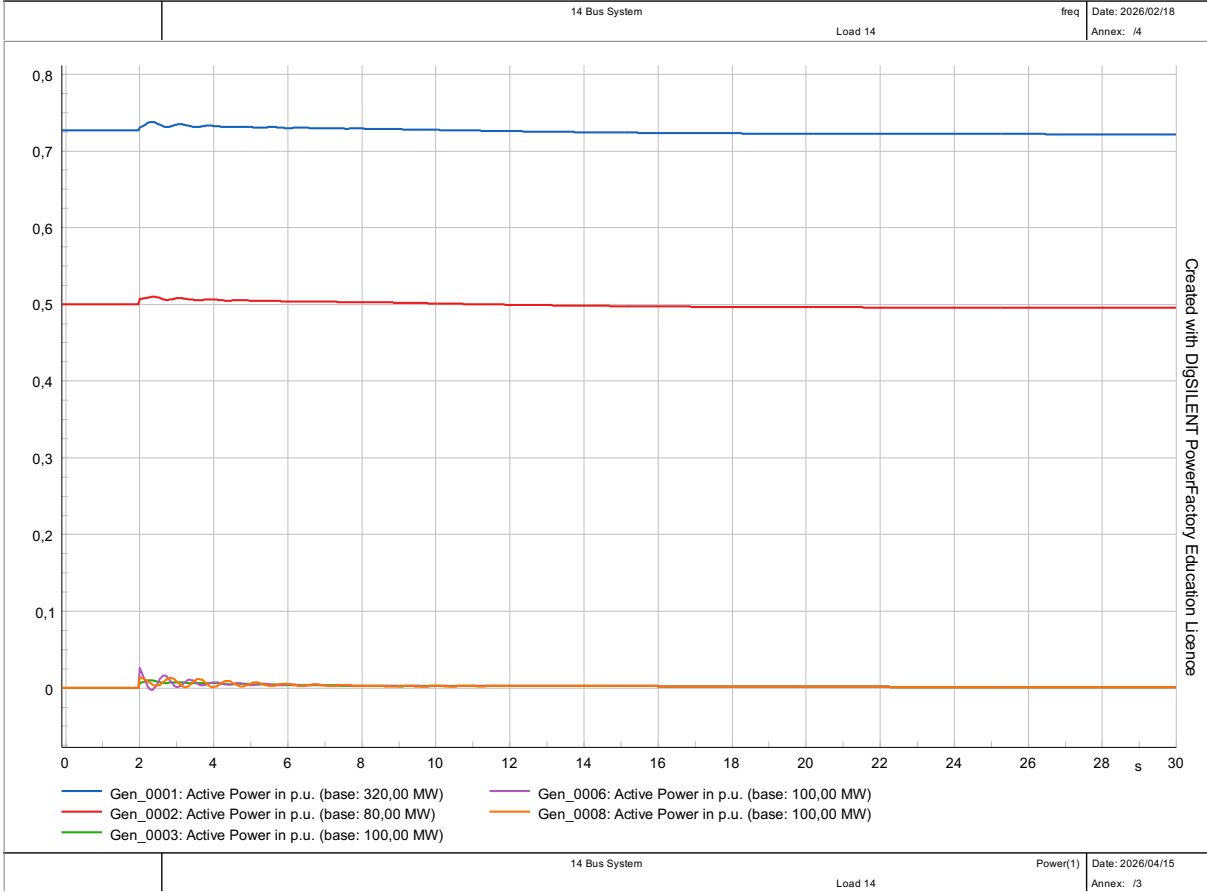
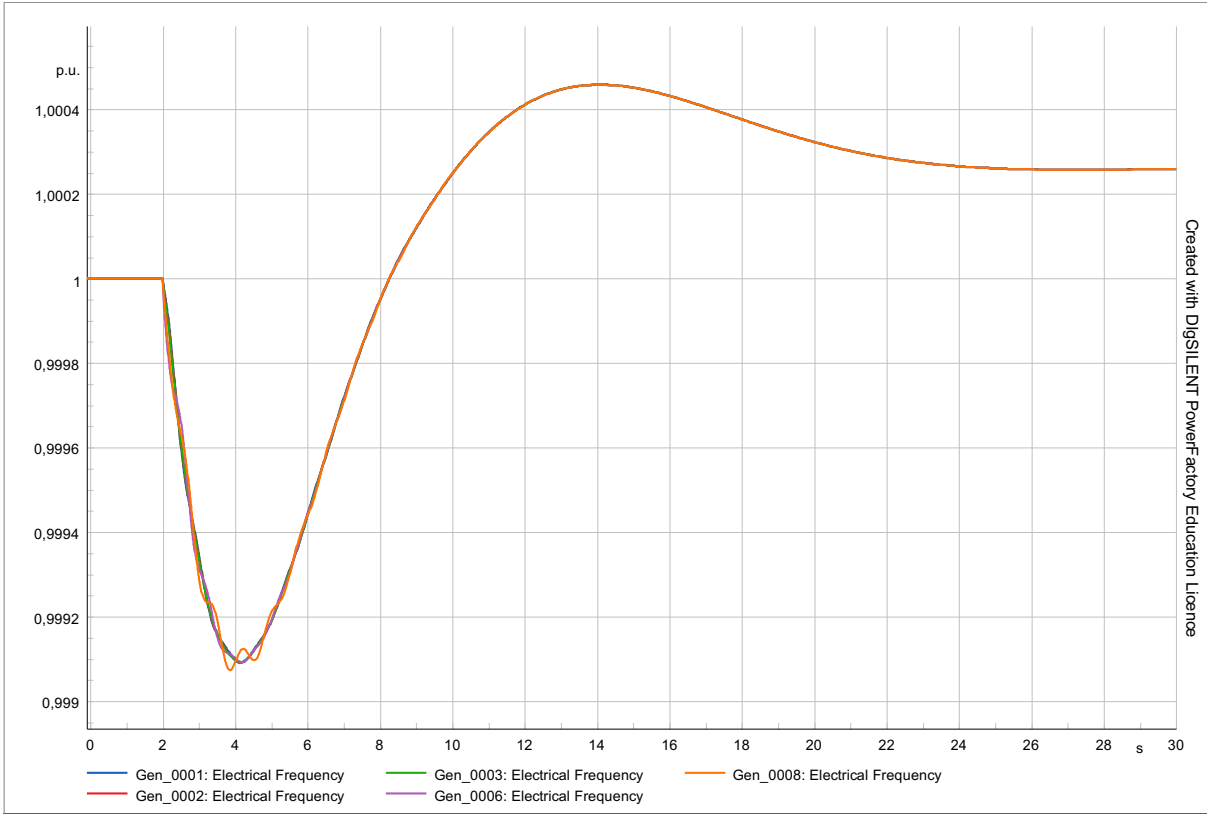
Load 13

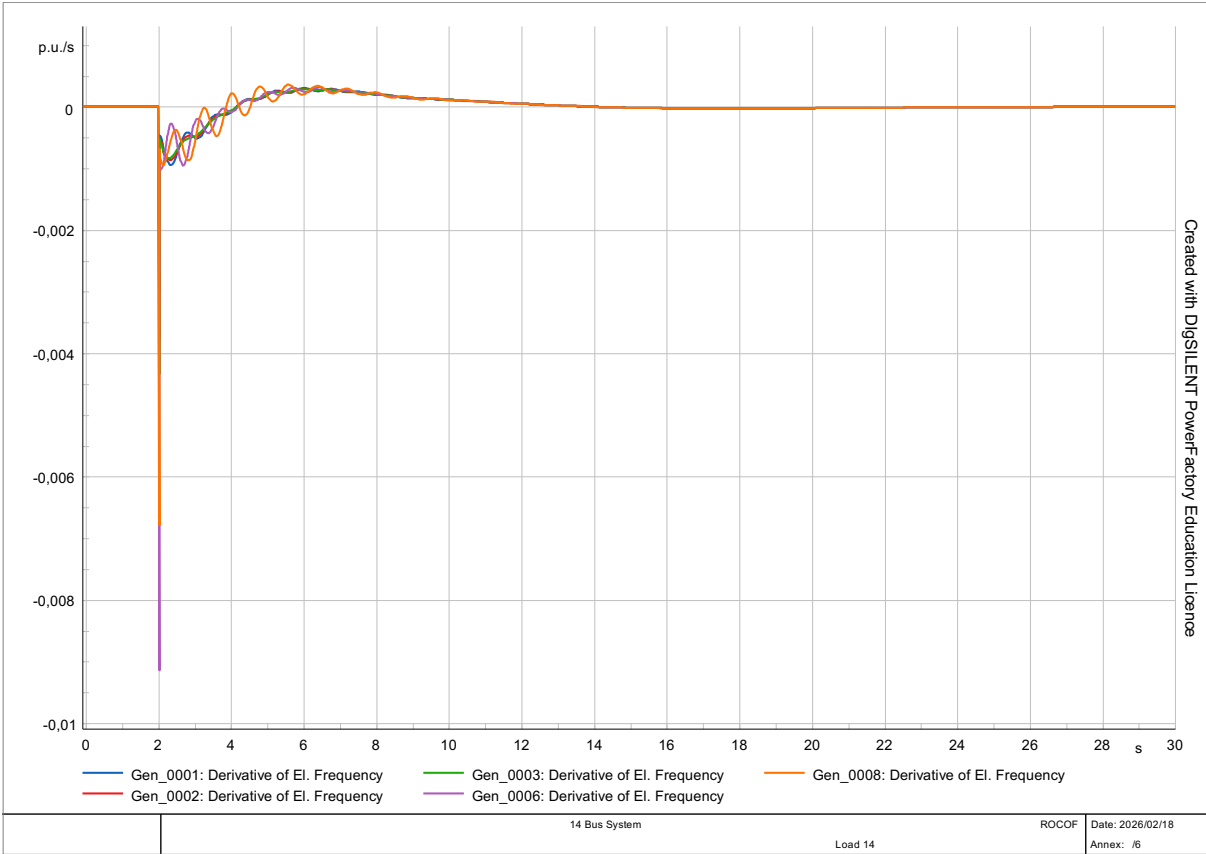
freq Date: 2026/02/18
Annex: /4



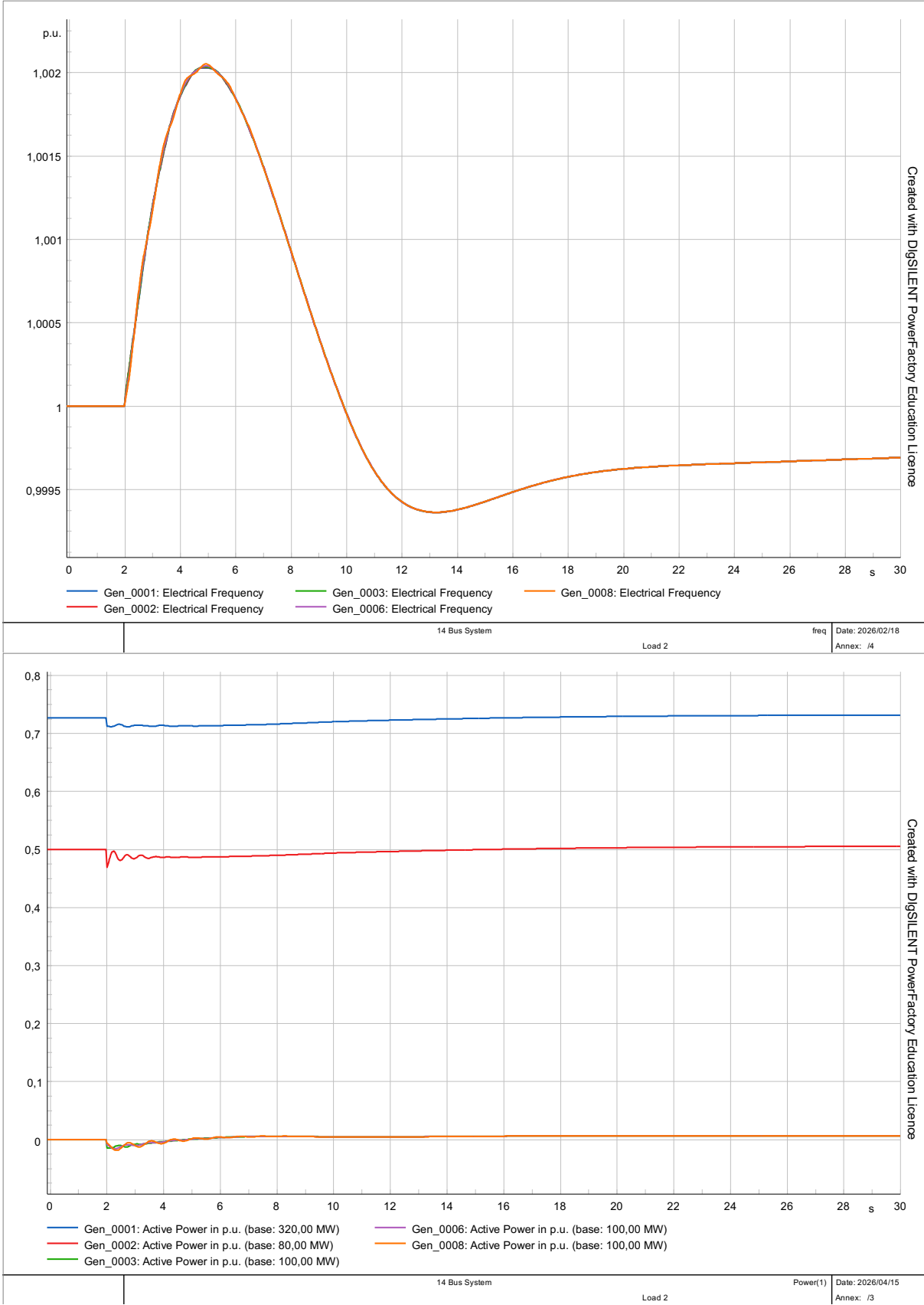
Load 13

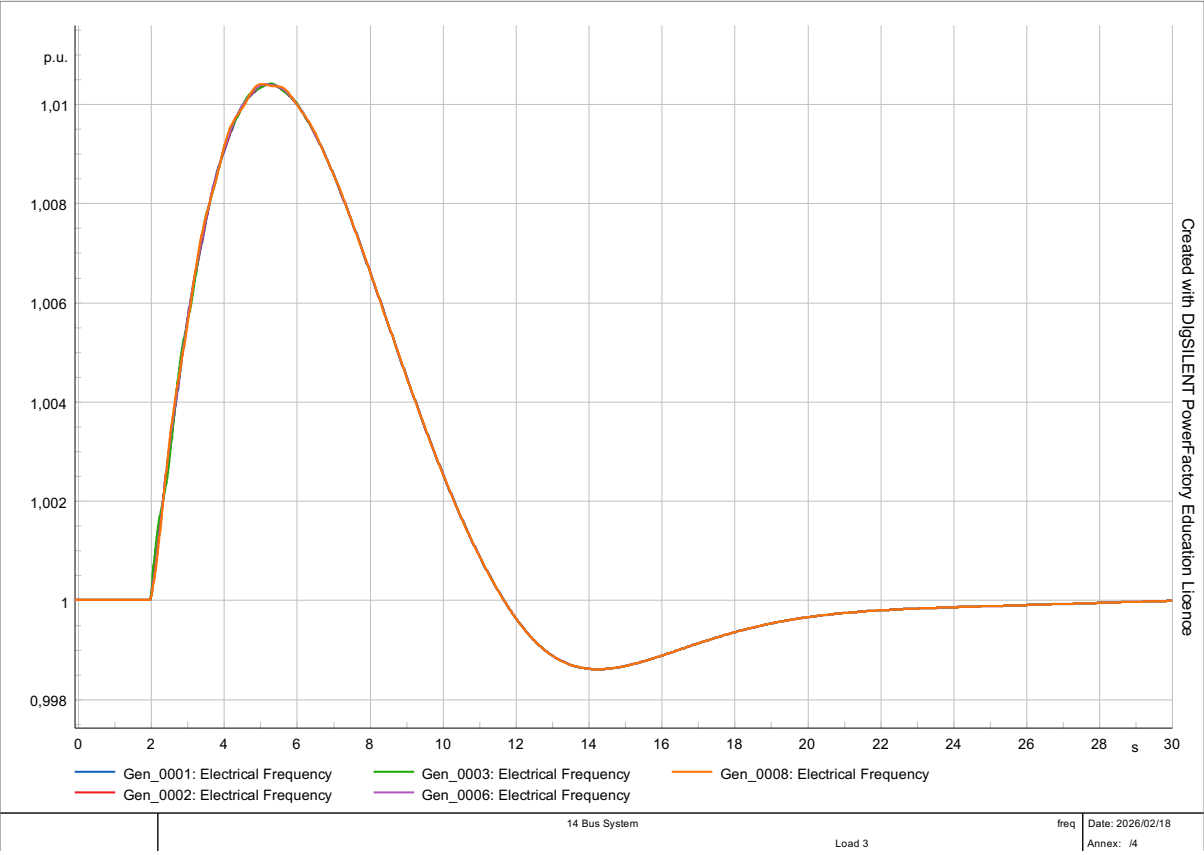
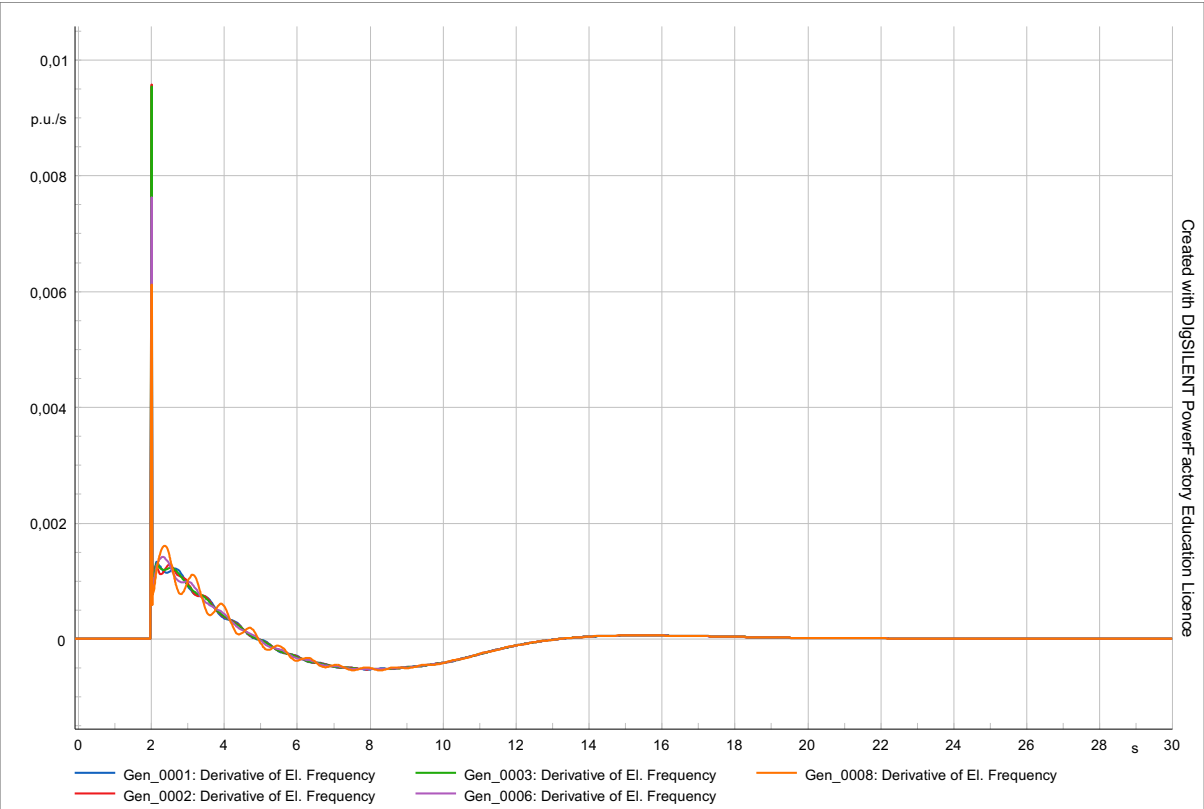
Power(1) Date: 2026/04/15
Annex: /3

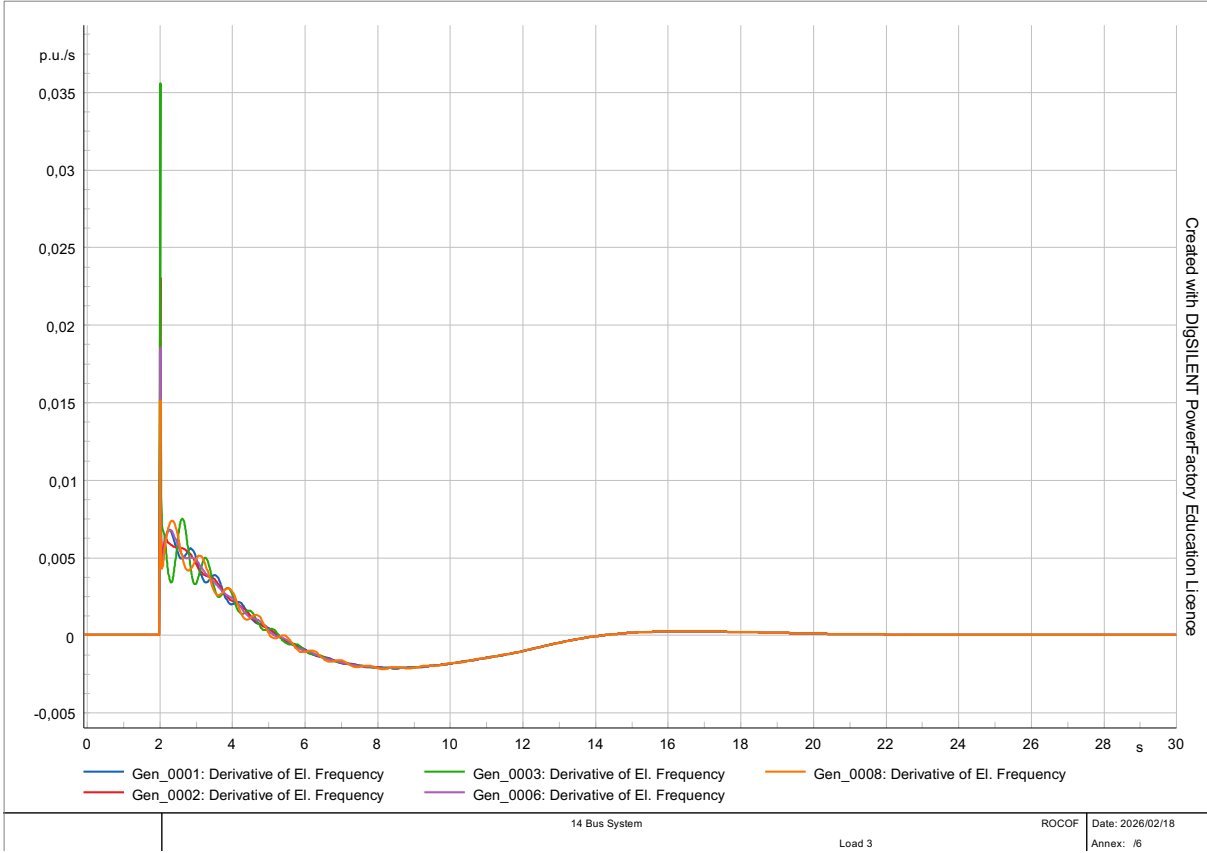
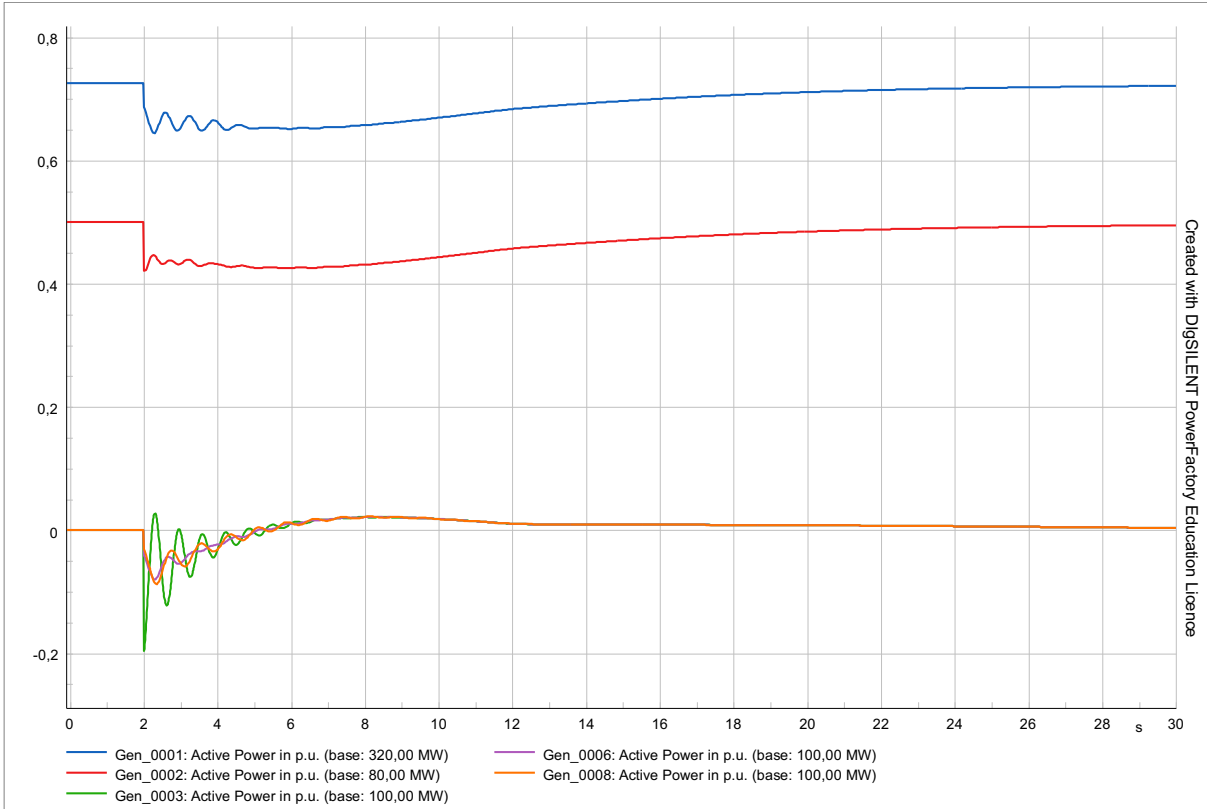


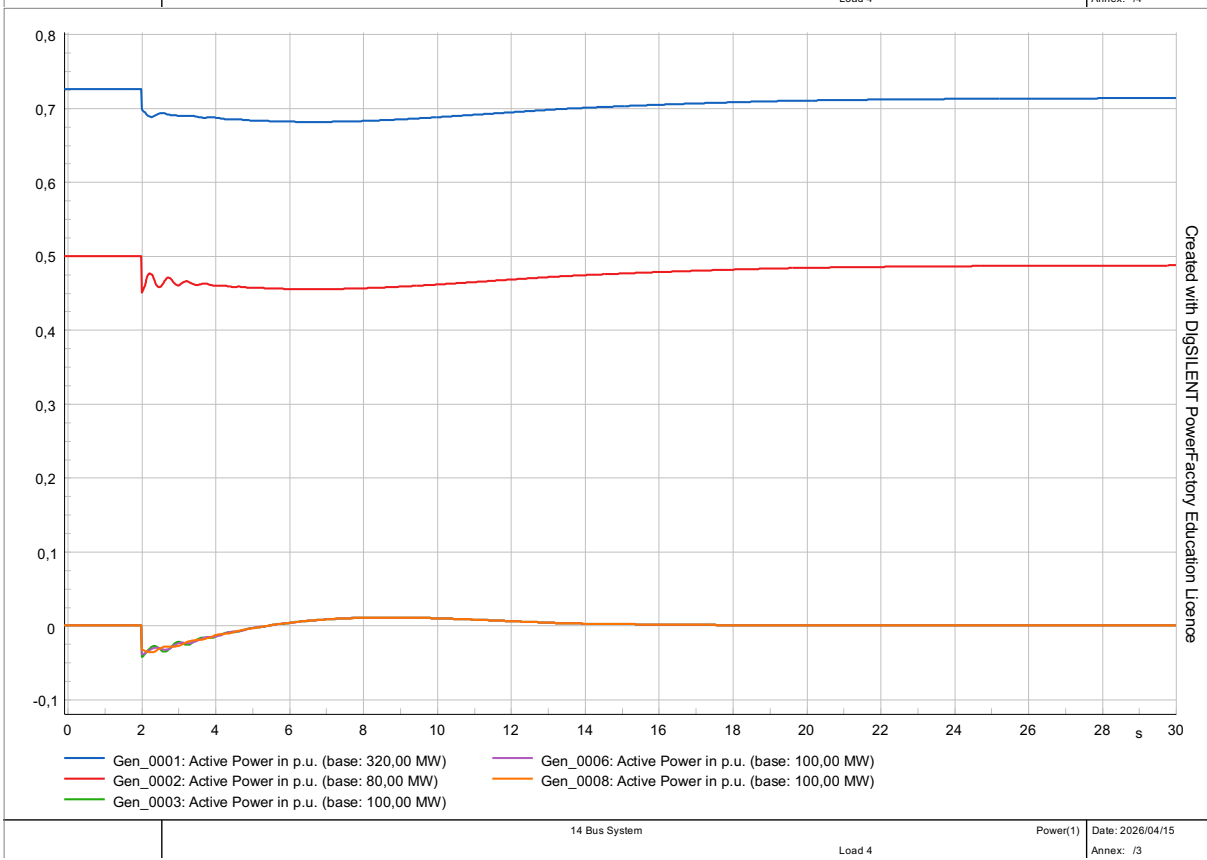
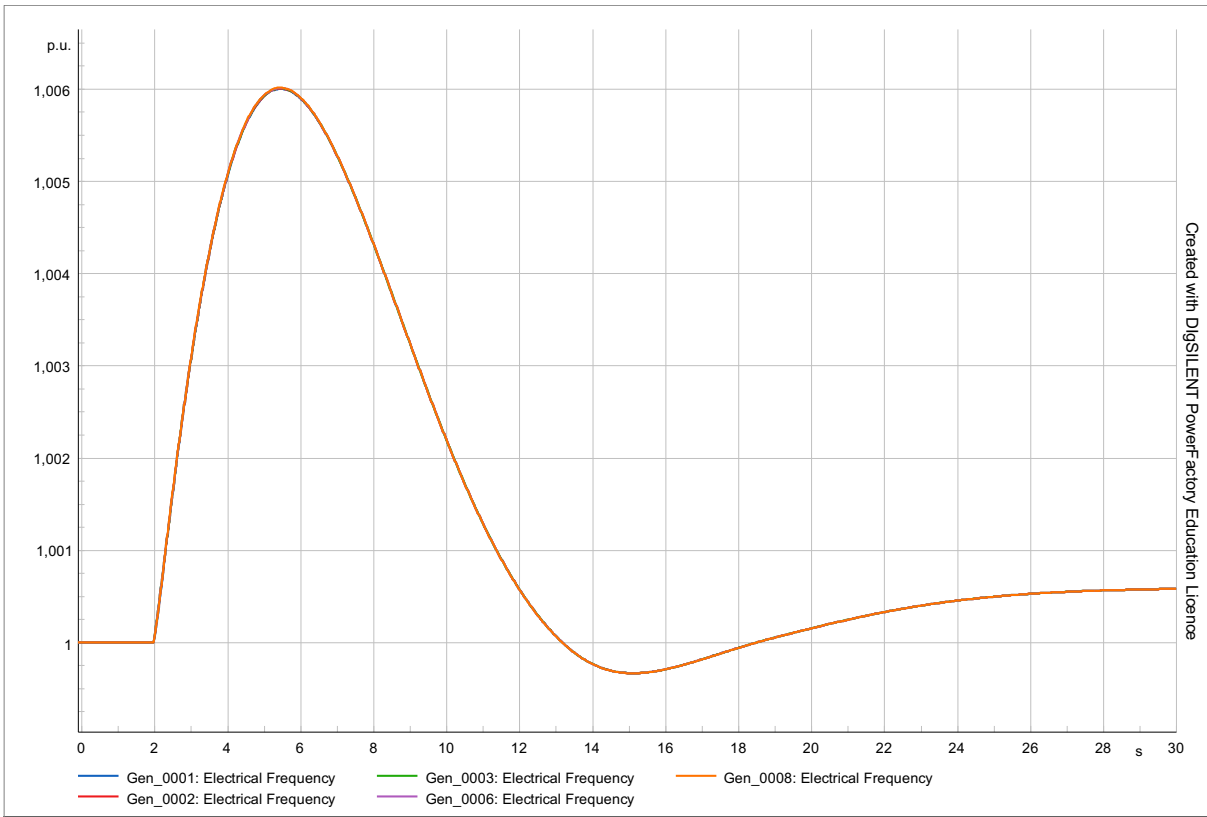


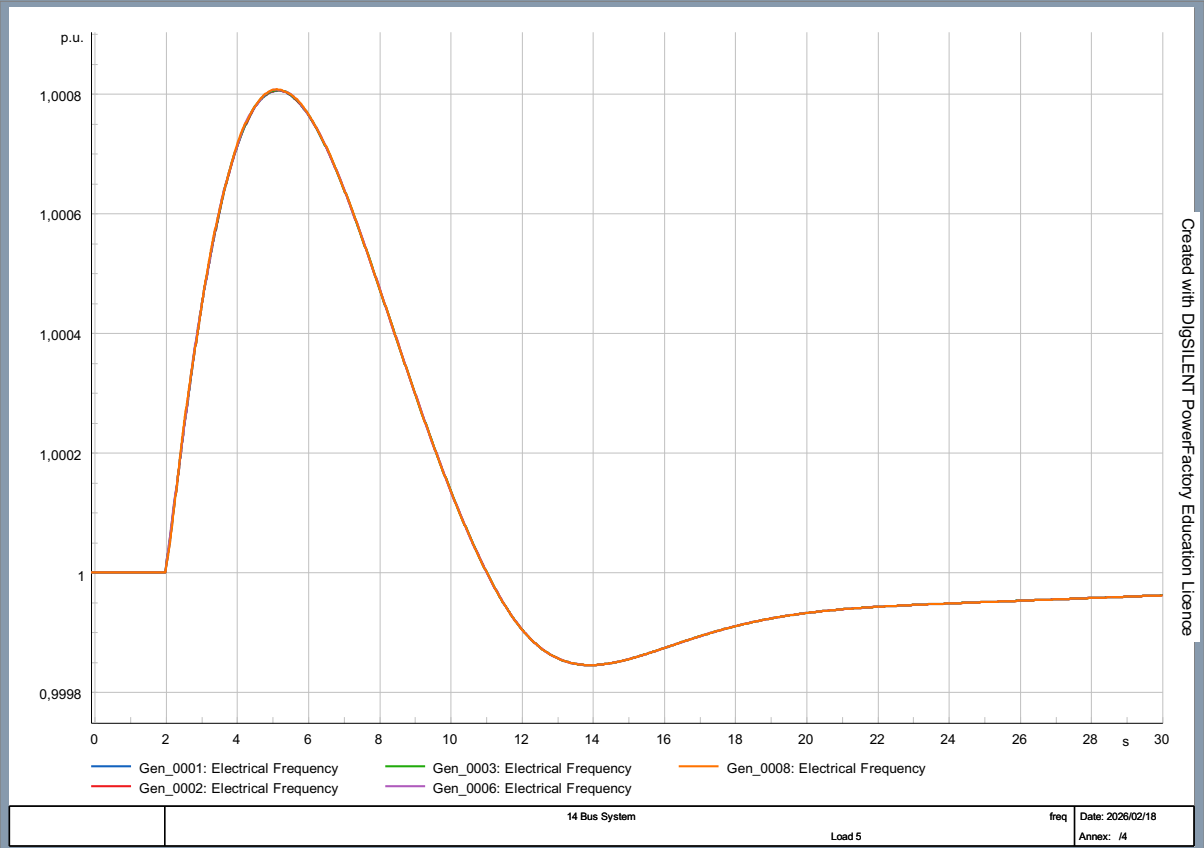
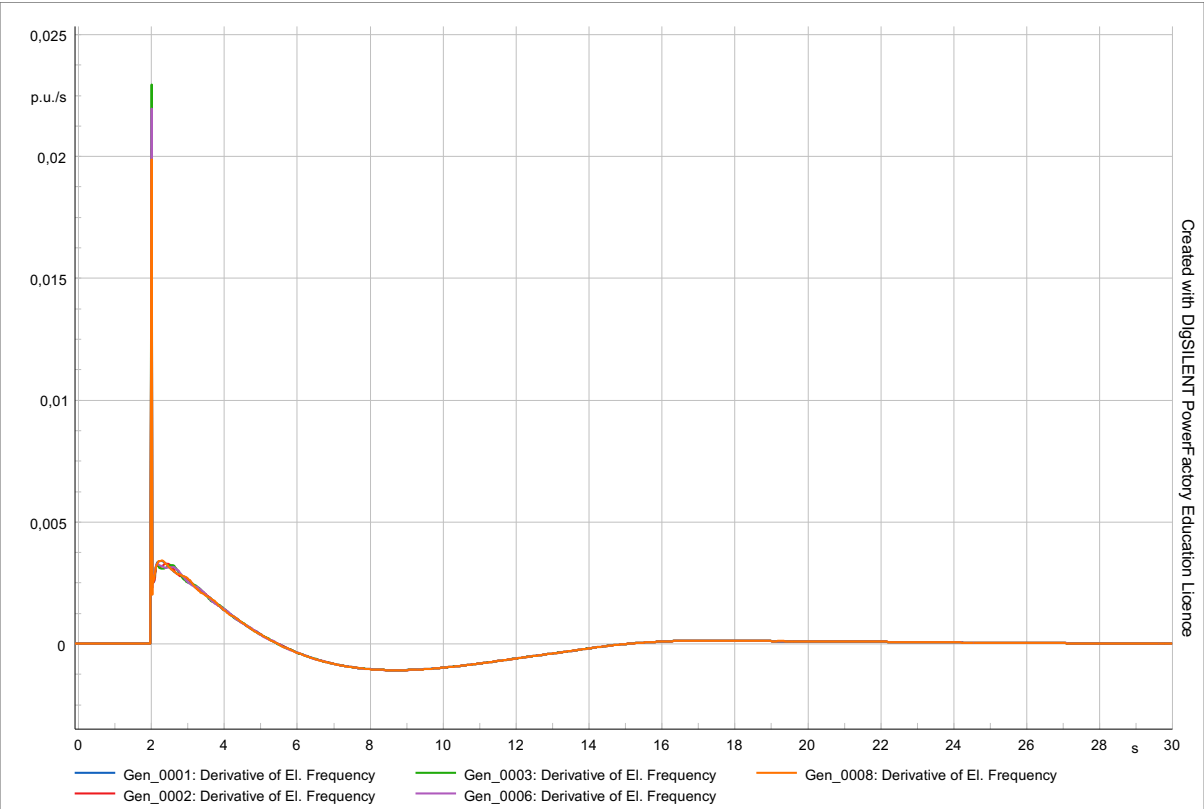
Case: Load Decrease

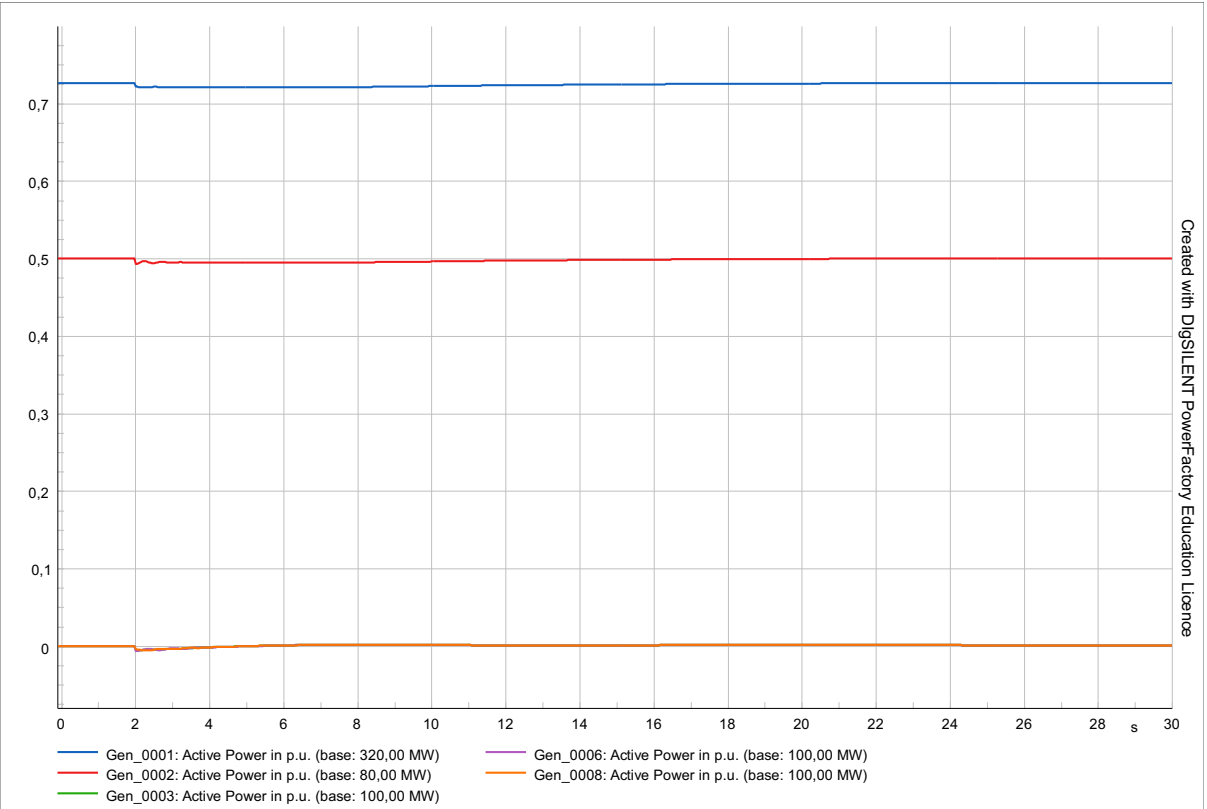




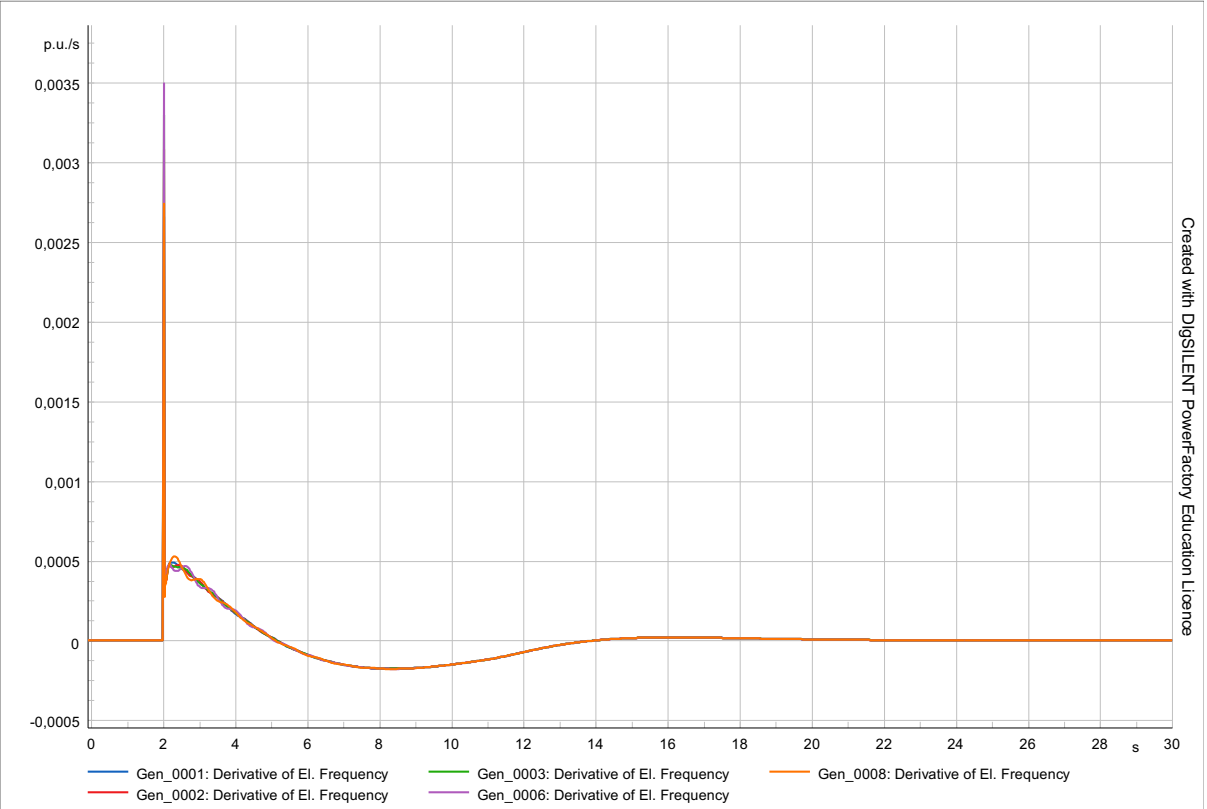




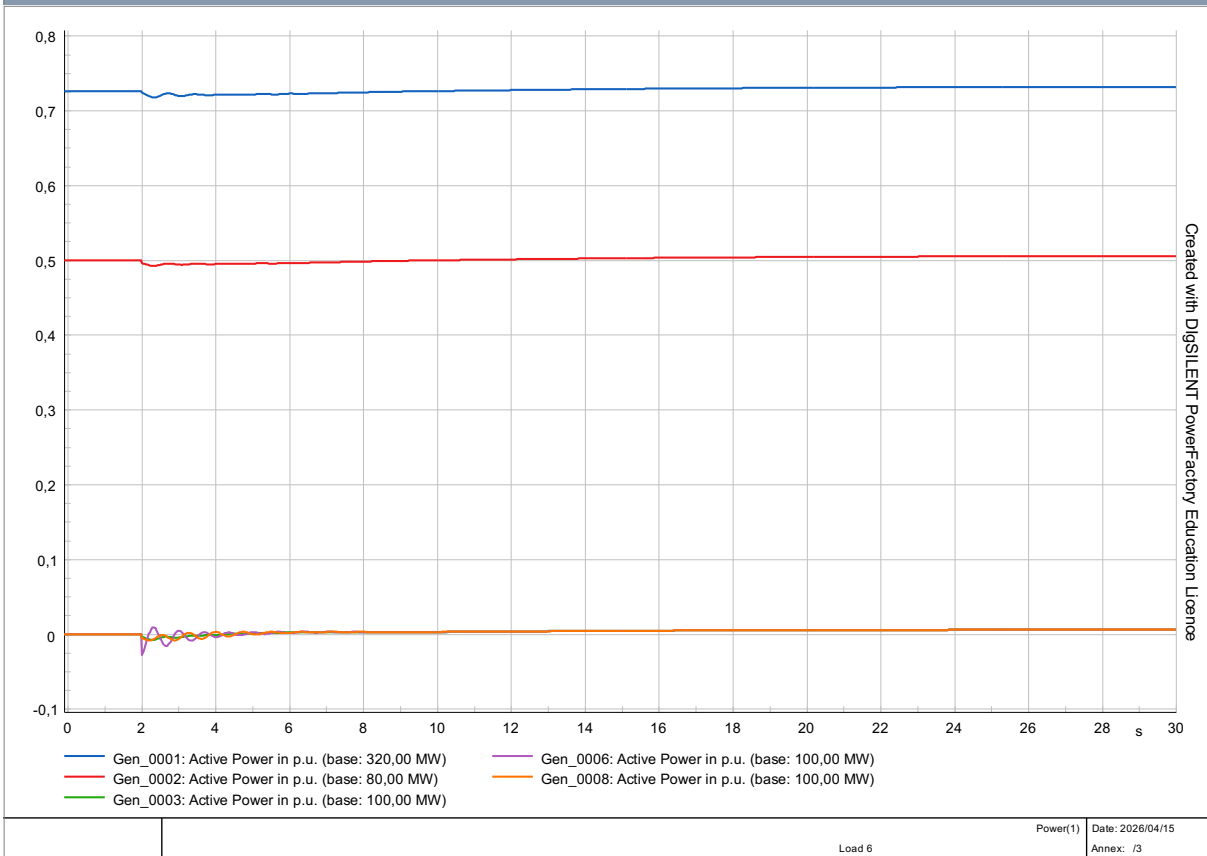
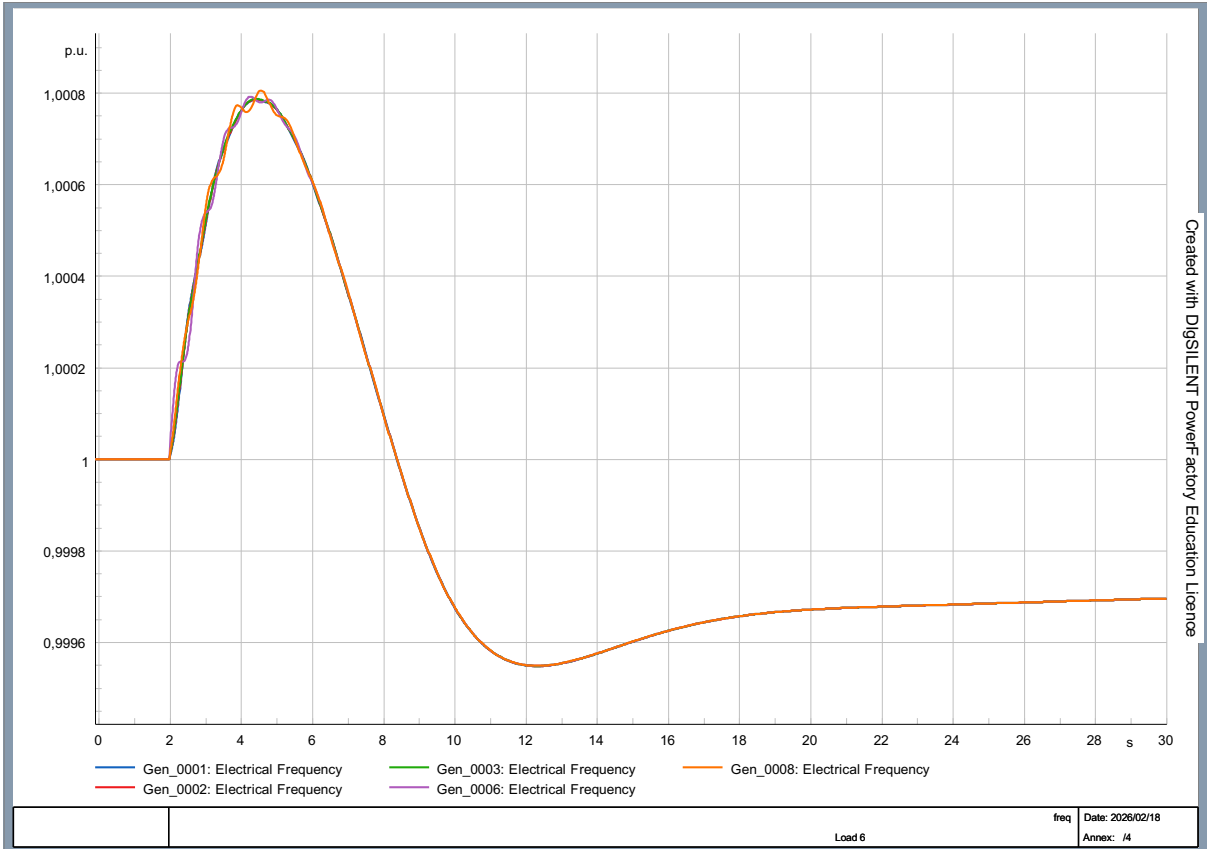


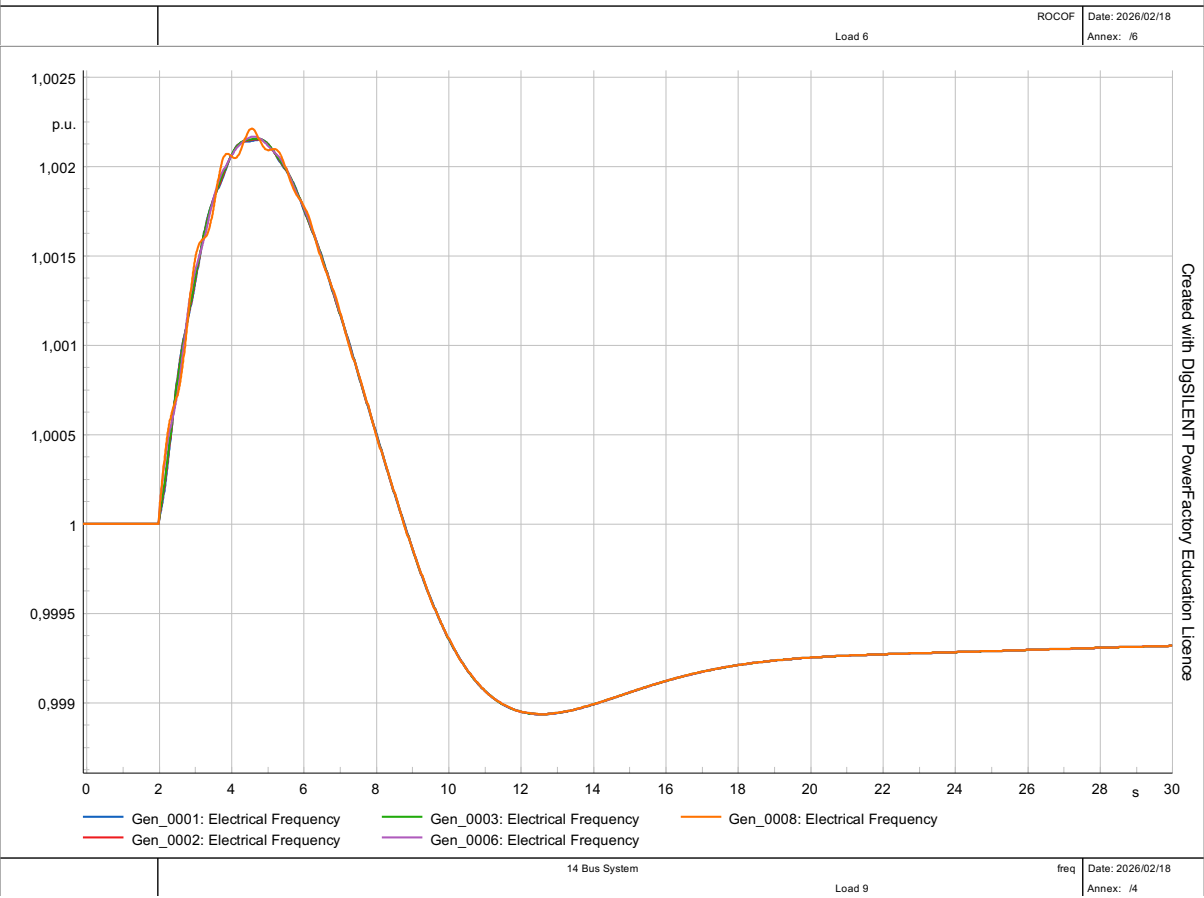
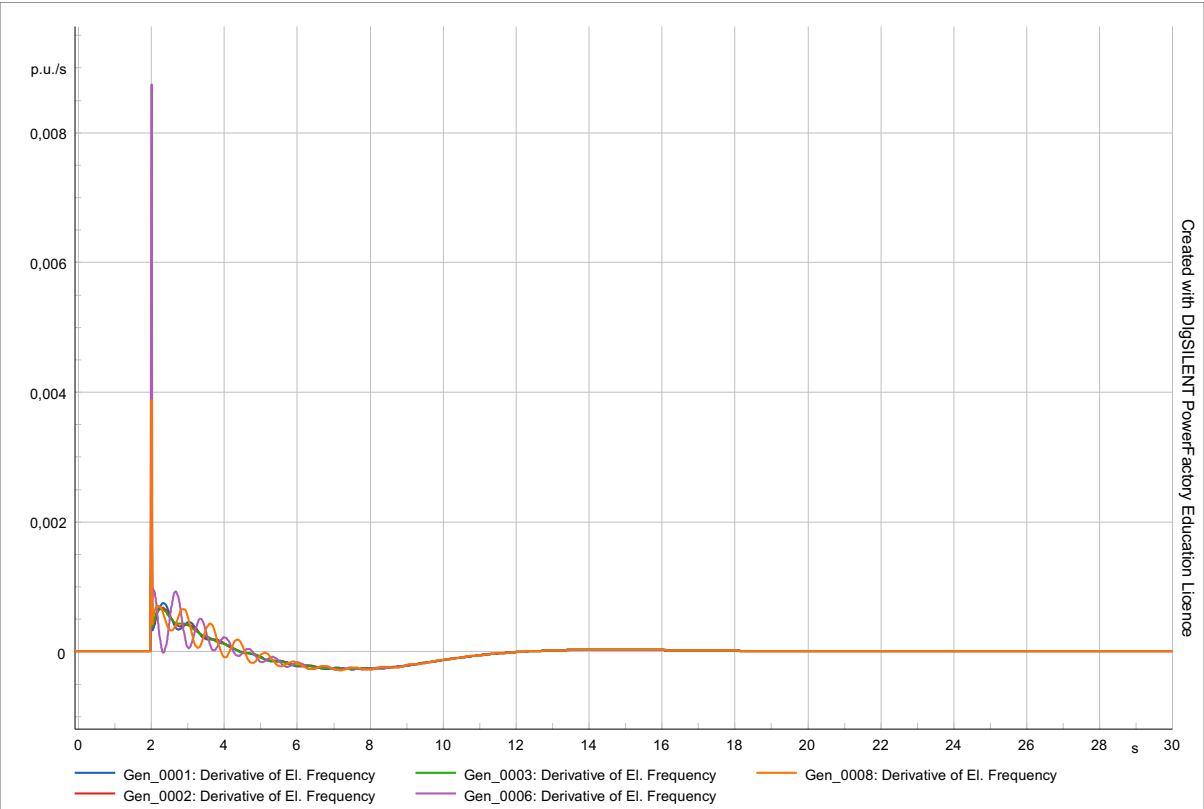


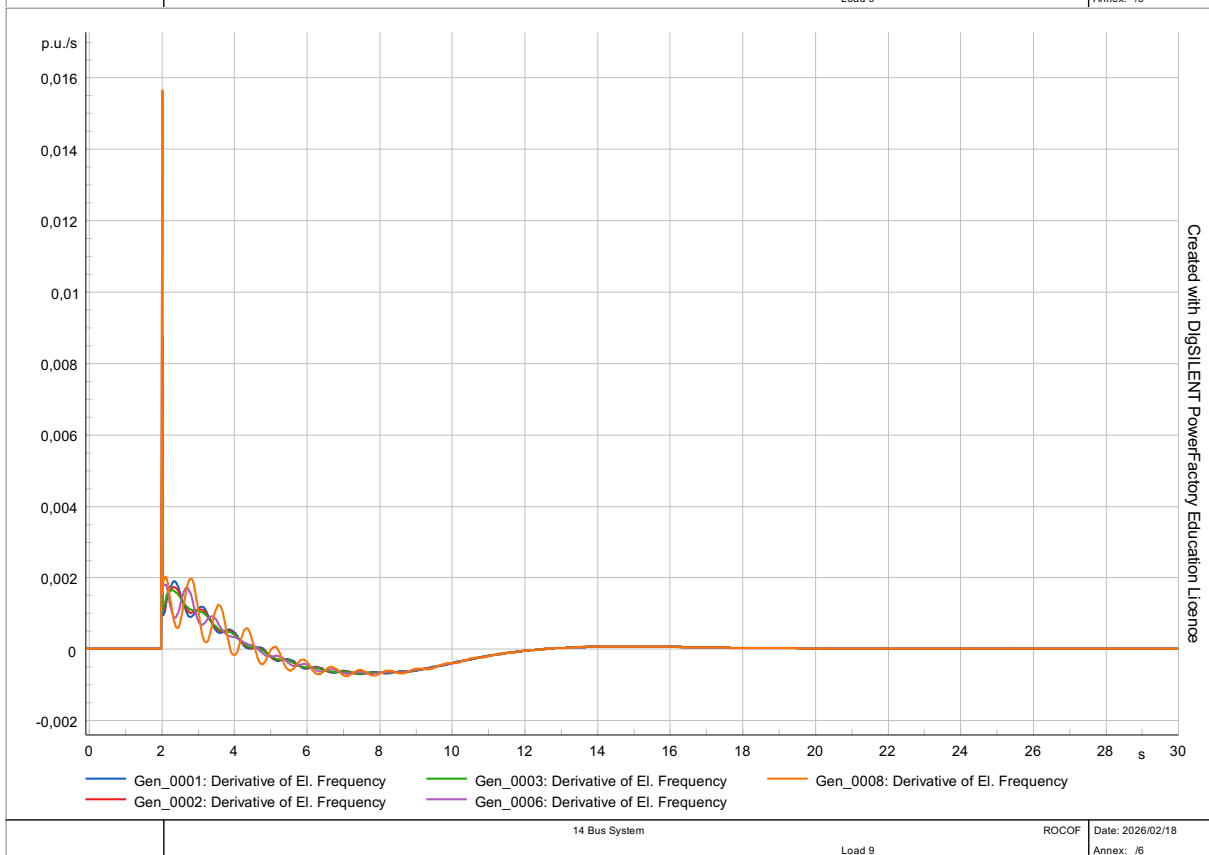
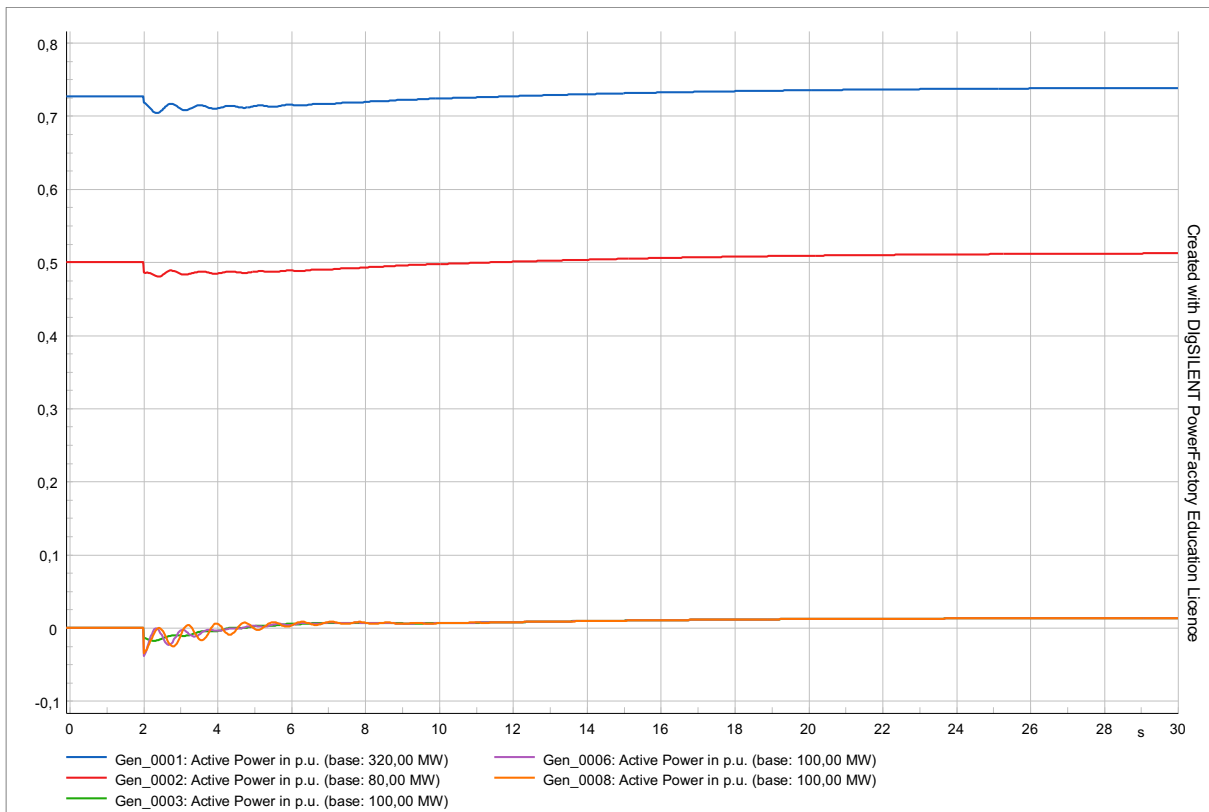
14 Bus System	Power(1)	Date: 2026/04/15
Load 5	Annex: /3	

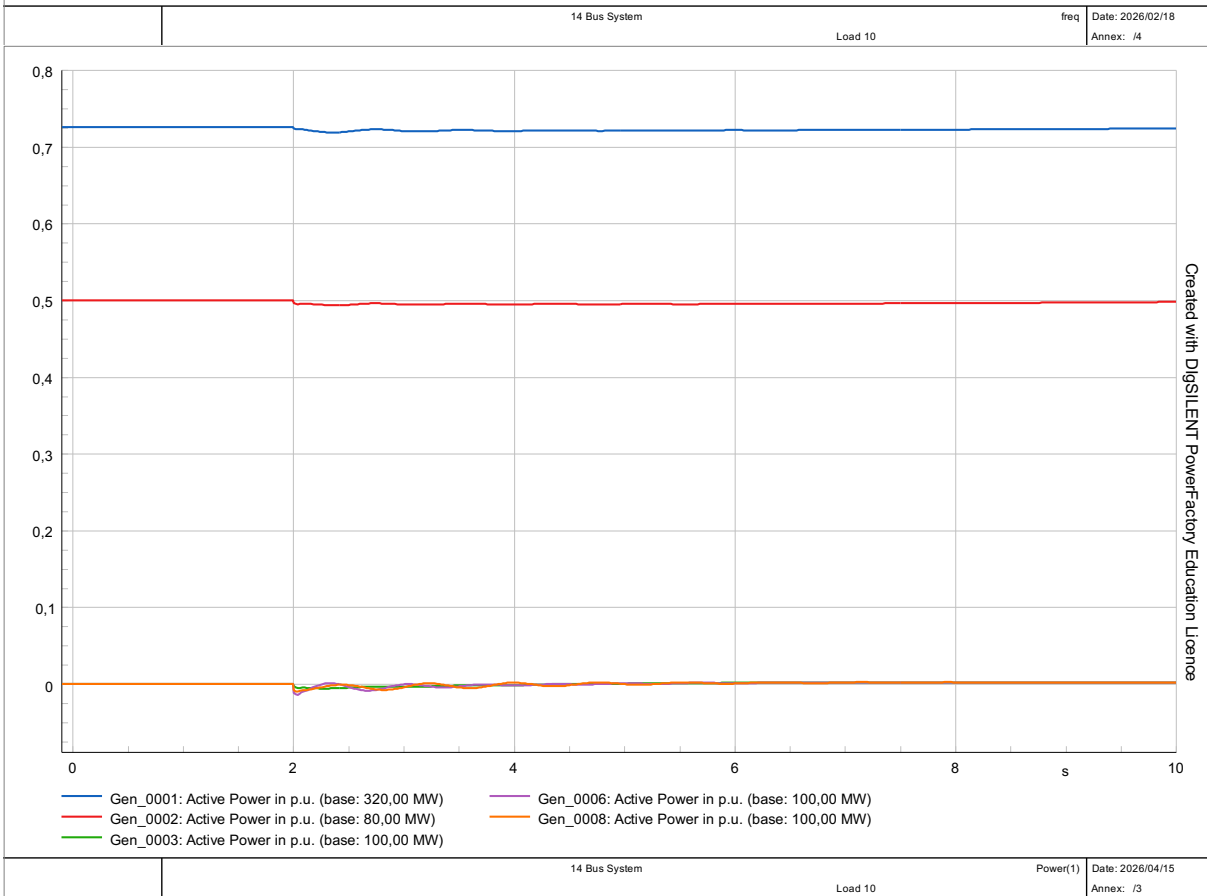
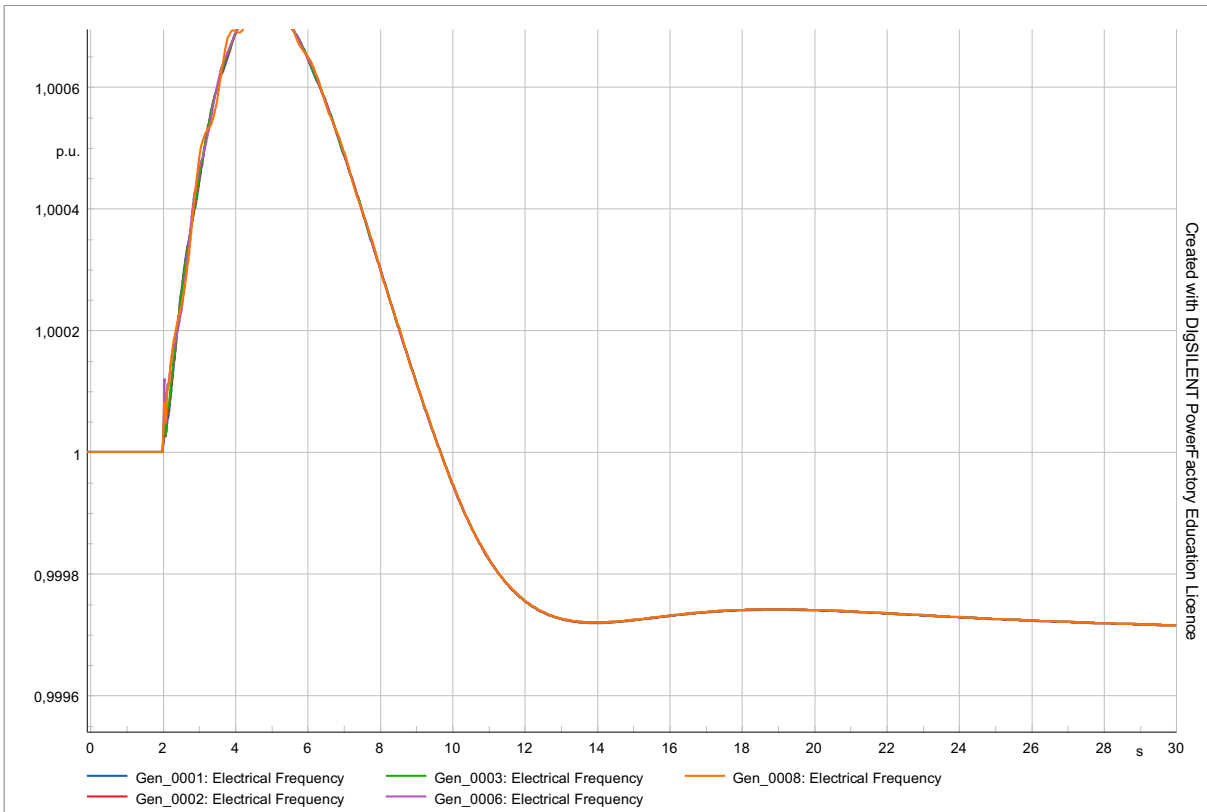


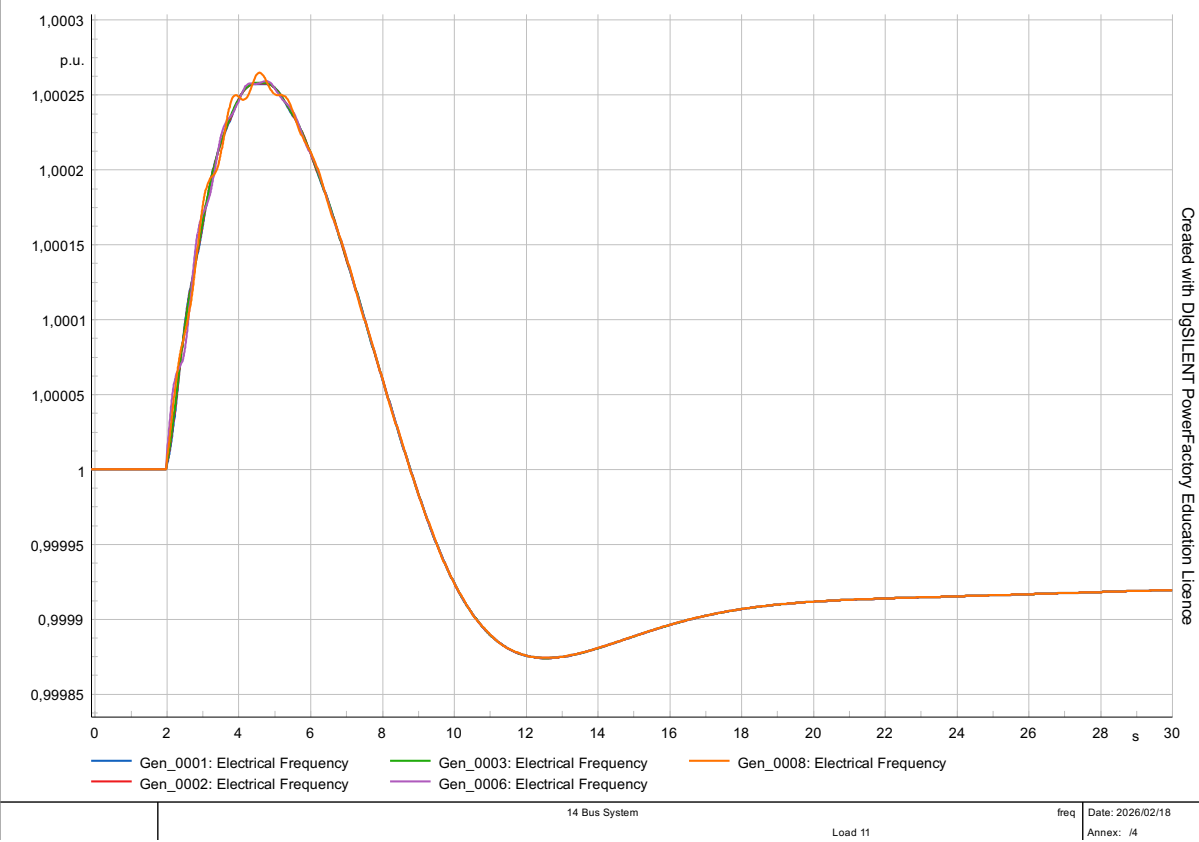
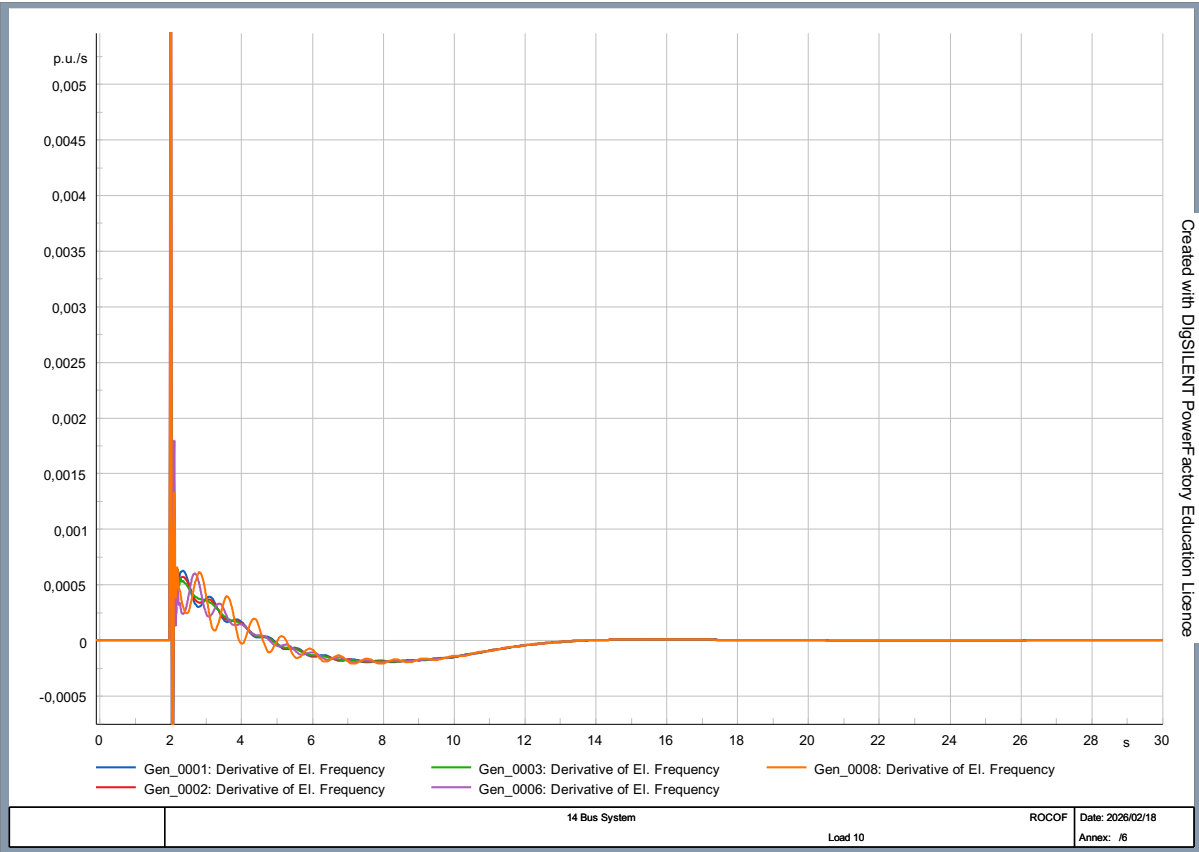
14 Bus System	ROCOF	Date: 2026/02/18
Load 5	Annex: /6	

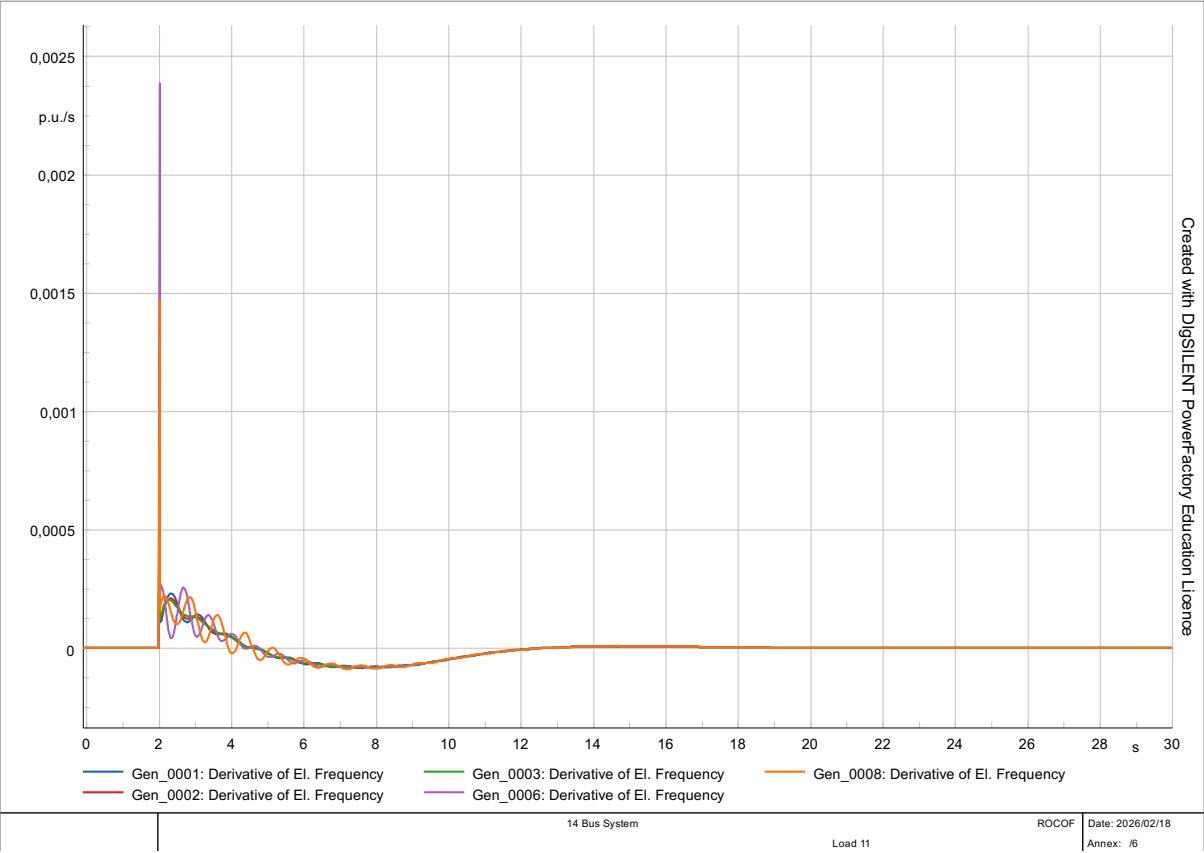
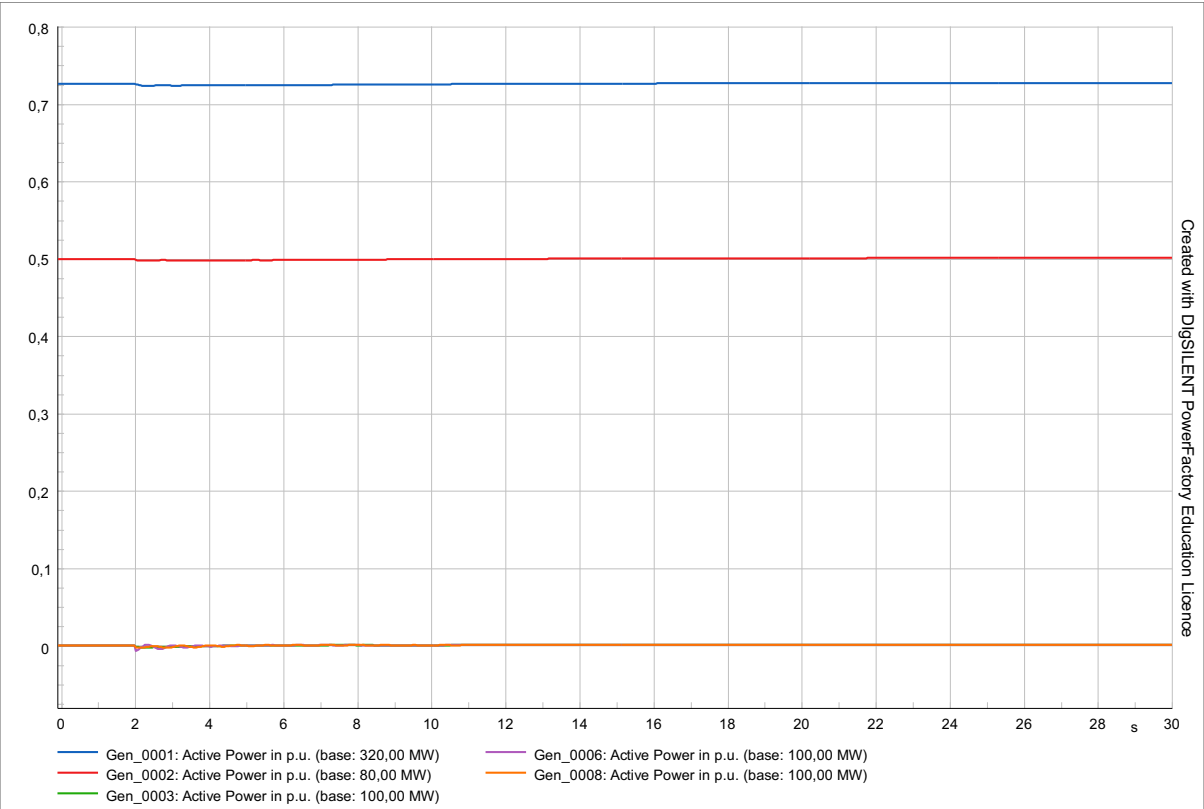


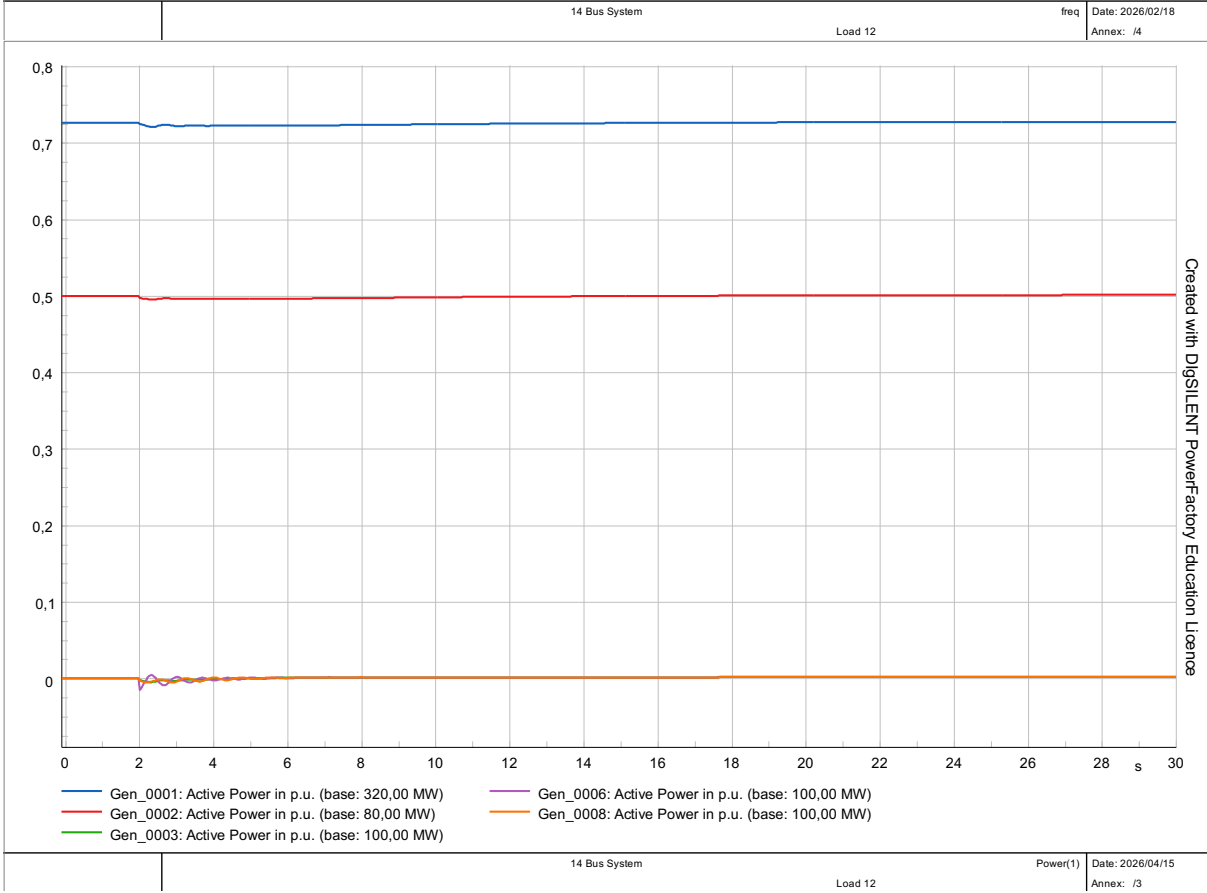
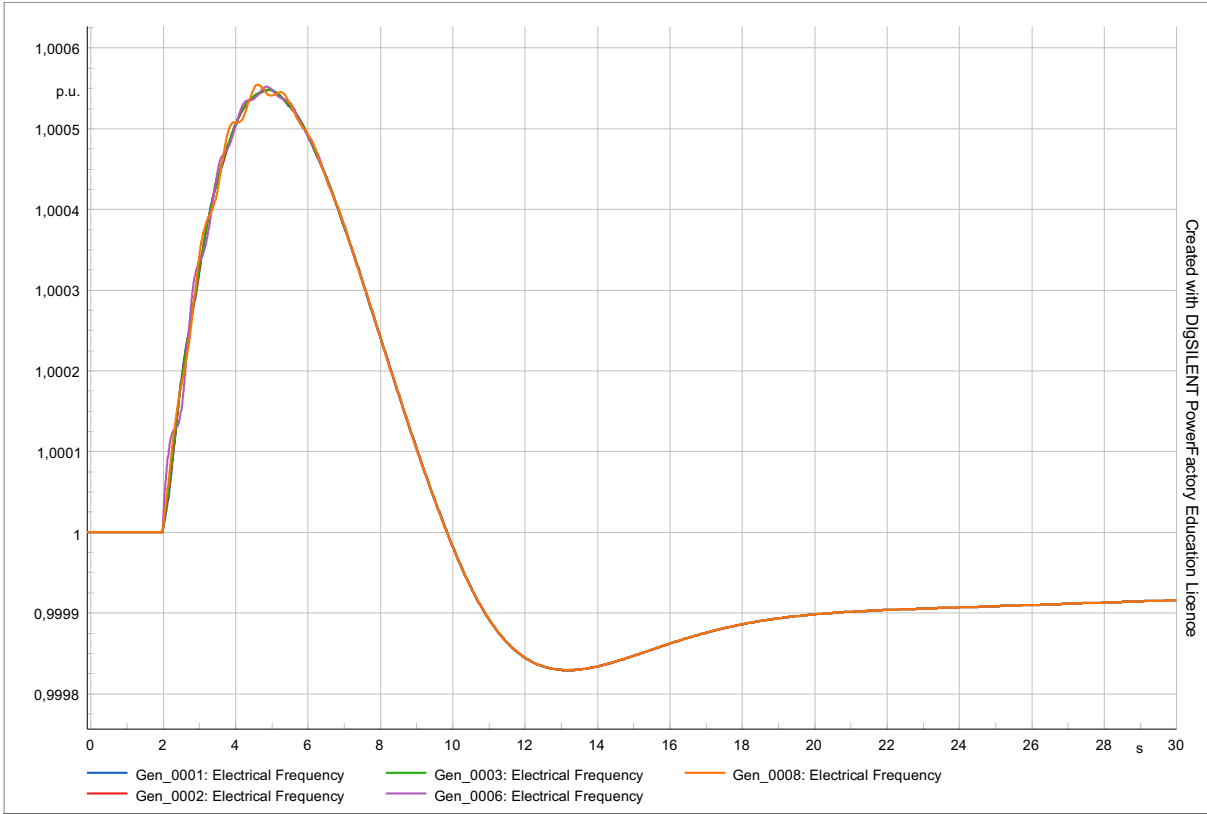


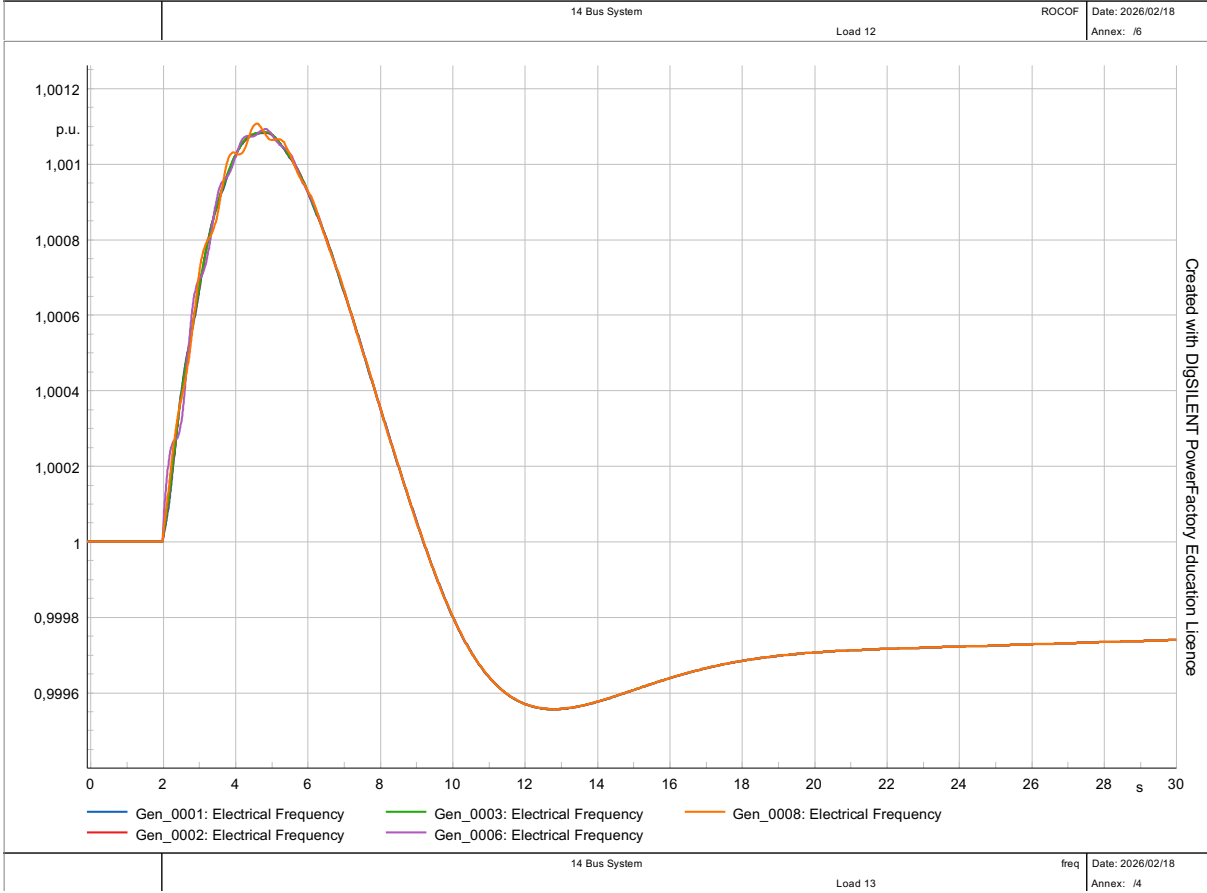
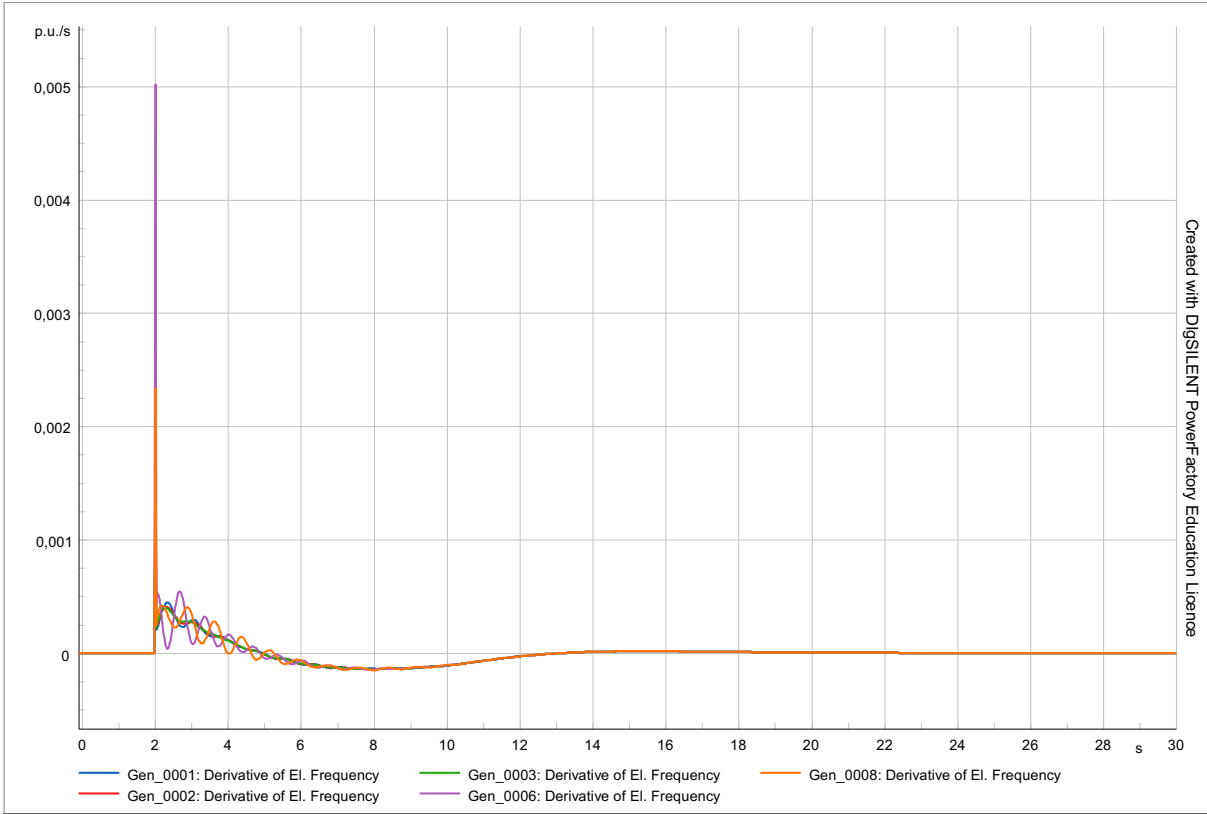


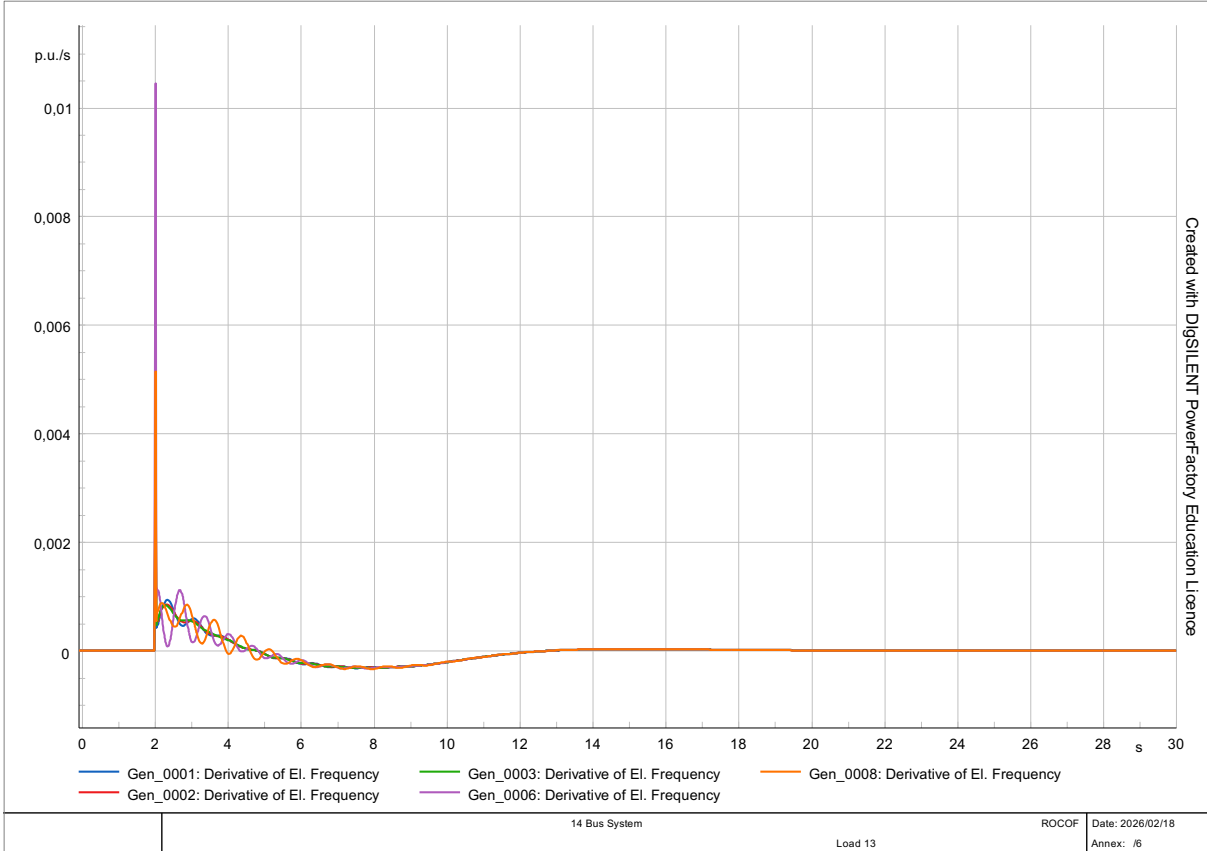
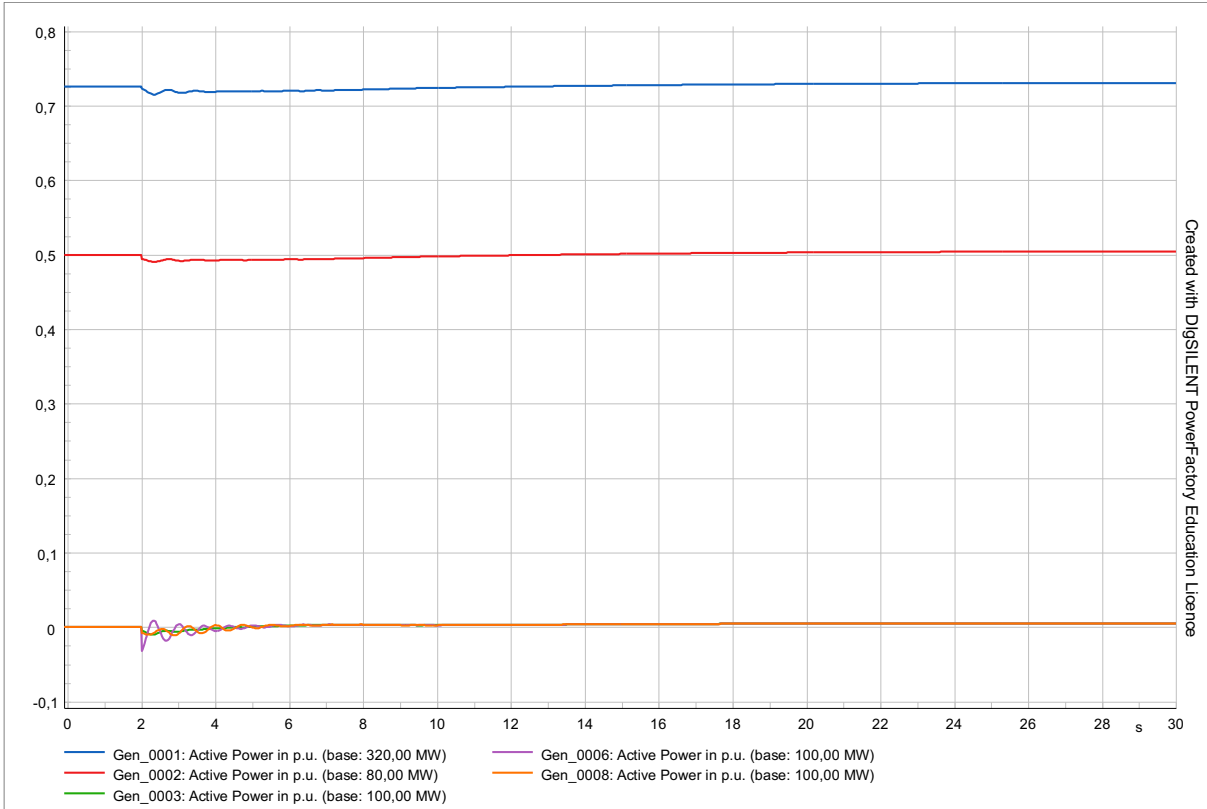


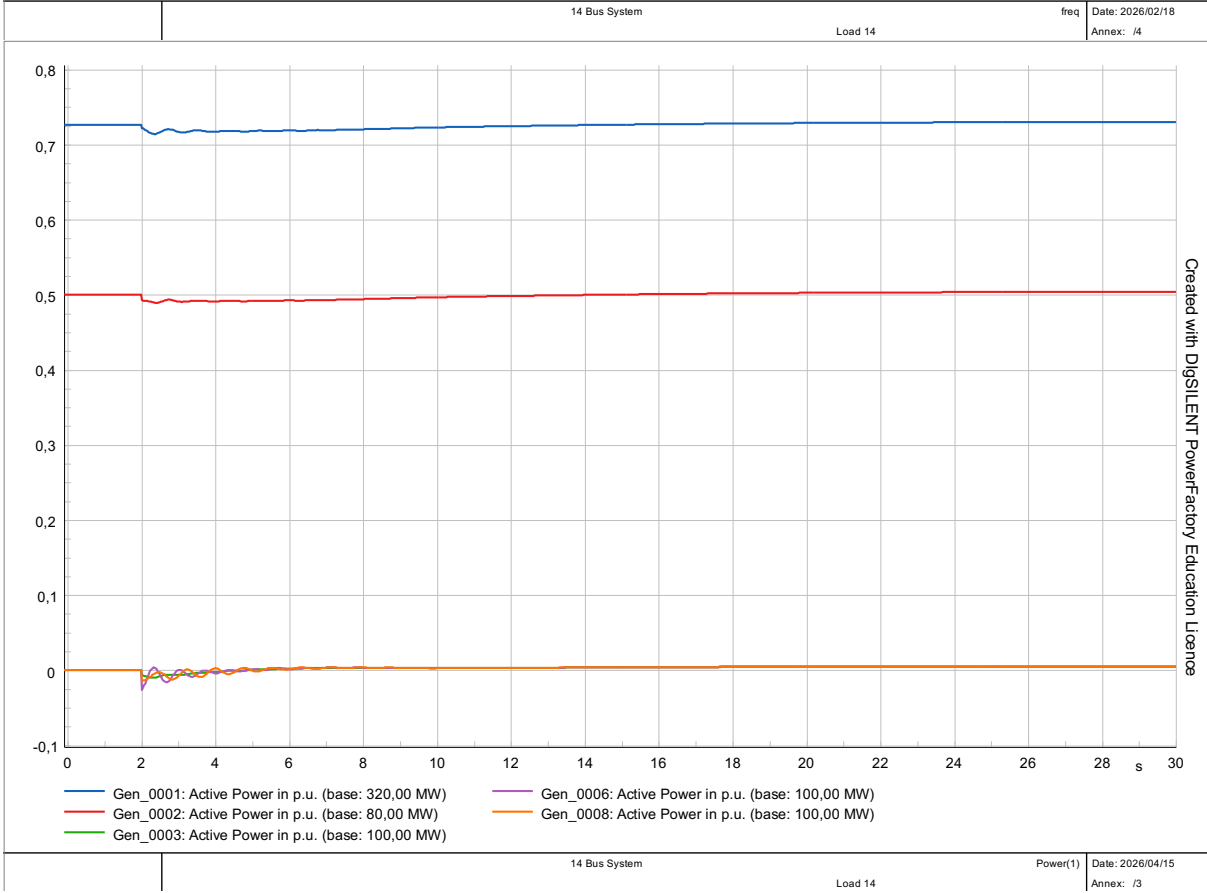
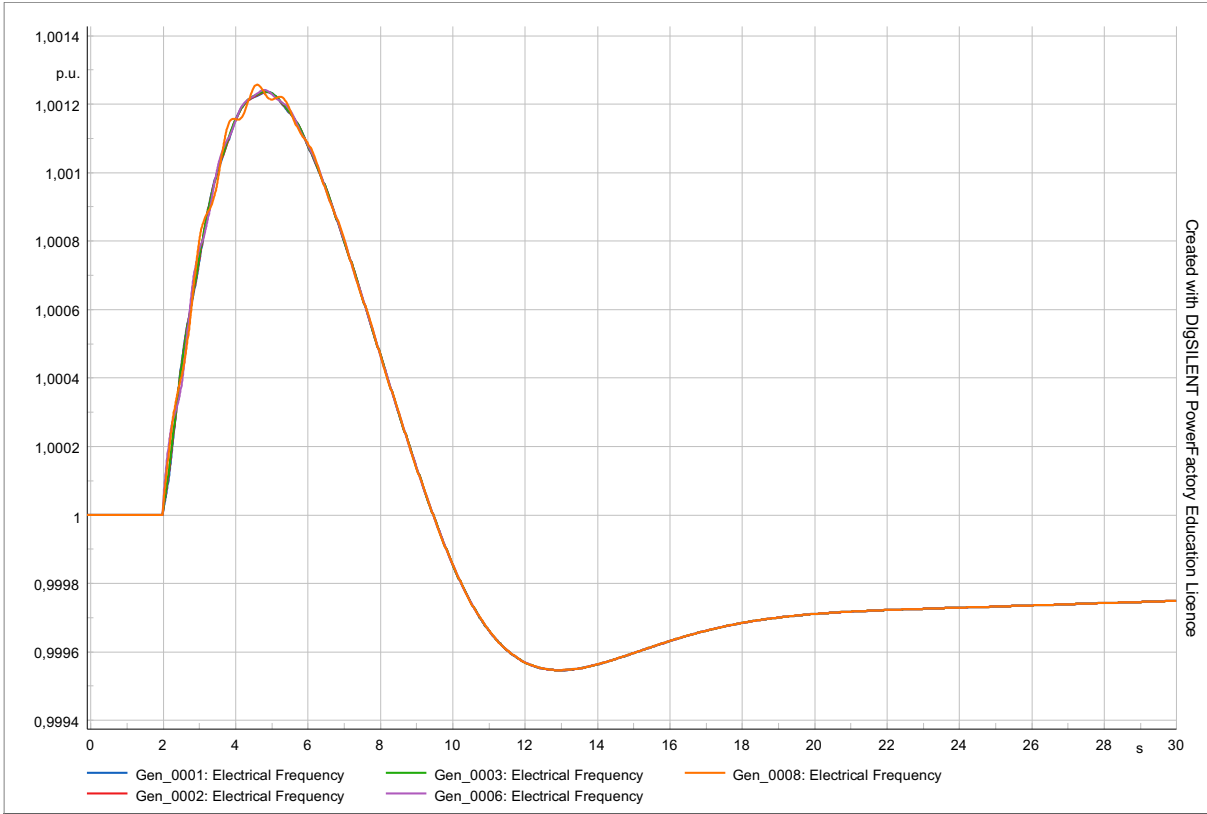


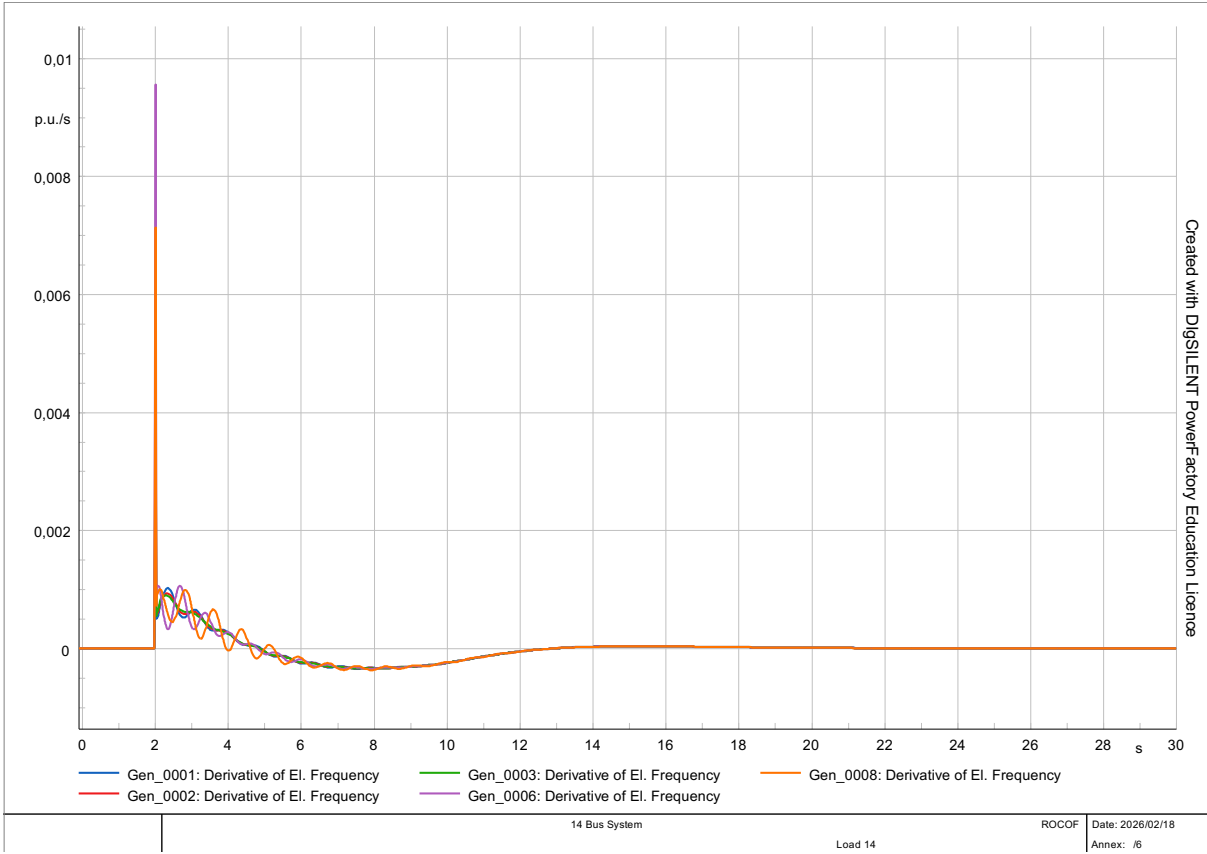












Appendix C Systems inertia results from algorithms

2 Zone System

Case 1: Gen-Loss

<i>Method 1</i>		<i>G1</i>	<i>G2</i>	<i>G3</i>	<i>G4</i>	<i>H System</i>
	H Target	6.50	0.00	6.18	6.18	4.93
						3.23
	Outage G1	0.00	0.00	4.40	15.60	5.23
						4.93
	Outage G2	6.01	0.00	1.38	1.37	2.29
						3.32
	Outage G3	0.18	0.00	0.00	22.00	5.80
						3.32
	Outage G4	0.06	0.00	17.84	0.00	4.68

<i>Method 2</i>		<i>G1</i>	<i>G2</i>	<i>G3</i>	<i>G4</i>	<i>H System</i>
	H Target	6.50	0.00	6.18	6.18	4.93
						3.23
	Outage G1	0.00	0.00	6.35	6.57	3.38
						4.93
	Outage G2	7.14	0.00	6.80	6.86	5.44
						3.32
	Outage G3	4.00	0.00	0.00	7.40	2.98
						3.32
	Outage G4	3.50	0.00	8.78	0.00	3.21

<i>Method 3</i>		<i>G1</i>	<i>G2</i>	<i>G3</i>	<i>G4</i>	<i>H System</i>
	H Target	6.50	0.00	6.18	6.18	4.93
						3.23
	Outage G1	0.00	0.00	6.13	4.78	2.85
						4.93
	Outage G2	9.17	0.00	1.78	1.73	3.32
						3.32
	Outage G3	0.43	0.00	0.00	17.38	4.66
						3.32
	Outage G4	0.11	0.00	2.85	0.00	0.78

Case 2: EarthFault

<i>Method 1</i>		<i>DivS</i>				
		G1	G2	G3	G4	H System
	H Target	6.50	0.00	6.18	6.18	4.93
	Bus1	4.95	0.00	0.22	0.35	1.44
	Bus2	0.62	0.00	0.00	0.00	0.16
	Bus3	0.55	0.00	3.42	0.14	1.07
	Bus4	1.51	0.00	3.95	4.18	2.52
	Bus5	4.64	0.00	0.28	0.44	1.40
	Bus6	1.70	0.00	0.35	0.68	0.71
	Bus7	7.88	0.00	0.10	0.41	2.20
	Bus8	6.15	0.00	0.60	0.44	1.88
	Bus9	2.75	0.00	5.78	8.50	4.46
	Bus10	1.76	0.00	4.70	4.70	2.92
	Bus11	0.63	0.00	3.71	0.03	1.14

<i>Method 2</i>		<i>G1</i>	<i>G2</i>	<i>G3</i>	<i>H System</i>
	H Target	6.50	0.00	6.18	6.18
	Bus1	0.17	0.00	7.63	7.81
	Bus2	0.72	0.00	7.67	7.83
	Bus3	17.00	0.00	15.00	17.00
	Bus4	11.70	0.00	12.00	12.00
	Bus5	0.03	0.00	7.66	7.95
	Bus6	33.00	0.00	40.00	14.00
	Bus7	11.00	0.00	10.00	11.00
	Bus8	10.00	0.00	16.00	15.00
	Bus9	8.70	0.00	9.90	10.40
	Bus10	11.00	0.00	11.80	12.00
	Bus11	16.50	0.00	15.00	17.00

Case 3 Load Loss

<i>Method 1</i>		<i>G1</i>	<i>G2</i>	<i>G3</i>	<i>G4</i>	<i>H System</i>
	H Target	6.50	0.00	6.18	6.18	4.93
	Drop L1	22.40	0.00	0.32	1.01	6.21
	Drop L2	0.57	0.40	13.30	42.75	14.90
	Drop Lboth	32.00	3.00	19.00	61.00	29.95

<i>Method 2</i>		<i>G1</i>	<i>G2</i>	<i>G3</i>	<i>G4</i>	<i>H System</i>
	H Target	6.50	0.00	6.18	6.18	4.93
	Drop L1	8.96	0.00	4.97	5.89	5.19
	Drop L2	7.22	0.00	7.18	10.20	6.44
	Drop Lboth	9.27	0.00	6.72	9.26	6.61

<i>Method 3</i>		<i>G1</i>	<i>G2</i>	<i>G3</i>	<i>G4</i>	<i>H System</i>
	H Target	6.50	0.00	6.18	6.18	4.93
	Drop L1	6.90	0.00	0.00	1.02	2.07
	Drop L2	1.84	1.12	23.42	47.35	19.24
	Drop Lboth	7.22	0.51	5.30	10.76	6.20

Case 4: Load Increase

<i>Method 1</i>		G1	G2	G3	G4	H System
	H Target	6.50	0.00	6.18	6.18	4.93
	Drop L1	10.96	0.00	0.15	0.50	3.04
	Drop L2	0.18	0.00	6.60	23.70	7.97
	Drop Lboth	13.30	0.00	8.29	29.56	13.38

<i>Method 2</i>		<i>G1</i>	<i>G2</i>	<i>G3</i>	<i>G4</i>	<i>H System</i>
	H Target	6.50	0.00	6.18	6.18	4.93
	Drop L1	6.67	0.50	4.00	4.43	4.06
	Drop L2	4.24	0.00	6.62	8.00	4.93
	Drop Lboth	5.85	0.00	6.08	6.94	4.94

<i>Method 3</i>		<i>G1</i>	<i>G2</i>	<i>G3</i>	<i>G4</i>	<i>H System</i>
	H Target	6.50	0.00	6.18	6.18	4.93
	Drop L1	0.90	0.54	4.30	7.80	3.52
	Drop L2	0.90	0.54	4.30	7.80	3.52

	Drop Lboth	2.07	0.71	1.07	2.30	1.58
9 Bus System						
Case 1: Gen-Loss						

<i>Method 1</i>	<i>Scenarios</i>	<i>G1</i>	<i>G2</i>	<i>G3</i>	<i>H System</i>
	H Target	9.55	0.00	2.76	4.78
					0.62
	Outage G1	0.00	0.00	0.03	0.01
					4.78
	Outage G2	11.38	0.00	1.14	5.21
					4.16
	Outage G3	3.60	0.00	0.00	1.57

<i>Method 2</i>	<i>Scenarios</i>	<i>G1</i>	<i>G2</i>	<i>G3</i>	<i>H System</i>
	H Target	9.55	0.00	2.76	4.78
					0.62
	Outage G1	0.00	0.00	2.66	0.60
					4.78
	Outage G2	10.51	0.00	2.55	5.15
					4.16
	Outage G3	10.41	0.00	0.00	4.53

<i>Method 3</i>	<i>Scenarios</i>	<i>G1</i>	<i>G2</i>	<i>G3</i>	<i>H System</i>
	H Target	9.55	0.00	2.76	4.78
					0.62
	Outage G1	0.00	0.00	0.36	0.08
					4.78
	Outage G2	11.53	0.00	0.11	5.05
					4.16
	Outage G3	8.35	0.15	0.00	3.69

Case 2: Earth Fault

<i>Method 1</i>		<i>G1</i>	<i>G2</i>	<i>G3</i>	<i>H System</i>
	H Target	9.55	0.00	2.76	4.78
	Bus1	5.32	0.00	7.31	3.97
	Bus2	0.37	0.00	0.10	0.19
	Bus3	3.82	0.00	3.90	2.55
	Bus4	2.26	0.00	1.88	1.41
	Bus5	2.07	0.00	2.12	1.38
	Bus6	2.86	0.00	3.29	1.99
	Bus7	0.93	0.00	0.57	0.53
	Bus8	1.51	0.00	1.16	0.92
	Bus9	5.32	0.00	7.31	3.97

	<i>G1</i>	<i>G2</i>	<i>G3</i>	<i>H</i> <i>System</i>	
<i>Method 2</i>	H Target	9.55	0.00	2.76	4.78
	Bus1	3.62	0.00	1.93	2.01
	Bus2	1.68	0.00	0.30	0.80
	Bus3	5.92	0.00	14.00	5.74
	Bus4	13.41	0.00	5.12	7.00
	Bus5	14.09	0.00	1.87	6.56
	Bus6	12.67	0.00	1.69	5.90
	Bus7	12.95	0.00	1.91	6.07
	Bus8	10.67	0.00	1.91	5.08
	Bus9	2.84	0.00	1.22	1.51

Case 3: Load Loss

	<i>G1</i>	<i>G2</i>	<i>G3</i>	<i>H System</i>	
<i>Method 1</i>	H Target	9.55	0.00	2.76	4.78
	Drop L1	7.11	0.00	3.54	3.90
	Drop L2	2.97	0.00	2.09	1.77
	Drop L3	2.95	0.00	5.13	2.44

	<i>G1</i>	<i>G2</i>	<i>G3</i>	<i>H</i> <i>System</i>	
<i>Method 2</i>	H Target	9.55	0.00	2.76	4.78
	Drop L1	10.61	0.00	2.73	5.24
	Drop L2	10.63	0.00	2.68	5.24
	Drop L3	16.30	0.00	2.53	7.67

	<i>G1</i>	<i>G2</i>	<i>G3</i>	<i>H</i> <i>System</i>
<i>Method 3</i>				
H Target	9.55	0.00	2.76	4.78
Drop L1	9.41	0.00	1.03	4.33
Drop L2	9.51	0.00	0.10	4.16
Drop L3	0.79	0.00	0.21	0.39

Case 4: Load Increase

	<i>G1</i>	<i>G2</i>	<i>G3</i>	<i>H</i> <i>System</i>
<i>Method 1</i>				
H Target	9.55	0.00	2.76	4.78
Drop L1	0.64	0.00	0.09	0.30
Drop L2	0.45	0.00	0.09	0.22
Drop L3	0.13	0.00	0.09	0.08

	<i>G1</i>	<i>G2</i>	<i>G3</i>	<i>H</i> <i>System</i>
<i>Method 2</i>				
H Target	9.55	0.00	2.76	4.78
Drop L1	12.20	0.00	4.55	6.34
Drop L2	12.21	0.00	4.56	6.35
Drop L3	3.88	0.00	4.63	2.73

	<i>G1</i>	<i>G2</i>	<i>G3</i>	<i>H</i> <i>System</i>
<i>Method 3</i>				
H Target	9.55	0.00	2.76	4.78
Drop L1	9.20	0.00	1.09	4.25
Drop L2	9.50	0.00	0.69	4.29
Drop L3	2.25	0.00	0.31	1.05

14 Bus System

Case 1: Gen-Loss

<i>Method 1</i>		<i>G1</i>	<i>G2</i>	<i>G3</i>	<i>G6</i>	<i>G8</i>	<i>H System</i>
	H Target	10.00	10.00	10.00	10.00	10.00	10.00
							5.00
	Outage G1		1.73	5.53	2.75	1.07	1.39
							8.75
	Outage G2	0.16		0.06	0.04	0.03	0.10
							8.75
	Outage G3	0.02	0.01		0.02	0.01	0.01
							8.75
	Outage G6	0.00	0.00	0.01		0.00	0.00
							8.75
	Outage G8	0.01	0.00	0.01	0.01		0.00

<i>Method 2</i>		<i>G1</i>	<i>G2</i>	<i>G3</i>	<i>G6</i>	<i>G8</i>	<i>H System</i>
	H Target	10.00	10.00	10.00	10.00	10.00	10.00
							5.00
	Outage G1		7.28	7.15	6.38	5.13	3.24
							8.75
	Outage G2	4.23		6.13	5.32	4.80	4.15
							8.75
	Outage G3	5.69	5.64		5.10	5.08	4.82
							8.75
	Outage G6	5.67	5.65	5.08		5.06	4.81
							8.75
	Outage G8	5.62	5.59	5.07	5.08		4.78

	G1	G2	G3	G6	G8	H System
H Target	10.00	10.00	10.00	10.00	10.00	10.00
						5.00
Outage G1		17.90	6.67	5.04	0.45	3.76
						8.75
Outage G2	3.60		4.43	4.64	4.46	3.49
						8.75
Outage G3	3.74	1.60		4.37	3.94	3.11
						8.75
Outage G6	3.50	2.34	4.47		3.96	3.10
						8.75
Outage G8	3.30	2.10	3.99	3.95		2.91

Case 2 Earth Fault

<i>Method 1</i>		<i>G1</i>	<i>G2</i>	<i>G3</i>	<i>G6</i>	<i>G8</i>	<i>H</i> <i>System</i>
	H Target	10.00	10.00	10.00	10.00	10.00	10.00
	Bus1	3.27	4.76	2.94	0.70	0.15	2.70
	Bus2	0.11	1.73	1.36	0.40	0.02	0.49
	Bus3	0.05	0.35	0.24	0.42	0.16	0.17
	Bus4	0.13	0.25	0.69	0.26	0.04	0.22
	Bus5	3.27	4.76	2.94	0.70	0.15	2.70
	Bus6	0.04	0.38	0.54	0.47	0.40	0.24
	Bus7	0.07	0.53	0.37	0.70	0.34	0.28
	Bus8	0.03	0.25	0.18	0.26	0.25	0.13
	Bus9	0.08	0.36	0.21	0.76	0.02	0.21
	Bus10	0.05	0.11	0.05	0.14	0.01	0.07
	Bus11	0.02	0.01	0.00	0.34	0.03	0.06
	Bus12	0.06	0.07	0.01	0.96	0.05	0.16
	Bus13	0.01	0.01	0.01	0.59	0.05	0.09
	Bus14	0.01	0.01	0.01	0.22	0.04	0.04

<i>Method 2</i>		<i>G1</i>	<i>G2</i>	<i>G3</i>	<i>G6</i>	<i>G8</i>	<i>H System</i>
	H Target	10.00	10.00	10.00	10.00	10.00	10.00
	Bus1	6.17	7.28	7.15	6.38	5.31	6.35
	Bus2	6.26	6.38	6.22	6.20	5.72	6.20
	Bus3	7.06	7.04	4.34	5.62	7.71	6.62
	Bus4	6.35	6.44	5.30	5.67	5.43	6.03
	Bus5	6.17	7.28	7.15	6.38	5.31	6.35
	Bus6	8.75	8.68	4.46	4.77	5.78	7.34
	Bus7	9.86	9.99	4.22	5.28	5.97	8.11
	Bus8	9.21	9.17	4.23	4.93	5.51	7.59
	Bus9	8.92	9.25	4.41	5.14	5.63	7.51
	Bus10	6.69	7.12	4.63	5.09	6.02	6.20
	Bus11	5.22	5.63	4.82	5.01	6.09	5.30
	Bus12	3.75	4.15	4.68	4.68	5.99	4.31
	Bus13	4.90	5.25	4.83	5.05	6.03	5.09
	Bus14	4.88	5.36	4.79	4.85	6.16	5.09

Case 3: Load Loss

<i>Method I</i>		<i>G1</i>	<i>G2</i>	<i>G3</i>	<i>G6</i>	<i>G8</i>	<i>H</i> <i>System</i>
	H Target	10.00	10.00	10.00	10.00	10.00	10.00
	Drop L2	0.01	0.00	0.01	0.01	0.01	0.01
	Drop L3	0.22	0.18	0.06	0.27	0.24	0.20
	Drop L4	0.06	0.04	0.07	0.07	0.07	0.06
	Drop L5	0.00	0.00	0.00	0.00	0.00	0.00
	Drop L6	0.00	0.00	0.00	0.00	0.00	0.00
	Drop L9	0.01	0.01	0.02	0.01	0.02	0.01
	Drop L10	0.00	0.00	0.00	0.00	0.00	0.00
	Drop L11	0.00	0.00	0.00	0.00	0.00	0.00
	Drop L12	0.00	0.00	0.00	0.00	0.00	0.00
	Drop L13	0.00	0.00	0.00	0.00	0.01	0.00
	Drop L14	0.00	0.00	0.00	0.00	0.01	0.00

<i>Method 2</i>		<i>G1</i>	<i>G2</i>	<i>G3</i>	<i>G6</i>	<i>G8</i>	<i>H System</i>
	H Target	10.00	10.00	10.00	10.00	10.00	10.00
	Drop L2	4.83	6.60	6.60	5.80	5.30	5.45
	Drop L3	3.68	4.56	8.03	4.60	4.38	4.54
	Drop L4	5.95	5.92	7.02	6.67	6.35	6.22
	Drop L5	4.70	5.80	6.65	7.15	6.00	5.55
	Drop L6	3.68	4.45	5.33	10.43	5.85	5.10
	Drop L9	4.00	4.90	6.00	8.53	7.68	5.39
	Drop L10	3.85	4.69	5.90	9.00	7.41	5.30
	Drop L11	3.83	4.64	5.61	9.82	6.70	5.26
	Drop L12	3.87	4.67	5.34	10.30	6.00	5.22
	Drop L13	3.80	4.60	5.40	10.30	6.12	5.20
	Drop L14	4.00	4.80	5.70	9.32	7.00	5.35

<i>Method 3</i>		<i>G1</i>	<i>G2</i>	<i>G3</i>	<i>G6</i>	<i>G8</i>	<i>H System</i>
	H Target	10.00	10.00	10.00	10.00	10.00	10.00
	Drop L2	3.78	1.03	4.61	4.87	4.73	3.79
	Drop L3	4.15	3.06	0.93	4.98	4.84	3.80
	Drop L4	3.73	2.41	4.00	4.20	4.50	3.75
	Drop L5	4.16	2.78	4.89	4.51	5.29	4.26
	Drop L6	3.80	3.88	5.16	0.06	3.02	3.41
	Drop L9	3.78	3.39	4.61	3.76	1.05	3.49
	Drop L10	3.66	3.52	4.72	0.88	2.30	3.26
	Drop L11	3.88	3.65	4.93	1.06	1.81	3.37
	Drop L12	3.90	3.69	5.09	0.24	3.26	3.49
	Drop L13	3.92	3.74	5.05	2.64	1.44	3.57
	Drop L14	3.82	3.48	4.78	1.84	1.58	3.37

Case 4: Load Increase

<i>Method I</i>		<i>G1</i>	<i>G2</i>	<i>G3</i>	<i>G6</i>	<i>G8</i>	<i>H</i> <i>System</i>
	H Target	10.00	10.00	10.00	10.00	10.00	10.00
	Drop L2	0.01	0.00	0.01	0.01	0.01	0.01
	Drop L3	0.18	0.14	0.06	0.21	0.19	0.16
	Drop L4	0.06	0.04	0.07	0.07	0.07	0.06
	Drop L5	0.00	0.00	0.00	0.00	0.00	0.00
	Drop L6	0.00	0.00	0.00	0.00	0.00	0.00
	Drop L9	0.01	0.01	0.01	0.01	0.02	0.01
	Drop L10	0.00	0.00	0.00	0.00	0.00	0.00
	Drop L11	0.00	0.00	0.00	0.00	0.00	0.00
	Drop L12	0.00	0.00	0.00	0.00	0.00	0.00
	Drop L13	0.00	0.00	0.00	0.00	0.01	0.00
	Drop L14	0.00	0.00	0.00	0.00	0.01	0.00

<i>Method 2</i>		<i>G1</i>	<i>G2</i>	<i>G3</i>	<i>G6</i>	<i>G8</i>	<i>H System</i>
	H Target	10.00	10.00	10.00	10.00	10.00	10.00
	Drop L2	6.36	6.27	7.97	7.99	7.98	6.96
	Drop L3	6.39	6.35	8.11	8.02	8.01	7.01
	Drop L4	6.19	6.15	7.72	7.73	7.76	6.77
	Drop L5	6.26	6.22	7.83	7.80	7.85	6.84
	Drop L6	6.60	6.60	8.34	10.48	8.41	7.53
	Drop L9	6.55	6.55	8.25	8.59	8.29	7.23
	Drop L10	6.60	6.60	8.31	9.10	8.36	7.35
	Drop L11	6.49	6.48	8.18	9.80	8.22	7.33
	Drop L12	6.37	6.36	8.03	10.32	8.06	7.28
	Drop L13	6.46	6.46	8.15	10.27	8.20	7.37
	Drop L14	6.42	6.42	8.09	9.36	8.11	7.21

<i>Method 3</i>		<i>G1</i>	<i>G2</i>	<i>G3</i>	<i>G6</i>	<i>G8</i>	<i>H System</i>
	H Target	10.00	10.00	10.00	10.00	10.00	10.00
	Drop L2	3.50	1.06	4.30	4.49	5.48	3.67
	Drop L3	3.76	2.77	0.70	4.58	4.41	3.44
	Drop L4	3.48	2.26	3.78	3.98	4.43	3.55
	Drop L5	3.42	2.29	4.07	3.76	4.38	3.52
	Drop L6	0.00	0.00	0.00	0.00	0.00	0.00
	Drop L9	37.58	3.24	4.50	1.93	12.37	21.55
	Drop L10	0.00	0.00	0.00	0.00	0.00	0.00
	Drop L11	0.00	0.00	0.00	0.00	0.00	0.00
	Drop L12	3.52	3.36	4.62	0.16	2.24	3.06
	Drop L13	0.00	0.00	0.00	0.00	0.00	0.00
	Drop L14	0.00	0.00	0.00	0.00	0.00	0.00

Appendix D Conference paper

Conference paper on: Validating Inertia Assessment Metrics in Distribution Systems with High RES Penetration.

Written for the 14th IEEE International Workshop on Applied Measurements for Power Systems, held at The University of Campania in Caserta Italy 2024.

Validating Inertia Assessment Metrics in Distribution Systems with High RES Penetration

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Abstract— The role of inertia in distribution networks is rapidly increasing. Many researchers are focused on ways to estimate, measure, and control inertia, as it has become a crucial parameter that provides valuable information for network management. However, the distribution network is not as stable and has many more nodes compared to the transmission network. Additionally, the distribution network is populated with various renewable energy sources. While this brings several advantages, such as reducing fossil fuel-based energy production and adjusting voltage in remote nodes of the network, it also significantly impacts the network's inertia due to the removal of rotating electrical assets in favor of renewable sources. To address this issue, the paper tests a new inertia metric on a section of a real network with significant presence of renewables. This metric, calculated using frequency and power measurements, demonstrates a strong capability to reflect the current state of inertia in the network. The paper concludes with a description of the network under consideration, the instrumentation used, and a brief uncertainty analysis.

Keywords— *Inertia, ROCOF, frequency, metrics, accuracy, renewables, uncertainty, distribution network*

I. INTRODUCTION

Power system management requires knowledge of system frequency and its rate of change. Tracking the Rate of Change of Frequency (ROCOF) helps power system operators maintain system dynamic stability. When the balance between generation and load is disturbed, the frequency can deviate from the nominal values of 50 Hz or 60 Hz. The rate at which frequency changes from one value to another is influenced by the availability of inertia in the interconnected power system. The working principles of an AC power system rely on the inertia within large synchronous generators, as it supports system dynamic stability by damping sudden changes in frequency. If sufficient inertia is available in a power system, a low ROCOF can be maintained, allowing for a safe and predictable transition between different states of power system operation.

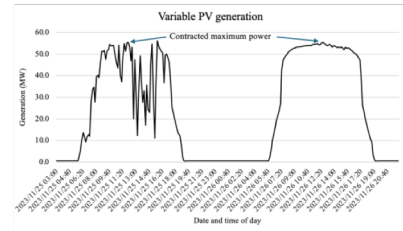


Fig. 1. A real-world example on PV production variability

Renewable power plants (RPPs) that convert energy from wind and photovoltaic (PV) sources inject power into the AC power system mostly through solid-state interfaces but do not store inertia in a mechanical system [1]. Maximum power production from these sources can be highly variable due to sudden and unpredictable changes in solar irradiation or wind speed. An example of the daily production at a grid-connected PV plant is shown in Fig. 1. In the graph it can be appreciated how power production suddenly changes up to 80 %.

An RPP typically does not participate in energy dispatch strategies and generates as much power as possible all the time. If a large portion of total power generation comes from RPPs, such sudden changes in generation can constrain effective frequency control measures. In a traditional power system, a sudden mismatch between generation and load typically results from a change in loading, not due to a change in generation as is the case with an RPP.

While it is possible to emulate inertia from solid-state generators, the extent to which this can be done is limited and requires longer reaction times compared to synchronous generators [2]. As engineering and technical considerations are not the only factors affecting the mix of generation

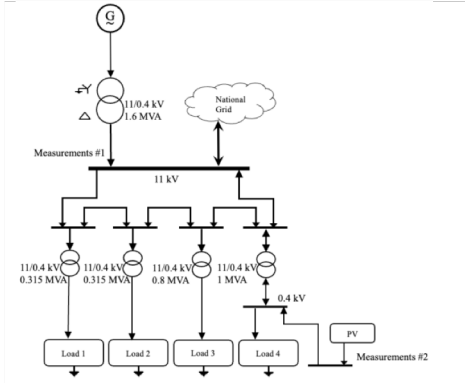


Fig. 2. Schematic of the distribution network described and used in this work

sources in modern power systems—political and environmental factors also play a role—RPPs are often preferred over traditional thermal solutions. Consequently, the availability of inertia decreases as renewable energy generation increases.

From the above discussion, it is evident that accurate knowledge of the available inertia in a power system is crucial for planning strategies to mitigate system frequency variations [3].

This paper evaluates practical solutions for tracking inertia in a distribution system with integrated renewable energy sources. In particular, the focus is on the adoption of a specific metric to quantify inertia and assess the status of the grid. Recent literature has proposed different metrics and methods to evaluate inertia variations [4]. In the vast majority, a numerical routine provides an evaluation of the overall system stability, based on a set of distributed synchronized measurements [5]. In this paper, instead, we focus on a local approach [6]. Based on the measurements collected in a single node of the network, we attempt to detect and identify inertia variations. Differently from the systemic methods, such an approach allows for evaluating the response of each node as a separate agent and potentially detect inconsistencies between the expected and the actual behavior of the closest generating unit.

The remainder of the paper is structured as follows. Section II reviews the basic principles of inertia and highlights the goal of the paper. The distribution network considered in the case study is described in Section III. In Section IV, instead, the experimental activity and the main results are presented. Finally, Section V draws the conclusion.

II. PRINCIPLES OF INERTIA

This section introduces some basic principles about inertia, recent developments, and the main goal of this study.

A. Inertia

Mechanical inertia within power systems serves to mitigate imbalances between generation and load demand so limiting frequency fluctuations. Monitoring instantaneous power system frequency offers insight into the equilibrium between generation and loading in an AC power system.

Inertia plays a critical role in moderating the ROCOF, ensuring sufficient stability for dynamic operations. For instance, the South African grid code [7], akin to other international standards, advocates for a ROCOF of less than 0.5 Hz/s for optimal performance [2].

To quantify available inertia, an inertia constant is defined, drawing from the mass and power rating of the mechanical generation system and the angular velocity of the rotating mass. The widely used swing equation expresses the power equilibrium (or imbalance) during abrupt disparities between generation and loading.

Considering a scenario where there is a sudden reduction in loading, the swing equation is represented by:

$$2H \frac{df(t)}{dt} = \Delta P_m(t) - \Delta P_e(t) = \Delta P(t), \quad (1)$$

where:

H : Synchronous generator inertia constant, in seconds (s).

f : frequency at synchronous generator terminals, in Hz.

$\Delta P_m(t)$: Change in mechanical power, W.

$\Delta P_e(t)$: Change in electrical power, W.

During an electrical power transient, being a relatively rapid occurrence in an electrical system, the mechanical system, and specifically the mechanical power, remains relatively stable throughout the duration of such rapid electrical transient, leading to the simplifying hypothesis that $\Delta P_m(t) \approx 0$. Therefore, starting from (1), the inertia constant H at $t = t_0$ can be well approximated by:

$$H \approx \left| \frac{-[P_e(t_0^+) - P_e(t_0^-)]}{2 \left[\frac{f(t_0^+) - f(t_0^-)}{t_0^+ - t_0^-} \right]} \right|, \quad (2)$$

with t_0^- and t_0^+ indicating the time instants before and after the power transient. The frequency derivative is approximated as the finite-difference incremental ratio of the frequency values in the two considered time instants. In (2), the absolute value is intended to guarantee that the inertia constant is a positive quantity. Nevertheless, it is also worth noticing that in practice power and frequency variations are typically characterized by opposite signs. A reduction in the power demand (i.e., $\Delta P_e < 0$) corresponds to a system frequency increase, and viceversa.

B. The goal of this paper

Considering the above, this paper aims to experimentally validate inertia metrics, proposed by the authors, in a distribution network where a significant penetration of RES exists. To this purpose, power, frequency, and ROCOF measures obtained from a South African distribution network were used. The metrics are then validated by extensive analysis of the results. Opportunities on the pragmatic application of these metrics are then discussed.

III. DESCRIPTION OF THE DISTRIBUTION SYSTEM

The following subsections present the distribution network considered in this study and the instrumentation used to collect the field data used in the analysis of the inertia metrics.

A. Distribution network configuration and states

A simple schematic of the distribution network that serves a Southern African (SA) university campus is shown in Fig. 2. The 11 kV 50 Hz ring-feed network serves end-users at 400 V. Under normal conditions, this distribution network is grid connected where generation sources are from a mix of turbine-generators and various renewable sources such as wind, sun and water.

Within this local network, a 50 kVA grid-connected rooftop photovoltaic (PV) system reduce the energy flow from the national grid. The national grid is disconnected several times each day. A 400 V 800 kVA diesel generator then supplies the majority of the energy demand. The PV inverters will shut down when the national grid disconnects, but will synchronize to the diesel generator that starts within a few seconds when the local grid is islanded.

The impact of the embedded PV system, quantified as the "penetration level of PV" [8], can be expressed by the ratio:

$$\text{Penetration} = \frac{\text{PV Power}}{\text{Load Demand}} \quad (3)$$

In the considered distribution system, the penetration level stands at approximately 26 %, with a load demand of nearly 200 kVA, and PV barely exceeding 50 kVA. This configuration is a controlled experimental setup as all contingencies can be reliably correlated to the field measurements.

In South Africa, national frequency control relies on scheduled disconnections of various network segments to match loading with available generation. These disconnections occur differently in different regions, in approximately 2-hour intervals. During such event the campus network is an islanded distribution network.

Upon loss of connection to the national grid, the entire distribution network experiences a power outage. Within a minute, the generator supplies energy, followed by synchronization of PV inverters within a few seconds. The amount of PV energy available depends on the daily solar irradiation. When the national grid is restored, the diesel generator synchronizes with the grid before disconnecting, ensuring an uninterrupted transition from diesel generation to the national grid. The PV inverters remain connected during this stage.

The sequence of events described above introduces significant variations in available inertia, facilitating comprehensive and comparative evaluations of stability quantification based on inertia availability in the distribution grid. To validate the mathematical implementation of the methodology for deriving inertia and subsequent assessment of frequency stability, this network underwent detailed modeling and simulation using DIGSILENT™.

Overall, four states of system inertia in the distribution system are considered in this paper:

- Only the national grid: The national grid is the only energy source, but with variable levels of traditional inertia and without any local embedded generation.
- Daytime with PV: The national grid is complemented by PV during daytime.
- Islanded state: Only diesel generation during night-time.

- Daytime with diesel and PV: Diesel generation is supported by PV generation during daytime.

All network states were known and correlated with the field data used to study the tracking of system inertia.

B. Instrumentation and field data

At every measurement point, the voltage and the current were measured with a Vectograph 3, that is a power quality instrument certified as compliant to the measurement requirements of IEC 61000-4-30, Class A, edition 3 [10]. The sampling rate of 500,000 Sa/s collected the 10/12 cycle blocks of waveform data. The manufacturer specify an accuracy of 0.1 % in the measurement range 10 % to 100 % of the rated quantity.

The reporting rate of the device is 200 ms. Computed quantities of interest were frequency, ROCOF, and active power, measured simultaneously at different points with a time-stamping uncertainty better than ± 100 ns.

IV. EXPERIMENTAL ACTIVITY

This section discusses the data collection, inertia metrics, and results obtained.

A. Data collection

Synchronous measurements were obtained where the inverters connect to the local 400 V bus and at the 400 V bus where the generation injects via a 11/04 kV transformer into the 11 kV ring, as shown in Fig. 2. The national grid connects at 11 kV.

B. Inertia metrics

Robust solutions to the quantification of inertia remains a topic of interest at transmission and distribution system operators [11]. In traditional power systems, this information could be derived from the inertia constants of different synchronous machines and other parameters from the network topology.

When a significant portion of generation is obtained from solid-state generators, knowledge on inertia becomes more complicated [12]. On one hand, the power output of renewable generation sources are not necessarily correlated to the system frequency or system operating point [13]. On the other hand, the concept of inertia constant may lose its significance if the response of a generating unit during a load change does not rely on a physical property such as mass, but is now controlled by power electronics [14]. Based on these considerations, it is preferred to study the response of the power system by the variations of inertia as a function of time.

Such an analysis could provide useful information about the stability of the power system and could be used to select the most suitable and effective control action to prevent service disruptions or (in the worst case) system contingencies [15].

Let's assume to measure, at each node of interest, the system frequency f and the active power P at a fixed reporting rate. In the presence of a sudden change in the operating conditions, it is possible to evaluate a stability index I_H related to the inertia constant H based on the time derivatives of f and P :

$$I_H(t_1) = \frac{\Delta P}{2 \cdot \Delta \left(\frac{df}{dt} \right)} = \frac{P(t_1) - P(t_0)}{2 \cdot (R_f(t_1) - R_f(t_0))} \quad (4)$$

where t_1 and t_0 are two consecutive reporting instants, and R_f denotes the ROCOF. It is worth noting that I_H does not account for the system inertia constant but allows for detecting anomalous behaviors in a rapid and immediate manner. Its variation range depends on many factors: e.g., the power flows in the node of interest, the method to measure the frequency and its derivative, and noise level. It is thus necessary to perform an accurate evaluation of its statistical distribution in normal operating conditions before configuring any anomaly detection rule.

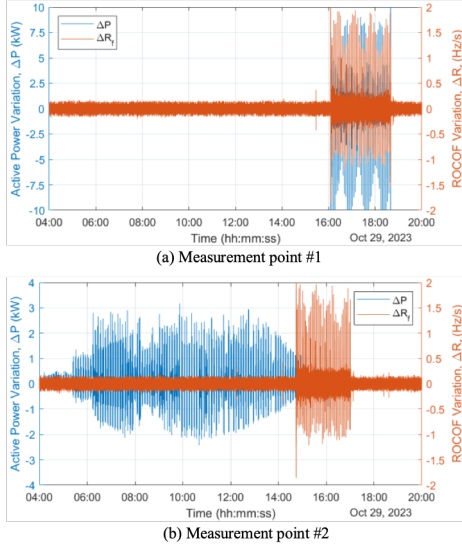


Fig. 3. Variations of active power (blue) and ROCOF (red) as measured at measurement point #1 and #2 in (a) and (b), respectively.

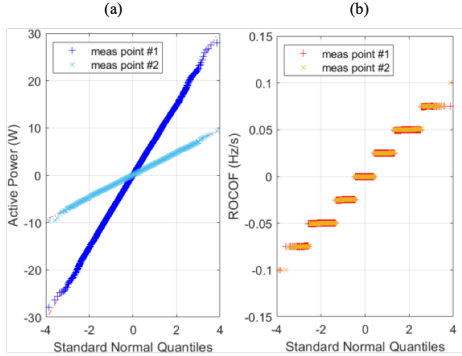


Fig. 4. Quantile-quantile plots for active power and ROCOF in normal operating conditions in (a) and (b), respectively.

C. Results

Till now, the stability index (4) has been tested only in numerical simulations. To validate its feasibility and reliability in real-world scenarios, the index is tested on the dataset presented in Section IV.A and relative to the distribution network introduced in Section III. For the sake of

brevity, the analysis will focus on a restricted set of measurements, but similar results could be obtained on larger datasets.

For this analysis, the considered measurements were performed on October 29th, 2023, at the measurement point #1 and #2, as identified in Fig. 2. The first one, close to the interconnection with the national grid, is representative of the overall system state. The second one, instead, is directly affected by the functioning of the PV power plant, i.e. it reflects the effects of the distortions introduced by power converter circuitry as well as the instability due to the inherent solar irradiance volatility.

During daylight period, the distribution network is relying on the PV power plant. In the absence of sufficient solar irradiance or during night period, the diesel generator and the connection with the national grid guarantees the continuity of service. This behavior is confirmed by the time evolution of the variations in active power and ROCOF in Fig. 3. At the measurement point #1, both quantities remain constant (affected only by measurement noise) until 15:00, when the diesel generator is started. Conversely, at the measurement point #2, the power variations reflect the solar irradiance profile. Also in this case, around 15:00, disturbances are noted.

It is interesting to observe how the ROCOF remained constant (affected only by measurement noise) while the PV power plant is active, whereas it exhibits fast switching spikes as soon as the diesel generation units are started.

First, the measurement noise at both measurement points and for both quantities must be characterized. To this end, it is a time span of two hours where no significant actions took place was considered: from 04:00 to 06:00 for measurement point #1, and from 18:00 to 20:00 for measurement point #2. In this regard, Fig. 4 presents the quantile-quantile plots of the power and ROCOF variations for the two measurement points.

The power measurements have a normal distribution between ± 30 and ± 10 W at measurement point #1 and #2, respectively. This confirms the assumption that the measurement noise is uncorrelated as it is normally distributed. Conversely, the ROCOF measurements are mostly affected by quantization noise, as the instrument has a finite resolution of 25 mHz/s.

Based on the distributions in Fig. 4, specific thresholds can be set on active power and ROCOF. It is needed to determine whether the variable of interest is varying and diverging from its nominal value, or if it is only the inherent uncertainty contributed by the measurement procedure. In this case, any active power variation lower than ± 30 W or ROCOF variation lower than ± 0.1 Hz/s are neglected for the computation of the system stability index I_H .

In the dataset under investigation, power and ROCOF variations were computed every 200 ms. However, such a restricted time-horizon may prove to be not so significant in terms of system stability assessment. For this reason, power and ROCOF variations are first processed via a moving average window with a duration of 10 s (i.e., corresponding to 50 consecutive measurement periods). This has a twofold advantage. It reduces the effect of additive uncorrelated noise (in particular, in the power measurements) and it smooths out the spikes due to switching events (in particular, in the ROCOF measurements). Secondly, similar to a Type-A uncertainty or confidence interval, when computed as the 95th percentile of the 50 values included in the moving average window, it can be associated to each average value.

In this regard, Fig. 5(a) presents the confidence interval associated with the ROCOF average values in both datasets. It is interesting to observe how this interval is consistent with the distribution shown in Fig. 4(b), apart from the time interval between 16:00 and 18:00, when the diesel generator kick in.

Based on these results, the stability index associated to measurement point #1 and #2 can be computed. For this analysis, only the intervals where both active power and ROCOF show variations whose confidence intervals exceed the expected noise level, are considered. The results are presented in Fig. 5(b). In terms of the PV power plant, the

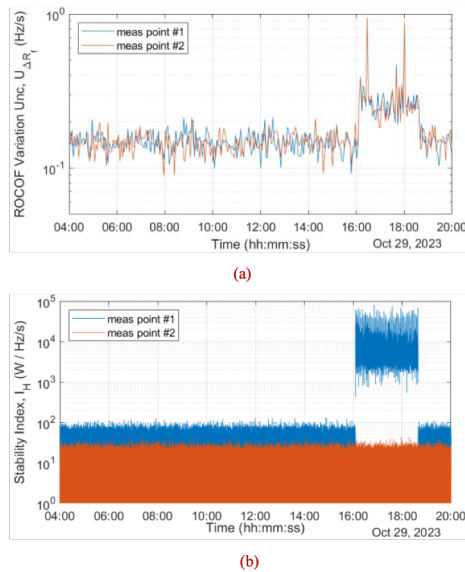


Fig. 5. In (a), confidence intervals associated to ROCOF variations in both measurement points. In (b), stability indices computed as per (4). Blue and red lines refer to measurement point #1 and #2, respectively.

system appears to be in a stable condition: the active power variations (due to the corresponding solar irradiance variations) do not impact the signal frequency and ROCOF. At the instance when ROCOF becomes irregular (around 16:00), the power output is nearly zero and why the stability index remains unaffected.

Conversely, at measurement point #1, the system shows a sudden change in correspondence of the diesel generators' start. In this case, the variation in active power and in ROCOF are significant and uncorrelated. Consequently, the stability index significantly increases as indication to the system operator and system engineers that some anomaly has occurred.

V. CONCLUSION

This study emphasized the growing importance of tracking inertia in distribution networks and the challenges posed by the integration of renewable energy sources. The instability and complexity of distribution networks, coupled with the shift from traditional rotating electrical assets to renewables, necessitate new approaches to estimate, track, and control

inertia. The distribution network considered was a perfect testbench to assess the implementation of a new inertia metric under known network conditions. During the testing, many different ROCOF events were recorded, to allow reliable assessment of the efficacy of the proposed new metric under real-life conditions. Future studies will be dedicated to the validation of the proposed work in different real and simulated scenarios. This work provides a foundation for future research to develop practical applications aimed at enhancing the stability and reliability of distribution networks in the evolving energy landscape.

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