



Final report from 1 July 2026

FORMIDABLE

Community-microgrid with grid-forming inverters equipped with improved damping and virtual inertia: their role on grid reliability and resilience



Source: HEIG-VD/IE 2026



Publisher:

Swiss Federal Office of Energy SFOE
Energy Research and Cleantech
CH-3003 Berne
www.energy-research.ch

Co-financing:

Imperix SA
CH-1950 Sion
www.imperix.com

Subsidy recipients:

HEIG-VD
CH-1400 Yverdon-les-Bains
www.heig-vd.ch

Authors:

Dr Philippe Morey, HEIG-VD, philippe.morey@heig-vd.ch
Dr Mohammad Rayati, HEIG-VD, mohammad.rayati@heig-vd.ch
Prof. Dr Mokhtar Bozorg, HEIG-VD, mohktar.bozorg@heig-vd.ch
Prof. Dr Mauro Carpita, HEIG-VD, mauro.carpita@heig-vd.ch

SFOE project coordinators:

Dr Michael Moser, michael.moser@bfe.admin.ch

SFOE contract number: SI/502668-1

The authors bear the entire responsibility for the content of this report and for the conclusions drawn therefrom.



Summary

The transition from synchronous generators to inverter-based distributed energy resources in modern power grids poses stability challenges due to the inability of grid-following inverters to emulate the inertial responses of synchronous generators. Grid-forming inverters, however, can mimic these characteristics and improve grid stability, reliability, and resilience, especially during power outages.

This project aims to explore the benefits and risks of grid-forming inverters, particularly by assessing their impact on a community microgrid's reliability and resilience. The project also seeks to develop a framework for grid restoration and resilience, as well as enhance decision-making for deploying new distributed energy resources. To do this, the control algorithms for grid-forming inverters are developed, and experimental hardware is built and tested in a laboratory community microgrid configuration.

The first phase of the project is to do the theoretical development of the primary control of the grid-forming inverter, the overload protection, and the management of unbalanced loads. The second phase is to assemble two experimental inverters, to integrate them into a laboratory community microgrid, as well as to program and test them. This allows the research team to demonstrate the ability of grid-forming inverters to generate and sustain a community microgrid in real life, as well as perform different practical manoeuvres such as black start, synchronization and short-circuit tests. The third and final phase of the project is to add a power systems approach where the results from the implementation experiments are evaluated under realistic grid conditions. In this context, particular focus is placed on the role of grid-forming inverters in enhancing grid reliability and resilience. Furthermore, the potential advantages and associated risks in low-voltage networks are assessed within a simulation environment, building upon the findings from the implementation experiments.

Main findings

This project demonstrated in real life that a microgrid, and by extension an electrical grid, can be fully composed of inverter-based energy resources thanks to the stabilizing effect of grid-forming inverters. These behave as voltage sources, which support the grid locally during normal functioning, as well as during faults. Speaking of faults, as opposed to conventional synchronous machines, inverters have no tolerance to overloads. To overcome this limitation, an overload management strategy was developed to protect the inverters while allowing them to provide as much support as possible to the grid. Furthermore, due to the fact that each grid-forming inverter is capable of black starting and synchronizing to the rest of the system, no single inverter is essential to the functioning of the microgrid. Its resilience is therefore improved significantly.



Zusammenfassung

Der Übergang von synchronen Generatoren zu inverterbasierten dezentralen Energieerzeugern in modernen Stromnetzen stellt Stabilitäts Herausforderungen dar, da netzfolgende Wechselrichter nicht in der Lage sind, die Trägheitsreaktionen synchroner Generatoren nachzubilden. Netzbildende Wechselrichter hingegen können diese Eigenschaften imitieren und die Stabilität, Zuverlässigkeit und Resilienz des Netzes verbessern, insbesondere bei Stromausfällen.

Ziel dieses Projekts ist es, die Vorteile und Risiken netzbildender Wechselrichter zu untersuchen, insbesondere durch die Bewertung ihres Einflusses auf die Zuverlässigkeit und Resilienz eines gemeinschaftlichen Mikronetzes. Darüber hinaus soll ein Rahmenkonzept für Netzwiederherstellung und Resilienz entwickelt sowie die Entscheidungsfindung für den Einsatz neuer dezentraler Energiequellen verbessert werden. Zu diesem Zweck werden Regelungsalgorithmen für netzbildende Wechselrichter entwickelt und experimentelle Hardware aufgebaut und in einer Laborumgebung eines gemeinschaftlichen Mikronetzes getestet.

Die erste Phase des Projekts umfasst die theoretische Entwicklung der Primärregelung eines netzbildenden Wechselrichters, des Überlastschutzes sowie des Managements unsymmetrischer Lasten. In der zweiten Phase werden zwei experimentelle Wechselrichter aufgebaut, in ein gemeinschaftliches Labormikronetz integriert sowie programmiert und getestet. Dadurch kann das Forschungsteam die Fähigkeit netzbildender Wechselrichter demonstrieren, ein gemeinschaftliches Mikronetz unter realen Bedingungen zu erzeugen und aufrechtzuerhalten, sowie verschiedene praktische Vorgänge wie Schwarzstart, Synchronisation und Kurzschluss tests durchführen. Die dritte und letzte Phase des Projekts erweitert den Ansatz um eine energietechnische Systemperspektive, bei der die Ergebnisse der Implementierungsexperimente unter realistischen Netzbedingungen bewertet werden. In diesem Zusammenhang wird besonderes Augenmerk auf die Rolle netzbildender Wechselrichter bei der Verbesserung der Netzzuverlässigkeit und -resilienz gelegt. Darüber hinaus werden potenzielle Vorteile und damit verbundene Risiken in Niederspannungsnetzen in einer Simulationsumgebung analysiert, basierend auf den Erkenntnissen aus den Implementierungsexperimenten.

Hauptergebnisse

Dieses Projekt hat praktisch gezeigt, dass ein Mikronetz, und damit auch ein elektrisches Netz, vollständig aus inverterbasierten Energiequellen bestehen kann, dank der stabilisierenden Wirkung netzbildender Wechselrichter. Diese verhalten sich wie Spannungsquellen, die das Netz lokal sowohl im Normalbetrieb als auch bei Störungen unterstützen. In Bezug auf Störungen gilt, dass Wechselrichter im Gegensatz zu konventionellen synchronen Maschinen keine Überlastfähigkeit besitzen. Um diese Einschränkung zu überwinden, wurde eine Strategie zur Überlastregelung entwickelt, die die Wechselrichter schützt und ihnen gleichzeitig ermöglicht, das Netz bestmöglich zu unterstützen. Darüber hinaus ist kein einzelner Wechselrichter für den Betrieb des Mikronetzes unverzichtbar, da jeder netzbildende Wechselrichter in der Lage ist, einen Schwarzstart durchzuführen und sich mit dem restlichen System zu synchronisieren. Die Resilienz des Systems wird dadurch erheblich verbessert.



Résumé

La transition des générateurs synchrones vers des ressources énergétiques distribuées basées sur des onduleurs dans les réseaux électriques modernes pose des défis en matière de stabilité, en raison de l'incapacité des onduleurs suiveurs de réseau à reproduire les réponses inertielles des générateurs synchrones. En revanche, les onduleurs formant réseau peuvent imiter ces caractéristiques et améliorer la stabilité, la fiabilité et la résilience du réseau, notamment en cas de coupure de courant.

Ce projet vise à explorer les avantages et les risques des onduleurs formant réseau, en particulier en évaluant leur impact sur la fiabilité et la résilience d'un microréseau communautaire. Il cherche également à développer un cadre pour la restauration du réseau et sa résilience, ainsi qu'à améliorer la prise de décision concernant le déploiement de nouvelles ressources énergétiques distribuées. Pour ce faire, des algorithmes de commande pour les onduleurs formant réseau sont développés, et du matériel expérimental est conçu et testé dans une configuration de microréseau communautaire en laboratoire.

La première phase du projet consiste à développer théoriquement la commande primaire de l'onduleur formant réseau, la protection contre les surcharges et la gestion des charges déséquilibrées. La deuxième phase consiste à assembler deux onduleurs expérimentaux, à les intégrer dans un microréseau communautaire de laboratoire, ainsi qu'à les programmer et les tester. Cela permet à l'équipe de recherche de démontrer la capacité des onduleurs formant réseau à créer et maintenir un microréseau dans des conditions réelles, ainsi qu'à réaliser diverses manœuvres pratiques telles que le démarrage à froid (black start), la synchronisation et les essais de court-circuit. La troisième et dernière phase du projet consiste à adopter une approche systèmes électriques, où les résultats des expériences de mise en œuvre sont évalués dans des conditions de réseau réalistes. Dans ce cadre, une attention particulière est portée au rôle des onduleurs formant réseau dans l'amélioration de la fiabilité et de la résilience du réseau. En outre, les avantages potentiels et les risques associés dans les réseaux basse tension sont évalués dans un environnement de simulation, en s'appuyant sur les résultats des expérimentations.

Principaux résultats

Ce projet a démontré concrètement qu'un microréseau – et par extension un réseau électrique – peut être entièrement composé de ressources énergétiques basées sur des onduleurs grâce à l'effet stabilisant des onduleurs formant réseau. Ceux-ci se comportent comme des sources de tension, soutenant le réseau localement aussi bien en régime normal qu'en situation de défaut. En ce qui concerne les défauts, contrairement aux machines synchrones conventionnelles, les onduleurs ne tolèrent pas les surcharges. Pour surmonter cette limitation, une stratégie de gestion des surcharges a été développée afin de protéger les onduleurs tout en leur permettant de soutenir le réseau autant que possible. De plus, étant donné que chaque onduleur formant réseau est capable de réaliser un démarrage à froid et de se synchroniser avec le reste du système, aucun onduleur n'est indispensable au fonctionnement du microréseau. Sa résilience s'en trouve donc considérablement améliorée.



Contents

Summary	3
Main findings	3
Zusammenfassung.....	4
Hauptergebnisse	4
Résumé.....	5
Principaux résultats	5
Contents	6
List of abbreviations	7
1 Introduction.....	9
1.1 Context and motivation.....	9
1.2 Project objectives	10
1.3 Procedure and methodology	11
1.3.1. Work packages	11
1.3.2. Milestones.....	12
2 Activities and results	13
2.1 Control design of the grid forming inverters (WP2)	13
2.1.1. Selfsync direct voltage droop control.....	13
2.1.2. Simulation of the selfsync direct voltage control	15
2.1.3. Neutral balancing.....	17
2.1.4. Overload and short-circuit protection.....	18
2.2 Experimental hardware (WP3)	22
2.2.1. Transformation and adaptation of inverter A	22
2.2.2. Adaptation of inverter B	23
2.2.3. Neutral point balancing.....	24
2.3 Integration and community microgrid test (WP4)	25
2.3.1. Structure of the community microgrid.....	25
2.3.2. Implementation of a SCADA interface to monitor and remotely control the inverters	26
2.4 Experimental results (WP5).....	27
2.4.1. Black start	27
2.4.2. Synchronization	27
2.4.3. Overload and short-circuit tests.....	28
2.4.4. Phase jump test.....	29
2.5 Analysis from a power system perspective (WP5).....	30
2.5.1. Distributed energy resource composition (PV, storage, GFL and GFM).....	31
2.5.2. Simulation Campaign.....	32
2.5.3. Results.....	32
3 Conclusions and outlook.....	35



3.1	Main results	35
3.2	Limitations and challenges	35
3.3	Future work	36
4	References	36
5	Appendix	38

List of abbreviations

AC	Alternating Current
BESS	Battery Energy Storage System
DC	Direct Current
DER	Distributed Energy Resource
DSO	Distribution System Operator
EMC	Electromagnetic Compatibility
EMT	Electromagnetic Transient
GFL	Grid Following
GFLI	Grid Following Inverter
GFM	Grid Forming
GFMI	Grid Forming Inverter
LV	Low Voltage
MPC	Model Predictive Control
OEDI	Open Energy Data Initiative
PCC	Point of Common Coupling
PLECS	Piecewise Linear Electrical Circuit Simulation
PV	Photovoltaic
PWM	Pulse Width Modulation
QSTS	Quasi-Static Time Series
RoCoF	Rate of Change of Frequency
ROZ	Resilient Operation Zone
RMS	Root Mean Square
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
SFOE	Swiss Federal Office of Energy
SG	Synchronous Generator
TSO	Transmission System Operator
VI	Virtual Impedance
WP	Work Package





1 Introduction

1.1 Context and motivation

Conventional power grids are dominated by synchronous generators that are responsible for ensuring the secure operation of the grid by providing ancillary services such as voltage and frequency regulation. However, the capacity of synchronous generators in modern power grids is reducing because of the transition to inverter-based distributed energy resources (DERs). The majority of DERs are equipped with grid-following inverters (GFLIs). Since GFLIs intrinsically cannot emulate the inertial responses of synchronous generators, this transition raises technical challenges for the grid's stability. However, grid-forming inverters (GFMI) equipped with improved damping and virtual inertia can alleviate this issue because they can emulate the characteristics of synchronous generators [1]. Additionally, the capacity of GFMI can enhance grid reliability and resilience by enabling the provision of energy to critical facilities during power outages (using intelligent load shedding) [2].

In this project, we investigate the advantages and risks of GFMI in modern power grids. To do so, we are using a 22 kVA fully programmable inverter provided by imperix to validate a suitable control strategy. We are also adapting a proprietary GFLI [3] into a 10 kVA GFMI prototype to have two separate hardware. We then study the role of GFMI in a community microgrid on grid reliability and resilience. Using GFMI within a community microgrid will enhance Switzerland's energy supply's resilience to external drivers and will participate in laying the groundwork for the implementation of the Energy Strategy 2050 [4] in an affordable and secure manner.

The project aims to develop a technical framework for assessing the reliability and resiliency of a community-based microgrid solution, focusing on how GFMI interact under both normal and contingency operating conditions. Another advantage of the proposed solution is the ability of the GFMI used inside the community microgrid to supply virtual inertia and other ancillary services to support the secure operation of the grid in both normal and emergency situations. Decision-making will also be improved using the community microgrid solution, which will make the planning of new DERs to be deployed inside the distribution grid easier and more reliable.



1.2 Project objectives

The interaction of multiple GFMI in a community microgrid in grid connected as well as standalone operation modes will be studied and tested by coupling the 22 kVA inverter provided by imperix with the proprietary 10 kVA inverter prototype. Other technical risks, including load imbalances and short circuits, will be studied with this community microgrid prototype.

The main objectives of this project are the following:

- First, the project aims to experimentally validate the operation and control of a community microgrid on a laboratory scale. The experimental validation of a community microgrid includes testing its performance in both operational modes as well as during the synchronization process. Note that unlike the GFLs, the GFMI can provide black-start capability.
- Second, the project aims to use the experimental data to evaluate and quantify the advantages and risks of the proposed community microgrid framework. The following advantages and risks are anticipated to be quantified (among others that will become known following the experimental validation):
 - ✓ The improvement of the energy reliability provided to critical facilities.
 - ✓ The support of grid restoration after a significant grid incident.
 - ✓ The improvement of the resilience of the energy infrastructure.
 - ✓ The potential supply of ancillary services (e.g., frequency support and voltage support).
 - ✓ The threats posed by voltage instability, load imbalance, and short circuits, in both operational modes.

This project introduces and studies a new arrangement based on the community microgrid framework, which aids grid restoration when the share of decentralized renewable energy sources increases. The project seeks to answer the following research question: How must concepts (technical and organizational) for grid restoration evolve with an increasing share of renewable energy sources? What arrangements will need to be made, when, and by whom?

To address the above question, the key technical and scientific questions of this project are as follows:

- 1) Which control strategies for GFMI within a community microgrid are most effective in grid-connected and standalone operational modes?
- 2) What are the key infrastructure advancements and upgrades required in existing grid infrastructure to allow for the seamless integration of DERs into a community microgrid?
- 3) What are the advantages and risks associated with creating a community microgrid with multiple GFMI?
- 4) To what extent would a community microgrid enhance grid reliability and resilience?

1.3 Procedure and methodology

1.3.1. Work packages

This project is organized into five work packages (WPs).

- **WP1:** Project management,
- **WP2:** Control design of GFMI with improved damping and virtual inertia, as well as control design for a community microgrid,
- **WP3:** Adaptation of the hardware to the smart grid laboratory and performance verification of the designed control algorithm for GFMIIs,
- **WP4:** GFMI installed on the smart grid laboratory (REINE) to establish a community microgrid,
- **WP5:** Analysis and dissemination of the experimental results.

In Figure 1, the interrelationships of different WPs are illustrated. As shown, systematic verification and validation will be done in this project to establish confidence that the designed control algorithm correctly exercises the requirements of both the system (i.e., community microgrid) and the components (i.e., GFMIIs).

In WP2, the control architecture of community microgrids and GFMI are investigated and simulated. In WP3, the imperix hardware is adapted to verify the performance of the designed control algorithm since it is readily modifiable and has many measurement points. A proprietary GFLI is also modified and integrated in the smart grid laboratory alongside the imperix hardware based on the derived control architecture. In WP4, the community microgrid framework is tested at the system level. Finally, the experimental findings are collected for system analysis in WP5. Using the experimental data, the advantages and risks of the proposed control design are assessed or estimated for increasing levels of GFMI. WP5 will disseminate experimental data and accompanying analysis.

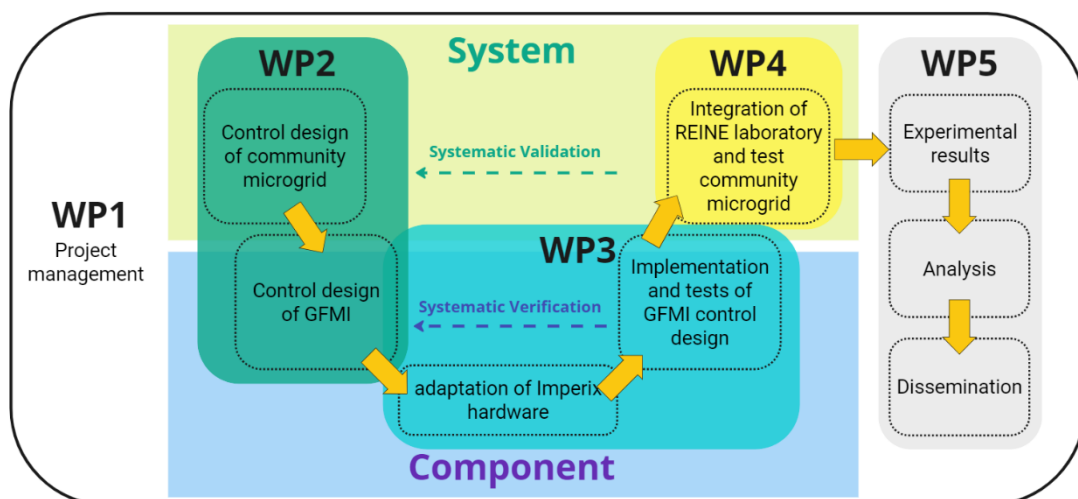


Figure 1: Interrelation of different WPs.



1.3.2. Milestones

Three milestones were considered for the project:

- **Milestone 1:** The first GFMI hardware is ready. Furthermore, the theoretical research for developing GFMI is complete. Finally, the first inverter has effectively been modified to show the perceived functional behaviours of GFMI.
- **Milestone 2:** It is the end of the control design. At this point, the control design strategy is being validated utilizing imperix hardware as well as a proprietary prototype inverter. Consequently, the final version of the control design is nearing completion.
- **Milestone 3:** The community microgrid is tested in both modes. Both operating modes of the community microgrid framework have been tested and validated. The experimental data is now accessible for further analysis and dissemination of the findings.

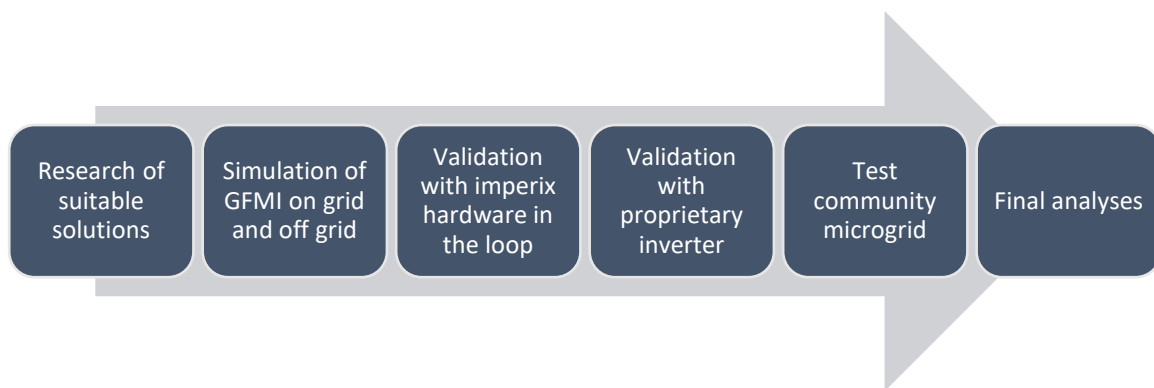


Figure 2: Approach and research methodology.



2 Activities and results

2.1 Control design of the grid forming inverters (WP2)

In this work, it has been chosen to concentrate on low voltage and low power (sub-megawatt) applications. This choice is motivated by the fact that the envisioned structure of a community microgrid would be owned by private citizens and installed in their homes. Because of this, the control design of the inverters needs to function for three phased inverters with a neutral point with large imbalances between the phased, as well as for single phased inverters. Nevertheless, all the following analysis also applies to larger scales.

Grid forming inverters are controlled by generating voltage amplitude and phase references. Many different strategies have been proposed [6]. Following a bibliographic review, the control strategy that was chosen is a direct voltage control, which is based on the selfsync droop control, presented in [7]. This choice is motivated by the inherent stability of direct voltage control across all load conditions. In contrast, it has been demonstrated [9] that conventional nested control systems become unstable under high impedance conditions. This instability is a common issue in all current-controlled inverters when the output impedance is excessively high. As a direct consequence, inverters employing current control loops are incapable or struggle to perform black-start operations under any condition. A summarised description of the developments is provided hereafter. However, for a full description of the system, please refer to Appendix 1: Control design of GFMLs.

2.1.1. Selfsync direct voltage droop control

This method does not rely on a phase locked loop (PLL) to function but rather generates the reference phase of the inverter based on active power, as well as the reference voltage amplitude, based on active and reactive power. This method follows the phase of the grid, rather than trying to match it exactly. Furthermore, the voltage amplitude U and phase δ are directly used as inputs to generate the pulse width modulation (PWM) controlling the power modules. Figure 3 shows the control loops based on active and reactive power.

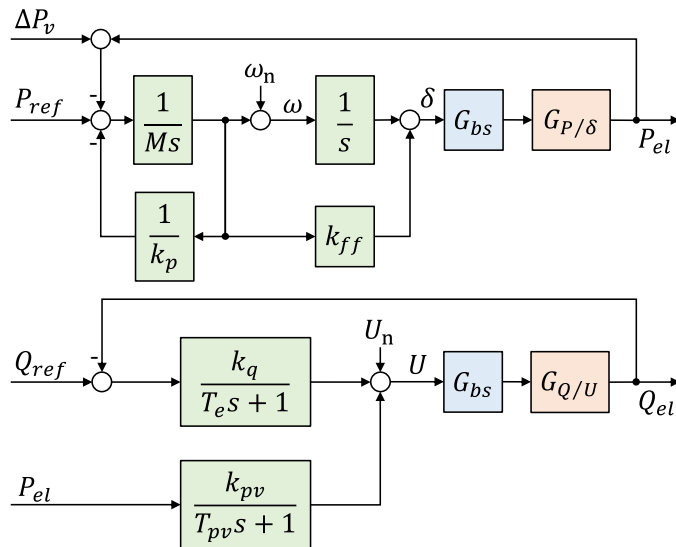


Figure 3: Active power (top) and reactive power (bottom) control loops.

As shown in Figure 3, the control loops are represented with three different colours, where the droop control is represented in green, band-stop filters are in blue and the physical interaction with the grid is in light salmon. In practice, there are cross-interactions between the top and bottom loops, but these are strongly damped by the band-stop filters, allowing us to neglect these effects for the analysis.



Active power control loop

The active power control loop is the one in which the phase δ is generated. A parallel can be done between this loop and the swing equation (4) that describes the behaviour of a synchronous machine.

$$M \frac{d^2 \delta}{dt^2} + D \frac{d\delta}{dt} = P_m - P_{el} \quad (1)$$

where M is the momentum, D is the damping coefficient, P_m is the mechanical power and P_{el} is the electrical power. In the present case, the droop coefficient k_p acts as the damping coefficient and k_{ff} is a feed-forward coefficient to improve the dynamic response of the system.

Momentum M defines the inertia of a rotating object. However, it is common and practical to define the inertia of a system by its inertia constant H which is independent of the nominal power of the system.

$$M = J \cdot \omega_n = 2 \cdot H \cdot \frac{S_n}{\omega_n} \quad (2)$$

Additionally, the active power control loop has an extra input ΔP_v which is virtual power and its usefulness is the following: Unlike a real synchronous machine, where the electric torque is proportional to the current and the rotor speed decreases in case of a fault, in the same situation the inverter's virtual rotor speed will increase. This is because during a fault, the inverter limits its current, which causes the active power P_{el} to drop dramatically. To counterbalance this, virtual power ΔP_v is added to keep the inverter synchronous (see Appendix 3: GFMI Protection).

Reactive power control loop

The reactive power control loop compensates for variations of the output voltage of the inverter due to the grid impedance. In medium or high voltage, the inductive part of the grid impedance is predominant, therefore, the voltage amplitude is strongly influenced by reactive power. However, in low voltage, the resistive part of the grid impedance is no longer negligible, therefore the amplitude of the voltage is also influenced by active power. The two droop coefficients k_q and k_{pv} , as well as the two time-constants T_e and T_{pv} are chosen according to the local grid requirements. Furthermore, it is to be noted that this structure can be adapted by adding for example an offset (setpoint) to the active power, as there is with the reactive power.

Effect of the coupling with the grid

The inverter with its coupling to the grid can be represented as two three-phased sinusoidal voltage sources connected via an impedance (represented in a single wire form in Figure 4). The one on the left U_i represents the inverter and the one on the right U_g represents the grid, and the resistive-inductive impedance represents the coupling between them.

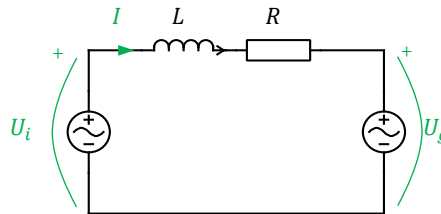


Figure 4: Coupling of the inverter with the grid.

Even though the circuit is a first order system, when a step is applied, either to the phase or to the amplitude of one of the voltage sources, the circuit resonates as a second order system. This is because the disturbance happens at different voltage angles on each of the three phases, and therefore their transients are different and do not cancel each other. Figure 5 shows the dynamic effect of a phase step on the active and reactive power.

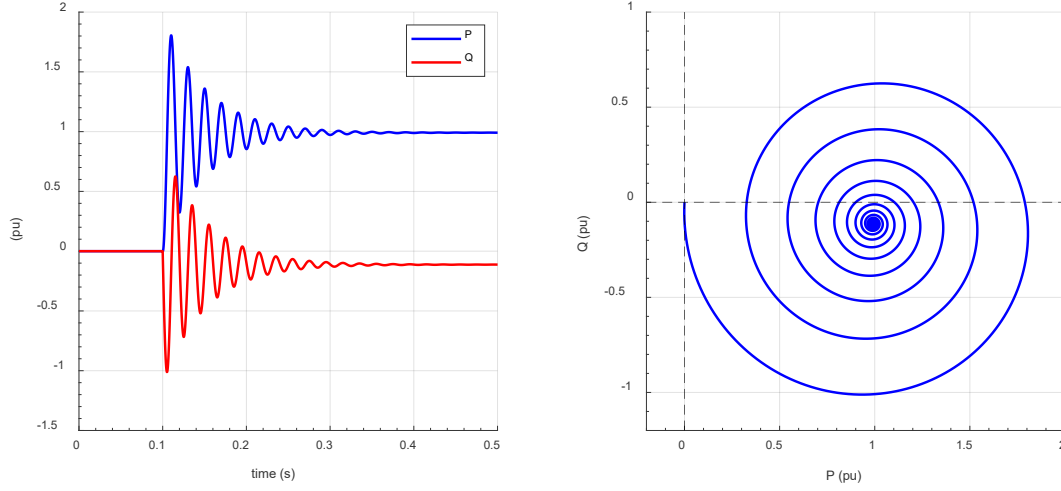


Figure 5 : Dynamic time response of a phase step on active and reactive power.

As shown, the system acts as a damped resonator when its equilibrium is upset. It can be demonstrated that the resonance ω_{res} and damping ξ are as shown in equations (5) and (4).

$$\omega_{res} = \sqrt{\omega_n^2 + \left(\frac{R}{L}\right)^2} \quad (3)$$

$$\xi = \frac{R}{\omega_{res}L} \quad (4)$$

In order not to excite this resonance, it is proposed to add a band-stop filter in series in the control loops (represented as G_{bs} in Figure 3).

2.1.2. Simulation of the selfsync direct voltage control

Figure 6 shows the result of a simulation where the inverter is connected to a stiff grid that has its frequency vary from 50 Hz to 48.5 Hz with a rate of change of frequency (RoCoF) of 1 Hz/s. The simulation parameters are presented in Table 1.

Table 1 : Simulation parameters.

Nominal grid voltage (L-N)	U_g	230	[V]
Nominal grid frequency	f_g	50	[Hz]
Inverter nominal power	S_N	10	[kVA]
Inverter gain	K_{inv}	100	[kVA]
Inertia constant	H	5	[s]
Active power droop coefficient	k_p	5	[%]
Reactive power droop coefficient	k_q	10	[%]

The ideal response is plotted as well; however, it would be the response if the coupling between the virtual inertia and the grid were perfectly stiff, which it is not and is not desirable either. The ideal response is plotted to check that the steady state response to a frequency variation of the proposed algorithm is correct.

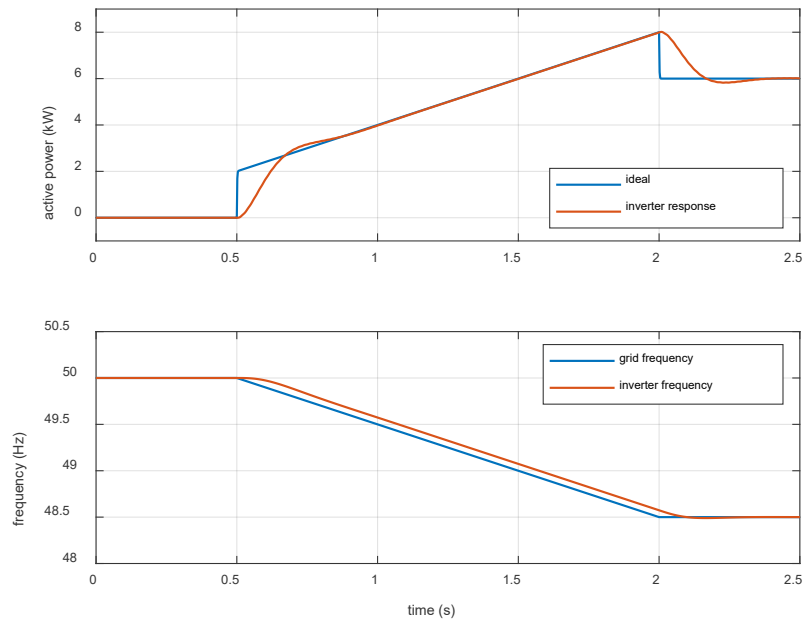


Figure 6: Active power response of the inverter to a frequency variation of the grid with a RoCoF of 1 Hz/s.

As shown in Figure 6, the active power response corresponds to what is expected, and the inverter stays synchronized with the grid despite a relatively large and rapid variation in the frequency. As mentioned earlier, the full development as well as the grid synchronization is presented in Appendix 1.



2.1.3. Neutral balancing

The proprietary inverter as well as the imperix inverter are both designed for three phased balanced loads. Both of their topologies are composed of three legs as shown in Figure 5, and the neutral conductor is connected to the central point of DC bus capacitor banc.

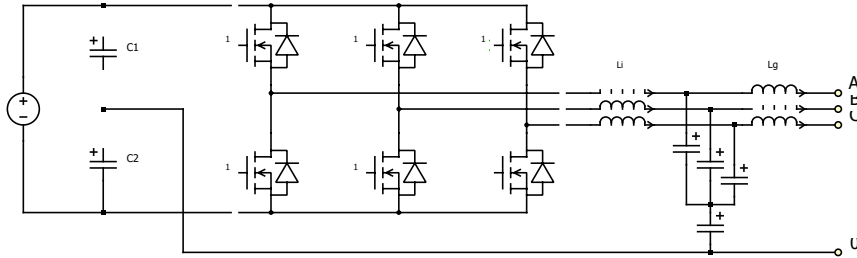


Figure 7: Three leg inverter topology with an LCL output filter and the neutral conductor connected to the central point of the DC bus capacitor banc.

In the case of an imbalanced load, the sum of the currents in phases A, B and C are no longer equal to zero. The difference flows through the neutral conductor. In case of a small symmetrical (AC) imbalance, the voltage across the DC bus capacitors will vary a bit. If the variation is small, it is not an issue. However, in the case of a large imbalance, or even worse, if there is a DC component in the neutral current, the voltage across the capacitors will no longer be balanced. This can lead to over-loading of the capacitors and ultimately to a catastrophic failure of the DC link. Therefore, it is paramount to manage the neutral current by balancing of the DC link capacitors. This can be done by adding an extra leg to the inverters as shown in Figure 6.

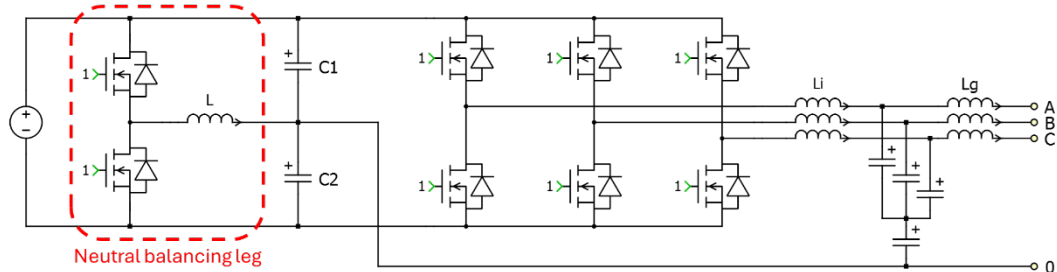


Figure 8: Three phase inverter with an additional leg to balance the DC link capacitor voltages.

Because the available inverters are not equipped with a fourth leg an external balancing system has been developed to manage the neutral current. The full development regarding the neutral balancing sizing and control can be found in Appendix 2.



2.1.4. Overload and short-circuit protection

Numerous strategies have been proposed to protect GFMs from overloads and short-circuits. Reference [10] provides a comprehensive and up-to-date overview of these approaches, which can be broadly categorized into two fundamental types:

- **Direct current control** using a current regulator
- **Indirect current control** via voltage reduction using Virtual Impedance (VI)

Direct current control offers the advantage of precise current regulation and benefits from a linear control structure, which simplifies system sizing and analysis. However, as mentioned above, approaches based on current regulation—such as current-forming or cross-forming—can become unstable under certain conditions, particularly in no-load scenarios. These strategies are perfectly relevant in situations where there are always loads. Additionally, they offer certain flexibilities in terms of controllability which can be complementary to maintain a stable grid.

In contrast, indirect current control is the only viable method compatible with direct voltage control. As previously discussed, direct voltage control ensures stability across all load conditions. The main drawback of the indirect approach lies in its reliance on the estimation of phasors, which introduces non-linearity into the control system, complicating both its analysis and tuning. However, the application of VI is strait forward. Figure 9 shows the equivalent circuit of an inverter connected to a grid as well as where the VI is applied in case of an overload.

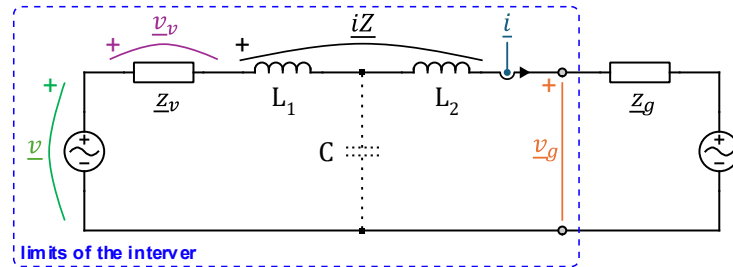


Figure 9: Single phase equivalent circuit of the inverter connected to the grid.

There are two complementary approaches to define the VI. The first is current threshold virtual impedance, which observes the current and generates a voltage drop to counter act it, and the second is voltage threshold virtual impedance, which observes the cause of the current and reacts to it.



Current threshold virtual impedance

The phasor diagram in Figure 10 shows the different voltages and current at play in the circuit. Two situations are illustrated: the first (a) is a normal functioning situation, whereas the second (b) is a fault situation, where the voltage amplitude has dropped dramatically. The dashed circles represent the lower and upper current thresholds between which the current threshold virtual impedance is varied to limit the current.

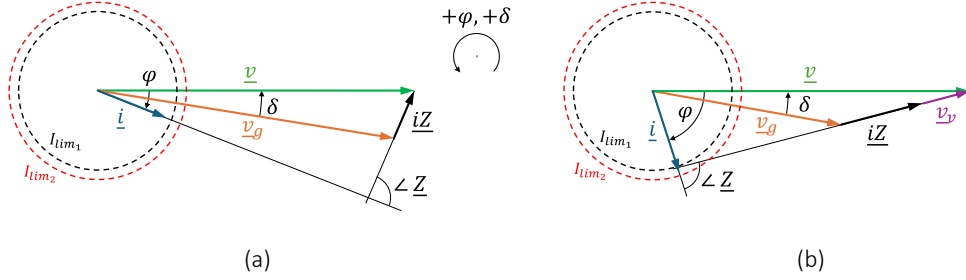


Figure 10: Phasor diagram with (a) pre-fault normal condition, where the current is below the maximum threshold, and (b) fault condition, where the virtual impedance is activated between I_{lim1} and I_{lim2} .

As shown in the phasor diagram, the ideal virtual impedance voltage $\underline{v}_v$, is colinear with the voltage drop across the filter $\underline{iZ}$ to complete the missing distance between grid voltage phasor $\underline{v}_g$ and internal voltage source $\underline{v}$. This implies that the ideal virtual impedance has the same argument as the filter impedance.

$$\angle \underline{z}_v = \angle \underline{Z} \quad (5)$$

Nevertheless, in practice, calculating the voltage drop across an inductance implies calculating the derivative of the current. This is unpractical because it amplifies high frequencies and induces instability. Therefore, in practice, a stable current threshold virtual impedance is resistive. The advantage of a resistive current threshold virtual impedance is that it damps well transient events, however, the drawback is that it does not participate in the support of the grid during faults. For this reason, voltage threshold virtual impedance is necessary.

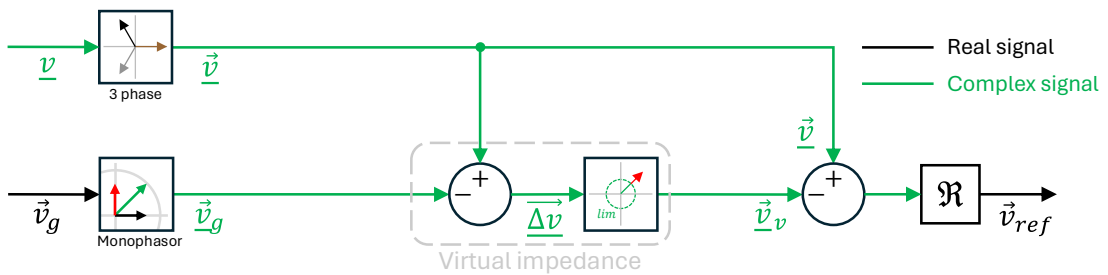


Figure 11: Current threshold virtual impedance application principle.



Voltage threshold virtual impedance

As mentioned above, voltage threshold virtual impedance observes and reacts to the cause of the over-current, which from the inverters point of view is the voltage drop across the output filter. As shown in Figure 12, the limit is no longer around the current phasor, but the voltage drop across the filter $\underline{iZ}$.

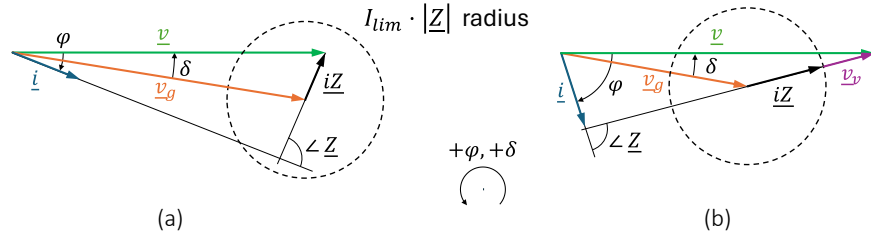


Figure 12: Phasor diagram with (a) pre-fault normal condition, where the current is below the maximum threshold, and (b) fault condition, where the voltage drop across the filter is limited to a predefined threshold.

Since the grid voltage phasor $\underline{v}_g$ is measured and the internal voltage source $\underline{v}$ is known, the virtual impedance voltage $\underline{v}_v$ can be calculated to maintain the voltage drop across the filter inside of the threshold.

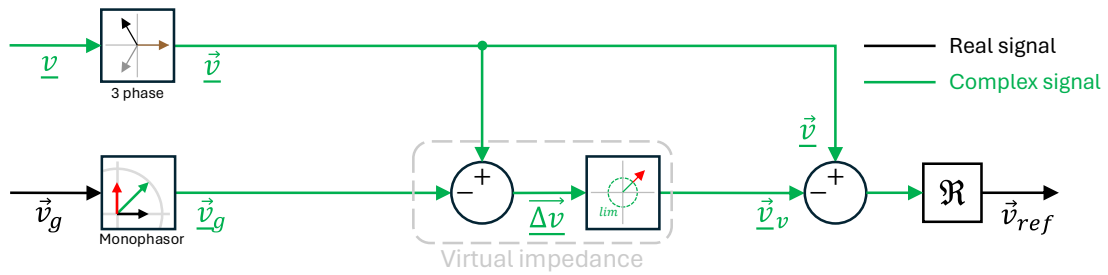


Figure 13: Voltage threshold virtual impedance application principle.

The advantage here is that it generates the ideal inductive response to support the grid, and its application is straightforward. However, the drawback is that it hardly offers any damping. Therefore, a combination of both current and voltage threshold virtual impedance is necessary to combine a damped inductive response.

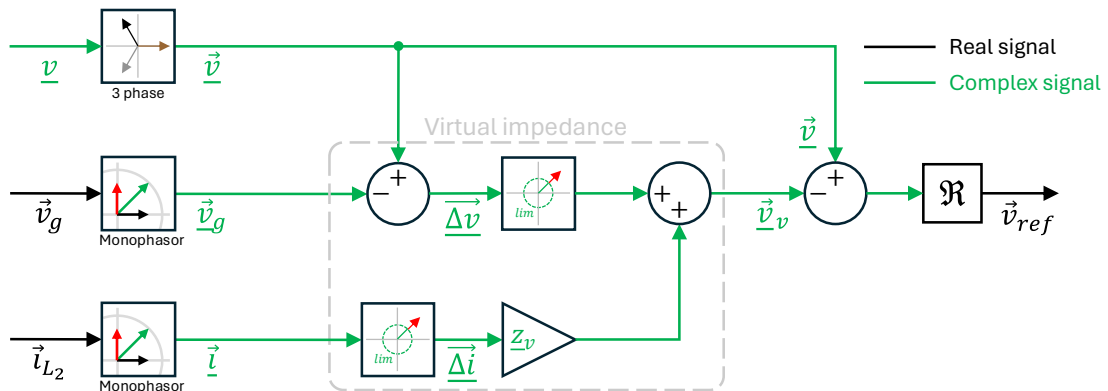


Figure 14: Combined voltage and current threshold virtual impedance application principle.



Filter resonance damping

Because the filter is an LCL filter, during a transient, there is a strong risk that its resonant frequency is excited. For this reason, the current in the capacitor must be damped. To do so, either a physical resistance can be added in series with the capacitor, or a virtual damping resistance can be implemented. The advantage of the latter is that it does not create any losses. Figure 15 shows in detail how resonance damping is implemented in parallel with the application of current and voltage threshold virtual impedances. Full details can be found in Appendix 3.

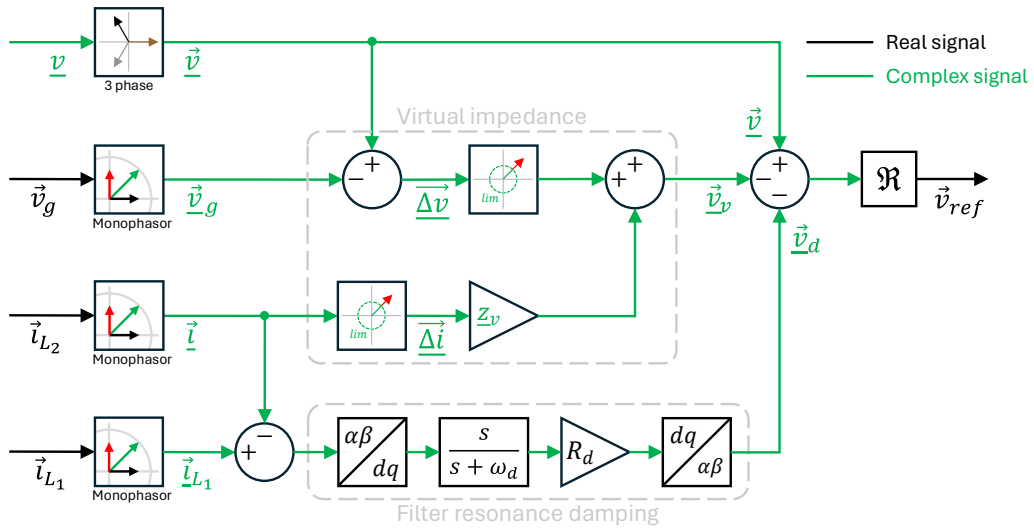


Figure 15: Virtual impedance application principle with resonance damping.



2.2 Experimental hardware (WP3)

The experimental hardware is composed of two inverters, a neutral balancing unit, as well as a power line to connect the two inverters together and the different switches to do manoeuvres (see Figure 21). One of the inverters is a proprietary 10kVA inverter that was designed and built inhouse and the other is a 22kVA imperix inverter. For simplicity, the inverters will be referred to as inverter A and B as following:

Table 2: Inverter designation

Inverter A	10 kVA proprietary inverter
Inverter B	22 kVA imperix inverter

2.2.1. Transformation and adaptation of inverter A

Inverter A was successfully converted from a Grid-Following Inverter (GFLI) to a Grid-Forming Inverter (GFMI), and preliminary tests were conducted to validate its new operating mode. Following these initial tests, further modifications were implemented to address specific technical issues.

The first major modification involved replacing the power part of the inverter. On the original inverter, the power semiconductors were Si IGBTs. These are slow to switch and required a switching deadtime of minimum 3 μ s. With a switching frequency of 15 kHz, such a deadtime represents 4.5% of the period. The main issue is that the deadtime causes major distortions to the generated output voltage and these depend on the sign of the current flowing through the power semiconductors. On a current controlled inverter, the deadtime can be compensated because the current is controlled. However, with the direct voltage control strategy, the current is not controlled and depends on the load. This makes compensating for these distortions very difficult without causing instability. Therefore, to reduce the distortions, the IGBTs were replaced with SiC MOSFETs. The deadtime was reduced to less than 300 ns, reducing the distortions by a factor 10.

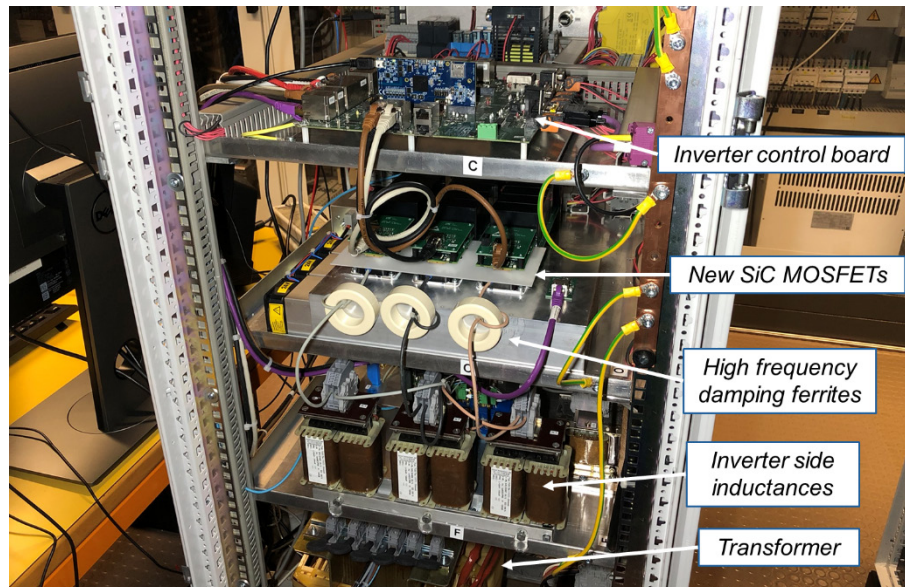


Figure 16: Rear view of inverter A with the different modifications.

The second major modification was to replace the original single-quadrant DC power supply with a two-quadrant power supply. This upgrade enables full bidirectional power flow, allowing the inverter to operate as if it were connected to a battery system.



Additionally, an isolation transformer was installed between the DC power supply and the inverter to provide galvanic isolation. This measure was taken to eliminate common-mode currents that had been observed during earlier testing phases.

Finally, ferrites were added on the lines between the power semiconductors and the inverter side inductances. As shown in Figure 17, ringing occurred at high frequencies with amplitudes of $\pm 30V$.

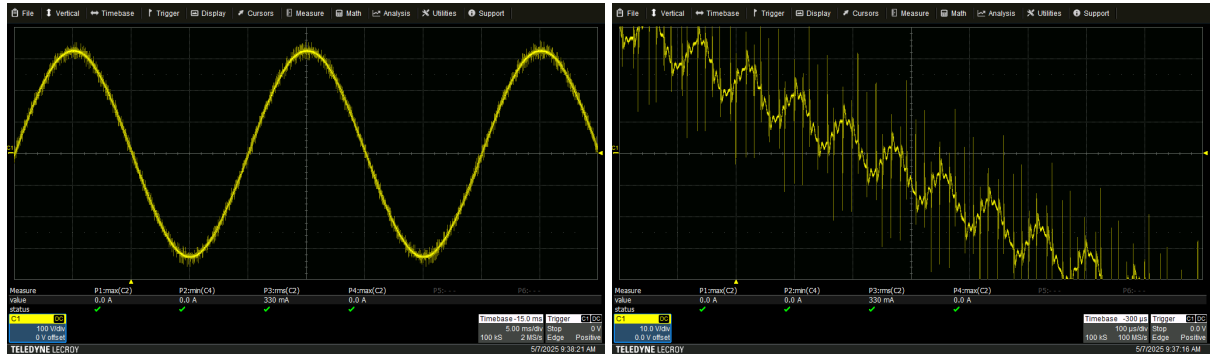


Figure 17: Left side: Output phase to neutral voltage with noise. Right side: Zoom on part of the voltage.

This ringing was being caused by the much faster switching of the MOSFETs. Adding the ferrites was sufficient to damp this ringing significantly, as shown in Figure 18.



Figure 18: Left side: Output phase to neutral voltage after the installation of the ferrites shown in Figure 16. Right side: Zoom on part of the voltage.

2.2.2. Adaptation of inverter B

Inverter B was adapted to meet the specific requirements of the microgrid setup. As part of this process, grid-side inductances were integrated to ensure proper filtering and improve power quality. The inverter was then installed in a standard 19-inch rack, allowing for modular integration and facilitating access for testing and maintenance.

As for inverter A, a bidirectional DC power supply was integrated to emulate the behaviour of a connected battery. Furthermore, an isolation transformer was also installed between the grid and the DC power supply to mitigate any risk of common-mode currents.



2.2.3. Neutral point balancing

Both inverters are three phased inverters that are initially designed to function with balanced loads or with only slight imbalances. As shown in Figure 19, the neutral point (0) is connected to the centre point of the DC link. If there is an unbalanced AC load, the centre point will oscillate. In the worst case, if there is a DC component in the unbalance (e.g., due to a broken diode in a rectifier), the DC link will diverge and potentially cause the DC link capacitors to fail. To mitigate this, a fourth branch is added to each inverter to balance the DC link.

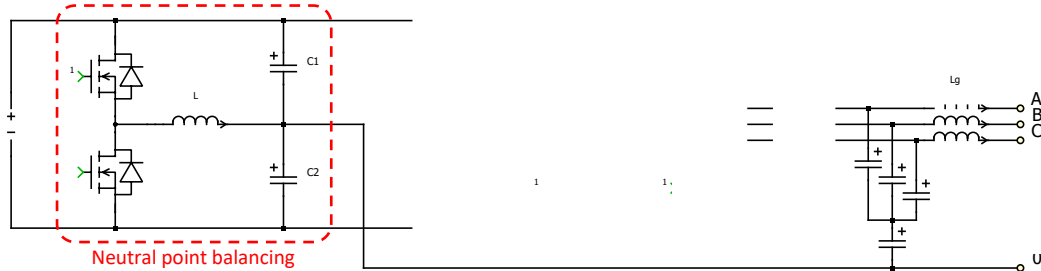


Figure 19: Three phase inverter with an additional leg to balance the DC link capacitor voltages.

Because each inverter is already fully integrated, the neutral balancing for both inverters was implemented exteriorly. The details of the full implementation can be found in Appendix 2.

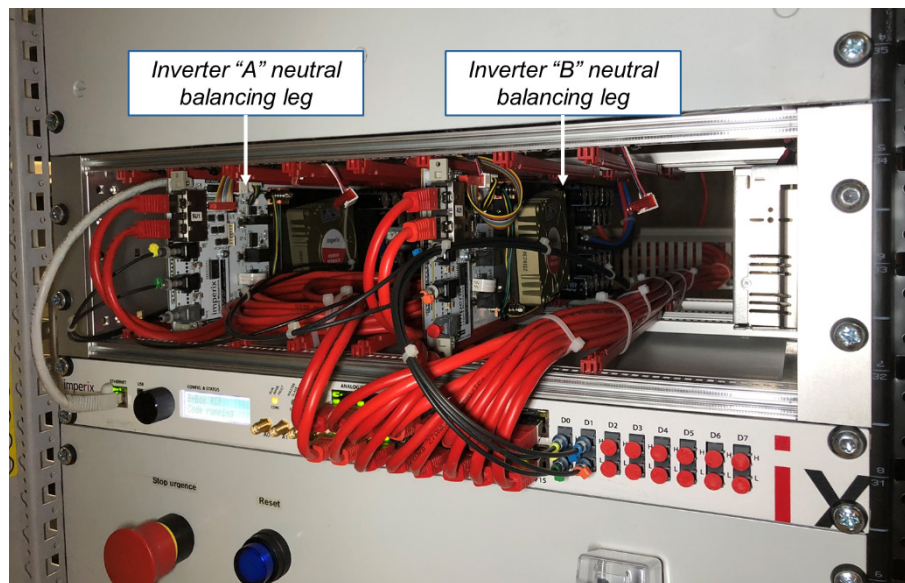


Figure 20: Implementation of the two neutral balancing legs

Each neutral balancing system aims to balance the voltage between the two capacitors in series composing the DC link. To do so, the voltage across the DC link, the voltage across one of the capacitors and the inductor current are necessary. Additionally, to improve the dynamics of the system, the neutral current can be measured and applied as a feed-forward to the current regulator. However, because the number of available measurement channels is limited, a choice had to be made concerning one of the feed-forward current measurements; one of the two would not have the feed-forward. The only consequence is that the amplitude of the voltage oscillation will be slightly higher for the one without. It was chosen that the 10kVA inverter (A) would not have the feed-forward because its currents would potentially be smaller than the 22kVA (B), giving it more margin.



2.3 Integration and community microgrid test (WP4)

2.3.1. Structure of the community microgrid

The two inverters previously described are installed in the smart grid laboratory at HEIG-VD to form the demonstration community microgrid. Each inverter can power its own loads directly, as if they were installed in separate houses and able to power the household. A local grid, represented by a power line, allows the two inverters to connect to each other through their own controlled switch. Furthermore, the local grid has a connection point to the macro-grid. The structure of the grid is illustrated in Figure 21.

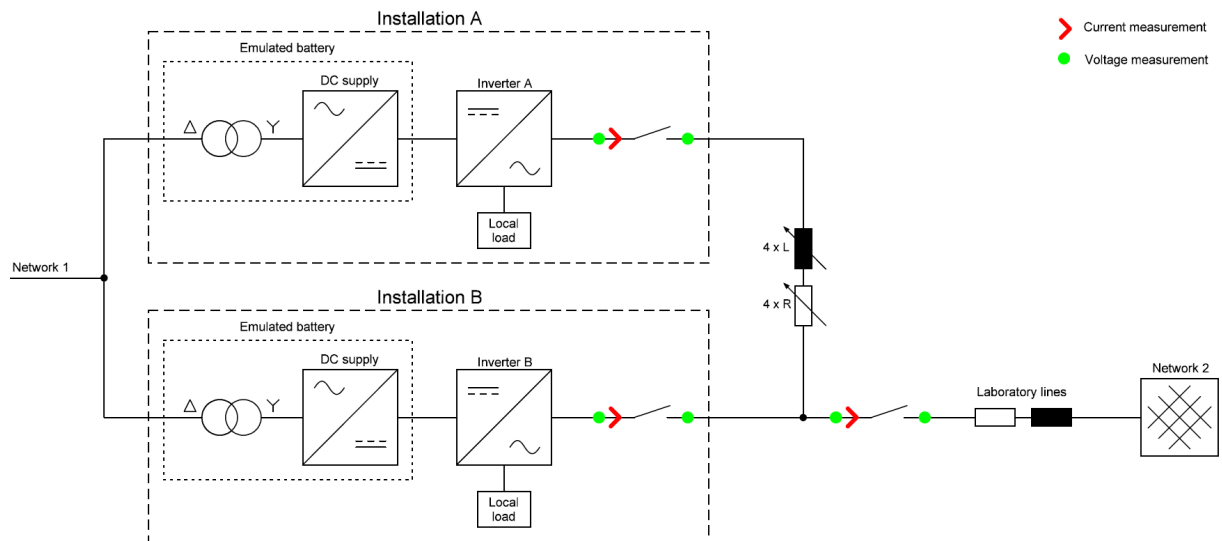


Figure 21: Structure of the community microgrid installed in the smart grid laboratory at HEIG-VD

In the smart grid laboratory, the macro-grid can either be a direct connection to the public grid through a 100 kVA transformer, or a grid can be emulated with a 100 kVA grid simulator. The grid simulator enables different tests to be performed such as voltage imbalances, frequency changes, harmonics and short circuits.

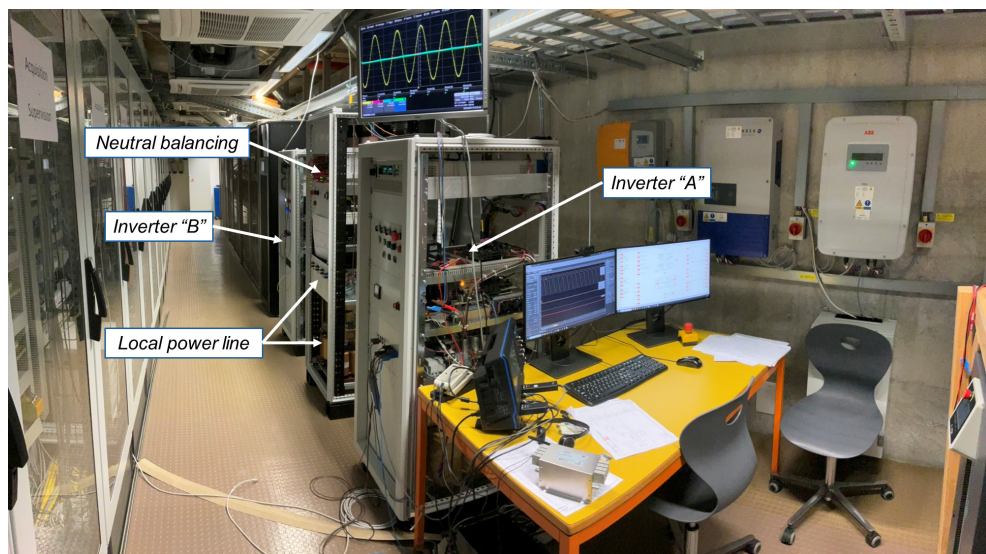


Figure 22: Inverters and neutral balance integrated in the smart grid laboratory



2.3.2. Implementation of a SCADA interface to monitor and remotely control the inverters

Both inverters A and B are equipped with a CAN bus communication capability. This has been utilized to implement full control and monitoring of both inverters through this communication bus. This allows us to remotely control the microgrid and test different scenarios. Furthermore, a SCADA like user interface has been developed to monitor and control the microgrid. Figure 23 shows view of the main screen of the microgrid's SCADA interface.

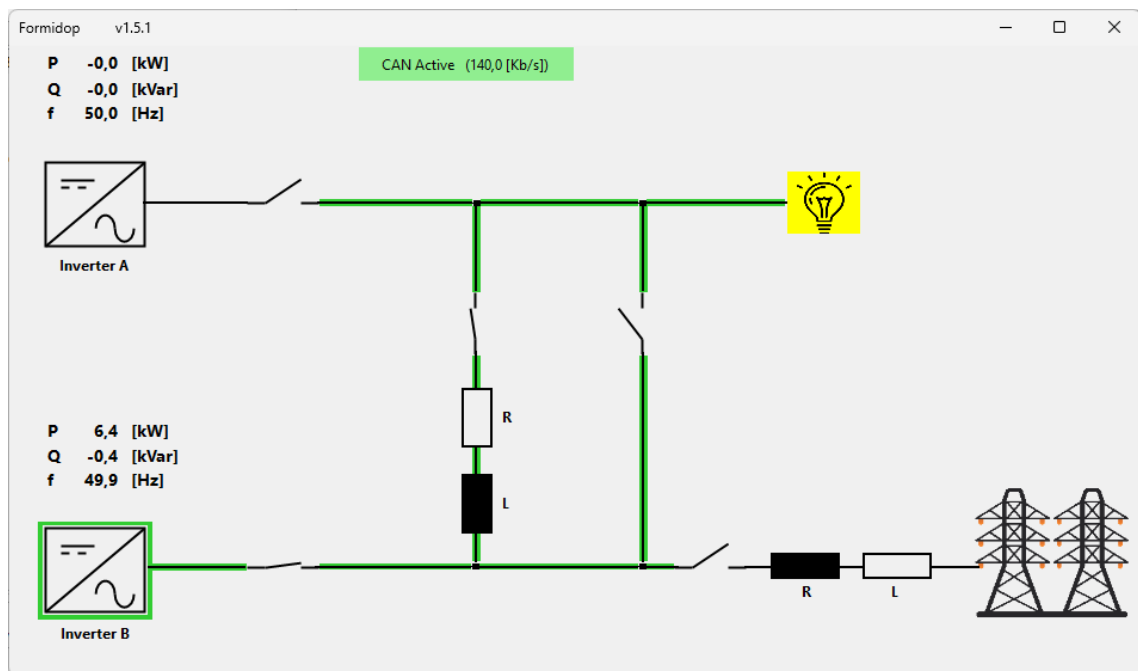


Figure 23: View of the main screen of the microgrid's SCADA interface.

A secondary screen is available for each inverter which allows the user to have detailed on the status of the different parts control. Furthermore, the active and reactive reference points can be changed manually.

An “Autopilot” mode has already been implemented for further use. This will allow us to define rules to automatically change the reference setpoint. This way, it will be possible to emulate centralized control strategies, as well as decentralized control strategies based on information only available to each inverter.

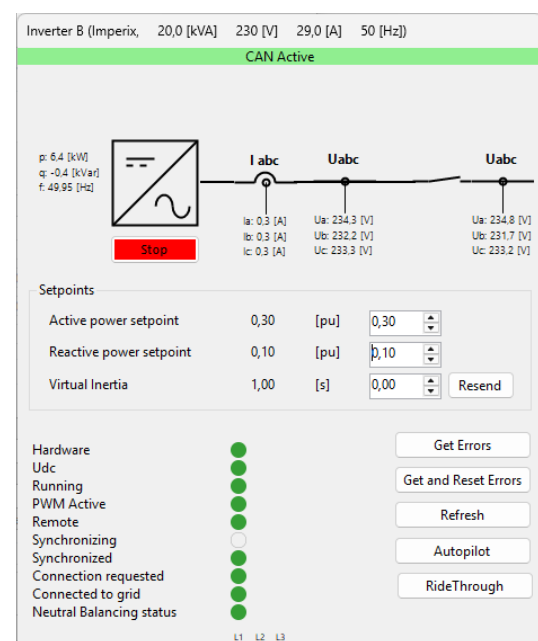


Figure 24: View of the secondary screen giving detailed information on the inverter status as well as controls.



2.4 Experimental results (WP5)

Once the individual components of the community microgrid had been successfully tested, they were interconnected to form a complete system. A series of experimental tests were then conducted to validate the full range of functionalities of the microgrid in its integrated configuration.

2.4.1. Black start

The first experimental test aimed to evaluate the black start capability of each inverter. Black start refers to the ability of an inverter to start up autonomously with or without loads already connected, without relying on an external power source. This test was successfully completed, confirming that each inverter can reliably initiate operation under different load conditions.

2.4.2. Synchronization

This test focused on the synchronization of two inverters and their ability to operate in parallel. This test presents a higher level of risk due to the potential for power exchange between the inverters, which can lead to instability or equipment damage if not properly managed. This test was successfully completed.

While interconnected, different loads were added and subtracted, and the inverter setpoints were varied. Tests were also conducted where power was exchanged between the two inverters. These tests showed that the inverters could successfully share the load and remain synchronous.

Furthermore, different tests were conducted where the two inverters were connected to the grid simulator. While attached to the grid simulator, the frequency of the grid was varied to simulate an event with a rate of change of frequency (RoCoF) of 2 Hz/s, which would be a massive event on the grid. Both inverters remained synchronous and provided their expected inertial responses. Figure 25 shows the response of inverter B to a frequency change of -1 Hz in 0.5 seconds.

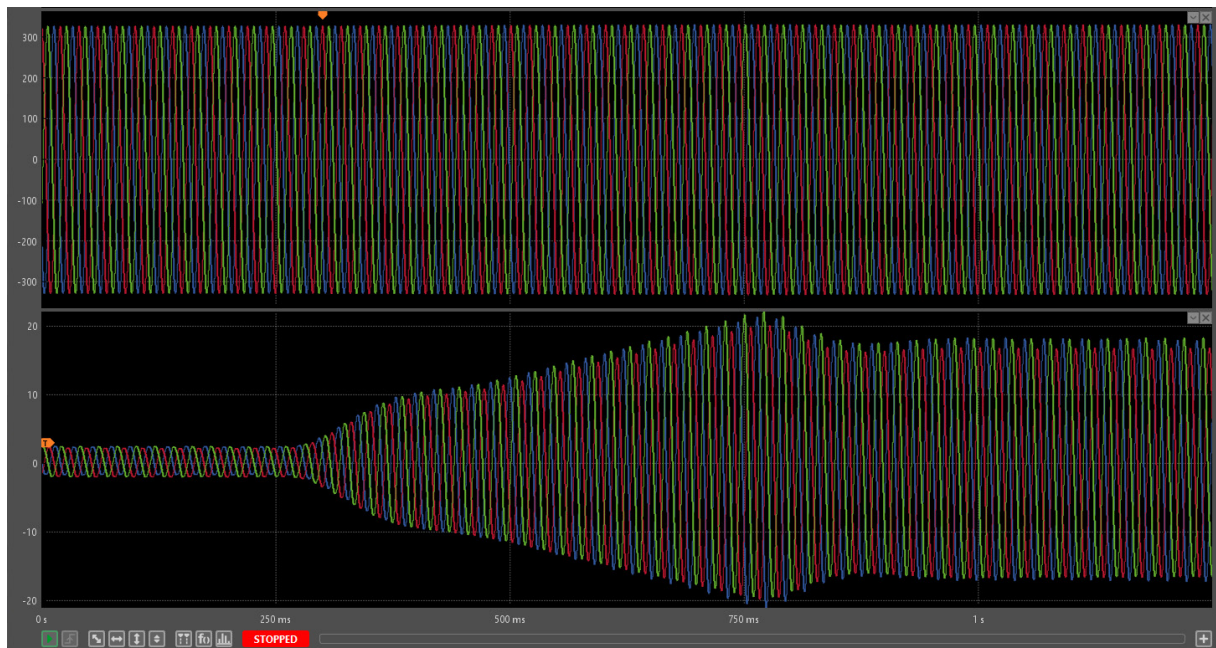


Figure 25: Inverter B response to a frequency change of -1 Hz in 0.5 seconds. Top: Grid voltage. Bottom: Inverter output current.



2.4.3. Overload and short-circuit tests

Overload tests were performed. First gradually, by increasing passive loads until the inverters started limiting their output current. Then, a more brutal test was performed by starting an induction motor directly connected to the inverters. The motor's inrush current was successfully limited while allowing it to start. Following this, direct short circuits were done at the output of the inverters by short-circuiting directly a phase to the neutral point, a phase to a phase, as well as all three phases together. All direct short-circuit tests were passed successfully. The next tests were to connect the grid simulator and emulate a fault coming from grid. These tests were of the highest risk so far because the load seen by the inverters is no longer passive, as well as the potential power of the grid simulator. The tests were performed by causing a voltage drop to the different phases to simulate the different short-circuit scenarios. Figure 26 shows a simulated three phase short-circuit where the grid voltage seen by the inverter drops by more than half. As shown, the inverter successfully limits its output current and maintains it until the fault is resolved.

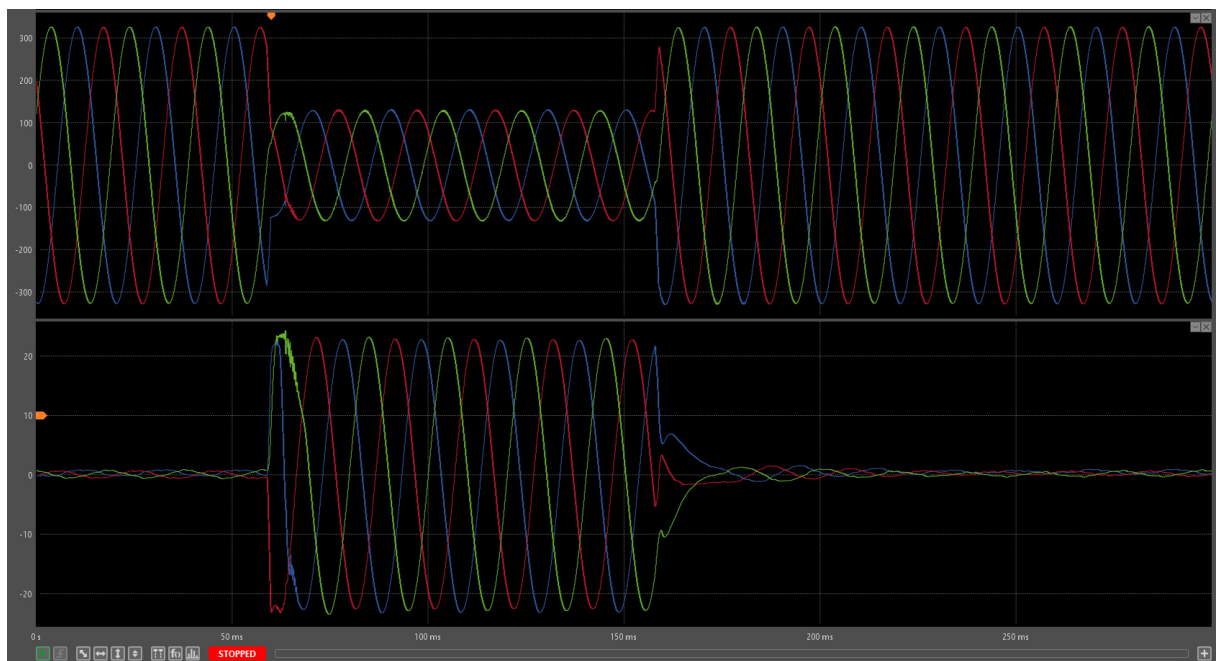


Figure 26: Simulated three phase short-circuit where the voltage seen by the inverter drops by more than half. Top: Grid voltage. Bottom: Inverter output current.



2.4.4. Phase jump test

The final test conducted is to submit the inverter to a voltage phase jump of 15° coming from the grid. This was emulated with the grid simulator while the inverters were connected to it. A phase jump can typically happen when a power line is connected or disconnected. A phase jump of 15° would be a massive event. Therefore, being able to ride through successfully such an event is a demonstration of robustness. Figure 27 shows the response of inverter B to the event.

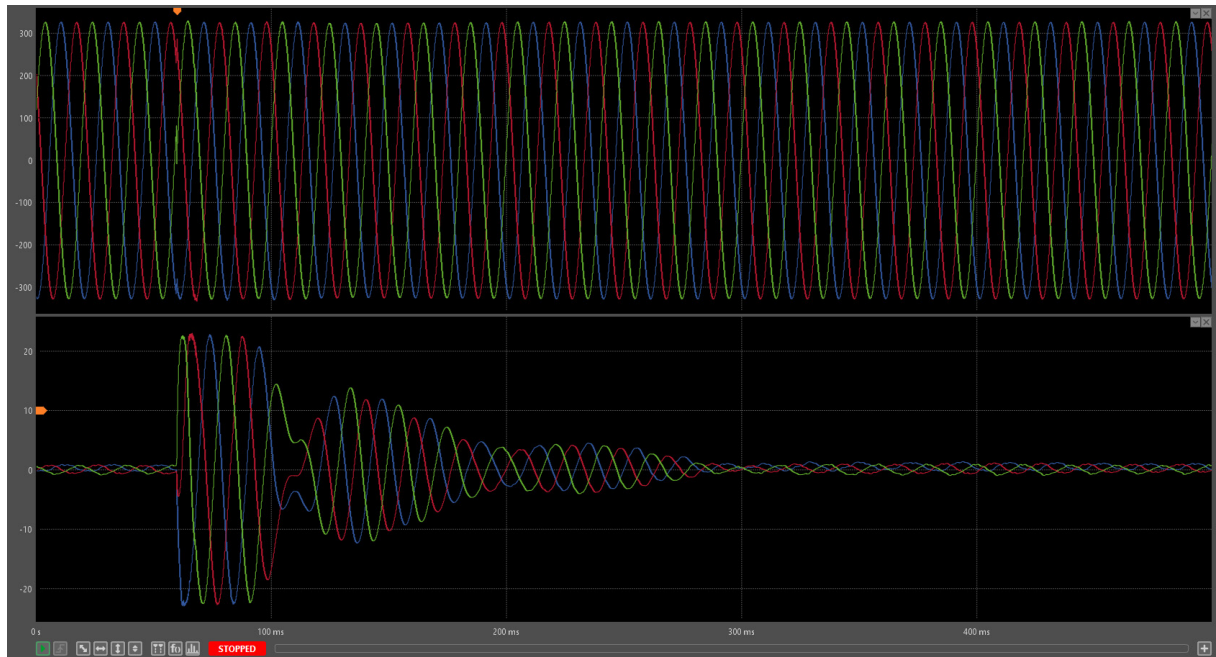


Figure 27: Voltage phase jump of 15° (top) and current response of inverter B (bottom)

As shown, when the phase jump occurs, because the load angle increases abruptly, the inverter is temporarily overloaded until it catches up with the grid's phase. The inverter successfully manages the event by limiting its output current, then by re-establishing normal conditions. The full event is resolved and attenuated in less than 300 milliseconds.



2.5 Analysis from a power system perspective (WP5)

The objective of this section is to assess the most relevant benefits and risks of GFMI and GFLI in a community microgrid. In this regard, a methodology is proposed relying on detailed simulations of a community microgrid with different configurations. The analysis is conducted on a low-voltage (LV) distribution network under two operating conditions: grid-connected and islanded operation.

Two complementary properties are used to characterise network performance: reliability and resiliency. Reliability concerns the grid's ability to deliver continuous service under normal operating conditions, whereas resiliency concerns its ability to withstand and recover from extreme or unexpected events. The following subsections define each property, clarify how it is quantified, and explain the extent to which it is addressed in this study.

- The reliability of an LV network is quantified by metrics such as System Average Interruption Frequency Index (SAIFI) and System Average Interruption Duration Index (SAIDI). They can be measured for an electrical grid at different level of GFMI adoption. SAIFI represents the average number of interruptions that a customer experiences over a given period, usually one year. SAIDI represents the average outage duration experienced by each customer over the same period. In practice, SAIFI and SAIDI are computed in accordance with utility and regulatory standards, e.g., IEEE 1366, which define interruption thresholds, reporting rules, and treatment of major events.
- While reliability evaluates the grid's capability to provide continuous service under normal conditions, resiliency characterizes the grid's ability to withstand and recover from extreme or unexpected events, such as faults or islanding. In this context, resiliency can be quantified through restoration time, defined as the time required to return the system to an acceptable operating state after a disturbance. In this study, resiliency is not considered. Resiliency is a higher-level system property that emerges from the interaction of several community microgrids, upstream network assets, and protection and restoration schemes. Individual community microgrids are therefore not the dominant drivers of overall grid resiliency.

To assess the benefits and potential risks of the proposed community microgrid framework, a standard LV distribution feeder was adapted to integrate multiple GFLIs and GFMI. The network, illustrated as Feeder 125 in Figure 28, was modelled and simulated in DigSILENT PowerFactory.

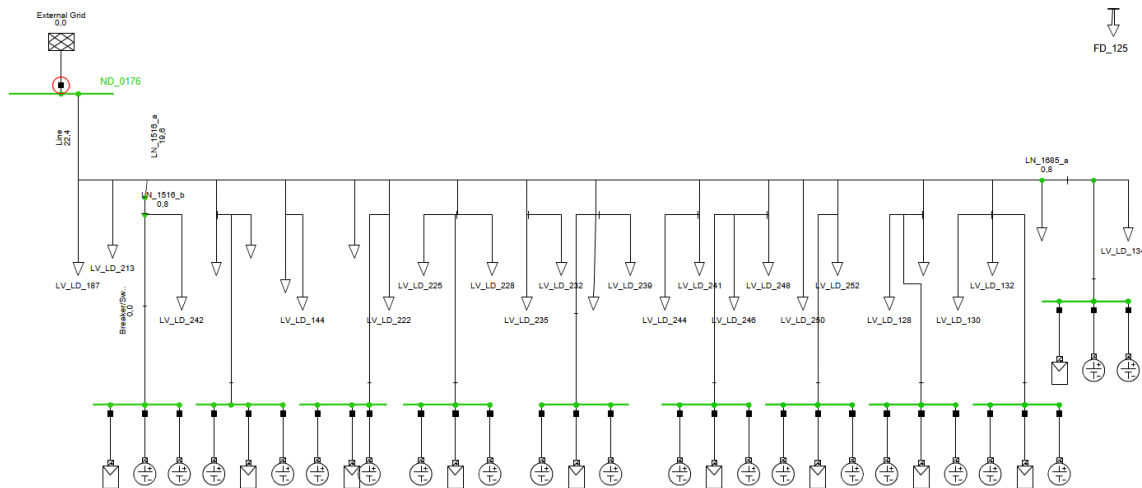


Figure 28: LV Feeder distribution network modelled in DigSILENT PowerFactory.

DigSILENT PowerFactory provides both Root Mean Square (RMS) and Electromagnetic Transient (EMT) simulation capabilities. RMS simulations model electrical quantities such as voltages and currents as sinusoidal phasors (i.e., magnitude and phase) rather than instantaneous waveforms. DigSILENT PowerFactory is widely used in industry for large-scale power system studies. It is particularly



suitable for analysing extensive networks. EMT simulations model the instantaneous time-domain behaviour of electrical signals, voltage and current waveforms, by solving differential equations at very small steps (microseconds or less). A key limitation of DlgSILENT PowerFactory is the implementation of custom control models, especially state-space representations of advanced GFMI control strategies, which require programming the DlgSILENT simulation language (DSL). Despite this, the software includes built-in models for key grid-forming control approaches such as virtual synchronous machine (VSM) and droop-based control. It also supports Python-based scripting, which enables automated execution of multiple simulations with varying parameters or load scenarios.

The feeder in Figure 28 operates at a nominal voltage level of 400 V. It consists of 38 nodes connected through approximately 410 m of distribution cables. A total of 27 loads are connected to the feeder, each with a nominal active power demand of 7 kW and nominal current of 10.6 A, resulting in an aggregate nominal active power demand of 189 kW. The feeder can be disconnected from the external utility grid through a switch indicated by the red circle in Figure 28.

It is worth mentioning that several simplifying assumptions are adopted in this study to reduce the complexity of the assessment. The analysis assumes that the only failure event is the disconnection of the community microgrid from the main grid at the point of common coupling (PCC) for a duration of 2 hours. Other types of failures are considered sufficiently rare and are therefore neglected. In addition, all GFMI and GFLI are assumed to remain operational throughout the simulations, meaning that inverter failures are not considered in quantification of reliability. Although these assumptions are not fully representative of real operating conditions, they allow the study to focus on the fundamental behaviour of the microgrid during islanded operation. The simulation analysis considers two complimentary dimensions: *system adequacy* and *system security*.

Details of this analysis and the results are given in Appendix 4 “*Assessment of the Benefits and Risks of Grid-Forming Inverters in Community Microgrids*”. In the following, a short summary of this analysis is given.

2.5.1. Distributed energy resource composition (PV, storage, GFL and GFM)

The studied community microgrid includes distributed energy resources (DERs) composed of PV generation and battery energy storage systems (BESSs) interfaced through power electronic converters. A total of 10 PV installations are distributed across the feeder, each rated at 27 kVA with a power factor of 0.95. The total installed PV capacity in the network is therefore 270 kVA, corresponding to approximately 256.5 kW of active power generation.

Each PV installation is connected to the distribution feeder through inverter-based interfacing units. To evaluate the impact of different inverter control strategies on islanded operation and system stability, three different DER configurations are considered at each PV node:

1. PV-only operation without energy storage support.
2. PV integrated with a 20 kW battery energy storage system operating as a GFMI using VSM control.
3. PV integrated with a 20 kW battery energy storage system operating as a GFMI using droop-based control with a frequency droop coefficient of 1 % (i.e., 0.01 per unit, equivalent to a power-frequency characteristic of 40 kW/Hz). This relatively stiff droop value was selected as it ensures the dynamic stability of the system under the tested conditions.

The objective of these scenarios is to evaluate the minimum required storage capacity and inverter control configuration necessary to maintain stable operation of the microgrid during islanded conditions. Particular emphasis is placed on assessing voltage and frequency stability, active and reactive power sharing, and transient response following disconnection from the external utility grid.

The PV inverters operate primarily in grid-following mode during grid-connected operation, whereas the storage converters are configured to provide grid-forming functionality during islanded operation. While grid-forming capability of PVs is technically possible, it necessitates significant power reserves for fre-



quency regulation, which is often economically inefficient due to the required curtailment of solar generation. This arrangement enables investigation of the interaction between GFLIs and GFMLIs under varying operating conditions.

2.5.2. Simulation Campaign

To test the robustness of the microgrid, each simulation follows a rigorous chronological sequence of events designed to challenge the system's primary control loops and transition capabilities. These events should be sustained in islanded and grid-connected mode.

The time sequence is defined as follows:

- $t = 0.0$ s: Islanding event (disconnection from the external grid).
- $t = 1.0$ s: Positive load step (+30 %) to evaluate load-following capability.
- $t = 1.5$ s: PV generation reduction (-30 %) to simulate sudden cloud cover.
- $t = 2.0$ s: Reconnection to the main distribution network.
- $t = 2.5$ s: Three-phase fault at the Point of Common Coupling (PCC) for 100 milliseconds with an impedance of 0.1 and X/R ratio of 3.

All results are automatically validated against standard operation. A case is flagged as “unstable” or “non-compliant” if frequency deviates beyond 49.8-50.2 Hz or if the voltage at any node exceeds the 0.95-1.05 per unit range. Furthermore, oscillatory instability is identified if the ratio of standard deviation to the average value for either frequency or voltage exceeds 0.01.

The study examines how system strength changes when the mix of GFMLIs is varied. The number of grid-following PV units is kept constant to preserve a fixed level of stochastic generation. Only the grid-forming composition is changed.

Two types of GFMLIs are considered: Droop-based GFMLIs range from 0 to 10 units and VSM GFMLIs range from 1 to 10 units. Combining these ranges produces 110 different system configurations. This setup allows evaluation of whether specific control strategies, or combinations of strategies, provide better voltage stability and frequency stability in a LV network in islanded operation.

To reflect realistic variations in operating conditions, four extreme cases are defined based on the balance between supply and demand. Scenario 0 represents high load (100 %) with no generation (0 %). Scenario 1 combines high load (100 %) with full PV generation (100 %). Scenario 2 considers medium load (50 %) with full PV generation (100 %). Scenario 3 models medium load (50 %) without PV generation (0 %).

The scale of the campaign is designed to provide statistically significant insights into microgrid reliability. The total volume of simulations is 8800 cases.

2.5.3. Results

For each scenario, the frequencies and the voltages are recorded over a 3-seconds window following the disturbance. From these time-series, the key performance indicators are computed. The evaluated metrics and their standard reference thresholds for microgrid operation are Frequency nadir (the minimum frequency reached during a transient event), Steady-state deviation, settling time, the rate of change of frequency (RoCoF), voltage deviation, and voltage recovery time. These metrics are defined in Appendix 4.

The simulations compare several GFMLI configurations operating under VSM control with different aggregated inertia constants (H) and droop capacities. To facilitate comparison and clarify system scaling, these parameters are expressed on a normalized, aggregated basis. For example, an aggregated inertia constant of ($H = 1$) second indicates that the network is provided with 1 second of virtual inertia per kW of its capacity. In practice, this level of aggregated inertia can be achieved, for example by a 1 kW GFMLI to be configured with an inertia constant of 1 second. Consequently, higher values of (H) provide stronger inertial support and result in slower frequency dynamics, like the behaviour of conventional synchronous machines. Similarly, a droop capacity of 10 % means that GFMLIs equipped with the specified droop setting (1 % in this case) represent 10 % of the total load capacity. Figure 29 presents the



system frequency response for three inertia constants (0.32 second, 1.59 second, and 3.17 second) combined with two droop capacities (21 % and 85 %).

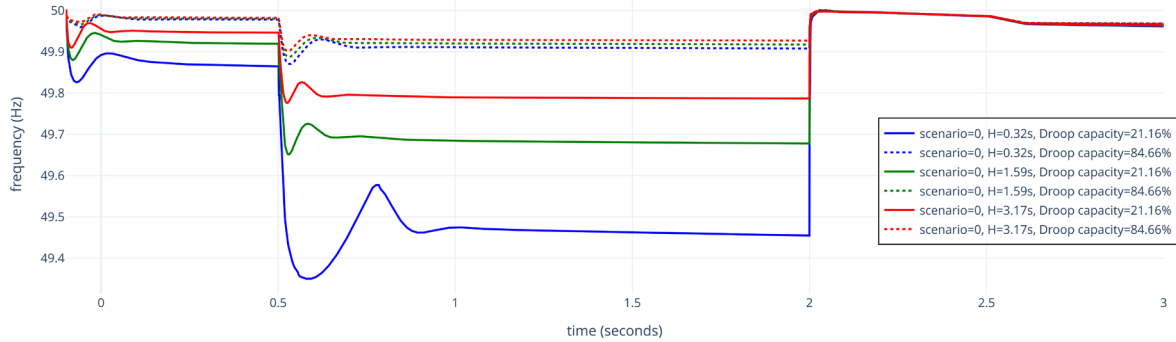


Figure 29: Frequency response for different configurations of GFMs.

The results show that increasing the inertia constant (H) improves the frequency response by reducing the initial frequency deviation following a disturbance. For example, the configuration where ($H = 3.17$) seconds exhibits a higher frequency nadir (minimum system frequency reached immediately after a disturbance) compared to the case with ($H = 0.32$) seconds. The increased virtual inertia reduces the rate of change of frequency (RoCoF) and mitigates transient oscillations.

However, the simulations also demonstrate that virtual inertia alone is insufficient to ensure satisfactory frequency regulation. The droop response has a more pronounced impact on the steady-state frequency behaviour. Increasing the droop capacity from 21 % to 85 % enables the system frequency to converge closer to the nominal value of 50 Hz and significantly attenuates oscillatory behaviour. In contrast, low droop capacities result in larger steady-state frequency deviations and weaker stabilization, particularly for low-inertia configurations.

Figure 30 shows the required load shedding in Scenario 0 as a function of the available virtual inertia per kilowatt of grid capacity and the droop capacity (i.e., the proportion of the total power capacity actively programmed to correct frequency deviations). Configurations with high GFMI penetration and appropriately tuned control parameters can reduce load shedding by nearly 100 %. The results reveal a sharp reliability threshold when the available aggregated virtual inertia falls below 1 second and the droop capacity drops below 50 %. Moreover, when the aggregated inertia remains below 1 second, even a high droop capacity cannot compensate for the lack of immediate inertial response. Consequently, the system experiences repeated frequency violations, leading to cascading load shedding and power outages.

These quantitative results should be interpreted considering the simplifying assumptions adopted in this study: a single failure event (disconnection at the PCC), a fixed outage duration of 2 hours, and the continuous availability of all GFMs and GFLIs throughout the simulations. In particular, the near elimination of load shedding reported above assumes that no inverter outages occur; relaxing this assumption would likely reduce the achievable reliability gains. The reported figures should therefore be understood as an upper bound on the benefits attainable under idealised converter availability.

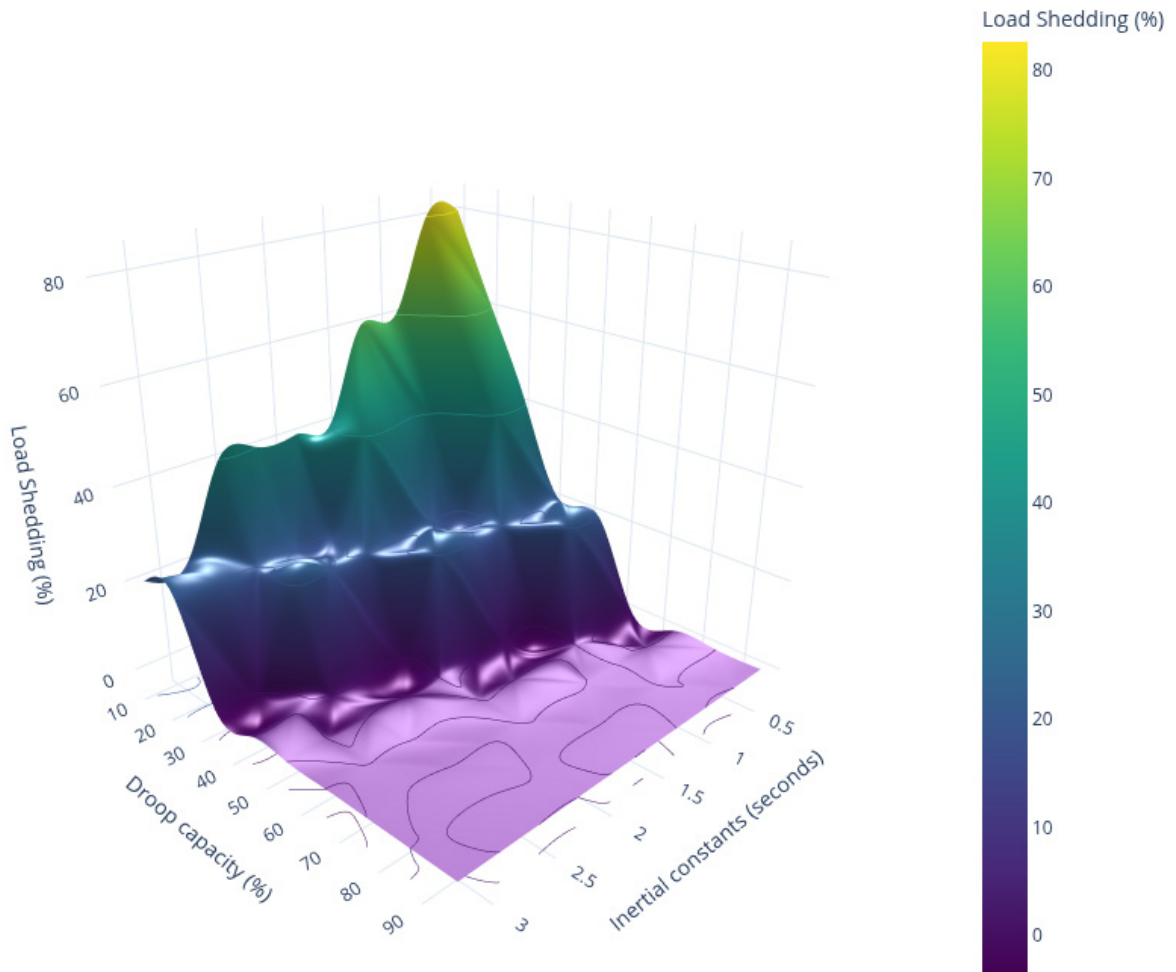


Figure 30: Load shedding percentage as a function of GFMI virtual inertia (VSM) and droop capacity during is-landed operation (Scenario 0).

In low inertia scenarios, the RoCoF is too high for the primary control to catch, leading to a total system collapse to react effectively, causing the system to collapse before the droop response can take effect. Conversely, in low-droop scenarios, the system may survive the initial transient, but the frequency fails to settle within the required 49.8–50.2 Hz operating range, resulting in the activation of protection mechanisms. To maximize loading capacity and minimize load shedding, the GFMI control strategy should provide sufficient droop capacity to ensure acceptable steady-state frequency regulation and maintain at least 1.5 seconds of virtual inertia to guarantee transient stability.



3 Conclusions and outlook

The increasing penetration of inverters reduces the inertia constant of the grid, compromising its reliability and stability. To address this challenge, the objective of this project was to design, develop, and test grid-forming inverters (GFMI) and assess their ability to improve grid reliability and resilience. This was achieved by developing GFMI control algorithms, validating them experimentally on hardware prototypes, and conducting simulation studies to assess their operation within a large-scale community microgrid.

3.1 Main results

The main goal of the experimental hardware was to demonstrate that two or more voltage-source inverters could operate together without conflict. Additional challenges, such as managing unbalanced loads and protecting inverters from overloads, were successfully addressed. Unbalanced loads, which can lead to catastrophic DC link failure, were mitigated by adding a fourth leg to each inverter for capacitor voltage balancing. Overload protection was implemented using monophasors to estimate current amplitude and phase in real time, enabling appropriate voltage drops to limit output current. These solutions were tested under demanding conditions, including short circuits, and all tests were passed successfully, confirming the robustness of the developed control algorithms. It is to be noted that the limited capacity of inverters to provide current during a fault can be a limiting factor in the design of the protection-coordination. To support further work, an open-source PLECS library was created to allow students and researchers to implement GFMI without starting from scratch. This library is available on GitHub (<https://github.com/heig-vd-ie/plecs-lib.git>).

Beyond the hardware and the library deliverables, an extensive simulation campaign was carried out to quantify the operational role of GFMI in a representative low-voltage (LV) community microgrid. The study covered 110 control configurations across four supply-demand scenarios and twenty load-shedding levels, totalling 8800 root-mean-square (RMS) cases stressed by a chronological sequence of islanding, load step, PV drop, reconnection, and PCC fault. The results consistently show that GFMI provide four practical benefits: i) seamless islanding through autonomous voltage and frequency reference, ii) higher loading capacity with required load-shedding falling from roughly 80 % in low-GFM configurations to near zero once thresholds are met, iii) superior voltage and frequency control combining virtual synchronous machine (VSM)-based inertial response with droop-based steady-state regulation, and iv) improved fault ride-through that translates into an improvement in system average interruption frequency and duration indices (SAIFI and SAIDI), approaching 95 % relative to a purely grid-following baseline.

3.2 Limitations and challenges

The simulation results also expose a set of significant risks, particularly a sharp *reliability cliff* at low GFM penetration. If the aggregated inertia constant (normalized to grid capacity) falls below 1 second, or if the droop capacity (i.e., the proportion of the total power capacity actively programmed to correct frequency deviations) falls below 50 %, the system risks collapsing during the initial transient or failing to stabilize within the 49.8-50.2 Hz band. Grid stability is highly sensitive to parameter tuning of control systems: inertia alone cannot regulate steady-state operations, while droop control alone is insufficient to contain a high RoCoF. Coordinating heterogeneous inertia and droop units introduces further complexity, carrying the risk of uneven power sharing, circulating flows, or amplified oscillations in weak networks.

A further challenge lies in the control architecture. Because small GFMI in a community microgrid will likely be privately owned, decentralized control strategies will also need to be developed to improve their acceptance by future owners, as well as to ease their integration. Accordingly, two levels of control must be developed: primary control at the hardware level and secondary control at the community microgrid level. The primary level reacts almost instantaneously to changing conditions on the microgrid and keeps it functional; however, it does not return the microgrid automatically to its nominal values. Furthermore,



primary control does not consider load distribution, nor resource availability. For this, secondary control is necessary. In this project, the primary control was achieved by developing specific control algorithms for GFMLs and validating them through experimental hardware. Furthermore, preliminary tests were performed to investigate a decentralized secondary level. At the microgrid level, simple rules can be defined based on resource availability (e.g., battery state of charge) and output power. With these, the deviation of the frequency from its nominal value can be reduced significantly and the load distribution between the energy resources can be improved. However, when resources are largely available and the frequency deviation is small (e.g., when connected to the main grid), large contribution differences appear between resources.

3.3 Future work

Resolving the challenges linked to coordination, power sharing, controller interactions, and decentralized secondary control will be the focus of the forthcoming research project. The large-scale deployment of GFMLs within community microgrids will also require coordination between distribution system operators (DSOs) and transmission system operators (TSOs) through a grid code. Most existing grid codes (covering frequency stability, fault ride-through, inertia provision, and system support services) were developed primarily from a transmission-system perspective. However, as GFMLs are increasingly embedded within distribution networks and community microgrids, grid codes must explicitly define how these resources respond to local disturbances and operating conditions while also considering their aggregated contribution to transmission system stability. Such coordination is necessary to ensure that local GFML control actions do not conflict with distribution-level constraints, protection schemes, or power quality requirements, while enabling their collective response to provide frequency support, voltage regulation, and stability at the transmission level.

Finally, grid-forming inverters do not necessarily have to be energy sources. They can also be loads. Forthcoming research will concentrate on grid-forming loads and will explore how controllable demand, such as EV chargers, heat pumps, and industrial drives, can actively contribute to local voltage and frequency stability alongside traditional generation. Finally, techno-economic studies are needed to assess incentives and market frameworks that encourage widespread adoption, while experimental validation and real-world pilots will be essential to demonstrate reliability and interoperability in the increasingly inverter-dominated power systems.

4 References

- [1] Z. Li, M. Shahidehpour, F. Aminifar, A. Alabdulwahab, and Y. Al-Turki, 'Networked Microgrids for Enhancing the Power System Resilience', *Proc. IEEE*, vol. 105, no. 7, pp. 1289–1310, Jul. 2017, doi: 10.1109/JPROC.2017.2685558.
- [2] B. Chen, J. Wang, X. Lu, C. Chen, and S. Zhao, 'Networked Microgrids for Grid Resilience, Robustness, and Efficiency: A Review', *IEEE Trans. Smart Grid*, vol. 12, no. 1, pp. 18–32, Jan. 2021, doi: 10.1109/TSG.2020.3010570.
- [3] S. Wasterlain, H. Parisod, D. Roggo, and M. Carpita, 'EMC studies on grid integration of Distributed Energy Resources. A 10 kW, IEC-61850 compliant inverter design and preliminary test results', in *2016 International Symposium on Power Electronics, Electrical Drives, Automation and Motion (SPEEDAM)*, Jun. 2016, pp. 1059–1066. doi: 10.1109/SPEEDAM.2016.7525988.
- [4] S. F. O. of E. SFOE, 'Energy perspectives 2050+'. Accessed: Nov. 04, 2024. [Online]. Available: <https://www.bfe.admin.ch/bfe/en/home/politik/energieperspektiven-2050-plus.html>
- [5] 'RS 734.27 - Ordonnance du 7 novembre 2001 sur les install...', Fedlex. Accessed: Nov. 04, 2024. [Online]. Available: <https://www.fedlex.admin.ch/eli/cc/2002/22/fr>
- [6] U. Tamrakar, D. Shrestha, M. Maharjan, B. Bhattarai, T. Hansen, and R. Tonkoski, 'Virtual Inertia: Current Trends and Future Directions', *Appl. Sci.*, vol. 7, no. 7, p. 654, Jun. 2017, doi: 10.3390/app7070654.
- [7] P. Unruh, M. Nuschke, P. Strauß, and F. Welck, 'Overview on Grid-Forming Inverter Control Methods', *Energies*, vol. 13, no. 10, p. 2589, May 2020, doi: 10.3390/en13102589.



- [8] P. Morey, M. Pellerin, D. Houmard, M. Bozorg, and M. Carpita, 'Sizing and experimental validation of a selfsync droop-based grid forming inverter with direct voltage control', *Sustain. Energy Grids Netw.*, vol. 38, p. 101332, Jun. 2024, doi: 10.1016/J.SEGAN.2024.101332.
- [9] T. Qoria, C. Li, K. Oue, F. Gruson, F. Colas, and X. Guillaud, 'Direct AC voltage control for grid-forming inverters', *J. Power Electron.*, vol. 20, no. 1, pp. 198–211, Jan. 2020, doi: 10.1007/s43236-019-00015-4.
- [10] X. He, M. A. Desai, L. Huang, and F. Dörfler, 'Cross-Forming Control and Fault Current Limiting for Grid-Forming Inverters', *IEEE Trans. Power Electron.*, vol. 40, no. 3, pp. 3980–4007, Mar. 2025, doi: 10.1109/TPEL.2024.3500885.



5 Appendix

Appendix 1: Control Design of GFMI

Appendix 2: Neutral Point Balancing

Appendix 3: GFMI over-current protection

Appendix 4: System Analysis



Final report from 1 July 2026

FORMIDABLE

Appendix 1: Control design of GFMI



Source: HEIG-VD/IE 2026



Publisher:

Swiss Federal Office of Energy SFOE
Energy Research and Cleantech
CH-3003 Berne
www.energy-research.ch

Co-financing:

Imperix SA
CH-1950 Sion
www.imperix.com

Subsidy recipients:

HEIG-VD
CH-1400 Yverdon-les-Bains
www.heig-vd.ch

Authors:

Dr Philippe Morey, HEIG-VD, philippe.morey@heig-vd.ch
Prof. Dr Mokhtar Bozorg, HEIG-VD, mohktar.bozorg@heig-vd.ch
Prof. Dr Mauro Carpita, HEIG-VD, mauro.carpita@heig-vd.ch

SFOE project coordinators:

Dr Michael Moser, michael.moser@bfe.admin.ch

SFOE contract number: SI/502668-1

The authors bear the entire responsibility for the content of this report and for the conclusions drawn therefrom.



Contents

Contents	3
List of abbreviations	4
1 Introduction	5
2 System description	6
2.1 Internal voltage reference	6
2.2 Selfsync control	7
2.3 Parallel with the swing equation	7
2.4 Inertial and droop typical values	8
3 System transfer function	9
3.1 Effect of the coupling with the grid	9
3.2 Sizing the filter inductance	11
3.3 Effect of switching/sampling frequency	12
3.4 Compensation of the resonant part	12
4 Sizing of the selfsync droop control	14
4.1 Active power chain	14
4.1.1. System without feedforward	14
4.1.2. System with feedforward	15
4.2 Reactive power chain	16
4.3 Verification with the cross-coupling effect	17
4.4 Simulation of the full system connected to a stiff grid	18
5 Voltage phase and amplitude synchronization	19
5.1 Measuring the phase and amplitude errors	19
5.2 Voltage phase synchronization	19
5.3 Voltage amplitude synchronization	22
6 Conclusions	24
7 References	25



List of abbreviations

GFL	Grid Following
GFLI	Grid Following Inverter
GFM	Grid Forming
GFMI	Grid Forming Inverter
MIMO	Multiple Input Multiple Output
PLL	Phase Locked Loop
PWM	Pulse Width Modulation
RMS	Root Mean Square
RoCoF	Rate of Change of Frequency
SFOE	Swiss Federal Office of Energy
SG	Synchronous Generator



1 Introduction

Many different strategies have been proposed to generate the reference voltage amplitude and phase [1] for grid-forming inverters. Probably the most obvious is the virtual synchronous machine which emulates the behaviour of a synchronous generator (SG). Much work has been done in this field (e.g., [2], [3], [4], [5], [6], [7]), however emulating an SG does not take fully advantage of the freedom offered by the virtual nature of the control, as well as the opportunity to simplify the control scheme. The basic concept of virtual inertia is based on the swing equation which in essence is a second order differential equation that describes the dynamic behaviour of the rotor of SGs as well as any flywheel.

Because of the low resilience of inverters to overloads, the designers of the first GFM inverters were reluctant to abandon the current control loop and instead built a voltage control loop around it (multiloop or cascaded control). However, current controlled inverters in GFL mode are known to have stability issues when the grid inductance is high [8]. Stable current controlled GFM inverters can be designed [9], [10], however they are also confronted with stability issues when the grid inductance is high. In [11] the authors show that the solution is to do direct voltage control and that the loss of direct control of the current can be effectively compensated by the implementation of a dynamic virtual impedance that kicks in when the current becomes too high. Furthermore, in [12] it is demonstrated that compared with the multi-loop droop control, direct voltage control has a simpler control structure and also provides a better dynamic performance.

Nevertheless, one could argue that GFL inverters could also help support the voltage in the case of a large disturbance on the grid. The issue is that GFL inverters depend on a phase locked loop (PLL) to track the grid voltage. However, in the event of a short-circuit, the voltage drops to nearly zero and the PLL can lose track of the phase and quickly become unstable (timescale of tens of milliseconds). On the other hand, a system whose phase is controlled with an inertial behaviour will not deviate as fast, which potentially allows it to recover directly if the disturbance is resolved rapidly (timescale of a few hundred milliseconds).

In this work we explore a direct voltage control, which is based on the selfsync droop control [13], originally introduced in [14] and [15]. This method does not rely on a phase locked loop (PLL) to function but rather generates the reference phase of the inverter based on active power, as well as the reference voltage amplitude, based on reactive power. The voltage amplitude and phase are directly used as input to generate the pulse width modulation (PWM) controlling the power modules.



2 System description

Figure 2-1 illustrates two three-phased sinusoidal voltage sources connected via an impedance (represented here in a single wire form). The one on the left represents the inverter, the one on the right represents the grid and the resistive-inductive impedance represents the coupling between them.

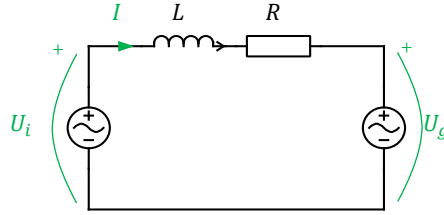


Figure 2-1: Two three-phased voltage sources connected via a resistive-inductive impedance.

In steady state and for small differences between the sources, the active power will be proportional to the phase difference between the two voltage sources and the reactive power will be proportional to their amplitude difference. The bloc diagram in Figure 2-2 shows the active and reactive power chains for the control of a grid following inverter.

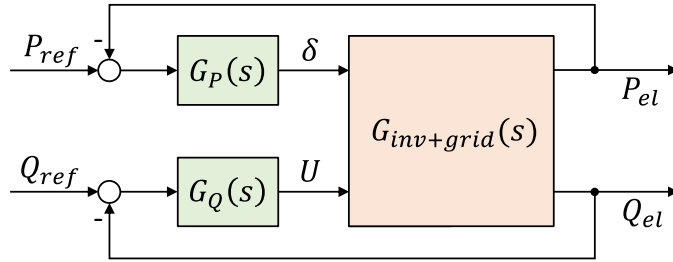


Figure 2-2 : Bloc diagram of the active and reactive power chains.

P_{ref} and Q_{ref} are the active and reactive power droop setpoints, $G_P(s)$ and $G_Q(s)$ are the respective droop controls, U and δ are the inverter voltage amplitude and phase, and P_{el} and Q_{el} are the electric active and reactive powers.

2.1 Internal voltage reference

The particularity with a grid forming inverter is that it has its own internal reference voltage $\underline{v}$ which is defined by its amplitude U and phase δ . This internal reference voltage can be expressed in as:

$$\underline{v} = \sqrt{2} \cdot U \cdot e^{j\delta} \quad (2-1)$$

From this, the three phases can be generated

$$\underline{\vec{v}} = \begin{bmatrix} 1 \\ \underline{\alpha} \\ \underline{\alpha}^2 \end{bmatrix} \cdot \underline{v} \quad (2-2)$$

where

$$\underline{\alpha} = e^{j\frac{2\pi}{3}} \quad (2-3)$$



2.2 Selfsync control

The particularity of the selfsync control method is the feedforward on the angle, which improves greatly the stability of the system. The block diagram of the self-sync control is given in Figure 2-3.

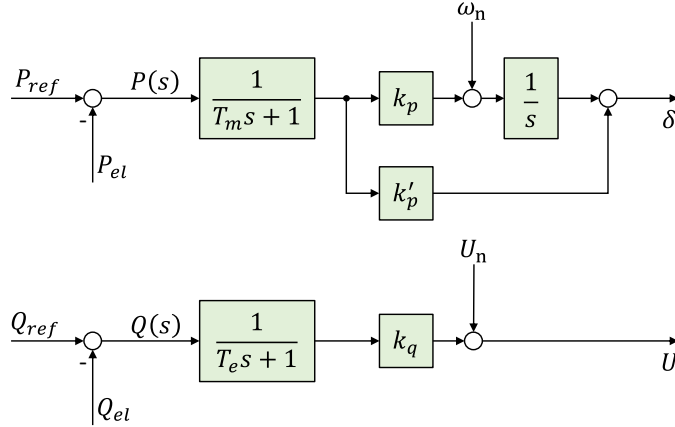


Figure 2-3 : Block diagram of the selfsync control as first proposed.

where P_{ref} and Q_{ref} are the active and reactive power setpoints, P_{el} and Q_{el} are the measured electric active and reactive powers, T_m and T_e are the mechanical and electrical time constants, k_p and k_q are the respective droop coefficients, k'_p is a feedforward gain (detailed later), and ω_n and U_n are the nominal grid frequency and voltage amplitude. The corresponding transfer functions for the active and reactive power parts are:

$$G_P(s) = \frac{\delta(s)}{P(s)} = \frac{1}{T_m s + 1} \cdot \left(\frac{k_p}{s} + k'_p \right) \quad (2-4)$$

$$G_Q(s) = \frac{U(s)}{Q(s)} = \frac{k_q}{T_e s + 1} \quad (2-5)$$

2.3 Parallel with the swing equation

The swing equation is given by equation (2-6), where M is the momentum, D is the damping coefficient, P_m is the mechanical power and P_{el} is the electrical power.

$$M \frac{d^2 \delta}{dt^2} + D \frac{d\delta}{dt} = P_m - P_{el} \quad (2-6)$$

Applying the Laplace transform gives

$$Ms^2 \delta(s) + Ds \delta(s) = P(s) \quad (2-7)$$

Rearranging (2-7) to obtain the transfer function of $\delta(s)/P(s)$ gives

$$\frac{\delta(s)}{P(s)} = \frac{1}{Ms^2 + Ds} = \frac{1}{Ms + D} \cdot \frac{1}{s} \quad (2-8)$$



To make a parallel between the swing equation and the active power droop control, equation (2-4) can be rearranged as:

$$G_P(s) = \frac{\delta(s)}{P(s)} = \frac{1}{\frac{T_m}{k_p}s + \frac{1}{k_p}} \cdot \left(\frac{1}{s} + \frac{k'_p}{k_p} \right) \quad (2-9)$$

Neglecting the effect of the feedforward, by identification it can be shown that the droop control emulates the behaviour described by the swing equation, where the momentum M is equal to T_m/k_p and the damping coefficient D is equal to $1/k_p$. Since the damping and the droop coefficient are linked, their effects cannot be decoupled. For the ease of reading, we define a feedforward variable:

$$k_{ff} = \frac{k'_p}{k_p} \quad (2-10)$$

Therefore, the active power droop control becomes:

$$G_P(s) = \frac{k_p}{Mk_p s + 1} \cdot \left(\frac{1}{s} + k_{ff} \right) \quad (2-11)$$

2.4 Inertial and droop typical values

The inertia constant H is the ratio of kinetic energy at the nominal frequency ω_n to the nominal apparent power S_N of the generator. The order of magnitude of H is typically in the range of 1 to 10 seconds.

$$H = \frac{\frac{1}{2} \cdot J \cdot \omega_n^2}{S_N} \quad [s] \quad (2-12)$$

The momentum M is given by equation (2-13).

$$M = J \cdot \omega_n = 2 \cdot H \cdot \frac{S_n}{\omega_n} = \frac{T_m}{k_p} \quad (2-13)$$

Regarding the droop coefficients, in per units (pu), k_p is usually 5% and k_q is 10%. The values of active power droop coefficient k_p and mechanical time constant T_m determine the value of the inertia. As for the electrical time constant T_e , it has no effect of the inertia and only defines the dynamics of the system to a voltage drop. Therefore, its value is of less importance here. However, a typical value of T_e is in the 1 second range.



3 System transfer function

3.1 Effect of the coupling with the grid

Even though the circuit is a first order system, when a step is applied, either to the phase or to the amplitude of one of the voltage sources, the circuit resonates as a second order system. This is because the disturbance happens at different voltage angles on each of the three phases, and therefore their transients are different and do not cancel each other. Figure 3-1 shows the dynamic effect of a phase step on the active and reactive power.

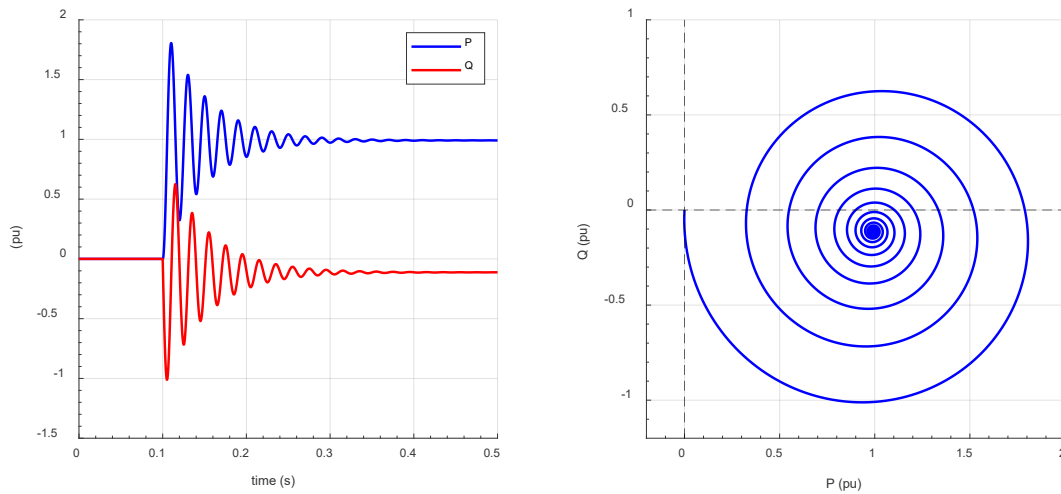


Figure 3-1 : Dynamic time response of a phase step on active and reactive power.

As shown, the system acts as a damped resonator when its equilibrium is upset.

To establish the system's transfer function the phasor diagram is helpful to write the equations. Figure 3-2 illustrates the corresponding steady state phasor diagram of the voltages and current of the circuit shown in figure 2-1.

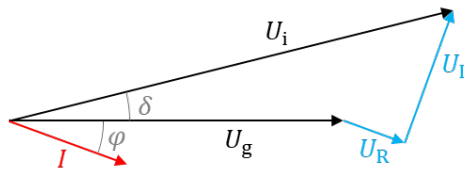


Figure 3-2 : Phasor diagram of the voltages and current of the circuit in figure 2-1.

In the following, voltages and currents represented with capital letters are RMS values, and those represented in lower case are instantaneous. Furthermore, the equations are developed in real values (as opposed to per units). The equations governing the voltages and current in the rotating dq frame are given in equation (3-1).

$$\begin{cases} u_{di} - u_{dg} = R \cdot i_d + L \frac{di_d}{dt} - \omega L i_q & [\text{V}] \\ u_{qi} - u_{qg} = R \cdot i_q + L \frac{di_q}{dt} + \omega L i_d & [\text{V}] \end{cases} \quad (3-1)$$



where u_{di} and u_{qi} are the inverter voltages, u_{dg} and u_{qg} are the grid voltages, and i_d and i_q are the currents, all in the dq axes. The active and reactive powers are defined as follows:

$$\begin{cases} P = \frac{3}{2}(u_{dg} \cdot i_d + u_{qg} \cdot i_q) & [\text{W}] \\ Q = \frac{3}{2}(u_{qg} \cdot i_d - u_{dg} \cdot i_q) & [\text{Var}] \end{cases} \quad (3-2)$$

We define the grid voltage U_i as the reference; therefore, its amplitude is solely in the d axis.

$$\begin{cases} u_{dg} = \sqrt{2} \cdot U_g \\ u_{qg} = 0 \end{cases} \quad (3-3)$$

Furthermore, we can define the inverter voltage with its amplitude U_i and an offset angle δ .

$$\begin{cases} u_{di} = \sqrt{2} \cdot U_i \cdot \cos(\delta) \\ u_{qi} = \sqrt{2} \cdot U_i \cdot \sin(\delta) \end{cases} \quad (3-4)$$

With these sets of equations, the state-space matrixes of this multiple input multiple output (MIMO) system can be established, where the state variable is $x = [i_d \ i_q]'$, the input variable is $u = [\delta \ U_i]'$, and the output variable is $y = [P \ Q]'$.

$$\begin{cases} \dot{x} = A \cdot x + B \cdot u \\ y = C \cdot x + D \cdot u \end{cases} \quad (3-5)$$

However, since the system is nonlinear, it needs to be linearized around a working point and considered for small variations. In the following section, all the variables refer to those small variations. Assuming δ is small, we linearize $\sin(\delta) \cong \delta$ and $\cos(\delta) = 1$. Furthermore, the angular velocity ω is equal to the nominal angular velocity ($\omega = \omega_n$) and the input voltage U_i is a constant, equal to the nominal voltage ($U_i = U_{ni}$). Therefore, the state-space matrixes are the following:

$$\begin{aligned} A &= \begin{bmatrix} -R/L & \omega_n \\ -\omega_n & -R/L \end{bmatrix} & B &= \frac{1}{L} \begin{bmatrix} \sqrt{2} & 0 \\ 0 & \sqrt{2} \cdot U_{ni} \end{bmatrix} \\ C &= \frac{3}{2} \begin{bmatrix} \sqrt{2} \cdot U_{ni} & 0 \\ 0 & -\sqrt{2} \cdot U_{ni} \end{bmatrix} & D &= \begin{bmatrix} 0 & 0 \\ 0 & 0 \end{bmatrix} \end{aligned} \quad (3-6)$$

The transfer functions are obtained as follows:

$$H(s) = C(sI - A)^{-1}B + D \quad (3-7)$$

where s is the Laplace variable (frequency) and I is the identity matrix. This gives the following transfer functions for the direct influence:

$$\frac{P(s)}{\delta(s)} = U_i \cdot \frac{Q(s)}{U_i(s)} = \frac{3U_g U_i}{X_L} \cdot \frac{\omega_n^2}{\left(s + \frac{R}{L}\right)^2 + \omega_n^2} \quad (3-8)$$

And for the cross-coupling influences:

$$\frac{P(s)}{U_i(s)} = -\frac{1}{U_i} \cdot \frac{Q(s)}{\delta(s)} = \frac{3U_g}{X_L} \cdot \frac{\left(s + \frac{R}{L}\right) \omega_n}{\left(s + \frac{R}{L}\right)^2 + \omega_n^2} \quad (3-9)$$



Equation (3-8) shows that $P(s)/\delta(s)$ and $Q(s)/U(s)$ are defined by a gain and a second order low pass filter with a resonance at ω_{res} , which is the constant part of the denominator.

$$\omega_{res} = \sqrt{\omega_n^2 + \left(\frac{R}{L}\right)^2} \quad (3-10)$$

Furthermore, this resonance is damped with a damping ratio ξ of:

$$\xi = \frac{R}{\omega_{res}L} \quad (3-11)$$

Equation (3-9) shows that the two cross-coupling transfer functions $P(s)/U(s)$ and $Q(s)/\delta(s)$ have a lower gain than the direct influence. They have the same second order low pass behaviour, with identical resonant frequencies and damping ratios, however they also have a first order high pass component. Furthermore, it is to be noted that $Q(s)/\delta(s)$ has a negative reaction, which causes the reactive power to decrease when δ increases. Figure 3-3 shows the Bode diagram of the MIMO system.

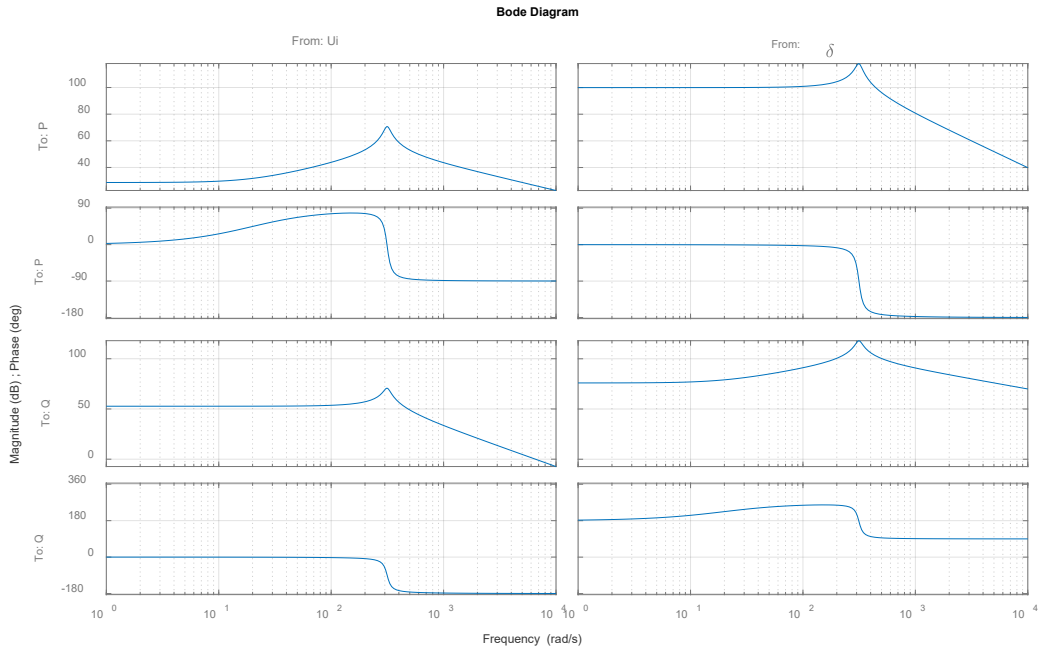


Figure 3-3 : Bode diagrams of the 2x2 MIMO system.

3.2 Sizing the filter inductance

In steady state and neglecting the resistive component, the active power is given by equation (3-12).

$$P = \frac{3 \cdot U_g \cdot U_i \cdot \sin(\delta)}{X_L} \quad [W] \quad (3-12)$$

For the assumption of δ being small to be true, at full power the load angle must be in the order of $\delta_{max} \cong 0.2$ rad (we linearize $\sin(\delta) \cong \delta$). This consequently implies that the single-phase inductor is:



$$L \cong \frac{3 \cdot U_n^2}{\frac{1}{\sin(\delta_{\max})} \cdot S_n \cdot \omega_n} = \frac{3 \cdot U_n^2}{5 \cdot S_n \cdot \omega_n} \quad [H] \quad (3-13)$$

Or put otherwise, the gain K_{inv} of the inverter is:

$$K_{inv} = \frac{3 \cdot U_g \cdot U_i}{X_L} \cong 5 \cdot S_n \quad (3-14)$$

As an example, if we will consider a nominal phase to neutral voltage U_n of 230 V, a nominal frequency of 50 Hz ($\omega_n = 100\pi$) and a nominal apparent power S_n of 10 kVA, the single-phase inductor is in the order of $L \cong 2.5$ mH.

3.3 Effect of switching/sampling frequency

Assuming that the switching and sampling frequencies are the same, the delay that is induced can be modelled by a first order low pass filter.

$$G_{sampling}(s) = \frac{1}{sT_{pe} + 1} \quad (3-15)$$

where $T_{pe} = 3/(2f_e) + \sum_{m=1}^n T_m$ (f_e is switching frequency and T_m are the small time-constants). Because the switching frequency is at least an order of magnitude higher than the grid frequency and that the power transfer functions have a 180° phase drop around the grid frequency, the cutoff frequencies of the active and reactive control loops will be below the grid frequency. Therefore, the effect of the switching/sampling frequency can be neglected.

3.4 Compensation of the resonant part

To avoid feedback or an excitation of the resonant part of both the active and reactive power loops, a band-stop filter is added in series in both systems (Figure 3-4).

$$G_{bs}(s) = \frac{s^2 + \omega_{0bs}^2}{s^2 + \omega_{1bs}s + \omega_{0bs}^2} \quad (3-16)$$

Where ω_{0bs} is the cutoff frequency and ω_{1bs} is the bandwidth. In the present case, $\omega_{0bs} = \omega_{1bs} = 100\pi$ gives satisfying results. Figure 3-4 shows the new system block diagram.

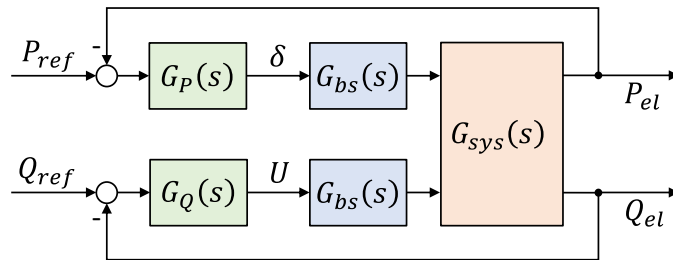


Figure 3-4 : Block diagram of both active and reactive droop-control chains.

Figure 3-5 shows the Bode diagram of the active power inverter transfer function $G_{invp}(s)$, the band-stop filter, and the combination of the two.

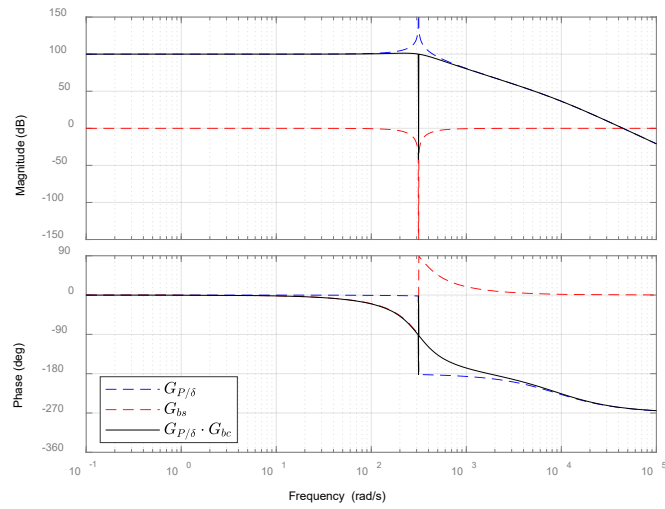


Figure 3-5 : Bode diagram of the active power inverter transfer function for a grid voltage of 230 V, a grid frequency of 50 Hz, a single-phase inductance of 5 mH and a switching frequency of 15 kHz.

The Bode diagram of the reactive power transfer function is the same as the one in Figure 3-5, except for the gain.



4 Sizing of the selfsync droop control

4.1 Active power chain

The full active power chain block diagram with the droop control as developed in equation (2-9) is shown in Figure 4-1.

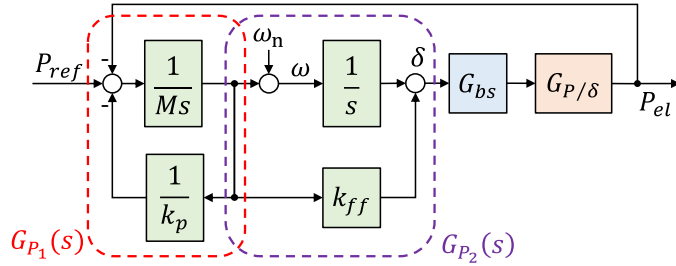


Figure 4-1 : Active power droop control as represented in equation (2-9) with the band-stop filter and the inverter transfer functions. $G_{P/\delta}$ is $P(s)/\delta(s)$ defined in equation (3-8).

4.1.1. System without feedforward

The first step is to analyse the system without the feedforward ($k_{ff} = 0$). To ease the analysis, the droop control is separated into two parts:

$$G_{P_1}(s) = \frac{k_p}{Mk_p s + 1} \quad (4-1)$$

$$G_{P_2}(s) = \frac{1}{s} + k_{ff} = \frac{k_{ff}s + 1}{s} \quad (4-2)$$

The Bode diagram of the different components of the active power droop is shown in Figure 4-2.

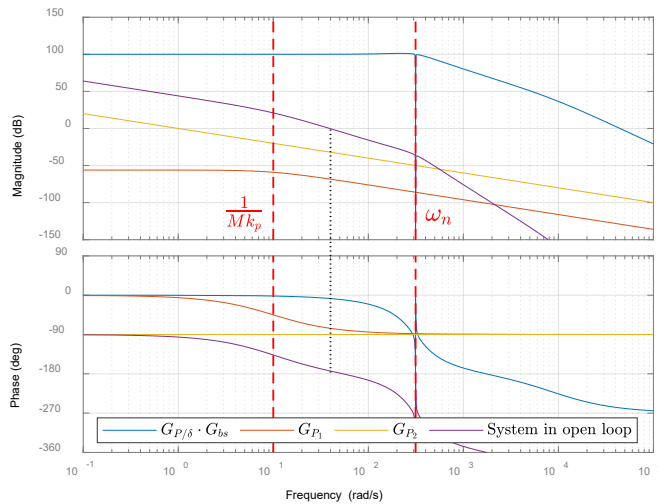


Figure 4-2 : Bode diagram of the different components of the active power droop control in open loop, with no feedforward. ($H=1$).



As highlighted with the dotted line on the full system in open loop, the phase margin is close to zero, which means the system is marginally stable. The feedforward introduces a zero in the system, which is used to increase the phase margin, however as a side effect it will also decrease the attenuation of high frequencies.

4.1.2. System with feedforward

Ideally, we would like to place the zero in such a way that it does not change the cutoff frequency (ω_c) of the full system to avoid modifying the inertia. However, there is a trade-off between the possibility of increasing the phase and not influencing the inertia. To get the most out of the zero, it should be placed close to ω_c . It can be shown that the cutoff frequency is:

$$\omega_c = \sqrt{\frac{K_{inv}}{M}} \quad (4-3)$$

Placing the zero at a frequency slightly lower than ω_c (20% less) allows to have a suitable phase margin (almost 60°) allowing for a dynamic response.

$$k_{ff} = 1.2 \sqrt{\frac{M}{K_{inv}}} \quad (4-4)$$

Furthermore, to compensate for the slight shift to the right of the resulting cutoff frequency (corresponding to a lower inertia), adding k_{ff} to the denominator of G_1 gives good results (Figure 4-8), without compromising the phase margin. The final proposed active power droop control is:

$$G_P(s) = \frac{k_p}{(Mk_p + k_{ff})s + 1} \cdot \left(\frac{1}{s} + k_{ff} \right) \quad (4-5)$$

The resulting Bode diagram is shown in Figure 4-3.

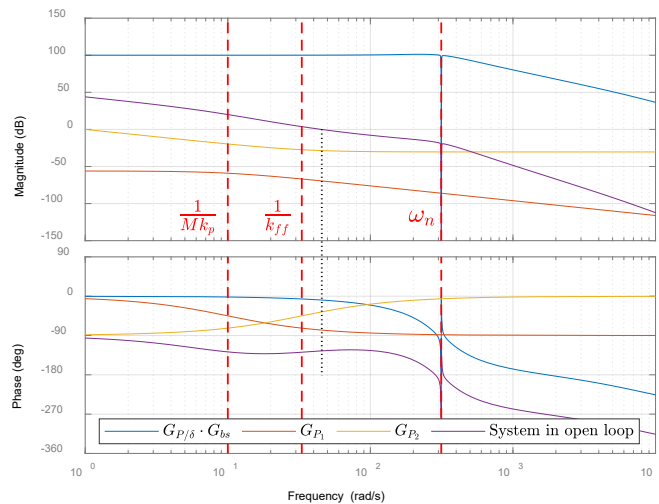


Figure 4-3 : Bode diagram of the different components of the active power droop control in open loop, with feedforward. ($H=1$).

The closed loop step responses for values of H ranging from 1 to 16 are shown in Figure 4-4.

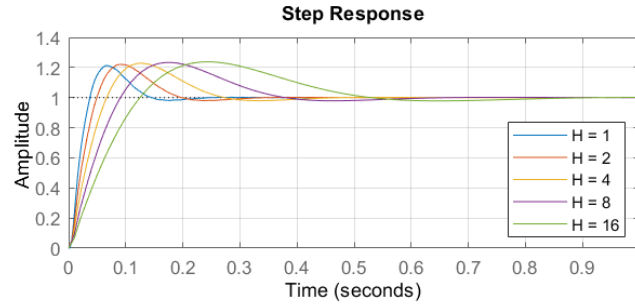


Figure 4-4 : Closed loop step responses of the active power droop control (in pu) for different values of H .

As shown in step responses, the response behaviour is consistent when the inertia constant is varied. Furthermore, if the inverter gain (K_{inv}) is kept constant, the responses are invariable from the rated power or the nominal voltage of the inverter.

4.2 Reactive power chain

The reactive power chain's function is to compensate for voltage drop due to impedance of the lines connecting the inverter to the grid. In high and medium voltage, the lines are predominantly inductive. Therefore, the voltage drop is usually dominated by the reactive power. However, in low voltage, the resistive component of the impedance is not negligible. Therefore, part of the voltage drop will also be proportional to the active power. Figure 4-5 shows the reactive power chain as shown in Figure 2-3.

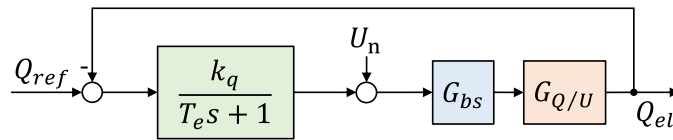


Figure 4-5 : Reactive power droop with the band-stop filter and inverter transfer function. $G_{Q/U}$ is $Q(s)/U(s)$ defined in equation (3-8).

To compensate for voltage drop of the resistive component of the lines, an extra branch is added with active power voltage coefficient k_{pv} and its respective time constant T_{pv} .

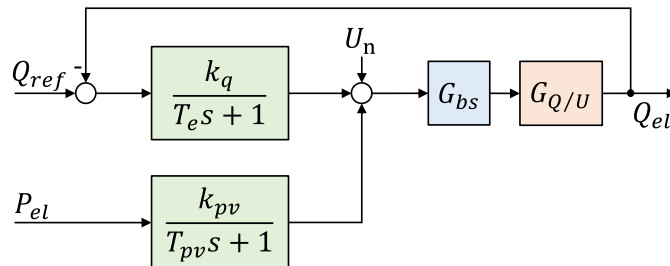


Figure 4-6 : Reactive power droop as in Figure 4-5 with additional active power compensation and time constant.

The reactive power chain does not need to have high dynamics. Furthermore, since a cross-coupling exists between the active and reactive loops, slower dynamics allows for the other loop to compensate more effectively.



4.3 Verification with the cross-coupling effect

The system in open loop $G_{ol}(s)$ is given in (4-6). Applying the feedback as shown in Figure 3-4.

$$G_{ol}(s) = \begin{bmatrix} G_P(s) & 0 \\ 0 & G_Q(s) \end{bmatrix} \cdot \begin{bmatrix} \frac{P(s)}{\delta(s)} & \frac{P(s)}{U(s)} \\ \frac{Q(s)}{\delta(s)} & \frac{Q(s)}{U(s)} \end{bmatrix} \quad (4-6)$$

The system in closed loop $G_{cl}(s)$ is:

$$G_{cl}(s) = \frac{G_{ol}(s)}{1 + I \cdot G_{ol}(s)} \quad (4-7)$$

where I is the identity matrix. Figure 4-7 shows the closed loop step response, with different inertial constants H .

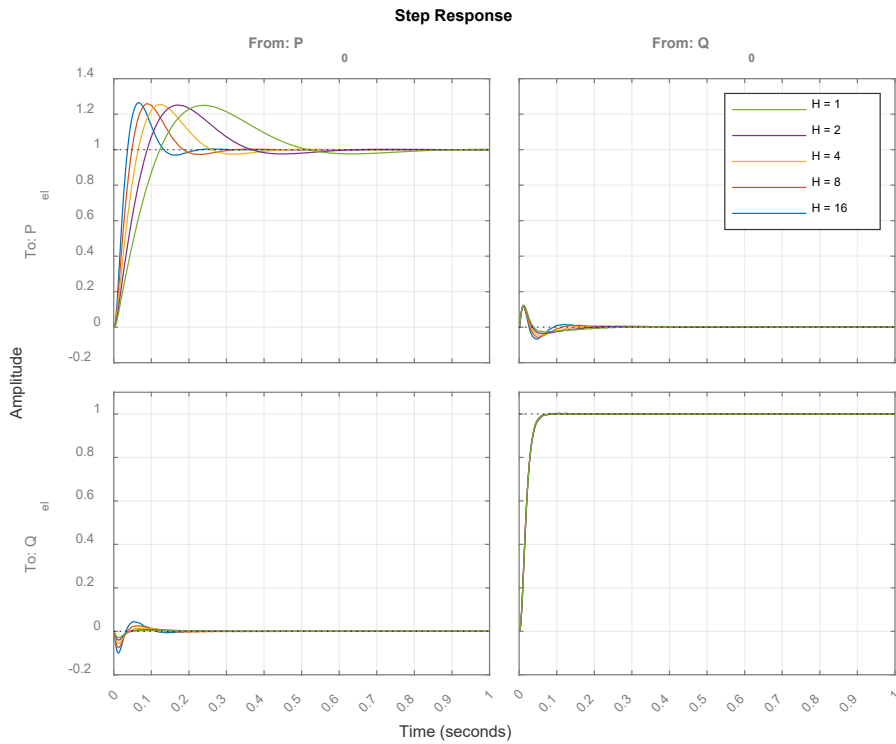


Figure 4-7 : Closed loop step responses with different inertial constants.

As shown in Figure 4-7, the cross-coupling effect is limited and is fully compensated by the regulators without any static error. Therefore, no cross-coupled compensation strategy on the active and the reactive loops have been implemented.



4.4 Simulation of the full system connected to a stiff grid

Simulations were performed using PLECS [23]. Because the dynamics of the droop control is orders of magnitude lower than usual switching frequency and control frequency of inverters, the inverter was modelled as an ideal voltage source. Furthermore, the grid was modelled as an ideal stiff grid. The simulation parameters are shown hereafter in Table 1.

Table 1. Simulation parameters

Nominal grid voltage (L-N)	U_g	230	[V]
Nominal grid frequency	f_g	50	[Hz]
Inverter nominal power	S_N	10	[kVA]
Inverter gain	K_{inv}	100	[kVA]
Active power droop coefficient	k_p	5	[%]
Reactive power droop coefficient	k_q	10	[%]

To validate the behaviour of the inertial droop control, the grid frequency is varied, and the response (amplitude) is compared to the calculated ideal, non-elastic response. Figure 4-8 shows the simulation result for a frequency decrease with a rate of change of frequency (RoCoF) of 1 Hz/s, with an inertia constant $H = 5$ s.

As shown in Figure 4-8, the compensated response's amplitude corresponds to the ideal response, and the dynamics are coherent with the ones shown in Figure 4-4.

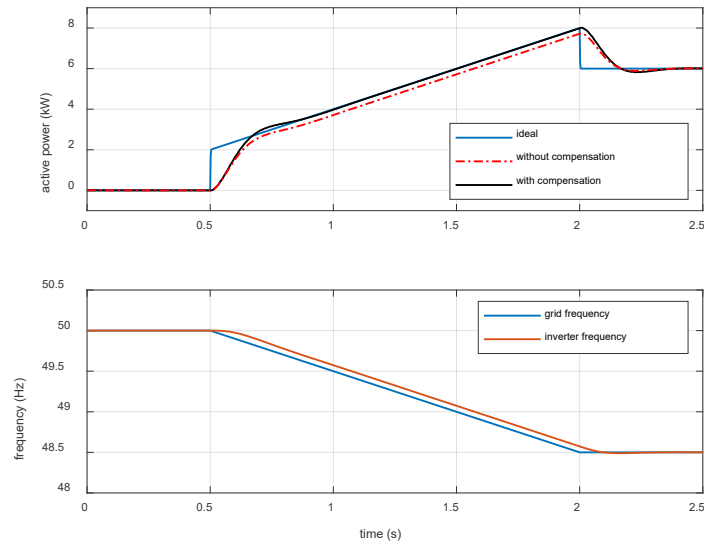


Figure 4-8 : Simulation result of a frequency drop with a RoCoF of 1 Hz/s and an inertia constant of $H=5$.



5 Voltage phase and amplitude synchronization

To connect an inverter to the grid, its voltage must be synchronized in phase and amplitude with that of the grid. Fortunately, these two variables are the outputs of the active and reactive power droop controls. Therefore, synchronization can be realised by varying their references. However, the first step consists in measuring/acquiring the phase and amplitude errors.

5.1 Measuring the phase and amplitude errors

The traditional approach to measuring the phase and amplitude errors is to implement a PLL. However, since the objective is not to read and follow the grid, and that the inverter is already generating an output voltage, there is a simpler mathematical approach. Figure 5-1 shows graphically how to measure the phase and amplitude errors.

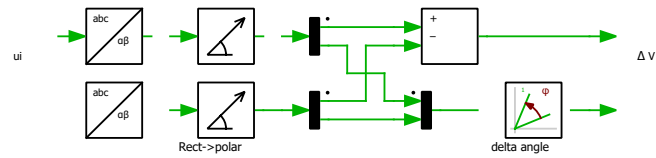


Figure 5-1 : Measurement of the amplitude and phase errors.

The first step is to apply an alpha-beta (Clarke) transformation to the three phase voltage signals to obtain their equivalent in a cartesian coordinate system. Then applying a rectangular to polar transformation on the alpha-beta signals returns the amplitude and angle of the voltages. Then it is a simple matter of comparing the amplitudes and the angles to obtain the errors.

5.2 Voltage phase synchronization

As shown hereafter, the system to regulate is $G_P(s) \cdot G_{bc}(s)$ of Figure 3-4. There are two additional inputs other than the power reference p_{ref} , the first being the measured electric power, and the second being the reference frequency. These two are essentially perturbations when trying to control precisely the output phase. However, the reference frequency is a constant, therefore it has no dynamic influence.

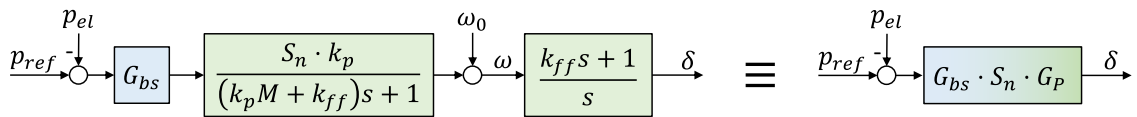


Figure 5-2 : System to regulate to synchronize the phase.

Here, the active powers, p_{ref} and p_{el} , are represented in per units.

To cancel for the perturbation, the electric power is added to the reference (see Figure 5-4). Figure 5-3 shows the bode diagram of the system to regulate and its components to synchronize the phase.

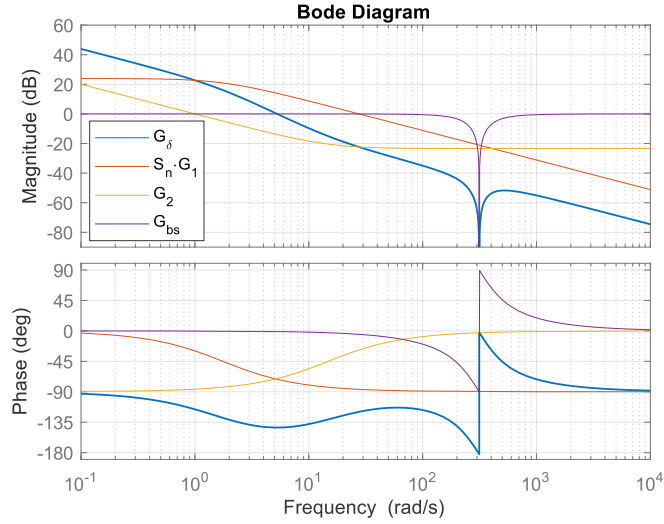


Figure 5-3 : Bode diagram of the system to regulate and its components to synchronize the phase, for H=5.

Because $G_\delta(s)$ has an infinite gain in steady state, a proportional regulator is sufficient to obtain zero steady state error. The phase margin is optimal around $\omega_{0\delta} = 70 \text{ rad/s}$. The gain to be applied to $G_\delta(s)$ (neglecting the effect of the band-cut filter) to bring its cutoff frequency to $\omega_{0\delta}$ is given in equation (5-1).

$$K_{p\delta} = \frac{1}{S_n \cdot G_{P_1}(\omega_{0\delta}) \cdot G_{P_2}(\omega_{0\delta})} = \frac{1}{k_p S_n} \sqrt{\frac{(Mk_p + k_{ff})^2 \omega_{0\delta}^2 + 1}{k_{ff}^2 + \frac{1}{\omega_{0\delta}^2}}} \quad (5-1)$$

The voltage phase synchronization loop is shown in Figure 5-4, where the phase error $\Delta\delta$ is acquired as show in Figure 5-1.

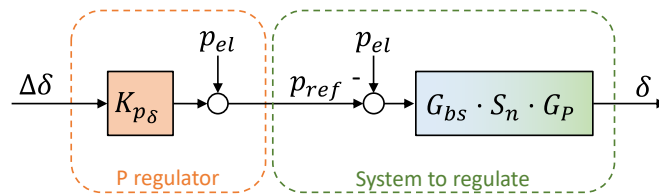


Figure 5-4 : Voltage phase synchronization loop bloc diagram.

Figure 5-5 shows the step response of the voltage phase synchronization in closed loop with the proportional regulator as sized in equation (5-1). As expected, the steady state error is zero.

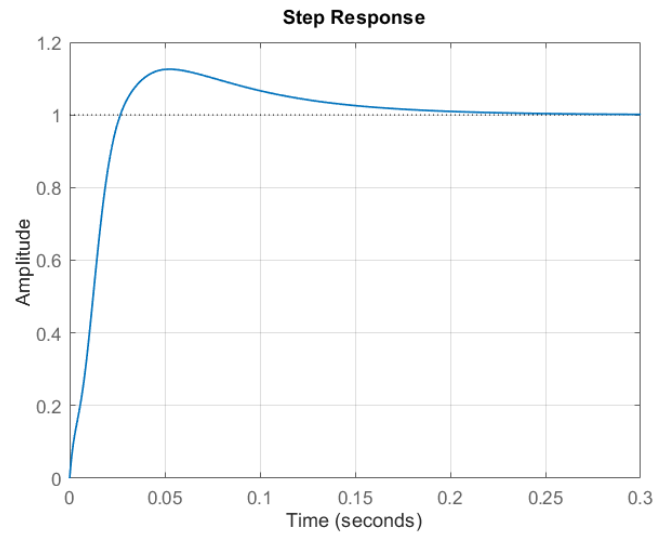


Figure 5-5 : Step response of the voltage phase synchronization in closed loop.



5.3 Voltage amplitude synchronization

To synchronize the voltage amplitude, the reactive power reference can be varied to change the output voltage of the inverter. Here, the influence of the active power is considered as a perturbation. Therefore, the system to regulate is as shown in Figure 5-6.

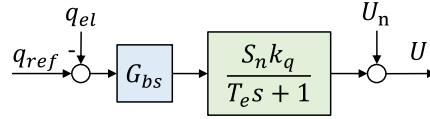


Figure 5-6 : System to regulate to synchronize the voltage amplitude.

As for the phase synchronization, the reactive powers are represented in per units. q_{el} and U_n and perturbations but are known, so they can be cancelled out. Therefore, the system to regulate is the following:

$$G_{qU}(s) = \frac{S_n k_q}{T_e s + 1} \cdot G_{bs}(s) \quad (5-2)$$

To avoid the effects of the singularity created by the band-stop filter at the grid frequency ω_n , the cutoff frequency of the voltage amplitude synchronization system in open loop will be kept below it.

Figure 5-7 shows the bode diagram of the system to regulate $G_{qU}(s)$ for the following values:

$$S_n = 10 \text{ [kVA]}, k_q = 0.1 \text{ [pu]} \text{ and } T_e = 1 \text{ [s]}$$

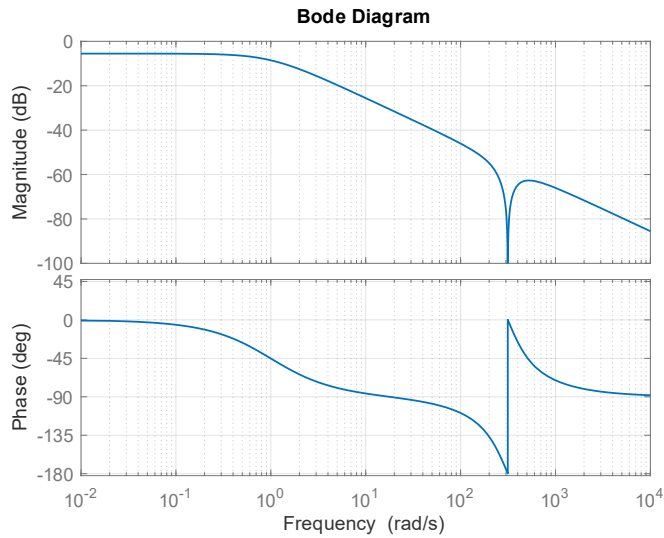


Figure 5-7 : Bode diagram of the system to regulate to synchronize the voltage amplitude.

In the present case, the steady state gain is not infinite. Therefore, a proportional integral (PI) regulator is necessary. Equation (5-3) gives the transfer function of the PI regulator in several different forms.

$$G_{PI}(s) = K_P + K_I \cdot \frac{1}{s} = K_P + \frac{K_P}{T_I s} = K_P \cdot \left(\frac{1}{T_I s} + 1 \right) = K_P \cdot \frac{T_I s + 1}{T_I s} \quad (5-3)$$



The system in open loop $G_{syncU_{ol}}$ is then:

$$G_{syncU_{ol}}(s) = G_{PI}(s) \cdot G_{qU}(s) = K_{PU} \cdot \frac{T_{IU}s + 1}{T_{IU}s} \cdot \frac{S_n k_q}{T_e s + 1} \cdot G_{bc}(s) \quad (5-4)$$

We choose to place the zero (T_{IU}) of the PI regulator at the pole (T_e) of the system du regulate, so they cancel out. Furthermore, to define the proportional gain K_{PU} , we first compensate the remaining gain, to be able to freely choose the cutoff frequency ω_{0U} of the open loop system.

$$K_{PU} = \omega_{0U} \cdot \frac{T_e}{S_n k_q} \quad (5-5)$$

$$K_I = \frac{K_{PU}}{T_{IU}} = \frac{\omega_{0U}}{S_n k_q} \quad (5-6)$$

We want to avoid any voltage overshoot; therefore, we choose a cutoff frequency with a sufficient phase margin. $\omega_{0U} = 70 \text{ rad/s}$ allows to have sufficient dynamics without any overshoot.

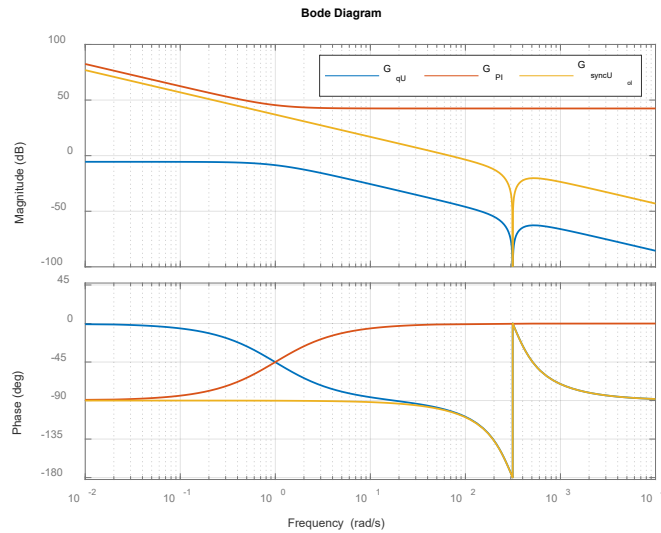


Figure 5-8 : Bode diagrams of the system to regulate G_{qU} , the PI regulator G_{PI} and the system in open loop $G_{syncU_{ol}}$

The voltage amplitude synchronization loop bloc diagram is shown in Figure 5-9, where the voltage amplitude error ΔV is acquired as show in Figure 5-1.

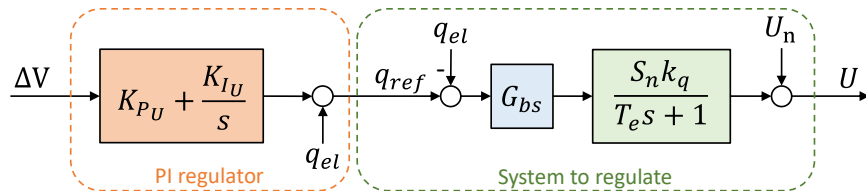


Figure 5-9 : Voltage amplitude synchronization loop bloc diagram.

Figure 5-10 shows the step response of the voltage phase synchronization in closed loop with the proportional-integral (PI) regulator as sized in equations (5-5) and (5-6). As expected, the system regulates quickly, there is no overshoot and the steady state error is zero.

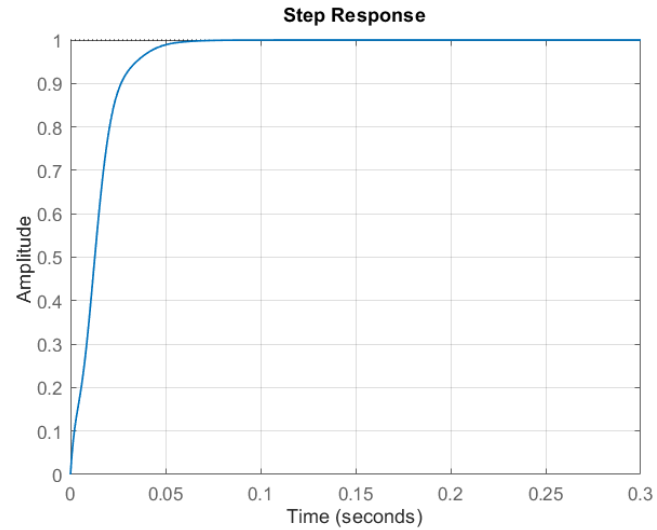


Figure 5-10 : Step response of the voltage amplitude synchronization in closed loop.

6 Conclusions

In the report, first the system to be controlled was described and a dynamic model was established. Following this, the control of the GFMI was developed and described, where the voltage phase is generated through active power feedback and the voltage amplitude is generated through reactive power feedback. Furthermore, the synchronisation regulators have been sized to allow the GFMI to synchronize with a grid. The control algorithm has been tested in grid connect mode as well as in stand-alone and performs as expected.



7 References

- [1] U. Tamrakar, D. Shrestha, M. Maharjan, B. Bhattarai, T. Hansen, and R. Tonkoski, 'Virtual Inertia: Current Trends and Future Directions', *Appl. Sci.*, vol. 7, no. 7, p. 654, Jun. 2017, doi: 10.3390/app7070654.
- [2] Y. Chen, R. Hesse, D. Turschner, and H.-P. Beck, 'Investigation of the Virtual Synchronous Machine in the island mode', in *2012 3rd IEEE PES Innovative Smart Grid Technologies Europe (ISGT Europe)*, Berlin, Germany: IEEE, Oct. 2012, pp. 1–6. doi: 10.1109/IS-GTEurope.2012.6465648.
- [3] C. Li, R. Burgos, I. Cvetkovic, D. Boroyevich, L. Mili, and P. Rodriguez, 'Analysis and design of virtual synchronous machine based STATCOM controller', in *2014 IEEE 15th Workshop on Control and Modeling for Power Electronics (COMPEL)*, Santander, Spain: IEEE, Jun. 2014, pp. 1–6. doi: 10.1109/COMPEL.2014.6877134.
- [4] M. Torres and L. A. C. Lopes, 'Virtual synchronous generator control in autonomous wind-diesel power systems', in *2009 IEEE Electrical Power & Energy Conference (EPEC)*, Oct. 2009, pp. 1–6. doi: 10.1109/EPEC.2009.5420953.
- [5] H. Wu *et al.*, 'Small-Signal Modeling and Parameters Design for Virtual Synchronous Generators', *IEEE Trans. Ind. Electron.*, vol. 63, no. 7, pp. 4292–4303, Jul. 2016, doi: 10.1109/TIE.2016.2543181.
- [6] H. Bevrani, T. Ise, and Y. Miura, 'Virtual synchronous generators: A survey and new perspectives', *Int. J. Electr. Power Energy Syst.*, vol. 54, pp. 244–254, Jan. 2014, doi: 10.1016/j.ijepes.2013.07.009.
- [7] M. Ebrahimi, S. A. Khajehoddin, and M. Karimi-Ghartemani, 'An Improved Damping Method for Virtual Synchronous Machines', *IEEE Trans. Sustain. Energy*, vol. 10, no. 3, pp. 1491–1500, Jul. 2019, doi: 10.1109/TSTE.2019.2902033.
- [8] J. Sun, 'Impedance-Based Stability Criterion for Grid-Connected Inverters', *IEEE Trans. Power Electron.*, vol. 26, no. 11, pp. 3075–3078, Nov. 2011, doi: 10.1109/TPEL.2011.2136439.
- [9] T. Qoria, F. Gruson, F. Colas, X. Guillaud, M.-S. Debry, and T. Prevost, 'Tuning of Cascaded Controllers for Robust Grid-Forming Voltage Source Converter', in *2018 Power Systems Computation Conference (PSCC)*, Jun. 2018, pp. 1–7. doi: 10.23919/PSCC.2018.8443018.
- [10] J. L. R. Amenedo, S. A. Gomez, J. Alonso-Martinez, and M. G. De Armas, 'Grid-Forming Converters Control Based on the Reactive Power Synchronization Method for Renewable Power Plants', *IEEE Access*, vol. 9, pp. 67989–68007, 2021, doi: 10.1109/ACCESS.2021.3078078.
- [11] T. Qoria, C. Li, K. Oue, F. Gruson, F. Colas, and X. Guillaud, 'Direct AC voltage control for grid-forming inverters', *J. Power Electron.*, vol. 20, no. 1, pp. 198–211, Jan. 2020, doi: 10.1007/s43236-019-00015-4.
- [12] W. Du *et al.*, 'A Comparative Study of Two Widely Used Grid-Forming Droop Controls on Microgrid Small-Signal Stability', *IEEE J. Emerg. Sel. Top. Power Electron.*, vol. 8, no. 2, pp. 963–975, Jun. 2020, doi: 10.1109/JESTPE.2019.2942491.
- [13] P. Unruh, M. Nuschke, P. Strauß, and F. Welck, 'Overview on Grid-Forming Inverter Control Methods', *Energies*, vol. 13, no. 10, p. 2589, May 2020, doi: 10.3390/en13102589.
- [14] A. Engler, 'Regelung von Batteriestromrichtern in Modularen und Erweiterbaren Inselnetzen.', PhD. Thesis, Berlin, Germany, 2002.
- [15] A. Engler, 'Device for Parallel Operation of Equal Range Single-Phase or Three-Phase Voltage Sources', EP1286444B1



Final report from 1 July 2026

FORMIDABLE

Appendix 2: Neutral Point Balancing



Source: HEIG-VD/IE 2026



Publisher:

Swiss Federal Office of Energy SFOE
Energy Research and Cleantech
CH-3003 Berne
www.energy-research.ch

Co-financing:

Imperix SA
CH-1950 Sion
www.imperix.com

Subsidy recipients:

HEIG-VD
CH-1400 Yverdon-les-Bains
www.heig-vd.ch

Authors:

Dr Philippe Morey, HEIG-VD, philippe.morey@heig-vd.ch
Prof. Dr Mokhtar Bozorg, HEIG-VD, mohktar.bozorg@heig-vd.ch
Prof. Dr Mauro Carpita, HEIG-VD, mauro.carpita@heig-vd.ch

SFOE project coordinators:

Dr Michael Moser, michael.moser@bfe.admin.ch

SFOE contract number: SI/502668-1

The authors bear the entire responsibility for the content of this report and for the conclusions drawn therefrom.



Contents

Contents	3
List of abbreviations	4
1 Introduction	5
1.1 Choice of hardware	6
1.2 System to be regulated	7
1.3 Target switching frequency	7
2 Sizing the inductance	8
2.1 Current ripple	8
2.2 Resonant frequency	9
2.3 Choice of the inductor	9
3 Current regulation	9
3.1 System definition	9
3.2 Sizing of the current regulator	10
3.3 Digital implementation of the current regulator	13
4 Voltage regulator	13
4.1 System definition	13
4.2 Sizing the voltage regulator	14
5 Simulation	15
5.1 Simulation model	15
5.2 Perturbation current	16
5.3 Measured perturbation feed-forward	17
5.4 Deadtime compensation	17
5.5 PWM offset	17
5.6 Simulation results	18
6 Saturated current drift compensation	20
6.1 Outer current loop	20
6.2 Adaptation of the voltage regulator	21
6.3 Simulation with outer current loop	21
7 Current capability sizing	23
8 Limitations	24
9 Conclusion	24
10 References	24



List of abbreviations

AC	Alternating Current
DC	Direct Current
MOSFET	Metal–Oxide–Semiconductor Field-Effect Transistor
PID	Proportional, Integral, Derivative
PWM	Pulse Width Modulation
SFOE	Swiss Federal Office of Energy
SiC	Silicon Carbide



1 Introduction

When a three-phase inverter, such as shown in Figure 1-1, has an unbalanced load, the sum of the three phase currents is no longer equal to zero. This causes current to flow through the neutral line (0). This is not an issue if the unbalance is small and only has an AC component. However, if the unbalance is large, or even worse, if there is a DC component, the voltage across the DC link capacitors will no longer be balanced. This can lead to overloading of the capacitors and ultimately to a catastrophic failure of the DC link.

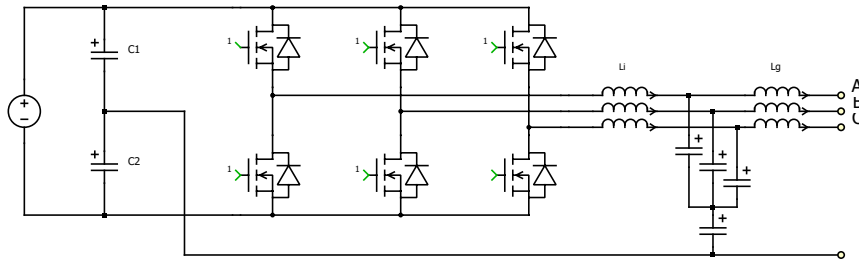


Figure 1-1: Three phase inverter with neutral point connected to the centre point of the DC link.

If the control of the inverter is “grid following” (GFL), then the currents in the three phases are controlled and there is no potential issue. However, if the inverter is controlled in “grid forming” (GFM) mode, it is a voltage source inverter and therefore the currents are not controlled. Most appliances connected to the grid are single phased and therefore it is paramount to manage the neutral current. This can be done by adding an extra branch to the inverter [1], as shown in Figure 1-2, to manage the balancing of the DC link capacitor voltages.

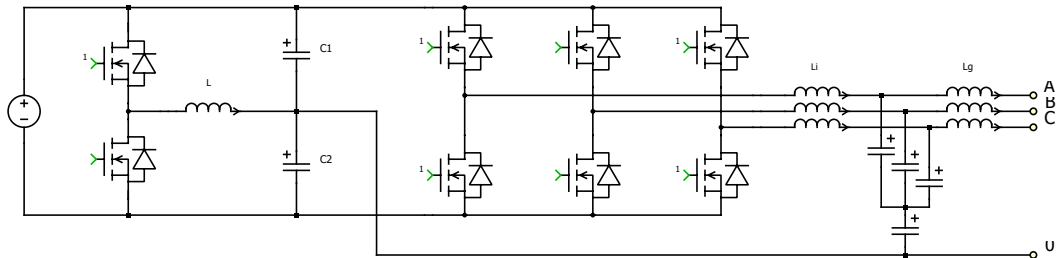


Figure 1-2: Three phase inverter with an additional branch to balance the DC link capacitor voltages.

This report details the sizing and the control of the neutral line current balancing circuit, shown in Figure 1-3, whose objective is to maintain the voltage across the DC link capacitors balanced.

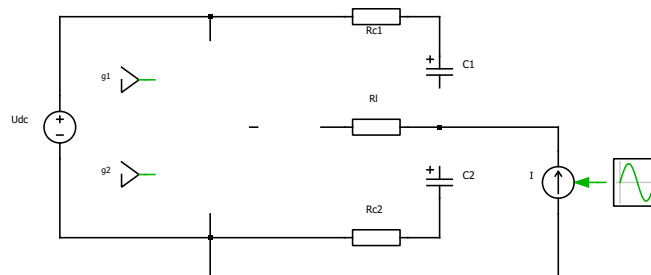


Figure 1-3: Neutral line balancing circuit with a disturbance current.



1.1 Choice of hardware

Because a capacitor voltage regulating system is trivial and an inhouse development would not add any value to research project, it was decided to purchase hardware from imperix to bypass the hardware development process and save time and money. In the project, two neutral balancing branches need to be implemented, one for each of the two inverters. The chosen hardware is composed of imperix PEB8038, 800V/38A Silicone Carbide (SiC) half bridge modules, one control B-BOX RCP 3.0 and the associated voltage and current modules.

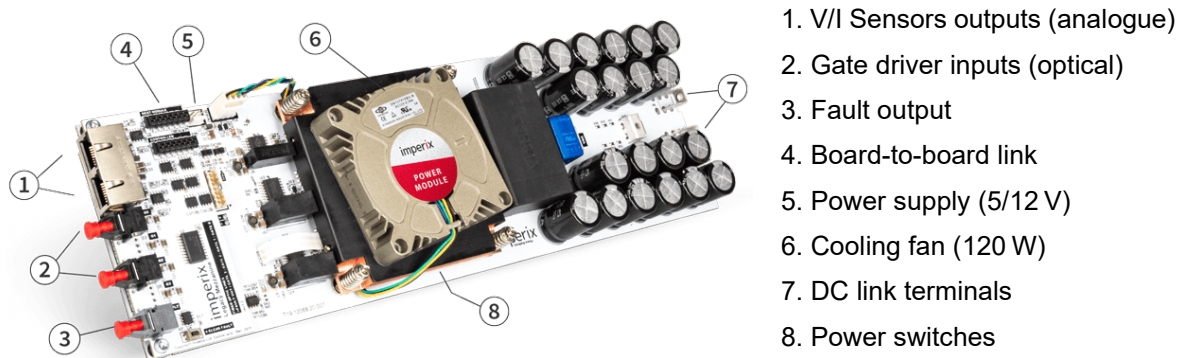


Figure 1-4: imperix PEB8038, 800V/38A SiC half bridge module [2].

The B-BOX is equipped with 16 analogue inputs to which voltage or current sensors can be connected. Each neutral balancing system will require four channels. Therefore, the eight remaining are available for other purposes in the project.

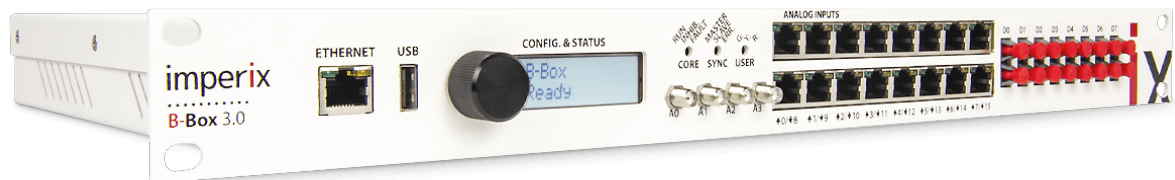


Figure 1-5: B-BOX RCP 3.0 rapid control prototyping module [3].



1.2 System to be regulated

The sizing will be generic. However, a specific sizing will be applied to a 22kW imperix TPI8032 inverter with the following DC link characteristics:

Table 1-1: TPI8032 DC link characteristics.

DC link voltage	800V
DC bus capacitors	mF @ 800V (C1 = C2 = 3 mF)

Each branch of the TPI8032 has two 1 mF capacitors in series. The extra branch that will be used to do the neutral balancing also has two 1 mF capacitors in series. Therefore, the total DC bus capacitors are composed of C1 = C2 = 4 mF. For the regulation, capacitors C1 and C2 appear in parallel. Therefore, we define

$$C = C1 + C2 = 8 \text{ mF}$$

1.3 Target switching frequency

To reduce the current ripple as well as the size of the necessary inductance, the switching frequency must be as high as possible. Figure 1-6 shows the current capability of the PEB8032 as un function of the DC-bus voltage and switching frequency.

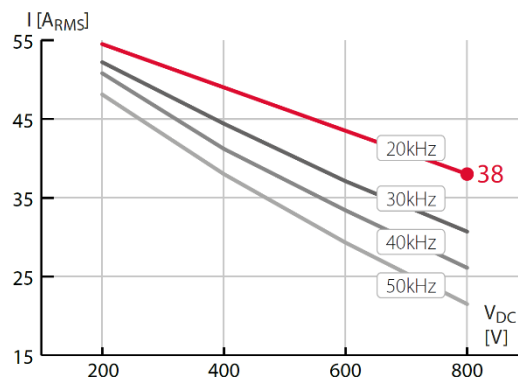


Figure 1-6: Current capability of the PEB8032 as a function of the DC-bus voltage and switching frequency.

The maximum current capability of the TPI8032 inverter is 32 A. Therefore, choosing a target switching frequency of 30 kHz is a good compromise.

$$f_e = 30 \text{ kHz}$$



2 Sizing the inductance

To size the inductance, there are two main criteria. The first is to limit the current ripple to an acceptable level, the second is to limit the physical size of the inductance. Furthermore, the resonant frequency of the circuit should not be too close to the grid frequency (f_{grid}), or the switching frequency (f_e).

2.1 Current ripple

To calculate the current ripple, the circuit is considered at steady state. The ratio between the DC voltage U_{dc} and the capacitor voltages are given by

$$U_{C_1} = U_{DC} \cdot (1 - D) \quad (2-1)$$

$$U_{C_2} = U_{DC} \cdot D \quad (2-2)$$

Where D is the duty cycle. When the top MOSFET is on, the current changes by

$$\Delta i_1 = \frac{U_{DC} - U_{C_2}}{L} \cdot T_e \cdot D \quad [A] \quad (2-3)$$

Where T_e is the switching period defined by

$$T_e = \frac{1}{f_e} \quad [s] \quad (2-4)$$

When the bottom MOSFET is on, the current changes by

$$\Delta i_2 = -\frac{U_{C_2}}{L} \cdot T_e \cdot (1 - D) \quad [A] \quad (2-5)$$

Since the circuit is considered in steady state, the current changes add up to zero

$$\Delta i_1 + \Delta i_2 = 0 \quad (2-6)$$

Therefore,

$$\Delta i = \frac{U_{DC} - U_{C_2}}{L} \cdot T \cdot D = \frac{U_{C_2}}{L} \cdot T \cdot (1 - D) \quad (2-7)$$

Replacing U_{C_2} by equation (2-2) gives

$$\Delta i = \frac{U_{DC}}{L \cdot f_e} \cdot (1 - D) \cdot D \quad (2-8)$$

The expression $(1 - D) \cdot D$ is maximum when $D = 0.5$. Therefore, the maximum current ripple is

$$\Delta i_{max} = \frac{U_{DC}}{4 \cdot L \cdot f_e} \quad [A] \quad (2-9)$$

Therefore, for a given maximum current ripple, the minimum inductance is

$$L_{min} < \frac{U_{DC}}{4 \cdot \Delta i_{max} \cdot f_e} \quad [H] \quad (2-10)$$



Using the values from Table 1-1 as well as the switching frequency defined previously, if we fix that the current ripple should stay below 10% (arbitrary value) of the peak value of the nominal current ($32 \cdot \sqrt{2} = 45.25 [A]$), then the minimum inductance is

$$L_{min} = 1.47 \text{ mH} \quad (2-11)$$

2.2 Resonant frequency

The resonant frequency of the LCC circuit can be compensated by the current regulator as long as it is not in saturation. In case of an over-current (e.g., short-circuit management), the regulator is no longer linear. Therefore, if the resonant frequency of the LCC circuit is too close to the grid frequency, the regulator may not be able to compensate for the resonant gain. Therefore, the inductance value to avoid is

$$L_{avoid} = \frac{1}{(2\pi f_{grid})^2 \cdot C} = 1.27 \text{ mH} \quad (2-12)$$

2.3 Choice of the inductor

For the current ripple to be as small as possible, the inductor should be as large as possible. However, for the current given above, for the size of the inductance to remain reasonable, the inductance should stay in the range of less than 2 mH. Furthermore, from a dynamic's perspective, a smaller inductance is better. Therefore, we choose the following value, which is double value used as the inverter side inductance in the imperix inverter:

$L = 1.9 \mu\text{H}$

3 Current regulation

3.1 System definition

The system to be regulated is an RLC circuit, as shown in Figure 3-1. The value that needs to be regulated is the current in the inductance I_L .

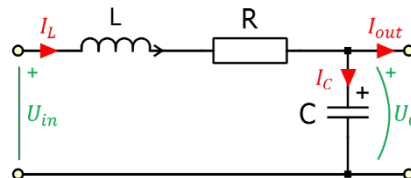


Figure 3-1: RLC circuit to be regulated.

For the current regulation, we consider the output current I_{out} as being a disturbance. Therefore, the currents in the inductance, in the resistor, and in the capacitor are all the same. The impedance of this circuit is the following



$$\underline{Z} = j\omega L + R + \frac{1}{j\omega C} \quad (3-1)$$

The transfer function $G_I(s)$ of the current as a function of voltage is the inverse of the impedance.

$$G_I(s) = \frac{I_L(s)}{U_{in}(s)} = \frac{1}{sL + R + \frac{1}{sC}} = \frac{sC}{s^2LC + sRC + 1} \quad (3-2)$$

The bode diagram of this transfer function, with $R = 100 \text{ m}\Omega$ (estimated), $L = 1.9 \text{ mH}$, and $C = 8 \text{ mF}$, is the following

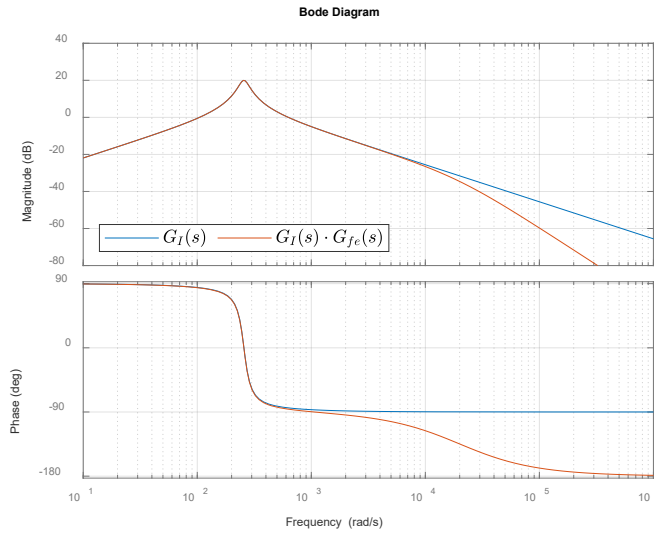


Figure 3-2: Bode diagram of the current as a function of voltage.

The effect of the switching is modelled with a first order low pass filter, where the time constant T_{pe} is the sum of the small time constants, usually estimated as $T_{pe} = 1.5 \cdot T_e$ (see equation (2-4) for T_e).

$$G_{fe}(s) = \frac{1}{sT_{pe} + 1} \quad (3-3)$$

A double integrator as well as a derivative component are necessary to regulate correctly this system.

3.2 Sizing of the current regulator

The transfer function in equation (3-2) is the inverse of a PID controller, as shown hereafter

$$H_1(s) = K_p + \frac{K_i}{s} + sK_d = \frac{s^2K_d + sK_p + K_i}{s} \quad (3-4)$$

By choosing the following values for K_p , K_i and K_d and multiplying $G(s)$ by $H_1(s)$ results in a flat characteristic.



$$K_p = R \quad (3-5)$$

$$K_i = \frac{1}{C} \quad (3-6)$$

$$K_d = L \quad (3-7)$$

With these parameters, $H_1(s)$ is in fact the impedance of the systems (equation (3-1)). However, for a real implementation, the amplification of the differential part must be attenuated at high frequencies. Therefore, $H_1(s)$ is rather defined as

$$H_1(s) = K_p + \frac{K_i}{s} + \frac{sK_d}{\frac{s}{K_f} + 1} \quad (3-8)$$

Where K_f is the cutoff frequency (in rad/s) of the differential part. Here, we set K_f at one decade below the switching frequency.

$$K_f = \frac{\omega_e}{10} = \frac{2\pi f_e}{10} \quad (3-9)$$

The resulting system is shown in Figure 3-3.

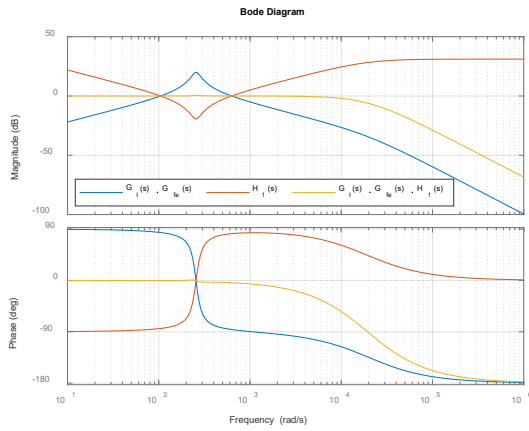


Figure 3-3: Bode diagram of the system $(G(s) \cdot G_{fe}(s))$ with the compensating PID $(H_1(s))$.

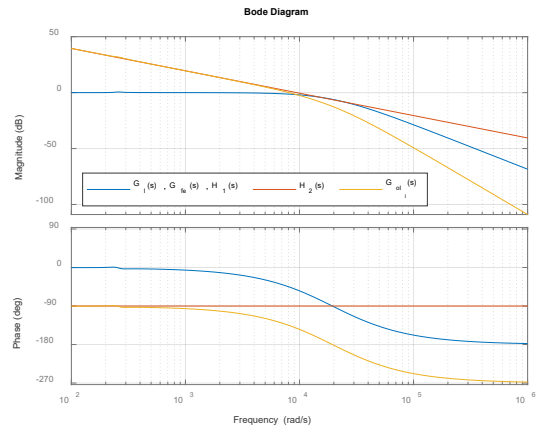


Figure 3-4: Bode diagram of the system with the compensating PID $(H_1(s))$, the second integrator $(H_2(s))$, as well as the regulated system in open loop (equation (3-14)).

Finally, the second integral part is added to the regulator.

$$H_2(s) = \frac{K_{i2}}{s} \quad (3-10)$$

Because the current regulator must be as dynamic as possible, we chose to set its gain K_{i2} (and its cutoff frequency) just a bit lower than K_f at $K_f/2$.

$$K_{i2} = \frac{K_f}{2} \quad (3-11)$$



The current regulator $G_{regI}(s)$ is the combination of the $H_1(s)$ and $H_2(s)$.

$$G_{regI}(s) = H_1(s) \cdot H_2(s) = \frac{K_{i2}}{s} \left(K_p + \frac{K_i}{s} + \frac{sK_d}{\frac{s}{K_f} + 1} \right) =$$

$$= \frac{K_{i2} \left(\frac{K_p}{K_f} + K_d \right) s^2 + K_{i2} \left(\frac{K_i}{K_f} + K_p \right) s + K_i K_{i2}}{s^2 \left(\frac{s}{K_f} + 1 \right)} \quad (3-12)$$

Since $K_{i2} = K_f/2$ then $G_{regI}(s)$ becomes:

$$G_{regI}(s) = \frac{(K_p + K_d K_f) s^2 + (K_i + K_p K_f) s + K_i K_f}{2 s^2 \left(\frac{s}{K_f} + 1 \right)} \quad (3-13)$$

$K_p = R \cong 100 \cdot 10^{-3}$	$K_i = \frac{1}{C} = 125$	$K_d = L = 1.9 \cdot 10^{-3}$	$K_f = \frac{2\pi f_e}{10} = 18.85 \cdot 10^3$	$K_{i2} = \frac{K_f}{2} = 9.42 \cdot 10^3$
-----------------------------------	---------------------------	-------------------------------	--	--

The open loop transfer function of the system given by equation (3-14) and is shown in Figure 3-4.

$$G_{olI}(s) = G_{regI} \cdot G_I \cdot G_{fe} \quad (3-14)$$

The phase margin with the chosen parameters is 45° (at $8 \cdot 10^3$ rad/s) and the gain margin is 12.3 dB (at $19.4 \cdot 10^3$ rad/s). The closed loop transfer function of the current regulation is then

$$G_{clI}(s) = \frac{G_{reg} \cdot G_I \cdot G_{fe}}{1 + G_{reg} \cdot G_I \cdot G_{fe}} \quad (3-15)$$

Figure 3-5 shows the Bode diagram of the current regulation in closed loop, and Figure 3-6 shows the closed loop step response of the current regulation.

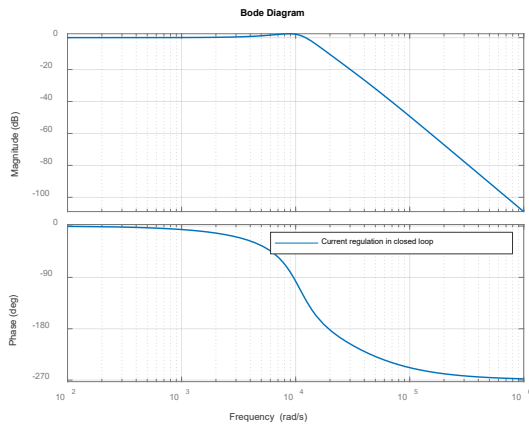


Figure 3-5 : Bode diagram of the current regulation in closed loop (equation (3-15)).

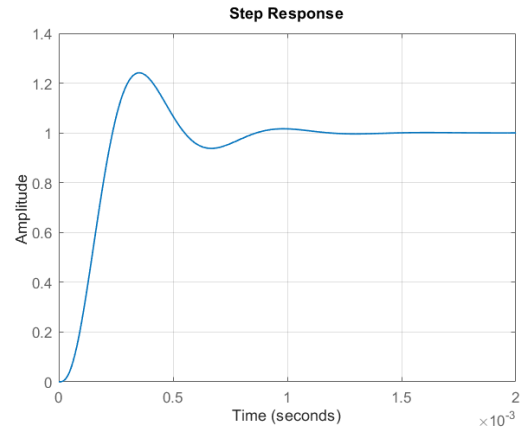


Figure 3-6 : Closed loop step response of the current regulation.



3.3 Digital implementation of the current regulator

The digital implementation of the current regulator is shown in Figure 3-7. Here, the integrators are estimated using the *Forward Euler* integration method. The anti-windup method is the conditional integration method. This method consists in stopping the integration only if the output is saturated and that the sign of the error is the same as the sign of the output.

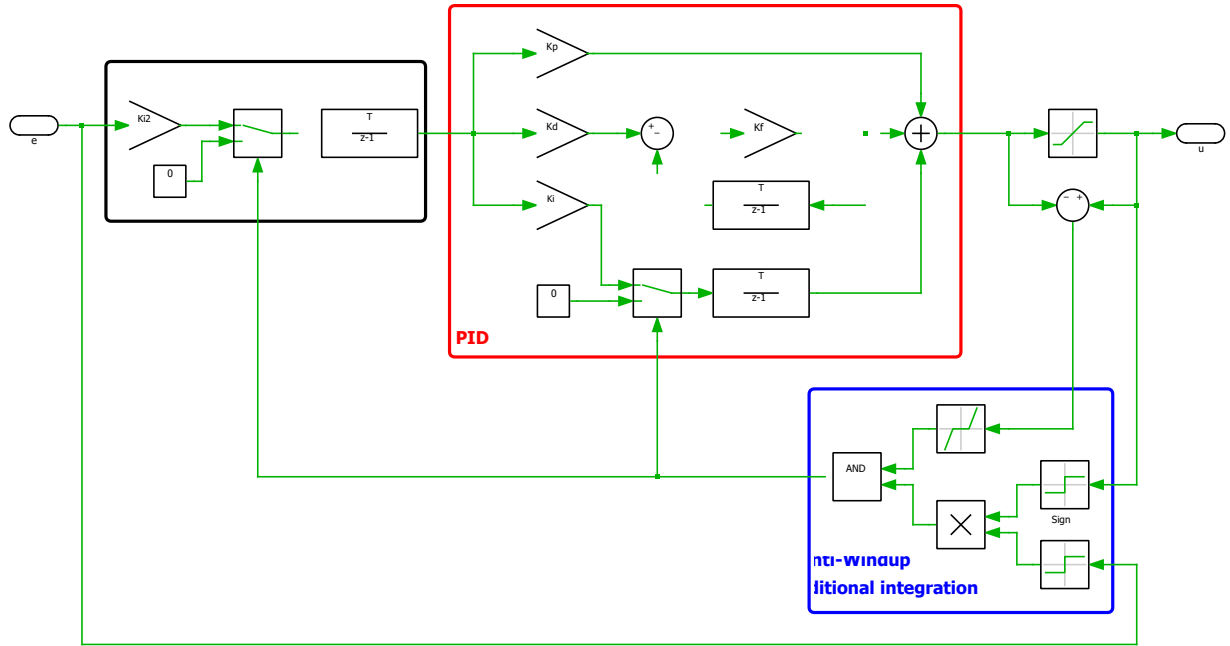


Figure 3-7 : Digital implementation of the PIID current regulator with conditional integration anti-windup.

4 Voltage regulator

4.1 System definition

The system to be regulated here is the capacitor voltage. As previously, the output current I_{out} is considered as a perturbation, and therefore $I_C = I_L$.

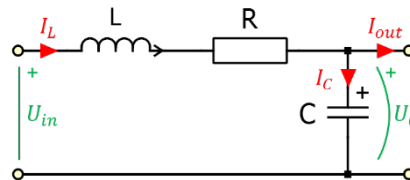


Figure 4-1 : RLC circuit with the capacitor to be regulated.

The transfer function $G_C(s)$ of the capacitor voltage as a function of the current is its impedance.

$$G_C(s) = \frac{U_C(s)}{I_C(s)} = \frac{1}{sC} \quad (4-1)$$

Since $I_C = I_L$ and I_L is regulated by $G_{cl_I}(s)$ (equation (3-15)), then the system to regulated becomes



$$G_U(s) = G_C(s) \cdot G_{cl_I}(s) \quad (4-2)$$

4.2 Sizing the voltage regulator

The system to regulate, shown in equation (4-1), is an integrator with a $1/C$ gain. Therefore, a simple proportional regulator is required to achieve zero steady state error. By fixing the proportional gain K_{p_U} , as shown in equation (4-3), the system gain is compensated with C and the open loop cutoff frequency can be set at ω_0 .

$$K_{p_U} = C \cdot \omega_0 \quad (4-3)$$

Since the full system to regulate in the one shown in equation (4-2), which is the combination of the Bode diagram in Figure 3-5 and an integrator, we can adequately place the cutoff frequency ω_0 so that the cutoff frequency of equation (4-2) is as high as possible, while keeping a sufficient phase margin. Setting $\omega_0 = K_f/10$ gives an open loop phase margin of 78.1° (at $1.92 \cdot 10^3$ rad/s) and a gain margin of 11.8 dB (at $9.6 \cdot 10^3$ rad/s).

$$K_{p_U} = C \cdot \frac{K_f}{10} = 15.1$$

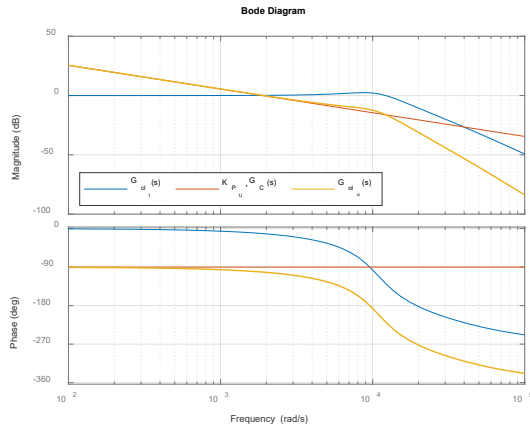


Figure 4-2 : Bode diagram of the voltage regulation system in open loop with its components.

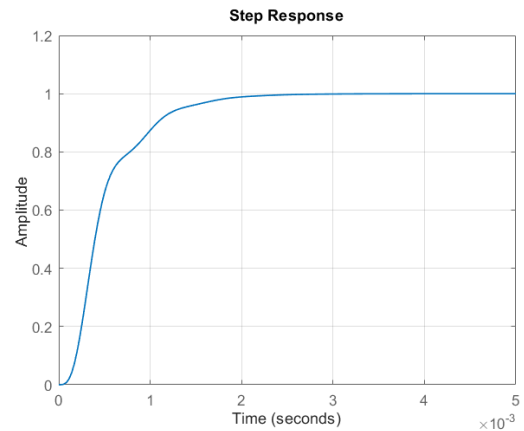


Figure 4-3 : Closed loop voltage step response.



5 Simulation

5.1 Simulation model

The Neutral balancing branch with its current and voltage loops was implemented and simulated using PLECS [4] as shown in Figure 5-1. In the simulation, the voltage regulation is done on capacitor C2.

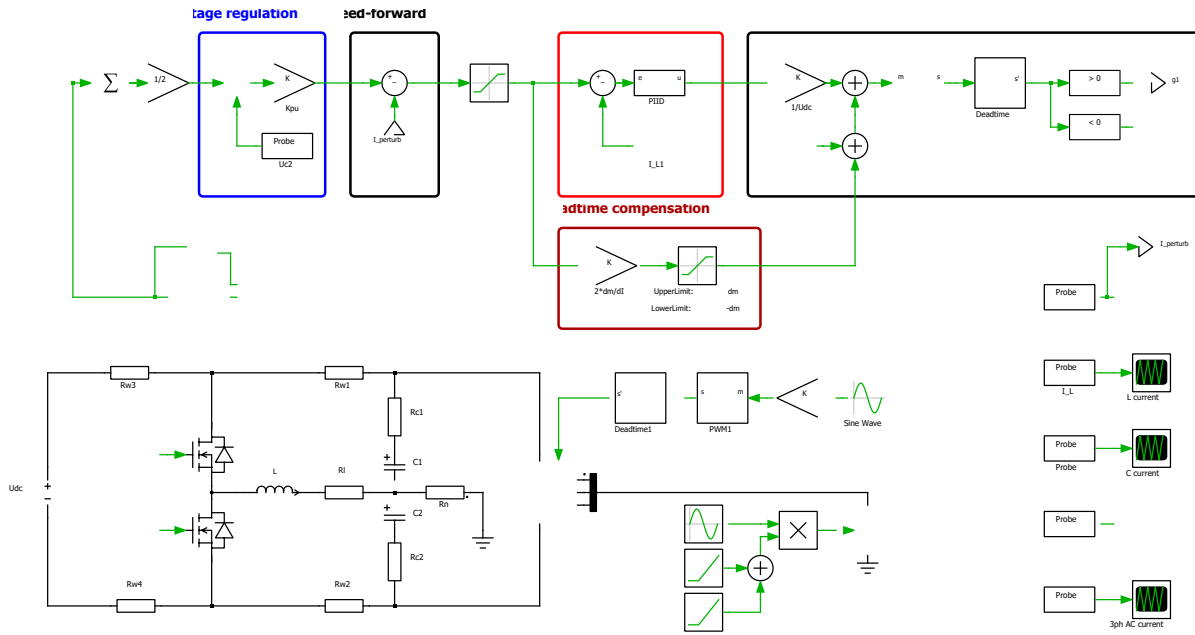


Figure 5-1 : PLECS simulation of the Neutral balancing branch with its current and voltage loops.

The simulation parameters, corresponding to the previous developments, are detailed hereafter:

```
1 Udc = 800;           % [V]          DC bus voltage
2 fe = 30e3;           % [Hz]         Switching frequency
3 Rds_on = 30e-3;      % [Ohm]        MOSFET on resistance
4 L = 1.9e-3;          % [H]          Inductance
5 Rl = 100e-3;         % [Ohm]        Inductance resistance
6 C = 4e-3;            % [F]          Capacitor
7 Rc = 10e-3;          % [Ohm]        Capacitor resistance
8 Rw = 10e-3;          % [Ohm]        Wire resistances
9
10 Initial_Cap_Unbalance = 10; % [V]
11
12 %% Current regulation %%
13 T = 1/fe;            % [s]          Switching and Sample frequency
14 Kp = R;              % [-]          Proportional gain
15 Ki = 1/(2*C);        % [-]          Integral gain
16 Kd = L;              % [-]          Differential gain
17 Kf = 2*pi*fe/10      % [rad/s]    Differential amplification cutoff frequency
18 Ki2= Kf/2;           % [rad/s]    Current reg cutoff frequency
19
20 %% Voltage regulation %%
21
22 w0 = Kf/10;          % [rad/s]    Voltage reg cutoff frequency
23 Kp_u = 2*C*w0;        % [-]          Proportional gain
24
25 %% deadtime compensation
26 deadtime = 150e-9;   % [s]          Blanking time
27 dI = Udc/(4*L*fe);   % [A]          Current ripple
28 dm = deadtime * fe;   % [-]          Blanking time to switching period ratio
```



5.2 Perturbation current

The following perturbation currents are generated for the three phases of the converter.

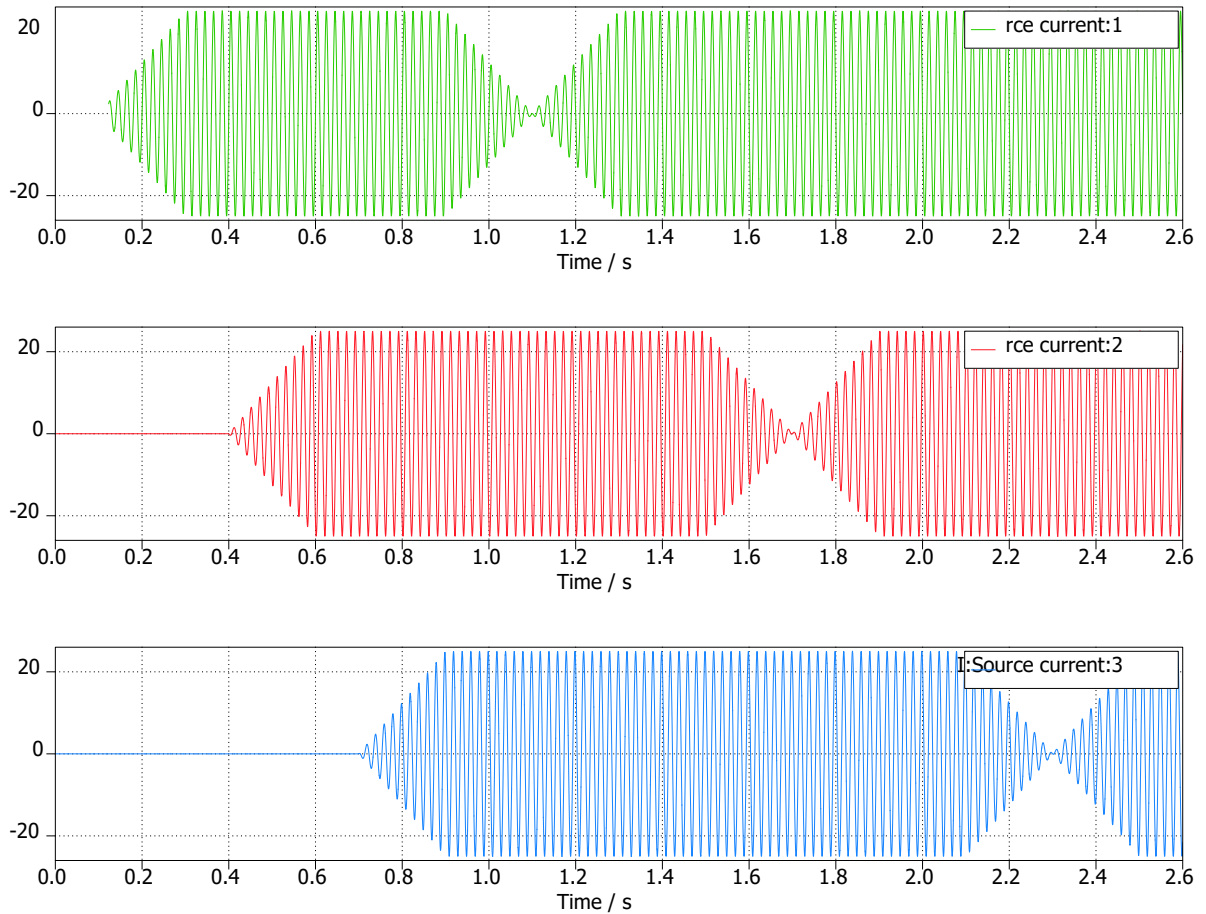


Figure 5-2 : Perturbation currents of the three phases of the converter.

The sum of the three-phase current adds up resulting in the following neutral current.

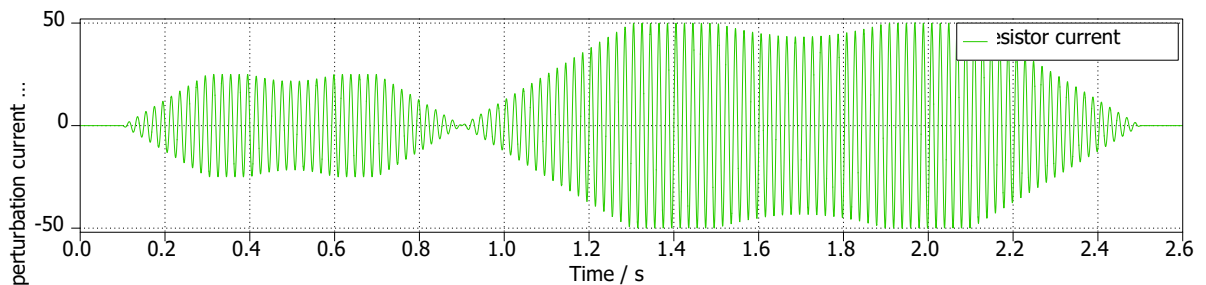


Figure 5-3: Resulting neutral current

The current limitation was fixed to the peak value of a 32 A rms sinusoidal current ($32 \cdot \sqrt{2} = 45.25$ [A]). The peak neutral current was voluntarily chosen to be larger than this to test the behaviour of the regulation to a saturation.



5.3 Measured perturbation feed-forward

As previously described, the current reference is generated by the voltage regulator. However, to improve the dynamics and the precision of the regulation, the perturbation current (neutral line current) is added to the current reference. The regulation functions fine without the feed-forward, however consequently there is a bit more ripple on the capacitor voltage.

5.4 Deadtime compensation

To compensate for the effect of the deadtime (blanking time), the ratio between the blanking time and the switching period must be added, or subtracted to the duty cycle, according to the sign of the current in the inductor. However, since there is a current ripple (equation (2-9)), when the current is near zero, there is a range between which the current changes sign twice during a switching period. In order not to overcompensate, the compensation is applied proportionally in this range, as shown in Figure 5-4.

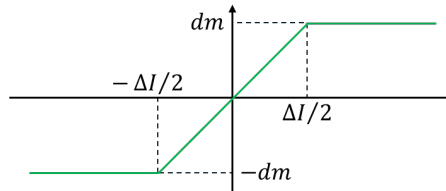


Figure 5-4 : Deadtime compensation logic near zero current.

Furthermore, the reference for the deadtime compensation is the current reference and not the measured current itself. Experience has shown that this yields better results.

5.5 PWM offset

Because the regulated capacitor voltage is half of the total DC link voltage, an offset is added to the PWM signal. If the PWM input range is 0 to 1, then this offset would be 0.5 if the voltage across the capacitors did not move. Nevertheless, since it can move, the offset to be applied when regulating the voltage on the lower side capacitor C_2 is

$$U_{ratio} = \frac{U_{C_2}}{U_{C_1} + U_{C_2}} \quad (5-1)$$

This improves the dynamics and the precision of the voltage regulation.



5.6 Simulation results

Figure 5-5 shows the simulated inductor current as well as the saturated current reference. As shown, the regulated current follows well the reference, however it struggles a bit when it is saturated. This is explainable by the fact that the perturbation current is dynamic, and it is not saturated.

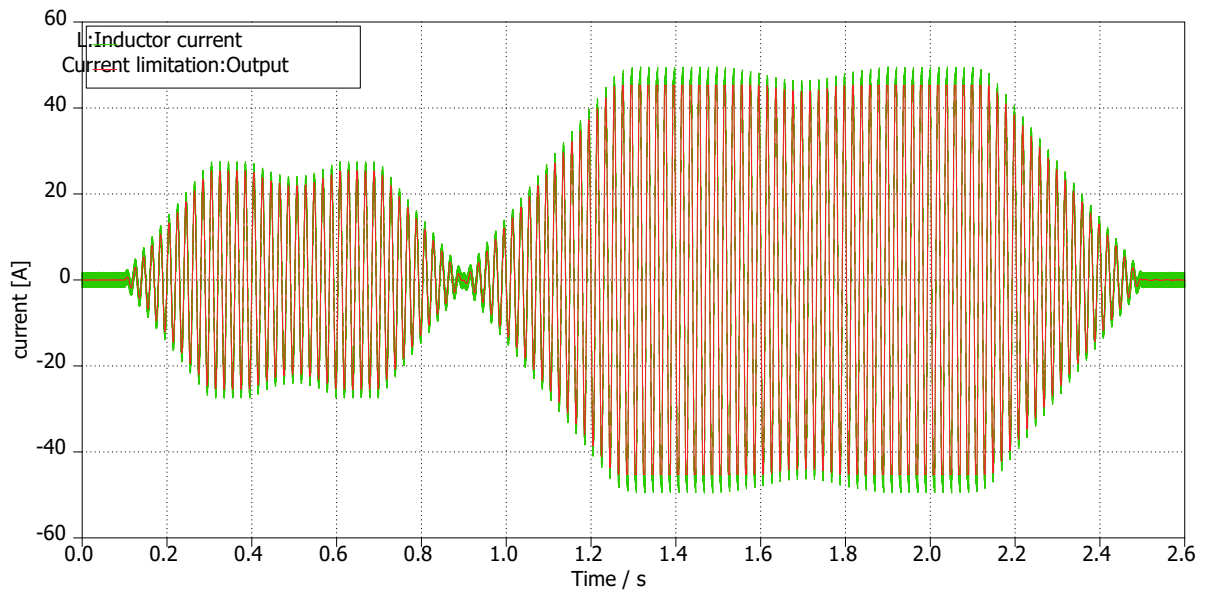


Figure 5-5: Inductor current and current regulator reference (saturated).

Figure 5-6 shows the simulated capacitor voltages. As shown, the voltages fluctuate due to the slight delay of the regulator, however the error here is less than 0.3%, even when the inductor current is saturated.

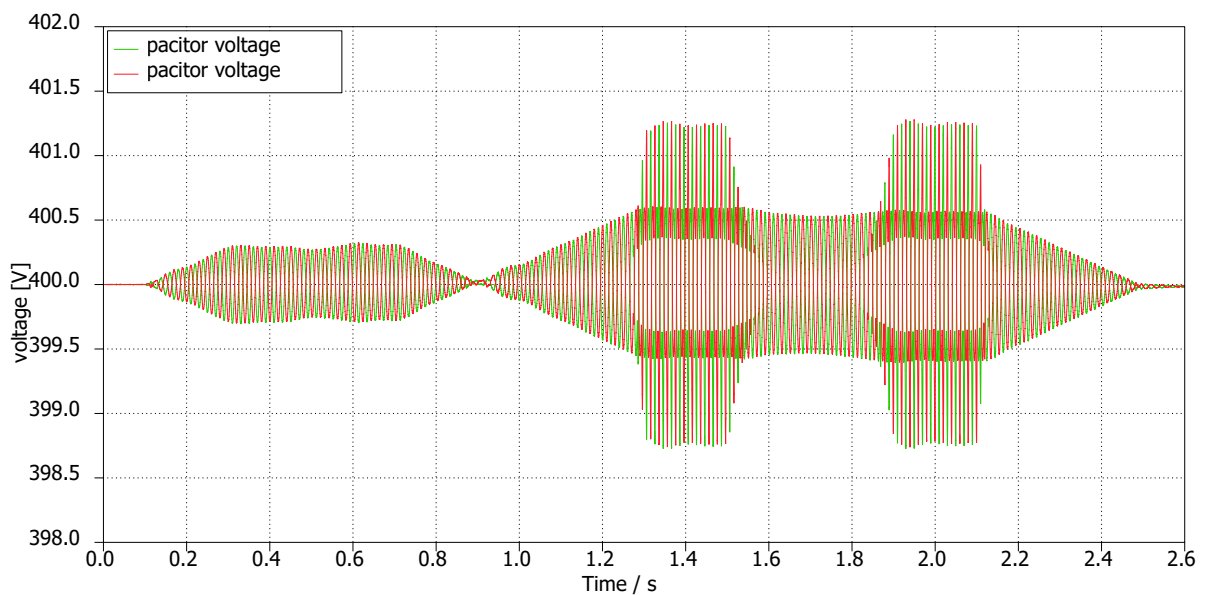


Figure 5-6: Simulated capacitor voltages.



Figure 5-7 shows a zoomed view between 0.3 and 0.4 seconds of the simulation. As shown, the current's amplitude is correctly regulated and has a phase lag as expected.

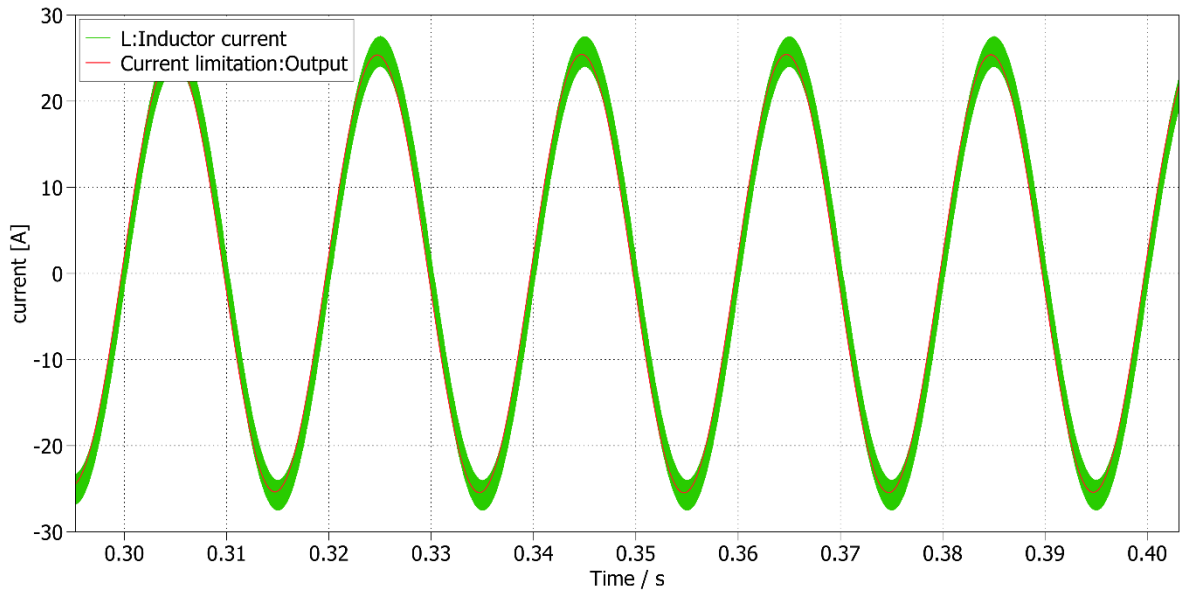


Figure 5-7: Zoomed view of the inductor current and the current regulator reference between 0.3 and 0.4 s.

Figure 5-8 shows a zoomed view between 1.3 and 1.4 seconds of the simulation. As shown, when the saturation occurs, the current is not perfectly compensated because of the perturbation current.

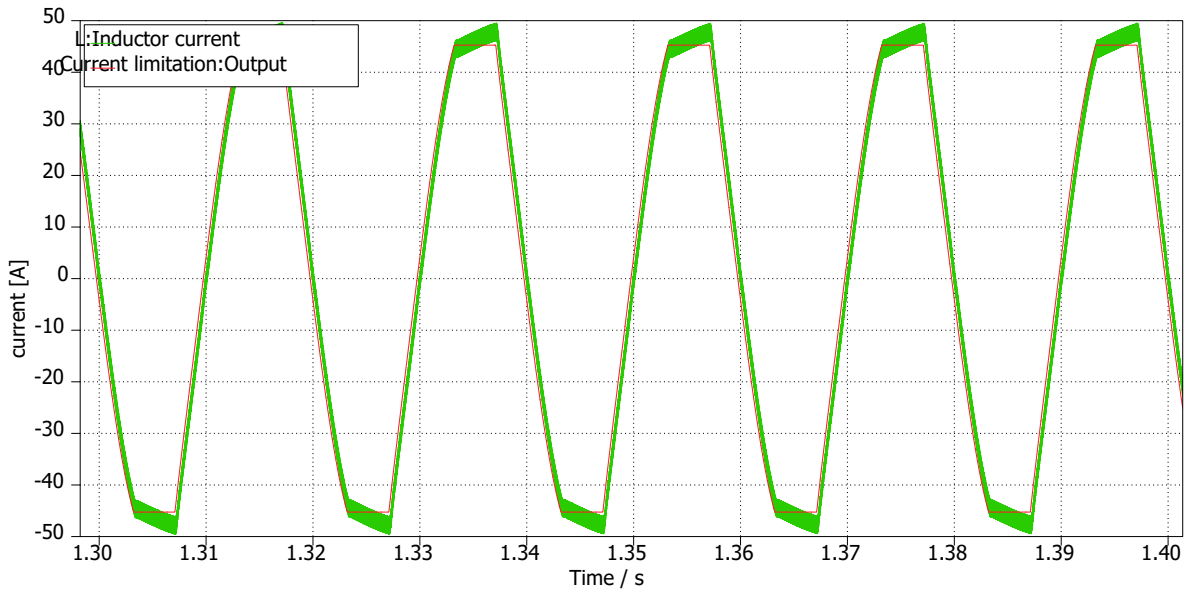


Figure 5-8: Zoomed view of the inductor current and the current regulator reference between 1.3 and 1.4 s.

To compensate for the drift during the saturation, an outer current regulating loop can be added, however it will slow down the global dynamics a bit and therefore increase the voltage oscillation on the capacitors.



6 Saturated current drift compensation

As shown in the previous section, the current regulator detailed in section 3.2 works perfectly if there is no saturation. When the current is saturated, because of the perturbation, which is not controlled, the current can exceed the desired limit and become a hazard for the hardware.

6.1 Outer current loop

By adding an outer loop with an extra integrator, it is possible to cancel the effect of the perturbation. However, the cost is the reduction of the current regulator dynamics. Starting from the closed loop current regulator transfer function $G_{cl_I}(s)$ defined in equation (3-15), we add an integrator with a cutoff frequency that we chose to place at $K_f/10$.

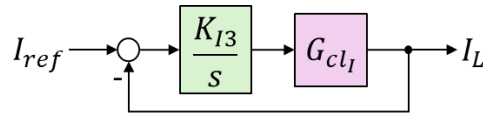


Figure 6-1: Structure of the outer current loop.

$$K_{I3} = \frac{K_f}{10} \quad (6-1)$$

This results in a open loop phase margin of 78.1° (at $1.92 \cdot 10^3$ rad/s) and a gain margin of 11.8 dB (at $9.6 \cdot 10^3$ rad/s).

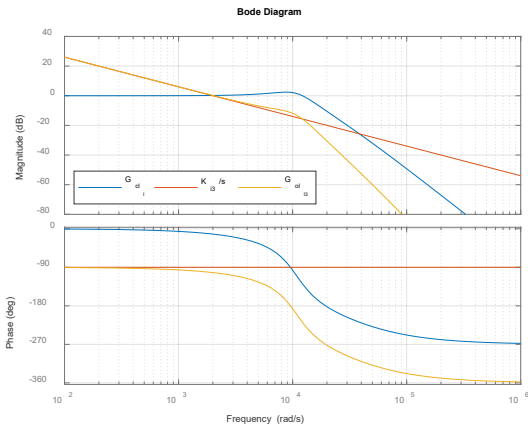


Figure 6-2: Bode diagram of the current regulator in close loop.

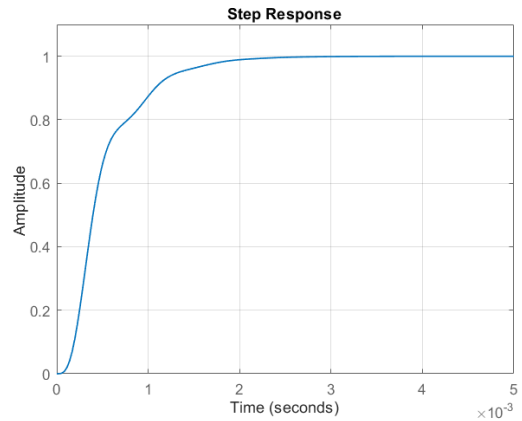


Figure 6-3 : Closed loop current step response.

The dynamics of the new current regulator is the same as the voltage regulator sized in section 4.2, therefore the voltage regulator must be slowed down to avoid a conflict.

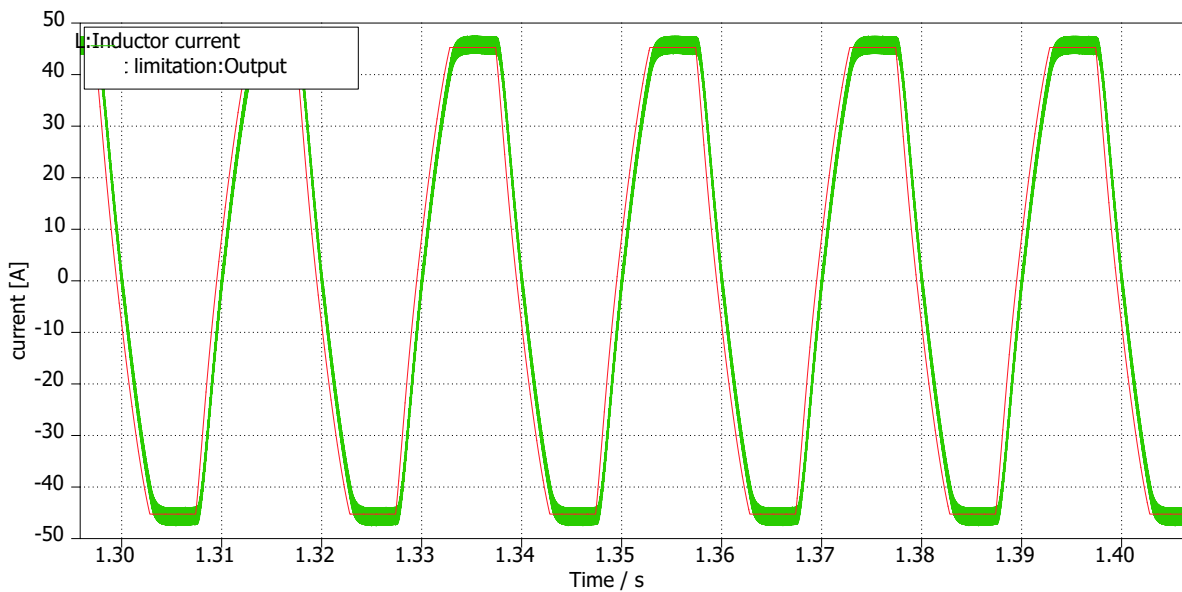


Figure 6-7: Zoomed view of the inductor current and the current regulator reference between 1.3 and 1.4 s with the outer current loop.

Figure 6-8 shows the resulting capacitor voltages with the same scale as in Figure 5-6. As expected, because of the lower dynamics the amplitude of the oscillations is larger by approximately a factor two. Nevertheless, the oscillations remain below 0.5% which is acceptable.

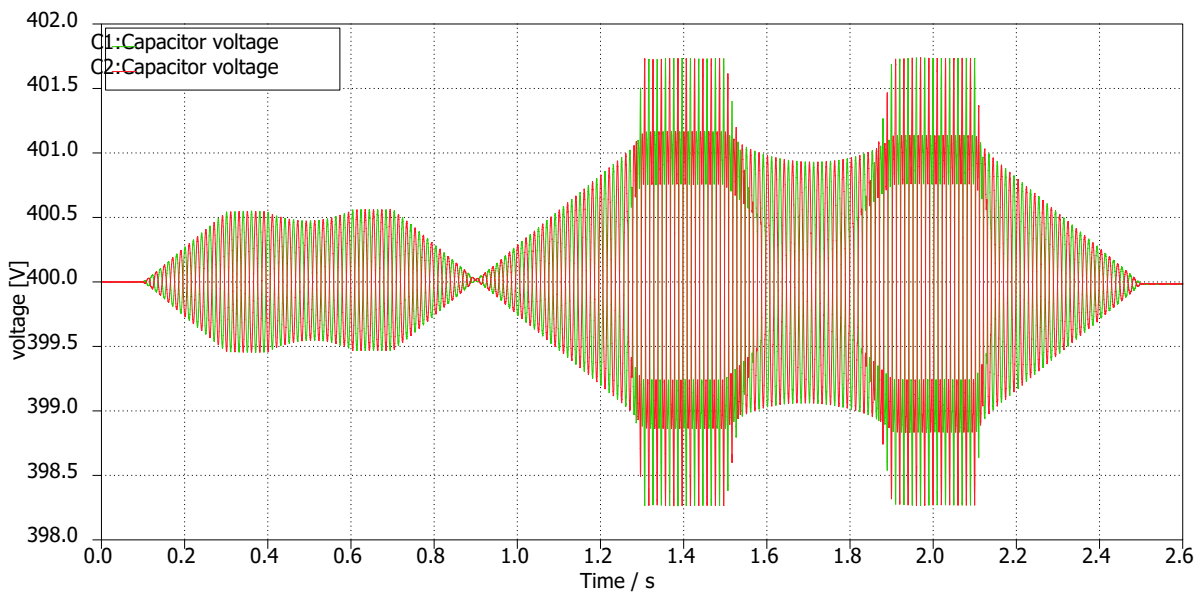


Figure 6-8: Simulated capacitor voltages with the two current loops and new voltage loop parameters.



7 Current capability sizing

Depending on the functioning envelope, the maximum neutral current can vary from two per unit to three per unit of the nominal phase current. The three phase currents are defined as

$$\begin{cases} \underline{I}_a = e^{j(\omega t + \varphi_1)} \\ \underline{I}_b = e^{j(\omega t + \varphi_2 + \frac{2\pi}{3})} \\ \underline{I}_c = e^{j(\omega t + \varphi_3 + \frac{4\pi}{3})} \end{cases} \quad (7-1)$$

As shown in Figure 7-1, it is possible that the three phase currents are in phase and add up. However, this is a particular situation which should not happen if the grid is planned adequately.

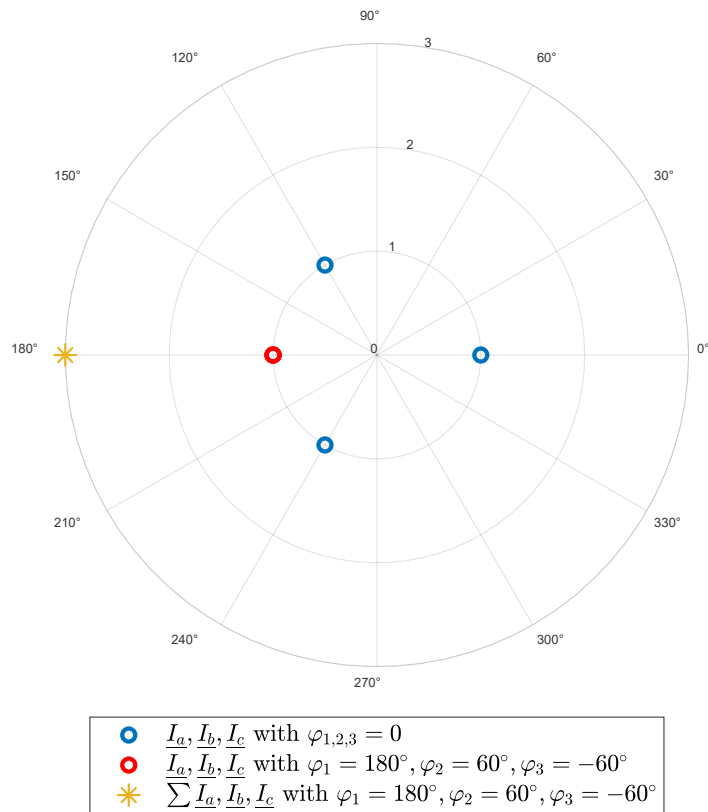


Figure 7-1 : Neutral current depending on the amplitude and sign of the phase currents.

Nevertheless, there is a situation where the neutral current can become high – if the inverter is absorbing power from the grid (e.g., charging its battery) and a short circuit occurs on one or two phases, their current will suddenly reverse, causing the neutral current to be at least as large as shown in Figure 7-1.



8 Limitations

When the perturbation current is too high, then the current limitation saturates the current reference. The consequence is that the voltage regulator, which balances the voltage across capacitors C1 and C2, cannot function correctly anymore. When this happens, the effect of the LCC resonance becomes apparent. Therefore, it is important that the resonant frequency of the LCC configuration is not too close to the grid frequency.

9 Conclusion

The current and voltage regulators are trivial and straightforward; however, the challenge is in managing the limits when things go wrong. In the event of a short-circuit on one or several phases, the neutral current can be large and the unbalance in the capacitor voltages can be catastrophic. As shown in Chapter 7, in normal conditions, the neutral current can be as large as three per units of the phase current. Therefore, a choice has to be made in the sizing of the neutral balancing branch which depends on the desired envelope of the inverter.

10 References

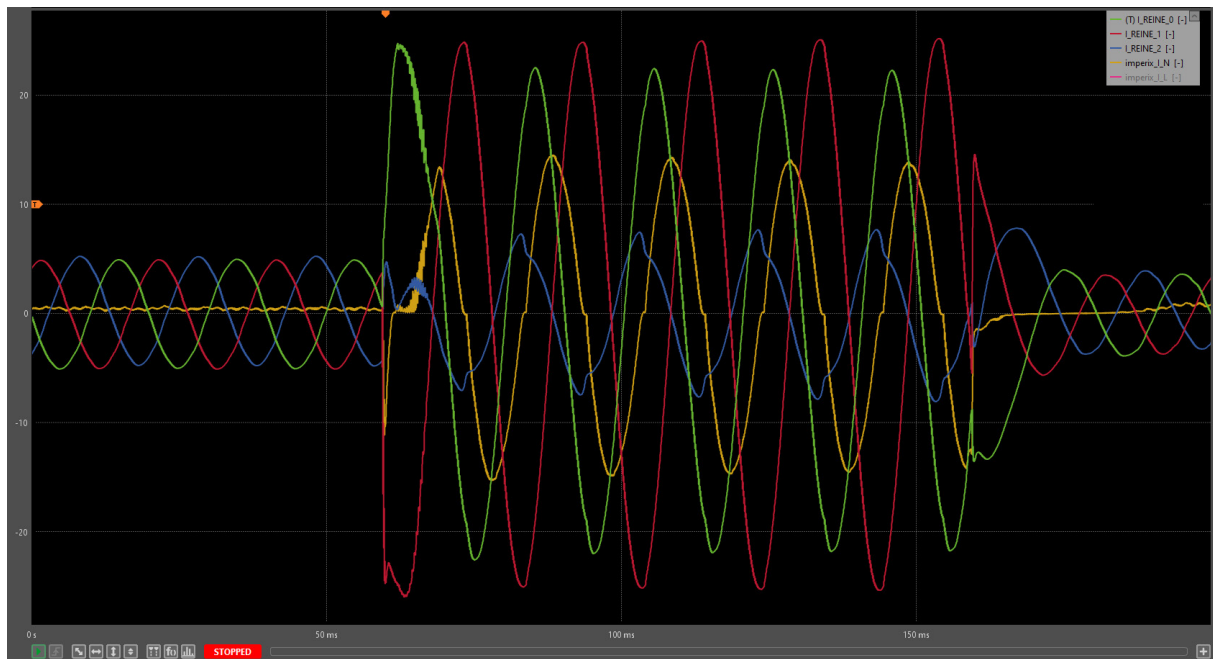
- [1] M. Passalacqua, G. Grosjean, S. Kissling, M. Bozorg, M. Marchesoni, and M. Carpita, 'A State-Space Approach to the Modelling and Control of the Neutral Leg of a Four Legs, Three-Phase Inverter', *IEEE Trans. Ind. Electron.*, vol. 69, no. 4, pp. 4056–4064, Apr. 2022, doi: 10.1109/TIE.2021.3070495.
- [2] 'Half bridge module - PEB8038 SiC power module - imperix'. Accessed: Nov. 06, 2024. [Online]. Available: <https://imperix.com/products/power/half-bridge-module/>
- [3] 'Rapid prototyping controller for power electronics - B-Box RCP - imperix'. Accessed: Nov. 06, 2024. [Online]. Available: <https://imperix.com/products/control/rapid-prototyping-controller/>
- [4] 'PLECS | Plexim'. Accessed: Dec. 19, 2022. [Online]. Available: <https://www.plexim.com/products/plecs>



Final report from 1 July 2026

FORMIDABLE

Appendix 3: GFMI over-current protection



Source: HEIG-VD/IE 2026



Publisher:

Swiss Federal Office of Energy SFOE
Energy Research and Cleantech
CH-3003 Berne
www.energy-research.ch

Co-financing:

Imperix SA
CH-1950 Sion
www.imperix.com

Subsidy recipients:

HEIG-VD
CH-1400 Yverdon-les-Bains
www.heig-vd.ch

Authors:

Dr Philippe Morey, HEIG-VD, philippe.morey@heig-vd.ch
Prof. Dr Mokhtar Bozorg, HEIG-VD, mohktar.bozorg@heig-vd.ch
Prof. Dr Mauro Carpita, HEIG-VD, mauro.carpita@heig-vd.ch

SFOE project coordinators:

Dr Michael Moser, michael.moser@bfe.admin.ch

SFOE contract number: SI/502668-1

The authors bear the entire responsibility for the content of this report and for the conclusions drawn therefrom.



Contents

Contents	3
List of abbreviations	4
1 Introduction	5
1.1 Circuit breaker characteristics	6
2 Current limiting strategies	7
2.1 Single phase current regulation	7
2.1.1. 100% Star configuration	7
2.1.2. 100% Delta configuration	8
2.1.3. Mix of Star and Delta configurations	8
2.2 Adaptive virtual impedance	9
2.2.1. Monophasors	9
2.2.2. Current threshold virtual impedance	11
2.2.3. Stability issue with current threshold virtual impedance	14
2.2.4. Voltage threshold virtual impedance	18
2.2.5. Limitations of voltage threshold virtual impedance	20
2.2.6. Combination of current and voltage threshold virtual impedance	22
2.3 Filter resonance damping	24
3 Staying synchronous during an overload	25
3.1 Observing the load angle	25
3.2 Virtual power	26
3.3 Application of the virtual power in the control loop	26
4 Conclusion	27
5 References	27



List of abbreviations

GFLI	Grid Following Inverter
GFMI	Grid Forming Inverter
MCB	Miniature Circuit Breakers
MCCB	Moulded Case Circuit Breakers
RMS	Root Mean Square
SFOE	Swiss Federal Office of Energy
VI	Virtual Impedance



1 Introduction

A grid forming inverter (GFMI) is a voltage source inverter, meaning that tries to impose a voltage at its output, as opposed to a grid following inverter (GFLI), which is a current source inverter, that tries to impose a current at its output. If a hard short-circuit happens at the output of a GFLI, it will quickly adapt and regulate the output current, avoiding an overload and a possibly destructive situation. However, for a GFMI, the situation is very different. If a hard short-circuit happens at its output, without appropriate measures, the current will rise very quickly and become destructive for the inverter in a matter of milliseconds.

The simplest solution is to switch off the inverter as soon as an overload is detected. Considering a GFMI based community microgrid that is functioning disconnected from the macro-grid, switching of the inverters effectively protects them; however, it does not solve the issue. The reason is that an inverter's ability to stop is much faster than the circuit-breaker's ability to break a fault. Therefore, stopping an inverter as soon as it detects an overload will certainly result in the fault which caused the overload to remain and not be isolated. The consequence is a loss of service which cannot resolve itself automatically.

A better solution is to limit the output current of the inverter to its maximum current for long enough so that the circuit breaker can do what it was designed for. However, before the current limitation strategy is defined, the characteristics of the circuit breakers must be studied to understand and define the operating limits.



1.1 Circuit breaker characteristics

In the present case we are looking at low voltage circuit breakers which include miniature circuit breakers (MCB) – rated up to 125A, moulded case circuit breakers (MCCB) – rated up to 1600A and low voltage power circuit breakers. Their characteristics are defined in IEC 60898-1 [1] for household and similar installations and IEC 60947-2 [2] for industrial applications. The current-time operating characteristics divide the circuit breakers into types, of which the most common are B, C, and D, as shown in Figure 1-1 [3]. The characteristics are composed of two parts: a thermal part and a magnetic part. All types have the same thermal part but are differentiated by their magnetic part. On the left side of the grey zones in Figure 1-1 the breaker must not trip. In the grey zones, the breaker can trip and on the right side of the grey zones, the breaker must trip.

Nevertheless, the full characteristics are theoretical. However, according to the standards, the circuit breakers must pass the following tests:

I_1 is applied. The breaker must not trip before at least one hour (two hours if the rating is more than 63A).

I_2 is applied following the test with I_1 . The breaker must trip in less than one hour (two hours if the rating is more than 63A).

I_3 is applied. The breaker must trip between one second and 60 seconds.

I_4 is applied. The breaker must not trip in less than 0.1 seconds.

I_5 is applied. The breaker must trip in less than 0.1 seconds.

The objective of installing GFMLs is to enhance the existing grid's capabilities, and not build an entire grid based on the GFML's limitations. The most common type of breaker is type C, however all types must trip magnetically in less than 100 ms for their respective ratings ($5 I_n$, $10 I_n$ and $20 I_n$). Therefore, to adequately allow the circuit breakers to function correctly, the inverters must be able to provide a high enough current for at least 100 ms. This can be achieved either by choosing circuit breakers with low enough ratings, or by allowing the inverter to overshoot their current rating for a limited time.

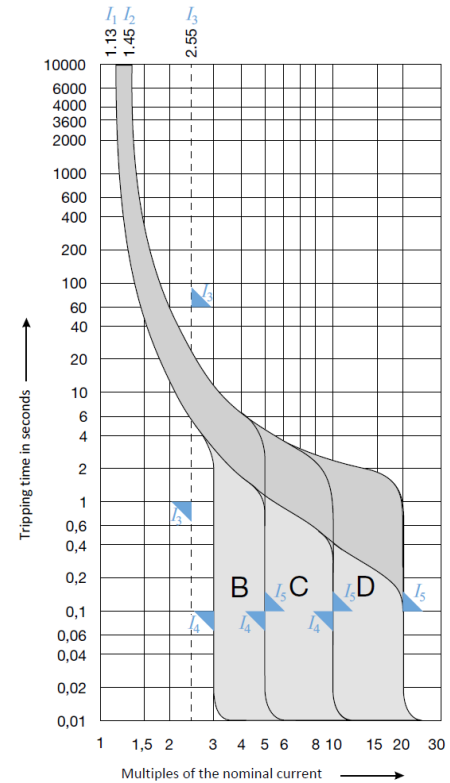


Figure 1-1 : Time-current operating characteristics for type B, C and D circuit breakers.



2 Current limiting strategies

In the present study we aim to develop low voltage GFMI for community micro-grids. These would need to be able to function on imbalanced loads with a neutral point and ideally without a heavy bulky 50Hz transformer. With these constraints, the inverter must be able to manage any neutral current, including DC components. The usual strategy to limit the current in an inverter is to have a current regulating loop that controls the current. However, in a GFMI it has been demonstrated that regulating the voltage with an internal current loop can be unstable in certain conditions. Nevertheless, a current regulator could be engaged only in case of an overload, just to manage it. A second option is to limit the output current of the inverter by calculating and applying a virtual impedance.

2.1 Single phase current regulation

To regulate the current in any system, the current to regulate must be known. In a three-phase system, there are two possible load configurations: star or delta. Faults will either fall in one, the other, or both configurations simultaneously. If a fault is between any of the phases and the neutral, it is in star configuration Figure 2-1, and if a fault is between any of the phases without the neutral, it is in delta configuration Figure 2-2.

For the following analysis, we consider that currents $\underline{i}_a$, $\underline{i}_b$, $\underline{i}_c$ and $\underline{i}_N$ in Figure 2-1 and Figure 2-2 are measured.

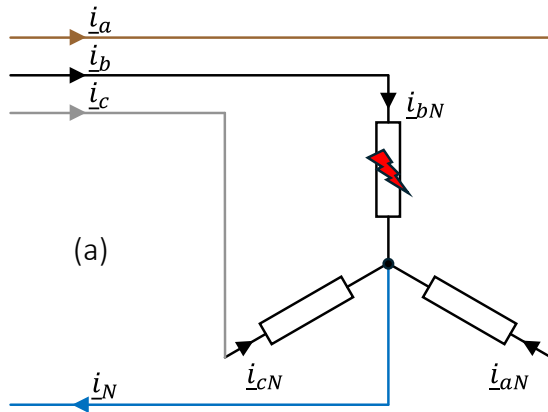


Figure 2-1 : Fault in Star configuration.

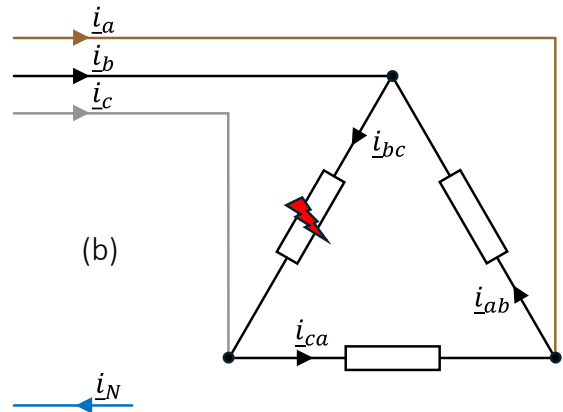


Figure 2-2 : Fault in Delta configuration.

2.1.1. 100% Star configuration

In star configuration, there is only one node, so the currents in this configuration are given by equation (2-1).

$$\underline{i}_N = \underline{i}_a + \underline{i}_b + \underline{i}_c = \underline{i}_{aN} + \underline{i}_{bN} + \underline{i}_{cN} \quad (2-1)$$

where, $\underline{i}_{aN} = \underline{i}_a$, $\underline{i}_{bN} = \underline{i}_b$ and $\underline{i}_{cN} = \underline{i}_c$. All variables can be determined. In the case of a phase to neutral fault (Figure 2-1), the inverter can detect the overcurrent and can activate a single-phase current regulation and control the current in the concerned phase. The current would be imposed and not just limited, so the transition would not necessarily be smooth.



2.1.2. 100% Delta configuration

In a delta configuration, there are three nodes, so the currents in this configuration are given by the following system of equations.

$$\begin{cases} \underline{i}_a = \underline{i}_{ab} - \underline{i}_{ca} \\ \underline{i}_b = \underline{i}_{bc} - \underline{i}_{ab} \\ \underline{i}_c = \underline{i}_{ca} - \underline{i}_{bc} \end{cases} \quad (2-2)$$

The neutral wire is not connected, so $\underline{i}_N = 0$. Since there are three equations and three unknown variables, it is possible to solve this system and impose the proper currents to manage a fault in delta mode. Nevertheless, in practice, because of the coupling between the phases it would certainly prove quite difficult to manage in real time.

2.1.3. Mix of Star and Delta configurations

In a configuration with only one star and one delta, the currents will be given by the following system of equations:

$$\begin{cases} \underline{i}_a = \underline{i}_{aN} + \underline{i}_{ab} - \underline{i}_{ca} \\ \underline{i}_b = \underline{i}_{bN} + \underline{i}_{bc} - \underline{i}_{ab} \\ \underline{i}_c = \underline{i}_{cN} + \underline{i}_{ca} - \underline{i}_{bc} \\ \underline{i}_N = \underline{i}_{aN} + \underline{i}_{bN} + \underline{i}_{cN} \end{cases} \quad (2-3)$$

In this case there are four equations and six unknown variables. Therefore, the system is unsolvable. Since in a real-life system, there will be multiple star and delta loads connected to multiple inverters, in case of an overload, the proper currents to be injected on each phase cannot be determined. Therefore, current control is not an adequate strategy for GFMI.



2.2 Adaptive virtual impedance

Current limiting through the application of a virtual impedance (VI) is a simple principle however its application is not necessarily trivial. The principle is to apply a voltage drop in series with virtual internal voltage reference as if the inverter had a larger impedance. Because the application of adaptive virtual impedance is dependent on the use of phasors, and that each phase must be dealt with separately, we must first introduce the notion of monophasors. These are based on observers and allow us to have one phasor for each phase.

2.2.1. Monophasors

Working with phasors is more convenient because the amplitude and phase of each component is always available. Monophasors are based on observers and are an estimation of the amplitudes and phases of each phase variable. The basic principle here is to reconstruct a second signal that is phase-shifted by 90° to obtain two signals in quadrature. Figure 2-3 shows the bloc diagram to calculate monophasors.

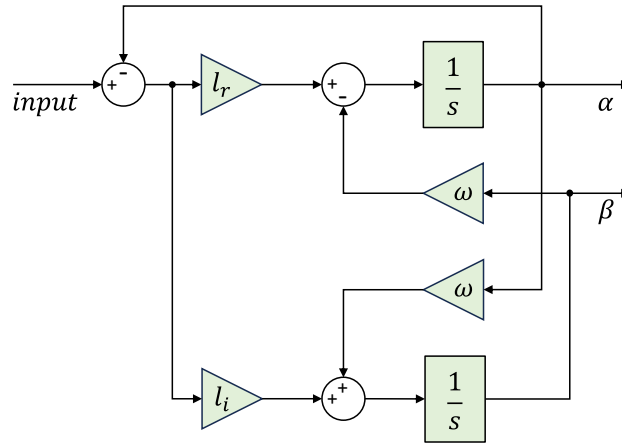


Figure 2-3: Block diagram to calculate monophasors

The expected input signal is a sinusoidal wave of nominal frequency ω . The output signal α is generated with the same amplitude and phase as the input signal (real axis). β is the generated signal that is also of same amplitude but in quadrature with the input signal (imaginary axis). l_r and l_i are the real and imaginary axis gains to obtain the desired response.

This system can be described with the following state space matrixes:

$$A = \begin{bmatrix} -l_r & -\omega \\ \omega - l_i & 0 \end{bmatrix} \quad B = \begin{bmatrix} l_r \\ l_i \end{bmatrix} \quad C = \begin{bmatrix} 1 & 0 \\ 0 & 1 \end{bmatrix} \quad D = \begin{bmatrix} 0 \\ 0 \end{bmatrix}$$

Two symmetrical poles can be placed. These poles are defined as:

$$p_{1,2} = -p_{real} \pm j \cdot p_{imag} \quad (2-4)$$

Then the gains l_r and l_i are:

$$l_r = 2 \cdot p_{real} \quad (2-5)$$

$$l_i = \omega - a \cdot \frac{p_{real}^2}{\omega} \quad (2-6)$$

where:



$$a = \frac{p_{imag}}{p_{real}} \quad (2-7)$$

The placing of the appropriate poles depends on criteria that must be chosen. The three chosen criteria are maximizing speed, while minimizing overshoot and the harmonics in the modulus of the monophasor during an abrupt change in the input signal. Since the modulus of the monophasor is a non-linear function the response of the system is dependent on the phase of the event. Figure 2-4 and Figure 2-5 show the different responses depending on the poles and the start times.

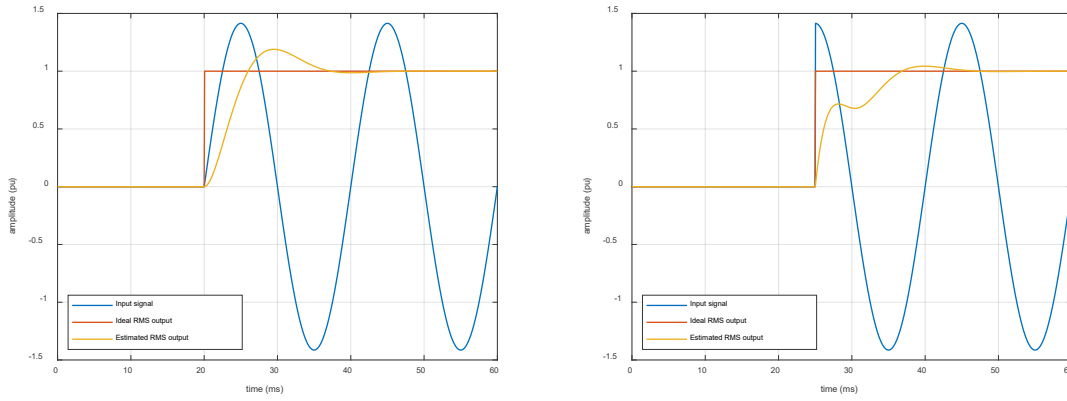


Figure 2-4 : Difference in response for two different start times with $p_{1,2} = -\omega$

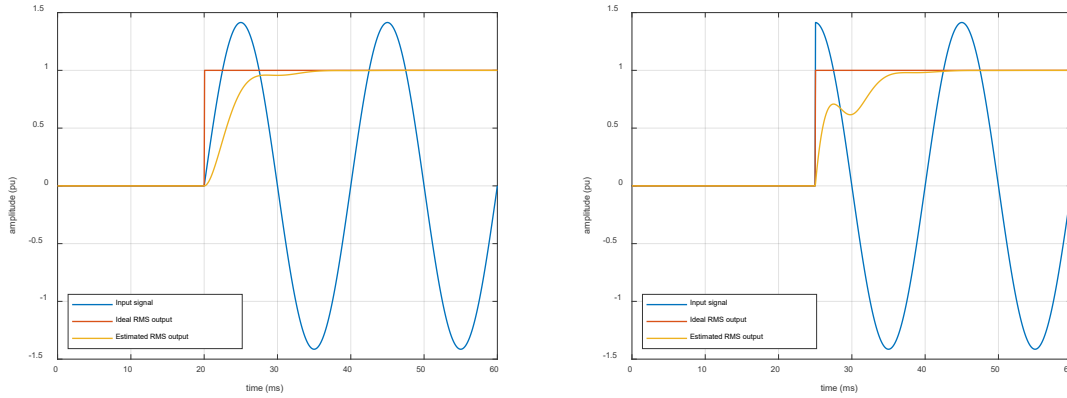


Figure 2-5 : Difference in response for two different start times with $p_{1,2} = -\omega \pm j\omega$

Iterative simulations were performed to determine adequate pole placement. For a fast damped response placing the poles at $p_{1,2} = -2\omega \pm j2\omega$ yields satisfying results.

Furthermore, because the frequency of the grid forming inverter can change depending on the load, the nominal frequency feedback is not a constant but is set to be the internal frequency of the inverter.



2.2.2. Current threshold virtual impedance

The principle is that when the current is above a predefined threshold, a current dependant virtual impedance voltage drop is applied in series with the virtual internal voltage reference $\underline{v}$. Consequently, the virtual impedance is not constant, but changes dynamically depending on the current. Figure 2-6 shows a single-phase schematic of a GFMI with a virtual impedance $\underline{z}_v$ and an LCL output filter, that is connected to a grid that has an impedance $\underline{z}_g$. The reference voltage $\underline{v}$ is the voltage provided by the droop control.

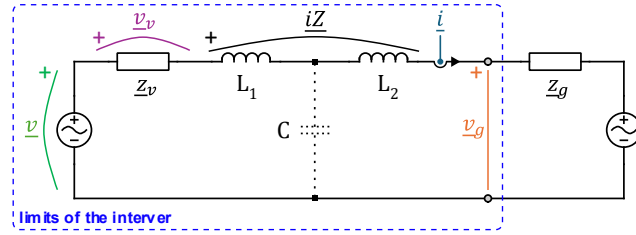


Figure 2-6: Single-phase schematic of a GFMI with a virtual impedance.

For the following analysis, the effect of the filter capacitor as well as the inductance resistances are negligible. Therefore, as a simplification, their effect is neglected. The impedance of the filter is approximated as follows.

$$\underline{Z} = j\omega(L_1 + L_2) \quad (2-8)$$

In the following figure (Figure 2-7), the phasor diagram shows the different voltages and current at play in the circuit. Two situations are illustrated: the first (a) is a normal functioning situation, whereas the second (b) is a fault situation, where the voltage amplitude has dropped dramatically. The dashed circles represent the lower and upper current thresholds between which the virtual impedance is varied to limit the current.

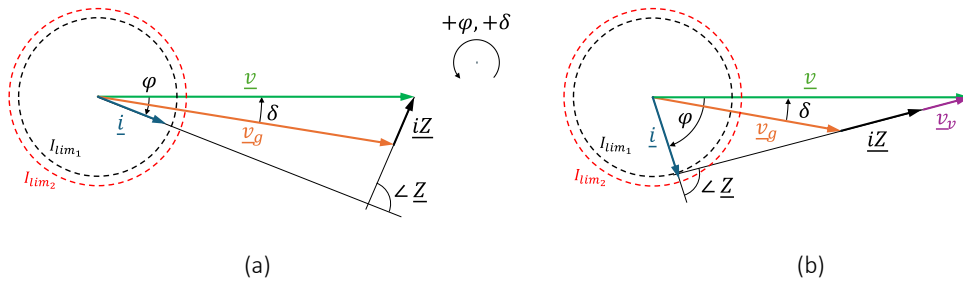


Figure 2-7: Phasor diagram with (a) pre-fault normal condition, where the current is below the maximum threshold, and (b) fault condition, where the virtual impedance is activated between I_{lim1} and I_{lim2} .

When a fault occurs, and the current becomes greater than the lower limit I_{lim1} , the virtual impedance increases to maintain the current below upper limit I_{lim2} . Because the cause of the current is the voltage drop across the filter $\underline{iZ}$, as shown in Figure 2-7, the virtual impedance voltage $\underline{v}_v$ must replace part of this voltage. Consequently, the virtual impedance voltage should be colinear with the voltage drop across the filter.

$$\angle \underline{z}_v = \angle \underline{Z} \quad (2-9)$$



To determine an appropriate rule defining the modulus of the virtual impedance, the worst-case scenario must first be determined. Probably the most intuitive scenario is a hard short-circuit at the output of the inverter, which would cause the apparent grid voltage to be zero. However, as shown in Figure 2-8, the worst-case scenario is to inadvertently connect the inverter to the grid in phase opposition.

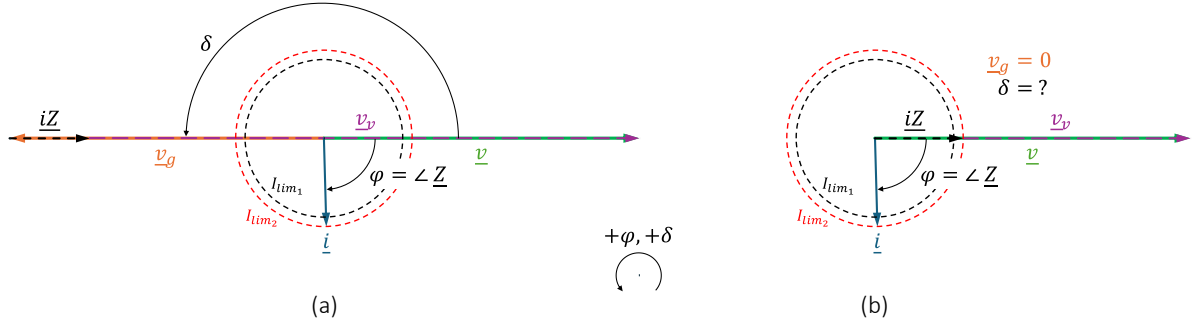


Figure 2-8: Phasor diagram of two fault conditions: (a) Inverter and grid in phase opposition, (b) Hard short-circuit at the output of the inverter, causing the apparent grid voltage to be zero.

In the case of a phase opposition, the virtual impedance voltage $\underline{v}_v$ must be much larger than in the case of a hard short-circuit to limit the current. Therefore, the phase opposition scenario is used as the worst case. Furthermore, considering that the inverter's virtual internal voltage reference can be as large as the grid voltage, plus the voltage drop across the filter, its maximum value will be considered as well.

$$\max\{|\underline{v}|\} = \max\{|\underline{v}_g|\} + \max\{|\underline{iZ}|\} \quad (2-10)$$

Kirchhoff's law tells us that

$$\underline{v} = \underline{v}_v + \underline{iZ} + \underline{v}_g \quad (2-11)$$

If the virtual internal voltage reference is at its maximum value and is in phase opposition with the grid voltage, then modulus of the maximum virtual impedance voltage is

$$\max\{|\underline{v}_v|\} = 2 \cdot \max\{|\underline{v}_g|\} = 2 \cdot v_{g_{max}} \quad (2-12)$$

Therefore, the modulus of the virtual impedance voltage is defined at two points: When the modulus of the current $|\underline{i}|$ is smaller than I_{lim1} , the virtual impedance voltage is equal to zero, and when it is equal to the upper current threshold I_{lim2} , the modulus of the virtual impedance voltage should be twice the modulus of the maximum grid voltage. For ease of reading, we define Δi as the strictly positive current exceeding I_{lim1} , as well as its corresponding complex value, and Δi_{max} as the maximum excess, where:

$$\Delta i = |\underline{i}| - I_{lim1} \Rightarrow \Delta i \in \mathbb{R}^+ \quad (2-13)$$

$$\underline{\Delta i} = \Delta i \angle \underline{i} \quad (2-14)$$

and

$$\Delta i_{max} = I_{lim2} - I_{lim1} \quad (2-15)$$

Then, the two points are as follows:

$$\begin{aligned} |\underline{v}_v| &= 0, & \text{if } \Delta i &= 0 \\ |\underline{v}_v| &= 2 \cdot v_{g_{max}}, & \text{if } \Delta i &= \Delta i_{max} \end{aligned} \quad (2-16)$$



We choose to make the variation of the virtual impedance voltage between these two points proportional to the current as shown in Figure 2-9. The virtual impedance voltage is then expressed as the following.

$$\begin{cases} v_v = 0, & \text{if } \Delta i \leq 0 \\ v_v = \Delta i \cdot \frac{2 \cdot v_{g_{max}}}{\Delta i_{max}} \angle iZ, & \text{if } \Delta i > 0 \end{cases} \quad (2-17)$$

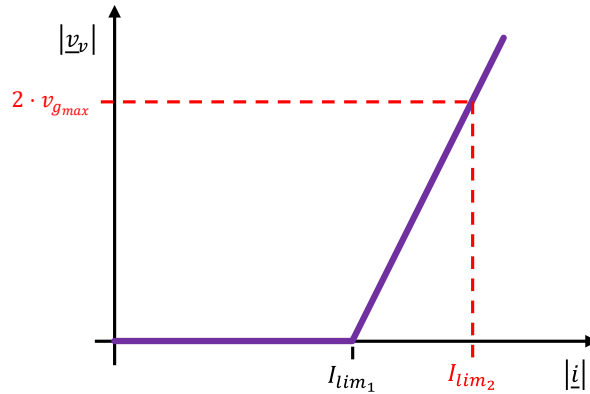


Figure 2-9: Variation of the modulus of the virtual impedance voltage as a function of the modulus of the current.

Because we defined in equation (2-14) that $\underline{\Delta i}$ and $\underline{i}$ have the same argument, then the virtual impedance can be deduced from equation (2-17) as:

$$\underline{z}_v = \frac{2 \cdot v_{g_{max}}}{\Delta i_{max}} \angle \underline{Z} \quad (2-18)$$

Figure 2-10 shows the application principle of the current threshold virtual impedance, where v is the voltage reference from the droop control, i_{L_2} is the grid side inductance current and v_{ref} is the voltage reference sent to the PWM modulator.

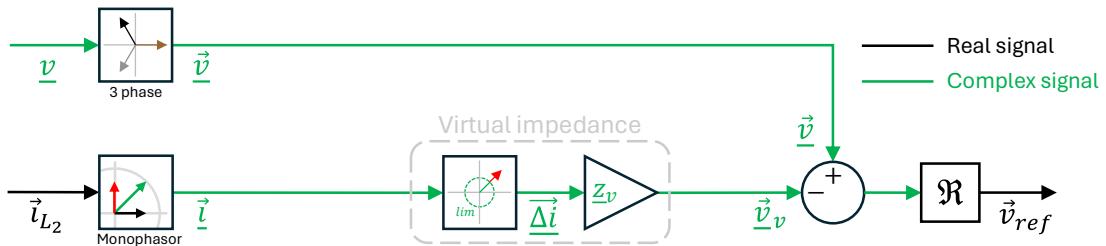


Figure 2-10: Current threshold virtual impedance application principle.



2.2.3. Stability issue with current threshold virtual impedance

Current threshold virtual impedance has been said to be notoriously difficult to tune [4], and for good reasons. As demonstrated in the previous section, the optimal argument for the virtual impedance is the same as the filter impedance (equation (2-9)). Since ideally the filter impedance is perfectly inductive with no resistance, both the filter impedance and the virtual impedance should be fully imaginary and their argument is 90° . Multiplying by the measured current results in a phase advance of 90° , which is equivalent to a derivative. The issue is that applying a derivative amplifies noise and reduces the stability of a system. In practice, a fully imaginary virtual impedance causes the system to be unstable. Additionally, because the calculation of monophasors introduces non-linearities, and notably time dependant non-linearities, small signal stability analysis cannot be done. Nevertheless, simulations can be done to demonstrate the stability or instability of the system in different configurations.

Figure 2-11 shows the schematic of a PLECS simulation, where a grid forming inverter, with the virtual impedance is implemented as shown in Figure 2-10, supplies a three-phase resistive load (0.5 pu), through a line. A second line offers the possibility to connect the system to a stiff grid.

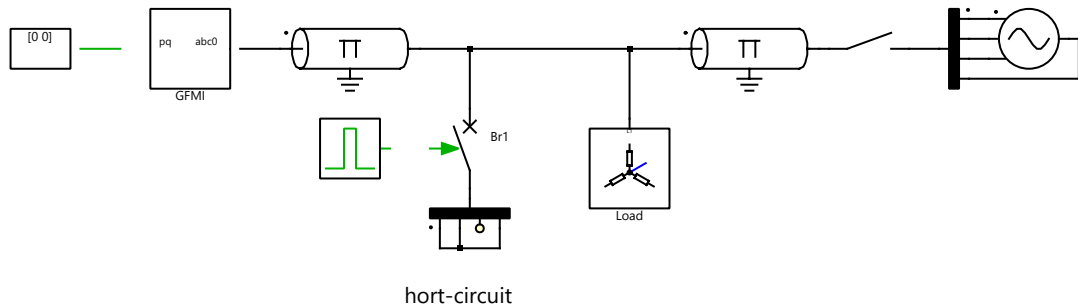


Figure 2-11: PLECS simulation schematic with one GFM in standalone or in grid connected, with a load and a two phase plus neutral short-circuit. Pi section lines simulate the cables.

In the simulation, two scenarios are done:

1. In the first, the grid forming inverter is in stand-alone and supplies the load.
2. In the second, the system is connected to a stiff grid, and the load is shared between the inverter and the grid.

In both cases, once the system is in steady state, a two phase to neutral hard short-circuit is done in parallel with the load (at 0.15 seconds, lasting 0.1 seconds). For ease of reading, the voltages and currents shown in the following figures are normalized to their nominal peak values (for the peaks to be at 1 pu when the values are nominal).

Figure 2-12 shows the simulation results for the voltages and currents at the output of the inverter, for the first scenario, where the inverter is in stand-alone, and the inverter's virtual impedance is fully inductive. As shown, when the short-circuit occurs, the system becomes unstable and diverges immediately, resulting in a massive overcurrent. Furthermore, then the short-circuit stops (at 0.25 seconds), the system remains unstable and keeps diverging.

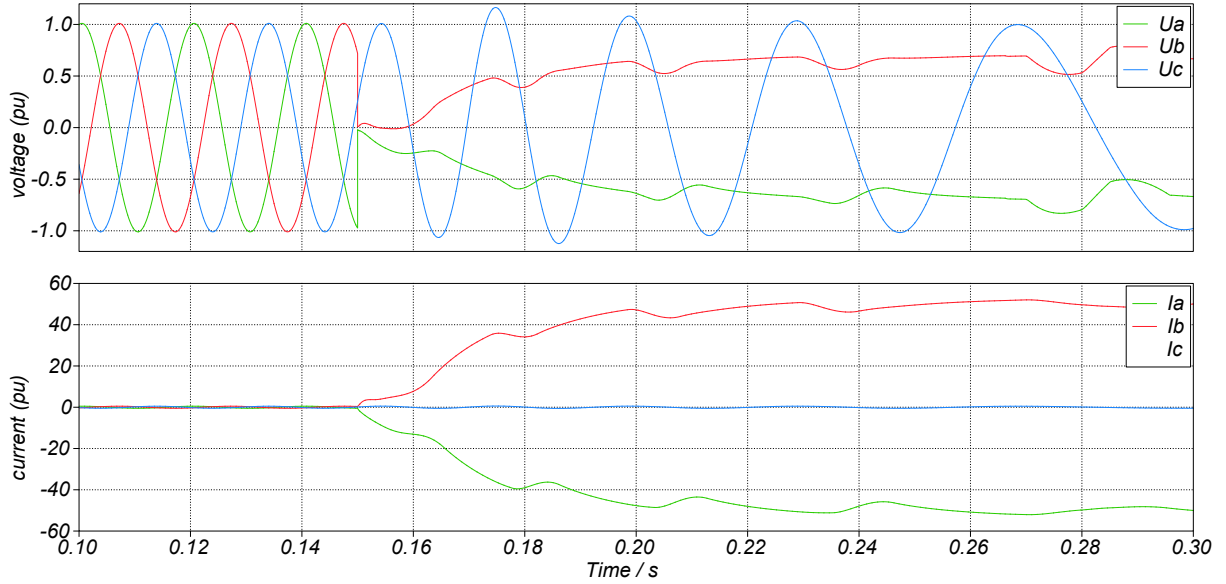


Figure 2-12: Simulation results of the GFMI in stand-alone, with a fully inductive virtual impedance, where a hard short-circuit between two phases and the neutral occurs at 0.15 seconds and lasts 0.1 seconds.

Because the system is unstable in stand-alone, there is no point in showing the result of the grid-connected simulation, because it is also unstable.

However, if the virtual impedance is fully resistive, the result is very different. As shown in Figure 2-13, performing the same simulation as previously, but with a resistive virtual impedance, the result is a stable system that keeps the current under control.

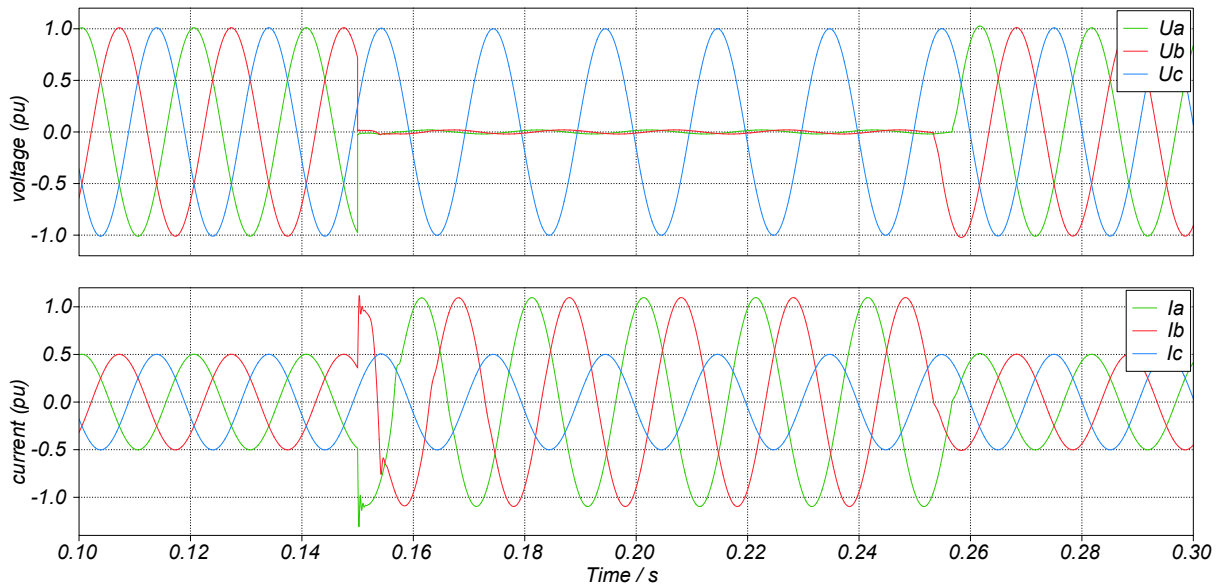


Figure 2-13: Simulation of the GFMI in stand-alone, with a fully resistive virtual impedance, where a hard short-circuit between two phases and the neutral occurs at 0.15 seconds and lasts 0.1 seconds.

Following this, the same simulation is performed but connected to the stiff grid. As shown in Figure 2-14, this also results in a stable system. However, the resolution of the short-circuit and return to steady state



is a bit longer. Furthermore, during the short-circuit, there is an overvoltage on phase C that is caused by the current flowing through the neutral line during the fault.

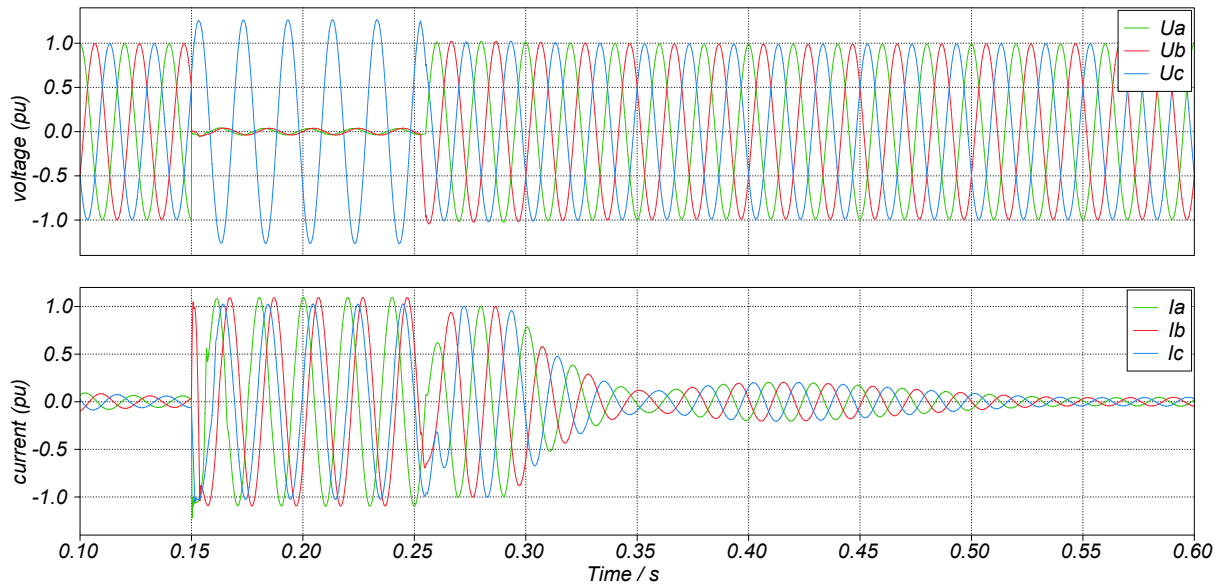


Figure 2-14: Simulation of the GFMI connected to a stiff grid, with a fully resistive virtual impedance, where a hard short-circuit between two phases and the neutral occurs at 0.15 seconds and lasts 0.1 seconds.

As shown above, a resistive virtual impedance results in a stable system and limits effectively the current in case of a fault. Then what is the issue with a resistive virtual impedance? The issue becomes more apparent when two GFMI's share a load and one becomes overloaded. Figure 2-15 shows a simulation setup where the shared load is not sufficient to overload the combined capability of the inverters if they share equally the load (load active power = 1.8 pu, reactive power = 0 pu).

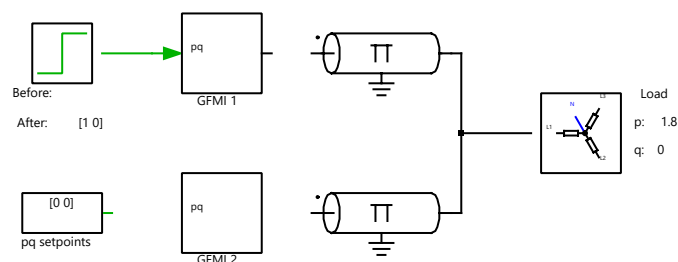


Figure 2-15: Simulation schematic where two GFMI's with resistive virtual impedances share a load and one GFMI becomes overloaded.

In this setup, once the system reaches steady state and both GFMI's are providing 0.9 pu of active power, the active power setpoint of GFMI 1 is set from 0 to 1 pu (at 0.1s). This causes it to try to take a larger load. However, the inverter's load quickly reaches its maximum limit. When its current reaches 1 pu, the virtual impedance kicks in to limit the current, causing a dip in the voltage as shown in Figure 2-16.

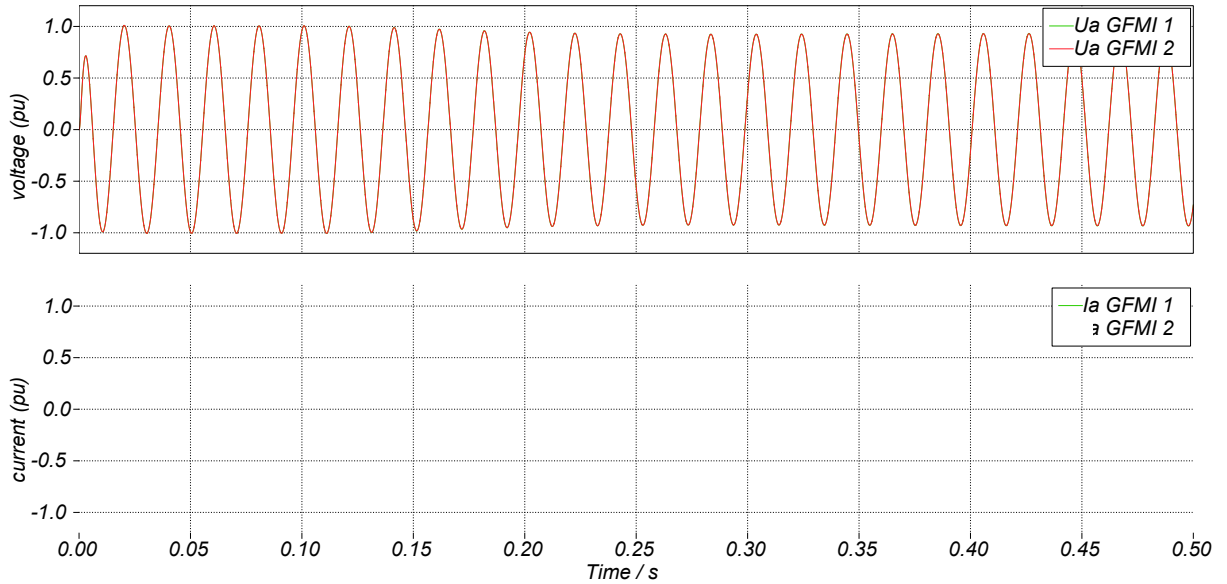


Figure 2-16: Voltages and currents of the first phase of GFMI 1 and 2, where at 0.1 seconds inverter 1 tries to take a larger load and becomes overloaded.

The direct consequence of the voltage dip caused by the resistive virtual impedance is that GFMI 1 starts absorbing reactive power and GFMI 2 provides the same to balance the demand (Figure 2-17).

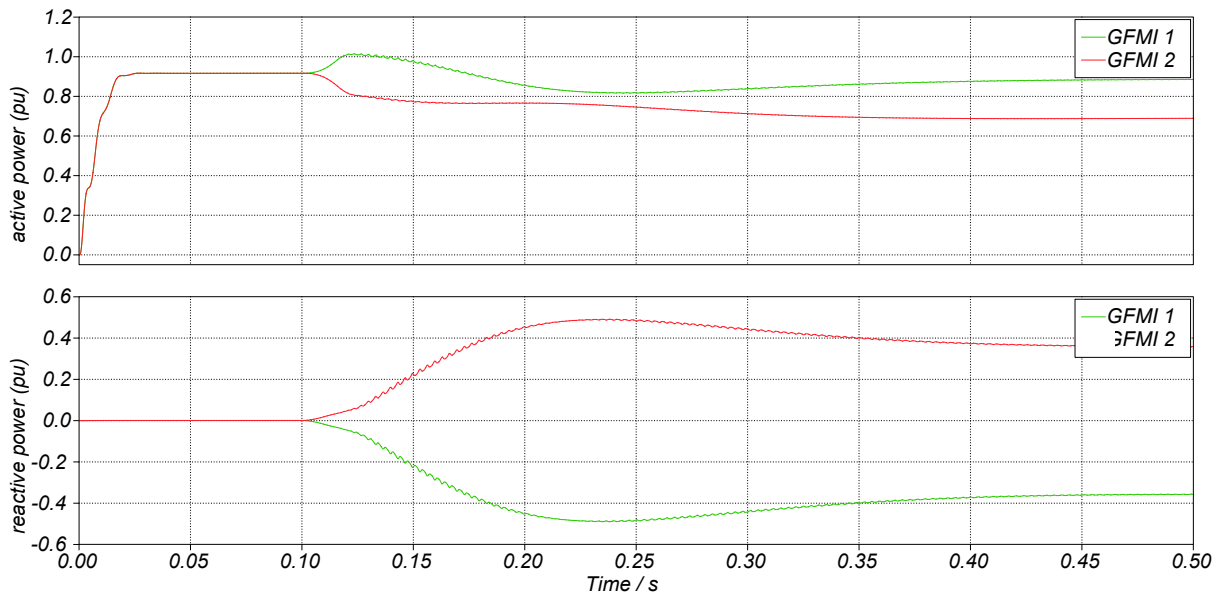


Figure 2-17: Active and reactive powers of GFMI 1 and 2, where the resistive virtual impedance causes the overload of GFMI 1 to start absorbing reactive power.

This demonstrates the problem with resistive virtual impedance. In fact, resistive virtual impedance actively reduces the total available active power by causing an unnecessary exchange of reactive power between the inverters. Therefore, it is necessary to have a solution that allows us to have an inductive behaviour, without the induced instability. This can be done through voltage threshold virtual impedance.



2.2.4. Voltage threshold virtual impedance

The principle of voltage threshold virtual impedance is to observe the cause of the current and react to what will cause an overcurrent. A voltage drop is also applied in series with the virtual internal voltage reference $\underline{v}$. Figure 2-18 shows a single-phase schematic of a GFMI with a virtual impedance $\underline{z}_v$ and an LCL output filter, that is connected to a grid that has an impedance $\underline{z}_g$. The reference voltage $\underline{v}$ is the voltage provided by the droop control.

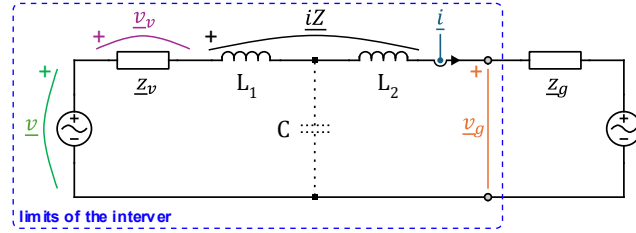


Figure 2-18: Single-phase schematic of a GFMI with a virtual impedance.

As for the current threshold virtual impedance, the effect of the filter capacitor as well as the inductance resistances are negligible for the analysis of the circuit. Therefore, as a simplification, their effect is neglected. The impedance of the filter is approximated as expressed in equation (2-8).

In the following figure (Figure 2-19), the phasor diagram shows the different voltages and current at play in the circuit. The same two situations as in section 2.2.2 are illustrated: the first (a) is a normal functioning situation, whereas the second (b) is a fault situation, where the voltage amplitude has dropped dramatically. The dashed circle represents the maximum voltage limit across the filter.

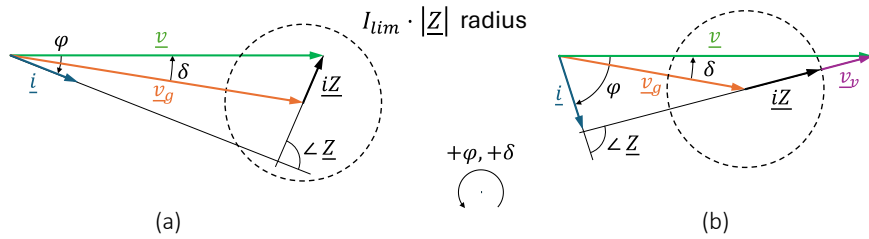


Figure 2-19: Phasor diagram with (a) pre-fault normal condition, where the current is below the maximum threshold, and (b) fault condition, where the voltage drop across the filter is limited to a predefined threshold.

Kirchhoff's law tells us that

$$\underline{v} = \underline{v}_v + \underline{iZ} + \underline{v}_g \quad (2-19)$$

The inverter's virtual internal voltage reference ($\underline{v}$) is known, and grid voltage ($\underline{v}_g$) is measured. We define the voltage difference between these two as $\underline{\Delta v}$.

$$\underline{\Delta v} = \underline{v} - \underline{v}_g = \underline{v}_v + \underline{iZ} \quad (2-20)$$

Because the goal of $\underline{v}_v$ is substitute part of $\underline{iZ}$, the most effective way to do this is for $\underline{v}_v$ and $\underline{iZ}$ to be colinear.

$$\angle \underline{v}_v = \angle \underline{iZ} = \angle \underline{\Delta v} \quad (2-21)$$



Since the maximum acceptable current (I_{lim}) is defined and the filter impedance ($\underline{Z}$) is also known, we can define the maximum voltage amplitude across the filter as

$$v_{z_{max}} = I_{lim} \cdot |\underline{Z}| \quad (2-22)$$

Therefore, for the voltage across the filter to be equal or smaller than the maximum threshold ($|\underline{iz}| \leq v_{z_{max}}$), the virtual impedance voltage $\underline{v}_v$ is the following.

$$\underline{v}_v = \begin{cases} 0, & \text{if } |\underline{\Delta v}| \leq v_{z_{max}} \\ (|\underline{\Delta v}| - v_{z_{max}}) \angle \underline{\Delta v}, & \text{if } |\underline{\Delta v}| > v_{z_{max}} \end{cases} \quad (2-23)$$

Because the virtual impedance voltage adapts to limit the voltage drop across the filter, there is no need to define the worst-case scenario as for the current threshold virtual impedance.

Figure 2-20 shows the application principle of the voltage threshold virtual impedance, where v is the voltage reference from the droop control, v_g is the grid side voltage and v_{ref} is the voltage reference sent to the PWM modulator.

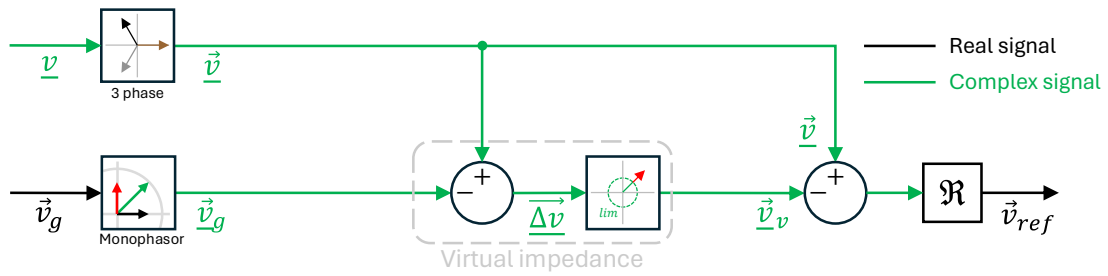


Figure 2-20: Voltage threshold virtual impedance application principle.



2.2.5. Limitations of voltage threshold virtual impedance

A solution that is so much simpler has limitations. The first limitation is that the virtual impedance can only have the same argument as the inverter's output filter $\underline{Z}$. As it will be demonstrated hereafter through simulation, being able to change it slightly can be desirable to increase damping during transients. The second limitation, or rather condition, is that the voltage measurements must be sufficiently precise because the maximum voltage across the filter $v_{Z_{max}}$ is in the order of 10% or less of their full scale.

To test the effectiveness of the voltage threshold virtual impedance the same simulation setup (shown hereafter) as for the current threshold virtual impedance (Figure 2-11) is used.

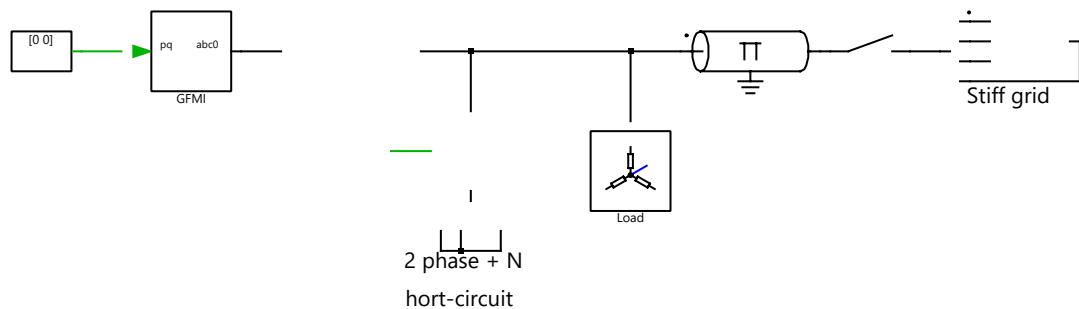


Figure 2-21: PLECS simulation schematic with one GFMI in standalone or in grid connected, with a load and a two phase plus neutral short-circuit. Pi section lines simulate the cables.

In the simulation, two scenarios are done:

1. In the first, the grid forming inverter is in stand-alone and supplies the load.
2. In the second, the system is connected to a stiff grid, and the load is shared between the inverter and the grid.

In both cases, once the system is in steady state, a two phase to neutral hard short-circuit is done in parallel with the load (at 0.15 seconds, lasting 0.1 seconds). Again, for ease of reading, the voltages and currents shown in the following figures are normalized to their nominal peak values (for the peaks to be at 1 pu when the values are nominal).

Figure 2-22 shows the simulation results for the voltages and currents at the output of the inverter, for the first scenario, where the inverter is in stand-alone.

As shown, the result is stable and the current is quickly limited to 1 pu. However, there is a transient that is characteristic of an inductive behaviour. This should not come as a surprise, since the virtual impedance now behaves as an inductor. The problem is, because of the asymmetry of the transient, the peak current is more than 1.5 pu, which could be unacceptable for the hardware.

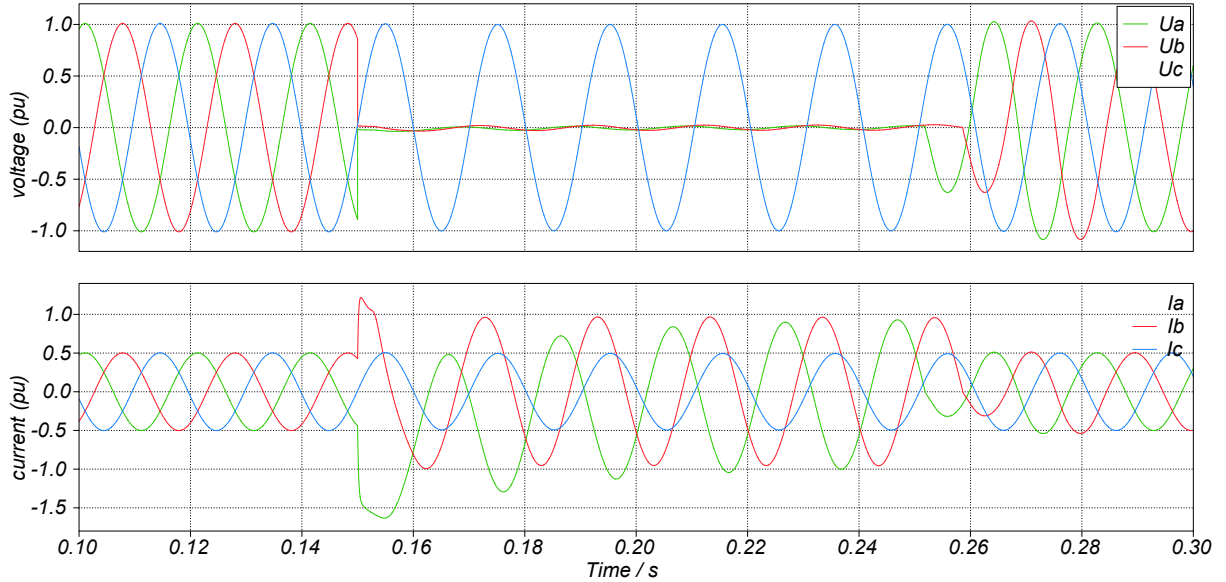


Figure 2-22: Simulation results of the GFMI in stand-alone, with a voltage threshold virtual impedance, where a hard short-circuit between two phases and the neutral occurs at 0.15 seconds and lasts 0.1 seconds.

Performing the same simulation, but connected to a stiff grid, also results in a stable system (Figure 2-23). Likewise, the asymmetrical transient is also clearly apparent.

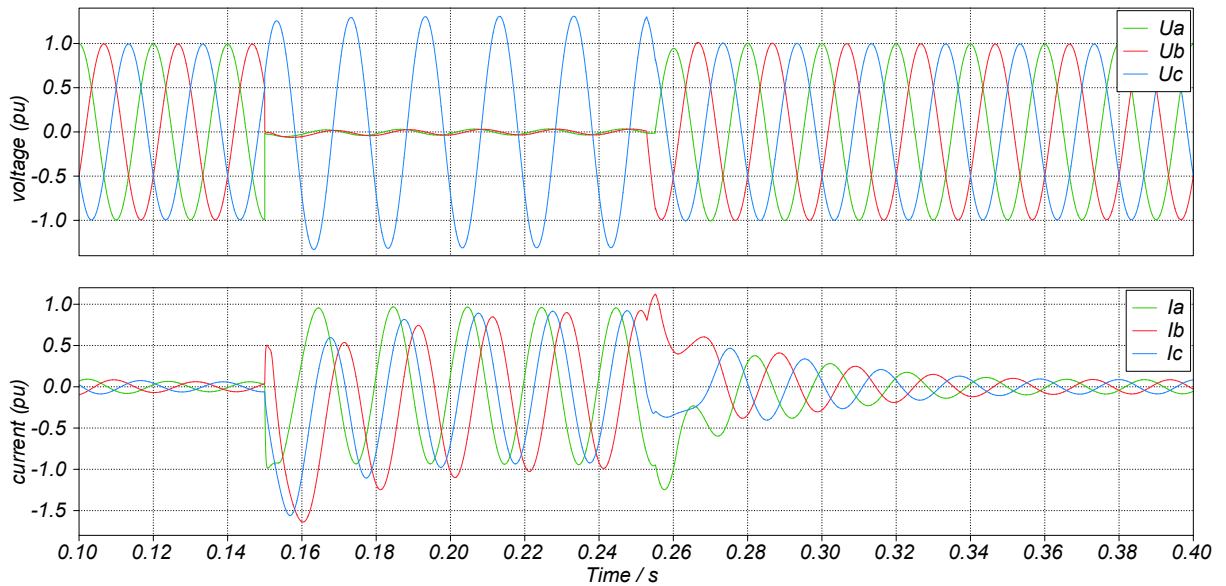


Figure 2-23: Simulation results of the GFMI connected to a stiff grid, with a voltage threshold virtual impedance, where a hard short-circuit between two phases and the neutral occurs at 0.15 seconds and lasts 0.1 seconds.

Because of the characteristic inductive asymmetrical transient, a resistive component would be desirable during the transient. Therefore, a combination of current threshold virtual impedance and voltage threshold virtual impedance is necessary, respectively for a resistive part to limit the initial transient overshoot, and an inductive part to limit effectively the inverter's current without becoming a reactive power sink.



2.2.6. Combination of current and voltage threshold virtual impedance

As shown in the previous sections, ideally, the virtual impedance should be perfectly inductive. However, to damp the asymmetry of the initial transient, some resistive behaviour is necessary. Current threshold virtual impedance is not stable if the virtual impedance is too inductive. Furthermore, due to the non-linear nature of the system, the limit at which it becomes unstable is difficult to define. Nevertheless, current threshold virtual impedance is stable if the virtual impedance is fully resistive. Additionally, we demonstrated in the previous section that the voltage threshold virtual impedance can provide a stable inductive response. Therefore, combining both techniques allows us to manage separately the resistive and inductive behaviour of the virtual impedance. As we want the inductive behaviour to be predominant, the threshold of the voltage threshold virtual impedance must be set slightly lower than current one. Figure 2-24 shows the bloc diagram of the combination of the two.

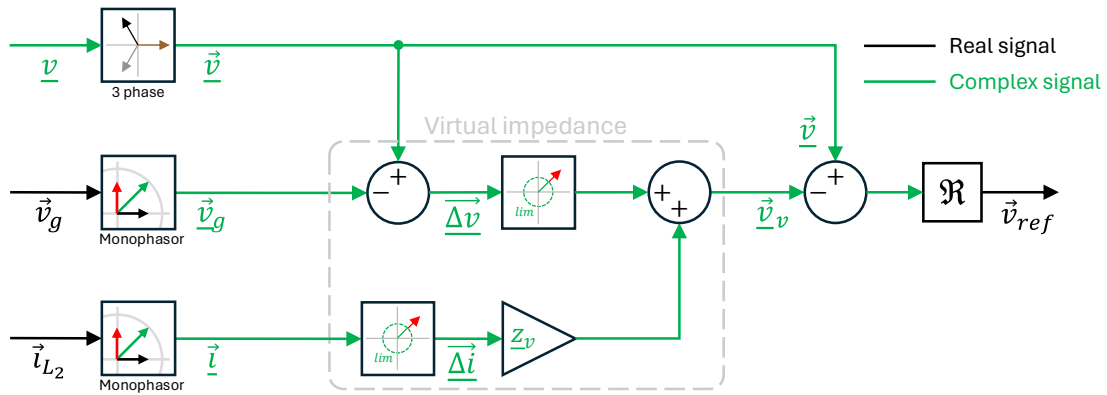


Figure 2-24: Combined voltage and current threshold virtual impedance application principle.

To test the effectiveness of the combination of the two threshold virtual impedance techniques, the same simulation setup as for the current and voltage threshold virtual impedances is used.

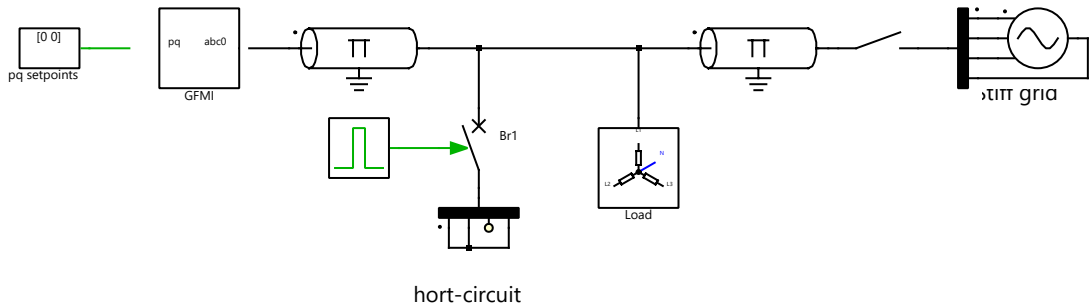


Figure 2-25: PLECS simulation schematic with one GFMI in standalone or in grid connected, with a load and a two phase plus neutral short-circuit. Pi section lines simulate the cables.

In the simulation, two scenarios are done:

1. In the first, the grid forming inverter is in stand-alone and supplies the load.
2. In the second, the system is connected to a stiff grid, and the load is shared between the inverter and the grid.

In both cases, once the system is in steady state, a two phase to neutral hard short-circuit is done in parallel with the load (at 0.15 seconds, lasting 0.1 seconds). Again, for ease of reading, the voltages and currents shown in the following figures are normalized to their nominal peak values (for the peaks



to be at 1 pu when the values are nominal). Figure 2-26 shows the simulation results for the voltages and currents at the output of the inverter, for the first scenario, where the inverter is in stand-alone.

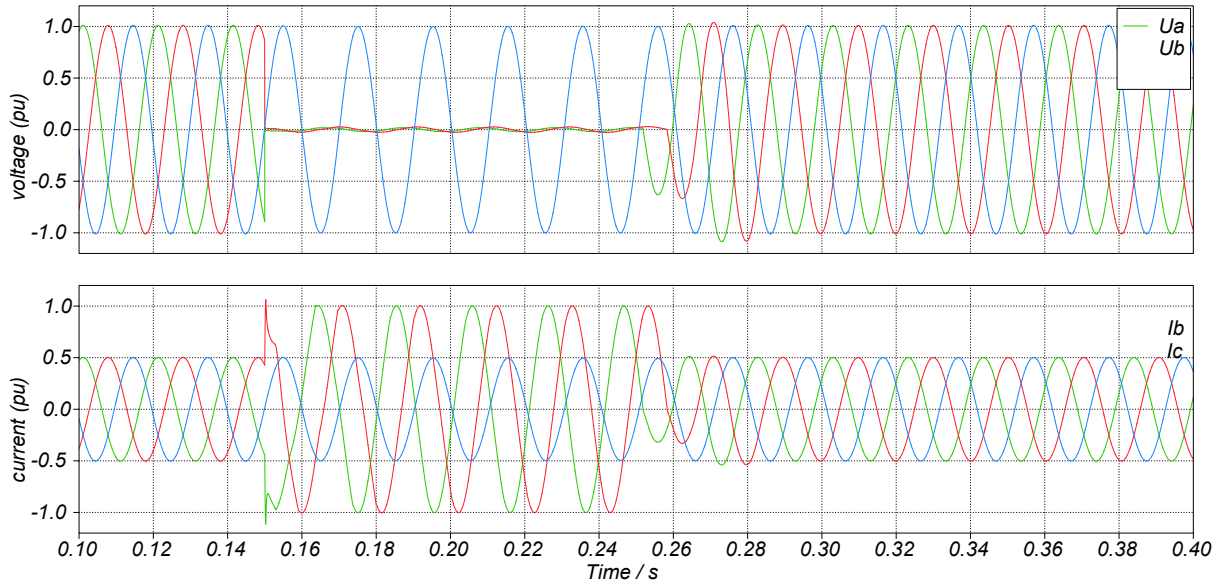


Figure 2-26: Simulation results of the GFMI in stand-alone, with the combined voltage and current threshold virtual impedances, where a hard short-circuit between two phases and the neutral occurs at 0.15 seconds and lasts 0.1 seconds.

As shown in Figure 2-25, the result is stable in standalone and no major overshoot occurs. Performing the same simulation, but connected to a stiff grid, also results in a stable system (Figure 2-27).

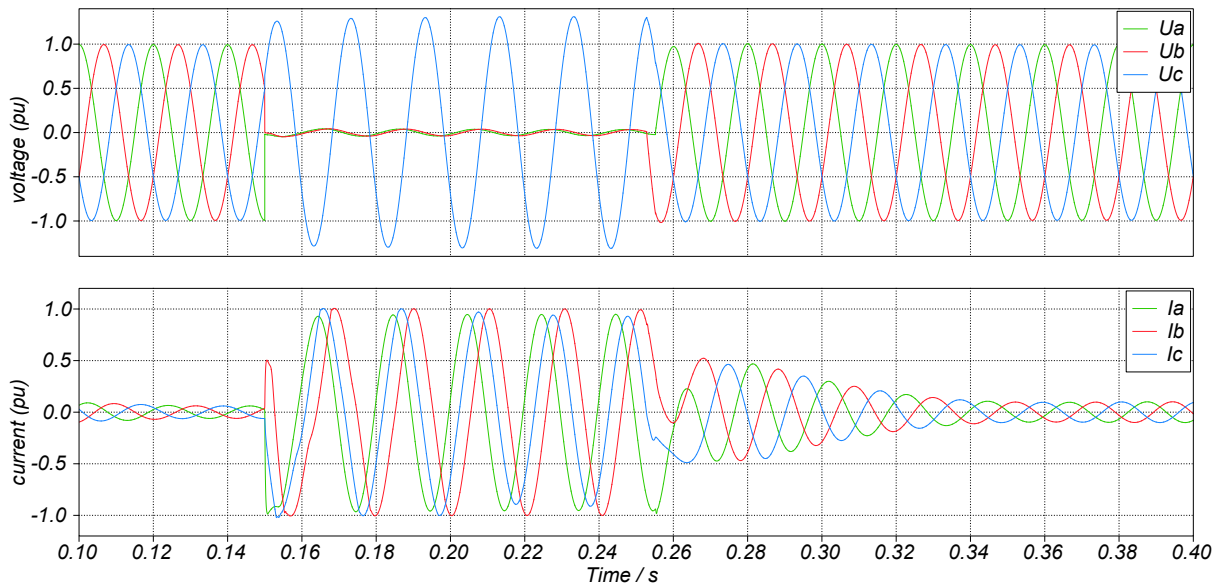


Figure 2-27: Simulation results of the GFMI connected to a stiff grid, with the combined voltage and current threshold virtual impedance, where a hard short-circuit between two phases and the neutral occurs at 0.15 seconds and lasts 0.1 seconds.

Again, the result is stable and no overshoot occurs. The combination is therefore a good compromise.



2.3 Filter resonance damping

When a fault or an overload occurs, the transient can easily excite the resonant frequency of the LCL filter. To avoid this from happening, a damper is added to the control scheme. The damper acts as a virtual resistance in series with the filter capacitor.

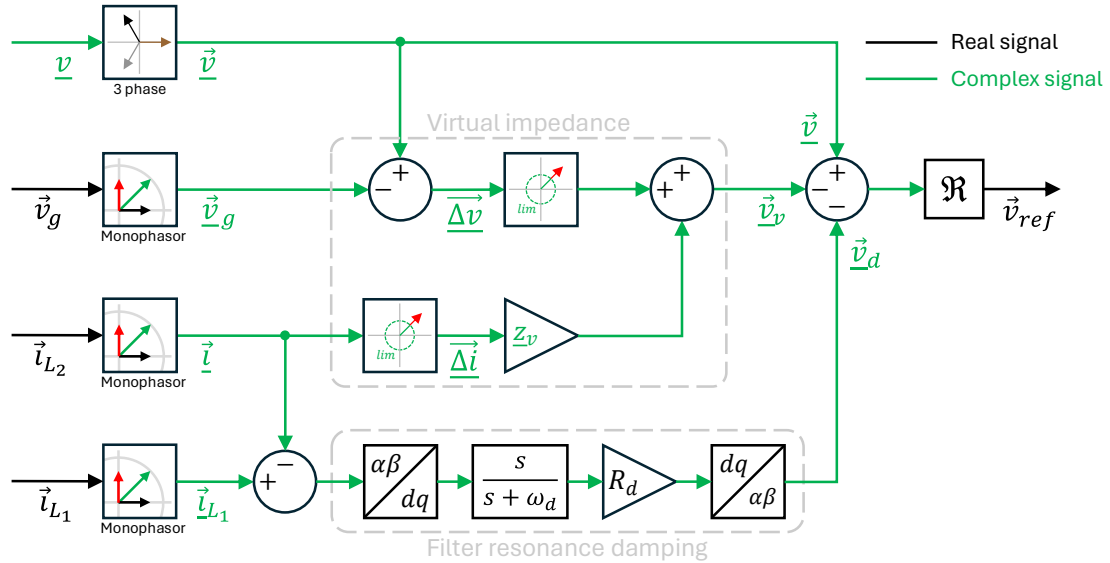


Figure 2-28: Virtual impedance application principle with resonance damping.

The way this damper is implemented, is by calculating the capacitor current by subtracting the filter's output current to its input current. The capacitor current is then passed into a rotating reference frame so that the component of the current that is at the grid frequency appears as a constant. In order not to filter out the effect of the capacitor but only higher frequencies, a high pass filter is then applied before multiplying by the damping resistance. The result is then passed back to the fixed reference frame before being subtracted from the reference voltage.

The cutoff frequency ω_d of the high pass filter must be placed adequately so it does not damp normal functioning of the inverter nor allow resonance to occur. Choosing $\omega_d = \omega_n$ gives satisfying results.

Finally, the damping resistance must be chosen as well. Again, if it is chosen too small, it does not have sufficient effect and it is too large it amplifies noise. Choosing a value between 2 and 5 pu gives good results.



3 Staying synchronous during an overload

During a fault, any accurate measurement of the load is lost because it is masked by the short-circuit. Consequently, the calculated active and reactive powers do not reflect the real demand, and the inverter will quickly deviate in voltage and frequency. To avoid losing synchronization, the solution is to observe the load angle between the internal voltage reference and the grid voltage, and apply virtual power to the droop control to remain synchronous.

3.1 Observing the load angle

In a three-phased unbalanced system, there are potentially three different load angles: one for each phase. A practical tool to observe unbalanced systems is the symmetrical components transformation, which decomposes the three phased system into three phasors. These are the positive, the negative and the zero sequences. The positive sequence is the one that is of interest because its phase and amplitude will follow the average phase and amplitude of the three phased system. Furthermore, the positive sequence's phase is a weighted average that is proportional to the amplitude of each phase. Therefore, in case of a voltage drop on one or two phases, their contribution decreases proportionally, avoiding inaccurate readings. The positive sequence of the grid voltage $\underline{v}_{g1}$ is given by the following:

$$\underline{v}_{g1} = \frac{1}{3} \cdot \begin{bmatrix} 1 & \alpha & \alpha^2 \end{bmatrix} \cdot \begin{bmatrix} \underline{v}_{ga} \\ \underline{v}_{gb} \\ \underline{v}_{gc} \end{bmatrix} \quad (3-1)$$

$$\underline{\alpha} = e^{j\frac{2\pi}{3}} \quad (3-2)$$

where $\underline{v}_{ga}$, $\underline{v}_{gb}$, $\underline{v}_{gc}$ are the complex phasors of the three grid voltages. The observed load angle δ_{obs} is the difference between the phase of the internal voltage reference $\underline{v}$ and the phase of the positive sequence of the grid voltage $\underline{v}_{g1}$.

$$\delta_{obs} = \angle \underline{v} - \angle \underline{v}_{g1} \quad (3-3)$$

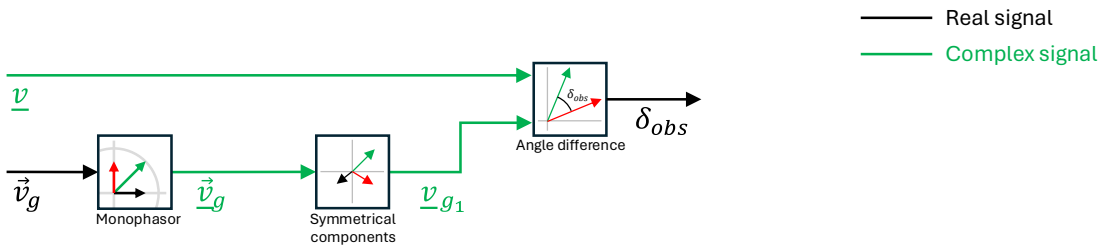


Figure 3-1: Observation of the load angle by comparing the positive sequence of the grid voltage to the internal voltage reference.



3.2 Virtual power

Using the observed load angle, the virtual active power can be calculated based on active power equation detailed in “Appendix 1: Control design of GFMLs”. Equation (3-4) gives the active power equation.

$$P = \frac{3 \cdot U_g \cdot U_i \cdot \sin(\delta)}{X_L} \cong \frac{3 \cdot U_n^2 \cdot \delta_{obs}}{\omega_n (L_1 + L_2)} \quad (3-4)$$

If we rewrite the approximated active power in per units and consider the nominal voltage for the virtual power as equal to 1 pu, then the virtual power p_{vpu} is:

$$p_{vpu} = \frac{\delta_{obs}}{L_{1pu} + L_{2pu}} \quad (3-5)$$

3.3 Application of the virtual power in the control loop

The application of the virtual active power must be done only in case of an overload. Therefore, an action is only performed when the virtual power is higher than 1 pu. Furthermore, a gain K_v is added to increase the effect of the virtual power when active. Figure 3-2 and Figure 3-3 show the full application of the virtual power to the active power droop control loop.

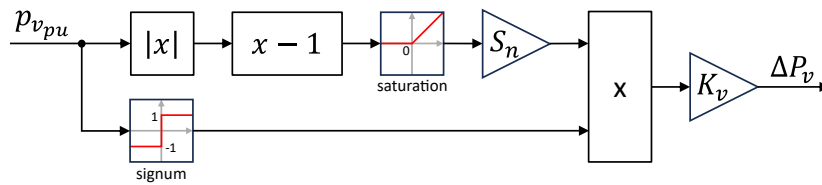


Figure 3-2: Calculation of the virtual power to be applied to the active power droop control loop.

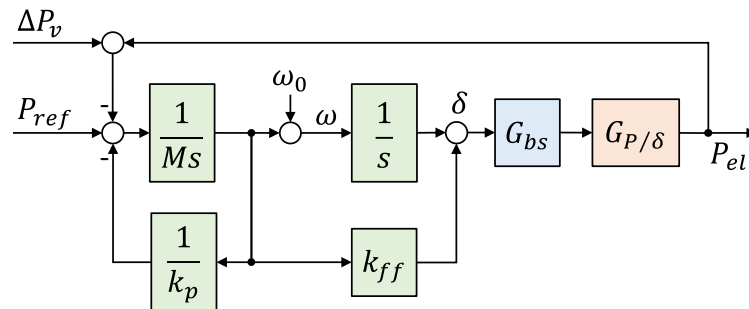


Figure 3-3: Application of the virtual power to the active power droop control loop.



4 Conclusion

As shown in this report, protecting a voltage source inverter is possible by implementing a virtual impedance in series with the inverter. This virtual impedance can effectively limit the current to the maximum acceptable current of the inverter while helping the circuit breakers to isolate a fault. Nevertheless, because inverters are limited to their nominal current, the short-circuit current will be much lower for isolated community microgrids. Therefore, the sizing of the circuit breakers is key.

5 References

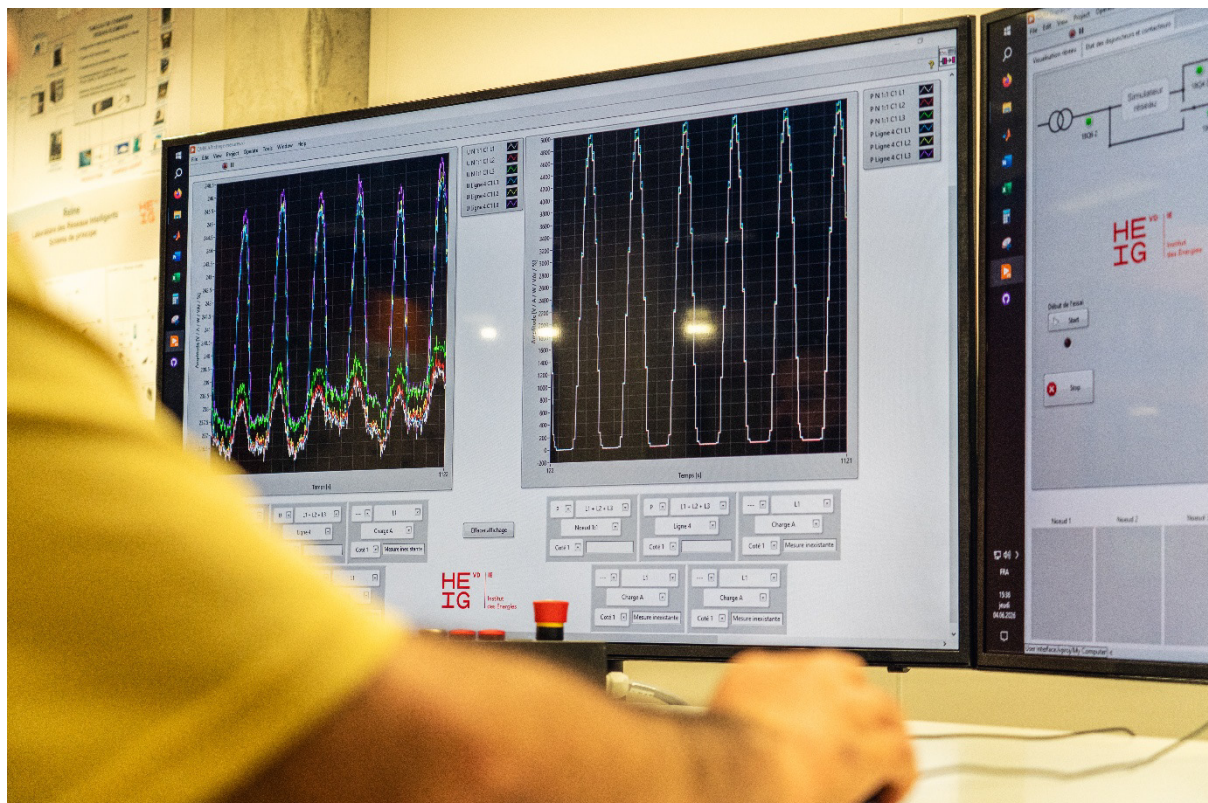
- [1] IEC 60898-1 - Electrical accessories - Circuit-breakers for overcurrent protection for household and similar installations - Part 1: Circuit-breakers for a.c. operation, 2019.
- [2] IEC 60947-2 - Low-voltage switchgear and controlgear - Part 2: Circuit Breakers, 2024.
- [3] 'Manuel Technique - Principes de protection'. :hager.
- [4] X. He, M. A. Desai, L. Huang, and F. Dörfler, 'Cross-Forming Control and Fault Current Limiting for Grid-Forming Inverters', IEEE Trans. Power Electron., vol. 40, no. 3, pp. 3980–4007, Mar. 2025, doi: 10.1109/TPEL.2024.3500885.



Final report from 1 July 2026

FORMIDABLE

Appendix 4: Assessment of the Benefits and Risks of Grid-Forming Inverters in Community Microgrids



Source: HEIG-VD/IE 2026



Publisher:

Swiss Federal Office of Energy SFOE
Energy Research and Cleantech
CH-3003 Berne
www.energy-research.ch

Co-financing:

Imperix SA
CH-1950 Sion
www.imperix.com

Subsidy recipients:

HEIG-VD
CH-1400 Yverdon-les-Bains
www.heig-vd.ch

Authors:

Dr Philippe Morey, HEIG-VD, philippe.morey@heig-vd.ch
Dr Mohammad Rayati, HEIG-VD, mohammad.rayati@heig-vd.ch
Prof. Dr Mokhtar Bozorg, HEIG-VD, mohktar.bozorg@heig-vd.ch
Prof. Dr Mauro Carpita, HEIG-VD, mauro.carpita@heig-vd.ch

SFOE project coordinators:

Dr Michael Moser, michael.moser@bfe.admin.ch

SFOE contract number: SI/502668-1

The authors bear the entire responsibility for the content of this report and for the conclusions drawn therefrom.



Contents

Contents	3
List of abbreviations	5
1 Introduction.....	6
1.1 Simulation tools	6
1.2 Simulations for Performance Evaluation of a Community Microgrid	7
1.2.1. Reliability	7
1.2.2. Resiliency	8
1.2.3. Grid restoration	9
1.2.4. Ancillary services	9
1.3 Technical and Operational Risks.....	10
1.3.1. Control interactions.....	10
1.3.2. Protection coordination	11
2 QSTS and Black-Start Simulations.....	11
3 Study Scope and Simulation Setup.....	13
3.1 Network Model.....	13
3.2 DER composition (PV, storage, grid-following and grid-forming).....	13
3.3 Control Strategies (Droop and VSM).....	14
4 Simulation Campaign.....	16
4.1 Events and Disturbances.....	16
4.2 Configuration Space	16
4.3 Operating Scenarios.....	17
4.4 Implementation and Scalability	17
5 Results: System Behaviour	18
5.1 Frequency Stability Across Configurations.....	19
5.2 Voltage Regulation and Power Sharing	19
5.3 Maximum Loading Capacity and System Limits.....	20
5.3.1. Load shedding and configuration sensitivity	20
5.3.2. Reliability Correlation (SAIFI/SAIDI).....	24
6 Synthesis: Benefits and Risks of GFMs.....	26
6.1 Benefits.....	26
6.1.1. Improved islanding capability	26
6.1.2. Higher loading capacity	26
6.1.3. Superior voltage and frequency control	26
6.1.4. Fault ride-through support	26



6.2	Risks and Limitations.....	26
6.2.1.	Instability Under Low Penetration.....	26
6.2.2.	Sensitivity to control parameters (droop, inertia).....	26
6.2.3.	Coordination issues between grid-forming types	27
6.2.4.	Complexity of control implementation.....	27
6.3	Key Insights for Microgrid Design.....	27
7	References	28



List of abbreviations

GFLI	Grid-Following Inverter
GFMI	Grid-Forming Inverter
RMS	Root Mean Square
EMT	Electromagnetic Transient
QSTS	Quasi-Static Time-Series
PCC	Point of Common Coupling
VSM	Virtual Synchronous Machine
LV	Low Voltage
DSL	DlgSILENT Simulation Language
SFOE	Swiss Federal Office of Energy
SAIFI	System Average Interruption Frequency Index
SAIDI	System Average Interruption Duration Index
ROZ	Resilient Operation Zone
FCR	Frequency Containment Reserve
aFRR	Automatic Frequency Restoration Reserve
mFRR	Manual Frequency Restoration Reserve
RR	Replacement Reserve
PLL	Phase-Locked Loop
DER	Distributed Energy Resource
PV	Photovoltaic
BESS	Battery Energy Storage System
RoCoF	Rate of Change of Frequency



1 Introduction

The objective of this study is to assess the most relevant benefits and risks of grid-forming inverters (GFMI) in a community microgrid. In this regard, a methodology is proposed relying on detailed simulations of a distribution network in grid-connected and islanded operation modes.

1.1 Simulation tools

Both open-source and commercial tools are adopted to cover different modelling requirements, levels of detail, and scalability. The analysis is conducted on a low-voltage (LV) distribution network under two operating conditions: grid-connected and islanded operation. Three software environments are used: PLECS, OpenDSS, and DlgSILENT PowerFactory.

PLECS supports detailed modelling of GFMI and enables both Root Mean Square (RMS)¹ and Electromagnetic Transient (EMT)² simulations. It is well suited for high-fidelity dynamic analysis and control validation. Its main limitation is scalability as simulations are restricted to systems with few numbers of nodes and a small number of GFMI. Simulation of large systems lead to long simulation times; therefore, the simulation of a real distribution network with heterogeneous GFMI and grid-following inverters (GFLI) is impractical. In other appendices, PLECS is mainly used for EMT simulations and experimental validation.

OpenDSS supports phasor-based, quasi-static time-series (QSTS)³ simulations. It offers high scalability, making it suitable for large distribution networks. It is open source⁴ and the Python Interfaces exist, but deep modelling of grid components generally requires scripting in the DSS language⁵. Another main challenge is that modelling a community microgrid in islanded operation is not straightforward. QSTS simulations do not inherently capture frequency dynamics, inertia, and swing equation. There are some efforts, e.g., [2] and [3], for extending the OpenDSS to include the swing equation but it is not available in open source. As a result, there is no ready-to-use solution for this type of simulation.

DlgSILENT PowerFactory provides both RMS and EMT simulation capabilities. It is widely used in industrial applications for large-scale power system studies. It is particularly suitable for analysing extensive networks. Despite its price, a key limitation is the implementation of custom control models, especially state-space representations of advanced GFMI control strategies, which require programming the DlgSILENT simulation language (DSL). However, the software includes built-in models for key grid-forming control approaches such as virtual synchronous machine (VSM) and droop-based control. It also supports Python-based scripting, which enables automated execution of multiple simulations with varying parameters or load scenarios. This feature is useful for performing Monte Carlo analyses.

¹ RMS simulations model electrical quantities such as voltages and currents as sinusoidal phasors (i.e., magnitude and phase) rather than instantaneous waveforms.

² EMT simulations model the instantaneous time-domain behaviour of electrical signals, voltage and current waveforms, by solving differential equations at very small steps (microseconds or less).

³ RMS simulations analyse short-term dynamic behaviour using phasors, while QSTS simulations track long-term, time-varying system performance by solving a sequence of steady-state power flows.

⁴ A brief comparison of widely used open-source software modules is presented in [1]. Based on this assessment, OpenDSS is selected among these open-source tools due to its mature architecture and comprehensive functionality.

⁵ DSS language is explained in <https://opendss.epri.com/BasicsoftheOpenDSSScriptingLangu.html>.



1.2 Simulations for Performance Evaluation of a Community Microgrid

A number of simulations are implemented to assess the performance of a community microgrid equipped with heterogeneous GFMI and GFLIs. These simulations address key dimensions, including reliability, resiliency, grid restoration capability, and the provision of ancillary services. It enables a systematic comparison of different GFMI penetration levels and their effects on operational security and economic performance. By defining consistent indicators and simulation scenarios, the simulations provide decision-relevant insights for stakeholders evaluating the deployment of GFMI in LV networks.

1.2.1. Reliability

The reliability of an LV network is quantified by metrics such as System Average Interruption Frequency Index (SAIFI) and System Average Interruption Duration Index (SAIDI). They can be measured for an electrical grid at different level of GFMI adoption.

SAIFI represents the average number of interruptions that a customer experiences over a given period, usually one year, and is defined as:

$$SAIFI = \frac{\sum_i \lambda_i N_i}{\sum_i N_i} \quad (1-1)$$

where λ_i is the failure rate at location i , and N_i is the number of customers affected.

SAIDI represents the average outage duration experienced by each customer over the same period and is defined as:

$$SAIDI = \frac{\sum_i U_i N_i}{\sum_i N_i} \quad (1-2)$$

where U_i is the outage duration at location i , and N_i is the number of customers affected.

In practice, SAIFI and SAIDI are computed in accordance with utility and regulatory standards, e.g., IEEE 1366, which define interruption thresholds, reporting rules, and treatment of major events.

From a system adequacy perspective, the objective is to verify if the available generation from PV systems and the available energy in storage systems are sufficient to meet demand over time. This condition can be expressed as a power balance equation.

$$P_{pv}(t) + P_{storage}(t) + P_{grid}(t) = P_{load}(t) + P_{unserved}(t), \quad \forall t \quad (1-3)$$

where $P_{pv}(t)$ and $P_{load}(t)$ are derived from measured profiles, and $P_{grid}(t) = 0$ in islanded operation. Deviations from this condition can be quantified through the unserved energy:

$$E_{unserved} = \sum_t P_{unserved}(t) \quad (1-4)$$

From a system security perspective, the objective is to ensure that operating conditions remain within technical limits under the given supply-demand balance. This is evaluated through detailed simulations of the grid following typical events. It is subject to network constraints:

$$V_{min} \leq V_i(t) \leq V_{max}, \forall i, t \quad (1-5)$$

$$f_{min} \leq f(t) \leq f_{max}, \forall t \quad (1-6)$$

The admissible limits depend on the operating mode and applicable standards. In grid-connected LV networks, voltage limits are typically defined according to EN50160, with V_{min} of 0.9 per unit and V_{max} of 1.1 per unit for 95% of the time over a week, and nominal frequency maintained within approximately



f_{min} of 49.8 Hz and f_{max} of 50.2Hz under normal European systems. In islanded operation, wider limits are generally acceptable.

These constraints ensure acceptable voltage profiles and frequency stability across the network. Both adequacy and security define the proportion of load that can be continuously supplied without violating operational limits at different levels of GFMI penetration.

Several simplifying assumptions are adopted in this study to reduce the complexity of the assessment. The analysis assumes that the only failure event is the disconnection of the community microgrid from the main grid at the point of common coupling (PCC) for a duration of 2 hours. Other types of failures are considered sufficiently rare and are therefore neglected. In addition, all GFMI and GFLI are assumed to remain operational throughout the simulations, meaning that inverter failures are not considered in quantification of reliability. Although these assumptions are not fully representative of real operating conditions, they allow the study to focus on the fundamental behaviour of the microgrid during islanded operation. The simulation analysis considers two complimentary dimensions: *system adequacy* and *system security*.

1.2.2. Resiliency

While reliability evaluates the grid's capability to provide continuous service under normal conditions, resiliency characterizes the grid's ability to withstand and recover from extreme or unexpected events, such as faults or islanding.

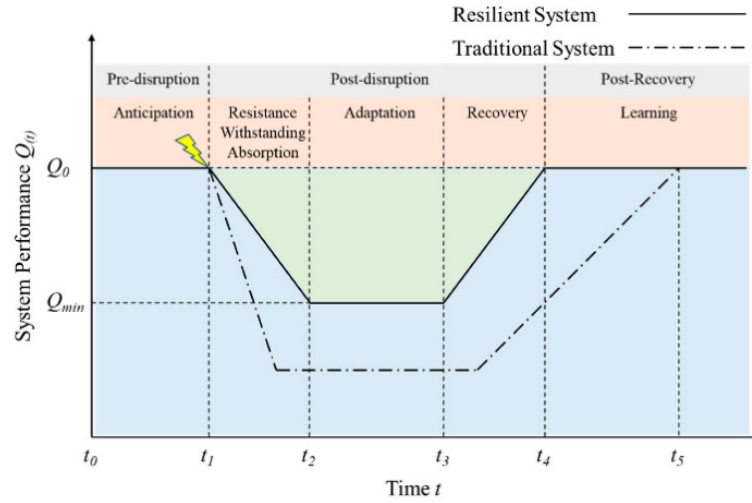


Figure 1-1: Conceptual resilience trapezoid curve associated to an event [4].

In this context, resiliency can be quantified through restoration time, defined as the time required to return the system to an acceptable operating state after a disturbance:

$$T_{restore} = t_4 - t_1 \quad (1-7)$$

where t_1 is the time at which the disturbance occurs and t_4 is the time at which system variables representing the system performance, e.g., voltage and frequency, return within acceptable limits.

To enhance system resiliency, an emergency control approach has been proposed that maintains the dynamic security of several community microgrids following an unintended disturbance in transmission system [5]. The method defines a *resilient operation zone* (ROZ), representing a bounded region in the system space within which stable operation is guaranteed. This can be expressed as:

$$x(t) \in \Omega_{ROZ}, \quad \forall t \geq t_1 \quad (1-8)$$



where $x(t)$ is the system state vector, e.g. voltages, frequencies, internal controller states, and Ω_{ROZ} defines the admissible operating region.

Emergency control actions are applied to ensure that system trajectories remain within this region following a disturbance. By maintaining system trajectories within the ROZ, unnecessary tripping of distributed energy resources (DERs) is avoided, and recovery is accelerated. Simulation results indicate that the ROZ-based approach improves distribution network resiliency by enabling community microgrids to rapidly recover from unintended islanding events while preserving stable operation.

In this study, resiliency is not considered. Resiliency is a higher-level system property that emerges from the interaction of several community microgrids, upstream network assets, and protection and restoration schemes. Individual community microgrids are therefore not the dominant drivers of overall grid resiliency.

1.2.3. Grid restoration

Swissgrid develops, maintains, and publishes a restoration procedure for the Swiss transmission network in coordination with transmission-connected power plant operators and neighbouring transmission system operators (TSOs) [6]. Personnel involved in restoration procedures receive dedicated training. Further operational details are defined in the VSE industry guideline Transmission Code [7].

In the Swiss electricity system, black-start capability at the community microgrid level is generally of lower strategic importance than in systems with limited dispatchable generation resources. Switzerland benefits from a highly reliable transmission network and a large share of flexible hydropower generation. According to the SFOE, the country operated 704 hydropower plants with capacities above 300 kW in 2024, producing approximately 37'350 GWh annually⁶. Most hydropower facilities inherently provide black-start capability due to their ability to restart independently without external grid support. As a result, large-scale restoration following a blackout is primarily expected to rely on transmission-level restoration strategies and hydroelectric resources rather than on distributed community microgrids.

Nevertheless, GFMI can contribute to black-start operation at the local level by establishing voltage and frequency references in islanded conditions and energising local sections of the network. In this context, black-start capability refers to the ability of a GFMI-based microgrid to transition from a de-energised state to stable autonomous operation without external grid support. Although GFMI-based black-start capability is technically relevant, it is not a primary focus of this work.

1.2.4. Ancillary services

Ancillary services in this context refer primarily to frequency control services that maintain the balance between generation and demand in the transmission system. In practice, these services are not for energy delivery in the classical sense, but for fast dynamic power adjustments that stabilize the system frequency when disturbances occur, e.g., load changes and generation loss. Four main services are: frequency containment reserve (FCR), frequency restoration reserve with automatic activation (aFRR), frequency restoration reserve with manual activation (mFRR), and replacement reserves (RR).

⁶ <https://www.bfe.admin.ch/bfe/en/home/supply/statistics-and-geodata/energy-statistics/electricity-statistics.html/>.

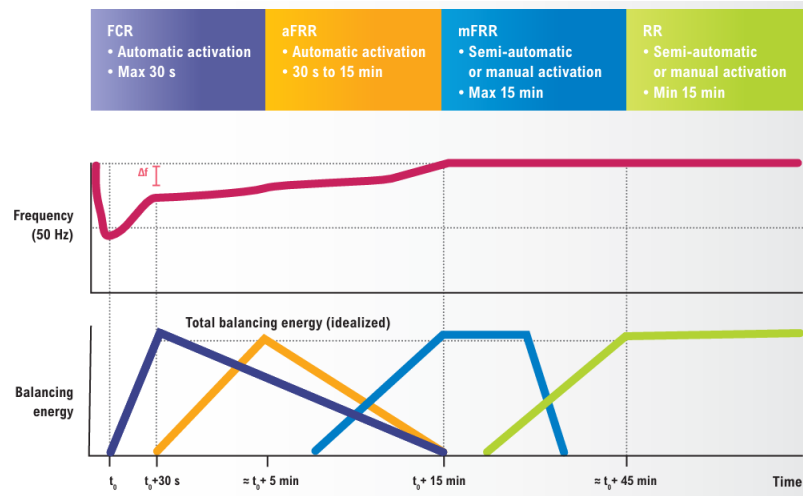


Figure 1-2: Balancing services according to the system envisaged by ENTSO-E [8].

The structure of these services follows the hierarchical balancing framework defined by ENTSO-E, where FCR provides the immediate containment of frequency deviations, followed by aFRR and mFRR restoring system frequency to nominal values, and RR ensuring longer-term system rebalancing and economical power flow. Most of the analysis in this work focuses on the primary control loop, which is the fastest local control loop. Each GFMI is modelled using droop-based control if they have any, meaning that its active power output is adjusted proportionally to local frequency deviation. The primary frequency response is expressed as:

$$\frac{\Delta P}{S_n} = -\frac{1}{k_p} \frac{\Delta f}{f_n} \quad (1-9)$$

where ΔP is the active power change, Δf is the frequency deviation, R is the droop coefficient, f_n is the nominal frequency at 50 Hz, and S_n is the unit nominal power. A steeper droop or smaller k_p implies stronger frequency support but also higher power variability.

In the QSTS simulation, the aggregated contribution of multiple GFMI could be evaluated by time-stepping the system dynamics over discrete intervals, typically seconds or minutes. At each time step, the system frequency deviation is taken from measured real-world data from the Swiss transmission system, and each GFMI updates its active power output according to its droop characteristic. The resulting time-series of power exchanges is then post-processed to quantify both technical performances, e.g., frequency support, response energy, and economic value, e.g., inferred ancillary service revenue.

It is worth mentioning that this analysis is possible, but again it is not the main focus of this study as we estimated that the contribution of GFMI to frequency support of the grid is marginal.

1.3 Technical and Operational Risks

The transition from GFLI-dominated systems to those incorporating high penetrations of GFMI introduces several technical and operational risks. While all are critical for deployment, this appendix prioritizes risks based on their impact on dynamic stability and the specific capabilities of the simulation tools used.

1.3.1. Control interactions

Unlike GFLIs, which synchronize to an established voltage vector via a Phase-Locked Loop (PLL), GFMI actively dictate the grid frequency and voltage. High densities of heterogeneous GFMI can lead to adverse control interactions, particularly when different architectures, e.g., VSM and droop-based,



coexist in a weak network with high impedance. This risk is the primary focus of the time-domain simulations, i.e., PLECS and PowerFactory.

1.3.2. Protection coordination

GFMI typically have limited overcurrent capability compared to traditional synchronous machines. This poses a risk to existing protection schemes in community microgrids, where fault currents may be insufficient to trigger legacy breakers or relays. The analysis assesses the risk of blindness in protection systems during islanded operation. While technically significant, protection coordination and the redesign of grounding or relay settings are addressed in a separate appendix. This section acknowledges the risk but does not perform the protective relay coordination study.

2 QSTS and Black-Start Simulations

The main objective of this section is to determine, for each GFMI penetration level, the maximum load that can be supplied while maintaining acceptable voltage limits and avoiding thermal or operational violations. In addition to this steady-state adequacy assessment, two practical resilience cases are explicitly included: islanded operation and black-start capability, as they can provide an indication of the system's resilience under abnormal operating conditions and its ability to maintain or restore service following disturbances.

For islanded operation, the system is tested under a defined autonomy requirement of 2 hours without external grid support. Given a nominal load of 189 kW and a photovoltaic capacity of 270 kW, the analysis quantifies the minimum storage energy capacity required to sustain the system during this isolation period equal to 380 kWh. This requirement is driven by the mismatch between time-varying PV production and demand, and it directly determines the minimum battery energy (kWh) and power (kW) ratings needed to prevent load shedding while maintaining voltage stability.

In OpenDSS, QSTS simulations represent the network as a sequence of steady-state power flow solutions over time. At each time step, the system is assumed to reach its electrical equilibrium, and a full power flow calculation is performed based on updated inputs such as load profiles, PV generation, and inverter dispatch settings. This formulation neglects sub-cycle electromagnetic transients but remains effective for capturing slower system dynamics. The key characteristics of the QSTS approach are the following: *First*, it captures slow temporal variations such as daily demand cycles, PV variability, and inverter control responses with finite time constants. *Second*, it enables long-duration simulations ranging from several hours to multi-year horizons with manageable computational cost.

A second analysis focuses on grid restoration from a black-start condition. In this case, the system is assumed to be fully de-energized, and the ability of GFMI and storage units to re-energize the network is evaluated. The study examines whether voltage build-up, frequency establishment, and load pickup can be achieved in a controlled sequence without exceeding operational limits. Particular attention is given to synchronization behaviour, staged reconnection of PV assets, and the ability of storage to provide initial voltage and frequency reference.

Figures 2-1, 2-2, and 2-3 illustrate PV output, storage response, and voltage evolution following black-start of the community microgrid. Immediately after connection, a short-lived power imbalance appears, followed by coordinated response from the storage units. Storage absorbs phase imbalance and compensates for power deficits, while PV generation stabilizes according to irradiance and control limits. Voltage returns to nominal levels after the transient period, indicating successful steady-state regulation in islanded operation.

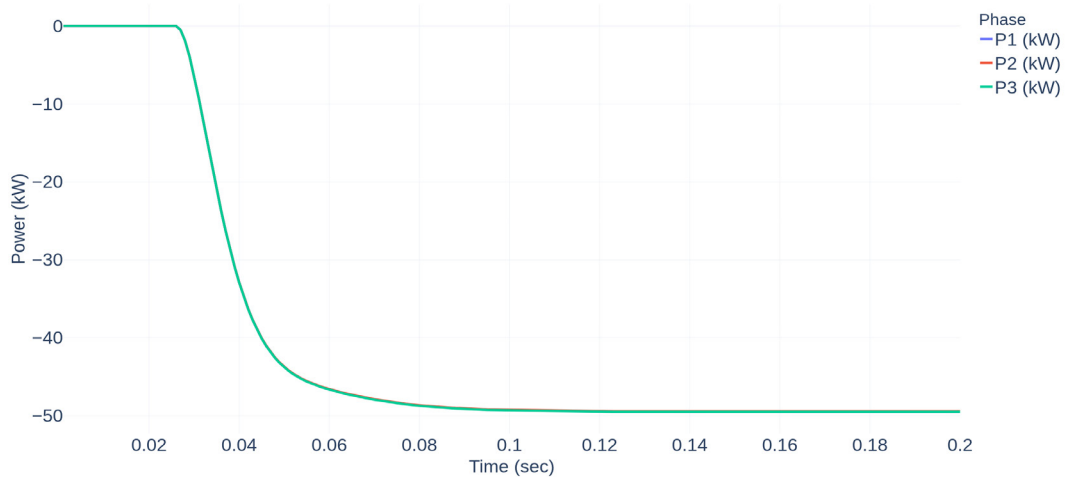


Figure 2-1: Power response of PV system after the black-start of the community microgrid.

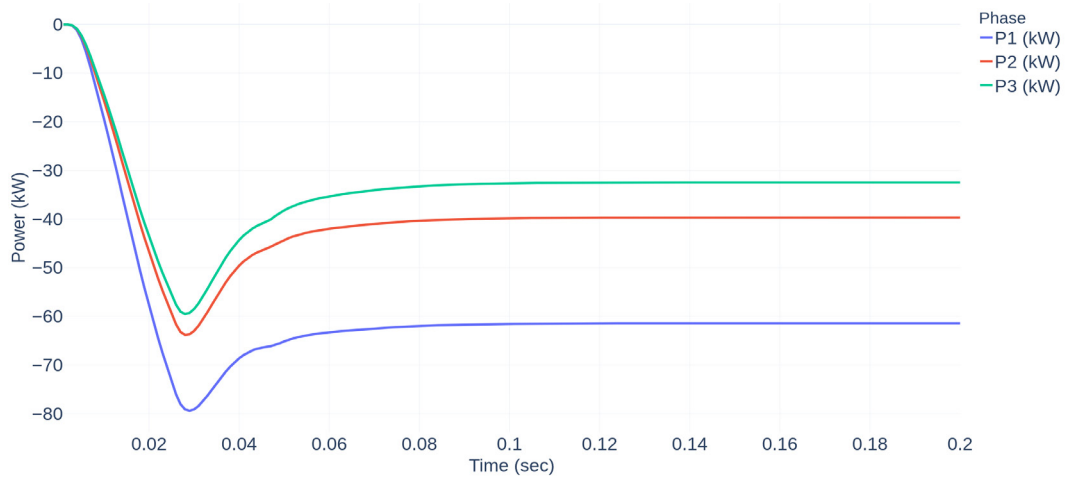


Figure 2-2: Power response of the storage system after the black-start of the community microgrid.

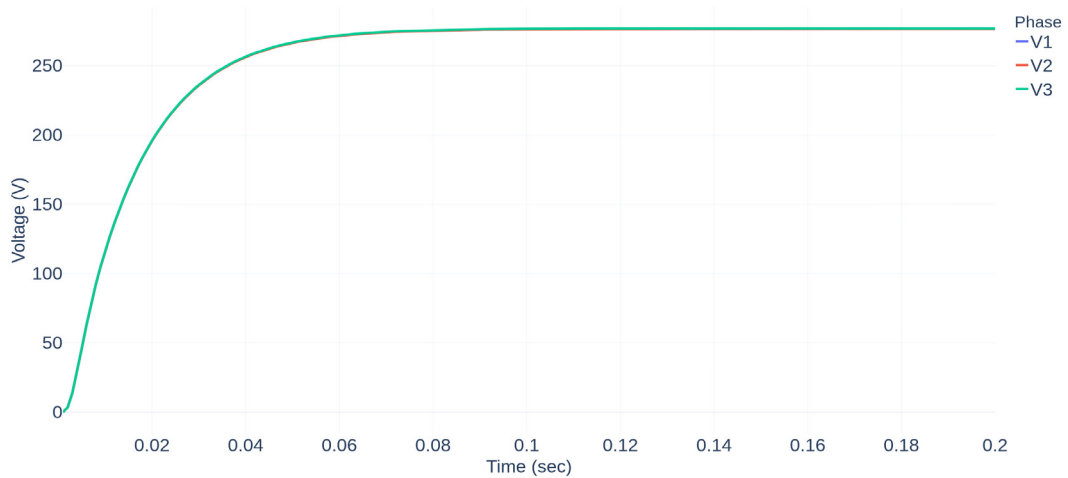


Figure 2-3: Response of the voltage after the black-start of the community microgrid.



3 Study Scope and Simulation Setup

3.1 Network Model

To evaluate and quantify the benefits and potential risks of the proposed community microgrid, a standard LV distribution feeder was adapted to integrate multiple GFLIs and GFMLs. The network, illustrated as Feeder 125 in Figure 3-1, was modelled and simulated in DlgSILENT PowerFactory.

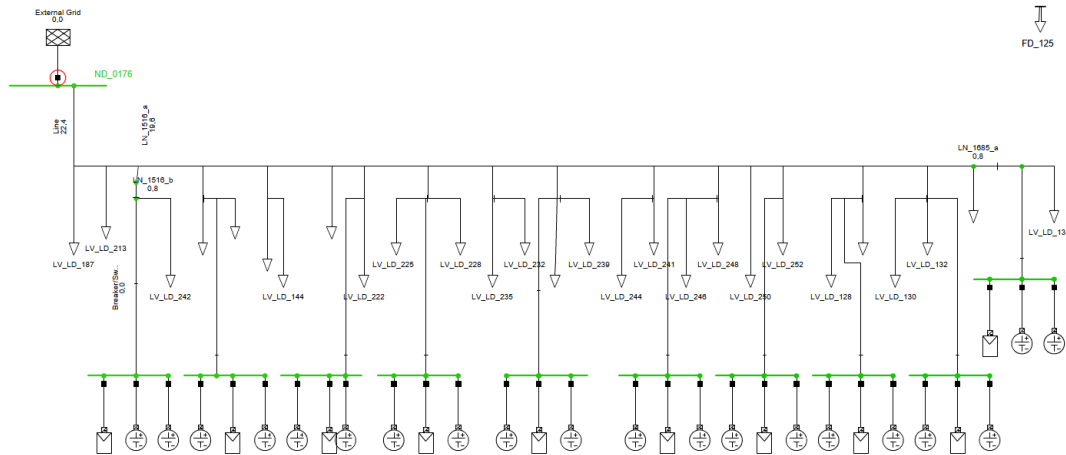


Figure 3-1: LV Feeder distribution network modelled in DlgSILENT PowerFactory.

The feeder operates at a nominal voltage level of 400 V. It consists of 38 nodes connected through approximately 410 m of distribution cables. A total of 27 loads are connected to the feeder, each with a nominal active power demand of 7 kW and a nominal current of 10.6 A, resulting in an aggregate nominal active power demand of 189 kW. The feeder can be disconnected from the external utility grid through a switch indicated by the red circle in Figure 3-1.

3.2 DER composition (PV, storage, grid-following and grid-forming)

The community microgrid includes DERs composed of PV generation and battery energy storage systems (BESSs) interfaced through power electronic converters. A total of 10 PV installation are distributed across the feeder, each rated at 27 kVA with a power factor of 0.95. The total installed PV capacity in the network is therefore 270 kVA, corresponding to approximately 256.5 kW of active power generation.

Each PV installation is connected to the distribution feeder through inverter-based interfacing units. To evaluate the impact of different inverter control strategies on islanded operation and system stability, three different DER configurations are considered at each PV node:

1. PV-only operation without energy storage support;
2. PV integrated with a 20 kW battery energy storage system operating as a GFMI using VSM control;
3. PV integrated with a 20 kW battery energy storage system operating as a GFMI using droop-based control with a frequency droop coefficient of 1 % (i.e., 0.01 per unit, equivalent to a power-frequency characteristic of 40 kW/Hz). This relatively stiff droop value was selected as it ensures the dynamic stability of the system under the tested conditions.

The objective of these compositions is to evaluate the minimum required storage capacity and inverter control configuration necessary to maintain stable operation of the microgrid during islanded conditions.

Particular emphasis is placed on system security or assessing voltage and frequency stability, active and reactive power sharing, and transient response following disconnection from the external utility grid.

The PV inverters operate primarily in grid-following mode during grid-connected operation, whereas the storage converters are configured to provide grid-forming functionality during islanded operation. While grid-forming capability of a PV is technically possible, it necessitates significant power reserves for frequency regulation, which is often economically inefficient due to the required curtailment of solar generation. This arrangement enables investigation of the interaction between GFMs and GFLIs under varying operating conditions.

3.3 Control Strategies (Droop and VSM)

Two grid-forming control strategies are implemented and evaluated in this study: conventional droop-based control and VSM control. Both controllers are integrated into the BESS converters to enable stable islanded operation of the community microgrid.

Figure 3-2 illustrates the control structure of the droop-controlled GFMI implemented in DigSILENT PowerFactory. The controller consists of outer active power-frequency and reactive power-voltage droop loops combined with inner voltage and current regulation loops. The active power control loop adjusts the inverter frequency according to the measured active power deviation, while the reactive power loop regulates the voltage magnitude based on reactive power variations.

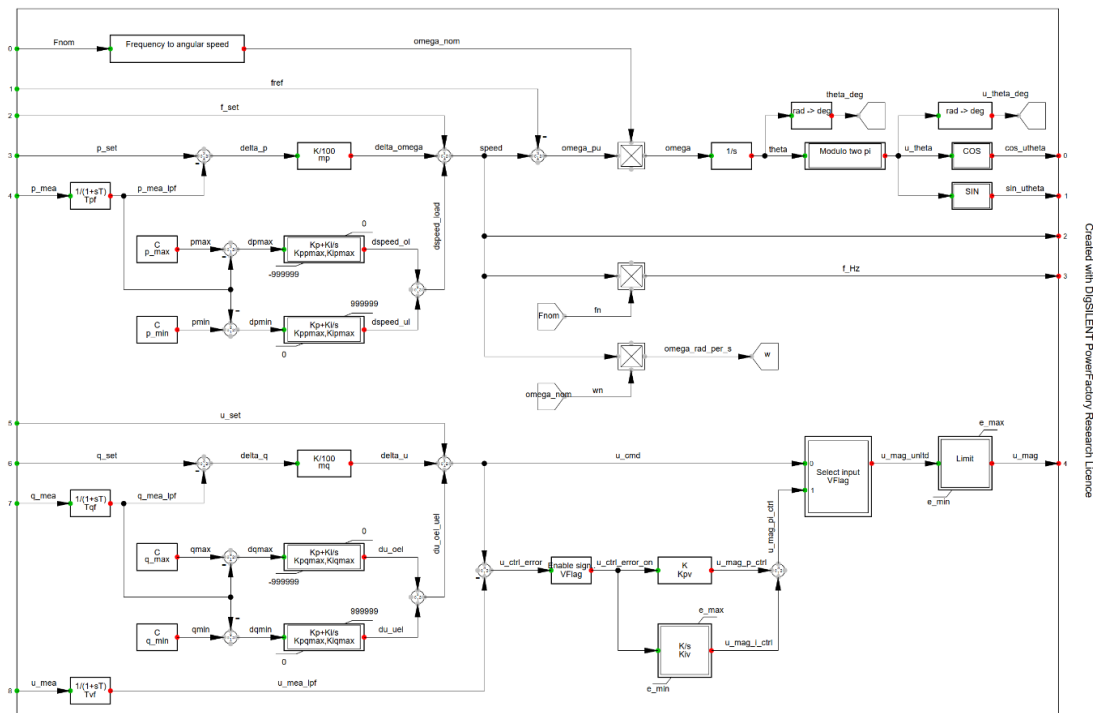


Figure 3-2: DIgSILENT implementation of the droop-controlled GFMI.

The frequency and voltage droop characteristics are defined as:

$$\Delta f/f_n = -k_p \Delta P/S_n \quad (2-1)$$

$$\Delta V/V_n = -k_q \Delta Q/S_n \quad (2-2)$$



where Δf and ΔV represent the deviation of frequency and voltage from the nominal values, ΔP and ΔQ are the deviation of active and reactive power from reference values, f_n and V_n are nominal frequency and voltage, S_n is the nominal power of the unit, and k_p and k_q denote the droop coefficients. In this study, the frequency droop coefficient of 1% (i.e., 0.01 per unit, equivalent to a power-frequency characteristic of 40 kW/Hz) is selected for all droop-controlled GFMs.

Figure 3-3 presents the DIgSILENT implementation of the VSM controller. For more information regarding Eqn 7-8-9 mentioned in the figure, refer to technical reference of DIgSILENT. Unlike conventional droop control, the VSM strategy emulates the electromechanical dynamics of a synchronous generator by introducing virtual inertia and damping terms into the inverter control structure. The controller includes a virtual swing equation block, power measurement filters, frequency generation unit, and cascaded voltage and current control loops.

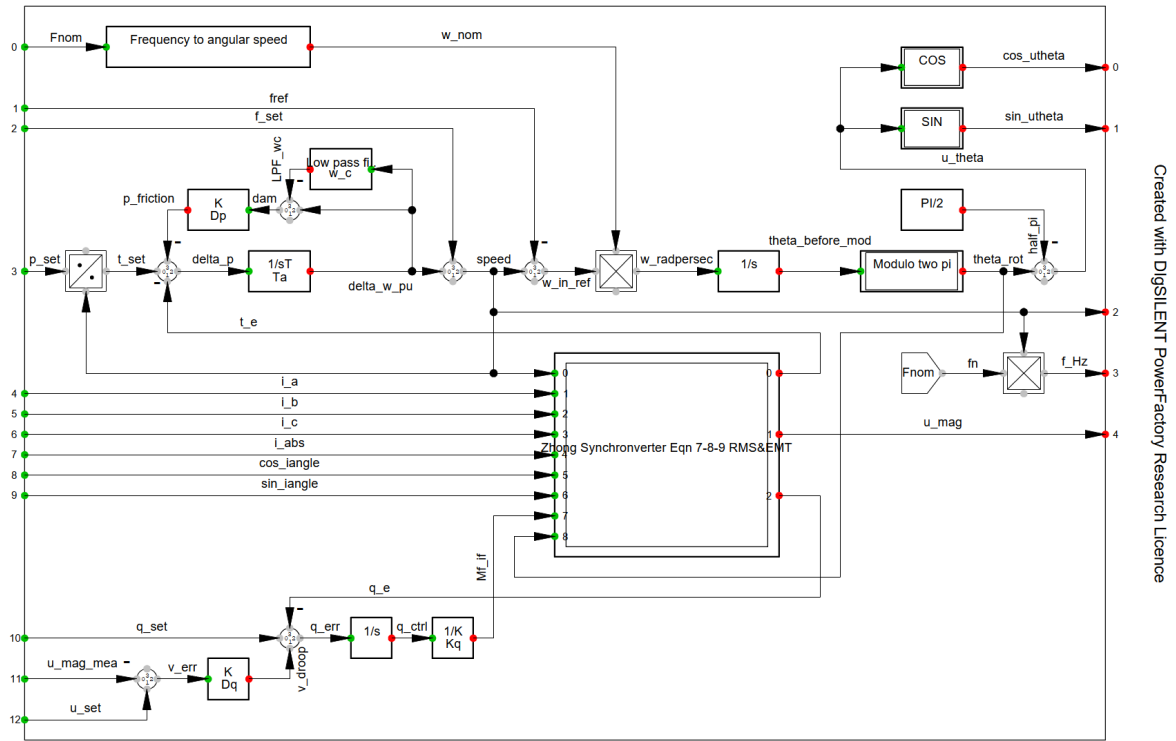


Figure 3-3: DIgSILENT implementation of the VSM-controlled GFMs.

The dynamic behaviour of the VSM controller is governed by the virtual swing equation:

$$T_a \frac{d\omega}{dt} = P_0 - P - 2\pi D(f - f_0) \quad (2-3)$$

where T_a is the virtual acceleration time constant representing the emulated inertia of the converter and D is the damping coefficient. In this work, emulated inertial of 3 seconds and damping coefficient of 100 per unit is selected for all VSM GFMs. By introducing virtual inertia, the VSM controller reduces the rate of change of frequency (RoCoF) and improves transient stability during disturbances and transitions to islanded operation.



4 Simulation Campaign

This section details the systematic methodology used to assess the impact of GFMI penetration on community microgrids. A comprehensive dataset was generated for statistical and technical analysis by varying control configurations, operating points, and disturbances. Simulations were conducted in Dlg-SILENT using automated scripts to manage the various control and operating parameters.

4.1 Events and Disturbances

To test the robustness of the microgrid, each simulation follows a rigorous chronological sequence of events designed to challenge the system's primary control loops and transition capabilities. These events should be sustained in islanded and grid-connected operation.

The time sequence is defined as follows:

- $t = 0.0$ s: Islanding event (disconnection from the external grid).
- $t = 1.0$ s: Positive load step (+30 %) to evaluate load-following capability.
- $t = 1.5$ s: PV generation reduction (-30 %) to simulate sudden cloud cover.
- $t = 2.0$ s: Reconnection to the main distribution network.
- $t = 2.5$ s: Three-phase fault at the PCC for 100 ms with the impedance of 0.1 and X/R ratio of 3.

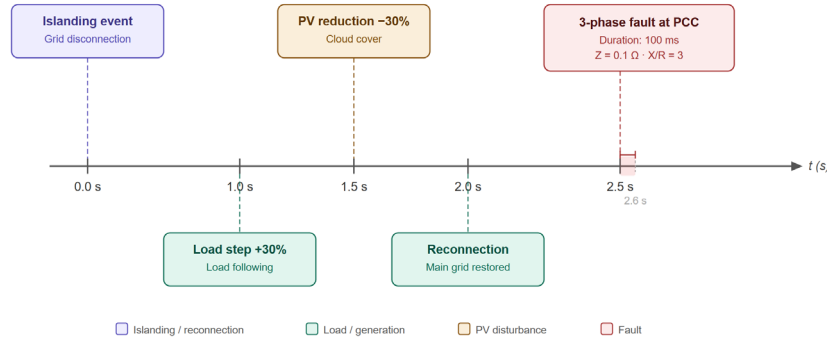


Figure 4-1: Chronological sequence of events.

All results are automatically validated against standard operation. A case is flagged as *unstable* or *non-compliant* if frequency deviates beyond 49.8-50.2 Hz or if the voltage at any node exceeds the 0.95-1.05 per unit range. Furthermore, oscillatory instability is identified if the ratio of standard deviation to the average value for either frequency or voltage exceeds 0.01.

$$\frac{std(f)}{avg(f)} > 0.01, \quad \frac{std(v)}{avg(v)} > 0.01 \quad (2-4)$$

4.2 Configuration Space

The study examines how system strength changes when the mix of GFMI is varied. The number of grid-following PV units is kept constant to preserve a fixed level of stochastic generation. Only the grid-forming composition is changed.

Two types of GFMI are considered:

- Droop-based GFMI range from 0 to 10 units.
- VSM GFMI range from 1 to 10 units.



Combining these ranges produces 110 different system configurations. This setup allows evaluation of whether specific control strategies, or combinations of strategies, provide better voltage stability and frequency stability in a LV network in islanded operation.

The spatial arrangement of inverters is also taken into account. GFMI and GFLI are assigned to fixed network locations. VSM-type inverters are placed sequentially from location 1 to location 10, while Droop-based inverters are assigned in the reverse order, from location 10 back to location 1.

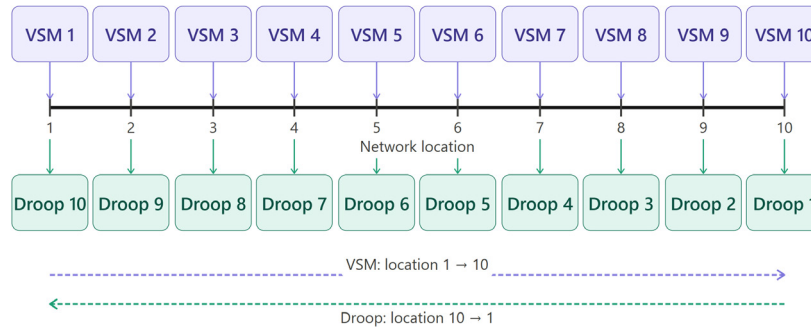


Figure 4-2: Locations of VSM and droop inverters.

4.3 Operating Scenarios

To reflect realistic variations in operating conditions, four extreme cases are defined based on the balance between supply and demand.

- Scenario 0 represents high load with no generation. It stresses the system by testing maximum discharge requirements and frequency support. Here, the full load is present (100 %), while PV generation is absent (0 %).
- Scenario 1 combines high load with full PV generation. This case is used to study how grid-forming storage and grid-following PV interact under heavy power flow conditions. Both load and PV generation are at 100 %.
- Scenario 2 considers medium load with full PV generation. It represents typical daytime operation and is used to evaluate system stability under normal operating conditions. Load is set to 50 %, while PV generation remains at 100 %.
- Scenario 3 models medium load without PV generation. This reflects night time operation and is used to assess the minimum required inertia and support from controllable sources. Load is 50 %, and PV generation is 0 %.

Together, these four cases represent the main stress conditions for both energy adequacy and dynamic stability. All these scenarios are run with different levels of load shedding from 0 %, 5 %, 10 %, ..., 95 %. The final SAIFI and SAIDI values are calculated as the average across all four scenarios.

4.4 Implementation and Scalability

The scale of the campaign is designed to provide statistically significant insights into microgrid reliability. The total volume is calculated as:

$$\text{Total simulations} = 110 \text{ configurations} \times 4 \text{ scenarios} \times 20 \text{ load shedding levels} = 8800 \text{ cases.}$$

Given the volume of data, the process is entirely automated. A Python-based orchestration script interfaces with DiGSILENT PowerFactory to iteratively modify the network topology, execute the RMS simulations, and export the resulting time-series data into CSV-based storage for post-processing.



5 Results: System Behaviour

For each scenario, frequency and voltage are recorded over a 3-seconds window following the disturbance. The frequency response in each case is summarized as shown in Figure 5-1.

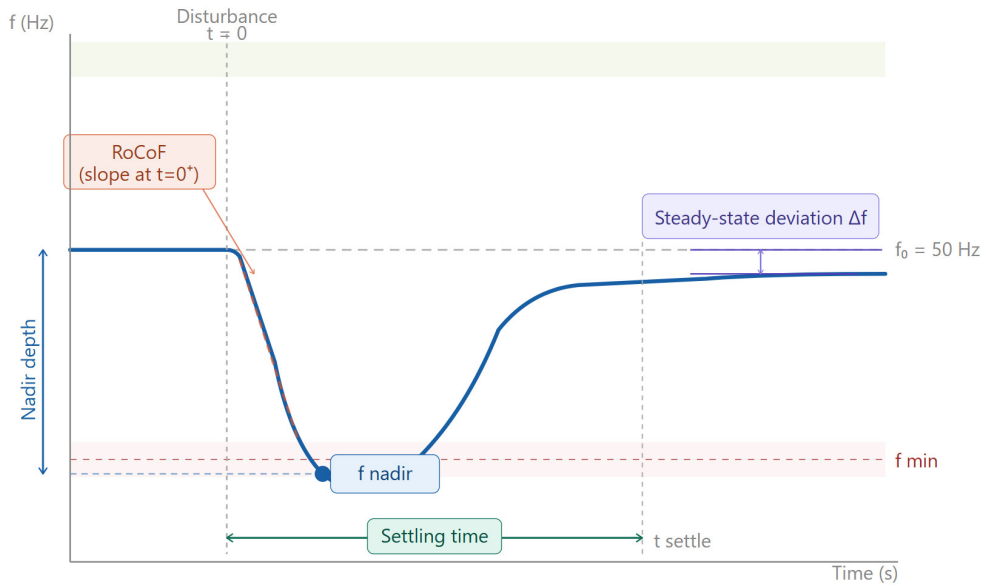


Figure 5-1: Frequency measurement after an event.

From these time-series, the key performance indicators are computed as follows. The metrics and their standard reference thresholds for microgrid operation are listed below (as we defined them).

Metric	Symbol / definition	Standard threshold (microgrid)
Frequency nadir	$f_{nadir} = \min f(t)$	≥ 49.8 Hz (grid-connected) ≥ 49.0 Hz (islanded operation)
Steady-state deviation	$\Delta f_{ss} = f_{ss} - f_0$	± 0.2 Hz (grid-connected) ± 1.0 Hz (islanded operation)
Settling time	$t_{settle} = \text{time to } \Delta f < \varepsilon$	< 10 seconds (grid-connected) < 30 seconds (islanded operation)
RoCoF	$\frac{df}{dt}$ at $(t = 0^+)$	< 1 Hz/second (grid-connected) < 2 Hz/second (islanded operation)
Voltage deviation	$\Delta V_i = V_i - 1.0 $ p. u.	± 0.10 per unit (grid-connected) ± 0.15 per unit (islanded operation)
Voltage recovery time	$t_{V, recover}$	$< 1-3$ second
Oscillation	$\frac{std(f)}{avg(f)} > 0.01 \rightarrow \text{flag}$	binary classification per case
Max survivable load	P_{max} stable, no V/f breach	-
Fault ride-through	V during fault, recovery after t_{clear}	Remain connected for $V > 0.15$ per unit up to 150 ms; recover within 1.5 second



5.1 Frequency Stability Across Configurations

This section evaluates the impact of GFMI control parameters on frequency stability during islanded operation. The analysis focuses on the role of virtual inertia and droop control in maintaining stable system frequency following disturbances and load changes.

The simulations compare several GFMI configurations with different total virtual inertia constants and total droop settings. In this context, a virtual inertia constant of 1 second implies that, for each kW of load, the network possesses 1 second of inertia. This corresponds to stronger inertial support and slower frequency dynamics, similar to the behaviour of conventional synchronous machines. In addition, a droop capacity of 10 % implies that GFMI units with the specified droop characteristic (here, 1 %) provide capacity equivalent to 10 % of the load. Figure 5-2 shows the system frequency response for three virtual inertia values (0.32 seconds, 1.59 seconds, and 3.17 seconds) combined with two droop capacities (21.16 % and 84.66 %).

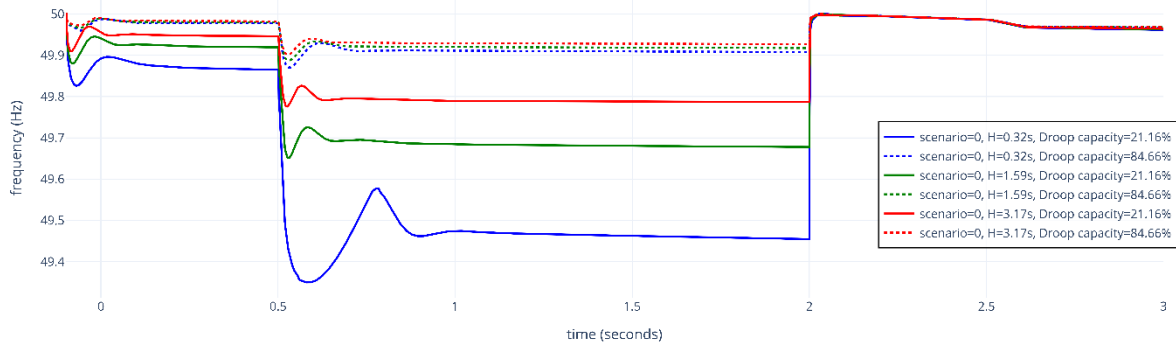


Figure 5-2: Frequency response for different configurations of GFMI.

The results show that increasing the virtual inertia improves the frequency response by reducing the initial frequency deviation immediately after the disturbance. For example, the configuration with virtual inertia of 3.17 seconds exhibits a smaller frequency nadir compared to the case with virtual inertia of 0.32 second. The higher virtual inertia slows the RoCoF and limits transient oscillations.

However, the simulations also demonstrate that virtual inertia alone is not sufficient to guarantee stable frequency establishment. The droop coefficient has a more critical influence on the steady-state frequency behaviour. When the droop capacity, i.e., the proportion of the total power capacity actively programmed to correct frequency deviations, is increased from 21 % to 84 %, the system frequency converges closer to the nominal value of 50 Hz and the oscillatory behaviour is significantly reduced. In contrast, low droop values lead to larger steady-state frequency deviations and weaker stabilization, particularly for low-inertia configurations.

The results indicate that to ensure a stable islanded grid, it is essential to strategically distribute both VSM and droop control across the GFMI. While inertia improves transient performance during the first few milliseconds of a disturbance, the droop determines the long-term frequency regulation capability.

5.2 Voltage Regulation and Power Sharing

This section analyses the voltage regulation capability of GFMI under different virtual inertia and droop configuration during islanded operation. As illustrated in Figure 5-3, the system ability to recover from voltage transients is heavily influenced by droop parameter. It is worth mentioning the reactive power droop is defined same as the active power one, which represent how much reactive power ΔQ is changed when there is voltage difference ΔV from nominal voltage V_{nom} .



$$k_p \frac{\Delta P}{S_{nom}} = -\frac{\Delta f}{f_{nom}}, \quad k_q \frac{\Delta Q}{S_{nom}} = -\frac{\Delta V}{V_{nom}} \quad (2-5)$$

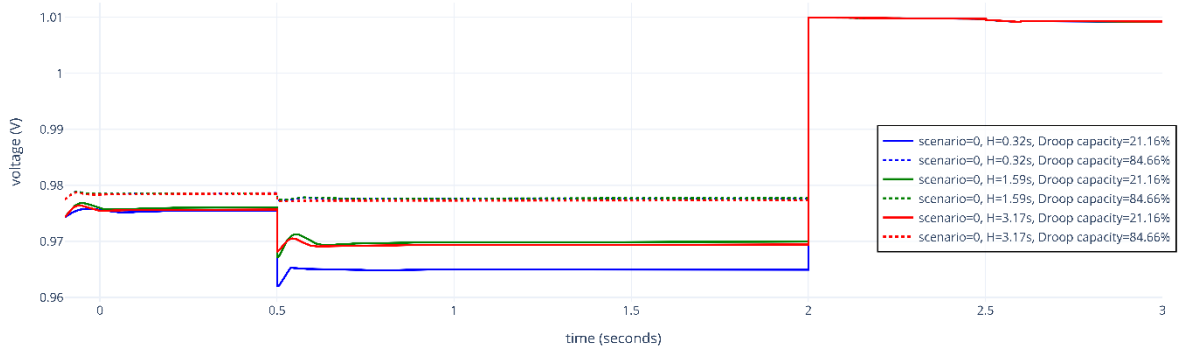


Figure 5-3: Voltage response for different configurations of GFMLs.

The simulations demonstrate that while traditional GFLIs often struggle with voltage sag during load changes, GFMLs act as a voltage source, actively supporting the profile across all nodes. In Figure 5-3, we observe that a higher droop capacity, i.e., the proportion of the total power capacity actively programmed to correct frequency deviations shown by dashed lines, results in a more stable and elevated voltage profile following a disturbance compared to lower droop configurations. Increasing the droop capacity from 21 % to 84 % reduces voltage oscillations and improves convergence toward the nominal operating point.

5.3 Maximum Loading Capacity and System Limits

This section defines the operational boundaries of the islanded grid by identifying the maximum load that can be sustained across various configurations and scenarios. These results quantify the survival capacity of the microgrid during a blackout.

5.3.1. Load shedding and configuration sensitivity

To determine the system limits, four primary scenarios were simulated with different load shedding, ranging from minimal intervention (0 %) to aggressive shedding (95 %) to maintain stability. The results are mapped in the 3D analysis below. Figures 5-4, 5-5, 5-6, and 5-7 show the results for scenarios 0 to 3, respectively.

As seen in these figures, the load shedding is highly sensitive to the interaction between VSM and droop control. At low virtual inertia (below 0.5 second) and low droop capacity (near 0 %), load shedding requirements spike to 80 % in all four scenarios. This indicates that without sufficient grid-forming capability, the system cannot support the local demand even in a restricted state.

Increasing the droop capacity provides a more immediate reduction in load shedding compared to virtual inertia alone. However, the most stable *valley* (where load shedding is minimized to near 0 %) requires a balanced distribution of both parameters, specifically droop capacity above 50 % and virtual inertia above 1.5 second.

The most common limitation for unfeasible area is excessive frequency deviation or frequency oscillation following islanding or sudden load changes. Poor droop tuning cause inadequate power balancing and leads to frequency collapse or sustained oscillations.

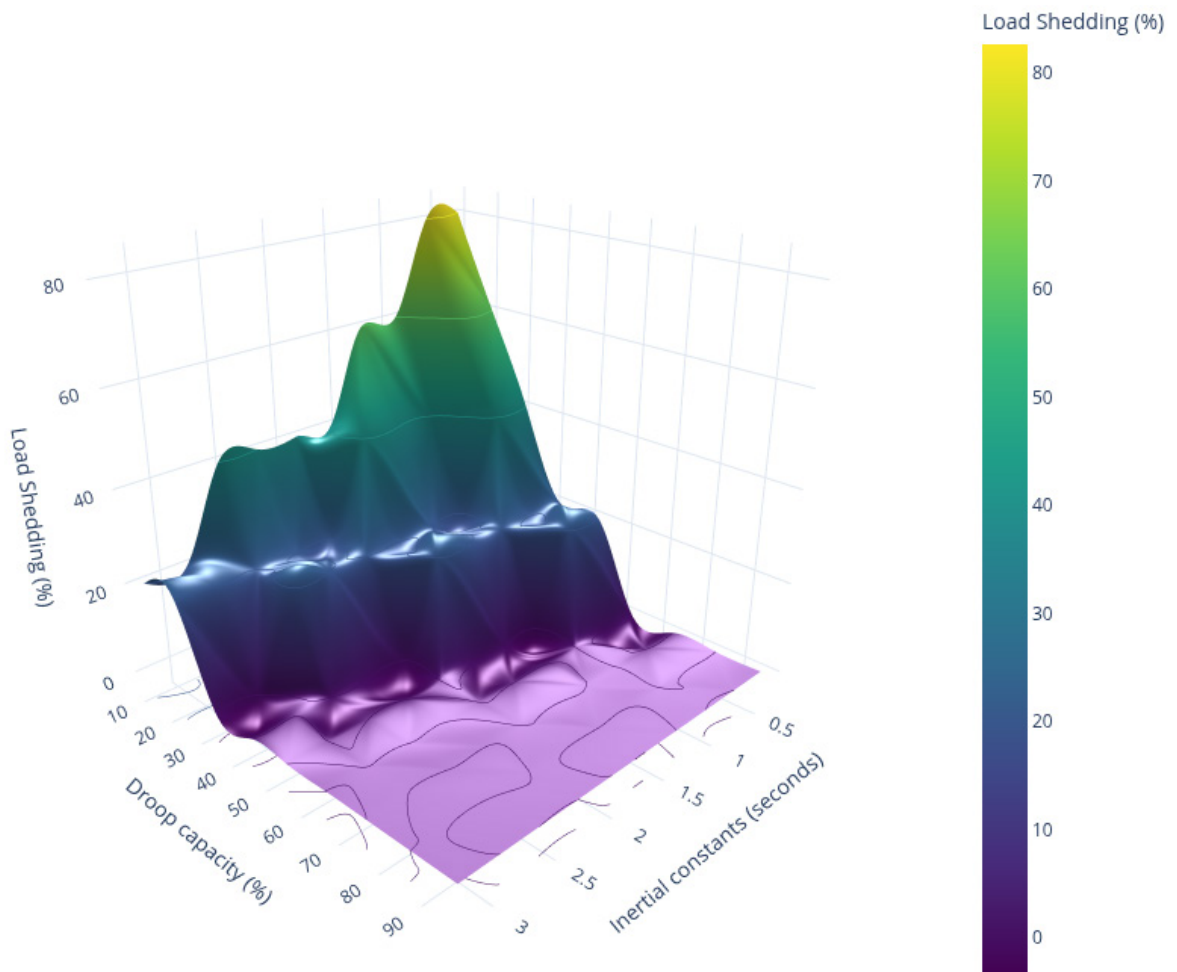


Figure 5-4: Load shedding percentage as a function of GFMI virtual inertia and droop capacity during islanded operation (Scenario 0).

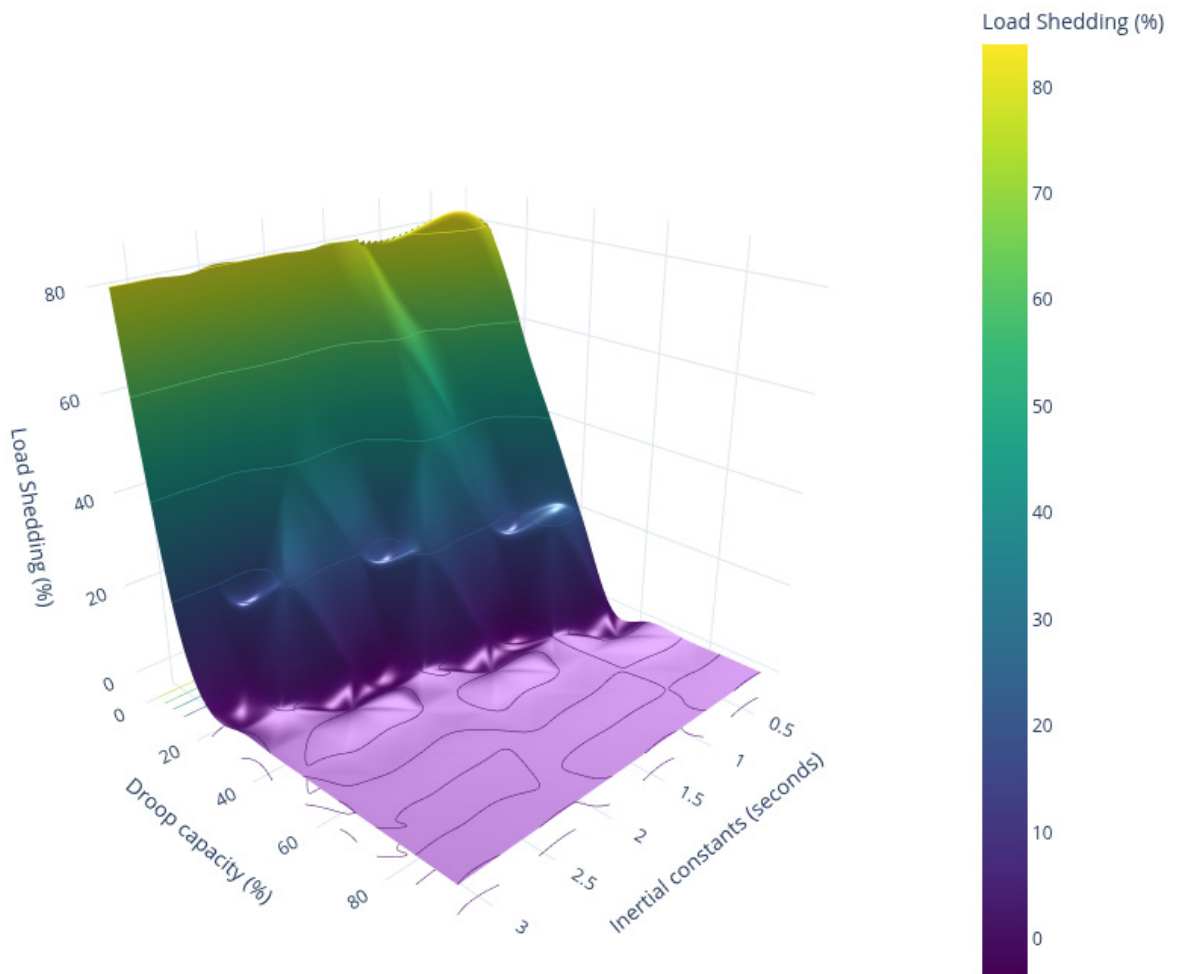


Figure 5-5: Load shedding percentage as a function of GFMI virtual inertia and droop capacity during islanded operation (Scenario 1).

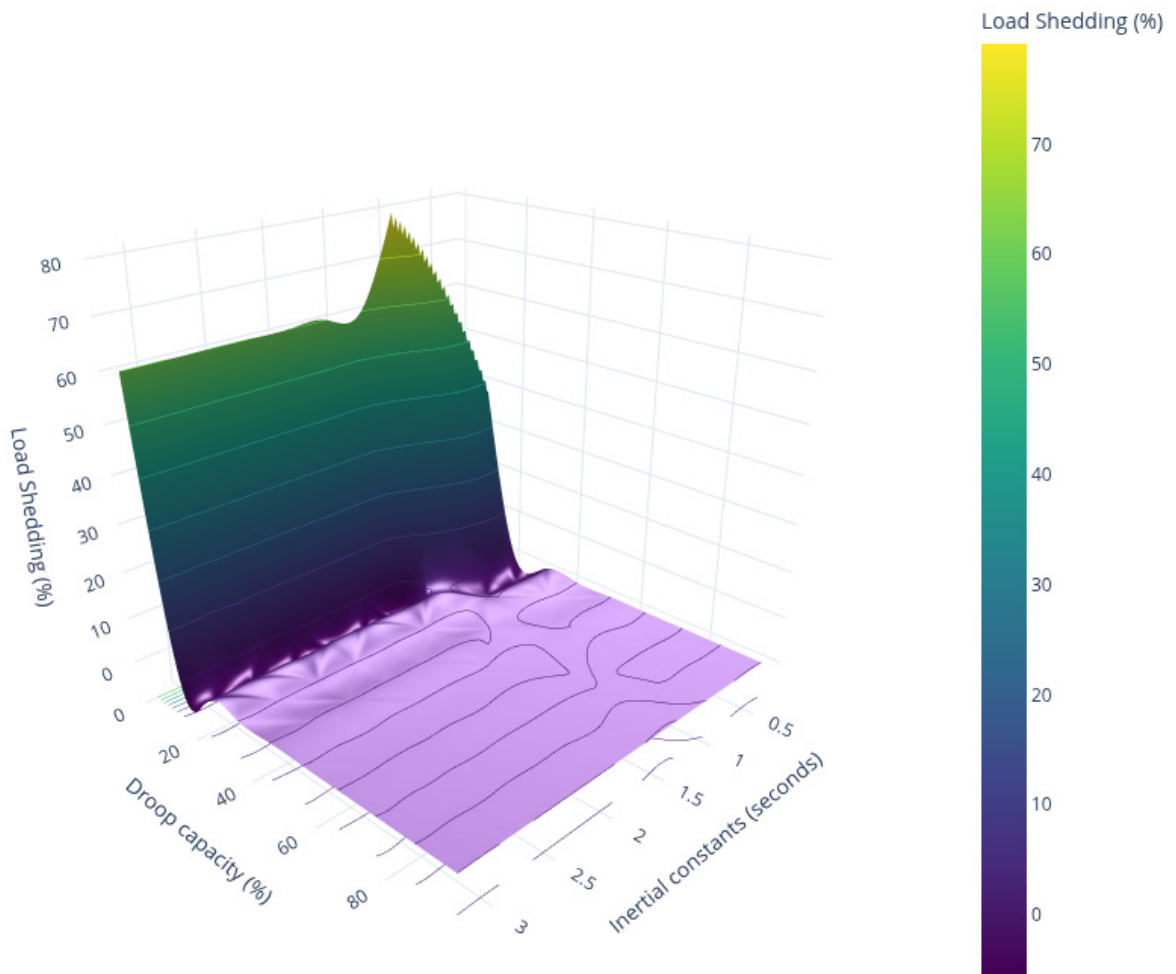


Figure 5-6: Load shedding percentage as a function of GFMI virtual inertia and droop capacity during islanded operation (Scenario 2).

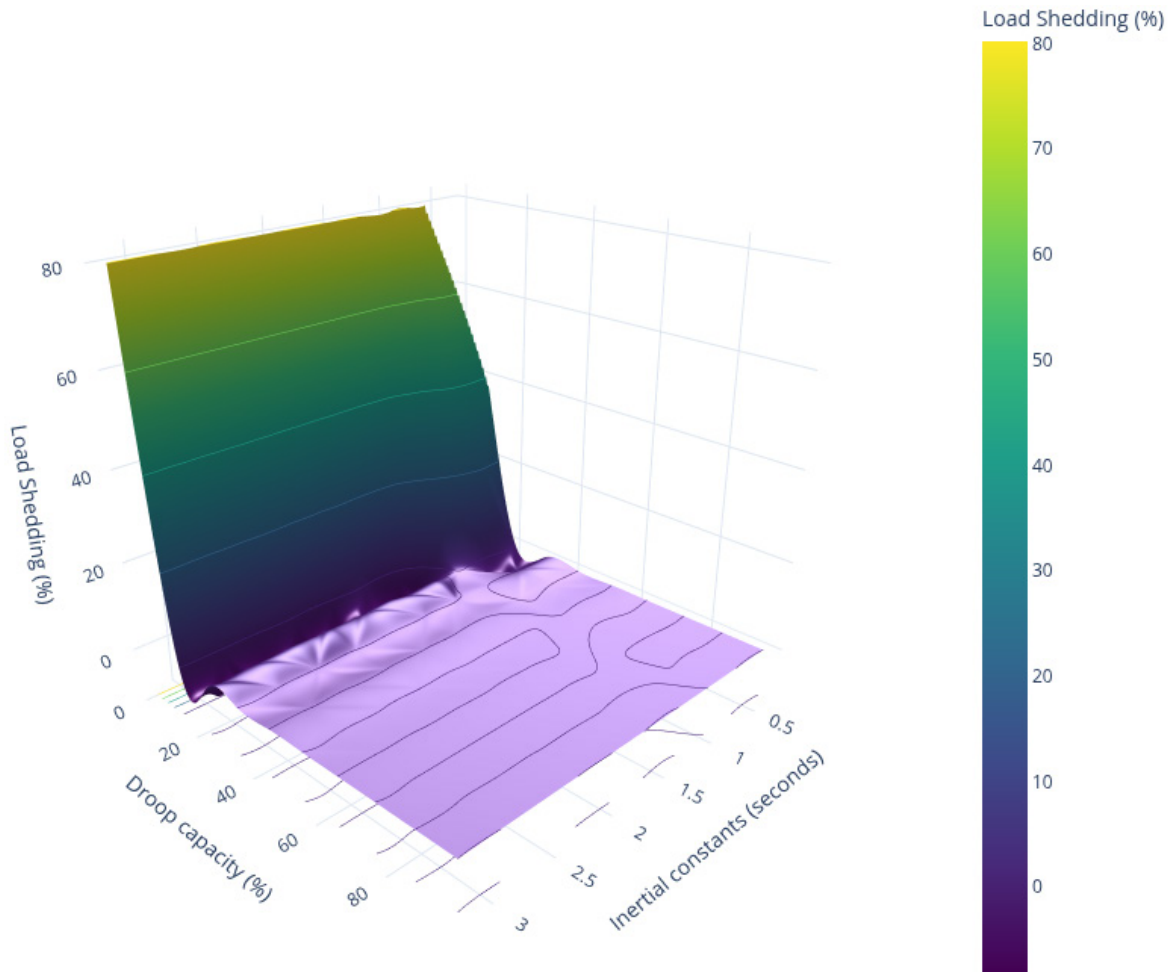


Figure 5-7: Load shedding percentage as a function of GFMI virtual inertia and droop capacity during islanded operation (Scenario 3).

5.3.2. Reliability Correlation (SAIFI/SAIDI)

The technical ability to carry load translates directly into improved reliability metrics for the end consumer. For simplification, it is assumed that all the faults last only 2 hours and there is no other outage of GFMLs. Figure 5-8 illustrates that the reliability improvement follows an inverse trend to load shedding. Configurations with high GFMI penetration and optimized settings achieve nearly *100 % improvement* in SAIFI/SAIDI compared to traditional grid-following setups.

The system experiences a sharp *reliability cliff* when virtual inertia drops below 1 second and droop capacity (the percentage of total power actively correcting frequency deviations) falls below 50 %. Notably, when inertia remains under 1 second, even a high droop capacity is insufficient to make up for the missing instantaneous inertial response. As a result, the system suffers from recurrent frequency violations and subsequent power outages.

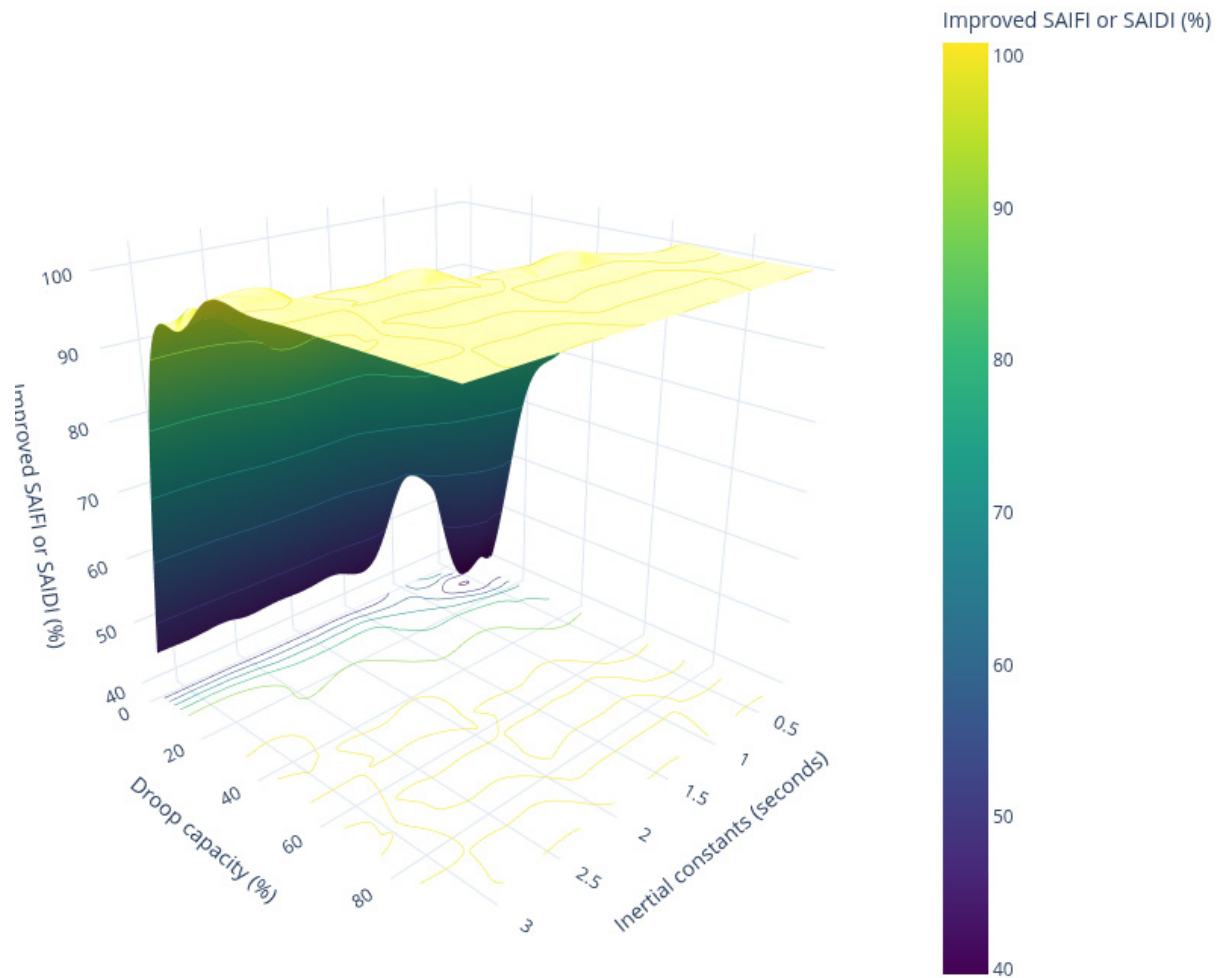


Figure 5-8: Improvement in Grid Reliability (SAIFI/SAIDI) via grid-forming Integration.

In low virtual inertia scenarios, the RoCoF is too high for the primary control to catch, leading to a total system collapse before the droop can respond. On the other hand, in low-droop scenarios, even if the system survives the initial transient, the frequency fails to settle within the required 49.8 – 50.2 Hz band, triggering automated protection. To maximize loading capacity and minimize shedding, the grid-forming strategy must prioritize high droop for steady-state settlement and a minimum of 1.5 seconds virtual inertia to ensure transient survival.



6 Synthesis: Benefits and Risks of GFMI

The synthesis integrates the findings from the simulation campaign to evaluate the role of GFMI in community microgrids.

6.1 Benefits

6.1.1. Improved islanding capability

The GFMI enable seamless islanding. Each GFMI act as independent voltage source, imposing a local voltage and frequency reference. The feeder survives disconnection from the upstream grid without an external synchronous reference, provided the aggregated parameters of GFMI are above the stability threshold (>1.5 seconds of inertia per kW of Load and >50 % droop capacity).

6.1.2. Higher loading capacity

GFMI increases the maximum load that can be supplied during islanded operation. Under the four scenarios examined, the load-shedding required to maintain stable operation falls from roughly 80 % in low-GFMI configurations to near zero once virtual inertia exceeds about 1.5 seconds and droop capacity exceeds about 50 %. The results therefore indicate that GFMI directly increase microgrid hosting capacity and operational flexibility by improving the ability of the system to sustain higher demand levels without violating stability constraints.

6.1.3. Superior voltage and frequency control

GFMI provide instantaneous frequency support via virtual inertia and long-term regulation through droop control. From the frequency perspective, VSM-based control reduces the initial RoCoF and mitigates frequency nadir immediately following disturbances. Larger droop coefficients improved convergence toward nominal frequency and reduced sustained oscillatory behaviour. From the voltage regulation perspective, GFMI improve voltage regulation by acting as voltage sources rather than current sources; a stiffer Q-V droop measurably reduces post-disturbance oscillations and produces a flatter voltage profile across the feeder.

6.1.4. Fault ride-through support

The combination of virtual inertia and droop reduces both the frequency nadir and the RoCoF, allowing the system to ride through the 100 milliseconds PCC fault without cascading trips. The cumulative effect on customer-facing reliability is large: SAIFI and SAIDI improvements approach 95% relative to a purely grid-following baseline if we assume that 100 % of the faults have period of 2 hours.

6.2 Risks and Limitations

6.2.1. Instability Under Low Penetration

The most important risk is a sharp reliability cliff at low GFMI penetration: when virtual inertia falls below 1 second and droop capacity below 50 %, the system either collapses on the initial transient or fails to settle within the 49.8 – 50.2 Hz band, and load-shedding requirements rise abruptly.

6.2.2. Sensitivity to control parameters (droop, inertia)

System stability is highly sensitive the tuning of inertia and droop. Inertia alone does not stabilize the steady state, and droop alone cannot contain a high RoCoF; mistuning of either parameter degrades performance disproportionately. Excessive frequency deviation or non-compliant voltage profiles occur if these parameters are not balanced, even if hardware capacity is available.



6.2.3. Coordination issues between grid-forming types

The coexistence of different GFMI control architectures introduces additional complexity. Although both inertia and droop controllers improve stability, their dynamic responses differ significantly. VSM units primarily contribute inertial response, while droop-controlled units dominate steady-state power sharing. Poor coordination between controllers may lead to uneven power sharing, circulating power flows, or control interactions that amplify oscillatory behaviour, particularly in weak LV networks with high impedance. The simulations indicate that stable operation is achieved when both control approaches are strategically distributed rather than concentrated in isolated regions of the feeder.

6.2.4. Complexity of control implementation

GFMI have limited overcurrent capability compared to synchronous machines, which can leave legacy protection devices blind during islanded faults. This risk is acknowledged here and analysed in detail in a dedicated appendix. Another complexity is that mixing different architectures or custom control design in a weak LV network can lead to adverse control interactions and phase imbalances, requiring sophisticated modelling in RMS to validate stability. Two practical constraints exist in simulation. PowerFactory requires DSL programming for custom grid-forming models, and OpenDSS lacks a native swing equation, so the choice of simulation tool itself constrains what can be studied. The results therefore indicate that large-scale deployment of GFMI will require standardized control frameworks, validated parameter tuning procedures, and improved interoperability between inverter manufacturers.

6.3 Key Insights for Microgrid Design

The simulation campaign provides several practical conclusions for the design of future community microgrids with high renewable penetration.

First, the minimum viable grid-forming share for the studied LV feeder corresponds roughly 1.5 seconds of aggregated virtual inertia per kW of consumption and at least 50 % droop capacity. The preferred control strategy is not a binary choice between droop and VSM but a deliberate combination: droop is used for steady-state frequency regulation, VSM is used for transient survival, and both must be present in the population of GFMI. If custom control design will be implemented, the inertia and droop can be provided by one GFMI but locations of them in the feeder is important in terms of stability.

Second, operating PV in grid-forming mode requires curtailment to keep a power reserve, which is rarely worthwhile economically; storage therefore carries the grid-forming role in realistic designs. Therefore, the natural role split is to keep PV in grid-following mode and to assign grid-forming functionality to battery storage; for example sized at 380 kWh, the storage delivers the 2 hours autonomy target for a 189 kW load supported by 270 kW of PV.

Third, the results confirm that the number and spatial distribution of GFMI across the feeder is important. For real deployment, the priority order is clear: tune droop first to guarantee that the islanded frequency settles inside $\pm 0.2\text{Hz}$, then provision enough inertial reserve to survive the first cycles of a disturbance, then verify that the number and placement of GFMI gives consistent behaviour across all supply/demand scenarios. In short, configurations with virtual inertia > 1.5 seconds per kW of consumption and droop capacity of $> 50\%$ work, configurations with virtual inertia < 1.5 seconds per kW of consumption and droop capacity of $< 50\%$ fail, and what matters most is the joint distribution of inertia and droop, not either parameter in isolation.

Overall, the simulations show that successful deployment of GFMI in community microgrids requires a coordinated design approach combining sufficient GFMI penetration, properly tuned inertia and droop settings, distributed storage resources, and hybrid control architectures.



7 References

- [1] Su, Tong, Jiangkai Peng, Alaa Selim, Junbo Zhao, and Jin Tan. "A survey of open-source power system dynamic simulators with grid-forming inverter for machine learning applications." In *2025 IEEE Power & Energy Society General Meeting (PESGM)*, pp. 1-5. IEEE, 2025.
- [2] Cunha, Vinicius C., Taehyung Kim, Piyapath Siratarnsophon, Nicholas Barry, Surya Santoso, and Walimir Freitas. "Quasi-static time-series power flow solution for islanded and unbalanced three-phase microgrids." *IEEE Open Access Journal of Power and Energy* 8 (2021): 97-106.
- [3] Montenegro, Davis, Roger Dugan, Mobolaji Bello, and Celso Rocha. "Grid Forming Inverter Modeling for Microgrid Studies in Distribution Systems." In *ISGT EUROPE*, pp. 1-5. 2023.
- [4] Panteli, Mathaios, Dimitris N. Trakas, Pierluigi Mancarella, and Nikos D. Hatziaargyriou. "Power systems resilience assessment: Hardening and smart operational enhancement strategies." *Proceedings of the IEEE* 105, no. 7 (2017): 1202-1213.
- [5] Shaker, Ayda, Mokhtar Bozorg, Amin Safari, and Sajad Najafi-Ravadanegh. "An adaptive emergency approach for hybrid networked microgrids resilience." *IEEE Access* 10 (2022): 103164-103175.
- [6] Swiss Federal Office of Energy SFOE. "Switzerland's Risk Preparedness with Regard to Electricity," September 23, 2022. <https://www.bfe.admin.ch/bfe/en/home/versorgung/stromversorgung/stromversorgungssicherheit.exturl.html/aHR0cHM6Ly9wdWJkYi5iZmUuY-WRtaW4uY2gvZW4vcHVibGljYX/Rpb24vZG93bmxvYWQvMTExMDQ=.html>.
- [7] Association of Swiss Electricity Companies (VSE). "Transmission Code 2019." Swissgrid Ltd, n.d. <https://www.swissgrid.ch/dam/swissgrid/customers/topics/transmission-code-2019-en.pdf>.
- [8] ELECTRICITY BALANCING IN EUROPE, 2018. Accessed: 2026-05-07, https://eepublicdownloads.entsoe.eu/clean-documents/Network%20codes%20documents/NC%20EB/entso-e_balancing_in%20_europe_report_Nov2018_web.pdf.