

École polytechnique de Louvain

Comparing Solutions to Strengthen Inertia in the Belgian Power System: Impacts on Frequency Stability and Grid Integration

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Abstract

The Belgian power system is transitioning rapidly towards renewable energy sources, leading to reduction in synchronous inertia. As conventional thermal and nuclear generation is gradually displaced by converter-interfaced wind and solar (i.e., connected to the grid through power electronics rather than directly rotating machinery), the system becomes more vulnerable to fast frequency deviations following generation losses. This raises concerns about frequency security, particularly during periods when nuclear units are offline.

This thesis investigates the frequency stability of the Belgian high-voltage transmission grid under low-inertia conditions, using root-mean-square simulations in DIgSILENT PowerFactory. A simplified eight-bus model of the Belgian grid is developed, including synchronous generators with governors and excitation systems, converter-interfaced generation, interconnections with neighbouring countries and frequency-dependent loads. Two operating scenarios are considered: a winter peak and a basic case, each tested with and without nuclear generation and across three levels of renewable energy sources penetration.

The results show that the Belgian grid remains frequency-secure in all tested cases when nuclear is online. In the basic case without nuclear, the frequency nadir falls below 49 Hz following the reference disturbance. This would trigger automatic load shedding in real operation. Three mitigation techniques are then evaluated: synchronous condensers, grid-forming converters and fast frequency response from battery storage.

Two synchronous condensers planned by Elia are found to improve the frequency response but only when equipped with a flywheel does the nadir cross back above 49 Hz. Connecting the future offshore capacity through grid-forming control produces a substantial recovery, restoring the nadir and the rate of change of frequency to levels comparable to the nuclear reference. Activating fast frequency response on batteries also restores the frequency nadir, though without the RoCoF benefit that grid-forming provides. These findings suggest that the converter control strategy for Princess Elisabeth Island is a consequential planning choice for Belgian frequency security in a no-nuclear period and that combining the three mitigation techniques yields the best overall frequency performance.

List of Abbreviations

AEMO	Australian Energy Market Operator
AVR	Automatic Voltage Regulator
BESS	Battery Energy Storage Systems
CCT	Critical Clearing Times
COI	Center Of Inertia
DFIG	Doubly-Fed Induction Generator
DSL	DIgSILENT Simulation Language
DSO	Distribution System Operators
ENTSO-E	European Network of Transmission System Operators for Electricity
FCR	Frequency Containment Reserve
FFR	Fast Frequency Response
GFM	Grid-Forming
GFL	Grid-Following
HVDC	High-Voltage Direct Current
LFDD	Low-Frequency Demand Disconnection
MPPT	Maximum Power Point Tracking
PLL	Phase-Locked Loop
PMSG	Permanent Magnet Synchronous Generator
PV	Photovoltaic
RES	Renewable Energy Sources

RoCoF	Rate of Change of Frequency
SC	Synchronous Condenser
SCR	Short Circuit Ratio
SG	Synchronous Generator
TSO	Transmission System Operator
UFLS	Under-Frequency Load Shedding
VSC	Voltage Source Converter
VSM	Virtual Synchronous Machine
WECC	Western Electricity Coordinating Council

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Chapter 1

Introduction

1.1 Energy transition and power system transformation

Power systems worldwide are undergoing a significant transformation, driven by climate-change mitigation policies, energy-security concerns, and the objective of achieving carbon neutrality.

Figure 1.1 shows that renewable energy sources (RES) have increased significantly since the early 2000s. Neither Europe nor Belgium is an exception to this trend. Ambitious targets have been set at both the European and national level. These are driving the rapid deployment of RES, while conventional thermal power plants are progressively being phased out [9].

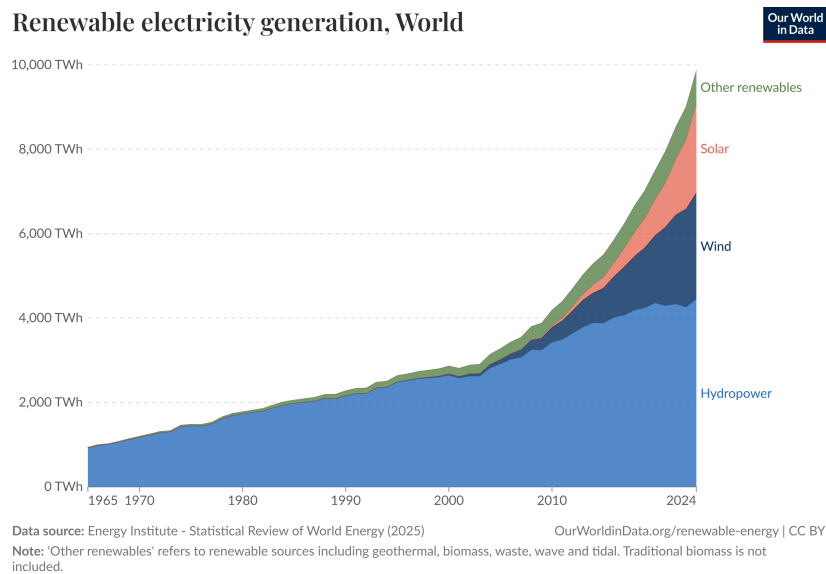


Figure 1.1: Evolution of RES in the world [TWh] [1].

Traditionally, electricity generation in power systems has relied on large power plants equipped with rotating synchronous generators, such as hydro, nuclear or thermal units. These rotating machines inherently provide rotational inertia, which slows down frequency variations following disturbances and thereby contributes to the overall stability of the grid. Rotational inertia refers to the physical tendency of a spinning mass to resist sudden changes in speed. This acts as a natural buffer against rapid frequency swings.

However, the rapid replacement of synchronous generators by converter-interfaced RES has led to a significant reduction in physical rotational inertia in modern power systems. As inertia decreases, the system frequency becomes more sensitive to power imbalances, resulting in more rapid drops in frequency and higher rates of change of frequency (RoCoF). Consequently, the traditional frequency control hierarchy (comprising inertial, primary, secondary and tertiary controls) is increasingly challenged, as the inertial response window of a few seconds is drastically reduced [10, 11].

1.2 Frequency stability as a critical challenge

Frequency reflects the instantaneous balance between electricity generation and consumption. Any significant mismatch results in a deviation from its nominal value. How quickly and how far it deviates depends on the inertia of the system.

In power systems dominated by synchronous machines, inertia and damping are relatively uniform and can be considered time-invariant over short time scales. When a generator trips and power suddenly drops, the remaining synchronous generators immediately release part of their stored kinetic energy. This inertial response slows down the frequency decline during the first seconds after the disturbance, thereby reducing the RoCoF and providing a delay sufficient for primary frequency control mechanisms to act. Governors, or fast frequency controllers on other units, can then increase their output, allowing the frequency to be arrested before under-frequency load shedding (UFLS). Thresholds are reached and subsequently restored towards its nominal value [12]. Figure 1.2 illustrates the different time scales at which the various frequency-control mechanisms operate.

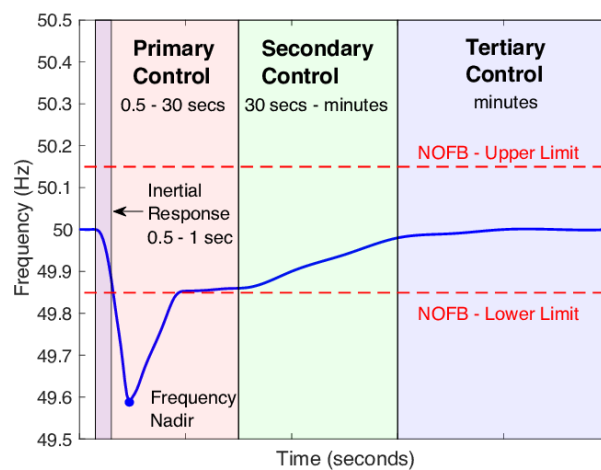


Figure 1.2: Fundamental frequency control principle [2].

Inertia and primary frequency control operate on complementary time scales. As detailed by Tielens and Van Hertem [13], inertia determines the initial slope of the frequency decline, while primary reserves limit the frequency nadir and initiate recovery once the inertial response has faded. Reduced inertia leads to higher RoCoF values and deeper frequency nadirs. However, inertia alone cannot restore the frequency, it merely slows its evolution, making additional control actions essential to bring the frequency back within normal operating limits (see Figure 1.2).

In converter-dominated power systems, inertia is no longer spatially uniform. Some areas of the network may still contain significant rotating masses, such as hydro or nuclear power plants. Others rely almost entirely on converter-interfaced renewable energy sources, such as photovoltaic (PV) or wind generation, which, in their standard grid-following (GFL) configuration, provide little or no physical inertia [14]. During a disturbance, different parts of the network may therefore experience distinct frequency trajectories during the same disturbance. Local frequency measurements can deviate significantly from the system average, particularly in weakly coupled or low-inertia regions [10, 14].

This heterogeneity challenges the traditional notion of a single uniform system frequency. While operators have historically relied on the centre of inertia (COI) frequency, defined as the inertia-weighted average speed of all rotating machines, the increasing share of converter-connected generation makes this concept less representative of actual system dynamics. GFL converters, which rely on phase-locked loops (PLLs), tend to track the grid voltage rather than actively contribute to frequency stabilization potentially leading to discrepancies between measured and effective dynamic frequency behaviour [10].

From an operational perspective, maintaining frequency stability under these conditions has become a growing challenge for transmission system operators (TSOs). In Europe, inertia is managed through coordinated operational standards rather than fixed numerical limits. The European network of transmission system operators for electricity (ENTSO-E) specifies that frequency stability must be ensured by keeping RoCoF within acceptable bounds across the continental European synchronous area [15]. As a result, TSOs continuously monitor system inertia, and they rely on a combination of planning criteria and fast frequency support mechanisms to ensure secure operation under low-inertia conditions.

1.3 Overview of existing mitigation strategies

Several mitigation strategies have emerged in response to these challenges: synchronous condensers (SCs) [16], which restore physical inertia and system strength; converter-based solutions such as GFM inverters [3], which provide synthetic inertia through control; and battery energy storage systems (BESS), which deliver fast frequency response [17]. These approaches are not mutually exclusive and are often complementary. A detailed review and comparison is provided in Chapter 2.

1.4 Research gap and objectives

The literature point to a coherent picture but several questions remain open. Physical inertia is unique in that its response is automatic and requires neither a control system nor an energy reserve. Well-tuned virtual inertia and FFR are necessary in converter-dominated power systems. Moreover, studies consistently show that uniformly distributed inertia combined with strategically placed damping, outperforms concentrated inertia and that hybrid portfolios combining SCs and converter-based resources offer enhanced robustness.

Many gaps nevertheless remain in the understanding and management of frequency stability in low-inertia power systems. First, many existing approaches still rely on simplified system-wide inertia metrics, even though inertia is increasingly time-varying and unevenly distributed. This can lead to local phenomena, such as high regional RoCoF or stressed interconnections, that are not adequately captured by centre-of-inertia models [11, 18]. Second, there is no clear consensus on how to value and coordinate synchronous inertia, synthetic inertia, and FFR, particularly given their different time scales, control behaviours and recovery characteristics [3, 19]. Third, many existing frequency-stability criteria and protection settings were developed for high-inertia power systems and may become inadequate or overly conservative in inverter-dominated grids. Robust methodologies for adapting RoCoF thresholds, UFLS schemes, and locational inertia requirements are still under development [11, 18, 19]. Finally, at the policy and planning level, several questions remain: how much inertia or equivalent services should be secured, how responsibilities should be shared across interconnected areas and how regulatory or market frameworks can procure an efficient mix of inertia and FFR without unnecessary costs or renewable curtailment [11, 19].

This work addresses these gaps through a system-level simulation study focused specifically on the Belgian grid, combining SCs, GFM converters and BESS within realistic operating scenarios.

1.5 Thesis structure

This thesis is organised into five chapters, which address the frequency stability problem in the Belgian power system.

Chapter 2 provides a literature review covering the theoretical foundations of frequency stability, the impact of increasing RES penetration on system inertia, and the main mitigation strategies that have been proposed to address low-inertia conditions. This review forms the basis for the modelling and scenario choices made in the rest of the work.

Chapter 3 describes the simplified model of the Belgian high-voltage transmission grid developed for this study. It covers the network topology, the generation mix, the load representation, the high-voltage direct current (HVDC) interconnections and the definition of the scenarios and disturbance used in the simulations.

Chapter 4 presents and analyses the simulation results. Starting from a reference scenario with nuclear generation, it introduces lower-inertia conditions and tests different solutions to assess their impact on frequency stability. The chapter ends with a comparative analysis and a discussion of the results, including the limitations of the modelling approach and perspectives for future work.

Chapter 5 draws the main conclusions of the thesis and summarises the key findings regarding the ability of the Belgian grid to maintain frequency security under low-inertia conditions.

Chapter 2

Theoretical Background: Frequency Stability, Inertia, and Mitigation Solutions

2.1 Frequency stability fundamentals

2.1.1 Frequency dynamics and system modelling

As introduced in Chapter 1, the post-disturbance dynamics of a power system depends on the interaction of rotating machines and converter-based resources through the transmission network.

To analyse this behaviour, simplified dynamic models are commonly used to represent the motion of synchronous generator rotors and their coupling through transmission lines. These models rely on the swing equation, which describes how the rotational speed of a machine evolves in response to an imbalance between mechanical and electrical power.

In power systems dominated by synchronous machines, inertia and damping are relatively uniform. The response of the grid can be approximated by a single average system frequency, assuming inertia to be time-invariant. This single-frequency approximation holds as long as the inertia is geographically well-distributed and the network is strongly coupled.

2.1.2 Inertia and the swing equation

The inertial response of synchronous machines comes from the kinetic energy stored in their rotating masses. This behaviour is captured by the swing equation, written in torque form as:

$$J \frac{d\omega_m}{dt} = T_m - T_e \quad (2.1)$$

Where J is the rotor moment of inertia, ω_m its angular velocity, and T_m , T_e the mechanical and electrical torques, respectively.

To move from torques to powers, one uses $P = \omega T$ and introduces the inertia constant H , defined as the kinetic energy stored at rated speed, normalised by the machine rated power S_B :

$$H = \frac{1}{2} \frac{J \omega_m^2}{S_B} \quad (2.2)$$

Substituting into the torque equation then gives the power form of the swing equation:

$$2H \frac{d\omega_m}{dt} = P_m - P_e \quad (2.3)$$

During the first few seconds following a disturbance, before governor action begins, the slope of the frequency change is primarily governed by the available rotational inertia. As primary control mechanisms start to act, this assumption becomes less accurate, since additional control actions influence the frequency response [13].

2.1.3 Frequency stability metrics

To quantify frequency stability under varying inertia conditions, several performance indicators are commonly used.

- **Rate of Change of Frequency (RoCoF):** the initial slope of the frequency trajectory following a disturbance. High RoCoF values may trigger protection devices or impose excessive mechanical stress on grid-connected equipment.
- **Frequency nadir:** the lowest frequency reached before recovery begins, determined by both inertia and early control actions.
- **Settling time and overshoot:** indicators describing how quickly the frequency stabilizes and the magnitude of oscillations during recovery. [20].

In the European synchronous area, the nominal system frequency is 50 Hz. A maximum RoCoF of approximately 1 Hz/s and a minimum frequency nadir of 49 Hz are widely adopted as operational reference thresholds [21–24].

These thresholds correspond to the activation levels of concrete system protection mechanisms. In Belgium, the low-frequency demand disconnection (LFDD) plan constitutes the automatic last-resort defence against a total blackout in the event of a severe frequency collapse [25]. LFDD relays are installed across the Belgian territory and are organised in ten successive steps.

The first step activates when the frequency falls below 49.0 Hz. Subsequent steps are triggered at progressively lower levels, each disconnecting a portion of the total load to arrest the frequency decline and allow the system to recover. This stepwise mechanism establishes a nadir below 49 Hz as a hard operational limit. Crossing that threshold initiates involuntary demand disconnection, which, even if it prevents a blackout, has significant carries real financial and social costs. Similarly, a high RoCoF increases the risk that frequency-based protection relays on generation units trip prematurely, potentially disconnecting machines that are still contributing to frequency recovery. This premature disconnection can worsen the disturbance in a cascading manner.

2.1.4 Mechanical versus virtual inertia

Although both synchronous condensers and power electronics devices can contribute to frequency stabilisation, the physical origin and dynamic behaviour of their inertial response are fundamentally different. In modern grids, three main forms of inertia can be distinguished: **mechanical** or **real inertia**, **synthetic** or **virtual inertia**, and **grid-forming inertia**.

Mechanical (real) inertia. Synchronous machines inherently possess mechanical inertia due to their rotating masses. When a disturbance occurs, the kinetic energy stored in the rotor is instantaneously released to partially offset the power imbalance, slowing the rate of frequency change according to the swing Equation (2.3). This response is physical and persists until primary control actions begin. Because synchronous machines are directly coupled to the grid voltage, their inertial contribution remains effective even during voltage disturbances [10, 11].

Synthetic (virtual) inertia. Converter-interfaced resources can emulate inertial behaviour through control algorithms that adjust active power in response to frequency deviations or RoCoF:

$$\Delta P = -K_p \Delta f - K_d \frac{df}{dt}. \quad (2.4)$$

Where K_p is the proportional gain (emulating damping) and K_d is the derivative gain (emulating inertia).

Virtual inertia reproduces the stabilising behaviour of synchronous machines using measurement and feedback control. Figure 2.1 summarises the concept of virtual inertia. This response is delayed by measurement and control dynamics, and is constrained by converter current limits and available energy. Although the gains are adjustable, excessive values may amplify measurement noise or cause control instability [3, 10, 26].

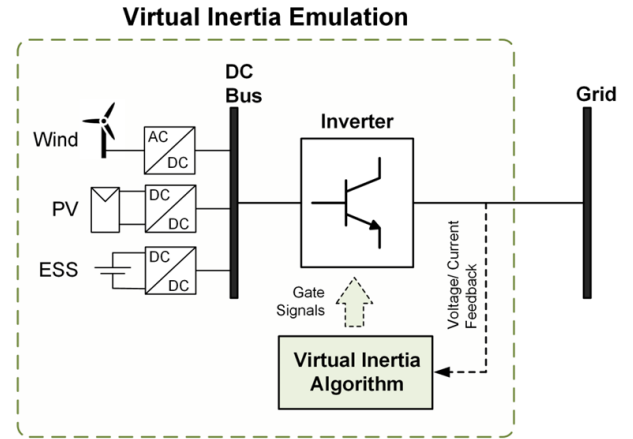


Figure 2.1: Concept of virtual inertia [3].

Grid-forming inertia. Grid-forming converters generate their own voltage and frequency reference, allowing them to mimic the electromechanical behaviour of synchronous machines. By embedding virtual inertia and damping directly into their control laws, they can provide fast, stable frequency support even in weak or islanded grids, with a response that closely approximates that of a physical synchronous machine [27]. The key distinction lies in the converter architecture: synthetic inertia is implemented on top of a grid-following converter that relies on a PLL to track an existing voltage, whereas grid-forming inertia is embedded in the converter's core control law, which generates its own voltage reference without measuring the grid frequency externally.

Mechanical, synthetic, and grid-forming inertia all contribute to limiting RoCoF and improving frequency stability. They differ in reliability, controllability and physical nature. Together, they form a continuum of mechanisms for maintaining frequency resilience in modern power systems [3, 15].

2.1.5 Primary control: frequency containment reserve in Belgium

To avoid a blackout and stabilise frequency during a frequency deviation, automatic reserve is needed. This is the frequency containment reserve (FCR), which is the primary control mechanism acting just after the inertial response. It responds automatically within a few seconds, offsetting frequency deviations and stabilising the frequency at a quasi-steady-state value.

Primary control does not activate instantaneously, it responds to a frequency deviation through the droop characteristic:

$$P_m = P_{m,0} - \frac{P_N}{\sigma} \cdot \frac{f - f_0}{f_0} \quad (2.5)$$

Where P_m is the mechanical power output, $P_{m,0}$ the initial power, P_N the nominal power of the generator, σ the droop coefficient, f the measured frequency, and f_0 the nominal frequency (50 Hz).

Secondary and tertiary control then take place to restore the frequency to its nominal value (see Figure 1.2).

As part of the Continental European synchronous area, Belgium is subject to ENTSO-E regulations that standardise the FCR procurement process, thereby reducing overall costs. In total 3,000 MW of common FCR is available in continental Europe and the FCR volume of Belgium is part of this pool [28, 29]. In 2026, the required FCR volume for Belgium is 94 MW, of which 27 MW constitute the core share that must be procured domestically [29, 30].

Since the liberalisation of electricity markets in the early 2000s, primary reserves are contracted in an annual tendering system in Belgium. Participants submit bids to Elia. On a day-ahead basis, participants must submit to the TSO which production units will provide the reserves. Daily offers are structured in six blocks of four hours. Full activation is reached when the frequency deviates by 200 mHz from the nominal frequency. Under current Belgian rules, variable renewable sources such as wind farms cannot provide FCR, as their availability is not guaranteed [31, 32].

2.2 Impact of RES and power electronics

The increasing penetration of RES and power-electronic interfaces fundamentally alters the assumptions underlying classical frequency-stability analysis. Unlike conventional synchronous generation, converter-interfaced resources are electrically decoupled from grid frequency and do not inherently contribute to mechanical inertia. As a result, both the magnitude and the spatial distribution of inertia within modern power systems are significantly modified.

The distribution of inertia within a power system is not homogeneous. It depends strongly on where synchronous machines are connected and how the electrical network is structured. Historically, most synchronous generation has been located at the transmission level, where large thermal, nuclear and hydro units directly couple their rotating masses

to the high-voltage grid. The bulk of the system's kinetic energy and thus its ability to resist frequency deviations, is therefore concentrated in the transmission network.

In contrast, most RES are connected to the medium- and low-voltage distribution networks through converters whose power output is not inherently tied to the grid frequency, unlike synchronous machines. Although these inverter-based resources inject active power, they do not provide mechanical inertia. As a result, even when a large share of generation is embedded in the distribution system, the effective inertia governing system-wide frequency dynamics remains primarily determined by transmission-connected synchronous machines [10, 11, 15].

2.2.1 Loss of inertia uniformity and spatial frequency effects

As discussed in Chapter 1, in converter-dominated systems, inertia becomes heterogeneous. Some areas of the network retain large rotating masses (e.g., hydro or nuclear plants), while others consist almost entirely of converter-interfaced renewable resources with little or no physical inertia (e.g., solar or wind) [14].

When a disturbance occurs, the rate at which the frequency changes depends inversely on the kinetic energy stored in the connected synchronous machines. If that inertia is low, frequency excursions propagate rapidly throughout the grid. Distribution-level inverters, which rely on PLLs to synchronize to the voltage waveform, may struggle to track such fast variations and can even lose synchronism or trip during severe events. This phenomenon was illustrated in the "Impact of Inertia Distribution" study funded by Elia and Brunel University [18]. At the same time, different parts of the network may experience distinct frequency trajectories during the same event, particularly in weakly coupled or low-inertia regions. Local frequency measurements can therefore deviate significantly from the system-average response [10, 14].

These effects challenge the traditional assumption of a uniform system frequency, making spatial considerations increasingly relevant in frequency stability assessment.

2.2.2 System frequency and spatial effects

As introduced in Chapter 1, the concept of a single uniform system frequency becomes less meaningful as inertia grows more heterogeneous.

As the share of converter-interfaced generation increases, defining a meaningful system frequency becomes increasingly challenging. Grid-following converters rely on PLLs to track the grid voltage rather than actively stabilizing it.

This may lead to discrepancies between measured and effective dynamic frequency behaviour during disturbances [10]. Consequently, the assumption of a single uniform system frequency becomes less representative of actual system dynamics [33].

2.2.3 Impacts of uneven inertia distribution

Beyond total system inertia, its spatial distribution directly shapes the initial frequency and power-flow transients following a disturbance. When inertia is concentrated in certain areas and scarce in others, several adverse effects can arise:

- **Local RoCoF spikes:** Low-inertia regions experience RoCoF values well above the system average, increasing the likelihood of local disconnections.
- **Inter-area oscillations:** Uneven inertia distribution leads to larger tie-line power oscillations and higher oscillation frequencies, degrading transient stability.
- **Protection risks:** Critical clearing times (CCT) of key transmission lines are reduced as local inertia falls, increasing the risk of relay misoperation. This effect concerns rotor-angle stability rather than frequency stability *per se*, but both are affected by reduced inertia.
- **COI versus local frequency divergence:** The COI may appear stable while local frequencies deviate significantly [14].

These findings show that maintaining a minimum inertia floor locally is essential for system security.

2.2.4 Implications for system operation and TSO responsibility

Because inertia and frequency stability are inherently system-wide phenomena, TSOs are responsible for monitoring and managing inertia levels across the transmission network.

System strength, often quantified through short-circuit levels, provides a local measure of voltage robustness and converter-control stability during disturbances. The Australian Energy Market Operator’s (AEMO) 2024 System Strength Report emphasises that such requirements are primarily defined at the transmission level, where insufficient system strength can compromise both voltage and frequency stability [24].

As discussed in the "Assessment of Policy Options for Securing Inertia" report by Artelys (2025), TSOs can secure inertia through a combination of market-based procurement mechanisms, installation of SC, and GFM requirements for converter-connected plants [19]. While distribution system operators (DSOs) may contribute locally by enabling advanced inverter functionalities, the effective mitigation of low-inertia conditions remains primarily a transmission-system responsibility.

Moreover, because inertia is shared across interconnected synchronous areas, ENTSO-E emphasises the importance of regional coordination and cross-border approaches to inertia management. It enables TSOs to collectively maintain adequate kinetic energy while optimising local investments [21].

Uneven and reduced inertia also affects fault dynamics and security margins. Higher local RoCoF values can cause frequency-based protection thresholds to be reached more rapidly, while reduced inertia shortens the critical clearing times of transmission lines and generators. These effects increase the risk of relay misoperation and cascading outages, particularly in weak or low-inertia regions. Inertia is therefore not only a frequency-stability parameter but also a direct contributor to system security.

2.3 Solutions to strengthen frequency stability

This section reviews the main solution families proposed in the literature to strengthen frequency stability in low-inertia power systems. The focus is placed on their operating principles, typical deployment contexts and reported advantages and limitations.

The literature distinguishes three main solutions to strengthen frequency stability in low-inertia power systems: **synchronous condensers**, **converter-based solutions**, and **storage-based fast frequency response**. Although these approaches share the objective of mitigating fast frequency deviations, they differ fundamentally in their physical principles, time scales and system-level impacts. Table 2.1 summarises the main qualitative differences reported in the literature.

2.3.1 Synchronous condensers

Synchronous Condensers and Flywheels

Synchronous condensers (SCs) remain the most mature option for restoring inertia and system strength. Modern SCs can include integrated flywheels to increase stored kinetic energy more cost-effectively than installing a larger machine [34].

Figure 2.2 shows that, depending on their configuration, SCs can achieve different inertia constants. Larger machines achieve higher inertia constants but also carry a significantly higher cost [4].

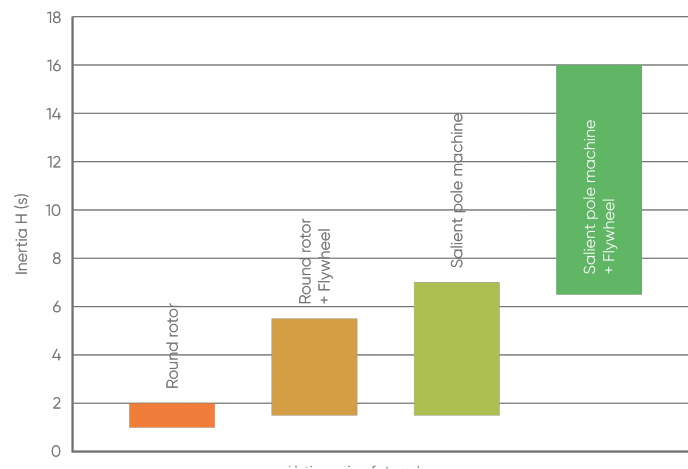


Figure 2.2: Achievable inertia constant of a SC [4].

Repurposing existing generation units into SCs can be achieved with several types of machines, each presenting specific mechanical and electrical characteristics. Three main categories of existing units are considered technically feasible for repurposing: hydro generators (simplest to convert, retaining most original inertia), gas-turbine units (convertible via clutch systems), and steam-turbine units (most complex, requiring flywheels to restore inertia)

According to the ARENA and DIgSILENT study [35], repurposing existing units typically cost 30–50% less than new synchronous condensers and can be delivered significantly faster, making it attractive for rapidly restoring inertia and system strength.

Locational requirements for synchronous condensers

As mentioned previously, synchronous condensers (SCs) contribute to three complementary stability services: reactive power and voltage control, short-circuit current and system strength, and rotational inertia. Their technical roles are distinct but interconnected. An SC improves voltage regulation and grid stability by continuously generating or absorbing reactive power and by enhancing system strength through its short-circuit current contribution. When equipped with an additional flywheel, it can also provide extra synchronous inertia to improve frequency stability [36].

Voltage control and system strength are both inherently local phenomena. Reactive power cannot be transmitted efficiently over long distances and short-circuit current depends on the network impedance at the point of connection. Therefore, SCs must be placed at buses where voltage is weak or where the short-circuit ratio (SCR) is low (typically at the end of long transmission lines, in coastal substations, or at offshore connection points). Such siting maximizes their ability to stabilize voltage, improve protection performance and reduce reactive-power losses. This conclusion is supported by Igbinovia *et al.* [37], who demonstrated that installing SCs at the end of a transmission line significantly improves the voltage profile and reduces reactive-power losses.

Unlike reactive power or fault current, inertia is a global property of the synchronous area. All synchronous machines contribute to the total kinetic energy that resists frequency changes, regardless of their location. Thus, adding a SC anywhere in the network increases the overall system inertia and helps limit the RoCoF. However, the local placement of inertia can still influence short-term dynamics: inertia added near low-inertia or weakly coupled areas mitigates local RoCoF spikes and reduces inter-area oscillations more effectively than if placed far away [15, 38]. The 2023 AEMO Inertia Report [38], for instance, describes how SCs installed at Robertstown and Davenport in South Australia were positioned primarily to correct system-strength shortfalls but also provided a measurable improvement in regional inertia and frequency stability.

Because voltage and system-strength deficiencies are spatially localized while inertia is system-wide, transmission planners typically identify weak or remote nodes first based on voltage-stability and protection criteria. SCs are then deployed at these nodes to provide local reactive power and short-circuit support, and their inertial contribution is considered a co-benefit rather than a separate siting criterion. This approach ensures that investments serve multiple stability objectives simultaneously, an idea reflected in both Elia’s Federal Development Plan [39] and AEMO’s system-strength planning methodology [24].

SCs offer several properties that converter-based devices cannot fully replicate. First, their rotating mass provides real, physical inertia and contributes substantial short-circuit current during faults, which strengthens protection coordination and supports voltage recovery. These are two aspects that converters struggle with due to their inherent current limits [34, 35]. Their electromechanical nature also makes them tolerant to voltage dips and frequency excursions: they respond smoothly without tripping or entering control instability [34]. Unlike converter-based devices, they do not inject harmonics into the grid, which helps maintain voltage waveform quality and reduces the need for harmonic filtering [34]. They can also supply or absorb reactive power dynamically, improving voltage stability and system strength in weak or low-inertia networks [35]. Finally, SCs are a mature technology whose behaviour is well understood by system operators, with proven reliability and compatibility with existing protection and control systems [35].

Despite these properties, SCs come with practical drawbacks. They consume auxiliary power, typically 1-2% of their rated capacity and require periodic mechanical maintenance, resulting in ongoing operational costs [35]. New installations also involve long lead times, typically 2-2.5 years from order to commissioning. Even repurposed units require detailed mechanical modifications and site-specific engineering [35]. On the cost side, new SCs are generally more expensive than converter-based alternatives when civil works and auxiliary systems are factored in, though repurposed units can partially offset this [34, 35]. Their location is also a constraint: existing generator sites may not coincide with the grid nodes where inertia and reactive power support would be most beneficial [35].

2.3.2 Converter-based solutions

Grid-following converters

Converter-based resources connected through grid-following (GFL) converters can contribute to frequency stability by providing frequency support through droop-based active power adjustment.

The main advantage of GFL-based solutions lies in their flexibility and scalability. They can be deployed in areas where synchronous machines are absent and tuned to provide fast active power injection within hundreds of milliseconds, which is particularly valuable in low-inertia systems. However, their contribution relies entirely on control algorithms and PLLs, making them sensitive to weak-grid conditions and large voltage disturbances. A PLL is the mechanism by which GFL converters synchronise to the grid voltage. Moreover, their fault current contribution is inherently limited by converter ratings, which restrict their ability to improve system strength or support protection coordination [10, 40].

Grid-forming converters

Grid-forming (GFM) converters represent a more fundamental shift in control philosophy. Instead of following an externally imposed voltage and frequency, GFM converters actively establish these quantities at their point of connection, allowing them to operate without a PLL. GFMs do not need one because they generate their own voltage reference. By emulating the behaviour of synchronous machines through control laws such as matching control or virtual oscillator control, GFM converters can provide synthetic inertia, damping, and voltage support in weak or islanded grids.

ENTSO-E recommends prioritizing the deployment of GFM in regions with low system strength, at the periphery of transmission networks or behind HVDC interfaces where conventional synchronous machines are scarce [27]. In these locations, GFM converters can stabilize local voltage and frequency and improve the dynamic response of the network. However, since their inertial contribution originates from control dynamics rather than stored kinetic energy, GFM do not increase the total mechanical inertia of the synchronous area. Their effectiveness therefore depends strongly on control design and coordination with other grid-supporting devices.

Overall, converter-based solutions offer fast and flexible frequency support but require careful tuning and coordination. They are more effective when combined with SCs or other sources of physical inertia, rather than deployed as standalone solutions in large interconnected systems.

2.3.3 Storage-based solutions

Energy storage systems, particularly battery energy storage systems (BESS), represent an emerging and increasingly important solution for strengthening frequency stability in low-inertia power systems. Unlike synchronous machines, inverter-based batteries are not constrained by mechanical dynamics and can modify their active power output extremely rapidly. This capability allows BESS to shape the frequency response during the first seconds following a disturbance, which is precisely the time window where low-inertia systems are most vulnerable [17].

The work of Tbaileh *et al.* [17] investigates how fast frequency response (FFR) from transmission-connected BESS can mitigate deep frequency nadirs and reduce the risk of under-frequency load shedding (UFLS) in very low-inertia scenarios. FFR refers to the rapid injection or absorption of active power in response to measured frequency deviations, typically within sub-second to a few seconds. Compared to conventional thermal governors, which are limited by mechanical delays, BESS can respond almost

instantaneously. This allows them to provide effective support during the arresting phase of the frequency transient.

By delivering active power proportionally to frequency deviation or RoCoF, BESS can mimic some beneficial effects of inertia, even though no physical kinetic energy is involved. This form of synthetic inertial support improves the frequency nadir and slows the initial frequency decline. However, the response is energy-limited and depends on the available state of charge. The contribution of BESS does not persist over longer time horizons without coordination with slower reserves.

It is important to note that the study by Tbaileh *et al.*, considers BESS operating in GFL mode, where the inverter reacts to an existing system frequency rather than establishing it. As such, storage-based FFR complements but does not replace synchronous inertia or grid-forming resources. In practice, BESS is best viewed as a fast-acting stabilizing resource that enhances the short-term frequency response while longer-term stability is ensured by synchronous machines, GFM and conventional reserves [17].

2.4 Comparison of approaches

Across the literature, the different mitigation solutions are often associated with distinct phases of the frequency transient.

Physical inertia from SCs primarily limits the initial RoCoF and supports protection performance, while GFM controls improve local voltage and frequency stability in weak-grid conditions. Storage-based FFR acts during the arresting phase, reducing the frequency nadir and mitigating the risk of UFLS. These three mechanisms are therefore complementary rather than interchangeable.

In converter-dominated systems, several studies report that GFM converters can complement SCs by providing a synthetic voltage and frequency reference in areas where both system strength and synchronous inertia are weak. GFM converters help stabilise local voltage and frequency, effectively reducing the need for synchronous inertia. However, because their contribution arises from control dynamics rather than stored kinetic energy, GFM reinforce stability locally but do not directly increase the total kinetic energy of the synchronous area. Their placement must therefore be co-optimised with that of SCs to avoid control interactions and ensure robust damping in low-inertia zones [27].

Beyond their spatial complementarity, the literature also points to fundamental differences in the nature of frequency support provided by each mitigation technique. SCs contribute physical inertia through stored kinetic energy, which is inherently available and independent

of measurement, communication, or control delays. By contrast, converter-based solutions, including GFM converters and FFR from storage, rely on control algorithms and power-electronic interfaces. While these approaches offer greater flexibility and tunability, their effectiveness depends on accurate measurements, control stability, and hardware limits, making them more sensitive to parameter tuning and system conditions [3, 10].

Another key distinction identified in the literature concerns the timescale and robustness of the frequency response. Mechanical inertia from synchronous condensers acts instantaneously following a disturbance and persists as long as the machine remains connected. In contrast, converter-based responses typically occur with a short delay and may be curtailed by current limits, energy constraints, or control saturation. As a result, several studies conclude that while converter-based solutions are effective at shaping the frequency nadir, they cannot fully replace the stabilising role of physical inertia in large interconnected systems [11, 15]. Storage-based FFR is notable for its very fast active power injection, in some cases faster than the synthetic inertia of GFM converters, making it particularly effective at limiting the frequency nadir. However, unlike physical inertia, it remains energy-limited and cannot sustain its response indefinitely [17]. Table 2.1 summarises the main characteristics of each mitigation technique across the criteria discussed above.

Table 2.1: Comparison of solution families for frequency stability in low-inertia power systems.

Criterion	Synchronous Condensers	GFL/GFM Converters	Storage-Based FFR
Nature of response	Physical (kinetic energy)	Control-based (synthetic or GFM inertia)	Control-based fast active power injection
Response time	Instantaneous	Fast but delayed	Very fast
Persistence of support	Sustained (while connected)	Limited by control and current limits	Energy-limited; short-duration
Impact on frequency nadir	Indirect (via slowed dynamics)	Effective if coordinated	Highly effective in arrest phase
System strength & fault current	High short-circuit contribution	Limited by converter rating	Limited; no inherent fault current
Voltage support	Continuous reactive power	Control-dependent	Limited (unless advanced controls)
Control dependence	None	High	High
Deployment flexibility	Site-specific, heavy infrastructure	Highly flexible and modular	Highly flexible and modular
Lead time	Long (months to years)	Short (months)	Short (months)
Key limitations	Cost, civil works, location	Control interactions, saturation	Energy & state-of-charge constraints

The comparison highlights that SCs provide physical inertia and system strength that converter-based solutions cannot fully replicate, in terms of fault current contribution and unconditional response, making them particularly valuable for reducing RoCoF and supporting protection systems in large interconnected grids.

Converter-based solutions offer greater flexibility and can stabilise voltage and frequency locally, especially when operated in GFM mode, but their contribution remains control-dependent and does not increase total system inertia.

Storage-based FFR stands out for its very rapid active power injection, which is highly effective at limiting frequency nadir in the first seconds following a disturbance. Unlike synchronous inertia, which exchanges power without explicit energy management, storage-based FFR is constrained by both inverter power ratings and available state of charge and its energy-limited nature prevents it from acting as a standalone replacement for inertia.

As a result, the literature consistently emphasises that coordinated portfolios combining these complementary solutions provide the most robust approach to frequency stability in low-inertia power systems [19]. No single solution dominates across all metrics. SCs, GFM converters, and BESS each address a different part of the problem. Chapter 3 translates these findings into modelling choices, building a simplified but representative model of the Belgian grid that captures the dynamics identified here.

Chapter 3

Modelling of the Belgian grid

3.1 High-voltage transmission network

To evaluate frequency stability under low-inertia conditions, a model of the Belgian high-voltage transmission grid was developed. As discussed in the previous chapters, inertia and system strength are primarily transmission-level phenomena, since large synchronous generators and major interconnections are connected to the high-voltage network. Operational requirements related to inertia and short-circuit strength are therefore typically defined and monitored at transmission nodes [24].

In Belgium, the TSO is Elia, which is responsible for ensuring system security, including adequate inertia and system strength. Elia can secure these services through market-based mechanisms, installation of SCs and technical requirements imposed on converter-connected plants [19]. Although distribution system operators may contribute locally through advanced inverter functionalities, the management of low-inertia risks remains predominantly a transmission-system responsibility.

For this reason, the present study focuses on the Belgian high-voltage transmission grid operated by Elia, represented in Figure 3.1. The model includes the 380 kV and 220 kV networks, which form the backbone of the Belgian transmission system and host the majority of large generation units, interconnections, and system-strength resources.

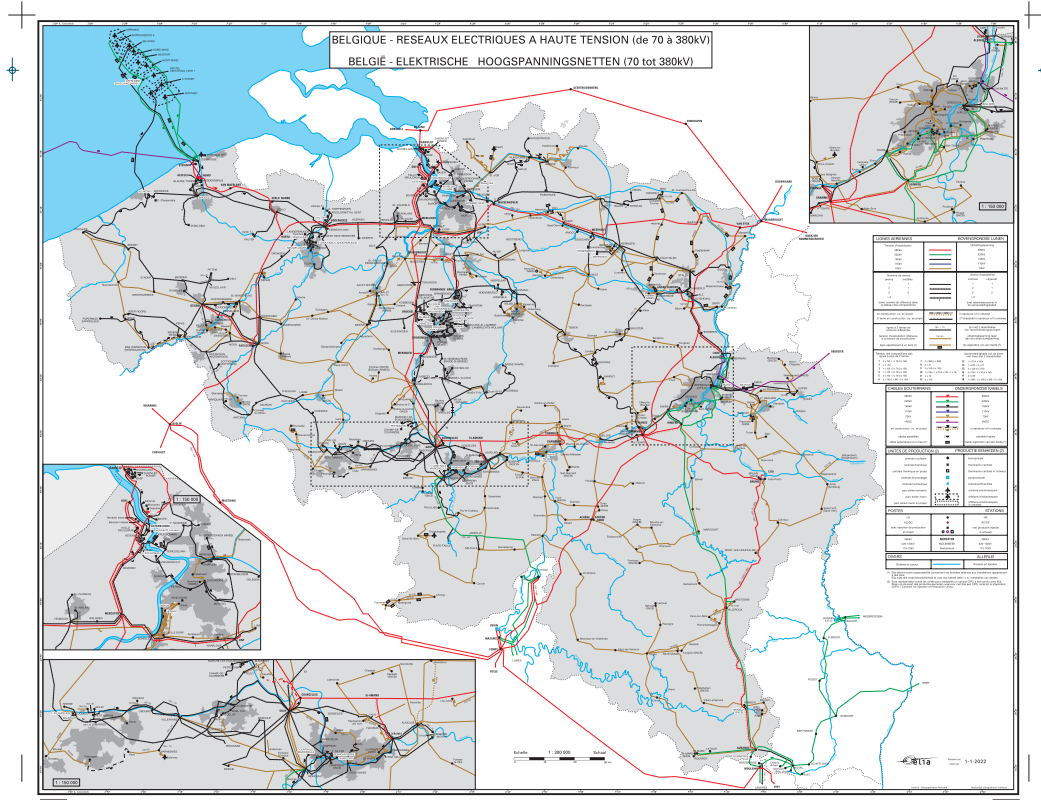


Figure 3.1: Belgian high-voltage grid. Red lines represent the 380 kV lines and green lines represent the 220 kV lines [5].

Lower-voltage distribution networks are not explicitly modelled. Instead, distributed generation and loads connected at lower voltage levels are aggregated at the corresponding high-voltage substations. This assumption allows the analysis to focus on system-level frequency dynamics and inertia distribution while maintaining a computationally efficient model. This aggregation neglects intra-distribution dynamics but is an appropriate simplification for transmission-level frequency studies, where the focus is on bulk power system inertia and primary frequency response.

3.2 Network topology modelling

As discussed in previous chapters, inertia is not spatially homogeneous in modern power systems. Capturing the geographical distribution of generation and interconnections, is therefore essential, when analysing frequency dynamics and locational effects.

A simplified network model, based on the HV grid shown in Figure 3.1, was developed that remains sufficiently detailed to represent inertia distribution, while limiting computational complexity. The Belgian transmission system is therefore represented by eight aggregated

nodes corresponding to major high-voltage substations and geographical areas. The exact allocation of generators to each node is provided in Appendix A.

The defined nodes are:

- **BE_COAST (b1)**: West-Flanders / Zeebrugge area / Nemo interconnection
- **BE_FL_NORTH (b2)**: Antwerp / Ghent industrial cluster / Dutch border
- **BE_CENTRAL (b3)**: Brussels and central region
- **BE_NDLS (b4)**: Limburg / Dutch border
- **BE_MONS (b5)**: Hainaut / French border
- **BE_NUC_SOUTH (b6)**: Liège / Tihange / Walloon industrial area / ALEGrO interconnection
- **BE_LUX (b7)**: Luxembourg province / Luxembourg border
- **BE_COO (b8)**: Coo hydraulic power plant

Each node has at least one equivalent synchronous generator and one aggregated load. Interconnection with neighbouring countries are explicitly represented at the corresponding border nodes.

The line parameters (resistance, reactance, and susceptance) are taken from Elia's static grid data [41]. Since the model aggregates the actual transmission network into eight equivalent nodes, each inter-node connection is represented by a single equivalent line whose parameters are derived by combining in parallel all the physical lines that connect the same pair of substations in the dataset.

It should be noted that in this work, neither the LFDD relays nor any generator tripping triggered by frequency protection is modelled. The simulations therefore assess how close the system comes to these limits, rather than simulating the cascading effects that would follow if they were exceeded.

As illustrated in Figure 3.1, the Belgian transmission grid is predominantly operated at 380 kV, with 220 kV lines mainly located in the southern part of the country. This voltage-level distinction is represented in the simplified model by introducing two additional buses, **b6'** and **b7'**, operating at 220 kV and connected through 380/220 kV step-down transformers. Figure 3.2, gives the simplified model of the Belgian high voltage grid¹.

¹Transformers and converters are omitted for clarity.

Nuclear generation units are modelled explicitly and are not aggregated into the equivalent synchronous machines. This modelling choice simplifies the implementation of scenario analysis, particularly when assessing the impact of a Belgian generation mix without nuclear power.

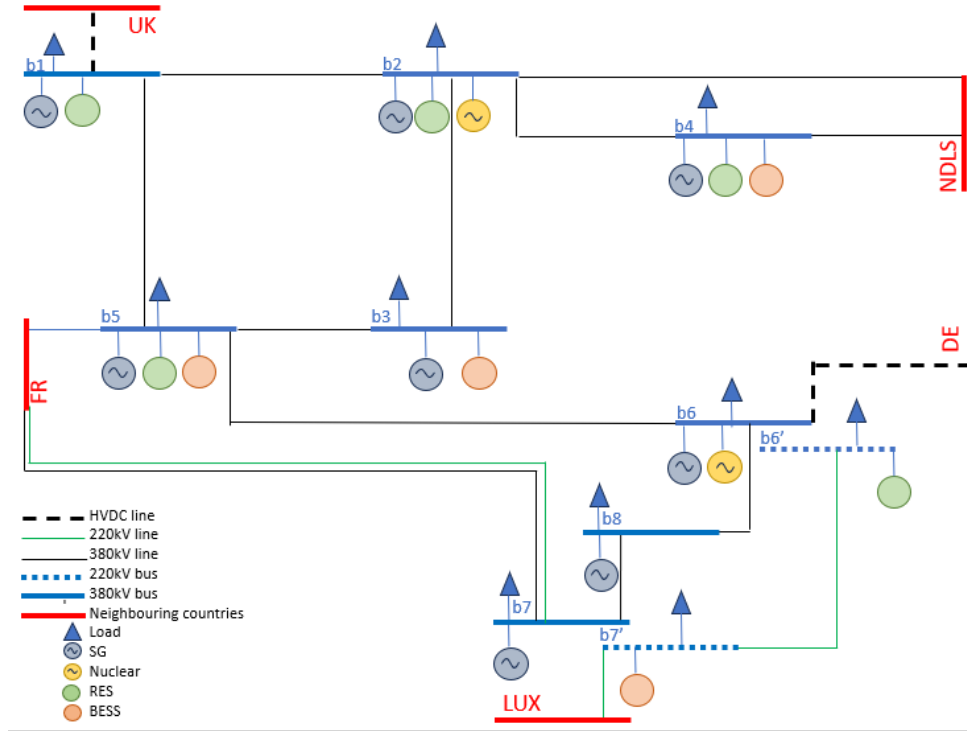


Figure 3.2: Simplified representation of the Belgian HV grid.

The modelling of the Belgian transmission grid is implemented using the DIgSILENT PowerFactory software environment.

3.3 Generation modelling

3.3.1 Power Generation in Belgium

This section details the modelling of the different production units connected to the Belgian HV grid. The allocation of generation units to the nodes of the simplified Belgian grid model is based on the ODS179 dataset published by Elia [42]. This dataset contains all technical units contracted with Elia for scheduling and outage planning purposes and therefore represents centrally dispatched and system-relevant generation units. These units constitute the main contributors to system inertia. Table 3.1 summarises the installed capacity per node and per technology. The values correspond to the maximum active power $P_{\max}$ of each unit.

Table 3.1: Technology breakdown per node: Installed P_{max} (MW).

Node	BATTERY	GAS	HYDRO	NUCLEAR	SOLAR	THERMAL	WIND	TOTAL
BE_CENTRAL	207.0	609.0	0.0	0.0	0.0	304.0	0.0	1115.0
BE_COAST	0.0	59.4	0.0	0.0	0.0	100.9	2081.1	2194.5
BE_NUCL_SOUTH	0.0	2050.5	0.0	1038.0	60.0	332.1	76.9	3557.5
BE_COO	0.0	0.0	1164.0	0.0	0.0	0.0	0.0	1164.0
BE_MONS	200.1	1124.0	0.0	0.0	0.0	162.0	106.1	1592.2
BE_NDLS	25.0	159.0	145.7	0.0	99.0	16.9	0.0	445.6
BE_FL_NORTH	0.0	1019.8	0.0	1039.0	0.0	465.0	84.7	2608.5
BE_LUX	11.5	0.0	1.8	0.0	0.0	18.0	0.0	31.3
TOTAL	443.6	5021.7	1311.5	2077.0	159.0	1313.8	2348.8	12675.4

Table 3.2: Inertia constants H per generation technology [7, 8].

Code	Generation Technology	H (s)
NUC	Nuclear power plant	6.4
ST	Steam turbine (coal / gas / biomass)	5.0
GT	Gas turbine (open cycle)	3.0
TJ	Turbojet / small thermal turbine	2.7
RoR	Run-of-river hydropower plant	3.4
HT	Pumped-storage hydropower plant	3.4
CE	Combustion engine / CHP unit	3.0
–	Converter-based generation (wind, PV, BESS)	0.0

3.3.2 Synchronous generators

Synchronous machines play a major role in grid frequency stability, as they provide physical inertia through their rotating masses. In the present work, the standard synchronous machine model available in DIgSILENT PowerFactory is used to represent the equivalent SG at each node.

The rated apparent power $S_{B,i}$ of each synchronous machine is not directly available in the dataset used for this work, which only provides the maximum active power output $P_{\max,i}$. To convert between the two, a uniform power factor of $\cos \varphi = 0.85$ is assumed for all synchronous machines:

$$S_{B,i} \approx \frac{P_{\max,i}}{\cos \varphi} \quad (3.1)$$

This value is consistent with typical nameplate ratings of large thermal and hydro generators, where power factors generally fall in the range 0.80–0.90 [43].

Applying a single value across all units is a simplification. In practice, each machine has its own rated power factor depending on its design and operating point. However, given that the inertia constant H is itself an approximation aggregated at the node level, the error introduced by this assumption remains small relative to the modelling uncertainty. The impact on the equivalent inertia H_{eq} is expected to be limited, since the same factor applies uniformly to all machines in the weighted average.

In load-flow calculations, synchronous machines can operate under three different control modes:

- **PV mode:** constant active power and constant voltage magnitude,
- **PQ mode:** constant active and reactive power,
- **Slack (reference) mode:** active and reactive power are adjusted automatically to ensure overall system power balance.

In the developed model, all synchronous machines are configured as PV buses. The slack bus is placed at the Dutch border interconnection, which is a modelling convention. This choice reflects the modelling convention that priority is given to Belgian generation, and that the interconnection between the Netherlands and Belgium is strong.

Inertia

The inertia contribution of a generation unit depends on its technology. Synchronous generators (SGs) inherently provide rotational inertia due to the kinetic energy stored in their rotating masses. Whereas converter-based generation does not provide physical rotational inertia since it is not directly coupled to the grid frequency.

For a synchronous machine i , the stored kinetic energy is given by:

$$E_i = H_i S_{B,i} \quad (3.2)$$

Where H_i is the inertia constant (in seconds) and $S_{B,i}$ is the rated apparent power of the machine.

As a uniform power factor of $\cos\phi = 0.85$ was assumed for all synchronous machines, the rated apparent power can be approximated as:

$$S_{B,i} \approx \frac{P_{\max,i}}{\cos\phi} \quad (3.3)$$

The kinetic energy then becomes:

$$E_i = H_i \frac{P_{\max,i}}{\cos\phi}. \quad (3.4)$$

The total kinetic energy at a node is therefore:

$$E_{\text{tot}} = \sum_i H_i \frac{P_{\max,i}}{\cos\phi}. \quad (3.5)$$

Because the power factor is assumed to be constant, the equivalent inertia constant can be expressed as a capacity-weighted average:

$$H_{\text{eq}} = \frac{\sum_i H_i S_{B,i}}{\sum_i S_{B,i}} \quad (3.6)$$

which simplifies to:

$$H_{\text{eq}} = \frac{\sum_i H_i P_{\max,i}}{\sum_i P_{\max,i}}. \quad (3.7)$$

The equivalent inertia constant per node is therefore computed as a capacity-weighted average of individual machine inertia constants. The technology-dependent inertia values used in this work are provided in Table 3.2.

This calculation is based on installed maximum capacity and therefore assumes that all synchronous machines are online. It represents a theoretical upper-bound inertia level and serves as a reference for scenario analysis. Table 3.3 summarises the equivalent inertia for each node.

Table 3.3: Equivalent inertia constant per SG at each node with and without nuclear generation.

Node	H_{eq} with nuclear (s)	H_{eq} without nuclear (s)
BE_CENTRAL	3.610	3.610
BE_COAST	2.899	2.899
BE_NUCLEAR_SOUTH	3.998	3.300
BE_MONS_FR	3.252	3.252
BE_NDLS	3.286	3.286
BE_FLANDERS_NORTH	4.727	3.571
BE_LUXEMBOURG	2.700	2.700

Excitation model

An excitation model is necessary for the synchronous machine to regulate voltage by adjusting the rotor's excitation which in turn influences the reactive power dynamics. As this work does not focus on reactive power dynamics, a standard model from the DIgSILENT library is used: `exc_ST` [44]. The implementation can be found in Appendix B.

Primary regulation: governor

As described in Section 2.1.5, FCR is the primary control mechanism acting just after the inertial response. The SGs participating in the FCR use a governor from DIgSILENT PowerFactory: `gov_SIMPLE` [44]. It is a generic model of governor with a droop of 0.05 (which is consistent with ENTSO-E standard [45]), a first-order filter and a lead-lag element. The implementation of the governor can be found in Appendix B.

The governor is active only on dedicated generator for the Belgian FCR. The other SGs provide inertia but do not participate in primary frequency regulation. The selection of the participating units and its impact on the results are discussed in Section 4.2.

The model also contains SGs with zero active power dispatch, representing the primary reserve imported from continental Europe to support frequency restoration in Belgium following a disturbance.

Secondary and tertiary control

As this work is focused on the frequency stability of the network in the first few seconds, secondary and tertiary control were not implemented. As a result, in the model, the frequency after a disturbance will stabilise at a value below the nominal value, since no secondary control mechanism is included to restore it.

3.3.3 Converter-interfaced generation

Wind farm

GFL control. DIgSILENT PowerFactory provides a comprehensive library of dynamic models for various technologies [44]. In particular, wind turbine models compliant with the IEC 61400-27-1 standard are available [46]. These models represent the aggregated dynamic behaviour of wind turbines connected to the grid.

For onshore wind generation in Belgium, doubly-fed induction generators (DFIGs) are commonly used [47]. Accordingly, all onshore wind farms are modelled using the IEC 61400-27-1 WT Type 3A template, which represents DFIG-based wind turbines with standard active and reactive power control functionalities.

Offshore wind farms connected to the coastal node include both DFIG and permanent magnet synchronous generator (PMSG) technologies. PMSG-based turbines are represented using the IEC 61400-27-1 WT Type 4A template. These turbines are converter-interfaced and therefore electrically decoupled from the grid frequency.

All wind generation units are modelled in GFL mode, meaning that they synchronise to the grid voltage via PLL mechanisms that are integrated into the IEC template [48]. In the base case simulations, no synthetic inertia or FCR functionalities are activated. Consequently, wind generation does not contribute inertia to the system and does not provide active frequency support during the inertial phase following a disturbance.

GFM control. In the scenarios investigating the impact of GFM control (see Section 3.6), the new 3.5 GW offshore wind farms are modelled using the virtual synchronous machine (VSM) extended model available in the DIgSILENT PowerFactory library [49]. Appendix B shows the implementation.

This model implements a GFM control strategy that emulates the electromechanical behaviour of a SG by embedding virtual inertia and damping directly into the converter control law. Instead of relying on a PLL to synchronise to the grid voltage, the VSM establishes its own internal voltage and frequency reference. This allows it to contribute to frequency stabilisation following a disturbance.

The key parameters of the VSM model are the acceleration time constant T_a , which governs the virtual inertia response and the damping coefficient D_p , which controls the active power response to frequency deviations. Based on values consistent with the literature, T_a is set to 10 s and D_p to 40 p.u. [3]. The maximum power output is set to 1 p.u., meaning that the full rated capacity of the wind farm is available for frequency response.

It is worth clarifying how this configuration is handled within DIgSILENT PowerFactory from a simulation standpoint. The parameter "number of machines in parallel" was used in DIgSILENT to represent multiple turbines instead of 1 machine that produce 3.5 GW. Rather than instantiating several independent dynamic models, the software treats the "number of parallel machines" parameter as a simple scaling factor: a single set of VSM differential equations is solved, and the resulting power output is multiplied by the number of units to obtain the total farm injection. The farm therefore appears to the transmission network as one equivalent converter of 3.5 GW, governed by a single VSM control instance sharing the same state variables, including the virtual angular velocity and the virtual rotor angle. This approach constitutes a standard homogeneous aggregation, and implicitly assumes that all turbines operate under identical conditions and respond uniformly to any system disturbance.

Photovoltaic Generation

Photovoltaic (PV) plants connected to the network are modelled using the WECC Large-Scale PV Plant model implemented in DIgSILENT PowerFactory, as described by Lammert *et al.* [50]. The implementation can be found in Appendix B. This model represents the aggregated dynamic behaviour of a transmission-connected PV plant and is suitable for transient stability, voltage stability and frequency stability analysis in RMS simulations. Unlike the IEC wind turbine models, this model does not include an explicit PLL. The

current commands are passed directly to the network interface, which is a simplified but acceptable representation for transmission-level stability studies.

In the simulations of this study, the PV plants operate in GFL mode and do not provide active frequency support during the inertial phase following a disturbance. Their active power output is assumed constant over the short time frame of frequency transients. Since PV generation is fully converter-interfaced and electrically decoupled from grid frequency, it does not contribute physical rotational inertia to the system.

In the Belgian generation mix, PV capacity contributes considerably less to total renewable output than offshore and onshore wind. Given this relatively limited role and since the focus of this work is on inertia and frequency response, PV generation is modelled exclusively in GFL mode throughout all simulations. No GFM variant is tested for PV, and the model is kept constant across all scenarios.

Battery energy storage systems (BESS)

BESS are modelled using the DIgSILENT BESS FrequencyCtrl template [51]. Appendix B shows the implementation. This model represents a generic AC-coupled battery connected to the network through a converter, including a simplified DC battery model with state-of-charge tracking, DC current limits and capacity constraints implemented in DIgSILENT Simulation Language (DSL). In load-flow calculations, BESS are represented as a bidirectional static generator, where positive active power corresponds to discharge and negative active power to charging.

BESS are equipped with a frequency-control loop allowing primary frequency response. A droop-based controller is implemented to emulate FCR, adjusting the active power output proportionally to frequency deviations from the nominal value. Unlike SGs, BESS do not provide physical rotational inertia. Their contribution to frequency stability arises entirely from control-based active power injection. Because the response is energy-limited and depends on the state of charge, BESS provide effective short-term frequency containment but cannot sustain support indefinitely without coordination with slower reserves.

For the BESS equipped with FFR simulations presented in Section 4.5.3, the DSL frequency control block was extended beyond the standard droop. The baseline DIgSILENT model computes an active power correction proportional to the frequency deviation Δf only. A derivative feedforward term was added, based on a wash-out filter that approximates df/dt from the measured per-unit frequency.

The resulting control law is:

$$\Delta P = -\frac{\Delta f}{\sigma} - K_d \cdot \frac{df}{dt} \quad (3.8)$$

With σ the droop and where the derivative is approximated through a first-order wash-out filter with state variable x_{filt} :

$$\dot{x}_{\text{filt}} = \frac{f - x_{\text{filt}}}{T_w}, \quad \frac{df}{dt} \approx \frac{f - x_{\text{filt}}}{T_w} \quad (3.9)$$

The parameters used in this work are $K_d = 20$ p.u. and $T_w = 2$ s. This configuration emulates a virtual inertia contribution broadly equivalent to $H \approx 3\text{--}6$ s depending on the rated capacity of the unit, placing it in the same order of magnitude as a large synchronous machine.

In practice, this type of FFR is implemented directly in the converter controller. A phase-locked loop measures the grid frequency in real time, with a typical measurement latency of 20–100 ms. A digital wash-out filter then estimates df/dt , and the resulting power reference is passed to the current regulator of the converter, which adjusts its output within roughly 100 ms end-to-end. The structure closely mirrors what is implemented in the DSL model, the main difference being that the simulation assumes an instantaneous converter response, whereas real hardware introduces measurement and actuation delays. In operational practice, FFR from BESS is typically contractualised with the TSO under specific requirements on response time and activation duration, which this model does not explicitly represent.

Droop-based FCR is used as the baseline and FFR is tested only in the dedicated simulations of Section 4.5.3, consistent with current Belgian practice: BESS units are contracted for primary frequency response rather than inertia emulation, and FFR with derivative action remains a product under development in the Elia ancillary services framework.

3.4 Load modelling

Each bus of the simplified network contains one equivalent aggregated load. As explained previously, distribution networks are not explicitly represented. Instead, loads connected at lower voltage levels are aggregated at their corresponding high-voltage substations. This aggregation reflects the total demand seen from the transmission system.

The aggregated load represents a mixture of residential, commercial, and industrial consumption. Because these loads include both static and motor-driven components, their behaviour influences the frequency dynamics of the system following a disturbance.

The spatial distribution of the loads across the eight nodes is not directly available from Elia’s dataset, which only reports the Belgian national total. The per-node allocation follows the methodology of Hernandez [52], who distributes the total demand in proportion to the load feeder transformer capacity connected at each node. The underlying assumption is that a node with twice the transformer capacity serves roughly twice the demand. The resulting weights are applied to the national load figure to obtain the nodal values summarised in Table 3.4.

Table 3.4: Spatial distribution of aggregated load across Belgian nodes (% of total system load).

Node	Load [%]
BE_CENTRAL	16.04
BE_COAST	11.5
BE_NUCLEAR_SOUTH	23.24
BE_MONS_FR	8.99
BE_NDLS	9.93
BE_FLANDERS_NORTH	27.01
BE_LUXEMBOURG	3.28

3.4.1 Frequency dependence of load

In real power systems, load consumption is not strictly constant but varies with frequency. A decrease in system frequency generally leads to a reduction in active power consumption. This natural damping effect contributes to stabilising the system.

The frequency-dependent active power is represented as:

$$P(f) = P_0 (1 + k_{pf}(f - 1)), \quad (3.10)$$

Where P_0 is the nominal active power demand and k_{pf} is the frequency sensitivity coefficient.

k_{pf} is set to 1 in this work. This value is consistent with the range of typical values reported in the literature for mixed residential and commercial loads [53]. Kundur [53] indicates that k_{pf} generally lies between 0 and 3, depending on the load composition of the

network. More specifically, values around 1 are representative of residential winter loads and commercial summer loads, which correspond well to the aggregated transmission-level demand modelled here.

It is worth noting that the influence of load frequency dependency on system-level frequency dynamics is inherently limited. Dubuc and Martin [54] showed that, for realistic values of k_{pf} , the effect on the frequency nadir is reduced by only a few percent compared to the case without frequency-dependent loads, and that the RoCoF is unaffected. Their simulations demonstrated that even at $k_{pf} = 2.8$ (close to the upper end of realistic values) the improvement in frequency nadir remained below 3%. This confirms that the precise choice of k_{pf} within the realistic range has a second-order impact on the results, and that the main dynamics are driven by system inertia and primary control, not by load damping.

3.4.2 Voltage dependence and ZIP representation

Loads may also depend on voltage magnitude. This behaviour is commonly represented using the ZIP model, which combines constant impedance (Z), constant current (I), and constant power (P) components:

$$P = P_0 \left(a_p \left(\frac{V}{V_0} \right)^{e_{ap}} + b_p \left(\frac{V}{V_0} \right)^{e_{bp}} + c_p \left(\frac{V}{V_0} \right)^{e_{cp}} \right), \quad (3.11)$$

Where $a_p + b_p + c_p = 1$, with a_p , b_p , and c_p the weighting coefficients of the impedance, current, and constant-power components, and e_{ap} , e_{bp} , e_{cp} the corresponding voltage sensitivity exponents (typically 2, 1, and 0 respectively). In the simplified case where a single exponent characterises the voltage sensitivity of the entire load, equation (3.11) reduces to:

$$P = P_0 \left(\frac{V}{V_0} \right)^\alpha, \quad (3.12)$$

Where $\alpha = 0$, 1, and 2 correspond to constant power, constant current and constant impedance behaviour respectively.

The voltage dependency of loads, captured through the ZIP representation (equation 3.11), is kept in the model to ensure a realistic load-flow initialisation and avoid numerical issues during transients. However, since the focus of this work is on inertial and primary frequency response rather than voltage dynamics, the active power component is the primary variable of interest and the reactive power is assumed to be independent of both frequency and voltage magnitude.

The Belgian transmission grid hosts a mix of residential, commercial and industrial consumers. As shown by Dubuc and Martin [54], the voltage exponent α varies significantly across load categories: residential and commercial loads exhibit α values close to 1 (constant current behaviour), while industrial loads are closer to $\alpha = 0$ (constant power). Since the loads in this model are aggregated at transmission-level buses and therefore represent a mixture of all these categories, a single intermediate value must be chosen. The constant power assumption ($\alpha = 0$) is adopted in this work because it represents the most conservative case from a frequency stability perspective: a constant power load does not reduce its consumption when voltage drops following a disturbance, meaning the full power imbalance is seen by the synchronous generators. A constant impedance load ($\alpha = 2$), by contrast, would partially self-correct by consuming less power when voltage falls, effectively reducing the apparent disturbance. Using constant power therefore avoids overestimating the load damping effect and produces more conservative, pessimistic frequency metrics. This conservative stance is appropriate when assessing whether security thresholds are met.

3.5 HVDC links and neighbouring countries

3.5.1 HVDC links

Belgium has two HVDC interconnections: **Nemo** Link, connecting to the United Kingdom, and **ALEGrO**, connecting to Germany. Both are point-to-point symmetrical monopole links rated at approximately 1,000 MW, and both use Voltage Source Converter (VSC) technology. The converters were built by Siemens using their HVDC PLUS technology, which is based on modular multilevel converter (MMC) topology. MMC-based VSC is well suited to submarine and cross-border applications of this scale: the converter stations are relatively compact, the active and reactive power outputs can be controlled independently, and the response to AC-side disturbances is fast [55, 56].

Nemo

Nemo can operate at a ± 400 kV DC system and has reactive power compensation capabilities of ± 320 MVar. It connects the Belgian high-voltage grid (380 kV) to the UK high voltage grid (400 kV) [55].

ALEGrO

The ALEGrO link has a nominal DC voltage of ± 320 kV. The converter offers a reactive power of ± 300 MVar maximum when active power transmission is enabled [56].

DIgSILENT model: HVDC links

To represent these HVDC links, the model from DIgSILENT library: *DIgSILENT HVDC MMC HB monopole* is used. It is a symmetric monopole system with half-bridge modular multilevel converters. The single-line diagram of this model is shown in Appendix B.3. In DIgSILENT, it was originally designed as a template made for the connection of offshore wind farms, but the electrical topology is identical to Nemo and ALEGrO with two converter VSC-MMC linked by a DC cable. The nominal rating has just to be adapted.

3.5.2 AC-connected neighbouring countries

France, the Netherlands, and Luxembourg are connected to the Belgian grid via AC lines. Each is represented in the model as an external grid (i.e., an infinite bus with a fixed voltage and frequency) coupled to an equivalent synchronous machine that carries the dynamic behaviour of the foreign system. The inertia constant of each equivalent machine was derived from the national generation mix reported by the IEA [57], combined with the per-technology inertia constants listed in Table 3.2. The aggregation follows the energy-weighted formula (see Equation 3.6).

Applying this to each country gives $H_{tot,FR} = 5.00$ s for France, $H_{tot,NL} = 2.43$ s for the Netherlands and $H_{tot,LU} = 2.21$ s for Luxembourg. France's higher value reflects its large nuclear fleet, which dominates its generation mix and carries the highest inertia constant among conventional technologies.

3.6 Scenario definition

Two load scenarios are used in this work: a winter peak case and a basic case. Each is tested with and without nuclear generation and within each scenario, three levels of RES penetration are examined. To keep comparisons consistent, the total generation and total load are held constant across penetration levels.

The representative operating points were extracted from Elia's dataset [58, 59], covering the period after September 2025. The resulting cases are summarised in Table 3.5.

Table 3.5: Summary of RES generation mix for winter peak and basic case scenarios in [MW].

Date	Pgen tot	Onshore	Offshore	Solar	RES (%)	Load
Winter Peak						
2025-12-01	8646.26	39.55	162.36	0	2.33%	8677.096
2026-01-06	8973.97	79.79	983.7	0	11.85%	8440.245
2026-01-27	8640.84	110.02	2055.15	3.16	25.10%	10199.447
Average	8753.69					9105.596
Basic Case						
2025-03-27	3115.47	0	0	0	0%	6859.604
2025-05-11	4629.17	37.33	521.55	0	12.07%	7048.907
2025-10-01	4474.96	217.77	2174.52	18.85	53.88%	4870.633
Average	4073.2					6259.71

Nuclear generation is kept as high and as constant as possible throughout the study. The main reason is inertia: at $H=6.4$ s (Table 3.2), nuclear units have the highest inertia constant of any technology in the Belgian mix. Beyond inertia, nuclear also provides stable and controllable output, which is relevant during winter peak demand, when generation margins are tightest [60].

For each scenario, the reference generation and load are set to the average across the three RES penetration levels. Cross-border exchanges with neighbouring countries are initialised from realistic operating points drawn from Elia's dataset. They are kept constant across the three RES penetration levels, so that changes in frequency response can be attributed solely to the RES mix rather than to variations in import or export flows.

A future scenario was also simulated in which the Ventilus line [61], Princess Elisabeth Island [62] and the planned battery projects have been implemented in the model ². The future network scenarios are simulated using the same total generation and load as the basic case, as this corresponds to the most critical operating conditions from a frequency stability perspective (low synchronous dispatch combined with high RES penetration). A winter peak equivalent of the future network was not investigated in this work.

²The project: "La Boucle du Hainault" has not been implemented as it is aggregated into bus 5: BE_MONS

Princess Elisabeth island is an artificial energy island. It will serve as an electricity hub and that will be connected to the Belgian network through an HVDC link and host 3.5 new GW of offshore wind production.

Elia projects an increase of 11.2 GW in battery capacity by 2034 [6]. This number take into account the reserved, pending and allocated storage projects. The exact spatial distribution is not known. Therefore, the volumes were distributed across the simplified Belgian buses using a map-based heuristic. The dominant shares were assigned to the buses corresponding to the largest storage clusters visible on Elia’s storage map (see Figure 3.3). The allocation has been summarised in Table 3.6.



Figure 3.3: Projected BESS capacity in Belgium by 2034 according to Elia’s grid hosting capacity assessment [6].

Table 3.6: Allocation of future installed generation capacity per bus.

Bus	Capacity (GW)
b4 BE_NDLS	3.1
b2 BE_FL_NORTH	2.4
b7 BE_LUX	1.8
b3 BE_CENTRAL	1.3
b5 BE_MONS	1.0
b6 BE_NUC_SOUTH	0.8
b1 BE_COAST	0.6
b8 BE_COO	0.2
Total	11.2

3.7 Simulation framework

The stability thresholds introduced in Section 2.1.3, a maximum RoCoF of 1 Hz/s and a minimum nadir of 49 Hz, are adopted as the reference limits for evaluating simulation results throughout this work.

All dynamic simulations are performed using DIgSILENT PowerFactory in root-mean-square (RMS) mode.

3.7.1 Software and RMS model

The RMS simulation model represents electromechanical dynamics of generators, converters, and loads. Each simulation is initialised from a solved load-flow operating point, obtained using the Newton–Raphson method. The RMS solver then integrates the dynamic equations of all components over time, allowing the evaluation of frequency and voltage behaviour following disturbances.

3.7.2 Time step and simulation duration

A simulation time step of 0.01 s is used to capture accurately fast frequency dynamics and RoCoF values. The time step can be adjusted if required, but this value provides a suitable compromise between numerical accuracy and computational efficiency.

Each simulation runs for a total duration of 30 s, which is sufficient to observe the inertial response, primary frequency containment, and the recovery phase towards steady state.

3.7.3 Disturbance scenario

The reference disturbance consists of a sudden loss of generation of 1,336.32 MW occurring at $t = 1$ s, ensuring the disturbance is severe but operationally credible. The loss of a nuclear reactor or the Coe pumped-storage plant, for instance, can represent an outage of this order. The event is implemented in PowerFactory using a generator disconnection. The equivalent SG connected at bus 2 is the unit lost in this scenario.

This contingency represents a severe but credible loss of a large synchronous unit or an equivalent generation block. The magnitude of the disturbance is selected relative to the total installed capacity and system inertia to expose frequency stability margins under low-inertia conditions.

3.7.4 Performance metrics

The system response is evaluated using the frequency stability metrics defined in Section 2.1.3:

- **Rate of Change of Frequency (RoCoF):** defined as $\frac{df}{dt}$ (Hz/s) immediately after the disturbance. It reflects the available inertia and damping.
- **Frequency nadir:** the minimum frequency reached following the disturbance, reflecting the combined inertial and primary frequency response.
- **Settling time:** the time required for frequency to return within $\pm 2\%$ of the stabilized frequency after primary control.

The model described in this chapter balances physical realism and computational tractability. The eight-bus topology, the equivalent generator representation, and the parameterisation of HVDC and storage components are all grounded in the literature reviewed in Chapter 2. The scenarios and disturbance defined in Section 3.7.3 provide a consistent basis for comparison across all simulations. Chapter 4 applies this framework to progressively more demanding operating conditions, starting from a nuclear reference and working towards a low-inertia future.

Chapter 4

Simulation Results: Frequency Response Analysis and Evaluation of Mitigation Techniques

The exact allocation of power for each generator and each scenario is given in Appendix C.

Model simplification

Before presenting the results, one important modelling limitation must be kept in mind. In the simplified model, each bus is represented by one equivalent synchronous generator with a fixed inertia constant. This means that reducing the active power dispatch of an equivalent SG does not reduce its inertia contribution, as the machine remains connected regardless of its output level. In reality, individual units aggregated into the equivalent generator may be disconnected when dispatch is low, which would reduce the effective inertia. As a consequence, some simulated cases may show identical frequency responses despite different dispatch levels, simply because no equivalent SG has been disconnected between the two cases. This effect is discussed further in Section 4.7.

4.1 Spatial uniformity of the frequency response

The literature reviewed in Chapter 2 highlights that inertia is not spatially homogeneous in modern power systems. As synchronous generation is displaced by converter-interfaced resources, different areas of the network can exhibit distinct frequency trajectories following a disturbance, particularly when interconnections are weak or when inertia is heavily concentrated at specific nodes.

In the Belgian system, however, this effect is largely absent. Figure 4.1 shows the frequency recorded at all eight buses following the reference disturbance in the basic case scenario with high RES penetration. All buses follow an almost identical trajectory throughout the event (the same spatial uniformity is observed across all other simulated

scenarios). The nadir, the RoCoF, and the recovery profile are virtually indistinguishable across nodes. This behaviour is consistent with the compact and densely interconnected nature of the Belgian transmission grid, where electrical distances between nodes are short and power can redistribute rapidly. As a result, the network responds essentially as a single coherent area rather than as a collection of loosely coupled zones.

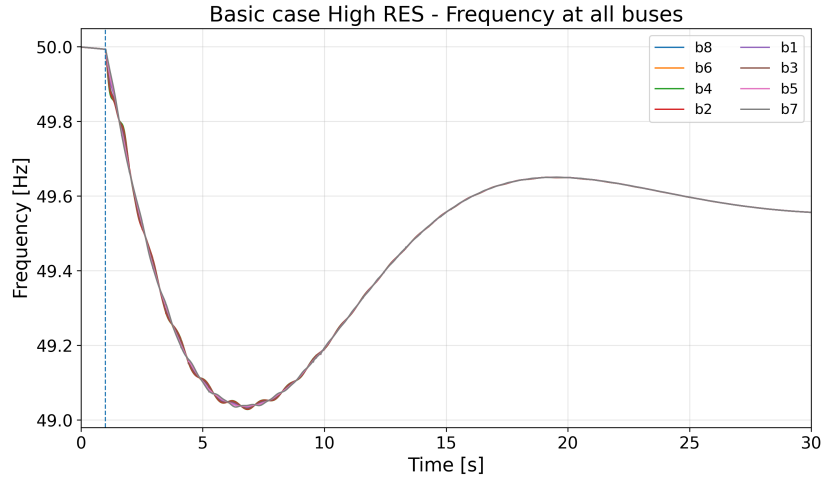


Figure 4.1: Bus frequency responses following the reference disturbance in the High RES scenario, illustrating the spatial uniformity of the frequency dynamics across the Belgian network.

Given this observation, the following simulations report the system frequency as the average across all buses. This representation is sufficient to characterise the frequency dynamics without loss of relevant spatial information.

4.2 Primary control

As described in Section 3.3.2, the FCR in this model is provided by three dedicated synchronous machines operating with a droop-based governor, representing Belgium's domestic allocation.

The three machines selected to provide FCR (the SGs located at buses 1, 4 and 6) were chosen to reflect a geographically distributed allocation across the Belgian network, consistent with how FCR is typically procured in practice. To verify that the results are not sensitive to this selection, simulations were repeated with alternative FCR providers, and the frequency response was found to be nearly identical in all tested configurations. This result is expected. As shown in Section 4.1, the Belgian grid behaves as a single coherent area, meaning that the location of FCR providers has little influence on the

aggregate frequency dynamics. What determines the nadir is the total droop response available in the system, not which specific units deliver it.

This section first assesses whether substituting conventional FCR, currently provided by synchronous generators, with BESS-provided FCR has a significant impact on the frequency response. Figure 4.2 compares the FCR response from both technologies under the same disturbance.

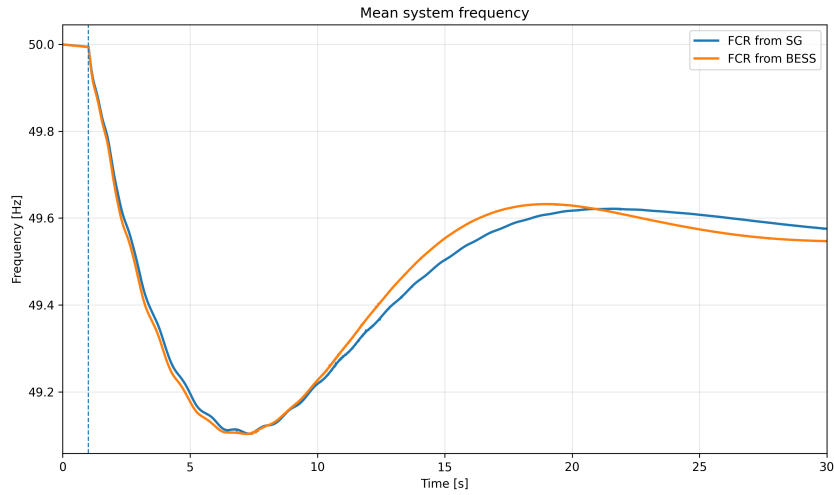


Figure 4.2: Mean system frequency response following a 1,336.32 MW generation loss, comparing FCR provided by SG and by BESS.

When FCR is provided by SGs only, the frequency nadir following the disturbance is 49.0999 Hz. When FCR is provided by BESS, the nadir is 49.1016 Hz.

BESS respond faster and inject power earlier than a synchronous generator. However, both technologies keep the frequency above the 49 Hz limit and are practically equivalent in terms of frequency security. This confirms that BESS-based FCR can replace conventional FCR from synchronous generators without degradation of frequency stability.

4.3 Reference scenario (with nuclear)

Winter peak

Three RES penetration levels are considered, as defined in Section 3.6, and shown in Figure 4.3.

The same disturbance (Section 3.7.3) is applied to each case, and the resulting frequency responses are compared. Figure 4.4 shows the frequency response averaged across all buses.

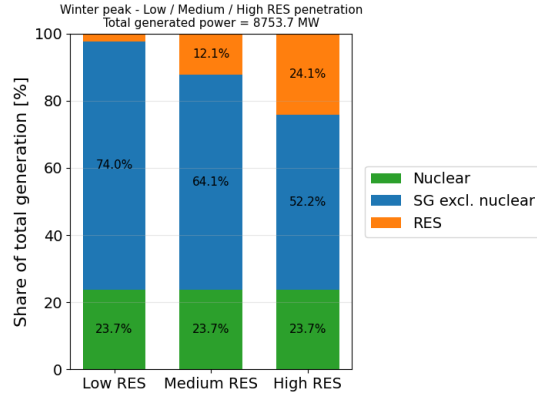


Figure 4.3: Winter Peak RES penetration.

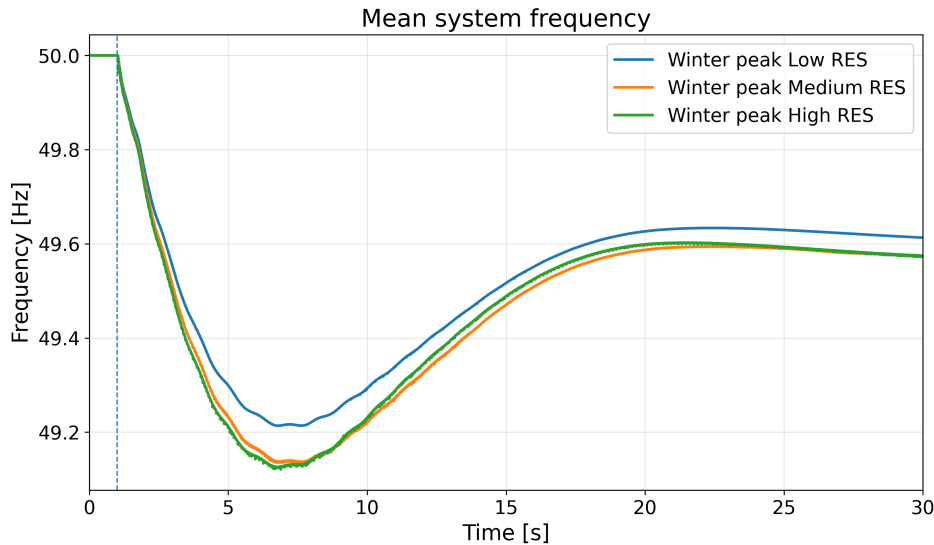


Figure 4.4: Mean system frequency response following a generation loss in the winter peak scenario, for three levels of RES penetration. Higher RES penetration leads to a lower nadir and higher RoCoF.

As expected, both the frequency nadir and the RoCoF worsen as RES penetration increases, since synchronous machines are the only source of inertia in this scenario. It is also worth noting that, despite the severity of the disturbance, the frequency remains above 49 Hz in all three cases, indicating that the Belgian network retains sufficient inertia to recover under current conditions.

This behaviour is consistent with the swing equation (Equation 2.3), where the RoCoF is inversely proportional to the system inertia constant H . As RES replace synchronous machines, H decreases, leading to a faster and deeper frequency excursion.

At first glance, Figure 4.4 presents a counterintuitive result: the high-RES scenario, despite having a worse nadir, recovers more quickly than the low-RES case. The following analysis explains why this is physically consistent with the swing equation.

The green curve exhibits a higher RoCoF and a lower frequency nadir than the orange curve, yet recovers faster and crosses above it well before the 10 second threshold conventionally associated with primary control activation. One might be tempted to conclude that the primary control acts earlier in the high RES scenario, but the behaviour is fully consistent with the underlying physics of frequency dynamics in low-inertia systems.

The foundation of this analysis lies in the swing equation, which governs the rate of change of frequency immediately following a power imbalance. Starting from Equation 2.3, we can obtain:

$$\left. \frac{df}{dt} \right|_{t=0} = \frac{f_0 \cdot \Delta P}{2H \cdot S_{nom}} \quad (4.1)$$

Where f_0 is the nominal frequency, ΔP the active power imbalance, H the equivalent inertia constant of the system, and S_{nom} the total nominal apparent power of the synchronous generators. This equation makes clear that for a given disturbance ΔP , a lower system inertia H directly produces a higher RoCoF. When SGs are removed from the generation mix and replaced by converter-interfaced RES, which has no synchronous inertia, the equivalent H of the system decreases significantly. This explains the steeper initial frequency drop observed on the green curve.

As described in Section 3.3.2, primary control does not activate instantaneously. It responds to a frequency deviation through the droop characteristic (see Equation 2.5). The droop control timescale (on the order of several seconds) is entirely decoupled from the inertial response timescale, which occurs within milliseconds of the disturbance (see Figure 1.2). The primary control therefore begins to act at approximately the same time in both scenarios.

After the nadir, the system enters a recovery phase driven by the net surplus of injected power over consumed power. The rate of frequency recovery is governed by the same swing equation:

$$\left. \frac{df}{dt} \right|_{\text{recovery}} \propto \frac{\Delta P_{\text{net}}}{2H \cdot S_{nom}} \quad (4.2)$$

Since H is lower in the high RES scenario, the same net power surplus from primary control produces a faster rate of frequency increase. In other words, the low-inertia

system is not only more vulnerable to the initial disturbance, it is also more responsive to the corrective action. Inertia acts symmetrically: it dampens both the fall and the rise.

This explains why the green curve, despite starting from a worse nadir, climbs more steeply and overtakes the orange curve before the two systems converge towards their respective quasi-steady-state equilibrium frequencies. The equilibrium frequency deviation, reached after full primary control action, is itself higher in the high RES scenario due to the reduced droop participation of synchronous generators:

$$\Delta f_{eq} = \frac{-\Delta P_G}{\frac{1}{f_0} \sum_{i=1}^N \frac{P_{N,i}}{\sigma_i}} \quad (4.3)$$

With fewer synchronous units contributing to the summation, Δf_{eq} is larger in magnitude, which is also consistent with what is observed in the figure.

Basic case

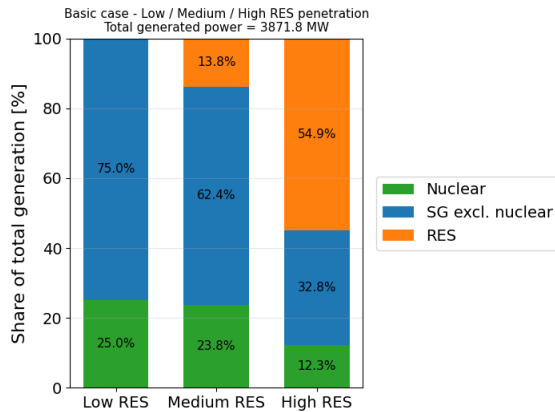


Figure 4.5: Basic case RES penetration.

The three RES penetration levels for the basic case are shown in Figure 4.5, and the mean frequency response following the disturbance is given in Figure 4.6. Note that nuclear generation could not be held constant in the high RES case. A reduction was necessary to maintain power balance and avoid over-generation as renewable output increased significantly.

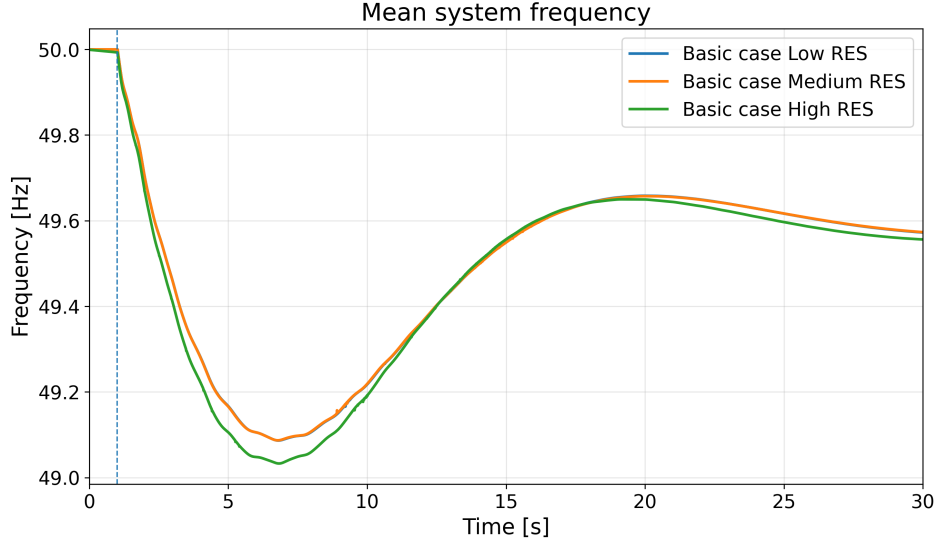


Figure 4.6: Mean system frequency response following a generation loss in the basic case, for three levels of RES penetration.

The results again follow the expected trend: the highest RES penetration case shows the worst nadir and RoCoF. The low and medium RES curves are indistinguishable, because no equivalent SG was disconnected between the two cases (the dispatch level changed, but the inertia did not).

4.4 Low inertia scenario (without nuclear)

Nuclear energy policy in Belgium has been heavily influenced by political considerations. A federal law in 2003 planned the phase-out of nuclear by 2025. This deadline was postponed by ten years in 2022. In May 2025, Belgium’s parliament repealed the 2003 phase-out law. The government now intends to extend the operating licences of Doel 4 and Tihange 3 to 2045, and to construct new reactors [60].

Belgium will operate without nuclear generation during the summers of 2026 to 2028, as the reactors undergo technical modifications required for life extension [63]. Although imports from neighbouring countries could be increased during this period, the aim of this section is to anticipate the frequency stability challenges that may arise and to assess mitigation solutions. In practice, during the transitional period of 2026–2028, Belgium can rely on increased power imports from France, whose grid remains highly stable thanks to its large nuclear fleet (see Section 3.5.2). However, this approach creates a dependency on a neighbouring country’s generation mix and reduces Belgium’s operational autonomy. Over-reliance on cross-border imports is generally not considered a desirable long-term strategy, both from a security-of-supply and a grid sovereignty perspective.

This section examines the frequency response when nuclear generation is removed from the dispatch, keeping all other parameters unchanged. Only the high RES penetration level is considered, as it represents the worst case for frequency stability (see Section 4.3). With fewer synchronous machines online, system inertia is at its lowest. The RES share corresponds to the values shown in Figures 4.3 and 4.5 for the winter peak and basic case respectively 54.9% and 67.2% of total generation. The reference disturbance (Section 3.7.3) is identical to the one applied in the previous section, so any difference in frequency response can be attributed directly to the removal of nuclear units.

Winter peak

Figure 4.7 shows the differences in reaction of a Belgian network with nuclear and one without.

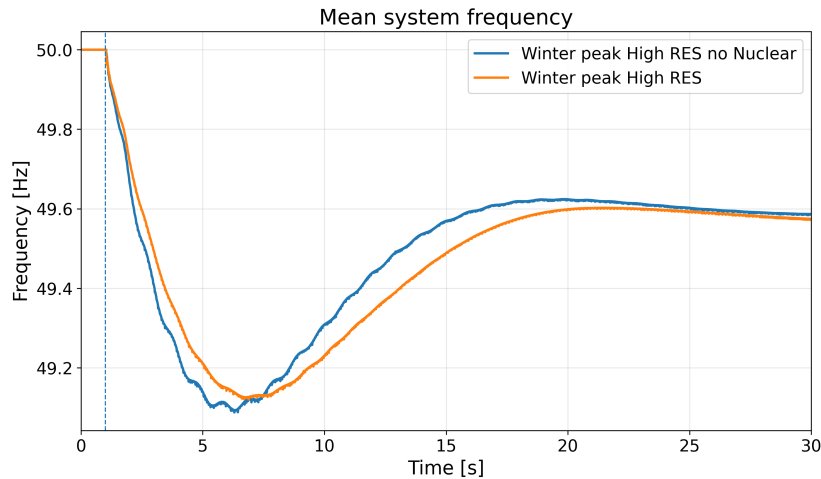


Figure 4.7: Mean system frequency response in the winter peak high RES scenario, with and without nuclear generation. Removal of nuclear degrades the nadir.

It can be seen that the RoCoF and the nadir are worse when there is no nuclear. Indeed without nuclear, the global inertia is reduced by 63% (see Appendix C). However, when a disturbance occurs under high RES penetration with nuclear power phased out, none of the thresholds are crossed and the Belgian network is still capable of withstanding the chosen disturbance.

Basic case

As for the winter peak scenario, Figure 4.8 shows how a system without nuclear power reacts compared to a system with nuclear generation under medium generation and load conditions.

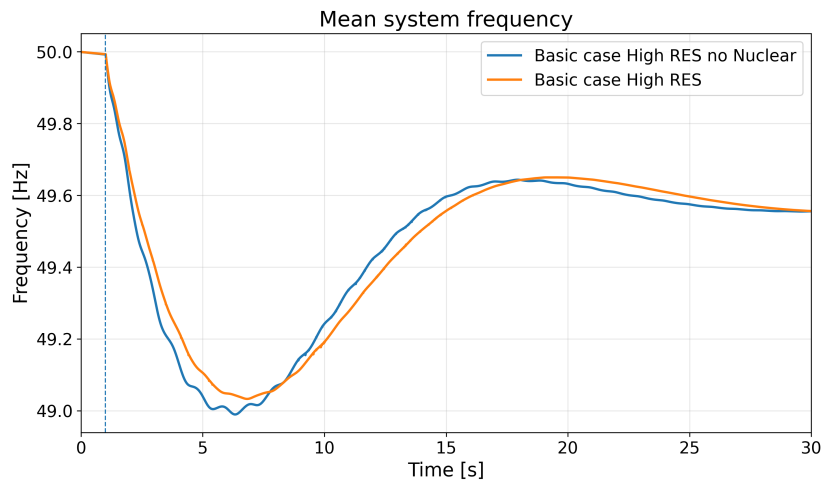


Figure 4.8: Mean system frequency response in the basic case high RES scenario, with and without nuclear generation. Removal of nuclear results in a lower nadir and drives the frequency below 49 Hz.

The same behaviour as in the winter peak case is observed, but now, without nuclear generation, the frequency following the applied disturbance falls below 49 Hz. In practice, this would trigger UFLS and potentially cascading generator trips, ultimately risking a blackout.

4.5 Inertia enhancement solutions

The behaviour observed in Figure 4.8 will become increasingly common if no corrective measures are taken. The following sections examine several solutions to improve the frequency response in the basic case.

4.5.1 Synchronous condensers

As discussed in Chapter 2, synchronous condensers are one candidate for improving frequency response. Elia has planned the installation of two SCs in the coastal area of Belgium by 2030. Each is rated at ± 280 MVar with auxiliary power consumption below 10 MW [64].

These units are primarily intended to reinforce system strength, as covered in Section 2.3.1, but they also contribute to the inertia of the grid. To assess their impact, the two condensers are connected to the coastal bus (b1) in the model. Figure 4.9 shows the effect of adding them compared to the baseline.

Since no further technical specifications are publicly available for these planned units, three different inertia values are tested in Figure 4.10. Indeed, the inertia constant of a SC depends on the technology and whether a flywheel is added, as illustrated in Figure 2.2 in section 2.3.1.

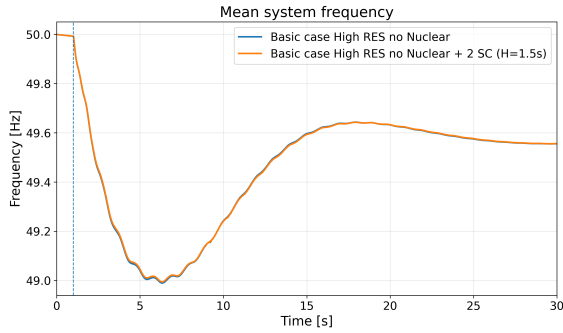


Figure 4.9: Mean system frequency response in the basic case high RES no nuclear scenario, with and without two synchronous condensers ($H = 1.5$ s). The improvement in nadir is marginal.

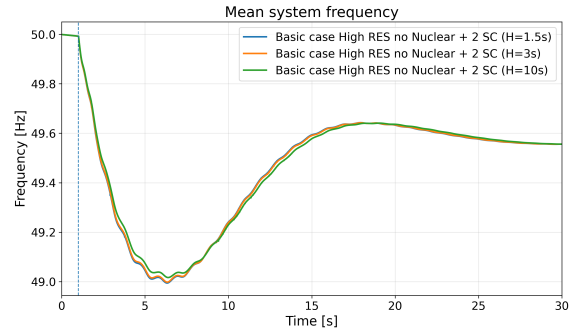


Figure 4.10: Mean system frequency response in the basic case high RES no nuclear scenario with two synchronous condensers, for three inertia constants ($H = 1.5, 3$ and 10 s).

Figures 4.9 and 4.10 confirm that adding the two SCs improves the frequency response, though the magnitude of the improvement depends strongly on the inertia constant. With a basic round-rotor machine without flywheel ($H=1.5$ s), the gain is marginal: the nadir improves from 48.9812 Hz to 48.9859 Hz, which remains below the 49 Hz threshold.

It is useful to quantify exactly how much inertia the two synchronous condensers actually add to the system and to put that number in context. We assumed that the SCs planned by Elia each have a rated apparent power of 300 MVA, giving a combined apparent power rating of $S_{SC} = 600$ MVA. Starting from the basic case, high RES penetration, without nuclear, the total mechanical inertia of the system is 18,502.4 MWs, corresponding to $H_{eq} = 1.89$ s on the 9,787.1 MW base³ (see Appendix C). Following Equation 2.2, the kinetic energy stored in a rotating machine is $E_k = 2 \times H \times S_n$. The kinetic energy added by the two SCs therefore depends directly on their inertia constant: with $H = 1.5$ s the contribution is $2 \times 1.5 \times 300 = 900$ MWs, with $H = 3$ s it rises to 1,800 MWs and

³Corresponding to the total maximum active power of all synchronous machines in the model when fully dispatched

with $H = 10$ s it reaches 6000 MWs. The resulting system totals and equivalent inertia constants are summarised in Table 4.1.

Table 4.1: Impact of synchronous condensers on system inertia.

Configuration	Total inertia (MWs)	H_{eq} (s)
Basic case no nuclear	18502.4	1.89
+ 2 SC ($H = 1.5$ s)	19402.4	1.98
+ 2 SC ($H = 3$ s)	20302.4	2.07
+ 2 SC ($H = 10$ s)	24502.4	2.50

Even in the most favourable case ($H = 10$ s with flywheel), the two condensers bring the equivalent inertia constant from 1.89 s to 2.50 s. This is a noticeable improvement, but one that still leaves the system in a low-inertia regime. More telling is the $H = 1.5$ s case, where the addition of 900 MWs raises H_{eq} by a mere 0.09 s. This immediately explains why the nadir improvement is so marginal in that configuration: the two SCs represent less than a 5% increase in total stored kinetic energy. This is not enough to meaningfully slow the frequency decline following the 1,336 MW generation loss of the reference disturbance. The flywheel-equipped machine performs considerably better, 6,000 MWs is a more substantial injection, pushing H_{eq} to 2.50 s but even then, the system remains below the inertia level of the reference scenario with nuclear, which underlines that two condensers at a single peripheral bus cannot on their own resolve the frequency security challenge identified in Section 4.4.

4.5.2 Converter-based solutions (GFM)

As discussed in Section 2.3, grid-forming converters are a candidate for emulating inertia in converter-dominated systems. In Belgium, all existing converters currently operate in grid-following mode, but connecting new wind farms or BESS through grid-forming converters is under active consideration. From this point onwards, the simulations use the future Belgian network described in Section 3.6.

Figure 4.11 shows the frequency response following the disturbance when the 3.5 GW of new wind offshore capacity is connected through GFM, compared to connected through GFL.

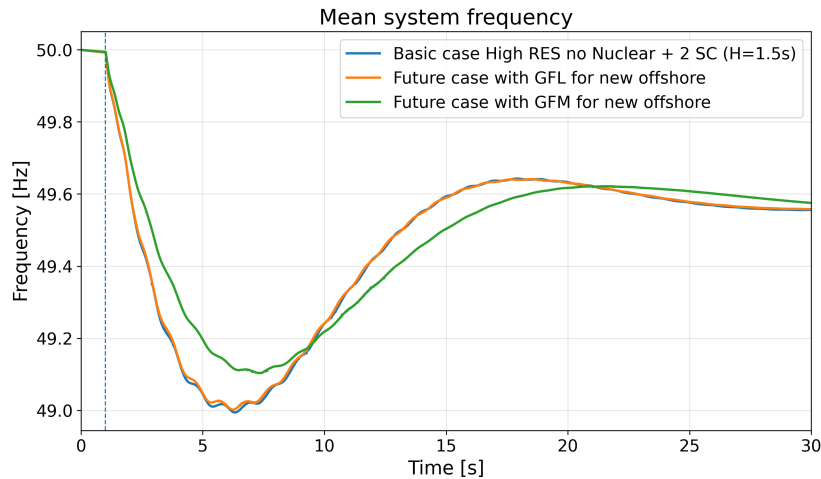


Figure 4.11: Mean system frequency response in the future scenario comparing GFL and GFM connection of 3.5 GW of new offshore capacity. GFM significantly improves the nadir and slows the RoCoF.

Figure 4.11 shows that connecting the new offshore capacity through GFL converters, as is currently the case for all existing capacity, produces a frequency response similar to the present network with the two SCs. When the same capacity is connected through GFM converters instead, the improvement in frequency response after the disturbance is considerable.

Looking further ahead, the long-term trajectory points towards even higher RES penetration. To reflect this, the RES share in the future scenario is increased to the point where, apart from G2 (the generator that trips), no synchronous machines are actively generating power. Figure 4.12 shows the generation mix for this case and the resulting frequency response.

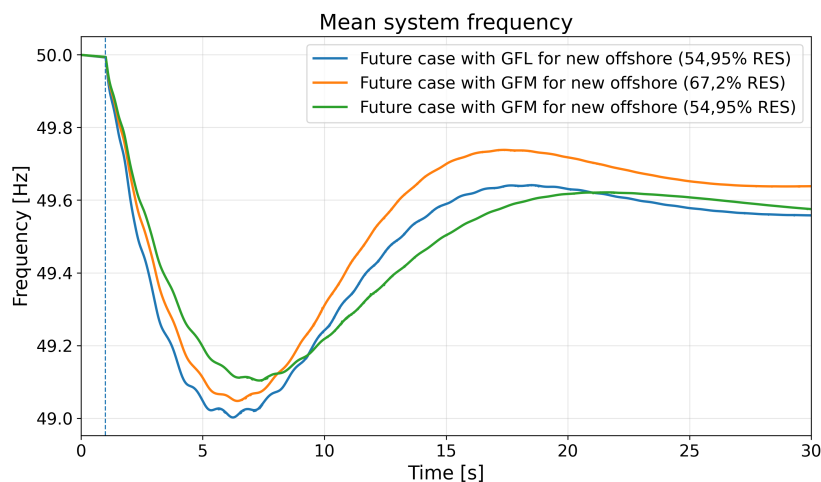


Figure 4.12: Mean system frequency response in the future scenario for two RES penetration levels (54.95% and 67.2%) with GFM offshore, compared to the GFL baseline.

As shown in Figure 4.12, increasing the RES penetration from 54.95% to 67.2% while keeping GFM control active does not significantly degrade the frequency response. Both scenarios remain above the 49 Hz nadir threshold. This suggests that the virtual inertia provided by the GFM offshore farm is sufficiently robust to accommodate further increases in RES penetration beyond the base future scenario.

It is also worth quantifying the inertial contribution that GFM control actually brings to the system. With the VSM parameters used in this work (an acceleration time constant $T_a = 10$ s and a rated capacity of 3,500 MW, see Section 3.3.3) the equivalent virtual inertia constant of the offshore farm is $H_{\text{virtual}} = T_a/2 = 5$ s, which translates to a stored virtual kinetic energy of $2 \times 5 \times 3,500 = 35,000$ MWs. To put this in perspective, the total mechanical inertia of the system in the basic case, high RES penetration, without nuclear is 18,502.4 MWs (see Appendix C), corresponding to $H_{\text{eq}} = 1.89$ s on the 9787.1 MW base. When the two SCs are added, the total becomes 19,402.4 MWs, giving $H = 1.98$ s.

Adding the GFM offshore contribution brings the total to 54,402.4 MWs, or equivalently $H_{\text{eq}} \approx 5.55$ s, nearly three times the mechanical inertia available without it. This explains the improvement observed in Figure 4.11: the GFM farm contributes an amount of synthetic inertia that exceeds what remains from the synchronous machines alone.

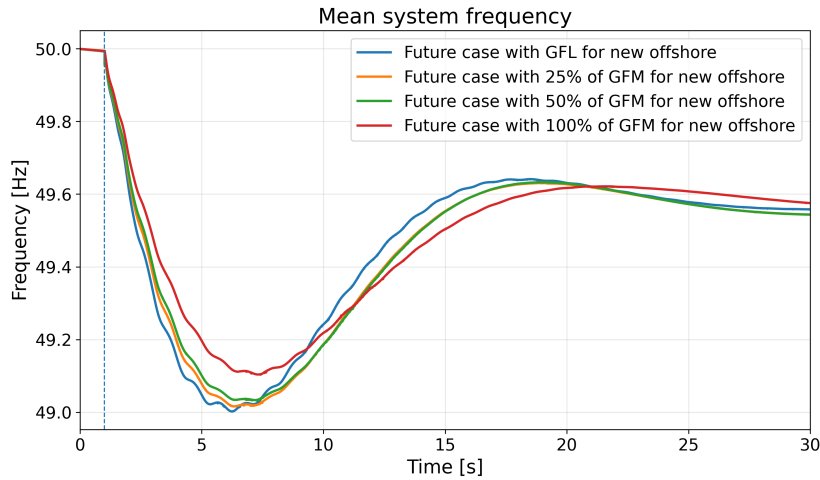


Figure 4.13: Mean system frequency response in the future scenario for four GFM deployment levels (0%, 25%, 50%, and 100% of the 3.5 GW offshore capacity).

Figure 4.13 shows the frequency response for four levels of GFM deployment: 0% (full GFL), 25%, 50% and 100% of the 3.5 GW offshore capacity. The GFL case and the two partial configurations (25% and 50%) produce nearly identical nadirs, around 49.00–49.05 Hz, which remain very close to the 49 Hz threshold. Only the 100% GFM configuration provides a meaningful improvement, pushing the nadir to approximately 49.16 Hz. From a practical standpoint, this means that a partial GFM deployment on Princess Elisabeth

Island is unlikely to resolve the frequency stability issue on its own, and that the curtailment cost associated with full GFM operation needs to be weighed against the full benefit.

Limitation of GFM for wind farm

Wind turbines do not have an inherent primary reserve, unlike synchronous generators which can increase their fuel supply. If we want them to participate in the frequency regulation they need to work under their maximum power point tracking (MPPT) to keep a margin. In the simulation made above we assumed that we were not at the MPPT.

In practice, GFM control in a wind farm is usually implemented through a hierarchical architecture: each turbine maintains its local converter control, while a plant-level supervisory controller coordinates the fleet by distributing power and voltage references and managing the overall reactive-power response [65]. The homogeneous aggregation used in this work does not capture this internal farm heterogeneity. Furthermore, the VSM model represents the full farm as a single equivalent converter and does not capture the aerodynamic and mechanical behaviour of the wind turbines themselves, in particular the pitch control response needed to maintain a sub-MPPT power reserve under variable wind conditions. If wind speed changes coincide with a grid disturbance, the power margin actually available may differ from the constant reserve assumed here. The virtual inertia contribution of a real GFM wind farm could therefore be lower than what the simulations show, depending on operating conditions. Pairing the offshore wind with co-located GFM BESS would mitigate this limitation [66].

4.5.3 Fast frequency response from BESS

The previous section showed that connecting Princess Elisabeth in GFL mode offers no meaningful improvement to frequency stability. A more direct alternative is to use part of the 11.2 GW of projected battery capacity to deliver fast frequency response (FFR). The BESS units already planned for the future can be configured to inject active power within tens of milliseconds in response to frequency deviations.

To quantify the potential benefit, four simulations are run on the future network with Princess Elisabeth connected in GFL mode. The total installed BESS capacity in the future scenario is 11.2 GW distributed across the Belgian buses (see Table 3.6). The fraction of this capacity actively providing FFR is varied: 0%, 27.68%, 65.18%, and 100% of the new BESS fleet. All other parameters remain unchanged, and the same 1,336 MW generation loss is applied in the basic case at high RES penetration. Figure 4.14 shows the mean system frequency response across the four configurations.

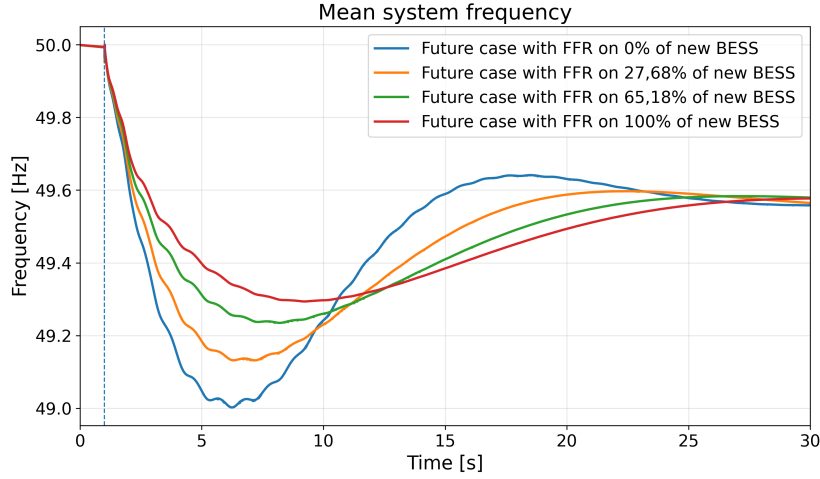


Figure 4.14: Mean system frequency response in the future GFL scenario for four FFR BESS deployment levels.

The results are consistent with the expected behaviour of BESS-based FFR. Without any BESS contributing FFR (0% case), the frequency nadir at bus b4 reaches 48.994 Hz at $t = 6.23$ s, which is below the 49 Hz threshold. This matches what was reported in the previous section for the GFL case.

As the share of BESS providing FFR increases, the nadir improves progressively. At 27.68% deployment, the nadir rises to 49.129 Hz. At 65.18%, it reaches 49.233 Hz, and at full deployment (100%), it peaks at 49.293 Hz. All three cases with active FFR stay above the 49 Hz limit, confirming that BESS-based FFR is sufficient to restore frequency compliance in this scenario, without any changes to the offshore wind connection mode.

The nadir timing also shifts. This delay is characteristic of FFR: the fast power injection limits the initial rate of decline, so the nadir is reached later and at a higher frequency.

The effect on RoCoF is much smaller, consistent with the nature of FFR. The RoCoF peak occurs within the first 100 ms after the disturbance, before the BESS response has accumulated enough power to affect it. The inertial phase, where RoCoF is determined, is largely over before the BESS response has had time to accumulate.

Overall, these results suggest that deploying FFR on roughly a quarter of the projected BESS capacity (27.68%) is already sufficient to bring the nadir above 49 Hz in the future GFL scenario. Full deployment pushes the nadir to 49.293 Hz, which provides a comfortable margin above the threshold but comes with the slower recovery noted above.

4.6 Evaluation of mitigation strategies

Table 4.2 summarises the three key frequency performance indicators across all simulated cases. The worst frequency nadir is defined as the minimum frequency recorded across all buses during the simulation. The RoCoF is computed using a centred sliding window of 100 ms applied independently to each bus signal. The value reported is the most negative instantaneous slope observed across all buses and all time steps. This smoothing approach filters out the numerical noise inherent to RMS simulations while remaining representative of the true rate of frequency decline experienced locally in the network. The settling time is defined as the first instant after which the mean system frequency remains permanently within a band of ± 0.02 Hz around its post-disturbance steady-state value. It should be noted that since no secondary frequency control is implemented in the model, this steady-state value is below the nominal 50 Hz. The settling time therefore reflects the stabilisation of the frequency at its post-primary-control plateau rather than its full restoration to the nominal value. It should also be noted that none of the simulated scenarios exhibits a RoCoF exceeding the 1 Hz/s threshold defined in Section 2.1.3.

Table 4.2: Summary of frequency performance metrics across all simulated cases.

Scenario	Case	Worst Nadir (Hz)	Worst RoCoF (Hz/s)	Settling Time (s)
<i>Reference scenario (with nuclear)</i>				
Winter Peak	Low RES	49.207	−0.706	22.25
	Medium RES	49.127	−0.709	21.68
	High RES	49.115	−0.769	23.66
Basic Case	Low RES	49.082	−0.787	26.21
	Medium RES	49.082	−0.782	26.19
	High RES	49.028	−0.812	25.86
<i>Low inertia scenario (without nuclear) — High RES only</i>				
Winter Peak	High RES no Nuclear	49.080	−0.936	23.13
Basic Case	High RES no Nuclear	48.981	−0.969	23.93
<i>Inertia enhancement solutions (Basic Case, High RES, no Nuclear)</i>				
Synchronous Condensers	+ 2 SC ($H = 1.5$ s)	48.986	−0.954	24.03
	+ 2 SC ($H = 3$ s)	48.990	−0.938	24.16
	+ 2 SC ($H = 10$ s)	49.010	−0.922	24.65
GFL offshore	54.95% RES	48.994	−0.940	23.96
	67.20% RES	48.992	−0.939	23.98
GFM offshore	54.95% RES	49.100	−0.812	25.86
	67.20% RES	49.042	−0.847	23.33
FFR from BESS	27.68% of new BESS	49.129	−0.914	25.12
	65.18% of new BESS	49.233	−0.912	20.92
	100% of new BESS	49.293	−0.909	23.89

 Nadir < 49 Hz (below the operational threshold).

Reference scenario (with nuclear)

The first thing that can be observed from Table 4.2 is that, when nuclear generation is present, the Belgian network handles the applied disturbance without any problem in all tested cases. The worst nadir recorded in the winter peak is 49.115 Hz at high RES penetration, which stays above the 49 Hz limit, and the RoCoF values remain between −0.706 and −0.769 Hz/s.

The basic case shows a similar behaviour, with nadirs ranging from 49.028 to 49.082 Hz. One thing worth noting is that the settling times are consistently longer in the basic case (around 26 s) than in the winter peak (21–24 s). This is likely because the total amount of synchronous generation dispatched is lower in the basic case (see Appendix C),

which means less damping is available during the recovery phase. As expected, increasing RES penetration makes both the nadir and the RoCoF worse in all cases, since more synchronous machines are displaced. But overall, the system remains secure as long as nuclear is online.

Low inertia scenario (without nuclear)

Removing nuclear generation from the model has a clear impact, but the severity depends on the operating condition. In the winter peak, the nadir drops by about 35 mHz compared to the nuclear case from 49.115 to 49.080 Hz, and the RoCoF worsens from -0.769 to -0.936 Hz/s, which represents roughly a 22% increase. Despite this, the winter peak case without nuclear still passes the 49 Hz threshold. It is because the total generation dispatched during peak hours is enough to keep sufficient synchronous inertia online.

The basic case is more problematic. Without nuclear, the nadir falls to 48.981 Hz, which is below the operational limit and the RoCoF reaches -0.969 Hz/s. This is the case that motivates the rest of the analysis. It shows that during summer-like operating conditions without nuclear, which is exactly what Belgium will face between 2026 and 2028, the grid may not be able to handle a large generation loss without violating frequency security criteria.

Inertia enhancement solutions: synchronous condensers

The two SCs planned by Elia and added to the coastal bus do improve the frequency response, but the improvement is smaller than one might hope. With a standard round rotor machine ($H=1.5$ s), the nadir only goes from 48.981 to 48.986 Hz, which is still below 49 Hz. Increasing the inertia to $H=3$ s gives a small additional gain (48.990 Hz) but it is still not enough. Only with $H=10$ s, which requires adding a flywheel to a salient pole machine, does the nadir finally cross back above 49 Hz, reaching 49.010 Hz. The RoCoF also improves progressively, from -0.969 to -0.922 Hz/s.

These results show that the inertia constant of the machine matters significantly. A basic SC without a flywheel is not sufficient to restore frequency compliance in this scenario. Connecting only two SCs at a single peripheral bus is probably not enough to significantly change the system-wide frequency response.

Inertia enhancement solutions: GFL versus GFM offshore connection

When the 3.5 GW of new offshore wind capacity is connected through GFL converters, the nadir stays below 49 Hz in both RES penetration cases (48.994 Hz at 54.95% and 48.992 Hz at 67.2%). This means that simply adding more renewable capacity in the conventional GFL mode does not improve frequency stability. Moreover, the situation remains as bad as in the no-nuclear base case. When the same capacity is connected through GFM converters, the results are very different. At 54.95% RES penetration, the

nadir jumps to 49.100 Hz, which is an improvement of more than 100 mHz compared to the GFL case. The RoCoF improves to -0.812 Hz/s, which is actually comparable to what was observed in the nuclear reference scenario. At 67.2% RES, the benefit is smaller but still significant, with a nadir of 49.042 Hz and a RoCoF of -0.847 Hz/s. The settling time is also longer with GFM (around 26 s at 54.95% RES), which reflects the more sustained frequency support that GFM control provides through its synthetic inertia.

What these results show is that GFM control fundamentally changes how offshore wind interacts with the grid during a disturbance. Instead of just injecting power passively, GFM converters actively participate in frequency regulation and provide synthetic inertia. This is exactly what ENTSO-E recommends in the context described in Section 2.3.2, where GFM deployment is prioritised at the periphery of the transmission network which is precisely the configuration tested here.

To put these results in perspective, it is worth comparing the two inertia enhancement solutions in terms of the kinetic energy they actually contribute to. The two synchronous condensers add at most 6,000 MWs ($H = 10$ s with flywheel) to the 18,502.4 MWs of the baseline, bringing H_{eq} to 2.50 s. The GFM offshore farm contributes 35,000 MWs of virtual inertia, pushing H_{eq} to 5.55 s, more than double what even the best SC configuration achieves. This difference in stored energy directly explains the gap observed in Table 4.2 between the two solutions. Two 300 MVA machines cannot compete in inertia terms with 3,500 MW of offshore capacity under virtual inertia control, regardless of how they are equipped.

Inertia enhancement solutions: FFR from BESS

The FFR results follow a different pattern from the inertia-based solutions. The nadir improves from 48.994 Hz (0% FFR⁴) to 49.293 Hz at full BESS deployment, while the RoCoF changes only marginally, from -0.940 to -0.909 Hz/s, a reduction of roughly 3%. This confirms that FFR acts on the arresting phase of the frequency transient rather than the inertial phase. The initial RoCoF is set within the first 100 ms after the disturbance, before the BESS response has had time to accumulate.

Even partial deployment is enough to restore compliance. At 27.68% of the BESS fleet, the nadir rises to 49.129 Hz, which already exceeds the 49 Hz threshold. Full deployment adds 160 mHz of margin, but comes with a trade-off. The settling time at 65.18% drops to 20.9 s, shorter than both adjacent cases, while the 27.68% case shows a longer settling time of 25.1 s. This non-monotonic behaviour reflects the interplay between the magnitude of the fast power injection during the arresting phase and the recovery dynamics once the BESS output tapers off. A small FFR contribution leaves the conventional governors to drive a slow recovery, whereas an intermediate contribution appears to produce a more

⁴The 0% FFR case corresponds to the future GFL network with 54.95% of RES penetration.

damped trajectory towards the post-disturbance plateau. This suggests that deployed capacity alone does not determine settling quality, and that the interaction between FFR magnitude and the primary control dynamics of the remaining synchronous units warrants further investigation.

A comparison between FFR and offshore GFM shows that both strategies restore the nadir above 49 Hz, although through fundamentally different mechanisms. GFM improves both the nadir and the RoCoF simultaneously, because synthetic inertia acts from the very first instants of the transient. FFR leaves RoCoF essentially unchanged and acts later, during the arresting phase. For a system where RoCoF is also a binding constraint, GFM remains the preferred option. For a system where RoCoF is also a binding constraint, GFM remains the stronger solution.

Interaction between GFM and FFR

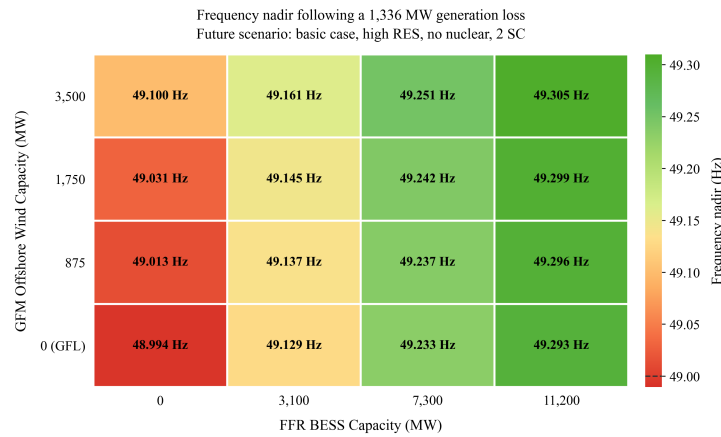


Figure 4.15: Frequency nadir heatmap.

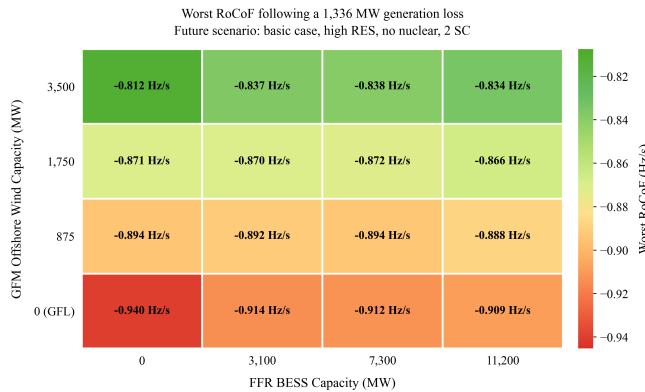


Figure 4.16: RoCoF heatmap.

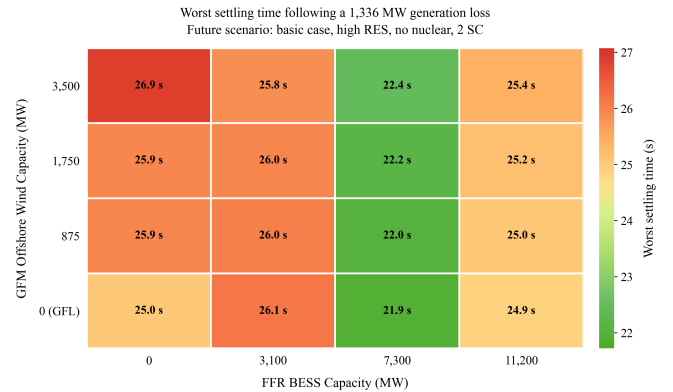


Figure 4.17: Settling time heatmap.

Figures 4.15, 4.16 and 4.17 consolidate these findings across different combinations of GFM wind and FFR BESS capacity, providing a broader view of the solution space beyond the discrete cases discussed above. Several patterns emerge from the three heatmaps.

Figure 4.15 shows that nadir compliance is primarily governed by BESS capacity. Even modest FFR deployment is sufficient to push the nadir above 49 Hz across most GFM configurations, and the improvement saturates relatively quickly with increasing BESS share. GFM capacity has a secondary but visible effect on the nadir, particularly at low BESS levels where it provides the margin needed to avoid threshold violations.

Figure 4.16 tells the opposite story for RoCoF. BESS deployment has almost no effect on the initial rate of change of frequency, confirming that FFR acts too slowly to influence the inertial phase. RoCoF improvement is driven almost entirely by GFM capacity, which injects synthetic inertia from the very first instants of the disturbance.

Figure 4.17 reveals a more nuanced behaviour for settling time. The optimum does not occur at maximum BESS deployment but at intermediate levels, reflecting the recovery trade-off described earlier. No single combination dominates across all three metrics simultaneously, which confirms that the choice of deployment strategy depends on which stability criterion is the binding constraint.

Synthesis

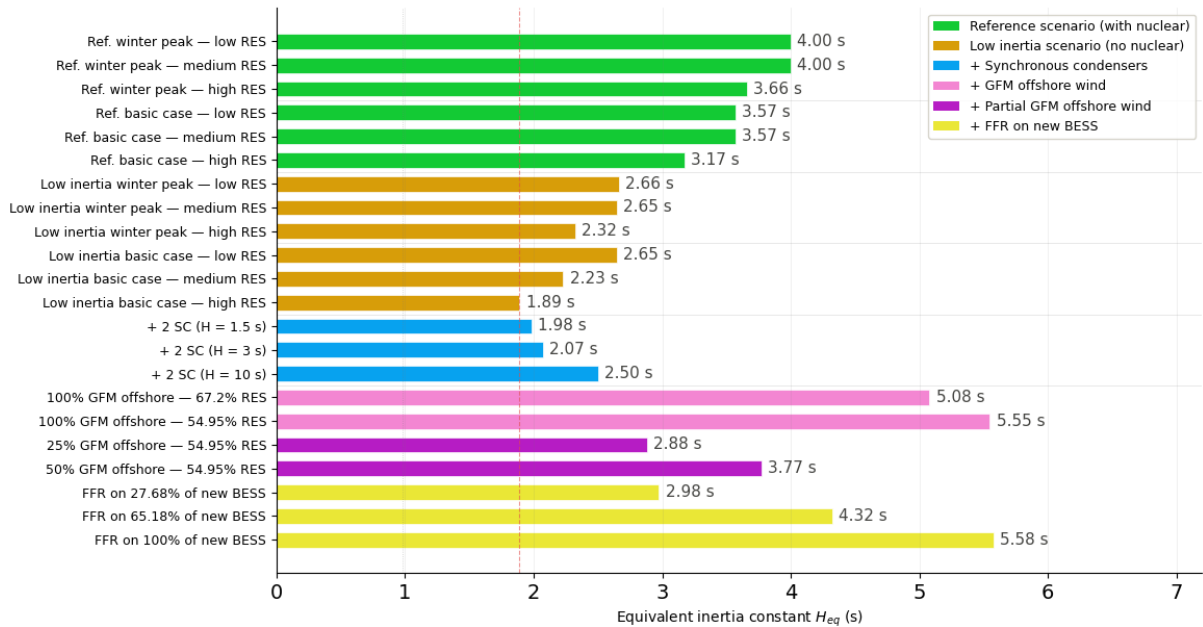


Figure 4.18: Inertia comparison between different simulations.

Taken together, the results in Table 4.2 and Figure 4.18 convey several key messages. The reference scenarios with nuclear sit comfortably between 3.17 and 4.00 s. Removing nuclear drags the system down to as low as 1.89 s in the worst basic case. That number is what drives the frequency violations observed in Section 4.4, and it is the baseline against which all solutions must be judged. The SCs produce a modest but visible improvement. The GFM offshore farm tells a completely different story, with H_{eq} jumping to 5.55 s at 54.95% RES, actually exceeding all reference scenarios with nuclear. The FFR cases should be read as a performance metric rather than a physical quantity, as the equivalent inertia values are derived from the observed frequency response rather than stored kinetic or virtual energy.

The most effective approach would therefore combine high-inertia SCs with GFM-connected offshore wind and FFR-enabled BESS. The SCs bring irreplaceable physical fault current and instantaneous mechanical response. The GFM farm provides the bulk of the synthetic inertia. The FFR adds a fast, controllable nadir buffer, and this combination is consistent with the recommendations found in the literature [19].

4.7 Discussion

The results obtained in this work are broadly consistent with what the literature predicts for low-inertia power systems. They also highlight some specificities of the Belgian context that are worth discussing.

The most fundamental finding is that nuclear generation plays a central role in frequency security in Belgium. This is not surprising given that nuclear units have the highest inertia constant among all generation technologies ($H = 6.4$ s, see Table 3.2). The simulations make it concrete. Its removal in the basic case pushes the frequency nadir below the 49 Hz operational threshold, while the winter peak case remains compliant thanks to the larger total synchronous dispatch. This confirms the concern raised among others by Ulbig *et al.* [11] and Milano *et al.* [10]. The progressive displacement of synchronous generation by converter-interfaced RES reduces the system's ability to resist frequency disturbances. Moreover, this effect becomes critical when large synchronous units are simultaneously offline.

The results on synchronous condensers are more nuanced. Adding two SCs at the coastal bus does improve the frequency response. However, the improvement is limited when the machines have a low inertia constant. A standard round rotor SC without flywheel ($H = 1.5$ s) is not sufficient to restore compliance in the critical scenario. Only a high-inertia machine with flywheel ($H = 10$ s) crosses back above 49 Hz. This is consistent with the

findings of the ARENA and DIgSILENT study [35], which emphasises that the inertial benefit of SCs depends strongly on their rating.

The simulation also illustrates the point made in Section 2.3.1. The SCs must be co-optimised with other solutions rather than deployed as a standalone fix. In the Belgian context, the two SCs planned by Elia for the coastal area were primarily motivated by system strength considerations rather than inertia. This explains why their inertial contribution alone is not sufficient to fully address the frequency stability problem.

It is also worth recalling that, as discussed in Section 2.3.1, the deployment of SCs does not necessarily require building new machines. Repurposing existing generation units offers a faster and significantly cheaper alternative [35].

Another important result of this work is the comparison between GFL and GFM connection of the future offshore capacity. Connecting 3.5 GW of new offshore wind through GFL converters brings essentially no improvement to frequency stability. By contrast, GFM connection produces a substantial improvement, restoring the nadir above 49 Hz and bringing the RoCoF down to levels comparable to the nuclear reference scenario. This is in line with the ENTSO-E technical report [27], which recommends prioritising GFM deployment at the periphery of transmission networks and behind HVDC interfaces. As well as with the broader literature conclusion that GFM converters can provide synthetic inertia and voltage support in weak-grid conditions where GFL converters struggle [10]. It is worth noting, however, that the GFM simulations assume that the wind turbines are not operating at their MPPT, meaning that a power margin is kept available for frequency response. This is a necessary condition for GFM wind to participate in frequency regulation. However, it implies a permanent production curtailment whose financial cost was not assessed in this work.

The FFR simulations address this constraint partially. By keeping the offshore connection in GFL mode and instead activating FFR on BESS, the nadir is restored without forcing any curtailment on the wind farm. The two approaches are not strict alternatives. GFM offshore improves both nadir and RoCoF at the cost of curtailment and FFR from BESS addresses the nadir at no curtailment cost but leaves RoCoF almost unchanged.

Model limitations

Several simplifications in the modelling approach deserve to be discussed explicitly, as they affect the interpretation of the results.

The most important limitation concerns the representation of synchronous generators, as introduced at the beginning of this chapter. The simplified model uses one equivalent SG per bus with a fixed inertia constant, regardless of the actual dispatch level. In reality, when synchronous generation is reduced, individual units would be disconnected and would no longer contribute inertia. This means that the effective inertia in the model is likely overestimated in low-generation scenarios. The real frequency response would probably be worse than what the simulations show.

A second limitation is the spatial resolution of the network model. Aggregating generation and load at eight buses is sufficient to capture inter-area frequency differences and the effect of inertia distribution at a regional level. It does not allow a precise assessment of localised effects.

A third limitation concerns the winter peak operating point of the future network. An attempt was made to simulate this scenario but increasing RES penetration led to voltage violations at several buses. Since voltage stability is outside the scope of this work, the scenario was not investigated further and no results are reported for it. Under a no-nuclear scenario in winter peak conditions, the future network may hit voltage limits before frequency stability becomes the primary issue. The interaction between reduced synchronous dispatch, high RES injection and reactive power balance in this operating point remains an open question.

Finally, as mentioned in Section 3.3.2, no secondary frequency control was implemented. This means that the frequency stabilises at a value below the nominal 50 Hz after a disturbance. This is an acceptable simplification for the purpose of assessing inertial response and primary frequency containment, which are the focus of this work. It also means that settling times should be interpreted with care, as the frequency is not fully restored within the 30 s simulation window.

Perspectives for future work

Several directions could be explored to build on the results of this thesis. A natural extension would be to investigate GFM control applied to the HVDC converters of the Nemo and ALEGrO interconnectors. These links already use VSC-MMC technology, which is technically capable of operating in GFM mode. Enabling this functionality could allow Belgium to draw frequency support from neighbouring synchronous areas during critical periods. This would effectively turn the interconnectors into active frequency stabilisers rather than passive power transfer links. This has received growing attention in the literature, in recent years [27].

The future BESS capacity planned by Elia also represents an opportunity that deserves more detailed investigation. Future studies could explore GFM-controlled BESS as a provider of both synthetic inertia and fast frequency response simultaneously. An interesting research question would be to determine the optimal combination of GFM-controlled BESS and GFM-controlled wind in terms of frequency performance, state-of-charge management, and energy cost.

Finally, a financial analysis is also missing from this work and would be an important complement to the technical results. The solutions tested here involve very different cost structures, lead times, and regulatory frameworks. A cost-benefit analysis, framed to account the market value of the frequency services provided, would help Elia and policymakers prioritise investments in a structured way. This kind of analysis is exactly what the Artelys report [19] calls for, at the European level, applying it to the Belgian context would be a useful contribution.

To conclude this chapter, the simulations carried out paint a consistent picture: the Belgian grid handles the reference disturbance comfortably when nuclear is online but loses its frequency security margin in the basic case once nuclear is removed. Among the solutions tested, GFM connection of the future offshore capacity produces a substantial improvement, while partial FFR deployment on BESS offers a practical complement that requires no change to converter architecture. These findings set the stage for the conclusions drawn in Chapter 5.

Chapter 5

Conclusion

The aim of this thesis was to characterise the frequency stability of the Belgian power system under low-inertia conditions and to quantify the effectiveness of different technical solutions. The work was motivated by a concrete and near-term challenge. Belgium will operate without nuclear generation during the summers of 2026 to 2028, while simultaneously integrating large amounts of new offshore wind capacity. The simulations confirm that this combination can push the system outside its operational frequency limits. The results provide some guidance on what could be done about it.

The first main finding is that nuclear generation is the dominant contributor to the Belgian frequency response. With an inertia constant of 6.4 s, nuclear units are the largest contributor to system kinetic energy. Their removal reduces total inertia by around 63% in the worst-case scenario. In the basic case without nuclear, the frequency nadir following a loss of 1,336 MW drops to 48.98 Hz, crossing the 49 Hz threshold that activates the low frequency demand disconnection relays. The winter peak scenario is less critical, because the higher total synchronous generation dispatched during peak hours provides enough residual inertia even without nuclear. This distinction matters for operational planning. The risk is not uniformly distributed across seasons or time of day, and the critical periods are precisely those where demand is low and synchronous dispatch is reduced.

The second finding concerns synchronous condensers. The two units planned by Elia for the coastal area do improve the response, but the effect is modest. Only a high-inertia machine equipped with a flywheel ($H = 10$ s) is sufficient to restore nadir compliance, while a standard round rotor SC ($H = 1.5$ s) is not. The two SCs were originally motivated by system strength considerations, which explains why their inertial contribution alone is not sufficient as a standalone fix for frequency stability. It is also worth noting that repurposing existing retired generation units as SCs, as discussed in the theoretical background, could offer a faster and cheaper path to deployment than building new machines.

The third finding concerns the connection mode of the future offshore capacity. Connecting 3.5 GW of new offshore wind in GFL mode brings essentially no improvement to the frequency response. By contrast, GFM connection produces a substantial improvement, restoring the nadir above 49 Hz and bringing the RoCoF down to levels comparable to the

nuclear reference scenario. This result is significant because it means that the converter control strategy chosen for Princess Elisabeth Island has more impact on frequency security than the number of synchronous condensers installed, at least in the scenarios tested here.

The FFR simulations also show that keeping the offshore connection in GFL mode while activating FFR on the future BESS fleet is sufficient to restore nadir compliance, though without the RoCoF benefit that GFM provides. The combined deployment analysis shows that the two levers are complementary rather than competing: BESS capacity primarily governs nadir depth, while GFM capacity governs RoCoF improvement. No single combination dominates across all three stability metrics simultaneously and the optimal deployment strategy depends on which criterion is the binding constraint.

It is worth highlighting what the model does not capture. The simplified representation with one equivalent synchronous generator per bus means that inertia is likely overestimated in low-dispatch scenarios, since individual units that would be disconnected in reality remain connected in the model. A more granular model would probably show worse frequency performance than what is reported here. The GFM simulations also assume the wind turbines are not operating at MPPT, which is a necessary condition for frequency participation but implies a permanent power curtailment that was not financially assessed. In practice, pairing GFM-controlled BESS with the offshore wind would be more practical, since the storage can provide the frequency response without forcing the turbines to sacrifice output.

The results suggest that Belgium can maintain frequency security through the nuclear transition but only if the right technical choices are made. The two planned synchronous condensers are not sufficient on their own. The connection mode of the future offshore capacity will matter. The large BESS deployment underway could provide additional support if properly controlled. These findings point to a coherent strategy: aligning grid-forming control and storage deployment would give Belgium the technical means to maintain frequency stability through this transition. Delayed investment decisions or fragmented coordination between solutions, on the other hand, risk pushing the system towards critical low-inertia conditions as nuclear inertia disappears and converter-based generation grows.

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Appendix A

Distribution of Generation Units

The allocation of generation units to the different nodes of the simplified Belgian grid model is based on the ODS179 dataset published by Elia [42]. This dataset contains all technical units contracted with Elia for scheduling and outage planning purposes and therefore represents centrally dispatched and system-relevant generation units. These units constitute the main contributors to system inertia.

For each technical unit, the maximum active power $P_{\max}$ is extracted and used to determine the installed capacity per node. These capacities are subsequently aggregated by technology type in order to define the equivalent generators used in the dynamic simulations. Table A.1 summarises the technology classification used in the dataset.

Table A.1: Generation unit type classification

Unit Type	Description
NUC	Nuclear power plant
GT	Gas turbine
ST	Steam turbine
TJ	Turbojet / small industrial turbine
HT	Hydropower turbine (pumped storage / reservoir)
RoR	Run-of-river hydropower plant
WOF	Offshore wind farm
WON	Onshore wind farm
PV	Photovoltaic plant
CHEM	Battery Energy Storage System (BESS)
CE	Combustion engine (biomass / gas)

Table A.2: Generation units connected to BE_CENTRAL

Technical Unit	Unit type	Pmax (MW)
VILVOORDE GT	GT	264.0
DROGENBOS ST	ST	160.0
DROGENBOS GT1	GT	150.0

Technical Unit	Unit type	Pmax (MW)
DROGENBOS GT2	GT	150.0
VILVOORDE ST	ST	121.0
Vilvoorde BESS 1	CHEM	100.0
Vilvoorde BESS 2	CHEM	100.0
IXELLES TJ	TJ	18.0
Schaerbeek Siomab ST1	GT	15.0
Schaerbeek Siomab ST2	GT	15.0
Schaerbeek Siomab ST3	GT	15.0
Drogenbos Batteries	CHEM	7.0
DROGENBOS DM 51	CE	2.5
DROGENBOS DM 52	CE	2.5

Table A.3: Generation units connected to BE_COAST

Technical Unit	Unit type	Pmax (MW)
Norther Offshore WP	WOF	370.0
Rentel Offshore WP	WOF	308.7
Mermaid Offshore WP	WOF	235.2
Northwester 2	WOF	219.0
Northwind	WOF	216.0
Thorntonbank - C-Power - Area SW	WOF	177.6
Belwind Phase 1	WOF	171.0
Nobelwind Offshore Windpark	WOF	165.0
Thorntonbank - C-Power - Area NE	WOF	147.6
ICO Windpark Zeebrugge	WON	44.0
Zeebrugge 2 Fluxys	GT	40.0
Greenpower Oostende	CE	20.3
Biostoom Oostende	GT	19.4
Electrawinds biomassa Oostende	CE	18.0
Noordschote TJ	TJ	18.0
Zedelgem TJ	TJ	18.0
Zeebrugge TJ	TJ	18.0
ZEEBRUGGE WIND	WON	15.0
WM Park Powerport Zeebrugge	WON	12.0
Electrawinds biomassa combustion engine 1	CE	8.6

Table A.4: Generation units connected to BE_FLANDERS_NORTH

Technical Unit	Unit type	Pmax (MW)
DOEL 4	NUC	1026.0
DOEL 1	NUC	445.0
DOEL 2	NUC	445.0
Zelzate 2 Knippegroen	GT	315.0
RODENHUIZE 4	ST	205.0
Scheldelaan Exxonmobil	GT	140.0
INESCO ST	ST	50.0
INESCO GT1	GT	49.0
INESCO GT2	GT	49.0
Wilmarsdonk Total GT1	GT	48.0
Wilmarsdonk Total GT2	GT	48.0
Wilmarsdonk Total GT3	GT	48.0
LANGERBRUGGE STORA ST 2	ST	44.7
Aalst Syral GT	GT	43.0
Lillo Degussa GT1	GT	43.0
Oorderen Bayer	GT	43.0
Oud-Lillo Monsanto	GT	43.0
Zwijndrecht Lanxess GT	GT	43.0
Beveren Sleco	ST	41.0
Lillo Degussa GT2	GT	32.0
Aspiravi Wuustwezel	WON	25.7
Beveren Ineos Phenolchemie	GT	25.1
Beveren 3 Indaver	ST	24.0
Beveren 2 Indaver	ST	21.0
AMB Gent WT Storm 2	WON	18.8
AALTER TJ	TJ	18.0
Zelzate TJ	TJ	18.0
VPK Paper Oudegem GT3	GT	15.0
Eurosilo	GT	12.9
AMB Gent WT Storm 1	WON	12.0
Aspiravi N49 Assenede	WON	12.0
WILRIJK ISVAG	GT	12.0
LANGERBRUGGE STORA ST 1	ST	11.0
VPK Paper Oudegem ST4	ST	11.0
Lillo Degussa ST	ST	10.0
ArcelorMittal Belgium Gent Wind Storm 1	WON	9.0

Technical Unit	Unit type	Pmax (MW)
ArcelorMittal Belgium Gent Wind Storm 2	WON	7.2
Taminco (Gent) WKK	ST	6.3
Umicore Olen GT1	GT	5.4
Umicore Olen GT2	GT	5.4
Aalst Syral ST	ST	5.0

Table A.5: Generation units connected to BE_LUX

Technical Unit	Unit type	Pmax (MW)
CIERREUX TJ	TJ	18.0
Estor-Lux _ Storage	CHEM	11.5
BUTGENBACH	RoR	1.8

Table A.6: Generation units connected to BE_MONS_FR

Technical Unit	Unit type	Pmax (MW)
Marcinelle Energie (Carsid)	GT	413.0
SAINT-GHISLAIN STEG	GT	386.0
Amercoeur 1 R GT	GT	289.0
Amercoeur 1 R ST	ST	162.0
Windvision Estinnes WIND	WON	81.2
Harmignies Energy Storage BESS	CHEM	75.0
Deux-Acren Energy Storage	CHEM	50.0
Eneco Ville-Sur-Haine BESS	CHEM	50.0
Ruilen Energy Storage	CHEM	25.1
Froidchapelle Wind	WON	24.9
Ipalle Thumaide GTA1	GT	18.0
Ipalle Thumaide GTA2	GT	18.0

Table A.7: Generation units connected to BE_NDLS

Technical Unit	Unit type	Pmax (MW)
Kristal _ Solar _ Park	PV	99.0
HAM31	GT	58.0
HAM32	GT	58.0
EDF Luminus Ham GT	GT	43.0

Technical Unit	Unit type	Pmax (MW)
PLATE-TAILLE 4 T	HT	37.7
PLATE-TAILLE 1 T	HT	36.0
PLATE-TAILLE 2 T	HT	36.0
PLATE-TAILLE 3 T	HT	36.0
Tessengerlo Kerley International Ham stoomturbine	ST	16.9
Nyrstar Belgium Balen BESS 1	CHEM	15.0
Nyrstar Belgium Balen BESS 2	CHEM	10.0

Table A.8: Generation units connected to BE_NUCLEAR_SOUTH

Technical Unit	Unit type	Pmax (MW)
TIHANGE 3	NUC	1030.00
Flémalle CCGT	GT	890.00
Seraing GT3	GT	586.53
TIHANGE 1N	NUC	481.00
TIHANGE 1S	NUC	481.00
Seraing ST2	ST	288.89
EDF Luminus Seraing GT1	GT	150.00
EDF Luminus Seraing GT2	GT	150.00
ANGLEUR TG 41	GT	64.00
ANGLEUR TG 42	GT	64.00
Jemeppe-sur-Sambre PV	PV	60.00
Jemeppe-sur-Sambre GT1	GT	48.00
Jemeppe-sur-Sambre GT2	GT	48.00
Luminus Villers-le-Bouillet WIND	WON	44.90
Infrabel Avernas Greensky Wind	WON	32.00
Intradel Herstal	CE	32.00
ANGLEUR TG31	GT	25.00
ANGLEUR TG32	GT	25.00
Jemeppe-sur-Sambre ST	ST	10.00
Intradel Herstal Biogaz Motor 1	CE	0.60
Intradel Herstal Biogaz Motor 2	CE	0.60

Table A.9: Generation units connected to BE_COO

Technical Unit	Unit type	Pmax (MW)
COO 4 T	HT	230.00
COO 5 T	HT	230.00
COO 6 T	HT	230.00
COO 1 T	HT	158.00
COO 2 T	HT	158.00
COO 3 T	HT	158.00

Appendix B

Implementation of elements from the DIgSILENT library

B.1 AVR: exc_ST

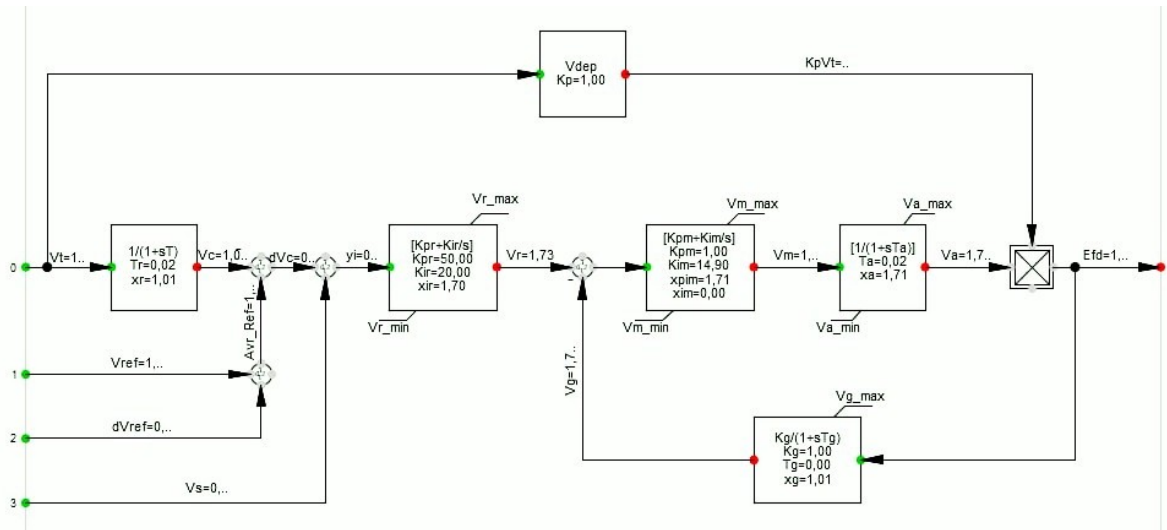


Figure B.1: Simplified static excitation system model.

B.2 FCR: gov_SIMPLE

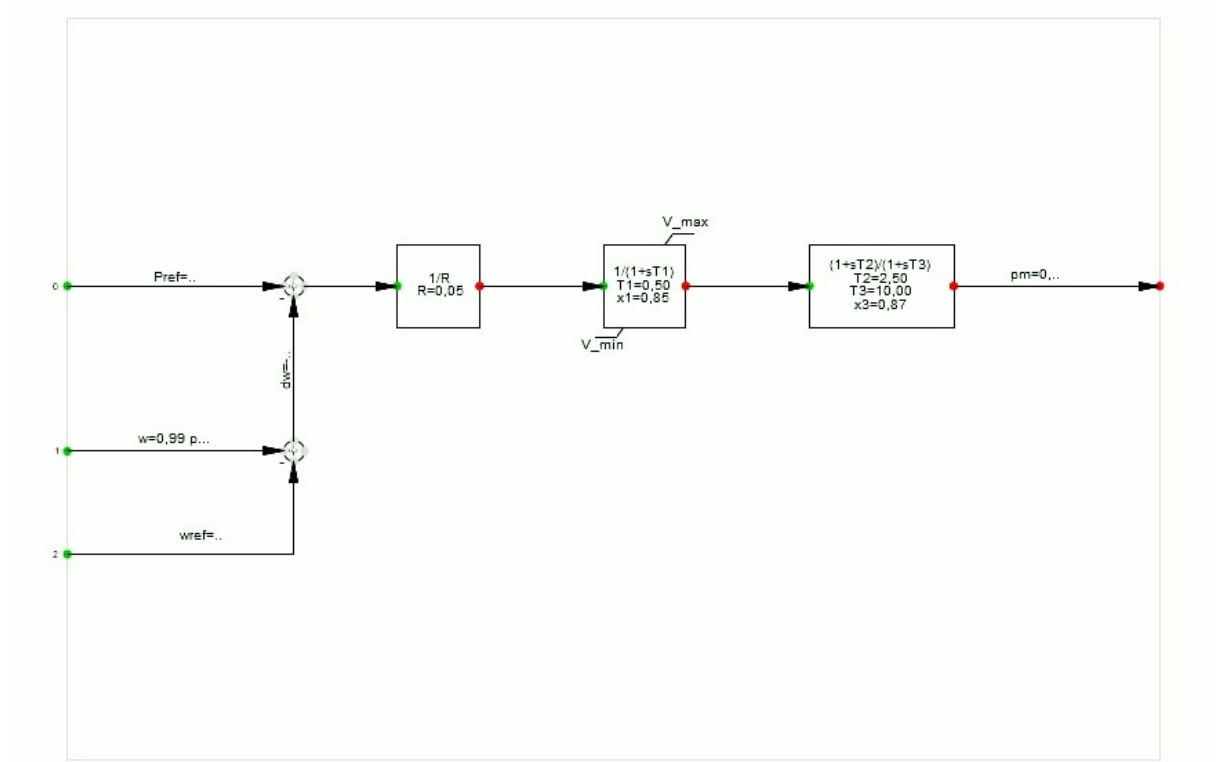


Figure B.2: Basic turbine governor model.

B.3 HVDC link

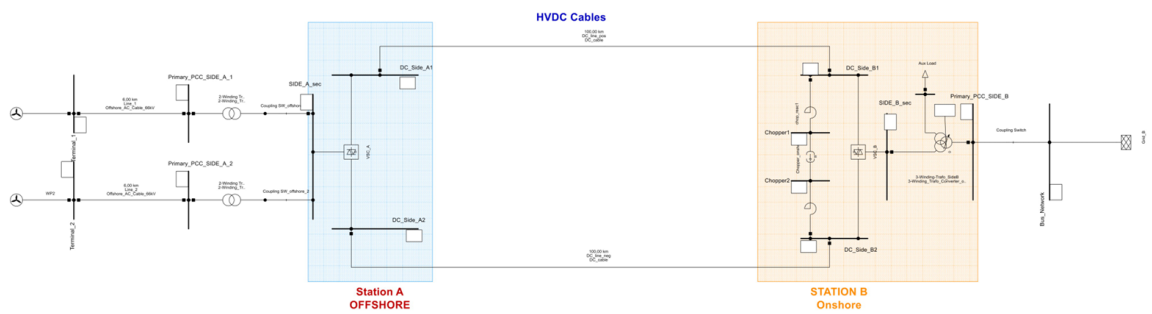
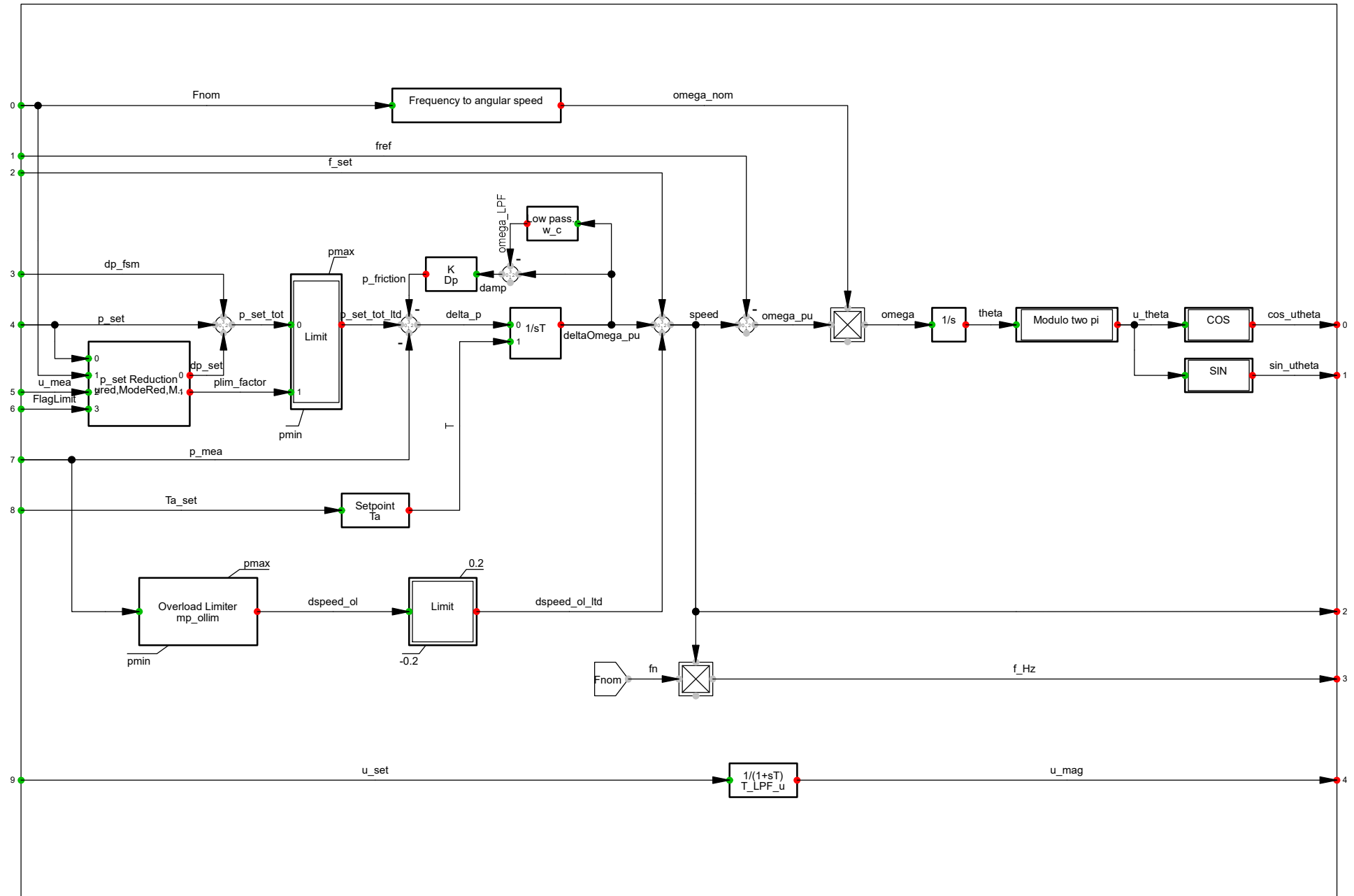


Figure B.3: Single-line diagram of the HVDC PLUS model

B.4 GFM: VSM

gfc_virtual synchronous machine extended: Virtual Synchronous Machine implementation with stabilizing extensions for EMT and balanced RMS sim.



B.5 PV: WECC Large-Scale PV Plant model.

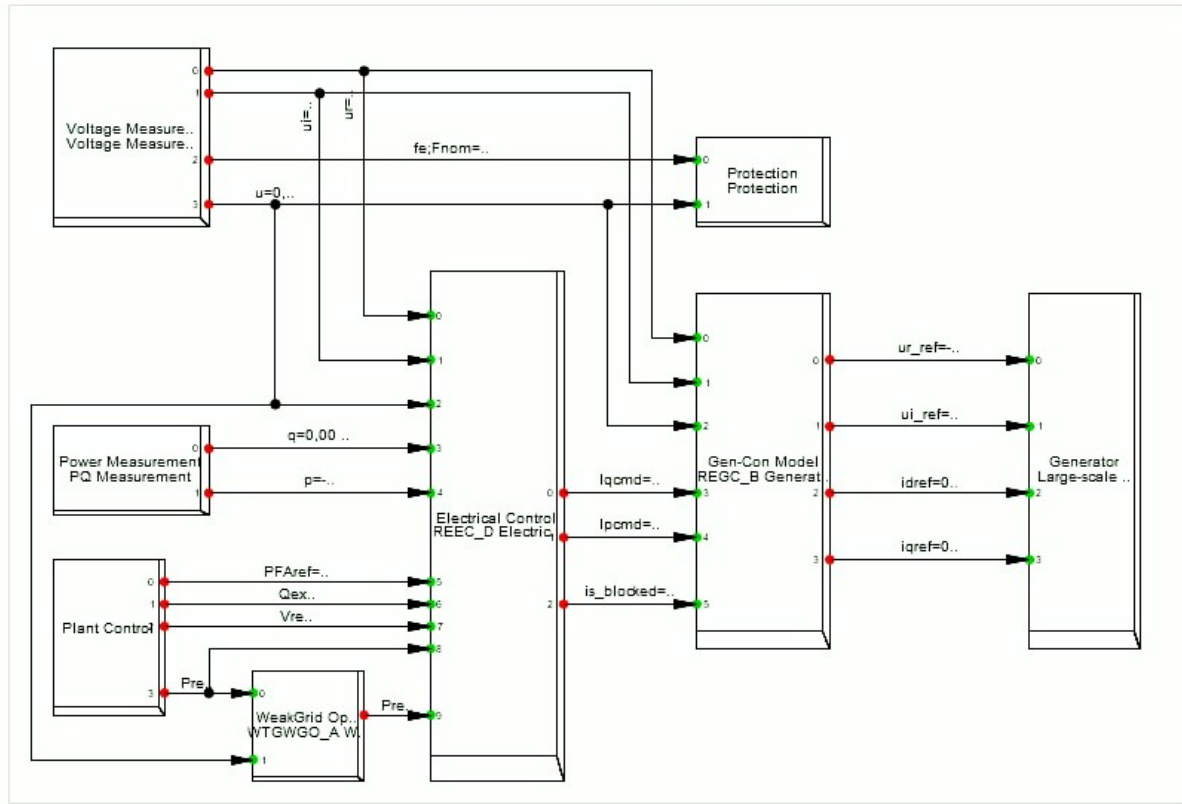


Figure B.4: WECC Large-scale Photovoltaic Plant Model

B.6 BESS: DIgSILENT BESS Frequency Ctrl

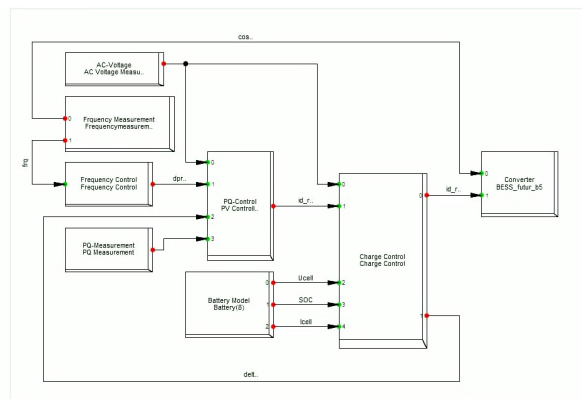


Figure B.5: BESS frequency control model.

Appendix C

Generation mix in simplified model

This appendix provides the detailed generation dispatch used in the dynamic simulations for each scenario. For each bus of the simplified Belgian grid model, the equivalent synchronous generator is labelled G1 through G8, where G1 corresponds to the equivalent synchronous generator at bus BE_COAST (b1), G2 to BE_FLANDERS_NORTH (b2), G3 to BE_CENTRAL (b3), G4 to BE_NDLS (b4), G5 to BE_MONS_FR (b5), G6 to BE_NUCLEAR_SOUTH (b6), G7 to BE_LUX (b7), and G8 to BE_COO (b8). Nuclear generation units are represented separately and are not included in these equivalent generators, as explained in Section 3.3.2.

The system inertia values reported in this appendix are expressed on a common base power of $S_{\text{base}} = 9,787.1$ MW, which corresponds to the total maximum active power of all synchronous machines in the model when fully dispatched. This fixed base was chosen to allow consistent comparison of inertia across scenarios with different dispatch levels, since the per-unit inertia of the system depends on the base chosen, fixing it to the same value in all cases ensures that changes in the reported H_{eq} reflect actual changes in stored kinetic energy rather than changes in the base.

Finally, generators G1, G4, and G6 are marked with an asterisk (*) in the tables below. These three machines were selected to provide the Frequency Containment Reserve in the simulations, as discussed in Section 3.3.2. As a consequence, they remain connected to the network even when their active power dispatch is set to zero, their governor is active and ready to respond to a frequency deviation, but they are not injecting power at the operating point. This is consistent with how FCR providers operate in practice, where units are held in a ready state to deliver upward or downward reserve as needed.

C.1 Reference scenario

Winter peak

Table C.1: Generation breakdown and inertia characteristics for reference scenario: winter peak.

Category / Unit	low RES	medium RES	high RES
Synchronous Generation			
G1*	144.27	144.27	144.27
G2	1336.00	1336.00	1336.00
NUC2	1039.00	1039.00	1039.00
G3	821.70	107.29	0.00
G4*	289.44	289.44	289.44
G5	721.76	593.65	304.21
G6*	2144.34	2144.34	1492.61
NUC6	1038.00	1038.00	1038.00
G7	17.82	0.00	0.00
G8	1000.00	1000.00	1000.00
Total synchronous	8552.33	7691.99	6643.53
Wind Generation			
WIND1	162.36	983.70	2000.00
WIND2	13.00	26.00	36.00
WIND5	13.00	26.00	36.00
WIND6	13.00	26.00	36.00
Total wind	201.36	1061.70	2108.00
PV Generation			
PV4	0.00	0.00	1.08
PV6	0.00	0.00	1.08
Total PV	0.00	0.00	2.16
BESS	0.00	0.00	0.00
Total Generation	8753.69	8753.69	8753.69
RES (Wind + PV)	201.36	1061.70	2110.16
RES share (%)	2.30	12.13	24.11
Inertia Characteristics			
Machines disconnected	None	G7	G7 + G3
Total inertia (MWs)	39185.5	39136.9	35842.8
H_{eq} (s)	4.00	4.00	3.66

Basic case

Table C.2: Generation breakdown and inertia characteristics for reference scenario: basic case

Category / Unit	Low RES	Medium RES	High RES
Synchronous Generation			
G1*	0.00	0.00	0.00
G2	1336.00	1336.00	1336.00
NUC2	485.10	485.10	249.91
G3	0.00	0.00	0.00
G4*	0.00	0.00	0.00
G5	0.00	0.00	0.00
G6*	1310.23	951.04	0.00
NUC6	484.20	484.20	249.44
G7	0.00	0.00	0.00
G8	256.31	256.31	0.00
Total synchronous	3871.84	3512.65	1835.35
Wind Generation			
WIND1	162.36	521.55	2000.00
WIND2	13.00	13.00	73.00
WIND5	13.00	13.00	73.00
WIND6	13.00	13.00	73.00
Total wind	201.36	560.55	2219.00
PV Generation			
PV4	0.00	0.00	9.43
PV6	0.00	0.00	9.43
Total PV	0.00	0.00	18.85
BESS	0.00	0.00	0.00
Total Generation	4073.20	4073.20	4073.20
RES (Wind + PV)	201.36	560.55	2237.85
RES share (%)	4.94	13.76	54.95
Inertia Characteristics			
Machines disconnected	G7+ G5	G7+ G5	G7+ G5 + G8
Total inertia (MWs)	34954.9	34954.9	30997.3
H_{eq} (s)	3.57	3.57	3.17

C.2 Low inertia scenario

Winter peak

Table C.3: Generation breakdown and inertia characteristics for low inertia scenario: winter peak

Category / Unit	Low RES	Medium RES	High RES
Synchronous Generation			
G1	160.30	160.30	160.30
G2	1336.00	1336.00	1336.00
G3	913.00	603.68	0.00
G4	321.60	321.60	321.60
G5	1286.00	1286.00	1279.03
G6	2382.60	2382.60	2382.60
G7	19.80	0.00	0.00
G8	1164.00	1164.00	1164.00
NUC2	0.00	0.00	0.00
NUC6	0.00	0.00	0.00
Total synchronous	7583.30	7254.18	6643.53
Wind Generation			
WIND1	944.83	1421.51	2000.00
WIND2	75.19	26.00	36.00
WIND5	75.19	26.00	36.00
WIND6	75.18	26.00	36.00
Total wind	1170.39	1499.51	2108.00
PV Generation			
PV4	0.00	0.00	1.08
PV6	0.00	0.00	1.08
Total PV	0.00	0.00	2.16
BESS	0.00	0.00	0.00
Total Generation (Belgium)	8753.69	8753.69	8753.69
RES (Wind + PV)	1170.39	1499.51	2110.16
RES share (%)	13.37	17.13	24.11
Inertia Characteristics			
Machines disconnected	None	G7	G7 + G3
Total inertia (MWs)	26027.1	25978.5	22684.4
H_{eq} (s)	2.66	2.65	2.32

Basic case

Table C.4: Generation breakdown and inertia characteristics for low inertia scenario: basic case

Category / Unit	Low RES	Medium RES	High RES
Synchronous Generation			
G1*	160.30	160.30	0.00
G2	1336.00	1336.00	1336.00
G3	500.00	389.70	0.00
G4*	250.00	250.00	100.00
G5	250.00	0.00	0.00
G6*	1119.23	1120.34	200.00
G7	0.00	0.00	0.00
G8	256.31	256.31	199.35
NUC2	0.00	0.00	0.00
NUC6	0.00	0.00	0.00
Total synchronous	3871.84	3512.65	1835.35
Wind Generation			
WIND1	162.36	521.55	2000.00
WIND2	13.00	13.00	73.00
WIND5	13.00	13.00	73.00
WIND6	13.00	13.00	73.00
Total wind	201.36	560.55	2219.00
PV Generation			
PV4	0.00	0.00	9.43
PV6	0.00	0.00	9.43
Total PV	0.00	0.00	18.85
BESS	0.00	0.00	0.00
Total Generation	4073.20	4073.20	4073.20
RES (Wind + PV)	201.36	560.55	2237.85
RES share (%)	4.94	13.76	54.95
Inertia Characteristics			
Machines disconnected	G7	G7 + G5	G7 + G5 + G3
Total inertia (MWs)	25978.5	21796.5	18502.4
H_{eq} (s)	2.65	2.23	1.89

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