

Frequency Stability in Grids with a High Share of Variable Generation: The Role of Gas Turbines

A Case Study of the Subtransmission Grid in Stenungsund Using DIgSILENT PowerFactory

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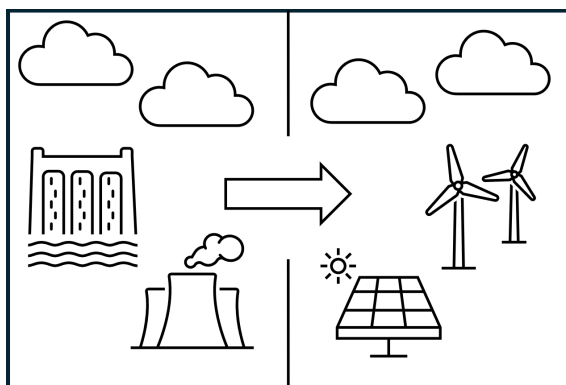
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Gasturbinens roll i ett elnät med hög andel förnybar energi

En fallstudie i Stenungsund undersöker hur gasturbiner kan bidra till frekvensstabilitet när vindkraft dominerar.

Sverige elektrifierar i snabb takt, vilket driver en stor energiomställning där förnybara energikällor som vind- och solkraft spelar en nyckelroll. Dessa medför väldigt lite koldioxidutsläpp och är ett nödvändigt steg mot ett mer hållbart samhälle. Men är det verkligen så enkelt som att bara bygga mer vind- och solkraft - och kan vi förvänta oss samma robusta och pålitliga elförsörjning som vi tidigare haft?



Övergången till en ökad andel förnybar variabel kraftproduktion

Sedan "Strömkriget" på 1800-talet mellan Edison och Tesla har elnät världen över använt växelström, där strömmen växlar riktning flera gånger per sekund. I Europa sker detta 50 gånger per sekund – en frekvens på 50 hertz.

Frekvenshållning i ett elkraftssystem är av största vikt och måste beaktas för att kunna tillgodose ett stabilt nät. Vid 50 Hz är produktion och konsumtion av electriciteten i balans. Produceras mer effekt uppstår överfrekvens, produceras mindre uppstår underfrekvens.

Hur stabil frekvensen är beror bland annat på svängmassan i systemet. I system med mycket kärnkraft och vattenkraft snur-

rar turbiner med stor massa - en energilagrings som hjälper till att hålla frekvensen stabil. Sättet vind- och solkraft är anslutna till nätet gör att de inte bidrar med svängmassa.

Det innebär att när intermittent förnybar energiproduktion ansluts till ett system minskar den relativa andelen lagrad energi i form av svängmassa. Mer förnybar energi kan alltså leda till ett elnät med högre instabilitet. När man designar framtidens elkraftssystem måste detta beaktas, och nya lösningar implementeras för att undvika att nätet försvagas.

Detta arbete har undersökt framtida integration av gasturbiner i elnät med hög andel vindkraft. Gasturbiner är ett kraftslag med hög verkningsgrad och stor flexibilitet. De kan startas mycket snabbt och producera kraft under så lång eller kort tid som behövs. Tack vare sin bränsleflexibilitet kan gasturbiner drivas med både fossila och förnybara bränslen.

Undersökningen visar att gasturbiner i hög grad bidrar till ökad stabilitet i elnät med hög andel intermittent energiproduktion. Simulerade testfall visar att man i de flesta fall gynnas av fler gasturbiner i systemet. Samtidigt kan många gasturbiner också skapa svagheter som måste planeras för vid utformning av nätet. Studien visar även på fördelar med att kombinera gasturbiner med batterilagring.

Sammanfattningsvis kan gasturbiner bidra till ökad driftsäkerhet och skapa flexibilitet i elkraftssystemet - vilket möjliggör en fortsatt utbyggnad av förnybara intermittenta kraftslag som vind och sol.

Preface

This master's thesis was conducted as part of the Master of Science in Mechanical Engineering programme at Lund University, Faculty of Engineering (LTH), for the Department of Energy Sciences. The investigation was carried out in collaboration with Siemens Energy in Finspång and explores the integration of gas turbines in a subtransmission grid with a high share of variable renewable electricity production.

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Abstract

The electric power system is undergoing a major change through the implementation of a large number of variable renewable energy sources (VRE), driven by the goal to reduce carbon-dioxide emissions from electricity production. This transition increases the need for a more flexible and dynamic power system capable of maintaining voltage and frequency stability under changing operating conditions. Under normal operating conditions, the grid is supported by numerous generating units across the synchronous area, such as the Nordic power system. However, during disturbances or planned maintenance, transmission lines may be disconnected, potentially forming an islanded network that must rely entirely on local resources to maintain balance and stability – otherwise a power outage is imminent.

This thesis investigates how gas turbines can support a subtransmission power grid with a high share of wind power, particularly during critical scenarios such as island operation and three-phase faults. Due to their fast start-up times and strong ramping capabilities, gas turbines remain well-suited for providing frequency support and reserves in a flexible power system. A simplified model of the Stenungsund region in western Sweden has been developed in DIgSILENT PowerFactory, including wind power, gas turbines, and battery storage. Transient RMS simulations were carried out to evaluate the grid’s stability during fault conditions and disconnection from the main grid, where the number of gas turbines is varied from one to six units.

In general, the results demonstrate that gas turbines can play a key role in maintaining system stability during transient events in grids dominated by inverter-based generation.

Under island operation, gas turbines effectively handled active power imbalances and maintained frequency stability, with increasing numbers contributing to a more resilient grid. The results also show that by incorporating future capabilities for the gas turbines, such as increased inertia and fast power injection, frequency stability can be greatly improved.

However, during short-circuit events, the results indicate that increasing the number of gas turbines without reinforcing the grid can reduce transient stability and increase the risk of loss of synchronism following a short-circuit. This highlights the need to ensure sufficient grid strength when expanding local generation capacity to maintain synchronism during fault events.

Acronyms	
aFRR	Automatic Frequency Restoration Reserve
BESS	Battery Energy Storage Systems
DSO	Distribution System Operator
FCR-D	Frequency Containment Reserve - Disturbance
FCR-N	Frequency Containment Reserve - Normal
FFR	Fast Frequency Reserve
GFL	Grid-Following
GFM	Grid-Forming
GT	Gas Turbine
HVDC	High Voltage Direct Current
mFRR	manual Frequency Restoration Reserve
QSS	Quasi Steady State
RoCoF	Rate of Change of Frequency
SG	Synchronous Generator
SO	System Operator
TSO	Transmission System Operator
VRE	Variable Renewable Energy
WPP	Wind Power Plant
WT	Wind Turbine

Contents

1	Introduction	1
1.1	Motivation and Context	1
1.2	Stenungsund	2
1.2.1	Stenungsundsverket	3
1.3	Fundamentals of an AC power system	4
1.4	Problem Statement and Objectives	5
1.5	Scope and Limitations	6
2	Background	7
2.1	The Swing Equation	7
2.2	Parallel Impedance of Generators	9
2.3	Speed Governing and Droop Control	9
2.4	The Gas Turbine	11
2.4.1	Single-Shaft Gas Turbines	12
2.4.2	Twin-Shaft Gas Turbines	13
2.4.3	Difference Between Single-Shaft and Multi-Shaft Gas Turbines in Power Generation Applications	13
2.4.4	Abilities of Gas Turbines	15
2.5	Evolution of Power Systems	15
2.5.1	Grid-following and Grid-forming power converters	17
2.6	Ancillary Services	18
2.6.1	Frequency related ancillary services	18
2.6.2	Non-frequency related ancillary services	20
2.7	Frequency Requirements in Grid Codes	21
3	Methodology	23
3.1	System Modeling and Simulation Environment	23
3.2	Creating the Model	23
3.3	Building the Model in PowerFactory	26
3.3.1	Wind Power Plant	27
3.3.2	Gas Turbine	28
3.3.3	Loads	28
3.3.4	Infinite Bus	29
3.3.5	Power Lines	29
3.3.6	Offshore Cable	29
3.3.7	Transformers	30
3.3.8	Battery	30
3.3.9	Secondary Frequency Control - AGC	31
3.4	Simulation Scenarios and Parameters	31
3.4.1	Case A — Grid with Wind Turbine and Gas Turbines Connected via Weak Link to an Infinite Bus	35

3.4.2	Case B — Transition Phase to Island Operation	35
3.4.3	Case C — Island Grid with Wind Power Plant and Gas Turbines . .	36
3.4.4	Meeting with Svenska Kraftnät	37
4	Results and Analysis	39
4.1	Simulation Results Case A — Grid Connected with Weak Link to Infinite Bus	39
4.2	Simulation Results Case B — Grid Disconnection with BESS Support and Subsequent Gas Turbine Activation	45
4.3	Simulation Results Case C — Island Grid with Wind Power Plant and Gas Turbines	50
4.3.1	Doubling the Inertia Constant H	52
4.3.2	FFR Response Incorporated in Island Operaion	54
4.3.3	Overfrequency in Island Grid Configuration	56
5	Discussion	58
5.1	Analysis of simulation Results Case A - Grid Connected with Weak Link to Infinite Bus	58
5.2	Analysis of simulation Results Case B - Transition phase	60
5.3	Analysis of simulation Results Case C - Island Grid with Wind Power Plant and Gas Turbines	61
5.3.1	Island grid with doubled inertia	61
5.3.2	FFR Response Incorporated in Island Operation	62
5.3.3	Overfrequency in Island Grid Configuration	62
5.4	Limitations and Uncertainties	63
6	Conclusion and Future Work	64
6.1	Summary of Findings	64
6.2	Future Research Directions	65
	Appendix	70
A	Creating the model in PowerFactory	70
A.1	Wind Power Plant	70
A.2	Gas turbine	70
B	Implementing Secondary Frequency Control in DIgSILENT PowerFac- tory	71
C	Implementing FFR for the gas turbine in PowerFactory	75
D	Model for Overfrequency Protection in Wind Turbine Model	79

1 Introduction

This chapter provides the background and motivation for the thesis. It begins by describing how the electric power system has evolved over time, highlighting the need for renewable energy to enable decarbonization and electrification of society. The focus then shifts to Stenungsund, a region in western Sweden with rapidly growing electricity demand due to the planned electrification of its chemical industry. Finally, the chapter outlines the main objective of the study: to evaluate how local electricity production using gas turbines can support frequency stability and grid reliability in a subtransmission power grid with a high share of wind power.

1.1 Motivation and Context

The electric power system is undergoing a major change. The implementation of a large number of variable renewable energy sources (VRE) is driven by the goal of reducing carbon dioxide emissions and mitigating climate change. The transition to non-fossil electricity production increases the need for a more flexible and dynamic power system - one where VREs account for a high share of the generation.

As efforts to reduce greenhouse gas emissions discourage the use of fossil-based energy sources, industries and households increasingly rely on electric utilities and are expected to consume even more power due to the growing adoption of electric vehicles and the use of heat pumps for heating and cooling.

The growing demand for electricity has increased the need for transmission capacity, calling for an expansion of the grid. When this capacity is insufficient, local production becomes increasingly important. As solar and wind power are the most prominent renewable technologies, they are driving the rapid expansion of distributed generation within the power system. This has sparked investments in localized forms of electricity production, such as solar parks and wind farms.

Due to the stochastic nature of these energy sources, their generation fluctuates. Unlike conventional synchronous generators, which typically provide power in a more predictable way. As a result, the fluctuating output from renewables makes real-time grid balancing increasingly difficult.

This has led to grid challenges, as the system must operate well year-round, and should even work when transfer capacity is limited, due to too few lines, or when variable power production is generating low output. In such cases, the system could benefit from more reliable forms of local production, such as battery energy storage or gas turbine power plants.

One particularly challenging case is when the grid operates in island configuration. In this case, all power must be supplied by local producers, who must also maintain frequency and voltage within the grid.

Another challenging case is when a short-circuit fault occurs, which can lead to loss of synchronism between generators in the system and the grid frequency. Such loss of synchronism can lead to power-producing units disconnecting, or worse, lead to equipment damage and failure.

Therefore, this thesis focuses on evaluating how gas turbines can support a subtransmission grid with varying support from the transmission grid - especially in scenarios such as island operation or operation with a weak connection to the transmission grid, with respect to frequency stability.

1.2 Stenungsund

This study has chosen to focus on the city of Stenungsund, north of Gothenburg, as a model due to its role as an important industrial hub with a high power demand in Sweden. The model includes "Kemiklustret", which houses a significant part of the chemical industry in Sweden and currently accounts for approximately 2% of greenhouse gas emissions[1]. The industries within the cluster aim to reduce their emissions by increasing the electrification of their processes, which in turn increases the electric power demand in the region[1]. The power demand for the industries is estimated to increase from today's 100 MW to 200-300 MW by 2030[2].

Already today, there is a power deficit in western Sweden, similar to the situation in southern Sweden, and the power demand is expected to increase by 70% by 2035 [1]. Vattenfall, the owner of the subtransmission grid, has therefore requested an expansion of transmission capacity by 2500 MW by 2035, but Svenska Kraftnät (TSO) has only approved 1200 MW, which is less than the projected power demand for Gothenburg in 2035 [1].

Since the transmission capacity is insufficient, there is a need to supply Stenungsund and western Sweden with more local electricity production. Vattenfall has received approval from the government on 04/11-2024 for the project "Poseidon", an offshore wind farm with a capacity of 1400 MW located off the coast of Stenungsund [3]. The project is being carried out by the company KonTiki Vind AB, a joint venture between Zephyr and Vattenfall, with Vattenfall being the majority owner.

In a joint venture between leading companies such as AI Sweden, Volvo, Hitachi Energy, Göteborgs Energi, Energiföretagen, and others, an open-source map was created to visualize the power and electricity demand in different regions of Sweden [4]. The map consists of 16 km^2 hexagonal grid cells, relying on data from open sources and collaborating partners. The power demand is divided into three categories: industry, transport, and buildings. Additionally, the map includes future predictions of power demand up to 2030. The map includes the region of Stenungsund with surroundings, see Figure 1, and the predictions for the future power demand align with the prognosis found in the articles cited previously [1][2].

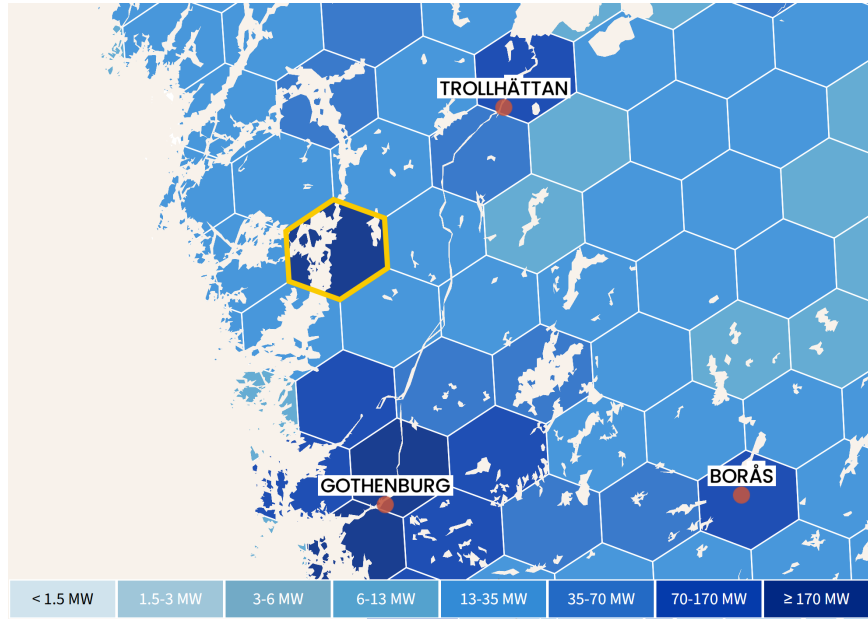


Figure 1: Visualization from Behovskartan developed by AI Sweden, highlighting the Stenungsund area in yellow. The map displays projected future electricity demand across Sweden. [4]

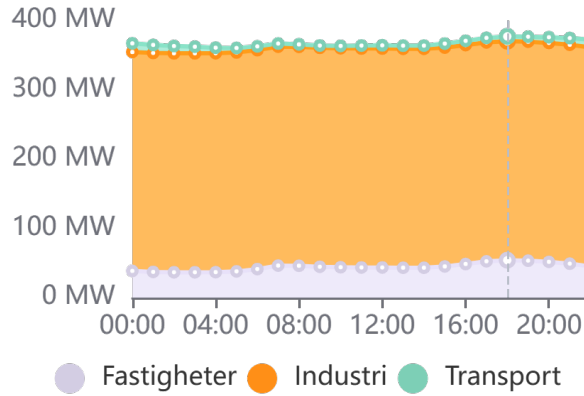


Figure 2: Estimated power demand for 2030 in the Stenungsund region. Peak values, Real estate: 54 MW, Industry: 316 MW, Transport: 7 MW, Total: 377 MW [4].

1.2.1 Stenungsundsverket

There already exists a power plant in the region, Stenungsundsverket. The plant is an oil-fired generation plant embedded in the rock beneath Vetteberget, adjacent to Stenungsund,

and was put into operation in 1959[5]. It has four steam turbines, the two older blocks have a rated power of 160 MW each, while the two later blocks (in operation 1966 and 1969) each had a rated power of 275 MW [5]. The first two blocks have not been in operation since the mid-1990s, while the two later have been a part of the Swedish power reserve between 2003 and 2015[5]. The last time the plant was running was in 2015[5]. No recent public announcements have been made about the future of the power plant.

1.3 Fundamentals of an AC power system

In an AC power system, there are two key parameters to control: frequency and voltage. Frequency stability is governed by the balance between generated and consumed active power. Under normal operating conditions, the frequency in the Nordic power system is 50 Hz. However, disturbances can cause fluctuations.

- If power consumption suddenly increases drastically, or a large generator trips and disconnects, the frequency drops - known as underfrequency.
- Conversely, if a large load or an exporting HVDC-link is lost, the frequency rises - known as overfrequency.

Unlike voltage, frequency acts globally within a synchronous area, meaning that changes affect the entire interconnected system. For instance, an increase in active power generation from hydropower in northern Sweden will raise the frequency by the same amount across the entire Nordic system, including southern Sweden.

Maintaining adequate voltage on the other hand, is mainly maintained through the balance of reactive power:

- Consuming reactive power (e.g. by inductive loads such as motors and power lines) decreases voltage.
- Supplying reactive power (e.g. by capacitive loads such as capacitor banks and HVAC cables) increases voltage.
- Synchronous generators can supply and consume reactive power by operating over- or under-excited.
- Inverter-based resources (e.g. BESS, solar, and some wind power) can also provide reactive power, although earlier generations offered limited capabilities.

Unlike frequency, voltage is a local phenomenon, as reactive power does not transfer well over long distances. This is due to the inductive nature of power lines in the transmission network, that consume reactive power. This means that hydropower plants in northern Sweden cannot effectively support voltage in the southern regions. Instead, voltage must be managed closer to the point of demand. An approach to maintaining adequate voltage levels is through local power generation, where generators supply reactive power near major loads. Another method is the use of shunt reactors and capacitors in substations, which

can absorb or inject reactive power as needed. Both techniques are widely used in power systems.

Sweden faces a challenge with high load and low production in its southern parts, resulting in high amounts of power transferred in the transmission grid from northern to southern Sweden. As power transfer increases, so does current, and since the losses are proportional to the square of the current, doubling the transmitted power results in four times the active power loss and four times the reactive power consumption in the lines, leading to voltage drops. Therefore, transmitting large amounts of power through the system will have a significant effect on voltage and needs to be compensated for.

1.4 Problem Statement and Objectives

This study investigates the combination of gas turbines in a subtransmission grid with a high share of renewable electricity production. Gas turbines can provide various support functions in such a system, but this report will primarily focus on their role in frequency dynamics.

Specifically, the study examines how gas turbines can contribute to maintaining stable frequency dynamics while ensuring compliance with grid codes set by the system operator.

To address this broad topic effectively, a set of research topics and overall objectives have been formulated to capture the most relevant aspects of the subject.

Subtransmission Grid Connected to the Nordic System – Out-of-Phase Scenario

- Examine a subtransmission power grid with $x\%$ variable renewable electricity generation, with the remaining share provided by *gas turbines*, with a weak connection to an *infinite bus*.
- Develop a dynamic model with appropriate control and protection functions.
- Using the dynamic model, simulate a short-circuit in the system and its subsequent clearing.
- For each value of x : Analyze the state of the system regarding out-of-phase scenarios.

Transition from Subtransmission Grid Connected to the Nordic System to Island Grid Operation

- Investigate a subtransmission grid as described above with a weak connection to an *infinite bus*, which becomes disconnected, initiating a transition to island operation.
- Develop a dynamic model that simulates the sequence of events during disconnection: support by BESS, start-up of gas turbines, and eventual disconnection of BESS.
- Analyze the dynamic response of the system in terms of frequency, and if it can maintain stability throughout the transition

- Identify any critical timing, coordination, or operational constraints during the transition sequence.

Subtransmission Grid in Island Operation – Frequency Control

- Define frequency stability requirements for a subtransmission island grid.
- Investigate a subtransmission power grid with $x\%$ variable renewable electricity generation, with the remaining share provided by *gas turbines*.
- Develop a dynamic single-machine model with appropriate frequency control and protection functions.
- Simulate a step disturbance in power balance and the following 5–10 seconds.
- For each $x\%$ variable power generation and given frequency quality requirements: Analyze the resulting state of the system.
- Examine potential benefits of future gas turbine capabilities.

1.5 Scope and Limitations

The software used to perform the simulation is the 2022 version of DIGSILENT PowerFactory.

Although the model used in this thesis is based on Stenungsund, the aim of this study is to provide a foundation for similar analyses of subtransmission grids with a high share of variable power production, where gas turbines can be used to provide system stability.

Due to the broad research topic, this study has chosen to focus on frequency-related ancillary services and transient stability.

Since voltage acts locally, a larger model would need to be used to analyze how voltage is affected by introducing gas turbines in Stenungsund. This is something that is encouraged to be evaluated in future work.

2 Background

This chapter outlines the theoretical foundations of the thesis, including the relationship between power balance and frequency, the parallel operation of generators, and frequency response control. It also provides an overview of gas turbine operation, with a comparison of single-shaft and twin-shaft configurations and their effects on grid dynamics. Finally, the chapter reviews the evolution of power systems and introduces the concept of ancillary services and their role in modern electricity networks.

2.1 The Swing Equation

Frequency stability is described by the swing equation, which correlates mechanical power and electrical power in rotor dynamics. The relationship can be seen in Equation 1.

$$J\omega_m \frac{d\omega}{dt} = P_m - P_e \iff \frac{2H}{f_{sys}} \frac{df}{dt} = (P_m - P_e)_{p.u.} \quad (1)$$

The inertia constant H represents the stored kinetic energy of the rotating masses of a generating unit relative to its apparent rated power - that is, how high the inertia of the spinning machine is relative to its generating capacity. The formula for the inertia constant H is shown in Equation 2.

$$H = \frac{1}{2} \cdot \frac{J\omega_m^2}{S_{base}} \quad [s] \quad (2)$$

Symbol	Meaning
J	Moment of inertia (kg·m ²)
ω_m	Mechanical angular velocity (rad/s)
$\frac{d\omega}{dt}$	Angular acceleration (rad/s ²)
P_m	Mechanical power input (MW or p.u.)
P_e	Electrical power output (MW or p.u.)
H	Inertia constant (s)
f_{sys}	Nominal system frequency (Hz)
f	Instantaneous frequency (Hz)
$\frac{df}{dt}$	Rate of change of frequency (Hz/s)

Table 1: List of variables used in the swing equation, including their units and physical significance.

The swing equation is fundamental to understanding frequency dynamics, as it links system frequency, inertia, and power balance. It demonstrates that a power imbalance between production and consumption causes frequency deviations, requiring adjustments of power

to restore the nominal frequency. The energy released as a result of the power imbalance due to system inertia is known as the inertial response.

In steady-state operation, generation and consumption are balanced, meaning inertia has no effect. When a power imbalance occurs, the Rate of Change of Frequency (RoCoF) depends on the magnitude of the imbalance and the inertia constant of the system. High-inertia systems are less susceptible to frequency deviations, whereas low-inertia systems experience more pronounced fluctuations. This well-known phenomenon is evident when analyzing frequency dynamics across different systems. Additionally, large synchronous systems and interconnected systems are less prone to larger frequency deviations due to a higher total system inertia [MWs] and higher system frequency response [MW/Hz]. Therefore, sudden disconnections of a generating unit will have a small impact relative to the total capacity of the system. For instance, the U.S. grid, a large interconnected power system, generally exhibits a very low instantaneous value of Δf . In contrast, smaller synchronous areas, such as the Irish grid, typically experience much higher Δf , as a disturbance is often larger in relation to the system size as well as the systems reduced frequency response and lower total inertia.[6]

Transient stability refers to the ability of a generator to maintain synchronism with the power system when it is subjected to large disturbances, such as short-circuits or sudden loss of generation. It is closely linked to the generator rotor angle dynamics, also governed by the swing equation, which can be rewritten in terms of rotor, or load angle acceleration, see Equation 3.

Transient stability refers to the ability of a generator to maintain synchronism with the power system when subjected to large disturbances, such as short circuits or sudden loss of generation. It is primarily governed by rotor angle dynamics, described by the swing equation. This can be expressed in terms of the rotor angle (or load angle) acceleration, as shown in Equation 3:

$$\frac{2H}{\omega_0} \frac{d^2\delta}{dt^2} = (P_m - P_e)_{p.u.} \quad (3)$$

During a short circuit, the terminal voltage, and consequently the electrical power output P_e , drops instantaneously, while the mechanical input power P_m remains unchanged. This imbalance causes the rotor to accelerate, increasing the rotor angle δ . If the fault is not resolved promptly, the rotor may lose synchronism with the magnetic field of the stator, known as stepping out of phase. This leads to severe torque oscillations, potentially several times greater than during normal operation, and may result in significant mechanical and electrical damage. The inertia of the system counteracts the acceleration, providing more time before loss of synchronism occurs, while the impedance and transient reactances in the network influence and uphold P_e , contributing to electromagnetic braking.

2.2 Parallel Impedance of Generators

To understand the grid response when multiple electrical generators are added to a system in parallel, it is important to consider the underlying electrical principles.

Suppose the internal impedance of a generator is Z . The formula for the parallel connection of impedances is given in Equation 4:

$$\frac{1}{Z_{eq}} = \frac{1}{Z} + \frac{1}{Z} \quad (4)$$

Solving for Z_{eq} gives Equation 5:

$$Z_{eq} = \left(\frac{1}{Z} + \frac{1}{Z} \right)^{-1} \quad (5)$$

In the case where both generators have the same impedance Z , the expression simplifies to Equation 6:

$$Z_{eq} = \left(\frac{1}{Z_{gen}} + \frac{1}{Z_{gen}} \right)^{-1} = \frac{Z_{gen}}{2} \quad (6)$$

The result is that connecting identical generators in parallel will decrease the impedance, as shown in Figure 3.

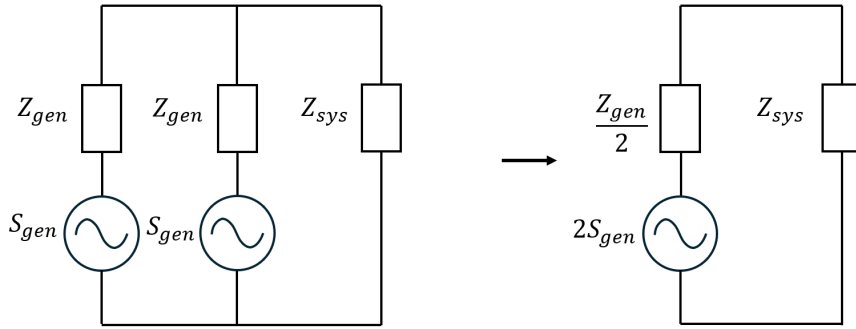


Figure 3: Two generators with impedance Z_{gen} connected in parallel.

2.3 Speed Governing and Droop Control

An AC power system should strive to maintain its nominal frequency. This is achieved through a speed governor in the generator, as illustrated in Figure 4. The angular velocity of the rotor is measured and compared to a reference velocity, corresponding to the nominal frequency of the system. By opening or closing a valve that feeds the turbine, the power

output compensates for the frequency deviation. For example, a steam valve in a steam turbine or a fuel valve in a gas turbine.

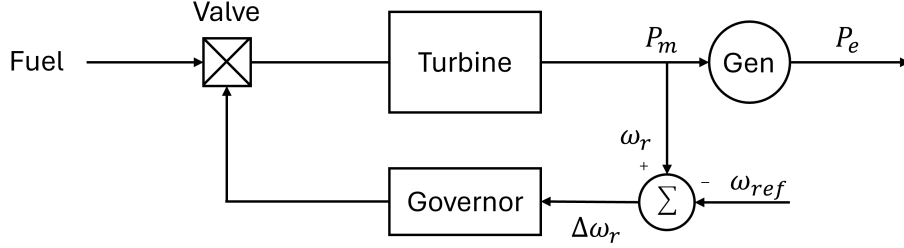


Figure 4: Speed governor of a generating unit

In a power system with multiple connected generators, having all the generators try to bring the frequency back to its nominal value would result in the generators counteracting each other, leading to instability issues. Additionally, the fastest unit would end up doing most of the work to balance the frequency, leading to poor load sharing. This could work in theory if all generators would have the same speed setting and be of the same rated power [7]. However, this is unrealistic since generating units differ both in their working principle - for example, hydro, steam, wind - and in their size and rated power.

One way to mitigate this and have a shared load response to a frequency deviation is with so-called droop response. Droop control gives a proportional power response to frequency change in the system. When the frequency drops due to an imbalance between load and generation, each generator increases its power output in proportion to the deviation. Since the response is proportional, the new steady-state frequency deviates from the nominal frequency, resulting in a stationary error. This stationary error is of importance, as it ensures that all generating units in the system perceive the deviation and contribute to restoring balance without requiring centralized coordination. Since the frequency acts globally, this occurs automatically to active power imbalances in the system. By having the response in p.u. or percent, all power plants respond according to their rated power. In Figure 5, the block diagram of the droop control is illustrated.

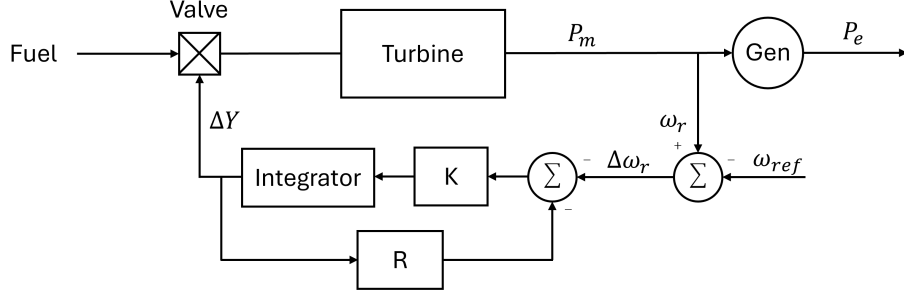


Figure 5: Droop control in a generating unit

The feedback signal R gives a proportional response to a frequency deviation. The load change in the generator in relation to the steady-state speed is determined by the value of R , called droop or speed regulation [7]. It can be expressed in percent or in p.u. The formula can be seen in Equation 7.

$$R = \frac{\text{frequency deviation in p.u.}}{\text{load response in p.u.}} \quad (7)$$

A droop value of 5% means that the generator increases its power output by 100% in response to a 5% frequency deviation.

2.4 The Gas Turbine

The gas turbine (GT) is an internal combustion engine that converts chemical energy from fuel into mechanical energy through combustion. It was first commercially available in the mid 20th century. When combined with a synchronous generator, a GT can reliably produce electricity [8]. GTs can be divided into two main configurations, single-shaft and multi-shaft turbines.

The basic operating principle of a gas turbine is as follows: Atmospheric air is drawn into the compressor and compressed to a high pressure. The compressed air then enters the combustion chamber where it is mixed with fuel and ignited. When the fuel-air mixture combusts, the exhaust gases expand rapidly and accelerate, driving the turbine. The turbine extracts energy from the high-velocity exhaust flow, driving a rotating shaft that powers both the compressor and a generator, thereby producing electricity.

The core thermodynamic process governing its operation is the Brayton cycle, a thermodynamic process that describes how chemical energy from fuel is converted into useful mechanical energy. The process is illustrated in Figure 6, and Table 2 outlines the phases of the cycle.

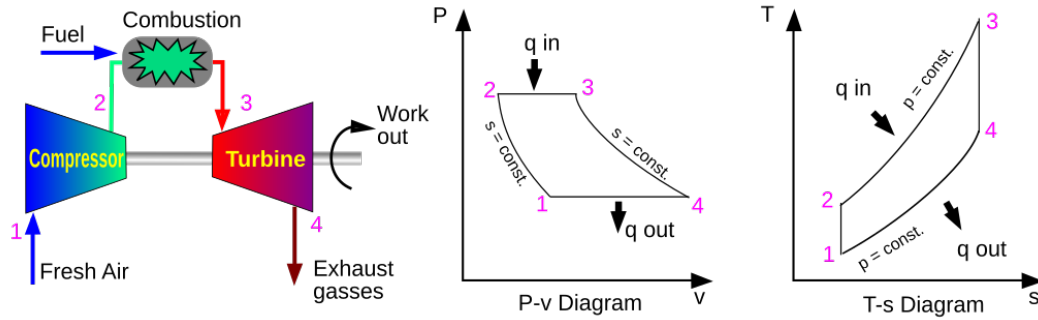


Figure 6: Diagram of a single-shaft gas turbine and the Brayton cycle. P denotes pressure, v is specific volume, T is temperature, s is entropy, and q represents heat transfer.

Step	Process
1	Isentropic compression – Air is compressed, increasing both pressure and temperature.
2	Isobaric heat addition – Fuel is combusted, raising the temperature.
3	Isentropic expansion – The high-temperature, high-pressure gas expands, driving the turbine.
4	Isobaric heat rejection – Excess heat is released as exhaust.

Table 2: Stages of the Brayton Cycle

2.4.1 Single-Shaft Gas Turbines

For educational purposes, an electricity-producing single-shaft GT can be divided into four main components. A compressor, a combustion chamber, a turbine, and a generator, as illustrated in 7,.

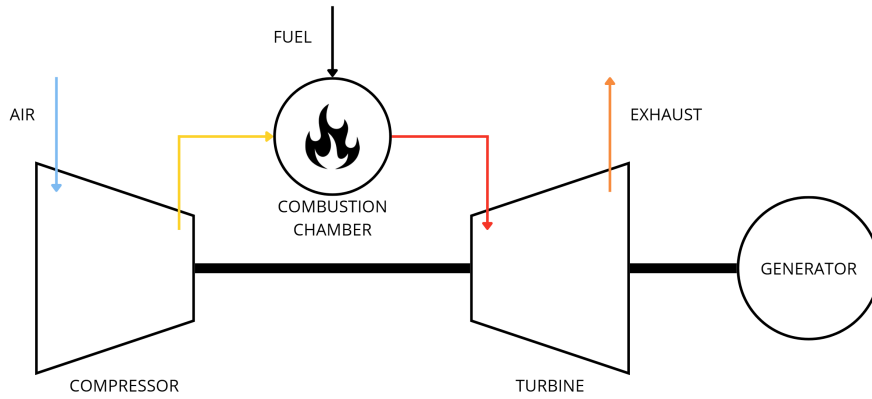


Figure 7: Single-shaft gas turbine

2.4.2 Twin-Shaft Gas Turbines

A twin-shaft, or multi-shaft, GT has a free power turbine that is decoupled from the gas generator, which consists of the compressor, shaft, and gas generator turbine, see Figure 8. This adds complexity to the machine and gives the turbine different characteristics, which are discussed in the following section.

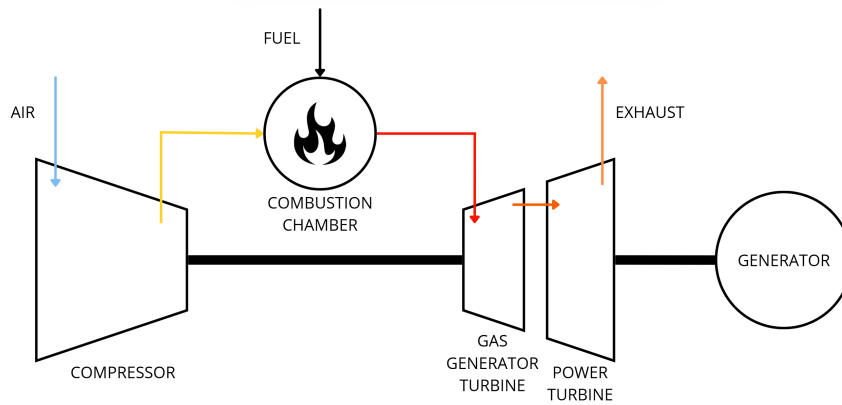


Figure 8: Twin-shaft gas turbine

2.4.3 Difference Between Single-Shaft and Multi-Shaft Gas Turbines in Power Generation Applications

The impact of single-shaft and multi-shaft gas turbines on grid stability and system performance is compared in this section.

In a single-shaft GT, the compressor, turbine and generator are all mechanically connected by a common shaft. This leads to high inertia from the combined rotating mass of said components, and consequently a higher H value, see Table 3 for common values. This makes it more resistant to rapid frequency deviations, but also means slower acceleration. The direct mechanical coupling also enables a fast load response as the airflow through the compressor can be quickly adjusted by modifying the inlet guide vanes (IGVs) or variable guide vanes (VGVs), rapidly affecting power output.

Generation unit	H [s]
Nuclear	6
Combined cycle GT	5.5
Single-shaft GT	4.5
Large scale hydro	3
Diesel genset	2
Converter-based units	0

Table 3: Typical inertia constants for generation units [9]

In contrast, a multi-shaft GT features a free power turbine connected to the generator, but decoupled from the gas generator. This design reduces the moment of inertia, resulting in a lower H value - typically between 1 and 3 seconds - depending on the specific configuration. This design therefore makes it more susceptible to frequency deviations, but allows for a faster start-up time and lower starting power requirements.

Additionally, multi-shaft turbines experience a slight delay, a lag in the load response, as the gas generator must first increase hot gas production before power output rises. This gives a somewhat slower response compared to single-shaft turbines.

The coupled nature of the single-shaft GT can be an issue during large frequency deviations. If the frequency drops, the compressor speed drops due to the synchronization with the grid, and the GT produces less power. This can be compensated by increasing the firing in the combustion chamber, but if the turbine is already working close to its thermal limit, firing cannot be increased. In that case, the power output continues to decrease, further worsening the frequency drop in a feedback loop. If the frequency drops significantly, e.g. down to 46 Hz (in a 50 Hz system), the airflow through the compressor, and the ability to withstand a high pressure ratio, may become insufficient due to the lower speed. This can cause a reversal of pressure gradients and send a shockwave back through the compressor toward the inlet, known as compressor surge. Surge is one of the most destructive events for a GT and can lead to severe mechanical damage to the compressor blades, bearings, and internal components.

This is not an issue for a multi-shaft turbine as the power turbine is not mechanically connected to the gas generating turbine. Therefore, a frequency event in the grid will not transfer to the compressor and slow down its rotational speed. This also gives better

part load performance as the compressor can spin at optimum speeds depending on airflow requirements, rather than the fixed speed supplied by the grid frequency.

2.4.4 Abilities of Gas Turbines

Beyond their mechanical design, gas turbines offer several properties that make them suitable for power production.

GTs are versatile machines capable of operating on a wide range of fuels, including petroleum derivatives, biofuels, and, to some extent, hydrogen [10]. However, they are primarily designed for clean-burning liquid and gaseous fuels that do not contain solid particles or produce excessive soot, as this can cause slagging or fouling on the turbine blades. This makes natural gas (methane) the most commonly used fuel in power generation applications due to its high efficiency, wide availability, and relatively clean combustion profile [11].

Natural gas combustion in a GT produces less CO_2 per unit of energy compared to other power plants that rely on hydrocarbon combustion, such as coal and oil plants. This is due to its higher energy content and lower carbon content per kilogram compared to oil and coal [11]. Furthermore, in systems where GTs are used as base load plants, a steam turbine is typically placed after the exhaust to extract the remaining thermal energy from the hot exhaust gases. This configuration is known as a combined cycle power plant, and state of the art plants can reach efficiencies of up to 64% [12]. GTs also provide a cleaner combustion process, emitting fewer pollutants such as nitrogen oxides (NO_x) and sulfur oxides (SO_x), compared to oil and coal combustion.

GTs also have the advantage of rapid startup times. Most other power plants that utilize thermal energy conversion - such as coal or nuclear - require several hours to reach full operation, while GTs can achieve full power output within minutes. This flexibility makes them well-suited for balancing fluctuations in power demand and supporting grids with high shares of variable renewable energy. However, it should be noted that combined cycle plants have longer start-up times and are therefore not typically used for peak load applications.

Despite mainly relying on the combustion of fossil fuels, GTs remain an important part of modern power systems due to their adaptability. The large rotating mass and high angular velocity of the compressor, turbine, and generator store high amounts of kinetic energy, providing an inertial response to frequency deviations. Therefore, GTs are well-suited for frequency regulation of power grids, stabilizing the grid against sudden frequency disturbances.

2.5 Evolution of Power Systems

Ever since electricity was first introduced into society, synchronous generators have played a central role in providing cheap, readily available, and reliable electricity. In the early days, both hydropower and coal-fired power plants were most common. For communities with convenient access to rivers, hydropower was a suitable option. In areas without such

resources, coal-fired power was the predominant alternative. Coal was inexpensive, relatively simple to use in combustion and power generation, and was widely available around the world.[13]

As technology advanced, new forms of electricity production emerged. The efficiency of hydropower and coal-fired power improved, and additional generation methods were introduced. Nuclear power plants and gas-fired power plants eventually became key components of many energy mixes worldwide.

All these aforementioned sources rely on synchronous generators for power production. This type of generator, which was developed in the 19th century, became widely adopted from the beginning of the 20th century. [14]

Synchronous generators have become the dominant type of generator in power production because they efficiently and cost-effectively produce high-quality AC power while also offering excellent frequency regulation capabilities. Their inherent inertia provides a time buffer, allowing the governor system to respond to load changes, maintaining a stable system frequency and ensuring a balanced supply and demand. Additionally, synchronous generators can generate or absorb reactive power, a valuable capability for managing voltage levels in an energized grid. Their black start capability further enhances grid resilience by enabling them to supply power to a de-energized grid. Moreover, synchronous generators contribute significantly to grid strength - measured through short-circuit capacity - making them essential for robust system support during disturbances.[7]

While synchronous generators have long been the backbone of power systems, a shift towards more variable renewable energy (VRE), such as solar and wind power, is taking place in most power systems globally. However, solar power cannot be synchronously connected to the grid - since it has no spinning parts - and therefore requires power electronic converters to transform DC current into AC power, as shown in Figure 9. As a result, when new solar power plants are installed in a grid, the total system inertia remains the same - despite the increase in power production - or may even decrease if the solar power replaces synchronous generation. This leads to a system with less inertia, making it more prone to frequency deviations and higher RoCoF when subjected to power imbalances.

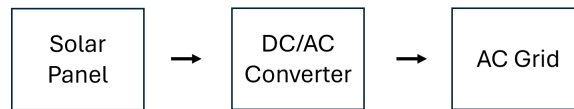


Figure 9: Grid connection of solar photovoltaics

Furthermore, most wind turbine units are also not synchronously connected to the grid. There are several reasons for this, but primarily, a wind turbine needs to be non-synchronously connected to spin at optimized speeds for maximum power production. This grid connection can be seen in Figure 10. Wind turbine power is first converted from AC to DC using power

electronics and then transformed back from DC to AC to be suitable for the grid. This process removes inertia response in the traditional sense, and just like with solar power, total system inertia is reduced. Modern wind turbines are often grid-following, meaning they synchronize to the current grid frequency and phase angle.



Figure 10: Grid connection of wind turbines

2.5.1 Grid-following and Grid-forming power converters

Power converters are devices that use power electronics to convert electrical energy from AC to DC or vice versa. Power converters have a variety of different control strategies but can broadly be defined as either traditional grid-following (GFL) or recently introduced grid-forming (GFM). Grid-following converters are the most commonly used, since this is a simpler and cheaper way of designing the control system. Grid-following converters follow the grid, meaning they require a sufficiently stiff AC voltage provided by other components in the grid, with 'grid-forming' abilities. These are synchronous generators or grid-forming converters as a reference. This in turn means that grid-following converters cannot operate in an island grid by themselves, and a grid with 100% grid-following technology will not work [15]. Introducing a high penetration of grid-following converters will also weaken the grid and can lead to instability issues. The control system is designed to deliver active and reactive power based on its set-points by following the grid via a phase-locked loop (PLL). The active and reactive power set-points are then converted into current references in a current control loop, and therefore the grid-following converter operates as a current source.[15]

Grid-forming converters form the grid, meaning they can determine the system frequency and voltage and can therefore operate an island grid. Unlike grid-following converters, grid-forming use voltage and frequency set-points and are implemented with voltage control loops. Consequently, they operate as voltage sources [15].

GFMs are more versatile than GFLs and provide better stability for a grid, as they have the ability to maintain their own frequency without an existing grid. They provide synthetic inertia, similar to that of a synchronous machine, and can regulate voltage and frequency dynamically, whereas GFLs only follow set points. These differences make GFMs more applicable for power grids, especially in weak grids or during fault events.

Despite these benefits, GFMs are hardly used at all for large-scale power production. This may be due to the technology being relatively new and more expensive. It may also be a question of market economics. While some frequency-related ancillary services, like FCR or aFRR, have well-defined markets in the Nordic grid, qualities like black start capability

and synthetic inertia-although very beneficial for the electric grid-may not generate revenue for the owner of the power production company.

2.6 Ancillary Services

Ancillary services are functions used to balance and stabilize the power grid. These services include frequency support, voltage control, and, to some extent, island operation and black start capability.

2.6.1 Frequency related ancillary services

Frequency-related ancillary services are connected to deviations between the production and consumption of active power. These services are divided into sub-categories, each with its own objective. The main objective is to maintain a resilient power system frequency of 50 Hz.

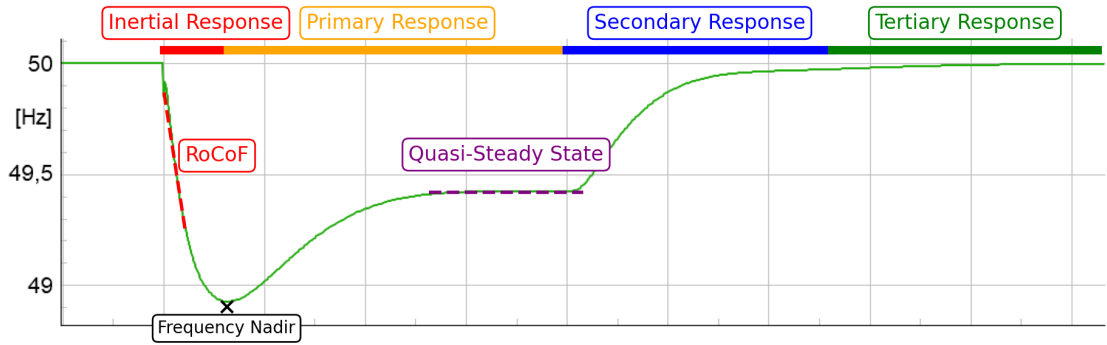


Figure 11: A typical frequency response after a step change, with ancillary service labeling. The Y-axis shows frequency, and the X-axis shows time.

Synchronous generators instantly respond to a change in frequency, providing the inertial response. This comes from the rotating mass of the rotor and occurs instantly since the generators are synchronized with the grid. There is no market for inertial responses, but the concern of decreasing system inertia has led to the introduction of FFR (fast frequency reserve).

FFR is an automatic remedial action that can be supplied through three alternatives to market purchase in the Nordic system [16]; see Table 4. It works by supplying or decreasing active power in a quick response to a frequency disturbance, as the swing equation implies, see Equation 1. In Figure 11 one can see *RoCoF* and *Inertial Response*. *RoCoF* is proportional to the power imbalance divided by the inertia constant in the system. A system with little inertia will reach high *RoCoF* values, which can be damaging to the power production units in the system.

FFR requirements from SvK	
Frequency at activation [Hz]	Maximum full activation time [s]
49,5	0,7
49,6	1,0
49,7	1,3

Table 4: Overview of FFR requirements from SvK

The FFR is then sustained for 5 s or 30 s and should be recharged and ready to perform the same operation again in 15 minutes [16]. The objective of FFR is to lower the rate of change of frequency (RoCoF) to minimize the potential harm that comes from a large step in generation or consumption in the system, for example, the loss of a large generator.

Another vital response for frequency stability defined by the TSO is frequency containment reserve (FCR). FCR consists of two reserves, FCR-N, used under normal operations and FCR-D, for a disturbance in the system. The frequency containment for normal operations is utilized to handle short-term small deviations between production and consumption of active power, so that the frequency stays in the normal band of 49.9-50.1 Hz. The frequency should not exceed this band more than 10,000 minutes per year [17]. The FCR-N reserve amounts to 224 MW in Sweden, 2025 [18].

FCR-D operates on the same principle as FCR-N but is specifically designed to handle sudden imbalances in production and consumption caused by disturbances. Unlike FCR-N, FCR-D is divided into two categories based on the direction of the frequency deviation:

- **FCR-D Up** is activated when the frequency drops below its nominal value, operating in the range of 49.9-49.5 Hz. It works by either increasing power generation or reducing consumption. The response must reach 50% activation within 5 seconds and full activation within 30 seconds, with a minimum endurance of 20 minutes. [19]
- **FCR-D Down** is activated when the frequency exceeds nominal levels, operating in the range of 50.1-50.5 Hz. It functions by either reducing power generation or increasing consumption. Like FCR-D Up, it must reach 50% activation within 5 seconds and full activation within 30 seconds, with a minimum endurance of 20 minutes. [19]

Another frequency-related ancillary service is the automatic Frequency Restoration Reserve (aFRR), which functions as a secondary frequency response. aFRR automatically responds to deviations from the nominal frequency by adjusting production and consumption to restore stability. It must be fully activated within five minutes and can remain active for up to one hour. [20]

If a frequency deviation remains after activation of primary and secondary reserves, tertiary reserve is used. In the Swedish ancillary services market, this is referred to as manual Frequency Restoration Reserve (mFRR), and as the name suggests, it is manually activated.

This typically involves the TSO contacting a generating unit to request an increase in production or the start-up of additional generation capacity.

In Table 5 the different frequency-related ancillary reserves are summarized. They are all related to the figure of a frequency response due to a step change seen in Figure 11.

Primary response is usually attributed to FFR and FCR. They are both fast-acting reserves and the first resources to be used in case of a rapid frequency-related event. Both of these resources have a market where producers can place bids for production. Secondary reserve corresponds to aFRR which is also a resource that uses bids in a market. aFRR is usually used to move the frequency towards a steady level close to the nominal frequency.

Overview of Reserve Requirements		
Category	Reserve Type	Specifications
Remedial Action	FFR (Fast Frequency Reserve)	0.5 MW, activation: 0.7-1.3 s, duration: 30 s
Frequency Containment Reserves	FCR-D up	0.1 MW, activation at 49.90-49.50 Hz, duration: 20 min
	FCR-D down	0.1 MW, activation at 50.10-50.50 Hz, duration: 20 min
	FCR-N	0.1 MW, activation at 49.90-50.10 Hz, duration: 1 h
Frequency Restoration Reserves	aFRR (Automatic)	1 MW, activation: 100% within 5 min, duration: 1 h
	mFRR (Manual)	1 MW (capacity), 5 MW (energy), activation: 100% within 15 min, duration: 1 h

Table 5: Overview of reserve requirements, the specified active power rating is the minimum bidding quantity.[21]

GT ancillary services For a gas turbine, the governor control system enables participation in Frequency Containment Reserve - Normal (FCR-N), Frequency Containment Reserve - Disturbance (FCR-D), and Automatic Frequency Restoration Reserve (aFRR) services. Lastly, due to their suitability for peaking applications such as fast start-up and ramp rate, GTs are a natural choice for manual frequency restoration reserve (mFRR).

2.6.2 Non-frequency related ancillary services

There are different ancillary services that are not related to frequency. For instance, there is voltage regulation and quick reactive power injection, both essential for maintaining adequate voltage across the system and ensuring efficient power transfer. The ancillary services related to reactive power and voltage control are currently managed by the TSO, Svenska Kraftnät. While these services do not yet operate within a market mechanism,

they are still provided, usually through agreements between SvK and producers with large capacity. However, SvK is actively exploring how market mechanisms could be structured to ensure these services are supplied in the most effective way.[22]

Another important non-frequency-related ancillary service that does not operate within a market mechanism is fault current contribution. This service involves rapidly injecting large amounts of current during and after a short-circuit to facilitate fault detection and fault clearing.[22]

There are also other non-frequency ancillary services that may become more significant in the future. The ability to operate a subtransmission grid in island mode is an increasingly important security feature in a world of complex geopolitics. Additionally, black start capabilities play a crucial role in system restoration. However, none of these ancillary services currently operate within modern market mechanisms.[22]

2.7 Frequency Requirements in Grid Codes

The aim of this investigation is to, in some sense, investigate how a subtransmission grid with a high share of variable power production can be efficiently supported by the integration of GTs.

To determine efficient integrations of GTs, one has to know what constitutes a well-functioning grid.

There is no clear definition about what constitutes a well-functioning grid in the Nordic system. There is a clear goal to reach for a nominal frequency of 50 Hz, and there is a market for frequency-related ancillary services - but as these services work well with the market, there are not clearly outlined definitions or outlined KPIs(Key Performance Indicators) to align the simulations after.

To support the investigation and simulations, definitions or goals will be outlined of what could be defined as a well-functioning grid (here we are looking at characteristics related to frequency dynamics).

To begin with, one can consider KPIs and requirements from RfG (Requirements for Generators), a European legislation outlining how generators are to be connected to power grids. This is used in combination with EIFS 2018:2 (Energimarknadsinspektionens föreskrifter), which are a set of regulations from Sweden's regulatory authority for the electricity market that complement the RfG legislation. Table 6 shows the frequency ranges that a production unit must be able to withstand without disconnection from the grid, as defined in RfG [23] and EIFS 2018:2 [24].

Frequency Range (Hz)	Time Limit
47.5–48.5	30 minutes
48.5–49.0	30 minutes
49.0–51.0	Unlimited
51.0–51.5	30 minutes

Table 6: Permitted operating time within different frequency ranges

As can be seen in Table 6, all generators must be able to stay connected for up to 30 minutes for all frequency ranges, except for the time span between 49.0–51.0 Hz. For this range, synchronous generators in the system must be able to stay connected continuously. It implies that a grid should maintain a frequency within this boundary. Furthermore, it means that at any time when the frequency drops below 47.5 Hz or exceeds 51.5 Hz, generators may disconnect immediately - implying a hard frequency limit that must not be exceeded.

Furthermore EIFS 2018:2 outlines another requirement that must be followed for a generator connected to the grid. It is outlined that a generating unit must be able to withstand a RoCoF of 2 Hz/s, measured over 500ms - which also implies a grid requirement [23].

Other requirements are related to the capability of supplying ancillary services, see Table 5. A well-functioning grid should have the ability to respond to frequency fluctuations, and a well-functioning market for ancillary services typically ensures that the system operates reliably. In this context, the requirements are interpreted as indicators of overall system performance.

3 Methodology

This section outlines the methodology of the investigation. More specifically, it focuses on how the model was created in PowerFactory and which parameters were used. Then a description of how the simulation cases were set up and run, focusing on three main cases: One where the gas turbines are connected to the transmission grid, and the system is subjected to short-circuits followed by clearing. The second case where the grid transitions to island operation, relying on batteries during start-up of the gas turbine. Lastly, a system in island operation relying on gas turbines, exposed to step changes in the power balance.

3.1 System Modeling and Simulation Environment

The simulation software used in this thesis is DIgSILENT PowerFactory, which is commonly used in the industry for electric power systems simulations. The license is given by LTH and the 2022 version is used. RMS simulations are conducted as the disturbances introduced to the system are all symmetric, and the transients can be captured with a sufficiently small time-step. It was decided that EMT simulations would be too time-consuming and not generate any added insight to the studies performed.

3.2 Creating the Model

It was decided that the same model will be used for the different simulation cases in the thesis. First, a sketch was created as a foundation for the model. The simple model contains an offshore wind farm, a synchronous generator representing one or more gas turbines, two loads representing the city Stenungsund and "Kemiklustret" and a voltage source as the infinite bus representing the rest of the Nordic grid. Between these main elements, lines, cables, and transformers were added.

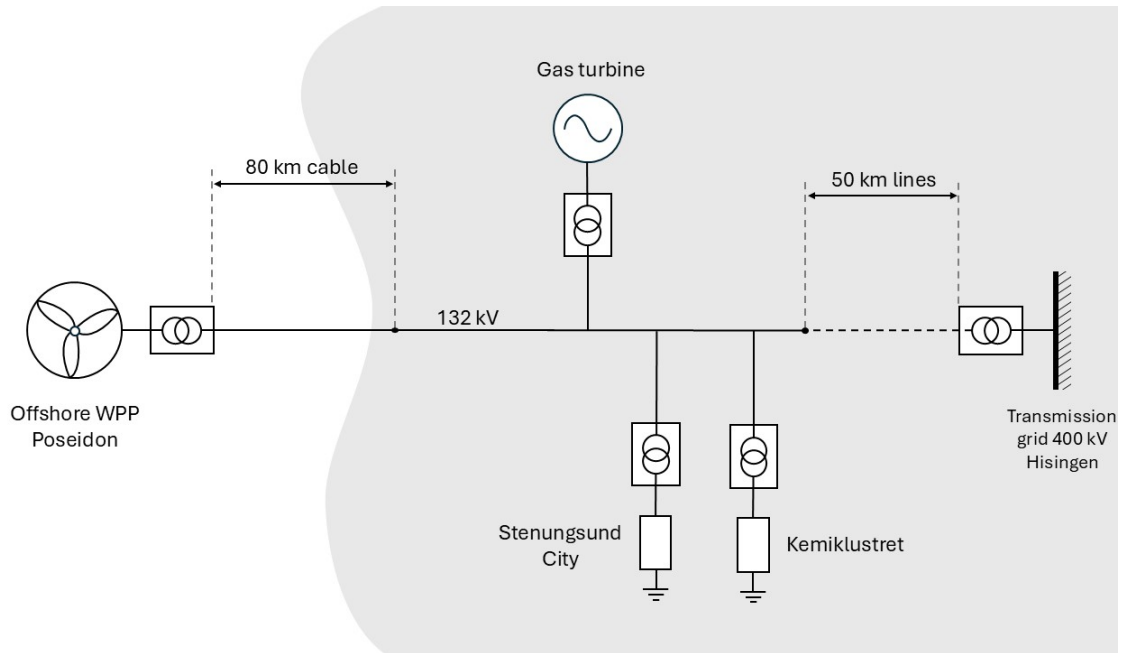


Figure 12: Schematic over Stenungsund used as foundation for the model in PowerFactory.

The open source infrastructure map openinframap.org was used to get a detailed schematic of the electrical grid of Stenungsund and its vicinity. This schematic allowed for the identification of the number of parallel power lines, line distances, voltage levels, and other relevant details, see Figure 13 and 14 below.

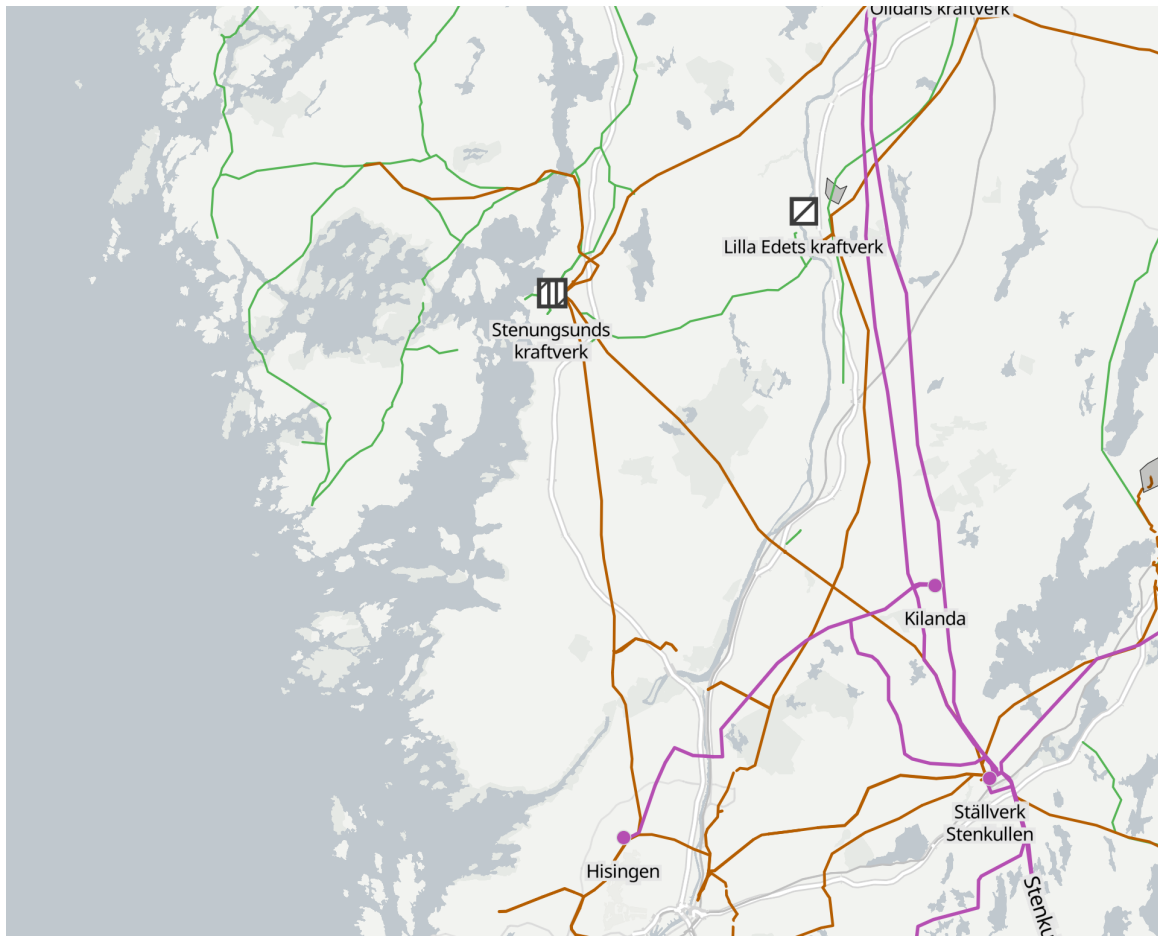


Figure 13: Open Infrastructure Map covering parts of the power grid in western Sweden. Purple lines mark 400 kV, orange 132 kV and green 45 kV lines [25].

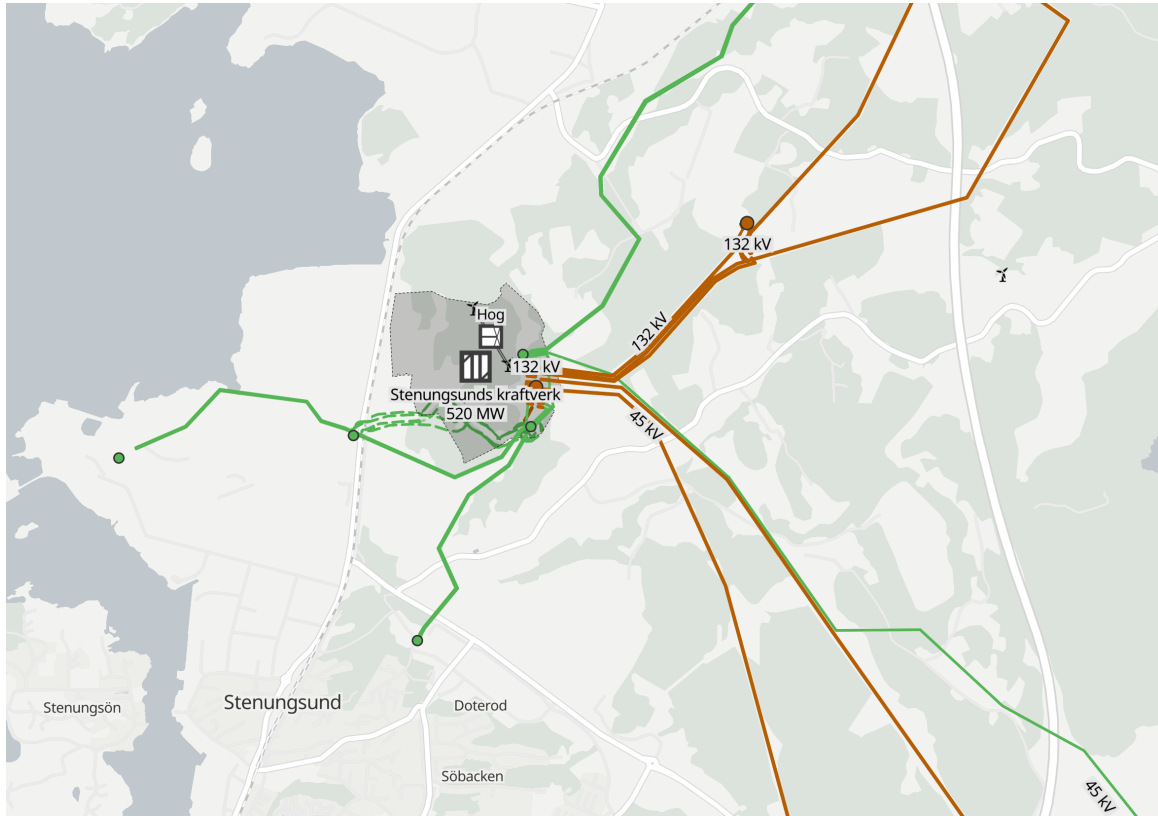


Figure 14: Open Infrastructure Map covering the power grid of Stenungsund and its close vicinity [25].

3.3 Building the Model in PowerFactory

The model was created in PowerFactory by adding the elements from the Figure 12 in a single line diagram. Below is a description of the main components and how they were added to the model. Additionally, during the thesis work, an interest in adding a battery to the model arose, and this was also added in the single line diagram.

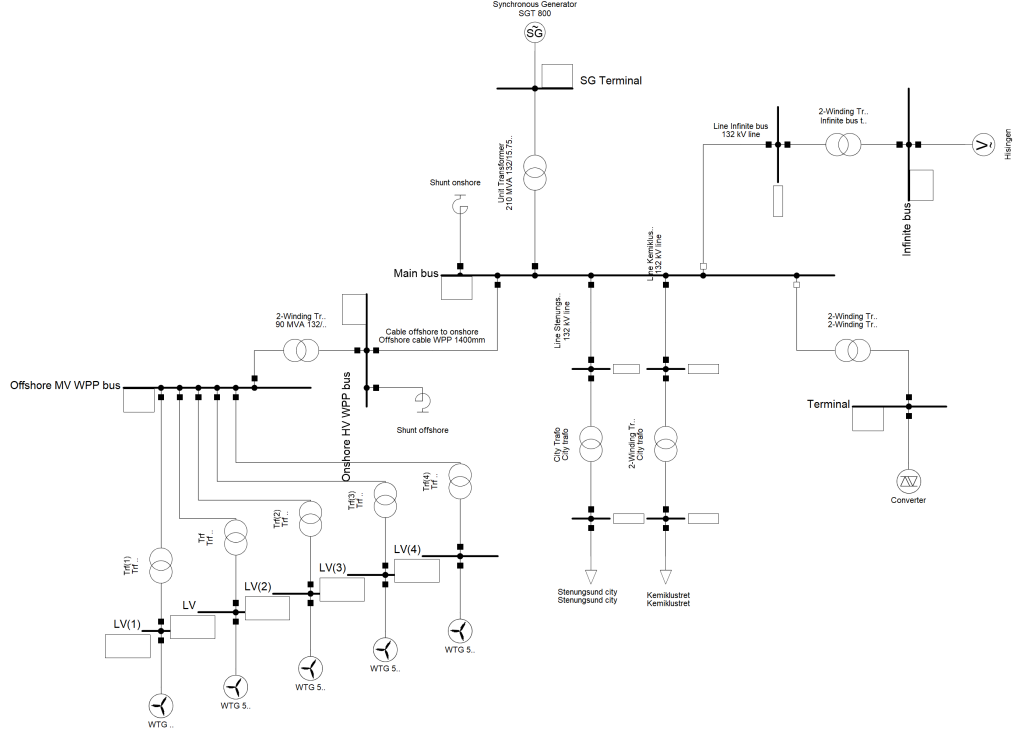


Figure 15: Single line diagram of the Stenungsund model in PowerFactory.

3.3.1 Wind Power Plant

The wind power plant modeled is representing one of four cable connections to shore of the planned offshore wind farm Poseidon, resulting in a rated power of 350 MW. This is based on information from the consultation document from Zephyr regarding the offshore power plant [26].

A template in the DIgSILENT library for a type 4, full power converter wind turbine was used. This type of wind turbine is modeled as a static generator and the 5 MW size per element was chosen. Five wind turbine elements were added to the single-line diagram, see Figure 15, four smaller branches with 10 units each and one main branch with 30 units. This method was used to be able to easily disconnect a certain number of wind turbines to analyze a step change of generation. 70 units in total were added, matching the rated 350 MW of the connection onshore. The template consists of a static generator, a bus bar and a step-up transformer which were connected to the main bus. For a detailed implementation,

see appendix A.1.

3.3.2 Gas Turbine

Several key components must be considered when modeling a gas turbine. Not only does the synchronous generator need the correct input data, the control units for the gas turbine, such as the governor and the automatic voltage regulator (AVR) also need the right models and parameters to accurately represent a real gas turbine. The paper *IEEE Recommended Practice for Excitation System Models for Power System Stability Studies* was used as a supporting document [27]. The governor and AVR implemented in the model are the same ones that have been used by Siemens Energy for simulation tests in real test scenarios for their gas turbines.

In the single-line diagram, a template of a gas power plant was inserted into the model by connecting it to the main bus bar. The template consists of a synchronous generator, a bus bar, and a step-up transformer. The correct control units, such as the governor and automatic voltage regulator, were added with parameter sets provided by Siemens Energy.

The apparent power rating of the version of SGT-800 used is 72 MVA, with the maximum active power at 64 MW. Data for the synchronous generator were specified to match the SGT-800, including rated voltage, inertia constant H , capability diagram, and other relevant characteristics. For a more detailed description of the implementation of the gas turbine, see appendix A.2.

3.3.3 Loads

The two loads in the model represent the city of Stenungsund and the chemical industry hub, "Kemiklustret." Both are connected to the 132 kV system in the model. In reality, Stenungsund is supplied via multiple 45 kV lines before the power is distributed throughout the local grid, but detailed modeling of this will have little significance in this study.

It is also important to note that this study aims to explore solutions for future energy challenges. As such, parts of the model are designed to represent a future scenario: one where the Poseidon wind power plant is fully operational, and the industrial hub has increased power demand due to further electrification.

For predicting the future power demand, the predicted power demand set out by the chemical industries collectively is used. [1] By 2030 the companies within sustainable chemistry industries will need 200-300 MW of installed power. This is confirmed by using the map "Behovskartan" [4]. The map agrees with the predictions made by the chemical industries, and it divides the loads into three parts: domestic use, industries, and transport. In the model, industries are modeled as one load named "Kemiklustret" while the domestic use and transport are lumped together into "Stenungsund city". The predicted peak power demand for the industries in 2030 is around 300 MW, and around 60 MW for transport and domestic use collectively [4]. Furthermore, 10% of the rated active power is set as

reactive power, resulting in a power factor of 0.995. This was chosen arbitrarily, but since the focus in the study lies on frequency and active power dynamics, a relatively high, but non-negligible power factor was used.

$$\cos(\varphi) = \frac{P}{S} = \frac{300}{\sqrt{300^2 + 30^2}} = 0.995 \quad (8)$$

The loads in this model are static, with a constant power consumption. Introducing dynamic loads would add complexity beyond the scope of this investigation and is not considered. However, dynamic load simulations can definitely have an impact on the system and could make the model more realistic.

3.3.4 Infinite Bus

The infinite bus represents the Nordic system and is modeled with the "Voltage Source" element. This gives it truly infinite characteristics, although it is a simplification. Since the Nordic system is significantly stronger than the modeled subtransmission grid, this approximation is deemed valid.

An alternative approach would be to model the infinite bus using the "External Grid" element in PowerFactory. However, this requires more detailed input data for the Nordic system, and the advantages of such increased model accuracy are negligible.

3.3.5 Power Lines

The lines connecting the system are 132 kV subtransmission lines and are based on data for a common 132 kV 593-line, see Table 7.

Parameter	Rating
Voltage	123-170 kV
Resistance	0,056 Ω /km
Inductance	0,355 Ω /km
Capacitance	0,0097 μ F/km
Maximum current	669 A/phase

Table 7: 593 mm^2 subtransmission power line

3.3.6 Offshore Cable

The offshore cable connecting the WPP to Stenungsund is based on an NKT 132 kV HVAC cable [28].

Parameter	Rating
Voltage	123 kV
Resistance	0,0175 Ω /km
Inductance	0,53 mH/km
Capacitance	0,322 μ F/km
Maximum current	1160 A/phase

Table 8: 132 kV 1400 mm^2 offshore power cable [28]

3.3.7 Transformers

Standard transformers from the DIgSILENT library have been used between generating units and power lines in the model.

3.3.8 Battery

The battery that was implemented in the model need to be able to provide power during the start-up of the gas turbine, to be able to examine the transition case from being connected to the infinite bus to island operation. For this to work, a grid-forming power converter is needed to provide stiff AC-power to the grid to act as a reference. This could be implemented for either the wind turbines or the battery. Battery energy storage systems, as a flexible and controllable power source with fast response, are among the best carriers for grid-forming energy storage applications [29]. Therefore, it was decided to implement grid-forming technology to the battery as it can quickly dispatch active and reactive power to uphold system stability without weather dependency. There are different ways to provide grid-forming control; common methods include droop control, Virtual Synchronous Machine (VSM) and Synchronverter. The VSM control system is the most common form and was therefore used. A template of a VSM from the DIgSILENT library in the 2024 version of PowerFactory was used due to added complexity in the model compared to the 2022 version. The apparent power rating was set to the same rating as the gas turbine for a simple study case.

The template does not include the battery side, only the power converter, meaning that the state of charge is not taken into account. This is a simplification of reality. However, since the battery only needs to supply power during a start-up of the gas turbine, and most batteries intended for grid support typically have a C-rating of 1 or lower, allowing full discharge within one hour at rated power [30]. The start-up time of an SGT-800 can be as fast as 8 minutes, and to be able to provide mFRR, a provider must be able to activate 100% of the bid quantity within 15 minutes [20]. It is therefore assumed that the battery will be able to provide steady power output during 15 minutes, and that measuring state of charge is considered out of scope.

3.3.9 Secondary Frequency Control - AGC

PowerFactory is excellent at performing transient simulations where the initial system response is analyzed, such as inertial response, fast frequency response (FFR), and the governor's primary frequency control. However, the templates do not have secondary frequency control pre-built within the models. Therefore, if the user wants to examine this, it must be implemented manually. The secondary frequency response is also referred to as an automatic generation control (AGC) and can be equated with Svenska Kraftnäs automatic frequency recovery reserve (aFRR). Having this control strategy is especially important in island operation, since the grid is disconnected from the sources that are normally responsible for restoring nominal frequency.

Since this thesis focuses on ancillary services that can be provided by gas turbines, as well as the formation of a grid capable of island operation, it was decided to implement and examine secondary frequency control.

There is limited literature on how to implement secondary frequency control in PowerFactory, but a guide on how to implement an AGC in the IEEE 14-bus test system was found in the book "PowerFactory Applications for Power System Analysis" [31]. The guide is quite short and concise and can be regarded more as a recipe rather than detailed instructions, but with it, and by downloading and using the test system IEEE 14-bus, an AGC could be implemented into the Stenungsund model. However, it was noted that the AGC implemented in the IEEE 14-bus system acts immediately upon any frequency deviations, thus acting at the same time as the inertial response and primary frequency control, which is not the case in an actual power system. Because of this, a 30-second time delay was implemented to the AGC model to better represent actual secondary frequency control. The method used to implement the AGC is described Appendix B. This AGC is still a simplified model and should not be regarded as equivalent with the secondary frequency control used in a real power system, but it is estimated to provide a sufficient result for this report and similar studies performed.

3.4 Simulation Scenarios and Parameters

To effectively obtain meaningful results from the investigation, clearly defined simulation scenarios are essential. The overall aim of this investigation is to enable subtransmission grids, characterized by a high share of renewable power production, to integrate gas turbines and batteries, ensuring reliable electricity supply in areas with limited transmission capacity from the TSO. A variety of scenarios will be analyzed to thoroughly assess this integration. Rather than focusing on normal operating conditions, these analyses will primarily explore scenarios involving system disturbances or operational challenges. Examining the system under stressed conditions is particularly valuable, as it provides deeper insights into system resilience and robustness precisely when performance matters most.

To examine why the chosen simulation scenarios are of importance, one has to examine "operation states" that a power system can enter.

Analyzing power systems, a frequent strategy is to classify system operation into 5 states depending on what actually happens in the system. The states represent the current condition of the grid and are essential for understanding its operations and control strategies. The states will help to define objectives for different types of emergencies. These states are: normal, alert, emergency, in-extremis and restorative. It can be graphically visualized in a diagram how the states are related to one another to examine their control strategies [32]. The states and interactions can be seen in Figure 16.

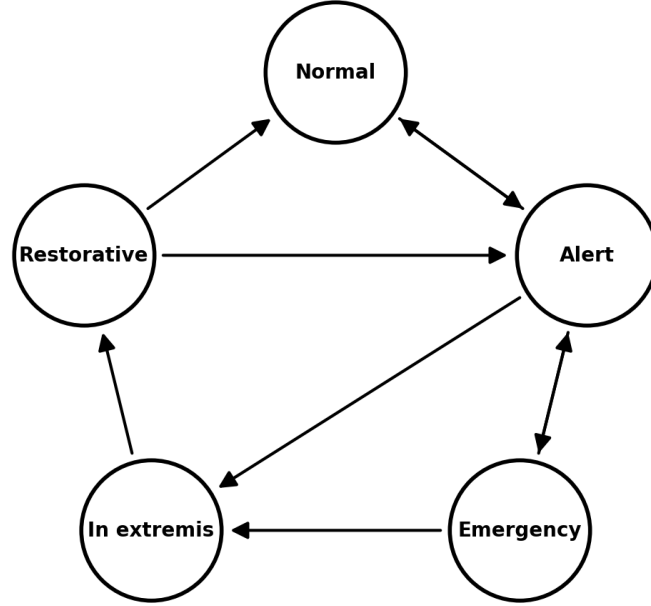


Figure 16: Operating states of a power system

The meaning of the different system states shown in Figure 16 is more clearly outlined in Table 9.

The system transitions from the normal state to the alert state when it is perceived as “less secure.” This can be triggered by a disturbance but may also result from other conditions that increase the overall risk to the system - such as a storm. As illustrated in the Figure 16, the arrows are two-sided, indicating that once security is improved, the system can return to the normal state.[33]

The system may transition directly from the alert state to in-extremis if the disturbance is sufficiently severe. Otherwise, the alert state may escalate to an emergency if the severity increases, without reaching the level of an extreme emergency.[33]

When the system enters the emergency state, it can be brought back to the alert state if adequate measures are taken. These could include clearing faults or increasing production.

If the actions taken are insufficient, the system may progress to the in-extremis state.[33]

The in-extremis state can shift to the restorative state through appropriate measures. These actions aim to return the system to its initial condition - such as reconnecting previously disconnected loads and bringing back facilities. From the restorative state, the system can transition either to the normal or alert state, depending on the effectiveness of the measures taken.[33]

The state descriptions can be seen in Table 9. The interaction of these different states should be more or less universal to power grids of different sizes, as a grid should have enough resilience for contingencies according to the aforementioned states.

System State	Description
Normal	The system is operating within its normal parameters, with all system KPIs within the expected range. No lines, transformers, generators, or other equipment are overloaded. The system is stable and operating at the N state, which indicates readiness for a contingency while still maintaining safety margins afterward.
Alert	The system has entered an elevated security state. A disturbance may have occurred, but KPIs remain within acceptable limits. However, the safety margin has significantly decreased. The system is now in the N-1 state, meaning that any additional contingency could push it into an Emergency state.
Emergency	The system's safety margin is now critically reduced. The system is in the N-2 state. Equipment may experience low bus voltages, and both lines and other components may be overloaded beyond emergency ratings.
In Extremis	The system is in a critical condition, leading to cascading outages and potential system shutdown.
Restorative	This is the phase where actions are taken to restore the grid by bringing production back online and reestablishing system load.

Table 9: Power system operational states and their descriptions

The subtransmission grid considered in Stenungsund should also be able to be represented by these different states. Therefore, to ensure the resilience of the system, one can examine the specific grid scenarios in the Stenungsund model and its relations to the operation scenarios. It is of value to determine how the grid would adapt to the operation scenarios in case they would occur.

The normal scenario in the Stenungsund model grid is a scenario where everything in the system is working well within margins of security and with a possibility of contingencies. At this point, the system is at N. In practice, it is a well-functioning grid like the one outlined in Figure 12. Note that in this scenario, the connection of the subtransmission grid to

the transmission grid is deemed "strong." I.e., it has a higher transfer capacity and more connections in place - as this is expected in the normal state.

Now imagine that the transfer ability to the transmission grid is hindered for some reason. This could be, for example, loss of a line to the transmission grid, a fault in a transformer, or related issues. The margins of safety that previously existed in the normal state are now lessened. Having lost one of the N devices in the system, it is now at N-1, or at the alert state. This grid scenario will be represented by a simulation case that will be investigated. This case is the one having the Stenungsund system with the wind turbines and gas turbines with a weak link to an infinite bus. In this context, a weak link refers to a weakness from a security standpoint, meaning that only one line remains between the subtransmission grid and the infinite bus. Losing this line would stop power transfer entirely. This case is more outlined later in the report.

As the system transitions from the alert state to the emergency state, it goes from N-1 to N-2. What can be seen here is the weak link to the infinite bus disconnecting. After the subsequent fault, the system is now in a state of emergency. This incurs - for this case - that the system is now in island grid operation. This case will be more clearly outlined later in the report.

Gas turbines are generally more expensive to operate in the current electricity market, which means they are more often used for contingency purposes. This gives rise to an interesting scenario. Suppose the grid is in an alert state: when operating under normal conditions without disturbances, most of the power would be supplied by the wind farm, supplemented by the weak link to the infinite bus. If the system transitions from the alert state to the emergency state, gas turbines will need to be started quickly to provide the much-needed stabilizing synchronous support to the island grid. To make this possible, the system may require energy stored in another form. To bridge the startup period while the gas turbines are ramping up, a BESS solution could be employed. This will be explored further in this report.

An application of these scenarios may be transferred onto the diagram of operating states of the power system. These can be seen in Figure 17.

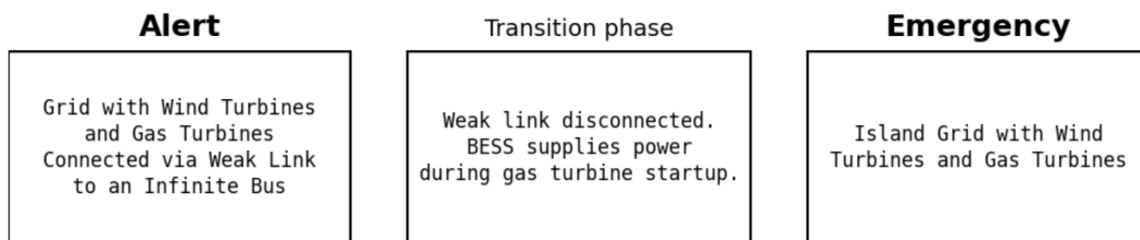


Figure 17: State transition from Alert to Emergency

Simulation scenarios of these three scenarios will be performed. They are outlined in more detail below.

3.4.1 Case A — Grid with Wind Turbine and Gas Turbines Connected via Weak Link to an Infinite Bus

This scenario is one that outlines a case where a subtransmission grid experiences a disturbance. The grid is moving from the state "Normal" to "Alert", as can be seen in Figure 16. This may be due, for example, to the loss of the line to the infinite bus. An infinite bus is an idealized model of a considerably larger grid characterized by constant voltage, stable frequency, and infinite short-circuit capacity. Given the substantial scale difference between the transmission and subtransmission grids, this method effectively approximates realistic grid interactions.

Unlike other scenarios, this analysis does not focus on sudden load changes at a load center, as the infinite bus would instantly compensate for such variations, mitigating potential disturbances. Instead, the study investigates how the grid responds to a temporary short-circuit fault, specifically simulated at the offshore wind farm. The short-circuit duration will be varied, but among the different duration values, $t = 200\text{ ms}$ will be used, aligning with the maximum permissible clearing time mandated by Energimarknadsinspektionen [24].

The quantity of gas turbines in the system will be varied to evaluate their effects on frequency dynamics and overall operational stability.

This scenario is particularly relevant as it simulates realistic contingency situations, providing critical insights into system performance indicators. The outcomes will indicate how effectively gas turbines and wind turbines can integrate into a subtransmission grid configuration while ensuring stability and reliability.

3.4.2 Case B — Transition Phase to Island Operation

During the transition phase, the last connection to the transmission grid is lost, and the BESS along with the wind power plant supplies the island grid during the gas turbine start-up time.

The case consists of three main events. First, after 5 seconds, the connection to the transmission grid is lost, and the system relies solely on the wind power plant and the VSM power converter representing the battery. Secondly, the gas turbine is started and connected to the system. Lastly, the VSM is disconnected, and the island grid is supplied with power from the wind and gas turbines.

As stated in Section 2.5.1, a stiff AC-voltage is needed to act as a reference for grid-following control systems. Therefore, an island grid without any grid-forming control would not work.

3.4.3 Case C — Island Grid with Wind Power Plant and Gas Turbines

This simulation scenario examines the subtransmission grid operating as an isolated island grid. This is again related to the system states outlined in Figure 16. The case is investigated where the last "weak link" to the grid is lost, implying the system is now in an island grid configuration.

An island grid configuration refers to a grid operation typically found in actual islands, characterized by exclusive reliance on localized electricity production without connections to a larger, external grid. A good example is Iceland, a small island nation located far from any extensive power grid infrastructure. Consequently, Iceland must independently manage its electricity generation and provide essential grid services to maintain stability. This operational independence poses significant challenges. Firstly, an island grid must continuously balance electricity production and consumption without the option to export or import power; a common solution in interconnected subtransmission grids. Secondly, a sudden disconnection of a generating unit will have a larger impact in relation to the total amount of generation in the system. This relative impact, in conjunction with the reduced total system inertia makes it challenging to maintain stable frequency levels when the power balance is disturbed.

This scenario is particularly relevant when determining the feasibility of integrating wind power and gas turbines within a grid. Successfully managing an isolated system according to grid codes is more challenging than operating connected to larger national grids. Therefore, it serves as a strong indicator that it will perform reliably when integrated into the wider grid.

Specifically, this scenario will test the response of the system to a step change caused by the loss of generation from the wind power plant. Practically, this simulates a scenario where a protective relay trips in a transformer or a cable connecting multiple wind turbines. The case study will highlight how a subtransmission grid, operating without external grid connections, handles such challenges. Again focusing on the frequency dynamics.

During the simulations, the number of active gas turbines in the system will be varied to observe their impact on system response.

Measurements focused on the frequency of the main bus bar system, from which key frequency characteristics - including Rate of Change of Frequency (RoCoF), frequency nadir, and overall dynamic response - will be determined. Since frequency is maintained globally in a system, the frequency of the main bus bar will be equivalent to the frequency of the system.

Additionally, the same tests were conducted with an increased inertia constant H to observe the impact of having more inertia in each generating gas turbine.

Moreover, a FFR response was incorporated by adding a step response to the gas turbine governor during a frequency deviation below a threshold value. This mimics sending a fuel

injection spike to the system, or opening up the inlet guide vanes to quickly increase power output. This ability was added to the governor by adding an input signal to the reference power P_{ref} , and a detailed description of the FFR control system is found in Appendix C. The threshold was set to 49.5 Hz and the activation duration was set to 5 s, following the requirements from Svenska Kraftnät [16]. The power output was either set as a fixed value, or scaled to the magnitude of the frequency deviation. The maximum value of 5 MW was estimated through discussions with Siemens Energy. Lastly, a ramp down requirement of maximum 20% of the procured power per second must be met to qualify for FFR. [16]. This was solved by adding a PI-regulator that gradually diminishes the FFR response after the 5 second duration.

The implemented response is referred to as FFR, as it delivers active power rapidly in response to frequency deviations. The term "synthetic inertia" implies a response proportional to the Rate of Change of Frequency (RoCoF) and would give a more suitable response in terms of system stability. However, the market for FFR requires almost instant injection of the procured power rating, thus the control design is implemented to meet these requirements. However, the implemented response can resemble synthetic inertia by altering the control design to be proportional to the RoCoF.

Lastly, simulations were performed to capture overfrequency phenomena in the grid. This was performed similarly to previous island grid cases, but by reducing active power consumption in a step at a load bus instead.

3.4.4 Meeting with Svenska Kraftnät

To get a better understanding of how island operation is conducted, a meeting was held with the Electrical Emergency Preparedness Department at Svenska Kraftnät. The key takeaways from the meeting are described below.

Under the authority of Elberedskapslagen [34], the TSO designates regions where island operation capabilities should be investigated, such as areas with critical infrastructure. This is typically a larger city or industrial area. The investigation is then performed by the subtransmission network owners, analyzing major loads and generation facilities in the area. Simulations are then conducted by a third party, usually consultancy firms, to evaluate operational stability in island mode.

There is no one solution to island operation since the loads and generation facilities vary from case to case. Therefore, a tailored action plan is created for the specified region where the DSO and generation facilities determine their respective responsibilities and the order of operation. During island operation, the one in charge is usually the generation company, since they determine how much power they can deliver. However, close communication between both parties is needed to ensure stable operation.

The meeting with Svenska kraftnät also highlighted that island operation requires stable power production, and wind power is typically not investigated due to the inherent fluctu-

ations from varying wind speeds.

4 Results and Analysis

This chapter showcases the results gathered from the simulations. The results are divided into three main parts: Transient stability during short circuits while connected to the transmission grid. Transition phase to island operation by relying on batteries during gas turbine start-up. Lastly, step changes in generation during island operation and observing the system response.

4.1 Simulation Results Case A — Grid Connected with Weak Link to Infinite Bus

This simulation case replicates a realistic scenario where a power grid at some point experiences a short-circuit. This short-circuit is cleared after a set time period, consequently disconnecting parts of the system. During this period, it is crucial for the system to maintain generation and avoid going out of phase.

In the subtransmission grid model of Stenungsund there is localized production in the form of gas turbines and wind power plants. When a short-circuit occurs in the system, there is a risk that generators lose synchronism with the rest of the grid. This is a phenomenon that may create non-converging oscillatory effects on generator performance as well as grid frequency. If this happens, the generator must be disconnected and re-synchronized to the system. Loss of synchronism can also lead to torque fluctuations several times greater than during normal operation, which can severely damage the generator.

The simulations were run with a range of varying parameters. The fault clearing time was varied from 200 ms up to a maximum of 1700 ms, with increments of 300 ms. The 200 ms point is of particular interest, as it represents the maximum allowable clearing time according to RfG and EIFS 2018:2. Furthermore, the number of gas turbines in the system was varied to generate the results.

Figure 18-26 outlines results for grid frequency measured from the main bus bar after varying the parameters.

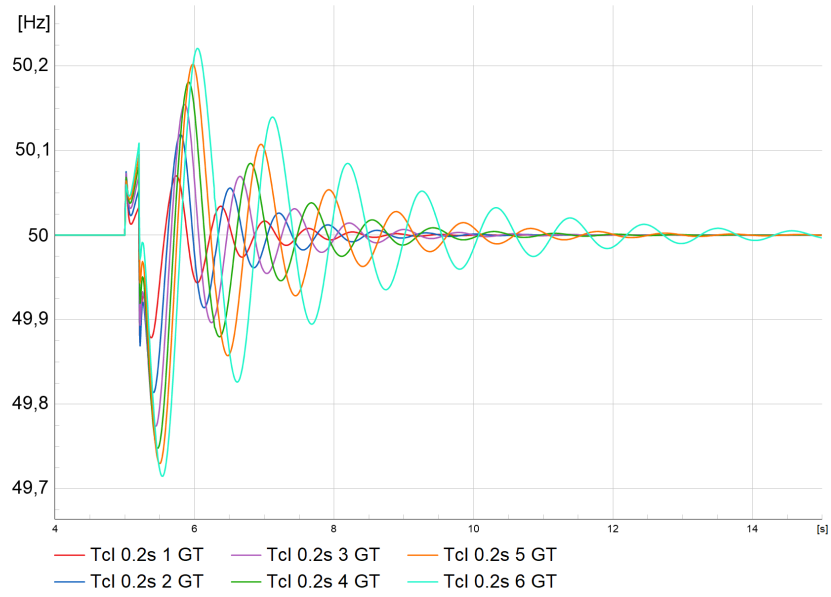


Figure 18: Frequency response post three-phase-fault at 5 s, and fault clearing 0.2 s later. For cases with 1-6 gas turbines.

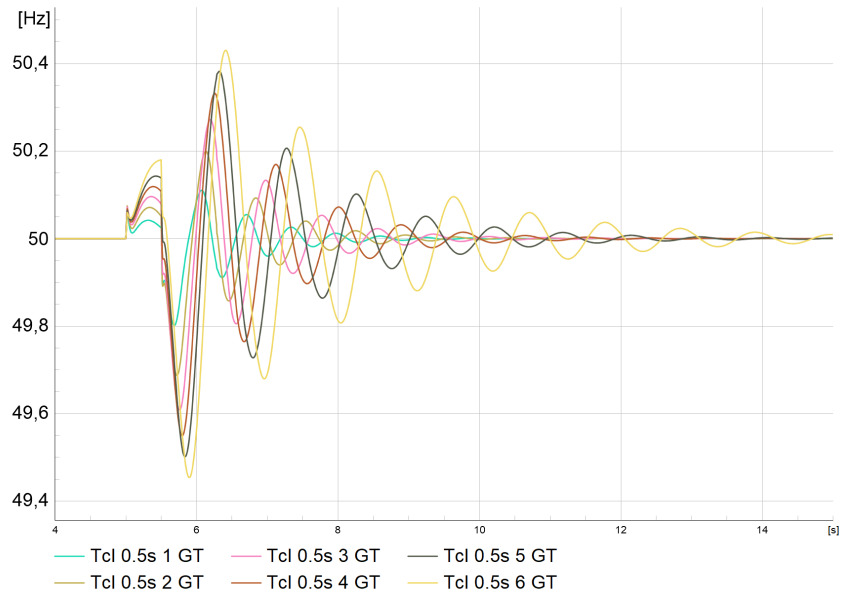


Figure 19: Frequency response post three-phase-fault at 5 s, and fault clearing 0.5 s later. For cases with 1-6 gas turbines.

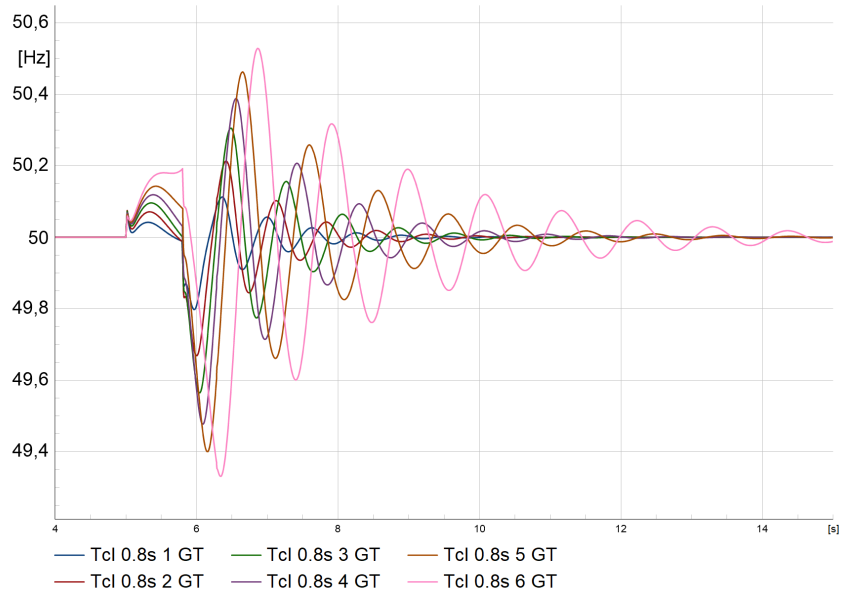


Figure 20: Frequency response post three-phase-fault at 5 s, and fault clearing 0.8 s later. For cases with 1-6 gas turbines.

In Figure 21 the first simulation with loss of synchronism can be seen; the system no longer has transient stability and is now out of phase. Figure 22 shows the results more zoomed out, clearly outlining the case where the system is out of phase.

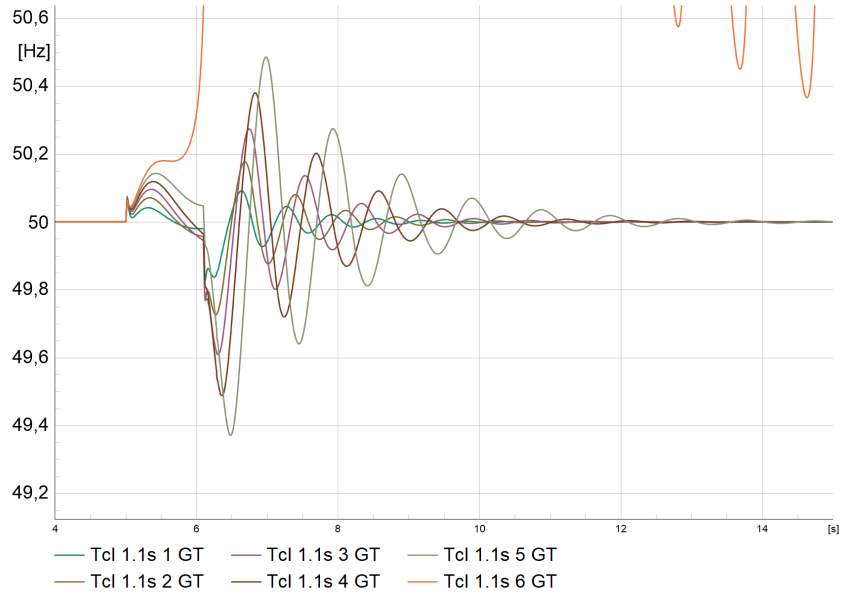


Figure 21: Frequency response post three-phase-fault at 5 s, and fault clearing 1.1 s later. For cases with 1-6 GTs. Case with 6 GTs showing the system out-of-phase.

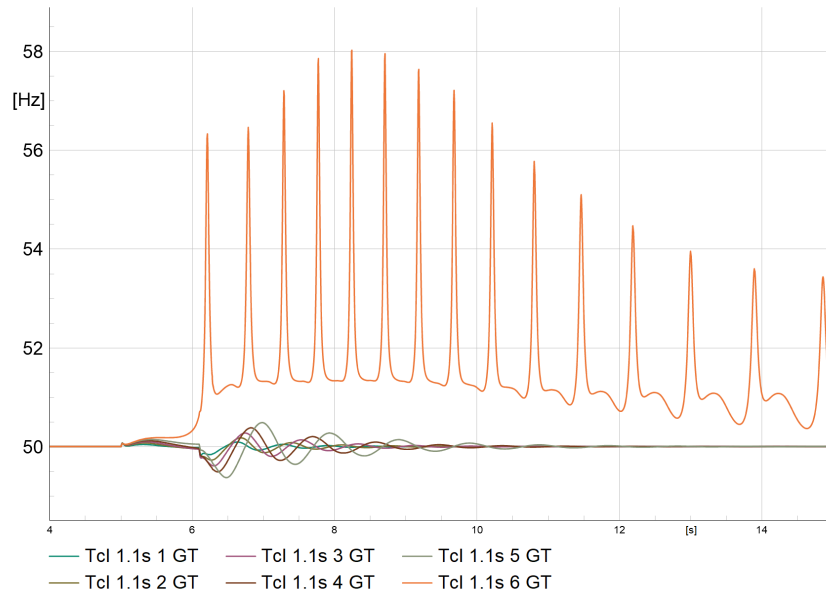


Figure 22: Frequency response post three-phase-fault at 5 s, and fault clearing 1.1 s later. For cases with 1-6 gas turbines. Case with 6 GTs showing the system out-of-phase. Zoomed out to see better.

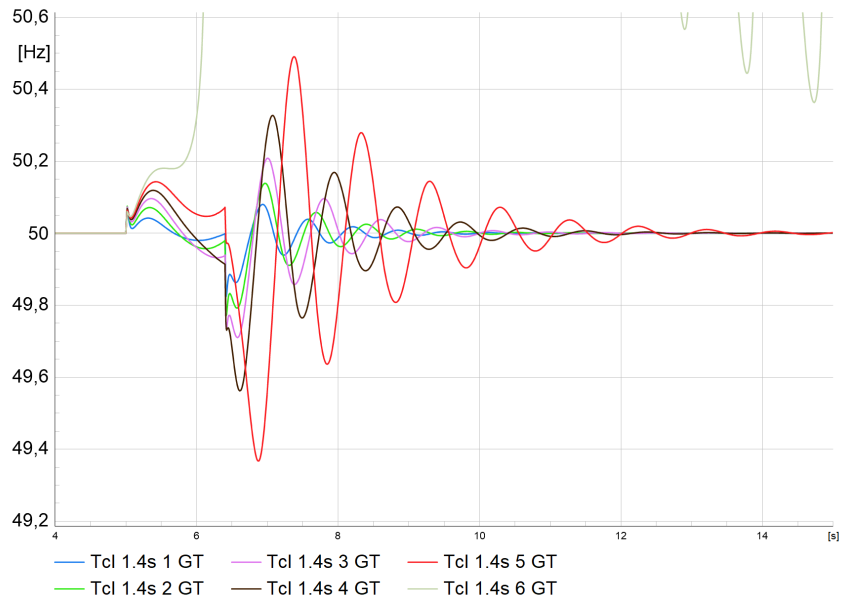


Figure 23: Frequency response post three-phase-fault at 5 s, and fault clearing 1.4 s later. For cases with 1-6 gas turbines. Case with 6 GTs showing the system out-of-phase.

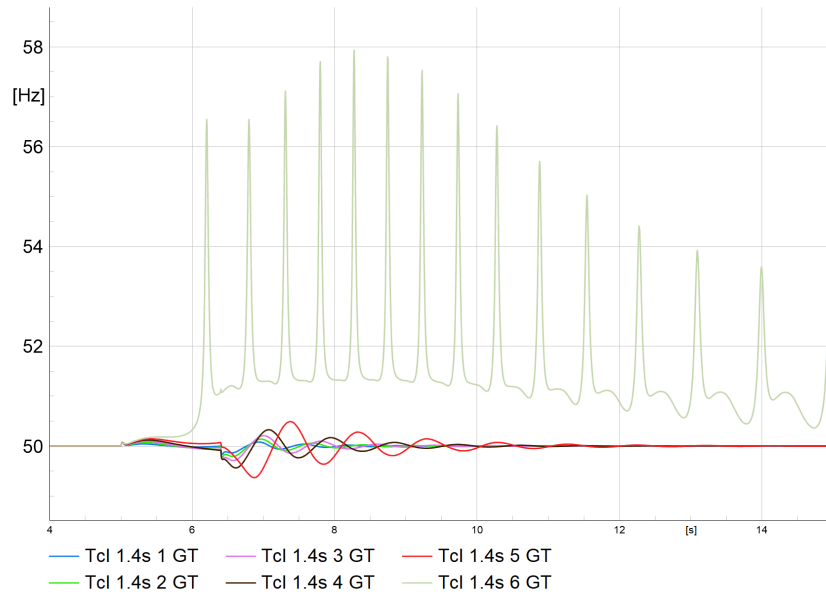


Figure 24: Frequency response post three-phase-fault at 5 s, and fault clearing 1.4 s later. For cases with 1-6 gas turbines. Case with 6 GTs showing the system out-of-phase. Zoomed out to see better.

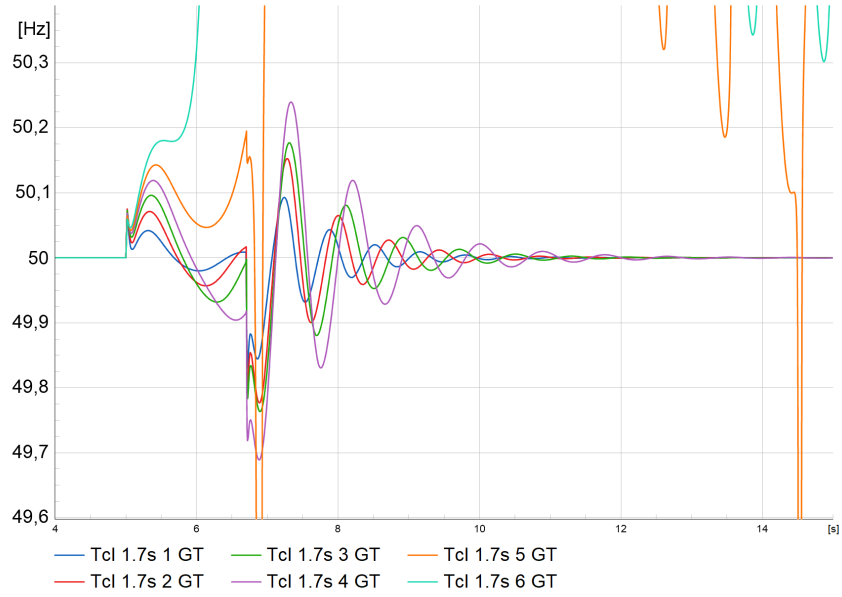


Figure 25: Frequency response post three-phase-fault at 5 s, and fault clearing 1.7 s later. For cases with 1-6 gas turbines. Cases with 5 and 6 GTs showing the system out-of-phase.

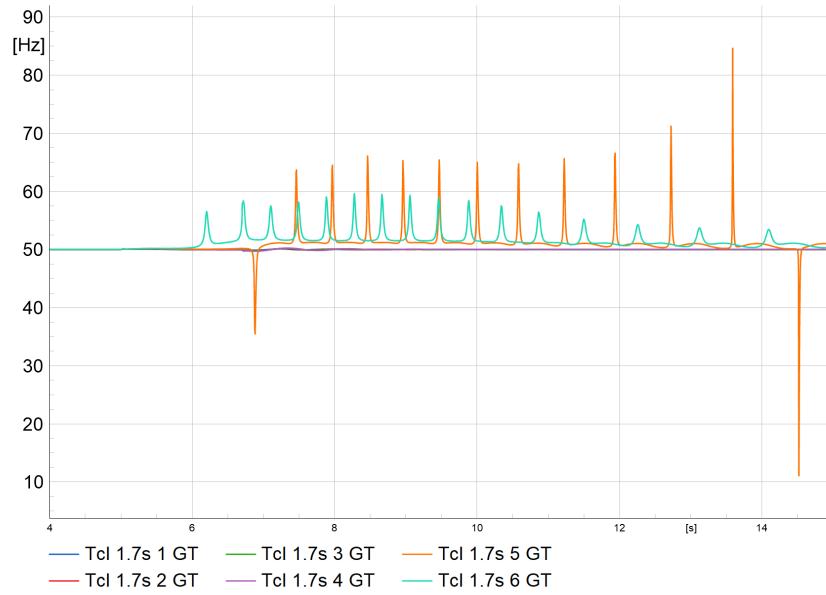


Figure 26: Frequency response post three-phase-fault at 5 s, and fault clearing 1.7 s later. For cases with 1-6 gas turbines. Cases with 5 and 6 GTs showing the system out-of-phase. Zoomed out to see better.

4.2 Simulation Results Case B — Grid Disconnection with BESS Support and Subsequent Gas Turbine Activation

The simulation replicates a scenario in which the system transitions from having a weak connection to an infinite bus to island operation. In this situation, the system only has its wind turbines providing power, and to support this, the system also has a virtual synchronous machine(VSM) from a BESS system. This VSM BESS system acts in the time period the GTs need to start up. The GT is then connected to the system. After a short period, the VSM BESS is further disconnected, leaving the system with an island grid solely based on wind turbines and gas turbines. In this simulation case, 3 GTs operate with a combined rated apparent power of 216 MVA, and the same apparent power is used for the VSM.

The VSM BESS is representing that of a GFM BESS system. The VSM BESS is a simplification of how a real grid forming BESS system would operate. It does not have a model implemented for the actual battery, being that it does not have a system of measuring the state of charge, varying voltage levels or similar. But for the purposes of this investigation, that is acceptable.

Because of its grid-forming abilities, the unit is crucial for the functioning of the system. Since the wind power plant is purely grid-following, a grid-forming power-producing unit is needed to maintain system synchronization.

For this simulation case, sequence of events can be seen in Table 10:

Time	Event	Description
T0 = 0s	Normal operation	The system is connected via a weak link to both the infinite bus and the wind farm. The VSM BESS is online and supports system stability.
T1 = 5s	Disconnection from infinite bus	The system loses connection to the infinite bus. The VSM BESS maintains frequency and synchronization.
T2 = 300s	Gas turbines are connected	As GT startup is not included in the model, GTs are set to connect at 300 s, representing a fast start-up time. Once ready, the GTs connect to the grid and supply active power.
T3 = 330s	VSM BESS is disconnected	The VSM BESS is disconnected after the gas turbines have taken over system support.
T4 = 380s	Secondary frequency response is activated	The gas turbines restore the frequency to 50 Hz.

Table 10: Sequence of events in the power system with VSM BESS.

The system frequency, turbine power, and VSM active power throughout the entire simu-

lation are shown in Figure 27. However, because the events occur at different times, the details in this graph are difficult to see. To address this, zoomed-in views corresponding to specific time intervals are provided in Figures 28–30.

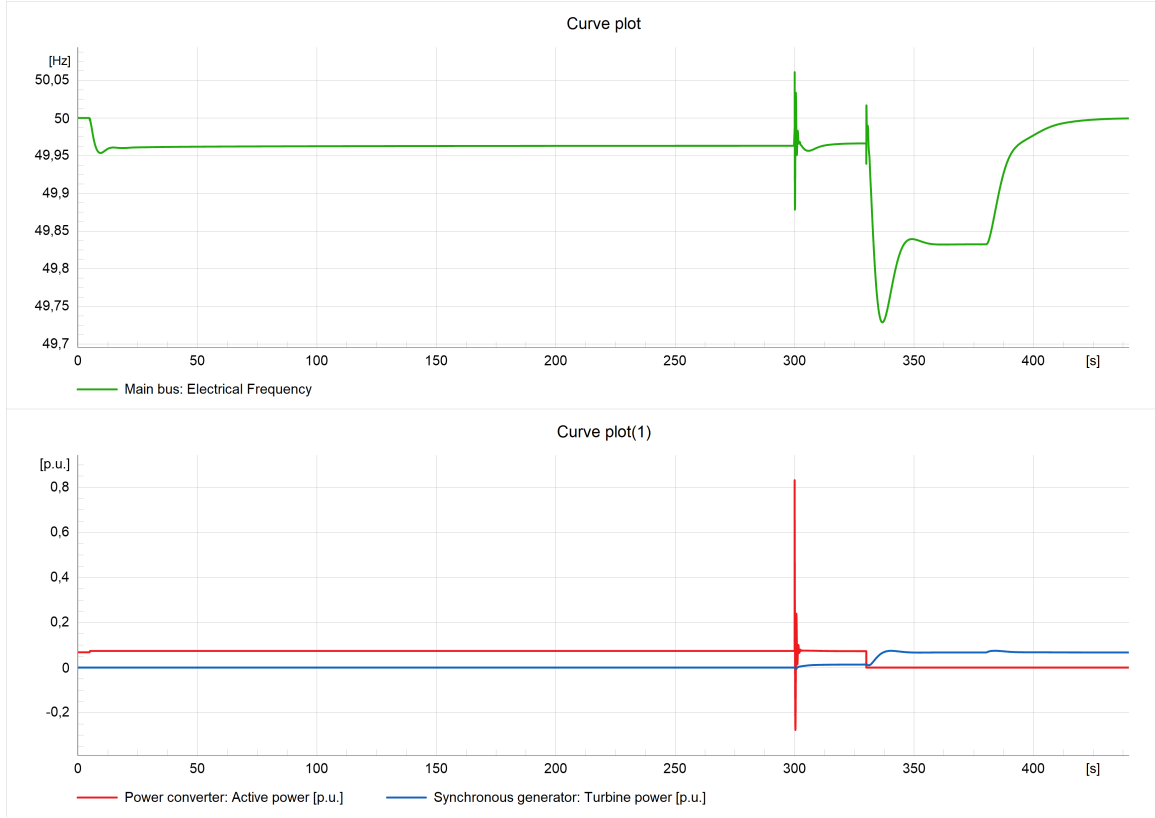


Figure 27: Graph of system frequency, GT turbine power and VSM active power. Displaying time event T0, T1, T2, T3 and T4. Showing simulation from 0 - 440 s.

In Figure 28 events T0 and T1 occur. The system is in steady state when connected to the infinite bus, but as this weak connection is disconnected, the frequency dips. The system sees a fully acceptable nadir at $f_{nadir} = 49.955Hz$ and a QSS (quasi steady state) at $f_{QSS} = 49.960Hz$. The GT is not providing turbine power, as it is not connected. Furthermore, it can be seen that at T1, when the weak link is disconnected, the VSM quickly increases its power output and provides primary response.

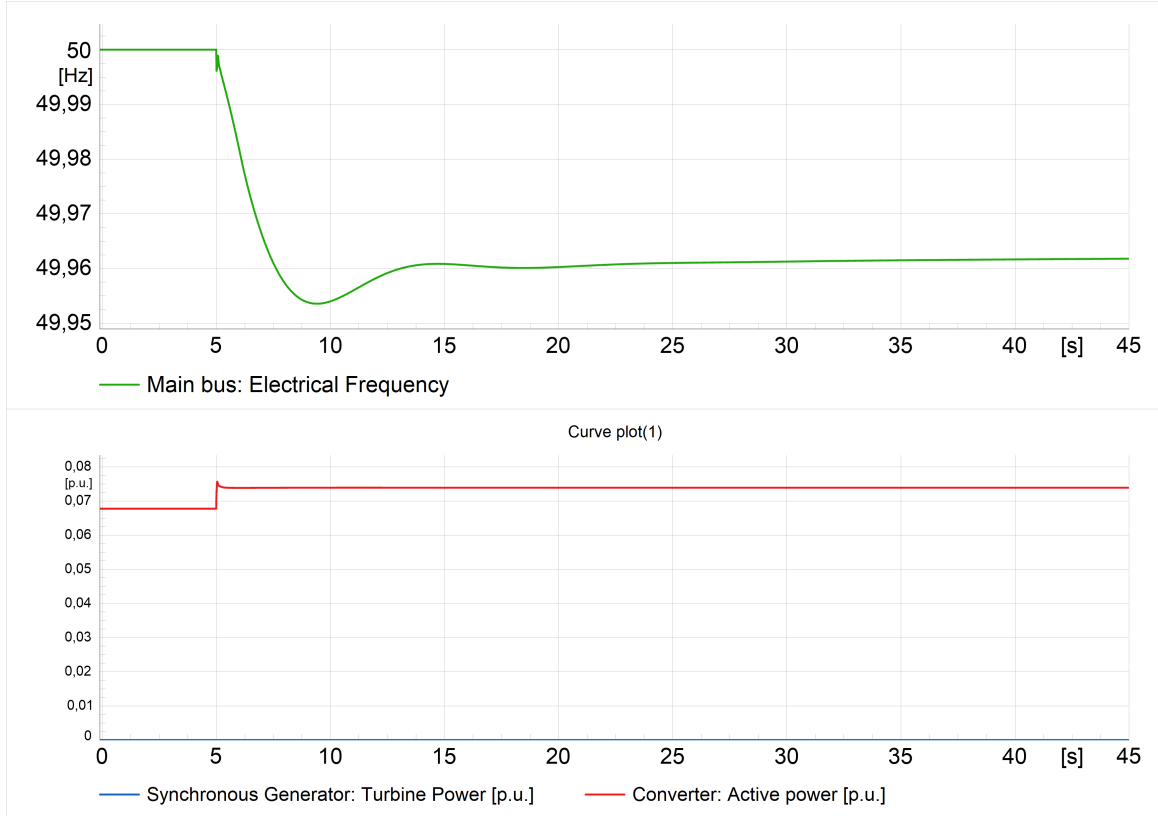


Figure 28: Graph of system frequency, GT turbine power and VSM active power. Displaying time events T0 and T1. Showing simulation from 0 - 45 s.

In Figure 29, time sequence T2 can be seen. Here, the GTs are connected at $T = 300s$. Immediately following the reconnection, the frequency oscillates but converges to a QSS after a few seconds. The oscillations are likely due to the mismatch between phase angles of the GTs and the VSM. Initially, they are unsynchronized, which causes these oscillations as they converge to a QSS. In practice, this reconnection would be synchronized to mitigate these oscillatory effects. Furthermore, in a real-world scenario, there would probably be a ramping connection of the GTs.

After the reconnection, the system reaches a QSS. The QSS-frequency, f_{QSS} , is more or less at the same level as before reconnection. Furthermore, it can be seen in Figure 29 that initially the converter active power and the GT turbine power do not change much after the reconnection. This may be explained by the fact that the generating units use droop control. Since the VSM is already providing much of the power required to maintain the frequency, the frequency drop is small. With the frequency drop being small, the droop control for the GTs causes only a small change in power output. A real-world scenario would likely involve more complex control mechanisms, such as secondary frequency response, to

increase power output from the GTs to a more optimal level.

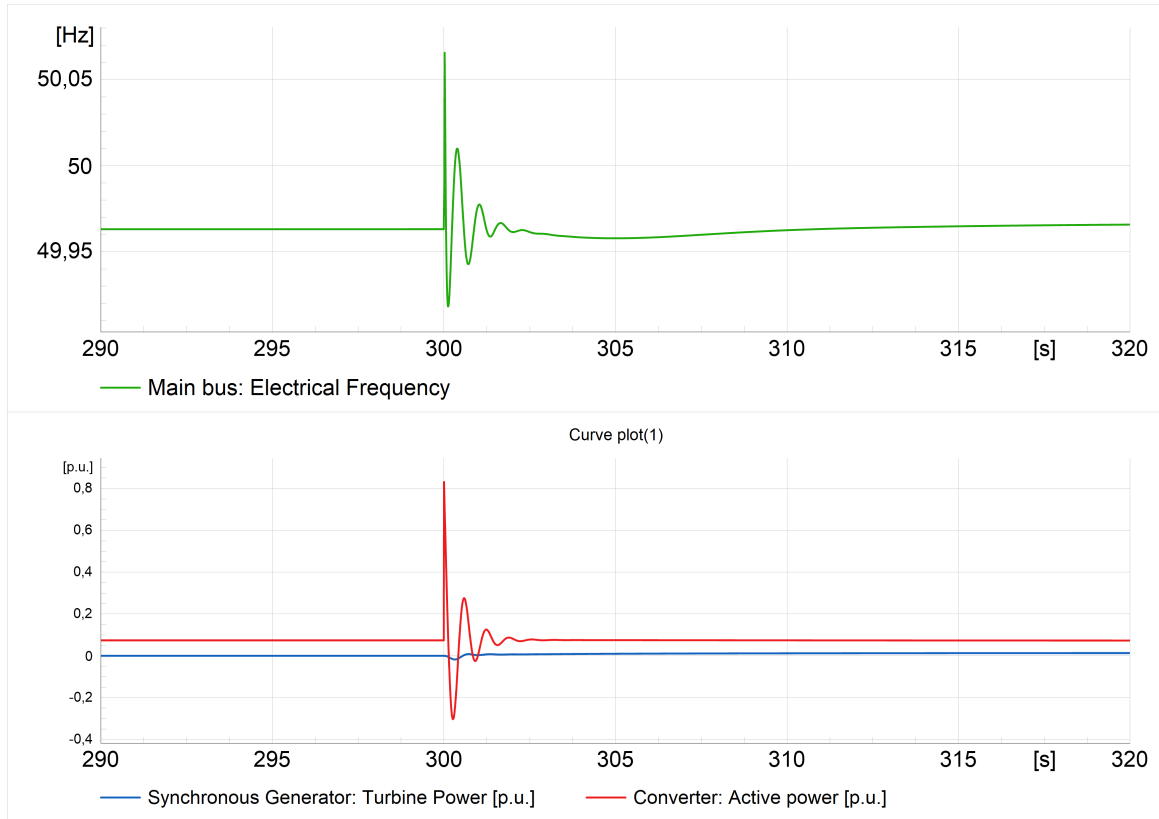


Figure 29: Upper: system frequency. Lower: p.u. GT active power and p.u. VSM active power. Event T2 shown. Simulation from 290–320 s.

In Figure 30 the VSM is finally disconnected. A positive frequency step is initially seen, followed by a larger frequency dip. The active power from the VSM sees a big step. In a real-life scenario, there would probably be a ramp here. It can be seen that as the frequency decreases rapidly, droop control of the generator kicks in to reach a new QSS.

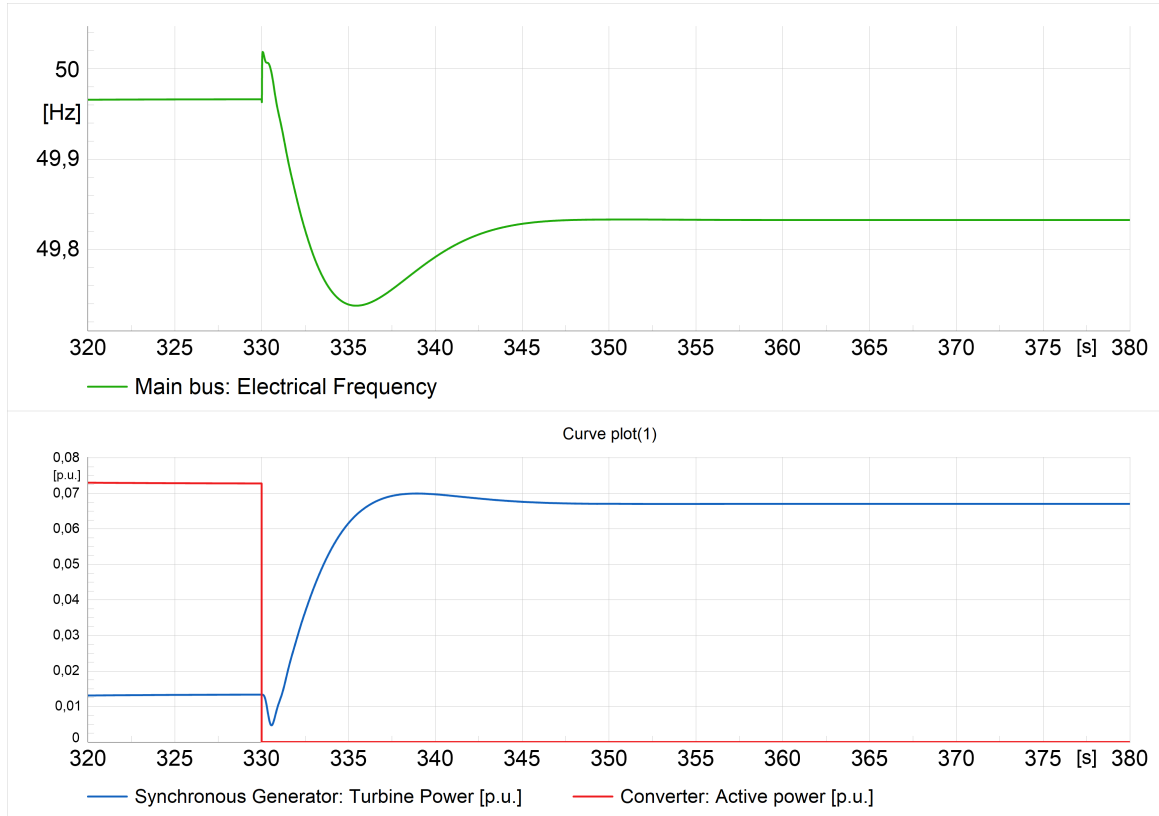


Figure 30: Graph of system frequency, GT turbine power and VSM active power. Displaying time event T3. Showing simulation from 320 - 380 s.

Lastly, the secondary frequency response is activated from the gas turbine to bring back the nominal frequency after some delay, shown in Figure 31. Under normal operation when connected to the transmission grid, secondary response is supplied by providers through the aFRR-market. However, during island operation this responsibility falls to the local power-generating units. By implementing an Automatic Generation Control (AGC) system, the frequency restoration can be handled automatically within the island grid. This can be facilitated, for example, by enabling an operating mode switch from grid-connected to island operation.

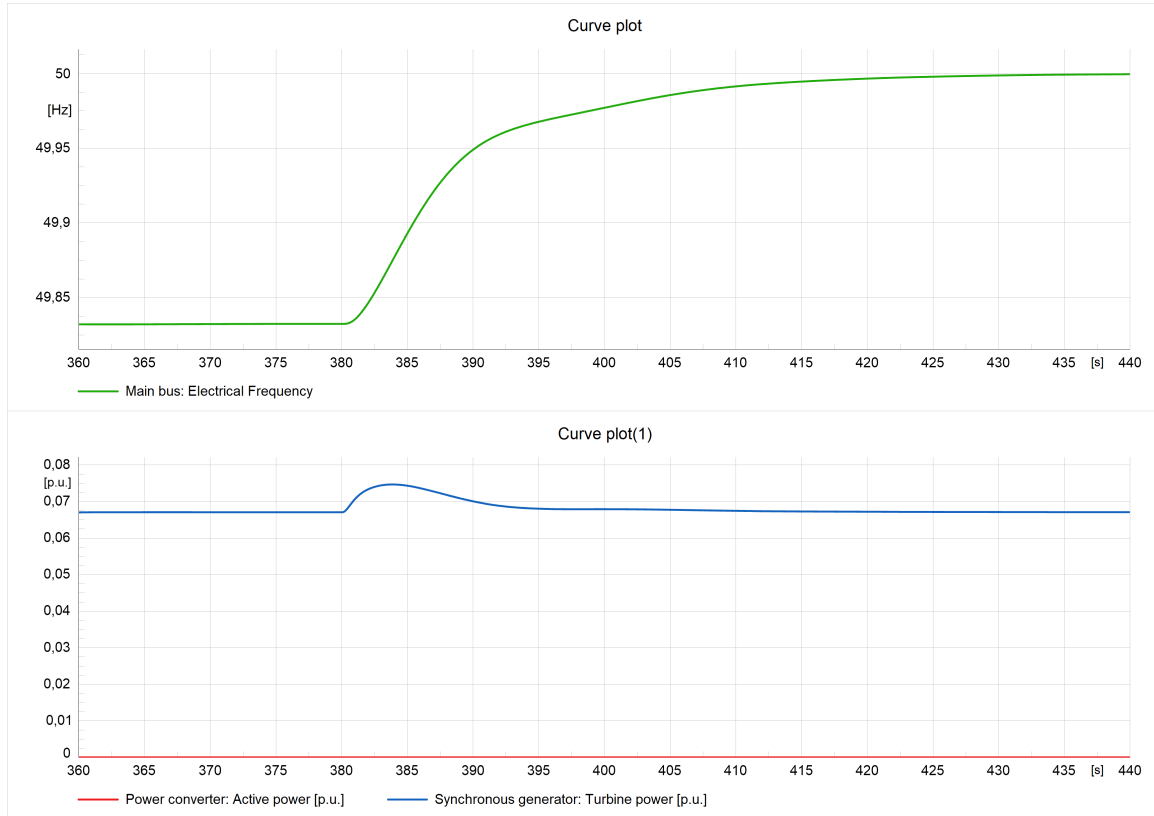


Figure 31: Graph of system frequency, GT turbine power and VSM active power. Displaying time event T4. Showing simulation from 360 - 440 s.

4.3 Simulation Results Case C — Island Grid with Wind Power Plant and Gas Turbines

In this simulation case, the grid is operating as an island grid, relying solely on power from the wind power plant and the gas turbine. Since the power output from the wind turbines is directly linked to the wind speed, the wind power plant cannot increase its power output. Thus, the unit handling frequency stability and system response is the gas turbine.

The simulations are carried out by having a sudden step decrease in generation due to a part of the wind power plant tripping after 5 seconds. The amount of wind turbines tripping simulates a realistic scenario that can occur when a protective relay trips, either in individual wind turbines or in a transformer connecting multiple wind turbines. The number of gas turbines is then varied, and the system frequency is measured during different load steps. The loss of generation can also be compared to a power-intensive industry starting up during island operation.

The amount of wind turbines that disconnect is varied from 10 to 40 units out of a total

of 70 units, and the number of gas turbines is varied from 1 to 6. The 6 gas turbines have a combined rating of 384 MW, close to the 350 MW rating of the wind power plant. The percentage shown in the Table below refers to the share of wind turbines disconnected in relation to the total number of wind turbines in the park.

The first plot shows the frequency in the system during the step response. The maximum RoCoF, the nadir (largest frequency dip) and the quasi-steady state frequency (the value of the frequency at the new steady state) were all noted. The maximum RoCoF was taken over a 500 ms period, as stated in EIFS:2018 [24], and was measured between 5.250 s and 5.750 s due to the sharp notch occurring at 5 s (likely due to a slight convergence error). In the second graph, the mechanical power of the gas turbine is plotted during the same period.

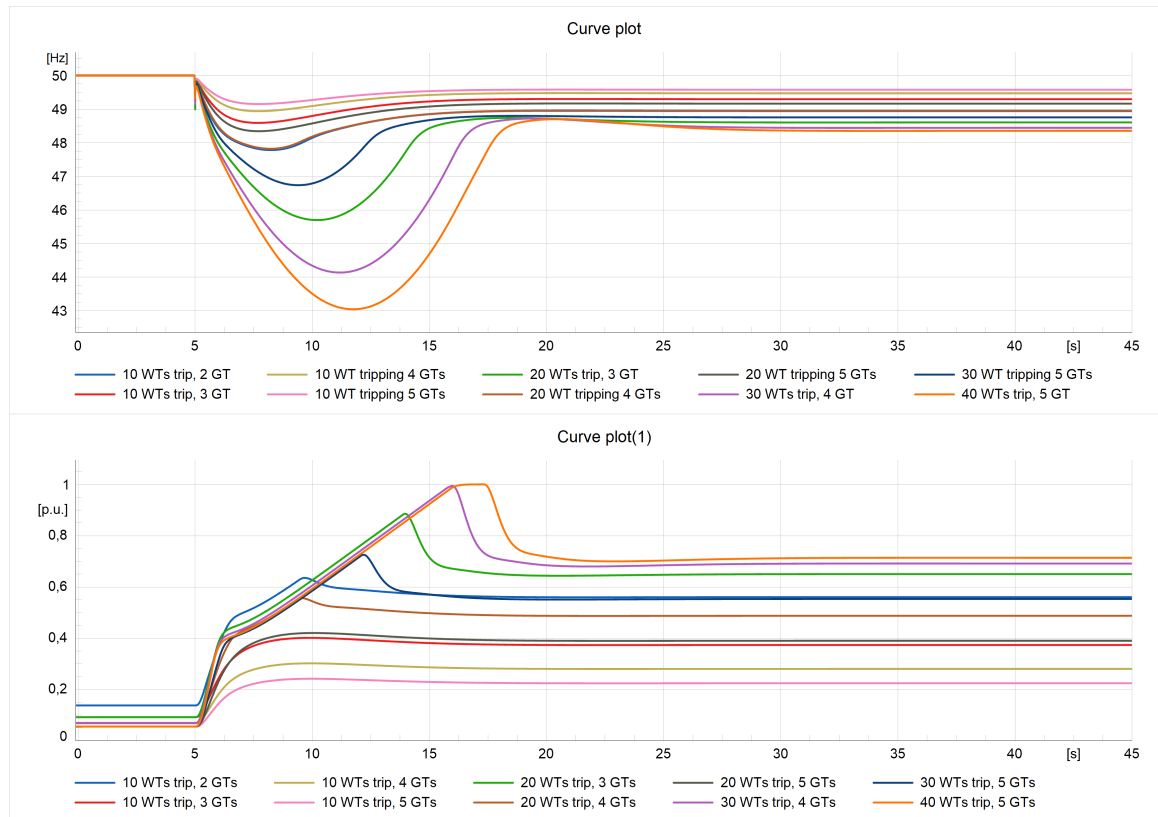


Figure 32: Plots of frequency and p.u power with WTs tripping at 5s.

The cases resulting in instability were removed from the plots due to difficulty in deciphering the results, but are presented in Table 11.

Trip Wind Turbines [Units]	Gas Turbines [Units]	Stable	RoCoF [Hz/s]	Nadir [Hz]	QSS Freq. [Hz]
10 (14%)	1	No	-	-	-
	2	Yes	-1.464	47.78	48.94
	3	Yes	-1.005	48.59	49.30
	4	Yes	-0.750	48.94	49.47
	5	Yes	-0.600	49.15	49.58
	6	Yes	-0.501	49.29	49.65
20 (29%)	1	No	-	-	-
	2	No	-	-	-
	3	Yes	-1.94	45.70	48.61
	4	Yes	-1.479	47.82	48.95
	5	Yes	-1.18	48.34	49.16
	6	Yes	-1.014	48.61	49.30
30 (43%)	1	No	-	-	-
	2	No	-	-	-
	3	No	-	-	-
	4	Yes	-2.19	44.14	48.44
	5	Yes	-1.75	46.74	48.76
	6	Yes	-1.486	47.85	48.97
40 (57%)	1	No	-	-	-
	2	No	-	-	-
	3	No	-	-	-
	4	No	-	-	-
	5	Yes	-2.31	43.04	48.35
	6	Yes	-1.96	45.75	48.63

Table 11: Frequency stability for varying numbers of gas turbines and wind turbine unit disconnections.

4.3.1 Doubling the Inertia Constant H

It is also of interest to evaluate future abilities of gas turbines. One such ability is to increase the inertia constant H by incorporating a flywheel and scaling up the generator to handle the increased inertia. This could be a valuable asset in a grid with a high penetration of VREs, where a large amount of inertia can be incorporated with just a few synchronous generators.

The same tests as in the previous section are conducted, but with twice the inertia, $H = 10$ s. For results, see Figure 33 and Table 12.

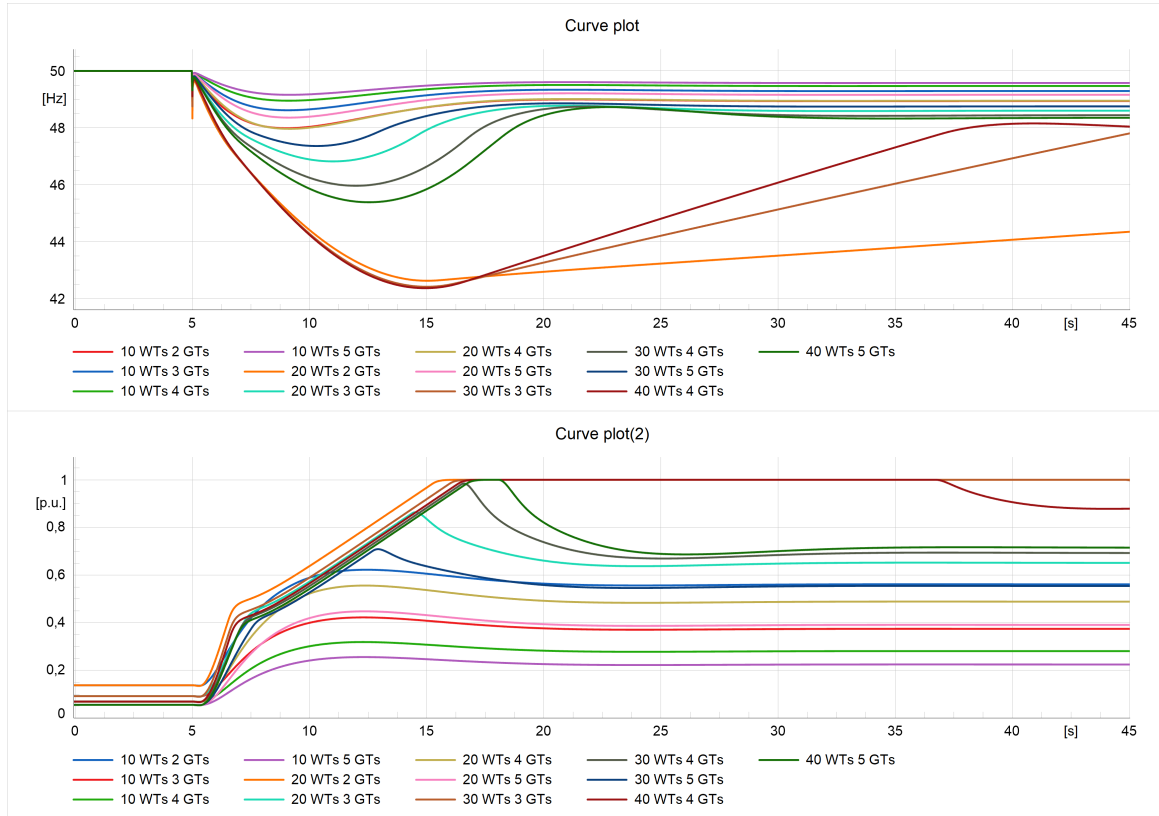


Figure 33: Plots of frequency and p.u power with WTs tripping at 5s.

Trip Wind Turbines [Units]	Gas Turbines [Units]	Stable	RoCoF [Hz/s]	Nadir [Hz]	QSS Freq. [Hz]
10 (14%)	1	No	-	-	-
	2	Yes	-1.015	47.99	48.94
	3	Yes	-0.658	48.62	49.29
	4	Yes	-0.484	48.95	49.47
	5	Yes	-0.383	49.16	49.58
	6	Yes	-0.317	49.30	49.65
20 (29%)	1	No	-	-	-
	2	Yes	-1.838	42.63	47.90
	3	Yes	-1.252	46.82	48.61
	4	Yes	-0.937	47.97	48.95
	5	Yes	-0.746	48.36	49.16
	6	Yes	-0.619	48.63	49.30
30 (43%)	1	No	-	-	-
	2	No	-	-	-
	3	Yes	-1.785	42.42	47.91
	4	Yes	-1.356	45.97	48.44
	5	Yes	-1.089	47.36	48.76
	6	Yes	-0.908	47.98	48.96
40 (57%)	1	No	-	-	-
	2	No	-	-	-
	3	No	-	-	-
	4	Yes	-1.751	42.37	48.06
	5	Yes	-1.414	45.39	48.35
	6	Yes	-1.185	46.83	48.63

Table 12: Frequency stability for varying numbers of gas turbines with doubled inertia and wind turbine unit disconnections.

By comparing the two tables, it can be observed that the RoCoF never goes below 2 Hz/s and three additional stable cases with the added inertia. The cases with two, three and four gas turbines and 20, 30 and 40 Wind turbines disconnecting respectively. However, these cases all have substantially lower nadir, around 42.5 Hz.

4.3.2 FFR Response Incorporated in Island Operaion

Another potential future ability that was also investigated was by incorporating an FFR response by providing "synthetic inertia" - in this case, extra power injection, from the gas turbine. The FFR is activated when the frequency goes below a threshold, in this case 49.5 Hz, and reacts with a step response input to the governor symbolizing the injection of a fuel spike in the gas turbine.

The simulation case run is with 50 MW of wind turbines disconnecting (14%) and 3 gas turbines operating in the island grid, with the standard inertia constant. This shows the effect of incorporating a fast frequency response during a step loss in generation, or similarly a step increase in load. The frequency response with and without FFR is shown in Figure 34. In Table 13 resulting data of frequency nadirs can be seen.

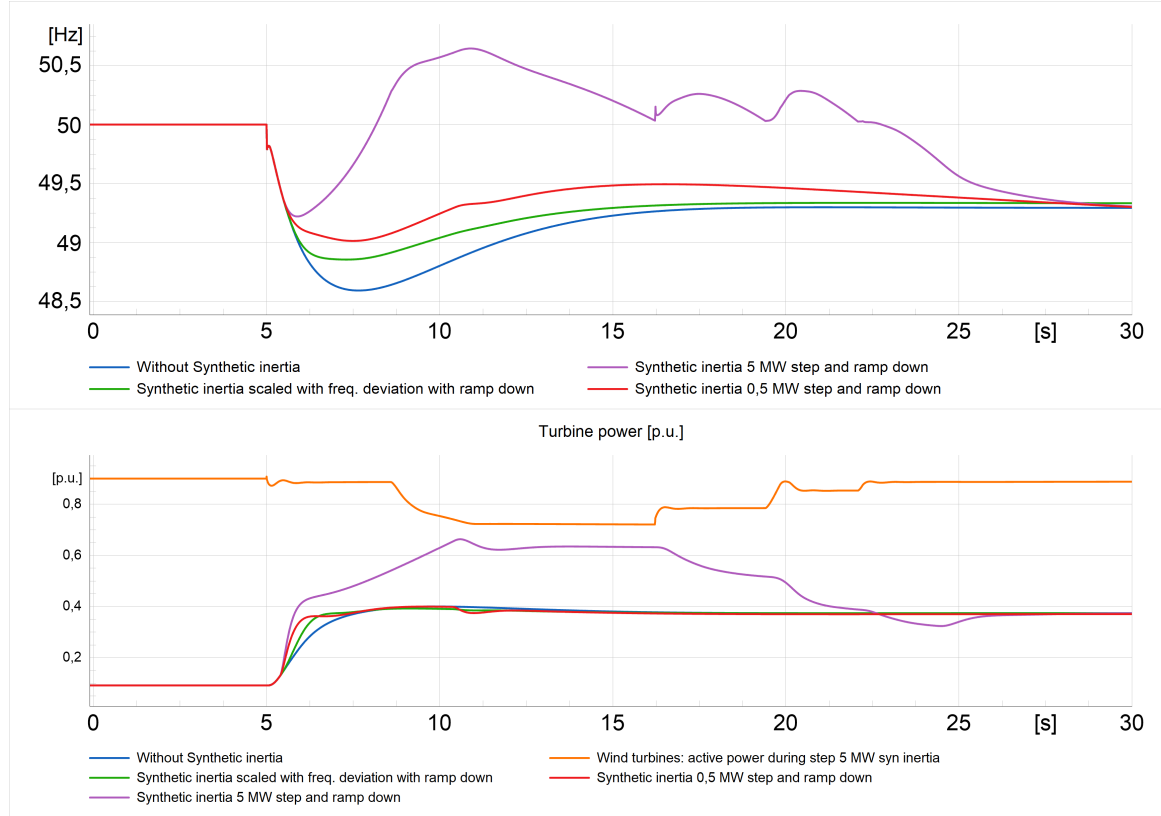


Figure 34: Frequency responses with different versions of FFR implemented, as well as p.u turbine power from GTs.

FFR response	Frequency nadir
Without FFR	48.59 Hz
5 MW	49.22 Hz
0.5 MW	49.01 Hz
$\propto \Delta f$	48.86 Hz

Table 13: Frequency nadirs resulting from different FFR implementations.

Comparing the results in Figure 34, the blue curve shows the response without the FFR.

With a 5MW FFR response, the frequency recovers before the deactivation of the FFR at 5s. This results in overfrequency in the system, and the wind turbine's overfrequency protection is automatically activated by reducing its power output. The wind turbine's active power output for the 5MW FFR is shown as the orange curve in the turbine power plot, showing the interaction between the gas turbine, wind power, and frequency. Due to the lack of coordination and bad system control, this results in an oscillatory system frequency.

For the red curve, the response is set to 0.5 MW instead of 5 MW. This results in a quick response without the over frequency. After 5 seconds, the ramp down is activated resulting in the slight notch in the curve just after 10 s.

Lastly for the green curve, the FFR response is proportional to the frequency deviation below the threshold value. This results in a smoother response, as this is a linear response, compared to the step responses from the other two cases.

4.3.3 Overfrequency in Island Grid Configuration

While underfrequency is a prominent issue in today's energy grids - typically resulting from a deficit in power production - another phenomenon that can occur is overfrequency. In this case, the system has an excess of power production relative to power use. A larger grid, with diverse power production units and greater inertia, may be able to manage this more easily. However, in an islanded grid with significantly less inertia, overfrequency may become a critical issue.

In Figure 35, graphs show the frequency response, GT power, and WT power. Table 14 presents KPIs related to the frequency dynamics.

Figure 35 illustrates that the system frequency rises rapidly following the event. It is evident that the system reaches higher frequencies when fewer gas turbines are present - an expected outcome due to the lower system inertia when fewer GTs are available in the system.

While the GTs provide valuable support in limiting the frequency spike caused by the step, the WTs may also contribute to frequency regulation. Although the WT model lacks underfrequency support capabilities, it does include functions for overfrequency scenarios. This is evident in Table 14, where the p.u. active power production from the WTs decreases rapidly. In real systems, this reflects how rotor blades quickly pitch to reduce power output. The GTs also provide support, but as can be seen in Figure 35, the response is slower than for the WTs.

Table 14 clearly shows that RoCoF decreases as more GTs are added. Furthermore, the frequency nadir is reduced with an increasing number of GTs. QSS remains similar across all cases, except for the scenario with two GTs.

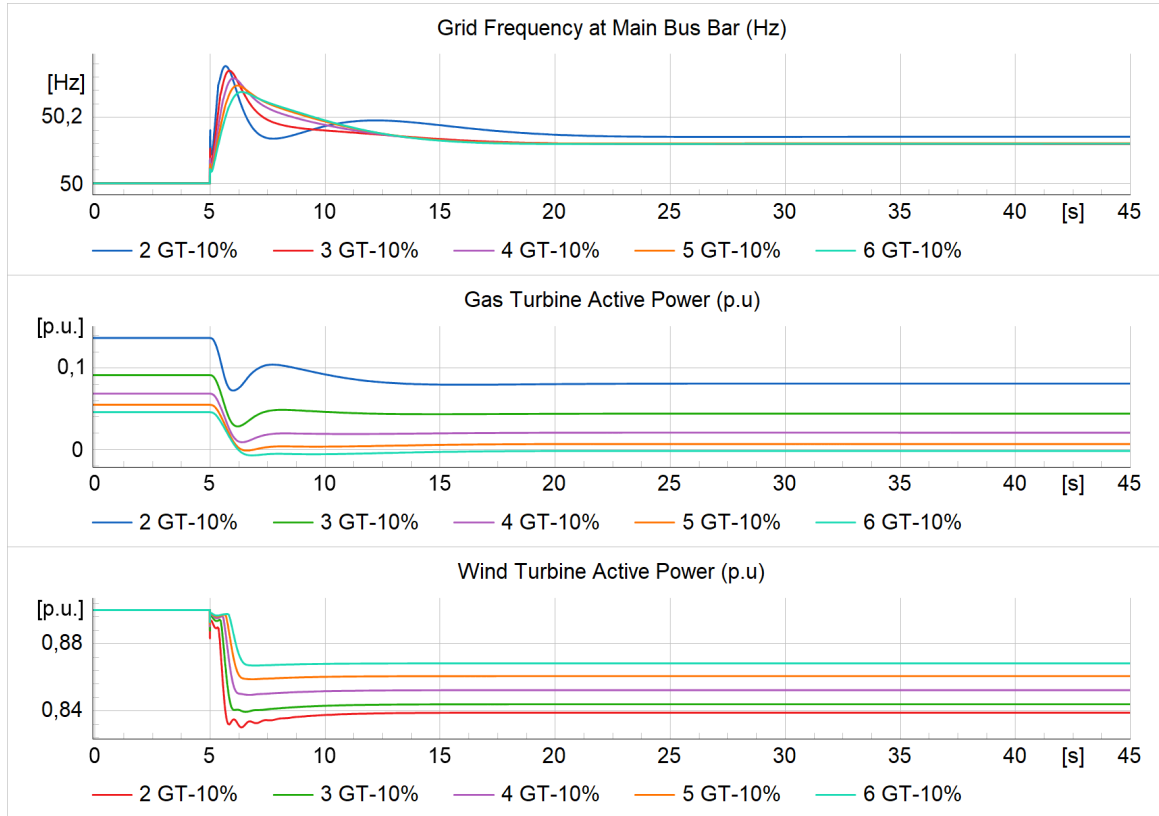


Figure 35: Frequency, GT active power in p.u and WT active power in p.u

Active Power Load Decrease [%]	Gas Turbines [Units]	Stable	RoCoF [Hz/s]	Nadir [Hz]	QSS Freq. [Hz]
-10% (-30 MW)	1	No	-	-	-
	2	Yes	0.51	50.35	50.14
	3	Yes	0.48	50.34	50.12
	4	Yes	0.40	50.32	50.12
	5	Yes	0.34	50.29	50.12
	6	Yes	0.29	50.28	50.12

Table 14: Frequency stability for varying active power load decrease and number of gas turbines.

5 Discussion

In this chapter, the results are analyzed and discussed. The cases are evaluated to system stability and if they follow the requirements set by current legislation. Lastly, uncertainties of the results are considered.

5.1 Analysis of simulation Results Case A - Grid Connected with Weak Link to Infinite Bus

Investigations of transient stability are crucial in power systems of all sizes and sorts. Events such as three-phase short-circuits do occur, and are routinely analyzed.

The frequency recordings from the system are shown in Figures 18-26, where the measurements are taken from the main busbar of the system.

The results obtained from the simulations are generally in line with expectations. Due to the connection to the infinite bus, the system benefits from a high level of inertia, as well as substantial active and reactive power support. As a result, typical step changes in active or reactive power do not cause significant imbalances that would shift the steady-state frequency level.

It is also important to note that the term "weak link" in this context refers to the reduced power transfer capacity of the line compared to its original state. From a system security perspective, the line is considered weak, and additional contingencies may result in a total loss of power transfer. However, in terms of power transfer capability under normal conditions, the line is still capable of supplying all the power required by load points in the Stenungsund grid.

By examining the frequency plots in Figures 18-26, it can be observed that the simulation cases in Figure 18 show increasing amplitude in the frequency responses as the number of gas turbines increases. The simulation case with six gas turbines exhibits the highest amplitude, while the case with only one gas turbine shows the lowest amplitude.

This behavior is attributed to the system dynamics during a short-circuit. When a fault occurs, the electrical torque instantly decreases while the mechanical torque momentarily remains unchanged. The gas turbines then start to accelerate, increasing their rotational speed. Each turbine experiences a rise in rotor angle, drifting out of sync with the rest of the system.

In a system with a short circuit, impedance acts as a brake by limiting the flow of fault current and thereby protecting the system. At the same time, it also limits the currents that would otherwise generate braking torque to slow down accelerating generators.

When running this simulation, the number of GTs is varied by connecting more GTs in parallel to the system. By doing this, the system changes. As more GTs are added, more impedance is connected in parallel. Impedance connected in parallel lowers the total

impedance. Therefore, increasing the number of GTs - while increasing power production capabilities - also lowers the overall impedance. See Figure 3 for a graphical representation of this phenomenon.

For the dynamical response of the system to remain the same, the impedance in the grid must also be reduced in the same way as the generators. Because the grid remains unchanged in these experiments, it becomes relatively weaker, and the counteracting torques become insufficient, which can cause the generators to lose synchronism with the grid.

Consequently, adding more GTs to a system - without strengthening the grid accordingly - may result in stronger oscillations during a short circuit and its subsequent clearing.

This finding is noteworthy, as it indicates that having too many gas turbines connected could introduce a potential vulnerability in the system under such conditions.

Furthermore, the plots in Figures 18-26 show that as the clearing time increases, the amplitude of the frequency responses also tends to rise. This outcome is anticipated, since longer clearing times allow the gas turbines more time to accelerate and further increase their rotor angles.

Now, as can be seen in Figure 18, for a clearing time of 200 ms, the system is able to successfully recover after a three-phase short-circuit event for configurations with 1–6 SGT-800 gas turbines. This is significant because RfG and EIFS 2018:2 stipulate that fault clearing of generating units must occur within 200 ms. Since the short-circuit is placed at the bus bar in this scenario, this requirement becomes particularly relevant.

The simulations show that the first test case where an out-of-phase scenario occurs is at a fault clearing time of 1.1 s with the configuration of 6 gas turbines. As seen in Figures 21-22, the frequency at the main bus bar reaches such high values that it no longer converges to a steady state. The short-circuit has thus caused the system to enter an out-of-phase condition. In practice, out-of-step protection is used to disconnect generation within 1 second when a generator loses synchronism with the rest of the grid. While the disconnection may lead to other issues, the figures still illustrate the dynamics of the system during short-circuits, showcasing what can happen if a grid is not strengthened while adding generation.

Similar results can be observed in the case with 6 gas turbines and a fault clearing time of 1.4 s. A qualitative comparison between Figures 22 and 24 shows that the graphs are almost identical. When increasing the clearing time to 1.7 s, the maximum clearing time in these simulations, the system remains stable for cases with 1–4 gas turbines. However, with 5 or 6 gas turbines, the system frequency again goes out of phase. As shown in Figure 24, the configuration with 6 gas turbines pushes the system out of phase earlier than the configuration with 5 turbines. A comparison of these two cases reveals that their responses differ in both amplitude and frequency: the configuration with fewer turbines exhibits higher-amplitude peaks, but with lower frequency and a much smaller area. Both out-of-phase scenarios would be unviable for any power grid, as the system reaches very high frequencies and high RoCoF values.

5.2 Analysis of simulation Results Case B - Transition phase

In the transition phase, the grid transitions from being connected to the infinite bus to operating solely on wind power and BESS after 5 s. At 300 s, the gas turbines are connected, and at 330 s, the battery is disconnected.

It can be seen in the full diagram Figure 27, that there occur oscillations at T2 when the gas turbines are connected to the system. The gas turbine is spinning at 50 Hz and the system frequency after the disconnection of the infinite bus is operating at around 49.96 Hz. As a result, phase angles between the turbine and the grid deviate, and synchronization should ideally occur when the phases are aligned. In real-world operation, synchronization is performed either automatically or manually to align the phases, which would mitigate the oscillations seen in the simulation.

It should also be noted that the simulation models the gas turbine as fully operational at the moment of connection, instantly injecting active power into the grid. This immediate power contribution further contributes to oscillations, due to the sudden interaction between the gas turbine and the grid. In practice, a gas turbine would typically be connected at idle and then gradually ramped up to assume load, thereby minimizing disturbances.

Another observation is that the quasi-steady-state frequency is higher during battery operation (grid-forming converter) than during gas turbine operation, see Figure 27, even though the gas turbine is rated for the same nominal power. This is due to the speed of the response from the converter, which instantly supplies active power to compensate for the frequency deviation compared to the slower turbine governor.

Nevertheless, the simulation case shows that the grid is fully functioning and with acceptable frequency deviations during a transition phase when using a grid-forming power converter.

As stated previously, the battery component of the power converter is not modeled explicitly, meaning that aspects such as state of charge and discharge rate are not considered. This simplification is deemed valid for the purposes of the simulation, as batteries intended for grid support typically have a C-rating of 1 or lower, allowing full discharge within one hour at rated power. Since mFRR activation is expected within 15 minutes, a battery with a C-rating of 3, providing approximately 20 minutes of full-power discharge, would still be reasonable for supporting the grid during the transition phase.

Finally, while the wind turbines in the simulation are grid-following, it is technically possible to equip fully rated converter-based wind turbines with grid-forming controls. However, this is currently uncommon in practice due to higher costs and the lack of strong economic incentives for operators to invest in such technology.

5.3 Analysis of simulation Results Case C - Island Grid with Wind Power Plant and Gas Turbines

In the island grid case, the system is subjected to a series of step losses in generating power from disconnecting the wind power units. The response during 45 seconds is then observed.

According to EIFS:2018, generators must remain connected with RoCoF of up to 2 Hz/s recorded over a 500 ms time period [24]. A RoCoF higher than 2 Hz/s runs the risk of a safety relay for the generator tripping, and is therefore determined as too severe for the island grid.

Additionally, too low of a nadir can have a detrimental impact on single-shaft gas turbines due to the risk of compressor surge. Therefore, a nadir below 47 Hz is problematic and below 46 Hz should be avoided completely. All cases with a nadir above 47.5 Hz are acceptable, due to the RfG requirement that generators should stay connected for at least 30 minutes in the frequency range 47.5-48.5 Hz [23].

When operating an island grid, different parameter sets for the system control would be used for a quicker response. Additionally, a generating unit could be responsible for bringing the frequency back to 50 Hz after a deviation through secondary frequency control. Therefore, the quasi-steady state frequency is of less interest when looking at how the system responds to a frequency deviation.

During a smaller loss of generation where only 14% of WPP is disconnected, the system is relatively stable with RoCoF and nadir within limits. During the slightly larger trip of 29% of the wind power plant, the cases with more than four gas turbines are within limits. However, for the case with 43% of the WPP tripping, six gas turbines are needed to have an acceptable nadir. Lastly, for the case with 57% of WPP tripping, the system reaches below 47.5 Hz for all cases. Realistically, the gas turbines would then trip since this frequency level falls below the requirements for RfG [23] and could lead to compressor surge.

5.3.1 Island grid with doubled inertia

Increasing the inertia of the system reduces both the RoCoF and the frequency nadir. However, the QSS frequency remains unchanged, which is expected as it is determined by the primary (governor) response, not by the inertial response. The RoCoF is significantly improved in the high-inertia case compared to the standard inertia value of the SGT-800, which aligns with theoretical expectations from the swing equation, see Equation 1. These findings indicate that even a small number of synchronous generators with high inertia constants can substantially reduce RoCoF.

All simulated cases had a RoCoF below 2 Hz/s, indicating that the system could tolerate the step losses without triggering RoCoF-based protection schemes. Therefore, the frequency nadir is the more critical metric for evaluating the system's ability to maintain stability. The nadir is reduced with doubled inertia, but the improvement is less compared to the change in RoCoF compared to the standard GTs. A better way to affect the frequency dip

would be to have a faster primary response. Nevertheless, a less steep RoCoF gives longer time for the rest of the system to respond. If batteries were to be incorporated in the step responses, then the added inertia with a faster primary response could greatly stabilize the grid with regards to frequency dynamics.

It should also be noted that the QSS for the three cases with a nadir of around 42.5 Hz is taken after a longer simulation time due to the longer recovery time after the frequency dip.

5.3.2 FFR Response Incorporated in Island Operation

Implementing an FFR response, or synthetic inertia, shows promising results compared to the default configured governor settings. It gives a notably improved nadir and reduces the duration of the low frequency. However, if not properly tuned, the response can lead to poor system control, as seen in the simulation results. Therefore, the findings should be interpreted as a proof of concept. A real-world implementation would require a more refined control strategy, for example by designing a response that is proportional to the RoCoF or have a feed-forward signal for when a large generator trips.

It should also be noted that to qualify for the FFR market, requirements for activation time must be met. For a frequency below 49.5 Hz the maximum activation time of the procured active power is 0.7 s. This requirement is met by the two responses with a step input, but not for the FFR which is proportional to the frequency response. While the proportional response demonstrates the most stable frequency behavior among the simulated cases, its slower activation time challenges its suitability for the FFR market requirements.

The result also show a trade-off between stability and rapidness in the system control. Step inputs enable fast correction, but risk instability due to overshoot, whereas proportional responses may be too slow to meet critical timing constraints but provide smoother dynamics.

Lastly, FFR is procured on the electricity market, and during the critical state of island operation, normal circumstances such as market and regulatory aspects can differ significantly. The cases studied here are based on an isolated grid to clearly illustrate the dynamic effects of different FFR strategies. These cases should not be interpreted as a recommendation of 5 MW as universally appropriate; the acceptable magnitude of the response depends on the size and inertia of the local system. Rather, the key conclusion is that rapidly injecting active power following a frequency deviation is a highly effective way to mitigate underfrequency events and preserve system stability.

5.3.3 Overfrequency in Island Grid Configuration

Running the system as an island grid and then decreasing active power use at a load bus generates the results shown in Table 14 and Figure 35. Looking only at the frequency plot,

it can be seen that the system handles overfrequencies well. The KPIs reflect this as well, with RoCoF values far below the 2 Hz/s requirement, in line with RfG.

The results for the QSS are also very low and more or less converge to a single value, with the exception of the case with 2 GTs, which produces a slightly higher QSS. What is expected in the simulations is that more GTs should lead to a lower QSS, with more GTs available to provide droop control. This does not happen in practice.

The reason for this may lie in the dynamics between the frequency response of the GTs and that of the WTs. While the GTs have grid-forming capabilities and an AVR to provide droop control, the WTs are only grid-following and do not provide droop control. To handle overfrequencies, the WT model applies a function for a linear power response to overfrequencies. More details about this control can be found in Appendix D. While this does not pose particular challenges for the simulation in this grid and under this fault, it highlights a vulnerability of the system. The control strategy for an island grid should be better coordinated and would show greater resilience with grid-forming power production.

The simulation also shows the gas turbines operating at very low active power values, lower than the capabilities of the gas turbines used in the model. Thus, future capabilities of GTs are also implied in the simulations, which would allow GTs to run at lower p.u. values than intended.

5.4 Limitations and Uncertainties

The results obtained from the simulations have not been explicitly validated, as simulations with our specific parameters do not exist. While the technical accuracy of the created model could be validated against a real grid model, this has not been possible in this thesis as grid owners are legally restricted from sharing detailed grid data. However, the models and templates used are based on real parameter sets from Siemens Energy and validated models from the DIgSILENT library. Additionally, the phenomena observed in the simulations aligned with general theoretical expectations. For example, step changes produced the expected frequency dips. Similarly, typical results were observed when simulating short-circuits and subsequently clearing the faults.

6 Conclusion and Future Work

In this chapter, reflections of the combined results from the simulations are presented, and connected to the research objectives of the thesis. Additionally, future research topics are presented.

6.1 Summary of Findings

This thesis aimed to evaluate how gas turbines could provide system stability in a grid with a high share of wind power through dynamic RMS simulations. The focus has been on frequency stability during short-circuit faults and island operation.

Gas turbines have shown to be excellent resources with great potential to provide system stability. They are fast to start up and have the ability to quickly generate power with good ramping capabilities. Furthermore, the strength of gas turbines can really be seen when the system is subjected to disturbances.

When running the system with a weak link to an infinite bus and subjecting it to a three-phase short-circuit, followed by subsequent clearing, it is seen that gas turbines help provide stability. Seeing as GTs have good inertia, they are a good resource in a system that otherwise would not have any inertia. It can be seen in the simulation results that while gas turbines provide some sort of stability and power generation during the fault, increasing the number of gas turbines may lead to vulnerabilities, which may cause the gas turbines to slip out of synchronism relative to the system frequency of the infinite bus. However, since all cases remain synchronized at fault clearing times well above the 200 ms mandated by EIFS:2018, adding a large number of gas turbines will not necessarily lead to system instability. Nevertheless, the rotor angle stability should be carefully evaluated, and the risk of adding a large number of GTs without additional grid support can have severe consequences.

The purpose of the simulation involving a grid disconnection, BESS support, and gas turbine activation was primarily to demonstrate the feasibility of such a transition. The results showed that the system could successfully shift from being connected to a larger grid, to operating solely on the BESS and the wind power plant, followed by gas turbine connection and eventual disconnection of the BESS.

The simulations demonstrate the necessity of having a grid-forming BESS. Since the wind farm is grid-following, it would be incapable of upholding system stability on its own. The simulations also show the need for efficient control strategies with a higher complexity than in these simulations. For instance, when connecting and disconnecting the BESS and GT, operations must be synchronized and power production should start ramping after the connection - else one might see unstable oscillatory behavior - as can be seen in the simulations run.

Running the subtransmission grid in island configuration with the wind park shows good

results. For static simulations, very little power is needed from the gas turbines to cover the power demand for the load points. When running dynamic simulations and simulating step losses of wind turbines, GTs are pivotal in maintaining stability. It is seen that more GTs in a system lead to lower RoCoF values, higher frequency nadir and a higher QSS. The results show that for all the tried simulations, one gas turbine with the wind plant will not generate results that converge. This may be due to the share of grid-forming power production being too low.

Furthermore, it is seen that for the cases with 40 lost wind turbines, 57% of the wind turbines, the gas turbines could not uphold a frequency nadir above 47.5 Hz. This was also the case when doubling the inertia of the GTs. This is significant as 47.5 Hz indicates a hard limit of what the frequency of a system could lie beneath, in line with earlier interpretation of grid requirements from RfG.

Doubling the inertia for the gas turbines show promising results for handling large step disturbances in the grid, providing more time for the primary frequency to handle the frequency deviation. This finding shows that having a smaller number of units, but with high inertia, can be one solution to handle grids with high amounts of inverter-based resources.

The future capability of FFR shows great potential for reducing the nadir during an under-frequency event. This could further be improved by tweaking the control design to obtain a fast response yet stable response. The question arises whether it is suitable for this ancillary service to be provided by gas turbines, or if it should be provided by batteries instead. Nevertheless, incorporating a synthetic inertia response based on a frequency deviation and the magnitude of the RoCoF seems like a promising strategy for GTs to effectively handle underfrequency events.

When simulations of overfrequency events are run in an island grid, the system generally performs well. The results show that the WTs respond more rapidly than GTs, due to faster controls when the frequency is outside of the deadband. However, the simulations also reveal certain vulnerabilities in the system related to overfrequency protection. Since the WTs are purely grid-following and lack droop control, their response is governed by a linear overfrequency protection mechanism. This type of response, without the stabilizing effect of droop control, can become a weakness in islanded operation.

The results from the thesis show that gas turbines can play a key role in a future sub-transmission grid, providing stability through various ancillary services. Due to their quick start-up times, excellent ramping capabilities and the inherent benefits in a power system that synchronous generators provide, they make valuable assets in power systems with large amounts of inverter-based renewable generation.

6.2 Future Research Directions

One major part of stability analysis is adequate voltage in the system. This part has been excluded in this thesis due to limitations in time, but would be a natural continuation of

this thesis and would add great value. As discussed in the introduction, voltage is a local phenomenon, and therefore expanding the model to include larger parts of western Sweden. Because of Sweden's large production in the north, and most of the consumption in the south, injecting reactive power at key locations to uphold voltage is of great importance.

Another part to investigate further is to model battery support during the step loss of generation in island operation. Since the BESS is modeled during the transition phase, being able to utilize them as frequency support, especially for FFR and FCR-D is a great opportunity to create a more resilient grid. Here, a control strategy to activate the battery based on a frequency deviation outside of the dead-band would be a good way of implementing the BESS, as this is the way the ancillary market works.

Furthermore, what needs to be further investigated is how the control of the system should be managed. While a larger interconnected grid has a market-oriented approach with bids for power production and ancillary services, subtransmission grids do not have the same functionality, especially in the cases of contingencies outlined in the report. A better coordination of power production resources could therefore be further studied.

The investigation would further benefit from investigating how dynamic load phenomena affect the system. Currently, the loads in the model are static and do not vary. In reality, for motor loads such as fans and pumps, the power consumption varies with the electrical frequency. For instance, the active power drawn by electric motors typically decreases as the frequency drops. Including such dynamic behavior in the model would lead to more realistic results.

A techno-economic analysis could also be conducted to assess the cost and value of integrating various solutions included in the simulations. Furthermore, it would be valuable to analyze how much of these costs could be recovered through electricity production and participation in the ancillary services market.

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Appendix

A Creating the model in PowerFactory

In this section, a detailed description is provided of how each component of the model of the test system "Stenungsund" was created in DIgSILENT PowerFactory.

A.1 Wind Power Plant

The wind power plant is modeled by using a template in PowerFactory. This was simply inserted through the *Drawing Tools* menu by going into *templates* → *DIgSILENT Library Templates* → *Wind Turbines* and selecting the fully rated converter 5 MW type. The template was then connected to the Onshore WPP bus. This was repeated five times to be able to quickly trip a certain number of wind turbines.

The rated power for the connection of the plant is 350 MW, so under *basic data* the amount under "parallel units" was changed to 10 units for the four smaller branches and 30 units for the main branch. This results in 70 units in total with a combined rated power of 350 MW. In the technical reference "DIgSILENT Fully Rated Converter Wind Turbine Templates", it is stated that the PQ LV element's power rating must match the nominal active power of the plant. This was performed by going into *model* → *PQ LV* and changing the power rating to 50 MVA, respectively 150 MVA.

A.2 Gas turbine

The first step of adding a gas turbine model was to copy a gas power plant template into the Stenungsund network. This was performed by opening *Data Manager* → *DIgSILENT Library* → *Templates*, copy the gas power plant and past it in the Stenungsund network. Simultaneously, under *Dynamic Models* → *IEEE* → *Excitation Systems*, the exc_AC11C model was copied, along with the governor gov_GGOV1 from *Governors and Turbines/Engines* and the vtc_IEEE_1 from *Voltage Transducer and Compensation*. Lastly, under *Equipment Types* → *Synchronous Machines* the 46 MVA gas turbine was copied and pasted into the Stenungsund network.

The next step was to open the synchronous generator and configure the control systems under *Basic Data* → *Plant Model*. The copied governor, excitation system, and voltage transducer and compensation model from the Stenungsund library were assigned to their respective slots. Finally, the parameters for each control system were adjusted using parameter sets provided by Siemens Energy. Lastly, the rated power, inertia and capability diagram were updated to represent a Siemens SGT-800.

B Implementing Secondary Frequency Control in DIgSILENT PowerFactory

In this section, a detailed description is provided of how the secondary frequency control or automatic generation control (AGC) was implemented on the gas turbines in the test system "Stenungsund" in PowerFactory. There are three main parts needed to create the simplified AGC model in PowerFactory. A *composite model frame*, *block definitions of the AGC controller*, and a *composite model*. The following steps outline the process of implementing AGC in PowerFactory:

Step 1: An AGC composite frame was created by selecting *insert* → *dynamic model* → *composite model frame*. The frame was named "AGC frame", with internal variable *fmeas* (for frequency measurement). Inside the block diagram, two slots were created, "Frequency measurement" and "AGC controller" with the signal *fmeas* connecting them, see Figure 36 below.

AGC frame:

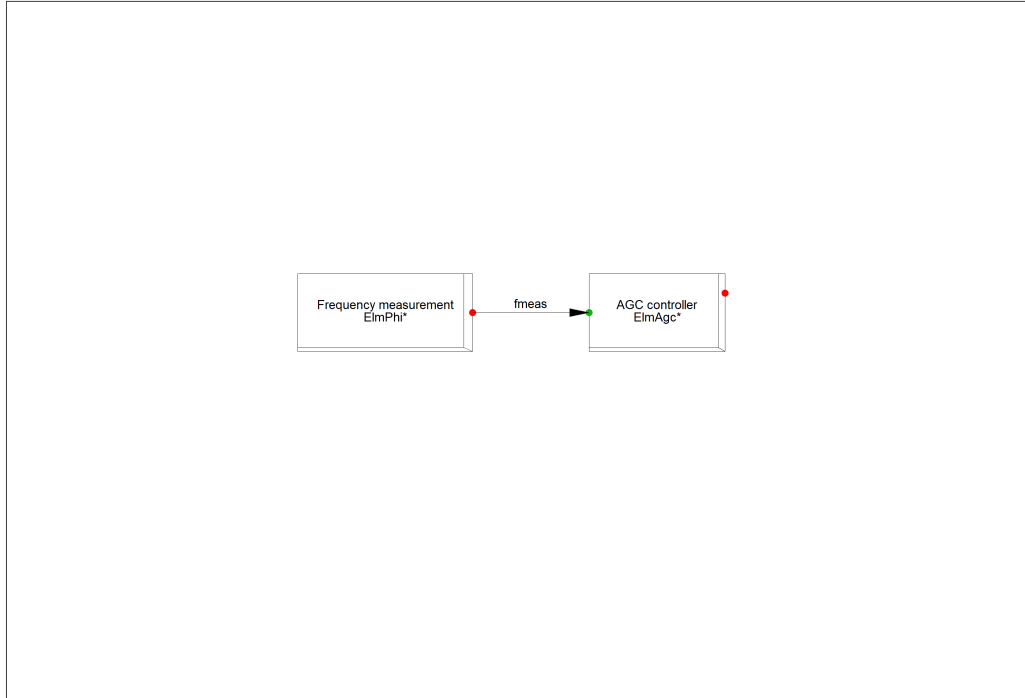


Figure 36: Block diagram of the AGC frame

Step 2: Four macros were created to be used later in the AGC controller, a constant, a PI-controller, a time delay and Logic gate. By going to *data manager* → *library* (within the project) → *dynamic models*. Then, by pressing *right-click* → *new* → *composite model* → *DSL model type*. The model type is named "constant" and the box macro was selected. The output signal is *yo* and the parameter

is C . In equations, the following code was inserted:

$$y_o = C$$

For the PI-controller, the same steps were performed to reach the *DSL model type*. The model was named "Kp + Ki/s" and the box macro was selected. The output is y_o , input is y_i , state variable is x and parameters are K_p , K_i . In equations, the following code was inserted:

$$\begin{aligned} x. &= K_i * y_i \\ y_o &= K_p * y_i + x \end{aligned}$$

For the time delay, the same steps were performed to reach the *DSL model type*. The model was named "Time delay" and the box macro was selected. The output is y_o , input is y_i and parameter is T_{delay} . In equations, the following code was inserted:

$$\begin{aligned} y_o &= \text{delay}(y_i, T_{delay}) \\ &\text{!delays the signal by } T_{delay} \end{aligned}$$

For the Logic controller, the same steps were performed to reach the *DSL model type*. The model was named "Logic controller" and the box macro was selected. The output is y_o , inputs are y_{i1}, y_{i2} . In equations, the following code was inserted:

$$\begin{aligned} y_o &= \text{select}(\text{abs}(y_{i2}) > 0.00001, y_{i1}, 0) \\ &\text{!if } y_{i2} \text{ differs from } 0.00001, y_{i1} \text{ will be output} \end{aligned}$$

Note: Since small frequency deviations occur at the start of the transient simulation, setting ($\text{abs}(y_{i2}) > 0$) would result in the secondary frequency control triggering 30 s after the simulation starts, rather than 30 s after a notable frequency deviation. However, by using the finite number 0.00001 the secondary frequency control stops when the frequency is 1 ± 0.00001 p.u. resulting in a small stationary error.

Step 3: The next step was creating the AGC controller block diagram. A *DSL model type* was created by selecting *insert* $\rightarrow$ *dynamic model* $\rightarrow$ *DSL model type*. The model type was named "AGC controller" with output signal P_{agc} , and input signal f_{meas} . The state variable is x and the parameters included are $K_p, K_i, f_{refpu}, T_{delay}$. In equations, the following code was inserted:

$$\begin{aligned} \text{inc}(x) &= 0 \\ \text{vardef}(K_p) &= \text{'p.u.'} ; \text{'Proportional gain of PI-controller'} \\ \text{vardef}(K_i) &= \text{'s-1'} ; \text{'Integral gain of PI-controller'} \\ \text{vardef}(f_{refpu}) &= \text{'p.u.'} ; \text{'Frequency setpoint'} \\ \text{vardef}(T_{delay}) &= \text{'s'} ; \text{'Time delay'} \end{aligned}$$

Then, the blocks are inserted as in the figure below. In the type for the blocks, the macros that were just created are chosen. In the constant block, the parameter C is changed to f_{refpu} . In the summation block, the box for inverting the signal *input 0* (f_{meas}) is selected. Lastly, the names for the signals are changed for clarity. The result is the block diagram shown in Figure 37.

AGC controller:

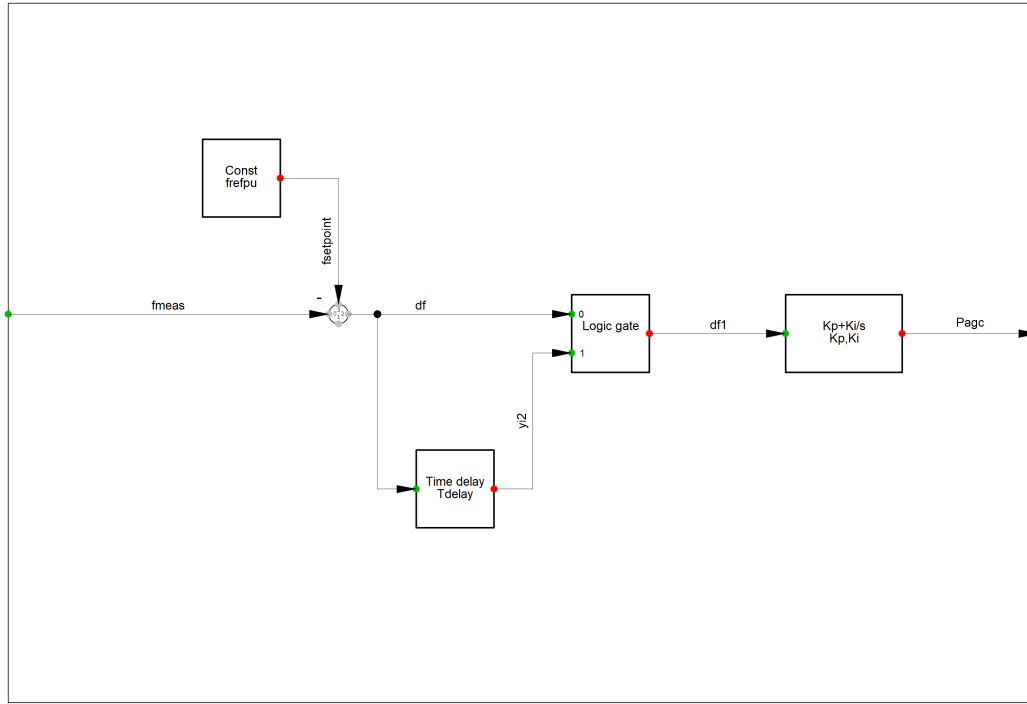


Figure 37: Block diagram of the AGC controller with time delay

Step 4: The next step was creating a *composite model* for the AGC by going to *Data manager* → *network model* (in the project). Then by selecting *new object* in the menu bar → *Dynamic model* was chosen with element *composite model*. In the frame slot *AGC frame* was chosen. In the slot AGC controller, by right-clicking and choosing *select element/type*, then by clicking on the *AGC model* and choosing *new object* → *DSL model* (ElmDsl) and selecting the *AGC controller* from dynamic models in the library, the AGC controller was implemented. The parameters were initially set to $frefpu = 1$, $Kp = 3$, $Ki = 2$. In the frequency measurement slot, by right-clicking and choosing *select element/type* then, by selecting *new object* and choosing *element Phase Measurement Device PLL-Type* (ElmPhi_pll) and selecting the main bus as the measurement point, the frequency measurement was implemented.

Step 5: The next step of implementing the AGC is to add the signal to the synchronous generator. This was done by double-clicking on the synchronous generator, going to *plant model* (where in this case, the gas turbine power plant from DIGSILENT library is copied and used in the system) → *Governor and turbine/engine*. Inside the gas turbine governor a signal "ureg" was implemented in the block diagram by pressing *show graphic*, then adding a signal to the summation point with Pref, as depicted in Figure 38 below. The next step is initializing the ureg signal by editing the GGOV1 type, pressing equations and adding:

$$\text{inc}(\text{ureg}) = 0$$

Lastly, by going to the advanced 3 tab inside the gas turbine governor model, pressing *interface update* and adding the *AGC controller* to the element slot, and typing *Page* in the signal name.

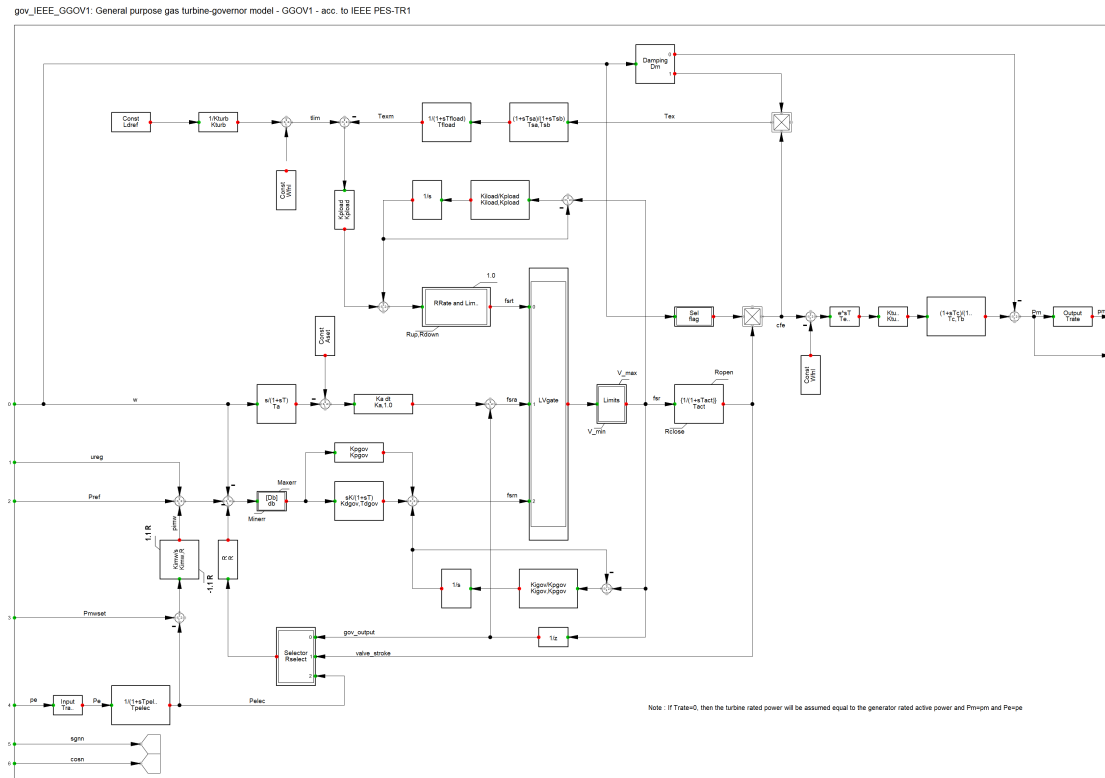


Figure 38: Block diagram of the gas turbine governor with the added signal $ureg$

Step 6: The last step is performing a RMS simulation with an active power step in the system to observe the secondary frequency control. By changing the parameters Kp and Ki inside *AGC controller* under *AGC model*, the response can be tweaked to satisfactory results.

C Implementing FFR for the gas turbine in PowerFactory

In this section, a detailed description is provided of how the FFR response - also referred to as synthetic inertia - is implemented for the gas turbines in the test system "Stenungsund" in PowerFactory.

The process is similar to the implementation of the AGC. There are three main parts needed to create the FFR control system, which is then connected to the gas turbine governor to send a step response to the reference power value P_{ref} . A *composite model frame*, *block definitions of the FFR controller*, and a *composite model*. The following steps outline the process of implementing the FFR control:

Step 1: An FFR composite frame was created by selecting *insert* $\rightarrow$ *dynamic model* $\rightarrow$ *composite model frame*. The frame was named "Synthetic inertia frame", with internal variable $fmeas$ (for frequency measurement). Inside the block diagram, two slots were created, "Frequency measurement" and "Synthetic inertia" with the signal $fmeas$ connecting them, see Figure 39.

Synthetic inertia frame:

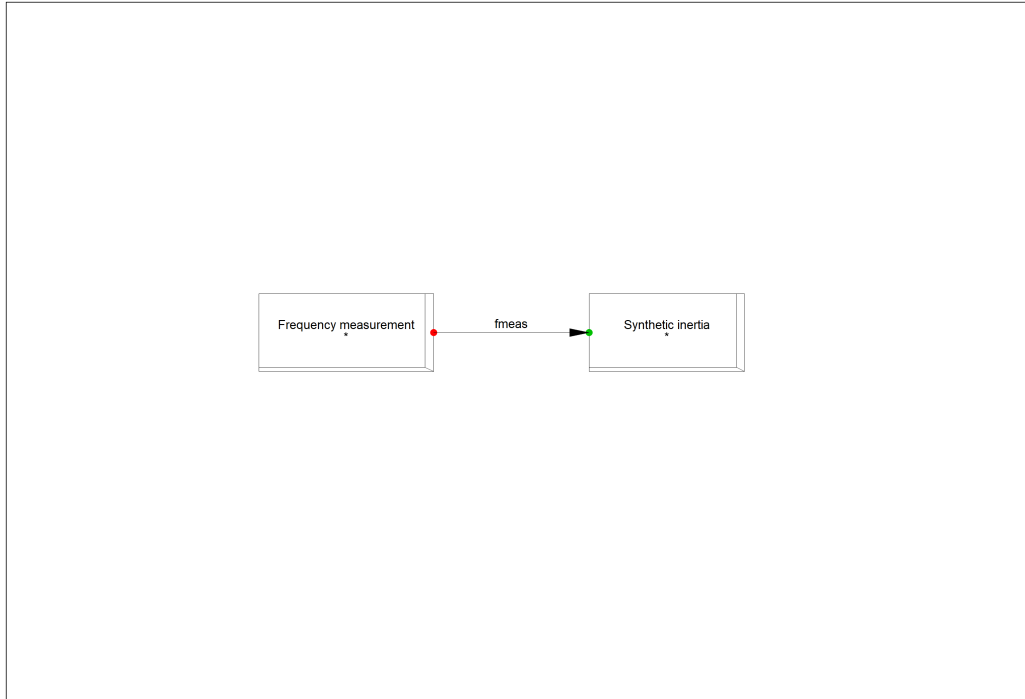


Figure 39: Block diagram of the Synthetic inertia frame

Step 2: The next step was creating the synthetic inertia controller block diagram. A *DSL model type* was created by selecting *insert* $\rightarrow$ *dynamic model* $\rightarrow$ *DSL model type*. The model type was named "Synthetic inertia" with output signal P_{ffr} , and input signal $fmeas$. The state variable is x

and the parameters included are $tduration$, $reset_FFR$, $factivation$, $Pffr_setpoint$. In equations, the following code was inserted:

```

inc(x) = 0
inc(init) = 0
inc(activate) = 0
inc(deactivate) = 0
inc(reset_init) = 0
vardef(Pffr_setpoint) = 'MW' ; 'Power output for synthetic inertia'
vardef(tduration) = 's' ; 'Duration of synthetic inertia'
vardef(reset_FFR) = 's' ; 'Time until FFR can be supplied again'
vardef(factivation) = 'Hz' ; 'Frequency activation setpoint'

```

Then, blocks were inserted as in the Figure 40. In the type for the block "Const", the macro Const created for the AGC was re-used. The parameter C was changed to $factivation$. The creation of the other macros used is described in the step 3. In the summation block, the box for inverting the signal *input 3* ($factivation$) was selected.

Synthetic inertia:

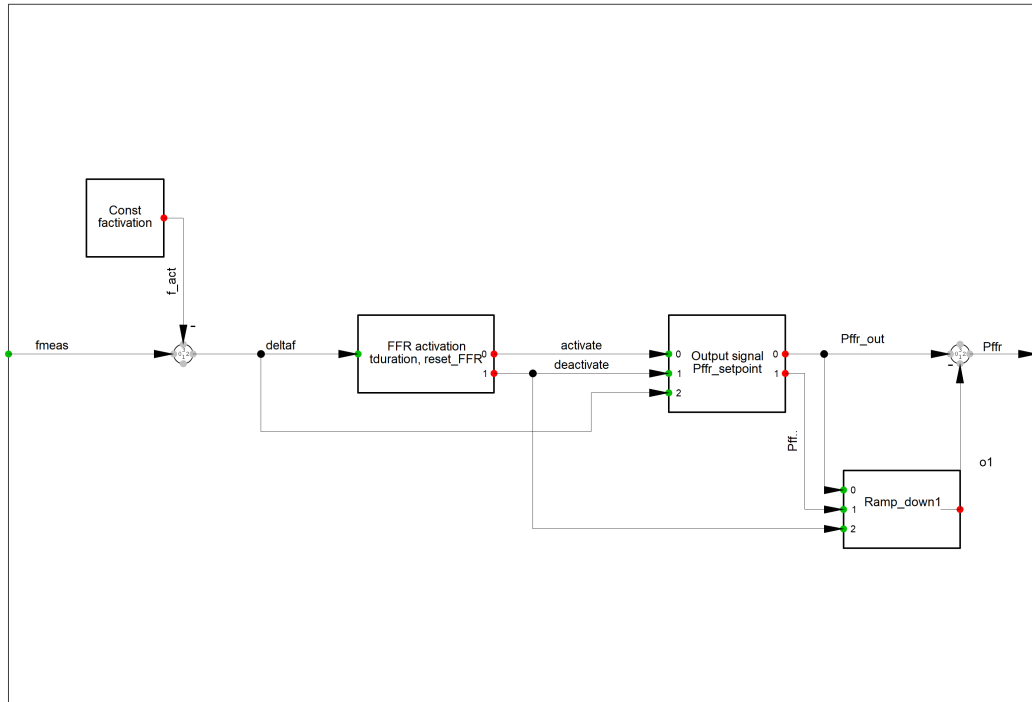


Figure 40: Block diagram of the Synthetic inertia controller

Step 3: The next step was creating each macro to be used in the controller. For the FFR activation block, *new project type* was selected. The model type is named "FFR activation" and the box macro was selected. The output signals are *activate, deactivate*, the input signal is *deltaf*, the parameters are *tduration, reset_FFR* and internal variables are *init, reset_init*. In equations, the following code was inserted:

```
!Both init and activate are used since DSL does not like self-referencing of variables
!If the frequency dips below the threshold factivation
!and FFR is not already activated: init = 1
init = flipflop(deltaf < 0 .and. delay(activate, 1e - 4) = 0, reset_init = 1))
activate = select(init = 1, 1, 0)
deactivate = delay(select(activate = 1, 1, 0), tduration)
reset_init = delay(select(init = 1, 1, 0), reset_FFR)
```

For the "Output signal" block, *new project type* was selected. The model type is named "Output signal" and the box macro was selected. The output signals are *Pffr_out, Pffr_pu*, the input signal are *activate, deactivate*, the parameters are *Pffr_setpoint*. The input signal *deltaf* was used for the response proportional to the frequency deviation, but not in the step FFR response. In equations, the following code was inserted:

```
Pffr_pu = Pffr_setpoint/62 !Convert to p.u.
Pffr_out = select(activate = 1, Pffr_pu, 0)
!y = lim(Pffr_pu*(-df*5),0,Pffr_pu)
```

The ramp down block is a PI-controller which sends a negative signal to the summation block that starts ramping up to the magnitude of *Pffr_out* when *deactivated = 1*. For the ramp down block, *new project type* was selected. The model type is named "ramp down" and the box macro was selected. The output signals is *yo*, the input signal are *Pffr_out, deactivate, Pffr_pu*, the state variable is *x*. In equations, the following code was inserted:

```
! Proportional Integral controller
Kp = 0.02
Ki = 0.04
x.=Ki*yi
yo = select(deactivate = 1, lim(Kp*yi+x, 0, yi), 0)
```

Lastly, the names of the signals were changed for clarity. The result is the block diagram shown in Figure 40.

Step 4: The next step was creating a *composite model* for the FFR by going to *Data manager* → *network model* (in the project). Then by selecting *new object* in the menu bar → *Dynamic model* was chosen with element *composite model*. In the frame slot *Synthetic inertia frame* was chosen. In the slot *Synthetic inertia*, by right-clicking and choosing *select element/type*, then by clicking on the composite model *Synthetic inertia* and choosing *new object* → *DSL model* (ElmDsl) and selecting the *Synthetic inertia* from dynamic models in the library, the FFR was implemented. The parameters were initially set to $Kp = 0.02$, $Ki = 0.04$. In the frequency measurement slot, by right-clicking and choosing *select element/type* then, by selecting *new object* and choosing *element*

Phase Measurement Device PLL-Type (ElmPhi_pll) and selecting the SG bus (closest to the gas turbine) as the measurement point, the frequency measurement was implemented.

Step 5: The next step of implementing the FFR is to add the signal to the synchronous generator. This was done by double-clicking on the synchronous generator, going to *plant model* → *Governor and turbine/engine*. Inside the gas turbine governor, a signal "Pffr" was implemented in the block diagram by pressing *show graphic*, then adding a signal to the summation point with ureg, as depicted in figure below. The next step is initializing the Pffr signal by editing the GGOV1 type, pressing equations and adding:

$$\text{inc}(\text{Pffr}) = 0$$

Lastly, by going to the advanced 3 tab inside the gas turbine governor model, pressing *interface update* and adding the *Synthetic inertia* to the element slot, and typing *Pffr* in the signal name.

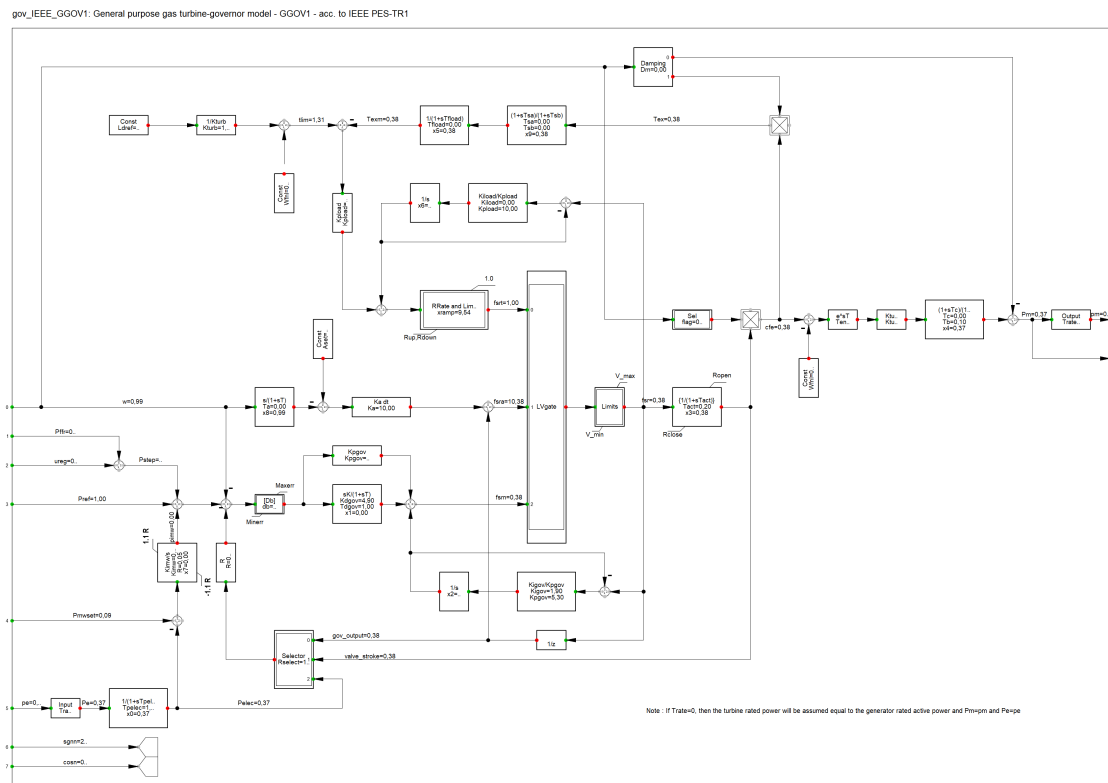


Figure 41: Block diagram of the gas turbine governor with the added Pffr signal

Step 6: The last step is performing an RMS simulation with an active power step in the system to observe the FFR. By changing the parameters Kp and Ki in the ramp down block, the deactivation of the response can be adjusted to satisfactory results.

D Model for Overfrequency Protection in Wind Turbine Model

This section displays briefly the control scheme of the overfrequency protection in the WTs. The model is strictly grid-following and does not have any droop control. Despite this, the wind turbine may handle overfrequencies with the built-in function for overfrequency protection.

The model can be seen in Figure 42. The operation is relatively simple. The frequency is measured at the bus of the WT. This signal is then sent through a low-pass filter and then to the block *OverfreqPowerReduction*. This block takes the signal and then applies a linear response with a set gradient - provided the frequency is outside the dead band of normal operations. The signal is then sent to a gradient limiter and then out as the signal *pref*.



Figure 42: Control scheme for overfrequency protection in WT