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WIND TURBINE RESPONSE FOR GRID STABILITY

Thesis for the degree of Master of Science (Technology)

Examiners: Professor Olli Pyrhönen
Professor Pasi Peltoniemi

Abstract

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Master's Thesis
Lappeenranta 2018
85 pages, 38 figures, 19 tables
Examiners: Professor Olli Pyrhönen and Professor Pasi Peltoniemi

Keywords: Wind turbine, synthetic inertia, grid stability, frequency control, electricity system inertia

Electricity grids are evolving to integrate increasing amounts of renewable generating sources. Wind and solar generation, while benefiting the system with a smaller footprint and starting to outperform other sources economically, also introduce challenges to grid stability and frequency control, as they are not directly connected to the grid, thus not providing inertia against frequency deviations from disturbances.

This work focused on investigating the potential of utilizing synthetic inertia from wind turbines in order to address this reduced intrinsic inertia of future electrical systems. The amount of available mechanical energy stored on typical wind turbines was evaluated, and a control scheme to release this energy during grid faults was proposed. A model to validate this approach was developed and simulated in Matlab with the power systems package.

The simulations showed that grid frequency response after a disturbance deteriorates significantly in high wind penetration scenarios while not using synthetic inertia from wind turbines, and frequency deviation was three times as severe as in a traditional system, for a scenario with 50% wind penetration. Nonetheless, with employment of synthetic inertia and a suitable control strategy, the maximum grid frequency deviation was restrained to the same level as conventional electricity systems, for wind penetration up to 50%. These results demonstrate that synthetic inertia is an effective solution to improve grid frequency control in future grids with high share of wind turbine generation.

Acknowledgements

I would like to thank my supervisors, Professor Olli Pyrhönen and Professor Pasi Peltoniemi, and post-doctoral researcher Katja Hynynen for their guidance, support and patience throughout this process. Our meetings provided the insights necessary to surpass the obstacles I met during the elaboration of this thesis, and our conversations about future electricity systems were really inspiring.

I would also like to express my sincere gratitude to my friends and family for their support, and specially to my wife, Mariana, for her unconditional affection and patience throughout this challenging moment in my life.

Thanks.

Pedro Guimarães Giorni
April 2018
Sorsakoski, Finland

Contents

Nomenclature

Latin alphabet

A	Area swept by a wind turbine rotor blades
C_P	Power coefficient
D	Damping constant
f	grid frequency
F_{HP}	Fraction of power generated by steam turbine high pressure section
G	Hydro power plant gate opening
H	Inertia constant
J	Inertia
K_I	Integral gain
K_P	Proportional gain
K_{sh}	Shaft stiffness constant
P	Real power
p	Number of generator field poles
R	Droop
r	Wind turbine rotor radius with blades
R_P	Hydroelectric turbine permanent speed droop
R_T	Hydroelectric turbine transient speed droop
R_{wind}	Power controller grid feedback gain
S	Apparent power
T	Torque
t	Time
T_{CH}	Volume charging time constant
T_{RH}	Reheater time constant
T_G	Governor time constant
T_R	Reset time
T_W	Water starting time
V	Wind speed
Y	gate or valve reference

Greek alphabet

β	Blade pitch angle
γ	angular displacement between two ends of a shaft
λ	Tip-speed ratio
ω	Angular velocity
π	Archimedes' constant
ρ	Air mass density

Superscripts

$\bar{\ }$	Per unit

Subscripts

0	Rated
$base$	Base value for per unit
$Comp$	Pitch compensation
e	Electrical
g	Generation
gen	Generator
hy	Hydro
l	Load
m	Mechanical
mg	Mechanical, at generator side
mr	Mechanical, at rotor side (hub and blades)
PC	Power controller
r	Rotor
REF	Reference

sys	System
th	Thermal
wt	Wind turbine

Abbreviations

AC	Alternating Current
DC	Direct Current
DFIG	Doubly-fed induction generator
ENTSO-E	European Network of Transmission System Operators for Electricity
EU	European Union
Hy	Hydro
PI	Proportional-integral (controller)
pos	Valve position
p.u.	Per unit
PV	Photovoltaic
Th	Thermal
TSO	Transmission System Operator
UCTE	Union for the Co-ordination of the Transmission of Electricity
UTC	Coordinated Universal Time
wi	Wind

1 Introduction

The share of renewable electricity generation in power systems around the world is growing fast [1, 2]. The amount of onshore wind capacity is expected to double from 2013 to 2020, while solar PV capacity is predicted triple and offshore wind to quadruple during the same period [3]. Several factors account for that, from increased concerns over carbon emissions and global warming to the dramatic drop in installation costs for wind turbines and solar photovoltaic panels, promoted by technological advances, gains in scale production and improvement of financing lines [4]. The global weighted average cost of electricity from new onshore wind farms in 2015 declined more than 30% compared to 2008, and from utility scale solar PV, the reduction was close to 80% [3]. This shift in the electricity matrix brings significant benefits, from increased diversity in energy sources providing strategic alternatives for electricity markets, reduction of demand in energy imports in several countries, as these new technologies are installed locally, deployment of generating sources closer to consumers improving overall system efficiency, reduction of the complexity of supply chain with the elimination of fuel-dependency provided by these energy sources, making long-term energy prices more stable, to the reduction in life-cycle greenhouse gas emissions and environmental footprint, which are concentrated on the manufacturing and installation phases and emissions in particular are absent during the operational phase.

Nonetheless, the integration of these non-conventional electricity sources to the existing power grids has its challenges. The first is intermittency of supply. Solar power is readily available during daytime, but unavailable at night, and seasonal variations between summer and winter are significant at higher latitudes of the globe. Wind power can fluctuate significantly throughout a single day, and might have some seasonal variability too. This characteristic makes the operation of systems with significant share of both wind and solar generation more dependent on good weather forecast and might implicate in the need of increased energy reserves to cover for the unavailability periods of these sources. Besides, the increased share of both these technologies reduce overall electricity system inertia, as solar PV panels don't have the rotating masses of conventional thermal and hydro generators, and wind turbines, while being rotating electrical machines at their core, are connected partially or completely asynchronously to the grid, through frequency converters [5]. This last characteristic impacts system stability, as it changes the grid instantaneous response to load and generation fluctuations, and may demand additional backup power reserve dedicated exclusively for frequency control, or call for new strategies to handle grid faults.

New strategies can be implemented to address the lower system inertia characteristics of electrical systems with high share of renewable sources. The intermittent characteristic of these systems already requires special attention related to operational flexibility of loads and other generating sources, dimensioning of power reserves and potentially the inclusion of new energy storage systems to the grid. The idea of utilizing loads in a more active way to improve power systems management is not new [6], and the current spread of smart grids and open electricity markets makes this implementation feasible [7–15]. The advent and further popularization of electric cars might enable their owners to play a role as energy storage providers [7, 10, 13, 16]. Adoption of battery banks or integrated power-to-fuels convertion by intermittent electricity generators to increase their flexibility at the electricity market by allowing them to store energy when the prices are low and sell this reserve in more profitable ways also enables these generators to take part in power balancing markets [17, 18]. The transmission system operator might also integrate to the system high power, low energy, fast response reserves, such as directly online flywheels [19, 20]. Solar photovoltaic arrays can reduce power for frequency down-regulation, and could feasibly, under some circumstances, be operated in a deloaded setting to provide full frequency regulation [21]. Finally, wind turbines can contribute in different ways in frequency control, their inertial potential can be used, they can provide droop control and contribute in primary control, by employment of appropriate control schemes and deloading [21–28].

The main objective of this work is to investigate the potential of wind turbines to improve grid frequency stability by utilization of synthetic inertial response from these turbines during system faults. The study is focused on the mechanical inertial characteristics of wind turbines, and control or system strategies to make this implementation feasible. A model of a grid with conventional generation and wind turbines fitted with synthetic inertia control is presented, and grid frequency control performance during a fault is simulated for several different scenarios.

The thesis is organized in the following fashion:

Chapter 1, Introduction, presents the current scenario of world energy matrix change towards renewable sources. Particularly, how these changes impact electricity system characteristics, such as generation availability and grid inertia, some challenges emerging from theses changes, pertaining electricity grid stability and operational safety, and emerging technologies that help handle these new challenges, of which wind turbine inertial response is of particular interest.

Chapter 2, System stability and the role of inertial machines, provides the background for understanding system dynamics regarding power balance between generators and loads. It evidences the relevance of the characteristic inertia provided by conventional generation technologies for grid stability, and provides the theoretical background to explain how a reduction of such characteristic, as resulting from employment of new renewable generation technologies, impacts system performance.

Chapter 3, Frequency control, discusses the active strategies and requirements utilized by transmission systems operators to keep grid stability, beyond relying on the intrinsic characteristics of the system. It presents typical control architectures and focuses on grids that currently handle a significant share of wind generation. This context is relevant to understand how new technologies providing support in grid frequency control can interact with currently available control schemes and regulations.

Chapter 4, Strategies for frequency control on systems with high share of intermittent generation, briefly discusses the main arising technologies that can improve future grid operation safety and frequency stability, providing ancillary services to future grids. In this context, as wind turbine penetration increases, the potential use of some of their features, and specially synthetic inertia emulation, is of strategic relevance.

Chapter 5, Wind turbines and inertial potential, presents the overview of wind turbine technology, providing the technical background for investigating wind turbine synthetic inertia potential. It focuses on the control systems and inertial characteristics of available wind turbines, as the deployment of synthetic inertia is dependent on suitable control strategies, and its magnitude is limited by the mechanical energy stored in the wind turbine rotating masses.

Chapter 6, Simulations, showcases the potential of wind turbine synthetic inertia contribution on grid frequency control. It starts by building a simplified grid model, focused on the power fluctuation impact on grid frequency and its feedback response provided by system inertial characteristics, as discussed in Chapter 2, and active frequency control, by deployment of droop control and reserves, from Chapter 3. Wind turbine synthetic inertia is selected from the technology options presented in Chapter 4 as a means to improve grid frequency control, and its model, based on the overview from Chapter 5, comprising wind turbine mechanical representation, to account for stored kinetic energy, and a suitable control scheme, is proposed. Simulations are carried out for different scenarios, starting from a simplified version of the Finnish national grid, which is later modified by increasing the share of wind generation, and fitted with synthetic inertia emulation from wind turbines. Finally, different strategies to utilize wind turbine synthetic inertia are explored and evaluated.

2 System stability and the role of inertial machines

An electricity grid is a connected network of generators, consumers and system auxiliary devices. The network itself is composed of transmission lines, distribution feeders, power transformers and protection devices. The generators main responsibility is to supply the consumers with the power demanded. Generators and auxiliary devices share the responsibility of grid stability, voltage regulation and energy safety. Auxiliary devices can be impedance compensation equipment, energy storage devices, among others.

Electricity systems work by dynamic exchanging power between power sources and loads, interconnected by grids currently operating in AC configuration at a set reference frequency. They must have instantaneous active power consumed and generated in equilibrium at every instant, otherwise there will be power deviation [29]. When power deviation in the grid occurs, grid frequency is affected. The disconnection of loads results in surplus power injected on the grid and this provokes an increase in system frequency. Conversely, the loss of generation creates a net load deficit, and decreases system frequency. The stabilization of grid frequency plays a critical role in electrical systems control to ensure safe and steady operation.

Historically, generators present in conventional grids are typically large rotating electrical machines with significant mechanical inertia, storing kinetic energy while in operation. This kinetic energy is discharged whenever there is a negative power imbalance, or increased when the power imbalance is positive, within the technical limits of each machine. While the total energy stored in this fashion is not significant to withstand long periods of grid disturbance, it plays a significant role at the initial instants during system fluctuations, limiting the rate of variation in the grid frequency and providing a window of time for system control mechanisms, namely primary, secondary and tertiary frequency controls, to actuate restoring stability. Solar PV has no rotating masses, and therefore no inertial characteristics to contribute to the system. Wind turbines, while being rotating electrical machines, are of lower bulk than conventional thermal or hydro units, and almost always are not directly connected to the grid, having some or all power delivered through a frequency converter. Nonetheless, wind turbine rotors are rotating inertial masses, and finding means to make use of this stored kinectic energy might have a positive impact on overall grid performance and stability [5, 30].

2.1 The swing equation

During any instant, the total amount of power generated in an electric grid must equal the total amount of power consumed by all the loads connected to the grid plus the losses of the transmission and distribution systems and power consumed by auxiliary devices [5]. Any deviation in this balance is reflected in a change in grid frequency. The generator mechanical angular velocity deviation due to unbalance between the mechanical torque provided by a turbine and the electrical torque demanded by the load is given by [29]:

$$T_{m,gen} - T_{e,gen} = J_{gen}\frac{\mathrm{d}\omega_m}{\mathrm{dt}} \tag{2.1}$$

$T_{m,gen}$ and $T_{e,gen}$ are the mechanical and electromagnetic torques of a single generator, respectively, J_{gen} is the combined inertia of the turbine and generator and ω_m is the rotor angular velocity. For a single generator, a commonly defined parameter that encompasses the inertia, and represents a rating between kinetic energy stored in a rotating electrical machine shaft and its power rating is the inertia constant H, defined in per unit as:

$$H_{gen} = \frac{1}{2}\frac{J_{gen} \times \omega_{m,0}^2}{S_{base}} \tag{2.2}$$

J_{gen} is the inertia an individual rotating machine, S_{base} is the apparent power for system per unit calculations and $\omega_{m,0}$ is rated angular velocity. Combining equations (2.1) and (2.2), by substituting J_{gen} results in:

$$T_{m,gen} - T_{e,gen} = \frac{2H_{gen}}{\omega_{m,0}^2} S_{base} \frac{\mathrm{d}\omega_m}{\mathrm{d}t} \tag{2.3}$$

Rearranging the terms in (2.3):

$$\frac{T_{m,gen} - T_{e,gen}}{S_{base}/\omega_{m,0}} = 2H \frac{\mathrm{d}}{\mathrm{d}t}\left(\frac{\omega_m}{\omega_{m,0}}\right) \tag{2.4}$$

Taking T_{base} as the base torque, and noting that $T_{base} = S_{base}/\omega_{m,0}$, and that $\omega_m/\omega_{m,0} = (\omega_e/p)/(\omega_{e,0}/p) = \bar{\omega_e}$, where p is the number of the generator field poles, ω_e is the rotor angular velocity in electrical rad/s, $\omega_{e,0}$ is its rated value and the parameter $\bar{\omega_e}$ is per unit angular velocity in electrical rad/s, the equation in per unit, denoted by the superbars, is:

$$\bar{T_m} - \bar{T_e} = 2H \frac{\mathrm{d}\bar{\omega_e}}{\mathrm{d}t} \tag{2.5}$$

Since $\bar{T} = \bar{P}/\bar{\omega}$, the swing equation expressed in power is:

$$\bar{P_m} - \bar{P_e} = 2H\bar{\omega_e} \frac{\mathrm{d}\bar{\omega_e}}{\mathrm{d}t} \tag{2.6}$$

This equation can be modified to represent the unbalance of the whole system, by aggregating all generation and all loads into two parameters, $\bar{P_g}$ and $\bar{P_l}$.

$$\bar{P_g} - \bar{P_l} = 2H_{sys}\bar{\omega_e} \frac{\mathrm{d}\bar{\omega_e}}{\mathrm{d}t} \tag{2.7}$$

The system frequency is a global parameter, and H_{sys} is the inertia constant of the whole system.

$$H_{sys} = \sum \frac{H_{gen} \times S_{gen}}{S_{base}} \tag{2.8}$$

When the system is in its steady state, $\bar{\omega_e}$ is very close to unity, and the system swing equation simplifies to:

$$\bar{P}_g - \bar{P}_l = 2H_{sys}\frac{\mathrm{d}\bar{\omega}_e}{\mathrm{d}t} \tag{2.9}$$

The system inertia constant is dependent on the number of generators in operation and the individual inertial characteristic of each generator. Formula (2.9) shows that the rate of variation of system frequency is related to the power swing and to the system inertia constant. Larger inertia constant limits the rate of frequency change, and improves grid stabilization.

Finally, some loads in the system are susceptible to grid frequency change. These usually are the rotating electrical machines directly connected to the mains, which vary power as the motor speed is affected by the electrical frequency. This relation is given by:

$$\Delta\bar{P}_l = \Delta\bar{P}_{l,0} + D\Delta\omega_e \tag{2.10}$$

The term $\Delta\bar{P}_{l,0}$ accounts for any alteration in the load not related to frequency change. For a grid level supply and demand balance, this term is directly reflected on the actual $\bar{P}_l$. The damping constant D represents the percentage load change as response to percentage grid frequency change, and a system representation of frequency dependence on supply and demand balance is:

$$\bar{P}_g - \bar{P}_l = 2H_{sys}\frac{\mathrm{d}\bar{\omega}_e}{\mathrm{d}t} + D\Delta\omega_e \tag{2.11}$$

2.2 Inertial response

As already discussed, under steady state conditions, there is equilibrium between input mechanical power and output electrical power for each machine, and the system speed, observed by the electrical frequency of the grid, remains constant. Any variation in load should be met by a answer from the generating units. The rotor mass of each machine, with its inertia, plays a significant role in that dynamic, as evidenciated in equation (2.9). These rotating masses absorb or release kinetic energy, opposing the frequency changes. Systems with lower overall inertia have less damping of frequency changes, and react faster during alterations in generation availability or load demand, giving a smaller window of time for control systems to respond [5].

The inertial response thus, is not a separate action in frequency control, but rather, it is an intrinsic reaction given by the rotating masses synchronously connected to the system when disturbances in the system frequency occur. The presence of this characteristic is of strategic importance as it provides a window of time for droop control and other primary frequency control schemes to engage. Electricity sources lacking rotating masses, such as solar photo-voltaic panels, and generators that have rotating masses, but are electrically decoupled from the synchronous grid, being connected through frequency converters, cannot intrinsically contribute to this system characteristic. Nonetheless, for wind turbines, which have rotors and thus inertia, there is a potential to take advantage of the stored kinetic energy in the rotor to attempt to emulate this characteristic, somehow helping the system inertial response, or at least improving system primary control [21, 24, 25].

3 Frequency control

Frequency control is a collection of actions and responses implemented in an electricity grid, aiming at system stability and operational safety. The power balance in an electricity system must be kept at all instants, otherwise frequency deviations appear, eventually resulting in activation of protection schemes to keep integrity of the connected units, leading to cascading shedding of generating sources and loads and, eventually, system collapse [31]. To maintain the equilibrium between loads and generation, the frequency is tracked and eventual disturbances are responded with adjustments on loads and power sources. Minor deviations in frequency are common; some generating units and loads in the grid take part in this instantaneous power balancing, and must be constantly tuned to keep the system running smoothly. Eventually, some major event, such as the sudden unavailability of one generating unit, or a major grid disconnection, imposes a more severe unbalance, which must be addressed by activating power and energy reserves. Power reserves are characterized as electricity generating or storage sources that can quickly respond to grid events, rapidly delivering power, but unable to keep supply for long. Some of those reserves might be available only for a few seconds, needing to recover thereafter before they are available for a subsequent event. Examples of such reserves are super-capacitors, flywheels, and battery banks. Energy reserves might not be able to respond so promptly, but they can deliver power for several hours, some of them even being able to run so long as the system needs them. They are not permanently dispatched, though, as they have strict startup characteristics and because of such are expensive. Thermal power plants used as back-up for the system, such as gas power plants with fast ramp-up, fall into this category. Other reserves, such as conventional hydro and thermal units running curtailed as spinning reserves, are able to have a quick response while being capable of delivering power for several hours, which can be understood as reserves with characteristics of both power and energy reserves.

Each transmission system operator (TSO) has different requisites for system stability, control and reserves, taking into account their grid specific characteristics, regarding load curves, generator types, grid length, amongst other features. When discussing the integration of new, inertialess, renewable sources, the German and Danish grid codes present a relevant reference, as those two countries already experience a very significant share of their electricity generation from solar photovoltaic and wind sources, amongst the highest in the world [1, 2, 32, 33]. The Danish national transmission system operator, in particular, handled the grid with the highest penetration of wind generation in the world as of 2016. The harmonized grid codes developed by the European Network of Transmission System Operators for Electricity are also of utmost relevance as these documents are the foundation of a completely integrated European electricity grid, and on its core is the integration of a high share of renewable sources in the European energy market [34].

Frequency control is usually implemented as a multiphase control scheme. The first phase is responsible to limit the extent of the disturbance inside the boundaries of a safe operational frequency band. It is supplied mostly by the power reserves of already operating generators, provided by droop control, and could potentially be provided by some power storages connected in stand-by, such as flywheels [20, 35], and variable, fast ramping loads [36]. Primary frequency control is activated automatically after any frequency disturbance is identified, and is dimensioned so that it is fully dispatched if the maximum allowed frequency deviation is reached. Primary control reserves should be dimensioned to be able to handle the disconnection of the single biggest generationg block on the grid, be it a large power plant or a important connection node. The second phase initializes right after the first, and re-establishes nominal system frequency and cross-border power exchange to their set points, using reserves with fast startup. They respond within minutes after frequency deviation. Secondary reserves dimensioning may have to take into account load prediction errors, resulting in larger capacity than primary reserves [30]. The third phase then takes over, sustaining the system through the dispatch of complimentary energy reserves, until overall system conditions are restored to the desired set points. An external, long-term control loop is also present. This control is called time control by ENTSO-E [37], and is used to correct discrepancies between the time of the synchronous area and the universal coordinated time (UTC).

3.1 Primary control

According to ENTSO-E, the primary control has the main objective to maintain instantaneous balance between load and generation [37]. It acts after disturbances, stabilizing the system frequency, and is not responsible to restore nominal frequency of the system (50 Hz in EU), but to stabilize the frequency to some value contained inside a band around the nominal value (49.2-50.8 Hz in EU). The primary frequency handles limited amounts of power deviation, dependent on system size and the largest generation capacity connected to a single bus bar (for reference, this value is 3000 MW in UCTE). The primary control alone must be able to keep the system stable right after a system incident occurs. If frequency deviations surpass the maximum and minimum permissible limits of the operating band.

The primary control makes use of generator droop control. Droop is a dimensionless ratio between frequency variation weighted by nominal frequency and power variation weighted by rated active power output. The generator droop informs of how the machine will respond to frequency disturbances, and in normal operation allows for machines of different characteristics to run synchronously in parallel, by sharing the load according with individual power rating. During a system fault, synchronously connected machines automatically vary their output. Units with smaller droop can vary their power faster as a response to frequency variation, and are capable of greater contribution to the correction of small disturbances, but their reserve will also drain faster under these circumstances, when compared to units of greater droop.

3.1.1 Droop control

Without control mechanisms, the inertia of generators and loads, as well as load sensibility to frequency change, might drive a system to equilibrium at some frequency. If any generator starts accelerating, its relative rotor angle will advance when referred to the other generators, and this will result in a higher share of the power demanded by the system being supplied by the accelerating unit. As the power share rises on this generator, its speed starts to reduce, while the other, less burdened generators, accelerate and, if enough torque from each generator is available, equilibrium will be reached at a new frequency, again common for every machine. This usually is not enough to guarantee system stability. The first action in primary frequency control is speed governor control, which allocates the system required power to each available generator. This governor control must be provided with a speed droop characteristic, so that adequate sharing of load between the generating units can be achieved.

A simple example of turbine without governor control is represented on figure 3.1. According to equations (2.9) and (2.11), any mismatch between mechanical power and demanded electrical power reflects in frequency deviation. The dynamics involving the balance of speed and torque are represented on figure 3.2. This unbalance can be inferred by measuring system frequency, which is used as a feedback to control generator power intake, represented by the actuator in the figure 3.1. In the case of conventional steam turbines, this feedback controls the turbine steam valve position, whereas in hydro power plants, it controls the water gate. The analogous for a wind turbine would be, to some extent, pitch control. Without the feedback loop from the governor, this system would respond solely based on the load dependence on frequency change (load damping) and system inertia. With the governor loop control, active power can be regulated to compensate for the load variation.

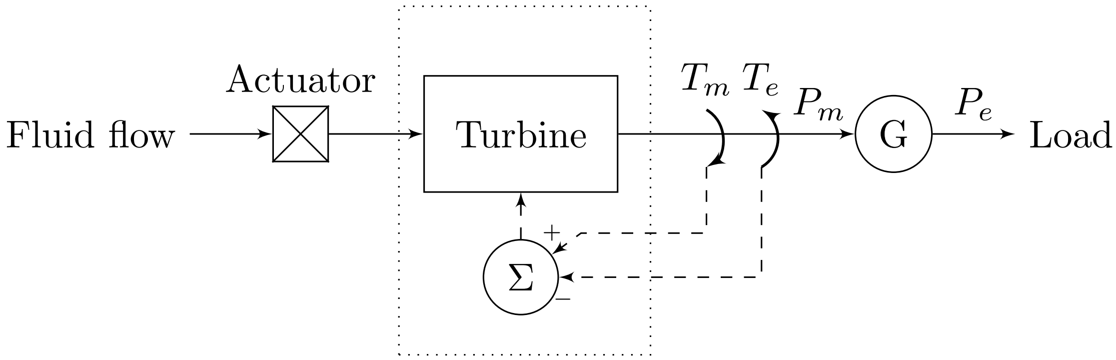

Figure 3.1: *Generic turbine without governor control. T_m, T_e, P_m and P_e are the mechanical and electrical torques and power outputs respectively.*

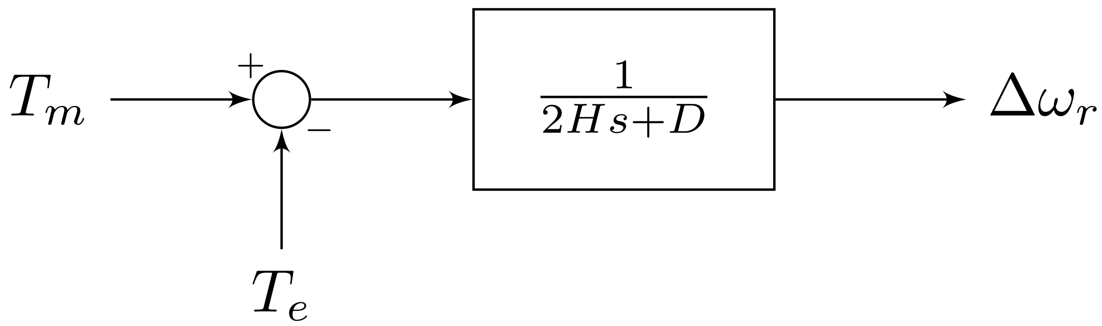

Figure 3.2: *Transfer function for speed deviation as a result of available mechanical torque and demanded electrical torque. H is the inertia constant, and D is the damping coefficient of connected loads*

The governor control loop with a proportional gain alone is not sufficient to keep system frequency stable, though. Even with the feedback control, there will be a steady-state error in system frequency. The utilization of an integrator on the control loop, as in figure 3.3 eliminates the steady state error when suitable reserves are available, which is a requirement of secondary control, as will be dicussed in section 3.2. This approach, however, only works for a single generator being responsible for any change in load demand. If two generators try to take control simultaneously using this logic, unless the machines are of similar characteristics and both have the same adjustment for speed control, they will struggle against each other, both trying to regulate the system frequency according to its own setting [29].

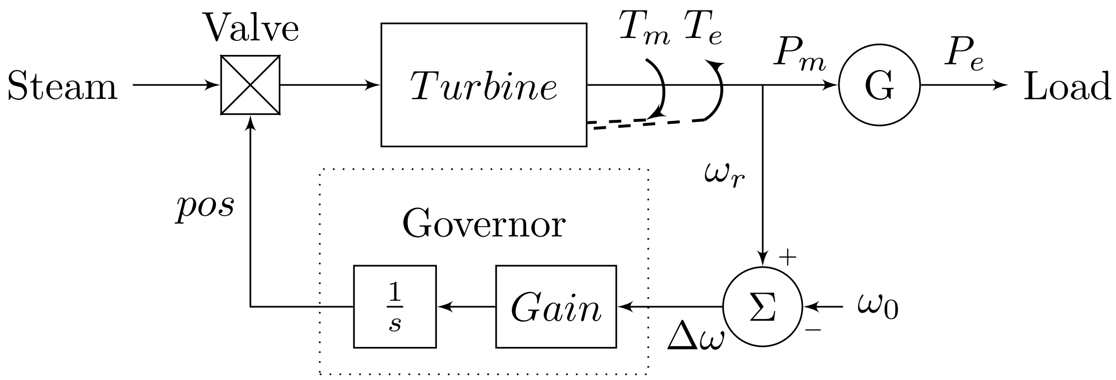

Figure 3.3: *Steam turbine with governor control. ω_0 is the reference frequency, ω_r is the measured frequency of the rotor, and pos is the resulting control signal for the valve position.*

In order to allow for multiple generators to take part in frequency control, as well as to enable adequate load sharing between these generators, a secondary loop on the control system around the integrator is required. The figure 3.4 represents a system with this secondary loop, which is implemented with proportional controller, utilizing a gain that can be adjusted for each generator. This gain sets each generator power output change as a function of frequency change, thus determining the share of the load each unit will pick, and is referred to as speed regulation, or droop. Droop is usually expressed as a percentage, and it defines the range in frequency deviation that results in a change from full load to no load output in the generator. Thus, an unit adjusted with 4% droop, when operating at full load will, ideally, reduce its output by 50% if the frequency rises 2%.

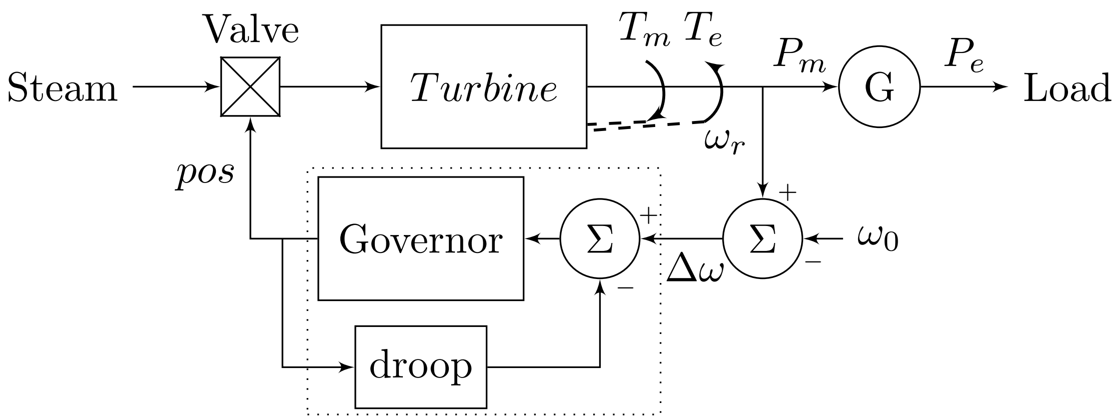

Figure 3.4: *Steam turbine with governor control utilizing droop.*

Control schemes based off the aforementioned droop control can be implemented in wind turbines [24, 28], taking into account the wind turbine own characteristics. This topic will be further explored in section 5.

3.1.2 Sample primary control requirements

The European Union grid policies, provided by ENTSO-E, as well as the German and Danish grid codes are presented below as a reference frame for grid policies related to integration of generating units in systems with high penetration of intermittent renewable sources.

European Union [37]:

Primary frequency control acts in the time-scale of seconds. It is a reaction shared by all parties connected.

Requirements for loads and generators to take part in primary control: accurate frequency measurement (equal or better than 10 mHz), fast time response (maximum 15 seconds to deliver up to 50% of the primary power reserve, with time rising linearly to 30 seconds for delivery from 50% to 100%), capacity to sustain delivery until deployment of secondary and tertiary controls (minimum 15 minutes).

Germany [30, 38, 39]:

Power plants larger than 100 MW must provide primary control power. Minimum available power for this purpose is 2% of rated power. Frequency measurement must be equal or better than 10 mHz, droop characteristic must be adjustable. The plant must activate the power evenly in 30 seconds and supply for a least 15 minutes. Primary control must be available again 15 minutes after activation if set point frequency was reached. Plants of power smaller than 100 MW might take part in primary power control, pending agreement with the systems operator responsible for the connection area.

All power plants in accordance with the German Renewable Energy Act [40], which includes onshore and offshore wind farms and solar radiation energy installations, are currently exempt from providing primary control power, including installations with capacity superior to 100 MW.

Nonetheless, some requirements that improve grid supply security under faulty conditions are in effect. Short circuits of small duration shall not result in wind turbine disconnection or instability. Wind turbines connected to the network after a failure have to resume power delivery up to their set point before the fault, with a 20% nominal power increase per second, to prevent further power shortage. These requirements are specially relevant for wind turbine design and operation. The traditional design of protection schemes for frequency converter-connected generation would suggest that changes in the operating conditions, for example voltage drops during system-wide faults, should result in equipment disconnection, due to the high sensibility of power electronic components to overcurrents. This behavior is evidently undesirable, as it would aggravate power balancing problems faced by the grid during such faults. Fortunately, there are strategies available to handle voltage drops on the converter terminals while limiting currents to nominal values in these sensible components, and this kind of fault-through operation for wind turbines is feasible [30].

Denmark [30, 41, 42]:

The Danish TSO Energinet.dk references the Nordel recommendation on frequency, time deviation, regulation strength and reserve, which describes primary control as the continuous regulation of output power by the generators to keep the system frequency as close as possible to the reference 50 Hz. This frequency is usually allowed to vary between 49.9 Hz and 50.1 Hz in the

Nordic system. The specific requirements for primary frequency control vary according to generator characteristics. During disturbances, at least half of primary reserves must respond within 5 seconds, and the remaining reserve must follow within 30 seconds. Technical requirements for the western part of the Danish grid must instead comply with continental European standards. All primary reserve must be delivered in up to 30 seconds.

The technical regulation for connection of wind turbines on grids at voltages over 100 kV in Denmark requires fault-through capabilities for faults under 100 ms duration. They must also be able to keep normal operation under abnormal voltage and frequency ranges. These characteristics are relevant to improve system robustness in face of disturbances, as they limit cascading effects on the wind farms.

Wind power plants over 11 kW are required to have frequency response. Plants above 25 MW or connected to transmission lines operating at voltages over 100 kV must also contribute to frequency control.

Frequency response: during frequency deviations, wind turbines must be able to automatic reduce active power if grid frequency rises above a certain limit, called f_R by this TSO. The reference f_R can be set to any value between 50.00 Hz and 52.00 Hz, and typically is set to 50.20 Hz.

The wind plant must be able to follow a droop set between 2% and 12% of the plant nominal power, with a standard value of 4%. This control must start in a maximum of 2 seconds, and conclude the change within 15 seconds.

Frequency control: wind turbines must provide upward and downward frequency control. For such, a power reserve (called P_{delta} by Energinet.dk) must be available. Frequency control must start at latest 2 seconds after frequency change and must execute the change to the new power level within 15 seconds. In the case of upward regulation surpassing 10% of the nominal power of the turbine, it is acceptable that the response be slower. For downward regulation, the turbines must be able to drop from full power production to under 20% in a matter of seconds.

This frequency control function must be adjustable to work in a frequency range from 47 Hz to 52 Hz. The droop characteristic required is variable for different segments of this frequency range.

3.2 Secondary control

Secondary control is responsible for keeping power balance between generation and load within each control zone of the transmission system. After fault, the power exchanges with neighboring areas must be returned to their scheduled values. It is also responsible to return the system frequency to the original set point (50 Hz in EU). It is of utmost importance that secondary control has the capability of working independently and in parallel with the primary control, without interfering with the former operation. The secondary control employs automatic centralized generation control, and adjusts the set points of the secondary control automatic reserves, that must be separate from primary control reserves. All the functions provided must be available constantly, to correct minor variations typical of system operation and also major events, such as grid faults and disconnection of generating units.

3.2.1 Sample secondary control requirements

European Union [37]:

Secondary frequency control acts after minutes, replacing primary control. There are specific responsible parties to account for it, under the TSOs. They are implemented as proportional-integral (PI) controllers, to be able to eliminate the frequency error.

Requirements: Secondary control must start action at most 30 seconds after frequency deviation, and must correct it steadily to the nominal system value within maximum 15 minutes. The secondary control must be solely dedicated to the purpose of area control error, bringing the power exchange between areas to their programmed values. Secondary control must also be capable of providing enough power to ensure that primary control full reserve is available afterwards. Secondary control power reserves must be sufficient to cover expected load and generation fluctuations.

Generators qualified for secondary control must be physically connected to the area they provide secondary control, and have available secondary control power reserve at all times, to ensure that they will be capable of providing secondary control whenever needed. It is allowed to exchange secondary control reserve between bordering control areas if the TSOs involved confirm the exchange. However, this exchange is limited, as at least 66% of the secondary control must be provided within the control area.

Germany [38, 39]:

Secondary control shall be employed by each TSO to assure balance between generation and load for each control area inside the synchronous interconnected grid. The TSO can invite external agents to take part in secondary control power, but these agents must be connected within the respective control area. Power stations in operation that did not previously qualified themselves for secondary control might nonetheless eventually participate if the secondary control power available proves insufficient, with posterior compensation being settled bilaterally.

Denmark [42, 43]:

The Danish TSO follows Nordel recommendations. Whenever frequency reaches the set limits (49.9 to 50.1 Hz) energy production must be adjusted so that system frequency is returned to its reference, and secondary control takes responsibility. This can be achieved by changing the set values of operating units with available power reserve, by powering in additional units or taking off excess power.

The secondary control must also detect and correct, for each subsystem area, the difference in current transmitted power and the planned values. The power exchange between areas may be changed, however, to help limit the variation in the interconnected system frequency.

There is also a technical regulation regarding the readjustment of power consumption for the purposes of mitigating critical grid frequency drop (below 49 Hz, 48.7 Hz or 48.5 Hz, depending on the region and on duration of frequency drop), imminent risk of network power failures and critical overloads. It is required that all distribution companies connected to the Energinet.dk grid comply with automatic and manual load relief. These companies may take part in the relief scheme alone or combined as a relief area.

The automatic relief should respond to frequency drops and automatically shed load proportionally to the deviation from a set frequency. The manual relief happens afterwards, if the system is still vulnerable, further reducing power consumption in the areas, and can take up to 15 minutes to conclude.

3.3 Tertiary control

Tertiary control is responsible for managing secondary control power reserves to guarantee and optimize its availability. It is also responsible for covering large power deficits in the grid. Tertiary control actions involve automatic and manual dispatching of units by TSOs, activation of power exchange between neighboring TSOs and energy procurement when necessary to cover for power deficit.

3.3.1 Sample tertiary control requirements

European Union [37]:

Tertiary control initially compliments secondary control (direct activated), then eventually replaces it (schedule activated). It involves generation dispatch rescheduling and is also executed by responsible parties / TSOs. The minimum total tertiary reserve of a control area must be sufficient to cover for the single largest expected power loss, originated from a generating unit, DC-link, power node in the system, or load. The tertiary control must also come online in case the secondary control reserve is not sufficient.

Germany [39]:

The German code calls tertiary control as Minutes reserve. It is used after large and prolonged system power imbalances, with the objective of restoring secondary control reserves. It is required that minutes reserved power be provided within 15 minutes after request.

3.4 Time control

According to ENTSO-E [37], there is one final step in frequency control, called time control. This last control scheme has the purpose of correcting long term global time deviations of the synchronous time of the system. The time control also sets a performance indicator for all other frequency control phases, as the accumulated offset between the synchronous zone time and universal coordinated time (UTC) during a given period is measured, and it should be kept under agreed limits.

4 Strategies for frequency control on systems with high share of intermittent generation

4.1 Demand response operated loads

One of the newer approaches made available by the introduction of smart grids is the operation of some loads connected to the system for overall power balancing, frequency control and electricity market competition [8]. These loads do not require a fixed amount of power at every instant, being able to have their demand varied throughout the day in different ways, and their owners can be rewarded by being able to buy energy at lower spot prices or taking part in the regulating markets. The faster response loads, that are able to vary their intake almost instantly, are the ones initially able to take part in regulating markets for frequency control. These loads can be compared to negative spinning reserves, changing the demand, instead of generation, in the case of system imbalances [36]. Some examples of such loads are electric cars while being charged [13, 16], large ventilation and air conditioning systems [11], technologies for production of synthetic fuels, such as power-to-gas [18, 44, 45] and even residential electric loads, such as refrigerators, air conditioners, heat pumps and water heaters [9]. Each of these loads can take part in different ways to help balance demand with the available supply, and to improve grid stability and response during system faults. Some of these loads might be largely operated as integral agents of future power systems, while others are mostly focused on delivering their functionality to their owners while seeking a better economical performance by taking a more active role in electricity markets, and their participation might be more restricted so to not compromise their primary goal.

The most desirable characteristics of a demand response operated load are high storage, good controlability, immediate response, quick startup, fast energy restoration, large aggregated size and low cost, related to the reduction of demand in installation of alternative reserves. High storage in this context actually relates to the load size in the system and the time lenght it can be curtailed. Converselly, fast energy restoration is related to the time the load must be kept online before it is able to be shut off again [36]. Load characteristics can vary drastically, and a large variety of loads can provide complimentary desirable characteristics, fulfilling different roles in system regulation. For instance, some smaller loads might present low storage but can have fast and reliable control, enabling immediate response. Other bigger loads could have higher storage, but slower response, being curtailed just before the faster, more limited loads must be restored. The aggregation of these loads can be perceived by the system as a reserve that is at the same time large and able to give fast response.

4.1.1 Residential loads

Recent developments in control systems and telecommunications, combined with modern free market regulations allow for a more active role of small consumers in the electricity sector [36]. These consumers are encouraged to seek different energy retailers and to find energy contracts to better fit their consumption curve, with reduced tariffs, helping adjust the grid demand side with the available energy production and availability. One future possibility for residential loads is to take part in fast demand response.

The employment of small loads response in grid control is, nonetheless, usually seen as a burdensome and complex task. The large number of participants in the grid poses challenges for coordination and might suggest intensive expenses in communications systems. In reality, though, it is possible to integrate some load response to grid imbalances just by keeping track of grid frequency, analogous to generator-side frequency control [6, 14]. Some loads could be controlled to function as energy users instead of power users, increasing or decreasing the power intake during a specific period, while keeping final energy constant, and thus functionality basically intact.

Residential thermostatically controlled loads usually have suitable characteristics to take part in electricity regulation markets. These loads are typically large thermal energy storage reservoirs, with a characteristic operation band, and they have the potential to flexibly respond to electricity prices, within their operational constraints. Specific load control strategies enable power consumption to track a specific trajectory, for instance governed by market prices or system frequency disturbances, while not significantly affecting end-user performance [13].

The employment of a large number of smaller loads might even prove benefits, when compared to larger loads. These small loads are more spatially distributed and utilize simpler control schemes. A large aggregation of small loads can provide a overall more reliable regulation and can respond continuously, contrasted with larger loads [36].

4.1.2 Plug-in electric cars

The popularization of electric vehicles for personal use, public mobility and as industrial machinery starts a shift for the transportation infrastructure energy matrix, which is currently mainly powered by fossil fuels, to a higher share of electric, renewable based energy. Plug-in electric cars will constitute a relevant load for the residential consumer sector where those cars advance in market share, and will also strongly affect the load curves of future electricity systems [46]. Considering the seasonality and unpredictability of solar photo-voltaic and wind generation, strategies to relocate this load increase are of utmost importance. Left uncontrolled, this load could have a very negative impact on the grid, but with planning and an adequate control scheme, they can instead improve grid performance and stability [16]. The possibility of flexibly purchasing the required energy in the electricity market at lower rates can help matching load and generation profiles.

With the support of smart grids, and the possibility of charging cars at different times of the day, during the night when the car is at home, or during the day at work parking areas, the combined battery capacity of several cars and intelligent changing units and the flexible operation of the charging times and power can assure increased flexibility to enable future systems to match the demand with availability of energy sources, while satisfactorily addressing the needs of plug-in electric car owners.

Electric car charging from the grid might reach more than 3% of total electric demand [13], and surpass the mark of 10% of the whole domestic electric demand for some periods in future electricity grids [46, 47], representing a significant share of the connected load. The operation of such loads, that can also temporarily work as sources, for frequency control is relevant, as again a system might improve performance by integrating electric cars in frequency control reserves operations [48]. The greatest difference, and advantage, of utilizing electric cars for this purpose when compared to other residential loads is the possibility of down regulation by keeping recharge at a rate lower than maximum, thus creating a buffer, and upwards regulation not just by shedding charging load, but also by actively returning power back to the grid, as electric cars can, for some period, act as battery banks connected to the grid. This kind of operation, however, must be carefully planned and monitored, so to not result in the cars not being properly charged when their owners need them, and some market mechanisms to reward the owners of electric cars for providing these ancillary services must be available, as the extra cycles imposed on the batteries of these cars for the purposes of grid balancing and frequency control might result in faster lifetime degradation of the batteries. One possible approach would be to keep the batteries of cars loaded at the 85% range, absorbing surplus power from the grid for frequency down regulation until the batteries reach 90% and providing power back for upwards regulation until battery charges are at around 80% [10]. The upper limit helps keeping battery life by not overloading it, and the lower limit guarantees the car will have adequate energy remaining for later use.

4.2 Power-to-fuels

Recently, power-to-fuels schemes have been studied as an alternative to circumvent the problems related to the intermittent nature of some renewable sources, namely wind and solar power [18, 44, 45, 49]. Integrated systems with wind turbines or solar photo-voltaic plants feeding surplus power to produce synthetic fuels, and utilizing these fuels in return when the primary source is unavailable but the grid demands power and the electricity market is willing to pay higher prices, are presented as a potential solution for future power systems [30].

One of the shares of the electricity market that could feasibly be exploited by such arrangement is the provision of secondary frequency control reserves [18]. A integrated system consisting of wind turbines, electrolysers and fuel cells could, for instance, shave off excess generation utilizing the surplus power to produce hydrogen in the electrolysers. This hydrogen can eventually be used to produce electricity back in the fuel cells. This scheme can provide either positive or negative regulation in the secondary control reserve market, according to current hydrogen availability and electricity market energy prices.

It is even possible that some power-to-fuels schemes, having sufficiently fast ramp-up and ramp-down characteristics, could take part in primary frequency control. In power systems with high penetration of renewable sources, a conventional thermal power plant operating with gas partially supplied from a power-to-gas conversion system could, by having the conversion system running continually, provide primary control, not only by its own capacity, but also by conveniently shaving off the conversion load or increasing it according to system needs and energy prices, while absorbing or complimenting the renewable output as demanded. This approach has a secondary bene

t of allowing the power plant to continuously run closer to its rated power, increasing its efficiency [44]. A similar scheme can be acchieved with the utilization of a power-to-hydrogen plant and back generation of electricity by employment of fuel cells. Fuel cells of several different technologies with distinguishing efficiency and operational characterisits are available. Hydrogen conversion can reach efficiency ranging from 65% to 90%, storage and transportation losses vary significantly according to specific requirements and distances, from 1% to more than 50%, and conversion back to electricity can reach an efficiency up to 70%, thus the potential round-trip efficiency of such technology is currently up to 60%. A fuel cell with suitable capability for fast power output variation can be selected for load following [30], and potentially, frequency control. Polymer electrolyte fuel cells, for instance, have flexible operation and can respond quickly to changes in demanded power.

4.3 Storage technologies

Due to the intermittent nature of wind generation, storage systems will potentially play a large role in the future electricity grids as providers of balancing services [50]. These storage systems provide a standing reserve that, while more expensive than a partially loaded synchronized reserve composed of conventional thermal power plants, might reach a more efficient result by improving grid operation and reducing the overall amount of fuel used by expanding the system capacity of absorbing wind power. As the infrastructure associated with storage technologies becomes available in the system, their operation can incorporate features to enable for frequency control in various stages.

4.3.1 Flywheels

The flywheel is a rotating mass connected to the rotor of an electrical machine that operates alternating the functions of generator and motor. A flywheel energy storage system utilizes inertia to store kinetic energy, and is loaded by feeding the electrical machine, operating as a motor, with power from a grid, which can later release the stored kinetic energy back as electricity by changing machine operation to generator and electromagnetically braking the rotor [19]. Similarly to wind turbines with synchronous generators, the whole system is connected to the grid through a frequency converter, as the flywheel side has variable frequency, but the grid must keep constant frequency.

Current flywheel rotating masses for electrical energy storage are made of metal or composite, with very low friction magnetic bearings, and contained in vacuum, to guarantee minimum energy loss over time. The complete flywheel power system also comprise switchgear and protection relays, ancillary services consisting of vacuum system and liquid cooling for stator and frequency converter, control system, and associated electrical components related to the converter. Single units are very compact, with rated energy storage of 0.42 to $0.55kWh$ occupying less than $0.7m^3$, suitable for operation with discharge power above $20kW$, and discharge times between 10 and 100 seconds [19]. Larger systems, composed of parallel units, and capable of continuous operation for up to 15 minutes are also feasible [20].

The flywheel control scheme is readily suitable for grid voltage regulation [19], but they are also feasible for frequency control [20, 51]. Flywheels can conveniently absorb or release energy, smoothing grid power fluctuations and potentially avoiding higher costs incurred by dispatch of expensive fast start-up reserves or potential energy waste from shedding of intermittent renewable generation [52].

One application that has been proposed is the coordinated operation of wind turbines and flywheel energy storage systems [35]. This coordinated operation aims at improving system performance for frequency regulation while potentially bringing economic benefits for both wind generator and flywheel energy storage owners, by allowing the provision of upward frequency regulation from the combined set without the need of turbine operation deloaded for reserve power, and thus not wasting real power potential, as energy can conveniently be previously stored in the coordinated flywheel energy storage system.

4.3.2 Batteries

Battery storage devices are not a new topic in electrical power systems. They were utilized in the early stages of DC grids, and after that, have been used extensively over the last decades to power all kinds of mobile devices. They are still used on a utility level, to provide back-up power to critical services, as power system operator installations deploy them as an emergency source for protection and control systems in power plants and grid substations, and utilize battery banks for distribution-level voltage stabilization.

Large battery storage systems have been developing quickly over the past few years, driven by the development of new technologies for electric cars [53] and grids with renewable energy sources, for instance for consumers with solar photovoltaic self-generation aimimg at improving own-electricity consumption and overall system economical performance, by decoupling generation and demand times [54]. These battery banks have the potential to play a significant role in balancing load demand and generation availability, specially for short daily or hourly cycles. For such applications, some specific performance characteristics are essential in the new battery technologies, such as the capability of a large number of operation cycles with reduced battery capacity degradation, and longer lifetime. As batteries become cheaper, more efficient and endurable, they start playing a larger role in present and future electricity power grids, and their potential as frequency support devices is already evident.

Battery storage already has very valuable properties for deployment of frequency control, in the ability to respond quickly to electronic control inputs, and to to ramp rapidly, adjusting its power absorption from the grid for frequency down regulation, or its power delivery back to the grid for upwards regulation. The utilization of battery storage as a independent agent in the frequency regulation market is technically feasible, and control schemes imitating the classical droop control of conventional machines has been proposed. Care must be taken, however to take into account the battery characteristics when implementing these control strategies, as the current state of charge of a battery affects its performance, and overcharge or over discharge cycles have an extremely negative effect on equipment life. For these reasons, complimentary control models can be implemented, such as the utilization of variable droop according to battery state of charge [55], or a coordination between control system for the battery operation and different bidding strategies according to the storage current state of charge [56].

The combination of complimentary characteristics between battery energy storage systems and intermittent renewable energy sources, for example wind turbines, can prove strategic for improving economic viability and operational safety of future electricity grids. One such integrated scheme is the cooperation of wind turbines and battery storage, which can be physically integrated or virtually joined for a single bidding strategy in the electricity market [17]. A coordinated control design, utilizing the wind turbines as primary source tracking the frequency control signal, and utilizing complimentary power or sink from the battery storage as needed, thus improving power prediction and reducing battery lifetime fatigue operation can enhance supply safety, frequency control capability, and might prove feasible. This strategy aims not only at securing a more reliable power source, with less vulnerabilities associated with wind forecast, and improvement of battery lifetime by avoiding frequent deep battery cycles, but also enables power reserve without necessarily wasting wind potential, and consequently allows for improved participation in the frequency regulation and reserve markets for wind turbines.

4.4 Wind turbines

Wind turbines are the technology that is currently reaching the greatest penetration in electricity grids evolving their power matrix from non-renewable sources to renewables [1, 2]. There are several factors for that, ranging from the maturity of current technologies for wind power harvesting to its global availability [3]. Consequently, future electricity systems will have different characteristics from traditional ones, and as discussed in section 2, grid inertia, as consequently grid stability, tends to reduce.

Nonetheless, the traditional concept of system inertia as a resistance to system change provided solely by physical rotating masses might need a revision [5]. The inertia of future electricity grids could be interpreted to be the conventional synchronous inertia, that is, the system resistance to frequency change provided by conventional generator, complimented by a virtual inertia, which would be the response from generation connected through frequency converters with grid frequency feedback for electrical torque control.

With the increased presence of wind turbines in future systems, it is relevant to develop strategies to utilize these turbines to improve grid stability, or at least to compensate for the reduction of synchronous inertia. Wind turbines can actively participate in primary control for regulating frequency downwards by reducing power output up to a minimum level before complete unit shutdown, and can also contribute rising frequency by increasing output when operated at a deloaded state [22, 24, 25, 28, 57, 58]. This frequency control can even have a response similar to the obtained from conventional generation, by operating wind turbines in a way analogous to droop control [26, 58–60]. Care must be taken, however, to access the available primary reserve at any instant, as wind power variability continuously impact it [61]. A drawback of deloaded operation is that in order to create a power reserve, the turbine must continuously waste energy. Coordinated operation with some energy storage reserves might prove more economically attractive, balancing invetsment costs while avoiding, or at least minimizing this loss and improving the predictability of primary power reserves [17, 23, 35].

It is also possible to utilize wind turbines for secondary frequency control, raising or lowering their power according to the transmission systems operator reference [22, 28, 62]. There are some different strategies to reach this objective. A wind farm can, instead of following the maximum point of power track, operate following an absolute power reference level from the system, as long as this amount of power is available from the wind. It can also operate by following a reference that indicates the percentage of to whole wind power available, ensuring for instance reserves for primary regulation. These systems can also respond to some sort of power gradient limiter, that sets a minimum response time for wind plants to deliver the demanded reference power. Strategies for primary and secondary control can be deployed at the individual turbine level, or at the wind farm level. The second option might take advantage of different wind conditions throughout a wind farm to optimize frequency control.

Finally, the utilization of the wind turbines mechanical inertia, currently decoupled from the grid but nonetheless storing kinetic energy, and a suitable control algorithm, in order to vary the turbine frequency converter output to the grid, mimicking the behavior of conventional steam or hydro power plants, can be acchieved [21–23, 25, 27, 28, 59, 60, 63]. These synthetic inertia emulation control schemes enable very quick rises or drops in power production , through fast changing of generation torque, resulting from crontrolled changes in electrical torque braking or accelerating the turbine rotor. This controlled response might even be more effective than the synchronous inertia, as the utilization of fast power electronics and suitable controller algorithms enables a deeper kinetic energy drain, and operation at high wind speeds allows optimal power production and kinetic energy storage, while at very low wind speeds the turbines can instead operate simply as kinetic energy storage [64]. The employment of synthetic inertia, however, must be executed carefully, as it risks the turbine stalling and might overload some mechanical components. It also introduces a period of recovery for the turbine after the kinetic energy release, as the turbine power becomes temporarily limited, which can adversely affect grid frequency. There are, nonetheless, strategies to account for this negative behavior. The previously discussed deloaded operation aimed at giving the turbine a frequency control reserve can also provide enough margin to keep generation stable after inertial response. A second strategy would be to accelerate the turbine for a short interval before releasing the kinetic energy, effectively accelerating the frequency drop but limiting its magnitude and splitting the kinetic recovery, as part of the kinetic energy needed for inertial response was gathered immediately before its release [65, 66]. Inertial response performance can be further improved by combined operation of flywheels [23]. The primary interest in integrating flywheel storage devices to wind farms is related to smoothing power generation and supply quality, as well as improving overall wind farm power delivery [52, 67], but they can also contribute in frequency control, as discussed in 4.3.1, and their coordinated dispatch can also reduce settling time and minimize the negative impact of kinetic recovery for the turbine rotor.

Ultimately, wind turbine synthetic inertial response might prove to be among the most strategic technologies for improving future grids frequency control as wind turbine penetration increases. Compared to the other strategies presented, this option does not require significant extra investments, as it only takes an adaptation in wind turbine control systems, and it automatically scales with the expansion of wind generation.

5 Wind turbines and inertial potential

5.1 Technology overview

Wind turbines available at commercial scale today mainly utilize rotor axis of rotation in a horizontal disposition [22]. A unit is composed of three blades mounted on a hub, generator, control systems and connection to the grid. Several models also utilize a gearbox between the mechanical shaft from the hub and generator rotor, as the hub rotational speed is typically low compared to the operating frequency of several generator designs. Frequency converters are usually also required, for conversion to the grid synchronous frequency. Hub, gearbox and generator are always mounted inside a nacelle that stands on top of a tower, while converter, control systems and ancillaries can be located in the nacelle or tower. The nacelle contains a yaw drive to continuously steer the turbine rotor towards the wind, and the position of the blades is controlled through pitch drives for energy yield optimization and also for protection against dangerous mechanical loads.

Until the end of the twentieth century, squirrel cage induction generators were typically employed, producing electricity at grid frequency [22, 30, 68]. Their mechanical rotor speed was not a function of wind speeds available, but instead of the generator design coupled with gearbox, while working at grid frequency. That meant the tip-speed-ratio, that is, ther ratio between the tangential speed of the tip of the rotor blades and the wind speed was variable, and the turbine would operate at maximum efficiency only at one specific wind speed. Afterwards, with improvements in power electronics that led to reduced production costs and improved performance, the utilization of frequency converters, to rectify the produced electricity and then convert it to grid frequency became widespread, and variable speed generators of different configurations started to dominate the market. These turbines have the advantage of being able to keep designed optimal tip-speed-ratio for a range of wind speeds, thus keeping efficiency high for a ample operating band [30]. Currently, doubly-fed induction generators, permanent magnet and wounded rotor synchronous generators are the most common models for variable speed wind turbines commercially available and each has advantages and disadvantages [69, 70].

Doubly-fed induction generators (DFIG) utilize a wound rotor generator, with the stator windings directly connected to grid frequency. The rotor is allowed to vary speed, which results in variable frequency and it requires a frequency converter for grid connection [70]. This frequency converter has a lower power rate than the generator itself, as the larger share of generated power flows directly from stator to grid, resulting in reduced power electronics equipment costs. On the other hand, this type of generator is not suited for low rotational speeds, and gearboxes are always required, with a combination of planetary and helical transmission system in a three stage configuration being typical. These units also utilize transformers with three windings, for connection of stator and frequency converter from the rotor to the grid.

Synchronous generators can utilize permanent magnets or electrically excited wound rotors. They can be designed for low, medium or high speed operation, with low speed enabling gearless solutions, and medium speed employing simpler gearboxes, with less stages. The generated electricity is allowed to vary in frequency, and a full power rated frequency converter must be utilized for grid connection. This configuration allows for a great control over the delivered energy, with flexible voltage and reactive power controls [30].

5.2 Standard control for wind turbines

Current wind turbine control systems aim at optimization of yield energy while keeping the various mechanical and electrical components within specified stress and load parameters. Blades and shaft must be protected from excessive mechanical stress from extreme wind conditions, while generator, converter and transformer must be prevented from undue heating due to extensive overloading. The turbine must also provide adjustable active and reactive power according to grid demands, and be able to withstand grid transients without shutting down, within limits defined by the transmission systems operators.

A simple method for power control is stall control. The blades are fixed on the rotor hub, and when wind speeds are too high, the rotor stalls, as a result of its aerodynamic design. This kind of turbine is cheaper, robust and has less power variations during fast wind changes, but lower efficiency at lower wind speeds, and their power cannot be controlled during connection, which limits its modes of operation [30].

Nowadays the dominating power control type for wind turbines is pitch control. The position of rotor blades is adjustable, being able to very the angle of incidence of the wind. Standard operation is divided into three distinct regions. When available wind speeds are too low, below a minimum cut-in speed, the turbine is on the first region, in stand still condition, and no power is being generated. It is strategic to keep yaw control operating when winds start approaching cut-in speeds so the turbine can begin operation at optimal power. After wind speeds surpass the cut-in reference, pitch control adjusts blades to starting position and the rotor is released, as the turbine enters the second region. It starts delivering variable power at variable speed, and blade pitch is kept constant to maximize energy yield. This region endures until wind speeds reach the nominal rated value of the turbine. After that, the third region starts, where blade pitch is controlled in order to keep rotor rotational speed and output power constant, within the physical limitations of the turbine components and under the maximum continuous power output from the generator, and effectively shedding extra wind power available. There is a narrow area between the second and third regions where the turbine transitions from variable speed to variable pitch control. Finally, if any dangerous condition arises from operation, such as caused by extremely strong wind causing rotor exceeding safe speed or atypical vibrations in mechanical components, or overloading causing temperature to rise above technical limits of generator, the turbine safety systems actuate, and a shutdown might be triggered. Pitch control has a drawback while operating at high wind speeds. The pitch servo cannot fully compensate for fast wind variations, and the power output has higher fluctuations while in this operating area.

A third method of power control is the active stall control. These turbines are equipped with blades with pitching mechanisms similar to pitch-controlled turbines. They are operated similarly to pitch control at lower wind speeds, targeting at improving efficiency. At high wind speeds, the blades are positioned opposite to what pitch control would command, resulting in a deeper stall operation. The result is a limited power, bu with smoother output, lacking the high power fluctuations characteristic of pitch control at high wind speeds.

5.2.1 Yaw control

Yaw control is responsible for adjusting the whole nacelle position so that the rotor axis is oriented towards wind direction, to allow for full absorption of the power available from the wind. Yaw control can be done in different ways, aerodynamically by use of wind vanes or fan-tail wheels, free yawning of downwind rotors with coning angle blades, and actively, with wind sensors and motors to rotate the nacelle. The dominating method currently utilized for yaw control is the last one, as it is more economically feasible and simpler for larger commercial turbines [70].

Yawning starts to act when wind speeds are close to the turbine cut-in speed. The rotor already starts being aligned with the wind, so that when the turbine begins operation it is already in optimal position for maximum power capture. From that onward, the yaw angle, that is, the deviation between rotor axis and wind direction, is kept as small as possible. Nevertheless, this angle is not necessarily held at zero value at all times, as the control system should not respond too sensibly to small wind direction variations, otherwise the mechanical parts involved in this control might suffer from reduction in life.

Different strategies can be used to balance power optimization while limiting equipment fatigue. For instance, operating ranges for no yawning, retarded yawning and instantaneous yawning can be defined. Using this setup, if the yaw angle is too low, the wind might just change to the current rotor position in a few moments, and the power loss from not adjusting yaw is low, being negligible if the turbine is operating over its nominal speed, so the yaw control does not actuate. For moderate yaw angles, the controller sets a delay, waiting to check if the wind direction change is not just a temporary gust, and afterwards it acts to correct rotor position. Large yawning angles suggest a more significant change in wind conditions, and force the yawning control system to act immediately.

Whenever the turbine is faced with severe wind conditions, beyond cut-off speeds, the active yaw control can be disengaged, and further yawing of the nacelle is accomplished by releasing the yaw brakes while allowing the turbine to be passively yawned. Under these circumstances, control system efforts are aimed at reducing mechanical stress on the blades and rotor.

5.2.2 Pitch control

Wind turbine operation differs significantly from conventional steam turbine operation as the control of primary energy source intake is not an option. This source varies constantly and unpredictably, and efficiently coping with this characteristic is necessary to achieve maximum power yield and safe operation for wind turbines. Pitch control affects primary power conversion capacity, and in conjunction with generator torque control, can adjust the output electrical power and rotor speed, within turbine specific operational limits and available wind power [70].

Pitch control is primarily used to efficiently match available input wind power and output electricity generation [30, 70]. Between cut-in wind speed and nominal point of operation, a turbine tip-speed-ratio is usually kept constant, at a value that depends on specific turbine model. During this operating range, for variable speed turbines, pitch control usually does not actuate, and pitch angle is kept at the position that results in maximum yield, following a maximum point power tracking process. Output electrical power and turbine speed both increase as wind speeds increase. If some event in the grid requires curtailment of generation from wind turbines, the pitch angle can be varied, thus reducing power conversion efficiency while keeping the turbines in operation and ready to subsequently deliver maximum power back to the grid following normalization of operating conditions.

After the turbine surpasses its nominal operating point, electrical power generated must be kept within generator specified limits. The turbine undergoes a change in operation from constant tip-speed-ratio to constant power and speed, and the pitch angle is varied to match the limit power. While operating under these higher wind speeds, the turbine must have tolerance for short duration overspeeding caused by wind bursts [70].

5.2.3 Frequency converter control

The employment of frequency converters in wind turbines for generator connection to the grid brings several advantages for wind turbine operation. The first and most relevant advantage is the decoupling of rotor and grid frequency, thus allowing for turbine operation with variable speed, which brings aerodynamic advantages for rotor design, reduces mechanical loads and helps flatten out electrical power output [30].

Moreover, frequency converters enable a very flexible reactive power control, and can be used to adjust speed and power to set levels according to wind power availability. In normal operation, during partial loading, the generator side electrical torque is varied following the wind turbine characteristic curve while pitch control is inactive. As the wind speed rises, electrical torque also rises, and the rotor speed is matched to the optimum speed for the specified tip-speed-ratio of the turbine. Other strategies could be employed during this operating range. For instance, pitch control could be active, and pitch angle set at a different value than the optimal. This would result in reduced power yield, but creates a power reserve for the wind turbines, which can prove relevant for systems with high wind penetration and limited energy storage.

Conversely, a feedback from the actual grid-side frequency to the rotor speed can be used, forcing the turbine to operate at varying speeds as the grid frequency changes, slowing or accelerating the turbine outside its optimal point of power tracking speed, within some limits, following grid disturbances. As the turbine has its own inertia, any acceleration or deceleration out of the optimal speed will result in kinetic energy to be absorbed by or released from the rotor, and the turbine would, for a short period, slightly decrease or increase its power output to the grid, thus contributing to the grid performance in face of disturbances, potentially improving grid stability.

The two previous actions can even be combined, resulting in wind turbines that not only react supporting grid inertia, thus improving grid robustness during faults, but can also help mitigate frequency drops by providing primary control reserves. Care must be taken, though, as the operation of wind turbines outside their optimal power production has negative impact on its expected revenue, and market mechanisms should be in place to reward units taking part in frequency regulation. Moreover, the mimicking of inertial behavior without energy reserve might negatively impact short-term grid performance as the wind turbine power will be temporarily reduced after the synthetic inertial response, while the turbine recovers to its set-point speed, and complimentary actions might be needed to keep supply quality under TSO's specified parameters.

The frequency converter sets the generator torque by adjusting its currents. In order to provide this control, the converter requires a power reference [30, 70]. The wind speed dictates the maximum available power. For large turbines, however, it is not feasible to control the power reference directly measuring the wind speed, as the measuring point will not be representative of the real average speed of wind for a rotor sweeping an area of thousands of square meters [30, 70, 71]. Instead, the actual output power is measured,and utilized as the input for the power control system. Other relevant inputs are the blade pitch angle and rotor rotational speed. The power-production curves of a wind turbine are non-linear and can be quite complex. A model with a lookup table is implemented in the controller, utilized to produce the reference electrical power and, taking into account the optimal frequency of operation, sets a reference electrical torque, which finally is used for the frequency converter control [64].

5.3 Inertial characteristics

The main wind turbine generators commercially available are doubly-fed induction generators (DFIG) and synchronous generators, which can be permanent magnet or wound rotor electrically excited synchronous machines. Doubly-fed induction generators have their stator circuitry directly connected to the grid, while the rotor circuit is connected through a partial-scale frequency converter, that handles approximately 30% of the turbine rated power. Synchronous generators are fully connected through frequency converters, which allows them to be operated in a wide speed range, with great flexibility for reactive power control and improved performance for voltage control, but total decoupling between the mechanical part and the electrical grid. These characteristics result in little to no inertial contribution from the wind turbines to system frequency stability. Nonetheless, the blades and rotor of a wind turbine, being rotating masses, store a significant amount of kinetic energy when the turbine is in operation.

Wind turbines commercially available have a wide range of configurations. Common model power ranges from sub-MW up to 4000 MW, and offshore wind turbines can have an even higher rated capacity [71–74]. Rotor diameter ranges from just under 30 meters to more than 80 meters, and nacelle and rotor weight varies widely, depending on rated power, rated wind speed, utilization of gearboxes and generator type. There is a trend to produce lighter turbines, with special attention at blade materials, for reduction of tower costs and improved performance. Nonetheless, low speed permanent magnet direct driven synchoronous generators, that are more bulky when compared with a high speed DFIG of same rated power, have been increasing in market share [68, 69]. These factors are important when trying to gauge the potencial for inertial response of future wind turbines. Typical ranges for wind turbine and generator rotor inertia and inertia constant, for turbines around the 2 MW rated power, are shown in Table 5.1. Thus, the potential kinetic energy stored to be explored, as indicated by inertia constant, is of a range somewhat similar to power plants of other conventional technologies [75].

Table 5.1: 2 MW Wind turbine typical ranges for inertia and inertia constant [30]

Component	Inertia ($kg\ m^2$)	Inertia constant (s)
Generator rotor J_{mg} and H_{mg}	65 – 130	$0.4 - 0.8$
Wind turbine J_{mr} and H_{mr}	$3 \times 10^6 - 9 \times 10^6$	$2 - 6$

5.4 Inertial response

Inertial response from widely used variable speed wind turbines does not occur naturally, as these turbines are partially or fully decoupled from the grid, effectively armored from the effects of grid frequency deviations. To produce this response, an action must be implemented in the power controller of the wind turbine frequency converter. With frequency measurement from the grid and suitable signal processing, a threshold for wind turbine kinetic energy discharge or absorption is set, and when a frequency deviation of significant magnitude is identified, the turbine reference power from the power control is modified. This results in the turbine point of operation being modified, and the rotor absorbs or releases kinetic energy as required.

Naturally, during normal operation at power production optimization, this response is possible only for a finite period of time and, after an inertial response action requiring energy discharge, the turbine will operate below its previous set power level, while it recovers the released kinetic energy. This characteristic recovery time is a negative of utilizing inertial response from wind turbines, specially when they are in wind conditions below rated, but nonetheless the inertial response from wind turbines gives time for primary reserves connected in the grid to start dispatching complimentary power, potentially limiting the amplitude of grid frequency deviations and improving overall grid stability [66].

It is possible to improve wind turbine inertial response by combining wider control strategies. Wind turbines fitted with generator, frequency converter and transformer designed for short duration overloads, working at wind speeds above nominal and already shedding wind power potential can instead momentarily work overloaded, giving inertial response without needing a recovery time. Several turbines controlled in a integrated system can be divided into groups, that will return to normal operation at different times, thus limiting the power dip during recovery. Some wind turbines might provide frequency reserve, selling capacity and operating deloaded, being thus able to provide frequency response without requiring recovery [64, 66].

6 Simulations

To illustrate the potential of utilizing the stored kinetic energy of wind turbines as a synthetic inertia on the system, a hypothetical scenario based on the Finnish electrical system is investigated. The simulation focus is on the variation of grid inertia as a consequence of increase in the share of wind turbines, and as such, employs a simple model, that does not account for inter-machine oscillations or delays introduced by the transmission lines. The existing generation infrastructure is clumped into one system source for each generation type (hydroelectric, thermal and wind) feeding one system-wide load while keeping the grid frequency at nominal value. The grid model, shown in Figure 6.1, is represented by the combined inertia constant of the generators and a system load damping constant, from equations (2.8) and (2.11), as discussed in section 2.

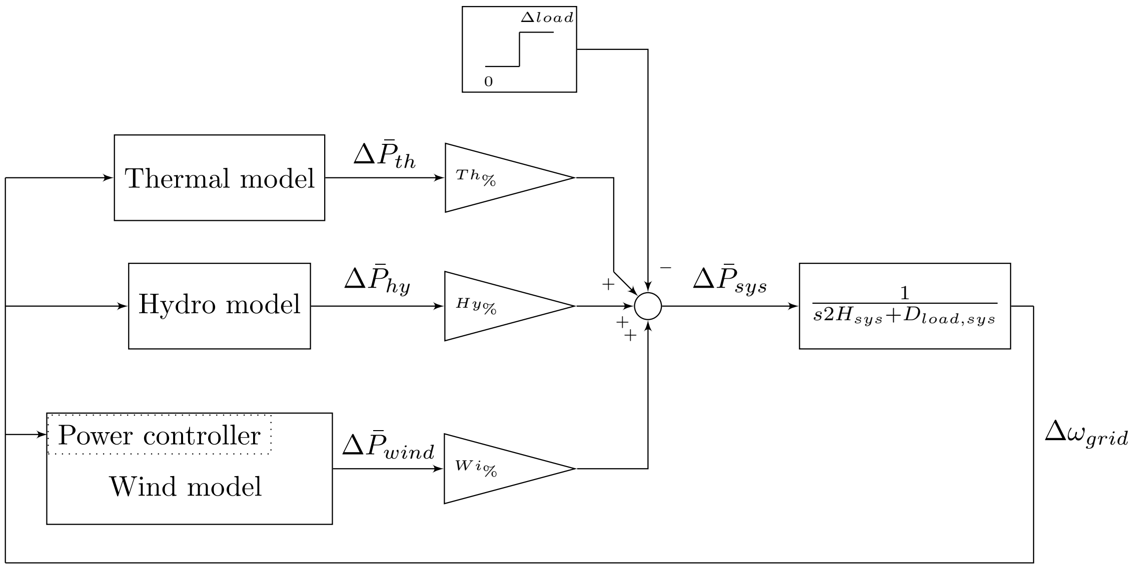

Figure 6.1: *Grid model for simulation of inertial response*

The simulations start from a base scenario containing the present generating infrastructure of Finland and estimated inertia of the Finnish grid. All the different generating technologies are modeled in per unit, and their output is adjusted by a gain that represents their share in the scenario. At an instant t, a fault is introduced to the grid. For the base scenario, this fault is the sudden loss of part of the generating infrastructure, which leads to a shortage of available supply over demand. The behavior of each generating unit and its primary frequency control, as well as the grid overall frequency deviation and power intake, are observed.

From the base scenario, different situations are explored. The amount of power provided by wind turbines is increased, represented by adjustments in all generating units output percentage gain. Wind turbine excitation from wind conditions is varied. Load loss, instead of generation loss, is simulated.

For the cases where part of the generation becomes unavailable, the fault is assumed to be from a thermal power plant. The thermal power plants have a higher average inertia constant, and a fault in such unit is more severe for the system. This fault is represented by a step change in the power equilibrium, downwards to a negative value at the fault instant. Overall grid inertia constant is evaluated taking into account this thermal generation loss, and the thermal model percentage share is also reduced by the magnitude of the fault.

During load loss simulation, grid inertia constant is unchanged. In practice this value should be reduced, but the present simulations already do not take into account load contribution to overall system inertia, and the inertia constant is somewhat underestimated. This error is acceptable, as the simulated scenarios are more severe than it would be for the real cases, resulting in conservative simulations.

In all scenarios and cases, the simulations start without implementation of a control loop on the wind turbines for synthetic inertia response. Afterwards this control loop is enabled, with different sets for a proportional gain, similar to an adjustment of droop for a conventional power plant. All simulations are executed in Matlab, with the Simscape power systems package.

6.1 Wind turbine model

The model developed for wind turbine simulation is focused on the turbine torque behavior when subject to a controlled change in set electric power production. As the hub, blades and generator rotor rotate, they store kinetic energy that can be used to temporarily boost turbine power production. Afterwards, available power will reduce below the optimal set while the turbine recovers its rotational speed. Conversely, these rotating masses can instead instantaneously absorb surplus power from the grid, and can either shed away this extra power by controlling blade pitch angle to sub-optimal values, or feed this absorbed power back to the grid if suitable.

At the core of the wind turbine model is a two-mass shaft representation. It is in this part that the turbine speed and torque response can be observed, when a controller modifies its demanded power setting. Wind turbines also require a wind power model, that takes into account available wind speed, blade pitching and rotor speed to produce the available power input for the turbine, as the required turbine responses will affect its speed and impact the actual available power. A pitch controller model is also present, to provide the suitable pitch angle for the wind power model.

Other element that must be modeled for the target simulation is an electrical power controller. The turbine power controller usually adjusts output power to the optimal value according to available wind speeds. For this simulation, it will be modified to incorporate a feedback from grid frequency. Whenever this frequency is disturbed, the power setting will deviate from the maximum point of power tracking, effectively forcing the turbine to accelerate or decelerate, thus absorbing or releasing kinetic power in response to frequency increases or drops, respectively.

6.1.1 Wind power

To properly simulate a wind turbine inertial behavior, the available power from the wind as a function of turbine speed must be known. The power P_{wind} available in a flowing air mass of density ρ, moving at a speed V through an area A is given by:

$$P_{wind} = \frac{1}{2}\rho A V^3 \tag{6.1}$$

Not all this power can be harvested by a wind turbine. The theoretical efficiency limit for this technology, derived from principles of mass and momentum conservation, was first calculated by the German physicist Albert Betz and is expressed as the Betz law, which states that no turbine can gather more than $16/27$, or 59.3% of the available kinetic energy in the flowing air mass [76]. This proportion, commonly referred to as the maximum power coefficient $C_{P,Betz}$, is the upper limit that any wind turbine could feasibly operate. Real, pitch controlled, variable speed wind turbines have variable C_P values, that depend on the blade pitch angle β and the tip-speed ratio λ, which is the ratio between the tangential rotor blades tip speed and wind speed, given by:

$$\lambda = \frac{\omega_{wt} r}{V} \tag{6.2}$$

where ω_{wt} is the wind turbine rotational speed and r is the total radius from the center of rotor hub to the tip of a blade. These C_P values are represented by several curves relating the three parameters, and curve fitting can be employed for simulation. A curve fitting to represent this behavior for a generic turbine is given by [77]:

$$C_P(\lambda,\beta) = C_1(C_2\left(\frac{1}{\lambda+0.08\beta} - \frac{0.035}{\beta^3+1}\right) - C_3\beta - C_4)e^{-C_5\left(\frac{1}{\lambda+0.08\beta} - \frac{0.035}{\beta^3+1}\right)} + C_6\lambda \tag{6.3}$$

with the parameters $C_1 = 0.51763$, $C_2 = 116$, $C_3 = 0.4$, $C_4 = 5$, $C_5 = 21$, and $C_6 = 0.006795$, for . The resulting torque available at the mechanical shaft is:

$$T_m = \frac{C_P(\lambda,\beta)P_{wind}}{\omega_{wt}} \tag{6.4}$$

The equations (6.1) to (6.4) are implemented in a block that has available wind speed V, pitch angle β and wind turbine rotational speed ω_{wt} as inputs and mechanical torque T_m as output, as shown on Figure 6.2. The model is implemented to represent a wind farm generating 1 p.u. power. All parameters, except β, are referred in p.u., and the equations are greatly simplified [78]. The turbine is modeled to produce 1 p.u. mechanical power P_m at 1 p.u. wind speed V, 1.2 p.u. ω_{wt} and pitch angle $\beta = 0°$. For instance, 1 p.u. wind speed V, which is the turbine rated speed, results in 1 p.u. available wind power P_{wind}. At 1 p.u. V and 1.2 p.u. ω_{wt}, tip-speed ration λ = 1 p.u., and with $\beta = 0°$, $C_P(\lambda,\beta)$ also results in 1 p.u. Thus, the model output mechanical torque is $\frac{1}{1.2}$ p.u. for rated wind speed, at β = 0. As an induction generator is employed, the rotor mechanical rotational speed for maximum power yield is 1.2 p.u. of the generator nominal electrical rotational speed. The nominal tip-speed ratio and maximum $C_P(\lambda,\beta)$, required for adjusting the input and output so that formula (6.3) results in 1 p.u. power coefficient output, are respectively $\lambda = 8.1$ and

$C_P(\lambda = 8.1, \beta = 0°) = 0.48$. The base for wind power, mechanical power and electrical power are different, so that 1 p.u. P_{wind} produces 1 p.u. P_m, which outputs 1 p.u. P_e.

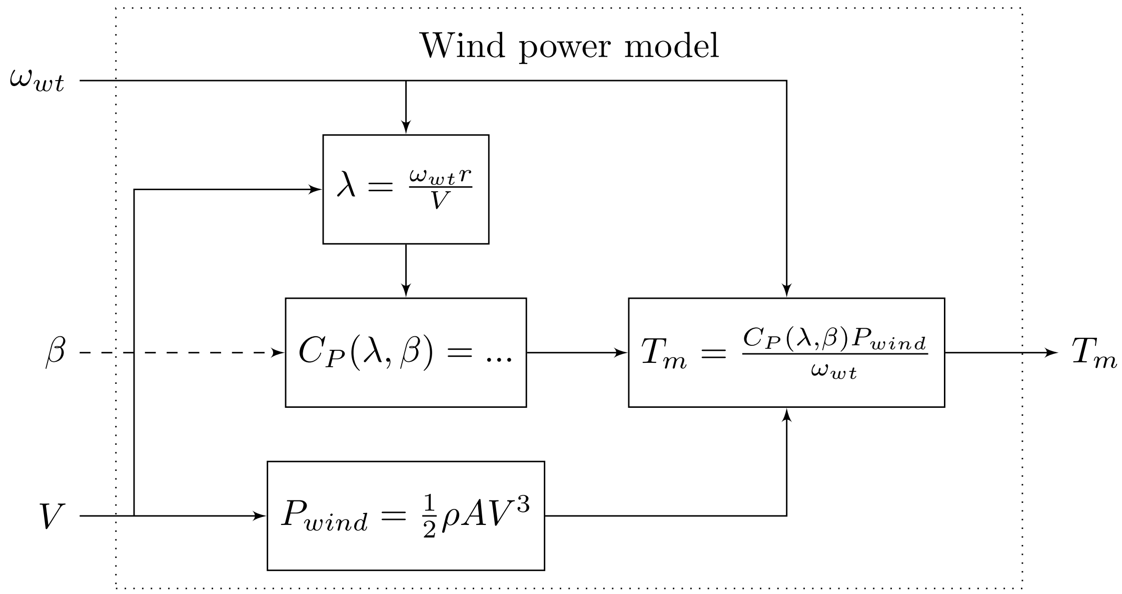

Figure 6.2: *Wind turbine available mechanical torque at the shaft as a function of wind speeds, rotor rotational speed and blade pitch angle*

6.1.2 Wind turbine shaft

For the variable speed wind turbine modeling, a shaft representation should be incorporated, as the low-speed shaft is relatively soft [30], which impacts the turbine behavior during transients. On the other hand, representation of high speed shaft and gearbox in the case of high speed models is not required for the purpose of this simulation, with the assumption that high speed shaft stiffness is infinite. This simplifies the choice of technology implementation, as for both high DFIG and low speed synchronous generators the turbine mechanical representation is the same. The following set of equations (6.5), is the base for a two-mass model, composed of rotor mass with inertia constant H_{mr} and generator mass with inertia constant H_{mg} separated by a shaft of stiffness constant K_{sh} and mutual damping D_{mutual} [30, 78, 79].

$$\begin{aligned}
\frac{d\omega_{wt}}{dt} &= \frac{T_m - K_{sh}\gamma - D_{mutual}(\omega_{wt} - \omega_{mg})}{2H_{mr}}, \\
\frac{d\omega_{mg}}{dt} &= \frac{K_{sh}\gamma - T_e - D_{mutual}(\omega_{mg} - \omega_{wt})}{2H_{mg}}, \\
\frac{d\gamma}{dt} &= 2\pi f(\omega_{wt} - \omega_{mg})
\end{aligned} \tag{6.5}$$

where ω_{mg} is the mechanical speed of the generator, γ is the angular displacement between the two ends of the shaft, T_e is the demanded electrical torque of the generator, and f is grid frequency in Hertz. As variable speed turbines are partially or fully connected to the grid through frequency converters, the electrical torque can be controlled by adjusting stator currents and converter firing, within thermal limits of the components and actual available power. Usually, electrical torque is simply set at the optimal value for electrical power generation, being controlled to keep turbine rotational speed following a set reference according to available wind power. Nonetheless, the strategy for setting this reference can be modified, and a feedback from grid frequency to demand extra torque in the case of frequency drop, and conversely to reduce electric torque for the event of frequency rise, is feasible [66, 80]. The turbine mechanical model is shown on Figure 6.3.

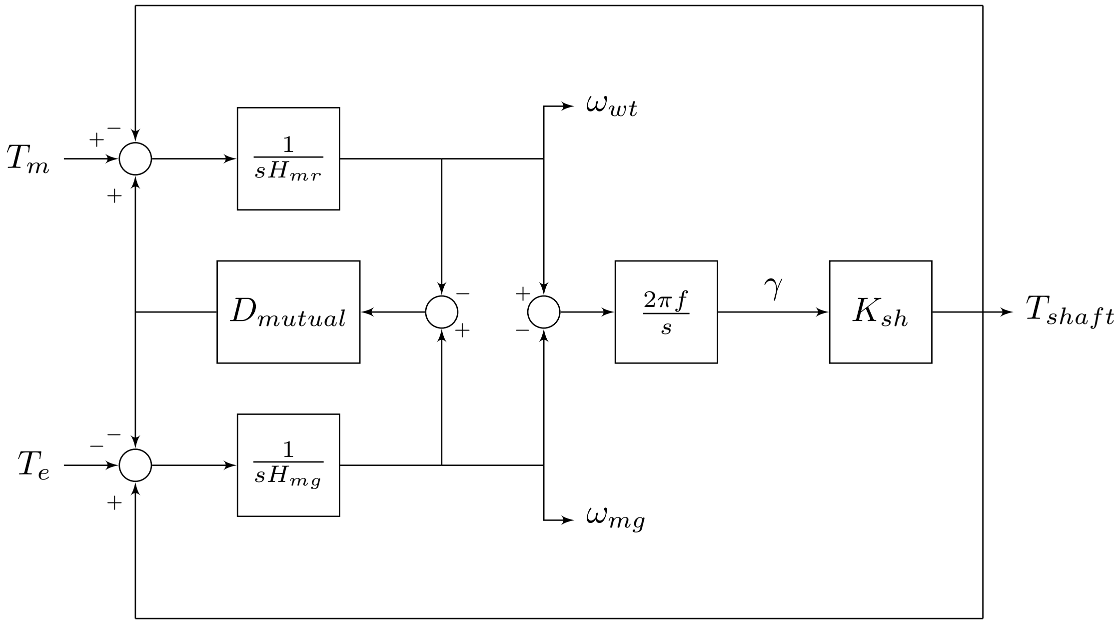

Figure 6.3: *Wind turbine two mass shaft model*

The input and output for this model are in p.u., but the parameters themselves are not. For a model based on a 1.5 MW DFIG wind turbine operating at grid frequency 50 Hz, the selected parameters are presented on Table 6.1. This specific turbine was chosen as a reference because it has a wide application and readily available data.

Table 6.1: Model selected parameters based on a 1.5 MW Wind turbine typical ranges [30, 79]

Component	unit	value
Turbine rotor inertia constant H_{wr}	s	4.33
Generator rotor inertia constant H_{mg}	s	0.96
Shaft stiffness constant K_{sh}	$p.u.torque/radians$	1.39
Mutual damping D_{mutual}	$p.u.torque/p.u.speed$	2.3
Nominal generator speed ω_{base}	$radians/seconds$	157.08

6.1.3 Pitch controller

A model of the pitch control, shown in Figure 6.4 is also included to provide the reference pitch angle β that defines the operating C_P. For wind speeds below nominal, the pitch is kept at the minimum position, referred as $\beta = 0°$. The pitch controller can use a simple proportional controller with a suitable gain $K_{P,pitch}$, in order to keep the turbine rotational speed under the nominal value. Even though proportional control has a steady state error and will occasionally allow the rotor speed to exceed its nominal value, it is suitable for a wind turbine pitch controller, as wind speeds are always varying, preventing a steady state to ever be truly reached, and a tolerance for short duration, small amplitude overspeeding is typical in wind turbine design [30, 70].

A second PI controller is implemented to keep turbine power under its rated value. This second controller, called pitch compensation, uses the difference between generator maximum output power and its actual power, further increasing pitch angle if the power surpasses the maximum allowed [78]. Its parameters are $K_{P,comp}$ and $K_{I,comp}$. The integrator has a minimum output of zero, and any pitch compensation to increase turbine power is done primarily by the proportional gain.

The output of the pitch controller passes through a rate limiter, to reflect the pitch actuator maximum rate of change, and a saturation, to account for minimum and maximum pitch angles. The parameters for this model are $K_{P,comp} = 3$, $K_{I,comp} = 30$ and $K_{P,pitch} = 150$ [79]. The pitch angle β can vary between $0°$ and $45°$

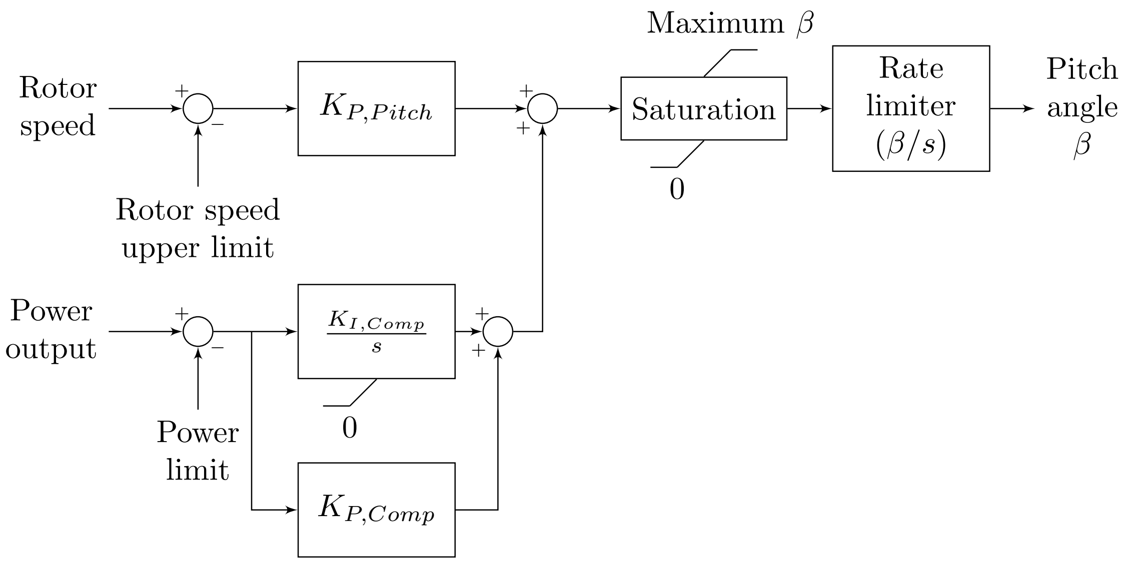

Figure 6.4: *Wind turbine pitch angle controller model*

The response of the pitch controller with pitch compensation is show on Figure 6.5. The incorporation of a pitch control representation to the model becomes relevant for simulating scenarios where the turbines are run at wind speeds above nominal for the model, or to decelerate the turbine to its limit speed in the event of a speed deviation during operation which might drive the turbine above this boundary. It would come into action on a wind turbine operating at wind speeds below nominal, for instance, if a controller for synthetic inertia is present and system frequency suffers a sudden rise. In order contain the frequency surge, the controller would accelerate the wind turbine, rapidly reducing its power output to the converter, and subsequently to the grid, while absorbing kinetic energy. This acceleration, however, must be limited, so that turbine speed does not significantly surpass the maximum for safety limits, and is not kept in overspeed for prolonged periods.

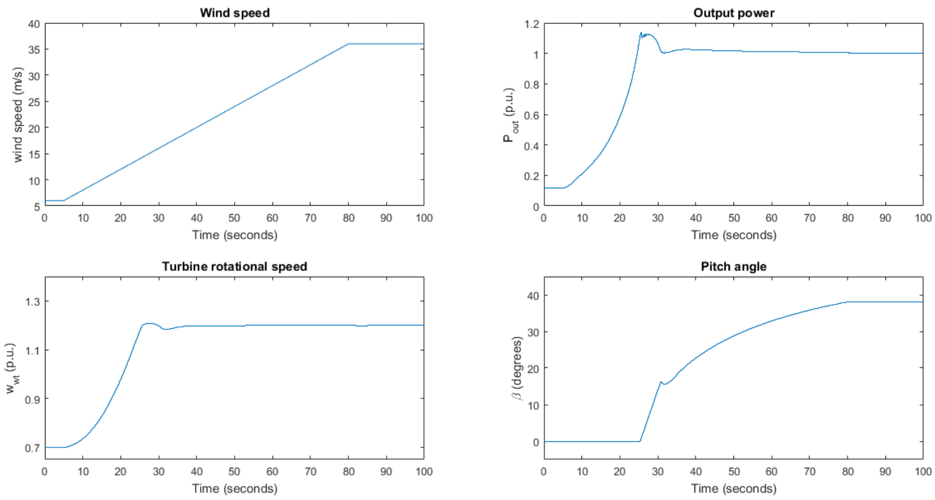

Figure 6.5: *Wind turbine pitch angle controller response to a rise in wind speed from 6 m/s to 36 m/s*

6.1.4 Power controller

On a real wind turbine, the power controller sets the reference electrical torque that is fed to the frequency converter control. The frequency converter will have its currents adjusted in order to produce the reference electrical torque, which in turn will affect the generator and subsequently the mechanical shaft behavior. The model presented does not intend to investigate the electrical characteristics of the wind turbine, so the generator electrical side and frequency converter are omitted, and the reference electrical torque is assumed to be followed, being directly used to feed the shaft model.

The power controller takes the output electrical power of the wind turbine as a reference and produces a suitable electrical torque reference, also taking into account the actual generator rotational speed. Turbine power characteristics usually come in various power curves, relating wind speed, rotational speed and pitch angle, as shown in Figure 6.6.

A lookup table, specific for each turbine model is usually employed, using the output power as a reference to set a reference rotor speed which in turn sets the reference electrical torque [70]. In the absence of the lookup table, a linear fit utilizing the maximum values of the power characteristics curve, resulting in a polynomial equation relating power and rotational speed, is suitable [79]. The curves used are the ones for pitch angle $\beta = 0°$, as the angle should be kept at minimum for optimal power production until wind speeds reach the nominal for the turbine. Beyond 1 p.u. input power, the reference speed is kept constant at 1.2 p.u., and the pitch controller acts to keep input power limited to the maximum rated. From the left graph in Figure 6.6, the pairs of points that yield the maximum power for wind speed are taken, as presented on Table 6.2. Linear fits of second to

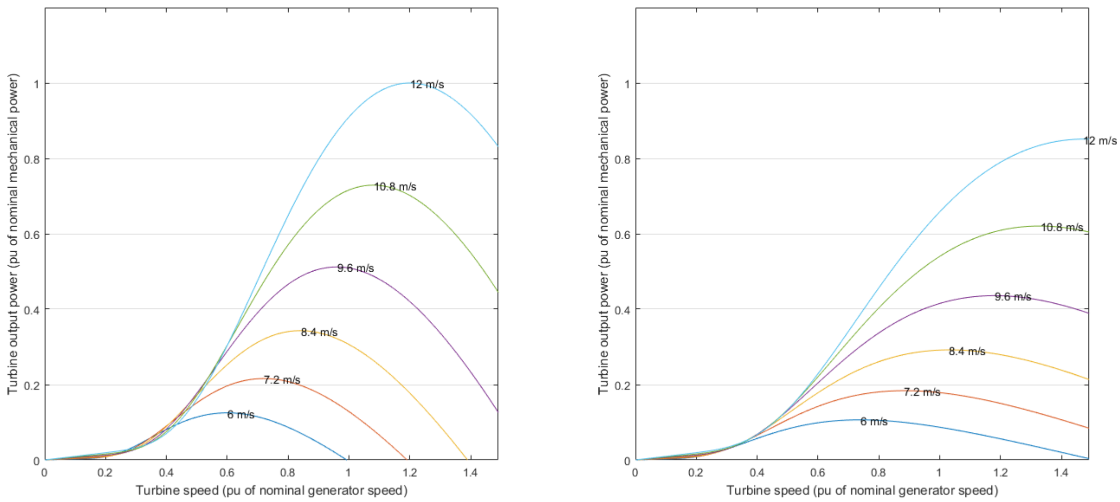

Figure 6.6: *Wind turbine power characteristics as a function of available wind speed, and rotor rotational speed, for blade pitch angle $\beta = 0°$ (left) and $\beta = 3°$ (right)*

fourth order are evaluated, as shown on Figure 6.7, and their standard deviation, calculated from the variance corrected by the number of coefficients of the resulting polynomial expression, are used to select the most adequate result.

Table 6.2: Maximum power in p.u. and respective rotational speed at given wind speeds

Wind speed (m/s)	Power P_e (p.u.)	Generator speed ω_{mg} (p.u.)
6	0.125	0.601
7.2	0.216	0.721
8.4	0.343	0.841
9.6	0.512	0.961
10.8	0.729	1.081
12	1	1.2

From the Table 6.3, the fourth order fit results in a standard deviation lower than 0.2%, and this fit is used to produce the reference rotational speed $\omega_{mg,REF}$. This value is compared with the actual generator speed, and the difference is input in a PI controller which outputs the commanded electrical torque $T_{e,REF}$:

$$T_{e,REF} = \omega_{mg} - \omega_{mg,REF} \frac{K_P s + K_I}{s} \tag{6.6}$$

The proportional and integral gains K_P and K_I can be chosen accordingly, to adjust speed and smoothness of the turbine response.

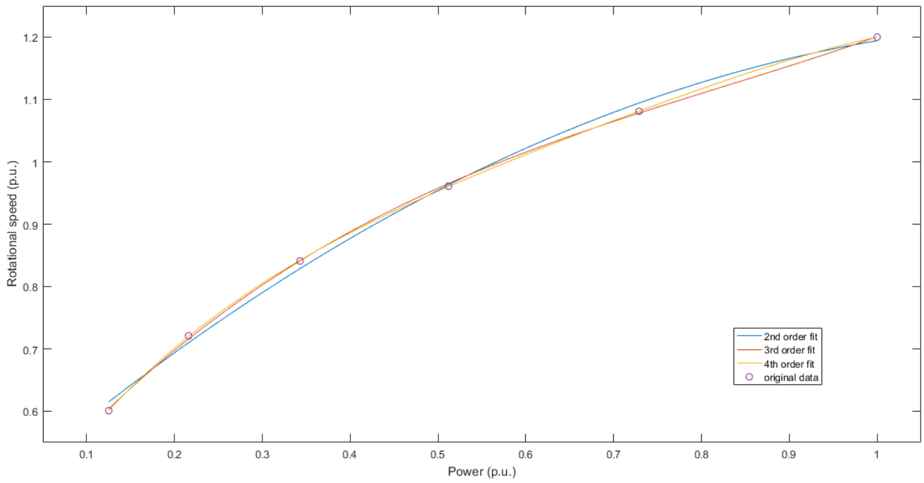

Figure 6.7: *Linear fit of second, third and fourth order for optimal rotational speed at a given power output, for pitch angle $\beta = 0°$*

Table 6.3: Polynomial coefficients, variance, and standard deviation of the linear fits

Polynomial	Variance	Standard deviation
Second order: $\omega = -0.4875\bar{P}_{out}^2 + 1.2087\bar{P}_{out} + 0.4715$	2.3×10^{-4}	0.0151
Third order: $\omega = 0.6185\bar{P}_{out}^3 - 1.5278\bar{P}_{out}^2 + 1.6951\bar{P}_{out} + 0.4147$	3.1×10^{-5}	0.0055
Forth order: $\omega = -1.0909\bar{P}_{out}^4 + 3.0021\bar{P}_{out}^3 - 3.2541\bar{P}_{out}^2 + 2.1672\bar{P}_{out} + 0.3757$	3.6×10^{-6}	0.0019

To implement inertial response on the wind turbine, electrical torque setup must be modified to receive a feedback from the grid frequency. There are several different strategies for this purpose, as discussed on section 4.4. Here, the grid frequency deviation, in p.u., is used to increase or decrease the reference rotational speed, resulting in a lower reference speed if the grid frequency drops, or higher reference speed if the grid frequency rises. Either way, the turbine will be forced out of its optimal operation. Nonetheless, the initial consequence of this control will be the release of rotor kinetic energy from increased electric torque when the rotational speed reference is reduced, or absorption of kinetic energy by the rotor, that will start accelerating as the electric torque reduces, effectively mimicking the inertial response of conventional machines synchronously connected to the grid and fitted with a governor control. This feedback from the grid can even be adjusted with a suitable gain, R_{wind}, that can amplify or reduce the effect of grid frequency on the reference frequency, ultimately behaving similarly to a speed droop. This effect is analogous, but not identical to the other machines in the grid. The characteristics of power and rotational speed of a wind turbine limit their contribution, so this feedback should not be kept indefinitely while the grid is facing a frequency deviation, specially for frequency drops. After the initial power surge, the wind turbine will lose output capacity as show on Figure 6.8, and the feedback frequency deviation from the grid must be cut out, otherwise the wind turbine will not recover to its optimal point while the grid frequency disturbance lasts, limiting its energy production, which could hinder instead of help system recovery afterwards. The power controller model, shown on Figure 6.10, has a limiter, implemented as a slow integral controller, with a time constant of 50 seconds, that reduces the input of frequency deviation from the grid to the model over time, effectively restricting the duration in which the turbine is actively participating in frequency control, and allowing the turbine to return to optimum power output, as shown on Figure 6.9.

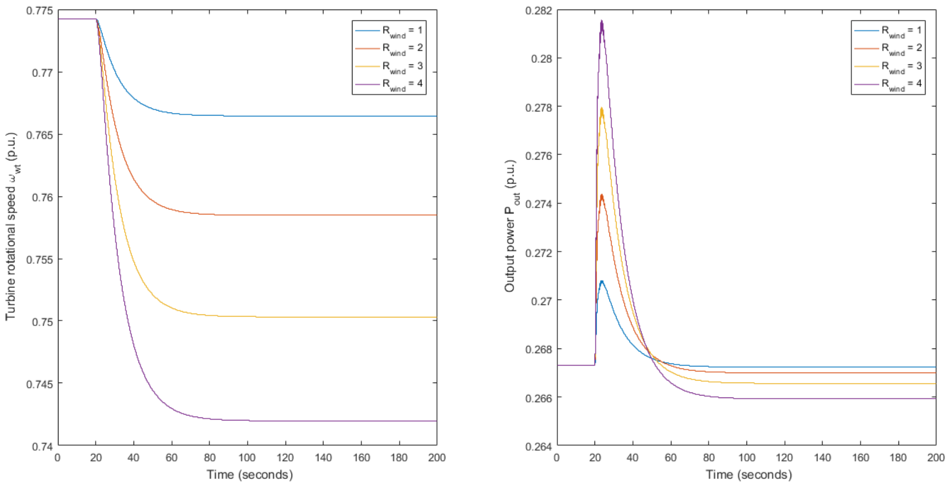

Figure 6.8: *Response of the wind turbine model with synthetic inertia enabled on the power controller, operating at 0.6442 p.u. wind speed, after a grid fault in t = 20 seconds resulting in a 0.01 p.u. grid frequency ω_{grid} drop, for different values of R_{wind}, and with the grid feedback limiter disabled.*

The final model parameters are $K_{P,PC} = 3$ and $K_{I,PC} = 0.6$. $R_{wind} = 3$ is varied during simulations, to investigate its overall effect on wind turbine synthetic inertia response.

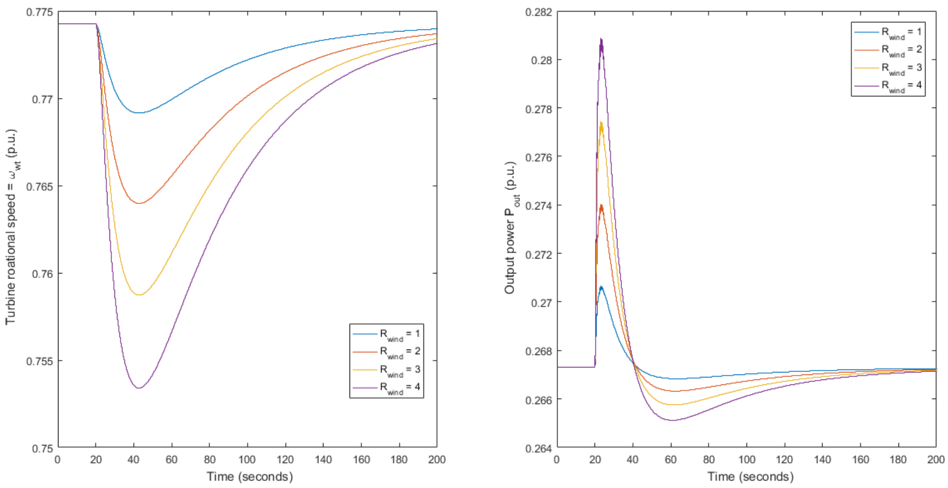

Figure 6.9: *Response of the wind turbine model with synthetic inertia enabled on the power controller, operating at 0.6442 p.u. wind speed, after a grid fault in t = 20 seconds resulting in a 0.01 p.u. grid frequency ω_{grid} drop, for different values of R_{wind}, with the grid feedback limiter enabled.*

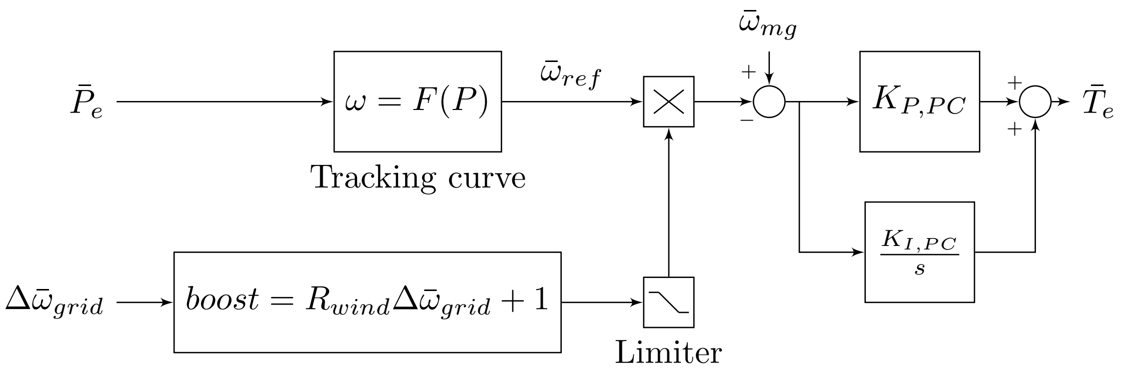

Figure 6.10: *Wind turbine power controller fitted with a feedback from grid frequency for simulation of synthetic inertia potential*

6.1.5 Wind turbine final model

The complete model for the wind turbine is presented on Figure 6.11. In order to connect this model to the system inertia, the reference power is subtracted from the output power, so that while no disturbance is present, $\Delta\bar{P}$ is equal to zero. As already mentioned, the wind turbine model presented does not include a model for the generator electric parameters and for the frequency converter. Nonetheless, for the purposes of this simulation, such simplification is tolerable, as the turbine electrical power delivered to the grid is fully controllable [66], and the reference electrical torque $\bar{T}_e$ will be set by adjusting converter currents and will followed by the generator as long as its value stays within feasible limits. The wind turbine rated wind speed, equivalent to 1 per unit, is 12 m/s.

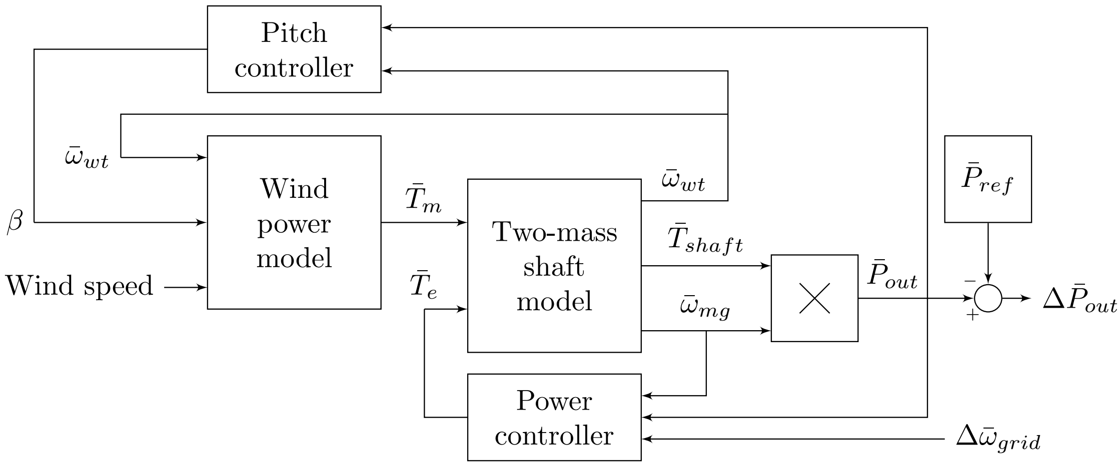

Figure 6.11: *Wind turbine model for frequency response, with synthetic inertia control implemented in the power controller, with adjustable R_{wind}*

6.2 Auxiliary models

The models for the other turbines used in the simulations are explained in this section. These models are based on the swing equation, and include, for each technology, speed governor and turbine. For units participating in automatic generation control, an additional loop and control block is present.

6.2.1 Hydro power plant

The basic transfer function for hydroelectric turbines, showing the variation in output mechanical power $\Delta\bar{P}_m$ in response to a variation in gate opening $\Delta\bar{G}$, in per unit, is [29]:

$$\frac{\Delta\bar{P}_m}{\Delta\bar{G}} = \frac{1 - T_W s}{1 + \frac{1}{2}T_W s} \tag{6.7}$$

The constant T_W is referred as the water starting time, and represents the time needed for a given hydraulic head to accelerate the water in penstock from standstill to the steady state value for that unit. This is a simplified transfer function for an ideal lossless turbine.

The governor is similar to the one in Figure 3.3, following the transfer functions:

$$\Delta Load = -\frac{1}{R_P}\Delta\omega_r \tag{6.8}$$

$$\Delta Y = \frac{1}{1 + sT_G}\Delta Load \tag{6.9}$$

R_p is the permanent speed regulation droop of the hydroelectric turbine. For an integral governor in the form $\frac{Gain}{s}$, T_G is the governor time constant, equal to $\frac{1}{Gain \times R_P}$. $\Delta Load$ is the perceived load increase that commands the gate positioning, and ΔY is the change in position reference for the gate.

Hydroelectric power plants utilize transient droop compensation to account for the initial opposite response, in order to stabilize speed control. The transfer function for this transient compensation is:

$$\Delta \bar{G} = \frac{1 + sT_R}{1 + s(R_T/R_P)T_R} \Delta Y \tag{6.10}$$

where R_T is a transient speed regulation droop and T_R is its reset time. This compensation results in a controller with high droop and resulting low gain during fast speed deviations, which limits gate movement to give the water flow time to react. Afterwards, this transient droop is dropped and the characteristic permanent droop R_p governs the steady state.

Finally, an integral control is added to implement automatic generation control. This integral control acts on the reference load of the hydroelectric unit, resetting this reference to a suitable level by adding a $\Delta Load_{REF}$, in order to eliminate the steady state error in grid frequency, effectively overriding the combined effects of frequency regulation of all generators connected, and eventually restoring their generation to the previously planned values. Its transfer function is given by:

$$\Delta Load_{REF} = -\frac{K_I}{s} \Delta \omega_r \tag{6.11}$$

This output is added to the one in equation 6.8, giving the integral control to ΔY an adjusted $\Delta Load$ boosted by $\Delta Load_{REF}$. The resulting representation of the hydroelectric unit is shown in Figure 6.12.

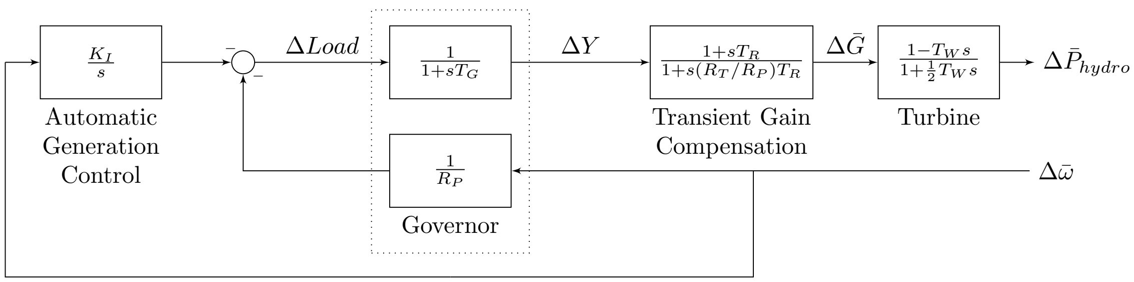

Figure 6.12: *Hydroelectric power plant model for frequency response, with governor droop control, transient droop compensation and automatic generation control for elimination of steady state frequency errors*

6.2.2 Steam power plant

The transfer function relating power variation, in per unit $\Delta\bar{P}_m$, as a function of valve position $\Delta V\bar{alve}$ for a tandem-compound single reheat steam turbine is presented below [29]:

$$
\begin{aligned}
\frac{\Delta\bar{P}_m}{\Delta V\bar{alve}} &= \frac{F_{HP}}{1+sT_{CH}} + \frac{1-F_{HP}}{(1+sT_{CH})(1+sT_{RH})} \\
&= \frac{1-sF_{HP}T_{RH}}{(1+sT_{CH})(1+sT_{RH})}
\end{aligned}
\tag{6.12}
$$

This is a simplified transfer function, assuming the time constant for charging of cross-piping and inlet volumes at the lower pressure section of the turbine is negligible when compared with the reheater time constant, T_{RH}. Boiler pressure is assumed constant. T_{CH} is time constant associated to the charging of main inlet volumes and control valves housing, and F_{HP} is the fraction of total power generated by the high pressure section of the turbine. The governor is identical to the hydroelectric power plant governor, with ΔY controlling the steam valve opening, and a single droop R instead of the permanent and transient droops. Steam turbines do not require transient droop compensation, as the peculiar behavior present in the former due to water inertia is absent here, and control is stable for the normal range of droop regulation in use. The representation of the whole steam turbine system for frequency control simulations, with governor controller, is shown in Figure 6.13.

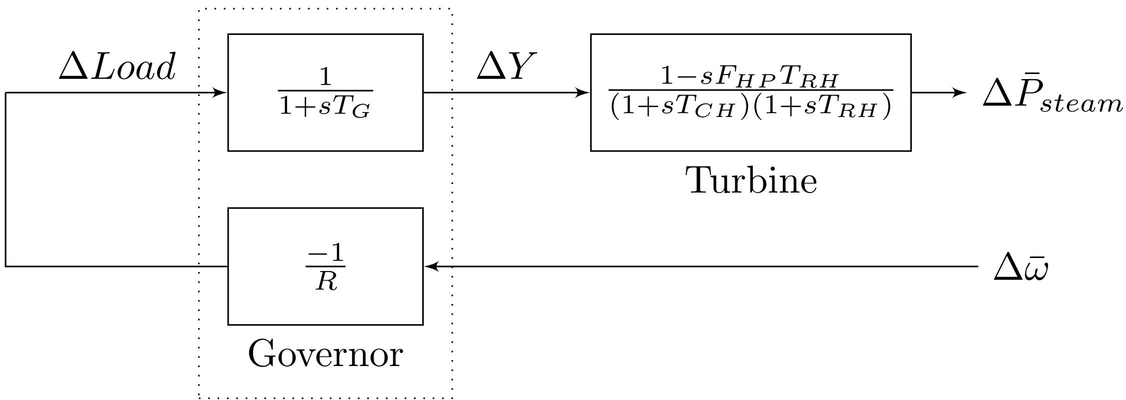

Figure 6.13: *Thermal power plant model for frequency response, with governor droop control*

6.3 Base scenario

The current Finnish electricity system is rather diversified. In 2015, the main sources of electricity were nuclear power plants, hydroelectric power stations, thermal power stations running on various combustibles, such as bio-fuels and waste, coal or natural gas, and wind turbines [1]. Some of the thermal power stations are combined cycle heat and electricity production plants, which run more loaded during winter, when heat demand is high.

Table 6.4: Electricity production in Finland in 2015 by source [1]

Source	Installed capacity (GW)	Capacity factor (%)	Annual production (TWh)	Share of annual production (%)
Total production	15.88	49.3	68.62	
Nuclear	2.75	96.4	23.25	33.9
Hydro	3.25	58.9	16.77	24.4
Combustible fuels	8.85	33.5	26.01	
of which:				
Bio-fuels and waste			11.81	17.2
Coal			8.79	12.8
Natural gas			5.20	7.6
Oil			0.21	0.3
Wind	1.01	26.4	2.33	3.4
Other	-	-	0.26	0.4

The Finnish grid, operated by Fingrid, is synchronously connected to the Nordic area Regional Group of the larger European electricity system coordinated by ENTSO-E. There are also direct current links from Finland to Russia and Estonia. Finland is part of Nord Pool electricity market and, as a net importer of electricity, a significant share of its consumption comes from sources external to the national system. In 2015, Finland imported 21459 GWh of electricity and exported 5122 GWh.

The base scenario is a simplified version of the Finnish system. The grid is taken as a simple node, where all generation is delivered. All existing thermal generation is clumped together in one group, representing the nuclear stations running at base load with only governor droop control, and the remaining thermal stations, which run more deloaded and can provide frequency control reserves. All hydroelectric power plants are gathered in another group, and their operation is also assumed to be deloaded. This group is the main responsible for frequency regulation, with enough reserves to cover for the loss of the single largest unit in the system, running in automatic generation control. Thermal and hydro power plants can, in reality, have a vast range of different characteristics inside their own groups. Thermal power plants, for instance, might utilize reheat or non-reheat turbines, which affects their valve positioning and power behavior in response to faults. Nonetheless, this simulation assumes all thermal units utilize reheat, as this is the common configuration of nuclear plants, and for the other thermal units it would be difficult to gather all the data to divide their power into the reheat and no-reheat groups. Still, the bigger differences between the behavior of thermal plants power output as dictated by the steam valve and the hydro plants power response following a change in water gate position, are preserved. This is relevant, as the hydroelectric power plant initial short-term response is opposite to what is desired, which impacts significantly system response immediately after a fault [29]. Wind turbines are also present, but initially they do not contribute to frequency control. It is assumed that all the demand is supplied by local generation, with no energy imports or exports.

The system is simulated for 7.797 GW, around 49% of maximum production. This value was the average power production in the Finnish grid during 2015. Each group has its output adjusted by a percentage gain, referent to the group contribution to the system, accordingly to its current share. The grid load damping coefficient is kept constant 0.9, which is typical for a electricity power system [29], while the system inertia is set according to the generation share, using average inertia constants for each technology, as presented in Table 6.5. For the purpose of system inertia calculation, all power plants are assumed to run at 0.9 power factor [75]. Hydroelectric power plants are assumed to produce their base share at 80% maximum power, with the remaining capacity used as a frequency regulation reserve. Thermal power plants are not fitted with automatic generation control, so they will not contribute to steady-state elimination of grid frequency error. Their share is reduced from the base annual value by 5%, as the power loss from the fault to be introduced is assumed to be from thermal units. The inertia constant estimated for this first scenario, taking into account the aforementioned assumptions and using the share for hydro, conventional thermal and nuclear representing the current Finnish electric system presented in Table 6.4, but already deducting the inertia from the fault, is H = 4.8106 s. This inertia constant might be slightly underestimated, as it is assumed that there is no contribution from industry electric drives directly connected to the grid.

Table 6.5: Average inertia constants by generation type [75]

Generation type	Inertia constant H (s)
Nuclear	6.3
Other thermal	4
Hydro conventional	3

The wind turbine model is run first without synthetic inertia, and then with synthetic inertia enabled with increasing values for R_{wind}. It is assumed to run at the average capacity factor of 26.4%, being thus propelled by an average wind speed of 0.6415 p.u (7.698 m/s). At the instant t = 5 seconds, a generation deficit of 5% of the system power is introduced. This fault, of roughly 390 MW, is of the same power range of an average thermal power plant, and is assumed to come from a sudden disconnection of one such unit. The system response, grid frequency variation, and each generating group contribution during the fault are plotted.

As it is based on the Finnish grid in 2015, this scenario has a very low share of wind generation (3.4%), so the overall contribution of synthetic inertia to grid stability, shown on Figure 6.14, is very small. The wind turbines output is temporarily increased during the first instants of the fault (Figure 6.15) which helps limit the amplitude of frequency drop slightly. The minimum frequency for each setup of synthetic inertia is presented on Table 6.6.

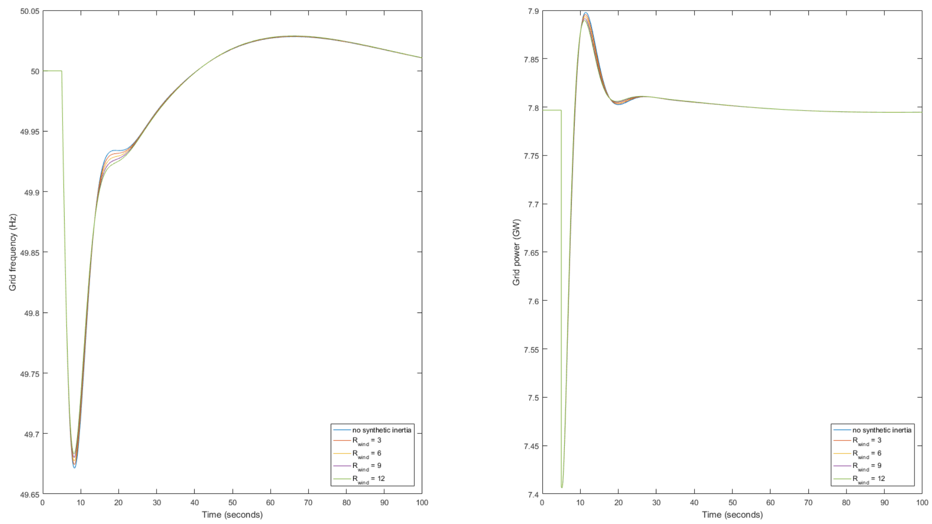

Figure 6.14: *Base scenario system response to a generation loss at the instant t = 5 seconds, for different wind synthetic inertia setups*

Table 6.6: Base scenario minimum frequency reached for each setup of synthetic inertia after generation loss

Synthetic inertia gain R_{wind}	Minimum grid frequency (Hz)
0 (No synthetic inertia)	49.671
3	49.674
6	49.677
9	49.680
12	49.683

It is observed that the hydroelectric model initial behavior is opposite to what is desirable for grid stability, as discussed in section 6.2.1, which aggravates system frequency response performance at the first moments after fault. It is also the slowest to respond, but eventually takes charge in correcting the remaining error from the mismatch in supply and demand, as it is assumed the frequency control reserves, with automatic generation control are available in this model, substituting the lost thermal share. Thermal generation provides the most robust initial response, partly for the fast intrinsic characteristics of steam valve response to control [29], but also partly because it is responsible for the larger share of generation in the base scenario.

This first scenario does not show a significant contribution of wind turbine synthetic inertia deployment for grid stability, but is nonetheless relevant as it defines the baseline against which the increased wind penetration scenarios can be compared.

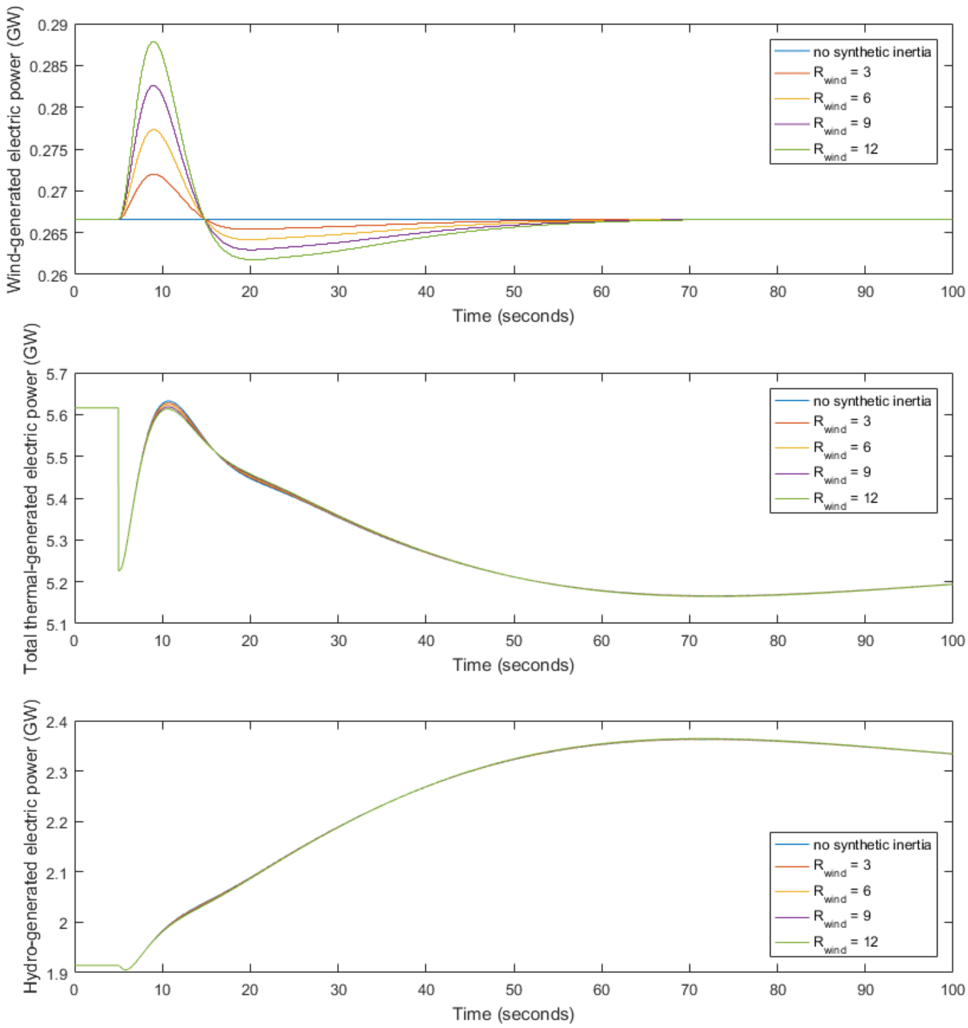

Figure 6.15: *Base scenario contribution of each generating block to the system after a generation loss at the instant t = 5 seconds, for different wind synthetic inertia setups*

6.4 Increased wind penetration scenarios

The scenarios of increased wind penetration start from the base scenario. All assumptions related to each model are still valid, except for the share of power generated for each technology, which is adjusted according to the amount of wind power increase, and the operating point of the wind turbines. The introduction of new renewable sources, with their lower marginal costs of operation, will likely result in a displacement of thermal power plants, with decommissioning of some units and operation at lower annual capacity factor of others [66]. Thus, for the increased wind penetration scenarios, thermal power will be substituted by wind power, with proportional reduction of shares for nuclear and non-nuclear thermal power plants. These power plants are the ones with greater inertia constant in the system, which will be significantly reduced as wind penetration reaches higher values. Also, scenarios when the overall wind infrastructure is kept constant, but available winds are higher, thus the instantaneous share of wind power in the grid reaches higher values, are evaluated. These scenarios illustrate more severe situations that might arise in high wind penetration systems.

6.4.1 Wind generation at 10% annual average scenario

For this first scenario, the capacities of the connected generation are as shown on Table 6.7. Wind penetration at 10% of average power production results in a reduction of grid inertia constant H to 4.4387 s, for the case of generation loss. In this scenario, the effects of synthetic inertial response from wind turbines on grid stability become more evident. While the minimum grid frequency without synthetic inertia is worse in this scenario when compared to the base, for R_{wind} = 12 it is improved to a similar level as the base scenario, as seen on Figure 6.16 and Table 6.8.

Table 6.7: Capacities of each generation group before fault for wind generation at 10% scenario

Source	Installed capacity (GW)	Capacity factor (%)	Generated power (GW)	Share of total power (%)
Total	16.74	46.6	7.7968	100.00
Hydro	3.25	58.9	1.9141	24.55
Thermal	10.54	48.4	5.1030	65.45
of which:				
Nuclear	2.50	96.4	2.4092	30.90
Conventional	8.04	33.5	2.6938	34.55
Wind	2.95	26.4	0.7797	10.00

The amplitude of power fluctuations after fault is reduced as R_{wind} increases. While there is a delay for frequency recovery between t = 15 s and t = 25 s with higher R_{wind}, in general the frequency change is smoother than without synthetic inertia, with all cases recovering to 49.9 Hz in no significant time difference, and having a similar behavior towards frequency stabilization afterwards. Figure 6.17 shows that as wind turbine synthetic inertia response increases, the initial strain on other generations is also reduced, specially for the fast response from thermal generation.

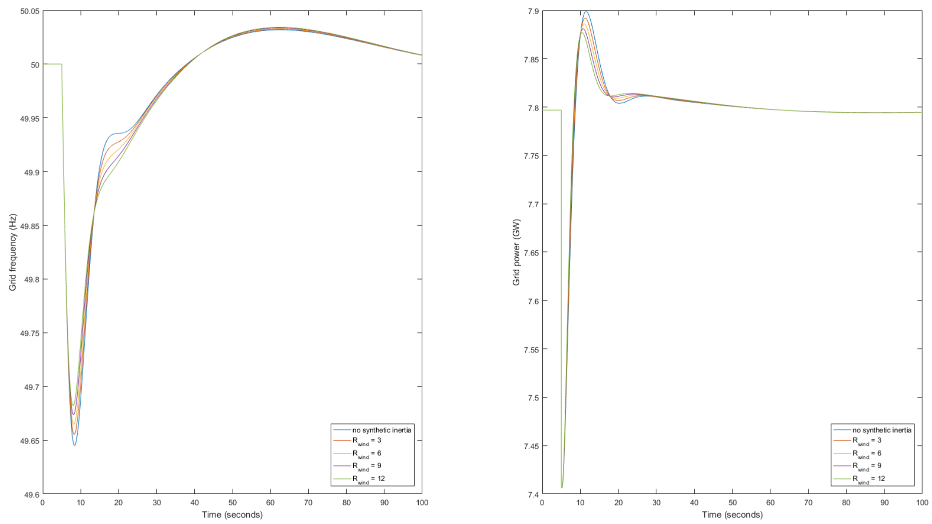

Figure 6.16: *10% scenario system response to a generation loss at the instant t = 5 seconds, for different wind synthetic inertia setups*

Table 6.8: 10% scenario minimum frequency reached for each setup of synthetic inertia after a generation loss

Synthetic inertia gain R_{wind}	Minimum grid frequency (Hz)
0 (No synthetic inertia)	49.645
3	49.655
6	49.665
9	49.674
12	49.682

A second group of simulations for the 10% scenario evaluates the synthetic inertia response for a disturbance from a sudden reduction in system demand, caused by disconnection of a large load, for instance after disconnection of transmission lines isolating one industrial area. For these simulations, an apparent generation surplus of 5% of the system power is introduced at the instant t = 5 seconds, and system response after fault, with grid frequency and power variation, are shown on Figures 6.18.

The grid inertia in this case is higher, as there is no generation lost, and the inertia constant H is 4.7213 s. The frequency deviation is smaller than in the case of lost generation, as seen on Table 6.9. Similarly to the power loss case, without synthetic inertia the overall frequency response deteriorates, but with R_{wind} = 12, the system frequency response reaches a more robust performance, with the amplitude of frequency deviation comparable to the base scenario. The hydroelectric group is again responsible for correcting the frequency error by automatic deployment of its reserves. As shown on Figure 6.19).

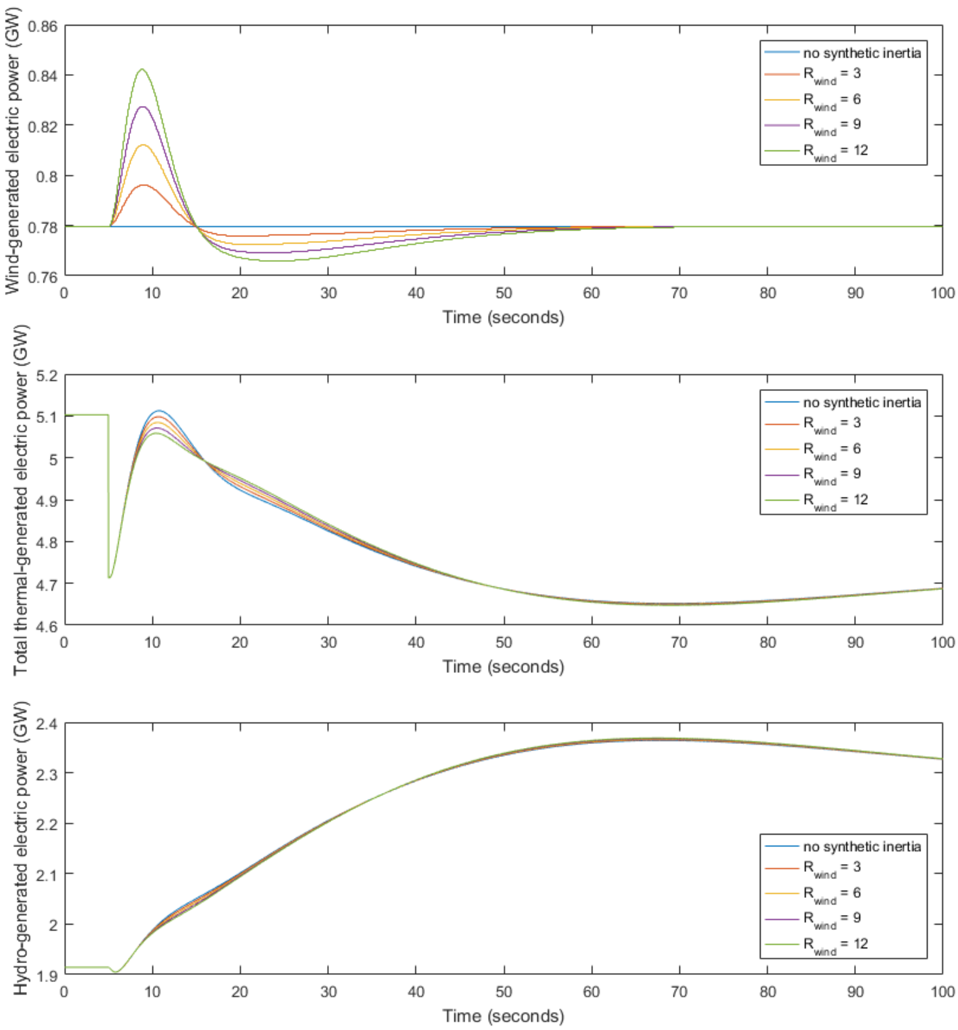

Figure 6.17: *10% scenario contribution of each generating block to the system after a generation loss at the instant t = 5 seconds, for different wind synthetic inertia setups*

In general, the load shedding scenarios are less demanding for the system than the generation loss scenarios. Without the loss of conventional generating units, system inertia is kept at a higher value, which contributes to a smoother grid frequency response. Wind turbine response in the events of grid over-frequency can be different than what is presented here, with active pitch control for further reduction in power available and improved response for power shedding. In fact, grid requirements for wind turbine response in case of over-frequency, as discussed in section 3.1.2 are already more severe than what is presented in these simulations, and a different control logic, without automatic recovery to optimum power production while grid frequency is unstable, is more advisable.

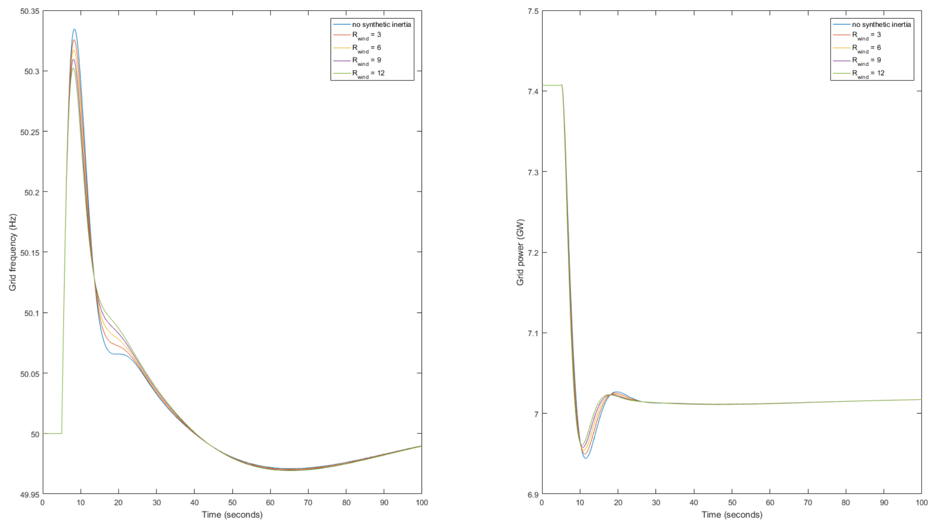

Figure 6.18: *10% scenario system response to a load loss at the instant t = 5 seconds, for different wind synthetic inertia setups*

Table 6.9: 10% scenario maximum frequency reached for each setup of synthetic inertia

Synthetic inertia gain R_{wind}	Minimum grid frequency (Hz)
0 (No synthetic inertia)	50.335
3	50.326
6	50.317
9	50.310
12	50.302

The overall contribution wind turbine synthetic inertia in this first scenario is still limited, as the combined responses of conventional steam and hydro power plants dominate, keeping the system behavior still close to the base case. Nonetheless, the contribution of this technique starts to be revealed, as the initial response of the steam group is relieved by the wind turbines, and there is some improvement in limiting the frequency deviation.

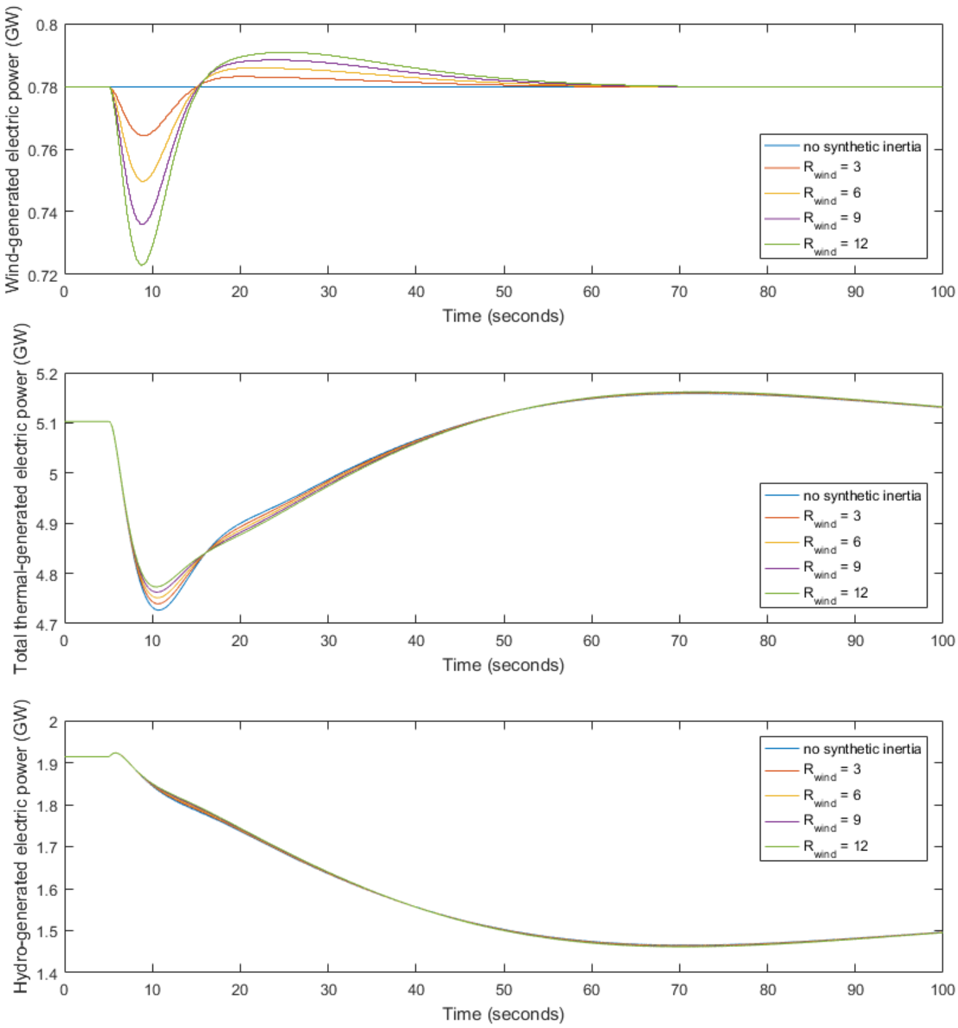

Figure 6.19: *10% scenario contribution of each generating block to the system after a load loss at the instant t = 5 seconds, for different wind synthetic inertia setups*

6.4.2 Wind generation at 30% annual average scenario

The generation groups for the wind penetration at 30% annual power production scenario are as shown on Table 6.10. The amount of conventional thermal connected is limited, and as a consequence, system inertia constant H drops to 3.3086 s. Without inertial response, grid frequency drops over 9% during a fault as seen on Figure 6.20. Increasing values of R_{wind} result in a significant enhancement in overall grid response as shown on Table 6.11.

Table 6.10: Capacities of each generation group before fault for wind generation at 30% scenario

Source	Installed capacity (GW)	Capacity factor (%)	Generated power (GW)	Share of total power (%)
Total	19.43	40.1	7.7968	100.00
Hydro	3.25	58.9	1.9141	24.55
Thermal	7.32	48.4	3.5437	45.45
of which:				
Nuclear	1.74	96.4	1.6732	21.46
Conventional	5.58	33.5	1.8705	23.99
Wind	8.86	26.4	2.3390	30.00

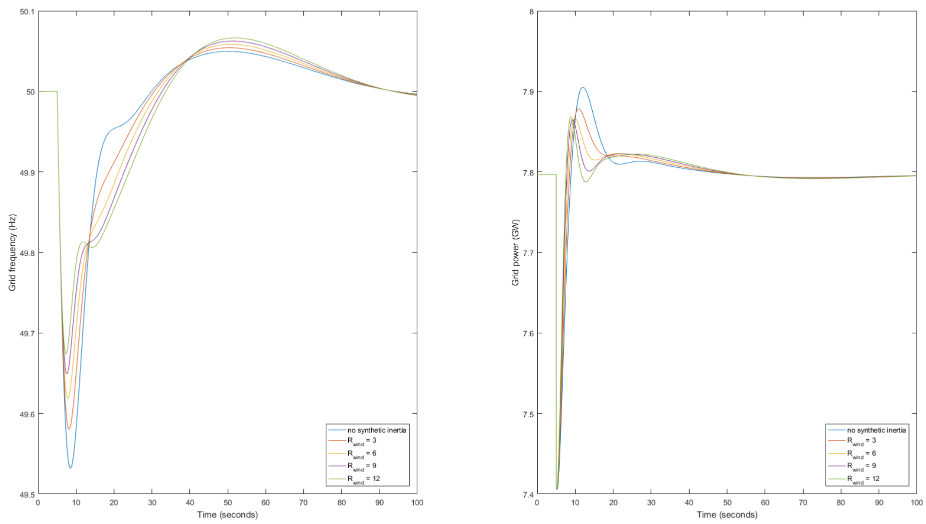

Figure 6.20: *30% scenario system response to a generation loss at the instant t = 5 seconds, for different wind synthetic inertia setups*

Wind generation share is significant for this scenario, and so is its initial contribution with synthetic inertial response, as shown on Figure 6.21, even responding faster than thermal units at R_{wind} = 12. As grid stability becomes more dependent on the wind turbines response with synthetic inertia, the negative aftereffect of these turbines recovery time following synthetic inertia response is more pronounced. While minimum frequency is kept limited, frequency recovery to 49.9 Hz is significantly delayed as R_{wind} increases, and there is a compromise in limiting the amplitude of frequency excursions and overall duration of frequency deviations.

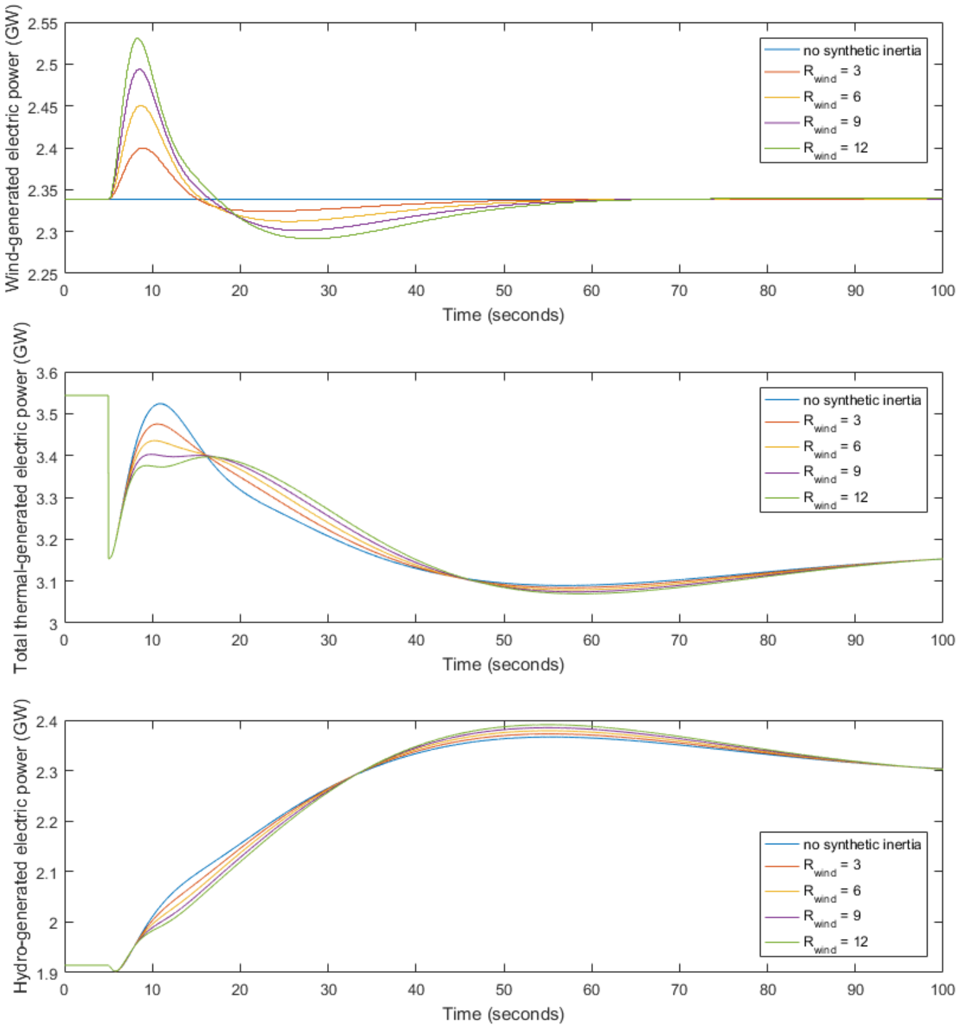

Figure 6.21: *30% scenario contribution of each generating block to the system after a generation loss at the instant t = 5 seconds, for different wind synthetic inertia setups*

Table 6.11: 30% scenario minimum frequency reached for each setup of synthetic inertia after a generation loss

Synthetic inertia gain R_{wind}	Minimum grid frequency (Hz)
0 (No synthetic inertia)	49.532
3	49.580
6	49.619
9	49.649
12	49.674

A similar situation, with wind contributing to 30% overall generation, could temporarily occur during high wind speed periods in a system with a smaller amount of wind generation capacity installed, or during low demand times. An alternate 30% wind penetration scenario utilizes the same wind turbines, but assumes wind speeds of 11.103 m/s (0.9252 p.u.) driving these turbines. The generation infrastructure of this scenario actually is the same as in the 10% scenario, presented on table 6.7, with the turbines temporarily loaded to 79.2% rated power, instead of 26.4%. It is assumed that when such situation happens, part of the thermal generation is not dispatched, as there is surplus power from the wind turbines [66], and overall system inertia constant is similar to the original 30% scenario. A comparison of both variants of the 30% wind generation scenario is show on Figures 6.22 and 6.23. The synthetic inertia contribution is more limited, as there are indeed less wind turbines connected. The initial response is slower, causing frequency deviation amplitude to increase, which causes a higher power production overshoot afterwards. This behavior is analogous to a system with conventional hydro and thermal power plants. When there are many plants running deloaded, system inertia is higher than when just a few units, running fully loaded, supply the whole grid.

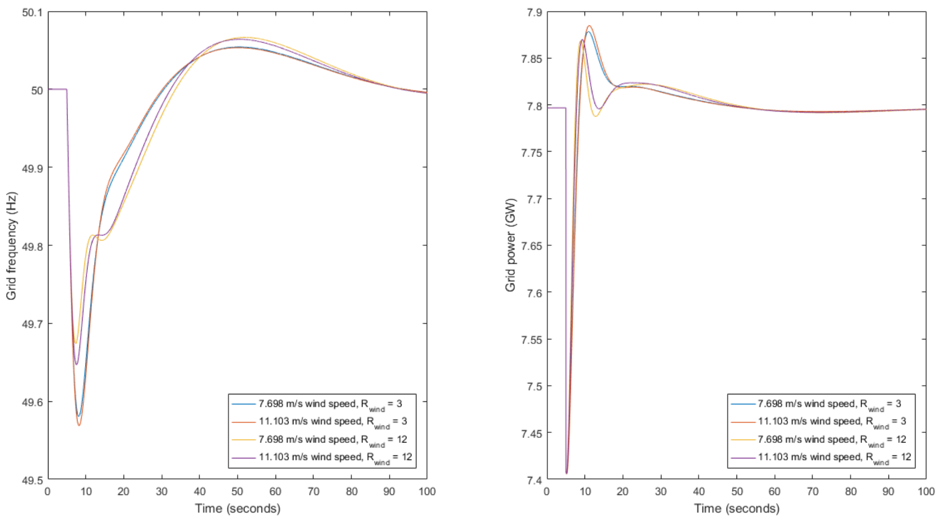

Figure 6.22: *Comparison of two different 30% wind penetration scenarios system response to a generation loss at the instant t = 5 seconds, for different wind synthetic inertia setups*

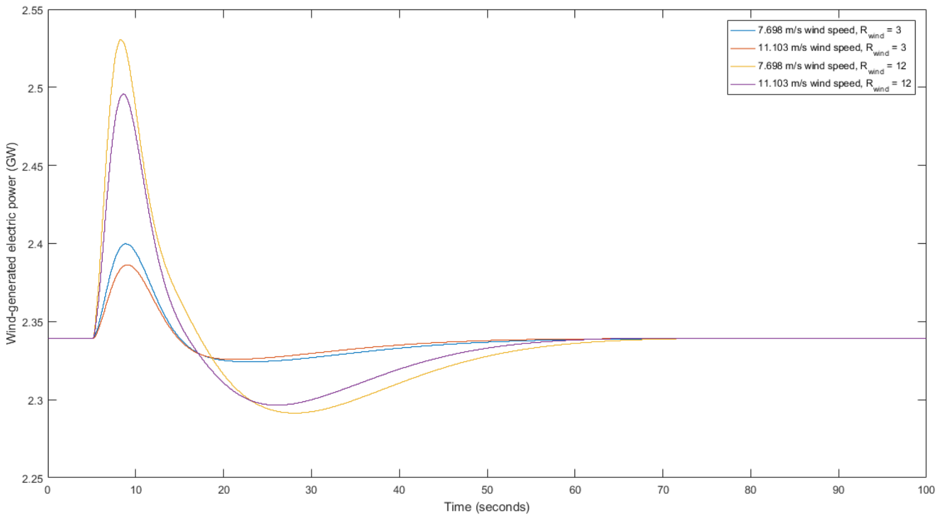

Figure 6.23: *Wind turbine response after grid fault at two different 30% wind penetration scenarios, for different wind synthetic inertia setups*

The 30% wind penetration scenarios demonstrate the significant contribution of employing synthetic inertia on wind turbines to improve grid stability after a fault. The minimum grid frequency after generation loss improves significantly when compared to this same penetration of wind generation but without synthetic inertia, reaching similar results as the base scenario where there was only 3.4% of wind generation. Nonetheless, the overall performance is different, as the wind turbines require a recovery period after delivering inertial response, delaying grid frequency recovery to nominal.

6.5 Scenarios with different wind turbine control strategies

6.5.1 Reserve power from wind turbines

As discussed in section 5.2, wind turbines are usually controlled for maximum power yield, but it is possible to operate them using different strategies, providing ancillary services to the grid. Wind turbines can, for instance, be operated slightly over optimal speed. This will result in an overall reduction of power production, but the turbines will have a small primary frequency control reserve and an improved condition for inertial response, as they can release stored kinetic energy without further recovery afterwards until system stabilizes, and they are freed to replenish the reserve.

Starting from the 30% wind power penetration scenario, the wind turbine reference rotational speed ω_{wt} is modified, so that in normal operation it has a small difference from the optimal speed for maximum power production. In order to keep the wind power production from this scenario still at 30%, the effective wind turbine infrastructure necessary has to be increased to cover the reserve power created. This has the overall effect of increasing wind turbine energy cost by the reserve power percentage, but in high wind penetration systems, this option should be evaluated, as this extra cost might be smaller than the cost for providing the same reserve, or ancillary services for grid frequency stabilization, from other sources.

In this scenario, the feedback grid frequency does not adjust turbine power production. Instead, it is used as a trigger for reserve deployment; when the frequency drops beyond a set limit, the reference rotational speed ω_{wt} is reset to the maximum point of power tracking, and the turbine will reduce its rotational speed as in returns to optimal operation, increasing overall production while at the same time releasing reserve kinetic energy, thus providing a fast response supporting grid stability. This controller model is shown on Figure 6.24.

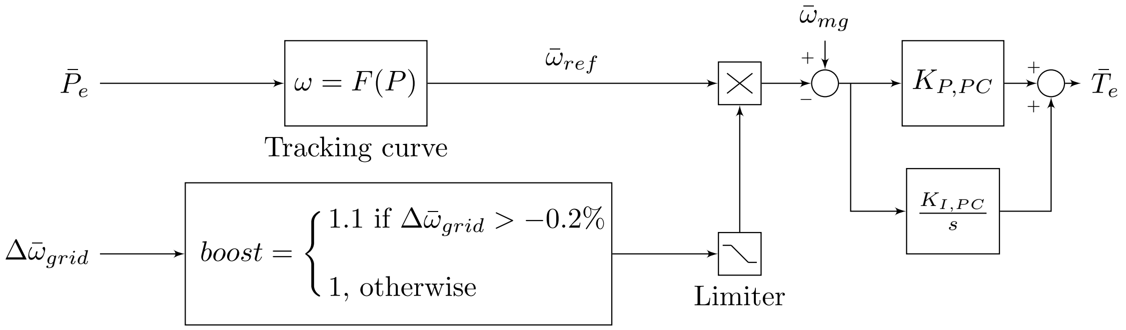

Figure 6.24: *Wind turbine power controller fitted with a feedback from grid frequency for triggering reserve deployment*

The controller also has a limiter on the output $boost$, but its purpose is different from the limiter in the original power controller. It is here to restrict $\Delta boost$, as abrupt variations in the $\bar{\omega}_{ref}$ cause high amplitude response in the reference electrical torque $\bar{T}_e$ with results in oscillations that can cause intolerable mechanical stress in the turbine shaft, as well as drive the turbine unstable. This limiter is also responsible for holding $boost$ to unity after a grid frequency drop is detected, and the controller must be reset only after the frequency deviation is eliminated.

The Figure 6.25 shows the grid response for the configurations presented on Table 6.12. The trigger for reserve deployment is grid frequency drop beyond 49.9 Hz. Grid frequency drop amplitude is significantly reduced, and frequency response reaches superior performance when compared to inertial response without reserves.

Table 6.12: 30% wind penetration scenario turbine reserve provision by sub-optimal adjustment of ω_{wt}

Adjusted ω_{wt} (p.u.)	Reserve power (% of available power)	Minimum grid frequency (Hz)
0.771 (no adjustment, base case)	0	49.532
0.807 (5% ω_{wt} reserve)	0.75	49.624
0.841 (10% ω_{wt} reserve)	2.60	49.697

The wind turbines supply some of the missing power, unburdening the hydroelectric group, as seen on Figure 6.26. Depending on the electricity matrix composition of a grid and the level of wind penetration, this kind of support from wind turbines might become mandatory, as already is the case for the Danish grid [43].

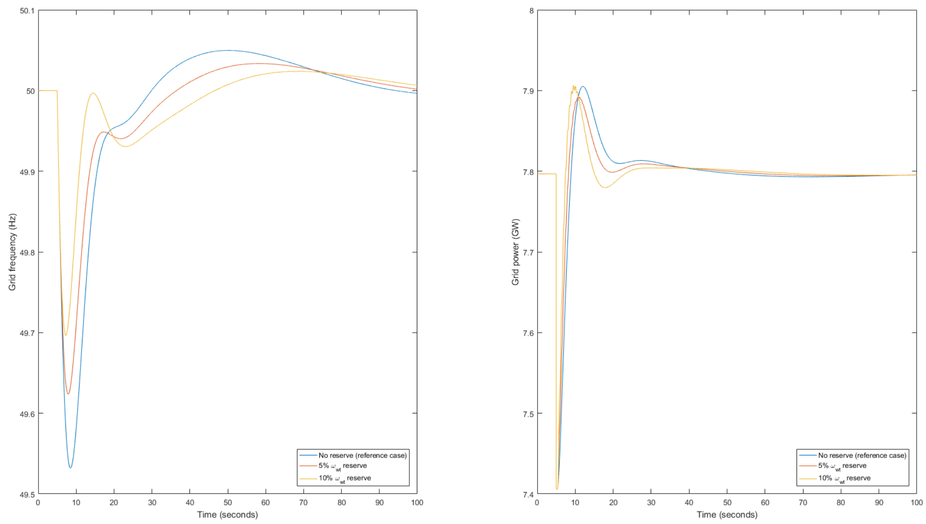

Figure 6.25: *30% wind power penetration system response to a generation loss, for different wind turbine primary frequency control reserve provision, utilizing oversped turbines*

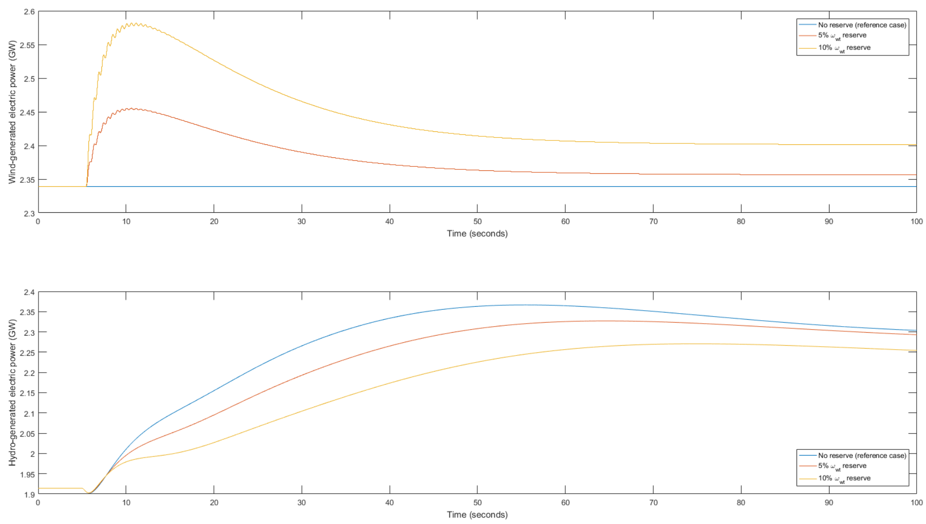

Figure 6.26: *30% wind power penetration wind turbine and hydroelectric response to a generation loss, for different wind turbine primary frequency control reserve provision, utilizing oversped turbines*

6.5.2 Inertial response from wind turbines operating at wind conditions above rated

If a wind turbine can withstand long term operation within a margin of its rated rotational speed, being allowed to overspeed when it is already producing maximum power but wind speeds are higher than the turbine rated value, a kinetic reserve can be built, to be used for downwards frequency response. In order to illustrate that, a scenario with 30% supply from wind turbines running with wind speeds higher than 12 m/s (1 p.u. of rated for the turbine) is simulated. The turbine optimal speed is ω_{wt} = 1.2 p.u., but it is assumed to tolerate continuous operation at 10% overspeed (1.32 p.u.). To allow extra power to be delivered by the turbine in such configuration, both generator and power converter must be able to withstand around 10% overload for a short duration (under one minute). The reference case assumes no turbine response during grid frequency deviation. The overspeed scenario utilize the same control as the reserve scenario, with turbine releasing kinetic energy in response to grid frequency dropping below 49.9 Hz. Figure 6.27 shows the improvement in grid frequency response is dependent on the wind condition. For lower wind speeds, the pitch angle β is kept at lower values, turbine response is faster, and power reaches a higher peak, even though the total amount of kinetic energy released over time is lower, as can be observed on Figure 6.28. The minimum grid frequencies are presented on Table 6.13.

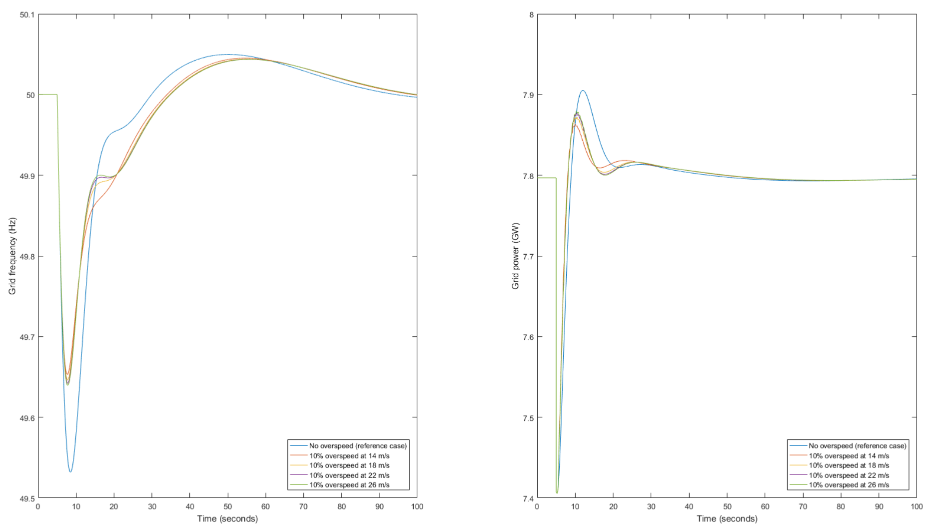

Figure 6.27: *30% wind power penetration grid behavior during generation loss, for wind turbines operating at speed 10% above nominal, under different wind speeds*

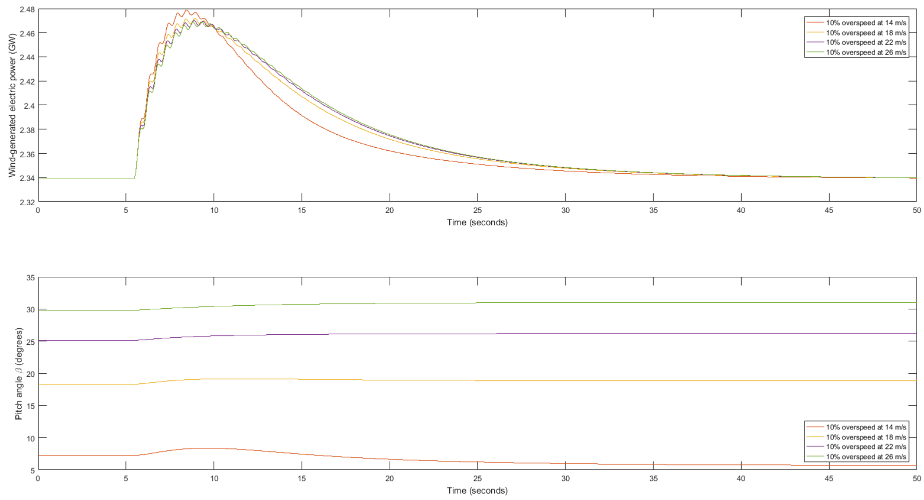

Figure 6.28: *30% wind power penetration wind turbine output power and pitch angle response to a generation loss at the instant t = 5 seconds, for wind turbines operating at speed 10% above nominal, under different wind speeds*

Table 6.13: 30% wind power penetration minimum grid frequencies after a fault for wind turbines operating at speed 10% above nominal, under different wind speeds

Wind speed (m/s)	Minimum grid frequency (Hz)
no overspeed (reference case)	49.532
14	49.653
18	49.646
22	49.642
26	49.640

In practice, for large systems, only a percentage of all turbines will be under high wind speeds at the same time. The capacity factor of wind turbines varies significantly, according to installation site and turbine specification. Average capacity factor of wind turbines, in systems with a significant share of wind penetration, is in the range of 20% to 30% [1, 2], and while the adoption of such strategy incurs benefits for the grid, its actual effect will be lower. The behavior of a system with different shares of turbines at speed above rated, operating under 14 m/s wind speed, providing support during frequency deviations in a grid with 30% wind power penetration can be seen on Figure 6.29, and grid minimum frequencies are shown on Table 6.14.

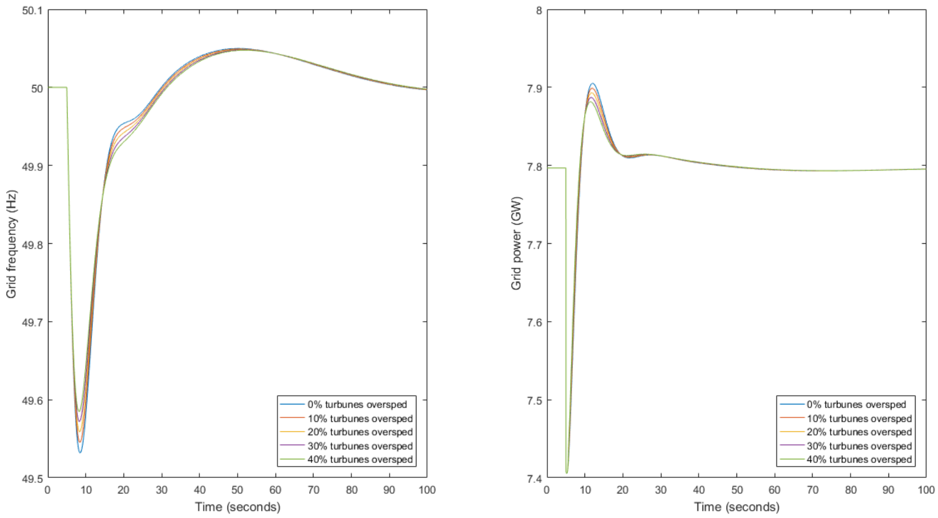

Figure 6.29: *30% wind power penetration grid behavior during generation loss, for different shares of wind turbines operating at 10% overspeed*

Table 6.14: 30% wind power penetration minimum grid frequencies after a fault for different shares of wind turbines operating at speed 10% above nominal under 14 m/s wind speed

Share of turbines at 14 m/s wind speed (%)	Minimum grid frequency (Hz)
0 (reference case)	49.532
10	49.546
20	49.559
30	49.572
40	49.585

6.5.3 Mixed strategy scenario

The last alternative to be explored is a combination of all strategies discussed so far. Starting from the 30% wind penetration scenario, the wind turbine group is split into three subgroups. The first subgroup utilizes only inertial response, the second has, in addition, a power reserve, and the third subgroup is in operation at 14 m/s wind speed, with rotor rotational speed ω_{wt} 10% above the reference 1.2 p.u. The cases simulated are summarized on Table 6.15. The share of turbines with reserve in cases 4 and 5 is selected so that the total reserve is the same as in cases 1 and 2, respectively. For all cases, R_{wind} = 12.

Figure 6.30 shows grid performance. In the cases 1 and 2, wind turbine contribution managed to limit the amplitude of grid frequency deviation more significantly than in cases 4 and 5 respectively, even though the amount of reserve available is matched between cases 1 and 4, and cases 2 and 5. As the reserve is split among more units, it can be deployed faster, improving initial response. A comparison between cases 1 and 3 shows that the turbines operating at speed 10% above

Table 6.15: 30% wind penetration scenario mixed strategy cases

Case	Share of turbines with reserve (%)	Reserve size (% of subgroup power)	Share of turbines operating under high wind speeds (%)	Minimum grid frequency (Hz)
1	40	0.75	10	49.701
2	80	0.75	10	49.720
3	40	0.75	40	49.712
4	11.539	2.6	10	49.692
5	23.077	2.6	40	49.705

nominal help restrict frequency drop in the initial instants, but afterwards their behavior is similar. In all cases, frequency recovers to 49.9 Hz between 18.3 and 18.8 seconds after the fault.

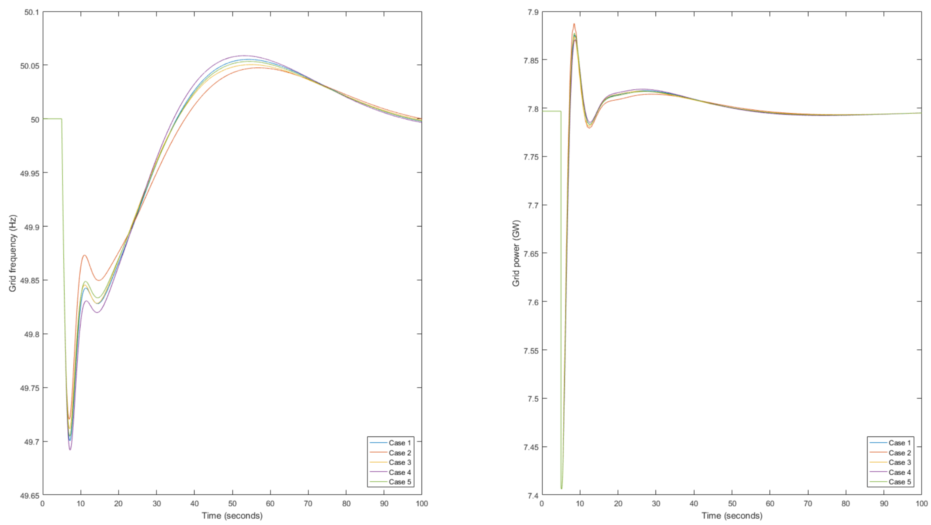

Figure 6.30: *30% wind power penetration grid behavior during generation loss, for different cases of mixed strategy for wind contribution to grid stability*

On Figure 6.31 overall wind power contribution to the grid can be observed. The cases with reserves less concentrated manage not only to deliver extra power faster, but also to avoid deeper power sinks after initial response, providing a more steady support for the grid.

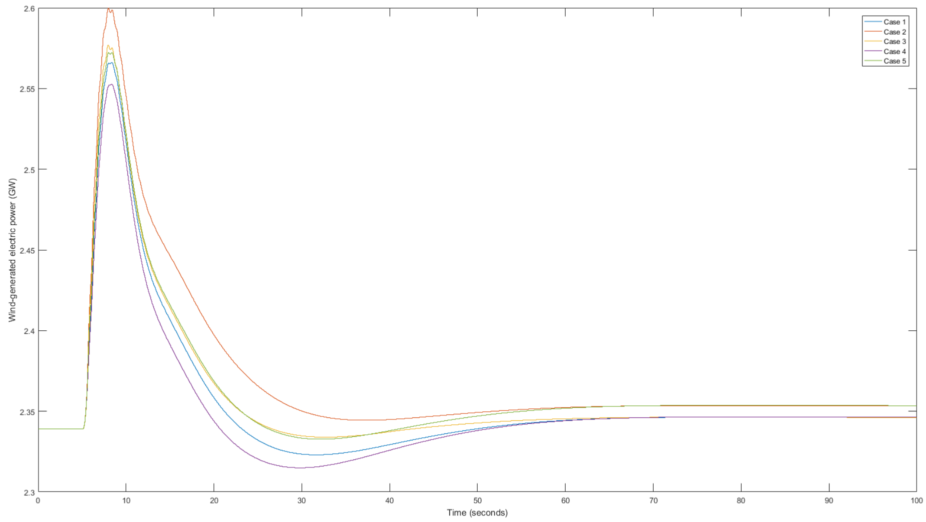

Figure 6.31: *30% wind power penetration wind turbine power output after generation loss, for different cases of mixed strategy for wind contribution to grid stability*

6.6 Extreme wind penetration scenario with mixed strategy

Finally, a scenario with 50% wind share is simulated. In this scenario, thermal power is further reduced to 25.45 % of supply before fault, and the capacities of the connected generation are presented on table 6.16. System inertia constant H is 2.1784 s. First, the system is run without wind synthetic inertia as a reference case. Then, synthetic inertia is enabled, and finally, a mixed strategy is utilized. For the second and third cases, R_{wind} = 12. The mixed strategy adopted has the same configuration as the case 3 from the 30% wind penetration scenario. Figure 6.32 shows grid response. Grid frequency drops significantly in the base case. This result is expected, as grid inertia is very low. Power recovery is very slow, as the thermal and hydro blocks reach their limit head. The amplitude of frequency drop is significantly diminished with synthetic inertia enabled. Minimum grid frequencies are shown on Table 6.17.

Table 6.16: Capacities of each generation group before fault for wind generation at 50% scenario

Source	Installed capacity (GW)	Capacity factor (%)	Generated power (GW)	Share of total power (%)
Total	22.12	35.3	7.7968	100.00
Hydro	3.25	58.9	1.9141	24.55
Thermal	4.10	48.4	1.9843	25.45
of which:				
Nuclear	0.97	96.4	0.9372	12.02
Conventional	3.13	33.5	1.0471	13.43
Wind	14.77	26.4	3.8984	50.00

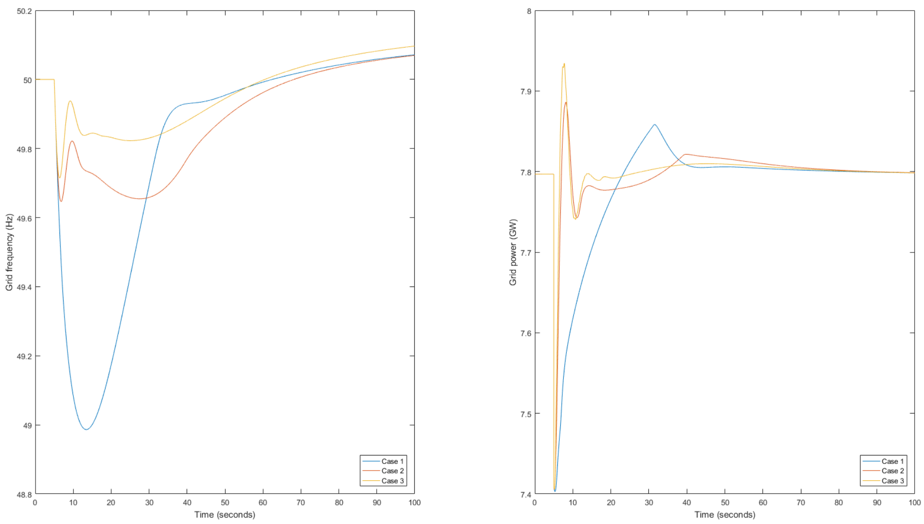

Figure 6.32: *50% wind power penetration grid behavior during generation loss*

Table 6.17: 50% wind penetration scenario minimum frequencies

Case	Minimum grid frequency (Hz)
Reference (no synthetic inertia)	48.986
Synthetic inertia	49.646
Mixed strategy	49.715

Figure 6.33 presents hydro and thermal response. Thermal generation in this scenario is limited. Moreover, this block is restricted to around 10% increase in power output which further hinders its contribution. With the limited reserve configuration of wind turbines, the hydroelectric block is responsible to provide most of the missing power, even on the mixed strategy scenario.

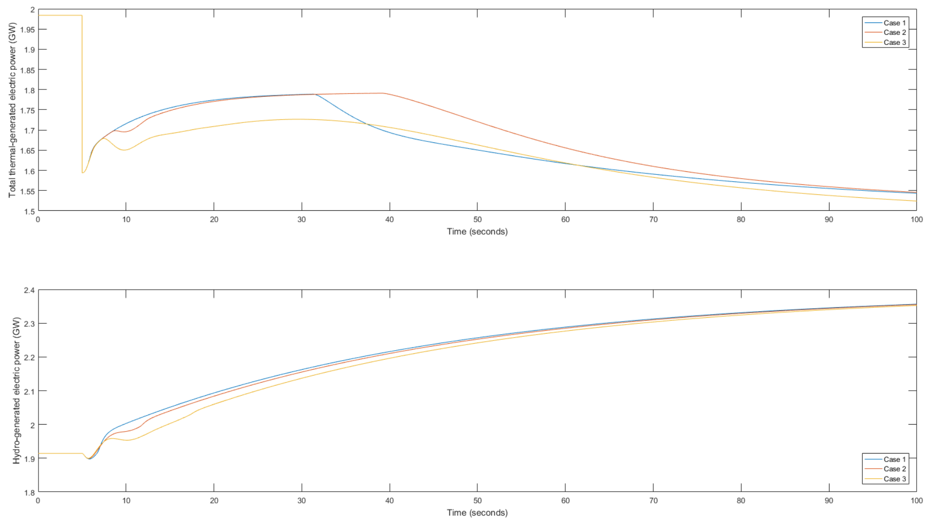

Figure 6.33: *50% wind power penetration thermal and hydro response to generation loss*

Wind turbine inertial response is of utmost importance in this scenario. Synthetic inertia alone already provides a solid initial contribution, as seen of Figure 6.34. The mixed strategy case goes further, avoiding power dropping to a level lower than the initial wind generation before fault.

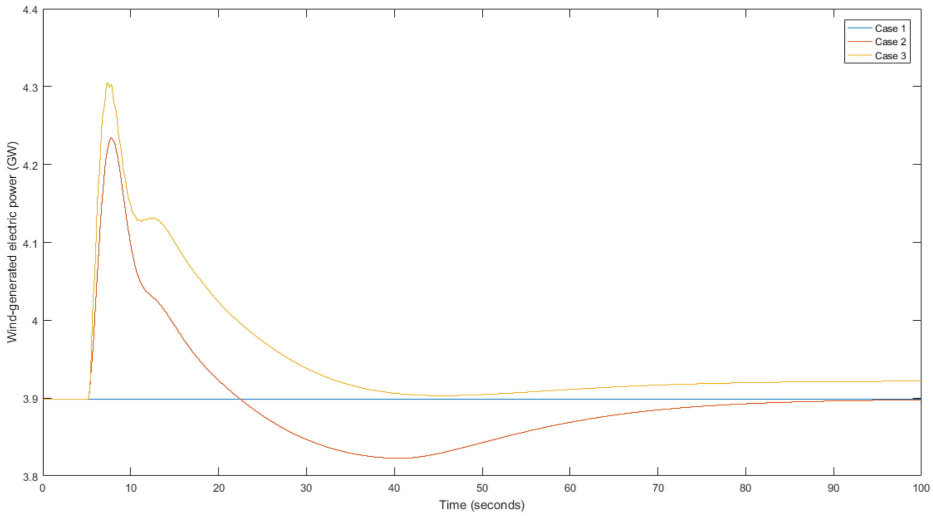

Figure 6.34: *50% wind power penetration wind turbine power output after generation loss*

6.7 Comparison of simulation results

Table 6.18 contains a summary of results from the simulations of the several cases presented. The base case, without synthetic inertia, is the reference case, as it most closely represents the current Finnish grid. For the other cases, the result from a simulation without synthetic inertia and the configuration employing synthetic inertia that obtained the lowest grid frequency deviation, are presented.

Table 6.18: Summary of results from the simulations

Case	Minimum grid frequency (Hz)	Frequency drop deviation from reference case (%)
3.4% wind with no synthetic inertia (reference case)	49.671	-
10% wind with no synthetic inertia	49.645	7.9
10% wind with synthetic inertia	49.682	-3.3
30% wind with no synthetic inertia	49.532	42.3
30% wind with synthetic inertia	49.674	-0.9
30% wind with 10% ω_{wt} reserve	49.697	-7.9
30% wind with turbines at 14 m/s wind speed	49.653	5.5
30% wind mixed strategy (best case)	49.720	-14.9
50% wind with no synthetic inertia	48.986	208.2
50% wind with synthetic inertia	49.646	7.6
50% wind mixed strategy	49.715	-13.4

Without synthetic inertia, grids with higher wind penetration have a very poor performance regarding frequency control after a fault. The grid frequency drop is 42.3% higher than in the base scenario for a grid with 30% wind penetration, and 208.2% higher when wind reaches 50% of system generation. The utilization of the simplest wind inertial response configuration already improves grid performance, and deviation in frequency drop for the 50% scenario is limited to 7.6% of the reference case, while in the 10% and 30% cases, the frequency drop is actually lower than in the base scenario, as evidenced by the negative deviations. Mixed strategies employing reserve power from wind turbines and taking advantage of turbines operating under wind speeds over their nominal point further improve overall grid reaction against frequency change.

7 Conclusion

Current changes in the electricity sector generation matrix, caused by technological development of renewable energy production and increased constraints on environmental requirements, have brought some challenges for frequency stability and control in electricity grids worldwide. This work focused on the impact of increased penetration of wind turbines in grid inertia and its subsequent effect on primary frequency control, and investigated current available options for improvement of grid stability under disturbances in the context of systems with low inertia, ultimately turning to the wind turbine itself as a solution for the issue it introduces.

Several technologies can provide ancillary services to the grid, for the specific purpose of frequency control, or contributing to grid stability as a positive side effect. Advancements in electricity market rules, telecommunications, and power electronics in general, opened very diverse options for load-side active participation in grid services, focused on load response to electricity prices for optimal matching of supply and demand, but that also can extend to reserves provision and, finally, frequency control. Future grids might also need to rely on systematic energy storage, with regular energy exchange to- and from the grid, diverse power and energy capacity characteristics, which can be operated utilizing dedicated controllers for frequency response, also aiming at grid stability. Finally, synthetic inertia provision by wind turbines is a promising approach for primary frequency control improvement, as wind turbine presence in grids become more pronounced, and it has the side advantages of requiring little to no extra investments, for all it takes to implement it is control and measurements that might as well already be available in commercial turbines, and of being a solution that escalates as the problem itself grows.

Wind turbine stored mechanical energy was evaluated and control loops were developed, utilizing the reference frequency from the grid to command a wind turbine to reduce rotational speed, thus releasing this stored energy and rapidly injecting extra power to the grid, mimicking the response of conventional generators in order to provide synthetic inertia. A model representing a conventional grid frequency response to a fault, and subsequently the integration in this model of a wind turbine fitted with synthetic inertial control, where implemented. The proposed model resulted in overall satisfactory frequency control performance for high wind penetration scenarios when synthetic inertial response was available. Moreover, it was revealed that there are diverse strategies to tackle the issue of synthetic inertia provision by wind turbines, and not only system stability, but overall system operational flexibility can be improved by deployment of such strategies.

8 Future work

There is still much to be done regarding wind turbine inertial response, from detailed investigation of other possible control algorithms to combined operation with other technologies integrated in the grid, specially the ones providing reserve in the form of short term storage.

The operation of wind turbine farms with different setups for each turbine according to available wind and overall grid situation, strategies for scheduling of wind turbine kinetic recovery after faults, and models for decision-making related to prioritization of power production or provision of ancillary services are interesting topics related solely to wind turbines.

Finally, broader inquiries can seek to build models for pair-wise integration of new technologies or system-wide operation of future systems, with integrated dispatch and curtailment of numerous varieties of sources, loads and energy storage devices, such as wind turbines, pumped-storage or reservoir-fitted hydroelectric plants, solar panels, battery banks, power-to-fuel facilities coupled with electricity-producing plants, flywheels, electric cars and decentralized thermostatically controlled loads, aiming at optimal use of available resources for energy production, but also taking into account safety of grid operation.

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