DELFT UNIVERSITY OF TECHNOLOGY

MSC THESIS

Effects Future Renewable Installations Will Have on System Synchronous and Synthetic Inertia

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Abstract

As wind and solar displace conventional generators, concerns are growing on the effect these asynchronous generators may have on such frequency stabilization services as primary and inertial response. An investigation into the system inertia of a future European energy scenario that integrates a high percentage of renewables was done using the output of a 2030 economic dispatch model to evaluate potential problems. The dispatch model provides a realistic view of possible scheduled generator mixes for three synchronous regions in Europe, as simulated for the year 2030, and allows an analysis of the available system inertia in this future scenario. This analysis yielded a positive view into the state of the synchronous system, and suggests that wind turbine installations alone is not a good predictor of a system synchronous inertia.

Also central to the analysis was an investigation of the possible ways wind turbines can contribute a synthetic inertial response in a contingency event. The literature based theoretical inertial capabilities present in wind turbines are used to estimate the resource of synthetic inertia available in future systems. This capability was aggregated after using mesoscale meteorological data for its computation.

Across each of the European synchronous regions for the 2030 energy scenario, the coincidence of the synthetic inertial capability was compared to the synchronous inertial capability and the stability of those systems was investigated.

Contents

Chapter 1

Introduction

With the scarcity and security of supply at play, there has been a major push to transition to renewable and sustainable energy sources for electricity, such as wind and solar[9]. However, differences in the way new energy is generated and supplied to consumers introduces some fundamental changes to the electricity grid, and car must be taken to handle this transition. With a requirement to maintain a minimum level of service and reliability, research is necessary to ensure that the introduction of sources such as wind and solar do not pose a threat to the health of the existing electrical grid.

Ensuring grid stability necessitates a focus on the balancing of supply and demand on very short timescales. On these very short timescales, stored kinetic energy in the rotating machines connected to a grid becomes the first defense against a power imbalance. It is this resource of stored kinetic energy that will be investigated in this study.

1.1 Concept of System Inertia

Transmission System Operators (TSOs) are normally tasked to maintain a certain voltage and frequency in the electrical grid. If the frequency in a system changes significantly it can lead to damage to machines connected to the grid, or force automatic disconnect of such machines for protection. If a disturbance leads to the disconnection of some generators, this can lead to more generator disconnects, and what follows is a potential catastrophic positive feedback cascading blackout. So, maintaining constant grid conditions is paramount. However, maintaining stability can be difficult when faced with large disturbances such as the loss of a major generator or major interconnect. This is why current TSOs require generators to provide a variety of frequency regulation services.

There are normally three broad categories of regulation services offered by generators to mitigate frequency deviations and are characterized by the amount of time required to take action. From fastest to slowest these services are inertial response, primary response, and secondary response. These responses can be seen on figure 1.1 where the first seconds of light dashed line indicates the inertial response, the rest of the light dashed line indicates the primary response, or droop, and finally the dark dashed line is the secondary response, which is reserve capacity. The energy source for these responses is made possible by the generator inertia for inertial response, turbine governor droop for primary response, and some type of automatic generator control for a secondary response. Currently these services are only required to be made available by conventional synchronous generators.

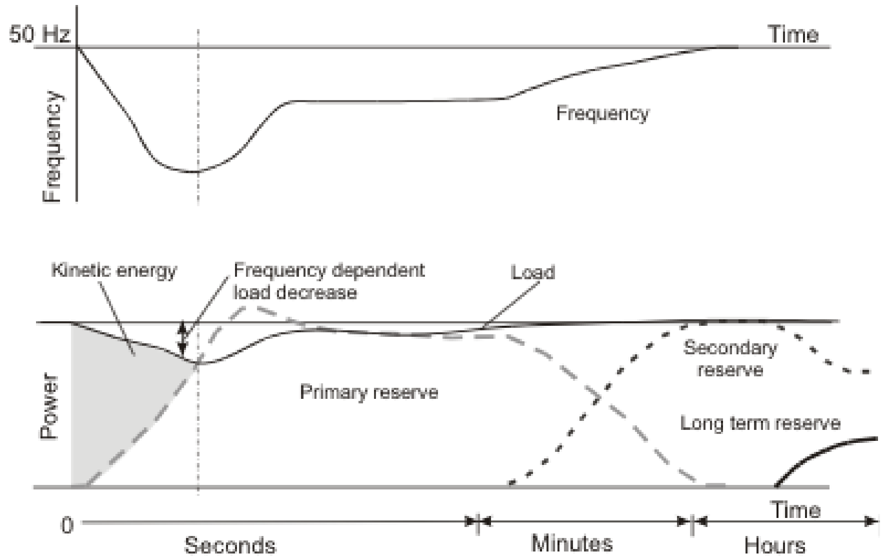


Figure 1.1: Effect a grid disturbance has on an power grid. The dashed line indicates the increase in primary reponse; the first few seconds of which are provided by the kinetic energy. The size of the kinetic energy affects the rate at which the primary response power can increase, and therefore the rate of system frequency decrease

Of the three responses, the inertial response becomes especially important for electrical power systems in the context of system stability. Although all the main frequency regulation services in an electrical grid can affect system stability, system inertia plays a major role in the initial rate at which a system's frequency changes following a disturbance. The higher the system inertia, the slower the rate of change of frequency (ROCOF) will be given a power imbalance. This is because inertia resists changes in frequency, as seen in equation 1.1 which describes how the rate at which a system will deviate from nominal frequency when faced with a power imbalance.

$$\frac{d\omega}{dt} = \frac{P_{gen} - P_{load}}{J \cdot \omega} = \frac{\Delta P}{J \cdot \omega} \quad (1.1)$$

Where J is the moment of inertia for the system, ΔP is the load imbalance created by the disturbance, ω is the system frequency, nominally at 50 Hz, P_{gen} is the mechanical power being generated, and P_{load} is the electrical power being consumed. It can be seen that the rate at which the system frequency changes will depend on the inertia of the system; the larger J the smaller $d\omega/dt$.

The ability these machines have to affect change in an electrical grid is due to the kinetic energy stored inside of the physically spinning mass of their components. Equation 1.2 defines the general form of kinetic energy for a rotating mass and can demonstrates that a change in rotational frequency, ω, would result in a change in kinetic energy of that generator.

$$E_k = \frac{1}{2} J\omega^2 \quad (1.2)$$

The quantity of stored kinetic energy in a machine is commonly used in power systems, and is useful to refer to this quantity in terms of a per unit *inertia constant H*, defined as the kinetic energy in watt-seconds at rated speed, ω_0, divided by the rated power, P_r, and is shown in equation 1.3[11].

$$H = \frac{E_k}{P_r} = \frac{1}{2} J\omega_0^2 \frac{1}{P_r} \quad (1.3)$$

The moment of inertia J in terms of H is

$$J = \frac{2H \cdot P_r}{\omega_0^2} \quad (1.4)$$

Electrical grids contain many rotating machines, and each machine's inertia depends on that machine's mass. In power systems, multiple machines connected to the same synchronous grid may contribute its own inertia to total, aggregated system inertia. It then follows that the amount of system inertia on the grid depends on the number of machines connected to the grid. This fact has a number of consequences.

Consider a growth in the overall system size: the more consumers being served, the more generators are necessary to generate electricity. The more generators, the more spinning mass. The more spinning mass the more inertia. And the more inertia, the more stable the system. So: a system grows through the addition of more machines and the fact that large systems differ mainly in the number of machines connected, rather than size of machines, is important in the event that one generator is unexpectedly shut down.

At any given time the worst disturbance is generally limited to the largest single generator. So a large system not only has more inertia due to the larger number of rotating machines, but also the size of the largest disturbance event is smaller in relation to the rest of the grid. This fact makes large synchronous systems more stable than smaller systems.

1.1.1 Inertia of Conventional generation

In the past the majority of system inertia was provided by conventional synchronous machines. These machines are mostly made up of generators at thermal and hydro power stations. In this conventional set up, the power station controls steam or water flow through the turbine to modulate the torque applied to its generator and in turn the power generated. These conventional power stations use synchronous machines [11] for the electromechanical conversion. In synchronous machines the stator coils are wired directly to the gird, the rotor is coupled directly to the turbine, and the two are linked by a torque determined by the construction and materials of the windings. This direct connection to the grid necessitates that the synchronous machine rotates at the same frequency as the grid, normally 50Hz. Any drop in grid frequency also necessarily results in a drop in the rotational frequency of the synchronous machine.

$$\Delta E_k = E_{k1} - E_{k2} = \frac{1}{2}J\omega_i^2 - \frac{1}{2}J\omega_f^2 = \frac{1}{2}J(\omega_i^2 - \omega_f^2) \tag{1.5}$$

Due to the coupled nature of the grid and all the synchronous machines, both the rotational frequency of the machines and the frequency of the grid must change in tandem. If there was a disturbance that would ultimately lead to a drop in system frequency, it wouldz first be necessary to decelerate all synchronous machines to that new, lower frequency. The process of deceleration would reduce the kinetic energy of all those machines, equal to that shown in equation 1.5. That kinetic energy will normally be released very quickly and automatically into the grid in the form of electrical energy.

1.1.2 Inertia of Renewables

With the introduction of new power generation techniques, it is important to note that novel ways of harnessing renewable sources can lead to a difference in the availability of inertia.

Some renewable energy source may still use a thermal cycle for power production. These sources such as biomass and solar thermal rely on the generation of heat from, for example, the combustion of biomatter or the concentration of sunlight, and then employ a thermal cycle heating fluid to turn a steam turbine, much like that of conventional generation. In these cases the generator is a synchronous machine, and the inertia of that machine is added to the system in much the same way as for conventional generators.

By contrast, energy sources that use power electronics to produce AC power for use in the electrical grid don't have a natural feedback via a mechanical connection between system frequency and kinetic energy.

Photovoltaic systems have no moving parts and, unmodified, are completely unable to provide any kind of inertial response. The power converters used in these systems are normally concerned entirely on the optimization of the energy extraction process and thus the power produced is typically only a function of the solar incidence and not dependent on present grid conditions. This lack of grid condition dependent power output means that photovoltaic systems will never inherently contribute extra energy to the grid in the case of a grid disturbance. In fact the power electronics are normally designed to only operate under a narrow range of grid conditions, and if that range is exceeded, the power converter would normally isolate itself from the grid for self protection [20], potentially exacerbating a power deficiency in the grid.

Wind turbines do have moving parts, unlike photovoltaics, and by extension contain a certain amount of kinetic energy while in operation. Some wind turbines operate at fixed rotational speeds, and can be connected directly to the grid. These turbines are capable of providing some inertial response like that of synchronous generators[18]. Fixed speed wind turbines, have fallen out of favor for current and new wind energy installations, and as such will not be further considered.

Variable speed wind turbines (VSWT), unlike fixed speed wind turbines, employ generators that are not connected directly to the grid, and do not rotate at a constant or near-constant rotational frequency. VSWT are generally preferred [12] over their fixed speed counterparts due to a decrease in mechanical stresses and an increase in energy extraction efficacy. But, since the VSWT rotate at various frequencies, it is necessary to convert the generated power to a consistent, grid compatible, frequency and voltage. This conversion process is normally done with the use of power electronics, either a full converter, or doubly fed induction generator (DFIG). This decoupled nature of VSWT means that there is no natural feedback between the grid frequency and the produced power from the wind turbine [4]. It is for this reason that VSWT are normally considered to have no inertial response when attached to the grid.

Despite not having a natural inertial response, research is being done by a number of researchers ([8], [13]) to harness some of the kinetic energy contained in the blades, generator, gearbox, etc. of a VSWT, and to provide a *synthetic inertia* through the use of a control system that monitors grid conditions and modulates power production. In fact the ability of a wind turbine to spin at a wide range of frequencies independently of the grid frequency can be advantageous since more of the stored kinetic energy could be available to the system.

Equation 1.6 shows how a drop from ω_{nom} to ω_f releases a certain amount of energy. A large drop in grid frequency might see ω_{nom} of 50Hz drop to ω_f of 49.5Hz. In the case of a synchronous generator, that drop in grid frequency is equal to the drop in the machines rotational frequency. A wind turbine on the other hand can drop from its nominal rotational frequency all the way to its minimum speed, independently of the grid frequency.

$$\Delta E_k = \frac{1}{2} J \omega_{nom}^2 (1 - \frac{\omega_f^2}{\omega_{nom}^2}) \tag{1.6}$$

Equation 1.6 can also be seen as ΔE_k being equal to E_{k1} multiplied by a change, here calculated by the inside of the brackets.
If the equation 1.3 is used to apply the inertia constant H and ω_{nom} is 50Hz, equation 1.6 transforms into an equivalent per unit equation 1.7.

$$\Delta E_{kpu} = H(1 - \frac{\omega_{fpu}^2}{\omega_{nom}^2}) \tag{1.7}$$

Since wind turbines don't necessarily spin at grid frequency, a separate per unit equation can be defined that uses per unit frequencies that are still scaled by a normal ω_{nom}. This is shown in equation 1.8 where ω_{ipu} is the rotational frequency at the moment of a disturbance, and ω_{fpu} is the lowest rotational frequency the turbine achieved.

$$\Delta E_{kpu} = H(\frac{\omega_{ipu}^2 - \omega_{fpu}^2}{\omega_{nom}^2}) \tag{1.8}$$

Table 1.1 shows an example of the released energy from a synchronous machine and a wind turbine in the event of a system frequency drop from 50Hz to 49.5Hz.

This research will investigate to what extent wind turbines might be able to contribute this energy in the form of an inertial response and to help manage system stability.

Generator	Initial Frequency (pu)	Final Frequency (pu)	Change in Kinetic Energy
Synchronous	1	0.99	2%
Wind Turbine	1	0.7	19%

Table 1.1: Changes in frequency possible and the fraction of kinetic energy released as a result, for a synchronous machine and a wind turbine using equation 1.6, and grid nominal frequency 50Hz, or 1pu.

1.2 Time Variation of System Inertia

Presently system inertia is provided exclusively from the kinetic energy of synchronous generators attached to the system. It then follows then that the actual amount of inertia at any given time is dependent on the number and size of all the generators currently committed and operational. Thus a time varying level of inertia is a natural property of an electrical system who's demand and supply are constantly varying; as System Operators (TSO) commit and de-commit generating stations to match load levels, so too does the amount of inertia on the system. Whenever a generating station is de-committed and detached from the grid, its kinetic energy also becomes unavailable. It is however, important to note that the kinetic energy of each generator is independent of the dispatched power level, and is dependent only on physical characteristics of the machine and the current grid frequency, when in operation.

The moment of inertia for conventional generators is linked directly to the rate of change of frequency (ROCOF) and resists change in system frequency, as shown in equation 1.1. The aggregate inertia value of a system allows it to resist changes in system frequency. As will be sown in the next section, renewable forms of generation may change this aggregate value.

Continental power systems generally have sufficiently large inertia from their synchronous generators at all times. Smaller island systems on the other hand might not. Some such system, like that of Ireland, introduce load-shedding protection devices which, during fast frequency deviations, relieve the power system of part of its load to prevent total loss.

Electricity grids in Europe are presently among the most reliable due to careful planning, engineering and adequate supply. This is helped by having a majority of electricity production met by conventional synchronous machines. But, if a growing renewables sector increases the share of non-inertia-contributing asynchronous generation, and even starts to displace conventional generators, it could result in a system with precariously low inertia.

With the introduction of renewables the fraction of conventional generators that are contributing inertia to the system might be reduced, and could mirror stability issues already seen in smaller island systems. This study will look to future energy scenarios to analyze the future of stability.

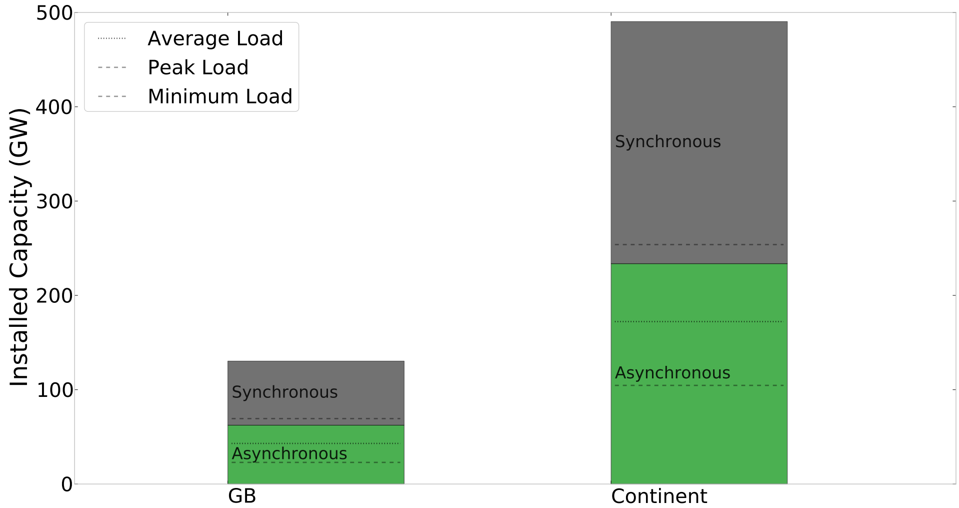


Figure 1.2: Installed capacity mix of the Great Britain and Continental systems in 2030 scenario

It can be seen from figure 1.2 that a growth in the continental system was considered relative to 2011 installed capacities. Further, the fraction of installed capacity that is from renewable generation stations has also increased as is outlined in table 1.2 and figure 1.3. This is a reflection in current political and popular opinions in Europe where the introduction and development of renewables is favored.

Country	2010	2020	2030
Netherlands	8	26	35
Germany	31	35	61
France	7	19	34
Belgium	0	19	29
Great Britain	4	29	48
Denmark	23	45	55
Sweden	4	29	32
Norway	2	12	34

Table 1.2: Percent of installed capacity that is wind or solar per country

The possibility of renewables displacing conventional generators has been a concern for some time in a number of jurisdictions for a variety of reasons.

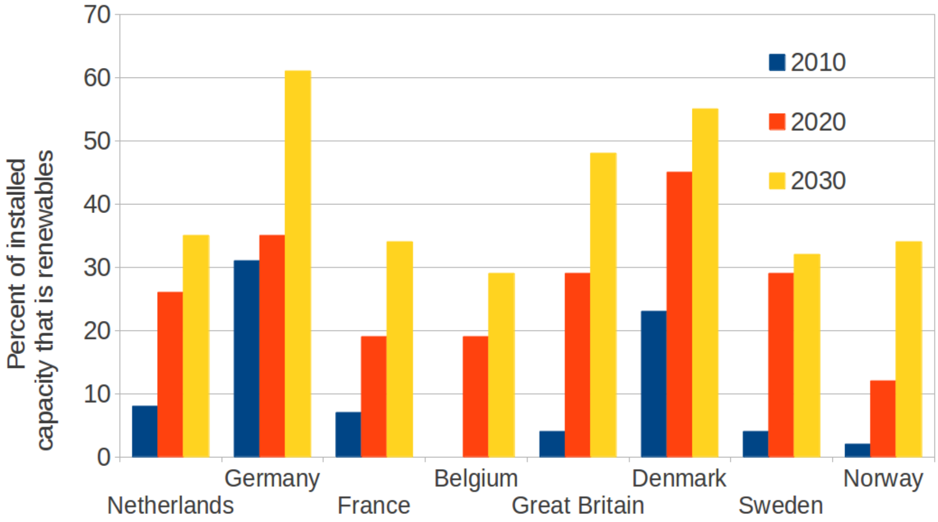


Figure 1.3: Percent of installed capacity that is wind or solar per country for each simulated year and 2010

In some jurisdictions, such as Ireland, have even legislated hard limits on the amount of system load that can be supplied by renewables at 50% [16]. In fact, Ireland has reached this limit on a number of occasions and has been forced to curtail wind energy. In addition, the island nature of the Irish grid means that the system is relatively small in terms of the number of generators connected, making it more vulnerable to a single generator loss. This in all makes the Irish system an important example in ways to learn how to balance a situation of increasing renewable installations and grid stability.

Figure 1.4 shows how the grid frequency dropped following a loss of an interconnector off the coast of Germany in 2008. Here, point 1 shows where the initial line cut out, leading to a deficiency in the grid. Because the system frequency starts to fall immediately it is up to the inertia of all the synchronous machines on the system to release energy and mitigate the rate of change. The lowest point 3, nadir, is another measure of the severity of a disturbance. The smaller the rate of change of the frequency during the first few seconds, the less severe the nadir will be.

Thus, for the protection of the grid, severe grid disruptions are managed by sufficient system inertia. This is to conserve the costs of damaging devices or machines connected to the grid, but also the high social and economic costs of a blackout for consumers.

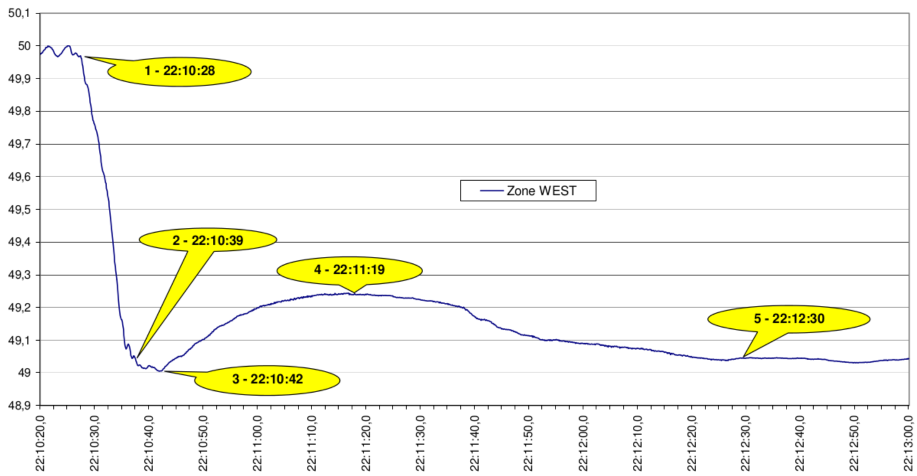


Figure 1.4: The system frequency of western Europe following a major disturbance in 2008

1.3 Research Objectives and Approach

An increase in the installation of renewables has the potential to displace conventional synchronous generators with asynchronous, intermittent generation such as wind and solar. The nature of these asynchronous generators is that no natural feedback exists between system frequency and inertial or primary response of the generator to a power imbalance. This response that had been traditionally provided by synchronous generators may no longer be available to grid operators and threaten grid stability in a future with lots of renewable generation.

1.3.1 Problem statement and Research Questions

> *To what extent will a future energy scenario with a high penetration of renewables reduce system inertia, and threaten to reduce system stability compared to a present-day system?*

> *To what extent could wind turbines, if outfitted with proper control systems, contribute a synthetic inertial response to aid in the maintenance of a future energy scenario with a high penetration of renewables?*

In addition to the above problem statements, the following research questions will be investigated.

What method can be employed to quantify synchronous inertia using dispatch records.

What information and assumptions are necessary, and what steps should be taken to model and quantify synthetic inertia available from a wind turbine.

Due to the variability of the wind and, as a consequence, the variability of wind energy, is it strictly necessary to use detailed wind data to compute availabilities of synthetic inertia? What information is lost, and what bias can be expected if average or aggregated wind data were used instead?

In what way can wind turbines contribute synthetic inertia? Will there be enough synthetic inertia to affect system inertia as a whole, and what is the time-dependent correlation of synthetic inertia with synchronous inertia? Ideally synthetic inertia will be available at least when synchronous inertia is low and the system is most vulnerable.

1.3.2 Research scope

The scope of this research will be to investigate the level of inertia from conventional synchronous machines using the dispatch records from the 2030 economic dispatch model. Also from the dispatch records, the operation of wind turbines will be investigated in order to determine the level of synthetic inertia that could be available from wind turbines. Photovoltaics will not be part of the investigation. Due to time constraints a more thorough investigation and comparison with a present-day dispatch record will not be made. Instead system fleets from year 2010, 2020, and 2030 will be compared using estimates of inertia based on load and fleet. This method will be able to show the likely range of inertia given a particular penetration of renewables.

1.3.3 Approach

Quantify System Inertia

One of the purposes of this work is to provide insight into the ability for the European grid to accommodate renewable energy sources without compromising the system stability. This investigation is centered on the inertial response of generators that would be available in the case of a contingency event on the grid. Since inertial response from synchronous generators is mainly provided by the inertia of said generators, the synchronous inertia available in the system will be studied closely. The research will look to simulated dispatch records for European generators to look for any significant drop in synchronous inertia that might be due to displacement of synchronous generators by renewables.

The results of this will be a time series of synchronous inertias.

Quantify Synthetic Inertia
Wind turbines don't naturally have an inertial response, so a method for turbines to replicate this behavior will be defined. Next, using windpeed data, analysis on the synthetic inertia resource will be made.

Comparison of synchronous and synthetic inertias
Once a resource of synthetic inertia is identified, it then becomes possible to determine if the synthetic inertia will aid in the maintenance of overall system inertia and help provide grid stability. Time coincidence will be investigated as well as the ability for the synthetic inertia to be added to synchronous inertia to maintain an improved level of overall system inertia.

Chapter 2

Modeling and Input Data

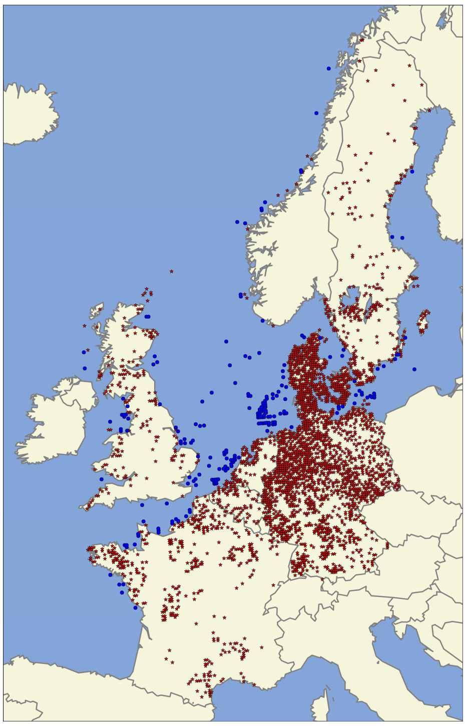


Figure 2.1: Sites of wind farms [6]

A zonal market model was developed by A. Ciupuligaet al. [6] in order to asses the ability for the European electrical grid to absorb a high percentage of renewable generation. The model uses a unit commitment and economic dispatch simulation to match a load profile designed to simulate demand in 2030. This model includes a variety of energy sources based on generation type and location, as well as energy availability and transmission constraints and is run as a least-cost optimization.

The output of this model acts as the input to the inertia research done for this thesis, and as such information on the model shall be included in this chapter.

2.1 Mesoscale Meteorological Data

At the heart of the economic dispatch model, as well as a main input directly into this study (See figure 2.2), is mesoscale meteorological data sourced from a numerical weather prediction.

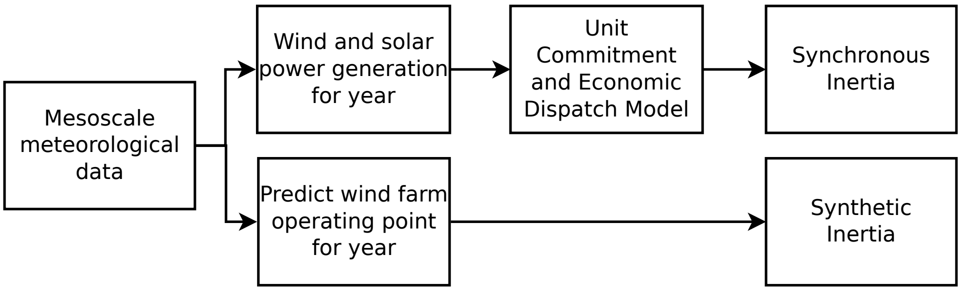


Figure 2.2: How mesoscale meteorological is used in the simulations

The meteorological data is organized in a 9x9km grid within Europe and uses climate modeling to synthesize its high frequency data. The initialization of the model and the initialization is carried out by meteorological reanalysis along with real measurements. More detailed analysis on the methods present in the mesoscale meteorological data can be seen in [3].

2.2 Unit commitment and Economic Dispatch Model

The unit commitment and economic dispatch model (UC-ED) splits Europe geographically into three synchronous regions: Great Britain, containing the island of Great Britain; Nordic, containing Norway and Sweden; and finally Continental, containing France, Belgium, the Netherlands, Denmark and Germany. Within each region no transmission constraints are considered, however, asynchronous interconnect capacity is modeled between each region.

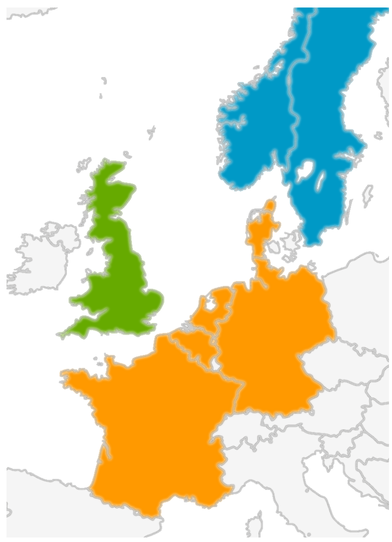


Figure 2.3: The three European regions used in the dispatch model. Nordic, Great Britain and Continental

The input of the dispatch model is a constructed hourly load demand. A load demand profile for 2011 was first analyzed and a growth rate based on System Adequacy Forecast (2011-2025) report from ENTSO-E [2] was added to increase the actual value of the loads to match predicted future consumption levels[6].

Region	Peak Load	Average Load	Minimum Load
Germany	103	67	42
France	112	69	38
Belgium	21.2	15.5	9.8
Netherlands	26.6	17.6	11.3
Denmark	7.7	4.9	2.7
Continent	264	174	106
Sweden	24.4	15.4	8.1
Norway	23.4	14.6	7.9
Nordic	47	30	16
Great Britain	70	44	24
Total	374	248	146

Table 2.1: List of 2030 load information per country (GW)

Examples of the load profiles can be seen in figure 2.4, and are outlined in table 2.1.

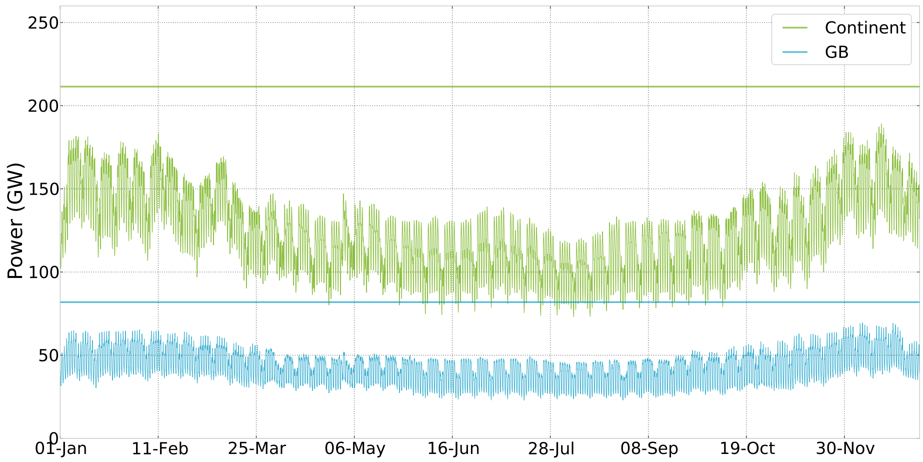


Figure 2.4: Load profiles used as input for the 2030 dispatch model with the installed capacity of each system shown as a horizontal line.

Figure 2.4 shows how a seasonal variation in load is stronger in the continental system versus the load in Great Britain, even after taking relative size differences into consideration.

2.3 Conventional generation

The generation mix for the 2030 scenario is based on the System Adequacy Forecast (2011-2025) report from ENTSO-E [2], plus a predicted growth through the future. Table 2.2 shows the generation types and installed capacities included in the model.

Generation Type	Nordic (MW)	Great Britain (MW)	Continent (MW)
Nuclear	10395	11945	69610
Gas	2433	33279	72976
Coal	222	18629	37135
Pumped Hydro	4200	3000	16080
Hydro	44970	1144	25316
Oil	2160	0	10410
Mixed Fuel	0	0	1977
Biomass	0	0	6000
Lignite	0	0	17212
Total	64379	67999	256717

Table 2.2: Installed capacity of conventional generators in 2030

Due to the complexity and lack of detailed information from generator and system operators, aggregation was done such that many actual generator units are represented by each station. However, the total generating capacity and fractional representation by generator type was designed to accurately represent the generator mix on a per-country basis.

For the purposes of an economic dispatch model, hydro generation in Norway and Sweden was deemed to act closely with each other. As a result the hydro units in Norway and Sweden have been highly aggregated into few large units. The consequence this decision has on inertia is that the hydro units are never de-committed. Even if in reality only a fraction of all hydro units would be committed at a particular time. The aggregated representation would require that the large aggregated model be continuously committed even for very small dispatch levels. This process would typically lead to over estimations of the actual inertia available. For this reason the Nordic synchronous region will not be further discussed.

Each generator type has a set of constraints so as to accurately represent their response during a real-world dispatch. These constraints are outlined in the table 2.3. The modeled conventional generators are represented by a generating stations that contain generating units sized to match typical unit sizes found in reality. The number of units in each station were also chosen to match real-

Generator Constraints	Energy Constraints	Flow Constraints
Ramp Rates	Minimum Water Levels	Transmission power flow limits
Minimum operation level		Minimum river flow rates
Minimum on times		
Minimum Off times		
Startup Costs		
Shutdown Costs		
System Reserve Capacity		

Table 2.3: Constraints in the Economic Dispatch Model

world generating capacities.

2.4 Renewable Generation

Many generation technologies represented in the economic dispatch model can be classically described as renewable given the fuel source. These include

- Wind Energy (asynchronous)
- Photovoltaic (asynchronous)
- Biomass (synchronous)
- Hydroelectric (synchronous)

However, there will be a focus on asynchronous generation, as these have an inherent lack of synchronous inertia and thus are assumed to most adversely affect the system stability. In addition, of the asynchronous generators (photovoltaic and wind) only wind has kinetic energy, so even of asynchronous generators, wind generation will be the primary focus of this study. The installed capacities of renewable generation in 2030 are listed in table 2.4.

Generation Type	Nordic (MW)	Great Britain (MW)	Continent (MW)
Wind	32167	62360	154628
Solar	0	0	79000
Total	32167	62360	233628

Table 2.4: Installed capacity of renewable generators in 2030

Renewables generators were highly aggregated in the dispatch model in order to simplify the algorithm. Each country's wind and solar power is thus represented by a single large generating station with rated capacity of the sum of all actual simulated wind and solar stations. The aggregation was a two-step

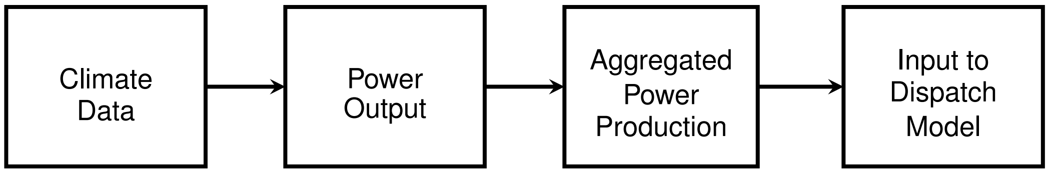


Figure 2.5: Aggregation of Renewables

process. First, determining the locations and ratings of future power stations required a study to predict how many wind and solar generating stations would be in operation by the year 2030. This entailed collecting information on all approved and proposed construction projects and documenting their capacities and locations. This resulted in a diverse spread of power station locations, shown in figure 2.1, and installed capacities to be operational in the year 2030. Using the ratings and locations of these generators along with data from the mesoscale meteorological model, a time series of power production for an entire year was created. The second step is to then take the predicted power outputs for all of the many power stations in each country and sum them to reach an aggregated power production for each country in each hour of the year. It is only after this step that the produced power is entered into the economic dispatch model.

2.5 Algorithm and Priority

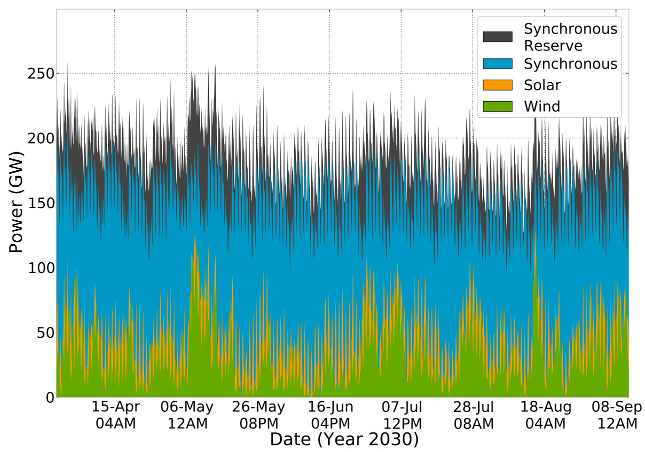
The algorithm used in producing the economic dispatch model an iterative, least-cost optimization run in PwrSym [5]. PwrSym is a proprietary dispatch simulation package originally developed by Tennessee Valley Power Authority. It was employed by Ciupuliga in order to research the ability for future European systems to adequately supply loads in the case of high renewable penetrations.

To match the load input, the UC-ED model works with a specified fleet of generators, all of which have certain characteristics such as cost, size and ramp rates. The dispatch model then runs an iterative least-cost optimization to determine the best mix for supplying the necessary generation to match the load, all while taking into account a variety of constraints outlined in table 2.3.

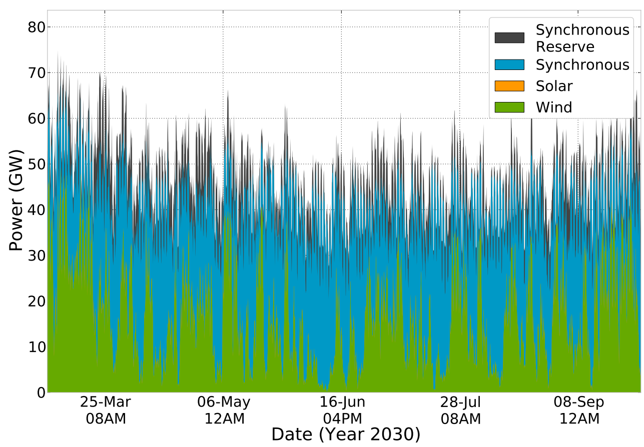
Fuel and running costs are the main drivers for the cost algorithm; for each timestep all generators are first dispatched, then if the generated power exceeds the load demand, the most expensive unit is de-committed.

As an input to the dispatch model, the power produced by the wind and solar is assigned a very low cost to prioritize the dispatch of renewable energy whenever it is available. Curtailment will occur in cases where wind production is high and load is low, or when conventional generation is unable to ramp quickly enough.

2.6 Dispatch Record Output



(a) Continent

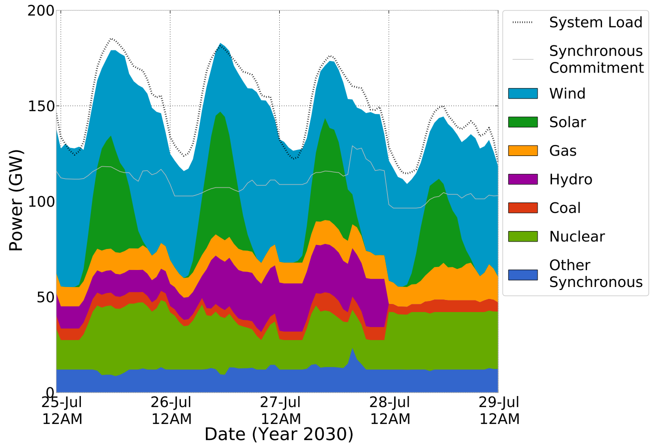


(b) Great Britain

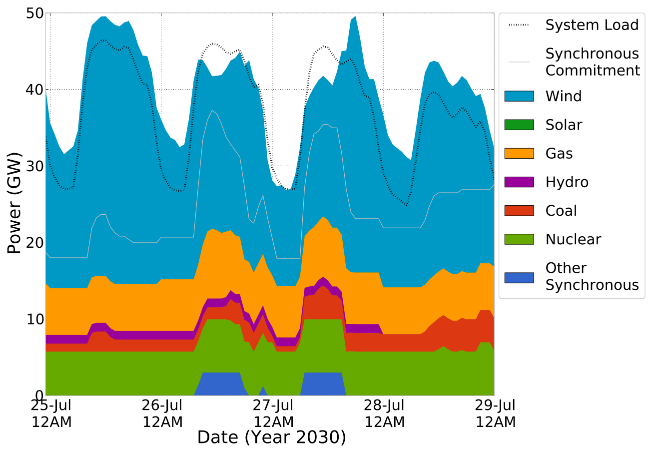
Figure 2.6: Dispatch record for year 2030 scenario

2.6.1 Time Series of Dispatch

Once a dispatch simulation is run, it is possible to read exactly which generators are committed and operational, as well as the level at which they would be called upon to generate by a system operator. Initially the dispatch records consist of a time series showing the exact generation mix for every hour. Figure 2.6 shows yearly dispatch records, with total wind, solar, and conventional generators each a different colour.



(a) Continent



(b) Great Britain

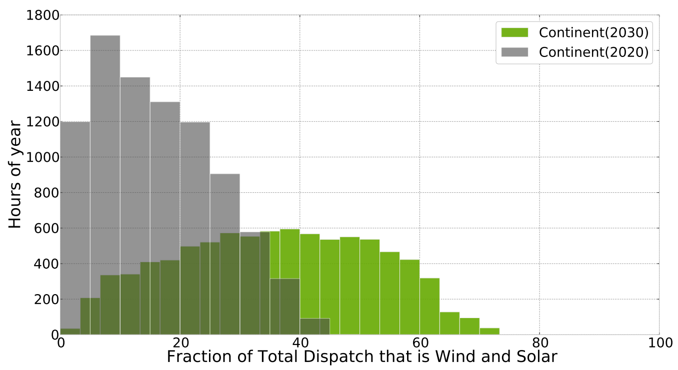
Figure 2.7: Example time series of the generation mix as determined by the dispatch model

2.6.2 Generation mix breakdown

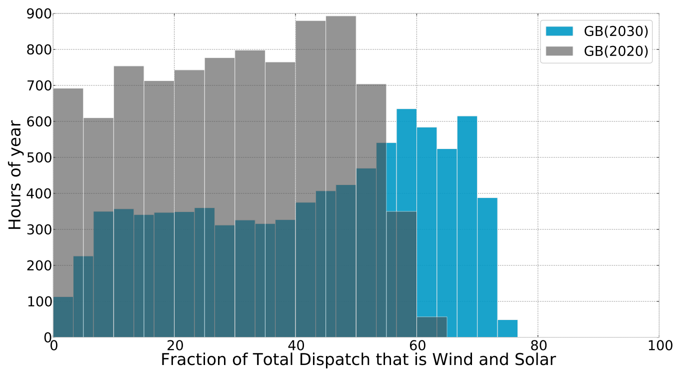
Figure 2.7 shows an example of the generation as optimized by the dispatch model displayed as a stacked curve, each colour representing its share of the energy it served to the load. Figure 2.7 also shows that there is actually a discrepancy between the total generated power and the load demand profile. This difference is actually trade through interconnectors to other regions in model.

The final colour representing "Other Synchronous" groups are smaller generation types (such as mixed fuel, run of the river hydro etc.) and are grouped for the purposes of visualization, but these types are handled in the dispatch model distinct from one another and dispatched accordingly.

2.6.3 Fraction of renewables



(a) Continent



(b) Great Britain

Figure 2.8: Histograms of the fraction of load met with wind and solar in years 2020 and 2030.

Figure 2.8 shows histograms that outline the number of hours in the simulated years where a range of percentage of renewables met load demand. That is to say, given a renewables fraction, for example 50%, figures in 2.8 will show for how many hours load is 50% met with renewable sources.

Because figure 2.8 looks at energy served, it takes into account the capacity factor of the sources. Said another way, if there was no wind, no matter how many wind turbines were built no energy would actually be met with wind turbines. This would be reflected in figure 2.8 by having a single bar at 0% fraction, representing all hours of the year. That is a low capacity factor. The histograms in figure 2.8 can be seen as a measure of renewable energy being served, and therefore also a look into capacity factor.

Chapter 3

Methodology

System inertia and primary response services are the first sources of stabilization in electrical systems to maintain frequency stability. This work focuses on the first one to ten seconds following a system disturbance, corresponding to inertial response, whether that inertial response is from synchronous machines, or from wind turbines in the form of synthetic inertia.

The research on these services necessitates some novel methods to interpret dispatch records to quantify the levels of inertia from both conventional and asynchronous machines. Further, quantification of synthetic inertia with the use of wind data will be done.

This chapter will investigate assumed machine properties presented by the dispatch model and their impact on inertial and primary response. Further methods and justifications of quantification will be discussed for both synchronous machines and wind turbines.

3.1 Computing Synchronous Inertia from Dispatch Records

The commitment and dispatch record from the economic dispatch model can be combined with unit inertia information to estimate the overall system synchronous inertia.

Based on the number $N(t)$ of units committed at each power station the kinetic energy contained in a generation station at a given hour is shown in equation 3.1.

$$E_k^i(t) = H^i \cdot P_{rated^i} \cdot N_{units}^i(t) \tag{3.1}$$

Where H is the inertial constant defined per type as in table 3.1 and P_{rated} is the rated power of a unit.

Generation Type	Inertia Constant, H (s)
Nuclear	5.5
Gas	4
Coal	5
Pumped Hydro	3
Hydro	3
Oil	4.5
Mixed Fuel	3
Biomass	3.5
Lignite	3.5
CCGT	5.5

Table 3.1: Typical inertia constants (H) by generation type

The total kinetic energy of a region is obtained by summing over all n stations, as in equation 3.2.

$$E_k(t) = \sum_{i=1}^{n} E_k^i(t) \tag{3.2}$$

It should also be noted that of the total kinetic energy in a synchronous machine, only a fraction is ever released in the event of a disturbance; depending on the change in rotational frequency.

In order to quantify the inertia provided by the synchronous generators, it was assumed that each system is nominally operating at 50Hz, and that the general form of the moment of inertia in a rotating body, equation 3.3, applies:

$$E_k = \frac{1}{2} J \omega_0^2 \tag{3.3}$$

where J is the inertia and ω_0 is nominal system frequency: 50Hz or 314rads/s. Rearranged, J can be calculated at each hour of the simulated time, yielding a time series of J, as seen in equation 3.4.

$$J(t) = \frac{2 \cdot E_k(t)}{\omega_0^2} \tag{3.4}$$

As equation 1.5 suggests, the energy released in an inertial response by a synchronous machine is a function of the change in grid frequency. This is notable in that despite having a certain resource of kinetic energy in synchronous machines only a small fraction is normally ever released, since grid disturbances rarely cause frequency deviation larger than a couple of tenths of a hertz. This fact will ultimately contrast with the inertia from wind turbines which are more able to widely alter their rotational frequency, and therefore access more of their kinetic energy.

3.2 Computing Synthetic Inertia from Wind Turbines

Like with synchronous generators, wind turbines contain rotating mass in their turbine blades and generators. However, unlike conventional generators many wind turbines are grid-connected via power electronics. This limits the inherent effectiveness and ability for a wind turbine to provide a natural inertial response to a system in the event of a disturbance. This is because the rotation speed of the turbine blades is de-coupled from the grid, so no natural feedback exists between a drop in system frequency and a drop in wind turbine rotor rotational speed. Instead, the power electronics will normally ride through minor disturbances, and disconnect from the grid following major disturbances[17].

However, with newly developed technology in the form of active control systems, wind turbines could provide an inertial response. The control system would have to monitor wind turbine rotor speed, grid-side frequency and then modulate power conversion. This could provide a boost in power output from the wind turbine following a disturbance, at least for a limited period while the turbine's rotor decelerates. At least one manufacturer offers this capability, which is required in Quebec [1]. Others confirm its feasibility [10].

Even in the case of new control systems, the ability for a wind turbine to increase production will be limited by a number of factors, and some assumptions will have to be made in order to fully quantify a potential inertial response from wind turbines. These limitations and assumption will be outlined in the following sections.

3.2.1 Control Schemes

In a system with conventional generation, the inertial response acts very quickly to a grid disturbance to provide an increase in power output, extracted from the rotating mass in their generators. Synchronous inertial response is a consequence of machine design and physics, and is an intrinsic response that acts automatically.

A control system for a wind turbine has to replicate this behaviour in order for it to be a useful contribution to inertial response. This controller would have to be able to act quickly to increase power output, and would have to be able to do so on demand. A controller that measures the grid-side frequency as an input to a control loop and modulates the power output (equation 3.5) would be appropriate for such a response, similar to governor droop controls that exist on synchronous machines. Similarly, since inertial response affects mainly the initial rate of change of frequency (ROCOF) of a system following a disturbance, a control loop that uses $d\omega/dt$ as an input would more closely mimic the response a synchronous machine has as an inertial response. A control loop that follows equation 3.5 should then, if acting quickly enough, behave in a similar manner to that of a synchronous generator in releasing its kinetic energy when the frequency drops (ie. $\frac{d\omega}{dt} < 0$).

$$\Delta P = -K \cdot \frac{d\omega}{dt} \tag{3.5}$$

3.2.2 Over Production Capability

The amount a wind turbine can increase its production is limited mainly by the capabilities of power converter and the operating point of the turbine. Given a converter with a particular rating, the power capabilities are limited first by its cooling. The design of converters focus on use cases where the converter provides sustained power conversion; temporary increases to over-rated conversion, are possible at modest over-production levels, modest over-production periods, and sufficient cool-down periods. In this work power converter design has been assumed to allow a temporary increase in power of 10% over-rated for periods of less than 20 seconds. This leads to a maximum total production of 110% of the wind turbine rating for no more than 20 seconds. In fact, due to a focus on inertial response in the first 10 seconds following a disturbance an over production period of 10 seconds was selected as the standard to be used for this study. Very fast, or abrupt changes in power output would also increase the acceleration or deceleration of the rotor and place the structure under significant mechanical stresses. Further studies would have to be made to determine safe over production levels that don't significantly reduce the lifetime of wind turbines.

The ability for a wind turbine to provide an overproduction is heavily based on its operating point; a wind turbine that is not spinning is unable to provide any overproduction, as a still rotor contains no kinetic energy. For this reason it becomes very important to properly quantify the operating point of a wind turbine.

Research into over production capabilities has been done by Tarnowski et al. in [19] where the ability to release kinetic energy was investigated. Tarnowski was able to study several rates of releasing kinetic energy from a wind turbine and are categorized as a function of wind speed and over production period, as shown in figure 3.1.

The over production capability curve presented in this study has been extracted from [19], and shown in figure 3.1. Figure 3.1 shows curves of constant energy, dependent on wind speeds and over production period. For this study an over production period of 10s was chosen, and a horizontal line was used on figure 3.1 to determine the over production level for each windspeed. The result of

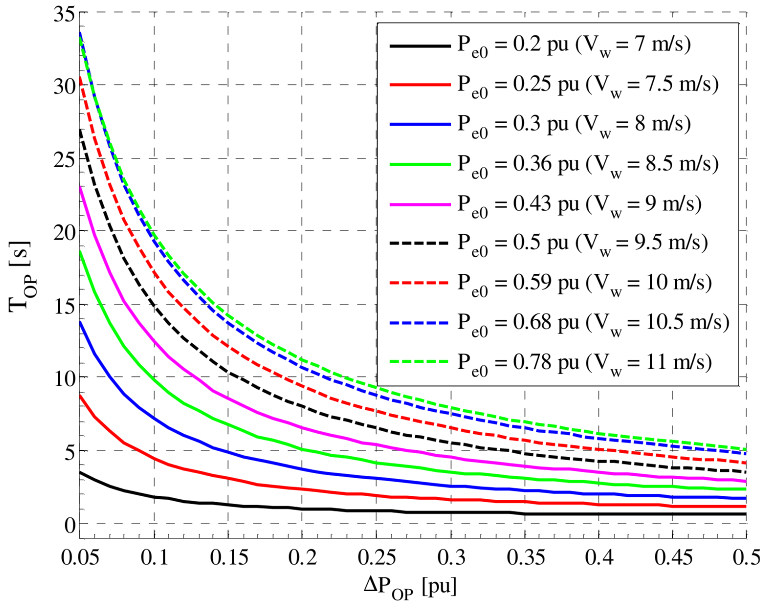
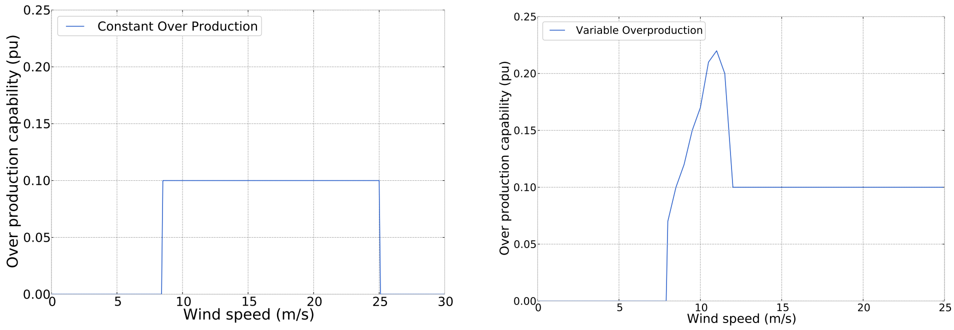


Figure 3.1: Over production rates as measured by Tarnowski [19]

this extraction process is shown in figure 3.2b.

The figure 3.2 illustrates two possible wind speed dependent over production capability curves. Figure 3.2a shows that during a defined operating range, the turbine can provide an over production capability of a constant 0.1pu. This type of curve has the advantage of being more predictable: if a turbine is within its operating range the capabilities would be known directly without further calculations. However, this would not always extract all the available kinetic energy. Conversely, Figure 3.2b – representing a windspeed dependent capability – has the potential of offering more capability during operating ranges that would allow for it; namely during the turbine's variable power mode. The curve shown in 3.2b is based on the aforementioned research from Tarnowski, and will be used for the remainder of this study.

The wind turbine's variable power mode can have more over production capability because the power converter is not running at its fully rated power production, allowing more room for an increase in power production. During the rated power production mode (between 13 and 15m/s), the power converter is already operating at 100% capacity, and therefore can only allow an additional 10% of rated – even if more kinetic energy is available in the turbine's rotor. Minimum rotor speed prevents any capability in lower windspeeds. The cut in wind speed for over production occurs at such windspeed where the rotor will



(a) Constant 0.1pu overproduction

(b) Maximized overproduction

Figure 3.2: Over production capabilities of a single wind turbine as a function of operating point, $P_{op}(v_w)$

be spinning fast enough to allow for 10 seconds of over production and not reduce the rotor rotational speed to below turbine's minimum speed, which may depend on converter limitations or cut-in windspeed.

3.2.3 Operating Point Dependence of Capability

The actual energy available in the rotor of a wind turbine depends on many factors, including

- Physical construction and materials of the turbine
- Physical construction and materials of the generator
- Local wind speed
- The present level of production curtailment by pitch control
- Present levels of de-loading by generator torque
- The speed of rotor rotation

In this work, the first two points are taken for granted and consider only the effects of the last four, which are related to operating point, and comprise not only of the current level of power production, but also rotational speed and wind conditions.

The energy available in active wind turbines has been studied on fleet [15], and machine [19] levels. Work was done by Tarnowski et al to analyze the available energy in a 2MW Vestas wind turbine in [19], and the over production curves introduced in the previous chapter 3.2.2 reflect the real-world energy available from the construction of that Vestas turbine. During the remainder of this study, it is assumed that all wind turbines have the same material and construction make up of the 2MW Vestas VSWT as described by Tarnowski. This assumption will allow the same over production curve to be applied to all the turbines represented in the dispatch simulation.

Since the energy available from a wind turbine depends on the rotational speed of its rotor, which in turn depends on the area's wind speed, and since wind speed information is highly probabilistic, it follows that the kinetic energy available from wind turbines is also going to be probabilistic. This is reflected, for example, in [15] where the available wind resource on Ireland can only be expressed as certain confidence intervals.

One of the purposes of this study is to analyze the capability of wind turbines to offer kinetic energy as part of an inertial response. And since the kinetic energy stored in a wind turbine is a function of operating point a method to determine the operating point of a fleet of wind turbines is necessary.

The main way to estimate operating point is to define an equivalent wind speed being applied to a wind turbine. At an equivalent windspeed there will be a corresponding over production capability, as shown in in figure 3.2. It should be noted that local windspeeds may not always translate to the windspeed being experienced by a wind turbine, for example, in a case where the nacelle wind tracking for a turbine isn't optimal. For the purposes of this study it will be assumed that the wind tracking of all the turbines is good and that wind turbines experience equivalent wind speeds head on.

Ways of estimating the operating point that each turbine in a fleet experiences is thus pursued, and will be outlined below in the following section.

3.2.4 Operating Point Estimation

In the UC-ED model, aggregate wind power production was sufficient for the purposes of deciding how many other generators are turned on, and by how much. However, as will be seen, a more accurate method for estimating synthetic inertial is necessary.

Three methods of estimating the operating point of wind turbines in a fleet were investigated and contrasted. The first uses the power output of turbines from the dispatch record, the second uses a country average windspeed to be applied to all turbines within that country and finally granular mesoscale meteorological wind data was used at each wind farm site.

Data Sources for Quantifying Synthetic Inertia

1. ***Dispatch Data***

   The first method takes the dispatch record of the aggregate wind turbine resource for each country and uses a normalized power production level with the inverse of the windspeed power function to estimate an equivalent wind speed.

   First, the initial power production of a wind turbine, P_e^i, is scaled by the size of the installation, P_{rated}^i, to obtain a per unit value, then the inverse of a wind turbine power production curve is used to arrive at an equivalent windspeed.

   $$v_{eq}^i(t) = P_e^{-1}\left(\frac{P_e^i(t)}{P_{rated}^i}\right) \tag{3.6}$$

   The next step uses the equivalent windspeed with the over production curves first introduced in section 3.2.2 and shown in figure 3.2.

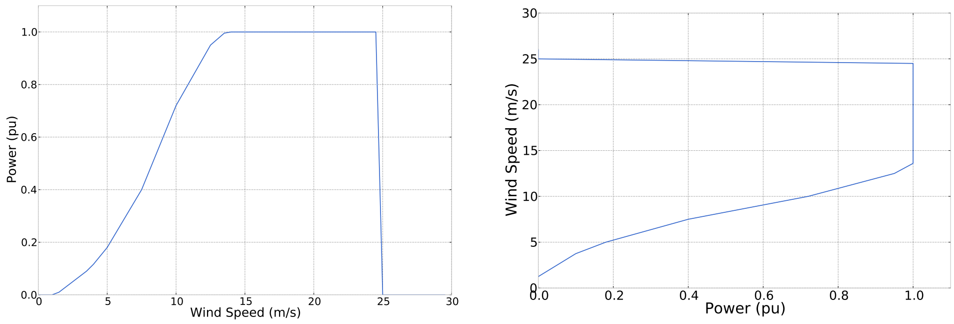
   $$P_{op}^i(t) = P_{op}(v_{eq}^i(t)) \tag{3.7}$$

   Finally, all the over production capabilities of each station were scaled with the respective station ratings, and summed over each m power station per country.

   $$P_{op}(t) = \sum_{i=1}^{m} P_{op}^i(t) \cdot P_{rated}^i \tag{3.8}$$

   This method effectively utilizes the inverse of the wind turbine's power production curve, figure 3.3b. An example of the power production curve is shown in figure 3.3a.

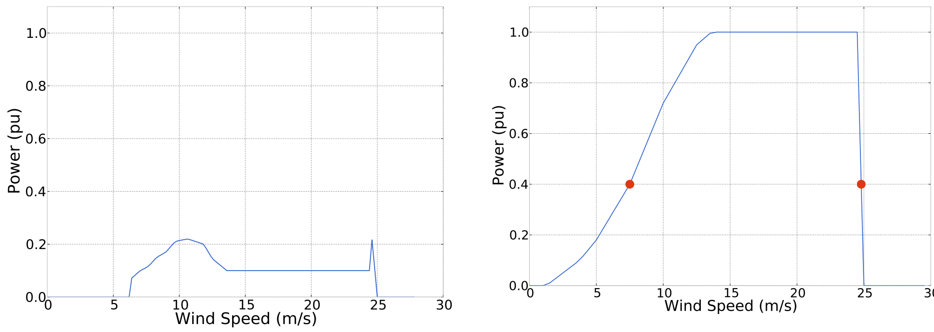
   The graphs shown in 3.3 can quickly identify a short fall apparent in this method, which is the inability to accurately estimate the true operating point when a turbine is at its rated power point. On the curve in 3.3b, there are actually two operating points for each level of power production. The net effect is that this estimation will effectively discard the operating points of higher windspeeds in favor of the operating point corresponding to the lower windspeed. Another problem that arises can be sen in the wind speed-power curve of a wind turbine shown in 3.3a; if the turbine is operating in an environment where the power being produced is at rated power mode, 1pu, it is impossible from that curve to definitively know what wind conditions that turbine is experiencing.



(a) Wind turbine power output $P_e(v)$

(b) Operating point as a function of power production $P_e^{-1}(v)$

Figure 3.3: Wind turbine power output curve, along with its inverse



(a) Over production as a function of real world wind speeds

(b) Power production of 0.4pu could mean the turbine is at 7.5 m/s or 24.8m/s

Figure 3.4: Wind turbine power output affects how over production is calculated

Taken one step further, figure 3.4a shows the complete results of applying this method to estimate over production levels. This figure shows the real world wind on the x-axis and the over production level that would be output given this method. In this case there is a noticeable increase in overproduction near rated speed. This is because of the inability to distinguish between a turbine whose power output is dropping due to being near cut-out speed, and a wind turbine in variable speed mode, as indicated on figure 3.4b. This means that a turbine producing 0.4pu at around 25m/s would be interpreted as a turbine in variable power mode, and then the over production of the variable power mode is then assigned.

The two-valued inverse of the power-speed curve actually becomes even more problematic when wind farm spatial separation, as will be discussed in section 3.2.9, is taken into account, as then the over production curves are highly variable in the operating ranges of 12 to 25 m/s where wind turbines produce rated power.

Because of these problems it is therefore prudent to investigate alternative methods to estimate the operating point of a wind turbine.

2. ***Country Average Wind Data***

For use as a comparison the average windspeed over all f farm sites in a country were calculated and then that one country average wind speed, $\bar{v}_w$ was used as an input to determine overproduction for each wind farm in that country. This provides a useful comparison to the errors and information loss encountered when making certain simplifications.

In order to achieve this, the first step of taking the average of all the farm site's wind speeds and producing an average.

$$\bar{v}_w(t) = \frac{1}{f} \sum_{i=1}^{f} v^i(t) \tag{3.9}$$

Then the country average windspeed was used to generate a time series of over productions at each farm site, using the country average windspeed as input to the over production capability function $P_{op}(v_w)$, shown in figure 3.2.

$$P^i_{op}(t) = P_{op}(\bar{v}_w(t)) \tag{3.10}$$

Finally the sum of all the over production capabilities are scaled by the installed capacity of each farm site and are added together.

$$P_{op}(t) = \sum_{i=1}^{f} P^i_{op}(t) \cdot P^i_{rated} \tag{3.11}$$

The first advantages of using the country average wind speed is that the problems of using non-function relations to estimate operating point, as with using initial power production, are eliminated. Instead, the windspeed can be used directly with the over production curves and yield unique over production capabilities.

On the other hand, the idea of a single wind speed accurately representing the wind conditions within a large geographical area such as a country is unrealistic. Regardless, the country average wind speed is a more accessible statistic that might be used in the case of a data source deficiency. The country average wind speed will also be used as a comparison to highlight the advantages of using a more precise dataset, which will be investigated and discussed at the end of this section.

Country average windspeeds were calculated by taking the average of all wind location sites in a single country. Calculating the country average windspeed this way does allow for some biased data if the site locations are not evenly spread over the country. For the purposes of this study it is assumed that the site locations are diverse and evenly spread, as to produce an average of the entire geographical area of the country.

In order to estimate the over production capabilities each country's average windspeed was applied to all stations, and then using the over production curves an over production capability was calculated for each station. Since the windspeed is the same for every station within a country, each station's per unit over production capability is the same, just scaled based on its rated capacity. Later, the over production capabilities over many countries were aggregated to investigate an overall system overproduction capability in each region.

3. ***Site Wind Data***

The third data source for computing over production capability is to use the mesoscale meteorological windspeed data directly to compute the over production capabilities.

The first step is to compute the per unit over production capability at each wind farm site, f, for each ten minute time step in each country.

$$P^i_{op}(t) = P_{op}(v^i(t)) \tag{3.12}$$

Then, the over production capabilities were scaled by the installed capacity of each farm and added over the entire country, and then later over the entire synchronous region.

$$P_{op}(t) = \sum_{i=1}^{f} P^i_{op} \cdot P^i_{rated} \tag{3.13}$$

Like with using country average windspeeds, using site wind data doesn't have issues with non-function relations to operating point, but also allows

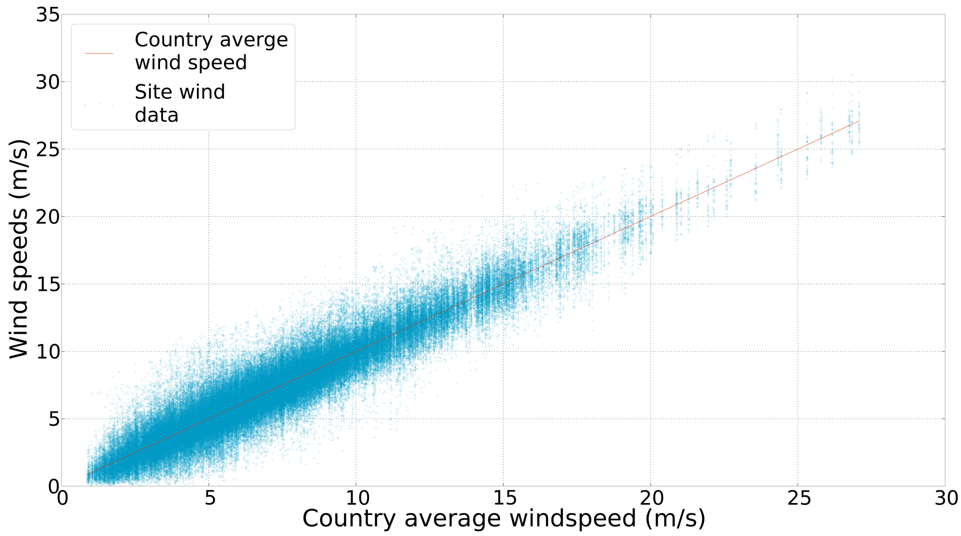


Figure 3.5: Wind speeds at each site in Belgium over a period of 25 days, plotted as a function of the country average windspeed

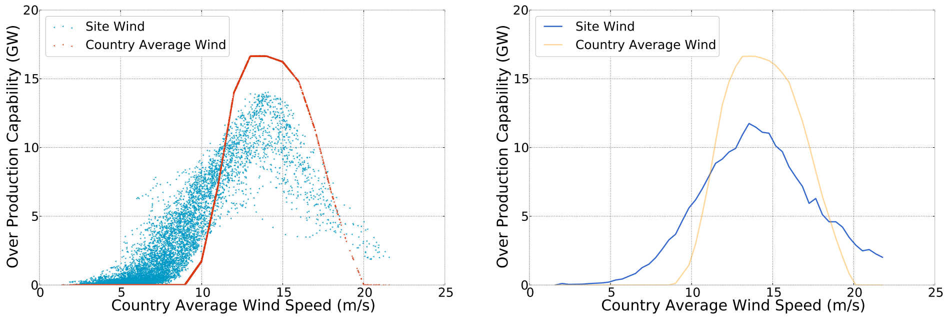
for each wind farm site to have its own unique and realistic windspeed conditions. It is then these more precise conditions that should make for a more accurate fleet wide estimate of the kinetic energy contained in the wind turbine fleets in each country.

Figure 3.5 shows a subset of windspeet data for each station location in Belgium over a period of 25 days. It goes to show how even a small subset of time yields a large variation in windspeeds around the region. The spread gets larger as longer time periods and larger regions are considered.

Data Source Comparison

Potential advantages of using high frequency wind speed data in computing the over production capabilities of a wind turbine fleet can be evaluated by running the over production capability algorithms with the different data inputs, and comparing the results. In fact, only the country average windspeeds and the site windspeeds will be presented here, as the results of the capabilities using dispatch records were of little interest due to the aforementioned shortfalls.

Figure 3.6 shows the sum of overproduction capabilities at all stations for each hour of the year in the continental system, plotted as function of the average windspeed over the region at each time instance. The graphs show the variety of total overproduction capabilities available when the average windspeed is a particular value.



(a) Over production capability in continent using both country average windspeeds, and site windspeeds

(b) Local average of the over production capabilities

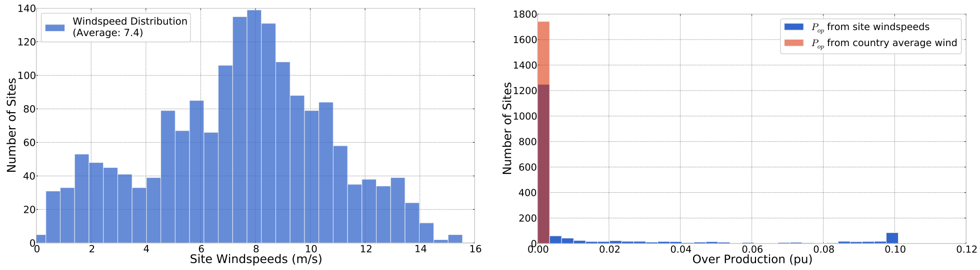
Figure 3.6: Over production capabilities in the continent

The spreads in figures 3.6a and 3.6b are of note in that the cloud of over production capabilities that appears around that of the country average wind shows the information that would have been lost had the study been done exclusively with country average wind. Again, it is these capabilities that would be lost in the case that precise, site level data were not available.

Figure 3.6b plots a local average of over production capabilities to highlight the overall shift in the curve of over production capabilities resultant from using the country average windspeeds rather than the mesoscale data.

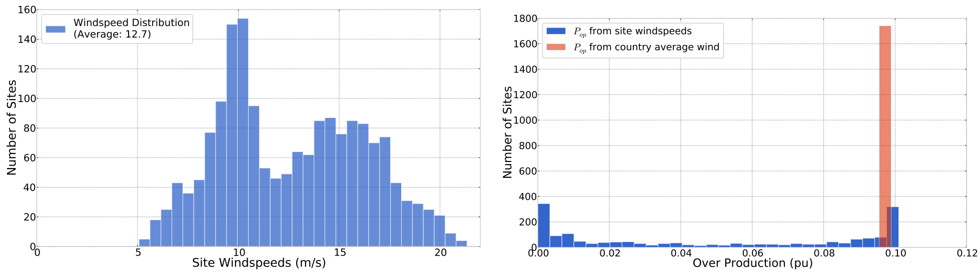
The graphs shown in figures 3.7a and 3.8a show a sample of the windspeeds at each site on hours when the country average windspeed in Germany is 7 m/s or 12m/s. This highlights the diversity of windspeeds in a country and the ways a countrywide fleet of turbines would be operating at any given time. For each country average windspeed, there is a notable spread of windspeed measured over the country. Further as figures 3.7b and 3.8b show, in addition to a spread in windspeeds a notable spread in over production capability is also present. The country average windspeed underestimated the over production capability in the case of figure 3.7b and overestimated the capability in the case of figure 3.8b.

Again, a realistic distribution of overproductions is only possible with the use of high frequency, site level data.



(a) Windspeeds (b) Overproduction capabilities

Figure 3.7: Instantaneous distribution of site windspeeds and over production capabilities in Germany when the country average windspeed was 7.4m/s



(a) Windspeeds (b) Overproduction capabilities

Figure 3.8: Instantaneous distribution of site windspeeds and over production capabilities in Germany when the country average windspeed was 12.7m/s

3.2.5 Recovery Period

When a wind turbine is asked to increase power production to a level above that of its current operating point, the energy is drawn from the kinetic energy contained in that wind turbine. This decrease in kinetic energy manifests itself as a lowering of rotor rotational velocity. Since the imbalance in energy being extracted from the wind and the energy being converted into electricity is limited to the amount of kinetic energy, the over production is naturally temporary. At the end of the over production phase, it then becomes necessary for the wind turbine to accelerate its rotor anew in order to return to its normal operating point and rotational velocity. This phase of returning to normal operational rotation is called the recovery period.

In fact returning the rotor to a normal operating rotational velocity requires additional energy input – normally provided by the wind – in order to accomplish this acceleration. The net effect is that following an overproduction episode where the wind turbine provides an over production of electrical power, the turbine will spend some time producing less electrical power than normal.

The rate at which the wind turbine is to accelerate during the recovery period can be chosen and is set by the control systems in the power electronics that would also handle the inertial response control. Depending on the exact service desired the recovery period can be short, but have a heavily reduced electricity production. Likewise, to minimize the reduction in electricity production, the recovery period may be elongated in time.

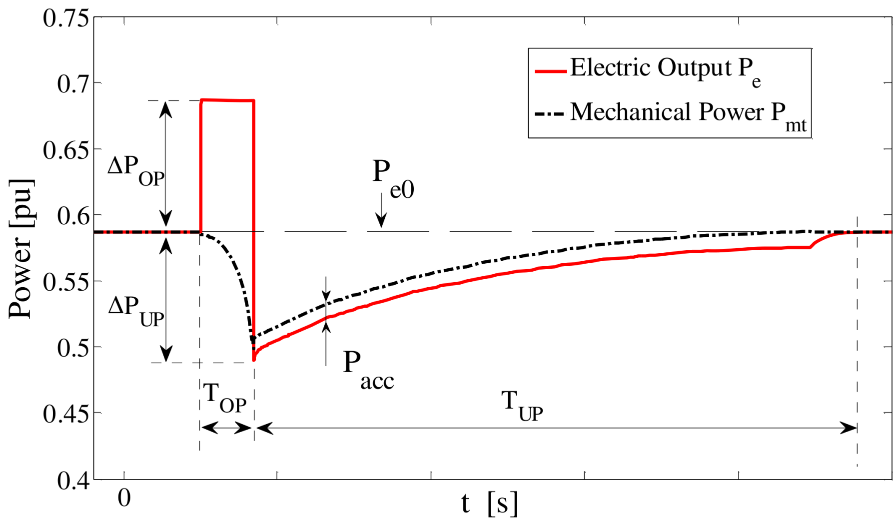


Figure 3.9: Following an over production episode, the wind turbine must generate less than normal in order to accelerate, P_{acc} [19]

It is important to recognize the potential, for a given disturbance, to actually be worsened if many wind turbines are to contribute an overproduction and all enter into a recovery period at the same time. For example, research done in [16] shows that if many turbines are going to provide a response, a second frequency nadir is possible in the grid as well as a delay to recovering to nominal frequency, all due to the recovery period of the turbines.

3.2.6 De-loading

Normally operating wind turbines posses control systems that maintain a wind turbine's characteristics – namely rotational speed (or tip-speed ratio) – to optimize energy conversion from wind to electricity. However, a different control scheme, as suggested by Rawn, et al. [14] where the generator in the wind turbine is de-loaded could instead prioritize the rotational speed. If the turbine's rotor is kept spinning faster, the stored kinetic energy would also be higher. The trade off is that by increasing the kinetic energy some electrical energy harvesting would be sacrificed by operating at a less efficient operating point.

If a wind turbine is de-loaded, it would translate to a larger over production capability. This additional resource could be employed in a number of ways such as simply increasing the synthetic inertia response, or reducing the recovery period. However, this is going to be left as further research, and as such deloading will not be employed in this study.

3.2.7 Curtailment by pitch control

Wind curtailment refers to a wind turbine's control system altering the rotor blade pitch angles such that they become non-optimal. This is done for a variety of reasons.

- To maintain a particular rotational velocity during rated power operation
- Reduce production in the case that there is an excess of production on the grid
- Mimic the droop control of synchronous machines
- Prioritize over production capability

Curtailment becomes relevant in the context of inertial response due to the fact that curtailment necessarily means there is untapped energy in the wind. This untapped wind energy could contribute a temporary overproduction without actually reducing the kinetic energy of the turbine. In fact, a wind turbine that is being curtailed acts very much like that of a synchronous generator in its ability to boost production without worrying about a recovery period.

Having an over production by tapping in otherwise spilled wind energy has been described by [16] and by turbine manufacturer GE in [7] in the WindINERTIA field test. Despite this capability for over production, there are also drawbacks. Limitations on the power converter are always present; if a turbine has been using pitch control to maintain rated power, the power converter might already be highly taxed and care should be taken during over production. Also, if the turbine is at rated and an overproduction is demanded, the mechanical stresses places on the turbine could also be of concern in reducing the lifetime of the turbine.

Finally, if the turbine is at rated, it means that the local average windspeeds are high. At higher windspeeds there will also be a higher amount of turbulence which will not only put more mechanical stresses on the turbine, but will also

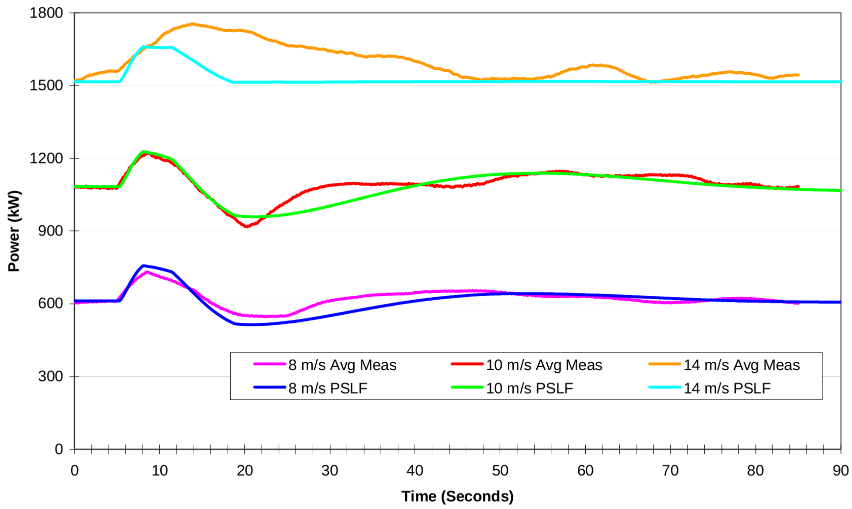


Figure 3.10: Over production curves from GE [7]

heavily tax the pitch control system; as can be seen in figure 3.10, the curve at 14 m/s is less smooth, possibly due to the turbulence, loose pitch control and exceeding the designed range of operation for the controls.

3.2.8 Droop control

In the case of synchronous generators, droop control is normally found in the form of governor systems that are able to modulate fuel flow in order to increase power output in the event of frequency drop. This is not normally possible in the case of wind turbines, since the fuel is the wind, and there exists no mechanism to directly increase wind. Under current industry standard control schemes, wind turbines operating at below rated are designed to maximize energy harvesting, and during rated operation they normally use pitch control to spill some wind power and maintain a constant power production. Spilling some wind at rated power mode keeps operation to within the physical design limits of the turbine and generator. This means that at any given operating point the turbine is either using all available 'fuel' already (as in the below-rated speeds) or is already operating at design limitation (in the case of rated power operation). What follows is that there is not normally the ability to provide a droop response with this type of control scheme.

However, researchers have been looking into the possibility of leveraging curtailment as a means to provide droop control such as in [16]. As mentioned in the previous section, the ability to provide a droop response lies in the ability for a turbine to tap otherwise untapped energy. This would mainly mean either curtailment or de-loading, both of which are discussed above.

For this study, wind turbines are assumed to have no droop control. This is justified because the dispatch model was designed such that any droop control or reserve necessary given the installation of wind turbines is provided by an extra dispatch of synchronous generators.

3.2.9 Wind Farm Spatial Distribution

Wind speeds can not only vary as a function of time, but also as a function of location. Not only will wind speed vary between regions in a country, but variation also exists within a wind farm site itself. Individual wind turbines within a single wind farm will therefore experience a distribution of wind speeds between each other.

In an attempt to quantify this inter-farm distribution of windspeeds, Barry Rawn performed an analysis where statistical indicators were retrieved from real data acquired from wind turbine units on individual turbines on a test farm in the Netherlands. These indicators could then be applied to site meteorological measurements and create confidence intervals of the wind speed distributions experienced by turbines at that farm site. This would give an accurate representation of the equivalent wind speed experiences by each turbine at a particular site, even if only one meteorological data point is available at that site.

Since over production capability is dependent on wind speeds, this method could be further applied to estimate a distribution of over production capabilities at that site. This method was employed and a convolution of the over production capability of a single turbine with the farm-wide wind speed confidence intervals was performed and yielded a series of confidence intervals of the overproduction capabilities.
The graph in figure 3.11 shows how the confidence levels of the spatial distribution affects the over production capabilities. The higher the confidence, the lower the maximum over production, and the smaller the range of wind speeds where there is capability. Also of note, is that the spatial distribution can be responsible for significantly reducing the peak over production capability as compared to the single turbine case. This is due to the fact that the single turbine curve has a very sharp peak near 11m/s, and even at a time where the wind farm site wind speed is 11m/s the spatial distribution says that the turbines within the farm see a spread of windspeeds around 11m/s. Since the over production capabilities around 11 m/s drop quickly, the total over production too, should be lower.

Generating these inter-farm confidence intervals is of high value in the pursuit

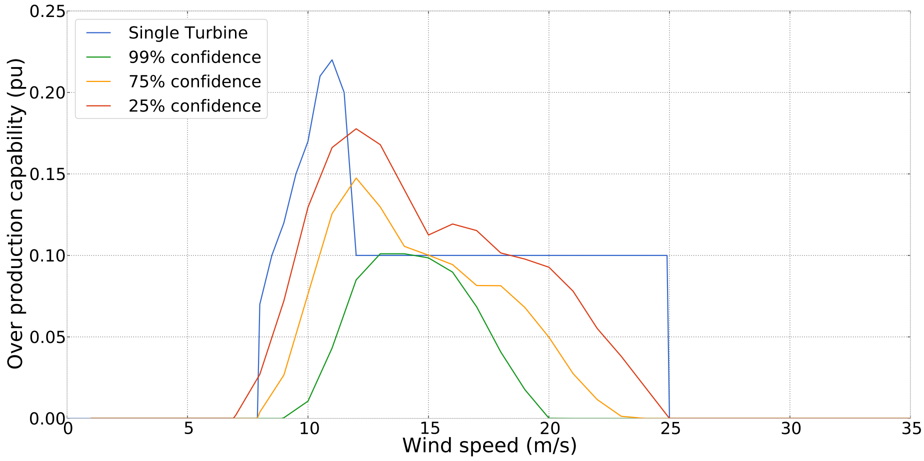


Figure 3.11: Over production capability as a function of wind speed with site-wide confidence intervals

of quantifying overproduction capabilities due to the otherwise stochastic nature of the wind resource. Being able to apply a confidence of, for example 99%, would be of value to a TSO who is risk averse.

For the purposes of this study, the 99% confidence interval was employed whenever appropriate.

3.2.10 Simulated primary response

Ideally, if a wind turbine can be treated similarly to a synchronous machine, then the process of defining a synthetic inertial response should also be similar to a synchronous machine. In an effort to replicate a synchronous inertial response, the following derivation is done.

A control loop that takes the system frequency as input, computes its rate of change, and modulates power output proportional to that change is represented by the following control:

$$\omega \rightarrow \frac{d}{dt} \rightarrow K \rightarrow \Delta P$$

A turbine outfitted with such a control would then, following a disturbance, produce an over production of $-K \cdot \frac{d\omega}{dt}$.

In a system with a single synchronous generator supplying a single load the primary response can be shown as:

$$\begin{aligned}
J\omega\frac{d\omega}{dt} &= P_m - P_L \\
&= (\bar{P}_m - D\Delta\omega) - (\bar{P}_L + \Delta L)
\end{aligned}$$

Where $D\Delta\omega$, reacts to a grid disturbance, ΔL, where D is the droop gain, and $\bar{P}_m$ is the initial power production and $\bar{P}_L$ is the initial demand. When there is no disturbance, $\Delta\omega$ is zero, and no primary response occurs. In fact under normal circumstances $P_m = P_L$.

In a case where two identically sized synchronous generators are connected to a single bus system and are providing for a load P_L, the following can characterize the primary response:

$$\begin{aligned}
\frac{J}{2}\omega \cdot \frac{d\omega_1}{dt} &= P_m^1 - \frac{P_L}{2} = \frac{-D}{2}\Delta\omega - \frac{\Delta L}{2} \\
\frac{J}{2}\omega \cdot \frac{d\omega_2}{dt} &= P_m^2 - \frac{P_L}{2} = \frac{-D}{2}\Delta\omega - \frac{\Delta L}{2}
\end{aligned}$$

This shows how the load P_L is shared between each generator, as well as the droop control response.

Now it is possible that instead of two synchronous machines, generator 2 is replaced by a wind turbine, whose response to a load imbalance, as shown above, is $-K \cdot \frac{d\omega}{dt}$.

$$P_e^{wind} = -K \cdot \frac{d\omega}{dt}$$

Note the lack of a droop term in the definition of P_e^{wind}. Although in a case of curtailment droop is possible from wind turbines, for this study it will be assumed that additional droop will be demanded from synchronous generators as compensation for the lack of droop response from the wind turbine.

So the new combination of the system can be defined as follows:

$$\begin{aligned}
\frac{J}{2}\omega \cdot \frac{d\omega_1}{dt} &= P_m^1 - \frac{P_L}{2} = -D\Delta\omega - \frac{\Delta L}{2} \\
\frac{d\omega_2}{dt} &= P_m^2 - \frac{P_L}{2} = -K \cdot \frac{d\omega}{dt} - \frac{\Delta L}{2}
\end{aligned}$$

Although since droop isn't available directly from wind turbines, it is assumed that extra synchronous droop is available to make up for a lack from wind turbines, so instead of the synchronous machine providing $D/2$, it will actually provide D.

If the perspective of the first generator is taken, it will see the grid disturbance take the form of $\Delta L - P_e^{wind}$. The two above equations combine to from a single equation representing the response on the entire system:

$$\frac{J}{2}\omega \cdot \frac{d\omega_1}{dt} = -D\Delta\omega - \Delta L + (-K \cdot \frac{d\omega}{dt})$$
$$(\frac{J}{2} + K)\omega \cdot \frac{d\omega_1}{dt} = -D\Delta\omega + \Delta L$$

Where $\frac{J}{2}$ represents the synchronous inertia of the synchronous half of the system, and D represents the droop of the synchronous machine as well as the droop the synchronous machine is providing on behalf of the wind turbine.

The above now defines the control signal K in the same term as the synchronous inertia J. For the rest of this study the control constant K is defined as the synthetic inertia.

In order to quantify K, it is necessary to set a target of:

$$K = \frac{J}{2}$$

This way, the wind turbine control should behave as if it is the second half of the above theoretical system. So it should be possible to relate K to the ROCOF of the system.

If in a synchronous only system the largest ROCOF experienced is defined as $\overline{RCF}$, it then becomes possible to select K such that:

$$-K \cdot \overline{RCF} \leq \overline{\Delta P}$$

Where $\overline{\Delta P}$ is total overproduction capability of the wind turbines. K should be chosen to ensure all the over production capability is released in the worst case ROCOF: $\overline{RCF}$.

$$\frac{P_{op}}{\overline{RCF}} = K \tag{3.14}$$

With that, the synthetic inertia, K, is defined by equation 3.14 as the ratio between the over production capability and the worst ROCOF that can be expected.

3.3 Loss Risk and Supported Inertia

In the case of a system disturbance where there is a power deficiency, it is possible to quantify a quantity, *loss risk*, which is an indicator of what an expected ROCOF would be if the largest generator unit were to suddenly go offline. The swing equation, as seen in equation 1.1, is used to define loss risk as the ratio of the rated power of the largest unit to the system inertia and frequency:

$$\frac{\Delta P^{largest}}{J \cdot \omega} = \frac{d\omega}{dt} \tag{3.15}$$

When defined this way, the loss risk is time dependent as both the largest unit and the system inertia vary with time. In fact, in the case of the continental system the largest unit doesn't change, according to the dispatch records, since the largest unit for the entire year remains a nuclear generating station in France, and in the case of Great Britain, the largest unit is one of either two combined cycle gas turbines.

Chapter 4

Results

The dispatch data was used as a record of the commitment of each synchronous generator and was used to compute the synchronous inertia. The wind speeds provided by the meteorological data was used to compute synthetic inertia. Together these inertias were used to analyze the different region's and year's systems. This chapter will present the inertias computed, as well as some further calculations to quantify the risk associated with inertia levels present in those systems.

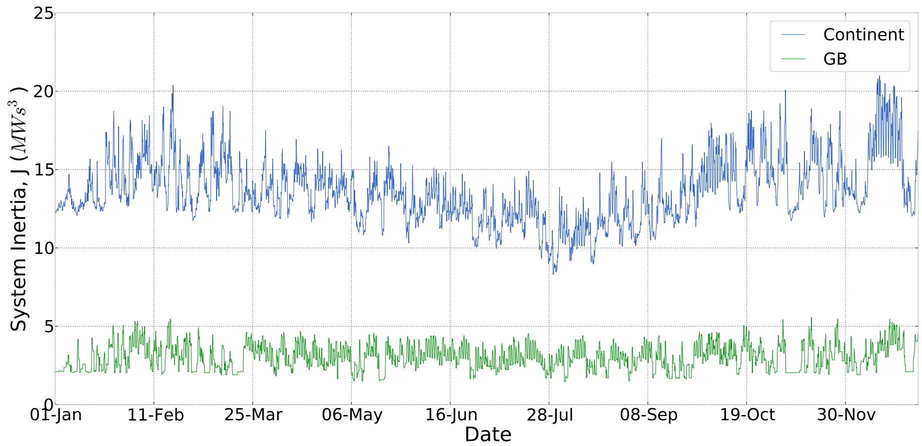


Figure 4.1: Time series of synchronous inertia in 2030 scenario

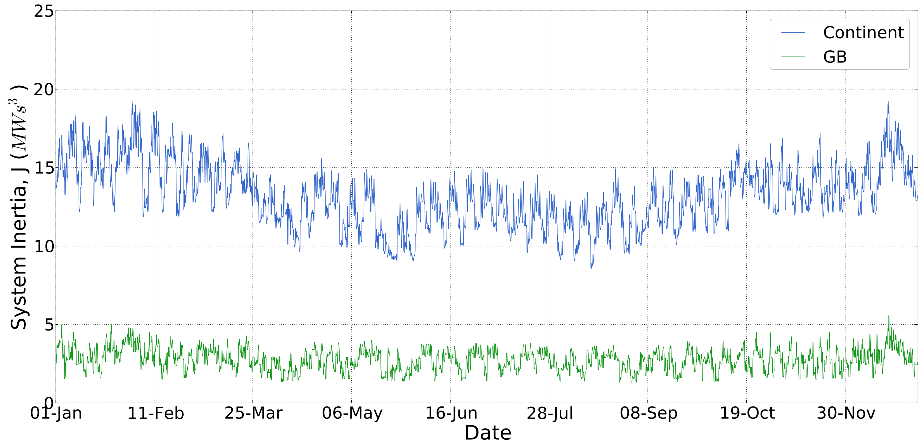


Figure 4.2: Time series of synchronous inertia in 2020 scenario

4.1 Inertia

4.1.1 Synchronous Inertia

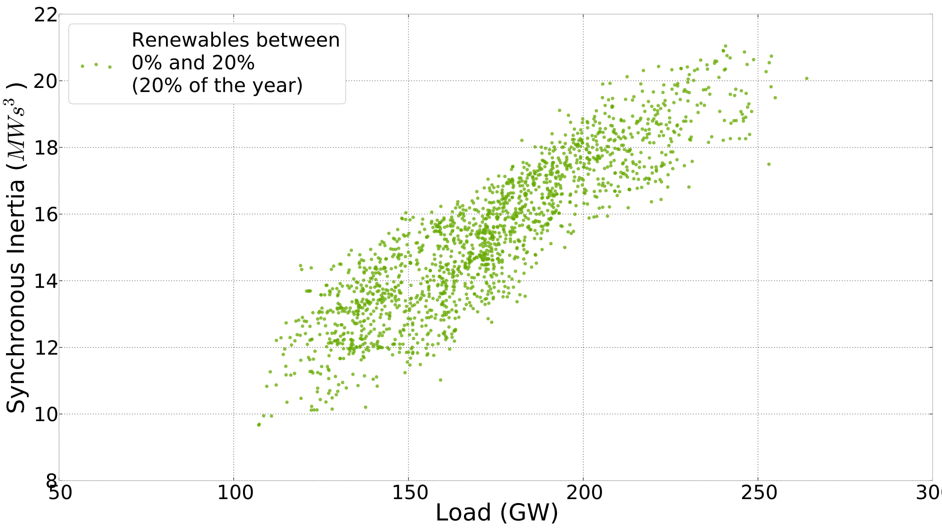
Figure 4.1 shows how the synchronous inertia varies over time in both modeled synchronous regions.

Investigation of figure 4.1 shows that system inertia indeed has a fair amount of variation over time. This is logical considering the way generation units are always being committed and de-committed depending on the dispatch algorithm.

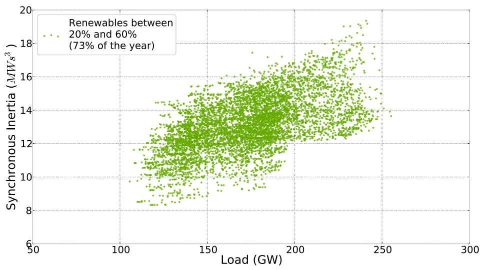
Seasonal variations also present themselves in the case of the continental system, corresponding to a seasonal drop in load on the continent (figure 2.4). Inertia in Great Britain on the other hand is less seasonally dependent, again matching the lack of seasonal dependence in the load.

For comparison, the 2020 simulation with half as much installed wind capacity is also shown in figure 4.2. What is notable is the difference in inertia levels. Despite including approximately twice the installed wind capacity as 2020, the 2030 scenario still contains more than half the synchronous inertia. This would suggest that increases in wind installed capacity don't directly translate to same-scale reductions in synchronous inertia.

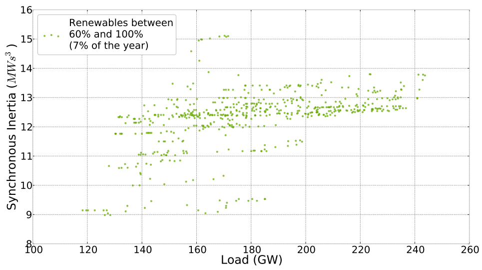
Figures 4.1 and 4.2 shows that the time series of inertia between 2030 and 2020 isn't extremely different. In fact the *max J*, *min J* and *mean J* in the dispatch records section of table 4.1 also suggests that a system with higher fraction of installed renewables doesn't necessarily result in a large difference in the level of synchronous inertia dispatched in that system. However, figures 4.3



(a) Inertia when the fraction of load being met by less than 20% renewables



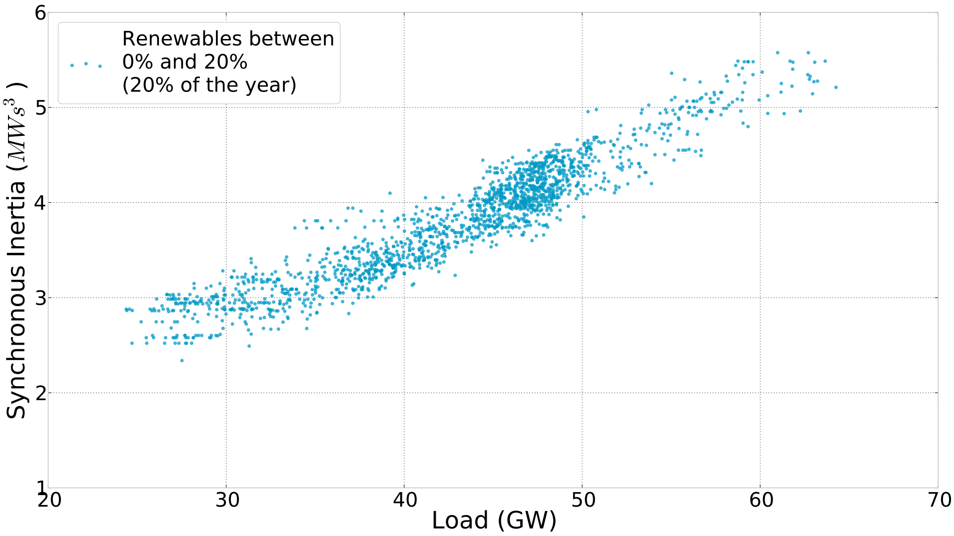
(b) Inertia when the fraction of load being met by between 20% and 60% renewables



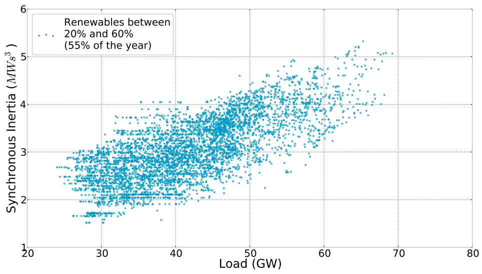
(c) Inertia when the fraction of load being met by between 60% and 100% renewables

Figure 4.3: Scatter plots of the inertia on the continent as a function of the load. Subsets of inertia were taken based on the fraction of load being met by wind and solar in 2030

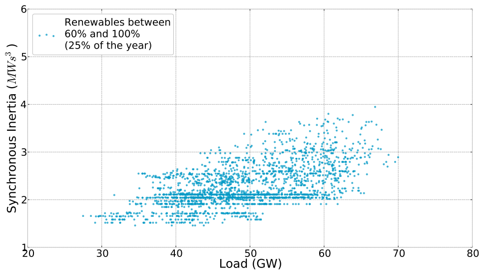
and 4.4 do suggest that the *dispatch* of renewables affects the way system inertia is present in a system. The scatter plots in 4.3a and 4.4a indicate that at the times where there is a low number of renewables contributing to the dispatch mix, then there is a strong relation between synchronous inertia and amount of load being served. This isn't surprising given that in the absence of renewables, as the load goes up so to does the number of committed synchronous generators – and also the synchronous inertia. Further inspecting figures 4.3b and 4.3c show how this linear relationship between generation level and synchronous inertia breaks down as data subsets contain instances of increasing fraction of renewables. This behavior is mirrored in much the same way for the system in Great Britain and is shown in figures 4.4b and 4.4c. This strongly suggests that there exists a relation between the dispatch level of renewables and an increase in the variability of synchronous inertia – and not necessarily an overall decrease in the absolute level of synchronous inertia.



(a) Inertia when the fraction of load being met by less than 20% renewables



(b) Inertia when the fraction of load being met by between 20% and 60% renewables



(c) Inertia when the fraction of load being met by between 60% and 100% renewables

Figure 4.4: Scatter plots of the inertia in Great Britain as a function of the load. Subsets of inertia were taken based on the fraction of load being met by wind and solar

Although no dispatch simulation was done for a 2010 energy scenario, an indication of how the inertia of installed capacity grew from 2010 to 2030 in response to a growth in renewable sources is shown in table 4.1. The inertia of the installed synchronous fleet is indicated by the row *Max*. It was determined by calculating the total inertia of all synchronous machines. Rows *Peak* and *Valley* in the *Installed Inertia* section indicate the amount of inertia in the system if the peak or valley loads respectively are met with only the synchronous machines based on a typical merit order (starting with nuclear and coal, and ending with gas).

Synchronous Inertia	Great Britain (MWs^3)			Continent (MWs^3)		
Installed Inertia	2010	2020	2030	2010	2020	2030
Max	7.38	6.20	6.15	24.52	22.04	22.61
Peak	6.9	5.9	5.9	19.7	19.6	20.5
Valley	3.2	2.6	2.8	9.5	10.1	11.5
From Dispatch Records						
Max J	(6.6)	5.6	5.6	(22.0)	19.2	21.0
Peak load J	–	2.6	2.9	–	13.9	20.7
Mean J	(3.4)	2.7	3.0	(14.6)	13.1	13.5
Min J	(1.7)	1.3	1.5	(9.3)	8.6	8.3
Valley load J	–	2.9	2.8	–	12.9	11.6
Std J	–	0.7	0.8	–	2.0	2.0

Table 4.1: Outline of synchronous inertia in the Continent and in Great Britain (MWs^3)

Also shown in table 4.1 are the absolute values of inertia at particular times as prescribed by the dispatch model. The *Max J* and *Min J* are the year's absolute maximum and minimum inertia receptively, based on the dispatch record. *Peak load J* and *Valley load J* are the inertias at the year's absolute peak load and absolute valley load respectively.

The bracketed values for the year 2010 dispatch *Max J* do not represent the output of a dispatch, but rather an estimation of the values given an assumption that the 2020 and 2030 ratios between installed *Max* inertia and dispatch record *Max J* hold for the year 2010 as well. The same process was applied for the rest of the bracketed 2010 values.

Reading table 4.1 across gives indications on how the synchronous inertia varies in systems with different fleets of renewable sources. For example, the *Mean J* in dispatch actually increases when moving from the 2020 fleet to the 2030 fleet. This, despite a doubling of wind power installations between the two years. In fact, Great Britain sees and increase of the *Mean J* in dispatch despite a drop in the total amount of synchronous inertia in its installed fleet. This would suggest that many conventional machines are being committed to ensure safe ramp rates and a safe synchronous reserve.

Another observation in Great Britain is that the *Peak load J* and the *Valley load J* have about average inertia. Suggesting that times of extremely high or extremely low fraction of renewables might not be occuring at the extreme load levels. This contrasts with the continent, where the *Peak load J* is near to the yearly *Max J*. This could suggest that unlike Great Britain, the renewable sources in the continent might be at their minimum at peak load times. These results, however need more analysis into the specifics of the daily peak and valley load times for verification.

Reading vertically in table 4.1 can give an indication of how dispatch records are important in predicting the system inertia. The values in the installed inertia section can easily be calculated without the need for a UC-ED model, however the predicted Max, Peak and Valley values in the installed inertia section don't match with the inertias seen using the output of the UC-ED model. In fact there is a tendency to over estimate the amount of inertia in a system by using installed capacities alone. One might be tempted to explain the higher inertia values from fleet capacity by citing asynchronous generators, but that would suggest that the ratios between Max, Peak and Valley from the installed to the dispatch would be different between the 2020 and 2030 systems. In fact those ratios do not differ much, so there must be more to the dispatch algorithm that explains the differences, and highlights the value of using a UC-ED for inertia calculations.

Overall, the values in table 4.1 beg more research into the factors in the dispatch algorithm that affect synchronous inertia, since it becomes apparent that installed capacity alone is not sufficient to draw conclusions on system synchronous inertia.

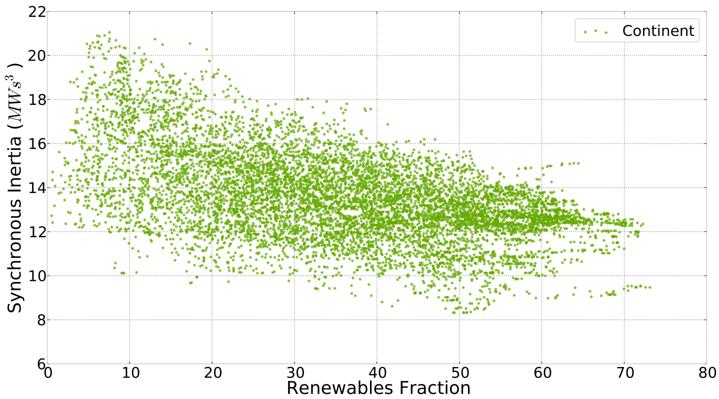


Figure 4.5: Synchronous inertia as a function of the fraction of dispatch being served by renewables in the continental system

Figures 4.5 and 4.6 show how the synchronous inertia varies with the fraction of the load being met by wind and solar generation. The spread is quite large, and although there is a general negative trend to the data, the fact that at any given fraction of dispatched renewables there are instances of most synchronous inertia values. This further shows that the amount of synchronous inertia in a system cannot be said to decrease given solely the amount of wind and solar generation.

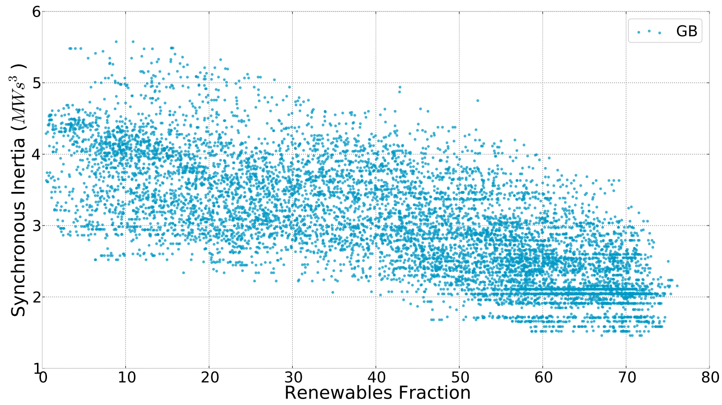


Figure 4.6: Synchronous inertia as a function of the fraction of dispatch being served by renewables in Great Britain

It follows, then from this section that neither the installed capacity of renewables nor the fraction of generation met by renewables is especially good predictors of the level of synchronous inertia. Instead, it can be said that when there is a large fraction of renewables serving power on a grid, the amount of synchronous inertia tends to take on a wider range of values. Table 4.1 shows that on the continent, the dispatch levels of J either increase in absolute spread or increase in standard deviation with larger installations of renewable generation. Figures 4.3 and 4.4 show that at times of low renewables the amount of synchronous inertia takes on a more predictable linear form, but is unpredictable at times where renewables contribute, with instances of both high and low synchronous inertia.

4.1.2 Synthetic Inertia

Computing the synthetic inertia was completed using the meteorological data and the over production curve with the 99% confidence interval, as shown in figure 3.11. The resultant time series of inertia in the continent is shown in Figure 4.7.

Unlike with synchronous inertia, which depends on demand load, which in turn depends on season, the synthetic doesn't have any obvious dependency on season. Just like how the wind itself is unpredictable, synthetic inertia is proving to be unpredictable as well.

Figure 4.8 shows a duration curve of the synthetic inertia and synchronous inertia in the studied synchronous regions. Here the fraction of time spent at certain levels becomes apparent, where the flatter line representing synchronous inertia means that its level changes less often and can more reliably be at some particular level. On the other hand, even though there are times of high syn-

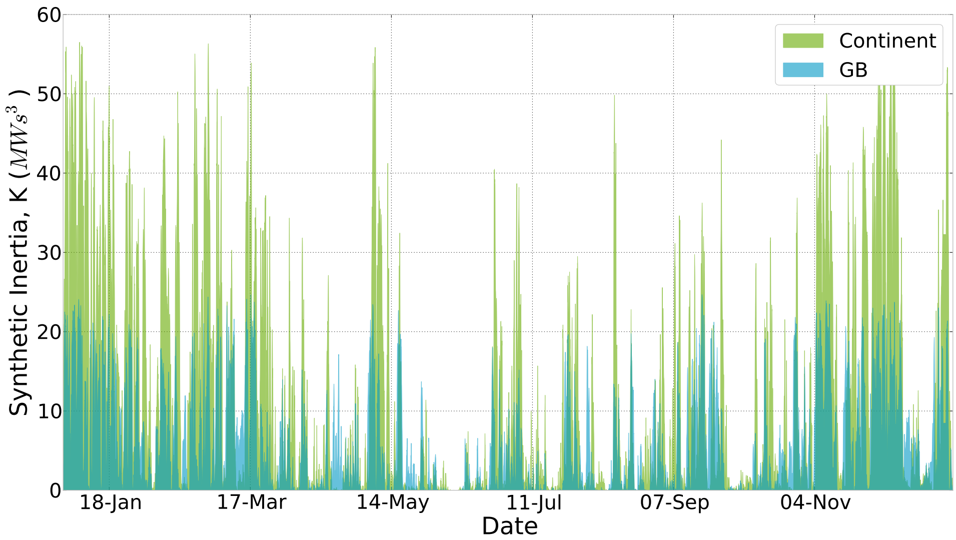
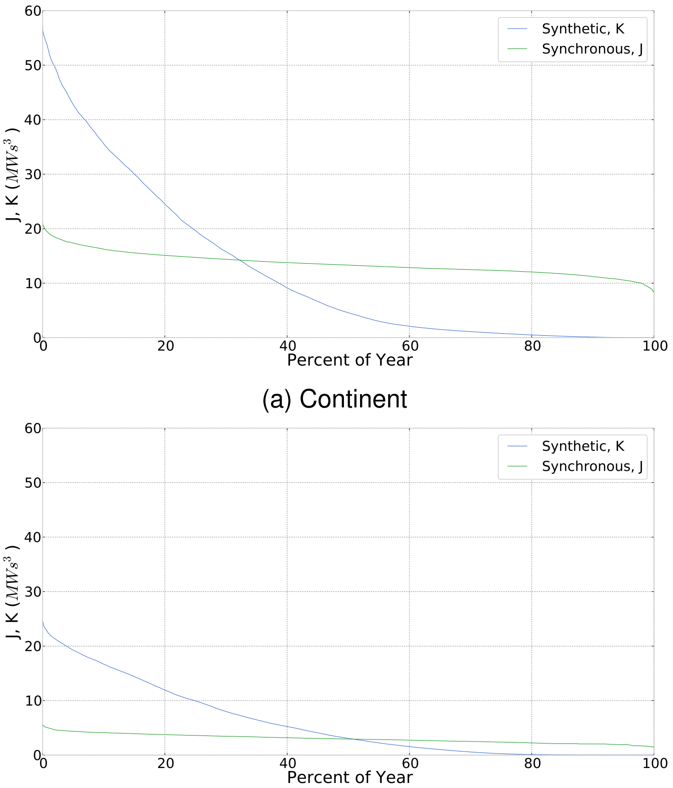


Figure 4.7: Time series of synthetic inertia in the continental and Great Britain synchronous regions for the year 2030

thetic inertia, the natural variability in the wind resource results in a dramatic drop in the duration of synthetic inertia.

It's also interesting to note that the synthetic inertia in Great Britain stays high for a longer fraction of the year, in fact the synthetic resource is at least as much as the synchronous almost 50% of the year. This is due to the relatively high fraction of installed wind energy in Great Britain.



(a) Continent

(b) Great Britain

Figure 4.8: Duration curve of synthetic and synchronous inertia in the studied synchronous regions for the year 2030

4.2 Coincidence of Synthetic and Synchronous Inertia

In order to identify the ability for synthetic to actually aid in increasing the stability of the systems, it is necessary to look at the magnitude and coincidence of the synchronous and synthetic inertias. Figure 4.9 shows the relative incidence of synchronous and synthetic inertias in the continental region. Of first note is the relative size of the synthetic compared to the synchronous. This can be partially explained by the increase in flexibility of the power electronics in the wind turbine. That flexibility is what allows for the turbine to have more freedom to vary in rotational speed and allows for more energy to be extracted.

The highly variable nature of the synthetic, as compared to the synchronous inertia is also striking, though understandable considering the heavy dependence on wind conditions. Indeed, as was seen in the duration plots in figure 4.8, although the resource of synthetic inertia can be high, it is only at a level comparable to that of the synchronous inertia about half the year, for both regions.

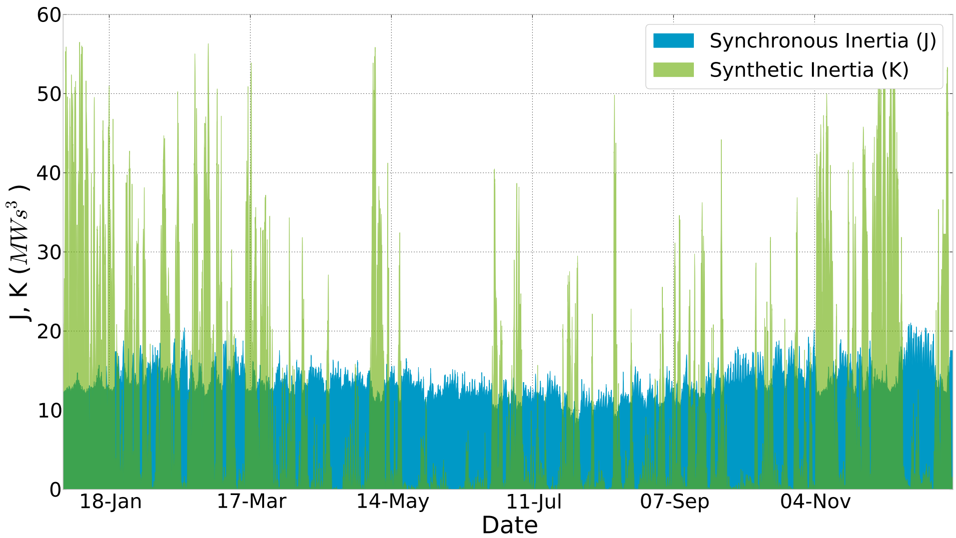


Figure 4.9: Time series of synthetic and synchronous inertia in the continental synchronous region for the year 2030. Correlation coefficient is -0.22

From the perspective of a TSO the variability might become a challenge to embrace when it comes to a potential reliance on synthetic inertia. It would be hard to depend on such a varied resource for system stability.

Despite being intermittent, an important question to make is whether the synthetic inertia is available at times when synchronous inertia is low. That way the synthetic might still be able to aid at times when the system is most vulnerable. The correlation of the synthetic inertia with the synchronous in time is -0.22 and -0.56 respectively for the continent and Great Britain systems. That would suggest some potential for the synthetic inertia to be available when the synchronous inertia is dropping, and can be observed in figure 4.10, but still paints an incomplete picture. Instead an analysis on the how often the synthetic can contribute *at least* enough inertial response to maintain a particular level of overall system inertia will be investigated.

In order to determine more accurately the amount of time the synthetic inertia is able to contribute in a significant way to the total system inertia, the synthetic inertia was added to the synchronous, whenever possible, to achieve a minimum level of overall system inertia, J_{min}. This addition was labeled *supported inertia*. The minimum level chosen to maintain is the maximum of level of synchronous inertia seen in 2030.

Figure 4.11a shows the level of supported inertia in the continental region. It can be seen that although the system inertia is aided at many time points, there

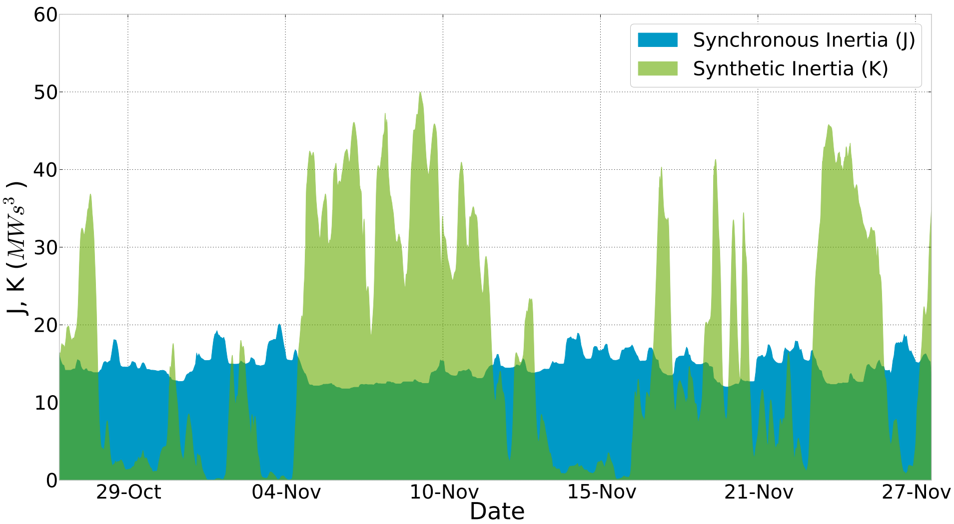
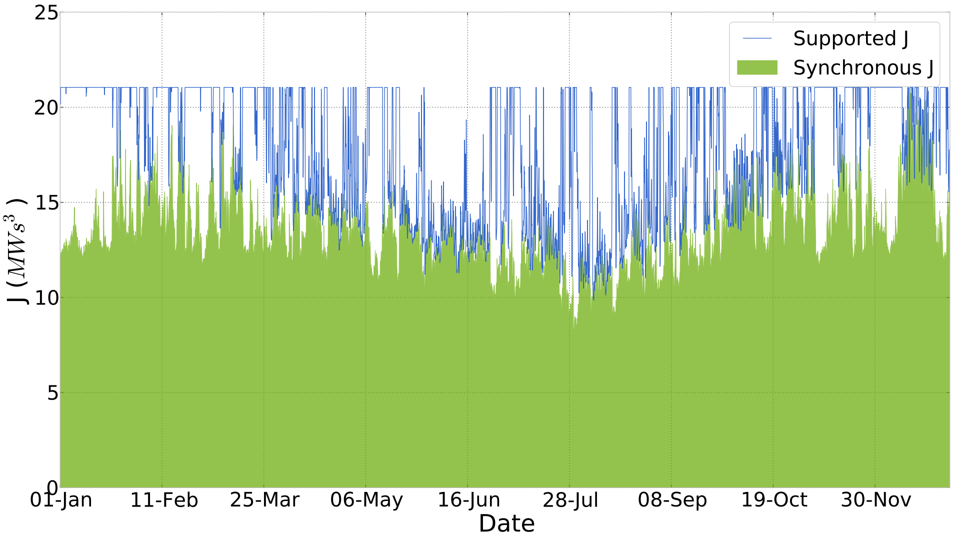


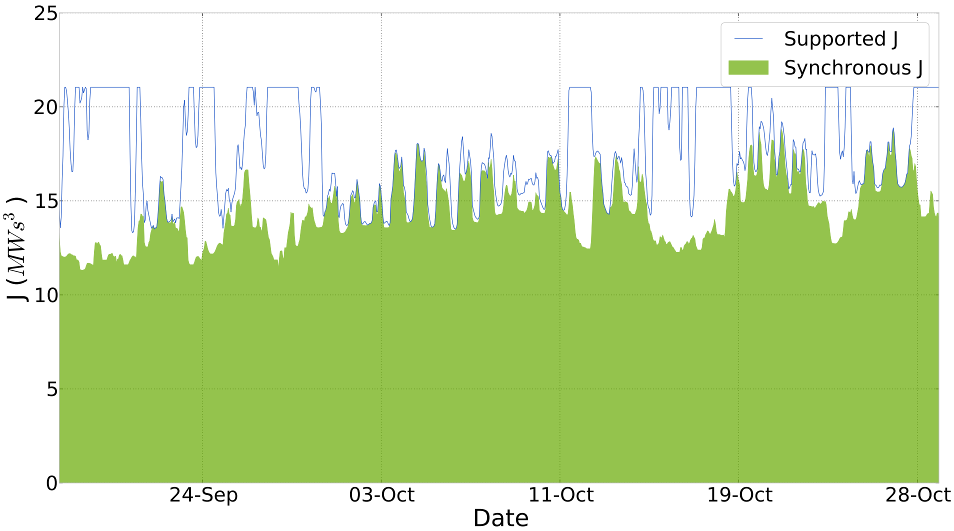
Figure 4.10: Time slice of the time series of synthetic and synchronous inertia in the continental synchronous region for the year 2030

are still a significant number of hours where the system inertia is as low as it would be without any aid from synthetic inertia, more visible in 4.11b.

The duration plots in figure 4.12 makes more clear the amount of time in a year that the synthetic inertia was able to significantly contribute a response, and thus maintain J_{min}. In this case, just under half the time in the continental system, and just over half the time in the Great British system the synthetic inertia was able to completely maintain J_{min}. This is mildly promising, in that a not insignificant fraction of the time the synthetic inertia was able to provide a good response. However, given a risk adverse mindset, like that of a TSO, the promise of an inertial response only 50% of the time is still likely to be disappointingly low.

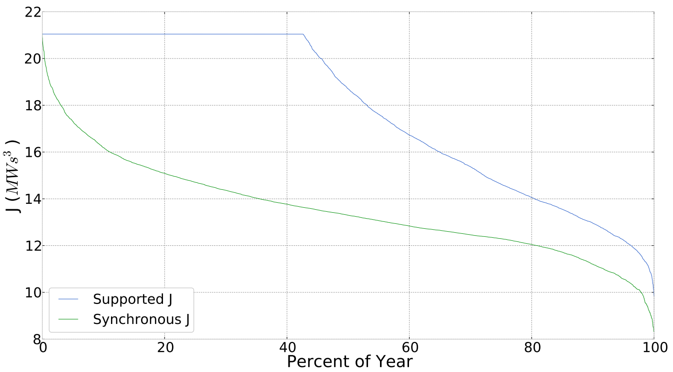


(a) Entire simulated year of supported J

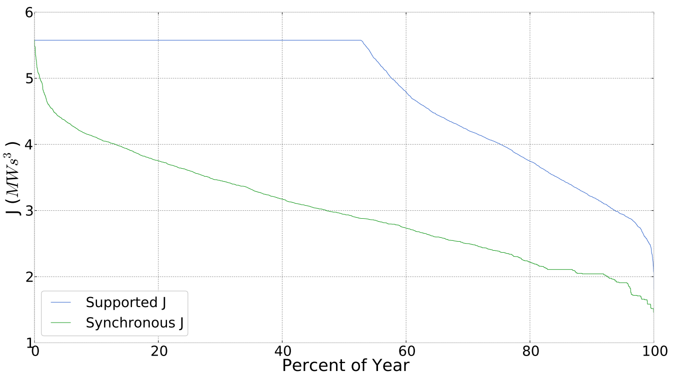


(b) Time slice of supported J

Figure 4.11: Time series of synchronous system inertia and system inertia when the synthetic inertia is employed as support to maintain a desired level of J on the continent.



(a) Continent



(b) Great Britain

Figure 4.12: Duration curve of total system inertia when the synthetic is employed as support to maintain a desired level of J

4.3 Effects on ROCOF

Given the system inertia, and the largest unit committed, it's possible to investigate the loss risk of the studied systems, as originally seen in equation 3.15, and rewritten below:

$$\frac{\Delta P^{largest}}{J \cdot \omega} = \frac{d\omega}{dt}$$

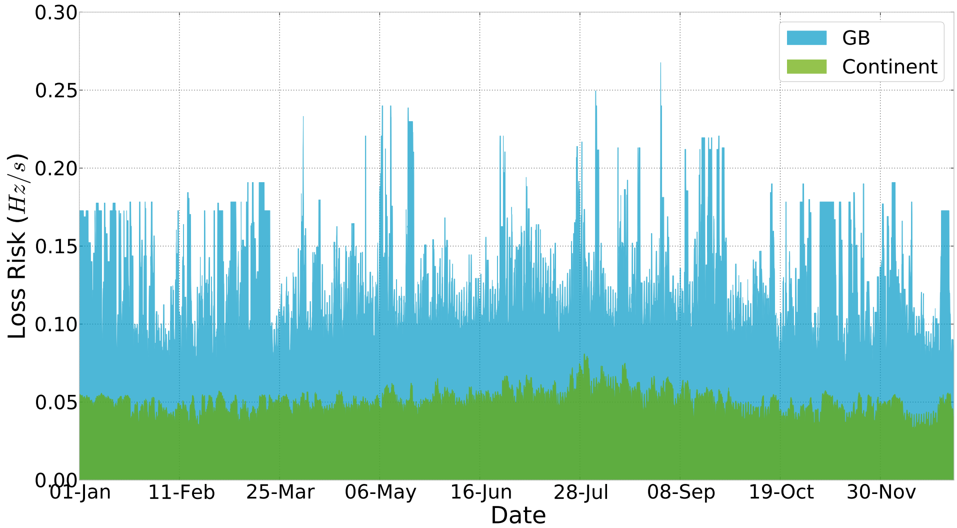


Figure 4.13: The loss risk present in the studied systems using only synchronous inertia

Unsurprisingly figure 4.13 shows how the loss risk found in the continental system remains much less, and less variable than that of Great Britain. As mentioned previously, the fact that the continental system has more generators and more inertia helps keep the loss risk low. Additionally, the continental system sees a more consistent base power generation in the fleet due to French nuclear plants being committed constantly and this leads to less variablity in the loss risk.

The investigation into risk loss was then repeated, but this time with the synthetic inertia employed as a support to the synchronous.

Figure 4.14 shows how the loss risk is reduced in the continent at many time instances to the overall lowest loss risk value, but times remain where there is no or little inertial capability from wind turbines to reduce the loss risk to its lowest value. The duration curve in figure 4.15a shows, that like with the supported J, the synthetic inertia was successful with the goal of J_{min} around 50% of the

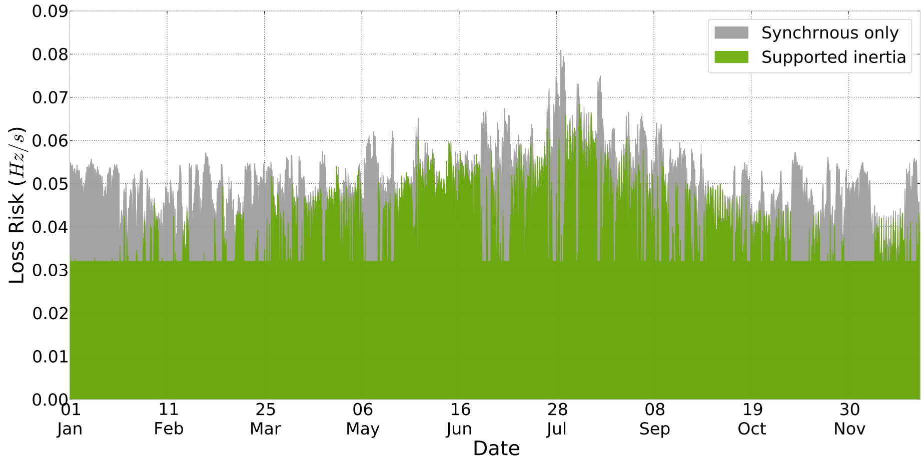
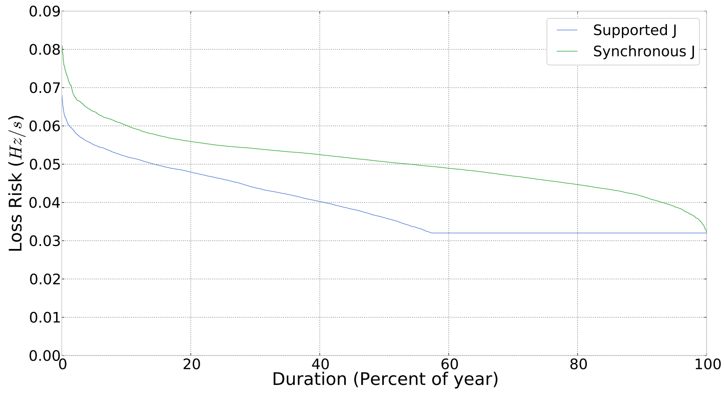


Figure 4.14: The loss risk present in the continent before and after using synthetic inertia to support the synchronous inertia

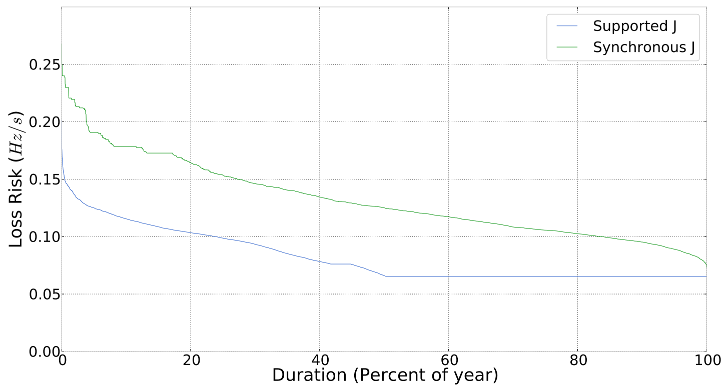
year.

The duration curves in figure 4.15 bring to light a number of facts. First is the absolute peaks in loss risk in both systems where reduced significantly. This indicates a contribution from the synthetic inertia during the times that the system was most vulnerable, and is promising. Additionally, both systems still see some instances with a high loss risk, but the slope of the loss risk with supported inertia is steeper, meaning that a significant fraction of time points saw benefit of the synthetic inertia. More specifically, in the Great British system, 90% of the time, the supported system saw a loss risk less than 50% of the non-supported system. The continental system, also saw a lesser reduction where 80% of the supported system was has loss risk less that 50% of the non-supported system. The great reduction in loss risk might be attributed to the higher penetration of wind energy in Great Britain, thus increasing the size of the synthetic inertia resource relative to its overall system size. Nonetheless, the fact that a significant reduction in loss risk in both systems achieved by employing synthetic inertia is promising.

In order to study a potential relationship and potential effect renewables have on loss risk, the scatter plots in figure 4.16 were made to show loss risk as a function of the fraction of load being supplied by renewables. When wind turbines are not being employed to provide synthetic inertia, figure 4.16a reveals an unsurprising relation between the loss risk and the fraction of energy provided by renewables: loss risk tends to increase with a higher fraction of load provided by renewables. On the other hand, when the synthetic inertia is added to support system inertia, a promising development in made and shown



(a) Continent



(b) Great Britain

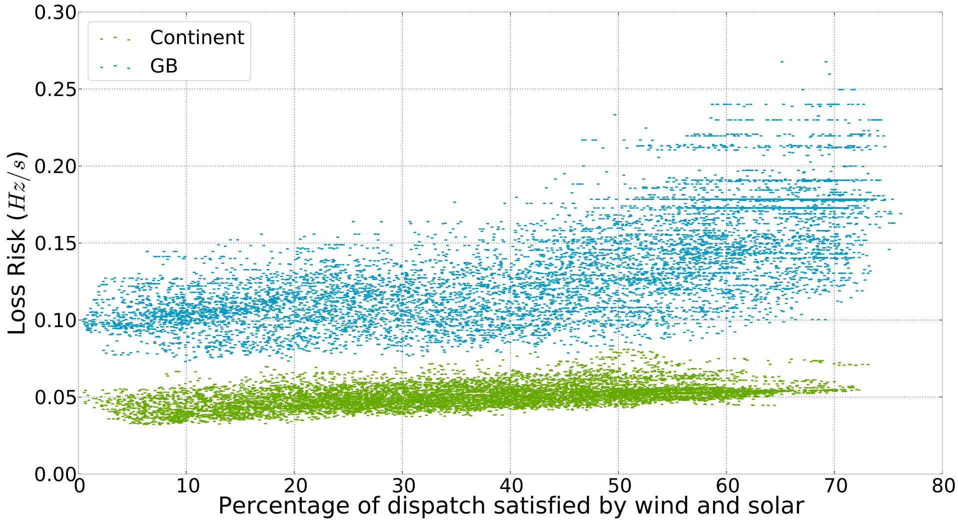
Figure 4.15: Duration curves of loss risk when the synthetic inertia is employed as support to maintain a desired level of J

in figure 4.16b, where the dependency of loss risk with increasing renewables has been significantly reduced. This follows from the fact that at times of higher renewables, generally, there is more synthetic inertia to contribute to the overall system inertia.

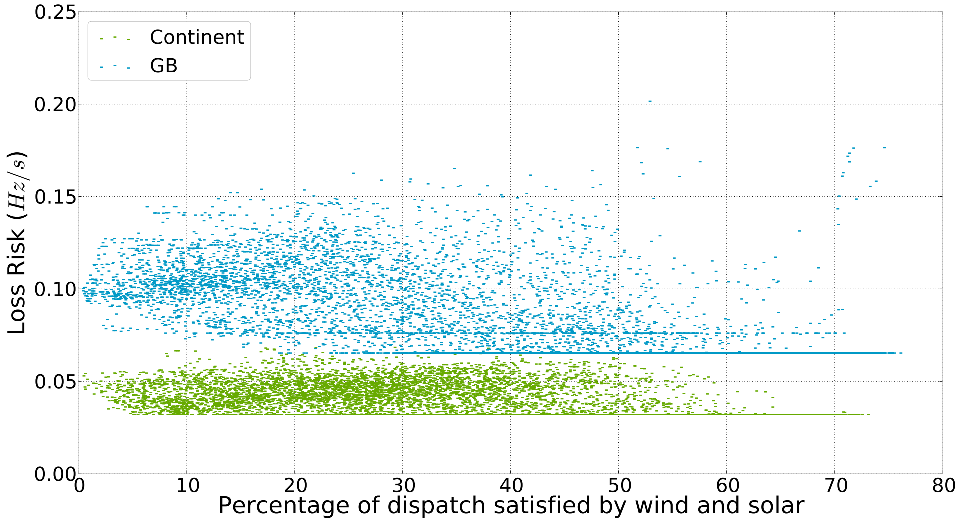
The plots shown in figure 4.16b are promising for the future of renewables in that it suggests that the stability of a system need not necessarily depend exclusively on synchronous inertia. Further, it goes to show that having higher more renewables doesn't necessarily result on a more unstable system. Instead, as the growth of renewables increases, so to are its potential contribution to inertia via a synthetic response, and thus a relation between higher loss risk and higher fraction of renewables is no longer clear-cut.

	Great Britain (Hz/s) Using J from:		Continent(Hz/s) Using J from:	
	Synchronous	Supported	Synchronous	Supported
Max	0.081	0.068	0.268	0.201
Mean	0.051	0.039	0.132	0.0821
Min	0.032	0.032	0.073	0.065

Table 4.2: Outline of loss risk observed in the Continent and in Great Britain systems (Hz/s)



(a) Without support from synthetic inertia



(b) With support from synthetic inertia

Figure 4.16: The loss risk present in the studied systems as a function of the fraction of dispatch being met by renewables

Chapter 5

Discussion and Conclusions

While investigating system inertia of a future energy system insight into a number of areas were provided, and detailed below.

Synchronous Inertia
An economic dispatch model that was originally designed to analyze the flexibility and ability for a system to absorb energy provided by renewables was extended for additional analysis into system inertia. The methods devised and employed to implement this extension proved to be successful by providing quantified results of synchronous inertia. Analyzing the synchronous inertia from the future systems gave good insight into the expected inertia those systems might face. Further work on validating the values resultant of the application of this method could further prove the usefulness in further studies on system stability.

When the method was applied in this study the results show that a drop in synchronous inertia following the addition of new installations of wind and solar inertia is not clear cut. Because the grid system is dynamic it's hard to speak of it in a single term, but in general, due to the increase in overall grid size — not only increase in renewables — it appears that even the minimum observed synchronous inertia isn't significantly less in the 2030 system than in the 2020 system. Even if cases where the dispatch of renewables is high, it is challenging to draw conclusions on the synchronous inertia due to a very high variability, mainly due to the fact that synchronous inertia depends on so many other factors.

Further study should include a more detailed analysis of a present day system. The lack of a true current day scenario limits the comparisons of synchronous inertia and the results lack a true reference point. Also, a study with a smaller temporal scope may yield stronger conclusions. For example if peak and valley load times are to be studied separately, there may be more of a pattern to uncover. Also, a more detailed study on the effect of synchronous machine parameters might have on the system. For example if a particular type of generator was favoured in the future, perhaps gas over coal, that too could have an impact on system inertia.

When comparing the inertia of the continental system and that of Great Britain, it was interesting to see how the larger continental system experienced less, relative to its size, daily variations. This observation adds to the general school of thought that larger systems tend to be more stable, and may also add to arguments for integrating wider areas into single synchronous electrical grids. When looking at loss risk, the larger base load nuclear units seem to have an affect also, with the continent seeing an even flatter loss risk profile. This contrasts with the high variability of both synchronous inertia and loss risk in Great Britain. Though the 2030 system in Great Britain also contain a higher fraction of installed wind energy, which could explain higher the variability. It would be interesting for a future study to do more alterations on the installed wind energy on the Great Britain system model, and investigate those effects.

Synthetic Inertia

This study also employed novel methods to quantify synthetic inertia. Although other research had been done on the ability for wind turbines to provide a synthetic response, none have combined a wide scale study with an economic dispatch model to see the actual levels of inertia that might arise.

Quantifying and comparing the size and coincidence of synthetic inertia has proved a valuable exercise. The results for synthetic inertia are interesting to illustrate just how this novel system resource behaves, and what can be expected. Firstly, the high variability is worth noting. The variability could prove to be a challenge for system operators to rely upon for grid stability and reliability. Further study would include ways of predicting the resource of synthetic inertia to aid TSOs. Without some foreknowledge of the levels of synthetic inertia, TSOs would be unlikely to implement operating schemes that would heavily integrate inertial responses from wind turbines. Similar to how energy production is currently predicted based on meteorological information, predictability would be an important step in the actual use of synthetic inertia in a future power gird. Further study into the implementation of a prediction scheme is recommended.

Next to the variability, is the actual size of the resource. Due to the ability of wind turbines to leverage much of their speed range, when a turbine is able to provide an inertial response it is able to provide a significant response. This would seem like a boon for the system, but, the peak-like nature of the synthetic inertia is so large and available for only short bursts, it's unlikely the extra energy availability could be used effectively without further research. Research into the energy availability of single turbines and control schemes that leverage a de-loading technique to further maximize the resource or maximize the temporal availability is recommended.

It is also worth noting, that even if a future power grid with renewables didn't significantly reduce synchronous inertia, the amount of synthetic inertia available certainly increased. Given this is the way the power grid is growing, it could be that a future grid that effectively harnesses the availability in asynchronous generators could in fact have more overall system inertia than a present day grid. This is seen especially in the case of Great Britain, where the synthetic inertia was able to contribute enough inertia to maintain the target J_{min} for well over half the year. Even the continental system sees such a significant contribution for over 40% of the year. This really goes to show how future grids could really benefit from synthetic inertia. Some TSOs such as Hydro Quebec [1] already require that wind turbines be capable of providing an inertial response in the case of a severe disturbance. In addition this kind of requirement is being investigated by other TSOs, but even more research on ways of consistently quantifying and codifying the inertial response of wind turbine would help facilitate the adoption of synchronous inertia on a system and is recommended.

In the course of the investigation into synthetic inertia, this study was also able to show how mesoscale meteorological data could successfully be employed to estimate synthetic inertia in a system. Further, justifications were provided to show that given a choice between an averaged wind speed data and a more precise mesoscale data, the mesoscale has advantages beyond simply higher frequency data and should be used in order to more accurately quantify synthetic inertia resource and avoid bias. Using aggregated or averaged data shows a disingenuous picture of the actual available resource, by either severely over estimating the inertial resource or severely underestimating. This miss-estimation would pose major barriers in the implementation of synthetic inertia into a system. A disturbance occurring at a time when the inertia is being overestimated could destabilize the entire grid. Chronically under-estimated synthetic inertia would make it appear that the wind turbines are not a worthwhile resource to consider. The mesoscale data allows for a wider range in spatial separation and the effects of the windspeed diversity in time and space. It has shown the usefulness and negative implications of performing a study with data that would throw out some data granularity. It is recommended that any study investigating kinetic energy resources from wind turbines should use windspeed data that has a higher degree of frequency and spatial precision.

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