THESIS FOR THE DEGREE OF LICENTIATE OF ENGINEERING

Optimization modeling of frequency reserves and inertia in the transition to a climate-neutral electricity system

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CHALMERS UNIVERSITY OF TECHNOLOGY

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Frequency reserves and inertia in electricity systems dominated by wind and solar power

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Abstract

The ongoing transition towards electricity production systems that are dominated by wind and solar power challenge both the traditional strategy for meeting a varying electricity demand and the traditional way of controlling the AC frequency of the electricity grid. This work investigates how frequency reserves (FR) and inertia, as well as inter-hourly variation management interact in the transition to a climate-neutral electricity system. For this purpose, a linear optimization model is developed to co-optimize investments in and operation of generation capacity and storage, as well as the supply of inertia and FR. The model is applied to three European geographic contexts, northern Europe, the British Isles, and the Iberian Peninsula, with different availability levels of wind, solar and hydro power resources. In addition, the model is applied to four separate indicative years, representing the current system and near-, mid- and long-term futures.

The results indicate that while FR and inertia may increase the total system cost and investments, this will not decrease the cost-optimal share of renewable energy as the electricity supply-side transitions away from fossil fuels. Instead, the modeling shows that double-use of battery investments for FR and inter-hourly variations slightly increases the share of electricity supplied by wind and solar power. It is also shown that an electrified car fleet has the potential to eliminate all system costs associated with FR and inertia if a sufficient share of vehicles (30%) participates at no cost.

The importance of specific technologies used for FR and inertia is investigated by excluding one-by-one the batteries, power-to-heat, and wind and solar power from the inertia and frequency reserve supply. The findings indicate that batteries confer the greatest reduction in the cost of FR and inertia, with wind and solar power and power-to-heat having system cost impacts only in the northern Europe case.

Keywords: Energy system modeling, generation expansion planning, frequency control, frequency reserves, inertia, synthetic inertia

List of publications

The thesis is based on the following appended papers, which are referred to in the text by their assigned Roman numerals:

I. J. Ullmark, L. Göransson, P. Chen, M. Bongiorno, F. Johnsson (2021). "Inclusion of frequency control constraints in energy system investment modeling". *Renewable Energy* **172**, pp. 249-262. DOI: 10.1016/j.renene.2021.03.114

II. J. Ullmark, L. Göransson, F. Johnsson (2022). "Frequency control in the transition to future electricity systems". Ready for submission.

Jonathan Ullmark is the principal author of **Papers I** and **II**, and conducted most of the modeling and calculations for these papers. Lisa Göransson and Filip Johnsson contributed with discussions and editing to all the papers. Peiyuan Chen and Massimo Bongiorno contributed with discussions about frequency control theory and provided an electrical engineer's perspective.

Other publications

Other publications by the author, not included in the thesis:

A. P. Holmér, J. Ullmark, L. Göransson, V. Walter and F. Johnsson (2020). “Impacts of thermal energy storage on the management of variable demand and production in electricity and district heating systems: a Swedish case study”. *International Journal of Sustainable Energy* **39**, pp. 446-464. DOI: 10.1080/14786451.2020.1716757
B. M. Lahtveer, L. Göransson, V. Heinisch, F. Johnsson, I. Karlsson, E. Nyholm, M. Odenberger, D. Romanchenko, J. Rootzén, G. Savvidou, M. Taljegard, A. Toktarova, J. Ullmark, K. Vilén, V. Walter (2021). ”Actuating the European Energy System Transition: Indicators for Translating Energy Systems Modelling Results into Policy-Making”. Front. Energy Res. 9:677208. DOI: 10.3389/fenrg.2021.677208

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Jonathan
Gothenburg, May 2022

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1. Introduction

The global ambition to curtail greenhouse gas emissions and the introduction of technological improvements are shifting electricity grids away from fossil fuels towards carbon-neutral energy sources. As thermal power is progressively replaced by inverter-based variable generators (such as solar PV and wind power) used in combination with storage technologies (such as batteries and hydrogen storage), there will inevitably be changes in the way that system operators ensure grid stability. The basis of grid stability is the ability to maintain a balance between the supply of and demand for electricity, which is reflected in the stability of the frequency of the alternating current (AC) in the grid. A stable grid frequency requires inertia to retard changes in the frequency and reserves to arrest the change and restore the frequency. Both of these elements can be supplied by thermal power plants. A future system for maintaining grid stability could employ technologies that exclusively provide grid inertia and power reserves. Alternatively, it may be possible to reduce the costs for reserves and inertia by making use of technologies that are already in use for supplying electricity.

1.1. Aim

The transition to an electricity supply system with high shares of solar and wind power decreases the grid inertia and increases the demand for reserve power, while at the same time access to traditional means of providing reserves is reduced. The aim of this research was to investigate the following aspects of frequency reserves (FR) and inertia:

- How FR and inertia affect the electricity system, in terms of the system cost and the cost-optimal technology mix, as the energy system transitions to carbon-neutrality.
- The technologies that can be used to provide FR and inertia at different stages of the transition to a carbon-neutral energy system.
- The extent to which the supply of FR and inertia interacts with the supply of inter-hourly variation management.

Paper I investigates the impacts of adding inertia and reserve requirements to the electricity system in four regions: Hungary, Ireland, northern Spain, and southern Sweden, using projected costs and loads for Year 2050 and assuming no direct CO_2 emissions from electricity production. **Paper II** extends the scope both geographically and temporally by investigating four different time-points, spanning from Year 2020 to a long-term future (Year 2040) for three larger geographic cases (northern Europe, the British Isles, and the Iberian Peninsula). To capture more precisely the development of the electricity supply, the geographic cases in **Paper II** include several subregions and the limitations associated with electricity transmission between them.

2. Background

Traditionally, the electricity supply has been dominated by a mix of thermal and hydro power plants, combining cheaper-to-run, albeit inflexible, plants to satisfy the base load and more flexible plants to manage variations in the load. The stability of the grid frequency, or the balancing of the electricity supply and load, has similarly been supplied by continuously adjusting the outputs of the power plant generators. This chapter describes the requirements and options for a flexible electricity supply, FR and inertia in wind and solar power-dominated electricity systems.

2.1. Variation management

An electricity system that is supplied to a large extent by variable renewable electricity (VRE), such as wind and solar power, will be more cost- and resource-efficient if there are strategies in place to manage variations. Batteries, household load shifting, flexible hydrogen production from electrolysis, strategic battery electric vehicle (BEV) charging, and flexible industry loads are all examples of non-traditional ways of managing variations. They may also be components of a cost-optimal mix of strategies and technologies for the electricity system. Since the flexibility provision potentials of the aforementioned strategies differ in terms of their amplitudes, costs, activation times and durability, they may fill different roles and have different degrees of suitability in different system contexts. One method to study the roles and impacts of these strategies and technologies is to apply energy system modeling with optimization. By optimizing the electricity supply (and/or demand) in the presence or absence of a certain technology, the potential value and role of that technology can be identified. This can be accomplished either by adding a technology to an already existing technology mix and observing the differences in operation or by co-optimizing investments and operation. Including investments in the optimization modeling reveals additional information about the studied system. For example, Zhou et al. (2011) have used a so-called 'generation expansion model' (involving co-optimization of investments and dispatch) to compare policy incentives for renewable energy investments. Kiviluoma et al. (2018) have applied combined investment and dispatch modeling to investigate the values of different flexibility options in the northern European electricity supply. More examples can be found in the reviews published by Koltsaklis & Dagoumas (2018) and Ringkjøb et al. (2018).

A functionality-based categorization of technologies to manage inter-hourly variations has been presented by Göransson & Johnsson (2018). It uses *shifting*, *absorbing* and *complementing* as categories to differentiate the effects that different technologies and strategies have on the system. This categorization has been used to analyze flexibility options by Johansson & Göransson (2020), Holmér et al. (2020), and Walter & Göransson (2022).

2.2. Grid frequency

While it can be argued that all forms of variation management come down to balancing the load and, thereby, avoiding grid frequency deviations, there are important differences between managing variations on an hourly to seasonal basis and managing them on a second-to-minute basis. Given accurate forecasting of the VRE and the load in the day-ahead market, other technologies can be scheduled to supply the resulting net load (load minus VRE). However, as it is not possible to forecast accurately the net load (load minus VRE) down to each second, a reactionary control system must be in place to deal with real-time imbalances even after market bids for generation and load have been accepted.

2.2.1. Imbalance causes

There are multiple reasons why an imbalance can occur. One reason is stochastic load variations, whereby a high number of smaller loads are being added and removed. The levels of reserves required to deal with these variations can either be determined by examining the history of stochastic load imbalances in the region or estimated using heuristic formulas. In either case, the nature of these stochastic variations means that the total amplitude is not instantaneously reached. Instead, the imbalance constantly changes as the smaller variations add up and nullify over time. This means that the highest expected levels of stochastic variations do not appear suddenly, so they do not require the corresponding levels of fast reserves. Figure 1 shows an example of varying load and generation, and the resulting imbalance, wherein the stochastic variations are illustrated as a seemingly random noise in the load.

Imbalances are also caused by variations in the power obtained from VRE generators, regardless of forecasting. On a larger, grid-wide scale (often encompassing large or multiple countries), the smaller but rapid fluctuations in VRE generation (arising, for example from a cloud over-shadowing a solar PV park) largely cancel each other out. However, more-pronounced trends of increasing and decreasing generation (such as when a large weather front enters a country) may be seen in the total VRE production of a grid. Both the amplitude and timing of these larger variations can be forecast the day before. This means that in an energy bidding market with sufficiently high time resolution, the varying VRE would not directly cause imbalances within each time-step, or bid, of the market. This also means that even in a market with a coarser time resolution, the reserves need not be fast, and they only need to last until the next time-step or market bid time-frame when the expected VRE output is updated. An analogous effect is shown in Figure 1a, where the positive trend in load during periods 1, 2 and 3 results in a repeating imbalance with a periodicity of one market period.

Another reason for imbalances is unexpected faults in the transmission, generation, or load equipment. This type of fault appears suddenly and, thus, requires inertia, fast reserves, and lasting reserves to counteract the consequences of the fault. Typically, grids are designed for N-1, meaning that they should be able to withstand a fault in any one unit. Besides local redundancy implications, this means that the amount of reserves required is determined by the largest active generator or DC connection to the grid, which is commonly referred to as the dimensioning fault, reference incident, or simply N-1. It should be noted that the dimensioning fault may refer to the simultaneous loss of more than one unit in large grids. For simplification, system operators may choose not to make the N-1 dependent upon those units that are active at any point in time, but instead set a constant value based on the largest installed unit. Sudden loss of generation and the resulting imbalance are illustrated in Figure 1, where the generation suddenly drops in period 4.

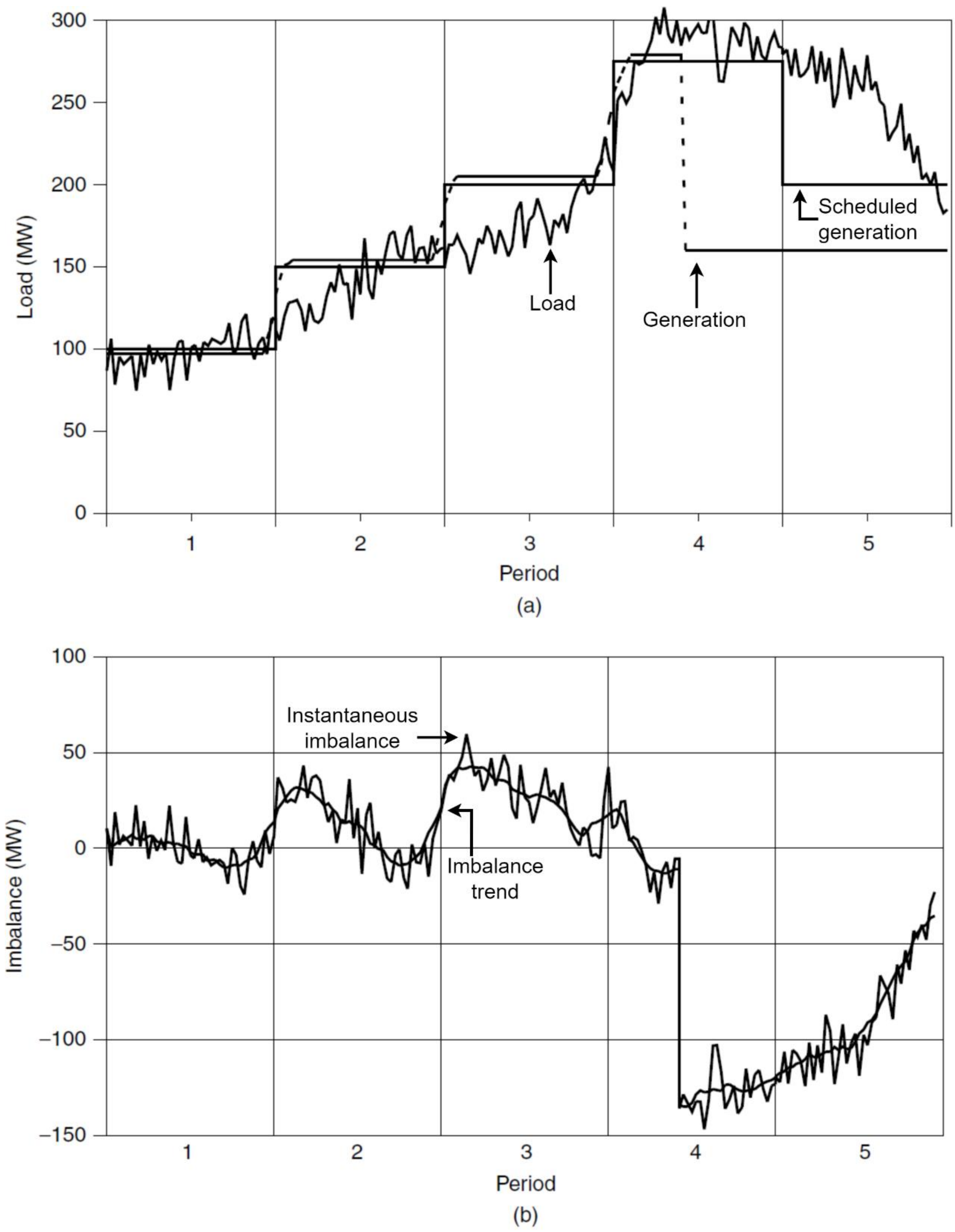

Figure 1. (a) Typical load and generation fluctuations over five market periods. (b) Imbalances resulting from these fluctuations. Figure and description copied, with permission, from Kirschen & Strbac (2005). *Arrows and explanations added by the author of this thesis.*

2.2.2. Inertia

Inertia, in the context of electrical grids, refers to the rotating mass in synchronous generators and motors that are connected directly to the AC grid. Connecting a generator or motor to the grid without an AC/DC interface reduces the investment costs but limits the rotations per minute (rpm) to multiples of the grid AC frequency (50 or 60 Hz). For example, a synchronous motor in a 50-Hz grid can run at 3,000, 6,000, and so on at intervals of 3,000 rpm. This means that any deviation of the grid frequency will directly affect the rotational speed of all synchronously connected machines, and that rapid frequency deviations can damage the equipment due to rapid (de)acceleration. On the other hand, the synchronous coupling of the machines' rotational speed to the grid frequency also lends inertia *to the grid frequency*. The same imbalance causes a slower frequency deviation when there is more inertia in place. This relationship is expressed as the *Swing equation* in Eq. (1), which gives the rate of change of frequency (RoCoF; $\frac{dF}{dt}$) for any imbalance (ΔP), grid frequency (f), and system inertia constant (H).

$$\frac{dF}{dt} = \Delta P \frac{f}{2H} \tag{1}$$

While inverter-interfaced motors and generators do not automatically slow down frequency changes, the power injected by inverter-based generators can be controlled so as to be independent of changes in the grid frequency. Due to the rapid control effected by power electronics, additional power can be injected in a way that emulates the effect of mechanical inertia, or in other ways that directly alleviate the imbalance [e.g., fast frequency reserves; see ENTSO-E (2021)]. For an example of how inertia affects frequency responses following a fault, Tan et al. (2018) have simulated frequency responses in scenarios with varying levels of inertia. While regulatory and control systems for synthetic inertia are still under development [see, for example, Lidstrom & Wall (2016) and Gloe et al. (2019)], synthetic inertia have already been delivered in places as diverse as Alberta, Canada (ENERCON, 2020); Québec, Canada (Fairley, 2016), and Queensland, Australia (Parkinson, 2021).

2.2.3. Frequency reserves

While inertia can slow down frequency changes when an imbalance occurs, there has to be some change in the generation or load for the balance to be reinstated. This is typically achieved by increasing or decreasing the output from generators with available reserve capacity. This reserve capacity is, like the electricity, negotiated on a market that ensures that sufficient reserves are available to compensate for foreseeable imbalances. While the exact requirements differ between systems, the reserves must generally start acting within seconds, and ultimately must last until the reason for the imbalance is resolved. The required activation speed depends on the size of the imbalance, the system inertia, and the minimum acceptable frequency that the nadir of the frequency deviation is allowed to reach. In other words, there exists a trade-off between inertia and fast reserves, where a shift towards inverter-based generators (less synchronous inertia) increases the need for fast reserves.

The European Network of Transmission System Operators for Electricity (ENTSO-E) divides frequency reserves into three categories: frequency containment reserves (FCR); frequency restoration reserves (FRR); and replacement reserves (RR). After an imbalance occurs, these reserves activate one after another to contain the imbalance for as long as needed. The FCR, also known as the primary control reserve, is an automatic and decentralized response to deviations in the frequency from the nominal value. The FRR can be automatically or manually activated by the system operator to alleviate the FCR and restore the frequency. The automatic and manual FRR, namely the aFRR and mFRR, are referred to as the secondary and tertiary control reserves, respectively.

Not all system operators in ENTSO-E use the same categories or have the same requirements for them. For example, the Nordic grid is not synchronous with the continental European grid and, thus, has a different dimensioning fault and reserve requirement. The same goes for Great Britain, Ireland, and the Baltic countries. However, there are clear similarities in structure and activation times between the different reserves. According to the ENTSO-E standards (ACER & ENTSO-E, 2017), for continental Europe FCR should be completely activated within 30 s and be available for at least 15 minutes, followed by aFRR which should be fully activated within 5 minutes and also last for at least 15 minutes. For mFRR, following aFRR, there is a minimum activation time of 12.5 min, which is just short of the previous reserves' minimum duration. In the Nordic grid, FCR-N (the 'N' stands for normal operation, as opposed to FCR-D for a sudden fault in the system) should be initiated within 30 s and be fully activated within 3 minutes, with the same rules for aFRR as recommended by ENTSO-E. While these requirements in terms of response time are designed with consideration of what is required for frequency stability, they are also based on the characteristics of the generators in the respective grids. As the decreasing inertia has made the available reserves too slow in the Nordic and British grids, a new reserve category has been created for fast frequency reserves (FFR) based on the requirements specified by ENTSO-E. The FFR should be fully activated within 1.3 s and last for at least 5 s or 30 s (negotiated beforehand). Since this reserve category is designed for storage, wind power, and loads, it also includes a recovery period during which the energy can be compensated.

2.2.4. Frequency reserves and inertia in optimization modeling

Frequency reserves and inertia considerations have previously been incorporated into electricity supply optimization models. For example, Daly et al. (2015) have investigated, using a unit commitment model, how the inertia consideration affects the operation of systems with instantaneous shares of inverter-based generation. They have shown that this increases fuel consumption and curtailment of wind power, although they did not consider operating reserves (herein referred to as frequency reserves or FR), investments or emulated inertia from wind power. Van Stiphout et al. (2017) have examined the impacts of FR on electricity supply investments, finding that additional constraints significantly impact the cost-optimal technology mix. However, they did not include inertia or any options for batteries, hydrogen storage or any flexible loads in the model. In the PhD thesis of Løvengreen (2021), an extensive model featuring multiple areas, generation and battery investments, unit-commitment dispatch, inertia and reserves was introduced and used to model representations of the Australian grid. However, the interactions between FR, inertia and the transition of the electricity supply system to a system with high shares of wind and solar power were not explicitly studied by Løvengreen (2021). González-Inostroza et al. (2021) have used a generation expansion model with hourly resolution to model the electricity supply in a fully renewable Year 2050 scenario in Chile. Their model included constraints on FR and inertia, but not investments in thermal generation or frequency control-exclusive investments, such as those in synchronous condensers[1] with a flywheel. They have shown that, in a solar PV-dominated Chile in Year 2050, the large battery

[1] ENTSO-E (n.d.) defines a synchronous condenser as "[..] a DC-excited synchronous machine (large rotating generators) whose shaft is not attached to any driving equipment. This device provides improved voltage regulation and stability by continuously generating/absorbing adjustable reactive power as well as improved near-circuit strength and frequency stability by providing synchronous inertia". These can be combined with a flywheel to increase the mass and, thereby, the inertia.

capacity for inter-hourly variation management can facilitate the supply of FR and inertia without significant changes in cost-optimal investments.

2.3. Differences in flexibility supply

Both inter-hourly variation management and frequency control are concerned with managing the mismatch between the electricity supply and demand, albeit on different time-scales and with inter-hourly variation management typically being included in the electricity supply scheduling. The similarities are greatest for variation management that shifts electricity for shorter periods of time, such as batteries or household load shifting. However, it can also be the case that industry (or other) loads that opportunistically increase or decrease consumption depending on the electricity price also offer flexibility to the reserve market. For example, hydrogen production through electrolysis may add electricity consumption for periods of low electricity prices, and while running, it can respond to an imbalance and decrease its consumption for the appropriate compensation (especially when the electricity price is close to the consumer's willingness-to-pay). Variation management technologies with lower levels of efficiency, higher variable costs or slower underlying processes are less suitable for fast frequency reserves due to their high utilization and rapid activation, although they may be applicable as slower reserves that activate less often.

This chapter establishes why imbalances occur, how these imbalances are connected to the grid frequency, how the grid frequency can be controlled, and the differences between managing variations on inter-hourly and intra-hourly time-scales. It also describes how this theory has been applied in previous research, as well as the scope-related limitations of previous studies. Using this theory, this work aims to investigate how FR and inertia interact with the electricity supply and inter-hourly variation management as the systems transition from traditional fossil fuels towards renewable energy.

3. Methodology

This chapter describes the development of the optimization model and the adoption of frequency control theory into parameters and assumptions that are usable in the model. The mathematical description of the model can be found in **Paper II**.

3.1. Electricity system investment model

In order to investigate how FR and inertia are cost-efficiently supplied in an electricity system that is dominated by wind and solar power, a cost-minimizing electricity system investment model is applied. The objective of the model is to minimize the investment and operational costs of an electricity system under several constraints, including the requirements to meet the demand for electricity at each time-step and assure the availability of FR and inertia. The initial model on which this work is based was created by Göransson et al. (2017) and further developed by Johansson & Göransson (2020), considering only a single, future year without any real-world generating capacity other than hydro power. The purpose of the model is to study the impacts of, and interactions between, strategies and technologies to manage variations in highly renewable future scenarios. For this, the model has an hourly resolution and a high number of available generation technologies and options for managing variations, such as thermal cycling, batteries, and load shifting, as well as electrolyzers and hydrogen storage. For **Paper I**, aspects related to FR and inertia were added to the model, and the interactions between FR, inertia and variation management on an inter-hourly time-scale were investigated for a single future year. For **Paper II**, the ability to add existing generation capacity as input was included in the model, to enable investigations of FR and inertia in the context of a transitioning electricity system. A method to control the inputs and outputs of the model, using Python, was developed to forward investments made each year in the form of an input to the following year. Furthermore, a database of real-world generation capacities was used to derive values for each generation technology and year, while taking into consideration how much capacity has yet to reach its technical lifetime within each modeled region. Efficiency improvements between capacities installed during different years were neglected to avoid the complexity of maintaining several versions of each technology. Instead, the average efficiency of all model investments and the real-world capacities were used, resulting in only two variants of each technology: pre-existing capacity (real-world and previously modeled years); and new investments. These additions made for **Paper II** are illustrated in Figure 2.

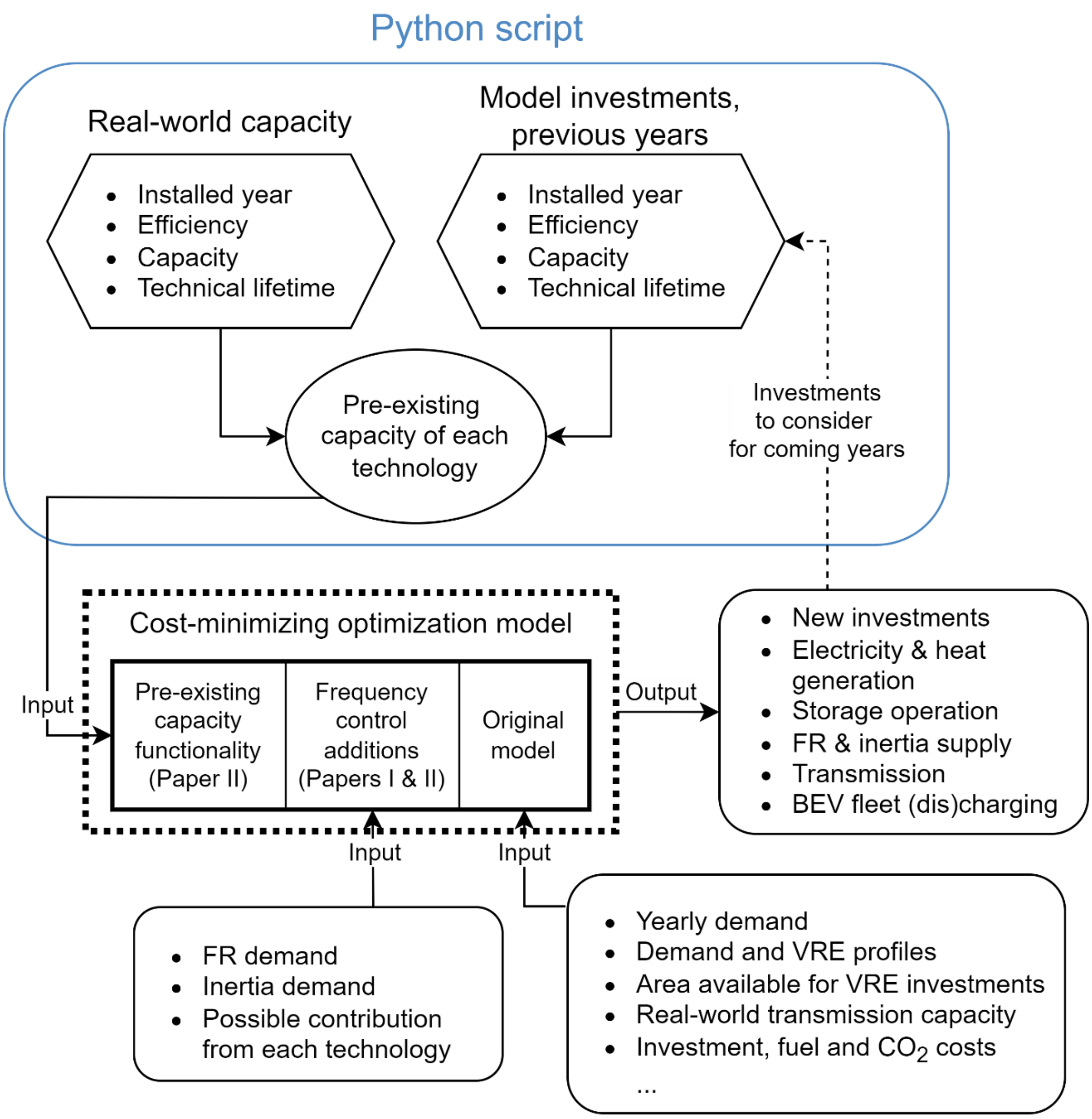

Figure 2. Illustration of the model development regarding pre-existing technology capacities for ***Paper II****.*

3.2. Frequency reserve and inertia implementation

To implement FR and inertia constraints in a mathematical model of the investments and dispatch of the electricity supply, the required FR and inertia must be quantified and the abilities of technologies to contribute must be specified. The amount of required inertia is determined using the dimensioning fault and the highest acceptable RoCoF. The dimensioning fault, being the largest power plant block or DC connection point, would ideally be implemented to depend, in each time-step, on the discrete units in operation. As this would require integer variables, thus increasing significantly the computational load, the options are instead to make the dimensioning fault either a pre-determined constant for each region and year or in some linear way dependent upon investments in and/or operation of the units. However, a linear dependency adds misaligned incentives to avoid technologies that typically define the dimensioning fault, even if the technology is already used to some extent. For example, this might make it preferable to use 3 GW of nuclear power rather than 6 GW of nuclear power to reduce the linear contribution to the dimensioning fault, even though both alternatives in reality might use blocks of 1.5 GW. Instead, for each grid in this work, the dimensioning faults are assumed to be constant. The dimensioning faults (or N-1 values) are listed in Table 1 and are divided among the subregions according to their yearly electricity load, such that the combined reserve response meets the dimensioning fault of each grid. Each region is without any internal bottlenecks in transmission, i.e., a “copper-plate region”. In the Nordic synchronous grid, the dimensioning fault is assumed to be 1,650 MW, which corresponds to the capacity of the Olkiluoto 3 European Pressurized Water Reactor in Finland. In the continental European grid, the dimensioning fault is 3,000 MW, corresponding to the loss of two 1,500-MW nuclear reactors (ENTSO-E, 2013). In the *Brit* case, a shared dimensioning fault of 1,000 MW is used, as if Ireland and UK were synchronously connected. This is discussed further in Chapter 0.

Table 1. N-1 values used for each modeled copper-plate region. The green, pink and orange cells make up the Nordic, British Isles, and Iberian scenarios, respectively. A map of the modeled regions can be found in Figure 4.

Region	SE + NO N	SE S	NO S	FI	DE N	UK 1	UK 2	UK 3	IE	ES N	ES S	PT
N-1 [GW]	0.08	0.40	0.48	0.37	0.14	0.83	0.08	0.02	0.08	0.16	0.06	0.06

The highest acceptable RoCoF is assumed to be 1.5 Hz/s [proposed by ENTSO-E (2017) as the limit for windows of 1 s], which is used in Eq. (1) together with the inertia constant H to give the increased power output from all synchronous generators. Both the inertia constants and the resulting increased power outputs are listed in Table 2, and include the synchronous condensers that are amenable to investments to provide additional inertia. Batteries are assumed to be able to deliver synthetic inertia, which is limited only by its storage level and available discharge capacity. It is also assumed that wind power can be controlled so as to contribute with synthetic inertia corresponding to an additional 13% of its output, based on the work of Imgart & Chen (2019). The combined inertial power response from synchronous sources and synthetic inertia from wind power and batteries must then, for each subregion, meet the N-1 values in Table 1.

Table 2. Inertia constants and inertial power responses for the different synchronous generator types included in this work.

	Nuclear power	Other thermal	Hydro power	Synchronous condensers	Wind power
H [s]	6	4	3	6	-
ΔP [%]	48	32	24	48	13

As described in Section 2.2.1, sudden faults (N-1), stochastic load variations, and ramping of VRE all give rise to a reserve demand. Although there can be other needs for reserves, such as forecasting errors, the demand for reserves is in this work assumed to be a combination of these three events. The reserves required to compensate for ramping VRE are approximated using the difference in expected output from each VRE technology for each consecutive time-step in each subregion. For the stochastic load variations, rather than extrapolating from historic data, the levels of reserves required are estimated using a heuristic formula from the UCTE Operational Handbook [Eq. (2)]. For some empirically established parameters a and b, this equation takes the peak load $L_{i,max}$ for day i and calculates the amount of reserves needed as R_i.

$$R_i = \sqrt{a\, L_{i,max} + b^2} - b \tag{2}$$

Section 2.2.1 also mentions how not all of these reserve demands are sudden, needing fast reserves. The dimensioning fault is necessarily sudden, although both the stochastic load variations and ramping VRE are slower and are assumed to follow the rates in Table 3. The intra-hourly intervals listed in Table 3 are roughly based on which of the different technologies are capable of delivering, with higher resolution of the intervals in the beginning when ramping rates limit thermal power plants. The intervals combine to cover fully each hour, for which reserves corresponding to at least the reserve demand must be available. The first and shortest interval, at 1–5 s, is assumed to be the first one to act after the inertial power response and it is only needed in case of sudden faults, as indicated by a non-zero only in the N-1 row. In the following intervals, stochastic load variations are assumed to start demanding reserves following the equation for a first-order response, $1 - e^{-1/\tau}$, with a time constant (τ) of 60. For VRE ramping, the fastest two intervals are excluded, since the need for reserves can be predicted to a degree.

Table 3. Share of each reserve demand source active in each intra-hourly interval.

	1–5 s	5–30 s	30 s–5 min	5–15 min	15–30 min	30–60 min
N-1	1	1	1	1	1	1
VRE ramping	0	0	1	1	1	1
Stochastic load variations	0	0.08	0.39	0.99	1	1

A simplified version of the reserve supply is visualized in Figure 3, which shows how storage systems, thermal power plants, power-to-heat plants, VRE and transmission with neighbors all contribute to the reserve supply. Battery and hydrogen storages are limited both by their storage levels and their unused discharge capacities. For storage units that are being charged, the potential reserve contribution corresponds to the sum of the charging rate and the unused discharge capacity, though still limited by the storage level. Thermal power plants can contribute according to their ramping rates, both while online and offline if the start-up time is sufficiently short. However, only part-load capacity can contribute without the start-up time. Since the model includes a part-load penalty corresponding to a loss of thermal efficiency, this reserve contribution is associated with a cost even though the reserve implementation only requires the *availability* of reserves. Hydro power works in a similar manner to thermal power plants, except that there are no differences in the contributions of the part-load and offline capacities of hydropower. Power-to-heat from heat pumps and electric boilers to district heating networks is assumed to be able to turn off to provide reserves. While activation of the reserve from storage units and power-to-heat would result in an energy deficiency in the storage or heat balances, it is assumed that reserves to increase consumption (or decrease generation), which are not considered in this work, would compensate for these energy deficiencies. Lastly, any curtailed VRE generation is added to the supply of available reserves. If the total supply of reserves in a subregion exceeds the demand and there is unused export capacity in the transmission lines, it is assumed that the excess reserves can be exported. The precise constraints governing the supply are detailed in the mathematical description of the model in **Paper II.**

Similar to the ways in which the demands for reserves differ between the reserve intervals, the supply to each interval varies according to the values in Table 4. The thermal ramping and start-up times are based on a technology catalogue issued by the Danish Energy Agency & Energinet (2017), with the exception of those for the nuclear technology, which are based on Schröder et al. (2013).

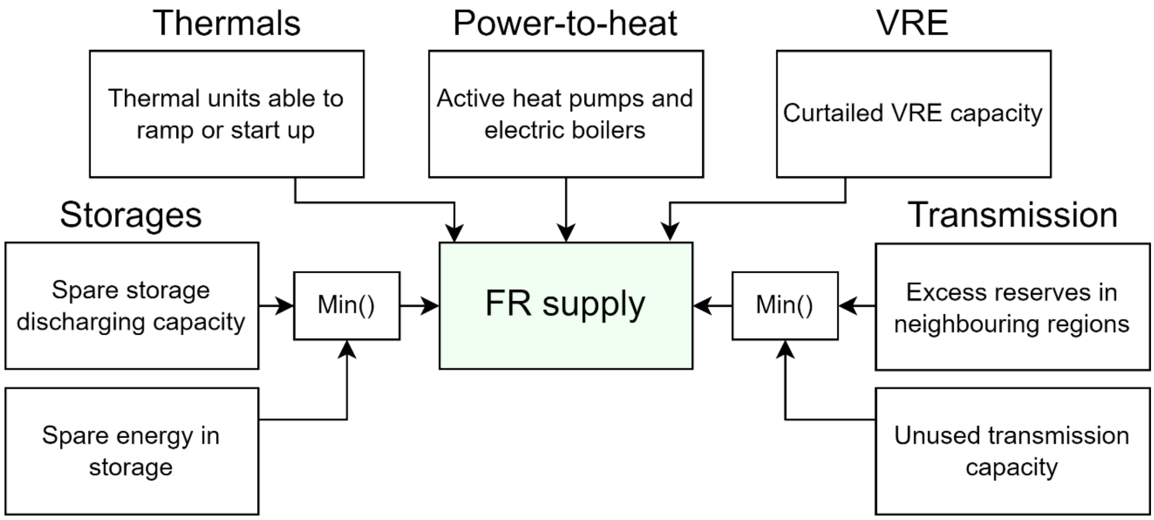

Figure 3. Simplified diagram of the various FR supply sources. The storage systems considered in this work are batteries and hydrogen caverns.

Table 4. For thermal power plants and hydro power plants, the table shows the factor of the rated capacity to which the production can be increased, from part-load or offline mode, for each technology and FR interval. For other reserve sources, the table shows the fraction of the available reserve power that can be used in each interval. CCGT, combined-cycle gas turbine; OCGT, open cycle gas turbine; ST, steam turbine,

	O_1^{dur} 1–5 s	O_2^{dur} 5–30 s	O_3^{dur} 30 s– 5 min	O_4^{dur} 5–15 min	O_5^{dur} 15–30 min	O_6^{dur} 30–60 min
Power-to-heat	1	1	1	1	1	1
Curtailed VRE	1	1	1	1	1	1
Energy storages						
Li-ion battery	1	1	1	1	1	1
Hydrogen	1	1	1	1	1	1
Flywheels	1	1	1	1	1	1
Hydro power	0	0.15	0.3	1	1	1
Online thermal plants						
CCGT	0	0.0125	0.075	0.75	1	1
OCGT	0	0.1	0.3	1	1	1
ST	0	0.025	0.05	0.2	0.6	1
Nuclear	0	0	0	0.375	1	1
Offline thermal plants						
CC GT	0	0	0	0	0	0
OC GT	0	0	0	0	1	1
ST	0	0	0	0	0	0
Nuclear	0	0	0	0	0	0

3.3. Scenarios

The results in Chapter 0 use the scenarios presented in Table 5, for four different time-points: a dispatch-only Year 2020, and the near-term, mid-term, and long-term futures. In terms of projected investments, fuel and CO_2 costs, as well as loads and real-world generating capacities, the futures are based on Years 2025, 2030 and 2040.

The geographic cases are illustrated in Figure 4, indicating also the subregions between which there is transmission of electricity through already existing transmission lines. *Nordic* is implemented with five subregions, *Brit* with four subregions and *Iberia* with three subregions.

Table 5. List and descriptions of the scenario groups and geographic cases included in this work.

	System flexibility
LowFlex	No V2G, no new transmission capacity and no H_2 storages
	Frequency control
No FC	No frequency control constraints
Full FC	Reserve and inertia demand
	Technology restriction
EnergyRes	Reserve and inertia demand, but reserves from batteries lock the corresponding energy in the battery for 12 hours
No bat. FC	Reserve and inertia demand, but batteries are excluded from the FR and inertia supply
No VRE FC	Reserve and inertia demand, but wind and solar power are excluded from the FR and inertia supply
No PtH FC	Reserve and inertia demand, but batteries are excluded from the FR and inertia supply
No bat. double-use	Reserve and inertia demand, but separate battery investments must be made in order to use batteries for FC
	Regional cases
Brit	British Isles (Great Britain + Ireland)
Iberia	Iberian Peninsula (Spain + Portugal)
Nordic	Northern Europe (Sweden + Norway + Finland + Denmark + Netherlands + northern Germany)

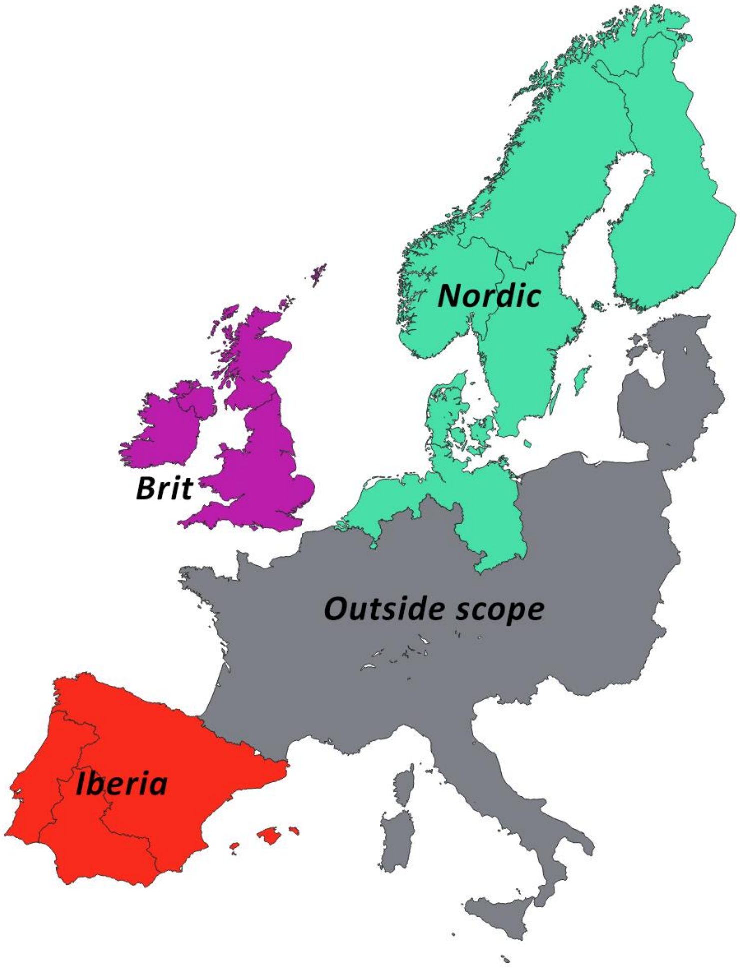

Figure 4. Map of part of Europe illustrating the three regional cases applied in this work with respect to existing generation and transmission capacities, VRE potentials and generation profiles, and electricity loads and load profiles. Brit: England + Wales, Scotland, Northern Ireland, and Ireland. Iberia: northeastern Spain, southwestern Spain, and Portugal. Nordic: Finland, northern Sweden + northern Norway, southern Norway, southern Sweden + eastern Denmark, and Netherlands + western Denmark + northeastern Germany.

The results in this thesis were obtained by running the model with a time resolution of 3 hours to save time for the many scenarios. However, the results for the main *No FC* and *Full FC* scenarios have been verified by comparison with results obtained with full hourly resolution.

4. Selected results and discussion

The results in **Paper I** show, for all four investigated high-VRE systems (Hungary, Ireland, northern Spain and southern Sweden in Year 2050), that batteries play a significant role in providing cost-efficient reserves and synthetic inertia. **Paper II** shows the same results for three larger regions (Northern Europe, the British Isles and the Iberian Peninsula) across multiple time-points. However, **Paper II** finds no impact from inertia demand alone. In **Paper I**, inertia to withstand a dimensioning fault is required from single regions and, thus, the corresponding impact represents an upper boundary. While many grids are shared across countries (as assumed in **Paper II**), there are isolated grids in which the inertia demand impact may be closer to that seen in **Paper I**. A notable instance of this is the Irish grid, whose isolation means that the impact of FC may be higher than is indicated by these results.

Paper II finds that, compared to running only the existing capacity with load representing Year 2020, the cost of providing FC is significantly reduced once investments in new capacity, including batteries, are allowed. **Paper II** also investigates scenarios with FR participation from BEVs at no explicit cost and shows that their participation completely eliminates the system cost impact of FC. As such, the results herein are focused on scenarios without BEV participation in the FR supply through vehicle-to-grid, though BEV participation is further discussed in Chapter 6, which relates to future work.

The total electricity supplied per technology group for each time-point in each regional case, as found in the modeling described in **Paper II**, is shown in Figure 5. Clear differences can be seen across the time-points and regions, with wind and solar power dominating all the regions in the mid-term and long-term. While there are differences in cost between the *No FC* and *Full FC* scenarios, Figure 5 illustrates that including FR and inertia in the model does not change to generate electricity. In other words, the need for FR and inertia does not constrain the expansion of wind and solar power.

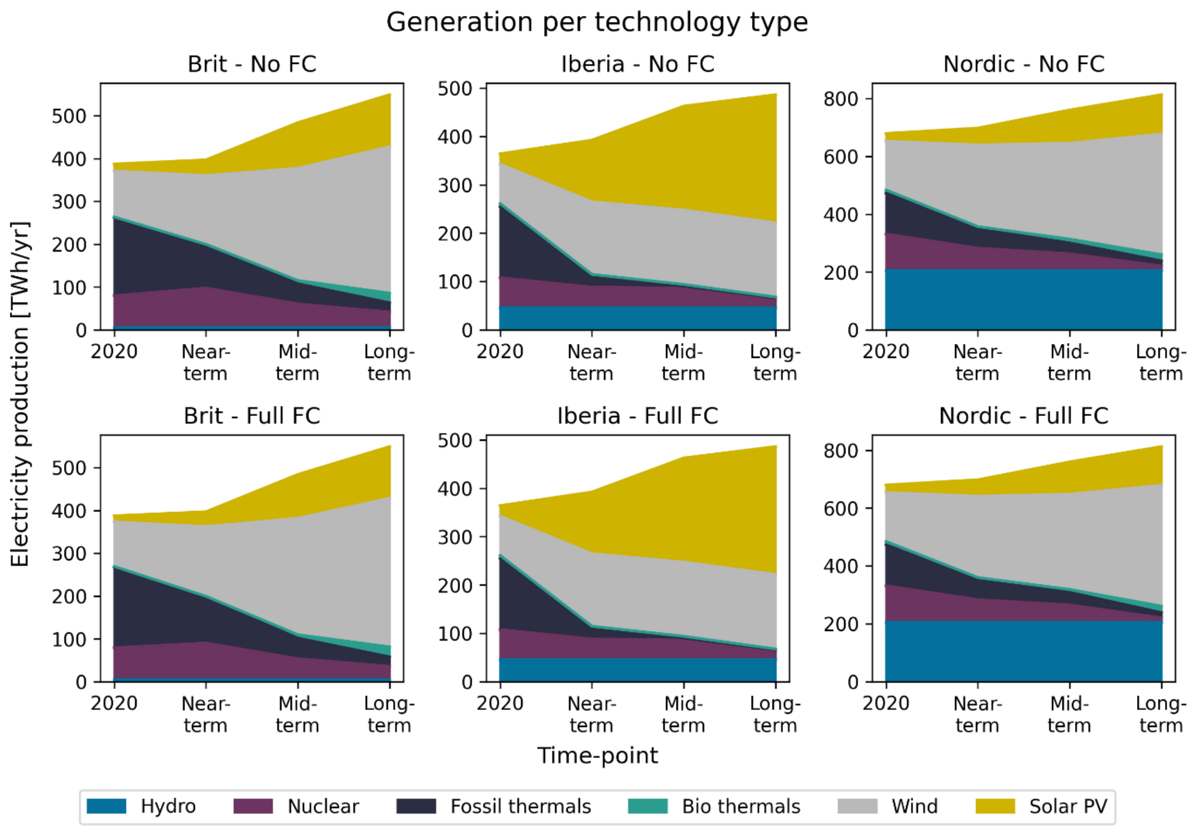

Figure 5. Yearly electricity supply development from Year 2020 to the long-term future for each generation technology type in each geographic case in the No FC *and* Full FC *scenarios.*

An additional analysis conducted for this thesis of the results obtained from the modeling in **Paper II** reveals that there is a large difference in hourly FR prices between the seasons. In the *Brit* and *Nordic* cases, the highest FR prices are found in winter for Year 2020 and the three future time-points investigated. The seasonal variations in FR price are not as clear in *Iberia*. This difference, between *Iberia* on one hand and the *Brit* and *Nordic* regions on the other, can also be seen in the correlations between the FR prices and net load or electricity price in Table 6. While the correlations in many cases are weak, there is a difference between the correlations made on an hourly and weekly time-scale. In Year 2020, when thermal and hydro power still dominate the electricity supply, the hourly reserve prices correlate strongly with the hourly electricity prices, and to a slightly lesser extent with the hourly net load. This is due to the electricity and reserve prices both being decided by the running cost of the thermal power plant on the margin, in each hour. In the mid-term and long-term futures, the hourly correlations generally decrease more than the weekly correlation. In these high-VRE futures, the hourly reserve and electricity prices are affected not only by the running cost of thermal power plants, but also by the increased availability of shifting VMS (grid batteries and strategic BEV charging), which can shift high loads across several hours or even days. Thus, while the correlations become weaker, the connection between high electricity prices and high reserve prices persists.

Table 6. Pearson correlation factors for each regional case and year. The correlations shown are between the FR prices and, in order, the hourly and weekly electricity net loads, and the hourly and weekly electricity prices. For the weekly correlations, both values are aggregated and summed for each week before the correlation is calculated.

		Correlation between FR price and:			
		Net load per hour	Net load per week	Electricity price per hour	Electricity price per week
Brit	Year 2020	0.46	0.39	0.59	0.53
	Near-term	0.2	0.46	0.21	0.46
	Mid-term	0.16	-0.02	0.17	-0.01
	Long-term	0.16	0.29	0.11	0.29
Iberia	Year 2020	0.34	0.14	0.47	0.19
	Near-term	0.14	0.0	0.06	-0.11
	Mid-term	0.07	0.13	0.03	-0.05
	Long-term	0.02	0.71	0.11	0.88
Nordic	Year 2020	0.61	0.63	0.74	0.76
	Near-term	0.34	0.6	0.49	0.68
	Mid-term	0.16	0.54	0.22	0.61
	Long-term	0.19	0.16	0.13	0.12
Average correlation		0.24	0.34	0.28	0.36

The correlations for *Iberia* are generally weaker and vary significantly for the different time-points. As explained in **Paper II**, with a high solar PV share in *Iberia* in the mid-term and long-term futures, the hourly FR prices are focused on mornings and evenings when solar PV is ramping, resulting in a high FR demand. In electricity systems that have a high share of solar PV, early mornings and evenings can also be the times when the net load and electricity prices are high. However, days of low wind and solar power production would see even higher net loads and electricity prices, without an increased FR demand. In the wind-dominated *Brit* and *Nordic* cases, FR prices are generally high during peak net-load periods when the batteries are fully discharging, and during long periods of high net load when the batteries have been fully discharged. As shown in Table 6, this shows a stronger correlation with the electricity price.

4.1. Key technologies for frequency reserves

Paper II includes the results for the technologies used to provide FR. It is important to recognize both the level of reserves supplied by each technology, and the value that is thereby rendered. The amount of reserves from each technology class is shown in Figure 6 for each regional case and time-point, excluding reserves that exceed the demand. Figure 6 also shows, as diamond symbols on the right-hand y-axis, the system cost difference between the *No FC* and *Full FC* scenarios, for each time-point. While the reserve share from thermal and hydro remains high in all the studied years, it is clear that the system cost associated with FC drops significantly when new investments (notably, those made in batteries) are allowed in the near-term future.

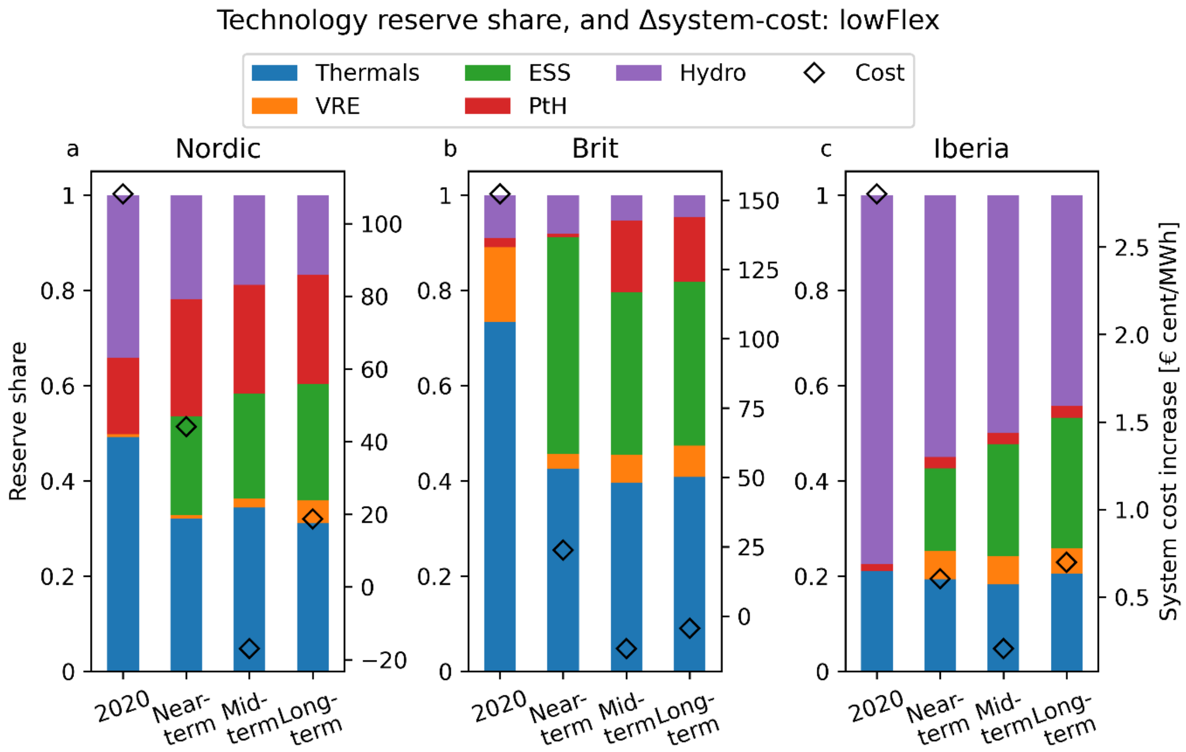

*Figure 6. The bars indicate the reserve shares per technology on the left-hand y-axis, for each year and region. The diamond symbols indicate the increases in system cost with FR and inertia constraints, expressed as system cost increase per year and electricity production, on the right-hand y-axis. Source: Figure 4 in **Paper II**.*

The value of reserves from batteries is also reflected in Table 7, which shows differences in the system cost and thermal cycling cost (accumulated across the investigated years), with various technologies excluded from the FR and inertia supply. Excluding batteries from FC has a strong impact on the accumulated system cost, whereas excluding VRE or heat pumps and electric boilers only has a minor impact on the system cost in the *Nordic* case. In the *No bat. FC* scenario, no single technology is used to compensate. Instead, the increased cost arises from a combination of increased curtailment (and fuel costs), increased investments in traditional power plants, and higher power-to-heat usage.

Table 7. Total system cost and thermal cycling cost, accumulated across all four time-points, in the Technology restriction *scenarios.*

	Total system cost [G€]				Thermal cycling cost [G€]			
	Full FC	*No bat. FC*	*No VRE FC*	*No PtH FC*	Full FC	*No bat. FC*	*No VRE FC*	*No PtH FC*
Brit	71.181	+2.99	+0.03	+0.01	0.94	+0.27	+0.00	+0.00
Iberia	44.044	+1.10	+0.00	+0.00	0.22	+0.11	+0.00	+0.00
Nordic	63.586	+3.11	+0.34	+0.73	0.10	+0.49	+0.02	+0.02

With regards to which technologies are most costly not to incorporate into the FR and inertia setup, it should be noted that not all technologies suitable for variation management are included in this work (excluded are, for example, pumped hydropower, compressed air storage, supercapacitors, and alternative grid scale batteries). As such, the apparent value of batteries should be attributed not to Li-ion batteries specifically, but to the class of variation management solutions with properties similar to those of grid-scale Li-ion batteries.

4.2. The extent of double-use

The *No bat. double-use* scenario is used to investigate the value of using the same batteries for inter-hourly variation management, FR and inertia, by requiring separate battery investments to provide FR and inertia. In Table 8, indicator values for the *Full FC* scenario are shown together with the differences in the *No bat. double-use* scenario (in parentheses). The values in the 'system cost' column can be compared to the costs associated with completely excluding batteries from FC in Table 7. This reveals that while there are increased system costs associated with using separate batteries for FC, the cost of not using batteries for FC at all is significantly higher. Furthermore, the 'VRE share' and 'thermal cycling cost' columns indicate that the rest of the system is largely unaffected by the use of FC-exclusive batteries. The right-most columns, showing the FR share for each technology class, reveals that the share of FR supplied by batteries is reduced and no single technology is used in place of batteries.

Table 8. Indicator values for all the regional cases and time-points in the Full FC scenario*, with change in the* No bat. double-use *scenario in parentheses.*

		System cost [G€/yr]	VRE share [%]	Battery [GWh]/[GW]	FC-exclusive battery [GWh]/[GW]	FR share [%]				
						Battery	**Thermal**	**Hydro**	**VRE**	**PtH**
Brit	**2020**	12.411 (+0.000)	30.5 (-0.0)	0 / 0 (+0 / +0)	0 / 0 (+0 / +0)	0 (+0)	73 (+0)	9 (+0)	16 (+0)	2 (+0)
	Near-term	14.636 (+0.074)	48.5 (-0.1)	17.9 / 8.1 (+0.1 / -2.2)	0 / 0 (+3.2 / +3.2)	45 (-2)	42 (+2)	8 (+1)	3 (+1)	1 (+0)
	Mid-term	19.09 (+0.171)	71.8 (+0.2)	111.4 / 21.9 (-9.1 / -2.6)	0 / 0 (+5.1 / +5.1)	34 (-5)	40 (+0)	5 (+1)	6 (+1)	15 (+2)
	Long-term	25.044 (+0.164)	78.0 (+0.2)	271.1 / 35.2 (-4.2 / -2.2)	0 / 0 (+7.3 / +7.3)	34 (-8)	41 (+0)	5 (+0)	7 (+2)	14 (+5)
Iberia	**2020**	9.628 (+0.000)	29.0 (-0.0)	0 / 0 (+0 / +0)	0 / 0 (+0 / +0)	0 (+0)	21 (+0)	77 (+0)	0 (+0)	2 (+0)
	Near-term	9.634 (+0.104)	65.1 (-0.4)	104.8 / 17.4 (-16.0 / -2.7)	0 / 0 (+1.6 / +1.6)	17 (-8)	19 (+1)	55 (+5)	6 (+3)	2 (+1)
	Mid-term	11.818 (+0.146)	68.6 (+0.0)	235.6 / 37.3 (-13.5 / -1.5)	0 / 0 (+4.8 / +4.8)	24 (-9)	18 (+0)	50 (+4)	6 (+3)	2 (+1)
	Long-term	12.964 (+0.182)	71.6 (-0.2)	315.5 / 49.8 (-10.6 / -1.6)	0 / 0 (+11.2 / +11.2)	27 (-8)	20 (+2)	44 (+4)	5 (+3)	3 (+0)
Nordic	**2020**	11.146 (+0.000)	28.7 (-0.0)	0 / 0 (+0 / +0)	0 / 0 (+0 / +0)	0 (+0)	49 (+0)	34 (+1)	1 (+0)	16 (+0)
	Near-term	12.917 (+0.098)	47.8 (+0.3)	20.7 / 10.9 (-3.4 / -5.5)	0 / 0 (+5.6 / +5.6)	27 (-7)	30 (+3)	21 (+1)	1 (+0)	22 (+2)
	Mid-term	17.207 (+0.137)	56.3 (-0.0)	117.2 / 23.5 (-5.8 / -4.5)	0 / 0 (+7.4 / +7.4)	24 (-4)	33 (+1)	18 (+1)	2 (+1)	23 (+1)
	Long-term	22.649 (+0.145)	64.0 (-0.3)	228.7 / 33.1 (+4.4 / -3.9)	0 / 0 (+8.4 / +8.4)	24 (-5)	31 (+1)	17 (+0)	5 (+1)	23 (+3)

4.3. The impacts of perfect foresight

The assumption made in the present work that reserves used to increase and to decrease generation cancel each other out energy-wise may be true on some time-scales but does not hold true for every hour. The optimization model exploits the assumption that no energy is withdrawn for reserve purposes, so as to double-count energy for reserves and for normal electricity supply operation. To investigate how this affects the value of batteries, a scenario (*EnergyRes*) was constructed in which energy committed for reserves had to remain unused in the battery for at least 12 hours (accumulatively). Table 9 shows the indicators for the normal *Full FC* scenario, together with the changes to each indicator (in parentheses) seen in the *EnergyRes* scenario. While the impacts on VRE share and curtailment are weak, there is a slight increase in the thermal cycling cost and a large increase in battery storage investments (highlighted by bold numbers).

Table 9. Indicator values for all regional cases and years in the Full FC *scenario, with changes observed in the* EnergyRes *scenario listed in parentheses.*

		System cost [G€/yr]	VRE share [%]	Thermal share [%]	Curt. [%]	Battery [GWh]/[GW]	Thermal cycling cost [G€/yr]
Brit	**2020**	12.411 (-0.0)	30.5 (-0.0)	68.0 (+0.0)	8.4 (+0.0)	0 / 0 (+0 / +0)	0.41 (+0.000)
	Near-term	14.636 (+0.203)	48.5 (+0.1)	48.8 (-0.0)	3.9 (-0.1)	17.9 / 8.1 (**+14.0** / -0.2)	0.182 (+0.042)
	Mid-term	19.09 (+0.228)	71.8 (+0.0)	21.5 (+0.3)	8.9 (-0.1)	111.4 / 21.9 (**+15.8** / -0.5)	0.15 (+0.017)
	Long-term	25.044 (+0.224)	78.0 (-1.6)	13.8 (+0.2)	10.3 (+0.1)	271.1 / 35.2 (**+16.7** / -0.5)	0.195 (+0.015)
Iberia	**2020**	9.628 (-0.0)	29.0 (+0.0)	59.2 (+0.0)	0.0 (+0.0)	0 / 0 (+0 / +0)	0.051 (+0.000)
	Near-term	9.634 (+0.028)	65.1 (-0.1)	17.7 (-0.3)	10.8 (-0.1)	104.8 / 17.4 (**+8.3** / +1.0)	0.06 (+0.000)
	Mid-term	11.818 (+0.04)	68.6 (-0.3)	10.5 (+0.2)	9.7 (-0.2)	235.6 / 37.3 (**+1.4** / -0.2)	0.055 (+0.001)
	Long-term	12.964 (+0.095)	71.6 (-0.3)	4.6 (-0.2)	7.6 (-1.3)	315.5 / 49.8 (**+21.9** / +2.4)	0.048 (-0.002)
Nordic	**2020**	11.146 (+0.000)	28.7 (+0.0)	41.1 (+0.0)	0.7 (+0.0)	0 / 0 (+0 / +0)	0.412 (+0.000)
	Near-term	12.917 (+0.233)	47.8 (-0.1)	21.8 (+0.2)	1.0 (-0.0)	20.7 / 10.9 (**+17.3** / -1.4)	0.26 (+0.040)
	Mid-term	17.207 (+0.344)	56.3 (+0.0)	14.3 (-0.1)	2.7 (-0.0)	117.2 / 23.5 (**+27.5** / -1.0)	0.202 (+0.022)
	Long-term	22.649 (+0.333)	64.0 (-0.9)	6.9 (-0.1)	5.7 (+0.2)	228.7 / 33.1 (+32.5 / -0.9)	0.138 (+0.014)

The impact of the *EnergyRes* scenario on the FR supply is illustrated in Figure 7, where the share of reserves from each technology is shown as bars, with units on the left-hand *y*-axis. The system cost increase, per produced unit of electricity, is indicated by diamond symbols, with units on the right-hand *y*-axis. As expected, there is no system cost increase in Year 2020 before battery investments are allowed. Once battery investments are allowed, in the future years, the system cost increases as the energy reservation restriction increases the battery storage investments. However, as shown on the right-hand *y*-axis, the impact is still low when compared to the cost of electricity production (0.1 to 0.5 €/MWh, or about 200-fold lower than regular electricity prices). Regarding the reserve share, there is little difference compared to the *Full FC* scenario in Figure 6, except that the reserve shares from curtailed VRE, thermal power plants and power to heat (PtH) all increase slightly.

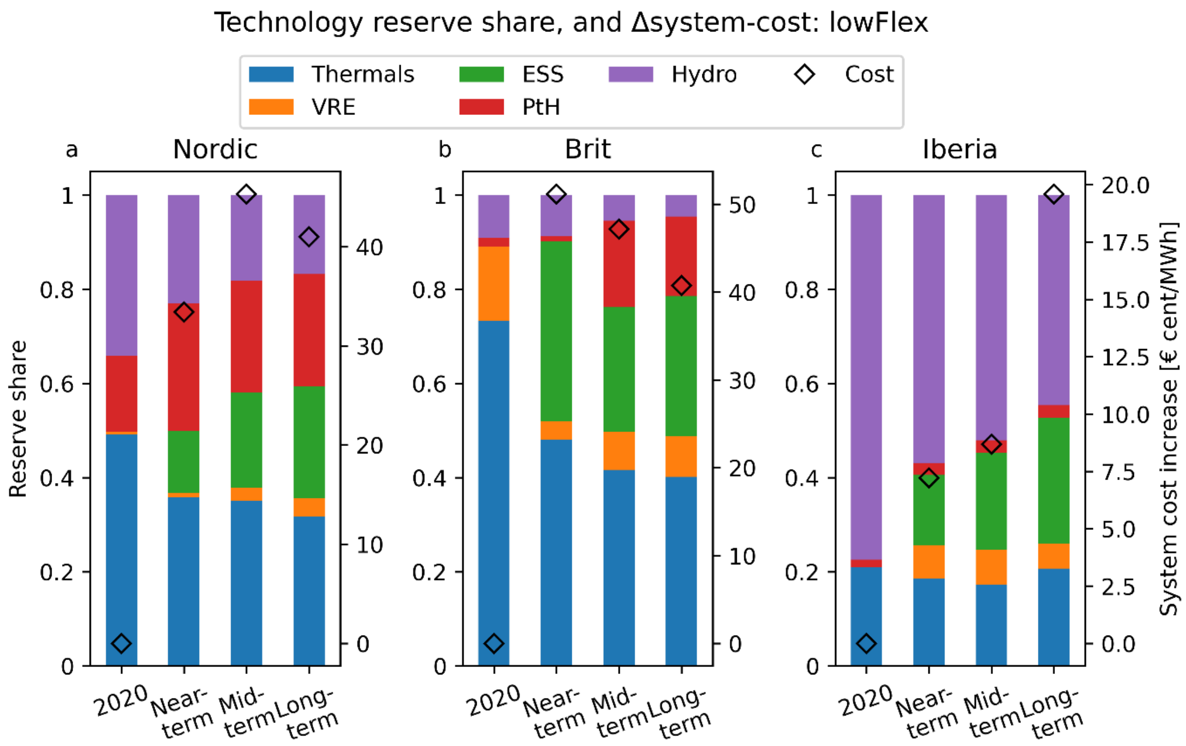

Figure 7. The bars indicate the reserve shares per technology on the left-hand y-axis, for each year and region in the EnergyRes *scenario. The diamond symbols indicate the increases in system cost compared to the* Full FC *scenario, expressed as system cost increase per year and electricity production, on the right-hand y-axis.*

While the *EnergyRes* scenario does not remove perfect foresight or the assumption that reserves are symmetrical (same demand for increased and decreased generation), it indicates that neither of these factors gives batteries a role in the FR supply that they otherwise would not have. The amount of batteries required may be underestimated, while their ability to reduce the total system cost (as shown in Table 9) may be overestimated, although the results clearly indicate that batteries are a key technology for future FC.

5. Conclusions

The results of this work show that the addition of frequency reserve (FR) and inertia constraints has a limited impact on system composition and cost. Three geographic regions with different conditions for wind and solar power generation have been studied, and in all three investigated regions the responses to adding FR and inertia constraints are similar. Only in the dispatch-only Year 2020 scenario is thermal part-load operation significantly increased to supply FR and inertia. When investments in electricity generation and storage technology are allowed, FR and inertia increase investments in batteries. The impact of including FR and inertia on the total system cost decreases as the VRE share (and the accompanying battery capacity to manage the intra-hourly VRE variations) is increased.

When limiting the ability of batteries to double-count energy for reserves and for energy supply, the battery storage capacity is increased further to compensate for the lower available storage capacity. Eliminating the ability to double-use batteries for FR and inertia on the one hand, and for inter-hourly variations on the other hand, increases the system cost but does not significantly change the cost-optimal technology mix to supply FR and inertia or to produce electricity. Furthermore, completely eliminating batteries from contributing to FR and inertia increases the contributions from all alternative sources at a relatively high cost (up to 5% increase in the accumulated system cost across the four investigated time-points).

6. Future work

In terms of future research in this area, four issues warrant investigation.

1. *A deeper analysis of batteries.* With batteries being highlighted as a key technology for the future of FC, both system operators and prospective investors would be interested in the answers to the following questions: *How complicated must an operating algorithm be to realize the value seen in this work? How sensitive is battery operation to variations in factors such as yearly electricity demand, local grid congestion and battery degradation?* and *What value could batteries bring to other ancillary services such as voltage control?*

2. *Widening of the scope*. This work investigates FR and inertia in regions with an existing traditional electricity supply. It is not clear how a cost-optimal electricity supply, FR and inertia can develop in regions with electricity systems that are still under development, which is the case in many of the poorer regions of the world. This work could also gain validity through the use of power system simulations to validate the FR of the electricity systems identified in the optimization modeling. Previous research by González-Inostroza et al. (2021) concluded that the location of the battery capacity could be important for the FR and inertia of a system. Higher geographic resolution and better representation of the electricity grid could, therefore, give further insights into the interactions between the electricity supply and FC from both the generation and consumer sides.

3. *Willingness-to-pay for consumer-side FC*. The results from **Paper II** show that synthetic inertia and FR from PtH has a moderate impact on system cost in the *Nordic* case, and that participation from the BEV fleet has the potential to eliminate the system cost impact of FC. While the value of this consumer-side FC is quantified in **Paper II**, the extent of the willingness-to-pay for synthetic inertia and reserves with different activation times and durations is not clear. Furthermore, since the heat produced through PtH must be supplied from some other source if heat pumps and electric boilers temporarily decrease their outputs, there is an inherent cost associated with reserves derived from PtH. This can be studied with only minor modifications to the existing model.

4. *Limiting perfect foresight with stochastic modeling*. The *EnergyRes* scenario aims to limit the impacts of perfect foresight and the assumption that reserves require zero energy due to symmetrical activation over time. However, all reserve sources benefit in some way from the reserves never being activated. Using stochastic modeling, reserves can be activated with limited perfect foresight of such events. This path requires additional method development and relaxation of the geographic, temporal or technologic resolution.

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