

Faculdade de Engenharia da Universidade do Porto

# Load-Frequency Control considering Hydrogen Electrolysers' response

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Doctoral Program in Sustainable Energy Systems

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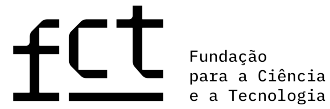
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**MIT**Portugal



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# Resumo

Da transição energética em curso irá emergir uma economia do hidrogénio, assente em eletrolisadores de hidrogénio (EHs). Vistos do lado da rede elétrica, EHs são cargas com rampas de resposta rápida, e portanto capazes de fornecer serviços de sistema tais como Controlo de Frequência (Load Frequency Control - LFC).

O primeiro objetivo desta tese foi analisar se uma grande capacidade instalada de EHs fornecendo reserva primária e reservas rápidas permite que o sistema elétrico seja operado de forma segura com níveis baixos de inércia síncrona. Usou-se o ponto de vista do operador da rede de transporte (TSO) e procedeu-se a simulações dinâmicas. Concluiu-se que a inércia crítica pode ser reduzida graças ao fornecimento destes serviços de sistema por parte dos EHs, e esta relação foi quantificada.

Em segundo lugar, foram propostos uma nova filosofia e esquema de controlo usando Modelo de Controlo Preditivo para a reserva secundária. Estes permitem que as rampas de resposta rápida de EHs sejam exploradas no contexto de recuperação de uma grande perda de geração na rede. Conclui-se que o esquema proposto tem uma performance superior ao controlo proporcional-integral que normalmente se utiliza no Controlo Automático de Geração (Automatic Generation Control - AGC).

Em terceiro lugar, foi criada uma ferramenta para calcular as receitas de uma Central Elétrica Virtual (Virtual Power Plant - VPP) que inclui EHs e participa na plataforma de mercado "FCR Cooperation". A análise económica inclui custos de oportunidade, e adotou-se o ponto de vista do proprietário de EHs usando dados reais de mercado. Os custos de participação dos TSOs português e espanhol na plataforma de mercado foram calculados.

Finalmente, um novo esquema de regulação foi proposto, que permite o cálculo dos

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pagamentos dos TSOs aos provedores de serviços (tais como EHs) neste mercado, e o esquema proposto foi comparado com o atualmente existente.

De um modo geral, deste trabalho conclui-se que os EHs são uma tecnologia promissora para participação em LFC, com benefícios tanto para os seus proprietários como para os operadores de sistema.

# Abstract

From the ongoing energy transition a hydrogen economy will emerge, enabled by hydrogen electrolyzers (HEs). From the power system point of view, HEs can be seen as loads with fast ramping capabilities, and thus able to provide ancillary services such as load-frequency control (LFC). The motivation for this thesis is to investigate to what extent HEs can be exploited in this context.

The first objective of this thesis was to analyze whether a large installed capacity of HEs providing primary and fast reserves allows for the power system to be operated securely at lower synchronous inertia levels. This was done adopting the Transmission System Operator (TSO) point of view and using power systems dynamic simulation. It was found that critical inertia can be reduced with ancillary service provision from HEs and this relation was quantified.

Secondly, a novel philosophy and control scheme using Model Predictive Control for the secondary reserve were proposed, which allow for the fast ramping capabilities of HEs to be fully exploited during post-fault recovery. It was found that the proposed scheme outperforms the proportional-integral used in conventional Automatic Generation Control.

Thirdly, the costs for Portuguese and Spanish TSOs to join the FCR Cooperation were assessed; a tool was created to compute the revenues of a Virtual Power Plant including HEs in this market. Economic analysis was performed using opportunity costs, adopting the point of view of the HEs owner and using real market data.

Fourthly, a novel regulatory scheme is proposed, which allows for calculating the costs that TSOs pay to balancing service providers such as HEs in the market, and the proposed scheme is compared against the currently existing scheme.

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Overall, HEs appear as a promising technology for participating in LFC, with benefits for both HE owners and TSOs.

# Acknowledgements

First and foremost, I would like to thank my supervisor Prof. Peças Lopes for accepting this supervision, for providing the guidance and for always finding the time to discuss the ideas contained in this thesis. I would like to thank Joel and André as my co-supervisors, for always being so constructive and for finding ways to motivate me throughout this whole period of time. I was fortunate to have Joel on my side also as a friend when I most needed. The success of this work was made possible by the support of my hosting institution, INESC TEC, and I thank Ricardo Bessa as CPES coordinator for this opportunity. I would like to express my gratitude to all the colleagues at INESC TEC for the inspiration at work and also for the good moments outside it. A big thank you for the crew of the old fourth floor.

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Many thanks to my friends who have been with me for all these years. Last but not least I would like to thank my family for the unconditional love, and for having once again been the foundation of my life.

July 29, 2025

Fernando Ribeiro

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“Water will one day be employed as fuel,  
that hydrogen and oxygen which constitute it [...] will furnish an inexhaustible source of heat and light,  
of an intensity of which coal is not capable.”

- Jules Verne,  
*The mysterious island*,  
**1874**

“It is not too much to expect that our children will enjoy in their homes electrical energy  
too cheap to meter [...]”

- Lewis Strauss,  
(*Chairman of the United States Atomic Energy Commission*,  
referring to nuclear power,  
in a speech delivered to the National Association of Science Writers),  
**1954**

“A year ago, our hydrogen targets were seen as unachievable.  
Now it looks like we might overshoot them in the next decade.  
The market might go faster than our biggest dreams on this.”

- Frans Timmermans,  
(*European Commissioner for Climate Action*,  
in a speech delivered at the annual conference of Eurogas),  
**2021**

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# Acronyms

**aFRR** Automatic Frequency Restoration Reserve

**BSP** Balancing Service Provider

**CBMP** Cross Border Marginal Price

**FCR** Frequency Containment Reserve

**GHG** greenhouse gas

**HE** Hydrogen Electrolyser

**IBR** Inverter-Based Resource

**IP** Iberian Peninsula

**LFC** Load-Frequency Control

**LMP** Local Marginal Price

**LOM** Loss of Mains

**mFRR** Manual Frequency Restoration Reserve

**PV** photovoltaics

**RoCoF** Rate of Change of Frequency

**RR** Replacement Reserves

**SI** Synthetic Inertia

**TSO** Transmission System Operator

**UFLS** Under-Frequency Load Shedding

**VPP** Virtual Power Plant

**VRES** Variable Renewable Energy Sources

## Symbols used in Section 2.1

$\delta$  Angular position of the rotor

$\delta_0$  Angular position of a synchronously rotating reference

$\delta_n$  Ideal voltage source angular displacement of the electric equivalent of area n (radians)

$\omega_m$  Angular velocity of the rotor

$\omega_{0m}$  Rated angular velocity of the rotor

$\omega_0$  Rated angular velocity of the rotor in electrical rad/s

$\omega_r$  Angular velocity of the rotor in electrical rad/s

$E_n$  Ideal voltage source voltage of the electric equivalent of area n

$f$  Electric frequency

$H$  Synchronous inertia

$J$  Moment of inertia

$K_D$  Damping coefficient

$P_{1-2}$  Active power flow from area 1 to area 2

$p_f$  Number of field poles

$Sb$  VA base

$T$  Synchronizing torque coefficient

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$T_a$  Accelerating torque

$T_e$  Electromagnetic torque

$T_m$  Accelerating torque

$X_n$  Equivalent reactance of the electric equivalent of area  $n$

$X_{tie\_line}$  Equivalent reactance of the tie lines that interconnect both areas

## Symbols used in Section 2.2

$\delta_{area}$  Ideal voltage source angle of the electric equivalent of *area*

$\Delta f_{area}$  Frequency deviation from the nominal value in *area*

$\Delta f_{max,pu}$  Frequency deviation at which maximum FCR activation is required in pu

$\Delta P$  Variation in active power output by HEs participating in synthetic inertia provision

$\Delta P_{1-2}$  Variation of active power import to *area*

$\Delta P_G$  Variation of active power output of generators participating in the FCR

$\Delta P_L$  Variation of load due to contingency

$D_{area}$  Load self-regulating characteristic (damping constant) of *area*

$FCR_{vol,pu}$  FCR volume in pu

$H_{area}$  Synchronous inertia of *area*

$K$  Synthetic inertia constant

$LPF$  Low-pass filter constant for synthetic inertia

$Or$  Original volume of FCR in IP

$Pc\_pec_y$  Percentage of motors interfaced with electronic converters in year *y*

$pf$  Power factor

$R$  Speed droop

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$S$  Apparent power

$T$  Synchronization coefficient

## Symbols used in Section 2.3

$ACE$  Area Control Error

$D$  Load damping

$DPL$  Generation Loss

$eme$  Binary variable that detects emergency mode

$H$  Synchronous inertia

$Ki$  AGC-PI integral gain

$Kp$  AGC-PI proportional gain

$lpf$  Low-pass filter time constant

$max$  Maximum power provided by unit

$pf$  Participation factor

$R$  Speed droop

$T$  Synchronization coefficient

$Tgp$  FCR governor time constant

$Tgs$  aFRR governor time constant

$Ttp$  FCR turbine time constant

$Tts$  aFRR turbine time constant



## Symbols used in Section 3.1

$B_{c,t}$  Symmetric bid size in country  $c$  at time  $t$

$CAE_{c,t}$  Cost of avoided energy not consumed by the HEs

$CBMP_t$  Cross-border marginal price at time  $t$

$D_{c,t}$  TSO demand  $c$  at time  $t$

$Dec_{c,t}$  Decision variable for participation in the market session in country  $c$  at time  $t$

$DH_{c,t}$  Demand of HEs taking place in country  $c$  at time  $t$

$DN\_en_{c,t}$  Activated downwards FCR energy in country  $c$  at time  $t$

$DN\_OPC_{c,t}$  Opportunity cost of downwards FCR activation  $c$  at time  $t$

$DN_{c,t}$  Share of downward reserve that can be supplied by solar and wind power under the VPP in country  $c$  at time  $t$

$DNRS_{c,t}$  Downward reserve revenue share in country  $c$  at time  $t$

$Ef$  Efficiency of hydrogen electrolyser

$EMP_{c,t}$  Average energy market price in country  $c$  at time  $t$

$G_{c,t}$  Wind and solar production taking place in country  $c$  at time  $t$

$HMin$  Value of  $G_{c,t}$  above which  $DH_{c,t}$  takes the nominal value

$HMin$  Value of  $G_{c,t}$  below which  $DH_{c,t}$  is zero

$NPH_{c,t}$  Amount of non-produced hydrogen due to activated FCR in country  $c$  at time  $t$

$OPC_{c,t}$  Sum of upward and downward opportunity costs in country  $c$  at time  $t$

$PN_c$  Aggregated nominal power of on-grid HEs in country  $c$

$PPAP$  Power purchase agreement price

$RDS_c$  Reserve margin for which contracted HE units provide reserve in country  $c$

$RGS_c$  Reserve margin for which contracted solar and wind units provide reserve in country  $c$

$TC_{c,t}$  TSO cost  $c$  at time  $t$

$UP\_en_{c,t}$  Activated upwards FCR energy in country  $c$  at time  $t$

$UP\_OPC_{c,t}$  Opportunity cost of upwards FCR activation in country  $c$  at time  $t$

$UP_{c,t}$  Share of upward reserve that can be supplied by HEs under the VPP in country  $c$  at time  $t$

$UPRS_{c,t}$  Upward reserve revenue share in country  $c$  at time  $t$

$VGS_c$  Proportion of solar and wind units contracted by the VPP in country  $c$

$VPR_{c,t}$  VPP potential revenues without taking opportunity costs into account in country  $c$  at time  $t$

$VRS_{c,t}$  VPP revenue share in country  $c$  at time  $t$

## Symbols used in Section 3.2

$AI_c$  Absolute imports of country  $c$

$AK_c$  Allocation key of country  $c$

$AOC_c$  Over-cost allocation of country  $c$

$CB_{c,n}$  Binary variable that indicates whether the bid  $n$  in country  $c$  has been accepted

$CBMP$  Cross-border marginal price

$CC\_TSO_c$  TSO costs of country  $c$  under the current scheme

$Coef_c$  Coefficient of country  $c$  share in total demand

$CP\_TSO_c$  TSO costs of country  $c$  in the proposed mechanism

$CP_c$  Compensation costs of country  $c$

$CS_c$  Core share of country  $c$

$CTSO_c$  Cost paid by TSO of country  $c$

$D_c$  Bid size demanded by  $TSO_c$

$EL_c$  Export limit of country  $c$

$exp$  Index for exporting countries

$I_c$  Imports of country  $c$

$IC_c$  Import costs of country  $c$

$ICAA_c$  Import costs after allocation of country  $c$

$ICP_c$  Costs of imports of country  $c$

$imp$  Index for importing countries

$IP_c$  Imported power of country  $c$

$LC_c$  Local costs of TSO from country  $c$

$LMP$  Local marginal price

$MM$  Missing money

$NP$  New price for the power that remains to be paid

$OC$  Over-cost

$OP$  Over-procurement

$OPC_c$  Over-procurement costs of country  $c$

$PB_{c,n}$  Price of bid number  $n$  in country  $c$

$PC\_OP$  Percentage of cases with over-procurement

$QB_{c,n}$  Quantity of bid number  $n$  in country  $c$

$QC_c$  Cleared quantity in country  $c$

$R\_BSP_c$  Sum of revenues of BSPs of country  $c$

$REBSP_{c,n}$  Revenue received by BSP number  $n$  of country  $c$

$TI$  Total imported power to be paid

$TOPC$  Total over-procurement costs

# Chapter 1

## Introduction

The Intergovernmental Panel on Climate Change places “high confidence” that climate change represents a “threat to human well-being and planetary health” [1]. The same report observes that “human activities, principally through emissions of greenhouse gases (GHGs), have unequivocally caused global warming” and that, in 2019, 79% of global GHGs emissions came from the sectors of “energy, industry, transport and buildings”. The report further states that the largest share of GHG emissions comes from fossil fuels combustion and industrial processes. The mitigation of global warming requires *decarbonization*, defined as a process aimed at achieving “zero fossil carbon existence”, through a significant reduction of carbon emissions associated with electricity, industry and transport [2]. Aligned with the decarbonization, the Paris Agreement, signed in 2015, aspires at keeping long-term mean global temperature well below 1.5°C above pre-industrial levels; this would imply that emissions should be reduced as soon as possible and reach net zero by 2050 [3].

This thesis begins with three quotations (page ix). The first comes from a science fiction book published a century and a half ago. The second and third quotations share with the first one a tone of unequivocal optimism about the future of technologies; on the other hand contrast with the first one, for they come not from science fiction writers but from policy makers with real world responsibilities. The second quotation is a reminder of past hopes about nuclear power: seven decades after the commissioning of the first

power plant of this kind, this technology has yet to deliver the promised abundance at insignificant cost. The third quotation again shows ambition and mentions “dreams”, thus pointing us in a circular way to the first one, in its prediction of hydrogen replacing coal. Yet, a century and a half after Jules Verne’s vision, the widespread use of hydrogen remains on the horizon, while our civilization still relies heavily on coal.

This thesis is based on the assumption that the *green hydrogen economy* envisioned by the third quotation will materialize and contribute to decarbonization in the coming years. In that case, it will necessarily be enabled by a new actor in power systems: the Hydrogen Electrolyser (HE), which is at the core of this work. The HEs will open both new challenges and opportunities to the future power systems; this thesis focuses on the opportunities brought by HEs to Load Frequency Control, since the HEs are flexible loads.

The remainder of this chapter is organized as follows: Section 1.1 provides a general background for the whole thesis while identifying some of the addressed challenges; thesis motivation and objectives are outlined in Section 1.2; the main thesis contributions can be found in Section 1.3; in Section 1.4 the remainder of the thesis structure is presented.

## 1.1 Thesis background

The main goal of this section is to provide a background that allows for the understanding of the thesis objectives outlined in Section 1.2.

Figure 1.1 takes the thesis title as the starting point and breaks it in two, according to the organization of the remainder of this section. Section 1.1.1 culminates with the emergence of HEs after providing an overview of the foreseeable evolution of the energy sector. Section 1.1.2 aims at providing an overview on Load-Frequency Control (LFC) and the challenges future power systems face in this context. The arrow linking the emergence of HEs with the opportunities in the context of LFC is the fundamental gap this thesis aims to bridge.

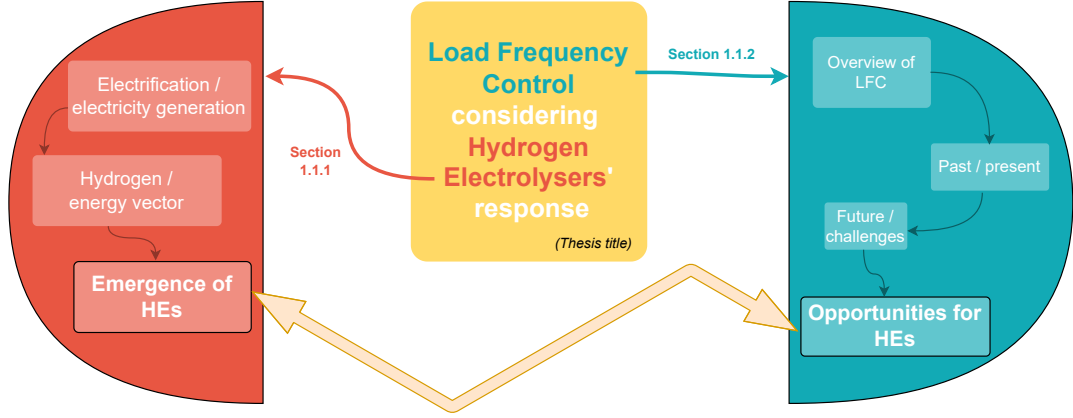


Figure 1.1: Section 1.1 outline.

### 1.1.1 The ongoing transition

The history of Mankind has been deeply shaped by energy use. It is common knowledge that the great technological advances of the Industrial Revolution were enabled by relying on coal as the main energy source. In his book “Energy Transitions” [4], the energy historian Vaclav Smil analyzes in detail the enormous challenge of ending our reliance on fossil fuels in a matter of few decades. The author prefers to discuss *transitions* rather than *revolutions*; he emphasizes that past energy transitions took 50 to 75 years to ripple through societies. Thus, it is useful to take this time-scale into account when discussing the state of the current energy transition: the worldwide final energy supply in the last 50 years (Figure 1.2) shows that in this period the supply of coal has almost tripled (present share of 27%), that of oil doubled (present share of 31%) and that of natural gas rose by a factor of 4 (the share grew from 16% to 23%).

In relative terms, the share of fossil fuels in the final energy supply has declined only slightly (from 87% to 81%) in this period while in absolute numbers it more than doubled. This means that Mankind’s dependence on fossil fuels is *still growing*.

Besides the already mentioned concerns with GHG emissions, fossil fuels have additional problems. A second source of concern about fossil fuels is that they are finite; at present rate of consumption, the known reserves of coal, oil and natural gas would last, respectively, 139, 57 and 49 years [6]. A third cause for apprehension is self-sufficiency and arises in certain nations or regions. For instance, the European Union is a net importer

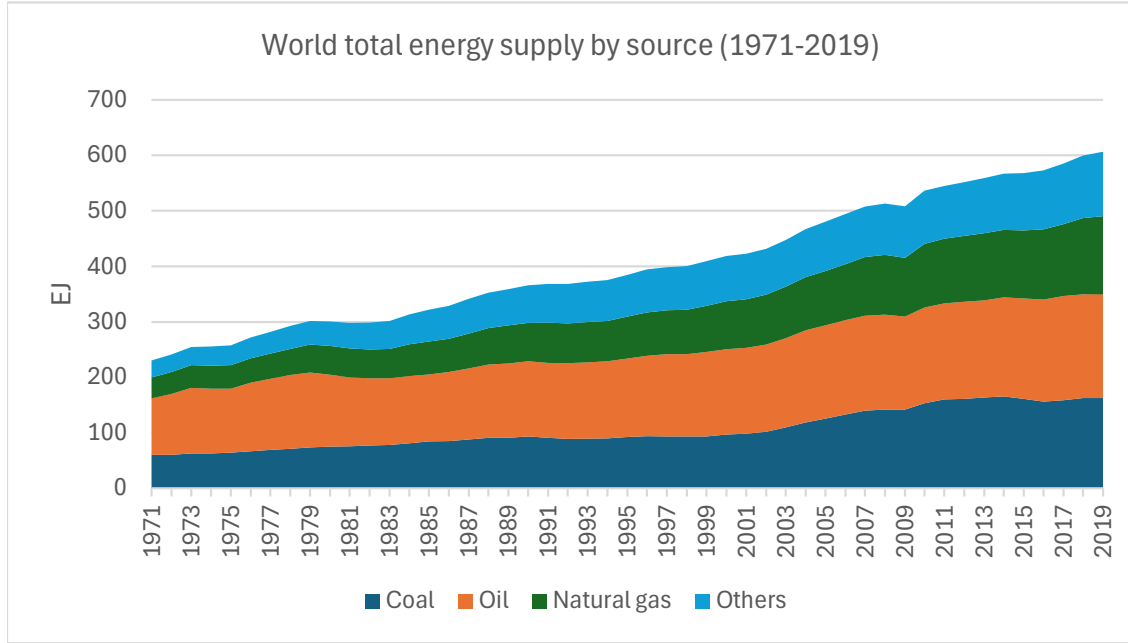


Figure 1.2: Worldwide final energy supply 1971-2019. Adapted from [5]. The category "others" includes hydro, nuclear, biofuels and waste, wind and solar and others.

of coal, oil and natural gas [7], and the same is true for China [8]. While this matter can normally be resolved by trade, geopolitical events such as the OPEC crisis in the 1970s highlighted the vulnerability of net importing countries.

The pathways to achieve the transition will impact distinct domains ranging from forestry to industry. Most of these domains are somehow related to energy use, but are not relevant for this thesis, such as carbon pricing [9] or more controversial ones such as carbon capture and storage [10]. The most interesting enablers for decarbonization in the scope of this thesis are *electrification* and *renewable energy generation*. In the context of energy use, these two key enablers constitute two sides of the same coin, respectively, the demand and supply side. The prospects of each are briefly outlined in the following pages.

#### 1.1.1.1 Electrification of the demand and supply

Electrification, on the demand side, is the conversion of systems from using non-electric energy sources to relying on electricity as the primary power source. Its importance can be underlined using two examples: buildings and transportation. Buildings are responsible for more than 40% of the energy used in the European Union; more than 80% of the

energy used in households is used for heating, cooling and hot water [11]. In Europe, heating systems rely in many cases in direct use of fossil fuels (particularly natural gas); studies show that electrification using efficient heat pumps can save around 60% of primary energy and 90% of associated  $CO_2$  emissions [12] by 2050. Regarding transportation, it is interesting to take the case of the automobile, which became ubiquitous in the last century thanks to the internal combustion engine powered by fossil fuels. Both the engine and fuel tanks were light and small enough to allow for the automobile revolution to take place, and this was in part thanks to the high density of power contained in fossil fuels. Nowadays, road transport accounts for roughly 18% of worldwide  $CO_2$  emissions [13], which makes this sector a hugely relevant in the decarbonization process and that has been leading to the adoption of electric vehicles. It is well known that presently an electric vehicle is more efficient than the ones using traditional internal combustion engines [14]. Heat pumps and electric vehicles illustrate that due to the fact that electric drives are efficient, relying on electrification allows to decrease the use of primary energy for the same process if compared to other fossil fuel-based technologies.

As previously stated, demand-side electrification, or in simple terms, “plugging” the demand side to the electricity grid, is only one side of the two aspects of decarbonization under consideration. The other side, without which electrified cannot be attained, is that the supply side, or electricity generation, must be decarbonized as well. These two aspects are represented in Figure 1.3, from the present point of situation up to the year 2050. On the one hand (left plot) it is shown that renewables’ share in electricity generation will experience a great increase. On the other hand there will be a relatively more modest increase in the rate of electrification; consequently, a significant portion of decarbonization is due to load that will not be electrified. This means that some consumption sectors will not be electrified and this is relevant for hydrogen, as will be seen in the remainder of this subsection.

According to [15], in 2050, the largest sources of renewable generation will be solar and wind power. Today, some countries are closer to decarbonizing their electricity generation sector than others. For instance, in Portugal in 2023, over 70% of the total generated

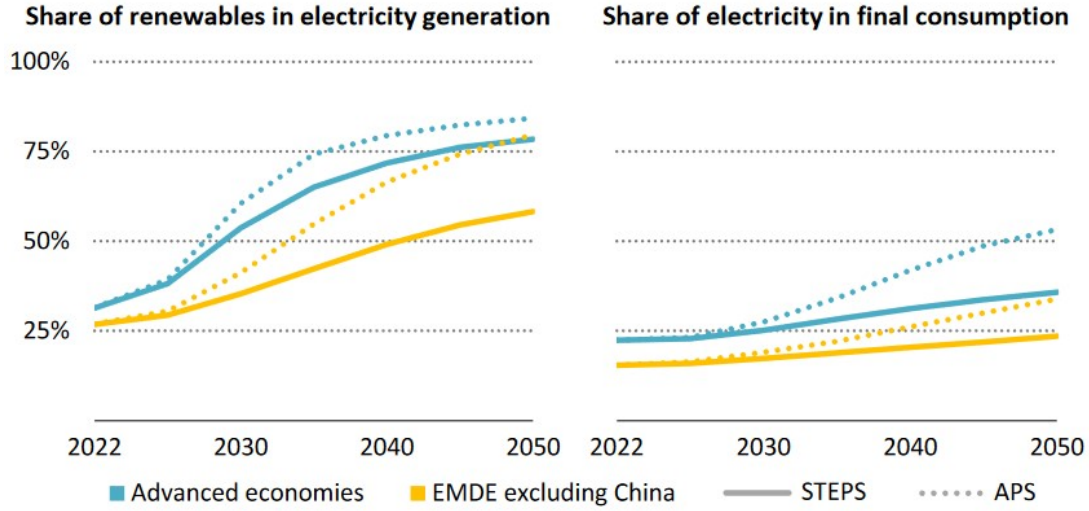


Figure 1.3: Share of renewables in power generation and electricity in final consumption, 2022-2050 [15]. "EMDE" stands for "emerging market and developing economies", "STEPS" for "stated policies scenario" and "APS" for "announced pledges scenario".

electricity came from renewable sources, led by wind power [16].

It is widely known that wind and solar generation units contrast in size with the conventional power plants from the twentieth century (coal, nuclear, natural gas, large hydro). It is interesting to compare the difference in scale when comparing the largest power plant in Europe (nuclear power plant with 6000 MW [17]) and the average power of newly installed wind turbines (still less than 10 MW [18]). The ongoing *decentralization* of the modern power systems is, thus, a consequence of the modular nature of solar and wind power units and also the fact that the wind and solar resource is geographically distributed. This is remarkable because the number of units participating in the electricity supply side is so much larger than in the past.

Another fundamental change in power systems introduced by solar and wind power can be summarized in the expression used where these sources fit: Variable Renewable Energy Sources (VRESs). They contrast with the conventional fossil fuel plants because their output is *variable*, since they generate power proportionally to the availability of their resource (sun or wind). Thus, while in the past there was controllable generation and inflexible demand; in the future there will be variable<sup>1</sup> generation and controllable

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<sup>1</sup>Here, the word "variable" was employed instead of "intermittent" or "uncontrollable", because when there is wind it is possible to forecast it and control the turbine in such a way to effectively decrease or

demand.

#### 1.1.1.2 Hydrogen as an energy vector

The fundamental challenge of a power system based on VRES, when compared to the fossil fuel generation is that while the latter has fuel stored on premises to generate electricity when needed, the former needs some kind of adaptation to buffer the energy generated when wind or solar production is higher than the demand. While it is unrealistic that all the energy demand can be shifted to the hours of high VRES generation, some possibilities for buffering this energy are (i) to store it in hydro reservoirs, (ii) to store it in electrical batteries or (iii) to store it as a renewable gas, such as hydrogen.

From Figure 1.3 it was established that a significant portion of the consumed energy will be decarbonized but not through the direct use of electricity. This “indirect use of clean energy” is due to the so-called “hard-to-abate sectors”: heavy-duty trucks, shipping, aviation, iron and steel and chemicals and petrochemicals [19]. The industry sector is considered the most difficult to electrify due to the need of high heat required for transforming raw materials into more refined materials. High and very high temperature ( $>500^{\circ}\text{C}$ ) processes account for most of the industrial heat demand, in sectors such as glass, ceramics, cement and steel. The electrification of these sectors faces several challenges such as high operation costs, electric delivery infrastructure needs, availability of electric process equipment or capacity to redesign manufacturing process lines, among others [20]. The decarbonization of these sectors will in part be achieved by green hydrogen, which will be either used directly or indirectly, for instance via produced commodities such as ammonia, methanol and iron [19]. Hydrogen is, thus, an energy vector, and an alternative to the electricity vector.

From the point of view of the electricity grid, the production of green hydrogen is enabled by HEs connected as loads. HEs use renewable electricity and take water as input to perform electrolysis, that is, to split the water molecules in oxygen and hydrogen (Figure 1.4).

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shut down generation: this is essentially “controllability”.

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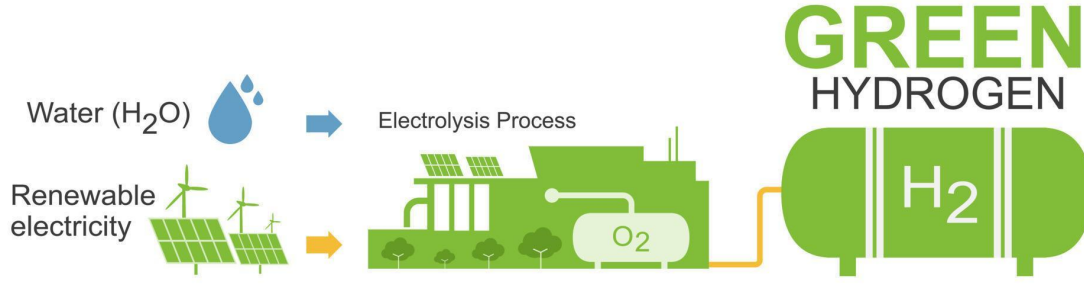


Figure 1.4: Green hydrogen process [21].

There are four electrolyser technologies currently available: alkaline, proton exchange membrane (PEM), solid oxide electrolyser cell (SOEC) and anion exchange membrane (AEM). Alkaline and PEM are currently the most mature technologies [22]. The most relevant HE's characteristic to this thesis is that they are *flexible loads*. When taken together with the intermittency of VRES, there is intrinsic value to shift the working hours of HEs to the hours of high VRES production. In fact, laboratory tests performed showed that HEs are able to vary their consumption abruptly according to a command signal (setpoint) in a fraction of a second [23]. In Section 1.1.2.2 the exploitation of such flexibility will be more detailed in the context of this work.

### 1.1.1.3 Emergence of HEs

Although in 2022 the production of HEs was only about 1 GW, in 2023 there was around 14 GW of HE manufacturing capacity, and this number is expected to grow to 155 GW by 2030 [24]. For comparison, solar photovoltaics, which is now a mature technology adopted worldwide, currently has a manufacturing capacity of about 1100 GW. [25] In 2050, the demand of hydrogen is forecasted to be about three times larger than the in 2030 [26].

Although the outlook of hydrogen looks promising, on the economic side serious uncertainty exists. For instance, it is recognized that the switch to hydrogen will not likely be attractive based on economics alone, and active mandates such as subsidies and  $CO_2$  prices are necessary to facilitate this switch [27]. It is, thus, important for the entities that sell hydrogen to participate in markets beyond that of hydrogen itself, in order to

be competitive. Such markets include ancillary services in electricity markets and are addressed in this thesis.

In the EU, the European Hydrogen Bank was launched in 2022 and rests in four pillars: EU domestic market creation, international imports to the EU, transparency and coordination, and streamline existing financing instruments [28]. Hydrogen is one of the key technologies of Europe’s Net Zero Industry Act, an initiative stemming from the Green Deal Industrial Plan, which aims to scale up manufacturing of clean technologies in the EU. The most relevant policy document in the EU remains “A hydrogen strategy for a climate-neutral Europe” from 2020 [29]. In this document it is stated that by 2030 the EU will aim at “completing an open and competitive hydrogen market with unhindered cross-border trade and efficient allocation of hydrogen supply among sectors”. Finally, the same document states that the EU industry has an ambitious plan of installing 80 GW of electrolyzers by 2030. Many European countries have designed their own national hydrogen strategies. Among these, Portugal has committed to install between 2 and 2.5 GW of installed HE capacity [30], whereas Spain committed to 4 GW [31] until 2030.

### 1.1.2 Load-Frequency Control

In power systems, Transmission System Operators (TSOs) are the entities that, among other tasks, manage the high voltage grid and ensure quality of service, namely of system frequency. The frequency of a power system depends on active power balance; a change in active power demand at one point is reflected throughout the system by a change of frequency [32]. An imbalance where supply is lower than demand causes the frequency to decrease from the nominal value (typically 50 Hz) and vice-versa, as per Figure 1.5.

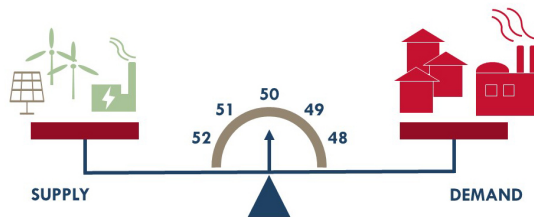


Figure 1.5: Relation between frequency and energy demand and supply [33].

A severe system stress resulting in an imbalance between generation and load seriously degrades the power system performance; it can impact the power system operation and reliability [34]. It is now over 100 years since power system stability and control was recognized as an important problem [35]. An imbalance between generation and load requires actions on generators and/or loads, to restore the frequency to the desirable level: this is the aim of Load-Frequency Control (LFC)<sup>2</sup>. The continuous change in production and demand requires that LFC operates continuously, to ensure that the supply and demand remain in equilibrium.

LFC is organized as a hierarchical control system; using the European nomenclature as example, it is organized as shown in Figure 1.6.

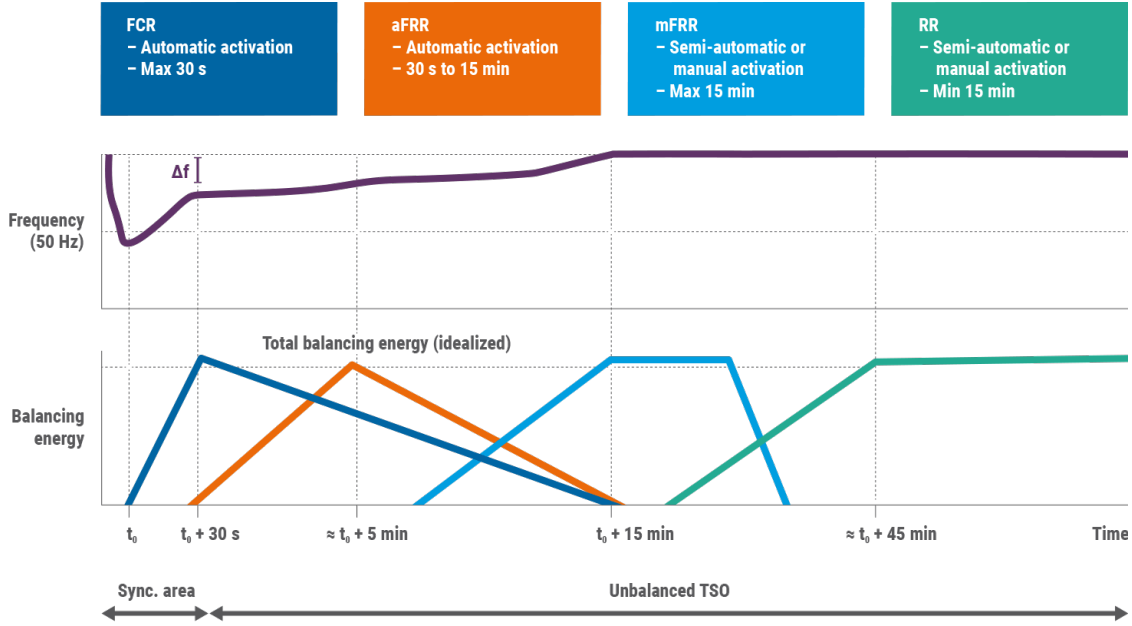


Figure 1.6: Frequency restoration process, using ENTSO-E terminology [36].

At instant  $t_0$  an imbalance takes place in a given control area<sup>3</sup>, so that frequency decreases all over the synchronous area<sup>4</sup>, as explained in the beginning of this section. The LFC action brings back the frequency to the nominal value, using the hierarchic sequence described below.

<sup>2</sup>Note that LFC can be also known as frequency regulation, frequency control, load frequency regulation, balancing, among others.

<sup>3</sup>A control area can coincide with a given country or region of a country in continental Europe.

<sup>4</sup>In this example, the synchronous area would be Continental Europe.

**Frequency Containment Reserve (FCR)** The units providing FCR (typically synchronous generators) all over the synchronous area react to the frequency decrease. The FCR controllers are local and automatic, that is, they react to the frequency measured locally and react to the deviation of the frequency from the nominal value according to a preset proportional gain. In this case, the frequency drops, so these units will increase their active power output to compensate for the drop of frequency. It is important to note that the control area that suffered the imbalance will import power from neighboring control areas that activated FCR: this implies that the TSO of this country is unbalanced. Also note that, when the power activated by FCR reaches its peak, the frequency is only stabilized but not on the desirable 50 Hz. FCR is also known as primary control or primary reserve. FCR is addressed in this work in Chapters 2 and 3.

**Automatic Frequency Restoration Reserve (aFRR)** Ideally, only the units providing aFRR in the control area where the loss of load happened are called to act. These activate roughly as much power as it was activated in the previous step by the units providing FCR in the whole synchronous area. As such, the goal of the aFRR is to solve the local imbalance, restoring the interconnections to their pre-fault value, and to restore the frequency to the nominal value of 50 Hz. The aFRR relies on an automatic controller (AGC - Automatic Generation Control), which receives every few seconds new setpoints from a central controller (for instance, one per country). Such controller is, typically, proportional-integral in nature. The setpoint is then distributed among the participants of the aFRR, which are traditionally generators. aFRR is also known as secondary control or secondary reserve. aFRR is addressed in this work in Section 2.3.

**Manual Frequency Restoration Reserve (mFRR) and Replacement Reserves (RR)** mFRR follows aFRR in order to replace it and their main difference is that mFRR is activated manually. RR is also manual and replaces mFRR in the same logic. Both of these reserves lie outside the scope of this thesis.

In some countries, a new type of reserve is emerging, normally under an umbrella which will be called in this thesis *fast reserves*, as they act faster than the FCR. The main idea

of fast reserves is to deliver active power very quickly, typically in less than 2 seconds, to restore system balance and maintain the power system stability [37]. The response can be either proportional to the frequency deviation, proportional to the derivative of the frequency or a step response [38]. These reserves are currently used mainly in islands (Australia, Ireland, UK, New Zealand), the only exception being that of Texas in the United States [38].

### 1.1.2.1 Future challenges for LFC

In the context of this thesis, the two most relevant challenges for future power systems operation in general and LFC in particular are (i) the decrease of synchronous inertia and (ii) the increase of the presence of variable renewable generation sources that increase the number of load-generation unbalances in the system. Traditional power systems possess high levels of synchronous inertia, which is provided by large generation units, such as coal, nuclear, natural gas and hydro power plants. The kinetic energy stored in the rotating parts of these synchronous generators is what contributes to the system inertia and maintain a synchronized operation of the power system. The replacement of fossil fuel power plants with solar and wind farms removes inertia from the system because the latter are interfaced with the system via power electronics and not via the rotating parts that would store inertia. Consequently, a sudden imbalance in the power system creates greater oscillations in a system with less synchronous inertia. It is not by chance that the countries first introducing fast reserves are islands, which naturally possess lower inertia due to the lack of interconnections. In 2016, there was a blackout in South Australia, following a cascading system failure that led to the disconnection of wind farms; low inertia was mentioned as a cause for rapid frequency decrease in the analysis of the blackout [39]. Consequently, Australia was among the first countries to implement fast reserves.

### 1.1.2.2 Opportunities for HEs

Having outlined the emergence of HEs and the functioning of LFC, some opportunities for HEs can be observed in this context:

1. HEs are loads that will be deployed in large quantities in future power systems;
2. The reduction of the energy consumption of a load is equivalent to the increase of a generator's output from the TSO point of view;
3. HEs are flexible loads that can quickly respond to setpoint changes, making them ideal candidates for participation in LFC;
4. While the main reason for connecting HEs in the grid is to produce hydrogen, they are able, at the same time, to participate in LFC and profit economically from the participation in such ancillary services markets.

## 1.2 Motivation, objectives and research questions

From the previous section, several challenges were identified for different domains and the relevant ones for this thesis can be summarized as follows:

- *Power system dynamics*: power systems with low synchronous inertia will, immediately after contingencies, be subject to higher frequency excursions and higher rate of change of frequency. This is relevant for TSOs that have the obligation to ensure power systems' quality of service.
- *Control theory*: adequate control systems are necessary to ensure the control of an increasing number of participants in the AGC, with very different characteristics among them, namely fast ramping capabilities that can change setpoints quickly after a disturbance. This is relevant, above all, for the TSOs that have to guarantee quality of service, but also for HE owners since it will make them more economically attractive as an asset to be used by the TSOs.
- *Markets*: the economic viability of green hydrogen remains highly dependent on policy making, because at least for now free market signals alone do not encourage the production of green hydrogen. It is thus relevant to assess possible revenues of HEs on markets besides the hydrogen market, such as participation of HE in the electricity markets, namely the reserves markets.

- *Regulation*: The market design and regulation of such markets to accommodate the hydrogen electrolyzers becomes a topic of research. This is relevant for HE owners and for regulators.

Taking into account the identified challenges and respective domains, the thesis motivation, objectives and methodologies can be organized as follows, in Figure 1.7.

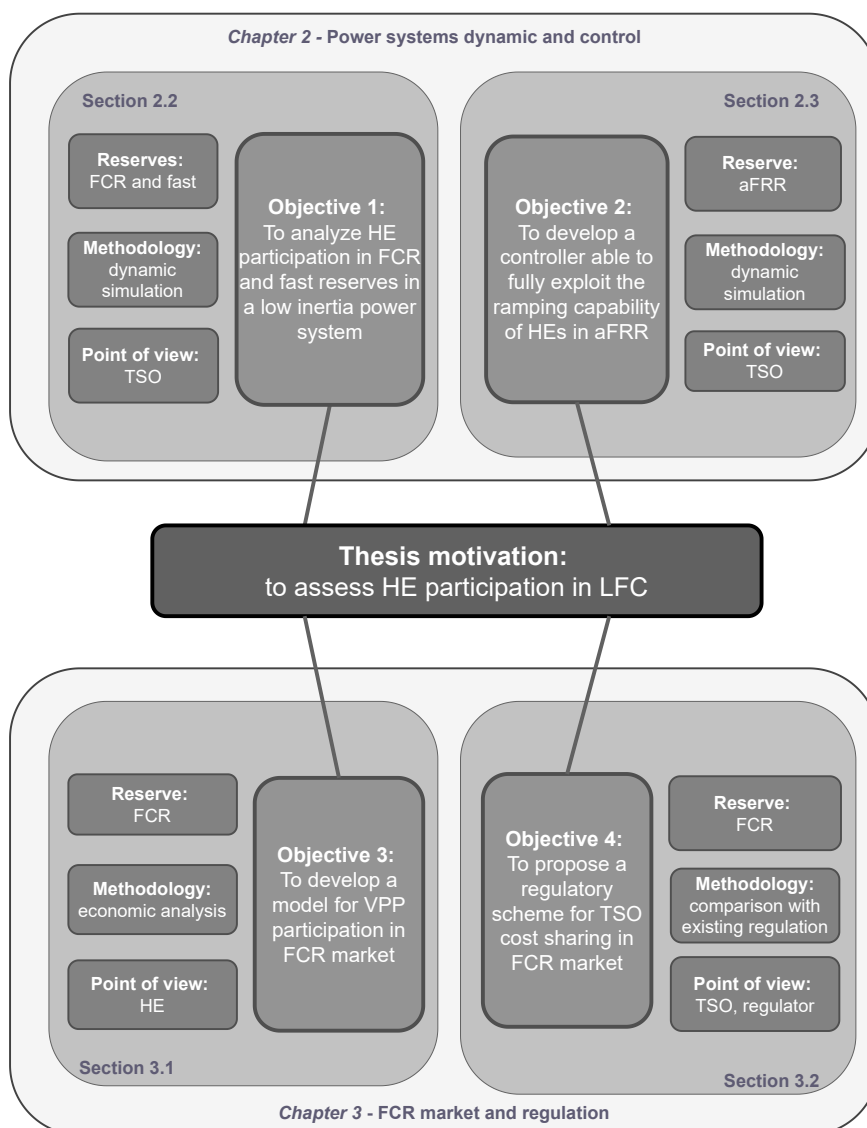


Figure 1.7: Thesis motivation and objectives.

The research questions are the following:

- 1 To what extent can HE participation in the FCR and fast reserves mitigate frequency and rate-of-change of frequency excursions in the future Iberian power system?
- 2 In the context of aFRR, can Model Predictive Control more adequately exploit the fast ramping capability of HEs than the conventional proportional-integral controller?
- 3 What revenues can a HE participating in FCR market obtain, considering opportunity costs?
- 4 Is the regulation of the existing FCR market (FCR Cooperation) adequate for ensuring the payments that TSOs make to Balancing Service Providers (such as HEs)?

## **1.3 Main thesis contributions**

### **1.3.1 Research and Innovation**

The key contributions of this thesis are the following:

- 1.1 A dynamic model that describes the contribution that HEs as primary and fast reserves providers was developed, which allows analyzing the frequency and rate of change of frequency excursion after a contingency;
- 1.2 The degree of mitigation of the excursions (mentioned in the previous point) thanks to the HE participation in the FCR and fast reserves is assessed;
- 2.1 Development of a novel control philosophy for the AGC problem during post-fault conditions;
- 2.2 Creation of a Model Predictive Controller that outperforms the conventional AGC-PI in case of post-fault;
- 3.1 The creation of a tool to assess the HEs' revenue for participating in a VPP that contracts HEs for FCR market;
- 3.2 The computation of Iberian TSO costs in the event that Portugal and Spain join the FCR Cooperation;

- 4.1 Identification and quantification of market distortions arising from the current market design of the FCR Cooperation;
- 4.2 The design of a new settlement mechanism without the distortions found on the previous point.

#### 1.3.2 Publications

The work developed in the course of this thesis resulted in six publications, namely three conference papers and three journal papers, as follows:

Conference papers:

1. F. J. Ribeiro, J. A. P. Lopes, F. S. Fernandes, F. J. Soares and A. G. Madureira, "The Role of Hydrogen Electrolysers in the Frequency Containment Reserve: A Case Study in the Iberian Peninsula up to 2040," 2022 International Conference on Smart Energy Systems and Technologies (SEST), Eindhoven, Netherlands, 2022, pp. 1-6, <https://doi.org/10.1109/SEST53650.2022.9898458>
2. F. J. Ribeiro, J. A. Peças Lopes, F. J. Soares and A. G. Madureira, "Assessing the Membership of Portugal and Spain in the FCR Cooperation: TSO Costs and VPP Revenues," 2023 International Conference on Smart Energy Systems and Technologies (SEST), Mugla, Turkiye, 2023, pp. 1-6, <https://doi.org/10.1109/SEST57387.2023.10257468>
3. F. J. Ribeiro, J. A. Peças Lopes, F. J. Soares and A. G. Madureira, "Hydrogen Electrolyser Participation in Automatic Generation Control using Model Predictive Control", 2024 International Conference on Smart Energy Systems and Technologies (SEST), Torino, Italy, 2024, pp.1-6, <https://doi.org/10.1109/SEST61601.2024.10694041>

Journal papers:

1. F. J. Ribeiro, J. A. P. Lopes, F. S. Fernandes, F. J. Soares and A. G. Madureira, "The role of hydrogen electrolysers in frequency related ancillary services: A case

study in the Iberian Peninsula up to 2040", Sustainable Energy, Grids and Networks, Volume 35, 2023, 101084, ISSN 2352-4677, <https://doi.org/10.1016/j.segan.2023.101084>.

2. F. J. Ribeiro, J. A. P. Lopes, F. J. Soares and A. G. Madureira, "VPP Participation in the FCR Cooperation Considering Opportunity Costs", Applied Science 2024, 14, 2985. <https://doi.org/10.3390/app14072985>
3. F. J. Ribeiro, J. A. P. Lopes, F. J. Soares, A. G. Madureira, "A novel TSO settlement scheme for the Frequency Containment Reserve Cooperation in Europe's integrated electricity market", Utilities Policy, 91, 101821. <https://doi.org/10.1016/j.jup.2024.101821>

## 1.4 Thesis structure

Besides the introduction, the thesis has three more chapters, all from the perspective of the integration of HEs in power systems' operation, as follows.

In Chapter 2 power systems' dynamics and control are addressed. The chapter is divided in three parts. Firstly, the fundamentals of power systems and dynamics relevant for the next sections are introduced. Secondly, dynamic simulations are used in the context of FCR and fast emerging reserves to investigate the possible role of HEs for mitigating the impacts of low inertia in power systems. Iberian Peninsula in 2040 is used as a case study. Thirdly, a new control scheme for the AGC problem using MPC is proposed. The control scheme is intended to be used in post-fault emergency, in the context of aFRR, to recover the interconnection flows faster than what is done conventionally, taking advantage of the fast ramping capability of HEs.

In Chapter 3 markets and regulation are addressed. The chapter is divided in two parts. Firstly, economic analysis of HEs as a part of a VPP participating in the FCR Cooperation market is performed. In this section it is also investigated what would be the costs for the Iberian TSOs to join the FCR Cooperation. Secondly, on the regulation

side, a new settlement scheme to distribute TSO costs for participation in this market is proposed.

Chapters 2 and 3 address the motivation and objectives presented in Figure 1.7. In fact, each of the sections of these chapters are self-contained and can be read independently. To facilitate the reading, and since each section addresses the HE participation in LFC using a different set of tools, it was decided that each section should include its own methodology. Whereas Section 1.1 provided a general background, in each section of chapters 2 and 3 a literature review is presented before the methodology.

Chapter 4 closes the thesis with concluding remarks.

## Chapter 2

# Dynamics and Control

*This chapter covers the dynamics and control of HE participation in LFC.*

*The first section provides the fundamentals of dynamics and control for the remainder of the chapter. It starts by defining the frequency stability problem. Then the equations of motion are reviewed. Afterwards, the power plant and interconnection models are introduced. The control schemes of primary and secondary reserves are reviewed. For all these steps, the representation in the Laplace domain is presented, using block diagrams that will be used in the remainder of the chapter.*

*The second section of this chapter investigates the contribution of HEs for the FCR, Synthetic Inertia (SI) and Fast Frequency Response (FFR) in future operation scenarios in the Iberian Peninsula (IP) considering low synchronous inertia. The proposed framework for analysis consists of a dynamic model developed in MATLAB/Simulink. Simulations show that an instantaneous tripping of Inverter-Based Resource (IBR) may lead to the occurrence of values of Rate of Change of Frequency (RoCoF) close to undesirable thresholds if the FCR is provided solely by conventional generators. The obtained results illustrate that HEs can outperform conventional generators on the provision of FCR. Furthermore, the FCR is unable to unlock the full potential of fast responding HEs. This suggests the advantage of providing additional Ancillary Services (AS) such as SI or FFR in critical periods. Simulations also show that the benefit of additional AS can be limited in specific conditions, especially depending on the evolution of HEs' ramping capabilities, but are still a relevant complement to other solutions designed to deal with low inertia in power systems*

such as synchronous condensers.

The third section of this chapter investigates Model Predictive Control (MPC) for the Automatic Generation Control (AGC) problem. Traditionally, proportional-integral (PI) control has ensured the successful application of AGC. Two design features of AGC-PI are the following: (1) it is merely a reactive system which does not take full advantage of existing knowledge about the system and (2) the control signal sent to all units is divided proportionally to their participation in the AGC. These two features ensure simplicity and, thus, reliability for the regular functioning of the power system. However, when the power system is recovering from a loss of generation, such features come with some limitations. This section proposes a model predictive control (MPC) to improve performance of AGC in such a scenario. The contrast with the traditional approach is as follows: instead of using merely two system measures which are also the control objectives (frequency and interconnection flow), the proposed controller relies on an internal model that takes advantage of further known variables of the power system, specifically the ramping capabilities of participating units. While still respecting the participation factors, it is shown that the proposed model allows to exhaust earlier the availability of faster units, such as some demand response, as the one to be provided by HEs, and thus reestablishes the frequency and interconnection flows in a faster way than typical PI-based AGC.

## 2.1 Introduction

### 2.1.1 Frequency stability

Power system stability has been defined as “the ability of an electric power system, for a given initial operating condition, to regain a state of operating equilibrium after being subjected to a physical disturbance, with most system variables bounded so that practically the entire system remains intact” [40].

Power system stability studies can be classified as indicated in Figure 2.1.

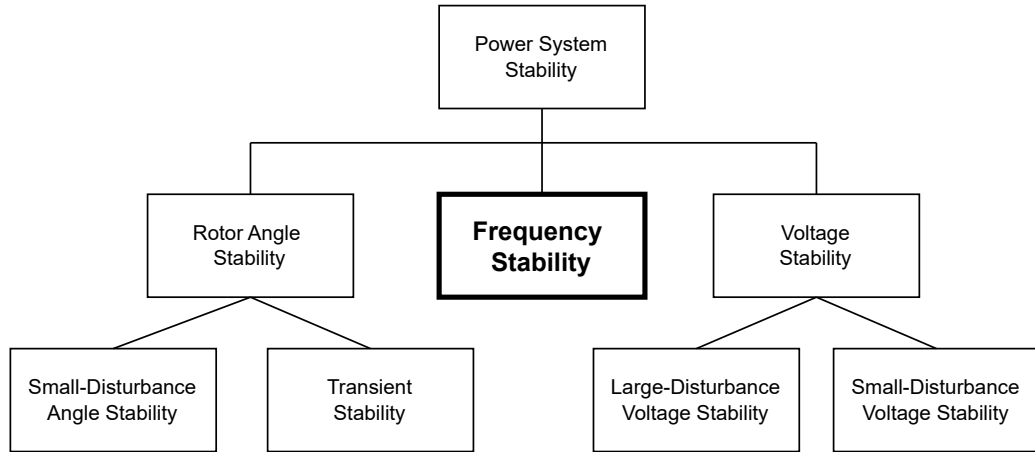


Figure 2.1: Power System Stability classification. Adapted from [40].

The present work addresses frequency stability, which in the same reference is defined as “the ability of a power system to maintain steady frequency following a severe system upset resulting in a significant imbalance between generation and load.” Furthermore, frequency stability “depends on the ability to maintain/restore equilibrium between system generation and load, with minimum unintentional loss of load.” [40]

### 2.1.2 Mechanics of motion

The mechanics of motion in power systems are now introduced, using the notation given in [32]. In a power system, the demanded electrical energy is independent from the mechanical energy being produced in the generators. When a turbine drives a synchronous generator, the turbine and generator can be represented as a large rotating mass with the

rotor subject to two opposing torques: a mechanical torque,  $T_m$  associated with the mechanical energy and an electromagnetic torque,  $T_e$ , associated with the electrical energy. An unbalance between the torques acting on the rotor causes an accelerating torque,  $T_a$ :

$$T_a = T_m - T_e \quad (2.1)$$

The combined inertia of the generator and prime mover is accelerated by the unbalance in the applied torques, thus the equation of motion:

$$J \frac{d\omega_m}{dt} = T_m - T_e \quad (2.2)$$

where

$J$  = combined moment of inertia of generator and turbine [ $kg.m^2$ ]

$\omega_m$  = angular velocity of the rotor [mech. rad/s]

$t$  = time [s]

Equation 2.2 can be normalized in terms of per unit inertia constant  $H$ , which is defined as the kinetic energy in watt-seconds at rated speed divided by the VA base,  $Sb$ . Using  $\omega_{0m}$  to denote rated angular velocity in mechanical radians per second, the inertia constant is

$$H = \frac{1}{2} \frac{J \omega_{0m}^2}{Sb} \quad (2.3)$$

The moment of inertia  $J$  in terms of  $H$  is:

$$J = \frac{2H}{\omega_{0m}^2} Sb \quad (2.4)$$

Substituting Equation (2.3) in Equation (2.4) gives:

$$\frac{2H}{\omega_{0m}^2} Sb \frac{d\omega_m}{dt} = T_m - T_e \quad (2.5)$$

Rearranging Equation (2.5) gives:

$$2H \frac{d}{dt} \left( \frac{\omega_m}{\omega_{0m}} \right) = \frac{T_m - T_e}{Sb/\omega_{0m}} \quad (2.6)$$

Taking into account that  $T_{base} = Sb/\omega_{0m}$ , the equation of motion in per unit<sup>1</sup> form is:

$$2H \frac{d\bar{\omega}_r}{dt} = \bar{T}_m - \bar{T}_e \quad (2.7)$$

In Equation (2.7):

$$\bar{\omega}_r = \frac{\omega_m}{\omega_{0m}} = \frac{\omega_r/p_f}{\omega_0/p_f} = \frac{\omega_r}{\omega_0} \quad (2.8)$$

where  $\omega_r$  is the angular velocity of the rotor in electrical rad/s,  $\omega_0$  is its rated value and  $p_f$  is the number of field poles pairs.

If  $\delta$  is the angular position of the rotor in electrical radians with respect to a nominal rotating reference and  $\delta_0$  is its value at  $t = 0$ ,

$$\delta = \omega_r t - \omega_0 t + \delta_0 \quad (2.9)$$

Taking the time derivative yields

$$\frac{d\delta}{dt} = \omega_r - \omega_0 = \Delta\omega_r \quad (2.10)$$

and

$$\frac{d^2\delta}{dt^2} = \frac{d\omega_r}{dt} = \omega_0 \frac{d\bar{\omega}_r}{dt} = \omega_0 \frac{d(\Delta\bar{\omega}_r)}{dt} \quad (2.11)$$

Substituting for  $d\bar{\omega}_r/dt$  in Equation (2.7), we get

$$\frac{2H}{\omega_0} \frac{d^2\delta}{dt^2} = \bar{T}_m - \bar{T}_e \quad (2.12)$$

It is desirable to include a component of damping torque separately, not accounted for in the calculation of  $T_e$ . This models the behavior reflecting the variation of active power

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<sup>1</sup>In the remainder of this section, per unit is denoted as a bar over a symbol.

load with frequency and damper windings of generators. Adding it to Equation (2.12) is accomplished by adding a term proportional to speed deviation as follows:

$$\frac{2H}{\omega_0} \frac{d^2\delta}{dt^2} = \bar{T}_m - \bar{T}_e - K_D \Delta\bar{\omega}_r \quad (2.13)$$

From Equation (2.10):

$$\Delta\bar{\omega}_r = \frac{\Delta\omega_r}{\omega_0} = \frac{1}{\omega_0} \frac{d\delta}{dt} \quad (2.14)$$

Equation 2.13 represents the equation of motion of a synchronous machine, commonly known as swing equation. It is common to use electric power (P) instead of torques since their values are equivalent in per unit [41].

### 2.1.3 Representation in the Laplace domain

The block representation of the swing equation in the Laplace domain is, thus:

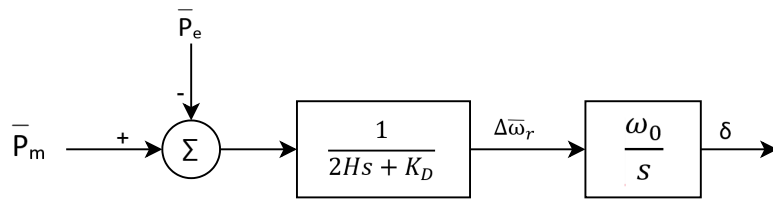


Figure 2.2: Block diagram representation of the swing equation considering damping.

The relation between electric frequency,  $f$ , and the machine rotational speed is the following:

$$f = \frac{\omega}{2\pi} \quad (2.15)$$

Considering a given mechanical power being supplied, when the system electrical load increases, the electric power demanded by the generators increases, thus, according to Equation (2.13) and Equation (2.14), the system electric frequency will decrease.

Up to this point, the dynamic behavior of a single generation unit has been considered. Considering that power systems consist of several machines, if one disregards the

intermachine oscillations, the whole control area can be represented by a single equivalent generation unit as in Figure 2.2. In that case, the inertia  $H$  will be equal to the summation of the inertia of every single machine being represented, and the damping constant  $K_D$  will be the sum of the damper windings of every generator and of the damping caused by the variation of active power loads.

Until now, only one control area has been considered. A power system is normally composed by multiple control areas. Generally, such areas are interconnected by multiple tie-lines that have to be modeled. Assuming that a control area electric equivalent is composed by an ideal voltage source and an equivalent reactance seen from the tie bus, the active power flow  $P_{1-2}$  on the tie line from one area to the other is given by Equation (2.16):

$$P_{1-2} = \frac{E_1 E_2}{X_T} \cdot \sin(\delta_1 - \delta_2) \quad (2.16)$$

$$X_T = X_{tie-line} + X_1 + X_2 \quad (2.17)$$

where:

$E_1$  is the ideal voltage source voltage of the electric equivalent of area 1 (pu.Volt),

$E_2$  is the ideal voltage source voltage of the electric equivalent of area 2 (pu.Volt),

$\delta_1$  is the ideal voltage source angular displacement of the electric equivalent of area 1 (radians),

$\delta_2$  is the ideal voltage source angular displacement of the electric equivalent of area 2 (radians),

$X_{tie-line}$  is the equivalent reactance of the tie lines that interconnect both areas (pu.ohm),

$X_1$  is the equivalent reactance of the electric equivalent of area 1 (pu.ohm),

$X_2$  is the equivalent reactance of the electric equivalent of area 2 (pu.ohm).

Equation (2.16) can be linearized considering an initial operating point where  $\delta_1 = \delta_{10}$  and  $\delta_2 = \delta_{20}$ , as per Equation (2.18)

$$\Delta P_{1-2} = \Delta \delta_{1-2} \cdot \left. \frac{\partial P_{1-2}}{\partial \delta_{1-2}} \right|_{\Delta \delta_{1-2} = (\Delta \delta_{1-2})_0} \quad (2.18)$$

where:

$$\left. \frac{\partial P_{1-2}}{\partial \Delta \delta_{1-2}} \right|_{\Delta \delta_{1-2}} = T = \frac{E_1 E_2}{X_T} \cdot \cos(\delta_1 - \delta_2) \quad (2.19)$$

where:

$T$  is the synchronizing torque coefficient (pu.GW/rad),

$$\Delta \delta_{1-2} = \Delta \delta_1 - \Delta \delta_2$$

Synchronous generators can have their mechanical power delivered by hydraulic, gas or steam turbines. Such mechanical power is controlled by a speed governor that depends on the system frequency and an active power setpoint.

For stability studies purposes, the classical thermal units can be modeled according to the representation proposed in [42], as shown in Figure 2.3:

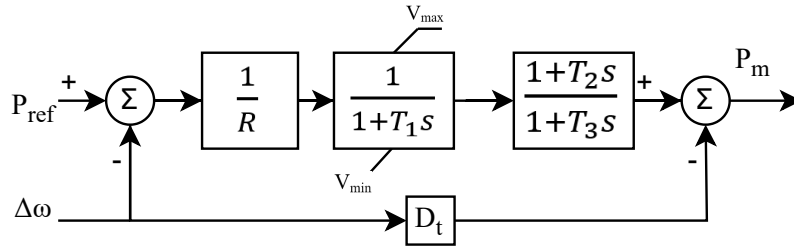


Figure 2.3: TGOV1 block diagram.

where:

$R$  is the turbine-governor droop (pu.Hz/pu.GW),

$T1$  is the governor time constant (s),

$T3$  is the reheater constant (s),

$T2/T3$  is the fraction of the total turbine power generated by the high pressure section,

$Dt$  is the turbine damping factor (for steam, nuclear and gas turbines can be considered zero),

$V_{max}$  is the maximum limit of the speed governor control loop (pu.GW),

$V_{min}$  is the minimum limit of the speed governor control loop (pu.GW).

Hydraulic generation units with reservoir can be modeled according to Figure 2.4 [32]:

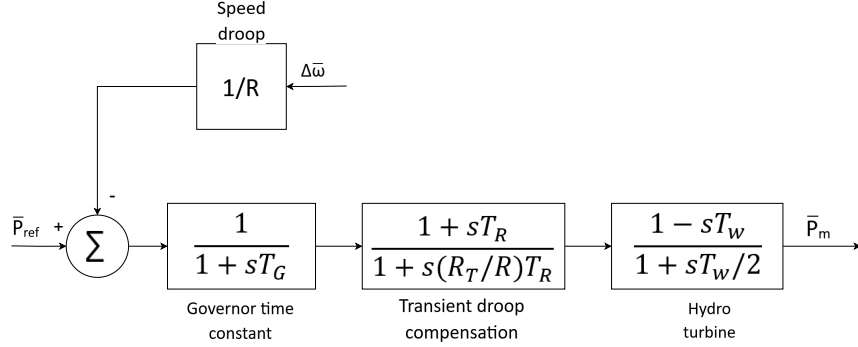


Figure 2.4: Hydraulic governor and turbine block diagram.

where:

$R_T$  is the transient droop (pu.Hz/pu.GW)

$T_G$  is the governor time constant (s)

$T_R$  is the reset time (s)

$T_w$  is the water starting time (s).

The main difference between Figure 2.3 and Figure 2.4 is the additional block of the transient droop. The requirement for a transient droop is because of the peculiar response of hydro turbines, due to water inertia: a change in gate position produces an initial turbine power change which is opposite to that sought. The transient droop is required for stable control performance, with a long resetting time.

Having introduced all the elements that are present in a two area interconnection power system, its diagram in block representation is presented in Figure 2.5.

#### 2.1.4 Frequency Containment Reserve

The FCR is of interest for Section 2.2. As stated in Section 1.1.2, units participating in the FCR react to the frequency such that a decrease in the frequency triggers an increase in active power output and, conversely, an increase in frequency triggers a decrease in active power output of the unit. In fact, the models of the power plant used (Figures 2.3 and 2.4) include a proportional term  $-1/R$  labelled as “speed droop” that will make the turbine have the desirable behavior mimicking participation in the FCR.

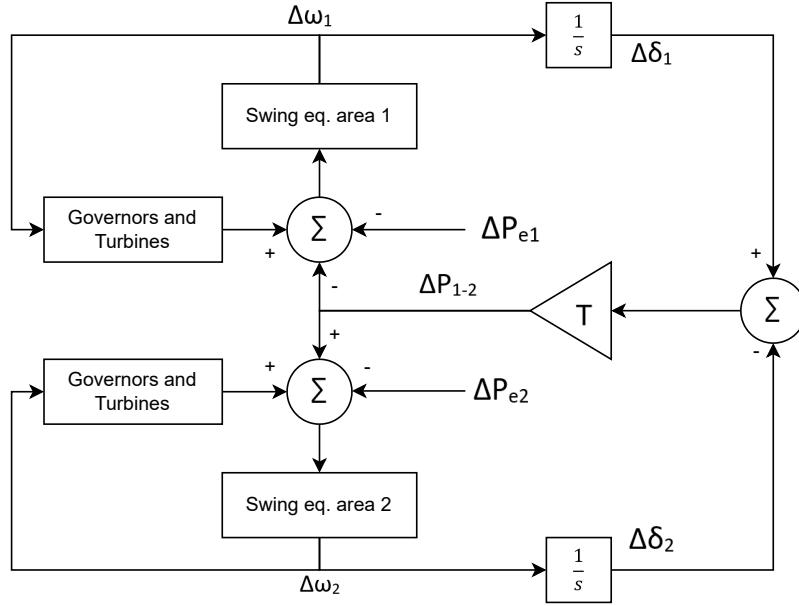


Figure 2.5: Block diagram representation of a two-area power system.

With primary speed control action, a change in system load will result in a steady-state frequency deviation, depending on the governor droop characteristic and frequency sensitivity of the load. All generating units on speed governing will contribute to the overall change in generation, irrespective of the location of the load change.

### 2.1.5 Automatic Frequency Restoration Reserve

The restoration of system frequency to the nominal value requires supplementary control action to the FCR, such that load reference setpoint is adjusted [32]. Such is the task of the Automatic Generation Control (AGC) also known as the automatic Frequency Restoration Reserve (aFRR). In the automatic Frequency Restoration Reserve schemes, the control actions are usually centralized in a dispatch centre [32]. As introduced in Section 1.1.2, the restoration of the frequency to its nominal value (in Europe, 50 Hz) and reestablishment of interconnection flows to pre-fault values is done via aFRR. For ENTSO-E, the configuration of such controller is proportional-integral [43, 41], as in Figure 2.6, where:

$f$  is the system frequency,

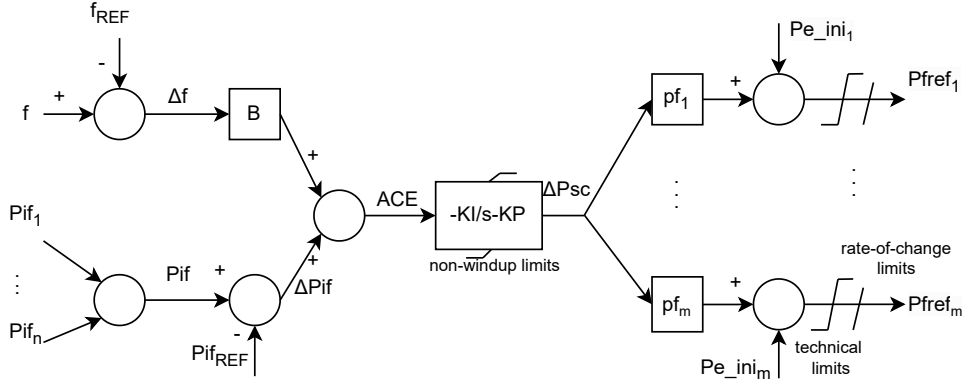


Figure 2.6: Block diagram representation of the AGC controller.

$f_{REF}$  is the frequency nominal value,

$\Delta f$  is the frequency deviation,

$Pif_k$  is the active power flow exported by control area  $i$  through tie-line  $k$ ,

$Pif_{REF}$  is the programmed value of power interchange of control area  $i$  with all neighbouring areas (export value),

$Pe\_ini_k$  is the current dispatch of machine  $k$ ,

$ACE$  is the area control error,

$B$  is the frequency bias (k-factor),

$KI$  is the integral gain,

$KP$  is the proportional gain,

$\Delta Psc$  is the control signal to be distributed,

$pf_k$  is the participation factor of machine  $k$ ,

$Pref_m$  is the new active power set-point value for machine  $m$ .

The control signal  $\Delta Psc$  is distributed to the units participating in secondary control, given their participation factor, which indicates the amount of their participation according to market results. The sum of all participation factors equals 1 [44].

Early publications on the performance of frequency regulation include [45] from 1953, which discussed the dynamic performance of automatic tie-line power and frequency control. Then, in 1970, automatic tie-line power and frequency control was considered as the

main function of AGC by an IEEE working group in [46]. Since then, the literature on AGC is voluminous. It has been suggested [34] that most of the applied LFC methodologies provide model-based controllers that are difficult to use for large-scale power systems with nonlinearities and uncertain parameters. In [44] an extensive literature review on AGC is provided; the authors address the literature of fuzzy logic controller, neuro-fuzzy and neural networks, genetic algorithms, multiagent and combined techniques. A recent critical literature review on AGC methods was made in [47]. Among the groups of controllers reviewed in [47], according to the authors, the disadvantages of each group are now briefly outlined:

- Proportional differential integral (PID) controllers have difficult parameter adjustment, are not applicable to all systems due to integral saturation problems and are sensitive to parameter changes;
- Fuzzy control strategies are difficult to handle in terms of reference adjustment and it is difficult to guarantee their performance and control. Also, the rules are difficult to design;
- Artificial neural networks have large data requirements, the hyperparameters are difficult to select, the results are subject to poor interpretability, it is easy to overfit the models and demand high computational resources;
- Adaptive control strategies have problems regarding parametric convergence and possess high real-time requirements;
- Model Predictive Control strategies have complex computation and high hardware requirements, as well as difficulties in meeting the real-time requirements; parameter estimation and system dynamic model have high design requirements and parameter adjustment requires empirical skills;
- Optimal control strategies have high requirements for system modeling and high computation complexity;

- Deep reinforcement learning control strategies possess high training costs, poor uncertainty and generalization handling, furthermore they are difficult to interpret.

The aFRR is addressed in Section 2.3.

## 2.2 Dynamics of HE participation in primary and fast reserves

Following the European Green Deal, in 2020 the European Commission (EC) published its Hydrogen Strategy for a climate-neutral Europe [29] where hydrogen is presented as “a vector for renewable energy storage” that “will play a role, alongside renewable electrification”. It is well known that renewable energy integration presents challenges to the power system planning and operation. ENTSO-E identifies two effects of decommissioning synchronous machines and their replacement by inverter connected generation, namely, decrease of inertia and short-circuit power reduction [48]; the former leads to faster transients following a disturbance and ultimately, both effects threaten the stability of the system and capability of protection equipment operation to respond properly. Two metrics are used by protection equipment: the majority of Under-Frequency Load Shedding (UFLS) relays activates by reaching frequency thresholds (e.g. 49.5 Hz), but some are based on Rate of Change of Frequency (RoCoF) measurement, which allows shedding more load preventively [48]. For instance, the Loss of Mains (LOM) protection used in the UK relies on RoCoF measurements as threshold to protect against the risk of a generator continuing to run as part of a non-viable isolated system for safety reasons [49]. Naturally, if the contingency that triggers high RoCoF is a loss of generation and LOM protection disconnects further generation, there is a systemic risk of a cascade of events. The first Transmission System Operators (TSO) to identify RoCoF as a potential problem were EirGrid and System Operator of Northern Ireland in 2010, after which the RoCoF limit for protections was raised from 0.5 Hz/s to 1 Hz/s limit measured over a 500 ms window [50]. Islanded systems are the first to implement protections based on RoCoF, but continental systems will likely use them in the future as synchronous generators are decommissioned and synchronous inertia decreased. On the other hand, short duration undervoltage disturbances have been identified in countries with high penetration of distributed photovoltaics (PV), particularly in Australia, where the system operator AEMO states that a severe but credible fault could cause disconnection of up to half of the distributed PV in South Australia [51].

Since the goal of the Hydrogen Strategy [29] is the production of hydrogen using renewable energy, the document distinguishes two forms of hydrogen: firstly, “renewable hydrogen”, for which dedicated renewable energy generation will need to be deployed alongside the HEs, and secondly “electricity-based hydrogen” that will be obtained in HEs connected to the grid and for which “demand for electricity should be enabled in particular at periods of abundant supply of renewable electricity in the grid”. The focus of this work is “electricity-based hydrogen”. The key idea about electricity-based hydrogen is that its production will be maximized in periods of higher renewable energy penetration. For the power grid system operators, maximum renewable energy penetration implies system fragility because inertia is reduced as a result of synchronous machines being displaced by Inverter-Based Resources (IBRs); on the other hand, HEs are controllable loads and the more they are present in the grid, the larger the potential of their response.

Critical inertia has been defined [52] as the minimum level of system inertia necessary to ensure that frequency responsive reserves have sufficient time to be deployed and prevent the operation of the first stage of UFLS after the largest credible contingency. This definition only concerns the frequency, but, as stated above, high RoCoF can also trigger other protections (LOM). It is interesting, therefore, to broaden the definition of critical inertia as to include both nadir and RoCoF. Consequently, this section asks the research question: can the critical inertia be reduced if the frequency-related reserves are provided by HEs in the case of the IP? Of particular interest is the assessment of the performance of HEs connected to the IP grid by 2040 in frequency control provision, and in particular if frequency and RoCoF unacceptable values can be mitigated due to HEs participation on the FCR and other fast reserves, such as a Nordic style fast frequency response [53] and synthetic inertia provision [54]. The main innovation of this work is the analysis of the collective response of a large HE fleet (8 GW, as per Section 2.2.1.6), in contrast to other approaches in the literature where HEs with far less installed power are analyzed (e.g. 1 MW HE in [55] and 250 MW in [56]). The HEs performance is assessed by varying HEs’ ramping capabilities described in the literature [55], ancillary service volume and influence of measurement acquisition delays.

The remainder of the section is structured as follows: Section 2.2.1 addresses the

simulation platform, HE dynamic model and parameters, Section 2.2.2 presents the results, Section 2.2.3 discusses the results and Section 2.2.4 draws conclusions.

### 2.2.1 Methodology

A simulation platform including HEs was developed in MATLAB / Simulink to model the electromechanical dynamics of the power system following a contingency. The model exploits the work developed in [57] and was calibrated using data from a real contingency as detailed in Section 2.2.1.4. Simulation allows for the computation of system frequency during the first 30s after the incident, which is the time-frame that concerns FCR requirements. From the values of the frequency it becomes possible to extract the two variables of interest in this study: the frequency nadir (*i.e.* the minimum frequency value) and RoCoF (*i.e.* maximum derivative of the frequency over a moving average of 500ms).<sup>2</sup>

The metrics presented in Table 2.1 are assessed in each simulation. RoCoF violation threshold is considered the same as in Ireland since 2013 [50], since this is the first power system where this issue has received critical analysis.

Table 2.1: Metrics and violation thresholds.

| Metrics                                  | Value    | Source |
|------------------------------------------|----------|--------|
| Dynamic frequency deviation / nadir [Hz] | <49.2 Hz | [43]   |
| Quasi-steady-state frequency deviation   | <49.8 Hz | [43]   |
| Rate of change of frequency (RoCoF)      | >1 Hz/s  | [50]   |

The remainder of the section details the simulation platform: Section 2.2.1.1 explores the power system dynamics, Section 2.2.1.2 the contingency under study, Section 2.2.1.3 the power plant models, Section 2.2.1.4 the calibration process, Section 2.2.1.5 the HE model, Section 2.2.1.6 the evolution of system parameters up to 2040 and finally Section 2.2.1.7 the limitations of the proposed approach.

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<sup>2</sup>Note that only negative variations of frequency are of interest because LOM should detect the islanding after a loss of generation. However, on the remainder of the section, the negative RoCoF values are presented as positive values for facilitating reading.

## 2.2.1.1 Power system dynamics

The simulation platform developed to assess the dynamic response of the IP and Continental Europe (CE) systems is presented in Figure 2.7.<sup>3</sup>

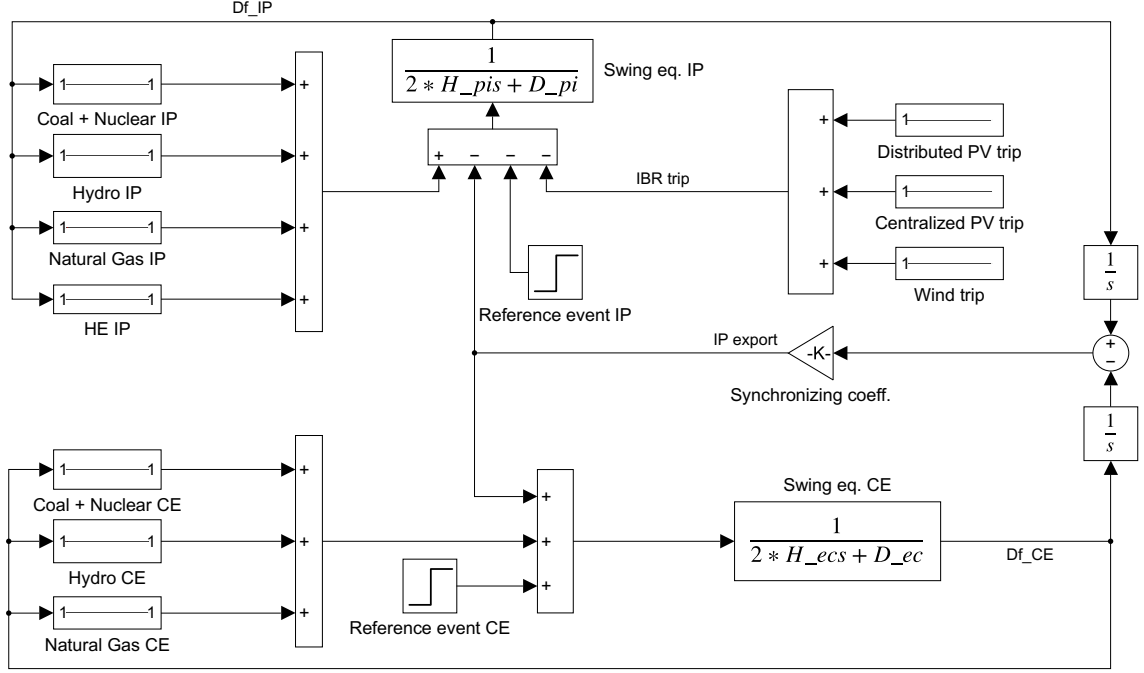


Figure 2.7: MATLAB/Simulink simulation platform

The proposed grid model consists of two equivalent nodes, corresponding to two control areas, connected via a transmission line, using the formulation of [32] and introduced in Section 2.1. In this section, the two nodes represent the IP and CE.

The frequency deviation from the nominal value (*i.e.* 50 Hz) in each area is modeled using the swing equation previously introduced, in the Laplace domain, as in Equation (2.20):

$$\Delta f = \frac{1}{(2 * H_{area} * s + D_{area})} \times (\Delta P_m - \Delta P_L) + \Delta P_{1-2} \quad (2.20)$$

where:

$\Delta f$  = frequency deviation from the nominal value;

$\Delta P_m$  = variation of mechanical power output of the primary control loops of generators participating in the FCR [pu.GW], as described in Section 2.2.1.3;

<sup>3</sup>System per unit (pu) base is 10 GVA.

$\Delta P_L$  = variation of load, due the contingency [pu.GW], as described in Section 2.2.1.2;

$H$  = system inertia in the control area [pu s];

$D$  = load self-regulating characteristic of control area [pu%];

$\Delta P_{1-2}$  import from the other control area, as explained in Equation (2.21) [pu.GW].

Considering only one area (*i.e.* disregarding  $\Delta P_{1-2}$  for now) and assuming that the model begins in equilibrium (*i.e.*  $\Delta P_G = \Delta P_L$ ), the system dynamics sequence can be summarized as follows: (i) the contingency implies that momentarily  $\Delta P_L > \Delta P_G$  and cause a negative  $\Delta f$ , (ii) this triggers an increase of  $\Delta P_G$ , (iii) until a new equilibrium is met with a frequency below the 50Hz.

Considering now two control areas, the tie-line active power flow between the two areas is modeled according to the Laplace transform of Equation (2.21) [58]:

$$\Delta P_{1-2} = \Delta \delta_{1-2} \times T \times k \quad (2.21)$$

where:

$\Delta P_{1-2}$  is the tie-line active power flow variation as a consequence of a frequency variation [pu.GW];

$T$  = the well known synchronization coefficient [pu.GW/rad] [32];

$k = 2\pi f$  (where  $f = 50$  Hz);

$\delta_1$  = the ideal voltage source angle of the electric equivalent of area 1 [rad];

$\delta_2$  = the ideal voltage source angle of the electric equivalent of area 2 [rad];

$\Delta \delta_{1-2} = \Delta \delta_1 - \Delta \delta_2$  [rad]

Going back to Equation (2.20): in practice, an increase in  $\Delta P_L$  in one of the areas results in  $\Delta f < 0$  in both areas and a tie line flow of  $\Delta P_{1-2} \neq 0$ . Restoration of  $\Delta P_{1-2} = 0$  (*i.e.* to the tie-line flows before the contingency) is the goal of the Frequency Restoration Reserves and therefore lies outside the scope of this section.

### 2.2.1.2 Inverter-based resources trip

The contingency of interest is a loss of generation, namely the trip of a large volume of IBR. As stated in Section 2.2.1.1 a contingency enters Equation (2.20) as  $\Delta P_L$ .

The IBR trip considered in this work is defined as an instantaneous loss of IBR production (e.g. PV, wind) in the IP, following a grid disturbance that instantly provokes the disconnection of IBR production, part of which is quickly recovered. Figure 2.8 shows the loss of generation under consideration. Appendix A details further considerations on the IBR trip.

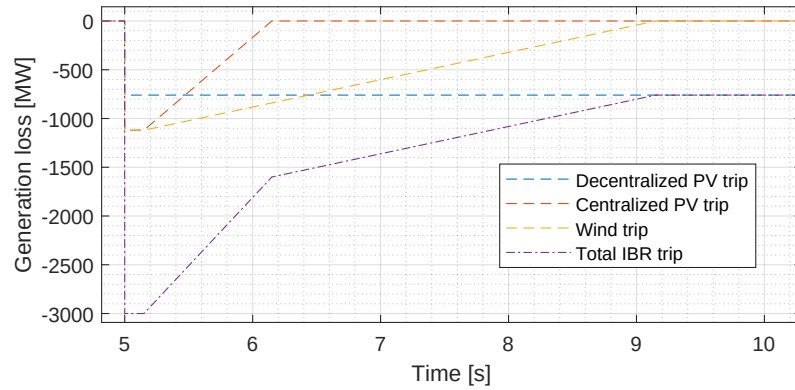


Figure 2.8: IBR trip components

### 2.2.1.3 Power plant models

The power plants included in the model are the conventional power plants participating in the FCR. Given the focus of the study (system frequency stability) the dynamic behavior of each generator is represented by their primary control loop, disregarding voltage control loops and transmission grid effects. The following types of conventional power plants are considered: coal fired, nuclear, natural gas and hydro. Each unit is the aggregation of all the units of the same technology that exist within each control area. As such, generic turbine-governor models were used, namely TGOV1 model previously introduced for nuclear, coal and natural gas units [42] and classic hydroelectric power plant model including a transient droop [32], as per Section 2.1.

Along with the generic models, typical values for parameters from [42] and [32] were used. The remaining model parameters needed to be calibrated, as addressed in Section 2.2.1.4.

#### 2.2.1.4 Model calibration

The model calibration is presented in detail in [57]. A 1 GW generation loss occurred in 2011, in Spain, more concretely the outage of Almaraz II Nuclear unit, from which frequency measurements in IP and CE were obtained [59]. Simulating this loss allowed to calibrate the proposed model. The objective was to estimate a combination of the model parameters that make the model produce the frequency measured in IP and CE.

A variation of the classical particle swarm algorithm was used for tuning the model's parameters [60]. The obtained estimated parameters using this approach are detailed in Appendix B.

Figure 2.9 shows the frequency in IP and CE obtained by the model when the 1 GW loss in the IP is simulated, together with the measured frequency after the event occurred in 2011.

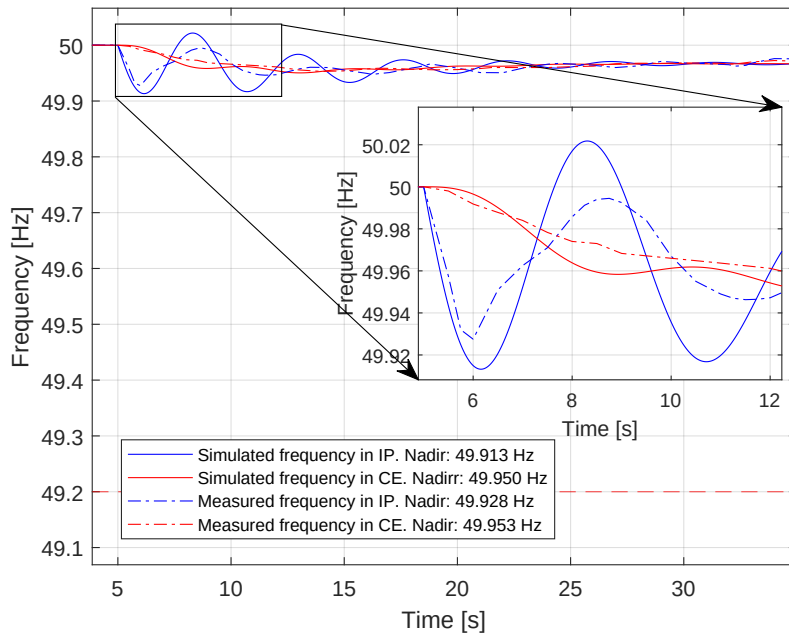


Figure 2.9: Model calibration

It can be concluded that the model output matches quite closely the measured frequencies in IP and CE. There is a certain deviation in the simulated frequency nadir in IP (-15 mHz than observed); it can simply be stated that the model is conservative *i.e.* it magnifies the frequency oscillation in IP and produces a frequency nadir which is slightly worse than observed. Note, however, that the dynamic frequency deviation limit (49.2 Hz as per Table 2.1) is around 730 mHz below the simulated values; the magnitude of 15 mHz is small in comparison.

### 2.2.1.5 HEs dynamic model

In Figure 2.7 the HEs are represented along with conventional power plants regarding active power provision. However, it should be noted that a HE is a load, which consumes power for performing electrolysis. Seen from the grid, the active power injection from a conventional generator (*i.e.* upward reserve provision) is equivalent to a load decrease in a HE.

In this study, it is assumed that HEs are working at nominal power when the contingency happens, so that the HEs are only able to provide upward reserve. Since in this section only a loss of generation is simulated, there is only need for upward reserve provision from HEs, so for the sake of simplicity the downward reserve is disregarded. The downward reserve (same volume as upward reserve) could easily be provided by solar and/or wind farms in a market scheme such as FCR Cooperation [61]. This kind of market allows the aggregation of distinct resources (which would conceptually behave like a Virtual Power Plant (VPP) [62]) so that the resulting FCR market bids of VPP (HEs + solar + wind) are symmetric and therefore allow upward and downward reserve. This is the followed approach in Section 3.1.1.

The HE model represents an aggregation at two levels: firstly because of its modular nature, large HEs will consist of many units in parallel [55], and secondly because the whole IP network is modelled in this work as a single node, so all HE facilities in this region are modelled as a single equivalent unit (in the same logic as done for power plants in Section 2.2.1.3).

Tuinema et al. [55] have performed a series of field measurements showing that HEs follow an almost linear response to given set point step changes. In practice, the HE active power response is only limited by a ramp rate (or ramping capability).

This makes for a simple representation of the HEs. According to [55], polymer electrolyte membrane (PEM) HEs ramping rates can be considered to range between 0.5 pu/s and 2.5 pu/s. A 0.5 pu/s rate means that the HE is able to decrease its output linearly 0.5 pu (*i.e.* from 100% to 50% of the nominal active power) in 1 second; an HE with 2.5 pu/s rate decreases the same amount of active power 5 times faster than the 0.5 pu/s rate.

Fig. 2.10 presents the HEs' model adopted in this work.

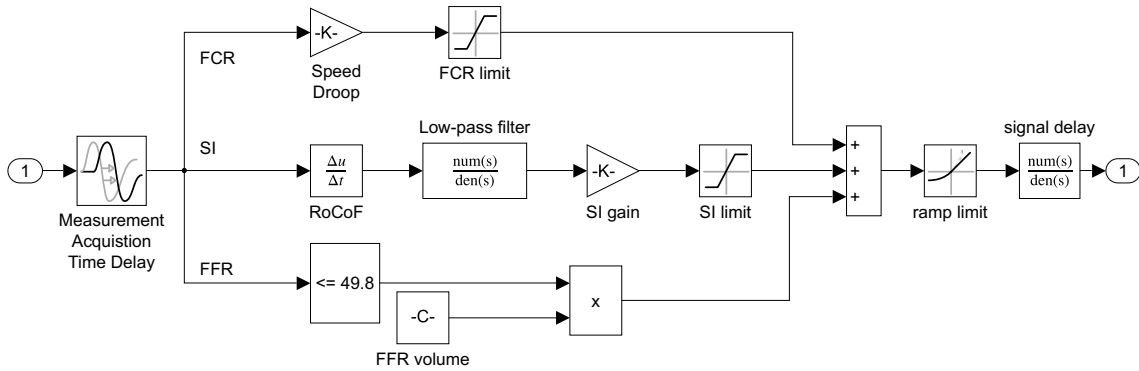


Figure 2.10: Dynamic model of HEs

In the present work, three control loops exist for HEs, each corresponding to an ancillary service: frequency containment reserve (FCR), synthetic inertia (SI) and fast frequency response (FFR).

Generically, the FCR is intended for activation of smaller frequency deviations, SI is intended for high RoCoF situations and FFR is intended when critically low frequency is achieved. In this study three combinations are studied: only FCR activation, FCR + SI and FCR + FFR. Note that the added responses of the control loops of the HEs are limited by the aforementioned ramping capability. Shared by all controllers is also the input: the system frequency deviation (*i.e.* from the nominal value). The value of the frequency needs to be measured in the electrical node, typically measuring the voltage signal and the zero-crossings [63]. This measurement process takes time, which is represented by a measurement acquisition time delay. This acquisition delay is parameterized as per

Section 2.2.1.6. According to [63] there is a further "signal delay", to get the activation signal to a number of individual devices (*i.e.* HE stacks), which is in the order of 1 to 10 ms. The "signal delay" is modelled as a transfer function with a pole in the Laplace domain ( $\frac{1}{0.01 \times s + 1}$ ).

Note that the power output of the HE is limited within each control loop: the maximum value is the respective ancillary service volume, the minimum value is zero, to guarantee that the HEs do not provide downward reserve as described above.

Each controller is detailed in the remainder of the subsection.

**FCR control loop** The aim of the FCR is to maintain the balance between generation and demand within the synchronous area, such that, after a disturbance, the system frequency is stabilized within  $\pm 200$  mHz from the nominal frequency, 50Hz [43]. Every control area within the synchronous area has its allocated FCR volume such that the sum equals 3 GW; in IP the FCR volume is 430 MW [64].

The set point that is dictated by the FCR controller follows a classical speed droop approach, *i.e.* responds proportionally ( $-1/R$ ) to the frequency deviation as introduced in Section 2.1. The negative sign in  $-1/R$  means an increase of active power injected in the grid (*i.e.* lower power consumption from the HE) if frequency is below the nominal value, as the case under study.  $R$  is computed such that full activation of FCR service volume contracted to HEs is achieved when frequency is below 49.8 Hz [65] according to Equation (2.22):

$$R = \frac{\Delta f_{max,pu}}{FCR_{vol,pu}} \quad (2.22)$$

where:

$R$  = speed droop;

$\Delta f_{max,pu}$  = frequency deviation at which maximum FCR activation is required:  $f_{max} = 49.8$  Hz;  $\Delta f_{max} = -0.2$  Hz, therefore in pu  $\Delta f_{max,pu} = -0.2/50$ ;

$FCR_{vol,pu}$  = FCR volume in IP and in pu: 430 MW / 10 GW;

A saturation is imposed on the FCR contracted volume, to ensure that in the context of FCR, no further active power is injected in the grid by the HEs if the frequency falls below 49.8Hz.

**SI control loop** Typically, synthetic inertia controllers are associated with the so-called Virtual Synchronous Generators, a technology that can mimic synchronous machines behavior [66]. The controller responds proportionally to the derivative of the frequency measurement. The output of the HE SI control loop is given in the Laplace domain by Equation (2.23):

$$\Delta P = F(s)s \times \frac{1}{LPF \times s + 1} \times K \quad (2.23)$$

where:

$\Delta P$  = variation in active power output by HEs;

$F(s)$  = frequency;

$LPF$  = low-pass filter constant;

$K$  = synthetic inertia constant.

Parameters  $LPF$  and  $K$  have been tuned by trial and error and to ensure smooth control (0.16 and 5, respectively). Note that Virtual Synchronous Generators properties are programmable in the inverter firmware [66] and can therefore be adapted to the power system's situation. The reason for using the low-pass filter is the same as why RoCoF should be measured over a 500 ms window instead of 100 ms when dealing with protections that detect high RoCoF: to better capture the dynamics of the overall grid frequency and avoid response to localised electro-magnetic transients [67]. Not using such filter would allow for a faster SI provision but would also induce the HEs to respond rapidly in situations where it might be unintended, such as local faults.

**FFR control loop** The fast frequency response is modelled as the existing mechanism in the Nordic synchronous area, which promotes the injection of a given active energy

volume when a frequency threshold (49.5 to 49.7 Hz) is achieved [53]. In this section, the threshold 49.8 Hz was chosen for the reasons discussed in Section 2.2.3.

After the activation of this mechanism, there is the need of a subsequent recovery time (e.g. for storage) [53]. This issue is not covered here, simply because HEs are loads and when provide FFR, instead of injecting active power in the grid, they are lowering their consumption and therefore no recovery time is necessary.

The control mechanism is straightforward: when the frequency is below 49.8 Hz, the HEs quickly reduce their load by the amount of the contracted FFR volume and are only limited by their ramping capability.

Note that the design of this controller is intrinsically simpler than SI controller, as there is no need to tune parameters such as low-pass filter and gain.

### 2.2.1.6 Model parameters up to 2040

The power system is modelled up to the year 2040. As a result of inertia decrease due to conventional power plant decommissioning, concerns with system frequency stability will increase as time passes. According to current projections all coal power plants will be decommissioned in the IP until 2030, followed by decommissioning of the last nuclear power plants by 2035 [68]. On the other hand, regarding HEs, in the 2020's this industry is still in its infancy and the 2030's are expected to represent a much faster growth. Given these two tendencies, the year chosen for the simulations in this section was therefore 2040.

The value of system inertia in the IP in 2040,  $H_{IP,2040}$ , is computed using Equations (2.24-2.26). It is known that a part of the inertia comes from demand,  $H_{demand,IP,2040}$ . A contributor for inertia from the demand side are motors, and decoupling them from the power system via a power electronic interface removes their contribution to system inertia. Other factor that increases inertia is the load increase throughout the years, which is here disregarded for achieving a conservative value of demand side inertia. Regarding  $H_{generation,IP,2040}$ , and taking into account that system inertia will be at its minimum in the summer peak due to low contribution from hydro plants, it is considered that the only online power plants contributing to inertia are run-of-river hydro plants and biomass. Biomass plants will correspond to 1.4 GW in IP [69] and are supposed to operate at

nominal power with an inertia constant of 1s [70]). Hydro power plants need to be taken into account: hydro run-of-river power plants (4 GW in IP [69] and assuming 3 s of inertia constant [70]); it is assumed that only one third of the turbines are operating, considering dry summer conditions.

$$H_{IP,2040} = H_{generation,IP,2040} + H_{demand,IP,2040} \quad (2.24)$$

$$H_{demand,IP,2040} = H_{IP,2011} \times Pc_{demand} \times \frac{(1 - Pc\_pec_{2040})}{(1 - Pc\_pec_{2011})} \quad (2.25)$$

$$H_{generation,IP,2040} = \frac{\frac{S_{biomass} \times H_{biomass} + S_{hydro} \times H_{hydro}}{pf}}{S_b} \quad (2.26)$$

where:

$H_{IP,2011} = 21.21$  pu.s is the inertia in the IP in 2011 as per Section 2.2.1.4;

$Pc_{demand,2011} = 20\%$ , the fraction of the inertia that comes from demand in 2011 [71];

$Pc\_pec_{2011} = 10\%$ , the estimated percentage of motors interfaced with electronic converters in 2011 [71];

$Pc\_pec_{2040} = 50\%$ , the forecasted percentage of motors interfaced with electronic converters in 2040 [71];

$S_{biomass} = 1.4$ , the apparent power of biomass power plants [GVA];

$S_{hydro} = 1.3$ , the apparent power of hydro plants [GVA];

$H_{biomass} = 1$ , inertia constant of biomass plants [s];

$H_{hydro} = 3$ , inertia constant of biomass plants [s];

$pf = 0.9$  power factor of power plants [70];

$S_b = 10$ , the per-unit system base [GVA].

This yields  $H_{IP,2040} = 2.95$  pu.s.

The decommissioning of power plants has an impact in the power plants participating in the FCR. As mentioned, in the IP it is considered that after 2035 all the coal and nuclear power plants have been decommissioned, so their participation is replaced by the existing natural gas and hydro power units, whereas in CE only coal is decommissioned.

An important topic concerning the IP and CE power systems is their interconnection. As noted in Section 2.2.1.4 the model was calibrated with 2011 data; the interconnection between IP and CE was 1.4 GW back then. In 2015 a new interconnection of the same capacity was finished [72]. The interconnection capacity is expected to increase to 5 GW in 2027 [73]. For the remaining period up to 2040 it was assumed that additional 1.5 GW will be built as per [74] projections, totaling the interconnection in 6.5 GW, or 4.6 times more interconnection than in 2011. In the modeling this implies increasing the parameter  $T$  proportionally.

Regarding HEs, the value of installed power in 2040 in IP is considered to be 12 GW. This value is found using the conservative scenario found in [75], which for 2040 forecasts 240 GW of HEs in the European Union; in this section it is considered that 50% of these HEs to be grid-connected and 10% of them installed in the IP. Moreover, taking into account that PEM will likely be the dominant technology in the 2030's [76], it is assumed that the installed capacity of HEs will be divided into 8 GW of PEM and 4 GW of other types of technologies. In this study only PEM HEs are considered. Both alkaline and anion exchange membrane electrolyzers were disregarded: anion exchange is still an immature technology and unlikely economical by 2030, whereas the ramping capability of alkaline HEs varies between 0.002 pu/s and 0.2 pu/s which is a very wide range and, at best, vastly inferior to PEM capabilities [77].

For PEM HEs, ramps are of 2.5 pu/s (*fast HEs*) and 0.5 pu/s (*slow HEs*) as per [55]. The minimum load that HEs need to operate (3-10% [78]) is inherently respected because the ancillary services addressed in this section activate always less power than these minima: considering that HEs will be operating at nominal power, even if 10 times the FCR volume (4.3 GW) is activated this volume is still about 50% of HEs' nominal power.

According to [63] the minimum time for measuring the frequency is two cycles (40 ms), and further activation time delay should be considered for the converter activation ( $\leq 10$  ms). These delays have both been included in the measurement acquisition time delay block, and two scenarios for the delay are considered: a minimum theoretical (40 ms) and

a realistic (3 cycles + 10 ms = 70 ms).

Table 2.2 shows the parameters related to HEs to be used as variables in the simulations presented in Section 2.2.2.3 and detailed in Table C.1.

| Parameter                     | Values                                           | Description                        |
|-------------------------------|--------------------------------------------------|------------------------------------|
| AS volume                     | Or (430 MW)<br>4*Or (1720 MW)<br>10*Or (4300 MW) | Original volume of FCR in IP       |
| Ramping capability            | 0.5 pu/s<br>2.5 pu/s                             | <i>Slow</i> HEs<br><i>Fast</i> HEs |
| Measurement acquisition delay | 70 ms<br>40 ms                                   | Realistic<br>Minimum theoretical   |

Table 2.2: Parameters under study

### 2.2.1.7 Limitations

As the main goal of this section is to study the frequency stability behavior some simplifications have been already mentioned: the fact that only one power plant of each type is representative of all the units of its kind in the control area, the absence of voltage control loops and uncertainty on modeling the future inertia.

The absence of the transmission system apart from the interconnection can be considered a limitation. This limitation is a trade-off: first and foremost, increasing grid size would require further grid parameters in the model and hence increase the sources of uncertainty, due to the difficulty in collecting and defining all relevant parameters. In any case, the extent of this limitation can be addressed by drawing conclusions from real events such as the separation of IP from CE in July 2021. This separation event is much more severe than the contingencies of the present study because of system split. Yet it can be concluded even as the frequency fell much below the thresholds considered in this study (frequency went close to 48.5 Hz), there was a small (less than 200 mHz) difference in the frequency nadir between the node of the substation closest to the trip and a substation on the other end of the IP [64]. The maximum RoCoF attained closest to the trip location was 1 Hz/s and about 0.5 Hz/s in the other tip of the IP, with other locations observing RoCoF values somewhere in between these values [64]. Computing a RoCoF for a single node is analogous of measuring it in the center of inertia in the IP and the value should

therefore be interpreted carefully. It can thus be concluded that for studying less severe frequency events in the IP (no separation between control areas), including the grid in the model would bring marginal gains at increasing costs of model complexity and further uncertainty.

The Iberian power system is a very specific case given the weak interconnection to CE. The conclusions of this section, regarding either unacceptable values of frequency or HEs' contribution to mitigate them, can only be generalized to power systems interconnected in similar circumstances.

A further limitation is that only a loss of generation is addressed in this study. The opposite case, the loss of load, is easily counteracted by actuation on reducing output of generation and would produce positive RoCoF, not threatening LOM protections. Concretely, it has been shown that solar power plants can provide this kind of response 24% to 30% faster than conventional generation [79]. In practice, this counteraction is already required in some grid codes regarding solar power, for instance in Portugal, where if the frequency raises above 50.5 Hz, solar units have to reduce the output proportionally to the frequency deviation [80].

### 2.2.2 Results

This section concerns the analysis of simulations done in the platform presented in Section 2.2.1.1. The IBR incident introduced in Section 2.2.1.2 is simulated. As addressed in Section 2.2.1.2, when the IBR trip occurs there is the instantaneous loss of active power of 3 GW in the IP, which is partially recovered afterwards. The FCR provision is addressed firstly in Section 2.2.2.1 with provision by conventional technologies and in Section 2.2.2.2 with provision by HEs. In Section 2.2.2.3, SI and FFR provision are analyzed in detail. Finally, in Section 2.2.2.4 the trade-off between RoCoF and AS provision is analyzed for various levels of system inertia.

#### 2.2.2.1 FCR provided by conventional technologies

In Figure 2.11 the IBR trip is simulated in the IP.

Two observations:

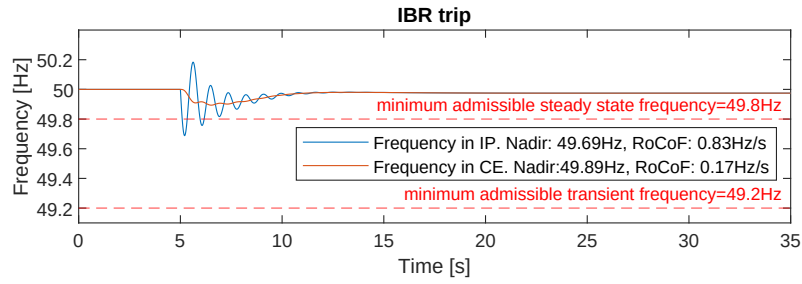


Figure 2.11: Frequency in IP and CE after IBR incident in IP. FCR provided by conventional technologies.

- In CE, the frequency (nadir and steady state) and RoCoF limits are well within the desirable thresholds;
- In IP, nadir and steady state frequency are respected, but RoCoF at the center of inertia of IP limit is closer to the threshold (0.83 Hz/s).

In Figure 2.12 the IBR trip in IP emphasizes the active power provision by FCR by conventional sources and interconnection flow from CE to the IP.

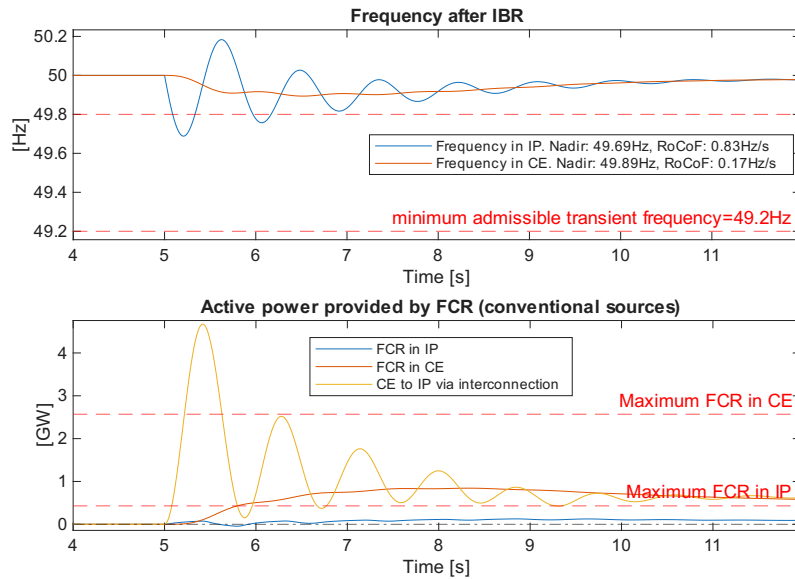


Figure 2.12: Frequency in IP and CE after IBR incident in IP. FCR provided by conventional technologies.

Some observations:

- The interconnection plays an important role and in fact provides much more active power to the IP than the FCR activation in IP;

- The FCR active power is not fully activated in the IP when provided by conventional technologies;
- The previous point implies extra costs for activating the secondary reserves (automatic and manual Frequency Restoration Reserves) after 30s, in order to reestablish the pre-fault cross-border power flows.

### 2.2.2.2 FCR provided by HEs

In Figure 2.13 the IBR trip in IP is compared regarding the technology providing FCR (conventional generators vs *slow* HEs with realistic measurement acquisition delay). The bottom plot shows FCR active power provision.

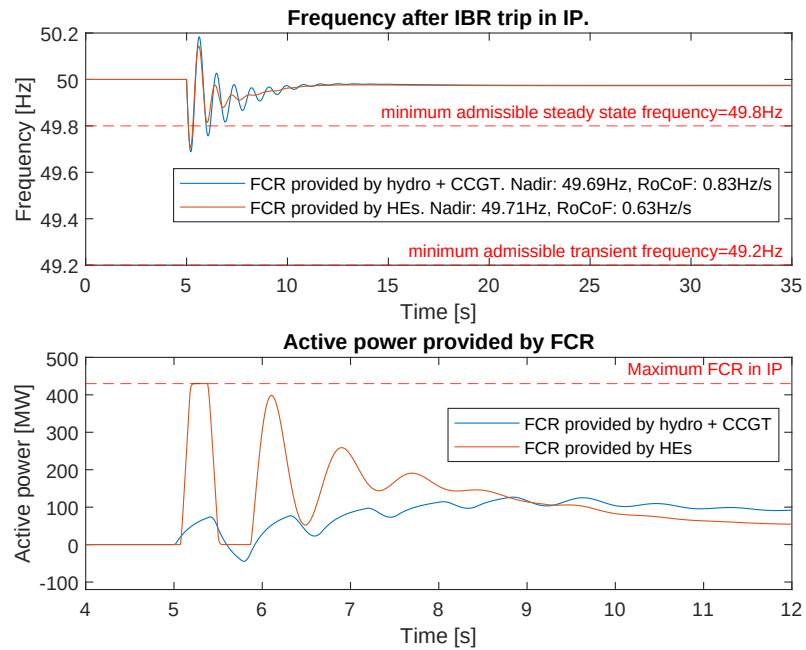


Figure 2.13: Frequency in IP and CE after IBR incident in IP and active power provision from FCR (conventional technologies vs HEs).

Some observations:

- Conventional technologies start to respond immediately after the incident (at 5 s mark), whereas HEs start responding after the measurement acquisition delay (70 ms after the incident);

- Although both technologies provide a frequency response below the RoCoF threshold, HEs provide a better response than the conventional sources (0.63 Hz/s against 0.83 Hz/s);
- HEs fully exploit the FCR volume in the IP (430 MW) whereas conventional technologies do explore about 25% of the volume of this ancillary service.

Further simulations were conducted in the scope of the FCR (results in Appendix C) and can be summarized as follows:

- RoCoF does not significantly improve if ramping capability is improved (*i.e.* results are almost the same for *fast* or *slow* HEs)
- RoCoF improves only marginally (0.63 Hz/s to 0.60 Hz/s) if measurement acquisition delays could be improved to the theoretical minimum.

Regarding the fact that improving the ramping capability does not improve the RoCoF, it is interesting to analyze Figure 2.14: it is clear from the figure that *slow* HEs are able to follow quite closely the command signal (droop, on yellow line). If the PEM on the HE fleet are exclusively *fast*, their active power output will at best be the yellow line and quickly saturate on the FCR limit. This does not allow for a meaningful RoCoF improvement under the FCR mechanism.

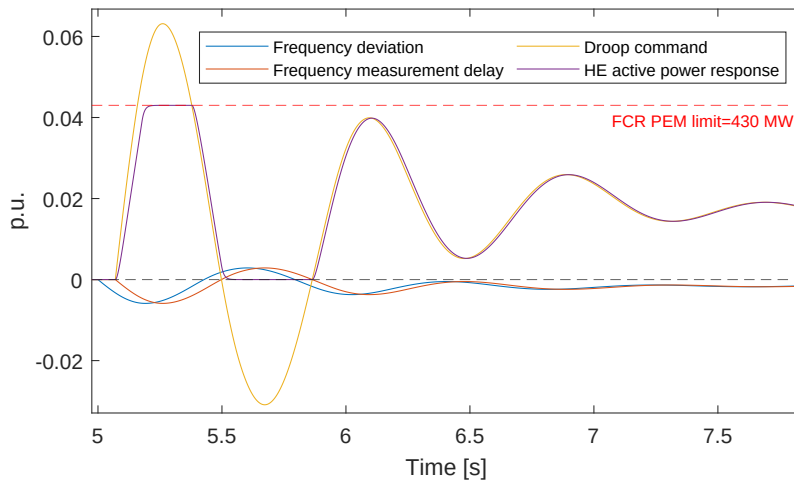


Figure 2.14: Frequency measurement, droop command and HEs response

In summary, it can be concluded that during low inertia periods in the IP, a traditional ancillary service (FCR) is not able to fully exploit the potential of a massive amount of HEs (8 GW) participating in the FCR, and the system operator may need additional solutions to contain the RoCoF further within the security threshold. For this purpose, the remainder of the section addresses fast reserves that can possibly exploit HEs' capabilities.

### 2.2.2.3 FCR plus fast reserves

In this section, using the platform from Section 2.2.1.1, further simulations were done, where the IBR trip is tested with HEs providing a combination of ancillary services: either FCR plus SI, or FCR plus FFR. In Appendix C the detailed results of all the simulations are included, along with the parameter values listed in Table 2.2 (AS volume, HE ramping capability and measurement and acquisition delay).

In the remainder of this section, in order to draw conclusions, each of these parameters is analyzed separately from the remaining ones.

Figure 2.15 shows how the system frequency in the IP evolves after an IBR, under three different combinations of ancillary services (FCR, FCR+SI, FCR+FFR), along with HEs' active power response.

Some observations:

- The nadir is lower under FCR-only, followed by FFR and finally SI, but all three far from the critical value of 49.2 Hz;
- Because the SI response is proportional to the RoCoF, the activated power is much more if compared to the FCR-only response;
- Under SI, almost immediately (*i.e.* after the 70ms of measurement acquisition delay), the HEs release active power;
- Under FFR, the active power release follows roughly the same ramp as the SI but later in time, since FFR is only activated after the measurement of 49.8 Hz is received by the HEs;

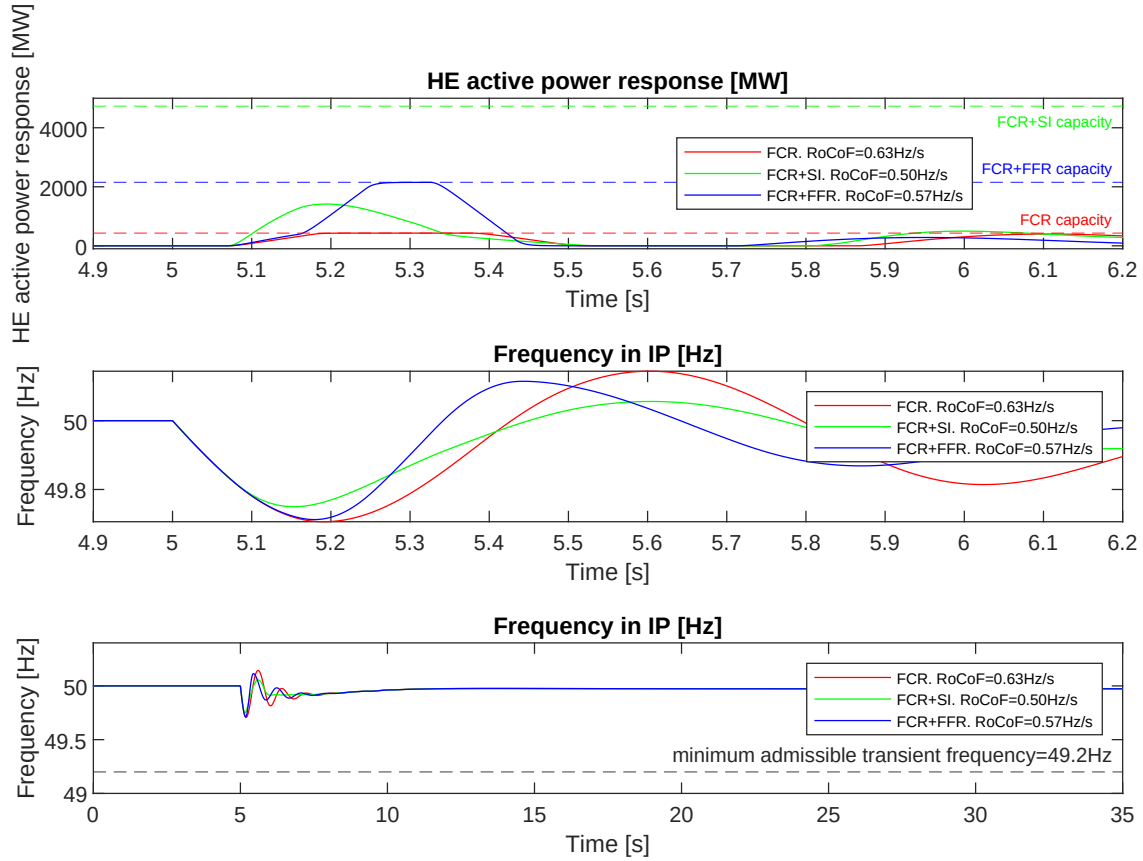


Figure 2.15: Comparison of system frequency and active power response from HEs under different ancillary services: FCR (simulation #2), FCR+SI (simulation #10), FCR+FFR (simulation #21), see simulations parameters in Appendix C.

- For the presented simulations, FFR reaches the contracted power, whereas SI does not, suggesting that even if the TSO is willing to contract a higher AS volume it may be unused in this case, as will be addressed in the remainder of this section.

Figure 2.16 relates the SI / FFR volume and the RoCoF. In each case of AS volume there is a bar representing the maximum and minimum obtained RoCoF for a given AS volume (varying the remaining parameters).

Some conclusions are drawn:

- SI produces better RoCoF than FFR either in the maximum or the minimum cases;
- There are some combinations of FFR provision that will induce a RoCoF in fact higher than the FCR-only case (0.74 Hz/s vs 0.63 Hz/s). This will be discussed in Section 2.2.3;

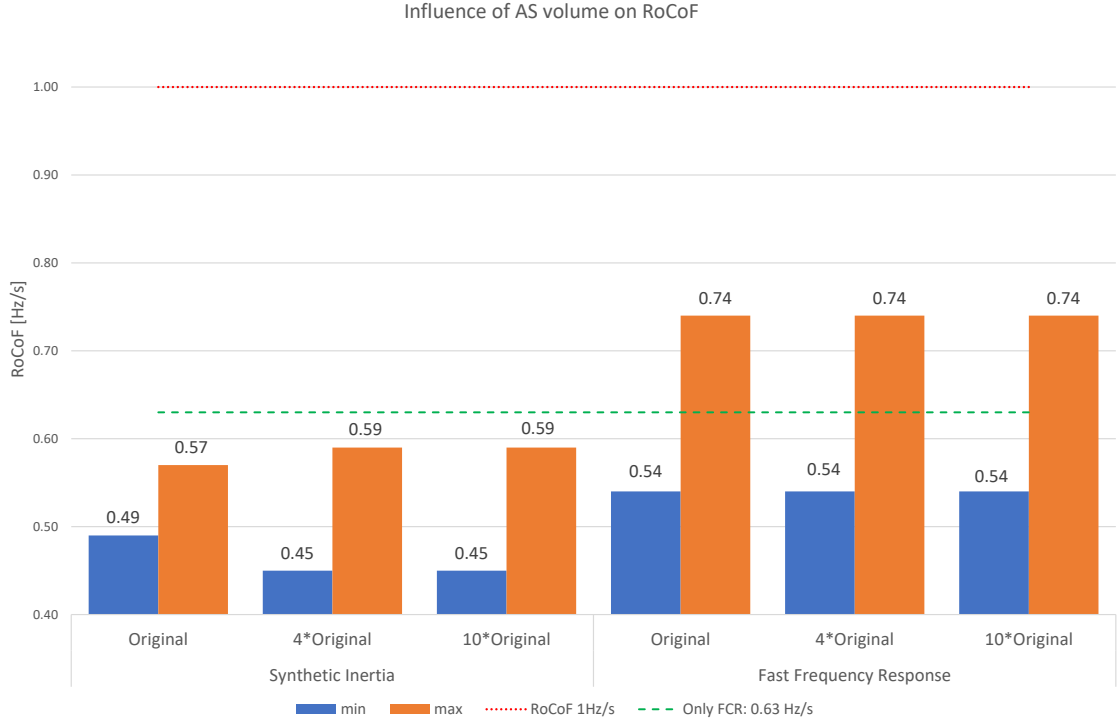


Figure 2.16: Influence of AS volume in RoCoF improvement

- Even a small AS volume (equal to the existing FCR) may be able to bring RoCoF down, regardless of the AS in question;
- Increasing the AS after a certain point (4\*430MW) produces apparently the same maxima and minima, suggesting that increasing the AS volume is not *per se* a feasible solution for lowering the RoCoF.

Figure 2.17 relates the influence of HEs ramp on the RoCoF. Only results showing realistic communication delays are presented.

The following conclusions are drawn:

- If the HEs are dominated by *slow* units, it is pointless for the TSO to procure FFR additionally to the FCR because they actually produce a worse RoCoF;
- Even if HEs are *fast*, it is pointless to procure above 4\*430 MW of SI;
- If the HEs are *slow*, no more than 430 MW of SI should be procured.

Figure 2.18 explores the potential impact of diminishing communication delays.

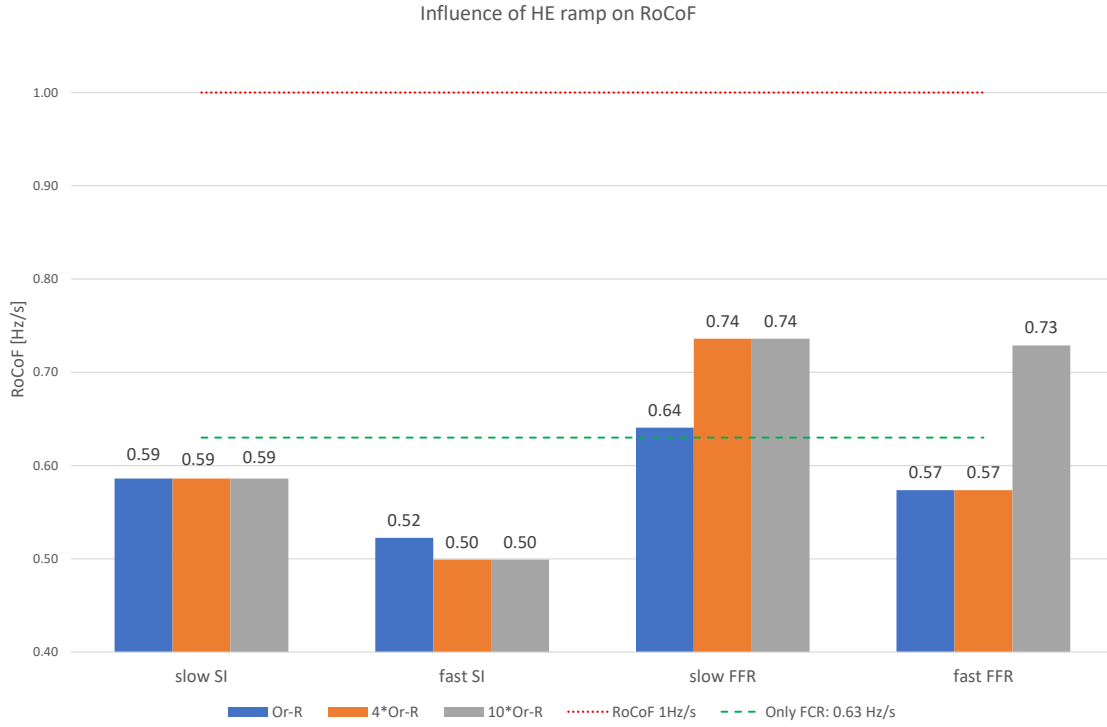


Figure 2.17: Influence of HEs ramp in RoCoF. Note that communication delay is assumed to be *realistic*.

The main conclusion is that the improvement in measurement and acquisition time delays would benefit more the provision of FFR than SI, but as already hinted in previous analysis only if associated with *fast* HEs.

### 2.2.2.4 RoCoF analysis for different system inertia and ancillary services

The main outcome of this work is represented in Figure 2.19, which has been drawn from several simulations changing the system inertia and obtaining the corresponding RoCoF, each series for a distinct combination of ancillary services (as per Figure 2.19 legend).

The objective of the system operator is to operate always the system with a RoCoF below the 1 Hz/s line. The RoCoF here obtained is for the center of inertia of the power system, so the interest of the system operator is to keep RoCoF well below that level for the reasons discussed in Section 2.2.1.7. In any case, the simulations show that the RoCoF in the center of inertia is always kept below 1 Hz/s but the system is safer if AS are provided by HEs than if provided by conventional technologies. It is also noted that

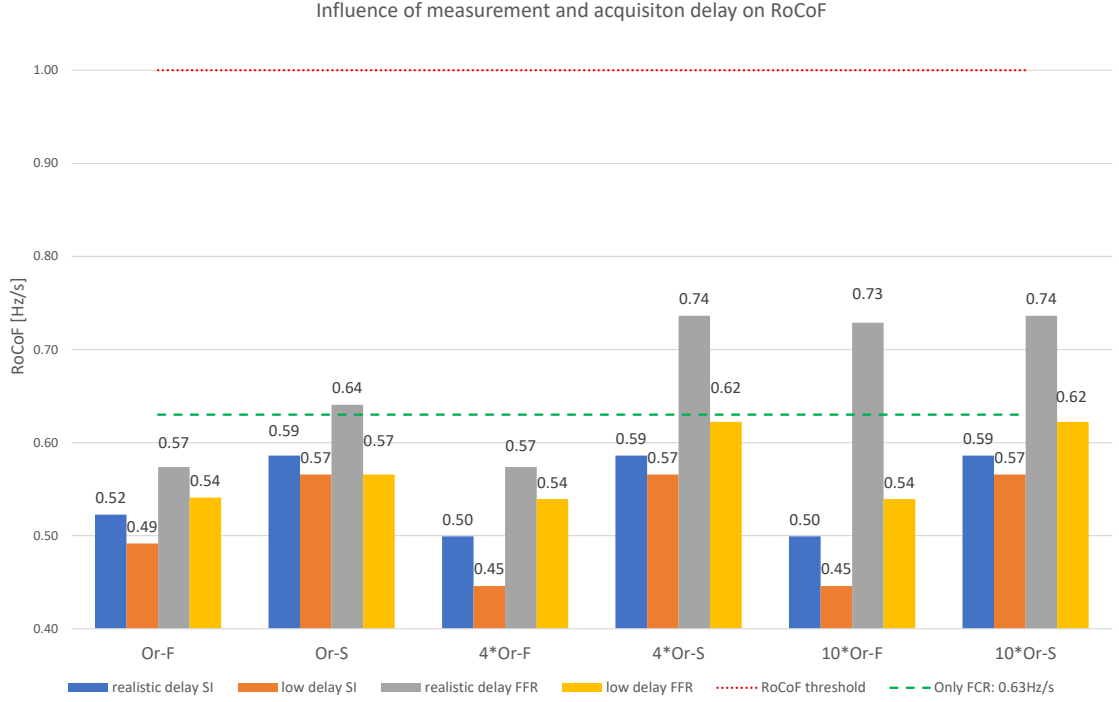


Figure 2.18: Influence of communication delays on RoCoF. On the x-axis "Or" refers to "original AS volume", F to *fast* and S to *slow* HEs.

when the inertia is lower the gap closes and the benefits of HEs are more limited. The implications are discussed in more detail in Section 2.2.3. In any case, the TSO should carefully monitor the evolution of the system inertia, in order to assess the most critical hours and which AS should be procured to mitigate RoCoF excursions during potential incidents.

### 2.2.3 Discussion

This section addresses HEs' performance in the context of frequency ancillary services: a HE suddenly reducing its power consumption is equivalent to a generator ramping up its power output. HEs are also perfectly capable of providing the opposite case, equivalent to a generator ramping down power output, however the case under study concerns a generation loss that triggers upward reserve. After such contingency, when critically low values of frequency in the power system are achieved, under frequency relays may be triggered and load shedding mechanisms activated, disconnecting load as quick as possible

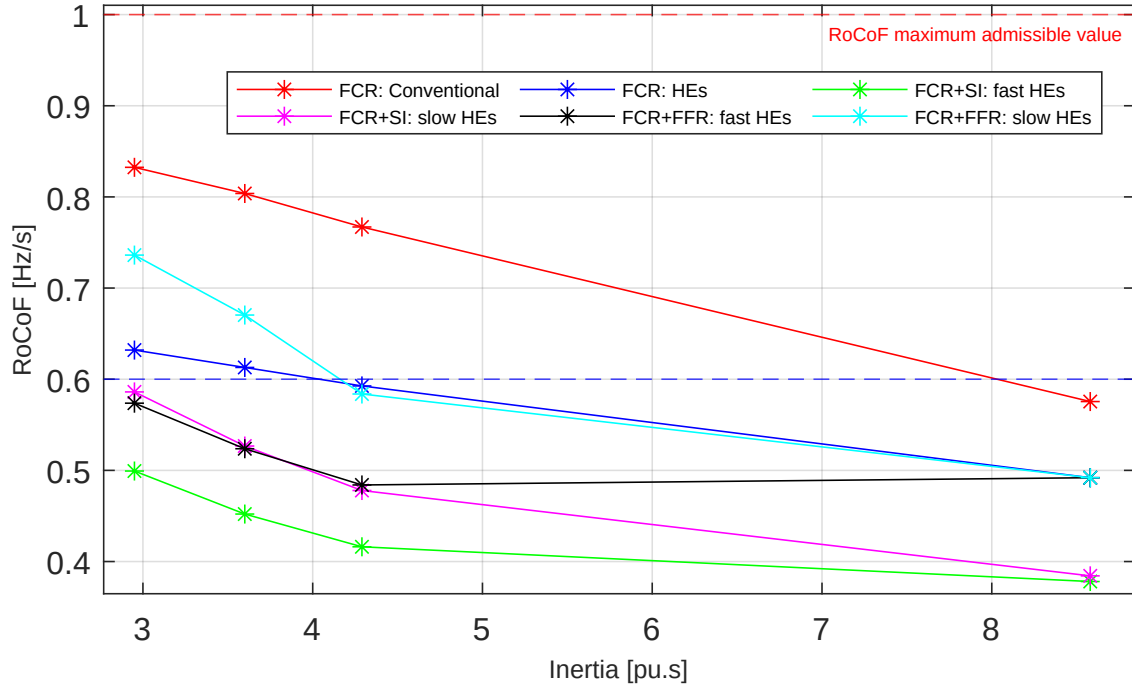


Figure 2.19: Impact of ancillary services on RoCoF after IBR trip in IP. Parameters for simulation: FCR volume = 430 MW, FCR + SI/FFR = 4\*430 MW, using realistic measurement acquisition delays.

to re-balance generation and demand. Besides this, distributed energy resources present in distribution grids can be disconnected from the grid by protections when frequency drops fast (*i.e.* high RoCoF), contributing further to the loss of generation.

It should be emphasized, as stated in Section 2.2.1.7, that due to the simplification of using only one node to represent the whole IP power system, RoCoF values should be evaluated with care: the TSO should be interested in having a RoCoF well below 1 Hz/s as this represents the RoCoF in the center of inertia of the IP and hence RoCoF will be higher closer to the loss of generation.

The key idea of this work is that in the future high RoCoF values may occur in extremely low inertia situations in the IP after a large loss of IBR generation, and that the fleet of HEs participating in ancillary services can contribute to keep RoCoF below the acceptable thresholds, at least as a complement to other technical solutions such as synchronous condensers. However, while synchronous condensers must be deployed for the single purpose of providing AS, HEs will be able to provide these services while doing their main task (electrolysis for hydrogen generation). This underlines the potential of

demand response and particularly of HEs, as it is proven that in case of a contingency, when aggregated, HEs effectively have the technical capability of providing the benefits of load shedding to system operators without the inconvenience of totally interrupting their main service, as is the case of load shedding programs. When in this section it is mentioned that the HEs inject active power in the grid what happens is in fact the temporary diminishing of power consumption by the HEs, very much like a load shedding, but activated before dangerous frequency or RoCoF values are achieved.

Although in none of the simulations performed the 49.2 Hz threshold is attained, the violation of this limit is less likely when HEs participate in the FCR. It has been seen that an IBR trip with participation of conventional technologies in FCR can achieve RoCoF close to the threshold of 1 Hz/s (concretely, 0.83 Hz/s) whereas if FCR is provided by HEs this value can drop very significantly (to 0.63 Hz/s), so it is safe to say that HEs outperform conventional generators.

In Figure 2.13 (bottom) it is observed that the conventional technologies start to respond immediately when frequency starts dropping due to the fact that they are synchronous machines and have synchronous inertia, *i.e.* they release the energy stored in their rotors; HEs start to respond later than the conventional units, after a measurement acquisition time delay. This quick response can be seen as an advantage of conventional synchronous technologies over the power electronics interfaced units, but on the other hand, and taking into account that the active power response of the FCR can theoretically reach 430 MW, it can be observed that if FCR is provided by conventional plants, in the critical moment before reaching the nadir not even 100 MW of FCR are activated. Therefore, it can be concluded that conventional plants do not fully take advantage of this AS, as they are not fast enough to deal with the frequency drop in very low inertia situations; in contrast, note that the HEs are fast enough to respond with the contracted 430 MW. These simulations were done using *slow* HEs, but it has been shown that if *fast* HEs are utilized instead, the RoCoF has only a marginal improvement. This suggests that the traditional FCR is unable to unlock HEs' full potential as a fast-responding dynamic load because of the FCR volume limit.

Obviously, if the FCR was not limited to 430 MW in the IP, the HEs would be able to

inject more active power in the grid and contribute to attenuate the RoCoF. But again, the main aim of the FCR is to stabilize the quasi-steady-state frequency above 49.8 Hz in the whole synchronous area, and this condition is observed after a severe IBR trip due to the existing FCR mechanism (3 GW in the whole synchronous area, 430 MW of which in the IP). So the RoCoF problems should be addressed with AS deployed at local level.

Regarding the additional AS under study (SI and FFR) the main conclusion can be summarized as follows: they can significantly improve the results, but this depends on the future evolution of the HEs technology itself: if *slow* HEs will be most of this fleet, the additional AS guarantee only a marginally lower RoCoF after an IBR incident. This is evidenced in Figure 2.17. If one considered that the desirable RoCoF threshold was 0.5 Hz/s (as in Ireland before 2013 [50]) and the system inertia really goes down to the values addressed in this study, the HEs fleet would at the very best case allow the RoCoF in the center of inertia to be in the threshold.

In principle, FCR should present worse results (*i.e.* lower nadir and greater RoCoF) than FFR and SI because less active power from reserves is activated in the former case. Also in principle, FFR should perform worse than SI, because in FFR the activation of additional reserves happens only after the frequency has already been degraded below the threshold. Both these principles can be observed in Figure 2.15; the results found in Section 2.2.2.3 confirm, as expected, that SI performs better than FFR and both better than FCR.

Assuming that the HE fleet is dominated by *fast* HEs, SI allows for better exploitation of the ramping capability than FFR. However, SI may open challenges in terms of control design (low-pass filter and gain addressed in Section 2.2.1.5), which is by definition more complex than the case of FFR.

Taking into account that one of the main conclusions of this section is the importance of the ramping capability for FFR and SI provision, a topic of future research, which is of interest to both TSOs and manufacturers, concerns test protocols. The QualyGridS project [81] designed test protocols for FCR and slower reserves (automatic Frequency Restoration Reserve and Replacement Reserves); future work could expand the aims of such project and test HEs with more challenging setpoints matching the needs of emerging

frequency services such as FFR and SI.

As stated in Section 2.2.1.5 the threshold for FFR activation chosen was 49.8 Hz. If it was either 49.5 Hz or 49.7 Hz as per [53] the mechanism would not be activated, since that the nadir of FCR-only cases is higher than 49.7 Hz.

The results presented in Section 2.2.2.3 make it clear that in exceptional cases FFR induces worse results than the use of FCR-only, namely for high volumes of AS especially in the context of *slow* HEs. This has to do with the overshoot of frequency above 50 Hz and is induced by two factors: (i) the IBR trip has a partial recovery of active power at the same time that the HEs are injecting power and (ii) the high volume of active power injected by HEs. As can be seen in Figure 2.15 the frequency can go above 50 Hz for a certain period, and the second time the frequency falls, the oscillation can induce a higher RoCoF than immediately after the fault.

It should be emphasized that the obtained results can be generalized, but taking into account that the used model concerns the particular case of the IP, namely with given system inertia values and given interconnection to other control area with more inertia.

Figure 2.19 is the main outcome of this work and allows to quantify HEs' contribution in the reduction of critical inertia. Let us assume that the TSO wants to guarantee that the RoCoF in the center of inertia of its power system needs to be kept below 0.6 Hz/s (horizontal line in blue in Figure 2.19). It can be seen that if the TSO is contracting FCR provided by the conventional technologies, the value read on the x-axis (around 8 pu.s) is the critical inertia. But if the TSO contracts the FCR exclusively to HEs, the critical inertia will be around 4.2 pu.s. Or if the TSO contracts a large volume of SI from a *fast* HE fleet, the critical inertia would be even lower than the 3 pu.s. Therefore it can be said that HEs contribute to reduce the system critical inertia and a plot like Figure 2.19 allows for quantifying this reduction.

### 2.2.4 Conclusions

Synchronous inertia in power systems will continue to decrease as renewable energy generators substitute conventional thermal power plants. In this section the foreseen dynamic response of the Iberian electrical system was described when facing large disturbances for

scenarios of operation in 2040. The impact of the minimum theoretical inertia is analyzed with regards to frequency and RoCoF. The response of conventional power plants is compared to that of HEs in the context of frequency related ancillary services provision.

The main task of the FCR is to achieve a quasi-steady-state frequency higher than 49.8 Hz following a contingency. The obtained results indicate that after an IBR generation loss of 3 GW, either conventional plants or HEs achieve the main FCR objective. However, simulations also show that FCR dominated by conventional plants may lead to RoCoF close to the maximum acceptable value (0.83 Hz/s), whereas if provided by HEs a lower value would be obtained (0.63 Hz/s).

The contribution of HEs in fast reserves (SI and FFR) to address this problem was studied in the remainder of the section. Regarding the research question of (“can the critical inertia be reduced if the frequency responsive reserves are provided by HEs?”), the answer is that HEs can definitely reduce critical inertia under the FCR and further reduction under SI and FFR is only significant under a certain combination of parameters of AS volume and ramping capability. Technological evolution of HEs (namely ramping capability) will be decisive in how much the critical inertia is reduced: it was shown that if the future HEs fleet is dominated by *slow* PEM, the benefits if compared to the traditional FCR are quite limited. On the other hand, if the HE fleet is dominated by *fast* HEs, SI will allow for better exploitation of the ramping capability than FFR, even if at the cost of increased challenges in terms of control design if compared with FFR. The use of FFR under certain circumstances can even induce higher RoCoF than the FCR-only case.

The HE fleet may minimize the deployment of other solutions (for instance, synchronous condensers) that could be deployed to provide exclusively AS.

This section explores only the sudden need to counteract a loss of generation in the power system using demand reduction via HEs (which is equivalent of ramping up power output of a generator). The conclusions of this section were drawn from a model concerning the IP power system interconnected with the CE system and thus generalizations need to take this into account, namely the system inertia values and interconnection between these power systems.

Taking into account that the HEs’ main task is to perform electrolysis, and having

proven that HEs are able to contribute for the secure operation of the power system, this section contributed to support the key idea that HEs can play an important role as balancing units of power systems for the coming future.

## 2.3 Model Predictive Control for the Automatic Generation

### Control problem

#### 2.3.1 Introduction

For many decades, Automatic Generation Control (AGC) has been successfully employed in each control area of a synchronous power system, guaranteeing a stable frequency on the whole synchronous area. Traditionally, a proportional-integral (PI) controller is employed for AGC, as exemplified in Figure 2.20.

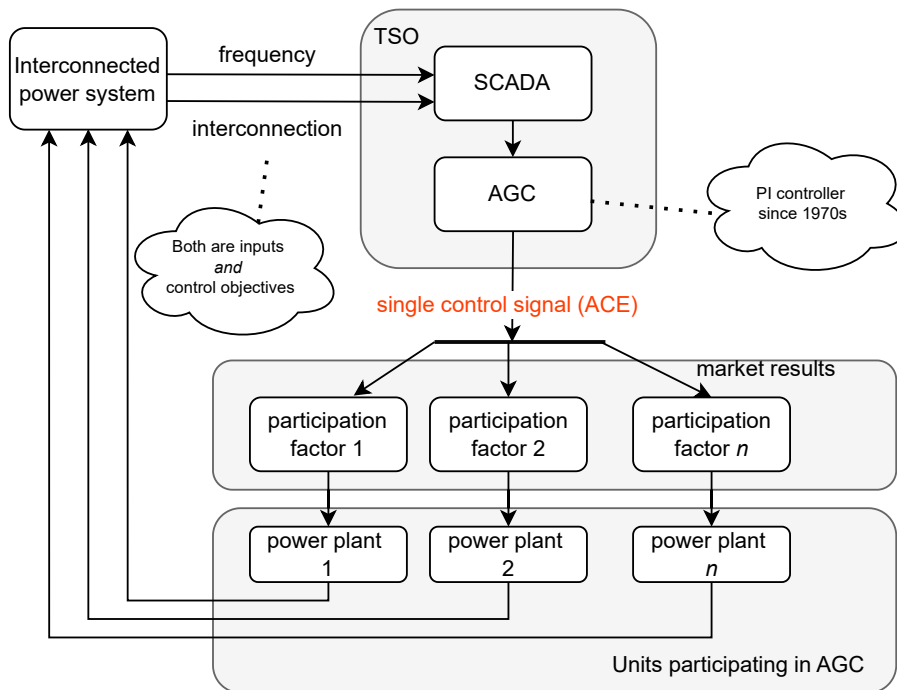


Figure 2.20: Simplified AGC scheme.

Such controller generates control signals using area control error (ACE) since the 1970s [82]. As introduced in Section 2.1.5, ACE is computed using a linear combination of two deviations: deviation of frequency from the nominal value (50 or 60 Hz depending on the country) and deviation of the pre-contracted interconnections power flow. The control signal is then distributed to the units participating in the secondary reserve proportionally to the results they obtain in the automatic Frequency Restoration Reserves (aFRR) market,

via the participation factor. Such units will increase or decrease their generation when required (thus, *reactively*), contributing to the reestablishment of the intended frequency and interconnection power flow.

The tried and tested use of AGC-PI is attractive due to its simplicity: it only depends on the frequency and interconnection power flow values, which are measured and read in the control centers of Transmission System Operators (TSOs). The system works using simple known rules of control theory. ENTSO-E evaluates the quality of service of each TSO according to two target values for the ACE [83]. Although the annual accumulated minutes outside the standard frequency range have respected the intended limits in the Continental Europe synchronous area, these figures have been increasing [84].

Units participating in the reserve markets are typically generators, although demand units<sup>4</sup> are increasingly participating [85]. The HE is an emerging technology from the demand side that possesses, in certain cases, ramping capabilities which exceed those of conventional generators and which can be used in reserve provision [55]. A further advantage of the use of HEs is that they do not need to be interfaced with the TSO by load aggregators. Thus, the control signal sent by the TSO can be distributed by HEs without the need for an aggregator first performing optimization to decide which units will change their setpoints. If applied in a traditional AGC-PI configuration, a HE will not be fully exploited for two reasons: (1) the outlined traditional AGC-PI is reactive and (2) the control signal sent to all units is divided proportionally to their participation factor. This work proposes a model predictive control (MPC) to overcome the two outlined issues, as detailed below.

Model Predictive Control is a family of controllers that formulate an optimization problem using an explicit model [86]. The present work hypothesizes that incorporating in MPC the ramping capabilities of units participating in the aFRR may achieve better results than the AGC-PI approach, because such a system is not merely reactive. Also, since MPC allows for easily computing a high number of outputs, it would be suitable to control multiple units and exploit the fast units before the slow ones, again contrasting

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<sup>4</sup>Note that seen from the grid, when a demand unit lowers its power consumption it is equivalent to a generator increasing its output.

with AGC-PI which generates a single control signal that is proportionally divided to participating units. MPC can also handle multiple constraints and market results can be incorporated in the problem as constraints. Let us consider a simplified example, in which a unit wins 10 MW out of a total of 100 MW awarded in the market. Such unit would have a participation factor of 10/100 and the control signal dispatched by the TSO would multiply the control signal by 0.1 in the case of AGC-PI; in the case of MPC the 10 MW would be included in the problem formulation as a constraint for the maximum power to be provided by the unit. If the unit is a fast one, it would be interesting to exploit these 10 MW as soon as possible, which may not happen in the AGC-PI in which the unit will be providing 10% of whatever is the control signal in a given moment.

Exploiting the fast units is typically a concern when addressing fast reserves such as frequency containment reserve (FCR) or even faster ones such as Fast Frequency Response as shown in Section 2.2; however, when a control area is recovering from a contingency, the contribution of the aFRR becomes relevant, because the purpose of fast reserves is merely avoid the frequency to go to low values and not to restore the frequency to its nominal value.

Several widely cited papers such as [87, 88, 89, 90] have employed MPC to the AGC problem. A recent literature review of papers using MPC in the AGC problem is given in [91].

The authors of [87] used a simplified grid topology to emphasize that MPC, besides performing the main duties of AGC, can be used to activate the reserves in a way that respects tie-line power flow limits or rather handle bottlenecks, something that AGC-PI isn't capable of. The same study also shows that by incorporating economic data in the objective function, it is also possible to extend the traditional duties of AGC and perform the activation of reserves taking into account cost minimization. The main objective of the same paper is to show that an AGC based on MPC requires less primary and secondary reserve activation than the traditional AGC-PI. However, what is achieved in [87] is done by testing small random variations in the load, in contrast to the present proposal, in which a large contingency takes place and triggers an emergency mode AGC to recover the frequency and interconnection to pre-fault values as fast as possible. Also, [87] does

not address the fact that faster units participating in the reserve can be more adequately exploited than slower units.

The authors of [88] argue that centralized control for the AGC problem is not feasible for geographically expansive power systems, which in fact is what the conventional AGC does nowadays. Even if these authors only include a simplified grid topology with the tie lines between different control areas in their study, they study the feasibility of a distributed MPC to control the AGC of several control areas cooperatively. They show that the proposed distributed MPC achieves performance equivalent to centralized MPC.

In [89] a multi-area power system is simulated, each area having its own MPC for providing AGC and compared with the classical PI controller. The objective of the study is to show that MPCs designed independently for each control area still provide overall closed-loop stability. Also, they show that the proposed approach is robust even if errors due to uncertainty are introduced in the model parameters.

In [90] the practical implementation and computational aspects of an MPC for a real-world power system are discussed, testing it on the all-island Irish transmission system consisting of over 1400 nodes. Given that the system consists of an island, there is no interconnections like in the present study. The emphasis of [90] is on the cost minimization of reserves activation. One of the conclusions of the study is that MPC does not provide a significant improvement over AGC-PI in face of significant communication delays.

Overall, papers found in the literature tend to use a more complex approach to the problem than the proposed in this work, often incorporating the grid topology, which can be avoided in the present work given the incremental approach proposed here. To the best of the authors' knowledge, none of the papers in the literature emphasize that MPC can be used to exploit faster units or to use MPC specifically as an emergency AGC during post-fault recovery.

#### **2.3.1.1 Motivation, research questions and section organization**

The ramping capabilities of each unit that participates in the aFRR are known by the respective TSO. Yet, as stated in the introduction, this knowledge is not incorporated in the AGC-PI. A further motivation for this study is, thus, to use such knowledge in a useful

way that is only slightly more complex than the present-day AGC-PI. Other motivation for the study is the need of TSOs to maintain an adequate quality of service. Maintaining the quality of service means ensuring that the number of minutes in which the frequency does not deviate from the standard frequency range ( $50Hz \pm 0.05Hz$ ) does not exceed 15000 minutes in a year. This limit has been respected in recent years but for instance in 2021 more than 11000 minutes were outside the standard frequency range and these figures have been increasing [84].

The study hypothesis is that it is possible to design an MPC controller that is activated only after an emergency is detected in a given control area and that will exploit the available resources more adequately than the conventional AGC-PI. The research questions are the following:

- Can the MPC outperform the AGC-PI controller following a contingency?
- Can the fast resources such as hydrogen electrolyzers be more adequately exploited by the MPC?
- How complex would such a controller be?

The remainder of the section is organized as follows: Section 2.3.2 details the used methodology, in Section 2.3.3 results are presented and in Section 2.3.4 are discussed, finally in Section 2.3.5 conclusions are drawn.

#### 2.3.2 Methodology

Figure 2.21 shows an overview of the simulation platform, of which further details are given in the remainder of the section.

The implemented system is a classical dynamic model with three nodes, each of them a control area equipped with AGC, and each connected to the remaining areas with tie-lines (interconnection); the dynamics of such system can be found in [32]. The model was implemented in MATLAB Simulink, with block diagram logic in the Laplace domain for representing the differential equations shown in Appendix D. Only one area (area  $i$ ) is shown in Figure 2.21 (remaining areas possess similar blocks). The model is in equilibrium



The FCR is represented by a traditional governor-turbine model<sup>7</sup> coupled with the speed droop ( $-1/R$ ) such that a negative frequency deviation increases active power output of the model. The values of the frequency and imports to the area are passed to a block labelled *LPF* or low pass filter. Such block is common in the control center to filter measurements and to ensure a smooth control signal by the aFRR controller [32]. In the present case, this block also feeds the finite-state machine (*state mach*), which is at the very core of the idea put forward by this work: it determines if there is an emergency (binary variable *eme*) in the control area. Put simply, *if there is a large import to the control area and a drop in the frequency it means that there was a loss of generation within the control area and the import from the remaining areas is counteracting this loss*. The import value is, thus, a proxy variable for the loss of generation, which is assumed that cannot be detected directly by the control center. Whereas traditionally there is in each area a single AGC-PI controller that counteracts such loss, in the present section the finite-state machine operates a digital switch that would enable the use of an MPC controller instead of the AGC-PI, if an emergency is detected. In the presented implementation it has only two states: the default is non-emergency, and when the system enters the emergency mode it does not go back to non-emergency as soon as frequency goes back to 50 Hz and interconnection is reestablished, as this could happen in a transient period and changing again to AGC-PI would defeat the purpose of showing the MPC in action. In a real-world implementation, the end of emergency mode could be triggered manually by an operator in the control center, in the same way that the tertiary reserve is manually activated to replace the secondary reserve after a contingency has been recovered by the AGC [92].

Details of both controllers are given later in the section. Note that the aFRR controls several units using governor-turbine model<sup>8</sup> similar to the one presented in the FCR, the control signal is not dispatched to the machine providing FCR (which happens frequently in the literature, for instance [93]). The used approach is in line with markets in central Europe, where one unit can participate in either the primary or secondary reserve market

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<sup>7</sup>All governors and units present in this section are represented by transfer function with a single pole in denominator and no poles in nominator, since the transients are not relevant for the time-scale being addressed.

<sup>8</sup>aFRR has a saturation block that represents a limitation of reserved power of each unit, not represented in Figure 2.21 for simplicity, but addressed in the model parameters.

if it so chooses. The remaining part of the model represents the interconnections: integrating the frequency deviation in one area and subtracting this value to the integral of frequency deviation of remaining control areas, multiplied by the well-known synchronization coefficients ( $2\pi T$ ), yields the imported active power. With appropriate action from FCR and aFRR, a well calibrated system again reaches equilibrium if there is no further loss of generation.

Figure 2.22 gives further detail about the used AGC-PI model, which is adapted from [93].

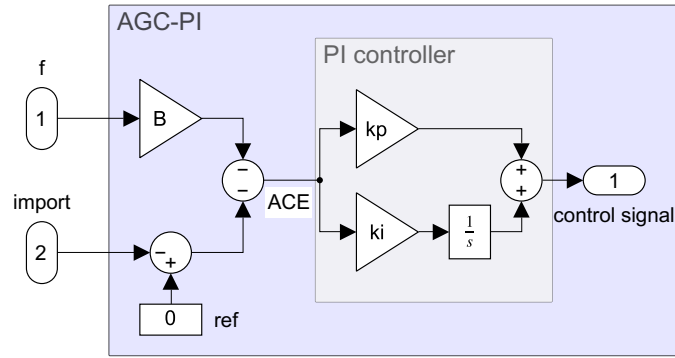


Figure 2.22: AGC-PI model

It can be seen that the Area Control Error (ACE) is a linear combination between the frequency deviation and export deviation. The frequency bias (B) is used to tune the controller, basically weighting the importance of correcting the frequency versus correcting the deviation of the exports. The ACE is then transformed by the PI gains in a control signal. Some adaptations were made on the [93] model, as follows. The PI gains were implemented in MATLAB Simulink block PID(z) which allows for discretizing the controller: this allows for mimicking the real-world AGC, which dispatches a control signal every 2-4 seconds [94]; in this work 4 seconds were used. Also, as previously said, the unit that participates in the aFRR is not the one participating in the FCR and this is useful because the objective of this section is to isolate and analyze the contribution of individual aFRR units. The final fundamental difference between [93] and the proposed model is that in this work the aFRR is shared by three units, so the control signal is sent to three units according to their participating factor. Here it is assumed that the aFRR

### 2.3. MODEL PREDICTIVE CONTROL FOR THE AUTOMATIC GENERATION CONTROL PROBLEM

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has a 2 GW market session, which is split evenly among participating units following the market result. The participation factor of a given unit is given by the awarded bid divided by the 2 GW of the session; the AGC cannot extract more than this reserved amount from this unit. Thus, using this example, a unit to which a 20 MW bid was awarded would have a participation factor of 1%.

Table 2.3 shows the parameters of the model and PI controller, excepting the MPC part.

Table 2.3: Model Parameters. The order of Parameters labelled with “\*” is (Fast, Medium, Slow Units)

| Parameter | Description                                    | Values                |
|-----------|------------------------------------------------|-----------------------|
| DPL       | Loss of generation                             | [0.1, 0, 0]           |
| D         | Load damping                                   | [1, 1.5, 1.8]         |
| H         | Synchronous inertia                            | [10, 12, 12]          |
| Tgp       | FCR governor time constant                     | [0.1, 0.17, 0.2]      |
| Ttp       | FCR turbine time constant                      | [0.3, 0.4, 0.35]      |
| Tgs       | aFRR governor time constant<br>(areas j and k) | [0.17, 0.2]           |
| Tts       | aFRR turbine time constant<br>(areas j and k)  | [0.4, 0.35]           |
| Tgs*      | aFRR governor time constant                    | [0.05, 0.1, 0.2]      |
| Tts*      | aFRR turbine time constant                     | [0.15, 0.3, 0.6]      |
| Kp        | AGC-PI proportional gain                       | [0.01, 0.2, 0.01]     |
| Ki        | AGC-PI integral gain                           | [0.05, 0.05, 0.05]    |
| pf*       | Participation factors                          | [1/3, 1/3, 1/3]       |
| max*      | Maximum power provided by unit                 | [0.2/3, 0.2/3, 0.2/3] |
| lpf       | Low-pass filter time constant                  | 4                     |
| T         | Synchronization coefficient<br>(ij, jk, ki)    | [0.20, 0.18, 0.21]    |

The same generation loss and PI gains provided in [93] are simulated for ensuring the model is well calibrated: a 1 GW in area  $i$  occurring at  $t=5s$ . Figure 2.23 shows the evolution of FCR and aFRR after this contingency.

Figure 2.23 shows that the used parameters provide a well calibrated system: in the first phase there is activation of FCR from all the areas, subsequently substituted exclusively by the AGC from area the affected area, i.e. area  $i$ .

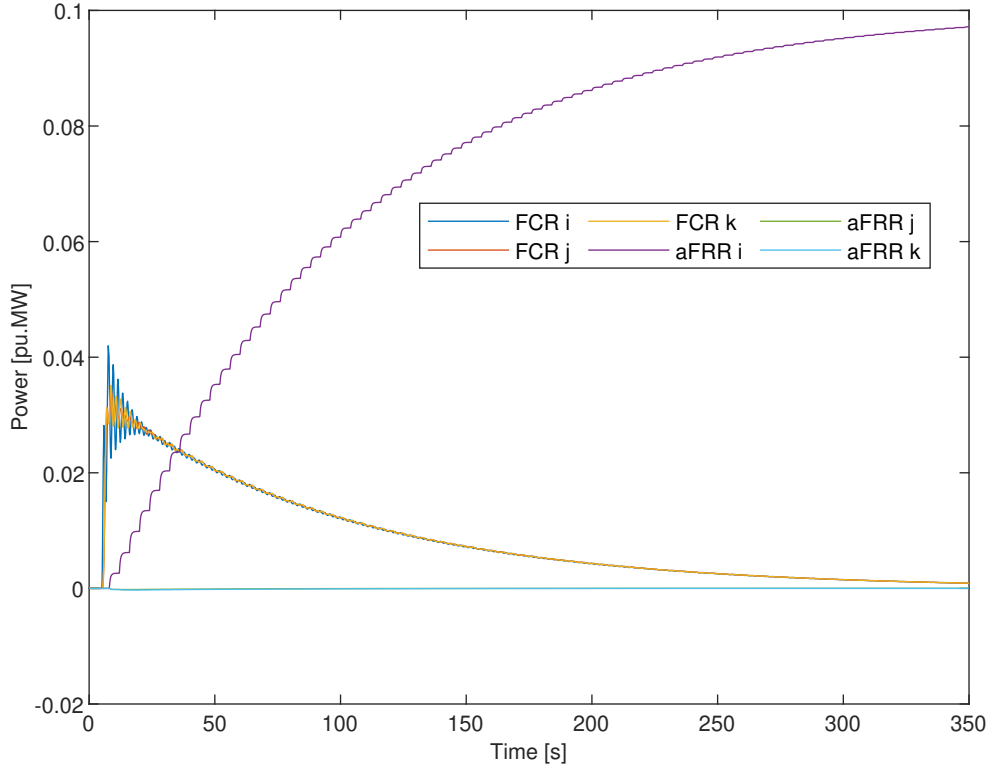


Figure 2.23: Model calibration: evolution of FCR and aFRR after a 1 GW loss. Note that aFRR from areas  $j$  and  $k$  are superposed and the contribution is almost null.

### 2.3.2.1 MPC controller

The objective of this work is to implement a simple MPC approach that would allow to extract more reserved power from faster resources and thus allow to reestablish the ACE and interconnection values as soon as possible. It is assumed that SCADA knows instantly the interconnection power flow and this is in fact what is intended to counteract after a contingency.

Since MPC is a control technique based on optimization, the system knowledge has to be incorporated in a plant model. This is necessary for the optimization, which aims to compute the optimal system inputs over the prediction horizon, taking into account the objective function. Then, the input for the first time step is applied to the system, while the system states are obtained from real measurements and the next iteration yields a new optimal set for the prediction horizon. The plant model used in this work is a linear

time-invariant state-space model represented as follows:

$$\begin{cases} \dot{x} = Ax + Bu \\ y = Cx + Du \end{cases} \quad (2.27)$$

where  $x$ ,  $y$  and  $u$  represent the vectors of states, outputs and inputs respectively, while  $A$ ,  $B$ ,  $C$  and  $D$  are the space-state matrices, as described below.

The  $x$  vector has a dimension of 16 and includes all the model's states, that is, all the variables existing in the differential equations, except for the system inputs:

$$\begin{aligned} x = [Df_i, Pgp_i, Ptp_i, Pgs\_fa_i, Pts\_fa_i, \\ Pgs\_me_i, Pts\_me_i, Pgs\_sl_i, Pts\_sl_i, \\ Df_j, Pgp_j, Ptp_j, Df_k, Pgp_k, Ptp_k, import_i]^\top \end{aligned} \quad (2.28)$$

where:

$Df_n$  is the frequency deviation in the area  $n$ ,

$Pgp_n$  is the power of the governor of primary reserve in area  $n$ ,

$Ptp_n$  is the power of the turbine of primary reserve in area  $n$ ,

$Pgs\_fa_i$  is the power of the governor of the fast unit of the secondary reserve in area  $i$ ,

$Pts\_fa_i$  is the power of the turbine of the fast unit of the secondary reserve in area  $i$ ,

$Pgs\_me_i$  is the power of the governor of the medium unit of the secondary reserve in area  $i$ ,

$Pts\_me_i$  is the power of the turbine of the medium unit of the secondary reserve in area  $i$ ,

$Pgs\_sl_i$  is the power of the governor of the slow unit of the secondary reserve in area  $i$ ,

$Pts\_sl_i$  is the power of the turbine of the slow unit of the secondary reserve in area  $i$ ,

$import_i$  is the sum of imports to area  $i$ , from area  $j$  and area  $k$ .

It is assumed that for the MPC of area  $i$  the action of the primary reserve units of areas  $j$  and  $k$  are relevant and the ones from secondary reserve units of these areas are

irrelevant. This is because in the event of a loss of generation in area  $i$  only the primary reserve units of the whole synchronous areas contribute to imports to area  $i$ . It is assumed that for the MPC plant model there is no power flow between areas  $j$  and  $k$ , since the Kalman filter (state estimator) is unable to converge if this flow is considered in the plant model. Naturally, the simulated model considers power flows between areas  $j$  and  $k$ .

The  $y$  vector has a dimension of 2 and includes the two *output variables* that are used to feed the MPC controller in Figure 2.21<sup>9</sup>:

$$y = [Df_i, import_i]^\top \quad (2.29)$$

The  $u$  vector includes control signals (*manipulated variables*) and unmeasured disturbances<sup>10</sup>:

$$u = [uFRR\_fa_i, uFRR\_me_i, uFRR\_sl_i, DPL_i, DPL_j, DPL_k]^\top \quad (2.30)$$

where:

$uFRR\_fa_i$  is the command signal for the fast unit of area  $i$ ,

$uFRR\_me_i$  is the command signal for the medium unit of area  $i$ ,

$uFRR\_sl_i$  is the command signal for the slow unit of area  $i$ ,

$DPL_n$  is the unmeasured loss of generation of area  $n$ .

The coefficients of matrices A, B, C and D of Equation (2.27) are obtained by manipulating the differential equations of the model derived from Figure 2.21. For instance, manipulating Equation (D.12) and taking into account that, in the Laplace domain that

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<sup>9</sup>Even if these two variables are seen by the controller as inputs, they are nonetheless outputs if seen from the system itself.

<sup>10</sup>The loss of load could also be represented in an additional vector normally represented by the letter  $w$  for uncontrolled disturbances, but in this work the formulation was kept compatible with the MATLAB state-space or *ss* function.

multiplication by  $s$  yields the derivative, Equation (D.2) can also be written as Equation (2.31):

$$P\dot{t}p_i = \frac{Pgp_i}{Tt} - \frac{Ptp_i}{Tt} \quad (2.31)$$

In Equation (2.31) the relation between one derivative of a state variable and two state variables is established, so two coefficients of matrix A (namely,  $A_{3,2}$  and  $A_{3,3}$ ) have been found. The same manipulation is done for the remaining equations. Values of the coefficients of matrices of A, B, C and D are presented in Appendix E.

The resulting matrices are similar to the ones in [93] except for the outlined differences between that model and the one in this work. The matrix dimensions are 16x16, 16x6, 2x16 and 1x1, respectively.

The system is discrete like the AGC-PI controller, with a time step of 4s. The MPC is implemented in MATLAB, using the MPC package on the command line. The  $x$ ,  $y$  and  $u$  vectors are passed to the MPC controller, along with the subset of variables of  $u$  that are in fact disturbances (generation loss) that the controller is not able to control. The estimator used is the default MATLAB Kalman filter, which has the objective of estimating unmeasurable states and disturbances.

As mentioned above MPC solves an optimization problem in each iteration. The objective function has the form of Equation (2.32) with four terms. Such formulation of a quadratic problem (QP) is proposed in [95]:

$$J(z_k) = J_y(z_k) + J_u(z_k) + J_{\Delta u}(z_k) + J_\varepsilon(z_k) \quad (2.32)$$

The first term refers to output reference tracking:

$$J_y(z_k) = \sum_{j=1}^{n_y} \sum_{i=1}^p \left\{ \frac{w_{i,j}^y}{s_j^y} [r_j(k+i|k) - y_j(k+i|k)] \right\}^2 \quad (2.33)$$

Here,

- $k$  – Current control interval

- $p$  – Prediction horizon (number of intervals)
- $n_y$  – Number of plant output variables, in this case two (frequency and interconnection deviations)
- $z_k$  – QP decision variables vector, given by:

$$z_k^T = \begin{bmatrix} u(k|k)^T & u(k+1|k)^T & \cdots & u(k+p-1|k)^T & \varepsilon_k^T \end{bmatrix}$$

- $y_j(k+i|k)$  – Predicted value of the  $j$ th plant output at the  $i$ th prediction horizon step, in engineering units
- $r_j(k+i|k)$  – Reference value for the  $j$ th plant output at the  $i$ th prediction horizon step, in engineering units
- $s_j^y$  – Scale factor for the  $j$ th plant output, in engineering units
- $w_{i,j}^y$  – Tuning weight for the  $j$ th plant output at the  $i$ th prediction horizon step (dimensionless)
- $\varepsilon_k$  – Slack variable at control interval  $k$  (dimensionless)

The values  $n_y$ ,  $p$ ,  $s_j^y$ , and  $w_{i,j}^y$  are constant controller specifications. The controller receives reference values,  $r_j(k+i|k)$ , for the entire prediction horizon. The controller uses the state observer to predict the plant outputs,  $y_j(k+i|k)$ , which depend on manipulated variable adjustments ( $z_k$ ), measured disturbances, and state estimates. At interval  $k$ , the controller state estimates and measured disturbances values are available. Therefore,  $J_y$  is a function of  $z_k$  only.

When there are more manipulated variables than plant outputs, the controller must keep selected manipulated variables (MVs) at or near specified target values. An MPC controller uses the following scalar performance measure for manipulated variable tracking:

$$J_u(z_k) = \sum_{j=1}^{n_u} \sum_{i=0}^{p-1} \left\{ \frac{w_{i,j}^u}{s_j^u} [u_j(k+i|k)] \right\}^2.$$

Here,

- $k$  — Current control interval
- $p$  — Prediction horizon (number of intervals)
- $n_u$  — Number of manipulated variables
- $z_k$  — QP decision variables vector, given by:

$$z_k^T = \begin{bmatrix} u(k|k)^T & u(k+1|k)^T & \cdots & u(k+p-1|k)^T & \varepsilon_k^T \end{bmatrix}$$

- $s_j^u$  — Scale factor for the  $j$ th MV, in engineering units
- $w_{i,j}^u$  — Tuning weight for the  $j$ th MV at the  $i$ th prediction horizon step (dimensionless)
- $\varepsilon_k$  — Slack variable at control interval  $k$  (dimensionless)

The values  $n_u$ ,  $p$ ,  $s_j^u$ , and  $w_{i,j}^u$  are constant controller specifications. The controller uses the state observer to predict the plant outputs. Thus,  $J_u$  is a function of  $z_k$  only.

Most applications prefer small manipulated variable adjustments. An MPC constant uses the following scalar performance measure for manipulated variable move suppression:

$$J_{\Delta u}(z_k) = \sum_{j=1}^{n_u} \sum_{i=0}^{p-1} \left\{ \frac{w_{i,j}^{\Delta u}}{s_j^{\Delta u}} [u_j(k+i|k) - u_j(k+i-1|k)] \right\}^2.$$

Here,

- $k$  — Current control interval
- $p$  — Prediction horizon (number of intervals)
- $n_u$  — Number of manipulated variables
- $z_k$  — QP decision variables vector, given by:

$$z_k^T = \begin{bmatrix} u(k|k)^T & u(k+1|k)^T & \cdots & u(k+p-1|k)^T & \varepsilon_k \end{bmatrix}$$

- $s_j^{\Delta u}$  — Scale factor for the  $j$ th MV, in engineering units

- $w_{i,j}^{\Delta u}$  — Tuning weight for the  $j$ th MV movement at the  $i$ th prediction horizon step (dimensionless)
- $\varepsilon_k$  — Slack variable at control interval  $k$  (dimensionless)

The values  $n_u$ ,  $p$ ,  $s_j^{\Delta u}$ , and  $w_{i,j}^{\Delta u}$  are constant controller specifications, and  $u(k-1|k)$  represents the known MVs from the previous control interval.  $J_{\Delta u}$  is a function of  $z_k$  only.

In practice, constraint violations might be unavoidable. Soft constraints allow a feasible QP solution under such conditions. An MPC controller employs a dimensionless, nonnegative slack variable,  $\epsilon_k$ , which quantifies the worst-case constraint violation (see Constraints). The corresponding performance measure is:

$$J_\epsilon(z_k) = \rho_\epsilon \epsilon_k^2.$$

Here,

- $z_k$  — QP decision variables vector, given by:

$$z_k^T = \begin{bmatrix} u(k|k)^T & u(k+1|k)^T & \cdots & u(k+p-1|k)^T & \varepsilon_k \end{bmatrix}.$$

- $\varepsilon_k$  — Slack variable at the control interval  $k$  (dimensionless).
- $\rho_\epsilon$  — Constraint violation penalty weight (dimensionless).

The remainder of the MPC parameters are included in Table 2.4.

Table 2.4: MPC Parameters. (The order of values in arrays is: \* for [Fast, Medium, Slow] units, \*\* for [Frequency, Interconnection])

| Parameter                              | Values                             |
|----------------------------------------|------------------------------------|
| Prediction horizon                     | 200 [s]                            |
| Control horizon                        | 60 [s]                             |
| Manipulated variables maximum*         | [0.2/3, 0.2/3, 0.2/3] <sup>⊤</sup> |
| Weights of manipulated variables rate* | [0.001, 0.001, 0.001] <sup>⊤</sup> |
| Weights of manipulated variables*      | [10, 20, 30] <sup>⊤</sup>          |
| Manipulated variables scale*           | [1, 1, 1] <sup>⊤</sup>             |
| Output variables scale**               | [0.01, 0.001] <sup>⊤</sup>         |
| Output variables weight**              | [0, 1] <sup>⊤</sup>                |

The values found for these parameters were obtained by trial and error but were easy to obtain due to the fact that they can be easily explained and there are few combinations of them, as follows. The prediction horizon is necessary for the controller to predict, in each iteration, the evolution of the system for the computed optimal inputs. The control horizon is a subset of the prediction horizon, for which the sequence of the optimal inputs are computed (even if, as noted, only the first set of the interval is applied to the system). The manipulated variables maximum values reflect the available reserve, and in the real-world, this is the market outcome. Here it is assumed that there are 2000 MW or 0.2 pu of reserve available, evenly split for the three units. The weights for the manipulated variables rate was left the same for the three units to create a plant mismatch: in reality the fastest units are by definition able to vary their output faster than slower units. Here they were left the same to show that the weight of manipulated variables alone determines which units are more used: here more weight was attributed to the slowest unit and vice-versa. The scale of manipulated variables is kept the same since they are in the same order of magnitude. The scale of output variables (even if measured in pu) is different and this value is assessed after observing the magnitudes of both variables following the contingency when no control is in use. The weight of output variables simply shows that the control objective only considers the reestablishment of the interconnection flows.

One note about the crucial variable for this controller, the weight of manipulated variables. In a real-world implementation, note that the TSO knows how fast each unit participating in the reserve is, since each of them has to pass a pre-qualification phase; weights could easily be assigned after each market session. Further information that can be estimated in real-time by the TSO's SCADA system are the values of inertia (H), self-regulating parameter (D) and frequency bias (B). Given the characteristics of the proposed MPC, a real world implementation of such model could easily be trained offline for the range of the admissible values of all the variables in the day-ahead phase. The current offline training of the MPC takes 2.64 seconds using a 2.10 GHz processor with 16 GB RAM. Note that while this can be more difficult to tune than the conventional AGC-PI, the MPC would only be called into action when contingencies happen in a given control area; several (adaptive) MPCs could be tuned so only one of them would be used according

to the severity of the fault, as the process is easily programmable offline.

The model limitations are as follows. In fact, no measurement acquisition time delays are implemented in the plant that is used by the MPC. However, the present study presents a so-called plant mismatch because the frequency and interconnection flows that are fed to the controller are passed first in a low pass filter. This results in wrong predictions of these variables by the model, which initially underestimate the fault severity and limit the action of the MPC controller in correcting the interconnection flows; this is precisely the interesting part of this study as it makes it more realistic. For instance, in the simulation present in Figure 2.23, the real model frequency nadir is around -0.12 pu.Hz, whereas the frequency after the low-pass filter is only slightly below -0.04 pu.Hz (which activates emergency mode). Also, the simulated parameters of  $H$ ,  $D$ ,  $B$  are kept the same in the plant and in the simulation model. But these approximations need only to be good enough, since the MPC is correcting the previous predictions with received measurements at each iteration of 4 seconds. A possible line for further research would be to include in real-time estimations of new values of  $H$ ,  $D$ ,  $B$  and other critical parameters due to plant-model mismatch, and update these values in the next MPC iteration.

### 2.3.3 Results

Simulations shown in this section use the simulation platform and the two controllers described in Section 2.3.2. Figure 2.24 shows the evolution of the frequency, active power imports and ACE in the control area  $i$ , which is affected by the 1GW generation loss.

The emergency mode is detected (or in other words, the threshold values of frequency and import pass the thresholds after the low pass filter, as per Section 2.3.2) in the control center 3.3 seconds after the generation loss occurs. It is visible that the MPC controller produces better results than the conventional PI controller, regardless if one evaluates the controller using the criterion of reestablishment of frequency in less than 5 minutes, active power imports or ACE (which is a combination of both). Considering the desirable performance criterion that the frequency stays within a band of  $50 \text{ Hz} \pm 20 \text{ mHz}$  until the end of the simulation, the AGC-PI achieves this band at 140 seconds, whereas the MPC achieves it much faster, at 24.5 seconds. It should be noted that in the first instants

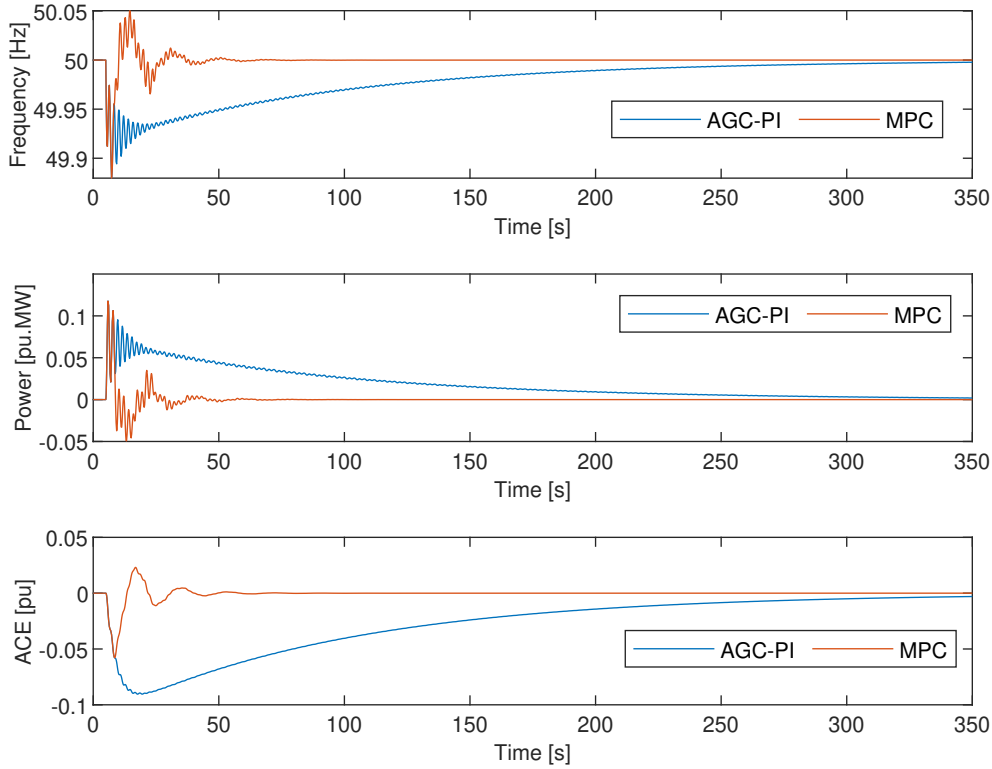


Figure 2.24: Evolution of frequency (top), imports (middle) and ACE (bottom) of area  $i$ .

after the active power from aFRR is released, the frequency goes briefly above 50 Hz (while the active power also exceeds briefly the loss of 1000 MW). Three notes on this aspect: (i) A hard constraint was added to ensure the frequency would not exceed 50 Hz, but (ii) the frequency which is read by the MPC controller (or control center) is much smoother due to the low pass filter; nonetheless (iii) the frequency stabilization on 50 Hz is much quicker than on the conventional controller and this was the main objective of this work. In the remainder of this section, the MPC is tuned in such a way that the release of active power is smoother.

Figure 2.25 shows the active power extracted by each source (fast, medium and slow) in the case of AGC-PI and MPC controllers.

As it can be seen, herein lies the fundamental difference between the AGC-PI and MPC controllers: whereas there is a juxtaposition between fast, medium and slow units in the AGC-PI controller, in the MPC the units provide three very different responses. The

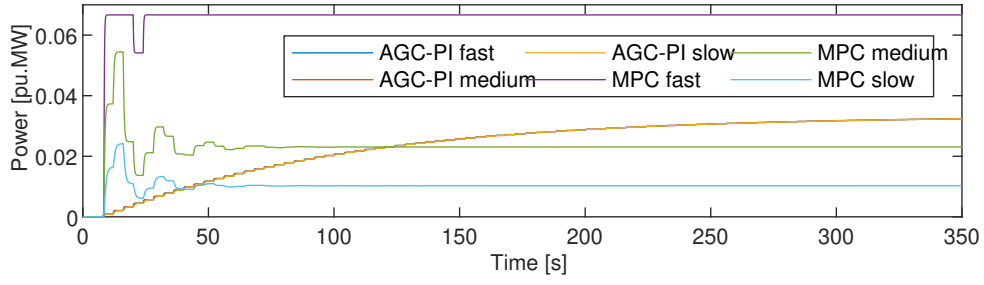


Figure 2.25: Comparison of released active power by different units under AGC-PI and MPC controllers. Note that the sources activated by AGC-PI are almost juxtaposed.

AGC-PI is simply unable to extract more power from the faster source (red), whereas the MPC (magenta) does exactly that. In fact, and to prove that the MPC is able to respect the participating factors, it can be seen that the fast unit is fully exploited (0.66 pu) as soon as the controller requires power activation, whereas in the case of AGC none of them is fully exploited. In the remainder of the section a MPC controller that avoids the “peak” shown by the sum of three outputs is designed.

### 2.3.3.1 MPC tuning

Whereas results of the previous subsection show that it is possible to have the faster units participating more than slower units in the recovery of frequency and interconnection values, the present subsection aims at tuning the MPC in such a way that frequency overshoot is avoided. Given that the plant model used by the MPC may be subject to errors (for instance, the real value of synchronous inertia in the control area may be higher or lower than estimated), the robustness of the controller is tested with plant-model mismatch. The ideal controller is, thus, one that is robust enough to deal with plant-model mismatch and recover the frequency without overshoot.

In Section 2.3.2 the manipulated variable move suppression was introduced as a mean to induce small manipulated variable adjustment. The tuning weights  $w_{i,j}^{\Delta u}$  are, thus, the key to ensure smooth control. The first task is to find the values of  $w_{i,j}^{\Delta u}$  for one controller which (i) is aggressive such that the settling time is low but frequency overshoot is avoided and then a second controller (ii) as smooth as the AGC-PI. In the simulation code a binary variable for detecting if frequency overshoot happens is introduced.

The weights  $w_{i,j}^{\Delta u}$  are  $\alpha \times [1, 2, 3]^T$ , where  $\alpha$  is a multiplier under study. The values  $[1, 2, 3]^T$  are proportional to the turbine time constants and guarantee that the faster the unit, the more it is exploited.

Simulations are performed, where the value of  $mult$  is raised iteratively from zero up to a point where condition (i) is met and then condition (ii) is met. Between values (i) and (ii) is the set of admissible range for the  $w_{i,j}^{\Delta u}$ . It was found that the condition (i) is met for  $mult = 2.9E5$  (settling time of 23.7 seconds) and condition (ii) is met for  $mult = 9E5$  (settling time of 139.7 seconds). A controller with  $mult = 6E5$  would be an intermediate solution and yields a settling time of 66 seconds.

To test the robustness of the controllers, plant-model mismatch is performed. The MPC plant is left the same as before, but the controller is run in simulations in which the parameters  $H$ ,  $D$ ,  $R$  and  $T$  for each area are subject to errors and do not coincide with the values for which the MPC plant model was trained. Each of these parameters was affected by a normally distributed error with mean  $\mu$  equal to the original value and standard deviation  $\sigma = \mu/5$ . The model was run for 1000 simulations and relevant results are Table 2.5

Table 2.5: Performance comparison between different controllers with plant-model mismatch.

| Controller                              | Aggressive | Intermediate | Non-aggressive | AGC-PI |
|-----------------------------------------|------------|--------------|----------------|--------|
| Average settling time [s]               | 22.7       | 65.7         | 139.6          | 141.3  |
| Standard deviation of settling time [s] | 2.1        | 2.7          | 2.5            | 4.1    |
| Instances with overshoot                | 43%        | 0%           | 0%             | 0%     |

It can be concluded that what was the controller that met condition (i), when subject to measurement errors would induce overshoot in 43% of the simulations. On the other hand, the previously introduced intermediate controller ( $mult = 6E5$ ) guarantees that no overshoot occurs in any simulation. The task of the MPC designer would be to find a controller with an intermediate gain between these two solutions, which would still yield a much lower settling time than the AGC-PI controller.

#### 2.3.4 Discussion

A brief discussion of results should emphasize that, as outlined in the Section 2.3.2, the weights attributed to the participating units are the key that enable the MPC to exploit more the fast resources than the slow ones. In practical terms, it would be necessary that, during the pre-qualification phase of a given unit, the TSO simply assesses and saves the values regarding ramping capabilities of such unit for future use. Typically, there are 24 day-ahead secondary reserve market sessions, one for each hour. The results of such market sessions are the number of participating units and maximum available reserve power to be provided by each. The MPC would thus need to be calibrated for each session, with the parameters given above (Table 2.3 and Table 2.4), for instance changing the number of outputs (units to be controlled) and the weights attributed to each unit, according to the ramping rates obtained during the pre-qualification.

Even if regulatory issues are outside the scope of this section, it can be pointed out that recently in some regions such as Australia and the UK new markets have been implemented such as the fast frequency response (FFR) that are, themselves, a kind of emergency FCR. Extrapolating to the present work, a possibility would be the emergence of a new market for aFRR post-fault recovery, possibly much participated by demand units with fast ramping rates such as hydrogen electrolyzers that would monetize a decrease of their energy consumption only in the case of contingency.

#### 2.3.5 Conclusions

In this section, an MPC controller is compared to the conventional PI controller in the context of AGC. Specifically, the MPC is activated only in the control area where a contingency triggers the lowering of the frequency, the trigger itself being the rise of imports to the given control area. To avoid unnecessarily being triggered by transient phenomena, frequency and interconnection values are filtered in a low-pass filter. Whereas the conventional PI controller is reactive the MPC is proactive; the other main difference being that the conventional controller distributes the burden of recovering the interconnection using all sources alike, regardless of their ramping capabilities. In the context of increasing

participation of demand-side resources in the reserves, and taking into account that in the future a significant portion of hydrogen electrolyzers with fast ramping capabilities may be willing to provide secondary reserve, in this section it is argued that an MPC controller can take more advantage of these fast units. This provides an advantage for the TSO of the affected area, which may improve the quality of its service, and also for the TSOs of remaining control areas, since all benefit with a faster return to the nominal frequency value, following a contingency. While the conventional PI controller is simpler than the proposed MPC controller, it can be argued that the latter is simpler than MPC controllers proposed in the literature of MPC applications for AGC. This is because the complexity of the power system in general and the grid topology in particular are not taken into consideration: the plant model used by the MPC is a simple linear-time invariant model built with simple differential equations and, like the conventional controller, the MPC uses simply frequency and interconnection values as inputs. The simulated model parameters achieve the proposed objective: it is possible to use the MPC to extract more power from faster units such as electrolyzers even if these units have the same market share as slower units. On the other hand, it was proven that the conventional AGC-PI controller activates reserves of the same magnitude from all units. The interconnection values are reestablished significantly faster with the MPC than with the conventional controller.

There is a trade-off between having a low settling time and being subject to a frequency overshoot, especially due to plant-model mismatch or bad estimation of parameters on the TSO control center. Based on this premise, the tuning of a robust controller is done. It is shown that it is possible to design a robust controller that, compared to the AGC-PI, reduces the settling time in more than 50% without risking frequency overshoot due to plant-model mismatch.

This methodology can also be applied to other fast units, such as some types of battery storage units.

Future work may include the use of time delays in the plant model and include the grid topology.

While the present chapter addressed the dynamics and control of the LFC, the next chapter focuses on the market and regulatory aspects.

## Chapter 3

# Frequency Containment Reserve Market and Regulation

*While the previous chapter addressed the dynamics and control, the present chapter covers the market and regulation of the Frequency Containment Reserve. It is divided in two sections.*

*In the first section, the participation of a Virtual Power Plant (VPP) in the FCR market is modeled to allow the calculation of its revenues. The participants of the VPP are wind and solar plants and hydrogen electrolyzers (HEs). The FCR activation makes the VPP participants incur in opportunity costs, which are quantified and included in the model. It is estimated that a VPP aggregating 50 MW of HEs in Portugal would have an annual revenue of over 800 k€.*

*Since in Portugal and Spain a FCR market does not yet exist, the costs for these TSOs to join the existing FCR market platform of central Europe (FCR Cooperation) are estimated. For instance, the Portuguese Transmission System Operator would have paid roughly the annual cost of 10 M€ to satisfy its FCR needs in the FCR Cooperation in 2022.*

*In the second section, regulation of the FCR Cooperation is addressed. Particularly, the existing mechanism through which TSOs pay Balancing Service Providers (BSPs) such as Hydrogen Electrolysers is analyzed. It was found that such mechanism presents market*

*inequities such as negative costs for some TSOs in specific conditions, which are discussed. In the proposed scheme TSOs begin paying the local BSPs for the cleared bids needed locally, and the remaining imports are calculated in a subsequent step. Doing so avoids using the “import/export costs” which are demonstrated to be the source of the distortion of the current scheme. It is shown that if the proposed pricing scheme had been adopted from July 2019 to December 2022, all TSOs would be affected, namely, the most negatively impacted TSO would have its accumulated costs increased by 16% and the most positively impacted TSO would have its accumulated cost decreased by 32%. The inequities of the current mechanism amounts to more than 50 M€ or 7.4% of the total accumulated costs.*

Before the market reforms that were promoted in the first decades of this century, the electricity sector was regarded as a vertically integrated natural monopoly. It was believed that the advantages of vertical integration was about cost savings through coordination advantages, sharing of information, use of common inputs, sharing of staff, efficient planning of investments, protection against uncertainty and financial risk, among others [96]. The unbundling (vertical separation) that followed reforms resulted in the segmentation of the electricity sector, and although the transmission and distribution sectors are still regarded as natural monopolies that need to be regulated, the remaining sectors (generation, retail) are now subject to open competition [97]. Energy is traded in the energy market. Besides the energy markets, ancillary services markets exist. Ancillary services are a provision necessary for the proper operation of a transmission or distribution system [98]. These can be divided in non-frequency ancillary services (such as voltage control) and frequency ancillary services [99]. In this chapter, the Frequency Containment Reserve market is addressed.

### **3.1 HE Participation in FCR Market**

#### **3.1.1 Introduction**

In this section, the participation of a Virtual Power Plant (VPP) in the FCR market is modelled to allow the calculation of its revenues. The costs for the Portuguese and Spanish TSOs to join the existing FCR market platform of central Europe (FCR Cooperation) are estimated.

Although the European Commission approved guidelines in 2017 that aimed at the creation of balancing markets [100], Portugal and Spain do not yet have a functioning FCR market [101]. The existing situation and a possible alternative can be described according to Figure 3.1, as follows.

The non-existence of an FCR market in these countries implies that the costs that consumers pay regarding this service are not transparent and are probably inefficient due to the lack of competition. The only allowed balancing service providers (BSPs) of FCR in Portugal and Spain are conventional power plants (e.g., hydro, coal, natural gas).

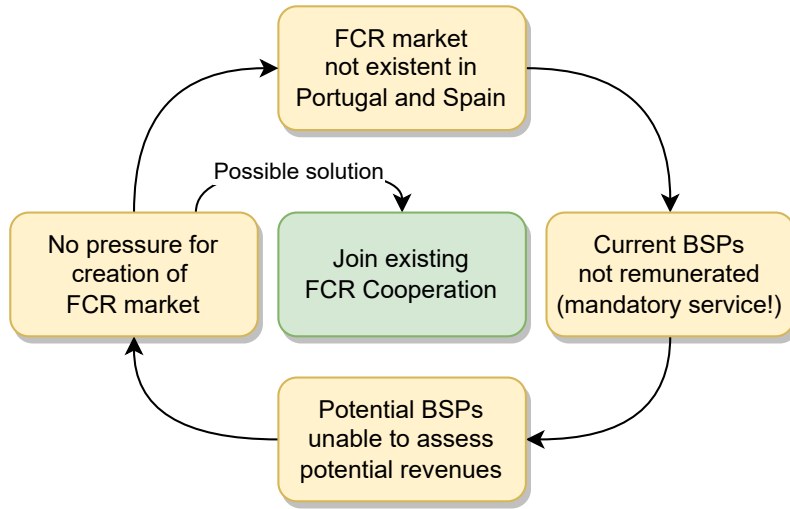


Figure 3.1: Problem formulation.

Besides not being a market subject to open competition, the BSPs are providing FCR as a mandatory and non-remunerated service. On the other hand renewable energy generators and hydrogen electrolyzers (HEs) could become BSPs and generate additional revenues in the FCR market that would complement their main sources of revenues (by selling energy and hydrogen, respectively). While these actors might be interested in providing FCR, they are naturally against providing this service if they cannot profit from it. They end up not constituting the critical mass that is needed for opening up a new FCR market. It is up to regulators of both countries to either keep this situation or to open up this sector to transparent market mechanisms. There are at least three ways for the regulator to ensure the existence of an FCR market: either a national market is created in each country, an international market with these two countries is created (like the present-day energy market), or these countries integrate an existing and wider international market. This study explored the latter option.

The FCR Cooperation is an international market that is presently open to nine European countries [102]. In general, it is expected that such a market integration is a benefit for the participants, which can share resources in a wider market, leading to market efficiency. Since Spain's bordering country (France) already participates in this market, Portugal and Spain may aspire to integrate it in the near future. Spain and Portugal's transmission grids are operated by different TSOs; therefore, each of them would join the

FCR Cooperation as a separate entity. BSPs from the participating countries provide supply bids to the FCR Cooperation, whereas TSOs demand them to ensure that the system frequency stability is kept close to 50 Hz. The product traded in this day-ahead market is valid for 4 hours; therefore, there are six daily market sessions.

According to the market rules [102], in this market, there is an international price, called the “cross-border marginal price” (CBMP), and in each country, there is a “national” local marginal price (LMP), which may or may not differ from the CBMP, as follows. For each country participating, there is a minimum and maximum aggregated volume [MW] of bids from BSPs that can be accepted in the process of market clearing. These are known as the “core” and “export limit” constraints, respectively: the maximum is due to the interconnection capacity and the minimum ensures that all countries participate to solve the frequency deviations (which affect all of the interconnected area).

If the aggregated volume of accepted bids from BSPs from a country is not hitting any constraint (“hitting a constraint” means that the aggregated volume of BSPs from a country is exactly equal to the “core” or “export limit” of that country [102]), the LMP in this country equals the CBMP. In case the sum of the accepted bids from the BSPs of a given country hits the “core” constraint, the local marginal price (LMP) in that country will be the price of the last bid, which will be higher than the CBMP; conversely, if the “export limit” constraint is hit, the LMP in that country is lower than the CBMP. The CBMP is the most expensive bid accepted in the session in a country where no constraints are hit.

The units participating in the FCR have a local controller that, according to the frequency of the grid, increases or decreases the output of the controlled unit. The basics behind the FCR can be explained using Figure 3.2 as an example.

When the frequency falls below 50 Hz (underfrequency), this means that the load in the system is greater than the generation, hence upward reserve activation (i.e., increase in generation) is required. The opposite is also true and results in downward reserve activation. According to [43], the FCR reserve activation is proportional if the frequency deviation is  $\pm 200$  mHz; when the frequency deviation from 50 Hz is higher than  $\pm 200$  mHz, the full reserve should be activated. Taking this into consideration and using the frequency

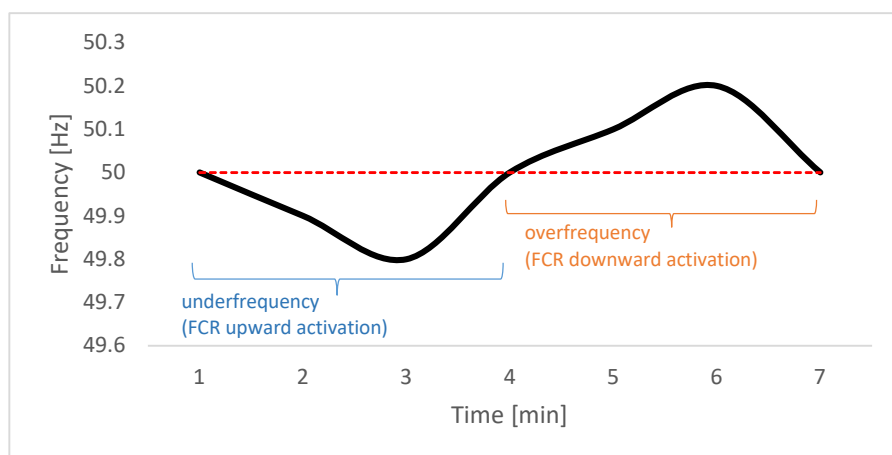


Figure 3.2: Example of a frequency variation and the need for FCR upward and downward activations.

variation presented in Figure 3.2, the output of a BSP unit (e.g., a combined cycle gas turbine power plant) reserving 5 MW for FCR would be the one presented in Figure 3.3. Since the plant in the example has a maximum capacity of 100 MW, in order to provide 5 MW of upward reserve, this means that at the nominal frequency, the plant can provide a maximum of 95 MW for the energy market, thus reserving 5 MW of *headroom* for the FCR market. In this case, reserving this *headroom* for the FCR market means that the plant is *permanently* missing the opportunity to sell these 5 MW to the energy market. This missed opportunity represents an opportunity cost.

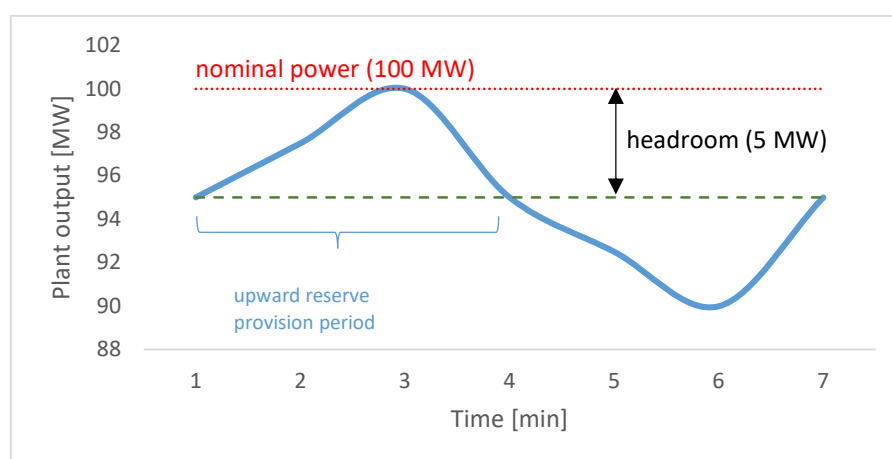


Figure 3.3: Active power response to frequency variation and concept of headroom.

Currently, in the FCR Cooperation, only symmetric bids are accepted, meaning that

when a bid of, e.g., 5 MW is accepted, the BSP must guarantee that when the FCR is activated, it can provide up to 5 MW downward and upward depending on the frequency value. The FCR Cooperation does not remunerate the activated energy; only the accepted power is remunerated.

The VPP solution envisioned in this chapter has three components: solar units, wind units, and HEs. The first hybrid power plant in Europe that includes solar and wind farms and will include HEs in the future is presented in [103]. Technically, if the resources are available, it is possible to control the output of all of these units to allow for FCR provision, as shown for wind farms [104], solar units [105], and HEs [106].

Each component of the VPP is capable of both upward and downward reserve provision. The real-world demonstration of both upward and downward FCR provision of a 300 MW solar unit is presented in [79]; instead of operating at an estimated available peak power, the plant reserves 30 MW headroom, like the previous comments about Figure 3.3 emphasize. Of course, with no headroom, only downward provision will be possible for wind and solar units; on the other hand, with no headroom, an HE can provide only upward reserve.

As shown in Figure 3.3, reserving headroom leads to opportunity costs. The contradiction is the following: reserving headroom allows for FCR provision but also diminishes the potential revenues of a solar unit on the energy market. It should be taken into account that the main purpose of a solar unit is to deliver energy to the grid on the energy market; similarly the HEs take energy from the grid mainly to produce hydrogen that is sold on the hydrogen market. FCR provision should be seen as an additional revenue for these units. The fact that FCR needs to be delivered as a symmetric product encourages the aggregation of solar and wind units that are solely downward providers with HEs that are only upward providers because the headroom is avoided completely for each of the components when they are aggregated. This is the aggregation proposed in this work, which is done through a VPP.

The concept of the VPP downward reserve provision is illustrated in Figure 3.4, still using the frequency evolution presented in Figure 3.2. Likewise, the HE upward reserve provision is illustrated in Figure 3.5.

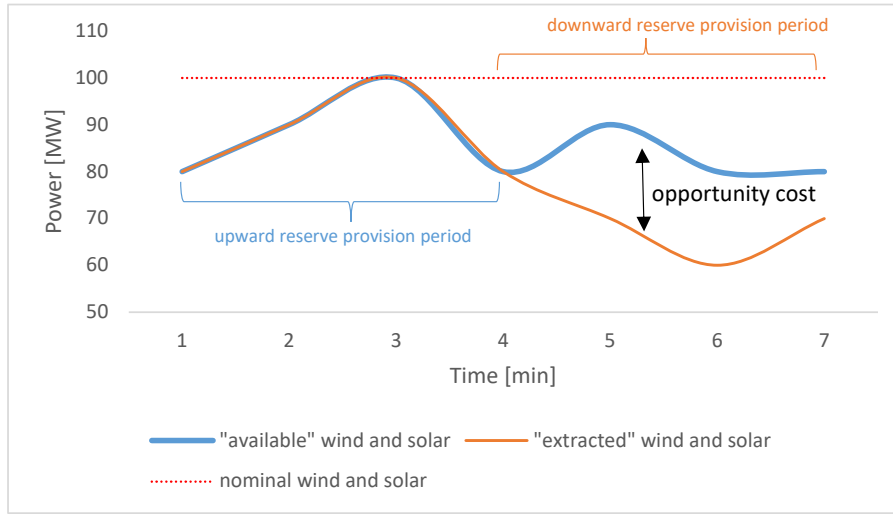


Figure 3.4: VPP downward reserve provision and associated opportunity costs.

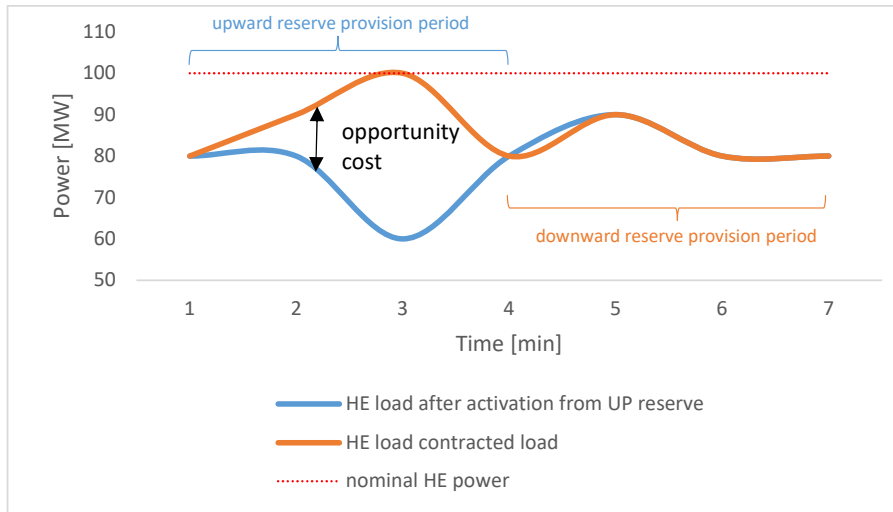


Figure 3.5: VPP upward reserve provision and associated opportunity costs.

From these examples it can be concluded that opportunity costs may be occurring in every instant *for the VPP as a whole*, but only half of the time for each of its participants, allowing them to operate with no headroom. It must be taken into account that this example has extreme variations in the frequency for demonstration purposes, but in reality, the frequency is closer to 50 Hz most of the time, allowing the VPP participants to dedicate their units to the energy market in normal conditions and only incur in opportunity costs when disturbances happen. One relevant question that arises is, thus, what is the volume of opportunity costs in this case? To answer this question, it is necessary to assess the

usage of upward and downward reserves in existing grids. For instance, the data from three years of market sessions in France spanning data from mid-2020 to the end of 2022 [107] is organized from the highest to lowest percentage of reserves activated in Figure 3.6. The value read on the y-axis is the ratio between the activated energy (MWh) to the contracted power (MW) of the upward/downward reserve. This plot shows that the maximum value of either upward and downward reserves that were measured was around 40% and the minimum was close to 0%. The average and median values were around 10%. Whether this small percentage translates into low or high opportunity costs for participants in a VPP was one of the motivations behind this study.

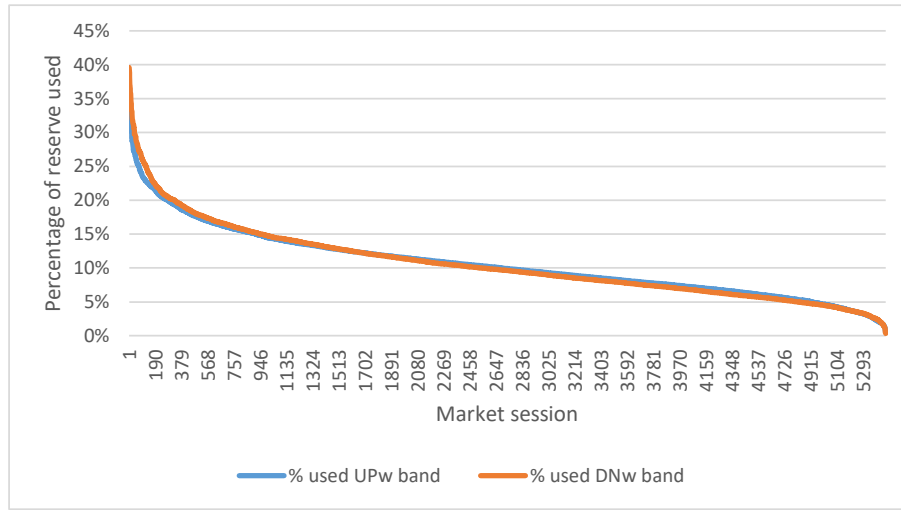


Figure 3.6: Percentage of upward and downward reserves used in France.

#### 3.1.1.1 Motivation, Literature Review, and Section Organization

As previously mentioned, eventually Portugal and Spain may consider joining the FCR Cooperation. The present study was motivated by the following:

- Potential BSPs are interested in assessing the order of magnitude of revenues. This is currently not known because the FCR in Portugal and Spain is mandatory and not remunerated. BSPs will be able to assess how much this market is *potentially* worth.

- A VPP including HEs and wind and solar plants is a particular case of the previous point and this study adopted this point of view.
- Assessment of opportunity costs of the VPP have to be taken into account.
- TSOs need to assess the costs of joining the FCR Cooperation, in order to pass such costs transparently to consumers.

The identified literature gap is now briefly outlined. From the broader to the most concrete, the main topics of interest for the present study were (1) the economic analysis of ancillary services provision by DERs; (2) the context of the FCR Cooperation; (3) focusing aggregation via VPPs; and, especially, (4) the participation of HEs. Although all these topics were previously addressed separately, it was found that no study covered them all.

Topic (1) consists of a vast and growing body of work: the interested reader is directed to the review presented in [108], which classified over 60,000 works about ancillary services provision by DERs, and concluded that around one fifth of the recent studies addressed scheduling, particularly bidding strategies on balancing markets. However, the particular market of topic (2) is much less covered; an example would be [109], where electric vehicles FCR provision is analyzed from a policy-making perspective; this chapter also covers topic (3) as it deals with aggregation. Still on topic (3) but from a more technical perspective, [101] addressed the prequalification process of aggregation. The participation of VPPs in the FCR Cooperation is already a reality: NextKraftwerke claims to be the largest VPP operating in Europe and participates in this market [110].

Covering topics (1) and (4), [106] proposed a techno-economic analysis for FCR provision in Belgium using a 25 MW HE. Regarding these topics, this paper is the literature case that comes closer to the aims of the present work. The authors [106] used a dynamic model for the HE, where the HE power consumption depends on the grid frequency. However, the opportunity costs implied in the participation of HEs in the FCR market were not analyzed in this study since they are implicit in the results. Another difference between this paper and present chapter is the fact that in [106], the HEs consumed electricity procured in the energy market, whereas the present study assumed that power purchase

agreements were used. Furthermore, [106] used the Belgian case with four distinct FCR products, whereas the present study proposed the context of FCR Cooperation, which is a simpler market with a single product. Finally, no aggregation via VPP was proposed in [106].

The remainder of this section is organized as follows: Section 3.1.2 details the methodology used, Section 3.1.3 presents the results, Section 3.1.4 discusses the results, and Section 3.1.5 draws conclusions.

### 3.1.2 Methodology

The methodology is represented in Figure 3.7. The main aim was to compute the VPP revenues obtained by participating in the FCR Cooperation and taking into account the opportunity costs of solar, wind, and HEs. This was done by changing a set of user-defined variables. The second objective was to compute the TSO costs for Portuguese and Spanish TSOs.

The model presented in this section uses a set of parameters and user-defined variables outlined in Table 3.1. The model's implementation is available in a downloadable spreadsheet on the Zenodo platform. [111]

The set  $t$  represents the tender (or market session) number, ranging from 1 to 5460, while set  $c$  refers to the country (Portugal, Spain). Although this study only focused on two countries, it could be readily extended to explore additional countries, offering a platform for investigating further integration within the FCR Cooperation. Each tender ( $t$ ) in the FCR Cooperation spanned a duration of four hours, serving as the time-step for the model.

The approach can be outlined through the following parts and steps:

**Part 1—Without opportunity costs:** VPP potential revenues were computed in this first part. The VPP *potential* revenues were computed by considering that the VPP operated at zero opportunity costs in order to assess what revenue the VPP would have in the tender, disregarding the costs it needs to pay in order to attract HE, wind, and solar plants in the FCR market participation.

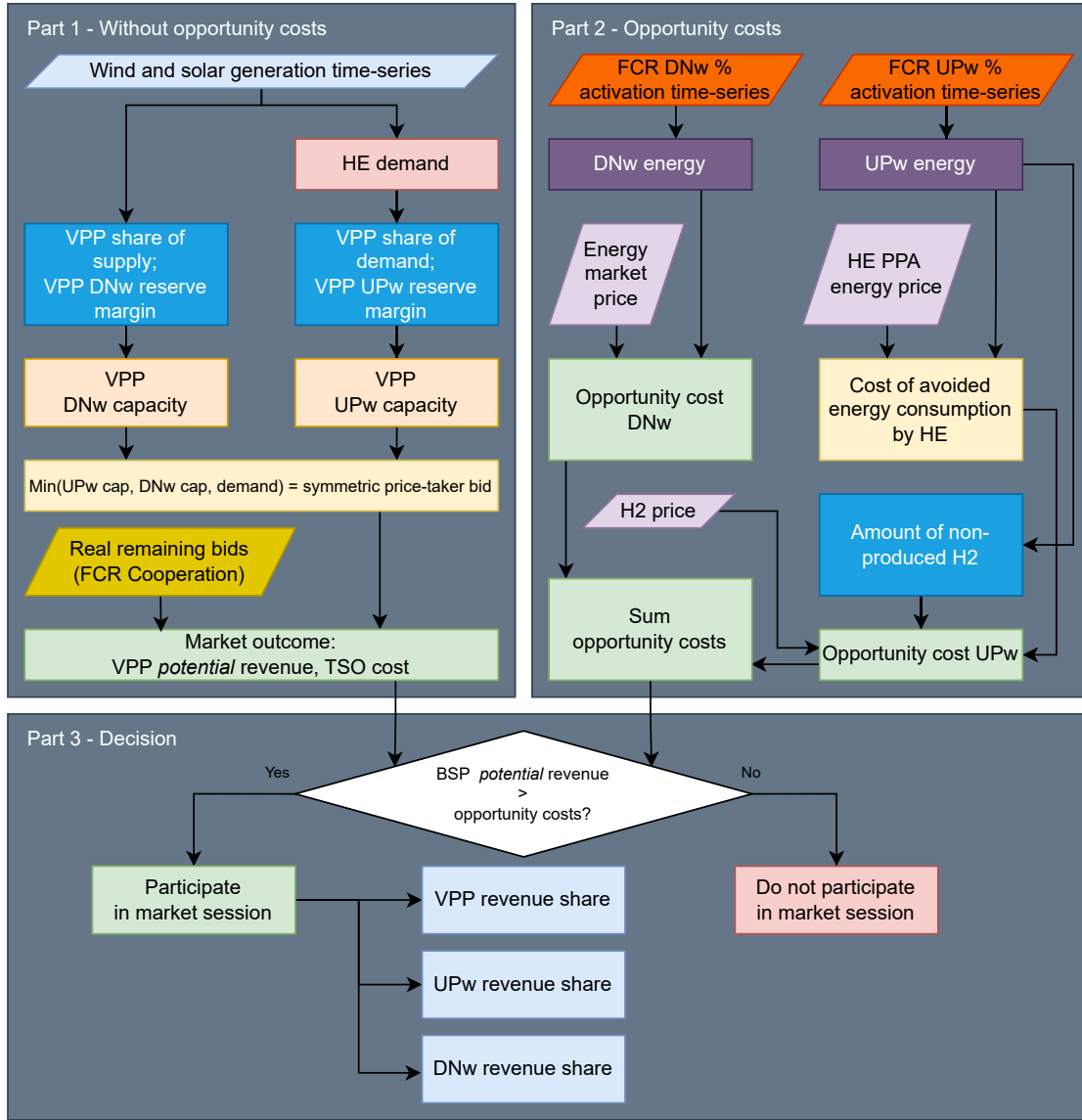


Figure 3.7: Methodology.

- **Wind and solar production time series**—The wind and solar generation taking place in period  $t$  in country  $c$ , denoted as  $G_{c,t}$ , was presumed to be known and is provided here as a parameter.
- **HE demand**—The demand of HEs ( $DH_{c,t}$ ) was likewise treated as a parameter that was dependent on the parameter  $G_{c,t}$ . Specifically, it is zero when  $G_{c,t}$  is below the user-defined variable  $HMin$ . Subsequently, it increases linearly until it reaches the installed HE installed capacity ( $PN_c$ ) when  $G_{c,t}$  surpasses the user-defined variable  $HMax$ , as outlined in Equation (3.1). The intuition for  $HMin$

and  $HMax$  is the following: if in a given hour, the renewable energy generation is small, no hydrogen is generated, and if there is a high renewable energy generation, the hydrogen electrolyzers work at full capacity. This is in line with the strategic objectives of the European Commission in ensuring that the hydrogen generated with grid connected electrolyzers work more during hours with more renewable generation. As for the values of  $Hmin$  and  $Hmax$ , they were found after analyzing the time series for renewable energy generation in each country and adjusting  $Hmin$  and  $Hmax$  such that the capacity factors of HEs (Tables in Appendix F) would be at least 50%.

- **VPP downward capacity**—The share of downward reserve that can be supplied by solar and wind power under the VPP, which is denoted as  $DN_{c,t}$ , was determined by the product of  $G_{c,t}$  and two coefficients. The first coefficient, i.e.,  $VGS_c$ , signifies the proportion of solar and wind units contracted by the VPP (e.g., 1% of the total solar and wind units). The second coefficient, i.e.,  $RGS_c$ , represents the reserve margin for which these units are available for FCR provision (e.g., 5%, ensuring that a minimum of 95% of the generated power at any given moment is reserved for the energy market). This relationship is expressed in Equation (3.2).
- **VPP upward capacity**—The share of upward reserve that can be supplied by the HEs under contract with the VPP, which is denoted as  $UP_{c,t}$ , was determined by the product of  $DH_{c,t}$  and  $RDS_c$ . Similar to  $RGS_c$ ,  $RDS_c$  signifies the reserve margin, representing the availability of these units for FCR provision. This relationship is expressed in Equation (3.3).
- **Symmetric price-taker bid**—Given that the bids need to be “symmetric”, meaning that they have the same size of upward and downward capacity, the proposed bid size, which is denoted as  $B_{c,t}$ , was determined as the minimum among the upward capacity, downward capacity, and the demand of the TSO ( $D_{c,t}$ ), as outlined in Equation (3.4). The term “price-taker” implies that  $B_{c,t}$  is offered at a low price, ensuring its acceptance and payment at the international price  $CBMP_t$ .

- **FCR Cooperation bids**—It was assumed that the existing bids (both demand and supply) from actual market sessions were already known. The value of  $CBMP_t$  is the result of these market sessions, and the “price-taker” strategy of the VPP does not alter it. This is because, given the balanced state of the country, the international price (CBMP) is already established and known.
- **Market outcome**—The VPP potential revenues, i.e.,  $VPR_{c,t}$ , were computed according to Equation (3.5).

**Part 2—Computing opportunity costs:** These refer to the participation of HE, solar, and wind plants in the FCR.

- **FCR downward/upward time series**—The values of energy activated by the downward and upward FCRs in France in the period  $t$ , i.e.,  $DN\_en_{FR,t}$  and  $UP\_en_{FR,t}$ , respectively, were retrieved from [107].
- **Downward/upward energy**—It was assumed that the values of the energy activated by the upward and downward FCR bids, i.e.,  $DN\_en_{c,t}$  and  $UP\_en_{c,t}$ , respectively, were known and proportional to the ones in France and to the submitted VPP bid capacity  $B_{c,t}$ , as per Equations (3.6) and (3.7). This means that these values were model inputs, which in reality, would be impossible to forecast, although Figure 3.6 gives us average and standard deviation values, which would be useful for the VPP bidding strategy.
- **Energy market price**—The average energy market price in the period  $t$ , i.e.,  $EMP_{c,t}$ , was assumed to be known and was retrieved from [112].
- **Downward opportunity cost**— $DN\_OPC_{c,t}$  represents the cost of  $DN\_en_{c,t}$ , which is essentially wind and solar energy that is not sold in the energy market due to being reserved for FCR. This potential (“potential” because only when the VPP participates in the tender, as decided in part 3 of the methodology, does this opportunity cost exist) cost was computed using Equation (3.8).

- **HE power purchase agreement (PPA) price ( $PPAP$ )**—It was assumed that HEs will operate with electricity procured via the PPA instead of the energy market [113]. The levelized cost of energy was assumed to be the low end of values for solar and wind energy found in [114], and thus, the  $PPAP$  was assumed to be 27 EUR/MWh.
- **Cost of avoided energy consumption by HE**—The upward energy required by the FCR, i.e.,  $UP_{enc,t}$ , comes from energy not consumed by the HEs. Therefore, the cost of this avoided energy, i.e.,  $CAE_{c,t}$ , was computed according to Equation (3.9).
- **Amount of non-produced H2**— $NPH$  was computed according to Equation (3.10), where the parameter  $Ef$  stands for the efficiency parameter assumed to be 50 kWh/kg [115].
- **Upward opportunity cost**— $UP\_OPC_{c,t}$  was computed according to Equation (3.11). The opportunity cost in this case is the missed opportunity of selling hydrogen that would have otherwise been produced if the HEs would consume  $UP_{enc,t}$ , discounted by the price that the energy would have cost.  $PH$  here stands for the hydrogen remuneration, which was assumed to be 2.8 EUR/kWh. This value came from the European Commission assessment of the costs of blue hydrogen in 2021 [116]; therefore, here it was assumed that “green hydrogen” was remunerated exactly as “blue hydrogen” in the hydrogen market instead of somehow being subsidized.
- **Sum of opportunity costs**—Upward and downward costs were added, as per Equation (3.12).

**Part 3—Decision:** Here, the decision refers to the VPP participation or not in the FCR Cooperation tender  $t$ .

- **Comparison of potential revenue and opportunity costs**—Put simply, if the potential revenue is lower than the opportunity costs, this means that the VPP would be losing money in the market FCR session; therefore, the logical decision is

not to participate, in which case, the binary *decision* variable  $Dec_{c,t}$  would be 0, as per Equation (3.13). If the VPP participates in the market session, the potential revenue becomes a revenue, as per Equation (3.14).

- **UPw revenue share**—One assumption of this study was that the HE owner would earn at least as much in the FCR market as it would in the hydrogen market; therefore, according to Equation (3.15), the UPw reserve share  $UPRS_{c,t}$  equals the respective opportunity costs. Naturally, if the VPP does not participate in the market tender,  $Dec_{c,t} = 0$ , and the opportunity costs are null.
- **DNw revenue share**—Likewise, the solar and wind plants receive their revenue share  $DNRS_{c,t}$ , according to Equation (3.16).
- **VPP revenue share**—The VPP owner, after paying both the upward and downward providers, reserves the remaining revenue  $VR_{c,t}$  for itself, according to Equation (3.17). This value can be understood as a profit of the VPP.
- **TSO cost**—The TSO cost,  $TC_{c,t}$ , is computed as per Equation (3.18) and is obtained by multiplying the TSO demand,  $D_{c,t}$  by the CBMP.

$$DH_{c,t} = \begin{cases} 0, \text{ if } G_{c,t} \leq HMin_c \\ PN_c, \text{ if } G_{c,t} \geq HMax_c \\ (G_{c,t} - HMin_c) \times \frac{PN_c}{HMax_c - HMin_c}, \text{ otherwise} \end{cases} \quad (3.1)$$

$$DN_{c,t} = G_{c,t} \times VGS_c \times RGS_c \quad (3.2)$$

$$UP_{c,t} = DH_{c,t} \times RDS_c \quad (3.3)$$

$$B_{c,t} = \min(DN_{c,t}, UP_{c,t}, D_{c,t}) \quad (3.4)$$

$$VPR_{c,t} = CBMP_t \times B_{c,t} \quad (3.5)$$

$$DN\_en_{c,t} = B_{c,t} \times \frac{DN\_en_{FR,t}}{D_{FR,t}} \quad (3.6)$$

$$UP\_en_{c,t} = B_{c,t} \times \frac{UP\_en_{FR,t}}{D_{FR,t}} \quad (3.7)$$

$$DN\_OPC_{c,t} = DN\_en_{c,t} \times EMP_{c,t} \quad (3.8)$$

$$CAE_{c,t} = UP\_en_{c,t} \times PPAP \quad (3.9)$$

$$NPH_{c,t} = UP\_en_{c,t} \times Ef \quad (3.10)$$

$$UP\_OPC_{c,t} = NPH_{c,t} \times PH - CAE_{c,t} \quad (3.11)$$

$$OPC_{c,t} = DN\_OPC_{c,t} + UP\_OPC_{c,t} \quad (3.12)$$

$$Dec_{c,t} = \begin{cases} 0, & \text{if } OPC_{c,t} > VPR_{c,t} \\ 1, & \text{otherwise} \end{cases} \quad (3.13)$$

$$VR_{c,t} = Dec_{c,t} \times VPR_{c,t} \quad (3.14)$$

$$UPRS_{c,t} = UP\_OPC_{c,t} \times Dec_{c,t} \quad (3.15)$$

$$DNRS_{c,t} = DN\_OPC_{c,t} \times Dec_{c,t} \quad (3.16)$$

$$VRS_{c,t} = (VR_{c,t} - OPC_{c,t}) \times Dec_{c,t} \quad (3.17)$$

$$TC_{c,t} = CBMP_t \times D_{c,t} \quad (3.18)$$

The inputs, user-defined variables, and outputs are given in Table 3.1. “Inputs” refer to the given data, whereas “user-defined variables” can be changed in the spreadsheet to achieve different “outputs”. The results presented for the scenarios thus result from different values of “user-defined variables”.

All the variables from Table 3.1 were assumed to be static over the years.

$D_{c,t}$  was 380 MW in Spain and 50 MW in Portugal as in 2021 [64].  $DH_{c,t}$  was obtained from Equation (3.1) and depended on the inputs and user-defined variables.

The information related to FCR Cooperation ( $CBMP$ ) spanning the period from

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1 July 2020 to 31 December 2022 was acquired from [117]. Data preceding this date, which involved a single daily tender, was excluded, as it was deemed less suitable for a VPP. VPPs require greater granularity in bids due to the substantial variability in renewable energy generation throughout the day. The initial data cleansing step involved eliminating the second tender. The decision to remove these 121 data points was based on the consideration that only certain TSOs participate in such tenders.

Furthermore, data from certain instances where a TSO did not submit demand bids were excluded. Specifically, during the period from 27 June 2022 to 30 June 2022, discrepancies were observed in the data, as most countries seemed to be importing their entire demand without other countries compensating for this. Following the data-cleansing process, there remained 5455 data points.

The information relative to wind and solar generation ( $G_{c,t}$ ) was acquired from [112]. The acquired values were provided at an hourly resolution. In order to align with the market data, it was imperative to resample the data to a 4 h time-step while preserving the lowest value in the series to ensure the activation of the bid in the worst-case scenario.

The progression of the monthly average CBMP is depicted in Figure 3.8. Notably, in the year 2021, the CBMP experienced a nearly tenfold increase. As the TSO demand is inelastic, this implies that the aggregated BSP revenues inevitably escalated in tandem with this proportion.

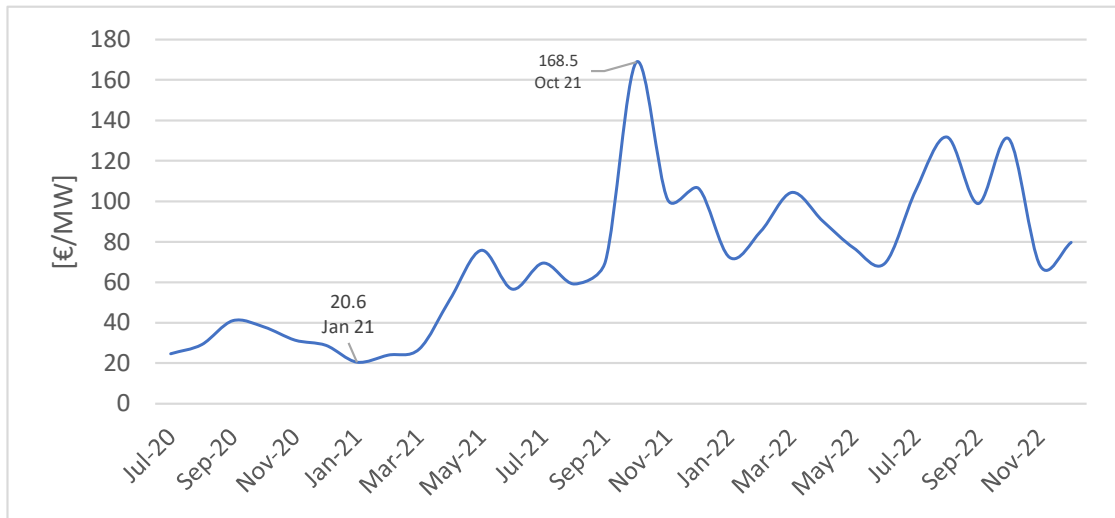


Figure 3.8: Monthly average values of the CBMP.

## 3.1.2.1 Scenarios

The scenarios examined in this study were formulated by employing distinct values for user-defined variables outlined in Table 3.1, and they are detailed in Table 3.2.

Table 3.1: Model inputs, user-defined variables ( $udv$ ), and outputs.

| Symbol          | Type   | Meaning                                                                                |
|-----------------|--------|----------------------------------------------------------------------------------------|
| $CBMP_t$        | Input  | Cross-border marginal price                                                            |
| $D_{c,t}$       | Input  | Inelastic demand bid of $TSO_c$                                                        |
| $G_{c,t}$       | Input  | Generation from VRESs                                                                  |
| $DH_{c,t}$      | Input  | Demand from HEs                                                                        |
| $DN\_en_{c,t}$  | Input  | Energy activated by the downward FCR                                                   |
| $UP\_en_{c,t}$  | Input  | Energy activated by the upward FCR                                                     |
| $EMP_{c,t}$     | Input  | Average day-ahead energy market price during the hours of the tender $t$               |
| $HMin$          | $udv$  | Value below which $DH_{c,t}$ is null                                                   |
| $HMax$          | $udv$  | Value above which HE demands its nominal power                                         |
| $VGS_c$         | $udv$  | Percentage of the $G_{c,t}$ contracted by the VPP                                      |
| $RGS_c$         | $udv$  | Percentage of the $VGS_c$ that can be offered as reserve                               |
| $PN_c$          | $udv$  | Aggregated nominal power of <i>on-grid</i> HEs                                         |
| $RDS_c$         | $udv$  | Percentage of the $DH_{c,t}$ that can be offered as reserve                            |
| $PPAP$          | $udv$  | Power purchase agreement price (for HEs)                                               |
| $Ef$            | $udv$  | Efficiency of HE conversion (energy to hydrogen)                                       |
| $DN_{c,t}$      | Output | Downward reserve bid capacity                                                          |
| $UP_{c,t}$      | Output | Upward reserve bid capacity                                                            |
| $B_{c,t}$       | Output | Submitted VPP bid in the market session                                                |
| $VPR_{c,t}$     | Output | VPP potential revenue in the market session (disregarding opportunity costs)           |
| $DN\_OPC_{c,t}$ | Output | Downward opportunity cost                                                              |
| $CAE_{c,t}$     | Output | Cost of avoided energy (not consumed by HEs due to energy activated by the upward FCR) |
| $NPH_{c,t}$     | Output | Non-produced hydrogen due to energy activated by the upward FCR                        |
| $UP\_OCP_{c,t}$ | Output | Upward opportunity cost                                                                |
| $Dec_{c,t}$     | Output | VPP's decision to participate in tender $t$                                            |
| $VR_{c,t}$      | Output | VPP revenue in the market session                                                      |
| $UPRS_{c,t}$    | Output | Upward VPP participants' revenue share                                                 |
| $DNRS_{c,t}$    | Output | Downward VPP participants' revenue share                                               |
| $VRS_{c,t}$     | Output | VPP's revenue share after discounting opportunity costs                                |

The main difference between the scenarios was the installed capacity of HEs. Portugal has committed to installing 2 to 2.5 GW of HEs by 2030 [30], whereas Spain has committed to 4 GW [31]. This study investigated this scenario (Scenario 3 “pledged” 2030), as well

Table 3.2: Scenarios used in simulations.

|             | Scenario 1<br>“Pessimistic”<br>2025 |        | Scenario 2<br>“Expected”<br>2025 |        | Scenario 3<br>“Pledged”<br>2030 |        |
|-------------|-------------------------------------|--------|----------------------------------|--------|---------------------------------|--------|
| Variable    | PT                                  | ES     | PT                               | ES     | PT                              | ES     |
| $VGS_c$     | 3%                                  | 2%     | 6%                               | 5%     | 12%                             | 10%    |
| $RGS_c$     | 20%                                 | 20%    | 20%                              | 20%    | 20%                             | 20%    |
| $PN_c$ [MW] | 50                                  | 200    | 100                              | 500    | 1,000                           | 2,000  |
| $HMin$ [MW] | 200                                 | 1,000  | 200                              | 1,000  | 500                             | 2,000  |
| $HMax$ [MW] | 2,000                               | 10,000 | 2,000                            | 10,000 | 5,000                           | 20,000 |
| $RDS_c$     | 20%                                 | 20%    | 20%                              | 20%    | 20%                             | 20%    |

as two scenarios (1 and 2), assuming that by mid-decade, only a small part (5–10%) of the 2030 targets were achieved.  $PN_c$  refers only to HEs producing *electricity-based hydrogen*: it was assumed that by 2030, 50% of the installed HEs were grid-connected. For scenario 3, the time series of wind and solar energy generation, i.e.,  $G_{c,t}$ , was increased proportionally to the expected increase in solar and wind power in both countries in 2030 [118, 119]. The assumption was made that both  $RGS_c$  and  $RDS_c$  were set at 20%.

### 3.1.2.2 Assumptions and Limitations

An assumption was made that Portugal and Spain were in balance, with no imports or exports. Note that the remaining countries had imports and exports based on the available data, and the local marginal prices (LMPs) may differ from CBMP in these cases; however, such variations did not impact the calculations in this study.

Following the market rules outlined in Section 3.1.1, under these circumstances, neither of these countries hit the *core* or *export* constraints, and their local marginal prices aligned with  $CBMP_t$ . Naturally, if it was the case that Portugal and Spain were exporting and hitting the “export limit” constraint in a given period, LMPs would be lower than the assumed CBMPs and the TSO costs would also be lower. But since there are no FCR market data in the past for Portugal and Spain, making a different assumption from the one that was made is intrinsically difficult. Note that this also impacts BSPs: Equation (3.5) stated that BSPs profits are also proportional to the LMP; therefore, if the tendency would be that BSPs from Portugal and Spain to have consistent scarcity of bids, the VPP

would have higher revenues than analyzed in the remainder of this study; conversely, if abundance was the rule, lower profits would be achieved. Another important limitation was the assumption that the CBMP is known in advance; naturally, the VPP would have to forecast it, compute opportunity costs based on forecasts, and decide to participate or not in the market sessions.

Further limitations existed relative to the VPP, as follows. The first one was related to the the assumption that in the day ahead, the energy that will be demanded by the HEs is known in advance. Note that this value is proportional to the generation from solar and wind at the national level, which nowadays can be predicted with somewhat good accuracy in the day ahead. The lowest value of the four hours (duration of FCR product) of renewable generation is chosen in the proposed methodology (see  $VGS_{c,t}$  in the methodology); therefore, it could be said that the HE demand, and hence, the bid size, is conservative. Another limitation was that there was a single VPP operating in each country. It is well known that increasing market competition drives down profit margins, but the investigation of multiple VPPs lay outside the scope of this study.

It was also assumed that the FCR upward and downward energy activations ( $UP_{en_{c,t}}$  and  $DN_{en_{c,t}}$ ) were known in advance; this directly influenced the computation of opportunity costs. Although, as stated, it is known that these values are, on average, 10% (Figure 3.6), the VPP would probably incur higher opportunity costs in some periods and less in others than what was computed, but this value cannot be accurately forecasted in the day ahead in any sense since this depends on imbalances occurring in real time. Also, the market price for hydrogen was assumed to be known and static.

All the presented limitations in this section would contribute, most likely, to the VPP bids being submitted more cautiously than anticipated in the remainder of the study.

### 3.1.3 Results

#### 3.1.3.1 VPP revenues

The results related to VPP participation in the market are presented in Table 3.3. Note that the results are split according to the intermediate steps corresponding to each part

### 3.1. HE PARTICIPATION IN FCR MARKET

of the methodology (Section 3.1.2). For the disaggregated results per country and year, consult the tables in Appendix F. For the results of each day of the available data, refer to the provided tool at [111].

Table 3.3: Results for the available data (mid 2020 to end of 2022). Note that the results are divided in the three phases of the methodology (Section 3.1.2). For the disaggregated results per year consult the tables in Appendix F.

|                                       | Scenario 1<br>"pessimistic"<br>2025 |       | Scenario 2<br>"expected"<br>2025 |       | Scenario 3<br>"pledged"<br>2030 |       |
|---------------------------------------|-------------------------------------|-------|----------------------------------|-------|---------------------------------|-------|
| Country ( <i>c</i> )                  | PT                                  | ES    | PT                               | ES    | PT                              | ES    |
| Part 1: Without opportunity costs     |                                     |       |                                  |       |                                 |       |
| % of market sessions VPP participates | 87%                                 | 99%   | 91%                              | 99%   | 91%                             | 99%   |
| % FCR covered by VPP                  | 10%                                 | 7%    | 21%                              | 13%   | 76%                             | 60%   |
| $\sum_T VPR_{c,t}$ [M€]               | 2.07                                | 11.13 | 4.28                             | 23.53 | 15.00                           | 85.45 |
| Part 2: Opportunity costs             |                                     |       |                                  |       |                                 |       |
| $\sum_T UP\_OPC_{c,t}$ [M€]           | 0.35                                | 1.90  | 0.72                             | 3.18  | 2.58                            | 15.63 |
| $\sum_T DN\_OPC_{c,t}$ [M€]           | 1.29                                | 6.97  | 2.67                             | 13.36 | 9.35                            | 51.49 |
| Part 3: Decision                      |                                     |       |                                  |       |                                 |       |
| % of market sessions VPP participates | 62%                                 | 57%   | 61%                              | 56%   | 61%                             | 57%   |
| % FCR covered by VPP                  | 6%                                  | 4%    | 13%                              | 9%    | 45%                             | 36%   |
| $\sum_T VR_{c,t}$ [M€]                | 1.56                                | 8.44  | 3.25                             | 19.04 | 11.44                           | 65.72 |
| $\sum_T UPRS_{c,t}$ [M€]              | 0.21                                | 1.11  | 0.35                             | 2.21  | 1.54                            | 9.26  |
| $\sum_T DNRS_{c,t}$ [M€]              | 0.58                                | 3.15  | 1.20                             | 7.04  | 4.32                            | 24.47 |
| $\sum_T VRS_{c,t}$ [M€]               | 0.78                                | 4.18  | 1.61                             | 9.80  | 5.58                            | 31.99 |
| Other indicators                      |                                     |       |                                  |       |                                 |       |
| Capacity factor of HEs                | 56%                                 | 71%   | 56%                              | 71%   | 50%                             | 58%   |
| $VGS_c$                               | 3%                                  | 2%    | 6%                               | 5%    | 12%                             | 10%   |

A brief interpretation of Table 3.3 is now presented using the figures regarding Scenario 1—"pessimistic" 2025 in Portugal for illustration. Note that the results in Table 3.3 are aggregated for all the available data, comprising the period between mid-2020 and the end of 2022.

For this period, if the VPP was to participate in the market while disregarding the opportunity costs (part 1 of methodology), it would have participated (with at least a 1 MW bid) in 87% of the market sessions and would have covered 10% of the country's FCR needs (in this case, the remaining 90% were necessarily covered by the competing

“conventional” BSPs). The VPP potential revenue  $VPR_{c,t}$  would have been over 2 M€.

Regarding the second part of the methodology, the sum of the upward and downward opportunity costs were computed, and it was found that such costs would have represented about 80% of the VPP potential revenue, which, when aggregated, was a very large percentage.

The third part of the methodology was the decision taken by the VPP whether to participate in each particular market session, informed by the associated opportunity costs associated with participation for that tender: this naturally led to a decrease in the number of sessions that were participated in. Concretely for the illustrative case, the VPP ended up participating in 62% of the market sessions (instead of the 87% computed in part 1), covering 6% of the total country’s FCR needs (instead of 10%). The VPP revenue  $VR_{c,t}$  ended up being over 1.5 M€, which was about 75% of the  $VPR_{c,t}$ . Since the VPP did not participate in the sessions where the opportunity costs exceeded the potential revenue, the shares of the revenues of the upward and downward providers, i.e.,  $UPRS_{c,t}$  and  $DNRS_{c,t}$ , respectively, were considerably smaller than the opportunity costs computed in part 2 of the methodology. As a result, the VPP revenue  $VR_{c,t}$  was distributed as follows: about 13% to the upward providers (HEs), 37% for the downward providers (wind and solar), and the remaining 50% for the VPP itself. Considering the particular year of 2022, in this scenario, the HEs would have an annual revenue of over 91 k€, as shown in Appendix F.

As for other indicators, the capacity factor <sup>1</sup> of the hydrogen electrolyzers in this case would be 56%. It was previously said that  $VGS_c$  is a user-defined variable that was also a result. In this case, the outcome was such that the VPP would need to control as little as 3% of the total installed solar and wind power in the country to assure the downward reserve provision. This is further discussed in Section 2.2.3.

One note regarding the differences between Portugal and Spain. Take into account that in scenario 1, the HE installed power was four times greater in Spain than in Portugal. For this case, the Portuguese VPP would cover more FCR share and participate in more

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<sup>1</sup>The “capacity factor” is normally understood as a ratio, e.g., between the generation (or load) in relation to its nominal value: for instance if the average load of the HE in one year is 500 MW and the installed capacity is 1000 MW, then the capacity factor is 50%.

### 3.1. HE PARTICIPATION IN FCR MARKET

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market sessions than the Spanish one, but overall, the monetary values in Spain were close to five times higher than in Portugal.

The observation from Figure 3.9 suggests that the monthly aggregated revenues for the VPP were notably comparable between Portugal and Spain, differing primarily in magnitude with only a few months showing distinctions.

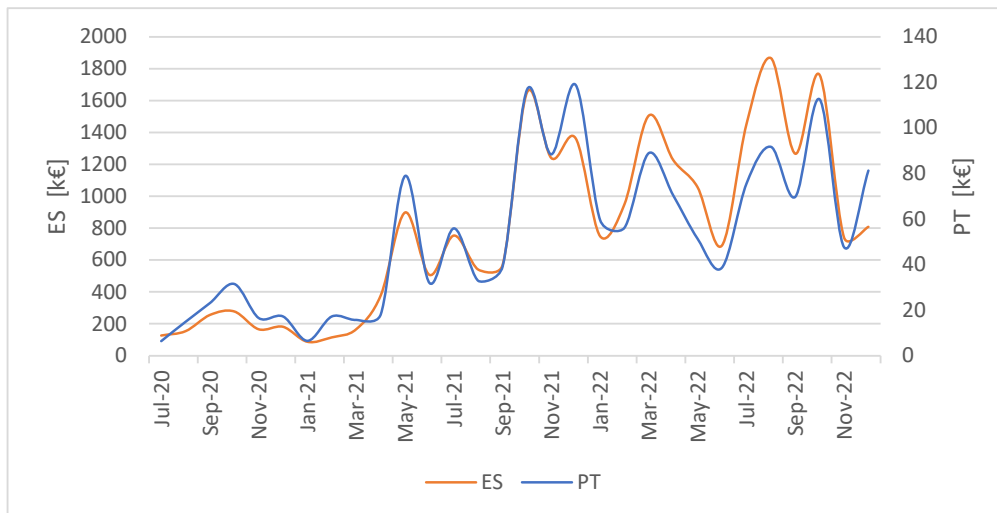


Figure 3.9: VPP monthly revenue in scenario 1. Used data from scenario 1.

However, Figure 3.10 illustrates that the distribution of bids per hour was not identical between the VPP in Portugal and the VPP in Spain.

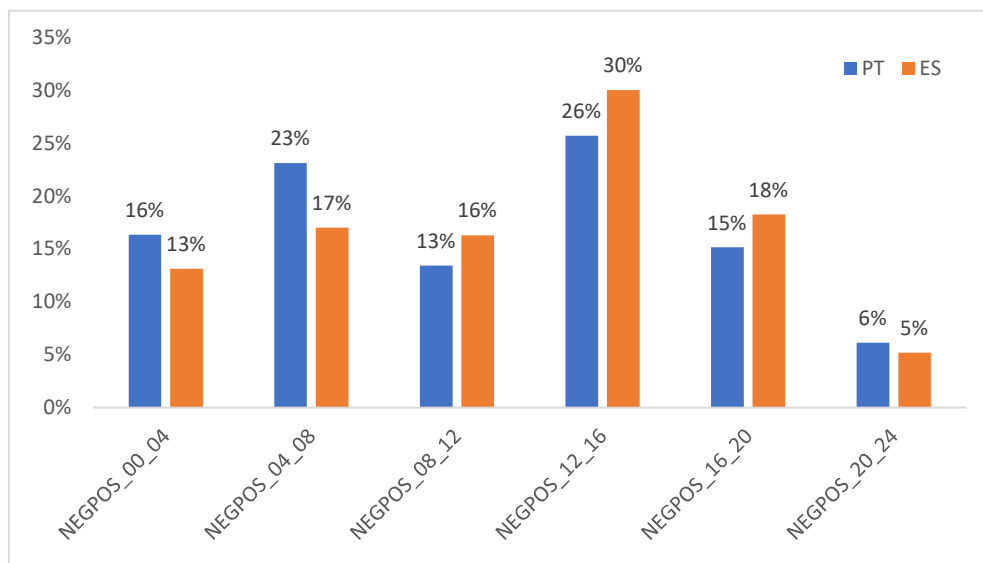


Figure 3.10: Distribution of VPP cleared volume per product. Used data from scenario 1.

Upon examination, it was determined that, for example, in Portugal, there was a slightly higher proportion of bids in the 04-08 period<sup>2</sup>. The average higher CBMP for the 04-08 product suggests that the revenues in Portugal were marginally greater than those in Spain during this time of day, as depicted in Figure 3.11.

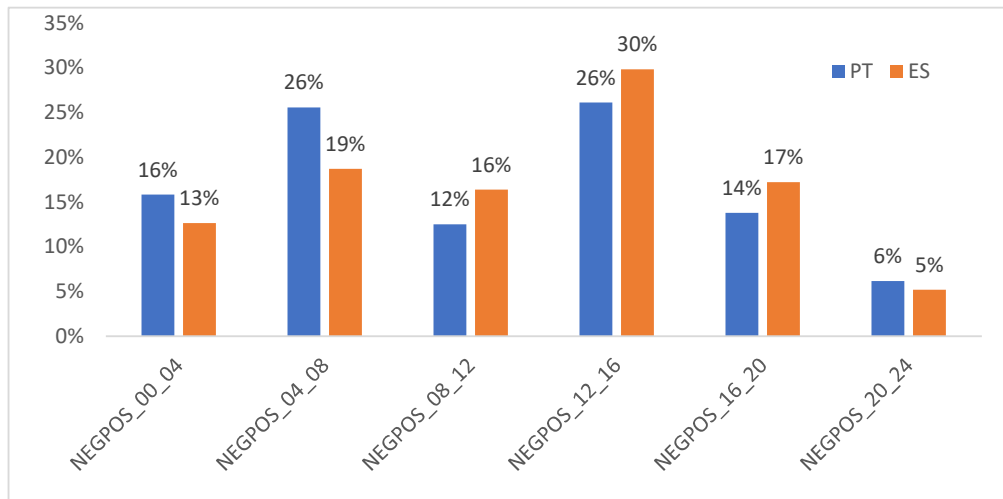


Figure 3.11: VPP revenues per product. Used data from scenario 1.

Figure 3.12 indicates that the monthly average market share of the VPP in Portugal and Spain exhibited only slight differences, except the scale.

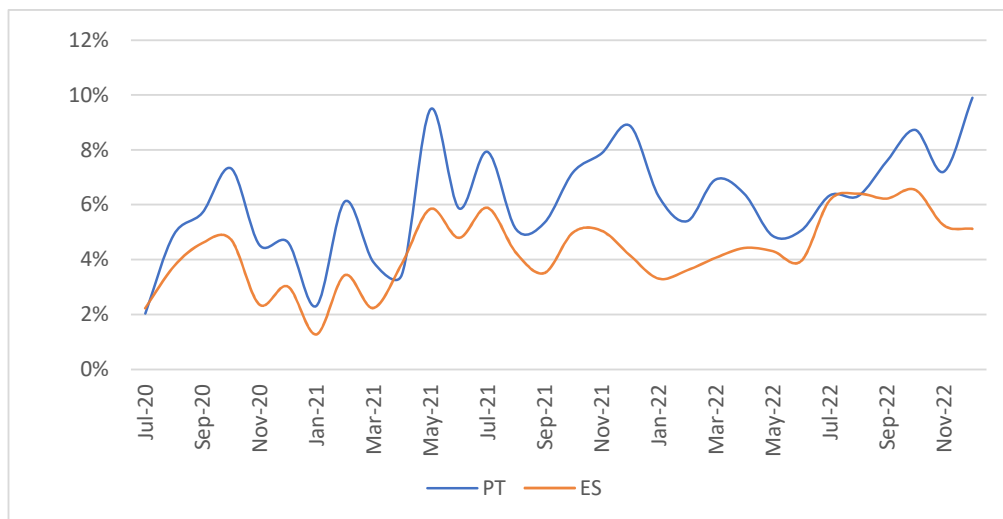


Figure 3.12: VPP monthly market share. Used data from scenario 1.

<sup>2</sup>NEGPOS\_04\_08 is the designation for the product in the existing FCR Cooperation, representing the time from 4 to 8 AM.

### 3.1. HE PARTICIPATION IN FCR MARKET

The plot in Figure 3.13 shows the data aggregated per month regarding VPP non-participation in market sessions (due to opportunity costs being higher than VPP potential revenue), along with the energy market and FCR market prices. It can be concluded that energy prices increased more than the FCR market prices, but over time, there was no strong tendency of either more or less participation in the market due to higher opportunity costs.

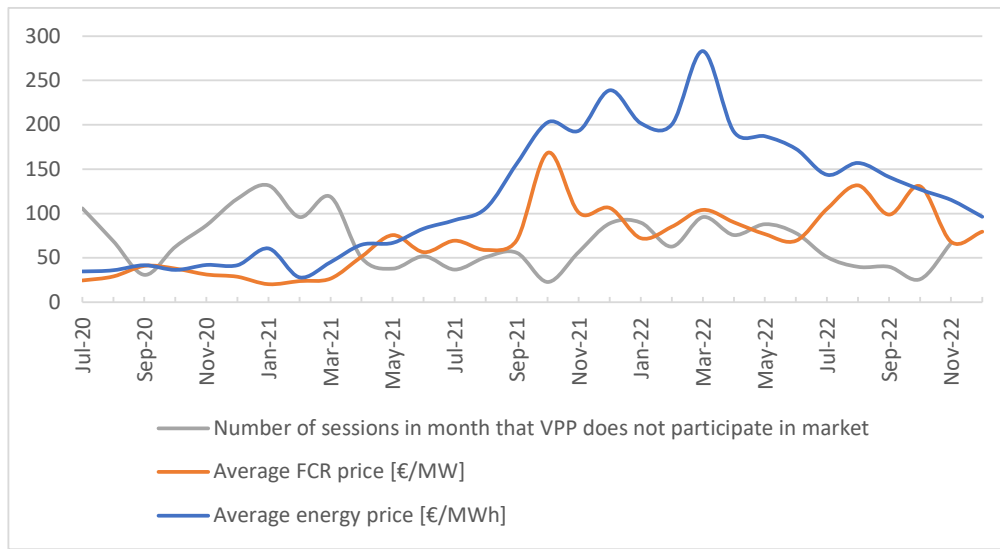


Figure 3.13: Number of market sessions each month in which VPP did not participate and its relation to energy and FCR prices. Used data from scenario 1.

Figure 3.14 shows the upward and downward bid components organized from the highest to the lowest for all the available data.<sup>3</sup> It was clear that increasing the upward bid component (by increasing  $VGS_c$ ) would push the blue curve to higher values but would result in the same bid size because, according to Equation (3.4), the bid size was limited by the lowest value of the two curves. The bid size, which was limited by its upward capacity, was equal to  $PN_c$  for around 20% of the tenders.

#### 3.1.3.2 TSO costs

Since Portugal and Spain are considered balanced there is no interference of the VPP bids on the CBMP. The TSO costs can be obtained according to Equation (3.18).

<sup>3</sup>From Figure 3.7, note that the bid size was the minimum value between the upward and downward components.

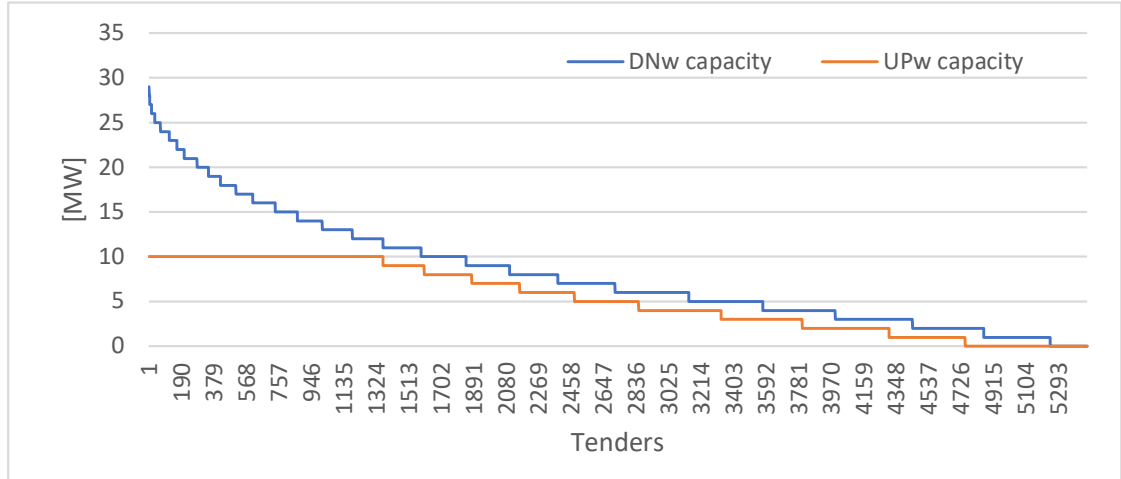


Figure 3.14: VPP bid size components per hour (organized from highest to lowest in the series). Used data from scenario 1.

Table 3.4 shows the TSO costs.

Table 3.4: TSO costs [M€] using 2020-2022 data. \*Note that for 2020 only 6 months of data are available as per Section 3.1.2.

|    | 2020  | 2021 | 2022 |
|----|-------|------|------|
| PT | 1.8*  | 7.6  | 10.1 |
| ES | 13.6* | 57.5 | 76.9 |

### 3.1.4 Discussion

In this study, it was assumed that Portugal and Spain joined the FCR Cooperation. Drawing upon a set of assumptions and historical FCR market data, the revenues of a VPP that aggregated solar and wind generation with HE demand was computed, along with the shares of revenues distributed among the VPP participants. Technical questions about the dispatch of existing sources within the VPP perimeter were left outside the scope of the study but should be considered for future work. For instance, suppose that in real time, it was required for the VPP to activate 1 MW of downward reserve; this leads to the question of where will this 1 MW come from. It is the VPP's task to decide whether this 1 MW will imply the reduction of production from one single wind turbine or from a whole solar farm, or even from the increase of the HEs consumption in case they

are not working at nominal capacity. Such a problem is already faced by VPPs, such as the one in [110]; therefore, it was assumed that VPPs already possessed knowledge about the best way to solve the real-time dispatch.

Note that in the present analysis, the hydrogen price was kept constant, but it was in itself a source of uncertainty. If the hydrogen price was very high, upward reserve activation implies that the electrolyzers decreased their energy consumption and, therefore, hydrogen production; this would lead to high opportunity costs. Future work should deal with forecasts and uncertainty regarding the parameters that were here considered to be known.

A critical assumption about the VPP was that it participated in the market sessions as a price-taker. This implies that when the VPP chose to submit a bid, it did so with a price below the CBMP so that the bid was accepted. This limitation is noteworthy, as, in the real-world the CBMP is not known in advance. A comprehensive assessment would necessitate to incorporate the strategies employed by other BSPs. Understanding their bidding strategy, considering both prices and volumes, is essential for forecasting CBMPs and LMPs. As mentioned by [120] regarding energy markets, due to the simplicity of model implementation, the common assumption was that producers could not impact the market-clearing price with their bids. These market agents are “price takers”, like the proposed VPP, which bids at zero price to ensure it was cleared. However, if the VPP presents a large portion of the bids, it will have an impact in the market-clearing price [120]: the market-clearing price would be lower because some of the more expensive bids would not be accepted. In this case, the revenue of the VPP itself would be lower, as it is proportional to the market-clearing price, as per Equation (3.5).

Recognizing the limitation inherent in this approach, it is essential to emphasize that the obtained results are likely more realistic when the installed capacity of HEs is minimal, exerting minimal influence on the market dynamics. Specifically, in a pessimistic scenario where only 50 MW of HEs were installed in Portugal by 2025 (scenario 1), and if these were incorporated into a VPP contracting only 3% of the total installed wind and solar power ( $VGS_c$ ), considering a 20% share for both upward and downward reserves ( $RGS_c$ ), the anticipated revenue for an entire year (at 2022 prices) amounted to 844 k€.

Figure 3.14 indicates that approximately 20% of the time, the bid size was constrained by  $PN_c$ . A larger value for  $PN_c$  would allow for a higher bid size, as there was ample wind and solar power available to support an increased bid (as noted by the blue curve being above the orange curve). This underscores the assertion made in Section 3.1.2 that  $VGS_c$  is not just a parameter but also an outcome. In scenario 1 for Portugal,  $VGS_c$  was set at 3%. Importantly, increasing the value of this parameter would not impact the VPP bid size since the constraint is on the HE side, specifically in the upward reserve. Certainly, if  $RDS_c$  exceeded 20%, the VPP could increase its revenues without a substantial increase in the contracted amount of downward reserve from solar and wind. The activation of reserves might potentially affect the longevity of HE stacks. Exploring this trade-off constitutes a potential line for future research.

The results in Portugal and Spain naturally differed in magnitude because Spain has a significantly higher population, more load and renewable energy generation, and, in the future, more hydrogen electrolyzers are expected to be installed there. Therefore, the results reflect this magnitude difference. The shape of the revenue curve in Figure 3.9 resembles the CBMP in Figure 3.8. This serves as a reminder that if the input data included CBMPs from before 2019, the VPP revenues would probably be lower than those computed here due to the proportionality outlined in Equation (3.5). Similarly, to compute future CBMPs, it is necessary to evaluate the evolution of exogenous variables, like the price of natural gas, the changes in the EU Emissions Trading System, and other factors that render long-term forecasts unpredictable. An assumption made in this study was that the components of the VPP (wind, solar, and HEs) would be inclined to participate in the VPP if it precisely covered the opportunity costs. Therefore, the values of the revenue share for these components, namely,  $UPRS_{c,t}$  and  $DNRS_{c,t}$ , should be interpreted attentively. If these entities were to demand revenue from the VPP that surpassed the opportunity costs, the VPP would participate in fewer market sessions, resulting in lower revenue. Conversely, if the VPP was managed directly by the owners of HEs and wind/solar parks, the revenue share of the VPP, denoted as  $VRS_{c,t}$ , would be distributed among these units and could be higher than the provided values of  $UPRS_{c,t}$  and  $DNRS_{c,t}$ .

#### 3.1.5 Conclusions

This study investigated the integration of Portugal and Spain in the existing FCR co-operation and answered the following question: what would be the revenues of a VPP aggregating wind and solar units along with HEs in this market? In responding to this question, the applied methodology facilitated the computation of the bid size of the VPP while accounting for opportunity costs. The VPP optimally reduced its opportunity costs by strategically combining units that provided downward reserve (wind, solar) with units that provide upward reserve (HEs), thus avoiding the need to reserve headroom. The results show that the opportunity costs were higher than possible revenues in some market sessions, and thus, the VPP refrained from participating in such sessions.

The model relied on actual market outcomes from the FCR Cooperation and verified data on renewable energy generation during the period 2020–2022. In this study, it was assumed that each country was in a state of balance (not importing nor exporting), meaning it did not encounter constraints within the FCR Cooperation, and consequently, maintained the LMPs equal to the CBMPs.

A prior analysis of the evolution of CBMPs showed that prices have increased over the years. This means that over the years, the VPP would increase the revenues proportionally. Although, here it was assumed that the CBMPs were known in advance, in reality, they would need to be forecasted. A noteworthy conclusion was that exogenous variables, such as natural gas prices, carbon pricing, and even market strategies employed by BSPs, pose challenges in assessment, rendering the precise computation of future CBMPs complex. Note that the forecasting would take place in the day ahead; it is likely that the natural gas and carbon pricing would be easy to forecast because variations would tend to be minimal in this time frame. More complex would probably be the understanding of market competitors' strategies. This is basically the same forecasting problem that market competitors face in the day-ahead energy market.

Three scenarios were formulated to calculate the VPP revenues. For example, even under conservative estimates for HE installation, a Portuguese VPP aggregating 50 MW of HEs and a mere 3% of the existing wind and solar generators, each operating with a

20% reserve margin, could potentially generate annual revenues exceeding 800k€ (based on the assumed 2022 CBMPs). Without opportunity cost consideration, the VPP would participate in 87% of the market sessions, whereas its computation resulted in market participation dropping to 64%. Taking opportunity costs into account, the HEs in this specific case would receive over EUR 90k€.

In an alternative scenario, taking into account the projected HE installation targets set by Spain for 2030, along with the forecasted additions of new wind and solar power capacity, the VPP could cover 58% of Spain's FCR requirements and generate revenues circa 31M€. This figure needs to be read carefully, as a limitation of this study arose from certain assumptions: the VPP was assumed to participate in the market as a price-taker, and we presumed that the CBMP was pre-determined and unaffected by the bid size of the VPP. In the event that the VPP was to encompass 60% of the FCR, it would transition to a price-maker role, potentially leading to a reduction in the LMP in Spain due to market splitting for a substantial portion of the year. Consequently, this could diminish the profits of the VPP.

It is acknowledged that the variables  $VGS_c$  and  $RDS_c$  utilized in this context can theoretically be increased, leading to a potential increase in the VPP bid size, opportunity costs, and possible increased degradation of the HE stack. Therefore, a subject for future investigation involves exploring the trade-off between the VPP bid size, revenues, opportunity costs, and the values associated with the variables  $RGS_c$  and  $RDS_c$ .

## 3.2 FCR Cooperation Regulation

In this section the mechanism through which TSOs participating in the FCR Cooperation pay the BSPs such as HEs is analyzed. The existing scheme presents market distortions such as negative costs for some TSOs in specific conditions, which are discussed. A novel scheme is proposed and compared with the existing one.

The objective of FCR in Europe’s integrated electricity markets is to guarantee the equilibrium between power supply and demand by stabilizing the frequency at a steady-state value after a disturbance. The frequency must be stabilized within the permissible maximum steady-state frequency deviation by joint action of FCR within the whole synchronous area [121]. Even if no common FCR market exists across the synchronous area, an incident in a given control area will require FCR activation from participating units in other control areas. In Europe, particularly within the European Union, given that the synchronous area includes several control areas that are well interconnected, regulation has been approved aiming to integrate electricity balancing markets that “ensure an efficient standardization, foster cross-border competition and liquidity and avoid undue market fragmentation” [100]. The FCR Cooperation was created as a common market for procurement and exchange of FCR, which aims to foster effective competition, non-discrimination, transparency, new entrants and increased liquidity while preventing undue distortions [122]. ENTSO-E is the market operator and represents the TSOs. In this market the traded product is power [MW]; this means that energy is not remunerated. The participants in this market are the Balancing Service Providers (BSPs)<sup>4</sup> on the supply side and TSOs on the demand side. The market allows different Local Marginal Prices (LMPs) (for reasons explained in Section 3.2.2.1); as such, the product being sold in a node with a given price may be bought in another node with a different price. Therefore, while it is trivial to calculate the revenues the BSPs receive (local price times quantity), a mechanism is necessary to ensure a zero-sum, such that the costs TSOs pay, in total, are exactly what BSPs need to receive for its product. This work focuses on such a mechanism within the scope of the FCR Cooperation.

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<sup>4</sup>BSPs are typically power plants, but demand-side participation such as HEs is allowed.

In principle, the proposed settlement mechanism can be adopted by other markets that allow different LMPs and suffer from the same inequities as those identified in the FCR Cooperation.

Until the end of 2022, 8 countries<sup>5</sup> participated in the FCR Cooperation: Austria (AT), Belgium (BE), Switzerland (CH), Denmark (DK)<sup>6</sup>, Germany (DE), France (FR), the Netherlands (NL) and Slovenia (SI). The Czech Republic joined in 2023 [123]. These countries have a total of around 200 million citizens.

Traded power and its market value from 2019 to 2022 are presented in Figure 3.15<sup>78</sup>. The month with the highest price is October 2021, with about 40 M€ of market value; this was about eight times the price in 2019 for roughly the same market volume.

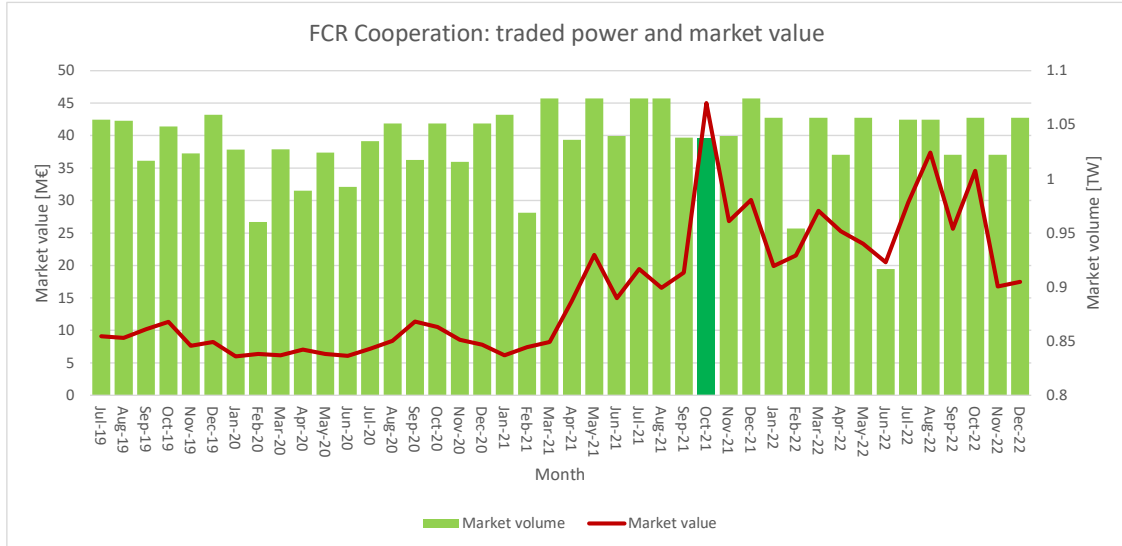


Figure 3.15: FCR Cooperation traded power and market volume.

### 3.2.1 Research motivation and section structure

This work aims to present a novel market mechanism design that ensures that, in a market that allows different LMPs, the total TSO costs equal the total BSP revenues, while

<sup>5</sup>There are eleven TSOs because Germany has 4 TSOs. In the remainder of this section it is assumed that each country has only one TSO for simplification.

<sup>6</sup>Actually, Western Denmark, but this is irrelevant for this work.

<sup>7</sup>See Section 3.2.4 for details on data collection.

<sup>8</sup>Until July 2020 there was only a daily product; since that date, there are 6 daily tenders of 4 hours each. The presented market volume multiplies the tenders MW per 24 in the first case and 4 in the second.

avoiding originating inequities that are identified in the FCR Cooperation under the current TSO settlement scheme, such as negative TSO costs. The TSO costs in the FCR Cooperation are used as a case study.

As will be discussed throughout the section, the identified inequities arise primarily because of the price differential between zones, and the scheme in question is necessary to distribute what is essentially a congestion rent, which exists when export limits or minimum share constraints are met.

The main contributions of this work are (a) the design of a novel market mechanism and (b) the identification of the inequities in the existing FCR Cooperation market and comparison with the proposed mechanism. A few simplified and real scenarios of FCR Cooperation tenders are used as test cases. Actual data from the FCR Cooperation is analyzed for the period 2019-2022; the accumulated TSO costs are calculated and compared with the existing and proposed mechanisms. In principle, such mechanism can be adopted by the FCR Cooperation and other markets that allow different LMPs, such as an international platform for the secondary or tertiary reserve.

The remainder of the section is organized as follows: in Section 3.2.2 the FCR market principles and the existing market settlement scheme currently used to compute TSO costs are introduced, in Section 3.2.3 the novel settlement scheme proposed in this work is presented, together with the scenarios to compare both schemes, in Section 3.2.4 the used data is presented, in Section 3.2.5 the results are presented and discussed, in Section 3.2.6 conclusions and policy implications are drawn.

#### 3.2.2 Background and literature review

This section begins by presenting a brief literature review. The rules of the FCR Cooperation tenders are then outlined (Section 3.2.2.1) as they are fundamental to explaining how TSO costs are currently calculated (Section 3.2.2.2).

It is well known that market integration generally increases market efficiency. In the particular case of balancing market integration, a realistic case in China reduces of balancing costs by over 30% [124]. A literature search for “FCR Cooperation” yields few results; most of the papers that have been published focus on the BSPs participation.

For instance, in [109] the implications for France’s joining the FCR Cooperation and particularly the participation of aggregators are analyzed. The role of small-scale flexibility providers and, specifically, the prequalification processes of several countries are discussed in [101]. In [125] the behavior of BSPs under different pricing schemes is simulated. The role of battery energy storage systems has also been addressed in [126]. In [127] the role of the TSO is partially analyzed (balancing capacity transfers) but the cost scheme of its participation in the FCR Cooperation is not addressed. To the authors’ best knowledge, the mechanism currently in use to calculate TSO costs in the FCR Cooperation has not been addressed in the literature.

### 3.2.2.1 General market principles of the FCR Cooperation

The principles of a FCR Cooperation tender [102] are presented next. Firstly, the market clearing process is outlined:

1. TSOs participate in the market on the demand side. The TSO of each country,  $TSO_c$ , submits one *inelastic* bid with size  $D_c$  [MW].
2. The  $n$  BSPs of each country  $c$  submit supply-side bids. Each bid is characterized by a price,  $PB_{c,n}$  [€], and a quantity,  $QB_{c,n}$  [MW].
3. The objective of the market clearing is to minimize costs by deciding which supply bids are accepted (“cleared”) and which are rejected: the binary decision variable,  $CB_{c,n}$ , is 1 for the cleared bids and 0 for the rejected ones. The objective function for the FCR Cooperation algorithm is formulated by Equation (3.19).

$$\min(cost) = \sum CB_{c,n} \times PB_{c,n} \times QB_{c,n} \quad (3.19)$$

The objective function Equation (3.19) is constrained by items 4, 5 and 6, as follows.

4. The sum of quantities [MW] of cleared bids in each country must observe the so-called “core share”,  $CS_c$  [MW], that amounts to a minimum of bids to be cleared in each country<sup>9</sup>, according to Equation (3.20);

---

<sup>9</sup>The  $CS_c$  is  $30\% \times D_c$  [102]; *e.g.*  $CS_{DE} = 168MW$  in 2022.

$$\sum_{n \in N_c} CB_{c,n} \times QB_{c,n} \geq CS_c \quad \forall c \in C \quad (3.20)$$

5. The sum of quantities [MW] of cleared bids in each country must observe the so-called “export limit”,  $EL_c$  [MW]<sup>10</sup>, according to Equation (3.21);

$$\sum_{n \in N_c} CB_{c,n} \times QB_{c,n} \leq D_c + EL_c \quad \forall c \in C \quad (3.21)$$

6. The total quantity [MW] to be procured by the countries that constitute the Cooperation has to be satisfied<sup>11</sup>, according to Equation (3.22);

$$\sum_{\substack{c \in C \\ n \in N_c}} CB_{c,n} \times QB_{c,n} \geq \sum_{c \in C} D_c \quad (3.22)$$

This formulation guarantees that TSOs’ demand is satisfied *at minimum cost*: more than one possible solution may exist<sup>12</sup> but this is irrelevant to our purposes.

Besides the selection of accepted bids, the market outcome is the price to be practiced in each country. This is, thus, a pay-as-cleared market, with the following characteristics:

1. One Cross Border Marginal Price (CBMP) [€/MW] will be determined equaling the price of the most expensive awarded bid in the overall cooperation, provided that no  $CS_c$  nor  $EL_c$  constraints are hit<sup>13</sup>. In each country there is one  $LMP_c$ . When all countries share the CBMP, this means that each  $LMP_c = CBMP$ ;
2. If the  $CS_{imp}$  is hit in an importing country  $imp$ , the Local Marginal Price (LMP) in this country will be the same as the last cleared bid in the country, and necessarily  $LMP_{imp} > CBMP$  (this reflects the scarcity of bids in the country);

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<sup>10</sup> $EL_c$  is defined by [117]. *e.g.*  $EL_{DE} = 167MW$

<sup>11</sup>*e.g.*  $D_{DE} = 555MW$  and  $\sum_C D_c = 1420MW$  in 2022. These values change every year according to rules specified in [100].

<sup>12</sup>For instance, when the cleared bids amount to  $FCR\_D - 1$  MW but there are still 2 bids of 1 MW each at the same price.

<sup>13</sup>A constraint being “hit” is ENTSO-E’s [102] terminology for what in optimization is known as “binding constraint”. For instance, the core share in Germany is 168 MW, so if the market outcome is such that 168 MW are cleared from german BSPs, the core constraint of Germany has been hit.

3. If the  $EL_{exp}$  is hit in an exporting country  $exp$ , the LMP in this country will be the same as the last cleared bid in the country, and necessarily  $LMP_{exp} < CBMP$  (this reflects the abundance of bids in the country);

Regarding the remuneration of BSPs and TSOs, two simple rules apply:

1. The revenue received by each BSP,  $REBSP_{c,n}$  is paid according to the LMP (which may or may not be the same as the CBMP), as per Equation (3.23)

$$REBSP_{c,n} = CB_{c,n} \times QB_{c,n} \times LMP_c \quad (3.23)$$

To facilitate reading the remainder of the section, let the total cleared quantity of bids from country  $c$ ,  $CQ_c$ , be defined by Equation (3.24).

$$CQ_c = \sum_{n \in N} CB_{c,n} \times QB_{c,n} \quad \forall c \in C \quad (3.24)$$

2. The BSPs are paid exclusively by the TSOs, according to Equation (3.25);

$$\sum_{c \in C} CQ_c \times LMP_c = \sum_{c \in C} C\_TSO_c \quad (3.25)$$

Calculating the BSPs' revenues in a given country is trivial, using Equation (3.23) and Equation (3.24). However, a mechanism is still necessary to calculate the contribution of each TSO,  $C\_TSO_c$ : this is the focus of this work.

Since indivisible bids are possible in this market<sup>14</sup>, the optimal solution may lead to *over-procurement*,  $OP$ , according to Equation (3.22) and Equation (3.26).

$$OP = \sum_{c \in C} CQ_c - \sum_{c \in C} D_c \quad (3.26)$$

---

<sup>14</sup>Suppose that the total demand is 100 MW and that 99 MW are already cleared. Suppose the remaining bids are: (a) 1 MW at 10 €/MW and (b) an indivisible bid of 2 MW at 4€/MW. Since the market clearing is performed with a cost minimization function, the bid (b) is accepted, in which case there is a total of 101 MW cleared (1 MW of *over-procurement*) due to the bid being indivisible.

### 3.2.2.2 Current TSO settlement scheme

The mechanism currently used to calculate the cost paid by each TSO can be consulted in [128] and is used in this work as a baseline for comparison with the proposed scheme.

The flowchart presented in Figure 3.16 provides an overview of the steps to arrive at TSO costs. The rationale of the scheme is discussed at length in Section 3.2.5.3.

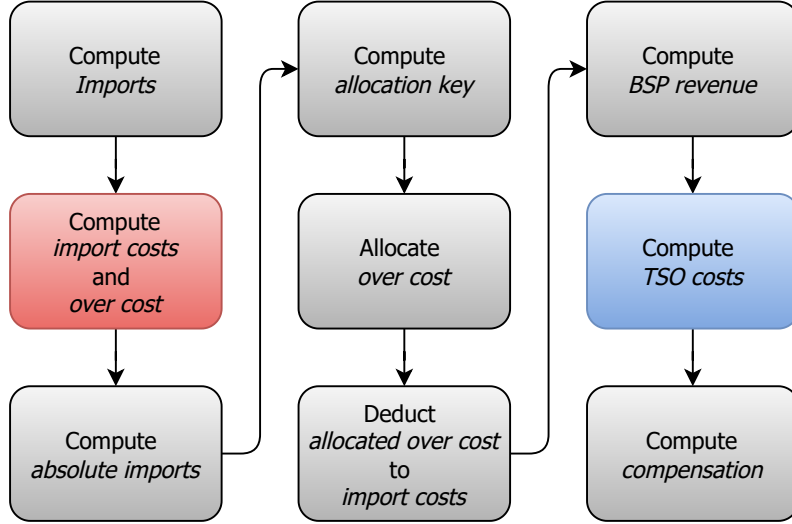


Figure 3.16: Algorithm of current scheme, with objective of arriving to TSO costs. The problematic step in red is discussed in detail in Section 2.2.3.

The steps and equations of the current scheme are the following:

1. **Imports**,  $I_c$  [MW]<sup>15</sup> : using Equation (3.27);

$$I_c = D_c - CQ_c \quad \forall c \in C \quad (3.27)$$

2. **Import costs**,  $IC_c$  [€]<sup>16</sup> : using Equation (3.28);

$$IC_c = I_c \times LMP_c \quad \forall c \in C \quad (3.28)$$

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<sup>15</sup>In the original nomenclature: “net position (satisfied demand)” which, in the authors’ opinion is misleading because an export will be presented as a *negative “satisfied demand”*. In the proposed nomenclature, importing countries have a positive “import” value and exporting countries a negative “import” value.

<sup>16</sup>In the original nomenclature: “import/export costs”. The authors prefer “import costs”, as it makes sense that a country importing power pays a positive cost for it (since there are no negative *LMPs* in the FCR Cooperation). Exporting countries have a negative cost.

3. **Over-cost,  $OC$  [€]**<sup>17</sup> : using Equation (3.29).

$$OC = \sum_{c \in C} IC_c \quad (3.29)$$

The distribution of the *over-cost* is the fundamental issue analyzed in this work. As will be discussed throughout the remainder of this work, the *over-cost* arises primarily because of the price differential between zones, and is essentially a congestion rent, which arises when export limits or minimum share constraints are met. This is discussed at length in Section 2.2.3. Here, it is sufficient to state that  $OC \neq 0$  if there is at least one  $LMP_c \neq CBMP$  or if  $OP \neq 0$ .

4. **“Absolute” imports,  $AI_c$  [MW]** : using Equation (3.30);

$$AI_c = \text{abs}(I_c) \quad \forall c \in C \quad (3.30)$$

5. **Allocation key,  $AK_c$**  : using Equation (3.31). (Only *imbalanced*<sup>18</sup> countries have an  $AK_c \neq 0$ .)

$$AK_c = \frac{AI_c}{\sum_{c \in C} \text{abs}(I_c)} \quad \forall c \in C \quad (3.31)$$

6. **Over-cost allocation,  $AOC_c$  [€]**<sup>19</sup> : using Equation (3.32). The intuition is that countries share a fraction of the *over-cost* proportionally to their *imbalance*:

$$AOC_c = AK_c \times OC \quad \forall c \in C \quad (3.32)$$

7. **Import costs after allocation,  $ICAA_c$  [€]**<sup>20</sup> : using Equation (3.33) deducting a share of the *over-cost* to the import costs initially calculated.

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<sup>17</sup>This term does not exist on the ENTSO-E nomenclature.

<sup>18</sup>A country  $c$  is *balanced* when  $D_c = CQ_c$  and *imbalanced* otherwise.

<sup>19</sup>In the original nomenclature: “cost surplus allocation”.

<sup>20</sup>In the original nomenclature: “import / export costs after allocation”.

$$ICAA_c = IC_c - AOC_c \quad \forall c \in C \quad (3.33)$$

8. **BSP revenue**,  $R\_BSP_c$  [€]<sup>21</sup>: using Equation (3.34). Note that  $R\_BSP_c$  stands for the sum of all revenues of the BSPs of a given country, whereas  $REBSP_{c,n}$  from Equation (3.23) referred to the revenues of each BSP individually.

$$R\_BSP_c = CQ_c \times LMP_c \quad \forall c \in C \quad (3.34)$$

9. **TSO costs**,  $CC\_TSO_c$  [€]<sup>22</sup> using Equation (3.35).

$$CC\_TSO_c = R\_BSP_c + ICAA_c \quad \forall c \in C \quad (3.35)$$

10. **Compensation**,  $Cp_c$  [€] using Equation (3.36) and Equation (3.37).

$$Cp_c = CC\_TSO_c - R\_BSP_c \quad \forall c \in C \quad (3.36)$$

$$\sum_{c \in C} Cp_c = 0 \quad (3.37)$$

This step does not contribute to the purpose of this work because the TSO costs have already been calculated. Nonetheless, these values are calculated by the Cooperation for the following reason: *since each TSO pays the local BSPs, there is a need for exporting TSOs to receive a compensation that will be used to pay local supply*, which exceeds the local demand. Likewise, importing TSOs pay a compensation that will

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<sup>21</sup>In the original nomenclature: “actual costs (TSO-BSP)”. In the authors’ opinion it is clearer to call it *BSP revenue*.

<sup>22</sup>In the original nomenclature: “target costs”. : In the authors’ opinion it is clearer to call this the TSO cost.

be used in exporting countries, originating a zero-sum between TSOs. Each TSO pays local BSPs and receives or pays the cumulative compensation at the end of the month.

An example for one tender where TSO costs are calculated is found on ENTSO-E documentation and is presented in Appendix G. The computation for the same delivery day using the proposed scheme can be found in Appendix H. The computation for both schemes for an actual tender occurring in 2021 is presented in Appendix J.

### 3.2.3 Methodology for comparison of existing and proposed mechanisms

In this subsection the methodology used in this work is presented. It consists of four steps, as follows:

1. A novel TSO cost scheme was designed (Section 3.2.3.1);
2. Scenarios to be used as test cases were built (Section 3.1.2.1);
3. Both schemes were used to calculate TSO costs in the scenarios (Section 3.2.5.1); this was used to identify the sources of inequities produced by the market;
4. TSO accumulated costs from 2019-2022 were calculate for both schemes using actual market data of the FCR Cooperation (Section 3.2.5.2).

#### 3.2.3.1 Proposed TSO costs scheme

The proposed scheme is both simple and intuitive. Applying such a scheme in the existing FCR Cooperation would face no barriers since it has no impact on the market clearing. It would only affect the settlement of TSO costs, which are financial transactions occurring after the market clearing. An overview is shown in Figure 3.17.

The algorithm can be summarized in the following steps:

1. **Calculate the revenues of BSPs of each country,  $R_{BSP_c}$  [€], and total BSP revenues** (exactly like the step 8 of the current scheme presented in Section 3.2.2.2) using Equation (3.38);

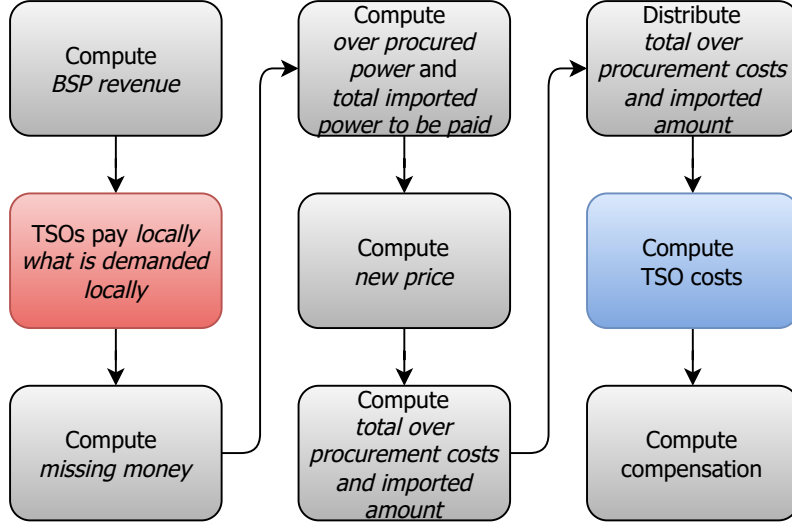


Figure 3.17: Algorithm of the proposed scheme for computing TSO costs. The fundamental difference between this and the current scheme is indicated in red is discussed in detail in Section 2.2.3.

$$R\_BSP_c = CQ_c \times LMP_c \quad \forall c \in C \quad (3.38)$$

2. **TSOs pay locally what is demanded locally [€]** using Equation (3.39), where  $LC_c$  is the “local cost” that  $TSO_c$  pays for the part of their demand that is satisfied by BSPs from the same country;  $IP_c$  stands for the imported power<sup>23</sup> which is calculated using Equation (3.40).

$$LC_c = LMP_c \times (D_c - IP_c) \quad \forall c \in C \quad (3.39)$$

$$IP_c = \begin{cases} 0, & \text{if } CQ_c > D_c \\ D_c - CQ_c, & \text{otherwise} \end{cases} \quad (3.40)$$

3. **Calculate missing money, MM [€]** using Equation (3.41);

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<sup>23</sup>The imported power  $IP_c$  of the proposed scheme is a non-negative number, whereas the imported power  $I_c$  used in the current scheme using Equation (3.27) is negative if the country is an exporter.

$$MM = \sum_{c \in C} R\_BSP_c - \sum_{c \in C} LC_c \quad (3.41)$$

4. Calculate *over procured power*,  $OP$  [MW] using Equation (3.42);

$$OP = \sum_{c \in C} (CQ_c - D_c) \quad (3.42)$$

5. Calculate *total imported power to be paid*,  $TI$  [MW] using Equation (3.43);

$$TI = \sum_C IP_c \quad (3.43)$$

6. Calculate *new price*,  $NP$  [€/MWh], for the power that remains to be paid using Equation (3.44);

$$NP = \frac{MM}{OP + TI} \quad (3.44)$$

7. Calculate *total over-procurement costs*,  $TOPC$  [€] using Equation (3.45);

$$TOPC = NP \times OP \quad (3.45)$$

8. Distribute *total over-procurement cost* among the TSOs,  $OPC_c$  [€], using Equation (3.46) and Equation (3.47), where  $Coeff$  is the proportion of the TSO demand on the total FCR Cooperation;

$$OPC_c = TOPC \times Coef_c \quad (3.46)$$

$$Coef_c = \frac{D_c}{\sum_{c \in C} D_c} \quad (3.47)$$

9. Distribute *costs of imported amount*,  $ICP_c$  [MW] of each country [€] using Equation (3.48). Note that  $ICP_c$  is different from  $IC_c$  of the current mechanism

(Equation (3.28)) because in the proposed mechanism if a country is an exporter its  $ICP_c$  is null.

$$ICP_c = IP_c \times NP \quad (3.48)$$

10. **Calculate TSO costs**,  $CP\_TSO_c$  [€] using Equation (3.49).

$$CP\_TSO_c = LC_c + OPC_c + ICP_c \quad (3.49)$$

Equations (3.38 - 3.49) guarantee that  $\sum_C CP\_TSO_c = \sum_C R\_BSP_c$  and  $CP\_TSO_c \geq 0$  for every country.

#### 3.2.3.2 Scenarios

In this work, five test cases are used. Each scenario represents a market session where each TSO demands a given amount of FCR volume and is subject to minimum and maximum constraints. The difference in the scenarios is the market outcome, and essentially, the difference is in the LMPs for the participating countries or the existence of *over-procurement*, which are both possibilities under the rules of the market explained in Section 3.2.2.1. The first four scenarios are simplifications with fewer countries than currently participate in the FCR Cooperation, and round numbers are used to facilitate the assessment of the results. The fifth scenario is drawn from an actual market session.

The scenarios can therefore be described as follows:

**Scenario 1** Simplified example with equal LMPs and no *over-procurement*, this should be interpreted as a base case;

**Scenario 2** Simplified example with equal LMPs and *over-procurement*;

**Scenario 3** Simplified example with different LMPs on the same order of magnitude;

**Scenario 4** Simplified example with LMPs on a different order of magnitude;

**Scenario 5** Actual market outcome with LMPs on a different order of magnitude and *over-procurement*.

|                                                         | Percentage of total tenders |
|---------------------------------------------------------|-----------------------------|
| All $LMP$ s equal                                       | 18.6%                       |
| At least one $LMP > CBMP$                               | 59.7%                       |
| At least one $LMP < CBMP$                               | 6.1%                        |
| At least one $LMP > CBMP$ and at least one $LMP < CBMP$ | 15.6%                       |
| <i>Total</i>                                            | <i>100%</i>                 |

Table 3.5: Distribution of tenders according to relation between LMPs.

Four fictitious countries (A, B, C, D) are used for these simplified scenarios. Real market outcomes in the remainder of the work use the initials of countries given in the beginning of the section.

### 3.2.4 Case study and data availability

The analyzed data was obtained from [117]. A total of 5965 data points were initially retrieved. The data begins in 2019-07-01, when only one daily tender was held. From 2020-07-01 onward, six daily tenders for periods of four hours were held. The first step was to proceed to data cleansing, firstly by eliminating the second tender: it was decided to remove these 121 data points because only some TSOs participate in such tenders. Also, from 2022-06-27 to 2022-06-30, there appeared to be some errors in the data, because most countries appear to be importing their whole demand and no exports from other countries exist compensating for this. After data cleansing there were 5827 data points (98% of all initially retrieved data).

A lot could be written about the seasonality of prices, imports and exports but that would fall outside the scope of this work. It is, however, important that all LMP in the data are positive except in two tenders in France where  $LMP = 0$  (2020-01-21)<sup>24</sup> <sup>25</sup>.

Table 3.5 presents the distribution of cases according to the resulting LMPs. Notably, the LMP are equal in all countries only in 19% of the tenders. These are the only tenders that may be free of market inequities, as will be shown in the remainder of the section.

<sup>24</sup>The bids provided by [117] in this day have been analyzed: all the bids from France are effectively offered at 0 €/MW in such a quantity that the *max export limit* is hit.

<sup>25</sup>Denmark and Slovenia participate in the FCR Cooperation only after 2021-19-01. But since these countries have *no demand* prior to this date they are disregarded from data until then.

|                                                   | AT   | BE    | CH    | DE    | DK    | FR    | NL    | SI   |
|---------------------------------------------------|------|-------|-------|-------|-------|-------|-------|------|
| Maximum LMP [€]                                   | 755  | 4257  | 492   | 492   | 3006  | 755   | 1971  | 755  |
| Minimum LMP [€]                                   | 10   | 11    | 8     | 10    | 10    | 0     | 10    | 10   |
| Maximum TSO cost in one tender [k€]               | 41   | 352   | 33    | 276   | 64    | 351   | 205   | 10   |
| Minimum TSO cost in one tender [k€]               | -10  | -9    | -23   | -11   | -4    | -18   | -26   | -4   |
| Percentage of tenders with negative TSO costs [%] | 1.44 | 0.45  | 10.11 | 0.02  | 1.63  | 3.14  | 1.34  | 7.62 |
| Accumulated TSO costs 2019-2022 [M€]              | 30.6 | 54.2  | 25.6  | 251.5 | 27.9  | 213.5 | 69.1  | 4.7  |
| Average price [€/MW]                              | 74.8 | 113.0 | 67.5  | 76.7  | 312.8 | 72.9  | 103.6 | 74.1 |

Table 3.6: Summary of data analysis for the period 2019-2022. Average price is the quotient of the accumulated TSO costs and TSO demand.

The data concerning *over-procurement* and negative TSO costs are especially relevant to the present work. The percentage of tenders in which *over-procurement* occurs is 61%. The maximum *over-procurement* volume is 78 MW, *i.e.* very small compared with the total procured volume, around 1400 MW. We also assess the proportion of *over-procurement*,  $Pc\_OP$ , relative to demand, occurring for all the tenders  $T$  of the period 2019-2022, calculated using Equation (3.50):

$$Pc\_OP = \sum_T \frac{OP}{OP + \sum_C D_c} = \frac{154.098}{8.451.314} = 1.82\% \quad (3.50)$$

It can thus be concluded that *over-procurement* is a minor source of inequity.

Table 3.6 shows that negative TSO costs are, in fact, relatively frequent and happen around 10% of the time in Switzerland. Also, note that the most expensive tender for the Swiss TSO is around 33 k€ and the “lowest” cost is around -23 k€. The accumulated TSO costs of these data amount to more than 677 M€.

Dataset and results under both schemes were compiled and made available in [129].

### 3.2.5 Results and discussion

The TSO costs are firstly calculated under both schemes (Section 2.2.2) and the differences are discussed (Section 2.2.3).

### 3.2.5.1 Results

In Section 3.2.5.1 the analysis of TSO costs under both schemes is calculated for the scenarios previously introduced, followed by the analysis of accumulated TSO costs from 2019 to 2022 (Section 3.2.5.2).

**Comparison of TSO costs under the existing and proposed schemes** The scenarios of a tender session (Section 3.1.2.1) are used to calculate TSO costs. The intermediate steps for arriving at TSO costs in each scenario using the existing mechanism are detailed in the tables of Appendix I. The reader is reminded to look at Scenario 1 as a “base case” for comparison with the remaining ones.

**Scenario 1:  $LMP = CBMP$  and no *over-procurement* (Table 3.7)** This result can be considered a “normal market outcome”. As expected, there is no difference in the TSO costs between both schemes; each TSO pays  $LMP_c \times D_c$ .

| Country    | Market input |                       |                         | Market result |             | Current scheme | Proposed scheme |
|------------|--------------|-----------------------|-------------------------|---------------|-------------|----------------|-----------------|
|            | Demand [MW]  | Min (Core share) [MW] | Max (Export limit) [MW] | LMP [€/MW]    | Export [MW] | TSO Costs [€]  | TSO Costs [€]   |
| A          | 100          | 40                    | 70                      | 1             | 20          | 100            | 100             |
| B          | 50           | 30                    | 30                      | 1             | -20         | 50             | 50              |
| C          | 30           | 20                    | 20                      | 1             | 0           | 30             | 30              |
| D          | 20           | 10                    | 10                      | 1             | 0           | 20             | 20              |
| <i>sum</i> | <i>200</i>   |                       |                         |               | <i>0</i>    | <i>200</i>     | <i>200</i>      |

Table 3.7: Scenario 1 : Simplified case, where all  $LMP = CBMP$  and no *over procurement* occurs; comparison between current and proposed schemes.

| Country    | Market input |                       |                         | Market result |             | Current scheme | Proposed scheme |
|------------|--------------|-----------------------|-------------------------|---------------|-------------|----------------|-----------------|
|            | Demand [MW]  | Min (Core share) [MW] | Max (Export limit) [MW] | LMP [€/MW]    | Export [MW] | TSO Costs [€]  | TSO Costs [€]   |
| A          | 100          | 40                    | 70                      | 1             | 20          | 104            | 105             |
| B          | 50           | 30                    | 30                      | 1             | -20         | 54             | 52.5            |
| C          | 30           | 20                    | 20                      | 1             | 10          | 32             | 31.5            |
| D          | 20           | 10                    | 10                      | 1             | 0           | 20             | 21              |
| <i>sum</i> | <i>200</i>   |                       |                         |               | <i>10</i>   | <i>210</i>     | <i>210</i>      |

Table 3.8: Scenario 2: Simplified case, where all  $LMP = CBMP$  and 10 MW of *over procurement* occurs: comparison between current and proposed schemes.

**Scenario 2:  $LMP = CBMP$  and *over-procurement* occurs (Table 3.8)** There are 10 MW of *over-procurement* and the difference with the previous case is that there is a supply of 10 MW from BSPs of country C; on the other hand, there is no change in LMP

(still 1 €/MW in each area). Before analyzing the market outcome two questions must be posed: (1) which TSO(s) will pay for these 10 MW that no TSO demanded and (2) how much of it each TSO pays?

Naturally, there will be 10 € more to be paid to BSPs than in scenario 1 (Table 3.7). Under the current scheme, this extra 10 € are divided as follows: TSOs A and B pay 4 € each and C pays 2 €. A quick analysis of the intermediate steps (Appendix I) allows for some conclusions:

1. *Over\_cost*  $\neq 0$ , not because LMPs are different but *because there is over-procurement*, which is not demanded by any TSO but still needs to be paid to BSPs.
2. The TSO of country D has no import costs because it is *balanced*.
3. Countries A and B are *imbalanced* by the same amount (in modulus) hence sharing the same burden of the *over-cost* even if country A is procuring the double amount than country B.

The differences in TSO costs under both schemes are small in magnitude, but they exist. The proposed scheme divides the *over-cost* caused by *over-procurement* proportionally to the *demand* of each TSO regardless of how *imbalanced* it is. The results analyzed here are further discussed in Section 2.2.3. However, the main critique of the current TSO cost scheme is not the inequity caused by *over-procurement*, but negative TSO costs. *Over-procurement* happens on a small scale and few times as observed in Section 3.2.4. Negative TSO costs (*i.e.* TSO revenues) may arise under certain conditions, which is a much more significant inequity and is examined in Section 3.2.5.3.

**Scenario 3: one  $LMP \neq CBMP$  but of the same order of magnitude; no *over-procurement* occurs (Table 3.9)** Here, country B hit its *core constraint* of 30 MW and  $LMP_B$  is 2 €/MW, whereas  $LMP_A = LMP_C = LMP_D$ , 1 €/MW. Country A is exporting to B; countries C and D are *balanced*.

Only the costs of  $TSO_C$  and  $TSO_D$  remain the same in both schemes. A fundamental difference is that in the proposed scheme  $TSO_A$  pays  $LMP_A \times D_A$  whereas in the current scheme this TSO gets a 10 € deduction because  $TSO_B$  has a higher *LMP*. Simply put, in

| Country    | Market input |                       |                         | Market result |             | Current scheme | Proposed scheme |
|------------|--------------|-----------------------|-------------------------|---------------|-------------|----------------|-----------------|
|            | Demand [MW]  | Min (Core share) [MW] | Max (Export limit) [MW] | LMP [€/MW]    | Export [MW] | TSO Costs [€]  | TSO Costs [€]   |
| A          | 100          | 40                    | 70                      | 1             | 20          | 90             | 100             |
| B          | 50           | 30                    | 30                      | 2             | -20         | 90             | 80              |
| C          | 30           | 20                    | 20                      | 1             | 0           | 30             | 30              |
| D          | 20           | 10                    | 10                      | 1             | 0           | 20             | 20              |
| <i>sum</i> | <i>200</i>   |                       |                         |               | <i>0</i>    | <i>230</i>     | <i>230</i>      |

Table 3.9: Scenario 3: Simplified case, where one  $LMP \neq CBMP$  but of the same order of magnitude (no *over procurement* occurs): comparison between current and proposed schemes.

the proposed scheme  $TSO_B$  pays for the fact that  $LMP_B$  is high but none of the remaining TSOs benefit from it, contrary to the current scheme.

**Scenario 4: one  $LMP \neq CBMP$  but on a different order of magnitude; no *over-procurement* occurs (Table 3.10)** Note that the input data of Table 3.10 is similar to Table 3.9 with the following exceptions: country A exports 10 MW more, which are imported to country D; two countries now hit the core constraint,  $LMP_B$  is again 2 €/MW and  $LMP_D$  is 50 €/MW.

| Country    | Market input |                       |                         | Market result |             | Current scheme | Proposed scheme |
|------------|--------------|-----------------------|-------------------------|---------------|-------------|----------------|-----------------|
|            | Demand [MW]  | Min (Core share) [MW] | Max (Export limit) [MW] | LMP [€/MW]    | Export [MW] | TSO Costs [€]  | TSO Costs [€]   |
| A          | 100          | 40                    | 70                      | 1             | 30          | -155           | 100             |
| B          | 50           | 30                    | 30                      | 2             | -20         | -70            | 80              |
| C          | 30           | 20                    | 20                      | 1             | 0           | 30             | 30              |
| D          | 20           | 10                    | 10                      | 50            | -10         | 915            | 510             |
| <i>sum</i> | <i>200</i>   |                       |                         |               | <i>0</i>    | <i>720</i>     | <i>720</i>      |

Table 3.10: Scenario 4: Simplified case, where one  $LMP \neq CBMP$  but on a different order of magnitude (no *over procurement* occurs): comparison between current and proposed schemes.

Some observations regarding the TSO costs under the current scheme (see Table I.4 for further details):

1. The *over-cost* is now large compared to what it was in scenario 3 (Table I.3).  $TSO_D$  is the causer of the high *over-cost*;
2.  $TSO_A$  is exporting and paying a negative cost;

3.  $TSO_B$  maintains the exact situation as in scenario 3. It imports as much as it can and its LMP is 2 €/MW, reflecting the scarcity of local BSP bids. Yet,  $TSO_B$  is paying much less than in Scenario 3, in fact paying a negative cost;
4.  $TSO_C$  is *balanced* and pays the same (positive) cost as in scenario 3.

It is noteworthy to compare the situations of countries B and C. There is a scarcity of bids in country B and no scarcity of bids in country C, yet  $TSO_C$  pays a positive cost and  $TSO_B$  pays a negative cost.

Regarding the proposed scheme, it can be concluded:

1. Only costs of  $TSO_C$  are equal to those of the current scheme;
2. TSOs from countries A, B and C pay the same as in scenario 3 under the proposed scheme, which makes sense since the LMPs of these countries remain the same;
3. Note that the BSPs that supply the 10 MW to country D are located in country A (the only exporter). Note that these BSPs are paid using  $LMP_A$ . It is easy to understand that  $TSO_D$  pays the 10 MW of local demand at  $LMP_D$  (10\*50) plus the imported demand at  $LMP_A$  (10\*10).

The proposed mechanism produces positive TSO costs in all cases.

**Scenario 5** The day occurring with the greatest inequity, *i.e.* the largest absolute difference of results in both schemes (which amounts to nearly 280 k€), is now analyzed.

| Country    | Market input |                       |                         | Market result |             | Current scheme | Proposed scheme | Inequity (proposed - current) [€] |
|------------|--------------|-----------------------|-------------------------|---------------|-------------|----------------|-----------------|-----------------------------------|
|            | Demand [MW]  | Min (Core share) [MW] | Max (export limit) [MW] | LMP [€/MW]    | Export [MW] | TSO costs [€]  | TSO costs [€]   |                                   |
| AT         | 71           | 22                    | 100                     | 83            | -29         | -8,267         | 6,105           | 14,373                            |
| BE         | 87           | 27                    | 100                     | 4257          | -38         | 351,810        | 212,010         | -139,800                          |
| CH         | 67           | 21                    | 100                     | 83            | 59          | -23,248        | 5,761           | 29,009                            |
| DE         | 562          | 169                   | 168                     | 83            | 56          | 19,302         | 48,326          | 29,024                            |
| DK         | 20           | 6                     | 6                       | 83            | 11          | -3,711         | 1,720           | 5,431                             |
| FR         | 508          | 153                   | 152                     | 83            | 49          | 18,238         | 43,682          | 25,444                            |
| NL         | 114          | 35                    | 100                     | 83            | -65         | -22,277        | 9,803           | 32,079                            |
| SI         | 15           | 0                     | 100                     | 83            | 9           | -3,150         | 1,290           | 4,439                             |
| <i>sum</i> | <i>1444</i>  |                       |                         |               | <i>52</i>   | <i>328,697</i> | <i>328,697</i>  | -                                 |

Table 3.11: Scenario 5: Comparison of TSO costs of real case 2021-05-15, product NEG-POS\_12\_16.

The results are summarized in Table 3.11, with the complete computation of both schemes in Appendix J.

Before analyzing the TSO results, it is necessary to observe the market results. The only country with  $LMP \neq CBMP$  is Belgium, with  $LMP = 4257 \text{ €/MW}$ , which is 51 times more than the remaining LMPs. At first inspection, the market outcome appeared inconsistent regarding the case of Belgium. If  $D_{BE} = 87 \text{ MW}$  and the country is importing 38 MW, then  $BSP\_cleared\_bids_{BE} = 87 - 38 = 49 \text{ MW}$  which is greater than  $core\_share_{BE} = 27 \text{ MW}$ . In principle the country is not hitting the *core constraint* and should have a LMP equal to that of other countries. But the fact is that a close inspection of the bids accepted in this tender (separate file<sup>26</sup> from [117]) shows the following: before the last accepted bid from Belgium, already 26 MW had been accepted from this country, so only 1 MW was missing to satisfy the *core share*. However, the last accepted bid in Belgium is a 23 MW *indivisible* bid with a price of 4257 €/MW<sup>27</sup>. In these conditions, the indivisible bid has to be accepted and the *core constraint* is hit, according to the FCR Cooperation rules [122], since the last bid was only accepted to avoid hitting the *core constraint* and therefore influences the solution, which is why the LMP in Belgium is 4257 €/MW.

Regarding the TSO costs in the current scheme, Table 3.11 presents an example that contains all the analyzed inequities: *over-procurement* of 52 MW and negative TSO costs in 6 out of 8 countries. Note that AT and NL also receive a revenue while *importing power*.

Belgium pays 40% less in the proposed scheme than in the current scheme.

What is interesting to point out is that under the current scheme, if the last bid in Belgium were above 4257 €/MW, the costs would be even lower for the remaining TSOs and higher for Belgium. It could be said that an internal problem of scarcity in Belgium *influences* the rest of the market. The proposed scheme is immune to this *influence*: since Belgium's last bid was accepted to fulfill demand from Belgium, only the Belgian TSO would be impacted, due to the principle of “paying locally what is demanded locally” first.

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<sup>26</sup>“RESULT\_LIST\_ANONYM\_CAPACITY\_MARKET\_FCR\_2021-01-01\_2021-12-31.xlsx”

<sup>27</sup>The high price may reflect scarcity or market power, but such an analysis is beyond the scope of this work.

### 3.2.5.2 TSO accumulated costs 2019-2022

The most significant outcomes of this work are shown in Table 3.12, which presents the TSO accumulated costs from 2019 to 2022 under both cost schemes, and in Figure 3.18 where the difference between both schemes is presented in proportion to the current scheme.

|                                           | AT   | BE   | CH   | DE    | DK   | FR    | NL   | SI  | sum   |
|-------------------------------------------|------|------|------|-------|------|-------|------|-----|-------|
| Accumulated costs in current scheme [M€]  | 30.6 | 54.2 | 25.6 | 251.5 | 27.9 | 213.5 | 69.1 | 4.7 | 677.1 |
| Accumulated costs in proposed scheme [M€] | 32.7 | 45.2 | 29.6 | 259.8 | 18.9 | 223.7 | 62.0 | 5.3 | 677.1 |
| Difference [M€]                           | 2.0  | -9.0 | 4.0  | 8.3   | -9.1 | 10.2  | -7.1 | 0.6 | 0.0   |
| Distortion [M€]                           | 2.0  | 9.0  | 4.0  | 8.3   | 9.1  | 10.2  | 7.1  | 0.6 | 50.3  |

Table 3.12: Accumulated costs from 2019 to 2022 under both schemes. The last row is the module of the difference between the two schemes.

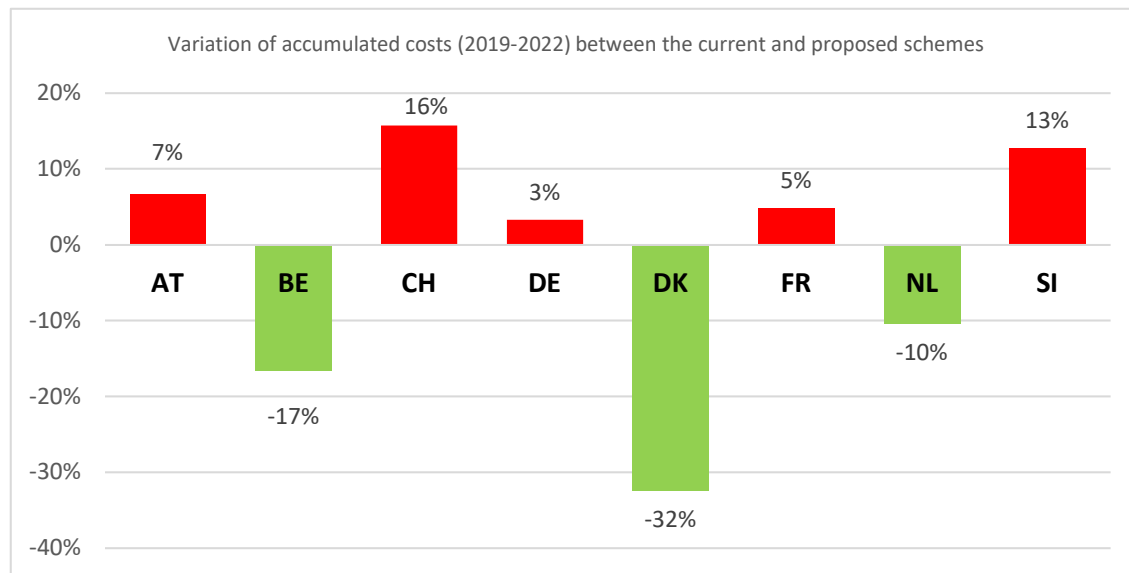


Figure 3.18: Difference of accumulated costs (2019-2022) between both schemes divided by the accumulated costs of the current scheme. Countries in green would benefit from the proposed scheme, countries in red would have their costs increased.

All TSOs would be highly impacted (in the order of M€) if the proposed cost scheme would have been adopted from 2019 to 2022. Looking at the variation in percentage,

the most negatively impacted TSO would be the Swiss TSO, which would increase its accumulated costs by 16% or around 4 M€. The most positively impacted would be the Danish TSO, which would reduce its accumulated costs by 32% or around 9 M€. The inequity of the current mechanism<sup>28</sup> amounts to 50 M€ or 7.4% of the total accumulated costs (677 M€).

Table 3.12 provides an overview of accumulated results under both schemes on the analyzed period; however, it does not elucidate on the contribution of single market sessions to the overall accumulated inequity. Figure 3.19 was obtained after sorting the inequities from highest to lowest and should be read as follows: the 10% market sessions with the highest inequities contribute to 40% of the accumulated inequities, whereas the 20% market sessions with the lowest inequities account for virtually no inequities.

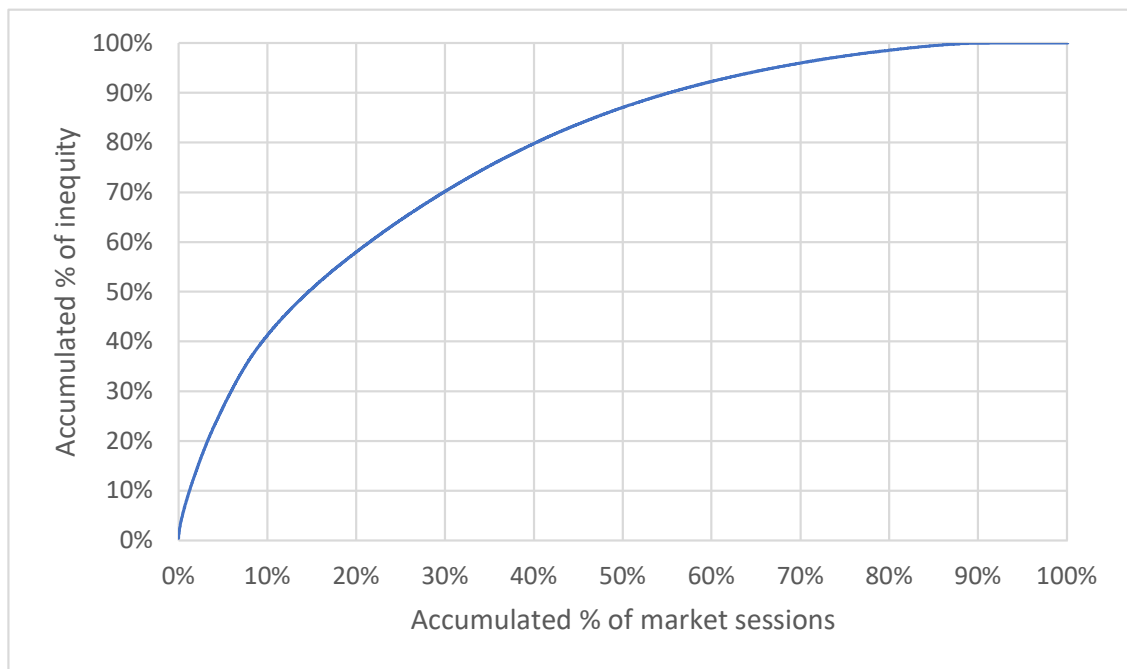


Figure 3.19: Distribution of inequity per market sessions. This plot is obtained after sorting the inequities from the greatest to the lowest.

### 3.2.5.3 Discussion

The rationale of the current TSO cost scheme presented in Section 3.2.2.2 is as follows: *each TSO pays the local BSP revenue, plus import costs (revenues) if the country is im-*

<sup>28</sup>Here defined as the module of the difference of accumulated costs in both schemes.

*balanced, plus, possibly, a deduction (or additional cost) arising either from the existence of distinct LMPs or from over-procurement.* As already made evident, *over-procurement* is a smaller inequity than that arising from different LMPs when these are of different orders of magnitude. The latter inequity can be interpreted as a congestion rent since LMPs become different when either the core or export limit constraints are met.

Below, the current scheme design is analyzed under the case of *over-procurement*; the possibility of being an importer while receiving a revenue is discussed, and finally it is shown why TSO costs should, in principle, be positive.

**Over-procurement** In the authors' view the following facts should be taken into account when addressing the question of how to pay the *over-procurement*:

1. *over-procurement* is made possible because of market design, not by TSO's decision to procure extra demand in a given tender;
2. the TSO of a country  $c$  where the cleared amount of  $CQ_c$  matches exactly  $D_c$ , should not be benefited over a TSO which is either importing or exporting (because  $CQ_c$  is the result of the market forces (BSPs) independent of the TSO);
3. the TSO of an importer country,  $TSO_{imp}$ , should ideally pay the imported power in such a way that neither  $BSP_{exp}$  nor remaining TSOs are impacted.

The last point is valid under the current scheme. However, the second point is not: in case there is 1 MW of *over-procurement*, a TSO demanding 48 MW (such as Belgium) or a country demanding 550 MW (such as Germany) which are imbalanced in 1 MW would pay the same *over-cost allocation*. TSOs demanding fewer products are thus paying a proportionally higher share of the *over-procurement* than TSOs demanding more products. Also, they would pay the same *regardless of whether the country is importing or exporting*, which does not even promote exports. In the authors' opinion, also considering the first point, it would make more sense to dilute the *over-cost* arising from *over-procurement* proportionally to the demand and regardless of the *imbalance*, as proposed in the Section 3.2.3.1. In Section 3.2.4 the authors have shown that *over-procurement* is not the major source of inequity.

**Receiving a revenue while importing** An interesting simplified example of the inequity of the current mechanism is presented in Table 3.13. This case takes Table 3.10 and adds 10 MW of exports from country A to country C.

| Country | Market input |                       |                         | Market result |             | Current scheme | Proposed scheme |
|---------|--------------|-----------------------|-------------------------|---------------|-------------|----------------|-----------------|
|         | Demand [MW]  | Min (Core share) [MW] | Max (Export limit) [MW] | LMP [€/MW]    | Export [MW] | TSO Costs [€]  | TSO Costs [€]   |
| A       | 100          | 40                    | 70                      | 1             | 40          | -155           | 100             |
| B       | 50           | 30                    | 30                      | 2             | -20         | -28            | 80              |
| C       | 30           | 20                    | 20                      | 1             | -10         | -34            | 30              |
| D       | 20           | 10                    | 10                      | 50            | -10         | 936            | 510             |
| sum     | 200          |                       |                         |               | 0           | 720            | 720             |

Table 3.13: Simplified case, where one  $LMP \neq CBMP$  but in a different order of magnitude (no *over procurement* occurs): comparison between current and proposed schemes. The difference between this case and Table 3.10 is that  $TSO_C$  is now importing 10 MW, which are exported from country A.

If country C is not *balanced* as it was in scenario 4 and now becomes an importer, then, *a priori*, it should increase its TSO costs, but under the current scheme, it will receive a revenue. The inequity produced by the market is, thus, evident.

$TSO_A$  still *receives* the same 155 € as in Table 3.10.  $TSO_B$  is also exactly in the same situation as before and receives slightly less.  $TSO_D$  is exactly in the same situation as in Scenario 4 and pays slightly more than before. It should be questioned why is  $TSO_D$  paying more than before if nothing changed regarding this country: it is importing the same amount from the same country of origin.

The reason for the inequity produced by the scheme, *i.e.* for  $TSO_C$  receiving a revenue is quite simple: the *absolute import* of country C is now 10 MW so this TSO benefits from a deduction of 12.5% (*allocation key*) of the substantial *over-cost* (720 €). The importing situation of country D causes the *over-cost* with its high LMP.

Note that the proposed scheme in Table 3.13 and Table 3.10 yields the same results. Note that if the only difference between the two cases is that the supply of C becomes imported from A, but at the same time there is no difference between  $LMP_A$  and  $LMP_C$ , it makes sense that the TSO costs for the two scenarios are the same.

The explanation for the inequity is as follows. Under the current scheme, when  $LMP_{imp} \gg LMP_{exp}$ ,  $TSO_{imp}$  is *paying the imported power to the  $BSP_{exp}$  at the cost of  $LMP_{imp} \times CQ_{exp}$ , which is much higher than  $LMP_{exp} \times CQ_{exp}$  (the real cost of this*

power); this creates a large deduction which is then appropriated by all the imbalanced TSOs and not only by the one already penalized.

An actual tender where this occurred is presented in Appendix J.

**The case against negative costs** The example provided in Table 3.13 points to the counter-intuition of the outcomes under the current mechanism. *In principle*, TSOs should not pay a negative cost (*i.e.* receive a revenue) for procuring a given demand in the FCR Cooperation, the argument being that the TSO cost should *at least* respect Inequation 3.51:

$$C\_TSO_A \geq LMP_A \times CS_A \quad (3.51)$$

Even considering a limit case in which *the imported power would be free*<sup>29</sup>, the TSO should pay for its core share: *the key is that both elements of Equation (3.51) are non-negative*.

It is then proven that a TSO cost should, *in principle*, be non-negative.

The proposed mechanism does not suffer from the inequity identified in the current scheme, discussed in this section: negative TSO costs and a questionable *over-procurement* cost allocation. Even in the cases of the most extreme LMP discrepancy, as shown in Section 2.2.2:

1. TSO costs remain at least positive,
2. *Over-procurement* is divided proportionally to TSO Demand regardless of the market outcomes and
3. TSO costs are always compatible with the Inequation (3.51).

An analysis of the cases presented so far (especially, Table 3.13) allows us to conclude that a high *over-cost* is the source of the inequity in the current scheme. The fundamental difference between both schemes is that in the one proposed here, by paying firstly the

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<sup>29</sup>Note that LMPs in the remaining countries are non-negative.

local imports needed locally and treating the “*missing money*” in a subsequent step, there is no room for inequity.

The proposed scheme would, thus, ensure a viable alternative to the current scheme.

### 3.2.6 Conclusions

This work analyzed the current scheme through which TSOs pay BSPs (such as HEs) for participating in an FCR Cooperation tender, identified inequities and proposed a novel scheme to overcome them. While this work proposes a novel settlement scheme for sharing costs among TSOs, it proposes no changes to existing market clearing rules; thus, its implementation would face no barriers in the TSO Cooperation.

One identified source of the inequity arises from the existence of different LMPs, when either the minimum core constraint or maximum export limit is met. Notably, when over-procurement occurs, only imbalanced TSOs pay for the over-procured quantity, regardless of their total demand, under the current TSO cost mechanism. It was found that TSOs demanding fewer products pay proportionally more for over-procurement than TSOs demanding more products.

Most importantly, it was found that some TSOs can receive revenue for participating in the FCR Cooperation, whereas others are heavily penalized when LMPs are of different orders of magnitude.

Both simplified examples and real cases are analyzed. The arguments against negative costs are demonstrated with simple equations.

The proposed mechanism overcomes the inequity currently occurring. It differs fundamentally from the current scheme because it departs from a logic of “paying locally what is needed locally” to BSPs (such as HEs) first, instead of computing an over-cost arising from different LMPs and distributing it afterwards through a questionable mechanism that benefits importers and exporters but not balanced TSOs.

It is shown that if the proposed pricing scheme had been adopted from July 2019 to December 2022, all TSOs would have been impacted; the most negatively impacted TSO would have its accumulated costs increased by 16%, and the most positively impacted TSO

would have its accumulated cost decreased 32%. The inequity of the current mechanism amounts to more than 50 M€ or 7.4% of the total accumulated costs.

Although the proposed mechanism is tested here under the FCR Cooperation, it can be applied to other markets where the rules allow different local settlement prices.

In September 2024, ENTSO-E updated the TSO settlement scheme after acknowledging that the existing mechanism was not fair and needed to be improved [130]. This scheme will come into force from 2026 onwards. Future work should compare the updated ENTSO-E scheme with the proposed one.

## Chapter 4

# Conclusions and Future Work

*This chapter closes the thesis, firstly summarizing the main contributions, secondly, outlining the findings, and thirdly, identifying possible paths for future work.*

### 4.1 Contributions

In the first chapter of this thesis, estimates of European future hydrogen demand were given, which imply that a large amount of HEs will be connected to the future power grid. Given that HEs are controllable loads connected to the grid, they will be able to contribute for LFC as a secondary task, at the same time that they perform their main task which is hydrogen production. LFC is essential for TSOs, given that the frequency itself is an indicator of the quality of the service that TSOs must guarantee. The overarching objective of this thesis was to assess the participation of HEs in LFC.

The first main contribution of this thesis, in the context of FCR and fast reserves, was the development of a methodology that allows the quantification of the relation between critical inertia and ancillary service provision by HEs. This was made possible by the the following contributions:

- 1.1 Inclusion of an HE dynamic representation in a two area power system model to analyze its contribution to mitigate the Rate of Change of**

**Frequency following a disturbance.** Such model was developed in MATLAB-Simulink and analyzes the system response following a loss of generation. The system response is then compared with ancillary service provision by conventional plants.

**1.2 Quantification of the relations between RoCoF and HE ancillary service volume, HE ramping capability and communication delay.** Scenarios were designed with parameters variation, and simulations were done for assessing the RoCoF values for each case.

**1.3 Quantification of the reduction of critical inertia due to HE ancillary service provision under a set of scenarios.** The comparison between ancillary service provision by conventional generators and by HEs for different levels of inertia allows computing the reduction of critical inertia guaranteed by HEs.

The second main contribution, in the context of secondary frequency control, was the proposal of a model predictive controller that takes advantage of the fast resources following a large contingency.

**2.1 Proposal of an emergency mode for the secondary reserve.** This conceptual contribution assumes that, in the same way that there are emerging reserves that are faster than the FCR (such as FCR and SI), an emergency mode might be suitable for the secondary reserve. Such mode is activated when the frequency measurement and interconnection flows are simultaneously surpassing a threshold value. The activation of such emergency mode triggers a newly designed controller for the units participating in the secondary reserve. It is shown that the designed controller allows for the proper exploitation of HEs.

**2.2 Inclusion of further system knowledge in the AGC controller.** While the existing AGC controller relies on a proportional-integral implementation with relatively limited knowledge of the system (which ensures generalization), the proposed MPC controller includes further knowledge such as the ramping capability of the participating units, namely the one provided by HEs.

The third main contribution, in the context of FCR market, was to calculate revenues of HEs in this market. This was made possible by the the following contributions:

- 3.1 **Development of a model that simulates the participation of a Virtual Power Plant in the FCR market.** The VPP, which aggregates wind and solar plants as well as HEs, participates in the market submitting symmetric bids. Real market data is used. A set of scenarios was designed, for Portugal and Spain, to compute the market share of the VPP in each market session and thus compute the revenues of the VPP under a set of customizable assumptions. The model was implemented in a spreadsheet which was made publicly available [111].
- 3.2 **Inclusion of opportunity costs.** In addition to the previous point, it proved essential to address opportunity costs, since the reserve activation results in impacts on the VPP participants. The impact is such that reserve activation implies that wind farms and solar plants deliver less energy to the energy market and HEs generate less hydrogen. Using data from real FCR activation, the opportunity costs for the VPP were quantified. Opportunity costs were incorporated in the economic study of VPP revenues.
- 3.3 **Assessment of costs for Portuguese and Spanish TSOs.** Presently, the Portuguese and Spanish TSOs do not have an FCR market. Using real market data from the years 2019 to 2022, the costs that these TSOs would pay annually if they joined the existing FCR Cooperation were estimated.

The fourth main contribution, in the context of FCR market regulation, was the proposal of a novel scheme through which TSOs pay the BSPs' (such as HEs) participation in this market. This was made possible by the the following contributions:

- 4.1 **Identification of market distortions in the existing settlement scheme.** An analysis of the existing settlement scheme was done using both simplified scenarios and real market sessions. The sources of market distortions were identified and discussed.

**4.2 Proposal of a new settlement scheme.** Taking into account the market distortions identified in the previous point, a novel market mechanism for overcoming such distortions is proposed and discussed. The proposed scheme is compared with the existing one. The proposed scheme ensures that costs of the service provided by BSPs such as HEs are adequately shared by TSOs.

## 4.2 Findings

The research questions posed in Section 1.2 are answered in this subsection.

*Research question 1: to what extent can HE participation in the FCR and sub-primary reserves mitigate frequency and RoCoF excursions in the future Iberian power system?*

- If the frequency containment reserve is provided by HEs instead of conventional generators, a very significant decrease of RoCoF excursion can be achieved in the system (0.83 Hz/s to 0.63 Hz/s).
- Additional decrease of RoCoF is possible with the use of synthetic inertia or fast frequency response but the benefit is highly dependent on the ramping capability of future HEs.
- Ancillary service provision by HEs reduces the critical inertia of the power system, which means the system can be operated securely at lower inertia levels if compared to ancillary service provision by conventional power plants. Simulations performed in this study for several scenarios allow to quantify this relation in the plane RoCoF vs inertia.

*Research question 2: in the context of aFRR, can Model Predictive Control more adequately exploit the fast ramping capability of HEs than the conventional proportional-integral controller?*

- It was found that in the developed approach the faster resources are more adequately exploited than in the case of the conventional controller, given that their ramping

capabilities are included in the problem formulation, which is particularly important when incorporating HE contributions.

- It was found that the developed approach outperforms the conventional controller even in the case that the system parameters are subject to estimation errors.

*Research question 3: what revenues can a HE participating in FCR market obtain, considering opportunity costs?*

- A set of different scenarios was created in the study. Here the research question is answered for a VPP with an aggregated power of HEs of 50 MW considering market participation in Portugal in 2022.
- Without considering opportunity costs, the VPP would participate in 87% of the market sessions, whereas considering opportunity costs the VPP would participate in considerably less - 62% - of the market sessions.
- Such VPP would have an annual revenue of over 800 k€. The corresponding revenue for the HE would have been 91 k€.

*Research question 4: is the regulation of the existing FCR market (FCR Cooperation) adequate for ensuring the payments that TSOs make to Balancing Service Providers (such as HEs)?*

- It was shown why in principle there should be no negative TSO costs and the proposed scheme avoids them.
- Using market data from 2019 to 2022 it was found that the total market distortion in the existing scheme is over 50 M€, which roughly corresponds to around 7% of the total market volume.
- It was found that the costs that TSOs of different countries pay to BSPs (such as HEs) are differently impacted under the proposed scheme: the Danish TSO would have reduced its accumulated costs by 32% and the Swiss TSO would have increased its accumulated costs by 16%.

## 4.3 Future Work

Throughout the thesis a set of future research topics was identified. Regarding the primary and sub-primary reserves (Section 2.2) the following topics deserve further attention:

- 1.1 **Design test protocols for HEs regarding FFR and SI:** in the same way that the project QualyGridS designed standardized test protocols for FCR and slower reserves [81], test protocols for FFR and SI are necessary. On the one hand, they are necessary for the TSOs to test the capability of HEs that intend to become ancillary service providers; on the other hand, HE manufacturers will become aware of the market needs and if possible adapt the production accordingly.
- 1.2 **Including grid topology in the dynamic simulation:** a more detailed yet complex study would be the inclusion of the transmission grid into the proposed methodology. It is in the interest of the TSO to analyze how the frequency and RoCoF would vary in different points of the grid, instead of doing this assessment in a simplified single node grid like proposed in this thesis.

In the context of secondary frequency control (Section 2.3) the following topics were identified as future research:

- 2.1 **Inclusion of grid topology:** Future work might expand the MPC to include the grid topology so that the controller can handle congestions in grid bottlenecks.
- 2.2 **Communication delays:** It was assumed in this work that the SCADA system receives system measurements in a given time interval. Future work might study the impact of measurement delays in the communication systems.

In the context of FCR markets and regulation (Chapter 3) the following topics were identified as future research:

- 3.1 **Real-time dispatch:** this is a technical operational issue for the VPP owner. It arises from the fact that the VPP is composed of several units of disparate technologies. The question is, when FCR needs to be activated in real-time, which of the

units will be requested to change their setpoints? Concretely, if 1 MW of upward reserve is suddenly necessary to be provided by the HEs participating in the VPP, how many of the HEs' stacks will be required to reduce their consumption? For instance, stack degradation must be taken into account.

- 3.2 Price-maker impact:** When the VPP includes many HEs and is a sufficiently large player, it becomes a price-maker and thus can influence the market outcomes. Future work should address the impact of the VPP being a price-maker.
- 3.3 Integrate forecasts:** The work done in this chapter assumed many constant parameters to be known in advance. Future work should integrate forecasts into the model, for instance, for the market clearing price.
- 4.1 Compare the future ENTSO-E TSO settlement scheme with the proposed:** From 2026 onwards, the FCR Cooperation will have a new scheme through which TSOs pay BSPs such as HEs. A future line of research is the comparison between the scheme proposed by this thesis and the future ENTSO-E scheme.



## Appendix A

# Inverter-based resources trip

As per Figure 2.8 there are three components in IBR production loss totalling 3 GW of instantaneous loss: (a) 760 MW of decentralized photovoltaics (PV) generation that is assumed to be lost and not reconnected in the following 30 s, (b) 1120 MW of centralized (“utility-scale”) PV generation that are lost during 150 ms, and then this power is fully recovered linearly 1 s later; (c) 1120 MW of wind power are lost during 150 ms, then this power is recovered linearly after 4 s [131]. This kind of IBR trip have been identified as a threat in Australia, where AEMO states that a severe but credible fault could cause the disconnection of up to half of the distributed PV generation in South Australia [51].

In this chapter it is considered that the IBR trip takes place in the Portuguese area (*i.e.* part of the IP). For comparison purposes, [132] mentions in 2040 it is expected that 9.6 GW of utility-scale PV generation, 7.3 GW of decentralized PV generation and 10.5 GW of wind generation, so the IBR trip would mean disconnecting 3 GW or 11% of the installed solar and wind power in the Portuguese control area or 1.4% of total installed solar and wind power within the whole IP.



## Appendix B

### Model calibration

| Parameter    | Description                                           | Value    | Units       |
|--------------|-------------------------------------------------------|----------|-------------|
| $H_{IP}$     | Inertia constant in IP                                | 21.2122  | pu.s        |
| $H_{CE}$     | Inertia constant in CE                                | 149.9957 | pu.s        |
| $D_{IP}$     | Damping constant in IP                                | 7.59     | pu.GW/pu.Hz |
| $D_{CE}$     | Damping constant in CE                                | 26.958   | pu.GW/pu.Hz |
| $R_{C+N,IP}$ | Speed governor droop of coal and nuclear plants in IP | 0.5728   | pu.Hz/pu.GW |
| $R_{H,IP}$   | Speed governor droop of hydro plants in IP            | 0.7373   | pu.Hz/pu.GW |
| $R_{NG,IP}$  | Speed governor droop of CCGT plants in IP             | 0.1436   | pu.Hz/pu.GW |
| $R_{C+N,CE}$ | Speed governor droop of coal and nuclear plants in CE | 0.0156   | pu.Hz/pu.GW |
| $R_{H,CE}$   | Speed governor droop of hydro plants in CE            | 0.0432   | pu.Hz/pu.GW |
| $R_{NG,CE}$  | Speed governor droop of CCGT plants in CE             | 0.0387   | pu.Hz/pu.GW |
| $TR_{H,IP}$  | Transient droop of hydro plants in IP                 | 23.2956  | pu.Hz/pu.GW |
| $TR_{H,CE}$  | Transient droop of hydro plants in CE                 | 1.5928   | pu.Hz/pu.GW |
| $Ti_{gov}$   | Speed governor time constant for all technologies     | 0.2      | s           |
| $T$          | Synchronizing torque coefficient                      | 0.2009   | pu.GW/rad   |

Table B.1: Model calibration parameters and respective values



## Appendix C

### Simulation parameters and results

| Simulation # | AS used | ASV   | RC | CD | Nadir | RoCoF |
|--------------|---------|-------|----|----|-------|-------|
| 1            | FCR     | Or    | F  | R  | 49.71 | 0.62  |
| 2            | FCR     | Or    | S  | R  | 49.71 | 0.63  |
| 3            | FCR     | Or    | F  | M  | 49.72 | 0.59  |
| 4            | FCR     | Or    | S  | M  | 49.71 | 0.60  |
| 5            | FCR+SI  | Or    | S  | R  | 49.71 | 0.59  |
| 6            | FCR+SI  | 4*Or  | S  | R  | 49.71 | 0.59  |
| 7            | FCR+SI  | 10*Or | S  | R  | 49.71 | 0.59  |
| 8            | FCR+SI  | Or    | F  | R  | 49.74 | 0.52  |
| 9            | FCR+SI  | 4*Or  | F  | R  | 49.75 | 0.50  |
| 10           | FCR+SI  | 10*Or | F  | R  | 49.75 | 0.50  |
| 11           | FCR+SI  | Or    | S  | M  | 49.72 | 0.57  |
| 12           | FCR+SI  | 4*Or  | S  | M  | 49.72 | 0.57  |
| 13           | FCR+SI  | 10*Or | S  | M  | 49.72 | 0.57  |
| 14           | FCR+SI  | Or    | F  | M  | 49.75 | 0.49  |
| 15           | FCR+SI  | 4*Or  | F  | M  | 49.78 | 0.45  |
| 16           | FCR+SI  | 10*Or | F  | M  | 49.78 | 0.45  |
| 17           | FCR+FFR | Or    | S  | R  | 49.71 | 0.64  |
| 18           | FCR+FFR | 4*Or  | S  | R  | 49.71 | 0.74  |
| 19           | FCR+FFR | 10*Or | S  | R  | 49.71 | 0.74  |
| 20           | FCR+FFR | Or    | F  | R  | 49.71 | 0.57  |
| 21           | FCR+FFR | 4*Or  | F  | R  | 49.71 | 0.57  |
| 22           | FCR+FFR | 10*Or | F  | R  | 49.71 | 0.73  |
| 23           | FCR+FFR | Or    | S  | M  | 49.72 | 0.57  |
| 24           | FCR+FFR | 4*Or  | S  | M  | 49.72 | 0.62  |
| 25           | FCR+FFR | 10*Or | S  | M  | 49.72 | 0.62  |
| 26           | FCR+FFR | Or    | F  | M  | 49.73 | 0.54  |
| 27           | FCR+FFR | 4*Or  | F  | M  | 49.73 | 0.54  |
| 28           | FCR+FFR | 10*Or | F  | M  | 49.73 | 0.54  |

Table C.1: Simulation platform results obtained by changing parameters, according to Table 2.2. ASV = ancillary service volume, RC = ramping capability, CD = communications delay

## Appendix D

# Equations in Laplace domain

The differential equations from the MATLAB-Simulink presented in Section 2.3 model are as follows:

$$Df_i = \frac{1}{2H_i.s + D_i}(-DPL_i + Ptp_i + Pts_{fa} + Pts_{me} + Pts_{sl} + import_i) \quad (D.1)$$

$$Ptp_i = Pgp_i \frac{1}{Tt.s + 1} \quad (D.2)$$

$$Pgp_i = Df_i \left(-\frac{1}{R}\right) \frac{1}{Tg.s + 1} \quad (D.3)$$

$$Pts_{fa_i} = Pgs_{fa_i} \frac{1}{Tts_{fa.s} + 1} \quad (D.4)$$

$$Pgs\_fa_i = uFRR\_fa \frac{1}{Tgs\_fa.s + 1} \quad (D.5)$$

$$Pts\_me_i = Pgs\_me_i \frac{1}{Tts\_me.s + 1} \quad (D.6)$$

$$Pgs\_me_i = uFRR\_me \frac{1}{Tgs\_me.s + 1} \quad (D.7)$$

$$Pts\_sl_i = Pgs\_sl_i \frac{1}{Tts\_sl.s + 1} \quad (D.8)$$

$$Pgs\_sl_i = uFRR\_sl \frac{1}{Tgs\_sl.s + 1} \quad (D.9)$$

$$import_i = \left(\frac{1}{s}Df_i - \frac{1}{s}Df_j\right)T_{ij} + \left(\frac{1}{s}Df_i - \frac{1}{s}Df_k\right)T_{ik} \quad (D.10)$$

$$Df_j = \frac{1}{2H_j s + D_j} (-DPL_j + Ptp_j + import_j) \quad (D.11)$$

$$Ptp_j = Pgp_j \frac{1}{Tt.s + 1} \quad (D.12)$$

$$Pgp_j = Df_j(-\frac{1}{R})\frac{1}{Tg.s+1} \quad (\text{D.13})$$

$$import_j = (\frac{1}{s}Df_j - \frac{1}{s}Df_i)T_{ij} + (\frac{1}{s}Df_j - \frac{1}{s}Df_k)T_{ik} \quad (\text{D.14})$$

$$Df_k = \frac{1}{2H_k s + D_k}(-DPL_k + Ptp_k + import_k) \quad (\text{D.15})$$

$$Ptp_k = Pgp_k\frac{1}{Tt.s+1} \quad (\text{D.16})$$

$$Pgp_k = Df_k(-\frac{1}{R})\frac{1}{Tg.s+1} \quad (\text{D.17})$$

$$import_k = (\frac{1}{s}Df_k - \frac{1}{s}Df_i)T_{ki} + (\frac{1}{s}Df_k - \frac{1}{s}Df_j)T_{kj} \quad (\text{D.18})$$



## Appendix E

### Space-state matrixes

In Section 2.3, the elements with non-zero values of matrixes A, B, C and D derived from the differential equations are the following:

$$A_{1,1} = -D_i/(2H_i)$$

$$A_{1,3} = 1/(2H_i)$$

$$A_{1,5} = 1/(2H_i)$$

$$A_{1,7} = 1/(2H_i)$$

$$A_{1,9} = 1/(2H_i)$$

$$A_{2,1} = -1/(R_i T g p_i)$$

$$A_{2,2} = -1/(T g p_i)$$

$$A_{3,2} = 1/T t p_i$$

$$A_{3,3} = -1/T t p_i$$

$$A_{4,4} = -1/T g s\_f a_i$$

$$A_{5,4} = 1/T t s\_f a_i$$

$$A_{5,5} = -1/T t s\_f a_i$$

$$A_{6,6} = -1/T t s\_m e_i$$

$$A_{7,6} = 1/T t s\_m e_i$$

$$A_{7,7} = -1/T t s\_m e_i$$

$$A_{8,8} = -1/T g s\_s l_i$$

$$A_{9,8} = 1/T t s\_s l_i$$

$$A_{9,9} = -1/Tts\_sl_i$$

$$A_{10,10} = -D_j/(2 \times H_j)$$

$$A_{10,12} = 1/(2 \times H_j)$$

$$A_{11,10} = 1/(2 \times H_j)$$

$$A_{11,11} = -1/(Tgp_j)$$

$$A_{12,11} = 1/Ttp_j$$

$$A_{12,12} = -1/Ttp_j$$

$$A_{13,13} = -D_k/(2 \times H_k)$$

$$A_{13,15} = 1/(2 \times H_k)$$

$$A_{14,13} = -1/(R_k \times Tgp_k)$$

$$A_{14,14} = -1/(Tgp_k)$$

$$A_{15,14} = 1/Ttp_k$$

$$A_{15,15} = -1/Ttp_k$$

$$A_{1,16} = 1/(2 \times H_i) + 1/(2 \times H_i)$$

$$A_{16,1} = -Tij \times 50 \times 2 \times \pi - Tik \times 50 \times 2 \times \pi$$

$$A_{10,16} = -1/(2 * H_j)$$

$$A_{16,10} = Tij \times 50 \times 2 \times \pi$$

$$A_{13,16} = -1/(2 * H_k)$$

$$A_{16,13} = Tik \times 50 \times 2 \times \pi$$

$$B_{1,4} = -1/(2 \times H_i)$$

$$B_{4,1} = 1/Tgs\_fa_i$$

$$B_{6,2} = 1/Tgs\_me_i$$

$$B_{8,3} = 1/Tgs\_sl_i$$

$$B_{10,5} = -1/(2 \times H_j)$$

$$B_{13,6} = -1/(2 \times H_k)$$

$$C_{1,1} = 1$$

$$C_{2,16} = 1$$

$$D_{1,1} = 0$$



## Appendix F

### Detailed results of Section 3.1.1

Table F.1: Results in Portugal, disaggregated per year.

| Scenario                              | Scenario 1 "pessimistic" 2025 |          |          | Scenario 2 "expected" 2025 |          |          | Scenario 3 "pledged" 2030 |          |          |
|---------------------------------------|-------------------------------|----------|----------|----------------------------|----------|----------|---------------------------|----------|----------|
| Year                                  | 2020                          | 2021     | 2022     | 2020                       | 2021     | 2022     | 2020                      | 2021     | 2022     |
| Part 1: Without opportunity costs     |                               |          |          |                            |          |          |                           |          |          |
| % of market sessions VPP participates | 87%                           | 88%      | 87%      | 91%                        | 91%      | 99%      | 92%                       | 92%      | 91%      |
| % FCR covered by VPP                  | 10%                           | 10%      | 11%      | 20%                        | 21%      | 22%      | 75%                       | 77%      | 76%      |
| $\sum_T VPR_{c,t}$                    | 173.5 k€                      | 805.1 k€ | 1.1 M€   | 357.6 k€                   | 1.7 M€   | 2.3 M€   | 1.3 M€                    | 5.9 M€   | 7.7 M€   |
| Part 2: Opportunity costs             |                               |          |          |                            |          |          |                           |          |          |
| $\sum_T UP\_OPC_{c,t}$                | 70.7 k€                       | 144.8 k€ | 137.9 k€ | 144.5 k€                   | 294.7 k€ | 283.7 k€ | 542.9 k€                  | 1.1 M€   | 953.6 k€ |
| $\sum_T DN\_OPC_{c,t}$                | 95.2 k€                       | 498.9 k€ | 697.7 k€ | 193.4 k€                   | 1.0 M€   | 1.4 M€   | 703.8 k€                  | 3.6 M€   | 5.0 M€   |
| Part 3: Decision                      |                               |          |          |                            |          |          |                           |          |          |
| % of market sessions VPP participates | 57%                           | 63%      | 64%      | 55%                        | 61%      | 63%      | 55%                       | 61%      | 63%      |
| % FCR covered by VPP                  | 5%                            | 6%       | 7%       | 10%                        | 13%      | 14%      | 39%                       | 46%      | 47%      |
| $\sum_T VR_{c,t}$                     | 110.0 k€                      | 621.0 k€ | 844.4 k€ | 228.4 k€                   | 1.3 M€   | 1.7 M€   | 855.0 k€                  | 4.6 M€   | 6.0 M€   |
| $\sum_T UPRS_{c,t}$                   | 34.3 k€                       | 85.1 k€  | 91.6 k€  | 71.3 k€                    | 176.2 k€ | 188.0 k€ | 270.3 k€                  | 647.0 k€ | 624.1 k€ |
| $\sum_T DNRS_{c,t}$                   | 36.1 k€                       | 242.2 k€ | 303.8 k€ | 75.2 k€                    | 501.9 k€ | 627.0 k€ | 282.4 k€                  | 1.8 M€   | 2.2 M€   |
| $\sum_T VRS_{c,t}$                    | 39.6 k€                       | 293.7 k€ | 449.1 k€ | 81.9 k€                    | 605.6 k€ | 923.1 k€ | 302.1 k€                  | 2.1 M€   | 3.2 M€   |
| Other indicators                      |                               |          |          |                            |          |          |                           |          |          |
| Capacity factor of HEs                | 53%                           | 56%      | 57%      | 53%                        | 56%      | 57%      | 46%                       | 50%      | 52%      |
| $VGS_c$                               | 3%                            | 3%       | 3%       | 6%                         | 6%       | 6%       | 12%                       | 12%      | 12%      |

Table F.2: Results in Spain, disaggregated per year.

| Scenario                              | Scenario 1 "pessimistic" 2025 |          |          | Scenario 2 "expected" 2025 |          |         | Scenario 3 "pledged" 2030 |         |         |
|---------------------------------------|-------------------------------|----------|----------|----------------------------|----------|---------|---------------------------|---------|---------|
| Year                                  | 2020                          | 2021     | 2022     | 2020                       | 2021     | 2022    | 2020                      | 2021    | 2022    |
| Part 1: Without opportunity costs     |                               |          |          |                            |          |         |                           |         |         |
| % of market sessions VPP participates | 99%                           | 99%      | 100%     | 99%                        | 99%      | 100%    | 99%                       | 99%     | 99%     |
| % FCR covered by VPP                  | 3%                            | 4%       | 5%       | 5%                         | 5%       | 5%      | 34%                       | 40%     | 32%     |
| $\sum_T VPR_{c,t}$                    | 894.2 k€                      | 4 M€     | 6.3 M€   | 1.2 M€                     | 8.3 M€   | 14.1 M€ | 8.6 M€                    | 38.0 M€ | 38.8 M€ |
| Part 2: Opportunity costs             |                               |          |          |                            |          |         |                           |         |         |
| $\sum_T UP\_OPC_{c,t}$                | 367.0 k€                      | 751.6 k€ | 776.4 k€ | 416.3 k€                   | 1.2 M€   | 1.5 M€  | 3.5 M€                    | 7.2 M€  | 4.9 M€  |
| $\sum_T DN\_OPC_{c,t}$                | 464.1 k€                      | 2.4 M€   | 4.1 M€   | 545.0 k€                   | 4.5 M€   | 8.3 M€  | 4.4 M€                    | 22.7 M€ | 24.3 M€ |
| Part 3: Decision                      |                               |          |          |                            |          |         |                           |         |         |
| % of market sessions VPP participates | 52%                           | 58%      | 58%      | 51%                        | 58%      | 58%     | 51%                       | 58%     | 58%     |
| % FCR covered by VPP                  | 3%                            | 4%       | 5%       | 5%                         | 8%       | 11%     | 34%                       | 40%     | 32%     |
| $\sum_T VR_{c,t}$                     | 585.0 k€                      | 3.1 M€   | 4.8 M€   | 854.7 k€                   | 6.8 M€   | 11.3 M€ | 5.6 M€                    | 29.5 M€ | 31.0 M€ |
| $\sum_T UPRS_{c,t}$                   | 183.9 k€                      | 432.4 k€ | 498.6 k€ | 253.0 k€                   | 852.2 k€ | 1.1 M€  | 1.8 M€                    | 4.2 M€  | 3.3 M€  |
| $\sum_T DNRS_{c,t}$                   | 188.7 k€                      | 1.2 M€   | 1.8 M€   | 270.6 k€                   | 2.6 M€   | 4.1 M€  | 1.8 M€                    | 11.4 M€ | 12 M€   |
| $\sum_T VRS_{c,t}$                    | 212.0 k€                      | 1.4 M€   | 2.5 M€   | 331.0 k€                   | 3.4 M€   | 6.1 M€  | 2.0 M€                    | 13.9 M€ | 16.1 M€ |
| Other indicators                      |                               |          |          |                            |          |         |                           |         |         |
| Capacity factor of HEs                | 64%                           | 68%      | 78%      | 64%                        | 68%      | 78%     | 62%                       | 66%     | 48%     |
| $VGS_c$                               | 2%                            | 2%       | 5%       | 5%                         | 5%       | 5%      | 10%                       | 10%     | 10%     |



## Appendix G

# Example of TSO costs computation with the current mechanism

The print below is taken from page 12 at [128], entitled “Explanatory document to the Amendment to the TSOs’ Proposal for the establishment of common and harmonised rules and processes for the exchange and procurement of Balancing Capacity for Frequency Containment Reserves (FCR) - September 2021” and below is the print of the section 11.2.5 Example for one delivery day.

As per communication with ENTSO-E in January 2023, the algorithm for computing TSO costs in this date was done according to this documentation. Please see the footnotes on nomenclature presented in Section 3.2.2.2; the relevant column is T with “target costs”, which are the “TSO costs”.

## Example of TSO costs computation with the current mechanism



Explanatory document to the Amendment to the TSOs' Proposal for the establishment of common and harmonised rules and processes for the exchange and procurement of Balancing Capacity for Frequency Containment Reserves (FCR)

### 11.2.5 Example for one delivery day

| A       | B                      | C                         | D                           | E                                             | F               | G                | H       | I                   | J         | K                   | L                   | M                                        | N                      |
|---------|------------------------|---------------------------|-----------------------------|-----------------------------------------------|-----------------|------------------|---------|---------------------|-----------|---------------------|---------------------|------------------------------------------|------------------------|
| Country | demand<br>[AuctionQty] | core<br>share<br>[MinQty] | export<br>limit<br>[MaxQty] | local<br>marginal<br>price<br>[MarginalPrice] | import<br>limit | max<br>local qty | awarded | satisfied<br>demand | position  | import<br>limit hit | export<br>limit hit | net<br>position<br>(satisfied<br>demand) | import/export<br>costs |
|         | MW                     | MW                        | MW                          | €/MW                                          | MW              | MW               | MW      | MW                  |           |                     |                     | I - H<br>MW                              | M * E<br>€             |
| AT      | 71                     | 22                        | 100                         | 124,00 €                                      | 49              | 171              | 123     | 71                  | exporting |                     |                     | -52                                      | - 6.448,00 €           |
| BE      | 87                     | 27                        | 100                         | 169,08 €                                      | 60              | 187              | 27      | 87                  | importing | yes                 |                     | 60                                       | 10.144,80 €            |
| CH      | 67                     | 21                        | 100                         | 124,00 €                                      | 46              | 167              | 105     | 67                  | exporting |                     |                     | -38                                      | - 4.712,00 €           |
| DE      | 562                    | 169                       | 168                         | 124,00 €                                      | 393             | 730              | 464     | 562                 | importing |                     |                     | 98                                       | 12.152,00 €            |
| DK      | 20                     | 6                         | 6                           | 124,00 €                                      | 14              | 26               | 9       | 20                  | importing |                     |                     | 11                                       | 1.364,00 €             |
| FR      | 508                    | 153                       | 152                         | 71,36 €                                       | 355             | 660              | 660     | 508                 | exporting |                     | yes                 | -152                                     | - 10.846,72 €          |
| NL      | 114                    | 35                        | 100                         | 124,00 €                                      | 79              | 214              | 50      | 114                 | importing |                     |                     | 64                                       | 7.936,00 €             |
| SI      | 15                     | 0                         | 100                         | 124,00 €                                      | 15              | 115              | 6       | 15                  | importing |                     |                     | 9                                        | 1.116,00 €             |
| Total   | 1444                   |                           |                             |                                               |                 |                  | 1444    | 1444                |           |                     |                     | 0                                        | 10.706,08 €            |

| A       | O                                    | P                 | Q                          | R                                          | S                         | T            | U             |
|---------|--------------------------------------|-------------------|----------------------------|--------------------------------------------|---------------------------|--------------|---------------|
| Country | net<br>position<br>absolute<br>value | allocation<br>key | cost surplus<br>allocation | import/export<br>costs after<br>allocation | actual costs<br>(TSO-BSP) | target costs | compensation  |
|         | abs(M)<br>MW                         | O / sum(O)<br>%   | P * sum(N)<br>€            | N - Q<br>€                                 | H * E<br>€                | R + S<br>€   | T - S<br>€    |
| AT      | 52                                   | 10,74%            | 1.150,24 €                 | - 7.598,24 €                               | 15.252,00 €               | 7.653,76 €   | - 7.598,24 €  |
| BE      | 60                                   | 12,40%            | 1.327,20 €                 | 8.817,60 €                                 | 4.565,16 €                | 13.382,76 €  | 8.817,60 €    |
| CH      | 38                                   | 7,85%             | 840,56 €                   | - 5.552,56 €                               | 13.020,00 €               | 7.467,44 €   | - 5.552,56 €  |
| DE      | 98                                   | 20,25%            | 2.167,76 €                 | 9.984,24 €                                 | 57.536,00 €               | 67.520,24 €  | 9.984,24 €    |
| DK      | 11                                   | 2,27%             | 243,32 €                   | 1.120,68 €                                 | 1.116,00 €                | 2.236,68 €   | 1.120,68 €    |
| FR      | 152                                  | 31,40%            | 3.362,24 €                 | - 14.208,96 €                              | 47.097,60 €               | 32.888,64 €  | - 14.208,96 € |
| NL      | 64                                   | 13,22%            | 1.415,68 €                 | 6.520,32 €                                 | 6.200,00 €                | 12.720,32 €  | 6.520,32 €    |
| SI      | 9                                    | 1,86%             | 199,08 €                   | 916,92 €                                   | 744,00 €                  | 1.660,92 €   | 916,92 €      |
| Total   | 484                                  | 100%              | 10.706,08 €                | - €                                        | 145.530,76 €              | 145.530,76 € | 0,00 €        |

### 11.3 Determination of financial compensation per country

Since payment flows are calculated for every month, the country costs per tender determined above are added up to monthly costs. The difference between the monthly actual costs and the monthly target costs of the country determines the payment obligation of the country.

If the compensation amount is positive, the country (respective TSO) has to pay. If it is negative, the country (respective TSO) receives the payment.

## 12. Article 10 - Accession of new parties

In this Article there are no changes.

## 13. Article 11 - Implementation roadmap

In this Article, the old implementation roadmap was removed.

## 14. Article 12 – Language

In this Article there are only editorial improvements.

## Appendix H

### Example of TSO costs computation with proposed mechanism

| Country | Market input   |                       |                         | Market result |                | Proposed scheme       |                             |                           |                                   |                                            |                        |                            |                                         |                        |                     |                         |
|---------|----------------|-----------------------|-------------------------|---------------|----------------|-----------------------|-----------------------------|---------------------------|-----------------------------------|--------------------------------------------|------------------------|----------------------------|-----------------------------------------|------------------------|---------------------|-------------------------|
|         | Demand<br>[MW] | Core<br>share<br>[MW] | Export<br>limit<br>[MW] | LMP<br>[MW]   | Export<br>[MW] | BSP<br>revenue<br>[€] | TSO<br>local<br>cost<br>[€] | "Missing<br>money"<br>[€] | Over<br>procured<br>power<br>[MW] | Imported<br>power<br>to be<br>paid<br>[MW] | New<br>price<br>[€/MW] | Country<br>coef<br>ficient | Over<br>procure<br>ment<br>costs<br>[€] | Import<br>costs<br>[€] | TSO<br>costs<br>[€] | Compen<br>sation<br>[€] |
| AT      | 71             | 22                    | 100                     | 124           | 52             | 15,252.00             | 8,804.00                    | 6,448.00                  | 52                                | 0                                          |                        | 4.9%                       | 0                                       | -                      | 8,804.00            | -6,448.00               |
| BE      | 87             | 27                    | 100                     | 169           | -60            | 4,565.16              | 4,565.16                    | -                         | -60                               | 60                                         |                        | 6.0%                       | 0                                       | 5,456.21               | 10,021.37           | 5,456.21                |
| CH      | 67             | 21                    | 100                     | 124           | 38             | 13,020.00             | 8,308.00                    | 4,712.00                  | 38                                | 0                                          |                        | 4.6%                       | 0                                       | -                      | 8,308.00            | -4,712.00               |
| DE      | 562            | 169                   | 168                     | 124           | -98            | 57,536.00             | 57,536.00                   | -                         | -98                               | 98                                         |                        | 38.9%                      | 0                                       | 8,911.81               | 66,447.81           | 8,911.81                |
| DK      | 20             | 6                     | 6                       | 124           | -11            | 1,116.00              | 1,116.00                    | -                         | -11                               | 11                                         |                        | 1.4%                       | 0                                       | 1,000.31               | 2,116.31            | 1,000.31                |
| FR      | 508            | 153                   | 152                     | 71            | 152            | 47,097.60             | 36,250.88                   | 10,846.72                 | 152                               | 0                                          |                        | 35.2%                      | 0                                       | -                      | 36,250.88           | -10,846.72              |
| NL      | 114            | 35                    | 100                     | 124           | -64            | 6,200.00              | 6,200.00                    | -                         | -64                               | 64                                         |                        | 7.9%                       | 0                                       | 5,819.96               | 12,019.96           | 5,819.96                |
| SI      | 15             | 0                     | 100                     | 124           | -9             | 744.00                | 744.00                      | -                         | -9                                | 9                                          |                        | 1.0%                       | 0                                       | 818.43                 | 1,562.43            | 818.43                  |
| sum     | 1444           |                       |                         |               | 0              | 145,530.76            | 123,524.04                  | 22,006.72                 | 0                                 | 242                                        | 90.94                  | 1                          | -                                       | 22,006.72              | 145,530.76          | -0.00                   |

Table H.1: Proposed scheme to compute TSO with intermediate steps, using the example supplied by ENTSO-E in [G](#).

## Appendix I

# Complete TSO costs computation for the used scenarios

| Country | Market input |                       |                         | Market result |             | Current scheme |                  |                       |                |                           |                                   |                 |               |
|---------|--------------|-----------------------|-------------------------|---------------|-------------|----------------|------------------|-----------------------|----------------|---------------------------|-----------------------------------|-----------------|---------------|
|         | Demand [MW]  | Min (Core share) [MW] | Max (export limit) [MW] | LMP [€/MW]    | Export [MW] | Import [MW]    | Import costs [€] | Absolute imports [MW] | Allocation key | Over cost allocation [MW] | Import costs after allocation [€] | BSP revenue [€] | TSO costs [€] |
| A       | 100          | 40                    | 70                      | 1             | 20          | -20            | 20               | 20                    | 0.5            | 0                         | -20                               | 120             | 100           |
| B       | 50           | 30                    | 30                      | 1             | -20         | 20             | -20              | 20                    | 0.5            | 0                         | 20                                | 30              | 50            |
| C       | 30           | 20                    | 20                      | 1             | 0           | 0              | 0                | 0                     | 0              | 0                         | 0                                 | 30              | 30            |
| D       | 20           | 10                    | 10                      | 1             | 0           | 0              | 0                | 0                     | 0              | 0                         | 0                                 | 20              | 20            |
| sum     | 200          |                       |                         |               | 0           | 0              | 0                | 40                    | 1              | 0                         | 0                                 | 200             | 200           |

Table I.1: Simplified case, where all  $LMP = CBMP$  and no *over procurement* occurs.

| Country | Market input |                       |                         | Market result |             | Current scheme |                  |                       |                |                           |                                   |                 |               |
|---------|--------------|-----------------------|-------------------------|---------------|-------------|----------------|------------------|-----------------------|----------------|---------------------------|-----------------------------------|-----------------|---------------|
|         | Demand [MW]  | Min (Core share) [MW] | Max (export limit) [MW] | LMP [€/MW]    | Export [MW] | Import [MW]    | Import costs [€] | Absolute imports [MW] | Allocation key | Over cost allocation [MW] | Import costs after allocation [€] | BSP revenue [€] | TSO costs [€] |
| A       | 100          | 40                    | 70                      | 1             | 20          | -20            | -20              | 20                    | 0.4            | -4                        | -16                               | 120             | 104           |
| B       | 50           | 30                    | 30                      | 1             | -20         | 20             | 20               | 20                    | 0.4            | -4                        | 24                                | 30              | 54            |
| C       | 30           | 20                    | 20                      | 1             | 10          | -10            | -10              | 10                    | 0.2            | -2                        | -8                                | 40              | 32            |
| D       | 20           | 10                    | 10                      | 1             | -           | -              | -                | -                     | -              | -                         | -                                 | 20              | 20            |
| sum     | 200          |                       |                         |               | 10          | -10            | -10              | 50                    | 1              | -10                       | -                                 | 210             | 210           |

Table I.2: Simplified case, where all  $LMP = CBMP$  and 10 MW of *over procurement* occurs.

| Country | Market input |                       |                         | Market result |             | Current scheme |                  |                       |                |                           |                                   |                 |               |
|---------|--------------|-----------------------|-------------------------|---------------|-------------|----------------|------------------|-----------------------|----------------|---------------------------|-----------------------------------|-----------------|---------------|
|         | Demand [MW]  | Min (Core share) [MW] | Max (export limit) [MW] | LMP [€/MW]    | Export [MW] | Import [MW]    | Import costs [€] | Absolute imports [MW] | Allocation key | Over cost allocation [MW] | Import costs after allocation [€] | BSP revenue [€] | TSO costs [€] |
| A       | 100          | 40                    | 70                      | 1             | 20          | -20            | -20              | 20                    | 0.5            | 10                        | -30                               | 120             | 90            |
| B       | 50           | 30                    | 30                      | 2             | -20         | 20             | 40               | 20                    | 0.5            | 10                        | 30                                | 60              | 90            |
| C       | 30           | 20                    | 20                      | 1             | -           | -              | -                | -                     | -              | -                         | -                                 | 30              | 30            |
| D       | 20           | 10                    | 10                      | 1             | -           | -              | -                | -                     | -              | -                         | -                                 | 20              | 20            |
| sum     | 200          |                       |                         |               | -           | -              | 20               | 40                    | 1              | 20                        | -                                 | 230             | 230           |

Table I.3: Simplified case, where one  $LMP \neq CBMP$  but has the same order of magnitude of remaining LMPs.

| Country    | Market input   |                             |                                  | Market result |                | Current scheme |                        |                             |                   |                                 |                                               |                       |                     |
|------------|----------------|-----------------------------|----------------------------------|---------------|----------------|----------------|------------------------|-----------------------------|-------------------|---------------------------------|-----------------------------------------------|-----------------------|---------------------|
|            | Demand<br>[MW] | Min<br>(Core share)<br>[MW] | Max<br>(export<br>limit)<br>[MW] | LMP<br>[€/MW] | Export<br>[MW] | Import<br>[MW] | Import<br>costs<br>[€] | Absolute<br>imports<br>[MW] | Allocation<br>key | Over cost<br>allocation<br>[MW] | Import<br>costs<br>after<br>allocation<br>[€] | BSP<br>revenue<br>[€] | TSO<br>costs<br>[€] |
| A          | 100            | 40                          | 70                               | 1             | 30             | -30            | -30                    | 30                          | 0.5               | 255                             | -285                                          | 130                   | -155                |
| B          | 50             | 30                          | 30                               | 2             | -20            | 20             | 40                     | 20                          | 0.333             | 170                             | -130                                          | 60                    | 70                  |
| C          | 30             | 20                          | 20                               | 1             | -              | -              | -                      | -                           | -                 | -                               | -                                             | 30                    | 30                  |
| D          | 20             | 10                          | 10                               | 50            | -10            | 10             | 500                    | 10                          | 0.167             | 85                              | 415                                           | 500                   | 915                 |
| <i>sum</i> | <i>200</i>     |                             |                                  |               | -              | -              | <i>510</i>             | <i>60</i>                   | <i>1</i>          | <i>510</i>                      | -                                             | <i>720</i>            | <i>720</i>          |

Table I.4: Simplified case, where one  $LMP \neq CBMP$  and has a different order of magnitude from the remaining LMPs.



## Appendix J

# Real case 2021-05-15, product NEGPOS\_12\_16, computation of both schemes

Table J.1 and Table J.2 detail the results resumed in Table 3.11.

| Country | Market input |                       |                         | Market result |             | Current scheme |                  |                       |                |                           |                                   |                 |               |                  |
|---------|--------------|-----------------------|-------------------------|---------------|-------------|----------------|------------------|-----------------------|----------------|---------------------------|-----------------------------------|-----------------|---------------|------------------|
|         | Demand [MW]  | Min (Core share) [MW] | Max (export limit) [MW] | LMP [€/MW]    | Export [MW] | Import [MW]    | Import costs [€] | Absolute imports [MW] | Allocation key | Over cost allocation [MW] | Import costs after allocation [€] | BSP revenue [€] | TSO costs [€] | Compensation [€] |
| AT      | 71           | 22                    | 100                     | 83            | -29         | 29             | 2,407            | 29                    | 9%             | 14,160                    | -11,753                           | 3,486           | -8,267        | -11,753          |
| BE      | 87           | 27                    | 100                     | 4257          | -38         | 38             | 161,769          | 38                    | 12%            | 18,555                    | 143,214                           | 208,596         | 351,810       | 143,214          |
| CH      | 67           | 21                    | 100                     | 83            | 59          | -59            | -4,897           | 59                    | 19%            | 28,809                    | -33,706                           | 10,458          | -23,248       | -33,706          |
| DE      | 562          | 169                   | 168                     | 83            | 56          | -56            | -4,648           | 56                    | 18%            | 27,344                    | -31,992                           | 51,294          | 19,302        | -31,992          |
| DK      | 20           | 6                     | 6                       | 83            | 11          | -11            | -913             | 11                    | 3%             | 5,371                     | -6,284                            | 2,573           | -3,711        | -6,284           |
| FR      | 508          | 153                   | 152                     | 83            | 49          | -49            | -4,067           | 49                    | 16%            | 23,926                    | -27,993                           | 46,231          | 18,238        | -27,993          |
| NL      | 114          | 35                    | 100                     | 83            | -65         | 65             | 5,395            | 65                    | 21%            | 31,739                    | -26,344                           | 4,067           | -22,277       | -26,344          |
| SI      | 15           | 0                     | 100                     | 83            | 9           | -9             | -747             | 9                     | 3%             | 4,395                     | -5,142                            | 1,992           | -3,150        | -5,142           |
| sum     | 1444         |                       |                         |               | 52          | -52            | 154,299          | 316                   | 100%           | 154,299                   | -                                 | 328,697         | 328,697       | -                |

Table J.1: Real case 2021-05-15, product NEGPOS\_12\_16. TSO costs computed with the current mechanism.

| Country | Market input |                       |                         | Market result |             | Proposed scheme |                    |                     |                          |                                |                  |                     |                            |                  |               |                  |
|---------|--------------|-----------------------|-------------------------|---------------|-------------|-----------------|--------------------|---------------------|--------------------------|--------------------------------|------------------|---------------------|----------------------------|------------------|---------------|------------------|
|         | Demand [MW]  | Min (Core share) [MW] | Max (export limit) [MW] | LMP [€/MW]    | Export [MW] | BSP revenue [€] | TSO local cost [€] | "Missing money" [€] | Over procured power [MW] | Imported power to be paid [MW] | New price [€/MW] | Country coefficient | Over procurement costs [€] | Import costs [€] | TSO costs [€] | Compensation [€] |
| AT      | 71           | 22                    | 100                     | 83            | -29         | 3,486           | 3,486              | -                   | -29                      | 29                             |                  | 0.049               | 212                        | 2,407            | 6,105         | 2,619            |
| BE      | 87           | 27                    | 100                     | 4,257.07      | -38         | 208,596         | 208,596            | -                   | -38                      | 38                             |                  | 0.06                | 260                        | 3,154            | 212,010       | 3,414            |
| CH      | 67           | 21                    | 100                     | 83            | 59          | 10,458          | 5,561              | 4,897               | 59                       | -                              |                  | 0.046               | 200                        | -                | 5,761         | -4,697           |
| DE      | 562          | 169                   | 168                     | 83            | 56          | 51,294          | 46,646             | 4,648               | 56                       | -                              |                  | 0.389               | 1,680                      | -                | 48,326        | -2,968           |
| DK      | 20           | 6                     | 6                       | 83            | 11          | 2,573           | 1,660              | 913                 | 11                       | -                              |                  | 0.014               | 60                         | -                | 1,720         | -853             |
| FR      | 508          | 153                   | 152                     | 83            | 49          | 46,231          | 42,164             | 4,067               | 49                       | -                              |                  | 0.352               | 1,518                      | -                | 43,682        | -2,549           |
| NL      | 114          | 35                    | 100                     | 83            | -65         | 4,067           | 4,067              | -                   | -65                      | 65                             |                  | 0.079               | 341                        | 5,395            | 9,803         | 5,736            |
| SI      | 15           | -                     | 100                     | 83            | 9           | 1,992           | 1,245              | 747                 | 9                        | -                              |                  | 0.01                | 45                         | -                | 1,290         | -702             |
| sum     | 1,444        |                       |                         |               | 52          | 328,697         | 313,425            | 15,272              | 52                       | 132                            | 83               | 1                   | 4,316                      | 10,956           | 328,697       | -                |

Table J.2: Real case 2021-05-15, product NEGPOS\_12\_16. TSO costs computed with the proposed mechanism.

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