Master's Thesis - master Energy Science

BESS investment decisions

Quantifying techno-economic influences on the business case of a grid-scale Battery Energy Storage System

Matthijs van Eck

Copernicus Institute of Sustainable Development
Utrecht University
ACTIAM
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Student:
Matthijs van Eck
5505917
m.vaneck@students.uu.nl

Supervisors:
Prof. dr. M. Gibescu
m.gibescu@uu.nl
Drs. ing. U. Huiskamp
u.n.j.huiskamp@uu.nl

Second reader:
Prof. dr. G.J. Kramer
g.j.kramer@uu.nl

Abstract

BESS investment decisions

Grid-scale Battery Energy Storage System (BESS) adoption is limited by investment decision uncertainty. One of the reasons for this uncertainty is revenue determination for the different markets grid-scale BESS could operate on. In this thesis BESS systems that operate on the electricity markets in Belgium and the Netherlands are analysed. The goal is to quantify significant parameters that influence business case result so that investment uncertainty might be reduced. In order to do so a Mixed Integer Linear Programming (MILP) model is developed that analyses BESS providing Frequency Containment Reserve (FCR) and reacting to the Imbalance Market (IM). Three model options are developed. Model option A provides FCR while managing State of Charge (SoC) against an average day-ahead price. Model option B only reacts to the system imbalance to generate revenue from the IM pricing mechanism. Model option C combines FCR provision with managing SoC through IM reaction, generating additional revenue. The most significant parameters are found to be BESS capital cost and FCR pricing. BESS efficiency change has a limited effect. Increasing duration of BESS systems has a significant effect on business case result, dependent on BESS investment costs. It is found that only reacting on the IM market (model option B) results in too much degradation to be a valid operating strategy. For model option C a certain FCR price level would incentivise BESS operators to shift power from FCR provision to more IM reaction to obtain better business case results. Three scenarios are developed, based on sources that project parameter development. The Business as Usual (BAU) scenario considers current levels of technical performance, BESS cost and FCR prices. The high Renewable Energy Source (high-RES) scenario considers moderate decline of FCR prices and conservative BESS cost decrease. The Battery Revolution (BR) scenario considers strong decline of FCR prices and strong BESS cost decrease. Results show that model option A results in positive IRR for all scenario's. Results for model option C are always highest in all cases. The business case result keeps improving from scenario BAU to scenario high-RES to scenario BR for this model option. It is therefore concluded that BESS give best business case result combining FCR and IM reaction. For investment decisions results show the importance of monitoring revenue streams, pricing and BESS cost development. Results imply that even with declining FCR prices BESS projects are expected to have positive business case results, if BESS cost decrease in expected ranges. This would result in increased adoption of BESS in Belgium and the Netherlands.

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List of Symbols

Δf	Frequency deviation [Hz]
f	Frequency [Hz]
f_n	Nominal frequency [Hz]

Parameters

η_{ch}	BESS charging efficiency [%]
η_{di}	BESS discharging efficiency [%]
Γ^{IC}	Total system CAPEX [€]
ϕ^{FCR}	Required maximum frequency deviation droop level control value [mHz]
π_t^{DA}	Day-ahead market energy price [€/kWh]
$\pi_t^{IM,f}$	Imbalance market energy feed price [€/kWh]
$\pi_t^{IM,t}$	Imbalance market energy take price [€/kWh]
C^{BO}	BESS operation cost [€/year]
C^{GO}	Grid connection yearly cost [€/year]
c_B	Battery degradation penalty cost [€/kWh]
D	Battery degradation fade factor [1/MWh]
eol	Battery end-of-life value [%/100]
f^{AP}	Grid apparent power yearly fee [€/kVA/year]
f^{con}	Energy consumption fee [€/kWh consumption]
f^{inj}	Energy injection fee [€/kWh consumption]
f^{PM}	Grid power monthly fee [€/kW/month]
f^{PY}	Grid power yearly fee [€/kW/year]
L	BESS business case lifetime [year]
$P^{DA,max}$	Day-ahead maximum power [kW]
$P^{FCR,b}$	Accepted FCR power bid [MW]

$P^{FCR,b}$	Accepted power bid on the FCR auction [kW]
$P^{IM,max}$	Imbalance market maximum power [kW]
Q^{B}	(Initial) Battery capacity [MWh]
SoC_0	Initial BESS State of Charge [%/100]
SoC_{max}	BESS maximum state of charge [%]
SoC_{min}	BESS minimum state of charge [%]
C^{BESS}	BESS CAPEX [€]
C^{GC}	Grid Connection CAPEX [€]

Variables

ΔSoC	BESS state of charge change [%]
Γ^{BESS}	Revenue of BESS [€]
Γ^{DA}	Revenue of Day-Ahead market [€]
Γ^{deg}	Degradation cost of BESS [€]
Γ^{FCR}	Revenue of FCR market [€]
Γ^{OC}	Cost of operation of the BESS [€]
$P^{B,ch}$	BESS charging power [kW]
$P_t^{B,ch}$	Charging power of the BESS in time step t [kW]
$P^{B,di}$	BESS discharging power [kW]
$P_t^{B,di}$	Discharging power of the BESS in time step t [kW]
$P_t^{FCR,f}$	Feed power for FCR in time step t [kWh]
$P_t^{FCR,t}$	Take power for FCR in time step t [kWh]
$P_t^{IM,ch,d}$	Decrease of charging power in time step t [kW]
$P_t^{IM,ch,i}$	Increase of charging power in time step t [kW]
$P_t^{IM,di,d}$	Decrease of discharging power in time step t [kW]
$P_t^{IM,di,i}$	Increase of discharging power in time step t [kW]
$P_t^{DA,ch}$	Day-ahead market charging power for time step t [kW]
$P_t^{DA,di}$	Day-ahead market discharging power for time step t [kW]
$Q^{B,rem}$	Remaining battery capacity end of lifetime [%/100]
$Q_t^{B,rem}$	Remaining battery capacity [%/100] in time step t
Q^{B}	BESS battery capacity [kWh]
SoC_t	Battery system state of charge [%]
TE_t	Total energy processed in time step t [kWh]

u_t	Binary variable for the day-ahead market
z_t^{down}	Binary variable for IM strategy downwards action
z_t^{up}	Binary variable for IM strategy upwards action

Chapter 1

Introduction

1.1 Background and motivation

As signatories to the 2015 Paris agreement, European countries aim to counteract climate change (United Nations 2015). Electrification of energy systems on the demand side as well as renewable electricity generation are means to achieve this aim. As the two most important sources of renewable electricity (solar energy and wind energy) are dependent on inherently variable supply (solar radiation and wind), an increase in electricity production from these intermittent sources leads to an increasing need for flexibility in the electricity grid. Flexibility in this sense is the capability to match electricity generation and load (demand) to ensure a stable grid frequency. Not only intermittent generation on the supply side, but also variability due to electrification on the demand side requires more flexibility in the electricity system. This is now widely regarded as one of the main challenges to the system (TenneT 2018a).

Flexibility can be provided in a number of ways, such as interconnection of power systems [1], demand- or supply side management and flexible fossil power generation (Lund et al. 2015). Next to this, energy storage systems (in this case focused on electricity) can provide fossil-free flexibility by providing ancillary services, such as reserve provision and renewable electricity integration. Luo et al. (2015) give a comprehensive overview, with experienced and promising energy storage technology options for flexibility provision. Battery Energy Storage Systems (BESS) are suited for the provision of most reserve applications and related services. This is due to BESS favourable characteristics for providing flexibility services over other storage technologies, such as quick response time, high efficiency, low self-discharge and scalability (Hesse, Schimpe, et al. 2017).

To balance supply and demand the European electricity market is split into different markets with different timescales. The wholesale markets are: Futures, Day ahead and Intraday. These markets are energy (MWh) based. The day-ahead market is often seen as representing the electricity price. Energy can be traded from years ahead through 5 minutes ahead. Through trading supply and demand are matched

[1] The network of electrical components deployed to supply, transfer, and consume electric power.

as accurately as possible. Trading takes place on the marketplaces, but also bilaterally between parties. The imbalance market (IM) is a mechanism to ensure participants are incentivised to balance their portfolio. Depending on the total system imbalance participants can be punished or rewarded for resulting energy after production/consumption. The remuneration for this is not known in advance, but determined after the respective time block.

Next to these markets, there are also the ancillary reserve markets, where the transmission system operator (TSO) is the only buyer. The aim of these markets is responding to frequency deviation, caused by variable supply and demand or malfunction in the system. Both energy excess and shortages are dealt with through reserve markets. On these markets a combination of power (MW) and energy (MWh) services are procured. In order of deployment after a frequency deviation there are three types of reserves: Frequency Containment Reserve (FCR), Frequency Restoration Reserve (FRR) and Restoration Reserves (RR). The specific structure and requirements may differ per country and TSO.

A BESS could combine provision of these different types of reserves with trading on the markets, providing reserve services and reacting to the IM mechanism. The BESS size and configuration to be used for this type of operation are so called grid-scale applications. These types of BESS applications have been examined extensively (Oudalov, Chartouni, and Ohler 2007; Thorbergsson et al. 2013; Zeh et al. 2016). Important conclusions from Borsche, Ulbig, and Andersson (2014) with regards to BESS in reserve markets are that reserve provision with a BESS is as reliable as reserve provision by conventional power plants. Additional advantages of BESS are fast ramp rates and the decoupling of reserve provision and electricity production as well as the reduction of environmental impacts. Real-life applications of grid-scale BESS for reserve applications are now starting to occur in the scale of megawatts (Thien et al. 2017).

1.2 Problem description

Large scale adoption of BESS has not taken off in Europe due to several issues that lead to uncertainty and therefore high-risk investment circumstances. Examples of such are (Bhatnagar et al. 2013; Zeh et al. 2016):

- Not fully understanding economics, life-cycle performance and longevity of a BESS.
- Uncertainty relating to reserve market demand resulting from electricity market structure and size. Prices in the electricity and reserve markets are also uncertain as these depend on varying supply and demand.
- Uncertainty in prices of battery and other storage technologies as well as renewable and non-renewable generation technologies that can provide imbalance services.
- Market and regulatory structures: changing market structures, renewable energy initiatives, subsidies, fossil fuel countermeasures and others.

1.3 Research goal

The goal of this research is to facilitate BESS investment decisions by quantifying the factors that influence the uncertainties that investors face in such decisions. The focus of this research is on technical and economic factors that could influence BESS investment feasibility over its lifetime. Examples of technical and economic factors and examples of the major contributors to these factors are presented in table 1.1. Investment cost, operational cost and degradation and replacement cost are taken into account to build a business case in this work, but the research focuses on revenue generation.

Factor	Major contributors (examples)
Revenue generation	Application specific revenue (power related, energy related, reliability related, markets that can be accessed)
Investment cost	Cost of storage (battery, periphery, casing) Cost of grid coupling (power electronics, transformer)
Operational cost	Conversion losses (power electronics, transformer, battery) Auxiliary consumption (thermal management, control and monitoring)
Degradation and replacement cost	Battery degradation (capacity fade, resistance increase) Replacement cost for fatigued materials (battery, power electronics)

Table 1.1: Investment factors and major contributors regarding the BESS business case (Hesse, Martins, et al. 2017)

1.4 Research question

In order to reach the stated research goal, the main research question of this thesis is:

"What is the influence of significant technical and economic factors on the grid-scale BESS business case in the current Dutch and Belgian context?"

To answer the research question the following sub-questions should be answered:

- What is a grid-scale BESS and what are its most relevant technical and economical characteristics?
- How can a grid-scale BESS operate on the Belgian and Dutch electricity markets and what revenue streams can be generated?
- How can grid-scale BESS participation in the electricity markets be modelled mathematically?

- What is the influence of significant technical en economic factors on the BESS business case?
- What is the Belgian and Dutch BESS business case result in current market conditions and in scenarios based on price and technology predictions?

1.5 Scope

The scope of this research is on grid-scale BESS that participate in the Dutch and Belgium wholesale (day-ahead), imbalance and reserve markets. The analyses of factors that cause uncertainty in BESS investment decision making is limited to technical and economic ones. In the reserve markets the FRR market is not taken into account. The reason for this is the need to model BESS operator decision making (based on price forecasts) on which markets to participate in (FCR vs. FRR). This is beyond the scope of this research. It is assumed for technical reasons and tax height determination that BESS are connected at the high-voltage grid at 150 kilovolts. For valid BESS operation regulation defined by the European Network of Transmission System Operators for Electricity (ENTSO-E) and country specific regulation applies. For Net Present Value determines a standard discount rate of 5% is assumed. Assumptions regarding BESS systems and markets are further elaborated in chapter 3 and 4, respectively.

Chapter 2

Method

2.1 Outline

In the following it is described what steps are taken to conduct the research. Figure 2.1 gives an overview of the research activities resulting from the sub-question described in section 1.4. All activities stated in the figure are detailed below.

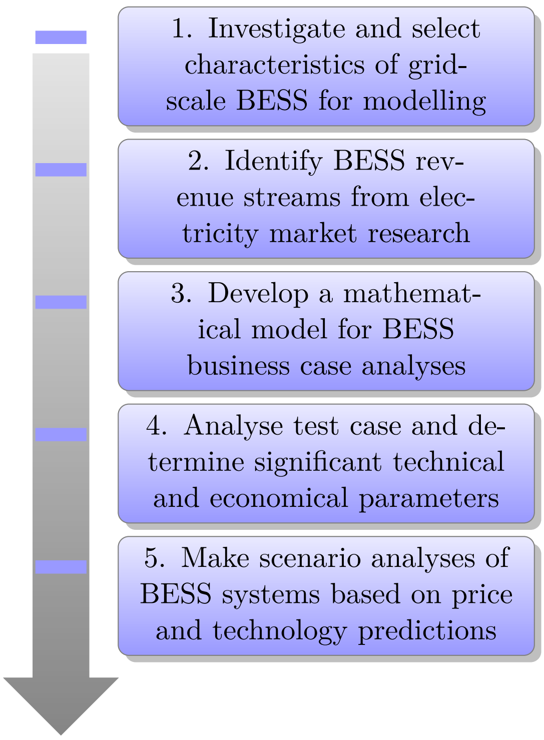

Figure 2.1: Research design

2.1.1 BESS technology overview and characteristics selection

Chapter 3 describes the physical components of BESS systems and different li-ion chemistries that are used in BESS. Next to this, important mechanisms such as degradation and BESS operation are explained. To be able to model BESS it is determined in 3.5.4 how these aspects are taken into account in the model that is developed in chapter 5. In addition technology and cost projection studies are analysed, in order to conduct scenario analyses in chapter 7.

2.1.2 Electricity market study and revenue stream identification

Belgian and Dutch electricity, reserve and imbalance markets are studied in chapter 4. It is examined how consumers, producers and operators act on the electricity grid. Also, the regulatory framework in place, requirements for participation and transaction structures are examined to determine how a BESS could participate in the markets. For the relevant markets expected prognosis of price levels are gathered from sources that will be used in the scenario analysis in chapter 7.

2.1.3 Model development

A Mixed Integer Linear Programming model is developed in chapter 5 to determine BESS operation and revenues. To do so the relevant electricity markets and BESS characteristics that were identified in chapters 3 and 4 are taken into account. For the different components of the BESS system and for the markets it is explained what constraints should be implemented in sections 5.2-5.7. From these different model components three model options are defined in 5.8, modelling the Imbalance and FCR markets.

2.1.4 Test case analyses and sensitivity analysis

A BESS test case and significant technical and economic parameters are analysed for each of the model options in chapter 6. With an analyses of 50% of the historical data of 2018 representative days are found that are used to analyse the scenarios. These representative days are also used to determine the influence of significant parameters through sensitivity analyses. It is described how these parameters should be taken into account in the scenario analyses.

2.1.5 Scenario analysis

Based on the test case and the parameter analysis scenarios are analysed in chapter 7. These scenarios are based on future expectations of parameters regarding markets and BESS technology in chapters 3 and 4.

2.2 Optimisation method

As stated in the introduction, storage systems can provide a range of grid services. However, it is challenging to quantify the benefits that can be gained with storage systems in the different applications (Drury, Denholm, and Sioshansi 2011). Among others, factors of importance in such determinations are energy and power density, response time, cost and economies scale, lifetime, monitoring and control equipment, efficiency and operating constraints (Mahlia et al. 2014). Such factors can be considered inputs and/or constraints. When analysing different markets to which services will be provided in an economically efficient manner subject to technical constraints, a performance indicator must be maximised. Therefore, the operation of storage systems, such as a BESS, can be defined as an optimisation problem under constraints with the profit function to be optimised.

Ommen et al. (2014) provide an overview of three frequently used mathematical optimisation methods in energy technology dispatch and analysis the differences between these. 1) Linear Programming (LP) is a method for optimising (maximising or minimising) a linear objective function, subject to linear constraints. Examples can be found in Youn and Cho (2009) and Berrada, Loudiyi, and Zorkani (2016). 2) In Non-Linear Programming (NLP), the constraints can be convex, quadratic or fractional. 3) Mixed Integer Linear Programming represents a programming form in which the constraints can be integers. This allows, for example, energy dispatch units to be on/off. Results in Ommen (2014) show that NLP and MILP generally perform much better than LP, as more optimal solutions are found. However, NLP can lead to a selection of a local optimum, instead of the global optimum. It is also possible to combine these methods. In Hemmati and Saboori (2017), for example, a home energy management system is optimised using Mixed Integer Non-Linear Programming (MINLP).

In this thesis the optimisation will be of the mixed integer type. This is based on the application of integers to constraints such as charging and discharging that define BESS. Also, BESS operation can be represented by linear formulation which is preferred over non-linear optimisation, as the latter is more complex.

Equations 2.1-2.4 represent MILP formulation in standard form. The goal is to minimise variables x and y in the objective function Z. This minimisation is subject to the constraints in 2.2-2.4. Parameters such as A, E and b can be used to force behaviour of the program (2.2). Also, the variables can be limited by the constraints, as in 2.3. As this is an integer program, constraint 2.4 forces that y can only take zero or one values.

$$Minimize\ x, y \quad Z \triangleq cx + dy \tag{2.1}$$

$$Subject\ to \qquad Ax + Ey \leq b \tag{2.2}$$

$$x_{min} \leq x \leq x_{max} \tag{2.3}$$

$$y \in \{0, 1\} \tag{2.4}$$

For optimisation problems in the energy field specific modelling tools have been used, an elaborate overview is given by Lund et al. (2015). In this thesis Python is used in combination with the Gurobi (Gurobi Optimization 2018) software package.

2.3 Data

To perform the analysis of BESS data is needed regarding cost parameters, the electricity grid and market prices. The cost parameter data will be gathered through literature review of similar BESS systems. The historical grid data will be downloaded from the Belgian TSO Elia (http://www.elia.be/nl/grid-data/data-download) and Dutch TSO TenneT (https://www.tennet.org/english/operational_management/export_data.aspx) websites. The historical pricing will be downloaded from these sources as well and from the Regelleistung platform (https://www.regelleistung.net). Whenever these sources are used this will be stated.

2.4 Business case analysis

While the optimisation is made over historical data, the business case analysis is future oriented. An approach is chosen, depicted in figure 2.2 to make a project lifetime business case analysis.

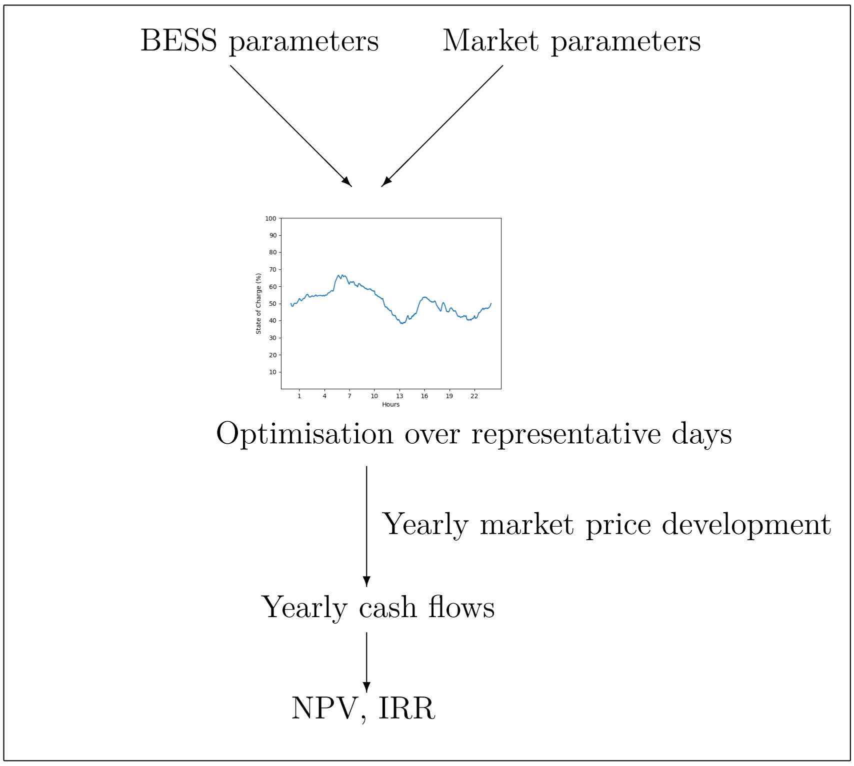

Figure 2.2: Business case analysis methodology

Based on the selected BESS and market parameters, a MILP optimisation is made over ”representative days”. This entails that the revenues of BESS resulting from optimisation over longer time periods are averaged. These averages are used to find ”representative days” that can be used to make analysis. An important reason for optimising over ”representative days” is the time required to run the model and obtain an outcome when longer time periods are analysed. To determine these representative days 50% of the historical data of 2018 is used. The optimisation result of these days is used to determine yearly revenues. This is possible as these days represent average BESS action and revenues. It is also possible to vary prices for the respective markets for each year of the business case lifetime. This is taken into account in the yearly cash flow statement. From this yearly cash flow statement the business case is evaluated using the metrics Net Present Value (NPV) and Internal Rate of Return (IRR). NPV determines the difference between the present value of cash inflows and cash outflows. A discount rate should be chosen to determine NPV. In the analysis the default discount rate is 5%. Since discount rates are project specific to investment cases the IRR is used in addition. IRR gives the discount rate that would make the project NPV zero and is not influenced by a predetermined discount rate.

Chapter 3

Battery Energy Storage Systems

3.1 Introduction

Of all electrical energy storage technologies, battery storage is one of the most applied technologies today. Batteries can be found in cars, mobile phones, laptops, industrial plants and many other equipments. Batteries applied on a grid scale, such as considered here, typically are comprised of the battery pack, the power conversion system and management systems, and are also called Battery Energy Storage Systems (BESS). A BESS overview is depicted in figure 3.1. The different BESS components will be explained in this chapter. The modelling of a BESS will not include all components, for simplification purposes. Therefore, the last paragraph of this chapter will describe the reasoning for selecting BESS key components and characteristics that accurately represent such a system in the further modelling in this thesis.

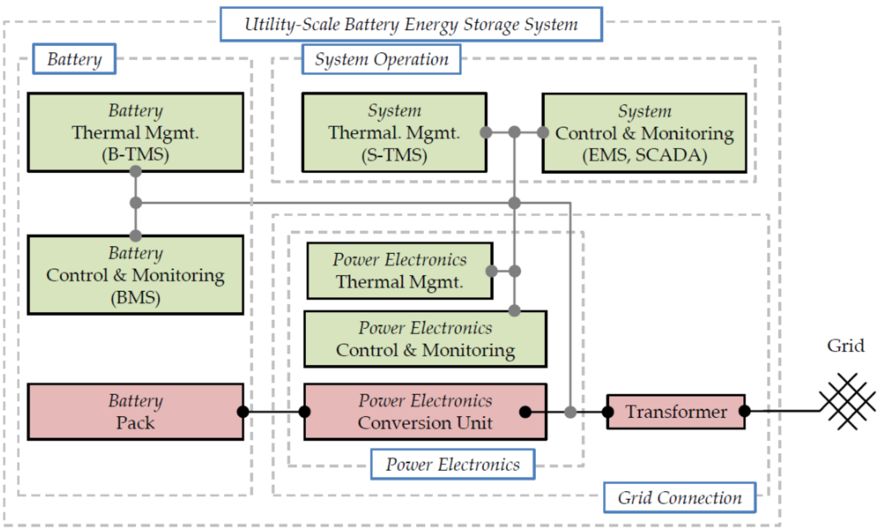

Figure 3.1: Grid scale Battery Energy Storage System overview (Hesse, Martins, et al. 2017)

3.2 Battery pack

The battery pack (BP) is comprised of electrochemical battery cells that are connected in series or parallel. Parallel connected cells will increase usable capacity, while serial connection raise the voltage to desired levels (Hesse, Schimpe, et al. 2017). Each cell consists of two electrodes, the anode (negative electrode) and cathode (positive electrode). The redox reactions, converting electrical energy to electrochemical potential or the other way around, take place at the electrodes. The electrolyte, usually a solution that contains dissociated salts, connects the electrodes and helps in transporting ions to and from the anode and cathode (Dunn, Kamath, and Tarascon 2011). When the electrodes are connected chemical reactions take place at both electrodes. In discharging mode electrons flow from the anode to the cathode via the external circuit, while at the same time ions flow from the anode through the electrolyte to the cathode. In charging mode the opposite of this process takes place. Figure 3.2 gives an example of a lithium-cobalt battery cell, where also reactions as described above are represented by arrows.

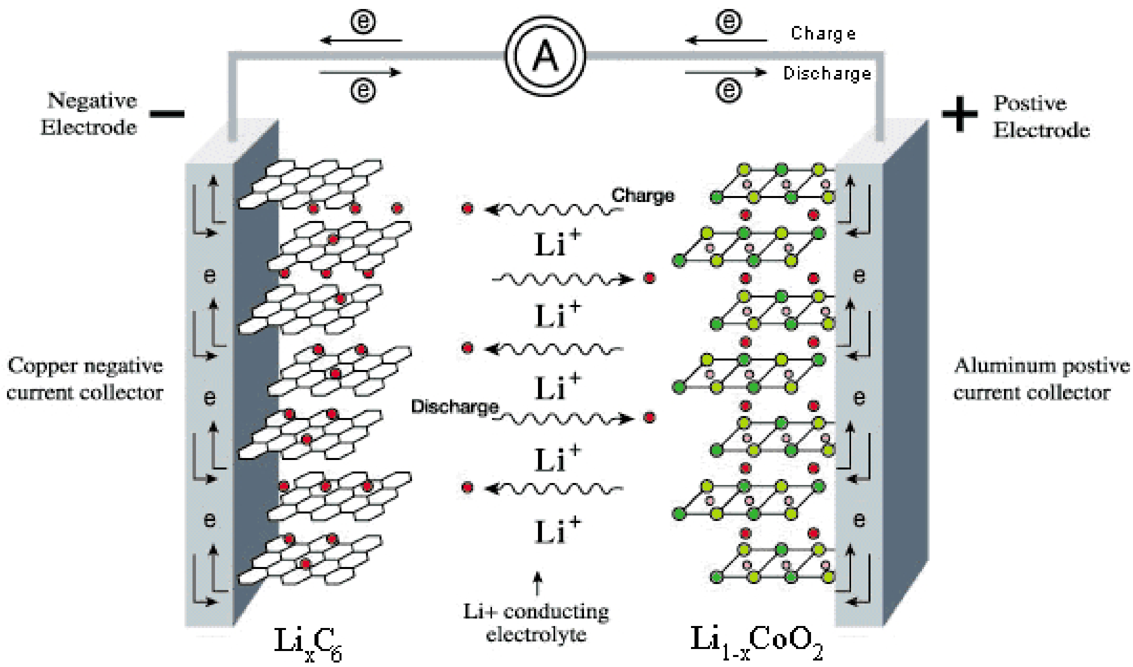

Figure 3.2: Lithium-cobalt battery cell (Fraunhofer 2002)

Among others, the storage capacity of a battery depends on the electrode characteristics and the power capacity depends on the surface area of electrodes as well as battery pack internal resistance. Therefore, in battery designs there are trade-offs between, for example, high energy or high power characteristics. The design of a battery determines its characteristics and is often based on the battery's intended application (Arteaga, Zareipour, and Thangadurai 2017).

3.2.1 Battery chemistries

Within the general working principles of a battery, different chemistries are applied that have different characteristics. The most common batteries and common types used today can be found in table 3.1. Note that flow batteries are a combination of battery and fuel cell technology and have different characteristics from most other battery technologies (Dunn, Kamath, and Tarascon 2011).

Battery	Types
Lead-acid	Lead calcium, Lead Antimony, Valve regulated lead acid, Advanced lead-acid
Li-ion	Lithium-iron phosphate, Lithium cobalt oxide, Lithium manganese oxide, Lithium nickel manganese cobalt oxide
Na-ion	Sodium sulfur
Ni-ion	Nickel-metal hydride, Nickel-iron
Flow battery	Vanadium redox flow battery, Proton flow, Zinc-bromine, Hydrogen-lithium bromate

Table 3.1: Different battery chemistries and common types (adapted from Aneke and Wang 2016; Dunn, Kamath, and Tarascon 2011)

Though there are different batteries suitable and available for grid-scale application, the analysis in this thesis will be on a Li-ion system. The most common Li-ion types are LiCoO (LCO), LiMnO (LMO), LiFePO (LFP), LiNiMnCoO (NMC) and LiNiCoAlO (NCA) (T. Lawder et al. 2014). Li-ion is often chosen for grid-scale applications due to long cycle life, high round-trip efficiency, low degradation and high energy density (Arteaga, Zareipour, and Thangadurai 2017).

3.3 Battery aging

One crucial aspect that should be considered is the estimation of the battery lifetime and battery ageing. The ageing of a battery cannot be explained via a single value or simple function result (Magnor et al. 2009). Various processes contribute to the battery degradation, such as electrolyte decomposition, passive film formation, particle cracking and material dissolution. These processes essentially lead to increased resistance, reduced capacity and unsafe battery states (Shi et al. 2017). On a cell level, these processes are not completely understood, but can be described by differential and algebraic equations that are too detailed to be considered in modelling such as proposed here. In order to deal with this, description and modelling of battery ageing is done on the basis of theoretical ageing mechanisms, combined with experimental observations (Shi et al. 2017). Battery ageing can generally be seen as a result of two ageing mechanisms; calendric- and cyclic ageing (Fleer, Zurmühlen, Badeda, et al. 2016). Calendric ageing is ageing due to time expended during storage. This type of ageing for lithium-ion batteries is depended on the battery temperature (Byrne et al. 2018) and cycle depth ΔSoC (Magnor et al. 2009). Next to this, calendric ageing also depends on the absolute state of charge. For example, cycling a battery with a ΔSoC of 80% from 100% to 20% SoC will give a far better life expectancy than from 80% to 0% SOC. Additionally, temperature, SoC and ΔSoC effects can also affect one another. Cyclic aging is the loss of lifetime resulting from the battery operation. Here the ΔSoC is the main contributor. As can be expected, a higher

ΔSoC leads to a decrease in life expectancy. For example a NMC battery has ten times more degradation when ΔSoC is 100% compared to 10% (Shi et al. 2017). The loss of battery life is the accumulation of the degradation resulting from each cycle. Therefore, to consider cyclic ageing the number of cycles as a result of battery operation should be counted.

Ageing model

Since this is not straightforward as the BESS will charge and discharge based on price incentives, a representative ageing model described by Wankmüller et al. (2017) will be used and incorporated in the optimisation. Here battery usable capacity degradation, as well as limiting battery cycling to prevent increasing degradation are incorporated. Equation 3.1 states the remaining battery capacity $Q_t^{B,rem}$. Here D is the battery degradation fade factor (Wankmüller et al. (2017) uses f_B for this factor), determined to be $2.71 * 10^-5$/MWh. TE_t is the processed energy up until and including the specific time step.

$$Q_t^{B,rem} = 1 - D * TE_t/Q^B \quad \forall t \tag{3.1}$$

The value at the last time step of $Q_t^{B,rem}$ is the expected degradation. Therefore $Q^{B,rem}$ is assigned to this value. This is further explained in section 5.3.

In the model battery capacity is assumed constant over the project lifetime. A cost is included in the business model for either over-sizing or upgrading the battery so that this assumption can be made. Therefore Q^B is not a variable but a parameter. The $Q^{B,rem}$ outcome will be used to determine the appropriate over-sizing/upgrading cost. If, for example, battery remaining capacity is 90% of the initial capacity, this cost is 10% of the initial investment cost of the BESS. In the cash-flow determination this cost will be taken into account halfway through the lifetime (relevant for NPV determination).

Even though this cost is taken into account, battery lifetime degradation larger than 20% is assumed unrealistic. Therefore strategies that result in less than 80% remaining battery capacity at the end of the lifetime are not considered valid. Wankmüller et al. (2017) also uses this 80% end of life value.

In order to limit BESS degradation and have realistic cycling behaviour, a degradation cost also described by Wankmüller et al. (2017) will be a subtraction term in the objective function. This degradation term, cost penalty and its impact will be further explained in section 5.3.2. For each model configuration the optimal value for the degradation cost penalty might differ, and therefore this parameter is calibrated each time a new model configuration is introduced.

3.4 Equipment and management

3.4.1 Power conversion and grid connection

Power electronics is the equipment that connects the direct current (DC) batteries to the alternating current (AC) grid. Battery feed-in power needs to be in sync with the frequency of the grid and take-off power needs to be converted to DC flow. Next to the conversion of flow, it is necessary to use a (number of) transformer(s) that transform the battery pack voltage to the voltage of the grid connection. In general there are low voltage grids (0.4 kV), medium voltage grids (1-36 kV), high voltage grids (36-150 kV) and extra high voltage grids (220-380 kv). In this thesis the BESS is assumed to be connected to the high voltage grid at 150 kV.

3.4.2 BESS management systems

For the management of the BESS, different systems are in place. The battery pack is managed by the Battery Management System (BMS) and the Battery Thermal Management System (B-TMS). The PMS is also managed and monitored. The overall system management connects all of these systems and is controlled by the BESS operator.

BMS and B-TMS

In order for BESS to be operational, reliable and safe a Battery Management System (BMS) is required. This system monitors and manages the battery pack. There are many reasons for the BMS, examples are the need for battery cells to charge and discharge evenly, apply the appropriate battery charge rate, manage voltage levels and not exceed individual cell charge and discharge rates (Arteaga, Zareipour, and Thangadurai 2017; Hesse, Schimpe, et al. 2017). Also the BMS provides information to the system operation so that the BESS can be properly managed.

Next to managing the battery pack on a cell level, temperature plays an important role in battery management. As described in the battery ageing section (3.3) temperature is of vital importance in managing the BP and preventing increased ageing. The Battery Thermal Management System (B-TMS) monitors the battery pack temperature and prevents non-ideal operating conditions.

Power electronics management

Next to the battery pack, also the power electronics should be monitored and controlled. The power electronics could consist of subsystems and transformers, thereby needing control for each of the individual items to get the correct BESS power flow response (T. Lawder et al. 2014). In addition, temperature and current measurements are needed to guarantee safe and reliable operating conditions.

3.4.3 System operation management

The system operation is where the power flow into- and from the grid is controlled. Also, the other management systems communicate here and are used in the power flow decision making process. Based on optimisation of market and battery rules and signals the battery operator will define automated battery control. In modelling BESS operation the system operation level hugely impacts the economic outcomes important to BESS investment decision making. Figure 3.3 gives a clear overview of the main inputs and steps in such a process. Ideally, management would take into account as precise as possible battery state and grid required action and generate the best battery commands (T. Lawder et al. 2014).

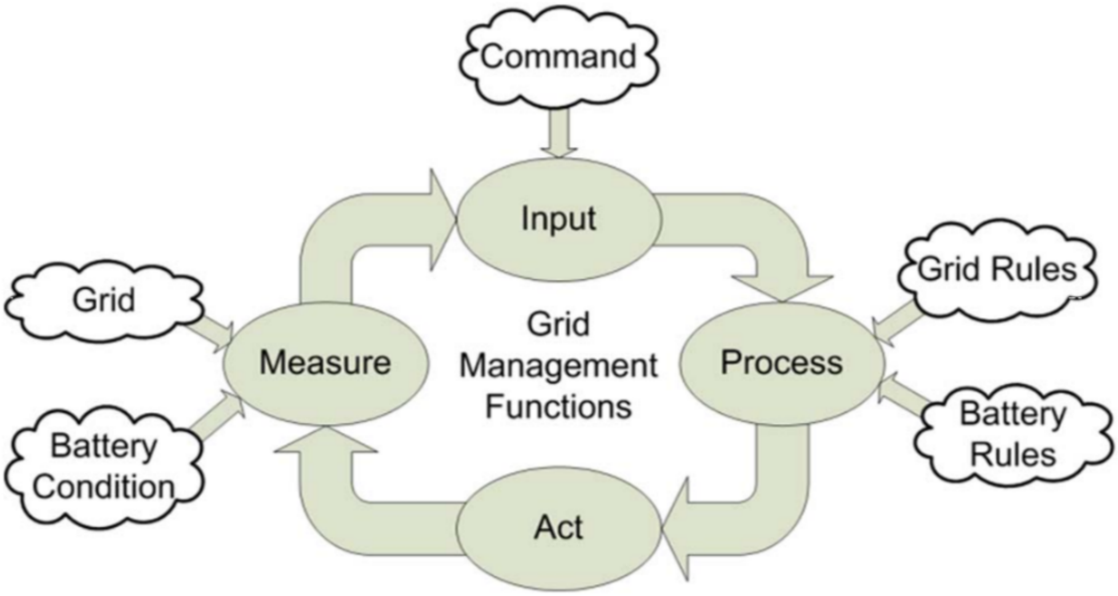

Figure 3.3: BESS control (T. Lawder et al. 2014)

3.5 BESS cost and characteristics

The BESS is modelled through cost and technical parameters. The projections of BESS cost are based on the literature study in the first section below. These cost are used as inputs to the model and their influence is analysed. The technical characteristics that are used to model BESS are described in the second section below.

3.5.1 BESS cost

Recently, Li-ion chemistries have seen great reduction of cost. According to Diouf and Pode (2015) electric vehicle development and its use of Li-ion batteries is the main driver behind this trend. A number of studies are the basis for determining realistic BESS cost C^{BESS}, needed to make techno-economic analysis of BESS. Schmidt et al. (2017) state that li-ion BESS cost can reach 650 USD/kWh in 2023 via cost curve analysis, but also states that systems of 500 USD/kWh are already on the market. The International Renewable Energy Agency (IRENA) identifies cost of 200 USD/kWh to 840 USD/kWh for li-ion chemistries (IRENA 2017), except for LTO chemistry. Combining these two sources a conservative estimate for current BESS capital cost is 550 USD/kWh or about 500 €/kWh.

BESS CAPEX per installed energy for NCA, NMC/LMO and LFP chemistries are expected to decline to a range from 80 to 340 USD/kWh by 2030 according to IRENA (2017). These figures are based on estimates from a number of sources and serve as a reasonable estimate that can be used in the scenario analysis. In the scenario analysis it will be stated what BESS cost are assumed and why. For BESS OPEX C^{BO}, such as system operation, IT and management an assumption is made of 2% yearly of BESS CAPEX.

3.5.2 BESS efficiency

Efficiency for BESS consists of the battery efficiency and efficiency of the inverter, transformer and other auxiliary equipment. Current battery round-trip efficiency for li-ion systems is in the range of 92%-96%, with projections for 2030 showing increases of about 2% for the respective technologies (IRENA 2017). For auxiliary equipment, such as inverters and transformers, 7% efficiency loss is assumed in this thesis. Therefore the overall round-trip efficiency is assumed to be 85% initially.

3.5.3 Grid connection cost and network fees

For the grid connection investment and operational costs assumptions are made (table 3.2). The assumption for grid connection cost C^{GC} is that these cost are 5% of the BESS CAPEX. The operational cost of the grid C^{GO} are assumed to be a yearly amount that is 0.5% of BESS CAPEX.

As stated earlier it is assumed that the BESS is connected at the 150kV level. The variable cost for grid connection and network are determined differently by Elia (BE) and TenneT (NL) and can be found in table 3.2. The cost in Belgium are made up of cost based on connection size and cost for injection and consumption (Elia 2016b). In the Netherlands cost at 150 kV are only for connection size (TenneT 2018b). The parameters needed are the yearly fee for power f^{PY}, the monthly fee for power f^{PM}, the yearly fee for apparent power[1] f^{AP} , the energy injection fee f^{inj} and the energy consumption fee f^{con}.

[1]To determine apparent power a power factor of $\phi = 0.8$ is assumed

Cost parameter	Notation	Unit	Value BE	Value NL
Grid connection CAPEX	C^{GC}	€	5% of BESS CAPEX	
Grid connection OPEX	C^{GO}	€/year	0.5% of BESS CAPEX	
Grid power yearly fee	f^{PY}	€/kW/year	5.007	17.1
Grid power monthly fee	f^{PM}	€/kW/month	0.2787	1.66
Grid ap. power yearly fee	f^{AP}	€/kVA/year	5.86	n.a.
Energy injection fee	f^{inj}	€/kWh inj.	0.9644	n.a.
Energy consumption fee	f^{con}	€/kWh cons.	2.469	n.a.

Table 3.2: Grid connection cost assumptions and network fees for connection at 150kV in Belgium and the Netherlands

3.5.4 Technical characteristics

Though the previous sections describe detailed characteristics and processes of batteries and equipment, the modelling in this thesis will be done based on parameters that represent the overall system behaviour. A number of assumptions is made that simplify BESS modelling, such as the exclusion of ramp rates for BESS power. Hereafter, the characteristics that are taken into account are explained. The BESS charging P^{ch} or discharging power P^{di} is the amount of energy that can be transferred to or from the BESS per second. In order to determine total BESS power, system and power conversion losses need to be taken into account. BESS maximum capacity Q^B is the maximum amount of energy that can be stored in the battery. Battery State of Charge SoC is the energy content of the BESS at a certain time relative to the maximum capacity of the BESS. It is common to have a BESS used for grid applications at 50% SoC so the battery can react in either direction. The starting value $SoC_0 = 0.5$ will set the initial BESS SoC. For limiting degradation and realistic battery operation minimum SoC_{min} and maximum SoC_{max} State of Charge levels are implemented. There are many different aspects that make for the total losses in the BESS, such as battery pack and power electronics. These are all taken into account in the BESS charging η^{ch} and BESS discharging η^{di} losses.

3.6 Chapter summary

This chapter is summarised in table 3.3 where each item selected for use in the modelling is stated. Based on the chapter this table answers the first research sub-question, as it specifies which characteristics can be used to model a grid-scale BESS technically and economically.

Item	Notation
State of Charge	SoC
Initial State of Charge	SoC_0
Minimum and maximum State of Charge	SoC_{min}/SoC_{max}
Battery capacity	Q^B
Powers	P^{ch}/P^{di}
Efficiencies	η^{ch}/η^{di}
BESS CAPEX	C^{BESS}
BESS OPEX	C^{BO}
Grid connection CAPEX	C^{GC}
Grid connection OPEX	C^{GO}
Remaining battery capacity	$Q^{B,rem}$

Table 3.3: Summary of chapter 3

Chapter 4

Electricity markets and BESS

4.1 Introduction

The electricity markets are a complex whole in which producers, consumers, system operators, traders and brokers all influence electricity demand, supply and pricing. At the same time the system is a physical infrastructure that is bounded by the laws of physics and the environment. All of these aspects influence the opportunities of BESS. Therefore, the following describes market as well as physical aspects of the system, relevant to BESS. Since the scope of this research is on the Dutch and Belgian markets, the differences between these will be described whenever relevant.

4.2 The electric grid

Generators and consumers in the electricity system are connected through the transmission and distribution grids. In order for the system to not have black-outs or harm equipment, supply must always equal demand. The flow in the grid follows the path of the least resistance, and cannot be steered other than through injection or off-take of electricity. The grid of continental Europe is single phase alternating current, with a nominal frequency of 50 Hz. Whenever consumption and losses are not equal to supply, the frequency deviates. Transmission System Operators (TSO's) are responsible for the transportation of electricity, through high voltage grids. The TSO of the Netherlands is TenneT and the TSO of Belgium is Elia. All European TSO's are organised in the European Network of Transmission System Operators for Electricity (ENTSO-E). On a local level Distribution System Operators (DSO's) procure a further distribution of electricity, in lower voltage grids.

4.3 Wholesale markets

The structure of the electricity markets is largely based on the principle that supply must equal demand as closely as possible (taking grid losses into account) at all times. In order to achieve this, electricity is traded on forward/future markets, day-ahead markets, intra-day markets and balancing markets. A representation of the markets can be found in figure 4.1.

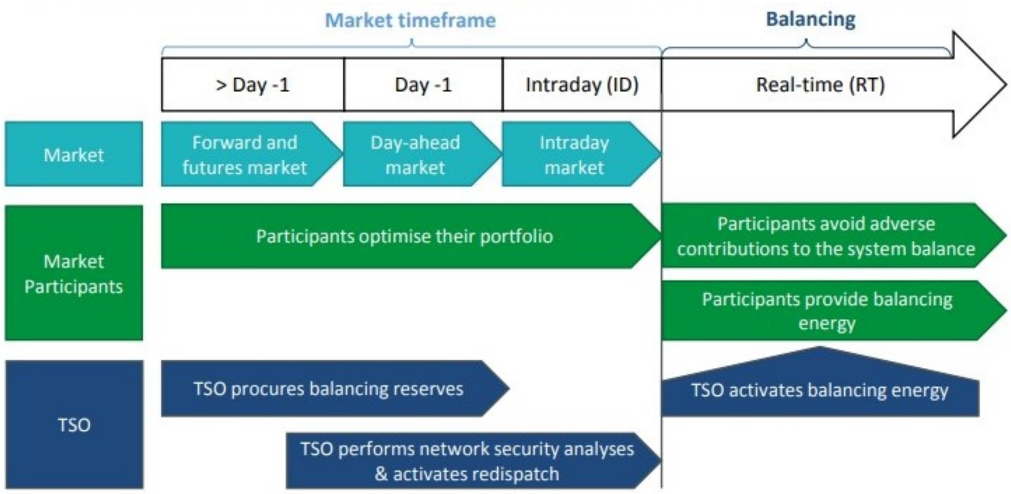

Figure 4.1: Structure of the Electricity markets (TenneT 2019a)

Months and years ahead, electricity is traded on the forward markets. Contracts are for the delivery/consumption of a certain amount of electricity at a certain future time. There are actually two types of contracts: forwards and futures. Forwards are mostly traded over-the-counter and are not standardised. Futures are standardised contracts. Since future prices are unknown, market parties buy and sell electricity on forward and futures markets to hedge their positions.

In the day-ahead market electricity is traded the day before delivery/consumption. Again, market parties can trade over-the-counter or via the power exchanges. A Balancing Responsible Party (BRP) is a legal entity that has its own portfolio of generation, demand or both. These parties are responsible for balancing this portfolio. At the end of the day-ahead market every BSP has to submit a balanced portfolio to the TSO (called a nomination). In this nomination all planned generation and consumption is stated. These nominations have quarterly hourly time blocks.

On the day of delivery, electricity is traded on the intra-day market. Here market parties correct their day-ahead nominations due to wind forecasts, power plant availability and so on. After the intra-day market, BRPs can submit nominations additional to the day-ahead nomination, to allow for the correction of schedules. After the intra-day market BRPs can be in imbalance, in contrast to the day-ahead market. These imbalances are dealt with through the imbalance market mechanism.

4.3.1 Imbalance market

Whenever a BRP has an imbalance (there is a difference between quarter-hour injection and off-take) it is subject to the imbalance market. The sum of all imbalances makes the system imbalance. This imbalance has to be corrected by the TSO through the activation of reserves. The payment of imbalance is based on the incremental price that the TSO pays for the activated reserves that are procured in advance by the TSO. The Imbalance Settlement Period (ISP) for Belgium and the Netherlands is 15 minutes.

For every ISP there are, dependent on the direction of the system imbalance, imbalance prices that provide an incentive/penalty for imbalance. Dependent on the direction of individual imbalance BSPs receive from the TSO the imbalance price times imbalance in that ISP for feed-in and pay to the TSO the imbalance price times imbalances in the ISP take-off of energy. Dependent on the direction of the imbalance system in that quarter hour, reserves are activated and imbalance prices are set. This price can be advantageous to the individual BSP (paying low prices for take-off or receiving high prices for feed-in) or disadvantageous (paying high prices for take-off or receiving low prices for feed-in).

4.4 Reserve markets

If the system load and generated power are not equal at some point in time in the power system, the frequency drops or rises due to a change in the kinetic energy of the rotating generators of power plants. In equation 4.1 this dynamic is shown, as the change of kinetic energy E_k is equal to the generated power P_g minus the load of the system P_l.

$$\frac{dE_k}{dt} = P_g - P_l \tag{4.1}$$

In equation 4.2 it is stated how frequency deviations are calculated. Here Δf is the frequency deviation, f is the frequency and f_n is the nominal frequency. The frequency should be restored to its nominal value in due time, as failing to do so will lead to cascading failures and possibly black-outs. This restoration of the frequency is procured via a number of reserve services. In general there are three types of reserves, for which the (sub)products can differ per TSO. An overview is given in figure 4.2.

$$\Delta f = f - f_n \tag{4.2}$$

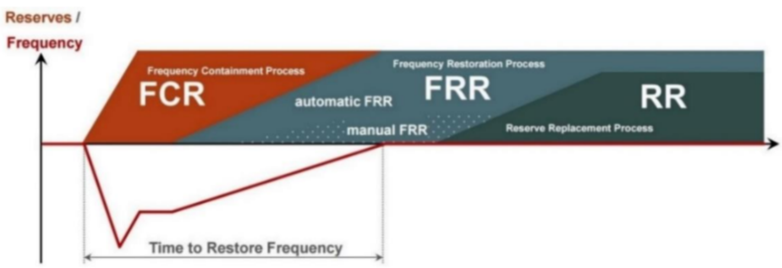

Figure 4.2: Reserve activation after a frequency deviation (Schittekatte and Meeus 2018)

4.4.1 Frequency Containment Reserve

Frequency Containment Reserve (FCR) is a capacity based reserve which should be activated within thirty seconds after a frequency deviation. Figure 4.3 depicts power output of a 5 MW FCR bid and how it should be related to the frequency deviation of the grid. The maximum droop level control value ϕ^{FCR} is 200 mHz. These are also the limits in the graph. To prevent reactions close to the nominal frequency assets do not need to provide reaction in the dead-band of 10 mHz per ENTSO-E guidelines (Commission of European Union 2017) around the nominal frequency, which is also shown in the figure.

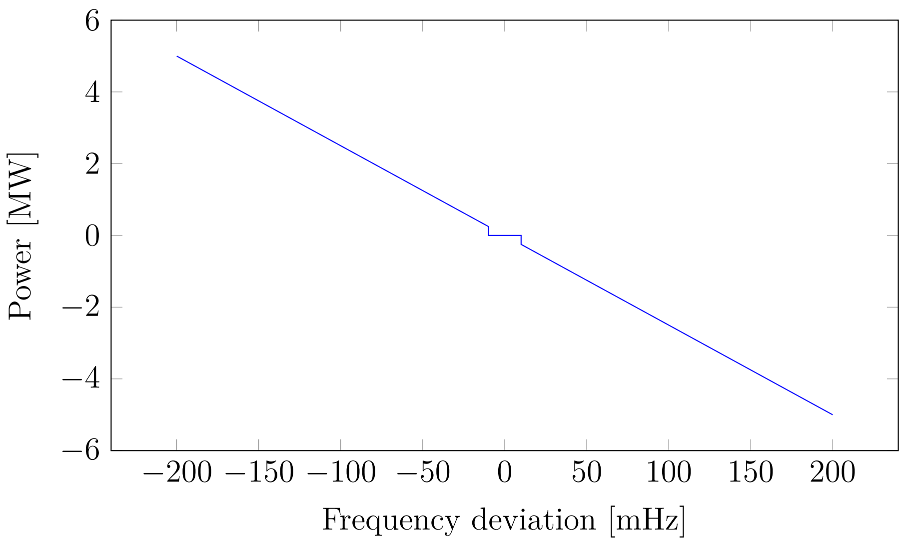

Figure 4.3: BESS reaction related to frequency deviation for a 5 MW FCR bid

FCR is procured on a European level in the FCR cooperation on the platform regelleistung.net. In this cooperation TSOs from Austria, Belgium, Switzerland, Germany, Western Denmark, France and the Netherlands participate. Proportionally to the size of the national system in relation to the ENTSO-E defined reference incident (approx. 3000 MW) (Commission of European Union 2017), countries should procure FCR. For the Netherlands and Belgium, the FCR requirements for 2019 are 111 and 81 MW, respectively. Of this requirement, a portion (for an outage of 1000 MW or about 30% of the FCR requirement) needs to be sourced locally due to an import limit of ENTSO-E. This results in FCR sourcing both in a national market and on the regional platform. An example of this national and European sourcing by the Belgian TSO Elia is given in figure 4.4. The national bidding price is linked to the regional FCR bidding price (Elia 2018) and therefore equal to or somewhat higher than the regional auction. The auctioning process used to be based on a pay-as-bid Common Merit Order List (CMOL). The lowest priced bids that make up the required power needed for FCR are remunerated at the price they offer in their bidding. From 2019 the bidding will be pay-as-cleared and all selected bids will be remunerated at the last selected bid that is needed to fulfil the FCR procurement (Elia 2018). This is a benefit to BESS technology as operators can set low bid prices to ensure selection in the CMOL, while being remunerated at the marginal price.

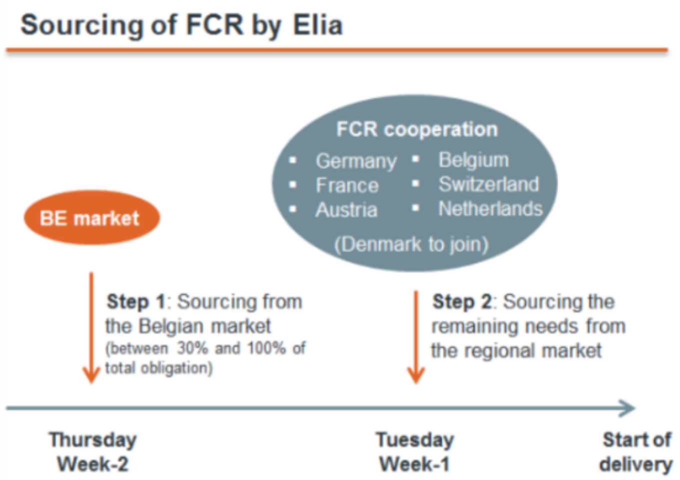

Figure 4.4: FCR sourcing by Belgian TSO Elia ()

4.4.2 Frequency Restoration Reserve

If a frequency deviation lasts for a longer time period, TSOs need to activate additional reserves. Frequency Restoration Reserve (FRR) should be activated within 30 seconds after TSO activation and should reach full activation within 15 minutes. The amount of FRR that needs to be sourced per control area is based on ENTSO-E requirements. FRR can be categorised into automatic FRR (aFRR) and manual FRR (mFRR). Activation of FRR is determined by the TSO on the basis of the Area Control Error (ACE). Determinants of this error are unplanned exchanges of electricity flow in the inter connectors that connect European countries and FCR activation.

Bids for aFRR reserve are placed on a bid-ladder for every ISP. From this bid-ladder the highest/lowest price for upwards/downwards regulation, as well as the need to activate mFRR determines the price for all activated aFRR reserves. In the end, activated reserves also determine the imbalance prices for each ISP.

The FRR markets are not taken into account in this thesis, as these markets require availability for multiple hours. This is not a good match for BESS that usually have energy to power ratios not greater than 2. If in the future these markets are split into shorter delivery blocks, BESS participation could serve as additional sources of revenue.

4.4.3 Restoration Reserves

In case of a large deviation, TSOs can use the Restoration Reserves (RR). These reserves are activated manually to restore the frequency to nominal value. Often these reserves require very long delivery periods, which is not beneficial to BESS. This market is therefore not a valid revenue stream, but could be in the future.

4.5 Electricity markets in the model

In the model the day-ahead, IM and FCR markets are taken into account. In this section it is stated how these are taken into account and price analysis is made that is used in the test case and scenario analysis. Three different model options are developed that are used to analyse individual markets and the combination of markets. Table 4.1 gives the three model options.

Model options	Markets accessed
A	FCR market & Day-ahead market
B	Imbalance market
C	FCR market & Imbalance market

Table 4.1: The different model options and markets accessed

Model option A includes the FCR market with the DA market for State of Charge (SoC) management. This model can be seen as a baseline model for FCR, since there is no extra revenue generated from other markets. Model option B represents a BESS that only reacts on the IM to generate revenue. It is the baseline model for IM. Model option C represents a BESS that participates as FCR provider, while managing SoC through the IM to generate more revenue.

4.5.1 Day-ahead market

In model option A the DA average market price is used as a price at which it is likely that BESS can manage SoC. The DA market is therefore only used as a way to show results of the base case FCR scenario and not for arbitraging. To make a base case FCR model option a fixed DA price equal to the average FCR price over 2018 is used.

4.5.2 FCR market

The FCR market will be taken into account by assuming the BESS is selected in the FCR bids. This is a reasonable assumption as BESS operators can set their bidding price so that selection is highly likely as the marginal price is set by other FCR providing technologies.

In order to represent realistic BESS cash-flow a price analysis is made of the marginal accepted common auction FCR bids in 2018, depicted in figure 4.5. These marginal prices were obtained from the platform regelleistung.net. The average marginal accepted bid price for 2018 was 13.78 €/MW/hour. The power accepted on the FCR bid is represented as $P^{FCR,b}$ and the accepted power bid price is represented as π^{FCR}. This will be further explained in the model sections 5.5.

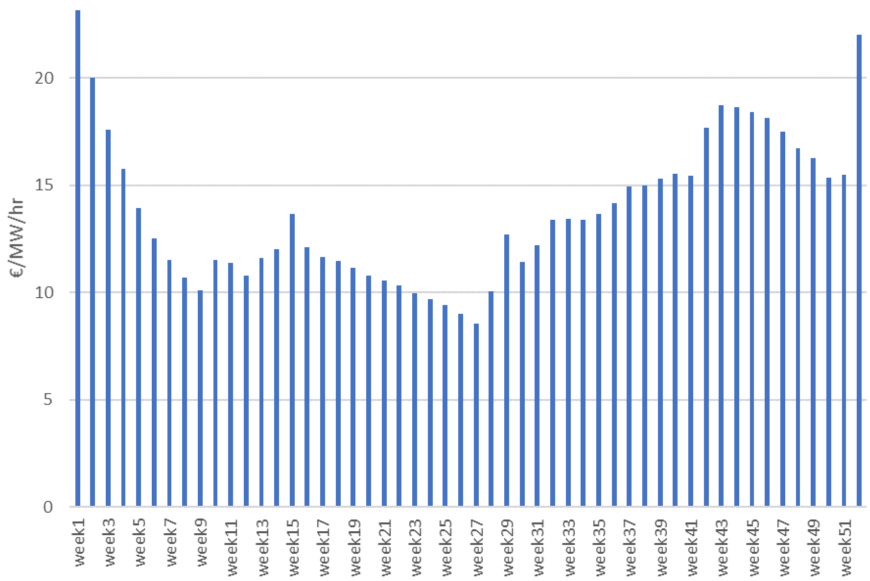

Figure 4.5: Marginal accepted EU FCR bids in 2018

The development of FCR prices depend on, amongst others, availability of gas and coal providers, gas and coal prices, hydro power station availability and storage and other technology adoption. Fleer, Zurmühlen, Meyer, et al. (2017) determine the effects of bidding strategies and addition of BESS in the German PCR (FCR) market (part of the joint market with BE and NL) and project four different price paths for the period 2017-2055. The first path assumes (per week prices are converted to per hour prices) constant price of 14.9 €/MW/hr for future prices (this would be 13.78 for 2018). The second path assumes a quick linear decrease to a constant 5.95 €/MW/hr. The third and fourth paths assume exponential decrease to 5.95 €/MW/hr in 2035 and 8.93 €/MW/hr in 2035, respectively. In the scenario analysis price paths are assumed based on the first path (constant price for 2018), the fourth path (exponential decrease to 8.93 €/MW/hr) and second path (quick linear decrease to constant 5.95 €/MW/hr).

4.5.3 Imbalance market

Through the Imbalance Market (IM) mechanism the BESS can charge or discharge at beneficial prices. To do so the BESS should react to imbalance and price signals at the right moments. When there is an overall energy shortage in the system and the BESS discharges the price per MWh received from the TSO is likely relatively high. Similarly, in case of energy excess in the system it is likely that prices are such that BESS can charge energy at relatively cheap prices that are paid to the

TSO. The prices for energy excess can even be negative (the TSO pays the BRP for charging energy).

Modelling over historic IM prices would lead to perfect foresight as the MILP would choose the exact times when discharge/charge is beneficial. In reality BESS operators react (or predict) the system imbalance. In order to model this, a strategy should be developed that ensures realistic imbalance market revenue. This is done in section 5.6.2.

In order to make realistic analysis of BESS projects a price analysis is needed for the IM. The revenue that can be made by trading on the imbalance market is related to the spread between the IM feed $\pi^{IM,f}$ and take $\pi^{IM,t}$ prices. Figures 4.6 and 4.7 depict the average price spread of the Belgian and Dutch IMs for 2018. The average spread in 2018 for the Dutch IM was 56 €/MWh, for the Belgian IM this was 69 €/MWh.

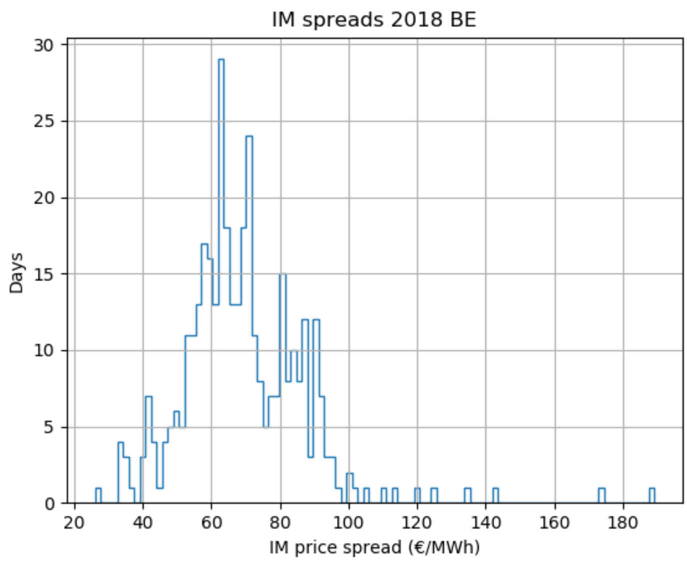

Figure 4.6: Average price spread for days on the Belgian IM for 2018

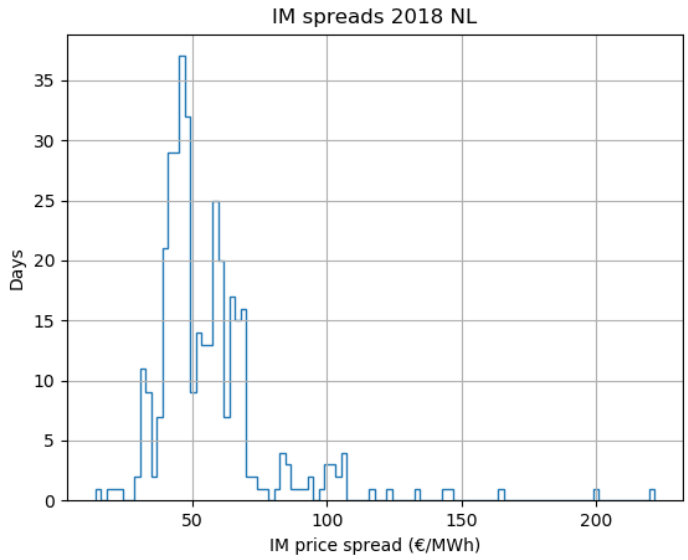

Figure 4.7: Average price spread for days on the Dutch IM for 2018

Revenue that can be gained from reacting on the IM are not directly related to these price spreads. It also matters how often which prices occur in a day, as the BESS has limits to *SoC* levels (reacting is not always possible/beneficial). Using 2018 data for the Belgium and Dutch IMs analysis is made with model options B and C to determine realistic IM revenue and find days with representative IM price variations. These days are used in the optimisation.

4.6 Chapter summary

In table 4.2 all relevant items are stated that are taken into account in the modelling, based on this chapter. This table and the above chapter answers research sub-question two. The table states which markets are taken into account and what future pricing levels are.

Item	Sign
Frequency and frequency deviation	$f/\Delta f$
FCR bid	$P^{FCR,b}$
FCR bid price	π^{FCR}
Droop level control frequency deviation	ϕ^{FCR}
IM feed price	$\pi^{IM,f}$
IM take price	$\pi^{IM,t}$
DA price	π^{DA}

Table 4.2: Summary of chapter 4

Chapter 5

Model

5.1 Introduction

In order to make an investment decision analysis of BESS systems, a mathematical Mixed-Integer Linear Programming model is formulated in this chapter. This model consists of constraints related to State of Charge, power flow, markets, capital and operational costs, ageing, etc. All constraints are explained in detail in sections 5.2-5.7 before the model options are described in their entirety in 5.8.

5.2 BESS model

The functioning of a BESS as described by characteristics in section 3.5.4 is the basis of the model. This section describes various constraints that implement the BESS behaviour.

5.2.1 State of Charge

In order to have the model represent the energy level of the battery for each time step, the powers of charging and discharging should influence the BESS State of Charge SoC_t. Also, the previous time step should be taken into account to determine the current time step State of Charge. Since the first time step is different from the rest as SoC here is dependent on initial state of charge SoC_0 two different constraints are needed for SoC. The first constraint is equation 5.1 where the SoC at time step 1 is described. In this equation $\eta^{B,di}$ and $\eta^{B,ch}$ are the BESS discharging and charging efficiency, Q^B is the BESS capacity and $P_t^{B,di}$ and $P_t^{B,ch}$ are the discharging and charging powers of the BESS per time step. Equation 5.2 describes all following time steps and is almost similar to 5.1 except for the previous time step which is now SoC_{t-1} instead of SoC_0. The initial State of Charge set-point SoC_0 is 0.5 since the BESS should be able to react in both directions on the first time step.

$$SoC_t = SoC_0 - (\frac{1}{\eta^{B,di}Q^B}P_t^{B,di}\Delta t) - (\frac{\eta^{B,ch}}{Q^B}P_t^{B,ch}\Delta t) \quad \forall t = 1 \tag{5.1}$$

$$SoC_t = SoC_{t-1} - (\frac{1}{\eta^{B,di} * Q^B} * P_t^{B,di} * \Delta t) - (\frac{\eta^{B,ch}}{Q^B} * P_t^{B,ch} * \Delta t) \quad \forall t > 1 \leq T \tag{5.2}$$

For many BESS systems there are limitations to the energy operation band that is suitable for operation. In this case the maximum and minimum State of Charge levels between which the energy level of the BESS is allowed are set as constraints in the model. The values of minimum and maximum *SoC* can result from battery optimal operation to prevent ageing, or the market requirements. In section 5.5.2 for example, minimum and maximum state of charge requirements for FCR participation are explained. In the model such minimum and maximum state of charge levels are set through the constraints stated in equations 5.3 and 5.4. Since the minimum and maximum *SoC* levels can also change (as will be explained in section 5.5.2) SoC_t^{min} and SoC_t^{max} are variables.

$$SoC_t^{min} \leq SoC_t \quad \forall t \leq T \tag{5.3}$$

$$SoC_t \leq SoC_t^{max} \quad \forall t \leq T \tag{5.4}$$

5.2.2 Charging and discharging powers

The discharging and charging powers of the BESS are equal to the sum of all discharging and charging powers, respectively, of the different market power variables. This can differ depending on which markets are taken into account in the model. Equations 5.5 and 5.6 give an example of the total discharging $P_t^{B,di}$ and charging $P_t^{B,ch}$ powers of the BESS when the FCR and day-ahead (DA) markets are exploited. Total discharging is equal to FCR feed power $P_t^{FCR,f}$ plus DA discharging power $P_t^{DA,di}$. Total charging is equal to FCR take power $P_t^{FCR,t}$ plus DA charging power $P_t^{DA,ch}$.

$$P_t^{B,di} = P_t^{FCR,f} + P_t^{DA,di} \quad \forall t \leq T \tag{5.5}$$

$$P_t^{B,ch} = P_t^{FCR,t} + P_t^{DA,ch} \quad \forall t \leq T \tag{5.6}$$

Since discharging and charging powers are separated, all powers are positive numbers limited by the maximum power limit. All different power variables should therefore be greater than zero and less than or equal to the maximum power for that specific variable. Constraints 5.7 and 5.8 force the discharging and charging powers for the day-ahead market $P_t^{DA,di}$ and $P_t^{DA,ch}$ to be greater than zero for the day-ahead market, as an example example.

$$0 \leq P_t^{DA,di} \quad \forall t \leq T \tag{5.7}$$

$$0 \leq P_t^{DA,ch} \quad \forall t \leq T \tag{5.8}$$

For a single market, discharging and charging cannot occur in the same time step. To prevent such behaviour, a binary variable is introduced that is included in the constraints that limits the power variables to their respective maxima. For example, the constraints in equations 5.9 and 5.10 do so for the imbalance market. Equation 5.9 constrains $P_t^{DA,di}$ to be smaller than or equal to the maximum day-ahead market reserved power $P^{DA,max}$ times the binary variable u_t. Equation 5.10 implements the same constraint for charging, but here the $(1 - u_t)$ term is used. The nature of binary variables ensures correct behaviour, as the day-ahead market power variables for discharging and charging cannot both be greater than zero. Equation 5.11 forces the optimiser to make a choice between either a discharging or charging action for each time step by forcing u_t to be zero or one.

$$P_t^{DA,di} \leq P^{DA,max} u_t \quad \forall t \leq T \tag{5.9}$$

$$P_t^{DA,ch} \leq P^{DA,max}(1 - u_t) \quad \forall t \leq T \tag{5.10}$$

$$u_t \in \{0, 1\} \quad \forall t \leq T \tag{5.11}$$

5.3 Degradation model

In order to deal with battery degradation aspects the theory adapted from Wankmüller et al. (2017) explained in section 3.3 is applied. Two concepts are implemented. The first concept is the degradation of BESS capacity and the second concept is the degradation cost that will be a subtraction term in the objective function.

5.3.1 Capacity degradation

As stated in section 3.3 degradation of BESS capacity is implemented via equation 3.1, repeated here (equation 5.12) for completeness. As explained previously, it states remaining battery capacity $Q_t^{B,rem}$ is equal to one minus battery degradation fade factor D ($2.71 * 10^-5$/MWh) times Total Energy TE_t over initial battery capacity.

$$Q_t^{B,rem} = 1 - D * TE_t/Q^B \quad \forall t \leq T \tag{5.12}$$

In order to be able to implement this constraint, Total Energy TE_t should be calculated at each time step. This is done by tracking BESS discharged energy via the two constraints in equations 5.13 and 5.14. Discharged power is used since there is no need to count energy throughput twice (Wankmüller et al. 2017). Equation 5.13 makes TE_t equal to $P_t^{B,di}$ times the time step length Δt to get the energy processed for only the first time step.

$$TE_t = P_t^{B,di} \Delta t \quad \forall t = 1 \leq T \tag{5.13}$$

For all other time steps Total Energy should be the sum of all energy processed up until t plus the current time step processed energy. Equation 5.14 implements this.

$$TE_t = TE_{t-1} + P_t^{B,di} \Delta t \quad \forall t > 1 \leq T \tag{5.14}$$

In the model the remaining battery capacity will not actually influence usable battery capacity and thereby revenue. In the business model parameters a cost for over-sizing/upgrading the battery capacity during the project lifetime will be assumed. This makes an active capacity approach valid, as the assumption can be made that initial capacity is be maintained.

5.3.2 Degradation cost term

In economic BESS operation, not all price incentives should result in discharging/charging action. Action where only small revenues can be generated will actually be economically unattractive due to battery degradation. In order to have the model represent this operational behaviour a degradation cost term is added to the objective function of the model. An example of such an objective function could be equation 5.15 where BESS revenue Γ^{BESS} is maximised for each time step. BESS revenue is equal to the revenue of the other markets $\Gamma^{markets}$ minus degradation cost Γ^{deg}.

$$Maximise \quad \Gamma^{BESS} = \Gamma^{Markets} - \Gamma^{deg} \tag{5.15}$$

This degradation cost should not be taken into account for calculating the revenues of the model. But it enforces less battery cycling as the energy selling minus energy buying revenue that can be made in the market has to be larger than this degradation cost for the BESS to take action. The degradation cost term is calculated for each time step through the constraint stated in equation 5.16. Here degradation cost Γ^{deg} is equal to the sum over all time steps of battery degradation fade factor D times discharged power $P_t^{B,di}$ times time step length Δt times battery penalty cost c_B [€/kWh] over one minus the end-of-life value eol for each time step. Notice that again discharged energy is used in the calculation as there is no need to count energy throughput twice.

$$\Gamma^{deg} = \sum_{t=0}^{T} D * P_t^{B,di} \Delta t \frac{c_B}{1 - eol} \tag{5.16}$$

In the analysis the end of life value of the battery is assumed to be 0.8. For the battery degradation penalty cost c_B Wankmüller et al. (2017) makes extensive analysis of its effects. In this thesis, c_B is analysed each time a new model configuration is introduced. This is done by varying the parameter in the range 0-700€/kWh with increments of 50. This type of analysis is needed as behaviour of the proposed model might differ from the Wankmüller et al. (2017) model behaviour.

5.4 Day-ahead market model

In order to model realistic behaviour and revenues, the DA market is taken into account in the optimisation with a constant price which is based on the average day-ahead price for the modelled period. This is explained in section 4.5.1.

To determine the revenues from DA market equation 5.17 defines the revenue constraint. Here day-ahead revenue Γ^{DA} is equal to the sum over all time steps of day-ahead market price π_t^{DA} times day-ahead market discharging $P_t^{DA,di}$ minus day-ahead market price π_t^{DA} times day-ahead market charging $P_t^{DA,ch}$, all multiplied by time step length Δt.

$$\Gamma^{DA} = \sum_{t=0}^{T} ((\pi_t^{DA} P_t^{DA,di}) - (\pi_t^{DA} P_t^{DA,ch}))\Delta t \tag{5.17}$$

5.5 FCR market model

In section 4.4.1 the FCR market is explained. Since this service is remunerated for power reserved in the asset, the revenue of this market is not dependent on energy feed/take per time step. The remuneration of FCR is based on price analysis of the bidding prices π^{FCR} (€/MW/h) of FCR and what can be expected of this price going forward. Therefore the FCR revenue Γ^{FCR} to be used in the objective function is not actually changing in time, but based on the assumed price π^{FCR}. The reason for this is the clarity of an an objective function in which the revenue of all markets is taken into account. Equation 5.18 implements this by making FCR revenue Γ^{FCR} equal to sum over all time steps of the FCR assumed price π^{FCR} in €/MW/h divided by thousands (since the model is kW/kWh based) times accepted FCR power bid $P^{FCR,b}$ and times time step length Δt as revenue variables are per time step.

$$\Gamma^{FCR} = \sum_{t=0}^{T} \frac{\pi^{FCR}}{1000} P^{FCR,b} * \Delta t \tag{5.18}$$

5.5.1 FCR frequency signal following

If we assume the BESS is selected in this market, the model should include the correct reaction (charging or discharging) corresponding to frequency deviation as stated in equation 4.2 based on the accepted power bid $P^{FCR,b}$ in the FCR auction. As depicted in figure 4.3 and per ENTSO-E guidelines (Commission of European Union 2017) the reaction of the BESS should be proportional to the frequency deviation. In order to follow this frequency signal constraint 5.19 forces the feed $P_t^{FCR,f}$ power for FCR participation. This power is equal to minus frequency deviation per time step $f_t - f_n$ divided by the maximum required droop level control frequency deviation ϕ^{FCR} (0.2Hz) times the accepted bid of FCR power $P^{FCR,b}$ in cases where the frequency is smaller than the nominal minus dead-band (50 Hz - 10 mHz) value of 49.99 Hz. For cases where the frequency is larger than the nominal plus dead-band (50 Hz + 10 mHz) value of 50.01 equation 5.20 forces the take $P_t^{FCR,t}$ power following the same logic, but without the minus sign as $f_t - f_n$ will be positive with frequencies greater than 50 Hz.

$$P_t^{FCR,f} = -((f_t - f_n)/\phi^{FCR} P^{FCR,b}) \quad \forall t \leq T \quad \forall f_t \leq 49.99 \tag{5.19}$$

$$P_t^{FCR,t} = ((f_t - f_n)/\phi^{FCR} P^{FCR,b}) \quad \forall t \leq T \quad \forall 50.01 \leq f_t \tag{5.20}$$

This feed and take power of FCR requirements are forced upon the BESS discharging $P_t^{B,di}$ and charging $P_t^{B,ch}$ totals by the following constraints, combining the FCR powers $P^{FCR,f}$ and $P^{FCR,t}$ and market powers $P_t^{Markets,di}$ and $P_t^{Markets,ch}$ (equations 5.21 and 5.22).

$$P_t^{B,di} = P_t^{Markets,di} + P^{FCR,f} \quad \forall t \leq T \tag{5.21}$$

$$P_t^{B,ch} = P_t^{Markets,ch} + P^{FCR,t} \quad \forall t \leq T \tag{5.22}$$

5.5.2 FCR requirements for BESS

BESS are different from other FCR providing technologies as they are Limited Energy Reservoirs (LER). To allow LER participation in the FCR procurement TSO's have proposed rules specific to LER (Elia 2016a; TenneT 2019b).

In case of large frequency deviations over longer time periods, BESS could run out of available energy in case of discharging ($f_t \leq 49.99$) or reach its upper energy content limit in case of charging ($50.01 \leq f_t$). Therefore TSOs have proposed the following set of rules:

- In the "standard frequency range" (explained below) the frequency deviations should be supported continuously by the BESS.
- In case of "alert state" (explained below) the BESS should be able to deliver the contracted FCR for a period of at least 15 minutes.
- In the period of larger frequency deviations leading up to "alert state" BESS should also follow the frequency signal.
- After an "alert state" reaction, the BESS should recover as quickly as possible and within two hours after "standard frequency range" is reached. Thereafter the contracted FCR reaction should again be available.
- Since also in non "alert state" frequency following influences BESS SoC there should be active SoC management. To apply this management sufficient BESS power should be reserved. Requirements for this can differ per TSO and are explained below.

The requirements for reserving BESS power for SoC management can differ per TSO. Dutch TSO TenneT has stated that it will use a requirement of power to pre-qualified FCR power of 1.25:1 or an alternative strategy with the same effect (TenneT 2019b), even though this ruling was rejected by ENTSO-E. In this case, for example, a 10 MW BESS can only submit bids for up to 8 MW power on the FCR market. Belgian TSO Elia states a same requirement will be implemented, but the exact ratio will be determined during the pre-qualification tests needed for FCR participation (Elia 2016a). Since this requirement of Elia is not specified in detail the 1.25:1 requirement of TenneT is also assumed for Belgian BESS cases.

"Alert state" is defined as (Elia 2016a; TenneT 2019b):

- $|\Delta f| > 100$ mHz during 5 minutes (Dutch TSO)
- $|\Delta f| > 50$ mHz during 15 minutes (Dutch and Belgian TSO's)
- $|\Delta f| > 100$ mHz during 10 minutes (Belgian TSO)

All other states are "normal states". To be clear, deviations outside "standard frequency range" ($|\Delta f| > 50$ mHz) are not automatically "alert states". The moments leading up to "alert state" should also lead to BESS continuous frequency following. Note that there are different requirements for the different countries. In order to be on the safe side of this requirement 10 minutes of full FCR reaction is reserved in both directions in addition to the 15 minute full FCR reaction that is required in "alert state" (Elia 2016a; TenneT 2019b). This leads to a total of 25 minutes of full

FCR reaction in both directions that has to be reserved in the BESS energy content to fulfil FCR requirements. This operation band is reserved in the BESS through the minimum and maximum FCR SoC level variables. Equation 5.23 forces the minimum SoC variable $SoC_t^{min,FCR}$ to be equal to the size of the FCR accepted bid $P^{FCR,bid}$ times 25 over 60 (as 25 minutes should be reserved) divided by total BESS energy content Q^{BESS}. Equation 5.24 forces the same constraint for the maximum SoC variable $SoC_t^{max,FCR}$.

$$SoC_t^{FCR,min} = \frac{P^{FCR,b}(25/60)}{Q^B} \quad \forall t \leq T \tag{5.23}$$

$$SoC_t^{FCR,max} = \frac{Q^B - P^{FCR,b}(25/60)}{Q^B} \quad \forall t \leq T \tag{5.24}$$

These constraints define an operation wherein the BESS can react in normal state (figure 5.1).

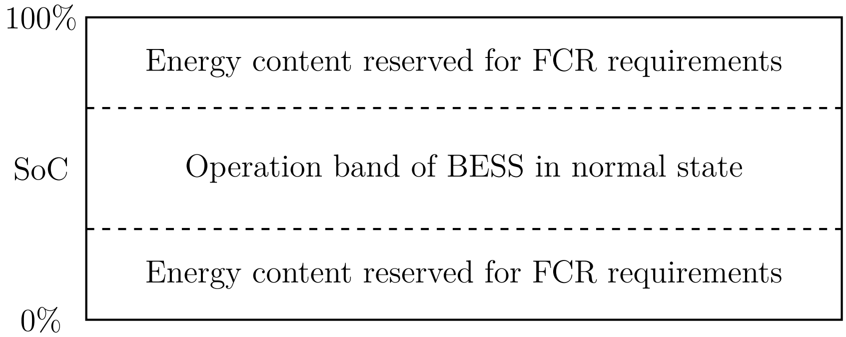

Figure 5.1: SoC operation band resulting from FCR requirements

In case of deviations outside "standard frequency range" and for "alert state" the BESS should be allowed to operate outside of this operation band (see the figure). Therefore binary variables are introduced to make behaviour of minimum SoC_t^{min} and maximum SoC_t^{max} levels correspondent to the requirements. In case of deviations outside "standard frequency range" binary variable v_t^a and v_t^b are introduced to allow the BESS to have 10 minutes additional full FCR reaction power reserved. In case of "alert state" binary variable w_t^a and w_t^b are introduced to have (on top of the allowed 10 minutes) 15 minutes of additional full FCR reaction. This is implemented by the constraints in equations 5.25 and 5.26. For all of these binary variables v_t^a, v_t^b, w_t^a and w_t^b 1 implies that the operation band is expanded by the amount of "full FCR reaction" minutes corresponding to the state of the system (deviation of "standard frequency range" and "alert state"). From analyses of the grid frequency input file the values of the binaries for non-normal operating states are set to 1 in advance to the optimisation.

$$\begin{aligned} SoC_t^{min} = SoC_t^{FCR,min} - \frac{P^{FCR,bid}(10/60)v_t^a}{Q^{BESS}} - \\ \frac{P^{FCR,bid}(15/60)w_t^a}{Q^{BESS}} \quad \forall t \leq T \end{aligned} \tag{5.25}$$

$$SoC_t^{max} = SoC_t^{FCR,max} + \frac{P^{FCR,bid}(10/60)v_t^b}{Q^{BESS}} + \frac{P^{FCR,bid}(15/60)w_t^b}{Q^{BESS}} \quad \forall t \leq T \tag{5.26}$$

Since two hours of recovery are allowed after ”alert state” reaction the frequency file values are adapted to 50 Hz for those two hours so the BESS does not react. Also in these two hours binary variables v_t^a, v_t^b, w_t^a and w_t^b are still 1, allowing the SoC to return to values within the normal operation band.

5.6 Imbalance market model

The imbalance market (IM) revenues are determined after the ending of the fifteen minute Imbalance Settlement Period (ISP).

5.6.1 Imbalance market powers

IM powers cannot be added to the total BESS powers $P_t^{B,di}$ and $P_t^{B,ch}$ as with the other markets. The reason for this is that IM action can change the net action of the BESS. The action of for example the FCR market can be added to total powers directly, as the BESS must follow this action. For the IM powers, this is not the case. The model can determine per time step what would be the most optimal IM action. The net action (charging vs. discharging) of the BESS can therefore change if IM action is in the opposite direction of FCR action. For example consider a time step where the request of the FCR market is 500 kW feed power following from the frequency signal. If the model decides IM action should be 2000 kW charging, the net BESS action in this time step should be a charging power of 1500 kW. Since all of the power variables in the model are greater than zero, it is not possible to get to this result by subtracting 2000 from 500 (-1500). One could propose workarounds like absolute values, however it should also be clear if this variable result means charging or discharging. For example considering the same time step, but now with IM action of 2000 kW discharging should result in total BESS discharging of 2500 kW (2000 + 500). So having just a charging and discharging power variable for IM it is not possible to represent IM market action.

In order to be able to model the IM market two power variables are introduced for both IM discharging and IM charging (Tohidi and Gibescu 2019). Those power variables are IM charging power increase $P_t^{IM,ch,i}$, IM charging power decrease $P_t^{IM,ch,d}$, IM discharging power increase $P_t^{IM,di,i}$ and IM discharging power decrease $P_t^{IM,di,d}$. Following from these variables charging powers of, for example, adding FCR and IM markets results in equations 5.27 and 5.28. Equation 5.27 makes BESS discharging $P_t^{B,di}$ equal to FCR feed power $P^{FCR,f}$ and increase of IM discharging power $P_t^{IM,di,i}$

minus decrease of IM discharging power $P_t^{IM,di,d}$. In equal fashion, equation 5.27 implements the appropriate constraint for charging.

$$P_t^{B,di} = P_t^{FCR,f} + P_t^{IM,di,i} - P_t^{IM,di,d} \quad \forall t \leq T \tag{5.27}$$

$$P_t^{B,ch} = P_t^{FCR,t} + P_t^{IM,ch,i} - P_t^{IM,ch,d} \quad \forall t \leq T \tag{5.28}$$

5.6.2 Imbalance market strategy

An optimisation model that runs over historical data of imbalance market prices per ISP overestimates revenues. This is due to perfect foresight that the model has over prices and when these prices occur. In reality, acting on the imbalance market with BESS is based on prediction of the system imbalance (as this is a good indicator of prices) or reacting to the system imbalance which is published by TSO's with a lag of about three minutes. Since the prediction of system imbalance and prices is operator specific and can be based on lots of data and algorithms the model considered estimates revenues through a simple reaction strategy which would give a lower bound for attainable revenues for imbalance market SoC management.

The minute imbalance data published by the TSO correspondent to the ISP is used to make the prediction. For every ISP the direction of system imbalance determines the direction of BESS reaction. This is done through setting binary variables. If the system imbalance three minutes back indicates that there was a shortage of energy in the system, the BESS is only allowed to increase discharging, decrease charging or take no action in the current minute. If the three minute lag imbalance data indicates energy excess in the system the BESS is only allowed to charge or take no action in the current minute.

Table 5.1 gives an example of a quarter hour ISP where the three minute lag system imbalance (SI) determines the value of binary variables z_t^{down} and z_t^{up}. Whenever the strategy implies the BESS should react by charging increase or discharging decrease the value of z_t^{down} is one. This same logic applies to z_t^{up}, set to one whenever the strategy implies the BESS can increase discharging or decrease charging. The evolution of the SI indicates that overall there was an excess of energy in the system in the ISP. Therefore with perfect foresight the BESS would have increased discharging or decreased charging the entire ISP. With the strategy, only the last 6 time steps can be used for this type of action in this ISP.

ISP minute	SI (MW)	Evolution of SI (MW)	z_t^{down}	z_t^{up}
1	-32	-32	0	0
2	-39	-36	0	0
3	-56	-43	0	0
4	-21	-37	0	1
5	91	-11	0	1
6	85	4	0	1
7	79	15	0	1
8	65	21	0	1
9	90	29	1	0
10	73	33	1	0
11	105	40	1	0
12	90	44	1	0
13	30	43	1	0
14	32	42	1	0
15	4	40	1	0

Table 5.1: Example of an ISP where the imbalance market strategy is applied

In order to apply the correct BESS behaviour correspondent to the IM strategy the two binaries are used in the limiting of IM powers. For downwards action (increased charging or decreased discharging) equations 5.29 and 5.30 force the correct behaviour.

$$P_t^{IM,ch,i} \leq P^{IM,max} z_t^{down} \quad \forall t \leq T \tag{5.29}$$

$$P_t^{IM,di,d} \leq P^{IM,max} z_t^{down} \quad \forall t \leq T \tag{5.30}$$

For upwards action (increased discharging or decreased charging) equations 5.31 and 5.32 implement the correct constraints.

$$P_t^{IM,ch,d} \leq P^{IM,max} z_t^{up} \quad \forall t \leq T \tag{5.31}$$

$$P_t^{IM,di,i} \leq P^{IM,max} z_t^{up} \quad \forall t \leq T \tag{5.32}$$

5.6.3 Imbalance market revenue

The settlement of imbalance is based on the net action of the BESS for each ISP. For reserve markets such as FCR, energy costs or revenues on the imbalance market should be taken into account as these are borne by the BESS operator, also stated in (TenneT 2019b). Therefore the revenue that can be earned from the imbalance market should, next to imbalance market powers, be dependent on FCR power for each time step.

This is also represented in equation 5.33 where imbalance market revenue Γ^{IM} is described. In this equation $\pi_t^{IM,f}$ is the imbalance price received for feeding energy to the grid and $\pi_t^{IM,f}$ is the price paid for taking energy from the grid. Time step length Δt coverts all power values (kW) to energy (kWh). All other variables were explained in above section. Prices (originally €/MWh) are converted to €/kWh in advance since the model is kW/kWh based.

$$\begin{aligned}\Gamma^{IM} = \sum_{t=0}^{T}((\pi_t^{IM,f}(P_t^{FCR,f} + P_t^{IM,ch,d} + P_t^{IM,di,i}))\\ -(\pi_t^{IM,t}(P_t^{FCR,t} + P_t^{IM,ch,i} + P_t^{IM,di,d}))\Delta t\end{aligned} \tag{5.33}$$

5.7 Cost

The cost related to BESS investment and operation are taken into account with a distinction between Capital Expenditure (CAPEX) and Operational Expenditure (OPEX). The makeup of these two is explained sections 3.5.1 and 3.5.3.

5.7.1 CAPEX

The BESS investment cost are included in the objective function as Γ^{IC}. This parameter includes all initial investment costs, including battery, grid and power equipment's and transformers. All of these cost are included in the parameters BESS investment cost C^{BESS}, grid connection investment cost C^{GC} and BESS over-sizing/upgrading (section 3.3 cost ($C^{BESS}1 - Q^{bat,rem}$ also stated in 5.34. The values used for this parameter will be stated when analysis/case study is made.

$$\Gamma^{IC} = C^{BESS} + C^{GC} + C^{BESS}(1 - Q^{bat,rem}) \tag{5.34}$$

5.7.2 OPEX

Equation 5.35 calculates total operational costs. The equation specifies that operational cost are yearly BESS system operation cost C^{BO} plus yearly grid connection cost C^{GC} plus yearly grid power fee f^{PY}, apparent power fee f^{AP} times power factor 0.8 and monthly grid fee f^{PM} times 12 months per year. All are multiplied by BESS power P^B. Part two (second line) of the equation is the sum over all time steps of grid fee for energy injection f^{inj} times BESS discharge power $P_t^{B,di}$ plus grid fee for energy consumption f^{con} multiplied by Δt as power values should be converted to energy values.

$$\Gamma^{OC} = (C^{BO} + C^{GO}) + (f^{PY} + f^{AP} * 0.8 + f^{PM} * 12) * \Delta t) + \\ (\sum_{t=0}^{T} (f^{inj} P_t^{B,di} + f^{con} P_t^{B,ch}) * \Delta t) \tag{5.35}$$

5.8 Model

In the previous sections the setup of the model was explained and it was reasoned what constraints should be implemented to represent the BESS business case for the different markets. As the BESS operator could access different markets four model options are defined. Table 5.2 states the different option setups. Per section the appropriate model functions and constraints are defined below.

Model option	Markets accessed
A	FCR market & Day-ahead market
B	Imbalance market
C	FCR market & Imbalance market

Table 5.2: The different model options and markets accessed

5.8.1 Revenue and cost constraints

Model A,B,C

For all of the model options investment cost, operational cost and degradation cost are taken into account. Equation 5.36 defines investment cost Γ^{IC} as the sum of BESS investment cost C^{BESS}, grid connection investment cost C^{GC} and upgrading cost $C^{BESS}(1 - Q^{bat,rem})$.

Equation 5.37 states operational cost Γ^{OC}. In this equation C^{BO} is BESS operation cost, C^{GO} is yearly grid connection cost, f^{PY}, f^{PM} and f^{AP} are the grid fees, P^B is the BESS power, f^{inj} is the grid fee for energy injection, $P_t^{B,di}$ is the BESS discharging in time step t, f^{con} is the grid fee for energy consumption, $P_t^{B,ch}$ is the BESS charging in time step t and Δt is the time step length.

Equation 5.38 defines degradation cost Γ^{deg}. Here D is the battery degradation fade factor, $P_t^{B,di}$ is the BESS discharging power for each time step, Δt time step length, c_B is battery degradation penalty cost and *eol* is the end-of-lifetime value.

$$\Gamma^{IC} = C^{BESS} + C^{GC} + C^{BESS}(1 - Q^{bat,rem}) \tag{5.36}$$

$$\Gamma^{OC} = (C^{BO} + C^{GO}) + (f^{PY} + f^{AP} * 0.8 + f^{PM} * 12) * \Delta t) + \\ (\sum_{t=0}^{T}(f^{inj} P_t^{B,di} + f^{con} P_t^{B,ch}) * \Delta t) \tag{5.37}$$

$$\Gamma^{deg} = \sum_{t=0}^{T} DP_t^{B,di} \Delta t \frac{c_B}{1 - eol} \tag{5.38}$$

Model A,C

For the models where the FCR market is part of the revenue generation equation 5.39 describes FCR revenue Γ^{FCR}. In this equation π^{FCR} is the assumed FCR price for accepted bids, $P^{FCR,b}$ is the power accepted for participating in FCR and Δt is the model time step length.

$$\Gamma^{FCR} = \sum_{t=0}^{T} \frac{\pi^{FCR}}{1000} P^{FCR,b} * \Delta t \tag{5.39}$$

Model A

For models A the DA market result is taken into account through formula 5.40. In this equation π_t^{DA} is the DA market price and $P_t^{DA,di}$ and $P_t^{DA,ch}$ are the DA discharging and charging powers per time step, respectively. Δt is the model time step length.

$$\Gamma^{DA} = \sum_{t=0}^{T}((\pi_t^{DA} P_t^{DA,di}) - (\pi_t^{DA} P_t^{DA,ch}))\Delta t \tag{5.40}$$

Model C

In model option C the provision of FCR is combined with IM reaction. Equation 5.41 is used to model IM result Γ^{IM}. In this equation the feed and take prices of IM are $\pi_t^{IM,f}$ and $\pi_t^{IM,t}$. The FCR feed and take powers are $P_t^{FCR,f}$ and $P_t^{FCR,t}$. For IM the time step power variables are increase of discharging $P_t^{IM,di,i}$, decrease of charging $P_t^{IM,ch,d}$, increase of charging $P_t^{IM,ch,i}$ and decrease of discharging $P_t^{IM,di,d}$. Again Δt is the model time step length.

$$\Gamma^{IM} = \sum_{t=0}^{T}((\pi_t^{IM,f}(P_t^{FCR,f} + P_t^{IM,ch,d} + P_t^{IM,di,i})) \\ -(\pi_t^{IM,t}(P_t^{FCR,t} + P_t^{IM,ch,i} + P_t^{IM,di,d})))\Delta t \tag{5.41}$$

Model B

In model option B the BESS operator is purely using the IM market to generate revenue. In this case IM result Γ^{IM} is represented by equation 5.42. Prices and powers are the same as in 5.41 excluding FCR powers.

$$\Gamma^{IM} = \sum_{t=0}^{T}((\pi_t^{IM,f}(P_t^{IM,ch,d} + P_t^{IM,di,i})) \\ -(\pi_t^{IM,t}(P_t^{IM,ch,i} + P_t^{IM,di,d})))\Delta t \tag{5.42}$$

5.8.2 State of charge constraints

Model A,B,C

For all model options the State of Charge SoC_t for each time step is modelled through equations 5.43 (first time step) and 5.44 (all other time steps). In these equations discharging and charging efficiencies of the BESS are $\eta^{B,di}$ and $\eta^{B,ch}$, the discharging and charging power of the BESS are $P_t^{B,di}$ and $P_t^{B,ch}$, Q^B is the BESS energy capacity and Δt is time step length. SoC_0 is the initial BESS state of charge and SoC_{t-1} is the BESS previous time step state of charge.

$$SoC_t = SoC_0 - (\frac{1}{\eta^{B,di}Q^B}P_t^{B,di}\Delta t) - \\ (\frac{\eta^{B,ch}}{Q^B}P_t^{B,ch}\Delta t) \quad \forall t = 1 \tag{5.43}$$

$$SoC_t = SoC_{t-1} - (\frac{1}{\eta^{B,di} * Q^B} * P_t^{B,di} * \Delta t) - \\ (\frac{\eta^{B,ch}}{Q^B} * P_t^{B,ch} * \Delta t) \quad \forall t > 1 \leq T \tag{5.44}$$

For all model options the SoC_t for time step t cannot go outside of minimum state of charge level SoC_t^{min} (equation 5.45) and maximum state of charge level SoC_t^{max} (equation 5.46).

$$SoC_t^{min} \leq SoC_t \quad \forall t \leq T \tag{5.45}$$

$$SoC_t^{max} \leq SoC_{max} \quad \forall t \leq T \tag{5.46}$$

Model A,C

In model options where the FCR market is included there is an operating band for the BESS, to reserve energy for alert state reaction. This operation band is defined by minimum FCR state of charge $SoC_t^{FCR,min}$ in equation 5.47 and maximum FCR state of charge $SoC_t^{FCR,max}$. In these equations $P^{FCR,b}$ is the accepted FCR power bid and Q^B is the BESS energy capacity.

$$SoC_t^{FCR,min} = \frac{P^{FCR,b}(25/60)}{Q^B} \quad \forall t \leq T \tag{5.47}$$

$$SoC_t^{FCR,max} = \frac{Q^B - P^{FCR,b}(25/60)}{Q^B} \quad \forall t \leq T \tag{5.48}$$

To force the minimum and maximum state of charge levels to change dependent on the triggering of alert state equations 5.49 and 5.50 are implemented. This is done through the pre-modelling determination of alert state binary variables v_t^a, v_t^b, w_t^a and w_t^b.

$$\begin{aligned} SoC_t^{min} = SoC_t^{FCR,min} - \frac{P^{FCR,bid}(10/60)v_t^a}{Q^B} - \\ \frac{P^{FCR,bid}(15/60)w_t^a}{Q^B} \quad \forall t \leq T \end{aligned} \tag{5.49}$$

$$\begin{aligned} SoC_t^{max} = SoC_t^{FCR,max} + \frac{P^{FCR,bid}(10/60)v_t^b}{Q^B} + \\ \frac{P^{FCR,bid}(15/60)w_t^b}{Q^B} \quad \forall t \leq T \end{aligned} \tag{5.50}$$

Model B

In model D the state of charge maximum and minimum values are not set through FCR regulation. Therefore in the model the SoC_t^{min} and SoC_t^{max} are set (equations 5.51 and 5.52) at values assumed representative for li-ion batteries, 0.1 and 0.9 respectively.

$$SoC_t^{min} = 0.1 \quad \forall t \leq T \tag{5.51}$$

$$SoC_t^{max} = 0.9 \quad \forall t \leq T \tag{5.52}$$

5.8.3 Discharging and charging power constraints

The discharging $P_t^{B,di}$ and charging $P_t^{B,ch}$ powers of the BESS per time step are set for each model option in equations 5.53-5.58. In these equations FCR feed and take power are $P_t^{FCR,f}$ and $P_t^{FCR,t}$. DA discharging and charging powers are $P_t^{DA,di}$

and $P_t^{DA,ch}$. The IM powers are increase of discharging $P_t^{IM,di,i}$ and decrease of discharging $P_t^{IM,di,d}$, increase of charging $P_t^{IM,ch,i}$ and decrease of charging $P_t^{IM,ch,d}$.

Model A

$$P_t^{B,di} = P_t^{FCR,f} + P_t^{DA,di} \quad \forall t \leq T \tag{5.53}$$

$$P_t^{B,ch} = P_t^{FCR,t} + P_t^{DA,ch} \quad \forall t \leq T \tag{5.54}$$

Model B

$$P_t^{B,di} = P_t^{IM,di,i} - P_t^{IM,di,d} \quad \forall t \leq T \tag{5.55}$$

$$P_t^{B,ch} = P_t^{IM,ch,i} - P_t^{IM,ch,d} \quad \forall t \leq T \tag{5.56}$$

Model C

$$P_t^{B,di} = P_t^{FCR,f} + P_t^{IM,di,i} - P_t^{IM,di,d} \quad \forall t \leq T \tag{5.57}$$

$$P_t^{B,ch} = P_t^{FCR,t} + P_t^{IM,ch,i} - P_t^{IM,ch,d} \quad \forall t \leq T \tag{5.58}$$

5.8.4 Power limit constraints

Model A

For the models where the DA market is included the DA power variables for time step t should be limited by zero and their maximum assigned power. This is implemented through constraints 5.59-5.63. Here DA powers are discharging power $P_t^{DA,di}$ and charging power $P_t^{DA,ch}$. The maximum DA power is $P^{DA,max}$. The binary variable u_t is used to not have discharging and charging in the same time step.

$$0 \leq P_t^{DA,di} \quad \forall t \leq T \tag{5.59}$$

$$0 \leq P_t^{DA,ch} \quad \forall t \leq T \tag{5.60}$$

$$P_t^{DA,di} \leq P^{DA,max} u_t \quad \forall t \leq T \tag{5.61}$$

$$P_t^{DA,ch} \leq P^{DA,max}(1 - u_t) \quad \forall t \leq T \tag{5.62}$$

$$u_t \in \{0,1\} \quad \forall t \leq T \tag{5.63}$$

Model B,C

For the models where the imbalance market is considered all IM powers for time step t should not be less than or equal to zero. This is implemented in constraints 5.64-5.67. The IM power variables are increase of discharging $P_t^{IM,di,i}$ and decrease of discharging $P_t^{IM,di,d}$, increase of charging $P_t^{IM,ch,i}$ and decrease of charging $P_t^{IM,ch,d}$.

$$0 \leq P_t^{IM,ch,i} \quad \forall t \leq T \tag{5.64}$$

$$0 \leq P_t^{IM,ch,d} \quad \forall t \leq T \tag{5.65}$$

$$0 \leq P_t^{IM,di,i} \quad \forall t \leq T \tag{5.66}$$

$$0 \leq P_t^{IM,di,d} \quad \forall t \leq T \tag{5.67}$$

For models where the IM is considered the IM powers should be limited by the maximum IM power times binary variables that implement the IM strategy. This is done with equations 5.68-5.71. Here the IM powers are as stated above. The maximum IM power is $P^{IM,max}$. The binary variables that implement the strategy as explained in section 5.6.2 are z_t^{down} and z_t^{up}.

$$P_t^{IM,ch,i} \leq P^{IM,max} z_t^{down} \quad \forall t \leq T \tag{5.68}$$

$$P_t^{IM,di,d} \leq P^{IM,max} z_t^{down} \quad \forall t \leq T \tag{5.69}$$

$$P_t^{IM,ch,d} \leq P^{IM,max} z_t^{up} \quad \forall t \leq T \tag{5.70}$$

$$P_t^{IM,di,i} \leq P^{IM,max} z_t^{up} \quad \forall t \leq T \tag{5.71}$$

5.8.5 Degradation constraints

Model A,B,C

For all models the degradation constraints that are modelled to analyse BESS operation degradation effects are implemented with constraints 5.72-5.74. In these constraints $Q_t^{B,rem}$ is remaining BESS battery energy capacity, Q^B is battery energy capacity, D is the battery degradation fade factor, TE_t is the total energy processed at each time step, TE_{t-1} is total energy processed at the previous time step and $P_t^{B,di}$ is the BESS discharging power for time step t.

$$Q_t^{B,rem} = 1 - \frac{D * TE_t}{Q^B} \quad \forall t \leq T \tag{5.72}$$

$$TE_t = P_t^{B,di} \Delta t \quad \forall t = 1 \tag{5.73}$$

$$TE_t = TE_{t-1} + P_t^{B,di} \Delta t \quad \forall t > 1 \tag{5.74}$$

5.8.6 Market specific constraints

Model A,C

In order to make the FCR power feed and take powers for time step t $P_t^{FCR,f}$ and $P_t^{FCR,t}$ correctly related to the grid frequency constraints 5.75 and 5.76 are implemented. In these equations $f_t - f_n$ is the frequency deviation, ϕ^{FCR} is the required maximum frequency deviation droop level control value and $P^{FCR,b}$ is the accepted power bid of the FCR auction.

$$P_t^{FCR,f} = -((f_t - f_n)/\phi^{FCR} P^{FCR,b}) \quad \forall t \leq T \quad \forall f_t \leq 49.99 \tag{5.75}$$

$$P_t^{FCR,t} = ((f_t - f_n)/\phi^{FCR} P^{FCR,b}) \quad \forall t \leq T \quad \forall 50.01 \leq f_t \tag{5.76}$$

5.8.7 Objective functions

Equations 5.77, 5.78 and 5.79 are the objective functions of the different model options stated in table 5.2. These equations define BESS revenue Γ^{BESS}. Here Γ^{FCR} is FCR revenue, Γ^{DA} is DA revenue, Γ^{IM} is imbalance market revenue, Γ^{IC} is investment cost, Γ^{OC} is operational cost and Γ^{deg} is degradation cost. It is also stated to which constraints described above the models are subjected.

Model A

$$Maximize \quad \Gamma^{BESS} = \Gamma^{FCR} + \Gamma^{DA} - \Gamma IC - \Gamma^{OC} - \Gamma^{deg} \tag{5.77}$$

Subject to constraints 5.36-5.40, 5.43-5.50, 5.53-5.54, 5.59-5.63 and 5.72-5.76.

Model B

$$Maximize \quad \Gamma^{BESS} = \Gamma^{IM} - \Gamma IC - \Gamma^{OC} - \Gamma^{deg} \tag{5.78}$$

Subject to constraints 5.36-5.38, 5.42-5.46, 5.51-5.52, 5.55-5.56 and 5.64-5.74.

Model C

$$Maximize \quad \Gamma^{BESS} = \Gamma^{FCR} + \Gamma^{IM} - \Gamma IC - \Gamma^{OC} - \Gamma^{deg} \tag{5.79}$$

Subject to constraints 5.36-5.39, 5.41, 5.43-5.50, 5.57-5.58 and 5.64-5.76.

5.8.8 Business case result

In order to get from the MILP optimisation result to business case result the methodology as explained in 2.4 is applied. To do so a cash-flow statement is set up which includes the yearly cash in- and outflows. Also, FCR market price projected development is taken into account. In the end this leads to the determination of NPV and IRR.

Chapter 6

Model Analysis

For the different model options analysis are made based on a test case that is introduced first. It is analysed how each of the model options represent BESS behaviour and what dynamics are present for the different markets. After the test case analysis the effect of input parameters on the business case result is analysed through a sensitivity analyses.

6.1 Test case

The test case represents a grid-scale BESS of 10 MWh capacity and with a power rating of 10 MW applied in the Netherlands and Belgium. The duration of the business case L is assumed to be 15 years. The discount rate r is assumed to be 5% for determining NPV. It's charging and discharging efficiencies are set at 92% (root of 85%) as the overall round-trip system efficiency is 85%. The power bid on the FCR market is 8 MW, resulting from the TSO's 1:1.25 requirement of FCR power over total BESS power. It is assumed that this power bid is always accepted. The power reserved for other markets (DA and IM) is 2 MW (10 - 8). Test case assumptions are presented in table 6.1.

Parameter	Unit	Value
Q^B	kW	10,000
P^B	kWh	10,000
n^{ch}	%	0.92%
n^{di}	%	0.92%
L	years	15

Table 6.1: test case technical parameters

The investment cost of the BESS are assumed to be 500 €/kWh (based on section 3.5.1) and therefore 5 M€ (500 €/kWh * 10,000 kWh). The initial cost for the grid connection are assumed to be 200 k€ (5% of BESS CAPEX). The operational cost of the BESS are assumed to be 100 k€ (2% of BESS CAPEX). The operational cost of the grid connection are assumed to be 25 k€ (0.5% of BESS CAPEX). The grid connection and network costs are taken into account as described in 3.5.3. Cost factors are stated in table 6.2.

Parameter	Unit	Value
C^{BC}	M€	5
C^{BO}	k€/year	100
C^{GC}	k€/	250
C^{GO}	k€/year	25

Table 6.2: Test case financial parameters

6.2 Model option A

This model represents the test case BESS providing FCR. Resulting energy that should be bought is procured against an average DA market price. An FCR price of 13.78 €/MW/h (mean price over 2018) is assumed for the duration of the lifetime, based on figure 4.5.

The model is ran with an average day of frequency deviation to make sure there are no unrepresentative BESS reaction (same day for both countries as grid deviation profiles can be expected equal). In figure 6.1 the state of charge profile is depicted for a day. Clearly the BESS energy content reserved for FCR alert states is visible here.

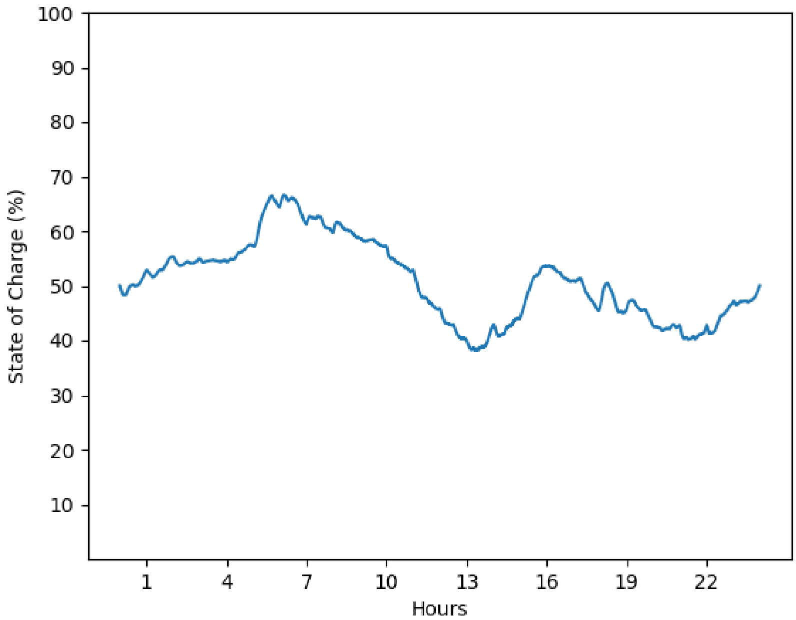

Figure 6.1: State of charge profile example for model option A

The results of the optimisation show that the business case results for Belgium and Netherlands are similar, except for the grid tariffs (table 6.3). Therefore the IRR and NPV for both countries differ, with the BE case giving higher results. As can be seen from the table degradation is about 13.5% over the BESS lifetime and cost for upgrading/over-sizing is 673.1 k€.

Result	Unit	Value BE	Value NL
Fixed grid fees	k€/year	75.1	196
Variable grid fees	k€/year	12.7	0
Cycling	Cycles per year	389.62	389.62
Remaining BESS capacity	%	86.54%	86.54%
BESS capacity upgrade cost	k€	673.1	673.1
FCR revenue	k€/year	965.7	965.7
DA revenue	k€/year	-85.8	-85.8
IRR	%	8.97%	6%
NPV	M€	1.478	0.355

Table 6.3: model option A test case results

6.3 Model option B

The BESS test case is used only for IM reaction in this case. This means 10 MW is used for IM reaction. First optimal model degradation penalty cost c_B is determined. This is done by varying the parameter in a range of 0-700 with increments of 50. This analysis was made for 10 random days in 2018 and results show that the optimal value for this model configuration are obtained when this parameter is set to 100 €/kWh.

As Imbalance Market revenue depends on highly variable prices, analysis is needed to be able to draw conclusions of revenues that could be obtained over historical data. An analysis is made over 60 random days of 2018 to determine a representative day and display the distribution of IM revenue. Figure 6.2 shows the distribution of IM revenue for these 180 days for both countries. For Belgium the average IM revenue per MW per day is €183.11 and the standard deviation is €108.81 For the Netherlands the average IM revenue per MW per day is €159.96 and the standard deviation is €121.81.

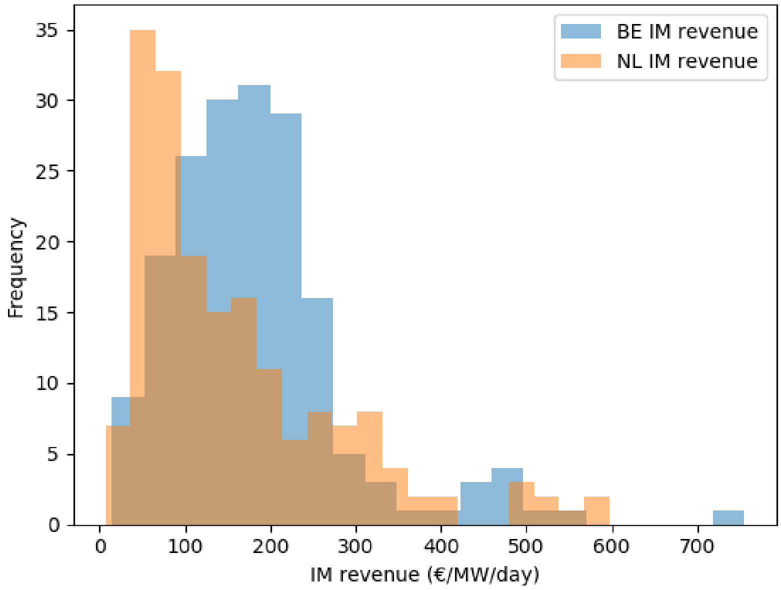

Figure 6.2: Option B IM revenue distribution for 2018 analysis

Through this analyses representative days are found for both countries. These days are the days that show the most average behaviour. With these representative days model option B is analysed for the test case and the scenario analyses of chapter 7 are made. An example of a state of charge profile is depicted in figure 6.3. Note the 10% and 90% borders to *SoC* that clearly bound the BESS behaviour.

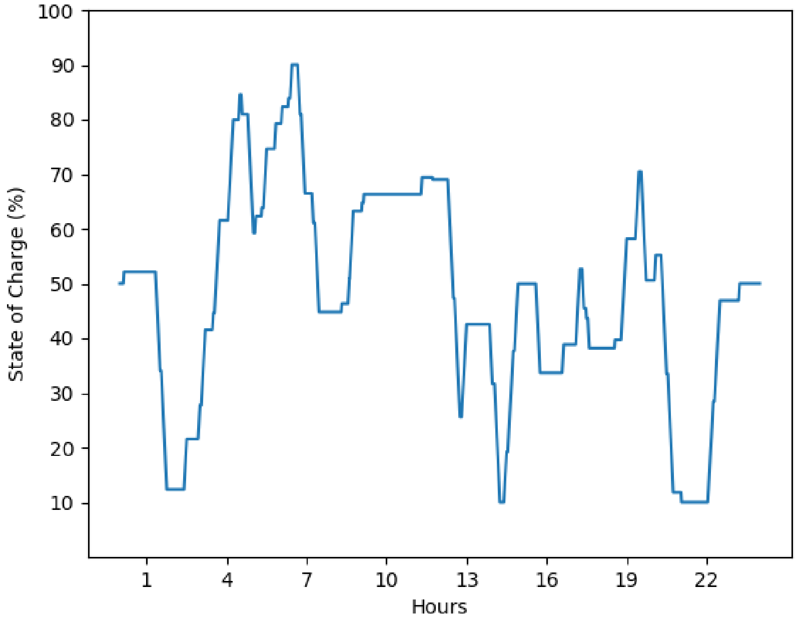

Figure 6.3: State of charge profile example for model option B

Results for the representative days that are used for scenario analysis in chapter 7 are shown in table 6.4 for both countries. From the table results show that the IM revenue in the Dutch case is about 200 k€ per year less than for the Belgian case. Degradation and therefore degradation cost for the BE case is higher, while for the NL case the grid fees are higher. The remaining BESS capacity is lower than 80% and therefore model option B results for both countries are regarded as invalid.

Result	Unit	Value BE	Value NL
Fixed grid fees	k€/year	75.1	196
Variable grid fees	k€/year	29.75	0
Cycling	Cycles per year	910.74	653.09
Remaining BESS capacity	%	68.53%	77.43%
BESS capacity upgrade cost	k€	1,573	1,128
IM revenue	k€/year	658	462
IRR	%	-0.04%	-12.5%
NPV	M€	-1.606	-4.286

Table 6.4: Model option B test case result

6.4 Model option C

This model option represents the test case BESS that provides FCR while managing state of charge on the IM. Initially 8 MW of power is used on the FCR market and the remaining 2 MW are used for IM reaction, as in model option A. In similar fashion to model option B degradation penalty cost c_B was determined by varying the parameter in the range 0-700 with increments of 50 over random days in 2018. The parameter was again determined to be to be 100 €/kWh for optimal results

Since this model contains IM reaction, analysis was made over 180 days of 2018 to find the distribution of IM revenue. Also, this data is used to find representative days used in the test case and later in the scenario analysis for model option C. The distribution of revenue can be found in figure 6.4. The average revenue for Belgium is €223.79 per MW per day and the standard deviation is €146.51 per MW per day. For the Netherlands the average revenue per MW per day is €292.22 and the standard deviation is €212.85 per MW per day. The distribution for both countries is depicted in figure 6.4. Note that there are a few days for both countries where FCR action combined with State of Charge management results in negative IM revenues.

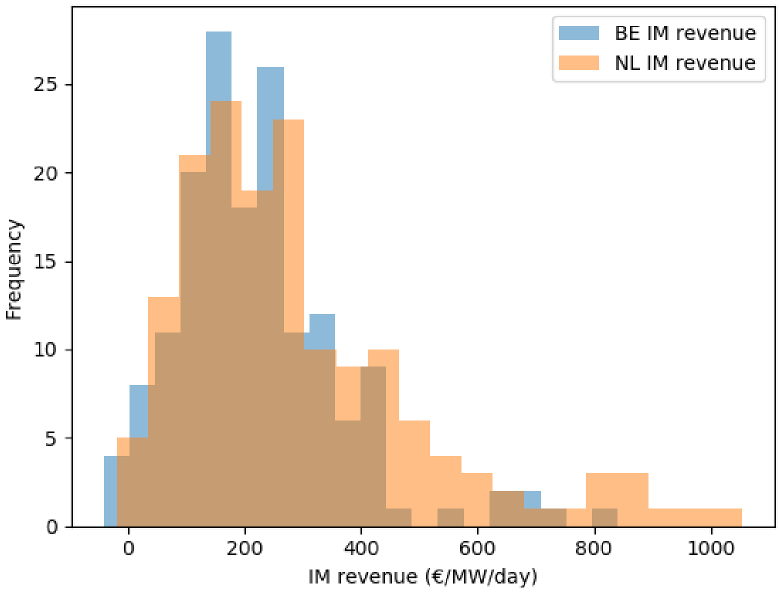

Figure 6.4: Option C IM revenue distribution for 2018 analysis

From this analysis representative days are determined that show behaviour most close to the average values. These days are used for the test case and scenario analysis. An example of a state of charge profile, resulting from analysis is given in figure 6.5. It is clear that behaviour differs from model options A and B as the program finds the best reaction to IM price incentives while still fulfilling FCR requirement.

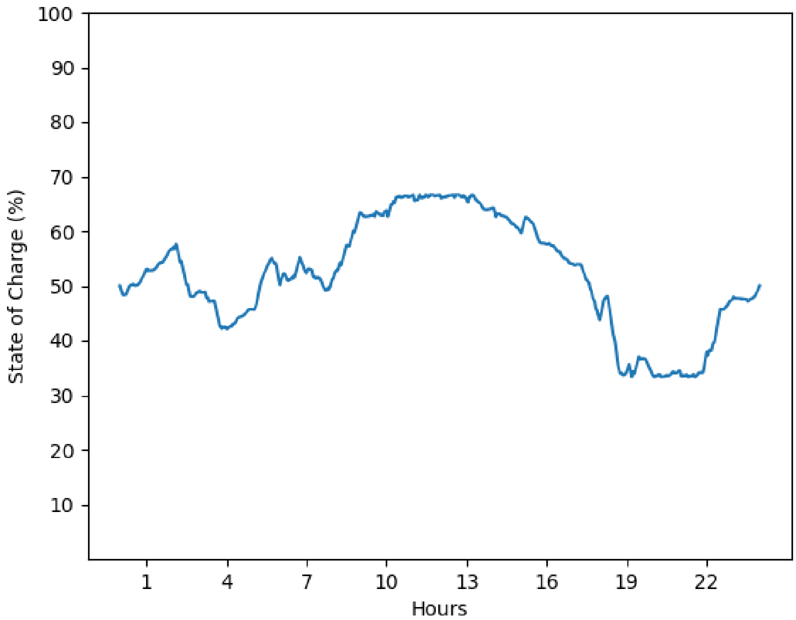

Figure 6.5: State of charge profile example for model option C

Results for the test case for the representative day that is used in the scenario analysis of chapter 7 are presented in table 6.5. For NL the results show less degradation than for BE and therefore less upgrade cost. The imbalance market revenues for the Belgian case are lower than for the Dutch case by about 40 k€ per year.

Result	Unit	Value BE	Value NL
Fixed grid fees	k€/year	75.1	196
Variable grid fees	k€/year	13.47	0
Cycling	Cycles per year	412.44	351.23
Remaining BESS capacity	%	85.75%	87.86%
BESS capacity upgrade cost	k€	713	607
FCR revenue	k€/year	966	966
IM revenue	k€/year	152	195
IRR	%	14.8%	13.4%
NPV	M€	3.914	3.310

Table 6.5: model option C results

6.5 Parameter analysis

For each of the models it is analysed how change in input parameters affects test case result. This is measured in IRR change. This is done for only the BE test case, as parameter influence might differ only in absolute size but not in direction of change between the countries.

6.5.1 Size and duration

To analyse the effect of the size of the storage system the BESS size is varied. In this analysis BESS capacity, power rating and division of market powers are increased proportionally. Figure 6.6 gives the result of this analysis. Project IRR does not change. This is the case for all model options and for both countries.

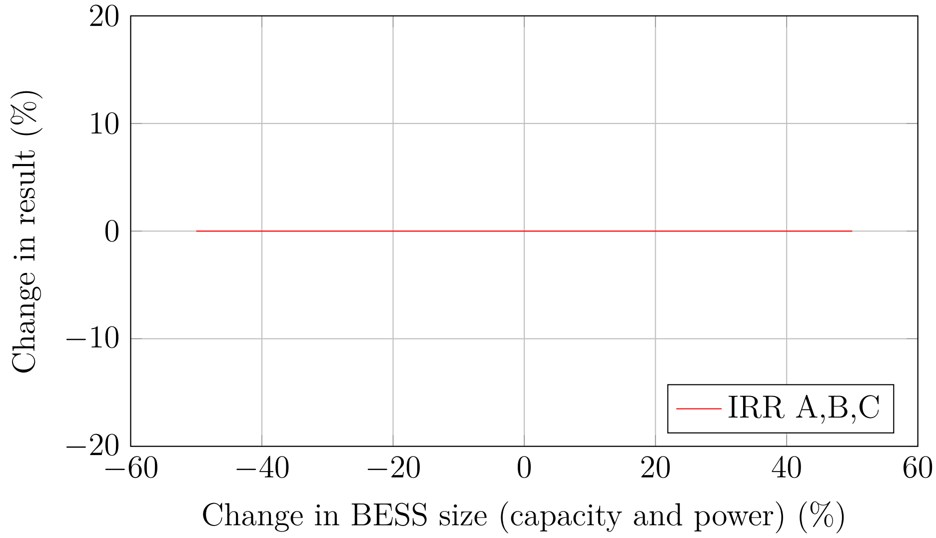

Figure 6.6: Change in result with varied BESS size (equal BESS capacity and power change)

Instead of keeping BESS capacity and power rating equal these parameters can be varied independently (varying duration). To do so BESS capacity is varied while power rating is kept equal. The duration (energy content divided by power) will be kept above one hour as it was assumed that at least 50 minutes (25x2) of full reaction is a safe assumption for FCR delivery. Therefore only the effect of increasing duration is analysed. Figure 6.7 depicts this analysis. For all models an increase in duration leads to lower IRR. Note that there could also be positive IRR change as revenue might increase. In this analysis however BESS capacity increase raises BESS CAPEX more than extra revenues that are gained with a larger system. In the scenario analysis it will be stated if increasing duration is beneficial to the business case.

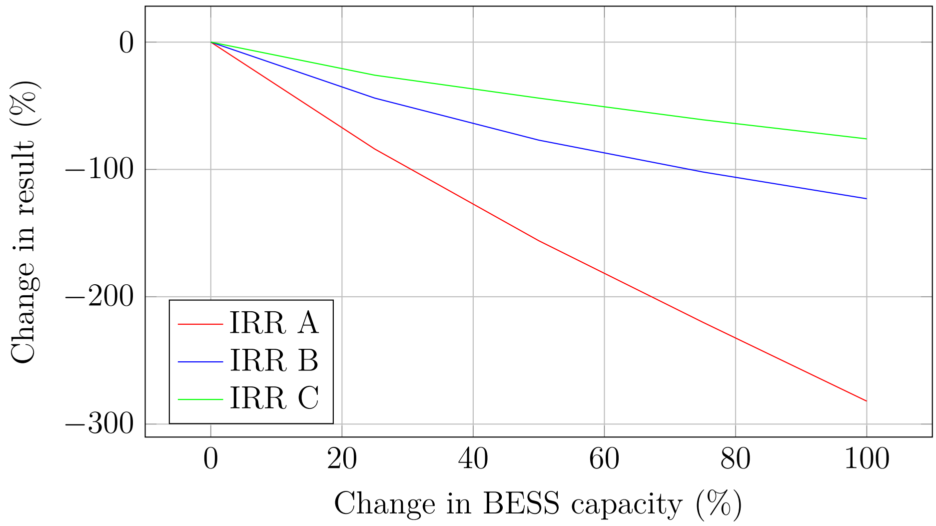

Figure 6.7: Change in result with varied BESS capacity (constant BESS power)

Not depicted in the figure, remaining BESS capacity is higher when duration is longer. For example in model option C when the BESS capacity is 17.5 MWh and power is 10 MW the remaining BESS capacity is 91.62%, compared to 86.85% when capacity is 10 MWh (test case).

6.5.2 Efficiency

The BESS efficiency is varied to see its impact on the business case for the different models. Figure 6.8 displays results. Note that efficiency change (x-axis) is not as large as with other parameters as BESS efficiency is varied from 75% to 95% in this analysis and taking an even broader range would be unrealistic. A more efficient BESS leads to higher IRR, as expected. For model option C this effect is less prominent than for model options A and B.

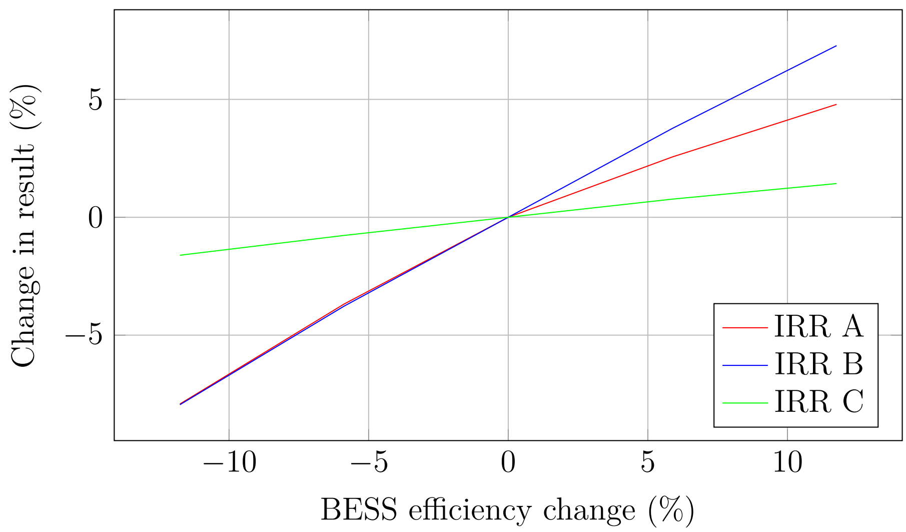

Figure 6.8: Change in result with varied BESS efficiency

6.5.3 Cost

For the cost parameter analysis again the Belgian test case is used. Even though results might differ a bit between countries due to grid fee structure, the goal here is to analyse the magnitude of IRR change IRR change is displayed in figures 6.9. Decreasing BESS cost lead to increasing IRR. This result is strongest for model option B and least strong for model option C.

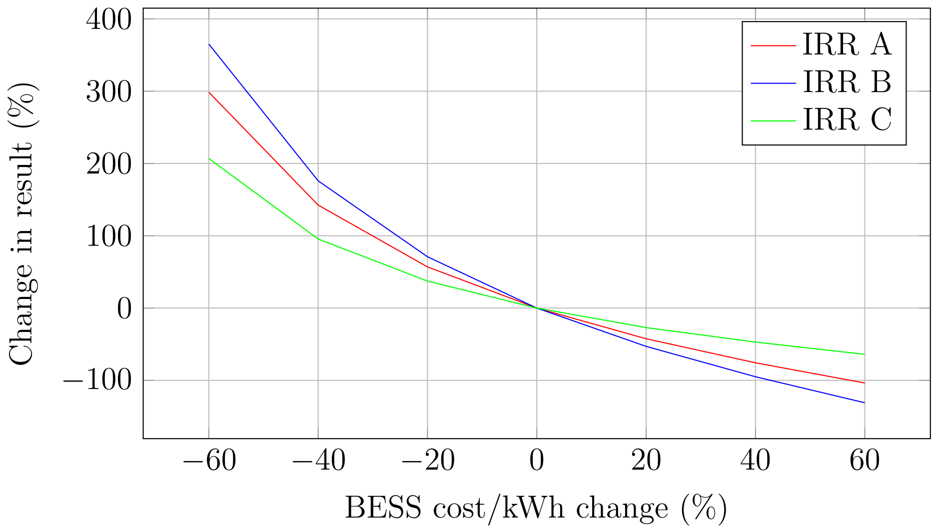

Figure 6.9: Change in result with varied BESS cost (BE)

6.6 Prices and strategy

6.6.1 FCR price

An analysis is made of the FCR price change effect for models A and C. Figure 6.10 depicts the result. Note that in this analysis the FCR power was 8 MW and the power for IM and DA was 2 MW. This ratio can be varied if prices are such that this is more profitable to the business case (see 6.6.2).

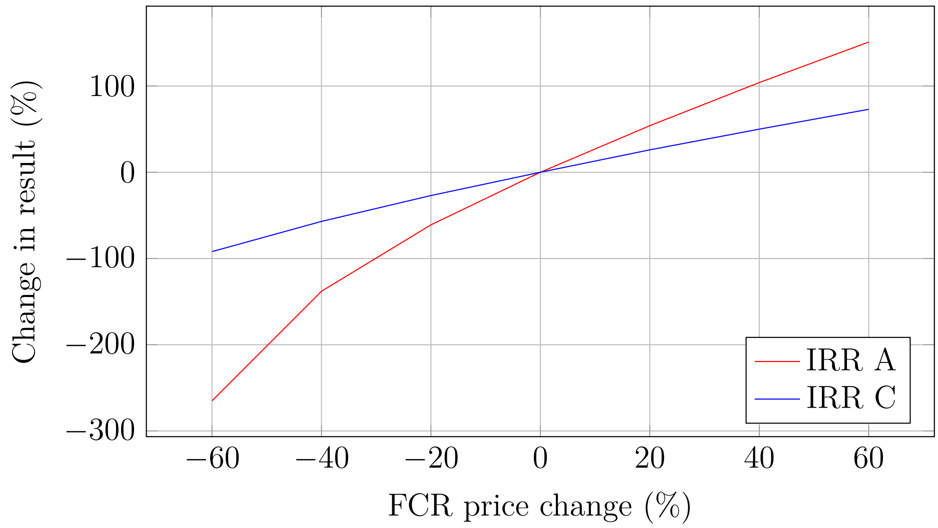

Figure 6.10: Change in result with varied FCR price

6.6.2 Power strategy model option C

Depending on the level of FCR pricing the BESS operator could choose to react on the IM with more power than the minimum 2 MW reserved for *SoC* management in model option C. In the test case prices of FCR (constant 13.78) are sufficiently high so that this is never beneficial. Still such analysis is helpful in analysing strategy decisions for BESS operators and revenue generation options. Therefore FCR price is set to an arbitrary level of 8 €/MW/h so that effects of such power shift can be analysed.

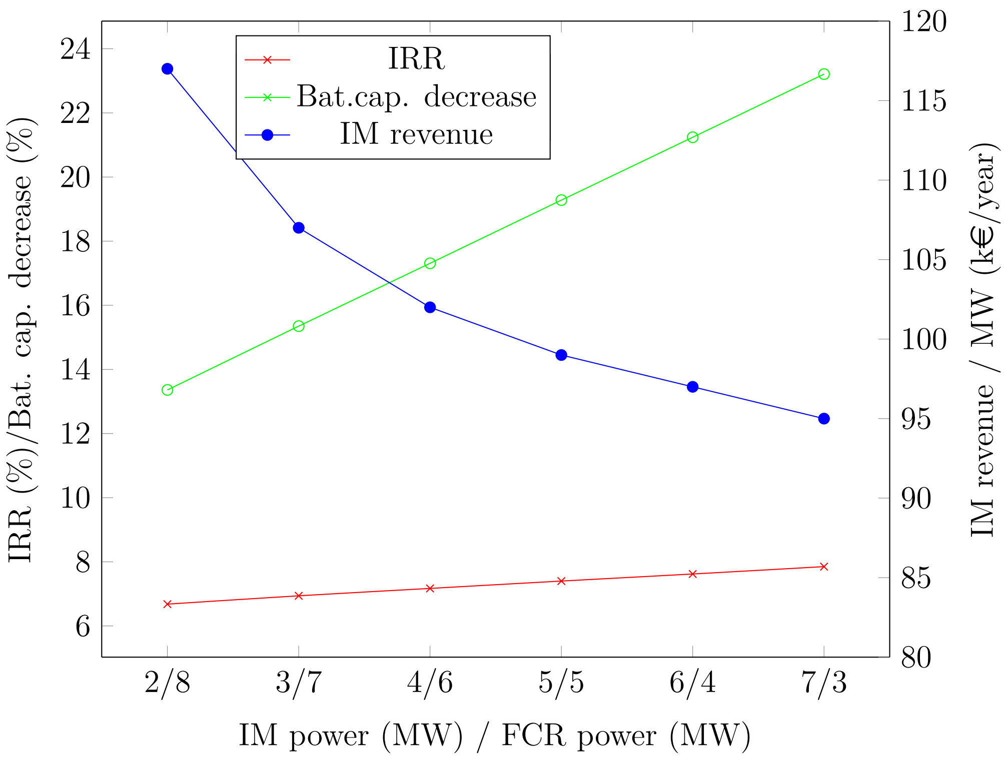

Figure 6.11: Power shift analysis

Figure 6.11 gives the results for this analysis (FCR price of 8 €/MW/hr for business case lifetime). When less power is used for FCR provision and more for IM reaction the IRR of the project increases. At the same time the decrease of battery capacity increases (more degradation) as the battery is used more for IM reaction. In this case the optimal power shift would be at 5 MW power on both markets, as more power shift to IM would lead to invalid degradation (section 3.3) of more than 20%. The IM revenue per MW levels decrease, more so when FCR is still a major part of revenue generation. When IM reaction becomes more dominant IM revenue decreases only little per MW.

In the scenario analysis for model option C it is analysed if such a shift can improve the respective scenario. If this is the case the optimal value is where remaining battery capacity is at least 80%.

6.7 Parameter analysis results

The results of the parameter analysis above are summarised here before the scenario analysis is conducted in the next chapter. For each of the parameters analysed it is stated what its effect are and how this parameter is taken into account in the scenario analysis. In this summary and together with the test case analysis the fourth research sub-question is answered.

6.7.1 Size and duration

Varying BESS capacity and power equally while keeping the FCR and IM powers at the same ratio does not affect the business case IRR. Increasing the duration (more energy over power) has an effect on business case result which depends on the per kWh price of BESS. The duration can be increased for each scenario as results might differ depending on specific BESS price. For each of the scenarios it is therefore analysed if increasing duration improves the business case.

6.7.2 Efficiency

The effect of efficiency change is not in the same order of magnitude as size, cost and price parameters. Efficiency can be varied nonetheless. Efficiency effects are largest in model option B, followed by model option C and model option A.

6.7.3 Cost

For both BE and NL decreasing BESS cost lead to a raise in the increase of IRR, with a slight difference between the model options. For the Netherlands this effect is larger. In the scenario analysis BESS costs are an influential determinant of business case result.

6.7.4 FCR price

For model options A and C FCR price is a significant parameter. For model A the FCR price is more influential than for model option C. In the scenario analyses the FCR price should be varied for both model options.

6.7.5 Power strategy

From the results of the power analysis in 6.6.2 it can be concluded that the effect of power shift from FCR provision to IM reaction should be analysed for model C. Dependent on IM revenues and expected FCR price a change in power strategy might benefit the business case. However, such a power shift is limited by increasing degradation resulting from more IM reaction.

Chapter 7

Scenario analysis

With the model and the analysed effects of model parameters scenario analysis can be made. For each scenario the BESS business case outcome is determined. In the first section the scenarios are defined, thereafter these scenarios are analysed. The change drivers used in the scenario analysis are BESS cost, BESS efficiency and FCR prices.

7.1 Scenarios

A BESS of initially 10 MW/10 MWh is analysed as in the test case. The project lifetime is again 15 years. Cost factors other than BESS cost are chosen as in table 3.2. The power of IM/DA is again 2 MW and the power for FCR is 8 MW. For all scenarios the discount rate is assumed to be 5%. The parameters that are changed in these scenarios are always stated. For parameters and assumption that are not mentioned in these section the test case in section 6.1 are considered.

For the future development of BESS cost and FCR prices the sources stated in sections 3.5.1 and 4.5.2 are the basis for the assumptions for each scenario explained below. The different scenario's are summarised in table 7.1 and figure 7.1.

Parameter	BAU	High RES	Battery revolution
BESS round-trip efficiency	85%	88%	90%
BESS cost	500 €/kWh	400 €/kWh	200 €/kWh

Table 7.1: Assumptions for each of the scenarios

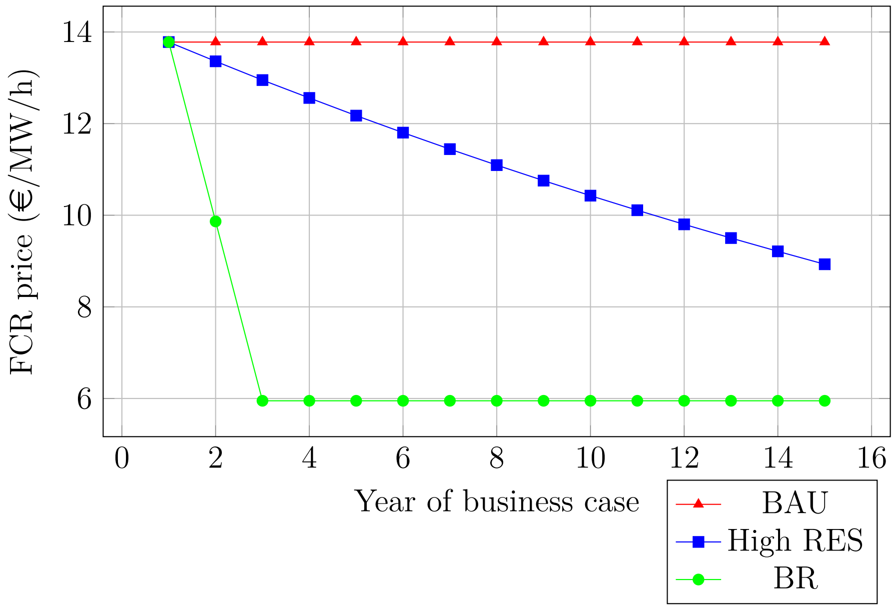

Figure 7.1: FCR price development in the scenarios

7.1.1 Business as usual (test case)

In the Business as Usual (BAU) scenario a BESS business case is analysed with input parameters at current levels (2019). This case is therefore similar to the test case as presented in chapter 6. BESS efficiency is 85%. The BESS cost remain around 500 €/kWh, while FCR prices are assumed to remain at 2018 levels of 13.78 €/MW/h for the duration of the BESS lifetime.

7.1.2 High RES

In this scenario it is assumed that renewable energy sources (RES) are adopted quickly. The prices in the FCR market are therefore no longer dependent on fossil providers, rather battery and other storage technologies determine prices. Since the marginal cost of these sources are expected to be lower than fossil marginal prices (due to for example start up cost) a price decline of FCR prices is expected. This price decline is path four in section 4.5.2. This path projects an exponential decrease from 13.78 €/MW/hr in year 1 to 8.93 €/MW/hr in year 15. FCR prices are depicted in figure 7.1. The BESS cost drop, but not as strong as expected by IRENA (section 3.5.1) as demand for BESS is high. Therefore, BESS cost are assumed to be around 400 €/kWh. This is a conservative assumption for the period when regarding price developments stated in 3.5.1. The efficiency of BESS increases as BESS technology follows expected development. The overall system efficiency increases to 88%, which is a reasonable estimate as per section 3.5.2.

7.1.3 Battery Revolution

In the Battery Revolution (BR) scenario there is large BESS development and adoption. The BESS cost drop to 200 €/kWh, the IRENA expected value for 2030 (section 3.5.1, avg. of 80-340 USD/kWh). BESS efficiency increases to 90%, as BESS technology is expected to develop stronger than predicted. This is 3% more than the IRENA estimated values in section 3.5.2. The FCR price declines linearly in the first three years to 5.95 €/MW/hr (section 4.5.2) and remains at this level for the duration of the business case as battery technologies make up the majority of FCR bidding's.

7.2 Scenario analyses results

7.2.1 Business as usual

Even though this scenario was analysed in chapter 6's test case it is summarised here for comparison purposes. In this scenario, because of a sufficiently high FCR price it is never beneficial to shift power from FCR provision to IM reaction. Increasing the duration is also never beneficial to the business case. The results are presented in table 7.2. For both countries model option C has the highest business case result. The results for model option B can be considered invalid as end of lifetime degradation is lower than 80% of initial capacity.

Country	Model	NPV (M€)	IRR	$Q^{b,rem}$
BE	A	1.478	8.97%	86.54%
BE	B	-1.606	-0.04%	65.22%
BE	C	3.914	14.8%	85.75%
NL	A	0.355	6%	86.54%
NL	B	-4.286	-12.5%	77.45%
NL	C	3.410	13.4%	87.86%

Table 7.2: BAU scenario results in Net Present Value (NPV), Internal Rate of Return (IRR) and remaining battery capacity $Q^{b,rem}$

7.2.2 High-RES

The results of the scenario can be found in table 7.3. In the high-RES scenario it is never beneficial to shift more power than required to IM reaction for model option C. Also, installing more BESS capacity (increasing duration) is never beneficial to the business case. Model C always gives highest business case result and only model B gives negative business case result for both countries. The degradation for model option B exceeds 20% for both countries and this model option can therefore be considered invalid.

Country	Model	NPV (M€)	IRR	$Q^{b,rem}$
BE	A	1.283	9.94%	86.54%
BE	B	-0.034	4.88%	68.34%
BE	C	3.718	17.78%	85.51%
NL	A	0.157	5.65%	86.45%
NL	B	-2.704	-7.22%	76.25%
NL	C	3.109	15.92%	87.16%

Table 7.3: High RES scenario results in Net Present Value (NPV), Internal Rate of Return (IRR) and remaining battery capacity $Q^{b,rem}$

7.2.3 Battery revolution

For this scenario it was beneficial to the business case of model option C to shift power from FCR provision to IM reaction, as depicted in figure 7.2. For the Belgian case the optimal power shift is when 4 MW is used for IM reaction and 6 MW is used for FCR provision as IRR is highest at 30.11%. The remaining battery capacity at this power division is 80.01% at the end of lifetime. This is just enough as the limit for degradation for a valid strategy is 80%. For the Dutch case the IRR keeps improving when more power is shifted to IM reaction (green line). However, the battery capacity decreases to less than 80% when more than 4 MW is used for IM reaction. Therefore the optimal strategy is 4 MW for IM reaction and 6 MW for FCR provision, the same as in the Belgian case.

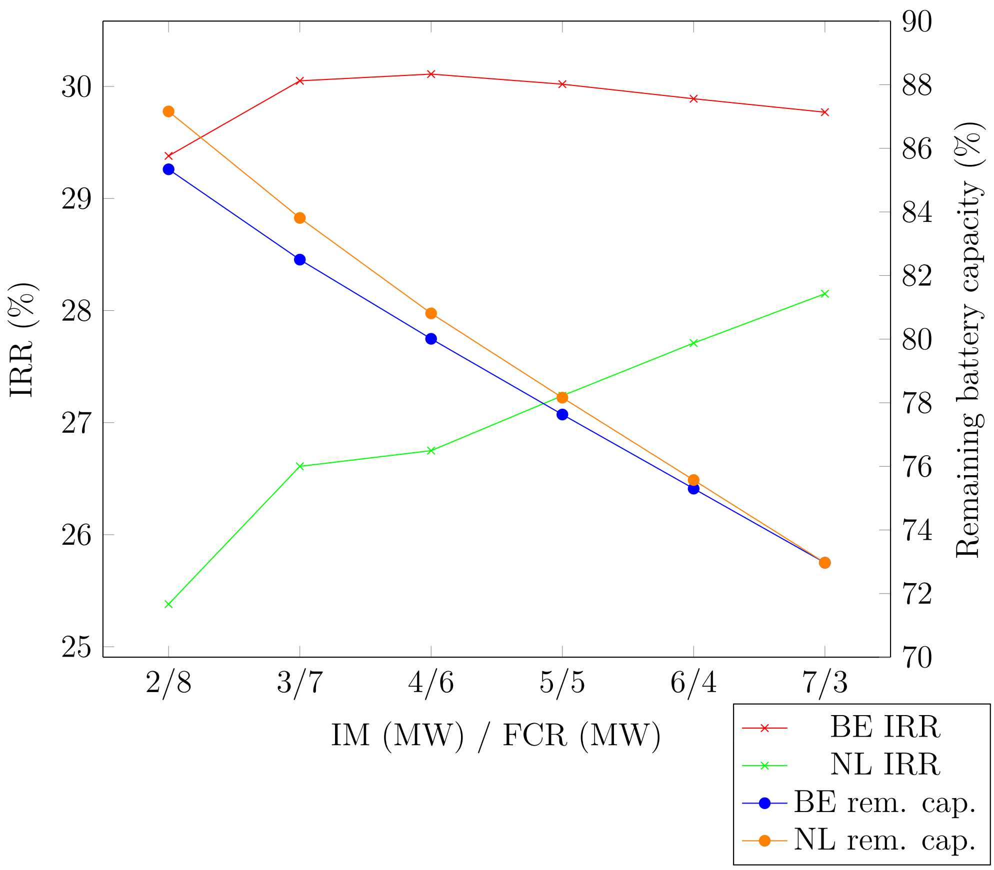

Figure 7.2: Model option C power shift analysis for BR scenario

Scenario BR results are presented in table 7.4. It is never beneficial to increase BESS duration. Results show the scenario results for all models and both countries. Model option C always gives highest business case results, while model B always performs worst. For model option B the degradation exceeds 20% of initial capacity and results for model option B can therefore be considered invalid.

Country	Model	NPV (M€)	IRR	$Q^{b,rem}$
BE	A	0.849	12.6%	86.39%
BE	B	3.050	23.15%	68.21%
BE	C	3.660	30.11%	80.01%
NL	A	-0.278	1.98%	86.39%
NL	B	0.307	7.13%	76.13%
NL	C	3.092	26.75%	80.81%

Table 7.4: Battery Revolution scenario results in Net Present Value (NPV), Internal Rate of Return (IRR) and remaining battery capacity $Q^{b,rem}$

7.2.4 Scenario comparison

The scenarios are compared on IRR basis in figure 7.3. Business case performance for model option A and C in scenario BR is best and in scenario BAU is worst. Model option B always leads to less than 80% remaining battery capacity and results of model option B can therefore be considered invalid. Model option C performs best for each scenario and for both countries. Notable is the difference between the countries for model option A. IRR increases for each scenario for the BE case, but decreases for each scenario for the NL case. The IRR for the Belgian case improves from the BAU to the BR scenario. For the Dutch case the IRR decreases for this model option from the BAU to the BR scenario. The IRR of the models that are valid (A and C) are positive for all scenarios and both countries. Not shown in the figure, the Dutch case for model option A in the BR scenario (IRR=2%) has a negative NPV (at 5% discount rate).

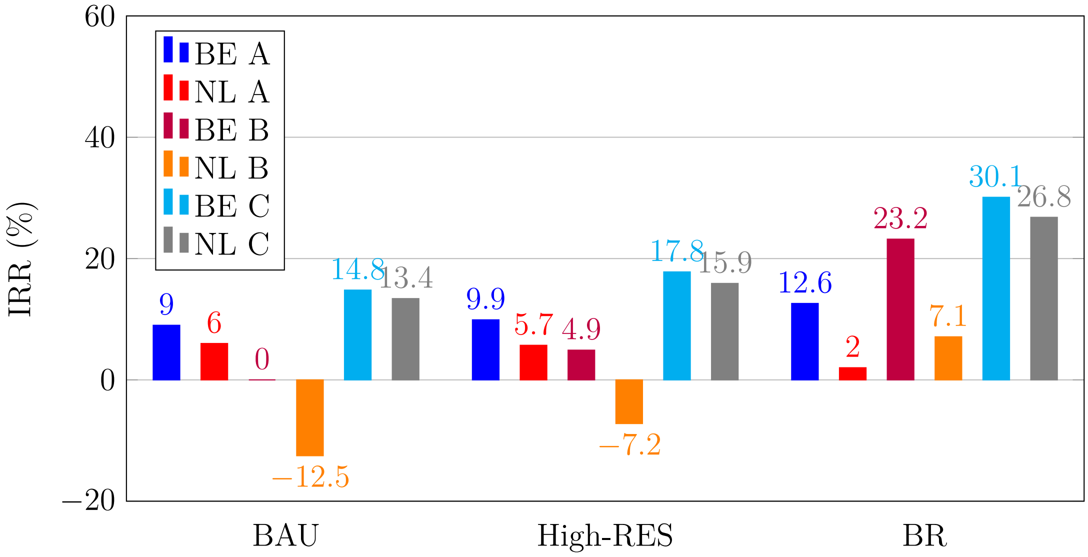

Figure 7.3: Comparison of scenarios

Chapter 8

Discussion and conclusion

8.1 Discussion

8.1.1 Interpretation of results

The results show which parameters are significant for Dutch and Belgian BESS business cases. The analysed business cases provide FCR, react on the IM, or combine these two strategies. The parameters that influence BESS business case result the most are BESS cost, market price and power strategy. Efficiency change is of less influence to the business case result and BESS size has no influence on the business case IRR. Increasing BESS duration is only beneficial if BESS capital cost are sufficiently low, which is never the case in the analyses.

The results also show that only reacting on the IM with a BESS is not a valid operating strategy as BESS remaining capacity would be lower than the end of lifetime value of 80% in all cases. As FCR is a service that is power based and frequency deviations are mostly close to the nominal frequency, energy feed and take for FCR provision is limited. This is a reason for efficiency change having only little influence on BESS that provide FCR. Also, remaining BESS capacity is in the valid range whenever FCR is provided. If FCR prices drop so that IM revenue per MW is higher than FCR revenue per MW, it can be beneficial to shift power from FCR bidding to IM reaction. This shift of power between markets is therefore limited by increasing degradation. In a case where the strategy is only IM reaction, IM revenue per MW is higher in the Belgian case than in the Dutch case. However, in case of IM reaction combined with FCR provision the IM revenue per MW is higher for the Dutch case. This is an unexpected result. A possible explanation for this is a better match of FCR reaction with the occurrence of beneficial IM prices, resulting in higher revenues.

As stated above results show that only reacting on the IM results in less than 80% remaining battery capacity for each scenario. The result of model option B are therefore considered invalid in the scenario analysis. For a BESS always participating in the FCR and managing State of Charge for an average DA energy price (model option A), the current situation (BAU) results in positive business case results for both countries. In a high-RES scenario where FCR prices decline moderately and a conservative BESS cost decrease is assumed, there is a difference in business case effect between Belgium and the Netherlands. The IRR for the Belgian case improves slightly, while the IRR for the Dutch case worsens slightly. This can be attributed to the difference in structure of the grid tarrifs for 150 kV connections between the countries. The higher yearly grid fees make for a lower yearly cashflow and therefore lower IRR in the Dutch case. This result is however not generalisable to all BESS cases as connection levels might differ. For a case where FCR provision is combines with IM reaction (model option C) the IRR improves for the high-RES scenario compared to the BAU scenario. Compared to the high-RES scenario the BR scenario results in higher IRR.

8.1.2 Implications

The results imply that BESS business cases in both the Netherlands and Belgium can be expected to have positive IRR and NPV in the future if prices and technical characteristics develop in expected ranges. Even with decreasing FCR prices in the future due to large-scale BESS adoption, BESS can have positive business case returns if future BESS CAPEX cost reductions are as high as most studies suggest. In certain cases, such as a drop in FCR price, operators would want to shift the power division between the markets. This can be expected to happen as operators would always try to find the most optimal mix of revenue generating activities.

In a broader context this implication indicates that BESS could see increased adoption in the Netherlands and Belgium in the coming years. Their main applications are expected to be in the FCR market, especially since this provision leads to less BESS degradation. This could lead to a drop in FCR prices if traditional generation does not set marginal FCR prices. This would lead to less revenues from this market and operators shifting power to imbalance reaction.

For investment decision it can be stated that the coming years are a crucial time for grid-scale BESS adoption as the NPV and IRR of most BESS applications examined are reaching attractive levels due to BESS technical improvements and CAPEX drop. It is especially important to monitor the developments of expected revenues from the different markets that can be accessed in reaction to adoption of renewable and storage technologies for making investment decisions in grid-scale BESS.

8.1.3 Limitations

Limitations of this research include the following. On a detailed level BESS technology and in particular lithium-ion technology is diverse and complicated cell-level reactions can be modelled. In this thesis however BESS are represented in a simplified manner, as the goal is to techno-economically analyse BESS business case results rather than optimise technical characteristics or describe detail-level processes. Results from such detailed analyses might differ from the results obtained in this work as certain effects are not taken into account. An example of such an effect is the power ramp rate of batteries, that can affect performance.

The MILP optimisation model has a number of limitations. This optimisation is likely to overestimate revenues as the model would choose unrealistic battery operation based on price incentives (perfect foresight). Even though a strategy for the imbalance market reaction is developed to prevent perfect foresight it can be expected that results in reality differ from the results presented. The strategy applied here is likely to underestimate revenues as a simple IM reaction strategy is applied. Here the knowledge and skill of the BESS operator, for example in predicting market prices, also influences business case result. This operator factor is not quantifiable in analysis such as this. Incorporation of such factors would lead to a model that is not usable as a general tool that can examine investment cases. However, this limitation could lead to business case results observed in practice that could differ from the results obtained in this thesis. This is therefore considered the most important limitation to this research.

Another limitation is that BESS operators could use Degrees of Freedom that result from provision requirements that are not modelled in this thesis. Examples of such are utilisation of the frequency signal in the deadband of FCR provision for managing state of charge and using the range of valid operation (FCR droop requirement time) for the FCR provision Thien et al. (2017). These degrees of freedom could bring additional advantages to BESS and improve business case result.

In the model a number of representative days is determined from analysis over 180 random days of 2018. These days are used to make test case and scenario analyses. There could be errors in degradation and revenues of these representative days, as these days might have different characteristics than the average revenue or degradation over the modelled period.

8.1.4 Suggestions for further research

Further research on grid-scale BESS for investment decision could include the following.

- In depth analyses of expected price levels for the different markets and thereby decision making between markets for each market time interval block. This is especially relevant now that FCR will be procured in smaller time blocks (eventually 4-hour blocks) in the coming years. An example of such analysis is on at which expected price levels it is more beneficial to bid on the FCR market versus reacting on the IM. This could lead to better business case performance and more realistic operation analysis
- Analysis of BESS systems that are combined with portfolios of flexible generation/demand response. In the FCR guidelines it is stated that it is allowed to form a group of FCR providing parties for submitting bids. Combining flexible assets with BESS can improve the business case of both.
- Implement Degrees of Freedom that follow from requirements for FCR provision. Different possibilities such as deadband utilisation and FCR operating range could be explored for the different TSO requirements.
- Analysis of the effects of large scale adoption of BESS and other storage tech-

nologies on the different markets and revenues that can be expected from these markets. Also, analysis of system change resulting from renewable energy adoption and the result this would have on BESS feasibility. Analysis of prices resulting from BESS adoption was for example conducted by Fleer, Zurmühlen, Meyer, et al. (2017) and could be expanded with new technology entry and market development.

8.2 Conclusion

Battery Energy Storage Systems (BESS) are suited for trading on the electricity markets, providing reserve services that balance the electricity grid and reacting to the imbalance market mechanism. However, due to business case uncertainty large-scale adoption of BESS has not taken off in Europe. The goal of this research was to facilitate BESS investment decisions through the quantification of factors that influence the aforementioned uncertainty. This research focused on BESS business cases in Belgium and the Netherlands. The research question was:

"What is the influence of significant technical and economic factors on the grid-scale BESS business case in the current Dutch and Belgian context?"

In order to answer this research question BESS characteristics were investigated. Current and expected performance and prices of BESS systems were determined to perform scenario analyses. It was determined what technical and economical characteristics can be used to model BESS. It was concluded that a relative simple representation of BESS could be used for the type of modelling that was conducted in this thesis. Next, the electricity markets were described to find what revenue streams could be accessible to BESS. It was found that the Frequency Containment Reserve (FCR) provision and Imbalance Market (IM) reaction are the most suited revenue streams to BESS.

To make analysis of BESS operating on these different market mechanisms a Mixed Integer Linear Programming (MILP) model was developed. This model uses historical data to determine the performance of BESS. Three options were developed. Model option A provides FCR while managing State of Charge by trading energy against an average day-ahead market price. This model option could be considered the base case for FCR provision. Model option B reacts to the system imbalances and by doing so generates revenue to the IM. A simple strategy was developed for the IM to prevent perfect foresight that would occur if the MILP model would be ran with IM prices that are known. Model option C combines the provision of FCR with the reacting on the IM. The strategy to prevent IM perfect foresight is also incorporated here. Through analysing over 2018 representative days were found for the different models so that BESS reaction resembles reality. The result of the optimisation were used to determine yearly energy cost, electricity cost and revenues. In order to make analysis of the entire business case of BESS the FCR price could also be varied for each year of the business case.

A parameter analysis was conducted to determine the significance of the technical and economical parameters. It was found that a change in BESS size does not influence business case return. Varying the duration influences the business case return dependent on the height of BESS investment cost. BESS investment cost and FCR prices were found to be the most important determinants of business case results. The efficiency was found to have much smaller, but significant, effects on business case outcome than BESS investment cost and FCR prices. If FCR prices were to drop a shift in power from FCR provision to IM reaction could be beneficial. This shift is however limited by increasing battery degradation.

To analyse combinations of parameters and show the effect of expected parameter change on the BESS business case a scenario analysis was conducted. The analyses showed that model option B (only IM reaction) always resulted in remaining battery capacity lower than the end of lifetime value of 80%. Therefore only IM reaction was determined to be an invalid BESS operating strategy. The scenario analysis also showed that in a business as usual scenario that considered 2018 parameter levels model options A and C showed positive IRR for both countries. The latter case performed better in all scenarios and both countries. With a moderate decrease of FCR prices and a moderate decrease in BESS investment costs the business case results became more positive for the combined FCR and IM model option. With strong decrease in FCR prices and strong decrease of BESS cost the business case results became even more positive. In model option C for this scenario the business case could be improved with a shift of power from FCR provision to IM reaction. Such a shift would be limited by BESS degradation. For the only FCR model option the Dutch case showed different results than the Belgian case due to grid fee structure. This result is however connection level specific and therefore not generalisable to all BESS cases.

The results of this research imply that BESS adoption is likely to increase in Belgium and the Netherlands as business cases can be expected to have positive returns. With more battery adoption FCR prices are expected to decrease. Declining BESS cost however make for more positive business cases despite revenue decrease. Combination of FCR and IM is most likely to result in business cases with higher IRR. For investment decisions it can be concluded that monitoring revenue streams, pricing and BESS cost development is essential to making informed decisions on grid-scale BESS. The most important limitation of the research is the MILP optimisation IM overestimation of revenues. Even though a simple strategy was developed exact revenue levels are case specific, therefore business case results observed in practice could differ from the model results. Additional limitations are stated in the discussions limitations section. A number of suggestions are made for further research. Examples are analysis of BESS operator decision making between markets and the impact of adoption of BESS and other storage technologies on expected pricing levels in the different markets.

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