Master's thesis

NTNU
Norwegian University of Science and Technology

Ingvild Eline Olsen

Multimarket Services for Stationary Batteries

Considering Activation of Frequency Containment Normal Operation Reserves

Master's thesis in Energy and Environmental Engineering
Supervisor: Magnus Korpås, Department of Electric Energy
Co-supervisor: Venkatachalam Lakshmanan and Kasper Emil Thorvaldsen, SINTEF Energy Research
June 2023

NTNU
Norwegian University of
Science and Technology

Ingvild Eline Olsen

Multimarket Services for Stationary Batteries

Considering Activation of Frequency Containment Normal Operation Reserves

Master's thesis in Energy and Environmental Engineering
Supervisor: Magnus Korpås, Department of Electric Energy
Co-supervisor: Venkatachalam Lakshmanan and Kasper Emil Thorvaldsen, SINTEF Energy Research
June 2023

Norwegian University of Science and Technology

NTNU
Norwegian University of Science and Technology

ABSTRACT

The power system is changing from a centralised and unidirectional system to a decentralised and bi-directional system [1]. This transformation is driven by the need to mitigate climate change and meet the growing electricity demand, which has increased the integration of renewable energy sources [1]. However, incorporating renewable generation, such as wind and solar power, poses challenges related to their weather-dependent nature and the need for rotational inertia in the system. These challenges necessitate exploring new sources of flexibility to ensure stable grid operation.

The objective of this master's thesis is to explore the viability of utilising stationary storage systems for delivering multiple services. Particular attention is given to markets for frequency reserves. This is done by formulating an optimisation model of a household with a photovoltaic (PV) generation and battery system connected to the grid. The battery is to cover the household demand, performing energy arbitrage and procuring and delivering frequency containment normal operation reserves (FCR-N).

As groundwork for the study, a literature review is conducted, focusing on research that formulates optimisation models for multimarket participation. Most papers indicate increased revenue from multimarket participation. However, few account for the activation of contracted reserves. Consequently, other literature is reviewed, examining papers that model batteries providing frequency containment reserves and considering the state of charge management. Many solutions have been proposed for controlling the state of charge during the activation of reserves. However, many solutions are not applicable in Norway. This includes solutions such as dead-band utilisation and over-fulfilment. However, set-point adjustments at different markets, such as the intraday and balancing markets, are identified as feasible options.

A case study is created for a household in Hvaler, Norway, equipped with a battery and PV system participating in markets for FCR-N reserves. The model is formulated as a deterministic mixed-integer linear optimisation problem (MILP). It was formulated as a two-stage model using model predictive control with a rolling time horizon to ensure a close approximation to real-world conditions without including stochastic elements. The model's functionalities are analysed, revealing its ability to adapt to prediction changes and activate procured reserves in response to frequency deviations. However, due to the limited energy capacity of the battery, the maximum and minimum state of charge (SOC) is reached in some hours, resulting in the battery failing to deliver the obligated reserves.

It was attempted to reduce the number of hours the model fails to deliver reserves by accounting for the risk of reaching the SOC limits. The risk assessment was incorporated during the procurement of reserves in the first stage of the problem. The number of hours the limits exceeded was reduced for all tested alternatives and done by considering FCR-N procurement of several consecutive hours. However, the alternatives taking the least risk in the process of acquiring FCR-N reserves had double the annual expenses compared to the alternative with no restrictions. Nevertheless, the cases taking the most risk in the FCR-N procurement reduced the number of hours where the SOC limits were exceeded without increasing the annual expenses.

SAMMENDRAG

Kraftsystemet er i endring; fra et sentralisert system til et desentralisert system [1]. Endringen drives av behovet for å begrense klimaendringer og imøtekomme samfunnets økende behov for elektrisitet. Som følge av dette øker andelen fornybar energiproduksjon i systemet [1]. Imidlertid er mye av den fornybare energiproduksjon vind- og solkraft, som er væravhengige energikilder. Man må derfor håndtere utfordringer knyttet til uforutsigbar kraftproduksjon og manglende roterende treghetsmoment. Nye kilder til fleksibilitet i kraftsystemet kan derfor være med på å sikre et stabilt og sikkert strømnett.

Målet med masteroppgaven er å muligheten for å utnytte stasjonære batterier til å levere flere tjenester i ulike markeder, med spesielt søkelys på reservemarkedene primære frekvensreserver (FCR-N). Dette er gjort ved å formulere en optimeringsmodell for en husholdning med solcellepanel og batteri, tilkoblet strømnettet. Batteriet skal bidra til å dekke husholdningens behov for elektrisitet, handle på spotmarkedet og anskaffe og levere primær reserver.

Som forarbeid for oppgaven er det gjennomført en litteraturstudie som omhandler ulike optimeringsmodeller for deltakelse i flere markeder. De fleste artiklene indikerer økt profitt ved deltakelse i flere markeder. Imidlertid tar få av dem hensyn til aktivering av anskaffede reserver. Videre litteraturstudie omhandler derfor modellering av batterier som leverer primærreserver for frekvenskontroll. Videre er også metoder for håndtering av energinivå i batteriet undersøkt. Av de foreslåtte løsningene for å håndtere energinivå under aktivering av reservene, er de fleste løsningen ikke anvendelige i det norske systemet. Dette inkluderer løsninger som utnytter dødbåndet for levering av frekvensreserver og å levere mer enn forpliktede reserver. Imidlertid er settpunktsjusteringer ved planlagte transaksjoner i andre markeder identifisert som en mulig løsning.

En case-studie er utført for en husholdning i Hvaler, Norge, utstyrt med et batteri og solcellesystem. Modellen omhandler deltakelse i reservemarkedene for primære reserver. Den er formulert som et deterministisk lineært optimaliseringsproblem med heltallsrestriksjoner (MILP). Videre er den formulert som en to-stegs modell som nyttiggjør seg av modellprediktiv regulering med en tidshorisont som forskyves i tid. Dette gjøres for å sikre en virkelighetsnær modell uten å måtte håndtere stokastisitet. Gjennom analyse av modellens funksjonalitet, kan man se at den er i stand til å tilpasse seg endringer i prognoser og at de anskaffede reservene er aktivert i henhold til frekvensavviket.

Imidlertid har modellen problemer knyttet til håndtering av energinivået. Siden batteriet er en ressurs med begrenset energikapasitet, når batteriet sine grenser ved lengre perioder med over- eller under frekvens. Det resulterer i at man ikke klarer å levere de reservene man har forpliktet seg til. Det ble forsøkt å redusere antall timer der modellen ikke leverer forpliktede reserver ved å ta hensyn til risikoen for å nå batteriets øvre og nedre grense for energinivå under anskaffelsen av reserver i første steg av problemet. Antallet timer der grensene ble overskredet ble redusert i alle alternativene som ble testet. Dette ble gjort ved at FCR-N anskaffelse i en time har betydning for anskaffelsen i neste time. Imidlertid hadde alternativene med minst risiko i prosessen med å skaffe FCR-N reserver dobbelt så høye årlige kostnader sammenlignet med alternativet uten begrensninger. Likevel oppnådde tilfellene med høyest risiko i FCR-N anskaffelsen en reduksjon i antall timer der grensene ble overskredet uten å øke de årlige kostnadene.

PREFACE

This thesis was delivered in June 2023 and is the final delivery of my Master of Technology in Energy and Environmental Engineering. The master's thesis was written at the Department of Electric Energy at the Norwegian University of Science and Technology (NTNU).

There are several people I would like to thank for their contribution to this thesis. First and foremost I will like to thank my supervisor Professor Magnus Korpås for his guidance, his knowledge and for listening to my ideas. A great thank you must also be directed to my co-supervisors Venkatachalam Lakshmanan and Kasper Emil Thorvaldsen at SINTEF Energy Research for countless discussions and guidance when I have been stuck. Thank you also for your enthusiasm and for teaching me the many interesting topics that could not fit into this master thesis.

Finally I want to thank my family and especially Erlend for endless love and support during this process and five years as a student. And last but not least, I want to thank my friends and fellow students for five memorable years. It would not have been nearly as fun without you.

Trondheim, 11th of June 2023

Ingvild Eline Olsen

Ingvild Eline Olsen

CONTENTS

Abstract **i**

Sammendrag **iii**

Preface **v**

Contents **vi**

List of Figures **viii**

List of Tables **x**

Abbreviations **xii**

1 Introduction **1**
1.1 Objectives and Contribution 2
1.2 Thesis Outline 3

2 Theoretical Background **4**
2.1 The Norwegian Power System 5
2.2 Changes in the Norwegian Power System 9
2.3 Flexibility 12
2.4 Ancillary Services 15
2.5 The Norwegian Power Markets 19
2.6 Batteries 21
2.7 Generating Forecasts 25
2.8 Model Predictive Control 29

3 Literature Review **31**
3.1 Battery Degradation Models 32
3.2 Energy Storage Revenue Stacking 35
3.3 Batteries Providing FCR Reserves - Identified Challanges 37
3.4 State of Charge Managment 39

4 Method **42**
4.1 Optimisation Method and Software 43
4.2 Optimisation Problem 48

5 Case Study **59**
5.1 Choice of Battery . . . 60
5.2 Input Data . . . 61
5.3 Performed Model Simulations . . . 68

6 Results **70**
6.1 Case 1: Running the Model without FCR-N Reserves . . . 71
6.2 Case 2: Running the Model without Activation of the FCR-N Reserves . . . 73
6.3 Case 3: Accounting for Activation of FCR-N Reserves . . . 74
6.4 Case 4: Accounting for Activation of FCR-N Reserves, Including Compensation for Activated Energy . . . 77
6.5 Case 5: Considering the Risk of Reaching the Battery's SOC Upper and Lower Limits . . 78

7 Discussion **81**
7.1 Case 1: Running the Model without FCR-N Reserves . . . 82
7.2 Case 2: Running the Model without Activation of the FCR-N Reserves . . . 83
7.3 Case 3: Accounting for Activation of FCR-N Reserves . . . 84
7.4 Case 4: Accounting for Activation of FCR-N Reserves, Including Compensation for Activated Energy . . . 87
7.5 Case 5: Considering the Risk of Reaching the Battery's SOC Upper and Lower Limits . . 88
7.6 Limitations . . . 89
7.7 Further Work . . . 90

8 Conclusions **92**

References **93**

Appendices: **98**

A Literature Review - Ancillary Service Provison **99**

B Calculation of Capacity Grid Tariffs **101**

C Complete Optimisation Problems **103**

LIST OF FIGURES

2.1.1 Grid levels in the Norwegian power grid. 5
2.1.2 The economic flow between participants in the power system. Figure 1.2 by reference [3], used with permission. 6
2.1.3 Percentage variation over the year in power use, inflow to reservoirs, land-based wind and solar power production. Figure 8.3 by reference [1]. 8
2.2.1 Projections of electricity use in 2020-2050, adopted from [1]. 9
2.2.2 Change in residential load profile when implementing charging of EVs and solar panels. Figure 1.4 by reference [3], used with permission. 10
2.3.1 Comprehensive illustration of important quantitative characteristics of flexibility resources. Figure 2 by reference [8], used under the Creative Commons CC-BY license. 12
2.3.2 Flexibility products offered to the TSO and DSO at the transmission system side and distribution system side, after the inspiration of figure 1 by reference [9]. 13
2.3.3 The aggregator acts as an intermediary between the flexibility buyers and the flexibility sellers. After the inspiration of figure 1 by reference [12]. 14
2.4.1 Overview of Ancillary Services listed by the Norwegian TSO, Statnett [15]. Figure obtained from my specialisation project [14]. 15
2.4.2 Diagram of frequency control after a loss of generation or a considerable load change. Figure 3 by reference [16]. 16
2.4.3 FCR reserves activation droop, figure 19 by reference [21]. 17
2.5.1 The timeline of the Norwegian power markets. Adapted by reference [24]. 19
2.6.1 Decline in battery prices over the last decade. 22
2.6.2 Cycle life as a function of DOD, figure 1 by reference [33] © [2016] IEEE. 24
2.7.1 Solar power forecasts for different weather types. The forecasts are more certain on a sunny day, than on a cloudy day. Figures 62-64 by reference [35]. 25
2.8.1 Rolling time horizon, after inspiration by reference [39]. 30
2.8.2 Receding time horizon, after inspiration by reference [39]. 30

3.4.1 Distribution of frequency in the years 2020 and 2021. 39

4.2.1 Illustration of the battery converter and the charge and discharge efficiencies. 50
4.2.2 System overview with power flows. 52
4.2.3 Reservation of capacity for FCR-N reserves. FCR-N is a symmetrical reserve. 53

5.2.1 Average daily elspot prices in 2020 and 2021 in price zone NO1 in Norway. 63
5.2.2 Daily average solar power output per month and average hourly solar power output per day. Figures from my specialisation project [14]. 64
5.2.3 Average daily demand per month and the average hourly demand per day, for an average household in Hvaler. Figures from my specialisation project [14]. 64

5.2.4 Boxplot of the frequency measurements. The frequency is near-normal, distributed around a mean of 49.99 Hz in both years. 65
5.2.5 Plot of the average hourly frequency in 2020 and 2021. 66
5.2.6 Average payment and total required volumes for FCR-N in the capacity markets. No data were available for the D2 market in 2020. 67

6.1.1 Energy level in the battery without reservation of FCR-N reserves. 72
6.2.1 Energy level in the battery with reservation of FCR-N reserves. 73
6.3.1 Change in first stage charge (ch) and discharge (dch) schedule due to activation of FCR-N reserves. 74
6.3.2 The number of hours the model exceeds the SOC limits and by how much when activation of procured FCR-N reserves are included. 75
6.3.3 Energy level in the battery with activation of FCR-N reserves. January 3rd illustrates an unsuccessful operational day, where the energy level in the battery reaches the upper SOC limit. January 6th illustrates a successful operational day. 75
6.3.4 Energy level in the battery with activation of procured FCR-N reserves. 76
6.4.1 The number of hours the model exceeds the SOC limits and by how much when compensation for activation of FCR-N reserves is included. 77
6.5.1 Annual expenses, adjusting the risk factor R and the number of hours in consideration, H. 78
6.5.2 Operational costs, adjusting the risk factor R and the number of hours in consideration, H. 78
6.5.3 Payment for FCR-N procurment, adjusting the risk factor R and the number of hours in consideration, H. 79
6.5.4 Payment for activated FCR-N reserves, adjusting the risk factor R and the number of hours in consideration, H. 79
6.5.5 Amount of procured FCR-N reserves, adjusting the risk factor R and the number of hours in consideration, H. 79
6.5.6 Annual expenses divided by the amount of procured FCR-N reserves, adjusting the risk factor R and the number of hours in consideration, H. 80
6.5.7 Number of hours the SOC limits are exceeded, adjusting the risk factor R and the number of hours in consideration, H. 80

LIST OF TABLES

2.4.1 Characteristics of frequency reserves in Norway [17]. 16
2.4.2 Requirments for delivery of reserves by resources with LER [21]. C_{FCR} is the procured FCR capacity. 18
2.5.1 Day ahead market regulations by Nordpool [25]. 19
2.5.2 Intraday market regulations by Nordpool [25]. 20
2.5.3 FCR-N market regulations by Statnett [20]. 20
2.6.1 Technical characteristics of battery types from references [27] and [28]. 21
2.6.2 A selection of electrochemical storage technologies' compatibility with a selection of grid applications, by reference [22]. The green colour indicates that the battery technology is suitable for the grid application, while the orange colour indicates that it is less suitable, and red indicates that it is unsuitable. 22
2.8.1 MPC algorithm by reference [38]. 29

3.1.1 Reviewed literature on implementing the battery degradation cost. 32
3.2.1 Reviewed literature on revenue stacking of battery operation. 35
3.3.1 Reviewed literature on challenges in using batteries for FCR provision. 37
3.4.1 Reviewed literature on methods for SOC management. 40

4.1.1 MPC algorithm used to solve the optimisation problem. 45

5.1.1 Battery specifications of Tesla Powerwall 2.0 [62]. 60
5.2.1 Energy component of the grid tariff in Hvaler, prices by Norgesnett [63]. 61
5.2.2 Capacity component of the grid tariff in Hvaler, prices by Norgesnett [63]. 61
5.2.3 Power component of the grid tariff per kWh in Hvaler in 2020 and 2021, prices by Norgesnett [63]. 62
5.2.4 Standard deviation in monthly elspot prices. 63
5.2.5 Key data of the frequency measurements. 65
5.2.6 Statistics of the frequency measurements. A slightly higher timeshare of under-frequency than over-frequency is present when a dead-band og $\pm$ 0.01 is defined. However, average over-frequency deviations are slightly greater. 66
5.2.7 The share of the acquired reserves in the D1 and D1 market that are activated. No data is available on the acquired reserves in the D2 market 2020. 67
5.3.1 Risk factors and the number of consecutive hours the reserve amount are considered. . . 69

6.1.1 Verification of MPC model. There is little change in the annual expenses between the two model formulations. 71
6.1.2 Verification of MPC model. A comparison of the energy flows shows that the MPC model uses the battery a little more than the deterministic model. 71
6.1.3 Operational costs and export benefits. 71
6.2.1 Annual expense when there is no activation of FCR-N reserves. 73

6.2.2 Operational costs, export benefit and benefit of FCR procurement when including procurement of FCR-N reserves. 73
6.2.3 Flow of energy when there is no activation of FCR-N reserves and total contracted FCR-N reserves. 73
6.3.1 Annual expense when activation of FCR-N reserves are included. 74
6.3.2 Expenses and revenue streams when including the activation of the procured FCR-N reserves. 75
6.3.3 Flow of energy the FCR-N reserves are activated and total contracted FCR-N reserves. . . 75
6.4.1 Annual expense when compensation for FCR-N reserves are included. 77
6.4.2 Expenses and revenue streams when including compensation for FCR-N activation. 77
6.4.3 Flow of energy the FCR-N reserves when compensation for activated energy and total contracted FCR-N reserves are included. 77

A.0.1 Reviewed literature for mapping ancillary service by provision of batteries. "-" mark no information in the literature. 99
A.0.2 Reviewed literature for mapping ancillary service by provision of EWH. "-" mark no information in the literature. 99
A.0.3 Reviewed literature for mapping ancillary service by provision of EVs. "-" mark no information in the literature. 99
A.0.4 Resulting mapping of ancillary services to the provision of flexible resources 100

B.0.1 Power component of the grid tariff in Hvaler in 2021, prices by Norgesnett [63]. 101
B.0.2 Power component of the grid tariff in Hvaler in 2020, prices by Norgesnett [63]. 102

ABBREVIATIONS

List of all abbreviations in alphabetic order:

- **aFRR** Automatic Restoration Reserves
- **BESS** Battery Energy System Storage
- **BRP** Balancing Responsible Party
- **CAPEX** Capital Economic Characteristics
- **CCGT** Combined Cycle and Gas Turbine
- **CHP** Combined Heat and Power Plant
- **DER** Distributed Energy Resources
- **DOD** Dept of Discharge
- **DR** Demand Response
- **DG** Distributed Generation
- **DS** Distributed Storage
- **DSO** Distribution System Operator
- **EV** Electric Vehicle
- **EWH** Electric Water Heaters
- **FCR** Frequency Containment Reserves
- **FCR-D** Frequency Containment Disturbance Reserves
- **FCR-N** Frequency Containment Normal Operation Reserves
- **FFR** Fast Frequency Reserves
- **LER** Limited Energy Resource
- **LP** Linear Programming
- **mFRR** Manual Restoration Reserves
- **MIP** Mixed Integer Problem
- **MILP** Mixed-Integer Linear Problem
- **MIQCP** Mixed-Integer Programming with Quadratic Constraints

- **MIQP** Mixed-Integer Quadratic Programming
- **MPC** Model Predictive Control
- **NBS** Nordic Balance Settlement
- **NVE** The Norwegian Water Resources and Energy Directorate
- **OPEX** Operational Economic Characteristics
- **PV** Photovoltaic Panel
- **P2G** Power to Gas
- **PX** Power Exchanger
- **QCP** Quadratic Constraint Programming
- **QP** Quadratic Programming
- **SOC** State of Charge
- **TOE** Time of Export
- **SOH** State of Health
- **TOU** Time of Use
- **TSO** Transmission System Operator

CHAPTER

ONE

INTRODUCTION

Following the Paris Agreement, all countries must reduce greenhouse gas emissions to limit global warming. The measures necessary to mitigate climate change require changing how we generate, distribute, and use energy. Facilitating the integration of more renewable generation poses a significant challenge due to the lack of rotational inertia in the system.

Rotational inertia traditionally provides stability to the power system, protecting it against sudden changes and disturbances, as the generators rotate at a constant speed. Nonetheless, with the increased penetration of non-synchronous and intermittent renewable generation, the system is more vulnerable to disturbances. Consequently, there is a growing interest in exploiting flexibility beyond conventional power plants to provide power reserves and contribute to system stabilisation following a disturbance.

Various forms of distributed storage, such as stationary batteries, electric vehicles and thermal storage, have been discussed as resources that can provide ancillary services by taking advantage of their flexibility. These resources can effectively contribute to grid stability by shifting energy consumption or exporting surplus energy. Depending on the specific services they aim to deliver, these resources can provide fast ramping capacity and flexibility close to where needed. The resource in focus in this thesis is stationary batteries.

There are many incentives for having a battery system, even though the cost of battery capacity is high. Batteries can be used for electricity cost savings by storing electricity when the electricity price is low and exporting the electricity when the electricity price is high. Furthermore, with time-of-use (TOU) pricing structures, one could benefit from using stored electricity during peak-rate periods. Batteries could also be necessary in rural areas or for renewable energy integration. Nevertheless, it must be profitable for the multimarket battery operation to be a valuable option for stakeholders.

1.1 Objectives and Contribution

The primary objective of this work is to develop an optimisation model capable of analysing the performance and profitability of a stationary battery providing multiple services. Specifically, these services include contributing to cover a household's demand for electricity, performing energy arbitrage and delivering frequency containment normal operation reserves (FCR-N). The system consists of a household with a photovoltaic (PV) generation and battery that are connected to the grid.

The work consists of creating a deterministic two-stage optimisation model from scratch that is solved with model predictive control (MPC) with a rolling time horizon. This is done aiming to mimic the actual operation of the battery, considering that the future data is unknown. The rolling time horizon enables the model to adapt to changes and includes uncertainty without incorporating stochastic elements. This allows for a less complex model that can simulate the system's operation that is close to reality.

In the model, the decision about procurement of FCR-N reserves is made in the first stage, making the battery owner obligated to fulfil the obligations in the second stage. Furthermore, the first stage charge and discharge schedule for the next 24 hours serves as a baseline. In the second stage, the battery is operated hour for hour, considering the energy exchange associated with activating FCR-N reserves.

In similar models, the activation of reserves is often overlooked. FCR-N is a symmetric reserve, demanding activation in both upward and downward directions. The net effect of activated energy is little since the frequency is near-normal distributed around a mean of 50 Hz. The natural frequency deviations, therefore, balance the impact of activation. However, the energy exchange can present challenges for resources with limited energy reserves (LER), in contrast to conventional power plants. If a one-sided frequency deviation persists for an extended period, the resource with limited energy resources can have difficulties delivering the obligated reserves. Thus, the main attention of this thesis is to incorporate the activation of the procured FCR-N reserves in the second stage of the model, to analyse the effect of and challenges that arise as a result of the activation of FCR-N reserves.

In summary, this master's thesis aims at the following:

- Formulate an optimisation model of a household with a PV generation and battery system connected to the grid from scratch.
- Develop the model into a two-stage optimisation model that simulates a battery delivering multiple services in different markets. The chosen services are to contribute to covering the household's demand for electricity, perform energy arbitrage and procure and deliver FCR-N reserves.
- The optimisation model aims to be as close to the real operation as possible. MPC with a rolling time horizon is explored to enable the model to respond to changes in predictions and frequency deviations quickly.
- Focus on activating procured FCR-N reserves for a resource with limited energy reserves in the model formulation. Analyse the feasibility of the model and challenges associated with the activation.
- Present a case study of a household in Hvaler, Norway.
- Perform a techno-economical optimisation of the system operation.

1.2 Thesis Outline

This master's thesis comprises a total of eight chapters:

Chapter 1: The introduction presents the background and motivation for the master's thesis. The objectives of the work, together with the research questions, are further explained. Lastly, the introduction introduces the outline of the master's thesis.

Chapter 2: The theoretical background presents the theoretical context this master's thesis is written in. Firstly, the chapter explains how the Norwegian power system is organised and operated in Section 2.1. Secondly, the current and future changes in how the Norwegian power system is operated are presented in Section 2.2. Then, Sections 2.3 and 2.4 discuss the terms flexibility and ancillary services, with a specific emphasis on FCR-N, which is the focus of this thesis. Section 2.5 further presents the Norwegian wholesale and balancing markets, followed by Section 2.6, which introduces the essential aspects of batteries. Batteries are the storage technology in focus in this thesis. Lastly, the chapter presents some forecast and optimisation methods in Sections 2.7 and 2.8.

Chapter 3: The literature review investigates four topics: battery degradation models, energy storage revenue stacking, challenges in providing frequency containment reserves by batteries and state of charge management during reserve activation.

Chapter 4: The methodology firstly presents the methods, algorithms and optimisation software and tools used to solve the optimisation problems. Secondly, it presents the assumptions and forecast method that is the starting point for solving the model. Lastly, the chapter presents the nomenclature, the complete two-stage deterministic MPC optimisation problem formulation.

Chapter 5: The case study presents the parameters and input data used to solve the optimisation model. This involves battery parameters, household consumption data, photovoltaic generation data, grid tariffs, elspot prices, frequency measurement data, data for FCR-N requested volumes and prices and regulating power prices. Lastly, the five simulation steps are presented.

Chapter 6: The results presents the complete results of all simulation steps in Chapter 5.

Chapter 7: The discussion analyses and interprets the results presented in Chapter 6. The model formulation is further verified, comparing it to a single-stage deterministic optimisation formulation. The chapter also provides insights into the limitations of the results and potential future research.

Chapter 8: The conclusion of the master's thesis attempts to summarise and conclude the findings presented in Chapter 6 and 7.

CHAPTER

TWO

THEORETICAL BACKGROUND

This Chapter details the theoretical background and concepts relevant to this thesis. Section 2.1 describes the important aspects of the Norwegian power system. Section 2.2 describes the current developments and changes in the Norwegian power system. Furthermore, Section 2.3 defines the term flexibility and discusses flexibility in the power system. Section 2.4 lists the ancillary services used in Norway and gives an overview of primary frequency control, especially frequency containment normal operation reserves, as this is the ancillary service the focus of this thesis. The wholesale and balancing markets are the focus in Section 2.5. The subsequent Section 2.6 discusses the important technical characteristics of batteries providing grid services. Lastly, Section 2.7.2 and Section 2.8 present forecasting methods and optimisation methods used in the model formulation later in this thesis.

2.1 The Norwegian Power System

The power system is a complex entity with many participants, each assigned its own roles to ensure the security of supply and operational stability within the power system. This section provides an overview of how the Norwegian power system is organised and operated. The different participants in the power system and their role in keeping the system stable and cost-effective is further explained. Lastly, weather dependency in the Norwegian system and important aspects of a secure energy supply are presented.

2.1.1 The Electricity Grid

The Norwegian electricity grid consists of three levels: the transmission grid, the regional distribution grid and the local distribution grid. The transmission grid transports the electricity from the producer to the consumers and encompasses grid levels of 132, 300, and 420 kV [2]. Operating the transmission system is the responsibility of the Norwegian transmission system operator (TSO), Statnett. However, Statnett additionally leases the capacity of the regional grid operators such as Hafslund Nett AS, BKK Nett AS and SKL Nett AS. The transmission grid is a nationwide system connecting different parts of the distribution system and connects the Norwegian system with International transmission systems.

The regional distribution system serves as an intermediary between the transmission and local distribution systems, operating at voltage levels ranging from 33 to 132 kV [2]. Multiple entities, including grid operators, power producers and industrial firms, own and oversee the regional distribution grid. Although the regional distribution system mainly connects the transmission and local distribution systems, some power-intensive industry companies are connected at this voltage level.

Lastly, the local distribution grid is the one that transports electricity to most consumers. The grid, seen in Figure 2.1.1, consists of grid levels 230 V to 22 kV and is operated by several distribution system operators (DSOs) [2].

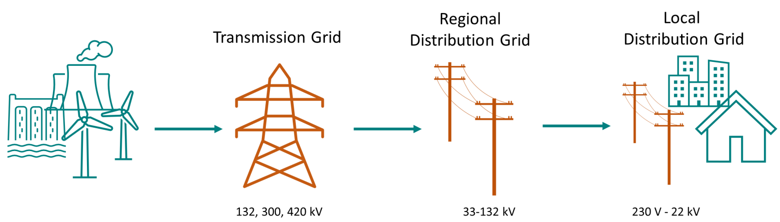


Figure 2.1.1: Grid levels in the Norwegian power grid.

2.1.2 Participants

The many participants in the power system each have an assigned role in ensuring the system is operated securely, reliably and cost-effectively. The following section briefly introduces the participants in the power system.

The TSO is responsible for electricity transmission from generation to distribution. It is also responsible for developing the high-voltage transmission grid to transmit electricity reliably and cost-effectively. Further tasks of the TSO involve monitoring and ensuring the system's stability.

The DSOs primarily operates the medium and low voltage grids and is responsible for delivering electricity to the consumers. The DSO manages congestion and mitigates voltage-related issues within the local grid. Furthermore, they oversee the connection process for new customers.

The power exchanger (PX) serves as the marketplace for electricity trading. In Nordic countries, Nordpool operates as the PX.

The retailer buys electricity at the wholesale markets and from the producers through bilateral contracts and subsequently sells it to the consumers. The consumer is free to choose the retailer of their wish.

The producers deliver electricity for trading the wholesale markets and for balancing purposes requested by the TSO. On the other hand, consumers buy electricity at the wholesale market or from a retailer for their consumption.

The relationship between the different participants and their economic flows are illustrated in Figure 2.1.2.

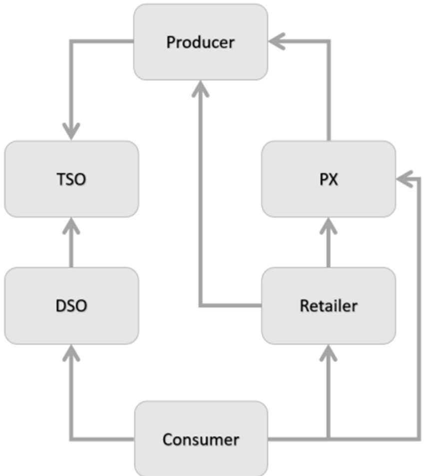


Figure 2.1.2: The economic flow between participants in the power system. Figure 1.2 by reference [3], used with permission.

2.1.3 Security in Supply of Electricity

Generating and distributing electrical energy from power plants to end users require a reliable power system that maintains stability and security. Achieving this objective requires the coordinated operation of various power system components and participants. Reference [4] identify three aspects of a secure electricity supply: energy security, adequacy, and operational security.

2.1.3.1 Energy Security

Energy security refers to the ability to consistently satisfy the electricity demand [4]. Access to flexible energy resources such as hydropower, coal, oil, and gas is essential in this context. These resources can be regulated to match fluctuations in demand. Energy shortages could arise in power systems that are still developing or are heavily reliant on intermittent energy sources. Unforeseen events or weather conditions can also pose a threat to energy security.

In the case of the Norwegian power system, which predominantly relies on hydropower, a significant degree of flexibility is achieved. The ability to regulate hydropower generation in response to demand fluctuations contributes to a stable power supply. Additionally, the hydropower reservoirs enable electricity production even during periods of low water inflows. Consequently, the Norwegian power system has a high level of energy security. In the event of an extended period of low water inflows, the Norwegian Water Resources and Energy Directorate (NVE) may implement rationing to ensure an adequate power supply. However, the likelihood of this scenario is considered low [4].

2.1.3.2 Adequacy

Adequacy, as defined by [4], relates to the power supply system's capacity to meet instantaneous load requirements. It is measured by the available installed production capacity and grid capacity. Production and transmission capacity shortages could result in an inability to meet immediate load demands. The challenge primarily arises in the early mornings between 07:00 and 11:00 and afternoon hours between 17:00 and 19:00 [1].

The transmission and distribution system must have sufficient transfer and import capacity to handle peak loads and periods with high imports in dry years. The TSO and the DSO must also plan for failures of components or interruption of supply. Consequently, they adhere to the N-1 criterion, which ensures that the loss of any single component does not compromise the electricity supply.

2.1.3.3 Operational Security

Operational security involves stabilising the frequency and voltage and avoiding blackouts after interruptions or disturbances. Achieving operational security necessitates a balance between supply and demand at all times. However, faults in lines, substations, or other components may occur, leading to supply interruptions.

The responsibility for maintaining supply-demand balance and responding to disturbances lies with the TSO, Statnett. An unbalance in supply and demand could be measured as a frequency imbalance. The Nordic system has a nominal frequency of 50 Hz. If the frequency deviates from this, the TSO must activate reserves to restore the balance.

2.1.4 Weather Dependency in the Norwegian Power System

The Norwegian power system, mainly based on hydropower, is weather-dependent. In an average year, 98% of the generated power is hydropower [1]. Consequently, power production relies heavily on reservoir inflows, resulting in annual variations in power generation [1].

The disparity in inflows between different years in Norway can be substantial, with the most considerable recorded difference reaching 76 TWh [1]. Years with low inflow are predicted to occur every 20-50 years. The challenge arises as the weather tends to be similar all over Europe, resulting in shorter or longer periods with little power production in the European system [1].

Figure 2.1.3 illustrates the annual variations in power consumption, reservoir inflows, wind power production, and solar power production. Wind power production, displayed at the bottom left, tends to be more significant in the winter than in the summer [1]. However, wind power production is small on the coldest winter days, when the electricity consumption is the highest [1].The inflow in water reservoirs, displayed in the top right, is greatest in the summer months, as opposed to wind power [1]. This suggests a potential complementary relationship between hydropower and wind power. In the winter, there is little inflow to the reservoirs due to precipitation mainly occurring as snow. In the spring and summer, the inflow increases due to snow melting. However, climate change is expected to change the known inflow patterns. The patterns of precipitation will likely shift towards increased winter rainfall. The inflow in the winter months will increase, while the inflow in the summer months will decrease due to less snow melting, leading to increased uncertainty and the likelihood of drought years [1]. Lastly, solar power has a characteristic seasonal variation. The highest solar power production is in the light summer months, while the production goes down in the dark winter months [1].

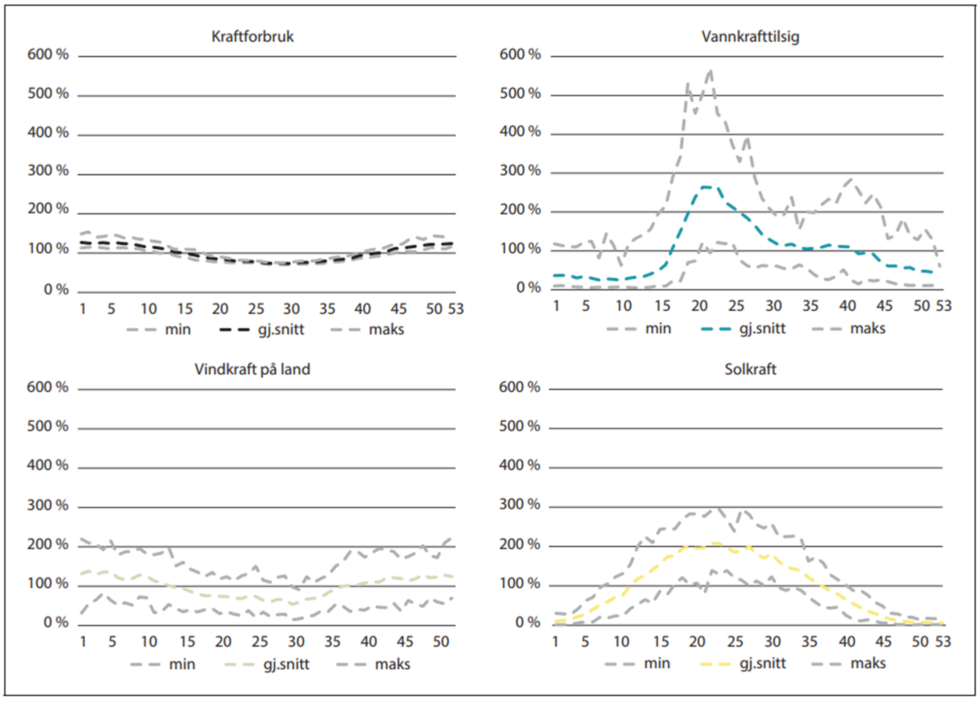


Figure 2.1.3: Percentage variation over the year in power use, inflow to reservoirs, land-based wind and solar power production. Figure 8.3 by reference [1].

2.2 Changes in the Norwegian Power System

The power system and how we generate, distribute and consume power, is changing. This transformation involves a transition towards a decentralized power system, a significant increase in electricity usage, and shifts in peak consumption patterns. This is mainly due to integrating distributed renewable energy resources (DER). This section explains the present and predicted changes in the Norwegian power system and how the changes initiate the interest in exploiting new sources of flexibility in power system operation.

2.2.1 Increased Use of Electricity

The need for electricity is expected to increase in the following years. The recent publication by the Norwegian Energy Commission encompasses various analyses wherein projections for electricity consumption have been presented. According to these estimates, the 2040 electricity use is predicted to be 174 to 213 TWh, as illustrated in Figure 2.2.1 [1]. The current annual electricity use is today about 140 TWh. The projections differ, but the report clearly states the need for increased generation, preferably by renewable sources.

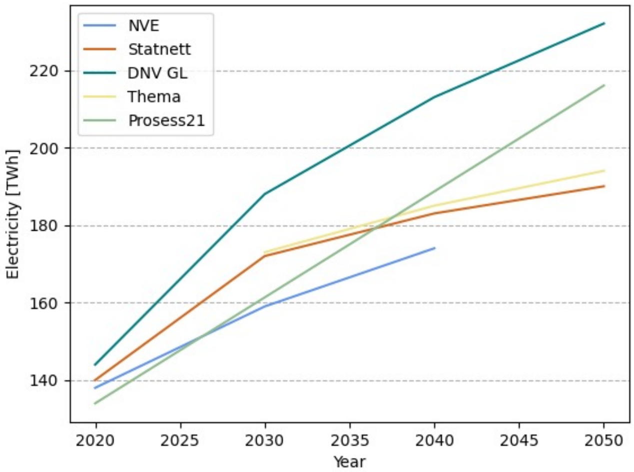


Figure 2.2.1: Projections of electricity use in 2020-2050, adopted from [1].

2.2.2 Intermittent and Uncontrollable Generation

Within the "2030 climate & energy framework", the European Union has established a target of achieving a 32% renewables in its pursuit of reducing greenhouse gas emissions [5]. The 2021 share of renewables in the EU reached 22.2%, according to the European Environment Agency [6]. The transition from fossil fuels to renewable energy results in a higher share of intermittency in the power system. Mainly due to renewable power generation from wind and solar. Integrating these renewable energy sources also presents challenges regarding their controllability and the ability to forecast generation accurately [6].

2.2.3 Change in Load Profiles

The transition towards a renewable power system also affects how we consume power. Transport, household electricity, and heating sectors have high energy consumption. Household energy use is 47-48 TWh per year [1].

The transportation sector, with 53-58 TWh energy use, consists mainly of energy from fossil fuels. 90% of transportation is based on fossil fuels. However, the share of electric vehicles has increased over the past years and is expected to increase in the following years. In 2021, electric vehicles accounted for 64.5 per cent of the sale of new passenger cars [1].

Reference [3] exemplify how the load profile of a household can change when implementing new technologies in the residential sector in Figure 2.2.2. Traditionally, the residential load profile exhibits a stable pattern throughout the day, characterized by peaks in the morning and afternoon. These peaks are attributed to high-power-demand appliances like heat pumps, electric water heaters, and induction ovens. The traditional load profile is illustrated in the top-left section of the figure.

Conversely, the top-right profile showcases the alteration in the residential load profile resulting from the charging of an electric vehicle (EV). It involves a drastic increase in power use, as EV's home charge levels are typically 2.3, 3.7 or 7.4 kW [3]. Furthermore, the bottom-right profile shows the generation of a household's PV. The generation does not coincide with the peaks in consumption, resulting in net generation in these hours. Additionally, the influence of weather conditions introduces fluctuations in power generation. Consequently, the resulting residential net profile at the bottom right significantly deviates from the traditional load profile observed at the top left. The alternative profile involves increased load peaks in the afternoon and morning and periods during the day with net generation. Therefore, the distribution system designed to accommodate the conventional load profile must change to handle the new profile, which also involves reverse power flows. Although the aggregated effect of several residential households presents a more damped profile, the power system must handle a changed way of consuming power [3].

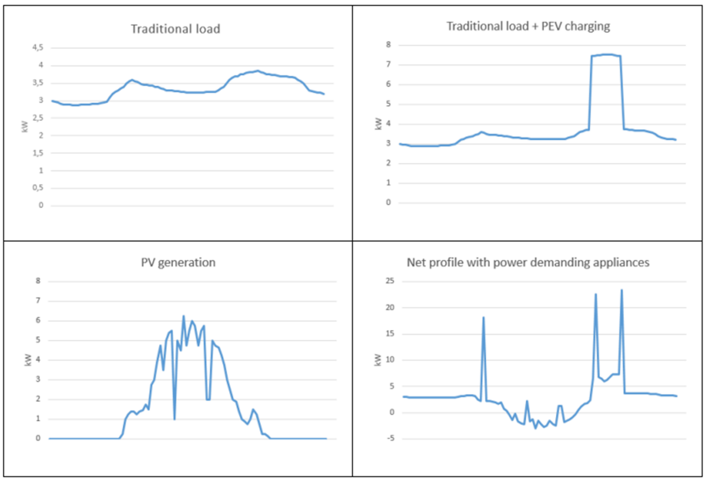


Figure 2.2.2: Change in residential load profile when implementing charging of EVs and solar panels. Figure 1.4 by reference [3], used with permission.

2.2.4 Transition to a Decentralized Power System

Due to the changes in the load profile mentioned in the previous section, the power system is changing from a centralised and unidirectional system to a decentralised and bi-directional system.

In a centralised power system, electricity is primarily generated at large-scale power plants and transmitted and distributed through the transmission and distribution network to end-users for consumption. In contrast, a decentralised power system is characterised by a more significant deployment of distributed energy resources close to the consumption point. The distributed energy resources could be small-scale generators, backup generators, wind power generation, combined heat and power (CHP) plants and solar panels meant for self-consumption [5], [7].

Facilitating this transition is the introduction of smart and intelligent systems and metering. The decentralised power system necessitates real-time control and bi-directional communication with consumers. The communication technology makes it possible to monitor the energy flows [5]. Notably, Norway has already replaced all its meters with smart meters, allowing for detailed bi-directional communication [5].

Distributed generation (DG) might reduce the need for extending the grid capacity [5], [7]. It could also reduce losses associated with transmitting power over long distances, as the DG often is located at the point of consumption. On the other hand, the decentralised power system could also pose some challenges regarding voltage limit violations, overloading problems, high line losses and power quality issues [5], [7]. Therefore, necessary to explore opportunities to increase the hosting capacity of distribution systems, preferably without implementing costly grid investments.

2.2.5 Drivers of Flexibility Use in the Power System

Interest has been in exploiting flexibility to solve the challenges mentioned in the changing power system. reference [5] identify and summarises three drivers for exploiting flexibility.

Firstly, a higher share of distributed renewable generation results in more intermittency and uncontrollable generation. It is more difficult to control the generation to respond to the changes in generation and consumption. An imbalance between generation and consumption can lead to frequency deviations, posing a risk of system blackout if not effectively managed by the TSO. Consequently, the TSO is vested in leveraging system flexibility to address these challenges [5].

Secondly, the bi-directional flow of electricity in the power system presents challenges since the system was initially designed for unidirectional power flow from centralised power plants to end-users [5]. The bi-directional flow can cause congestion and overloading of lines. Flexibility can be used by the DSO as a solution, as opposed to expensive grid investments [5].

Thirdly, prosumers can deliver flexibility by controlling DER or changing their consumption patterns [5]. This is denoted by demand-side flexibility and demand response (DR). Prosumers can adjust equipment such as heat pumps and electric water heaters (EWH), shifting their consumption patterns. Additionally, they can control distributed storage systems like EVs or stationary batteries [5], [3]. The flexibility could be provided on the signal by the system operator, by price-signal or by trading flexibility on flexibility markets [5].

2.3 Flexibility

Flexibility can be a valuable tool to maintain the power system's energy security, adequacy and operational security. However, the literature has no uniform consensus about what the term flexibility should encompass. Addressing this issue, reference [8] provides three criteria for the definition of flexibility: the type of flexible resource, the duration of activation and the incentive for activation of the flexible resource. Taking these criteria into account, flexibility is defined by the authors as:

> The ability of power system operation, power system assets, loads, energy storage assets and generators to change or modify their routine operation for a limited duration and respond to external service request signals without inducing unplanned disruptions [8].

This section further discusses the characteristics of flexibility and the different flexibility products. Lastly, demand-side flexibility and the steps necessary to provide flexibility are concerned.

2.3.1 Characteristics of Flexibility

Figure 2.3.1 illustrates flexible resources' most important quantitative technical characteristics.

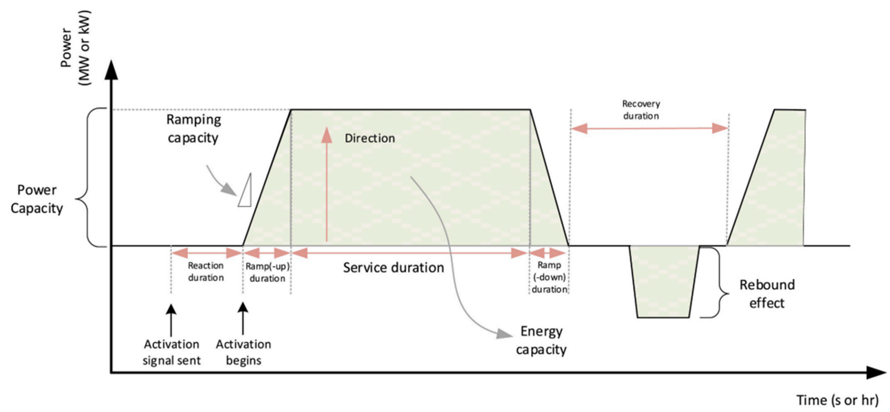


Figure 2.3.1: Comprehensive illustration of important quantitative characteristics of flexibility resources. Figure 2 by reference [8], used under the Creative Commons CC-BY license.

In the literature, three key characteristics are extensively discussed in relation to flexible resources: ramping capacity, energy capacity, and power capacity. The ramping capacity is especially important for the TSO in maintaining the frequency stable. In a frequency deviation, the TSO requires that the reserves quickly ramp up or down power to obtain the balance between generation and demand. At the distribution level, the DSO focuses on the energy capacity offered by flexible resources to effectively address issues such as congestion, reverse power flows, and the deferral of costly grid investments. These services are delivered over a long period and therefore need high energy capacity.

2.3.2 Flexibility Products

Flexibility provision encompasses both the transmission and distribution systems. The TSO is interested in balancing flexibility, offered through the intraday market or as ancillary services at the balancing markets [9]. The flexibility is traditionally provided by sizeable dispatchable power plants, interzonal connections or demand response by large customers at the transmission system side. Moreover, new emerging markets are considered, aiming to provide alternative flexibility. For instance, in the United

States, ramping capacity markets are being integrated alongside existing markets [9].

Similarly, flexibility is offered to the DSO or balancing responsible party (BRP) at the distribution system side to minimise losses in the distribution and for voltage control and congestion management [9]. These services are typically provided by DR, DG and storage systems since they must be located close to the point needing flexibility.

An illustration of the flexibility products offered to the TSO and DSO from the transmission system side and distribution system side is provided in Figure 2.3.2.

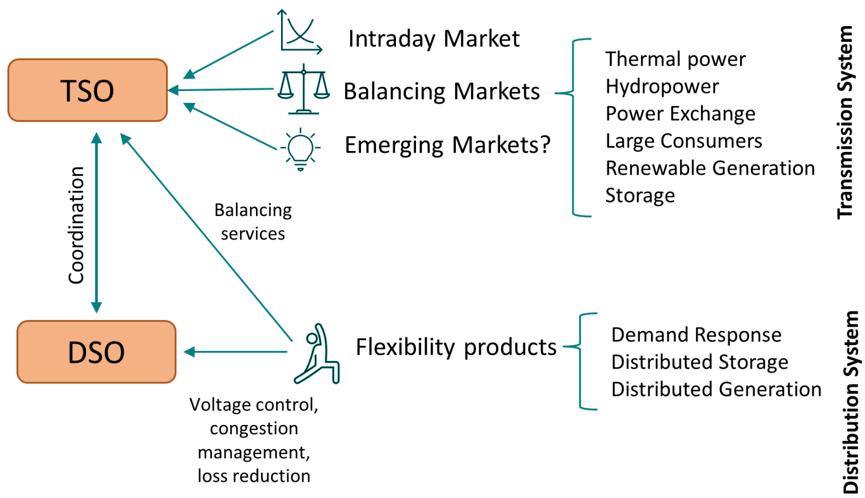


Figure 2.3.2: Flexibility products offered to the TSO and DSO at the transmission system side and distribution system side, after the inspiration of figure 1 by reference [9].

2.3.3 Demand Side Flexibility

Demand side flexibility is defined by the International Renewable Energy Agency (IRENA) as

> "[...] the portion of demand in the system (including via electrified heat and transport) that can be reduced, increased or shifted within a specific duration." [10]

It could be provided by several assets, where the main categories are:

- Load units: EV chargers, EWHs, air-conditioning, appliances etc.
- Generation units: PVs or small wind turbines.
- Storage units: stationary batteries, EVs or thermal storage.

By aggregating the individual response of several small consumers, one can provide flexibility to the system. Reference [11] identifies six steps in the demand side flexibility process.

1. Baseline estimation: The baseline is the planned/predicted consumption/generation if no flexibility is utilised. The baseline is derived from a forecast of predicted prices, generation and demand.
2. Bid generation: After establishing the baseline, bids for providing flexibility could be generated. These are based on possible deviation from the baseline, providing flexibility in an upward or downward direction. The bids are based on the regulations and guidelines set by the marketplace operator and reflect the prosumer's capacity and ability to participate in the market, reflected by the bid size and price.

3. Market clearing: The bids are either accepted or declined in the market clearing phase, and accepted bids results in an obligation to provide flexibility if necessary.

4. Flexibility activation: In the activation phase, the prosumer must adjust his setpoints or disconnect or reconnect load according to the activation signal to decrease or increase his load.

5. Flexibility verification: The verification step involves documentation that the flexibility was activated according to the contract.

6. Financial settlement: In the financial phase, a financial settlement is calculated according to agreed contracts and documented activation.

2.3.4 Aggregation of Flexibility

Essential for realising flexibility is the developing aggregator role [11]. The aggregator is an intermediary between the flexibility buyers and the flexibility sellers. The flexibility offered by the demand or supply of individual end-users needs to be bigger to play a significant role. By consolidating the flexibility of active demand and supply from various end-users, including commercial, industrial, and residential ones, the aggregator accumulates a pool of flexibility that can be offered to the system operator [3].

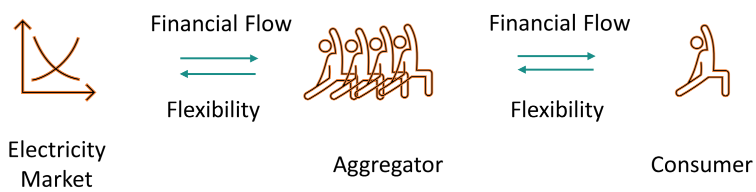


Figure 2.3.3: The aggregator acts as an intermediary between the flexibility buyers and the flexibility sellers. After the inspiration of figure 1 by reference [12].

The aggregator could participate in several electricity markets; trading flexibility in the day-ahead market, trading flexibility in the intra-day market, providing power reserves, balancing portfolio internally or managing congestion [12]. Given the aggregation of demand-side flexibility, it is essential for the aggregator's business model that both the aggregator and consumer/prosumer profit from the flexibility delivery.

Several actors could play the role of an aggregator, BRP, retailer or an independent actor [12]. The authors of [12] point out that it is easiest for a retailer to gain the aggregator role due to the need for fewer contracts and an already established relationship with consumers/prosumers. The retailer also has the opportunity to modify the retail prices for economic feasibility. Nevertheless, the authors summarise three critical points for enabling all actors to become an aggregator:

1. Standardisation of financial relations between actors.

2. Standardisation of information exchange.

3. Raising customer awareness of the opportunities facilitated by BRP and independent aggregators.

2.4 Ancillary Services

This section aims to provide an overview of the ancillary services within the Norwegian power system. Emphasis will be placed on frequency control, particularly the frequency containment reserves (FCR) and the technical requirements associated with their provision, as it will be the focus of this master's thesis.

Ancillary services encompass a range of services offered to the power system operators to ensure the reliable operation of transmission and distribution systems. Flexible operators could provide the services. The directive 2009/72/EC of the European Commission defines ancillary services as "services necessary for the operation of a transmission or distribution system" [13]. According to the directive, the responsibility of ensuring the availability of these services rests with the system operator.

The specific types of ancillary services and their corresponding market solutions can vary among countries. Figure 2.4.1 displays the ancillary services in Norway listed by the Norwegian TSO Statnett. Conventional large power plants have been the primary providers of ancillary services. However, there has been growing interest in exploring the potential of flexibility derived from DER and DR programs to deliver these services. Especially frequency control, voltage control and load shedding can be provided by DR programs. The following section elaborates on the provision of frequency control, where existing markets make it possible to trade flexibility for these purposes. Considerable parts of Section 2.4.1 are obtained from my specialisation project [14] but are elaborated with the tables, the figures and additional technical requirements on activation of the reserves.

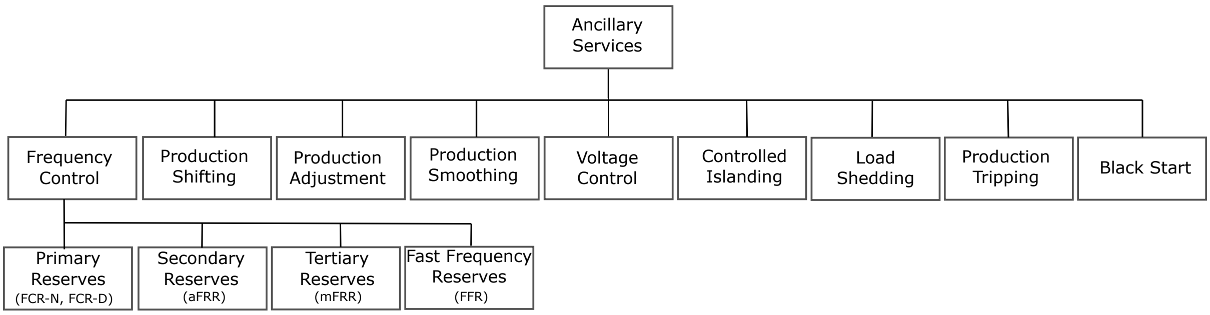


Figure 2.4.1: Overview of Ancillary Services listed by the Norwegian TSO, Statnett [15]. Figure obtained from my specialisation project [14].

FCR-N: frequency-controlled normal operation reserves, FCR-D: frequency-controlled disturbance reserves, aFRR: automatic restoration reserves, mFRR: manual restoration reserves, FFR: fast frequency reserves.

2.4.1 Frequency Control

During an imbalance between the generation and consumption of active power, the frequency will deviate from its nominal value. The frequency will increase with more generation available in the system than what is consumed. In the opposite case, the frequency will decrease.

In the Nordic region, TSOs employ four distinct categories of frequency reserves to address imbalances in frequency: fast frequency reserves (FFR), frequency containment reserves (FCR), automatic frequency restoration reserves (aFRR), and manual frequency restoration reserves (mFRR). The characteristics of the frequency reserves are displayed in Table 2.4.1. In addition, the order of response can be seen in Figure 2.4.2. In this thesis, the focus is on FCR.

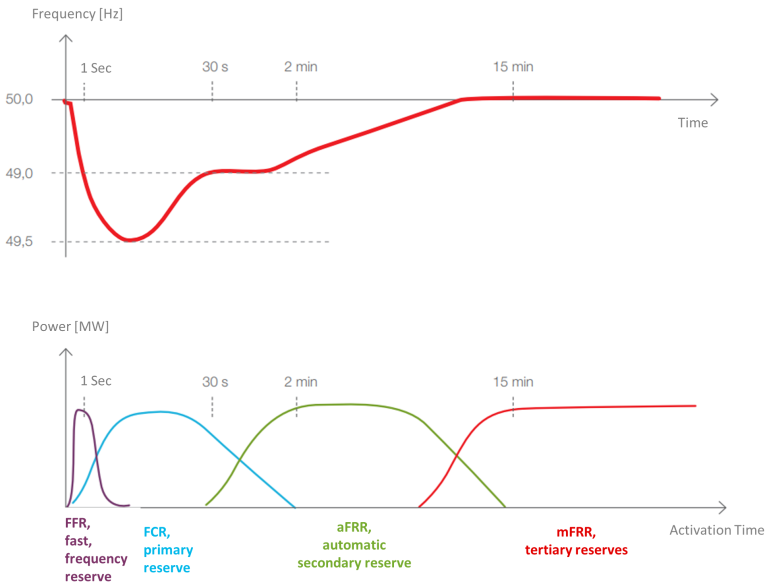


Figure 2.4.2: Diagram of frequency control after a loss of generation or a considerable load change. Figure 3 by reference [16].

Table 2.4.1: Characteristics of frequency reserves in Norway [17].

Reserve type	Activation signal [Hz]	Activation time [s]	Bid size [MW]	Comment
FFR	49.7, 49.6, 49.5	1.3, 1.0, 0.7	1	Only upward regulation.
FCR-N	49.9-50, 50-50.1	30	1	Symmetrical reserve
FCR-D	49.5-49.9, 50.1-50.5	30	1	Upward or downward reserve
aFRR	According to LFC function	300	1	Automatically activated on signal form TSO.
mFRR	By signal from TSO	900	5 or 10	Activated manually.

2.4.1.1 Primarly Control - Frequency Containment Reserves (FCR)

Primary frequency control serve as the initial response when a frequency deviation occurs, assuming the deviation is not excessively large. Primarily control eliminates the imbalance between generation and consumption by adjusting the active power generation and thus stabilising the deviation. However, it does not restore the frequency to its nominal value [18], [19].

In the Nordic system, FCR is split between frequency-controlled normal operation reserves (FCR-N) and frequency-controlled disturbance reserves (FCR-D) [20]. For deviations of ±100 mHz, FCR-N is activated. The activation is done automatically and proportionally to the frequency deviation, with full activation from ±100 mHz. For deviations more significant than ±100 mHz, FCR-D is activated. FCR-D is divided into FCR-D up for deviations from 49.9-49.5 Hz and FCR-D down for deviations 50.1-50.5 Hz. Similarly to FCR-N, FCR-D is activated proportionally to the frequency deviation with full activation from 49.5 and 50.5 Hz [20]. The droop characteristics of FCR-N and FCR-D activation are displayed in Figure 2.4.3. This is the required response of an FCR supplier. However, one is allowed to over-deliver by 10 % and under-deliver by 5 %. If one provides both FCR-N and FCR-D simultaneously, the red line must be followed [21].

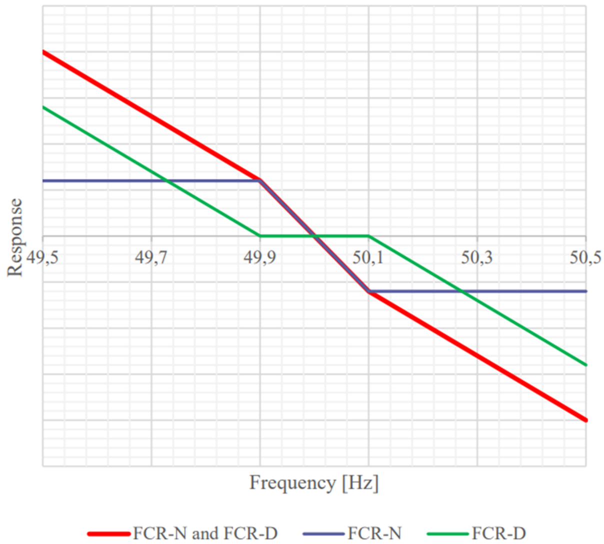


Figure 2.4.3: FCR reserves activation droop, figure 19 by reference [21].

Minimum bid size for FCR-N, FCR-D upward, and FCR-D downward is 1 MW [20]. It is required that the providers of FCR-N can deliver the service within 5 seconds, with full activation from 30 seconds [22]. Similarly, the activation of FCR-D must start within 2-3 minutes [22]. Suppose a supplier repeatedly fails to fulfil his obligation, and this is due to conditions within the supplier's control, the TSO can exclude the supplier from participating FCR market [20]. Additionally, the supplier must pay a deviation price for the obligation that is not delivered.

The bid is based on possible deviation according to an established baseline. The response is calculated as the deviation in active power output after the activation compared to the active power output if no reserves had been activated [21]. For suppliers that easily adjust the power setpoint or have a predetermined production, the baseline establishment could be done using the power set point. Other entities must be able to forecast the available FCR capacity [21].

According to ENTSO-E, the reserve activation should be maintained for the whole duration of the frequency deviation [21]. Therefore, it is required that the supplier of FCR-N can continuously deliver for 60 minutes in both directions if the frequency deviation requires it. For FCR-D, the requirement is 15 minutes. The Nordic TSO requires suppliers with LER to implement an energy management solution. Table 2.4.2 shows the proposed energy and power capacity requirements for FCR entities with limited energy reserves. However, the requirements are still under review and have not been implemented. The finalised new technical requirements will be published in May 2023 and implemented in the first quarter of 2024.

Table 2.4.2: Requirments for delivery of reserves by resources with LER [21]. C_{FCR} is the procured FCR capacity.

	Required power upwards [MW]	Required power downwards [MW]	Required energy upwards [MWh]	Required energy downwards [MWh]
FCR-N	$+1.34 * c_{FCR-N}$	$-1.34 * c_{FCR-N}$	$1h * c_{FCR-N}$	$1h * c_{FCR-N}$
FCR-D Up	$+C_{FCR_D,up}$	$-0.20 * c_{FCR-D,up}$	$\frac{1}{3}h * c_{FCR-D,up}$	0
FCR-D Down	$+0.20 * c_{FCR-D,down}$	$-C_{FCR_D,down}$	0	$-\frac{1}{3}h * c_{FCR-D,down}$

The activation of the reserves involve an energy exchange. Reducing or increasing the load, changes the rate at which energy is imported or exported. The energy exchange could involve increased costs of importing or exporting stored energy in the battery at a lower price. Therefore, the activated energy of FCR-N is compensating according to the regulating power prices [20]. The regulating power price has a price for both up and down-regulation. Most of the time, the supplier is compensated for up and down-regulation at different prices. However, in some hours, there is a negative regulating power price, which implies that the supplier must pay for his activation. The activated energy of FCR-D is not compensated.

2.5 The Norwegian Power Markets

The Norwegian power market is part of a joint Nordic market with Sweden, Denmark and Finland [23]. This ensures optimal use of capacity and production resources. The Power Markets is split into five segments: the financial market, the day ahead market, the intraday market, the balancing markets and the imbalance settlement market. The timeline of the Norwegian power market is displayed in Figure 2.5.1.

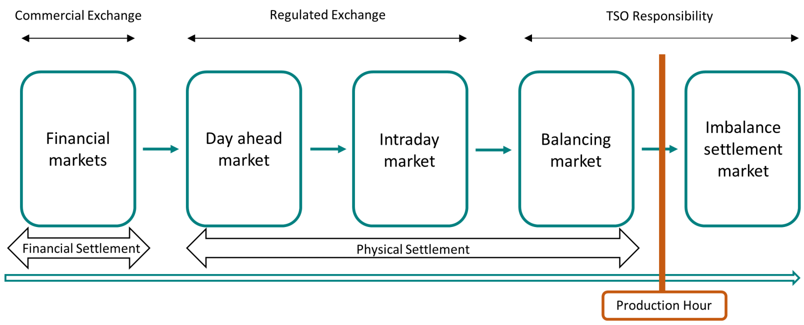


Figure 2.5.1: The timeline of the Norwegian power markets. Adapted by reference [24].

2.5.1 Day-ahead Market

The Day-ahead market settles the contracts for the power delivery for the next day. It is the primary marketplace where significant power volumes are traded. The market in the Nordic region is operated by PX Nordpool on a one-hour basis, with trading occurring one day before the actual operation [24], [23]. Volumes and prices in each price zone are determined through an implicit auction, utilizing a common European algorithm and considering the marginal price.

The Day-ahead auction opens at 08:00 in the morning, accepting bids until it concludes at noon. The bids consider the physical restrictions on the interzonal connections. At 10:00 each day, the TSO reports the capacities on the connections [24], [23].

Efforts are underway to establish price coupling between the Nordic region and the rest of Europe, employing a standardised European algorithm for price calculation [23]. It is worth noting that the Nordic region is already indirectly price-coupled with Europe. Some Day-ahead market regulations are summarized in Table 2.5.1.

Table 2.5.1: Day ahead market regulations by Nordpool [25].

Order types	Trade hours	Gate closure	Bid size [MW]	Maximum Bblock bid [MW]	Maximum price [EUR/MWh]
Hourly orders, block orders, flexible orders, other amendments	Next 24h starting from 00:00 CET.	12:00 CET	0.1	500	3000

2.5.2 Intraday Market

The intraday market is a complementary platform to the day-ahead market, addressing imbalances that may arise within each hour due to various uncertainties, including weather conditions and fluctuations in demand and generation capacities [24]. Operated by PX Nordpool, the intraday market opens three hours after the day-ahead market closes and is open for trading until the hour before the operation. The bids are accepted based on a first-come, first-served principle, which automatically matches bids after they are submitted [25]. Some Intraday market regulations are summarised in Table 2.5.2.

Table 2.5.2: Intraday market regulations by Nordpool [25].

Order types	Trade hours	Gate closure	Bid size [MW]
1 hour, block order	Next day starting from 00:00 CET.	One hour before operation.	0.1

2.5.3 Balancing Markets

Balancing markets encompass the operations conducted within each operational hour to maintain system stability [17]. While the day-ahead and intraday markets aim to balance generation and demand, unforeseen events, such as the sudden disconnection of large loads or generation units, may disrupt this balance. Therefore, the balancing markets ensure the instantaneous balance between generation and demand. In Norway, there are currently four frequency reserve products: the market for FFR, markets for FCR, the market for aFRR and markets for mFRR [17]. Technical specifications about these markets are described in Section 2.4.1. Table 2.5.3 presents some of the regulations of the FCR markets, which consist of the D1 and D2 markets. The D1 market is run one day before the operation day, and the D2 market is run two days before the operation.

Table 2.5.3: FCR-N market regulations by Statnett [20].

Market	Order types	Trade hours	Gate closure	Bid size [MW]
D1	1 hour	Next day	18:00 CET the day before operation.	1
D2	1 hour	In two days	17:30 CET two days before operation.	1

2.5.4 Imbalance Settlement Market

The imbalance settlement market, Nordic Balance Settlement (NBS), is joint for Norway, Sweden and Finland. The market aims to ensure that market participants are financially compensated for imbalances. The imbalances are calculated based on the difference between forecasted and recorded values.

2.6 Batteries

This thesis represents a continuation of my previous specialisation project, which focused on using storage systems, specifically batteries, on providing multiple services [14]. The decision was made in light of a literature study investigating the use of stationary batteries, electric vehicles and electric water heaters for ancillary services. A summary of the literature study is attached in Appendix A. In the subsequent section, the fundamental characteristics of stationary batteries are discussed. Most of this section is obtained from my specialisation project [14]. However, Section 2.6.3 is extended with additional information about the specific factors contributing to calendar and cycle ageing.

2.6.1 Characteristics

Batteries store electrical energy as chemical energy by applying potential at the electrodes. The chemical reaction, which stores the electricity, is reversible, making storing energy for later use possible. Various types of batteries are available in the market, including low-temperature options such as lithium-ion, lead-acid, and nickel-cadmium, as well as high-temperature options like sodium nickel chloride and sodium-sulfur and redox flow batteries such as vanadium and zinc-bromine [26].

When selecting a battery technology, numerous factors must be considered. Technical characteristics of a battery include the capacity, measured in MWh or kWh, power capability, measured in MW or kW, efficiency, response time, number of cycles and lifetime [26]. In addition, different applications may require different technical features. For example, a battery used for frequency regulation requires fast charge and discharge cycles, while a battery used for peak load shifting requires high energy capability [26].

Table 2.6.1 presents an overview of technical characteristics for the battery types mentioned above, extracted from reference [27] and supplemented with additional information from reference [28]. It is important to note that the listed articles were published in 2012 and 2014, and technological advancements have occurred since then. Among the listed battery types, lithium-ion batteries are a battery type with both high energy and power density. In addition, it also has a relatively long lifetime and high charge and discharge efficiencies. Table 2.6.2 shows some battery technologies compatibility with different grid applications [22]. The lead-acid, sodium-sulphur and lithium-ion batteries are the technologies with the best capability to offer grid services. All three types can deliver frequency services. Nevertheless, lithium-ion batteries are the most widely adopted battery type today and are a good choice for grid services [26].

Table 2.6.1: Technical characteristics of battery types from references [27] and [28].

Type	Power density [W/kg]	Energy density [Wh/kg]	Efficiency [%]	Cycles [number]	Lifetime [years]
Li-ion	245-2000	80–200	78-80	1500-3500	14-16
Lead-acid	180-200	30-50	70-80	200-1800	5-15
Nickel-cadium	100-160	30-80	72	3500	13-20
Sodium-sulphur	90-230	100-170	75-87	2500	10-20
Vanadium	166	20-35	65-88	2000-2500	8-10
Zinc-bromide	1-25 [28]	65 [28]	65-75 [28]	1000-3650 [28]	5-10 [28]

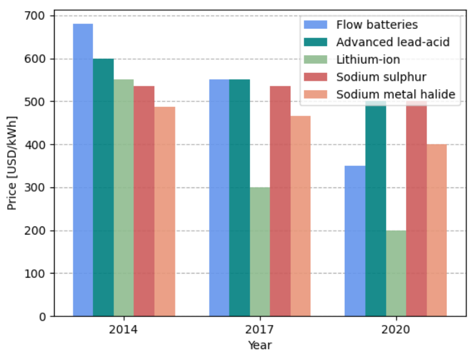
Table 2.6.2: A selection of electrochemical storage technologies' compatibility with a selection of grid applications, by reference [22]. The green colour indicates that the battery technology is suitable for the grid application, while the orange colour indicates that it is less suitable, and red indicates that it is unsuitable.

Application	Lead-acid	Nickel metal hydride	Sodium-sulphur	Sodium nickel chloride	Redox flow	Lithium -ion	Super-capacitor
Time-shift							
Renewable integration							
Network investment deferral							
Primary regulation							
Secondary regulation							
Tertiary regulation							
Black start							
Voltage support							
Power quality							

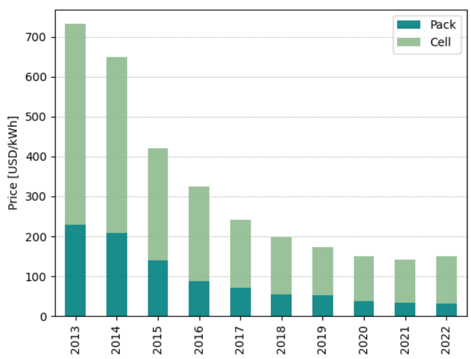
2.6.2 Cost of Battery Capacity

The critical prerequisite for the broad adoption of batteries used for grid services is the declining capacity cost. Figure 2.6.1a shows the declining price trend for several battery types. The most significant decline has been seen for lithium-ion batteries. Many factors contribute to this development, including greater manufacturing capacity, EV development and higher interest.

In BloombergNEF's annual battery price survey, the volume-weighted average price of lithium-ion batteries deviated from the declining trend in 2022 [29]. Instead, despite the increasing demand for batteries, the prices exhibited a 7% increase compared to 2021. Since the survey started in 2010, the prices have dropped more than 80% from 2010 to 2021, as seen in Figure 2.6.1b. Reference [29] reports that the incline in battery prices is due to inclined prices on raw materials and components. As a result, the price is expected to remain elevated in 2023 but decline again from 2024 onwards.



(a) Decline in battery prices among several battery types. Data by reference [26]



(b) Volume-weighted average lithium-ion price split in cell and pack price. Data by reference [29]

Figure 2.6.1: Decline in battery prices over the last decade.

2.6.3 Battery Degradation

Battery degradation is a critical consideration as it directly impacts revenue loss or the need for battery replacement. Reference [30] points out that battery lifetime models are required in many projects since performance parameters such as capacity and power capability of batteries are degrading at different conditions. An accurate battery lifetime model could ensure that the battery can deliver the necessary services throughout its lifetime. Neglecting degradation in a battery model may lead to a bias towards frequent charge and discharge cycles, which accelerates battery degradation.

Degradation is characterised by two factors: calendar and cycle life. Calendar life is the years the battery operates before it is considered degraded. Cycle life is how many charge and discharge cycles the battery can undergo before losing considerable performance [26]. A battery delivering 60-80% of its capacity is considered at its life end. A battery participating in the ancillary service markets could cycle multiple times per day, contributing to battery degradation. The current energy capacity of a battery is often expressed as a percentage of its initial energy capacity, known as the state of health (SOH) [26]:

$$SOH(t) = \frac{Energy\ capacity\ at\ time\ t}{Initial\ energy\ capacity}\ [\%] \tag{2.1}$$

Calander Ageing

Calander ageing is the degradation of the battery due to non-operational factors [31]. These include:

- Ambient temperature that may affect a battery's performance and lifetime. The optimal operating temperature for a lithium-ion battery is 15-35 °C [32].
- Ambient humidity in the storage environment can result in capacity fade.
- The current battery state of life will affect the remaining lifetime's length.
- The current calendar age that will affect the length of the remaining lifetime.

Cycle Ageing

Cycle ageing is the degradation of the battery that is linked to the use and operation of the battery [31]. These operational factors include:

- Dept of Discharge (DOD).
- Over-charge and over-discharge.
- Average state of charge (SOC).
- Current rate.

The DOD, meaning the percentage of the battery capacity used, has been identified as a significant factor contributing to battery degradation. The lifetime, measured in charge cycles, declines with a higher depth of discharge. DOD$>$ 80% is defined as deep cycle [26]. Figure 2.6.2 displays the number of life cycles declining with the DOD.

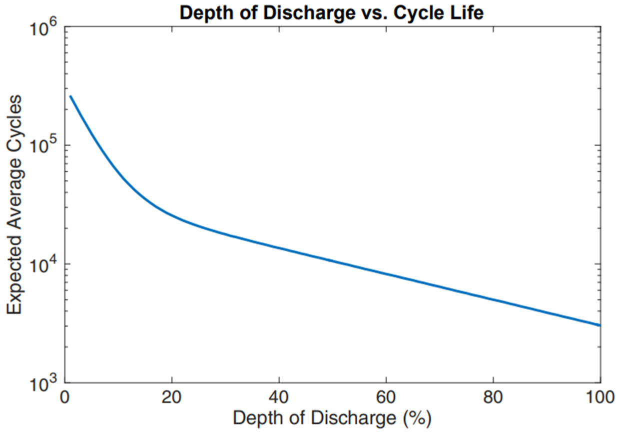


Figure 2.6.2: Cycle life as a function of DOD, figure 1 by reference [33] © [2016] IEEE.

2.7 Generating Forecasts

This section explains the uncertainty in parameters relevant to the optimisation problem defined in Section 4.2 and the time horizon of certainty for some of the parameters. The section further lists some simple forecast methods that can be used to predict uncertain parameters.

2.7.1 Uncertainty in Parameters

Sections 2.7.1.1 - 2.7.1.5 explain the uncertainty in generation from photovoltaic panels, domestic consumption, spot prices, grid tariffs and FCR-N markets prices and volumes.

2.7.1.1 Generation from Photovoltaic Panels

The power injected into the system by the PV generation is not known in real time. However, solar power can be predicted with varying levels of certainty. Some aspects of the production are known with certainty, such as that there will be no solar power generation at night. The maximum power output is also known since we know the sun's exact position at any time of year and day. The solar position at any time of day and year can be calculated with Equation (2.2) [34].

$$h = \sin^{-1}\left(1 - \sin^2 u * \cos^2 \alpha * \cos\beta * \cos\gamma + \sin u * \cos\alpha * \sin\beta\right) \tag{2.2}$$

where

h - The position of the sun for a chosen location [°].

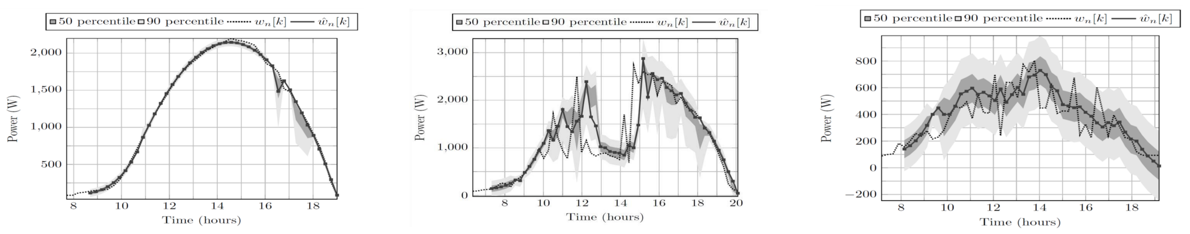
β - The latitude of the location [°].

α - Time of year, degree calculated from 21. of June [°].

γ - Time of day, degree calculated form 12 pm. [°]. $\gamma = 15° * x - 180°$, where x is the time of day.

u - The constant angle of inclination between the plane of the equator and the ecliptic planet ($u \approx 23.5°$).

However, solar power production is highly dependent on the weather. Therefore, certainty in the predictions is not necessarily increased closer to real-time. Generally, solar power forecasts are more confident on a sunny day than on a cloudy day [35]. For example, figure 2.7.1 shows how the uncertainty, the grey-shaded areas, increases with more cloudy weather.



(a) Sunny. **(b)** Mixed. **(c)** Cloudy.

Figure 2.7.1: Solar power forecasts for different weather types. The forecasts are more certain on a sunny day, than on a cloudy day. Figures 62-64 by reference [35].

2.7.1.2 Household Consumption

The household consumption is also first known in real-time. It is difficult to predict the use of individual appliances [35]. Nevertheless, households' aggregated consumer behaviour patterns can be predicted based on historical data. Based on the time of day, time of year, location and weather, the consumption can be predicted with high certainty [35].

2.7.1.3 Elspot Price

The spot price is an essential parameter in the operation of a storage unit. If the spot price is high, one typically wants to buy electricity from the grid, while in high price hours, one will consume or export the stored electricity.

The Norwegian spot price market is open for bids between 08:00-12:00 every day [36]. At 10:00, the TSO (Statnett) publishes each bidding area's trading capacities. The market closes at noon, and the hour-by-hour prices for the next day are published shortly after [36]. The spot prices are, therefore, always known for the next 12-36 hours, depending on the time of day.

2.7.1.4 Grid Tariffs

The grid tariff comprises two components: the power component and the energy component. The power component is a monthly expense calculated based on the average of the three highest import peaks during the month. The energy component is a fixed expense paid per kWh of imported electricity. Although the tariff level is not known in advance, the tariffs do not change frequently [35]. It is difficult to include a long-term price signal in short-term models. The tariffs could therefore be simplified. The tariffs could therefore be simplified.

2.7.1.5 Requested Volumes and Payment for Reservation of FCR-N

The Norwegian TSO Statnett is responsible for the markets for trading primary energy reserves. FCR-N are traded on two markets: the D2 market and the D1 market.

The D2 market is open from 00:00 two days before operation [20]. The bids must be submitted before 17:30, and Statnett provides information about the accepted bids by 18:30 [20]. Thus the hour-by-hour reserved volumes and payment in the D2 market are always known for the next 28.5 to 52.5 hours, depending on the time of day.

The D1 market is open from 00:00 one day before operation [20]. Bids must be placed before 18:00 and are accepted by 19:00 [20]. Thus the hour-by-hour reserved volumes and payment in the D1 market are always known for the next 4 to 28 hours, depending on the time of day.

Nevertheless, participation in the reserve markets requires bidding capacity before closing the markets. If the bid is accepted and to what marginal price is unknown at the bidding time. In real life, these parameters are therefore unknown at the time of decision.

2.7.2 Forecast Methods

Authors of [37] define forecasting as "the process of making predictions of the future based on past and present data". The goal is to analyse historical data, trends, observations and qualitative considerations of the future to predict future data with high accuracy.

It is distinguished between long-term, medium-term and short-term forecasts [37]. The first usually has a horizon of more than two years, demanding good knowledge about the data one attempts to predict. Medium-term forecasting usually has a horizon of 2 months and up to 2 years, while short-term predictions have a horizon of less than two months [37].

Time-series methods are used for short-term forecasting to provide forecasted future data with relatively simple techniques [37]. More advanced methods are available, but the resulting forecast is not necessarily more accurate. Herefore, the simple time-series methods are often preferable to avoid complexity in the model. The time-series methods involve the naïve method, the simple moving average, the weighted moving average, exponential smoothing and seasonal index [37]. These methods will briefly be explained in the following Sections 2.7.2.1 - 2.7.2.5.

2.7.2.1 The Naïve Method

The Naïve method is the simplest of the time-series methods [37]. It uses the previous period's actual data as the prediction for the next period. This is done without any adjustments. The Naïve method works well if the changes in the underlying information leading to the data are small. The drawback of the method is that it does not capture rapid changes. Equation (2.3) presents the basic logic of the naïve method.

$$forecast^{t+1} = observation^{t} \tag{2.3}$$

2.7.2.2 Simple Moving Average

The simple moving average involves using the average of the last n periods as the forecast for the next period [37]. The number of periods, n, is decided by the timeframe one wishes to review. Like the naïve method, the simple moving average works well for data that remains close to constant over time. However, the technique is not good at capturing rapid changes. The basic logic of the simple moving average is displayed in Equation (2.4).

$$forcast^{t+1} = \frac{\sum_{i=1}^{n} observation^{i}}{n} \tag{2.4}$$

2.7.2.3 Weighted Moving Average

The weighted moving average is similar to the moving average, but an additional weight is assigned to each data point [37]. In addition, greater weight is given to the most recent data, making them have more influence on the forecast than data points far away in time. The weighted moving average is better than the simple moving average at capturing trends in the data points but still has difficulties capturing rapid changes. The basic logic of the weighted moving average is displayed in Equation (2.5).

$$forecast^{t+1} = \sum_{i=1}^{n} weight^{i} * obervation^{i} \tag{2.5}$$

$$\sum_{i=1}^{n} weight^{i} = 1$$

2.7.2.4 Exponential Smoothing

Exponential smoothing combines observations and past forecasts to create a new forecast [37]. A smoothing factor, α, determines how quickly the forecast should respond to changes. As a result, there is no need for much historical data, and the method is often more accurate. The apparent upside of the technique is that it can respond to and capture rapid changes. The basic logic of the exponential smoothing method is displayed in Equation (2.6), where α is the smoothing factor.

$$forcast^{t+1} = (1-\alpha) * forcast^{t} + \alpha * Obervation^{t} \tag{2.6}$$
$$0 \leq \alpha \leq 1$$

2.7.2.5 Seasonal Index

The seasonal index method accounts for seasonal variations due to, i.e. changes in weather [37]. It is based on the average of the whole cycle but accounts for seasonal variations.

2.8 Model Predictive Control

A scheduling problem should be able to generate a good schedule and respond quickly and well to any deviations from that schedule. An iterative process can respond to changes and adjust the planning process.

MPC is a method that combines dynamic optimisation and control. It is a form of closed-loop optimisation that periodically re-optimises the problem to include feedback. In reference [38], model predictive control is defined as:

> A form of control in which the current control action is obtained by solving, at each sampling instant, a finite horizon open-loop optimal control problem, using the current state of the plant as the initial state; the optimisation yields an optimal control sequence, and the first control in this sequence is applied to the plant.

The basic algorithm is given in Table 2.8.1.

Table 2.8.1: MPC algorithm by reference [38].

MPC Algorithm
for t = 0, 1, 2, . . .:
Get the current state x_t.
Solve a dynamic optimization problem from t to t + N
on the prediction horizon with x_t as the initial condition.
Apply the first control move u_t from the solution above.
end for

2.8.1 Moving Time Horizon

Model predictive control uses a moving horizon [38]. The moving time horizon is a way to handle uncertain future predictions. A scheduling problem base its decisions on forecasts of the future to develop the best solution. The solution is optimal if the predictions are correct. However, it is like predictions to be unprecise. It is, therefore, essential to consider the error in the forecast. By moving the horizon forward in time, one can adapt to changing conditions. There are several ways to decide the moving horizon. Two common ways are the rolling time horizon and the receding time horizon.

The rolling time horizon method involves fixing the optimisation planning period, denoted by the scheduling horizon [39]. The deterministic problem is solved iteratively, and the time horizon in which it is optimised is moved forward for each iteration. This time horizon is denoted prediction horizon and is of the same size for each iteration and is the time horizon in which the problem is solved repeatedly [39]. The control horizon is a subinterval of the prediction horizon and is the time interval where the optimal actions are implemented [39]. The logic of the rolling time horizon method is displayed in Figure 2.8.1.

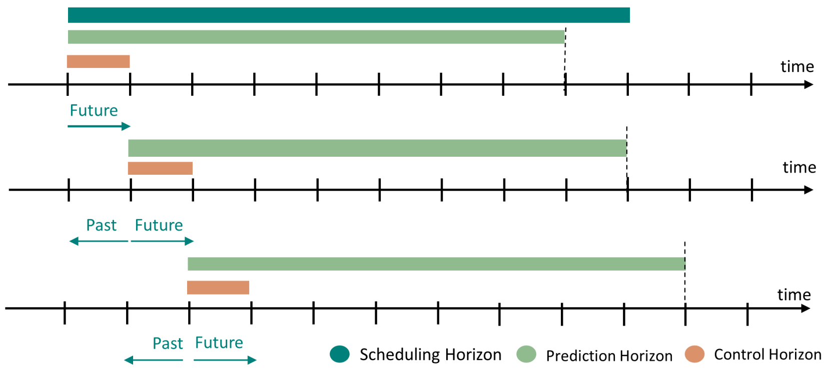


Figure 2.8.1: Rolling time horizon, after inspiration by reference [39].

The receding time horizon method involves defining a planning period, a prediction horizon and a control horizon similar to the rolling time horizon method [39]. However, the prediction horizon is not constant for each iteration. When approaching the end of the planning period, the prediction horizon will not exceed the planning period. Instead, the prediction horizon will be shorter for each iteration. The logic of the receding time horizon method is displayed in Figure 2.8.2.

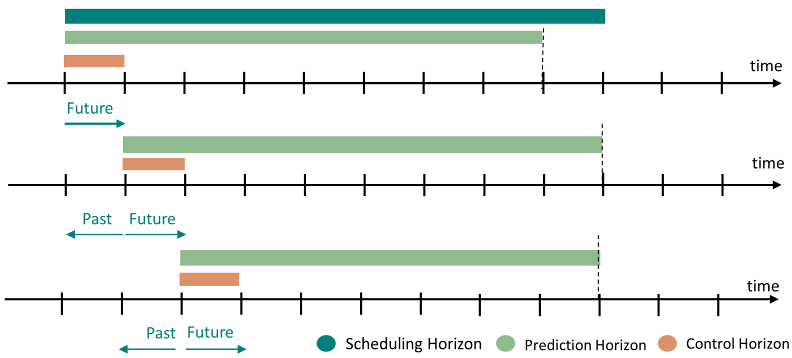


Figure 2.8.2: Receding time horizon, after inspiration by reference [39].

CHAPTER

THREE

LITERATURE REVIEW

This Chapter consists of four literature reviews conducted to enlighten important research questions relevant to solving the problem in this thesis. The purpose of the literature search is to use the previous work of others as a solid foundation to answer the questions raised in this thesis.

Firstly Section 3.1 investigates mathematical formulations that could describe battery degradation in an optimisation model. Secondly, literature is studied for cases where batteries provide multiple services in Section 3.2. Then, Section 3.3 searches for identified challenges in providing frequency containment reserves with batteries. Lastly, the literature searched for ways to keep the state of charge in the battery at an acceptable level during reserve provision in Section 3.4.

3.1 Battery Degradation Models

A literature review regarding the modelling of battery degradation was conducted during my specialisation project and founded the basis for the battery degradation model I implemented during the project. The following chapter is a repetition and an extension of chapter 5.2 in my specialisation project [14]. The literature review has been extended with an article by reference [30].

Table 3.1.1: Reviewed literature on implementing the battery degradation cost.

Ref.	Main results	Model
[31], [40]	Piecewise linear upper-approximation function to the Rainflow Counting Algorithm. The function divide the cycle dept into segments, J, evenly from 0% to 100%.	Linear
[41], [33]	Battery cost represented by battery's total replacement cost divided by the total lifecycle energy throughput as a function of the DOD	Linear
[42]	Estimates the rate of degradation under standard markov-operating uncertainty. Defined as a function of maximum SOC divided by total charge and discharge before the battery has reached its end of life	Linear
[30]	Investigates capacity fade and the power capability decrease due to both calendar and cycle ageing of a Li-ion battery cell when it is subjected to a field measured mission profile, used for primary frequency regulation.	Non-linear

References [31] and [40] model the battery degradation cost as a piecewise linear cost per segment of discharge depth. The loss of life, L, is given as the sum of the loss of life in each cycle, I:

$$L = \sum_{i=1}^{I} \Phi(\delta_i) \tag{3.1}$$

The battery's cycle depth in time step t depends on the cycle dept in the time step. It is calculated assuming battery ageing occurs when discharging, according to:

$$\delta_t = \delta_{t-1} + \frac{1}{\eta_{dch}} * \frac{1}{E^{rate}} * g^t \tag{3.2}$$

Where η_{dch} is the discharge efficiency and g^t is the power output.

The marginal cycle ageing is further derived as:

$$\frac{\partial \Phi(\delta_i)}{\partial g^t} = \frac{\partial \Phi(\delta_i)}{\partial \delta_i} * \frac{\partial \delta_i}{\partial g^t} = \frac{1}{\eta_{dch} * E^{rate}} * \frac{\partial \Phi(\delta_i)}{\partial \delta_i} \tag{3.3}$$

The marginal cost of cycle ageing is calculated by distributing the replacement cost, R, over the cycle ageing, consisting of J segments dividing the SOC from 0% to 100%:

$$c_j(\delta_t) = \begin{cases} c_1 \ if \quad \delta_t \in [0, \frac{1}{J}), \\ . \\ . \\ . \\ c_j \ if \quad \delta_t \in [\frac{j-1}{J}, \frac{j}{J}), \\ . \\ . \\ . \\ c_J \ if \quad \delta_t \in [\frac{J-1}{J}, 1] \end{cases} \tag{3.4}$$

δ_t is the cycle dept in any time step t, and the cost equals:

$$c_j = \frac{R}{\eta_{dch} * E^{rate}} * J[\Phi(\frac{j}{J}) - \Phi(\frac{j-1}{J})] \tag{3.5}$$

The revenue from the additional reserves provision is the main focus of this project. Therefore, a very accurate battery degradation model is unnecessary for studying the effects of reserving capacity for ancillary services. Therefore, a more straightforward model of the battery degradation cost is desired. A way to model battery degradation is to assign the battery replacement cost to the total battery energy throughput during the lifetime, as done by references [41] and [33].

$$c_d = \frac{Battery\ replacement\ cost}{Total\ energy\ throughput\ during\ life\ cycle} \quad [NOK/kWh] \tag{3.6}$$

The total battery degradation cost is then calculated dependent on lifecycles as a function of depth of discharge:

$$c_d = \frac{c_{bu} * E_b}{2 * L_b(DOD) * E_b * DOD} \tag{3.7}$$

In Equation (3.7), c_{bu} is the unit cost, E_b is the battery rated capacity, and L_b is the life cycles.

Reference [30] investigates the degradation of LiFePO4 battery cells used for primary frequency in western Denmark. It is important to mark that the battery is only used for upward regulation since asymmetrical bids are possible in Denmark. The lifetime degradation model was developed based on laboratory tests that tested three stress levels for each stress factor (i.e. SOC-level, storage temperature, ambient temperature, cycle depth and charging/discharging current rate) [30].

The resulting calendar lifetime degradation model is:

$$C_{f_cal} = 0.1723 * e^{0.007388*SOC} * t^{0.8} \tag{3.8a}$$
$$PC_{d_cal} = 0.0033 * SOC^{0.4513} * t \tag{3.8b}$$

Where C_{f_cal} and PC_{d_cal} are the capacity fade and power capability decrease, respectively. Note that the capacity fade follows a non-linear trend, while the power capability fade is linear. It should also be noted that the decrease in power capability is slight compared to the capacity fade. Tests by reference [30] also confirmed that the battery capacity is the limiting factor, not the power capability decrease.

In the same manner, the cycle lifetime degradation follows:

$$C_{f_cyc} = 0.021 * e^{0.01943SOC} * cd^{0.7162} * nc^{0.5} \tag{3.9a}$$
$$PC_{d_cyc} = 1.1725 * 106 * cd^{0.7891} * nc \tag{3.9b}$$

The result is a capacity fade that follows a square-root function on the number of cycles performed. Additionally, the power capability decreases linearly with the number of cycles.

3.2 Energy Storage Revenue Stacking

This section investigates revenue stacking of battery storage providing multiple services, in the literature. The focus is mainly on the method used and if the authors found an increased revenue.

Table 3.2.1: Reviewed literature on revenue stacking of battery operation.

Ref.	Services	Increased revenue?	Simontanious delivery?	Content	Comment
[43]	FCR-N and FCR-D.	Yes	No	Economic value of multi-market bidding in nordic frequency markets.	Choosing the most profitable service in each hour.
[44]	Energy arbitrage, frequency regulation, reserves and investment deferral.	Yes	Yes	Analysis of multiple revenue streams for privately-owned energy storage systems.	Co-optimisation.
[45]	Energy shifting, frequency regulation, and outage mitigation.	Yes	No	Stacked Revenue and technical benefits of a grid-connected energy storage system.	Sequential Monte Carlo Simulation and non-linear programming.
[46]	Peak-shaving, frequency regulation and reserve support.	Yes	Yes	Establishing the stacked value of battery energy storage providing multiple services.	Non-linear (MIP).
[47]	Energy markets, spinning reserve and balancing markets.	No	Yes	Economic viability of NaS battery plant in a competitive electricity market.	Non-linear (MIP).

Reference [43] investigated the stacked revenue of a battery storage system providing FCR-D and FCR-N in the Danish system. The battery is solely used to provide frequency regulation. Revenue stacking is done by choosing the most profitable service in each hour based on forecasts of prices, expected cost of losses and tariffs. It is assumed that a perfect prediction of the average market value is available. The results show that multimarket bidding is more profitable in all cases. The increase in revenue is between 2-46% compared to FCR-N and 2-128% compared to FCR-D.

Reference [44] performed co-optimisation of two or more services. The considered services were energy arbitrage, frequency regulation, reserves and investment deferral. The authors found that of the single services, frequency regulation provided the highest revenue, while energy arbitrage provided the lowest. However, they discovered that giving all four services provided the highest income. The revenue was 79.3% of the sum of all individual revenues. The model does not consider uncertainties and estimates the maximum benefits one can obtain by providing multiple services.

Reference [45] considered revenue stacking by providing energy shifting, frequency regulation and mitigating outages. Monte Carlo simulations and non-linear programming is used in the analysis. The authors found that delivering all three services generates the highest revenue. However, the model included a non-linear constraint that assumes that only one service could be provided at a time.

Several articles use Mixed-integer programming (MIP) to evaluate the stacked value. Authors of reference [46] found that providing peak-shaving, frequency regulation, and reserve support yields more profit than providing one service in an Arizona-based test system. Similarly, authors of reference [47] investigated multimarket participation in the energy market, the spinning reserve and the balancing markets with a NaS battery. The authors found that the operation should be financially supported. However, battery prices have declined since 2009, when the article was written and could be more profitable now.

In summary, the articles fund that revenue stacking yields more profit than delivering only one service. However, the approaches to providing multiple services differ. Some methods involve simultaneous delivery, others such that reference [43], limit the delivery to one service at a time.

3.3 Batteries Providing FCR Reserves - Identified Challanges

Although using batteries to provide various types of flexibility is a common thought, there needs to be more experience with using them for FCR services, in practice. In the seek to find suitable solutions for providing FCR, it is, therefore, necessary to understand the challenges and limitations. Thus, this section summarises some of the challanges identified in the literature.

Table 3.3.1: Reviewed literature on challenges in using batteries for FCR provision.

Ref.	Content	Challenges	Solutions
[48]	Two generic methods to calculate the resulting limits of the normal operation range are proposed.	Too long minimum activation period.	Reduce FCR capacity range, increase battery size, change regulations.
[49]	Effects of battery aging on BESS participation in frequency service markets.	Battery degradation reducing profitability of participating in the FCR markets.	Include battery degradation in profitability study.
[50]	Considering againg effects on EVs providing frequency regulation.	Unfortunate effects on battery degradation if aging due to frequency regulation is ignored.	Adjust charge and discharge power.
[51]	Analysing the profitability of consumer batteries providing frequency containment reserves.	Cost of batteries are high.	Reducing consumer electricity costs, but not a profitable investment alternative.
[52]	Evaluating the economic feasibility of frequency reserve provision using battery energy storage.	High cost of capacity, disadvatagious regulations.	Change regulations.

Reference [48] identified the importance of the minimum activation time; that is, the minimum time FCR reserves should be activated if there is a frequency activation. The authors investigated a 15 and a 30-minute minimum activation period. They found that the share of the battery capacity used for corrective measures of the SOC level increased for the 30-minute period compared to the 15-minute period. When large percentages of the battery capacity were reserved for FCR in the 30-minute period, the reserves' delivery became impossible without exceeding the battery state of charge limits. The solution in such cases is to either increase the battery capacity or reduce the amount of FCR reserves. The authors, therefore, advise that regulations be reviewed and that shorter minimum activation periods are considered to include a broader range of FCR service providers [48]. The same challenges will be present for batteries providing FCR reserves in the Norwegian FCR markets, as the minimum period for FCR-N is 60 minutes [20].

Several articles highlight the importance of including the degradation of the batteries when participating in the FCR markets. Reference [49] found that the profit of providing FCR in the Finnish market is reduced by 6.06 cents/kWh when including the cycling effects. [50] investigated the provision of frequency reserves with EVs treated as a distributed storage system. The authors point out that the nature of providing frequency reserves leads to fast charge and discharge cycles, accelerating the degradation. The proposed solution is to manage the maximum charge and discharge power to reduce ageing effects.

There is a uniform agreement in the literature that the cost of batteries is high. However, they have decreased in the past decade, leading to the discussion that providing FCR with batteries could be profitable. Authors of reference [51] found that reserving FCR capacity with consumer batteries reduced the annual electricity costs for the battery owner. However, they found that investing in batteries is not profitable for consumers without time of use (TOU) and time of export (TOE) tariffs. An alternative is that investment costs of the battery are split between the consumer and the aggregator [51]. One should also notice that the analysis conducted by reference [51] does not include activation of the FCR reserves.

Furthermore, reference [52] found the economic feasibility of using BESS to provide FCR unsatisfactory. The authors found that both the cost of degradation and the cost of battery capacity contribute to the difficulty of using BESS for FCR provision. Nevertheless, the authors point out that unsatisfactory regulations are the greatest hindrance to utilising batteries for FCR, resulting in reduced battery lifetime and unavailability during service provision. This complies well with the founds by authors of reference [48].

3.4 State of Charge Managment

The deployment of FCR using batteries presents additional challenges due to their limited energy reserve, as identified in the previous section. According to SO GL article 156.7-9, the automatic response to a frequency deviation must remain active for the duration of the deviation [21]. Therefore, effective management of the battery's state of charge is critical to prevent exceeding energy capacity limits.

In particular, FCR-N rely on the symmetric provision, as outlined in Section 2.4.1.1. The frequency in the power system is near-normal, distributed around 50 Hz, as demonstrated in Figure 3.4.1. By activating reserves in both upward and downward directions, the battery's state of charge is maintained at an acceptable level most of the time. However, there are small biases in the distributions that can be seen in Figure 3.4.1 as a displacement of the curves. Research by reference [53] reports that these biases are around 1.5%, leading to energy capacity limits being reached over time if the state of charge is not appropriately managed. Additionally, historical data reveals that incidents with prolonged frequency disturbances in a single direction may cause the battery to exceed its capacity limits.

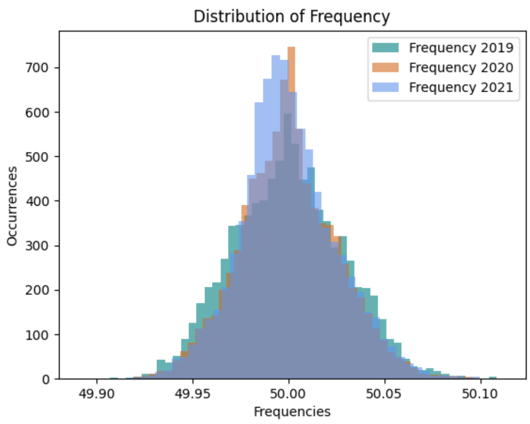


Figure 3.4.1: Distribution of frequency in the years 2020 and 2021.

The Nordic TSOs require that energy resources with limited energy reserves adopt an energy management strategy [21]. An acceptable energy management solution must incorporate an energy recovery process that does not interfere with the delivery of reserves [21]. The literature is therefore searched for energy recovery solutions that comply with these requirements.

Table 3.4.1: Reviewed literature on methods for SOC management.

Ref.	Resource	Content	Control Method	Comment
[54]	BESS	Impact analysis of different operation strategies for battery energy storage systems providing primary control reserves in Germany.	Overfulfillment, deadband utilization and scheduled transactions on the intraday market.	Deadband utilization not possible in the Norwegian system.
[55]	BESS	Real-world operating strategy and sensitivity analysis of frequency containment reserve provision with battery energy storage systems in the German market.	Overfulfillment, deadband utilization and scheduled transactions on the intraday market.	Deadband utilization not possible in the Norwegian system.
[56]	BESS	Control Strategy for Frequency Regulation using Battery Energy Storage with Optimal Utilization	FCR activation based on SOC level.	Involves restricting FCR activation for undesirable SOC levels.
[57]	BSS	Optimum Operation of Battery Storage System in Frequency Containment Reserves Market	Deadband utilisation, reserve Time for SOC Recovery and overfulfillment.	Deadband utilisation not possible in Norway. Little profit for the other methods.
[53]	BESS	Use storage systems for the provision of ancillary services by adjusting the setpoint.	Setpoint adjustment	Could be easily implemnted.

References [54] and [55] proposes three methods for recovering the energy after activation. The first proposed method is recovery through over-fulfilment. One can overfill the delivery of primary energy reserves by 20% in the German system. It allows for room to charge or discharge the battery. However, only 10% of over-fulfilment or 5% under-fulfilment is allowed in the Norwegian system [21].

The second method proposed by references [54] and [55] is to take advantage of the dead-band between 49.99 and 50.01 Hz, where there is no requirement to deliver primary frequency control services. However, there is no dead band in the Norwegian system. Hence, the method is not applicable there.

The last option proposed by references [54] and [55] is charging or discharging through scheduled transactions on the intraday market. It is essential that the net energy supply still complies with the delivery of primary energy reserves. In situations where energy is bought on the intraday market, there is an additional cost. On the other hand, in cases where energy is sold on the intraday market, there is extra revenue.

Reference [56] propose a control strategy for batteries providing frequency regulation based on the state of charge. The paper discusses frequency regulation specifically for the Indian system, where the frequency is mainly on the low side. The authors, therefore, point out that the control strategy must provide more opportunities for charging than discharging. The method involves allowing FCR activation only in specific predefined SOC ranges. Outside this range, FCR activation is not allowed [56]. This does not comply with the Nordic system, where one must always provide FCR activation if required.

Reference [57] also proposes dead-band utilisation for SOC recovery in the Finnish system, where there is a dead band between 49.99 Hz and 50.01 Hz. The paper simulates the method for battery system storage using constrained particle swarm optimisation. The results in reference [57] suggest large profits through providing FCR reserves with dead-band utilisation SOC recovery. The profit was increased by 80% in the use case due to increased capacity revenue and decreased capacity penalty. Additional revenue is created since the SOC recovery usually is in the opposite direction of FCR-N regulation, thus reducing the grid tariff. However, reference [57] points out that this method will not be allowed by future technical requirements in Finland. It is also the case in the Norwegian system. The technique is, therefore, not applicable.

Reference [57] further investigated SOC recovery through over-fulfilment and reserved time for SOC recovery. The first method involves activating more significant FCR-N reserves agreed upon if the system requires regulating power to match SOC recovery direction. Since the process involves providing FCR-N activation without any capacity payment, the profit is small due to internal losses and demand tariffs. The use case profit increase was less than 1% [57]. The second method with reserved time for SOC recovery generates little profit; the use case profit is just above 4%. The method involves letting go of low-capacity revenue to avoid high-capacity penalties. However, the profit is little in systems where there is little difference between the capacity revenue and capacity penalty. In the Finnish system, the capacity penalty and the capacity revenue are equal [57].

Reference [53] discuss a similar control strategy as references [54] and [55] with set point adjustments and scheduled transactions. The energy needed for the set point adjustment could be contracted through the intraday market, balancing markets, bilateral agreements or pooling with a power plant [53]. The authors point out that SOC management through the intraday market and bilateral agreements is more economically reasonable than SOC management through the balancing markets. However, these solutions involve longer delivery times. Energy contracted on the balancing markets are immediately available.

The overall advantage of set point adjustment is the easy implementation and few technical and regulatory limits. The authors of reference [53] proposes Equation (3.10) to calculate the set point offset. The set point adjustment should account for both the ancillary service delivery and the battery loss.

$$P_{WP}(k+d) = \frac{\sum_{j=k-a}^{k}(-P_{AS}(j)) + P_{loss}(j)}{a} \tag{3.10}$$

Where P_{WP} is defined as the working point, P_{AS} the requested ancilalry service power and P_{loss} the battery loss. The working point is calculated at time k and applied after a delay of d time steps. Parameter a denotes the period where the average is calculated. Equation (3.11) gives the resulting set point adjustment power.

$$P_{WP,adj} = P_{WP} + P_{AS} \tag{3.11}$$

In summary, the technical requirements of FCR provision in the Norwegian markets restrict the number of feasible solutions for SOC recovery strategies. Overfulfillment is challenging to implement since only 10% over-fulfilment and 5% under-fulfilment are allowed. Furthermore, dead band utilisation is also ruled out since FCR reserves are activated once the frequency deviates from 50 Hz. This also leaves out methods that restrict activation based on SOC levels. The only feasible strategy is set point adjustments by scheduled transactions that recover the SOC level. The market must be chosen based on what is best for the specific battery operation.

CHAPTER

FOUR

METHOD

This chapter describes the optimisation methods and software used to solve the formulated problem and answer the research objectives. The applied algorithm and the assumptions made before solving the problem are described in Section 4.1.4 and Section 4.1.5. Further, Section 4.1.6 discusses how the unknown parameters are predicted. Section 4.2 provides the complete formulation of the optimisation model developed during the work of this thesis.

4.1 Optimisation Method and Software

The optimisation model is developed to analyse the potential savings in electricity costs for a consumer with a battery and PV generation system. The possible savings for the consumer originated in performing energy arbitrage and participating in the FCR-N markets.

An economic analysis of the annual expenses was done in my specialisation project with a simple optimisation model [14]. The results showed considerable savings in participating in the markets for FCR-N reserves. However, the work did not account for the activation of the reserves. To this author's knowledge, little literature discusses the effect of reserve activation. The activation is often left out of the analysis since the net energy involved is zero due to the near-normal distribution of the frequency. This is an acceptable assumption for a conventional power plant that can quickly ramp up and down the power. However, when a resource with limited energy reserves delivers the services, there is a risk that the storage will reach its maximum or minimum state of charge during a longer event with over- or under-frequency. Therefore, the reserve activation is an essential element in the optimisation model.

4.1.1 Revenue Stacking

An essential part of the optimisation problem is to provide several services simultaneously to increase revenue for the battery owner. This is known as revenue stacking and involves investigating if providing multiple services results in more significant revenue than providing only the primary service. The services must be technically and operationally compatible and can be provided simultaneously or in separate periods, depending on the services. The storage system will be modelled by providing three services simultaneously:

1. Cover the household's consumption of electricity.
2. Performing energy arbitrage, i.e. storing and trading electricity for increased revenue.
3. Providing and delivering FCR-N reserves.

4.1.2 Mixed Integer Linear Optimisation Problem

The problem is formulated as a mixed integer linear optimisation problem (MILP) which involves continuous and integer variables subject to a set of linear constraints. The integer variables enable the modelling of decisions; apply the decision if the integer variable is one, and do not apply the decision if the value of the integer variable is zero. MILP can be solved with various algorithms, such as branch and bound, interior point methods and cutting plane methods [58].

The problem is further modelled as a deterministic problem, which is a problem where the parameters and inputs of the model are fixed. Therefore, the decision variables and the problem's objective are solely determined by the model's inputs and constraints. Even though the problem is deterministic, the uncertainty in parameters is considered by using forecasts as input to the model.

4.1.3 Software

The optimisation problem is formulated and implemented in Python. Python is an open-source programming language used worldwide for several applications. The language features several software packages designed for a given purpose, making it easy to use.

Among the diverse library of software packages, Pyomo is used for formulating the optimisation problem. Pyomo is an open-based package that enables the formulation, solving, and analysis of optimisation problems [59]. It allows the formulation of a wide range of optimisation problems.

Furthermore, Gurobi is used as the optimisation problem solver. Gurobi is an optimisation software that solves numeric problems and applies problem reformulation and heuristic methods to find the optimal solution quickly [58]. It can solve linear problems (LP), quadratic problems (QP), quadratic constraint programming (QCP), MILP, mixed-integer quadratic programming (MIQP), and mixed-integer programming with quadratic constraints (MIQCP) [58].

4.1.4 Two-stage MPC Algorithm

The problem is solved using model predictive control with a rolling time horizon, as described in Section 2.8. The equations of the optimisation problem are described in the next section, but the following Table 4.1.1 describes the logic of the optimisation method used to solve the problem. The algorithm is an extension of the basic algorithm in Table 2.8.1 in Section 2.8.

The problem is formulated as a two-stage optimisation problem. In the first stage, the decision to procure FCR-N reserves in the D1 and D2 market are taken concerning the next day. Since frequency reserves are delivered as a deviation from a baseline scenario (i.e. the delivered or consumed power if no reserves are activated), a baseline consumption or production must be established. In accordance with the baseline, the amount of reserves can be decided. This also applies to FCR-N reserves delivered by storage units or load entities. The first stage's battery charge and discharge decisions will be a baseline for calculating the activated reserves.

In the second stage, the frequency for hour zero of the prediction horizon (the control horizon) is used to calculate the activation of reserves as a deviation from the baseline decided in the first stage. Then, based on the PV generation, the domestic demand for electricity, prices and activated reserves, the charge and discharge schedule and the import and export schedule is calculated for the prediction horizon length and applied to the control horizon.

Table 4.1.1: MPC algorithm used to solve the optimisation problem.

Algorithm
for day=1, 2, ... 365 **do**
Get SOC_{init}.
Get predictions for demand and PV generation.
Get spot prices, required reserves and prices in the D1 and D2 market for FCR-N reserves.
Solve optimisation problem for period t=1, .., 48.
Obtain the allocated reserves in the D1 and D2 market and the charge and discharge schedule for period t=1, ..., 24.
for hour=1, 2, ..., 24 **do**
Get SOC_{init}, the average frequency deviation for the current hour and actual household demand and PV generation of the current hour.
Get the charge and discharge schedule and the allocated reserves in the D1 and D2 market for t=1, ..., 24.
Get predictions of household demand and PV generation for period t=2,.., 72 + hour.
Get the known and predicted spot prices, required reserves and prices in the D1 and D2 market for FCR-N reserves for hours t=1, ..., 72..
Solve dynamic optimisation problem for t=1, .., 72.
Get the regulating power prices of the current hour.
Obtain the charge and discharge schedule and the import and export schedule.
Apply schedule for t=1.
end for
end for

4.1.5 Assumptions

General Assumptions

- A consideration of investment costs is not included. It is assumed that the battery and PV system already exists.
- The household consumption is not altered.
- SOC management is assumed to be handled with scheduled transactions on a different market but is not included in the model. Instead, it is attempted to reduce the number of times the battery's start of charge limits are exceeded.
- Financial penalties for failed delivery is not included.
- There is assumed no aggregator. In reality, an aggregator must be present to aggregate the small contribution of the household with other suppliers of reserves. The aggregator would also keep some profit from the balancing markets, as described in Section 2.3.4.

First-Stage Assumptions

- The scheduling horizon is 365 days. The first stage problem is solved once for each day.
- The optimisation horizon is set to 48 hours.
- The procured FCR-N reserves in the D1 and D2 market are determined simultaneously at 00:00 at the start of the day. In reality, the contracted reserves at the D2 market are determined at 18:30, two days before the operation, and the reserves at the D1 market at 19:00, the day before the operation.

- There is assumed no bidding process as described in Section 2.3.3 point 2. Instead, reserves are assumed to be provided at the battery owner's convenience according to required market volumes.
- There are assumed no market clearing as described in Section 2.3.3 point 3. Prices at the balancing markets are either known or predicted at the point of reservation.
- The state of charge, $E_{b,init}$, in hour one of day one of the whole optimisation problem, is set to $0.5 * E_{b,cap}$.
- The state of charge, $E_{b,init}$, in the rest of the optimisation problem is equal to the SOC of the end of the previous hour.

Second-Stage Assumptions

- The control horizon is 1 hour; thus, the decisions of the first hour in every iteration are applied.
- The prediction horizon is 72 hours.
- The problem is solved repeatedly 24 times to find and apply the decisions of the first 24 hours.
- $E_{b,init}$ in the first hour of the whole optimisation problem, $hour_{curren}$, is set to $0.5 * E_{b,cap}$.
- $E_{b,init}$ in the rest of the optimisation problem is set equal to the previous hour.
- The procured FCR-N reserves in the D1 and D2 market are determind in the fisrt stage problem. The contracted reserves are therefore treated as parameters in the second stage problem.
- The regulating power prices are always assumed to be known.

4.1.6 Forecasts

Predictions of prices in the spot and reserve markets, the volumes, the household demand and the PV generation are predicted according to the Naïve Method explained in Section 2.7.2. It is the simplest of the forecast methods but is used for illustration purposes. A more complex forecast method can easily be implemented at a later stage.

First-Stage Forecasts

- The spot price is known for the first 24 hours of the horizon. According to the Naïve Method, the spot price in the last 24 hours of the horizon is predicted to be equal to the first 24 hours.
- The D1 marginal price and required volumes are known for the first 24 hours of the horizon. According to the Naïve Method, the D1 marginal price and required volumes in the last 24 hours of the horizon are predicted to equal the first 24 hours.
- The D2 marginal price and required volumes are known for 48 hours and do not need to be predicted.
- The PV generation is unknown until the hour of operation. According to the Naïve method, the PV generation for the whole horizon of 48 hours is predicted to be equal to the PV generation of the previous day. Thus, it is predicted that there will be two following days with equal PV generation.
- The household consumption is unknown until the hour of operation. According to the Naïve method, the household consumption for the whole horizon of 48 hours is predicted to equal the previous day's consumption. Thus, it is predicted that there will be two following days with equal household consumption.

Second-Stage Forecasts

- The spot price is known for the next 24-36 hours, depending on the time of day. At the start of the prediction horizon, the spot prices for the last 48 hours are equal to those for the first 24 hours, according to the Naïve method. Resulting in three consequent days with equal spot prices. After noon each day, the spot prices are updated according to the released spot prices.
- The D1 marginal prices and requested volumes are known for the first 24 hours. Therefore, the prices and volumes are equal to zero in the last 24 hours since there only are contracted reserves for the first 24 hours, as decided in the first stage problem.
- The D2 marginal prices and requested volumes are known for the first 24 hours. Therefore, the prices and volumes are equal to zero in the last 24 hours since there are only contracted reserves for the first 24 hours, as decided in the first stage problem.
- The PV generation is unknown until the hour of operation. According to the Naïve method, the PV generation for the whole prediction horizon of 72 hours is predicted to be equal to the PV generation of the previous day. Thus, it is anticipated that there will be three following days with similar PV generation. The actual PV generation becomes known for the operation hour in the control horizon. The predictions are, therefore, continuously updated with the latest data.
- The household consumption is unknown until the hour of operation. According to the Naïve method, the household consumption for the whole horizon of 72 hours is predicted to be equal to the previous day's consumption. Thus, it is expected that there will be three following days with similar consumption. The actual household consumption becomes known for the operation hour in the control horizon. The predictions are, therefore, continuously updated with the latest data.

4.2 Optimisation Problem

This section describes the parameters, variables and sets used in the optimisation problem. It further describes the equations used to model the different parts of the system in Sections 4.2.2 - 4.2.9. The optimisation problem is based on the one-stage deterministic problem formulated in my specialisation project [14]. However, the specialisation project problem was re-formulated to a two-stage optimisation problem to account for parameter uncertainties. Furthermore, an essential part of the work in this master thesis has been to account for the activation of FCR-N reserves and reflect the risk of reaching the battery state of charge limits due to activation in the model formulation. The model is therefore altered to consider these aspects.

4.2.1 Nomenclature

Variables

P_{exp}^t - Power exported to the grid in time step t [kW]

P_{imp}^t - Power imported from the grid in time step t [kW]

P_{ch}^t - Charged power to the battery in time step t [kW]

P_{dch}^t - Discharged power to the battery in time step t [kW]

E_b^t - Energy stored in the battery in time step t [kWh]

SOC^t - State of charge of battery in time step t [%]

SOH^t - State of health of battery in time step t [%]

$E_b^{cap,t}$ - Energy capacity of the battery in time step t [kWh]

P_{D1}^t - Capacity reserved in the battery for FCR-N reserves in time step t, traded on the D1 market [kW]

P_{D2}^t - Capacity reserved in the battery for FCR-N reserves in time step t, traded on the D2 market [kW]

$P_{D1,act}^t$ - Activated FCR-N reserves according to the D1 market in time step t [kW]

$P_{D2,act}^t$ - Activated FCR-N reserves according to the D2 market in time step t [kW]

$S_{slack,pos}^t$ - Slack variable, if the battery reaches its minimum SOC in time step t[kW]

$S_{slack,neg}^t$ - Slack variable, if battery reached its maximum SOC in time step t [kW]

Binary Variables

$\delta_{2g}^t \in \{0,1\}$- Equals 1 if power is exported to the grid in time step t, 0 otherwise

$\delta_{ch}^t \in \{0,1\}$ - Equals 1 if the battery is charging in time step t, 0 otherwise

Sets

D - Days, $d \in D$

T - Time steps, $t \in T$

Parameters

K - Large number [-]

R - Risk factor restricting the amount of FCR-N reserves that can be procured [%]

H - The number of previous hours (t-H) considered when reserving capacity for FCR-N reserves in time step t [-]

$h_{current}$ - Hour of the year of current iteration [-]

Δt - Time step size [h]

P^t_{pv} - Power generated by the PV panels in time step t [kW]

P^t_{demand} - Household demand in time step t [kW]

$C^t_{gt,power}$ - Grid tariff, power component in time step t [NOK/kWh]

$C^t_{gt,energy}$ - Grid tariff, energy component in time step t [NOK/kWh]

$C^t_{gt,surplu}$ - Grid tariff, surplus power component in time step t [NOK/kW]

P^{min}_{ch} - Minimum charging power to the battery [kW]

P^{min}_{dch} - Minimum discharging power from the battery [kW]

P^{max}_{ch} - Maximum charging charging power to the battery [kW]

P^{max}_{dch} - Maximum discharging power from the battery [kW]

η_{ch} - Battery's charging efficiency [%]

η_{dch} - Battery's discharging efficiency [%]

η_{RT} - Battery's round trip efficiency [%]

E^{cap}_{b} - Installed battery capacity [kWh]

$E^{init,t}_{b}$ - Initial energy level in the battery in hour t [kWh]

SOC_{min} - Minimum state of charge of the battery [%]

SOC_{max} - Maximum state of charge of the battery [%]

SOH^d_{init} - The initial state of health at the beginning of day d [%]

Deg - Battery degradation in each time step [%]

C_{deg} - Cost of battery degradation per kWh discharged power [EUR/kWh]

Pr^t_{spot} - Elspot price in time step t [EUR/kWh]

Pr^t_{D1} - Payment for the procured FCR-N reserves in time step t, in the D1 market [EUR/kW]

Pr^t_{D2} - Payment for the procured FCR-N reserves in time step t, in the D2 market [EUR/kW]

$Pr^t_{rk,up}$ - Regulating power price for upward regulation in time step t [EUR/kWh]

$Pr^t_{rk,dwn}$ - Regulating power price for downward regulation in time step t [EUR/kWh]

$P^t_{D1,volume}$ - Requested volume of FCR-N reserves in the D1 market in time step t [kW]

$P^t_{D2,volume}$ - Requested volume of FCR-N reserves in the D2 market in time step t [kW]

$P^t_{D1,res}$ - Reserved capacity in the battery in the first stage for FCR-N reserves procured in the D1 market in time step t [kW]

$P^t_{D2,res}$ - Reserved capacity in the battery in the first stage for FCR-N reserves procured in the D2 market in time step t [kW]

$Freq^t_{dev,dwn}$ - Absolute value of the average frequency deviation from 50 Hz in negative direction in time step t [Hz]

$Freq^t_{dev,up}$ - Absolute value of the average frequency deviation from 50 Hz in positive direction in time step t [Hz]

$P^t_{act,up}$ - Absolute value of activated power due to FCR-N reserves for up-regulation in time step t [kW]

$P^t_{act,dwn}$ - Absolute value of activated power due to FCR-N reserves for down-regulation in time step t [kW]

Conversion Factors

$EUR_{to}NOK$=10.36 as of 16/11/2022

$NOK_{to}EUR$=0.096 as of 16/11/2022

4.2.2 Converter

The converter is responsible for converting the stored electrical energy in the battery from DC to AC and the desired voltage level. Associated with this process is some loss during charging and discharging, as illustrated in Figure 4.2.1.

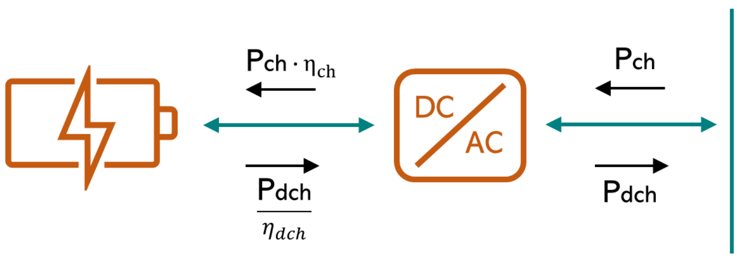


Figure 4.2.1: Illustration of the battery converter and the charge and discharge efficiencies.

The battery stores energy and charges and discharges according to the charge and discharge efficiency. It means that there is a loss in a charge/discharge cycle that must be accounted for. The charge and discharge efficiency is given according to the square root of the battery round trip efficiency:

$$\eta_{ch} = \eta_{dch} = \sqrt{\eta_{RT}} \tag{4.1}$$

Notice that the efficiencies are constant, as a normal simplification. The real-life converter efficiency is non-linear, depending on the input/output power of the converter.

The charge and discharge of the battery are limited by the converter's minimum and maximum charge power, given in Equations (4.2a) and (4.2b). The binary variable, S^t_{ch}, ensures that the battery is either charging or discharging.

$$P^{min}_{ch} * S^t_{ch} \leq P^t_{ch} \leq P^{max}_{ch} * S^t_{ch} \tag{4.2a}$$
$$p^{min}_{dch} * (1 - S^t_{ch}) \leq P^t_{dch} \leq P^{max}_{dch} * (1 - S^t_{ch}) \tag{4.2b}$$

4.2.3 Energy Storage Unit

Equation (4.3b) and (4.3a) represent the energy level in the battery in each time step. It depends on the energy level in the previous timestep and the power charged and discharged to the battery. The energy level in the first timestep is decided based on an initial storage level passed as input to the optimisation problem. The battery is considered ideal; there is no loss associated with the stored energy.

$$E_b^1 = E_b^{init,t} + \eta_{ch} * P_{ch}^1 * \Delta t - \frac{1}{\eta_{dch}} * P_{dch}^1 * \Delta t \tag{4.3a}$$

$$E_b^t = E_b^{t-1} + \eta_{ch} * P_{ch}^t * \Delta t - \frac{1}{\eta_{dch}} * P_{dch}^t * \Delta t \; for \; t > 1 \tag{4.3b}$$

The SOC, that is, the energy level in the battery referred to as the rated capacity, is kept between a minimum and maximum percentage:

$$SOC_{min} \leq SOC^t \leq SOC_{max} \tag{4.4}$$

Due to the relationship between depth of discharge and battery degradation, as described in Section 2.6.3, a possibility is to limit the minimum SOC level to minimise battery degradation. However, it is not implemented in this model.

The current battery capacity, $E_b^{cap,t}$, always restricts the energy level in the battery and the minimum and maximum SOC. The battery capacity, $E_b^{cap,t}$, will decrease with time due to degradation and will be explained in Section 4.2.4.

$$E_b^{cap,t} * SOC_{min} \leq E_b^t \leq E_b^{cap,t} * SOC_{max} \tag{4.5}$$

4.2.4 Battery Degradation

Due to degradation, the battery capacity will decrease with time. The degradation results from several factors, as Section 2.6.3 explains. The current battery capacity could be expressed as the state of health, SOH, times the initial rated capacity:

$$E_b^{cap,t} = SOH^t * E_b^{cap} \tag{4.6}$$

Where the SOH is a factor between 0 and 1:

$$0 \leq SOH^t \leq 1 \tag{4.7}$$

As a simplification, the SOH is linear, decreasing according to a percentage degradation in each time step. The initial SOH is set equal to 1 in the first time step of the year and decreases linearly with $Deg = 3.424657 * 10^{-4}$ in each time step, corresponding to a decrease of 3% every year. The degradation is independent of the battery use, which is a simplification.

$$SOH^t = SOH^{t-1} - Deg \; for \; t > 1 \tag{4.8a}$$

$$SOH^1 = SOH_{init}^d \tag{4.8b}$$

$$SOH_{init}^d = 1 - h_{start} * Deg \tag{4.8c}$$

Where h_{start} is the hour of the start of the iteration.

To account for the cycle ageing of the battery, a degradation cost is associated with discharging of the battery and is expressed in the objective function as an additional cost:

$$c_{degradation} = C_{deg} * P_{dch}^t \tag{4.9}$$

4.2.5 Import and Export to the Grid

energy can be both bought and sold to the grid. One assumes that the grid is unsaturated, which means there is assumed to be no cap on the amount of energy that can be imported or exported to the grid. However, the energy will be restricted by the other variables; P^t_{pv}, P^{max}_{ch}, P^{max}_{dch}, E^t_b and P^t_{damnd}.

A binary variable, δ^t_{2g}, is introduced in the import and export restrictions to ensure that power is not exported and imported from the grid simultaneously. K represents a large number. The value must be set large enough for the restriction to be valid. However, a smaller number results in a smaller branch and bound algorithm and a faster solution.

$$0 \leq P^t_{exp} \leq K * \delta^t_{2g} \tag{4.10a}$$

$$0 \leq P^t_{imp} \leq K * (1 - \delta^t_{2g}) \tag{4.10b}$$

By selling power to the grid, the battery owner obtain revenue. This revenue equals the amount of exported energy times the spot price at that given time step. Additionally, in parts of the grid where surplus power is considered a benefit in the grid operation, the battery owner can also receive a surplus grid tariff for the exported power. The revenue from exporting power in a given time step is therefore given as:

$$r_{exp} = -P_{exp} * \Delta t * (Pr_{spot} + C_{gt,surplus}) \tag{4.11}$$

The costs associated with import to the grid are similar to the revenues from the export. The battery owner must pay the spot price per kWh of imported energy. Additionally, the battery owner must pay a grid tariff consisting of two parts; the energy and power components. The energy component is a charge per kWh of imported energy. The power component is a determined payment according to the three highest peaks in consumption during one month. To simplify, the capacity grid tariff can be implemented as a per kWh tariff, explained more thoroughly in Section 5.2.1. The resulting costs associated with the import are:

$$c_{imp} = P_{imp} * \Delta t * (Pr_{spot} + C_{gt,power} + C_{gt,energy}) \tag{4.12}$$

4.2.6 System

The system, as a whole, consists of an energy storage system, a load and a photovoltaic panel connected to the grid. The storage system is modelled as a stationary storage system but could be modified to represent other forms of storage systems, such as EVs. The load is modelled as a household with electricity demand. Figure 4.2.2 shows the input and output flows of the system.

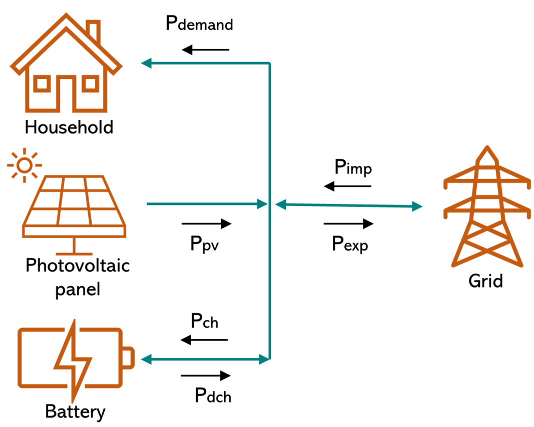


Figure 4.2.2: System overview with power flows.

P_{imp} and P_{exp} are the imported and exported power to the grid and consist of both powers used to cover household demand and power associated with the activation of reserves. The power balance equation is:

$$P^t_{pv} + P^t_{imp} - P^t_{exp} + P^t_{dch} - P^t_{ch} - P^t_{demand} = 0 \tag{4.13}$$

4.2.7 Reservation of FCR-N Reserves

When participating in the FCR-N market, the energy level in the battery must account for the contracted capacity in these markets. FCR-N is a symmetrical reserve, meaning an equal amount of reserves must be reserved in an upward and downward direction, as illustrated in Figure 4.2.3.

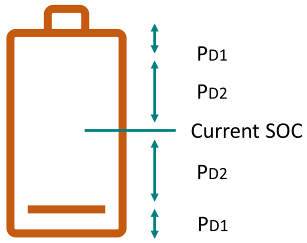


Figure 4.2.3: Reservation of capacity for FCR-N reserves. FCR-N is a symmetrical reserve.

Equation (4.5) is modified to also account for the reserved capacity, P^t_{D1} and P^t_{D2}. This ensures that the storage system can deliver the contracted reserves in an upward or downward direction.

$$E^t_b - P^t_{D1,res} * \Delta t - P^t_{D2,res} * \Delta t \geq E^{cap,t}_b * SOC_{min} \tag{4.14a}$$

$$E^t_b + P^t_{D1,res} * \Delta t + P^t_{D2,res} * \Delta t \leq E^{cap,t}_b * SOC_{max} \tag{4.14b}$$

The volumes that are reserved for FCR-N can not be greater than the total required volumes in the D1 and D2 markets:

$$P^t_{D1} <= P^t_{D1,volume} \tag{4.15a}$$

$$P^t_{D2} <= P^t_{D2,volume} \tag{4.15b}$$

In addition to the limitation of the energy capacity of the storage unit, the possible amount of reserves are also limited by the maximum charge and discharge power of the converter, P^{max}_{ch} and P^{max}_{dch}. Since FCR-N is a symmetric service, the reservation of reserves must be limited by the smallest possible upward or downward reservation. The reservation is dependent on the current charging or discharging of the battery. The reservation is restricted by the strictest constraint of Equations (4.16a) and (4.16b).

$$P^t_{D1} + P^t_{D2} \leq P^t_{ch} + P^{max}_{dch} - P^t_{dch} \tag{4.16a}$$

$$P^t_{D1} + P^t_{D2} \leq P^t_{dch} + P^{max}_{ch} - P^t_{ch} \tag{4.16b}$$

Say, the maximum charge and discharge power is 5 kW. If initially charging 2 kW, we can decrease the load by 7 kW. However, we can only increase the load by 3 kW since we are already charging. Consequently, the maximum possible reserves we can provide is 3 kW. The same logic is applied if the storage unit is discharging.

The storage owner is compensated for the capacity reservation by the prices determined in the D1 and D2 markets for FCR-N reserves. The revenue from the capacity reservation in each time step is therefore given as:

$$r_{res} = P^t_{D1} * Pr^t_{D1} + P^t_{D2} * Pr^t_{D2} \tag{4.17}$$

,where Pr^t_{D1} and Pr^t_{D2} is the prices in the D1 and D2 market for FCR-N reserves.

4.2.8 Activation of FCR-N Reserves

The vital part of the model is how to account for the activation of the reserves. By signal, the storage owner has to either increase or decrease the load according to the frequency deviation. Activation of the reserves is done proportionally to the frequency deviation from 50 Hz, with full activation from ±100 Hz, as described in Section 2.4.1.1. The activation is considered upwards regulation; when the frequency is less than 50 Hz or downward regulation; when the frequency is greater than 50 Hz. The former is viewed with a positive sign and the latter with a negative sign.

$$P^t_{act} = P^t_{act,UP} - P^t_{act,DWN} \tag{4.18}$$

,where:

$$P^t_{act,UP} = \frac{Freq^t_{dev,UP}}{0.1} * P^t_{D1,res} + \frac{Freq^t_{dev,UP}}{0.1} * P^t_{D2,res} \tag{4.19a}$$

$$P^t_{act,DWN} = \frac{Freq^t_{dev,DWN}}{0.1} * P^t_{D1,res} + \frac{Freq^t_{dev,DWN}}{0.1} * P^t_{D2,res} \tag{4.19b}$$

$Freq^t_{dev,UP}$ and $Freq^t_{dev,DWN}$, is the absolute value of the frequency deviation from 50 Hz, and P^t_{D1} and P^t_{D2} is the contracted reserves in the D1 and D2 markets.

In modelling the activation, it is crucial to have a baseline. The baseline ensures that the resulting schedule can be compared to the planned schedule to verify that the activation of the reserves is done are required. Therefore, schedule change is calculated with Equation (4.20). Equation (4.20a) is applied when the activation signal is to reduce load, and Equation (4.20b) is used when the activation signal is to increase load. $P^t_{ch,plan}$ and $P^t_{dch,plan}$ are the baseline charge and discharge plan calculated in the first stage of the problem.

$$P^t_{ch,plan} - P^t_{dch,plan} - P^t_{act} + S^t_{slack,pos} - S^t_{slack,neg} \geq P^t_{ch} - P^t_{dch} \; if \; freq^t < 50Hz \tag{4.20a}$$

$$P^t_{ch,plan} - P^t_{dch,plan} - P^t_{act} + S^t_{slack,pos} - S^t_{slack,neg} \leq P^t_{ch} - P^t_{dch} \; if \; freq^t > 50Hz \tag{4.20b}$$

,where:

$$P^t_{ch,plan} = P^t_{ch} \; of \; the \; first \; stage \; problem. \tag{4.21a}$$

$$P^t_{dch,plan} = P^t_{dch} \; of \; the \; first \; stage \; problem. \tag{4.21b}$$

The cost or revenue of activation of reserves is associated with increased import or export and additional cost of degradation due to increased discharge. The slack variables, $S^t_{slack,pos}, S^t_{slack,neg}$, in Equation (4.20) is a source of unlimited reserves to avoid unfeasibility. Since the consequence of repeatedly failing to deliver the reserves could lead to exclusion from the market, this is treated as the last opportunity. Therefore, the cost of using the slack variables is set to 100 000 EUR.

Furthermore, compensation for activated FCR-N reserves is given according to the regulating power prices. The regulating power prices are divided into upward and downward regulating prices, involving payment for both up and down-regulation. The only exception is if the price is negative, it involves the provider must pay for the activation.

$$c_{activation} = 100\,000 * (S^t_{slack,pos} + S^t_{slack,neg}) * \Delta t - Pr^t_{rk,up} * P^t_{act,up} * \Delta t - Pr^t_{rk,dwn} * P^t_{act,dwn} * \Delta t \tag{4.22}$$

4.2.9 Handeling Risk

activation of the reserves proposes a new challenge regarding the reservation of the reserves due to the changed state of charge of the battery. In longer periods with over-frequency or under-frequency, we risk that the state of charge either reaches its maximum or its minimum due to continuous one-sided service delivery. The reservation of the reserves must therefore consider the risk of longer periods of over- or under-frequency. The amount of reserves is therefore limited by the amount of reserves contracted in the previous hours:

$$E_b^t + \sum_{max(0,t1-H)}^{t} (P_{D1}^{t1} + P_{D2}^{t1}) * \Delta t * R \leq E_b^{cap,t} * SOC_{max} \tag{4.23a}$$

$$E_b^t - \sum_{max(0,t1-H)}^{t} (P_{D1}^{t1} + P_{D2}^{t1}) * \Delta t * R \geq E_b^{cap,t} * SOC_{min} \tag{4.23b}$$

Where h is the number of previous hours we consider, and r is a risk factor. The equations do not consider reserves contracted the previous day, so the summation runs from minimum zero to the current hour. The factor r is proposed to capture different degrees of risk.

4.2.10 Objective

The objective is to minimise the cost and maximise the revenues explained in Sections 4.2.4 - 4.2.8, according to Equation (4.24).

$$minimise \sum_{t=N_{start}}^{N_{end}} c_{degradation} - r_{exp} + c_{imp} - r_{res} + c_{activation} \tag{4.24}$$

Which in detail results in the following objective function:

$$minimise \sum_{t=N_{start}}^{N_{end}} C_{deg} * P_{dch}^t - (Pr_{spot}^t + C_{gt,surplus}) * P_{exp}^t * \Delta t \tag{4.25}$$

$$+(Pr_{spot}^t + C_{gt,energy} + C_{gt,power}) * P_{imp}^t * \Delta t - Pr_{D1}^t * P_{D1}^t - Pr_{D2}^t * P_{D2}^t$$

$$+100\,000 * (S_{slack,pos} + S_{slack,neg}) * \Delta t - Pr_{rk,up}^t * P_{act,up}^t * \Delta t - Pr_{rk,dwn}^t * P_{act,dwn}^t * \Delta t$$

4.2.11 Mathematical Formulation of the Problem

The optimisation problem is solved with model predictive control with a rolling time horizon, as Section 2.8 explains. The problem is formulated as a two-stage problem. Obtaining the solution involves applying the algorithm provided in Section 4.1.4. The complete first-stage and second-stage optimisation problems are subsequently provided.

4.2.11.1 First Stage Problem

$$minimise \sum_{t=0}^{48} C_{deg} * P_{dch}^{t} - (Pr_{spot}^{t} + C_{gt,surplus}) * P_{exp}^{t} * \Delta t + (Pr_{spot}^{t} + C_{gt,energy} \tag{4.26a}$$

$$+C_{gt,power}) * P_{imp}^{t} * \Delta t - Pr_{D1}^{t} * P_{D1}^{t} - Pr_{D2}^{t} * P_{D2}^{t}$$

$$s.t.$$

$$P_{pv}^{t} + P_{imp}^{t} - P_{exp}^{t} + P_{dch}^{t} * \eta_{dch} - P_{ch}^{t} * \frac{1}{\eta_{ch}} - P_{demand}^{t} = 0 \qquad for\ t = 1, ..., 48 \tag{4.26b}$$

$$P_{ch}^{min} * S_{ch}^{t} \leq P_{ch}^{t} \leq P_{ch}^{max} * S_{ch}^{t} \qquad for\ t = 1, ..., 48 \tag{4.26c}$$

$$p_{dch}^{min} * (1 - S_{ch}^{t}) \leq P_{dch}^{t} \leq P_{dch}^{max} * (1 - S_{ch}^{t}) \qquad for\ t = 1, ..., 48 \tag{4.26d}$$

$$E_{b}^{t} = E_{b}^{t-1} + \eta_{ch} * P_{ch}^{t} * \Delta t - \frac{1}{\eta_{dch}} * P_{dch}^{t} * \Delta t \qquad for\ t = 2, ..., 48 \tag{4.26e}$$

$$E_{b}^{t} = E_{b}^{init,t} + \eta_{ch} * P_{ch}^{t} * \Delta t - \frac{1}{\eta_{dch}} * P_{dch}^{t} * \Delta t \qquad for\ t = 1 \tag{4.26f}$$

$$SOC_{min} \leq SOC^{t} \leq SOC_{max} \qquad for\ t = 1, ..., 48 \tag{4.26g}$$

$$E_{b}^{cap,t} = SOH^{t} * E_{b}^{cap} \qquad for\ t = 1, ..., 48 \tag{4.26h}$$

$$0 \leq SOH^{t} \leq 1 \qquad for\ t = 1, ..., 48 \tag{4.26i}$$

$$SOH^{t} = SOH^{t-1} - Deg \qquad for\ t = 2, ..., 48 \tag{4.26j}$$

$$SOH^{t} = 1 - h_{current} * Deg \qquad for\ t = 1 \tag{4.26k}$$

$$0 \leq P_{exp}^{t} \leq K * \delta_{2g}^{t} \qquad for\ t = 1, ..., 48 \tag{4.26l}$$

$$0 \leq P_{imp}^{t} \leq K * (1 - \delta_{2g}^{t}) \qquad for\ t = 1, ..., 48 \tag{4.26m}$$

$$P_{D1}^{t} + P_{D2}^{t} \leq P_{ch}^{t} + P_{dch}^{max} - P_{dch}^{t} \qquad for\ t = 1, ..., 48 \tag{4.26n}$$

$$P_{D1}^{t} + P_{D2}^{t} \leq P_{dch}^{t} + P_{ch}^{max} - P_{ch}^{t} \qquad for\ t = 1, ..., 48 \tag{4.26o}$$

$$P_{D1}^{t} <= P_{D1,volume}^{t} \qquad for\ t = 1, ..., 48 \tag{4.26p}$$

$$P_{D2}^{t} <= P_{D2,volume}^{t} \qquad for\ t = 1, ..., 48 \tag{4.26q}$$

$$E_{b}^{t} + \sum_{max(0,t1-H)}^{t} (P_{D1}^{t1} + P_{D2}^{t1}) * \Delta t * R \leq E_{b}^{cap,t} * SOC_{max} \qquad for\ t = 1, ..., 48 \tag{4.26r}$$

$$E_{b}^{t} - \sum_{max(0,t1-H)}^{t} (P_{D1}^{t1} + P_{D2}^{t1}) * \Delta t * R \geq E_{b}^{cap,t} * SOC_{min} \qquad for\ t = 1, ..., 48 \tag{4.26s}$$

4.2.11.2 Second Stage Problem

$$minimise \sum_{t=0}^{72} C_{deg} * P^t_{dch} - (Pr^t_{spot} + C_{gt,surplus}) * P^t_{exp} * \Delta t + (Pr^t_{spot} + C_{gt,energy} \tag{4.27a}$$

$$+C_{gt,power}) * P^t_{imp} * \Delta t - Pr^t_{D1} * P^t_{D1,res} - Pr^t_{D2} * P^t_{D2,res} + 100\,000*$$
$$(S_{slack,pos} + S_{slack,neg}) * \Delta t - Pr^t_{rk,up} * P^t_{act,up} * \Delta t - Pr^t_{rk,dwn} * P^t_{act,dwn} * \Delta t$$

$s.t.$

$$P^t_{pv} + P^t_{imp} - P^t_{exp} + P^t_{dch} * \eta_{dch} - P^t_{ch} * \frac{1}{\eta_{ch}} - P^t_{demand} = 0 \qquad for\ t = 1, ..., 72 \tag{4.27b}$$
$$P^{min}_{ch} * S^t_{ch} \leq P^t_{ch} \leq P^{max}_{ch} * S^t_{ch} \qquad for\ t = 1, ..., 72 \tag{4.27c}$$
$$p^{min}_{dch} * (1 - S^t_{ch}) \leq P^t_{dch} \leq P^{max}_{dch} * (1 - S^t_{ch}) \qquad for\ t = 1, ..., 72 \tag{4.27d}$$
$$E^t_b = E^{t-1}_b + \eta_{ch} * P^t_{ch} * \Delta t - \frac{1}{\eta_{dch}} * P^t_{dch} * \Delta t \qquad for\ t = 2, ..., 72 \tag{4.27e}$$
$$E^t_b = E^{init,t}_b + \eta_{ch} * P^t_{ch} * \Delta t - \frac{1}{\eta_{dch}} * P^t_{dch} * \Delta t \qquad for\ t = 1 \tag{4.27f}$$
$$SOC_{min} \leq SOC^t \leq SOC_{max} \qquad for\ t = 1, ..., 72 \tag{4.27g}$$
$$E^{cap,t}_b = SOH^t * E^{cap}_b \qquad for\ t = 1, ..., 72 \tag{4.27h}$$
$$0 \leq SOH^t \leq 1 \qquad for\ t = 1, ..., 72 \tag{4.27i}$$
$$SOH^t = SOH^{t-1} - Deg \qquad for\ t = 2, ..., 72 \tag{4.27j}$$
$$SOH^t = 1 - h_{current} * Deg \qquad for\ t = 1 \tag{4.27k}$$
$$0 \leq P^t_{exp} \leq K * \delta^t_{2g} \qquad for\ t = 1, ..., 72 \tag{4.27l}$$
$$0 \leq P^t_{imp} \leq K * (1 - \delta^t_{2g}) \qquad for\ t = 1, ..., 72 \tag{4.27m}$$
$$E^{cap,t}_b * SOC_{min} \leq E^t_b \leq E^{cap,t}_b * SOC_{max} \qquad for\ t = 1 \tag{4.27n}$$
$$E^t_b - P^t_{D1,res} * \Delta t - P^t_{D2,res} * \Delta t \geq E^{cap,t}_b * SOC_{min} \qquad for\ t = 2, ..., 72 \tag{4.27o}$$
$$E^t_b + P^t_{D1,res} * \Delta t + P^t_{D2,res} * \Delta t \leq E^{cap,t}_b * SOC_{max} \qquad for\ t = 2, ..., 72 \tag{4.27p}$$
$$P^t_{ch,plan} - P^t_{dch,plan} - P^t_{act} + S^t_{slack,pos} - S^t_{slack,neg} \geq P^t_{ch} - P^t_{dch}\ ,\ f < 50\ for\ t = 1 \tag{4.27q}$$
$$P^t_{ch,plan} - P^t_{dch,plan} - P^t_{act} + S^t_{slack,pos} - S^t_{slack,neg} \leq P^t_{ch} - P^t_{dch}\ ,\ f > 50\ for\ t = 1 \tag{4.27r}$$
$$P^t_{act} = 0 \qquad for\ t = 2, ..., 72 \tag{4.27s}$$
$$P^t_{act} = \frac{Freq^t_{dev,UP}}{0.1} * P^t_{D1,res} + \frac{Freq^t_{dev,UP}}{0.1} * P^t_{D2,res} - \frac{Freq^t_{dev,DWN}}{0.1} * P^t_{D1,res} \tag{4.27t}$$
$$-\frac{Freq^t_{dev,DWN}}{0.1} * P^t_{D2,res} \qquad for\ t = 1$$

4.2.11.3 Optimal Objective

The optimal objective does not equal the objective functions of the above optimisation problems. Only the first hour's decisions, the control horizon decisions, are applied. Therefore the optimal objective is the sum of the objective of hour zero in every iteration:

$$Optimal\ Objective = \sum_{t=1}^{365} Objective^{t}_{Control\ horizon} \tag{4.28}$$

In case the slack variables are non-zero, that is, additional energy must be traded on the other markets for SOC management. As a simplification, the cost is set to the slack variable times the electricity price. Note also that the penalty, 100 000 EUR, associated with the slack variable is left out of the optimal objective.

CHAPTER

FIVE

CASE STUDY

This chapter presents the case study used to test the functionality of the proposed model formulation of Chapter 4. Section 5 will present the system, the chosen parameters and the relevant input data. The input data consists of data for household consumption, grid tariffs, PV data, elspot prices and frequency measurements. It also comprises data on the D1 and D2 markets for FCR-N reserves and regulating power prices.

The case study consists of a household in Hvaler, Norway. The household has a yearly energy consumption of 25 486 kWh [60]. This consumption is covered by self-generated energy from a connected PV and energy imported from the grid. The PV panel generates a total of 7142 kWh every year [61]. Additionally, a small-scale battery (13.5kWh/5kW) is installed and allows for storing surplus energy from the PV panels and trading at the elspot market. The use of the battery to procure and provide FCR-N reserves is also exploited.

5.1 Choice of Battery

The household's electricity consumption is analysed and used to choose battery energy system storage. Household consumption is 2-5 kWh/h in most hours and seldom exceeds 8 kWh/h. Therefore the battery is dimensioned accordingly. A Tesla powerwall 2.0 is chosen as a starting point for the analysis [62]. The battery specifications are displayed in Table 5.1.1.

Table 5.1.1: Battery specifications of Tesla Powerwall 2.0 [62].

Total energy [kWh]	14
Usable energy [kWh]	13.5
Real Power, max continuous, charge and discharge [kW]	5
Round trip efficiency [%]	90
Warranty [years]	10

5.2 Input Data

This section presents the input data used in the case study. First, data for household electricity consumption, PV generation, grid tariffs, and electricity prices are collected. Additionally, data for FCR-N reserve prices and volumes and frequency data are collected to investigate the reservation and activation of FCR-N reserves. Lastly, the regulating power prices are collected. Much of the same data was used in my specialisation project [14]. This section, therefore, bears similarities with the section describing the input data in my specialisation project.

5.2.1 Grid Tariffs

The grid tariff for private households varies according to the location in Norway. For Hvaler, located in the southeast of Norway, the grid tariffs are set according to Norgesnett's prices as of January 2023 [63]. The grid tariffs consist of two components, an energy component and a power component. The energy component is paid per kWh of imported energy. It is typically lower at night and higher during the day, reflecting the grid's congestion level. The power component is paid monthly and calculated based on the average of the three highest peak consumption hours on three days. Table 5.2.1 and Table 5.2.2 display the energy component and the power component, respectively [63].

Table 5.2.1: Energy component of the grid tariff in Hvaler, prices by Norgesnett [63].

Day (06:00-22:00) [øre/kWh]	40.61
Night (22:00-06:00) [øre/kWh]	30.99

Table 5.2.2: Capacity component of the grid tariff in Hvaler, prices by Norgesnett [63].

Step	Monthly peak [kWh/h]	Expense [NOK/month]
1	0-2	129.94
2	2-5	216.56
3	5-10	356.13
4	10-15	633.33
5	15-20	841.23
6	20-25	1043.35
7	25-50	1617.00
8	50-75	2531.38
9	75-100	3445.75
10	100-	5584.43

Since the power component is calculated monthly, modelling this expense is a challenge when the optimisation problem horizon is shorter than one month. In this case, the horizon varies from 48 - 72 hours. Since the grid tariff is not the main focus of this thesis, the challenge is to reflect the grid tariff in a manner that includes its importance but does not over-complicate the model formulation.

The optimisation problem is first run over one year without including the power component to calculate the average of the three highest consumption peaks in every month. Although this simulation does not reflect the extra cost of increased power import, it approximates the average monthly peak consumption. Therefore, the energy component is included when running this simulation. According to the three highest peak consumption hours in each month, the power component of each month is decided according to Table 5.2.2. Next, the power component is divided by the total imported electricity in the respective month. This results in the power component being distributed by all imported electricity. Even though this approach does not reflect the desire to keep the simultaneous import low, it restricts the import of electricity. The resulting per kWh power component grid tariff for 2020 and 2021 is displayed in Table 5.2.3. These values are calculated in Appendix B.

Table 5.2.3: Power component of the grid tariff per kWh in Hvaler in 2020 and 2021, prices by Norgesnett [63].

Month	Expense [NOK/kWh]	
	2020	2021
Jan	0.101921	0.101932
Feb	0.139937	0.139662
Mar	0.17794	0.177943
Apr	0.169833	0.169833
May	0.242799	0.242799
Jun	0.359096	0.359095
Jul	0.443008	0.443017
Aug	0.286088	0.283078
Sep	0.235440	0.235440
Oct	0.110204	0.180661
Nov	0.127935	0.226934
Dec	0.123478	0.122609

5.2.2 Surplus Grid Tariffs

The PV panel and battery system can be classified as a surplus customer, wherein the customer generates surplus power exported to the grid. A surplus customer does not pay any grid tariffs on the surplus power, only on power imported from the grid. Instead, they are recognised for reducing grid losses and compensated accordingly. However, Norgesnett, the distribution system operator, compensates surplus customers in Fredrikstad, Askøy, and Follo regions for their surplus power. In contrast, customers in Hvaler region do not receive such compensation [63].

5.2.3 Elspot Prices

The elspot prices for 2020 and 2021 of price zone NO1 are fetched from Nordpool's data portal [64].

There are some hours with missing data. This applies for 28/03/2021 02:00:00-03:00:00 and 29/03/2020 02:00:00-03:00:00. The elspot price in these hours was set to the average before and after the missing hours. Additionally, the data from 29/02/2020 was removed since 2020 was a leap year. This was done to make the data set fit the other data sets.

The difference in elspot prices is quite considerable between 2020 and 2021. The analysis is therefore done for both years to consider the impact of different elspot prices. Figure 5.2.1 show the average daily elspot prices. Table 5.2.4 shows the standard deviation in the monthly elspot prices. As indicated in the table, the elspot prices fluctuate more from October to December than the rest of the year.

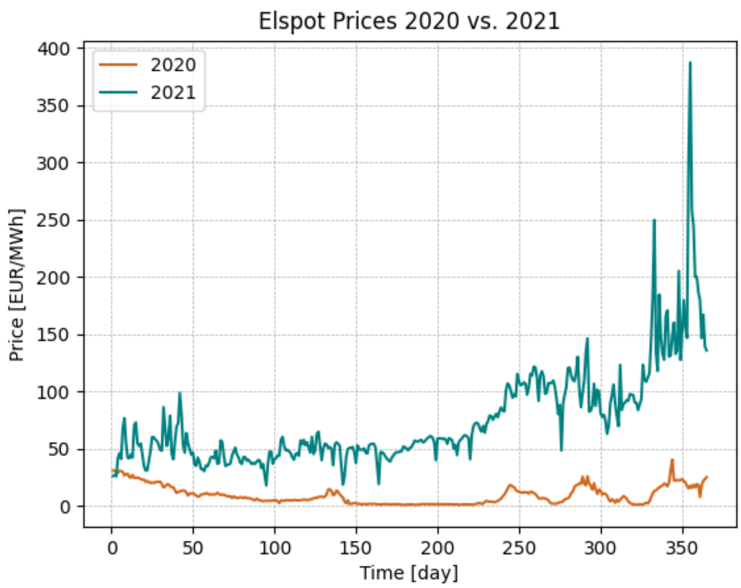


Figure 5.2.1: Average daily elspot prices in 2020 and 2021 in price zone NO1 in Norway.

Table 5.2.4: Standard deviation in monthly elspot prices.

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2020	0.3931	0.3201	0.1878	0.0706	0.3909	0.0298	0.0254	0.3443	0.4804	0.7533	0.3677	0.9071
2021	1.7415	2.8929	0.8250	1.2762	1.2712	0.8969	0.6621	1.4815	1.1410	2.7134	4.2804	7.1512

5.2.4 Photovoltaic Generation

The dataset for the photovoltaic generation is fetched from RenewablesNinja for Hvaler (Lat: 58,9475, Long: 10,7820) [61]. The dataset is only available for 2019. However, the variation in solar radiation from year to year is assumed to be small. Based on papers by references [65], and [66], a simulation provides an hourly PV power output over a year.

In the simulation, the settings are set as follows:

- Tracking is set to *"2-axis (tilt & azimuth)"* with tilt 35° and azimuth 180°. This ensures that the solar panels are facing south.
- Installed solar panel capacity is set to 5 kW.
- System loss is set to 0.1.

Figure 5.2.2 displays the daily average solar power output per month and the average hourly solar power output per day. It shows that solar power generation is greatest during mid-day and in the summer months.

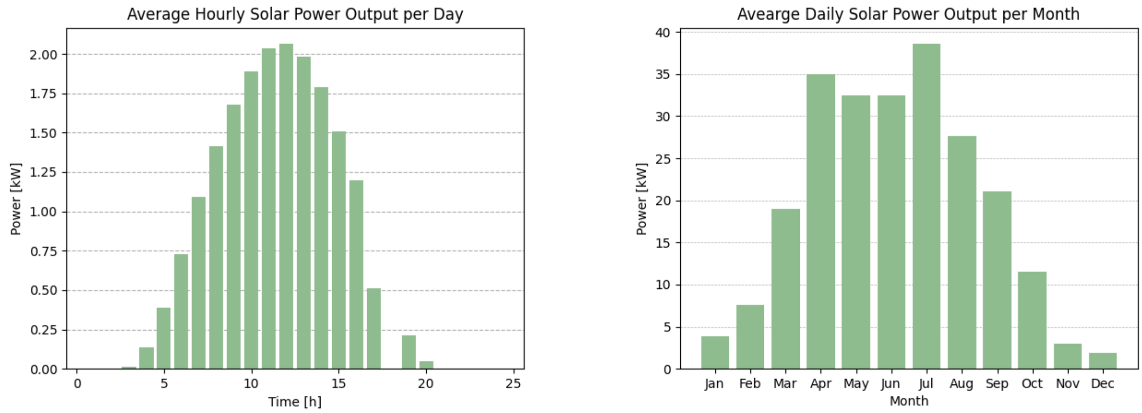


Figure 5.2.2: Daily average solar power output per month and average hourly solar power output per day. Figures from my specialisation project [14].

5.2.5 Household Consumption

A dataset with hourly consumption data of 17 anonymised households in Hvaler, Norway, in 2016, is used as the basis for the household consumption data input. There is only available data for 2016. However, there is little variation in household consumption from year to year, so the dataset from 2016 is used for analysing both 2020 and 2021. The year 2016 was a leap year. Consequently, the data of 29/02/2016 is removed to fit the other datasets. The households are located in the area of the Norwegian DSO Norgesnett [60], and is of varying size. An average household is established based on the values of the 17 households. The average household represents a typical Norwegian household with higher consumption during the cold winter; see Figure 5.2.3. It also shows the typical consumption patterns with peaks between 07:00-09:00 and the evening from 17:00.

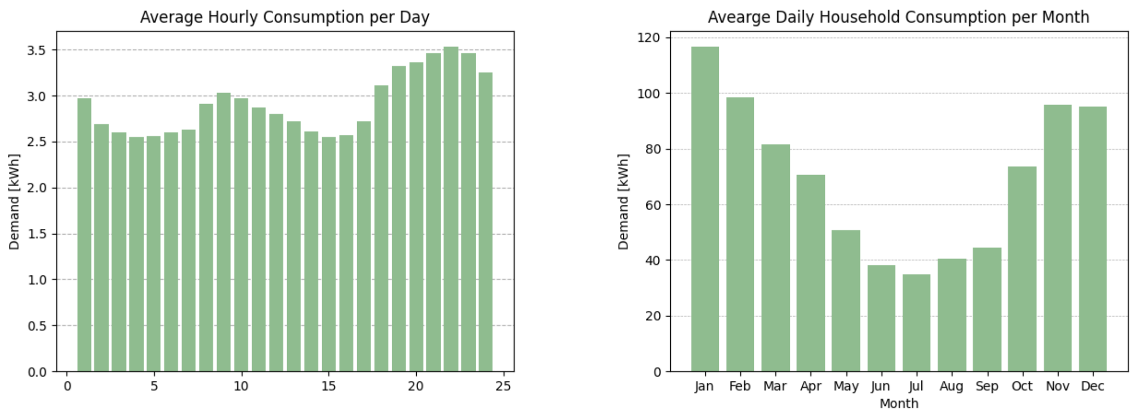


Figure 5.2.3: Average daily demand per month and the average hourly demand per day, for an average household in Hvaler. Figures from my specialisation project [14].

5.2.6 Frequency Measurements

The frequency data for the Nordic system of 2020 and 2021 was obtained from Fingrid's open data portal [67]. The data has a sampling rate of 10 Hz (0.1 s). The data was aggregated to an hourly frequency value to simplify the analysis and reduce simulation time. The aggregated value is calculated as the average of all frequency measurements within each hour. Using average values makes it possible to analyse the overall impact of deviations and energy exchange during an hour. The downside of this method is that incidents with a significant frequency deviation over a short period will not be captured.

There are some incidents with missing data. These hours are filled with the average data in the previous and subsequent hours. For the instances where several consecutive hours are missing data, the frequency is set to 50 Hz.

The frequency measurements with a 10 Hz sampling rate are near-normal distributed around a mean of 49.99 Hz, except for a few outliers as seen in Figure 5.2.4. This applies to both the years 2020 and 2021. It could be worth noticing that the outliers of 2020 are shifted towards the high end of the scale, and the outliers of 2019 are shifted towards the low end. Key numbers of the frequency data are summarised in Table 5.2.5.

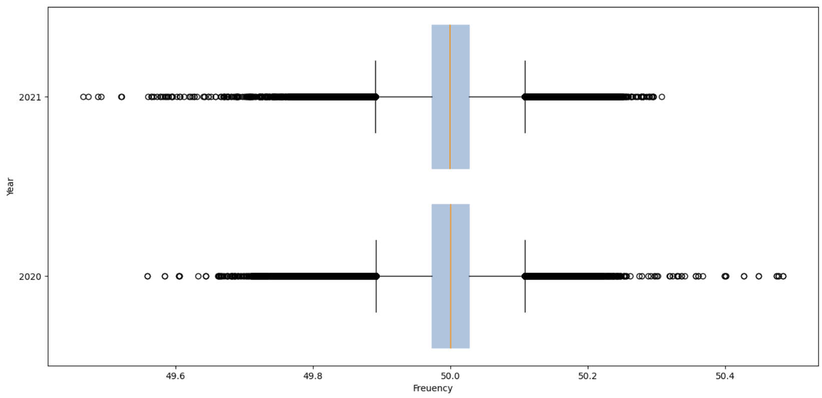


Figure 5.2.4: Boxplot of the frequency measurements. The frequency is near-normal, distributed around a mean of 49.99 Hz in both years.

Table 5.2.5: Key data of the frequency measurements.

	2020	2021
Mean	49.9999 Hz	49.9999 Hz
Medain	49.9996 Hz	49.9992 Hz
Standard deviation	0.0414 Hz	0.0420 Hz
Min	49.5585 Hz	49.4649 Hz
Max	50.4841 Hz	50.307 Hz
Max low-frequency duration	244 min, 32 s	100 min, 41 s
Mean low-frequency duration	40.3 s	39.6 s
Max high-frequency duration	130 min, 28 s	158 min, 59 s
Mean high-frequency duration	40.63 s	39.72 s

The nominal frequency is 50 Hz, and the TSO will always try to keep the frequency as close to 50 Hz as possible. Therefore, a frequency of 49.9-50-1 Hz is considered within the normal operating range. However, FCR-N is activated already within this range to stabilise the frequency. The Norwegian TSO does not operate with a dead band. However, we can define a dead band of ±0.01 Hz for analysis. This is a standard dead-band definition in other countries. A plot of the frequency and the defined dead band can be seen in Figure 5.2.5. With the defined dead-band, in Table 5.2.6, one can observe that the timeshare of under-frequencies is slightly more significant than the timeshare of over-frequencies.

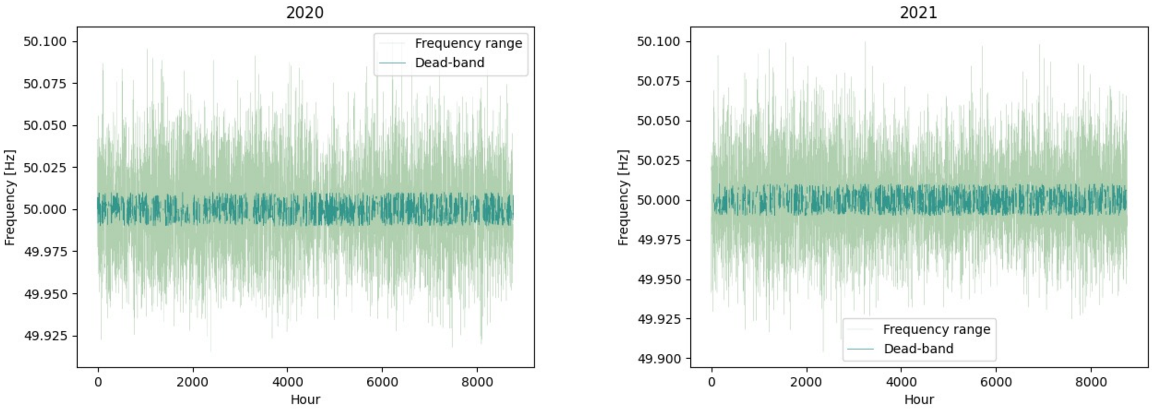


Figure 5.2.5: Plot of the average hourly frequency in 2020 and 2021.

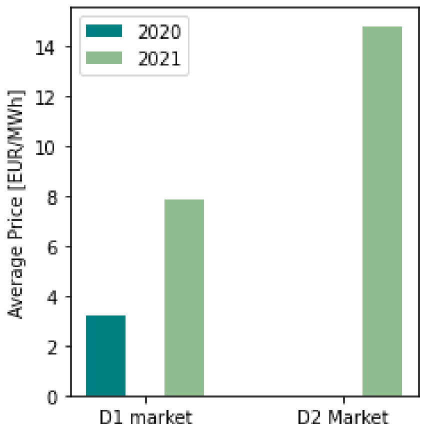
Table 5.2.6: Statistics of the frequency measurements. A slightly higher timeshare of under-frequency than over-frequency is present when a dead-band og ± 0.01 is defined. However, average over-frequency deviations are slightly greater.

Year	Time share [%]			Average frequency deviation [Hz]	
	Under-frequency	Over-frequency	Dead-band	Under-frequency	Over-frequency
2020	40.49	39.85	19.66	0.0391	0.0397
2021	40.85	39.60	19.54	0.0392	0.0405

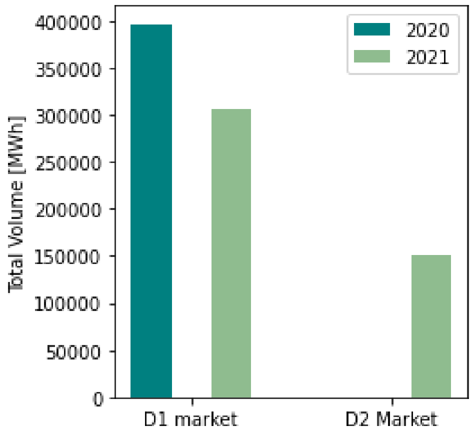
5.2.7 FCR-N Requested Volumes and Prices

The payment and required volumes of FCR-N reserves in the D1 and D2 market can be found at Statnett's data portal for reserve markets [68]. Data for the two markets are separated. Data for the D1 market is fetched for both years 2020 and 2021. Furthermore, the data for the D2 market of 2021 is fetched. However, there is no available data for the D2 market of 2020. Consequently, the data for the D2 market of 2021 is also used for 2020. The data for 01.01.2021-10.01.2021 are missing for the D2 market. Therefore, the data from the same period of 2022 is used, assuming that the need for reserves is similar at the same time of year.

Bids for FCR-N reserves are accepted according to marginal price and required volumes. Figure 5.2.6a shows the average payment per MW in the D1 and D2 markets, while Figure 5.2.6b shows the total required volume on the D1 and D2 markets. As displayed in the figures, the average payment in the D2 market is more than in the D1 market. However, there are higher volumes traded in the D1 market.



(a) Average payment in the D1 and D2 market for FCR-N in Norway.



(b) Total required volume on the D1 and D2 market for FCR-N in Norway.

Figure 5.2.6: Average payment and total required volumes for FCR-N in the capacity markets. No data were available for the D2 market in 2020.

The share of the total volumes activated due to frequency deviation is displayed in Table 5.2.7. The activated volumes are calculated using frequency data with a 1 Hz sampling rate and a droop value 0.1. It shows that only 16 % of the total acquired volumes in the capacity markets are activated in both years. However, the share would increase if more detailed frequency data was used since that would capture more of the activated volumes.

Table 5.2.7: The share of the acquired reserves in the D1 and D1 market that are activated. No data is available on the acquired reserves in the D2 market 2020.

Year	D1 Market		D2 Market	
	Up [%]	Down [%]	Up [%]	Down [%]
2020	16.20	16.11	-	-
2021	16.30	16.27	16.44	16.27

5.2.8 Regulating Power Prices

The compensation for activated energy associated with FCR-N reserves is paid at the rate of regulating power prices. They are obtained from Nordpool's data portal [64]. The prices consist of a price for upward regulation (decreasing load) and a price for downward regulation (increasing load). In most hours, the regulating power price involves payment for regulation in both directions. However, the battery owner will be charged for regulation in hours with a negative power price.

There are no data available for 2020. As a result, the data of 2021 is used for both years.

5.3 Performed Model Simulations

The work with this master thesis has been a continuous process of developing an optimisation model that captures the activation of the FCR-N reserves well. To understand the steps taken to formulate the final optimisation model, an analysis of all cases could provide valuable information. The simulation results are presented in Section 6 and discussed in Section 7.

Case 1: Running the Model without FCR-N Reserves
Firstly, the model is run without any reservation of FCR-N reserves. The model is compared to a one-stage deterministic model developed in my specialisation project for verification purposes. Furthermore, the first case will work as a baseline to which the later cases will be compared. The complete optimisation problem is attached in Appendix C1

Case 2: Running the Model without Activation of the FCR-N Reserves
Secondly, the model is run with reservation of FCR-N reserves, but without considering the activation of the contracted reserves (energy exchange). The simulation represents a best-case scenario since reserving capacity in consecutive hours has no consequence. The complete optimisation problem is attached in Appendix C2.

Case 3: Accounting for Activation of FCR-N Reserves
The model is changed to include activation of the FCR-N reserves. The activation consists of an energy exchange according to the amount of contracted reserves and depending on the frequency deviation. If the frequency is less than 50 Hz, and there is an agreement on delivering reserves, this involves the obligation to reduce load. This is done either by exporting power to the grid or reducing the import from the grid. In the opposite case, when the frequency exceeds 50 Hz, there is an obligation to increase the load. This is done either by increasing the import or by reducing the export.

The optimisation model is formulated in Section 4.2. However, the consideration of risk described in Section 4.2.9 is left out. Thus, the consequence of activating reserves in consecutive hours is not considered. The method involves letting the natural frequency deviations adjust the SOC level. However, one will risk that the minimum and maximum SOC is reached if there is a longer period of unilateral frequency deviation. The complete optimisation problem is attached in Appendix C3.

Case 4: Accounting for Activation of FCR-N Reserves, Including Compensation for Activated Energy
The optimisation model is similar to the model in Case 3, but the compensation for activated energy is included. According to the regulating power prices, the storage owner is paid for the activated energy in upward and downward directions. However, the storage owner must pay for the activated energy in hours with a negative price. The complete optimisation problem is attached in Appendix C4.

Case 5: Considering the Risk of Reaching the Battery's SOC Upper and Lower Limits
The complete optimisation model is formulated in Section 4.2.11, and includes the consideration of risk described in Section 4.2.9. The model considers the activated reserves in consecutive hours, so reserving unlimited reserves every hour is not possible. The purpose is to analyse whether, including risk factors, could reduce the number of times the model exceeds the upper and lower SOC limits. The equations handling risk could be adjusted by two parameters, as seen below in Equation (5.3). H is the number of consecutive hours considered. A higher H means restricting the model to procure fewer FCR-N reserves. The risk factor, R, enables the model to put less importance on the reserves in every hour. A higher R means taking less risk, ultimately procuring fewer reserves in every hour. In the opposite case, a lower R means taking more risk, ultimately procuring more FCR-N reserves.

$$E_b^t + \sum_{max(0,t1-H)}^{t} (P_{D1}^{t1} + P_{D2}^{t1}) * \Delta t * R \leq E_b^{cap,t} * SOC_{max} \tag{5.1}$$

$$E_b^t - \sum_{max(0,t1-H)}^{t} (P_{D1}^{t1} + P_{D2}^{t1}) * \Delta t * R \geq E_b^{cap,t} * SOC_{min} \tag{5.2}$$

The model will be tested for factors specified in Table 5.3.1.

Table 5.3.1: Risk factors and the number of consecutive hours the reserve amount are considered.

Parameter	Value
Risk factor (R)	1, 0.8, 0.6, 0.4, 0.2
Consecutive hours (H)	8, 6, 4, 2

CHAPTER

SIX

RESULTS

This chapter presents the outcomes of the five simulation cases, presented in Section 5.3. The results are further discussed in Chapter 7. Case 1 serves as a baseline, running the model without implementing the FCR-N reserves. It also verifies the model, comparing it to a simpler one-stage deterministic model formulation. In Case 2, procurement of FCR-N reserves is included, but the simulation does not consider the activation and energy exchange associated with the reserves.

The primary emphasis of this master's thesis is on Case 3, which centres around establishing an effective approach for incorporating the activation of FCR-N reserves. The results involve verification of the model functionalities. Case 4 involves including compensation for exchanged energy associated with the activation. It is an essential step in the analysis for assessing the economic feasibility of battery participation in the FCR-N markets, which is an important aspect for stakeholders. Lastly, challenges regarding the state of charge management were identified during the formulation of the model. Case 5 and Case 6 strive to address these challenges, including considering risk factors.

The cases are analysed considering annual expenses, operational cost, export benefit, the benefit of FCR-N procurement, the benefit of FCR-N activation and the cost of reaching the upper and lower SOC limits. Annual expenses are defined as the cost of electricity for the battery owner after all benefits of participating in multiple markets are accounted for. Operational cost is the cost of trading energy at the spot market and cast of battery operation. The export benefit is the payment for exported electricity. Furthermore, the benefit of FCR-N procurement is the payment for reserved battery capacity, according to the prices in the D1 and D2 market for FCR-N reserves. The benefit of FCR-N activation is the payment for the energy exchanged associated with the procured FCR-N reserves, according to the regulating power prices. Lastly, the cost of reaching the upper and lower SOC limits is trading the excess or missing energy associated with FCR-N activation, traded at the elspot market. This is a simplification since SOC management through set point adjustment at additional markets is out of the scope of this thesis.

6.1 Case 1: Running the Model without FCR-N Reserves

The two-stage optimisation problem without FCR-N reserves works as a reference case, in which the subsequent cases will be compared. It will also be used to verify the two-stage deterministic model by comparing the results to a more simple model.

To verify the correctness and performance of the proposed two-stage deterministic MPC model, it is compared to a one-stage deterministic model. The model is obtained from my specialisation project [14]. A one-stage deterministic model can be considered a best-case scenario since all parameters are known in advance with certainty.

Table 6.1.1 displays the annual expenses of the one-stage and two-stage MPC models. Table 6.1.2 shows the energy flows for the two model formulations. Table 6.1.3 displays the operational cost and export benefit. Figure 6.1.1 displays the battery charge and discharge over a year, illustrated by the battery energy level.

Table 6.1.1: Verification of MPC model. There is little change in the annual expenses between the two model formulations.

	Objective 2020 [EUR]	Objective 2021 [EUR]
One-Stage	1 282	2 568
Two-Stage MPC	1 290	2 609
Deviation [%]	**+0.62**	**+1.60**

Table 6.1.2: Verification of MPC model. A comparison of the energy flows shows that the MPC model uses the battery a little more than the deterministic model.

	2020				2021			
	E_{imp} [kWh]	E_{exp} [kWh]	E_{ch} [kWh]	E_{dch} [kWh]	E_{imp} [kWh]	E_{exp} [kWh]	E_{ch} [kWh]	E_{dch} [kWh]
One-Stage	20 549	2 177	145	131	20 585	2 194	237	213
Two-Stage MPC	19 762	1 326	973	881	19 975	1 518	1 190	1 076
Deviation [kWh]	-787	-851	+828	+750	-610	-676	+953	+863

Table 6.1.3: Operational costs and export benefits.

	2020	2021
Operational Costs [EUR]	1290.01	2609.00
Export Benefits [EUR]	- 6.26	- 100.18

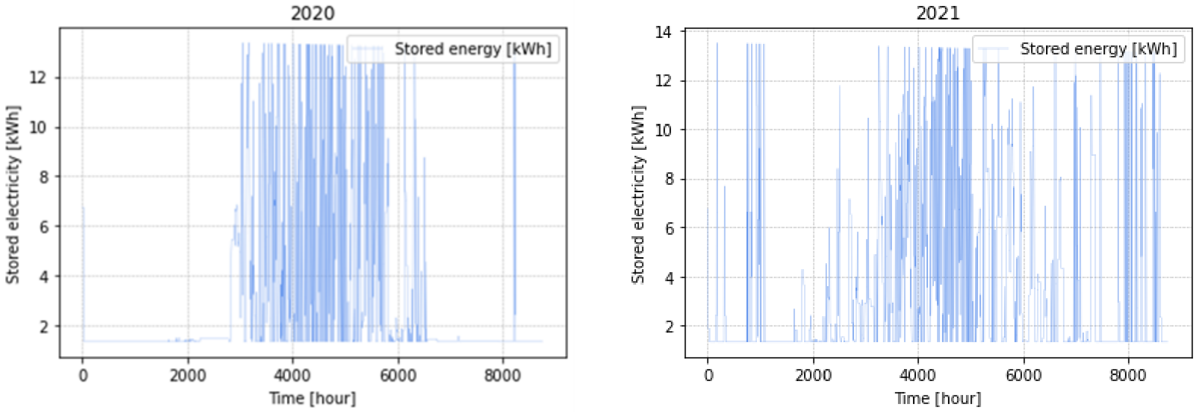


Figure 6.1.1: Energy level in the battery without reservation of FCR-N reserves.

6.2 Case 2: Running the Model without Activation of the FCR-N Reserves

The two-stage optimisation problem is adjusted to also participate in the FCR-N reserve markets but does not account for the activation of the procured reserves. The problem allows reserving capacity in the battery allocated for FCR-N without considering the effect of reserve activation for several consecutive hours. This allows for allocating more FCR-N reserves than one can deliver since it only has a consequence within the hour of reserve allocation. Table 6.2.1 shows the annual expenses, and Table 6.2.2 shows the operational costs, the export benefit and the benefit of FCR-N procurement. Table 6.2.3 displays the energy flows. Figure 6.2.1 indicates how the battery charge and discharges over a year, illustrated by the energy level in the battery.

Table 6.2.1: Annual expense when there is no activation of FCR-N reserves.

Year	Annual Expense [EUR]
2020	998.82
2021	2318.11

Table 6.2.2: Operational costs, export benefit and benefit of FCR procurement when including procurement of FCR-N reserves.

	Operational Costs [EUR]	Export Benefit [EUR]	FCR-N Procurement Benefit [EUR]
2020	1 297.37	- 6.84	- 298.56
2021	2 626.74	-105.20	-308.63

Table 6.2.3: Flow of energy when there is no activation of FCR-N reserves and total contracted FCR-N reserves.

Year	E_{imp} [kWh]	E_{exp} [kWh]	E_{ch} [kWh]	E_{dch} [kWh]	P_{D1} [kW/h]	P_{D2} [kW/h]
2020	19 912.46	1 480.53	891.22	802.52	475.32	19 273.41
2021	20 052.87	1 613.80	972.18	876.34	2 945.72	16 919.17

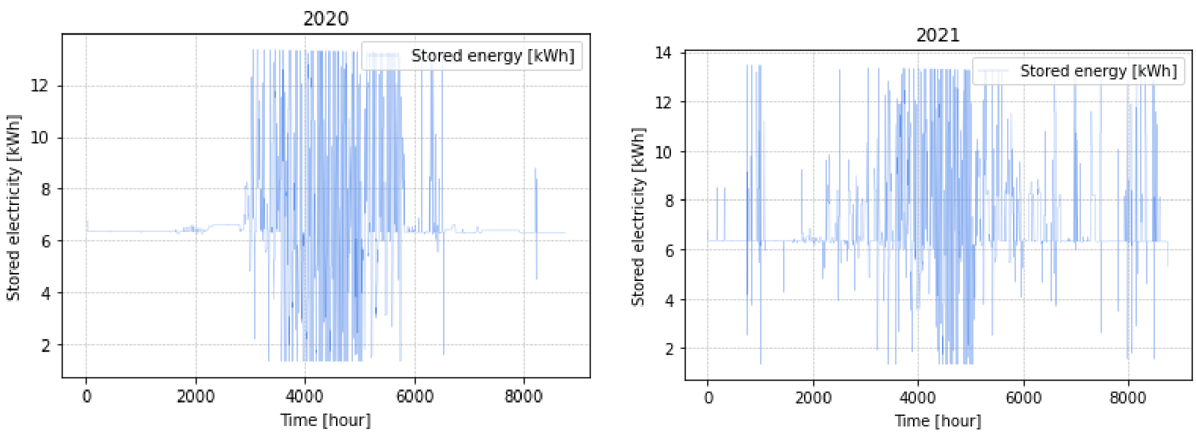


Figure 6.2.1: Energy level in the battery with reservation of FCR-N reserves.

6.3 Case 3: Accounting for Activation of FCR-N Reserves

The two-stage optimisation problem is adjusted to consider the activation of the reserves. That means a frequency deviation is followed by an obligation to exchange energy according to the direction of the frequency deviation and the procured FCR-N reserves. It results in a change in the SOC. Figure 6.3.1 shows how the first stage schedule changes due to the obligation to activate the FCR-N reserves for one day.

Table 6.3.1 shows the annual expenses, and Table 6.3.2 displays the operational costs, export benefits, benefit of FCR-N procurement and cost of reaching the SOC limits.

Table 6.3.3 displays the energy flows and the total amount of contracted reserves. Figure 6.3.2 indicates the number of hours the SOC limits are exceeded and by how much. Figure 6.3.3 illustrates two days of activated reserves and the corresponding energy level in the battery. Lastly, Figure 6.3.4 shows the energy level in the battery over the course of a year.

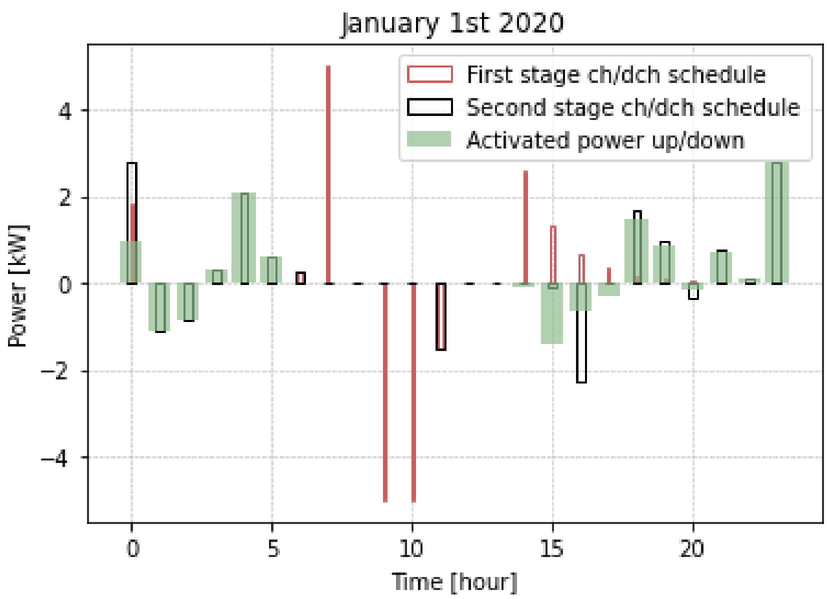


Figure 6.3.1: Change in first stage charge (ch) and discharge (dch) schedule due to activation of FCR-N reserves.

Table 6.3.1: Annual expense when activation of FCR-N reserves are included.

Year	Annual Expense [EUR]
2020	1 219.53
2021	2 563.01

Table 6.3.2: Expenses and revenue streams when including the activation of the procured FCR-N reserves.

	Operational Costs [EUR]	Export Benefit [EUR]	FCR-N Procurement Benefit [EUR]	Cost of Reaching the SOC Limits [EUR]
2020	1 510.64	- 10.20	- 289.58	- 1.59
2021	2 872.87	- 146.15	- 299.78	- 10.08

Table 6.3.3: Flow of energy the FCR-N reserves are activated and total contracted FCR-N reserves.

Year	E_{imp} [kWh]	E_{exp} [kWh]	E_{ch} [kWh]	E_{dch} [kWh]	P_{D1} [kW/h]	P_{D2} [kW/h]
2020	20 934.35	2 229.24	3 602.36	3 240.48	445.59	18 449.45
2021	21 019.20	2 313.54	3 638.07	3 275.64	2 840.57	16 252.86

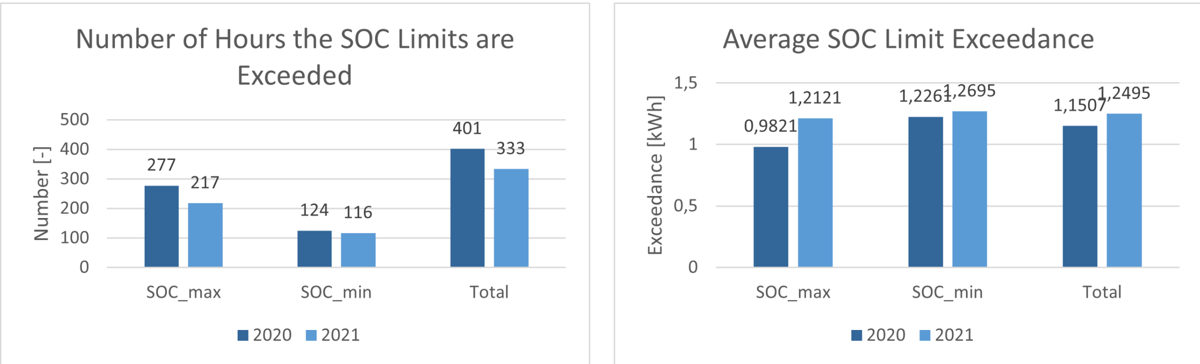


Figure 6.3.2: The number of hours the model exceeds the SOC limits and by how much when activation of procured FCR-N reserves are included.

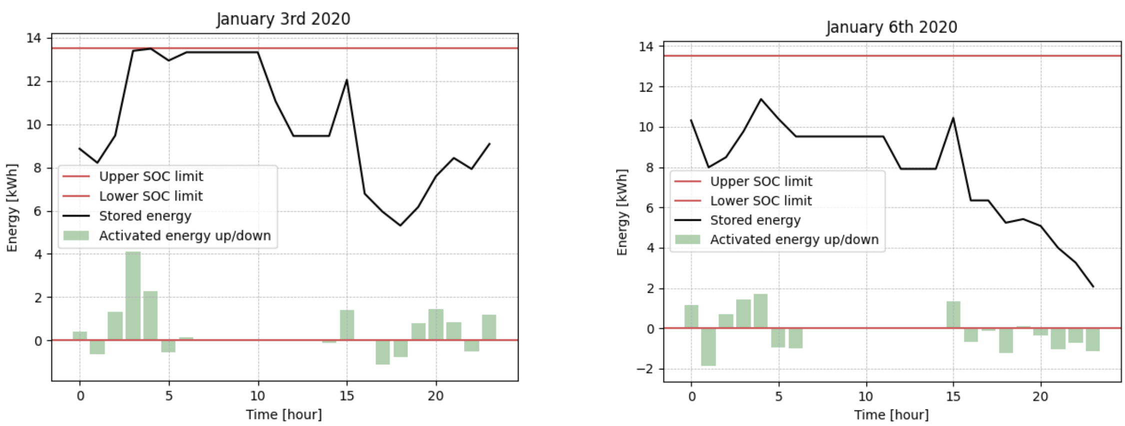
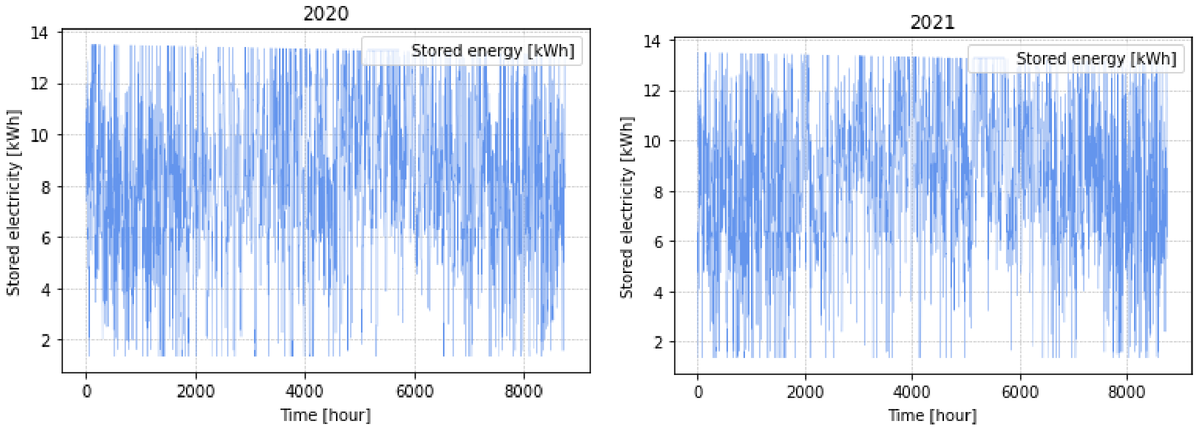


Figure 6.3.3: Energy level in the battery with activation of FCR-N reserves. January 3rd illustrates an unsuccessful operational day, where the energy level in the battery reaches the upper SOC limit. January 6th illustrates a successful operational day.

Figure 6.3.4: Energy level in the battery with activation of procured FCR-N reserves.



6.4 Case 4: Accounting for Activation of FCR-N Reserves, Including Compensation for Activated Energy

The two-stage optimisation problem of Case 3 is adjusted to include compensation for activated energy one must deliver after procurement of FCR-N reserves. Table 6.4.1 shows the annual expenses. Table 6.4.2 show the operational costs, the export benefit, the benefit of FCR-N reserve procurement, the benefit of activating the FCR-N reserves and the cost of reaching the SOC limits. Table 6.4.3 show the energy flows and the total amount of contracted reserves.

Furthermore, Figure 6.4.1 shows how many hours the SOC limits are reached and by how much.

Table 6.4.1: Annual expense when compensation for FCR-N reserves are included.

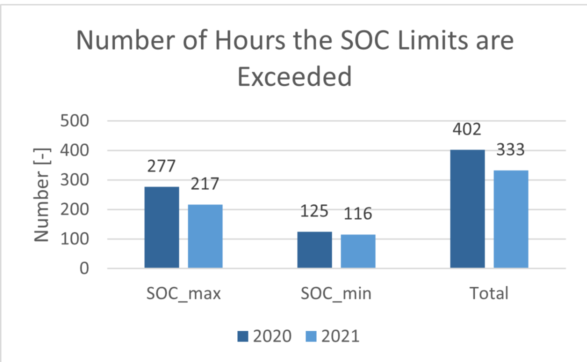
	2020	2021
Annual Expense [EUR]	913.17	2 254.28

Table 6.4.2: Expenses and revenue streams when including compensation for FCR-N activation.

	Operational Costs [EUR]	Export Benefit [EUR]	FCR-N Procurement Benefit [EUR]	Benefit of Activated FCR-N Reserves [EUR]	Cost of Reaching the SOC Limits [EUR]
2020	1510.39	- 10.08	- 289.58	0.06	-1.51
2021	2 872.87	- 146.15	- 299.78	- 308.72	- 10.08

Table 6.4.3: Flow of energy the FCR-N reserves when compensation for activated energy and total contracted FCR-N reserves are included.

Year	E_{imp} [kWh]	E_{exp} [kWh]	E_{ch} [kWh]	E_{dch} [kWh]	P_{D1} [kW/h]	P_{D2} [kW/h]
2020	20 932.14	2 227.27	3 599.90	3 238.27	445.59	18 448.41
2021	21 019.20	2 313.54	3 638.07	3 275.64	2 840.57	16 252.86



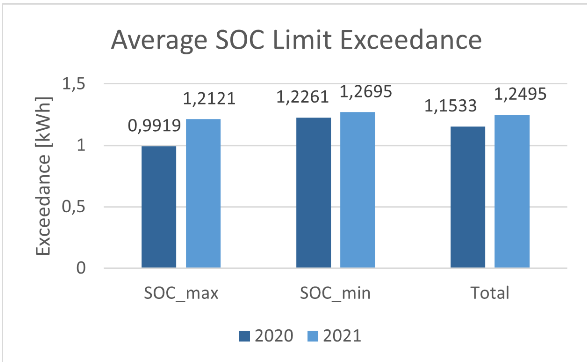


Figure 6.4.1: The number of hours the model exceeds the SOC limits and by how much when compensation for activation of FCR-N reserves is included.

6.5 Case 5: Considering the Risk of Reaching the Battery's SOC Upper and Lower Limits

The two-stage optimisation problem in Case 4 is in Case 5, tested for different risk factors, R. Additionally, by adjusting parameter H, the number of consecutive hours the model account for when deciding the amount of reserves in the first stage is also tested. This is done by additional consider Equations (4.23a) and (4.23b). The tested values of R and H were explained in Section 5.3 and listed in Table 5.3.1. The simulations are done with the aim of reducing the number of hours the SOC limits are reached.

Figure 6.5.1 displays the annual expenses in 2020 and 2020 for the different risk factors and the considered number of hours. Figure 6.5.2 displays the operational costs, according to the definition at the beginning of this Chapter. Figure 6.5.3 and Figure 6.5.4 display the benefit of procuring FCR-N reserves, and the benefit acossiated with the activation of the procured reserves. Figure 6.5.5 displayd the resultig amount of procured reserves, while FIgure 6.5.6 showes the coherence between the annual expenses and the amount of procured reserves.

Furthermore, the number of hours the SOC limits are exceeded are displayed in Figure 6.5.7. In some of the figures results from Case 1 and Case 4 are included for analysis purposes.

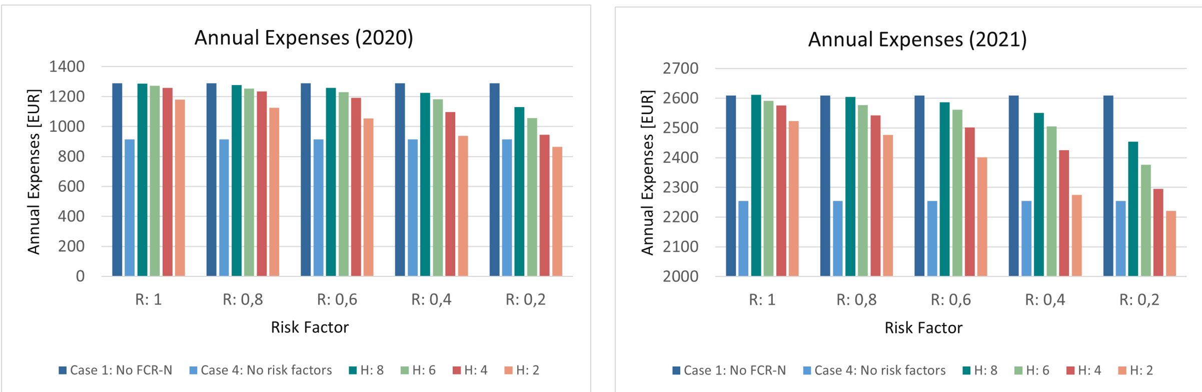


Figure 6.5.1: Annual expenses, adjusting the risk factor R and the number of hours in consideration, H.

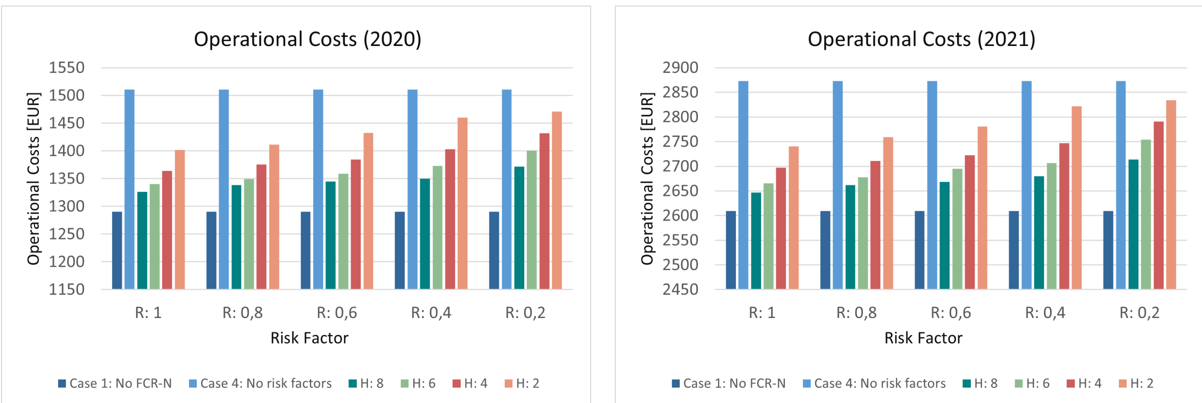


Figure 6.5.2: Operational costs, adjusting the risk factor R and the number of hours in consideration, H.

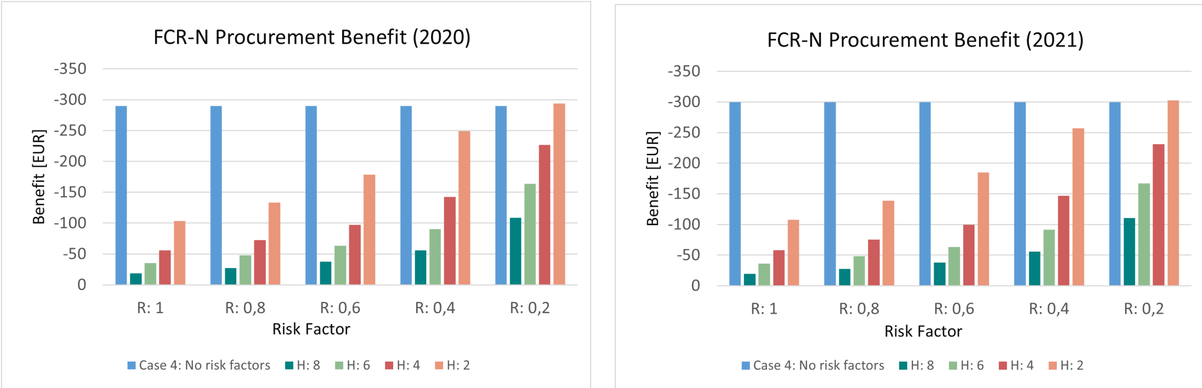


Figure 6.5.3: Payment for FCR-N procurment, adjusting the risk factor R and the number of hours in consideration, H.

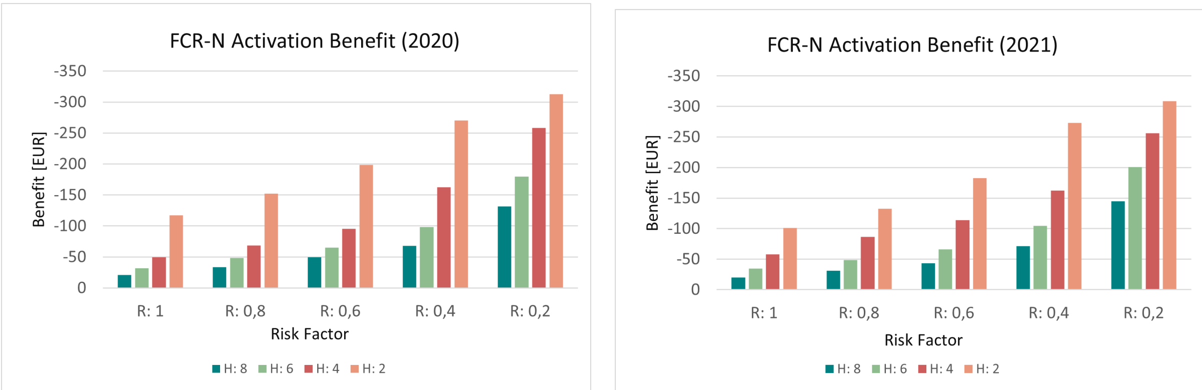


Figure 6.5.4: Payment for activated FCR-N reserves, adjusting the risk factor R and the number of hours in consideration, H.

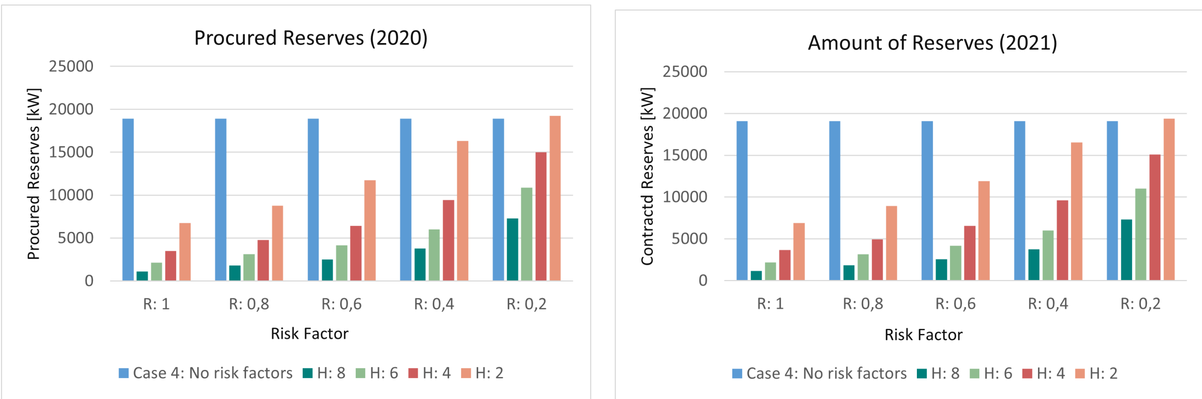


Figure 6.5.5: Amount of procured FCR-N reserves, adjusting the risk factor R and the number of hours in consideration, H.

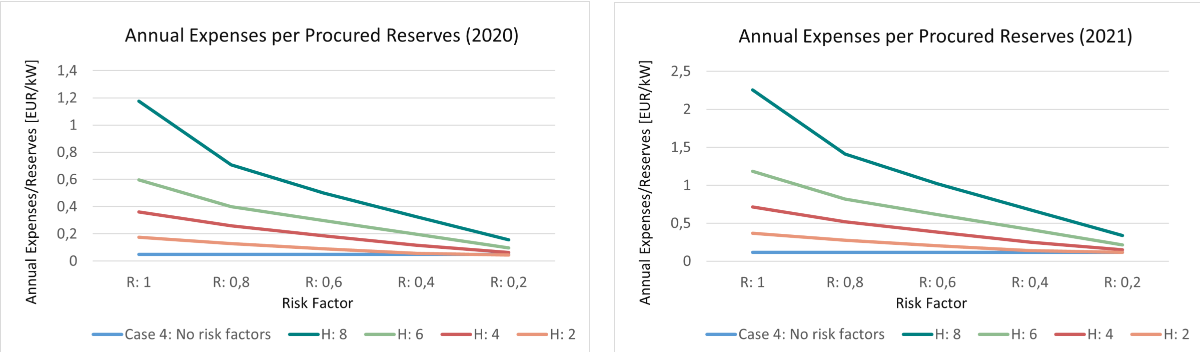


Figure 6.5.6: Annual expenses divided by the amount of procured FCR-N reserves, adjusting the risk factor R and the number of hours in consideration, H.

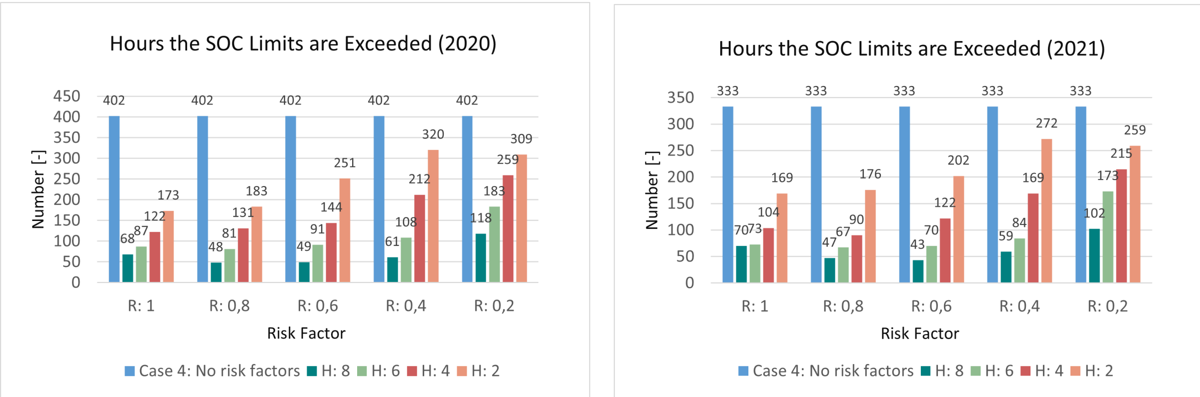


Figure 6.5.7: Number of hours the SOC limits are exceeded, adjusting the risk factor R and the number of hours in consideration, H.

CHAPTER

SEVEN

DISCUSSION

Based on the results in Chapter 6, this chapter analyses and discusses the findings of the performed simulations. It involves an analysis of all five cases formulated in Section 5.3. The discussion also consists of a verification of the model formulation. The chapter further discusses the limitations of the results and the further work necessary to understand the model functionalities well and improve the model for further relevance.

7.1 Case 1: Running the Model without FCR-N Reserves

Case 1 serves as a base case of the system that consists of a household with a PV and battery system. The annual expenses serves as an important assessment criterion when one, in later Cases, is considering participation in multiple markets. The results of Case 1 are also used to verify the problem formulation.

7.1.1 Verification of Model Formulation

The model formulation is compared against a single-stage deterministic optimisation model. The annual expenses can be seen in Table 6.1.1. The expectation was a slight increase in the annual expenses compared to the single-stage model since the optimisation of the MPC model is done based on imperfect forecasts. This was confirmed, experiencing a 0.62 % and 1.60 % increase in 2020 and 2021, respectively. It is also important to note that the MCP model handles the power component of the grid tariff differently than the deterministic model, which could contribute to the increased annual expenses. Handling of the power component of the grid tariff in the MPC model was explained in Section 5.2.1. The MPC model was additionally adjusted to consider Norgesnett's updated grid tariffs of January 2023 [63].

Table 6.1.2 shows the energy flows for the two model formulations. It can be seen that the MPC model uses the battery a bit more than the one-stage model and that the energy exchange with the grid is reduced accordingly. The difference is that the MPC model does not have complete and accurate information about future elspot prices. The model could therefore value the stored energy more than the value of exported electricity. In summary, the model formulation works as wanted.

7.1.2 Expense Analysis and Procurement of FCR-N Reserves

Row three of Table 6.1.1 shows the annual expenses associated with the household's electricity consumption for 2020 and 2021. However, the differences in annual expenses are substantial. The actual consumption and solar power generation data are used for 2020 and 2021. The main contributing factor to the difference is the varying elspot prices of 2020 and 2020. The difference in prices between 2020 and 2021 are seen in Figure 5.2.1 in Section 5.2.3.

Table 6.1.3 show that the operational costs of covering the household's demand for electricity equal the annual expenses. It is due to the fact that the only expense is the operation of the battery and PV system to cover the household's demand. Included in these costs are the export benefit. However, this benefit is small compared to the operational costs. It indicates that the benefit of energy arbitrage is small compared to the cost of loss during a charge and discharge cycle and the cost of battery degradation.

7.1.3 Battery Usage

Studying the battery's energy level in Figure 6.1.1, one can observe that the battery is frequently used in the summer. It corresponds to the time of year when the PV generation is high. The battery stores excess generation for later consumption or exportation, when the elspot prices are higher. Additionally, there is an increase in battery charge and discharge cycles at the start and end of 2021. The increase corresponds to the time of year with varying prices. Table 5.2.4 in Section 5.2.3 show that the elspot prices vary more in 2021 than in 2020, making trading more desirable. The battery use at this time of year is therefore associated with energy arbitrage. Notice also that the battery is frequently emptied.

Secondly, by studying the energy flows in Table 6.1.2, one can notice the loss associated with charging and discharging of the battery. The loss is 9.46% in 2020 and 9.58% in 2021. The losses correspond well with the battery round trip efficiency of 90%.

7.2 Case 2: Running the Model without Activation of the FCR-N Reserves

Case 2 represents a best-case scenario since it enables the battery owner to participate in the FCR-N capacity reserve markets and get paid for the contracted reserves, without being obligated to activate them.

7.2.1 Expense Analysis and Procurement of FCR-N Reserves

The resulting annual expenses, seen in Table 6.3.1 dropped compared to the annual expenses in Case 1. Table 6.2.2 shows that the benefit of FCR-N procurement is substantial, contributing to the decreased annual expenses. If observing the amount of reserves contracted, most transactions are done at the D2 market. The prices in the D2 market are much higher than in the D1 market. However, there is required more volumes in the D1 market. Nevertheless, it is assumed that there are no restrictions in securing a purchase in the markets. Therefore, the model will likely make obligations in the D2 market. The D1 market is mainly used in the hours when the payment for reserves is higher than in the D2 market.

Compared to Case 1, the operational costs of the battery have slightly increased. Reserving capacity in the battery for FCR-N reserves means that less capacity is available for energy arbitrage and storing PV-generated electricity. Table 6.2.3 shows how the exported and imported electricity has increased due to less battery usage. One can additionally observe that the export benefits have increased. It indicates that the FCR-N procurements result in the battery being less available for energy arbitrage. Ultimately increasing operational expenses.

7.2.2 Battery Usage

As mentioned, the battery usage decreased in Case 2 compared to Case 1, due to the procurement of FCR-N reserves, allocating battery capacity for frequency reserves. The reserved capacity for FCR-N could be observed in the battery energy level in Figure 6.2.1. Unlike Case 1, the energy level returns to around half the energy capacity. Since FCR-N is a symmetric reserve, the amount of possible FCR-N procurement is always restricted by the smallest available capacity in the upward or downward direction. Therefore, the battery energy level should be 50%, and the desired charge and discharge plan should be 0 kW, if the battery is solely optimised for procurement of FCR-N reserves.

7.3 Case 3: Accounting for Activation of FCR-N Reserves

In Case 3, the obligation to activate the procured FCR-N reserves due to frequency deviations are accounted for. It involves increasing the load if the frequency is above 50 Hz and decreasing the load if it is below 50 Hz. The increase or decrease of the load is done by adjusting the charge or discharge schedule of the battery.

7.3.1 Verification of Model Functionalities

Figure 6.3.1 shows the change in the first stage charge and discharge schedule. The schedule changes due to several reasons; activation of procured FCR-N reserves, updated predictions, or unforeseen events during the operational hour. One is obligated to deliver the procured FCR-N reserves, so it requires the schedule to change. Additionally, the household's demand for electricity must be covered at all times. Since the time horizon is moved forward in time, it allows the model to adapt the first-stage schedule to changing conditions in the second stage.

The red line shows the first stage schedule. The first stage optimisation process creates an optimal charge and discharge schedule that considers the occupied battery capacity for procured FCR-N reserves, the PV generation and household consumption, but does not account for any activation. In the second stage, there is an obligation to activate the procured reserves according to the frequency deviation. The activated energy can be seen in green in Figure 6.3.1. A second stage charge and discharge schedule is created to account for the activated energy and any necessary changes due to deviations from price and generation forecasts. The second stage charge and discharge schedule can be seen in black.

The black curve follows the direction of the activated energy, meaning the obligation to deliver FCR-N reserves is fulfilled. In an hour with no planned charging or discharging (e.g. hour 5), the second stage charge schedule is identical to the activated energy. In some hours (e.g. hour 0), the scheduled charging or discharging is increased due to an obligation to activate. In other hours (e.g. hour 15), the obligation to deliver reserves involves changing from charging to discharging or vice versa.

Furthermore, the second stage schedule could involve charging or discharging more than the reserve delivery requires (e.g. hour 18). To this author's knowledge, the battery owner is free to operate the battery in a way that delivers more in the direction of the reserve activation. When there is neither a first-stage schedule nor an obligation to provide reserves (e.g. hour 7), the second-stage decision is free. Lastly, the second-stage decisions could follow the first-stage decisions perfectly (e.g. hour 11) if the predictions comply well with reality. In summary, the change in battery charge and discharge schedule in the model works as intended.

7.3.2 Expense Analysis and Procurement of FCR-N Reserves

The activation of procured FCR-N reserves results in an increase in annual expenses compared to Case 2, where only the reservation of the FCR-N reserves was accounted for. However, the annual expenses are still less than in Case 1. Participation in multiple markets is still more profitable than not participating.

The operational costs increased compared to Case 1 and Case 2, even though the export benefits increased compared to Case 2. Looking at the energy flows and the procured FCR-N reserves displayed in Table 6.3.3, it can be seen that imported and exported energy increases compared to Case 2, explaining the increased operational costs and export benefits. Increased import and export can be explained by the obligation to activate FCR-N reserves, which involves an energy exchange with the grid. This does not necessarily happen at the optimal time instances regarding elspot price. It is also supported by the increased use of the battery, seen as increased charging and discharging in Table 6.3.3.

Additionally, there are fewer procured FCR-N reserves in Case 3 than in Case 2. As discussed earlier, the optimal energy level in the battery for FCR-N procurement is about 50% of the battery capacity since FCR-N is a symmetrical reserve. In the formulated model, the first stage (when the decision about the amount of procured FCR-N reserves is made) does not consider the activation of the reserves in the second stage. Consequently, the activation is simply a consequence of the first-stage actions. Therefore, the resulting energy level in the battery is not optimal for maximising the procurement of FCR-N reserves. Ultimately resulting in reserving fewer FCR-N reserves in the first stage. The activation of the FCR-N reserves can be observed in Figure 6.3.4, as more frequent charging and discharging. One can also observe that the energy level is attempted to be kept at 50%. However, the activation frequently shifts the energy level away from this level.

7.3.3 SOC Management

A challenge arising when accounting for reserve activation is that the SOC limits are reached in some time instances. Figure 6.3.2 shows the total number of times the SOC limits are reached over a year and by how much. Figure 6.3.3 displays one day where the upper SOC limit is reached and one day with successful operation of the battery. On January 3rd, in hour 4, the activation of reserves in a downward direction (increase load) results in the upper SOC limit being exceeded by 2.98 kWh. On January 6th, 2020, the energy level in the battery was successfully kept between the upper and lower SOC limit.

In the model formulation, little consequence is associated with reaching the SOC limits. It is attempted to avoid reaching the SOC limits by setting a penalty of 100 000 EUR for using the slack variables in Equation (4.20). This way, the model only uses the slack variables as a last resort.

Nevertheless, the penalty is excluded from the final annual expenses. Failing to deliver the procured reserves could lead to exclusion from participating in the FCR-N capacity markets. The model should incorporate an adequate penalty for delivery failure so it is reflected in the annual costs. However, this is left for further work. As concluded in the literature study in Section 3.4, problems with reaching the SOC limits should be handled with scheduled transactions on a different market, e.g. the intraday market. As a simplification, the "excess" energy associated with reaching the upper SOC is "exported" since adjusting the set points is out of scope in this thesis. The "missing" energy associated with reaching the lower SOC limit is "imported" and bought at the elspot price. As seen in Table 6.3.2, this results in a negative cost, benefitting the operation and giving an overly positive result. This aspect of the model requires further work. However, the benefit is small and does not affect the overall operation.

The maximum SOC limit is reached more often than the lower SOC limit. The upper SOC limits are reached 65-70% of the time, and the lower limit is reached 30-35% of the time. The frequency statistics in Table 5.2.6 in Section 5.2.6 suggest that there should not be any bias in energy activation. There is a slightly higher timeshare of under-frequencies than over-frequencies. However, both are close to 40% if you count a dead band of $\pm$ 0.01 Hz. Also, the average frequency deviation of over- and under-frequencies events are similar. One would, therefore, not expect that the upper SOC limit is reached more often than the lower limit.

If one looks at the hours the upper SOC limit is reached, this is typical during the mid-day. It coincides with the time of day with PV generation. It could suggest that the upper SOC limit is reached because PV power is stored in the battery, shifting the energy level towards the upper limit. However, this should be investigated more thoroughly to be able to draw any clear conclusions.

7.4 Case 4: Accounting for Activation of FCR-N Reserves, Including Compensation for Activated Energy

Case 4 includes compensation for the energy exchange associated with activating the FCR-N reserves. Activated energy is valued at regulating power prices.

7.4.1 Expense Analysis and Procurement of FCR-N Reserves

As seen in Table 6.4.1, the annual expenses have decreased compared to all previous cases. Compared to not participating in the capacity markets for FCR-N reserves, the annual savings were 29.2 % in 2020 and 13.6 % in 2021.

The operational costs, the export benefits, FCR-N procurement benefits, the benefits of activating the reserves, and the cost of reaching the SOC limits equal those of Case 3. This is due to the energy flows and the amount of procured FCR-N reserves equal to Case 3. The activated reserves are not part of the first-stage FCR-N reserve procurement decision-making. The activation is calculated in the second stage based on the frequency deviation and the procured reserves. Consequently, the compensation for this activation is not affecting the optimisation process and decision-making.

7.4.2 SOC Management

The battery usage is equal to Case 3, as the decisions taken in Case 4 are equal to those taken in Case 3. However, the minimum SOC limit exceeded one additional time in 2020, compared to Case 3. There is no obvious explanation for this change. It could be that marginal changes in Case 4 make the battery exceed the limit.

7.5 Case 5: Considering the Risk of Reaching the Battery's SOC Upper and Lower Limits

In Case 5, an attempt is made to reduce the number of hours the SOC limits are reached. In case 4, the limits were reached 402 and 333 times in 2020 and 2021, respectively. The attempt to reduce the challenge with SOC limits is made by adjusting the factors R and H of Equations (4.23a) and (4.23b). A smaller R and H means the model can procure more reserves every hour, eventually taking a higher risk that the SOC limits could be reached. A higher R and H indicates that the reserves obtained in one hour have greater significance in the following hour, limiting the amount of reserves that can be procured in each hour.

7.5.1 Expense Analysis and Procurement of FCR-N Reserves

The annual expenses are in all alternatives lower than in Case 1 (not procuring any FCR-N reserves). However, they are generally higher than in Case 4 (not considering any risk factors). Only alternative H=2, R=0.2 has lower annual expenses than Case 4. Generally, the effect of adjusted risk factors has a greater effect on lower annual expenses of 2021, which has higher elspot prices than in 2020.

The operational costs are less than in Case 4. They have also been observed to increase with decreasing H and R. It can be seen in the context of the amount of procured reserves, which are high for Case 4 and increasing with lower H and R. As previously stated, acquiring more FCR-N reserves involves allocating a significant portion of the battery capacity to the reserves. The operational costs, therefore, increase since it allows for less energy arbitrage, and more of the household's demand for electricity must be covered by imported electricity, ultimately increasing the operational costs. Increasing charge and discharge cycles due to the activation of reserves could also contribute to increased operational costs since it results in higher degradation costs.

Nevertheless, the annual expenses are decreasing with lower H and R, even though it is associated with higher operational costs. It is due to the financial benefit of procured reserves and the economic benefit of activating them are high, ultimately decreasing the overall expenses. This is further supported by Figure 6.5.6, where annual expenses are seen near linear decreasing with an increased amount of procured reserves. It indicates that the amount of reserves should be maximised to lower the annual expenses. It could suggest that bigger battery sizes should be considered for increased reserve procurement. However, the trend flattens out for sufficiently small R and H. It is, therefore, a trade-off between greater battery size and, thus, more reserve procurement, and the cost of battery capacity.

7.5.2 SOC Management

The number of hours the SOC limits were reached decreased compared to Case 4 for all alternatives. It indicates that the goal of reducing the challenges associated with SOC management was successfully accomplished. However, lowering the number of times the SOC limits were reached also resulted in the annual expenses increasing. The annual expenses have doubled for the alternatives with the least number of hours with SOC limit exceedance. Nevertheless, the alternatives that take the most risk (e.g. H=2, R=0.2) have annual expenses at the level of Case 4 and still fewer hours with SOC limit exceedance.

7.6 Limitations

Following the assumptions and model formulation, the results have some limitations. Firstly, it is not assumed that an aggregator will act as an intermediary between the market for FCR-N reserves and the provider of FCR-N reserves. Since the individual contribution of one battery is too small to reach the requirement of 1 MW bid size in the D1 and D2 market, one depends on an aggregator to aggregate the contribution of several small providers. The aggregator would keep some of the profit from the reserve markets, resulting in smaller revenue for the battery owner.

The investment cost is not included in the analysis. As a result, it is unknown whether the additional profits made on the reserve markets are sufficient for it to be logical to invest in a PV and battery system is present.

The simulations are run with a single prediction model: the Naïve method, described in Section 2.7.2.1. The Naïve method is the simplest forecast method and is included for illustration purposes. However, it does not necessarily give the most accurate forecasts. Other prediction methods discussed in Section 2.7 should be explored. More complex prediction algorithms should also be considered.

Furthermore, the work is done considering only one battery size and case data set. The results, therefore, lack generality, making it difficult to identify general patterns and trends. Nonetheless, the case study allows for an in-depth analysis of one case so that the model functionalities can be confirmed.

Finally, there is no penalty for failing to provide the FCR-N reserves. The model attempts to avoid such scenarios, but if there is no other solution, the battery's SOC limits will be reached, and one will not be able to deliver the procured reserves. This does not affect the operation other than the lost revenue associated with FCR-N procurement since fewer reserves can be contracted in the next step. Since the SOC limits are exceeded in several hours, the simulations give an overly optimistic conclusion.

7.7 Further Work

This section aims to identify the directions in which it would be interesting to continue the work done in this master's thesis. The further work includes both continued work with improving input to the model and the type of problem formulation.

Firstly, there were simplifications in how the power component of the grid tariff was incorporated into the model. The power component of the grid tariff for each month is decided based on the three highest peak consumption hours of three independent days during one month. Because the grid tariff was not the primary emphasis of this master's thesis, it was decided to structure it as a linear component. However, the grid tariff could play a significant role in the decision-making. Further work should include a better formulation of the power component of the grid tariff and an analysis of how it affects the FCR-N procurement.

Second, the model's input data comprises hourly values. However, data with a sampling rate of 1 Hz (0.1 s) for frequency in the Nordic system are available. Yet, hourly average values were used due to simplicity and reduced computational time. It would be strongly advised to run the model with a greater sampling rate since an hourly average only reflects the net effect of the frequency variations. In reality, if incidents with a great deviation of frequency over a short time period occur, they will not be captured. Further work should include incorporating frequency measurement data with higher resolution and analysing how it affects FCR procurement and if the challenges regarding activation are changed.

It should be investigated how a set point adjustment, which is not covered in this thesis, affects the FCR-N procurement and the resulting annual expenses.

The developed model in this thesis tried to capture uncertainties by incorporating predictions in the input data and updating the predictions with the most recent information as the optimisation horizon moves forward in time. However, developing a stochastic model, on the other hand, would be desirable to completely incorporate the effect of uncertainty and unpredictability in the model. A stochastic model considers variability and uncertainty in the input parameters by probability, with the ultimate objective of providing a realistic representation and robust decision-making.

Nevertheless, a stochastic model would necessitate precise data on the probabilistic behaviour of input parameters, which could be difficult to obtain with certainty. It also increases the complexity of the model and reduces the computational efficiency.

Another logical progression of the work would be to explore other market options. There are, as described in section 2.4, several balancing markets with the aim of keeping the frequency stable, which include markets for FFR, FCR-D, aFRR and mFRR.

Since the main challenge in working with the model formulation in this thesis has been the effect of activating the reserves, it could be interesting to look into participating in the markets for FCR-D, considering that they are seldom activated. Since the markets for FCR-D have many of the same technical requirements as those for FCR-N, it could be a logical next Case. Another option is to investigate FFR, which requires faster ramping and fewer energy capabilities than other ancillary services. Since the main challenges regarding the activation of the FCR-N reserves have been the limited energy reserve of the battery, and batteries possess fast ramping capability, FFR could also be a good option to look into.

Furthermore, it would also be interesting to look into which services the battery could provide to the DSO. It is conceivable that small distributed batteries could be more useful in providing services close to the point of service delivery (e.g. to the DSO) than providing services to the TSO. However, services relevant to the DSO, such as congestion management and peak shifting, require high energy capability. Therefore, it is necessary to consider whether delivering the services using batteries is technically feasible.

The cost of battery capacity remains high, despite significant reductions over the last decade, as described td in Section 2.6.2. Because of the high cost, it is necessary to investigate alternate resource options that can provide the same services. One possibility is to study whether EVs could provide the same services and to expand the model formulation to include EV charging patterns and availability likelihood. Except when unavailable, an EV could theoretically work as a stationary battery if equipped with vehicle-to-grid capabilities.

Lastly, the results of Case 5 indicate a linear declining coherence between the annual expenses and the amount of procured FCR-N reserves. Larger battery sizes may enable more reserve procurement. However, the cost of battery capacity is high (although decreasing), so there is a trade-off between profit made on the reserve markets and the cost of battery capacity. Nevertheless, investigating optimal battery size should be a part of further work.

CHAPTER

EIGHT

CONCLUSIONS

This thesis investigated the use of a small-scale battery system participating in multiple markets and delivering multiple services. The services in focus included covering a household's demand for electricity, performing energy arbitrage and procuring and delivering FCR-N reserves. An extensive theory chapter investigated the challenges regarding integrating renewable energy sources and the present and predicted changes in the power system. The chapter highlights challenges regarding the need for rotational inertia. It motivates exploring the utilisation of flexible resources to provide services to the grid to secure a stable grid operation.

A literature review was conducted to address the challenges regarding batteries delivering FCR. Since batteries have a limited energy reserve, they could fail to deliver the procured reserves during more extended periods with over- or under-frequencies. Several methods for SOC management were identified in the literature. However, only scheduled transactions on different markets were identified as possible options in the Norwegian power system.

A model of a battery and PV system for a household was formulated from scratch as a two-stage deterministic mixed-integer linear optimisation problem solved using model predictive control with a rolling time horizon. The aim was to develop a model with proximity to reality, incorporating uncertain input data, predicted using the Naïve forecast method. A case study consisting of 5 cases was further formulated for a household in Hvaler, Norway.

A particular focus in the model formulation was the activation of the FCR-N reserves since this aspect often is left out of scope in similar research. The reason is that it has little effect on the operation of conventional power plants. However, for a battery with a limited energy reserve, it is a vital aspect. The model functionalities were confirmed in Section 6.3, where the second stage charge and discharge schedule were observed to adapt to changing conditions and activation signals.

The case study results showed that providing FCR-N reserves in addition to other services resulted in declined annual expenses. Although the operational costs increased, the financial benefit of procuring FCR-N reserves resulted in overall decreased expenses. Further, the annual expenses decreased considerably after incorporating the compensation for activated energy accosted with FCR-N reserves.

In the early cases, it was a challenge keeping the energy level in the battery at an acceptable level. In Case 5, it was attempted to minimise these challenges, as SOC management otherwise is out of the scope of this thesis. It was successfully achieved to reduce the number of hours the SOC limits were exceeded without increasing the annual expenses. However, the problem is still not completely removed. Therefore, this aspect should be a part of further work.

REFERENCES

[1] Energikommisjonen. *Mer av alt - raskere*. Tech. rep. 2023. URL: https://www.regjeringen.no/contentassets/5f15fcecae3143d1bf9cade7da6afe6e/no/pdfs/nou202320230003000dddpdfs.pdf.

[2] Eivind Reiten et al. *Et bedre organisert strømnett*. Tech. rep. 2014. URL: https://www.regjeringen.no/globalassets/upload/oed/pdf_filer_2/rapport_et_bedre_organisert_stroemnett.pdf.

[3] Stig Ødegaard Ottesen. "Techno-economic models in Smart Grids - Demand side flexibility optimization for bidding and scheduling problems". PhD thesis. Norwegian University of Science and Technology (NTNU), 2017.

[4] Energifakta Norge. *Security of Electricity Supply*. URL: https://energifaktanorge.no/en/norsk-energiforsyning/forsyningssikkerhet/ (visited on 02/09/2023).

[5] Xiaolong Jina, Qiuwei Wua, and Hongjie Jiab. "Local flexibility markets: Literature review on concepts, models and clearing methods". In: *Applied Energy* 261 (2020).

[6] The international energy agency (IEA). *Implementation of bioenergy in Norway – 2021 update*. Tech. rep. 2021. URL: https://www.ieabioenergy.com/wp-content/uploads/2021/11/CountryReport2021_Norway_final.pdf#:~:text=Renewables%5C%5C%5C%20make%5C%5C%5C%20up%5C%5C%5C%20almost%5C%5C%5C%20half%5C%5C%5C%20of%5C%5C%5C%20total%5C%5C%5C%20energy,is%5C%5C%5C%20mainly%5C%5C%5C%20used%5C%5C%5C%20for%5C%5C%5C%20heat%5C%5C%5C%20and%5C%5C%5C%20liquid%5C%5C%5C%20biofuels..

[7] Pol Olivella-Rosell et al. "Local Flexibility Market Design for Aggregators Providing Multiple Flexibility Services at Distribution Network Level". In: *Eenrgies* 11 (2018).

[8] Merkebu Zenebe Degefa, Iver Bakken Sperstad, and Hanne Sæle. "Comprehensive classifications and characterizations of power system flexibility resources". In: *Electric Power Systems Research* 194 (2021).

[9] José Villar, Ricardo Bessa, and Manuel Matos. "Flexibility products and markets: Literature review". In: *Electric Power Systems Research* 154 (2018), pp. 329–340.

[10] International Renewable Energy Agency (IRENA). *Demand-side flexibility for power sector transformation*. Tech. rep. 2019. URL: https://www.irena.org/publications/2019/Dec/Demand-side-flexibility-for-power-sector-transformation.

[11] Stig Ødegaard Ottesen, Martin Haug, and Heidi S. Nygård. "A Framework for Offering Short-Term Demand-Side Flexibility to a Flexibility Marketplace". In: *Energies* 13 (2020).

[12] Ozge Okur, Petra Heijnen, and Zofia Lukszo. "Aggregator's Business Models: Challenges Faced by Different Roles". In: *2020 IEEE PES Innovative Smart Grid Technologies Europe (ISGT-Europe)*. Virtual: IEEE, 2020.

[13] The European Parliament and the Council of the European Union. *Directive 2009/72/EC of the European Parliament and of the Council of 13 July 2009 concerning common rules for the internal market in electricity and repealing Directive 2003/54/*. Official journal of the European Union. Aug. 2009. URL: https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/uri=CELEX:32009L0072#:~:text=Directive%5C%5C%5C%202009%5C%5C%5C%2F72%5C%5C%5C%2FEC%5C%5C%5C%20of%5C%5C%5C%20the%5C%5C%5C%20European%5C%5C%5C%20Parliament%5C%5C%5C%20and%5C%5C%5C%20of,internal%5C%5C%5C%20market%5C%5C%5C%20in%5C%5C%5C%20electricity%5C%5C%5C%20and%5C%5C%5C%20repealing%5C%5C%5C%20Directive%5C%5C%5C%202003%5C%5C%5C%2F54%5C%5C%5C%2FEC.

[14] Ingvild Eline Olsen. "Multimarket Services for Stationary Batteries - Case of Providing Primary Frequency Reserves". *Spesialisation project*. Norwegian University of Science an Technology (NTNU), 2022.

[15] Statnett. *Utvikling av systemtjenester 2016-2021*. Tech. rep. 2016. URL: %5C%5Chttps://www.statnett.no/for-aktorer-i-kraftbransjen/utvikling-av-kraftsystemet%5C%5C/systemdrifts-og-markedsutviklings/.

[16] Statnett. *Systemdrifts- og markedsutviklingsplan 2022-2030*. Tech. rep. 2021. URL: https://www.statnett.no/globalassets/for-aktorer-i-kraftsystemet/utvikling-av-kraftsystemet/smup/systemdrifts--og-markedsutviklingsplan-2022-2030.pdf.

[17] Statnett. *Reservemarkedene*. 2023. URL: https://www.statnett.no/for-aktorer-i-kraftbransjen/systemansvaret/kraftmarkedet/reservemarkeder/introduksjon-til-reserver/ (visited on 03/18/2023).

[18] Andreas Ulbig. "Operational Flexibility in Electric Power Systems". PhD thesis. ETH Zurich, 2014.

[19] Yann G. Rebours et al. "A Survey of Frequency and Voltage Control Ancillary Services—Part I: Technical Features". In: *IEEE Transactions on Power Systems* 22 (2007).

[20] Statnett. *Vilkår - tilbud, aksept, aktivering, rapportering og avregning i marked for FCR til Statnett*. Tech. rep. 2022. URL: https://www.statnett.no/for-aktorer-i-kraftbransjen/systemansvaret/kraftmarkedet/reservemarkeder/primarreserver/.

[21] European Network of Transmission System Operators of Electricity. *Technical Requirements for Frequency Containment Reserve Provision in the Nordic Synchronous Area*. Tech. rep. 2022. URL: https://www.statnett.no/globalassets/for-aktorer-i-kraftsystemet/marked/reservemarkeder/fcr-technical-requirements-2022-06-27.pdf.

[22] Julia Merino et al. *Ancillary service provision by RES and DSM connected at distribution level in the future power system*. Tech. rep. 2016. URL: https://smartnet-project.eu/wp-content/uploads/2016/12/D1-1_20161220_V1.0.pdf.

[23] Energy facts Norway. *THE POWER MARKET*. 2022. URL: https://energifaktanorge.no/en/norsk-energiforsyning/kraftmarkedet/ (visited on 03/21/2023).

[24] The Norwegian Energy Regulatory Authority (NVE-RME). *Wholesale market: Timeframes*. 2021. URL: https://www.nve.no/norwegian-energy-regulatory-authority/wholesale-market/wholesale-market-timeframes/ (visited on 03/21/2023).

[25] Nordpool. *Product Specifications - Nordic/ Baltic Market Areas*. Tech. rep. 2021. URL: https://www.nordpoolgroup.com/49649b/globalassets/download-center/rules-and-regulations/product-specifications-nordic-and-baltic-market-05.04.21.pdf.

[26] Ruud Kempener and Eric Borden. *Battery Storage for Renewables: Market Status and Technology Outlook*. Tech. rep. hdfh, 2015.

[27] Francisco Díaz-González et al. "A review of energy storage technologies for wind power applications". In: *Renewable and Sustainable Energy Reviews* 16 (2012).

[28] Haoran Zhao et al. "Review of energy storage system for wind power integration support". In: *Applied Energy* 137 (2014).

[29] Veronika Henze at Bloomberg NEF. *Lithium-ion Battery Pack Prices Rise for First Time to an Average of $151/kWh*. 2022. URL: https://about.bnef.com/blog/lithium-ion-battery-pack-prices-rise-for-first-time-to-an-average-of-151-kwh/ (visited on 12/07/2022).

[30] Daniel-Ioan Stroe et al. "Degradation Behavior of Lithium-Ion Batteries Based on Lifetime Models and Field Measured Frequency Regulation Mission Profile". In: *IEEE TRANSACTIONS ON INDUSTRY APPLICATIONS* 52 (2016).

[31] Bolun Xu et al. "Factoring the Cycle Aging Cost of Batteries Participating in Electricity Markets". In: *IEEE TRANSACTIONS ON POWER SYSTEMS* 33 (2018).

[32] Shuai Ma et al. "Temperature effect and thermal impact in lithium-ion batteries: A review". In: *Progress in Natural Science: Materials International* 28 (2018), pp. 653–666.

[33] Yuan Zhang and Mo-Yuen Chow. "Microgrid Cooperative Distributed Energy Scheduling (CoDES) Considering Battery Degradation Cost". In: *2016 IEEE 25th International Symposium on Industrial Electronics (ISIE)*. Santa Clara, CA, USA: IEEE, 2016.

[34] K. Tvete. *Solens Gang II. Tangenten*. 2000. URL: https://tangenten.no/tidligere-nummer/2000-2/ (visited on 02/08/2023).

[35] Stig Ødegaard Ottesen et al. *Simplified Battery operation and control algorithm*. Tech. rep. 2017. URL: https://h2020invade.eu/wp-content/uploads/2017/05/D5.3_Simplified-Battery-operation-and-control-algorithm.pdf.

[36] Energifakta Norge. *THE POWER MARKET*. URL: https://energifaktanorge.no/en/norsk-energiforsyning/kraftmarkedet/ (visited on 02/08/2023).

[37] Mary Drane and Hamid Faramarzi. *Introduction to Operations Management*. Seneca College.

[38] Bjarne Foss and Tor Aksel N. Heirung. *Merging Optimization and Control*. 1st ed. Department of Engineering Cybernetics Norwegian University of Science and Technology — NTNU, 2016.

[39] Javier Silvente et al. "A rolling horizon optimization framework for the simultaneous energy supply and demand planning in microgrids". In: *Applied Energy* 155 (2015), pp. 485–501.

[40] Sigurd Bjarghov et al. "Battery Degradation-Aware Congestion Management in Local Flexibility Markets". In: *2021 IEEE Madrid PowerTech*. Madrid, Spain: IEEE, 2021.

[41] Fulong Li, Claudio Cañizares, and Zhengyu Lin. "Energy Management System for DC Microgrids Considering Battery Degradatio". In: *IEEE Power Energy Society General Meeting (PESGM)*. Montreal, QC, Canada: IEEE, 2020.

[42] Jonathan Donadee and Marija Ilić. "Estimating the rate of battery degradation under a stationary Markov operating policy". In: *2014 IEEE PES General Meeting | Conference Exposition*. MD, USA: IEEE, 2014.

[43] Andreas Thingvada et al. "Economic Value of Multi-Market Bidding in Nordic Frequency Markets". In: *2022 International Conference on Renewable Energies and Smart Technologies (REST)*. Tirana, Albania: IEEE, 2022.

[44] Sadegh Vejdan and Santiago Grijalva. "Analysis of multiple revenue streams for privately-owned energy storage systems". In: *2018 IEEE Power and Energy Conference at Illinois (PECI)*. Champaign, IL, USA: IEEE, 2018.

[45] Yuting Tian et al. "Stacked Revenue and Technical Benefits of a Grid-Connected Energy Storage System". In: *IEEE Transactions on Industry Applications* 54 (2018), pp. 3034–3043.

[46] Sujit Tripathy et al. "Establishing the Stacked Value of Battery Energy Storage in Electric Power Systems". In: *2018 North American Power Symposium (NAPS)*. Fargo, ND, USA: IEEE, 2018.

[47] S. Jalal Kazempour and Mohsen Parsa Moghaddam. "Economic Viability of NaS Battery Plant in a Competitive Electricity Market". In: *2009 International Conference on Clean Electrical Power*. Capri, Italy: IEEE, 2009.

[48] Raphael Hollinger et al. “Analysis of the minimum activation period of batteries in frequency containment reserve”. In: *2017 14th International Conference on the European Energy Market (EEM)*. Dresden, Germany: IEEE, 2017.

[49] Hosna Khajeh, Chethan Parthasarathy, and Hannu Laaksonen. “Effects of Battery Aging on BESS Participation in Frequency Service Markets – Finnish Case Study”. In: *2022 18th International Conference on the European Energy Market (EEM)*. Ljubljana, Slovenia: IEEE, 2022.

[50] Huachun Han et al. “Energy Storage Frequency Response Control Considering Battery Aging of Electric Vehicle”. In: *2017 IEEE International Conference on Energy Internet (ICEI)*. Beijing, China: IEEE, 2017.

[51] Özge Okur, Petra Heijnen, and Zofia Lukszo. “Profitability Analysis of Consumer Batteries Providing Frequency Containment Reserve”. In: *2019 IEEE PES Innovative Smart Grid Technologies Europe (ISGT-Europe)*. Bucharest, Romania: IEEE, 2019.

[52] Alessandro Filippa, Seyedmostafa Hashemi, and Chresten Træholt. “Economic Evaluation of Frequency Reserve Provision using Battery Energy Storage”. In: *2019 IEEE 2nd International Conference on Renewable Energy and Power Engineering (REPE)*. Toronto, ON, Canada: IEEE, 2019.

[53] Theodor Borsche, Michael Koller Andreas Ulbig, and Goran Andersson. “Power and Energy Capacity Requirements of Storages Providing Frequency Control Reserves”. In: *2013 IEEE Power Energy Society General Meeting*. Vancouver, BC, Canada: IEEE, 2013.

[54] Johannes Fleer and Peter Stenzela. “Impact analysis of different operation strategies for battery energy storage systems providing primary control reserve”. In: *Journal of Energy and Storage* 8 (2016), pp. 320–338.

[55] Tjark Thiena et al. “Real-world operating strategy and sensitivity analysis of frequency containment reserve provision with battery energy storage systems in the german market”. In: *Journal of Energy Storages* 13 (2017), pp. 143–163.

[56] I.S.Jha et al. “Control Strategy for Frequency Regulation using Battery Energy Storage with Optimal Utilization”. In: *Proceedings of 2014 IEEE 6th India International Conference on Power Electronics (IICPE)*. IEEE, June 2015.

[57] Poria Hasanpor Divshali and Corentin Evens. “Optimum Operation of Battery Storage System in Frequency Containment Reserves Markets”. In: *IEEE TRANSACTIONS ON SMART GRID* 11 (2020).

[58] Gurobi. *About Us*. 2023. URL: https://www.gurobi.com/ (visited on 03/18/2023).

[59] Pyomo. *About Pyomo*. 2023. URL: http://www.pyomo.org/about (visited on 03/18/2023).

[60] Norgesnett. *Excel: Anonymized Household Consumption for 17 Customer in Hvaler, Norway*. 2016. URL: https://norgesnett.no/.

[61] Stefan Pfenninger and Iain Staffell. *Renewables.ninja*. 2023. URL: https://www.renewables.ninja/ (visited on 06/06/2023).

[62] Tesla. *Powerwall*. Tech. rep. 2019. URL: https://www.tesla.com/sites/default/files/pdfs/powerwall/Powerwall%5C%202_AC_Datasheet_en_AU.pdf.

[63] Norgesnett. *Nettleie privat*. 2023. URL: https://norgesnett.no/nettleie-privat/ (visited on 01/27/2023).

[64] Nordpool. *Data Portal*. 2022. URL: https://www.nordpoolgroup.com/en/services/power-market-data-services/dataportalregistration/ (visited on 03/04/2023).

[65] Stefan Pfenninger and Iain Staffell. “Long-term patterns of European PV output using 30 years of validated hourly reanalysis and satellite data”. In: *Energy* 114 (2016), pp. 1251–1265.

[66] Stefan Pfenninger and Iain Staffell. “Using Bias-Corrected Reanalysis to Simulate Current and Future Wind Power Output”. In: *Energy* 114 (2016), pp. 1224–1239.

[67] Fingrid. *Frequency - historical data*. 2023. URL: https://data.fingrid.fi/en/dataset/frequency-historical-data (visited on 02/10/2023).

[68] Statnett. *Tall og data fra reservemarkeder*. 2023. URL: https://www.statnett.no/for-aktorer-i-kraftbransjen/systemansvaret/kraftmarkedet/reservemarkeder/tall-og-data-fra-reservemarkeder/ (visited on 02/12/2023).

[69] DNV-GL. *Batterier i distribusjonsnettet*. Tech. rep. 2018. URL: https://publikasjoner.nve.no/rapport/2018%5C%5C/rapport2018_02.pdf.

[70] Julien Le Baut et al. *Characterization of flexibility resources and distribution networks*. Tech. rep. 2017. URL: https://sintef.brage.unit.no/sintef-xmlui/handle/11250/2496147.

[71] Zeenat Hameed et al. "Placement of Battery Energy Storage for Provision of Grid Services – A Bornholm Case Study". In: *2021 the 9th International Conference on Smart Energy Grid Engineering*. Oshawa, ON, Canada: IEEE, 2021.

[72] Qian Deng Sujit Tripathy et al. "Establishing the Stacked Value of Battery Energy Storage in Electric Power Systems". In: *North American Power Symposium (NAPS)* (2018).

[73] Thomas Clark et al. "Aggregation of Residential Water Heaters for Peak Shifting and Frequency Response Services". In: *IEEE Open Acess Journal of Power and Energy* (2019).

[74] Jaroslav Hlava and Nikita Zemtsov. "Aggregated Control of Electrical Heaters for Ancillary Services Provision". In: *2015 19th International Conference on System Theory, Control and Computing (ICSTCC)*. Cheile Gradistei, Romania: IEEE, 2015.

[75] William Mendieta and Claudio A. Cañizares. "Primary Frequency Control in Isolated Microgrids Using Thermostatically Controllable Loads". In: *IEEE TRANSACTIONS ON SMART GRID* 12 (2021).

[76] Lasse Peltonen et al. "Distributed small loads as fast frequency reserves: Impact on system performance". In: *IEEE Texas Power and Energy Conference (TPEC)* (2020).

[77] Andersson S. L. et al. "Plug-in hybrid electric vehicles as regulating power providers: Case studies of Sweden and Germany". In: *Energy Policy* 38 (2010).

[78] Siyamak Sarabi1 et al. In: *Energy Policy* 38 (2010).

[79] Katarina Knezovi´c et al. "Enhancing the Role of Electric Vehicles in the Power Grid: Field Validation of Multiple Ancillary Services". In: *IEEE TRANSACTIONS ON TRANSPORTATION ELECTRIFICATION* 3 (2017).

[80] Statnett. *Fast Frequency Reserves 2018 - pilot for raske frekvensreserver*. Tech. rep. 2020. URL: https://www.statnett.no/for-aktorer-i-kraftbransjen/systemansvaret/kraftmarkedet/reservemarkeder/ffr/.

[81] Anurag Sharma, Dipti Srinivasan, and IEEE Anupam Trivedi Student Member. "A Decentralized Multiagent System Approach for Service Restoration Using DG Islanding". In: *IEEE TRANSACTIONS ON SMART GRID* 6 (2015).

APPENDICES

APPENDIX

A

LITERATURE REVIEW - ANCILLARY SERVICE PROVISON

Appendix A contains the results of the literature review conducted in my specialisation project [14], which led to the decision to look into the provision of FCR-N by batteries.

Table A.0.1: Reviewed literature for mapping ancillary service by provision of batteries. "-" mark no information in the literature.

Reference	Primary Freq. Control	Secondary Freq. Control	Tertiary Freq. Control	Fast Freq. Reserves	Voltage Control	Controlled Islanding	Load Shedding	Generation Tripping	Black Start
[22]	Yes	Yes	Yes	-	Yes	-	-	-	-
[69]	Yes	Yes	Yes	-	Yes	Yes	Yes	-	Yes
[26]	Yes	Yes	Yes	Yes	Yes	Yes	-	-	Yes
[70]	Yes	Yes	Yes	Yes	Yes		Yes?	-	Yes
[71]	Yes	Yes	Yes	-	-	-	Yes	-	Yes
[72]	Yes	Yes	Yes	-	Yes	Yes	-	-	Yes

Table A.0.2: Reviewed literature for mapping ancillary service by provision of EWH. "-" mark no information in the literature.

Reference	Primary Freq. Control	Secondary Freq. Control	Tertiary Freq. Control	Fast Freq. Reserves	Voltage Control	Controlled Islanding	Load Shedding	Generation Tripping	Black Start
[70]	Yes	Yes	Yes	No	No	-	Yes	No	No
[73]	Yes	Yes	Yes	-	-	-	Yes	No	-
[74]	-	Yes	-	-	-	-	-	No	-
[75]	-	Yes	-	-	No	-			
[76]	Yes	Yes	Yes	Yes	-	-	Yes	No	-

Table A.0.3: Reviewed literature for mapping ancillary service by provision of EVs. "-" mark no information in the literature.

Reference	Primary Freq. Control	Secondary Freq. Control	Tertiary Freq. Control	Fast Freq. Reserves	Voltage Control	Controlled Islanding	Load Shedding	Generation Tripping	Black Start
[70]	Yes	Yes	Yes	Yes	Yes	-	Yes	-	No
[77]	Yes	Yes	Yes	-	-	-	-	-	-
[78]	Yes	Yes	Yes	-	Yes	-	Yes	-	-
[79]	Yes	Yes	Yes	-	Yes	-	Yes	-	-
[80]	-	-	-	Yes	-	-	-	-	-
[81]	-	-	-	-	-	Yes	-	-	-

Table A.0.4: Resulting mapping of ancillary services to the provision of flexible resources

	Primary Freq. Control	Secondary Freq. Control	Tertiary Freq. Control	Fast Freq. Reserves	Generation Shifting	Generation Smoothing	Generation Adjustment	Voltage Control	Controlled Islanding	Load Shedding	Generation Tripping	Black Start
BESS	Yes	Yes	Yes	Yes	No	No	No	Yes	Yes	Yes	No	Yes
EWHs	Yes	Yes	Yes	-	No	No	No	No	No	Yes	No	No
EVs	Yes	Yes	Yes	Yes	No	No	No	Yes	-	Yes	No	No

APPENDIX

B

CALCULATION OF CAPACITY GRID TARIFFS

Appendix B contains detailed calculations of the power component of the grid tariff. *Average peak consumption* denotes the average of the three highest peak hours on three different days when running the simulations without the procurement of FCR-N reserves. The *resulting power component* of the grid tariff is set according to Norgesnett's grid tariffs [63]. The resulting linear power component of the grid tariff (in bold), is calculated by dividing the grid tariff by the imported power.

Table B.0.1: Power component of the grid tariff in Hvaler in 2021, prices by Norgesnett [63].

Month	Avg peek consumption [kWh/h]	Resulting power component[NOK/month]	Total imported electricity [kWh]	Per kWh expense [NOK/kWh]
Jan	7.2878	356.13	3493.79	**0.101932**
Feb	8.9884	356.13	2549.94	**0.139662**
Mar	5.4151	356.13	2001.37	**0.177943**
Apr	4.7553	216.56	1275.13	**0.169833**
May	3.8853	216.56	891.93	**0.242799**
Jun	3.1724	216.56	603.07	**0.359095**
Jul	2.6308	216.56	488.83	**0.443017**
Aug	3.3006	216.56	765.02	**0.283078**
Sep	3.5388	216.56	919.81	**0.235440**
Oct	8.6553	356.13	1971.26	**0.180661**
Nov	10.3034	633.33	2790.81	**0.226934**
Dec	9.8241	356.13	2904.59	**0.122609**

Table B.0.2: Power component of the grid tariff in Hvaler in 2020, prices by Norgesnett [63].

Month	Avg peek consumption [kWh/h]	Resulting power component [NOK/month]	Total imported electricity [kWh]	Per kWh expense [NOK/kWh]
Jan	7.2878	356.13	3494.16	**0.101921**
Feb	5.8166	356.13	2544.94	**0.139937**
Mar	5.4151	356.13	2001.38	**0.17794**
Apr	4.7553	216.56	1275.13	**0.169833**
May	3.8853	216.56	891.93	**0.242799**
Jun	3.1724	216.56	603.07	**0.359096**
Jul	2.6308	216.56	488.84	**0.443008**
Aug	3.3006	216.56	765.97	**0.286088**
Sep	3.5388	216.56	919.81	**0.235440**
Oct	4.8547	216.56	1965.08	**0.110204**
Nov	6.3212	356.13	2783.69	**0.127935**
Dec	5.6555	356.13	2884.17	**0.123478**

APPENDIX

C

COMPLETE OPTIMISATION PROBLEMS

Appendix C contains the complete formulations of the two-stage optimisation problems of Case 1 to Case 4. The formulation of each case is divided into *First Stage Problem* and *Second Stage Problem*.

C1 Step 1: Running the Model Without FCR-N Reserves

First Stage Problem

$$minimise \sum_{t=0}^{48} C_{deg} * P_{dch}^t - (Pr_{spot}^t + C_{gt,surplus}) * P_{exp}^t * \Delta t + (Pr_{spot}^t + C_{gt,energy} \tag{C.1a}$$

$$+C_{gt,power}) * P_{imp}^t * \Delta t$$

$s.t.$

$$P_{pv}^t + P_{imp}^t - P_{exp}^t + P_{dch}^t * \eta_{dch} - P_{ch}^t * \frac{1}{\eta_{ch}} - P_{demand}^t = 0 \qquad for\ t = 1, ..., 48 \tag{C.1b}$$

$$P_{ch}^{min} * S_{ch}^t \leq P_{ch}^t \leq P_{ch}^{max} * S_{ch}^t \qquad for\ t = 1, ..., 48 \tag{C.1c}$$

$$p_{dch}^{min} * (1 - S_{ch}^t) \leq P_{dch}^t \leq P_{dch}^{max} * (1 - S_{ch}^t) \qquad for\ t = 1, ..., 48 \tag{C.1d}$$

$$E_b^t = E_b^{t-1} + \eta_{ch} * P_{ch}^t * \Delta t - \frac{1}{\eta_{dch}} * P_{dch}^t * \Delta t \qquad for\ t = 2, ..., 48 \tag{C.1e}$$

$$E_b^t = E_b^{init,t} + \eta_{ch} * P_{ch}^t * \Delta t - \frac{1}{\eta_{dch}} * P_{dch}^t * \Delta t \qquad for\ t = 1 \tag{C.1f}$$

$$SOC_{min} \leq SOC^t \leq SOC_{max} \qquad for\ t = 1, ..., 48 \tag{C.1g}$$

$$E_b^{cap,t} = SOH^t * E_b^{cap} \qquad for\ t = 1, ..., 48 \tag{C.1h}$$

$$0 \leq SOH^t \leq 1 \qquad for\ t = 1, ..., 48 \tag{C.1i}$$

$$SOH^t = SOH^{t-1} - Deg \qquad for\ t = 2, ..., 48 \tag{C.1j}$$

$$SOH^t = 1 - h_{current} * Deg \qquad for\ t = 1 \tag{C.1k}$$

$$E_b^{cap,t} * SOC_{min} \leq E_b^t \leq E_b^{cap,t} * SOC_{max} \qquad for\ t = 2, ..., 48 \tag{C.1l}$$

$$0 \leq P_{exp}^t \leq K * \delta_{2g}^t \qquad for\ t = 1, ..., 48 \tag{C.1m}$$

$$0 \leq P_{imp}^t \leq K * (1 - \delta_{2g}^t) \qquad for\ t = 1, ..., 48 \tag{C.1n}$$

Second Stage Problem

$$minimise \sum_{t=0}^{72} C_{deg} * P_{dch}^t - (Pr_{spot}^t + C_{gt,surplus}) * P_{exp}^t * \Delta t + (Pr_{spot}^t + C_{gt,energy} \tag{C.2a}$$

$$+C_{gt,power}) * P_{imp}^t * \Delta t$$

$s.t.$

$$P_{pv}^t + P_{imp}^t - P_{exp}^t + P_{dch}^t * \eta_{dch} - P_{ch}^t * \frac{1}{\eta_{ch}} - P_{demand}^t = 0 \qquad for\ t = 1, ..., 72 \tag{C.2b}$$

$$P_{ch}^{min} * S_{ch}^t \leq P_{ch}^t \leq P_{ch}^{max} * S_{ch}^t \qquad for\ t = 1, ..., 72 \tag{C.2c}$$

$$p_{dch}^{min} * (1 - S_{ch}^t) \leq P_{dch}^t \leq P_{dch}^{max} * (1 - S_{ch}^t) \qquad for\ t = 1, ..., 72 \tag{C.2d}$$

$$E_b^t = E_b^{t-1} + \eta_{ch} * P_{ch}^t * \Delta t - \frac{1}{\eta_{dch}} * P_{dch}^t * \Delta t \qquad for\ t = 2, ..., 72 \tag{C.2e}$$

$$E_b^t = E_b^{init,t} + \eta_{ch} * P_{ch}^t * \Delta t - \frac{1}{\eta_{dch}} * P_{dch}^t * \Delta t \qquad for\ t = 1 \tag{C.2f}$$

$$SOC_{min} \leq SOC^t \leq SOC_{max} \qquad for\ t = 1, ..., 72 \tag{C.2g}$$

$$E_b^{cap,t} = SOH^t * E_b^{cap} \qquad for\ t = 1, ..., 72 \tag{C.2h}$$

$$0 \leq SOH^t \leq 1 \qquad for\ t = 1, ..., 72 \tag{C.2i}$$

$$SOH^t = SOH^{t-1} - Deg \qquad for\ t = 2, ..., 72 \tag{C.2j}$$

$$SOH^t = 1 - h_{current} * Deg \qquad for\ t = 1 \tag{C.2k}$$

$$E_b^{cap,t} * SOC_{min} \leq E_b^t \leq E_b^{cap,t} * SOC_{max} \qquad for\ t = 2, ..., 72 \tag{C.2l}$$

$$0 \leq P_{exp}^t \leq K * \delta_{2g}^t \qquad for\ t = 1, ..., 72 \tag{C.2m}$$

$$0 \leq P_{imp}^t \leq K * (1 - \delta_{2g}^t) \qquad for\ t = 1, ..., 72 \tag{C.2n}$$

C2 Step 2: Running the Model Without Activation of the FCR-N Reserves

First Stage Problem

$$minimise \sum_{t=0}^{48} C_{deg} * P_{dch}^t - (Pr_{spot}^t + C_{gt,surplus}) * P_{exp}^t * \Delta t + (Pr_{spot}^t + C_{gt,energy} \tag{C.3a}$$

$$+C_{gt,power}) * P_{imp}^t * \Delta t - Pr_{D1}^t * P_{D1}^t - Pr_{D2}^t * P_{D2}^t$$

$s.t.$

$$P_{pv}^t + P_{imp}^t - P_{exp}^t + P_{dch}^t * \eta_{dch} - P_{ch}^t * \frac{1}{\eta_{ch}} - P_{demand}^t = 0 \qquad for\ t = 1, ..., 48 \tag{C.3b}$$

$$P_{ch}^{min} * S_{ch}^t \leq P_{ch}^t \leq P_{ch}^{max} * S_{ch}^t \qquad for\ t = 1, ..., 48 \tag{C.3c}$$

$$p_{dch}^{min} * (1 - S_{ch}^t) \leq P_{dch}^t \leq P_{dch}^{max} * (1 - S_{ch}^t) \qquad for\ t = 1, ..., 48 \tag{C.3d}$$

$$E_b^t = E_b^{t-1} + \eta_{ch} * P_{ch}^t * \Delta t - \frac{1}{\eta_{dch}} * P_{dch}^t * \Delta t \qquad for\ t = 2, ..., 48 \tag{C.3e}$$

$$E_b^t = E_b^{init,t} + \eta_{ch} * P_{ch}^t * \Delta t - \frac{1}{\eta_{dch}} * P_{dch}^t * \Delta t \qquad for\ t = 1 \tag{C.3f}$$

$$SOC_{min} \leq SOC^t \leq SOC_{max} \qquad for\ t = 1, ..., 48 \tag{C.3g}$$

$$E_b^{cap,t} = SOH^t * E_b^{cap} \qquad for\ t = 1, ..., 48 \tag{C.3h}$$

$$0 \leq SOH^t \leq 1 \qquad for\ t = 1, ..., 48 \tag{C.3i}$$

$$SOH^t = SOH^{t-1} - Deg \qquad for\ t = 2, ..., 48 \tag{C.3j}$$

$$SOH^t = 1 - h_{current} * Deg \qquad for\ t = 1 \tag{C.3k}$$

$$0 \leq P_{exp}^t \leq K * \delta_{2g}^t \qquad for\ t = 1, ..., 48 \tag{C.3l}$$

$$0 \leq P_{imp}^t \leq K * (1 - \delta_{2g}^t) \qquad for\ t = 1, ..., 48 \tag{C.3m}$$

$$E_b^t - P_{D1}^t * \Delta t - P_{D2}^t * \Delta t \geq E_b^{cap,t} * SOC_{min} \qquad for\ t = 1, ..., 48 \tag{C.3n}$$

$$E_b^t + P_{D1}^t * \Delta t + P_{D2}^t * \Delta t \leq E_b^{cap,t} * SOC_{max} \qquad for\ t = 1, ..., 48 \tag{C.3o}$$

$$P_{D1}^t + P_{D2}^t \leq P_{ch}^t + P_{dch}^{max} - P_{dch}^t \qquad for\ t = 1, ..., 48 \tag{C.3p}$$

$$P_{D1}^t + P_{D2}^t \leq P_{dch}^t + P_{ch}^{max} - P_{ch}^t \qquad for\ t = 1, ..., 48 \tag{C.3q}$$

$$P_{D1}^t <= P_{D1,volume}^t \qquad for\ t = 1, ..., 48 \tag{C.3r}$$

$$P_{D2}^t <= P_{D2,volume}^t \qquad for\ t = 1, ..., 48 \tag{C.3s}$$

Second Stage Problem

$$minimise \sum_{t=0}^{72} C_{deg} * P_{dch}^{t} - (Pr_{spot}^{t} + C_{gt,surplus}) * P_{exp}^{t} * \Delta t + (Pr_{spot}^{t} + C_{gt,energy} \tag{C.4a}$$

$$+C_{gt,power}) * P_{imp}^{t} * \Delta t - Pr_{D1}^{t} * P_{D1,res}^{t} - Pr_{D2}^{t} * P_{D2,res}^{t}$$

$s.t.$

$$P_{pv}^{t} + P_{imp}^{t} - P_{exp}^{t} + P_{dch}^{t} * \eta_{dch} - P_{ch}^{t} * \frac{1}{\eta_{ch}} - P_{demand}^{t} = 0 \qquad for\ t = 1, ..., 72 \tag{C.4b}$$

$$P_{ch}^{min} * S_{ch}^{t} \leq P_{ch}^{t} \leq P_{ch}^{max} * S_{ch}^{t} \qquad for\ t = 1, ..., 72 \tag{C.4c}$$

$$p_{dch}^{min} * (1 - S_{ch}^{t}) \leq P_{dch}^{t} \leq P_{dch}^{max} * (1 - S_{ch}^{t}) \qquad for\ t = 1, ..., 72 \tag{C.4d}$$

$$E_{b}^{t} = E_{b}^{t-1} + \eta_{ch} * P_{ch}^{t} * \Delta t - \frac{1}{\eta_{dch}} * P_{dch}^{t} * \Delta t \qquad for\ t = 2, ..., 72 \tag{C.4e}$$

$$E_{b}^{t} = E_{b}^{init,t} + \eta_{ch} * P_{ch}^{t} * \Delta t - \frac{1}{\eta_{dch}} * P_{dch}^{t} * \Delta t \qquad for\ t = 1 \tag{C.4f}$$

$$SOC_{min} \leq SOC^{t} \leq SOC_{max} \qquad for\ t = 1, ..., 72 \tag{C.4g}$$

$$E_{b}^{cap,t} = SOH^{t} * E_{b}^{cap} \qquad for\ t = 1, ..., 72 \tag{C.4h}$$

$$0 \leq SOH^{t} \leq 1 \qquad for\ t = 1, ..., 72 \tag{C.4i}$$

$$SOH^{t} = SOH^{t-1} - Deg \qquad for\ t = 2, ..., 72 \tag{C.4j}$$

$$SOH^{t} = 1 - h_{current} * Deg \qquad for\ t = 1 \tag{C.4k}$$

$$E_{b}^{cap,t} * SOC_{min} \leq E_{b}^{t} \leq E_{b}^{cap,t} * SOC_{max} \qquad for\ t = 2, ..., 72 \tag{C.4l}$$

$$0 \leq P_{exp}^{t} \leq K * \delta_{2g}^{t} \qquad for\ t = 1, ..., 72 \tag{C.4m}$$

$$0 \leq P_{imp}^{t} \leq K * (1 - \delta_{2g}^{t}) \qquad for\ t = 1, ..., 72 \tag{C.4n}$$

$$E_{b}^{t} - P_{D1,res}^{t} * \Delta t - P_{D2,res}^{t} * \Delta t \geq E_{b}^{cap,t} * SOC_{min} \qquad for\ t = 2, ..., 72 \tag{C.4o}$$

$$E_{b}^{t} + P_{D1,res}^{t} * \Delta t + P_{D2,res}^{t} * \Delta t \leq E_{b}^{cap,t} * SOC_{max} \qquad for\ t = 2, ..., 72 \tag{C.4p}$$

C3 Step 3: Accounting for Activation of FCR-N Reserves

First Stage Problem

$$minimise \sum_{t=0}^{48} C_{deg} * P_{dch}^t - (Pr_{spot}^t + C_{gt,surplus}) * P_{exp}^t * \Delta t + (Pr_{spot}^t + C_{gt,energy} \tag{C.5a}$$

$$+C_{gt,power}) * P_{imp}^t * \Delta t - Pr_{D1}^t * P_{D1}^t - Pr_{D2}^t * P_{D2}^t$$

$s.t.$

$$P_{pv}^t + P_{imp}^t - P_{exp}^t + P_{dch}^t * \eta_{dch} - P_{ch}^t * \frac{1}{\eta_{ch}} - P_{demand}^t = 0 \qquad for\ t = 1, ..., 48 \tag{C.5b}$$

$$P_{ch}^{min} * S_{ch}^t \leq P_{ch}^t \leq P_{ch}^{max} * S_{ch}^t \qquad for\ t = 1, ..., 48 \tag{C.5c}$$

$$p_{dch}^{min} * (1 - S_{ch}^t) \leq P_{dch}^t \leq P_{dch}^{max} * (1 - S_{ch}^t) \qquad for\ t = 1, ..., 48 \tag{C.5d}$$

$$E_b^t = E_b^{t-1} + \eta_{ch} * P_{ch}^t * \Delta t - \frac{1}{\eta_{dch}} * P_{dch}^t * \Delta t \qquad for\ t = 2, ..., 48 \tag{C.5e}$$

$$E_b^t = E_b^{init,t} + \eta_{ch} * P_{ch}^t * \Delta t - \frac{1}{\eta_{dch}} * P_{dch}^t * \Delta t \qquad for\ t = 1 \tag{C.5f}$$

$$SOC_{min} \leq SOC^t \leq SOC_{max} \qquad for\ t = 1, ..., 48 \tag{C.5g}$$

$$E_b^{cap,t} = SOH^t * E_b^{cap} \qquad for\ t = 1, ..., 48 \tag{C.5h}$$

$$0 \leq SOH^t \leq 1 \qquad for\ t = 1, ..., 48 \tag{C.5i}$$

$$SOH^t = SOH^{t-1} - Deg \qquad for\ t = 2, ..., 48 \tag{C.5j}$$

$$SOH^t = 1 - h_{current} * Deg \qquad for\ t = 1 \tag{C.5k}$$

$$0 \leq P_{exp}^t \leq K * \delta_{2g}^t \qquad for\ t = 1, ..., 48 \tag{C.5l}$$

$$0 \leq P_{imp}^t \leq K * (1 - \delta_{2g}^t) \qquad for\ t = 1, ..., 48 \tag{C.5m}$$

$$E_b^t - P_{D1}^t * \Delta t - P_{D2}^t * \Delta t \geq E_b^{cap,t} * SOC_{min} \qquad for\ t = 1, ..., 48 \tag{C.5n}$$

$$E_b^t + P_{D1}^t * \Delta t + P_{D2}^t * \Delta t \leq E_b^{cap,t} * SOC_{max} \qquad for\ t = 1, ..., 48 \tag{C.5o}$$

$$P_{D1}^t + P_{D2}^t \leq P_{ch}^t + P_{dch}^{max} - P_{dch}^t \qquad for\ t = 1, ..., 48 \tag{C.5p}$$

$$P_{D1}^t + P_{D2}^t \leq P_{dch}^t + P_{ch}^{max} - P_{ch}^t \qquad for\ t = 1, ..., 48 \tag{C.5q}$$

$$P_{D1}^t <= P_{D1,volume}^t \qquad for\ t = 1, ..., 48 \tag{C.5r}$$

$$P_{D2}^t <= P_{D2,volume}^t \qquad for\ t = 1, ..., 48 \tag{C.5s}$$

Second Stage Problem

$$minimise \sum_{t=0}^{72} C_{deg} * P_{dch}^{t} - (Pr_{spot}^{t} + C_{gt,surplus}) * P_{exp}^{t} * \Delta t + (Pr_{spot}^{t} + C_{gt,energy} \tag{C.6a}$$

$$+C_{gt,power}) * P_{imp}^{t} * \Delta t - Pr_{D1}^{t} * P_{D1,res}^{t} - Pr_{D2}^{t} * P_{D2,res}^{t} + 100\,000*$$
$$(S_{slack,pos} + S_{slack,neg}) * \Delta t$$

$s.t.$

$$P_{pv}^{t} + P_{imp}^{t} - P_{exp}^{t} + P_{dch}^{t} * \eta_{dch} - P_{ch}^{t} * \frac{1}{\eta_{ch}} - P_{demand}^{t} = 0 \qquad for\ t = 1, ..., 72 \tag{C.6b}$$

$$P_{ch}^{min} * S_{ch}^{t} \leq P_{ch}^{t} \leq P_{ch}^{max} * S_{ch}^{t} \qquad for\ t = 1, ..., 72 \tag{C.6c}$$

$$p_{dch}^{min} * (1 - S_{ch}^{t}) \leq P_{dch}^{t} \leq P_{dch}^{max} * (1 - S_{ch}^{t}) \qquad for\ t = 1, ..., 72 \tag{C.6d}$$

$$E_{b}^{t} = E_{b}^{t-1} + \eta_{ch} * P_{ch}^{t} * \Delta t - \frac{1}{\eta_{dch}} * P_{dch}^{t} * \Delta t \qquad for\ t = 2, ..., 72 \tag{C.6e}$$

$$E_{b}^{t} = E_{b}^{init,t} + \eta_{ch} * P_{ch}^{t} * \Delta t - \frac{1}{\eta_{dch}} * P_{dch}^{t} * \Delta t \qquad for\ t = 1 \tag{C.6f}$$

$$SOC_{min} \leq SOC^{t} \leq SOC_{max} \qquad for\ t = 1, ..., 72 \tag{C.6g}$$

$$E_{b}^{cap,t} = SOH^{t} * E_{b}^{cap} \qquad for\ t = 1, ..., 72 \tag{C.6h}$$

$$0 \leq SOH^{t} \leq 1 \qquad for\ t = 1, ..., 72 \tag{C.6i}$$

$$SOH^{t} = SOH^{t-1} - Deg \qquad for\ t = 2, ..., 72 \tag{C.6j}$$

$$SOH^{t} = 1 - h_{current} * Deg \qquad for\ t = 1 \tag{C.6k}$$

$$E_{b}^{cap,t} * SOC_{min} \leq E_{b}^{t} \leq E_{b}^{cap,t} * SOC_{max} \qquad for\ t = 2, ..., 72 \tag{C.6l}$$

$$0 \leq P_{exp}^{t} \leq K * \delta_{2g}^{t} \qquad for\ t = 1, ..., 72 \tag{C.6m}$$

$$0 \leq P_{imp}^{t} \leq K * (1 - \delta_{2g}^{t}) \qquad for\ t = 1, ..., 72 \tag{C.6n}$$

$$E_{b}^{t} - P_{D1,res}^{t} * \Delta t - P_{D2,res}^{t} * \Delta t \geq E_{b}^{cap,t} * SOC_{min} \qquad for\ t = 2, ..., 72 \tag{C.6o}$$

$$E_{b}^{t} + P_{D1,res}^{t} * \Delta t + P_{D2,res}^{t} * \Delta t \leq E_{b}^{cap,t} * SOC_{max} \qquad for\ t = 2, ..., 72 \tag{C.6p}$$

$$P_{ch,plan}^{t} - P_{dch,plan}^{t} - P_{act}^{t} + S_{slack,pos}^{t} - S_{slack,neg}^{t} \geq P_{ch}^{t} - P_{dch}^{t}\ ,\ f < 50\ for\ t = 1 \tag{C.6q}$$

$$P_{ch,plan}^{t} - P_{dch,plan}^{t} - P_{act}^{t} + S_{slack,pos}^{t} - S_{slack,neg}^{t} \leq P_{ch}^{t} - P_{dch}^{t}\ ,\ f > 50\ for\ t = 1 \tag{C.6r}$$

$$P_{act}^{t} = 0 \qquad for\ t = 2, ..., 72 \tag{C.6s}$$

$$P_{act}^{t} = \frac{Freq_{dev,UP}^{t}}{0.1} * P_{D1,res}^{t} + \frac{Freq_{dev,UP}^{t}}{0.1} * P_{D2,res}^{t} - \frac{Freq_{dev,DWN}^{t}}{0.1} * P_{D1,res}^{t} \tag{C.6t}$$

$$-\frac{Freq_{dev,DWN}^{t}}{0.1} * P_{D2,res}^{t} \qquad for\ t = 1$$

C4 Step 4: Accounting for Activation of FCR-N Reserves, Including Compensation for Activated Energy

First Stage Problem

$$minimise \sum_{t=0}^{48} C_{deg} * P_{dch}^t - (Pr_{spot}^t + C_{gt,surplus}) * P_{exp}^t * \Delta t + (Pr_{spot}^t + C_{gt,energy} \tag{C.7a}$$

$$+C_{gt,power}) * P_{imp}^t * \Delta t - Pr_{D1}^t * P_{D1}^t - Pr_{D2}^t * P_{D2}^t$$

$$s.t.$$

$$P_{pv}^t + P_{imp}^t - P_{exp}^t + P_{dch}^t * \eta_{dch} - P_{ch}^t * \frac{1}{\eta_{ch}} - P_{demand}^t = 0 \qquad for\ t = 1, ..., 48 \tag{C.7b}$$

$$P_{ch}^{min} * S_{ch}^t \leq P_{ch}^t \leq P_{ch}^{max} * S_{ch}^t \qquad for\ t = 1, ..., 48 \tag{C.7c}$$

$$p_{dch}^{min} * (1 - S_{ch}^t) \leq P_{dch}^t \leq P_{dch}^{max} * (1 - S_{ch}^t) \qquad for\ t = 1, ..., 48 \tag{C.7d}$$

$$E_b^t = E_b^{t-1} + \eta_{ch} * P_{ch}^t * \Delta t - \frac{1}{\eta_{dch}} * P_{dch}^t * \Delta t \qquad for\ t = 2, ..., 48 \tag{C.7e}$$

$$E_b^t = E_b^{init,t} + \eta_{ch} * P_{ch}^t * \Delta t - \frac{1}{\eta_{dch}} * P_{dch}^t * \Delta t \qquad for\ t = 1 \tag{C.7f}$$

$$SOC_{min} \leq SOC^t \leq SOC_{max} \qquad for\ t = 1, ..., 48 \tag{C.7g}$$

$$E_b^{cap,t} = SOH^t * E_b^{cap} \qquad for\ t = 1, ..., 48 \tag{C.7h}$$

$$0 \leq SOH^t \leq 1 \qquad for\ t = 1, ..., 48 \tag{C.7i}$$

$$SOH^t = SOH^{t-1} - Deg \qquad for\ t = 2, ..., 48 \tag{C.7j}$$

$$SOH^t = 1 - h_{current} * Deg \qquad for\ t = 1 \tag{C.7k}$$

$$0 \leq P_{exp}^t \leq K * \delta_{2g}^t \qquad for\ t = 1, ..., 48 \tag{C.7l}$$

$$0 \leq P_{imp}^t \leq K * (1 - \delta_{2g}^t) \qquad for\ t = 1, ..., 48 \tag{C.7m}$$

$$E_b^t - P_{D1}^t * \Delta t - P_{D2}^t * \Delta t \geq E_b^{cap,t} * SOC_{min} \qquad for\ t = 1, ..., 48 \tag{C.7n}$$

$$E_b^t + P_{D1}^t * \Delta t + P_{D2}^t * \Delta t \leq E_b^{cap,t} * SOC_{max} \qquad for\ t = 1, ..., 48 \tag{C.7o}$$

$$P_{D1}^t + P_{D2}^t \leq P_{ch}^t + P_{dch}^{max} - P_{dch}^t \qquad for\ t = 1, ..., 48 \tag{C.7p}$$

$$P_{D1}^t + P_{D2}^t \leq P_{dch}^t + P_{ch}^{max} - P_{ch}^t \qquad for\ t = 1, ..., 48 \tag{C.7q}$$

$$P_{D1}^t <= P_{D1,volume}^t \qquad for\ t = 1, ..., 48 \tag{C.7r}$$

$$P_{D2}^t <= P_{D2,volume}^t \qquad for\ t = 1, ..., 48 \tag{C.7s}$$

Second Stage Problem

$$minimise \sum_{t=0}^{72} C_{deg} * P^t_{dch} - (Pr^t_{spot} + C_{gt,surplus}) * P^t_{exp} * \Delta t + (Pr^t_{spot} + C_{gt,energy} \tag{C.8a}$$

$$+C_{gt,power}) * P^t_{imp} * \Delta t - Pr^t_{D1} * P^t_{D1,res} - Pr^t_{D2} * P^t_{D2,res} + 100\,000*$$
$$(S_{slack,pos} + S_{slack,neg}) * \Delta t - Pr^t_{rk,up} * P^t_{act,up} * \Delta t - Pr^t_{rk,dwn} * P^t_{act,dwn} * \Delta t$$

$s.t.$

$$P^t_{pv} + P^t_{imp} - P^t_{exp} + P^t_{dch} * \eta_{dch} - P^t_{ch} * \frac{1}{\eta_{ch}} - P^t_{demand} = 0 \qquad for\ t = 1, ..., 72 \tag{C.8b}$$

$$P^{min}_{ch} * S^t_{ch} \leq P^t_{ch} \leq P^{max}_{ch} * S^t_{ch} \qquad for\ t = 1, ..., 72 \tag{C.8c}$$

$$p^{min}_{dch} * (1 - S^t_{ch}) \leq P^t_{dch} \leq P^{max}_{dch} * (1 - S^t_{ch}) \qquad for\ t = 1, ..., 72 \tag{C.8d}$$

$$E^t_b = E^{t-1}_b + \eta_{ch} * P^t_{ch} * \Delta t - \frac{1}{\eta_{dch}} * P^t_{dch} * \Delta t \qquad for\ t = 2, ..., 72 \tag{C.8e}$$

$$E^t_b = E^{init,t}_b + \eta_{ch} * P^t_{ch} * \Delta t - \frac{1}{\eta_{dch}} * P^t_{dch} * \Delta t \qquad for\ t = 1 \tag{C.8f}$$

$$SOC_{min} \leq SOC^t \leq SOC_{max} \qquad for\ t = 1, ..., 72 \tag{C.8g}$$

$$E^{cap,t}_b = SOH^t * E^{cap}_b \qquad for\ t = 1, ..., 72 \tag{C.8h}$$

$$0 \leq SOH^t \leq 1 \qquad for\ t = 1, ..., 72 \tag{C.8i}$$

$$SOH^t = SOH^{t-1} - Deg \qquad for\ t = 2, ..., 72 \tag{C.8j}$$

$$SOH^t = 1 - h_{current} * Deg \qquad for\ t = 1 \tag{C.8k}$$

$$E^{cap,t}_b * SOC_{min} \leq E^t_b \leq E^{cap,t}_b * SOC_{max} \qquad for\ t = 2, ..., 72 \tag{C.8l}$$

$$0 \leq P^t_{exp} \leq K * \delta^t_{2g} \qquad for\ t = 1, ..., 72 \tag{C.8m}$$

$$0 \leq P^t_{imp} \leq K * (1 - \delta^t_{2g}) \qquad for\ t = 1, ..., 72 \tag{C.8n}$$

$$E^t_b - P^t_{D1,res} * \Delta t - P^t_{D2,res} * \Delta t \geq E^{cap,t}_b * SOC_{min} \qquad for\ t = 2, ..., 72 \tag{C.8o}$$

$$E^t_b + P^t_{D1,res} * \Delta t + P^t_{D2,res} * \Delta t \leq E^{cap,t}_b * SOC_{max} \qquad for\ t = 2, ..., 72 \tag{C.8p}$$

$$P^t_{ch,plan} - P^t_{dch,plan} - P^t_{act} + S^t_{slack,pos} - S^t_{slack,neg} \geq P^t_{ch} - P^t_{dch}\ ,\ f < 50\ for\ t = 1 \tag{C.8q}$$

$$P^t_{ch,plan} - P^t_{dch,plan} - P^t_{act} + S^t_{slack,pos} - S^t_{slack,neg} \leq P^t_{ch} - P^t_{dch}\ ,\ f > 50\ for\ t = 1 \tag{C.8r}$$

$$P^t_{act} = 0 \qquad for\ t = 2, ..., 72 \tag{C.8s}$$

$$P^t_{act} = \frac{Freq^t_{dev,UP}}{0.1} * P^t_{D1,res} + \frac{Freq^t_{dev,UP}}{0.1} * P^t_{D2,res} - \frac{Freq^t_{dev,DWN}}{0.1} * P^t_{D1,res} \tag{C.8t}$$

$$-\frac{Freq^t_{dev,DWN}}{0.1} * P^t_{D2,res} \qquad for\ t = 1$$

NTNU
Norwegian University of
Science and Technology