Hydrogen and Battery Energy Storage Systems: A Techno-economic modelling of Ancillary Services and Additional Income flows

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LUND
UNIVERSITY

Thesis for the degree of Master of Science
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To be presented, with the permission of the Faculty of Engineering of Lund University, for public criticism at the Department of Energy Sciences on Monday, the 10th of June 2024 at 13:00.

This degree project for the degree of Master of Science in Engineering has been conducted at the Division of Thermal Power Engineering, Department of Energy Sciences, Faculty of Engineering, Lund University.

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Examiner at Lund University was Professor Martin Tunér.

The project was carried out in cooperation with Trelleborg Energi.

Department of Energy Sciences
Faculty of Engineering
Lund University

ISSN: <0282-1990>
LUTMDN/TMHP-24/5575-SE

Typeset in LaTeX
Lund 10th June 2024

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Nomenclature

Abbreviations

$aFRR$ automatic Frequency Restoration Reserve

ALE Alkaline Electrolyzer

$BESS$ Battery Energy Storage System

BMS Battery Management System

$CAPEX$ Capital expenses

$COPV$ Composite Overwrapped Pressure Vessel

EV Electric Vehicle

FC Fuel Cell

$FCR-D$ Disturbance Frequency Containment Reserve

$FCR-N$ Normal Frequency Containment Reserve

FFR Fast Frequency Reserve

$HESS$ Hydrogen Energy Storage System

HFS Hydrogen Refueling Station

IRR Internal Rate of Return

$LCOH$ Levelized Cost of Hydrogen

$mFRR$ manual Frequency Restoration Reserve

NPV Net Present Value

$O\&M$ Operation and Maintenance

$PEMEC$ Proton Exchange Membrane Electrolyzer

$PEMFC$ Proton Exchange Membrane Fuel Cell

RTE Round Trip Efficiency

SoC State of Charge

SoH State of Health

TRL Technology Readiness Level

Sammanfattning

För att minska beroendet av fossila bränslen fokuserar många regeringar och industrier nya investeringar på elektricitet och alternativa bränslen så som grön vätgas från elektrolysörer drivna av förnybar elektricitet. Höga investeringskostnader och elkostnader är ett hinder för den framtida utvecklingen av en vätgasekonomi som kan utnyttja en ökande intermittent elproduktion. Syftet med detta examensarbete var att bygga en tekno-ekonomisk modell som undersöker alternativa användningar av ett vätgas- och batterisystem; främst genom stödtjänster men även som stöd för en DC-snabbladdningsstation. Modellresultaten visade att användning av batteriet, elektrolysören och bränslecellen på balansmarknader ökade lönsamheten för varje system, från små till stora system. De högsta intäkterna genererades från FCR-tjänster följt av aFRR med mFRR långt efter. Batteriet gav störst intäkt per MW med lägst relativ kostnad, och deltog endast på FCR- och FFR-marknader. Den låga efterfrågan på vätgas frigjorde elektrolysören så att den kunde delta som en balanseringstjänst stora delar av året, men fortfarande mindre än batteriet som deltog nästan alla timmar. Bränslecellen hade en varierande deltagarfrekvens för olika tjänster. Slutligen minskade användningen av ett batteri och en bränslecell elkostnaderna genom att leverera el till en DC-snabbladdningsstation. Modellen visade också att dessa komponenter kan agera som den enda eltillförseln till stationen, exempelvis när andra inkomstkällor är uttömda.

Abstract

In order to move away from fossil fuels many governments and industries are focusing their new investments in electricity and alternative fuels such as green hydrogen from electrolyzers using renewable electricity. High investment costs and electricity costs are a hindrance for the future development of a hydrogen economy which can utilize an increasing intermittent power generation. The aim of this thesis is to build a techno-economic model that investigates alternative uses of a hydrogen and battery system, mainly through ancillary services but also as a support for an DC fast charging station. Model results showed that using the battery, electrolyzer and fuel cell (FC) on balancing markets increased the profitability of each system, varying from small to large systems. The highest income was generated from FCR services followed by aFRR with mFRR trailing far behind. The battery provided the largest income per MW with the lowest relative cost, only acting on FCR and FFR markets. The low hydrogen demand freed up the electrolyzer to participate as a balancing service most of the time, but still less than the battery which participated almost the entire year. The FC participation rate varied greatly for different services. Finally, using a battery and FC to provide power for a DC fast charging station decreased electricity costs and can be used as the station's sole electricity provider, e.g. when other income streams are exhausted.

Acknowledgements

This Master's Thesis was carried out at the Department of Energy Sciences at the Faculty of Engineering at Lund University together with Trelleborgs Energi.

I want to thank my supervisor Martin Andersson at LTH who helped keeping me on the correct path by providing insights and advice. I also extend my sincerest gratitude to my supervisors Jenny Sackner Christensen and Marcus Ek at Trelleborgs Energi who provided me with guidance throughout the entire process. Special thanks also to Elin Lenntoft and Sofia Rapp, who's collaboration and discussions contributed greatly to this thesis. Finally, I would like to thank everyone at Trelleborgs Energi, and everyone else, who provided their time and knowledge.

Chapter 1.

Introduction

1.1. Background

With climate change being on the main agenda in many parts of the world, the need for low emission technology are rapidly increasing. States and governments are pushing for low carbon alternatives to fossil fuels through subsidies and research grants, such as EU's Fit for 55 through the Green Deal and United State's Inflation Reduction Act [1]. In Sweden the goal has been set on net zero emissions by 2045 with a large part being achieved through electrification of the entire society. The goal is to meet an electricity consumption of 300 TWh by 2045, an over 200 % increase from 2023 [2].

Renewable power from wind and sun will be the main driver for the increased production capacity. Systems with large proportions of intermittent power production are volatile and require ways to balance the power supply either using smart systems, balancing services and energy storage or displaced consumption. A large part of the Swedish model is green hydrogen production through electrolyzers that can operate when there is a high amount of production capacity to the grid, which also has the possibility of being used to provide power when the power production drops either using fuel cells or hydrogen turbines. Batteries are other components which will have a key role to play in balancing the volatile future electricity production.

Trelleborg is a city located in the southernmost parts of Sweden in SE4, the area with the highest electricity prices and the largest importer of electricity of all four pricing areas. The current situation is about to change with many new energy producing facilities being planned or under construction. Off the southern shores of Skåne there are several wind farms to be completed in the near future which will facilitate green hydrogen production here as well. As a harbour city with connections to Germany, Poland and Lithuania, Trelleborg is uniquely situated to deliver hydrogen as a fuel for goods transportation that enter and leave the country.

Although the main plans of hydrogen today are for industrial processes there are many other purposes that make use of hydrogen's many beneficial characteristics. With increasing demands on buildings' climate impact, hydrogen systems are a way to create better self-sufficiency regarding both electricity and heat, especially in combination with solar panels. This could reduce the impact on the electric grid and even help it by selling electricity when needed. Another component that can play a similar energy storage role as the hydrogen system is the battery which also is able to store solar power thus increasing the self-sufficiency.

One key issue with these energy storage systems is the high investment, and often times also operational, costs. Therefore alternative uses are needed that will allow for an easier adoption of these technologies. Varying the operation of components and acting on the ancillary market is an attractive option, generating both additional income and providing a societal service. Energy storage systems are also able to provide peak shavings and moving energy hours in time. Reserve power is also a potential use-case for some of the components. The battery and fuel cell are also able to act as storage and power delivery for electric vehicle (EV) charging stations, which often are plagued by high and infrequent power demand.

1.1.1. Hydrogen in Trelleborg

The hydrogen plans in Trelleborg that this thesis has focused is divided into three separate projects that are in varying degrees of maturity. First is the smallest project, which in this report will be called the 0.1 MW scenario, which is an upgrade of Trelleborg Energis's office (Blixten) to include a battery and hydrogen system which will increase the self-sufficiency of the building. The slightly larger system, denoted 0.5 MW system, is meant to be a part of an apartment complex that is planned in Trelleborg city, called Västra Sjöstaden. This is also meant to increase self-sufficiency of the buildings and lower electricity costs. Lastly is the largest project, called the 10 MW system, which is meant to produce hydrogen for hydrogen fueled transport vehicles that drive through Trelleborg from its harbour. All systems consist of an electrolyzer, fuel cell, battery and storage with auxiliary devices, and more specifics will be presented later on in the report. The study of these systems will be done through a created model in Excel which, through a techno-economic approach, will calculate the economic viability of these systems in different scenarios.

1.2. Objective

The objective of this thesis is to build a system model in Excel consisting of an electrolyzer, fuel cell and battery component that are connected to the grid. The main purpose is to investigate how these components can provide ancillary services, with an additional scenario where a combined battery and fuel cell provide power to a DC fast charging station. Based upon the model outcomes an economical result will be calculated. The fundamental characteristics of how each model component functions will be based upon previous literature, and communication from industry actors.

To this aim the following research questions will be considered:

- How can electrolyzers, fuel cells and batteries provide ancillary services to the grid?
- What is the economic outlook of the hydrogen and battery storage systems, including ancillary systems?
- What are the existing and possible financial income streams for these systems in Trelleborg?

1.3. Constraints

The thesis has been limited by a number of constraints:

- Model results have been limited to 2023 data.
- Model is based upon hourly data from 2023, with all events taking place over shorter periods of time than an hour being approximated as hourly averages.
- Model methods have been created from scratch in approximation of reality, model function does not represent how a real agent would act on the respective markets.
- Location has been limited to Trelleborg in SE4, although when no relevant could be found the constraint has been extended to include Swedish or Nordic data when needed.

1.3.1. Model construction collaboration

The base of the model in Excel was created together with another thesis, *A Techno-Economic analysis of combined Hydrogen and Battery systems participating with Ancillary services in SE4*, by Elin Lenntoft and Sofia Rapp. Each group contributed to the creation of the model by collecting data for the base function of the model: economical, technical and physical parameters that were required as inputs. More specifically it has been the collection of historical data of electricity markets, how balancing markets work, and how the different components are able to act on each market. The base model and the frequency models were created together based on this data, with both groups working on control functions and logic. Minor changes were made separately afterwards, resulting in small deviations in the final models. The operation of the fuel cell and the storage volume in the middle and large system differ between the two final models. The addition of by-products and supporting machinery to the model was also done separately. The economic analysis of the model was done independently. During the thesis process the two groups have helped each other with data, sources and interviews, however, the writing has been done completely separately.

Chapter 2.

Theory

This chapter describes the basic theory of hydrogen gas as an energy carrier, batteries and electric vehicle (EV) charging. It will provide an overview of different technologies most relevant for grid connected systems with focus on ancillary services. Furthermore, this section will provide an overview of the electricity system in Sweden.

2.1. Electricity

Since its conception in the early 1700s electricity's societal importance has grown from a mere curiosity to the vital energy provider it is today. Powering everything from transportation systems and temperature regulation to the computers and algorithms that govern our daily life. This section will give an overview of the electricity system in Sweden.

2.1.1. Electricity grid

Electricity is produced by converting other forms of energy into flowing electrons. Globally this is most commonly done using either fossil fuels (61 %) or renewable energy sources (30 %) [3]. Once converted into electricity the energy needs to be transported from producer to user through the electrical grid. Due to the nature of the flowing electron, moving at close to the speed of light, the produced electricity must be met by an equal demand at all times. To achieve this a complex system of producers, infrastructure, actors and regulations have evolved which makes sure that every appliance, machine and lamp receives electricity on demand.

The Swedish electricity grid consists of 589 000 km of power lines. This network is divided into four bidding areas with separate pricing, SE1-4, meant to represent where there are bottlenecks in the national grid. A further separation depending on grid characteristics: transmission, regional and local grid [4].

Transmission grid

The transmission grid is the backbone that transports electricity across the nation and its neighbours. Using high voltage cables of 220 and 400 kV [5] the transmission grid consists of 17 500 km of power lines and 175 substations, switching stations and international connection points [6]. The owner and operator of a transmission grid is called a transmission system operator (TSO) and in Sweden this is Svenska Kraftnät (SvK). Their mission is to make sure that the power system functions and can handle future demand in a cost efficient, safe and environmentally sound way [4].

Regional and local grids

Connecting the high voltage power from the transmission lines to the consumer is the regional and local grids. Regional grids consist of 40 - 130 kV power lines that transport electricity from the transmission grid to the local grid where it is distributed to the user through 230 V - 40 kV lines. In Sweden the regional grids are owned by 5 companies whereas the local grids are owned by over 100 companies, both large and small [5]. For each respective grid the owner has a local monopoly on electricity distribution [4].

2.1.2. Electricity market

To make sure that the produced electricity meets the demand at each moment a system of four submarkets is used: forward market, day-ahead market, intraday market and balancing market. How each of these markets work and their function is described in Table 2.1.

Table 2.1.: Electricity markets and their function, actors and time of purchase. Adapted from [7].

	Forward	Day-ahead	Intraday	Balancing
Function	Market for long term contracts and price hedging opportunities with the intent to stabilize the electricity price.	Matching selling and buying bids to get an electricity price for each area. Price is determined by the cost of the last produced kWh.	Where the actors from the day-ahead market can adjust their contracts for changes before delivery hour. Only small volumes.	The purchasing of ancillary services and balancing the continuous power demand with power delivery.
Actors	Electricity buyers and producers, large consumers and speculators.	Balance responsible parties.	Balance responsible parties.	TSOs.
Time	Up to 10 years before delivery.	12-36 hours before delivery.	Until 1 hour before delivery.	Up until delivery time.

2.1.3. Ancillary services to the grid

A robust and secure electricity delivery requires that the grid frequency and voltage are kept at correct levels at all times. If either were to deviate too far it would cause problems for connected devices. Too keep the grid at 50 Hz the rotational inertia of connected synchronous generators with a tuned rotational angle plays a key role in slowing down the change in frequency [8], [9]. However, with an increasing amount of renewable energy and fewer large turbines that provide rotational energy, balancing the grid has become more difficult. The main tool used by TSOs to strengthen delivery security is ancillary services.

Swedish ancillary services are divided into two categories: frequency and non-frequency related services. The non-frequency ancillary services include: balancing the voltage, supplying fast reactive power or short circuit current, inertia in local grids and island operation. Frequency balancing services are divided into three groups: Fast Frequency Reserve (FFR), Frequency Containment Reserve (FCR) and Frequency Restoration Reserve (FRR) [10]. Following sections will go into depth about each service, but an overview can be found in Table 2.2 below.

Table 2.2.: Overview of ancillary services in Sweden, partially adapted from [11].

Services	Remedial action	FCR			FRR	
	FFR	FCR-N	FCR-D up	FCR-D down	aFRR	mFRR
Frequency [Hz]	49.5-49.7	49.9-50.1	49.5-49.9	50.1-50.5	Deviation from 50 Hz	Manually by SvK
Regulation	Up	Up and Down	Up	Down	Up and Down	Up and Down
Min. bid [MW]	0.1	0.1	0.1	0.1	1	1 or 5
Activation	Automatic when low rotational energy	Automatic linear	Automatic linear	Automatic linear	Automatic	Manual
Activation time	100 % within: 0.7 s (49.5 Hz) 1.0 s (49.6 Hz) 1.3 s (49.7 Hz)	63 % (60 s) 95 % (180 s)	50 % (5 s) 100 % (30 s)	50 % (5 s) 100 % (30 s)	100 % in 5 min	100 % in 15 min
Endurance	30 or 5 s	1 h	20 min	20 min	1 h	1 h
Repeatability	≤15 min	-	-	-	-	-
Swedish Demand [MW]	100	235	567	547	111	300
Capacity market	Yes	Yes	Yes	Yes	Yes	Yes
Energy market	No	Yes	No	No	Yes	Yes
Set price	Marginal	Marginal	Marginal	Marginal	Marginal	Marginal

Fast frequency reserve

The purpose of FFR is to quickly mitigate large disturbances (mainly sudden disconnections of large turbines such as nuclear power plants) to an electric grid with less rotational energy in the system. The service requires a quick activation time which is inversely proportional to the frequency loss, with activation occurring between 49.5 - 49.7 Hz, and active time of either 5 or 30 seconds. This reserve is mostly bought from May to November when it is needed the most [12].

During activation there is not a strict requirement for how the start up occurs, ramping, step-wise and similar are all accepted. But overdelivery must be limited to 20 % of the prequalified power. For long duration (30 seconds) there are no requirements for how the deactivation should occur but for short duration (5 seconds) the deactivation is limited to maximum 20 % of the prequalified load per second. For both types the maximum cycle (activation, still time and recovery) duration is 15 minutes, after which it must be ready to deliver again. The recovery is limited to 25 % of prequalified power. Long duration FFR recovery can start directly after deactivation while for short duration FFR it has to start at earliest 15 seconds after minimum support duration (5 or 30 seconds) [13].

Frequency containment reserve

FCR is activated for deviations from the 50 Hz ground state in the span 49.5 - 50.5 Hz and act to stabilize grid frequency. These services have longer duration requirements than FFR and is divided into three separate ancillary services: Frequency containment reserve - Normal (FCR-N), Downward Frequency Containment Reserve - Disturbance (FCR-D down) and Upward Frequency Containment Reserve - Disturbance (FCR-D up) [11].

- **FCR-N:** Activated during normal grid load interval 49.9 - 50.1 Hz, approximately 98 % of the year [14]. The activated response is required to be linearly proportional to the frequency deviation. Activation and deactivation time for FCR-N occurs on a periodicity of 10 s, with 63 % of full capacity being used after 60 s and 95 % after 3 min when responding to a ± 100 mHz deviation. This dynamic behaviour is meant to dampen the grid's frequency oscillation [15].

- **FCR-D down:** Activated for disturbances that cause the grid frequency increases to 50.1 - 50.5 Hz with a proportional response to the disturbance. There are two categories of FCR-D down: dynamic and static. Dynamic FCR-D down must both stabilize frequency and mitigate frequency oscillations; static FCR-D down reseves are only required to contain frequency, and not negatively impact oscillations [15]. In 2022 the frequency deviated >50.1 Hz 1.0 % of the time [14].

- **FCR-D up:** Activated when a disturbance occurs and the grid frequency drops to somewhere in the interval 49.5 - 49.9 Hz and should be proportional to the deviation. Dynamic and static FCR-D up reserves follow same principle as for FCR-D down [15]. In 2022 this reserve was activated (< 49.9 Hz) 0.8 % of the time [14].

Frequency restoration reserve

FRR is activated as soon as the frequency deviates from 50 Hz and are meant to restore the frequency to 50 Hz. FRR is divided into two different categories: automatic FRR (a-FRR) and manual FRR (m-FRR). These services have the longest requirements on activation time [11].

- **a-FRR:** Automatic activation from a control signal exemplifies this ancillary service and requires an activation time under 30 s with 100 % delivery within 5 min. Deactivation is also limited to 0 % within 5 min after the service has been called off. Deviations for services > 10 MW are allowed max 10 % deviation from setpoint (what SvK calls for); services < 10 MW are limited to 1 MW deviation [16].

- **m-FRR:** Activated manually by SvK. There are two categories of m-FRR depending on activation time: category 1 has activation under 15 min and category 2 over 15 min. SvK might either prioritise large bids which may fall under category 2 at some points and fast activation with a smaller bid at other times [17].

2.2. Hydrogen technology

Hydrogen is the most abundant element in the universe but still not easily available for human use; although recent research points to geological hydrogen being more abundant than previously thought [18]. Hydrogen has the highest energy density by weight of any fuel and sees a varied use-case: transportation fuel, heating and electricity production, and in industries such as oil refining, ammonia-, methanol- and steel production [1], [19]. Today the main source of hydrogen is production via steam reformation using fossil fuels, but electrolysis is a growing contender [1]. Other sources include: reforming using biomass fuels, cracking of hydrocarbons and iron-water reactions, but these are not used to the same extent [19]. Electrolysis using renewable electricity is called green hydrogen, and will be the focus of this research.

2.2.1. Hydrogen the energy carrier

Hydrogen has been identified as an important part in the transition away from fossil fuels. Its fuel properties give it great potential to replace natural gas and oil in today's system, especially as a means of storing energy chemically and either using it directly or by conversion into other fuels. Future prospects are positive, with large projects being announced and finding investments in many parts of the world [1], [20]. An important driver are the various investment strategies from governments and organizations around the world; EU's *Hydrogen Backbone*, US's *Inflation reduction act* and China's *Medium and long-term plan for the development of hydrogen energy industry (2021-2035)* [1] are just a few incentives that drive this rampant transition.

Hydrogen fuel/e-fuel

Direct use of hydrogen is a minor use-case today. For heating purposes and electricity production using fuel cells (FC) or hydrogen turbines it is not cost competitive with other methods. FC are a relatively new technology and systems which incorporate them are often built with this electricity source in mind, such as hydrogen vehicles. Hydrogen turbines on the other hand are able to replace existing gas turbines in power plants with minor changes. But using pure hydrogen comes with the challenge of storing and transporting the substance; an often difficult and expensive task, and that is not taking into account high production and investment costs.

The largest use of hydrogen today is conversion into other fuels; mainly by oil refining, ammonia- and methanol production. Green hydrogen can thus be used with carbon dioxide captured from flue gases to produce synthetic fuels such as methane, methanol and ammonia, creating what is called e-fuels [21].

2.2.2. Electrolysis

Electrolysis is a process where electrical energy is used to split water molecules into hydrogen and oxygen gas through redox reactions [19]. Although the specific amount of reactants and products vary depending on electrolysis method, the overall reaction is the same, as is shown in Equation 2.1.

$$H_2O \rightarrow H_2 + \frac{1}{2}O_2 \qquad (2.1)$$

This reaction takes place in what is called an electrochemical cell consisting of an anode, a cathode, electrolyte and two separate flow channels for water and oxygen. A basic electrochemical diagram can be found in Figure 2.1. At each of the electrodes a half cell reaction occurs when a high enough voltage is applied [19]. There are several ways of inducing electrolysis using different materials and techniques. Stacks of these cells are the hydrogen producing unit of the electrolyzer.

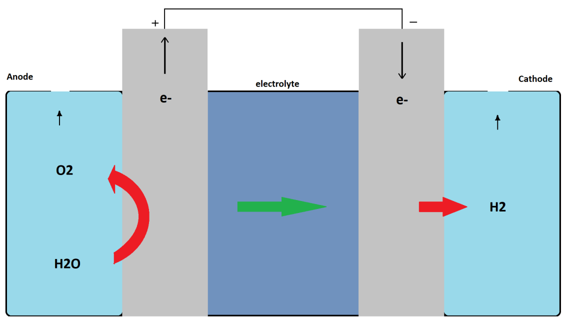


Figure 2.1.: Working principle sketch of electrolyzer cell, produced by author.

The two main technologies used today are the Alkaline Electrolyzer (ALE) and the Proton Exchange Membrane Electrolyzer (PEMEC), with ALE accounting for 60 % of installed capacity in 2022 and PEMEC for around 30 % [1]. However, emerging technologies such as Solid Oxide Electrolysis Cell (SOEC) (< 1 % capacity in 2022 [1]) are promising for the future of the hydrogen economy, operating at higher efficiencies and being able to both act as electrolyzer and fuel cell [20].

Alkaline electrolyzer

ALE are the most mature electrolyzers in use today [22]. The working principle of alkaline electrolysis is using electrodes submerged in an alkaline electrolyte, usually potassium or sodium hydroxide (KOH/NaOH) [22]. The half cell reactions of the ALE are as follows [23]:

$$\text{Cathode:} \quad 2H_2O + 2e^- \rightarrow H_2 + 2OH^- \tag{2.2}$$

$$\text{Anode:} \quad 2OH^- \rightarrow \frac{1}{2}O_2 + H_2O + 2e^- \tag{2.3}$$

With a history stretching back over 100 years, ALE are at technology readiness level (TRL) 9 [24], close to full maturity. ALE have a low cost compared to other electrolyzers and operate at high efficiencies. They do not require catalysts of noble metals [19], [24], instead using electrodes of asbestos diaphragm and nickel materials [25]. However, several drawbacks impact the future of the technology: they use a corrosive electrolyte which require special consideration, have poor flexibility , low operating pressure [26] and low cell current density [27].

Proton exchange membrane electrolyzer

PEMEC are characterised by a solid permeable membrane of polysulfonated materials (Nafion®, fumapem®) [26] acting as electrolyte and separating the anode from the cathode. These electrolyzers are an emerging technology, at TRL 6-8, which has seen increased adoption the last couple of years. For PEM electrolyzers the following half cell reactions occur [23]:

$$\text{Cathode:} \quad 2H^+ + 2e^- \rightarrow H_2 \tag{2.4}$$

$$\text{Anode:} \quad 2H_2O \rightarrow 2H^+ + \frac{1}{2}O_2 + 2e^- \tag{2.5}$$

PEMEC was developed in the 1960s by General Electric to improve upon and deal with the drawbacks of the ALE [28]. Today it is a competitive alternative to the ALE but with a higher investment cost, mainly due to the rare earth metals used in the electrodes [1], [25]. Mostly it concerns the platinum/palladium for the cathode and iridium-/ruthenium oxides for the anode. This, along with lower operating efficiency, are the major drawbacks of the technology. However, there are several other areas where they excel: high operating pressure, compact design, flexible operation, high current density, easy balancing and low overall climate impact [25].

2.2.3. Hydrogen transport

Transportation is a vital part of any material product's supply chain. Special care is especially required for handling pressurized gases and explosive chemicals, both of which hydrogen gas transport fall under. Current hydrogen transportation is done through either trailers, boats or pipelines. Trailers and boats have the possibility to transport all forms of hydrogen while pipelines are limited to the gaseous or liquid forms. Most of the methods are not yet in use today; mostly it is compressed gas in containers on trailers and synthesised fuels that are transported [29]. With larger projects and new applications gas pipelines and liquid transport in fuel trailers will likely become more common.

When determining the appropriate mode of transport consideration for production capacity, distance and hydrogen form are all important. Pipelines have high upfront cost but are the most suitable method for long distances and high quantities, with a levelised cost of 3.5-4.1 SEK/kg for 100 km transport of compressed hydrogen. Comparably, for a large trailer the cost becomes 28-47.4 SEK/kg for the same distance, although at 500 bar [29]. There is also a large potential of upgrading existing natural gas pipelines to handle hydrogen gas to lower costs.

2.2.4. Hydrogen storage

Hydrogen, characterised by its low mass and high reactivity, is inherently hard to store in its gaseous form. It has a very low density at atmospheric conditions making it impractical to store without first converting it. Several methods of storing it has arisen wherein some of the most common ones include: compressed gas, cryogenically liquefied, cryogenically compressed and liquefied, or bound into other molecules such as ammonia, metal-/chemical hydrides or carbohydrates [19].

For fueling stations the most common storage option today is compressed gas at either 350 or 700 bars (H35 and H70) [30], same as the output pressure to the vehicles. Using liquid storage is more optimal on a volume basis but since this requires cryogenic temperatures this is not yet a viable solution for large scale operations [31]. Both compressed and cryogenic storage comprise tanks which does not benefit greatly from economy of scale; so larger operations often seek other means of storing the hydrogen. When geology allows for it solutions such as upgraded abandoned mines, caverns and aquifers offer a cheaper alternative for the storage of large quantities of hydrogen.

For compressed gaseous hydrogen there are four levels of tanks used: types I and II are the cheaper variant, mostly made out of steel and are quite heavy. Types III and IV refers to composite overwrapped pressure vessels (COPV) using fiber composites such as fiberglass. While COPV are too expensive for large scale storage they are common in refueling stations, which also benefit from the high purity level and mobility these tanks allow for [29]. An application of these tanks is the mobile storage used by Lhyfe, consisting of containers of several cylinders that are fueled directly by the electrolyzer output and then transported via trailer to the costumer[1].

The hydrogen refueling station (HFS) works similarly to other types of refueling stations. First, the fuel needs to be transported to the HFS or produced on-site [31]. The hydrogen often arrives with lower pressure than the HFS requires so a compressor is needed. The storage tanks are most commonly installed in a cascade system with several different pressures so that for the different pressure stages in the fueling process the appropriate storage pressure can be used [32], [33]. Since a higher pressure is required for the hydrogen to flow to the vehicle the cascade system can range from 250 - 900 bar (for 700 bar vehicles) [31]. The final step before the hydrogen reaches the dispenser is a cooling unit which counteracts the heating of the expanding gas [32]. Compression and cooling are also required at the electrolyzer hydrogen output to bring it from operational pressure to storage/transportation pressure.

2.2.5. Fuel cells

FCs work on the reverse principle of electrolyzers, using hydrogen and oxygen as fuel to generate electricity with water being produced as a result. The overall reaction in a FC in Equation 2.6 is realised by oxygen entering at the cathode side and hydrogen at the anode side. The hydrogen reaches the oxygen through the electrolyte after being split into protons and electrons using a catalyst and there forming water, emitting heat during the process. Only the Proton Exchange Membrane FC (PEMFC) will be considered in this thesis.

$$H_2 + \frac{1}{2}O_2 \rightarrow H_2O \tag{2.6}$$

A FC consist of the electrolyte, or membrane, surrounded by the anode and cathode with their gas flow channels. At the electrodes there is a gas diffusion layer where the catalysts drive the redox reactions.

FC are potential alternatives to the typical power generator due their high energy conversion efficiency using clean energy[2], low maintenance, modularity and low sound emissions. A large blow to the complete system usage is the overall system efficiency which can be as low as 30-50 %[19], [34]. However, the flexible operation and ability to produce electricity as long as fuel is present has made them a competitor for batteries and generators alike in certain use-cases [34].

[1]Communication with Christian Swanson, Business Developer at Lhyfe.
[2]Depending on hydrogen source.

PEMFC

PEMFCs are mostly low temperate FCs able to operate in the range 30 - 100 °C with common operation at 80 °C. Efficiency of the modern variants is 50 - 60 %. Similar to PEMEC the electrolyte is a hydrated solid (most commonly Nafion®) which allows the protons to cross to the cathode to form water with oxygen. Platinum is used to facilitate the reactions at the carbon electrodes [19], a must due to the low temperature. Avoiding the higher temperature operation is beneficial for reducing maintenance, degradation and corrosion [35]. Higher temperature PEMFCs are also available using other materials, polymer–nanocomposite electrolytes, which can operate at 100-120 °C (intermediate temperature) or up to 200 °C (high-temperature) [34].

An important aspect of the PEMFC is water management. This is caused by the formation of liquid water at the cathode side as opposed to gaseous, which needs to be transported away at a balanced rate. Too much removal causes dry membranes and too little results in flooding, decreasing the efficiency. When current density is high it also results in electro-osmotic drag at the cathode, drying up the anode side [19].

2.2.6. Hydrogen as an ancillary service

In order to act as an ancillary service for the grid fast reaction times together with sustained and controlled operations are key. With coming changes to the Swedish electricity market, implementing 15-minute intervals instead of one hour, reaction time will become even more of a requirement [36]. However, this does not exclude Hydrogen Energy Storage Systems (HESS) from acting on the balancing markets. Using different control methods and strategies it is possible for electrolyzers to meet both current and future demands and requirements. HESS can provide ancillary services through different means: stabilizing the frequency oscillations, varying the energy in-/output during operation as well as quick start ups and deactivation [27].

Acting on the ancillary services markets requires a deviation from normal operation of whatever device it concerns. For HESS this is realised through losses in total amount of produced hydrogen [36]. Considerations must be made for the hydrogen needs which supersede the power sold as ancillary service. Hydrogen production through electrolysis must therefore be equal to or greater than the consumer requirements and potential FC usage.

One method is to sell the entire load of the electrolyzer/FC on the ancillary market. This requires full stops and start ups which, depending on technology, may exclude them from certain markets. However, start up time of an electrolyzer is determined by its idle condition and is divided into cold and warm start up. For a warm start up the device is kept at the operating temperature before any hydrogen is produced. This allows for a much faster start of the system [27], [36], [37]. However, both FC and electrolyzer cold starts require another means of power provision if the services are to be sold from this conditions, and for the alkaline electrolyzer it may not be possible at all.

Another way of selling ancillary service load is through partial load operations, allowing for faster operation variation which opens up more markets. How operational mode impacts available services can be seen in Table 2.3 [37].

Table 2.3.: Ancillary services available for different operations.

	Full load	Partial load	Idle
Electrolyzer	· FFR · FCR-D up · aFRR up · mFRR up	· FFR · FCR-N · FCR-D (up/down) · aFRR (up/down) · mFRR (up/down)	· FCR-D down · aFRR down · mFRR down
Fuel cell	· FCR-D down · aFRR down · mFRR down	· FFR · FCR-N · FCR-D (up/down) · aFRR (up/down) · mFRR (up/down)	· FFR · FCR-D up · aFRR up · mFRR up

Table 2.3 provides the possible ancillary services, but there are limitations inherent in each technology as well. When in partial operation the load can be changed in seconds for both electrolyzer types, although some ALE manufacturers recommend minutes instead [36]. Similarly, turning off the operation from full load can be done at similar time frames. Electrolyzer warm start up usually takes minutes and from cold it is minutes to over an hour. The PEMFC has a better outlook, with cold start up occurring in less than a minute. Possible operation flexibility, provided in Table 2.4, does not always match up with manufacturer's recommendations and a trade-off must always be made between degradation costs and profits from ancillary service operation.

Where temperature limits the cold start-up it is mostly the supporting machinery (compressor, pumps, etc.) that limits the warm start-up. While the system is in operation it is the cell dynamics and safety regulations that limit how fast the load gradient may be varied [27], [38]. Fast cycle shut-downs and start-ups should be kept to a minimum since these may cause degradation which the slower, controlled, will not [36].

Table 2.4.: Flexibility parameters for ALE, PEMEC and FC.

	Cold start	Warm start	Operation interval	Response time	Source
PEMEC	<10-15 min	<10 s	0-160 %	<1 s	[27]
PEMEC	<20 min	-	5-130 %	-	[39]
PEMEC	-	-	10-100 %	10-15 %/s	[36]
PEMEC	5-10 min	<10 s	0-100 (160) %	<1 s	[40]
PEMEC	1-<60 min	30 s	<20-100 %	1 s	[37]
ALE	5-10 min	1-5 min	20-100 %	<1 s	[27]
ALE	<50 min	-	15-100 %	-	[39]
ALE	-	-	20-100 %	10 %/min	[36]
ALE	1-2 h	1-5 min	20-100 %	<1 s	[40]
ALE	30-60 min	30-60 min	<20-100 %	Seconds to Tens of min	[37]
PEMFC	<1 min	-	0-100 %	<1 s	[41]

The operational interval is limited by inherent characteristics with each technology. For PEMEC the lower boundary is set due to a heightened degradation on the membrane occurring at lower than around 20 % of nominal load and too much oxygen entering the hydrogen stream, breaking EU regulation of 2 % [36]. However, many manufacturers allow for operation down to 10 % as can be seen in Table 2.4. The ALE at low partial operation has the problem of lye gases mixing with the hydrogen flow, requiring separate flow channels [27], [40]. Recommended operation for ALE is also limited to 20 % [27], [36], [38]. Partial load operation also has the benefit of higher electrical efficiency at lower capacity, with some manufacturers stating optimal operation at 80 % capacity [36].

In order to act as a frequency stabilizing entity on the grid very fast reaction times are required for controlling the fluctuation. All three devices have shown to be capable of these kinds of operations [40], although it is doubtful if ALE can act on the faster balancing markets. For electrolyzers, this is made possible by modular control strategies on the cell level. Ref. [27] describes three strategies: segment principle, start-stop principle and slow-start principle. Segment control means that each stack is switched on separately, and when one cell has reached a certain power level the next stack is turned on, followed by increasing to nominal power in the same order when each has been turned on. Turn off occurs in reverse. Start-stop control means that each stack only operates at nominal power is turned off. Slow-start control uses a minimum power for each stack for when they will be turned on, and the next stack is turned on when the nominal power of the previous stack with its own minimum level is reached. Using these principles it is possible to operate an electrolyzer flexibly.

Overall, the PEMEC is more suited for the short-term grid balancing than ALE, especially for FCR services which require response time in seconds. However, when used in hybrid systems, which combines more than one type of energy storage, it is possible to use another source (e.g. a battery) to provide power in the meantime. It is still possible for the ALE to act on the FRR markets which has a lower requirement for the activation time. aFRR and mFRR are are not as desirable since they require a full hour of activation and more frequent activation, meaning substantial loss in production. This may be become more sustainable with ongoing changes of the markets from balancing on hour basis to every 15 min [42]. Due to all of the above, only the PEMEC will be considered in the model.

2.2.7. Other economic benefits of Hydrogen System

The hydrogen system produces several useful byproducts that increases the viability of the technology. Prime among these are residual heat and oxygen gas. With both economical and environmental gains, by replacing carbon heavier methods, taking these value chains into account at the start of the project could prove to be very fruitful.

Residual heat

Electrolyzer and FC both generate heat from the electrochemical reactions in their cells. This would allow for a large increase of the entire system efficiency, with each component reaching efficiencies over 90 % [43]. The heat recovery amount is 15 % - 30 % [43][44] of the electrical power in an electrolyzer. For FC heat recovery has been reported up to 30 % of the electrical power produced by the stack, which is the remaining energy not used to heat up the stack to appropriate temperature [45].

For PEM technology the extracted heat is in the temperature ranges 55 - 65 °C [46] for electrolyzers and 60 - 80 °C for FC [47], and for ALE the possible waste heat is 80 °C [46]. The waste heat temperature is dependant on the operating temperature. With these temperatures the water can directly be sold to low temperature district heating networks and a building's internal heat system. With an average 86 °C in the Swedish district heating network [48] a heat pump might be required to sell the residual heat, although in some cases it is possible to sell the low temperature heat directly.

The district heating system in Trelleborg is relatively new, with construction started in 2002, and is today supplied primarily by boilers burning biofuels. The network is owned by Trelleborgs Energi and the heat is supplied by Adven. With recent shortages in biofuels due to the Ukraine-Russia war, and a new residential district being constructed in the city requiring district heating, the residual heat from an electrolyzer has a likely market to be sold to. However, with a temperature of 98 °C during winter months a heat pump would be a requirement no matter which electrolyzer/FC used. With flexible electrolyzer operations a problem could arise during summer when the total heat load is low, if majority of the heat were to be supplied by the electrolyzer the fast variation can not be met by the slow boilers, causing catastrophic failure [49].

Oxygen gas

There are several avenues available for the oxygen gas: sewage treatment, healthcare, breweries and food production, fish farms, and more locally to oxygenate the oxygen poor Baltic Sea bed [33], [50]. The purity of the oxygen gas as well as size and location are important factors when gauging the potential market. Healthcare requires very high purity for their patients while water treatment plants can handle a wider margin. With a sizable 8 kg of oxygen being produced per kg hydrogen [50], [51] many of these possibilities may be realized.

The role of oxygen in sewage treatment plants is as an ozonation agent. This will help the aerobic breakdown of certain chemicals in the water. There is a potential market in Sweden of up to 25 000 tons. Replacing blowers which is used in many plants today this could also be a large potential electricity saving for cities [50]. From Ref. [33] the estimated price of oxygen when replacing other methods was 0.70 - 1.07 SEK/kg. However, there must be a local demand for this oxygen gas because the value depreciates fast with transport distance. There are two potential uses in Trelleborg, one is a new treatment plant which is going to be built in the near future and the other is transporting the gas to the Baltic sea with the purpose of oxygenating the sea bed. Although note that none of these options are at current date seen as financially profitable [3].

2.2.8. Techno-economical analysis: Hydrogen Energy Storage System

This HESS consists of the electrolyzer, the storage and a FC. Each of these components requires supporting devices in order to work and deliver peak performance. These include everything from: the transformers and converters, control systems and signaling equipment, separators for oxygen and fly gases, heat extraction and cooling systems, and compressor and water supply units. A comprehensive cost guide for the main components can be found in Table 2.5, and Table 2.6 provides technical characteristics of the technologies.

[3] From internal communication with Trelleborgs Energi.

Table 2.5.: Economical parameters of HESS.

	System Cost [kSEK/kW,kg]	O&M [%]	Lifetime	Degradation [%/year]	Source
ALE	3.5-17	-	-	-	[1]
	5-10	-	60 000 h	-	[39]
	8.2-15	-	55-96 000 h	0.25-1.5	[40]
	3.1-22	1.5	60-75 000 h	-	[52]
	12	5	75 000 h	-	[53]
PEMEC	20	-		-	[1]
	7-14	-	50-80 000 h	-	[39]
	14-22	-	60-100 000 h	0.5-2.5	[40]
	4.6-25	1.5	50-80 000 h	-	[52]
	28	5	40 000 h	-	[53]
Electrolyzer (not specified)	11-50	-	-	-	*
	13-17	-	-	-	**
PEMFC	30-40	-	40-80 000 h	1	[35], [47]
	22	-	-	-	*
	22	-	-	-	**
Compr. storage (350 bar)	4-7	2	-	-	[47], [54]
	5	-	-	-	*
	6.5	-	-	-	**
Compressor	-	4	10 years	-	[55]
	2.2-7.8	-	-	-	*
	<7.8	-	-	-	**

- *Communication with Carl Jönsson Lindholm, Account Manager - Hydrogen at Euromekanik (Disclaimer: These values are not accurate for the company's products, only a guideline that are accurate for the hydrogen market generally).

- **Communication with Dr. Abdallah Abou-Taouk, Senior Technical Sales at Nilsson Energy.

Values found in Tables 2.5 and 2.6 are comprised of combined data collected from research papers and reviews, technical reports and communication with manufacturers. Due to the changing market conditions, both from increasing demand and resource scarcity, the price is ever fluctuating for many of the components. The higher end of the electrolyzer cost is based on 2022 data, a year which saw severe price increases[1]. The technical parameters in Table 2.6 are given for possible operational mode for each component, but certain operational modes are generally preferred over others. Maximizing voltage efficiency is one such parameter, but higher efficiency means operating at higher temperature which causes faster stack degradation [38]. Operation of a PEMEC required stack change after 10 years, a reinvestment amounting to 30 % of initial investment costs.

Table 2.6.: Technical parameters of Hydrogen technology.

	Cell pressure [bar]	Operating temperature [°C]	Electrical efficiency [kWh/kg hydrogen]	Voltage efficiency LHV* [%]	Source
PEMEC	≤ 50	50-80	50-83	50-68	[39]
PEMEC	20-50	50-80	56-72	46-60	[40]
ALE	<30	50-90	50-78	50-68	[39]
ALE	10-30	60-90	56-66	54-71	[40]
PEMFC	-	80	-	60	[41]
PEMFC	1.5-3.0	60-85	-	50-60	[56]

- *Low Heating Value

Table 2.7 shows the costs and earnings of process flows related to the production of 1 kg of hydrogen gas.

Table 2.7.: Production of 1 kg of Hydrogen.

Process flow	Amount required/produced	Selling/Buying price	Source
Hydrogen	1.0 kg	90 SEK/kg	[33]
Desalinated water	8.9 kg	0.08 SEK/kg	[57]
Oxygen	8.0 kg	0.70-1.1 SEK/kg	[33]
Residual heat	16-24 kWh	0.10-0.59 SEK/kWh	[44], [49], [51]

2.3. Battery Energy Storage System

Since Alessandro Volta invented the first way to store electricity in the year 1799, humanity has had a way of keeping this most flighty energy form bound to one location. At least for a while. This is done by converting electrical energy into chemical energy and then back again when needed. Batteries are electrochemical cells consisting of two electrodes submerged in electrolyte and divided with a separator. Mass flow takes place in the electrolyte so that reduction and oxidation reactions can occur at the cathode and anode, respectively [58]. Stacking several cells together in series and parallel increases the voltage and current, respectively, which allows for greater power.

Since the time of Volta battery technology has come a long way. The invention of rechargeable batteries is just one improvement that has expanded the possible uses of modern variants. This has been a great part in allowing for storage and discharge of electricity over many cycles, with many modern batteries being capable of 1000s of cycles before degradation becomes too severe [19], [58]. Of the rechargeable battery types on the market today lithium-ion batteries has been one of the most adopted for many decades [59], [60], being the preferred choice for everything from smartphones and watches to cars and grid storage as Battery Energy Storage Systems (BESS).

The rising use of batteries for grid storage worldwide amounted to a total of 15.5 GW installed capacity in 2020 with the expected growth to be 25-fold until 2040 [61]. In Sweden the expected storage of battery parks (> 5 MW) is 603 MWh (577 MW) at the end of 2024 with planed installations up to 2 851 MWh (1 826 MW). Majority of the actors are investing in lithium-ion batteries [62]. However, other new battery technologies have high potential to act as grid storage without the negative environmental impact of Li-ion batteries [61]: sodium-ion, potassium-ion, flow, all-solid-state and multivalent batteries [63] are just a few examples.

The battery health is a measure of degradation from initial purchase and thus how long the lifetime is. This can be described by State of Health (SoH), how much of the original capacity is available. This is affected by both the operational mode of the battery as well as thermal management. In order to monitor and control these factors for optimal usage a battery management system (BMS) is used in every battery pack. These monitor both the state of charge (SoC), how much energy is available at the moment, and thermal profile of each cell. Thermal monitoring is especially important to avoid thermal runaway, a state which is induced by over-charging or over-discharging. Thermal runaway occurs when failure to dissipate heat causes exothermic reactions to increase which increases auto-oxidation rate which leads to more heat, resulting in a destroyed battery and possibly a serious accident. But temperature also impact the efficiency and lifetime of a battery, with optimal operating range being 15-35 °C [19].

2.3.1. Lithium-ion batteries

The basic concept of Li-ion batteries is the usage of lithium in the positive cathode together with an insertion material (e.g. oxides of cobalt, nickel, iron or manganese) and a negative cathode of carbon (commonly graphite or hard carbon). The electrolyte is a lithium salt in an organic solvent [19]. The combination of their high power and energy density, high efficiency, low self-discharge, flexible design and continuous improvements these last couple of decades [59], [63], [64] has made them the preferred choice for users world wide.

The Li-ion cell has a comparatively high nominal voltage of 3.7 V. It also boasts a greater lifetime (spanning 1000-10 000 cycles), have a higher energy density (80-200 Wh/kg), low self discharge rate (under 5 % per month) and high round trip efficiency (RTE) (90-97 %) [65], [66]. Some of the more popular commercialized variants of the Li-ion batteries are cobalt oxide ($LiCoO_2$), manganese dioxide ($LiMnO_2$) and iron phosphate ($LiFePO_4$). The redox reactions at the anode and cathode for the lithium cobalt oxide battery are [65]:

$$\text{Anode:}\quad LiC_6 \rightleftharpoons Li^+ + e^- + 6C \tag{2.7}$$

$$\text{Cathode:} \quad CoO_2 + Li^+ + e^- \rightleftharpoons LiCoO_2 \tag{2.8}$$

Despite the continuing success of Li-ion batteries there are draw-backs and challenges that cannot be overlooked. Their high cost due to material scarcity and the environmental impact attributed to lithium mining have taken center stage for many years now [66].

2.3.2. BESS as an ancillary service

Key features of grid connected BESS is its ability to act as everything from peak shaving and load leveling devices, voltage and frequency regulation (local, regional and transmission) and emergency energy storage [67]. Peak shaving and load leveling refers to when a battery is used to store energy during times with high intermittent power in the grid and discharging the energy when there is a high demand. Voltage and frequency regulation is when the battery is used as one of the services described under section *Ancillary services to the grid*. An emergency energy storage is used when there is a problem with the grid connection and island drift is required. Batteries also have the advantage of being a mature technology so fast construction time, modularization and flexible installations are common features [67].

Compared to hydrogen's long storage time, batteries can only store energy efficiently on the scale of hours or days. This makes them unsuitable for seasonal storage but they work well as load leveling for short time frames, such as the large difference in production for systems with a high percentage of wind and solar power.

In Sweden's ancillary market today batteries are one of the dominant types for the FFR and has been for a few years [68]. The technical potential is there for it to act as other ancillary services as well. With its fast reaction time and accurate control ability it is mainly limited by the power and capacity of the installed battery. The short duration of called capacity also means that only a small storage is required compared to the available power, making 1-hour batteries very popular for profit driven ventures [62], [66].

Today the primary markets in Sweden are FCR-D up and down as well as FFR [62]. Both FFR and FCR-D would require a certain size of battery (at least 0.1 MW/0.1 MWh) or selling the capacity to an aggregator. FCR-D, which has a minimum duration of 20 minutes, differ from FFR in that if the capacity is called on a noticeable decrease in SoC occurs which requires recharging and must be taken into account when providing the battery's capacity over long periods of time.

2.3.3. Techno-economical analysis: BESS

The main components of the BESS are the Li-ion packs themselves, management, monitoring and control systems, inverters and enclosures. Generally BESS for grid applications are divided into 3 categories which specify how long they can output max power: 4-hour, 2-hour and 1-hour batteries. The model of building high power batteries with low storage capacity has been optimal for regulating markets and ancillary services, but it lowers the potential of the battery to ”value-stack”, maximize the types of values it can bring. There has been an increased interest in evaluating the potential of longer lasting batteries for these saturated markets [69]. Once these high value markets are exhausted a lower cost is a must for batteries to stay competitive as grid storage [63]. Using old EV batteries show potential for cheap alternatives while also extending the lifetime of these batteries which cannot be used in cars anymore [70].

In Table 2.8 economical parameters for the battery used (Li-ion) in the model can be found, taken from technical reports and reported purchases.

Table 2.8.: Economical parameters of BESS (Li-ion).

Battery Specifics	System cost [SEK/kW]	O&M	Lifetime [years]	Degradation [%/year]	Source
20 MW/ 20 MWh	5000	-	-	-	[62]
100 MW/ 100 MWh	5000-8000	15-33 (SEK/kWh)	20	2.6	[71]
Commercial Scale	12 000 17 000	290-420 (SEK/kW-yr)	20	-	[72]

2.4. Electric vehicle charging

Electric vehicles (EV) in Sweden today number around 560 000, including plug in hybrids, amounting to 11 % of all personal vehicles. Together with the around 22 000 busses, light- and heavy-duty trucks this represents 11.5 GWh battery capacity which needs charging daily. With a continued interest in replacing fossil driven vehicles with EVs the demand on infrastructure also becomes higher [73], and this is not least seen in the rising amount of charging stations required. While most vehicles still charge in private stations such as residential [74] for long distance travel frequent charging stations are needed.

Charging ports are divided into two types: normal (<22kW) and fast chargers (>22 kW). Furthermore, three grades of charging stations exist (levels 1-3) with Level 3 consisting of DC fast chargers. These are the fastest but also the most expensive. Today there are 3000 fast chargers in Sweden [74]. By 2030 the goal is for the EV fleet to reach 1 million, assuming 1 fast charger per 100 EVs this means 10 000 of them are required by then [75]. With a large part of all charging occurring at slower but cheaper chargers either at home or at work places, the usage of DC fast chargers is sparse and mostly used by working drivers or during long trips. Start of charging event probability (normalised) for fast chargers in Sweden can be seen in Figure 2.2, which shows peak usage occurring between 11:00 and 16:00, and very small usage from late evening to early morning [76].

Figure 2.2.: Normalised probability of start of charging event in Sweden.

For a single DC fast charging station the power curve can be very sporadic with single charging events resulting in large power spikes form the otherwise low utilization, causing large and unpredictable loads on the local grid. A typical power demand for one such station is shown in Figure 2.3. This is further complicated by individual EV models having different charge profile throughout the charging process. Some vehicles have a very high power demand at the start of the charge cycle, when the SoC is low, and decreasing inversely with SoC. Other models have an even power draw with minor variations throughout the charge. With no knowledge of which car will arrive and when this causes an unpredictable power demand which further impact grid stability.

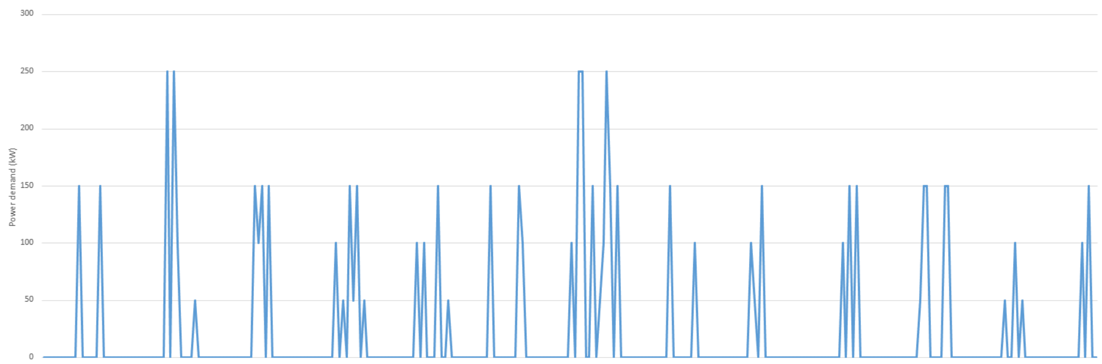


Figure 2.3.: Example of power demand from a DC fast charging station with 4 different power levels.

2.4.1. Techno-economical analysis: DC Fast Charging station

The cost of constructing a commercial charging station can be divided into four separate categories: infrastructure costs, equipment costs, soft costs and software. Infrastructure is one of two main cost drivers and consist of the required above 480 V grid connection, the other expensive part is the equipment, but this can vary greatly depending on charger type. Soft costs and software costs are small in comparison and consists of the environmental/parking spot costs to have the public charger and the digital systems managing charging data, respectively. Recent pricing of a DC fast charger can be found in Table 2.9

Table 2.9.: Economical parameters of a DC fast charger.

Construction	Grid connection	O&M	Source
350 000 SEK	260 000 SEK	61 000 SEK/year	[76]

Since the system is located in Trelleborg local pricing for network connection will be considered. Pricing for a high voltage connection point with Trelleborgs Energi is divided into two components: a fixed part consisting of a yearly cost of 21 379 SEK and a subscription dependant on the max power, 650 SEK/kW per year [77]. Trelleborgs Energi offers up to 22 kW already at 2.50 or 4.00 SEK/kWh depending on if you are customer of theirs already. With no data of the number of members a 50/50 split was assumed for all charging events, resulting in the average cost at 3.25 SEK/kWh.

2.4.2. Battery and FC connected to EV Charging station

Fast charging stations will require a large connecting point to the grid, especially with the addition of truck and buss availability for which several MWs might be required per charger. The fluctuating demand of the short but high peaks will also negatively impact the grid stability [75]. An on-site battery and FC for local power delivery allows for both a smaller connecting point and grid subscription by providing DC directly to the car batteries [70]. Previous studies have found that using a battery could save 800 000 SEK for city chargers (up to 200 kW draw) and 5.1 million SEK per MW on highway charging station (up to 10 MW draw) on subscription only [75].

2.5. Combined Battery and Hydrogen system

The increasing amount of renewable energy penetration in the energy system has led to much research into hydrogen and batteries as energy storage. Both are mature industries but the application as grid storage/ancillary service is more recent. Combining these has therefore been a topic of interest recently, with several cases and models being built in Sweden [33], [78] and internationally [79], [80]. This section will give a brief overview of the current state of affairs.

A recent review from Saudi Arabia [80] analyzed the gains from combining energy storages with different characteristics with renewable energy. The HESS consist of two components: one high power storage (battery) and one high energy storage (hydrogen). They identified three control methods for such a system: cascade, passive (direct) parallel and active parallel. They found that a HESS improved the power quality of the storage, i.e. clean and stable power, constant power flow, high availability and pure and noise free sinusoidal electricity. They were also able to better smooth power fluctuations, unbalanced loads and harmonics in grids with high renewable energy production. When applied in micro grids, a hybrid system was also found to better stabilize the grid frequency than only using a battery. Finally, hybrid storage systems also showed improvements upon single type storage for peak shaving purposes. In Ref. [79] from China a model was created for a battery/hydrogen storage system connected to the grid with a wind farm nearby. They found that harnessing the hybrid system led to improved energy retention from the wind power and smoother power fluctuations at a similar cost to only using a battery.

In Mariestad, Sweden, a model was built around an existing HFS with a connected battery and photo voltaic cells [33]. The study showed that it is possible to decrease the subscribed effect with 1 or 2 MW (180 vs. 4000 kg storage) and shave many high peaks over the subscribed effect throughout the year. When simulating how the system could act on the frequency balancing market (battery as FFR, electrolyzer as FCR-N and FC as FCR-D up) the battery and FC showed great promise since these had very high availability and could act on the markets without impacting the refueling station. With a lower capacity usage on the electrolyzer it could be used for FCR-N and a combined control system for optimal operation of all three units could be developed.

Chapter 3.

Model method

In order to assess the techno-economic potential of the hybrid hydrogen and battery storage a model was built using Excel. This chapter gives an overview of the model. The first section describes the model system and included modules. The second part covers the economical analysis. The third part describes the scenario architecture. This model was created together with another group writing their thesis together with Trelleborgs Energi, Elin Lenntoft and Sofia Rapp in their thesis *A Techno-Economic analysis of combined Hydrogen and Battery systems participating with Ancillary services in SE4*.

3.1. Model architecture

The model is built in Excel by a system of connected modules representing the different components in the HESS, see overview in Figure 3.1. The model architecture consist of a primary base case consisting of two scenarios, one looking only at how the components operate when only buying and selling electricity based upon spot pricing, and one where ancillary services are included, as well as residual heat and oxygen. Finally a scenario will be modelled where a battery and FC support at DC fast charging station.

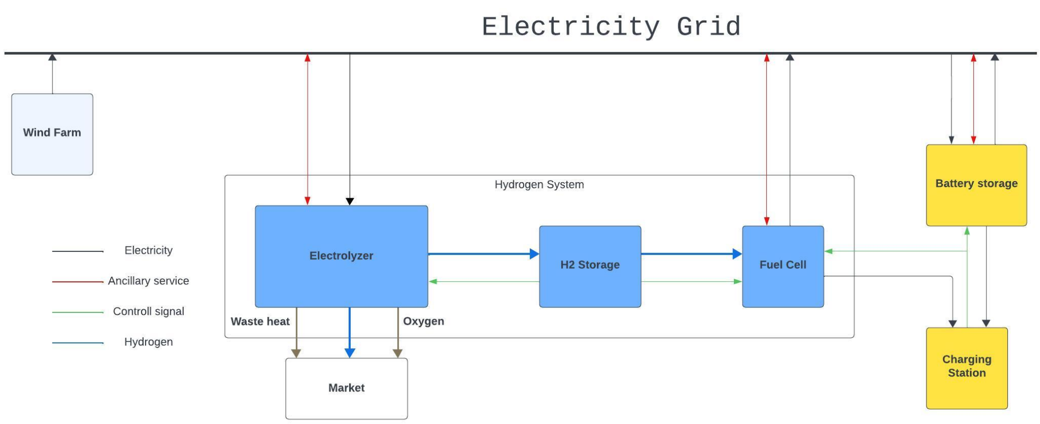


Figure 3.1.: System overview of model, created by author.

3.1.1. Grid

The Grid module consists of all the inputs that the HESS operation requires from the electrical grid. These values are from 2023 and include ancillary service data and spot pricing. All data types used in the model can be found in Table 3.1. No taxes and network costs have been included in the electricity pricing used in the model.

Table 3.1.: Grid inputs to the model (from 2023).

Input	Comment	Source
Spot pricing	From SE4	Trelleborgs Energi AB
FFR	May-Nov.	[81]
FCR, Capacity	Swedish/Danish Balance Market	[82]
FCR-N, Energy	SE4	[82]
FRR, Capacity*	SE1-4,DK2	[82]
FRR, Energy	SE4	[82]

- *The capacity market for mFRR started on October 18th 2023 so data is only available from this point.

The activation frequency over the year of each ancillary service can be found in Table 3.2.

Table 3.2.: Activation time of ancillary services.

Ancillary service	Active time over the year [%]	Source
FCR-D (up/down)	1.0/0.81	[14]
FCR-N	13	[83]
mFRR (up/down)	3.2/4.2	[82]
aFRR (up/down)	46/34	[83]

3.1.2. Electrolyzer

The electrolyzer module is where the input of hydrogen into the system is determined. Only the PEMEC will be modelled due to its greater affinity for ancillary services. The control hierarchy varies depending on the scenario in question, but the general structure is as follows:

1. Check availability in hydrogen storage.
2. Check availability of priority one target.

3. ...
4. Check availability of priority final targets.
5. Do not run the electrolyzer.

Operational modes

How the electrolyzer can operate depends on the electrolyzer technology, shown in Table 2.4. In Table 2.6 the technological parameters can be found. Based on these values the parameters for the model's PEMEC could be determined, see Table 3.3.

Table 3.3.: PEMEC parameters used in model.

Operation interval [%]	10-100
Voltage efficiency [%]	60
Operation temperature [°C]	80
Cell pressure [bar]	40

The hydrogen production is calculated with Equation 3.1:

$$\dot{m}_{hydrogen} = \frac{P_{electrolyzer,nominal} \cdot \eta_{electrolyzer}}{\mathrm{LHV}_{hydrogen}} \tag{3.1}$$

where $P_{electrolyzer,nominal}$ is the rated power of the electrolyzer, $\eta_{electrolyzer}$ is the voltage efficiency and $LHV_{hydrogen}$ is the LHV energy content of one kg of hydrogen (33.3 kWh).

Additional flows

In addition to electricity and hydrogen flow, the electrolyzer also produces oxygen and residual heat as by-products and requires water for operation. All three of these are directly dependant on the hydrogen production. As is shown in Table 2.7, the rate of oxygen to hydrogen is 8:1 so the produced oxygen is calculated with Equation 3.2.

$$\dot{m}_{oxygen} = 8 \cdot \dot{m}_{hydrogen} \tag{3.2}$$

Similarly, the water consumption is calculated using Equation 3.3, with the proportion of 9 kg of water per kg of hydrogen produced. Note that only the water used to produce the hydrogen has been included; water for other purposes such as cooling has been excluded.

$$\dot{m}_{water} = 9 \cdot \dot{m}_{hydrogen} \tag{3.3}$$

The residual heat is calculated by assuming a conservative 20 % of nominal electrical power used by the PEMEC as the power to useful heat as is seen in Equation 3.4.

$$P_{electrolyzer,RH} = 0.20 \cdot P_{electrolyzer,nominal} \tag{3.4}$$

Compressor and Chiller

Part of the electrolyzer module are the compression and cooling required for delivering the high pressure output the storage requires. These are driven by electricity supplied from the grid. The compressor work is calculated using Equation 3.5,

$$W_{compressor} = m_{hydrogen} \cdot \frac{h_{out} - h_{in}}{n_{mechanical} \cdot n_{motor}} \tag{3.5}$$

where $W_{compressor}$ is the work done by the compressor, $m_{hydrogen}$ is the hydrogen production, h_{out} and h_{in} are the specific enthalpy of hydrogen, and $n_{mechanical}$ and n_{motor} are the efficiencies of the mechanical and motor efficiencies of the compressor. Outlet temperature of the hydrogen is calculated using Equation 3.6,

$$T_{out} = T_{in} \cdot (\frac{P_{out}}{P_{in}})^{\frac{k-1}{k}} \tag{3.6}$$

where k is the specific heat ratio for hydrogen which is 1.41 assuming ideal gas.

The cooling power requirements are calculated using Equation 3.7,

$$W_{chiller} = m_{hydrogen} \frac{h_{in} - h_{tank}}{COP} \tag{3.7}$$

where COP is the coefficient of performance [84], with a conservative value of 2.5 being used. Values used in the model can be found in Table 3.4.

Table 3.4.: Values used to calculate work done by compressor and chiller.

	Pressure [bar]	Temperature [°C]	Specific enthalpy [kWh/kg]
Inlet	40	80	1.2
Outlet	350	390	2.6
Tank	350	25	1.1

3.1.3. Fuel cell

The FC is controlled in a similar way as the electrolyzer; in the Spot price scenario it sells electricity by comparing the spot price to the minimum selling price and by checking if there is hydrogen in the storage. In the extended base case, with ancillary services included, the capacity sold as ancillary service is prioritised over the spot price, which is only considered when the bid is higher than the market price. The energy required from the hydrogen storage to operate the FC is calculated with Equation 3.8, where η_{PEMFC} is the system efficiency of the PEMFC. To determine the hydrogen mass used, Equation 3.9 is used.

$$P_{FC,required} = \frac{P_{FC,nominal}}{\eta_{PEMFC}} \tag{3.8}$$

$$\dot{m}_{hydrogen,FC} = \frac{P_{FC,required}}{\mathrm{LHV}_{hydrogen}} \tag{3.9}$$

Additional flows

Waste heat from the FC is also considered. It is higher for the FC compared to electrolyzer, 30 % of electrical power production, and the heat energy is calculated using Equation 3.10.

$$P_{FC,residualheat} = 0.30 \cdot P_{FC,nominal} \tag{3.10}$$

3.1.4. Hydrogen storage

The hydrogen storage is where the electrolyzer stores the energy produced, see Equation 3.1, and from where the FC takes the hydrogen it converts into electricity, see Equation 3.9. However, in the actual model the storage is calculated in MWh instead of hydrogen mass for simplicity's sake. The storing process is assumed to be ideal with no hydrogen leakage both during the storing process and while it is stored, based upon low total leakage rates (1-4 %) over the entire hydrogen supply chain [85].

The sold hydrogen is taken from the hydrogen storage directly and from where the first control parameter to most scenarios occurs (a check if there is enough capacity for either hydrogen production or usage). Since the storage is a dynamic system, which both is dependant on and is depended on by all other hydrogen modules, it is determined using the t-1 principle. The first hour of the year is determined manually (assuming storage is half full) while all other hours are calculated using Equation 3.11,

$$E_{storage,n} = E_{storage,t-1} + E_{electrolyzer,t-1} + E_{FC,t-1} \tag{3.11}$$

where $E_{storage,n}$ and $E_{storage,t-1}$ is the hydrogen storage capacity at time n and (t-1), respectively. $E_{electrolyzer,t-1}$ and $E_{FC,t-1}$ are the energy content of the produced/consumed hydrogen from one hour of operation at time (t-1).

3.1.5. Heat pump

The heat pump is used to upgrade the waste heat from the electrolyzer so it can be delivered to the district heating network, from 78-80 °C to 97 °C. Dimensioning of the heat pump is according to nominal power output, calculated with Equation 3.12. COP used for such a heat pump is generally 3.5[1].

$$W_{net,in} = \frac{Q_{in}}{COP_{HP} - 1} \tag{3.12}$$

In Equation 3.12 $W_{net,in}$ is the work done by the heat pump, COP_{HP} the coefficient of performance of the heat pump and Q_{in} the heat delivered from the hydrogen system. The heat delivered to the district heating network is the work from the heat pump and the heat from the hydrogen system, see Equation 3.13.

$$Q_{out} = W_{net,in} + Qin \tag{3.13}$$

3.1.6. Battery

The battery module is controlled partially using a (t+1) logic, similar to the hydrogen storage, and partially by real time values. A schematic of the controll scheme is presented later on in Figure 3.2. The forward looking function is a check for ancillary services to ascertain that there is storage capacity for the battery to sell. This differs from the electrolyzer and fuel cell since for the battery stored energy is directly linked to the discharged/charged energy, and not a separate storage component. This is especially important for the FFR, where the capacity for each hour is sold only twice a week. If a bid has been accepted then this check makes sure that battery is able to either charge or discharge if called upon.

[1] Communication with Marcus Thern, Senior lecturer at Thermal Power Engineering at Lund University.

3.1.7. EV charging station

The charging station module consist of electricity demand from charging EVs. The aim is that this load primarily will be covered by electricity from the battery. However, when not available due to low storage the FC will start to cover the demand. To get a profile of the EV charging load a simple model of charging events was created based upon results from a Swedish study on queing times in Sweden and Norway [76]. The probability of a charging event starting was used for each charging port which varies throughout the day, week and season. This is further described under Charging Station scenario.

The power demand is based on a model of the hourly variation in traffic arriving at the station throughout a day, distributed according to monthly trends presented in Table 3.7, with each day following a similar pattern with no regard for weekends/holidays. The electricity can be delivered from the either grid, battery or fuel cell.

3.2. Economical analysis

In order to assess the financial viability of the HESS an economical analysis was done using both values found in the literature review and communication with industry actors, combined with results from the model. Three different aspects of the system were identified and calculated to give a good overview of the financial outcome: internal rate of return (IRR), payback time and levelised cost of hydrogen (LCOH).

3.2.1. Internal Rate of Return

The metric IRR is used to assess the profitability of a potential investment. It is based upon the Net Present Value (NPV) method which takes the costs and earnings of the entire investment into account and calculates the current value. NPV is calculated using Equation 3.14. The aim of the IRR method is to solve for the discount rate if the NPV were equal to zero. See Equation 3.15.

$$\mathrm{NPV} = \sum_{n=1}^{N} \frac{C_n}{(1+r)^n} - C_0 \tag{3.14}$$

N is the financial lifetime of investment, n is each time period, C_n is cash flow at time period n, r is the discount rate and C_0 is the initial investment at time period 0.

$$0 = \sum_{n=1}^{N} \frac{C_n}{(1+IRR)^n} - C_0 \tag{3.15}$$

In these equations the cash flow C_n is defined as the total income and expenditures throughout time period n. This can be expressed as:

$$\begin{aligned} C_n = C_{n,Hydrogen} + C_{n,Ancillary\ service} + C_{n,Electricity\ sold} + C_{n,Oxygen} + C_{n,Residual\ heat} \\ - C_{n,Electricity\ bought} - C_{n,Water} - C_{n,O\&M} - C_{n,Replace\ component} \end{aligned} \tag{3.16}$$

3.2.2. Levelised Cost of Hydrogen

LCOH is meant to give a cost evaluation of producing one kg of hydrogen, taking the NPV cost of the hydrogen system into account, see Equation 3.17. NPV cost of hydrogen system refers to all costs associated with producing hydrogen (i.e. not the battery and fuel cell).

$$\text{LCOH} = \frac{\text{CAPEX} \cdot \text{CRF} + \text{OPEX}}{\text{Annual hydrogen production}} \tag{3.17}$$

CRF is the capital recovery factor, see Equation 3.18, which divides the CAPEX equally into each time period n according to the discount rate.

$$CRF = \frac{r}{1 - (1+r)^{-N}} \tag{3.18}$$

3.2.3. Payback time

To give a rough estimate of the reimbursement period a payback method is used, see Equation 3.19. This only takes into account the system costs and cash flows until the initial investment is payed back.

$$\text{Payback time} = \frac{CAPEX}{\sum_{p=1}^{P} C_p} \tag{3.19}$$

In Equation 3.19 P is the time period when the return equals the investment cost and C_p is the cash flow every year until time period P.

3.3. Scenarios

The scenario structure is divided into a base model consisting of two scenarios, spot price and ancillary services, and a charging station scenario. The base model was constructed based upon the spot price scenario and changed accordingly in order to allow for ancillary services and charging station scenarios.

3.3.1. Spot price and ancillary service scenarios

The base model consists of two scenarios. The first scenario only considers the modules controlled by optimized bid for buying and selling electricity (spot price). In this case the income consists of sold hydrogen from electrolyzer and electricity from FC and battery. Using Excel solver an optimal bid is found for each component which will result in maximized income for each system size. In the second scenario ancillary services are included in the model, and take priority for controlling the operation over spot price. Similar to the spot price scenario a solver was used to find the optimal bid for each service by maximizing the income. Ancillary service modelled for each component can be found in Table 3.5. In addition to ancillary service waste heat and oxygen flows are included in the ancillary service scenario.

Table 3.5.: Ancillary services tested for each component.

Battery	Electrolyzer	Fuel cell
FFR & FCR-D	FCR-D (up/down) & FCR-N mFRR (up/down) aFRR (up/down)	FCR-D (up/down) mFRR (up/down) aFRR (up/down)

It is possible to sell different services as long as pre-qualification is carried out, but this thesis has limited to only testing one category at a time with an exception for FFR which is bought further in advance than the others and can therefore be planned for more easily. However, both upward and downward regulation are looked at at the same time. The electrolyzer and FC are also combined to provide the same service for each case, i.e. FCR for both electrolyzer and FC and then aFRR and lastly mFRR.

Both the Spot price and Ancillary service scenarios cover all three different sizes of the system, see Table 3.6, which are presented below. It is assumed that each of these systems are able to operate in a similar fashion for capacity delivered to the ancillary service market, with the smaller components selling to aggregators when not achieving the minimum capacity requirements as described in Table 2.2.

Table 3.6.: Component sizes for each system size.

System	Small	Medium	Large
Electrolyzer size [MW]	0.1	0.5	10
PEMFC size [MW]	0.1	0.5	1
H2 Storage size [kg]	430	1720	4800
Battery size [MW]	0.1	0.5	10

Due to fundamental differences between the function of each system size there are some parts of the model that require changes for a more accurate representation of the real system. The most important variable parameters are: sold hydrogen, residual heat and oxygen flow and storage control scheme. These adaptations are described below:

10 MW system

- The hydrogen is only sold to refueling stations in Trelleborg which is meant to cover hydrogen trailers arriving at the city's harbour, amounting to 20 000 trailers per year or 600 tons hydrogen per year (1.7 ton/day) [86]. Using container transport of pressurised hydrogen gas that individually contains 430 kg of hydrogen (350 bar), two transports are required every day of 2 containers each (every 12 hours).
- Waste heat is sold to the district heat network after being upgraded by a heat pump dimensioned to 800 kW.
- Oxygen gas is collected and sold to a waste treatment plant.
- Electrolyzer and FC operations are downwards limited by when the containers need to be transported to refueling station; if the hydrogen storage drops bellow the hydrogen amount that is to be transported to the fueling station the FC is turned off and electrolyzer turned on at full capacity without regard for electricity price or ancillary services, so that the next transport can be delivered.

0.5 MW system

- No hydrogen is sold in this scenario, only usage of the hydrogen is for the FC and refueling a few of the principality's vehicles. The FC electricity is meant to deliver electricity to the residents in Västra Sjöstaden, so no electricity is sold to the grid directly. In this scenario 20 cars of 5 kg each are fueled each day.
- Waste heat is used to heat the apartment buildings' low temperature heat network in combination with return flow from district heating network.
- No oxygen is collected in this system.

- Electrolyzer is limited by FC and refueling car capacity for 24 hours (6.6 MWh) when below it is always producing at max capacity.

0.1 MW system

- No hydrogen is sold in this scenario, only usage of the hydrogen is for the FC and refueling hydrogen vehicles used by Trelleborgs Energi, 2 cars with 5 kg of refueling each day.
- Waste heat is delivered to the building's internal heating system.
- No oxygen is collected in this system.
- Electrolyzer and FC operation are downwards limited by requirement of FC being able to power the building for 72 h in case of emergency, when under the electrolyzer produced hydrogen at nominal capacity.

Control diagrams

As mentioned above, each component has its own control scheme for how it should operate every hour (each t) and this depends both on the previous model state $t-1$ as well as how other components operate at the current state t. In this section a control diagram for each component will be provided.

The control diagram of the battery can be seen in Figure 3.2 below, were t refers to the current state.

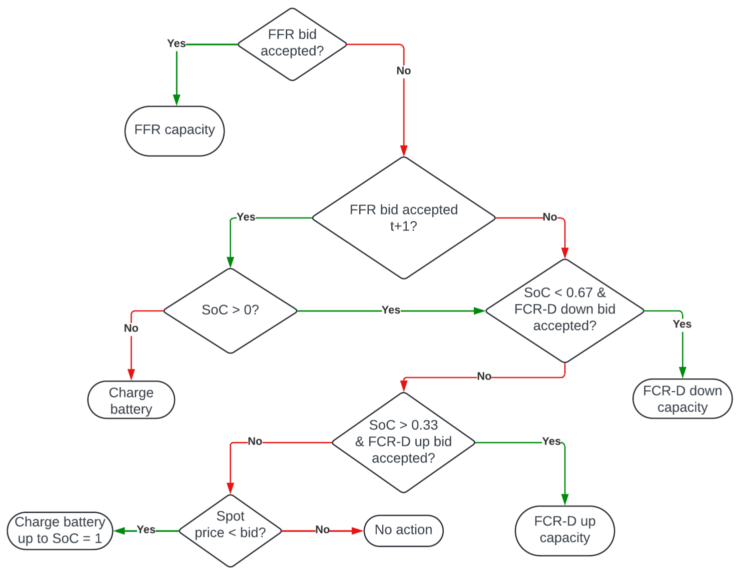


Figure 3.2.: Battery control diagram - FCR-D up/down and FFR.

Similar control diagrams for the HESS components electrolyzer and FC, bidding their capacity on the FCR markets, can be seen in Figures 3.3 and 3.4 respectively. The remaining control schemes, for the FRR markets, can be found in Appendix A.

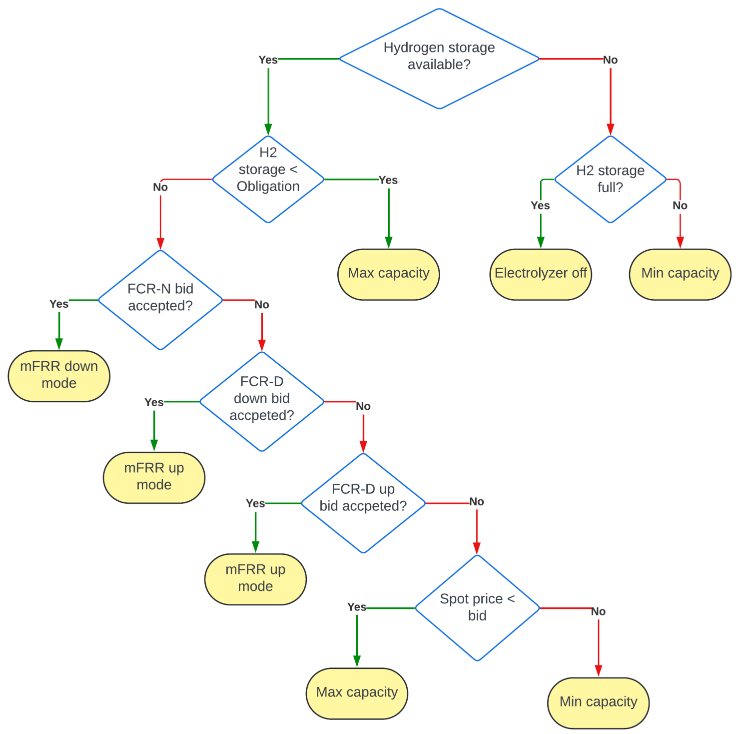


Figure 3.3.: Electrolyzer control diagram - FCR-D up/down and FCR-N.

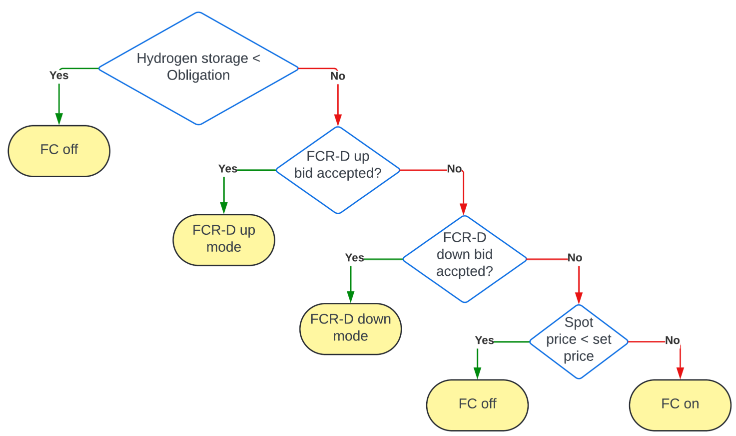


Figure 3.4.: Fuel cell control diagram - FCR-D up/down.

3.3.2. Charging station scenario

This scenario will look at the battery and FC being utilized as the main power providing components for a level 3 DC fast charging station with several chargers. The battery will primarily be used to charge the EVs with the FC acting as back-up in the case that the battery is out of energy. The modelled system consists of a 4 MW/4 MWh battery and a 0.4 MW FC, meant to mirror the scale of the 10 MW hydrogen/battery system with 1 MW FC. The max charging station capacity will equal 75 % of the battery's max power, 3 MW or 20 DC fast chargers at 150 kW per port.

Power demand profile

Such large charging stations are not common and actual data is lacking. The power demand has been modeled based upon a previous study looking at charging behaviour in Sweden and Norway [76], which provides the hourly distribution of start of charging events in Sweden, see Figure 2.2, as well as monthly distribution and max number of charging events per charger and type of charging event (20, 40 and 60 kWh) over a year, see Tables 3.7 and 3.8 respectively.

Table 3.7.: Variation in amount of charging events in Norway per month [76].

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Deviation	0.94	0.84	0.63	0.85	0.89	0.99	1.28	1.04	1.04	1.30	1.19	1.02

Table 3.8.: Max amount of charging events occurring per 150 kW charger in Sweden over one year [76].

Charging event	20 kWh	40 kWh	60 kWh
Max occurrences	18 438	8 221	6 415

Only charging events of 150 kW were assumed to take place in this model and an equal distribution between 20, 40 and 60 kWh events. Also assumed was that every day throughout the year followed the profile shown in Figure 2.2. The amount of charging events per hour were calculated by dividing the occurrences in Table 3.8 over every day and splitting the amount of events over the hourly probability. These values were then given a monthly weight based on Table 3.7. To more accurately model the randomness of arriving drivers a random normally distributed value was generated for each data point with the previously calculated power demand used as the mean. A normal distribution of 2.5 was used for this purpose.

Battery and FC model

With the aim of this scenario being a DC fast charging station that is entirely provided with power from a battery and FC with no additional grid connection, or at least minimize these occurrences, the principle of the model control is to minimize events when the battery and FC are not enough to provide the required energy. However, since a grid connection is still required for the battery's max capacity it is always possible to still use the grid. How the model determines the state of the battery each hour the control hierarchy seen in Figure 3.5 is used.

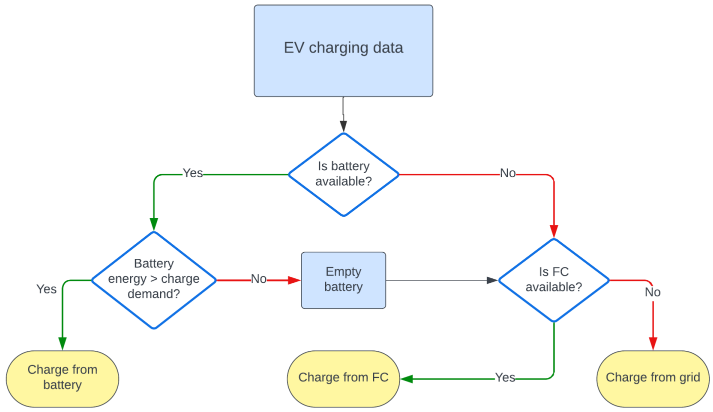


Figure 3.5.: DC fast charging station with battery and FC control diagram.

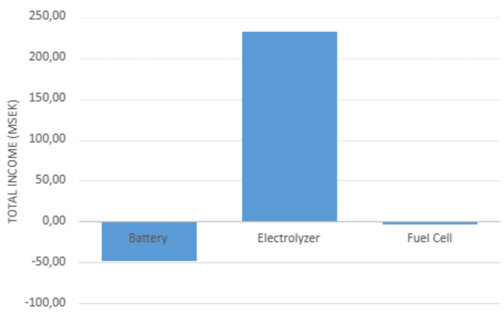
Chapter 4.

Results

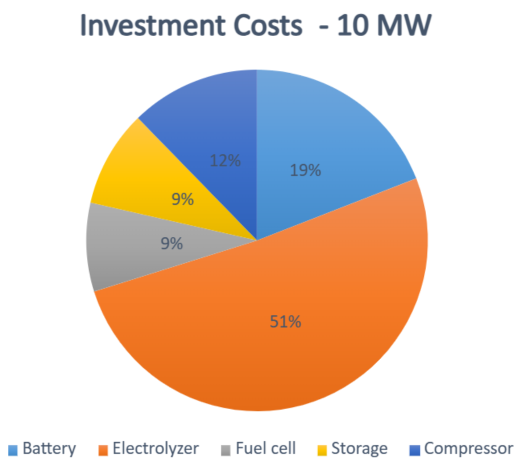
Results from each scenario is presented in this chapter. Both economical and operational results are presented. All results are produced from the Excel model described under *Model method*.

4.1. Spot price

A cash flow from each component was calculated by comparing total income with variable and fixed costs for the lifetime of each component, see Figures 4.1a, 4.2a and 4.3a for the 10, 0.5 and 0.1 MW cases respectively. Investment cost comparisons for each system size can be found in Figures 4.1b, 4.2b and 4.3b, which includes both initial investment costs and present value costs of reinvestments. These investment costs amounted to 216, 35.8 and 7.5 MSEK respectively.

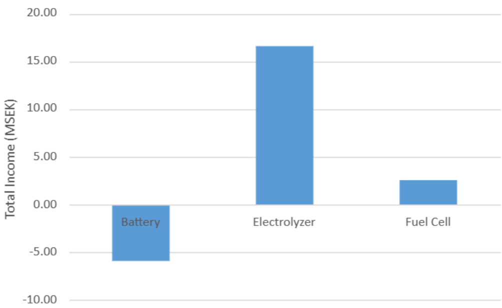


(a) Accumulated total cash flow years 0-20.

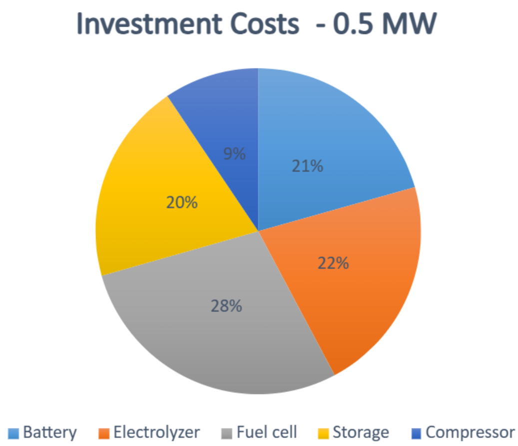


(b) Cost breakdown of total system investments, initial and reinvestments.

Figure 4.1.: System cost and income of 10 MW - Spot price.

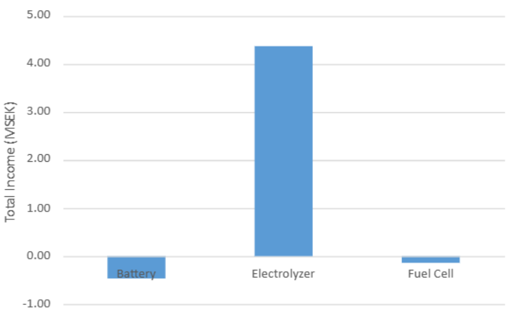


(a) Accumulated total cash flow years 0-20.

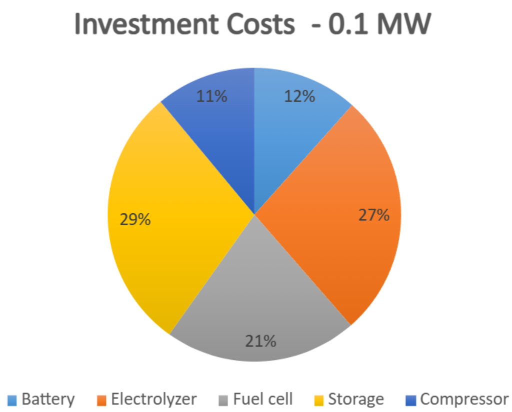


(b) Cost breakdown of total system investments, initial and reinvestments.

Figure 4.2.: System cost and income of 0.5 MW - Spot price.



(a) Accumulated total cash flow years 0-20.



(b) Cost breakdown of total system investments, initial and reinvestments.

Figure 4.3.: System cost and income of 0.1 MW - Spot price.

These results, presented in Figures 4.1-4.3, were given from the optimized bids shown in Table 4.1, which were found using the Excel solver. The similar bids for the battery led to very similar proportional outcomes for all 3 battery sizes, since the only difference between the three systems were the battery size. The hydrogen system had proportionally different component sizes for electrolyzer, FC and storage, and thus the results from these varied more in the three system sizes.

Table 4.1.: Optimized bids (SEK/MWh) in each of the three Spot price systems.

Component	Battery	Electrolyzer	FC
10 MW	660	670	2300
0.5 MW	650	520	2000
0.1 MW	670	580	2400

Using a discount rate of 8 %, a common value used by organisations such as the International Energy Agency for hydrogen projects [87], the NPV and LCOH was calculated. IRR and payback time were determined according to Equations 3.15 and 3.19, respectively. These results from each system size can be found in Table 4.2. The results show the negative economical outcome of the modeled systems, with only the large system having a payback time less than the system's economical lifetime of 20 years. Operational results of the year show that majority of active time the electrolyzer was operating at minimum capacity, missing out on much of the potential hydrogen production.

Table 4.2.: Economical analysis and operation results - Spot price.

Case	10 MW	0.5 MW	0.1 MW
NPV [MSEK]	-110	-35	-12
IRR [%]	-1.3	-	-
Payback time [Years]	17	>20	>20
LCOH [SEK/kg]	59	81	199
H_2 production [GWh]	28	1.4	0.14
Battery Cycles	530	530	530
Electrolyzer Operation time [% of year]	100	100	89
Electrolyzer Min. load [% of year]	61	60	49

4.1.1. Operation characteristics

Electrolyzer and FC operation are inherently dependant on the hydrogen storage status, with high storage status limiting electrolyzer operations and low status limiting FC activation. Due to the variation in hydrogen output between the systems the storage profile is very different for each case. Figures 4.4-4.6 show the hourly level of the three systems.

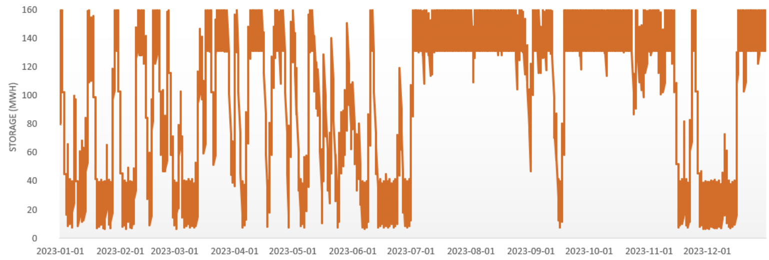


Figure 4.4.: Hourly storage profile of 10 MW system over the year.

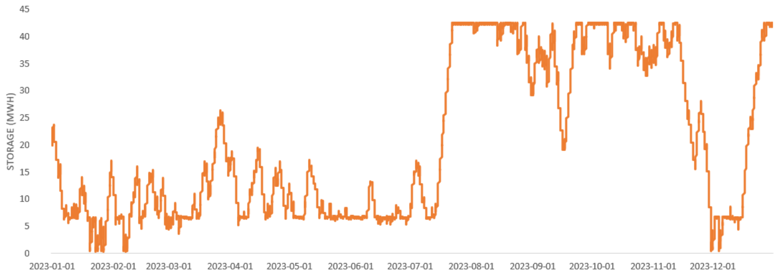


Figure 4.5.: Hourly storage profile of 0.5 MW system over the year.

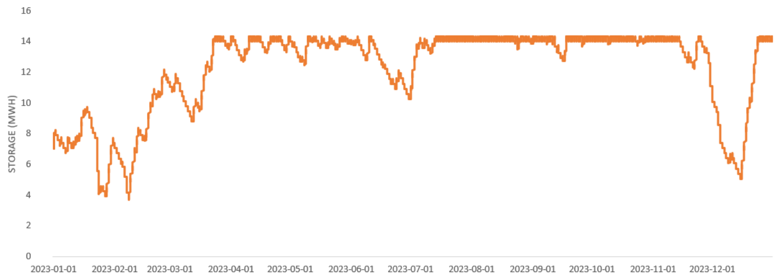


Figure 4.6.: Hourly storage profile of 0.1 MW system over the year.

In Figure 4.7 the operational behaviour of each component is shown during one week in January and how they relate to the spot price. During this week the FC is turned off every hour despite high spot prices, since the optimized bid was set even higher. The battery is charged during a few hours of the week, but there are many high spot price spikes were it has not been able to charge before due to high bid. The electrolyzer activation mostly follows the low spot prices.

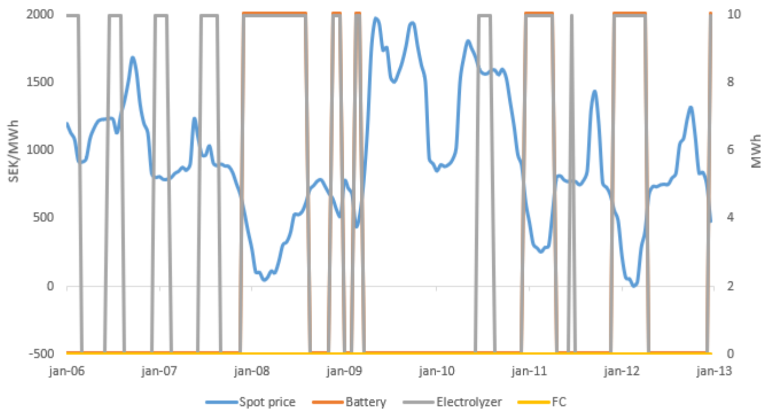


Figure 4.7.: Operational behaviour for one week in Spot price case - 10 MW.

4.2. Ancillary services and additional flows

With the inclusion of ancillary services and sold heat and oxygen to the model a new cash flow analysis was required. Incomes and costs divided on each category for year 1 can be found in Figures 4.8, 4.9 and 4.10 for 10 MW system FCR, aFRR and mFRR, respectively. Note that the battery is only included in Figure 4.8. Since it only sold capacity to the FCR and FFR markets it had the same results in all sub-scenarios. The battery is still included in each system's economical analysis later on. The cost component in these figures includes the annually reoccurring costs: electrical costs, water costs and fixed O&M. Year 1 incomes and costs for 0.1 and 0.5 MW systems are found in Appendix C.

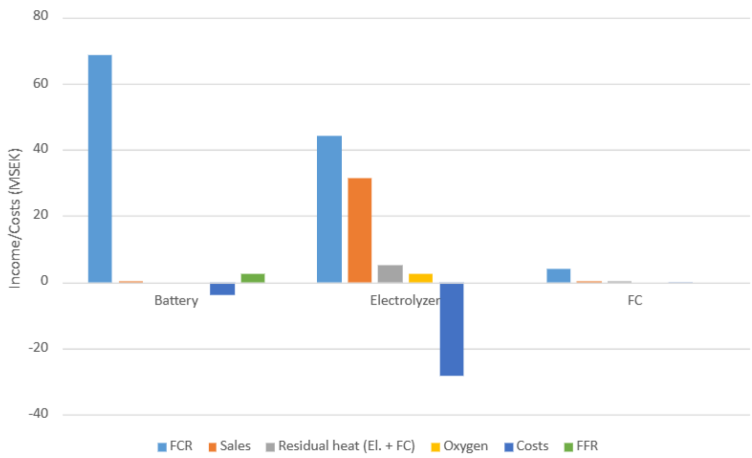


Figure 4.8.: Income and cost from battery, electrolyzer and FC in FCR case - 10 MW.

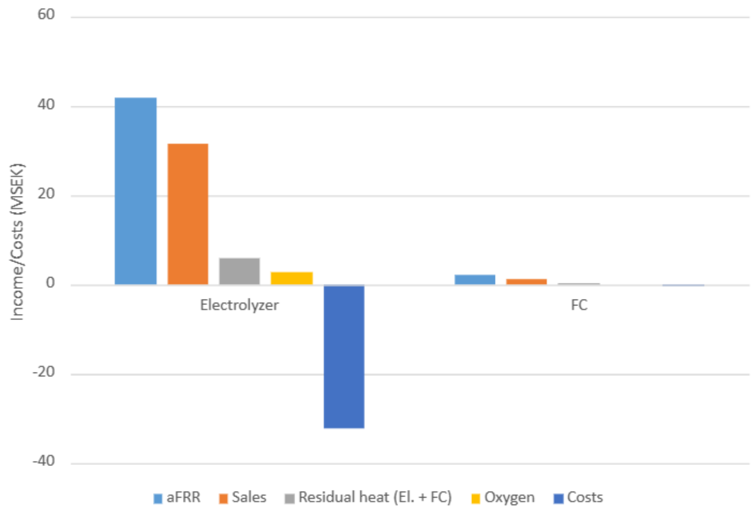


Figure 4.9.: Income and cost from electrolyzer and FC in aFRR case - 10 MW.

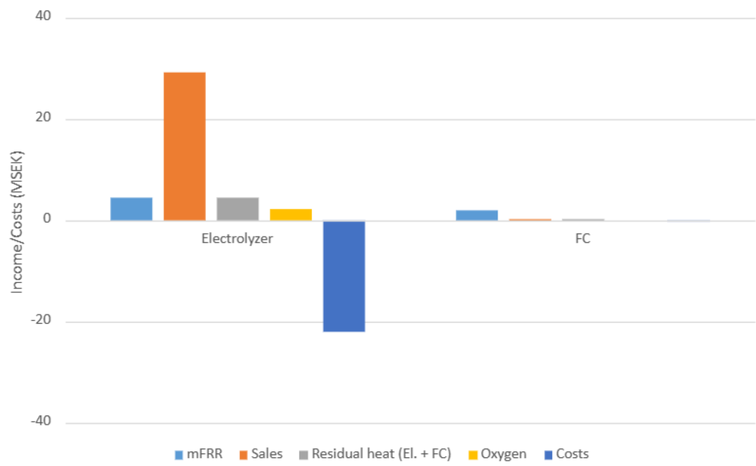


Figure 4.10.: Income and cost from electrolyzer and FC in mFRR case - 10 MW.

The battery was the the greatest profit driver in all the systems with both the greatest income from ancillary services. The greatest income from the electrolyzer component was seen in the FCR case, which had a greater total income than the battery but also a much higher yearly cost associated with it. The aFRR electrolyzer has an income comparable to the FCR, but the mFRR falls far behind with smallest ancillary service income. The FC has the lowest profitability of all components, but it should be noted that in the 10 MW system the FC is only 1 MW, which means that while the total income is smaller the proportional income can be higher. However, since the smaller FC was chosen due to its high indirect cost of using hydrogen, it is likely that with greater FC component a negative scale effect would be observed.

Set bidding prices for each service and spot price were determined using the Excel solver to maximize revenue over the year, which gave the results seen above. Resulting bids can be found in Tables 4.3-4.5 below.

Table 4.3.: Optimized bids for Ancillary services and additional flows scenario - 0.1 MW.

	0.1 MW El.	0.1 MW FC	0.1 MW Battery
FCR-D up/down [SEK/MW]	140/160	170/990	730/11
FCR-N or FFR [SEK/MW]	2000	-	1800
FCR, Spot price [SEK/MWh]	380	1600	2200
aFRR up/down [SEK/MW]	260/480	380/1000	-
aFRR, Spot price [SEK/MWh]	1400	2100	-
mFRR up/down [SEK/MW]	1200/420	0/2.3	-
mFRR, Spot price [SEK/MWh]	860	860	-

Table 4.4.: Optimized bids for Ancillary services and additional flows scenario - 0.5 MW.

	0.5 MW El.	0.5 MW FC	0.5 MW Battery
FCR-D up/down [SEK/MW]	1300/280	0/1000	1000/0
FCR-N or FFR [SEK/MW]	2500	-	1500
FCR, Spot price [SEK/MWh]	750	2500	2400
aFRR up/down [SEK/MW]	1700/0	2500/2000	-
aFRR, Spot price [SEK/MWh]	2200	2100	-
mFRR up/down [SEK/MW]	1500/600	700/1600	-
mFRR, Spot price [SEK/MWh]	670	2500	-

Table 4.5.: Optimized bids for Ancillary services and additional flows scenario - 10 MW.

	10 MW El.	1 MW FC	10 MW Battery
FCR-D up/down [SEK/MW]	940/78	70/1000	1500/39
FCR-N or FFR [SEK/MW]	1800	-	1800
FCR, Spot price [SEK/MWh]	1100	520	0
aFRR up/down [SEK/MW]	930/96	1000/660	-
aFRR, Spot price [SEK/MWh]	1600	520	-
mFRR up/down [SEK/MW]	930/96	1000/660	-
mFRR, Spot price [SEK/MWh]	78	600	-

Tables 4.3-4.5 point to down regulation services are preferable for battery and electrolyzer during 2023 with lower bids. The FC was the opposite with lower bids for upward regulation in most cases, with a few exceptions.

With the optimized static bids above the model returned the economical results found in Tables 4.6- 4.8. These were calculated according to Equations 3.15, 3.17 and 3.19. Also included are operational features such as hydrogen production and active time. Operation time refers to total time the electrolyzer is turned on and min. load time is the total time it runs at 10 % capacity throughout the year. Income for each component refers to the total income during year 1, from ancillary services, electricity, heat and oxygen.

Table 4.6.: Economical analysis and operation results - 0.1 MW system.

	FCR	aFRR	mFRR
NPV [MSEK]	4.5	0.58	-0.80
IRR [%]	20	10	5
Payback time [Years]	4.6	7.6	10
LCOH [SEK/kg]	160	95	120
Income battery [MSEK]	0.70	-	-
Income electrolyzer [MSEK]	0.60	0.38	0.07
-sold hydrogen [MSEK]	0.18	0.18	0.18
Income FC [MSEK]	0.39	0.32	0.29
H_2 production [GWh]	0.14	0.30	0.17
Battery Cycles	191	-	-
Electrolyzer Operation time [%]	100	100	89
Electrolyzer Min. load [%]	61	60	49
Ancillary service active - Battery [%]	98	-	-
Ancillary service active - Electrolyzer [%]	91	40	0.18
Ancillary service active - FC [%]	96	24	100

Table 4.7.: Economical analysis and operation results - 0.5 MW system.

	FCR	aFRR	mFRR
NPV [MSEK]	50	35	24
IRR [%]	44	33	26
Payback time [Years]	2.3	2.9	3.7
LCOH [SEK/kg]	80	81	71
Income battery [MSEK]	35	-	-
Income electrolyzer [MSEK]	2.2	2.6	0.46
-sold hydrogen [MSEK]	1.8	1.8	1.8
Income FC [MSEK]	2.0	0.15	0.48
H_2 production [GWh]	1.3	1.3	1.3
Battery Cycles	210	-	-
Electrolyzer Operation time [%]	100	100	89
Electrolyzer Min. load [%]	61	60	49
Ancillary service active - Battery [%]	98	-	-
Ancillary service active - Electrolyzer [%]	43	52	1.9
Ancillary service active - FC [%]	100	0.15	4.8

Table 4.8.: Economical analysis and operation results - 10 MW system.

	FCR	aFRR	mFRR
NPV [MSEK]	950	910	620
IRR [%]	59	57	42
Payback time [Years]	1.7	1.7	2.4
LCOH [SEK/kg]	72	67	75
Income battery [MSEK]	71	-	-
Income electrolyzer [MSEK]	52	51	11
-sold hydrogen [MSEK]	31	31	31
Income FC [MSEK]	3.9	3.1	2.3
H_2 production [GWh]	21	29	17
Battery Cycles	218	-	-
Electrolyzer Operation time [%]	100	100	100
Electrolyzer Min. load [%]	69	55	77
Ancillary service active - Battery [%]	99	-	-
Ancillary service active - Electrolyzer [%]	70	53	1.5
Ancillary service active - FC [%]	100	21	90

All three cases had positive financial outcomes, with very short payback time and high NPV and IRR. The LCOH values are quite high, with all systems having a higher cost than the selling price of hydrogen at 50 SEK per kg. Most systems produced a similar amount of hydrogen despite different ancillary service markets (within the same system sizes), with the exceptions being 0.1 MW and 10 MW aFRR, both of which produced 50-100 % more than the other systems of equal size. The electrolyzer had almost more than 90 % activation rate for all cases but the min. load operation was active over 50 % of the year at the same time. Time active on the ancillary service market varied greatly between system sizes, components and different markets.

4.2.1. Operation characteristics

The varying impacts of the balancing markets and unique obligations of each system size caused a different hydrogen storage profile for each case. Figures 4.11-4.13 show the hourly hydrogen storage levels of the FCR systems over the year for all system sizes. Systems 0.1 and 0.5 MW show similar patterns in low storage level over the summer and high during the winter/autumn, following high and low FCR-D prices over longer periods of time. The 10 MW system shows that the storage is low throughout most of the year; mostly with high production spikes when it falls under 30 MWh, the amount transported to the refueling station every 12 hours, when max. electrolyzer capacity always is activated.

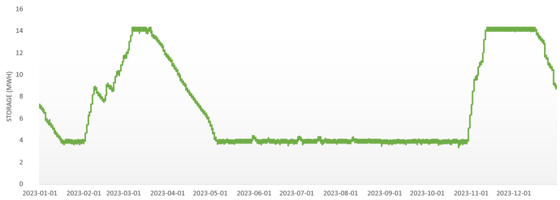


Figure 4.11.: FCR hydrogen storage level - 0.1 MW.

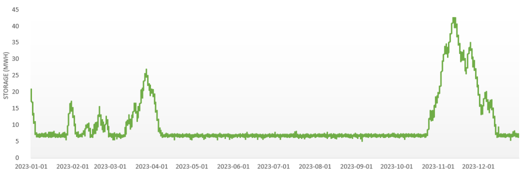


Figure 4.12.: FCR hydrogen storage level - 0.5 MW.

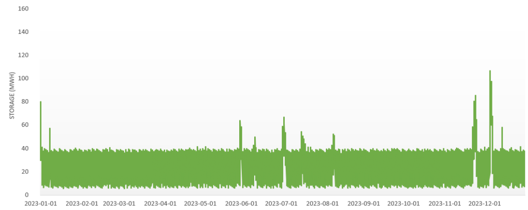


Figure 4.13.: FCR hydrogen storage level - 10 MW.

In Figures 4.14-4.16 the hydrogen storage level of the aFRR sub-scenarios are shown for each of the system sizes. Some common features can be found in all three systems; the low production during summer months and high production during autumn and early winter.

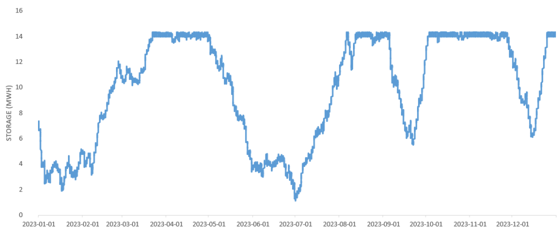


Figure 4.14.: aFRR hydrogen storage level - 0.1 MW.

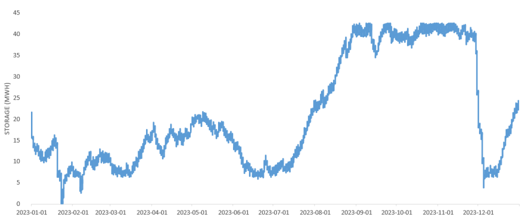


Figure 4.15.: aFRR hydrogen storage level - 0.5 MW.

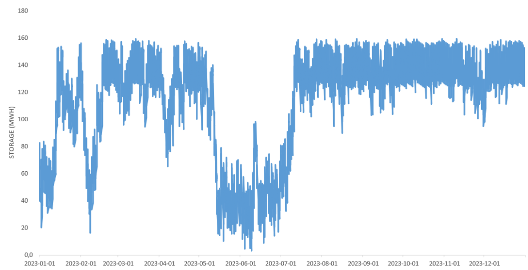


Figure 4.16.: aFRR hydrogen storage level - 10 MW.

In Figures 4.17-4.19 the hydrogen storage level of the mFRR sub-scenarios are shown for each of the system sizes. There are very few common features between the three systems, with the small one having high storage levels throughout the whole year, medium system mostly keeping high storage level but with periods of low production, and the large system which mostly has a low storage level but showing some spikes of high production.

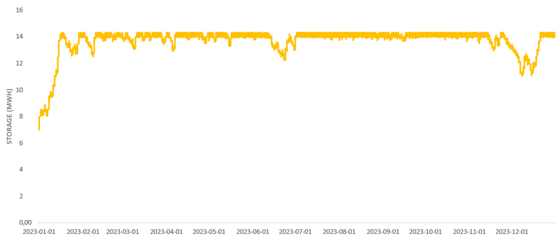


Figure 4.17.: mFRR hydrogen storage level - 0.1 MW.

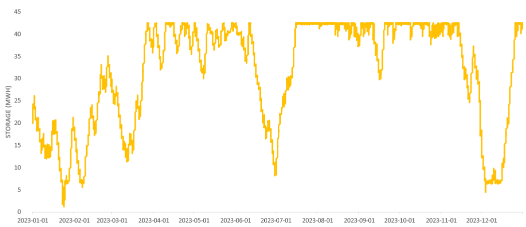


Figure 4.18.: mFRR hydrogen storage level - 0.5 MW.

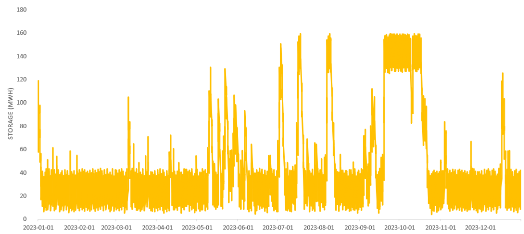


Figure 4.19.: mFRR hydrogen storage level - 10 MW.

In Figures 4.20-4.22 the operational profile of each component in the 10 MW systems are shown for a week in January. Since the battery's operation profile is identical in each system this was only included in the FCR system (Figure 4.20). Additional profiles of sub-scenarios not included here are found in Appendix B.

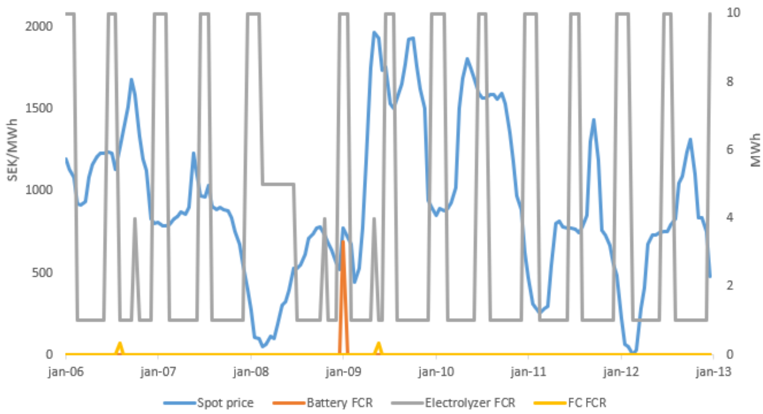


Figure 4.20.: Operational behaviour for one week in FCR system - 10 MW.

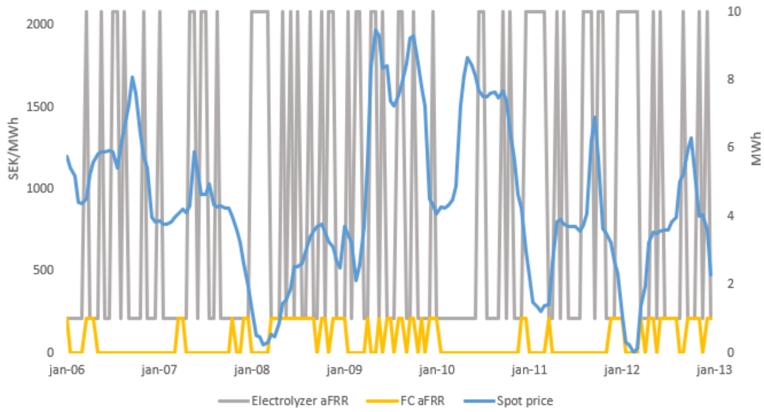


Figure 4.21.: Operational behaviour for one week in aFRR system - 10 MW.

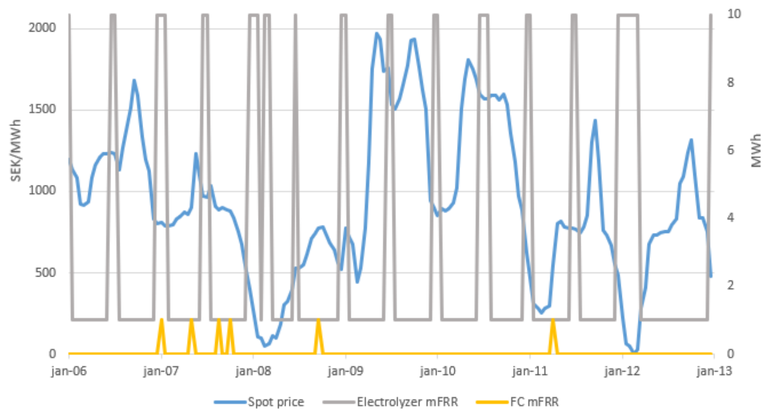


Figure 4.22.: Operational behaviour for one week in mFRR system- 10 MW.

Figures 4.20-4.22 show that there is no discernible trend between component operation and spot price anymore. The battery and electrolyzer are both operating at down markets throughout the entire week, except the few hours that FCR-N is active during January 8th and when the electrolyzer has to produce at max. capacity to fill hydrogen storage (a maximum of twice daily). The FC is active on the up regulation markets throughout most of the week. Operational variation is most distinct for aFRR, which has a much higher activation frequency than both FCR and mFRR. The shorter FCR spikes for the battery and FC represent the 20-min activation time for this service; i.e. the full activation is limited to 20 minutes which in the model is represented by the hourly average, or a third of the total capacity.

4.3. Charging station

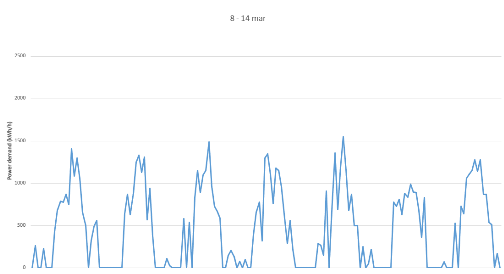
The scenario Charging station explored the ability of a 1-hour battery and FC to act as main power providing units for a DC fast charging station. A grid connection of the scale required for the modelled charging station with battery (3 MW) in Trelleborg specifically, as well as construction costs of one such station, can be found in Table 4.9.

Table 4.9.: Investment and annual costs of the DC fast charging station (20x150 kW).

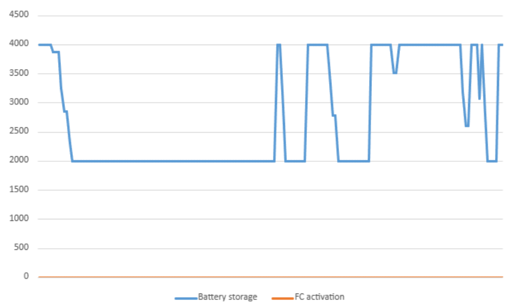
	Construction (DC chargers)	Connection
Investment costs [MSEK]	7.0	3.9
O&M [MSEK/year]	0.7	1.5

Using the system represented in the model means that the charging station will be constructed where there already exists a battery with a grid connection and subscription.

Two example weeks are shown in Figures 4.23 and 4.24, representing the months with least and most amount of charging events per charger. Figures 4.23a and 4.23b show the power demand profile and battery level/FC activation for the week in March. The same are shown for the week in October in Figures 4.24a and 4.24b. The battery/FC system should be able to provide power to the charging ports each hour, otherwise the battery empties and the final power is provided from the grid directly without charging the battery. One such event can be seen during day 3 in October in Figure 4.24b.

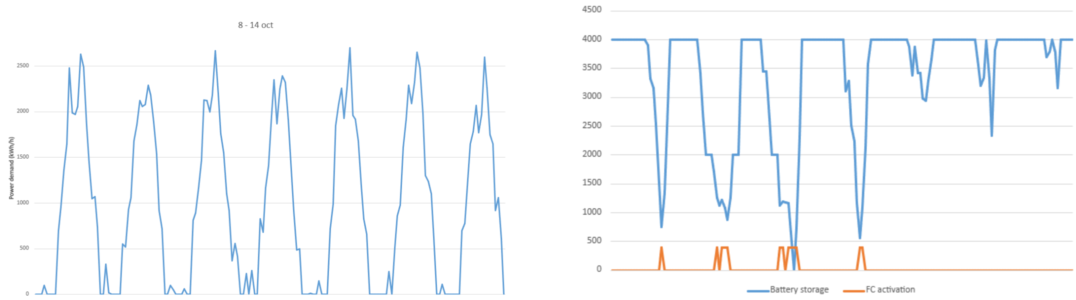


(a) Power demand of the 3 MW (20x150 kW) charging station during one week in March.



(b) Battery storage level (kWh) and FC activation (kW) during the same week in March.

Figure 4.23.: Representation of the charge demand profile (a) as well as battery level and FC activation (b) over the same week in the month where the least amount of charging station usage occurs.



(a) Power demand of the 3 MW (20x150 kW) charging station during one week in October.

(b) Battery storage level (kWh) and FC activation (kW) during the same week in October.

Figure 4.24.: Representation of the charge demand profile (a) as well as battery level and FC activation (b) over the same week in the month where the highest amount of charging station usage occurs.

In addition to the saved costs on the subscription and construction of additional grid capacity for the DC fast chargers there is also a revenue stream from the sold electricity. The resulting profit depends on the purchasing of cheaper electricity to charge the battery and the cost of the hydrogen. Electricity was bought from the grid to charge the battery when the spot price was under the yearly average (740 SEK/MWh) and the hydrogen for FC price was assumed to be 90 SEK/kg. Model results for income, costs and operation are found in Table 4.10.

Table 4.10.: Income, costs and operational characteristics of the DC fast charging station.

Energy sold [MWh]	6700
Electricity costs [MSEK]	4.8
- without battery [MSEK]	5.1
Hydrogen consumption [MWh]	24
Hydrogen costs [MSEK]	0.12
Income [MSEK]	21

With 6,700 MWh sold means an average occupancy of 25 % over the year. The electricity costs are the cost of charging the battery in real time according to spot pricing and without battery would be the costs if the charging station used the grid directly. This showed savings of 250,000 SEK, or 37 SEK/MWh. Since hydrogen is not produced on site it was assumed to be bought for a price of 90 SEK/kg from a third party. The income was calculated from the average customer being charged 3,250 SEK/MWh.

Chapter 5.

Sensitivity analysis

5.1. Yearly variation 2021-2023

In this section the model will instead be based upon market data from 2021 and 2022 and comparing the incomes and costs from each year with results from 2023. This analysis will only cover the 10 MW ancillary service case looking at FCR markets and will exclude residual heat and oxygen production. This is because the ancillary services is the main focus of this sensitivity analysis and are the parameters that see the largest change based upon the market conditions.

Ancillary service results from each year is presented in Table 5.1, including both income and active time for each component.

Table 5.1.: Ancillary service income and operation for 2021-2023.

	2021	**2022**	**2023**
Battery			
FFR [MSEK]	15	16	2.5
FCR-D up [MSEK]	51	37	0.0
FCR-D down [MSEK]	1.5	0.0	68
Total [MSEK]	68	53	71
Active time [% of year]	97	99	98
Electrolyzer			
FCR-N [MSEK]	1.2	0.0	1.7
FCR-D up [MSEK]	16	14	0.35
FCR-D down [MSEK]	3.6	0.0	42
Total [MSEK]	21	14	44
Active time [% of year]	36	53	100
FC			
FCR-D up [MSEK]	5.9	4.0	3.9
FCR-D down [MSEK]	0.0	0.0	0.0
Total [MSEK]	5.9	4.0	3.9
Active time [% of year]	100	100	100

Electricity costs and operational characteristics are presented in Table 5.2.

Table 5.2.: General income, cost of operation and operational characteristics for 2021-2023.

	2021	**2022**	**2023**
Battery			
Electricity costs [MSEK]	-0.28	-0.22	-0.026
Cycles	85	66	218
Electrolyzer			
Electricity costs [MSEK]	-45	-25	-23
H2 production [GWh]	21	21	21
Max load [% of year]	40	43	31
Min load [% of year]	31	13	69
FC			
Electricity income [MSEK]	0.0	0.0	0.0
H2 usage [MWh]	48	45	42
Activated [% of year]	1.0	1.0	0.90

5.2. Maximum production and market capacity

This section is meant to give a picture of the limit of the components if they were not constrained by the rules set for them in the model, i.e. produce hydrogen and sell electricity from FC the entire year. An arbitrary system size of 1 MW was chosen, only the electrolyzer and FC are investigated since the battery does not benefit from this type of investigation. This is presented in two tables below. The first one, Table 5.3, presents the maximal production capacity of the electrolyzer and income from FC if they were operational the entire year at 1 MW capacity. The second one, Table 5.4, shows maximum earnings from each balancing market over 2023 with 1 MW capacity.

Table 5.3.: Hydrogen system max usage for 1 MW capacity.

	Max. case	**Base model**
Electrolyzer		
H2 production [GWh]	5.7	2.1
Average electricity price [SEK/kg]	40	24
FC		
Income [MSEK]	6.5	0.13
H2 usage [GWh]	15	0.080
Income per GWh H2 [MSEK]	0.44	1.6

Table 5.4.: Maximum income from each ancillary service market with 1 MW capacity in SE4.

	Income [MSEK]
FFR	0.4
FCR-N	6.7
FCR-D up	3.9
FCR-D down	7.1
aFRR up	2.4
aFRR down	3.6
mFRR up	0.33
mFRR down	0.13
Energy market up	7.4
Energy market down	5.4

Table 5.3 show that there is potential to use both the electrolyzer and battery more than in the modeled scenarios, but at substantially lower income per produced/sold unit. Table 5.4 shows that the downward regulation markets were mostly more profitable than the upward regulation in 2023; with the mFRR and energy markets being the exception.

Chapter 6.

Discussion

This chapter aims to provide an overall discussion of the work carried out during this thesis. First, a section discussing the model itself in regards to functions, assumptions and limitations. Secondly, a section solely discussing the model results provided from each scenario modelled.

6.1. Method and model

This section will discuss the created Excel model in regards to function, assumptions and limitations.

6.1.1. Model functions

The model was created with the goal of doing a techno-economical analysis of a single year's operation of the battery-hydrogen system, providing results both in regards to financial factors but also operational values. To do this it determines the components operation each hour based upon gathered data of electricity markets. The logic for how the model determines each state was described and shown in the control diagrams in the method and Appendix A. While the control diagrams are the same for all component sizes, the different obligations and component proportions meant that results from same balancing market could vary greatly for the three system sizes.

The determining parameters are the bids or set prices which are constant over the year and are optimized to provide the best income from each component. Using a set value for when to activate and disable components is a gross simplification of reality. The operation of a real system depends on the obligations, such as hydrogen demand, which can vary greatly depending on current demand. Using only one hydrogen market, in the form of the hydrogen refueling station or refueling of a small vehicle fleet, will only occupy a small portion of the total capacity. This can be seen in the sensitivity analysis in Table 5.3, giving system operation a high degree of freedom. How often the electrolyzer operates at minimal load while selling the ability to ramp up production quickly is also an indication of the operational freedom of the component. The battery was only limited by whether it had charge or not, which was easily managed since both FCR and FFR only required a portion of the stored energy when activated, so after a bid had been accepted there was always time to set correct SoC before delivery.

By optimizing each component an optimal operation was found, from an economical perspective, which takes into account the markets with the highest monetary return while still meeting the demand of either hydrogen delivery or other market operations (such as providing FFR over FCR for the battery). This method is only viable on past data since the complexity and volatility of these markets would result in a set bidding price based only on historical data to become outdated. Supplementing the model with forecasted market pricing would be a better option, and an operator would need to determine the ancillary service market bid depending on both short term and long term obligations as well as storage status.

The model's method for selling hydrogen, with two containers' worth of hydrogen emptied twice daily, is only a simple approximation. This method only takes into account the yearly obligation and distributing it equally over the year. The variation in demand over days, weeks and months as well as storage capacity/available space at the refueling stations could be included for a more accurate representation of how to operate the electrolyzer and FC.

6.1.2. Assumptions and limitations

Several assumptions and limitations were made during the model construction. These relate both to how the model operates as well as the underlying input parameters.

When constructing the model logic it was assumed that since there are two closing times for most capacity markets an actor would be able to first try to sell their capacity on one market, and if that failed then there would be an attempt at the other market. This is only viable since the model is based upon historic data. A more accurate representation of a real time operator determining how to operate the system would need to create an algorithm which takes into account both electricity prices on relevant markets (day-ahead, obligation) and forecasted ancillary service market pricing both on the first and second day. It was also assumed that energy bids always won when activation occurred, which was modelled according to historical data.

The model has not taken into account the specific operation of the components but instead relied on literary and manufacturer sources for possible operation. With such simplifications many nuances of real operation are lost. Aspects such as maintenance time, short-term deviations and how the components are managed (start/stop sequencing, temperature maintenance, ancillary components, etc.) are not taken into account for the operational profile, only in the cost analysis. The start/stop problem of the electrolyzer was partially solved by limiting many of the control sequences to operating it at minimal load instead of shut off, but this does not accurately represent a real electrolyzer which sees a more nuanced variability of the operational profile.

When sourcing data to use in the model some issues were made apparent. One problem was the mFRR capacity market which began in October 2023 in Sweden, which meant much of the year it was selling capacity to DK2 market where only up capacity was bought. This is related to another issue regarding all ancillary services (except FFR): the electricity area of the sold capacity. Since the focus of this thesis is on a system in Trelleborg in SE4 a potential strategy would be to limit the bids to only SE4 and the connecting SE3 and DK2. This could be useful from a perspective of where the grid is known to have few choke points, but it is not an actual representation of a future capacity market. The capacity per electricity area is only a representation of where the historical capacity has been sold and does not represent an actual limitation in the grid, but instead is based upon where the most competitive units are located. E.g. hydro power, which is the largest balancing power capacity provider, is located almost entirely in SE1 and SE2. In the model it is assumed that if the bid is less than any bid in Sweden or DK2 then it will be able to act on the ancillary service market in the order SE4 > SE3 > DK2 > SE2 > SE1. For mFRR, where the price is different for each pricing area, it first checks SE4 then SE3 and finally DK2 until an accepted bid is achieved. For the energy market SE4 pricing was always used since this is available for every hour, even when no energy is delivered in a specific area.

Other simplifications were made for the process flows as well. These mainly include the assumption of flat rates throughout the year. Not just sold hydrogen is affected by this, the residual heat and oxygen demand are also variable markets. In the model it is assumed that there always is a customer for these by-products based on the lower selling price of waste heat than biofuel district heating (as is the case in Trelleborg). For a nearby wastewater plant the oxygen from the electrolysis would have to be cheaper than pumping air. Especially the waste heat could be misleading by assuming sold capacity over the entire year since in the summer the pricing and consumption is very low, which if taken into account would result in lower heating sold over the year. To take into account the district heat price variability an average value for 2023 prices in Trelleborg was used. For the oxygen production it should also be noted that not all electrolyzers have the ability to separate the oxygen flow for other uses so this has to be taken into account when choosing the component.

With only spot pricing as model base, aspects such as grid costs and compensations, as well as electricity taxes are missing, which impact both bought and sold electricity. Since electricity is both produced and sold, some of these costs could be neglected. Especially if they both are behind the same meter, network costs could be reduced if not neglected. Specific costs and compensations depend on grid owner, but they can be expected to be significant and drive up the pricing of the produced hydrogen. The battery is not as affected since this unit both buy and sell electricity, so the compensation might equal out the extra costs. However, without further investigation it is hard to give a more accurate total system impact.

6.2. Model results

6.2.1. Spot price model

Results from the Spot price model are meant to represent a case were hydrogen to vehicles and electricity to grid are the sole income. These are fundamental parts of the components and isolating these give an overview of a barebones system without any other economical pathways included. This is not meant to represent the real system since it is limited by not only other income drivers but also in the amount of sold hydrogen. The battery in this case only tries to find highest margin possible for buying and selling the electricity at different hours with a set price point; the electrolyzer tries to meet the sold hydrogen obligation at the lowest possible price and the FC maximizes the revenue from sold electricity minus the increase in hydrogen production costs. Especially the battery is not appropriate for buying and selling electricity only.

None of the three modelled systems were profitable as can be seen in Table 4.2 with negative NPV and IRR, long payback time and mostly high LCOH. The large difference in in LCOH between the 0.1 MW compared to the 0.5 and 10 MW systems is likely the relatively smaller hydrogen production in the 0.1 MW system. The poor overall performance can mainly be attributed to the high investment and fixed O&M costs for each component. Especially bad were the 0.1 MW results which, while making a positive variable profit, ended up with a negative cash flow for each component. The accumulated cash flow over the years 0-20 shown in Figures 4.1a, 4.2a and 4.3a also includes the degradation of the electrolyzer (1.25 % per year) and FC (1 % per year) and shows that it is mostly the electrolyzer which contribute to any positive income despite large reinvestments.

The electrolyzer was the largest income source in all systems, and only in 0.5 MW did the FC also contribute with positive profit whereas the battery was negative in all cases. The battery was limited by the margin in buying electricity cheap and selling it expensive, giving a profit lower than the fixed O&M. A profit increase could be found with more than one price point for buying and selling electricity, allowing for larger margins. The FC also had a very small profit compared to its O&M, despite it not accumulating any variable O&M since the hydrogen production cost was attributed to the electrolyzer.

In the Spot price scenario no control for avoiding start and stop events of the electrolyzer is implemented, as can be seen in Figure 4.7 where the electrolyzer is turned on and off 11 times over the week; even more frequently during weeks with more variable electricity pricing. Especially troubling are the short spikes seen during January 9th and 11th which causes unnecessary strain on the stacks. Spot price variability can thus also be linked to the chaotic behaviour of the 10 MW system's hydrogen storage in Figure 4.4. Figures

4.5 and 4.6 for medium and small systems show that the medium system varies a lot during the first half of the year, but then similar to the small system, keeps it at high levels. The exception, which is seen in all systems, is the dip during the last part of the year when electricity prices were high during a long period of time, resulting in higher FC activation but lower electrolyzer operation.

The profile in Figure 4.7 also shows the problem with buying and selling electricity with the battery based upon the same bid, with it buying electricity during price drops and selling during increases instead of during valleys and peaks. The same problem does not impact electrolyzer and FC since these only turn on or off depending on the price, but this does not mean that variable pricing would negatively impact the hydrogen components. Electrolyzer operation from variable bidding could allow for greater planning of when to produce hydrogen, decreasing the amount of times the electrolyzer has to produce at maximum capacity to meet obligations.

6.2.2. Ancillary services, heat and oxygen

In the ancillary services model hydrogen to vehicles still took priority over ancillary services in the control schemes to make sure hydrogen transportation always occurred. Electricity to grid was left as a last check after all other options were exhausted. Figures 4.8-4.10 show every part of the cash flow year one (modelled year) for the 10 MW case; the other system's year 1 cash flows are found in Appendix C. The ancillary services contributed with the largest income flow in almost all cases, with only the sold hydrogen being comparable. This shows that selling ancillary services could realise green hydrogen technology when otherwise unprofitable.

As opposed to the Spot price scenario almost every modelled system selling ancillary services had positive outcomes from the economical analysis. Based upon only balancing market performance the battery was the component with the highest income, followed by the electrolyzer and lastly the FC. When looking at total income the battery was only comparable with electrolyzer on FCR and aFRR markets, both of which had a higher total income, with mFRR netting a much smaller income. However, when including cost of operations the battery had the highest profit since it did not have a large variable cost component as opposed to the electrolyzer's electricity cost. The battery being the highest income is explained by it not being limited by any obligations which are not related to the ancillary service markets.

Model results show that the most profitable market for the combined system was FCR followed by aFRR then mFRR, with FFR being limited by very few active hours over the year. This result is not entirely unexpected since FFR and FCR-D have the highest requirements followed by FCR-N and aFRR, and lastly mFRR, meaning fewer possible actors. This is supported by the sensitivity analysis of maximum market income shown in Table 5.4. However, it is not only the market potential that determines the most profitable system; the limiting factors and obligations such as hydrogen storage capacity, hydrogen demand, minimum storage status and possible operation dynamics play a large part for the individual components.

An example of the model constrains at work is the electrolyzer component where the theoretical maximum income is from FCR-N with energy markets. Likely due to limited storage capacity the model instead found it more profitable to sell electrolyzer capacity on the FCR-D down market where the electrolyzer operates at minimum load while still fulfilling obligations. The minimum operation can also be seen in the hydrogen storage profile in Figure 4.13, were the storage is close to empty throughout the year. However, it is hard to draw any concrete conclusions about how large hydrogen storage should be constructed from this since the yearly variation in balancing markets (Table 5.1) might mean a completely different profile next year. Also here the fixed bidding could be limiting possible operation; a greater load variety could increase the utilization of the storage over the year.

The 10 MW aFRR system is almost as profitable as the FCR system despite a much lower maximum income from the capacity market. This is likely due to the energy market income from the electrolyzer which mainly operates at aFRR down. The high energy market income is because of high activation frequency and the 9 MW capacity which is sold (compared to FCR-N which only is 4 MW). This also means that the FC will be used less often since actual activation of this component often is a net loss due to hydrogen consumption. For the 0.5 and 0.1 MW systems the aFRR sub-scenario is not as comparable to the FCR. The 0.5 MW aFRR system works similar to the 10 MW with down regulation being prioritized, as can be seen in the bids in Table 4.4; but for the 0.1 MW case the strategy is completely different with very similar bids for both up and down markets. This might be due to the comparatively smaller hydrogen obligation in the 0.1 MW system, allowing for even more freedom of hydrogen component operations.

Hydrogen storage is an expensive component, especially so when in compressed vessels. Decreasing the storage capacity could be one way to save on costs, but the impact on operations needs to be considered. As was briefly discussed above, some cases are more viable than others. From the operational profiles in Figures 4.11-4.19 most cases use the entire storage capacity to a certain degree and reducing storage size would have significant impact on the electrolyzer and FC operations. An alternative solution for the large system that was mentioned by Lhyfe was only using mobile containers that are placed at the refueling stations, so instead of a limited on site storage in the model the entire container fleet could be considered. For the small and medium systems the storage capacity is instead limited by the requirements at the site and local fleet refueling needs. But these are very small in comparison to the storage size in both system sizes. Especially the 0.1 MW system storage could be reduced in size for higher profits, but it should be weighted against the advantages of having large quantities of hydrogen available in storage.

The hydrogen storage profiles are defined by the prices and specific characteristics of each balancing market. The FCR cases, Figures 4.11-4.13, show how the electrolyzer runs at mostly minimum load, with a few hours each day having to produce at maximum capacity when the storage becomes too low. The spikes when the storage is more full are times when FCR-D down is not activated as much due to low prices on that market. For the mFRR systems hydrogen storage profiles in Figures 4.17-4.18 a sort of reverse of the FCR can be seen with a higher percentage being full instead of empty. The exception is the large system in Figure 4.19 which is very similar to 10 MW FCR system. A likely explanation for this is that the electrolyzer capacity is sold as ancillary service to a much lesser degree than the other cases. The aFRR system sees the most changing load, with hydrogen level varying between full and empty many times. This is likely an effect of the high activation degree to which the electrolyzer goes from minimum to maximum load.

Operation profiles in Figures 4.20-4.22 show how the battery and FC both act on the ancillary service markets by being empty/on-standby by providing down or up regulation, respectively. In contrast, the electrolyzer variation is drastic. This could be explained by the low storage level, seen in Figures 4.13, 4.16 and 4.19, which means that the electrolyzer must be turned to nominal load at many instances for a short while to bring the storage over minimal allowed hydrogen level. However, the very short (1-hour) 10 MW spikes for the aFRR might also be attributed to the high activation frequency. The high electrolyzer variation from 10-100 % could also be problematic. With the model adjusted for minimizing stop and start events no consideration for this type of load variations were taken into account. Varying the load this many times each week could be a concern for further degradation. Using an optimized stack operation that manages the power to each stack is a solution to minimize potential degradation.

In addition to ancillary services this scenario also looked at potential income from residual heat and oxygen. Residual heat especially has the potential of making green hydrogen production more profitable when there is district heating or similar demand that can accept the heat. For the small systems it is always a good idea to integrate it into the building's heating system if possible, to maximize efficiency. This is mainly due to the high percentage of both the electrolyzer (20 %) and FC (30 %) electricity usage that becomes waste heat and otherwise becomes losses. The optimal scenario would be to directly sell the low quality heat, but as the 10 MW scenario results show it is also viable to buy a heat pump if required.

The oxygen is not as obvious. It both has a lower production value per kilogram of hydrogen and faces larger issues in regards to transportation and use. While heat demand is not a certainty, especially during summer, oxygen demand is a scarce market. Trelleborg has two potential use cases, only one of which might see a monetary value. Oxygenating the Baltic sea is a good environmental use case but not a financial one. Selling it to the planned water treatment plant has in literature been identified as a good income source, but this is only if the electrolyzer is situated nearby and requires that the waste water treatment plant is willing to pay for it. None of these situations are a foregone conclusion in Trelleborg, which would make the 2-2.5 MSEK oxygen revenue a lost income.

The economical analysis of the system has been carried out on all components together, but the system model is mostly a collection of several separate units that act individually. Hydrogen storage is an exception which is one of the main limiting factors for the electrolyzer/FC operation. The FC is the only component which is hard to operate by itself because of hydrogen requirements.

Looking at each component individually shows a large difference in impact on the financial outcome. In all cases the battery is the largest income driver, with its ancillary service revenue, while at the same time being the proportionally cheapest component at 5-12 MSEK/MW compared to electrolyzer (12-20 MSEK/MW) and FC (22 MSEK/MW). The battery is also the most independent component in this model and would constitute a good investment by itself, assuming 2023 FCR-D and FFR market conditions. FCR-D is the most important market for the battery due to capacity being bought all hours of the year. FFR has the highest income per activated hour, and almost no actual energy moved.

The FC's financial results are a reverse of the battery's, with both highest relative investment cost and lowest return on investment. While the direct cost of running the FC is not high, the indirect cost in the form of hydrogen consumption is substantial which is not helped by the stacking losses occurring both in the electrolyzer and FC. Lenntoft and Rapp found that when excluding the FC from their 10 MW systems it improved the financial outcome in every case.

One of the primary purposes of the systems in Trelleborg is to create use-cases of green hydrogen, making the electrolyzer the most vital component. Electrolyzers are expensive components and combined with high electricity prices results in high production costs, a hard sell for industries that are built around using less expensive hydrogen with fossil origins. The model's LCOH results vary from just over the hydrogen selling price of 50 SEK per kg to substantially more, spanning from 59-199 SEK/kg. The lowest LCOH are in the 10 MW Spot price scenario where it can produce almost all hydrogen during low spot pricing hours since no other factors determine the operation. With ancillary services the hydrogen production is more probable to occur during high cost hours. However, investment costs and fixed O&M result in higher LCOH when hydrogen production is low, so with a higher FC activation some systems see a reduced LCOH because of the higher hydrogen demand.

6.2.3. Charging station

The purpose of the Charging station scenario is to look at an alternative usage of a large grid connected battery as opposed to ancillary services. This model scenario would thus make use of an already existing grid connection which would cost 5.2 MSEK. The spot price scenario showed that only buying and selling electricity is not a profitable venture. By instead using the battery as a supporting device for a DC fast charging station it could provide a function of both providing cheaper electricity and a more constant power demand from the grid. The results from this model showed that there was some gain by moving the electricity bought to cheaper hours, 250,000 SEK over the year, but still a small amount compared to the 21 MSEK in total income from the charging EVs. This is not as profitable as the ancillary service scenario with FCR-D and FFR, which had an income of 7.1 MSEK per MW compared to the charging stations 5 MSEK per 1 MW battery and 0.1 MW FC. It should also be noted that using the battery for the charging station causes much more strain since the battery is in constant use, resulting in more frequent battery changes.

A limit of using hourly averages in the model is that it could not show the reduction in power demand spikes against the grid that a DC fast charging station without a battery is plagued by. And since it was controlled to buy electricity to keep it at 50 % SoC or higher when possible, it often bought electricity at the same time as the charging occurred, although to a lesser degree. With hourly data the model could not capture the single charging events, which are the main problem for grid stability. The hourly precision instead required an hourly average energy demand instead of instantaneous power. From Figures 4.23a and 4.24a we see that the peak demand only last for a few hours, so increasing the battery's energy capacity would alleviate how often the battery requires charging. This could also be a solution for decreasing the battery to charging station capacity ratio, which was 4 MW (battery) to 3 MW (charging station). This ratio was chosen since a 1-hour 3 MW battery would be emptied too fast which resulted in direct grid charging significantly more hours of the year.

Since the use case of this scenario was a comparison to large system in the other scenarios a large DC fast charging station was required to match the 4 MW/4 MWh battery and 0.4 MW FC. This station is out of proportion for a small city like Trelleborg, which means that the power demand profile might not match the current situation. With increasing penetration of EVs the demand on fast chargers will also increase, making this a more reasonable for the future. Using 2023 data would then not be representative, but it is uncertain whether the load profile will be much different in the future. If the electricity market were to become more volatile than 2023 spot prices this would increase the value of displacing consumption with the battery, but a more stable market would negatively impact the battery's profitability.

Chapter 7.

Conclusions

The main conclusions from the study are presented in this chapter, these are specifically based on the result from the literature overview performed and the model which was based on 2023 data. The conclusions are thus also commenting on the 2023 data when not otherwise specified. These are summarised in the following list.

- Out of all the capacity and energy ancillary services, FFR, FCR-D, FCR-N, and FRR, batteries are able to provide every service while both electrolyzers and FCs are able to provide every service except FFR, for which they are too slow. However, each component is not appropriate for every service; for example, the battery is most appropriate for the fastest services, FFR and FCR-D.
- Acting in the ancillary service markets and including additional income streams increased the profitability of all three system sizes (0.1, 0.5, and 10 MW). When compared to only the spot price scenarios, where all systems had negative economic parameters, the additions in the ancillary service scenario resulted in almost all systems becoming profitable.
- Ancillary services, residual heat, and support for DC fast charging stations are all possible additional revenue streams for the hybrid hydrogen and battery energy storage systems examined in this report, located in Trelleborg. Oxygen from large-scale hydrogen production is a possible avenue, but no definite income from this has been found for these systems.
- The most profitable ancillary services for all components are the FCR-D markets, with high capacity market prices and high availability over the year. This was also supported by the low activation frequency of these markets, so that the components were not operated at the less optimal level for as much of the time. The most profitable single component was the battery, which had the greatest freedom to sell its capacity on the ancillary service markets.
- For the hydrogen components, aFRR was the second most profitable ancillary service followed lastly by mFRR. Especially for the electrolyzer, the aFRR was nearly as profitable as the FCR systems; however, it was limited by its high activation rates, especially for the FC.

- In all the systems where the components are acting in the ancillary service markets, the obligations in the form of delivering hydrogen for vehicle refueling are still met.
- Based upon the sensitivity analysis, acting in the ancillary services in the years 2023 and 2022 would also increase the profitability of the systems, but mostly to a lesser degree, specifically in the FCR and FFR markets. Especially the electrolyzer saw large decreases in ancillary service revenue, with the battery only losing 5-25 %. The FC, on the other hand, saw an increase in revenue during both 2021 and 2022.

Chapter 8.

Future work

8.1. Future outlook

Hydrogen and battery technologies are on the rise with many governments investing in green, intermittent, electricity production that require balancing to work well at large scale. However, recent economical instability has led to higher uncertainties and risk causing increased project interests. Recent outlooks also show electrolyzer costs increasing in the near future due to higher material and supply chain costs, but there are also large investments in electrolyzer production capacity. While much of the costs depend on the material, technologies such as the PEMFC and PEMEC are newer than components such as the Li-ion battery, ALE or compressed storage vessels that have been used in industry for a longer time. This means that there is a larger potential in streamlining supply chains.

The profitability of hydrogen and battery storage is interchangeable with electricity markets. Variable and low cost electricity combined with balancing markets are drivers of investments into these systems. 2023 was a year with high balancing market pricing and was preceded by two years of both record high electricity prices and comparable balancing markets. With increasing amount of batteries much of the very fast markets, FCR and FFR, will likely become saturated and drastically lower the possible income from selling capacity on them. With large green hydrogen investments the electricity market might become less variable, with hydrogen production ramping up when electricity is cheap. At the same time an increase in intermittent electricity generation is a driver of more balancing services. New possibilities will also open up with changing market rules, such as the change in mFRR from blocks of one hour to 15 minutes.

8.2. Model improvements

The model used in this thesis has been limited in several regards that can be improved upon, both regarding complexity and scope.

- Dynamic control functions that more accurately act as an agent would on the balancing and energy markets, using real time predictions instead of historical data. The model would then be able to take into account for the two different closing calls on the balancing markets, two days and one day ahead, which has different prices.
- Increase quality from one hour to 15 minutes to take into account coming changes of mFRR market as well as more accurately represent the operational behaviour of the components.
- Add a combined system model of all components that make use of synergies for how the components can act on balancing markets together, making use of differences in activation time and endurance.
- Add the option of running an alkaline electrolyzer in the model, taking into account its slower dynamical response and limited balancing market availability.
- Add on-standby costs for each component when they are ready to deliver an ancillary service but not turned on (e.g. warm start-up).
- Include grants and subsidies available for green energy projects from governments and NGOs in the economical analysis.
- Include other ancillary services in the model: supplying reserve power, peak shavings, reactive power and voltage regulation.

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Appendix A.

Control schemes - FRR markets

This appendix provides the control schemes for the electrolyzer and FC components on the mFRR and aFRR markets. Figures A.1 and A.2 show the control schemes when the electrolyzer and FC act on the aFRR markets (both up and down).

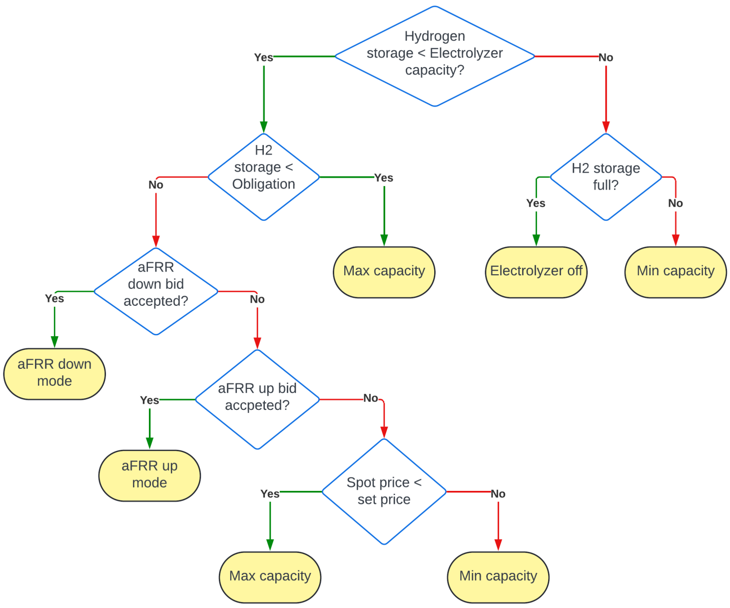

Figure A.1.: Electrolyzer control diagram - aFRR up/down

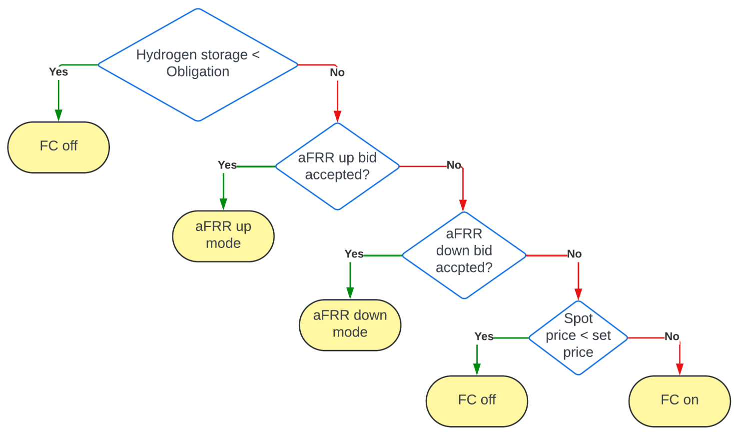

Figure A.2.: Fuel cell control diagram - aFRR up/down

Figures A.3 and A.4 show the control schemes of the electrolyzer and FC when acting on the up and down regulating mFRR markets.

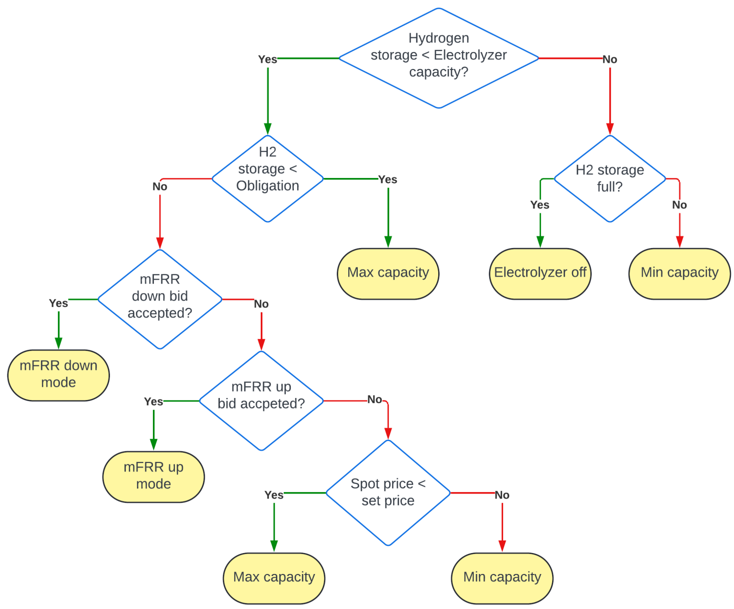

Figure A.3.: Electrolyzer control diagram - mFRR up/down

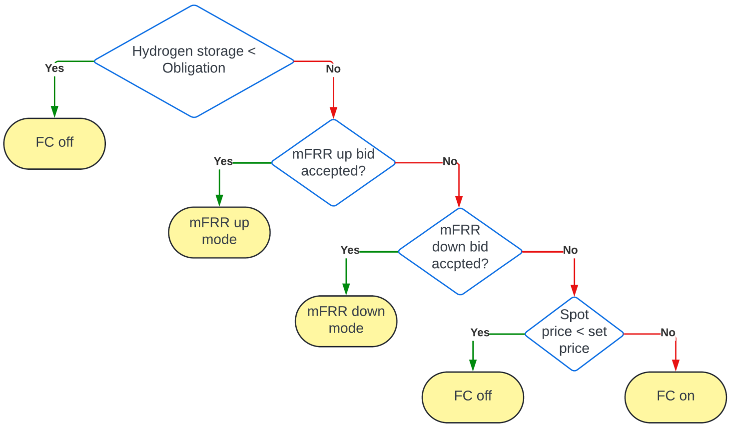

Figure A.4.: Fuel cell control diagram - mFRR up/down

Appendix B.

Operational profiles - 0.1 and 0.5 MW systems

Operational profiles of the 0.1 and 0.5 MW systems are found in this appendix. Figures B.1 and B.2 show the operational profiles of the Base system - spot price model.

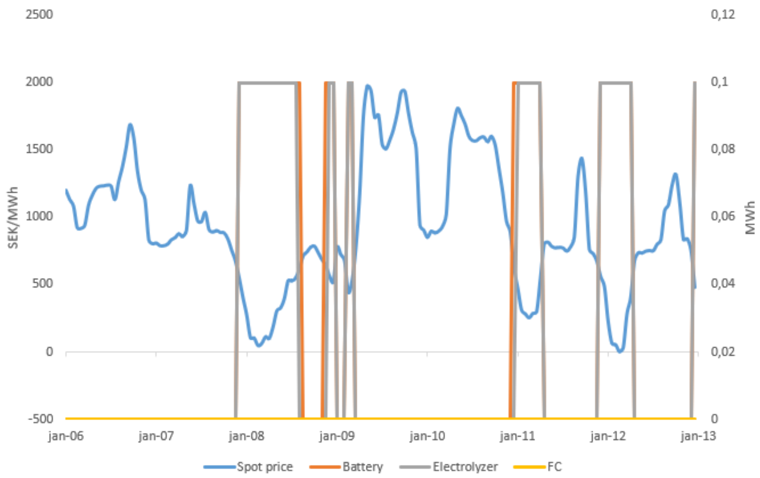

Figure B.1.: Operational behaviour for one week in spot price system - 0.1 MW.

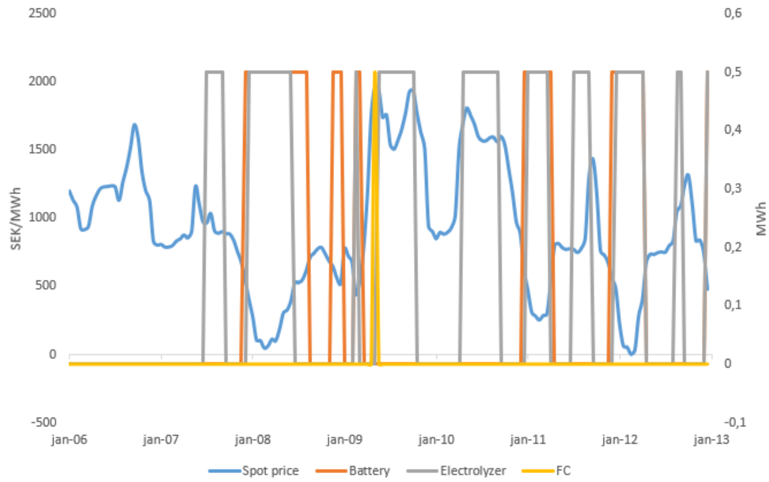

Figure B.2.: Operational behaviour for one week in spot price system - 0.5 MW.

Figures B.3 and B.4 show the operational profiles of the FCR systems.

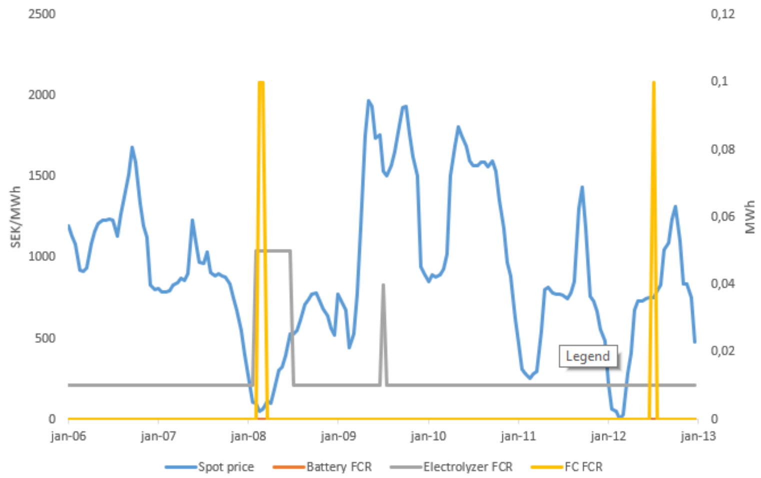

Figure B.3.: Operational behaviour for one week in FCR system - 0.1 MW.

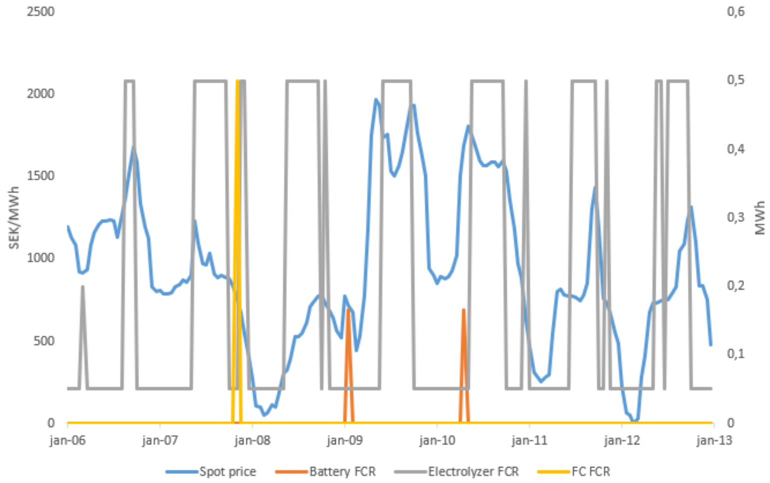

Figure B.4.: Operational behaviour for one week in FCR system - 0.5 MW.

Figures B.5 and B.6 show the operational profiles of the aFRR systems.

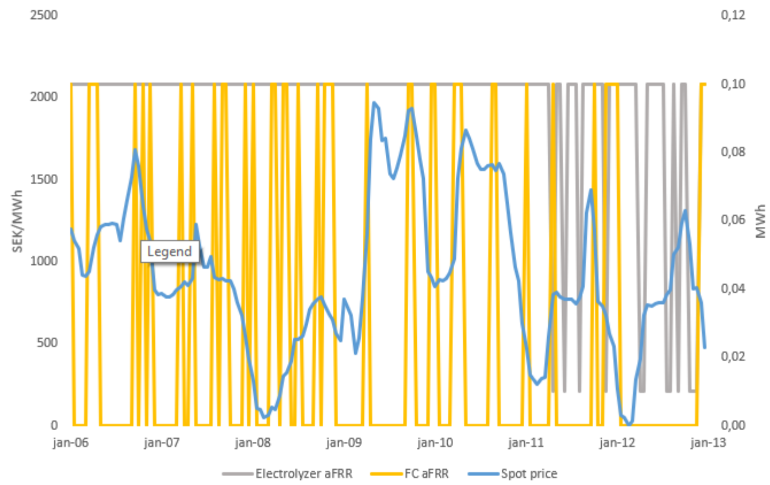

Figure B.5.: Operational behaviour for one week in aFRR system - 0.1 MW.

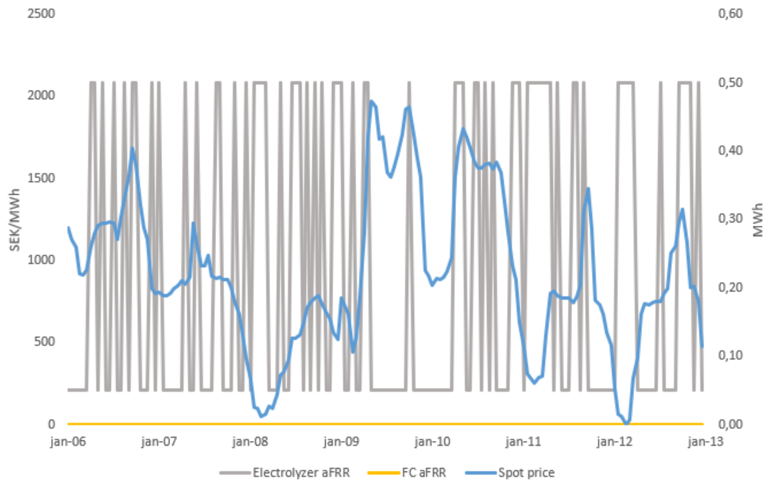

Figure B.6.: Operational behaviour for one week in aFRR system - 0.5 MW.

Figures B.7 and B.8 show the operational profiles of the mFRR systems.

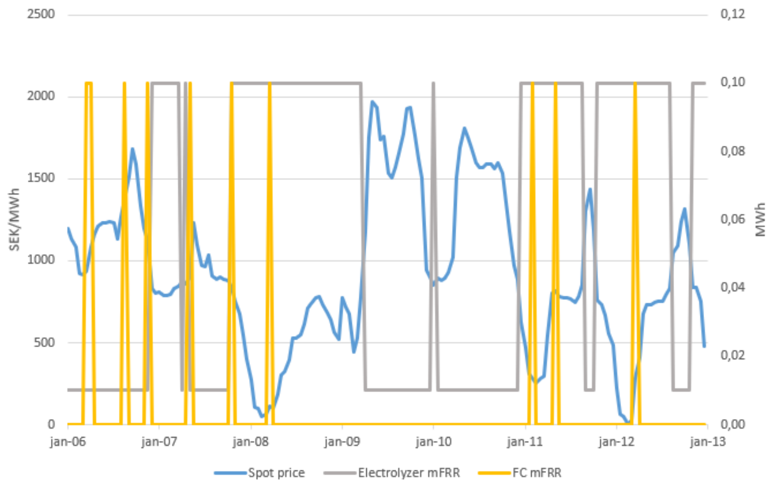

Figure B.7.: Operational behaviour for one week in mFRR system - 0.1 MW.

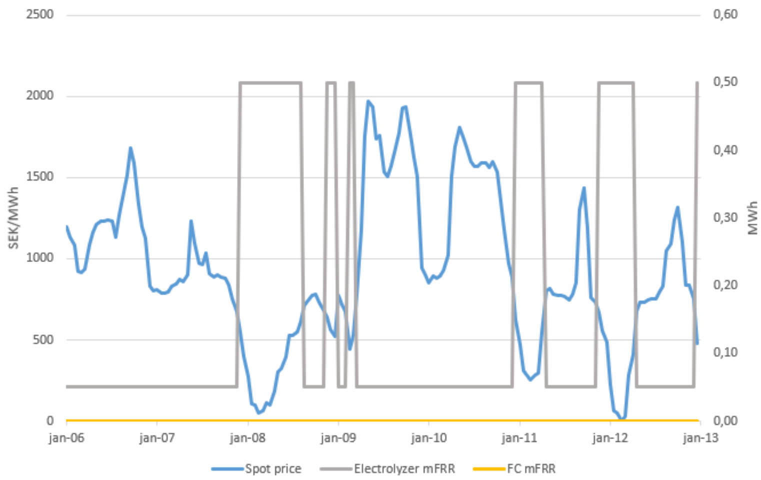

Figure B.8.: Operational behaviour for one week in mFRR system - 0.5 MW.

Appendix C.

Income and costs - 0.1 and 0.5 MW systems

In this appendix the income and costs associated with year 1 for the 0.1 and 0.5 MW systems can be found. Figures C.1 - C.3 show the 0.1 MW systems, Figures C.4 - C.6 show the 0.5 MW systems.

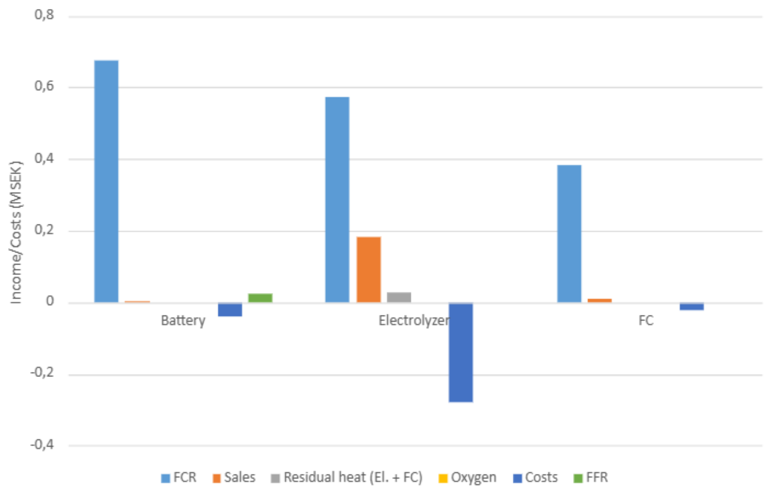

Figure C.1.: Income and cost year 1 for FCR system - 0.1 MW.

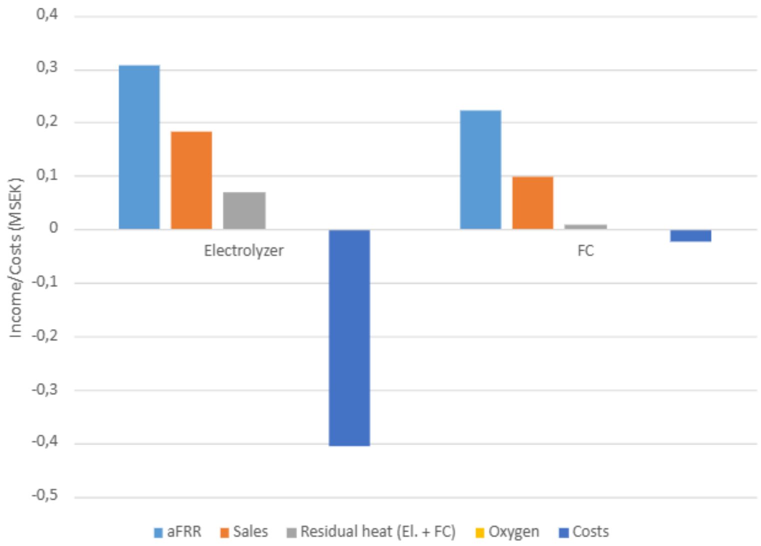

Figure C.2.: Income and cost year 1 for aFRR system - 0.1 MW.

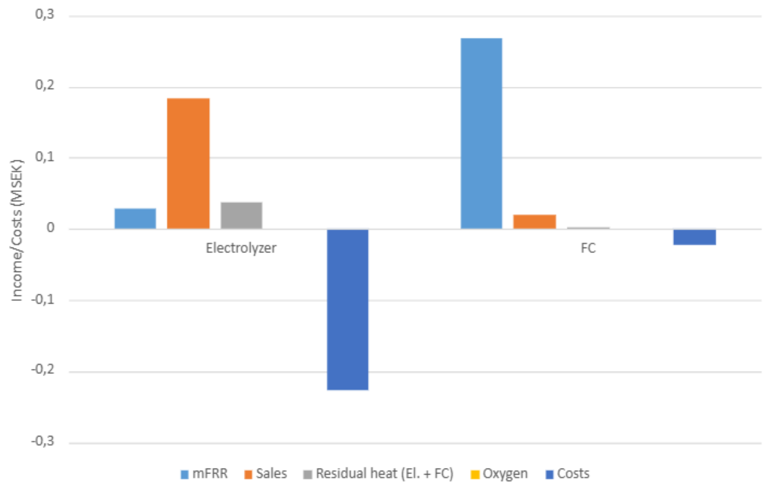

Figure C.3.: Income and cost year 1 for mFRR system - 0.1 MW.

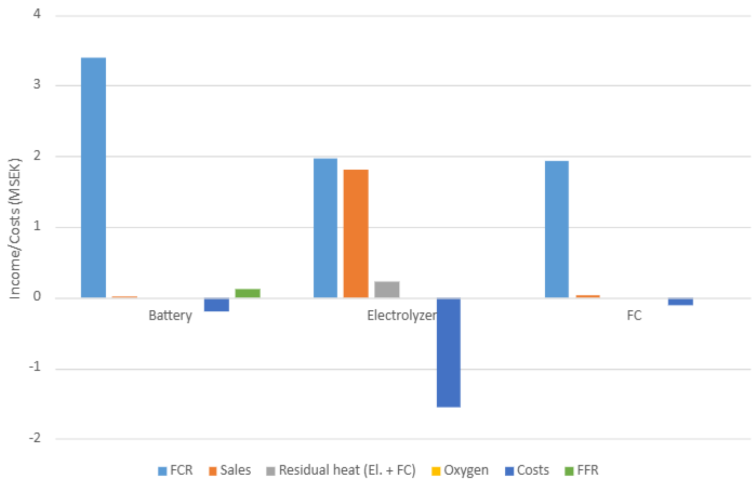

Figure C.4.: Income and cost year 1 for FCR system - 0.5 MW.

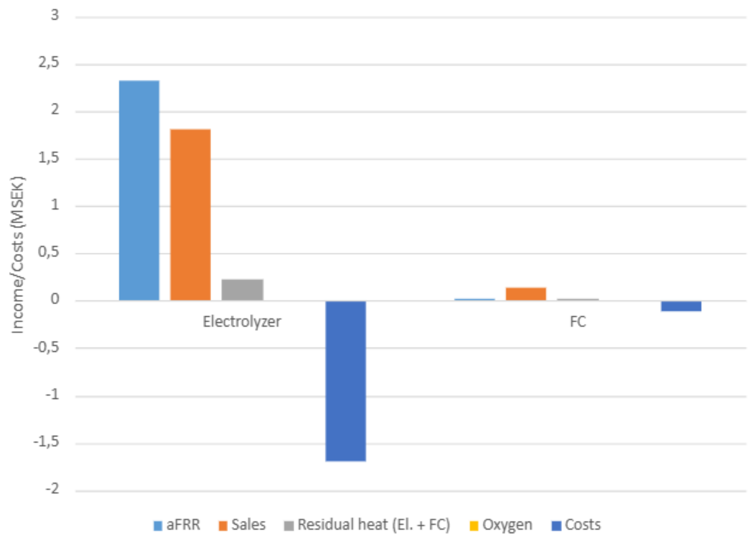

Figure C.5.: Income and cost year 1 for aFRR system - 0.5 MW.

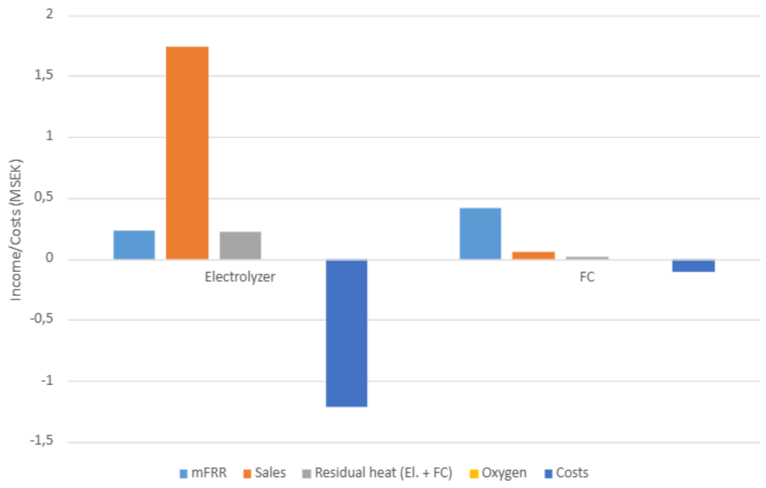

Figure C.6.: Income and cost year 1 for mFRR system - 0.5 MW.