A Techno-Economic Case Study of the Implementation of Hydrogen Technology in Connection to a CHP Plant

An Investigation of the Potential to Provide Ancillary Services and Utilize Residual Heat

by Amanda Kander & Kristina Häggström Wedding

Thesis for the degree of Master of Science
Thesis advisor: Marcus Thern

To be presented, with the permission of the Faculty of Engineering of Lund University, for public criticism on the online meeting and at the Department of Energy Sciences on Friday, the 27th of January at 09:00.

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 in collaboration with the company Energy Opticon in Lund, Sweden.

Supervisor at the Division of Thermal Power Engineering was Marcus Thern. Supervisor at Energy Opticon was Björn Kjeang Funkqvist.

Examiner at Lund University was Martin Andersson.

The project was carried out in cooperation with the operation department at Energy Opticon. In addition, guidance was received form RISE and their project HyCoGen. Finally, Kraftringen participated with information about their CHP plant at Örtofta.

Department of Energy Sciences
Faculty of Engineering
Lund University

ISSN: <0282-1990>
LUTMDN/TMHP-23/5516-SE

Typeset in LaTeX
Lund 7th February 2023

Contents

List of Figures

List of Tables

Nomenclature

Abbreviations

AEC Alkaline Electrolysis Cell

$aFRR$ Automatic Frequency Restoration Reserve

BRP Balance Responsible Party

BSP Balance Service Party

$CAPEX$ Capital Expenditure

CHP Combined Heat and Power

DH District Heating

EC Electrolyzer

Ei The Swedish Energy Market Inspectorate

EU European Union

FC Fuel Cell

FCR Frequency Containment Reserve

$FCR-D$ Frequency Containment Reserve - Disturbance

$FCR-N$ Frequency Containment Reserve - Normal

FFR Fast Frequency Reserve

$LCOH$ Levelized Cost of Hydrogen

$MCFC$ Molten Carbonate Fuel Cell

$mFRR$ Manual Frequency Restoration Reserve

P2G Power to Gas

PAFC Phosphoric Acid Fuel Cell

PEMEC Proton Exchange Membrane Electrolyzer

PEMFC Proton Exchange Membrane Fuel Cell

SOEC Solid Oxide Electrolyzer

SOEC Solid Oxide Electrolysis Cell

SOFC Solid Oxide Fuel Cell

SvK Svenska Kraftnät

TSO Transmission System Operator

Sammanfattning

Med klimatförändringarna som den främsta drivkraften genomgår energisystemet just nu förändringar. Både andelen förnybara resurser som används för att producera el och den totala elektrifieringen ökar. Ett sätt att hantera de resulterande utmaningarna med mer intermittent elproduktion är att implementera vätgasteknik. Vätgasteknik kan bidra till att balansera elnätet både genom ett driftmönster som anpassas efter spotpriset och genom att erbjuda stödtjänster. Detta examensarbete undersöker den teknoekonomiska potentialen för implementering av ett vätgassystem integrerat med Örtofta kraftvärmeverk. Mer specifikt undersöks tillgodogörande av restvärme i fjärrvärmenätet och tillhandanhållandet av stödtjänster.

Två vätgassystem undersöks, ett power to gas-system (P2G System) och ett komplett vätgassystem (Hydrogen System). Vätgas säljs från power to gas-systemet medan el säljs från det kompletta vätgassystemet. Båda systemen inkluderar en PEM-elektrolysör, en kompressor och en trycksatt lagringstank. En PEM-bränslecell ingår också i det kompletta vätgassystemet. En jämförande litteraturstudie användes för att välja lämpliga vätgasteknologier. Vidare modelleras systemen i Energy Optima 3, en programvara som optimerar produktionsplaner baserat på ekonomisk lönsamhet. Optimeringen utförs på historisk data mellan oktober 2021 och oktober 2022. Metoden består av två huvudmodeller, en basmodell och en balansmodell. I basmodellen undersöks drift av vätgassystemet i anslutning till Örtofta kraftvärmeverk med elhandel endast på spotmarknaden. I balansmodellen utreds vätgassystemets bidrag med stödtjänster.

Resultatet visar en återbetalningstid för det kompletta vätgassystemet på 2,86 till 3,06 år och en återbetalningstid för power to gas-systemet på 2,15 till 2,39 år. Investeringskostnaderna i beräkningarna inkluderar dock endast kostnaden för de faktiska enheterna och omkringliggande kostnader är exkluderade. Resultatet visar också att implementeringen av det kompletta vätgassystemet innebär en ökad vinst mellan oktober 2021 och oktober 2022 på 19,9 % till 21,2 %, jämfört med ett referensscenario i Örtofta utan vätgasteknik. Den ökade vinsten för power to gas-systemet under samma period är 13,3 % till 14,8 %. För båda systemen intjänades huvuddelen av vinsten genom deltagande på balansmarknaderna. Den övergripande slutsatsen från examensarbetet är att om restvärme utnyttjas i fjärrvärmenätet och systemet bidrar med stödtjänster så visar vätgasteknik i integration med Örtofta kraftvärmeverk både teknisk och ekonomisk potential.

Abstract

With climate change as the main driving force, the energy system is currently undergoing changes. Both the share of renewable resources used to produce electricity and the overall electrification is increasing. A way to handle the resulting challenges from more intermittent electricity production is by the implementation hydrogen technology. Hydrogen technology can help balance the electricity network both by operating after spot price and by providing ancillary services. This thesis investigates the techno-economic potential of the implementation of a hydrogen system with Örtofta combined heat and power (CHP) plant. More specifically, utilization of residual heat in the district heating network and the contribution of ancillary services are examined.

Two hydrogen systems are investigated, a power to gas (P2G) system and a complete hydrogen system (Hydrogen System). Hydrogen is sold from the P2G system whereas electricity is sold from the Hydrogen System. Both systems include a PEM electrolyzer, a compressor and a pressurized storage tank. A PEM fuel cell is also included in the Hydrogen System. A comparative literature review was used to choose the suitable technologies. Furthermore, the systems are modeled in Energy Optima 3, a software that optimizes production plans. Optimizations are performed on historical data between October 2021 and October 2022. The method consists of two main models, the Base Model and the Balance Model. In the Base Model, operation of the hydrogen system in connection to Örtofta CHP plant, when only trading on the spot market, is investigated. In the Balance Model, the hydrogen system's contribution with ancillary services is investigated.

The results show a Payback time of 2.86 to 3.06 years for the Hydrogen System and 2.15 to 2.39 years for the P2G system. Important to note is that the investment costs in the calculation only include the cost of the actual units, i.e. the surrounding investment costs are excluded. Moreover, with the implementation of the Hydrogen System the profit between October 2021 and October 2022 is increased by 19.9 % to 21.2 %, compared to a reference scenario without hydrogen technology at Örtofta. The increased profit for the P2G system during the same period is 13.3 % to 14.8 %. For both systems, the majority of the profit was earned from the participation on the balancing markets. The overall conclusion from the thesis is that, with the utilization of residual heat and the contribution with ancillary services, hydrogen technology in integration with Örtofta CHP plant shows both technical and economical potential.

Acknowledgments

This thesis has been performed at the company Energy Opticon and at the Department of Energy Sciences at the Faculty of Engineering, Lund University. With this master thesis, we finish our education on the program Environmental Engineering with specialization in Energy Systems. The work was performed during the autumn of 2022.

Throughout the process we have received guidance and support from many people surrounding us. Without them, our work would not have been possible. We would like to thank everybody at Energy Opticon for all the support you have given us throughout this process. Especially we would like to thank our supervisor at Energy Opticon Björn Kjeang Funkqvist and the rest of the people in the operations team for important guidance. Moreover, Victor Vannerberg has been fantastic in solving all our IT-related issues quickly. Furthermore, we would like to thank our supervisor at LTH, Marcus Thern for all your valuable advice.

During our process we had the privilege of collaborating with RISE and people in the project HyCoGen. We would like to thank everybody involved, especially Anders Wickström and Mats Goldberg, for providing us with important data and knowledge. Without you, understanding the balancing markets would have taken much longer. Speaking of the balancing markets, we would like to thank Ebba Helfer for our rewarding discussions and exchange of information. We would also like to thank our examiner Martin Andersson for valuable feedback regarding our model of participation on the balancing markets.

We also want to thank Kraftringen for taking the time to explain possibilities and limitations within their processes at Örtofta. Especially we would like to thank Håkan Skarrie for providing us with data and knowledge regarding electricity network fees.

Last but not least, we would like to thank each other for great collaboration and support throughout the process.

Chapter 1

Introduction

The energy sector in Sweden faces major changes, with resulting challenges and possibilities. With climate change as a driving force, electrification is taking place in many sectors and therefore both electricity and power demand are expected to increase in the coming years. In its forecasts, Svenska Kraftnät reports a maximum scenario for electricity demand in 2045 of 290 TW h (compared to today's 140 TW h) (Svenska Kraftnät, 2021j). The increased electricity demand is expected to be mainly met by the expansion of renewable, intermittent, electricity generation. In addition, the electricity generation has already undergone a change in the last 10 years. Major expansion of wind power, and to some extent also solar power, has been combined with the phasing out of planned electricity production, especially in southern Sweden. The resulting decreasing share of dispatchable electricity production in Sweden poses challenges for the balance of the electricity system. Today, the regulation of electricity production after electricity demand is mainly done by hydro-power, but already today there is a need for additional sources of regulation. Thus, Sweden is in a situation where the need for solutions that ensure a balance between electricity production and consumption has increased drastically (Svenska Kraftnät, 2021j).

In addition to hydro-power, combined heat and power production plants (CHP plants) are today also potential contributors in maintaining the balance of the electricity system. The main task of CHP plants is to produce district heating (DH). This can be done in different ways depending on the balancing needs of the electricity system. At low electricity prices, heat can be produced by electric boilers and heat pumps, while at high electricity prices, heat can be produced by cogeneration. Thus, CHP plants can vary between being consumers and a producers of electricity depending on the state of the electricity system. Furthermore, CHP plants are often located near electricity consumers, spread across the country, which reduces the need for transmission capacity (Royal Swedish Academy of Engineering Sciences, 2019).

But, as mentioned above, there is a need for additional regulating power in the system. A possible contributor to the balancing mechanism of the electricity system could be energy storage in the form of hydrogen.

Great hopes are placed on the role of hydrogen in the future energy system. With green hydrogen as an energy carrier, the hope is that fossil fuels can be phased out of most sectors. In order for Sweden to take advantage of the opportunities hydrogen offers, a national hydrogen strategy was launched in 2021. Within the strategy, an important goal is to expand the electrolyzer capacity. The potential for hydrogen is mainly described in the form of input commodity in industries and as a fuel in the transport sector. But the possibility of using hydrogen storage to balance the electricity system is also emphasized (Swedish Energy Agency, 2022b).

Hydrogen storage is a new method that can contribute to the balance of the electricity system. Hydrogen can be produced from electricity at low electricity prices, stored with small energy losses, and then oxidized for the extraction of electricity at high electricity prices. Consequently, electricity is consumed when the supply of power is high and electricity is produced when there is a lack of power. However, one problem with this solution is that the energy conversions involve energy losses (Svenska Kraftnät, 2021j).

There are methods to handle the challenge of low efficiency regarding the use of hydrogen as energy storage. One way, which also improves the system's function of balancing the grid, is to let the system participate on the balancing markets. This participation enables the system to trade with capacity and not only with actual energy, which decreases the importance of efficiency. On the balancing market, capacity, i.e. preparedness to regulate production/consumption of energy, is sold. If there is a need to balance the electricity grid, offered capacity can be activated and production/consumption of energy must then be regulated. Thus, by providing balancing services the system can contribute both with actual balancing, by regulating load, and with only capacity. When sold capacity is not activated, the efficiency of the system is not relevant.

An additional way to handle the challenge of low efficiency regarding the use of hydrogen as energy storage is to combine the production and consumption of hydrogen with a CHP plant. Advantages of such a combination are many. CHP plants already have an existing infrastructure and great possibilities to utilize residual heat. With utilization of the residual heat produced by the hydrogen system, the overall efficiency of the system could be increased. Moreover, the residual product oxygen, which is produced in the production of hydrogen, can be used for more efficient combustion in the boilers of the cogeneration unit. Furthermore, hydrogen storage can further increase the ability of CHP plants to balance the grid while at the same time providing an opportunity for increased profitability. With the challenges that cogeneration plants face, with among other things, increasing fuel prices and more variable electricity prices, there is also a need for diversification and increased flexibility within the industry. The implementation of a hydrogen system within the plant could offer both flexibility and diversification. Finally, the use of hydrogen in cogeneration can also contribute to reducing emissions, both by replacing fossil fuels and by utilizing oxygen in the combustion process.

The overall system idea is illustrated by an energy diagram in figure 1.1 below. The system presented in the figure represents an investigation focus of the thesis and is henceforth referred to as "Hydrogen System".

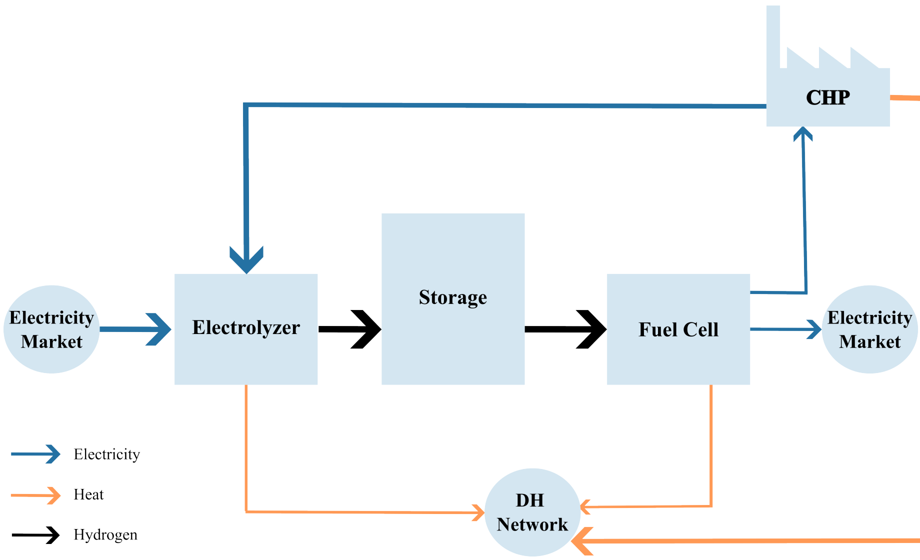

Figure 1.1: A schematic energy diagram of a hydrogen system integrated with a CHP plant.

The system in figure 1.1 is constituted by a hydrogen system connected to a CHP plant. The arrows represent energy flows between the units. The hydrogen system is composed by an electrolyzer, a storage unit and a fuel cell. The energy flows in the system are district heating, electricity and hydrogen. Hydrogen is produced from electricity and water in the electrolyzer and then stored in a storage unit. From the storage, hydrogen enters the fuel cell which, together with air, converts the hydrogen back into water and electricity. District heating is produced within the CHP plant, by the electrolyzer and by the fuel cell. Electricity to and from the units within the system can be either produced/used in the CHP plant or sold/bought at the electricity market. In addition, the system can participate on the balancing markets by the provision of ancillary services. This participation is however not illustrated in the figure.

Figure 1.2 presents an energy diagram for another system option, where the fuel cell is excluded and only the first parts of the system, the electrolyzer and the storage is included. This system represents another investigation focus and is henceforth referred to as "P2G system" (Power to Gas system).

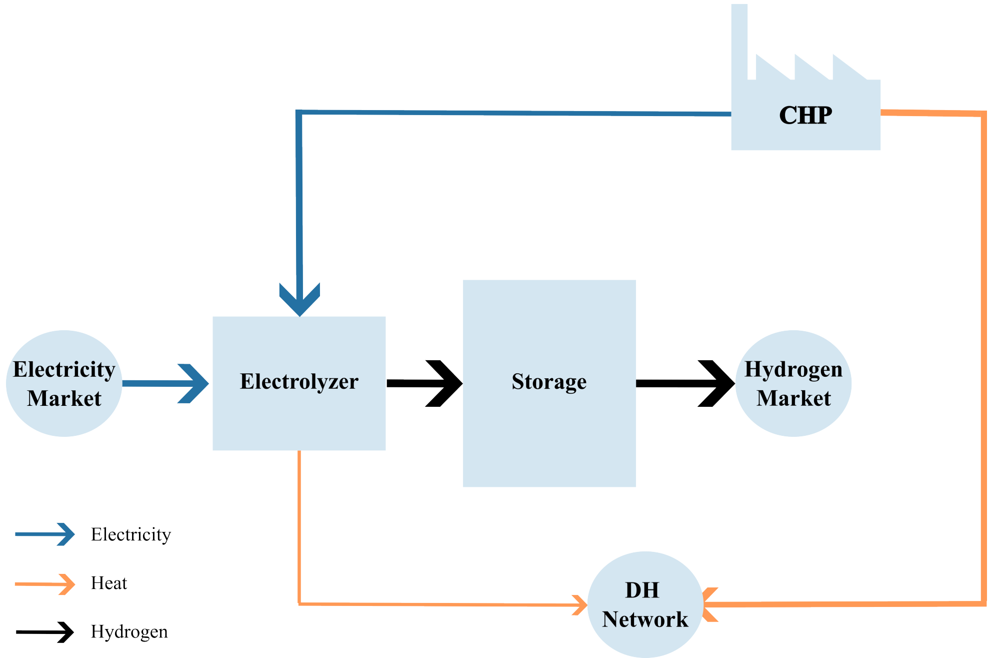

Figure 1.2: A schematic energy diagram of a P2G system integrated with a CHP plant.

Figure 1.2 represents a hydrogen system where, instead of converting hydrogen back to electricity, hydrogen is sold directly. The arrows in the figure represent energy flows between different units. In comparison to the system in figure 1.1, this system has lower capital cost as well as lower energy losses. However, the system's possibility to participate with flexibility on the electricity market decreases and so does the overall synergies resulting from the integration with the CHP plant.

The idea of integrating a hydrogen system with a CHP plant is not new. RISE has started the project "HyCoGen", which aims to investigate the possibilities for profitable hydrogen production in combination with combined heat and power production. Moreover, participation with ancillary services is also examined within HyCoGen (RISE, 2022). At the time of this thesis work, the publications within HyCoGen have so far mainly been based on literature studies. Moreover, in Germany, a sustainability project is run by Green Hydrogen Esslingen. Within the project, a new sustainable district has been created, where the core is hydrogen production in combination with a CHP plant (Green Hydrogen Esslingen, 2022). Information about the project is however inadequate.

The National Hydrogen Strategy describes, among other things, system studies, scenarios and modeling as desirable in order to expand the knowledge base around hydrogen and to complement technical research and development (Swedish Energy Agency, 2022b). Thus, there is still a need for studies that map the possibility for hydrogen to act as a balancing component in the electricity system in combination with cogeneration. More specifically, case studies to investigate the potential for integration into existing CHP plants during optimal operation is of interest. Other master thesises have attempted such investigations before. Among others, a master thesis at the Royal Institute of Technology (KTH) examined the techno-economic assessment for hydrogen production at Igelsta CHP plant. In the study, at Igelsta CHP plant, two new energy systems that included hydrogen production were modeled in python and optimized based on cost (Öhman, 2021). For further investigation it is therefore interesting both to study the potential for other CHP plants to integrate hydrogen technology as well as doing so using a well-tested optimization tool.

Our thesis is performed in collaboration with Energy Opticon and their optimization tool Energy Optima 3 is used. Due to a non-disclosure agreement (NDA) there are restrictions regarding which information that can be presented throughout the report. The customers of Energy Opticon are mainly cogeneration producers, and the software is primarily used to optimize the operation of the customers' facilities. The main objective of the optimization is to minimize the cost for the production of district heating. As tax rates and fees are included in the software, environmental impact of the production in also accounted for. One of the goals of this thesis is to develop a well functioning model for the software that can be used to model hydrogen technology in combined heat and power production. By optimizing an energy system with integrated hydrogen technology, another goal of the thesis is to contribute to knowledge about what the market potential for the system looks like today and what the potential could look like in the future. Furthermore, the created model could be used in investment decisions for hydrogen technology in combination with CHP plants in the future.

1.1 Aim

The overall purpose of the thesis is to investigate how hydrogen can contribute with flexibility to the electricity system in connection with a combined heat and power production plant. This is done by performing a case study in which two different hydrogen systems are compared - a P2G system and a Hydrogen System. Furthermore, the thesis aims to investigate the potential economical profitability of such a system, given that it is controlled by the optimization software Energy Optima 3.

1.2 Research Questions

The following research questions should be answered in order to fulfill the aim of the thesis:

- Which technologies for the production, storage and oxidation of hydrogen are best suited to combine with CHP plants and to use to provide ancillary services?
- How should a hydrogen system, integrated with a CHP plant, be operated to generate maximal profitability?
- How should a hydrogen system, integrated with a CHP plant, participate on the balancing markets to generate maximal profitability?
- What is the economic potential of a hydrogen system integrated with a CHP plant?
- What are the potential environmental impacts of integrating a hydrogen system with a CHP plant?
- What are the technical and economic challenges with the implementation of hydrogen technology in combination with cogeneration?

1.3 Method

To answer the research questions, both a literature review and a case study is performed. The case study refers to a hydrogen system integrated with a cogeneration plant, as illustrated in figure 1.1 and 1.2. More specifically, the hydrogen system is integrated with Örtofta CHP plant outside of Lund, Sweden. Örtofta CHP plant is connected to a larger district heating network called EVITA.

The aim of the literature study is to determine the type of electrolyzer, storage and fuel cell that is best suited to use in combination with cogeneration and for participation on the balancing markets. The results from the literature review is then used to define the hydrogen system modeled in the simulation part. The simulation part is carried out in Energy Optima 3 and the aim is to quantify possible benefits that the defined hydrogen system can contribute with.

Energy Optima 3 optimizes production plans, i.e. the energy flows in the model, based on input data such as cost factors, efficiencies, electricity prices and district heating load. The program focuses on the energy flows between different units and the corresponding costs. Energy Optima 3 does not handle separate processes within units, instead the units are treated as ”boxes” with specific properties. Therefore, the units in the integrated system are modeled as boxes, as illustrated in figures 1.1 and 1.2. Long term optimization over one year is performed.

The simulation part is composed of two main parts that are based on each other. The first part, denoted Base Optimization, investigates the operation of the system when only trading on the day-ahead market. The second part, denoted Balance

Optimization, investigates the system's participation on the balancing markets by the means of contributing with ancillary services. Figure 1.3 describes how the Base Optimization is connected to the Balance Optimization.

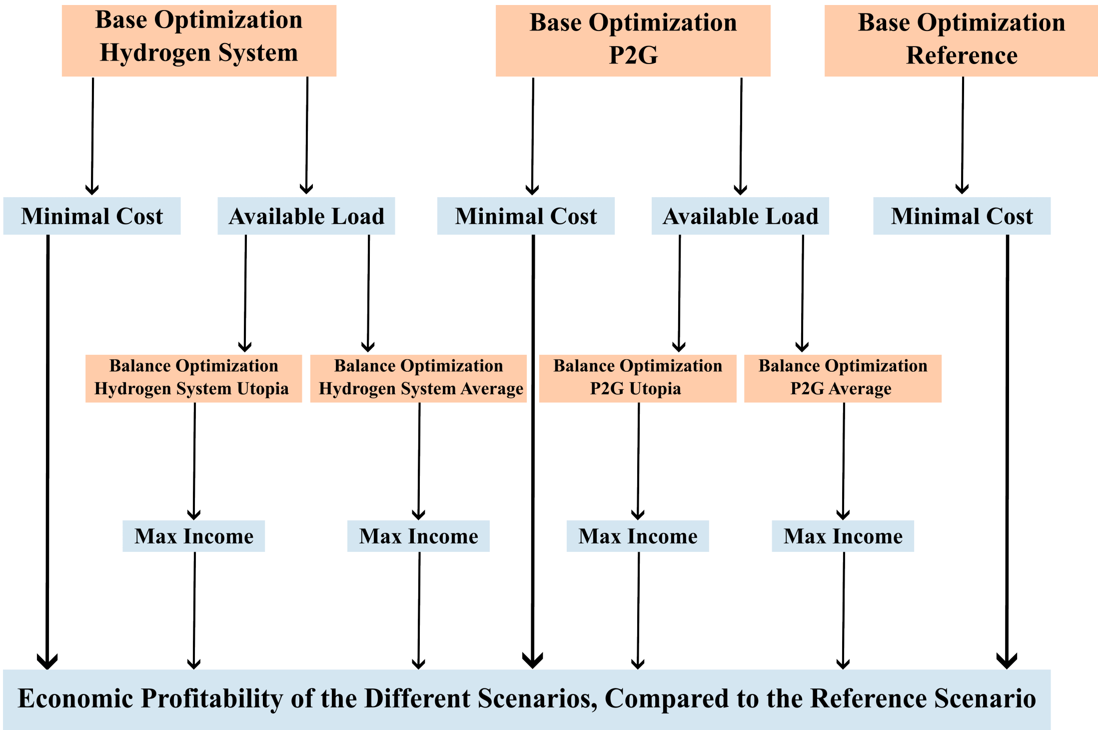

Figure 1.3: An overview of the overall methodology of the optimization.

As can be seen in figure 1.3, the Base Optimization is done for three different scenarios, the Hydrogen System Scenario in which the complete hydrogen system is included, the P2G Scenario in which the fuel cell is excluded, and a Reference scenario where no hydrogen technology is included. The result from these Base scenarios consist mainly of the production plan for the system and the overall minimized costs. In the Hydrogen System and P2G scenarios the production plan decides the available capacity for both the electrolyzer and fuel cell that can participate on the balancing markets. Thus, this result is used as input in the Balance Optimization. As with the Base Optimization, the Balance Optimization is also composed of different scenarios. These scenarios and the entire simulation methodology is described further in detail in chapter 6. When all simulation parts are put together a resulting economic profitability for the different scenarios can be calculated. The economic profitability is based on calculations of Payback Time.

1.4 Delimitiations

The delimitations of the thesis are listed below.

- The only technologies investigated for production of hydrogen and heat are different electrolyzers.
- The only technologies investigated for oxidation of hydrogen to generate electricity and heat are different fuel cells.
- No investigation of the potential safety measures needed for integration of a hydrogen system with a CHP plant is included.
- Legal aspects and aspects regarding permit processes are not investigated in the thesis.
- No investigation of the potential to utilize oxygen generated in the electrolyzer is included.

1.5 Division of Work

The work regarding this master thesis has been performed in collaboration between Amanda Kander and Kristina Häggström Wedding. Both have been involved in all parts of the thesis, although for some parts, one has had the main responsibility. Kristina has been mainly responsible for:

- Chapter 3: The Electricity System
- Chapter 4: Hydrogen Technology
- Data collection for the optimizations
- The tables
- Compilation of the result from the Balance Model
- Presentation and discussion of the result from the Balance Model

Amanda has been mainly responsible for:

- Chapter 1: Introduction
- Chapter 2: Cogeneration and District Heating
- Chapter 5: The Integrated System
- Figures

- Compilation of the result from the Base Model
- Presentation and discussion of the result from the Base Model

The actual modeling and simulations were carried out in complete collaboration.

1.6 Ethics

Some ethical aspects of this master thesis can be emphasized. The purpose of the study is ultimately to aid the transition towards a fossil free energy system. The idea is that improved flexibility in the electricity system can enable higher ratios of intermittent renewable energy sources. Moreover, the introduction of a hydrogen system integrated with a CHP plant can also directly replace combustion of peak load fuels, which are often fossil. However, some problematic aspect can be raised regarding the manufacturing of electrolyzers and fuel cells. Rare metals are needed in the products and, just as in the case for batteries, the work conditions for the people extracting them can be problematic. Moreover, the extraction can also cause large emissions of green house gases as well as negative impacts on the local environment. These aspect are not examined in this thesis, but could be important when determining the suitability of this solution.

1.7 Disposition

The literature review, with relevant theory regarding the subject, is presented in chapters 2-4. In chapter 2: Cogeneration and District Heating, theory regarding CHP production and district heating is presented. Chapter 3: The Electricity System, provides necessary background in order to understand how hydrogen technology can participate in the electricity system. The chapter is composed of relevant theory regarding the electricity system, grid and market. In chapter 4: Hydrogen Technology, theory regarding hydrogen, electrolyzers, storage technology and fuel cells is presented. Moreover, the chapter covers sector coupling, hydrogen economy, financial instruments regarding hydrogen technology as well as taxation with regards to hydrogen technology.

In chapter 5: The Integrated System, the result of the literature review is presented, i.e. the chosen hydrogen system design. Moreover, specific properties of these units and resulting implications for the entire system are presented in summary. How the integrated system is modeled and simulated in Energy Optima 3 is presented in chapter 6: Modeling and Simulation. The results of the optimizations are presented in chapter 7: Optimization Results, followed by a presentation of the sensitivity analysis in chapter 8. Finally, a discussion can be found in chapter 9, followed by conclusions and recommendations for future work in chapter 10.

Chapter 2

Cogeneration and District Heating

The main idea behind district heating is effective transfer of heat from centralized sources. Heat is transferred in district heating networks through an energy carrier, usually pressurized hot water. Heat is usually produced in heating plants or combined heat and power (CHP) plants. Furthermore, residual heat from industrial processes can be used. With the use of CHP, both electricity and heat is produced. In Sweden, the most common type of CHP is based on steam turbines. A simplified overview of the process in such a Swedish CHP plant can be illustrated by an ideal steam Rankine cycle, see figure 2.1. The figure was provided to us by Marcus Thern (personal communication, October 20, 2022).

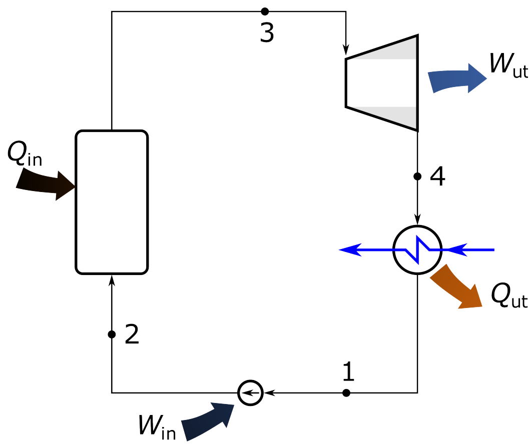

Figure 2.1: A simple ideal steam Rankine cycle.

Boilers are units within a CHP plant with the general function to produce steam. Generally, heat used to vaporize water is produced in a combustion chamber. Different types of fuels can be used in a boiler and today common fuel types are waste and biomass (Frederiksen & Werner, 2014). A boiler is illustrated between point two and three in figure 2.1. The generated steam can then enter a turbine, which generates electricity by the expansion of a fluid (Dincer & Bicer, 2020). A turbine is illustrated between point three and four. The steam emitted from the turbine enters a condenser, in which the steam is condensed to transfer heat to the district heating network. The steam can also enter a condenser directly from the boiler (Frederiksen & Werner, 2014). A condenser is illustrated between point four and one. Finally, the condensed water is pumped back to the boiler. In reality, however, in order to increase the efficiency and flexibility of the plant, much more complex systems are used. For instance, heat pumps and heat accumulator tanks are common features (Frederiksen & Werner, 2014).

A heat pump can be used to transfer heat from lower temperature reservoirs to higher temperature reservoir by the addition of electricity. The efficiency of the heat transfer is typically defined by the Coefficient of Performance (COP). COP of a heat pump is always > 1 (Dincer & Bicer, 2020). The definition for COP is presented in equation 2.1 below, and is used in a sensitivity analysis scenario that investigates the implementation of heat pumps within the investigated hydrogen system. No heat pump is included in figure 2.1.

$$COP = \frac{\dot{Q}_{out}}{\dot{W}} \tag{2.1}$$

$\dot{Q}_{out}$ = Generated heat [W]
$\dot{W}$ = Input power [W]

2.1 Cogeneration and District Heating in Sweden

District heating has been used in Sweden since the 1950's and was originally mostly produced in heating plants. Since then production in cogeneration plants has increased and in 2020, 45 % of the total district heating in Sweden was produced in cogeneration plants. Furthermore, the use of district heating has increased gradually in Sweden from 1970, when total use amounted to 13.4 TWh, until around the year 2000. Since 2000 the use of district heating in Sweden has varied between 50 and 60 TWh annually. The latest available data is from 2020, when total use was 54.4 TWh. The absolute majority of district heating is used within the residential and services sector, around 58 % of the total energy used for heating in this sector is delivered as district heating (Swedish Energy Agency, 2022a).

Furthermore, the input energy used to produce district heating has changed remarkably since the 70's. Originally, almost all input was fossil, mainly petroleum products. Since then the industry has gone through a major shift and today, bio fuels constitute a majority of the input energy. Moreover, waste and residual heat are important sources of energy in today's district heating production. Fossil energy sources such as natural gas and petroleum products only constitute a small part of the total energy input and are mainly used to accommodate the heat demand during peak loads (Swedish Energy Agency, 2022a).

Between 2010 and 2020 the annual electricity production in CHP plants varied between 6.7 TWh and 12.6 TWh. The total electricity production in Sweden varied between 145 TWh and 165 TWh the same years (Swedish Energy Agency, 2022a).

Currently, there is a development in Sweden, and Europe, towards ”the fourth generation of district heating”. Two main properties of this generation are lower temperatures in the thermal grids and more integrated IT-solutions. With lower temperatures the possibility to utilize residual heat, from for example hydrogen technology, increases (Frederiksen & Werner, 2014).

Chapter 3

The Electricity System

The following chapter investigates the electricity system in Sweden. A general understanding for how the sector works is crucial to understand how hydrogen can contribute to the sector.

3.1 Actors in the Electricity System

Several actors play a role in the electricity system and to get an understanding of how the system works a brief introduction about the most important actors will be given below.

3.1.1 Electricity Producer

The electricity producer is simply an actor producing electricity to deliver it to the electricity network, after agreement with the electricity net operator (Svenska Kraftnät, 2021f). The producers vary between large corporations and small scale producers. The larger producers typically sell their electricity on the power market whereas the smaller producers oftentimes sell their electricity to a larger actor who in turn acts on the power market (Swedish Energy Market Inspectorate, 2022). The electricity producer can also choose to sell its electricity directly to its customer, according to a PPA (Power Purchase Agreement) (Svenska Kraftnät, 2021f).

3.1.2 Electricity Network Operator

An electricity network operator is a company that owns an electricity network and that is responsible for transferring electricity between suppliers and consumers. The electricity network operators have monopoly on their respective parts of the grid. In Sweden there are approximately 16 electricity network operators, who own the regional and local electrical girds, whereas the transmission grid is controlled by Svenska Kraftnät (Swedish Energy Market Inspectorate, 2015).

3.1.3 Electricity Supplier

The electricity supplier has an agreement with the customer and sells electricity to the consumer according to the agreement. The electricity supplier can either have their own electricity production, or buy electricity on the power market (Svenska Kraftnät, 2021f). The electricity supplier can also have financial long-term agreements to reduce risks related to price variations (Swedish Energy Market Inspectorate, 2022).

3.1.4 Balance Responsible Party (BRP)

According to agreement with Svenska Kraftnät, the BRP is responsible to ensure that there is balance on the grid at the locations the agreement covers. For these parts of grid, the BRP is responsible to ensure that the amount of electricity supplied to the grid always matches what is withdrawn from the grid (Swedish Energy Market Inspectorate, 2015). All electricity suppliers in fact have the responsibility to ensure that production matches consumption. However, the supplier can choose to take on the responsibility themselves, or to hire another actor as their BRP (Svenska Kraftnät, 2021f). In Sweden there were 37 BRP:s in the year of 2020 (Axberg et al., 2020). Today, the actors contributing to the balancing markets with different types of reserves must either be a BRP, or have an agreement with a BRP. However, these responsibilities are in the future supposed to be divided into two new roles, namely Balance Responsible Party (BRP) and Balance Service Provider (BSP) (Svenska Kraftnät, 2021j).

3.1.5 Svenska Kraftnät - TSO (Transmission System Operator)

Svenska Kraftnät (SvK) is a state-owned authority and acts as the Transmission System Operator (TSO) in Sweden, meaning that they are responsible for maintenance and development of the national grid power lines (the transmission grid). Furthermore, they are responsible for the grid connections to other countries and thus the export and import to and from other countries. SvK is also responsible for the electricity balance in Sweden, i.e. that production matches consumption in every operating moment. They also contract actors that can provide power reserves in case of shortages. Finally, SvK is also responsible for the ultimate grid resilience, and that the electricity supply can withstand various extreme events and strains (Axberg et al., 2020).

3.1.6 The Swedish Energy Markets Inspectorate (Energimarknadsbyrån, Ei)

Ei is a governmental authority with purpose to work for a well functioning energy market. This includes the electricity sector as well as the district heating and natural gas networks (Diamant et al., 2022). Ei ensures that the actors on the energy market abide by the rules and laws, and are responsible for issuing concessions of electrical grid lines, and also for developing and proposing new rules within the energy markets. Ei is also responsible for the provision of comprehensive customer information (Axberg et al., 2020).

3.1.7 The Swedish Energy Agency (Energimyndigheten)

The Swedish Energy Agency is the government authority for energy policy issues. Their purpose is to provide actors in the energy sector with knowledge and expertise (Swedish Energy Agency, 2022c). They are supposed to work towards a sustainable energy system aligning with the climate goals set up by both EU and the Swedish government and do so for example by research and innovation projects (Swedish Energy Market Inspectorate, 2015).

3.2 The Electrical Grid

The Swedish electrical grid consists of around 584 000 km of electrical lines. It can be dived into three parts: the national (transmission), regional and local grid(s). The national grid covers long distances with high voltage. Regional grids connect the national grid to the local grids. In turn, the local grids are connected to the end consumers. In addition, there are electrical lines that connect the Swedish national grid to other countries, namely Denmark, Norway, Finland, Germany, Poland and Lithuania (Diamant et al., 2022).

Grid operators are active within a regulated monopoly. The reason, simply put, is that it is most socioeconomically profitable to only have one grid operator in each area. In Sweden, the Swedish Energy Markets Inspectorate (Ei) is the supervisory authority that is responsible for controlling the market and the grid operators (Diamant et al., 2022).

The delivery reliability of electricity is evaluated by Ei, based on reported incidents of power outage. Generally, delivery reliability has been high since 2010 when Ei started collecting data on reported incidents. If a customer experiences more than 11 cases of power outage within a year, the quality of power transmission has not been sufficient. In 2020, a year when Sweden was not subject to any big events which can affect power delivery, such as storms, only 0.3 % of the customers were subject to more than 11 power outages (Seratelius & Emanuelsson, 2021).

To ensure a high delivery reliability of electricity in Sweden is not without challenges. Sweden has one of the oldest national grids in the world and many electrical lines are at the end of their technical lifetime. Furthermore, new electricity production, transmission limitations and ongoing electrification is increasing the need for new power lines and stations in the national grid (Diamant et al., 2022).

3.3 Costs for Electricity

There are various costs summing up to the total fee for consuming electricity. In general, an electricity consumer is charged by a network operator and an electricity supplier. For electricity producers there is also compensation to be received when electricity is exported to the grid. The cost factors related to electricity consumption can be fixed or variable, and vary depending on if the consumer is a private person, an electricity producer or electricity supplier. In general the cost and compensation factors listed below arise. However, they do not apply to all consumers. Exceptions and variations in the costs for electricity between different types of consumer will not be further described.

- **Power Fee [SEK/MW]:**
  The power fee is supposed to cover costs for operation, maintenance and investment costs related to the electrical grid. It can quantified in different ways, for example it can be based on the subscribed transmission capacity that the actor has, i.e. the maximum power that will be transferred to/from the grid from/to the actor during a year. The power fee is thus also a tool to avoid that the physical power limit on the electrical grid and its components is exceeded. In case the actor would exceed the power limit of the subscription, an excess capacity charge is added (Svenska Kraftnät, 2022e). This could be the case for an electricity producer that injects more power to the grid than their subscription covers, or for an electricity supplier or BRP withdrawing more power from the grid than the power limit according to their subscription.
- **Subscription Fee [SEK/year]:**
  An electricity consumer pays a yearly/monthly subscription fee to the network operator. This fee is fixed, and usually based on fuse size for a household, or the subscribed peak power transmission (Diamant et al., 2022). Commonly a fixed subscription fee is paid to the electricity supplier as well (Konsumenternas Energimarknadsbyrå, 2022).
- **Transfer Fee [SEK/MWh]:**

The transfer fee is a variable costs paid to the network operator and is related to the amount of electricity consumed. This fee is supposed to cover the losses of transferring electricity through the grid (Lindholm, 2018).

- **Energy taxation on electricity [SEK/MWh]:**
  A consumer of electricity pays a tax relative to the amount of electricity used. This fee is paid to the network operator (Diamant et al., 2022).
- **Electricity Trading [SEK/MWh]:**
  This is the cost factor related to the actual electricity price of consumed electricity. Depending on agreement, it could be the actual spot-price on the power market, variable with a fee corresponding to the monthly average of the spot-price, or a fixed cost (Energimarknadsinspektionen, n.d.).
- **Compensation for Network Benefit [SEK/MWh]:**
  An electricity producer receives compensation from the network operator for electricity exported to the grid. The compensation is related to the amount of electricity that is exported.

3.4 The Electricity Market - An Overview

Unlike the electricity distribution market, the electricity market in Sweden is a deregulated market, but this has not always been the case. In 1996, the electricity production and trading was deregulated, and Sweden's entry to the European Union opened up for a common electricity market within Europe (Svenska Kraftnät, 2021b). The aim with the deregulation was to make it more cost-effective, efficient and to simplify trading with electricity (European Comission, n.d.).

The characteristics of the electricity trading is connected to the physical electricity net. Sweden is divided into four different bidding areas. The borders are determined based on limitations in the transmission grid, and that northern Sweden is characterized by overproduction of electricity whereas southern Sweden has larger consumption than production. The division causes the prices in the different areas to vary, depending on supply, demand and transmission capacity (Svenska Kraftnät, 2022a).

The electricity market can be divided into two main fields; the financial trading market and the physical electricity market. The physical electricity market serves two purposes. Firstly, it involves the actual buy of electric energy and secondly it involves the market concerning electric capacity. The financial market works like a stock market and determines the electricity price (Svenska Kraftnät, 2021e). Furthermore, the financial market primarily involves long term contracts for fixed prices, and ensures that actors with contract are not affected by variation in spot prices. However, the financial contracts does not involve any physical transfer of electricity (Diamant et al., 2022). The trading occurs on different markets and the most common actors on the market are the electricity producers, electricity suppliers and large energy consuming entities (Svenska Kraftnät, 2021c).

The electricity trade is not only necessary to ensure that all homes have electricity, but also to achieve the electricity balance. As mentioned above, there are actors responsible for balancing production with consumption. For the planning phase, the day-ahead markets and intra-day markets are important and they will be introduced in section 3.4.1 below. However, real-time balancing is also important. This is controlled by Svenska Kraftnät, that act on the balancing and regulating markets. Real-time balancing is explained further in section 3.4.2.

3.4.1 Planning for balance

The BRPs strive for balance between electricity consumption and production on an hourly basis by planning production after the forecasted demand, and also by buying electricity on the power market (Svenska Kraftnät, 2021a). For the planning phase, the spot markets play an important role. Electricity can be bought either through bilateral agreements between electricity suppliers and producers, or at a power market. Most of the trade in Sweden occurs at the power market Nord Pool, either at the day-ahead market or at the intra-day market (Diamant et al., 2022). The day-ahead-market involves bidding on an hourly basis and is determined at latest by noon on the day before delivery. The electricity price depends on supply and demand and will naturally vary temporally since neither demand nor supply are constant. When the bidding is done, spot-prices for every hour are determined. The intra-day market enables trading up until one hour before the time of the electricity use and thus acts as an additional tool for planning the balance between production and consumption (Svenska Kraftnät, 2021a).

Even though most of the electricity trading in Sweden occurs at the spot markets of Nord Pool, Sweden is also part of the EPEX power market. Both Nord Pool and EPEX Spot offer day-ahead as well as intra-day trading (epexspot, n.d.; Nord Pool, n.d.).

3.4.2 Real-time balancing

Neither the use nor production of electricity is entirely predictable or controllable. Hence, there is a need for real-time balancing, which in Sweden is controlled by Svenska Kraftnät. They operate on different markets, the balancing markets and the regulating market, on which they can buy different types of ancillary services to maintain balance in real-time (Svenska Kraftnät, 2021a).

The balancing markets are important to ensure that supply matches demand at all times, which means that a stable frequency of 50 Hz should be maintained in the grid. If the frequency deviates too much from 50 Hz it can damage components in the electricity network and ultimately lead to power grid break down (Svenska Kraftnät, 2021a). The frequency of the grid is affected by the balance between produced power and electricity consumption every second. When the electricity production is lower than the use, the frequency will be lower than 50 Hz. In that case, up-regulation is necessary to recreate balance, which can be achieved either by increase in production or reduction in consumption. On the contrary, when production exceeds consumption the frequency will be too high, and down-regulation either through decreased production or increased consumption is required (Power Circle, 2019).

Svenska Kraftnät has contracts with actors that can contribute with different types of support to the power system (Svenska Kraftnät, 2021a). Overall, the balancing mechanism entails both services to ensure frequency balance and to provide sufficient energy. The services include measures to contain and restore frequency - *Ancillary Services*, as well as a disturbance reserve and a power reserve (Power Circle, 2019). Actors that can supply reserves are for instance electricity producers able to adjust their production or actors that can adjust their electricity consumption. Historically in Sweden, mainly hydro-power have contributed to the balancing and regulating markets. Today, the supply of ancillary services is also constituted by thermal power, gas turbines, energy storage, flexible consumption, solar power and wind power to some extent (Svenska Kraftnät, 2022f). Still though, the vast majority originates from hydro-power. The need for balancing and flexibility is increasing and thus additional ancillary services from other sources is needed. In section 5.2.2, how hydrogen technology specifically can contribute with ancillary services is introduced. The different types of ancillary services, as well as the disturbance reserve and power reserve, are further explained below.

Frequency Containment Reserve (FCR):

FCR is a reserve type that is automatically activated to maintain a stable frequency of the grid at 50 Hz. All types of FCR:s respond very quickly to changes in frequency. SvK purchases FCR services one and two days before the operating hour for price according to bid. Consequently, bids at different price can be accepted for the same time period (Goldberg, 2022). FCR is composed by three sub-types of reserves:

- **Frequency Containment Reserve - Normal (FCR-N)**:
  FCR-N is used during normal grid operation and should quickly stabilize the frequency in case of small changes in consumption or production, i.e. when the frequency deviates slightly from 50 Hz, in the interval of $49.9 - 50.1$ Hz (Svenska Kraftnät, n.d.). Activation of FCR-N can in a time perspective of hours to days be expected to occur asymmetrically between up and down

regulation. However, in a longer perspective activation of FCR-N is more or less symmetrical and therefore it has small impact on the service provider's long term electrical consumption and production (Goldberg, 2022).

- **Upwards Frequency Containment Reserve - Disturbance (FCR-D Up)**:
  FCR-D Up is activated to stabilize the frequency when it is too low, during disturbed operation of the electricity network (Svenska Kraftnät, n.d.). The reserve is activated at frequencies in the interval of $49.50 - 49.90$ Hz (Svenska Kraftnät, 2022c). Activation of FCR-D up can be expected a very small ratio, around 0.3 %, of the time. Thus, it has a very small impact on the service provider's production and/or consumption of electricity (Goldberg, 2022).

- **Downwards Frequency Containment Reserve - Disturbance (FCR-D Down)**:
  FCR-D Down is another automatic reserve activated during disturbance. Its purpose is to down-regulate during high frequencies, and it is activated in the interval of $50.1 - 50.5$ Hz (Svenska Kraftnät, 2022b). FCR-D Down is a new type of reserve, which entered the balancing markets the 1:st of January 2022 as a tool to contend with the increased variable electricity production, mainly from wind power, that can cause disturbances to the electricity system (Svenska Kraftnät, 2021i). The activation ratio is similar to FCR-D Up (Goldberg, 2022).

Automatic Frequency Restoration Reserve (aFRR):

aFRR is also automatically activated to restore frequency to 50 Hz at all times of deviations. aFRR can be offered as both up-regulation and down-regulation (Svenska Kraftnät, n.d.). It has a slightly slower response compared to FCR but longer duration (Power Circle, 2019). The function of aFRR is to compensate for when actual electricity production and/or consumption differ from the prognosticated. Until recently, May 2022, aFRR was purchased week wise at price according to bid. In May 2022 a Nordic capacity market for aFRR was implemented with new rules. Presently SvK purchases aFRR services one day before the operating hour at marginal price. Consequently, the pricing is the same for all purchases each time period. Activation of aFRR can be expected a significant ratio of the time and can therefore be expected to have an impact on the service provider's production and/or consumption of electricity. If both down- and up-regulation is offered, the overall impact can be balanced over time. But, over a time period of hours to days, imbalances can still be expected (Goldberg, 2022).

Manual Frequency Restoration Reserve (mFRR):

mFRR has a purpose to aid the automatic reserves, so that they can be available in case of future need, and is activated manually at demand from Svenska Kraftnät when the frequency deviates from 50 Hz (Svenska Kraftnät, n.d.). The mFRR reserves are bought on the regulating market and thus only have compensation for energy (Power Circle, 2019). SvK purchases mFRR services from 1 day up to 45 min before the operating hour at marginal price (Goldberg, 2022).

Fast Frequency Reserves (FFR):

FFR is also a relatively new reserve, that was introduced during the summer of 2020. The main purpose of the service is to compensate for the reduced amount of rotational energy in the electricity system (Wickström, 2021, October 20). The rotational energy comes from the large generators used in e.g. hydro power and nuclear power plants and provides stability to the electricity system. FFR is used to counteract the fast and deep frequency changes emerging during disturbances and at low levels of rotational energy. It is activated automatically at frequencies of 49.5 – 49.7 Hz and should reach full power after around one second (Svenska Kraftnät, 2021g). SvK purchases FRR services season wise for marginal price. Activation of FFR can be expected a very small ratio of the time. The impact the service provider's production and/or consumption of electricity is very small to negligible (Goldberg, 2022).

Summary and Comparison of Frequency Reserves

In table 3.1 below, the requirements of each of the ancillary services are specified, as well as characteristics and compensation mechanisms. Compensation for capacity is received regardless of activation, as long as the service is purchased. Compensation for electricity on the other hand is only received/payed in cases of activation. Regarding activation of up-regulation, the provider of a service receives compensation, as SvK buys energy from the actor at up-regulation price. The situation is reverse in cases of down-regulation, when the service provider buys energy from SvK at down-regulating price (Svenska Kraftnät, 2019b).

Table 3.1: Ancillary service types and their characteristics and requirements.

	FCR-N	**FCR-D Up**	**FCR-D Down**	**aFRR**	**mFRR**	**FFR**
Regulation	Up and Down	Up	Down	Up or Down	Up or Down	Up
Minimum bid size [MW]	0.1	0.1	0.1	1	10 (5 in SE4)	0.1
Activation	Automatic	Automatic	Automatic	Automatic	Manual	Automatic
Frequency	49.9-50.1	49.5-49.9	50.1-50.5	Deviations from 50 Hz	-	49.5-49.7
Activation time	63 %: 60 s 100 %: 3 min	50 %: 5 s 100 %: 30 s	50 %: 5 s 100 %: 30 s	100 %: 5 min	100 %: 15 min	100 % within: 0.7 s at 49.5 Hz 1.0 s at 49.6 Hz 1.3 s at 49.7 Hz
Estimated Required Volume in Sweden [MW]	230	556	530	140		100
Endurance	1 h	$\geq$ 20 min	$\geq$ 20 min	1 h	1 h	30 s or 5 s
Compensation Capacity	Yes	Yes	Yes	Yes	-	Yes
Compensation Electricity	Yes	-	-	Yes	Yes	-
Price	By bid	By bid	By bid	Marginal Pricing	Marginal Pricing	Marginal Pricing
Procurement [time before operating hour]	1 and 2 days	1 and 2 days	1 and 2 days	1 day	1 day to $\geq$ 45 min	1 year

Within HyCoGen, Goldberg (2022) found that both the capacity prices and up- and down-regulating prices on the balancing markets correlate with spot prices in general. At times of high spot prices, generally, prices also become high on all capacity markets and on the regulating market. The opposite applies in times of low spot prices.

To be able to contribute with ancillary services, a pre-qualification is necessary. The pre-qualification should show that the provider can meet all the technical requirements and abide by the market rules associated with the ancillary service (Svenska Kraftnät, 2022d). Moreover, control systems that enable the technology to respond to frequency signals from the grid are required for most of the services (Power Circle, 2019).

Disturbance Reserve:

The purpose of the disturbance reserve is to back up the electricity system during disturbances, if production unit(s) stop producing or problems on the transmission grid arise. The disturbance reserve is activated by Svenska Kraftnät if the bids on the regulating market do not suffice to counter the disturbance. The disturbance reserve is composed mainly by gas turbines in bidding areas 3 and 4 in southern Sweden, and should be able to activate within 15 minutes (Power Circle, 2019). Today, the disturbance reserve does not include any capacity to reduce consumption, but it would be possible as long as other technical requirements are fulfilled (Svenska Kraftnät, 2019a). Furthermore, the disturbance reserve can be used to restart the electrical grid after a complete shut down and for island operation. The disturbance reserve is purchased by SvK with yearly/multi year contracts (Svenska Kraftnät, 2021h).

Power Reserve:

The power reserve can be activated in case of expected power shortage, typically during cold winter days with unfavorable weather conditions for wind and solar power production. The power reserve is contracted by Svenska Kraftnät and should be available between the 16th of November to the 15th of March. During this time, units that are part of the power reserve cannot participate on the day-ahead market (Svenska Kraftnät, 2021d). Svenska Kraftnät can order the power reserve to be ready for activation when they anticipate that the power supply will not be sufficient, and all the reserves available on the regulating market will not cover the need. In Sweden, the power reserve is constituted by the oil-fired power plant Karlshamnsverket. The power reserve from Karlshamnsverket takes hours to start (Svenska Kraftnät, 2021d). Consequently, Svenska Kraftnät must predict if it will be required in advance of the operating hour.

3.4.3 The Electricity Market in the Future

Currently, during the fall of 2022, both the electricity and energy market as a whole is in an extreme situation and, consequently, foreseeing the future is hard. However, reasonable long term estimations for the future state of the electricity market are still possible, although recent world events highlight the uncertainty of such estimations. Moreover, in order to face future and current challenges, the electricity market is currently undergoing many changes. Below some of these changes, as well as future estimates and scenarios for the electricity market are presented.

Current Changes

Generally, there is a strive within EU towards harmonization of the electrical markets and increasingly interconnected grids. Thus, many EU regulations and directives that affect the Swedish system have been presented during the recent years. An example is rules regarding capacity mechanisms, presented in regulation (EU) 2019/943 on the internal market for electricity, that affect the Swedish power reserve. The regulation states that the usage of capacity mechanisms is only allowed under special circumstances. Instead, obstacles that hinder a well functioning electricity market should be removed and/or the electric connections with other countries should increase (Swedish Energy Market Inspectorate, 2021).

Thus, to comply with EU regulations, Ei suggested changes in the current Swedish legislation regarding the power reserve. Three suggestions are of relevance for this thesis. Firstly, instead of the current terminology that states that Svenska Kraftnät ”are responsible for the availability of a power reserve of maximum 2000 MW”, it is suggested that Svenska Kraftnät, ”are allowed, as a last resort, to solve issues regarding resource adequacy, to ensure that a power reserve of maximum 2000 MW is available” (Husblad et al., 2020, p. 52). Secondly, it was suggested that facilities with energy storage should be able to be part of the power reserve. Finally, it was suggested that facilities which are part of the power reserve should not be allowed to take part in the balancing and electricity markets (Husblad et al., 2020).

Furthermore, the role as balance responsible party will be divided into two new separate actors, Balance Responsible Party (BRP) and Balancing Service Provider (BSP). The BRP will be economically responsible for the imbalances while the BSP will be a provider of ancillary services. The purpose of the change is to simplify participation on the balancing markets as well as promoting competition within the market (Svenska Kraftnät, 2022g).

Another project which aims for European and especially Nordic harmonization is the Nordic Balancing Model (NBM). With prerequisites such as finer granularity, increased trade closer to the operational hour, increased cross border exchange and more renewable, intermittent energy production, NBM is working on solutions to meet the future balancing needs on the Nordic market (Nordic Balancing Model, 2021b). Below some projects, deemed most relevant for hydrogen technology, within NBM are presented. To begin with, the granularity in the Nordic balancing markets, regarding the imbalance settlement period, imbalance price and cross border trading on intra-day, will be changed from 60 min to 15 min. The purpose of the change is to increase the market’s ability to handle imbalances between consumption and production of electricity (Nordic Balancing Model, 2021a). The activation time for mFRR will as a result probably be changed to 12.5 min (Nordic Balancing Model, 2022).

Furthermore, a Nordic market for mFRR will be implemented, instead of the national market present today. Consequently, the minimum bid size will be changed to 1 MW. Moreover, the activation market for mFRR, which is today operated manually, will be automated. Finally, compensation for FCR is planned to change to marginal price in 2024 (Goldberg, 2022).

Future Scenarios

In 2021 SvK presented a long term analysis of the electricity market. In the report the consequences on the electricity market of four different scenarios for the development of the Swedish energy market are analyzed. The scenarios are ”small scale renewables”, ”road-maps mixed”, ”electrification planable” and ”electrification renewables”. The resulting electricity prices varied for the different scenarios, but they all, except ”electrification planable”, resulted in electricity costs below 10 €/MWh, 20-40 % of the time by 2045. Furthermore, the scenarios resulted in a difference between the lowest and highest average weekly spot price during one year of around 50-100 €/MWh in SE3 in both 2035 and 2045 (Brunge et al., 2021).

Regarding the balancing markets, there is currently a maximum price limit on the Swedish regulating market on 5000 €/MWh, to be compared with the maximum limit in Europe on 99 999 €/MWh. When the Nordic countries join the European balancing markets, if not before, the maximum price limit will increase. The exact level is not yet decided, but it will be significantly higher than the current Swedish limit (Svenska Kraftnät, 2022h).

Local Flexibility Markets

As a consequence of the increased need for flexibility in the energy system, local flexibility markets have been introduced as a potential contributor to a more resilient electricity system. A problem today is that the power demand in certain areas cannot be met due to capacity limitations in the electrical grid lines on a local/regional scale even though enough power is available. A solution to this could be a local flexibility market, as a complement to the already existing balancing markets. Presently, there are only pilot projects of local flexibility markets (Power Circle, 2022). Depending on the challenges related to the respective local/regional grids, the purpose of the projects differ. One aim of the local flexibility markets is to reduce congestion in the regional grid and provide a solution for e.g. disturbances or lost production (Bjarup et al., n.d.). Another aim is to investigate if the project enables collaboration between network operators (Ruwaida et al., 2021).

Chapter 4

Hydrogen Technology

This chapter includes a literature review of hydrogen technology. The aim with the chapter is to provide basic understanding of hydrogen as an energy carrier, and hydrogen technologies. This includes hydrogen production via electrolysis, storage solutions, and electricity generation from hydrogen using fuel cells. Furthermore, more thorough information about some of the most established technologies is given, which is used as a decision basis for the design of the hydrogen system. Finally, this chapter provides insights in hydrogen economy, sector coupling using hydrogen, and financial instruments and taxation in relation to hydrogen.

4.1 Hydrogen as Energy Carrier

Hydrogen is a colorless, odorless gas constituted by two hydrogen atoms, each built up by one proton and one electron. Hydrogen has a low density of 0.0824 kg/m^3 at standard conditions. The low density results in a low volumetric energy content of 10 MJ/m^3. However, the specific energy (Lower Heating Value, LHV) is substantially higher with a value of 120 MJ/kg. This can be compared with e.g. gasoline and diesel, having a specific energy content of 47.3 MJ/kg and 44.8 MJ/kg, respectively (Sundén, 2019). The high energy content of hydrogen gas means that it potentially can pose as an important energy carrier. The chemical energy content of hydrogen can be converted into useful energy of other forms, such as electric energy.

Hydrogen gas is easily ignited, and mixtures of air and hydrogen gas are flammable and possibly explosive at a range of concentrations (Sundén, 2019). In mixtures of hydrogen and air, the gas is flammable for a hydrogen concentration of 4 % to 74 %. In mixtures of hydrogen and oxygen the gas is flammable in ranges of 4 % to 94 % of hydrogen (Rhodes, n.d.). Consequently, safety aspects are important when concerning hydrogen systems. However, hydrogen has been used in industries for over 100 years. Hence, knowledge of how to handle hydrogen is not lacking, and handling of hydrogen gas is regulated by Swedish law (Fossilfritt Sverige, 2021).

4.2 Classification of Hydrogen

Hydrogen can be classified into three main categories: *Green Hydrogen*, *Blue Hydrogen* and *Grey Hydrogen*. The classification is in principle based on how the hydrogen is produced, both regarding production method and source of the electricity being used. Hence, the climate impact from each type varies.

Green Hydrogen is produced using renewable electricity to drive the electrolytic process, which is a chemical process splitting water into hydrogen and oxygen gas (Fossilfritt Sverige, 2021). The electrolytic process is further explained in section 4.3. The green house gas emissions from this process is low. Furthermore, green hydrogen can also refer to hydrogen produced from other renewable energy sources such as biogas or biowaste through thermochemical or biochemical reforming, also resulting in a low climate impact for the production (Hydrogen Europe, n.d.).

Blue Hydrogen refers to hydrogen produced from fossil resources but with carbon capture and storage lowering the net climate impact. Additionally, hydrogen produced from electrolysis with electricity from neither renewable nor fossil sources but with low climate impact, such as nuclear power, is often also labeled as blue hydrogen. Other terminology for hydrogen produced in this manner is *Pink Hydrogen* or simply fossil free hydrogen (Fossilfritt Sverige, 2021; Hydrogen Europe, n.d.).

Grey Hydrogen is by far the most common type of hydrogen on the market today and is produced from fossil resources. Typically it is produced through steam methane reforming (SMR), or through coal gasification. Hence, the climate impact of grey hydrogen is high (Fossilfritt Sverige, 2021).

4.3 Production of Hydrogen Gas via Electrolysis

Hydrogen is not a primary energy source as it is not accessible in pure form in nature. Instead, hydrogen gas needs to be produced, which can be done in several ways. In this work, the focus is limited to hydrogen production from electrolysis of water. Electrolysis is the process of water being split into hydrogen gas and oxygen gas, by the means of electricity. The general reaction is described below.

$$\mathrm{H_2O} + \text{Electricity} \longrightarrow \mathrm{H_2} + \frac{1}{2}\,\mathrm{O_2} + \text{Thermal Energy} \tag{4.1}$$

Figure 4.1 illustrates the principal operation of an electrolyzer.

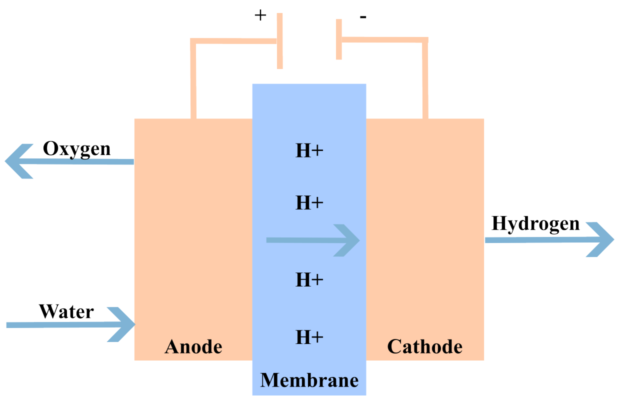

Figure 4.1: The principal operation of an electrolyzer.

An electrolyzer is an electrochemical cell in which the electrolysis occurs. It's typically constituted by two electrodes conducting current and an electrolyte conducting charged ions. The electrodes are connected to an electricity source. One electrode is called cathode, at which reduction happens. The second one is called the anode and this is where the oxidation occurs. The different designs of electrolyzers results in different chemical compounds being added and/or produced at different components in the electrolyzer. However, the overall reaction is always as described above (Sundén, 2019).

4.3.1 Alkaline Electrolysis Cell (AEC)

There are several different technologies for electrolysis. The most common historically is the alkaline electrolysis cell (AEC), that was developed in the beginning of the 19:th century. The principle of the alkaline electrolyzer is that the electrolyte is an alkaline solution, commonly NaOH or KOH. Both the anode and the cathode are immersed in the electrolyte and separated by a membrane. This allows free hydroxide (OH^-) ions to be transported from the anode to the cathode, through the membrane. Hydrogen gas is produced at the cathode side whereas oxygen gas is produced at the anode side (Buttler & Spliethoff, 2018). The half cell reactions can be seen below.

$$\text{Anode: } 2\,\mathrm{OH^-} \longrightarrow \frac{1}{2}\,\mathrm{O_2} + \mathrm{H_2O} + 2\,\mathrm{e^-}$$
$$\text{Cathode: } 2\,\mathrm{H_2O} + 2\,\mathrm{e^-} \longrightarrow \mathrm{H_2} + 2\,\mathrm{OH^-}$$

Typical electrode materials are Nickel, Nickel-Molybdenum and Nickel-Cobolt alloys (Schmidt et al., 2017). Nickel can also be used as a catalyst. None of the commonly used materials is particularly rare or expensive, which is an advantage. However, ongoing research aims to find other materials that can perform better.

The efficiency is at 65 % to 85 % and the the operating temperature is relatively low - at 20 °C to 80 °C. At higher temperatures, risk of corrosion occurs due to the alkaline electrolyte and sensitive electrodes. The maturity of the AEC technology is a strong advantage, as is the cost, and that the electrolyzer is relatively stable (Carlson et al., 2021). The start-up time if the cell is warm is at around 1 min to 5 min whereas the cold start-up time is at around 1 h to 2 h. The AEC is fairly dynamic when operating, which means that it could act as a balancing component for the electric grid. Load flexibility lies at 20 % to 100 % of nominal load. The lifetime of an AEC plant can be around 30 to 50 years. A stack typically has an operating lifetime of 55 000 h to 120 000 h (Buttler & Spliethoff, 2018).

4.3.2 Proton Exchange Membrane Electrolyzer (PEMEC)

Another technology is the proton exchange membrane electrolyzer (PEMEC) that has been strongly developed in the past decades and is one of the most commonly used technologies today (Carlson et al., 2021). The PEM electrolyzers has a solid polymer electrolyte - a proton exchange membrane that separates the two half cells. Typically, the electrodes are mounted to the membrane. This forms a so called membrane electrode assembly. Catalysts are required both for the anode and the cathode and typically iridium and platinum are used (Buttler & Spliethoff, 2018). However, this is a factor limiting competitiveness as the noble metals are scarce and thus expensive. Other materials that are being used as catalysts in PEMECs are e.g. metal sulfides and metal phosphides containing for instance iron, cobolt and nickel (Zhang et al., 2020). For the electrolysis mechanism, the water is supplied at the anode. Oxygen is therefore also produced at the anode as the water reacts. Hydrogen gas is produced at the cathode (Sundén, 2019). The half cell reactions are described below.

$$\text{Anode: } \mathrm{H_2O} \longrightarrow \frac{1}{2}\,\mathrm{H_2} + 2\,\mathrm{OH^-}$$
$$\text{Cathode: } 2\,\mathrm{H^+} + 2\,\mathrm{e^-} \longrightarrow \mathrm{H_2}$$

A strong advantage with the technology is that the production is flexible and the startup quick. The load can in principle vary between 0 % to 100 % of the nominal load. Start-up time when cold is at around 5 min to 10 min and warm start-up time is in the range of seconds. The possibility to operate the PEMEC flexibly makes it suitable as a grid balancing component (Buttler & Spliethoff, 2018). Operating temperature is 20 °C to 200 °C. Challenges related to PEMEC arise because of the rare resources being used in different components, and some of the materials being costly. The efficiency reported within HyCoGen is 59 % to 70 % (Carlson et al., 2021). However, suppliers of PEM electrolyzers state higher values. Green Hydrogen Systems report an efficiency of 73 % (Green Hydrogen Systems, 2022) while H-Tech Systems reports a system efficiency of 74 % (H-TEC Systems, n.d.). Lifetime for a PEMEC plant is reported to be around 20 years, whereas the stack lifetime has reported to vary between 20 000-100 000 operating hours (Buttler & Spliethoff, 2018; Schmidt et al., 2017).

4.3.3 Solid Oxide Electrolysis Cell (SOEC)

A third technology which is relatively new on the market is the solid oxide electrolysis cell (SOEC). Electrolyzers of this type have started to appear on the market in the recent years (Carlson et al., 2021). The electrolyte is composed of a solid ceramic material. Water is added at the cathode, where electrons are supplied from an external circuit which gives hydrogen gas and negatively charged oxygen ions (O^{2-}). The electrolyte allows oxygen ions to pass to the anode where oxygen gas is formed and electrons are generated (Sundén, 2019). The half cell reactions are presented below.

$$\text{Anode: } {O_2}^- \longrightarrow \frac{1}{2}\,O_2 + 2\,e^-$$
$$\text{Cathode: } H_2O + 2\,e^- \longrightarrow H_2 + {O_2}^-$$

A SOEC operates at high temperatures, at around 500 °C to 1000 °C and can have an efficiency of up to 100 %, making the technology promising for the future. The higher efficiency of the SOEC compared to AEC and PEMEC also leads to lower energy consumption. A potential challenge with the technology is that the constituent materials are sensitive to cool down to room temperature at times when the production plant is not in use. One solution to the problem is to always keep the parts in the plant warm, even when no hydrogen is produced, but it is uncertain how this affects the lifetime. Furthermore, energy is naturally required to maintain the high temperature of the stack. In addition, rare materials are used in the electrolyzer. This regards for instance zirconium and lanthanium, that are used in both electrodes and in the ceramic electrolyte (Carlson et al., 2021). Dynamic production is possible when the plant is hot, but if the electrolyzer is cold, start-up takes several hours. Warm start-up takes around 15 minutes. Load range is flexible for SOEC:s, and they even show potential of working in reverse mode, i.e. as a fuel cell. Load range can thus be considered to vary from −100 % to 100 % of nominal load. The lifetime of a SOEC is uncertain as the technology is new (Buttler & Spliethoff, 2018).

4.3.4 Summary & Comparison

In the table below, summarized specifications of the different technologies are given. The table can be used to get an overview of the different technologies, but should not be used alone.

Table 4.1: Summarized technical specifications of the three investigated electrolyzer types; AEC, PEMEC and SOEC.

Electrolysis technology	**AEC**	**PEMEC**	**SOEC**
Technical Maturity	Commercial	Commercial	New to Market
Operating Temperature [°C]	20-80	20-200	500-1000
Material and components	Ni, NiMo, NiCo	Pt, Ir, Ni, Co, Fe	Zr, La
Dynamical Operation	Limited	Yes	If plant is hot
Load Interval [% of nominal load]	20-100	0-100	-100 - 100
Warm start-up time	1-5 min	$\leq 10\,\mathrm{s}$	15 min
Cold start-up time	1-2 h	5-10 min	$\approx$ h
Lifetime plant [years]	30-50	$\approx$ 20	Uncertain
Lifetime stack [kh]	55-120	20-100	Uncertain
Efficiency [%]	65 - 85	59 - 74	Up to 100

4.4 Storage

This work is based on the potential of hydrogen as energy storage. Because hydrogen has a low volumetric energy content and is explosive in mixtures with oxygen, it is essential with safe and efficient storing technologies. An alternative for storage is in geological formations or fissures. However, this possibility is limited in the southern part of Sweden which is why storage in tanks adjacent to the use, either in gaseous or liquid form, is considered a reasonable alternative for storage on a larger scale (Swedish Energy Agency, 2022b).

In principle the main forms of hydrogen storage can be divided into physical-based storage and material-based storage, also denoted chemical storage. Physical storage includes hydrogen stored as compressed gas, cryo-compressed and liquid. In essence, material-based or chemical storage makes use of other materials as hydrogen carriers. Different substances are considered and hydrogen is either adsorbed, absorbed or chemically bonded to the material (Sundén, 2019).

Presently, few of the chemical storing technologies are commercially available (Kayfeci & Keçebaş, 2019) and will thus not be considered in this report.

4.4.1 Compressed Gas

Hydrogen stored as compressed gas is the most established form of storage. The technology requires tanks in which the gas can be stored, as well as compressors necessary to achieve the right pressure. The pressure in the tanks varies between 200 bar to 1000 bar, depending on what material the tanks consist of (Langmi et al., 2022). The compression of the gas implicates some energy losses. Approximately 5 % to 10 % of the energy content of the hydrogen is used to utilize the compression. However, the energy losses in the storage tank over time are considered negligible, as long as the system is closed, proper materials are used and design of the storage vessels is correct (Elberry et al., 2021).

4.4.2 Liquid H_2

Another method is to store hydrogen in liquid form, which is a relatively well-established method. The boiling point of hydrogen is at −253 °C at atmospheric pressure. This means that hydrogen needs to be cooled down substantially, which costs energy (Andersson & Grönkvist, 2019). The process requires energy equivalent to 25 % to 40 % of the energy content of hydrogen (Langmi et al., 2022). In addition, further energy losses are at risk due to the hydrogen evaporating (Sundén, 2019). This is referred to as boil-off and implicates loss in hydrogen as the evaporated hydrogen must be vented out from the storage tank to not risk too high pressures in the storage tank. Consequently, a sophisticated design of the storage tank is required to minimize heat transfer and hence losses (Andersson & Grönkvist, 2019). Advantages of the Liquid storage is a more compact form of storage in comparison with that in gaseous form. Furthermore, the form of storage is safer and entails significantly higher density compared to compressed gas storage.

4.4.3 Cryo-compressed storage

Another option that combines both temperature reduction and compression is cryo-compressed storage. This technology aims to overcome the problems with volume uptake and the need for very high pressures that compression storage entails, and the disadvantage of energy losses from boil-off that liquid storage entails. The hydrogen is cooled to −253 °C and then compressed at a pressure of

240 bar, resulting in a storage capacity of 87 kg/m^3. However, the solution is not yet commercially available and the costs are high (Langmi et al., 2022).

4.5 Electricity Production - Oxidation in Fuel Cell

As a final step of the hydrogen cycle, the hydrogen can be used as fuel for electricity generation in a fuel cell. A fuel cell acts as a reverse electrolyzer, in which hydrogen can be used as fuel, along with pure oxygen or oxygen supplied as air. In the chemical reaction, water is obtained as a product, and electricity and heat is generated, according to the reaction below.

$$H_2 + \frac{1}{2}O_2 \longrightarrow \text{Electricity} + \text{Thermal Energy} + H_2O \tag{4.2}$$

Figure 4.2 illustrates the principal operation of a fuel cell.

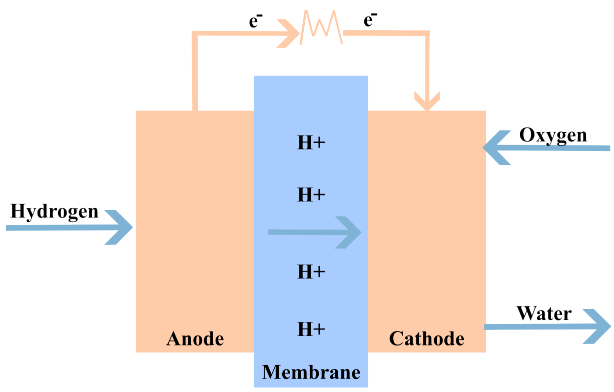

Figure 4.2: The principal operation of a fuel cell.

Below, a more thorough description of four types of fuel cells, considered to be most mature for the commercial market, is provided.

4.5.1 Proton-Exchange Membrane Fuel Cell (PEMFC)

Proton-exchange membrane fuel cells (PEMFCs) are currently used in several applications. PEM fuel cells have a high power density and are quick to start and regulate. After a minute, an efficiency of 50 % can be achieved and after a couple of minutes a stable level of efficiency is reached, with a value of up to 60 % (Carlsson et al., 2021). Marcus Wademyr at PowerCell states that for some applications, PEMFCs can start-up in the range of seconds (personal communication, October

5, 2022). The efficiency varies among different suppliers and usage, and between stack and system. The efficiency is typically higher in partial load ranges compared to operation at full load. Furthermore, as the technology is relatively new, the efficiency is constantly improved. Efficiencies between 40 % to 60 % have been reported in literature (Carlsson et al., 2021; PowerCell, n.d.; Sundén, 2019). Typical operating temperatures are 80 °C to 120 °C (Sundén, 2019). Challenges with the technology are that rare and expensive materials such as platinum and ruthenium are used in the structure to achieve a high efficiency, and that the fuel cell requires high purity of the hydrogen supplied as fuel. Applications at present are for transport, as well as backup power and portable power source (Carlsson et al., 2021). The lifetime of PEM fuel cells are reported to vary, and it is hard to determine since the technology still is relatively immature. Lifetimes between 40 000 h to 80 000 h have been reported in literature (Cigolotti et al., 2021). Furthermore, lifetime depends on application and use of the fuel cell. Marcus Wademyr at PowerCell, a company offering PEM fuel cells, state an approximate lifetime of 20 000 h to 30 000 h, mainly depending on application and hence how the fuel cell is operated (personal communication, October 5, 2022). Within the project HyCoGen, a lifetime of 20 000 h is assumed (personal communication, September 28, 2022). PEM fuel cells are cooled with an active cooling system with water as coolant (Carlsson et al., 2021).

4.5.2 Solid Oxide Fuel Cell (SOFC)

Solid oxide fuel cell (SOFC) is another technology currently being researched a great deal. An advantage with the technology is that the materials are relatively inexpensive, and that it can be designed in different ways, which provides greater flexibility for different applications (Carlsson et al., 2021). A SOFC has high operating temperatures, around 500 °C to 1000 °C, which means that expensive catalyst materials are not required to achieve a high reaction rate. Heat is recovered within the unit to warm the inflow of gas and consequently the temperature of the outflow gas is relatively low, despite the high operating temperature (Carlsson et al., 2021). Typical efficiency is at 60 %. Applications for which SOFCs are used are as decentralized electric power and for electricity generation. Strengths with the technology is that it is good for combined electricity and heat generation and that it can be combined with gas turbines to achieve higher efficiency. In addition, SOFC is not sensitive to fuel pollution and thus different fuel types can be used. Disadvantages of the technology is that use is not very flexible due to long start-up time, as well as the number of cycles for start-up and stop being limited, posing as a risk to affect the lifetime negatively (Sundén, 2019). Reported values of expected lifetime are 20 000 h to 90 000 h (Cigolotti et al., 2021).

4.5.3 Molten Carbonate Fuel Cell (MCFC)

Molten carbonate fuel cell (MCFC) is a technology developed since the 50s and today the fuel cell is available in several different applications, primarily for decentralized electric power, electricity generation and for combined electricity and heat generation. The operating temperature is 600 °C to 700 °C and typical efficiency is 50 %. SOFCs alike, MCFCs can be combined with a gas turbine and run on different fuels. The technology has no existing active cooling system with water, instead heat recovery is possible from the warm exhaust gas. A strong disadvantage of the technology is that the start-up time is long. It takes about 10 h before a MCFC plant can run at full power. An MCFC also has slow dynamics and is only able to change operating power with 10 %/h. Furthermore, the plants are very sensitive to start-up/shutdown, which is why existing plants run basically without stopping. Finally, the high operating temperature means that components risk corroding, something that limits the lifetime (Carlsson et al., 2021). Values of lifetime reported in literature are 15 000 h to 30 000 h (Cigolotti et al., 2021).

4.5.4 Phosphoric Acid Fuel Cell (PAFC)

Phosphoric acid fuel cells (PAFCs) have been on the market since the 90s and were thus one of the earliest commercialized fuel cell types. Applications are mainly available as decentralized electric power and as combined heat and power generation. However, today there are not many manufacturers of PAFC and the fuel cell type is not well established on the market (Carlsson et al., 2021). PAFC typically has an efficiency around 40 % to 50 % and operates on temperatures between 150 °C to 200 °C (Sundén, 2019). PAFC is relatively insensitive to impurities in the fuel, except when it comes to sulphur. Disadvantages are, for example, costly catalysts and slow start-up. However, the fuel cell type is flexible when operating and the operating power can be regulated up and down within a couple of minutes. Moreover, like PEMFC, PAFCs are cooled with an active cooling system which simplifies integration with district heating (Carlsson et al., 2021). Lifetime seem to vary greatly according to literature and lie between 30 000 h to 130 000 h (Cigolotti et al., 2021).

4.5.5 Summary & Comparison

In table 4.2 below, some of the characteristics of the technologies describes above are summarized.

Table 4.2: Summarized technical specifications of the investigated fuel cell technologies.

Fuel Cell Technology	**PEMFC**	**SOFC**	**MCFC**	**PAFC**
Technical Maturity	Commercial	Commercial	New to Market	Not Established
Operating Temperature [°C]	80-120	500-1000	600 - 700	150 - 200
Start-up time	Quick	Long	Long	Long
Dynamic Operation	Yes	No	No	Yes
Lifetime [kh]	20-80	20-90	15-30	30-130
Electrical Efficiency [%]	40-60	60	50	40-50

4.6 Sector Coupling

Sector coupling refers to increased integration between actors in the energy system, i.e. the various energy consuming and energy producing sectors, respectively. To interconnect different sectors could provide increased flexibility and efficiency of the energy sector, and could also increase the pace of decarbonization due to cost reductions (Van Nuffel et al., 2018). It is evident that hydrogen is a versatile energy carrier with potential to participate in, and aid decarbonization of, multiple sectors. Hence, hydrogen is suggested as an option to achieve increased sector coupling and consequently the hydrogen market is expected to grow (IRENA, 2019).

There are various way to use hydrogen in addition to electricity generation. Within EU, the yearly usage of hydrogen is around 339 TW h. Today, the vast majority of the hydrogen usage is in industrial processes. It is used in the chemical industry for production of e.g. methanol, ammonia and chlorine gas. Furthermore, it is used in refineries and for metallurgical processes (Fossilfritt Sverige, 2021).

There are multiple other sectors in which hydrogen has a potential to contribute to reduced climate impact and increased flexibility of the energy system. For example, hydrogen can be mixed into e.g. biogas or natural gas to be used in combustion processes (e.g. in gas turbines), or injected into natural gas grids for heating of buildings. Moreover, hydrogen can also be used in the transport sector, for instance as a fuel in fuel cell electric vehicles (FCEV's) but also for the maritime sector and long-haul trucking industry. There are already vehicles using hydrogen as fuel, but the share of hydrogen used is currently negligible. However, Sweden's aim to reduce the emissions from the transport with 70 % until 2030 could pose as an incentive for increased usage of hydrogen in the transport sector. Hydrogen is also expected to be used for production of electrofuels (i.e. various types of fuels that are produced from hydrogen and captured CO_2, possessing similar characteristics as traditional fossil fuels), that has a potential to replace fossil fuels mainly in the aviation industry (Fossilfritt Sverige, 2021).

In this work, the end use of hydrogen will not be examined. Nevertheless, the potential profitability of selling hydrogen instead of producing electricity is investigated and thus a brief review of the economy of hydrogen at present and the future is presented below.

4.7 Hydrogen Economy

The cost of producing hydrogen varies greatly depending on production method. Levelized Cost of Hydrogen (LCOH) is according to IRENA (2019) varying in the range between around 1.5 $\mathrm{USD/kg_{H_2}}$ to 7 $\mathrm{USD/kg_{H_2}}$. Green Hydrogen is estimated to be around 2 to 4 times more expensive than the most feasible fossil based alternative. The competitiveness of green hydrogen is projected to increase though, resulting from both cheaper renewable electricity and reduced investment cost of electrolyzers (IRENA, 2019).

The market price for hydrogen seem to fluctuate. This depends on multiple factors, such as the production method for the hydrogen, as well as which market sector it is sold to. The market price for industrial hydrogen is generally lower compared to other sectors, primarily because the hydrogen is fossil based and thus cheaper to produce. Moreover, prices of electricity and natural gas as well as other fossil fuels have a large impact on the final market price (Nordin Fürdös et al., 2022). The price also varies greatly in different countries. Recently, highly fluctuating electricity prices and expensive natural gas has also had an impact on the hydrogen gas price. During April 2022 it was reported that the price for green hydrogen was cheaper than that of grey hydrogen in parts of Europe, the Middle East area and Africa, as a result of the record high prices on natural gas (Witsch, 2022). However, it was also reported in July 2022 that the prices for green hydrogen in the U.S. had increased almost threefold due to raised electricity costs (Penrod, 2022).

For this work, Swedish prices for green hydrogen are relevant. The hydrogen price at a Swedish gas station was reported to be 90 $\mathrm{SEK/kg_{H_2}}$ during 2021 (Alpman, 2021). The selling price for a hydrogen production facility to a distributor will naturally be lower. Furthermore, within the project HyCoGen the value of green hydrogen for different sectors was investigated. For the steel making industry, it was estimated to be $\leq$25 $\mathrm{SEK/kg_{H_2}}$ for the usage to be competitive with other types of hydrogen. Furthermore, the value of hydrogen was evaluated to range between 25-60 $\mathrm{SEK/kg_{H_2}}$ for the automotive sector. Finally, is was stated that green hydrogen for the industry faces challenges in competing with the alternative of grey hydrogen used in the industry sectors, but values up to 40 $\mathrm{SEK/kg_{H_2}}$ occur

(Nordin Fürdös et al., 2022).

4.8 Financial instruments

Presently, there are financial incentives to increase the pace of investment in hydrogen technology. The European Union (EU) aims to invest €430 billion in hydrogen by 2030 and Swedish actors have a great opportunities to take part in these investments (Fossilfritt Sverige, 2021).

There are also several opportunities to apply for grants for hydrogen projects from Swedish actors. Among others, it is possible to seek financial help through ”industriklivet”, ”klimatklivet” and ”regionala elektrifieringspiloter”. Additional instruments are government credit guarantees and loan guarantees for climate investments that reduce risk the banks’ take when lending to companies that want to invest in sustainable projects (Swedish Energy Agency, 2022b).

Furthermore, EU ETS is mentioned as one of the main incentives for investments in hydrogen technology in Sweden’s national hydrogen strategy. However, it is estimated that the prices for emission allowances, depending on the electricity price, will need to increase to 100-200 €/tonne of carbon dioxide in order for fossil-free hydrogen to become competitive with fossil hydrogen. Moreover, even when green hydrogen is not used to directly replace fossil hydrogen, the investment in fossil-free hydrogen, if used to avoid the use of fossil fuels, can result in large cost savings at high prices for emission allowances (Swedish Energy Agency, 2022b).

In the future, the cost of electrolyzers is also expected to fall, provided that demand increases. In Sweden’s national hydrogen strategy, this aspect is emphasized as crucial for the future of technology. In order for prices to fall, more electrolyzers need to be constructed. Therefore, to achieve the market potential and cost savings for electrolyzers, policy instruments may be needed in the commercialization phase. The national strategy thus outlines a need for additional financial incentives. However, no concrete proposals are mentioned, but further studies to map the needs and design of such instruments are recommended (Swedish Energy Agency, 2022b).

4.9 Taxation in Relation to Hydrogen as Energy Storage

In this section, a brief introduction of the current taxation and legislation regarding hydrogen technology is provided.

For the case of hydrogen production using an electrolyzer, the energy taxation on electricity is of relevance as the electrolyzer with its peripheral components consumes electricity. In general, consumers of electricity pay a certain amount of tax based on the amount consumed. The tax differs depending on the type of business and whether the electricity is consumed in the northern or southern part of Sweden, among other things (Swedish Energy Agency, 2022a). Furthermore, a tax relief can be designated for certain consumers depending what the electricity is used for. According to the Swedish Tax Agency, Skatteverket, a tax relief of 100 % is applicable for actors using electricity for electrolytic processes (Skatteverket, n.d.).

Within the project HyCoGen at RISE, a study has been conducted regarding policy instruments and taxes for hydrogen production, storage and consumption in combination with CHP plants. The main conclusion drawn is that energy taxation, due to the technology's large electricity consumption, has a major impact on the economy of the business. At present, to what extent a business receives tax relief depends on its ”main business”. The electricity used directly in the electrolyzer is regardless subject to a tax relief of 100 %. Instead the difference concerns the electricity to peripheral components, such as pumps and compressor, surrounding the electrolyzer.

District heating companies usually do not receive any tax relief on the electric energy they use, and pay the standard tax of 36 öre/kWh while most industrial companies only pay an energy tax of 0.6 öre/kWh (Skattevarket, n.d.). The values are applicable for the year of 2022. As a consequence of the different tax rates, cogeneration companies that integrate hydrogen production into their operations risk incurring higher tax costs on electricity to components that surround the electrolyzer than a hydrogen, or other industrial, company (Dotzauer et al., 2021).

According to Dotzauer et al. (2021), the law regarding taxation on electricity for electrolytic processes is ambiguous and it is unclear which electricity consuming components involved in the electrolytic hydrogen production that are covered by the law regarding tax relief. In the report, the cogeneration company Karlstad Energi that owns a hypothetical hydrogen plant is compared to a hydrogen company owning the same plant. For these two operators, the estimated tax differences amount to 2.7 million Swedish crowns annually, if a difference in taxation because of the difference in ”main business” is assumed (Dotzauer et al., 2021). Thus, Dotzauer et al. (2021) state that the tax policy regarding hydrogen needs to be reviewed to ensure fair competition in the market and that environmental friendly, more efficient ways of producing hydrogen are not disfavored.

Chapter 5

The Integrated System

This chapter provides an assessment for which of the investigated hydrogen technologies that are best suited both to be used in connection to a CHP plant, and to provide ancillary services. The characteristics and parameters connected to those technologies are used for the modeling and optimization of the hydrogen system. Furthermore, the chapter describes the implications of the chosen technologies, with focus on how residual heat from the electrolyzer and fuel cell can be used and the possibility for them to participate with ancillary services.

The complete integrated Hydrogen System is presented in figure 5.1 and the P2G system is presented in figure 5.2. The arrows represent energy flows between the components and the size of the arrows illustrate the relative amount of energy flowing between the units.

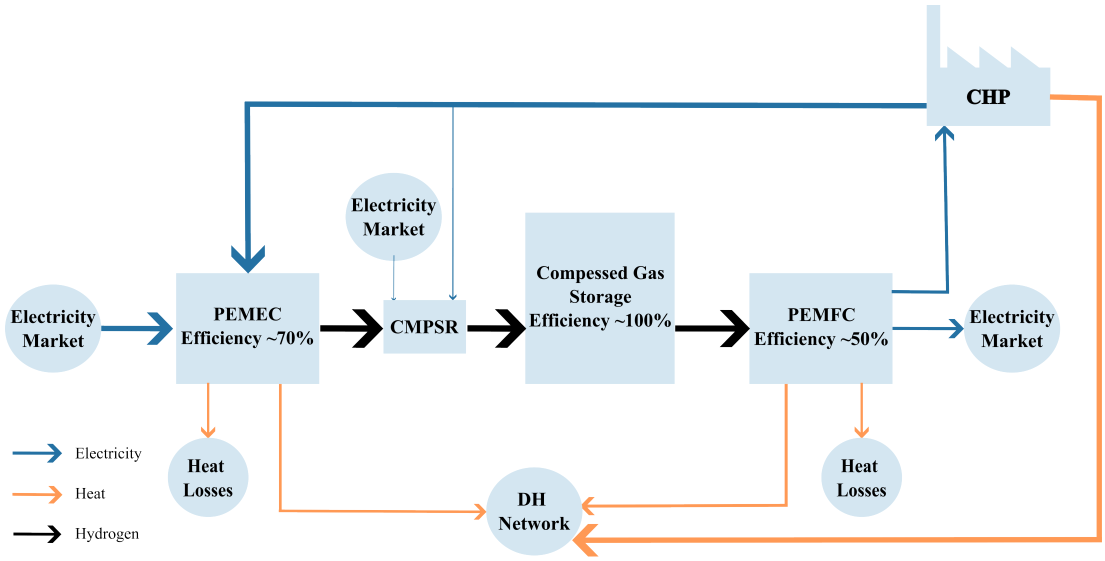

Figure 5.1: A schematic energy diagram of the Hydrogen System model.

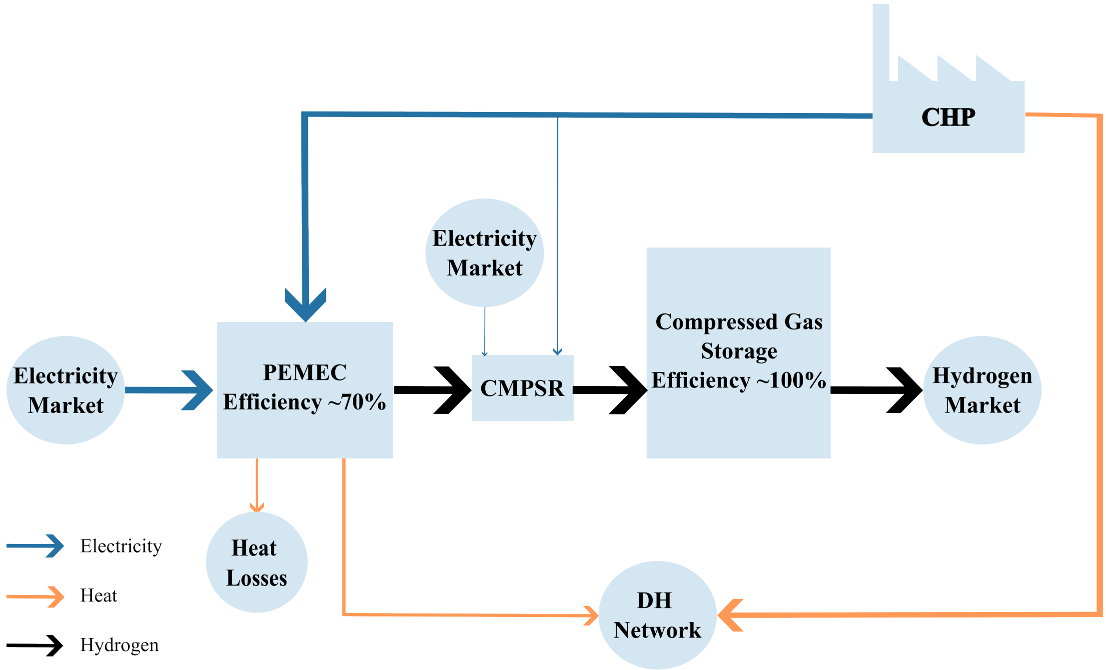

Figure 5.2: A schematic illustration of the P2G system model.

The chosen electrolyzer is in both scenarios a PEMEC and the chosen storage is compressed gas storage. In the Hydrogen System Scenario, the chosen fuel cell is a PEMFC. Both in the P2G and in the Hydrogen System, the residual heat from the hydrogen system is assumed to be directly injected into the district heating network at Örtofta. Heat transferred to the heat sinks is both the heat that cannot be unitized due to technical reasons as well as heat that is not profitable to utilize. Motivation for the chosen technologies is presented below.

5.1 Choice of Technologies

This section presents motivations for choosing the specific technologies. The decision is based on factors such as technical maturity, possibility of utilizing residual heat, efficiency, and most importantly ability to operate flexibly. This as a major purpose of this thesis is to analyze the potential for hydrogen technology to act on the balancing markets, in which fast activation time is required, as seen in table 3.1.

5.1.1 Motivations for Chosen Electrolyzer

The most suitable electrolyzer was determined to be a PEMEC. The AEC is both more mature and has higher efficiency than PEMEC. However, the main advantage with PEMEC over AEC is its fast response times and strong ability to operate flexibly. PEMECs have faster start-up times compared to AECs, and are able to operate at a wider load range. As one purpose of this work is to investigate how hydrogen can contribute with ancillary services, this aspect was determined most important. SOEC was determined not suitable mainly since it is not suitable for flexible operation and in addition is not well established on the market yet.

5.1.2 Motivations for Chosen Storage

The most suitable storage option was evaluated to be compressed gas storage, even though the method is indeed the most space requiring one. For this case study though, the aspect of minimizing energy losses and the maturity of the technology were considered most important. Liquid storage was ruled out based on high energy losses associated with liquefaction. The cryo-compressed storage was not considered a viable solution due to the low maturity of the technology. There are several different solution types and systems for compressed gas storage which are not described in detail in this work.

5.1.3 Motivations for Chosen Fuel Cell

Regarding the fuel cell type, the PEMFC was determined to be most suitable. One important aspect is the advantage in dynamic operation compared to the other investigated technologies. Just as for the PEM electrolyzer, essential characteristics are the quick start-up and possibility for dynamical operation. Furthermore, the technology is the most mature on the market and the efficiency is relatively high. All other investigated fuel cell types (i.e. SOFC, MCFC and PAFC) are stated to be suitable for combined heat and power generation. However, the technologies are less mature than the PEMFC technology. In addition, none of them have the same ability of dynamical operation.

5.1.4 Investment Cost and Lifetime of Hydrogen System

In the investment cost used to compute Payback Time for the hydrogen systems only the cost for the actual components are considered. This includes the investment costs for the electrolyzer, compressor, storage and in the case of the Hydrogen System, fuel cell. No cost surrounding the implementation of a hydrogen system are included. Surrounding costs are for example costs related to permits, additional pipelines, control system and cost associated with redesigning units to enable heat recovery. In addition, the investment cost of the components is assumed to be linearly scalable with size. All investment costs were retrieved from HyCoGen. The values concern a PEM electrolyzer, a compressor, a compressed gas storage tank with tubular container system and a PEM fuel cell (HyCoGen, personal communication, September 28, 2022). Due to NDA no absolute values are presented for investment costs.

We assume a lifetime of 20 years for the electrolyzer, compressor, hydrogen storage tank and fuel cell. This value is mainly based on the literature review in chapter 4 and information provided by HyCoGen (personal communication, September 28, 2022).

5.2 Implications for Chosen Technologies

This section provides more thorough information of the potential of utilizing residual heat from a PEMEC and a PEMFC. Moreover, an evaluation of how the chosen technologies can participate on the electricity markets and provide ancillary services and other reserves is provided.

5.2.1 Utilization of Heat

Utilizing residual heat from a hydrogen system is not without technical challenges. Within HyCoGen, some of these aspects have been evaluated. Regarding technical prerequisites, the outlet temperature of the cooling water is 55 °C to 65 °C for PEM electrolyzers (Carlson et al., 2021). Regarding PEMFCs, a possible theoretical heat recovery of 97 % is presented by suppliers (HyCoGen, personal communication, September 28, 2022). Marcus Wademyr at PowerCell states a temperature of 60 °C to 80 °C for the residual heat of PEMFCs (personal communication, October 3, 2022), whereas the company themselves state an outlet temperature of 80 °C for the coolant in their data sheet for a 100 kW PEMFC (PowerCell, n.d.). Heat recovery from PEMFCs is simplified by the already existing active cooling system (Carlsson et al., 2021).

By interviewing manufactures of electrolyzers, RISE has been able to conclude that utilization of residual heat with a temperature above 50 °C from the electrolyzers is possible, but would require special designs of the units. However, the manufactures were unable to define the cost of such changes. Furthermore, beyond the cost of redesigning components, utilization of residual heat require investments in pipelines, possibly high temperature heat pumps and other structural components (Carlson et al., 2021).

Below in table 5.1 the theoretical possibility for heat recovery and outlet temperatures of the cooling water are summarized for PEMEC and PEMFC. The same theoretical heat recovery is assumed for PEMEC as for PEMFC.

Table 5.1: Theoretical possibility for heat recovery and outlet temperature of residual heat for PEMEC and PEMFC.

Technology	**PEMEC**	**PEMFC**
Theoretical Heat Recovery [%]	97	97
Temperature Residual Heat [°C]	55 to 65	60 to 80

The forward and return temperatures in district heating networks vary, but are on average in Sweden 86.0 °C and 47.2 °C, respectively (Frederiksen & Werner, 2014). However, the forward temperature varies with season and it is possible that 60 °C residual heat is enough at times, especially at lower energy flows and during summer (Kraftringen, personal communication, October 7, 2022). In our model residual heat from the hydrogen system is assumed to be of high enough temperature to be injected directly into the district heating network, without affecting the forward temperature. A scenario in which temperatures of the residual heat are in the lower range of the interval presented in table 5.1, is examined with the implementation of heat pumps in a sensitivity analysis in section 8.1.

5.2.2 The Role of the Hydrogen System on the Electricity Market

Regarding the role of PEM electrolyzers and fuel cells on the electricity markets, they can both act on the day-ahead and intra-day spot markets. The electrolyzer can produce hydrogen when spot prices are low, whereas the fuel cell can sell electricity produced from hydrogen at times of high spot prices. Another benefit with introducing fuel cells in connection to local electricity grids is that local production of electricity can help avoid the exceeding of subscribed capacities at high loads (Lindblad et al., 2022).

Furthermore, the electrolyzer and fuel cell can also act on the balancing markets by the provisioning of ancillary services. Below in table 5.2 an overview of which ancillary services and reserves that PEMECs and PEMFCs can provide is presented. Some of the ancillary services require the units to be on stand by, i.e. kept warm, in order to achieve the required activation time indicated in table 3.1.

Table 5.2: Ancillary Services and Reserves that a PEMEC and PEMFC, operating within a CHP plant, can qualify for.

Balancing Technology	PEMEC	PEMFC
FCR-D	Yes	Yes
FCR-N	Yes	Yes
aFRR	Yes	Yes
mFRR	Yes	Yes
FFR	Yes*	No
Disturbance Reserve	Yes**	Yes***
Power Reserve	No	No

* It is uncertain if the PEMEC can reach the activation time
** If the electrolyzer is continuously operated.
*** If enough hydrogen and regulating capacity is always available.

Within HyCoGen, RISE has examined the potential for hydrogen systems to provide system services. The report concludes that PEM fuel cells can be qualified for all of SvK's ancillary services, except FFR, while PEM electrolyzers can qualify for all of SvK's ancillary services. However, the type of service that is most suitable is highly dependent on operation, regarding both electrolyzers and fuel cells. Participating with FFR and FCR-D means contributing mainly with capacity and not energy, as the activation ratio of FFR and FCR-D is relatively small. For FFR the energy exchange is negligible and regarding FCR-D, on a yearly basis, 0.3 % of the available power is activated. The other ancillary services have a bigger effect on the actual operation of the hydrogen system. Thus the normal operation and purpose of the hydrogen system has a big effect on which balancing services that are suitable (Goldberg, 2022).

Regarding the reserves, the operation of the hydrogen system within a CHP plant, which trades on the spot market, disqualifies it from participating in the power reserve. Both PEMEC and PEMFC could however theoretically participate in the disturbance reserve, if limitations are imposed on their operation. Units participating in the disturbance reserve need to have sufficient capacity for up-regulation ready at all time. Thus, in order for a PEMEC to participate, it needs to be continuously operated. In order for a PEMFC to participate in the disturbance reserve, enough hydrogen as well as up-regulating capacity needs to be available at all times.

It should be noted that frequently starting and stopping the electrolyzer and fuel cell can increase the wear on the components, especially if the units are cold-started. A way of reducing the wear, and also increasing the flexibility of the units is to keep the stack heated at operating temperature also when not operating. Possibly, a heated stack would enable a PEMFC to contribute with FFR-services, but this needs to be investigated further (Marcus Wademyr, PowerCell, personal communication, October 10, 2022).

An evaluation of the potential profitability of participating on the frequency balancing markets was made within HyCoGen. In conclusion, the report states that participating in the frequency balancing markets can result in substantial revenues for an owner of electrolyzers and/or fuel cells.

Furthermore, the project HyBalance, lead by Air Liquide, has demonstrated the possibility of PEM electrolyzers to contribute to the balancing of the electricity grid on an industrial scale. In 2018 a facility with PEM electrolyzers with a capacity of 1.25 MW was inaugurated in Hobro, Denmark. Since then the performance of the project has been evaluated. Regarding economics, the facility is active on both the balancing markets and the spot electricity market. The plant is certified by the Danish energy authorities as a bidder for all electricity markets and both prices on the spot and capacity markets determine how the plant is operated. However, HyBalance emphasizes the need for optimization tools to improve the operation of the plant. With such tools the assessment is that grid balancing services could result in revenues equal to 15 % to 25 % of the electricity cost (HyBalance, 2021).

Chapter 6

Modeling and Simulation

This chapter describes the created models in Energy Optima 3, the general methodology of the simulation, as well as the different optimization scenarios. In principal, two different main models are created, denoted as Base Model and Balance Model. The Base Model includes the hydrogen system integrated with the energy system of Örtofta, with electricity trading exclusively on the day-ahead spot market. The Balance Model is a separate model that studies participation on the balancing markets, i.e. contribution with ancillary services. The optimizations are performed separately for the two models. Within both the Base Model and the Balance Model, different scenarios are studied. The optimizations are performed for the historical period between 1st of October 2021 and 1st of October 2022 for all scenarios.

Section 6.1 describes the overall methodology of the simulation part, and how the two models are connected. An overview of the results produced from the different models and scenarios is also provided. Section 6.2 describes the Base Model, the scenarios included and how the optimizations are performed. Finally, section 6.3 describes the Balance Model, how the participation on the balancing markets is modeled in Energy Optima 3, the scenarios investigated and how the optimizations are performed.

6.1 Overall Methodology of Modeling and Optimization

Figure 6.1 below, also presented in chapter 1, provides an overview of the simulation methodology.

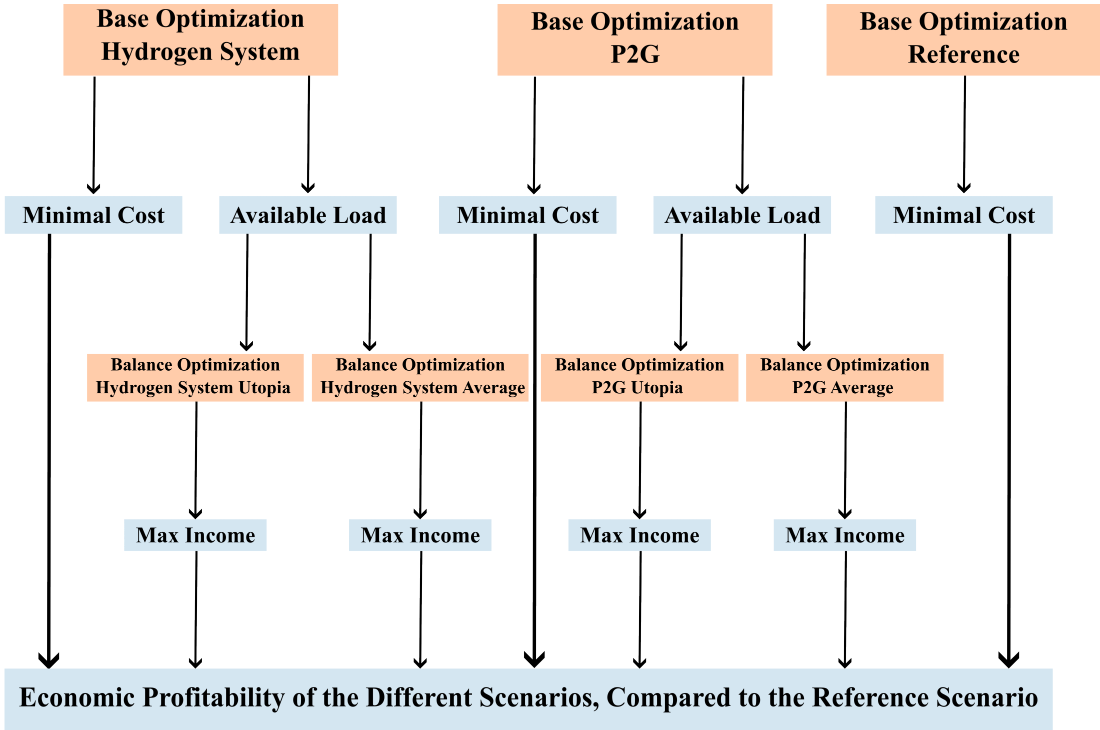

Figure 6.1: An overview of the overall methodology of the optimizations.

As indicated in figure 6.1, initially the Base Model is optimized. This is done for three different scenarios: Hydrogen System, P2G and Reference. The result from the Base Model, namely the operational load of the electrolyzer and fuel cell, determines the available capacity for up- and down-regulation in the Balance Model. Thus, the result from the Base Model is used as input data in the Balance Model. The optimization of the Balance Model is performed to determine which ancillary services to offer every hour. The Balance Model includes two different scenarios: Utopia and Average, with different pricing mechanisms. In total, when the two models are combined, the results from four complete scenarios are obtained, Hydrogen System Utopia, Hydrogen System Average, P2G Utopia and P2G Average. The different scenarios are explained further in section 6.2 and 6.3.

There are two main reasons for performing the Base and Balance optimizations separately. Firstly, in reality a basic production plan with participation on the day-ahead market is usually optimized first. This optimization determines the amount of electricity bought and sold at the spot market, as well as the amount of capacity that potentially could be sold at the balancing markets. By doing separate optimizations, this procedure is imitated.

Secondly, due to limitations in the software used, it would have been complicated to include the model of the balancing markets and the investigated energy system (i.e. hydrogen system integrated with the CHP-plant) in the same model. This as trading on the day-ahead market concerns energy, whereas provision of ancillary services mainly concerns capacity. The two models and the scenarios will be further explained in section 6.2 and 6.3.

6.1.1 Economic Evaluation of the Scenarios

The profitability of the hydrogen system is evaluated in terms of Payback Time, calculated according to equation 6.1.

$$\text{Payback Time} = \frac{\text{Investment Cost}}{\text{Profit}} \tag{6.1}$$

Investment Cost refers to the investment cost of the hydrogen system and Profit refers to the increased income that the implementation of the hydrogen system generates, compared to the Reference Scenario. The profit is calculated according to equation 6.2 below.

$$\text{Profit} = \text{Total Profit Hydrogen Scenario} - \text{Total Profit Reference Scenario} \tag{6.2}$$

The total investment cost for the hydrogen system includes the investment cost for the electrolyzer, compressor, storage and, in the Hydrogen System, fuel cell. These values were obtained from HyCoGen (personal communication, September 28, 2022). No surrounding cost for connections, additional buildings, permits etc. are included in the total investment cost for the systems.

The profit, investment cost and resulting Payback Time is calculated for all four hydrogen scenarios, presented in figure 6.1. Investment cost is not presented due to NDA.

6.1.2 Overall Efficiency of the Hydrogen Systems

The overall efficiency of the complete Hydrogen System is calculated according to equation 6.3.

$$\eta_{tot} = \frac{Q_{Utilized} + W_{FC}}{W_{EC}} \tag{6.3}$$

where $Q_{Utilized}$ is the total amount of residual heat from the hydrogen system that is utilized in the DH network, W_{FC} is the total output of electrical energy from the fuel cell and W_{EC} is the total input of electrical energy to the electrolyzer.

The overall efficiency of the P2G system is calculated according to equation 6.4 below.

$$\eta_{tot} = \frac{Q_{Utilized} + H_{H_2}}{W_{EC}} \tag{6.4}$$

where $Q_{Utilized}$ is the total amount of residual heat from the hydrogen system that is utilized in the DH network, H_{H_2} is the energy content of the total amount of produced hydrogen and W_{EC} is the total input of electrical energy to the electrolyzer.

6.1.3 Overall Results

Apart from the Payback Time, calculated by equation 6.1, and overall efficiencies, calculated by equations 6.3 and 6.4, other results are produced and presented to help answer the research questions. Below, all relevant results from the optimizations are summarized.

Base Model - Results

- Production plans of the systems that specify the operation of electrolyzer and fuel cell, and change in hydrogen storage content.
- Increased profit of the scenarios compared to the Reference scenario, [%].
- Amount of utilized heat, [%].
- Payback Times for the respective systems.
- Average spot price for electricity when the electrolyzer and fuel cell operate, respectively.
- Overall efficiencies for the hydrogen systems.
- Type of fuels replaced by the hydrogen system.
- Cost factor analysis.

Balance Model - Results

- Evaluation of participation on the balancing markets for all scenarios. Presentation of the total amount of capacity offered for up- and down-regulation and of the amount offered for each ancillary service.
- Increased profit from participation on the balancing markets for all scenarios, compared to the Reference scenario, [%].
- Payback Time for all scenarios.

Total - Results

- Increased profit for the complete scenarios, i.e. the combined results from Base Model and Balance Model, compared to the Reference scenario, [%].
- Payback Time for the complete scenarios, including results both from Base Model and Balance Model.

6.2 Base Model

In this section, the different systems included in the Base Model are described. The systems included are a model of Örtofta's CHP plant, integrated with EVITA, the Hydrogen System and the P2G System. Moreover, a description of the methodology for simulation and optimization of the Base Model is included.

6.2.1 Scenarios

The Base Model is divided into three different scenarios that are optimized separately and compared. The following scenarios are optimized:

- **Hydrogen System Scenario**
  The complete hydrogen system with electrolyzer, storage and fuel cell integrated within Örtofta CHP plant is optimized to investigate how hydrogen technology can act as a flexibility resource during times of both low and high electricity availability.
- **P2G Scenario**
  In this scenario, only an electrolyzer and a storage unit is integrated with Örtofta CHP plant, and the hydrogen is sold instead of used for electricity generation. The scenario is included to enable a comparison of profitability between selling electricity produced from hydrogen and selling hydrogen directly.
- **Reference Scenario**
  The Reference Scenario is an optimization of the EVITA system alone and represents the normal operation of the plants, without the integration of any hydrogen technology. This scenario is used as a basis for comparison, to investigate the possible profitability of incorporating hydrogen technology within the existing energy system.

6.2.2 Kraftringen's Energy System

Kraftringen is together with Öresundskraft and Landskrona Energi part of the bigger district heating system EVITA. EVITA covers Helsingborg, Landskrona and Lund and contains production units spread out in the area. This system is already modeled in the software, and provided to us by Energy Opticon.

Kraftringen has already implemented a low temperature network in Brunnshög in Lund. They are also planning an expansion of low temperature district heating in other parts of Lund, something that enhances the possibility of utilizing residual heat. The forward temperature in Kraftringen's district heating network differs both depending on season and location. Naturally, the low temperature network has lower forward temperature than the conventional network. Kraftringen is planning the construction of a new CHP plant in Örtofta. The construction of a new plant implies a good opportunity to integrate new technologies and therefore the location of the hydrogen system is set to Örtofta. In the district heating network connected to Örtofta, the forward temperature of the conventional network is applicable. In the future however, this could change.

Kraftringen currently pays certain fees and taxes related to their electrical export and import to and from the grid at Örtofta. These fees are included in the model and are summarized in table 6.1. Fees and taxes related to electricity are described in chapter 3. The Power Fee for Kraftringen is calculated with the average of the two peak power values imported from the grid during two different winter months between November and March during weekdays between 06:00 and 22:00. The Subscription Fee is based on the maximum amount of power exported to the grid (Kraftringen, personal communication, December 14, 2022).

Table 6.1: Electricity network fees and energy tax that are relevant for Kraftringen.

Variable	Value	Comment
Fixed Fee [SEK/year]	50 000	
Subscription Fee [SEK/kW, year]	85	
Power Fee [SEK/MW]	355	
Transfer Fee [SEK/MWh]	77	Fee on electricity imported from the grid
Compensation for Network Benefit [SEK/MWh]	76	Compensation for electricity exported to the grid
Energy Tax [SEK/MWh]	360	Tax on all imported electricity

Data concerning electricity tax is based on the tax rate for 2022 (Skattevarket, n.d.). The rest of the data presented in table 6.1 was provided by Kraftringen (personal communication, December 14, 2022).

6.2.3 Model of Hydrogen System

The investigated hydrogen system is composed of a PEM electrolyzer, a compressor, a compressed gas storage and a PEM fuel cell. A schematic energy flow diagram of the system is illustrated in figure 5.1. The units are treated as boxes with energy inflows and outflows. The property of the boxes define costs, efficiencies and technical specifications concerning nominal load. All technical specifications of the hydrogen system are presented in tables 6.2-6.5.

Input Parameters for Electrolyzer Included in Model

Table 6.2: Summarized input data for the electrolyzer.

Input Parameters	Value	Comment
Size [MW]	10	
Efficiency [%]	70	
Load interval [%]	5 to 100	
Load Change Speed [MW/s]	5	
$\text{Start}_{O\&M}$ Cost [SEK/start]	$2.17 \cdot 10^3$	
$\text{Stop}_{O\&M}$ Cost [SEK/stop]	$2.17 \cdot 10^3$	
$\text{Energy}_{O\&M}$ [SEK/MWh]	77.5	
Auxiliary power [% of load]	0.5	For cooling pump
Energy Tax [SEK/MWh]	0	No tax on electricity used in EC
Cost of Water [$\text{SEK/MWh}_{\text{H}_2}$]	0	Water is assumed to be recirculated
Possible Heat Recovery to DH [%]	97	No heat pump is assumed to be needed
Output pressure of H_2 gas [bar]	20	Assumed value from HyCoGen

Input Parameters for Compressor Included in Model

Table 6.3: Summarized input data for the compressor. The electrical consumption is presented as percent of energy content in the hydrogen flow.

Input Parameters	Value	Comment
Efficiency [%]	100	The energy content of the hydrogen gas is not affected Electricity is provided by external source
Load interval [MWh]	0.35 to 7	Matches EC load interval
Load Change Speed [MW/s]	5	Same as electrolyzer
$\text{Start}_{O\&M}$ Cost [SEK/start]	183	
$\text{Stop}_{O\&M}$ Cost [SEK/stop]	183	
$\text{Energy}_{O\&M}$ Cost [SEK/MWh]	6.54	
Auxiliary power [% of load]	5	Electrical consumption for compression from 20 bar to 350 bar
Energy Tax [SEK/MWh]	360	Standard tax rate
Inlet Pressure [bar]	20	Assumed value from HyCoGen
Outlet Pressure [bar]	350	Assumed value from HyCoGen

Input Parameters for Hydrogen Storage Unit Included in Model

Table 6.4: Summarized input data for the hydrogen storage unit.

Input Parameters	Value	Comment
Size [MWh_{H_2}]	504	Corresponding to maximum hydrogen production from electrolyzer for 3 days
Size [$m^3_{H_2}$]	412	The volume uptake of 504 MWh hydrogen gas at 350 bar
Minimum Content [MWh_{H_2}]	11	Corresponding to the amount of hydrogen required for up-regulation with fuel cell at full capacity for 1 hour
Start Value [MWh_{H_2}]	252	Condition for optimization
Stop Value [MWh_{H_2}]	252	Condition for optimization
Efficiency [%]	100	

Input Parameters for Fuel Cell Included in Model

Table 6.5: Summarized input data for the fuel cell.

Input Parameters	Value	Comment
Size [MW]	5	
Efficiency [%]	47	
Load Interval [%]	15-100	
Load Change Speed [MW/s]	2.5	
$\text{Start}_{O\&M}$ Cost [SEK/Start]	$1.43 \cdot 10^3$	
$\text{Stop}_{O\&M}$ Cost [SEK/Stop]	$1.43 \cdot 10^3$	
$\text{Energy}_{O\&M}$ [SEK/MWh]	127	
Auxiliary Power [% of load]	0.5	For cooling pump

The storage size is defined based on maximal stored energy (MWh_{H_2}), the size of the EC is defined as maximal input of electrical energy (MW), whereas the size of the FC is defined as maximal output of electrical energy (MW). The method for determining the size of the units is described in the section 6.2.5: Dimensioning of System, whereas the method for determining O&M costs is described in section 6.2.6: O&M Costs. Furthermore, the efficiency, load interval and load change speed of the units are based on the literature review in chapter 4. As explained in chapter 4: Hydrogen Technology, the efficiency of both PEMEC and PEMFC vary depending both on operational load and supplier. Efficiencies were chosen based on the behavior of the system, with units operating on full load the majority of the operating time. Data concerning auxiliary power and electrical consumption was provided by HyCoGen, as was the output pressure of hydrogen gas from the electrolyzer and operating pressures of the compressor (personal communication, September 28, 2022). The storage size in unit $m^3_{H_2}$ corresponds to the volume uptake by the hydrogen, for an assumed pressure of 350 bar. The value is calculated using the ideal gas law, assuming constant temperature. A minimum content of hydrogen in the storage unit is set to lower the risk of more hydrogen than available being used in the Balance Model.

The model also includes input data concerning electricity network fees and energy tax. As explained in section 4.9, different tax rates are applied to electricity depending on application. The energy tax rate for electricity bought at the spot market and used directly in the electrolyzer, presented in table 6.2, is zero. Electricity used in processes related to hydrogen production, i.e. in cooling pumps and in the compressor, is charged with the standard tax fee of 360 SEK/MWh. All other fees are the same as in table 6.1. For all scenarios, only energy tax is included as a parameter in the optimization. All other fees are calculated based on the operation of the system, and added to the result separately.

6.2.4 Model of P2G System

The P2G model only contains an electrolyzer, a compressor and a storage unit. A schematic energy diagram of the system is presented in figure 5.2. The characteristics of the system are mainly the same as in the full hydrogen system described above. Unique values for the P2G system are presented in table 6.6 below.

Table 6.6: Summarized unique input data for the P2G Scenario.

Unique Input Parameters	**Value**	**Comment**
Cost of Water [SEK/MWh$_{H_2}$]	2.9	See calculation below
Size of Storage [MWh$_{H_2}$]	168	Corresponding to maximum hydrogen production for 1 day
Size of Storage [$m^3_{H_2}$]	137	The volume uptake of 168 MWh hydrogen gas at 350 bar
Storage Content Start Value [MWh$_{H_2}$]	84	Condition for optimization
Storage Content Stop Value [MWh$_{H_2}$]	84	Condition for optimization
Hydrogen Selling Price [SEK/kg]	60	

The cost of water is based on the cost of water in Eslöv's municipality where Örtofta CHP plant is located, the higher heating value of hydrogen and the water consumption of an electrolyzer and is calculated according to the equation below. The cost of water is of 10.22 SEK/m^3 in Eslöv's municipality (VA Syd, 2022). The higher heating value of hydrogen is 39.41 kWh/kg and the water consumption of an electrolyzer is 11.19 L/kg hydrogen produced (HyCoGen, personal communication, September 28, 2022).

$$\text{Cost of Water [SEK/MWh}_{\text{H}_2}] = \frac{10.22 \cdot 11.19 \cdot 39.41 \cdot 1000}{10^6}$$

The storage unit is assumed to be emptied each day, and thus the storage is dimensioned to fit for the amount of hydrogen being produced if the electrolyzer operates at full capacity during one day. The storage size in unit $m^3_{H_2}$ corresponds to the volume uptake by the hydrogen, for an assumed pressure of 350 bar. The value is calculated using the ideal gas law, assuming constant temperature.

As mentioned in section 4.7, the Swedish selling prices for hydrogen gas varies. The hydrogen selling price is set to 60 SEK/kg$_{H_2}$ in the Base Model, but varied in the sensitivity analysis, see section 8.6.

6.2.5 Dimensioning of System

The system is dimensioned based on profitability. The size of the electrolyzer, storage and fuel cell is varied in different optimizations and then compared in terms of Payback Time, see equation 6.1. The optimization methodology is described in section 6.2.7. The models with varying sizes are only optimized in the Base Model, i.e. only participation on the day-ahead spot market is included. The revenues from participation on the balancing markets is not considered. All input data presented in section 6.2 in tables 6.2-6.4, except O&M costs, are included in the optimizations. The input data for electrical trade presented in table 6.1 is not included in the optimizations.

Three different system sizes, denoted as Small, Medium and Large, with set values on sizes of electrolyzer, storage and fuel cell, are compared to each other. Next, the storage size in the set system with the lowest Payback Time is varied. The system size option with the lowest Payback Time is then used to dimension the system, i.e. used as input data in the Base Model. The result showing the Payback Time for the investigated system sizes is presented in the appendix A.

6.2.6 O&M Costs

After dimensioning the system, operation and maintenance (O&M) costs are estimated. The annual O&M cost is defined as 3 % of the investment cost for the electrolyzer and fuel cell, 1.5 % for the compressor, and 2 % for the storage tank. Different sources state different values for O&M costs, and they also differ between different components in a hydrogen system. Lazard state an annual O&M cost of 1.5 % of CAPEX for PEM electrolyzer (Lazard, 2021). RISE state annual O&M costs relative to investment cost as 5 % for PEM electrolyzer, 4 % for compressor, 2 % for compressed storage tank and 1 % for PEM fuel cell (HyCOGen, personal communication, September 28, 2022). O&M in the same order of magnitude as the values listed above are chosen in our model. A sensitivity analysis is also performed to investigate the impact of different O&M cost scenarios, see section 8.5.

Costs related to operation and maintenance arise primarily because of wear on the components. The wear in turn depends on the operation of the units. To let an electrolyzer or a fuel cell operate flexibly typically lowers their lifetime, and results in more frequent required maintenance and thus higher costs. Furthermore, the more a unit is used, the larger the damages on components, also resulting in higher costs. Over a lifetime, a stack replacement is often necessary within an electrolyzer and a fuel cell. This cost factor is typically included in the O&M cost factor and can also be affected by the operation of the units. To conclude, O&M costs are affected both by how, and how much, a unit operates. Because of this, our model in Energy Optima 3 will include costs related to both start and stop of the unit, and variable maintenance cost related to the operating load.

The cost factors are denoted as $\text{Energy}_{O\&M}$, [SEK/MWh], and Start & $\text{Stop}_{O\&M}$, [SEK/start and SEK/stop]. The two cost factors are quantified as stated below.

$$\text{Energy}_{O\&M} = \frac{\text{Total Investment Cost} \cdot \text{Annual O\&M Cost Rate} \cdot 0.5}{\text{Operation Load}} \tag{6.5}$$

$$\text{Start \& Stop}_{O\&M} = \frac{\text{Total Investment Cost} \cdot \text{Annual O\&M Cost Rate} \cdot 0.5}{(\text{Number of Starts} + \text{Number of Stops})} \tag{6.6}$$

As an assumption, 50% of the total O&M cost is applied to the number of start and stops (SEK/Start and SEK/Stop) according to equation 6.6 and 50% is applied to the operational load (SEK/MWh), according to equation 6.5.

To get relevant input data for equations 6.5 and 6.6, the Base Model containing the entire hydrogen system is optimized without any O&M costs. The optimization methodology is described in section 6.2.7. For the electrolyzer, compressor and fuel cell, the number of start and stops and the total operational load from that optimization is then used to split the total O&M costs between start- and stop costs, and variable maintenance costs, according to equations 6.5 and 6.6 above. The O&M cost for the storage tank is included outside of the optimization.

The behavior of the system is then tested on a weekly basis before determining the final cost parameters. Three different scenarios are optimized in Energy Optima 3 and compared.

- Reference: Hydrogen System with no O&M costs
- Total O&M cost allocated to start and stop costs.
- Total O&M cost allocated to variable maintenance costs.

When testing, it was noted that the total operational load of the hydrogen system is the same for all scenarios. Both the electrolyzer and fuel cell have to same total load for all the scenarios. However, the optimized total cost differ between the scenarios. The total cost is lowest for the reference scenario, and highest for the scenario in which the total O&M cost is allocated to variable maintenance cost (i.e. $\text{Energy}_{O\&M}$). The scenarios are simulated over a time period of 1 week only, but to examine the impact on the system from different cost mechanisms this is considered sufficient. The conclusion that the O&M costs are quantified and divided reasonably is therefore drawn.

6.2.7 Simulation & Optimization of Base Model

This section describes the optimization procedure of the Base Model. The aim with the optimization of the Base Model is to generate production plans in which operational costs are minimized for the investigated year. Production plans are optimized for the three scenarios Hydrogen System, P2G and Reference.

For all scenarios, historical input data concerning, among other things, district heating load and electricity prices, is provided by the program. Energy Optima 3 optimizes a production plan, based on input data, to minimize the production cost while fulfilling the district heating load. The purchase of electricity is considered a positive cost while the selling of electricity is considered a negative cost. The Base Model examines the integrated system with electricity trading on day-ahead market only. Electricity trading on intra-day is excluded to avoid an unrealistic optimization. When testing a model that included trading on intra-day, it was seen that during certain times of operation, a large amount of electricity was bought on the day-ahead market to be sold at intra-day, when the price on the intra-day market was much higher than on the day-ahead market.

In figure 6.2 below, an overview of how the optimization works is provided.

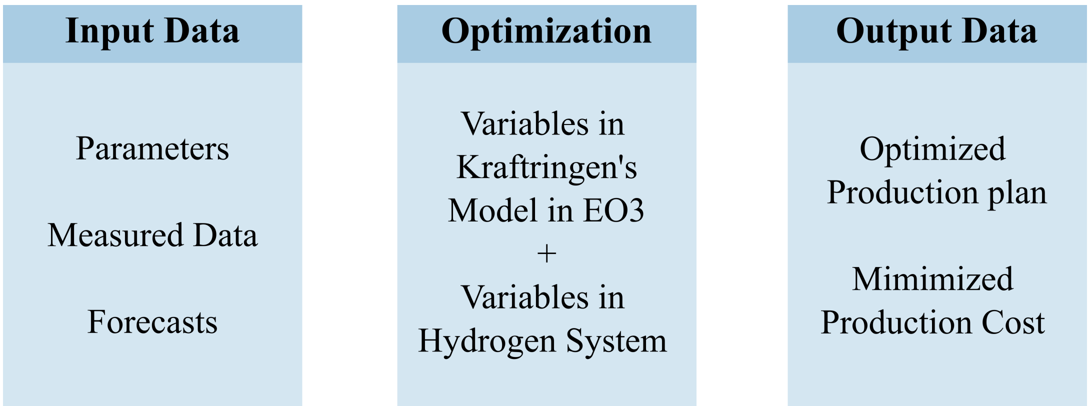

Figure 6.2: An overview of how the optimization of the Base Model is executed in Energy Optima 3.

Below, the values in figure 6.2, i.e. the vales that Energy Optima 3 uses for optimization, are listed.

Variables
The variables determine the production plan, i.e. how different units within the plant should operate, and are optimized based on relevant input data.

Parameters
Predefined values that define specifications for the units within the energy system.

Example of these specifications are efficiencies, load intervals, start and stop costs, maintenance cost and load change speed.

Forecasts
The main forecasts generally used within the program are forecasts of district heating load, electricity spot price and fuel price. The district heating forecast is based on weather prognosis and consumption patterns. Forecasts on electricity and fuel price are imported to the program. Forecast are used when real-time optimizations are performed.

Measured data
Measured data from the production plant is collected continuously. This concerns for instance actual spot price, actual district heating load and actual production from units. In the case of historical optimizations, measured data is used over forecasts when possible.

The objective function for the optimization is as mentioned to minimize the operating cost for producing sufficient amount of district heat. To do this, a number of **cost factors** are taken into account in Energy Optima 3. These are listed below.

Cost factors:

- **Fuel**
  Fuel costs for all fuels that are used by the production plants are included in the optimization. Consequently, the production plan is directed towards units that run on cheap fuel, such as the waste boiler. The load of units running on more expensive fuels, like a oil hot water boiler, is minimized. Costs for emission allowances as well as carbon taxes are included when applicable.
- **Start-up and stop costs**
  Many units in the production plant has a cost related to start and stop. Units that are very inert or that wear with start and stop can in this way be steered towards a more continuous operation. The basis of the cost is the loss of efficiency and increased maintenance need associated with start and stop. The cost is decided differently based on the real costs associated with running a unit.
- **Cost related to load change**
  Changes in load often result in both increased wear and maintenance. Load change costs are used to quantify the cost related to these aspects.
- **Cost related to operating load**
  The more a unit operates, the higher the wear and maintenance. Maintenance cost related to the operational load is used to quantify the cost related to these aspects.
- **Electrical trade**
  Electrical trade can result in both negative and positive costs. Purchasing

electricity results in positive costs, according to the price on the market they are bought. Selling electricity results in negative costs, according to the price on the market they are sold.

Evaluation and Verification of Base Model

Implementation of the hydrogen system was initially done in a simple, isolated modeling environment in Energy Optima 3. The system was integrated with a small and simple principal model of a CHP plant. The models of the hydrogen systems were implemented using general programming syntax, and special programming was used to implement some specifics of the model. In the simplified system, the modeled system was tested and the characteristics and behavior of the system were evaluated.

Optimizations of the models were performed for one week according to the methodology described above. The optimization of the Base Model was evaluated mainly based on the behavior of the integrated system. In the time horizon of the optimization, the electricity price varied substantially between days. It was seen that the electrolyzer was used when electricity was cheap, and that the fuel cell was used during days of higher electricity prices. In addition, a system behaviour where the units either ran on full load or not at all was observed. Furthermore, the electrolyzer was never used at the same time as the fuel cell. These system dynamics were considered reasonable and appropriate for the model.

After testing, the hydrogen system was integrated with a copy of the EVITA system. This model was also tested repeatedly, and optimizations for several shorter time periods were executed to verify that the behavior of the system, and that the optimized results, seemed reasonable.

6.2.8 Delimitations and Assumptions Base Model

As with all modeling, delimitations and assumptions were made. These are listed below.

- The cost of water is not included in the ”Hydrogen System Scenario”, instead water is assumed to be recirculated. However, in the ”P2G Scenario”, the cost of water is included.
- Purification of water is assumed not to be necessary.
- It is assumed that residual heat from the hydrogen system can be transferred directly into the district heating network, without the usage of a heat pump. Heat that is not utilized in the district heating network is lead to a heat sink.

- Loss of efficiency due to degradation of components over time is not included in the model.
- Start-up time for the electrolyzer and fuel cell is assumed to be negligible and is not included in the model.
- Potential changes in for example efficiency due to special design of the electrolyzer and fuel cell, to enable utilization of residual heat, are assumed negligible.
- Electricity trading only takes place on NordPool day-ahead Spot Market.

6.3 Balance Model

This section describes the modeling and optimization of the participation on the balancing markets. Participation on the balancing markets is also modeled in Energy Optima 3, but the model is decoupled from the Base Model, and optimized separately.

The optimization of the Base Model, described in the section above, decides the original operation of the fuel cell and electrolyzer. These results are used to determine available capacity for up- and down-regulation of both electrolyzer and fuel cell.

6.3.1 Model of Participation on Balancing Markets

The participation on the balancing markets is modeled with Ancillary Service Units that buy and sell capacity. In the case of mFRR, the unit sells and buys electricity. The general principal is illustrated in figure 6.3.

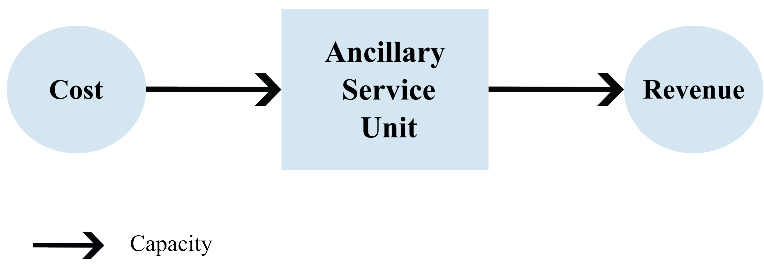

Figure 6.3: An illustration of how the Balance Model is built.

The ancillary service units represent the participation with ancillary services with the electrolyzer and the fuel cell, respectively. These units are connected to buying and selling contracts, representing the estimated costs and revenues related to providing each service. For both the electrolyzer and fuel cell, the model contains one ancillary service unit for each service and regulating direction. For example, one ancillary unit represents the trading of capacity on the aFRR up-regulating market for the electrolyzer.

The chosen ancillary services used in the Balance Model are FCR-D, aFRR, mFFR as well as FCR-N, for both the fuel cell and the electrolyzer. FFR is excluded based on the fast activation time, as it is uncertain whether it is achievable or not. Disturbance reserve is excluded as it is not suitable when units are allowed to operate flexibly. For FCR-D, aFRR and mFRR both up- and down- regulation is possible in the model. For FCR-N, equal amount of up- and down- regulation needs to be offered. In total, there are thus sixteen ancillary service units included the model. Both the electrolyzer and fuel cell are assumed to be kept on stand-by to achieve the required activation times.

Available Capacity

The available capacity for participating on the balancing markets is calculated with an hourly granularity from the original operation (i.e. the result from the optimization of the Base Model) according to equations 6.7-6.10.

Fuel Cell

$$\mathrm{UP}_{FC}(h) = \mathrm{MaxLoad}_{FC} - \mathrm{Load}_{FC}(h) \tag{6.7}$$

$$\mathrm{DOWN}_{FC}(h) = \mathrm{Load}_{FC}(h) - \mathrm{MinLoad}_{FC} \tag{6.8}$$

$\mathrm{UP}_{FC}(h)$ = Available capacity for up-regulation for fuel cell [MW]
$\mathrm{MaxLoad}_{FC}$ = Maximum load fuel cell [MW]
$\mathrm{Load}_{FC}(h)$ = Operational load of fuel cell from Base Optimization [MW]
$\mathrm{DOWN}_{FC}(h)$ = Available capacity for down-regulation for fuel cell [MW]
$\mathrm{MinLoad}_{FC}$ = Minimum load fuel cell [MW]

Electrolyzer

$$\mathrm{UP}_{EC}(h) = \mathrm{Load}_{EC}(h) - \mathrm{MinLoad}_{EC} \tag{6.9}$$

$$\mathrm{DOWN}_{EC} = \mathrm{MaxLoad}_{EC} - \mathrm{Load}_{EC}(h) \tag{6.10}$$

$\mathrm{UP}_{EC}(h)$ = Available capacity for up-regulation for electrolyzer [MW]
$\mathrm{MaxLoad}_{EC}$ = Maximum load electrolyzer [MW]

$\text{Load}_{EC}(h)$ = Operational load of electrolyzer from Base Optimization [MW]
$\text{DOWN}_{EC}(h)$ = Available capacity for down-regulation for electrolyzer [MW]
MinLoad_{EC} = Minimum load electrolyzer [MW]

Costs and Incomes Related to Participation with Ancillary Services

The principal cost and corresponding income for participating with different ancillary services are displayed in tables 6.7 and 6.8 below. The different units [SEK/MW] and [SEK/MWh] correspond to compensation regarding capacity and energy, respectively. See section 3.4.2 for an explanation of compensation for the provisioning of each ancillary service.

Table 6.7: Principal cost and income on an hourly basis for the **electrolyzer** to participate on the balancing markets.

Ancillary Service	**Cost [SEK/MWh]**	**Income Capacity** [SEK/MW]	**Income Energy** [SEK/MWh]
FCR-D Up	0 or Avg. Income_{EC}	Capacity Price	-
FCR-D Down	0 or O&M	Capacity Price	-
FCR-N	0 or Down-Regulating Price + O&M or Avg. Income_{EC}	Capacity Price	0 Avg. Income_{EC} or Up-Regulating Price
aFRR Up	0 or Avg. Income_{EC}	Capacity Price	0 or Up-Regulating Price
aFRR Down	0 or Down-Regulating Price + O&M	Capacity Price	0 or Avg. Income_{EC}
mFRR Up	Avg. Income_{EC}	-	Spot Price + Up-Regulating Price
mFRR Down	Down-Regulating Price + O&M	-	Avg. Income_{EC}

Table 6.8: Principal cost and income on an hourly basis for the **fuel cell** to participate on the balancing markets.

Ancillary Service	**Cost SEK/MWh**	**Income Capacity** [SEK/MW]	**Income Energy** [SEK/MWh]
FCR-D Up	0 or Avg. Production Cost$_{FC}$ + O&M	Capacity Price	-
FCR-D Down	0	Capacity Price	-
FCR-N	0 or Down-Regulating Price or Avg. Production Cost$_{FC}$ + O&M	Capacity Price	0 or Avg. Income$_{FC}$ or Up-Regulating Price
aFRR Up	0 or Avg. Production Cost$_{FC}$ + O&M	Capacity Price	0 or Up-Regulating Price
aFRR Down	0 or Down-Regulating Price	Capacity Price	0 or Avg. Income$_{FC}$
mFRR Up	Avg. Production Cost$_{FC}$ + O&M	-	Up-Regulating Price
mFRR Down	Down-Regulating Price	-	Avg. Income$_{FC}$

The Average Production Cost (Avg. Production Cost$_{FC}$) quantifies the average cost of producing electricity in the fuel cell. The Average Production Cost is calculated based on the results from the optimization of the Base Model according to equation 6.11 below.

$$\text{Avg. Production Cost}_{FC} = \frac{\text{Average Spot Price EC}}{\eta_{el}} \tag{6.11}$$

Average Spot Price EC = The average spot price when the electrolyzer produces hydrogen
η_{el} = Total system electric efficiency

The Average Income (Avg. Income) quantifies the revenue/cost related to an increased/decreased production or decreased consumption of hydrogen, compared to the Base Model. A change in the production of hydrogen is related to up- or down-regulation with the electrolyzer while a decreased consumption of hydrogen is related to down-regulation with the fuel cell. The Average Income is also calculated based on the results from the optimization of the Base Model and differ between the P2G and the Hydrogen System scenarios. In the case of the Hydrogen System scenario it is calculated according to equation 6.12 for the fuel cell and equation 6.13 for the electrolyzer. In the case of the P2G Scenario, it is calculated according to equation 6.14.

$$\text{Avg. Income}_{FC} = \text{Average Spot Price FC} \tag{6.12}$$

Average Spot Price FC = The average spot price when the fuel cell produces electricity

$$\text{Avg. Income}_{EC} = \text{Average Income}_{FC} * \eta_{el} \tag{6.13}$$

$$\text{Avg. Income}_{P2G} = \text{Income}_{H_2} * \eta_{EC} \tag{6.14}$$

Income_{H_2} = The selling price of hydrogen
η_{EC} = The efficiency of the electrolyzer

As presented in tables 6.7 and 6.8, the associated costs and incomes for the ancillary services are based on capacity and regulating prices as well as on the result from the optimization of the Base Model. The main idea is that the actual cost and income in the form of capacity prices and down- and up-regulating prices are combined with costs or revenues associated with change in operation. This includes both Average Production Cost and Average Income, defined in the equations above, as well as $\text{Energy}_{O\&M}$. This way, the results from the two optimizations can be combined with each other. Furthermore, the associated cost and income each hour depends on whether the service is activated or not. The cost also depends on how long a service is activated, which is estimated by an activation ratio, defined in equation 6.15 below.

$$\text{Activation Ratio} = \frac{\text{Activated Capacity [MWh]}}{\text{Maximum Energy from Purchased Capacity [MWh]}} \tag{6.15}$$

Activated Capacity quantifies the activated capacity, i.e. delivered down- or up-regulation, while "Maximum Energy from Purchased Capacity" represents the delivered down- or up-regulation in a case of 100 % activation. The activation ratio is used as a factor in all costs and all incomes associated with activation. Incomes associated with activation are listed under "Income Energy" in tables 6.7 and 6.8.

Up- and down-regulation prices as well as capacity prices and activation data are historical values from Nord Pool, Svenska Kraftnät and ENTSO-E. No activation data is available for FCR-D, instead an activation ratio provided by RISE is used (Goldberg, 2022). Compensation for capacity is given according to bid while the prices for up- and down-regulation are marginal prices. In the case of aFRR the capacity prices are marginal since May 2022, but compensated according to bid before then. The marginal prices correspond to the actual income/cost associated with the service. In the case of compensation according to bid, the historical available data is average prices. Thus, it is possible for actors to have income both below and above the average capacity prices for the different services. As no other data is available, average capacity prices are used in the model.

A few more aspects of the Balance Model require commenting. In reality, due to utilization of residual heat in the district heating network, the overall efficiency is higher than the electrical efficiency, η_{el}, used in equations 6.10 and 6.12. However, the resulting income from selling district heating is not part of the model. Moreover, as seen in the energy diagram of the system in figure 5.1, electricity can be both delivered and supplied directly to/from the CHP plant. As a simplification, cost and income is however estimated based solely on spot price in the equations. Finally, statistics about activation of the different ancillary services is divided between the electricity price areas. However, the location of activation is not accounted for in the Balance Model. Today, the majority of the of ancillary services are constituted by hydro-power in northern Sweden. Thus, the activation of ancillary services is naturally significantly higher in bidding areas SE1 and SE2. However, there is a demand for balancing power also in southern Sweden. The total, national, activation of ancillary power is included in the model as it indicates the total need for balancing.

6.3.2 Scenarios for Balance Model

When optimizing participation on the balancing markets with historical values, the algorithm has access to activation data, which is not the case in reality. With this information, the algorithm can optimize participation in an unrealistic way. This is most problematic for mFRR, which only has compensation for energy, as participation only will take place in case of activation. In the case of the other services, the problem is not as significant but it still exists. Therefore, two different scenarios with different pricing mechanisms are used, called Utopia and Average. For both scenarios, the historical capacity prices are used and the difference arise in the pricing mechanism related to activation. The scenarios are further explained below.

- **Utopia Scenario**
  In this scenario, the program has access to all activation data and down- and up-regulating prices on an hourly granularity. The purpose of the Utopia Scenario is to show potential. It gives an indication of the profitability of contributing with ancillary services if a perfect bidding strategy is applied. The actual, hourly, activation ratio of each service is included in the corresponding

costs and incomes arising from activation. The activation ratio is used as an estimate for how long an offered service needs to be activated, and thus how large the corresponding costs and incomes associated with changing operation are. This means that the optimizer can choose to bid only when there's low activation and thus low corresponding costs for changing operation, or when the activation is high and the price for energy compensation is high.

- **Average Scenario**
  In this scenario, the cost and income from activation is spread out evenly on all optimization hours using the average activation ratio over the year, for each service. Furthermore, average values for the investigated year are used for up- and down-regulating prices. The purpose of the Average Scenario is to examine the importance of timing and to provide a comparative profitability for participating on the balancing markets. As activation data is included as average values in the Average Scenario, this scenario is more restrictive.

Both scenarios are applied on the result from the Hydrogen System Scenario as well as the P2G Scenario. Thus, in total 4 optimizations are performed, Hydrogen System Utopia, Hydrogen System Average, P2G Utopia and P2G Average.

6.3.3 Simulation and Optimization of Balance Model

The Balance Model is modeled in an isolated environment that only contains the model described above. The optimization determines the amount of capacity offered for each ancillary service at every hour and the total income. The objective function is to maximize the income. In figure 6.4 below, an overview of how the optimization of the Balance Model works is provided.

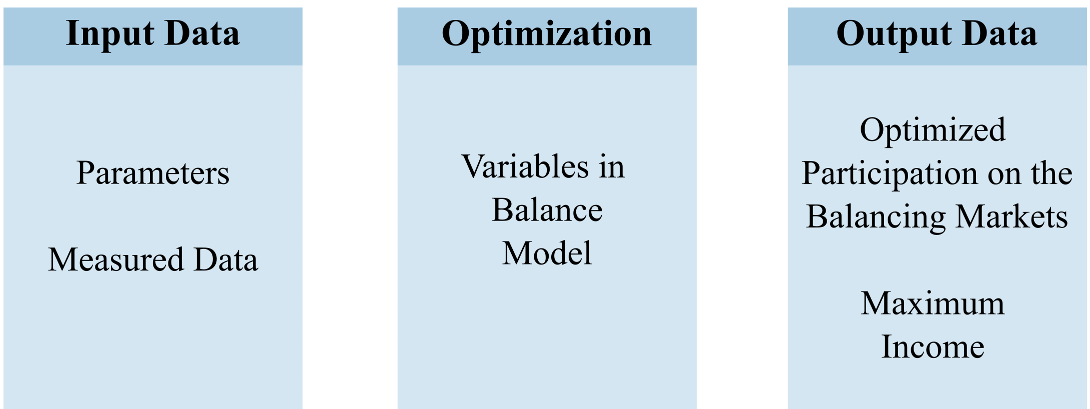

Figure 6.4: An overview of how the optimization of the Balance Model is executed in the program.

The values used in the optimization of the Balance Model are listed below.

Variables
The variables are, except for mFRR, capacity sold to each frequency reserve type, from both electrolyzer and fuel cell. For mFRR the variables are energy sold. In total there are 16 variables.

Parameters
The main parameter in the system is the minimum bid size for each frequency reserve.

Measured Data
The measured data is constituted by costs and incomes for participating with different ancillary services. Furthermore it is constituted by the available loads for up- and down-regulating. The costs and incomes are composed of historical values of capacity and regulation prices, as well as estimated costs/incomes related to change in operation for the fuel cell or electrolyzer. See tables 6.7-6.8 for a more detailed explanation.

Conditions & Constraints

In both scenarios, there are conditions and constraints included in the model, which are summarized below.

- For FCR-N, sold capacity for down- and up-regulation needs to be equal. Up- and down-regulation can however be offered from different units.
- The minimum bid sizes for all ancillary services, presented in table 3.1, are included in the model.
- The sum of capacity allocated for different services cannot exceed the amount of calculated available capacity for up- and down-regulation.
- Price is used as the only parameter to determine whether a bid is accepted on a market or not. If the optimizer decides that participation on the market is profitable at set price, the bid is assumed to be included in the accepted volume.

Evaluation and Verification of Balance Model

As the Base Model, the Balance Model was tested to evaluate the results and behaviour of the model. Initially, results from the optimization of the Base Model integrated with the simple CHP system was used as input data to test the Balance Model. Operation of the electrolyzer and fuel cell in the simple Base Model was used to define available capacity for up- and down-regulation for the electrolyzer and fuel cell, respectively. Electricity prices and operation of units were used to estimate average production cost and average income, defined in equations 6.11-6.13. Regulating prices and capacity prices were also included. The optimization was performed for a week, and the results were controlled to validate that the model seemed correctly built.

6.3.4 Delimitations Balance Model

Assumptions and aspects not included in the model of the balancing markets are summarized below.

- Consequences on the hydrogen storage tank from activation is not modeled. The consequences are examined outside of the optimization instead.
- Consequences on heat production from activation is not modeled.
- The cost and income associated with a change in operation are estimated as averages. The actual consequences on the economy can differ from these in reality.
- If both down- and up-regulation of a service is required during the same hour, only the dominating direction of balancing is accounted for.
- Profitability from heat utilization is not included in the model.
- Due to limitations in data availability, capacity prices are assumed as average price. Capacity price for aFRR is applied as marginal between May-October 2022.
- Only electrical efficiency of the system is accounted for in the model.
- Different activation ratios based on bidding area is neglected. The same activation ratio is assumed for the whole country.
- Up-regulation for electrolyzer and down-regulation for fuel cell is limited to lowering the operational load to minimum load. The units are not allowed to be shut off when operating, to reduce wear on units. The available capacity for up-regulation for electrolyzer and down-regulation for fuel cell will not be highly affected, as the minimum load is fairly low. However, the units are allowed to start. The benefits with contributing with ancillary services are assumed to outweigh the possible drawbacks related to increased wear when starting the units.
- The timing of the procurement is not accounted for in the model.

Chapter 7

Optimization Results

This chapter presents all results from the optimizations. In the first section, 7.1, the total results are presented in the form of key values. These key values include the combined results from the optimizations of both the Base Model and the Balance Model. In section 7.2, results from the Base Model are presented including key values, system behaviour, system costs analysis and fuel replacement analysis. Lastly, the results from the Balance Model are presented in section 7.3. These results include key values along with the amount of capacity offered to each ancillary service and an analysis of the hydrogen storage sizing.

7.1 Total Results

Key values from the combined results from both the Base Model and the Balance Model are summarized and presented in table 7.1 below. The results are presented for both the Hydrogen System and P2G scenarios, and for both the Average and Utopia scenarios used in the Balance Model. In the table, Profit is compared to the profit in the Reference Scenario.

Table 7.1: Summarized results for all optimizations.

Variable	**Hydrogen System Average Scenario**	**Hydrogen System Utopia Scenario**	**P2G Average Scenario**	**P2G Utopia Scenario**
Increased Profit [%]	19.9	21.2	14.8	13.29
Payback Time [years]	3.06	2.86	2.15	2.39
Total Load EC [GWh]	36.7	31.7	46.9	41.4
Total Load FC [GWh]	11.6	8.73	-	-
O&M Cost EC [% of CAPEX]	3.46	2.80	3.98	3.24
O&M Cost CMPSR [% of CAPEX]	1.33	1.33	2.07	2.07
O&M Cost FC [% of CAPEX]	3.08	2.59	-	-

As indicated in the table above, the Hydrogen System scenarios result in a higher profit compared to the P2G scenarios. However, since the investment cost is lower for the P2G system, the Payback Time is lower. Furthermore, it can be seen that the electrolyzer load is greater in the P2G system. It is also notable that the total hydrogen and electricity production is lower in the Utopia Scenario compared to the Average Scenario.

Regarding O&M costs, the presented values are values calculated from the actual total operation from both models and the assumed input values for Start & Stop$_{O\&M}$ costs and Energy$_{O\&M}$ costs. In all scenarios, the O&M costs for the electrolyzer, compressor and fuel cell differ less than one percentage point from the assumed annual ratios stated in section 6.2.6. Furthermore, due to the higher load of the electrolyzer in the P2G scenarios, the O&M costs for the electrolyzer are higher in the P2G system than in the Hydrogen System Scenarios.

7.2 Results Base Model

In this section, results from the optimization of the Base Model are presented.

7.2.1 Key Results Base Optimization

In table 7.2 below, the key values from the results from the Base Model are summarized.

Table 7.2: Summarized results from optimization of the Base Model, with values presented for both the Hydrogen System Scenario and the P2G Scenario.

Variable	**Hydrogen System Scenario**	**P2G Scenario**
Profit [%]	2.34	3.64
Payback Time [years]	26.0	8.72
Electricity to EC [GWh]	24.5	38.0
Electricity to EC from Spot [%]	25.9	19.9
Electricity Production from FC [GWh]	8.07	-
District Heat from EC [GWh]	4.21	7.18
District Heat from FC [GWh]	4.04	-
Utilized Heat of Total Hydrogen System Heat Production [%]	50.1	62.5
Utilized Heat of Total Heat Production at Örtofta [%]	1.12	0.982
Overall System Efficiency [%]	66.5	88.9
Average Spot Price when EC Operates [SEK/MWh]	427	620
Average Spot Price when FC Operates [SEK/MWh]	2770	-
EC Operating Time [%]	35.3	53.5
FC Operating Time [%]	22.8	-
Difference between highest and lowest weekly average spot price [SEK/MWh]	3690	3690

In the table, Profit is compared to the Reference Scenario while FC and EC Operating Time is related to total optimization time. Electricity from Spot refers to the share of the total electricity usage in the electrolyzer that is bought from the spot market, the other share is electricity produced at Örtofta. Utilized Heat refers to heat transferred to the district heating network from the hydrogen system and is related both to amount of heat generated in the hydrogen system, and the total heat generated at Örtofta.

In the Base optimizations, the increased profit is higher in the P2G Scenario than in the Hydrogen System Scenario and, consequently, the Payback time is also significantly lower in the P2G Scenario. The operating load of the electrolyzer as well as the amount of EC operating hours in the P2G Scenario are also higher than in the Hydrogen System Scenario. A higher absolute amount of district heat is generated in the Hydrogen System Scenario, however a higher share of residual heat is utilized in the district heating network in the P2G Scenario. Furthermore, the overall system efficiency is higher in the P2G Scenario than in the Hydrogen System scenario. The share of total heat production at Örtofta, that the utilized heat from the hydrogen system constitute, is in both scenarios low, around 1 %. In both scenarios, the majority of the electricity used by the electrolyzer is produced at Örtofta. In the P2G Scenario, it is overall profitable to operate the electrolyzer at higher spot prices than in the Hydrogen System Scenario. Finally, table 7.2 displays a large variation in average spot price between when the EC and FC operate in the Hydrogen System Scenario.

7.2.2 System Behaviour

The operational behaviours of the hydrogen systems in the Base Model scenarios are presented in figures 7.1-7.5 below. Figure 7.1 presents the operational behaviour of the hydrogen system in the Hydrogen System Scenario during one week in October 2021.

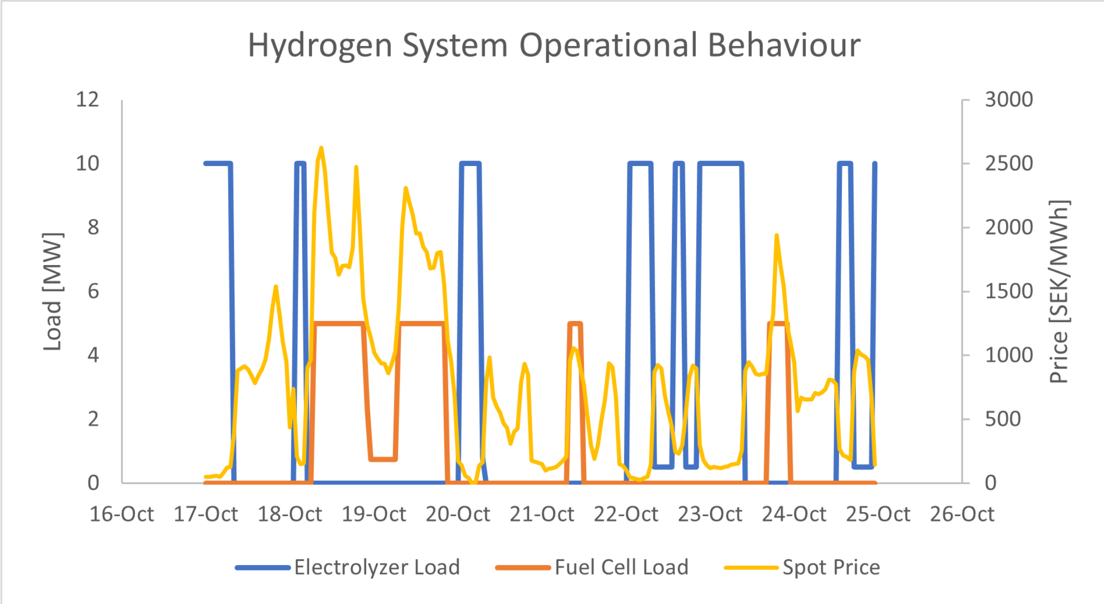

Figure 7.1: The operational behaviour of the hydrogen system in the Hydrogen System Scenario during one week in October 2021. The load of the fuel cell and electrolyzer is presented together with the spot price.

A clear correlation between spot price and the hydrogen system operational load can be seen in figure 7.1. In times of high spot prices, the fuel cell operates while in times of low spot prices, the electrolyzer operates. The two units never operate at the same time. Moreover, the units seem to either run on full load, not at all, or on minimum load. The electrolyzer runs on minimum load at times of short peaks in spot price while the fuel cell runs on minimum load at times of short valleys in spot price. This way the costs related to starting and stopping the units are avoided.

Figure 7.2 below presents the operational behaviour of the hydrogen system in the P2G Scenario during the same week in October 2021.

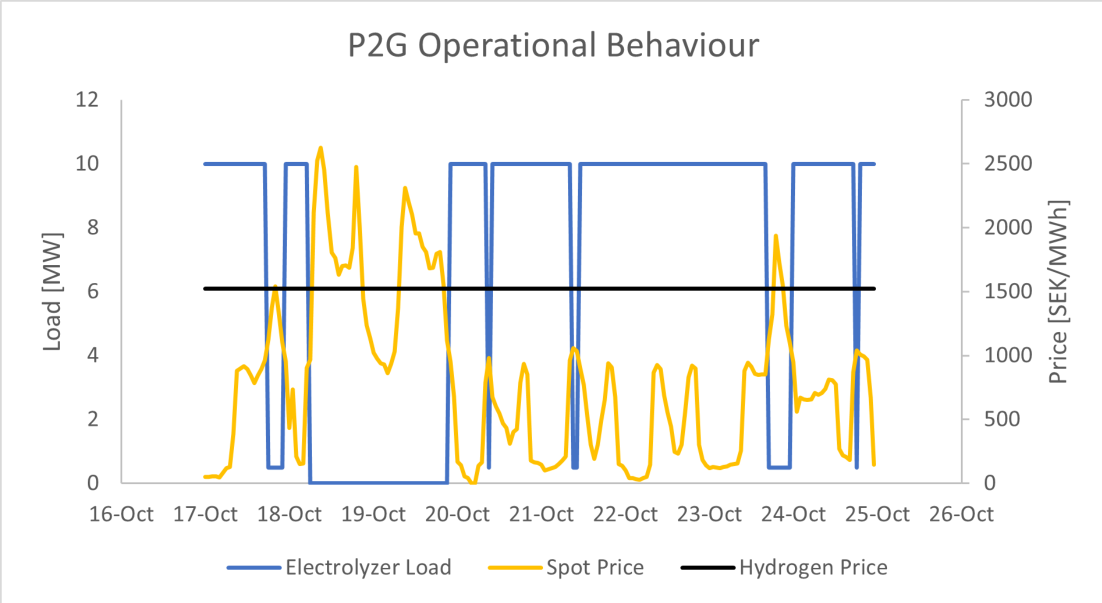

Figure 7.2: The operational behaviour of the P2G Scenario during one week in October 2021. The load of the electrolyzer is presented together with the spot price and hydrogen selling price.

The electrolyzer in the P2G scenario, displayed in figure 7.2, shows similar behaviour as the electrolyzer in the Hydrogen System Scenario. When, at given spot price, it is profitable to produce hydrogen, the electrolyzer runs at full load. In times of longer peaks in spot price the electrolyzer is shut off while it in times of shorter peaks runs on minimum load. When comparing the operation of the electrolyzer in figures 7.1 and 7.2, the electrolyzer runs on higher spot prices in the P2G Scenario than in the Hydrogen System Scenario.

Figure 7.3 displays the operational behaviour of the hydrogen system in the Hydrogen System Scenario during the entire optimization period.

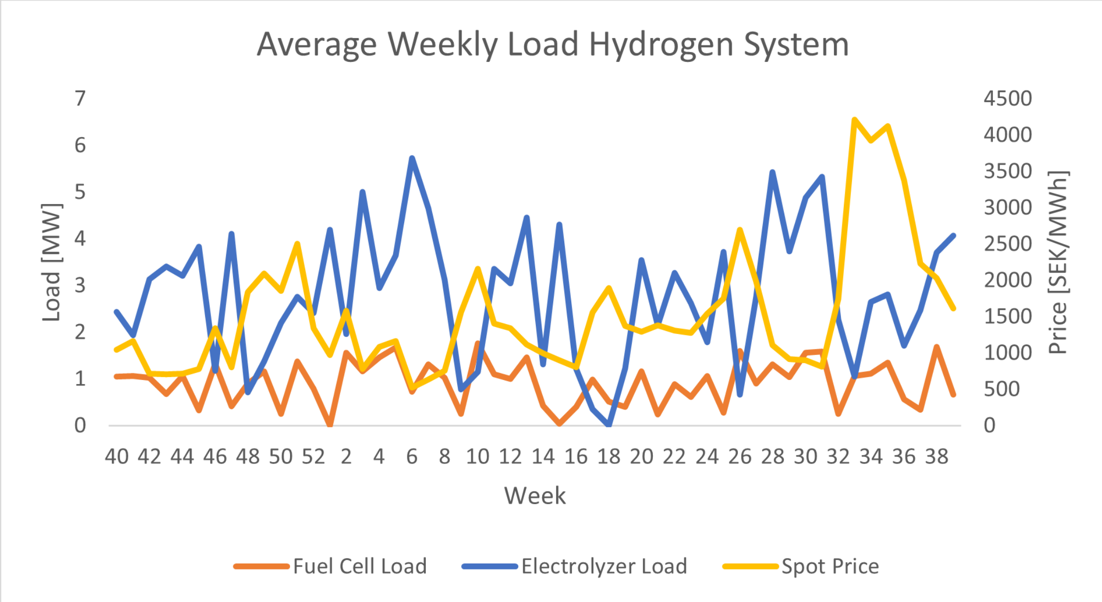

Figure 7.3: The operational behaviour of the hydrogen system in the Hydrogen System Scenario during the entire year, October 2021-October 2022. The average weekly load of the fuel cell and electrolyzer is presented together with the average weekly spot price.

In figure 7.3, operational load and spot price are presented as average weekly values. The figure shows the same correlation between spot price and operational load as presented in figure 7.1. With increasing average weekly spot price, the average weekly load of the fuel cell is increased while the average weekly load of the electrolyzer is decreased. The opposite applies if the spot price is decreased.

Figure 7.4 displays the operational behaviour of the hydrogen system in the P2G Scenario during the entire optimization period.

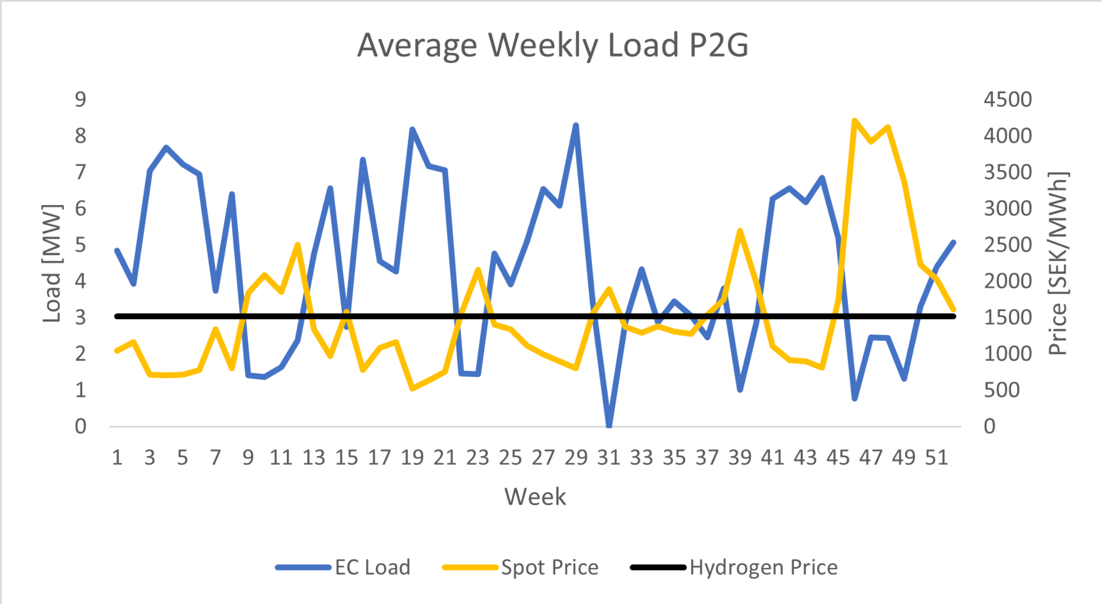

Figure 7.4: The operational behaviour of the hydrogen system in the P2G Scenario during the entire year, October 2021-October 2022. The average weekly load of the electrolyzer is presented together with the average weekly spot and hydrogen price.

In figure 7.4, operational load as well as spot price are presented as average weekly values. The figure shows the same correlation between spot price and operational load as presented in figure 7.2. With increasing average weekly spot price, the average weekly load of the electrolyzer is decreased.

Figure 7.5 displays the hydrogen content in the storage tank in the Hydrogen System Scenario during the entire optimization period

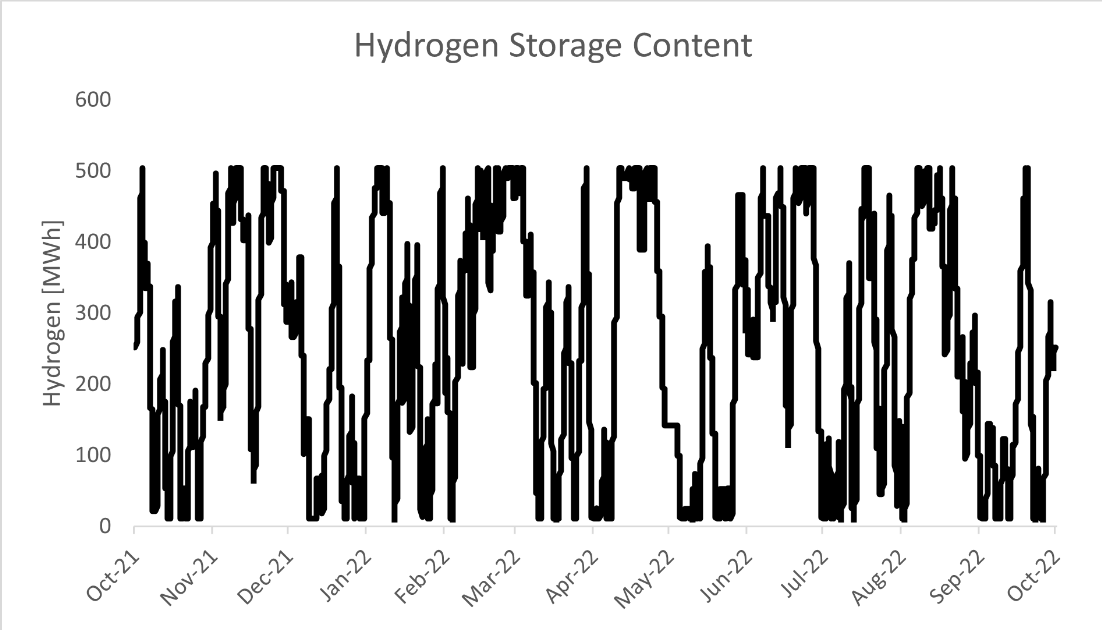

Figure 7.5: The content in the hydrogen storage during the entire optimization period.

During the year, the hydrogen content in the storage varies and is at times both full and at its lowest allowed content. The storage is at its lowest content of 11 MWh during 558 hours, i.e. 6.37 % of the time, and full 785 hours, i.e. 8.97 % of the time.

7.2.3 Operational Costs

Operational costs related to the hydrogen system that are accounted for in the Base Model scenarios are electricity costs, O&M costs, cost of water, electrical network fees and energy tax. The division of these costs in the Hydrogen System and P2G scenarios are displayed in figure 7.6 below.

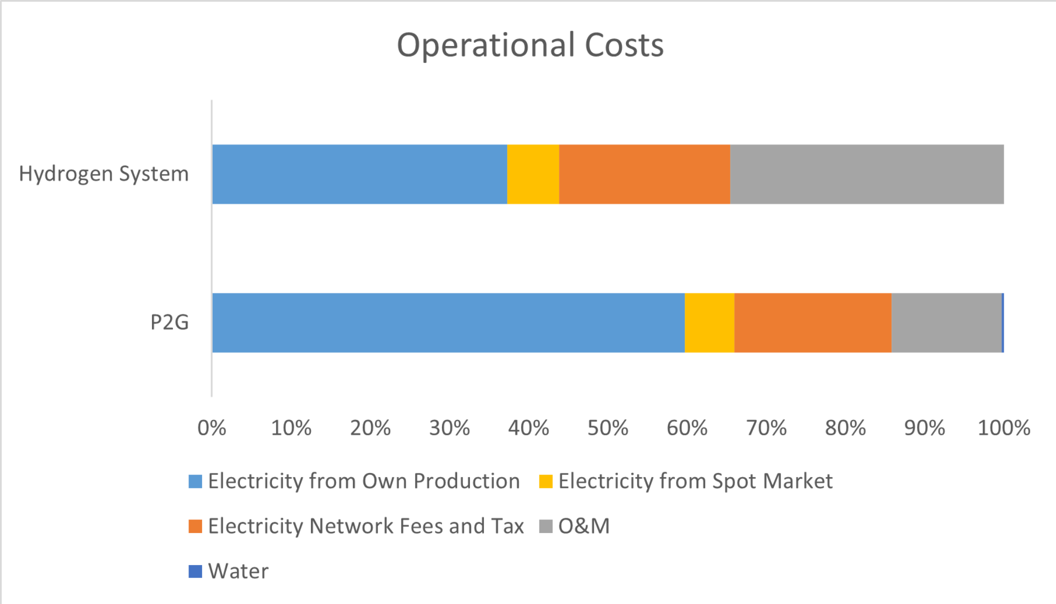

Figure 7.6: The cost division of operational costs in the Hydrogen System and P2G scenarios.

The cost of electricity from own production is quantified as a alternative income, i.e. by the spot price at the time the electricity is used.

In both scenarios electricity usage constitutes the highest operational cost. The total cost of electricity from own production is higher than the total cost of electricity from the spot market. Worth emphasizing is however that the total use of electricity from own production is higher than the amount of electricity from the spot market, see table 7.2.1. Operation and maintenance costs constitute a larger share of the total operational cost in the Hydrogen System Scenario than in the P2G Scenario. Electrical fees and energy tax make up around 20 % of the total operational cost in both scenarios.

Electricity Network Fees and Energy Tax

How electricity network fees and the energy tax change, due to the implementation of the investigated hydrogen systems, is presented in this section. The fees are described in chapter 3 and presented in table 6.1. The size of the fees, related to the Reference Scenario, in the P2G and Hydrogen System scenarios are presented in table 7.3 below. The table also shows the amount of imported and exported electricity from and to the grid, relative to the Reference Scenario.

Table 7.3: Changes in imported/exported electricity from/to the grid and related fees for the Hydrogen System Scenario and P2G Scenario, compared to the Reference scenario.

Variable	**Hydrogen System Scenario**	**P2G Scenario**
Exported Electricity [%]	-4.63	-12.5
Imported Electricity [%]	44.3	56.2
Fixed Fee [%]	0	0
Subscription Fee [%]	13.7	0
Power Fee [%]	17.2	20.9
Transfer Fee [%]	44.3	56.1
Compensation for Network Benefit [%]	-4.63	-12.5
Energy Tax [%]	-0.141	0.131

Overall, table 7.3, shows an increase in electrical network fees for both scenarios. The biggest increase is found in the transfer fee in both scenarios while the only decrease is found in the compensation for network benefit, i.e. in an income. Regarding energy tax, an increase in is found in the P2G Scenario whereas the tax decreases in the Hydrogen System Scenario.

Figure 7.7 below present the cost division of the increased electricity network fees in the Hydrogen System and P2G scenarios, compared to the Reference Scenario. The post ”compensation for network benefit” is smaller in both scenarios than in the Reference Scenario, see table 7.3, and is therefore considered a cost. The energy tax is only considered a cost in the P2G Scenario.

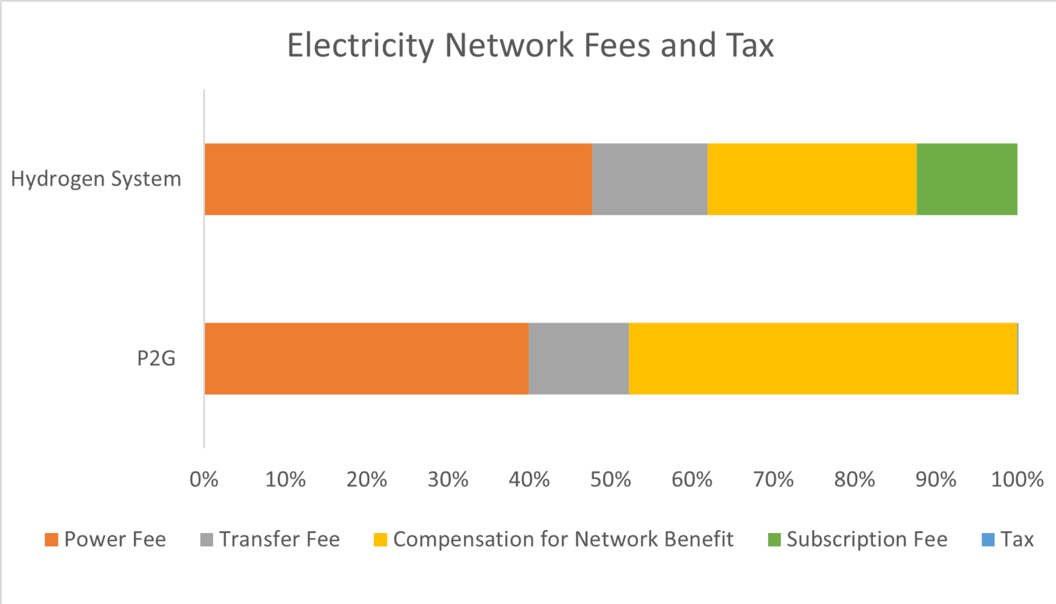

Figure 7.7: The cost division of the electricity network fees and energy tax in the Hydrogen System and P2G scenario.

In both scenarios, an increased power fee and a decrease in compensation for network benefit, compared to the Reference Scenario, constitute the highest costs. In the P2G Scenario, the decrease in compensation for network benefit make up the highest cost while the increase in power fee constitute the highest cost in the Hydrogen System Scenario. The cost contribution of energy tax in the P2G Scenario is below one percent.

7.2.4 Fuel

The implementation of a hydrogen system at Örtofta changes the production plan in the entire EVITA system. As presented in section 7.2.1, residual heat from the hydrogen system is utilized in the district heating network in both the P2G and Hydrogen System scenarios. Consequently, heat production in other parts of the network is changed. Therefore, an analysis on the resulting consequences on fuel consumption is performed. Table 7.4 presents the total change in fuel use, and energy taken from other sources, in the entire EVITA system due to the implementation of a hydrogen system. Values for both the P2G and Hydrogen System scenarios are presented.

Table 7.4: Change in fuel use in relation to the Reference Scenario. The fuels are ordered from most to least expensive.

Heat Source	Hydrogen System Scenario	P2G Scenario	Price
Natural Gas [%]	-89.8	-63.7	1
Biogas [%]	-8.20	-0.055	2
Bio-Oil [%]	-5.03	-1.70	3
E05 [%]	-4.96	-5.20	4
Pellets [%]	0.104	-1.20	5
Bio Mix [%]	-0.256	-0.589	6
Wastewater [%]	-2.38	-2.93	7
Geothermal Energy [%]	-3.42	-1.02	8
Waste [%]	-0.246	0.209	9

The most expensive fuel, natural gas, also has the highest percental decrease in usage. Worth mentioning is, however, that the usage of natural gas was low also in the Reference Scenario. Except in the changed usage of natural gas, the correlation between price and degree of replacement is not evident. Additional to price, flexibility also has influence in which heat sources that are replaced. The different processes, reliant on different sources of heat, have a variation of stop/start cost and load change speeds in the program that determine their flexibility. Generally, the large boilers running on different types of bio fuels or waste are the least flexible while the processes reliant on waste water, geothermal energy and natural gas are the most flexible.

7.3 Results Balance Model

This section contains relevant results from the optimization of the Balance Model. As described in the methods section, both the Hydrogen System Scenario and P2G Scenario are modeled and optimized using two different pricing scenarios - Average and Utopia. First, relevant input data and information about the ancillary services is presented. This information will aid interpretation of the results. The results are constituted by summarized key values, an analysis regarding capacity sold of each ancillary service, and an evaluation of the impact that the contribution with ancillary services has on the hydrogen storage content.

Below, input data corresponding to the parameters presented in equations 6.11-6.14 is presented. These values are calculated from the results of the Base optimization.

Hydrogen System:

$$\begin{aligned}\text{Avg. Income}_{EC} &= 911 \text{ SEK/MWh}\\ \text{Avg. Income}_{FC} &= 2770 \text{ SEK/MWh}\\ \text{Avg. Production Cost}_{FC} &= 1300 \text{ SEK/MWh}\end{aligned}$$

P2G System:

$$\text{Avg. Income}_{EC} = 1070 \text{ SEK/MWh}$$

Average Capacity and Regulating Prices

In the tables 7.5 and 7.6 below, the average values of capacity prices for the ancillary services as well as the average regulating prices are presented. The average capacity prices are not included in the model, but can give an indication of the profitability for the services in general. The average regulating prices are used in the Average Scenario. The average values are calculated for the optimization period between October 2021 and October 2022.

Table 7.5: Average capacity prices between October 2021 and October 2022 for the investigated ancillary services.

Ancillary Service	Average Capacity Price [SEK/MW]
aFRR Up	808
FCR-N	615
FCR-D Up	611
aFRR Down	576
FCR-D Down	262

Table 7.6: Average regulating prices between October 2021 and October 2022.

Regulation Type	Average Regulating Price [SEK/MWh]
Up-regulation	1700
Down-regulation	1300

Activation Ratio:

The activation ratios (defined in equation 6.15) for all investigated ancillary services are presented in table 7.7 below. All values except those regarding FCR-D are calculated based on historical data between 1st of October 2021 and 1st of October 2022, and presented as averages. The values regarding FCR-D are obtained from RISE (Goldberg, 2022).

Table 7.7: Computed average values of activation ratios for all investigated ancillary services.

Ancillary Service	Activation Ratio [%]
aFRR Up	26.4
aFRR Down	42.7
FCR-D Up	0.3
FCR-D Down	0.3
FCR-N Up	3.20
FCR-N Down	5.27
mFRR Up	3.17
mFRR Down	4.22

7.3.1 Key Results Balance Model

In tables 7.8 and 7.9 below, summarized results for the optimizations of the Balance Model are provided.

Table 7.8: Summarized results for the optimization of participation on the balancing markets for the Hydrogen System.

Variable	**Hydrogen System Average Scenario**	**Hydrogen System Utopia Scenario**
Increased Profit [%]	17.6	18.9
Payback Time [years]	3.47	3.22
EC Up [GW]	23.0	23.0
EC Down [GW]	60.8	59.5
FC Up [GW]	35.7	35.7
FC Down [GW]	6.53	6.45
EC Up Utilized [%]	99.9	99.9
EC Down Utilized [%]	96.4	94.3
FC Up Utilized [%]	99.8	99.8
FC Down Utilized [%]	99.3	98.2
EC Up Activated [%]	17.1	7.1
EC Down Activated [%]	26.5	14.7
FC UP Activated [%]	17.4	8.92
FC Down Activated [%]	41.1	39.0
Accumulated Change in Storage [GWh]	1.04	3.57

Table 7.9: Summarized results for the optimization of the participation on the balancing markets for the P2G system.

Variable	**P2G Average Scenario**	**P2G Utopia Scenario**
Increased Profit [%]	11.1	9.65
Payback Time [years]	2.85	3.29
EC Up [GW]	35.6	35.6
EC Down [GW]	47.4	46.7
EC Up Utilized [%]	99.9	100
EC Down Utilized [%]	95.6	94.2
EC Up Activated [%]	18.4	10.7
EC Down Activated [%]	32.5	15.4
Accumulated Change in Storage [GWh]	6.19	2.36

In the tables above, EC and FC Up and Down respectively, represent the total amount of capacity sold to each category. The utilized capacity is also presented, and is calculated as a fraction of sold capacity over total available capacity for up- or down-regulation for electrolyzer and fuel cell, respectively. The activated reserves represent the fraction of the total sold capacity to either up- or down-regulation services that is activated.

As indicated in tables 7.8 and 7.9, the complete Hydrogen System results in a higher increased profit compared to the P2G system. This can be explained by that the total sold capacity is higher in the Hydrogen System scenarios compared to the P2G scenarios. It can also be seen that the Payback Time is higher for the Hydrogen System compared to the P2G system in both scenarios, which is explained by the higher investment cost for the Hydrogen System. Finally, it should be noted that up-regulation with the electrolyzer is higher in the P2G system as compared to the Hydrogen System, which can be explained by the generally higher operating load according to the Base Optimization.

Furthermore, it can be seen that the electrolyzer mainly offers down-regulation, which results in increased hydrogen production in relation to the original production plan. The fuel cell mainly offers up-regulation, i.e. increased electricity production. However, tables 7.8 and 7.9 also show that the utilization of available capacity is higher for up-regulation than down-regulation for the electrolyzer, with a value close to 100 % in all scenarios. This means, that to a larger extent of the time it is more profitable to offer up-regulation for the electrolyzer compared to down-regulation. For the fuel cell, the utilization of up- and down-regulation respectively is similar, and relatively close to 100 % in both scenarios. The utilization of up-regulating capacity for the fuel cell is slightly higher than that of down-regulating capacity in both scenarios though.

Regarding the activation of the ancillary services, it can be seen that the activation of down-regulation is higher than the activation of up-regulation for both the electrolyzer and fuel cell. This has an impact on the hydrogen storage, which also can be seen in tables 7.8 and 7.9 above. The accumulated change in hydrogen content in the storage tank, resulting from participation with ancillary services, is well above the designed storage size of 504 MWh. The impact on the storage content is further investigated in subsection 7.3.3 below. Furthermore, the activation of different reserves is highly dependent on which type of ancillary service that is offered. As stated in section 5.2.2, the impact on the actual operation is highly dependent on which type of ancillary service that is offered, as the activation ratio is different between the different service types which is displayed in table 7.7.

Regarding the differences between the scenarios Average and Utopia, it can be seen that the Utopia Scenario is more profitable for the Hydrogen System Scenario, whereas the Average Scenario is more profitable for the P2G Scenario. The activation of the reserves is substantially lower in the Utopia Scenario for both the Hydrogen System and the P2G system. In addition, it can be seen that the total amount of capacity sold is similar between the Average and Utopia Scenarios.

7.3.2 Analysis of the Contribution with Ancillary Services

The figures below aim to provide a more detailed insight into the participation on the balancing markets. In the figures, the amount of capacity offered for each ancillary service, for the electrolyzer and fuel cell respectively, is presented. The participation is presented for all scenarios.

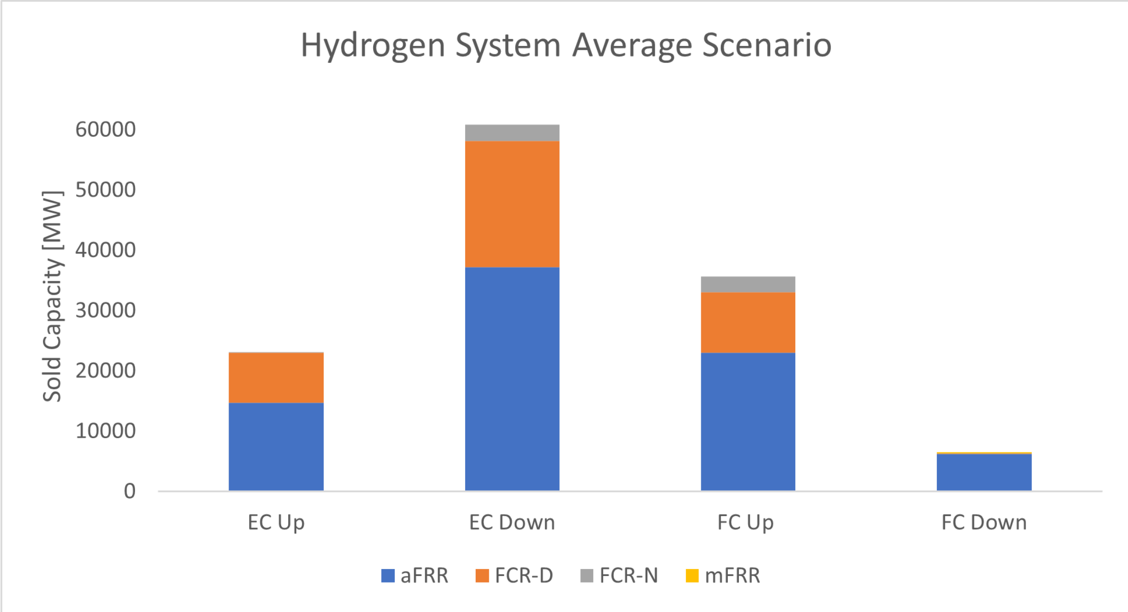

Figure 7.8: Offered Capacity to each Ancillary Service for the Hydrogen System Average Scenario.

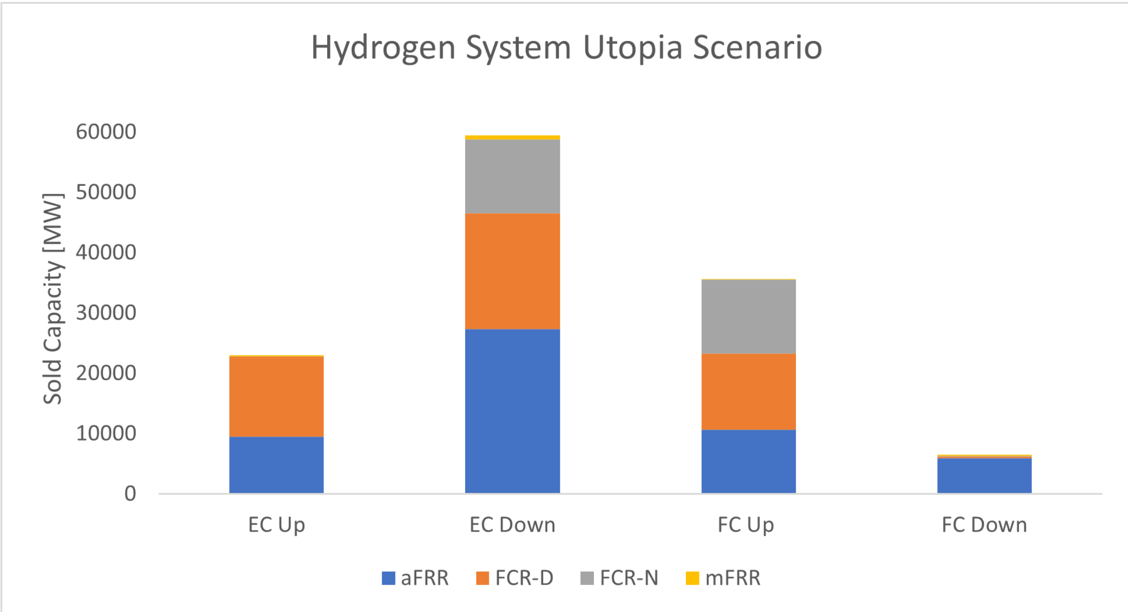

Figure 7.9: Offered capacity to each ancillary service for the Hydrogen System Utopia Scenario.

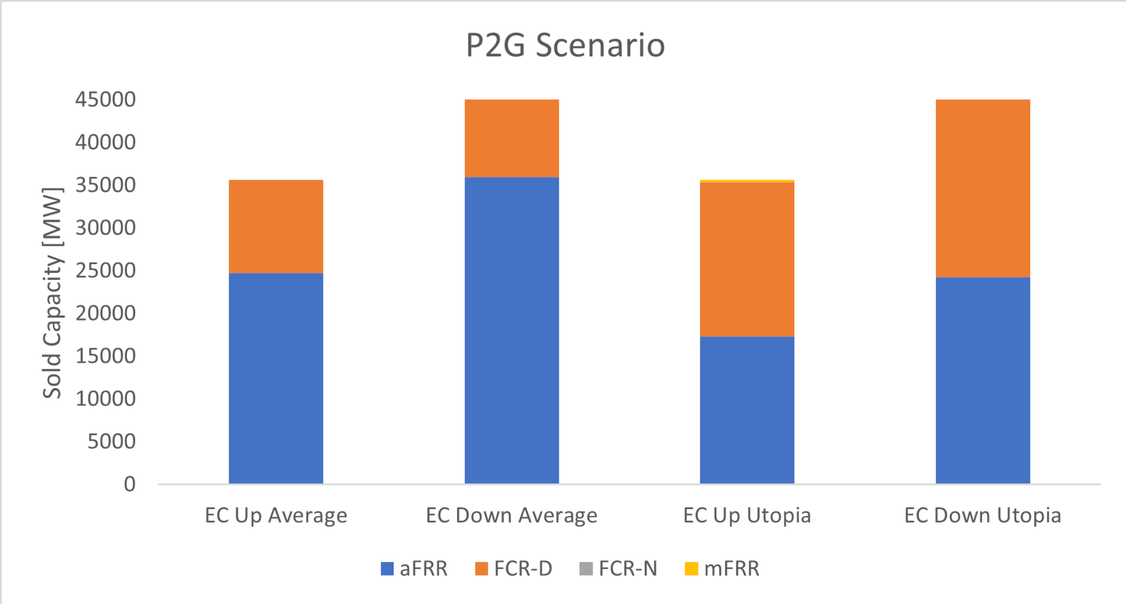

Figure 7.10: Offered capacity to each ancillary service for the P2G scenarios.

As indicated in the figures above, it can be seen that the most beneficial ancillary service to offer is aFRR, followed by FCR-D. In the P2G system no FCR-N is offered, although it is to a substantial part in the Hydrogen System Utopia Scenario, and to some extent in the Hydrogen System Average Scenario. Furthermore, it can be seen that mFRR is only offered to a low extent.

Some differences can be seen between the Average and Utopia scenarios. In both the Hydrogen System and the P2G system, the share of aFRR is lower, whereas the share of FCR-D is higher in the Utopia Scenario as to the Average Scenario. For the Hydrogen System the share of FCR-N is higher in the Utopia Scenario. It can also be seen that the share of mFRR is slightly higher in the Hydrogen System Utopia Scenario, as compared to the Hydrogen System Average Scenario.

7.3.3 Evaluation of Storage Content

As explained in section 6.4, the influence on the hydrogen storage from participating on the balancing markets is not included in the optimizations. However, calculations made outside of the optimizations show that the participation on the balancing markets results in a large increase in produced hydrogen. These values are presented in tables 7.8 and 7.9, in the variable Accumulated Change in Storage. To evaluate the consequences on the storage unit on an hourly basis, the production patterns from the Balance Hydrogen System Average Scenario and the Base Hydrogen System Scenario are combined with each other, without limitations on storage. As can be seen in tables 7.8 and 7.9, the Hydrogen System Average Scenario has the lowest accumulated change in storage. Thus, this result can be used as an indication of the minimum impact that participation on the balancing markets has on the storage unit. The resulting consequences on the storage unit are significant and presented in table 7.10 below.

Table 7.10: Consequences on the storage unit combining the optimization results from the Base Model and the Balance Model.

Hydrogen Storage Variables	**Hydrogen System Average Scenario**
Hours with content above 504 MWh	5140
Hours with content below 0 MWh	2290
Maximum content [GWh]	2.08
Size [MWh]	504

From table 7.10 it is evident that the combined operation of the hydrogen system when participating both on the spot and balancing markets exceeds the limitations of the set hydrogen storage size. To enable the optimized operation of the Hydrogen System Average Scenario, the storage would need to be increased by 1.58 GWh. If a storage of this size is chosen instead, the Payback Time of the system would increase to 5.93 years, compared to 3.06 years for the Hydrogen System Average Scenario, as seen in table 7.1. An increased storage size would however not solve the problem with the fuel cell running when there is no hydrogen available, which happens 2290 hours.

Chapter 8

Sensitivity Analysis

In this chapter the method and result from the performed sensitivity analysis is presented. Due to time limitations and long optimization times, the majority of the sensitivity analyses is performed over one week and on the model containing the entire hydrogen system. The week is chosen based on the result from the optimization of the Base Model. Spot prices, operational loads and residual heat utilization are considered key. The chosen week is October 17 to October 24, 2021. During this week both the electrolyzer and fuel cell operate over multiple hours and residual heat is both utilized and wasted. Regarding spot prices, a large variation exists over the week, but the average spot price is lower than the average spot price during the entire year. A comparison between the week and the entire year is made in table 8.1.

Table 8.1: A comparison of key values from the Base Hydrogen System optimization between the entire year and 17 to October 24, 2021.

Variable	**1 Year**	**17/10-24/10 2021**
Average Spot Price [SEK/MWh]	1535	805
Heat Utilization [%]	50.1	50.8
FC Average Load [MW]	0.92	1.03
EC Average Load [MW]	2.80	3.19

Overall, the chosen week in October corresponds well with the entire year. However, it is not completely representative. As can be seen in table 8.1 the biggest difference occurs in spot price. Still, sensitivity analyses performed between October 17 to October 24, 2021 can be used to give an indication of how variations in the input data affect the result.

The sensitivity analysis includes variations in spot prices, prices on the balancing market, efficiencies, O&M costs, tax rates, the implementation of heat pumps and hydrogen prices. Sensitivity analyses regarding the implementation of heat pumps, spot prices and prices on the balancing markets are performed over one year while the rest of the sensitivity analyses were performed between October 17 to October 24, 2021. With the exception of hydrogen prices, all sensitivity analyses were performed on the Hydrogen System Scenario.

In table 8.2 below, key values for the Hydrogen System Scenario and the P2G Scenario for the week between October 17 to October 24, 2021 is presented. The profit is compared to the Reference Scenario, i.e. the system without any hydrogen technology, during the same week. These values are the base of comparison for all sensitivity analyses performed on the Base Model over the same time period, i.e. Energy Taxation, System Efficiency, O&M Costs and Hydrogen Selling Price.

Table 8.2: Key Values for the Hydrogen System Scenario and P2G Scenario optimized in the Base Model between October 17 and October 24, 2021. The values act as reference values in the different sensitivity analysis scenarios that are optimized for 1 week.

Variable	**Hydrogen System Reference Scenario**	**P2G system Reference Scenario**
Profit [%]	8.75	29.1
EC Load [MW]	559	1130
FC Load [MW]	184	-
Heat Utilization [%]	58.8	96.8
Average Spot Price EC [SEK/MWh]	353	538
Average Spot Price FC [SEK/MWh]	1650	-
Share of Spot to EC [%]	11.4	7.15

In the table, Profit corresponds the change in profit compared to the Reference System, EC Load and FC Load are the total operating loads for the electrolyzer and the fuel cell respectively, during the time period. Utilized heat is the fraction of residual heat produced in the hydrogen system that is utilized within the district heating network. Average Spot Price EC and Average Spot Price FC are the average spot prices during times when the electrolyzer and the fuel cell operate, respectively. Share of Spot to EC is the fraction of electricity used in the electrolyzer that is bought from the spot market. The rest is produced within Örtofta CHP plant.

8.1 Heat Pumps

This sensitivity analysis scenario estimates the impact from the implementation of heat pumps in the Base Hydrogen System Scenario. In this scenario, the temperature of the residual heat streams from the hydrogen system is assumed to be in the lower range of the values presented in table 5.1. Thus, to enable the utilization of the residual heat from the electrolyzer and fuel cell, heat pumps are required. This optimization is performed over 1 year.

Two heat pumps are assumed to be needed in the system, one for the electrolyzer and one for the fuel cell. Figure 8.1 illustrates how one heat pump is modeled, the same principal applies for the other heat pump.

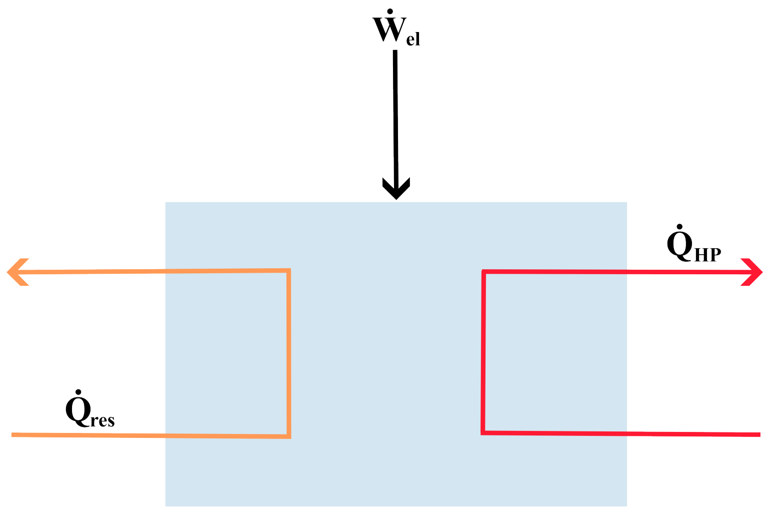

Figure 8.1: A principal illustration of how a heat pump connected to the hydrogen system is modeled.

Heat is retrieved from the residual heat streams from the electrolyzer or fuel cell, named $\dot{Q}_{res}$, and then transferred to the district heating stream through a heat pump. The residual heat flow is depicted on the left hand side of the heat pump and the district heating flow is depicted on the right side. Q_{HP} is the output of thermal energy from the heat pump and $\dot{W}_{el}$ represents the addition of electricity to the heat pump.

In order to model the heat pumps in Energy Optima 3, the output energy from the heat pumps needs to be computed. Furthermore, O&M costs and investment cost needs to be defined. The energy output from a heat pump is defined below.

The energy output from the heat pumps can be expressed in two different ways. Equation 8.1 has been presented in equation 2.1 before and expresses the output energy from the heat pump, $\dot{Q}_{HP}$. Equation 8.2 is a result of the energy balance in figure 8.1.

$$\dot{Q}_{HP} = COP \cdot \dot{W}_{el} \tag{8.1}$$

$$\dot{Q}_{HP} = \dot{W}_{el} + Q_{res} \tag{8.2}$$

The energy flow corresponding to the residual heat from the electrolyzer or fuel cell, denoted $\dot{Q}_{res}$, is known as it relates to the operational load and efficiency of the fuel cell and electrolyzer, respectively. The COP value of the heat pump is based on a study that examined and modeled high temperature heat pumps (Cox et al., 2022). COP is assumed to be 4. Equations 8.3 and 8.4 can then derived.

$$\dot{Q}_{HP} = \frac{\dot{Q}_{res}}{0.75} \tag{8.3}$$

$$\dot{W}_{el} = 0.25 \cdot \dot{Q}_{HP} \tag{8.4}$$

Equation 8.3 is based on equations 8.1 and 8.2 and expresses the energy output from the heat pump as a function of the residual heat from the electrolyzer or fuel cell. Equation 8.4 expresses the electricity consumption in the heat pump as a function of the energy output from the heat pump.

Finally, O&M costs and investment cost for the heat pumps are also included in the result from the sensitivity analysis. Based on the on the study performed by Cox et al. (2022), the investment cost is assumed to be 3150 SEK/kW of installed electric power while the O&M cost is set to 5 % of CAPEX.

In table 8.3 below, summarized results for the heat pump sensitivity analysis are presented. All values are presented in percent and are compared to the Base Hydrogen System Scenario.

Table 8.3: Summarized results from the optimization of the Base Hydrogen System Scenario with heat pumps included. All values with the unit percent are presented as a comparison to the Base Hydrogen System Scenario.

Variable	**Heat Pump Scenario**
Profit [%]	-0.305
Payback Time [%]	18.7
Payback Time [years]	30.8
EC Load [%]	-4.46
FC Load [%]	-4.46
Heat Utilization EC [%]	7.31
Heat Utilization FC [%]	-45.0
Total Heat Utilization [%]	-40.2
Average Spot Price EC [%]	2.70
Average Spot Price FC [%]	-0.05
Share of Spot to EC [%]	-4.98

As indicated in the table, the profit of the system including heat pumps is slightly lower compared to the reference scenario. Consequently, with the added investment cost to the Hydrogen System, the Payback Time of the Hydrogen System Scenario in the Base Model is increased substantially. The decreased profit of the system is likely explained both by the decreased total operational load of the hydrogen system and the decreased heat utilization. Regarding heat utilization, it is decreased almost by half in the case of the fuel cell, which operates when electricity spot prices are high, but increased in the case of the electrolyzer, which operates when electricity spot prices are low.

8.2 Electricity Spot Prices

The sensitivity analysis regarding variations in spot prices is performed over one year and on the Base Hydrogen System Scenario. Three different variations of spot prices are tested, referred to as Low Spot, High Spot and Fluctuating Spot. The input data to the sensitivity analysis is presented in table 8.4 below.

Table 8.4: Input data for the sensitivity analysis regarding spot prices. The values are presented as changes compared to the historical values between October 2021 and October 2022.

Parameter	**Low Spot**	**High Spot**	**Fluctuating Spot**
Spot Price [%]	-10.0	+10.0	+10.0/-10.0

In the Low Spot Scenario, all spot prices are decreased by 10 % while they are increased by 10 % in the High Spot Scenario. In the Fluctuating Spot Scenario, all spot prices below the yearly average are decreased by 10 % while all prices above the yearly average are increased by 10 %. All other input data is kept constant.

The result from the sensitivity analysis regarding spot prices is presented in table 8.5 below. All values are compared to the reference scenario, Base Hydrogen System Scenario.

Table 8.5: Summarized results from the sensitivity analysis regarding spot prices.

Variable	**Low Spot**	**High Spot**	**Fluctuating Spot**
Income Hydrogen System [%]	-11.0	31.8	38.1
Payback Time [%]	12.3	-24.2	-27.6
EC Load [%]	0.20	0.20	7.34
FC Load [%]	0.20	0.20	7.34
Heat Utilization [%]	5.97	1.3	3.78
Average Spot Price EC [%]	4.44	-4.29	5.75
Average Spot Price FC [%]	-0.37	0.54	-0.61
Share of Spot to EC %	17.1	-7.08	1.92

Fluctuating Spot results in the shortest Payback Time while Low Spot results in the longest Payback Time. The operational load is also increased the most in Fluctuating Spot. In Low Spot the average spot price when the electrolyzer operates is increased while the average spot price when the fuel cell operates is decreased. The same applies for Fluctuating Spot while the opposite applies is the High Spot Scenario. Regarding origin of the electricity used by the electrolyzer, a higher fraction of electricity originates from the spot market in Low and Fluctuating Spot than in the Base Hydrogen System Scenario.

The result shows that with lower spot prices, more electricity is bought from the spot market while at higher spot prices, more is taken from own production. Moreover, a consistent increase or decrease of the spot prices does not seem to affect the operational load of the system. More fluctuating prices on the other hand, increases the operational load.

Furthermore, Fluctuating Spot results in the largest decrease in Payback Time. The increased profitability seems to be mainly a result of increased operational load. Regarding the Payback Time of High and Low Spot, the system benefits from higher prices on the spot market while the profit decreases with lower spot prices. Mainly, the reason is probably the construction of the sensitivity analysis with price changes in percent. The fuel cell operates at high spot prices while the electrolyzer operates at low spot prices. A 10 % decrease or increase in price will therefore have a bigger absolute effect on the spot prices when the fuel cell operates. Since high spot prices are beneficial when operating the fuel cell, High Spot is more beneficial than Low Spot.

8.3 Energy Taxation

The energy taxation is also varied. As mentioned in section 4.9, it is uncertain which of the processes requiring electricity within an electrolytic process that are subject to tax-relief. In the Base Model, it is assumed that the electricity used directly to run the electrolyzer is tax-free, but all auxiliary power used in connection to the electrolyzer, i.e. for cooling pump and compressor, is taxed. In this sensitivity analysis, also the auxiliary power used in connection to the electrolyzer is tax-free. All other electricity bought from the spot market and used within the plant is still subject to energy taxation. The sensitivity analysis regarding tax is performed for 1 week and on the Hydrogen System Scenario.

The impact on key variables from the adjusted energy taxation is presented in table 8.6 below. The values are presented as change in percent relative to the Hydrogen System Scenario.

Table 8.6: Summarized results from the sensitivity analysis using different energy taxation on electricity. All values are presented as change in percent relative to the Hydrogen System Scenario.

Variable	No Energy Taxation for Electrolysis
Profit [%]	0.0468
EC Load [%]	1.21
FC Load [%]	1.21
Heat Utilization [%]	-7.06
Average Spot Price EC [%]	0.00
Average Spot Price FC [%]	0.00

As can be seen in the table above, there is a slight change in profit and total load of the electrolyzer and fuel cell. The average spot prices during the times when the electrolyzer and fuel cell operate, respectively, remain at the same levels. The heat utilization, i.e. the ratio of residual heat generated in the hydrogen system that is recovered in the district heating network, is lower in the case with full tax relief on electricity used for the electrolytic process. A possible explanation is that, since the operating costs associated with running the electrolyzer are lower, it is profitable to operate more in general, even though excess heat is wasted.

8.4 System Efficiency

The sensitivity analysis on efficiency is performed over one week. The input data to the sensitivity analysis is displayed in table 8.7. Two different scenarios are tested, Low Efficiency and High Efficiency. The values are based on the literature review performed in section 4.

Table 8.7: Input data regarding efficiency in the sensitivity analysis.

Parameter	**Base Hydrogen System**	**Low Efficiency**	**High Efficiency**
EC Efficiency [%]	70	60	80
FC Efficiency [%]	47	40	60
Hydrogen System Efficiency [%]	32.9	24.0	48.0
Change in System Efficiency [%]	-	-8.90	15.1

The result from the sensitivity analysis is presented in table 8.8 below. Both scenarios are compared to the Base Hydrogen System Scenario, optimized between 17/10-24/20 2021.

Table 8.8: The resulting consequences on both operation and profitability from changing efficiencies. All values are compared to the Base Hydrogen System Scenario.

Variable	**Low Efficiency**	**High Efficiency**
Profit [%]	-1.40	2.14
EC Load [%]	12.7	-5.05
Hydrogen Production [%]	-3.39	8.51
FC Load [%]	-17.8	38.5
Heat Utilization [%]	5.05	9.16
Average Spot Price EC [%]	1.73	0.00
Average Spot Price FC [%]	10.9	-7.95

The result from the sensitivity analysis show that profit increases with efficiency. Moreover, High Efficiency shows an increasing load on the fuel cell while the load on the electrolyzer decreases. However, the resulting total hydrogen production still increases in High Efficiency while it decreases in Low Efficiency. With increasing efficiency, the average spot price when the fuel cell operates is also lowered. The opposite applies for Low Efficiency. The average spot price when the electrolyzer operates remains unchanged with increasing efficiency but is increased when the efficiency is lowered.

The result can be explained with how the amount of energy losses changes with efficiency. With higher efficiency, the electrolyzer can operate at a lower load and still produce more hydrogen. Similarly, the fuel cell can operate at a higher load, i.e. produce more electricity, while still consuming less hydrogen. Thus, the load of the electrolyzer decreases while the load of the fuel cell increases in the High Efficiency scenario. The opposite applies for the Low Efficiency scenario. Finally, less energy losses in the system enables the fuel cell to operate at a lower spot price while still being profitable.

8.5 O&M Costs

The sensitivity analysis on O&M cost is performed over one week. The input data to the sensitivity analysis is displayed in table 8.9.

Table 8.9: Input data regarding O&M cost in the sensitivity analysis.

O&M Cost [% of CAPEX]	Base Hydrogen System Scenario	Low O&M	High O&M
EC	3	1	5
Compressor	1.5	0.5	2.5
Storage	2	0.5	3.5
FC	3	1	5

Two different scenarios are tested, Low O&M and High O&M. As in the Base Model, O&M costs are quantified as % of CAPEX and are included in the optimization model as costs on load ($\text{Energy}_{O\&M}$) and on start/stop ($\text{Start/Stop}_{O\&M}$). In both scenarios, O&M cost is divided equally on load and on start/stop.

The result from the sensitivity analysis is presented in table 8.10. Both scenarios are compared to the Base Hydrogen System Scenario, optimized between 17/10-24/10 2021.

Table 8.10: The resulting consequences on profitability from changing O&M costs.

Variable	**Low O&M**	**High O&M**
Profit [%]	2.29	-1.63
Total O&M Cost [%]	-59.6	44.3
EC Load [%]	6.89	-5.37
FC Load [%]	6.89	-5.37
Number of Starts/Stops EC [%]	66.67	-33.33
Number of Starts/Stops FC [%]	50.0	-50.0
Heat Utilization [%]	-2.01	-5.58
Average Spot Price EC [%]	-25.6	1.73
Average Spot Price FC [%]	1.44	0.13

Table 8.10 shows that an increase in O&M costs, by increasing both the ($\text{Energy}_{O\&M}$) and the ($\text{Start/Stop}_{O\&M}$), results in a decrease in profitability. The reason for this is twofold. The total O&M cost increases and the operational behavior of the system changes. Low O&M has a higher total operational load as well more starts and stops than the reference case. The opposite applies for High O&M. Consequently, less cost associated with running the units and with starting and stopping them, enables them to operate more flexibly and during longer time. The increased flexibility of the system ensures an operation better suited to the spot prices. In turn, this increases the profitability of the system.

8.6 Hydrogen Selling Price

In this section, a sensitivity analysis specifically for the P2G Scenario is performed, in which the selling price of hydrogen gas is varied. Three different scenarios are investigated, where the hydrogen selling price is set to 25 SEK/kg_{H_2}, 40 SEK/kg_{H_2}, and 90 SEK/kg_{H_2}, respectively. The scenarios are denoted Low Scenario, Medium Scenario and High Scenario. The sensitivity analysis scenarios are optimized for a week between 17/10-24/10-21 and key values are compared to the result of the reference P2G Scenario, with a hydrogen gas selling price of 60 SEK/kg_{H_2}. All other input data is kept constant.

The input data to the optimization, and the difference in percent compared to the P2G Scenario acting as reference, is presented in the table below.

Table 8.11: Input parameters to the sensitivity analysis performed on Hydrogen Gas Selling Price.

Scenario	**H_2 Selling Price [SEK/kg$_{H_2}$]**	**H_2 Selling Price [SEK/MWh$_{H_2}$]**	**Change in H_2 Selling Price [%]**
P2G Scenario	60	1520	-
Low Scenario	25	634	-58.3
Medium Scenario	40	1010	-33.3
High Scenario	90	2280	50.1

In the table below, the difference in key values are presented for the three sensitivity analysis scenarios, all compared to the P2G Scenario.

Table 8.12: Impact on key values for optimization results from sensitivity analysis with varying hydrogen gas selling price. All valued are compared to the reference P2G Scenario, and presented as change in percent.

Variable	**Low Scenario**	**Medium Scenario**	**High Scenario**
Profit [%]	-16.7	-11.6	23.7
EC Load [%]	-46.2	-33.9	22.8
Heat Utilization [%]	0.167	-0.0944	-13.9
Average Spot Price EC [%]	-34.5	-16.7	50.4
Share of Spot to EC [%]	54.2	51.7	-23.2

As can be seen in table 8.12 above, the profit is significantly affected by the hydrogen gas selling price. Both the Low and Medium scenarios result in lower profit compared to the reference P2G Scenario, although the difference in percent is not as high as the change in the hydrogen selling price used as input parameter, suggesting that other aspects also play an important role in contributing to the total profit of the system. The largest change in profit can be seen for the High Scenario, with an increased profit of 23.7 %, even though the change in input parameter is higher for the Low Scenario. The impact on heat utilization rate is negligible for the Low and Medium Scenarios, but notably lower in the High Scenario compared to the P2G Scenario. The latter characteristic can be explained by the production of hydrogen gas being profitable due to the high selling price, regardless of amount heat being utilized.

The load of the electrolyzer is also highly affected by the hydrogen selling price. The same goes for the average spot price when the electrolyzer operates. Table 8.12 clearly indicates that both total operating load and average spot price when the electrolyzer operates decrease for the two scenarios with hydrogen selling price below the reference, and increase for the scenario with higher hydrogen selling price. The price of electricity used in the electrolyzer needs to be low enough for the energy conversion to be profitable, at given hydrogen selling price. The share of electricity from the spot market increases when the hydrogen selling price is low. A possible explanation for this is that it more often is profitable to sell the own produced electricity on the spot market instead of using it in the electrolyzer, due to the low selling price of hydrogen. On the contrary, the share of own produced electricity used in the electrolyzer increases for the High Scenario. The selling price of hydrogen is 2280 SEK/MWh in the High Scenario, compared to the average spot price during the investigated week of 805 SEK/MWh, which explains why it is more profitable to produce and sell hydrogen as to selling the electricity on the spot market, despite the energy losses.

8.7 Prices on the Balancing Markets

For the Balance Model, sensitivity analysis is performed on the Hydrogen System Utopia Scenario. The parameters varied are the corresponding capacity prices related to offering each ancillary service, as well as the regulating prices. Three scenarios are developed called Low, High and Fluctuating. In the Low Scenario, capacity and regulating prices for the investigated time period are lowered with 10 %. In the High Scenario, all capacity and regulating prices are increased by 10 %. In the Fluctuating Scenario, capacity and regulating prices below the yearly average values are lowered by 10 % and all prices above average are increased by 10 %. All other input data is kept constant. The impact on the P2G System is assumed to be similar to the impact on the Hydrogen System, and is therefore not investigated. The reason for choosing the Utopia Scenario for the sensitivity analysis is that since the input data is temporally fluctuating, the impact from varying the input data with different factors should be more significant as to the Average Scenario.

In table 8.13 below, the change in input parameters for the sensitivity analysis is summarized.

Table 8.13: The change in input parameters used for the sensitivity analysis of the Balance Model.

Parameter	**Low Scenario**	**High Scenario**	**Fluctuating Scenario**
Capacity Prices [%]	-10	+10	-10/+10
Regulating Prices [%]	-10	+10	-10/+10

The optimization of the sensitivity analysis scenarios are performed over the time period between 1st of October 2021 and 1st of October 2022. In the table below, key values for the optimizations are presented. All values are presented as change in percent relative to the result from Hydrogen System Utopia Scenario.

Table 8.14: Key results from the sensitivity analysis on Balance Model. All values are presented as change in percent relative to the Hydrogen System Utopia Scenario, acting as reference.

Variable	**Low Scenario**	**High Scenario**	**Fluctuating Scenario**
Profit [%]	-7.42	8.76	4.04
Pay Back Time [%]	1.44	-13.7	-9.74
EC Up [%]	-0.02	0.00	-0.02
EC Down [%]	0.28	-0.29	-0.23
FC Up [%]	-0.01	0.02	0.00
FC Down [%]	0.25	-0.11	-0.14

The results show that the largest change in profit can be seen for the High Scenario, followed by the Low Scenario. The change in offered capacity for up-regulation is zero or very low. Greater variations can be seen in total capacity offered for down-regulation, however the numbers are not as significant as those for change in profit.

In table 8.15 below, the change in offered capacity for each ancillary service is presented for the three sensitivity analysis scenarios. This table aids to provide a deeper understanding of the impact from the variation in capacity and regulating prices.

Table 8.15: Change in offered capacity for each ancillary service for different sensitivity analysis scenarios.

Change in Offered Capacity for each Ancillary Service	Low Scenario	High Scenario	Fluctuating Scenario
EC aFRR Down [%]	2.22	-1.79	-2.53
EC aFRR Up [%]	-3.46	2.00	-3.27
EC FCR-D Down [%]	-4.83	4.14	4.38
EC FCR-D Up [%]	2.40	-1.41	2.13
EC FCR-N Down [%]	3.53	-3.50	-3.04
EC FCR-N Up [%]	0.00	0.00	0.00
EC mFRR Down [%]	7.36	-5.89	11.38
EC mFRR Up [%]	0.00	0.00	15.17
FC aFRR Down [%]	-0.35	0.53	-1.78
FC aFRR Up [%]	-7.89	8.49	-1.38
FC FCR-D Down [%]	-6.09	1.38	36.88
FC FCR-D Up [%]	3.44	-4.00	3.80
FC FCR-N Down [%]	-3.89	0.00	-3.89
FC FCR-N Up [%]	3.51	-3.49	-3.04
FC mFRR Down [%]	28.9	-22.2	-4.44
FC mFRR Up [%]	-22.22	25.93	29.63

Overall, table 8.15 indicates that there is variation in amount of offered capacity for each ancillary service, even though the change in total offered capacity for up- and down-regulation respectively, is slim. Large changes can be seen in offered capacity for mFRR, however from very low levels as indicated in figure 7.9. The greatest change can be seen for FCR-D Down with the fuel cell in the Fluctuating Scenario, that increases by around 37 %. All other down-regulating services for the fuel cell decreases. It should be noted that the high percental increase for FCR-D Down arises as a very low amount was offered in the reference scenario, i.e. Hydrogen System Utopia Scenario, as indicated in figure 7.9, since the vast majority of sold capacity for down-regulation with the fuel cell was aFRR Down. That aFRR is replaced by FCR-D could have to do with the divergent activation ratios of the two services, and that the Fluctuating Scenario causes the participation with activated services to become less profitable. The aspect of activation ratio and impact on participation considering activated reserves is further results in the discussion section 9.2.

In general, it can be concluded that variations in capacity and regulating prices will alter the relations between costs and incomes corresponding to the provisioning of ancillary services, which consequently can impact the times during which a service is profitable to provide or not. Furthermore, the variations also affect which type of service that's most profitable during a certain hour. At these times, the available capacity is offered to a different reserve type compared to the reference scenario.

8.8 Investment Cost

Another important factor that contributes to uncertainty in the results is the assumed values for investment costs of the different hydrogen technologies. These values are not used directly in the optimizations. However, the investment costs are used both to estimate to O&M costs included in the model and to calculate the Payback Time of the system in the different scenarios. The assumed investment costs only cover the technologies themselves and not surrounding costs such as costs related to new buildings, permits and connections. In reality, it is likely that these costs are substantial. Hence, this sensitivity analysis investigates how much the assumed investment cost can increase until the Payback Time reaches the lifetime of the hydrogen system. A lifetime of 20 years is assumed. This analysis is performed on the total results, i.e. the revenues both from the optimization of the Base Model and the Balance Model are included. The results are presented in table 8.16 below.

Table 8.16: The results from the sensitivity analysis performed on investment costs. The table shows possible increase in the investment costs for the Payback Time to equal the assumed lifetime of 20 years.

Scenario	**Possible Increase in Investment Costs [%]**
Hydrogen System Average Scenario	554
Hydrogen System Utopia Scenario	598
P2G System Average Scenario	831
P2G System Utopia Scenario	737

As indicated in the table, there is a significant marginal for the investment cost to increase while still maintaining a Payback Time below the lifetime of the system. For the Hydrogen System, the investment cost could increase around five- to sixfold for the profitability to break even, whereas the investment cost for the P2G system could increase around seven- to eightfold.

Chapter 9

Discussion

9.1 Base Model

The results from the Base Model are discussed in this section. Fuels and heat utilization are discussed first, followed by operational cost and a scenario analysis. In the scenario analysis, general comparisons between the two systems are made.

9.1.1 Fuels and Heat Utilization

Regarding the utilization of heat, displayed in table 7.2, around 40 % and 50 % of the produced residual heat from the hydrogen system is wasted in the P2G and Hydrogen System scenarios, respectively. Probable reasons that not all heat is utilized has to do with flexibility and DH load. The hydrogen system has the ability to operate very flexibly while other processes in the EVITA system are much more inert. Many times it can therefore become unprofitable, or even impossible, to utilize residual heat from the flexible hydrogen system. Possibly, it could therefore be a good idea to integrate a heat storage in the system.

The heat that is utilized from the hydrogen system can replace fossil fuels. In the Hydrogen System scenario, 90 % of the natural gas used in the EVITA system is replaced. In the P2G system scenario, 64 % is replaced. This despite the fact that the system operates mainly based on spot price and not to optimize utilization of heat. The system could instead be operated with the purpose of utilizing maximum heat and towards replacing specific fuels. This would however decrease the profitability of the system.

9.1.2 Operational Costs

One way to improve the profitability of the two hydrogen systems in the Base Model, is to lower the cost of operating them. The operational costs are presented in section 7.2.3. Some cost, for example related to the amount of electricity consumption, are hard to avoid without significantly decreasing the profitability of the system. Electrical network fees, on the other hand, could potentially be lowered by changing the operation of the system. As seen in section 7.2.3, the increased power fee constitutes a big share of the total increase in electrical network fees in the P2G and Hydrogen System scenarios, compared to the Reference Scenario. Potentially, by imposing limitations on the power usage for the hydrogen system at certain times, the power fee could be decreased without significantly decreasing the overall profitability of the system. Possibly, this could also be done to avoid the increased subscription fee. The costs related to energy and not power, i.e. the increased transfer fee and the decreased compensation for network benefit are, however, harder to change without significantly influencing the operation of the system.

The increased amount of energy tax between the Reference and the two hydrogen system scenarios is quite low, only around 0.15 %. If the electricity used in the electrolyzer was not tax free, the increased energy tax would however be much higher. Furthermore, with inspiration from the investigation performed by RISE regarding energy taxation legislation for actors producing hydrogen, presented in section 4.9, a sensitivity analysis regarding tax rates on electricity used in processes surrounding the electrolytic process in the Hydrogen System scenario, see section 8.3, was performed. In contrast to RISE, the results from this analysis showed that a change in the energy tax rates for these processes only has a small impact on the profitability of the hydrogen system. Likely explanations for the different results are the relatively low operating time of the electrolyzer of around 35 % and the low share of electricity bought from the spot market, around 26 %, in the Hydrogen System Scenario. In a hydrogen system with higher operating times, and where all electricity is bought from the spot market, the impact on profitability of different tax rates on processes that surround the hydrogen system would be higher.

9.1.3 Scenario Analysis

Looking only at the Base Model, results displayed in table 7.2, the Payback time in the Hydrogen System Scenario exceeds the assumed system lifetime of 20 years. As discussed above there is however potential to decrease certain operational cost for the system. Nevertheless, as the investment cost only includes the cost of the actual units included in the system, it is very probable that the investment cost in reality increases more than the operational costs can decrease. Thus, it can be concluded that the implementation of the complete hydrogen system in combination with Örtofta probably isn't profitable if no ancillary services are provided. Regarding the P2G system on the other hand, the investment cost could increase around twofold before the Payback Time reaches 20 years. With the assumed hydrogen price it is therefore possible that the power to gas system could reach a Payback

Time lower than 20 years without participation on the balancing markets, even with all investment costs included. However, as seen in the sensitivity analysis regarding hydrogen price, variations in hydrogen price have a significant impact on the profitability of the P2G Scenario.

When comparing the results from the Hydrogen System Scenario with the results from the P2G Scenario in the Base Model, the P2G Scenario seems to be more profitable. An important explanation for the lower Payback Time in the P2G Scenario is the lower investment cost for the system, due to a smaller hydrogen storage and no fuel cell. Two probable explanations for the larger profit of the P2G Scenario compared to the Hydrogen System Scenario are that the P2G system has a higher overall system efficiency compared to the complete hydrogen system, and the assumed hydrogen selling price. The lower overall efficiency for the hydrogen system in the Hydrogen System Scenario is a consequence of both the lower share of utilized heat and the implementation of a fuel cell. The implementation of a fuel cell in the system implies an extra energy conversion which results in higher energy losses, i.e. higher share of heat production, compared to the P2G system. Moreover, as seen in section 7.2.1, the electrolyzer in the P2G Scenario operates at higher spot price than it does in the Hydrogen System Scenario. As the hydrogen price is the dominating factor in determining which spot price the electrolyzer can operate at, a lower hydrogen price would probably result in a decrease in the operational load of the electrolyzer. Naturally, a lower hydrogen price would also decrease the profitability of the P2G system.

9.2 Balance Model

This section aims to provide a discussion and explanations for the results of the Balance Model. The chief focus of the discussion is both to compare the pricing scenarios Utopia and Average and to compare the behavior of the two different systems P2G and Hydrogen System, with regards to the participation on the balancing markets. Finally, general observations and explanations for the results of the Balance Model is provided.

9.2.1 Differences between Average and Utopia Scenarios

When comparing the Average and Utopia scenarios, the total capacity sold to the different markets is similar, when not considering which types of services that are sold. This is reasonable, as the objective function of the optimization is to maximize the profit. Consequently, as long as it is profitable to sell a service and there is available capacity, the capacity will be sold. The results indicate that as long as there is available capacity, it is almost always profitable to offer at least one ancillary service.

There are some notable differences regarding which types of services that are sold. As presented in section 7.3, the amount of aFRR is lower in the Utopia scenarios as compared to the Average scenarios. A likely explanation for this is that the actual activation data every hour is included in the Utopia Scenario, but not in the Average Scenario. The activation ratio of aFRR is generally substantially higher compared to all other investigated services. Hence, during the hours when aFRR is disfavored in the Utopia Scenario compared to the Average Scenario, it is likely that the cost for activation outweighs the revenues from activation in the Utopia Scenario, resulting in another service being more profitable. Additionally, that the amount of mFRR offered is higher in the Hydrogen System Utopia Scenario than in the Hydrogen System Average Scenario is likely explained by high peaks in regulating prices in case of up-regulation, and low peaks or even negative values in the case of down-regulation.

Participation will happen for the most profitable option, which depends both on capacity prices and costs and incomes related to activation. The participation in the Utopia Scenario can be steered based on both activation data and on up- and down-regulating prices associated with activation. Thus, the activation has a greater impact on the overall profitability for participation in the Utopia Scenario. The result shows that the activation of the services is generally lower in the Utopia Scenario compared to the Average Scenario. This indicates that more often than not, activation of a service makes it less profitable. The optimizer in the Utopia Scenario can steer away from activation both in the choice of ancillary service and in the timing of participation. The results shows that the service aFRR, with highest activation ratio of all services, is offered to a substantially lower extent in the Utopia Scenario compared to the Average Scenario. Instead, the optimization is steered towards offering services with lower activation.

A remarkable difference between the scenarios is that the profit is higher in the Utopia Scenario for the Hydrogen System, but higher in the Average Scenario for the P2G System. This is slightly unexpected, as the Utopia Scenario is designed to enable perfect timing on the markets. Possibly the explanation has to with the different possibilities for the two systems to participate on the balancing markets. In general, it can be said that the P2G System has lower flexibility as only the electrolyzer can participate. In the P2G System, most often there is only capacity available for either up- or down-regulation. In the Hydrogen System on the other hand, there is more often available capacity for both up- and down-regulation. For both systems, there is available capacity for both regulation directions when a unit operates on partial load. However, the majority of the time the units operate either on full load or not at all. But, for the Hydrogen System there is also always available capacity for both up- and down-regulation during times when neither the electrolyzer or the fuel cell operate according to the production plan retrieved in the Base Optimization. It could be that during points in time when a specific service would be most profitable in the Utopia Scenario, there is no available capacity in the P2G System. In the Average Scenario on the other hand, the costs and revenues related to activation are spread out evenly throughout the year, and hence it could lead to more points in time when both participation is profitable, and capacity is available. Hence, it seems as if the Utopia Scenario is beneficial for systems with a lot of available capacity. In cases when the available capacity is more constrained, so is the participation as there might arise a temporal miss-match between available capacity and profitable conditions on the markets. Thus, in cases with less available capacity, the Average Scenario seems to be more profitable.

9.2.2 Differences between P2G and Hydrogen System

One major difference between the P2G system and the Hydrogen System regarding the participation on the balancing markets is the higher profit for the Hydrogen System. This can be explained mainly by that the total available capacity is higher in the Hydrogen System compared to the P2G System. The P2G system only contains an electrolyzer whereas the Hydrogen System contains both an electrolyzer and a fuel cell, meaning that the ability to offer ancillary services overall is higher in the Hydrogen System Scenario. However, the Payback Time for the P2G scenarios are lower than those for the Hydrogen System scenarios, as a consequence of the lower investment costs of the P2G system.

Moreover, some differences regarding which services that are offered occur between the systems. The main difference is that no FCR-N is offered in the P2G System whereas it is to some extent in the Hydrogen System Average Scenario and to a notable extent in the Hydrogen System Utopia Scenario. This can be explained by the constraint on FCR-N. FCR-N is symmetrical, implicating that equal amount of capacity for up- and down-regulation needs to be offered simultaneously. As the P2G system only contains an electrolyzer, the ability to offer both up- and down-regulation simultaneously is limited, as it requires the electrolyzer to run on partial load. Even though it would be possible to offer FCR-N in the P2G system during certain hours, other services seem to be more profitable. For the Hydrogen System on the other hand, it is possible to offer FCR-N Down from the electrolyzer and FCR-N Up from the fuel cell at the same time, which mainly is what is done as seen in figures 7.8 and 7.9.

9.2.3 General Characteristics

As presented in section 7.3, the electrolyzer mainly offers down-regulation whereas the fuel cell mainly offers up-regulation. This is a consequence from the available capacity which is determined from the optimization of the Base Model. As can be seen in table 7.2, the time which electrolyzer and fuel cell operate is below 50 % for the Hydrogen System Scenario. Thus, the time and consequently capacity available for down-regulation is higher than the capacity available for up-regulation for the electrolyzer, and vice versa for the fuel cell. For the P2G Scenario, the time when the electrolyzer operates is above 50 % as seen in table 7.2. However, the available capacity for up-regulation with the electrolyzer is constrained by the minimum load of the electrolyzer, meaning that the unit cannot be shut off. This causes the available capacity for down-regulation to be higher than that for up-regulation also in the P2G scenarios. This explains why the total capacity sold to down-regulating services is higher than the sold capacity to up-regulating services for the electrolyzer in the P2G scenarios.

For the electrolyzer it was seen that the utilization of capacity available for up-regulation was higher than that for down-regulation. An explanation could be that the capacity prices for up-regulation generally are higher than those for down-regulation. Possibly, the lower activation ratio for up-regulating services is also beneficial. In the Hydrogen System scenarios, the utilization of available capacity for up-regulation for the fuel cell is also higher than that for down-regulation, although the difference is slim. The same conditions of higher capacity prices and lower activation ratios for up-regulating services are also applicable for the fuel cell. The smaller difference between utilized capacity for up- and down-regulation for the fuel cell is probably explained by the income associated with down-regulation with the fuel cell, i.e. Avg. Income_{FC}. As presented in the result, this alternative income is high. Consequently, activation of down-regulation for the fuel is often beneficial. This can be seen in table 7.8, which shows a very small difference between the activated down-regulating capacity for the fuel cell in the Utopia and Average scenarios.

aFRR and FCR-D together constitute almost all offered capacity for all services. The exception is that some FCR-N is offered in the Hydrogen System scenarios. When comparing the average capacity prices in table 7.5, capacity prices for up-regulation are generally higher than for down-regulation. With direction taken into account, aFFR has the highest average capacity price whereas FCR-D has the lowest. However, FCR-D has a very low activation ratio, compared to aFFR which has a high activation ratio. As indicated in the comparison between Utopia and Average, activation of a service generally seems to make it less profitable, although some exceptions naturally occur. When combining the two aspects of capacity price and activation ratio, it seems like the main driving force for the profitability of aFFR is its high capacity prices whereas for FCR-D, it is its low activation ratio. Furthermore, the results show that mFRR is only sold to a marginal extent which is reasonable as it is the only service type with compensation for only energy, i.e. when activated, whereas all other services also have compensation regardless of activation.

A limitation with the Balance Model is that utilization of heat is not accounted for in case of activation. If that aspect were to be included, the heat utilization might contribute to a larger profit than seen in our results. However, due to the generally short activation times on the balancing markets and the inert characteristics of the overall EVITA energy system, heat utilization might not be possible to a substantial extent. It could therefore be of interest to investigate the implementation of a heat accumulator tank to enable the utilization of residual heat.

Currently, the balancing markets are undergoing major changes with new rules and new markets. This results in uncertainties of how the investigated system could participate on the markets, and how the changes will affect the revenues and costs from participation in the future. In the future, there could also be an option to participate on the local flexibility markets mentioned in 3.4.3.

9.3 Combined Model

This section aims to provide a discussion of the combined results from the Base Model and the Balance Model. The main focus lies on limitations in the connection between the two models and corresponding consequences.

A major limitation with our method is that the two models are optimized separately. As the Balance Model is decoupled from the model of the CHP plant, the aspects of heat utilization and impact on hydrogen storage content are excluded. In reality however, the participation on the balancing markets also has an impact on the general operation of the plant. For instance, our results show that the participation with ancillary services result in a significant change of operation for both the electrolyzer and fuel cell, that in turn lead to a total increase in hydrogen production. Consequently, combining the models would likely have an impact on the operation of the electrolyzer and fuel cell in general. A combination of the models would affect the operational behaviour of the system in an interactive process. As the prerequisites for the optimization in the Base Model changes, so does the optimized operation, which in turn has an impact on the possibility to act on the balancing markets. This, again, changes the prerequisites for the optimization in the Base Model, and so the loop continues.

An important aspect when participating with ancillary services is how the available capacity for participation is decided. Our model lets the optimization of the Base Model determine the ability to participate with ancillary services in the Balance Model. However, since the hydrogen system operates mainly based on spot price in the Base Model and there is a correlation between spot price and prices on the balancing markets, there is a risk that our method limits the profitability of the system. For example, during times of high spot prices, the fuel cell is likely operating on full load whilst the electrolyzer is not operating, according to the production plan from the Base Model. This implies that during high peaks in spot price, there is no available capacity for up-regulation. During these times, it is also likely both that the need for up-regulation and that the up-regulation prices are high. Other steering mechanisms could therefore also be investigated. For instance, an option could be to allow a flexible operation of the electrolyzer and fuel cell but to not allow the units to operate on full load when trading on the spot market. This would mean that capacity is always available for both up- and down-regulation, and thus the flexibility to participate on the balancing markets increases.

In section 7.10 we concluded that the combination of the Base and Balance models resulted in significant consequences for the hydrogen storage content. In the evaluation, the hydrogen content exceeds the size of the storage 5140 hours of the time in the Hydrogen System Average Scenario. Moreover, more hydrogen than what is actually available is used 2290 hours of the time. An evident solution to the problem with hydrogen content exceeding the size of the storage is to increase the hydrogen storage size. But there are also solutions to this problem that don't involve an increase in storage size and a resulting higher investment cost. In reality, the two models P2G and Hydrogen System could be combined and hydrogen could either be sold directly or used in a fuel cell. This could both solve the problem of excess hydrogen and increase the flexibility and profitability of the system. Moreover, it is possible that with real time optimizations on a weekly or daily basis, neither the problem with excess or shortage of hydrogen would arise. Instead the interactive process, discussed in the beginning of this section, would ensure balance in the storage.

The total results show that the majority of the revenue originates from the Balance Model and not the Base Model. Considering this, it might be an option to have a stand-alone hydrogen system that is not integrated with a CHP plant and where heat is not utilized. This way, one could avoid costs associated with utilizing heat. It might be profitable as the main drive for the system seems to be related to electricity trading, and not heat utilization. In addition, especially when the hydrogen system participates on the balancing markets, the degree of heat utilization is hard to predict. Moreover, the option of a stand alone hydrogen system is especially relevant if there is a need to implement heat pumps in the system. As shown in the sensitivity analysis, the implementation of heat pumps both decrease the profit and the heat utilization from the hydrogen system. Although, the results from the Base Model show that the majority of the electricity used in the electrolyzer originates from the production within Örtofta. Accordingly, a stand alone system would implicate increased costs for electricity regarding network fees, tax and trading. Moreover, the overall system benefits and resource efficiency that the utilization of heat entails would be decreased. Another disadvantage with implementing a stand-alone hydrogen system is that the cost for connection to the electricity grid would be higher. In a CHP plant crucial infrastructure is already in place which decreases connection costs. For the same reason, the cost for connection to the

DH network would also be higher for a stand-alone hydrogen system, if residual heat is to be utilized. These aspects should be further investigated to determine which option that is most suitable and profitable.

Regarding the economic evaluation of the hydrogen systems, our model has some limitations. To begin with, the optimizations are only performed over one specific year. As the prerequisites for the optimizations can differ between different years, it is also likely that the increased revenue that the implementation of the hydrogen systems results in could vary. An indication of these variations is given in the sensitivity analysis. In the case of investment cost, no surrounding costs are included and it is likely that these are considerable. This aspect clearly needs further investigation. However, as seen in the sensitivity analysis, the investment costs of both systems could increase around five to eight times for them to economically break even, if using Payback Time and economic lifetime of the system as financial indicators. It is, however, important to note that the calculations of Payback Time used in our results are simple and do not include parameters such as discount rate. It could therefore be of interest to use more sophisticated economic indicators. Finally, there are several grants to apply for when investing in hydrogen technology, as mentioned in section 4.8. This is not accounted for in our results, but should certainly be considered when making investment decisions.

9.4 Sensitivity Analysis

Overall, the sensitivity analysis indicates that variations in spot prices, hydrogen selling price and prices on the balancing markets have the largest impact on the profit of the system. Regarding the hydrogen selling price the reported values vary a lot, and depend both on how the hydrogen is produced and to which market it is sold to. Consequently it is crucial to identify a suitable market to sell the hydrogen to, and preferably identify appropriate customer(s) for the selling of hydrogen gas before implementing such a system, to ensure profitability and liability.

The sensitivity analysis can also give an indication of the potential of implementing a hydrogen system in a future scenario. Both the electricity market and hence the balancing markets have undergone an extreme situation during the past year, for which the optimization is performed. Great fluctuations and record high prices have been seen, both on the spot market and balancing markets. In section 3.4.3 it is stated that a projected price difference between the lowest and highest weekly average spot price is estimated to vary between 50-100 €/MWh, corresponding to around 550-1100 SEK/MWh by the years of 2035 and 2045. However, our result show that this difference was 3690 SEK/MWh already during the investigated year between 1st of October 2021 and 1st of October 2022. This clearly implicates that foreseeing the future is hard, which is why our results should be seen merely as an indication of the potential for the implementation of hydrogen technology.

Nevertheless, a discussion for the potential to invest in hydrogen technology in the future is made with our results and sensitivity analysis results as a basis. In a best case scenario, the efficiency of the technologies is increased whereas the investment costs decrease. Furthermore, for the complete hydrogen system, the fluctuations on the spot market as well the prices on the balancing markets are further increased. As the ambition for the future is electrification of the energy sector and an increased production of electricity from intermittent renewable resources, this best case scenario is not unlikely. However, it could be that the situation on the electricity market seen during the last year has just been a rare extreme event, and that the prices will fall to notably lower levels again, or that they at least will stabilize. Such development would not be beneficial for the potential of a hydrogen system.

For the P2G Scenario, a future scenario with low spot prices would be beneficial, combined with high prices on the balancing markets. Furthermore, a hydrogen gas selling price lying in the higher range of the investigated ones would be beneficial, which could be the case if the demand for green hydrogen gas increases in the future. A low spot price scenario is not probable in the foreseeable future though. Fluctuating prices could also be beneficial for the P2G system since it implicates that the electrolyzer would not operate continuously and thus there would be available capacity for contributing with ancillary services.

Chapter 10

Conclusions & Recommendations for Future Work

The results from our study indicate that a flexible operation of a system including hydrogen technology is beneficial. Flexible operation of the Hydrogen System allows for the fluctuations in spot prices to be taken advantage of. In a system containing both an electrolyzer and a fuel cell, the units can operate at different points in time and at different spot prices. Our results shows a difference in spot price between when the electrolyzer and fuel cell operate of around 6 times. Flexible operation of the P2G system allows the electrolyzer to operate only when the spot prices are low enough to entail that the selling of hydrogen is profitable.

Furthermore, a flexible operation of a hydrogen system enables participation with ancillary services. A general conclusion regarding the combination of the results from the Base Model and Balance Model is that the participation on the balancing markets results in a prominent increase in revenue and overall system benefits in a greater perspective. When participating with ancillary services, the time the system generates revenue is increased significantly.

To enable flexible operation and participation with ancillary services, the most suitable technologies were deduced to be a PEM electrolyzer and a PEM fuel cell. Based on our results, we conclude that the choice was appropriate. Other technologies could however be more suitable to integrate with a CHP plant with regards to utilization of heat. The choice of technology should be based on the chief aim for using the technology.

An overall conclusion from the optimization of the Balance Model is that, in general, the participation with aFRR seem to be most profitable, followed by FCR-D. In the Hydrogen System, participation with FCR-N is also profitable. None of the scenarios showed a prominent participation with mFRR. Furthermore, the differences between the scenarios Average and Utopia show that the timing of participation with regards to the prices on the balancing markets as well as activation of services is of importance.

Moreover, implementation of hydrogen technology within a CHP plant can generate reduced environmental impact. Our results show that the majority of the natural gas used in the Reference Scenario can be replaced with the implementation of hydrogen technology. In addition, when a hydrogen system operates based on spot prices and offer ancillary services, it contributes with increased flexibility to the electricity system. Consequently, a hydrogen system is beneficial in a greater perspective as it aids the transition to an increased share of renewable energy production in the electricity system.

This thesis studies the potential for hydrogen technology and the optimization is performed based on historical data for one year. This means both that a perfect optimization is performed and that long-term variations in spot prices and prices on the balancing markets is not considered. Moreover, implementing hydrogen technology within a CHP plant results in both technical and economical challenges. To enable utilization of residual heat, the units might need to be specially designed, and heat pumps might be necessary depending on the outlet temperature of the cooling water. Connections between the hydrogen system and the district heating network need to be implemented. To provide ancillary services a pre-qualification process is required, and control systems need to be installed. The high investment costs and surrounding costs for e.g. piping, connections and permits cause economical challenges. For the P2G System, the hydrogen selling price is of essence for profitability. Consequently, a prerequisite for a P2G system is to have a pre-defined market with reliable selling prices.

In general, despite the challenges listed above, we can conclude that hydrogen technology integrated with a CHP plant that acts both on the spot market and the balancing markets shows great potential. Our results show that the implementation of both the P2G system and the Hydrogen System generates a significant increase in profit. Consequently, the corresponding Payback Times for the systems are low.

Based on the limitations of our thesis and the remaining challenges related to implementing a hydrogen system, we suggest the following recommendations for future work.

- Investment costs and grants need to be further investigated to examine the profitability of implementing hydrogen technology.
- Before investing in a P2G system, the market conditions require further investigations. Appropriate customer(s) and distribution routes should be identified.
- Development of the model to enable real-time optimization is recommended. To include trading on intra-day is suggested.
- The potential of decreasing the increase of electricity network fees associated with implementing a hydrogen system could be further investigated.

Therefore, we suggest that electricity network fees are implemented in an optimization model.

- Different strategies for bidding on the spot and balancing markets should be further investigated.
- Participation on local flexibility markets could also show potential and can be examined.
- It could be investigated how hydrogen can be used in turbines instead of fuel cells for electricity generation.
- Further investigations regarding technical, juridical and economical aspects of the implementation of hydrogen technology in connection to a CHP plant should be performed.

Bibliography

Alpman, M. (2021, February 24). *Vätgas växer i mariestad*. Retrieved October 14, 2022, from https://www.energigas.se/publikationer/tidningen-energigas/vatgas-vaxer-i-mariestad/

Andersson, J., & Grönkvist, S. (2019). Large-scale storage of hydrogen. *International Journal of Hydrogen Energy*, *44*, 11901–11919. https://doi.org/10.1016/j.ijhydene.2019.03.063

Axberg, E., Alkefjärd, T., Grahn, P., Jigvall, C., Karlsson, J., Karlsson, T., Pandur, S., Vendel Nylander, C., & Wallnerström, C. J. (2020). *Kapacitetsutmaningen i elnäten*. (Ei R2020:06). Swedish Energy Market Inspectorate. https://www.ei.se/download/18.5b0e2a2a176843ef8f56cb0a/1611643287162/Kapacitetsutmaningen-i-eln%C3%A4ten-Ei-R2020-06.pdf

Bjarup, D., Hansson, K., & Haglund, A. (n.d.). *Deliverable d4.6: Finalized full-scale demonstration including all sites, all customers and all functionality*. https://private.coordinet-project.eu//files/documentos/62cc71ef6a851COORDINET_WP4_D%204.6_FINALIZED%20FULL-SCALE%20DEMONSTRATION%20INCLUDING%20ALL%20SITES,%20ALL%20CUSTOMERS%20AND%20ALL%20FUNCTIONALITY_V1.0_4.07.22.pdf

Brunge, K., Hellström, E., Jakobsson, M., & Thornberg, E. (2021). *Långsiktig marknadsanalys 2021: Scenarier för elsystemets utveckling fram till 2050*. Svenska Kraftnät. https://www.svk.se/siteassets/om-oss/rapporter/2021/langsiktig-marknadsanalys-2021.pdf

Buttler, A., & Spliethoff, H. (2018). Current status of water electrolysis for energy storage, grid balancing and sector coupling via power-to-gas and power-to-liquids: A review. *Renewable and Sustainable Energy Reviews*, *82*, 2440–2454. https://doi.org/https://doi.org/10.1016/j.rser.2017.09.003

Carlson, A., Fürdös, A., Lindborg, J., & Wickström, A. (2021). *Studie över elektrolys-teknologier idag och i framtiden*. RISE. https://www.ri.se/sites/default/files/2022-05/HyCoGen%20Studie%20%C3%B6ver%20elektrolys-teknologier%20idag%20och%20i%20framtiden.pdf?fbclid=IwAR3wFNB-6smVf8uyC6B77agym9qOTtlNxNFg7ZpoyqvthB%5C%5CmvzfP9enzmaSk

Carlsson, A., Fürdös, A. N., Lindborg, J., Lundblad, A., & Wickström, A. (2021). *Utvärdering av Bränslecells-teknologier för sektorkoppling till fjärrvärme*. RISE. https://www.ri.se/sites/default/files/2022-05/HyCoGen-Utv%C3%A4rdering%20av%20br%C3%A4nslecells-teknologier%20f%C3%B6r%20sektorkoppling%20till%20fj%C3%A4rrv%C3%A4rme_0.pdf

Cigolotti, V., Genovese, M., & Fragiacomo, P. (2021). Comprehensive review on fuel cell technology for stationary applications as sustainable and efficient poly-generation energy systems. *Energies*, *14*(16). https://doi.org/10.3390/en14164963

Cox, J., Scott, B., & Lowder, T. (2022). Application of a novel heat pump model for estimating economic viability and barriers of heat pumps in dairy applications in the united states. *Applied Energy*, *315*. https://www.sciencedirect.com/science/article/pii/S0306261921017153

Diamant, I., Dolovac, A., Dalheim, M., & Nyberg, J. (2022). *Sveriges el- och naturgasmarknad 2021.* (Ei R2022:06). Swedish Energy Market Inspectorate. https://ei.se/download/18.5626efdf182e94d305658b8/1662558440109/Sveriges-el-och-naturgasmarknad-2021-Ei-R2022-06.pdf

Dincer, I., & Bicer, Y. (2020). *Integrated Energy Systems for Multigeneration.* Elsevier. https://doi.org/https://doi.org/10.1016/B978-0-12-809943-8.00002-9

Dotzauer, E., Thelander, J., Wickström, A., & Stridh, B. (2021). *Styrmedel för vätgasproduktion med sektorkoppling till fjärrvärme.* RISE. https://www.ri.se/sites/default/files/2022-05/HyCoGen%20Studie%20%C3%B6ver%20skatter%20och%20styrmedel%20f%C3%B6r%20v%C3%A4tgasproduktion%20och%20med%20koppling%20till%20fj%C3%A4rrv%C3%A4rme%20v2.pdf

Elberry, A. M., Thakur, J., Santasalo-Aarnio, A., & Larmi, M. (2021). Large-scale compressed hydrogen storage as part of renewable electricity storage systems. *International Journal of Hydrogen Energy*, *46*(29), 15671–15690. https://doi.org/https://doi.org/10.1016/j.ijhydene.2021.02.080

Energimarknadsinspektionen. (n.d.). *Avtalstyp och elområde.* Retrieved November 25, 2022, from https://ei.se/konsument/el/elavtal/jamfor-elavtal---elpriskollen/avtalstyp-och-elomrade

epexspot. (n.d.). *Epexspot.* Retrieved September 21, 2022, from https://www.epexspot.com/en

European Comission. (n.d.). *Electricity market design.* Retrieved September 22, 2022, from https://energy.ec.europa.eu/topics/markets-and-consumers/market-legislation/electricity-market-design_en

Fossilfritt Sverige. (2021). *Strategi för fossilfri konkurrenskraft - vätgas.* https://fossilfrittsverige.se/wp-content/uploads/2021/01/Vatgasstrategi-for-fossilfri-konkurrenskraft-1.pdf

Frederiksen, S., & Werner, S. (2014). *Fjärrvärme och fjärrkyla.* Studentlitteratur.

Goldberg, M. (2022). *Vätgassystems potential och värde för att tillhandahålla systemtjänster till elnätet.* (HyCoGen P107879). RISE. https://www.ri.se/sites/default/files/2022-09/HyCoGen%20V%C3%A4tgasens%20potential%20och%20v%C3%A4rde%20f%C3%B6r%20att%20tillhandah%C3%A5lla%20systemtj%C3%A4nster%20till%20eln%C3%A4tet%20-%20PUBLIK%20utg%C3%A5va%201_0.pdf

Green Hydrogen Esslingen. (2022). *Klimaneutrales stadtquartier in esslingen*. Retrieved September 6, 2022, from https://green-hydrogen-esslingen.de/#Gesellschafter

Green Hydrogen Systems. (2022). *Technical overview, hyprovide a-series & hyprovide x-series*. Retrieved January 6, 2023, from https://www.greenhydrogensystems.com/hubfs/Brochures/Technical%20specs/Technical%20Overview_2022-11-09.pdf

H-TEC Systems. (n.d.). *Pem electrolyser – the connecting link for sector integration and the decentralised production of hydrogen*. Retrieved January 6, 2023, from https://www.euromekanik.se/app/uploads/HTEC_SYSTEMS-Data_Sheet_Elektrolyser-ME450_1400_EN-04022019.pdf

Husblad, R., Morén, G., Nordström, J., Nylander, C., Tedebrand, L., & Wahlberg, S. (2020). *Ren energi inom EU*. (Ei R2020:02). Swedish Energy Market Inspectorate. https://ei.se/download/18.1e4309991774c3fe50b83bf1/1613135492591/Ren-energi-inom-EU-Ett-genomf%C3%B6rande-av-fem-r%C3%A4ttsakter-Ei-R2020-02.pdf

HyBalance. (2021). *Final report with strategic learnings from performance reporting, business case analysis*. https://hybalance.eu/wp-content/uploads/2021/12/HyBalance-D7.8-Final-report-with-strategic-learnings-from-performance-reporting-business-case-analysis.pdf

Hydrogen Europe. (n.d.). *H_2 In a nutshell: The colors of hydrogen*. Retrieved October 14, 2022, from https://hydrogeneurope.eu/in-a-nutshell/

IRENA. (2019). *Hydrogen: A renewable energy perspective*. International Renewable Energy Agency.

Kayfeci, M., & Keçebaş, A. (2019). Chapter 4 - hydrogen storage. In F. Calise, M. D. D'Accadia, M. Santarelli, A. Lanzini & D. Ferrero (Eds.), *Solar hydrogen production* (pp. 85–110). Academic Press. https://doi.org/https://doi.org/10.1016/B978-0-12-814853-2.00004-7

Konsumenternas Energimarknadsbyrå. (2022). *Elräkningen*. Retrieved November 25, 2022, from https://www.energimarknadsbyran.se/el/dina-avtal-och-kostnader/elrakningen/#:~:text=Andra%20avgifter%20fr%C3%A5n%20elhandlaren,samtliga%20dessa%20kostnader%20tillkommer%20moms.

Langmi, H. W., Engelbrecht, N., Modisha, P. M., & Bessarabov, D. (2022). Chapter 13 - Hydrogen storage. In T. Smolinka & J. Garche (Eds.), *Electrochemical power sources: Fundamentals, systems, and applications* (pp. 455–486). Elsevier. https://doi.org/https://doi.org/10.1016/B978-0-12-819424-9.00006-9

Lazard. (2021). *Lazard's levelized cost of hydrogen analysis - version 2.0*. Retrieved November 30, 2022, from lazard.com/media/451922/lazards-levelized-cost-of-hydrogen-analysis-version-20-vf.pdf

Lindblad, E., Olofsson, A., Wallmark, C., Edfeldt Wehjte, E., Arvidsson, L., & Frost, D. (2022). *Internationell och nationell sammanställning av vätgas och vätgasklusters utveckling*. SWECO. https://ei.se/download/18.213fc9e217f2a7937fd568/1645703506659/Internationel-och-nationell-sammanst%

C3%A4llning-av-v%C3%A4tgas-och-v%C3%A4tgasklusters-utveckling.pdf

Lindholm, K. (2018). *Elnätsavgifter faq*. Retrieved November 25, 2022, from https://www.energiforetagen.se/energifakta/elsystemet/elnatet--distribution-av-el/fragor--svar/

Nord Pool. (n.d.). *The power market*. Retrieved September 21, 2022, from https://www.nordpoolgroup.com/en/the-power-market/

Nordic Balancing Model. (2021a). *15 min Imbalance Settlement Period*. Retrieved September 26, 2022, from https://nordicbalancingmodel.net/roadmap-and-projects/15-min-time-resolution/

Nordic Balancing Model. (2022). *BSP - Implementation Guide: mFRR energy activation market*. https://nordicbalancingmodel.net/wp-content/uploads/2022/05/Implementation-Guide-mFRR-energy-activation-market-BSP-v113.pdf

Nordic Balancing Model. (2021b). *Nordic Balancing Model*. Retrieved September 26, 2022, from https://nordicbalancingmodel.net/

Nordin Fürdös, A., Lindborg, J., Algebrant, E., & Wickström, A. (2022). *Vätgasens potentiella värde som bränsle för framdrift av fordon samt andra industriella processer*. (HyCOGen P107879). RISE. Retrieved October 14, 2022, from https://www.ri.se/sites/default/files/2022-05/HyCoGen%20V%C3%A4tgasens%20potentiella%20v%C3%A4rde%20som%20br%C3%A4nsle%20f%C3%B6r%20framdrift%20av%20fordon%20samt%20industriella%20processer%20PUBLIK.pdf

Öhman, A. (2021). *Green hydrogen production at Igelsta CHP plant: A techno-economic assessment conducted at Söderenergi AB* [Master Thesis, KTH]. Digitala Vetenskapliga Arkivet. http://www.diva-portal.org/smash/get/diva2:1583588/FULLTEXT01.pdf

Penrod, E. (2022). Green hydrogen prices have nearly tripled as energy costs climb: S&p. *Industry Dive*. Retrieved October 14, 2022, from https://www.utilitydive.com/news/green-hydrogen-prices-global-report/627776/

Power Circle. (2022). *Lokala flexibilitetsmarknader: Faktablad från power circle*. Retrieved September 26, 2022, from https://powercircle.org/lokala-flexibilitetsmarknader-2022.pdf

Power Circle. (2019). *Stödtjänster från nya tekniker: Faktablad från power circle*. Retrieved September 22, 2022, from https://www.powercircle.org/stodtjanster.pdf

PowerCell. (n.d.). *Powercellution: Power generation system 100*.

Rhodes, R. (n.d.). Explosive lessons in hydrogen safety. *Ask Magazine*. https://www.nasa.gov/pdf/513855main_ASK_41s_explosive.pdf

RISE. (2022). *System perspective of hydrogen production in connection to district heating*. Retrieved September 26, 2022, from https://www.ri.se/en/what-we-do/projects/system-perspective-of-hydrogen-production-in-connection-to-district-heating

Royal Swedish Academy of Engineering Sciences. (2019). *Så klarar det svenska energisystemet klimatmålen: En delrapport från IVA-projektet Vägval för klimatet*. https://www.iva.se/globalassets/bilder/projekt/vagval-klimat/201909-iva-vagval-for-klimatet-delrapport4-i.pdf

Ruwaida, Y., Johansson, B., & Schumacher, L. (2021). *En rapport om sthlmflex: En lokal flexibilitetsmarknad i stockholmsregionen*. sthlmflex. Retrieved September 26, 2022, from https://www.svk.se/siteassets/2.utveckling-av-kraftsystemet/forskning-och-utveckling/sthlmflex/sthlmflex-rapport-vintern-2020_2021.pdf

Schmidt, O., Gambhir, A., Staffell, I., Hawkes, A., Nelson, J., & Few, S. (2017). Future cost and performance of water electrolysis: An expert elicitation study. *International Journal of Hydrogen Energy*, *42*, 30470–30492. https://doi.org/10.1016/j.ijhydene.2017.10.045

Seratelius, M., & Emanuelsson, A. (2021). *Leveranssäkerhet i Sveriges elnät 2020*. (Ei R2021:11). Swedish Energy Market Inspectorate. https://ei.se/download/18.5626efdf182e94d305658b8/1662558440109/Sveriges-el-och-naturgasmarknad-2021-Ei-R2022-06.pdf

Skattevarket. (n.d.). *Energiskatt på elektrisk kraft*. Retrieved January 13, 2023, from https://www.skatteverket.se/download/18.1997e70d1848dabbac932d9/1671032271889/skattesatser%20el%20t.o.m.%202022.pdf

Skatteverket. (n.d.). *Energiskatter: Skattebefrielse vid förbrukning av el*. Retrieved November 24, 2022, from https://skatteverket.se/foretag/skatterochavdrag/punktskatter/energiskatter.4.18e1b10334ebe8bc8000843.html

Sundén, B. (2019). *Hydrogen, Batteries and Fuel Cells*. Academic Press. https://doi.org/https://doi.org/10.1016/C2018-0-01247-5

Svenska Kraftnät. (2021a). *Balansering av kraftsystemet*. Retrieved September 22, 2022, from https://www.svk.se/om-kraftsystemet/om-systemansvaret/balansering-av-kraftsystemet/

Svenska Kraftnät. (2021b). *Den gemensamma elmarknaden i Europa*. Retrieved September 22, 2022, from https://www.svk.se/press-och-nyheter/temasidor/tema-elmarknad-och-elpriser/den-gemensamma-elmarknaden-i-europa/

Svenska Kraftnät. (2022a). *Elområden*. Retrieved September 22, 2022, from https://www.svk.se/om-kraftsystemet/om-elmarknaden/elomraden/

Svenska Kraftnät. (2022b). *Frekvenshållningsreserv störning nedreglering (FCR-D ned)*. Retrieved September 22, 2022, from https://www.svk.se/aktorsportalen/bidra-med-reserver/om-olika-reserver/fcr-d-ned/

Svenska Kraftnät. (2022c). *Frekvenshållningsreserv störning uppreglering (fcr-d upp)*. Retrieved September 22, 2022, from https://www.svk.se/aktorsportalen/bidra-med-reserver/om-olika-reserver/fcr-d-upp/

Svenska Kraftnät. (2021c). *Handel med el*. Retrieved September 22, 2022, from https://www.svk.se/om-kraftsystemet/om-elmarknaden/handel-med-el/

Svenska Kraftnät. (2021d). *Kraftbalansen på den svenska elmarknaden, rapport 2021: En rapport till Infrastrulturdepartementet*. https://www.svk.se/

siteassets / om - oss / rapporter / 2021 / kraftbalansen - pa - den - svenska - elmarknaden-rapport-2021.pdf

Svenska Kraftnät. (2021e). *Om elmarknaden*. Retrieved September 22, 2022, from https://www.svk.se/om-kraftsystemet/om-elmarknaden/

Svenska Kraftnät. (2022d). *Prequalification*. Retrieved January 12, 2023, from https://www.svk.se/en/stakeholders-portal/electricity-market/information-about-ancillary-services/prequalification/

Svenska Kraftnät. (2021f). *Roller i kraftsystemet*. Retrieved September 23, 2022, from https://www.svk.se/om-kraftsystemet/oversikt-av-kraftsystemet/roller-i-kraftsystemet/

Svenska Kraftnät. (2021g). *Snabb frekvensreserv (FFR)*. Retrieved September 23, 2022, from https://www.svk.se/aktorsportalen/bidra-med-reserver/om-olika-reserver/ffr/

Svenska Kraftnät. (2021h). *Stödtjänster och avhjälpande åtgärder i ett energisystem under förändring*. (Svk 2020/4162). https://www.svk.se/siteassets/om-oss/rapporter/2021/rapport-regeringsuppdrag-avseende-stodtjanster_211018_.pdf?fbclid=IwAR27aZNo6PhDsLUx2RYekRzsUeScx7UKGuVmC6doapOOX%5C%5Ck7d7GXUkmj0oBM

Svenska Kraftnät. (2019a). *Störningsreserven*. Retrieved September 23, 2022, from https://www.svk.se/aktorsportalen/bidra-med-reserver/om-olika-reserver/storningsreserven/

Svenska Kraftnät. (2021i). *Svenska kraftnät börjar upphandla FCR-D ned för 2022*. Retrieved September 22, 2022, from https://www.svk.se/press-och-nyheter/nyheter/elmarknad-allmant/2021/svenska-kraftnat-borjar-upphandla-fcr-d-ned-for-2022/

Svenska Kraftnät. (2019b). *Svenska kraftnäts reviderade förslag till villkor avseende balansering i enlighet med artikel 18 i kommissionens förordning (eu) 2017/2195 av den 23 november 2017 om fastställande av riktlinjer för balanshållning av el*. Retrieved October 31, 2022, from https://www.ei.se/download/18.1b304ff817849ed4f2b51c57/1617628786724/EB-Artikel-18-Svenska-kraftn%C3%A4ts-reviderade-f%C3%B6rslag.pdf

Svenska Kraftnät. (2021j). *Systemutvecklingsplan 2022-2031: Vägen mot en dubblerad elanvändning*. https://www.svk.se/siteassets/om-oss/rapporter/2021/svk_systemutvecklingsplan_2022-2031.pdf

Svenska Kraftnät. (2022e). *Tariff, prislistor, avtal och abonnemang*. Retrieved November 24, 2022, from https://www.svk.se/aktorsportalen/anslut-till-transmissionsnatet/transmissionsnatstariffen/tariff-prislistor-avtal-abonnemang/

Svenska Kraftnät. (2022f). *Utbud på marknaderna för reserver*. Retrieved January 6, 2023, from https://www.svk.se/aktorsportalen/bidra-med-reserver/behov-av-reserver-nu-och-i-framtiden/utbud-pa-marknaderna-for-reserver/

Svenska Kraftnät. (2022g). *Vad balansansvaret innebär*. Retrieved September 26, 2022, from https://www.svk.se/aktorsportalen/balansansvarig/vad-balansansvaret-innebar/

Svenska Kraftnät. (n.d.). *Vägledning för att leverera reserver: Vägledning och svar på eventuella frågor*. Retrieved September 26, 2022, from https://docplayer.se/137746947-Vagledning-for-att-leverera-reserver-vagledning-och-svar-pa-eventuella-fragor.html

Svenska Kraftnät. (2022h, February 7). *Varje MW på reglerkraftmarknaden är värdefull*. [Press Release]. https://www.svk.se/press-och-nyheter/nyheter/elmarknad-allmant/2022/varje-mw-pa-reglerkraftmarknaden-ar-vardefull/

Swedish Energy Agency. (2022a). *Energy in Sweden Facts and Figures 2022*. Retrieved September 12, 2022, from https://www.energimyndigheten.se/statistik/energilaget/?currentTab=1#mainheading

Swedish Energy Agency. (2022b). *Förslag till Sveriges nationella strategi för vätgas, elektrobränslen och ammoniak*.

Swedish Energy Agency. (2022c). *Hållbar energi för alla*. Retrieved September 26, 2022, from https://www.energimyndigheten.se/om-oss/

Swedish Energy Market Inspectorate. (2022). *Aktörerna på energimarknaderna*. Retrieved September 23, 2022, from https://ei.se/konsument/aktorerna-pa-energimarknaderna

Swedish Energy Market Inspectorate. (2015). *Description of the actors on the electricity and natural gas markets: A fact sheet from the Swedish Energy Markets Inspectorate*. Retrieved September 23, 2022, from https://www.energimarknadsbyran.se/media/1148/actors-on-the-electricity-and-natural-gas-markets.pdf

Swedish Energy Market Inspectorate. (2021). *Ei föreslår en tillförlitlighetsnorm för Sverige*. Retrieved September 26, 2022, from https://www.ei.se/om-oss/nyheter/2021/2021-05-31-ei-foreslar-en-tillforlitlighetsnorm-for-sverige

VA Syd. (2022). *Taxebilaga 2 brukningsavgifter (inkl moms)*. Retrieved November 25, 2022, from https://www.vasyd.se/-/media/Dokument_ny_webb/Taxor/Avgifter-for-vatten-och-avlopp/2022/Taxebilaga2_brukningsavgifter_Eslov2022.pdf

Van Nuffel, L., Gorenstein, D., Smit, T., & Rademaekers, K. (2018). *Sector coupling: How can it be enhanced in the eu to foster grid stability and decarbonise?* (PE 626.091). European Parliament. Retrieved October 14, 2022, from https://www.europarl.europa.eu/RegData/etudes/STUD/2018/626091/IPOL_STU(2018)626091_EN.pdf

Wickström, J. (2021, October 20). Så vill Svenska Kraftnät stärka stabiliteten i kraftsystemet. *Tidningen Energi*. https://www.energi.se/artiklar/2021/oktober-2021/sa-vill-svenska-kraftnat-starka-stabiliteten-i-kraftsystemet/

Witsch, K. (2022). Grüner wasserstoff ist zum ersten mal günstiger als wasserstoff aus erdgas. *Handelsblatt*. Retrieved October 14, 2022, from https://www.handelsblatt.com/unternehmen/erneuerbare-energien-gruener-wasserstoff-ist-zum-ersten-mal-guenstiger-als-wasserstoff-aus-erdgas/28251636.html

Zhang, L., Zhao, H., P. Wilkinson, D., Sun, X., & Zhang, J. (2020). *Electrochemical Water Electrolysis: Fundamentals and technologies* (1st ed). CRC Press. https://doi.org/https://doi.org/10.1201/9780429447884

Appendix A

Dimensioning

Before executing the optimizations of the Base scenarios, the hydrogen system was dimensioned, according to the method described in section 6.2.5. Three different system sizes were tested and compared in terms of Payback Time. The size of the components in the set sizes and the resulting Payback Time is presented in table A.1 below. Due to NDA specific numbers of the investment cost cannot be presented.

Table A.1: The dimensions of the components in the set system sizes Small, Medium and Large, and the corresponding Payback Time.

	System Dimensioning		
Parameter	**Small**	**Medium**	**Large**
EC Size [MW]	2	10	20
Storage Size [MWh]	34	168	336
FC Size [MW]	1	5	10
Payback Time [years]	15.3	13.3	13.8

The sizes of the components in table A.1 are presented in energy and power units. The storage is defined based on maximal stored energy (MWh), the size of the EC is defined as maximal input of electrical energy (MW), whereas the size of the FC is defined as maximal output of electrical energy (MW). The storage is set to a size that corresponds to the hydrogen production from the electrolyzer when running on full load for one day, while the size of the electrolyzer and fuel cell are set to match in hydrogen production and consumption. As presented in table A.1, the Medium sized system has the lowest Payback Time.

The tested varying storage sizes for the Medium system size are based on the size of the electrolyzer. Storage sizes that correspond to the hydrogen production of the electrolyzer when running on full load for half a day, one day, three days and one week are tested. The sizes and resulting Payback Time is presented in table A.2 below. The size of the electrolyzer and fuel cell is kept constant according to the medium sized system in table A.1.

Table A.2: The tested varying storage sizes for the medium system size and the resulting Payback Time.

Storage Dimensioning For Medium Sized System	**Storage Size** [MWh]	**Payback Time** [years]
1/2 day	84	16.5
1 day	168	13.3
3 days	504	12.5
1 week	1176	15.4

As can be seen in table A.2, a storage size of 504 MWh results in the lowest Payback Time. The obtained values for optimum size of electrolyzer, storage unit and fuel cell are used as input data in the Base Model.