Sveriges lantbruksuniversitet
Swedish University of Agricultural Sciences

Institutionen för energi och teknik

Power-to-Gas and zero-emission buses in Uppsala Challenges and Opportunities from a techno-economic perspective

- *Power-to-Gas och utsläppsfria bussar i Uppsala Utmaningar och möjligheter från ett tekno-ekonomiskt perspektiv*

Mårten Rosell

Civilingenjörsprogrammet i energisystem

Examensarbete 2021:06
ISSN 1654-9392
Uppsala 2021

Power-to-Gas and zero-emission buses in Uppsala

Challenges and Opportunities from a techno-economic perspective

Power-to-Gas och utsläppsfria bussar i Uppsala

Utmaningar och möjligheter från ett tekno-ekonomiskt perspektiv

Mårten Rosell

Supervisors: Leandro Janke, institutionen för energi och teknik, SLU
Subject reviewer: Gunnar Larsson, institutionen för energi och teknik, SLU
Examiner: Åke Nordberg, institutionen för energi och teknik, SLU

Credits: 30 hp
Level, depth descriptor and subject: Second cycle, A2E, Technology
Course title: Degree Project in Energy Systems Engineering
Course code: EX0724
Programme: Energy Systems Engineering 300 hp
Course coordination department: Department of energy and technology, SLU

City of publication: Uppsala
Year of publication: 2021
Series: Examensarbete (department of energy and technology, SLU)
Volume/Sequential designation: 2021:06
ISSN: 1654-9392
Electronic publication: http://stud.epsilon.slu.se

Key words: Power-to-gas, bränsleceller, medicinsk syrgas, modellering, lönsamhet

Sveriges lantbruksuniversitet
Swedish University of Agricultural Sciences

Fakulteten för naturresurser och jordbruksvetenskap
Institutionen för energi och teknik

Publicering och arkivering

Godkända självständiga arbeten (examensarbeten) vid SLU publiceras elektroniskt. Som student äger du upphovsrätten till ditt arbete och behöver godkänna publiceringen. Om du kryssar i **JA**, så kommer fulltexten (pdf-filen) och metadata bli synliga och sökbara på internet. Om du kryssar i **NEJ**, kommer endast metadata och sammanfattning bli synliga och sökbara. Fulltexten kommer dock i samband med att dokumentet laddas upp arkiveras digitalt.

Om ni är fler än en person som skrivit arbetet så gäller krysset för alla författare, ni behöver alltså vara överens. Läs om SLU:s publiceringsavtal här: https://www.slu.se/site/bibliotek/publicera-och-analysera/registrera-och-publicera/avtal-for-publicering/.

☒ JA, jag/vi ger härmed min/vår tillåtelse till att föreliggande arbete publiceras enligt SLU:s avtal om överlåtelse av rätt att publicera verk.

☐ NEJ, jag/vi ger inte min/vår tillåtelse att publicera fulltexten av föreliggande arbete. Arbetet laddas dock upp för arkivering och metadata och sammanfattning blir synliga och sökbara.

Abstract

This thesis has explored the use of power-to-gas technology as a means to produce hydrogen for fuel cell electric buses. The municipal council of Uppsala are looking at options to electrify the local city and regional bus fleet but have been faced with power capacity constraints on the local electrical grid. For an extended period of the day, the bus depots may only utilize 1.5 MW of power, which has proven a hurdle as battery electric buses were considered to be introduced. This thesis explored the techno-economic feasibility of using hydrogen to electrify buses, as the power consumption of fuel production can be shifted to hours where the grid is less constrained. Additionally, the co-products of the electrolytic hydrogen production were considered as a potential cost reduction or revenue.

In order to evaluate the economic feasibility, a model was created. Different scenarios of fuel cell electric bus fleets were described, and their assumed refueling strategy was derived from historic refueling behavior. Existing electricity demand for both depots were described, and the city bus depot, which only just started operating, had its electricity load profile modeled for a year from historical data in conjunction with insights from a previous thesis study. The model subsequently evaluated two different aspects, first the potential of power-to-gas without power constraints, and secondly the potential of a system faced with the power constraints.

From the simulations, the model behavior was described, and the equipment sizes were determined based on meeting a set of criteria. The equipment sizes, energy consumption, hydrogen, and oxygen production and so forth, was then used to estimate the levelized cost of hydrogen. Oxygen was considered to be used as high value medical oxygen or as low value oxygen for local processes, such as for aeration in the local wastewater treatment plant. The heat developed from cooling the electrolyzer was considered for the site district heating demand as well as low value return heat. As a result, the levelized cost of hydrogen was shown to converge towards a cost of 35 – 43 SEK/kg H_2, as the scale of the scenarios were increased. In the constrained scenarios, there were only two fleet sizes which could operate with the given constraints and criteria.

The levelized cost of hydrogen of the largest possible constrained scenario was then used to compare the total cost of ownership for a fuel cell electric bus, a HVO diesel bus, and a compressed biogas bus. It showed that fuel cell electric buses with the existing capital cost, and the projected cost of fuel, is close to competitive with compressed biogas buses on price. The thesis also highlighted the industry price targets for fuel cell electric buses and determined the necessary fuel price to reach price parity with the existing buses.

There is a plethora of aspects which could have been explored in better detail, and there are questions raised which could be explored in future studies. The model may include more dynamics, such as a stochastic behavior of fuel demand, a more rigid control method, an increased amount of renewable energy and so forth. Future studies could explore means to reduce the electrical load of the depots to improve the conditions for fleet electrification.

Sammanfattning

Det här examensarbetet har utforskat användandet av power-to-gas-teknik för att producera vätgas till bränslecellsbussar. Region Uppsala ser över alternativ för att elektrifiera den lokala stadsbuss- och regionbussflottan, men har stött på en utmaning då det råder effektbrist på det lokala elnätet. Dagtid är den nya bussdepån begränsad i sitt effektuttag, då de endast kan använda 1.5 MW eleffekt, vilket är något som står i vägen för att introducera batteridrivna bussar. Detta arbete har undersökt den tekno-ekonomiska lämpligheten att använda vätgas för att elektrifiera busstrafiken, eftersom effektbehovet för att producera vätgas kan förskjutas till timmar då elnätet inte är lika begränsat. Dessutom har merprodukterna från den elektrolytiska vätgasproduktionen tagits i åtanke som en potentiell kostnadsreduktion eller intäkt.

För att utvärdera den ekonomiska lämpligheten skapades en modell. Scenarion ställdes upp för olika storlekar på en hypotetisk fordonsflotta. Fordonsflottans bränslebehov beskrevs med hjälp av historiska data för tankning av existerande biogasbussar. Det existerande effektbehovet för bägge depåer beskrevs, där speciellt effektbehovet för den nyligen driftsatta stadsbussdepån blev modellerat utifrån begränsad historiska data i samspel med en beskrivning av effektuttaget i ett tidigare arbete. Modellen utvärderade två olika aspekter, först potentialen för power-to-gas i en kontext utan kapacitetsbrist på elnätet, och sedan potentialen för ett system som är utsatt för effektbrist.

Utifrån simuleringarna beskrevs sedan modellen och dess beteende. Resultatet gav föreslagna storlekar på utrustning utifrån kriterier för tillgodosett vätgasbehov. Den specificerade utrustningen, energianvändningen, vätgas- och syrgasproduktion och så vidare, låg sedan till grund för att beräkna en viktad produktionskostnad för vätgas (levelized cost of hydrogen). Syrgas antogs ha två användningsområden: dels en högvärdig produkt, då den eventuellt kan användas som medicinsk syrgas; dels som en lågvärdig produkt, där syret exempelvis kan driva syresättning i det lokala reningsverkets bassänger. Värmen som utvecklas vid elektrolysen antogs ha ett ekonomiskt värde då den kan ersätta fjärrvärme på plats, eller säljas tillbaka med ett lågt värde till fjärrvärmenätet. Resultatet blev att produktionskostnaden för vätgas blev påvisad att konvergera mot 35 – 43 SEK/kg H_2, när storleken på produktionsanläggningen ökar i storlek. I det begränsade scenariot påvisades det att endast två mindre bussflottor är möjliga utifrån studiens effektbegränsning och modellkriterier.

Produktionskostnaden för vätgas i det största begränsade scenariot användes sedan för att jämföra den totala ägandekostnaden för en bränslecellsbuss, relativt en HVO-biodieselbuss och en biogasbuss. Det påvisade att kostnaden för bränslecellsbussar med existerande fordonskostnader, samt den simulerade bränslekostnaden, är nära att vara jämförbar med kostnaden för biogasbussar. Arbetet belyste också de industrimål som satts upp för fordonskostnaden, och konstaterade vilket bränslepris som var nödvändigt för att nå paritet i kostnad med de existerande bussarna.

Slutligen, det finns flera aspekter som kan undersökas i närmare detalj. Det har även uppstått frågor som skulle kunna utforskas i framtida studier. Modellen som skapades skulle kunnat inkludera flera dynamiska beteenden, såsom ett stokastiskt bränslebehov för bussflottan, en starkare styrmodell för produktion, utökad elproduktion på plats, och så vidare. Framtida studier skulle exempelvis kunna utforska vägar att minska den elektriska lasten på depån för att förbättra förutsättningarna för elektrifiering av bussflottorna.

Executive Summary

On-site hydrogen production in a Power-to-Gas plant is anticipated to produce hydrogen fuel at a levelized cost of 21.7 – 61.1 SEK/kg H2, which equates to roughly 2.2 – 6.1 SEK/km. The ultimate price for hydrogen is inherently linked to the size of the project, equipment cost, potential auxiliary revenues and operational constraints linked to existing electricity demands and limitations. Efforts in capitalizing on high purity oxygen for medical purposes in Region Uppsala's health care responsibilities is particularly impactful and should be prioritized. The feasible plant sizes are today very restricted as a distribution grid power deficit, in combination with a decision to utilize electrical bus cabin heaters, drastically restrict the electrical energy supply that is available to produce hydrogen.

Hydrogen can be used in fuel cell electric buses (FCEBs) which constitute a feasible option to electrify long distance bus routes. Due to the significantly longer range of FCEBs compared to battery electric buses (BEBs), they are suggested to be considered as a zero-emission alternative for otherwise hard to electrify routes. FCEB prices are projected to be markedly reduced until 2030, indicating competitive or cheaper cost of ownership with existing biofuel bus options. For shorter routes however, electrification efforts should be prioritized with BEBs, as they offer better energy efficiencies in a landscape where renewable energy production is not yet abundant.

Preface

I want to thank Leandro Janke with SLU, who has been inspiring and supervising me in conducting this thesis; Marcus Nystrand with Region Uppsala, who has been sharing insights and data from the bus depot as well as general considerations for conducting feasibility studies; and Gunnar Larsson with SLU, who has been my subject reviewer for his help and perceptive feedback. I would also like to thank Lovisa Dannelind, Emil Eriksson, Theodorik Leao, Noor Alsabti, and Erik Jonasson for their support and friendship. Lastly, I want to thank my family, Anders, Maria, and Jonas, for all their encouragement and backing.

Table of contents

List of tables

List of figures

Abbreviations

AEM	Anion Exchange Membrane Electrolyzer
BEB	Battery Electric Bus
Capex	Capital Expenditure
CBG-B	Compressed Biogas Gas Bus
CB-P	Simulation scenario: City Bus (depot) – Pilot scale
CB-S	Simulation scenario: City Bus (depot) – Small scale
CB-M	Simulation scenario: City Bus (depot) – Medium scale
CB-L	Simulation scenario: City Bus (depot) – Large scale
CHP-plant	Combined Heat and Power plant
CO2	Carbon Dioxide
DSO	Distribution System Operator
FCEB	Fuel Cell Electric Bus
GUB AB	Gamla Uppsala Buss AB
H2	Hydrogen
HVO	Hydrogenated Vegetable Oil (a biodiesel product).
ICE	Internal Combustion Engine
IEA	International Energy Agency
kWp	Kilo-watt peak. Refers to the installed peak capacity of solar panels. (The production of solar power is dependent on the amount of insolation and will not necessarily operate at peak installed capacity because of it.)
LCOH2	Levelized Cost of Hydrogen
Nm3 Hydrogen	Normal cubic meter of Hydrogen. To convert to kg of hydrogen, multiply by a factor 0.0899.
NOX	Nitrogen Oxides
O2	Oxygen
Opex	Operational Expenditure
PEM	Proton Exchange Membrane Electrolyzer or Polymer Electrolyte Membrane Electrolyzer
PEMFC	Proton Exchange Membrane Fuel Cell or Polymer Electrolyte Membrane Fuel Cell
PM	Particulate Matter
PPA	Power Purchase Agreement
PtG	Power-to-Gas

RB-P	Simulation scenario: Regional Bus (depot) – Pilot scale
RB-S	Simulation scenario: Regional Bus (depot) – Small scale
RB-M	Simulation scenario: Regional Bus (depot) – Medium scale
RME	Rape-Methyl-Ester (a biodiesel product)
SLU	Sveriges Lantbruksuniversitet
SMR	Steam Methane Reformation
SOX	Sulfur Oxides
SOEC	Solid Oxide Electrolyzer Cell
SvK	Svenska Kraftnät
TCO	Total Cost of Ownership
TSO	Transmission System Operator

1. Introduction

City commuter traffic is today generally operated using internal combustion engines (ICE) burning both fossil and biofuels. Biofuels are good replacements in ICEs to reduce the overall carbon emissions of CO_2 as long as fuel feedstock is considered sustainable. Biofuels can however not escape the other negative aspects of ICEs, namely particulate matter (PM), NO_X and SO_X emissions. These emissions effects are felt locally in the city landscapes where the vehicles operate.

Air quality concerns, as well as carbon emission reductions, are now driving municipalities to explore zero-emission solutions to replace ICE vehicles. The most widely considered technologies are battery electric buses (BEBs) and fuel cell electric buses (FCEBs) as they both operate on electric drivetrains and thus have no combustion in the vehicle and subsequently none of the aforementioned emissions. Both technologies carry their own set of challenges with regards to infrastructure, cost of fuel, range, and refueling/recharging logistics. Additionally, the technologies can only be considered zero-emission if the energy used in propulsion is from renewable sources, e.g., renewable electricity, or renewable hydrogen. BEBs face a hurdle with regards to adaptation as the required recharging infrastructure and time to recharge is drastically different to the infrastructure and time required for ICE vehicles. FCEBs on the other hand require a sustainable hydrogen supply, where the biggest hurdle is currently the supply of affordable renewable hydrogen. The traditional production of hydrogen is done through steam methane reformation (SMR). However, with the onset of increasing renewable electricity production from wind and solar, hydrogen production through electrolysis is becoming increasingly popular. In contrast to BEBs, FCEBs refueling infrastructure is similar in operation to compressed biogas buses (CBG-B) and require considerable shorter time to refuel.

Region Uppsala, the regional council in Uppsala, are looking at alternatives to incorporate zero-emission bus traffic for the very reasons outlined above. They are looking to both BEBs and potentially FCEBs to reach their goal. This thesis will explore the techno-economic feasibility of operating FCEBs with on-site fuel production at the city bus depot, namely a power-to-gas electrolyzer plant. And attempt to put the cost into context with the existing bus technologies.

1.1. Project Scope

The scope of this thesis is limited to a water electrolysis system at the bus depot in Fyrislund, managed by Region Uppsala. The sizing of the system was determined by the identifying potential fuel demand of a FCEB fleet operating similarly to the existing bus fleet. To offset the high anticipated electricity cost, the system was also considered with planned and existing solar power on-site to offset electricity costs. Economic considerations include the purchase of electricity; installation and operation of the electrolyzer system; hydrogen compression and storage; as well as potential revenue gain from utilization of oxygen and heat. Cost considerations of an FCEB were separate from the cost of the Power-to-Gas system for clarity of the specific system cost. However, cost factors for FCEB buses were included to compare FCEBs and existing bus options.

1.2. Project Purpose

The purpose of this project is to conduct a techno-economic feasibility study of producing hydrogen in the city of Uppsala, Sweden, to fuel a potential fleet of FCEBs and to attempt answering the following questions:

1. What is the technical feasibility of producing hydrogen for zero-emission buses in the context of a bus depot in Uppsala?
2. What are the technical boundary conditions and constraints for implementing power-to-gas, and what are identifiable means to address them?
3. How does the capturing of prospective revenues or cost omissions from oxygen and heat production impact the feasibility of the technology?
4. What is the economic feasibility, and how does the estimated cost for fuel (hydrogen) and ownership cost of FCEBs compare against the fuels and buses that are presently in operation?

1.3. Delimitations

1. The project did not consider off-site production of hydrogen, nor the production of hydrogen through means other than electrolysis (SMR, gasification and so forth).
2. Price information for system components was derived from other similar studies and recent price data. No survey of manufacturers was conducted.

2. Background

2.1. Region Uppsala and Project Background

Region Uppsala is the regional council for the municipalities in the county of Uppsala. It for example manages health care, public transport, regional development, and facility services. Facilities under management are either their own operations, such as the hospital, but also partner facilities such as the bus depots that are central to this project. At the start of 2021 Region Uppsala and the Swedish University of Agricultural Sciences (Sveriges lantbruksuniversitet, SLU) entered a joint research project.

As part of this research project, Leandro Janke, the project manager with SLU, has supervised and reviewed three thesis's, including this one, on different aspects of hydrogen production and methanation. This thesis was targeted to focus on simulating and estimating the techno-economic feasibility of producing hydrogen to operate a FCEB fleet. The fact that the project would potentially be owned by Region Uppsala has an interesting caveat as it would potentially result in an in-house production of high quality oxygen, which is a valuable commodity for its health care operations. Region Uppsala are looking at electrifying the public transport within the city limits. The plan has been to introduce BEBs as a zero-emissions alternative, but with the electrical grid capacity constrained, there are uncertainties on how and when such an implementation is feasible at scale. FCEBs might prove an option, as hydrogen can be produced over extended periods of time and more flexibly, taking the constrained grid into account.

2.2. Description of the Bus Depots

The studied bus depots are located next to each other in Fyrislund, on the outskirts of Uppsala. There is one newly constructed depot for the city buses, where Gamla Uppsala Buss (GUB AB) is operating the bus traffic. The previous city depot was located closer to the city center, see Figure 1. As of 2021, the city buses have shifted to the new location. Adjacent to the newly constructed city bus depot, there is a separate depot for the regional buses, where Nobina Sverige AB is operating. Both facilities are managed by Region Uppsala, and the facility works, as well as invoices for district heating and electricity costs are directed to Region Uppsala. The majority of the buses at the depots are parked and dispatched from outside, also during winter cold seasons. This means that there is a seasonal heating demand for each individual bus, which will be discussed further in Section 4.1.1.

Figure 1. Location of the regional bus depot, the new city bus depot as well as the old city bus depot in Uppsala.

2.2.1. Existing Bus fleet

The city bus fleet is comprised of 120 12-meter buses, and 60 18-meter articulated buses, see Table 1. Today the buses run exclusively on biofuels, half of the bus fleet are compressed biogas busses (CBG-Bs) and the other buses operate on hydrogenated vegetable oil (HVO)-diesel. The biogas is supplied by an anaerobic digestion facility, which is operated by Uppsala Vatten AB, and supplies the gas via pipeline. In rare events, the supply and demand of biogas is not met, and fossil natural gas can act as make-up fuel. During a typical year, the average city bus travel 65,000 km, with reduced service during the summer and weekends. Region Uppsala has noted that they anticipate the price for HVO to increase in the near-term, and that they are looking at alternatives to replace the bio-diesel buses as they reach their end-of-life. All of the city buses are dispatched, refueled, and serviced at the depot.

The regional bus fleet accounts for 80 buses, 64 buses run on rape-methyl-ester (RME)-diesel and the remaining 16 buses are biogas buses. Similarly, like the city bus traffic, the regional buses operate with reduced service during the summer and weekends but travel on average 134,000 km per year.

Table 1. Existing bus fleet information.

	City Bus Depot	**Regional Bus Depot**
Bus fleet (short buses)	120 buses	80 buses
Bus fleet (articulated)	60 buses	-
Total Fleet Size	**180 buses**	**80 buses**
Biogas buses	90 buses	16 buses
Biodiesel buses	90 buses	64 buses
Average Annual Distance	65,000 km	134,000 km

2.2.2. Heating demand

Both bus depots are connected to the district heating network, which is supplied from the local combined heat and power (CHP)-plant. The heat is used to heat workshops, office buildings, and in the case of Nobina, to heat the regional buses. As buses are parked and dispatched from outside, they require heating during the cold days of the year. Prior to bus dispatching, the bus cabins need to be at a temperature of at least 6 °C. In practice, this means that buses are heated before dispatching from September through May, with variable heat demand depending on the season.

All of the city buses are heated using electric space heaters. This is an easy way to heat the buses as connecting a cord to the bus space heater does not come with the risk for spillage. It does however come with a large electricity demand for the heating season. In February of 2021, electricity demand eclipsed 2.1 MW in the morning hours due to the demand for space heating. For reference, the average baseload demand is about 500 – 600 kW.

2.2.3. Grid capacity constraints

The city bus depot has a newly built grid connection dimensioned for 6 MW of electricity, which was sized to consider a future BEB fleet. However, in the construction phase of the bus depot, the city of Uppsala was suddenly faced with an unanticipated obstacle. As the bus depot in 2017 formally inquired for grid service to cover their anticipated electricity consumption they were denied by the distribution system operator (DSO), Vattenfall AB [1]. This is due to a current constraint on the transmission lines within the region. They did however agree to an augmented service agreement, as electricity demand could be planned to low-demand hours.

As a result of this revelation, in combination with fears of how this would affect future development in the region, a joint effort was initiated to describe and tackle the grid capacity constraint. One such solution was the augmented, flexible service agreement with Vattenfall. Currently, the agreement is that the city bus depot is limited to 1.5 MW from 6.00 – 22.00 and a maximum of 4 MW at other hours by directions from Vattenfall. The regional bus depot has a 1.2 MW service agreement which they can utilize fully at all times, however, should they need to renegotiate their service agreement, they may face similar service agreements.

Vattenfall made a request to Svenska Kraftnät (SvK), which is the Swedish transmission system operator (TSO), for an increased power subscription of 200 MW to Uppsala by 2020 [2]. But as the transmission grid also services other regions, like Västerås, with similar increasing demands, the transmission capacity is strained and needs expanding. SvK are currently working to alleviate the capacity issue, for example by testing high-temperature transmission lines able to increase capacity of 100 MW within 2 – 3 years [2]. This expansion will alleviate some of the constraints, but according to Region Uppsala, this capacity has already been booked by upcoming power subscriptions. This means that although there will be resolution ahead as the TSO strengthens the transmission capacity, considerations for the constrained grid will be necessary for the foreseeable future.

2.2.4. Solar PV production

The two depots have or will have solar PV plants installed at each facility. The city bus depot is installing a capacity of 500 kWp, mounted flat on top of the building and service roofs. At the regional bus depot there is an additional installed capacity of 400 kWp installed in a similar fashion. In a personal conversation with Marcus Nystrand at Region Uppsala, it was noted that there is a possibility to construct an additional PV plant adjacent to the depots with an estimated capacity of 1,000 kWp. However, in order to connect an adjacent solar park to the depots, the applicant would have to seek special permits to circumvent the grid concessional duties.

In Sweden, all electricity grid enterprises are required to apply for grid concession by law (Ellagen 1997:857). Any high power transmission or distribution grid, including internal micro-grids, need to be approved before they are constructed [3]. The construction of a connection between an adjacent solar power plant and the bus depot, would hence be subject to concessional duties. However, the responsible agency, Energimarknadsinspektionen, may permit an exemption if the business is approved to meet their stated criteria [4].

2.3. Subsidies and Tax exemptions

There are a number of tax exemptions and subsidies that can target a potential FCEB fleet and have significant impact on the cost of hydrogen production, hydrogen as a fuel, as well as the purchasing price of the FCEBs themselves.

2.3.1. Tax exemption on electricity used in electrolysis.

According to Swedish tax law (1994:1776), chapter 11, paragraph 9§, section 2, there is a tax exemption provided for electricity used in electrolytic processes [5]. For the sake of this report, tax on energy shall not be included in the price of electricity.

2.3.2. Taxation on hydrogen as a fuel.

Hydrogen that is converted into electrical energy in a fuel cell, shall not be subject to energy nor carbon tax. However, hydrogen used in combustion engines is subject to the same taxation as natural gas [6]. Subsequently, this thesis will assume no tax on fuel for the FCEBs.

2.3.3. Regulation on subsidies for electric propulsion buses.

The Swedish government has instituted a regulation targeted for electric transit-traffic, including fuel cell electric buses. Any municipality, city government or companies operating municipal transit-traffic are eligible for a 10 % subsidy on the price of an electric bus. The subsidy payout cannot exceed 100 % of the difference in price between the electric bus and the price of a typical diesel engine bus [7].

Eligible buses have to have a maximum carrying capacity of at least 15 passengers. Furthermore, each applicant is only eligible for 25 MSEK in subsidies each calendar year [8]. For this thesis, FCEBs are a high-cost item that will be eligible for the full 10 % subsidy. The subsidy limit of 25 MSEK will not be considered as the expansion of the bus fleet will be assumed as incremental, taking the subsidies at each incremental purchase.

3. Theory

3.1. Power-to-Gas

Power-to-Gas (PtG) is an umbrella term that cover the process of producing multiple possible gaseous fuels by means of electrical power. While hydrogen is the primary gas generated, methane (CH_4) or ammonia (NH_3), are gases which are also frequently discussed with PtG through synthetization [9]–[11]. Water electrolysis is the process of producing hydrogen and oxygen molecules out of water molecules by applying an electric current. It is not a novel process, the first discovery of water electrolysis was done by the Dutch Troostwijk and Deiman in 1789 [12]. Electrolysis has however never dominated the markets for producing hydrogen, instead hydrogen is frequently produced by steam methane reformation (SMR) of fossil methane gas. In the International Energy Agency (IEA) roadmap report for hydrogen and fuel cells from 2015, about 96 % of hydrogen was produced by fossil fuels [13]. However, with the increasing urgency to reduce the reliance of fossil fuels, and the rapidly falling prices of renewable energy production, electrolysis is increasingly being considered at increasingly larger scale. Hydrogen produced through electrolysis, often referred to as green hydrogen, can potentially decarbonize several energy intensive sectors and industries such as by replacing coking coal to produce steel [14]; by acting as fuel in transportation and aviation [9]; being a renewable feedstock to produce fertilizer [15]; and replacing fossil fuel in the production of cement.

Naturally, with increasing interest, the electrolyzer technologies is a frontline research topic, and primarily four different technologies are currently in focus. The technologies are Alkaline-, Polymer Electrolyte Membrane (PEM)-, Anion Exchange Membrane (AEM) Electrolyzers and Solid Oxide Electrolyzer Cells (SOEC) [16]. Out of the four technologies, only two are at a commercial state, the Alkaline Electrolyzer and the PEM Electrolyzer, both of which will be explored further in the following sections.

A PtG plant is comprised of different components depending on the technology that is being used. Common to all of them is the electrolyzer stack, producing the hydrogen and oxygen from water; a rectifier or DC power supply, providing the voltage potential and current; water pre-treatment equipment; and compression and storage equipment for the produced gases.

3.1.1. Alkaline Electrolyzer

The alkaline electrolyzer is the most widely used technology today, with mature commercialization and a long track record [13]. As the name suggests, the electrodes are submerged into an alkaline solution that acts as the electrolyte, most commonly a potassium hydroxide lye (KOH) solution of 20 – 40 % [17], [18]. Pure water has poor electric conductivity hence, why the water is mixed into a lye solution to reduce the resistivity. The electrodes are separated by a porous membrane through which the hydroxide can pass freely. The cathode splits the water molecule into hydroxide (OH^-) and hydrogen gas. Hydroxide anions are then recombined at the anode, releasing one oxygen atom and a water molecule.

$$Cathode: H_2O \rightarrow H^+ + OH^- \qquad \text{Eq. 1}$$

$$Anode: 2\ OH^- \rightarrow H_2O + O^{2-} \qquad \text{Eq. 2}$$

$$Total: 2\ H_2O \rightarrow\ H_2 + \frac{1}{2}O_2 + H_2O \qquad \text{Eq. 3}$$

Electrodes are commonly made out of metallic nickel (Ni) mesh, permitting electrolyte and gases to freely circulate through them. This is in contrast to other electrolyzer technologies, where the alkaline electrolyzer does not need expensive and scarce electrocatalysts. The overall industry performance of alkaline electrolyzers is in the range of 52 – 62 % efficiency [17]. Efficiency is estimated based on the lower heating value of hydrogen and the total system electric input.

The resulting hydrogen and oxygen gas streams are pure, about 99.9 vol. % and 99.0 – 99.5 vol. % respectively [19], however there may be residual traces of electrolyte, oxygen, and water vapor. For this reason, an alkaline system needs a lye separator and scrubber to remove any electrolyte residual; a deoxidizer to remove oxygen from the hydrogen gas by forming water; and a gas dryer stage to finally remove the water. A schematic illustration can be found in Figure 2. If the oxygen gas is to be utilized with high purity requirements, the same treatment is required here as well [20], [21].

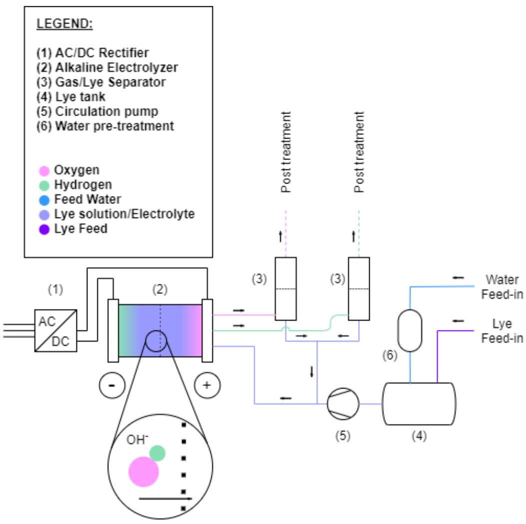


Figure 2. Alkaline Electrolyzer System.

One consideration for when selecting the electrolyzer technology, is the anticipated operation cycle. Both PEM and alkaline electrolyzers are low temperature processes, operating in the range of 50 – 90 °C. The alkaline electrolyzer has a liquid electrolyte which is circulated by pumps to maintain the KOH concentration. This constitutes considerable thermal mass that needs to maintain its temperature to operate properly. During normal operation, heat is maintained by the electrolytic process and cooling heat exchangers, but during non-operational hours, the electrolyzer need be in warm stand-by to permit timely ramp-up. If an alkaline electrolyzer is conducting a cold-start, the time to warm-up can take upwards of 1 – 2 hours [15]. Another consideration is also the load range of the electrolyzer, an alkaline electrolyzer should not go below 25 – 35 % of its rated capacity, because this can lead to hydrogen diffusing through the membrane at a devastating rate, resulting in an explosion hazard as it mixed with oxygen [15]. The preference should therefore be to have the electrolyzers operate in parallel for lower loading rates. Lastly, liquid electrolyte and its inability to operate at higher pressures make the equipment bulkier than PEM systems, as the balance of plant equipment, electrolyzer stack itself [22] and additional compressors require more space.

3.1.2. Polymer Electrolyte Membrane Electrolyzer

The Proton Exchange Membrane (PEM) or Polymer Electrolyte Membrane electrolyzer, both used interchangeably, is the second most commercialized electrolyzer technology [16]. Contrary to the alkaline electrolyzer, where the electrolyte is moving anions between the electrodes, the PEM electrolyte is moving the hydrogen protons themselves.

$$Anode: H_2O \rightarrow 2\,H^+ + \frac{1}{2}O_2 \qquad \text{Eq. 4}$$

$$Cathode: 2\,H^+ \rightarrow H_2 \qquad \text{Eq. 5}$$

$$Total:\ H_2O \rightarrow\ H_2 + \frac{1}{2}O_2 \qquad \text{Eq. 6}$$

PEM electrolyzers have a solid polymer membrane sandwiched between the electrodes, greatly reducing the footprint of the electrolyzer. Instead of lye solution, pure water is supplied to the anode and a pure hydrogen gas is formed at the cathode, with only trace amount of water formation due to electroosmosis, see Figure 3. The proton transfer is highly corrosive, why the electrodes have to be manufactured with expensive rare mineral catalysts iridium (Ir) and platinum (Pt) [15]. Today, industry performance of PEM electrolyzers are in the range of 57 – 64 % efficiency [17].

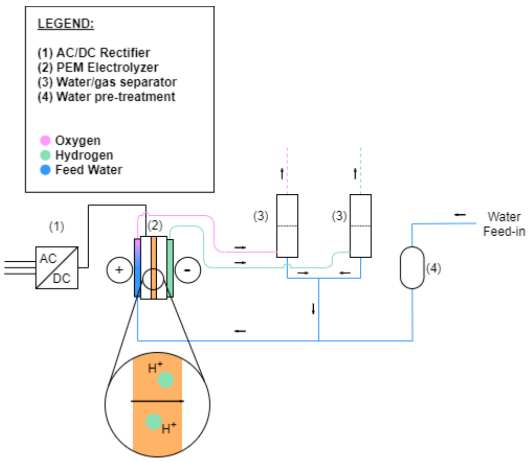


Figure 3. PEM Electrolyzer System.

With the solid electrolyte, the PEM electrolyzer can generate gas at higher pressures than alkaline electrolyzers, which equates to energy saved on gas compression. The low permeability of the membrane and use of pure water also reduces the requirements of post-treatment of the gas stream. Gases are produced at purities of 99.99 % after a gas drying stage removing water from the gas streams [23],[24].

Other benefits of the PEM electrolyzer is fast response times and wide load range. The electrolyzer can conduct a cold-start in seconds to minutes, where alkaline electrolyzers need minutes to hours. A wide load range is the function of the previously mentioned low permeability of the membrane, where the risk of hydrogen diffusing into the cathode side and mixing with oxygen is very low. Additionally, some manufacturers claim the ability of exceeding the nominal loading rate of the electrolyzer as the technology permits high current densities [15]. That brings added specification requirements for power supply and equipment cooling. PEM electrolyzers have been favored in industrial applications because the balance-of-plant; that is the auxiliary systems of cooling, electrolyte circulation and so forth; are more manageable compared to alkaline systems [23]. The compression needed can be reduced, less post-treatment is required, and no lye system needs to be maintained.

3.1.3. Feed-water requirements

Both of the aforementioned electrolyzer technologies have requirements on their feedwater, although they are differently stringent. Degradation rates of the electrolyzer stacks are affected by the prevalence of water impurities [16]. The alkaline electrolyzer is less sensitive yet does have issues with impurities deteriorating the diaphragm which separate the electrodes. Even though the water is mixed with KOH for the electrolyte, manufacturers specify the feed water requirements on water conductivity to be at least below 10 µS/cm [25], [26]. The PEM electrolyzer on the other hand is even more sensitive to impurities, and require conductivity below 1 µS/cm, and preferably below 0.1 µS/cm [24], [27]. To meet these requirements, the feed water needs to be pre-treated. Either through ion-exchange water softening or ion-exchange deionization. The PEM electrolyzer, which is especially sensitive to poor water quality as it results in degradation of stack conductivity and proton exchange, require deionized water [17].

3.1.4. Hydrogen Storage and Refueling

Hydrogen has a very high energy density of 120 MJ/kg, which can be compared with biogas which has about 50 MJ/kg. Hydrogen also has a very low volumetric density of 0.0823 kg/m^3 at ambient conditions. Whereas methane has a volumetric density of 0.657 kg/m^3 under the same conditions. This translates to a considerably higher volumetric energy density for biogas by comparison. Naturally, the low volumetric density of hydrogen poses a challenge when it comes to transporting and storing large amount of hydrogen gas. Storage is therefore achieved either by compression to high pressures, or through liquification, depending on the application and dispensing scheme. Liquification is primarily considered for transporting hydrogen great distances as it has the highest energy density, but requires the hydrogen be cooled down below its boiling point, -252.8 °C. Given the poor mass density of hydrogen gas, the compression needs to be to a greater pressure as opposed to what for example methane gas require. Compression of hydrogen for high pressure applications is achieved through ionic compression or cryogenic compression. Ionic compression uses ionic liquids and pistons in stages to compress the gaseous hydrogen. Cryogenic compression requires cooling hydrogen below its boiling point and then controlled evaporation and compression to the desired pressure, often more suitable for very high pressure applications. It is a suitable technology for externally produced hydrogen that has already been transported in liquid form.

Due to the low volumetric density outlined above, storage applications for bus depots are generally high pressure systems in the range of 350 – 500 bar [28]. The storage pressure on FCEBs is typically 350 bar. Storage capacities at a bus depot or hydrogen refueling location has pressures of 350 or 500 bar, which permits either booster compressor dispensing or overflow dispensing, respectively. By comparison, storage systems on fuel cell electric cars are even more demanding as they use 700 bar compression. FCEBs permit storage in more, and larger tanks, why the pressure can be reduced by half. The tanks for these high pressure hydrogen storage applications are manufactured out of carbon fiber composites, which makes them expensive.

Overflow dispensing requires storage pressures above the target pressure, in this case the 350 bar pressure of the FCEB tanks. It is either achieved with multiple pressure stages called cascading storage, or in a single constant pressure storage vessel with hydraulic compression. Cascading storage is three or more pressure stages which are operated through valves when refueling the bus. Each pressure stage is equalized with the bus storage tanks in a cascading low-to-high pressure order, to achieve the final 350 bar pressure. An overflow dispenser with hydraulic compression can extract more hydrogen from the storage tank, as the volume of the tank is shrunk. If gas is stored in a constant-volume storage tank, the pressure within the tank will fall as gas is dispensed to the bus. A booster compressor dispensing scheme is a second set of compression stages to maintain 350 bar at the dispenser outlet. The hydrogen is piped to a dispensing unit, which is then connected with a seal to the bus. Dispensing speeds per dispensing unit is subject to aspects of plant design, ambient temperature and pressures held in the storage tanks. Fuel dispensing speeds can be in the range of 108 – 432 kg hydrogen/hour for a single dispenser [28].

3.2. Fuel Cell Electric Buses

Fuel cell electric buses (FCEBs) are vehicles that generate electric power in a fuel cell. Fuel cells are just like batteries a galvanic cell, only their electrodes are not consumed, but instead are instead reliant on the supply of the reactants, hydrogen, and oxygen. Essentially, the process of generating electricity in a fuel cell is the reverse to that of electrolysis, generating only electricity, heat, and water. For automobile applications, the low-temperature Proton Exchange Membrane Fuel Cell (PEMFC), is the leading technology. The PEMFC is comprised of stacks of mechanically secured assemblies of anodes, cathodes, solid electrolyte, catalyst covered membranes, and cooling plates [29].

Fuel cells are being adapted on bus platforms as they have good storage space for the hydrogen tanks and have greater fuel efficiencies compared to diesel and gas powered buses. A FCEB with a mileage of 0.10 kg H_2 per kilometer, consumes an equivalent 3.3 kWh per kilometer. By comparison, HVO diesel buses consume approximately 4.2 kWh per kilometer, and biogas buses 5.2 kWh per kilometer [30]. The FCEBs are today commonly equipped with batteries, which control the power output of the electric motors and enable regenerative breaking for enhanced fuel efficiency. The fuel cells can then in turn either drive the motor or recharge the batteries, illustrated in Figure 4. For example, the manufacturer Solaris is delivering multiple FCEBs to cities in Europe [31] [32], their buses are equipped with 70 kW fuel cells and high power batteries [33] to supply their two 125 kW electric motors.

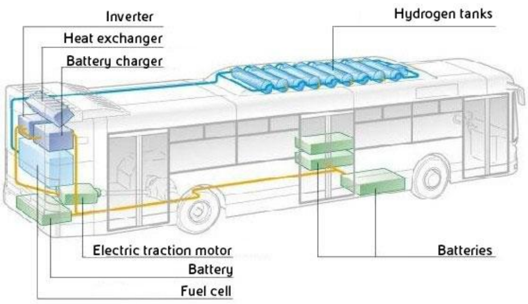


Figure 4. FCEB system layout [59].

Identifiable market prices for FCEBs were at the time of writing € 625,000 [31]. The high price for the FCEB buses is expected to fall, with targets of about € 400,000, equivalently about 4.0 MSEK, by 2030[34]. By comparison HVO buses, CBG-Bs, and BEBs cost about 3.0 – 3.5 MSEK today [30]. More manufacturers, such as the existing city bus provider to Region Uppsala, MAN [35] or the manufacturing groups Daimler & Volvo [36], are also looking to provide fuel cell electric drivetrains, indicating price reductions as the market develops.

The benefit of FCEBs as compared to BEBs is their extended range, and reduced need for added infrastructure. FCEBs have storage tanks, expandable depending on range demands, where hydrogen is stored at 350 bar. The range of operation can be 350 – 450 km, with comparatively brief refueling times of 10 – 20 minutes [28] depending on ambient temperature, tank pressure, piping layout and dispensing method which all impact the speed with which gas is moved between the storage tank to the bus tanks. BEBs by comparison employ overnight charging or continuous top-off charging throughout the day [37]. Hence, FCEBs can utilize a single refueling point to service a larger area, while BEBs require infrastructure considerations such as deciding between more charge points, high power chargers or larger batteries.

BEBs do however operate at significantly better energy efficiencies as charging and discharging batteries does not come with the same energy losses as PtG for fuel cells. The roundtrip energy efficiency of BEBs is about 77 %, whereas the round trip energy efficiency for FCEB is about 28 %, see Appendix A. FCEBs do have some benefits as hydrogen can be produced over longer periods of time, at a single location, limiting the instantaneous electric power demand. Additionally, the fuel cells produce heat which can be used for cabin heating where a BEB require other heating equipment.

3.3. Production of oxygen.

As previously mentioned, electrolysis produces oxygen which is a gas used in a plethora of industries. Different utilizations come with different product requirements and subsequently a varying cost premium of the oxygen. Pure oxygen can for example be used to improve combustion in power plants, blast furnaces and glass production; to aerate the sludge in wastewater treatment plants and improve bacteria growth; for oxygenation of water in aquaculture; or as medical oxygen [38]. Medical oxygen is a high value gas as the production requirements are strict, while oxygen used in wastewater treatment for example has a low value by comparison. And the technical specifications and requirements are different as well.

According to the Swedish Medical Products Agency, Läkemedelsverket, medical oxygen has to be at minimum 99.5 % v/v of O_2 (% volume per volume of solution). Carbon dioxide (CO_2) content must be a maximum of 300 ppm v/v, Carbon Monoxide (CO) content a maximum of 5 ppm v/v, and water content a maximum of 67 ppm v/v, with no other impurities [39]. Most commonly, this is produced using cryogenic distillation or pressure swing adsorption (PSA), where cryogenic distillation is typically used for medical gas purposes [38]. Oxygen produced for medical use is considered a medicinal gas, and its production is subsequently subject to following Good Manufacturing Practice standards (GMP) [40] and Swedish pharmaceutical law (2015:315) [41].

The prospect of producing medical oxygen through electrolysis is not unheard of [38]. Manufacturing standards that are used in conventional methods apply here as well, and the oxygen stream from the electrolyzer should come with little or no other gases as long as the electrolyzer is selected with care. A gas dryer stage is necessary as water mist or vapor is likely in the oxygen stream. Furthermore, in the case of using an alkaline electrolyzer, special care has to be taken with regards to the alkaline electrolyte solution. Lastly, CO_2 and CO is not generated in the electrolytic processes.

4. Methodology

4.1. System description of Power-to-Gas plant

Simulating the PtG-plant requires modeling of the electrolyzer operation. It also includes describing the dynamics that are imposed on the system given its setting, illustrated in Figure 5. Such dynamics are the number of buses that are to be supplied; how much fuel is being consumed and when the refueling events take place; the electricity and heat consumption of the depots; as well as solar power production. Different sizes of bus fleets require differently sized PtG-plants, and hence seven different fleet configurations are explored. All of this is described in the following sections.

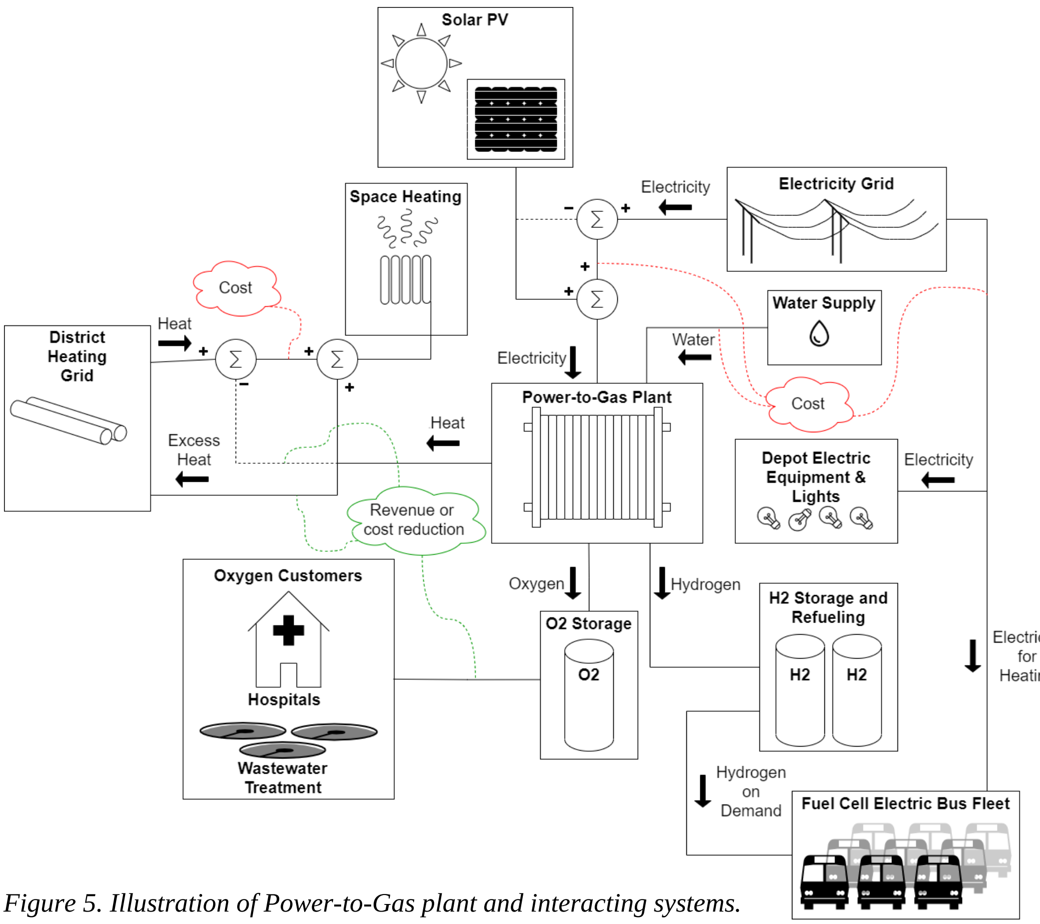


Figure 5. Illustration of Power-to-Gas plant and interacting systems.

A simplified control strategy was established to dictate when the plant should operate, which in turn would affect the cost of production as energy consumption prices vary with time. The system operation was simulated through a stepwise hourly iteration over an assumed nominal year. Through iterating over a range of different electrolyzer ratings and storage tank volumes, similarly to the other previous studies [42], feasible equipment sizes are determined. Equipment sizing was then evaluated based on whether the hydrogen demand was met for all hours; whether the capacity factor was deemed reasonable; as well as whether the electrolyzer was reasonably sized based on overloading criteria.

4.1.1. Electricity load and consumption

The regional bus depot has stable electricity consumption. During the cold winter months, electric power load is only as high as about 250 kW. This then decreases towards about 150 kW during the summertime. In brief, the electricity load of the regional bus depot was not an interesting dynamic to investigate, but only a comparatively rigid limitation to the total 1.2 MW service connection.

The city bus depot on the other hand has significantly more dynamics in its electricity supply. The depot has not yet introduced any zero-emission vehicles, such as BEBs, however the entire fleet of 180 city buses are heated with electric cabin heaters. Furthermore, the bus depot was not in operation until early February 2021, which meant empirical data on the existing electric power demand was very limited.

In a previous thesis conducted in 2019, which studied the electrification of the city bus depot [43], the electric power demand for the bus depot was estimated two years ahead of it being taken into service. The paper was in part describing the shift in electric load as all city buses were now to be heated with electric heaters, where there previously were a number of buses heated by other means. The descriptions were invaluable to fast-track an estimation of the load profile. The paper itself suggest a number of projected load profiles. However, for this project some empirical data from the bus depot was now available for comparison and it was decided to instead modify the description and use historical data from the old bus city bus depot, as the peak demand modeling failed to match the empirical data of the new depot.

In Figure 6, the electric load profile of the new depot for a week of February; the initially suggested peak load profile, accounting only for heating as described in the previous thesis [43]; as well as the historic load profile from the previous depot are presented. From the empirical data, the heating of buses is sustained for a longer period of time; load peaks do not vary radically from weekday to weekend; and the average load during weekends is actually elevated from the base load, rather than the opposite. Looking back at historical data from the previous depot, this pattern of power demand is documented there as well throughout the year, with a disruption in electric heating from mid-May to mid-September. One can also observe that the peak loads, which are a result of the electric heaters, are increased compared to the historic peaks of the old depot.

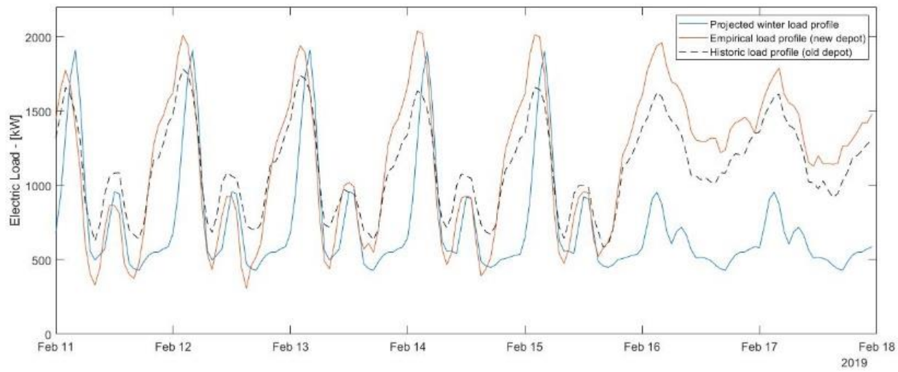


Figure 6. Comparison of empirical and estimated electricity consumption profiles.

In order to modify the historical data from the old depot to more closely reflect the increased electrical heating load of the new depot, the base load of the depot was first extracted and recalculated in accordance with the methodology and research that was conducted in the previous thesis [43]. The total historic base load was removed from the data set to allow for rescaling of the peaks, see Eq. 7 and Eq. 8. As can be seen in Figure 6, it is primarily the large peaks that need to be rescaled. For this reason, it was decided to use an exponential scaling function based on the ratio between the base load and historic load, along with an adjustable scaling factor.

$$Peak\ load_{new} = Peak\ load_{old} \cdot e^{\left(a \cdot (1 - \frac{Peak\ load_{old}}{Total\ load_{old}}\right)} \quad \text{Eq. 7}$$

$$Peak\ load_{old} = Total\ load_{old} - Base\ load_{old} \quad \text{Eq. 8}$$

Where the constant *a* was set to 0.65, determined by minimizing the error relative to the available dataset from the new depot in Fyrislund. Ultimately, the data was fit with an average 15 % error to the limited available data (Feb 11th – Mar 31st, 2021). Each hourly data value of the model was compared against the data from the new bus depot to produce the average error estimate. The load profile seems to

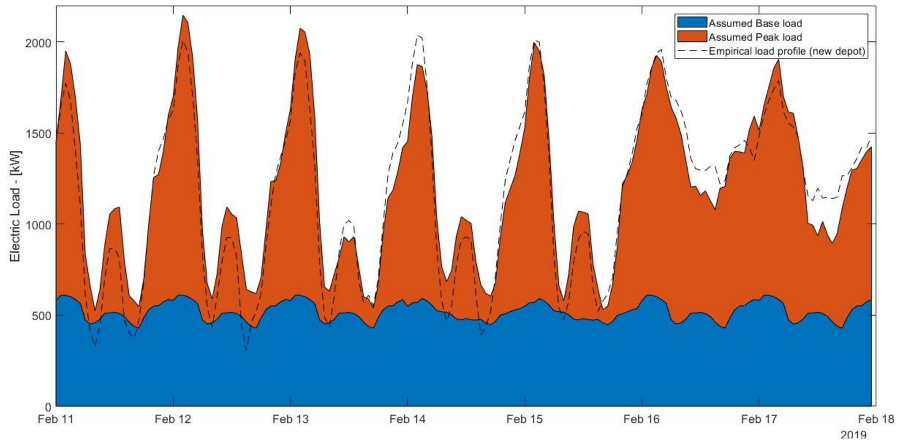


Figure 7. Visualization of rescaled data vs. the actual consumption of the city bus depot. Feb 11th is a Monday.

skew a bit higher for the base load, which was assumed as a more conservative estimate. The general fit of the data for a week is visualized in Figure 7.

4.1.2. Solar Electricity Production

While the electrolyzer was expected to rely largely on grid supplied electricity, the solar panels could make an interesting contribution of "free" electricity. The solar photovoltaic system that is installed on the roofs was estimated using irradiation data from the PVGIS database [44]. The database provided an estimation of historical solar power production, given specified panel tilts, azimuths as well as a system efficiency. The irradiation data was retrieved based on coordinate locations, of the depot location in Fyrislund was selected (*latitude 59.854, longitude 17.722*).

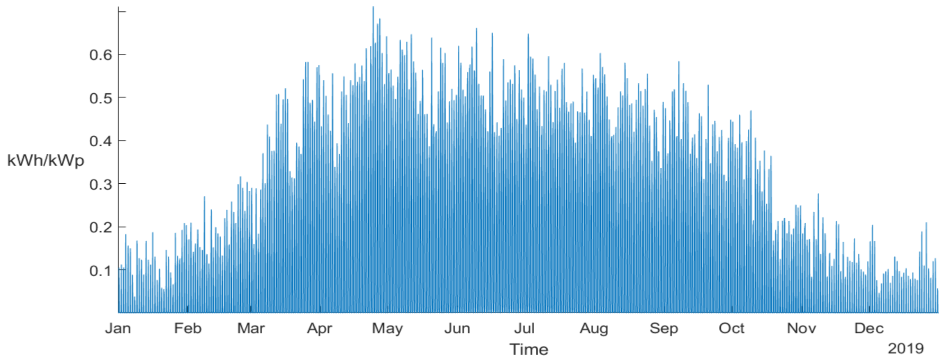


Figure 8. Assumed kWh solar production per kWp of solar capacity.

For the purpose of this thesis, hourly data for a crystalline silicon solar cell system with 14 % system losses were obtained with a 10-year record from 2005 to 2016, as 2019 irradiation data was not available at this source. The panel orientation was set to an azimuth orientation based on the observable orientations and a 0° tilt, based on Google Maps images of the depots, see Figure 1, and descriptions from a previous paper [43]. Data was obtained for production of a 1 kW_p system to allow for easy rescaling of the data to either fit the city bus depot (500 kW_p) or the regional bus depot (400 kW_p). The 10-year set of data was then used to create an average hourly solar production profile for a full year, see Figure 8.

4.1.3. Selection of Electrolyzer Technology

Part of the purpose of this thesis was to consider the cost benefits of utilizing the oxygen offtake from the electrolyzer for medical purposes. As has been highlighted in 3.1.1, 3.1.2, and 3.3, the two most commonly used electrolyzer technologies have different needs for post-treatment [21]. The PEM electrolyzer has the advantage of producing gas streams only contaminated by trace amounts of water and possibly the minute traces of their respective co-product, oxygen gas in the hydrogen stream or vice versa. Considering the alkaline electrolyzer, additional equipment such as a scrubber is necessary to ensure no contamination from the lye-electrolyte. For this purpose, and to limit the scope of this thesis, the alkaline electrolyzer was not considered further in this study.

4.1.4. Assumed PtG system performance.

Current state-of-the-art electrolyzer system energy consumption is in the range of 50-55 kWh/kg H_2 [15], [45] or equivalently 60 – 66 % efficient. The PEM electrolyzer can operate on a load range from 5 – 120 %, with quick ramp-up times. As the operation of the plant is conducted at an hourly resolution, and system ramp-up times are in the range of minutes, this aspect was not considered.

There are uncertainties as to how overloading of PEM electrolyzers may impact the lifetime, but general lifetime estimates are between 40,000-100,000 hours [46], [47]. Due to limited availability of information about long-term degradation of PEM electrolyzers, the lifetime was be assumed to be 40,000 hours for a PEM electrolyzer stack, which was considered as a conservative assumption.

As mentioned, the electrolyzer is a hot system, generating heat which can be utilized. In previous studies, the useful electrolyzer heat generation has been suggested at 17.1 % of installed rated capacity [42]. The technical specifications of the electrolyzer are summarized in Table 2.

Table 2. Simulation Parameters - PEM electrolyzers

Electrolyzer Technology	**PEM**
Power Consumption	55 kWh/kg H_2
Load Range	5-120 %
Heat Generation	0.171 kWh heat/kWh el
Stack Lifetime	40,000 hours

The system energy consumption does not include the power consumption to compress hydrogen for high pressure storage. In order to account for this, a compression stage was assumed where hydrogen is compressed to 500 bar. Energy consumption for compression was assumed to be 2.8 kWh/kg H_2 [48].

The consumption of water and parallel production of oxygen was calculated based on the stoichiometric balance of the reaction. One kilogram of hydrogen requires approximately 8.94 kilograms of water and is co-produced with about 7.94 kilograms of oxygen, see Table 3.

Table 3. Stoichiometric production of hydrogen and oxygen through electrolysis.

Molecule	**Oxygen [O_2]**	**Hydrogen [H_2]**	**Water [H_2O]**
Molecular Weight	31.998 g/mole	2.016 g/mole	18.015 g/mole
Production Equivalent	7.936 kg/kg H_2	1 kg/kg H_2	8.936 kg/kg H_2

The production volumes are a good indication for the water need and oxygen production but should be considered with the following caveats. Water will need pretreatment; water may be used as a coolant for the electrolyzer; water may also evaporate in the electrolytic process; the hydrogen and oxygen offtake may include water vapor in the gas stream which needs to be processed. Production of oxygen and consumption of water was considered as stoichiometric. The oxygen offtake was therefore assumed to separate water vapor from the oxygen and reclaim the water.

4.1.5. Storage capacity

The hydrogen demand that was modeled and described further in a later section is cyclical on a daily basis. For this reason, there needs to be a storage capacity that can hold the hydrogen gas and provide a buffer as hydrogen production occurs throughout the day. Hydrogen storage solutions are quite flexible when it comes to storage volumes, whether they be tanks or gas cannisters. For this reason, the storage capacity was iterated upon in steps of storage capacity in kilograms of hydrogen.

To simulate steady-state operation, the storage was initialized to 80 % of maximum capacity. In the simulation of the constrained grid, the production of hydrogen was observed to struggle during the cold season. The resiliency of the plant during the constrained scenarios were evaluated by initializing the tank capacity at 30 %.

4.1.6. PtG plant operation – Unconstrained grid utilization

Two different operational schemes for the plant were considered. At the time of writing, the city bus depot is dealing with a constrained grid and have been directed in agreement with the DSO to limit their electricity usage during peak hours to 1.5 MW and 4 MW at night. Their installed grid capacity is 6 MW, which poses the question of how the system might operate differently with and without constraints to how much electricity could be used.

For the unconstrained scenario, it was assumed that the electrolyzer plant operates to fill the hydrogen storage which in turn feed the bus hydrogen demand. With regards to other base load electricity demand, the unconstrained scenario did not take it into consideration, other than to limit the electrolyzer rating to 4 MW to permit 2 MW for other services, such as the existing cabin heating. The only signal which is crucial is the tank storage level. To navigate how urgently production is needed, a simplified control regimen was implemented. Operation of the plant was therefore dictated by the "urgency" to produce hydrogen, see Table 4. See Figure 9 for the assumed simplified controls flow chart.

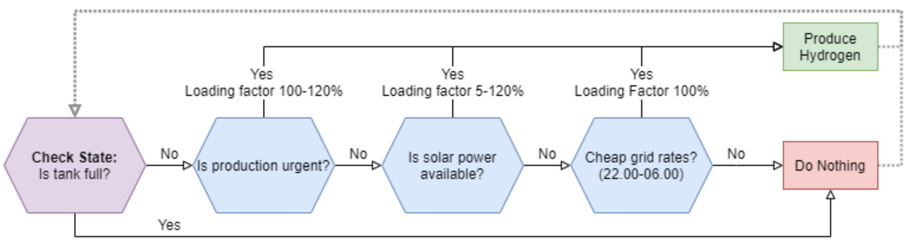


Figure 9. PtG Operation Scheme

The load factor was typically set to the nominal capacity of the electrolyzer. However, in the case of photovoltaic power production, the loading factor could either be increased to produce in urgent situations; or adjusted to reflect whatever the hourly solar electricity production is. A higher load factor was also considered when the storage was getting low.

Table 4. Assumed permissible loading factors and their respective thresholds.

Scenario	Storage level	Loading
No production needed	>95 %	0 %
Production not urgent, prioritize solar	>80 %	5-120%
Production is needed	<80 % and >30%	100%
Production is needed and urgent	<30 %	120%

In this manner, each hour's production of hydrogen was determined, and the amount oxygen and heat produced, as well as water used, was calculated based on the load factor. The potential on-site heat use was determined, by comparing the produced heat from the electrolyzer with the heating data, see Eq. 9. The remaining available heat was then considered to be sold back to the district heating grid.

$$E_{heat\ used} = \begin{cases} E_{heat\ produced} & if\ E_{heat\ demand} \geq E_{heat\ produced} \\ E_{heat\ demand} & else \end{cases} \qquad \text{Eq. 9}$$

4.1.7. PtG plant operation – Constrained grid utilization

In this scenario, the existing constraints of the grid as well as the auxiliary electricity demand are considered for the city bus depot. The regional bus depot was not considered in this section, as it is not subject to the same conditions today. The power supply constraints of 1.5 MW and 4 MW, specified in Section 2.2.3, were to be adhered to, while also accounting for the existing power demand, as described in Section 4.1.1. For the scope of this thesis, it was decided to only consider the difference between the power supply constraint and the existing electric energy consumption, here referred to as the "available energy". In practice, the consumption of electricity would require more complex forecasting strategies or focused allocation of electricity use.

As the focus of this thesis was not to determine the actual operation of a plant, it instead focused on maximum opportunity utilization. The assumed control strategy remains the same as outlined in Section 4.1.6, however the amount of energy used was dictated by the constraints of the grid and auxiliary electricity consumption. In brief, the simulation either utilized the loading factors outlined in Table 4 or the *available load factor specified in* Eq. 10, whichever was smaller.

$$available\ load\ factor = \frac{available\ energy + solar}{system\ power\ rating} \qquad \text{Eq. 10}$$

4.1.8. Capacity factor

The capacity factor, *CF*, is a metric which tracks the utilization of a producing asset. In the context of this PtG plant, this was translated to what electrolyzer capacity is actually used in relation to what capacity is possible, see Eq. 11.

$$CF = \sum_{i=1}^{n} \frac{LF_i \cdot ER}{ER} \qquad \text{Eq. 11}$$

Where *LF* is the hourly loading factor and *ER* is the electrolyzer rated capacity. This introduces a caveat when evaluating the PEM electrolyzer, as they can operate at a higher loading factor, and subsequently above their rated capacity. The capacity factor was to be used as a gauge of how well utilized the PtG plant is between the unconstrained and constrained scenarios. For the unconstrained scenarios, it was shown that the capacity factor exceeds 100 %. This is due to the overloading capability that the simulation permits. In practice, there would be a downtime event for routine maintenance. During that time, an external hydrogen supply or a hydrogen buffer storage would be necessary. This aspect was not considered in this project.

4.1.9. Fleet scenarios

The primary dimensioning factor to the PtG plant is the hydrogen demand, which in turn is dictated by the number of buses that are in operation. For the purpose of this thesis, seven different fleet scenarios are considered for the simulations, as shown in Table 5. For the city bus fleet, the implementation of a pilot-scale fleet, small-scale, mid-scale and large-scale fleet make up four scenarios. With regards to regional bus scenarios, a pilot-scale, small-scale and mid-scale fleet size are considered. While larger fleets may be interesting, the regional buses generally drive longer distances per day, increasing the demand of hydrogen. A large scale PtG plant for a regional bus fleet was estimated to require a capacity of over 5.7 MW, assuming a 100 % capacity factor. A capacity which is unfeasible given the electrical constraints and services that are present.

Table 5. Fleet Scenarios

Fleet	**City Bus**				**Regional Bus**		
Scale	Pilot	Small	Mid	Large	Pilot	Small	Mid
Buses	5	10	30	60	5	10	30
Abbreviation	CB-P	CB-S	CB-M	CB-L	RB-P	RB-S	RB-M

4.1.10. Hydrogen Demand

In order to approach an electrolyzer power rating and required hydrogen storage volume, the hydrogen demand profile for the plant had to be determined. The demand profile dictates when and how much hydrogen that needs to be available and dispensed. This was achieved by surveying an existing fuel demand profile for CBG from 2018, as the operation was assumed to be similar for hydrogen refueling. The fueling insights allowed for a real-life refueling scheme for the FCEBs, with some modifications to propagate greater utilization to offset the difference in cost for the different bus technologies.

Region Uppsala provided a dataset containing approximately a year's worth of daily and hourly CBG fueling data. The hourly data was not available at high resolution, but by averaging the hourly consumption profile for the entire dataset, an average daily demand profile was obtained. The fuel demand profile showed a behavior where refueling is conducted in the evening, with only a few buses refueling during the day.

The fueling events of the FCEB fleet was then modeled assuming a similar distribution. However, as bus refueling is a down-time event, it is preferable to only refuel at the end of the day. In the CBG refueling data, a portion of the bus refueling is conducted at other hours, these events were not considered for the FCEB fleet. FCEBs have good range capabilities of up to 450 km depending on tank-dimensioning [34]. It was therefore assumed that all refueling events are at the end of the day, see Figure 10.

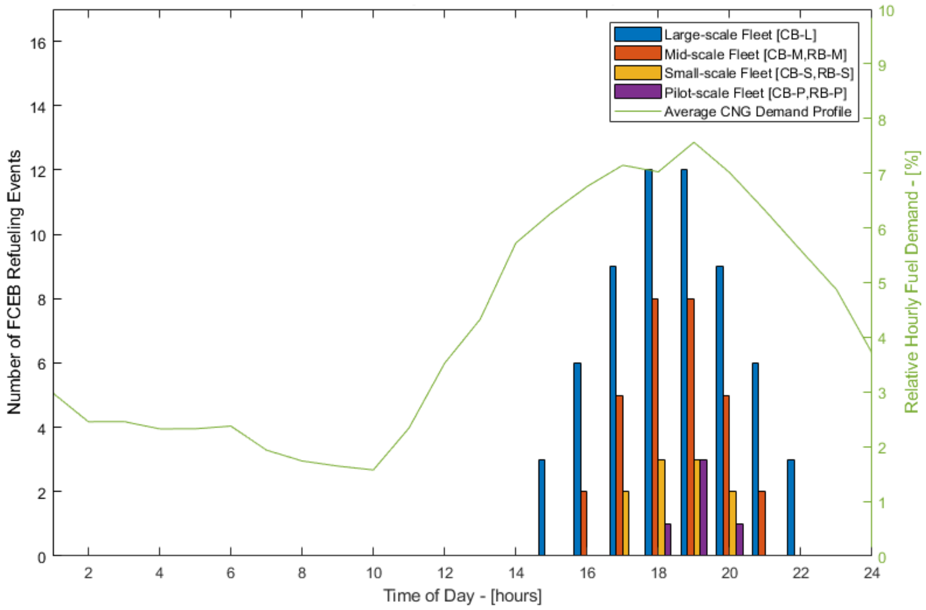


Figure 10. Distribution of refueling events for an average day and assumed refueling events for the fleet scenarios.

Daily data for the year of 2018 could have been used to extrapolate the data over a full year, considering the seasonality of the demand as well as the work week/weekend dynamics of the demand. An FCEB fleet is a costly asset, but it has lower fuel mileage costs, it was therefore assumed that the FCEBs operate at full capacity every day. For this reason, any fluctuations in demand as seen in reduced traffic during the weekends and summer months were assumed to be met by reducing the number of CBG or in particular diesel buses in service. According to Region Uppsala, the vehicles in service during the weekends and summer season account for about 60-80 % of the full fleet capacity. With a bus fleet of 180 buses in city traffic and 80 in regional traffic, there is arguably enough headroom to support the assumption that any of the suggested FCEB fleets may still operate at full capacity.

Finally, the amount of hydrogen required at each individual refueling event was determined from the typical gas mileage of FCEBs and their expected average driving distance. The average distances traveled by an existing city bus is about 195 km/day according to Region Uppsala. For the purpose of maximizing the utilization of the FCEBs to cover the increased asset cost, it was assumed that they travel longer trips, as shown in Table 6. In an interview of the technical manager for GUB, conducted by the authors of another thesis, it was suggested that BEBs should be operated for 330-350 km/day [43]. The same distance was assumed for this study. The corresponding distance for regional buses is 415 km/day, as they conduct inter-city travel. 415 km/day is close to the maximum considerable range for a FCEB without refueling and therefore remained unaltered.

Table 6. Fuel demand per hydrogen refueling event.

	City Bus	**Regional Bus**	
Average Annual Distance, existing	65,000	134,000	km
Suggested Annual Distance, FCEB	127,750	134,000	km
Estimated Hydrogen Mileage (12-m bus)	0.1	0.1	kg/km
Weekend availability, existing	70 %	60 %	
Suggested Weekend availability, FCEB	100 %	100 %	
Average Daily Distance, existing	195	415	km/day
Suggested Daily Distance, FCEB	350	415	km/day
Average Hydrogen Demand, existing	19.5	41.5	kg/day
Suggested Hydrogen Demand	35	41.5	kg/day

4.1.11. District heating demand

The purpose of this thesis was not to investigate the heating demand, however, as heat is generated in PtG plant, it could be used to offset purchased heat from the district heating network. The heating demand profiles vary over the year with the ambient temperature, similarly to the electricity demand. With regards to the regional bus depot, the depot has historical data, and the hourly consumption data of 2019 was used as the assumed heat demand.

As it relates to the city bus depot however, the depot was only recently taken into service, and historical data is limited. For the purpose of this project, the heating demand of 2019 for the depot was used anyway. Space heating was supplied during 2019, and it showed the same general demand profile as the regional bus depot, albeit at a lower level.

The city bus depot could potentially have had a greater district heating demand if the buses were compatible with water heat exchangers. However, they are at the time of writing fitted with electric heaters, and thus have not been considered as a potential use for excess heat.

4.1.12. Evaluating the simulation results.

There are likely numerous ways to determine the electrolyzer size and hydrogen storage capacity that is necessary to maintain a bus fleet. In this thesis, the sizes are determined by iterating over different combinations of storage capacity and electrolyzer ratings. Whether the hydrogen demand has been met for all hours of the simulation was a key indicator of how viable the configuration was. Also, the load factor of the electrolyzer would indicate how well the system actually performed. Since it was possible to run the PEM electrolyzers at a higher load factor, which should be considered a special condition peak operation rather than normal operation, the number of hours that are operated at a higher load factor are limited. For this reason, the ratio of hours with overloading was limited to 20 %, see Table 7. The described processes were modeled in MATLAB, Appendix F.

Table 7. Criteria set to assume valid solution.

Criteria	**Requirement**
Hydrogen Demand hours met	100 %
Ratio – hours operating above rated capacity (*LF* > 100 %)	≤ 20 %

4.2. Economic Assessment

4.2.1. Economical cost components – PtG-plant

The PtG-plant is comprised of the electrolyzer stack, control units, rectifier power electronics, compressor stages, heat exchangers, storage vessels, water treatment equipment and hydrogen dispensers. In the literature, plenty of the components such as power electronics, controls, heat exchangers and compressors, are compiled into an ambiguous system cost, paired with the dominant cost of the electrolyzer stack. This cost was accounted for in an assumed balance-of-plant cost, a percentage of the electrolyzer capital expenditure (Capex).

For the purpose of running electrolyzers to produce fuel for a bus-fleet of 5 – 60 FCEBs, the plant size had to consider a range in capacity and their respective expected cost per kW. One solution to estimate the electrolyzer cost in an easily interpreted cost function is described in the EU-funded project Store&Go, using the so-called *"six-tenth-factor rule"* [45]. In brief, it utilizes a logarithmic relationship to extrapolate the electrolyzer system price, see Eq. 12.

$$C_b = C_a \left(\frac{S_b}{S_a}\right)^f \qquad \text{Eq. 12}$$

Where C_b is the sought cost, C_a is the known cost of a reference component, S_b is the rated nominal power of the component, S_a is the nominal power of the reference component and *f* is a scaling factor, typically *0.6* (six-tenth). However, in the Store&Go report, it was suggested that a scaling factor of *0.75* is a good approximation for both PEM and alkaline electrolyzer systems.

By using the cost function as described, based on the known per kW cost of a 5 MW plant, extrapolating the cost to smaller plants was achieved. According to the authors, the cost of a 5 MW PEM electrolyzer will be € 970 per kW [45], the extrapolated per kW cost is illustrated in Figure 11.

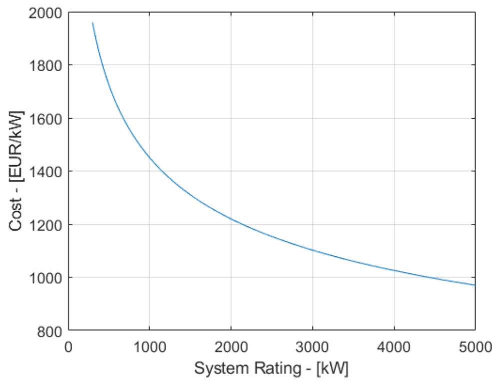


Figure 11. PEM cost per kW as a function of the system rating.

In addition, balance-of-plant costs, hydrogen and oxygen storage costs, dispenser cost and operational costs need to be included in the economic consideration. These costs were assumed based on similar previous studies, see Table 8. It was assumed that dispenser system can serve up to 3-6 buses each hour, as indicated in Sections 3.1.4 and 3.2. The dispenser cost was assumed to be 2 MSEK and the number of dispensers was dictated by the assumed refueling events in Section 4.1.10. It resulted in an assumption of one dispenser for the pilot and small scale scenarios, and two dispensers for the other scenarios.

Region Uppsala annually purchase 65,000 kg of medical grade oxygen in bulk, to a price of about 2 MSEK. This cost breaks down to 30.77 SEK/kg in potential oxygen revenues. Region Uppsala is also purchasing medical oxygen cylinders, which are not considered in this study given the added bottling operation. The value of medical oxygen cylinders could potentially be included and should be considered in conjunction with the sensitivity analysis. Oxygen will however be produced in excess, and once the anticipated medical oxygen demand is fulfilled, the economic value of oxygen is markedly smaller. The potential end-use as mentioned in Section 3.3 could be numerous. The municipal wastewater plant, also operated by Uppsala Vatten, are currently using fans to blow air in their aeration process. They use air to the tune of 12,000 – 20,000 m^3/h, of which an estimated 11,000 – 13,000 kg of oxygen is consumed in the aeration per day (personal communication). A possible use for the excess oxygen could hence be for the aeration process, to reduce the need of fan equipment. Due to the uncertainty of the economic value, a low value of 0.25 SEK/kg was assumed [47].

Table 8. Cost and revenue components for PtG system.

Cost Item	Cost	Reference
Capex Electrolyzer (5 MW)	9,700 SEK/kW	[45]
Balance-of-Plant	15 % of electrolyzer Capex	[42]
Capex Hydrogen storage	6,000 SEK/kg	[42]
Capex Oxygen storage	6,000 SEK/kg	*assumption
Capex Dispenser	2,000,000 SEK	[28]
Opex Electrolyzer	4 % of Capex	[42]
Opex Storage	2 % of Capex per system	*assumption
Opex Dispenser	2 % of Capex	*assumption
Electrolyzer stack replacement	5,250 SEK/kW	[47]
Price of Water	20.98 SEK/m^3	Region Uppsala
Price of Medical Oxygen	30.77 SEK/kg	Region Uppsala
Price of Oxygen	0.25 SEK/kg	[47]
Price of Return Heat	300 SEK/MWh*	Region Uppsala
Price of Electricity	See 4.2.2	[49]
Price of Heat	See 4.2.3	[50]

* Price is assumed to be 300 SEK/MWh, or the lowest value indicated in Section 4.2.3, whichever is the lowest at the time.

4.2.2. Cost of Electricity

The economics of electrolytic processes are sensitive to the market price of electricity. Region Uppsala has signed a power purchasing agreement (PPA) with the utility company Vattenfall for their electricity supply. The PPA permit more oversight of the energy costs by locking in a price for power, as opposed to adhering to the hourly spot market price. For the purpose of this project, the PPA prices for 2019 were used, as it was the price data available, which ranged from 306 – 309 SEK/MWh. It is worth mentioning that the cost of electricity fluctuates from year to year and with electricity market developments, hence electricity contracts come with some uncertainty for the future, which may impact the cost of electricity.

Aside from market prices for electricity and taxes, a sizeable cost component to the electricity price is the cost of the grid connection. Region Uppsala has installed a high voltage grid behind the meter at the bus depot and are purchasing electricity from Vattenfall on a power-tariff [49]. Within this tariff-structure, there are different cost components, which makes the cost of electricity dependent on the capacity factor and maximum power of the equipment; what hours or days the equipment is running and during what season.

At the time of writing, there were two different tariff structures, one for the regional bus depot and one for the city bus depot. The city bus depot had a higher fixed fee and lower tariffs, as well as a higher electricity consumption given their utilization of electric cabin heaters. The tariffs are listed in Table 9. The peak monthly fee applies during the period November through March. The peak energy transfer charge applies weekdays from 6.00 – 22.00. Finally, the power fee is dependent on the peak power that was consumed from the grid during that month [47].

Table 9. Grid charges signed with Vattenfall.

Tariff	City Bus Depot	Regional Bus Depot	
Fixed Fee	22,000	2,400	SEK/Month
Monthly Power Fee	27	27	SEK/kW/Month
Peak Monthly Fee	27 + 38	27 + 55	SEK/kW/Month
Energy Transfer Charge	9.5	18.9	cSEK/kWh
Peak Energy Transfer Charge	5.0	6.6	cSEK/kWh

To calculate the grid charges, a model was developed in MATLAB to consider all the dimensions in the agreement. Per kWh charges were easily accounted for. The power capacity dependent fees and charges were calculated based on the peak power consumption of the month, and then divided by the monthly kWh consumption to get their respective per kWh cost. The result was then validated against old invoices and their respective monthly electricity consumption, see Appendix B. As outlined in Section 2.3.1, it is assumed that there will be no electricity tax as the electricity is primarily consumed in an electrolytic process.

4.2.3. Cost of Heat

District heating is purchased based on three components: thermal power, heat, and water flow. Thermal power is paid for, based on how much thermal power you have subscribed for during the period. Heat is bought on a per MWh basis, similarly to how electric energy is purchased. The price of heat varies depending on season, with three different price levels, spring/fall, winter, and summer. Lastly, water flow is a component which the consumer can control themselves to improve the temperature quality of the return water to the district heating company. If the customer regulates their water flow and use less water compared to their local peers, they are offered a bonus/reimbursement [50].

The city bus depot has a variable pricing agreement, without any thermal power cost component, Table 10. In the case of the regional bus depot, the heat costs are lower, but they also pay for thermal power. For the purpose of this project, avoided heat costs were considered as a potential revenue. No consideration was taken with regards to any potential cost benefit of reducing the thermal power subscription or regulating the flow.

Table 10. District Heating costs.

Cost	City Bus Depot	Regional Bus Depot	
Thermal Power	0	925	SEK/kW/year
Heat – Winter	931	560	SEK/MWh
Heat – Spring/Fall	623	376	SEK/MWh
Heat – Summer	426	243	SEK/MWh

4.2.4. Levelized Cost of Hydrogen

The levelized cost of hydrogen ($LCOH_2$) is an adaptation of a commonly used KPI which is widely used in the renewable energy industry, being the levelized cost of energy (LCOE). By aggregating the capital expenditures, operational expenditures, and revenues as well as estimating the production of hydrogen, you calculate the levelized cost accrued over the lifetime of a project.

$$LCOH_2 = \sum_{i=0}^{lifetime} \frac{\frac{CAPEX_i + OPEX_i - R_i}{(1+r)^i}}{\frac{kg\,H_{2_i}}{(1+r)^i}} \qquad \text{Eq. 13}$$

Where r is the discount rate, and R_i is the yearly revenues. The discount rate that Region Uppsala employ for their projects is 5.5 % and was subsequently the discount rate applied in this thesis as well. The calculated $LCOH_2$ considered as the cost of hydrogen for the FCEBs.

In order to determine the impact of the revenue components, the levelized cost was calculated both with and without revenues from heat and oxygen. Where a configuration without revenues would exclude capital and operational expenditures for oxygen storage.

4.2.5. Total Cost of Ownership

To be able to contrast the cost of operating FCEBs against other vehicle types, the total cost of ownership (TCO), sometimes also called the life-cycle cost (LCC), was estimated. TCO is calculated as a function of capital costs for the bus less the residual values and any subsidies, along with the cost of maintenance and fuel.

$$TCO_{km} = \sum_{i=0}^{lifetime} \frac{\frac{(CAPEX - RV - ES + M + D \cdot BM \cdot LCOH_2)_i}{(1+r)^i}}{\frac{D_i}{(1+r)^i}} \qquad \text{Eq. 14}$$

Where *RV* is the residual value of the vehicle; *ES* is the economic subsidy, in this case the 10 % zero-emission bus subsidy described in Section 2.3.3; *M* is the maintenance cost; *D* is the annual distance; and *BM* is the bus mileage. Fuel costs for the FCEB was the $LCOH_2$ estimated from the largest possible implementation in the constrained scenario, with no tax on fuel, as per the indication from the Swedish Tax Agency, Skatteverket, in Section 2.3.2.

The lifetime of a bus is set to 10 years [37]. The price data for FCEBs is at the time of writing very limited. The assumed cost was therefore the publicly available information of € 625,000per FCEB sold by Solaris [31] to a number of cities in Europe. The Solaris FCEB has a small high power battery of 30 kWh, which was included in the cost of ownership as a maintenance cost event based on an assumed 5 year battery lifetime. Additionally, according to Ballard, who is supplying the FC stack with a capacity of 70 kW for Solaris, the operational lifetime of their FC stack is more than 30,000 hours [51]. Hence, a maintenance event for replacing the fuel cell stack at the same time as the battery was included. According to the US Department of Energy, medium duty vehicle FC stacks cost were projected to cost 100 USD/kW in 2018 [52], which was translated to an assumed 900 SEK/kW for this thesis.

The comparison was conducted against similar operation of CBG buses and HVO diesel buses, with fuel pricing data and mileage information from Region Uppsala. Maintenance cost for FCEB was assumed to be equal to that of a BEB. For the remaining economic parameters, a guiding document from the Swedish Energy Agency was used [30]. All parameters can be found in Table 11. BEBs have not been considered as their recharging infrastructure and mileage limitations make like-for-like comparison more difficult.

Table 11. Input information for TCO analysis and comparison

	FCEB	HVO Diesel	Biogas	Reference
Bus Capex	6.25 MSEK	3.00 MSEK	3.50 MSEK	[31], [30]
Residual Value	0 SEK	0 SEK	0 SEK	[30]
Subsidy	10 %	0 %	0 %	Section 2.3.3
Bus Lifetime	10 years	10 years	10 years	
Battery cost	3 kSEK/kWh	-	-	[30]
Battery size	30 kWh	-	-	Section 3.2
FC stack cost	900 SEK/kW	-	-	[52]
FC capacity	70 kW	-	-	Section 3.2
Battery & Fuel Cell Lifetime	5 years	-	-	[30]
Maintenance Cost	2 SEK/km	2 SEK/km	3 SEK/km	[30]
Annual Distance	127,725 km	127,725 km	127,725 km	
Fuel Mileage	0.1 kg/km	0.44 liter/km	0.37 kg/km	Region Uppsala
Cost of Fuel	$LCOH_2$	11.8 SEK/liter	13.8 SEK/kg	Region Uppsala

4.3. Sensitivity Analysis

A sensitivity analysis is a means to assess how variations to cost dynamics impact an economic metric. Some costs have a greater influence than others and are more constructive to investigate. In order to identify the most impactful cost components, the lifetime cost and potential revenue were documented in a component breakdown. This was conducted for both the lifetime cost of hydrogen production, as well as the total cost of ownership for a FCEB.

From the cost breakdown, the following components were determined to have the largest impact on the net cost. With regards to the $LCOH_2$, the electrolyzer cost, electricity price, grid fees, electrolyzer replacement cost and auxiliary revenues or cost offsets had the greatest impact. The economic considerations for the TCO had far fewer components and was most impacted by the capital cost of the FCEB along with the fuel cost.

Most of the aforementioned components address the price of fuel for a FCEB fleet. To assess the impact on the TCO, the fuel cost was also varied to analyze the impact. Another aspect is the distance traveled, also impacting expected maintenance cost and fuel costs. See Table 12 for a summary of all components that are analyzed. These cost components were then varied to deviate from the default value. The deviations are then presented in a spider graph plot to visualize the impact deviation on the $LCOH_2$ and TCO.

Table 12. Cost components to be analyzed and their respective impacted metric.

Cost Component	Deviation	Economic Metric
Electrolyzer Capex	± 10 – 30 %	$LCOH_2$
Stack lifetime	± 10 – 30 %	$LCOH_2$
PPA price	± 10 – 30 %	$LCOH_2$
kWh electricity purchased	± 10 – 30 %	$LCOH_2$
Heat Revenues	± 10 – 30 %	$LCOH_2$
Oxygen Revenues	± 10 – 30 %	$LCOH_2$
FCEB Capex	± 10 – 30 %	TCO
Fuel Cost	± 10 – 30 %	TCO
Bus range	± 10 – 30 %	TCO

5. Results

5.1. Plant simulation

In the following sections, the simulation results are summarized based on what capacities are closest in line with the specified criteria in Section 4.1.12. They give an indication of what capacity configurations are necessary and suggest whether the scenarios are feasible or not. There are many possible configurations, but through iteration over different electrolyzer capacities and different storage volumes, a matrix is formed where the performance of each individual iteration can be compared against the rest. In Figure 12, a visualization of a typical selection from the simulation results is presented. To the left, the figure shows which configurations managed to fulfill the demand of hydrogen for all hours. To the right, the figure shows the proportion of operational hours with electrolyzer overloading for the respective configurations. Highlighted is the selection where overloading does not exceed the criteria of maximum 20 %. This means that for the selected configuration, all hours of demand were met and 17.5 % of the operational hours utilized overloading. Note that an increase in storage capacity is typically cheaper than an increase in electrolyzer capacity, why the selections has been done in the illustrated manner.

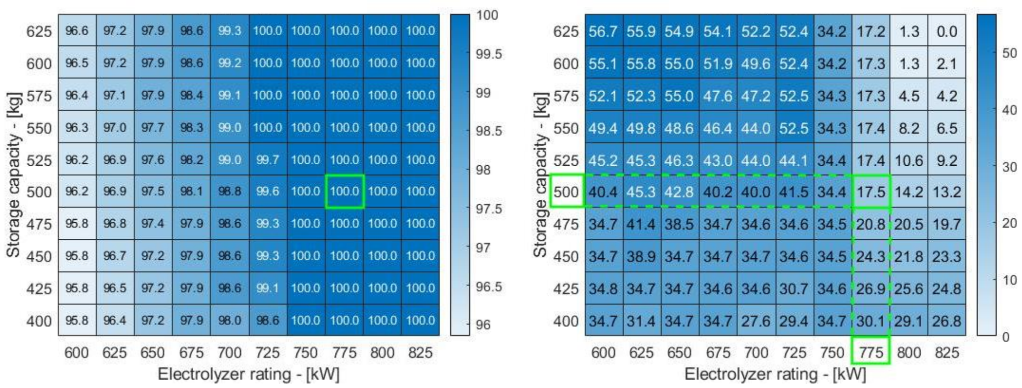


Figure 12. Picking dimension on storage and electrolyzer for the unconstrained case CB-S. (left) Configurations meeting 100% of the demand hours. (right) Configurations not exceeding 20 % overloading.

5.1.1. Unconstrained grid scenarios

The operation of the PtG-plant under assumed unconstrained conditions, was able to maintain production to meet demand for a number of scenarios. The system was configured to focus on maintaining 80 % tank capacity, and when exceeding that threshold, produce hydrogen if conditions were good. Given the criteria limits in Table 7, and looking at the results with the least margin from said criteria, there is a preference for smaller storage configurations, where the daily demand can be stored but not much more. This is illustrated in Figure 13, which reflects a typical daily operation. With the small storage capacity, the electrolyzer has to operate at full capacity or overloading capacity.

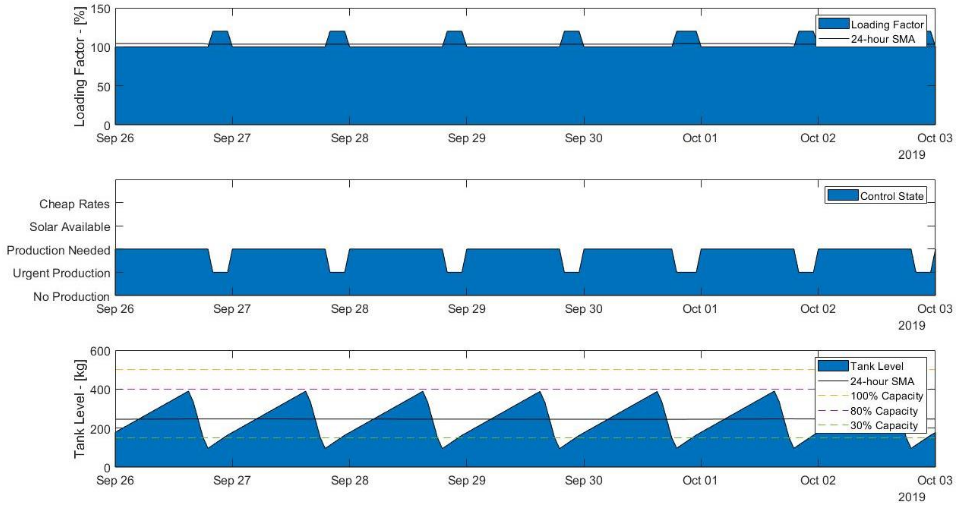


Figure 13. Typical operation for a week in the unconstrained CB-S scenario. (24-hour MA is a 24 hour moving average)

As the demand has been modeled as uniform throughout, the plant is preferring continuous operation. The unconstrained grid scenarios resulted in a theoretical plant operations with high capacity factors, as no dynamics effected the production other than those imposed by the control regimen and the uniform refueling demand, Table 13.

Table 13. System configurations meeting criteria with most utilization (least margin from criteria) in the case of an unconstrained grid.

Case:	**Electrolyzer Rating**	**Storage Capacity**	**Capacity Factor**
CB-P	400 kW	275 kg H_2	100.6 %
CB-S	775 kW	500 kg H_2	103.3 %
CB-M	2,350 kW	1,300 kg H_2	102.2 %
CB-L	4,650 kW	2,400 kg H_2	103.3 %
RB-P	475 kW	325 kg H_2	99.9 %
RB-S	925 kW	575 kg H_2	102.6 %
RB-M	2,750 kW	1,525 kg H_2	103.6 %

Conclusively, all but the largest of the proposed scenarios for FCEBs in city bus traffic could theoretically be met with the existing grid connection capacity of 6 MW. Scenario CB-L would be hampered by the electric heaters and depot base load which exist and are considered in the constrained case. The potential for the regional bus depot itself is further limited, as only fleet sizes up to 10 buses could be supplied with the existing grid connection of 1.2 MW. For larger regional bus fleets, the electrolyzer could be located at the adjacent city bus depot. The theoretical plant configurations do give an indication about the quantities of water and electricity needed to reach the proposed demand, listed in Table 14. One noteworthy aspect is that the required water supply ranges from 570 m^3 per year for a pilot scale plant up to 6,800 m^3 per year for a large scale plant. In relation to the city water supply, is not a significant amount of drinking water that is needed for a PtG plant. According to Uppsala Vatten, they produce 17 million m^3 of drinking water annually [53].

Table 14. Annual quantity of water & electricity used, as well as hydrogen and oxygen produced for unconstrained scenarios.

	Water Used [ton]	**Electricity Used [MWh]**	**PV Electricity Used [MWh]**	**Hydrogen Produced [ton]**	**Oxygen Produced [ton]**
CB-P	569.7	3,229.2	455.5	63.7	505.9
CB-S	1,139.5	6,914.3	456.0	127.5	1,012.0
CB-M	3,418.8	21,663.0	450.9	382.6	3,036.2
CB-L	6,838.8	43,780.0	454.9	765.3	6,073.5
RB-P	675.5	4,005.3	363.8	75.6	599.9
RB-S	1,351.1	8,375.4	364.0	151.2	1,199.9
RB-M	4,054.0	25,857.0	364.8	453.7	3,600.3

5.1.2. Constrained grid scenarios

The constraint on power consumption, in combination with the simple control regimen, means that the storage has to be larger and more resilient for periods where electricity use at the depot increases, particularly during the cold season. Storage capacities for both scenario CB-P and CB-S doubled in size, and the electrolyzer capacities also increased, see Table 15. In Figure 14, the hydrogen storage level is recorded throughout the year, along with the different storage thresholds. It can be determined that storage resilience is important from November through February. For the simulated year, December was the most impacted as the average demand exceed the average production for the period, and the storage is being depleted.

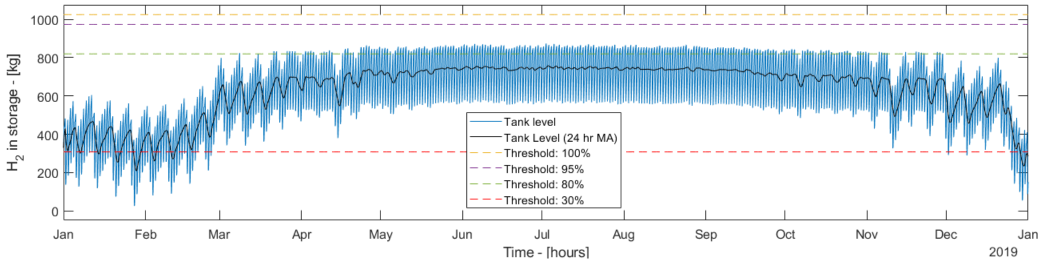


Figure 14. Annual storage level simulation for constrained CB-S scenario. (24 hr MA is a 24-hour moving average, to better visualize the space-time trend of the simulation.)

Looking at the hourly operation for a week in January, see Figure 15, the weekend load on the depot is shown to be a main contributing factor for the need in storage resilience. As the plant enters the weekend on January 19th, the elevated electrical load that was modeled is felt (Section 4.1.1). The electrolyzer load factor is further limited and the storage is being depleted. The weekday operation is shown to be stable and recover the storage from the low tank level of the prior weekend. This explains the hacksaw profile of the winter period in Figure 14.

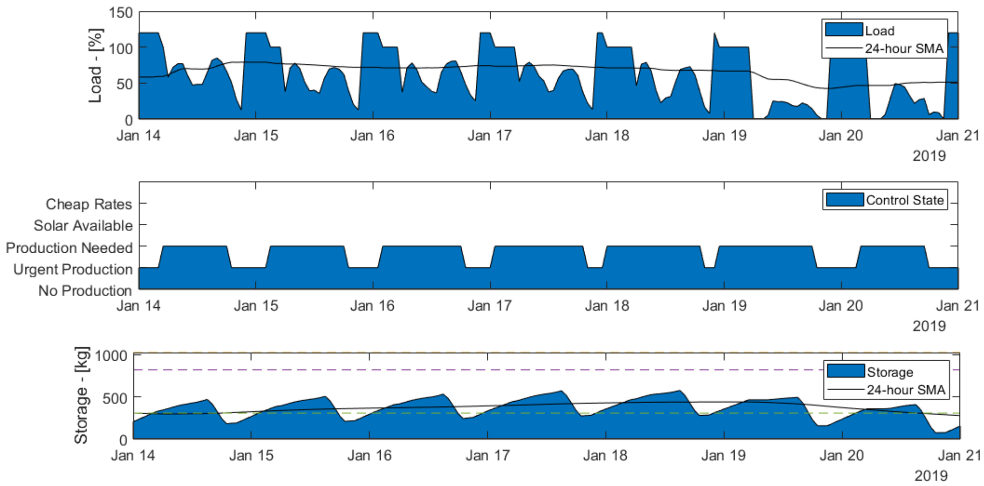


Figure 15. Plant operation during week in January. (constrained CB-S)

During a typical summer week in July, see Figure 16, the operation dynamics are different, and the hydrogen storage is never critical. After the refueling events, the electrolyzer is quick to replenish the storage and reach the nominal storage capacity.

After which the electrolyzer can capitalize on available solar power and cheap electricity rates.

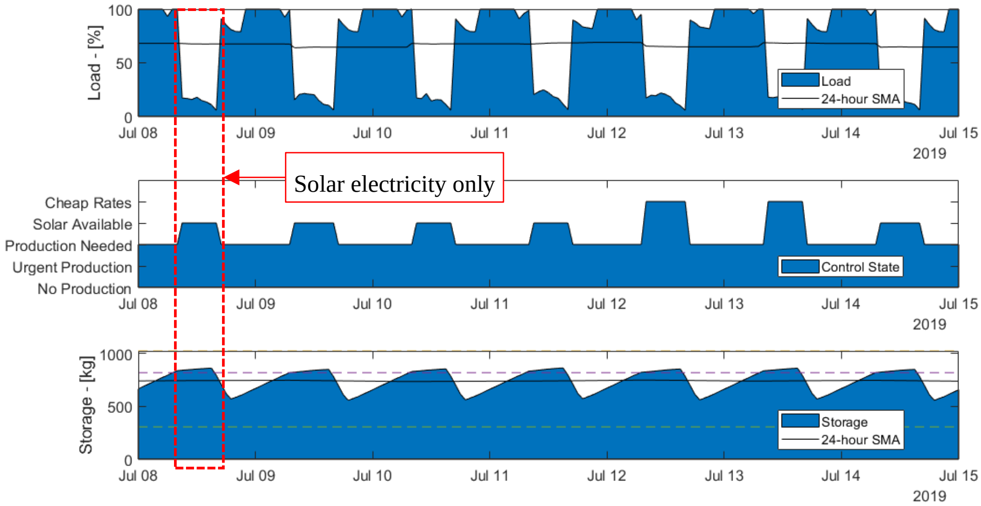


Figure 16. Plant operation during week in July. (constrained CB-S)

Only scenario CB-P and CB-S could fulfill the criteria, Table 15. Compared to the unconstrained scenarios, the constrained grid requires greater capacities, both with regards to electrolyzer rating and storage capacity. No configuration could meet the demand postulated in cases CB-M or CB-L. In attempting to find a configuration to supply scenario CB-M, even significantly oversized electrolyzer configurations could only meet about 75 % of the hours where hydrogen demand was exerted on the system. This is the ratio of hours where the supply met demand, the hydrogen deficiency is greater.

Table 15. System configurations meeting criteria with most utilization (least margin from criteria) in the case of a constrained grid. Note: Scenarios CB-M, CB-L and RB-M had no configuration that could meet the demand.

Case:	**Electrolyzer Rating**	**Storage Capacity**	**Capacity Factor**
CB-P	450 kW	450 kg H_2	88.8 %
CB-S	1,200 kW	1,025 kg H_2	66.5 %
CB-M	-	-	-
CB-L	-	-	-

By comparing the energy required to supply the CB-M fleet in the unconstrained scenario, there is a simple explanation. Accounting the available energy as if one could capitalize on all of it, there was a potential 12.7 GWh of electricity available for the simulated year, while the unconstrained fleet where the hydrogen demand was met has an annual demand of 21.6 GWh, see Appendix D. In actuality, by only adhering to the capacity constraints that have been agreed to with the DSO, as specified in Section 2.2.3, the city bus depot would still not be able to supply scenarios CB-M and CB-L, as the potentially available energy amounts to 20.6 GWh. Add to that the electricity needed for the depot baseload and the prospect of operating the larger scenarios with the imposed grid constraints are not possible. By comparison, the constrained CB-S scenario only require 6.9 GWh of electricity.

5.2. Economic Assessments

The economic results are central to the feasibility of PtG and FCEBs as an option to existing technologies. Based on the results from the previous section, the economic costs of the PtG-plants were calculated. The lifetime cost and revenue breakdowns for each simulated system size that was selected in Section 5.1.1 and 0, can be found in Figure 17.

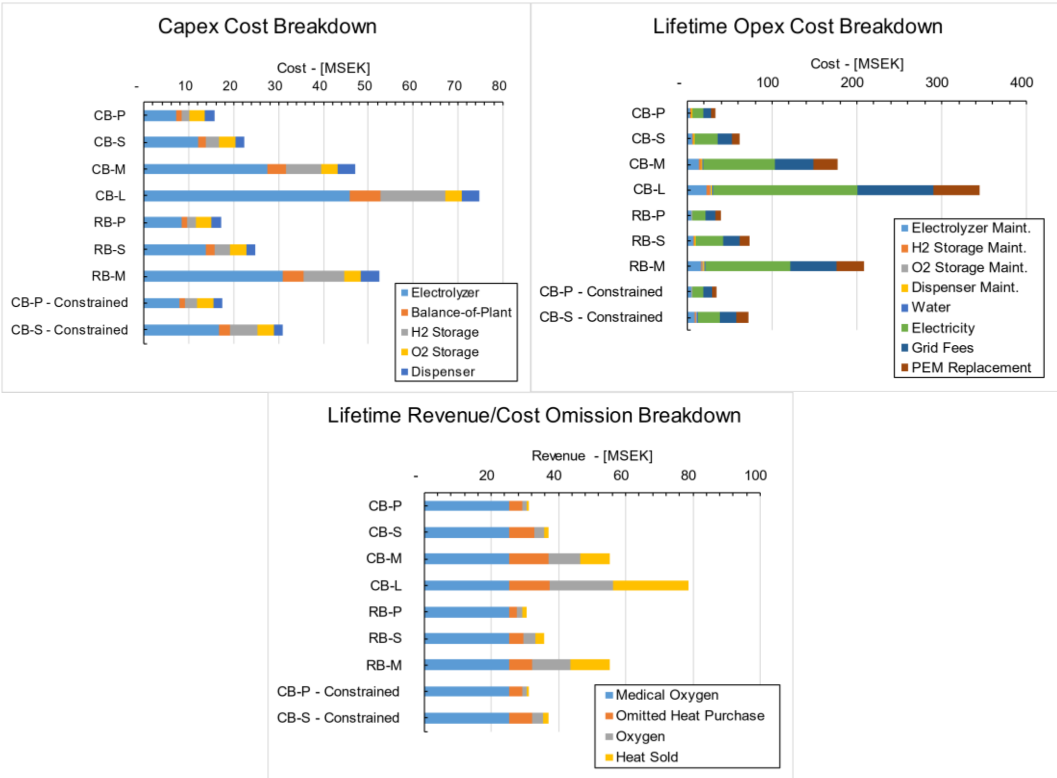


Figure 17. Cost & Revenue breakdown for all selected scenarios.

It is evident that electricity consumption and grid fees constitute the most significant cost for the lifespan of a PtG-plant. Water expenses, estimated maintenance costs, and electrolyzer replacement cost are dwarfed by comparison. Secondly, the biggest potential revenue is producing oxygen, followed by utilizing excess heat to reduce the demand for district heating. All configurations are able to meet the annual demand for oxygen, which will have a significant impact on the $LCOH_2$. Additionally, for the city bus depot, it is observed that once a fleet of 30 buses is introduced, the waste heat from the electrolyzer could potentially be used to cover the entire existing district heat demand.

5.2.1. Levelized cost of Hydrogen

The $LCOH_2$ is based on the results displayed in Figure 17, and the amount of hydrogen each bus fleet and respective plant configuration produce over its lifetime. When it comes to the $LCOH_2$ and the impact of selecting the plant configurations as described in Figure 12, it is shown that cost does not vary significantly in between the different configurations of electrolyzer size and storage capacity. Referring to Figure 18, it is observed that the LCOH2 for the unconstrained case CB-S, the same scenario as was illustrated in Figure 12, only vary marginally in-between the configurations which could meet the demand.

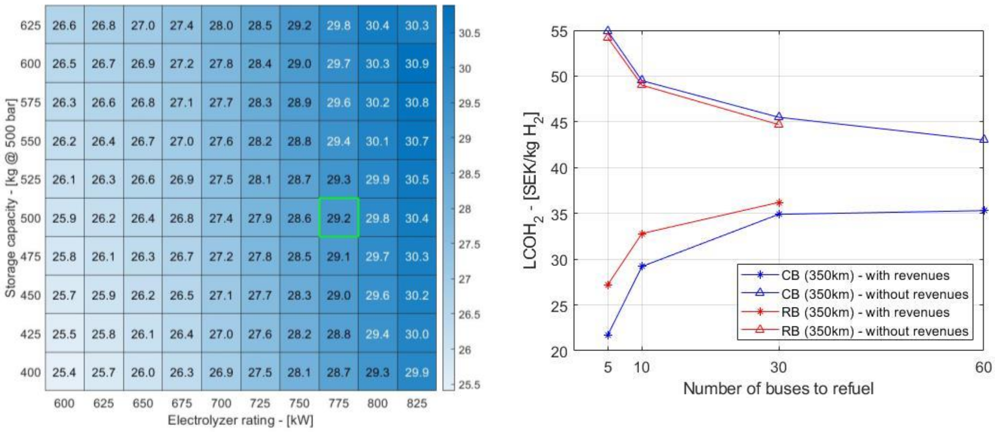


Figure 18. (left) $LCOH_2$ simulation results for the unconstrained CB-S scenario. (right) $LCOH_2$ is dependent on how big of a bus fleet is supplied.

In Figure 18, the $LCOH_2$ of the unconstrained scenarios are shown, both with and without accounting for revenues. The values themselves can be found in Appendix E. One can observe that the impact of any potential revenues is significant, especially for small scale implementations. The markedly lower $LCOH_2$ for the small scenarios is tied to the proportionally large revenues that can be obtained from oxygen in particular. Furthermore, in the small scale scenario, about 1,000 ton of oxygen is produced annually, whereas the medical demand as described and simulated is only 65 ton per annum. The rest is considerably lower value and should additional high value use of pure oxygen supply be found, there would be further significant reductions to $LCOH_2$.

There is a noticeable difference between the CB and RB scenarios, as the RB scenarios have a markedly higher $LCOH_2$ for the smaller scenarios when including revenues. The price difference can be attributed to the hydrogen demand of the RB fleet, which results in greater equipment costs and most significantly increased electricity demand. Additionally, the potential gain from the omitted heat demand is lower for the regional depot. The city bus depot uses less district heating as they for example employ electrical cabin heaters. In Section 4.2.3, the district heating subscription indicate the city bus depot has higher per MWh heating fees. Therefore, any omitted heat purchase, especially during the cold season, is a substantially greater cost saving. However, as was described in the previous section, the potential cost benefit of utilizing the excess heat to omit using district heating, is diminishing with the size of the plant as the heating demand is being met. This can explain why the $LCOH_2$ of the two different depots, converge at 30 buses served, accounting for potential revenues.

As the bus fleet and the accompanying PtG plant is increased in size, revenues have a diminishing effect on price. The increasing levelized cost of hydrogen is most noticeable when comparing a pilot scale implementation versus a small scale. This is largely attributed to the considerable revenue that can be obtained from producing medical oxygen.

When it comes to the constrained scenarios, presented in Table 16, the cost of hydrogen is getting markedly more expensive. The pilot scale scenario could operate at approximately 90 % capacity factor, fairly similar to the unconstrained scenarios, while the constraints on the small scale plant limits the capacity factor to only 66 %, drastically impacting the $LCOH_2$.

Table 16. Levelized cost of Hydrogen for the constrained scenarios

Case:	With revenues	Without revenues
CB-P – Constrained	25.5 SEK/kg	58.8 SEK/kg
CB-S – Constrained	41.0 SEK/kg	61.3 SEK/kg
CB-M – Constrained	-	-
CB-L – Constrained	-	-

Seeing as a FCEB reportedly can operate on 0.10 kg H_2/km, the constrained CB-S scenario $LCOH_2$ of 41.0 SEK/kg results in a cost of fuel per km of 4.1 SEK/km. By comparison, considering the price paid for HVO fuel, as well as the fuel mileage of Region Uppsala's diesel bus, the cost of fuel per km is 5.19 SEK/km. Similarly, by looking at the biogas buses, the cost of fuel per km is 5.12 SEK/km. The FCEB fleet would seemingly have a cheaper fuel cost compared to the existing ICE buses.

5.2.2. Total Cost of Ownership

As a second component to the economic assessment, the cost of ownership of FCEBs versus the existing fleets was compared. By comparing the three technologies, FCEBs, CBG-Bs and HVO diesel buses, and their respective purchasing price, maintenance cost and fuel expenditures, the estimated TCO is put into context.

The TCO comparison, presented in Figure 19, show the FCEB cost in the constrained CB-S scenario. The result indicates that even given the relatively high price for hydrogen within the context of this study, of 41.0 SEK/kg, a FCEB is still close to competitive with biogas buses. One consideration to bear in mind is that the scenarios have assumed high annual mileages, which benefit a FCEB fleet with lower fuel expenses. Conclusively, the biggest cost component to a FCEB is the capital expenditure. Should the projected cost reductions with price targets of 400,000 € come to fruition, this would improve the competitiveness.

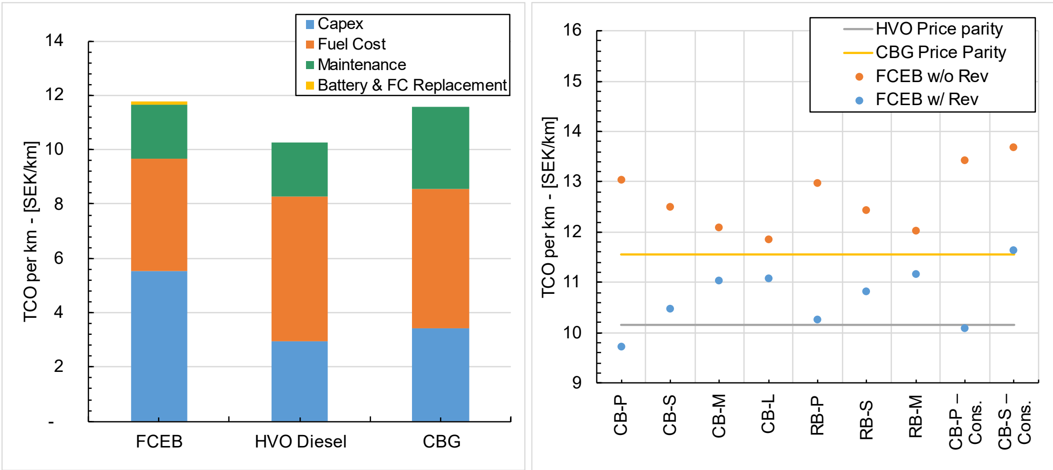


Figure 19. (left) Comparison between calculated TCO per km for FCEBs, HVO diesel buses and Biogas buses (CB-S). (right) Comparison of TCO for all scenarios

Comparing the FCEB TCO of all scenarios against the TCO of CBG- and HVO buses it is revealed that almost all scenarios are estimated to be cheaper than CBG-Bs. For scenarios where the PtG-plant does not capitalize on revenues or omitted costs however, the cost of fuel never reaches price parity. In order to compete with HVO buses, the $LCOH_2$ has to fall below 26.1 SEK/kg.

Were the purchasing price for the FCEBs to fall to the previously mentioned price target, the requirement on $LCOH_2$ for price parity are much less stringent. Eq. 15 is a rewritten adaptation on Eq. 14, which gives the required fuel cost (SEK/kg H_2) for price parity.

$$Fuel\ Cost = \frac{TCO_{km} \cdot \sum_i \frac{D_i}{(1+r)^i} - \sum_i \frac{CAPEX - ES + M}{(1+r)^i}}{\sum_i \frac{BM \cdot D}{(1+r)^i}} \qquad \text{Eq. 15}$$

The TCO_{km} for HVO buses is 10.15 SEK/km. With FCEB cost according to the price target of about 4,000,000 SEK, price parity is reached with $LCOH_2$ of 44.80 SEK/kg. By comparison, the TCO_{km} for CBG-Bs is 11.56 SEK/km, which would require $LCOH_2$ to be at 58.95 SEK/kg. Conclusively, with cheaper FCEBs, the requirements on auxiliary revenues for a PtG-plant are diminishing.

5.2.3. Sensitivity analysis

As was described in Section 4.3, the first step of the sensitivity analysis was conducted by documenting what cost components make up the net lifetime cost of hydrogen and the TCO of a FCEB. As the constrained cases are most in line with the limitations facing the city bus depot today, the constrained CB-S scenario was selected for analysis. Figure 20 shows the cost breakdown for both the PtG-plant and the corresponding FCEB bus cost. For the PtG-plant, the largest cost components are the electricity price and grid fees, followed by fuel cell stack replacement and electrolyzer installation cost. Any potential revenues are illustrated to have significant impact on the net lifetime cost of the plant. With regards to the FCEB, operational costs and investment cost are about equal. Fuel cost and FCEB cost are the most impactful to the net lifetime cost.

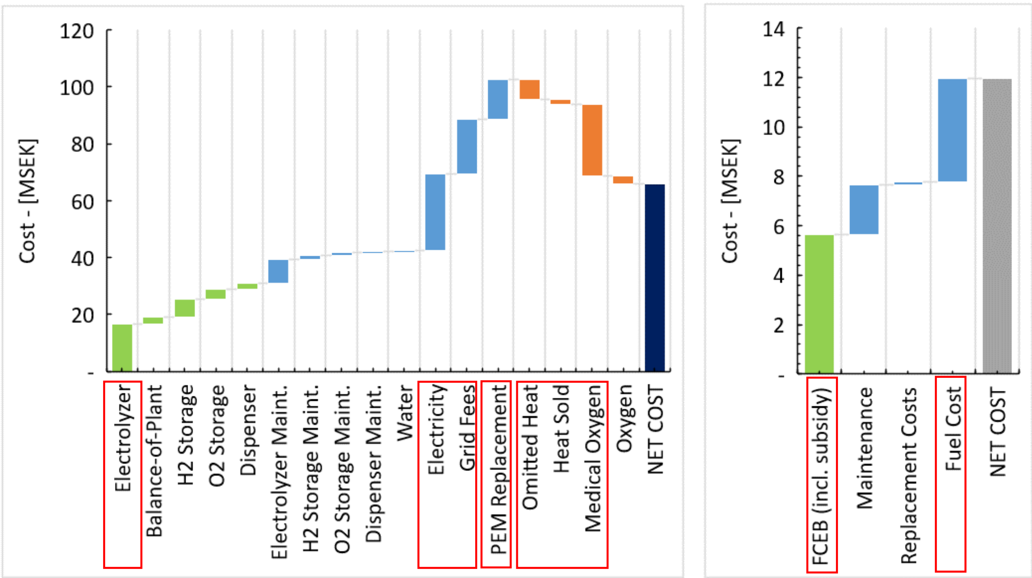


Figure 20. Lifetime Cost and Revenue breakdown of the constrained CB-S scenario, and the investigated cost parameters.

Using the highlighted cost components in Figure 20 and deviations specified in Table 12, the spider graphs presented in Figure 21 were produced.

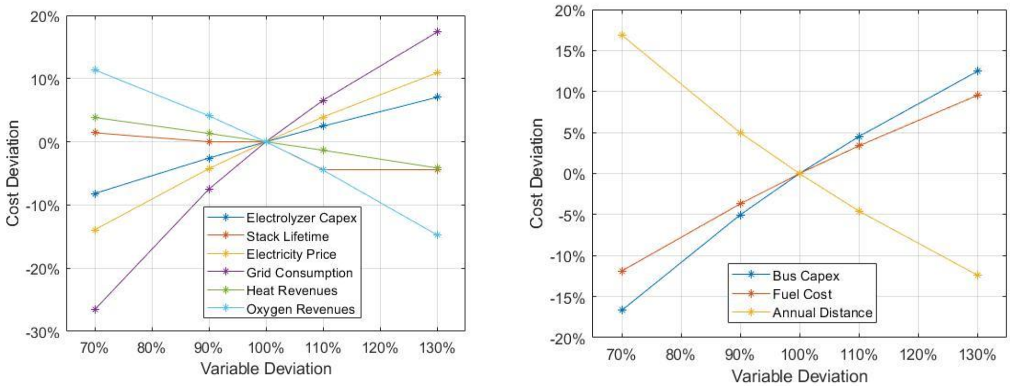


Figure 21. (left) Spider graph – LCOH$_2$. (right) Spider graph – TCO.

First and foremost, the conservative estimate for electrolyzer stack lifetime is shown to not significantly impact to the cost of hydrogen. At a 30% increase in lifetime, adding another year and a half of operational hours, the LCOH$_2$ is only reduced by 4 %. The 40,000 hour lifetime equates to four replacements during the 20 year lifespan. Better stack lifetime would possibly remove the need to conduct the fourth replacement, as well as reduce the present value cost of the maintenance event.

Secondly, striking a low electricity price and reducing the amount of electricity that is being purchased from the grid have the most significant impact on the LCOH$_2$. The Swedish power generation is transitioning to an energy mix of more non-dispatchable renewable energy sources, and nuclear power generation may or may not be decommissioned. This transition may potentially introduce an increase in electricity price volatility [54], which in extension could impact the long term power purchasing agreements that are being offered. From the spider graph, its observable that a change in PPA pricing could have a large impact on operational expenditure. Furthermore, in the presented scenario the cost of electricity and the accompanying grid service fees amount to an expected 3.6 MSEK, purchasing 6,900 MWh of electricity annually. For this particular scenario, about 460 MWh of solar energy was produced by the 500 kW$_p$ solar plant. Additional on-site energy production, either through solar or wind could greatly reduce the amount of electricity purchased. The PtG-plant has a good capture rate of any additional energy production given the preference for high capacity factor operation.

The capital cost of the electrolyzer is subject to significant uncertainties due to opaque market data on PtG-system costs. Since the price function established in Section 4.2.1 is only an estimation based on observed trends, the actual cost per kW of installed capacity is uncertain. An Analysis of the electrolyzer capex cost is hence a good way to gauge the range of possible costs. A 9,700 SEK/kW reference cost of the electrolyzer was based on a single total-cost reference case, where the facility component investments were opaque. The city bus depot does already have some significant infrastructure installed, namely the grid connection. This cost may or may not be included in the reference scenario, although it is likely that it is, which means the per kW cost would in fact be lower.

Finally, the auxiliary revenues are shown to have considerable impact on the $LCOH_2$. Reduced or increased heat revenues does not in fact impact the CB-S scenario significantly, however the oxygen revenues do. In Figure 20, it is illustrated that medical oxygen has the greatest negative cost impact and decreasing or increasing the amount of high value oxygen that can be sold, impacts the $LCOH_2$ markedly. As previously mentioned, the majority of the high purity oxygen is not considered for medical use, and subsequently the value was assumed to be low.

In the second spider graph, the cost impact of Capex and distance traveled are the most significant. The variation on the cost of purchasing a bus greatly impacts how cheap the cost of fuel can be to be competitive. It is not unreasonable to expect that the average travel distance for the buses would be shorter than the assumed 127,725 km. More FCEBs on more routes would impact the average annual trip distance. This study assumed 100 % availability, which is highly idealized and in reality, one can expect bus downtime, which would reduce annual trip distance as well.

6. Discussion

6.1. Technical Feasibility

The prospect of utilizing power-to-gas for zero-emission FCEBs in Uppsala is intriguing considering the added benefit of oxygen production for the already existing regional demand of medical oxygen. Additionally, the local wastewater treatment plant does have an aeration process, where Uppsala Vatten has the potential to utilize the remaining oxygen production. Other studies [55], have already explored incorporating a wastewater treatment plant with pure oxygen supply from an electrolyzer. The studied wastewater treatment plant drew its conclusions of the economic benefit based on replacing aeration using atmospheric air and blowers, presumably in a similar configuration to that of the wastewater treatment plant in Uppsala. However, they indicate that the electrolyzer capacity needs to be in the larger scales to be economically feasible given the system installation costs and gains in omitted electricity costs for blower operation. These conclusions are difficult to compare with the scenario described in Uppsala. It does however suggest that the economic value of oxygen produced outside of the wastewater treatment plant should maintain its assumed low value. The greater economic value is likely found in maximizing the economic potential of medical oxygen, where gas bottling is a potential revenue. This aspect was omitted as it entails additional equipment and labor costs which were not considered within the scope of this thesis.

Considering the solution as an option for zero-emission commuter traffic, FCEBs are still novel, but are making an entrance across Europe [56] and manufacturers are increasingly signaling that their future offering of fuel cell solutions. This thesis has shown that FCEBs operating long distances, are close to competitive with existing CBG buses on price. The competitiveness of FCEBs was shown to be highly dependent on the capital cost of the bus, as well as the average annual distance traveled. By considering the capital cost price targets, the potential for price parity with HVO and CBG buses is attainable with some margin to the estimated $LCOH_2$ cost of 25.5 – 41.0 SEK/kg H_2.

The main benefit of FCEBs is the possibility to electrify long distance routes without the need to add additional electrical charging infrastructure. For shorter routes, BEBs are likely the better option. The net electrical efficiency of a FCEB drivetrain is about 28 %, while the net electrical efficiency of a BEB drivetrain is about 77 %, see Appendix A. As society is shifting towards increasing electrification, while the international electricity production is not yet renewable in its entirety, one consideration to technology adaptation should be the energy efficiencies of the solutions. For each step of energy conversion, for example by converting electrical energy into chemical energy through electrolysis, there is a loss as heat is generated. To meet the climate challenge, it is important to be economical about the renewable energy production that is available, and limit wasteful applications. For shorter trips, where BEBs can comfortably navigate with the range constraints of their batteries, they are arguably the more prudent zero-emission option from a conservation of energy standpoint. For longer trips however, the BEBs currently need to either have expanded infrastructure, or additional buses to cover the routes. These are the hard-to-electrify operations, where FCEBs are a good option. Then again, the benefit to Region Uppsala of producing their own medical grade oxygen may be enough of an incentive to introduce a few FCEBs.

6.2. Constraints and conditions for hydrogen production

For this thesis, the boundary conditions that have been described are the electrical constraints, the solar electricity production, the different bus fleet scenarios, their respective hydrogen demand as well as the identifiable revenues from oxygen and heat. What was not included which could impact the outcome are planned downtime events for the electrolyzer, such as maintenance events; and stochastic variance, or noise, in the fuel consumption of the bus fleets as fuel consumption will vary with driving conditions, traffic, vehicle downtime, and temperature. Planned downtime events could imply a need to increase storage capacity, further raising the $LCOH_2$. Noisy fuel consumption can either increase or decrease the hydrogen demand from the bus fleet on an intra-day or seasonal basis. However, for the purpose of this study, the level of detail selected does give an indication of the feasibility of the technology that satisfies the project purpose.

What has been identified are the two main constraints on production, the existing electrical load, and the limited electrical supply. It has been illustrated that the service agreement with the DSO already limits the prospective size of a FCEB fleet. If the project should come to realization at a larger scale, the service agreement would either need to be renegotiated or the on-site renewable electricity production needs to be expanded. The larger fleets were shown to need an electrolyzer capacity of 2.4 – 4.7 MW, which could capture more solar, or wind power, than what was modeled as available. Still, the existing electrical load is further constraining, and more crucially, it is limiting during the periods where the available solar resources are reduced. While the service agreement has been indicated as limiting to implementing BEBs where a number of buses need charging during the day [43], the electrical heating load is hampering the prospect of implementing FCEB at scale. The electrical heating load increases the need of storage capacity, as particularly the weekend loads were shown to deplete the hydrogen storage.

Once again, discussing economical pathways of using renewable electricity is appropriate. The Swedish electricity production is cheap, and primarily renewable or fossil-free [57], but it is not abundant as we head towards increased electrification. It is an unfortunate decision to use electrical cabin heaters in the city buses when district heating is readily available at the facility. At the old bus depot, 29 of the 180 buses were heated with district heating [43]. In conserving the energy quality of electricity for more impactful electrification such as zero-emission transportation, employing district heating solutions for heating the entire bus fleet is arguably more pragmatic. One could even envision a covering of the buses, so that they are not exposed to the elements, either a hangar structure or a parking garage, which can then be heated with the available district heat. Perhaps this would be an interesting future topic for a thesis to consider.

6.3. Impact of prospective revenues

The potential revenues and cost omissions from oxygen and heat have been illustrated to impact the $LCOH_2$ in a significant way. The medical oxygen demand can be met already with a small electrolyzer plant, but even as scale is increased, the revenues were shown to potentially reduce the $LCOH_2$ by as much as about 20 % and especially bottling of medical oxygen could further add to the cost reduction.

Heat recovery has been considered primarily as a cost omission, as the electrolytic process expels heat during load. In this thesis, the heat production has been assumed as a linear function of the electrolyzer load. In practice, given the wide load range cited for the electrolyzer, the heating capacity is probably non-linear. Lower loads produce less useful heat as lower amperages will lower the operating temperature. Should the plant be sized to operate at the higher load range, the excess heat can be used to offset more district heating load if the heating of buses with hot water were introduced. The DSO service constraint showed hydrogen production would be primarily at nighttime, which coincidentally is where the depot has the greatest heating load, resulting in a beneficial prospective synergy.

6.4. Economical evaluation

While the unconstrained scenarios do not reflect a realistic scenario for the foreseeable future. They offer an indication about the proportions of hydrogen, electricity, heat, water, and oxygen that is produced and consumed. Another insight is the prospective price dynamic of increasing plant scale. It was shown that if there are no new limiting dynamics as you increase the plant scale, the $LCOH_2$ is not diverging to greater costs. Cost of hydrogen production is indicated to converge towards 35 – 43 SEK/kg H_2. On the other hand, the constrained case showed that as the electrical load limitations increase with scale, the plant has to increase in the size of equipment and as a result reduce the capacity factor. Compared to the unconstrained scenario, the small scale plant requires 50 % more electrolyzer capacity and 100 % more storage volume. Even with the added capacity and reduced capacity factor, the estimated costs with or without revenues of 25 – 61 SEK/kg H_2 are in the same range as current production cost estimates [58].

Capturing revenues and cost omissions brings the prospective price paid for fuel well within the projected targets for 2020 of about 20 – 58 SEK/kg H_2. Conclusively, the TCO is shown to be feasible and competitive as long as FCEB cost move towards the price target of 4,000,000 SEK, and if they travel an appropriate trip distance.

One aspect which has not been explored, but that will impact the $LCOH_2$ is the attainable capacity factor. The unconstrained scenarios have a highly idealized capacity factor, and the constrained scenarios are likely more realistic. A lower capacity factor for the same production demand will negatively impact $LCOH_2$. The arrangement infers that larger capacities are installed at greater cost, and operated at fewer hours, producing less gas per installed capacity. Comparing the constrained and unconstrained CB-S scenarios attest to the negative impact of reduced capacity factors.

7. Conclusions

This project has shown that it is feasible to construct a pilot or small scale Power-to-Gas electrolyzer plant, which can supply 5 – 10 fuel cell electric buses. A model was created to simulate the operation of a PtG-plant and the dynamics that are imposed on the system have been described. The existing electrical infrastructure at the city bus depot does support larger fleets but are hampered by a constrained power supply subscription and large electric power demand for electric bus cabin heaters. Electricity constraints and electric heating of bus cabins resulted in requirements of increased storage capacities for intra-day resiliency, as well as larger electrolyzer capacities. In contrast to BEBs, the electric power use can be shifted from constrained hours to where the capacity is available. FCEBs could therefore be deployed today.

The total cost of ownership of a FCEB was estimated and compared against existing cost parameters for biogas buses and biodiesel buses. The TCO was shown to be able to equate that of the existing fleet, provided the buses are extensively utilized on longer routes. It was shown that bus cost and fuel cost, or the levelized cost of hydrogen, are the leading cost components to take into consideration. If the purchasing price of FCEBs would reach the projected price targets, the demand on low fuel cost was revealed to decrease significantly.

The $LCOH_2$ is shown to be tied to the size of the electrolyzer plant but are demonstrating indications of converging to a cost between 35 – 43 SEK/kg H_2, as long as no new constraints are introduced with larger scale plants. Even cheaper hydrogen prices are obtained in smaller plant configurations when oxygen is sold. Constructing a pilot scale plant is a good way to get acquainted with the new hydrogen systems, while allowing the full capture of the potential revenue from regional medical oxygen demand. A pilot scale plant was calculated to be able to produce hydrogen at a levelized cost of 25.5 SEK/kg H_2. The largest operational expense of the electrolyzer was the cost of electricity. The simulations suggest that a PtG-plant has a good ability to utilize self-produced solar power, which would reduce the demand to purchase electricity and have a significant impact on $LCOH_2$. Lastly, revenues of oxygen and heat all present an opportunity to reduce bus fuel cost. Finding more uses for high purity oxygen and utilizing the self-produced heat alter the cost of hydrogen significantly.

7.1. Future Studies

A few prospective future topics of interest have emerged during the writing of this thesis. In the following paragraphs the topics will be listed in no particular order and could lay as groundwork for future thesis topics.

Evaluation of Steam Methane Reformation of Biogas to Hydrogen As FCEBs have better fuel mileage and energy efficiency compared to ICE buses, an interesting study would be to look at the economic feasibility of producing hydrogen from the biomethane that is purchased from Uppsala Vatten.

Techno-economic assessment of ways to reduce bus depot heating load. It has become evident that the constraint on the grid and the decision to use electric space heaters in the buses are an unfortunate circumstance as Region Uppsala and UL are looking to introduce zero-emission electric buses. By parking buses in a large scale hangar or parking building which can be heated by district heating would improve the electricity constraints, and possibly reduce the overall heating demand in the cold season.

Explore incorporation of more solar and wind power production. The electrolyzer plant should preferably operate at a high capacity factor. As has been discussed in this thesis, the plant captured almost all of the annual solar production. Were more renewable energy production available, would this reduce the cost of electricity and subsequently the cost of fuel. Investigating constructing a wind turbine and/or more solar panels could produce interesting results.

Technical comparison between BEB and FCEB through all seasons. How does the drive efficiency of BEBs compare with FCEBs when one has to account for space heating during cold winter trips. FCEBs should have enough excess heat from the fuel cell electric generation to heat the cabin, while BEB mileage should be reduced.

References

[1] M. Nystrand, “# Uppsalaeffekten – en beskrivning av hur samhället gick samman för att fixa kapacitetsutmaningarna i elsystemet Introduktion Befintliga strukturer,” 2020.

[2] Tillväxt- och regionplaneförvaltningen Stockholm, “Kraftförsörjning inom östra Mellansverige,” 2019.

[3] Sveriges Riksdag, *Ellagen (1997:857)*. https://www.riksdagen.se/sv/dokument-lagar/dokument/svensk-forfattningssamling/ellag-1997857_sfs-1997-857, 1997.

[4] Energimarknadsinspektionen, “Undantag från kravet på nätkoncession - IKN.” [Online]. Available: https://www.ei.se/bransch/koncessioner/undantag-fran-kravet-pa-natkoncession---ikn. [Accessed: 21-May-2021].

[5] Skatteverket, “Lag(1994:1776) om skatt på Energi.” [Online]. Available: https://www4.skatteverket.se/rattsligvagledning/2785.html?date=2021-03-08&q=1994%3A1776#h-11-kap-Energiskatt-pa-elektrisk-kraft. [Accessed: 09-Mar-2021].

[6] Skatteverket, “Ställningstagande: Beskattning av vätgas som förbrukas i motordrivet fordon, fartyg eller luftfartyg.” [Online]. Available: https://www4.skatteverket.se/rattsligvagledning/390294.html?date=2021-02-23. [Accessed: 09-Mar-2021].

[7] Energimyndigheten, “Elbusspremie,” 2019. [Online]. Available: http://www.energimyndigheten.se/klimat--miljo/transporter/transporteffektivt-samhalle/elbusspremie/. [Accessed: 09-Mar-2021].

[8] Miljödepartementet, “Förordning (2016:836) om elbusspremie.” [Online]. Available: http://rkrattsbaser.gov.se/sfst?bet=2016:836. [Accessed: 09-Mar-2021].

[9] Z. Abdin, A. Zafaranloo, A. Rafiee, W. Mérida, W. Lipiński, and K. R. Khalilpour, “Hydrogen as an energy vector,” *Renewable and Sustainable Energy Reviews*. 2020, doi: 10.1016/j.rser.2019.109620.

[10] A. Valera-Medina, H. Xiao, M. Owen-Jones, W. I. F. David, and P. J.

Bowen, “Ammonia for power,” *Progress in Energy and Combustion Science*, vol. 69. Elsevier Ltd, pp. 63–102, 01-Nov-2018, doi: 10.1016/j.pecs.2018.07.001.

[11] C. Wulf, J. Linßen, and P. Zapp, “Review of power-to-gas projects in Europe,” in *Energy Procedia*, 2018, vol. 155, pp. 367–378, doi: 10.1016/j.egypro.2018.11.041.

[12] R. de Levie, “The eletrolysis of water,” *J. Electroanal. Chem.*, vol. 476, pp. 92–93, 1999.

[13] International Energy Agency, “Technology Roadmap - Hydrogen and Fuel Cells,” 2015.

[14] D. Kushnir, T. Hansen, V. Vogl, and M. Åhman, “Adopting hydrogen direct reduction for the Swedish steel industry: A technological innovation system (TIS) study,” *J. Clean. Prod.*, vol. 242, p. 118185, 2020, doi: 10.1016/j.jclepro.2019.118185.

[15] A. Buttler and H. Spliethoff, “Current status of water electrolysis for energy storage, grid balancing and sector coupling via power-to-gas and power-to-liquids: A review,” *Renew. Sustain. Energy Rev.*, vol. 82, no. September 2017, pp. 2440–2454, 2018, doi: 10.1016/j.rser.2017.09.003.

[16] IRENA, “Green Hydrogen Cost Reduction - Scaling up electrolysers to meet the 1.5°C climate goal,” 2020.

[17] M. David, C. Ocampo-Martínez, and R. Sánchez-Peña, “Advances in alkaline water electrolyzers: A review,” *J. Energy Storage*, vol. 23, no. December 2018, pp. 392–403, 2019, doi: 10.1016/j.est.2019.03.001.

[18] I. Abe, “Alkaline Water Electrolysis,” in *Energy Carriers and Conversion Systems*, vol. I, EOLSS, 2009, pp. 320–324.

[19] J. Brauns and T. Turek, “Alkaline water electrolysis powered by renewable energy: A review,” *Processes*, vol. 8, no. 2, 2020, doi: 10.3390/pr8020248.

[20] R. Reissner, J. Vaes, and S. S. Hosseiny, “RESelyser: System Concept for a combined RES-Electrolyser plant with optimised efficiency: Part 1 Review of electrolyser system with special emphasis on the HYSOLAR system,” pp. 1–31, 2015.

[21] Nel Hydrogen, “The World’s Most Efficient and Reliable Electrolysers,” *NEL electrolyzers brochure*. 2019.

[22] M. Carmo, D. L. Fritz, J. Mergel, and D. Stolten, “A comprehensive review on PEM water electrolysis,” *Int. J. Hydrogen Energy*, vol. 38, no. 12, pp. 4901–4934, 2013, doi: 10.1016/j.ijhydene.2013.01.151.

[23] S. Shiva Kumar and V. Himabindu, “Hydrogen production by PEM water

electrolysis – A review," *Mater. Sci. Energy Technol.*, vol. 2, no. 3, pp. 442–454, 2019, doi: 10.1016/j.mset.2019.03.002.

[24] Nel Hydrogen, "M Series Containerized - Proton Exchange Memrane (PEM) Hydrogen generation systems." .

[25] Water2H2, "Alkaline Electrolyzers." [Online]. Available: https://www.water2h2.com/alkaline-electrolyzers/. [Accessed: 09-Apr-2021].

[26] Green Hydrogen System, "HyProvide ™ A series." .

[27] Water2H2, "Proton PEM Electrolyzers." [Online]. Available: https://www.water2h2.com/proton-pem-electrolyzers/. [Accessed: 09-Apr-2021].

[28] B. Reuter, M. Faltenbacher, O. Schuller, N. Whitehouse, and S. Whitehouse, "New Bus Refuelling for European Hydrogen Bus Depots," *Fuel Cell Hydrog. Jt. Undert.*, no. 1, pp. 1–38, 2017.

[29] A. G. Olabi, T. Wilberforce, and M. A. Abdelkareem, "Fuel cell application in the automotive industry and future perspective," *Energy*, vol. 214, p. 118955, 2021, doi: 10.1016/j.energy.2020.118955.

[30] Energimyndigheten, "Informationsstöd om elbussupplägg till kollektivtrafikhuvudmän Åtagande i den strategiska planen för omställning av transportsektorn till fossilfrihet (SOFT) ER 2019:03," 2019.

[31] ULO, "25 bränslecellsbussar från Solaris (uppdaterad version)," *Bussmagasinet*, 2020. [Online]. Available: https://www.bussmagasinet.se/2020/03/mer-branslecellsbussar-fran-solaris/. [Accessed: 30-Mar-2021].

[32] AutomotiveWorld.com, "Solaris receives first order under a tender for 530 e-buses for Hamburg," 2020. [Online]. Available: https://www.automotiveworld.com/news-releases/truck-bus-news-releases/solaris-receives-first-order-under-a-tender-for-530-e-buses-for-hamburg/. [Accessed: 05-May-2021].

[33] sustainable-bus.com, "A new batch of Solaris Urbino hydrogen in the Netherlands." [Online]. Available: https://www.sustainable-bus.com/news/solaris-urbino-hydrogen-arriva-netherlands/.

[34] H. Ammerman, Y. Ruf, S. Lange, D. Fundulea, and A. Martin, "Fuel Cell Electric Buses - Potential for Sustainable Public Transport in Eurpoe," p. 19, 2015.

[35] MAN, "MAN presents Zero-Emission Roadmap," 2020. [Online]. Available: https://press.mantruckandbus.com/corporate/man-presents-zero-emission-roadmap/. [Accessed: 22-Apr-2021].

[36] Daimler, “Fuel-cell joint venture. Volvo Group and Daimler Truck AG sign binding agreement,” 2020. [Online]. Available: https://www.daimler.com/company/news/fuel-cell-joint-venture-volvo.html. [Accessed: 22-Apr-2021].

[37] A. Lundström, M. N. Holmström, and E. Torstensson, “Elbussar i Sveriges kollektivtrafik Skånetrafiken och Västtrafik utifrån fyra perspektiv,” 2019.

[38] T. Kato, M. Kubota, N. Kobayashi, and Y. Suzuoki, “Effective utilization of by-product oxygen from electrolysis hydrogen production,” *Energy*, vol. 30, no. 14, pp. 2580–2595, 2005, doi: 10.1016/j.energy.2004.07.004.

[39] Läkemedelsverket, “Svensk läkemedelsstandard - Oxygen.” pp. 1–4.

[40] European Commission, “Eudralex Volume 4 Annex 6 - Manufacture of Medicinal Gases,” *Enterprise and Industry Directorate-General*, vol. 4. pp. 309–317, 2010.

[41] Socialdepartementet, “Läkemedelslag (2015:315).” [Online]. Available: https://www.riksdagen.se/sv/dokument-lagar/dokument/svensk-forfattningssamling/lakemedelslag-2015315_sfs-2015-315.

[42] L. Janke, S. McDonagh, S. Weinrich, D. Nilsson, P. A. Hansson, and Å. Nordberg, “Techno-Economic Assessment of Demand-Driven Small-Scale Green Hydrogen Production for Low Carbon Agriculture in Sweden,” *Front. Energy Res.*, vol. 8, no. November, pp. 1–19, 2020, doi: 10.3389/fenrg.2020.595224.

[43] J. Andersson and V. Bernström, “Elektrifiering av Uppsalas stadsbussar Lösningar för att hantera kapacitetsbristen i en växande region Electrification of city buses in Uppsala : Solutions for managing the capacity shortage in a growing region,” 2019.

[44] JRC, “The PVGIS project, a bit of background.” [Online]. Available: https://ec.europa.eu/jrc/en/PVGIS/about/who. [Accessed: 01-Apr-2021].

[45] A. Zauner, H. Böhm, D. C. Rosenfeld, and R. Tichler, “Innovative large-scale energy storage technologies and Power-to-Gas concepts after optimization. D7.7 Analysis on future technology options and on techno-economic optimization,” no. 691797, pp. 1–89, 2019.

[46] M. Lappalainen, “Mikko Lappalainen TECHNO-ECONOMIC FEASIBILITY OF HYDROGEN PRODUCTION VIA POLYMER MEMBRANE ELECTROLYTE POWER-TO-X SYSTEMS Faculty of Natural Sciences,” 2019.

[47] Fuel Cells and Hydrogen Joint Undertaking, “Early business cases for H2 in energy storage and more broadly power to H2 applications, Final Report, Fuel cells and hydrogen joint undertaking, P2H-BC/4NT/0550274/000/03, 2017,” no. June, pp. 1–228, 2017.

[48] Linde, “Linde Hydrogen FuelTech - Tomorrow’s Fuel today.” 2020, doi: 10.3726/b14469.

[49] Vattenfall AB, “Effekttariffer 2021 - Område Söder.” p. 2021, 2021.

[50] Vattenfall AB, “Fjärrvärmepriser för företag i Uppsala 2020.” 2020.

[51] Ballard, “Heavy Duty Modules.” [Online]. Available: https://www.ballard.com/fuel-cell-solutions/fuel-cell-power-products/motive-modules. [Accessed: 07-May-2021].

[52] US Department of Energy, “2018 Cost Projections of PEM Fuel Cell Systems for Automobiles and Medium-Duty Vehicles Webinar,” 2018. [Online]. Available: https://www.energy.gov/eere/fuelcells/downloads/2018-cost-projections-pem-fuel-cell-systems-automobiles-and-medium-duty. [Accessed: 07-May-2021].

[53] Uppsala Vatten, “Vattenförsörjningen i Uppsala Stad.” .

[54] L. Söder, “Studie av sannolikhet för hög elförbrukning, effektbrist, effektvärden och höga elpriser,” pp. 1–30, 2015.

[55] M. Kluge and D. Bach, “WP3 – Biogas valorization and efficient energy management,” 2018.

[56] Fuel Cell and Hydrogen Joint Undertaking, “Towards clean public transport.” .

[57] Statistikmyndigheten SCB, “Tillförsel och Användning av el 2001 - 2019 (GWh).” [Online]. Available: https://www.scb.se/hitta-statistik/statistik-efter-amne/energi/tillforsel-och-anvandning-av-energi/arlig-energistatistik-el-gas-och-fjarrvarme/pong/tabell-och-diagram/tillforsel-och-anvandning-av-el-gwh/. [Accessed: 27-May-2021].

[58] Fossilfritt Sverige, “Strategi för fossilfri konkurrens-kraft.” 2021.

[59] E. Energy&environment, “Hydrogen Bus.” [Online]. Available: http://www.eniscuola.net/en/mediateca/hydrogen-bus/. [Accessed: 03-May-2021].

Appendix A. Bus Efficiency comparison

Based on the process efficiencies listed in Appendix Table A-1, the energy losses and subsequent energy efficiency of FCEB and BEB drivetrains are illustrated in Appendix Table A-2

Appendix Table A-1. System fuel to wheel conversion and efficiency assumptions.

FCEB Processes	Efficiency
Rectifier	95%
Electrolyzer	63%
Compressors	93%
Fuel Cell	60%
Inverter	95%
Electric Engine	90%

BEB Processes	Efficiency
Rectifier	95%
Battery	95%
Inverter	95%
Electric Engine	90%

Appendix Table A-2. Visualization of round trip energy efficiency for BEBs and FCEBs. Assumed PtG plant, compression performance in line with project assumptions.

	BEB	FCEB
Electricity input	100%	100%
Rectifier losses (AC-DC)	95%	95%
Battery charging losses	90%	-
Electrolyzer plant losses	-	60%
Compression losses	-	55%
Fuel cell heat losses	-	33%
Inverter losses (DC-AC)	86%	32%
Engine losses	77%	28%
Net Efficiency	77%	28%

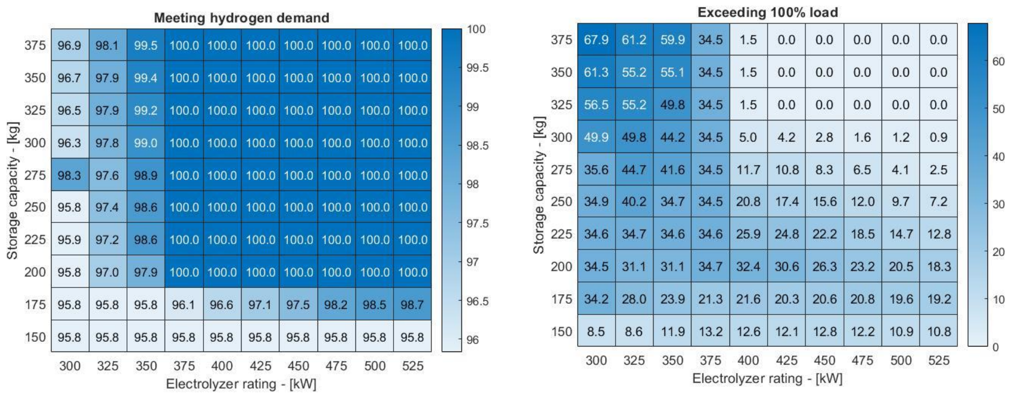
Appendix B. Grid fee verification

The verification of the grid fees, addressed in Section 4.2.2, was done by reviewing invoices from the regional bus depot. Invoices were obtained for October and November of 2020, and the corresponding fees and charges for 2020 were used. The only considerable deviation in the verification process was the energy transfer fee in September, Appendix Table B-3. The error comes from the recorded peak power usage that was recorded. In the simulated model, the peak power was 261 kW, while the invoice cited 211 kW.

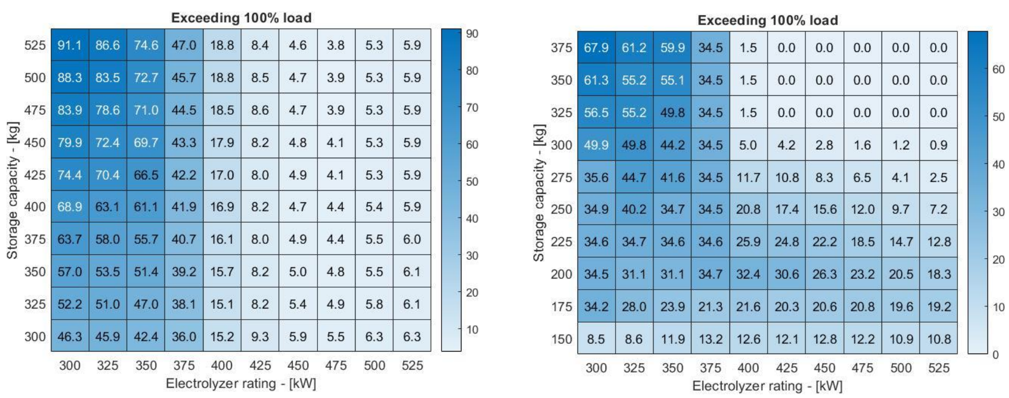
Appendix Table B-3. Verification of simulated grid fees against invoices.

Month	Fee	Invoice	Simulated
O	Fixed fee	2,500 SEK	2,500 SEK
C	Energy Transfer fee (normal & peak)	5,908 SEK	7,506 SEK
T	Power charge (normal & peak)	7,138 SEK	6,874 SEK
N	Fixed fee	2,500 SEK	2,500 SEK
O	Energy Transfer fee (normal & peak)	14,999 SEK	14,555 SEK
V	Power charge (normal & peak)	19,006 SEK	18,981 SEK

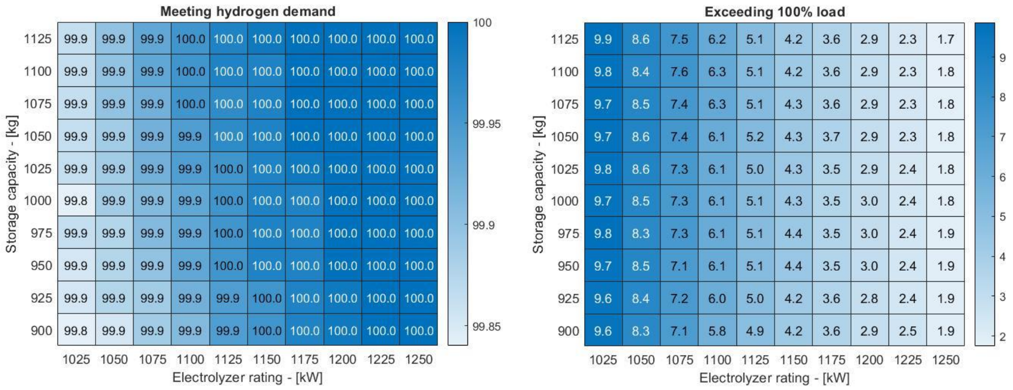
Appendix C. System matrices



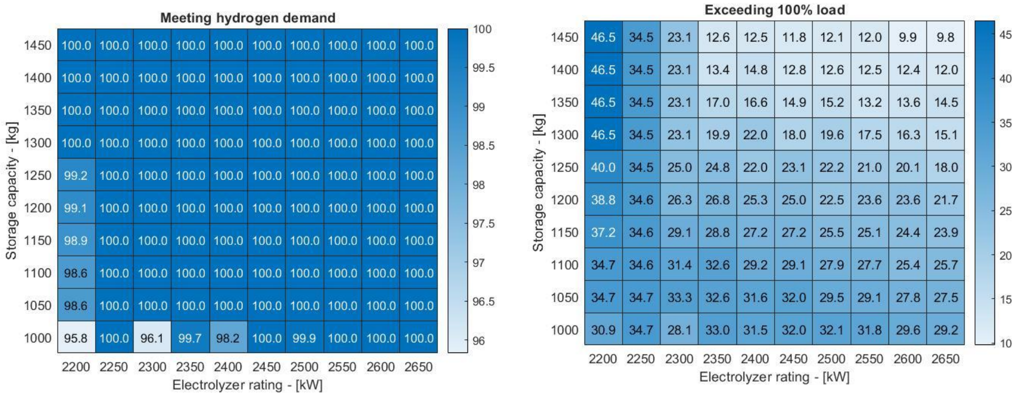
Appendix Figure B-1. Case 1 - Unconstrained



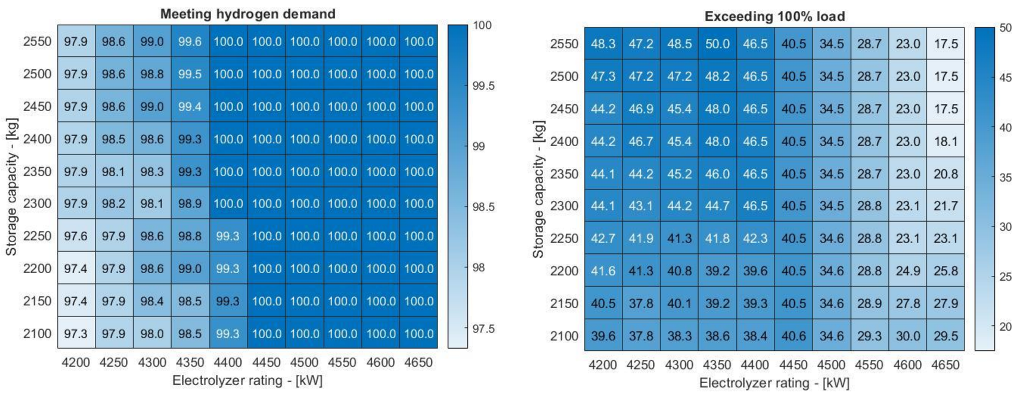
Appendix Figure C-2. Case 1 - Constrained



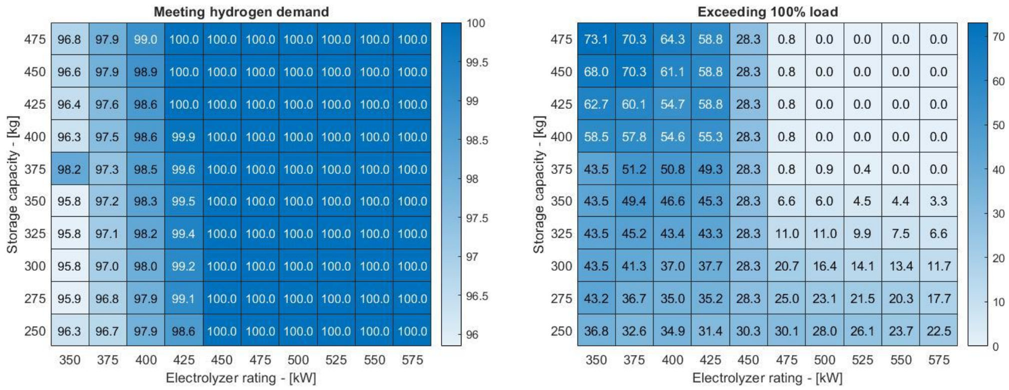
Appendix Figure C-3. Case 2 - Constrained



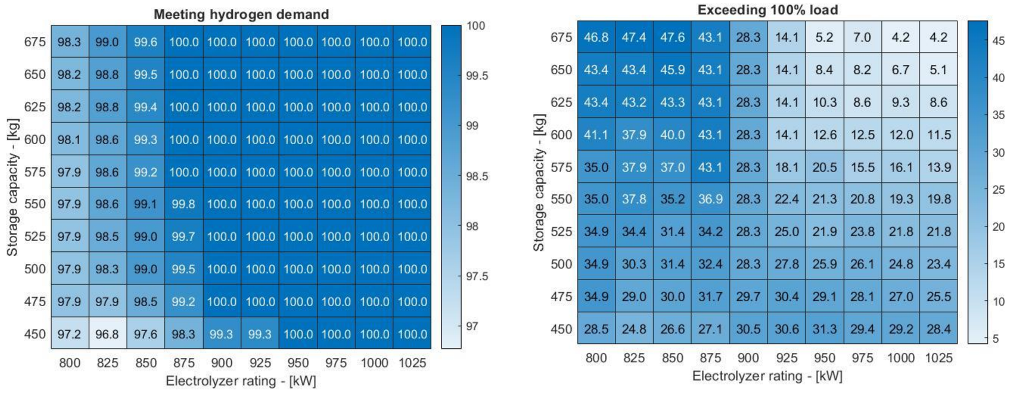
Appendix Figure C-4. Case 4 - Unconstrained



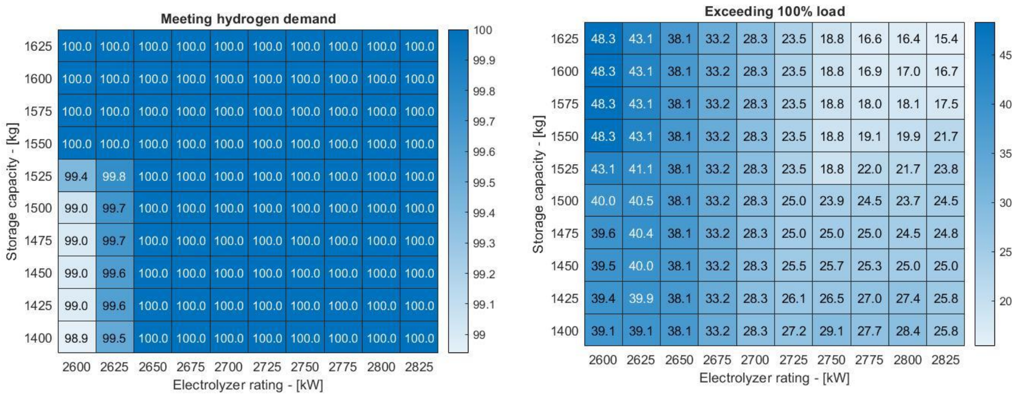
Appendix Figure C-5. Case 3 - Unconstrained



Appendix Figure C-6. Case 5 - Unconstrained



Appendix Figure C-7. Case 6 - Unconstrained



Appendix Figure C-8. Case 7 - Unconstrained

Appendix D. System consumption & production

Appendix Table D-4. System consumption of water, grid-, and solar electricity. Production of hydrogen and oxygen.

	Water Used [kg]	Electricity Used [kWh]	PV Electricity Used [kWh]	Hydrogen Produced [kg]	Oxygen Produced [kg]
CB-P	569,660	3,229,200	455,480	63,749	505,910
CB-S	1,139,500	6,914,300	455,980	127,514	1,012,000
CB-M	3,418,800	21,663,000	450,900	382,588	3,036,200
CB-L	6,838,800	43,780,000	454,910	765,305	6,073,500
RB-P	675,460	4,005,300	363,780	75,589	599,870
RB-S	1,351,100	8,375,400	363,970	151,201	1,199,900
RB-M	4,054,000	25,857,000	364,780	453,670	3,600,300
CB-P – Constr.	568,490	3,223,000	454,090	63,618	504,870
CB-S – Constr.	1,135,600	6,895,400	449,940	127,083	1,008,500

Appendix E. $LCOH_2$ values

Appendix Table E-5. $LCOH_2$ values for all systems and configurations.

Case:	With revenues	Without revenues
CB-P – Unconstrained	21.7 SEK/kg	54.9 SEK/kg
CB-S – Unconstrained	29.2 SEK/kg	49.5 SEK/kg
CB-M – Unconstrained	34.9 SEK/kg	45.5 SEK/kg
CB-L – Unconstrained	35.3 SEK/kg	43.0 SEK/kg
RB-P – Unconstrained	27.2 SEK/kg	54.2 SEK/kg
RB-S – Unconstrained	32.8 SEK/kg	49.0 SEK/kg
RB-M – Unconstrained	36.2 SEK/kg	44.7 SEK/kg
CB-P – Constrained	25.5 SEK/kg	58.8 SEK/kg
CB-S – Constrained	41.0 SEK/kg	61.3 SEK/kg
CB-M – Constrained	-	-
CB-L – Constrained	-	-

Appendix F. MATLAB-Code (Scenario Select.)

```
%========= BUS SCENARIO =========%
%CITY BUS OR REGIONAL BUS - DICTATES DEMAND AND HEAT USE
choice = input('1-4 for pilot-large CB fleet, 5-7 for pilot-mid RB
fleet\n');
c_choice = input('0 - unconstrained, 1 - constrained\n');
rev_choice = input('1 - include revenue, 0 - exclude revenue\n');

%====== USER VARIABLES =======%

%ELECTROLYZER
e_rating = 600:25:825; %kW

%STORAGE
tank_size = 400:25:625; %kg

%CITY BUS DAILY DISTANCE
dist = 350;
%==============================%

%========= LOAD DATA =========%
%scalable bus demand profile
load('bus_demand_profiles.mat');

if c_choice == 1
    load('el_available.mat');
    el_avail = el_available.available_kWh;
else
    el_avail = zeros(8760,1);
end

%spot market prices - "2019 typical year"
load('C:\Users\marte\Desktop\School\03. Master Thesis\Data\SPOT -
Price Data\SE3_spot2019.mat');

%PPA prices - same year
load('C:\Users\marte\Desktop\School\03. Master
Thesis\Data\PPA_2019.mat');

%Heat Demand - same year (City Bus depot data incomplete for 2019
- use
%2020)
if choice < 5
    load('C:\Users\marte\Desktop\School\03. Master Thesis\Data\FV
- Stadsbuss\FV_SB_2020_W_PRICE.mat');
else
    load('C:\Users\marte\Desktop\School\03. Master Thesis\Data\FV
- Regionbuss\FV_RB_2019_W_Price.mat');
end
FV_demand = FV_Demand; clear FV_Demand

%solar data - JRC Typical Meteorological Year
load('solar_kWp');
```

```
%==============================%

%========= CONSTANTS =========%
if choice < 5
    %average distance city bus
    bus_avg_dist = dist*365; %km/year
else
    %average distance regional bus
    bus_avg_dist = 134000; %km/year
end

%FCEB
%single bus
FCEB_fc_12m = 0.1; %2017. NewBusFuel [p.51], 2018. NREL
(0.085:0.12 kg/km)

%PV PARK - city bus depot
PV_rating = 500; %Default 500 kWp city bus depot

%BUSES
switch choice
    case 1 %CB-P
        demand = bus_demand_profiles.demand_pilot_year;
        no_buses = 5;
        daily_dist = dist;
        no_disp = 1;
    case 2 %CB-S
        demand = bus_demand_profiles.demand_small_year;
        no_buses = 10;
        daily_dist = dist;
        no_disp = 1;
        end
    case 3 %CB-M
        demand = bus_demand_profiles.demand_mid_year;
        no_buses = 30;
        daily_dist = dist;
        no_disp = 2;
    case 4 %CB-L
        demand = bus_demand_profiles.demand_large_year;
        no_buses = 60;
        daily_dist = dist;
        no_disp = 2;
    case 5 %RB-P
        demand = bus_demand_profiles.demand_pilot_year;
        no_buses = 5;
        daily_dist = 415;
        PV_rating = 400; %adjust PV rating
        no_disp = 1;
    case 6 %RB-S
        demand = bus_demand_profiles.demand_small_year;
        no_buses = 10;
        daily_dist = 415;
        PV_rating = 400; %adjust PV rating
        no_disp = 1;
    case 7 %RB-M
        demand = bus_demand_profiles.demand_mid_year;
        no_buses = 30;
        daily_dist = 415;
```

```
        PV_rating = 400; %adjust PV rating
        no_disp = 2;
    end
bus_demand = table(demand);
%==============================%

%======== CALCULATION ========%
%BUS CALCULATION
bus_demand.demand = demand * daily_dist * FCEB_fc_12m;
%SOLAR CALCULATION
PV_prod = PV_rating.*solar_kWp.kWh;
%==============================%

%========= VARIABLES =========%
%ECONOMIC RESULT VARIABLES
LCOH2 = zeros(size(tank_size,2),size(e_rating,2)); TCO = LCOH2;
TCO_per_km = LCOH2; cap_fac = LCOH2;
d_met = LCOH2; pl = LCOH2;
%==============================%

%========= SIMULATE ==========%
for i = 1 : size(tank_size,2)
%     tank_max = tank_size(1,i);
    for j = 1 : size(e_rating,2)
        %simulate plant
        [run_hours , cap_fac(i,j) , kg_h2_yr , o2_prod , h2o_u ,
kWh_el_used , kWh_pv_used , heat_prod , heat_used , d_met(i,j) ,
pl(i,j) , grid_fees] =
simulate_plant(tank_size(1,i),e_rating(1,j),PPA_2019,SE3_spot2019,
PV_prod,bus_demand,FV_demand,el_avail,c_choice);
        %calculate LCOH2a
        [LCOH2(i,j) , cost_table_LCOH2] = CalcLCOH2(grid_fees ,
PPA_2019.PPA ,
kWh_el_used.kWh,tank_size(1,i),kg_h2_yr,heat_used,sum(heat_prod-
heat_used),sum(o2_prod),e_rating(1,j),run_hours,FV_Price.Energy_Pr
ice,h2o_u,no_disp,rev_choice);
        %calculate TCO per bus
        [C_bus,O_M,O_rep,O_fuel] =
CalcTCO(bus_avg_dist,LCOH2(i,j));
    end
end
%==============================%
figure
h1 = heatmap(e_rating,flip(tank_size),flip(LCOH2));
xlabel('Electrolyzer rating - [kW]')
ylabel('Storage capacity - [kg @ 500 bar]')
title('LCOH2 - [SEK/kg]');
h1.CellLabelFormat = '%.1f';
figure
h2 = heatmap(e_rating,flip(tank_size),flip(d_met*100));
xlabel('Electrolyzer rating - [kW]')
ylabel('Storage capacity - [kg]')
title('Meeting hydrogen demand');
h2.CellLabelFormat = '%.1f';
figure
h3 = heatmap(e_rating,flip(tank_size),flip(pl*100));
xlabel('Electrolyzer rating - [kW]')
ylabel('Storage capacity - [kg]')
```

```
title('Exceeding 100% load');
h3.CellLabelFormat = '%.1f';
```

Appendix G. MATLAB-Code (Simulate Plant)

```
function
[run_hours,cap_factor,kg_h2_yr,o2_prod,h2o_used,kWh_el_used,kWh_pv
_used,heat_prod,heat_used,d_met,pl,tot_grid_fees] =
simulate_plant(tank_max,e_rating,PPA,spot,solar_pv,bus_demand,heat
_demand,el_avail,constrained)

%========= VARIABLES =========%
Time = PPA.Time;
kWh = zeros(8760,1);
kWh_el_used = table2timetable(table(Time,kWh));
kWh_pv_used = kWh_el_used;
heat_prod = zeros(8760,1);
heat_used = heat_prod;
o2_prod = zeros(8760,1);
h2o_used = zeros(8760,1);
tank_current = zeros(8760,1);
tank_signal = tank_current;
load = tank_current;

kg_h2_yr = 0;

d_met = ones(8760,1);
record_trigger = zeros(8760,1);
run_hours = 0;

storage_check_frequency = 1;
tank_nominal = 0.8;

%==============================%
for i = 1:8760
    %% update tank
    if i>1
        tank_current(i) = tank_current(i-1);
        tank_signal(i) = tank_signal(i-1);
    else
        tank_current(i) = tank_max * 0.3; % initialize tank volume
    end

    %% Run Electrolyzer - tank is not full?
    if tank_signal(i) >= 0.95*tank_max
        %TANK IS FULL - Do Nothing
    elseif tank_signal(i) >tank_nominal*tank_max%
        %Production is not urgent
        if hour(spot.Time(i)) < 6 || hour(spot.Time(i)) > 22 ||
weekday(spot.Time(i)) >= 6
            % off hours or weekends.

[load(i),tank_current(i),kWh_el_used.kWh(i),kWh_pv_used.kWh(i),hea
t_prod(i),o2_prod(i),h2o_used(i),kg_h2_yr] =
ProduceHydrogen(e_rating,solar_pv(i),tank_current(i),kg_h2_yr,tank
_max,constrained,el_avail(i));
```

```
            record_trigger(i) = 4;
        elseif solar_pv(i) > 0
            % solar is available

[load(i),tank_current(i),kWh_el_used.kWh(i),kWh_pv_used.kWh(i),hea
t_prod(i),o2_prod(i),h2o_used(i),kg_h2_yr] =
ProduceHydrogen(e_rating,solar_pv(i),tank_current(i),kg_h2_yr,tank
_max,constrained,el_avail(i));
            record_trigger(i) = 3;
        end

    elseif tank_signal(i) < tank_nominal*tank_max
        %TANK IS LOW - Produce at any cost
        if tank_signal(i) < 0.3*tank_max
            record_trigger(i) = 1;
        else
            record_trigger(i) = 2;
        end

[load(i),tank_current(i),kWh_el_used.kWh(i),kWh_pv_used.kWh(i),hea
t_prod(i),o2_prod(i),h2o_used(i),kg_h2_yr] =
ProduceHydrogen(e_rating,solar_pv(i),tank_current(i),kg_h2_yr,tank
_max,constrained,el_avail(i));



    end
    %% Refuel Buses?
    if bus_demand.demand(i) > 0 && bus_demand.demand(i) <
tank_current(i)
        tank_current(i) = tank_current(i) - bus_demand.demand(i);
    elseif bus_demand.demand(i) > 0 && bus_demand.demand(i) >=
tank_current(i)
        d_met(i) = 0; %demand was not met
    end
    % NOTE! d_met only accounts for hours where refueling was not
met.
    % Not with hours of empty storage.

    %% Meet heat demand?
    if heat_demand.kWh(i) > 0
        if heat_demand.kWh(i) >= heat_prod(i)
            heat_used(i) = heat_prod(i); % Can use entire heat
production
        else
            heat_used(i) = heat_demand.kWh(i); % Can only use heat
demand
        end
    end

    %% update signal with current tank level according to
frequency set.
    if mod(i,storage_check_frequency) == 0
        tank_signal(i) = tank_current(i);  %critera met - update
signal level
    elseif i > 1
        tank_signal(i) = tank_signal(i-1); %criteria not met -
keep signal level
```

```
    end

    if record_trigger(i) > 0
        run_hours = run_hours+1;
    end

end
%%calculate capacity factor
cap_factor = sum(load)*e_rating/(8760*e_rating);

%% check what the actual electricity cost would have been for the
past year.
el_data = Electricity_Price(spot,kWh_el_used,-1);
tot_grid_fees = el_data.Fixed_grid_fee + el_data.Grid_fee +
el_data.Power_Capacity_Cost + el_data.Other_costs + el_data.Tax;

%Gives a ratio of the hours, in which the demand was met
d_met = mean(d_met);
pl = sum(load(:)>1)/8760;

%calculate SMAs
period = 24; %hours
tank_SMA = SMA(tank_current,period);
load_SMA = SMA(load,period);

subplot(2,1,1)
plot(Time,tank_current)
hold on
plot(Time,tank_SMA,'black')
x = zeros(8760,1);
x(1:8760) = tank_max;
plot(Time,x,'--')
x = 0.95*x;
plot(Time,x,'--')
x(1:8760) = tank_max;
x = 0.8*x;
plot(Time,x,'--')
x(1:8760) = tank_max;
x = 0.3*x;
plot(Time,x,'-- red')
% title('Annual operation of PtG plant')
legend('Tank level','Tank Level (24 hr MA)','Threshold:
100%','Threshold: 95%','Threshold: 80%','Threshold: 30%')
hold off
ylabel('H_2 in storage - [kg]')
xlabel('Time - [hours]')
ylim([-50,tank_max*1.05])

subplot(2,1,2)
bar(Time,load*100);
hold on
plot(Time,load_SMA*100,'black');
ylabel('Loading Factor - [%]')
xlabel('Time - [hours]')
legend('Loading Factor','Loading Factor (24 hr MA)')
end
```

Appendix H. MATLAB-Code (Produce Hydrogen)

```
function [load, tank_current,kWh_el,kWh_pv,heat,o2,h2o,h2_tot] =
ProduceHydrogen(e_rat,solar,tank_current,h2_tot,tank_max,constr,e_
avail)
    %% ===== CONSTANTS ==========================
    el_to_h2 = 55; %kWh/kg h2 %2018. Buttler et al [p.2], 2020.
IRENA [p.66-p.68] 50-83 kWh/kg H2 for BoP in PEM, 50-78 in
Alkaline
    heat_gen = 0.171; %heat production 17.1%. 2020. Janke et al.
    kg_water_per_kg_h2 = 18.015/2.016; %stoichiometric yield.
18.015 kg Water/2.016 kg Hydrogen
    kg_oxygen_per_kg_h2 = 15.999/2.016; %stoichiometric yield. H20
-> H2 + 1/2 O2
    kg_h2 = e_rat/el_to_h2; % hydrogen produced at full operation
    %EMPIRICAL - COMPRESSOR
    kWh_comp = 2.8; %kWh/kg H2 - either LINDE Twin IC/60-L or
LINDE IC P/140 XL
    load_range = [0.05,1.2]; %minimum load factor 5%, max 120%
%constrained or not?
if constr %constrained scenario - focus on available electricity
    avail_load = min(load_range(2),(e_avail+solar)/e_rat);
    if avail_load < load_range(1)
            avail_load = 0;
    end

    if solar >= e_rat*load_range(2) + kWh_comp*kg_h2*load_range(2)
        %% solar is available in excess
            load = load_range(2);
            kWh_pv = e_rat*load + kWh_comp*kg_h2*load;
            kWh_el = 0;
    elseif tank_current < 0.3*tank_max
        %%tank is low, need urgent production
            load = avail_load;
            kWh_pv = solar;
            kWh_el = e_rat*load - solar + kWh_comp*kg_h2*load;
    elseif tank_current < 0.8*tank_max
        %% tank below nominal, attempt nominal production.
            load = min(1,avail_load);
            kWh_pv = solar;
            kWh_el = e_rat*load - solar + kWh_comp*kg_h2*load;
    elseif solar >= e_rat*load_range(1)
        %% solar is available, greater than minimum load factor
and production is not urgent
            load = solar/e_rat;
            kWh_pv = solar;
            kWh_el = kWh_comp*kg_h2*load;
    elseif tank_current <= tank_max - avail_load*kg_h2
            load = avail_load;
            kWh_pv = 0;
            kWh_el = e_rat*load + kWh_comp*kg_h2*load;
    else
        load = 0;
        kWh_pv = 0;
        kWh_el = 0;
    end
```

```
else %unconstrained scenario
    if solar >= e_rat*load_range(2) + kWh_comp*kg_h2*load_range(2)
        %% solar is available in excess
            load = load_range(2);
            kWh_pv = e_rat*load + kWh_comp*kg_h2*load;
            kWh_el = 0;
    elseif tank_current < 0.3*tank_max
        %% tank is low, need urgent production
            load = load_range(2);
            kWh_pv = solar;
            kWh_el = e_rat*load - solar + kWh_comp*kg_h2*load;
    elseif tank_current < 0.8*tank_max
        %% tank below nominal, produce at nominal rating
            load = 1;
            kWh_pv = solar;
            kWh_el = e_rat*load - solar + kWh_comp*kg_h2*load;
    elseif solar/e_rat >= load_range(1)
        %% solar is available, greater than minimum loading factor
and production is not urgent
            load = min(solar/e_rat,load_range(2));
            kWh_pv = e_rat*load;
            kWh_el = kWh_comp*kg_h2*load;
    else
        load = 0;
        kWh_pv = 0;
        kWh_el = 0;
    end
end
%PRODUCE BASED ON LOAD!
    %% fill tank, produce heat, oxygen and h2, consume water
    tank_current = tank_current + kg_h2*load; %update tank
    heat = e_rat*load * heat_gen; %save heat produced
    o2 = kg_h2*load * kg_oxygen_per_kg_h2; %save oxygen produced
    h2o = kg_h2*load * kg_water_per_kg_h2; %save water used
    h2_tot = h2_tot + kg_h2*load; %update hydrogen produced
end
```

Appendix I. MATLAB-Code (Electricity Price)

```
function TT = Electricity_Price(spot_price,kWh,include_tax)
%spot_price is a timetable object that contains price [SEK/MWh],
date and time
%information. kWh is the consumption profile

%adjust spot price from SEK/MWh to SEK/kWh
spot_price.SE3 = spot_price.SE3/1000;

%iterative objects used to discern months
mo_mem1 = month(kWh.Time(1));
mo_mem2 = mo_mem1;

Spot_price = zeros(size(kWh,1),1);
Fixed_grid_fee = Spot_price;
Grid_fee = Spot_price;
Power_Capacity_Cost = Spot_price;
Tax = Spot_price;
Other_costs = Spot_price;
```

```
%======= GRID FEES =======%
%2020 fees (N3T) (VERIFICATION AGAINST INVOICE)
% mo_fixed = 2500; %SEK/Mo
% power_fee_typ = 28; %SEK/kW (peak kW of the month)
% power_fee_peak = 58; %SEK/kW (added cost to power_fee_typ for
NOV-MAR)
% grid_fee_peak = 0.20; %SEK/kWh (fee during peak hours 6-22)
% grid_fee_off = 0.071; %SEK/kWh (fee during off hours 23-5)

%2021 fees (N3T)
% mo_fixed = 2400; %SEK/Mo
% power_fee_typ = 27; %SEK/kW (peak kW of the month)
% power_fee_peak = 55; %SEK/kW (added cost to power_fee_typ for
NOV-MAR)
% grid_fee_peak = 0.189; %SEK/kWh (fee during peak hours 6-22)
% grid_fee_off = 0.066; %SEK/kWh (fee during off hours 23-5)

%2021 fees (N2T)
mo_fixed = 22200; %SEK/Mo
power_fee_typ = 27; %SEK/kW (peak kW of the month)
power_fee_peak = 38; %SEK/kW (added cost to power_fee_typ for NOV-
MAR)
grid_fee_peak = 0.095; %SEK/kWh (fee during peak hours 6-22)
grid_fee_off = 0.05; %SEK/kWh (fee during off hours 23-5)

%======= ELECTRICITY COST =======%
%just an average estimate from invoices
avg_misc = 0.008 + 0.0065 + 0.00101; %SEK/kWh, spot_fee, green
cert, Svk etc.

%======= TAX ========%
tax = 0.356; %SEK/kWh
for i = 1: size(kWh,1)
    if include_tax > 0
        Tax(i) = tax; %kWh{i,1}*tax;
    else
        Tax(i) = 0;
    end
    Other_costs(i) = avg_misc; %kWh{i,1}*(avg_misc);
    Spot_price(i) = spot_price{i,1}; %kWh{i,1}*spot_price{i,1}

    %monthly fees are calculated at the end of each month - this
is my way
    %of keeping track of which month I am in.
    if i < size(kWh,1)
        mo_mem2 = month(kWh.Time(i+1)); %read next month number
    else
        mo_mem2 = mo_mem2 + 1; %at the end of the year, add a
month to read data from 01-dec-201x to 01-jan-(201x+1)
    end

    %grid fee costs are dependent on the time of day.

    if(hour(kWh.Time(i)) >= 6 && hour(kWh.Time(i)) < 22 &&
weekday(kWh.Time(i)) < 6 )
        %peak rates
```

```
        if(month(kWh.Time(i)) <= 3 || month(kWh.Time(i)) >= 11)
            Grid_fee(i) = grid_fee_peak;%kWh{i,1}*(grid_fee_peak);
        else
            Grid_fee(i) = grid_fee_off; %kWh{i,1}*(grid_fee_off);
        end
    else
        %off rates
        Grid_fee(i) = grid_fee_off; %kWh{i,1}*(grid_fee_off);
    end

    %monthly costs
    if(month(kWh.Time(i)) <= 3 || month(kWh.Time(i)) >= 11)
        %winter rates
        if(mo_mem1 ~= mo_mem2)
            %extract last months data
            temp =
kWh(timerange(datetime(year(kWh.Time(1)),mo_mem1,1),datetime(year(
kWh.Time(1)),mo_mem2,1)),:);
            %read total energy used
            energy_used_mo = sum(temp.kWh);
            %find maximum power used (dictates kW/month fee)
            kWp = max(temp.kWh);

            %calculate power fee for winter consumption
            mo_power_fee_payed = kWp*(power_fee_typ +
power_fee_peak);

            %calculate monthly average
            pf_avg = mo_power_fee_payed/energy_used_mo;
            ff_avg = mo_fixed/energy_used_mo;
            %spread monthly average over the hours passed during
the month
            %in question.
            for j = 0 : day(kWh.Time(i))*24 - 1
                Power_Capacity_Cost(i-j) = pf_avg;
                Fixed_grid_fee(i-j) = ff_avg;
            end
            if mo_mem2<13
                mo_mem1 = mo_mem2;
            end
        end
    else
        %summer time
        if(mo_mem1 ~= mo_mem2)
            temp =
kWh(timerange(datetime(year(kWh.Time(1)),mo_mem1,1),datetime(year(
kWh.Time(1)),mo_mem2,1)),:);
            energy_used_mo = sum(temp.kWh);
            kWp = max(temp.kWh);

            mo_power_fee_payed = kWp*(power_fee_typ);

            pf_avg = mo_power_fee_payed/energy_used_mo;
            ff_avg = mo_fixed/energy_used_mo;

            for j = 0:day(kWh.Time(i))*24 - 1
                Power_Capacity_Cost(i-j) = pf_avg;
                Fixed_grid_fee(i-j) = ff_avg;
```

```
            end
            if mo_mem2<13
                mo_mem1 = mo_mem2;
            end
        end
    end
end
%return timetable
Time = spot_price.Time;
T =
table(Time,Spot_price,Fixed_grid_fee,Grid_fee,Power_Capacity_Cost,
Other_costs,Tax);
TT = table2timetable(T);
end
```

SLU
Institutionen för energi och teknik
Box 7032
750 07 UPPSALA
Tel. 018-67 10 00
pdf.fil: www.slu.se/energiochteknik

SLU
Department of Energy and Technology
P. O. Box 7032
SE-750 07 UPPSALA
SWEDEN
Phone +46 18 671000