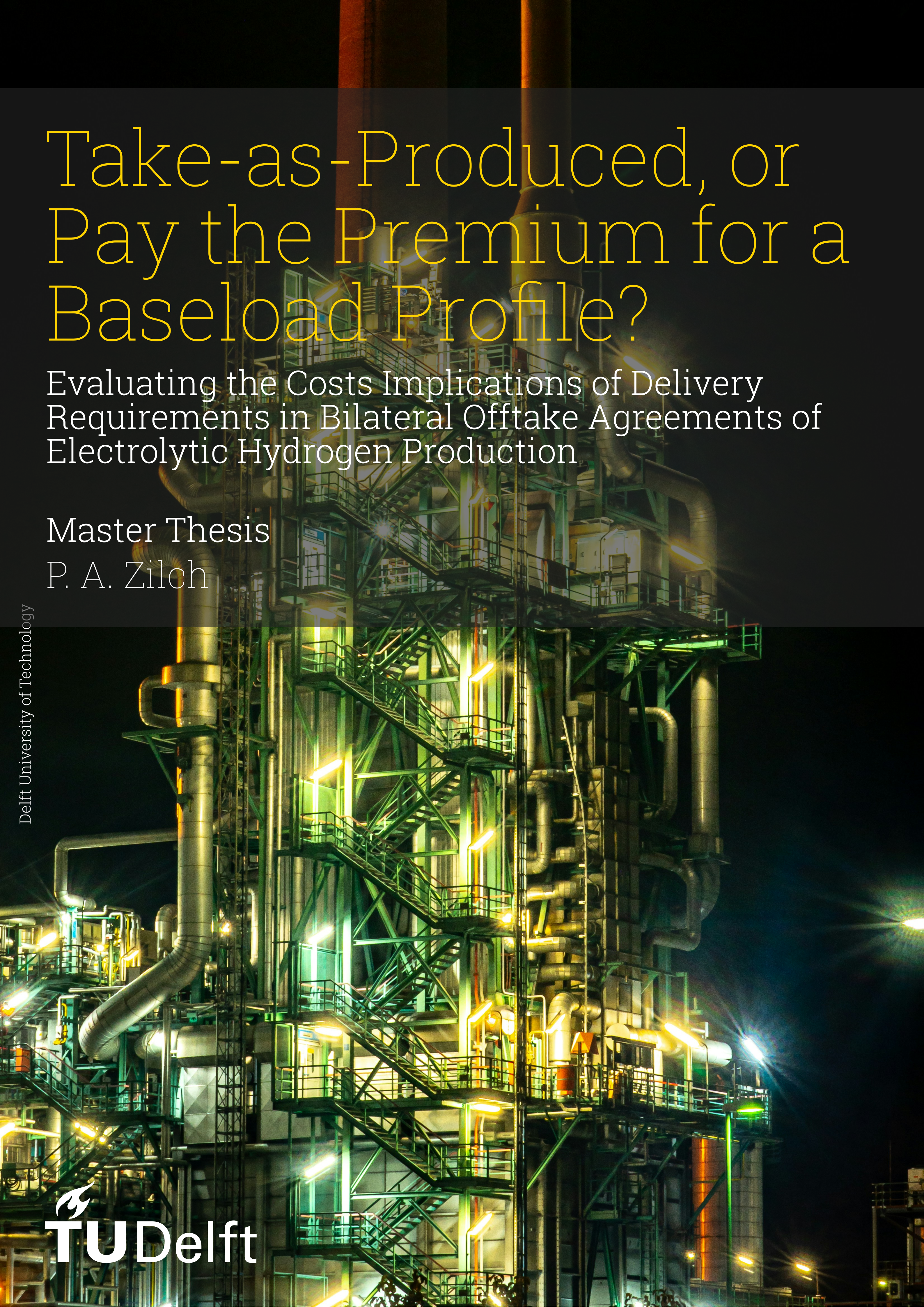

Take-as-Produced, or Pay the Premium for a Baseload Profile?

Evaluating the Costs Implications of Delivery Requirements in Bilateral Offtake Agreements of Electrolytic Hydrogen Production

Master Thesis

P. A. Zilch

Delft University of Technology

Take-as-Produced, or Pay the Premium for a Baseload Profile?

Evaluating the Costs Implications of Delivery Requirements in Bilateral Offtake Agreements of Electrolytic Hydrogen Production

by

P. A. Zilch

to obtain the degree of Master of Science
in Complex Systems Engineering and Management
at the Delft University of Technology,

Student number:	4881168	
Project duration:	February 12, 2024 – November 21, 2024	
Thesis committee:	Dr. A. F. Correljé,	TU Delft, Chair
	Dr. ir. K. Bruninx,	TU Delft, First supervisor
External advisors:	L. S. F. Frowijn,	TU Delft, External advisor
	R. Hilkes,	Eneco, External advisor

Cover: brown and black factory during night time by Patrick Schätz via unsplash.com

TU Delft

Acknowledgements

I would like to express my sincere gratitude to Aad Correljé, for being the chair of my research committee and helping me successfully complete this project.

I would like to express my deepest gratitude to Kenneth Bruninx, for providing me with the optimisation backbone, providing me with valuable feedback and pointing me towards insightful literature.

I'm extremely grateful to my external advisor Laurens Frowijn, for the practical feedback but most of all for the unconditional enthusiasm during our recurring meetings.

I'm deeply indebted to my external advisor, Ron Hilkes. Completing my graduation internship at Eneco Energy Trade has been an outstanding learning opportunity, and your guidance has been invaluable throughout this journey.

Disclaimer *The views expressed in this thesis are solely those of the author and do not necessarily reflect the views of Eneco. Eneco's involvement was limited to providing facilitative support and serving as a source of inspiration. The company did not influence the content, analysis, or findings presented in this work.*

AI Disclosure *During the preparation of this work the author used ChatGPT and Grammarly in order to check the grammar and improve the readability. After using these tools, the author reviewed and edited the content as needed and therefore takes full responsibility for the content of the publication.*

P. A. Zilch
Delft, November 2024

Abstract

The absence of a liquid market for renewable hydrogen causes uncertainty in the revenue stream for early water electrolysis facilities in the Netherlands, and a highly volatile day ahead market causes uncertainty in production costs.

The EU is promoting renewable hydrogen projects to engage in bilateral contracts to mitigate these uncertainties. Hydrogen Purchase Agreements (HPA) can be used to secure an offtaker and a price, reducing demand- and price uncertainty. While a Power Purchase Agreement (PPA) secures a renewable power supply and mitigates price uncertainty, the inherent volume uncertainty of renewable energy sources (RES) remains a significant challenge.

This challenge is exacerbated by the requirement of most offtakers to be supplied with a consistent baseload volume. The hydrogen producer is thus tasked with creating a a consistent supply of hydrogen out of an intermittent supply of renewable power, and takes on the volume risk of renewable power. It is not yet clear how this and other offtake requirements affect the production cost of hydrogen.

The main question of this thesis was: *"How are the hydrogen production costs under a long-term hydrogen purchase agreement, affected by the offtake volume, offtake profile, the availability of hydrogen storage and the type and size of the RES portfolio?"*

This thesis utilises mathematical optimisation to quantify the impact of these offtake requirements on the levelised cost of hydrogen (LCOH). The dispatch of the electrolyser and the operation of the storage is the central decision in the model. Through a case study, the sensibility of the LCOH with respect to the offtake volume, the size of the RES portfolio and the size of the storage is determined.

The results show that the LCOH increases by $11-28\%$ if a baseload profile is required and no hydrogen storage is available. Access to an optimal amount of hydrogen storage reduces the extra costs to $2-8\%$. To achieve the maximum benefit out of hydrogen storage, the outflow capacity should be bigger than the baseload volume, so that the storage can accommodate for the entire demand at times when the power prices are high. Our results also show that with the current investment costs the utilisation factor plays a big role in the final LCOH, with a utilisation factor of 90% leading to the lowest overall LCOH, even though the average power price at this point is much higher than with lower utilisation factors.

Future research could dive into different project ownership structures for electrolyser facilities, and quantify the difference in costs. Or perform a complete risk analysis with Monte Carlo simulations. The addition of a more dynamic market model would also benefit the value of the analysis, or the addition of more markets, like intraday and balancing. Or studies can assess the impact of linepack flexibility service in the hydrogen pipelines on the need for storage.

Contents

List of Figures

List of Tables

Nomenclature

Abbreviations

Abbreviation	Definition
AE	Alkaline Electrolysis
BL	Baseload
CfD	Contract for Difference
CoSEM	Complex Systems Engineering and Management
HPA	Hydrogen Purchase Agreement
LCOE	Levelised Cost Of Electricity
LCOH	Levelised Cost Of Hydrogen
LNG	Liquefied Natural Gas
PEM	Proton Exchange Membrane
PPA	Power Purchase Agreement
RES	Renewable Energy Source
RFNBO	Renewable Fuel of Non-Biological Origin
TAP	Take-As-Produced
SO	Solid Oxide electrolysis

Symbols

Symbol	Definition	Unit
C^{In}	Investment Cost	€
C^{OM}	Operation and Maintenance Cost	€$/y$
C^{P}	Cost of Power	€$/MWh$
C^{TP}	Electricity grid tariff	€$/y$
C^{TH}	Hydrogen network tariff	$/y$
H^{del}	Hydrogen Delivered	kg
H^{dem}	Hydrogen Demand	kg/h
H^{pr}	Hydrogen Production	kg/h
H^{S}	Hydrogen Stored	kg
$H^{S_{in}}$	Hydrogen Inflow Storage	kg/h
I	Number of Scenarios	$-$
P^{co}	Power Consumption Compressor	MW
P^{el}	Power Consumption Electrolyser	MW
P^{grid}	Power from/to Grid	MW
P^{PV}	Power Production Solar PV	MW
P^{RES}	Power Production from Renewable Energy Source	MW
P^{W}	Power Production Wind	MW
Q^{el}	Capacity Electrolyser	MW
Q^{I}	Inflow Capacity of Hydrogen Storage	kg/h
Q^{S}	Capacity of Hydrogen Storage	kg
r	Discount Rate	$\%/y$
T	Number of Time Periods	$-$
Y	Number of Years	$-$
z^{on}	Electrolyser State	$-$
α^{PV}	Capacity Factor Solar PV	$\%$

Symbol	Definition	Unit
α^W	Capacity Factor Wind	$\%$
κ^{co}	Rated Power Consumption Compressor	kWh/kg
κ^{el}	Rated Power Consumption Electrolyser	kWh/kg
λ^{grid}	Price of Power in Day Ahead Market	€$/MWh$
λ^{PV}	Fixed Price for Solar Power	€$/MWh$
λ^W	Fixed Price for Wind Power	€$/MWh$

1 Introduction

1.1. Problem Statement

Hydrogen serves as a versatile energy solution. It can be utilized as a feedstock, a fuel and an energy storage medium. Applications of hydrogen span a variety of sectors including industry, chemicals, mobility and power [1] [2]. In industry, hydrogen will play a vital role in the decarbonisation of processes where direct electrification is not feasible or economically efficient, such as those requiring high temperatures, including steel and cement production. For these high-heat applications, hydrogen has a significant potential to replace natural gas [3]. Hydrogen is an essential chemical agent in the production of ammonia, methanol, polymers, and numerous other compounds and therefore can drive decarbonisation of the chemical and refining industry [3] [2].

In the hydrogen roadmap, the Dutch National Hydrogen Programme [4] sets a target for 2030, to domestically produce $80PJ$ of green hydrogen each year. This translates to $6-8GW$ of water electrolysis capacity. Only a few pilot-size water-electrolysis plants are currently operational. Some commercial-size plants have been announced, but only one company has made the final investment decision [5]. In a study among hydrogen stakeholders and experts, Jesse et al. [6] identify factors contributing to the slow development of the green hydrogen value chain. The absence of a liquid market creates a high investment risk for both the supply and the demand side, as there is uncertainty about the volume and price at which green hydrogen can be purchased or sold. Uncertainty and lack of movement in the market create a mutual dependency dilemma.

One way to reduce risk mutually is to enter into a Hydrogen Purchase Agreement (HPA) [7]. A HPA is a bilateral long-term agreement, which specifies the terms and conditions of a recurring hydrogen sale. The contract concerns the duration of the sale, the quantity and quality of hydrogen to be supplied, pricing mechanisms, delivery schedules, responsibilities of both parties and dispute resolution procedures [8].

Producers and consumers of renewable power have used a similar approach, the Power Purchase Agreement (PPA). The PPA proves to be a successful tool to mitigate risk on both the demand and the supply side [9]. Green Hydrogen Producers, relying on renewable power for their production process, can secure part of their power supply with a PPA to reduce the price risk of volatile energy prices, and part of their demand with an HPA, to reduce demand- and price risk [8].

An HPA is not only beneficial for a green hydrogen producer but also for an offtaker of green hydrogen. Most offtaker of green hydrogen will have processes that ideally run around the clock, for instance, caused by technical constraints or high capital investment requiring a high number of operational hours to be competitive [10]. An HPA can reduce exposure to uncertain market prices, and a baseload HPA can reduce the exposure to the availability of green hydrogen, as this will be transferred to the offtaker. Green hydrogen producers who can supply a baseload HPA will gain a competitive advantage and will be able to ask a premium for this transfer of risk [11].

An essential difference between power and hydrogen is that the former comes in the form of electrons, whereas the latter consists of molecules. Storing electrons is more complex than storing molecules, for long-term storage applications, this means lower energy losses and lower levelised storage costs. The fact that hydrogen is easy to store creates an arbitrage opportunity for green hydrogen producers. They can produce hydrogen when power costs are low and fill up hydrogen storage. When power costs are high, stored hydrogen can be sold at a higher price when demand is high. It creates a similar opportunity for hydrogen producers under a fixed hydrogen offtake agreement.

It is therefore interesting for green hydrogen producers to look into ways of creating a baseload profile, and understand the extra costs incurred in doing so. An oversized and diversified power portfolio can help to create a more reliable input [12]. Hydrogen storage can spread out the production. Another option would be to purchase additional green hydrogen from a third party. These alternatives are not equally available for every hydrogen producer and depend on the location of the project, the infrastructure available and the level of maturity of the greater hydrogen value chain. The availability of a third party to purchase hydrogen, for instance, requires a highly liquid hydrogen market, which will probably not be available in the near future [8]. Both producers and consumers of green hydrogen, as early adopters, will likely rely on hydrogen purchase agreements to finance the development of their projects.

Despite extensive research on the techno-economic optimisation of water-electrolysis technologies, there remains a significant lack of understanding of the financial risks associated with producing and selling green hydrogen, arising from a lack of real-world experience.

1.2. Research Questions

This thesis aims to shed light on the cost implications of clauses in long-term agreements of green hydrogen production. The main research question is: *”How are the hydrogen production costs under a long-term hydrogen purchase agreement, affected by the offtake volume, offtake profile, the availability of hydrogen storage and the type and size of the RES portfolio?”*

The main research question introduces the aspects relevant to determining the cost elements of a hydrogen purchase agreement from the perspective of an electrolyser. The sub-questions elaborate on the individual topics.

i. *”What is the difference in cost of providing different hydrogen offtake profiles in a fixed-price hydrogen purchase agreement?”*
ii. *”How does the capacity of solar PV and onshore wind contracted in a power purchase agreement influence the cost of hydrogen production?”*
iii. *”How does the offtake volume affect the production cost of hydrogen?”*
iv. *”How much can hydrogen storage contribute to lowering the cost of power for hydrogen production under different hydrogen offtake profiles?”*

Sub-question i dives into the effect of the different offtake profiles, question ii studies the oversizing of RES’, question iii dives into the question how the contracted volume influences the cost, question iv researches the effect of storage on the cost of production.

1.3. Research Approach

The research questions will be addressed by first analysing the state-of-the-art literature relevant to green hydrogen production. Next, a conceptual model is developed that captures the essential characteristics of an electrolyser producing hydrogen for a bilateral offtake agreement, sourcing power from various energy sources. This conceptual model forms the basis for constructing an optimal scheduling problem to minimise the power costs of producing a hydrogen production profile of a given volume, sometimes using hydrogen storage. These power costs are subsequently incorporated into a levelised cost of hydrogen (LCOH) calculation. In a case study, the LCOH for different system configurations is evaluated to analyse the impact of various input parameters on hydrogen production costs.

Previous electrolyser optimisation problems have mostly been executed on a single price scenario [13]. Since the energy system is undergoing fundamental changes, this approach is inappropriate for long-term decision-making, like investment decisions or price agreements [14]. A deterministic optimisation can result in a theoretical optimal strategy for a specific scenario; this strategy might, however, perform poorly in the real world, as external factors like the realised power prices or renewable power generation can deviate from the forecasted or expected values. Decision-making can be better supported by insights from modelling on a range of price scenarios [14]. This study, therefore, performs optimisation over a set of day-ahead spot prices for electricity and renewable power generation forecasts. The objective of the optimisation is to minimise the cost of hydrogen production in an uncertain power market, focusing on inter-annual variations in RES power production and resulting power prices. A case study will uncover the impact of various HPA clauses on the levelised cost of hydrogen at which the producer can fulfil these requirements.

The advantage of an optimisation approach is that it allows for narrowing down a complex problem into a more comprehensible set of variables and relationships, represented by mathematical formulation. By studying the behaviour within the model, insights can be gained for decision-making in the real world. A well-constructed model maps the relevant features while neglecting less important aspects, to achieve a set of objectives [15]. These include providing deeper insights into the problem while optimizing specific objectives achieving cost-effective experimentation and promoting the careful use of resources. Furthermore, models serve as a valuable tool for hypothesis testing and scenario analysis, allowing decision-makers to explore various strategies and their potential outcomes. This approach not only enhances understanding but also supports the development of robust strategies in complex systems like the green hydrogen market.

There are, however, also drawbacks of these types of studies. The first is that the results are often highly impacted by the data selection procedure and the data quality [16]. Even if a large data set is used, the model will never be able to predict the future. This is why a set of scenarios is used, and a probabilistic approach is valuable. By considering a range of scenarios, it is possible to construct a probability space and improve the depth of analysis of the economics of electrolysers in the future energy system.

1.4. Structure of Thesis

Chapter 2 provides a comprehensive review of existing literature relevant to hydrogen production, infrastructure, and energy markets, discussing previous studies and identifying a research gap that this thesis aims to address. Chapter 3 elaborates on the conceptualization of the model, the mathematical formulation of the optimization problem, and the implementation of the model, including details on model validation, verification and the setup of the case study. Chapter 4 presents the findings from the model simulations, offering a detailed analysis of the cost implications of different hydrogen offtake profiles and the impact of hydrogen storage on production costs. Chapter 5 interprets the results in the context of the broader literature, discussing the implications of the findings for hydrogen production while identifying limitations and areas for future research. Chapter 6 summarizes the key findings of the research and answers the research question. Chapter 7 reflects back on the process of completing this thesis.

2 Literature Review

This section summarizes the core concepts from the academic literature. Several business reports and government documents are included to extend the analysis. Section 2.1 explores the different pathways for hydrogen production and specifies the common technologies for water-electrolysis. Section 2.2 elaborates on how hydrogen can be transported and stored and touches upon the Dutch hydrogen infrastructure. Section 2.3 introduces the concept of an ideal market, and explains the development of previous energy markets to draw conclusions for the formation of a hydrogen market. Section 2.4 introduces the long-term contract as an institution to facilitate transactions in absence of a liquid market. Section 2.5 dives into the design of long-term contracts for power. Section 2.6 explains different structures for pricing of a long-term power purchase agreement. Section 2.7 touches upon the current subsidies that the EU and the US have in place to stimulate development of green hydrogen facilities. Section 2.8 explains the regulatory landscape in the EU that governs the production and certification of green hydrogen. Section 2.9 dives into the production of hydrogen. Section 2.10 explains some of the techno-economic modelling approaches for renewable hydrogen. Section 2.11 summarizes the knowledge gap in the literature.

2.1. Hydrogen Production

Hydrogen plays a major role in our energy system, and its importance is expected to grow as the world transitions to a decarbonized energy future [17]. Current large-scale hydrogen production methods rely on fossil fuels as feedstock, resulting in significant carbon dioxide emissions and contributing to global warming [18].

Numerous low-carbon hydrogen production pathways exist. Figure 2.1 gives an overview of the production paths for hydrogen [19]. The choice of the appropriate production method requires to choose between environmental, economical and technical considerations [18]. Because of the recent large-scale implementation of renewable energy sources the interest in water electrolysis has particularly increased [20], this is further exacerbated by the system integration options offered [18]. Water electrolysis is the process by which electrical energy is used to split water into hydrogen and oxygen. When using renewable power, hydrogen can be produced without the emission of greenhouse gasses [3]. Water-electrolysis is still expensive compared to its fossil-based alternatives, as the technology matures cost reductions are expected to increase the competitiveness [21].

Alkaline electrolysis (AE), proton exchange membrane (PEM) electrolysis, and solid oxide (SO) electrolysis are the most mature technologies used for water-electrolysis. Figure 2.2 displays the chemical reactions of AE, SO and PEM. The technologies differ in the material of the cathode, anode and electrode. Each process has specific advantages and disadvantages, making them suitable for different applications. Table 2.1 summarizes the key differences. The main benefit of AE is the high level of maturity. Drawbacks are low efficiency and longer start-up times which reduce the operational flexibility [22]. For applications that do require a flexible operation or high purity of hydrogen, PEM is preferred, as it produces hydrogen with the highest purity and is easier and safer to ramp up and down, and

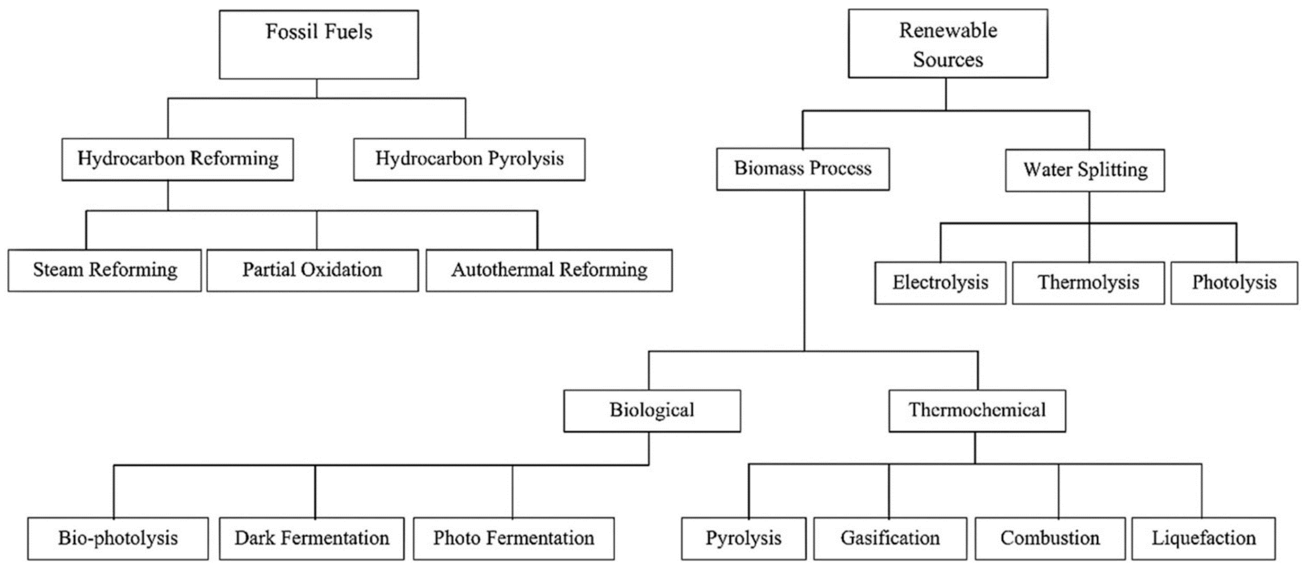

Figure 2.1: Hydrogen production pathways categorised by their origin and the type of production process [17]

has the lowest minimum partial load [3]. A drawback of PEM compared to AE is that the capital and operational cost are higher and the lifetime of the stack is shorter [3]. Significant improvements in CAPEX and OPEX of PEM are expected as the technology further matures [23]. The highest efficiency is achieved by SO however currently this technology is limited by a rapid stack degradation rate and a low level of technology readiness [22]. Both PEM and AE are low-temperature processes and SO is a high-temperature process [24], if residual heat is available the high temperature process can lead to higher efficiencies.

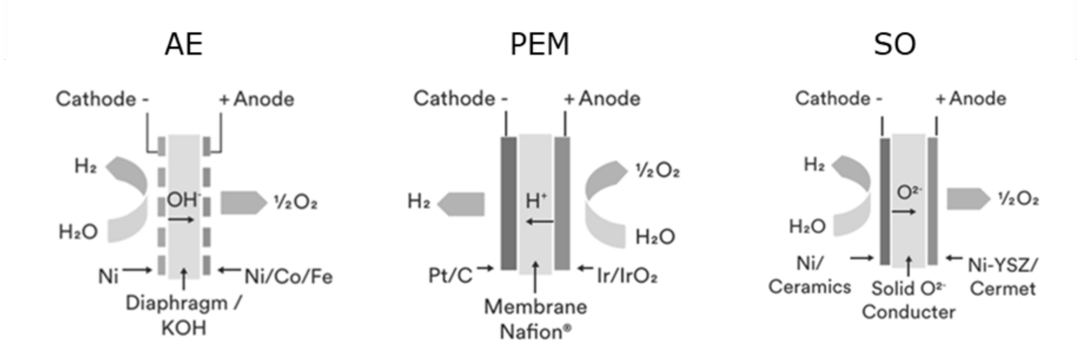

Figure 2.2: Schematic representation of chemistry behind different water-electrolysis technologies, adapted from [22]

Table 2.1: Simplified water-electrolysis technology comparison between alkaline electrolysis (AE), proton exchange membrane electrolysis (PEM) and solix-oxide electrolysis (SO). [25] [22] [21]

Technology	Efficiency [%]	CAPEX	OPEX	Lifetime	Flexibility	Purity	Maturity
AE	$70-80$	Low	Low	Long	Low	Low	GW
PEM	$80-90$	Medium	Medium	Medium	High	High	MW
SO	$90-100$	High	High	Short	Low	Medium	kW

2.2. Hydrogen Infrastructure

Hydrogen is mostly transported as a gas or liquid by truck, ship or pipeline or as ammonia [26]. Hydrogen transport faces challenges arising from the low volumetric density [27]. Nevertheless, hydrogen is anticipated to be transported over great distances, as the optimal conditions for green hydrogen production are in regions with abundant renewable energy which are currently far away from the consumption centres [26].

In the Netherlands, hydrogen will primarily be transported compressed via a pipeline network, which will consist of retrofitted natural gas pipelines along with dedicated hydrogen pipelines [28]. The Dutch hydrogen network will be operated by HyNetwork, a subsidiary of GasUnie, the natural gas network owner and operator. By 2030, HyNetwork is planning to have connected the major industrial clusters in the Netherlands with the caverns of HyStock and interconnection capacity with neighbouring countries of Belgium and Germany [28]. Figure 2.3 displays the plans for the (inter)national hydrogen pipeline and shipping network. One benefit of transport by pipeline is that it offers inherent flexibility in the system through variation in the volume of gas in the network, referred to as linepack. HyNetwork has already reported it will also offer this pipeline flexibility service for their network, however as the size and price of flexibility allowances are still unknown and depend on the system size, this flexibility service is not considered in this thesis [29].

Hydrogen storage will become an important infrastructure [30], as hydrogen production from water electrolysis will likely be intermittent [31]. Hydrogen can be stored in several ways, for instance, compressed, liquefied, as a metal hybrid or as a chemical hybrid [32]. Liquefied and compressed storage are the technologies that are most ready to be deployed [32] [30]. Underground hydrogen storage is found to be more economical compared to above-ground alternatives [33]. Underground storage also requires less land surface area, which is a scarce resource in the Netherlands. Underground salt caverns is the most mature form of underground hydrogen storage [10].

The Netherlands has favourable conditions for storage in salt caverns [30]. HyStock, the Dutch national hydrogen storage operator, is developing 4 underground salt caverns with a storage capacity of $216GWh$ each [34]. The first of these storages is to become operational in 2028, and the auction for capacity will take place at the end of 2024 [34]. The large size and low cost compared to other types of storage make it an interesting opportunity for green hydrogen actors. In the auction, bidders are asked to what they are willing to pay for hydrogen storage. The highest bids will be awarded with bundles of storage. Each bundle consists of a storage capacity of $1000MWh$ of storage and $3.3MW$ storage injection capacity [34].

2.3. Energy Markets

This section will draw lessons from the development of energy markets for natural gas and power which can be relevant for the development of a green hydrogen market.

The distinction between natural gas and power markets is significant due to inherent differences in their physical properties and storage capabilities. Power generation and consumption must be matched in real time as it is a flow of electrons. This real-time consumption requirement is a fundamental characteristic of the electricity market, leading to intra-day price fluctuations and the necessity for a balancing market to manage supply and demand continuously [35]. In contrast, natural gas consists of physical molecules. These molecules are more easily stored and transported. The natural gas pipeline system can accommodate fluctuations in pressure [36], which introduces a degree of flexibility that is absent in the electricity market. The fact that natural gas can be more easily stored and transported also makes it more of a global commodity, especially since the rise of liquified natural gas (LNG) [37]. This is also reflected in a different price variability, where natural gas is more affected by seasonal and long-term supply developments [38]. The hydrogen price will be affected by price shifts in both natural gas and power prices since both are cost drivers for the production methods of hydrogen [39].

R. Coase describes an ideal market as one that connects many producers to consumers, enabling fair competition in a market with low transaction costs. The European Commission highlights the need for a liquid hydrogen market in their hydrogen strategy, as this ensures that investment decisions are based on price signals [1]. Unfortunately, there are not that many suppliers of green hydrogen nor are there consumers that are willing to pay the premium of green hydrogen [6]. High investment costs involved

Figure 2.3: Planned hydrogen pipeline network and envisioned demand and import centre. Translation of Dutch text: hydrogen network 2030 and beyond [28].

in building an electrolyser facility ensure no rational agent would construct a large production facility without securing an offtaker, as this would leave them exposed to a high volume and price risk, similar to investments in natural gas described by Klein et al. [40]. Since there are only a limited number of counterparties willing to purchase hydrogen, they would be exposed to opportunistic behaviour [41]. Based on the pace of development from the LNG and the renewable power sector, Craen et al. [8] estimate that it could take another two decades before hydrogen becomes a globally traded commodity, although regional markets might develop a bit sooner.

2.4. Long-Term Contracts

The literature on institutional economics introduces the long-term contract as a risk-reducing mechanism for transactions that concern high sunk investment costs [40]. The effectiveness of long-term contracts at distributing risks has more recently also been observed in the early development of LNG projects [42]. As the LNG market became more liquid from an increase in demand and supply the need for long-term contracts decreased, as short-term and spot markets trades became more profitable, however the volume under long-term contracts is still significant [43] [44].

PPAs are a form of bilateral long-term contracts in the power sector. PPAs have historically been employed for reducing the risk of investment in conventional generation capacity [45], and are now increasingly gaining in popularity for reducing risk of renewable generation [9]. The high volatility of power markets creates a very uncertain revenue stream [11].

An example of a coal power plant illustrates how a PPA with a utility and a fuel supply contract with a fuel supplier can reduce investment risk. The example is based on insights from [46], [47] and [45]. The price and availability of coal determine the plant's marginal costs, while the power price dictates the plant's revenues. Both the price of coal and the price of power are uncertain making the investment risky. The power plant secures a supply of coal through a take-or-pay agreement with a fuel provider. In a take-or-pay contract, the power plant has to take the delivery of coal or pay a penalty for non-performance. The power plant enters into a power purchase agreement with a utility to produce a certain amount of power, guaranteeing a consistent revenue stream. If the utility fails to offtake the agreed-upon quantity of power, any extra costs incurred from the take-or-pay clause with the fuel supplier can be passed on to the utility. This arrangement mitigates financial risks by securing fuel supply and power offtake, thus

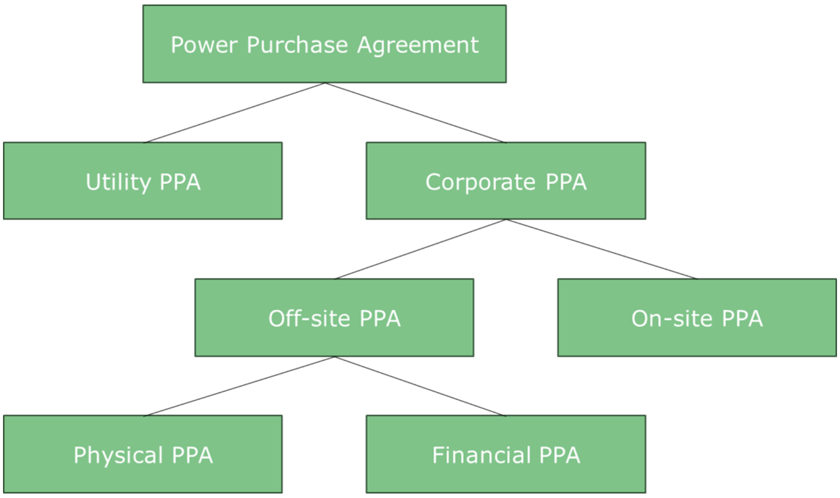

Figure 2.4: Classification of power purchase agreements identified from [11], figure was constructed by the author

stabilising costs and revenues for the power plant.

2.5. Design of Long-Term Contracts

A variety of PPA structures exist. The rest of this analysis will focus on renewable PPAs, as the characteristics of hydrogen production will more resemble the risk profile of renewable power generation [8] and because hydrogen producers are obliged to source their renewable power from renewable energy sources through PPAs. Renewable PPAs are gaining popularity due to their economic benefits and environmental impact [11]. Figure 2.4 shows a number of PPA characteristics introduced by Hollmen et al. [11]. By analysing the contract structures of PPAs, valuable insights can be gained for electrolysers. These insights are pertinent because electrolysers will need to procure their power through either PPAs or dedicated assets [48]. Additionally, their hydrogen purchase agreements are expected to share common features with renewable PPAs [8].

One factor discussed is the location of the producer and consumer. The first category is the on-site, direct wire or behind-the-meter PPA. The power is generated close to the electrolyser, which eliminates the need for a grid connection [49]. Especially in countries where the grid is overloaded making grid connection impossible or costly, this could be an option. The grid connection brings significant capital and operation expenses which should not be overlooked [50]. The second category is the off-site PPAs, which refer to agreements where the renewable power is generated further away from the buyer, necessitating transmission of energy through the grid [49]. Tang et al. [51] find that grid-connected electrolysers can achieve a 50% cost reduction compared to off-grid electrolysers, caused by access to cheap grid power which increases the full load hours. A cross-border PPA is an agreement where the power is generated in one country and consumed in another [11]. Because the geographical correlation requirement generally requires PPAs to be in the same bidding zone as the electrolyser, the cross-border PPA is not further discussed in this thesis.

A factor that also influences the transaction is the project ownership structure and the commercial structure, Craen et al. [8] identify three relevant ownership structures for electrolysers which produce hydrogen, which is exported as ammonia, drawing from lessons of contracting of LNG and offshore wind. The integrated merchant model, the segregated merchant model and the tolling model are discussed. The first two models are merchant models, where the producer acts as the seller of ammonia. In the integrated model, the producer owns the power assets, whereas the power is sourced from a third party through a PPA in the segregated model. In the segregated model, the size of the project is reduced and thus the financing need. It does increase contractual complexity as there is a need for both a PPA and a HPA. The tolling model, also called the energy conversion agreement [52] involves a contractual arrangement where the toller processes raw materials or fuel provided by the buyer and then returns the processed product, typically in exchange for a fee. As the tolling agreement requires flexibility from the offtaker [8], and this research focuses on inflexible offtakers, this model is not further considered.

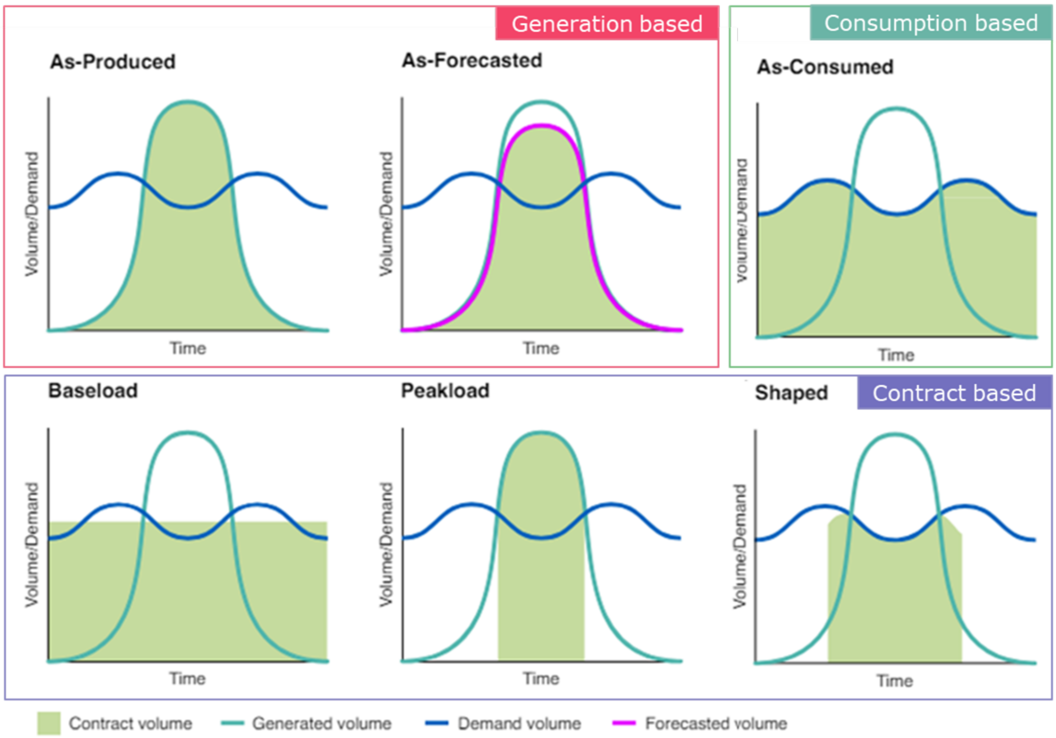

Figure 2.5: Delivery structure of renewable power purchase agreements (PPAs), structures from [54] and categorisation from [55].

Another contract parameter is the choice between a physical or financial PPA. A physical PPA involves the delivery of power from the producer to the consumer, either through a direct line or via the grid. A Financial or Virtual PPA involves both parties buying and selling electricity on the market, with the financial difference between the agreed PPA price and the market price being settled through a Contract for Difference (CfD). The financial PPA is not so common in Europe [53].

The delivery profile is also an important parameter in contract design. Different delivery profiles have been identified in the literature by Mittler et al. [54]. A categorisation from Kowalczyk [55] is used to group the delivery profiles.

The first category is the generation-based profiles: as-produced and as-forecasted. Under the as-produced profile, the purchaser buys electricity as it is generated by the producer. The amount of electricity delivered varies based on the real-time production, which entails that the buyer bears the risk of forecast errors and curtailment [54]. Under the as-forecasted delivery scheme, the producer takes on these risks, as the buyer consumes the forecasted amount of power, and thus can plan its energy consumption pattern accordingly [49]. The second category of delivery profiles is the contract-based profiles: baseload, peak-load and shaped profile. In a baseload PPA, a fixed volume is guaranteed by the seller, which takes responsibility for settling the difference between the generated and the agreed-upon volume. By agreeing to this profile, the seller takes on forecasting, balancing and merchant risk, which is translated into a risk premium. In their study, Moradpoor et al. [12] conclude this is the most economically attractive option for hydrogen production. Contrary to a baseload profile, shaped PPAs require the seller to deliver a predetermined shape. The shape can depend on the generation or the consumption, if the shape is based on the generation the seller risk can be reduced [54]. In a peak load PPA, power is supplied at a discount during hours of high generation [53]. The last category consists of the as-consumed profile, where the profile is consumption-based. In an as-consumed PPA, the buyer pays for the exact amount of electricity consumed at that moment, regardless of the amount of energy generated by the asset. In this contract, all the risk lies with the seller, as there is no pre-defined volume. There is not much information on the as-consumed profile, the current author hypothesizes that it mainly concerns smaller consumers like households.

As risk and pricing are closely related, sellers are often willing to offer a take-as-produced PPA for a significantly lower price, as this secures them with a cash flow and limits their risk. offtakers conversely might be willing to pay significantly more for a baseload profile HPA, as this limits their own risk [11].

A diverse portfolio of power generation can reduce the profile risk of power for the buyer [54]. Diversification can be achieved by engaging in multi-technology and multi-location PPAs. Moradpoor et al. [12] find that a combination of PV and wind on land leads to a significant reduction in hydrogen costs. By engaging in PPAs from multiple technologies the generation variability decreases, which reduces the risk involved in financing the electrolyser, making the project more attractive to investors [51].

2.6. Pricing of long term contracts

There are various pricing structures for PPAs [54]. A fixed price PPA establishes a set rate for power over the duration of the agreement. This provides predictability for both the seller and the buyer, ensuring stable revenue for the producer and predictable costs for the consumer. By eliminating price volatility, fixed price PPAs help in securing financing and reducing financial risk [54]. Stepped-price PPAs involve pre-determined adjustments to the electricity price at specific intervals. These adjustments can be based on factors like inflation or other economic indicators [54]. The price can for instance be adjusted by $2\%/y$ to ensure a fair value in the longer duration contracts. PPAs with a price floor or price cap set minimum or maximum prices for electricity, respectively. It is common that the LCOE for the power source, which can be known to a certain extent in advance, is used to set a price floor [11]. The price floor guarantees a minimum revenue for the producer, protecting them to a market price drop. Conversely, a price cap limits the maximum price, protecting the buyer from excessive costs during periods of high market prices [54]. If both a price floor and price cap are enforced the PPA is called a collar PPA. More complex pricing structures also exist. Due to time constraints, these are not discussed in the rest of this thesis. For more details, the author suggests the seminal work of Mittler et al. on the configurations of PPAs [54]. Craen et al. [8] suggest the fixed price will be mostly used in green hydrogen projects, as indexing against a commodity it is supposed to replace seems inappropriate and would further increase risk.

Hirth et al. [56] introduced the profile costs of renewables. Which became important factors to consider in the valuation of renewable power sources. The profile costs reduce the value of power from a technology, as the time at which the generation is high the prices are comparatively low [57]. The magnitude of profile costs depends on several factors [57]. Firstly, the integration of RES plays a role, with higher percentages of renewable power leading to increased profile costs. The type of RES also matters, as offshore wind profiles are generally flatter than onshore wind profiles, which in turn are flatter than solar PV profiles. Additionally, the correlation between RES generation and load impacts profile costs. Geographical dispersion of renewable power sources can reduce profile costs, as more dispersed sources lead to lower costs. The merit order also influences profile costs, with a steeper merit order amplifying the profile effect. Lastly, the flexibility of the power system, including interconnection, demand response, and storage capabilities, can mitigate profile costs.

In a perfectly liquid market, the price of a PPA should reflect the expected market value [11]. Through continuous trading of futures, the forward market should provide a transparent and predictable value for power, which can be used to set the price of a PPA [11]. If future markets lack sufficient liquidity, pricing of a PPA becomes more complex. The scarcity of long-term price signals necessitates the inclusion of a higher risk margin to account for uncertainty [11]. In reality, the value of a PPA is harder to predict, as futures markets are not perfectly liquid and power prices are highly volatile. Other factors like balancing, profile costs and curtailment are also hard to estimate, as our power system is undergoing fundamental changes. The expected value is thus based on forecasted power curves generated by fundamental energy system models. Companies then adjust this value by considering the offtake profile and pricing structure [58].

2.7. Hydrogen Subsidies

The EU and the US have introduced subsidy schemes promoting hydrogen from water-electrolysis [59] [60]. The rest of this section will briefly describe first the Dutch subsidy scheme called the Opschaling Waterstof Electrolyse 2024 (OWE2024) [61] and then describe the US Inflation Reduction Act [60].

In the Netherlands, the subsidy for hydrogen electrolysis projects is offered through a tender process, where companies compete for available funding. Projects are ranked based on the subsidy amount requested relative to the electrical input capacity of their electrolyser, with a lower subsidy per megawatt of nominal electric capacity increasing the chances of receiving the subsidy. The subsidy covers both the investment costs of the production installation and operational costs for producing hydrogen over a period of 5 to 10 years. CAPEX subsidies can be used for equipment like electrolysers, hydrogen purification systems, cooling equipment, and safety apparatus, as well as for project engineering and development costs and cover up to 80% of the costs. Operational subsidies are provided per kilogram of hydrogen produced, with the amount adjusted based on the cost difference between producing hydrogen using electrolysis and the reference cost of producing hydrogen using a steam methane reforming (SMR) process. If avoided costs (e.g., due to higher gas prices) increase, the subsidy amount decreases, and vice versa. However, no subsidy is granted if the production cost in a calendar year is lower than the established correction amount.

The US Inflation Reduction Act (IRA) of 2022 introduces several clean energy tax credits to boost domestic renewable energy production, including substantial incentives for clean hydrogen and fuel cell technologies. The Advanced Energy Project Credit extends the 30% investment tax credit and allocates $10\ B\$$ for projects that manufacture fuel cell electric vehicles, hydrogen infrastructure, electrolysers, and other products. This credit also supports projects at manufacturing facilities that aim to reduce greenhouse gas emissions by at least 20%. The Clean Hydrogen Production Tax Credit offers a new ten year incentive, providing up to $3.00\ \$/kg$ of clean hydrogen, with the credit amount based on the carbon intensity of the hydrogen production process.

2.8. Green Hydrogen Production Regulation

Hydrogen produced from water-electrolysis only achieves carbon reduction if the power consumed originates from renewable energy sources [26]. To ensure that green hydrogen production contributes positively to the energy transition the European Commission has introduced the Renewable Energy Directive [48] and the supplementing Delegated regulation on Renewable Fuels of Non-Biological Origin (RFNBO) [62]. According to the RFNBO, power consumed for hydrogen production can only be counted as renewable under the following conditions:

Direct connection The electricity is connected via a direct line with a RES (Article 3).

High renewable grid Power consumed from the grid can be counted as renewable when the grid has more than 90% renewable energy (Article 4.1). The percentage of renewable power in the market zone is used to determine the maximum allowed full load hours of an electrolyser. A renewable percentage of 90% corresponds to a maximum of $0.9 * 8,760 = 7,884$ full load hours in a non-leap year.

Low Emission Intensity If the emission intensity in the bidding zone is less than 18 $gCO2eq/MJ$, only temporal and geographical correlation are required, and the additionality requirement does not have to be fulfilled by the renewable PPA (Article 4.2).

Imbalance settlement Electricity consumed for hydrogen production, which reduces the need for downward redispatching of renewable power production during an imbalance settlement, can be counted as fully renewable (Article 4.3).

Other criteria In all other cases, the electricity consumed can only be counted as fully renewable when it meets the criteria of additionality (Article 5), temporal correlation (Article 6), and geographical correlation (Article 7).

- **Additionality** A renewable PPA shall be used for power generation, where the renewable power sources became operational less than 36 months before and have not received prior government support (Article 5). If an electrolyser becomes operational before 2028, it is exempted from this requirement until 2038 (article 11). In this case, a PPA with an existing power plant which has received prior government is allowed.
- **Temporal correlation** Power consumption must occur within the same calendar month as the RES production specified in the renewable PPA (Article 6). Starting in 2030, this requirement will tighten, requiring hourly matching of power production and consumption. The temporal

correlation condition is automatically satisfied if the price in the bidding zone is below 20 €$/MWh$ or 0.36 times the price of a carbon dioxide emission allowance.

Geographical correlation The power must be generated within the same bidding zone as where it is consumed (article 7). Alternatively the power can be generated in a interconnected bidding zone where the power prices are equal or higher than the bidding zone of the electrolyser. Power generated in an interconnected offshore bidding zone can also qualify this requirement.

Hydrogen producers are required to provide detailed information on their power consumption, including a specification of the proportion of renewable electricity and indicate under which article (3, 4.1, 4.2, 4.3, or 4.4) this power is considered fully renewable. Additionally, they must report the total amount of hydrogen produced. This data will be verified and the producers will be awarded RFNBO certificates for their compliant production.

2.9. Cost of Electrolytic Hydrogen

The production cost of hydrogen from electrolysis is still significantly higher than its fossil fuel-based alternative [63]. One measure to compare the costs of hydrogen is the LCOH. The LCOH measures the discounted average cost per unit of hydrogen produced, often expressed in €$/kg$. The LCOH accounts for the costs incurred over the lifecycle of the hydrogen production facility [64]. The LCOH can vary significantly depending on the system boundaries [65]. However, depending on the goal of the calculation, there are different requirements for the calculation methodology rather than right or wrong choices for system boundaries. High-level studies may have a tendency to overlook minor cost drivers in general and to overlook specific costs like taxes or contingency costs [65].

Ali et al. [66] offer a framework for determining the LCOH of hydrogen projects. The CAPEX costs consist of several key components; expenses related to the procurement of raw materials and equipment necessary for the project; costs incurred for the transportation of materials and equipment from suppliers to the project site; Expenses associated with preparing the physical location for the project; expenses of professional engineering services required for design, planning, and project management and finally unforeseen costs that may arise during the project's implementation. The main components of the OPEX include expenses related to the consumption of power and water; regular expenses for maintenance of the equipment and the facility and general expenses necessary for day-to-day operations, such as labour and administrative expenses. Both the CAPEX and OPEX are significantly influenced by the electrolyser parameters, like the energy and water consumption, the efficiency and the degradation rate of the stack. Table 2.1 shows the distribution of cost between CAPEX and OPEX and the differences between AE, PEM and SO. The choice of stack technology is thus not straightforward and it depends on the specific situation and the envisioned way of operation, which in turn is determined by the available power supply. If the power only enables limited full load hours, the high investment costs will weigh heavily on the LCOH.

The estimates for the LCOH from different projects vary greatly. Gül et al. [67] attribute this variability to fluctuations in power prices, differing capacity factors and the application of differing discount rates throughout the literature. They find that the capital investment cost of the RES significantly impact the system costs. Eblé and Weeda find that even with current cost estimates in the Netherlands the capital cost of the electrolyser can deviate greatly, which also significantly influences the LCOH [50].

Matute et al. [68] simulated the LCOH of various electrolyser facilities supplied by a solar pv PPA. Throughout 12 scenarios power makes up between 67.81% and 74.11% of the costs. This underscores the importance of a well-executed power procurement process, to reduce the input cost of power and ensure sufficient operational hours.

In a recent study for the TNO, Eblé and Weeda cooperated with hydrogen stakeholders in the Netherlands to determine the cost components of LCOH of electrolysis in the Netherlands [50]. They conclude that the biggest cost contributions come from investment and power costs. This finding further highlights that the price and availability of clean power is an essential requirement for an electrolyser to compete with other hydrogen producers, as power influences the LCOH both directly through the cost of power, indirectly through the number of full load hours [26] and the certification of the product.

Table 2.2: Summary of previous techno-economical modelling studies of water-electrolysis. over-sizing (OS), cost estimation (CE), stochastic optimisation (SO), Mixed Integer Linear Programming (MILP) Mixed Integer Non-Linear Programming (MINLP), geothermal (GT), natural gas (NG), downstream-flexibility (DSF), take-as-produced (TAP), baseload (BL)

Reference	Model	Objective	Grid	RES	RES Type	OS	Storage	Offtake profile
[12]	CE	Min. Cost	✓/-	on-/off-site	W	-	-	-
[70]	CE	Max. Utilisation	-	on-site	W/PV	✓	-	-
[67]	CE	Min. Cost	✓	on-site	PV	-	✓	-
[71]	CE	Min. Cost	-	on-site	W/PV/GT	-	✓	Mobility and NG Injection
[72]	SO	Min. Cost	-	on-site	W	-	✓	-
[73]	MILP	Max. Revenue	✓	on-site	W	-	-	-
[74]	MILP	Max. Profit	✓	-	-	-	~	Scheduled Tube Trailers
[10]	MILP	Min. Cost	✓	on-site	W/PV	✓	✓	DSF
This work	MINLP	Min. Cost Sensitivity Analysis	✓	off-site	W/PV	✓	✓	TAP, BL

A factor that is often overlooked, which can decrease the LCOH is the availability of large-scale underground hydrogen storage [31] [69]. Storage capacity allows the hydrogen producer to benefit from periods of cheap and abundant power because the hydrogen can be stored and sold later, especially when offering a baseload profile. Just like with renewable power in a PPA, the profile of hydrogen delivery can also heavily influence the costs [69].

2.10. Previous Modelling Approaches to the System

This section concerns the analysis of previous techno-economic modelling of electrolysers. The models were analysed on model type, objective, inclusion of grid connection, location of RES, type of RES, Sizing of the RES compared to the electrolyser, availability of hydrogen storage and whether offtake profiles were considered. Table 2.2 gives an overview of the analysis.

When modelling the costs of hydrogen production, hydrogen offtake is often outside of the scope, which is an influential assumption [69]. For example, Papadopoulos et al. [70] and Fragiacomo et al. [71] both assume that the consumer will consistently offtake the entire hydrogen output, a scenario deemed unrealistic as it entails minimal operational hours and high flexibility, characteristics typically not favoured by industry. Moran et al. [31] also highlight that hydrogen storage is often not considered in techno-economic analyses of hydrogen production costs. They emphasize the need to include temporal storage modelling in the techno-economic modelling of hydrogen supply, given its potential for incurring high costs. They find that with large-scale storage in salt caverns the benefits of storage outweigh the costs, especially when operating a grid-connected electrolyser. This results from a lower curtailment of variable renewable energy that was contracted and the possibility of purchasing more power from the grid when prices are low.

Another important driver for the cost of hydrogen is the capacity of renewable power to procure via long term contracts. Moran et al. [31] suggest to oversize PPA capacity compared to electrolyser capacity. The unutilised power can be sold on the spot market and some curtailment will probably have to be accepted. This strategy increases the full-load hours of an electrolyser. When the electrolyser utilisation is higher, the CAPEX weigh less in the LCOH, meaning that the willingness to accept higher power prices increases [70]. Ali Khan et al. [66] suggest that oversizing can be beneficial even in an on-site PPA configuration, for the same reason of boosting the full load hours and achieving more economical electrolyser operation.

Xiao et al. [73] use MILP to model a wind-electrolytic hydrogen storage system in the electricity and hydrogen markets. They employ a stochastic scenario-based approach which determines an optimal strategy based on the conditional value at risk (CVaR) measure. Their study is of limited applicability for early hydrogen producers since they assume a liquid hydrogen market with a fixed price where there is always an offtaker.

Yu et al. [72] also develop a risk-averse stochastic operational model. They find that with more hydrogen storage capacity the need for oversizing of renewables reduces significantly. The goal of the optimisation however is to maximise the profits on the power market instead of production of hydrogen for the sale of hydrogen.

L. Eble's [10] study focuses on the optimization of electrolyser design, particularly under the constraints of temporal correlation requirements. This research incorporates the consideration of storage to enhance the flexibility and efficiency of hydrogen production systems. A key aspect of the study is the techno-economic analysis of hydrogen production, which emphasizes the importance of matching power production with hydrogen production on an hourly basis. This matching is identified as a critical factor influencing the cost of hydrogen. The study is unique in addressing the temporal correlation requirement, ensuring that hydrogen production is matched with the needs of downstream processes, such as baseload and flexibility demands. By doing so, it aims to optimize the design and operational strategies for electrolysers.

However, the study presents several limitations. It considers only a single price scenario without incorporating some form of electricity price uncertainty. And the single price is only represented by a couple of representative days from one year of power prices. This approach will not capture long-term variability and the inherent uncertainties in renewable power production and power prices.

Baumhof et al [75] study how much detail is needed for electrolyser operation. They find that for investment purposes, less detailed operational models are sufficient. They further conclude that a linear electrolyser efficiency results in an underestimation of hydrogen production and logistical inefficiencies [75]. This highlights that for optimal scheduling problems, the hydrogen production curve of the electrolyser is an important parameter towards revenue maximisation.

2.11. Summary of Knowledge Gap and Research Approach

Hydrogen producers will not soon have access to competitive markets, so they will have to rely on bilateral contracts for the sale of hydrogen. Furthermore though the RFNBO they are obliged to enter into PPAs for their power, which will determine a large part of their cost. To fully leverage the benefits of long-term agreements with both a supplier and an offtaker, hydrogen producers must understand the cost implications of the clauses in the contracts [9].

As the demands of the industry are not covered by the techno-economical studies performed to date, this thesis will model the effects of the offtake profile, offtake volume, and the capacity of RES under contract, while also quantifying the financial benefits of hydrogen storage in balancing the supply of power and demand for hydrogen, ultimately aiming to provide insights into the interplay between the contractual arrangements and the technological configuration.

To achieve this, this thesis will form a stylised operational scheduling model for an electrolyser, for which the constraints can be adjusted. The dispatch of the electrolyser will be based on the power market and the renewable generation. The novelty will lie in that it focusses on the scheduling of the operation based on demand side requirements such as a baseload profile or a certain volume. The operation schedule will then be used to calculate the LCOH. A case study will highlight the sensitivity of the LCOH on the model parameters to shed light on this research gap. The next section will explain in detail how this study will perform this optimisation.

3

Methodology

This chapter outlines the methodology employed in this thesis. Section 3.1 introduces the key elements of the system and defines the scope of the study. Section 3.2 provides a high-level overview of the research approach, setting the stage for the more detailed analyses that follow. Section 3.3 examines the cost minimization process, with the problem being presented in a detailed diagram. Section 3.4 introduces the mathematical formulation of the optimization problem, describing the equations and constraints that govern the model. Section 3.5 provides a detailed explanation of the temporal resolution adopted in the model, which defines the granularity of time intervals used for simulations, and discusses the rationale behind the chosen modelling period. Section 3.6 describes the digital implementation of the optimization problem, including the software and hardware used to solve it.

3.1. System Diagram

Figure 3.1 shows the elements included in the analysis. Central in the system is the electrolyser, which links the power system to the hydrogen system. The electricity grid connects the electrolyser to energy sources, where the dedicated RES portfolio is separated from the day-ahead spot market. The electrolyser has a varying amount of capacity of solar PV and onshore wind contracted, which stays the same throughout the run. The electrolyser can choose to buy or sell power on the spot market. When the electrolyser consumes electricity, it produces hydrogen. All hydrogen is transported via pipeline, either to a storage unit or to the the offtaker. The system captures the essence of two complex networks in a simple diagram. The following section discusses the research approach and elaborates on the parameters and variables used in the optimisation.

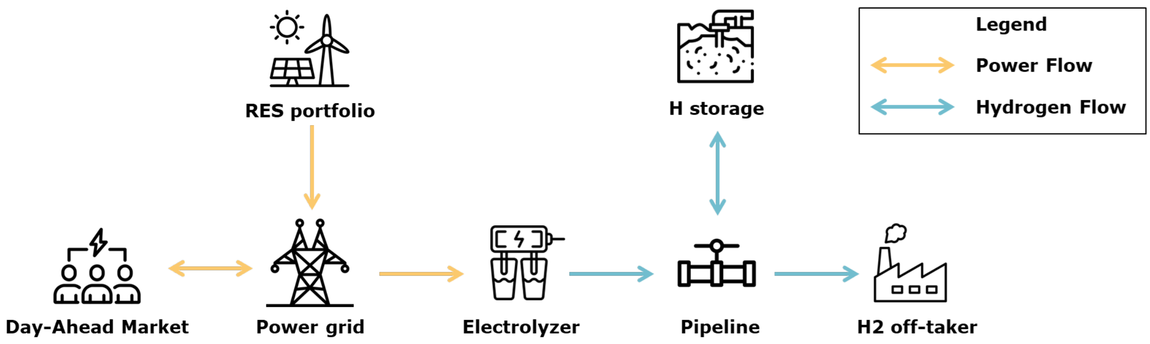

Figure 3.1: Representation of the scope of the system. Icons from [76] [77] [78] [79] [80] [81] [82]

3.2. Research Approach

Figure 3.2 provides a comprehensive overview of the inputs and outputs associated with the optimization. The core objective of the optimisation is to minimize power costs. The inputs are categorized into four groups: day-ahead market price and renewable generation projections, parameters related to the configuration of the Power Purchase Agreement, parameters on the technological configuration, and parameters concerning the volume and profile of hydrogen delivery.

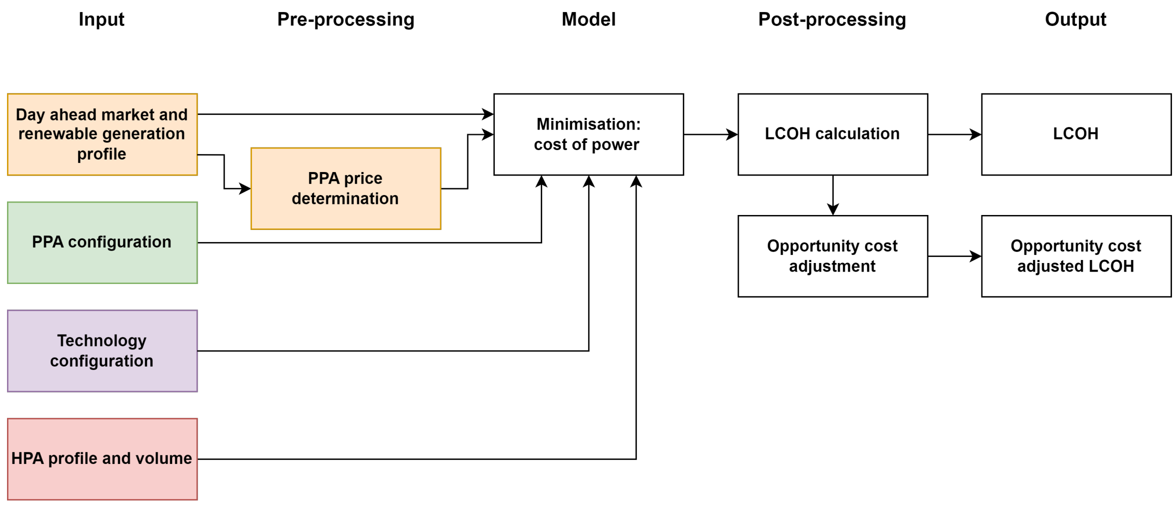

Figure 3.2: Schematic overview of the research approach, colours from input and pre-processing are re-used in Figure 3.3

The price determination for the PPAs from the day-ahead market and renewable generation data is displayed in Figure 3.4 and elaborated in Section 3.3.1. Figure 3.3 gives a more detailed overview of the cost minimisation problem. The colours of the inputs are used to declare from which category of inputs the parameters in Figure 3.3 stem. Section 3.4.6 gives the formula for the LCOH and explains what components are included.

3.3. Diagram Cost Minimisation

Following the structure and the colours of the inputs from Figure 3.1, Figure 3.3 zooms in on the formulation of the cost minimisation. For every renewable energy source, a generation volume for every hour of the simulation is determined by multiplying the capacity factor for every hour with the capacity of the PPA. Together with the day ahead market price and the contract price of the RES, the generation of solar and wind form the starting point of the scheduling problem of the electrolyser, which has the goal to minimise the electricity costs. The scheduling of the electrolyser is further influenced by the configuration of offtake volume and profile of the HPA. The technology configuration consists of the electrolyser parameters on the capacity and the minimum partial load of the electrolyser, as well as the number of storage bundles. The storage size lays out the constraints for the storage operation, which is coupled to the operating schedule of the electrolyser. An optimal solution will give the minimum electricity costs required to produce the HPA. Section 3.4.6 will elaborate further how these costs are used to calculate the LCOH.

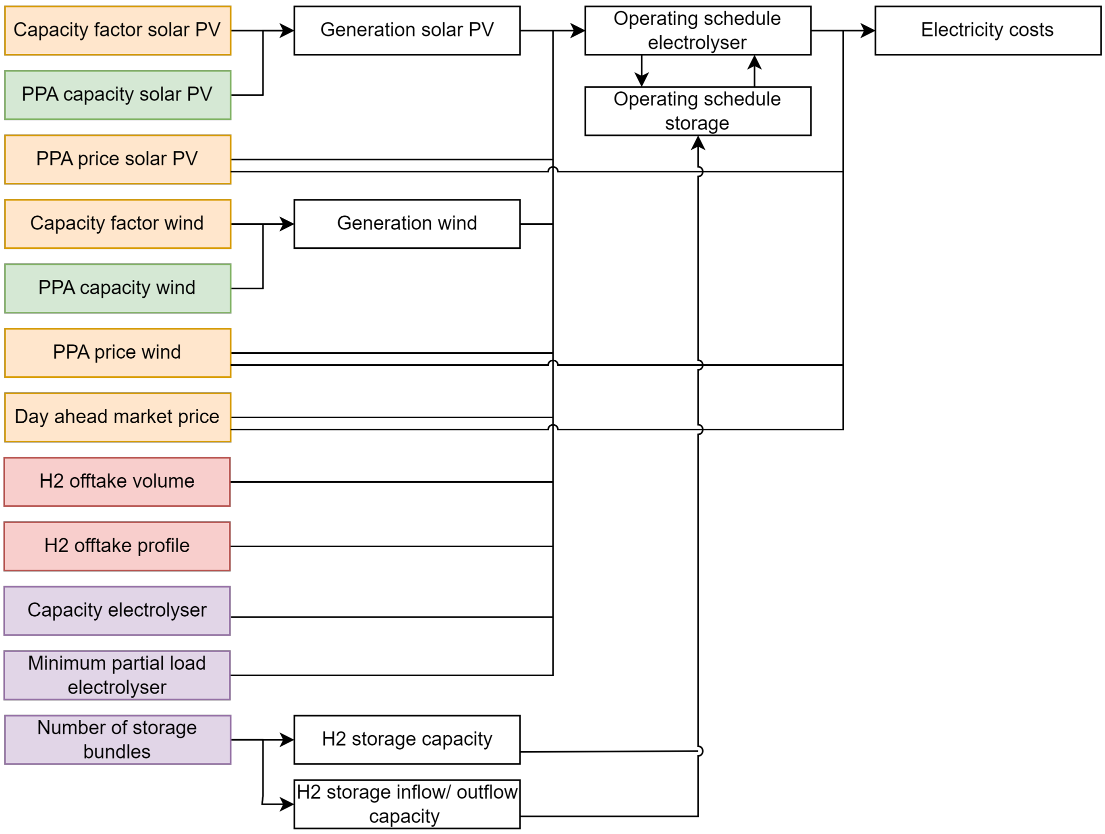

Figure 3.3: Cost minimisation, colours are re-used from Figure 3.2

3.3.1. PPA Price Calculation

A supporting calculation which is performed in advance of the optimisation and the result of which serves as an important input is the price at which the RES are contracted in the PPA. The literature analysis showed that there are many pricing structures for PPAs, however, in this thesis only the fixed price PPA will be considered, as this is the most common pricing structure.

There are two perspectives when looking at the price of a PPA. For the power producer, the PPA should cover at least the LCOE achieved by the power project, but ideally, the PPA price should also include some profit margin. A fixed PPA price above the levelised cost will enable the producer to finance the investment in the project.

For a PPA offtaker, the acceptable price range typically aligns with their valuation of the contract, reflecting either the fair market value or the anticipated capture price of the project. offtakers with carbon emission reduction obligations are often willing to pay a premium for renewable energy, as it mitigates their exposure to carbon markets and ensures access to a predetermined number of carbon credits.

If the LCOE for a project falls below the offtakers willingness to pay, there exists an opportunity for both parties to agree on a mutually acceptable price. Historically, most renewable energy projects could not achieve an LCOE below the anticipated capture price of the project. As governments wanted to achieve their carbon reduction targets, they granted subsidies to facilitate these transactions and enable the realisation of renewable energy projects.

As the RFNBO does not allow the hydrogen producer to offtake power from a renewable power project that has received a subsidy, the renewable power project will have to realise an unsubsidized LCOE below the capture price. As there is much uncertainty as to what the LCOE of renewable power projects are, and as the LCOE can differ between individual projects, this study uses the expected capture price as a metric to define a fair PPA price.

The capture price measures the average revenue per unit of electricity generated, reflecting the market price at the times when renewable power is produced. The day-ahead prices and capacity factors serve as inputs for this calculation. The formula for the capture price is displayed in Equation 3.1. The superscript RES is used here, as the formula to determine the capture price applies to both technologies. The capture price is determined separately for Solar PV and Wind as their capture price differs.

$$\text{Capture Price} = \frac{\sum_{i=1}^{I}\sum_{y=1}^{Y}\sum_{t=1}^{T} P_{i,y,t}^{RES} \cdot \lambda_{i,y,t}^{grid}}{\sum_{i=1}^{I}\sum_{y=1}^{Y}\sum_{t=1}^{T} P_{i,y,t}^{RES}} \tag{3.1}$$

When setting a fixed price for a PPA, one of the parties likely benefits from the fixed price being lower (or higher) than the realised capture price. To model the variability in electrolyser profitability relative to a fixed price PPA, a single PPA price is applied consistently across all scenarios. This approach simulates instances where the electrolyser benefits from the fixed price and others where it incurs a disadvantage. To choose a PPA price that is somewhere in the range of the possible power prices, the average capture price over all scenarios is determined.

Figure 3.4 displays how the average capture price is calculated. Every forecast consists of a generation profile for solar PV and wind and an associated projection of day-ahead spot market prices. The generation forecast and day-ahead price prediction are used to determine the capture price of a renewable source in this scenario. The average capture price over all forecasts is used to set the price at which a RES can be contracted in a PPA. Averaged out over all scenarios, this price will be a fair price for renewable power.

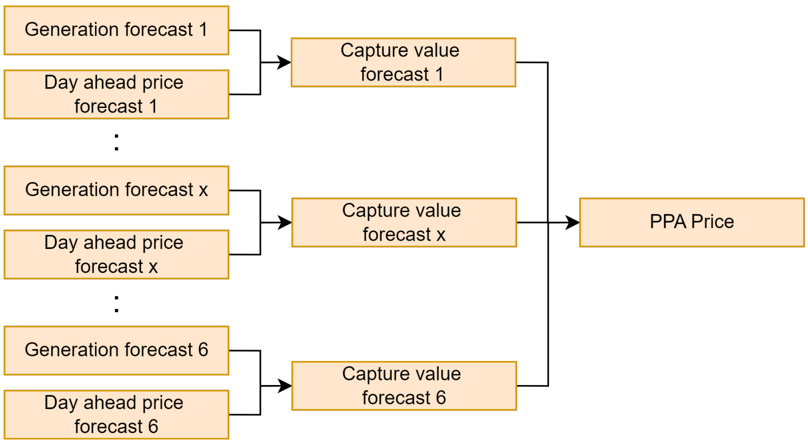

Figure 3.4: PPA price determination, all six forecasts weigh equally in determining the average capture value of a renewable energy source.

3.4. Problem Formulation

The starting point of the formulation is the work of Johnsen et al. [74]. As their problem only included power from the spot market, the model was adapted to include power from dedicated renewable assets via PPAs. The dispatch is solved using mathematical programming. In his book on mathematical programming, Kallrath et al. [15] describe three parts of the problem that need to be identified: The variables, the objectives and the constraints. This structure is used for the further explanation of the problem.

3.4.1. Sets

The model is formulated to utilise different price forecasts and timesteps, which are displayed in the subscript of the variables. The following sets are used:

$$I = \{i_1, i_2, \ldots, i_n\}$$
$$Y = \{y_1, y_2, \ldots, y_{10}\}$$
$$T = \{t_1, t_2, \ldots, t_{8760}\}$$

Where the set (I) represents the different price and generation projections i. The set of years y in the model is represented by (Y) . The timesteps, or hours in a year, are represented by (T).

3.4.2. Variables

Costs are represented by C, where the superscript P stands for power in the form of electricity. Hydrogen is represented by H, where the superscripts del is for delivery of hydrogen, dem for demand of hydrogen, pr for production, s for storage, and S^{in} for an inflow into storage. Variable P stands for electrical power, where the superscripts are co for compressor, el for electrolyser, $grid$ for power going to or coming from the grid, pv for power generation from solar photovoltaics, and W for power generation from onshore wind. The capital Q is used for capacities, where superscript el represents the electrolyser, I is used for inflow capacity, and S represents storage capacity. A small z is used for the operating state, denoted by the superscript on. The Greek letter α is used for capacity factors of renewable energy sources, where PV stands for solar photovoltaics and W represents onshore wind. The Greek letter κ is used for power consumption constants, where co stands for compressor and el represents the electrolyser. The Greek letter λ is used for prices of power, where $grid$ represents the power prices on the spot market, PV represents the PPA price for solar photovoltaics, and W represents the PPA price for wind. The full collection of variables and superscripts is given in Table 3.1.

Variable	Symbol
Costs	C
Power	C^P
Hydrogen	H
Delivery	H^{del}
Demand	H^{dem}
Production	H^{pr}
Storage	H^S
Storage Inflow	$H^{S_{in}}$
Power	P
Compressor	P^{co}
Electrolyser	P^{el}
Grid	P^{grid}
Photovoltaic	P^{pv}
Wind	P^W
Capacities	Q
Electrolyser	Q^{el}
Storage Inflow	Q^I
Storage	Q^S
Binary Variables	z
On/Off Status	z^{on}
Load Factors	α
Photovoltaic	α^{pv}
Wind	α^W
Power Consumption Coefficients	κ
Compressor	κ^{co}
Electrolyser	κ^{el}
Price	λ
Grid	λ^{grid}
Photovoltaic	λ^{pv}
Wind	λ^W

Table 3.1: Variables and Symbols

3.4.3. Objective Function

$$min \sum_{y=1}^{Y} \sum_{t=1}^{T} C^P_{y,t} \tag{3.2}$$

3.4.4. Constraints

$$C^P_{y,t} = \lambda^{grid}_{y,t} \cdot P^{grid}_{y,t} + \lambda^{pv} \cdot P^{PV}_{y,t} + \lambda^W \cdot P^W_{y,t} \qquad \forall y, t \tag{3.3}$$

$$P^W_{y,t} + P^{pv}_{y,t} + P^{grid}_{y,t} = P^{Co}_{y,t} + P^{el}_{y,t} \qquad \forall y, t \tag{3.4}$$

$$P^W_{y,t} = Q^W \cdot \alpha^W_{y,t} \qquad \forall y, t \tag{3.5}$$

$$P^{PV}_{y,t} = Q^{pv} \cdot \alpha^{pv}_{y,t} \qquad \forall y, t \tag{3.6}$$

$$P^{co}_{y,t} = K^{co} \cdot H^{pr}_{y,t} \qquad \forall y, t \tag{3.7}$$

$$H^{pr}_{y,t} = z^{on}_{y,t} \cdot P^{el}_{y,t} \cdot K^{el} \qquad \forall y,t \tag{3.8}$$

$$z^{on}_{y,t} \in \{0,1\} \qquad \forall y,t \tag{3.9}$$

$$P^{co}_{y,t} + P^{el}_{y,t} \leq Q^{el} \qquad \forall y,t \tag{3.10}$$

$$H^{pr}_{y,t} \geq z^{on}_{y,t} \cdot Q^{min} \qquad \forall y,t \tag{3.11}$$

$$H^{pr}_{y,t} = H^{del}_{y,t} + H^{S_{in}}_{y,t} \qquad \forall y,t \tag{3.12}$$

$$H^{S}_{y,t} = H^{S}_{y,t-1} + H^{S_{in}}_{y,t-1} \qquad \forall y,t \tag{3.13}$$

$$H^{S}_{y,t} \in [0, Q^{S}] \qquad \forall y,t \tag{3.14}$$

$$H^{S_{in}}_{y,t} \in [-Q^{I}, Q^{I}] \qquad \forall y,t \tag{3.15}$$

Note that for equation 3.15 there are two equations. For the baseload model, equation 3.15a is used, if the delivery profile is take-as-produced only equation 3.15b is used.

$$H^{del}_{y,t} = H^{dem} \qquad \forall y,t \tag{3.16a}$$

$$\sum_{t=1}^{T} H^{del}_{y,t} = T \cdot H^{dem} \qquad \forall y,t \tag{3.16b}$$

$$P^{W}_{y,t}, P^{pv}_{y,t}, P^{Co}_{y,t}, P^{el}_{y,t}, H^{pr}_{y,t}, H^{del}_{y,t} \geq 0 \qquad \forall y,t \tag{3.17}$$

Equation 3.2 shows the objective of the optimisation problem as a minimisation of power costs. Which is represented by Equation 3.3. The power costs are a function of the costs for the grid, PV and wind respectively. A negative flow from the grid means power is sold on the spot market.

The power balance is given by Equation 3.4. The power coming from the renewable assets plus the power coming from the grid should always equal the power consumed by the electrolyser and the compressor. Equation 3.5 and 3.6 show the power generation from onshore wind and solar PV. The power generated by the RES is determined by the capacity contracted and the availability or capacity factor of the asset at that hour. An availability factor gives the power production as a percentage of peak generation capacity.

Equation 3.7 shows the compressor's power consumption, which is linear with the mass flow rate of hydrogen [75]. K^{co} is the compressor constant, which remains unchanged as long as the inlet and outlet pressure and the inlet temperature stay constant.

Equation 3.8 ensures Hydrogen is only produced when the electrolyser is on. Equation 3.9 ensures the electrolyser is either on or off. When on, the hydrogen production equals the power times the power consumption of the electrolyser in kg/kWh. The power consumption of the electrolyser is constrained by Equation 3.10. The power consumption of the electrolyser can never be more than the rated power. The minimum partial load is enforced by Equation 3.11, ensuring the power consumption of the electrolyser is never below the minimal partial load, except for when it is switched off.

Equation 3.12 enforces the hydrogen balance. The hydrogen that is produced should equal the hydrogen that is delivered plus the hydrogen that is stored. A negative flow into the storage means a hydrogen outflow from the storage.

Equations 3.13, 3.14 and 3.15 enforce the hydrogen storage operation. The hydrogen stored in one timestep equals the amount already stored in the last timestep plus the new hydrogen stored in the last timestep. The level of hydrogen in storage can never exceed the storage capacity and the inflow or outflow can never exceed the inflow capacity of the storage.

Equations 3.16a and 3.16b describe the constraints that determine the hydrogen delivery, for each demand profile a separate problem is created. Equation 3.16a ensures the hydrogen delivery every hour equals the baseload volume in a baseload HPA. Equation 3.16b ensures that in a take-as-produced HPA the yearly amount, which is a multiplication of the hourly demand times the hours in a year, equals the total hydrogen production in that year.

3.4.5. Opportunity Costs

The concept of opportunity cost, as described by J. M. Buchanan [83], highlights the value of the alternative that is not chosen. Instead of entering into an HPA and committing to produce and deliver hydrogen for one offtaker, the company can also select another way to use the contracted renewable power; it can be sold on the day-ahead market. Selling renewable power on the spot market can lead to high profits but it can also lead to high losses. An opportunity scenario is not always better than the chosen scenario, as we will illustrate later in this section.

In the base scenario, the operator produces hydrogen according to the HPA and sources power from the spot market and from a fixed-price PPA. Price differences between the spot price and the PPA price create an opportunity for the electrolyser to earn revenue based on the price difference, if the spot price is higher than the PPA price and the RES generate electricity, the electrolyser can earn a profit on excess power. When the spot price is lower than the PPA price, the electrolyser has to pay more for the renewable energy than it can be sold on the market, leaving the electrolyser with potential losses. By choosing to enter into the HPA, however, the electrolyser has to fulfil specific requirements regarding hydrogen production and, therefore, power consumption. Through these restrictions, they will have less freedom to earn a profit on the power market. In the opportunity scenario, the electrolyser chooses not to restrict themselves to hydrogen production but instead sell renewable power to the market rather than consume it to produce hydrogen. When the electrolyser chooses to produce hydrogen, they forgo potential profits from selling electricity on the spot market. This foregone profit is referred to as the "opportunity cost" of hydrogen production.

In this case, the opportunity cost is the difference between the revenue that could have been earned from selling electricity and the revenue earned from selling hydrogen, an approach also used by L. Eblé [10]. The formula from L. Eblé [10] is adapted to the variables in this study in equation 3.18.

$$C^{adjusted} = (R^{opp} - C^{opp}) - (R - C) \tag{3.18}$$

Where $C^{adjusted}$ is the adjusted costs, R^{opp} is the revenue made in the opportunity scenario and C^{opp} are the costs incurred in the opportunity scenario. R and C represent the revenue and cost in the base scenario. In this work, the revenue earned from the sale of hydrogen is unknown, as the hydrogen price in the HPA remains to be determined. The revenue for the electrolyser thus solely consists of the sale of electricity, which is modelled as negative power costs and is thus already included in C^{opp} and C. This means that R^{opp} and R are redundant and can be removed from the equation. The equation can then be rewritten into Equation 3.19, where the opportunity costs are deducted from the costs of the base scenario.

$$C^{P_{adjusted}} = C^{P} - C^{P_{opp}} \tag{3.19}$$

If the opportunity costs are positive, it means the costs in the opportunity scenario were higher than the revenues in the opportunity scenario. This means some costs would have been incurred irrespective of the choice of the electrolyser to produce hydrogen. Conversely, negative opportunity costs mean revenues exceeded the costs in the opportunity scenario. Thus, some profit would have been made irrespective of the choice to produce or not produce hydrogen.

Numeric Example of Opportunity Costs
In this example, we analyse the opportunity costs for an electrolyser operating under a PPA with a wind farm. The electrolyser must offtake all power generated by the wind farm at the agreed fixed PPA price and is able to buy (or sell) additional (or excess) power in the spot market. This example provides a simplified numerical illustration of the opportunity cost calculations presented in this report.

The PPA price is set at 80 € $/MWh$. Market prices fluctuate throughout the day, with 10 hours priced at 40€ $/MWh$, another 10 hours at 65 € $/MWh$, and the remaining 4 hours at 100 € $/MWh$. The wind farm generates a constant 50 MW of electricity during each hour of the 24-hour day. The electrolyser has a maximum electrical capacity of 100 MW, and has a conversion efficiency from one MWh electricity to one $MWhhydrogen$ of 50%, meaning that half of the energy input power is converted into hydrogen energy. The daily hydrogen production requirement is set at 600 MWh H_2, and the electrolyser is free to deliver any amount of hydrogen every hour as long as the daily amount is met. This implies that the electrolyser must operate at 50% capacity over the 24 hours, as the maximum production in one day would be:

$$24h \cdot 100MWe \cdot 0,5MWh$$

H_2/MWh e = 1,200 MWh H_2 (3.20)

Cost Calculations Base Case
The cost for the electrolyser includes both the obligatory purchase from the wind farm under the PPA and any additional electricity purchases needed to meet the hydrogen production target in the most economical way. This means the electrolyser is producing during the hours that the spot market prices are lowest and selling when the spot prices are highest.

The electrolyser is required to offtake all power generated by the wind farm according to the PPA, which is priced at 80 € $/MWh$. Over the 24 hours, with a constant generation of 50 MW, the total cost of purchasing power from the wind farm is calculated as follows:

$$24h \times 50MW \times 80\text{€}/MWh = 96{,}000\text{€} \tag{3.21}$$

To meet production requirements at lower costs, the electrolyser sources power from the spot market during the 12 hours when prices are lowest. This includes 10 hours at a price of 40 € $/MWh$ and 2 hours at a price of 65 € $/MWh$, leading to the following costs:

$$10h \times 50MW \times 40\text{€}/MWh = 20{,}000\text{€} \tag{3.22}$$

$$2h \times 50MW \times 65\text{€}/MWh = 6{,}500\text{€} \tag{3.23}$$

Summing up the costs from both the wind farm and the spot market yields the total power procurement costs:

$$96{,}000,\text{€} + 20{,}000,\text{€} + 6{,}500,\text{€} = 122{,}500\text{€} \tag{3.24}$$

When the electrolyser is not operating at full capacity for hydrogen production, it sells the surplus power back to the market when the market price is highest. This occurs for 8 hours at a price of 65 € $/MWh$ and for 4 hours at 100 € $/MWh$. Afterwards both revenue streams are added:

$$8h \times 50MW \times 65\text{€}/MWh = 26{,}000\text{€} \tag{3.25}$$

$$4h \times 50MW \times 100\text{€}/MWh = 20{,}000\text{€} \tag{3.26}$$

$$26{,}000\text{€} + 20{,}000\text{€} = 46{,}000\text{€} \tag{3.27}$$

The net costs are calculated by subtracting the revenue from selling excess power from the total power procurement costs:

$$122{,}500\text{€} - 46{,}000\text{€} = 76{,}500\text{€} \tag{3.28}$$

Using the higher heating value of hydrogen, the amount of hydrogen is converted to kg:

$$600MWh$$

H_2 $\cdot 0.03939 kg$ H_2/MWh H_2 = 15,234 kg H_2 (3.29)

The levelised power cost is derived by dividing the net cost by the amount of hydrogen produced:

$$\frac{76{,}500€}{15{,}234, kg} = 5.02, €/kg \tag{3.30}$$

Opportunity Cost Scenario (No Hydrogen Production)
If the electrolyser were to sell all renewable power instead of producing hydrogen, also described as the opportunity scenario, the costs would consist of the obligation to purchase renewable power from the wind farm:

$$24\,h \times 50\,MW \times 80\,€/MWh = 96{,}000€ \tag{3.31}$$

The revenue is made from selling excess power on the spot market:

$$10h \times 50MW \times 40€/MWh = 20{,}000€ \tag{3.32}$$

$$10h \times 50MW \times 65€/MWh = 32{,}500€ \tag{3.33}$$

$$4h \times 50MW \times 100€/MWh = 20{,}000€ \tag{3.34}$$

$$20{,}000€ + 32{,}500€ + 20{,}000€ = 72{,}500€ \tag{3.35}$$

The net costs in case no hydrogen was produced are calculated by subtracting the revenue from the total costs:

$$96{,}000€ - 72{,}500€ = 23{,}500€ \tag{3.36}$$

Adjusted Levelised Cost Calculation
The opportunity cost represents profits or, in this case, losses, that would also have been incurred if no hydrogen was produced. To more accurately determine the production costs they are excluded from the LCOH.

The opportunity costs adjusted total power costs are then:

$$76{,}500€ - 23{,}500€ = 53{,}000€ \tag{3.37}$$

And the opportunity costs adjusted levelised power costs:

$$\frac{53{,}000€}{15{,}234\,kg} = 3.48\,€/kg \tag{3.38}$$

Summary
The example shows how the costs are accounted for in the rest of this thesis. In the base case, all expenses and income from buying and selling power from the day ahead market and the expenses related to the PPA lead to a total levelised power cost of $5.02\,€/kg\ H_2$ produced. If the electrolyser decides not to enter into the HPA nor produce any hydrogen but decides to sell all the renewable power on the spot market, it would in this case lose money on the PPA. This money is already lost as the PPA is already agreed upon. The costs can thus be excluded from the production cost of hydrogen, leaving an adjusted levelised power cost of $3.48\,€/kg$.

In the example discussed above, the PPA price is higher than the market value of the generated power. It is also possible that the PPA price ends up being lower than the market price, which enables the electrolyser to benefit from selling excess power on the spot market. In extreme cases, the electrolyser could earn more revenue from selling renewable power on the spot market than it spends on producing hydrogen. If the opportunity costs are not considered in this case, the levelised power costs can be negative. If the electrolyser had not produced any hydrogen but instead sold the power on the spot market, the profit would have been even higher. By choosing to produce hydrogen, the electrolyser incurs extra costs and reduces profits; thus, the cost of producing hydrogen is not negative but positive, if you consider the opportunity costs.

The opportunity cost adjusted LCOH more accurately represents the costs actually incurred in hydrogen production by considering the scenario where the electrolyser decides not to produce hydrogen, any revenue or expenses that would have occurred irrespective of the hydrogen production are thus left out of the calculation of production cost of hydrogen.

Thus, there are two ways of accounting for the power costs in the LCOH. As both methods can add value to the analysis, both will be used and discussed in the next section.

3.4.6. LCOH Calculation

After the optimal cost of power is determined, it is used to determine the cost in a high-level abstraction of the LCOH, adapted from [84]. The other cost components included in the LCOH calculation are the cost of investment C_y^{In}, a fixed yearly operation and maintenance cost C_y^{OM}, a fixed yearly network tariff for power C_y^{TP} and a fixed yearly network tariff for hydrogen C_y^{TH}. All costs are discounted back to their value in year 1. The costs are then divided over the total hydrogen production, which is also discounted to the first year. The LCOH calculation is displayed in Equation 3.39.

$$\mathsf{LCOH} = \frac{\sum_{y=1}^{Y} \left(\frac{C_y^{\mathsf{In}} + C_y^{\mathsf{OM}} + C_y^{\mathsf{P}} + C_y^{\mathsf{TP}} + C_y^{\mathsf{TH}}}{(1+r)^y} \right)}{\sum_{y=1}^{Y} \left(\frac{H_y}{(1+r)^y} \right)} \tag{3.39}$$

3.5. Temporal Resolution and Modelling Period

The model operates with an hourly resolution, aligning with the granularity used in the day-ahead spot market and the available spot market market data. While intraday and balancing markets can also provide sources of power and income for electrolysers, as highlighted by Johnsen et al. [74], this study focuses exclusively on the spot market. The volumes traded in intraday and balancing markets are often more volatile and unpredictable, and not all electrolysers are suitable for participation in balancing services, as noted by Flis et al. [22].

The model employs a perfect foresight approach, simulating a 10-year period of power prices and production profiles to determine the optimal dispatch strategy under the given circumstances. This approach is informed by the argument presented by Lambert et al. [85], who suggest that when the objective is to simulate the long-term impacts of decisions made before the simulation, it is crucial to have an extensive foresight horizon. They emphasize that longer foresight periods are necessary to capture the lasting consequences of these decisions, while also acknowledging that the computational costs increase with the length of the foresight horizon [85]. The choice of a 10-year optimization period allows the model to capture both seasonal and inter-annual variations, ensuring that it adequately reflects the long-term dynamics that can impact the operation of the electrolyser. This duration aligns with the maximum duration of subsidy from the Dutch subsidy scheme OWE 2024, which supports green hydrogen projects in the Netherlands, and corresponds roughly to the typical operational lifetime of an electrolyser stack, as discussed by Younas et al. [21]. This methodology thus ensures that the model captures the financial impact of the parameters of the hydrogen purchase agreement in combination with the technological configuration.

3.6. Model Implementation

The model was implemented using the Julia programming language within the Microsoft Visual Studio Code environment, a robust and flexible setup that supports advanced coding and debugging functionalities. Julia Mathematical Programming (JuMP) was employed to formulate and operationalize the optimization problem, offering a high-level interface for defining the mathematical structure of the model. JuMP's integration with Julia allows for efficient handling of complex optimization tasks, making it well-suited for the large-scale computations required in this study.

The optimization problem was solved using the Gurobi solver, which is renowned for its performance in solving linear and mixed-integer programming problems. Gurobi's advanced algorithms are specifically designed to handle large datasets and complex constraints, ensuring that the model could be solved both accurately and efficiently. To access Gurobi, a free academic license was obtained, enabling full utilization of its robust features within the scope of this research. The specific version used was Gurobi Optimizer version 11.0.2, build v11.0.2rc0 (win64 - Windows 11.0, build 22621.2).

In this research, specific Gurobi settings were adjusted to optimize the solver's performance and address certain computational issues encountered during the execution of the optimization model. These settings were configured as follows:

The "Method" and "NodeMethod" parameters were set to a value of "2" to address the issue of the solver being stuck at "Waiting for Other Threads to Finish." Setting the Method to 2 configures Gurobi to use the barrier method for solving linear programming (LP) problems, as well as quadratic programming (QP) or quadratically constrained programming (QCP) problems. The "NodeMethod" which specifies the method used to solve MIP node relaxations. Setting NodeMethod to 2 configures Gurobi to use the barrier method for solving these relaxations. This adjustment helped mitigate the bug of the solver being stuck when performing the computations.

The "StartNodeLimit" parameter was set to -2 to mitigate the problem of the solver taking excessive time when processing the mixed-integer programming (MIP) start. This setting limits the number of branch-and-bound nodes explored when completing a partial MIP start. By setting it to -2, the solver is instructed to only check full MIP starts for feasibility and to ignore partial MIP starts, effectively mitigating excessive start-up time and reducing the overall computation time required for this step.

These settings were critical in improving the performance and efficiency of the Gurobi solver, particularly in dealing with specific challenges that arose during the optimization runs.

Computational tasks were carried out on a Windows Surface 3 device equipped with an Intel i7-1065G7 CPU, which operates at $1.30\ GHz$. This processor features 4 physical cores and 8 logical processors, allowing the use of up to 8 threads. Additionally, the device is supported by 16 GB of RAM, which provides sufficient capacity to handle the extensive calculations involved in the optimization tasks.

The Baseload model was optimized with $1,138,809 rows$, $876,000$ columns, and $2,102,397$ nonzeros, including $87,600$ quadratic constraints. The variables in this model consisted of $788,400$ continuous, $87,600$ integer, and $87,600$ binary variables. Similarly, the Take-as-Produced model involved the optimization of $1,051,219$ rows, $876,000$ columns, and $2,102,397$ nonzeros, with the same number of quadratic constraints and variable types.

This hardware configuration provided sufficient processing power and memory to manage the extensive calculations involved in the optimization, including the handling of large datasets and the execution of iterative solution processes over a multi-year simulation period. For a single instantiation, the performance was adequate, with a single solve taking approximately 2 to 3 minutes.

However, as multiple solves were performed consecutively, performance declined significantly. After completing around five solves, the time required per solve increased to 7 minutes, and this time continued to rise exponentially with each additional solve. Given that a couple of hundred solves were necessary, the total running time became substantial. Therefore, it is advisable to plan out experiments meticulously, as careful planning can help manage computational resources effectively and save considerable time when using the model.

3.6.1. Code Availability

The structure of the code for the optimization problem was adapted from a GitHub repository from the supervisor, K. Bruninx. This repository contains a framework for handling inputs via a yaml file and loading in time-series data from a csv, which was customized and expanded upon to suit the specific requirements of this thesis.

To promote transparency and reproducibility, the code developed during this thesis is available upon request. By sharing the code, the research community is encouraged to engage with the work, whether through validation, critique, or further development. This commitment to open access upon request ensures that the methodology and results can be independently verified and that the tools developed can be utilized in future research, fostering collaboration and innovation in the field.

4
Results

This chapter presents the results of the thesis, beginning with a detailed explanation of the methodology used to gather the data in Section 4.1. This is followed by Section 4.2, which justifies the experimental setup of the case study. Section 4.3 then clarifies the processes undertaken to verify and validate the model, ensuring confidence in the results. The analysis proceeds with a comparison of the LCOH for the take-as-produced and baseload offtake profiles under the base case parameters, discussed in Section 4.4. Section 4.5 investigates the effect of the size and type of technology of the PPA on the overall costs. Section 4.6 explores the impact of offtake volume on the LCOH, providing insights into how different volumes influence costs. Finally, Section 4.7 examines the role of the storage size in reducing the power contribution to the LCOH, highlighting the importance of storage in optimizing overall system performance, especially when constructing a baseload profile.

4.1. Data Collection

This chapter details the data collection process undertaken for the analysis, focusing on the parameters and price projections that are used in the optimization model.

4.1.1. Technological Components

As the costs of different component of electrolysers vary widely in the literature and can depend on many factors not included in this thesis, the estimates for cost components of developing and operating an electrolyser in the Netherlands from Eblé & Weeda [50] have been used. The data collection for the cost components of hydrogen production in their study involved a structured approach in collaboration with market parties and the Ministry of Economic Affairs and Climate. Initially, cost determinants were identified and categorized into unit capital cost, operational costs, variable costs, plant performance, and financial parameters. They assigned starting values based on the SDE++, which market parties then adjusted based on current projects. Data was submitted, aggregated, and processed into an anonymized dataset for a $100\ MWe$ electrolysis reference unit.

The investment cost for the electrolyser is set at $3,050,000$ € $/MW$ [50], reflecting the capital expenditure required for the installation of the technology. The ongoing operational and maintenance (OM) costs are estimated at $75,340$ € $/MW/year$ [50], covering routine maintenance and operational activities necessary to ensure the electrolyser's functionality over its lifespan.

Additionally, the model includes the costs associated with grid connection and hydrogen distribution. The electricity grid tariff is set at $143,570$ € $/MW/year$ [50], representing the cost of connecting the electrolyser to the power grid. The hydrogen network tariff, which covers the expenses related to transporting hydrogen through the network, is set at $21,130$ € $/MW/year$ [50].

Furthermore, power consumption values are critical to the model's accuracy. These include the power consumption of the compressor of $0.005\ MWh/kg$ and the electrolyser $0.051\ MWh/kg$, both of which are sourced from Eble and Weeda [50]. These figures are used to calculate the electricity consumption and the associated costs of producing and compressing the hydrogen.

For the Minimum Partial Load (MPL) of the electrolyser, [22] suggests a range of $10-40$% for an alkaline electrolyser, with this study opting to use a value of 20% as a representative figure within that range.

Regarding hydrogen storage capacity, the study references data from HyStock [34], where each bundle is defined as having a storage capacity of $1,000\ MWh$, equivalent to $25,390\ kg$ of hydrogen per bundle. Additionally, the inflow and outflow capacity of the hydrogen storage is set based on HyStock's bundle specifications, with each bundle capable of handling $3.3\ MW$, which translates to an inflow and outflow rate of $84\ kg$ of hydrogen per hour per bundle. Table 4.1 shows all the model parameters and their source.

Table 4.1: Parameters for the case study, including the unit they express, the value they had during the case study and the source where this value was derived from.

Parameter	Unit	Value	Source
Investment Cost	€$/MW$	$3,050,000$	[50]
Operation and Maintenance	€$/MW/y$	$75,340$	[50]
Electricity Grid Tariff	€$/MW/y$	$143,570$	[50]
Hydrogen Network Tariff	€$/MW/y$	$21,130$	[50]
Power Consumption Compressor	MWh/kg	0.005	[50]
Power Consumption Electrolyser	MWh/kg	0.051	[50]
Electrolyser Capacity	MW	100	-
Minimum Partial Load	MW	20	[22]
H_2 storage capacity	$kg/bundle$	$25,390$	[34]
H_2 storage inflow/ outflow capacity	$kg/h/bundle$	84	[34]
Discount rate	$\%/y$	5	-
Lifetime	y	10	-

4.1.2. Time-Series Projections

An Integrated Energy Model was used by Eneco to produce projections for time-series data of hourly spot prices and renewable power generation profiles. The model simulates an array of factors that influence the Dutch energy system. These include hourly demand profiles, installed capacities of both conventional and renewable energy sources, renewable power generation outputs, European Union Emissions Trading System prices, and the prices of coal and gas. By integrating these elements, the model produced a forecast of spot market prices in the Netherlands to the year 2050.

The model generated six distinct scenarios to account for uncertainties and potential future developments in the energy sector. Each scenario reflects a different set of assumptions about future developments in the power system, such as changes in energy policy, technological advancements, or shifts in fuel prices. These scenarios resulted in six different time series, each representing a unique combination of day-ahead spot price forecasts and renewable generation capacity factors.

Throughout the remainder of this study, these six scenarios are referred to as price forecasts for the day-ahead market prices and generation forecasts for the capacity factors of renewable energy sources. More generally, these are collectively termed "forecasts," indicating the combined projections of future prices and renewable generation outputs under varying conditions. These forecasts are integral to the optimization framework, providing a range of possible outcomes that help assess the economic performance of the hydrogen production system under different future scenarios.

The forecasted time-series data generated by this model served as inputs for the cost minimisation within this study. The current author did not contribute in any way to the formulation of the model or any of its inputs but was granted access to use this data for the duration of their graduation internship. The data will not be publicly available as it contains sensitive information.

4.2. Setup Case Study

This section outlines the setup of the case study conducted to explore how various factors influence the cost of hydrogen production. The parameters under investigation include the size of hydrogen storage, the offtake profile, the offtake volume, and the type and capacity of the PPA. These parameters are varied systematically to address the research questions posed by this study. Table 4.2 summarizes the experimental setup for the case study.

The base scenario for this study is defined as follows. The size of hydrogen storage is set to zero bundles, meaning no hydrogen storage capacity is included. The offtake volume is set at a volume that translates to an average utilisation of 50%. The capacity of RES is set at $200MW$ each for wind and solar PV. This means the electrolyser has its PPAs oversizing the capacity of the electrolyser by a factor of 4. Finally, the offtake profiles considered in this scenario include both the take-as-produced (TAP) profile and the baseload (BL) profile, allowing for comparison between these two profiles as well as comparison with the same profile under varying conditions.

To answer the first sub-research question, "What is the difference in cost of providing different hydrogen offtake profiles in a fixed-price hydrogen purchase agreement?" the base scenario is optimised in every forecast for both the TAP and the BL offtake profiles, leaving all other parameters unchanged.

The second sub-research question, "How does the amount and type of RES in the PPA influence the cost of hydrogen production?" is addressed by varying the capacity of solar PV and wind contracted in the PPA. The capacity values are varied between 0, 100, 200, and $300MW$ for both solar PV and wind. This analysis is conducted for both offtake profiles.

To answer the third sub-research question, "How does the offtake volume affect the production cost of hydrogen?", the offtake volume is varied between 30, 40, 50, 60, 70, 80 and 90% of the maximum production capacity of the electrolyser. A 50% volume offtake agreement relates to a 50% utilisation rate or 4380 full load hours per year. This analysis is performed for both offtake profiles.

Finally, the fourth sub-research question, "How much can hydrogen storage contribute to lowering the cost of power for hydrogen production under different hydrogen offtake profiles?" is investigated by evaluating the cost reduction achieved through the addition of 1 to 20 HyStock storage bundles to the system. This analysis focuses on the impact of storage size on production costs under the two offtake profiles TAP and BL. The experiment is initially conducted for the 30, 50, and 70% offtake volume agreements using the first price generation forecast. Subsequently, the analysis is extended to all six scenarios to assess how the results for the 50% volume offtake agreement vary under different market conditions, providing a comprehensive understanding of the role of storage in various economic environments. The TAP profile is not considered in this part of the analysis as preliminary testing shows no added value of storage for this profile.

Table 4.2: Case study set-up of experiments, ranges are defined as [start:stop:step size]

		Experiment				
Variable	Unit	RQ-1	RQ-2	RQ-3	RQ-4.1	RQ-4.2
Capacity Wind	MW	200	$[0:300:100]$	200	200	200
Capacity PV	MW	200	$[0:300:100]$	200	200	200
Storage	bundles	0	0	0	$[0:20:1]$	$[0:20:1]$
Utilisation	% of time	50	50	$[20:90:10]$	$[30, 50, 70]$	50
Profiles		BL,TAP	BL,TAP	BL,TAP	BL	BL
Scenarios	-	$[1:6]$	$[1:6]$	$[1:6]$	1	$[1:6]$

4.3. Validation and Verification

This section concerns the model validation and verification. The validation and verification have been performed throughout the different phases of research, and both qualitative and quantitative validation have been performed to increase confidence in the model outputs [16].

Illustration of functionality

This section validates the model by illustrating the functionality. The observed behaviour will be compared to the expected behaviour under similar conditions, which will help identify the strengths and weaknesses of the model.

This validation is conducted for both the TAP and BL model to confirm their reliability [86]. Figure 4.1 shows the model behaviour under the TAP agreement, and Figure 4.2 and 4.3 show the model behaviour under the BL agreement. All figures show a week (144 hours) of results under parameters from the base scenario, except for the size of the storage. Figure 4.2 has a storage of ten bundles, whereas Figure 4.3 does not have any hydrogen storage available.

The simulated week spans from hour 1001 to 1144, corresponding to day 41 at 17:00 to day 47 at 16:00 in February of the first year in a ten-year simulation horizon. As this period falls in winter in the Netherlands, it is characterized by low solar energy production but relatively higher wind speeds, typical for the season. This results in relatively high renewable energy production, particularly between hours 1060 and 1080, where wind speeds are notably strong. However, as this is the first year of the simulation, hydrogen storage levels are low, as high winter power prices have limited the opportunity for cost-effective storage filling, and there has not yet been a summer period with lower prices to replenish storage.

Figure 4.1 A shows the power generated by the RES and the power flow to or from the grid. It shows the RES generates a lot of power, sometimes more than the electrolyser can consume. The electrolyser sells power to the grid when this is beneficial, the interaction with the grid is denoted by P Grid. Figure 4.1 B shows that the electrolyser is either running at full capacity, or is switched off, and furthermore, it shows that the electrolyser is undergoing many ramping cycles. The max power consumption of the electrolyser aligns with the input of 100 MW. Figure 4.1 C shows the hydrogen production as a result of the power consumption of the electrolyser. It shows that the hydrogen production curve follows the power consumption and that the hydrogen produced is directly shipped to the offtaker, as the hydrogen delivered curve follows the hydrogen production curve. Figure 4.1 D shows that in the TAP hydrogen purchase agreement, there is no need for the use of hydrogen storage, as the model already finds the optimal operating strategy for the electrolyser and the hydrogen produced can be delivered to the offtaker at any time.

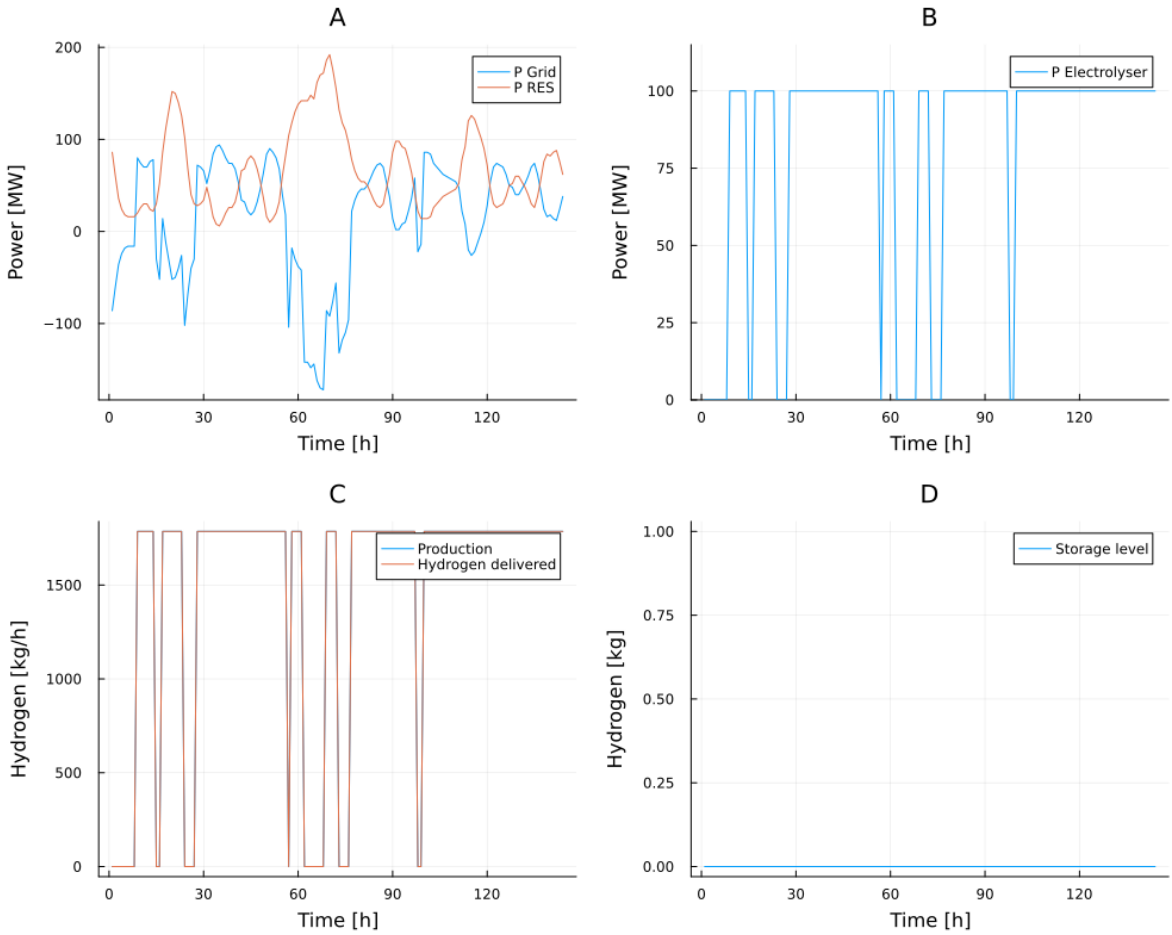

Figure 4.1: Validation take-as-produced model. A) Power generation from RES and power flow to and from the grid. B) Power consumption by the electrolyser. C) Hydrogen production and delivery to the offtaker. D) Storage is not used by TAP profile

Figure 4.2 A shows the power flows in the BL profile with storage are more constant compared to the power flows of the TAP profile in Figure 4.1 A. Figure 4.2 B shows the electrolyser undergoes fewer ramping cycles, and the electrolyser is not switched off during the simulated time. The electrolyser is running just above the minimum partial load for part of the time. The reason it is producing at this capacity is that the outflow capacity of the storage is not sufficient to supply the baseload volume, and therefore, the electrolyser has to produce some hydrogen all of the time. Figure 4.1 C similarly shows that the hydrogen delivery is constant, whereas Figure 4.1 D shows that the storage is utilised to fulfil the demand. The maximum storage capacity with 10 bundles is $253,900kg$. The storage in the simulated week is cycled between 0 and $25,000kg$. This low storage capacity is unsurprising, as it is wintertime and the power prices are comparatively higher in the winter compared to the summer, and the displayed hours are only in the second month of the simulation of ten years.

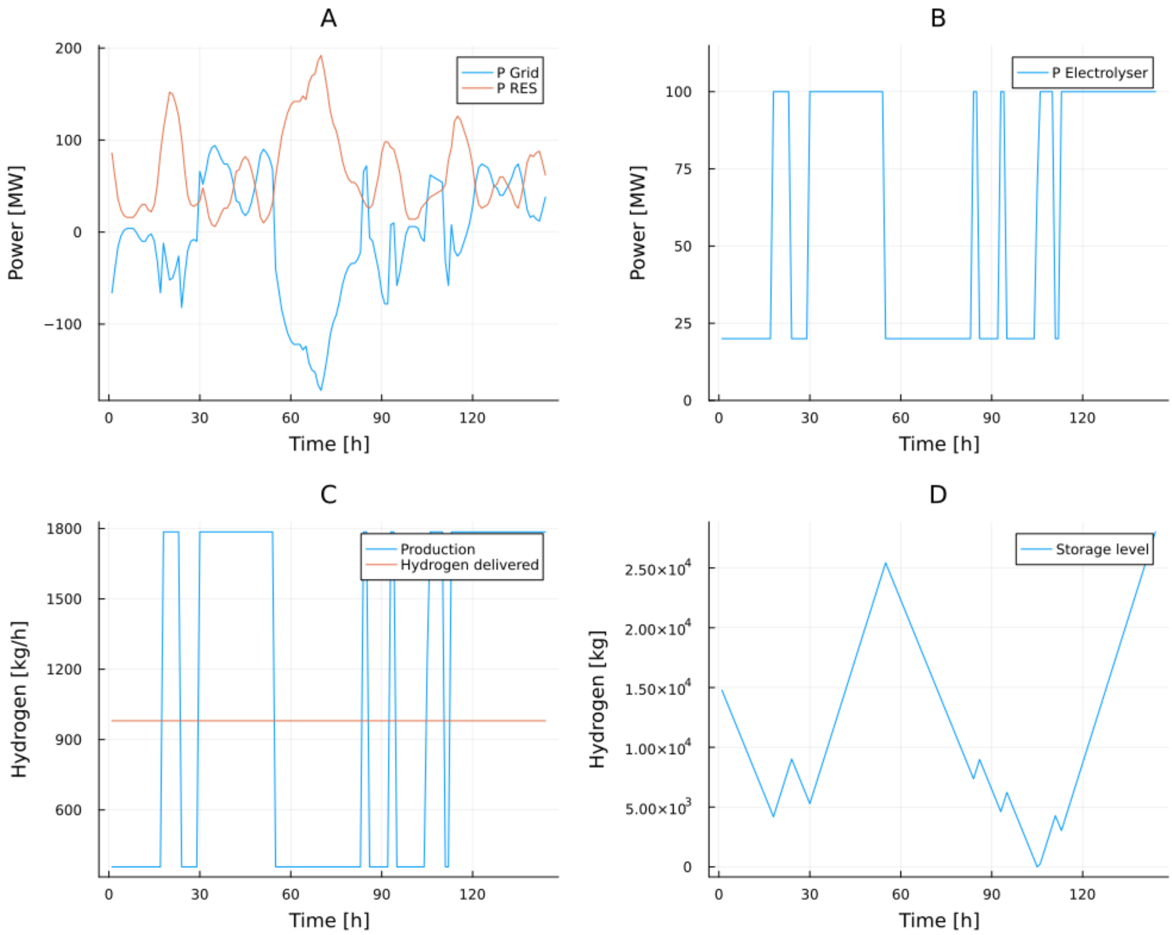

Figure 4.2: Validation of Baseload model with storage. A) Power generation from RES and power flow to and from the grid. B) Power consumption by the electrolyser. C) Hydrogen production and delivery to the offtaker. D) The baseload profile utilises storage

Figure 4.3 A shows that without storage the flow of electricity to the grid mirroring the power bought from the market mirrored around the constant power consumption of the electrolyser, which is displayed in Figure 4.3 B. When no hydrogen storage is available, and the electrolyser has to deliver a baseload volume, the electrolyser has to operate at a constant level to produce a continuous outflow of hydrogen. As the power generation of the RES portfolio is sometimes producing below the required power level, the electrolyser will have to buy power from the grid to maintain the necessary hydrogen outflow.

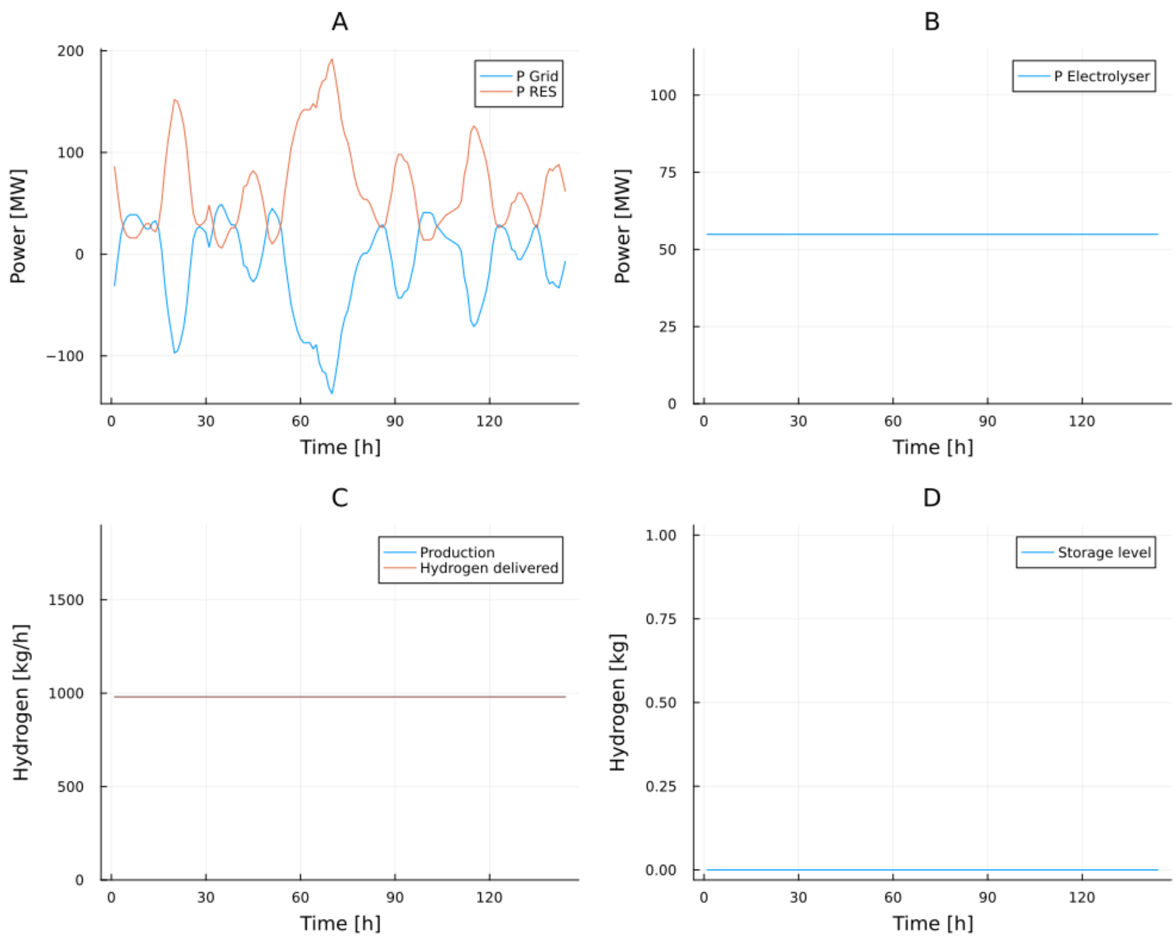

Figure 4.3: Validation of Baseload model without storage. A) Power generation from RES and power flow to and from the grid. B) Power consumption by the electrolyser is constant. C) Hydrogen production and delivery to the offtaker is constant. D) Storage is unavailable

Extreme conditions test

In extreme conditions testing, the behaviour of the model is predicted to see if the model behaviour matches the expectation [16]. The extreme condition tested is the absence of a hydrogen offtake requirement. The expectation is that the electrolyser will not produce any hydrogen and sell all power generated by the RES to the market, similar to the opportunity cost scenario. Figure 4.4 shows that the model behaviour matches the expected behaviour. As a result, no hydrogen is produced, which leads to an infinitely high LCOH, as the costs are divided over 0.

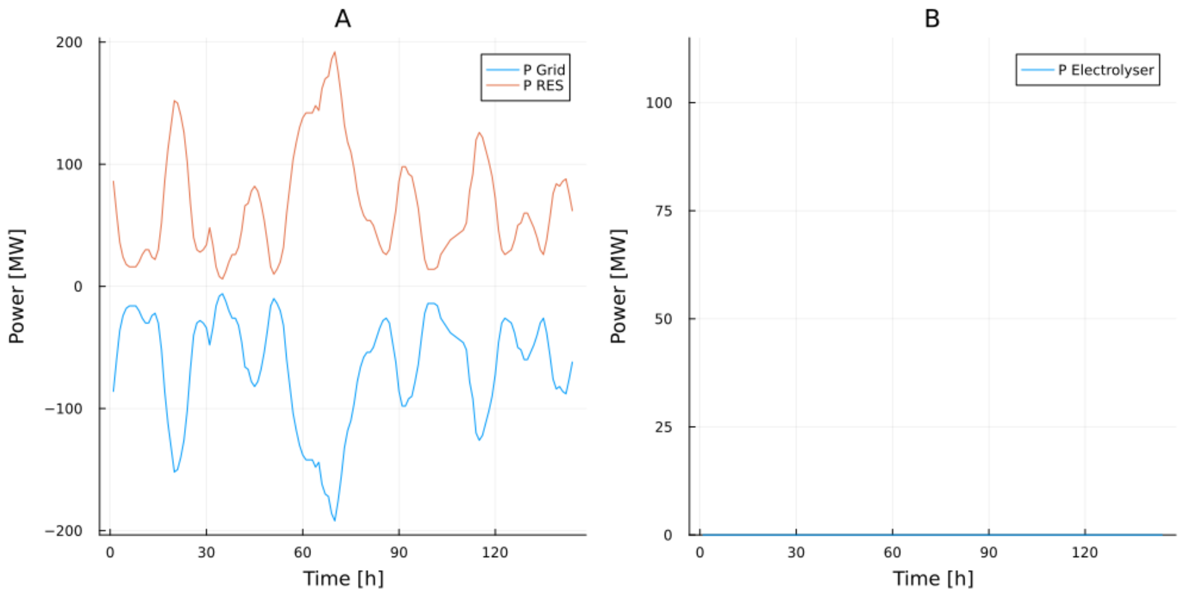

Figure 4.4: Validation under extreme conditions: No offtake requirement scenario, equating to the opportunity scenario where no hydrogen is produced. er generation from RES and power flow to and from the grid. B) Power consumption by the electrolyser is constant.

4.4. Profile Costs Base Case

This section starts the comparison between the TAP profile and the BL profile using the base scenario for all parameters. The base scenario represents an electrolyser of $100MW$, with a $200MW$ solar PV PPA and a $200MW$ wind PPA, without any hydrogen storage and with a volume obligation that translates to an average production capacity of 50%, or $4,380FLH$. For this analysis, the 6 different forecasts have been used to construct a range to indicate the possible LCOH.

The resulting LCOH throughout the forecasts has been displayed in Figure 4.5. The figure shows the LCOH for both offtake profiles. The figure shows the unprocessed results and adjusted results for the opportunity costs. The adjusted and unadjusted results should be interpreted differently, as they differ in their view on accounting for power costs. When adjusting for the opportunity costs, the power costs reflect the day-ahead price and thus ignore any profits or losses achieved by contracting renewable power for a certain price. The unadjusted LCOH provides valuable information on the merchant risk of the hydrogen producer, as it considers the profits and losses of selling excess power on the spot market.

The costs for the TAP profile are between 8.3 €$/kg$ and 10.2 €$/kg$, and the costs for a BL profile are spread between 10.5 €$/kg$ and 12.3 €$/kg$. The LCOH for the BL profile is on average 1.8 €$/kg$ (19%) higher than the TAP profile, throughout the 6 forecasts of power prices and renewable generation profiles. The cost difference of the two profiles is caused by a different operating schedule. Without any storage available the baseload profile is produced by running the electrolyser at a constant hydrogen flow around the clock. As the TAP profile has the option to operate at higher and lower capacities and the option to shut down completely, it can achieve a lower cost of power. This cost reduction is reflected in a difference in final costs.

When adjusted for the opportunity costs, the costs of providing the BL profile are still 19% higher on

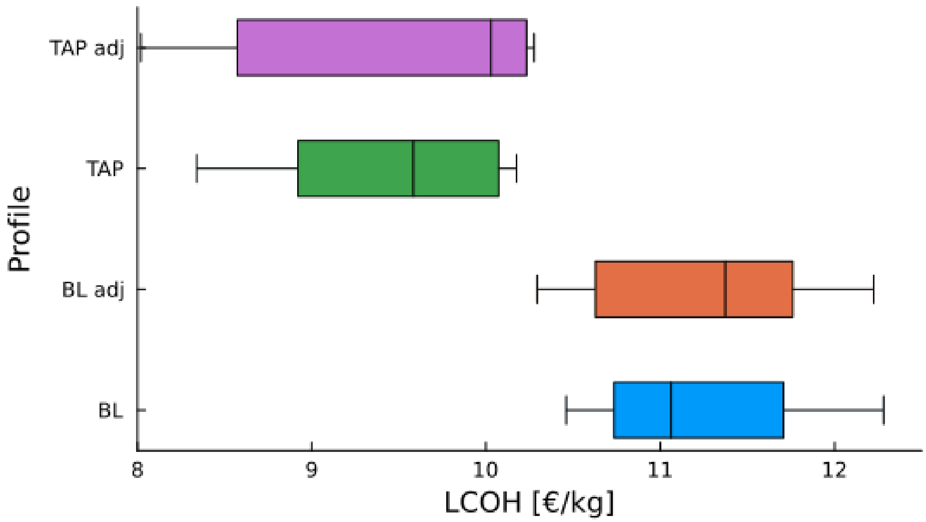

Figure 4.5: Boxplot of the Levelised Cost of Hydrogen for the take-as-produced and baseload profiles across all price forecasts. "Adj" indicates values have been adjusted for opportunity costs.

average, with a minimum of 10.3 €$/kg$, a maximum of 12.2 €$/kg$ and a mean of 11.3 €$/kg$. The TAP profile ranges from 8.0 €$/kg$ to 10.3 €$/kg$, with a mean of 9.5 €$/kg$. The opportunity costs adjusted LCOH has a higher mean than the unadjusted LCOH and a wider range in LCOH. This result underscores that even if the profits from selling renewable power are corrected for, the baseload profile is still 19% more costly to produce.

Figure 4.6 illustrates the cost contributions of the various components analyzed in this thesis. The observed variation in the LCOH in Figure 4.6 is entirely attributable to differences in power costs, as the other parameters remain constant. These parameters include capital expenditure (CAPEX) of 4.3€$/kg$, operating expenses (OPEX) of 1.0€$/kg$, an electricity network tariff of 1.8€$/kg$, and a hydrogen network tariff of 0.2€$/kg$. These values represent assumptions for the analysis, isolating the impact of fluctuating power costs on the overall cost. Note: these costs will change if the volume of hydrogen that should be delivered changes.

However, it should be noted that these cost components are sensitive to the volume of hydrogen delivered. Larger volumes could dilute fixed costs but increase power costs, while smaller volumes may increase the per-unit fixed costs while reducing power costs. Section 4.6 discusses the effect of the offtake volume on the levelised costs.

The median contribution of power in the base scenario is 3.9 €$/kg$ (unadjusted) and 4.2 €$/kg$ (adjusted) for the BL profile and 2.4 €$/kg$ (unadjusted) and 2.9 €$/kg$ (adjusted) for the TAP profile.

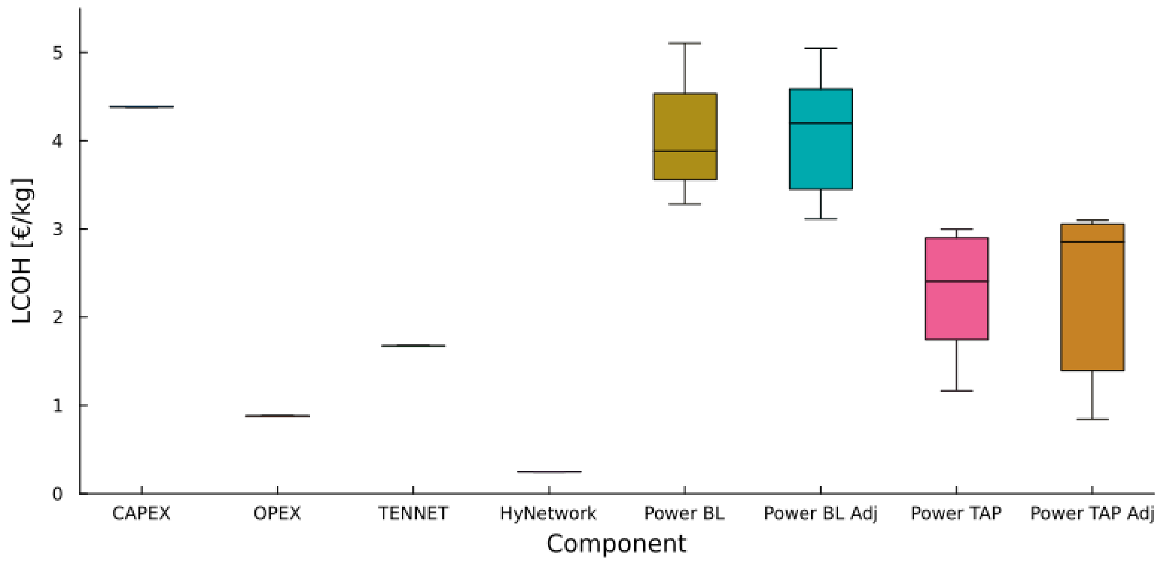

Figure 4.6: Boxplot of levelised cost contributions of CAPEX, OPEX, TENNET, HyNetwork and power to LCOH, where TENNET refers to the electricity network tariffs and HyNetwork the hydrogen network tariffs. "Adj" indicates values have been adjusted for opportunity costs.

4.5. PPA Size and Type

This section discusses the effect of the size and the technology in a PPA on the LCOH. Table 4.3 shows the statistics of the levelised cost of hydrogen from different configurations of RES technology and capacity contracted in a PPA to provide insight into how the different configurations of RES perform in different price forecasts. The experiments are performed as described in Table 4.2.

Table 4.3: Levelised Cost of Hydrogen statistics on mean, minimum, median, maximum and standard deviation under Various Renewable Power Purchase Agreement capacities resulting from solving in 6 different price scenarios. "Adj" indicates values adjusted for opportunity costs.

	Capacity		Mean		Minimum		Median		Maximum		STDDev	
Adj	Solar	Wind	TAP	BL	TAP	BL	TAP	BL	TAP	BL	TAP	BL
No	0	0	9.5	11.3	8.0	10.3	10.0	11.4	10.3	12.2	1.1	0.8
No	100	0	9.5	11.3	8.0	10.3	9.8	11.3	10.3	12.2	1.0	0.7
No	200	0	9.4	11.2	7.9	10.3	9.6	11.3	10.4	12.2	0.9	0.7
No	300	0	9.4	11.2	7.9	10.2	9.3	11.3	10.5	12.3	0.9	0.7
No	0	100	9.5	11.3	8.2	10.6	9.8	11.2	10.1	12.0	0.8	0.5
No	0	200	9.5	11.3	8.5	10.8	9.6	11,2	10.0	11.8	0.6	0.4
No	0	300	9.5	11.3	8.7	10.8	9.6	11.0	10.0	12.2	0.6	0.5
No	100	100	9.5	11.3	8.2	10.5	9.5	11.3	10.2	12.0	0.8	0.5
No	200	200	9.4	11.2	8.3	10.5	9.6	11.1	10.1	12.2	0.8	0.7
No	300	300	9.4	11.2	8.3	10.0	9.3	11.1	11.1	13.3	1.1	1.1
Yes	-	-	9.5	11.3	8.0	10.3	10.0	11.4	10.3	12.2	1.1	0.8

The mean value for the TAP profile ($9.4/9.5$ €$/kg$) is consistently 1.8 €$/kg$ more than the mean of the BL profile ($11.2/11.3$ €$/kg$). The variance inside the mean of each profile is almost zero, with a difference between the minimum- and maximum mean of only 0.1 €$/kg$. The absence of variance in the mean arises from a modelling choice regarding using a single PPA price set at the average capture price of the RES. Averaged out over all 6 scenarios, the capture price of the renewables will always end up with a market value equal to the PPA price. The addition of any amount of capacity of renewables therefore does not affect the mean LCOH.

Even though the profiles are equally un-effected in their mean, there is a difference in the distribution of the individual samples, meaning the profiles are differently affected by the addition of renewable capacity to their PPA portfolio.

The lowest LCOH (7.9 €$/kg$) for the TAP profile is observed with a 200 or 300 MW solar PV PPA. The highest LCOH (11.1 €$/kg$) is observed with a hybrid PPA of $300MW$ capacity for both solar and wind. The difference between the lowest and the highest LCOH for the TAP profile is 2.2 €$/kg$.

For the BL profile, both the lowest LCOH (10.0 €$/kg$) and the highest LCOH (13.3 €$/kg$) are observed at a hybrid PPA with $300MW$ solar and $300MW$ wind. The difference between the lowest and the highest LOCH for the BL profile is 3.3 €$/kg$. The difference is 50%more than the difference between the lowest and the highest LCOH for the TAP profile. The baseload profile is thus more sensitive to the correct sizing of the renewable capacity.

The high exposure to market prices is caused by a large amount of excess power production. In some cases, this excess power can be sold at a profit. In other cases, it has to be sold at a lower market price than the contract price, which results in a loss, driving up the costs of power and, thus, the LCOH.

As the number of experiments is low (n=6), it is unsure how reliable the standard deviation is. The results indicate that pure wind PPAs exhibit higher cost confidence than pure solar PPAs. For baseload HPAs, the lowest standard deviation (0.4) is observed in the $200MW$ wind PPA scenario. For the TAP HPA, the lowest standard deviation (0.6) is observed for the $300MW$ wind PPA. For both hydrogen offtake profiles, the highest standard deviation is observed at the hybrid PPA with $300MW$ wind and $300MW$ solar. This is the largest PPA configuration studied in this thesis, where the power sources oversize the electrolyser capacity by a factor of 6, and the exposure creates a high sensitivity to spot market prices. A standard deviation is lower for pure wind PPAs, implying that an electrolyser sourcing power from a pure wind PPA experiences better predictable costs in the data provided. This increased cost stability enhances confidence in the financial projections for the project, reducing the perceived risk. As a result, the project may benefit from a lower cost of capital, as investors and lenders are likely to require a lower risk premium. Consequently, this reduction in financing costs could lead to lower overall project costs, ultimately making the LCOH more competitive.

As the opportunity cost adjustment rectifies any power trading profits or losses, all configurations of renewable PPAs have the same LCOH. The difference between the adjustment for opportunity costs is essentially an accounting difference. If the opportunity scenario is accounted for, the day ahead price always serves as the cost of power. If the costs are not accounted for, the profits or losses from the purchase and sale of power on the day ahead market are also accounted for within the power costs of the electrolyser.

Figure 4.7 shows the load duration curves of the configuration of renewable PPAs from Table 4.3. In the figure, there is a horizontal line at the capacity factor of 1. Any production above 1 is counted as excess production since the electrolyser can not produce more than the rated capacity. Any production below one is summed up to determine the full load hours during which the electrolyser can produce RFNBO-compliant green hydrogen.

More excess output leaves the electrolyser with a higher exposure to market prices, as this power can not be consumed to produce hydrogen and thus has to be sold no matter the market price. An amount of FLH above the volume requirement also increases the exposure. The S3W3 scenario illustrates this, if the electrolyser has contracted $300MW$ solar PV and $300MW$ wind, almost one-third of the renewable power is produced at times when the electrolyser is already producing at full capacity. Table 4.3 also highlights this, as the spread of LCOH is the highest at this configuration.

The base case for the analysis before and after this section, where a $100MW$ electrolyser has $200MW$ solar PV and $200MW$ wind contracted in a PPA, produces $5,157$ useful FLH and 921 excess FLH. This indicates that under an hourly matching scheme between renewable power generation and hydrogen production, the electrolyser can certify 59% of its operational hours as producing RFNBO-compliant hydrogen. In contrast, when using a yearly matching criterion, $69\%$of the total hydrogen production can be certified as green hydrogen. This higher percentage is achieved because excess renewable energy production at certain times of the year can be allocated to periods with insufficient renewable generation, thus allowing for more flexible accounting over the annual cycle. Note that this analysis is based on a single year of power production, and yearly variations in renewable power production can influence these numbers.

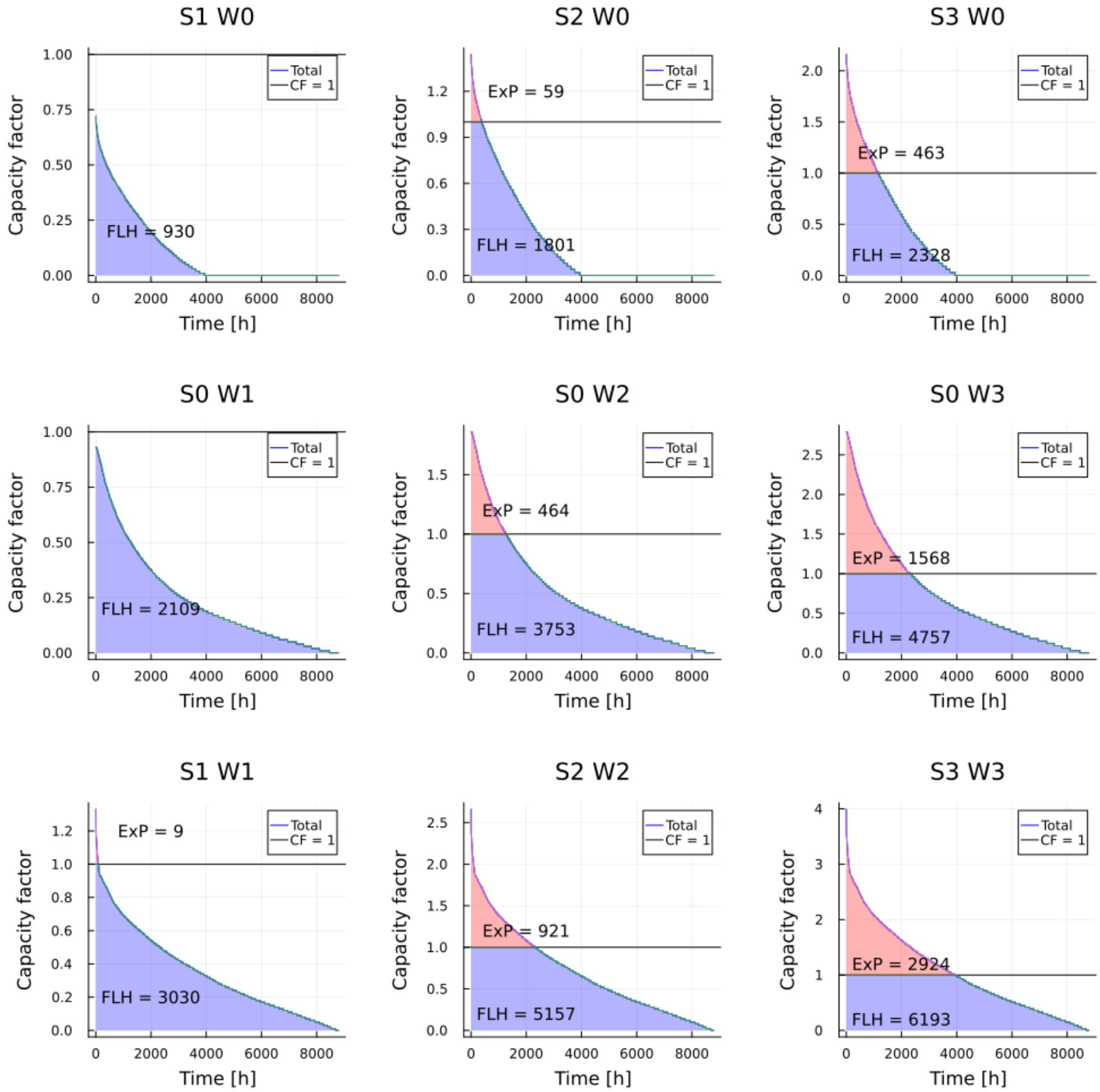

Figure 4.7: Load duration curves of the renewable PPA configurations. In the title of the subplots, S stands for Solar, W stands for Wind, and the number relates to the capacity of RES compared to the capacity of the electrolyser. For a $100MW$ electrolyser, S2 W0 is $200MW$solar and $0MW$ wind. FLH = Full Load Hours, ExP = Excess Production, calculated as all the production that exceeds the electrolyser's capacity.

4.6. Offtake Volume

This section shows the effect of the offtake volume on the LCOH and analyzes the contribution of power costs to the overall LCOH. The experiments are performed as described in Table 4.2.

Figure 4.8 shows the LCOH which is not adjusted for opportunity costs, and Figure 4.9 the opportunity costs adjusted LCOH, with different offtake volumes, displayed as a range from the results form the six scenarios.

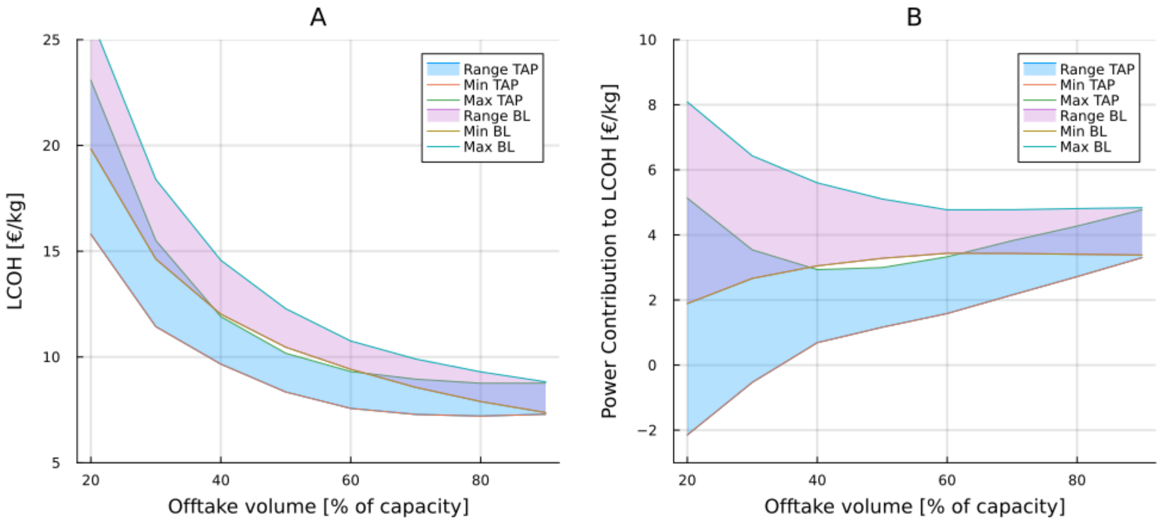

Figure 4.8: A: Effect of offtake volume on LCOH, B: Contribution of power to LCOH with different offtake volumes, not adjusted for opportunity cost

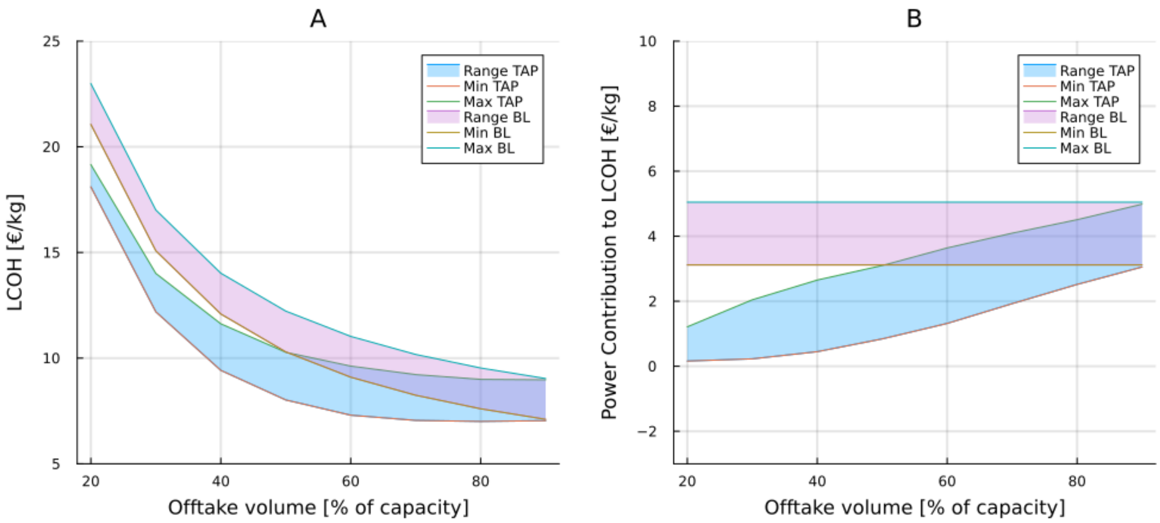

Figure 4.9: A: Effect of offtake volume on LCOH, B: Contribution of power to LCOH with different offtake volumes, adjusted for opportunity cost

When the results are unadjusted for opportunity costs, there is a wide range of uncertainty in the contribution of power costs at low offtake volumes. This uncertainty is caused by windfall profits or losses arising from a lower or higher than anticipated market value for renewable power.

For the TAP profile, the range of power costs at 20% utilisation is between -2.1 and 5.13 €$/kg\ H_2$. At 90% utilisation the levelised power costs are between 3.3 and 4.77 €$/kg\ H_2$. For the BL profile, the range of power costs at 20% utilisation is between 1.9 and 8.1 €$/kg\ H_2$. At 90% utilisation, the levelised power costs are between 3.4 and 4.8 €$/kg\ H_2$. The lower bound of both profiles increased while the higher bound decreased. With this shift, the uncertainty was also reduced. This is due to the higher volumes depending more on grid power and day-ahead prices as the electrolyser consumes more power than the RES provides. The low or high PPA price, in this case, has less impact on the overall power price.

For both profiles, a lower offtake volume leads to a high levelised cost uncertainty. At lower volumes, more renewable power is contracted than used, which causes merchant exposure. In some cases, this merchant exposure leads to power costs being accounted as negative, as profits from the sale of power in the day-ahead market are higher than the costs of power from hydrogen production. In reality, average power costs will only be negative if more profits are made from selling power than costs incurred from producing hydrogen. In some cases, the opposite is true. As the PPA contract price is higher than the market price, the PPA power costs are higher than the market price, and the net power costs are high.

If the results are adjusted for opportunity costs, the previously discussed exposure for the PPA price is not included, as the power costs are adjusted to exclude this variability. The result is that for the BL profile HPA, the average power costs are the average power price over the production lifetime, and the PPA price is ignored. The result is that the levelised power costs are the same for every offtake volume within every scenario. In the different scenarios they range between 3.2 and 5.0 €$/kg\ H_2$. For the TAP profile HPA the average power price increases as the offtake volume of hydrogen increases, as the electrolyser has to produce during more expensive hours. The levelised power costs at the 20% offtake volume are between 0.2 and 1.0 €$/kg\ H_2$, which increases towards a range between 3.0 to 5.0 €$/kg\ H_2$ for the 90% offtake volume.

As the offtake volume increases, the LCOH for the BL and the TAP profiles converge. At 100% offtake, the LCOH for both profiles becomes identical, as the electrolyser operates continuously under both scenarios, resulting in identical operating schedules and power costs. In scenarios where an offtaker agrees to an HPA requiring the electrolyser to operate at full capacity at all times, the expected power prices can be directly used to determine the contribution of power costs to the LCOH. However, it should be noted that under such conditions, the electrolyser will not be able to produce RFNBO-compliant hydrogen consistently throughout the year. Consequently, the offtaker cannot rely on certification for the entirety of the hydrogen produced.

Over all scenarios and forecasts, the reduction in levelised capital costs is greater than the increase in levelised power costs. This shows that with the current unit capital costs, electrolysers are willing to operate even during high power prices, to realise a reduction in the levelised cost of hydrogen.

4.7. Storage Size

This section examines whether a reduction in power costs can result from the accessibility to hydrogen storage. The section first presents an analysis of the impact of hydrogen storage on different offtake volume agreements. The second part of the section discusses the analysis of different price forecasts to build confidence in the conclusions drawn in the first part.

Figure 4.10 displays the reduction in production costs of hydrogen under various volume offtake agreements, resulting from an increased storage size. This figure displays the reduction in costs in a single-price forecast. Figure 4.11 shows the same for the results that have been adjusted for the opportunity costs. In Figure 4.10 A and Figure 4.11 A, a horizontal reference line is added at the production cost of the TAP profile. In Figure 4.10 B and Figure 4.11 B a vertical reference line is added at the amount of bundles where the outflow capacity of the hydrogen storage matches the offtake volume.

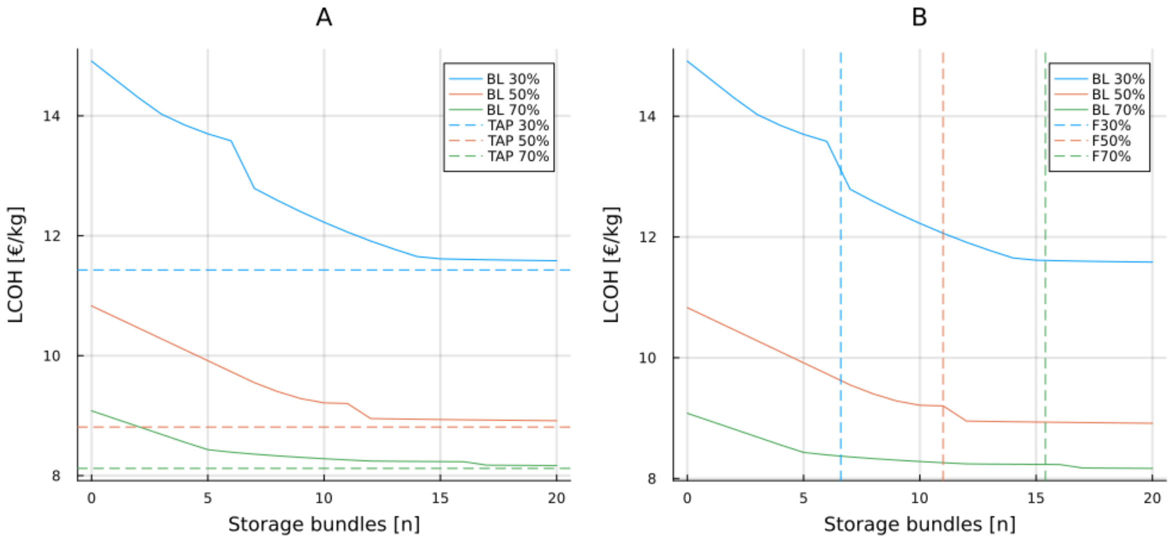

Figure 4.10: A: Cost reduction of storage bundles compared to reference price for take-as-produced profile, B: Cost reduction of storage bundles compared to the point where the storage outflow capacity is bigger than the offtake volume

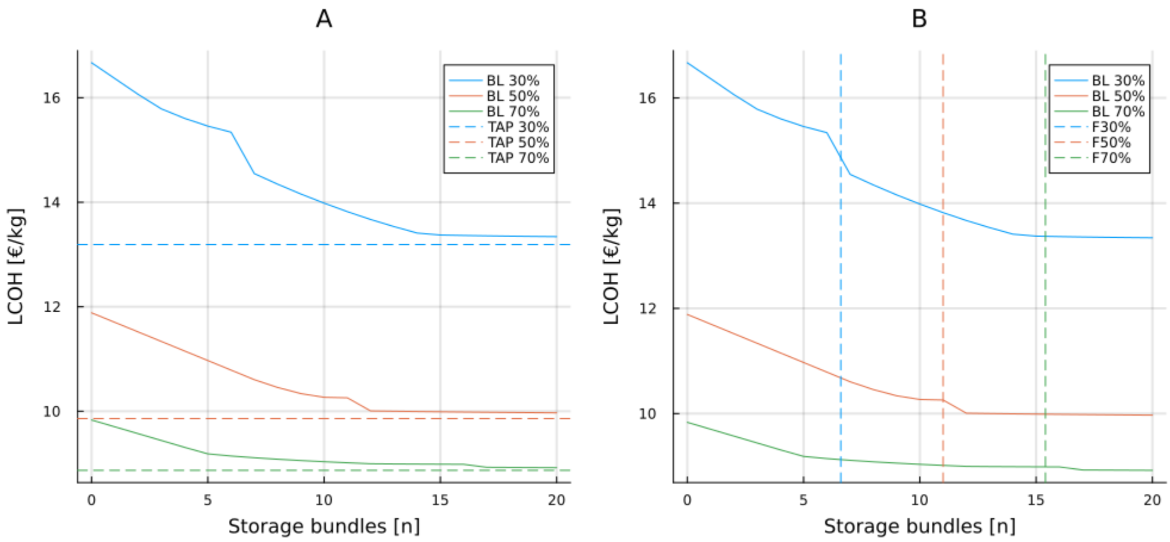

Figure 4.11: A: Reduction in opportunity cost adjusted LCOH of storage bundles compared to reference price for take-as-produced profile, B: Reduction in opportunity cost adjusted LCOH of storage bundles compared to the point where the storage outflow capacity is bigger than the offtake volume

Figure 4.10 A and Figure 4.11 A show the impact of the storage size on the LCOH of the baseload hydrogen offtake profile. For every offtake volume, the LCOH can be reduced using hydrogen storage.

If storage costs are ignored, a large enough storage enables the production of a BL profile with levelised costs close to those of delivering a TAP profile, however, the costs of producing a BL profile are never smaller than the costs of producing a TAP profile. If the storage costs are considered and added to the costs of producing a baseload profile, the final costs will be further from those of the TAP profile which does not require or benefit from hydrogen storage, according to the current model. The reference lines in Figure 4.10 B and Figure 4.11 B will be discussed after the analysis of the marginal cost reduction that follows.

Figure 4.12 A shows the marginal cost reduction of one extra storage bundle, defined as a reduction in the LCOH in €$/kg$, compared to a baseload profile with one fewer storage bundle. Figure 4.12 B shows the marginal lifetime cost reduction in €. The lifetime cost reduction is determined by multiplying the marginal reduction in LCOH over the discounted lifetime hydrogen production. They are thus measures of how much costs are reduced for the producer to satisfy the same hydrogen offtake agreement.

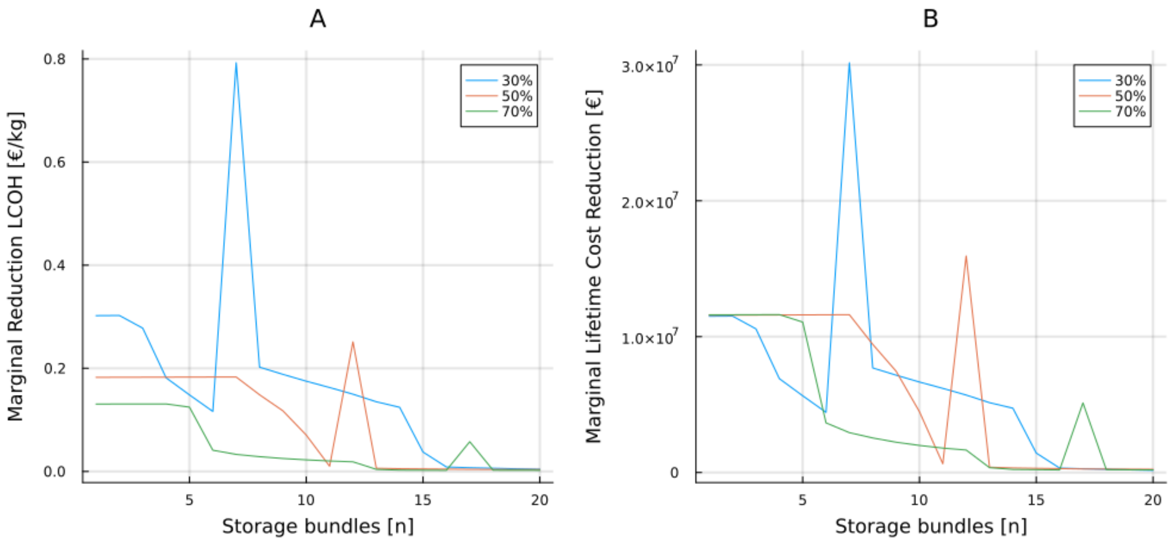

Figure 4.12: A: Marginal reduction of storage bundles on LCOH. B: Marginal lifetime cost reduction of storage bundles

For every offtake volume, Figure 4.12 A and Figure 4.12 B show a spike in marginal cost reduction. This spike is higher for profiles with a lower utilisation rate, both in cost reduction per kilo and in cost reduction over the lifetime of the contract. For the 30% offtake agreement, the spike occurs at the seventh bundle, resulting in a marginal reduction of 0.8 €$/kg$ in the LCOH, which translates to a lifetime cost reduction of $30\ M$€. At the 50% offtake level, the spike occurs at the twelfth bundle, with a reduction of 0.24 €$/kg$ in LCOH, corresponding to lifetime cost savings of $16\ M$€. For the 70% offtake agreement, the spike occurs at the seventeenth bundle, leading to a marginal reduction of 0.05 €$/kg$ in LCOH, resulting in a lifetime cost reduction of $6\ M$€. This trend indicates that while additional storage capacity provides cost savings at offtake levels at least up to 70%, the potential savings diminish as the offtake volume increases. For every offtake volume, there is also a point where the cost reduction of one extra bundle becomes negligible as the costs approach the costs of delivering a TAP profile.

Peak in marginal cost reduction
Figures 4.10 B and 4.11 B indicate that the cost reduction spike occurs at the point where the outflow capacity of the storage exceeds the offtake volume. Table 4.4 provides the numbers underlying the vertical lines in these figures, showing the hourly demand for each volume obligation and the theoretical number of bundles required to meet this demand solely from hydrogen outflow from the storage. The amount of bundles needed to accommodate this flow is calculated by dividing the hourly demand by the outflow capacity of one bundle.

Table 4.4: Baseload offtake volume in number of bundles. The amount of bundles needed to accommodate the hourly flow is calculated by dividing the hourly demand by the outflow capacity of one bundle.

	Units	Volume Obligation		
Metric	%	30	50	70
Hourly demand	kg/h	556	926	1296
Bundles needed to accommodate this flow	n	6.6	11.0	15.4

The observed cost reduction spike for the 30 and 50% offtake volumes occurs precisely when the storage outflow capacity exceeds the offtake volume. This is because the storage system can then fully meet the offtake demand, effectively reducing the need for the electrolyser to operate during periods of higher power prices, and causing a reduction in overall costs. For the 70% offtake agreement, the spike in cost reduction does not align exactly with the point where the storage outflow capacity exceeds the offtake volume; however, it is observed shortly after this threshold. This suggests that for higher offtake agreements, additional factors may influence the magnitude of cost reductions, potentially due to more complex interactions between storage capacity and the larger offtake requirements.

Cost Reduction With Maximum Storage Capacity
The cost savings achieved by hydrogen storage in the size of 20 bundles are displayed in Table 4.5. A reduction in LCOH of 3.4, 2.0 and 1.0€/kg means a relative reduction in LCOH of 22.1, 17.6 and 9.9%, which is a big share of the total levelised costs. The reduction in power costs is highest for the lowest utilisation rate, but also significant for the other utilisation rates. For the 30% utilisation rate, the power costs are reduced by 117.2%, leading to negative power costs of -0.5 €$/kg$ in this scenario. Remember the power costs are not accounted for opportunity costs and that this part of the analysis looks at a single price forecast, which can lead to skewed results in relative reduction, but the absolute reduction in power costs is the same for the base and the opportunity scenarios. From figure 4.14 onwards, the results of all six price forecasts are considered and analysed.

Utilisation	Initial		With 20 Bundles		Absolute Reduction		Relative Reduction	
(%)	LCOH (€$/kg$)	Power (€$/kg$)	LCOH (€$/kg$)	Power (€$/kg$)	LCOH (€$/kg$)	Power (€$/kg$)	LCOH (%)	Power (%)
30	14.9	2.9	11.6	-0.5	3.3	3.4	22.1	117.2
50	10.8	3.7	8.9	1.7	1.9	2.0	17.6	54.1
70	9.1	4.0	8.2	3.0	0.9	1.0	9.9	25.0

Table 4.5: Overview of LCOH and power cost reductions with storage at varying utilisation levels, including initial values, values with 20 bundles of storage, and absolute- and relative reductions, from scenario 1, not adjusted for opportunity costs.

Cumulative savings in power cost

Figure 4.13 shows the cumulative lifetime cost reduction in euro, which is calculated by summing the lifetime cost reduction of all bundles. The total cost reductions achieved from the accessibility to 20 bundles of hydrogen storage, which translates to $20,000MWh$ storage capacity and $66MW$ outflow capacity per hour, is the highest for the lowest volume offtake agreement, around 127 $M€$ over 10 years of the contract for the 30% offtake agreement. For the 50% volume offtake agreements the savings are 121 $M€$ and for the 70% offtake agreement the savings are $81M€$. As Table 4.5 already showed the absolute reduction in power costs is much higher for the lower utilisation rates (2-3.4 times higher for the lowest utilisation rate), however, the cumulative lifetime savings are much closer together as the higher utilisation rates represent more hydrogen production, especially for the 30 and the 50% utilisation rate.

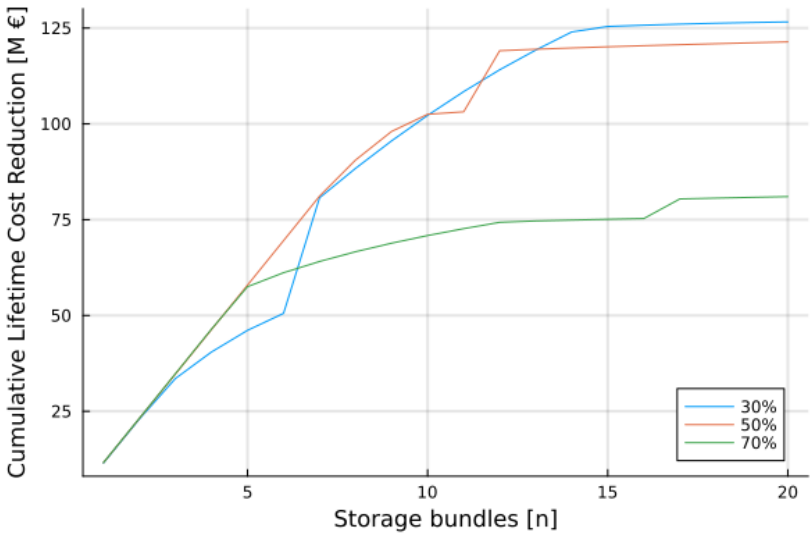

Figure 4.13: Cumulative power cost reductions from different storage sizes for different offtake volumes

Value of storage in different scenarios

Figure 4.14 zooms in on the value of the storage bundles for the 50% utilisation rate in different power price scenarios. The storage bundles have a similar effect throughout the different forecasts. Cost reductions are observed in all forecasts, A peak of 0.1 to 0.5 € $/kg$ reduction is observed at the twelfth storage bundle and the cumulative cost reductions are between 70 and $129 M$€.

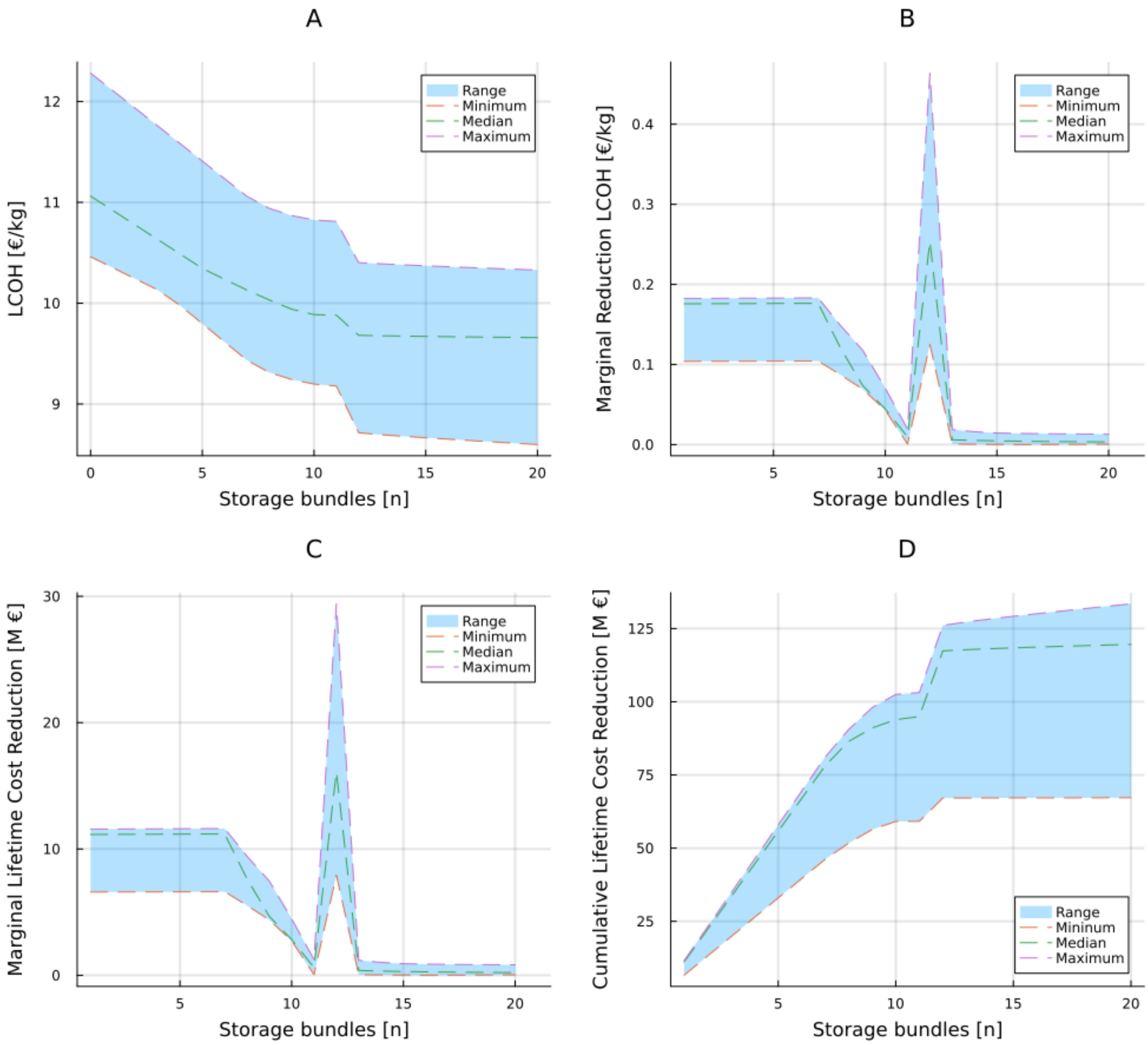

Figure 4.14: Metrics for the impact of hydrogen storage on production costs of hydrogen, excluding storage costs. A) range of LCOH to produce a baseload profile with different storage sizes. B) range of marginal reduction in LCOH with different storage sizes C) range of Marginal lifetime cost reduction with different storage sizes. D) Range of cumulative lifetime cost reduction with different storage sizes.

Cost and benefit of storage

To put things in perspective, a former HyStock auction document noted the price for a bundle to be between $100 - 200\ K$€ $/bundle/yr$ [87]. The discounted cost of a storage bundle over the lifetime of the contract is then 0.8 to $1.6\ M$€. If the electrolyser has 12 storage bundles, the lifetime cost of storage is 9.6 to $19.2 M$€. The discounted lifetime cost reduction of these 12 storage bundles is between $70\ M$€ and $125\ M$€, as displayed in Figure 4.14 D. In this example, the cost reductions of the storage facility outweigh the costs by a factor of 3.6 to 13.0. Assuming a hydrogen purchase agreement obliges the production of a baseload profile. These cost reductions can lead to the producer being more competitive in their price offering of a baseload profile for a potential offtaker.

Size and cost of storage
In Figure 4.15 the low and high storage costs have been included in the LCOH.

For all of the scenarios, the cost reduction achieved by the storage is bigger than the extra costs incurred for the low and high storage costs scenario.

The lowest LCOH of the baseload profile is with 12 bundles of storage for all scenarios except one. For all of these cases, a further scale-up of the storage capacity costs more than that it achieves a reduction in power costs. The one exception where hydrogen storage beyond 12 bundles reduces more power costs than it adds storage costs is in scenario 4 with low storage costs. In this case, the savings outweigh the costs until 20 bundles, which is the maximum number of bundles studied. It can be argued that beyond the $12th$ storage bundle, the outflow capacity has no added value anymore, as the outflow to the offtaker never has to be more than the outflow that is already possible with 12 bundles. Beyond the $12th$ bundle the added value therefore must come from an increased total volume of storage. The exception shows that the total volume of storage also has some value, however it is most likely not more than $100K€/bundle/year$.

In Table 4.6 the results from the LCOH calculation, including storage costs, have been compared to the reference costs of producing a take-as-produced profile in that scenario. The difference in levelised costs of producing a BL profile compared to a TAP profile ranges from 0.2 to 0.5 $€/kg$, an increase of 2.2 to 6.2% in the low storage costs scenario. In the high storage costs scenario, it costs between 0.4 and 0.7 $€/kg$ more to produce a BL profile compared to a TAP profile, which is 3.7 to 8.4% more.

Table 4.6: The minimum LCOH to produce a baseload profile with a 50% utilisation volume offtake obligation, in a low and high storage scenario. The difference is the difference with the TAP profile. The increase is the percentage increase to produce the BL profile compared to the TAP profile. The amount of bundles refers to the number of bundles that result in this optimum.

	Low Storage Costs				High Storage Costs			
Scenario	LCOH $€/kg$	Difference $€/kg$	Increase $\%$	Bundles n	LCOH $€/kg$	Difference $€/kg$	Increase $\%$	Bundles n
1	9.1	0.3	3.5	12	9.3	0.5	5.3	12
2	10.4	0.2	2.2	12	10.6	0.4	3.7	12
3	9.5	0.2	2.6	12	9.7	0.4	4.3	12
4	8.9	0.5	6.2	20	9.0	0.7	8.4	12
5	10.6	0.4	4.3	12	10.7	0.6	5.9	12
6	10.2	0.3	2.8	12	10.4	0.5	4.6	12

The results should also be compared to the LCOH without storage. A capacity of 12 bundles of storage realises an 8 to 17% reduction in costs of producing a baseload profile under low storage costs and 6 to 16% reduction under high storage costs if the costs of storage are considered.

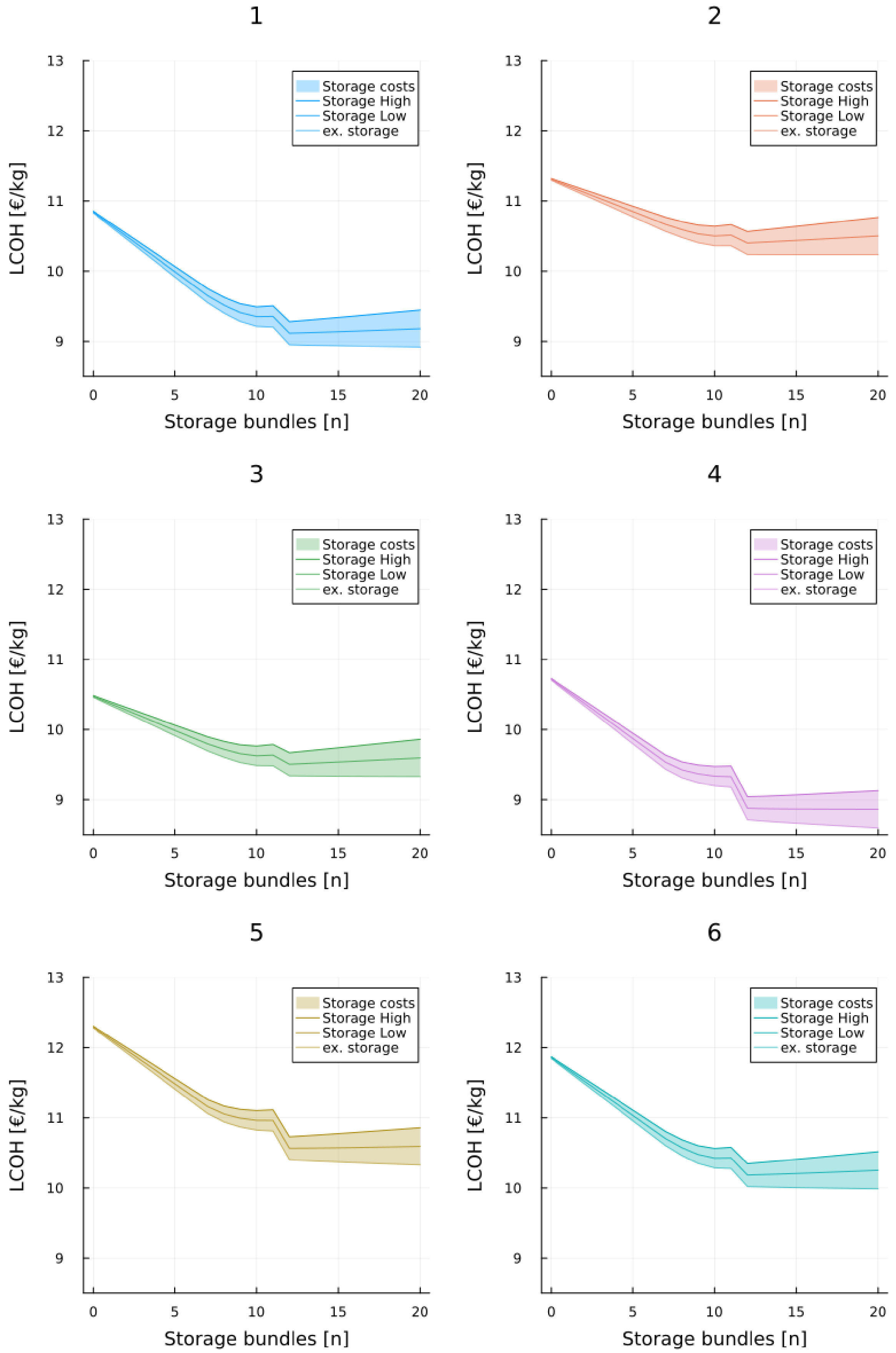

Figure 4.15: LCOH to produce a baseload profile with different storage sizes, for low and high storage costs, in 6 different price projections

5 Discussion

5.1. Interpretation of Results

The interpretation of results is structured based on the findings from Section 4 and discussed in relation to the most relevant literature. While the findings align with several previous studies, they also offer unique insights.

LCOH

Without accounting for power trading profits or losses, the LCOH for the TAP profile ranges between 8.02 and 10.3 €$/kg$, whereas the LCOH for the BL profile ranges between 10.3 and 12.2 €$/kg$. When the price sensitivity associated with the fixed price PPA is factored in, the LCOH for the TAP profile shifts to between 8.3 and 10.2 €$/kg$ while the LCOH for the BL profile increases to between 10.5 and 12.3 €$/kg$.

These findings are notably lower than the LCOHs reported by Eblé and Weeda [50]. The full range of LCOHs of participants in their study was between 9 and 16 €$/kg$, and for an electrolyser of the same size and with the same utilisation an LCOH of around 12.7 €$/kg$ was estimated. Since their study did not consider storage or downstream inflexibility, their LCOH indications are better comparable with the TAP profile from this study, which suggests that the current study produces low LCOH estimates. The major contributor to this difference is the difference in electricity costs. Where the electricity costs in their study were 5.2 €$/kg$ this study estimated electricity costs of 0.9 to 3.2 €$/kg$. The fact that the other cost components are relatively close is no surprise as most of our input costs stem from their analysis.

The contribution of power cost towards the total LCOH of the TAP profile in this study is $11-31\%$. These numbers are very low compared to the study performed by Matute et al. [68] where power costs made up between 68 and 74% of the cost of electrolysers connected to solar PV installations. The context they are studying is different, their electrolyser is localised in Spain, where we would expect solar PV to be cheap and sun in excess, however, the contribution they estimate is a lot bigger than what this study found. One possible explanation could be that they spread their investment out over double the lifetime (20 compared to 10 years in this study), which means the levelised capex could be more discounted. Other project finance explanations can be imagined but are beyond the scope of this discussion.

The LCOHs determined in this study can also be compared to those submitted to the European Hydrogen Bank [88], which reflect real-world green hydrogen projects at various stages of development, including some based in the Netherlands. The seven participating projects based in the Netherlands reported LCOH values between 7.6 and 13.9 €$/kg$. Both the estimates for the TAP and the BL profile fall within this range, with the TAP costs within the lower half and the BL costs within the upper half. The electrolyser would thus be able to compete for a subsidy with the other green hydrogen projects in the Netherlands.

Sizing of PPA portfolio

This study does not find any conclusive results on which RES technology leads to lower LCOH due to the choice for determining the PPA price. This study did uncover a higher sensitivity to oversizing of solar PV capacity compared to onshore wind capacity, in the Dutch power market.

Another study by Poudel et al. [89] performed a comparative analysis of various configurations of electrolysers coupled to RES or nuclear power stations with the goal of providing a continuous and reliable supply of hydrogen. They found that complementary hybrids of RES (PV and Wind) have a better economic performance than pure wind or solar PV, caused by their ability to provide a less fluctuating power supply. The best economically performing configuration, however, was an electrolyser coupled to a nuclear light water reactor. The reason it performed so much better was the fact that it did not deal with the inherent uncertainties of renewable power sources.

The least cost LCOH to deliver a baseload volume from a study by Rioja et al. [90] was achieved by the oversizing of their directly connected RES. This might be due to the fact that their system configuration was off-grid and the RES had to supply all the power for hydrogen production. They also had hydrogen storage available on-site. Interestingly, their minimisation of LCOH led to the exact opposite result regarding the utilisation rate.

Offtake Volume
In this thesis higher volumes always led to a reduction in LCOH and the electrolyser was operating at 90% of the capacity for the lowest cost LCOH. Contrarily, Rioja et al. [90] found an optimal demand rate of $12\ kg/min$ for a similar size electrolyser, which translates to a capacity factor of only 17%. One dissimilarity that might have caused their results to differ from this thesis is that their electrolyser is not grid-connected and therefore only produces hydrogen from a direct line with the RES. They therefore also produce RFNBO-compliant hydrogen at all times. Low utilisation rates for RES-connected electrolysers were also highlighted by Poudel et al. [89], who likewise studied the cheapest configurations of baseload hydrogen production using RES. If the RFNBO regulation were more strictly imposed in this study, the results might have been more similar, as there would have been fewer hours when power could be purchased from the grid.

Baseload Premium
This study finds that without storage, producing a baseload profile is $11 - 28\%$ more expensive than producing a TAP profile. However, when low-cost storage is included, the cost difference narrows significantly, with the baseload profile being only $2 - 6\%$ more expensive. Under high storage costs, this difference increases slightly to $4 - 8\%$. While storage reduces the cost gap between producing TAP and baseload profiles, baseload production remains consistently more expensive. Similarly, Rioja et al. [90] report a baseload premium of $0.38 - 0.75$ €$/kg$, equivalent to $16 - 20\%$ of the LCOH. The relative premium for a baseload profile they find is comparable with the premium this thesis finds for a baseload profile without storage. Their study, however, includes the use of storage to arrive at this premium for a baseload profile.

The difference could again arise from a difference in system configuration, e.g. they studied an off-grid electrolyser and this study focussed on a grid-connected electrolyser. Another dissimilarity is that their input price for power is based on the costs of installing renewable power instead of the market value. Furthermore, the investments are spread out over 30 years of lifetime, which can explain why the LCOH estimated in their study is a fraction of the LCOH in this study.

Hydrogen Storage
While the current study demonstrates that hydrogen storage is effective at reducing power costs for delivering a baseload profile, the cost reduction is not as big as the reduction found by Moradpoor et al. [12]. This thesis finds a $8 - 17\%$ reduction in LCOH under low storage costs and a $6 - 16\%$ reduction under high storage costs compared to a 35% reduction in LCOH in their study. The amount of costs that storage can save also depends on the share of the initial components of the LCOH. If power makes up only a small amount of costs, the potential for storage to reduce costs is also small, and vice versa. The studies do agree on the fact that the benefits of hydrogen storage outweigh the costs, a conclusion which was also highlighted by Moran et al. [31]. In this study, the reduction in LCOH through the availability of hydrogen storage outweighs the storage costs by a factor of $3.6 - 13\%$, but only for a baseload-producing electrolyser. The study therewith fails to identify the benefit of long-term storage and potential seasonal variations, as these would also apply to take-as-produced electrolysers.

5.2. Strengths and Limitations

The scope of this research was limited to a project-ownership structure that is based on previous experience with LNG and offshore wind, the segregated merchant model with a fixed-price PPA. Other configurations are possible. As [8] notes the green hydrogen value chain is unique, contract structures that have no precedent might emerge to adapt to the characteristics of hydrogen.

The model combines PPAs and spot market, however, other markets exist that could enhance the profitability of an electrolyser. Ancillary services can significantly enhance the profitability of a hydrogen project by providing additional revenue streams [74]. By not accounting for these markets, the model may underestimate the economic profitability of hydrogen projects. Combining the work of Johnsen et al. [74] of an electrolyser operating in spot and ancillary services markets and the current work where long-term contracts with RES are taken into account, could provide a more comprehensive assessment of the costs of power to operate an electrolyser. The market model could further be improved to accommodate suitability for bigger electrolysers, which impact the day-ahead market. For this purpose, a dynamic power market model would be needed.

The LCOH metric used was on a high abstraction level, fit for the purpose of comparing the implications of the contract structures. It is therefore important to underscore that the numbers should not be directly used to determine the price of hydrogen. Furthermore, in this thesis, certain components of the LCOH were fixed, including the power grid tariff and hydrogen network tariff. These fixed tariffs assume a constant cost irrespective of the amount of hydrogen produced. However, it is worth considering how these costs might change if they were changed into variable components. For instance, a variable power grid tariff could include demand charges, grid congestion or imbalance payments. Similarly, a variable hydrogen network tariff could change with the volume of hydrogen transported, utilisation of flexibility or linepack services. Introducing variability in these tariffs potentially leads to a more realistic assessment of the LCOH, providing deeper insights into the economic feasibility and optimization of electrolyser operations under different contractual and operational conditions.

An assumption that impacted the outcome was the way trading of power was treated in the balance sheet. The model considers profit from energy trading as a reduction in costs, thereby achieving low power costs. While this approach may potentially lead to an underestimation of actual costs, it can still serve as a useful tool to compare different contract structures. If the optimal costs, including more storage, are significantly lower, it indicates that the operation of the electrolyser is more economical. Consequently, the realized costs will reflect this improved efficiency, reinforcing the economic viability of the electrolyser under the modelled conditions.

Another limitation is that storage costs have not been included in this model. It remains to be determined whether the benefits of storage are higher than the costs, as the price at which the HyStock auction is awarded is unknown.

The data in the model served a good purpose for a general case study, however, the profiles that were used for renewable assets were based on the national average. If the location and technical specifications of the RES project are known, a more detailed analysis can be constructed to analyse the value of storage capacity for a specific project.

There are numerous other risks. Future research could, for example, analyse merchant risk, credit risk [11], balancing risk, profile risk, cannibalisation risk, regulatory risk [45], maintenance and operational risk, and disruptions in water supply. A comprehensive risk analysis could assess the impact and probability of these risks, determining whether they should be financially hedged.

6 Conclusion

6.1. Research Questions

The characteristics of green hydrogen make it a unique product, and therefore, the forming of a market for green hydrogen is unlike the forming of any precedented market. It will take time before enough suppliers and offtakers are connected to support a competitive market. In the absence of a liquid market for hydrogen, bilateral contracts can be used as a mechanism to reduce financial risk for a hydrogen producer by securing a future offtaker. The design of a bilateral contract for green hydrogen concerns many parameters. This thesis studied two important design parameters: the hydrogen production volume and the hydrogen offtake profile, and how these contract parameters influence the production cost of hydrogen for a grid-connected electrolyser whose production schedule is determined by the hydrogen purchase agreement, a renewable power portfolio, spot market prices and hydrogen storage for the years 2030-2039.

The main research question: *"How are the hydrogen production costs under a long-term hydrogen purchase agreement, affected by the offtake volume, offtake profile, the availability of hydrogen storage and the type and size of the RES portfolio?"* guided the research. The analysis was segmented into sub-research questions to address each aspect of the research question, offering detailed insights into the cost dynamics of green hydrogen production under a hydrogen purchase agreement.

The first sub-research question: *"What is the difference in cost of providing different hydrogen offtake profiles in a fixed-price hydrogen purchase agreement?"* focused on understanding the cost implications of different hydrogen offtake profiles within a fixed-price hydrogen purchase agreement. The research finds that producing a baseload volume of hydrogen without being able to store hydrogen is 11 to 28% more expensive than producing a take-as-produced volume. In the current study this cost difference is solely attributable to increased power costs. The power costs of the baseload profile are made up of a constant baseload volume of power. If the RES portfolio does not supply enough renewable power to maintain this production, the electrolyser sources power from the spot market. In the TAP profile the electrolyser has more freedom in the time of production and time of delivery of hydrogen. The electrolyser can identify upfront what is the best time to produce hydrogen and can benefit more from selling excess renewable power to the market. This scheduling flexibility reduces the mean power costs by $1.8\,€/kg$ throughout six scenarios, resulting in 19% higher levelised cost of hydrogen.

To answer the second sub-research question: *"How does the capacity of solar PV and onshore wind contracted in a power purchase agreement influence the cost of hydrogen production?"* this study examined different PPA portfolios and the impact of the type and size of renewable in the portfolio on the hydrogen production costs. The findings suggest that contracting renewable power capacity directly impacts the full load hours of the electrolyser, which affects how much renewable hydrogen can be produced. The findings do not necessarily point to solar PV or onshore wind leading to lower LCOH estimates due to the setup of the experiment and the decision to base the PPA price on the average capture price over all the scenarios. It should be noted that oversizing the renewable capacity relative to the electrolyser's capacity can lead to significant merchant risk, caused by the variability in power prices. The research highlights that the Dutch power market exhibits lower cost uncertainty for onshore wind capacity compared to solar PV. Even with a fixed-price PPA, there remains considerable variability in the LCOH when accounting for potential profits or losses from trading in the day-ahead market. This indicates that while fixed-price PPAs can provide some stability, the market dynamics introduce significant cost uncertainty.

The third sub-research question: *”How does the offtake volume affect the production cost of hydrogen?”* addressed the impact of the offtake volume in a hydrogen purchase agreement on hydrogen production costs. The analysis revealed that higher offtake volumes lead to a reduction in LCOH in all scenarios of the case study. The power costs of the take-as-produced profile rise with increased utilisation rates, however, the reduction in levelised capital expenditures overpowers the increase in power costs leading to an overall reduction in LCOH with higher utilisation. A baseload electrolyser without storage must operate continuously and accept any power price; thus, its power price remains unaffected by higher utilisation, while its levelised capital expenditures decrease with increased utilisation. The lowest LCOH was found at the highest utilisation rate. It is thus beneficial for take-as-produced and especially for baseload electrolysers to secure an offtaker for a major part of their production capacity to produce at a low levelised cost of hydrogen. When looking at the production costs of hydrogen, it can also be important to look at the type of hydrogen produced. The higher utilisation rates might benefit from lower levelised costs, they do not produce green hydrogen, or RFNBO-compliant hydrogen for their entire production. Our analysis indicates that under a yearly matching criterion for renewable power generation and hydrogen production, a $100MW$ electrolyser paired with 200 MW of solar PV and $200MW$ of onshore wind can achieve approximately $6,000$ full-load hours of green hydrogen production. However, with an hourly matching criterion, the electrolyser’s operation is limited to around $5,000$ full-load hours of green hydrogen production.

The fourth sub-question: *”How much can hydrogen storage contribute to lowering the cost of power for hydrogen production under different hydrogen offtake profiles?”* studied the impact of hydrogen storage in reducing the cost of delivering a baseload profile. The incorporation of hydrogen storage plays a significant role in reducing the LCOH for delivering a baseload volume but does not contribute to lowering the LCOH for a take-as-produced profile. Under the take-as-produced profile, the electrolyser already has optimised its hydrogen production schedule and therefore the addition of storage capacity did not have any effect, other than adding costs. For the baseload profile, the availability of hydrogen storage means that production can shift to hours with lower power prices. The reduction in power costs was $3.6 - 13$ times as big as the increase in costs. By sizing the storage outflow capacity to be at least as big as the baseload volume, levelised costs can be reduced by $8 - 17\%$ in case of low storage costs, and $6 - 16\%$ in case of high storage costs. The cost premium for producing a baseload profile can then be reduced to $2 - 6\%$ under low storage costs, and $4 - 8\%$ under high storage costs, down from 19% without any storage capacity. This underscores that hydrogen storage is essential for any hydrogen producer that considers producing a baseload volume at competitive costs.

By answering each sub-question, the research improves the understanding of how hydrogen production costs are influenced under a long-term hydrogen purchase agreement. The findings demonstrate that cost-efficient green hydrogen production under a hydrogen purchase agreement depends on a synergistic design of the hydrogen offtake profile, hydrogen offtake volume, PPA portfolio and storage capacity, along with the technical considerations of an electrolyser and the electricity market it is connected to. Balancing these factors enables hydrogen producers to reduce costs and risk when developing an electrolyser before a fully functioning hydrogen market has developed.

6.2. Reflection on Societal Relevance

The reflection on societal relevance is divided into different sections, one for every major group of actors. First, the relevance of the findings hydrogen producers will be explained in section 6.2.1. Second the relevance for industry actors who want to, or are forced to use green hydrogen as part of their production process is given in section 6.2.2. The third group of actors that are addressed are the policymakers in section 6.2.3.

6.2.1. Relevance for Hydrogen Producers

Green hydrogen producers face a daunting challenge. Developing commercial-size electrolysers with high investment costs, uncertain power costs and no guaranteed access to a functioning market.

Bilateral contracts can be used to mitigate some critical uncertainties. For power procurement, this means that a PPA portfolio leads to a steady supply of renewable power, for a fair price. Too small of a portfolio of PPAs will cause a low utilisation factor and high levelised costs. Too big of a portfolio of PPAs will increase the risk of fluctuating market prices, especially for solar PV PPAs. On the other hand, it also increases the amount of green hydrogen that can be produced. When deciding the size of the portfolio, the renewable hydrogen certification scheme will have an impact, as well as the volume and the profile demanded by the offtaker.

If the offtaker requires a baseload profile, it is essential to secure or develop hydrogen storage. Our model suggests that hydrogen storage is very efficient at reducing power costs, which it achieves by shifting production to cheaper hours. The most important parameter of the storage according to our model is the outflow capacity of the storage, which should be able to supply the entire baseload offtake volume to the customer. This will enable a drastic reduction in the levelised cost to deliver a baseload profile and improve your competitiveness compared to other hydrogen producers. If the hydrogen storage costs are comparable to those of the Dutch national hydrogen storage operator HyStock, this study suggests the benefit of storage outweighs the costs by a factor 3.6 to 13, reducing your levelised costs of hydrogen by $6-17\%$. Aside from cost savings, this shift in the production schedule of baseload serving electrolysers will also increase the flexibility of electrolysers to participate in intraday and balancing markets thereby introducing additional revenue streams and reducing pressure on the grid.

If the offtaker is sufficiently flexible to offtake the entire production profile, this thesis suggests that developing hydrogen storage capacity is unnecessary. In such scenarios, storage would only increase the levelised costs without effectively reducing power costs, as it does for the baseload volume.

6.2.2. Relevance for industry

Industrial customers of green hydrogen will have to choose between creating flexibility themselves or paying a premium for inflexibility.

This study makes an attempt to quantify the premium from the producer's perspective. Renewable power production is inherently variable, it is therefore more straightforward to have a likewise variable production schedule of green hydrogen. By demanding a baseload profile, green hydrogen production costs increase by at least 2 to 8%. The production costs will increase due to the necessity of hydrogen storage, but more importantly, the power costs will increase significantly. Next to the production costs the hydrogen producer will likely require an additional risk premium for creating a flat profile out of a variable RES production curve. As power prices and renewable generation are highly volatile, this premium for a baseload profile will be substantial.

If contrarily, the producer is given flexibility in their production schedule, green hydrogen production costs will be at least 2 to 8% lower. Additionally, hydrogen production will likely emit less CO2 and potentially offer balancing services to the grid.

It is not straightforward to demand a baseload profile of hydrogen. Before including such a requirement in negotiations with a hydrogen producer, it is advisable to evaluate whether any flexibility can be accommodated on the offtakers side. Increased flexibility may result in a more socially optimal solution, potentially reducing costs for both parties involved in the hydrogen purchase agreement.

6.2.3. Relevance for policymakers

Hydrogen is an essential ingredient for successful deep decarbonisation. As the hydrogen economy is not matured yet, there are countless uncertainties which hinder investment in green hydrogen production. One of them is the mismatch between the production and the demand profile of hydrogen actors. This thesis studied how hydrogen producers can adapt their production profile to accommodate the baseload supply that is required by many offtakers. Although it is possible for a grid-connected electrolyser to produce a baseload profile, it increases power costs significantly and reduces the flexibility of electrolysers, reducing their potential to accommodate balancing services to the grid and decreasing the share of green hydrogen produced.

One way of mitigating some of these problems is to facilitate the development of hydrogen storage, which allows producers to shift their hydrogen production to reduce power costs while also decreasing their demand during expensive peak hours. As the lowest cost storage is currently underground storage in salt caverns, promoting the development of this type of storage is advised. Make sure storage is developed centrally (as larger storages are less costly) so all hydrogen producers or consumers can use this storage to optimise their processes and reduce the switching costs to green/ low carbon hydrogen. Ensuring hydrogen storage is available to everyone will guarantee a level playing field for all hydrogen producers and consumers. If central hydrogen storage is not possible, start by organizing clusters of hydrogen production and demand and ensure that each cluster has access to a low-cost hydrogen storage facility. With specific costs of storage of 0.1 or 0.2 €$/MWh/yr$, the benefits for producers heavily outweigh the costs. If hydrogen storage can be realised below this number no additional subsidy is thus required to see the benefits described by this thesis.

While this study focused on solutions to the mismatch from the producer's perspective, it is important to recognize that flexibility can also come from the demand side. Take-as-produce contracts naturally shift hydrogen production to when the supply of power is high and demand is low, as the price signal incentivises electrolyser to do so. Before awarding subsidies for hydrogen storage, it is recommended to evaluate the potential for demand-side flexibility in the offtake profile. Such flexibility may provide a more cost-effective alternative towards reducing the mismatch of production and demand profiles, depending on the specific context. By assessing demand-side opportunities, policymakers can ensure that resources are allocated efficiently and that the most economical and sustainable solutions are realised.

6.3. CoSEM Perspective

This thesis embodies the core of the CoSEM (Complex Systems Engineering and Management) programme by designing a solution in a complex socio-technical environment. As the energy system is undergoing structural change and expectations of the impact of green hydrogen in the energy transition are high, the value chain of hydrogen must be developed efficiently. By developing a framework for analysing the cost implications of different contract structures, price negotiations can be aided by providing estimates of costs implications of contract clauses.

The thesis has a clear design component in the design of an institutional artefact: the HPA. It uniquely studies the cost differences between offtake profiles and offtake volume, an area not often addressed in the existing literature. This systematic and creative approach to design highlights the innovative nature of the research.

The thesis explores process management strategies relevant to stakeholders interested in hydrogen production or consumption capacity, who currently refrain from investing. By understanding the institutional framework that could drive investment, the research provides a pathway forward. Additionally, the electrolyser technology discussed in the thesis further couples the power sector with heavy industry, creating an even more interconnected system with numerous stakeholders involved.

The research employs a comprehensive literature study that integrates insights from technical, economic, political, and institutional research fields. It includes an institutional economic analysis of the future hydrogen market and follows a systematic approach to the modeling cycle, including validation and experimentation. A case study in the Netherlands applies optimal scheduling of electrolyser and hydrogen storage operation to understand long lasting consequences of various contract clauses.

The thesis covers values from both public and private domains. Public values include the reduction of greenhouse gas emissions, the development of a hydrogen economy, and sector coupling, all crucial for the Netherlands' ambition to become an international hydrogen hub. Private values focus on the creation of bilateral contracts in the absence of a liquid market, gaining competitive advantage through early entry, and collaboration with a company currently developing an electrolyser, ensuring that the insights can be directly applied.

6.4. Future Work

While this research focused on the segregated merchant model, future research could explore other project ownership models for electrolyser facilities, such as integrated merchant and tolling agreements. Each ownership structure has distinct financial implications, risk profiles, and operational efficiencies. By comparing these models, researchers could analyse differences in capital and operational costs, financing mechanisms, and profitability. This analysis would provide insights into the most cost-effective ownership configurations, enabling stakeholders to make informed decisions based on financial viability and risk tolerance.

A complete risk analysis, particularly focusing on merchant risk, is crucial for understanding the financial viability of electrolyser projects. Merchant risk refers to the uncertainty in revenue streams due to fluctuating market prices when selling hydrogen without fixed price agreements. Research could quantify the impact of market volatility, price uncertainties, and demand fluctuations on project returns. This analysis could include the development of risk mitigation strategies to enhance the financial stability of electrolyser projects.

Incorporating a more dynamic market model into the analysis would better reflect the real-time fluctuations in energy prices and demand, providing a more accurate assessment of the economic performance of electrolyser projects. Additionally, expanding the scope of the model to include other relevant markets, such as intraday and balancing markets, would offer a comprehensive view of revenue opportunities and operational flexibility. This would allow for a more detailed assessment of the potential benefits of participating in multiple energy markets, thereby optimizing operational strategies for electrolysers.

The role of linepack flexibility, the ability to store gas within pipelines by varying the pressure, could significantly influence the storage requirements for hydrogen. Future studies could evaluate If this flexibility reduces the need for dedicated hydrogen storage, potentially lowering costs and improving the efficiency of the hydrogen supply chain. This research would be crucial for optimizing pipeline and storage operations, thereby enhancing the overall efficiency and cost-effectiveness of hydrogen delivery.

7 Reflection

This thesis represents the final assignment of my Master's degree in Complex Systems Engineering and Management at TU Delft. My work contributes to an emerging area of research by bridging the gap between techno-economic and institutional considerations, a link that remains underdeveloped in the current body of literature on the optimisation of hydrogen systems. Through this integration, I aimed to model the complex interplay between technical constraints and institutional requirements, addressing how hydrogen offtake volume and profile affect the financial viability of electrolyser operations.

Reflecting on the journey, I am proud of the progress I have made, both academically and personally. Constructing and adapting a model in Julia, a programming language I had not used before, was a significant challenge that I successfully navigated. Additionally, I found a balance between academic relevance and practical contributions, particularly in supporting hydrogen asset developers at Eneco. Their efforts in developing an electrolyser, navigating subsidies and regulations, and valuing hydrogen storage provided a dynamic and constantly evolving context that enriched my understanding of the sector.

This thesis highlights the critical role of hydrogen storage in energy systems and studies the financial impact of the configuration of bilateral offtake agreements on the levelised cost of hydrogen. To my knowledge, it is among the first attempts at integrated modelling of electrolyser operation and demand requirements within such an optimisation framework. While the theoretical advancements may be incremental, the approach demonstrates a novel perspective that integrates institutional and techno-economic dimensions into optimization.

However, the journey was not without its challenges. Defining and narrowing the scope of the research proved difficult, as I initially struggled to choose a specific focus. A more targeted literature review and seeking earlier feedback might have streamlined this process. Additionally, I underestimated the depth of exploration expected in a thesis compared to an academic article. Adjusting to these expectations late in the process highlighted the need for a more exhaustive exploration of the background, theoretical framework, and detailed methodology in writing this thesis.

The experience has profoundly shaped me as a researcher. I gained valuable skills in programming, optimization techniques, and understanding the complexities of energy markets and hydrogen systems. Beyond technical skills, I developed a deeper appreciation for the complexities of the energy transition and the risks involved in investing in renewable energy assets. This project also underscored the importance of flexibility, facing unforeseen hurdles, adjusting my approach, and making the most of available resources to complete this work.

Finally, I am humbled by the depth of expertise required in this field and the contributions of researchers working on optimization and energy systems. While my understanding remains limited, this thesis has strengthened my respect for the interdisciplinary efforts driving the researchers in this field and has provided me with a foundation to continue contributing to this critical area.

References

[1] European Commission, “A hydrogen strategy for a climate-neutral europe,” Jul. 8, 2020. [Online]. Available: https://energy.ec.europa.eu/system/files/2020-07/hydrogen_strategy_0.pdf.

[2] M. Yue, H. Lambert, E. Pahon, R. Roche, S. Jemei, and D. Hissel, “Hydrogen energy systems: A critical review of technologies, applications, trends and challenges,” *Renewable and Sustainable Energy Reviews*, vol. 146, p. 111 180, Aug. 2021, ISSN: 13640321. DOI: 10.1016/j.rser.2021.111180.

[3] L. Vidas and R. Castro, “Recent developments on hydrogen production technologies: State-of-the-art review with a focus on green-electrolysis,” *Applied Sciences*, vol. 11, p. 11 363, 23 Dec. 2021, ISSN: 2076-3417. DOI: 10.3390/app112311363.

[4] Nationaal Waterstofprogamma, “Routekaart waterstof,” Nov. 2022. [Online]. Available: https://nationaalwaterstofprogramma.nl/documenten/handlerdownloadfiles.ashx?idnv=2339011.

[5] Shell Nederland B.V. “Shell start bouw van europa’s grootste groene waterstoffabriek in rotterdam | over ons.” (Jul. 6, 2022), [Online]. Available: https://www.shell.nl/over-ons/nieuws/nieuwsberichten-2022/holland-hydrogen-1.html.

[6] B.-J. Jesse, G. J. Kramer, V. Koning, S. Vögele, and W. Kuckshinrichs, “Stakeholder perspectives on the scale-up of green hydrogen and electrolyzers,” *Energy Reports*, vol. 11, pp. 208–217, Jun. 2024, ISSN: 23524847. DOI: 10.1016/j.egyr.2023.11.046.

[7] J. Burchardt, E. Hegnsholt, M. Holm, F. Klose, D. Ritter, and S. Schönberger, *Turning the european green hydrogen dream into reality: A call to action without additional regulatory support, european green hydrogen may remain the fuel of the future*, Nov. 2023.

[8] S. Craen, “Financing a world scale hydrogen export project,” p. 49,

[9] Y. Ghiassi-Farrokhfal, W. Ketter, and J. Collins, “Making green power purchase agreements more predictable and reliable for companies,” *Decision Support Systems*, vol. 144, p. 113 514, May 2021, ISSN: 01679236. DOI: 10.1016/j.dss.2021.113514.

[10] L. F. J. Eblé, “Temporal-correlation requirements for industrial onsite electrolysis on the impact of temporal-correlation requirements and downstream industrial flexibility on the optimal design and costs for onsite electrolytic hydrogen production,” 2023. [Online]. Available: http://repository.tudelft.nl/..

[11] S. Hollmen, F. Levihn, and G. Martinsson, “When markets don’t deliver : – bilateral hedging by means of ppas in managing intertemporal price risks in power generation investments,” IEEE, Sep. 2022, pp. 1–6, ISBN: 978-1-6654-0896-7. DOI: 10.1109/EEM54602.2022.9921036.

[12] I. Moradpoor, S. Syri, and A. Santasalo-Aarnio, “Green hydrogen production for oil refining – finnish case,” *Renewable and Sustainable Energy Reviews*, vol. 175, p. 113 159, Apr. 2023, ISSN: 13640321. DOI: 10.1016/j.rser.2023.113159.

[13] F. Biggins, M. Kataria, D. Roberts, and D. S. Brown, “Green hydrogen investments: Investigating the option to wait,” *Energy*, vol. 241, p. 122 842, Feb. 2022, ISSN: 03605442. DOI: 10.1016/j.energy.2021.122842.

[14] DNV, *Power price forecasting deeper understanding of merchant risk to support decision making in energy investments*.

[15] J. Kallrath, “Optimization: Using models, validating models, solutions, answers,” in *Business Optimization Using Mathematical Programming: An Introduction with Case Studies and Solutions in Various Algebraic Modeling Languages*. Cham: Springer International Publishing, 2021, pp. 1–32, ISBN: 978-3-030-73237-0. DOI: 10.1007/978-3-030-73237-0_1. [Online]. Available: https://doi.org/10.1007/978-3-030-73237-0_1.

[16] R. G. Sargent, "Verification and validation of simulation models," in *Proceedings of the 2010 Winter Simulation Conference*, Dec. 2010, pp. 166–183. DOI: 10.1109/WSC.2010.5679166.

[17] E. B. Agyekum, C. Nutakor, A. M. Agwa, and S. Kamel, "A Critical Review of Renewable Hydrogen Production Methods: Factors Affecting Their Scale-Up and Its Role in Future Energy Generation," *Membranes*, vol. 12, no. 2, p. 173, Feb. 2022. DOI: 10.3390/membranes12020173. [Online]. Available: https://doi.org/10.3390/membranes12020173.

[18] I. Dincer, "Green methods for hydrogen production," *International journal of hydrogen energy*, vol. 37, no. 2, pp. 1954–1971, Jan. 1, 2012. DOI: 10.1016/j.ijhydene.2011.03.173. [Online]. Available: https://doi.org/10.1016/j.ijhydene.2011.03.173.

[19] L. M. Ringsgwandl, J. Schaffert, N. Brücken, R. Albus, and K. Görner, "Current legislative framework for green hydrogen production by electrolysis plants in germany," *Energies*, vol. 15, p. 1786, 5 Feb. 2022, ISSN: 1996-1073. DOI: 10.3390/en15051786.

[20] S. Grigoriev, V. Fateev, D. Bessarabov, and P. Millet, "Current status, research trends, and challenges in water electrolysis science and technology," *International journal of hydrogen energy*, vol. 45, no. 49, pp. 26 036–26 058, Oct. 2020. DOI: 10.1016/j.ijhydene.2020.03.109. [Online]. Available: https://doi.org/10.1016/j.ijhydene.2020.03.109.

[21] M. Younas, S. Shafique, A. Hafeez, F. Javed, and F. Rehman, "An overview of hydrogen production: Current status, potential, and challenges," *Fuel*, vol. 316, p. 123 317, May 2022, ISSN: 00162361. DOI: 10.1016/j.fuel.2022.123317.

[22] G. Flis, G. Wakim, and C. A. T. Force, "Solid Oxide Electrolysis: A Technology Status assessment," Tech. Rep., Nov. 2023. [Online]. Available: https://cdn.catf.us/wp-content/uploads/2023/11/15092028/solid-oxide-electrolysis-report.pdf.

[23] S. M. Saba, M. Müller, M. Robinius, and D. Stolten, "The investment costs of electrolysis – a comparison of cost studies from the past 30 years," *International Journal of Hydrogen Energy*, vol. 43, pp. 1209–1223, 3 Jan. 2018, ISSN: 03603199. DOI: 10.1016/j.ijhydene.2017.11.115.

[24] T. Wang, X. Cao, and L. Jiao, "Pem water electrolysis for hydrogen production: Fundamentals, advances, and prospects," *Carbon Neutrality*, vol. 1, p. 21, 1 Dec. 2022, ISSN: 2731-3948. DOI: 10.1007/s43979-022-00022-8.

[25] M. Jayachandran, R. K. Gatla, A. Flah, *et al.*, "Challenges and opportunities in green hydrogen adoption for decarbonizing hard-to-abate industries: A comprehensive review," *IEEE Access*, vol. 12, pp. 23 363–23 388, 2024, ISSN: 21693536. DOI: 10.1109/ACCESS.2024.3363869.

[26] M. Hermesmann, C. Tsiklios, and T. Müller, "The environmental impact of renewable hydrogen supply chains: Local vs. remote production and long-distance hydrogen transport," *Applied Energy*, vol. 351, p. 121 920, Dec. 2023, ISSN: 03062619. DOI: 10.1016/j.apenergy.2023.121920.

[27] A. M. Abdalla, S. Hossain, O. B. Nisfindy, A. T. Azad, M. Dawood, and A. K. Azad, "Hydrogen production, storage, transportation and key challenges with applications: A review," *Energy Conversion and Management*, vol. 165, pp. 602–627, Jun. 2018, ISSN: 01968904. DOI: 10.1016/j.enconman.2018.03.088.

[28] Hynetwork. "Waterstofnetwerk nederland." (2024), [Online]. Available: https://www.hynetwork.nl/over-hynetwork/waterstofnetwerk-nederland.

[29] HyNetwork, *Hns general terms and conditions transport annex 6. pipeline flexibility service 1*, 2022. [Online]. Available: https://www.hynetwork.nl/zakelijk/contracten.

[30] J. Andersson and S. Grönkvist, "Large-scale storage of hydrogen," *International Journal of Hydrogen Energy*, vol. 44, pp. 11 901–11 919, 23 May 2019, ISSN: 03603199. DOI: 10.1016/j.ijhydene.2019.03.063.

[31] C. Moran, P. Deane, S. Yousefian, and R. F. Monaghan, "The hydrogen storage challenge: Does storage method and size affect the cost and operational flexibility of hydrogen supply chains?" *International Journal of Hydrogen Energy*, vol. 52, pp. 1090–1100, Jan. 2024, ISSN: 03603199. DOI: 10.1016/j.ijhydene.2023.06.269.

[32] H. Barthelemy, M. Weber, and F. Barbier, "Hydrogen storage: Recent improvements and industrial perspectives," *International Journal of Hydrogen Energy*, vol. 42, pp. 7254–7262, 11 Mar. 2017, ISSN: 03603199. DOI: 10.1016/j.ijhydene.2016.03.178.

[33] R. Tarkowski, "Underground hydrogen storage: Characteristics and prospects," *Renewable and Sustainable Energy Reviews*, vol. 105, pp. 86–94, May 2019, ISSN: 13640321. DOI: 10.1016/j.rser.2019.01.051.

[34] HyStock, "Succesvolle open season: Ruime belangstelling voor waterstofopslag eerste zoutcaverne hystock," Jul. 24, 2023. [Online]. Available: https://www.hystock.nl/nieuws/succesvolle-open-season-ruime-belangstelling-voor-waterstofopslag-eerste-zoutcaverne-hystock.

[35] F. Mousavi, M. Nazari-Heris, B. Mohammadi-Ivatloo, and S. Asadi, "Energy market fundamentals and overview," in Elsevier, Jan. 2021, pp. 1–21, ISBN: 9780128200957. DOI: 10.1016/B978-0-12-820095-7.00005-4.

[36] Gasunie Transport Services. "Linepack flexibility service." (), [Online]. Available: https://www.gasunietransportservices.nl/shipper-trader/balanceringsregime/linepack-flexibility-service.

[37] A. Correlje, "Natural gas: A tale of three markets," English, in *The Routledge companion to network industries*, M. Finger and C. Jaag, Eds. Routledge - Taylor Francis Group, 2016, pp. 55–67, ISBN: 9781138782822.

[38] J. Rogel-Salazar and N. Sapsford, "Seasonal effects in natural gas prices and the impact of the economic recession," *Wilmott*, vol. 2014, no. 74, pp. 74–81, 2014. DOI: https://doi.org/10.1002/wilm.10383. eprint: https://onlinelibrary.wiley.com/doi/pdf/10.1002/wilm.10383. [Online]. Available: https://onlinelibrary.wiley.com/doi/abs/10.1002/wilm.10383.

[39] HyXchange. "Projects | hyxchange." (Mar. 1, 2022), [Online]. Available: https://hyxchange.nl/projects/#p1.

[40] B. Klein, R. G. Crawford, and A. A. Alchian, "Vertical integration, appropriable rents, and the competitive contracting process," *The Journal of law economics/The journal of law economics*, vol. 21, no. 2, pp. 297–326, Oct. 1, 1978. DOI: 10.1086/466922. [Online]. Available: https://doi.org/10.1086/466922.

[41] A. Neumann, S. Rüster, and C. von Hirschhausen, *Long-term contracts in the natural gas industry: Literature survey and data on 426 contracts (1965-2014)*, 2015. [Online]. Available: www.diw.de.

[42] M. Dailami and R. Hauswald, "Risk shifting and long-term contracts : evidence from the Ras Gas Project," The World Bank, Policy Research Working Paper Series 2469, Nov. 2000. [Online]. Available: https://ideas.repec.org/p/wbk/wbrwps/2469.html.

[43] D. L. Brito and P. R. Hartley, "Evolution of the international LNG market," Tech. Rep., Sep. 2002. [Online]. Available: http://www.bakerinstitute.org/research/evolution-of-the-international-lng-market/.

[44] P. R. Hartley, "The future of long-term lng contracts," *Energy Journal*, vol. 36, pp. 209–233, 3 2015, ISSN: 01956574. DOI: 10.5547/01956574.36.3.phar.

[45] P. Wallace, "Long-term power purchase agreements: The factors that influence contract design," in Edward Elgar Publishing, Sep. 2019. DOI: 10.4337/9781786436153.00023.

[46] de Vries and EnergyX: Sustainable Energy: Design A Renewable Future, *Bilateral markets - sustainable energy - tu delft*, Sep. 10, 2016. [Online]. Available: https://www.youtube.com/watch?v=p24p0tEwQ1Q.

[47] S. E. Masten and K. J. Crocker, "Efficient adaptation in long-term contracts: Take-or-pay provisions for natural gas," *The American Economic Review*, vol. 75, no. 5, pp. 1083–1093, 1985, ISSN: 00028282. [Online]. Available: http://www.jstor.org/stable/1818647 (visited on 06/21/2024).

[48] European Union, “Directive (eu) 2023/2413 of the european parliament and of the council of 18 october 2023 amending directive (eu) 2018/2001, regulation (eu) 2018/1999 and directive 98/70/ec as regards the promotion of energy from renewable sources, and repealing council directive (eu) 2015/652,” directive, Oct. 31, 2023. eprint: OJL,2023/2413,31.10.2023,pp.1-77. [Online]. Available: http://data.europa.eu/eli/dir/2023/2413/oj.

[49] S. Schnorr, “Bepreisung von ppa,” in *Power Purchase Agreements: Stromlieferverträge für Erneuerbare Energien*. Wiesbaden: Springer Fachmedien Wiesbaden, 2022, pp. 21–32, ISBN: 978-3-658-37910-0. DOI: 10.1007/978-3-658-37910-0_3. [Online]. Available: https://doi.org/10.1007/978-3-658-37910-0_3.

[50] L. F. J. Eblé and M. Weeda, “Evaluation of the levelised cost of hydrogen based on proposed electrolyser projects in the netherlands, Renewable hydrogen cost element evaluation tool (rhyceet),” TNO 2024 R10766, May 13, 2024.

[51] O. Tang, J. Rehme, and P. Cerin, “Levelized cost of hydrogen for refueling stations with solar pv and wind in sweden: On-grid or off-grid?” *Energy*, vol. 241, p. 122 906, Feb. 2022, ISSN: 03605442. DOI: 10.1016/j.energy.2021.122906.

[52] M. McHugh. “Electricity tolling agreements: Unlocking revenue for renewable energy projects — solis renewables.” (Aug. 3, 2023), [Online]. Available: https://www.solisrenewables.com/blog/electricity-tolling-agreements.

[53] PEXAPARK. “Ppa glossary: Your ppa knowledge library.” (Mar. 3, 2023), [Online]. Available: https://pexapark.com/blog/glossary-energy-terms-ppa-explanation/#:~:text=Peak%20load%20PPA,typically%20from%208am%20to%208pm..

[54] C. Mittler, M. Bucksteeg, and P. Staudt, “Review of renewable power purchasing agreement types and classification through morphological analysis,” *Social Science Research Network*, Jan. 1, 2023. DOI: 10.2139/ssrn.4626108. [Online]. Available: https://doi.org/10.2139/ssrn.4626108.

[55] A. Kowalczyk and Enel Green. “Everything you always wanted to know about ppas (but were afraid to ask).” (Jul. 29, 2020), [Online]. Available: https://www.linkedin.com/pulse/everything-you-always-wanted-know-ppas-were-afraid-ask-anna-kowalczyk/.

[56] L. Hirth, “The market value of variable renewables,” *Energy Economics*, vol. 38, pp. 218–236, Jul. 2013, ISSN: 01409883. DOI: 10.1016/j.eneco.2013.02.004.

[57] L. Hirth, F. Ueckerdt, and O. Edenhofer, “Integration costs revisited – an economic framework for wind and solar variability,” *Renewable Energy*, vol. 74, pp. 925–939, Feb. 2015, ISSN: 09601481. DOI: 10.1016/j.renene.2014.08.065.

[58] W. Trabesinger. “Ppas, benchmarking and the price of risk.” (Jan. 9, 2023), [Online]. Available: https://www.linkedin.com/pulse/ppas-benchmarking-price-risk-werner-trabesinger/.

[59] European Commission. “Hydrogen value chain.” (), [Online]. Available: https://competition-policy.ec.europa.eu/state-aid/ipcei/approved-ipceis/hydrogen-value-chain_en.

[60] Office of Energy Efficiency and Renewable Energy. “Financial incentives for hydrogen and fuel cell projects.” (), [Online]. Available: https://www.energy.gov/eere/fuelcells/financial-incentives-hydrogen-and-fuel-cell-projects.

[61] Rijksdienst Voor Ondernemen. “Subsidieregeling opschaling volledig hernieuwbare waterstofproductie via elektrolyse (owe).” (Jun. 19, 2024), [Online]. Available: https://www.rvo.nl/subsidies-financiering/owe.

[62] E. Commission, *Commission Delegated Regulation (EU) 2023/1184 of 10 February 2023 supplementing Directive (EU) 2018/2001 of the European Parliament and of the Council by establishing a Union methodology setting out detailed rules for the production of renewable liquid and gaseous transport fuels of non-biological origin*, Jun. 2023. [Online]. Available: https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX%3A32023R1184&qid=1704969010792.

[63] P. Nikolaidis and A. Poullikkas, “A comparative overview of hydrogen production processes,” *Renewable sustainable energy reviews*, vol. 67, pp. 597–611, Jan. 1, 2017. DOI: 10.1016/j.rser.2016.09.044. [Online]. Available: https://doi.org/10.1016/j.rser.2016.09.044.

[64] P. Dodds, *Economics of hydrogen production*. Jan. 1, 2015, pp. 63–79. DOI: 10.1016/b978-1-78242-361-4.00003-0. [Online]. Available: https://doi.org/10.1016/b978-1-78242-361-4.00003-0.

[65] Agora Industry, Umlaut, F. Nigbur, M. Robinius, P. Wienert, and M. Deutsch, *Levelised cost of hydrogen*. Agora Industry, Jun. 2023. [Online]. Available: https://static.agora-energiewende.de/fileadmin/Projekte/2022/2022-12-10_Trans4Real/A-EW_301_LCOH_WEB.pdf.

[66] M. H. A. Khan, R. Daiyan, Z. Han, *et al.*, "Designing optimal integrated electricity supply configurations for renewable hydrogen generation in australia," *iScience*, vol. 24, p. 102 539, 6 Jun. 2021, ISSN: 25890042. DOI: 10.1016/j.isci.2021.102539.

[67] M. Gül and E. Akyüz, "Techno-economic viability and future price projections of photovoltaic-powered green hydrogen production in strategic regions of turkey," *Journal of Cleaner Production*, vol. 430, p. 139 627, Dec. 2023, ISSN: 09596526. DOI: 10.1016/j.jclepro.2023.139627.

[68] G. Matute, J. Yusta, and N. Naval, "Techno-economic model and feasibility assessment of green hydrogen projects based on electrolysis supplied by photovoltaic ppas," *International Journal of Hydrogen Energy*, vol. 48, pp. 5053–5068, 13 Feb. 2023, ISSN: 03603199. DOI: 10.1016/j.ijhydene.2022.11.035.

[69] E. Zeyen, I. Riepin, and T. Brown, "Temporal regulation of renewable supply for electrolytic hydrogen," *Environmental Research Letters*, vol. 19, p. 024 034, 2 Feb. 2024, ISSN: 1748-9326. DOI: 10.1088/1748-9326/ad2239.

[70] V. Papadopoulos, J. Desmet, J. Knockaert, and C. Develder, "Improving the utilization factor of a pem electrolyzer powered by a 15mw pv park by combining wind power and battery storage – feasibility study," *International Journal of Hydrogen Energy*, vol. 43, pp. 16 468–16 478, 34 Aug. 2018, ISSN: 03603199. DOI: 10.1016/j.ijhydene.2018.07.069.

[71] P. Fragiacomo and M. Genovese, "Technical-economic analysis of a hydrogen production facility for power-to-gas and hydrogen mobility under different renewable sources in southern italy," *Energy Conversion and Management*, vol. 223, p. 113 332, Nov. 2020, ISSN: 01968904. DOI: 10.1016/j.enconman.2020.113332.

[72] D. Yu, J. Wang, D. Li, K. Jermsittiparsert, and S. Nojavan, "Risk-averse stochastic operation of a power system integrated with hydrogen storage system and wind generation in the presence of demand response program," *International Journal of Hydrogen Energy*, vol. 44, pp. 31 204–31 215, 59 Nov. 2019, ISSN: 03603199. DOI: 10.1016/j.ijhydene.2019.09.222.

[73] P. Xiao, W. Hu, X. Xu, W. Liu, Q. Huang, and Z. Chen, "Optimal operation of a wind-electrolytic hydrogen storage system in the electricity/hydrogen markets," *International Journal of Hydrogen Energy*, vol. 45, pp. 24 412–24 423, 46 Sep. 2020, ISSN: 03603199. DOI: 10.1016/j.ijhydene.2020.06.302.

[74] A. G. Johnsen, L. Mitidatri, D. Zarrilli, and J. Kazempour, "The value of ancillary services for electrolyzers," Oct. 2023. [Online]. Available: http://arxiv.org/abs/2310.04321.

[75] M. T. Baumhof, E. Raheli, A. G. Johnsen, and J. Kazempour, "Optimization of hybrid power plants: When is a detailed electrolyzer model necessary?," Institute of Electrical and Electronics Engineers Inc., 2023, ISBN: 9781665487788. DOI: 10.1109/PowerTech55446.2023.10202860.

[76] DinosoftLabs, *Factory icons*, https://www.flaticon.com/free-icons/factory.

[77] M. Mbarki, *Pipeline icon*, https://www.freepik.com/search.

[78] Pause08, *Tower icons*, https://www.flaticon.com/free-icons/tower.

[79] Ylivdesign, *Power market icon*, https://www.freepik.com/search.

[80] juicy$_{fish}$, *Ecology icons*, https://www.flaticon.com/free-icons/ecology.

[81] Dreamstale, *Green energy icons*, https://www.flaticon.com/free-icons/green-energy.

[82] Freepik, *Underground icons*, https://www.flaticon.com/free-icons/underground.

[83] J. M. Buchanan, "Opportunity cost," in *The World of Economics*, J. Eatwell, M. Milgate, and P. Newman, Eds. London: Palgrave Macmillan UK, 1991, pp. 520–525, ISBN: 978-1-349-21315-3. DOI: 10.1007/978-1-349-21315-3_69. [Online]. Available: https://doi.org/10.1007/978-1-349-21315-3_69.

[84] S. Furfari. “The present and future green hydrogen production cost | science, climat et énergie.” (Jul. 16, 2021), [Online]. Available: https://www.science-climat-energie.be/2021/07/16/the-present-and-future-green-hydrogen-production-cost/.

[85] J. Lambert, A. Hanel, S. Fendt, and H. Spliethoff, “Evaluation of sector-coupled energy systems using different foresight horizons,” *Renewable and Sustainable Energy Reviews*, vol. 184, p. 113 562, Sep. 1, 2023. DOI: 10.1016/j.rser.2023.113562. [Online]. Available: https://doi.org/10.1016/j.rser.2023.113562.

[86] M. S. Martis, “Validation of simulation based models: A theoretical outlook,” *The Electronic Journal of Business Research Methods*, vol. 4, pp. 39–46, 2006, ISSN: 1477-7029. [Online]. Available: www.ejbrm.com.

[87] HyStock, *Bid submission guidelines for hystock storage auction*, Unpublished auction document, 2023.

[88] European Commission. “European hydrogen bank.” (Apr. 30, 2024), [Online]. Available: https://energy.ec.europa.eu/topics/energy-systems-integration/hydrogen/european-hydrogen-bank_en.

[89] B. Poudel, D. Wendt, T. McJunkin, N. Kang, and R. Boardman, “Baseload hydrogen production using nuclear and renewable energy: A comparative analysis,” in *2024 IEEE Green Technologies Conference (GreenTech)*, 2024, pp. 106–110. DOI: 10.1109/GreenTech58819.2024.10520502.

[90] A. I. Rioja, P. Puranen, L. Järvinen, *et al.*, “Baseload hydrogen supply from an off-grid solar pv-wind power-battery-water electrolyzer plant,” *Energy Journal*, Jan. 1, 2024. DOI: 10.2139/ssrn.4969305. [Online]. Available: https://doi.org/10.2139/ssrn.4969305.