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Research Paper

Techno-economic evaluation of renewable hydrogen generation strategies for the industrial sector

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Abstract: Renewable hydrogen is considered as one of the key technologies that may be needed to fully decarbonise our economies, providing the high-temperature heat, fuels and feedstock that might not be possible to electrify. Several pilot projects are underway, and some assessments of the economics of green hydrogen have been published. However, most of them have assessed the costs of producing renewable hydrogen in large-scale, grid-connected units. Another option, pointed by many as a robust strategy in the early stages, is to produce hydrogen locally, in "hydrogen valleys", to serve industrial demand. In this paper, the economics of the different technical configurations and strategies that might be used for this decentralised, variable-demand option are analysed, accounting for the impact that a non-constant operation may cause on the operational efficiency of electrolysers, and for the potential benefits of local hydrogen storage. Our results show that when hydrogen demand is variable, production costs are higher compared to the constant demand case, due to the higher electrolyser size required. Electricity price optimisation plus hydrogen storage can be a valuable option in some cases, although the cost benefit is negligible (about 1%) unless price volatility in the market increases with higher RES shares, or investment costs decrease significantly. Sourcing electricity exclusively from a dedicated renewable power plant can only become competitive if electricity market prices rise as observed recently or triggered by increasing CO_2 prices.

Keywords: hydrogen; industry; decarbonisation; renewable energy systems; storage; variability; climate change

1. Introduction

The Paris Agreement climate goals define the pathway to decarbonise energy consumption towards 2050, demanding to restructure the current energy system, implying new requirements and challenges. Whereas several applications in the end-consumption sectors such as transport, industry and residential heating and cooling can be adapted to the direct use of green electricity, others will need to rely on decarbonised gaseous or liquid fuels as an energy carrier or feedstock. Power-to-X technologies enable the transformation of renewable electricity (wind and solar power) into gas or liquids. Renewable gas may provide long-term renewable energy storage and, more critically, provide an energy source or feedstock to many industrial processes that cannot be electrified directly (Rissman et al., 2020). It may therefore represent an essential element for decarbonising CO_2-intensive processes through sector coupling, which allows more flexible use of renewable electricity in all end-consumption sectors (Ramsebner, Haas, et al., 2021; Tang et al., 2021).

Some relevant industrial processes already heavily rely on hydrogen as an input, such as oil refining or ammonia production, with an expected growing trend in the coming years (International Energy Agency (IEA), 2019). However, so far, 96% of this hydrogen is produced from fossil fuels (natural gas 48%, fossil oil 30%, coal 18%), causing a substantial amount of CO_2 emissions (830 Mt CO_2/a in the industrial sector (Tang et al., 2021)). Green hydrogen, produced through the electrolysis of water with renewable energy, is a promising alternative to decarbonise these processes.

In addition, green hydrogen can supply high-temperature heat to other industrial processes (Gerres, Chaves Ávila, et al., 2019; Rissman et al., 2020). For example, in the steel industry, several projects consider replacing the coke-driven blast furnace with an electric arc furnace and the direct reduction of iron ore by green hydrogen (Tlili et al., 2020). The large-scale introduction of green hydrogen in the industry will depend on its cost competitiveness, not only with natural gas but also with other low-carbon alternatives (such as biogas or blue hydrogen). Currently, the cost of green H_2 production mainly depends on the electrolyser investment cost, the cost of electricity consumption, and the system efficiency, and usually accounts for about $2.5–6/kg or 76-181$/MWh H_2 (Rissman et al., 2020). Natural gas, for example, had an average market price in Europe of 24 $/MWh in 2019 (IEA, 2022). A continuous cost reduction for renewable H_2 needs to be promoted by supportive policies to achieve market penetration (Gerres et al., 2019; Linares et al., 2008; Neuhoff et al., 2019, 2020, 2021).

Several studies, such as Bristowe & Smallbone (2021), Frischmuth & Härtel (2022) and Weidner et al. (2018), have assessed the potential H_2 cost reduction with upscaling of capacities in a central European context. Brändle et al. (2020) estimate the global H_2 production development and supply cost from renewables and natural gas until 2050. Their results show that a substantial cost decrease could drive green H_2 towards competitiveness. The authors expect a hydrogen cost decrease for PV and wind connected electrolysis from about 4.0 $/kg in 2020 down to 1.8 $/kg in 2050 in a not too optimistic scenario. Hydrogen production from Qatar or Russia-sourced natural gas is expected to reach 0.4-0.6 $/kg for pyrolysis and 0.95-1.2 $/kg for natural gas reforming (NGR) with carbon capture and storage (CCS) in 2025. If a gas price of 40 $/MWh is assumed this could increase up to about 2.8-3.2 $/kg for pyrolysis or NGR with CCS.

However, these studies mainly focus on large-scale, grid-connected electrolysers. While this centralised production benefits from high production volumes and the pooling of many varying demand profiles, it also relies on an appropriate hydrogen transport and distribution infrastructure, which entails significant costs. For example, a Hydrogen Backbone could be built in Europe using existing and new dedicated H_2 pipelines (Wang et al., 2020).

An alternative option, which would prove to be more robust in the early stages, would be to produce hydrogen locally in what is termed "hydrogen valleys" or industrial hubs (Tu et al., 2021; Di Micco et al, 2023). Hydrogen refueling stations (or HRS) are also interesting decentralised possibilities (Barhoumi et al, 2022a; 2022b; 2023). This decentralised H_2 production might be beneficial due to the elimination of distribution infrastructure requirements and associated cost as well as the possibility to optimise electricity consumption according to specific demand situations. On the other hand, it poses several challenges, such as coupling H_2 production with industrial demand or optimising the cost of electricity supply, which in turn will affect the cost of the hydrogen produced. Although Matute et al. (2019) observe that a large part of the cost of green hydrogen depends on the cost of electricity, the potential need for hydrogen storage, the definition of the capacity of the electrolyser and the operation regime will also influence the final cost of the hydrogen delivered to industry to a large extent.

In this paper, we assess the different technical configurations and strategies that may be used to provide renewable hydrogen for the industry by looking at different on-site operation strategies and storage and electrolyser configurations and the implications that these may have for the cost of producing hydrogen in industrial hubs. While the importance and potential of a deep decarbonisation of the industrial sector is evident, the knowledge among companies, analysts and policy makers lags behind the ambitions and specific goals for decarbonisation of other end-consumption sectors such as transport and heating (Bataille, Fischedick et al., 2014b; Loftus et al., 2015).

When it comes to the electricity source, Schlund & Theile (2021) define three possibilities of electricity procurement that are applicable. A direct connection with a renewable power plant, an additional link to the public grid for risk management and supply balancing purposes, and a purely grid-connected electrolyser. Sourcing from the grid is convenient due to constant electricity availability, allowing for several H_2 deployment strategies. However, the electricity consumption from the grid requires certification of the consumed amount as green electricity, and grid fees need to be considered unless regulations exempt H_2 production plants from paying them. Sourcing electricity from a dedicated renewable power plant would avoid these fees but implies substantial supply variability for the electrolyser and low flexibility in H_2 production (El-Emam & Özcan, 2019). According to Gahleitner (2013), balancing the supply variability requires additional battery storage to match demand reliably. This investment, of course, increases the total cost of H_2 production.

If a high capacity utilisation of the electrolyser is achieved, meaning high full load hours, the capacity cost per MWh is lower, and electricity consumption becomes the larger share of the levelised cost of hydrogen (LCOH). This significant part of the green hydrogen cost is increasingly exposed to market price variability (Machhammer et al., 2016; Schlund & Theile, 2021). However, full load operation requires a constant hydrogen demand or substantial storage capacities, which are not necessarily feasible for industrial hubs. In these cases, hydrogen may be produced in a more "passive" way, following demand requirements (Just in Time, JIT), or trying to optimise the cost of electricity (which would, in turn, require storing the electricity purchased or the hydrogen[1] produced to fit demand). In both cases, the variable operation of the electrolyser means that the conversion efficiencies may be affected. As a result, the capacity optimization of the electrolyser is not trivial and subject to uncertainty.

We aim to assess the cost implications of these different configurations: just-in-time (JIT) production without storage[2], electricity price optimisation plus storage, and RES island configurations. To better showcase the effect of the different strategies this work focuses on the two more extreme options defined by Schlund & Theile (2021) and does not provide a case in which renewable and grid feed-in are mixed[3]. We do this for two different types of industrial hubs: a variable demand scenario,

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[1] For H_2 storage, Gahleitner (2013) finds that the best option is pressure tanks (CHG), characterised by low cost and high capacities without the necessity of spending cost and losing efficiency through compression.

[2] A potential outcome of price optimisation would be the JIT solution, that is, a zero storage. That would be the case when the benefits of optimising electricity prices are not enough to pay for the added cost of storage. However, we still keep an exogenously-determined JIT solution to represent the more "passive" strategy and compare it explicitly to the price optimization strategy.

[3] Since this mix would have many possible values, we believe that considering it would add complexity without adding much to the basic messages of our research. One possible extension of our work would be to find the optimal mix of grid and renewable feed-in.

representing a hydrogen valley, and a full-load, constant demand case, which can represent either a constant demand industrial facility or a centralised production scenario. We acknowledge that a constant demand scenario has already been studied extensively by the previous literature both for centralised and decentralised generation, but in this case we use it as a reference to compare against the other alternatives, under the same assumptions and parameters. We also compare the performance of two electrolyser technologies, alkaline (ALK) and proton-exchange membrane (PEM), given their different Faraday efficiencies under variable operation.

The novelty of our contribution lies in assessing different strategies for producing hydrogen to supply a variable demand, in comparing them to constant demand options, and in doing this while considering the Faraday efficiency of the electrolyzers, which can significantly affect the cost with variable generation or demand. The cost assessment for these options has not yet been undertaken in the literature but may contribute to making better decisions in deploying green hydrogen in industrial hubs.

The structure of the paper is as follows: After reviewing the state of the art on this topic, we describe in detail the different configurations assessed, in particular the assumptions about operation efficiency and the optimization model. We then apply these configurations to the two types of hydrogen demand and discuss the implications on costs, choice of electrolyser technology, and system capacity. Finally, we analyse the sensitivity of our results to changes in our assumptions and provide some conclusions and recommendations.

2. State of the art

2.1. Hydrogen supply in industry

Scientific literature already covers many aspects of green H_2 production and its competitiveness with conventional H_2 from the present to the long-term future. Jacobasch et al. (2021) evaluate the long-term economic aspects of low-carbon steelmaking in an industrial context. They name similar studies by Abdul Quader et al. (2016), Fischedick et al. (2014), Joas et al. (2019), and Otto et al. (2017), mainly focusing on the technological development for and competitiveness of green steelmaking processes.

Several studies analyse the suitability and cost of different electricity input sources for centralised H_2 production: hydro, PV, wind power plants, or the grid. Mohammadi & Mehrpooya (2018) find that hydropower achieves low production costs, but wind and solar energy are available more widely and support an increase in H_2 production. Timmerberg et al. (2020) consider a combined wind and photovoltaic (PV) system without grid connection as well as gas combined cycle power plants. The cost of electricity is defined as the LCOE and is input to the model as a constant value. Bhandari & Shah (2021) analyse the cost of decentralised H_2 production in Germany for a set of refuelling stations with a PV power plant as an electricity source. They consider a grid-connected PV power system in which the grid functions as a buffer at times of low solar PV availability. Additionally, an isolated system with additional battery storage to balance feed-in to the electrolyser is analysed. The refuelling station demand already functions as a sort of storage, balancing the PV system's variable electricity supply. Due to the electricity supply from a dedicated plant, there is no electricity price optimisation possible.

Gorre et al. (2020) optimise H_2 storage and methanation capacity by evaluating three different electricity sources to use otherwise curtailed renewable electricity: a PV power plant, grid electricity and a wind power plant. They aim to optimise H_2 storage and methanation capacities to minimise levelised synthetic natural gas (SNG) production costs. Bertuccioli et al. (2014) point out that the electricity market price variability represents a promising characteristic for electricity consumption optimisation. Low electricity prices usually coincide with low demand or large amounts of renewable feed-in. In Austria, the correlation in 2018 between wind and PV power feed-in and electricity prices accounted for -0.28. Therefore, optimising industrial processes according to electricity prices seems to be a feasible balancing method. A broad range of work focuses on centralised applications of H_2 production optimization according to electricity prices. However, such optimisation can only be carried out with a continuous electricity supply from the grid. The economic performance is much more uncertain if the RES plant's variable input needs to be balanced through additional battery storage.

Larscheid et al. (2018) optimise a grid-connected electrolyser for H_2 revenue maximisation and use it for grid congestion management. Fragiacomo & Genovese (2020) allow the P2G plant to receive electricity from local RE plants and the public grid while considering H_2 feed-in into the gas grid and supply for the transport sector. In their study, the authors also apply a power purchase agreement[4] (PPA) within a range of 50-100€/MWh for electricity from renewable power plants and the electricity grid cost for grid consumption. They state that the potential of PPAs lies in hedging against market fluctuations.

As may be seen, most studies have focused on large-scale, centralised production of H_2, assuming a constant demand for hydrogen. However, decentralised, on-site production of H_2 is also an interesting possibility, mainly to avoid the upgrading or new construction of hydrogen transport infrastructure. On-site production, or production limited to "hydrogen valleys", has been proposed by Agora Energiewende et al. (2021) as a non-regret, robust way of starting the deployment of this technology and achieving higher production scales to decrease the cost.

There are, however, few investigations into decentralised supply strategies to fulfil local industrial demand[5]. On the decentralised H_2 production level, research offers a selection on the potential of industrial DSM (iDSM) concerning industrial electricity consumption. DSM requires a shift of production schedules according to electricity prices. These approaches are electricity focused and do not consider storage due to its cost. Arnold & Janssen (2016) define the electrolysis of ammonia as a suitable process for electricity DSM. In a study investigating the potential of iDSM for electricity markets in Germany, Paulus & Borggrefe (2011) identified that electric arc furnaces in steel manufacturing could provide a significant positive reserve capacity by decreasing demand when the electricity system falls short of capacity. Castro et al. (2013) investigate the economic potential of iDSM according to fluctuating energy prices. They find that large-scale, energy-intensive processes may play an important role. Chen et al. (2021) confirm the potential of industrial load shifting.

Apart from the price-based approach where customers respond to the electricity price by exploiting low-priced periods and avoiding production in high-priced periods, Castro et al. (2013) describe an incentive-based program. In that case, electricity can be bought at a lower price if the electricity consumption is contracted ahead of time and the agreed consumption curve is followed as closely as possible. Potential demand-side load shifting could provide additional flexibility to decentralised H_2 production and electricity price optimisation. Arnold & Janssen (2016), however, find that the willingness of industry players to participate in DSM is low due to adverse effects on the industrial process. iDSM is an electricity-focused approach that does not allow for the benefit of storage due to the cost. Electricity price optimization for H_2 production in the industrial sector may harm the production performance but could still represent a cost-competitive scenario.

Another relevant study that should be cited is Di Micco et al (2023), where a techno-economic analysis is performed of an off-grid multi-energy system for the co-production of green hydrogen, renewable electricity, and heat. The input energy is provided by wind energy and biogas, and hydrogen is used mostly for a HRS. In this case, however, hydrogen demand is assumed to be constant, contrary to our study.

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[4] Power purchase agreements define the delivery of a specific amount of renewable electricity, in this case from a dedicated renewable power plant at a defined price, still with the option to source this amount from the grid and enable certification of green electricity at continuous supply. PPAs furthermore act as a funding support towards investors.

[5] There are however many studies of hydrogen refueling stations (HRS), see e.g. Barhoumi et al (2022a; 2022b; 2023). These studies however assume constant demand, and high storage pressures (because of the need to fuel vehicles at these higher pressures).

2.2. Electrolyser efficiency and operating range

Current commercially relevant technologies for electrolysis are alkaline (ALK) and proton exchange membrane (PEM) electrolysers. While the ALK electrolyser has already reached technology readiness level 9, the PEM electrolyser has not yet achieved this level for larger capacities (Wulf et al., 2018). The ALK technology is based on a liquid electrolyte to achieve electrochemical reactions, while the PEM electrolyser uses a solid polymer electrolyte conducting positive ions such as protons (Caparrós Mancera et al., 2019).

The ALK electrolyser has advantages such as its maturity, lower investment cost and a higher lifetime of the stack, and has downsides in the longer time response and longer cold start time. The PEM electrolyser has benefits in dynamic operation and partial load performance facing variable operation and disadvantages such as the stack's lower lifetime, the need for platinum group metals and a backlog of maturity (Matute et al., 2019; Wulf et al., 2018). The ALK electrolyser can operate down to 20% of its installed capacity. The lowest operating range of a PEM electrolyser lies between 0-10% due to a higher current density achieved with the PEM technology and the solid electrolyte (Caparrós Mancera et al., 2019; Pascuzzi et al., 2016; Tom Smolinka et al., 2010).

The theoretical maximum conversion efficiency of ALK and PEM electrolysers is estimated by several references under different conditions (Table 1). Experiments with relatively small PV-connected systems described by Zini & Tartarini (2009) reveal an efficiency of 62% for a 5kW ALK electrolyser and 70% for a PEM electrolyser. Pascuzzi et al. (2016) carry out an analysis with an ALK electrolyser of 2.5 kW, which achieves a maximum energy efficiency of 67%. Since this study assumes rather large electrolysers for industrial use, maximum efficiency of 70% is considered appropriate.

Tom Smolinka et al. (2010) point out that the electrolyser efficiency increases to a maximum at a specific size of about 100Nm^3/h. Assuming a higher heating value of hydrogen of 3.54kWh/m^3 and a conversion efficiency of about 65%, this represents a 0.5 MW electrolyser (Kopp et al., 2017). The authors claim that this maximum can represent about 85% system efficiency. Nguyen et al. (2019) decide to assume one average efficiency each for the ALK (62%) and PEM (64%) electrolyser irrespective of the implemented size. Kopp et al. (2017) analyse a 6 MW PEM electrolyser and observe a maximum conversion efficiency of 64%.

Due to its characteristics, the PEM electrolyser provides better performance in the case of electricity price optimization implying variable electricity feed-in. It may be worth the additional cost, while the ALK electrolyser is favourable for continuous operation ranges with higher load factors.

Table 1 Theoretical efficiency of PEM and alkaline electrolysers

ALK	PEM	Reference
62%	70%	Zini & Tartarini (2009)
67%		Pascuzzi et al. (2016)
<85%		Tom Smolinka et al. (2010)
62%	64%	Nguyen et al. (2019)
	64%	Kopp et al. (2017)

Nevertheless, load changes affect temperature and pressure levels and may negatively affect the actual conversion efficiency (Tjarks et al., 2016; Wulf et al., 2018). Specifically, loads below 30% lead to a much higher energy demand per kWh of hydrogen produced (Bourasseau & Guinot, 2015; Wulf et al., 2018). After a complete shutdown of the electrolyser, the ramp-up causes substantial efficiency losses and takes up to several tens of minutes (Bourasseau & Guinot, 2015). The actual efficiency may differ from the theoretical maximum efficiency in Table 1, depending on the load factor. The actual efficiency is a major aspect modelled in this work and described in Section 3.3.1, determining to a large extent the economic performance of the H_2 production strategies and technology decisions.

2.3. Techno-economic characteristics

2.3.1. Electrolyser investment cost

Available research includes a broad range of estimations for the investment cost per kW electrolyser capacity, especially for short-term development. Figure 1 shows the investment costs gathered from literature for alkaline and PEM electrolysers between 2020 and 2050. For 2020, different types of literature estimated costs for alkaline electrolysers between 370 €/kW in the most optimistic case and 2,600 €/kW in the most pessimistic one. Currently, this is the more established technology, while PEM electrolysers are more expensive, leading to cost estimates between 700 €/kW and 3,700 €/kW in 2020. The data for long-term projections is scarce in literature, for both the ALK and PEM technology. While for 2020 there were about 10 different estimates available, this number decreases down to one or two in 2040 and 2050.

The development towards substantial cost decreases due to technological learning and increasing production volumes is replicated in the estimations found in literature for specifically for the ALK but also the PEM technology. The average estimations for the PEM electrolyser, however, seem to stagnate between 2030 and 2050 and remain more uncertain in the long-term compared to the ALK technology, shown by a broader range of estimations in 2050. The investment cost estimate in 2050 ranges between 250 €/kW in the optimistic case and 800 €/kW in the pessimistic case for ALK electrolyser, but PEM cost projections range up to 1,600 €/kW.

The CAPEX usually include stack or actual fuel cell cost, the balance of plant (BoP) including additional electronic equipment apart from the main stack such as sensors, compressors, pumps etc. and the power supply unit (Matute et al., 2019). The indirect investment cost is added based on Matute et al. (2019) explained in the Appendix. In a study by Nguyen et al. (2019), direct and indirect investment cost makes up 28.4% of the LCOH. The direct cost for the electrolyser represents about 15% of the LCOH and 55% of the total investment cost. Nguyen et al. (2019) provide a detailed analysis of the investment cost decrease with increasing electrolyser capacities. Above an installed capacity of 10 MW, the cost seems to stagnate for ALK electrolysers, and the decline visibly slows down for the PEM technology.

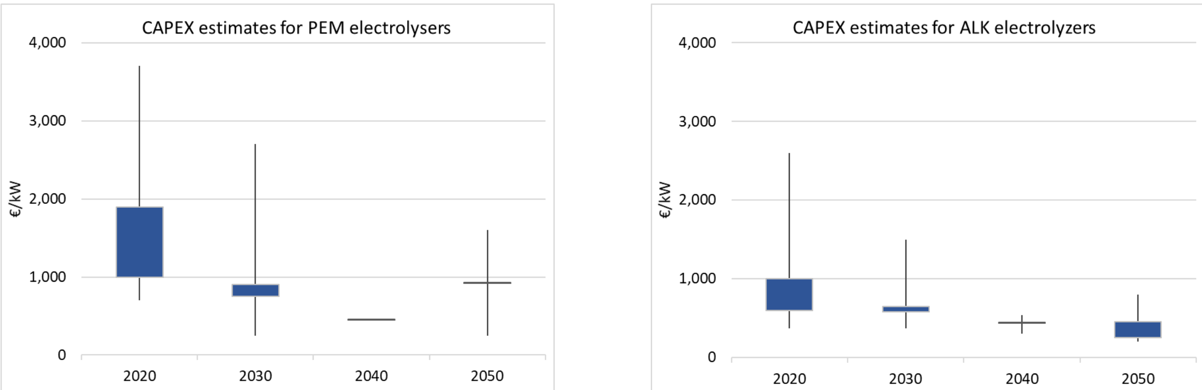

Figure 1 Literature review on PEM electrolyser investment cost (l) and ALK electrolyser investment cost (r) [€/kW]
(Sources: (Bertuccioli et al., 2014; Bhandari & Shah, 2021; Brändle et al., 2020; Brynolf et al., 2018; European Commission (EC), 2020; Gorre et al., 2020; International Energy Agency (IEA), 2019; Machhammer et al., 2016; Mansilla et al., 2012; Parkinson et al., 2019; Tlili et al., 2019, 2020))

2.3.2. *Electricity prices*

Renewable electricity prices are a significant driver of green hydrogen production costs. A vast amount of research is available on the expected development of electricity market prices with increasing renewable feed-in. The feed-in of renewables with a negligible marginal cost usually leads to a decrease in the electricity price. However, it needs to be considered that variable renewables need backup or storage, which will set prices based on the merit order approach. With increasing CO_2 prices, spot market prices may therefore increase during the operation of fossil backup capacities and develop a more attractive environment for the sale of renewables on the market and the value of renewables (Hartner, 2016). Furthermore, current turbulence in energy markets shows that global political and health risks causing uncertainties and scarcity can cause significant price increases. Higher electricity market prices, however, will also increase the cost of grid-connected hydrogen production.

If an electrolyser is operated to minimise electricity consumption cost, it will produce hydrogen at low spot market prices, usually implying high renewable feed-in. A more continuous operation cannot account for such aspects. Nevertheless, with a specific renewable electricity contract, a yearly amount of renewable electricity could be sourced decoupled from the time of consumption. A power purchase agreement can provide a basis that even allows for the definition of a fixed electricity price. Additionally, PPAs are considered an alternative support option for renewable power plants for investors. This could be an opportunity to achieve a lower price for electricity consumption. At the same time, market volatility risk can be reduced, the certification of the green electricity consumed simplified, and storage avoided.

2.3.3. *Storage cost*

Few references exist on the cost of tank storage for hydrogen. Existing work primarily provides cost as €/kg of hydrogen storage capacity. Gorre et al. (2020) for example, assume 490 €/kg hydrogen storage in a pessimistic and 350 €/kg in an optimistic scenario. Barhoumi et al (2022a) assume 500 €/kg at 100 bar[6]. Since 1 kg of hydrogen corresponds to about 33 kWh, this equals 15 €/kWh, representing the high-cost and 11€ the low-cost case (see Figure 2). Tlili et al. (2020) assume a hydrogen storage cost of 245 €/kg, which would translate to about 7 €/kWh. In all cases, we are assuming a storage at 30-60 bar, since these are the typical values for industrial supply.

It should be noted that these costs do not include the cost of compression from the electrolyzer outlet (at 30 bar) to the storage pressure. This cost may be very relevant, with the largest impact corresponding to the case of final use. Since that would be the same for all strategies analyzed in this paper, and we are assessing exclusively generation strategies for industry (which typically works with lower pressures, 30-80 bar), we opted not to include it in our model. We have however included some estimations in the Results section.

Within the literature review, no future estimation of the development of hydrogen storage cost was found. Therefore, contrary to the outlook available for electrolyser capacity cost, only current estimations can be stated in Figure 2 due to a lack of data. This clearly reveals a research gap, which needs to be filled to support reliable investigations.

[6] Barhoumi et al (2023) assume 100 €/kg, but since this is much below the typical lower range in literature we opted not to consider it.

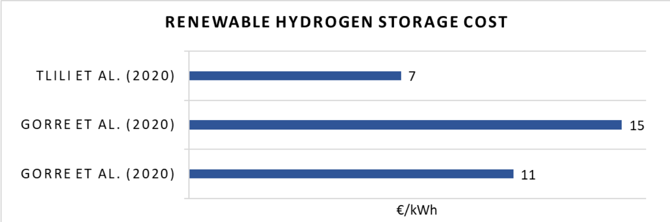

Figure 2 Cost for hydrogen tank storage (Gorre et al., 2020; Tlili et al., 2020)

2.3.4. H_2 cost

In this paper we estimate the cost of producing hydrogen with different configurations. However, an in order to provide a reference to our results, we also present a review of the costs from the literature, to help put our results in context. This review The review of H_2 cost shows a denser landscape of estimations for the short-term horizon until 2030 than towards 2050 (see Figure 3). Driven by the broad range of scenarios on electrolyser investment cost, H_2 production cost ranges between 36 €/MWh and 220 €/MWh (from the whiskers of the boxplot), or 1.3 and 7.3 €/kg, short term. Since more long-term estimations are harder to make and with fewer studies available (only 2 different studies with optimistic and pessimistic estimations, compared to the six different studies available for 2020), the production cost and the uncertainty replicated in the cost range decreases and arrives at 63-88 €/MWh.

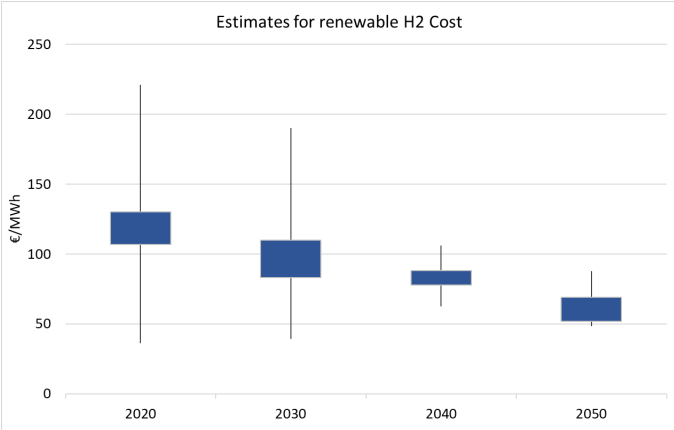

Figure 3 Renewable hydrogen cost estimates from literature (Sources: (Bertuccioli et al., 2014; Bhandari & Shah, 2021; Brändle et al., 2020; Brynolf et al., 2018; European Commission (EC), 2020; Gorre et al., 2020; International Energy Agency (IEA), 2019; Machhammer et al., 2016; Mansilla et al., 2012; Parkinson et al., 2019; Tlili et al., 2019, 2020))

3. Methodology

In this section we describe how, depending on the investment cost for the electrolyser and storage capacity as well as the electricity price, the different H_2 supply strategies are compared based on their economic performance, defined by the lowest LCOH, and also based on hypotheses about the variation in hydrogen demand.

Expanding on the previous literature, we analyse a scenario with variable demand, which would correspond to a hydrogen valley with a variety of industries demanding hydrogen, which is represented here by the Spanish current industrial high-temperature heat demand. We compare this to the usual scenario considered in the literature, a constant-demand one, either associated with a constant industrial production (such as a steel production facility in Austria), or by the aggregation at the system level (hence a centralised production of hydrogen). For comparability reasons, both alternatives have been normalised to the same yearly H_2 demand and optimised against the Austrian electricity market price in 2019. The spot market data of 2019 is considered a valuable base scenario since it has been a stable situation for a substantial amount of time. The sensitivity analysis in Section 4.3 provides insights into the impact of a potential electricity price increase as currently experienced due to multiple crises since 2020, as well as of a future potential price profile consistent with systems with larger renewable shares.

Exemplary four weeks of hydrogen demand in both cases are shown in Figure 4. Since exemplary demand profiles of total sectors or the industry are used as the main driver of the supply strategy comparison, this work does not represent a feasibility study on the installed plant capacities. The main result is derived from comparing the strategies for the same H_2 demand and electricity price variability.

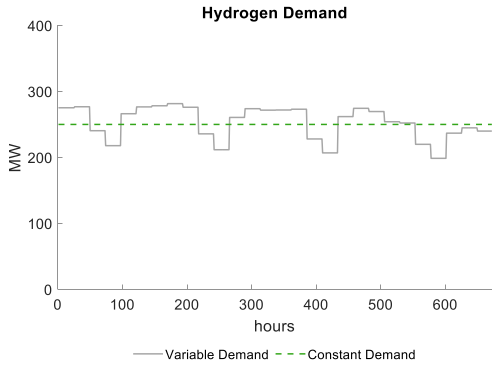

Figure 4 Exemplary 4-week hourly hydrogen demand (continuous vs. variable)

The base scenario is based on an electrolyser CAPEX of 1,500 €/kW and a hydrogen storage cost of 15 €/kWh, both derived from the literature in Section 2.3.1. The critical question that we want to address, however, is not the exact overall cost but the difference between the H_2 production strategies based on the same cost parameters. A sensitivity analysis in Section 4.3 provides insights into the impact of CAPEX on the strategy comparison.

3.1. Hydrogen generation process

Figure 5 describes the H_2 generation process assumed in our research. The electrolyser sources green electricity from the grid or a dedicated RES plant to split water (H_2O) into H_2 and oxygen (O_2). H_2 can either directly cover demand or be stored in tanks intermediately.

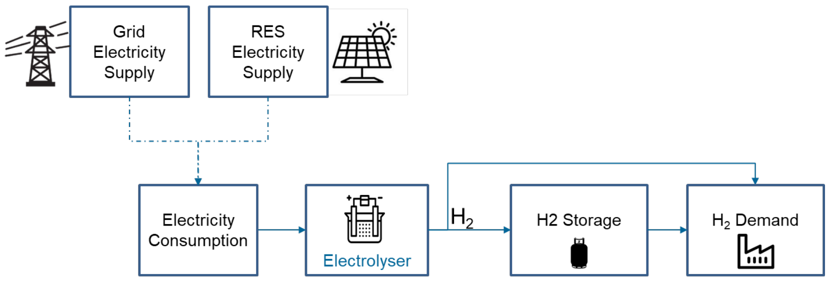

Figure 5 Hydrogen Production process

3.2. Hydrogen supply strategies

<u>**Grid connected electrolyser:**</u>

a) <u>**Electricity price optimisation**</u>: The electrolyser consumes electricity at times of low electricity prices. Hydrogen is stored after transformation to balance against demand. An advantage of this approach is the possibility to exploit low and avoid high electricity prices through hydrogen storage. This approach may require greater electrolyser and storage capacity to increase electricity consumption at low prices but minimises electricity cost. Nevertheless, the substantial variability in the production of the electrolyser could reduce actual H_2 conversion efficiency, and the storage cost must not offset the benefit of price optimisation.

b) Just in time sourcing: H_2 is produced JIT and electricity is sourced according to demand. Just-in-time production does not consider any hydrogen storage facility. This scenario, which could be an outcome of the earlier price optimisation (if the model chooses not to build storage), is explicitly included as a reference for a passive strategy, by exogenously setting a storage tank of zero. Depending on the hydrogen demand characteristics, production variability may be negligible. With JIT H_2 production, electricity consumption cost is subject to the electricity price variations.

Island solution – electrolyser connected to a dedicated RES power plant:

This scenario presents the direct connection of the electrolyser to a dedicated wind or PV power plant without any grid support. Electricity supply and H_2 demand are only balanced through hydrogen storage. Several scenarios are considered, both for solar PV and wind, and for the Austrian and Spanish generation profiles for 2019.

The cost of electricity is evaluated based on an average LCOE. Fraunhofer ISE (2021) arrive at an LCOE for isolated PV of about 30 €/MWh and for wind at minimum 40€/MWh. According to IEA (2020) and IRENA (2021), based on an exchange rate of 1/1.2 USD/EUR in 2021, large-scale PV power has an LCOE of about 15-30 €/MWh and wind of 25-37 €/MWh. In this scenario, the electrolyser optimization depends on the RES availability and storage is used to balance against demand. The RES capacity in the model is minimised to fulfil hydrogen demand.

3.3. Optimisation model and data

3.3.1. Faraday efficiency

As described in Section 2.2, the actual efficiency of an electrolyser can be lower than the theoretical maximum efficiency at lower loads. Therefore, the model aims to consider this dynamic actual efficiency.

The Faraday efficiency (η_{fa}) in Eq. **¡Error! No se encuentra el origen de la referencia.** describes the share of the actual efficiency (η_{ac}) based on the theoretical maximum efficiency (η_{th}) and decreases with a declining load factor (r_h) (Pascuzzi et al., 2016).

$$\eta_{fa}(r_h) = \frac{\eta_{ac}}{\eta_{th}} \quad (1)$$

The load factor (r_h) represents the share of electricity consumption (P_{con}^{el}) on installed electrolyser capacity (P_{Ely}^{el}) and is described in Eq. **¡Error! No se encuentra el origen de la referencia.**. The maximum electricity input defines the electrolyser capacity.

$$r_h = \frac{P_{con}^{el}}{P_{Ely}^{el}} \quad (2)$$

P_{con}^{el} .... *Electricity consumption [kW]*
P_{Ely}^{el} .... *Electrolyser Capacity [kW]*

The Faraday efficiency is different for the PEM and the ALK electrolyser, with the first performing better at lower loads. In the following subsections we present the different curves obtained from the literature on Faraday efficiencies for PEM and ALK electrolyzers, from which we have derived efficiency loss curves..

a. PEM electrolyser

The Faraday efficiency of PEM electrolysers remains more stable at lower load factors than that of ALK electrolysers (Tijani & Rahim, 2016; Yodwong et al., 2020). Assuming that the maximum current density of 200 mA.cm^{-2} in both studies represents a load factor of one, the Faraday efficiency evolves as shown in Figure 6. This relationship can be modelled with one single curve. The theoretical efficiency is defined as 70%. The Faraday efficiency is therefore 100% once the effective efficiency reaches the theoretical maximum of 70%.

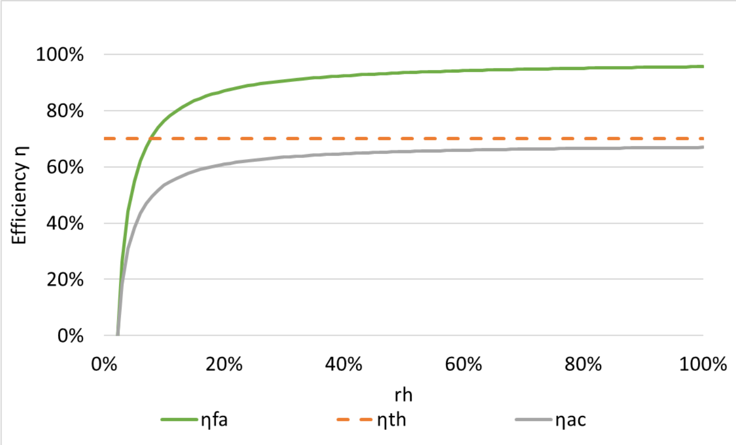

Figure 6 Faraday efficiency of a PEM electrolyser (Tijani & Rahim, 2016; Yodwong et al., 2020); actual efficiency (η_{ac}), theoretical efficiency (η_{th}), Faraday efficiency (η_{fa})

The actual efficiency is calculated as additional losses at certain load factors. This is the reason for the initial optimization of the electrolyser capacity on which the load factor depends. The absolute additional loss can be modelled as a linear function in which a specific utilization rate causes a certain absolute additional efficiency loss in MWh (see Figure 7). Due to the relatively low losses at low loads with a PEM electrolyser, the absolute losses increase with higher utilisation.

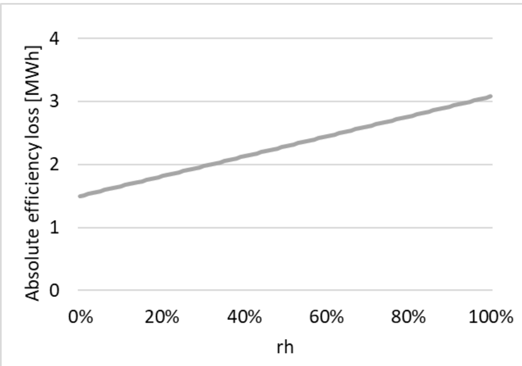

Figure 7 Absolute additional hourly efficiency loss at a particular load factor (for an exemplary PEM electrolyser capacity of 100 MW)

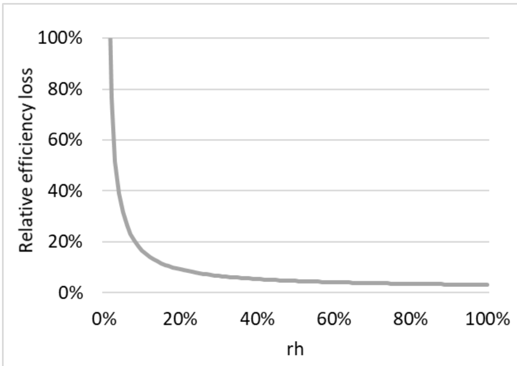

Figure 8 Additional efficiency loss at a particular load factor related to the electricity consumption (for an exemplary PEM electrolyser capacity of 100 MW)

Nevertheless, the relative loss compared to the electricity consumption decreases as expected (see Figure 8). This curve indicates the loss that leads to decreased Faraday efficiency at lower loads in Figure 6.

b. ALK electrolyser

Pascuzzi et al. (2016) provide a detailed analysis of the actual efficiency of an ALK electrolyser and measured data on the Faraday efficiency. Figure 9 shows the theoretical and the observed actual and Faraday efficiency relative to the electrolyser load factor. Since a stop of the electrolyser and a cold restart comes at substantial efficiency losses, also zero operation leads to losses of 0.25% of installed capacity in the model. Mohanpurkar et al. (2017) provide a similar analysis of the decreasing effective efficiency with decreasing loads.

Replicating the observations from Pascuzzi et al. (2016) across the whole load factor range from 0-1 requires two modelled curves with differing gradients for loads below and above 0.36 (see Figure 10).

JIT production, however, only causes a minimum load factor for the hydrogen valley case study with variable demand of 0.39. Therefore, the blue curve is sufficient, and no MILP model is required to switch between the two curves based on the load factor.

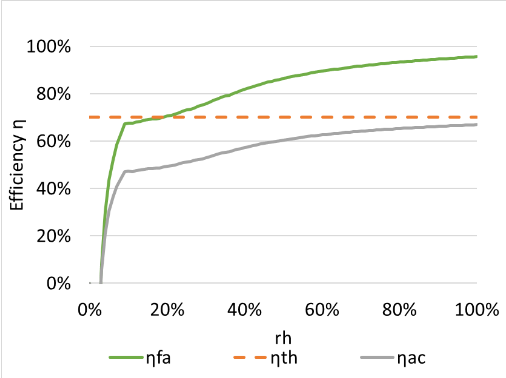

Figure 9 Faraday efficiency of an alkaline electrolyser (Pascuzzi et al., 2016)

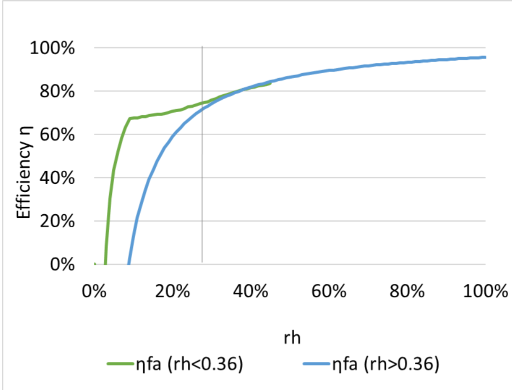

Figure 10 Replication of the Faraday efficiency for an ALK electrolyser based on the load factor

To match the overall Faraday efficiency, the additional loss is also modelled by two functions in which a specific utilisation rate causes a certain absolute additional efficiency loss in MWh. **¡Error! No se encuentra el origen de la referencia.** shows the two curves compared to the PEM efficiency losses shown earlier. The function ALK1 is approximated manually and modelled with integers to achieve the desired Faraday-efficiency curve. Function ALK2 represents a linear function that can be input to the model. The absolute losses at very low loads are substantial with the ALK technology and must increase even with increasing electrolyser utilisation. The relative efficiency losses, however, decrease with increasing loads (see **¡Error! No se encuentra el origen de la referencia.**)

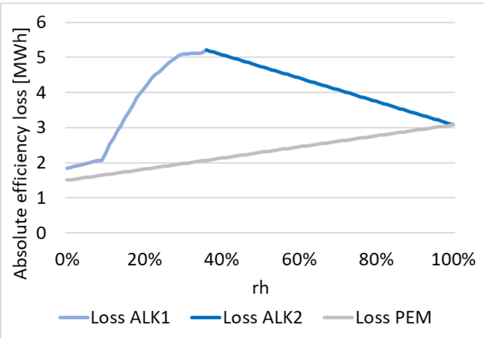

Figure 11 Absolute additional efficiency loss at a particular load factor (for an exemplary ALK electrolyser capacity of 100 MW) in relation to the PEM electrolyser

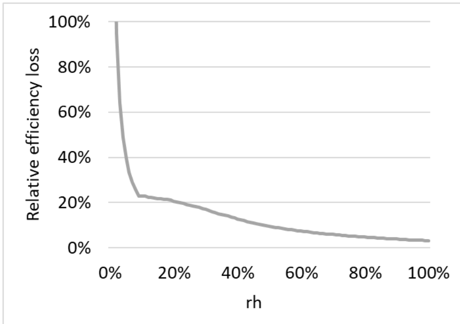

Figure 12 Additional efficiency loss at a particular load factor related to the electricity consumption (for an exemplary ALK electrolyser capacity of 100 MW)

3.3.2. Summary of input data

In the following table we summarize the major parameters for our analysis. It should be remarked here that our analysis does not correspond to a specific plant, but to the aggregate H2 demand in a region (which may require several plants). More specific input data is offered in the Appendix (Tables A.1 and A.2).

Table 2. Input data for the strategies considered

	Island – PV	Island – Wind	Grid - 2019	Grid - 2030
Total H2 demand	2,190,000 MWh/yr	2,190,000 MWh/yr	2,190,000 MWh/yr	2,190,000 MWh/yr
Electrolyzer CAPEX	1,500 €/kW	1,500 €/kW	1,500 €/kW	1,500 €/kW
Storage tank cost CAPEX	15 €/kWh	15 €/kWh	15 €/kWh	15 €/kWh
Electrolyzer efficiency	Variable, see section 3.3.1	Variable, see section 3.3.1	Variable, see section 3.3.1	Variable, see section 3.3.1
Electricity price	26 €/MWh	36 €/MWh	41.4 €/MWh	28 €/MWh

3.3.3. Optimization model

The optimisation model aims to minimise the levelised cost of hydrogen and potential storage (LCOH&S) depending on investment cost, the variable cost for electricity consumption, and the Faraday efficiency. The interdependency of the Faraday efficiency with the load factor based on the installed capacity always leads to a non-linear optimisation. Therefore, the optimisation model is set up as a two-stage optimisation similar to Luo et al. (2020) (see Figure 13). Determining the electrolyser capacity in the first step enables consideration of a dynamic Faraday efficiency depending on the load factor in the second step. With the defined electrolyser capacity from the first step, the actual efficiency is determined and the storage capacity can be slightly adjusted in the second iteration to account for the efficiency losses.

For the electricity price and the isolated RES optimisation, the first iteration optimises the electrolyser capacity by minimising the LCOH&S, including CAPEX (€/kW installed capacity), the electricity spot market price, an estimated overall efficiency plus additional cost for taxes and electricity fees and storage cost. This electrolyser capacity is then equally used for the respective strategy for ALK and PEM electrolysers. The optimisation is based on grid or RES electricity supply. The available electricity supply is, therefore, a constraint.

In the case of just-in-time production, however, the electrolyser capacity ($\mathrm{P}_{ely}^{\mathrm{el}}$) is designed to match the maximum hydrogen demand ($\mathrm{P}_{con}^{\mathrm{H_2}}$) and the storage capacity is exogenously set to zero. The Faraday efficiency is first estimated based on the expected load factor range in the chosen production strategy and can only be calculated precisely in the second step[7].. The resulting installed capacity will differ for the two variable and continuous H_2 demand.

$$\mathrm{P}_{ely}^{\mathrm{el}} = \frac{\max(\mathrm{P}_{con}^{\mathrm{H_2}})}{\eta_{th}\,\eta_{fa(r_h)}} \qquad (3)$$

$\mathrm{P}_{con}^{\mathrm{H_2}}$ .... *Hydrogen demand [kW]*

The second iteration determines the LCOH using the electrolyser capacity from step one as a constraint and considering efficiency losses depending on the load factor according to section 3.3.1. The model aims at minimising the LCOH&S for the respective operation strategy. This is achieved in two steps: the optimisation of the electrolyser—and in the island case, the renewable capacity—followed by the electrolyser and hydrogen storage operation. More details about the model can be found in the Appendix.

[7] This explains why, under some scenarios, the JIT strategy may not be chosen as the optimal in the price optimisation model, even if cheaper. Differences however are almost negligible (less than 1%).

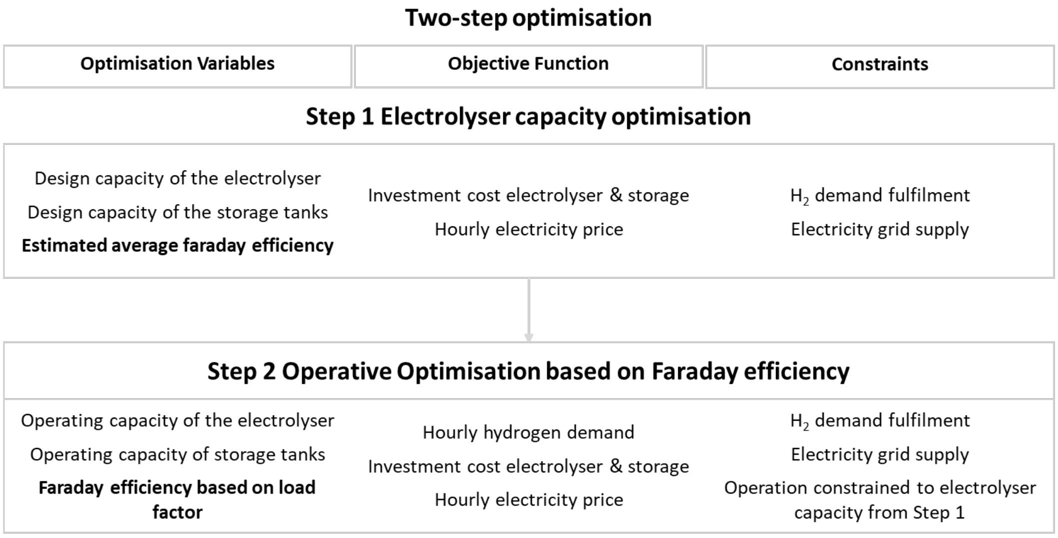

Figure 13 Two-step optimization framework

3.3.4. Limitations

In contrast to Matute et al. (2019), there is no stack replacement cost or demand access cost considered in this study.

The stack replacement directly depends on the full load hours. In our study, the full load hours correlate negatively with the electrolyser capacity optimized by the model. For the renewable feed-in scenarios, full load hours are around 3000h, for grid connected around 8000h with a corresponding smaller optimum electroyzer capacity. Assuming that the cost for replacement is higher for larger electrolyzers, the less frequent replacement need for more expensive electrolyzers is assumed to be a negligible difference to more frequent replacement at smaller, cheaper electrolyzers, moreover given the large difference in cost between the renewable feed-in and grid-connected cases. For the cases in which there is a very small difference (JIT vs PO in grid-connected) the difference in full load hours is negliglible so we opted for not including stack replacement to make the model simpler to compute.

Usually, a demand access cost applies to the maximum power rate during the billing period. The purpose of this demand charge is to encourage an even distribution of electricity load to reduce the total load during the peak demand period (Nguyen et al., 2019). Such cost significantly affects the feasibility of electricity price optimization, which requires higher capacity installation and variable electricity sourcing. The demand charge, therefore, has not been considered in this study. The impact of a demand charge is also specifically relevant in the island case where the electrolyser needs to handle substantial variability of electricity loads. The cost of electricity from the dedicated PV or wind power plant is defined as the LCOE derived from Fraunhofer ISE (2021), IEA (2020) and IRENA (2021) and set to 26 €/MWh and 36 €/MWh, respectively.

Also, as mentioned earlier, we have not included compression costs in the model, but calculated them exogenously based on the amount of hydrogen stored in each case, in order to keep the model simpler.

Finally, as may be noted from the description of the model, we are not considering a multi-energy system (as in Di Micco et al, 2023) or selling oxygen or heat from our system. Selling the emitted heat and oxygen of course could be an option and can differ between the scenarios, with higher amounts in the less efficient cases. For the RES scenarios, efficiency is low and therefore heat and oxygen emissions higher. However, the amount of full load hours is lower due to larger electrolyzer capacities due to the variability. In the grid connected scenarios, efficiency is higher and therefore heat and oxygen emissions lower. Full load hours, however, are much higher due to the better optimisation possibilities of the electrolyzer with less variability. Eventually, the effect on the final cost is expected to be low compared to the added complexity and scope extension, and negligible for the cases in which the price difference is small (the grid-connected cases).

4. Results

First, the base scenario is presented with an electrolyser investment cost of 1,500 €/kW and a medium storage cost (15 €/kWh). These results are outlined for the different supply strategies described in Section 3.2 in two parts: variable demand in a hydrogen valley and constant demand in a centralised or facility-specific H_2 production. The operation strategies include a PEM electrolyser directly connected to a PV or wind power plant, a grid-connected PEM or ALK electrolyser with electricity price optimisation, and JIT production exposed to the Austrian electricity price of 2019. The corresponding actual efficiencies described in the methodology were considered for each case.

Only PEM electrolysers were considered for electricity feed-in from a renewable power plant. The highly variable electricity feed-in and the corresponding losses during low loads do not make the ALK electrolyser a feasible technology. Even with the more flexible technology, a certain amount of electricity storage had to be implemented with the PV and wind power plant to cover the losses due to the supply variability.

In the grid-connected scenarios, an equal investment cost was assumed for the ALK and PEM electrolyser for simplicity reasons. In reality, however, the ALK electrolyser is currently available at lower cost than the PEM technology due to its maturity. This situation is expected to remain until 2040 (see Section 2.3.1). After a more detailed discussion of the results for the variable and constant demand alternatives, a sensitivity analysis considers a broader range of scenarios in terms of investment cost and the effect on hydrogen production cost.

It is important to note that compression costs, which may be an important component of the final cost of hydrogen, have not been considered except for a sensitivity analysis with a storage at 60 bar (which is within the range of industrial supply). If final hydrogen demand needs to be supplied at higher pressures (such as for vehicle fueling), then total costs would increase 33-47 €/MWh for 350 bar, or 46-66 €/MWh for 700 bar.

4.1. Base Scenario

4.1.1. Constant demand

Constant demand (or demand pooling) allows for centralised, constant bulk H_2 production. As explained earlier, this is the typical assumption in most of the literature, and is computed here in order to compare it, on the same terms, with the variable demand situation.

Figure 14 describes the resulting renewable hydrogen production cost per MWh ordered from highest to lowest. For better visibility of the low-cost scenarios, the higher-cost scenarios have been compressed between 150 and 500 €/MWh.

The results show that direct electricity feed-in from a dedicated PV power plant results in up to five-fold hydrogen production cost per MWh compared to a grid-connected case based on 2019 spot market prices. The latter leads to an H_2 cost of 105 €/MWh producing JIT (which would also be the optimal strategy under price optimisation). PV power generation is characterised by long periods of zero availability, requiring daily ramp down and restart of the electrolyser causing substantial efficiency losses and additional capacity needs along the supply chain from RES supply to hydrogen storage. In addition, and to minimise these efficiency losses, the model installed an electricity storage of 17% of the PV capacity to cover hydrogen demand, proving the findings by Gahleitner (2013) mentioned in Section 1. The RES and battery storage capacity were minimised to fulfil hydrogen demand.

The Spanish hourly wind generation profile of 2019 is characterised by a lower variance and higher mean availability. Spanish wind availability hardly requires any battery storage and seems to provide a more stable electricity supply to achieve costs closer to a grid-connected case. With the Austrian wind profile, however, the size of the electricity storage installed by the model is 22% of the RES capacity.

Figure 15 shows the required RES capacity to fulfil demand from a PV or Wind power plant with the Spanish or Austrian renewable profile[8]. Since the presented case studies are characterised by national or sector-wide H_2 demand and our goal is not to aim for a feasibility study, capacities are related to the scenario with the largest installed capacity—the so-called reference capacity—, which represents 100%. This refers to the Austrian PV-powered case for RES capacity, while the other RES-powered scenarios operate at 60-40% of this reference capacity.

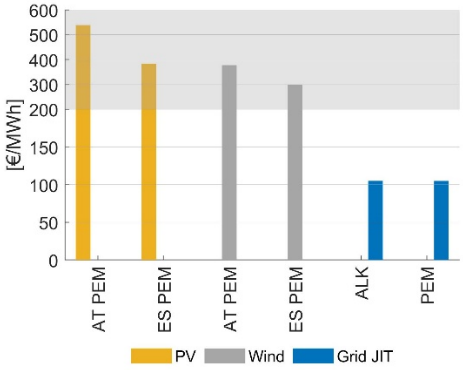

Figure 14 Renewable hydrogen production cost with constant demand; *Just in Time (JIT); Austrian renewable profile (AT), Spanish renewable profile (ES)*

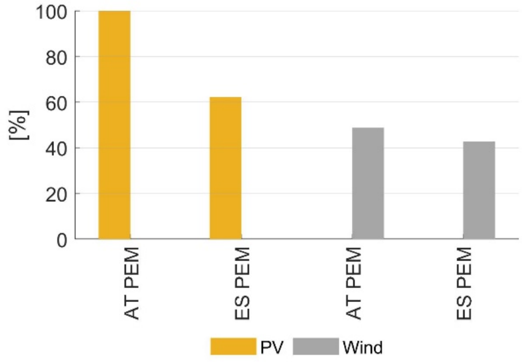

Figure 15 Relative RES capacity with constant demand; *Austrian renewable profile (AT), Spanish renewable profile (ES)*

The cost of electricity from dedicated RES plants is considered as a fixed LCOE from the literature, and does not vary according to the optimal PV or wind power capacity. PV capacity needs to be between 17-30% and wind capacity about 7% higher than electrolyser capacity to fulfil demand. Nevertheless, even the most promising RES case with a Spanish wind power profile leads to a 178% higher cost (299.0 €/MWh H_2) than a grid-connected JIT scenario. The lower costs for electricity consumption from the PV or wind power plant with an LCOE of 26 €/MWh and 36 €/MWh compared to the average Austrian electricity market price in 2019 of about 40 €/MWh, cannot fully compensate for the additional capacity investment required.

The electrolyser capacity for each production strategy relative to the largest installed reference capacity is described in **Figure 16**. Electrolyser capacity also needs to be higher for renewable electricity feed-in than with constant grid supply. The reference capacity refers to Austria's PV-connected case characterised by high supply variability. With wind power, electrolyser capacity can be reduced to about 50%, and in the grid-connected case, only 20% of the reference capacity is still required. The **full load hours** account for about 2,000 with RES feed-in, more than 8,600 can be reached in a grid-connected JIT scenario.

Table 3 shows the electricity consumed in the different strategies, with the final efficiency of the electrolyzer. It may be observed how the actual efficiency improves when the electricity supply is more stable.

Table 3. Electricity consumed and electrolyzer actual efficiency

Strategy	Electricity consumption (MWh)	Electrolyzer efficiency
AT PEM PV	3,544,193	61.79%

[8] The grid-connected case is not shown since this calculation does not apply. Same applies to Fig. 17 and 20

ES PEM PV	3,449,554	63.49%
AT PEM Wind	3,342,719	65.52%
ES PEM Wind	3,309,754	66.17%
ALK Grid JIT	3,231,127	67.78%
PEM Grid JIT	3,228,763	67.83%

In this work, intermittent electricity feed-in or consumption is mainly compensated by hydrogen storage. The hydrogen storage capacity for each production strategy is presented relative to the largest installed capacity in **Figure 17.** It is substantially higher for the renewable electricity feed-in than for the grid-connected scenario. The highest hydrogen storage capacities are required for PV-connected electrolysis in Austria, marking the reference capacity at 100%. The characteristics of Spanish PV or Austrian wind power reduce the capacity needs to about 70% and Spanish wind power to 45%.

The grid-connected production strategies only require 0.18% of the reference capacity. A deeper analysis of the grid-connected scenarios indicates that the lowest hydrogen production cost can be achieved with zero storage, or JIT production. In this case, full operation throughout the year with full load hours of almost 8,700 can be achieved, representing full utilization of the electrolyser capacity investment. Exposure to the electricity market price does not harm these effects that maximise the Faraday efficiency while refraining from storage.

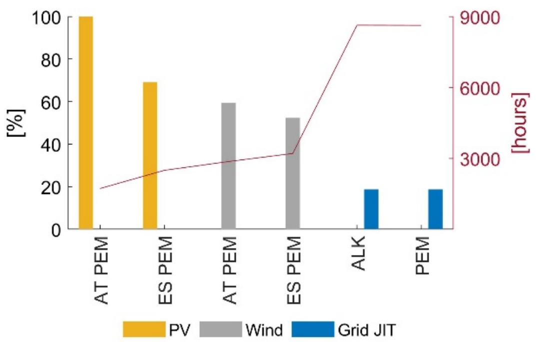

Figure 16 Relative electrolyser capacity and FLH with constant demand; *Just in Time (JIT), Austrian renewable profile (AT), Spanish renewable profile (ES)*

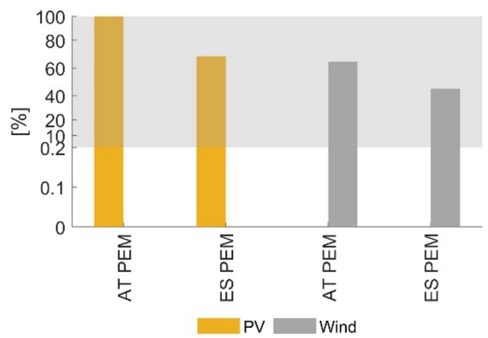

Figure 17 Relative hydrogen storage capacity with constant demand; *Austrian renewable profile (AT), Spanish renewable* profile (ES)

Figure 18 shows the results obtained for the system configuration in each scenario at a glance. The x-axis shows the relative electrolyser capacity installed in the optimisation, while the y-axis provides the relative H_2 storage size. The size of the bubbles refers to the overall hydrogen provision cost per kWh.

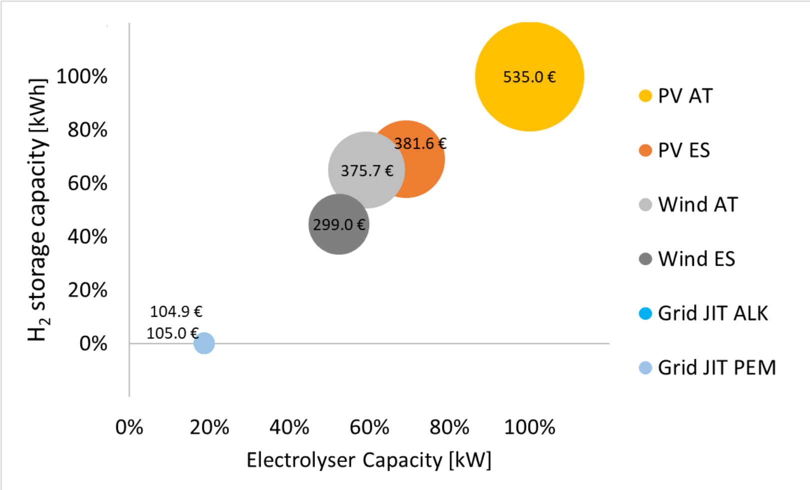

Figure 18 System configuration for each scenario with constant demand: Electrolyser capacity, H_2 storage capacity and the bubble size according to the overall H_2 cost

4.1.2. Variable demand

Variable hydrogen demand can be more realistic in a situation of decentralised H_2 production for a specific industry or group of industries characterised by variable operation. Figure 19 describes the resulting renewable hydrogen production cost per MWh for each strategy ordered from highest to lowest. The results have again been compressed between 150 and 500 €/MWh to improve visibility. The hydrogen production cost from a dedicated PV power plant is at 525.7 €/MWh, almost 4.8 times higher than with a grid-connected electricity price optimization based on the 2019 spot market price (109.7 €/MWh). Electricity storage of 17% of PV capacity was required to cover hydrogen demand. If electricity is sourced directly from a wind power plant, the electricity storage needs to increase to 30% of the wind installed capacity when the Austrian renewable profile is used. The Spanish wind availability hardly requires any battery storage (only 2% of RES capacity). It seems to provide a more stable electricity supply to achieve costs closer to a grid-connected case.

Figure 20 shows the required RES capacity to fulfil demand from a PV or Wind power plant with the Spanish or Austrian renewable profile. The results are very similar to the constant demand case. The capacities are again related to the largest installed capacity—the so-called reference capacity—, which represents 100%. This refers to the Austrian PV-powered case, while the other RES-powered scenarios operate at 60-40% of this reference capacity. With variable demand, direct electricity sourcing from a wind power plant in Spain still causes a 159% higher cost (283.6 €/MWh H_2) than in a grid-connected scenario. PV capacity needs to be between 17-30% and wind capacity about 7% higher than the electrolyser capacity to fulfil demand.

Table 4 shows the electricity consumed in the different strategies, with the final efficiency of the electrolyzer. It may be observed how the actual efficiency improves when the electricity supply is more stable, and that price optimization strategies have a cost in terms of electricity consumption.

Table 4. Electricity consumed and electrolyzer actual efficiency

Strategy	**Electricity consumption (MWh)**	**Electrolyzer efficiency**
AT PEM PV	3,541,285	61.84%

ES PEM PV	3,449,665	63.48%
AT PEM Wind	3,343,426	65.50%
ES PEM Wind	3,308,760	66.19%
ALK Grid JIT	3,264,603	67.08%
PEM Grid JIT	3,236,977	67.66%
ALK Grid price opt	3,266,063	67.05%
PEM Grid price opt	3,259,179	67.19%

The electrolyser capacity for each production strategy relative to the most extensive installed reference capacity in Figure 21 shows the difference between scenarios with renewable electricity feed-in and constant grid supply. The reference capacity is represented by Austria's PV-connected case, whereas grid-connection reduces capacity requirements to about 21%. It is, however, interesting that H_2 production with a JIT approach is slightly more expensive than electricity price optimization, according to Figure 19, despite featuring a marginally lower electrolyser capacity and higher full load hours. Hence, electricity price optimization successfully reduces the cost of electricity consumption to achieve a lower overall LCOH&S. This is even true irrespective of the chosen electrolyser technology. With variable hydrogen demand, full load hours of a maximum of 7,490 can be achieved through JIT production.

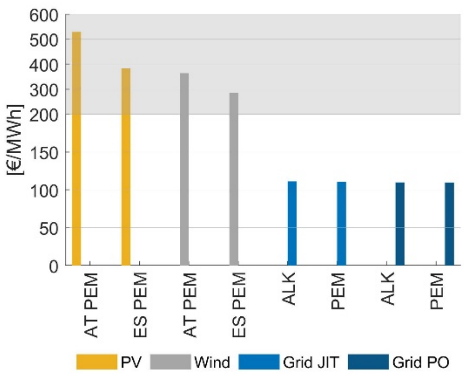

Figure 19 Renewable hydrogen production cost with variable demand for different operation strategies; *price optimization (PO), Just in Time (JIT), Austrian renewable profile (AT), Spanish renewable profile (ES)*

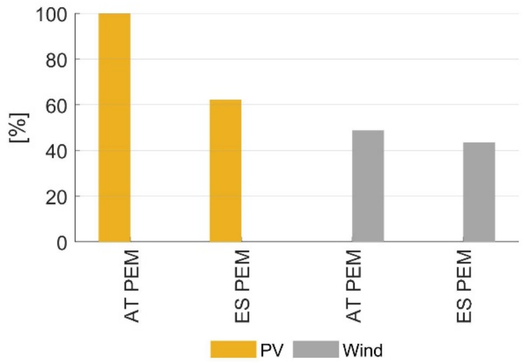

Figure 20 Relative RES capacity with variable demand for different operation strategies; *Austrian renewable profile (AT), Spanish renewable profile (ES)*

The hydrogen storage capacity for each production strategy relative to the largest installed capacity is described in Figure 22. PV-connected electrolysis in Austria requires the highest hydrogen storage capacities, followed by Spanish PV or Austrian wind power feed-in and Spanish wind connection, not differing much from the constant demand case with about 70% and 45%, respectively. The grid-connected production strategies only require 0.19% of the reference capacity.

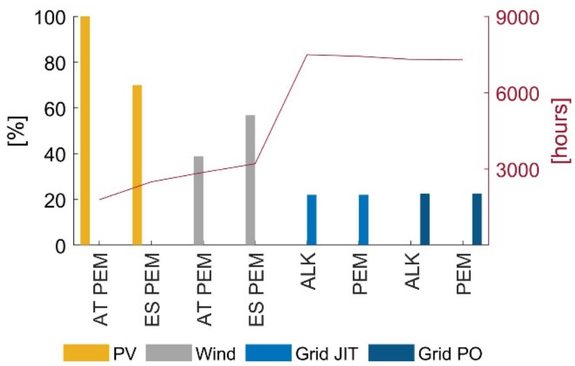

Figure 21 Relative electrolyser capacity and FLH with variable demand for different operation strategies; *price optimization (PO), Just in Time (JIT), Austrian renewable profile (AT), Spanish renewable profile (ES)*

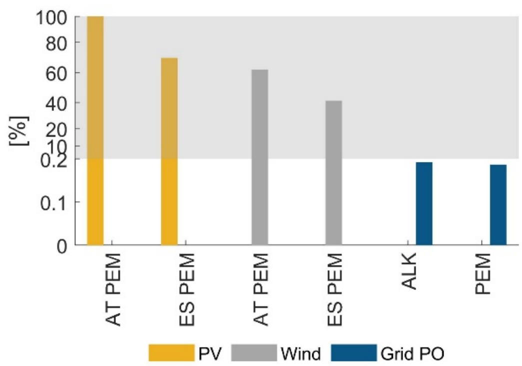

Figure 22 Hydrogen storage capacity with variable demand for different operation strategies; *price optimization (PO), Austrian renewable profile (AT), Spanish renewable profile (ES)*

A closer look at the grid-connected scenarios reveals that based on the electricity price of 2019, the lowest hydrogen production cost can be achieved through electricity price optimization. The cost decrease through arbitrage on electricity consumption exceeds the additional investment into electrolyser and storage capacities. Nevertheless, the benefit is almost negligible, with a 0.90 €/MWh or 1.30 €/MWh cost decrease for the PEM and ALK technology respectively representing 0.8-1.2%.

Figure 23 shows the system configuration in each scenario at a glance. The x-axis shows the relative electrolyser capacity installed in the optimisation, while the y-axis provides the relative H_2 storage size. The size of the bubbles refers to the overall hydrogen provision cost per kWh.

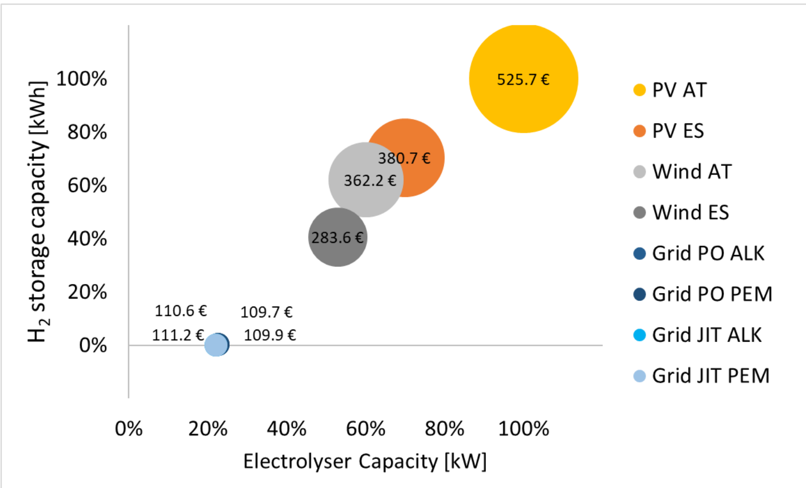

Figure 23 System configuration for each scenario with variable demand: Electrolyser capacity, H_2 storage capacity and the bubble size according to the overall H_2 cost

4.2. Discussion on the base scenario

In general, constant hydrogen demand allows for a lower hydrogen production cost than variable demand due to the more efficient use of the capacity of the electrolyser (see Figure 16 and Figure 21 in Section 4.1). If demand is more variable, electricity price optimization and storage achieve lower costs than JIT production.

The PEM technology usually leads to lower hydrogen production cost than the ALK electrolyser when assuming the same electrolyser investment cost, due to better performance at lower loads. However, since the ALK technology is more mature and currently cheaper and electrolyser investment cost represents a significant cost aspect of hydrogen production, the ALK electrolyser has an economic advantage for grid-connected scenarios.

In RES-connected scenarios, the renewable electricity profile is the primary cost driver. For example, while using PV power is more expensive with the Austrian PV profile than the Spanish one—a logical conclusion due to the climate characteristics (see (Ramsebner, Linares, et al., 2021))—the results do not differ much between constant and variable demand.

With grid connection, JIT is 5.4% and electricity price optimization 2.1% more expensive than in a constant demand situation with about 111.0 € and 109.7 €, respectively. Electrolyser capacity requirements shown in Figure 21 are higher with variable demand: by about 7% for price optimization and 16% for JIT production. Since with JIT production, the electrolyser capacity needs to correspond to maximum demand, variable hydrogen demand does not enable full utilization, which causes lower full load hours leading to a higher cost per MWh (**Figure 21**). It is interesting to see that with variable hydrogen demand, JIT production becomes more expensive than electricity price optimization (see Figure 19) even if the full load hours as described in Figure 21 are higher in a JIT approach (7,450) compared to price optimization (7,300). In this case, electricity price arbitrage is sufficient to decrease hydrogen production costs. In the constant demand case, JIT achieved full load hours of >8600 - driving the low-cost result. Variable demand leads to slightly higher H_2 storage capacity needs than constant demand in grid-connected scenarios. Therefore, the hydrogen storage capacity cost, according to Figure 21, also seems to be a minor cost driver.

Apart from the cost aspect, the decision on a specific H_2 generation strategy may also have an impact on the overall energy system if H_2 production becomes a significant part of electricity demand. Sourcing electricity directly from the electricity grid, on the one hand, imposes specific grid infrastructure requirements to guarantee stability with the connection of an additional consumer. On the other hand, optimization based on electricity prices is a form of demand response that can help manage better the whole power system.

4.3. Sensitivity Analysis

Electricity cost

Exposure to market prices entails risks, such as mid- to long-term price increases. The average Austrian electricity market price of 2019 used in the scenarios is shown in **¡Error! No se encuentra el origen de la referencia.** and accounted for 40.2 €/MWh (APG, 2022) plus a grid access tariff of 1.2 €/MWh. The electricity directly sourced from the PV power plant costs 26 €/MWh and from the wind power plant 36 €/MWh, without any additional connection cost. However, the results revealed cheaper H_2 production with grid-connected strategies than RES-based electrolysis because of the impact of variable operation on the efficiency of the electrolyser. The current market situation, with an average electricity price in Austria that surged to 109 €/MWh in 2021 even reaching 207 €/MWh in at the end of May 2022 (APG, 2022) would, however, support the competitiveness of direct sourcing from a renewable plant instead of being exposed to the market price.

Lifting the 2019 spot market price to an average electricity price of 150 €/MWh would result in hydrogen production costs of 267 €/MWh with JIT production in the constant demand base scenario. This would almost make the wind power-connected scenario competitive, which, at least in Spain, could be achieved with a reasonably low RES capacity effort at 283 €/MWh for variable demand (see Figure 14). An average electricity market price of 250 €/MWh would lead to a hydrogen production cost of 414 €/MWh with JIT production. In this situation, even a dedicated PV power plant in Spain would become cost-competitive with the grid-connected case at 380 €/MWh.

Power purchase agreements might be a favourable solution for risk minimization that combines both stable renewable electricity supply and fixed price**s**. Since the results for grid-connected JIT operation are very promising in this study, a favourable PPA could lead to a further H_2 cost reduction. As a result, in the variable demand case, the zero-storage (JIT) could become the optimal strategy under electricity price optimization. With this solution, renewable electricity generation can be decoupled from demand through the electricity grid (although this means free-riding on the backup that the grid provides). If a favourable PPA price can be agreed upon for the upcoming years, potential market price increases can be avoided, and H_2 production costs further decreased (depending on how the cost of the backup is charged).

As another sensitivity analysis, a prognosis on a potential price pattern in 2030, with a large renewables share, was considered (taken from Spanish 2030 scenarios) and also provided in **¡Error! No se encuentra el origen de la referencia.**. There is a strong seasonal pattern in the estimated electricity price of 2030 due to a large share of renewable electricity generation. Therefore, in a scenario of constant demand, again JIT production avoiding storage represents the most cost efficient H_2 production strategy. Exploiting the very low electricity prices during two thirds of the year in order to fulfil H_2 demand during the winter months would require vast hydrogen storage and electrolyzer capacity. This investment cost is avoided by JIT production at a similar electrolyzer capacity as in the calculations made in the grid connected base scenarios, while still having almost zero electricity cost during a long period of the year. With this price scenario for 2030, the average yearly price decreases from 40.2 €/MWh in the base scenario to only 28.0 €/MWh. This results in a cost reduction for hydrogen production in the grid connected case down to 87.4 €/MWh for constant and 90.3 €/MWh for variable demand.

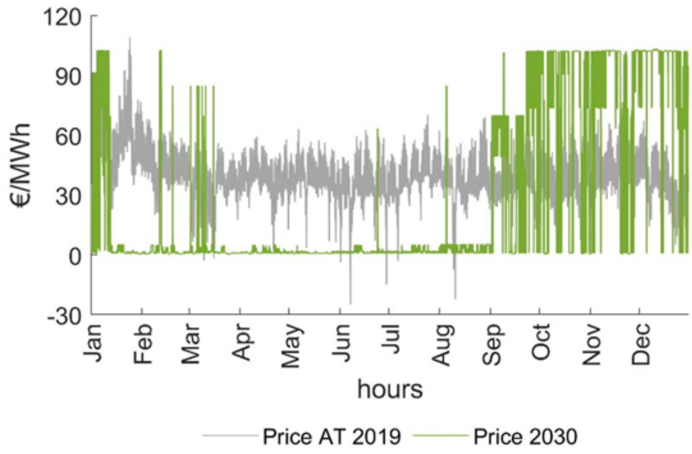

Figure 24 Comparison of the Austrian sport market price of 2019 (grey) with a price prognosis for 2030 Spanish market conditions (green)

<u>Demand access fee</u>

A demand access fee for grid-connected electrolyser could deteriorate the economic performance compared to direct renewable feed-in. This cost for the maximum power capacity sourced from the grid has been exempt for electrolyser operation since it represents a significant financial barrier to variable operation.

<u>Intermediate storage at 60 bar</u>

When intermediate storage (or final demand) is assumed to be at 60 bar, there is a cost of compression. These costs have been calculated exogenously to the model, assuming a compression efficiency of 0.7, an electric efficiency of 0.85, a CAPEX of 24 €/MW, and a lifetime of 20 years.

For the island cases the cost of compression ranges from 7 to 9 €/MWh, both for constant and variable demand, therefore becoming negligible compared to the total cost of hydrogen.

For the grid-connected cases, however, and given the small difference in the cost of hydrogen among these two options, the cost of compression becomes relevant. In this case, the cost of compression is 9 €/MWh of H2 compressed. If all hydrogen is compressed, then this should be added to the final cost.

If final demand still takes place at 30 bar, but intermediate storage requires 60 bar, then only hydrogen stored adds to the final cost. And only the price-optimization option stores hydrogen. The share of hydrogen compressed is 13.9% for the ALK electrolyzer, and 12.3% for the PEM electrolyzer, hence resulting in an increase of 1.3 €/MWh for ALK and 1.1 €/MWh for PEM. This difference is enough to make price optimization more costly than the JIT option, given the very small difference between them.

Impact of electrolyser and storage investment cost on LCOH&S

A reduced electrolyser investment cost enables a more vigorous exploitation of the electricity price variability with higher electricity consumption ranges. Paired with low hydrogen storage cost, this effect is even more substantial.

In the base case, for constant demand, JIT is the cheapest option under electricity price optimisation. However, a non-zero storage strategy could be cheaper once the electrolyser investment cost goes below 500 €/kW. Under this assumption, the cost impact of larger electrolyser capacities is lower, and arbitrage can be exploited to a greater extent with larger production ranges. Storage costs below 15 €/kWh can further support this. However, such a significant price decrease is only expected to be likely after 2040 (see section 2.3.1). Above 500 €/kW electrolyser capacity cost, JIT production is the cheapest H_2 generation approach for constant demand. For variable demand, JIT is more expensive than electricity price optimization for all scenarios, with storage costs between 2-24 €/kWh and electrolyser investment costs between 250 €/kW and 3,000 €/kW.

Figure 25 and Figure 26 show an exemplary optimisation week with low or high investment costs. In the low-cost scenario, the optimal electrolyser capacity is more significant, and hydrogen production varies more to exploit electricity prices. In the scenario with higher investment cost, however, the production range is reduced to minimise the investment cost share in the LCOH&S. Maximum electricity consumption, which is limited by the electrolyser capacity, is reduced by about 50% in the high compared to the low-cost scenario.

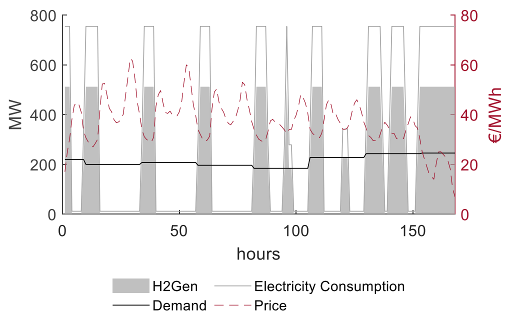

Figure 25 Exemplary week electricity price optimisation at 250 €/kW electrolyser investment cost and low storage cost

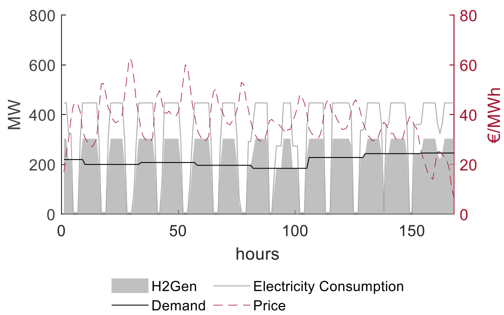

Figure 26 Exemplary week electricity price optimisation at 3,000 €/kW electrolyser investment cost and high storage cost

Additional analyses reveal that the electrolyser investment cost makes up a much larger part of the cost per MWh than the storage cost. The electrolyser capacity cost, therefore, has a major impact on the operation configuration. As described in Figure 27, related to the yearly demand, the impact of storage on the cost per MWh of hydrogen demand is minimal and, within the assumptions of this work, accounts for less than 2% of the hydrogen LCOH&S. Not every hydrogen unit is stored, but part of it is directly used. Electrolyser investment costs, however, are a primary driver of hydrogen cost. This raises the question of why storage is not used more extensively to exploit electricity variability more and reduce hydrogen production costs. The reason is that such an increase in operation variability would also require even higher electrolyser capacities installed. This additional cost cannot offset the benefits of arbitrage.

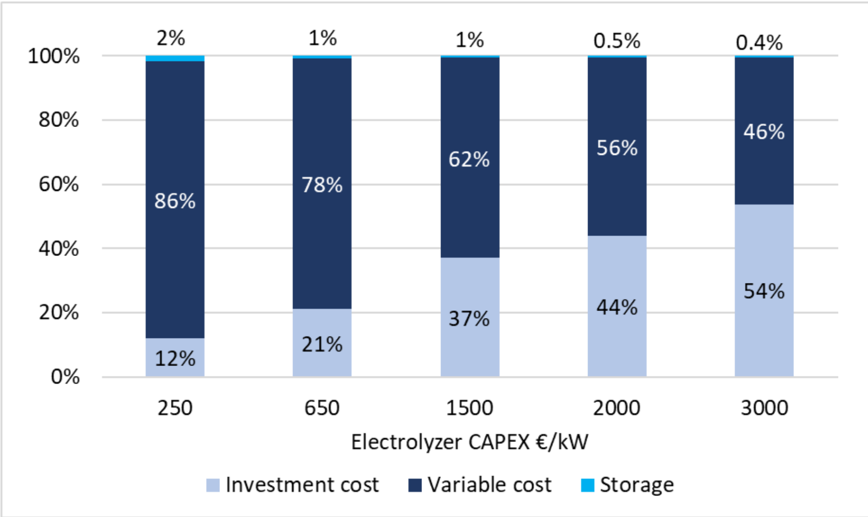

Figure 27 Electricity and investment cost share of hydrogen production cost for constant demand

Up to a 2,000 €/kW electrolyser investment cost, the variable cost based on electricity consumption makes up the largest share of hydrogen production cost. At 250 €/kW, the investment cost only makes up 12% of the overall hydrogen production cost despite the higher installed capacity for arbitrage reasons. At the same storage capacity cost in the base case of 15 €/kWh, 83% lower electrolyser investment cost achieves only 5% lower electricity consumption cost per MWh due to higher arbitrage exploitation. In comparison, the investment cost per MWh decreases by 77%. Figure 27 shows that at an electrolyser investment cost of 250 €/kW, variable cost, including electricity cost plus additional fees and water consumption, makes up for 86% of overall hydrogen production cost. This share decreases to only 46% with an electrolyser investment cost of 3,000 €/kW. In the base case, this study reveals an electricity consumption cost share of 62%, which corresponds with findings in the literature.

5. Conclusions

Renewable hydrogen is expected to play a major role in decarbonising the industrial sector as feedstock and fuel to many processes and products. On-site production, or production limited to "hydrogen valleys", has been proposed as a non-regret, robust way of starting the deployment of this technology and achieving higher production scales to decrease the cost. However, this option may imply having to follow a variable hydrogen demand pattern, which in turn may affect the conversion efficiency of the electrolyser, or require investing in hydrogen storage. This situation may be particularly acute in the case of hydrogen production fed exclusively with off-grid renewable plants. In this paper we have looked at the economics of these configurations, for both PEM and ALK electrolysers.

In a situation with grid-connection—assuming the same investment cost for comparability reasons—the cost of producing hydrogen with the ALK technology is slightly higher than with a PEM electrolyser. However, since the ALK technology is more mature and usually cheaper, it may have a major economic advantage for grid-connected scenarios. The PEM electrolyser may catch up in terms of investment cost although needs to handle its current shorter stack lifetime and the need for platinum group metals.

In a grid-connected scenario, constant demand representing centralised bulk production always allows for cheaper hydrogen production by optimizing electrolyser operation. In this case, electricity price optimization does not provide economic benefits unless the electrolyser investment cost decreases or price profiles change significantly. Grid-connected zero-storage (JIT) production achieves the lowest renewable hydrogen cost with constant hydrogen demand. In this case, maximising asset utilisation with more than 8,600 full load hours leads to a cost-optimal solution. Power purchase agreements would also be helpful in reducing the cost of the electricity sourced from the grid while ensuring its renewable character.

In case hydrogen demand is variable, then electricity price optimization and hydrogen storage can be used to achieve lower costs. These results are valid under the assumption of no demand access fee applied for the maximum power sourced from the grid, and no need for compression for intermediate storage. Cost advantages may be intensified with higher electricity price spreads through higher renewable shares. Electricity price optimization would also, in this case, become a demand response tool to help manage the system.

It is also interesting to note that the difference in costs between the variable and constant demand alternatives is just 2%. This small difference may not justify efforts to aggregate demands or to focus only on constant demand industrial facilities.

However, cost differences are much larger when comparing grid-connected and island configurations. According to our results, wind power feed-in is 2.5 times, and PV power up to 5 times more expensive than a grid-connected scenario for hydrogen production based on the Austrian electricity market price for 2019. The intermittency of renewable resources leads to substantial electrolyser and storage capacity requirements and huge variability, harming actual operation efficiency. The RES profiles drive hydrogen production cost and capacity requirements more than the hydrogen demand profile. Wind power seems to be more favourable than PV in terms of availability. Based on the findings and in line with the available literature, we do not recommend the ALK electrolyser for direct renewable electricity feed-in due to the supply variability causing substantial performance losses.

An electrolyser's isolated RES connection may only become competitive if electricity market prices skyrocket, as currently observed. With the current average Austrian electricity price reaching 207 €/MWh by the end of May 2022, even the Spanish PV power could almost compete in the presented base scenario. Additionally, a mid-to-long-term expected decrease in electrolyser investment cost would also support the economic performance of direct renewable electricity feed-in. These results are however subject to the existence or not of demand charges imposed on electrolysers, something which is currently being discussed in several countries.

Hence, our results show that, although the production of green hydrogen in grid-connected configurations is more competitive in normal circumstances, this is subject to several uncertainties, such as the evolution in the cost and efficiency of electrolysers, or the regulation of the power system. Including these uncertainties into the analysis to produce more robust investment decisions would be a natural next step in this research.

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Appendix

Optimisation Model

The yearly cost for hydrogen production and storage is minimised. According to Matute et al. (2019), the annual cost for H_2 production or the levelised cost of hydrogen LCOH&S is defined as equipment cost (C_{EQ}) plus variable energy cost (C_E). In this study, the relative cost per MWh is based on hydrogen demand.

$$min \sum_{t=1}^{T} \frac{C_{EQ(a)} + \sum_{t=1}^{T} C_{E(t)}}{P^{H2}_{con(t)}} \text{ [€/MWh]}$$

C_{EQ} .... *annual equipment cost [€]*
C_E .... *hourly variable cost [€]*
$P^{H_2}_{con}$ .... *H_2 demand [kW]*
t .... *time step [h]*
T .... *8760 hours of a year*
a .... *annual*

The annual C_{EQ} includes CAPEX and OPEX of the electrolyser (C^{Ely}_{C}, $C^{Ely}_{O\&M}$) and the storage tanks (C^{St}_{C}, $C^{St}_{O\&M}$) plus indirect other CAPEX (C^{OT}_{C}) for engineering works and land permits and their respective OPEX ($C^{OT}_{O\&M}$) (Matute et al., 2019).

$$C_{EQ(a)} = C^{Ely}_{C} + C^{St}_{C} + C^{OT}_{C} + C^{Ely}_{O\&M} + C^{OT}_{O\&M} + C^{St}_{O\&M}$$

C^{Ely}_{C} .... *CAPEX electrolyser [€]*
C^{St}_{C} .... *CAPEX storage [€]*
$C^{Ely}_{O\&M}$ .... *OPEX electrolyser [€]*
$C^{St}_{O\&M}$ .... *OPEX storage [€]*
C^{OT}_{C} .... *CAPEX other [€]*
$C^{OT}_{O\&M}$ .... *OPEX other [€]*

The annual C^{Ely}_{C} is calculated as the annuity from the initial investment cost for the electrolyser. To calculate the yearly investment cost Haas et al. (2021) describe the calculation of the annuity as a product of an annuity factor (α) and the initial investment cost ($C^{Ely}_{C(t=0)}$). The annuity factor (α) results from the expected rate of return (r) and the predicted depreciation period or lifetime (n)[9].

$$C^{Ely}_{C(a)} = \alpha \, C^{Ely}_{C(t=0)}$$

$$\alpha = \frac{i\,(1+i)^n}{(1+i)^n - 1}$$

$C^{Ely}_{C(t=0)}$ .... *initial investment cost [€]*
α .... *annuity factor*
n .... *lifetime [y]*
i .... *interest rate*

The variable energy cost (C_E) consists of the wholesale or spot market (C_{WM}) cost for electricity consumption, access tariff for electricity (C_{ATE}), electricity tax (C_{ET}), municipal tax (C_{MT}), retailer operational cost, operation costs for accessing energy markets (C_{OC}), financing fees (C_{FF}) and water cost (C_W). This cost largely depends on the hourly electricity consumption and, therefore, on the chosen supply strategy.

$$C_{E(t)} = \sum C_{WM(t)} + C_{ATE(t)} + C_{ET(t)} + C_{MT(t)} + C_{OC(t)} + C_{FF(t)}\,)\, P^{el}_{con(t)} + C_{W(t)}\ Water$$

[9] The depreciation may vary on the time of use and influences the yearly investment cost annuity

C_{WM} .... *wholesale market price [€/kWh]*
C_{ATE} .... *access tariff for electricity [€/kWh]*
C_{ET} .... *electricity tax [€/kWh]*
C_{MT} .... *municipal tax [€/kWh]*
C_{OC} .... *operational cost [€/kWh]*
C_{FF} .... *financing fees [€/kWh]*
C_{W} .... *water cost [€/L]*
$Water$ .... *water consumption [L]*

<u>Cost data</u>

The levelised cost of hydrogen (LCOH) is based on the costs described in Table A.1 derived from Matute et al. (2019). The data input is presented inTable A.2.

Table A.1Cost parameters for the optimization model

Variable cost	Electricity spot market price – Austria 2019	C_{WM}	€/kWh electricity	
	Access tariff	C_{ATE}	€/kWh electricity	0.0012
	Electricity tax	C_{ET}	€/kWh electricity	0.0031
	Municipal tax	C_{MT}	€/kWh electricity	0.0005
	Operation cost	C_{OC}	€/kWh electricity	0.0012
	Financial cost	C_{FF}	€/kWh electricity	0.0002
	Water consumption	$Water$	€/L	0.004
CAPEX	Electrolyser	C_C^{Ely}	€/kW	Scenarios
	Other CAPEX	C_C^{OT}	% of CAPEX	60
	Storage	C_C^{St}	€/kW	Scenarios
	Lifetime	n	Years	20
	WACC	i	%	5
OPEX	OPEX electrolyser	$C_{O\&M}^{Ely}$	% of CAPEX	3
	Other OPEX electrolyser	$C_{O\&M}^{OT}$	% of CAPEX	2.4
	OPEX Storage	$C_{O\&M}^{St}$	% of CAPEX	1

Table A.2 Data input to the optimization model

Type	Source	Temporal resolution	Unit
Electricity supply	Grid 2019	h	MW
H_2 Demand	Annual demand for H_2-based steel production process Austria 2050	y	MWh
H_2 Demand Profile	Spain: industrial gas demand profile (daily variability, weekly cycle) Austria: H_2-based steel production process (constant)	d	
LCOE PV power	Fraunhofer ISE (2021), IEA (2020) and IRENA (2021)	26	€/MWh

LCOE wind power	(Fraunhofer ISE, 2021; IEA, 2020; IRENA, 2021)	36	€/MWh

Capacity modelling

In order to optimise the electrolyser capacity in the first modelling step, the levelised cost of hydrogen and storage are minimised, as described in Eq. **¡Error! No se encuentra el origen de la referencia.**.

$$min\ \sum_{t=1}^{T} \frac{C_{EQ(a)} + \sum_{t=1}^{T} C_{E(t)}}{P_{con(t)}^{H2}}\ [€/MWh] \quad (4)$$

Hydrogen demand ($P_{con}^{H_2}$) is fulfilled either through discharging the H_2 storage ($P_{DC(t)}^{H_2}$) or directly from the electrolyser ($P_{dir(t)}^{H_2}$) (see Eq. (5)).

$$P_{con}^{H_2} = P_{DC(t)}^{H_2} + P_{dir(t)}^{H_2} \quad (5)$$

Eq. (6) makes sure that hydrogen generation ($P_{gen}^{H_2}$) equals the gross H_2 storage input ($P_{Ch(t)}^{H_2}$) and the direct demand fulfilment. In every time step t, electricity consumption (P_{con}^{el}) equals hydrogen generation divided by the P2G efficiency (see Eq. (7)).

$$P_{gen}^{H_2} = P_{Ch(t)}^{H_2} + P_{dir(t)}^{H_2} \quad (6)$$

$$P_{con}^{el} = \frac{P_{gen}^{H_2}}{\eta_t^{P2G}} \quad (7)$$

η_t^{P2G} is assumed to be 0.60. This is below the maximum of 0.70-0.75 to account for the additional load dependent efficiency losses. These detailed losses are the result of the operational optimization.

The hydrogen state of charge is defined in Eq. (8) by the storage level from t-1 plus the hydrogen storage input or charge ($P_{Ch(t)}^{H_2}$) minus hydrogen output or discharge ($P_{DC(t)}^{H_2}$) to fulfil demand.

The storage input ($P_{Ch(t)}^{H_2}$) in Eq. (9) and output ($P_{DC(t)}^{H_2}$) in Eq. (10) are derived by the gross hydrogen amount adjusted by the storage efficiency (η_t^{stor}).

$$SOC_t^{H2} = SOC_{t-1}^{H2} + P_{Ch(t)}^{H_2} - P_{DC(t)}^{H_2} \quad (8)$$

$$P_{Ch(t)}^{H_2} = P_{Ch_{gross}(t-1)}^{H_2}\ \eta_t^{stor} \quad (9)$$

$$P_{DC(t)}^{H_2} = \frac{P_{DC gross(t)}^{H_2}}{\eta_t^{stor}} \quad (10)$$

To achieve a storage balance throughout the year, the hydrogen state of charge in time step 1 needs to equal the SOC at the end of the time horizon (see Eq. (11)).

$$SOC_1^{H2} = SOC_{T+1}^{H2} \quad (11)$$

As stated in Eq. (12), electricity consumption may not exceed electricity supply (P_s^{el}), which can be grid supply (Eq. (13)) or from a dedicated RES plant defined by the renewable generation profile and the RES capacity (P_{RES}^{el}) as shown in Eq. (14).

$$P_{con(t)}^{el} \leq P_{s(t)}^{el} \quad (12)$$

Grid connected electrolyser:

$$P_{s(t)}^{el} = grid\ supply \quad (13)$$

RES connected electrolyser:

$$P_{s(t)}^{el} \leq \text{Profile}_{RES(t)}\ P_{RES}^{el} \quad (14)$$

According to Eq. (15), electricity consumption may also not exceed electrolyser capacity (P^{el}_{Ely}), which is the one result that is an input to the operational efficiency modelling in the next step.

$$P^{el}_{con(t)} \leq P^{el}_{Ely} \quad (15)$$

Variables:

SOC_t^{H2} .... *state of charge H_2 [kWh]*
$P^{H_2}_{Ch}$ .... *charge H_2 (H_2 storage input) [kW]*
$P^{H_2}_{DC}$ .... *discharge H_2 (H_2 storage output) [kW]*
$P^{H_2}_{dir}$ .... *direct H_2 supply [kW]*
$P^{H_2}_{Ch_{gross}}$ .... *gross H_2 charge (gross storage input) [kW]*
$P^{H_2}_{DC_{gross}}$ .... *gross H_2 discharge (gross storage output) [kW]*
P^{el}_{con} .... *electricity consumption [kW]*
$P^{H_2}_{gen}$ .... *net H_2 generation [kW]*
P^{el}_{Ely} .... *electrolyser capacity [kW]*
P^{el}_{RES} .... *optimal RES capacity [kW]*

Input Data:

$P^{H_2}_{con}$ .... *H_2 Demand [kWh]*
P^{el}_{s} .... *electricity supply [kW]*
Profile_{RES} .... *RES generation profile (PV or wind) [0-1]*

Parameters:

η^{P2G}_t .... *electrolyser efficiency (static) [%]*
η^{stor}_t .... *storage efficiency [%]*

__Operational efficiency modelling__

The goal of this second step operational modelling is to consider load and therefore electrolyser capacity dependent efficiency losses according to section 3.3. To avoid multiple interdependencies in the model, the electrolyser capacity (P^{el}_{Ely}) is no longer a decision variable but a fixed parameter resulting from the former capacity optimization.

The Faraday efficiency curve differ between the more flexible PEM and the ALK electrolyser and need to be replicated differently in the model.

a. PEM electrolyser

For the PEM electrolyser, the Faraday efficiency can be modelled with one single curve, which makes the setup easier and leads to a solid model performance (see section 3.3.1).

Additional losses due to low loads are calculated based on the electricity consumption, which in relation to the fixed electrolyser capacity results in a certain utilization rate. The function described in Figure 7 is implemented in the operational model as a linear function to consider losses at specific load factors.

In the following Eq. (18) and Eq. (17), the gradient (*k*) and the axial interception (*d*) are derived for the loss function. L^{ele} and P^{el}_{con} represent a certain relationship between additional efficiency losses and a certain electricity consumption or load factor.

The loss function in Eq. (18) defines the loss at a certain electricity consumption (Figure 6):

$$k = \frac{L_1^{ele} - L_2^{ele}}{Con_1^{ele} - Con_2^{ele}} \quad (16)$$

$$d = L_1^{ele} - P^{el}_{con_1} * k \quad (17)$$

$L_t^{ele} \leq\ k\ \mathrm{P}_{con(t)}^{\mathrm{el}}\ + d$ (18)

L_t^{ele} ....efficiency loss at a certain load [kW]
k ....gradient
d ....axial interception

Furthermore, the H_2 generation balance needs to be extended by this additional loss (Eq. (19)).

$$\mathrm{P}_{con(t)}^{\mathrm{el}}\ =\ \frac{\mathrm{P}_{gen(t)}^{\mathrm{H_2}} + L_t^{ele}}{\eta_t^{\mathrm{P2G}}} \qquad (19)$$

b. ALK electrolyser

The function ALK2 described in **¡Error! No se encuentra el origen de la referencia.** is implemented in the operational model as a linear function for a load factor >0.36, while the function ALK1 is added as a manual input, to consider losses at specific load factors ≤0.36.

For the manual function ALK1 described in Eq. (20)– a matrix listing the load factor and corresponding absolute loss for the load factors 0-0.36 with 36 data points *(x)* - an integer decision variable *$(INT_{t,x}^1)$* enables the model's choice of operation. The integer variable decides on the combination of loss ($L_{t,x}$) and utilization ($U_{t,x}$). The utilization depends on the electricity consumption ($\mathrm{P}_{con(t)}^{\mathrm{el}}$) at the given electrolyser capacity (see Eq. (21)).

$$LM_t^{ele} = \sum_{x=1}^{36} INT_{t,x}^1\ L_{t,x} \qquad (20)$$

$$\mathrm{P}_{con(t)}^{\mathrm{el}}\ =\ \sum_{x=1}^{36}(INT_{t,x}^1\ U_{t,x})\ \mathrm{P}_{Ely}^{\mathrm{el}} \qquad (21)$$

LM_t^{ele} ....loss manual function [kW]
$INT_{t,x}^1$ ....integer decision variable 1 [0 1]
x ....data points in manual function [0-36]
L ....loss in manual function [kW]
U ....utilization in manual function [%]

If, however, the electricity consumption is above a load factor of 0.36, the model chooses the linear ALK2 function with another integer decision variable as shown in Eq. (22).

$$0.36\ INT_t^2 \leq \frac{\mathrm{P}_{con(t)}^{\mathrm{el}}}{\mathrm{P}_{Ely}^{\mathrm{el}}} \leq\ 1\ INT_t^2 \qquad (22)$$

$INT_{t,x}^2$ ....integer decision variable 2 [0 1]

For the linear function ALK2 (LL_t^{ele}), the same approach as for the PEM electrolyser can be used and k and d are derived for the loss function in Eq. (25) (Figure 9):

$$k = \frac{LL_1^{ele} - LL_2^{ele}}{Con_1^{ele} - Con_2^{ele}} \qquad (23)$$

$$d = LL_1^{ele} - Con_t^{ele} * k \qquad (24)$$

$$LL_t^{ele} \leq\ k\ Con_t^{ele} + d \qquad (25)$$

LL_t^{ele} ....loss linear function [kW]

To force a decision for one point along both loss functions, in every time step only one integer decision variable may be one, the other zero (see Eq. (26)).

$$\sum_{x=1}^{36} INT_{t,x}^1\ + INT_t^2 \leq\ 1 \qquad (26)$$

In addition, the H_2 generation balance needs to be extended by this additional loss from both functions according to Eq. (27).

$$Con_t^{\mathrm{ele}} = \frac{\mathrm{Gen}_t^{\mathrm{H2}} + \boldsymbol{LL_t^{ele}} + \boldsymbol{LM_t^{ele}}}{\eta_t^{\mathrm{P2G}}} \tag{27}$$