Effect of large-scale variable electric loads and operation strategy in decentralized electricity markets: Case of large electrolyzers

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Effect of large-scale variable electric loads and operation strategy in decentralized electricity markets: Case of large electrolyzers

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ABSTRACT

A main characteristic of modern and future energy systems is the intermittent nature of renewable power generation, which is reflected in the day-ahead price of electricity as large fluctuations. Connecting significant new grid-connected loads lead to increased average electricity price in the day-ahead market. This occurs through demand-pull inflation. This study uses bid curves from NordPool to evaluate the effect of different large electrical loads in the day-ahead market. The methodology applied in this study enables the study of the effect of large variable grid-connected loads in the day-ahead markets with different operational electricity price limits within which they are allowed to operate. The results indicate a significant impact on electricity price. The operation strategy plays a key role as increasing the day-ahead price of electricity will disproportionally affect the rest of the market under study. For example, connecting a 400 MW electrolyzer to the grid and day-ahead markets could increase the electricity price by 35 €/MWh, meaning a 52% increase over the median day-ahead price in 2023. The lowest levelized cost of hydrogen was achieved at 45 €/MWh (1.4 €/kg). The results highlight the need for additional power generation to be built alongside large grid-connected loads to maintain low, and competitive electricity price in the day-ahead market.

1. Introduction

In order to mitigate the effects of climate change and reach the climate goals set out by the Paris Agreement of limiting the increase of average temperature to +1.5 °C [1], national energy systems must be decarbonized. This is most commonly achieved by transitioning to renewable sources of energy, such as solar or wind power, together with overall electrification of the power system where possible [2]. Sectors that cannot be directly electrified can utilize e-hydrogen and other e-fuels [3]. Green e-hydrogen is a potent energy carrier that can be produced carbon neutrally by electrolysis of water using electricity from renewable sources. It is also often referred to as green hydrogen due to being carbon neutral.

The European Union (EU) has set 2030 targets for the production of 10 Mt/a (million tonnes per annum) of e-hydrogen within the EU and the importing of a further 10 mt/a [4,5]. RePowerEU [5] aims to accelerate the energy independence of the EU by promoting local e-hydrogen production, made with local renewable sources of power, over importing e-hydrogen from outside of the EU, including regions such as the commonly discussed Chile [6,7], Morocco [6–8], Australia [7], or even the Shetland Islands [9].

Electrolyzers connected to the grid have many benefits, not only in terms of producing carbon-neutral e-hydrogen, derived from renewable sources of power, but also by providing grid stability from intermittent renewable power generation through ancillary services [10]. Renewable sources of power are intermittent in nature and often stress the grid and electricity markets with over- or undersupply of power. Electrolyzers are capable of matching dynamic renewable power generation and consume otherwise curtailed power by operating at partial or full load. Electrolyzer stacks can be switched off during periods of lower power availability in the main grid. It is possible to down-regulate wind power generation by turning the turbine hub away from the wind and rotate the blades to harvest kinetic energy less efficiently [11]. Solar power generation is more difficult to down-regulate without disconnecting whole arrays of panels [12]. Having a variable load response to the unstable supply of power can be an efficient and even profitable way to regulate the power in the grid without the need for curtailment of power [10].

Sector coupling and demand response are effective ways to deal with changes in the electricity markets; however, they can be difficult

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Nomenclature

Abbreviations

BESS	Battery Energy Storage System
Capex	Capital expenditures
CO_2	carbon dioxide
e-ammonia	Renewable electricity-based ammonia
e-fertilizer	Renewable electricity-based fertilizer
e-fuel	Renewable electricity-based fuels
e-hydrogen	Renewable electricity-based hydrogen
e-kerosine	Renewable electricity-based kerosine
EU	European Union
FCR	Frequency containment reserves
FFR	Fast frequency reserve
FLH	Full load hour(s)
LCOE	Levelized cost of electricity
LCOH	Levelized cost of hydrogen
LHV	Lower heating value
MCP	Market clearing price
mFRR	Manual fast frequency reserve
Opex	Operational expenditures
PEM	Proton exchange membrane
SOEC	Solid oxide electrolysis cell

Variables & Symbols

η	Efficiency
AE	After electrolyzer
BE	Before electrolyzer
E	Amount of electricity
n	Lifetime
P	Power
p	price
r	Discount rate
V	Volume

Sub- & superscripts

con	Consumption
eq	Equivalent
H_2	Hydrogen
h	hour
SOC	Society

to implement on a large scale without an expensive system overhaul [13]. Stationary battery electric storage systems (BESSs) can provide flexibility to the power system but tend to be expensive compared with installing additional power generation capacity, which amplifies the issues associated with intermittent supply. Batteries are required for shorter-term flexibility on the day or week scale, but due to the costs of long-term storage, they are not typically a viable option.

The role of e-hydrogen in the energy system is that of an energy carrier that can be produced at times of abundant power and used in the production of e-fuels [3] or as a chemical. It can also be burned for heat in processes where electrification is not yet possible. Owing to its poor round trip efficiency between 22% and 29% [14], the main purpose of e-hydrogen should not be to convert it back into electricity; however, it can be used to provide power in extreme situations without having to rely on traditional fossil fuel peaker plants [15]. For e-fuel production, e-hydrogen, when combined with hydrocarbons (usually CO_2), can be used to produce e-ammonia and e-kerosine, which will probably be required to decarbonize the shipping [16,17] and aviation industries [18,19]. Also e-fertilizers can be made, which are traditionally produced with hydrogen from methane using steam-methane reforming [20,21].

Germany is looking into electrolyzers to provide support for its present power system [22]. Germany faces challenges with the integration of renewable energy due to the main wind resources being located in the north of Germany and the load centers in the south [23]. For Germany, e-hydrogen production in the north would alleviate grid load with the capability to use e-hydrogen in peaker plants to cover peak demand locally without having to rely on the transmission grid [24]. E-hydrogen would displace natural gas, which is currently used in most peaker plants in Germany and many other European countries [15,25,26]. Ongoing studies are investigating the use of the present vast natural gas network for hydrogen transportation [27].

There is also a need for e-hydrogen as a chemical for example in steel making in the reduction of iron as well as to reach the required temperatures to melt steel [28]. Several steel manufacturers have plans to use e-hydrogen to reach emission goals such as Afry [29], Tata Steel [30] and Arcelor Mittal [31]. Thus, e-hydrogen would replace fossil fuels, which are a significant source of pollution [32]. The steel-making industry accounts for 7%–8% of the global greenhouse gas emissions [33].

Finland has been implementing new renewable power into its grid at a record rate. In 2024, a total of 8.1 GW of on-shore wind power was connected to the grid [34]. Fingrid, the Finnish transmission system operator, has received connection requests for over 400 GW of renewable power generation [35]. Even if only 10% of this power generation comes to fruition, it will contribute a significant amount to overall capacity, multiple times the current electrical winter peak demand load of around 15 GW [36]. The penetration rate of renewable energy in the energy share is high; this can be observed in the day-ahead prices, which showed 468 h of negative prices in 2023 [37] and 721 h in 2024 [38]. It has been stated that Finland has become the most volatile power market in Europe, despite the low average electricity price mostly due to the rapid implementation of onshore wind power [39,40]. In order to be able to install further renewable capacity, the electricity load must also increase. In that case, the addition of electrolyzers as a large variable load makes most sense considering the climate goals of Finland to be carbon-neutral by 2035 [41].

There are uncertainties regarding the total capacities of the electrolyzers that could be connected to the grid. What is the effect of adding large-scale electrolyzers of varying sizes on the present grid and electricity markets if no additional power generation capacity is installed alongside it? The European Commission states that after 2027 the new renewable power generation capacity must be built alongside the electrolyzers, and the power cannot come from the already existing capacity [42]. There is an exception that if the carbon intensity of electricity from the grid is below 18 $gCO_{2,eq}$/MJ, grid electricity may be used [42]. Finland is close with 92.4% of all its energy consumed coming from low-carbon sources: mainly wind, hydro, and nuclear power in 2023 [43]. Adding significant loads to the grid will inevitably increase the average price in the day-ahead markets. In 2023, 31% of all electricity contracts were dynamic price contracts, up from 14% in 2022 [44]. The research questions that arise in this context are discussed in Section 1.1.

1.1. Aims of the paper

Large-scale electrolyzers play a key role in decarbonizing countries through the production of carbon-neutral e-hydrogen, which can be further processed into e-fuels for use in hard-to-abate sectors, such as aviation and maritime transportation [3]. A concern commonly held by the public is that increasing the electricity demand by a significant amount will increase consumer electricity prices too much for the rest of the consumers. However, in the long run, electrolyzers can be a

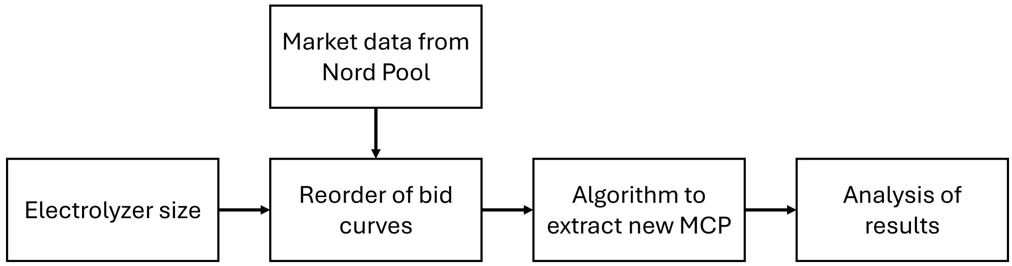


Fig. 1. Overview of the overall methodology; MCP refers to the market clearing price.

reliable source of variable electrical load to balance intermittent supply and enable further adoption of renewable energy in the grid, generally stabilizing the electricity prices if operated correctly [10].

This paper seeks to answer the following research questions:

1. What are the societal costs if different capacities of new electrolyzers are connected to the grid in the day-ahead markets?
2. How should an electrolyzer be operated to benefit both the producer of hydrogen and society as a whole?
3. What is the role of grid electricity in a future low-carbon energy system? Should electrolyzers be fully operated on grid electricity only?

This paper seeks to analyze the effect of utilizing purely grid electricity on day-ahead prices and whether this should be considered an option or not. It is important to note that because Finland is a single-price area, the total electrolyzer capacity used in this paper is the sum of all new electrolyzer capacity. As the whole country has the same price throughout, the net effect on the electricity markets is the same irrespective of whether centralized or decentralized electrolyzer capacity is considered. For simplicity, when discussing the electrolyzer capacity, it is considered centralized as one unit. The benefits and drawbacks of centralized and decentralized electrolyzers are further discussed in Section 6.1. This paper does not favor one type of deployment over the other.

According to market theory, increasing electricity demand leads to a higher electricity price on average due to demand-pull inflation. The focus of this paper is to analyze how much the electricity prices would increase with different electrolyzer capacities, and how sensitive the current electricity markets are to demand-pull inflation.

The hypothesis is that large electrical loads in the grid elevate the electricity prices for the whole market. The question is: How much? Future work is planned on an overview of the different price area bid curves and their readiness to adopt these large-scale variable loads in the Nordic countries in their different respective price areas; this is further discussed in Section 7. This paper focuses on the price area of Finland, which coincides with its land borders.

It is important to note that the main driving force of large scale electrolyzers in Finland is to utilize it directly as a chemical or energy carrier in for example steel-making as well as in the production of e-fuels. Finland possesses significant biogenic carbon dioxide point sources from pulp and paper mills. The biogenic carbon dioxide together with renewable based e-hydrogen forms a strong base for large scale export opportunities of e-fuels to for example Germany, as evaluated by VTT [45]. Satymov et al. [46] discuss Finland's opportunities for export and identifies Europe as a potential market enabling domestic expansion. There is currently no intent for the e-hydrogen to be converted back into electricity, unlike in many European countries, such as Germany [22]. As a result, the conversion of e-hydrogen back into electricity is not considered in the paper.

2. Research novelty

The presented research studies the effect of additional electrolyzer capacity in the day-ahead market. The methodology (Section 3) is novel, globally applicable and quantifies the effect of large scale variable loads on the day-ahead electricity price with a deeper look at the case of electrolyzers. The methodology can be applied to any large-scale electrical load.

The societal impacts of implementing large variable loads on the day-ahead market was quantified and the cost of e-hydrogen production estimated according to different electricity price and electrolyzer capacity combinations.

The results provide insight to the rapid implementation of large-scale variable loads, more specifically electrolyzers. This is further supported by the in-depth discussion on whether the electrolyzer capacity should be centralized or decentralized. The results showcase the need for additional renewable power generation to be built alongside electrolyzers and not solely rely on electricity from the grid. In addition, the ability for electrolyzers to stabilize electricity prices has been shown.

3. Method

The effect of an electrolyzer in the day-ahead markets was modeled at varying electrolyzer capacities applying different day-ahead electricity price limits for operation outlined in Section 3.4; the modeling was based on a day-ahead market analysis explained in Section 3.2. Information regarding the algorithm and the data used from NordPool is found in Section 3.1. The assumptions regarding the operation of the electrolyzer are presented and discussed in Section 3.3.

The overall method used in this paper is depicted in Fig. 1 and explained in detail in Section 3.

3.1. NordPool

NordPool is the leading power market in Europe, operating in the wholesale electricity market across multiple European countries. Established in 1993, it provides a platform where electricity producers, suppliers, and large consumers can trade electricity in the day-ahead and intraday markets [47].

In this paper, to investigate the effect of electrolyzer electricity demand in Finland, the supply and demand bids within Finland were employed for the year 2023 [48]. Due to market data availability, and data quality limitations only the year 2023 is modeled. Additionally, it was important to use full year data in order to not introduce seasonal biases. Based on these bids, the area price of Finland can be obtained. The methodology for extracting market clearing price based on altered supply and demand bids is explained in detail by Salmelin et al. [49], where the location of new wind power installations was optimized to maximize day-ahead market benefit by maximizing revenue, reducing price cannibalization and maximizing societal benefit. Same optimization was performed for solar PV location [50]. How the new market price is extracted is summarized in Section 3.2.

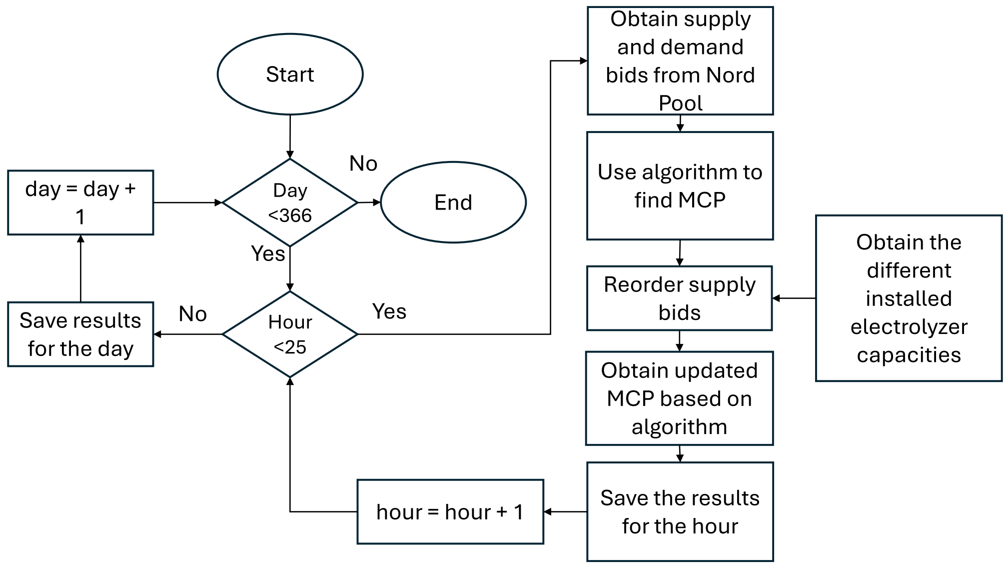


Fig. 2. Overall methodology to determine the market clearing price (MCP) and the maximum electrolyzer operation capacity.

3.2. Python algorithm to analyze market data

The market data analysis is based on the method introduced in Salmelin et al. [49]. Fig. 2 shows a summary of the method used in this paper to determine the new Market Clearing Price (MCP).

First, the original market-cleared price is found by combining the supply and demand bid curves, and it is compared with the actual MCP. The verification process provides confidence that the market price is calculated correctly. This is followed by the modification of the bid curves where the demand of electricity is increased, resulting in a new market-cleared price. Due to regulations and green climate goals, it can be assumed that the energy consumed will come from renewable energy sources that are produced at zero marginal cost. When the new MCP has been found, the result is saved and repeated for different levels of electrical load. This process is repeated hourly for the whole calendar year of 2023.

3.3. Electrolyzer information and operation

As stated in the aims of the paper (Section 1.1), the operating strategy should be such that both the operator of the electrolyzer and the other consumers in the day-ahead markets will benefit. The electrolyzer should be dynamically operated so that it obtains a high revenue and has the capability to down-regulate when electricity prices are high. If the societal gains outweigh the losses in profits, society should be prioritized.

If the size of an electrolyzer is large enough, it becomes a load that impacts the power balance of the whole power system. Hence, the electrolyzer load should be included in the demand bid for the day-ahead power market auction. In that case, the electrolyzer is no more only a price taker, but a price setter. As a result, scheduling of the electrolyzer load will have an impact on the day-ahead marker price of all the electricity market participants. There are several ways in which an electrolyzer can be run. This paper focuses on the following:

- Operate the electrolyzer according to an electricity price ceiling;
- Operate the electrolyzer to minimize the hydrogen cost;
- Operate the electrolyzer to obtain a certain number of full-load hours;
- A mix of the above.

The electricity demand profiles of the electrolyzer consist of a set of 40 fixed demand profiles from 10 to 400 MW in 10 MW increments. The final profiles of operation are calculated and optimized in post-processing according to the electricity price limit and the electrolyzer capacity outlined in Section 3.4.

As the market effects are analyzed at an hour level, at all electrolyzer capacities up to 400 MW, it is possible to select the optimum level of load for every hour to remain within the given day-ahead electricity price constraints while maximizing e-hydrogen production at full or partial load.

3.4. Electrolyzer operation constraints and assumptions

There are three main types of electrolyzers: proton exchange membrane (PEM), alkaline, and solid oxide (SOEC), which all have different characteristics and costs associated with them. In 2022, the installed capacity was 162 MW in Europe and 600–700 MW globally, which is only 0.2% of the total global hydrogen production capacity [51]. In 2023, the capacity in the EU mounted to from 228 MW with a projected total capacity of between 900 MW and 3.4 GW are projected by the end of 2025 in the EU [52]. The typical capacity of a single project in Europe was small, close to 1.5 MW [52], but this is expected to increase even to the GW scale soon. For instance, there are plans to build 1 GW plants by Vetyalfa [53,54] and PlugPower [55] and a 3 GW plant by OX2 [55]. Extensive lists of plans can be found in [54,55]; however, many projects have faced delays.

The efficiency of the electrolyzer depends on the selected electrolyzer technology. The estimated efficiencies per electrolyzer technology are given in Table 1. Solid oxide electrolyzers can reach nearly 100% stack efficiencies but require additional heat input, which reduces the overall system efficiency [56]. According to Virah-Sawmy et al. [57], the electrolyzer efficiency decreases at higher loads, and using a fixed efficiency tends to overestimate the hydrogen production. However, there are effects that may also cause a lower part-load efficiency [58]. For the purpose of this paper, as large scale electrolyzers are likely to be built modularly by combining many smaller stacks together, it can be assumed that each stack will be operated at constant power and therefore efficiency. When flexibility is desired on the plant level, individual complete stacks can be switched off. Therefore, it can be assumed that at the plant level the efficiency is fixed. As this paper only is concerned about hourly average load level, the participation in different ancillary services is not modeled, where quick changes in individual cell, and stack loads could be observed. The opportunities that electrolyzers have in participating in ancillary services are further

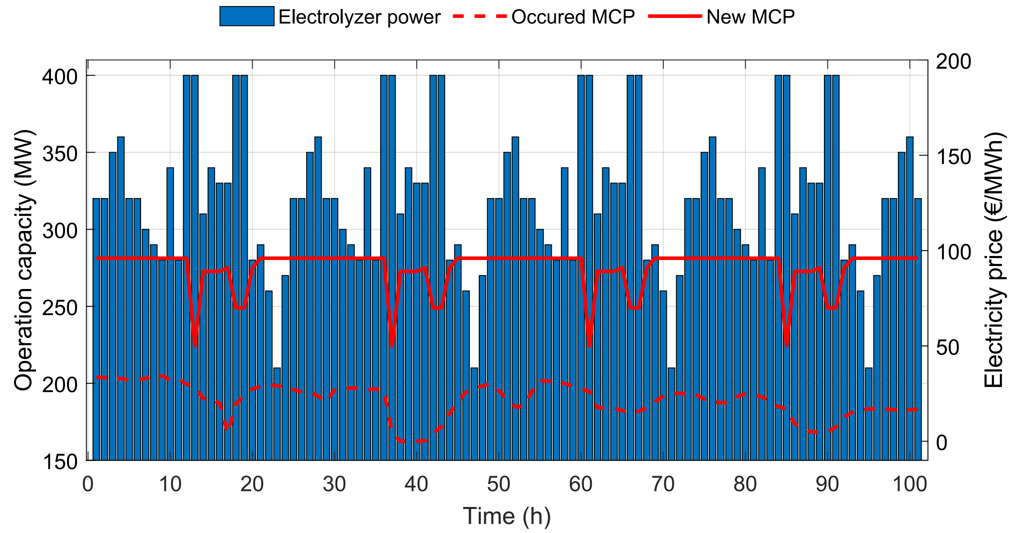


Fig. 3. Sample 100 h operation period with a 400 MW electrolyzer and a 100 €/MWh electricity price limit plotted against the actual market price and the new calculated clearing price.

Table 1
Comparing electrolyzer system efficiencies at lower heating values (LHV) for PEM, Alkaline, and SOEC.

Technology	Authors	Efficiency	Year	Reference
PEM	Akyuz et al.	64%–70%	2012	[59]
PEM	Kosonen et al.	52%–65%	2016	[60]
PEM	Saebea et al.	67%–82%	2017	[61]
PEM	Buttler and Spliethoff	46%–60%	2018	[62]
PEM	Wang et al.	60%–85%	2022	[63]
PEM	Schmidhalter et al.	68.2%	2024	[64]
Alkaline	Smolinka et al.	62%–82%	2011	[65]
Alkaline	Kosonen et al.	57%–65%	2016	[60]
Alkaline	Buttler and Spliethoff	60%–68%	2018	[62]
Alkaline	Gorre et al.	63.5%	2020	[66]
SOEC	Buttler and Spliethoff	76.8–84.6%	2018	[62]

discussed in Section 6 and plans for future work modeling ancillary services in Section 7.

The costs associated with scaling electrolyzers also have large margins as the electrolyzer stack markets are only developing [67]. The specific investment cost benefits from scale-up, but the effect decreases after a certain number of stacks [68]. In the future, a heavy cost decrease is predicted [69,70].

Some of the assumptions regarding the operation of the electrolyzer are as follows:

- The electrolyzer is built of modular 10 MW stacks, which are either operating at nominal power or turned off to the warm idle state.
- The ramp-up and ramp-down rates are not considered, because the ramp duration makes up only a small proportion of the hour during which it will operate. According to Buttler and Spliethoff [62], even the warm start-up time is as short as 1–5 min for alkaline and a few seconds for PEM electrolysis.
- The heat and associated costs required to maintain the electrolyzer stack temperature at warm idle are not considered.
- The costs associated with the downtime and restarting of a stack are not considered.
- It is assumed that the electrolyzer is connected to a hydrogen pipeline with a capability to take in all the hydrogen produced without additional compression.

In the future work, it is planned to tie the electrolyzer to a location with mainly off-grid power generation available on-site and to evaluate the effects on different electricity markets with a weaker grid connection available. This is discussed further in Section 7.

4. Case study

In this study, the individual electrolyzer stacks are considered to be a black box in terms of operational characteristics. Electricity is put in and e-hydrogen comes out with a certain efficiency coefficient. As the focus is on the analysis of the effect on the day-ahead markets, these simplifications and assumptions can be applied as the market operates on an hourly basis where the differences for instance in ramp-rates play a minimal role overall when operating the plant at constant load that is re-evaluated hourly. If the hydrogen plant were tied to variable generation as the European Commission mandates after 2027 [42], then the ramp rates would play a more significant role. A system efficiency of 70% is assumed based on efficiency estimates in Section 3.4.

In the case under study, the electrolyzer system can be operated at partial load in 10 MW increments. An example of the operation of a 400 MW electrolyzer is shown in Fig. 3. The duration curve of the operation at varying electrolyzer sizes with an electricity price limit of 100 €/MWh is shown in Fig. 4. It is important to note that this electricity price limit has been chosen here simply to demonstrate the operation of the electrolyzer. The electricity price limit refers to the price ceiling in the day-ahead market above which the electrolyzer is not allowed to operate. As the increased electricity demand by the electrolyzer affects the MCP, the electrolyzer is set to operate at the maximum allowed load without exceeding the electricity price limit, including partial load.

As seen in Fig. 3, the overall market price approaches the set electricity price limit of 100 €/MWh when operating at a high but partial load most of the time. When the electrolyzer is operating at full capacity, the market price is equal or under the set price limit, and thus, it can be interpreted that there is capacity available to operate more electrolyzer capacity to reach the desired price limit. If the electricity price were above the predetermined price limit, the electrolyzer would not be in operation until the price decreases below the set price limit.

The duration curves are plotted in Fig. 4, where the color scale refers to the installed electrolyzer capacity. It can be seen that with a 100 €/MWh electricity price limit the higher-capacity electrolyzers are forced to operate at partial load more than smaller electrolyzers, whose operation is closer to binary. This is due to the larger electrolyzers having much more capability to influence the electricity markets at different load points. With smaller electrolyzers, the operation is much

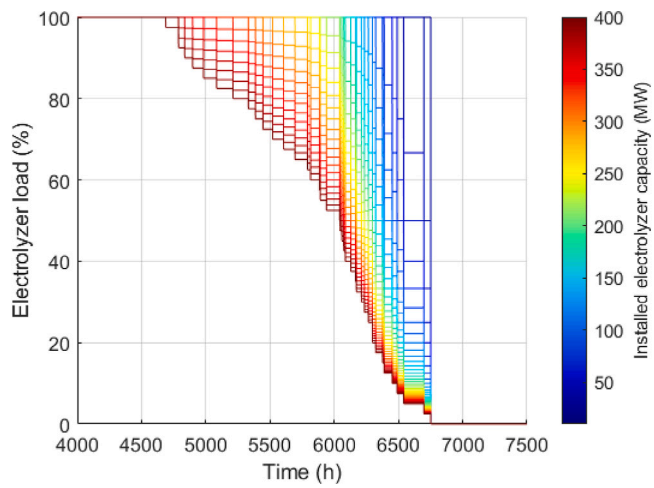


Fig. 4. Duration curves of the different electrolyzer capacities with a 100 €/MWh electricity price limit.

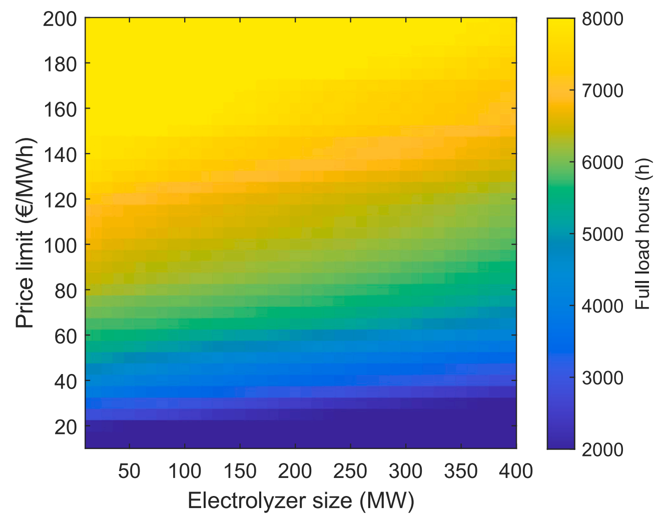


Fig. 5. Full-load hours of the electrolyzers at different capacities and electricity price limits.

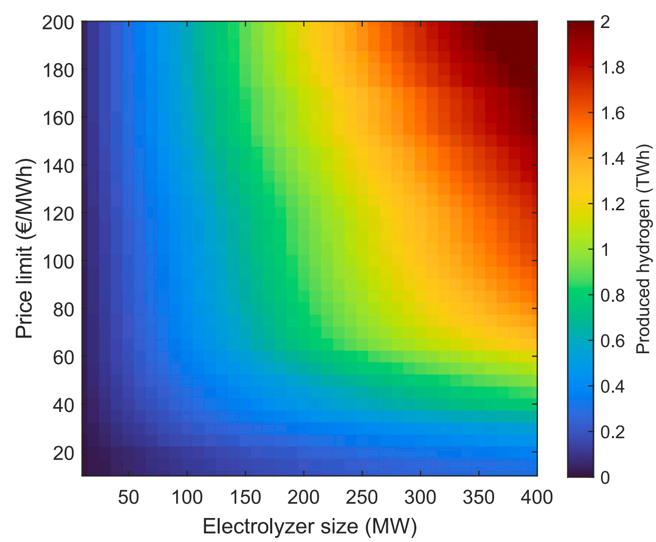


Fig. 6. Volume of hydrogen produced in TWh at different electrolyzer sizes and electricity price limits.

more binary as the electrolyzer has overall less effect on the MCP and less overall intermediary power level increments at which to operate. With the 100 €/MWh electricity price limit, all the electrolyzers were able to operate at least 4500 h of the year at full load. Larger electrolyzers operated for around 2000 h at partial load. The number of partial load hours was smaller with a smaller electrolyzer size as they were allowed to operate at full capacity for more hours. All electrolyzers operated at zero load for around 2000 h due to the electricity price being higher than 100 €/MWh without any load, not allowing for any load to be engaged.

5. Results

The full-load hours of the electrolyzer at different electrolyzer sizes with different electricity price limits are presented in Section 5.1 together with the volume of e-hydrogen produced. The investment costs and operational costs are calculated in Section 5.2. The effects on the day-ahead markets and associated increased electricity prices on society are addressed in Section 5.4. Finally, the levelized cost of hydrogen (LCOH) is calculated in Section 5.3 and the LCOH including the societal costs in Section 5.5.

5.1. Hydrogen volume and full-load hours

The full-load hours of the electrolyzers at different capacities with different electricity price limits are presented in Fig. 5. With a hard electricity price limit (≤30 €/MWh), the total full-load hours remain low at around <3000 h. As the price limit is relaxed, the full-load hours increase steadily with the relatively smaller electrolyzers reaching higher full-load hours faster with relatively lower electricity prices, albeit only marginally. According to Hofrichter et al. [71], with lower full-load hours, the power ratio between the electrolyzer size and the renewable energy capacity must be optimized more precisely; however, with higher full-load hours, the optimization becomes less strict. With a fixed electricity price, the cost of produced e-hydrogen is directly linked to the total production volume; however, with variable day-ahead pricing, a balance has to be met between volume and electricity cost.

The total volume of produced hydrogen (V_{H_2}) is calculated on an hourly basis using the electrolyzer power ($P_{\text{Electrolyzer}}$) multiplied by the efficiency (η) of the electrolyzer (70%):

$$V_{H_2,\text{MWh}} = \sum_{h=1}^{8760} P_{\text{Electrolyzer},h} \times \eta_{\text{Electrolyzer}} \tag{1}$$

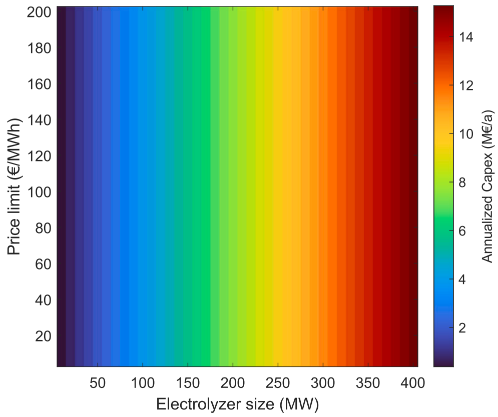
The volume of hydrogen produced at different electrolyzer sizes and electricity price limits is shown in Fig. 6. Most of the hydrogen is produced with larger electrolyzer sizes with looser price limits. With smaller electrolyzer sizes also the total production volume is smaller. A similar effect is seen when the price limit is tightened.

5.2. Investment and operational costs

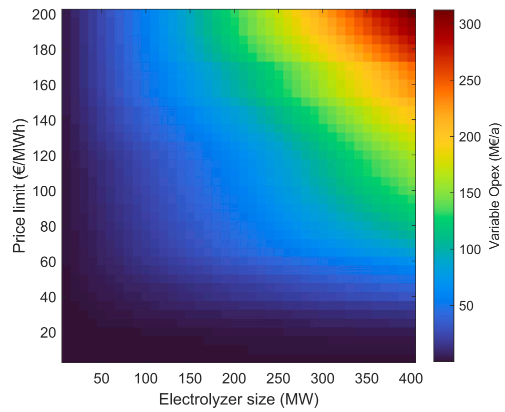
The electrolyzer investment cost was set at 0.587 M€/MW based on cost estimates by ElSayed et al. [72] for 2025. Plant efficiency of 70% was used in converting from unit costs per €/kW$_{\text{el}}$ into €/kW$_{\text{H2,LHV}}$. A discount rate (r) of 5% and a lifetime (n) of 30 years were used. The annualized capital expenditure is calculated with:

$$\text{Annualized Capex} = \frac{\text{Total Capex} \times r}{1-(1+r)^{-n}} \tag{2}$$

The total operational cost of the electrolyzer (Total Opex) consists of a fixed (Fixed Opex) and a variable (Variable Opex) component. The Fixed Opex consists of the general maintenance of the electrolyzer plant, and it is set at 2% of Capex annually [73,74]. The variable costs



(a) Annualized Capex



(b) Total Annual Opex

Fig. 7. Investment and operational costs of the electrolyzer.

depend on the volume of e-hydrogen produced by the plant and the fuel cost. In this case, the fuel cost is the price of electricity ($p_{\text{electricity}}$) at the specific hour multiplied by the electricity consumed ($E_{\text{electrolyzer}}$).

$$\text{Variable Opex} = \sum_{h=1}^{8760} p_{\text{electricity,h}} \times E_{\text{electrolyzer,h}} \tag{3}$$

$$\text{Fixed Opex} = 0.02 \times \text{Capex} \tag{4}$$

$$\text{Total Annual Opex} = \text{Fixed Opex} + \text{Variable Opex} \tag{5}$$

The Opex is divided into fixed and variable costs of operation. The fixed costs consist of the costs of investments made to the electrolyzer plant, annualized for a 30-year investment period. The relationship between the Capex and the electrolyzer size is considered linear without scaling factor. The costs associated with the different electrolyzer capacities are illustrated in Fig. 7.

The annualized costs, including investment and operational costs, are dominated by the variable costs, which in this case consist of mainly the electricity cost used in the electrolyzer. The fixed operational cost set at 2% of Capex does not contribute significantly to the cost. The inclusion of start-up costs, which includes planning and permitting, are unlikely to contribute significantly to the total cost due to the order of magnitude higher Opex compared to Capex. The total annual costs can be seen in Fig. 8. The figure highlights the strong need for low price electricity, without which the economic drive can quickly disappear. The annualized Capex is marginal compared to the annual Opex.

5.3. Levelized cost of hydrogen

While the paper focuses to quantify the effect new significant grid-connected electrical loads can have on the day-ahead price, calculating the LCOH is an important metric to highlight the implications of cannibalized affordable day-ahead electricity price on a electricity price dependent product if no new generation capacity is built alongside the new demand. The cost of the final hydrogen product can rapidly inflate as seen from the results of this section.

The LCOH is calculated by summing the annualized Capex and the total Opex divided by the annual hydrogen output (V_{H_2}):

$$\text{LCOH} = \frac{\text{Annualized Capex} + \text{Total Annual Opex}}{V_{H_2,\text{MWh}}} \tag{6}$$

The LCOH produced is shown in Fig. 9. The cost of hydrogen is high below the 20 €/MWh electricity price limit due to the overall lower amount of hydrogen produced as seen from the full-load hours in Fig. 5. With the larger electrolyzer sizes, the investment costs are far more

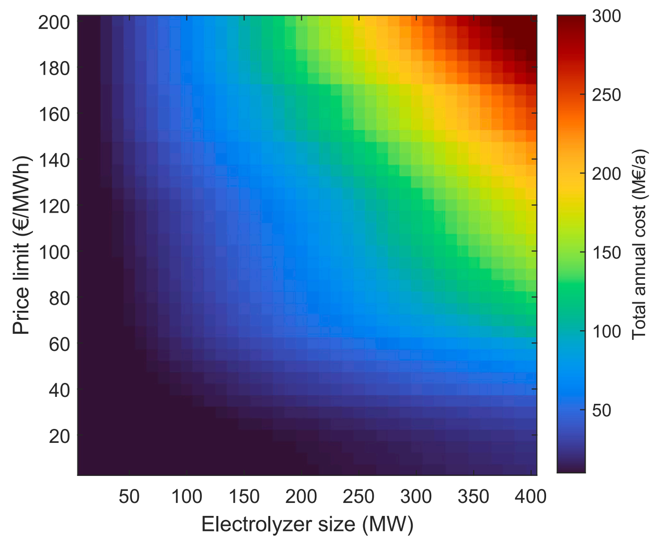


Fig. 8. Total annualized costs including Capex and Opex.

strongly reflected in the hydrogen price. The LCOH is the lowest with the smaller electrolyzer sizes at each respective electricity price limit levels. This is due to the smaller electrolyzers being more capable of operating at full capacity with a lower influence on the day-ahead prices. The cost of hydrogen produced by larger electrolyzers benefits from the use of cheaper electricity but is negatively affected by their size; larger electrolyzers are more likely to have to operate at partial loads in order to stay within the electricity price limit constraints, as supported by Fig. 4. Relaxing the price limit further above 120 €/MWh increases the hydrogen cost due to the increase in the variable operational costs as shown in Fig. 7(b). Relaxing the price limit, however, allows for more hydrogen to be produced as shown in Fig. 6. Increasing the electrolyzer size with a loose price limit significantly increases the hydrogen price as the large electrolyzer has more capability to influence the day-ahead market price where the electrolyzer cannibalizes the low day-ahead price from which it seeks to benefit through demand-pull inflation.

The LCOH as a function of electricity price limit for some sample electrolyzer sizes is illustrated in Fig. 10 based on results from Fig. 9. At a very low price limit, the plant costs are reflected more strongly in the LCOH due to lower hydrogen production volumes at all electrolyzer sizes. A minimum in costs is observed at all electrolyzer sizes at around 50 €/MWh. A steady increase in LCOH is seen above 50 €/MWh;

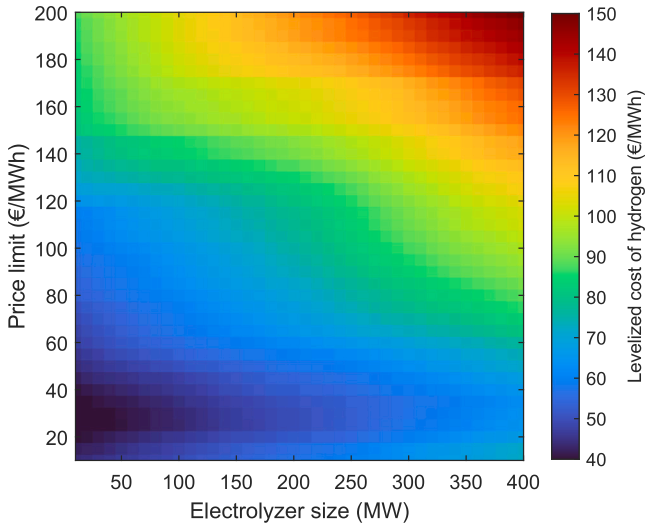


Fig. 9. LCOH at different electrolyzer capacities and price limits.

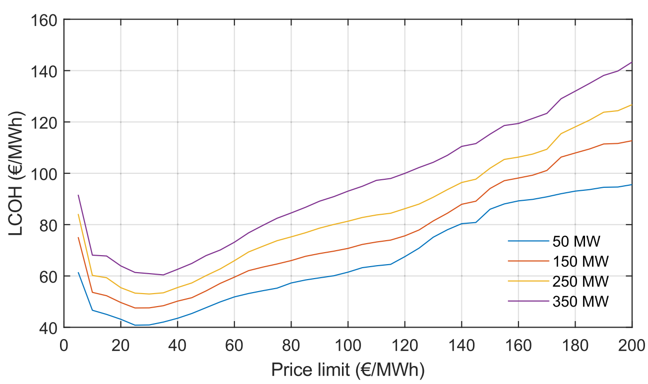


Fig. 10. LCOH as a function of electricity price limit from sample electrolyzer capacities based on data from Fig. 9.

however, with much higher total hydrogen production volumes as depicted in Fig. 6.

The increase in LCOH is relatively marginal with higher electricity price limits. This raises the question of how increasing the price limit affects the rest of the day-ahead market participants. This question is addressed in Section 5.4.

5.4. Costs to society

As mentioned above, the more electrolyzer capacity is installed, the more it will increase the electricity price in the day-ahead market, unless new renewable power generation is built alongside the new electrolyzer capacity. If the electrolyzer is operated with a high electricity price limit, the effect on the rest of society's electricity prices will also be significant because of the considerable increase in electricity demand without new renewable power generation capacity.

The cost to society is defined as the difference in the MCP before (BE) and after (AE) the addition of the electrolyzer capacity multiplied by the electricity consumption (E_{con}) in the day-ahead market on that specific hour according to:

$$Societal\ cost = \sum_{h=1}^{8760} (P^{\mathrm{BE}}_{\mathrm{MCP,h}} - P^{\mathrm{AE}}_{\mathrm{MCP,h}}) \cdot E_{\mathrm{con,day\text{-}ahead,h}} \tag{7}$$

The consumption of electricity in the day-ahead market is calculated using the bid curves obtained from NordPool [48]. This definition of societal cost has been employed previously in Salmelin et al. [49]. The total electricity consumption for 2023 in the day-ahead market was 58 TWh.

The greatest increases in electricity prices are seen with larger electrolyzer sizes and looser electricity price limits as expected, illustrated in Fig. 11. The increase in electricity price can be as high as 35 €/MWh for the rest of the day-ahead market participants, the increase being smaller with smaller electrolyzer sizes and tighter price limits.

5.5. Levelized cost of hydrogen with societal costs

Due to the price increase caused by the additional electricity demand in the day-ahead markets, the price of electricity for the other consumers in the day-ahead markets has also increased. To obtain the LCOH considering the effects on societal electricity prices ($\mathrm{LCOH_{SOC}}$), the same formula is employed as to determine the regular LCOH (Eq. (6)) with the modification that the societal cost (Eq. (7)) is added as a cost of production:

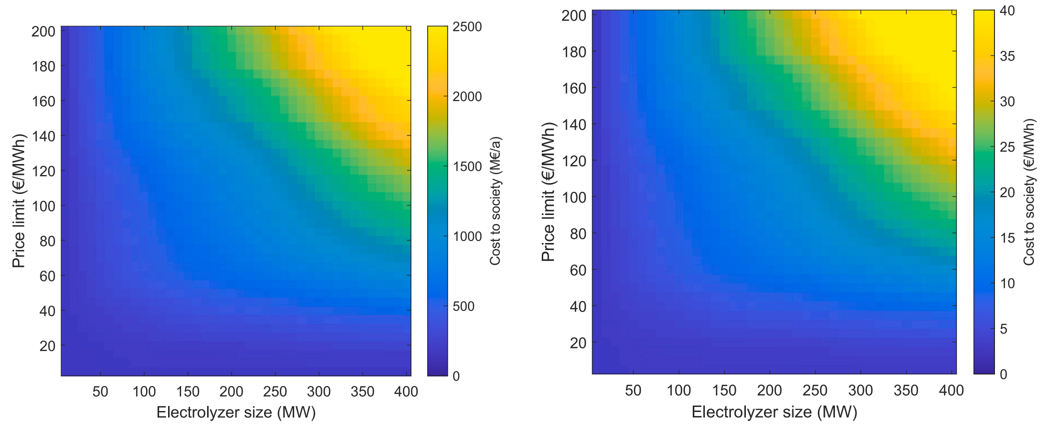
$$LCOH_{SOC} = \frac{\text{Annualized Capex} + \text{Total Annual Opex} + \text{Societal cost}}{V_{\mathrm{H_2,MWh}}} \tag{8}$$

For characterization purposes, the societal cost of the increase in electricity costs was added as a production cost in Fig. 12 to determine the $\mathrm{LCOH_{SOC}}$. This would be unrealistic in the real world; however, it is an effective way to demonstrate the effect of the electrolyzer on the day-ahead markets and the other consumers if no additional power generation capacity is installed alongside the electrolyzer, as required by the regulation of the European Commission effective after 2027 [42]. This set of results focuses on the caveat that grid electricity may be used if the carbon intensity of the grid is below a certain threshold. This result strongly shows that while it is allowed to operate on grid electricity only, it is not advisable as it disproportionally influences the rest of the market participants as shown in Figs. 11(b) and 12.

The volume of hydrogen produced greatly affects the result of this hypothetical scenario where the increased cost of electricity is added to the production of hydrogen as a production cost. It can be seen that with the smaller electrolyzer sizes, the smaller volume of total hydrogen is less capable of dispersing the increased cost. By increasing the electrolyzer size and thereby production volume, the costs spread over a larger volume of hydrogen, thus reducing the price of the final hypothetical product. However, with the large electrolyzer sizes, the electricity price limit should remain relatively low to not further inflate the costs to society. As the price deviates from the equilibrium, the increase in societal costs scales more aggressively than the increase in volume, which leads to a divergence of the cost to volume ratio. This points to large-scale electrolyzers being operated at partial load to be the best solution in this hypothetical scenario.

The LCOH including the societal costs was compared with the societal cost in Fig. 13 for four different sample electrolyzer sizes. For the smallest electrolyzer size of 50 MW, a decoupling of the societal cost and the LCOH is observed where the societal cost contributes greatly per unit hydrogen produced to the final cost. As the electrolyzer capacity is increased, the cost per unit of hydrogen decreases.

The lowest cost of hydrogen when considering the effects on society is obtained at higher electrolyzer capacities with tight electricity price limits of around ≤100 €/MWh. Above 100 €/MWh, for the electrolyzer capacities above 250 MW, the societal costs increase per unit hydrogen faster than the LCOH. For the smaller electrolyzer sizes, the ratio between the two compared parameters remains the same. The observed decoupling observed in the $\mathrm{LCOH_{SOC}}$ is explained by the overall lower total hydrogen volume produced.



(a) Societal cost in M€/a.

(b) Societal cost in €/MWh.

Fig. 11. Societal costs due to new installed electrolyzer capacity.

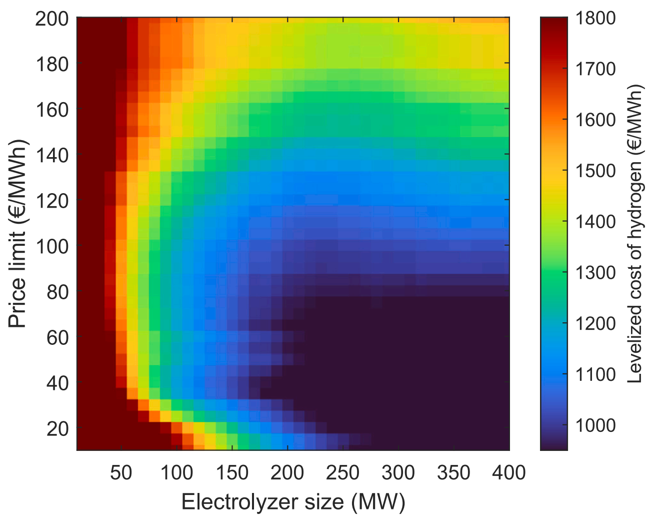


Fig. 12. LCOH in a hypothetical scenario where the increased cost of electricity for the other participants in the day-ahead markets is added as a production cost for hydrogen.

6. Discussion

Large-scale electrolyzers are required to reach climate goals as e-hydrogen plays a key role in decarbonizing maritime and aviation industries and many others. Implementing new electrolyzer capacity in a legacy system comes with its challenges.

As plant-level investments are made with the longer term in mind, often over 20 years, it is important to plan the operation accordingly. The electricity markets have witnessed a significant change in the last few years, transitioning from a very stable system mostly powered by fossil fuels to a system where intermittency is key. It is impossible to say with certainty what the nature of future markets will be; however, it is certain that intermittency from renewable power sources is here to stay. For the longer term, to reduce risks and reliance on the electricity markets, it may be favorable for an electrolyzer plant to produce its own electricity locally through wind and solar and only utilize the electricity markets as a source of flexibility through a lower capacity grid connection.

As the adoption of new renewable power capacity is only now accelerating, the cannibalization of revenue from additional renewable generation capacity has only started to become relevant in some locations, such as California with solar power [75,76], Germany [77], and Finland with wind power due to its unique installation challenges [49]. This is the first time that demand-pull inflation has been quantified in literature due to large-scale variable electrical loads as a kind of cannibalization of variable Opex.

In Fig. 14, some sample hours are plotted throughout the year at 50 h intervals for a total of 175 curves. Each line represents the effect of the electrolyzer at different electrolyzer sizes on the electricity price for that specific hour. It is evident that as the electrolyzer size is smaller, it has a smaller effect on the day-ahead markets. At larger electrolyzer sizes the deviation from the 0 €/MWh price increase is also larger. When considering operation of an electrolyzer by cutting a small number of production hours or operating at partial load, the majority of the moments of large price increase can be avoided. As mentioned above, on-site renewable power generation could reduce the risk and dependence on the electricity markets, thereby allowing for further flexibility.

According to results presented in Section 5.5, the impact on society can be reduced with different control strategies and incentives. Even a slight increase in electricity price can have major repercussions on the electricity costs of the rest of society. In the year 2023, the amount of electricity in the day-ahead markets was 58 TWh, which is around 70% of all the electricity consumed in Finland. Policies and laws must be put in place to prevent sharp price surges and to protect consumers. Large electrical loads connected to the grid should also aim to build dedicated power generation to cover the main power consumption. The grid can be used for flexibility but should not be the main source of power.

It is important to understand the role of electrolyzers in the energy system as a whole. Not only is it a facility to produce hydrogen but it also plays a key role in stabilizing the power system through ancillary services: Fast Frequency Reserve (FFR), balancing energy and balancing capacity markets (mFRR), and frequency containment reserves (FCR). These services contribute to more stable electricity prices and can be an additional source of revenue for the hydrogen producers. A literature review by Cozzolino and Bella [10] analyze the different opportunities electrolyzer based systems have to provide ancillary services. They identified electrolyzers play a crucial role in maintaining stability, reliability and efficiency of modern electricity grids. Due to the fast response time they are excellently suited for providing frequency control services. A large 25 MW PEM electrolyzer was tested in the FCR market of Belgium, as documented by Samani et al. [78]. Samani concludes that by operating the electrolyzer at 55% baseload while providing the remaining capacity as power reserve was the optimal economic strategy for this case. It is important to note that depending on the market where the electrolyzer is introduced, a different optimum can be achieved. The importance of the consideration of ancillary services grows with increasing penetration of variable renewable power generation. Future

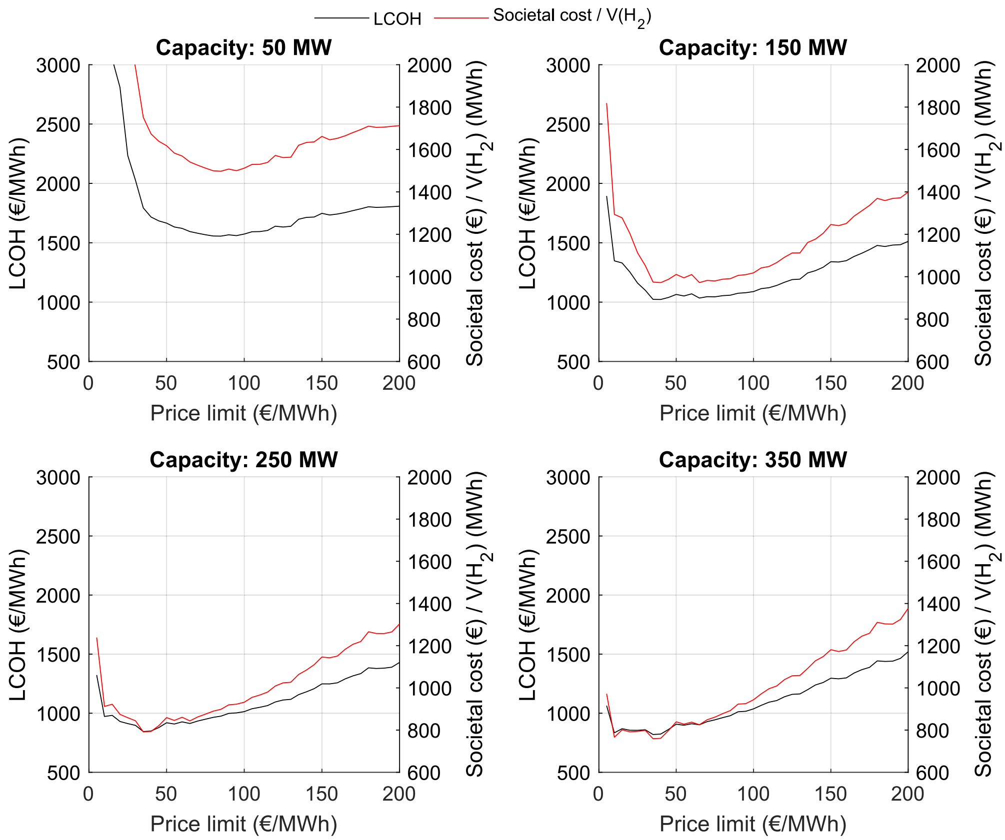


Fig. 13. LCOH with societal costs divided by the hydrogen volume,in units of MWh, at different electricity price limits with sample electrolyzer capacities. The data is from Fig. 12.

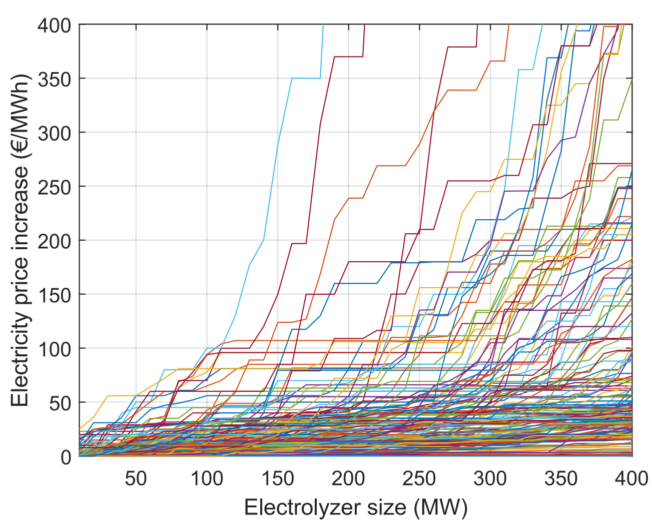


Fig. 14. Effect of electrolyzer size on the electricity price; each line represents a single hour. A sample of 175 h from 2023 taken at 50 h intervals from the start of the year and covering the whole year of the effect on electricity price in the day-ahead market.

work is planned to evaluate the benefits of operating electrolyzers in different ancillary service markets (Section 7).

The results are price-area-specific and depend on the characteristics of the system. A more flexible system will exhibit an overall flatter demand curve, which means that a relatively large amount of change in power consumption is required to achieve a large change in the day-ahead market price. A steeper demand curve is more susceptible to price changes. A deeper analysis of this is planned to be conducted in the future as discussed in Section 7.

How electrolyzers are operated depends largely on the motives behind why the electrolyzers are built. If the main goal is to fight climate change and reduce dependency on fossil fuel use, then producing at large scale is essential to reach climate targets. Policies from the government and key players should support a fat and clean transition, but protect regular consumers from rising electricity costs. The green hydrogen market is still in its infancy and has great potential in enabling the growth of other industries such as efuels. Some increase in electricity price may be acceptable if it leads to jobs, innovation and increased societal welfare. Additionally, electrolyzers can help balance the power system and support further adoption of intermittent renewable generation capacity beyond society's current needs. These plants can then operate on a plant level at partial load at a price level that is societally acceptable, overall stabilizing electricity prices. These are complex issues that should be discussed within society between regular electricity consumers, governments, investors as cost of electricity affects everyone and interests may not always be fully aligned. What is certain that everyone benefits from low-cost electricity, and controllable variable loads near sites of generation enable the adoption of further low-cost renewable power generation.

Questions such as "Where should the new capacity be installed?" and "Should the electrolyzer capacities be centralized?" are not within the scope of this paper but are important questions in the green transition and thus discussed in Section 6.1. Future work on this topic is planned and discussed in Section 7.

6.1. System planning: Centralized or decentralized electrolyzers and other grid considerations

While the grid and other related considerations are not directly within the scope of this paper, the authors deemed it important to dedicate a section to general considerations when constructing new electrolyzers and to include discussion on whether electrolyzer capacity should be centralized or decentralized. Many aspects must be considered when planning new electrolyzers:

- Electrical energy and power availability;
- Safety and reliability of the value chain;
- Incorporation of other resources into the value chain;
- Grid considerations, such as hosting capacity;
- Making use of side streams, such as waste heat;
- Risk assessment;
- Local workforce.

Decentralized infrastructure has many benefits in reducing different risks. Having highly centralized hydrogen production can bring a whole value chain to a halt in case of a fault. There are also national safety concerns about highly centralized hydrogen production as decentralized hydrogen production allows for many individual nodes to operate independently with a lower risk if a single site becomes inoperable. Small-volume activity clusters may not have the same opportunity for acquiring cost-efficient large-scale storage as large-volume sites. Monitoring and safety could also have some economy of scale benefits. On the other hand, small-scale projects are easier and faster to implement and fund, with a lower risk.

Future flexible electrolyzers play a key role as a significant balancer of renewable power. It is plausible that in the future electrolyzers and renewable power generation come hand in hand. This would reduce overall grid congestion reducing the need for long-distance transfer of power on the GW scale to electrolyzers. Will these large-scale variable loads take away the opportunities of other smaller-scale loads?

If large-scale electrolyzers become a part of the grid, whether dispersed or centralized, what is the role of border interconnectors in a future like this? Will they become interconnectors to only import electricity? Will there be any inexpensive electricity to export or will it all be consumed domestically?

Grids are planned according to peak power, and as a result, the electrolyzers should be built while keeping the current state of the grid infrastructure in mind. Operation will still play a significant role as ideally when the grid is being stressed, these electrolyzers should down-regulate or even completely switch off. If this is the case and the electrolyzer does not increase the peak power by its operation, then the electrolyzer may be connected where there is hosting capacity available.

It is also important to account for the local resources and needs when considering electrolyzers. If there is a district heating system or large buildings or other facilities nearby that require constant heating, while keeping the strong seasonal variations in heat demand in mind, these targets could benefit from the electrolyzer waste heat. However, utilization of heat would also probably require heat storages to match the temporal availability and demand of heat. Countries such as the Nordic countries, where the growing season of crops is short due to the long winters, could benefit from greenhouses built in the vicinity of electrolyzers to make use of the waste heat. For district heating networks where the temperature of the network is between 65–115 °C, depending on the season [79], the temperature of the waste heat from the electrolyzers must be elevated from around 50–80 °C of the PEM electrolyzers [80] to district heating levels. Greenhouses, on the other hand, only need to reach around 18–24 °C [81], and thus, the waste heat could be directly used allowing for larger-scale domestic food production year-round with carbon-free heat from renewable sources of power, thereby eliminating much of the food imports from warmer regions closer to the equator or in the Southern Hemisphere and reducing the need for aviation and maritime fuels.

It is also worth considering local and national and perhaps even international CO_2 availability for the manufacturing of e-fuels. It is unlikely that e-hydrogen will be the final product in the value chain as e-fuels play an important role in decarbonizing many industries, such as maritime transport, steel, aviation, and fertilizer manufacturing account for 14.4% of the global greenhouse gas emissions [82]. If there are significant point sources of especially biogenic carbon for example from paper or pulp mills, they should be utilized. The e-fuel plants that require e-hydrogen will likely match the electrolyzer sizes in terms of volume unless a pipeline is built for large-scale hydrogen transport and storage, which could allow for large-scale centralized e-fuel production. A pipeline would enable the decoupling of the sizes and geographical locations of electrolyzers and e-fuel plants along the hydrogen pipeline. Although sector integration can have economic benefits, it can also complicate the project. Unexpected outages can lead to challenges in the downstream processes.

As shown in regional hydrogen valley reports for North and South Savonia [83,84], even just the renewable power generation required for the electrolyzers—if installed locally and without relying on long-distance transmission lines–constitutes a significant source of revenue for the municipalities from taxation alone for a long timeframe of 30 years or even more. Decentralized electrolyzers also provide jobs in areas with smaller population centers, which could benefit significantly from the new jobs and demand for services.

If new renewable power generation capacity is built alongside electrolyzers, these plants have the capability to become prosumers of power and, in addition to the down- and up-regulating electricity markets, also participate in the day-ahead market. If the electrolyzer remains a load in the system, it will only stress the grid; however, if the electrolyzer plant does install some on-site renewable power generation capacity and be able to feed some of it into the main grid, it is now able to support the grid. The energy transition is taking place at a fast pace, and the grid and gas pipelines are facing challenges in keeping up. Long-distance transmission lines often take around 7–10 years to plan and build, depending on the readiness level. Hydrogen pipelines are planned and built on similar timescales. These processes can be accelerated with government support and different preliminary studies. Could decentralized hydrogen production alleviate the effects of a fast energy transition and reduce the electricity transmission bottlenecks that are starting to appear worldwide? If large-scale renewable power generation is installed behind the electrolyzer plants with the ability to feed some of the power to the main grid, this effectively reduces transmission line bottlenecks if the plants are built near centers of high load. If no generation is built alongside the plant, then the plant should be situated near sites of power generation.

7. Future work

The following topics have been identified and planned for future work:

Comparison of the readiness of different price areas in the Nordic countries to implement large-scale electrolyzers.

Evaluation of the effect of already-existing grid infrastructure and its limitations in evaluating electrolyzer sites and whether they should be centralized or decentralized using connections available. Other grid and system planning aspects would be considered.

Simulation of the operation of an electrolyzer together with co-built off-grid renewable power generation with wind power or possible hybrid solutions of combining wind and solar power. Evaluation of the opportunities of electrolyzer to operate in difference ancillary service markets could be considered.

Further questions to be answered in future studies could include the following: How does the marginal price of electricity from the grid affect price formation? What opportunities do large-scale electrolyzer plants have in participating in different ancillary services? What is their marginal cost of power as a result?

8. Conclusion

The adoption of new large-scale electrolyzer capacity is inevitable, and it plays a significant role in the green transition away from fossil fuels while stabilizing the grid. Operating electrolyzers in the day-ahead market can have a significant effect on the day-ahead prices, and the operation should be planned accordingly. Policies and regulations should be put in place to protect consumers as the rest of the participants in the day-ahead markets disproportionally suffer from demand-pull inflation of electricity prices.

When analyzing the investment and operational costs of the electrolyzers, it was observed that the variable cost component of the operational costs dominates the total annualized cost share dramatically. While the investment costs for large electrolyzers can be significant, the main contributor to the final hydrogen cost is the price of the electricity used to produce the hydrogen. If grid electricity is used for e-hydrogen, must the electricity remain cheap through continuous investments into renewable sources of electricity as the cost of the produced hydrogen is heavily tied to the electricity price.

It was found that the lowest LCOH of 45 €/MWh (1.36 €/kg) was obtained for a 10 MW electrolyzer operating with a price ceiling of 30 €/MWh, reaching 4000 full-load hours and 40 GWh (1 212 kg) of e-hydrogen. A sharp increase in hydrogen costs is seen above the 225 MW electrolyzer capacity and beyond the 100 €/MWh electricity price limit. With a slightly higher per unit cost of e-hydrogen, larger electrolyzers with a significantly higher total production volume could be implemented, reaching volumes of 500 GWh (15 151 kg) at a price point of around 65 €/MWh with a 200 MW electrolyzer with the price limit of 70 €/MWh.

Considering the effects of demand-pull inflation on the price of electricity, a small change in electricity price disproportionately increases the electricity price for the rest of the day-ahead market participants. Connecting a 400 MW electrolyzer to the day-ahead market operating with a loose electricity price limit led to a 35 €/MWh increase in electricity price. Electrolyzers should be operated using low-price electricity only. There is small overlap where the LCOH and the cost to society through increased electricity costs have an optimum at a large (>250 MW) electrolyzer capacity and a low (<100 €/MWh) price ceiling.

Still, the main take-away of this paper is that while operating electrolyzers purely off of the day-ahead markets and the grid is possible and permitted according to the guidelines of the European Commission, new electrolyzer capacity should incorporate new renewable power generation capacity alongside the electrolyzer and have the existing grid and day-ahead markets as a two-way source of flexibility for both the electrolyzer and the rest of the grid.

CRediT authorship contribution statement

Markus Salmelin: Writing – review & editing, Writing – original draft, Methodology, Investigation, Formal analysis, Data curation, Conceptualization. **Eero Inkeri:** Writing – review & editing, Writing – original draft, Methodology, Formal analysis. **Araavind Sridhar:** Writing – review & editing, Writing – original draft, Methodology, Data curation. **Samuli Honkapuro:** Writing – review & editing, Supervision, Methodology, Funding acquisition, Conceptualization. **Jukka Lassila:** Writing – review & editing, Supervision, Methodology, Funding acquisition, Conceptualization.

Declaration of competing interest

The authors declare the following financial interests/personal relationships which may be considered as potential competing interests: Markus Salmelin reports financial support was provided by Strategic Research Council Finland. Markus Salmelin reports financial support was provided by Business Finland. If there are other authors, they declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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Data availability

The authors do not have permission to share data.

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