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Marketability analysis of green hydrogen production in Denmark: scale-up effects on grid-connected electrolysis

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Abstract: Green hydrogen is produced through different methods in the lab but only a few technologies are commercialized. Cost reduction is widely expected to compete with the existing carbon-emitting alternatives. This paper compares alkaline, proton exchange membrane, and solid oxide electrolysis cells as the dominant technologies. Economic analyses with scale-up effects show meaningful differences between PEM and alkaline electrolyzers as relatively settled methods and solid oxide as an immature technology. Monte Carlo simulations on grid-connected electrolysis using the Danish electricity market confirm that both PEM and alkaline electrolyzers can already produce hydrogen with less than 3 €/Kg if taxes and levies are removed. The price may even drop below 2 €/Kg after the mass adoption of all three technologies. Furthermore, if electricity is delivered at half prices, the levelized cost of hydrogen falls around 1 €/Kg. The capabilities for cost reduction after scaling-up are 33%, 34%, and 50% in alkaline, PEM, and solid oxide electrolyzers respectively while they could get intensified with subsidization to 56%, 59%, and 70%. The results indicate that solid oxide electrolyzers can be as economical as alkaline and PEM ones. However, grey hydrogen seems to remain unbeatable without subsidized electricity and/or carbon tax adjustments.

Keywords: Alkaline Water Electrolysis, Levelized Cost, Net Present Value, Proton Exchange Membrane, Solid Oxide Electrolysis Cell, Subsidy Policy.

1. Introduction

Thanks to global awareness, carbon reduction is a common target today. Hydrogen is a promising solution for several hard-to-abate sectors even though explicit targets today are not completely in line with 1.5°C decarbonization pathways [1]. Steam methane reforming (SMR) is currently the dominant hydrogen production way on commercial scales [2]. However, it has to be phased out by low/zero carbon-emitting alternatives such as biomass gasification [3] and electrolysis. Regarding economic potentials, some reports suggest focusing on low-carbon hydrogen in the mid-term before the full transition to zero-emission hydrogen [4]. As green hydrogen, produced from renewable energy, gained popularity in recent years, several studies focused on economic feasibilities besides technological developments [5][6][7][8]. Not only governmental institutes but also private companies are developing techno-economic analyses in this field. While the profitability horizon of hydrogen production is realized in some sectors, it may not be far away from the others. Despite having great emission reduction capabilities, economic problems barricade widespread applications of electrolysis [9][10][11]. The required energy for producing hydrogen by splitting water (286 kJ/mol) is seven times larger than the extraction from methane (41 kJ/mol). Uncompetitive prices in comparison to fossil fuels impede investments in hydrogen fuel which in turn slow down infrastructure expansions such as refueling stations. Subsequently, insufficient demand decelerates mass production and cost reduction.

Many emerging technologies face such vicious cycles before commercialization. The transition from the immature phase can be accelerated by CO2 tax regulations, CAPEX & OPEX reduction, direct and indirect subsidies, end-user awareness, etc. The International Energy Agency (IEA) reports urged that hydrogen trades beyond the borders need to rapidly grow to leave meaningful impacts on the global energy systems. To date, contracts are signed between France and Germany regarding hydrogen blending in their natural gas networks. Japan and Brunei have already started hydrogen shipping in the form of methylcyclohexane [12]. Governments in particular have high acceleration capacity at this stage. Coordination, regulation, and standardization can facilitate hydrogen markets via private sectors participation [13]. A recent example is Britain where four economic models are proposed as investment incentives: contractual payments to producers, regulated returns, obligations, and end-user subsidies [12]. In parallel, carbon pricing is an effective way to confine emitting ways of hydrogen production in favor of electrolysis. In doing so, industries are pushed to optimize cost-effective methods in line with emission reductions. Subsequently, additional revenues are provided to boost other enabling plans like green subsidies, R&D expansion, and market enlargement. Furthermore, VAT on carbon-intensive fuels can gradually increase to make space for Fuel Cell Electric Vehicles (FCEV). Market expansion in hydrogen-based transportation systems can noticeably cheapen the cost of hydrogen chains, especially in the distribution sector [12]. Regarding the agreement among China, Japan, the USA, and South Korea, 10 million hydrogen-driven vehicles will be on the roads by 2030. Consequently, 10,000 refueling stations are expected to emerge to facilitate long-haul transportations on hydrogen [14].

More specifically, water electrolysis using RES has garnered attention compared to grid-connected alternatives [15]. Several studies conclude that dealing with RES intermittencies might be preferred over the costs of electricity from national grids [16][17]. Off-grid electrolysis in mid and long-term scenarios can already present competitive results. The Atacama Desert and Patagonia region are respectively known for solar and wind energy in Chile while 11% of Australia is suitable for green hydrogen production [15]. Blessed with ample RES, the two countries aim for reaching 1.27 €/kgH_2 by 2030 to become the cheapest in the world [1]. Although RES-driven electrolyzers are free from grid cots and tariffs, lack of consistency in production and long-distance transfers impose extra costs.

Apart from the technical aspects, social considerations can be crucial in the wider deployment of new technologies. The significance of public perception of hydrogen should not be undermined. A recent study indicates half of the people in the UK have positive attitudes toward upgrading home heating to hydrogen-fired systems [12]. High levels of awareness about hydrogen fuels are reported in Spain [18] while an American study revealed only 35% of people correctly answered basic questions about hydrogen technologies. A questionnaire regarding hydrogen and fuel cell indicated that 90% of Americans find themselves ‘not familiar’ or ‘slightly familiar’ [12]. Although the results are encouraging, a big space for improvement is obvious.

The acceptable marginal price of hydrogen varies in different industries and sectors. Based on a study in the UK, more than 60% of participants showed unable to pay for hydrogen fuel for home appliances even if they wished to, mainly because of low wages and energy bills [19]. Furthermore, a common concern about the necessity of purchasing new appliances at the top of the higher hydrogen costs is reported [12]. A survey on the acceptability of FCEV in Spain identified O&M costs as the main hesitancy [18]. A study in Norway validates that younger people have more willing to pay for hydrogen fuels due to easier access to information on the consequences of fossil fuels [20]. Mature markets already exist for fuel cell forklifts where 6-7 €/kg is settled due to zero-emission and quick refueling. However, the hydrogen fuel only below 3 €/kg is attractive as jet fuel [21]. Altogether, long-haul transportation followed by rail, shipping, and aviation are apt sectors for economic feasibility by low-cost hydrogen [22].

Many studies indicate that the electricity price is the dominant barrier in hydrogen cost reduction [23] while some others believe that CAPEX is the most critical parameter for investors [24][25]. In some cases, the delivery distance can be a game-changer [26] especially for remote RES-driven electrolysis sites [27][28] and intercontinental transportations [29][30][5]. In a wider sense, geospatial factors such as proximity to markets and supporting infrastructure are substantially involved in the RES-based electrolysis [31]. Conversely, grid-connected electrolyzers are generally free from geospatial constraints; hence, their reduced CAPEX is more attractive to investors. The other side of the coin is higher OPEX, mainly caused by electricity bills, that repels new investment. Large-scale deployment is shown influential effects not only on CAPEX [24][32][33] but also on hydrogen storage systems [34][16][35][36]; however, the best suitable technology may vary with sizing. For instance, underground pipes are economically advantageous for smaller amounts while salt caverns are preferred on larger scales [37]. Similarly, the proper transportation systems are decided with regard to the hydrogen supply amounts [26][38][39]. Besides, the operating regime and optimizations in design can affect both CAPEX and OPEX [33]. A study on the users' side in Britain showed that the cost of hydrogen-burning appliances could be four times higher than existing natural gas ones for the first 1,000 units installed. However, when scaled up to 100,000 units, the costs would become just 1.5 times higher [12]. Although alkaline electrolyzers are considered mature, still a potential of CAPEX reduction by 27% is reported by 2030 [40]. Using the learning curve method, steeper CAPEX reductions are expected for PEM and solid oxide in comparison to alkaline electrolyzers. Overall cost reductions of up to 75% are reported in holistic up-scaling scenarios for multi-MW plants [41].

It is still hard to talk about the definite hydrogen pathway since policy statements in many countries are at the early stage. However, the general overview is to promote green hydrogen via incentive packages to absorb mass investments in scalable projects. In parallel, there might be more customers, mostly in developed countries, willing to pay extra money for clean fuels. Moreover, electricity prices have downward trends in long term due to RES deployment [42]. Subsequently, intermittent power systems may experience surplus generation in periods when the electricity price dramatically falls. This can be in favor of electrolyzers to run on cheap electricity and store low-cost hydrogen [43].

A size-dependent financial study is developed on the cogeneration of hydrogen and oxygen with various RES-driven electrolyzers from 100 kW to 10 MW. The analysis is from the viewpoint of private assessors whether or not to invest in green hydrogen production using already available PV plants. The second scenario was to invest in establishing PV plants besides electrolyzers extracting economically feasible oxygen and hydrogen. Assuming the market prices of 10 €/kgH_2 and 1-7 €/kgO_2, the Net Present Value (NPV) comparisons indicated that larger electrolyzers were more profitable. As long as the oxygen market price stays above 4 €/kgO_2, the economic profitability for all the cases is guaranteed. However, large-scale electrolyzers still managed to hold profitability with around 2 €/kgO_2. Further assessments are also developed around a 1 MW alkaline electrolyzer coupled with a 1.25 MW PV plant. Simulations with decreasing hydrogen prices between 10 €/kg to 6 €/kg over 20 years validate that the investment is still profitable [14].

Another RES-based study compares levelized cost of hydrogen (LCOH) production by low and high-temperature electrolyzers with the assumption of aggressive deployment of RES along with carbon emission taxes. Both short and mid-term analytic results were in favor of alkaline and PEM electrolysis. But solid oxide electrolyzers become more cost-competitive in the longer horizons reaping the benefit of RES potentials. Longer annual running time by PV or wind turbines besides higher efficiency can compensate for the higher CAPEX of SOEC. The study identifies Chile, UK, Germany, and France as apt locations for high-temperature electrolysis coupled with off-shore wind turbines. On the other hand, integrations of PV and wind turbines vote for the superiority of low-temperature electrolysis due to CAPEX effects. Altogether, off-shore wind turbines may not compete with on-shore renewables due to higher CAPEX. 65% of LCOH stands for CAPEX in off-shore driven electrolysis; whilst, it is relatively smaller for PV and on-shore, 41% and 56% respectively [44].

An economic analysis through the lens of a potential corporate investor on the attractiveness of hydrogen production projects is developed in Germany and Texas. The findings say that such investments might be already cost-competitive (3.23 €/kgH_2); even further, industrial-scale deployments can reduce the price to 2.5 €/kgH_2 [45].

A study on grid-connected hydrogen production via alkaline electrolyzers (6 MW) in Germany, Spain, and Austria is developed to assess the profitability differences. The outcomes show that although OPEX in Spain is slightly lower, it cannot outweigh the effects of higher electricity prices. Hence, from the business perspective, investments in alkaline electrolyzers in Germany are more lucrative than in Spain or Austria [46].

Regarding the reviewed literature, RES-driven electrolysis is more studied than grid-connected for the sake of electricity prices. However, the majority of studies are developed for specific geographies where ample renewable energies are available. In reality, the costs of storage and transportation can change the results for remote electrolysis sites. Some studies oversimplified such secondary costs while many others developed overoptimistic scenarios. This paper focuses on grid-connected electrolysis using different technologies without extreme geographic constraints. The effects of large-scale adoptions on CAPEX are particularly addressed here. Besides, the case study is the national grid of Denmark which is known for wind energy. The uncertainties in electricity prices are observed through Monte Carlo simulations.

1.1. Contributions and findings

This study investigates trends in technological developments and scale-up effects resulting in green hydrogen price reduction. The main findings are bulleted below:

- Alkaline and PEM electrolyzers can be already profitable investments if the tax and levies are removed. Grid-connected electrolysis with higher load factors may lead to hydrogen production below 3 €/KgH_2 which is marketable under circumstances.
- Scale-up effects and technology developments can drop the hydrogen price below 2 €/Kg. The electrolysis method becomes less important in large-scale deployments.
- Electricity price remains the dominant factor in grid-connected electrolysis regardless of the technology. Green hydrogen production can compete with carbon-emitting methods if favored by taxes and subsidies. Half-price electricity and scale-up effects can drop the hydrogen price to 1 €/Kg which is strongly marketable for fossil fuel replacements.
- The levelized cost of hydrogen in alkaline, PEM, and solid oxide electrolyzers are capable of reduction by 33%, 34%, and 50% respectively after scaling-up. These values are enhanced to 56%, 59%, and 70% through subsidized electricity.

2. Electrolysis Methods

Green hydrogen can be produced via several methods in the lab but the most promising methods for large-scale commercialization are briefly explained in this section. A basic model is given in (1) to quantify the dynamic behavior of a generic electrolyzer [13].

$$V_{cell} = V_0 + V_{act} + V_{ohm} + V_{con} \tag{1}$$

where V_0, V_{act}, V_{ohm}, and V_{con} are the open-circuit, activation, ohmic, and concentration voltages respectively.

Eq. (1) can be expanded and rewritten as (2) to show the relation of current and voltage [13].

$$V_{cell} = V_0 + \frac{RT}{2F} \times \ln\left(\frac{P_{H_2}P_{O_2}^{0.5}}{a_{H_2O}}\right) + \left(R_{eq} + R_m\right) \times i + \frac{RT}{\alpha_a 2F} \times \ln\left(\frac{i}{i_0}\right) + \frac{RT}{\alpha_c 2F} \times \ln\left(1 + \frac{i}{i_{lim}}\right) \tag{2}$$

where a and c stand for anode and cathode respectively, R is the gas constant, T is the temperature, F is the Faraday's constant, i_0 is the exchange current, α_a and α_c are the charge transfer coefficients, R_{eq} is the equivalent resistance of the interface (including both electrodes), R_m is the resistance of membrane, P_{H_2} and P_{O_2} are pressures, and a_{H_2O} is the water phase (1 if water is liquid).

The operating point of commercial electrolyzers is typically controlled by the injected current. Regarding Eq. (2), the injected current should be increased to increase the production rate, which also results in higher operational voltages. However, higher voltages would inversely affect the stack voltage efficiency as (3) [13]. This reveals a trade-off between production rate and efficiency even though there have been significant improvements in recent years [47][48].

$$\eta = (-\frac{\Delta G_f}{2F})/V_{cell} \tag{3}$$

where ΔG_f is the free enthalpy of water (285.83 kJ/mol).

The system efficiency can be calculated by the ratio of the high heating value (HHV) of the product over the consumed electricity as (4). In a nutshell, the current intensity should be wisely chosen to minimize the specific electrolyzers cost on one hand and to maximize the system efficiency on the other hand.

$$\eta_{sys} = \frac{HHV\ (kWh/kg) \times H_2(kg)}{\frac{stack\ input\ energy\ (kWh)}{power\ supply\ efficiency} + ancillary\ losses\ (kWh)} \tag{4}$$

2.1. Alkaline

Alkaline electrolyzers are a relatively developed method capable of production in MW scales. This technology is advantageous for continuous and stable production in large-scale industrial environments. Alkaline electrolyzers are reliable technologies with proven lifetimes up to 100,000 h. However, the main drawback appears when connected to intermittent RES where dynamic operating points are inevitable. The system efficiency is profoundly affected by lower load factors; therefore, it cannot be a successful couple with off-grid renewable electricity. Besides, the current density is relatively low due to ohmic losses across the electrolyte and diaphragm [49]. Additional costs of compression are often necessary for downstream applications because of the low-pressure hydrogen produced [12].

2.2. Protone exchange membrane

PEM electrolyzers have significant superiorities over alkaline ones including flexible operating regimes, high current density, and efficient production in partial loads. Such traits along with reasonable CAPEX make PEM electrolyzers the best option for coupling with RES. Many researchers believe that PEM electrolyzers will be preferred over alkaline pairs by 2030 due to the huge expansion of RES [50]. However, the current technology still suffers from degradation and durability due to the catalyst loss and membrane lifetime [49]. Today, PEM electrolyzers are being utilized for capacities beyond 10 MW [15].

2.3. Solid oxide

Solid oxide electrolyzers have very high efficiency but they need improvements in many ways for commercialization. In addition to slow start-ups and high CAPEX, they are not reliably proven for long-term operations. They may survive lifetimes of 20,000 hours in constant operating points. When coupled with RES, inherent intermittency and frequent thermo-chemical cycles deteriorate the degradation rate [1]. Other noticeable challenges are corrosion of anode, stable operation under high pressure, and sealing issues [50].

On the bright side, since SOEC works in high temperatures, they are interesting options for industrial applications and waste heat reuse. Besides, SOEC can be adopted in chemical processes such as methanation and syngas production. A unique feature offered by solid oxide cells is reversibility as the structure of electrolyzer and fuel cell are the same. Therefore, the concept of regenerative FC/electrolyzer systems is affordable with reasonable costs [50].

Table I summarizes the advantages/disadvantages of the three technologies. It should be noted that the planned projects for the upcoming years indicate that there is no single dominant technology to outcompete the others.

Table I: The advantages and disadvantages of alkaline, PEM, and solid oxide electrolyzers.

Electrolyzer	Advantages	Disadvantages
Alkaline	Proven performance MW stack size Durability Low CAPEX Non-noble materials	Low current density Corrosive electrolyte Slow dynamics Low gas purity Low operational pressure
PEM	High current density Simple and compact structure high-pressure hydrogen production Flexible operation	Expensive membrane Noble materials Acidic environment Degradation
Solid Oxide	High efficiency Non-noble materials Co-electrolysis (syngas) Reversible operation (fuel cell)	Bulky design High CAPEX Degradation Brittle ceramics Sealing issues

3. Economic Analysis

As mentioned earlier, the hydrogen sector needs mega investments to find a stable place in the energy market. Nowadays, many private investors are still in doubt if green hydrogen projects are profitable compared to parallel markets. This section investigates the effects of technological developments and mass productions in CAPEX reduction as substantial parameters for investment attraction. The investment attractiveness of projects is quantized and compared via Net Present Value (NPV) assessments. Besides, the dependency of the end product value on the operating regime and the electricity price is analyzed for different electrolysis technologies.

3.1. Large-Scale Adoption

Several strategies including market uptake, supply chain enhancement, product standardization, raw material replacement, and mass production are suggested for hydrogen cost reduction [51]. R&D activities are mostly focused on enhancing the operating current density to reduce the CAPEX in parallel with improving efficiency to reduce the OPEX [50].

The concept of European Hydrogen Valleys is to integrate several applications of hydrogen in a geographical unit. A hydrogen valley can be as big as an industrial site up to a city where the entire hydrogen value chain from generation to the end-users is included [50]. The Port of Rotterdam is an example where a carbon-neutral economy in a three-step transition is evolving using hydrogen integrations with many other low-carbon technologies [12]. Many believe if rapid scale-up takes place, green hydrogen will be price competitive in many countries around in less than a decade [1]. It is estimated that 1,600 GW of electrolysis can completely decarbonize heavy-duty transport in Europe. Storage costs for chemical energy as hydrogen are several times lower than battery; therefore, massive adoption of hydrogen storage units (liquid chemicals) is expected [52]. It is also believed that mass production along with larger stack size, i. e. upgrading from 1 MW to 20 MW, can remarkably reduce costs. For instance, the tipping point for PEM electrolyzers is approximated 1,000 units (of 1 MW) per year to make 50 % cost reduction in stack manufacturing happen [1]. However, predictions on cost reduction are erroneous due to several technological, economic, and political uncertainties. Tables II, III, and IV respectively summarize the recent reports on alkaline, PEM, and solid oxide electrolyzers. It should be noted that several projected values in the literature review are outdated and already incorrect mostly due to underestimation of cost reduction trends. This paper relies only on dependable surveys in recent publications. In general, innovation and mass deployment are expected to converge all the three technologies towards similar costs [1].

Table II: Current and projected values for alkaline electrolyzers.

Parameter	Current Value	Projected Value
CAPEX (€/kW)	426-853 [1] 750 [51] 600 [49]	<170 [1] 660 [51] 440 [41]

	700-800 [50]	400 [49]
Stack unit size (MW)	1 [1]	10 [1]
Stack life time (kh)	90 [4] 60 [1]	100 [1] 60 [51]
Consumption (kWh/kgH2)	50-78 [1] 50 [49]	<45 [1] 48 [49]
Cold start-up (minutes)	>15 [4] >50 [1]	>30[1]

Table III: Current and projected values for PEM electrolyzers.

Parameter	Current Value	Projected Value
CAPEX (€/kW)	600-1,200 [1] 1,000 [51] 500 [53] 900 [49] 950-1,550 [15] 1,000-1,500 [50]	<170 [1] 385 [51] 290 [41] 255 [53] 220 [54] 500 [55][49]
Stack unit size (MW)	1 [1]	10 [1]
Stack life time (kh)	40 [4] 50-80 [1] 50 [51] 20-60 [12]	100-120 [1] 60 [51] 125 [53] 80 [54]
Consumption (kWh/kgH2)	50-83 [1] 55.8 [56] 50 [53] 55 [49]	<45 [1] 47 [51] 46 [53] 50 [49]
Cold start-up (minutes)	10> [4] 5>[57] 20> [1] 0.5> [49]	5> [1] 0.25> [49]

Table IV: Current and projected values for solid oxide electrolyzers.

Parameter	Current Value	Projected Value
CAPEX (€/kW)	>2,000 [58][59] 4,500 [49] 2,400-4,800 [15] 2,000-4,000 [50]	<250 [1] 170 [4] 610 [41] 210 [60] 430-640 [44]
Stack unit size MW	0.005 [1]	0.2 [1]
Stack life time (kh)	<40 [4] <20 [1] <50 [52] <10 [12]	80 [1]
Consumption (kWh/kgH2)	45-55 [1] 40 [49]	<40 [1] 37 [49]
Cold start-up (minutes)	>60 [4] >600 [1]	<300 [1]

3.2. Net Present Value

Green hydrogen producers are competing with each other to absorb more investments. More finances can help reduce costs, improve marginal prices, and gain higher profits. However, initial investments require studies on the future stream of paybacks. Net present value can be calculated as (5) for capital budgeting and investment planning to decide on profitability and risks. In other words, NPV is a comparative index among several investment opportunities by finding today's value of future monetary streams [24]. The leading commercialized projects of alkaline, PEM, and solid oxide in terms of production rate are listed in Table V. Fig. 1 depicts the NPV surfaces regarding the electricity and hydrogen market prices using the available technology today. A uniform 8% discount rate or Weighted Average Cost of Capital (WACC) is assumed for the investments [44]. In addition, a 10-year lifetime is considered in the calculations due to the ever-growing technology of electrolyzers. Both alkaline and PEM are well-established and commercialized; hence, investment in such projects is more attractive. SOEC can also be profitable with promoted hydrogen and low-price electricity but the NPV gap is not easily ignorable especially for private investors. Taking the projected scale-up effects by 2050 into account [1], NPV planes are upgraded as Fig. 2. Although the NPV gaps between technologies are bridged, the dependency of SOEC on the hydrogen market price is higher than the others. However, the higher efficiency of SOEC makes it less vulnerable to expensive electricity. All in all, it can be concluded that the electrolysis method becomes less important in large-scale deployments. Note that manufacturers might have different upscaling approaches but they all pursue "cost reduction". The electrolyzers are seen as "black boxes" in NPV analysis to compare investment opportunities regardless of electrolysis upscaling technical details.

$$NPV = \sum_{i=1}^{N} \frac{Net\ cash\ flow\ in\ year\ i}{(1+discount\ rate)^{i}} \tag{5}$$

where N is the number of years.

Table V. The available parameters of the case study electrolyzers by different technologies/manufacturers [57][61][62].

Electrolyzer	Alkaline (Hylink)	PEM (M2000)	Solid Oxide (Hylink)
Nominal Power (MW)	10.5	9	2.7
Production Rate (KgH2/h)	200	180	67
Production Rate (Nm³/h @ 0°C, 1 bar)	2,230	2,000	750
Production Capacity Dynamic Range (%)	40-100	10-100	5-100
Operating Temperature (c)	85	10-40	~800
Electricity Consumption (kWh/KgH2)	52.28	50.05	40.04
Electricity Consumption (kWh/Nm³H2)	4.7	4.5	3.6
Delivery Pressure (barg)	30	30	1-40

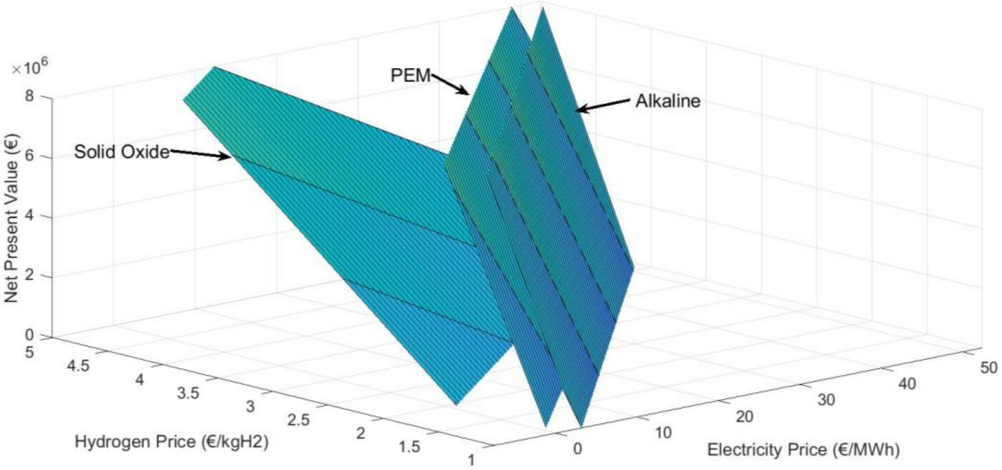

Fig. 1. The net present value of the case study electrolyzers by technology today.

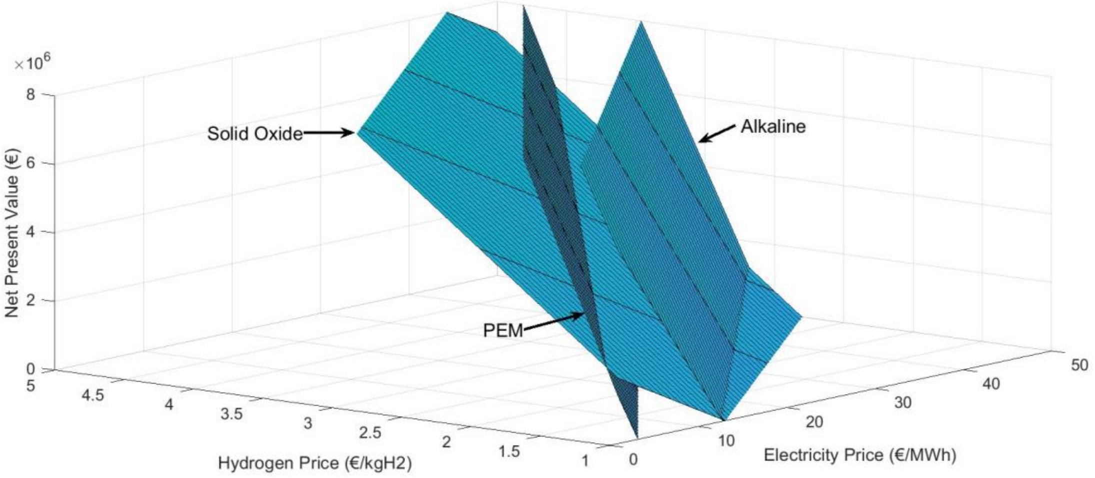

Fig. 2. The net present value of electrolyzers by technology after large adoption by 2050.

3.3. Levelized Cost of Hydrogen

The value of the end product is critical in marketability. The levelized cost of hydrogen is an average value over the lifetime calculated as (6) [24]. LCOH is a multivariable function with uncertainties of energy source, electrolysis method, hydrogen market, transportation, and storage [63][64][65]. The reported estimations on LCOH can be noticeably different in the literature. The marginal values for LCOH are listed in Table VI regarding various configurations/operations in 2020.

Using the given data in Table V and assumptions of Table VII, the levelized cost contours for the alkaline, PEM, and solid oxide electrolyzers are drawn in Figs. 3, 4, and 5 respectively. As expected, lower electricity prices along with higher load factors result in favorable cost reductions. The LCOH planes for all three technologies are also plotted in Fig. 6. It is noteworthy that when the electrolyzers are active the majority of times (higher load factors) the LCOH gaps are reduced. Conversely, LCOH differences are more obvious when the electricity price grows and the electrolyzers are inactive for many hours. The scale-up effects are depicted in Fig. 7 where the levelized costs become closer to each other. This can be interpreted that the electricity price will be more significant than the electrolysis method on larger scales.

$$LCOH = \left(\sum_{i=1}^{N} \frac{total\ costs\ in\ year\ i}{(1+discount\ rate)^{i}}\right) / \left(\sum_{i=1}^{N} \frac{produced\ hydrogen\ in\ year\ i}{(1+discount\ rate)^{i}}\right) \tag{6}$$

where N is the number of the years.

Table VI. The marginal values of LCOH reported by 2020 [66].

Configuration/Operation	Region	LCOH (€/kg)	Source
Grid-connected	USA	7.4	[67]
	USA	5.2	[68]
	Europe	11	[67]
	Germany	5	[69]
	Germany	5.9	[35]
	Belgium	8.1	[35]
	The Netherlands	5	[69]
	Spain	5	[69]
	Iceland	8.5	[35]
	Denmark	2.5	[22]
	Denmark	4.8	[70]
	China	4.6	[68]
	Japan	8.4	[22]
	New Zealand	4	[23]
Grid-connected/off-peak	USA	3.4	[68]
	China	2.3	[68]
Curtailed Electricity	USA	9.3	[67]
	USA	4.6	[68]
	Europe	9.1	[67]
	China	1	[68]
Offshore WT	Global	4-8	[21]
	Denmark	5	[71]
	Norway	5.2	[72]
	Ireland	5	[16]
WT	USA	3.6	[73]
PV	USA	3.1	[74]
	Spain	3.4	[74]
	Saudi Arabia	3.3	[22]
	Australia	3.1-3.6	[22]
	Australia	3.3	[74]
	Japan	4	[74]
	Chile	3	[74]

Table VII. The assumped values for LCOH calculations [66].

Parameter	Value
Compressor CAPEX (€)	125,000
Tank CAPEX [€/kgH2]	300
Installation & design [% of CAPEX]	30
OPEX per Year [% of CAPEX]	6.2

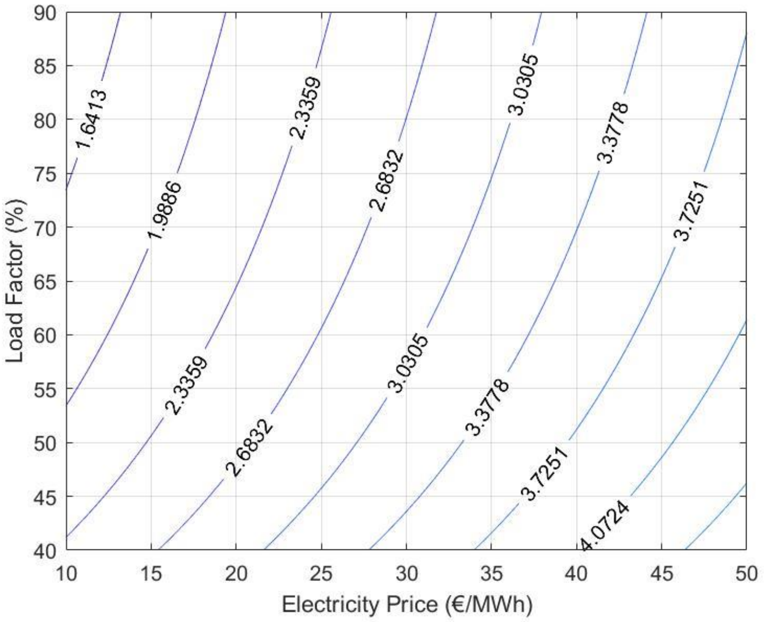

Fig. 3. The levelized cost of hydrogen production by the alkaline electrolyzer under different operation regimes and electricity prices.

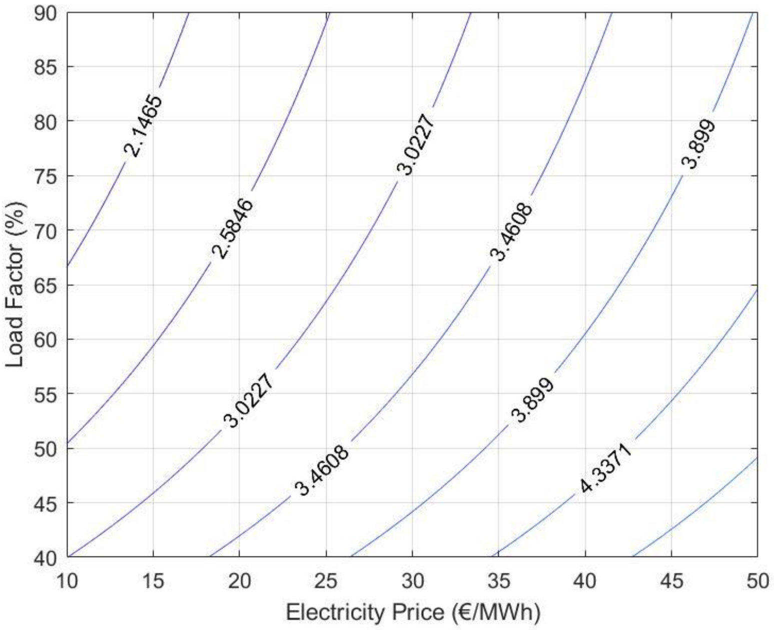

Fig. 4. The levelized cost of hydrogen production by the PEM electrolyzer under different operation regimes and electricity prices.

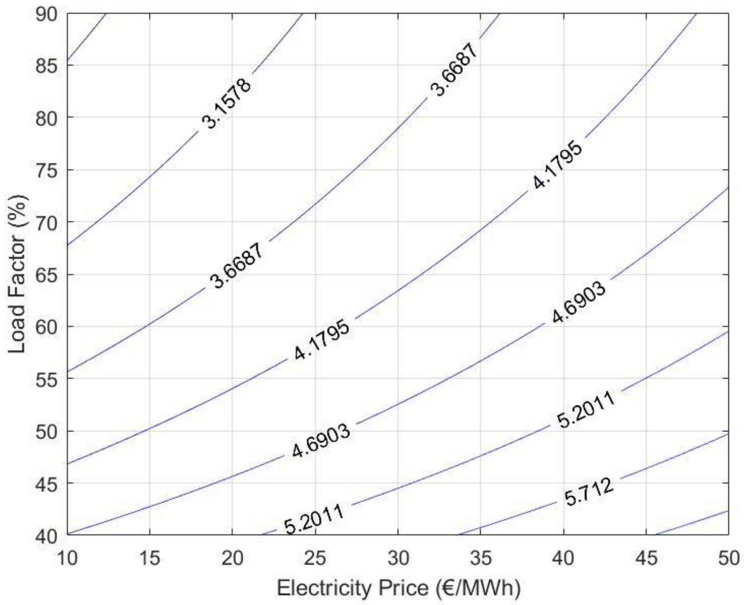

Fig. 5. The levelized cost of hydrogen production by the solid oxide electrolyzer under different operation regimes and electricity prices.

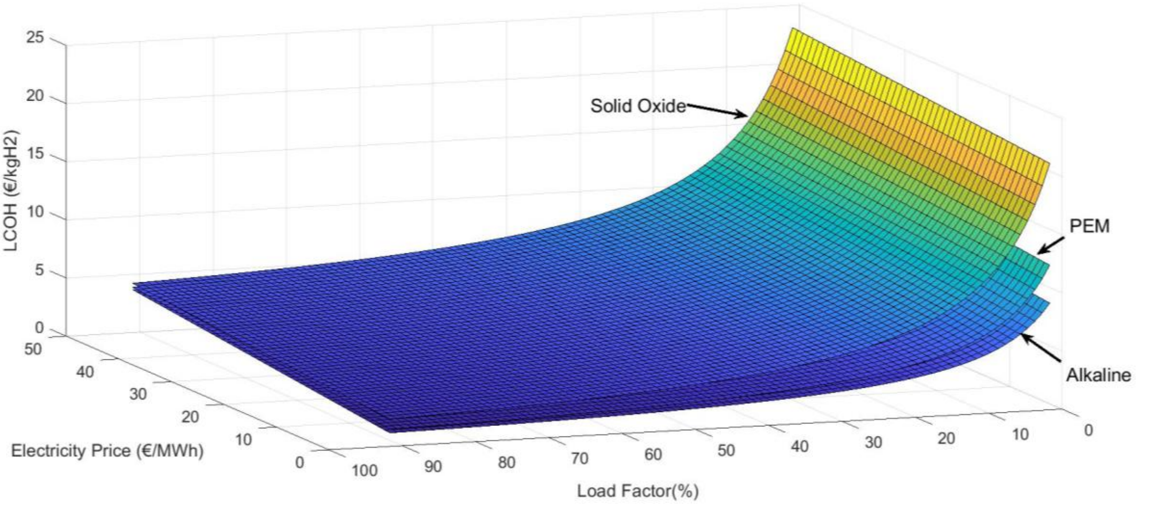

Fig. 6. The levelized cost of hydrogen production by the electrolyzers under different operation regimes and electricity prices.

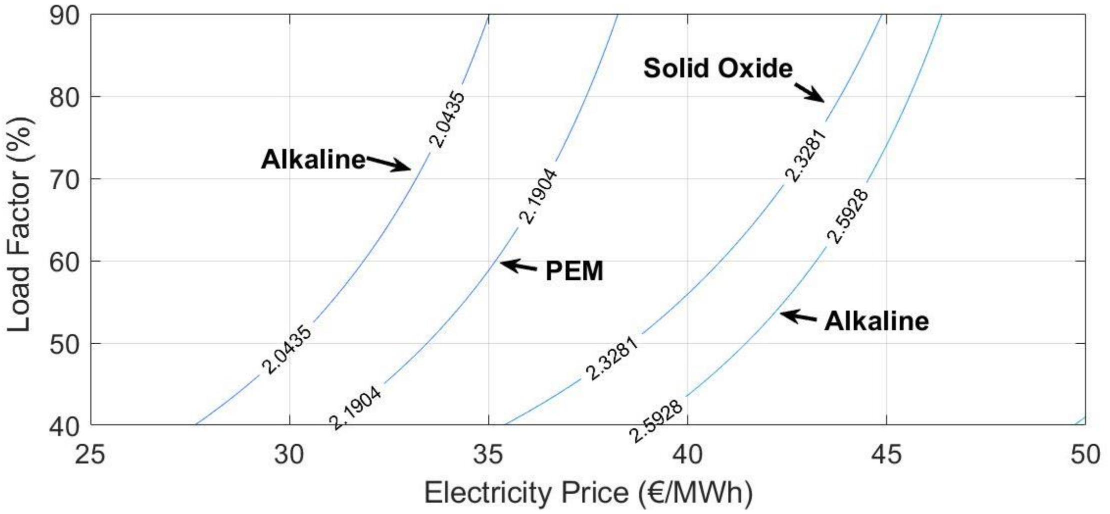

Fig. 7. The levelized cost of hydrogen production by the electrolyzer after large adoption.

4. Monte Carlo Simulations

As it was shown above, the prime energy price will eventually define the cost of hydrogen as the final product. Some analyses indicate that electricity can count for up to 70% of OPEX in electrolysis-based fuels [52]. The cost of electricity during period T can be formulated as (7). Note that the electrolysis consumption rate (η_{ideal}) cannot go below 39.39 kWh/kgH2 [53].

$$C_E = \pi_E \times P_H \times \eta \tag{7}$$

where C_E is the cost of electricity (€), π_E is the electricity price (€/kWh), P_H is the produced hydrogen (kg), and η is the electrolyzer's consumption rate (kWh/kg)

Although Denmark is designated with remarkable wind capacity, the share of hours with excess wind energy may not suffice low-cost electrolysis. For instance, the accumulation of such periods in 2018 was only 1,238 h which equals 14% of a year. This is far below the acceptable running time for the economic viability of any commercial plant [75]. Therefore, green hydrogen costs are still highly dependent on the electricity markets. A scenario-based analysis is developed in this section to scrutinize the effects of electricity prices using the real market data. The day-ahead market prices are adopted from Nord Pool in DK2. Since many electrolyzers (except for PEM) have relatively slow dynamics, it is more efficient to follow a constant operating point. A case study on MW scales verifies that optimally designed alkaline electrolyzers for nominal load operations are severely downgraded in terms of efficiency under partial loading regimes [33]. Therefore, the electricity price is categorized based on the weekly average to avoid costly start-up/shut-downs. Fig. 8 shows the day-ahead prices for 2019 and 2020 on a weekly basis. Next, they are clustered and sorted as Fig. 9. It can be concluded that the total periods when electricity prices exceed 44 €/kWh is approximately 10%.

Assuming 5% deviations in electricity prices, several scenarios are generated with normal distribution [32] to estimate the levelized cost of hydrogen. Note that the probabilities of scenario groups correspond to the category values in Fig. 9. Considering today's technology, Fig. 10 shows that LCOH is around 2.5 €/kg via alkaline electrolysis. This can be reduced down to 2 €/kg when the scale-up effects are taken into account. A further step is also simulated when the electricity is 50% subsidized. The results indicate that the levelized cost is dropped to around 1 €/kgH2. Similarly, PEM electrolyzers are capable of delivering hydrogen at 1 €/kg after large-scale adoption and subsidization (Fig. 11). The simulated scenarios for SOEC have the same trend; however, mass production and large adoption have steeper effects on cost reductions. Besides, SOEC is privileged because of higher efficiencies over alkaline and PEM electrolyzers. Fig. 12 illustrates that LCOH is noticeably cheapened by scaling up from above 3 €/kg to below 2 €/kg. From this point, further cost reductions are mainly driven by electricity prices.

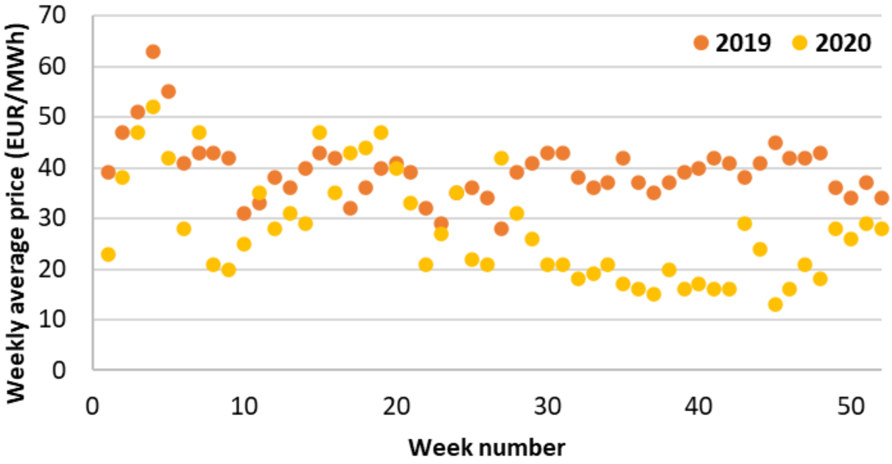

Fig. 8. The weekly average day-ahead prices in East Denmark (2019-2020).

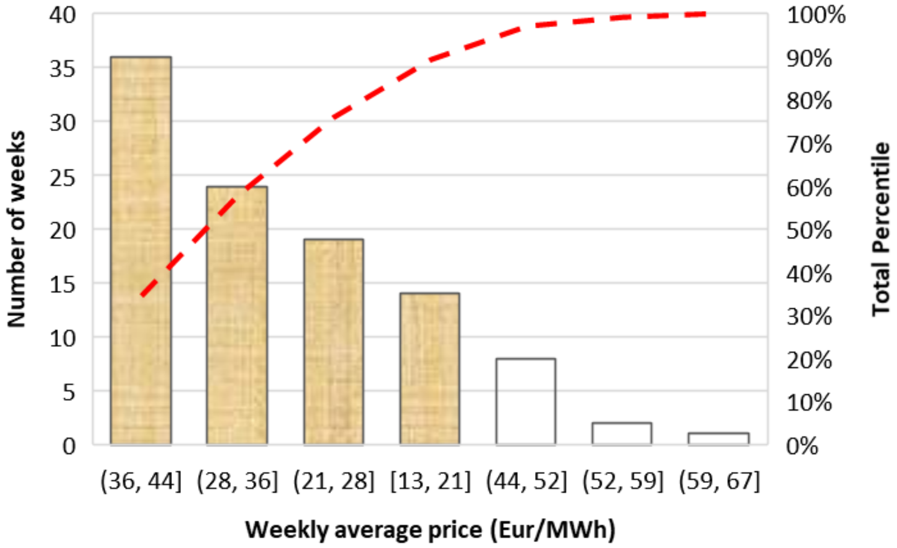

Fig. 9. The categorized day-ahead market price in East Denmark (2019-2020).

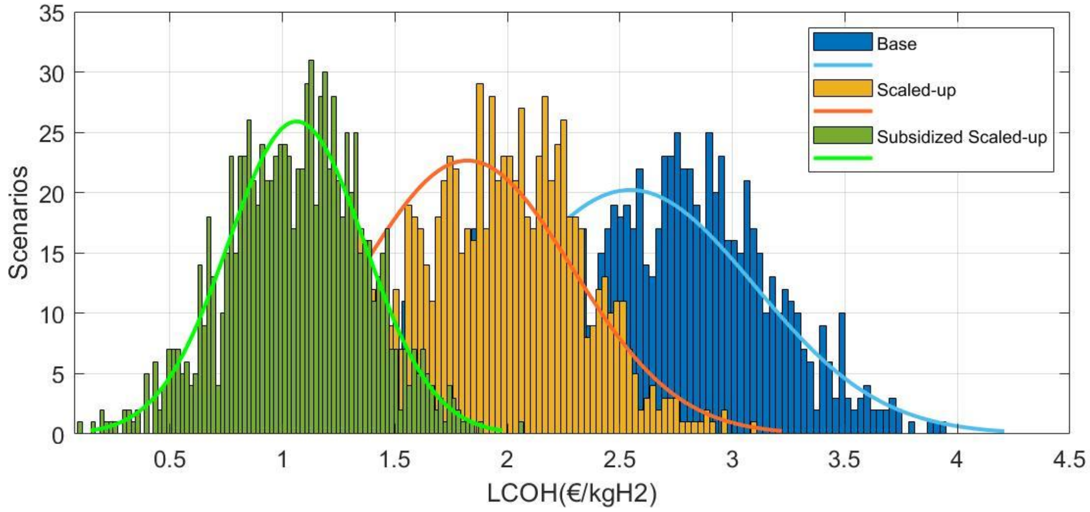

Fig. 10. The normalized scenarios of levelized cost of hydrogen production by the alkaline electrolyzer after large adoption and half-price electricity.

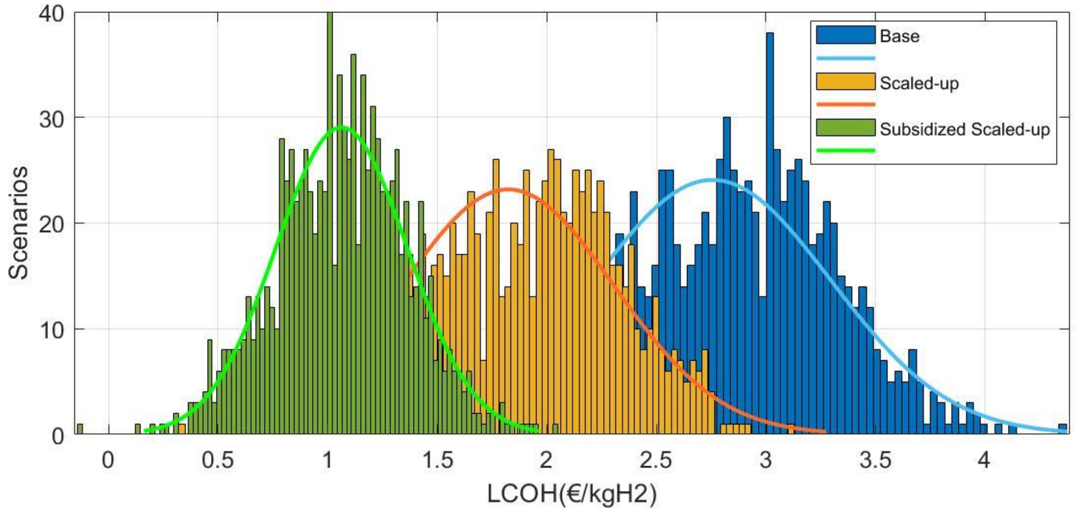

Fig. 11. The normalized scenarios of levelized cost of hydrogen production by the PEM electrolyzer after large adoption and half-price electricity.

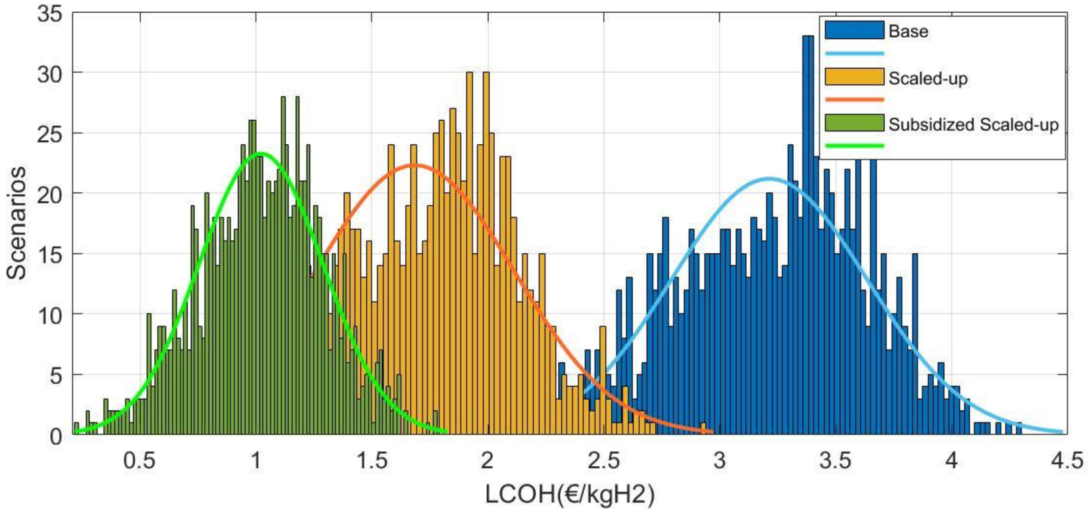

Fig. 12. The normalized scenarios of levelized cost of hydrogen production by the solid oxide electrolyzer after large adoption and half-price electricity.

5. Conclusions

Electrolysis cost reduction capabilities are analyzed for alkaline, PEM, and solid oxide electrolyzers due to large-scale adoptions. Net present value comparisons validate that investments in alkaline and PEM electrolyzers are more attractive; however, the cost reduction trends are steeper in SOEC. Besides, the levelized cost of hydrogen production is shown to be remarkably influenced by electricity prices. Considering a pilot case study in Denmark, several scenarios were generated using the market data from 2019 to 2020. The scenarios, including 5% normally distributed uncertainties, were assigned different probabilities regarding the electricity price history. The results confirm that both alkaline and PEM electrolyzers can deliver hydrogen at less than 3 €/Kg if fully exempted from taxes and levies. The scale-up effects can reduce the price below 2 €/Kg in all three technologies. Furthermore, when electricity is subsidized at half prices, the levelized cost of hydrogen falls around 1 €/Kg. This validates that large-scale deployment can cause cost reductions by 33%, 34%, and 50% in alkaline, PEM, and solid oxide respectively. In other words, alkaline and PEM electrolyzers have been partially blessed with mass production effects today. However, the capacity for cost reduction via technology development and large-scale adoption still exists. In parallel, SOEC cost reduction is at a faster pace meaning that after a certain level all three technologies will settle in the market. Then, SOEC might be privileged due to higher efficiencies. The ultimate scenarios for large-scale adoption driven by subsidized electricity indicate 56%, 59%, and 70% cost reduction in alkaline, PEM, and solid oxide respectively.

The following steps are suggested for further studies:

- Involving local taxes and regional regulations in the attractiveness of investments.
- Considering the integration effects of electrolysis with other industries.
- Expansion of the analysis with the downstream industries including storage, transportation, and distribution technologies.

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