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Green hydrogen production for oil refining – Finnish case

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ABSTRACT

This study investigates the production of green hydrogen for use in oil refining, as specified in the draft of European union delegated act published in May 2022. The European union plans to set strict requirements of additionality and reporting regarding the criteria of renewable electricity used in hydrogen production. Alkaline electrolyzer, proton exchange membrane electrolyzer and solid oxide electrolyzer are evaluated in various scenarios supplied by wind power: power purchase agreement-based scenarios and wind power investment-based scenarios. In power purchase agreement-based scenarios baseload and pay as produced power purchase agreements (with and without electricity storage) are assessed. According to results, the use of 600 MW compressed air energy storage could reduce the dependency on the grid by 7% but increase the cost of green hydrogen significantly. Investment-based scenarios produce green hydrogen with a lower operation cost, but higher break-even price compared to power purchase agreement-based scenarios. The cheapest green hydrogen can be achieved by alkaline electrolyzer with baseload power purchase agreement. Direct ownership of wind power is outside the operation of oil refining industry, thus power purchase agreements contracting is more likely to realize.

1. Introduction

Hydrogen is used in many applications in various industries such as oil refining, ammonia production and steel production. Regarding transport fuels and natural gas use in energy production, so-called green hydrogen (hydrogen produced from water electrolysis by renewable electricity) may play a key role in reaching the global targets of carbon neutrality [1]. Currently, about 80% of the global hydrogen production (almost 90 Mt/a) is based on fossil fuels (grey hydrogen) According to the Net Zero Emission Scenarios (NZES), the total production will be increased to 200 Mt/a by 2030, and about 70% of it should be provided by low-carbon sources (electrolysis and fossil fuels with Carbon Capture Utilization and Storage (CCUS)) [1]. In Finland, the current level of dedicated production of hydrogen is about 140,000–150,000 t/a, and 99% of it is based on fossil fuels. It is estimated that the total production could reach almost 175,000 t/a by 2030 [2].

The legislative proposals published by the European Commission in December of 2021 aim at decarbonizing the European Union (EU) gas market [3]. In the proposal known as Proposed Gas and Hydrogen Directive, the renewable hydrogen is defined as hydrogen produced based on renewable sources other than biomass fuels that has the potential to reduce Green House Gas (GHG) emissions by 70% compared to fossil fuels [4]. This definition is compatible with the definition of renewable hydrogen by the Renewable Energy Directive (RED II), however, according to RED II, renewable hydrogen should cover 50% of total hydrogen consumption in energy sector and industries consuming hydrogen as feedstock by 2030. This figure for the transport sector is 2.6% [5]. The EU Commission published in May 2022 public consultation of Delegated Act (DA) specifying what can be counted as renewable electricity to produce green hydrogen and what would be the related reporting requirements. The requirements are strict to ensure additionality, to prevent the use of already subsided renewable electricity and to prevent causing additional demand for fossil electricity [6]. Acceptable provisions of renewable electricity are mainly Power Purchase Agreements (PPA) built no longer than 36 months before use in hydrogen production and off-grid dedicated renewable electricity production, and installations are not allowed to have public financial support. These strict requirements are proposed to apply from 2027 onwards.

Shifting from grey hydrogen to green hydrogen requires a significant increase in renewable electricity generation. For instance, to meet the current level of annual hydrogen demand in Finland by green hydrogen, about 5 TW h electricity from renewable sources is required, which equals to almost 8% of the annual electricity generation in Finland [7]. However, due to the large potential of wind power, Finland could

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Abbreviations

AE	Alkaline Electrolyzer
BEP	Break-Even Price
BES	Battery Energy Storages
C	Specific heat capacity
CAES	Compressed Energy Storage
CCUS	Carbon Capture Utilization and Storage
$C_{Electricity}$	Electricity cost
C_M	Maintenance cost
$C_{Operation}$	Operation cost
C_{Water}	Water cost
DA	Delegated Act
EU	European Union
GHG	Greenhouse Gas
HRS	Hydrogen Refueling Stations
LCOH	Levelized Cost of Hydrogen
$\dot{m}$	mass flow rates
NPV	Net Present Value
NZES	Net Zero Emission Scenarios
PEME	Proton Exchange Membrane Electrolyzer
PPA	Power Purchase Agreement
r	Interest rate
RED	Renewable Energy Directive
$R_{Hydrogen}$	Revenue from selling hydrogen
R_{Oxygen}	Revenue from selling oxygen
SOE	Solid Oxide Electrolyzer
T_{C_i}	Inlet cold temperature
T_{C_o}	Outlet cold temperature
T_{H_i}	Inlet hot temperature

become an important country in green hydrogen production. Currently, wind power is being built without economic subsidies at a pace of 500–1000 MW annually. It has been estimated by Ref. [8] that the total annual production could increase to 50 TW h by 2030 (almost 10 times higher than the current level) and 150 TW h by 2050. A recent assessment for the Finnish Government estimated that annual low-carbon hydrogen production in Finland could be in the range of 60–135 TW h in moderate and high growth scenarios by 2050 [9].

Among different industries consuming hydrogen as a feedstock, the oil refining industry has a significant share (almost 40 Mt H_2 out of 90 Mt H_2 in the global demand for hydrogen in 2020) [1]. In oil refining industry, hydrogen mainly is used to crack the long carbon chain of raw oil, however it is also used to reach a lower level of sulfur content of diesel fuel. The rising demand for diesel fuel and more strict regulations on sulfur content are regarded as a reason behind the increased need for hydrogen in oil refining industry [10]. Oil refining industry in Finland aims for more sustainable fuels and hydrogen produced with zero-carbon electricity is their key focus of R&D [11–13].

The Nordic electricity market (Nord Pool) was established in the early 1990s when the Nordic countries decided to deregulate their individual power markets. Estonia, Latvia, and Lithuania also joined this market in 2010–2013 [14]. In Nord Pool there is free competition, and the hourly electricity price is based on the balance between supply and demand [14]. The electricity sources are mainly hydro, nuclear, wind and thermal power. However, especially in dry years, Nordic countries have also imported electricity from neighbor countries such as Poland, Russia and Germany [15].

In this study, a techno-economic analysis on green hydrogen production in Finland is carried out to find the impact of various ways of supplying wind power to electrolysis, considering alternative ways of procuring electricity, including those currently accepted by the draft DA. The price of green hydrogen produced through different electrolyzers and with different electricity procurement strategies is analyzed. The study includes five sections. Following the introduction (section 1), the literature review (section 2) presents a variety of relevant studies analyzing green hydrogen production from different viewpoints. Then, the final part of this section introduces the contribution and the novelty of the paper. The analysis methods, programs, and datasets used in the study are introduced in section 3, then the results are presented and discussed in section 4. Finally, the conclusion of the paper is provided in section 5.

2. Literature review on production of green hydrogen and contribution of this paper

The price of green hydrogen is strongly affected by the electricity price and the type of power source supplying electrolyzers. According to data from McKinsey & Company and the Hydrogen Council, the Levelized Cost of Hydrogen (LCOH) supplied by solar PV in Europe was about 7.5 USD/kg H_2 in 2020, while this value for wind offshore and wind onshore was significantly lower as 4.4 USD/kg H_2 and 4.2 USD/kg H_2, respectively [1]. Payam Ghaebi Panah et al. [16] found that removing taxes on electricity price can decline hydrogen price to less than 3 €/kg H_2 in Denmark. They also concluded that decreasing electricity price by 50% can reduce the LCOH by 1 €/kg H_2. They studied the effect of scaling-up in different technologies producing hydrogen i. e, Alkaline Electrolyzer (AE), Proton Exchange Membrane Electrolyzer (PEME) and Solid Oxide Electrolyzer (SOE) on the hydrogen price in Denmark, and concluded 33%, 34%, and 50% reduction in hydrogen price by large-scale utilization of each electrolyzer, respectively. Ou Tang et al. [17] concluded that green hydrogen price is more affected by wind speed compared to solar radiation. They found LCOH about 3.5 €/kg H_2 for on-grid plants integrating wind and solar power in Stockholm, while this value for on-grid solar plants was about 7.2 €/kg H_2. They also concluded that in off-grid plants LCOH was almost two times higher compared to on-grid scenarios.

The potential of wind power in producing green hydrogen is an important issue which has been investigated in many studies. The capacity factor (the ratio of actual power produced by a plant over a certain period to the maximum theoretical power during the same period) is an important issue in determining the profitability, and in Finnish wind farms it has increased significantly in recent years [18]. Julien Armijo et al. [19] found that lower variability in the power generated system decreases the production cost of hydrogen significantly. They carried out techno-economic analysis for an off-grid plant combining solar and wind power to supply AE producing hydrogen and concluded that due to lower variations in power generated by the combined plant, LCOH is lower compared to scenarios in which AE is supplied by off-grid solar plant or off-grid wind plant individually. Ramchandra Bhandari et al. [20] found that the availability of electricity to supply electrolyzers affects LCOH significantly. They compared grid connected plants with off-grid plants in different scenarios and concluded that the grid connected power plants produce much cheaper hydrogen compared to off-grid plants. They found the LCOH for a grid connected PV plant powering AE as the cheapest scenario with 6.23 €/kg H_2. Rami S. El-Emam et al. [21] concluded that the lower capacity factor of wind and solar energy affects the price of green hydrogen produced by these sources significantly, while nuclear power and geothermal energy have the potential to produce cheaper green hydrogen competing with grey hydrogen price. It should be noted that the current draft of the EU DA does not allow nuclear power as source of producing green hydrogen. Sabrina Fernandes Macedo et al. [22] found that increasing operation hours of plants powering electrolyzers has a significant impact on the price of hydrogen. They concluded that an economically feasible green hydrogen would be achievable in Brazil if the power plants supplying electrolyzers operate over 3000 h/a, and the electrolyzers have a capital cost about 650 USD/kW$_e$. As a result of the study by T.R.Ayodele et al. [23], among various operating parameters in a wind turbine, the rated wind speed that determines the range of power variations has the highest impact on the hydrogen production cost. Shahid Hussain Siyal et al. [24] carried out the economic analysis of AE powered by off-grid wind plants to produce hydrogen refueling stations in three different sites in Sweden. As a result, they found that by increasing wind speed from 4.5 to 5 m/s, the LCOH declines by 17%–19%. M. Minutillo et al. [25] found that increasing the hydrogen production capacity from 50 kg/day to 200 kg/day can make a reduction of 20% in LCOH. They carried out a techno-economic analysis on Hydrogen Refueling Stations (HRS) powered by grid connected PV plants and investigated it in a variety of scenarios based on different capacities for hydrogen production (50 kg/day, 100 kg/day, 200 kg/day) and different shares for grid supplying the electrolysis unit. As a result, they concluded a range for LCOH from 9.29 €/kg H_2 (for the scenario with 200 kg/day, and 50% grid) to 12.48 €/kg H_2 (for the scenario of 50 kg/day, and 100% grid).

The price of green hydrogen is also influenced by operational factors describing the performance of electrolyzers. The common electrolyzer technologies are AE, PEME, and SOE. SOE is currently still in development phase whereas AE and PEME are considered more matured technologies. Literature suggests that the capital cost and maintenance cost by AE and PEME are significantly lower compared to SOE [26], but SOE has lower specific electricity consumption [27]. SOE operates at high temperatures, thus making it an interesting technology for sites with excess heat streams available (such as steel making and oil refining).

However, the previous studies have not considered the EU draft DA rules nor Power Purchase Agreements (PPA) in production of green hydrogen. PPA agreements for renewable energies (a long-term contract between producer and consumer to trade renewable energy for a certain period at a pre-agreed price) secure large consumers against variations in electricity price and they can be used to ascertain for example a quota of wind power for the consumer [28]. PPA is also presented in the EU draft DA as one important option to supply electricity for green hydrogen production.

PPA schemes had a significant growth in Finland in recent years [28]. Most currently announced green hydrogen production plans in Finland rely on bilateral contracting with a new wind power park [29], and the variations in supply are handled as part of normal electricity market balancing operations. The typical term in PPA contracts for wind power is 10–20 years, which not only paves the way for wind farm developers to build their own power plant even without state aid but also helps industries purchasing wind energy to reach the sustainability goals [30].

The current study aims to answer the following research questions.

- How could green hydrogen be produced according to the EU draft DA? Participating in PPA contracts or investing in a new wind farm: which one provides cheaper green hydrogen for an oil refining company and what other positive and negative aspects are there for the company?
- Baseload PPA or Pay as produced PPA: which one brings more benefits to an industrial company consuming electricity?
- In which group of scenarios (Participating in PPA contracts or investing in a new wind farm) is the green hydrogen price more affected by electricity market price?
- Which electrolyzer (i.e., AE, PEME, and SOE) is more economical in various scenarios supplying electrolysis unit?
- What is the impact of PPA price level, electricity market price, wind speed, and specific electricity consumption (by each electrolyzer) on the price of green hydrogen in various scenarios and electrolyzers?

Moreover, our study investigates the impact of electrical energy storages (Compressed Air Energy Storage (CAES) used in this study) on the price of green hydrogen. To answer the above questions, we carry out Break-Even Price (BEP) and sensitivity analyses for each scenario and electrolyzer by using mathematical and techno-economic methods based on available data (wind speed and electricity market price) for 2019–2021. The Finnish electricity market experienced totally different prices in 2019–2021 (by considering the annual average of electricity market price, the years 2019–2021 can be described as medium, cheap, and very expensive, respectively). Furthermore, the studied hypothetical wind farms experienced different values for the annual capacity factor in the mentioned years. Therefore, we consider 2019–2021 as three sample years and carry out the BEP analysis for each year separately.

The evaluated scenarios supplying the power demand by the green hydrogen production unit are classified into three main groups.

1. Scenarios based on PPA contracts
2. Scenarios based on the oil refinery investing in a new wind power plant
3. Scenarios based on electricity market (“earmarked” wind energy)

Fig. 1 represents a basic schematic diagram for the studied scenarios, and a detailed description for each scenario is provided in Tables 1 and 2.

In the scenarios 1–2 and 1–3, the electricity grid is acting as the balancing agent. However, in scenario 1-1 the PPA contract is baseload type in which the wind plant developer undertakes to provide a certain amount of electricity at a pre-agreed price to the oil refining company. Therefore, the wind plant developer is responsible for balancing their production. In scenario 1–2, the contract type is pay as produced PPA, and the oil refining company undertakes to buy all the electricity produced by wind park at any time during the agreed period. Then the oil refining company needs to make a separate balancing contract to cover variations in wind power. Oil refineries are large electricity consumers and do balancing also in their normal operation. In scenario 1–3 like scenario 1–2, the contract between the oil refining company and the wind plant developer is pay as produced PPA, but in scenario 1–3 we assumed that the oil refining company has invested in a Compressed Air Energy Storage (CAES) to cover variations in wind power along with electricity grid. This scenario is particularly compared with the scenario 1–2 in terms of hydrogen price and sensitivity analysis.

The second group of scenarios supplying electrolyzer includes scenarios where the oil refining company invests in a new wind power plant in the same region as assumed in previous scenarios. These scenarios deviate from the EU DA draft in using national electricity grid instead of own separate connection and by using grid to balance over-/undersupply situations. We justify this choice with comparability and with the fact that wind resource at the hypothetical case site of oil refinery is considerably poorer than in the Vaasa location (see Fig. 2). Although these scenarios are out of the company’s business and expertise, the goal of this study is to investigate all the possible scenarios in supplying green hydrogen production and then compare the strengths and weaknesses. In scenario 2–1 it has been assumed that the invested wind park has an average capacity equal to the capacity of electrolysis unit. In other words, in this scenario the oil refining company invests in a 140 MW wind park (the capacity of the electrolysis unit is 50 MW, and the average capacity factor has been assumed as 0.36). However, in scenario 2-2 the capacity of invested wind park is equal to the capacity of the electrolysis unit. Therefore, in scenario 2–1 the oil refining company has income from selling surplus electricity to the grid, but in scenario 2-2 there would be no surplus power to sell, and the grid’s role is just providing the deficit power.

The third group of scenarios supplying electrolyzer includes scenario 3 in which the green hydrogen production unit is supplied only by the electricity grid. It has been assumed that the electricity purchased from the grid is earmarked wind energy, i.e., guaranteed origin [31]. In most cases, this may not qualify with the conditions required by the EU DA.

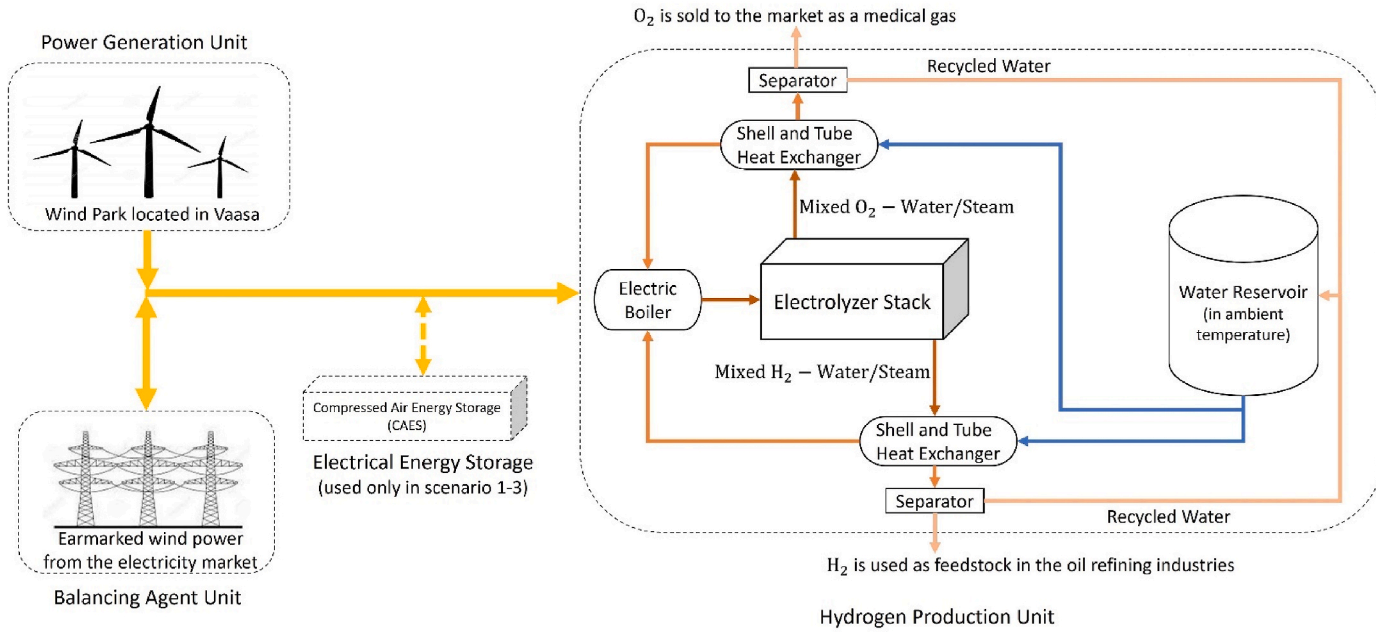

Fig. 1. The basic schematic diagram for the studied scenarios. The electrical energy storage (in this study CAES) is used only in one scenario (scenario 1–3). Each scenario is described separately in Table 2.

3. Material and methods

3.1. Wind park and selected turbine properties

The hourly wind speed data used in this study are obtained from Renewable. ninja as time series for the whole year. Renewable. ninja provides hourly weather data which are based on global analysis models and satellite observations to simulate wind and solar power plants in any area around the world [32]. To find more information about the methods used by this tool, please see Refs. [33,34].

In selection a proper site of wind park, two criteria were considered by this study, i.e., lower stress on the national electricity grid and higher capacity factor of wind park. To have less stress on the national electricity grid, Southern and Central Finland were selected, as the main stress is the transmission between the Northern and Southern parts of the country. Then, to find the highest capacity factor among different locations in Southern and Central Finland, different locations were investigated, and Vaasa located at the West coast of Finland is selected as the best site for wind park by this study. The result of this investigation is illustrated in Fig. 2. In this case, Porvoo region wind resource would be only about 10% less, but many other announced hydrogen production sites are located inland, with wind properties similar to those of Kuopio and Jyväskylä.

The technical and economic parameters of wind turbine used in the modeling wind park by this study are presented in Table 3 [35,36].

3.2. Electrolysis unit

3.2.1. Electrolyzer

Table 4 compares the technical and economic parameters for the evaluated electrolysers in this study. To have more accuracy and fairness in comparing results, the selected value by this study in each case is the average of values reported by different references [26,27,37,38]. In some cases, the most reliable reference has been preferred, however values reported by other references have been presented as more information.

3.2.2. Compressed air energy storage (CAES)

As was explained in section 2, a CAES system with a specific energy capacity and specific power rate was considered to supply electrolyzer in scenario 1–3. CAES was chosen for this analysis, as its properties (power rate, energy capacity and energy capital cost) are more suitable than Battery Energy Storages (BES) with the current status of these technologies [39]. It was assumed that the storage has a power rate equal to the average electrical capacity of the electrolyzers which is 50 MW, and its energy capacity is 600 MW h. The technical and economic parameters for this storage are presented in Table 5.

3.2.3. Auxiliary equipment (E-boiler and heat exchangers)

As illustrated in the basic schematic diagram (see Fig. 1), two shell and tube heat exchangers are used to recover waste heat by the output of electrolyzer and heating its inlet water. In each scenario an electric boiler is considered after the heat exchangers to increase the inlet water temperature up to the operating temperature of the electrolyzer. This electric boiler is powered by the supply system in each scenario. The considered type for the heat exchangers in this study is shell and tube used in various industries, including petrochemical [42]. Both heat exchangers are placed before the separation unit, therefore the hot fluids in them are mixed water-hydrogen and mixed water-oxygen, respectively. According to the balance of energy for heat exchangers 1 and 2, respectively:

$$\dot{m}_{\text{inlet water}}C_{\text{inlet water}}\left(T_{C_{o1}} - T_{C_i}\right) = \dot{m}_{\text{water-hydrogen}}C_{\text{water-hydrogen}}\left(T_{H_i} - T_{H_{o1}}\right) \quad (1)$$

$$\dot{m}_{\text{inlet water}}C_{\text{inlet water}}\left(T_{C_{o2}} - T_{C_i}\right) = \dot{m}_{\text{water-oxygen}}C_{\text{water-oxygen}}\left(T_{H_i} - T_{H_{o2}}\right) \quad (2)$$

In which T_{C_i} is the temperature of inlet water which equals to ambient temperature (15 °C), $T_{C_{o1}}$ and $T_{C_{o2}}$ are the temperature of outlet mixed water-hydrogen and mixed water-oxygen from heat exchangers 1 and 2, respectively. T_{H_i} is the temperature of inlet water-hydrogen and water-oxygen which equals the operating temperature of the electrolyzer. To estimate the mass flow rate, according to the overall equation in electrolyzers (equation (3)), the water consumption factor without having any waste is 5 kg H_2O/kg H_2, however, in reality the water consumption factor is by far higher due to low efficiency in converting water to hydrogen by different electrolyzers. In this study, the actual water consumption factor for all the scenarios is considered as 18.5 kg H_2O/kg H_2 [43]. In other words, the mass fraction in the outlet mixture of water-hydrogen is 87%–13%, and in water-oxygen is 63%–37%.

Table 1
Summary of studies reviewing the production cost of green hydrogen and its sensitivity to decisive factors.

Reference	Country	Power Source	Off-Grid/ On-Grid	Electrolyzer	Summary of Results
[16]	Denmark	Electricity grid	On-grid	AE, PEME, SOE	• 50% reduction in electricity price may reduce LCOH by 1 €/kg H2. • Scaling-up technologies producing hydrogen can reduce hydrogen price but not enough for cost competition with grey hydrogen.
[17]	Sweden	Wind power, Solar power, Electricity grid	On-grid, Off-grid	Not mentioned	• Green hydrogen price is more affected by wind speed compared to solar radiation. • In off-grid plants LCOH was almost two times higher compared to on-grid scenarios. • Integrating wind and solar power reduce hydrogen price compared to cases in which solar or wind are stand-alone.
[19]	Chile, Argentina	Wind Power, Solar Power	Off-grid	AE	• Lower variability in the power generated system decreases the production cost of hydrogen significantly. • A combined plant of solar and wind power produces cheaper hydrogen compared to wind or solar power operating alone.
[20]	Germany	Solar Power	On-grid, Off-grid	AE, PEME	• The availability of electricity to supply electrolyzers affects LCOH significantly. • A grid connected power plant produces much cheaper hydrogen compared to an off-grid plant.
[22]	Brazil	Wind Power, Solar Power	Off-grid	Not mentioned	• Economically feasible green hydrogen would be achievable in Brazil if the power plants supplying electrolyzers operate over 3000 h/a, and the electrolyzers have a CAPEX about 650 USD/kWe.
[23]	South Africa	Wind Power	Off-grid	PEME	• Among various operating parameters in a wind turbine, the rated wind speed has the highest impact on the hydrogen production cost.
[24]	Sweden	Wind Power	Off-Grid	AE	• By increasing wind speed from 4.5 to 5 m/s, the LCOH declines by 17%–19%.
[25]	Italy	Solar Power	On-Grid	AE	• Increasing the hydrogen production capacity from 50 kg/day to 200 kg/day can make a reduction of 20% in LCOH.

Moreover, to calculate the mass flow in each heat exchanger, the hydrogen production rate has been assumed as 1 ton H_2/hour.

$$2H_2O \rightarrow 2H_2 + O_2 \quad (3)$$

In each heat exchanger, the effectiveness is defined as below:

$$\text{Effectiveness} = \frac{\text{The actual heat transferred}}{\text{The maximum possible heat tranferred}} = \frac{\dot{m}_{water} C_{water} (T_{C_o} - T_{C_i})}{(\dot{m}C)_{max} (T_{H_i} - T_{C_i})} \quad (4)$$

The considered value for the effectiveness of shell and tube heat exchanger in this study is 0.42 [44]. The techno-economic data for the

Table 2
The description of different scenarios investigated by this study.

The studied scenarios		PPA Contract type	Description
1-PPA-based scenarios	Scenario 1-1	Baseload PPA	The electricity market is in the role of balancing agent. In a baseload PPA, the buyer (in this study oil refining company) is not responsible for selling/purchasing the surplus/deficit power.
	Scenario 1-2	Pay as produced PPA	The electricity market is in the role of balancing agent. In a pay as produced PPA, the buyer oil refining company sells/purchases the surplus/deficit power to/from the balancing agent.
	Scenario 1-3	Pay as produced PPA	All the circumstances of scenario 1–2 is still valid in this scenario. However, in this scenario the oil refining company is investing in electrical energy storage (In this study CAES) to decrease the dependency on the balancing agent (electricity market). In hours with surplus/deficit power, charging/discharging the storage has priority over selling/purchasing power to/from the balancing agent (electricity market).
2-Investment-based scenarios	Scenario 2-1	–	The oil refining company is investing in a 140 MW wind park (So the company needs to pay the initial investment as the capital cost and only the transmission fee and maintenance cost as the operation cost). The electricity market is in the role of balancing agent, so the surplus/deficit power is sold/purchased to/from the electricity grid.
	Scenario 2-2	–	The oil refining company is investing in a 50 MW wind park (So the company needs to pay the initial investment as the capital cost and only the transmission fee and maintenance cost as the operation cost). The electricity market is in the role of balancing agent, so the surplus/deficit power is sold/purchased to/from the electricity grid.
3-Grid-based scenarios	Scenario 3	–	The total electricity demand is supplied by the electricity grid (Earmarked wind power).

heat exchangers, the estimated values for mass flow rates, and the calculated outlet temperatures are presented in Table 6. The capital cost of heat exchanger in this study is according to the cost model carried out by Refs. [42,45] for shell and tube heat exchangers. The required surface area for heat exchanger has been estimated according to data available in Ref. [46]. Moreover, capital cost for the electric boiler is based on [47].

3.3. Economic analysis

In this study, EnergyPro software is used to model and to calculate the annual operation cost in all the investigated scenarios. To find more information about EnergyPro software please refer to Ref. [49]. Then, the goal seek function in Excel software is used to calculate the BEP of hydrogen in each scenario.

In all the scenarios, the operation cost includes electricity cost, water cost, maintenance cost of different equipment, and revenue from selling oxygen as a medical gas.

$$\text{Operation Cost} = C_{\text{Electricity}} + C_{\text{Water}} + C_{\text{M}} - R_{\text{Oxygen}} \tag{5}$$

The electricity cost includes the electricity price, transmission fee and taxation. The estimated price for pay as produced PPA contracts (Scenarios 1–2 and 1–3) are based on the price indexes provided by Ref. [50] for wind energy in Finland. Moreover, to estimate the price level in baseload PPA contracts (scenario 1-1), this study follows [51] and considers the baseload PPA price level about 10% higher than the price level in pay as produced PPA contracts. Table 7 shows the considered values by this study as the price of wind power in each PPA contract for 2019–2021 in Finland. Moreover, the electricity spot price to calculate the price of surplus or deficit power in pay as produced PPA contracts (Scenarios 1–2 and 1–3) in different years were derived from Ref. [52]. It should be noted that in equation (5), the electricity cost represents the final cost of electricity which includes the cost of purchasing wind power, the cost of purchasing deficit power from electricity grid and the income from selling the surplus power to the grid.

The electricity transmission fee and taxation are according to Refs. [53,54], which are summarized in Table 8. Furthermore, in all the scenarios, water cost has estimated as 0.07 €/kg H_2 [37], and the selling price of oxygen was considered as 20 €/ton O_2 [2].

To calculate the BEP of hydrogen produced in each scenario, the net income and the Net Present Value (NPV) are calculated as below:

$$\text{Net Income} = R_{\text{Hydrogen}} - C_{\text{Operation}} \tag{6}$$

$$NPV_n = \sum_{t=1}^{t=n} \frac{\text{Net Income}}{(1+r)^t} - \text{Initial investment} \tag{7}$$

The BEP of hydrogen is calculated by setting the NPV after the considered payback time equal to zero. In equation (7), n is the payback time in years, assumed 10 years, and r represents the interest rate (including the impact of inflation), which is assumed as 6%.

3.4. Sensitivity analysis

. In the calculation of BEP, there are parameters with uncertain values which can affect the result of the analysis significantly. In this section, a sensitivity analysis is carried out to find the sensitivity of BEP to changes in variable parameters which have uncertain values i.e., electricity market price, wind speed, PPA level price and specific electricity consumption by electrolyzers. The sensitivity analysis is carried out by making small changes ($\pm$ 10 %) in variable parameter and then finding its effect on the BEP of hydrogen as the target parameter of the analysis.

4. Results and discussion

4.1. Capital cost and annual operation cost

Fig. 3 shows the capital cost and annual operation cost in all the studied scenarios with different electrolyzers. As can be seen, the annual operation cost in scenario based on baseload PPA (scenario 1-1) is significantly lower compared to that in scenario based on pay as produced PPA (scenario 1–2) in all the studied electrolyzers. Comparing scenario 1–2 and scenario 1–3 reveals that using CAES as the electrical energy storage in the oil refining company increases both operation cost and capital cost significantly.

As was expected, building a 140 MW wind farm (scenario 2–1) brings the highest capital cost but lowest operation cost for the oil refining company. However, building a 50 MW wind farm (scenario 2-2) may still have potential to compete with PPA based scenarios. Finally, the operation cost in the grid-based scenario (scenario 3) is higher compared to the other investigated scenarios.

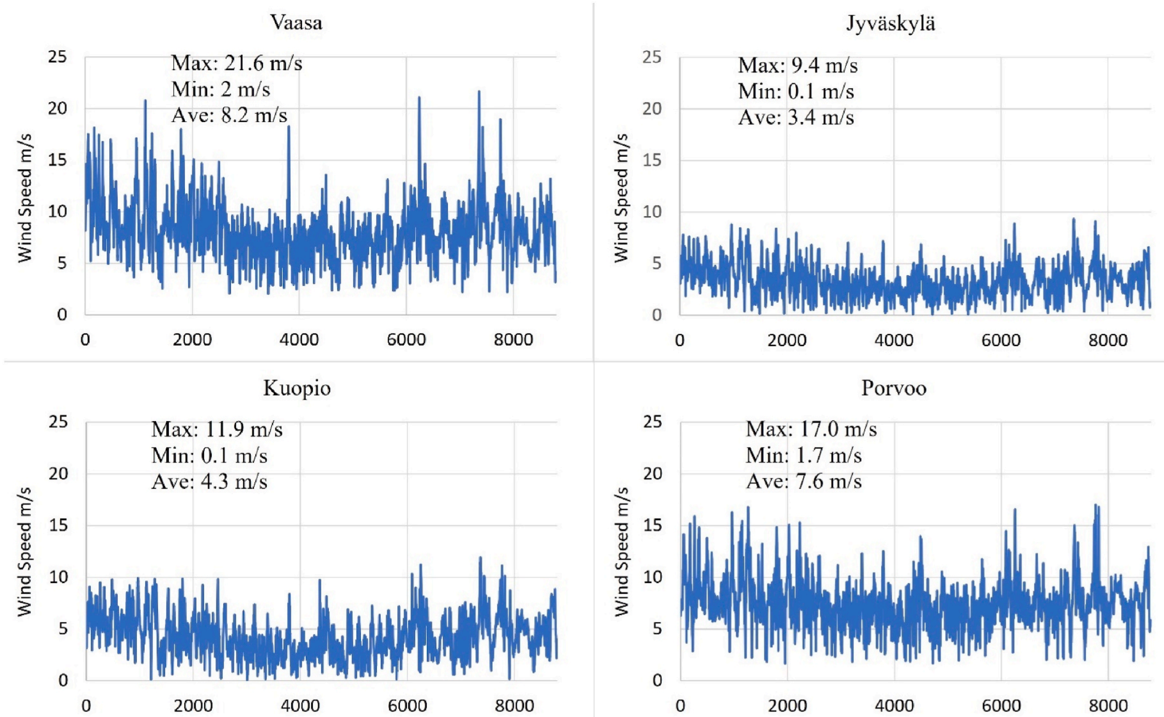

Fig. 2. The result of site selection for wind park. Vaasa located on West coast of Finland was selected as the best site to establish the wind park due to the best wind availability. The presented data are for the year 2020.

Table 3
Technical and economic data of wind turbines used in the wind park [35,36].

Parameter	Value	Parameter	Value
Turbine model	Vestas V164 8000	Cut-in wind speed [m/s]	3.5
Hub Height [m]	125	Rated wind speed [m/s]	13
Rated Power [kW]	8000	Cut-off wind speed [m/s]	25
Investment [M€/MW]	1.12	Fixed O&M [€/MW/a]	14,000
Technical lifetime [Years]	27	Variable O&M [€/MWh]	1.5

It should be noted that the operation cost in Fig. 3 is the average annual operation cost in 2019–2021. Since the electricity market price was totally different in the mentioned years, the operation cost per kilogram hydrogen produced by different electrolyzers in each scenario is illustrated in Fig. 4 for individual years as well. As can be seen in Fig. 4, in scenarios based on PPA contracts, the difference between operation cost in different years is smaller due to the lower dependency on the electricity market (see chapter 4.3). In other words, in scenarios which are more dependent on the electricity market, variations in electricity market price change the production cost of hydrogen significantly. The average electricity market prices in 2019–2021 were 44 €/MWh, 28 €/MWh and 72.3 €/MWh, respectively.

An interesting result can be seen in the impact of electricity market price on the operation cost of hydrogen production in different scenarios. For example, in scenarios 2-2 and 3 which have the highest dependency on the electricity market, the operation cost hits a peak in 2021 when the electricity market price is highest, and the minimum operation cost happens in 2020 when the electricity market price is lowest. However, lower dependency on the electricity market changes the order: in scenario 2–1 the minimum operation cost took place in 2021 and the maximum in 2019. In other words, in scenarios with lower buying dependency on the electricity market, not only the amount of purchased electricity from the market is lower but also more electricity can be sold to it, therefore a higher market price leads to higher revenue and consequently lower operation cost in hydrogen production.

Finally, comparing PPA based scenarios (scenarios 1-1, 1–2, and 1–3)

Table 4
Techno-economic data for AE, PEME, and SOE [26,27,37,38].

Techno-economic parameters	AE		PEME		SOE	
	Literature	This study	Literature	This study	Literature	This study
Operating Temperature [°C]	70-90, 60–80	70	50–80	65	700-850, 650–1000	800
Capital Cost [€/kW$_e$]	450-900, 450-1250, 1000	1000	650-1250, 1000-1600, 1450	1450	>1800, 2500–5000	3750
Specific electricity consumption [kWh/kg H_2]	50–78	64	50–83	66	40–50	45
Lifetime [1000 h]	60, 60–90	75	50-80, 30–90	60	<20, 10–30	20
Fixed O&M [€/kW$_e$-a]	1–3% of capital cost, 45	2% of the capital cost	1–3% of capital cost, 45	2% of the capital cost	1–3% of capital cost, 45	2% of the capital cost

Table 5
The techno-economic parameters used in modeling CAES system [39–41]. The data represented here is for an adiabatic and underground CAES.

Parameter	Value	Parameter	Value
Rated power [MW]	50	Cost of power conversion system [€/kW]	843
Energy Capacity [MWh]	600	Cost of storage [€/kWh]	40
Roundtrip efficiency %	70	Fixed O&M cost [€/kW-a]	3.9
Charging efficiency %	84	Variable O&M [€/kWh]	0.0027
Discharging efficiency %	84		

Table 6
Techno-Economic data in modeling E-boiler and the heat exchanger [42,44–48].

Parameter	Value	Parameter		Value
Heat exchanger type	Shell and Tube	T_{C_i} [°C]		15
Effectiveness	0.42	T_{H_i} [°C]	AE	70
			PEME	65
			SOE	800
$\dot{m}_{water-hydrogen}$ [kg/s]	2.2	$T_{C_{o1}}$ [°C]	AE	41.1
			PEME	38.9
			SOE	387
$\dot{m}_{water-oxygen}$ [kg/s]	3	$T_{C_{o2}}$ [°C]	AE	38.1
			PEME	36
			SOE	344.7
$\dot{m}_{inlet\ water}$ (Heat Exchanger 1) [kg/s]	2.6	Surface Area [m^2]	AE and PEME	30
			SOE	534
$\dot{m}_{inlet\ water}$ (Heat Exchanger 2) [kg/s]	2.6	Purchase Price [€]	AE and PEME	2500
			SOE	45,000
$C_{water-hydrogen}$ [kJ/kg.K] (Mass Frac. 87% H_2O-13% H_2)	5.6	Electric boiler Capacity [kW]	AE and PEME	900
			SOE	10,000
$C_{water-oxygen}$ [kJ/kg.K] (Mass Frac. 63% H_2O-37% O_2)	3	Electric boiler capital cost		150
C_{water} [kJ/kg.K]	4.2			

Table 7
The considered values by this study for wind power price in baseload and pay as produced PPA contracts in Finland [50,51].

Parameter	Value		
	2019	2020	2021
Baseload PPA [€/MWh]	30.8	31.9	33
Pay as produced PPA [€/MWh]	28	29	30

Table 8
The electricity transmission fee and taxation used by this study [53,54].

Parameter		Value
Transmission fee [€/MWh]	Weekdays, December–February, 7.00 a.m. 9.00 p.m.	9.88
	Other times	3.47
Taxation [€/MWh]		0.63

and own wind investment scenarios (2–1, and 2-2) reveals that operation cost in PPA based scenarios is less sensitive to electricity market price.

4.2. Break-even price of hydrogen

Fig. 5 compares BEP of hydrogen produced by different electrolyzers in each scenario for 2019–2021. Obviously, the BEP of hydrogen in PPA based scenarios is lower compared to investment-based scenarios since the capital cost is lower. Although applying CAES as electrical energy storage decreases dependency on the electricity market, its expensive investment increases the BEP of hydrogen significantly (comparing scenario 1–2 and scenario 1–3).

As a result of dependency on the electricity market (chapter 4.3), in PPA based scenarios the variation between BEP of hydrogen in different years is almost zero, while in investment-based scenarios the variation is higher. Scenario 3 brings a lower BEP of hydrogen compared to investment-based scenarios but has a higher variation in different years.

4.3. Dependency on the grid

Fig. 6 shows the dependency of different scenarios to the electricity grid in different years. It is calculated as the ratio of power purchased from the electricity market to the total power consumption by electrolysis unit. Thus, it does not consider the amount sold to the grid. Scenario 1-1 which represents baseload PPA contract is totally independent from electricity market, while scenario 3 is 100% dependent on the electricity market. Comparing scenario 1–2 and scenario 1–3 shows that applying CAES decreases dependency on the grid by 7% on average. The annual power generation by the wind farm can be regarded as a decisive factor in dependency on the electricity market for each scenario. The annual generation by the 140 MW wind farm was 0.47 GW h, 0.52 GW h, and 0.64 GW h in 2019–2021, respectively. As can be seen, lower power generation by the wind farm leads to more dependency on the electricity market.

As a comparison between different electrolyzers, the electrolyzers with lower specific electricity consumption have a lower dependency on the electricity market. In this study, the specific electricity consumption for AE, PEME, and SOE are 64, 66, and 45 kW h/kg H_2, respectively (see Table 4).

4.4. Sensitivity analysis

The results of sensitivity analysis reveal how sensitive the BEP of hydrogen in different scenarios is against variations in decisive factors, i.e., electricity market price, wind speed, PPA price level and specific electricity consumption by electrolyzers. As can be seen in Fig. 7.

- Overall, scenarios based on PPA are more stable against variations in decisive factors, however in some cases investment-based scenarios are less sensitive.
- CAES brings higher stability for the BEP of hydrogen against variations in electricity market price, PPA price level and specific electricity consumption by electrolyzers, but lower stability against variations in wind speed (compare scenarios 1–2 and 1–3).
- As can be expected, baseload PPA has the highest sensitivity to changes in PPA price level compared to pay as produced PPA.
- Among the investigated scenarios, pay as produced PPA has the highest sensitivity to variations in specific electricity consumption by different electrolyzers.
- Finally, comparing different electrolyzers in each scenario reveals that the BEP of hydrogen produced by SOE has the highest stability against variations in all the investigated factors.

5. Conclusions

The purpose of this study was to evaluate how green hydrogen could be produced with wind power, following the recent draft ruling of the EU, for use in oil refining industry in Finland to replace natural gas-based hydrogen. Globally, this technology could make a significant contribution to climate change mitigation. The study developed alternative scenarios for wind power procurement and evaluated the price of green hydrogen and its sensitivity to the decisive factors.

The main findings of the study are as below.

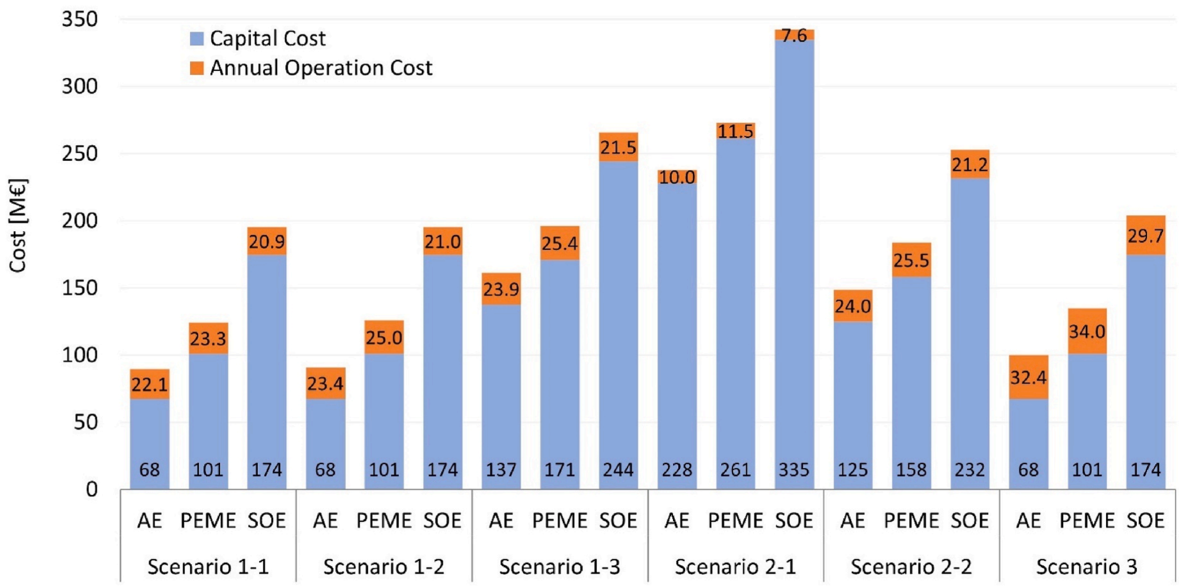

Fig. 3. Capital cost represents the total investment in each scenario, and the annual operation cost includes O&M, electricity cost, water cost, and income from selling oxygen. In each scenario, annual operation cost is the average value of 2019–2021.

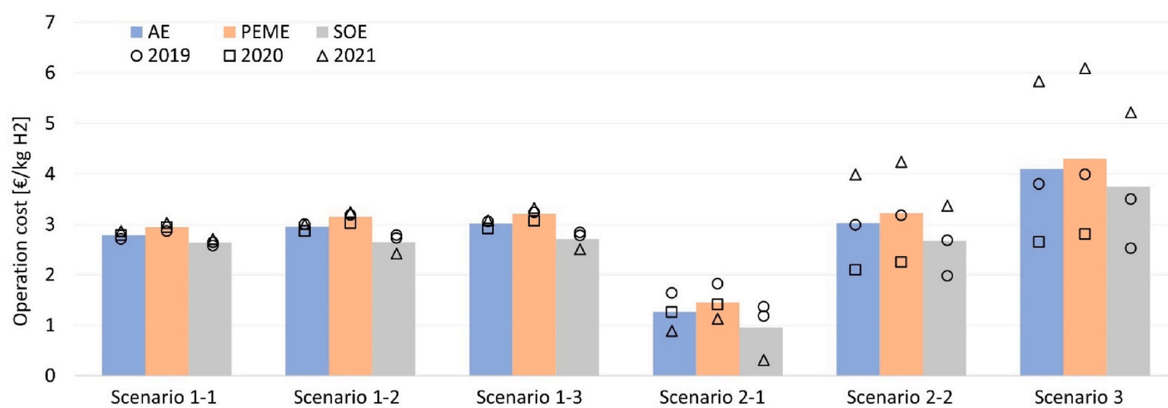

Fig. 4. The operation cost (operation cost includes O&M, electricity cost, water cost, and income from selling oxygen) of hydrogen by different electrolyzers in each scenario for 2019–2021. The average electricity market price in 2019–2021 is 44 €/MWh, 28 €/MWh, and 72.3 €/MWh, respectively. The colored bar in each case represents the average operation cost per kilogram hydrogen produced in 2019–2021.

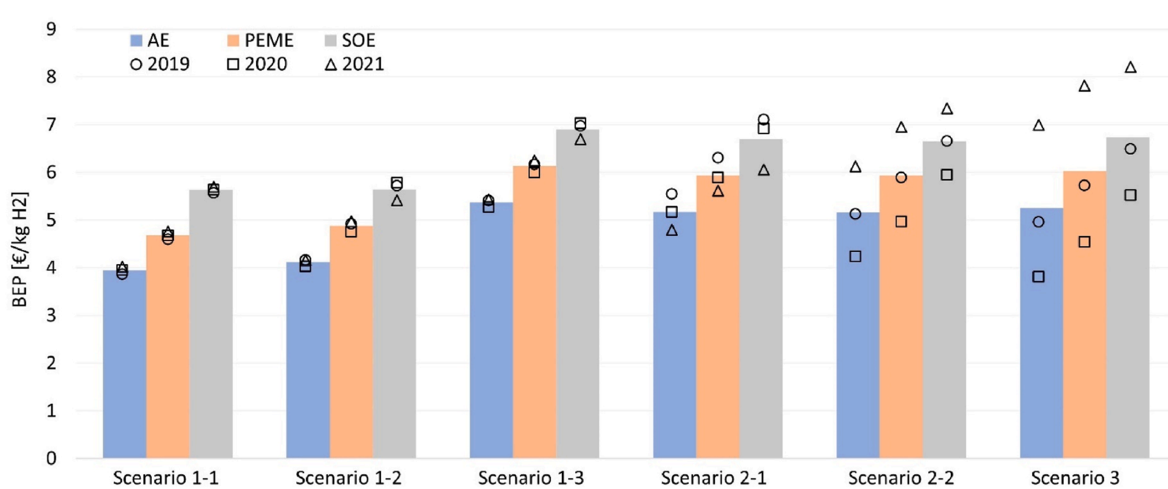

Fig. 5. BEP of hydrogen produced by each electrolyzer in different scenarios for 2019–2021. The colored bar in each case represents the average BEP in 2019–2021. Payback time of 10 years and 6% interest rate has been used in the analysis.

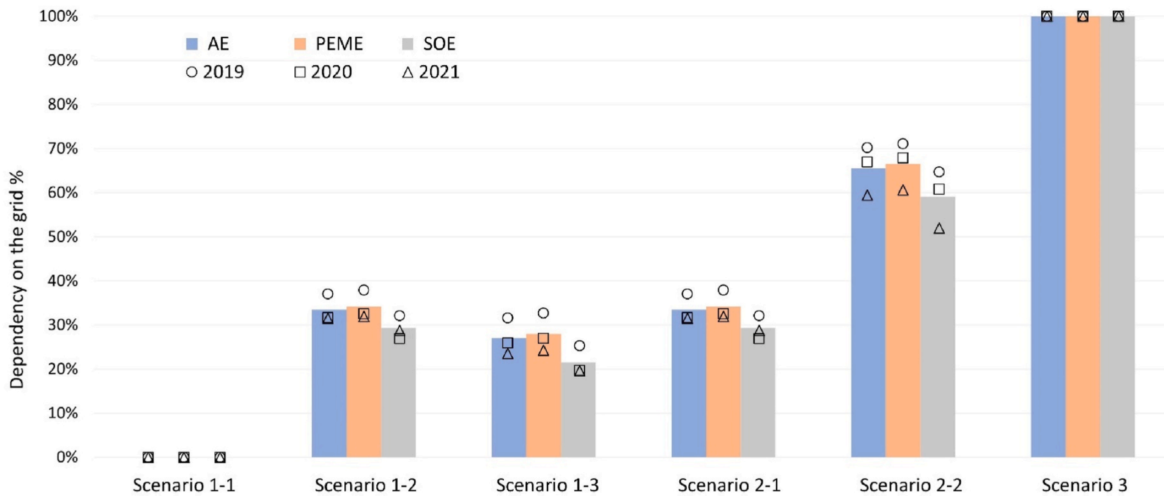

Fig. 6. The dependency on the grid (the ratio of power purchased from the electricity market to the total power consumption by electrolysis unit) for different scenarios and electrolyzers. The annual power generation by the 140 MW wind farm was 0.47 GW h, 0.52 GW h, and 0.64 GW h in 2019–2021, respectively. The colored bar in each case represents the average value in 2019–2021.

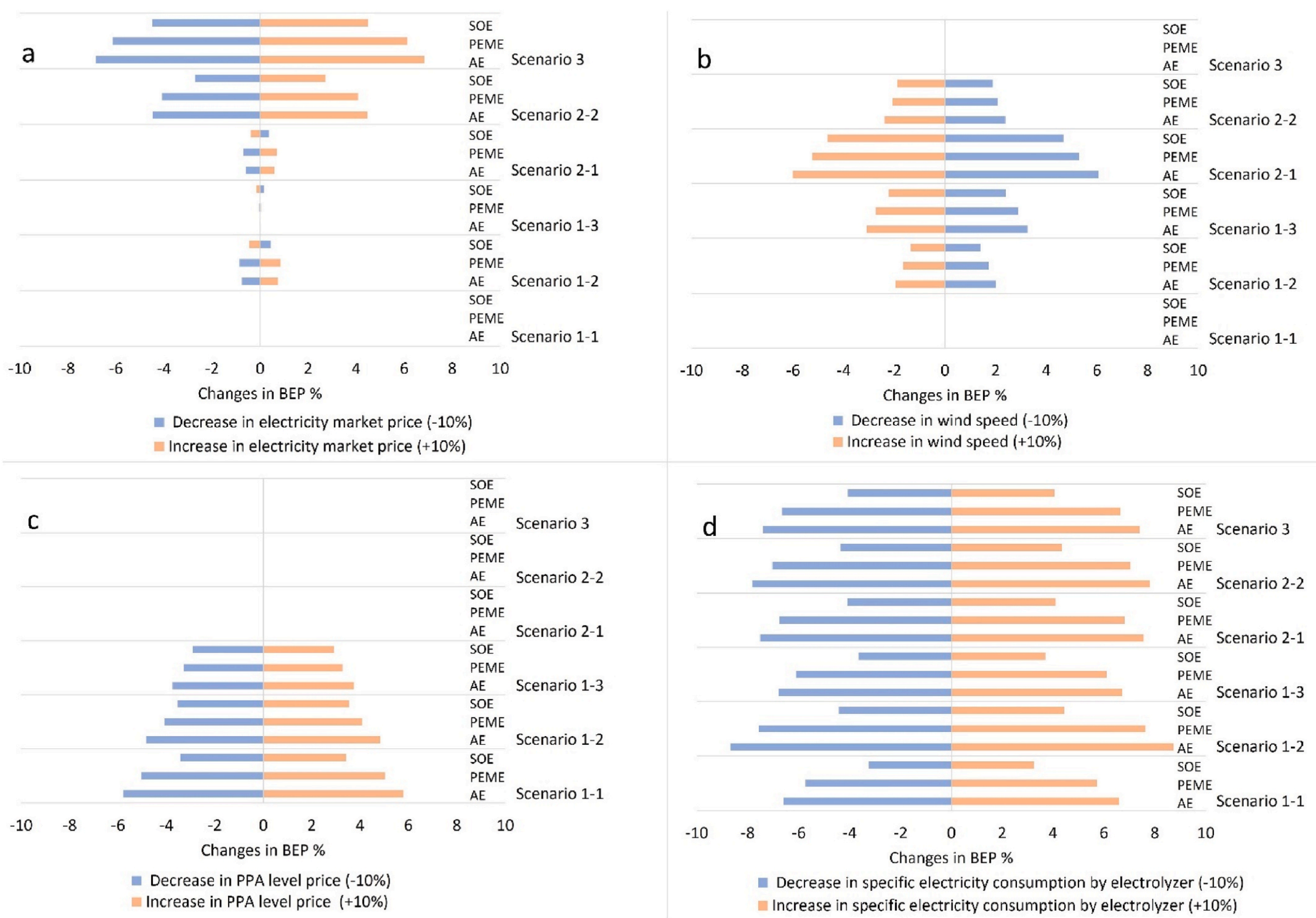

Fig. 7. The sensitivity of BEP of hydrogen produced by different electrolyzers in various scenarios to variations in decisive factors, i.e., (a) electricity market price, (b) wind speed, (c) PPA price level, and (d) specific electricity consumption by electrolyzers. The BEP in this analysis is the average of BEP in 2019–2021.

- PPA contracts have become common ways of companies purchasing dedicated wind energy. Unless significant changes are made to the current draft DA of the EU Commission, this is likely to become the main way of procuring renewable electricity for green hydrogen production. This allows industrial companies to concentrate on their main business and the construction of renewable electricity to take place in the most suitable locations. In this study, PPA-based scenarios were found to produce green hydrogen with a lower BEP, but higher operation cost compared to investment-based scenarios. Also in this case, the PPA contracts would allow the oil refining company to concentrate on their own business, which can be considered a significant advantage of this alternative.

- With AE and PEME electrolyzer technologies, Baseload PPA brings lower operation cost compared to pay as produced during all the studied years, but with SOE technology, pay as produced PPA has a lower operation cost especially when the electricity market price is higher. The average operation cost in Baseload PPA with AE and PEME is 2.79 and 2.95 €/kgH_2, respectively, and in pay as produced PPA with SOE is 2.65 €/kgH_2.
- Applying a 600 MW CAES as the electrical energy storage along with a pay as produced PPA can reduce the dependency on the grid by 7% compared to the scenario based on only pay as produced PPA without electrical energy storages, but it brings a large additional investment cost. This results in the highest hydrogen BEP for all the electrolyzers as 5.38 €/kgH_2, 6.14 €/kgH_2 and 6.90 €/kgH_2 for AE, PEME, and SOE respectively.
- The case of the oil refining company owning and constructing a 140 MW wind farm supplying electrolysis unit brings the lowest operation cost among all the studied scenarios but by considering hydrogen BEP, it is one of the most expensive scenarios as the wind park is a large investment of about 160 M€. This would probably not be an attractive option for an oil refining company to divest their operations to such a large extent. In addition, this case deviates from the proposed EU DA, as the national electricity grid would be used instead of own connection, and the grid is used to compensate for the moments of over-/undersupply.
- The scenario with earmarked wind energy from electricity market has the highest variation in different years. The operation cost in this scenario is by far higher than other scenarios (about 4.10, 4.30, and 3.75 €/kgH_2 for AE, PEME, and SOE, respectively), but hydrogen BEP is average among the alternatives studied. It should be noted that this is probably not an accepted option in the EU DA in most cases of earmarked electricity provision, especially after the year 2027.
- Finally, the sensitivity analysis reveals that pay as produced PPA has the highest sensitivity to variations in specific electricity consumption by different electrolyzers. Furthermore, BEP of hydrogen produced by SOE has the highest stability against variations in all the investigated factors.

Overall, the study provides information for industrial companies aiming to use green hydrogen in their processes, to find the best option meeting their requirements. The current draft of the EU DA specifies the acceptable renewable electricity in a strict manner and the exclusion of using the national grid may result in renewable electricity construction to suboptimal sites, especially when the hydrogen consuming industry would be located away from the windiest regions, i.e., away from coastal sites in the case of Finland. For efficient mitigation of climate change, nuclear energy as a baseload low-carbon electricity source should also be defined. Electrolysis on large-scale is a rapidly developing field. Thus, it is important to refine these analyses when new information about the performance of these technologies is reported. Similarly, wind power technology develops rapidly and more efficient turbines than those assumed in this study are already under licensing in Finland. More efficient wind turbines may make electricity cheaper than what was assumed in this study.

Credit author statement

Iraj Moradpoor: Conceptualization, Methodology, Software, Data curation, Writing – original draft. Sanna Syri: Conceptualization, Methodology, Supervision, Project administration, Funding acquisition, Writing – review & editing. Annukka Santasalo-Aarnio: Writing – review & editing.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Data availability

Data will be made available on request.

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