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Risk Analysis and Impact of Technology Advancements, Cost Changes, and Opportunities from Electrolysing Sea Water

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Abstract

Green hydrogen (H_2) has garnered significant scholarly interest as a viable strategy for the decarbonisation of sectors that are challenging to electrify, while simultaneously promoting the proliferation of renewable energy resources. As the global appetite for clean energy escalates, the significance of hydrogen in fulfilling prospective energy requirements becomes increasingly paramount. Nonetheless, literature offers little insights into the risk factors for hydrogen production through seawater electrolysis, particularly within the framework of early technologies and economic dynamics. Thus, there is a less than a comprehensive understanding of the viability and scalability of seawater electrolysis for the generation of green hydrogen. To mitigate this research void, the current investigation undertakes a systematic risk assessment, scrutinising various critical determinants that affect hydrogen production via seawater electrolysis. Specifically, the analysis appraises the capital investments necessitated for photovoltaic (PV) systems and electrolysers, the efficiency metrics of both technological approaches, and the operational and maintenance (O&M) expenditures. By integrating these essential components, the research aspires to offer an exhaustive comprehension of the financial and operational risks, while also examining the prospective ramifications of technological innovations and cost fluctuations on the future trajectory of seawater electrolysis for green hydrogen production. The findings reveal a pronounced sensitivity of the aggregate project cost to presumptions concerning PV and electrolyser efficiency and capital expenditure. Throughout the analysed scenarios, total project costs exhibit considerable variability, oscillating between approximately 498.24 billion USD and 2913.84 billion USD, thereby highlighting significant economic uncertainty. Qualitatively, the results illustrate those ongoing reductions in costs and enhancements in efficiency of PV and electrolysis technologies are vital facilitators for bolstering economic feasibility, whereas enduring cost and performance risks continue to pose a formidable obstacle to the large-scale implementation of seawater electrolysis.

Keywords

Green Hydrogen, Seawater Electrolysis, Electrolyser, Photovoltaic Systems, Economic Feasibility, Risk Analysis

1. Introduction

The global demand for energy has surged significantly in recent years, with projections indicating an increase of 20% - 30% by 2050, according to a recent report by the International Energy Agency (IEA) [1]. Currently, fossil fuels account for over two-thirds of global energy consumption [2]. However, the finite nature of fossil fuel reserves, coupled with their detrimental environmental impact through the emission of greenhouse gases (GHGs), particularly CO_2, raises significant concerns regarding climate change and environmental degradation [3]. In response to these challenges, the role of renewable energy sources, such as wind, solar, and hydroelectric power, has steadily expanded in sectors amenable to electrification [4]. Conversely, sectors that are difficult to electrify, such as long-haul commercial shipping and aviation, continue to face substantial barriers to decarbonisation. These industries require alternative green solutions, with hydrogen (H_2) emerging as a viable option due to its clean combustion process, which produces only water as a byproduct [5].

The anticipated high demand for green hydrogen in countries like Germany and Japan suggests that a portion of this demand will need to be met through international trade, leveraging greater renewable energy potential in other regions. Globally, it is essential to assess the implications of green hydrogen production on the local energy transitions of exporting countries. Ensuring that renewable energy is used effectively to support both domestic electricity needs and hydrogen production for export is vital. Ideally, the development of export capacities should complement domestic energy transformations. As an example, hydrogen production via electrolysis can facilitate the integration of renewable energy into the local electricity system [6].

Decarbonisation extends beyond the transition away from fossil fuels; it requires an integrated, multidimensional approach that encompasses renewable energy adoption, technological innovation, and coordinated international collaboration. One pivotal aspect of this transition is the concept of global electricity interconnections, which enable the exchange of renewable resources such as solar energy across geographically diverse regions. This approach not only supports environmental sustainability but also strengthens long-term economic resilience and reinforces the prudent management of natural resources, highlighting the interdependency between energy security, climate goals, and economic stability. In this context, economies historically reliant on oil exports are under growing pressure to diversify and transition towards cleaner and more sustainable energy pathways [7] [8].

The objective of this study is to provide a comprehensive analysis of the key factors influencing the production of green hydrogen from seawater, with a focus on the economic, technological, and operational challenges associated with this process. The research specifically examines risks and opportunities stemming from rapid technological advancements, fluctuating capital costs, and evolving market conditions, all of which significantly shape the competitiveness of emerging hydrogen systems.

Addressing these uncertainties is essential, as seawater electrolysis introduces unique technical considerations including corrosion, pre-treatment requirements, and system durability that influence both operational efficiency and lifecycle costs [9]-[11]. This work addresses these gaps by conducting an in-depth evaluation of risk factors related to hydrogen production from seawater electrolysis, with emphasis on capital expenditures, conversion efficiencies, and long-term cost trajectories. Through this approach, the study aims to advance understanding of the feasibility, scalability, and strategic relevance of seawater electrolysis as a reliable source of green hydrogen, while also assessing its broader implications for energy policy, industrial decarbonisation, and global energy transitions.

2. Scenario-Based Risk and Sensitivity Analysis of Key Variables

This section presents a scenario-based analysis to evaluate the impact of technological performance and cost-related variables on the deployment of integrated solar-powered seawater electrolysis systems. Three scenarios pessimistic, baseline, and optimistic were constructed to assess the influence of fluctuations in five key variables:

1) PV panel efficiency,
2) capital cost of PV panels,
3) electrolyser efficiency,
4) capital cost of the electrolyser, and
5) operation and maintenance (O&M) costs for both PV and electrolyser systems.

The selection of these variables is motivated by their central role in determining the levelised cost of hydrogen, techno-economic feasibility, and system-scale performance of solar-driven electrolysis pathways. While large scale hydrogen production is influenced by a broad spectrum of risks including policy and regulatory uncertainty, geopolitical dynamics, grid integration challenges, water quality variability, supply chain constraints, financing conditions, and land-use permitting this analysis deliberately focuses on technological and cost-related parameters. These factors are consistently identified in the literature as the dominant and most quantifiable drivers of system economics and performance and are therefore particularly well suited to structured scenario-based sensitivity analysis [12]-[14].

The variables considered in this study are those most directly influenced by technological advancement, engineering design choices, manufacturing scale-up, and innovation trajectories. In contrast, many external risks are highly context-dependent and difficult to determine within a transparent scenario framework. By concentrating on technology-driven uncertainties, the analysis enables a clearer examination of how future improvements or setbacks in key technologies may affect overall system viability.

It is important to emphasise that the objective of this section is not to provide a comprehensive, investment-grade risk assessment, but rather to demonstrate the methodological application of scenario-based risk and sensitivity analysis within the TERA framework. A full evaluation suitable for commercial financing or infrastructure investment would require additional methodological development, including probabilistic uncertainty modelling, stochastic cost distributions, policy and market risk analysis, macroeconomic indicators, supply-chain resilience assessments, and detailed engineering reliability evaluations. While these extensions lie beyond the scope of the present work, the analytical structure developed here provides a robust foundation for future integration with more advanced risk assessment tools.

Moreover, the credibility of the scenario construction is supported by the availability of well-established cost and performance datasets. Photovoltaic system costs are extensively documented through national and regional monitoring programmes covering residential, commercial, and utility-scale installations. Similarly, capital and operational cost data for commercial electrolysers, including proton-exchange membrane (PEM) and alkaline (AWE) technologies, are widely reported and validated through industry disclosures and manufacturer data [15]. These reliable datasets provide a transparent and defensible empirical basis for defining pessimistic, baseline, and optimistic scenario values, thereby strengthening the robustness of the resulting risk analysis.

2.1. PV Panel Efficiency

PV panel efficiency is one of the most critical performance parameters influencing the spatial footprint, energy yield, and overall economic performance of solar powered hydrogen systems. Higher efficiencies reduce the required land area, lower installation and balance of system costs, and increase hydrogen output per unit of installed capacity.

Recent research has demonstrated that integrated solar driven seawater splitting systems can achieve more than 12% solar to hydrogen conversion efficiency using real seawater samples [16]. In the pessimistic scenario, an efficiency of 12% is assumed to reflect older technologies, sub optimal materials, or environmental degradation such as dust accumulation an especially relevant factor in desert conditions. This low efficiency case increases land requirements and raises capital expenditure for mounting structures, cabling, and power electronics.

The baseline scenario adopts an efficiency of 14%, corresponding to widely deployed commercial crystalline silicon modules that currently dominate the global PV market [17]. This efficiency level represents a moderate and realistic performance assumption grounded in observed field data and manufacturer specifications.

In the optimistic scenario, efficiency increases to 24%, representing advanced tandem or perovskite silicon heterojunction architectures. These next generation modules significantly improve the energy yield per square metre, reduce land-use intensity, and enhance the overall techno economic attractiveness of solar electrolytic hydrogen production [17] [18]. Achieving such high efficiency would be particularly advantageous in remote desert regions where land preparation costs and logistical considerations are substantial.

2.2. Capital Cost of PV Panels

The capital cost of photovoltaic (PV) panels represents one of the most influential determinants of the upfront investment in solar powered hydrogen production systems. Because PV modules constitute a substantial proportion of the total installed cost, variations in module pricing have a direct and measurable effect on both the levelised cost of electricity (LCOE) and, consequently, the levelised cost of hydrogen (LCOH). In the pessimistic scenario, a capital cost of 450 USD/kW is assumed. This higher cost reflects potential global supply-chain disruptions, volatility in the prices of critical materials such as polysilicon, silver, and aluminium, and the possibility of trade restrictions or tariff increases affecting module imports. Elevated costs at this level would significantly constrain project bankability, lengthen the payback period, and limit the attractiveness of large-scale hydrogen production investments in emerging markets.

The baseline scenario adopts a value of 384 USD/kW, which corresponds to current international averages for utility scale PV deployment and reflects the maturity of existing manufacturing infrastructure [17]. This cost level captures the benefits of stable supply chains, incremental improvements in cell efficiency, and economies of scale achieved over the past decade. It provides a realistic midpoint estimate for present day project development in regions with established procurement channels.

In the optimistic scenario, the capital cost is projected to fall to 120 USD/kW. Such a reduction is consistent with long-term historical trends in PV price decline, which have been driven by aggressive learning curve behaviour, advances in automation, reductions in material intensity, and increasing competition among global manufacturers. Continued innovation in high-efficiency cell architectures such as heterojunction, and tandem perovskite silicon technologies further supports the plausibility of substantial cost reductions [18] [19]. Achieving this lower cost threshold would greatly enhance the economic viability of solar-powered seawater electrolysis, especially in high-insolation regions like Libya, where low-cost renewable electricity is fundamental to producing competitive green hydrogen at scale.

2.3. Electrolyser Efficiency

Electrolyser efficiency is a central determinant of the energy intensity, operational performance, and overall techno-economic viability of solar driven seawater electrolysis systems. Because the electricity requirement per kilogram of hydrogen directly scales with electrolyser efficiency, even modest improvements can result in substantial reductions in both renewable electricity demand and total system cost. Considerable research efforts have therefore focused on enhancing efficiency through the development of advanced catalysts, corrosion resistant electrode materials, improved membrane architectures, and optimised operating conditions. For seawater electrolysis in particular, specialised strategies such as bipolar electrolysis designs, selective ion-exchange membranes, and the use of additives that suppress chloride induced corrosion and unwanted by product formation have demonstrated significant promise in improving durability and performance under harsh saline conditions [20].

In the pessimistic scenario, an electrolyser efficiency of 50% is assumed. This value reflects older alkaline systems or inadequately optimised PEM configurations, where kinetic losses, parasitic resistances, and degradation mechanisms limit performance. Low efficiencies of this magnitude substantially increase the electrical energy required per kilogram of hydrogen, which in turn necessitates a larger PV array and increases both capital expenditure and system footprint.

The baseline scenario adopts an efficiency of 65%, consistent with today's commercially available PEM electrolysers operating under standard conditions. This level provides a realistic benchmark that balances achievable technical performance with manageable electricity consumption, making it an appropriate reference point for comparative scenario analysis.

In the optimistic scenario, efficiency is assumed to rise to 80%, a value aligned with advancements in high-temperature solid oxide electrolysis and next generation PEM technologies. Achieving such levels would meaningfully reduce the electricity input required for hydrogen production, thereby lowering operating costs, improving system lifetime energy yield, and reducing overall environmental impact. Higher efficiency would also enhance the dynamic responsiveness of the electrolysis unit, improving its ability to operate effectively under the variable and intermittent power supply characteristic of solar PV systems [21] [22]. This responsiveness is particularly important for large-scale seawater electrolysis facilities situated in regions with high solar resource availability.

2.4. Capital Cost of Electrolyser

The capital cost of the electrolyser system is a substantial contributor to the total system cost. Electrolyser capital costs are expressed on a 100 MW unit basis and are intended to represent commercial-scale installed costs inclusive of the principal balance-of-plant requirements. In the pessimistic scenario, the cost is estimated at approximately 73.85 million USD, reflecting a situation with limited supply, low manufacturing scale, or reliance on expensive materials such as platinum group metals in catalyst layers. This level of expenditure may act as a major barrier to widespread deployment, especially in developing regions with constrained budgets. The baseline scenario adopts a more realistic estimate of 60 million USD, which reflects current market conditions for commercial-scale electrolyser systems. This figure assumes moderate economies of scale and technology maturity. Under the optimistic scenario, the capital cost is significantly reduced to 46.15 million USD, made possible by breakthroughs in materials science, process design, and manufacturing automation. This reduction is essential to achieving competitive hydrogen prices and would substantially improve the investment attractiveness of large-scale electrolytic hydrogen production using seawater and renewable power [21] [22].

2.5. Operation and Maintenance Costs

Although this study considers hydrogen production within a seawater-based context, the modelling framework adopts an indirect seawater electrolysis pathway. In this configuration, seawater is assumed to be abstracted from coastal sources, subsequently filtered and desalinated (or otherwise purified), and then supplied as feedwater to commercially mature electrolyser systems. This approach reflects the current state of technological development, as direct seawater electrolysis remains at a relatively low technology readiness level (TRL) and continues to face significant technical challenges, including chlorine evolution, electrode corrosion, membrane degradation, and long-term operational instability.

Accordingly, this modelling assumption is supported by several considerations. First, the energy and cost contributions associated with desalination are relatively minor when compared to the overall electricity demand of large-scale electrolysis systems. Specifically, the cost of reverse osmosis seawater purification is estimated to be less than 0.10 USD per kilogram of hydrogen, representing only a small fraction of the total hydrogen production cost. Furthermore, the cost of desalination itself typically ranges between 4 and 11 USD per cubic metre of water, depending on system efficiency and local energy conditions [23]. Second, once purified water is supplied to the electrolyser, system performance can be sufficiently characterised through the electrolyser efficiency and operational assumptions already embedded within the scenario framework. Third, the results of this study demonstrate that the dominant cost drivers and system sensitivities are primarily governed by photovoltaic performance, electrolyser efficiency, and capital expenditure, rather than by ancillary water treatment processes.

In parallel, operation and maintenance (O&M) costs are treated as a critical component of lifecycle system performance, influencing long-term reliability, system availability, and effective annual energy output. Within this study, O&M costs are represented using scenario-dependent rates applied to both PV and electrolyser systems, enabling the model to capture uncertainties associated with maintenance frequency, component degradation, environmental exposure, and operational complexity. This approach provides a structured basis for evaluating the sensitivity of overall project economics to long-term operational conditions, particularly in harsh environments such as desert regions where dust accumulation, thermal stress, and logistical constraints can significantly influence maintenance requirements [24].

Operation and maintenance (O&M) costs represent a crucial component of the long-term economic performance and reliability of both PV systems and electrolysers. In this study, the O&M rates for both components were derived from informed assumptions based on expected service needs, environmental exposure, and the degree of automation available in each scenario. These assumed percentages are applied relative to capital costs or per unit of generated or processed energy, allowing for comparative analysis across different technology configurations.

In the pessimistic scenario, the assumed O&M cost rates are 0.06 for PV systems and 0.04 for electrolysers. These values reflect more challenging operational conditions, such as increased dust accumulation in desert environments, higher wear and tear due to thermal stress, and limited availability of automated monitoring and maintenance technologies. These elevated maintenance burdens would require more frequent manual interventions, potentially increasing downtime and operational expenses. The baseline scenario adopts moderate O&M assumptions, with rates of 0.05 for PV and 0.03 for electrolysers. These figures are consistent with current utility-scale solar and hydrogen production projects operating under average conditions with standard maintenance protocols. They reflect a balanced expectation regarding performance degradation, technician access, and system reliability over the project's lifetime. In the optimistic scenario, the O&M cost assumptions are lowered to 0.04 for PV and 0.02 for electrolysers. These values are grounded in the potential of advanced technologies and data-driven predictive maintenance strategies to reduce operational overhead. Enhanced system design, automated diagnostics, and remote-control capabilities are assumed to significantly lower service frequency and associated costs. Additionally, improved component lifetimes and reduced failure rates contribute to these more favourable O&M expectations.

Table 1. Three scenarios for key variables in risk analysis.

Variable	Pessimistic Scenario	Baseline Scenario	Optimistic Scenario
PV Panel Efficiency	12%	14%	24%
Capital Cost of PV Panels (USD/kW)	450	384	120
Electrolyser Efficiency	50%	65%	80%
Electrolyser Capital Cost (USD million)	73,846,154	60,000,000	46,153,846
O&M Costs (PV/Electrolyser) (%)	0.06/0.04	0.05/0.03	0.04/0.02

By incorporating these assumption-based O&M values across all three scenarios, the analysis provides a structured framework to evaluate the sensitivity of project economics to long-term operational expenditures. These assumptions also help to highlight the substantial cost-saving potential offered by technological innovation and operational optimisation, particularly in remote or environmentally extreme settings such as Libya's desert regions. All assumptions and scenario-specific values for the five variables discussed above are outlined in **Table 1**.

3. Evaluation of Winter Season-Based Requirements

The study investigates the optimal deployment of solar farms to maximize their energy generation capacity, taking into consideration critical site-specific factors such as geographic location, annual irradiance, and seasonal variations in solar illumination. Attention is given to desert areas in Libya at a latitude of approximately 25˚N, selected due to their sparse population, high solar resource availability, and strategic location within the southern region of the country. These regions are widely recognized as possessing some of the highest solar irradiation levels in North Africa, making them well-suited for large-scale photovoltaic (PV) projects that can contribute significantly to national energy security [23].

4. Calculation Basis for Export Target and System Sizing

To improve transparency in the system-sizing methodology, the annual hydrogen export target is translated into infrastructure requirements through a structured calculation framework. The target adopted in this study is 2100 PJ/year of hydrogen export. Using the lower heating value (LHV) of hydrogen, assumed to be approximately 120 MJ/kg, this corresponds to an annual hydrogen production requirement of approximately 17.5 million tonnes.

The associated electricity demand is derived based on the assumed electrolyser efficiency. Under the baseline scenario, this corresponds to an electricity consumption of approximately 50 - 55 kWh per kilogram of hydrogen, resulting in a total annual electricity demand in the range of 875 - 960 TWh. This demand is subsequently converted into required PV capacity using site-specific solar resource data, in conjunction with assumptions regarding PV efficiency, utilisation factors, weather conditions, fouling losses, contingency allowances, and plant availability.

Electrolyser capacity is then sized to meet the hydrogen production rate implied by the export target, while hydrogen storage and transmission infrastructure are determined based on system balancing and energy delivery requirements. The winter-based sizing approach adopted in this study is intentionally conservative, as it reflects the least favourable seasonal conditions for solar generation. Consequently, all reported infrastructure capacities should be interpreted as those required to reliably meet the export target under constrained winter operating conditions.

5. Infrastructure Requirements and Technology Performance Sensitivity

As part of the baseline scenario which represents a realistic and balanced projection of future electricity and hydrogen production needs an iterative modelling approach was employed to determine the required solar farm area capable of meeting total electricity demand during the winter season. This period is particularly important because winter brings reduced daylight hours and lower solar elevation angles, thereby limiting energy production potential. Using relevant site-specific solar data and seasonal derating factors, the analysis identified that a substantial land area of approximately 12,033 km^2 would be necessary to ensure sufficient electricity generation and maintain reliable system performance during winter under the baseline conditions [25]. This finding highlights the importance of accounting for seasonal variability when planning national-scale renewable energy systems, especially in regions where winter output can constrain annual performance.

This estimate was based on several key factors, including the efficiency of the photovoltaic (PV) cells (0.14), indicating that 14% of the incident sunlight is converted into electrical energy. The spatial allocation of PV cells was set at 0.39, representing the fraction of the total installation area covered by the panels. A weather factor of 0.833 was applied, reflecting the assumption of 300 days of effective sunlight per year. To account for performance degradation due to environmental conditions, a fouling factor of 0.97 was used, acknowledging high levels of dust accumulation, although mitigated by the possibility of nighttime maintenance. Similarly, a contingency factor of 0.98 was included to address uncertainties in system performance, and an availability factor of 0.98 was adopted, assuming high system uptime due to effective scheduling of maintenance during non-operational hours.

To explore the sensitivity of the system to changes in PV performance, two additional scenarios were evaluated. In the pessimistic scenario, where a lower PV efficiency of 0.12 was assumed reflecting potential degradation or use of lower-performing technology the required area increased significantly to approximately 18,056 km^2 to compensate for reduced energy conversion capability. Conversely, in the optimistic scenario, where technological advancements or improved module performance allow for a higher PV efficiency of 0.24, the required area was considerably reduced to approximately 5769 km^2, highlighting the potential for substantial land savings under improved efficiency conditions. The results of all three scenarios are summarised in **Table 2**.

Table 2. National requirements for three scenarios: exporting yearly 2100 PJ of hydrogen using solar PV farms to their full capacity.

Scenario	**Solar Farm (GW)**	**Solar Farm (km^2)**	**600MW H_2 CCGTS**	**Electrolysers (GW)**	**Storage H_2 (tonnes)**	**Transmission (GW)**	**H_2 Export (PJ)**
Pessimistic	845	18,056	54	637	43,710	655	2100
Baseline	657	12,033	54	491	43,726	510	2100
Optimistic	540	5769	54	400	43,757	419	2100

Figure 1 illustrates the inverse relationship between photovoltaic (PV) efficiency and the land area required for solar farm deployment across the three defined scenarios: pessimistic, baseline, and optimistic. As PV efficiency improves from 12% in the pessimistic case to 24% in the optimistic case, the corresponding land area requirement for producing 2100 PJ of hydrogen annually decreases significantly from 18,056 km^2 to 5769 km^2. The baseline scenario, assuming a PV efficiency of 14%, requires 12,033 km^2 of land. This trend clearly demonstrates the critical influence of PV efficiency on spatial resource demands, emphasizing that technological advancements in panel efficiency can substantially reduce the geographical footprint of large-scale hydrogen production systems. The results also highlight the spatial opportunity cost in regions like southern Libya, where land availability is relatively high, but minimising land use remains important for reducing environmental disruption and infrastructure complexity.

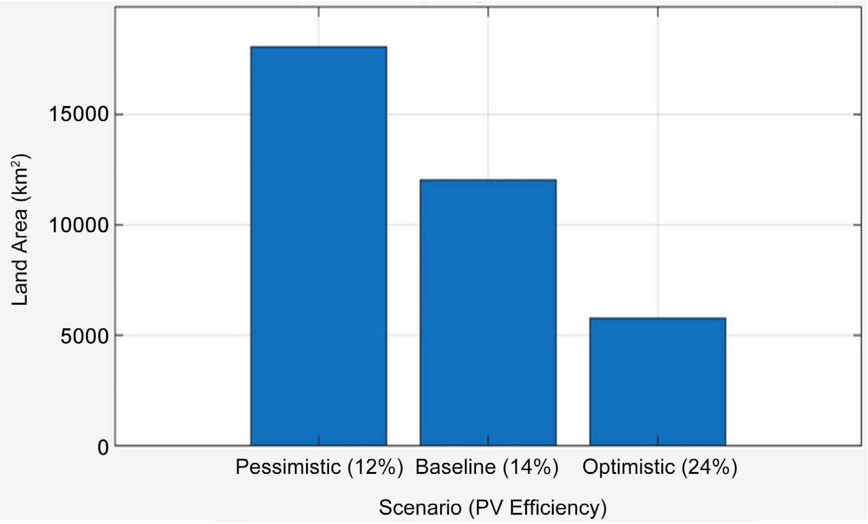

Figure 1. Relationship between PV efficiency and required land area across scenarios.

Figure 2 presents the effect of electrolyser efficiency on the required nominal PV capacity to achieve the annual export target of 2100 PJ of hydrogen. As the efficiency of the electrolyser increases from 50% in the pessimistic scenario to 80% in the optimistic scenario, the corresponding PV capacity requirement declines markedly from 845 GW to 540 GW. The baseline scenario, assuming a 65% electrolyser efficiency, requires 657 GW of PV capacity. This trend highlights the strong dependency of overall system size on electrolyser performance: lower efficiency demands significantly more electricity input to produce the same hydrogen output, thereby increasing the size and cost of the upstream solar infrastructure. These results highlight the critical role of electrolyser technology improvements in reducing the scale, cost, and complexity of integrated renewable hydrogen systems. Enhancing conversion efficiency not only optimises energy use but also directly impacts capital investment and land footprint, especially in large-scale national deployment strategies.

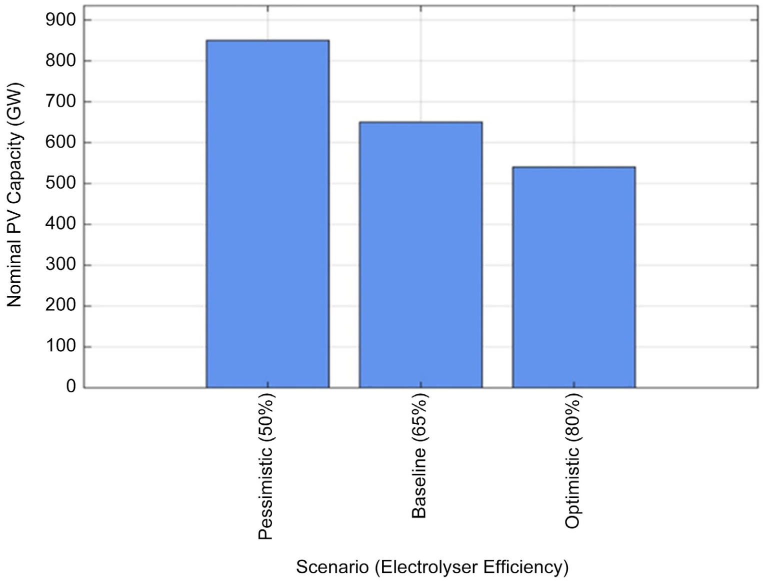

Figure 2. Impact of electrolyser efficiency on required nominal PV capacity across scenarios.

6. Component Costs

Table 3 provides a summary of the estimated Capital Expenditure (CAPEX), Operational Expenditure (OPEX), component replacement costs, and lifetimes associated with the key elements of a solar PV-supported hydrogen production plant. These estimates are based on the baseline scenario, which reflects current commercial technologies and realistic economic assumptions. The baseline scenario integrates a PV efficiency of 14% and an electrolyser efficiency of 65%, representing a balanced outlook on system performance and cost. The associated financial and technical parameters in this scenario offer a representative framework for evaluating the feasibility and investment requirements of large-scale hydrogen production under current market conditions. The costs in USD presented in Table 3 were reviewed during the period 2017 to 2024, and the underlying assumptions guiding their determination are given in subsequent sections.

Table 3. Specific capital and operational expenditures for all components of the green hydrogen production plant.

Component	CAPEX [B-USD]	Annual OPEX [B-USD]	Lifetime [Years]
Power Generation			
PV System	765	561	25
H2 CCGT	23	6.02	25
Transmission	0.023	0.0034	/
Hydrogen Production			
Electrolyser	295	130.23	25
Hydrogen Storage	15	2.04	25

For a solar PV system, the capital cost per unit, represented by a single PV panel capable of generating 330 watts, was chosen at $384.12 with an accompanying operation and maintenance (O&M) rate of 0.05 [17] [26]. Similarly, the investment required for one 600 MW hydrogen gas combined cycle turbine (H2GCCT) unit was selected at $418,200,000 coupled with an O&M rate of 0.02 [26]. Using 100 MW proton exchange membrane electrolyser units, the capital outlay per unit is estimated at $60,000,000 accompanied by an O&M rate of 0.03 [21] [22]. For H2 storage, the capital cost per kilogram (kg) of storage capacity is estimated at $350, with an O&M rate of 0.01 [17]. Furthermore, transmission infrastructure, essential for efficient energy distribution, incurs an estimated capital expenditure of $54,000 per gigawatt (GW) alongside an O&M rate of 0.01 [27]. Understanding and accounting for these costs is imperative for conducting robust economic assessments and devising sustainable energy strategies.

Comprehending and accounting for these expenditures is essential for executing rigorous economic evaluations and formulating sustainable energy initiatives. Empirical investigations illustrate that decreases in capital expenditures for photovoltaic (PV) systems and electrolysers, facilitated by learning curves and the diffusion of technology, can markedly affect the levelized cost of hydrogen (LCOH), with anticipated declines in the capital costs of PV and electrolysers projected to be in the range of 60% - 70% by the mid-century under moderate deployment scenarios [28]. Scholarly research has established that learning phenomena and economies of scale are instrumental in achieving significant cost reductions in electrolyser technologies, with recent empirical analyses suggesting that proton exchange membrane (PEM) and alkaline (AEL) electrolysers demonstrate notable learning rates as cumulative deployment increases, with estimated historical learning rates of approximately 32.1% and 22.9% respectively, based on European deployment experiences, thereby reflecting the potential for cost reductions as production escalates over time [29]. Moreover, techno-economic modelling of PV-driven hydrogen systems suggests that improvements in solar conversion efficiency and electrolyser efficacy not only diminish capital and operational expenditures but also enhance system integration and operational flexibility, resulting in a lower levelized cost of hydrogen (LCOH) and improved economic performance amidst uncertainty [30].

7. A Foundation Baseline for Future Policy and R&D Investments

The present study provides insights for shaping national and international research, development, and financial agendas in the field of electricity generation and energy storage. The focus is on a comprehensive approach involving solar energy and H2 CCGTs, along with ancillary systems. The study serves as a valuable baseline for evaluating alternatives and establishing R&D requirements essential for a country's decarbonisation agenda, despite uncertainties and alternative approaches. Key R&D challenges included hydrogen production, with options like seawater electrolysis and a two-step process involving desalination and will be the focus of a future study. Demand patterns were explored, and demand management was suggested to optimise cost benefits by aligning peak demand with solar supply. The study also addressed the social duty of oil-exporting countries, such as Libya, to consider alternative energy exports since environmental policies will impact oil demand. The discussion extended to the potential export of hydrogen to Europe, raising questions about the mode of transport (liquid vs. gaseous) and electricity export. The study assumed gaseous hydrogen export, but a mix of options is likely. The choice of energy storage alternatives, including technologies such as batteries and compressed air storage, can vary, recognising that different regions may require diverse solutions.

Table 4 outlines the financial considerations, with the total capital expenditure (CAPEX) calculated at $1097 billion, total operational expenditure (OPEX) at $699.64 billion, resulting in a total cost of $1796.9 billion.

Table 4. Total capital and operational (in Billion USD).

Total costs for green hydrogen production and export	Billion USD
Capital Cost (CAPEX)	1097
O&M (OPEX)	699.64
Total Cost	1796.9

Figure 3 presents the frequency distribution of total project cost outcomes derived from 243 simulation runs generated through a full 3^5 factorial design. The simulations systematically vary five key techno-economic parameters: photovoltaic (PV) efficiency, PV capital cost, electrolyser efficiency, electrolyser capital cost, and the operation and maintenance (O&M) costs associated with both systems. Each parameter assumes pessimistic, baseline, and optimistic values, thereby creating a structured and exhaustive exploration of plausible future technological and economic states.

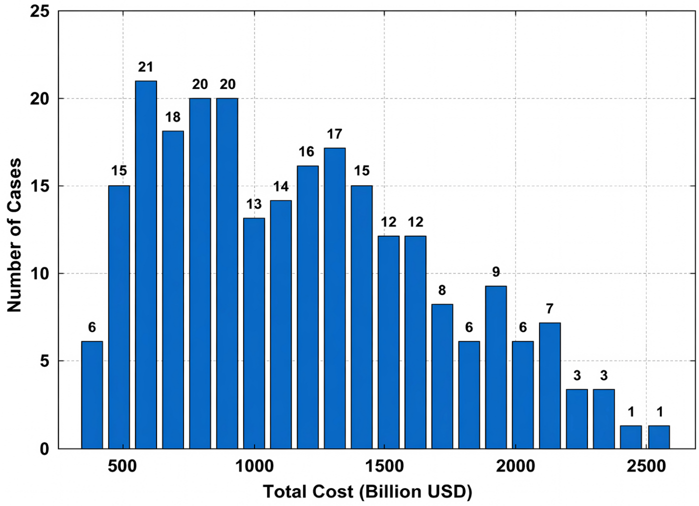

Figure 3. Frequency distribution of total project cost (Billion USD) based on scenario-based simulation iterations.

The resulting cost distribution spans approximately 498.24 billion USD to 2913.837 billion USD, representing the extreme optimistic and pessimistic combinations of assumptions. This range alone illustrates the magnitude of structural economic uncertainty embedded within large-scale solar-powered seawater electrolysis systems.

The histogram indicates that total project cost is positively skewed, with most simulated outcomes concentrated between approximately 500 and 1500 billion USD, and the highest frequency observed within the 600 to 1000 billion USD range. This suggests that moderate-to-high-cost outcomes are the most probable across the simulation space. However, the distribution is not tightly concentrated, as the broad spread within this central region demonstrates that even the most likely outcomes are associated with substantial financial variability rather than a single stable cost estimate. This is analytically significant because it indicates that the project remains economically uncertain even before the extreme outcomes are considered. Furthermore, the continued presence of relatively high frequencies across the 1000 to 1500 billion USD range suggests that cost escalation is not limited to rare events but instead develops progressively across a broad and structurally plausible middle-cost range.

This distribution is shaped by the combined influence of the five underlying variables: PV panel efficiency, PV capital cost, electrolyser efficiency, electrolyser capital cost, and O&M costs. Collectively, these variables affect total project cost through interconnected mechanisms that influence system scale, capital intensity, conversion burden, and life-cycle operating expenditure. The dense clustering in the central part of the histogram suggests that, in many simulation cases, unfavourable movement in one variable is partially offset by more favourable conditions in others, thereby preventing immediate transition into the highest-cost range. Nevertheless, the width of the distribution also indicates that this balancing effect is limited, since partial underperformance across several variables is still sufficient to shift the project into materially higher expenditure levels.

The upper portion of the histogram, beginning at around 1500 billion USD and becoming particularly sparse beyond 2000 billion USD, is the most critical region from a risk perspective. The gradual decline in frequency across this range indicates that such outcomes are less probable, but their persistence confirms that very high expenditures remain structurally possible within the model. These low-frequency, high-cost cases are of particular importance in large-scale infrastructure analysis because they define the limits of financial resilience, investment risk, and policy credibility. The extension of the distribution into the 2000 to 2900 billion USD range implies that the model includes scenarios in which the project cost structure becomes severely stressed. Such outcomes are most likely to emerge when the five variables deteriorate simultaneously, creating reinforcing pressures across the system: weaker technical performance increases the required infrastructure scale, higher capital intensity raises the cost of that enlarged system, and greater operational burdens intensify life-cycle expenditure. The upper tail therefore represents more than simple statistical dispersion; it reflects a structural vulnerability through which interconnected techno-economic underperformance can drive the project into a substantially higher expenditure regime. Overall, the histogram demonstrates that, although the project is most associated with moderate-cost outcomes, it remains vulnerable to severe financial stress when multiple adverse conditions occur concurrently.

Thus, **Figure 3** not only displays cost variability but reveals the structural sensitivity of national-scale hydrogen export systems to coordinated technological advancement. The distribution demonstrates that economic viability depends less on isolated parameter improvements and more on avoiding simultaneous degradation across multiple key variables.

Figure 4 presents the normalized sensitivity of total project cost to systematic variation of the five techno-economic parameters across the pessimistic-to-optimistic scenario spectrum. The baseline case (normalized value = 0.5) serves as the reference point, and deviations illustrate how movement toward pessimistic (0) or optimistic (1) conditions alters aggregate expenditure.

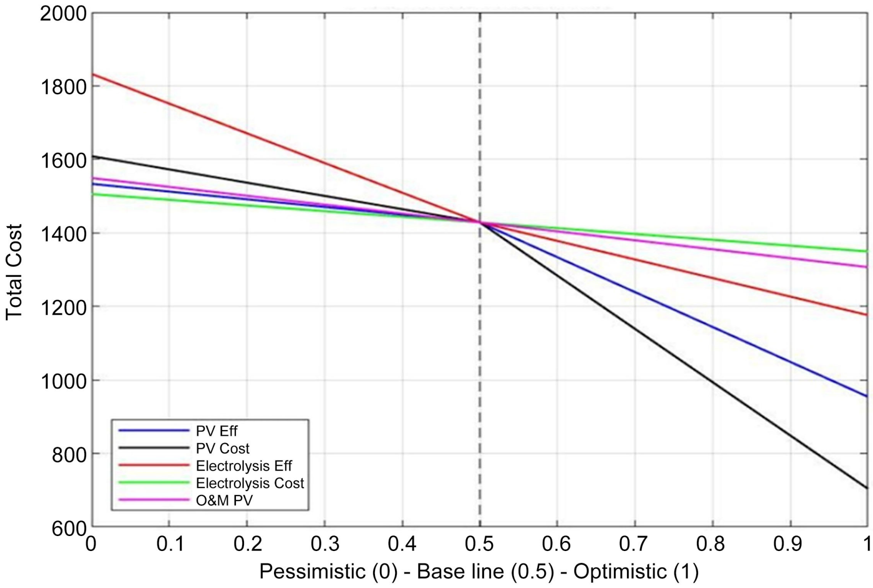

Figure 4. Normalized sensitivity of total project cost to key variables across scenario spectrum in a performance evaluation plot.

The slopes of the sensitivity curves provide insight into both magnitudes of influence and directional elasticity of each parameter. Two dominant patterns emerge.

First, PV efficiency and electrolyser efficiency exhibit the steepest negative gradients, indicating a strong inverse relationship with total project cost. Improvements in conversion efficiency reduce electricity losses and decrease the installed capacity required to achieve the fixed hydrogen export target. Because system infrastructure is dimensioned according to energy throughput, efficiency gains cascade across multiple components reducing PV capacity, electrolyser sizing, transmission requirements, and associated balance-of-plant costs. The resulting cost reduction effect is multiplicative rather than isolated. This explains the pronounced sensitivity observed.

Second, PV capital cost and electrolyser capital cost demonstrate strong positive sensitivity. These parameters directly scale with installed capacity and therefore act as primary cost multipliers. However, compared with efficiency variables, their influence is more linear and less structurally amplifying. While reductions in capital cost improve economic feasibility, they do not fundamentally alter system energy demand or physical scale in the way efficiency improvements do.

In contrast, O&M costs also increase total project cost, although their impact is less than that of efficiency and capital cost parameters. This indicates that, within the tested scenario range, operational expenditures play a role relative to capital intensity and energy conversion performance. Given the scale and capital-dominant nature of solar-hydrogen infrastructure, lifecycle economics are overwhelmingly determined by upfront investment and system efficiency rather than recurring operational costs.

From a risk perspective, Figure 4 reveals a hierarchy of economic leverage:

1) Efficiency improvements provide the highest structural impact.
2) Capital cost reductions provide substantial but more proportional influence.
3) O&M variations exert a positive but comparatively system-wide effect.

Importantly, the near-linear but steep slopes also suggest that the system's economic response is continuous rather than discontinuous across the scenario range. However, when interpreted alongside the bimodal distribution in Figure 3, it becomes evident that interaction effects among efficiency and capital cost parameters can collectively push the system into a higher-cost regime.

Therefore, Figure 3 identifies the principal drivers of economic uncertainty and provides strategic direction for innovation policy. Targeted advancement in PV module efficiency and electrolyser performance offers the most effective pathway to reducing aggregate system risk. While cost reductions through manufacturing scale-up remain important, transformative gains in energy conversion efficiency yield deeper structural benefits by reducing both physical infrastructure requirements and associated capital exposure.

Collectively, Figure 3 and Figure 4 demonstrate that the economic viability of large-scale solar-powered seawater electrolysis is governed by compounded technological dynamics rather than isolated cost factors. Sustained innovation in conversion efficiency emerges as the most decisive mechanism for stabilizing long-term project feasibility.

8. Conclusions

This research describes a methodical scenario-based risk analysis aimed at evaluating the susceptibility of aggregate project expenditures to fluctuations in pivotal technological and economic parameters pertinent to large-scale solar-powered seawater electrolysis. The analysis used a comprehensive simulation framework consisting of 243 iterations, produced through a full 3^5 factorial design wherein five essential variables PV module efficiency (PV), PV panel capital cost (PV_Cost), electrolyser efficiency (Electrolysis), electrolyser capital cost (Elec_Cost), and operational and maintenance rates for both PV and electrolysis systems (O&M_PV and O&M_Elec) were ascribed pessimistic, baseline, and optimistic values. This methodological approach facilitated an extensive investigation into plausible technological trajectories and cost dynamics that may substantially impact future project viability.

The level of precision adopted in this analysis is considered adequate for the objectives of an early-stage, system-level techno-economic risk assessment. By discretising each key variable into three representative states and systematically evaluating all possible combinations, the factorial design ensures sufficient resolution to capture first-order sensitivities, directional trends, and interaction effects among the dominant cost drivers. The resulting scenario space provides a robust basis for identifying relative risk magnitudes and comparative influences of technological and economic parameters, while avoiding the false sense of accuracy that may arise from overly granular assumptions in the absence of reliable probabilistic data. As such, the precision of the framework is well aligned with the exploratory and strategic nature of the assessment.

The results show that total project cost varies substantially, oscillating from approximately 498.24 billion USD to 2913.84 billion USD. This marked variability accentuates the extent to which financial outcomes are dependent upon conjectures surrounding technological advancement, cost mitigation, and system performance. The completion and analysis of the comprehensive simulation dataset will yield further insights into the magnitude and distribution of economic risk, as well as the identification of the most significant determinants influencing project viability.

From a methodological perspective, the analytical framework employed in this study is robust, transparent, and suitable for early-stage techno-economic evaluation. It offers a clear mechanism for isolating and scrutinizing the impact of individual technical and cost parameters under structured scenario conditions. However, it is crucial to recognize that the approach represents an initial, illustrative variant of risk analysis. A fully comprehensive, investment-grade assessment would necessitate methodological enhancements, including the integration of probabilistic uncertainty modelling, stochastic cost distributions, long-term policy and market risk analysis, dynamic financial modelling, and detailed engineering reliability assessments. Such refinements would augment the framework's capability to facilitate commercial decision-making, infrastructure financing, and large-scale deployment planning.

In conclusion, the findings highlight both the substantial potential of technological innovation in PV and electrolyser systems to enhance economic feasibility, as well as the considerable uncertainties that must be addressed to enable the reliable and cost-effective implementation of seawater electrolysis at scale.

Conflicts of Interest

The authors declare no conflicts of interest regarding the publication of this paper.

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