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Techno-economic assessment with alkaline electrolysis in Nepal's perspective

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Hydrogen production from surplus hydropower: Techno-economic assessment with alkaline electrolysis in Nepal's perspective

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ABSTRACT

With the increasing number of hydropower plants under construction and proposed in Nepal, the country is anticipated to experience a surplus of hydropower that exceeds its peak load demand. This surplus electricity becomes particularly high during the wet seasons, when hydropower production reaches its maximum capacity. This research focuses on the mathematical modeling of an alkaline electrolyzer, specifically analyzing the stack performance and the electricity flow within the balance of plants required to support the stack operation. The developed model is then used to estimate the production cost of hydrogen by utilizing forecasted surplus electricity up until the year 2030. The output of the study is expected to help in the sustainable utilization of surplus hydropower in the country, thus enhancing the low carbon economic development path. The study shows that there is a significant opportunity for hydrogen production from surplus hydroelectricity, ranging from 91 ktonne/year to maximum, of 414 ktonne/year. The average levelized cost of hydrogen is estimated at 5.65 USD/kg. The cost can be further reduced if policy interventions like tax rebates and tariff rate subsidies are in place.

Nomenclature

Abbreviations	
AEL	Alkaline Electrolyzer
BOP	Balance of Plant
CAPEX	Capital Expenditure
CF	Capacity Factor
COD	Commercial Operational Date
DR	Degradation Rate
ktonne	Kilo Ton
PV	Photovoltaics
LCOE	Levelized Cost of Electricity
LCOH	Levelized Cost of Hydrogen
NEA	Nepal Electricity Authority
O&M	Operational & Maintenance
OPEX	Operational Expenditure
PEMEL	Proton Exchange Membrane Electrolyzer
PL	Peak Load
PtX	Power-to-X
REVH	Revenue from Hydrogen Sales
SE	Surplus Electricity
SOEL	Solid Oxide Electrolyzer
SP	Selling Price
TIC	Total Installed Capacity
TR	Tax Rate
USD	United States Dollar
Symbols	
I	Stack current [A]
N	Stack Life [years]
r	Discount rate [%]
$T_{nominal}$	Nominal operating temperature [K]
U	Voltage [V]
γ	Electrolyzer installed capacity [kW]
θ	Electrolyzer installation year [year]

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1. Introduction

With estimated runoff of perennial rivers up to 170 billion m^3 that flows the steep gradient, Nepal possesses significant potential for hydroelectricity [1]. In 2023, 10,693.000 GWh of electricity were consumed nationwide in Nepal. Compared to the previous year's usage of 9336.000 GWh, this represented an increase in hydroelectricity production [2] and it is estimated that 43 GW of hydroelectricity generation is feasible economically for Nepal which is equivalent to 50% of the theoretical maximum potential of 83 GW [3]. However, despite this considerable hydro energy potential, Nepal faces a problem of low per capita electricity consumption, which stood at 351 kWh in 2022–2023 [4]. Limited accessibility to commercial fuels due to high costs, such as diesel, gasoline, natural gas, etc., has led to a reliance on biofuels and waste, comprising 72% of the country's energy sources. However, electricity's minimal contribution, only 4% of the energy mix, poses a significant challenge [5]. To address these issues, the Nepal Electricity Authority (NEA) has set ambitious goals to increase per capita energy consumption from 700 kWh to 1500 kWh by 2028 [6,7]. Also, as a national goal, Nepal is determined to increase its generation capacity to 15 GW by the year 2030, ensuring 15% of the total energy demand is supplied by a cleaner source [8]. Despite increasing electricity demand, progress on hydroelectric projects has been slow, casting doubt on meeting NEA's consumption targets within the designated timeframe [9,10].

The construction of multiple hydropower projects underway raises concerns about the potential for excess electricity production in Nepal. A total of 753 MW worth of generation capacity was connected to the grid in the fiscal year of 2021/2022 [9]. Nepal is already selling electricity during off-peak hours of wet season months and has earned over 11.6 billion Nepali Rupees -NPR in one year since June 2022 [11]. The electricity sales from hydroelectric plants were 10 GWh in the fiscal year 2019/20, it increased to 33.3 GWh in the year 2020/21, and in 2021/22, it increased significantly to a total of 493.6 GWh of electricity sales to India [7]. With the imminent connection of additional hydroelectric projects, Nepal expects a surplus of electricity beyond domestic needs, posing a significant challenge in effectively managing and utilizing the excess energy. Regarding incentives, in addition to granting exemptions from registration fees and yearly vehicle taxes for battery-operated and electric cars, the government has been urged to give special discounts on the provision of power as a "service" for the charging of electric vehicles [12]. A capacity royalty of NPR 200 per kW applies to hydropower development up to the first 15 years, after which it is NPR 1500 per kW. Up to the first 15 years of COD, the energy royalty is 2% of energy revenues; after that, it is 10% [13]. The exact information regarding incentives has not been disclosed by the government to date.

The surplus energy challenge can be dealt with in three possible ways, as proposed by Bhandari and Subedi in Ref. [14]: increasing usage, selling, and transforming to other forms of energy. To utilize surplus energy, Nepal can promote energy consumption through efficiency programs, incentivize usage during off-peak hours, and raise awareness. Additionally, selling excess electricity to neighboring countries like India and Bangladesh, with growing energy demands, offers a viable option [14,15]. Studies on-demand analysis have projected that there would be a large increase in electricity consumption from an increasing economy and adoption of air conditioning technologies in the building sectors of India [16,17]. Bangladesh, with its increasing population and industrial growth, requires a significant amount of additional power to sustain its development [18,19]. Besides, the seasonal demand profile of India and Bangladesh match well with the seasonal supply profiles of Nepalese hydropower plants, as its peak supply occurs during peak demand in the neighboring countries. Geographical proximity to India and Bangladesh simplifies cross-border electricity trade for Nepal. Leveraging existing transmission networks can enhance efficient and cost-effective electricity exchange. The Dhalkebar-Muzaffarpur 400 kV transmission line between India and Nepal has been utilized for selling excess electricity during wet seasons [9]. While India has opened the door for Nepal to sell electricity in its power exchange market, Nepal and Bangladesh are also holding talks for the trading of power between the two countries. Bangladesh has already issued an interest to buy 500 MW of electricity from the 900 MW Upper Karnali Hydropower [20]. The Nepal Electricity Authority and Power Grid Corporation of India have signed an agreement to develop the 400 kV Butwal-Gorakhpur Cross-Border Transmission Line on the Indian side through joint investment. Nepal will, however, develop part of the cross-border transmission line on the Nepali side alone [21]. The third option is the production of green hydrogen, also called a power-to-X (PtX) system [22].

The term "power-to-X" (PtX) denotes a technology suite converting surplus electrical power, such as excess hydropower, into versatile energy carriers like green hydrogen, pivotal for clean fuel and chemical production. Clarifying the integration of electrolysis with renewable resources underscores the significance of PtX systems, emphasizing green hydrogen's potential applications and addressing its economic feasibility, specifically in utilizing surplus hydropower for competitive hydrogen production. One key process in PtX systems is water electrolysis, which involves splitting water into hydrogen and oxygen. This process enables the conversion of surplus electricity, particularly from intermittent sources, into hydrogen. The produced hydrogen can be utilized in various sectors such as chemical industries, electricity generation, and transportation, offering a versatile energy carrier [23,24]. Currently, there are three commercially available types of electrolyzers: alkaline electrolyzer (AEL), proton exchange membrane electrolyzer (PEMEL), and solid oxide electrolyzer (SOEL). Among these, AEL stands out as the most mature technology, with over a century of experience and existing MW-scale installations that demonstrate good stack efficiency [25]. PEMEL, although relatively compact and flexible in operation with low start-up time and fast response, has a shorter lifespan compared to AEL and is more expensive [26]. The scarcity and costliness of platinum-group metals, particularly platinum, essential as a catalyst in PEMEL electrodes, contribute to the higher expenses and shorter operational lifespan of PEM electrolyzers compared to AELs [27]. While Solid Oxide Electrolyzer (SOEL) technology exhibits superior efficiency reaching up to 100% LHV, surpassing AEL's 63%–71% and PEMEL's 60%–68%, its high operating temperatures (500 °C–1000 °C) present challenges in material requirements, energy consumption, system complexity, durability, and cost, limiting its widespread adoption for large-scale production [28–30]. Considering the current state of technology, AEL emerges as the better option for large-scale hydrogen production, offering a reliable and efficient solution for Nepal's energy market integration and facilitating the utilization of intermittent hydroelectricity production [31]. Declining capital expenditure (CAPEX) for water electrolysis systems, especially in China, where costs are around USD 420 per kilowatt of electrical capacity, highlights the potential for green hydrogen production in Nepal [14].

There have been few studies on the utilization of surplus hydroelectricity in green hydrogen production in Nepal. In the study [32], Thapa et al. explored the potential of green hydrogen production from surplus hydropower energy and its applications in electricity regeneration and the substitution of petroleum products in Nepal's transportation sector. The research considered different scenarios of surplus energy utilization, spanning the period from 2022 to 2030. The findings revealed a significant range of hydrogen production potential, varying from 63,072 tons to 3,153,360 tons in 2030, based on the utilization of surplus energy at 20% and 100% capacity, respectively. The research findings indicate that 1 kg of hydrogen can be produced from surplus electricity, potentially at a cost as low as 1.17 USD during the off-peak load time. In another study [14], Bhandari et al. developed the hydroelectricity generation profile and demand profiles under different scenarios; low growth, medium growth, and high growth of electricity demand. The calculated cost of hydrogen under different scenarios ranged from 4.07 USD/kg to 4.82 USD/kg. In a study of 2008 [33], Ale et al. studied the prospective utilization of off-peak hydroelectricity to produce hydrogen, aimed at substituting current fossil fuel reliance in transportation, cooking, and peak-demand electricity generation. It was found that approximately 50% of off-peak hydroelectricity could be utilized to produce green hydrogen, with the potential to produce from 27 ktonne to 140 ktonne by 2020 [34]. Nepal's abundant renewable energy, primarily hydropower, is poised to enable cost-effective green hydrogen production. Projections indicate surplus hydropower of 10, 000 MW by 2030 and 39,000 MW by 2040, potentially yielding hydrogen at less than 1 USD per kilogram by 2050. The use of green hydrogen in Nepal's chemical industry could resolve fertilizer shortages, potentially producing 2,150,000 tons of green urea from surplus hydropower, surpassing the 180,000 tons imported in fiscal 2021–22. This move supports agricultural productivity, addresses food security for many Nepalese reliant on agriculture, and offers growth potential in iron, steel, and transportation sectors through hydrogen-based technology. The authors in the study [35], did the techno-economic analysis of urea production in Nepal using hydropower. Economic, sensitivity, and uncertainty analyses were done for green hydrogen production and its conversion to green ammonia. The levelized cost of hydrogen and ammonia varied from 2845 USD/ton to 4361 USD/ton and 634 USD/ton to 1018 USD/ton, respectively. The minimum possible cost of hydrogen was calculated as 2340 USD/ton, which is equivalent to 2.58 USD/kg. The global market for green hydrogen is projected to expand, with anticipated costs plummeting to 2 USD/kg by 2030 in regions like India and Western Europe, compared to the current rate of 8 USD/kg [36,37].

It is worth noting that numerous studies have been conducted globally on the economic analysis of integrating alkaline electrolyzers with renewable energy sources, specifically solar, wind, and hydroelectricity. In Ref. [38], the authors developed an electrolysis model for hydrogen production from an Alkaline Electrolyzer, which considered the calculation of the energy expenditure and the overall energy flow within the system. The model utilized Ulleberg's model of alkaline electrolysis, which has been widely recognized in the field [39]. In Ref. [40], Rezaei et al. examined the combination of wind energy with alkaline electrolysis. The unit cost of electricity was reported as 63 USD/MWh, and the electrolyzer's power consumption was found to be 55.6 kWh/kg, with an efficiency of 20.14%. The levelized cost of hydrogen in this scenario ranged from 2.118 to 2.261 USD/kg. Similarly, in Ref. [41], Rahil et al. calculated short-term and long-term hydrogen prices for 2015 and 2030 using wind energy integrated with AEL. The electrolyzer consumption was calculated as 54.6 kWh/kg for 2015 and 50 kWh/kg with cost of hydrogen ranging from 11.87 to 12.62 USD/kg and 7.83 to 8.21 USD/kg respectively. The advancement in technology has reduced the cost of electrolyzers in the long term. Solar energy is utilized in Ref. [42]. The electricity cost ranged from 18 to 21 USD/MWh, and the electrolyzer's power consumption ranged from 49 to 54 kWh/kg. The calculated hydrogen cost for this configuration was 2.20 USD/kg in 2018 and is projected to decrease to 1.67 USD/kg by 2025.

In [43], green hydrogen production in a photovoltaic power station in Salalah city-Oman, the energy produced from the photovoltaic system and the hydrogen produced were calculated through an analytical model. The system produced about 90,910 kg/year with an investment cost of 5,301,760 €. The calculated hydrogen cost was equal to 6.2 €/kg at a discount rate of 2%. It was found that a Photovoltaic (PV) system with a total capacity of 5 MW could produce around 90,910 kg/year if only 70% of the produced electricity was converted into hydrogen. PV refers to the technology of converting sunlight into electricity through photovoltaic cells, commonly used in solar panels composed of Photovoltaic cells for renewable energy generation.

In a study [44], researchers aimed to model hydrogen production in Venezuela by considering various components of the total production cost, including consumption, investment, and operation and maintenance. Through their analysis, the authors discovered that the production cost of hydrogen was significantly lower when the percentage cost for electricity ranged between 17% and 45% of the total cost, with variations depending on the year and population considered. These findings highlight the importance of considering the cost of electricity in assessing the overall production cost of hydrogen in Venezuela.

In a study [45], the possibilities of hydrogen cogeneration in run-of-river hydropower in Slovenia were investigated. The authors examined the economic viability by considering the electricity cost of 53.91 USD/MWh. The cost of hydrogen, according to the researchers' study, is 4.16 USD/kg, demonstrating the feasibility of hydrogen cogeneration as a cost-effective energy option in the area. The tests carried out in Slovenia and the theoretical situation envisioned for Nepal both demonstrate the viability of using hydropower to produce inexpensive green hydrogen. The following table compares the data from the study in Slovenia with the data previously mentioned for Nepal:

This paper examines the possibility of producing green hydrogen in Nepal using surplus hydropower until 2030. It specifically investigates the economic feasibility of alkaline electrolysis systems and discusses the adaptability of the modeling approach and its implications. The study develops a mathematical model for alkaline electrolyzers based on experimental parameters, making it widely applicable for hydrogen generation research. It predicts surplus hydroelectricity production in Nepal and estimates hydrogen output. Results are obtained through economic analysis, assessing the viability of using surplus hydroelectricity for hydrogen production. Nepal's 15 GW hydropower capacity by 2030 could enable hydrogen production during low demand, addressing peak power demands and utilizing surplus energy [46]. This initiative enables energy producers to utilize excess energy, sold at low prices to the Nepal Electricity Authority, while also tackling climate change through cleaner energy sources like green hydrogen, promoting sustainable development.

2. Methodology

The paper develops a detailed mathematical model to analyze the electrochemical and thermal behavior of an alkaline electrolyzer system for hydrogen production. The model, as illustrated in Fig. 1, consists of an electrochemical equation to capture the electrolysis reactions and a thermal equation to account for heat transfer effects. Key elements of the model include Faraday's efficiency, voltage-current relationships, heat generation, and heat dissipation. The governing equations are derived from previous experimental studies on alkaline electrolysis cells by various authors [38,39,47–52].

The model forecasts hydrogen production potential from surplus hydropower in Nepal until 2030 by projecting capacity and demand scenarios. Surplus electricity for hydrogen production is calculated by the difference between projected capacity and demand. The electrolyzer model estimates hydrogen output from surplus electricity, showcasing its adaptability for regions with surplus renewable resources.

2.1. Hydrogen production through alkaline electrolysis

The AEL comprises two electrodes: the anode and the cathode. Facilitating the electrochemical reactions within the electrolyzer is the presence of an alkaline electrolyte (KOH or NaOH), crucial for ion transport and maintaining electrical neutrality [53]. The operating temperature of AEL is generally between 50 and 80 $^\circ C$ [54]. The alkaline electrolyzer is made up of many parallel stacks that are linked to one another. Each stack has the same number of bipolar cells organized in it, and a central anode is shared by two cathode electrodes at either end. One of the electrolytes employed is a 25% weight-based KOH solution.

To comprehensively represent the power consumed by the AEL, it is necessary to undertake an in-depth analysis of the energy consumption by the electrolyzer stack and the other components within the system. Alkaline water electrolyzers can be stacked in multiple stacks, with multiple numbers of cells in each stack. This makes it possible to scale up the electrolyzer to MW scale by adding up the stacks [55].

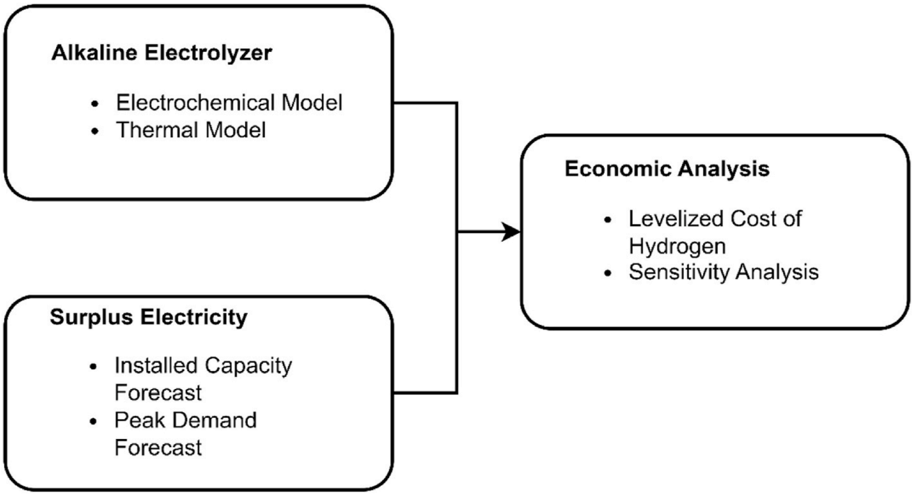

Fig. 1. General methodology framework.

The alkaline hydrogen production system in this paper considers.

- An electrochemical model describes the electrical behavior of the electrolyzer stack and includes Balance of Plant (BOP) components such as water purification systems, gas separators, and power electronics essential for safe operation.
- and a thermal model, describing the thermal behavior of the stack including heat loss to the environment.

In this study, the mathematical models representing the electrolyzer system are constructed as MATLAB function blocks, within the Simulink environment [56]. These function blocks represent essential building blocks for accurately modeling the alkaline electrolyzer system. The key model accounts for electrochemical and thermal behavior, while MATLAB models simulate the Balance of Plant (BOP) components. Integrating these models enables a comprehensive analysis of the system's behavior and performance.

The models for alkaline electrolyzers are generally complex due to the presence of various multiphysics phenomena. To achieve a detailed representation of these models, several researchers have incorporated phenomena such as concentration overpotentials arising from concentration gradients of reactant species such as hydrogen gas [57], mass transport limitations from the diffusion of species through the electrolyte [58], effects of the separator on species transport and current distribution [59], gas void fraction changes and bubble dynamics that impact surface area and reaction kinetics [60], and electrode surface recovery dynamics as bubbles detach and expose fresh reactive sites [61]. Various factors, including concentration overpotentials, diffusion, separator effects, bubble dynamics, and recovery mechanisms, influence alkaline electrolyzer performance. Understanding these effects allows for a detailed characterization of electrolyzer behavior [62]. Considering all these phenomena, even the steady-state models can be challenging to develop. To perform dynamic simulations, a simplified empirical relationship, as given by Ulleberg et al. [39] is employed. This relationship incorporates experimental correlations to estimate the Faraday efficiency and the voltage required by the electrolyzer. The electrical energy consumed by the BOP is considered a percentage of the electricity consumed by the main electrolyzer stack. This percentage is calculated using a correlation equation obtained from the experimental data utilized in this study [52].

2.2. Electro-chemical model

The alkaline electrolyzer is constructed by connecting multiple stacks in parallel, with each stack containing an equal number of cells. The stacks are composed of a bipolar configuration, where two cathode electrodes are located at both ends, sharing an anode in the middle. The electrolyte utilized in this system is taken as a solution with a concentration of 25% KOH by weight.

The hydrogen production rate is directly proportional to the electrical current in the circuit which is the transfer rate of electrons to the electrodes [46]. It can be expressed in terms of stack current I, number of cells per stack N_{cell} and Faraday efficiency $\left(\eta_{faraday}\right)$ as:

$$\dot{n}_{H_2} = \eta_{faraday} \cdot I \cdot \frac{N_{cell}}{zF} \tag{1}$$

Here, z is the number of moles of electrons transferred in the reaction, which is 2 in this case and $\eta_{faraday}$ is the efficiency of the stack to carry out the reaction. All the other mathematical relations needed for developing the MATLAB function blocks along with their validation is provided in the supplementary material (see Table 1).

To successfully integrate the modeled alkaline electrolyzer with the surplus electricity, a crucial step is to scale up the size of the electrolyzer. The MATLAB model simulates a single electrolyzer stack comprising multiple cells connected in series, which, alongside the BOP units, consumes 1 MW of electricity. To determine the feasibility of utilizing large-scale surplus electricity generation, the electrolyzer size can be scaled up by increasing the number of 1 MW stacks in parallel. Commercial electrolyzers with 1 MW stack capacity are readily available, and multiple stacks can be combined to build larger systems above 1 MW as needed. With multiple 1 MW stacks in parallel, the electrolyzer system can flexibly match the surplus renewable electricity availability for a given location and timeframe. The input parameters used are shown in Table 2 below.

The alkaline electrolyzer nominal pressure of 9.44 bar was chosen to match typical operating conditions and experimental validation data from a previous study [38]. This pressure level allows stable electrolyzer operation and hydrogen production. The nominal temperature of 353 K (80 °C) represents the normal operating point for many commercial alkaline electrolyzer systems. At higher temperatures, the electrode overpotentials are reduced, improving the overall electrolyzer efficiency.

The maximum Faraday efficiency of 68% was achieved with the

Table 1
Hydrogen Cogeneration Comparison: Slovenia vs. Nepal.

Parameter	Slovenia	Nepal
Electricity Cost	53.91 USD/MWh	50 USD/kWh
Cost of Hydrogen	4.16 USD/kg	2.58 USD/kg

Table 2
Scaled-up model input parameters for 1 MW stack.

Items	Units	Value
Current	A	220
Number of Cells	[−]	2058
Area	cm^2	2095
Pressure	Bar	9.44
$T_{nominal}$	Kelvin	353
Simulation Time	H	1

alkaline electrolyzer modeled in this work, as validated against experimental data from Ref. [52]. While more advanced electrolyzers with higher efficiencies up to unity are now commercially available [63], the current density was not modified in the model. The model assumptions and governing equations still hold for an electrolyzer with a larger Faraday efficiency. However, the higher efficiency would increase the hydrogen production calculated by the model. Further validation of the model predictions against data from a state-of-the-art electrolyzer stack could be useful to ensure the model provides accurate results for modern systems. Overall, the model provides valuable insights into the potential for hydrogen production from surplus hydropower in Nepal, but the absolute production values may be conservative estimates given the rapid improvements in electrolyzer efficiency. Considering this advancement in electrolyzer technology, Faraday efficiency is considered to be unity. Refer to Table 3 for the scaled-up model simulation results.

2.2.1. surplus electricity

Surplus electricity (SE) is the electricity available beyond immediate demand. There is a consistent availability of SE during specific times of the year in Nepal. The majority of hydroelectric projects in Nepal operate on the Run of River principle [64], meaning they lack storage reservoirs to collect water for later use. As a result, the production of hydroelectricity is directly influenced by the amount of water flowing through the river. Wet seasons (i.e., June to September), characterized by monsoon rains and increased river flow, witness the highest levels of electricity production. Conversely, dry seasons (i.e., October to May) experience reduced water flow, leading to lower electricity production. The monsoon season from June to September brings heavy rains that feed the rivers and enable hydropower plants to operate at full capacity. During the dry winter and spring months, snowmelt decreases, and river flows drop, leading to reduced hydroelectric generation [65]. During the dry season, Nepal has relied on electricity imports from neighboring countries to meet the demand [66]. To fulfill the demand for energy during dry seasons, more hydropower stations are required. As a result, during wet seasons, solar electrolyzer output will continue since current hydroelectric projects will continue to create excess electricity.

The SE can be calculated as the difference between these two variables i.e. generation and demand, as indicated by equation (2). It is important to note that both electricity generation and demand are not constant and can vary throughout the day and even across different times of the year. To obtain a conservative estimation of SE, a method, as demonstrated by Thapa et al. [32] for hydroelectricity, involves subtracting the total installed capacity (TIC) from the annual peak load demand (PL) and multiplying it by the average capacity factor (CF) for hydropower, as in equation (3). It gives the average value of surplus electricity above peak load demand. The capacity factor for hydropower plants is the ratio of the actual electrical energy output achieved over a year to the maximum theoretical electrical energy output that could be attained during that same period [67]. The CF is 0.65 as per the recent report of 2021/22 [7]. This approach offers a reliable means of calculating SE as it accounts for the dynamic nature of electricity generation and demand, and it also considers the capacity factor, which reflects real-world operational factors that determine actual power output. The capacity factor serves as a performance indicator for hydropower plants, reflecting the actual energy output achieved relative to the maximum potential output.

Table 3
Scaled-up model simulation results.

Items	Units	Value
Hydrogen Produced	$[Nm^3/h]$	181.3
Cell Voltage	[V]	2.1
Faraday Efficiency	[−]	1
Stack Power	[kW]	988.1
BoP Power	[kW]	12.8
System Power	[kW]	1000.9
Specific Energy Consumption	[kWh/kg]	57.7

$$SE = Generation - Demand \tag{2}$$

$$SE = (TIC - PL)^* \, CF_g{}^* 8760 \tag{3}$$

Here, CF_g is the capacity factor of electricity generation taken on average per year.

The TIC of hydropower in Nepal exhibits yearly variations. This fluctuation is primarily attributed to the ongoing construction of hydropower projects. To accurately determine the TIC, it is necessary to consider the commercial operational dates (COD) of these under-construction hydropower plants. Fig. 2 presents a forecast of the TIC in Nepal up to 2030, adapted from Ref. [14]. The figure indicates a large increase in hydropower installations starting from 2022, with a projected saturation point after 2028 to 10 GW. It is important to note that the absence of further increases in TIC beyond 2028 in the forecast is due to the utilization of under-construction hydropower projects and their expected COD dates.

The Nepal Electricity Authority (NEA) and Water and Energy Secretariat (WECs) have conducted a comprehensive study on energy demand projection in Nepal [68,69]. As the country's public sector electric utility, NEA actively forecasts regular demand. This process involves extrapolating historical data and analyzing factors such as grid extension, population growth in grid-connected areas, and overall economic growth. In this study, the NEA projection, which is a simple peak load forecasting, is used, as outlined in Fig. 3. In 2020, the peak load was projected as 2225.7 MW, and by 2023, it is projected to reach 3366.0 MW, indicating substantial growth within a short period. Looking ahead to 2030, the peak load is expected to be 6848.5 MW.

When it comes to utilizing surplus energy for hydrogen production, it is not feasible to use all of it solely for that purpose. This is because a considerable amount of energy is needed for tasks like transportation, compression, and converting it into ammonia, for instance. Therefore, this paper explores three different scenarios with varying levels of SE utilization for hydrogen production.

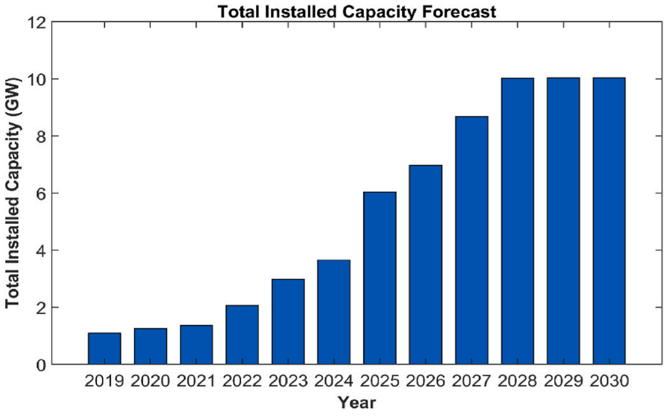

Fig. 2. Forecast of the total installed capacity (TIC) [14].

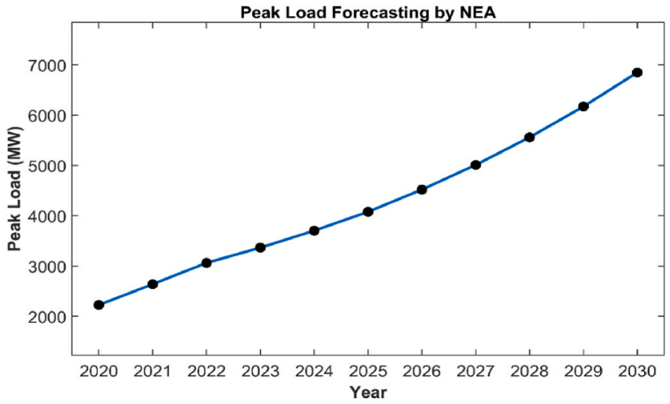

Fig. 3. NEA forecasted peak load [68].

Case 1. 50 % SE use (C1)

Case 2. 80% SE use (C2)

Case 3. 100% SE use (C3)

In the first scenario, 50% of the SE is utilized, indicating a lower use of SE for hydrogen production. The second scenario involves 80% utilization, where almost all the SE is dedicated to hydrogen conversion, while the remaining 20% is utilized for processing hydrogen for its end use. The third scenario, involving 100% surplus utilization, is impractical, among others, due to the absence of infrastructure in Nepal for immediate consumption of the produced hydrogen. Despite its infeasibility, this scenario is included in the study to understand the outcomes of complete SE utilization solely for hydrogen conversion.

2.3. *Levelized cost of hydrogen (LCOH)*

The LCOH, represented by equation (4), is calculated by dividing the total lifetime cost by the total hydrogen production during a specific period. To expand equation (4), the approach proposed by the author [70] is employed as equation (5), where N is the total life of the electrolyzer stack, CAPEX is capital expenditure, operational expenditure (OPEX), tax rate (TR), revenue from hydrogen sales ($REVH_n$), discount factor (r), system degradation rate (DR), and annual mass of hydrogen production (mH2). The revenue from hydrogen sales is calculated using equation (6), where SP_{H_2} is the selling price of hydrogen. CAPEX represents the cost of setting up the electrolyzer plant, encompassing expenses related to the electrolyzer, BOP, and installation. OPEX accounts for the yearly operational and maintenance costs, as well as electrical expenses. Additionally, the LCOH equation incorporates the revenue tax, which is applied to the revenue generated from hydrogen sales. The DR is employed to simulate the gradual degradation of the system over time, ensuring that 10% of the system is degraded after 80,000 h of plant operation [71].

$$LCOH = \frac{Total\ Lifetime\ Cost}{Total\ Lifetime\ H_2\ Production} \tag{4}$$

$$LCOH = \frac{CAPEX + \sum_{n=1}^{N} \frac{OPEX_n}{(1+r)^n} + TR \sum_{n=1}^{N} \frac{REVH_n}{(1+r)^n}}{\sum_{n=1}^{N} \frac{m_{h2}(1-DR)^n}{(1+r)^n}} \tag{5}$$

$$\sum_{n=1}^{N} \frac{REVH_n}{(1+r)^n} = \sum_{n=1}^{N} \frac{m_{H2}(1-DR)^n . SP_{H_2}}{(1+r)^n} \tag{6}$$

Determining accurately the cost of the electrolyzer poses a challenge as the study aims to calculate LCOH for different values of SE and over different years. To overcome this challenge, a solution is proposed by utilizing the CAPEX projection equation as shown by equation (7) introduced by Reksten et al. in the research [72] and the projection parameters the value of CAPEX for different scales of electrolyzer were calculated. The CAPEX projection equation is empirically derived from a comprehensive literature review and fitting to real cost data for alkaline electrolyzers over time. The key innovation was accounting for both plant size and technology improvements in the cost model. The projected cost encompasses not only the cost of the electrolyzer stack but also includes the balance of the plant components such as water purification systems, gas separators and driers, pumps, valves, and all the necessary power electronics and rectifiers. The costs associated with civil works and plant installation are not included in the projected cost. Instead, these costs are separately incorporated as a percentage of the CAPEX as in Table 3.

$$CAPEX = \left(301.04 + \frac{11603}{\gamma} \cdot \gamma^{0.649}\right) \left(\frac{\theta}{2020}\right)^{-27.33} \tag{7}$$

Here, CAPEX is cost the cost of electrolyzer (USD/kW), γ is electrolyzer plant capacity (kW) and θ is the installation year.

Figs. 4 and 5 show the CAPEX cost of the electrolyzer per kW for increasing installed capacity and year of installation, respectively. From 1 MW to 100 MW, the cost of the electrolyzer experiences a significant decrease, while beyond that point, the cost reduction becomes more gradual. To visually represent this trend, a logarithmic plot is employed, which better highlights the minor decrease in cost observed after reaching the 100 MW mark. For instance, in the year 2025, the cost of the electrolyzer decreases from 1240 USD/kW for a 1 MW plant to 460 USD/kW for a 100 MW plant and further decreases to 365 USD/kW for a 1 GW plant. Additionally, the analysis indicates a linear decrease in the CAPEX of the electrolyzer over time. However, the difference in CAPEX between different years becomes relatively minimal for higher installed capacity plants.

Table 4 includes the parameters required for the LCOH calculation. The scaled model stacks are added to consume all the available SE during operational hours within a year. As the SE is only available during wet seasons, a CF of 50% is assumed for the installed electrolyzer plant, resulting in the electrolyzer running for 4320 h per year. The installation cost and operational & maintenance (O&M) cost are considered as a percentage of the electrolyzer cost. A higher discount rate of 8% is used in this study. In the renewable energy sector of Nepal, the tax rate is typically 20%, which is also adopted for this study [73]. Recent literature indicates that the alkaline electrolyzer stack has a lifespan of approximately 80,000 h, requiring replacement after that point [74]. However, since the installed plant will operate at 50% CF and reach the 80,000-h limit in the 18th year, which is within the plant's 20-year lifetime, stack replacement is not considered. But, to account for system degradation over time, a DR is chosen such that it degrades system performance by 10% in terms of hydrogen production over the

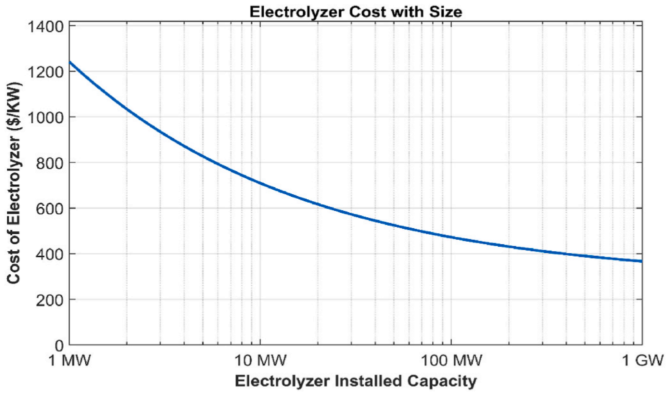

Fig. 4. Electrolyzer Cost with Installed Capacity for the year 2025.

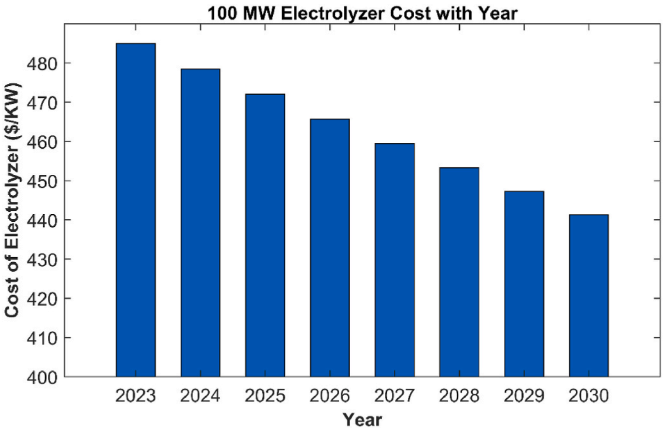

Fig. 5. Cost of 100 MW Electrolyzer with year.

Table 4
Economic analysis parameters.

Items	Value	Unit
System Installation Cost	20	% of CAPEX
O & M	5	% of CAPEX/year
Electricity price [14]	0.051	USD/kWh
Discount Rate (r)	8	%
Tax Rate (TR) [73]	20	% of revenue
Stack Lifetime (N)	80,000	hours
Capacity Factor (CF)	50	%
Degradation Rate (DR)	0.525	%/year
Hydrogen SP [71]	7.5	USD/kg

lifetime.

The average purchase price of electricity for the NEA from Independent Power Producers is 0.051 USD/kWh [14]. However, it should be noted that the electricity price distributed to the industry by the NEA may differ significantly depending on the time of day. Table 5 presents the electricity prices for the 132 kV industrial line during peak, off-peak, and normal times in the year 2022. As SE is available beyond the peak demand, it is expected to become cheaper by the year 2025. However, it is worth noting that the interest in selling electricity to neighboring countries may prevent a significant decrease in prices.

2.4. Sensitivity analysis

Sensitivity analysis is widely employed for identifying critical input parameters. The present study conducts a sensitivity analysis to determine the effects of various variables on the LCOH. The analysis focuses on the base case of the year 2025, utilizing 50% of SE for that specific year. To assess the sensitivity of the LCOH, the economic parameters listed in Table 3 were systematically increased and decreased by 20%, and the resulting LCOH values were compared with the base case LCOH.

3. Results

This section includes the SE available from the year 2025–2030, the size of the electrolyzer, the amount of hydrogen produced, and the levelized cost of hydrogen for different levels of SE. Additionally, the results of the sensitivity analysis are presented, providing insights into the sensitivity of the model to different input parameters.

Table 5
NEA electricity price for industrial 132 kV line [7].

Time	Price (USD/kWh)
Peak Time (17.00–23.00)	0.077
Off Peak Time (23.00–5.00)	0.036
Normal Time (5.00–17.00)	0.063

Fig. 6 illustrates the proportion of peak electricity demand and SE across different years. Starting from 2020 until 2024, there is a shortage of electricity during peak demand in Nepal. Consequently, the country relies on importing electricity to meet the demand. In this study, the baseline is the peak load, which is used to estimate the SE for a conservative approximation. This approach always ensures the calculation of the minimum SE available. Thus, until 2024, there will be no SE beyond the peak demand. Going further in 2025, there will be a minimum of 11 TW-hours (TWh) of SE available beyond the peak demand, and this surplus will gradually increase over time. By 2028, the SE will reach a maximum of approximately 25 TWh. Although the TIC remains the same from 2028 to 2030 (Fig. 2), as it is forecasted based on the COD and without considering upcoming hydropower projects, the peak load demand is projected to increase during those years as shown in Fig. 3. As a result, the calculated SE in this study shows a lower SE estimate in 2030, approximately 18 TWh.

The required size of the electrolyzer for utilizing different cases of SE usage, denoted as C1 (50% SE), C2 (80% SE), and C3 (100% SE) for the years 2025–2030, is presented in Fig. 7. Analysis of the figure reveals a linear relationship between the electrolyzer size, and the SE usage cases (C1, C2, and C3). Specifically, in the year 2025, the C1 case requires a 1.3 GW electrolyzer plant, the C2 case necessitates a 2 GW plant, and the C3 case demands a 2.5 GW electrolyzer plant. For the C1 case, the electrolyzer size reaches a maximum of 2.9 GW in 2028, corresponding to the availability of the maximum amount of SE. In the years 2026, 2027, 2029, and 2030, the sizes are 1.6 GW, 2.4 GW, 2.5 GW, and 2.1 GW, respectively. The decrease in 2029 and 2030 is because demand growth rate increases in those years, but the total installed capacity is the same. For the C2 case, the required electrolyzer sizes range from 2 GW to 4.6 GW from 2025 to 2030. Similarly, for the C3 case, the sizes range from 2.5 GW to 5.8 GW over the same period. The maximum electrolyzer sizes required for this decade occur in 2028, amounting to 2.9 GW, 4.6 GW, and 5.8 GW for C1, C2, and C3, respectively.

Fig. 8 illustrates the potential for sizable growth in hydrogen production through alkaline electrolysis of surplus hydropower in Nepal from 2025 to 2030. The increasing production trends align with the growing electrolyzer capacities required, as discussed earlier. Under the most conservative scenario C1 utilizing 50% of surplus electricity, hydrogen production is forecasted to rise from 91 ktonne/year in 2025 to 148 ktonne/year in 2030. The intermediate scenario C2 sees even greater growth, with projected production climbing from 145 ktonne/year to 236 ktonne/year over the same period by tapping into 80% of surplus electricity. Finally, the most ambitious scenario C3 allowing full

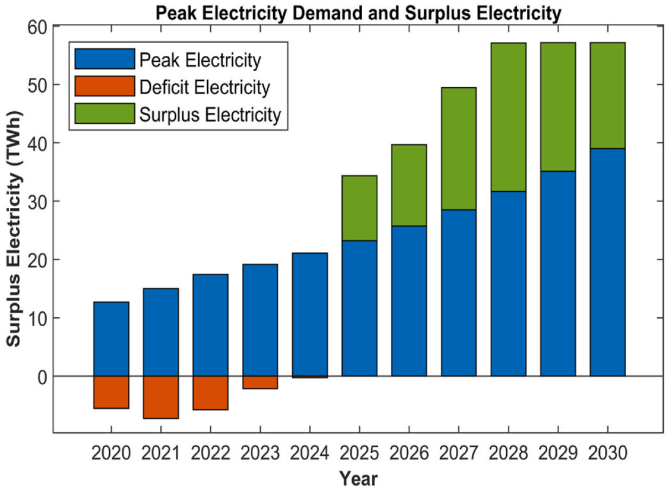

Fig. 6. Calculated SE with year.

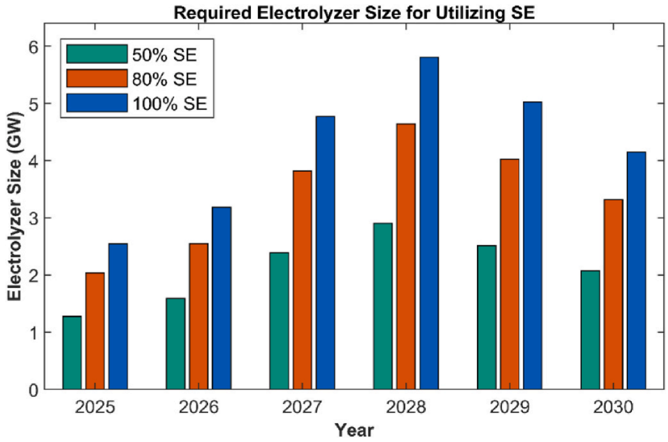

Fig. 7. Electrolyzer size for different cases of SE

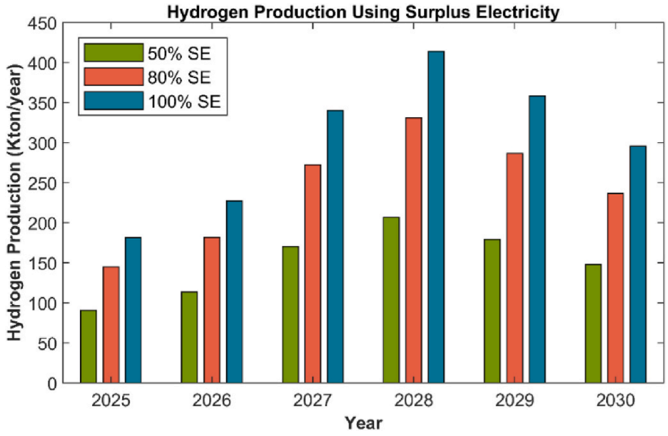

Fig. 8. Hydrogen production for different cases of SE

utilization of surplus electricity is anticipated to boost hydrogen output from 181 ktonne/year to 296 ktonne/year between 2025 and 2030. The maximum production levels are achieved in 2028, reaching 207 ktonne/year, 331 ktonne/year, and 414 ktonne/year for scenarios C1, C2, and C3, respectively. Overall, Fig. 8 highlights the potential for Nepal's surplus hydropower resource to promote a sizable expansion of green hydrogen production through alkaline electrolysis in the coming years.

Fig. 9 shows the LCOH calculation for each SE use case. In the C1 case, the LCOH is at its maximum value in 2025, amounting to 5.72 USD/kg, and gradually decreases to a minimum of 5.63 USD/kg by 2030. Similarly, for the C2 case, the LCOH starts at 5.69 USD/kg in 2025 and steadily decreases to 5.61 USD/kg in 2030. In the C3 case, the LCOH is 5.68 USD/kg in 2025 and decreases to 5.59 USD/kg over the same period. The observed trend in all cases is a consistent decrease in LCOH over time. This can be attributed to the declining CAPEX of the electrolyzer within a year, as depicted in Fig. 5. Although there is a decrease in LCOH, the reduction is relatively small. However, the reduction is relatively small because the CAPEX change has a minor impact on LCOH for large-scale electrolyzers. Over five years, the decrement amounts to 0.093 USD/kg, 0.0864 USD/kg, and 0.0835 USD/kg for the C1, C2, and C3 cases, respectively which are the values for the decrease in the value of LCOH by decrement of the value of the initial CAPEX value calculated for the modeled electrolyzer. Additionally, when comparing different cases within the same year, the difference in LCOH is relatively low. Fig. 6 shows that for electrolyzers larger than 100 MW, the price difference decreases gradually. Therefore, even when the installed electrolyzer utilizes 50% of the SE, operating at a gigawatt (GW) scale, the CAPEX difference remains minimal. Little variations in capital and operational expenses cause LCOH to stay constant throughout a range of solar electrolyzer usage capacities and installation years, suggesting insensitivity to these variables.

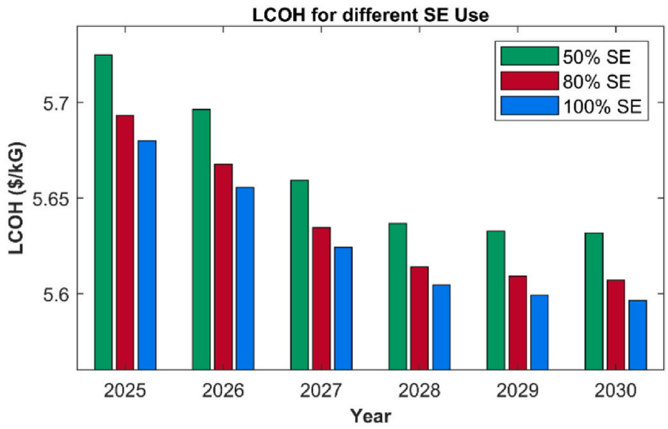

Fig. 9. Lcoh for different cases of SE use.

A sensitivity analysis is conducted using the C1 case as the base value. The base value consists of 5.5 TWh of SE, requiring a 1.3 GW alkaline electrolyzer capable of producing 91 ktonne/year of hydrogen. The levelized cost of hydrogen for this base case is 5.72 USD/kg. To assess the sensitivity of economic parameters, Table 3 is adjusted by increasing and decreasing them by 20%, and the resulting LCOH is calculated. The changes in input parameters are visualized in Fig. 10, highlighting that the variation in electric cost has the greatest impact on LCOH. Furthermore, the CAPEX, TR, CF, and SP of hydrogen significantly influence LCOH, while O&M, discount rate, and DR have the least effect.

The sensitivity analysis in Fig. 10 shows the impact of different parameters on the LCOH. When the initial CAPEX value is increased by 20%, the LCOH increases by 0.2 USD/kg, resulting in 5.92 USD/kg. This increase is seen because a higher CAPEX leads to greater total costs spread over the project lifetime, which directly contributes to the LCOH calculation. Conversely, when the CAPEX value is decreased by 20%, the LCOH decreases by 0.19, reaching 5.53 USD/kg. This means there is fractional reduction in LCOH with fractional reduction of CAPEX. The variation in LCOH is symmetric for both increments and decrements of the CAPEX value, indicating a noticeable difference. This occurs because the CAPEX has a proportional effect on the capital costs. On the other hand, the effect of O&M variation is relatively small, with an increase of 0.07 resulting in 5.66 USD/kg, and a decrease of 0.06 leading to 5.79 USD/kg. This minor change is observed because O&M costs comprise a

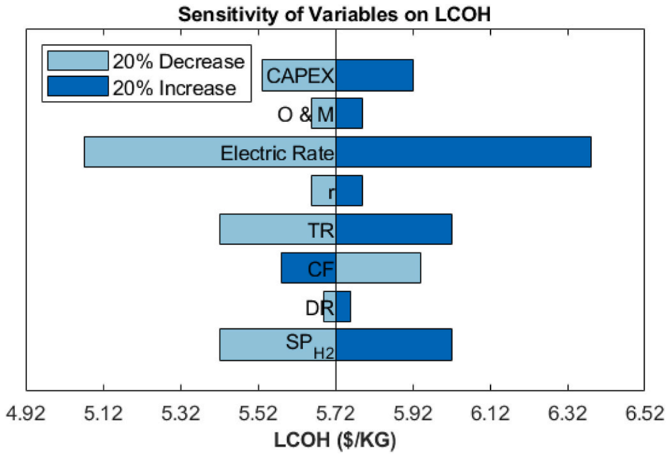

Fig. 10. Sensitivity of variables on LCOH

smaller share of the overall hydrogen production costs compared to capital costs. So, LCOH is more sensitive to changes in CAPEX versus O&M costs given their relative contribution to the hydrogen production costs.

The cost of electricity demonstrates the maximum variation in LCOH due to its significant contribution to the OPEX. Since the electricity utilization for hydrogen production is on the order of TWh, even a slight change in the electricity price (in USD/kWh) has a substantial impact on the total electricity cost. This large electricity demand magnifies the effect of electricity price fluctuations on the overall operating expenses. Decreasing the cost of electricity by 20% leads to a decrease in LCOH from 5.72 to 5.07 USD/kg, while increasing the electric cost by 20% results in an increase in LCOH to 6.38 USD/kg. The electricity price has a proportional impact on the LCOH because electricity accounts for the largest share of operating costs. Even minor variations in electricity rates are amplified into noticeable LCOH changes due to the large quantities of electricity required for electrolysis.

The discount rate has little effect on LCOH, with an increase leading to 5.79 USD/kg and a decrease resulting in 5.66 USD/kg when varied by 20% in either direction. In contrast, the Tax Rate demonstrates a considerable effect on LCOH, with an increase of 20% resulting in 6.03 USD/kg and a decrease leading to 5.42 USD/kg. The Capacity Factor (CF) exhibits an inverse effect, where an increase in CF leads to an increase in LCOH and a decrease in CF leads to a decrease in LCOH. This can be explained by the need for a larger capacity electrolyzer to utilize the same amount of Surplus Electricity (SE) when CF is low, thereby increasing the CAPEX. The LCOH increases to 5.94 USD/kg when CF increases and decreases to 5.58 USD/kg when CF decreases from 50%.

The discount rate has little effect on LCOH, with an increase leading to 5.79 USD/kg and a decrease resulting in 5.66 USD/kg when varied by 20% in either direction. This minor impact is observed because the discount rate only affects the annualization of capital costs, while operational expenses are unchanged. In contrast, the Tax Rate demonstrates a considerable effect on LCOH, with an increase of 20% resulting in 6.03 USD/kg and a decrease leading to 5.42 USD/kg. The Capacity Factor (CF) exhibits an inverse effect, where an increase in CF leads to an increase in LCOH and a decrease in CF leads to a decrease in LCOH. This opposite trend occurs because a lower CF requires a larger electrolyzer capacity to utilize the same amount of Surplus Electricity (SE), thereby increasing the CAPEX contribution to LCOH. The LCOH increases to 5.94 USD/kg when CF increases and decreases to 5.58 USD/kg when CF decreases from 50%.

The System Degradation Rate (DR) has the lowest effect on LCOH, with an increase of 20% resulting in 5.76 USD/kg and a decrease of 20% leading to 5.69 USD/kg. Finally, the Selling Price (SP) of hydrogen has a noticeable impact on LCOH, as it affects the overall revenue generated from hydrogen sales, which in turn influences the tax used in the LCOH formula. When the SP increased by 20%, the LCOH increases to 5.02 USD/kg, and when the same SP is decreased by 20%, the LCOH decreases to 5.42 USD/kg.

Fig. 11 provides a further understanding of the relationship between LCOH and electricity rate. It can be seen that LCOH changes linearly with increasing electric cost costs. Two cases are considered, one with a hydrogen SP of 7.5 USD/kg and the other with a hydrogen SP of 9 USD/kg. Regardless of the electric cost, the LCOH changes with a constant step for different SP of hydrogen. Table 4 presents the electricity prices in Nepal provided by NEA for peak time (17:00–23:00), off-peak time (23:00–5:00), and normal time (5:00–17:00), which are 0.077 USD/kWh, 0.036 USD/kWh, and 0.063 USD/kWh, respectively. These prices exhibit significant variation. For a hydrogen SP of 7.5 USD/kg, the LCOH corresponding to the peak time price is 7.39 USD/kg, while for normal time and off-peak time prices, it is 6.49 USD/kg and 4.76 USD/kg, respectively. When the hydrogen SP increases to 9 USD/kg, the LCOH for peak time, normal time, off-peak time, and the base price are 7.69 USD/kg, 6.79 USD/kg, 5.06 USD/kg, and 6.02 USD/kg, respectively. As the SP of hydrogen increases, the LCOH shifts by a constant value. This is due to the utilization of the tax rate in the LCOH calculation. When the SP of hydrogen increases, the revenue also increases, resulting in a higher overall tax burden, thus increasing the LCOH. However, despite the higher LCOH, selling hydrogen at a higher price yields greater profits in return.

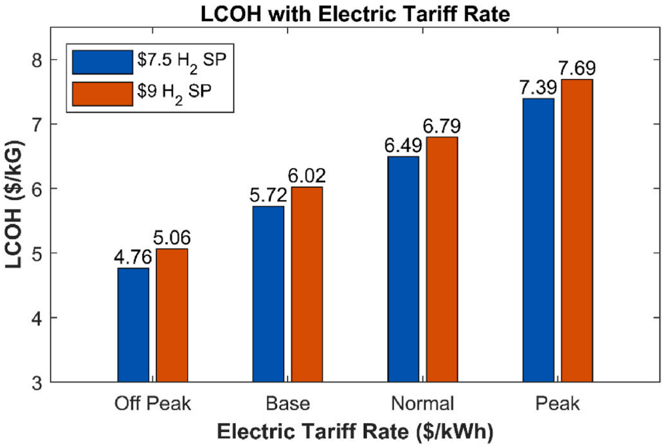

Fig. 11. Electric cost effect on LCOH

Fig. 12 presents additional calculations of LCOH for different Tax rates, ranging from no tax rate to 20% of the TR. It is observed that the TR does not exceed 20% due to the project falling under the energy sector, which already has a tax rate of 20%. This rate is lower compared to other sectors, which typically have tax rates of 25% and 30%. When there is no tax at all, the LCOH can decrease significantly to as low as 4.22 USD/kg. Importantly, this value is independent of the hydrogen SP. As the tax rate increases from 5% to 10%, 15%, and 20%, the LCOH linearly increases from 4.60 USD/kg to 4.97 USD/kg, 5.35 USD/kg, and 5.72 USD/kg, respectively. While the LCOH values obtained are lower than the assumed hydrogen selling price of 7.5 USD/kg, government support through incentives and favorable policies could further reduce costs and encourage private sector investment in scaling up hydrogen production. This could lead to even lower LCOH through economies of scale and accelerate the adoption of hydrogen as an energy carrier.

Fig. 13 illustrates the impact of CF on LCOH. In the range of 10%–50% CF, the LCOH decreases rapidly from 9 USD/kg to 5.72 USD/kg. Beyond that range, the decrease becomes more gradual, reaching 5.38 USD/kg for an 80% capacity factor. The reason for the higher LCOH at lower CF is that a lower CF implies fewer operating hours available for the electrolyzer plant to utilize all the SE within that period. Consequently, a higher capacity plant is required, which increases the CAPEX cost of the electrolyzer and other economic parameters that depend on

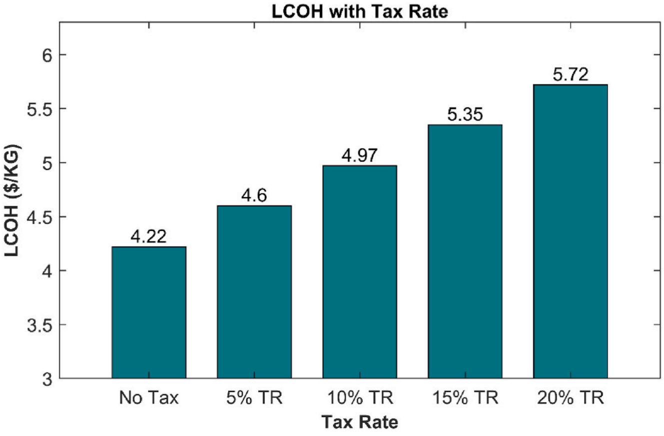

Fig. 12. Tax rate effect on LCOH

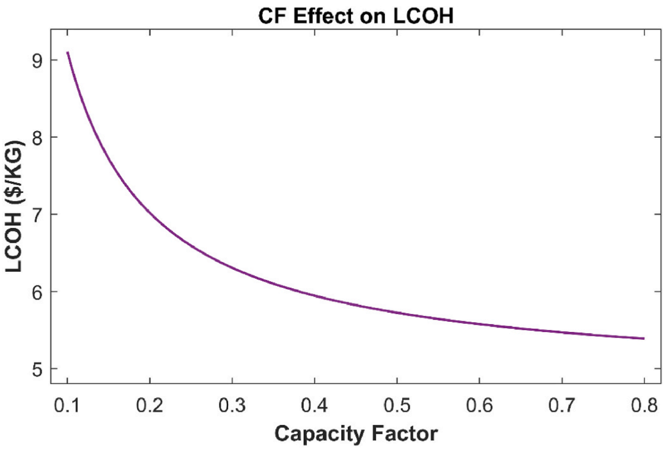

Fig. 13. Electrolyzer CF effect on LCOH

CAPEX. As the CF increases, the plant capacity decreases, leading to an overall decrease in LCOH.

The outcomes show the amount of hydrogen produced, the sizes of electrolyzers, the availability of SE from 2025 to 2030, and the levelized cost of hydrogen at different SE levels. The model's sensitivity to various input parameters is demonstrated via a sensitivity study which showed Nepal has power shortages between 2020 and 2024 during periods of high demand, but beginning in 2025, there is a surplus of SE. This surplus peaks in 2028 at around 25 TWh, but by 2030, it has dropped to about 18 TWh as a result of higher peak load demand. Calculations of electrolyzer sizes under various scenarios of SE consumption reveal a linear connection with SE usage, but by 2030, alkaline electrolysis is expected to produce a large amount of hydrogen. LCOH estimate is quite sensitive to the electricity price assumption and could potentially decline significantly if surplus power is available at lower tariffs. The sensitivity analysis highlights the outsized influence of the electricity price, indicating the need for clear surplus electricity pricing policies and mechanisms to enable bankable investments in electrolytic hydrogen. The calculated levelized cost of 5.65 USD/kg is competitive with other renewable hydrogen pathways in Nepal but remains above conventional steam methane reforming costs [75]. Tax rates significantly affect hydrogen's levelized cost. The base case assumes a 20% tax rate, but eliminating taxes could reduce the cost to 4.22 USD/kg, while a 10% rate lowers it to 4.97 USD/kg. Such information obtained highlights the effect of various parameters on the LCOH of hydrogen, underscoring the Strong forecasting is required, as well as regulatory measures that acknowledge uncertainty in surplus resource estimates and future power price, to lower investment risks.

4. Discussion

The methodology developed in this paper provided a useful framework to model alkaline electrolyzers and scale up the systems to match available renewable resources. Modeled Simulink blocks were used to scale up capacity and simulate alkaline electrolysis in the MATLAB model. However, uncertainties remain in the lab-scale to commercial system performance, indicating that optimization should be coupled with the model to increase its dependability. The electrochemical and thermal equations capture the key physics of the electrolysis process while using experimentally derived coefficients allows flexibility in representing different commercial electrolyzer units. This physics-based yet empirically fitted modeling approach enabled reasonably accurate projections of electrolyzer performance at scale. The methodology is also replicable, allowing the model to be adapted using data from other electrolyzer technologies.

The MATLAB model provided the core simulation platform to represent the alkaline electrolysis system and generate results for techno-economic analysis. Using modular Simulink blocks, the model scales up electrolysis capacity by simulating additional 1 MW stacks in parallel. However, uncertainty remains around how lab-scale performance translates to commercial megawatt systems. To enhance reliability, the model could couple electrolyzer simulations with optimization to determine optimal operating points while adding constraints. Expanding the model boundary to include storage tanks, compressors, and gas pipelines would also improve system-level analysis but increase complexity.

Taxes on hydrogen revenue directly increase production costs, suggesting a need for government incentives to scale up electrolysis. However, reducing tax revenue might hinder infrastructure development. Alternatively, subsidizing electricity prices for electrolysis could be considered. This analysis underscores the impact of fiscal policies on hydrogen costs, shaping Nepal's electrolysis-based production growth. Policymakers can leverage these insights from techno-economic modeling to stimulate the sector efficiently.

Furthermore, over time, the levelized cost of hydrogen (LCOH) steadily declines due to factors such as capacity factor, tax rate, CAPEX, and electricity cost. Because even small changes in the price of energy have a significant impact on LCOH, it is crucial to maximize SE use to cut expenditures. The adoption of hydrogen production and private-sector investment might be accelerated by government incentives and regulations that further reduce LCOH. In addition to it, the LCOH value is less affected by discount rate.

In summary, the paper develops a sound methodology for modeling and scaling alkaline electrolysis systems for grid-integrated hydrogen production. The Nepal case study provides useful insights into harnessing surplus renewables. However, uncertainty in the surplus resource estimate and future electricity prices warrants caution in the national projections. More robust forecasting and policies on electricity pricing and access will be key to de-risking investments for electrolytic hydrogen. The modeling approach could also be enhanced by adding flexibility for dynamic operation.

5. Conclusion

This study develops a mathematical model to analyze the electrochemical and thermal characteristics of an alkaline electrolyzer system for hydrogen production from surplus hydropower in Nepal. The techno-economic analysis demonstrates the feasibility of utilizing the growing surplus of renewable electricity for large-scale, low-cost green hydrogen generation.

The modeling approach enables easy estimation of hydrogen production potential and system scaling. The results project 91–414 ktonne/year of hydrogen can be produced from surplus hydropower by 2030, with levelized costs of 5.59–5.72 USD/kg. The findings highlight the role of key economic factors in changing the costs.

Overall, this work provides a robust, replicable methodology to evaluate green hydrogen systems powered by excess hydropower worldwide. The model can assist in planning and development of such sustainable projects to advance the hydrogen economy.

CRediT authorship contribution statement

Anup Paudel: Conceptualization, Methodology, Writing-review and editing, Formal analysis, Writing – original draft, Data-curation, Validation, Resources. **Bishwash Paneru:** Methodology, Writing-review and editing, Formal analysis, Writing – original draft, Validation, resources. **Durga Prasad Mainali:** Project administration, Supervision, Validation, Writing – review & editing. **Sameep Karki:** Formal analysis, Supervision, Project administration, Methodology, Writing – original draft, Validation, Writing – review & editing. **Yashwanth Pochareddy:** Data curation, Supervision, Methodology, Resources, Writing – review & editing. **Shree Raj Shakya:** Supervision, Validation, Writing – review & editing. **Seemant Karki:** Conceptualization, Resources, Visualization.

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Appendix A. Supplementary data

Supplementary data to this article can be found online at https://doi.org/10.1016/j.ijhydene.2024.06.117.

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