Integrating Variable Renewable Energy and Storage for Green Hydrogen Production

Jhih-Shyang Shih, Dallas Burtraw, and Karen Palmer

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About the Authors

Jhih-Shyang Shih is a fellow at Resources for the Future (RFF). He has extensive experience in energy and environmental modeling. His research focuses on integrated system analysis of environmental and resource policy and decisionmaking. His work has been published in leading journals, including PNAS, Environmental Science & Technology, the Review of Economics and Statistics, and the European Journal of Operational Research.

Dallas Burtraw is a Darius Gaskins Senior Fellow at RFF. Burtraw has worked to promote efficient control of air pollution and written extensively on electricity industry regulation and environmental outcomes. Burtraw's current research includes analysis of the distributional and regional consequences of climate policy, the evolution of electricity markets including renewable integration, and the interaction of climate policy with electricity markets. He has provided technical support in the design of carbon dioxide emissions trading programs in the Northeast states, California, and the European Union. He also has studied regulation of nitrogen oxides and sulfur dioxide under the Clean Air Act and conducted integrated assessment of costs, and modeled health and ecosystem effects and valuation, including ecosystem improvement in the Adirondack Park and the southern Appalachian region.

Karen Palmer is a senior fellow at RFF and an expert on the economics of environmental, climate and public utility regulation of the electric power sector. Her work seeks to improve the design of environmental and technology regulations in the sector and the development of new institutions to help guide the ongoing transition of the electricity sector. To these ends, she explores climate policy design, analyzes efficient ways to promote use of renewable and other clean sources of electricity, and investigates new market designs, new approaches to electricity pricing and regulatory reforms to pave the way for long-term decarbonization of electricity supply and electrification of the energy economy.

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Sharing Our Work

NOTE: These five sections (about the authors, about RFF, sharing our work, about the project, acknowledgements) can be rearranged as is necessary to make the layout look nice.

Abstract

System-level design that integrates hydrogen production with the electricity system may improve market uptake and enable green hydrogen to contribute significantly to a sustainable energy future. Government policies, incentives, and funding opportunities provide the necessary support and financial backing to foster technological advancements.

In this paper, we develop a decision-making model to simultaneously optimize capacity investments and system operations in electricity generation and hydrogen production. We investigate the optimal deployment and operation of electrolyzers to produce green hydrogen using grid-connected sources of electricity, an off-grid system that couples variable renewable energy (VRE) resources with long duration energy storage (LDES), or a mix of both. We assess the economic and environmental performance of the hydrogen production system under carbon pricing and various tax incentive policy[1] scenarios—in particular, the Section 45V Production Tax Credit (PTC) for green hydrogen and the Section 48 Investment Tax Credit (ITC) for VRE and LDES—along with sensitivity analysis on LDES capital costs.

Eleven scenarios showcase the model's capability and highlight the complexity of interactions between system components. We calculate the unit net cost of hydrogen production for each scenario and decompose the unit cost into four components: electricity cost, capital investment, social cost of carbon dioxide emissions, and tax revenue. We find, for example, that the ITC and PTC could potentially reduce unit hydrogen production cost from $10.62 per kilogram in a no-policy scenario to $0.96 per kilogram. This model provides a foundation for further investigation of the full integration of hydrogen infrastructure within the electricity system.

1 We evaluate scenarios accounting for the Section 48 Energy Credit, known as the Investment Tax Credit (ITC), of the Internal Revenue Code (IRC), as well as the Section 45V Clean Hydrogen Production Tax Credit (PTC). We note that Section 48 was expanded under the IRA of 2022. Previously, the ITC applied to energy storage only when it was installed in connection with a solar generation facility. The IRA has broadened this to include stand-alone energy storage projects, making them eligible for a tax credit of up to 30 percent of investment cost (Shah et al. 2024; IRS 2024). The ITC is available for renewable energy technologies even if they are not grid-connected. The ITC can be claimed for off-grid renewable energy systems, such as solar photovoltaic (PV) systems, wind turbines, and other qualifying technologies, as long as they meet the eligibility criteria set by the IRS (DOE 2024).

Contents

1. Introduction

Hydrogen may be essential for climate change mitigation and carbon dioxide (CO_2) reduction because it produces only water vapor when combusted, making it a strong candidate for decarbonizing sectors, such as heavy industry and transportation, that are difficult to electrify.

Hydrogen production primarily relies on two methods: fossil fuel–based and electrolytic processes. Fossil fuel–based production, mainly through steam methane reforming (SMR), involves reacting natural gas with steam to produce hydrogen and carbon dioxide. This method is widely used due to its technological maturity, relative cost-effectiveness, and well-established infrastructure, but it results in significant CO_2 emissions unless paired with carbon capture and storage (CCS). In contrast, electrolysis offers a cleaner alternative by splitting water into hydrogen and oxygen. However, the environmental impact of electrolysis depends heavily on the electricity source. When the power grid is predominantly supplied by variable renewable energy (VRE) sources like wind, solar, or hydropower, electrolysis produces green hydrogen with a minimal carbon footprint. Conversely, if the grid relies heavily on fossil fuels, such as coal or natural gas, the use of electrolysis can increase overall emissions, reducing its environmental benefits. A growing discussion and body of research (reviewed below) focuses on producing green hydrogen using off-grid VRE systems. In this paper, we address the challenges hydrogen production developers face using the electrolysis method, and we consider tradeoffs among using electricity from the existing power grid, newly constructed and additional VRE infrastructure, or a mix of these sources of electricity. We have developed a tool designed to optimize the investment and operation of hydrogen production systems with and without policy incentives.

While producing hydrogen via electrolysis using VRE is more environmentally sustainable, it faces two significant challenges. The first challenge is the intermittency of these energy sources. Electrolyzers produce hydrogen solely when electricity is available, but in reality, the sun doesn't always shine, and the wind doesn't always blow. Energy storage systems can help mitigate this issue by storing excess energy generated during periods of high generation and discharging it when generation is low or absent, thus smoothing out fluctuations in energy supply. We consider one such system, Long-Duration Energy Storage (LDES).[2] By providing a reliable and continuous energy source, LDES ensures a steady supply of electricity for electrolysis, enabling consistent hydrogen production and lowering capital investments in electrolyzers. Beyond these economic benefits, LDES can also deliver environmental benefits by using stored energy from lower-emitting electricity sources to replace electricity from the grid during periods of high emissions, reducing the carbon footprint of hydrogen production.

2 LDES refers to energy storage systems capable of delivering electricity at their maximum power rate for extended periods, typically defined as 10 or more hours (see **https://www.energy.gov/oced/long-duration-energy-storage**). In this paper, we use the terms LDES, energy storage systems, storage, battery, and battery storage, interchangeably, and consider a 10-hour LDES.

The second challenge lies in the considerable up-front capital investment needed for green hydrogen production infrastructure, which requires increased investment in VRE infrastructure, such as wind and solar. Although the marginal costs of renewable energy may be low, the significant initial investment required to produce the same amount of hydrogen as with uninterruptible energy sources is influenced by the intermittent nature of renewable sources.

Today, the United States produces approximately 10 million metric tons (MMT) annually of hydrogen, primarily from natural gas. Matching that level by 2030, while also achieving the US Department of Energy (DOE) Hydrogen Shot Initiative goal of reducing clean hydrogen production costs to $1 per kilogram (kg),[3] presents significant economic challenges. To support green hydrogen production, the US government has introduced numerous financial incentives.

Section 48E of the Internal Revenue Code provides investment tax credits (ITCs) for renewable energy projects, including wind, solar, and other clean energy technologies. The Inflation Reduction Act (IRA) of 2022 expanded these tax credits to include new technologies, such as stand-alone battery storage systems, which are eligible for a tax credit of up to 30 percent of investment cost (Shah et al. 2024; IRS 2024). The ITC can be claimed for off-grid renewable energy systems as long as they meet the eligibility criteria set by the Internal Revenue Service (DOE 2024).

The IRA also introduced Section 45V, a new Clean Hydrogen Production Tax Credit (PTC), offering up to $3 per kg of hydrogen produced by projects with a lifecycle greenhouse gas emissions intensity of less than 0.45 kg of CO2 equivalent (CO_2e) per kg of hydrogen. However, to qualify for the PTC and achieve 100 percent green hydrogen production with the existing grid, hydrogen production must adhere to the three pillars: additionality, time-matching, and deliverability in maintaining the integrity and sustainability of green hydrogen production (ACP 2023).[4] This means that in the absence of electricity storage capability, a substantial electrolyzer capacity is needed to produce hydrogen during specific times when renewable energy is available, a practice known as hourly matching (Bergman 2023).

Additionally, the Infrastructure Investment and Job Act has allocated $8 billion to the DOE's Regional Clean Hydrogen Hubs Program (H2Hubs), which aims to establish at least four regional hubs that will produce, distribute, and use clean hydrogen across various regions, creating a foundational national clean hydrogen network that will significantly contribute to decarbonizing the energy, industrial, and transportation sectors.

3 The primary goal of Hydrogen Shot is to reduce the cost of clean hydrogen production to $1 per kilogram within a decade. This target is commonly referred to as the "1-1-1" goal—$1 per kilogram of hydrogen within 1 decade.

4 Additionality requires that the renewable electricity is sourced from new renewable generation sources. Time-matching requires the electrolyzers' electric consumption to match renewable electricity production by the hour. Deliverability requires electrolyzers to source renewable electricity from within the same market or operating region.

To inform efforts to enhance and scale green hydrogen production efficiently, this paper presents an optimization model for green hydrogen production with options for using grid-connected electricity supply and an off-grid VRE and LDES system to examine the interactions among technologies, economics, and financial incentives affecting production. The model has three main objectives: (1) analyzing investment and operational decisions in green hydrogen production; (2) assessing the environmental and economic impacts of different policies, including carbon pricing and tax credits; and (3) analyzing sensitivity to storage costs and other parameters, encompassing both systems costs and associated benefits.

In Section 2, we conduct a literature review. Section 3 presents details of the optimization model. Section 4 outlines the data requirements for the model, while Section 5 covers the modeling scenarios and results. Finally, Section 6 provides conclusions and a discussion of future research directions.

2. Literature Review

A growing discussion and body of research focuses on producing green hydrogen using off-grid systems. This approach typically involves integrating renewable energy sources like solar, wind, or hydropower with water electrolysis systems to produce hydrogen without relying on traditional grid electricity. Several pilot projects and research initiatives are actively exploring the feasibility of off-grid hydrogen production systems. Examples include the OffgridH2 Project in Finland (CLIC n.d.) and efforts in regions like Australia, Chile, Europe, North America, and North Africa (Clerici and Furfari 2021; Largue 2024; León et al. 2023).

2.1. Modeling VRE

Oliva H. and Garcia G. (2023) analyze on-site renewable energy, grid energy, and a combination of both. They developed a linear programming optimization model to minimize the annualized cost of hydrogen production and determine the optimal capacity of the electrolyzer, on-site solar and wind generators, and grid energy. Their study finds that the fluctuating energy prices and the intermittency of VRE generation greatly influences the balance between on-site renewable investments and grid energy use in minimizing the annualized cost of hydrogen production. Their article does not incorporate energy storage; however, it notes that future research could explore the inclusion of storage and transport costs associated with hydrogen delivery.

2.2. Energy Storage

A recent National Petroleum Council report (NPC 2024) focuses on hydrogen production via electrolyzers powered by renewable energy, emphasizing the role of energy storage. Achieving hydrogen production targets under the NPC Net Zero by 2050 scenario requires a significant increase in renewable energy capacity, along with strategies to manage the variability of renewable sources. The report finds that storing excess renewable electricity in batteries, while technically feasible, is economically inefficient, suggesting that an overbuild of renewable capacity would be necessary for consistent electrolyzer operation. Consequently, the report highlights several alternatives to battery storage for addressing the variability of renewable energy, including enhanced hydro storage and compressed air energy storage. The report also suggests that the storage of excess hydrogen generated during periods of high renewable energy availability would help ensure a more stable and reliable hydrogen supply.

In contrast, other studies have found that optimal energy management strategies that incorporate battery storage and solar photovoltaics (PV) can significantly reduce hydrogen production costs while enhancing system reliability (Bracci et al. 2023; Ordóñez et al. 2023). Abomazid, El-Taweel, and Farag (2022) proposed an energy management system model that integrates battery energy storage systems (BESS) with solar photovoltaic (PV) systems to enable efficient seasonal hydrogen storage and maximize the use of low-cost electricity. This integration significantly enhances the operational efficiency of hydrogen production by allowing for the storage of excess energy generated during peak sunlight hours, ultimately minimizing the cost of hydrogen production and demonstrating substantial techno-economic benefits.

2.3. Hourly Matching

He et al. (2021) developed the DOLPHYN model (Decision Optimization of Low-Carbon Power-Hydrogen Nexus) to assess investments and operations across the electricity and hydrogen supply chains, including production, storage, transmission, and end-use demand. The model determines the least-cost combination of production, storage, and transmission infrastructures to meet both electricity and hydrogen demands while adhering to policy and operational constraints, such as the supply–demand balance of electricity. The DOLPHYN model incorporates a variety of technologies, such as VRE generation, SMR, CCS, and hydrogen transportation. The model operates at an hourly resolution for representative weeks, simulating annual system operations, and applies a carbon price to penalize process-level CO_2 emissions.

Cybulsky et al. (2023) applied the DOLPHYN model to analyze the IRA, particularly focusing on the PTC designed to support low-carbon hydrogen. Their research addressed the challenge of quantifying emissions from electrolyzers that use grid electricity and contract for grid-interconnected renewable energy. It also evaluates the implications of hydrogen production for the power sector, considering different additionality frameworks and their effects on the levelized cost of hydrogen. The study highlights the importance of understanding the interactions between hydrogen production, renewable energy deployment, and grid decarbonization efforts to scale up electrolytic hydrogen production while minimizing emissions. It illustrates the complexity of measuring emissions intensity under varying scenarios of hydrogen demand, time-matching requirements, and VRE investment, which could itself pose a barrier to investments in hydrogen.

3. Hydrogen Production Model

In this paper, we present a tractable model that is significantly narrower in scope than DOLPHYN. Our main goal is to develop a simplified model that is transparent, easy to parameterize, and runs efficiently to evaluate the optimal deployment and operation of off-grid renewable energy resources, energy storage systems, and grid-connected electrolyzers. The objective of the model is to minimize the net costs of the integrated system in producing a specified and fixed quantity of hydrogen. This encompasses the amortized capital investments in wind turbines, solar panels, batteries, and electrolyzers; the cost of grid electricity consumption and associated social cost of CO_2 emissions; and revenues from ITC and PTC tax credits. We demonstrate the value of our tool to evaluate the PTC and ITC and interactions among system components, and to estimate hydrogen production costs and the effects of policy incentives. We anticipate the model will be valuable for policymakers and investors to understand the interaction of policy with technology investment options and will provide a foundation for further modeling of the integration and optimal simultaneous deployment of hydrogen production infrastructure with electricity system operation.

3.1. Systems Configuration

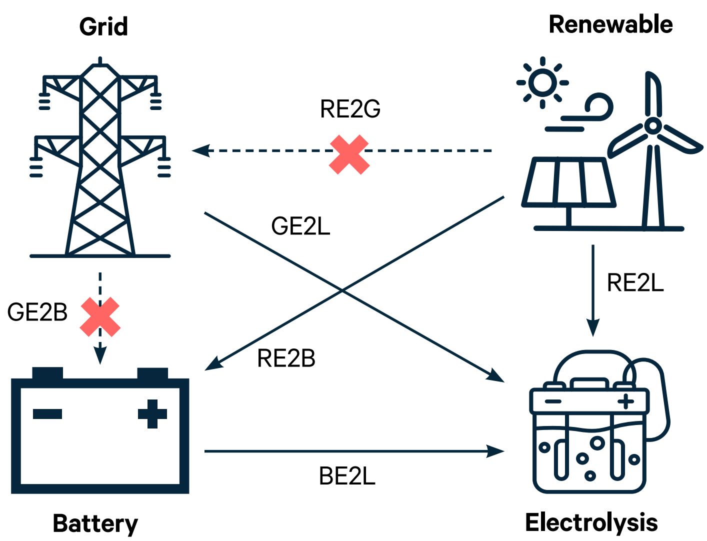
Figure 1 depicts the configuration of our modeling system. We consider off-grid renewable energy resources, such as wind, solar, and storage, that are located near the electrolyzer facility, and hence transmission investments are not considered.[5] Various energy sources, including grid electricity and off-grid wind, solar, and battery storage, power the electrolyzer to produce hydrogen. The battery in this system is charged solely by renewable energy sources, specifically wind and solar, and does not receive power from the grid. This approach simplifies the calculation of carbon intensity by eliminating the need to account for electricity transfer from the power grid to the battery, thereby avoiding potential embedded CO_2 in stored electricity. This restriction would avoid the complicated hourly matching required by 45V PTC. Wind and solar are used both for recharging the battery and for on-site hydrogen production. The eligibility for tax credits in any hour is simply a reflection of the proportion of VRE and battery-supplied energy used in hydrogen production.

It is important to note that this implementation of the model is limited in two contrasting ways. This analysis does not account for the possibility that wind, solar, and energy storage investments made to produce green hydrogen could be used to send electricity to the power grid for other energy consumption—for example, during a period of peak electricity demand. This extension will be our next phase of analysis. If VRE production or battery storage could episodically provide grid-related services in addition to serving hydrogen production, the return on investments could be greater than estimated.

5 Investment in hydrogen transportation is a key factor in the selection and implementation of the IIJA Regional Hydrogen Hub Program.

In contrast, by assuming the co-location of VRE generation and hydrogen production, we do not account for potential transmission costs. We also assume no constraints on water consumption and land use, allowing for the construction of electrolyzer, renewable energy generators and batteries as needed, thereby likely underestimating their costs.

Figure 1. Systems Configuration



Note: GE2B: Grid to battery; RE2B: Renewables to battery; BE2L: Battery to electrolysis; RE2G: Renewable to grid; RE2L: Renewable to electrolysis; GE2L: Grid to electrolysis; GE2B: Grid to battery.

3.2. The Model

We present a quantitative decision-making model that integrates capacity investment planning with the operational management of hydrogen production systems. The model addresses both infrastructure and operational dynamics, optimizing energy flow management, capital investments, CO_2 emissions management, and hourly operational decisions, such as electricity generation and consumption. This study aims to provide insights for stakeholders in energy storage and green hydrogen production, informing investment decisions and illustrating the interconnected incentives shaped by current policies. It establishes a framework for evaluating policies and understanding potential state-level responses to federal tax incentives, considering factors like capital and operational costs, green hydrogen tax incentives, carbon pricing, and the environmental impact of production processes. Policymakers, facility developers, and operators in the hydrogen production sector are the key decisionmakers who could benefit from this model.

Specifically, this non-linear optimization model's inputs include capital expenditures on VRE, LDES, and electrolyzer; electrolyzer performance; grid electricity prices; social cost of carbon; marginal CO_2 emissions; capacity factors of VRE resources; and the annual hydrogen production requirement.

The objective function seeks to minimize the net system costs by minimizing: (1) amortized capital expenditures for investments in wind, solar, battery storage, and electrolyzer; (2) energy costs related to system operation and maintenance; (3) the social cost of CO_2 emissions; and maximizing: (4) the ITC for VRE and LDES and the PTC for hydrogen production.

Several constraints are integral to the model's functionality. These include balance of hourly renewable energy supply and consumption; balance of hourly battery recharge and discharge; renewable energy generator and LDES capacities; hourly hydrogen production as a function of energy inputs to the electrolyzer, specific energy consumption[6] of the electrolyzer, and electrolyzer efficiency; CO_2 emissions; and the annual hydrogen demand requirement. The hourly matching conditions specified by the 45V PTC determine the financial payments received from this incentive. Through these constraints and optimization criteria, the model ensures an efficient and cost-effective approach to integrating renewable energy sources and hydrogen production facilities. The model was solved using CONOPT4 solver in GAMS.[7]

The model simultaneously assesses the optimal investments in VRE and storage capacity, as well as the hourly performance of off-grid renewable energy generations. It tracks energy flow within the system, the charging and discharging of energy storage systems, electrolyzer energy consumption from various energy sources, and CO_2 emissions over the course of a year. Key decision variables include the capacities of electrolyzer, renewable generators (wind and solar), and energy storage systems and several other factors. For detailed descriptions and formulations of the model, please refer to Appendix A.

4. Data Requirements

In this section, we discuss the data required for the hydrogen production model.

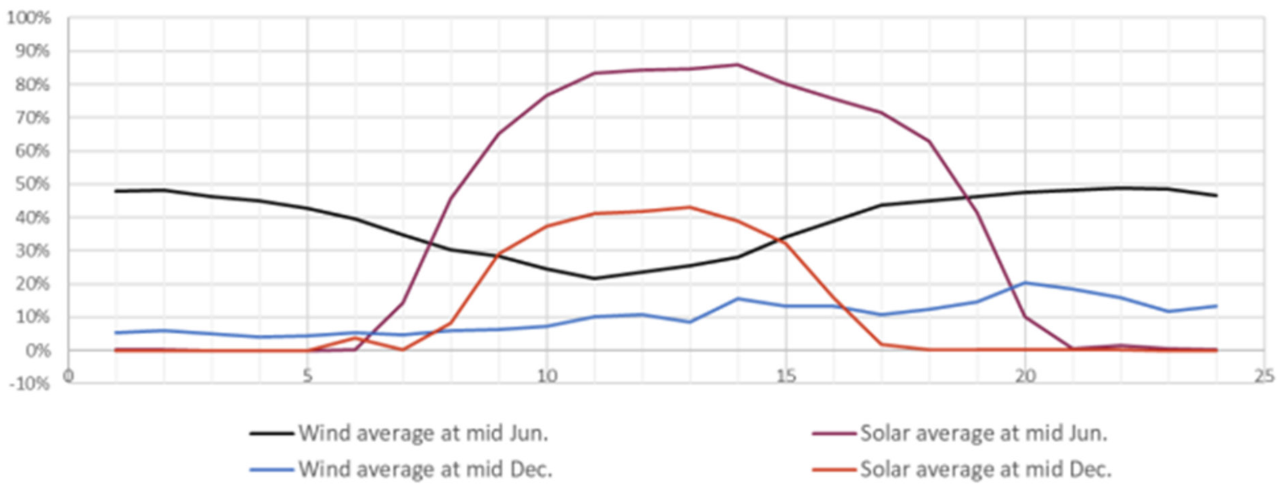
4.1. Renewable Energy Resource Profile

Solar power generation fluctuates throughout the day based on the amount of sunlight received. Similarly, wind power generation is influenced by wind speed, which can be affected by such factors as daily and seasonal patterns, microclimates, local geography, and land cover. To simulate these variations, we use average hourly capacity factors (CF) for wind and solar in mid-June and mid-December, computed using data from the California Independent System Operator for the years 2017 and 2018 (Hingtgen, Popa, and Gutierrez 2021). This data is represented in Figure 2. We apply these mid-

6 The energy requirement per unit of hydrogen production for an electrolyzer is commonly referred to as the "specific energy consumption" or "specific energy requirement." This metric indicates the amount of energy needed to produce a certain amount of hydrogen, typically expressed in kilowatt-hours per kilogram (kWh/kg) of hydrogen.

7 The General Algebraic Model System; see **https://www.gams.com/**.

Figure 2. Average Wind and Solar Profiles by Hour in Mid-June and Mid-December



Source: Hingtgen, Popa, and Gutierrez 2021

June hourly CFs to each day from April through September, and the mid-December hourly CFs to each day from October through March. These assumptions are simplistic, especially given California's distinct spring performance and CF for solar, which can significantly impact the accuracy of projections for renewable energy generation and grid integration.

4.2. Renewable Energy Technologies and Costs

According to the National Renewable Energy Laboratory's (NREL) Annual Technology Baseline (ATB), the 2023 capital costs for utility-scale solar PV and land-based wind were $1,611 per kilowatt (kW) and $1,810 per kW, respectively. The fixed operations and maintenance costs for utility-scale solar PV and land-based wind were $22.2 and $32.3 per kW-year, respectively (NREL 2024a).

In this paper, we consider a 10-hour LDES as our energy storage system. Capital costs for 10-hour LDES vary depending on battery technology; we focus on lithium-ion batteries, with capital costs ranging from $200–$300 per kilowatt hour (kWh) (Viswanathan et al. 2022). These costs are expected to decrease as technologies advance. The cost of recently developed LDES systems using iron-air technology are predicted to fall to as low as $20/kWh (Form Energy 2024).[8] For this paper, we used

8 The price is possible because the batteries primarily use iron, one of the most abundant and commonly mined metals on earth, with a supply chain dominated by domestic suppliers. The goal of Form Energy, the US energy storage company that manufactures this system, was to develop a battery that would last 100 hours and store energy at one-tenth the cost of lithium-ion batteries (Board 2024).

$300/kWh, close to the high capital cost projection for lithium-ion batteries, as the capital cost for LDES in the base case study, while conducting sensitivity analysis at $100/kWh and $60/kWh.[9]

For the computation of the yearly payment on a capital investment, we consider a 25-year investment period with an interest rate of 5 percent. Wind, solar, and energy storage technologies all have nearly negligible marginal costs (Helm 2023). Therefore, with co-located VRE, batteries, and electrolyzers (i.e., no transmission or distribution costs), we consider the per kWh energy costs of wind, solar, and energy storage to be zero.

4.3. Electrolyzer Technologies and Costs

Several types of electrolyzer technologies exist, such as alkaline, proton exchange membrane (PEM), and solid oxide electrolyzers (SOE). The capital expenditure is approximately $1,065 per kW, as cited by Christensen (2020) and Glenk and Reichelstein (2019). According to Tashie-Lewis and Nnabuife (2021), leading manufacturers report that both alkaline and PEM electrolyzers require approximately 50 to 55 kWh of electricity to generate 1 kg of hydrogen. Additionally, we assume an electrolyzer efficiency of 80 percent (NREL 2004b).

4.4. Grid Electricity Price

We model electricity prices based on the CI-TOD4 Commercial and Industrial Time-of-Day (TOD) dynamic pricing schedule from Sacramento Municipal Utility District (2024). Figure 3 shows the TOD rate clocks for commercial and residential customers, categorized by season and time block. In this study, we apply the weekday rates throughout the entire week for each season, without differentiating between weekend and weekday rates; both are treated equally. Table 1 shows electricity usage charge by season and time block. The purpose of TOD pricing is to motivate consumers to adjust their electricity use away from peak demand periods. This anticipated response to time-varying pricing helps to reduce power system stress during peak times and prevent blackouts. It also leads to cost savings for the utility and customers.

9 DOE's Long Duration Storage Shot initiative seeks to reduce the cost of grid-scale LDES by 90 percent within a decade (see **https://www.energy.gov/topics/long-duration-storage-shot**.)

Figure 3. Time-of-Day Rate Clocks for Commercial and Industrial Customers

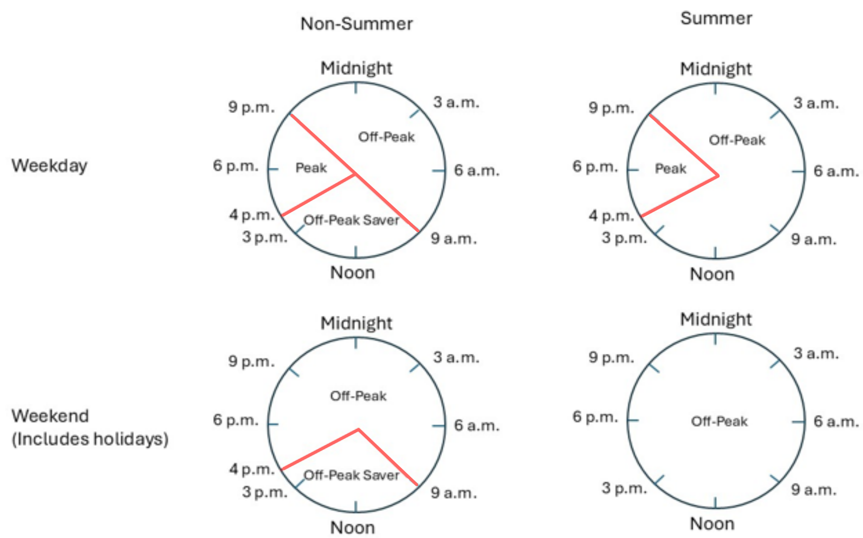


Figure 3. Time-of-Day Rate Clocks for Commercial and Industrial Customers

Adapted from Sacramento Municipal Utility District 2024.

Source: Sacramento Municipal Utility District 2024

Table 1. Commercial and Industrial Time-of-Day Rate Schedule CI-TOD4 (Dollars per kilowatt hour)

	Peak	Off-Peak	Off-Peak Saver
Non-Summer Season (October–May)	0.1331	0.1080	0.0697
Summer Season (June–September)	0.2052	0.1042	

Source: Sacramento Municipal Utility District 2024

4.5. Grid CO_2 Emissions

In our modeling exercise, we utilize the hourly CO_2 marginal emissions factor provided by the California Self-Generation Incentive Program (2024).

4.6. Tax Credits

4.6.1. Hydrogen Production Tax Credit

The IRA created a new tax credit opportunity for the production and sale of clean hydrogen under Section 45V (IRS 2023a). The hydrogen PTC offers taxpayers credit for a period of 10 years. Credit eligibility varies depending on lifecycle CO_2 emissions intensity with five levels of credit eligibility:

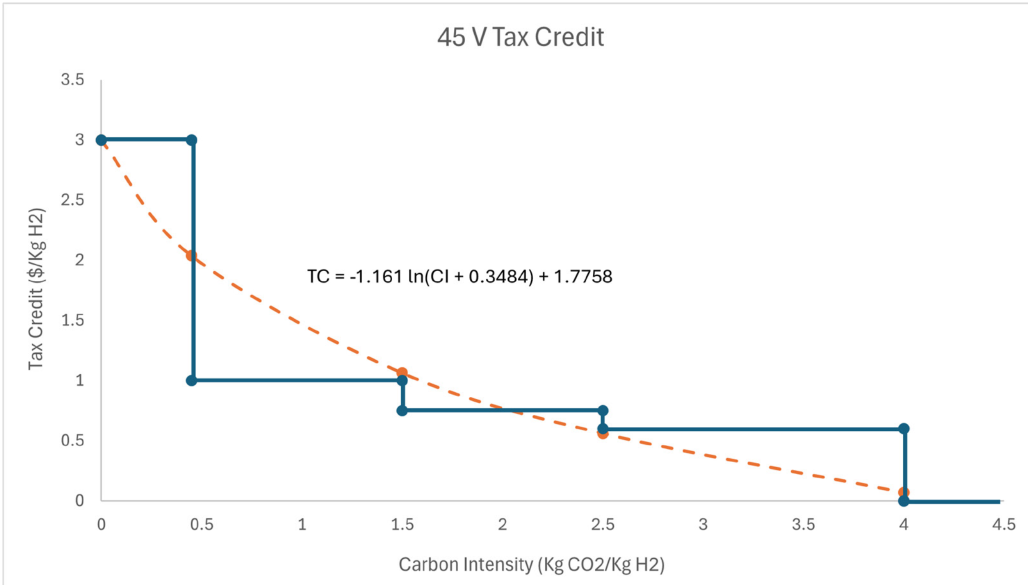
No credit for production that results in greater than 4 kg of CO_2e per kg of hydrogen.

1. An 80 percent reduction for CO_2e between 4 kg and 2.5 kg.
2. A 75 percent reduction for CO_2e between less than 2.5 kg and 1.5 kg.
3. A 66.6 percent reduction for CO_2e between less than 1.5 kg and 0.45 kg.
4. No reduction for CO_2e less than 0.45 kg (i.e., full credit value of $3/kg hydrogen).

The blue line in Figure 4 illustrates the above 45V tax credit schedule for hydrogen production. The horizontal axis represents the carbon intensity of the hydrogen produced in a specific hour, measured in kg CO_2/kg H_2. The vertical axis indicates the tax credit in \$/kg H_2 for the produced hydrogen.

Incorporating the step function of tax incentive into our model would require a binary integer variable for each time period to denote each step of the interval of carbon intensity. Considering that our model runs on an hourly timeframe for an entire year, this step function would introduce 8760 X 4 binary integers, which could create substantial computational challenges. Thus, we opt to approximate the step function using a logarithmic function, as depicted by the orange dashed line in Figure 4 with an additional constraint that the tax credit is no more than \$3/kg H_2.

Figure 4. Section 45V Hydrogen Production Tax Credit Schedule and Non-Linear Approximation



Note: TC=tax credit; CI=carbon intensity.

Produced hydrogen receives a maximum tax credit of $3/kg H_2 when the carbon intensity is 0. So, we fitted a natural log function through point (0, 3), 0 kg CO_2/Kg H_2 carbon intensity, $3/kg H_2 tax credit, and obtained following function:

$$TC = -1.161 \ln(CI + 0.3484) + 1.7758$$

Where, *TC* is the hydrogen production tax credit and *CI* is the carbon intensity of hydrogen produced.

4.6.2. Clean Energy Technology Investment Tax Credit[10]

The IRA has introduced significant tax incentives to support the clean energy economy (Bartlett 2023, 2024; Bartlett and Krupnick 2020). The IRA modifies and extends the clean energy ITC, providing a 30 percent credit for qualifying investments in wind, solar, energy storage, and other renewable energy projects (DOE 2022; IRS 2023b; Kennedy 2023). A further 10 percent tax credit adder is offered to projects installed in

10 We consider only ITC for clean energy technologies in this study. Under the IRA, a VRE facility can generally claim either the ITC or the PTC, but not for the same project. PTC is typically better for large projects with high energy output, especially where ongoing production is stable and predictable, providing a long-term tax benefit. ITC is generally preferable for projects with high up-front costs, on a smaller scale, or where the project developer prefers an up-front tax benefit (Batra et al. 2022).

eligible Energy Communities, which are defined by income status and the economic impact of legacy energy systems in their area. Another 10 percent adder can be applied to projects that meet domestic content requirements. A large portion of the spending in the IRA is directed toward supporting the buildout of US-based clean energy manufacturing, and the 10 percent domestic content adder is designed to stimulate demand for these products. The three credits can be combined to cover 50 percent of the installed system costs. In the current modeling, we consider only 30 percent ITC for off-grid renewable investments in wind, solar, and storage.

Table 2 below outlines the key parameters and input values discussed in this section, which will be used in the scenario analysis in Section 5.

Table 2. Key Model Parameters and Values

Parameter	Description	Unit	Value
SCC	Carbon tax/pricing at social cost of CO_2	\$/metric ton of CO_2	185
pG	Grid electricity price	\$/kWh	CI-TOD4*
aWind	Wind capital cost (CAPEX) parameter	\$1,000/MW	1810
aSolar	Solar capital cost (CAPEX) parameter	\$1,000/MW	1611
omWInd	Wind fixed operations and management (O&M) cost parameter	\$1,000/kW-year	32.3
omSolar	Solar fixed O&M cost parameter	\$1,000/kW-year	22.2
aL	Electrolyzer capital cost parameter	\$1,000/MW	1,065
aS	Battery storage capital cost parameter	\$1,000/MWh	300
rWind	Wind capital cost recovery factor	%/year	7
rSolar	Solar capital cost recovery factor	%/year	7
rL	Electrolyzer capital cost recovery factor	%/year	7
rS	Battery storage capital cost recovery factor	%/year	7

theta	Electrolyzer efficiency	%	80
H2GER	Hydrogen production gross electricity requirement	MWh/metric ton	50
H2DMD	Hydrogen demand	Metric ton/year	$2.5x10^6$
S0	Initial long duration energy storage (LDES)	MWh	0
bloss	Battery roundtrip energy loss	%	10

**Sacramento Municipal Utility District (2024) Commercial & Industrial Time-of-Day Rate Schedule CI-TOD 4.*

5. Modeling

5.1. Scenarios

We analyze eleven scenarios, including a baseline scenario of hydrogen production using only grid electricity, a second scenario involving grid electricity with investments in VRE and LDES, and combinations of three policy scenarios—carbon pricing, tax credits, and a joint carbon pricing and tax credits policy—across three different LDES capital cost levels.

Table 3 provides a list of scenario numbers, names, and descriptions.

Table 3. List of Scenario Number, Name and Description

Scenario No.	Scenario Name	Description
1	BL	The baseline (BL) scenario minimizes electrolyzer capital investment and hydrogen production costs by using grid electricity with time-of-day pricing, without investing in variable renewable energy (VRE) or long duration energy storage (LDES).
2	BL+VRE+S	An expansion of the BL scenario allowing for investments in VREs and LDES (S for storage).

3	BL+VRE+S+SCC	This scenario extends the objective function of BL+VRE+S to include minimizing the social cost of CO_2 emissions (SCC).*
4	BL+VRE+S+TC	This scenario extends the objective function of BL+VRE+S to include the maximization of tax credit (TC) revenue associated with Investment Tax Credit (ITC) for VRE and LDES and Production Tax Credit (PTC) for hydrogen.
5	BL+VRE+S+SCC+TC	This scenario extends the objective function of BL+VRE+S to include joint minimization of social cost of CO2 emissions and maximization of tax credit revenue associated with ITC and PTC.
6 7 8	BL+VRE+0.33S+SCC BL+VRE+0.33S+TC BL+VRE+0.33S+SCC+TC	In these three scenarios, the capital cost of LDES is reduced to 33 percent compared to BL+VRE+S+SCC, BL+VRE+S+SCC, and BL+VRE+S+SCC+TC, respectively.
9 10 11	BL+VRE+0.2S+SCC BL+VRE+0.2S+TC BL+VRE+0.2S+SCC+TC	In these three scenarios, the capital cost of LDES is reduced to 20 percent compared to BL+VRE+S+SCC, BL+VRE+S+SCC, and BL+VRE+S+SCC+TC, respectively.

* California's electricity prices do not directly include a separate, explicit charge for the social cost of carbon. However, California has a statewide cap-and-trade program under the California Air Resources Board. Power plants and other major greenhouse gas emitters are required to buy permits (or allowances) for their carbon emissions. The costs of these allowances tend to be passed on to consumers through electricity prices, indirectly embedding the cost of carbon into electricity rates. We plan to revisit this

5.2. Scenario Results

Table 4 presents the model results for each of the eleven scenarios. The results are categorized into the following eleven main groups: investment capacities by VRE, LDES, and electrolyzer (Rows 4–7); electrolyzer energy consumption by energy source (Rows 9–12); levelized capital costs for VRE and storage (Rows 14–16); electrolyzer utilization rate (Row 18); CO2 emissions (Row 20); annualized costs and breakdown (Rows 22–28); annualized tax credits and breakdown (Rows 30–34); annualized net costs (Rows 36–37); unit hydrogen production cost (Rows 39–41); unit grid electricity cost (Row 42); unit capital cost and breakdown (Rows 43–47); and unit tax credit and breakdown (Rows 48–52).

In the rest of this Section 5, we initially present the details for each scenario in Table 4. Subsequently, we conduct an in-depth discussion on policy and the sensitivity analysis of LDES capital costs.

Scenario 1 serves as the baseline (BL) scenario, aiming to produce 2.5 million metric tons of hydrogen annually using only grid electricity with TOD dynamic pricing with no charge for CO_2 emissions and no other source of electricity. The objective is to minimize annual private costs, encompassing both electrolyzer capacity investment and operational energy costs from grid electricity. The optimization model for hydrogen production indicates that a 38.9 gigawatt (GW) electrolyzer investment is necessary to achieve the annual target of 2.5 million metric tons of hydrogen. The annual cost of electricity consumption is $14.4 billion, representing 83.2 percent of the annual total costs of $17.3 billion. The remaining 16.8 percent, or $2.9 billion,[11] is attributed to the annualized electrolyzer capital cost.

The model capitalizes on dynamic electricity pricing by producing hydrogen during the hours when electricity prices are at their lowest. As shown in Table 1, TOD pricing ranges from $0.07/kWh (Off-Peak Saver) to $0.13/kWh (Peak) for the non-summer season days and from $0.11/kWh (Off-Peak) to $0.21/kWh (Peak) for the summer season days. Optimal hydrogen production occurs exclusively during the hours when electricity is the cheapest. Cost minimization is achieved by trading off high-capacity investment for low energy prices and, consequently, the electrolyzer utilization factor is limited to 0.46.

In the BL, the social cost of CO_2 is not minimized and the overall societal costs amount to $26.6 billion per year. This is the sum of the private cost, which is $17.3 billion per year, and the social cost of CO_2, which is $9.28 billion per year. When we break it down per unit of hydrogen production, the private cost is $6.9/kg of hydrogen (which includes energy cost of $5.75/kg of hydrogen and electrolyzer capital cost of $1.16/kg of hydrogen) and the total social cost (private costs plus SCC) is $10.6/kg of hydrogen.

In Scenario 2—BL+VRE+S (LDES)—hydrogen production is evaluated using a combination of existing grid energy and energy from VRE sources, such as wind and solar, supplemented by LDES investments. All other model inputs are identical to those in BL. BL+VAR+S results in hydrogen production using a mix of energy sources, including grid electricity, wind, and solar, but excluding LDES because of the associated high capital costs. It identifies investments in wind (28.15 GW) and solar (31.67 GW), and electrolyzer capacity (35.18 GW), which is 9.6 percent smaller than BL electrolyzer capacity (38.88 GW) because of the adoption of VRE to complement grid electricity. The private cost of BL+VRE+S ($13.30 billion) is 23 percent smaller than the private cost of BL ($17.29 billion). Despite a $8.4 billion increase in capital investments, including new wind and solar projects (rising from $2.9 billion to $11.3 billion), the cost of grid electricity decreased by $12.47 billion, leading to a net saving of $4.07 billion. For BL+VRE+S, the unit hydrogen production private cost using VRE and energy storage dropped to $5.32/kg from $6.91/kg in BL.

In Scenario 3—BL+VRE+S+SCC (social cost of carbon)—we adjust BL+VRE+S by incorporating the minimization of social cost associated with CO_2 emissions into the objective function while keeping other model inputs unchanged. This adjustment led to a substantial increase in energy consumption from VRE and storage, eliminating grid energy use entirely and reducing CO_2 emissions from 8.04 to 0.01 million metric tons. By factoring in CO_2 social cost, the system shifts energy sources to achieve hydrogen production in a more sustainable way, significantly lowering grid electricity consumption and CO_2 emissions compared to BL+VRE+S. With reduced grid reliance,

11 All dollar values are annual.

solar and wind energy use increased to sustain hydrogen production levels. However, due to high LDES costs, this increased dependence on VRE required additional electrolyzer capacity.

In Scenario 4—BL+VRE+S+TC (tax credit)—we include the Section 45V PTC for hydrogen production and Section 48 ITC for VRE and storage adoption in the objective function, while keeping all other inputs the same as in the BL+VRE+S scenario. We find that these financial incentives effectively boost the use of VRE, resulting in zero CO_2 emissions. Storage investment remains at zero. The system lowers the carbon intensity of hydrogen production to zero to qualify for the maximum PTC of $3/kg during hours of hydrogen production. As a result, grid electricity is not used, and all hydrogen is produced using VRE to maximize tax credit revenue.

In Scenario 5 (BL+VRE+S+SCC+TC), we incorporate the minimization of social cost of CO_2 into the objective function, while keeping all other inputs the same as in the BL+VRE+S+TC scenario. Unsurprisingly, the results are identical to those in the BL+VRE+S+TC scenario because the hydrogen production tax credit already incentivizes hydrogen production with zero carbon intensity. Therefore, minimizing the social cost of CO_2 becomes redundant and has no impact on the optimal solutions. This also holds true when comparing Scenarios 7 and 10, which include tax credits, with 8 and 11, respectively, which layer on SCC. These findings suggest that financial incentive policies alone are sufficient to achieve both economic and environmental sustainability objectives.

In Scenario 6 (BL+VRE+0.33S+SCC), the capital cost of LDES is reduced to 33 percent while keeping all other inputs identical to those in BL+VRE+S+SCC. Our findings indicate that reducing LDES costs to 33 percent significantly boosts LDES investment. Although the environmental impact remains similar between the two scenarios, with CO_2 emissions at 0.01 million metric tons, the increased LDES investment yields notable economic benefits by reducing the required electrolyzer capacity from 42.46 GW to 27.38 GW.

In Scenario 7 (BL+VRE+0.33S+TC), we incorporate investment and production tax credits (ITC and PTC) into the objective function, while keeping all other inputs the same as in BL+VRE+0.33S. We find that tax credits slightly increase VRE and LDES investments, fully eliminating the residual CO_2 emissions of 0.01 MMT. Scenario 8 (BL+VRE+0.33S+SCC+TC) produces the same outcomes as Scenario 7 for the same reasons observed in scenarios without LDES capital cost reduction.

Scenarios 9, 10, and 11 follow the same structure as Scenarios 3, 4, 5 and Scenarios 6, 7, 8, but with a further reduction in energy storage capital costs to 20 percent of the original LDES capital cost. In comparison to the S and 0.33S storage cost scenarios, we observe that solar capacity grows and wind capacity declines to zero. This is likely because wind has higher capital costs compared to solar, and solar energy resources generally have a higher capacity factor than wind energy resources. These economic trade-offs result in a stronger preference for solar over wind. We also find that financial incentives effectively boost investments in LDES, which not only reduces the required electrolyzer capacity but also increases the electrolyzer utilization rate.

Table 4. Scenario Analysis Results

Row No.	SCENARIO NO.	1	2	3	4	5	6	7	8	9	10	11
1	SCENARIO NAME	BL	BL +VRE +S	BL +VRE +S +SCC	BL +VRE +S +TC	BL +VRE +S +TC +SCC	BL +VRE +0.33S +SCC	BL +VRE +0.33S +TC	BL +VRE +0.33S +TC +SCC	BL +VRE +0.2S +SCC	BL +VRE +0.2S +TC	BL +VRE +0.2S +TC +SCC
2	**RESULTS**											
3	**Investment Capacity**											
4	Wind capacity (GW)	0.00	28.15	33.96	63.88	63.88	33.97	34.00	34.00	33.34	0.00	0.00
5	Solar capacity (GW)	0.00	31.67	38.21	7.99	7.99	38.22	38.25	38.25	38.90	72.67	72.67
6	Storage capacity (GWh)	0.00	0.00	0.00	0.00	0.00	150.85	151.01	151.01	154.10	358.02	358.02
7	Electrolyzer capacity (GW)	38.88	35.18	42.46	33.86	33.86	27.38	27.39	27.39	27.38	26.69	26.69
8	**Electrolyzer energy consumption in TWh**											
9	Grid electricity (TWh)	156.25	26.86	0.12	0.00	0.00	0.12	0.00	0.00	0.03	0.00	0.00
10	Solar (TWh)	0.00	68.11	82.19	17.18	17.18	76.12	72.08	66.03	60.71	98.50	98.53
11	Wind (TWh)	0.00	61.28	73.94	139.07	139.07	55.85	60.05	66.10	70.79	0.00	0.00

12	Battery storage (TWh)	0.00	0.00	0.00	0.00	0.00	24.19	24.14	24.14	24.75	57.80	57.78
13	**Levelized (capital) cost ($/kWh)**											
14	Solar levelized cost ($/kWh)	0.00	0.05	0.05	0.05	0.05	0.05	0.052	0.05	0.05	0.05	0.05
15	Wind levelized Cost ($/jWh)	0.00	0.06	0.06	0.06	0.06	0.06	0.058	0.06	0.06	0.00	0.00
16	Storage levelized cost ($/kWh)	0.00	0.00	0.00	0.00	0.00	0.04	0.044	0.04	0.03	0.03	0.03
17	**Utilization rate**											
18	Electrolyzer utilization rate	0.46	0.51	0.42	0.53	0.53	0.65	0.651	0.65	0.65	0.67	0.67
19	**CO_2 emissions (MMT)**											
20	CO_2 emissions (MMT)	50.14	8.04	0.01	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00
21	**Annualized cost (B$/year)**											
22	Wind capital cost (B$/year)	0.00	4.48	5.40	10.16	10.16	5.40	5.41	5.41	5.30	0.00	0.00
23	Solar capital cost (B$/year)	0.00	4.27	5.16	1.08	1.08	5.16	5.16	5.16	5.25	9.81	9.81
24	Storage capital cost (B$/year)	0.00	0.00	0.00	0.00	0.00	1.06	1.06	1.06	0.65	1.50	1.50
25	Electrolyzer capital cost (B$/year)	2.90	2.62	3.17	2.52	2.52	2.04	2.04	2.04	2.04	1.99	1.99
26	(Total) capital cost (B$/year)	2.90	11.37	13.72	13.76	13.76	13.66	13.67	13.67	13.24	13.30	13.30

27	(Total) energy cost (B$/year)	14.39	1.92	0.01	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00
28	(Total) social cost of CO2 (SCC) (B$/year)	9.28	1.49	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
29	**Annualized tax credit revenue (B$/year)**											
30	Hydrogen production tax credit (PTC) revenue (B$/year)	0.00	0.00	0.00	7.50	7.50	0.00	7.50	7.50	0.00	7.50	7.50
31	Wind investment tax credit (ITC) revenue (B$/year)	0.00	0.00	0.00	3.05	3.05	0.00	1.62	1.62	0.00	0.00	0.00
32	Solar ITC revenue (B$/year)	0.00	0.00	0.00	0.32	0.32	0.00	1.55	1.55	0.00	2.94	2.94
33	Storage ITC revenue (B$/year)	0.00	0.00	0.00	0.00	0.00	0.00	0.32	0.32	0.00	0.45	0.45
34	Total tax revenue (B$/year)	0.00	0.00	0.00	10.87	10.87	0.00	10.99	10.99	0.00	10.89	10.89
35	**Annualized net cost (B$/year)**											
36	Total system net cost, excluding SCC (B$/year)	17.29	13.30	13.73	2.89	2.89	13.66	2.68	2.68	13.24	2.41	2.41
37	Total system net cost, including SCC (B/year$)	26.56	14.78	13.73	2.89	2.89	13.67	2.68	2.68	13.24	2.41	2.41
38	**Unit production cost ($/Kg H_2)**											
39	- H_2 unit production cost, excluding SCC ($/Kg H_2)	6.91	5.32	5.49	1.16	1.16	5.47	1.07	1.07	5.30	0.96	0.96

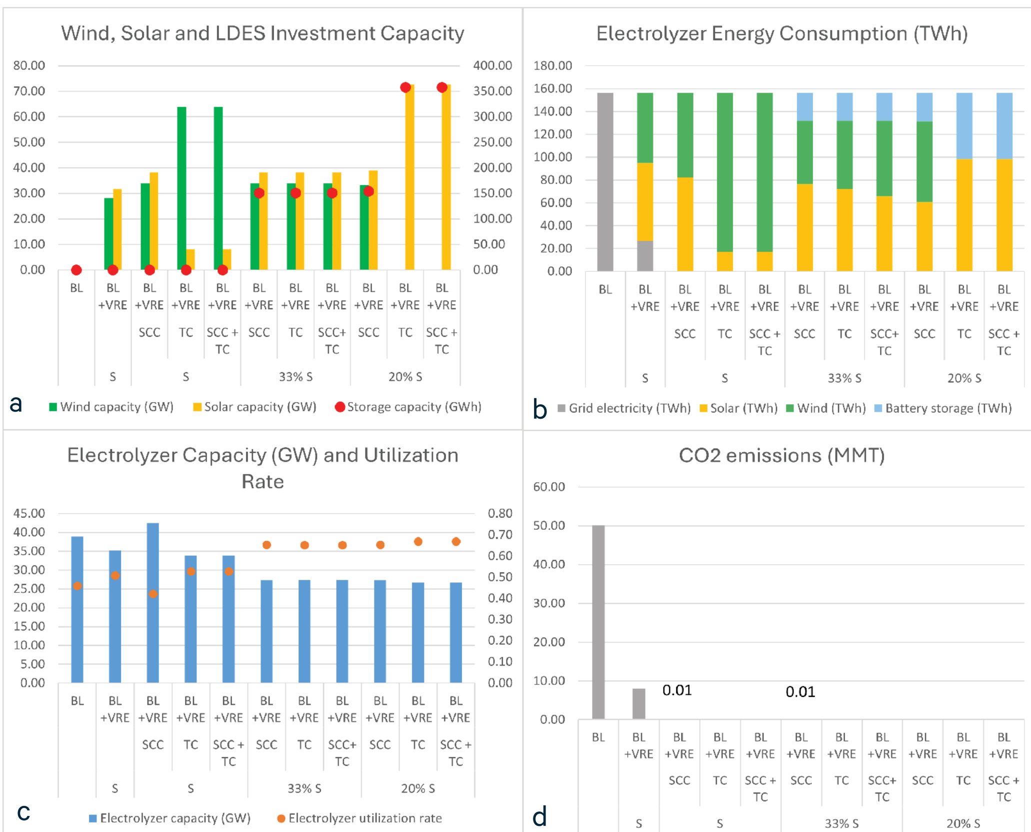
40	- Unit SCC ($/Kg H_2)	3.71	0.60	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
41	- H_2 unit production cost, including SCC ($/Kg H_2)	10.63	5.91	5.49	1.16	1.16	5.47	1.07	1.07	5.30	0.96	0.96
42	**Unit energy cost ($/Kg H_2)**	5.75	0.77	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
43	**Unit capital cost ($/Kg H_2)**	1.16	4.55	5.49	5.50	5.50	5.46	5.47	5.47	5.30	5.32	5.32
44	- Unit wind capital costs ($/Kg H_2)	0.00	1.79	2.16	4.06	4.06	2.16	2.16	2.16	2.12	0.00	0.00
45	- Unit solar capital costs ($/Kg H_2)	0.00	1.71	2.06	0.43	0.43	2.06	2.06	2.06	2.10	3.92	3.92
46	- Unit storage capital costs ($/Kg H_2)	0.00	0.00	0.00	0.00	0.00	0.42	0.42	0.42	0.26	0.60	0.60
47	- Unit electrolyzer capital cost ($/Kg H_2)	1.16	1.05	1.27	1.01	1.01	0.82	0.82	0.82	0.82	0.80	0.80
48	**Unit tax credit ($/Kg H_2)**	0.00	0.00	0.00	4.35	4.35	0.00	4.39	4.39	0.00	4.36	4.36
49	- Hydrogen PTC ($/Kg H_2)	0.00	0.00	0.00	3.00	3.00	0.00	3.00	3.00	0.00	3.00	3.00
50	- Wind ITC ($/Kg H_2)	0.00	0.00	0.00	1.22	1.22	0.00	0.65	0.65	0.00	0.00	0.00
51	- Solar ITC ($/Kg H_2)	0.00	0.00	0.00	0.13	0.13	0.00	0.62	0.62	0.00	1.18	1.18
52	-Storage ITC ($/Kg H_2)	0.00	0.00	0.00	0.00	0.00	0.00	0.13	0.13	0.00	0.18	0.18

Notes: BL=baseline; VRE=variable renewable energy; S=long duration energy storage; SCC=social cost of CO2; TC=tax credits.

Figure 5 offers a graphical summary and illustration of the investment results for the above eleven scenarios. The figure is divided into four panels. Panel 5a depicts capital investments in VRE and LDES. Panel 5b illustrates the energy consumption mix of electrolyzers. Panel 5c presents the electrolyzer capacity and utilization rate for these scenarios, while Panel 5d shows the corresponding CO_2 emissions.

Figure 5 highlights several important trends. In the BL context with a TOD pricing scheme for grid electricity and the assumed renewable resource profile, the availability of VRE lowers CO_2 emissions (5d), reduces the required electrolyzer capacity (5c), and increases the electrolyzer utilization rate (5c).[12] With the availability of tax credits, lower LDES capital costs lead to increased LDES and solar investments or deployments (5a), further reducing the need for electrolyzer capacity and improving utilization rates (5c).

Figure 5. Summary of Eleven Scenario Results

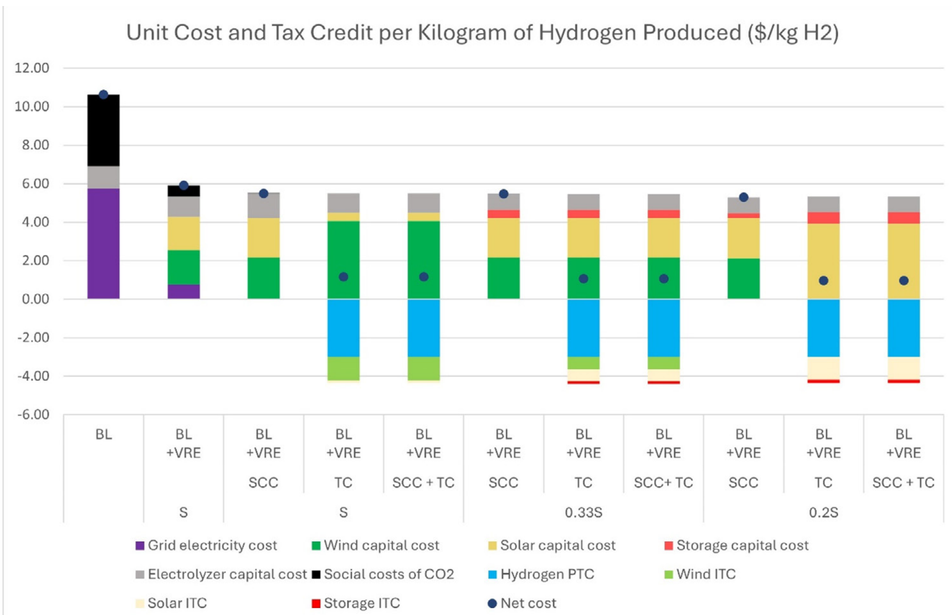


Notes: BL=baseline; VRE=variable renewable energy; S=long duration energy storage; SCC=social cost of CO2; TC=tax credits.

12 Scenario 3 is an exception where, in the absence of tax credits and with high LDES capital costs, there are no investments in VRE and storage. This leads to a larger electrolyzer capacity and a lower utilization rate.

Table 5 presents a comprehensive overview of the costs and tax credits associated with hydrogen production per kilogram. It outlines various cost components, including unit energy costs, capital costs for VRE and storage, electrolyzer capital costs, and social cost of CO_2. The table also details the impact of different tax credits, such as the Clean Hydrogen PTC, Wind ITC, Solar ITC, and Storage ITC, on the overall production costs. The hydrogen unit production cost, excluding social cost of CO_2, ranges from \$0.96 to \$6.91/kg, while including social cost of CO_2 raises the range from \$0.96 to \$10.63/kg. This highlights the significant influence of both capital investments and tax incentives on the economic viability of hydrogen production. Figure 6 summarizes and presents the same results as those in Table 5.

Figure 6. Unit Cost and Tax Credit, Dollars per Kilogram of Hydrogen Produced



Notes: BL=baseline; VRE=variable renewable energy; S=long duration energy storage; SCC=social cost of CO_2; TC=tax credits.

Table 5. Unit Cost and Tax Credit (Dollar per Kilogram of Hydrogen Produced)

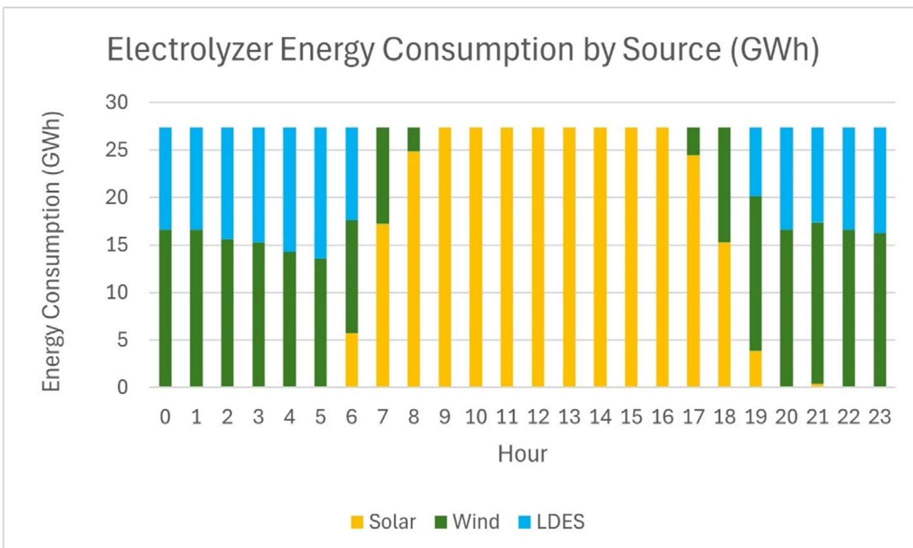
SCENARIO NO.	1	2	3	4	5	6	7	8	9	10	11
SCENARIO NAME	BL	BL +VRE +S	BL +VRE +S +SCC	BL +VRE +S +TC	BL +VRE +S +TC +SCC	BL +VRE +0.33S +SCC	BL +VRE +0.33S +TC	BL +VRE +0.33S +TC +SCC	BL +VRE +0.2S +SCC	BL +VRE +0.2S +TC	BL +VRE +0.2S +TC +SCC
Grid electricity cost	5.75	0.77	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Wind capital cost	0.00	1.79	2.16	4.06	4.06	2.16	2.16	2.16	2.12	0.00	0.00
Solar capital cost	0.00	1.71	2.06	0.43	0.43	2.06	2.06	2.06	2.10	3.92	3.92
Storage capital cost	0.00	0.00	0.00	0.00	0.00	0.42	0.42	0.42	0.26	0.60	0.60
Electrolyzer capital cost	1.16	1.05	1.27	1.01	1.01	0.82	0.82	0.82	0.82	0.80	0.80
Social cost of CO_2 (SCC)	3.71	0.60	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Hydrogen Production Tax Credit	0.00	0.00	0.00	-3.00	-3.00	0.00	-3.00	-3.00	0.00	-3.00	-3.00
Wind Investment Tax Credit (ITC)	0.00	0.00	0.00	-1.22	-1.22	0.00	-0.65	-0.65	0.00	0.00	0.00
Solar ITC	0.00	0.00	0.00	-0.13	-0.13	0.00	-0.62	-0.62	0.00	-1.18	-1.18
Storage ITC	0.00	0.00	0.00	0.00	0.00	0.00	-0.13	-0.13	0.00	-0.18	-0.18
H2 unit production cost, excluding SCC	6.91	5.32	5.49	1.16	1.16	5.47	1.07	1.07	5.30	0.96	0.96
H2 unit production cost, including SCC	10.62	5.91	5.49	1.16	1.16	5.47	1.07	1.07	5.30	0.96	0.96

Notes: BL=baseline; VRE=variable renewable energy; S=long duration energy storage; SCC=social cost of CO_2; TC=tax credits.

5.3. Time Profile Analysis Result

Figure 7 illustrates the electrolyzer energy consumption for hydrogen production using various energy sources, including VRE and LDES systems, over a 24-hour period, based on the results from BL+VRE+0.33S+TC scenario. Starting at midnight, the electrolyzer primarily consumes electricity from wind sources, which is gradually supplemented by LDES. Around 6 a.m., solar energy consumption begins to increase and then gradually decreases and is supplemented by wind energy. After 7 p.m., solar energy tapers off, and the battery, charged by wind and solar energy, starts to discharge to support wind energy in powering the electrolyzer.

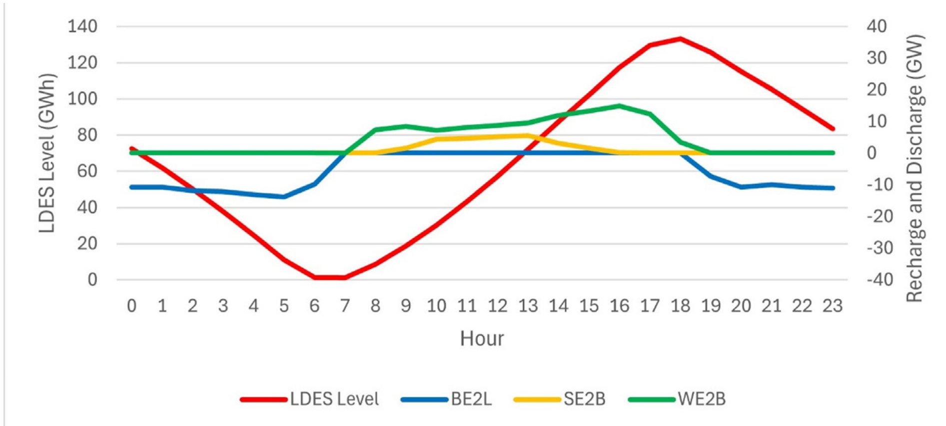
Figure 7. Electrolyzer Energy Consumption by Source for Hydrogen Production



Notes: LDES=long duration energy storage; BL=baseline; VRE=variable renewable energy; S=storage; TC=tax credits.

Figure 8 depicts the level of battery storage and its recharging and discharging behavior over a 24-hour period. The energy level of the LDES over time is shown in red. The hourly battery energy discharged to the electrolyzer is represented in blue. The hourly battery charging by solar is in yellow, and the hourly battery charging by wind is in green. For each hour, the sum of discharge (blue) and charge (yellow and green) equals the marginal change of the level of the LDES (red).

Figure 8. Long Duration Energy Storage (LDES) Level and Recharge and Discharge



Notes: LDES=long duration energy storage; BL=baseline; VRE=variable renewable energy; S=storage; TC=tax credits.

As illustrated, the battery begins discharging (blue) electricity to the electrolyzer at midnight, gradually increasing to a peak around 5 am. Wind energy begins charging (green) the battery at 7 a.m. and continues until 7 p.m. Solar energy starts charging (yellow) the battery from 8 a.m. until 5 p.m. (Note that solar energy is also consumed by the electrolyzer for hydrogen production between 6 a.m. and 7 p.m., as shown in Figure 8.) The level of LDES (red) decreases from midnight to the lowest level at around 7 a.m., starts recharging from solar, and peaks at 7 p.m. when wind stops charging.

6. Conclusion and Future Work

To achieve a net-zero greenhouse gas emissions target and accelerate green hydrogen production, it is crucial to integrate renewable energy sources into hydrogen production processes. Innovations in hydrogen production technologies are also vital for reducing costs and improving economic viability. Moreover, government policies, incentives, and funding opportunities that support the development and adoption of hydrogen production technologies play a significant role. These measures can provide the necessary support and financial backing to foster technological advancements and market uptake, ensuring that green hydrogen can play a role in a sustainable energy future.

This paper introduces an optimization model to support efficient, scalable green hydrogen production using a system that couples off-grid variable renewable energy (VRE) and long-duration energy storage (LDES), a relatively emerging area within the field of green hydrogen production. The model explores interactions among technology, economic factors, and financial incentives that impact production. Using this model, we have undertaken the following analysis: (1) evaluate investment and operational decisions for green hydrogen production, (2) assess environmental and economic effects of policies such as carbon pricing and tax credits, and (3) analyze storage cost sensitivity, including system costs and benefits.

We identify several key findings. First, using grid power to produce hydrogen is expensive and environmentally damaging. Electricity energy costs represent the largest portion of hydrogen production expenses, followed by electrolyzer capital costs and the social cost of emitting CO_2.

Off-grid green hydrogen production requires significant up-front capital investment but offers advantages compared to using grid-connected electricity supply. VRE sources and LDES technologies have low marginal costs, which can lead to substantial reductions in hydrogen production costs while simultaneously lowering CO_2 emissions. Further, off-grid VRE systems simplify eligibility for clean energy tax credits by avoiding the complex hourly matching requirements associated with grid-connected systems. This streamlined access to incentives, combined with the additionality of renewable energy, makes off-grid configurations favorable for clean hydrogen production. The integration of VRE and LDES in off-grid systems supports financial incentives, which can significantly reduce the cost of green hydrogen production to approximately $1 per kilogram, aligning with policy goals for affordable and sustainable hydrogen production.

However, off-grid systems may sacrifice certain ancillary benefits available through grid connections, such as enhanced stability and resource sharing, which could be incorporated in future iterations. A critical consideration is the potential underestimation of VRE-related costs, as expenses tied to land use, environmental impacts, and permitting may not always be fully accounted for.

Similar to the NPC (2024) study, we find that LDES remains too costly for widespread adoption at this time. However, if RD&D efforts lower the capital cost of LDES, investing in LDES alongside VRE could substantially lower emissions and reduce the need for VRE and electrolyzer investments and increase electrolyzer utilization rate. This is because LDES would enable a more balanced distribution of VRE to electrolyzer use over time.

We analyze two policy tools—carbon pricing and tax incentives—to address CO_2 emissions and assess their impacts on investment choices. Our findings indicate that, while both policies achieve similar environmental/emissions outcomes and similar total investment costs, the allocation of investments varies significantly, and economic benefits for developers are different. While a carbon tax raises the cost of hydrogen production, the Clean Hydrogen Production Tax Credit and Investment Tax Credit for VRE and LDES could potentially reduce unit hydrogen production cost from $10.62 per kg in a no-policy scenario to $0.96 per kg. Even without consideration of the social cost of CO_2, financial incentive policy alone is enough to reach both economic and environmental sustainability objectives.

Future research will incorporate several extensions. The current model does not have new renewable generation capacity connected to the grid. However, integrating VREs and energy storage systems with the existing power grid would more fully characterize the potential value of VREs and energy storage systems to supply the grid when there is excess VRE resource available or during times when electricity demand exceeds other sources of grid supply (Johnsen et al. 2025). Such a system integration could offer ancillary services like demand-supply balancing, frequency regulation, and reserve capacity while also improving the flexibility and stability of existing power grids. Moreover, when electricity prices reach peak values, hydrogen production might be curtailed to direct available electricity to its momentary highest-valued use on the grid. This integrated operation of infrastructure might enhance the value of hydrogen, VRE, and LDES investments. Beyond power grids, integrating hydrogen production with other energy-intensive industries, such as iron and steel, will provide a more holistic understanding of potential market dynamics and demand (Bartlett and Krupnick 2020).

Addressing uncertainties related to renewable resources is another important area. Future work will investigate a broader set of hourly capacity factors of wind and solar energy and their variability by season and inter-day to better understand their impact on investments and operation decisions. Economic and technological uncertainties related to electrolyzers, VRE, and battery storage also must be examined. In this study, we performed a limited sensitivity analysis on LDES capital cost. However, conducting a comprehensive literature review and a more detailed sensitivity analysis will help evaluate performance and economic uncertainties, thereby improving the robustness of our model. By addressing these areas, we can develop a more accurate and reliable model for green hydrogen production. Finally, while the current model is calibrated to California, several other regional hydrogen hubs are likely to arise. Each region has unique characteristics in terms of electricity prices, emissions, and availability of renewable resources. Therefore, conducting a regional investment and sensitivity analysis using the model developed in this research would be valuable.

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Appendix: The Hydrogen Production Model

We focus exclusively on off-grid renewable energy and do not consider renewable energy contributions to the power grid, as it is beyond the scope of this study and part of our ongoing research.

A.1. Nomenclature

t	hour index, 1, 2, … T
T	8760
SCC	social cost of carbon, $/t$CO_2$, 185
pG	grid electricity price, $/kWh, CA TOD prices
CEITC	clean energy investment tax credit
H2PTC	hydrogen production tax credit
Electricity Sources	
GE	grid electricity
SE	solar renewable electricity
WE	wind renewable electricity
BE	battery electricity
CapSolar	solar design capacity
CapWind	wind design capacity
Solarratio	solar energy intensity
Windratio	wind energy intensity

α_{Wind}	wind capital cost parameter, \$/kW, 1810
α_{Solar}	solar capital cost parameter, \$/kW, 1611
β_{Wind}	wind fixed O&M cost, \$/KW-YR, 32.3
β_{Solar}	solar fixed O&M cost, \$/KW-YR, 22.2
r_{Wind}	wind capital cost recovery factor
r_{Solar}	solar capital cost recovery factor
Electricity Flow	
GE2L	grid electricity to electrolyzer, kWh
SE2B	solar energy recharge battery
SE2L	solar energy to electrolyzer
WE2B	wind energy recharge battery
WE2L	wind energy to electrolyzer
BE2L	battery energy discharge to electrolyzer, kW
GEMER	grid electricity marginal emissions rate, kg CO_2/kWh
Electrolyzer	
θ	electrolyzer efficiency, %, 80
ϵ	electrolyzer capacity factor, %, 50
H2GER	hydrogen production gross electricity requirement (kWh/kg), 50

H2DMD	hydrogen demand, MMT/year, 2.5
L	electrolyzer energy consumption
CapL	electrolyzer design capacity, MW
α_L	electrolyzer capital cost parameter, $/kW 1065 (Christensen 2020)
r_L	electrolyzer capital cost recovery factor
LDES	
CapS	battery storage design capacity, kWh
S	battery storage, kWh
α_s	battery capital cost parameter, $/kWh, 300
r_s	battery capital cost recovery factor
bduration	LDES discharging hours, 10

A.2. Model Formulation

Renewable Energy Supply and Consumptions

Solar and wind energy data are externally supplied through forecasting/estimation. Solar and wind energy supplies must be equal to their design capacities, CapSolar and CapWind, respectively. At any time, renewable energy is consumed by battery recharge and electrolyzer.

Battery Recharge and Discharge

$$SE2B_t + SE2L_t = Solarratio_t * CapSolar \qquad \forall t \qquad (1)$$

$$WE2B_t + WE2L_t = Windratio_t * CapWind \qquad \forall t \qquad (2)$$

Here we formulate battery recharge and discharge for every period. The battery replenishes its capacity by drawing energy from offline renewable sources, such as dedicated solar (SE2B) and/or wind (WE2B) power. Subsequently, the battery releases its stored energy to the electrolyzer (BE2L) for hydrogen production. At any time, LDES (S) must be smaller than the battery capacity (CapS).

Hydrogen (H2) Production

$$S_t = S_{t-1} + SE2B_t + WE2B_t - BE2L_t \qquad \forall t \qquad (3)$$

$$S_t \leq CapS \qquad \forall t \qquad (4)$$

$$BE2L_t \leq \frac{CapS}{bduration} \qquad \forall t \qquad (5)$$

$$SE2B_t + WE2B_t \leq \frac{CapS}{bduration} \qquad \forall t \qquad (6)$$

H2 production can be expressed using the following equation (6). $H2_t$ is the amount of hydrogen (in kg) produced in time (hour) t. *GE2L, SE2L, WE2L*, and *BE2L* are electricity from power grid, on-site renewable energy, and on-site battery energy, respectively, into electrolyzer to produce hydrogen. *H2GER* is a hydrogen production gross electricity requirement.

For any period, electricity consumed by the electrolyzer cannot be bigger than the

$$\begin{aligned} H2_t = (&GE2L_t + SE2L_t + WE2L_t \\ &+ BE2L_t * (1 - \frac{bloss}{100})) * \theta / H2GER \end{aligned} \qquad \forall t \qquad (7)$$

electrolyzer capacity:

$$(GE2L_t + SE2L_t + WE2L_t + BE2L_t) \leq CapL \qquad \forall t \qquad (8)$$

Emissions

Assuming hourly CO_2 marginal emissions rate from power grid are given. The total CO_2 emissions can be calculated using the following equation:

$$CO2E = \sum_t GEMEF_t * GE2L_t \qquad (9)$$

H2 PTC

$$H2PTC_t = -1.161 * \ln\left(GEMEF_t * \frac{GE2L_t + 0.0001}{H2_t + 0.0001} + 0.3484\right) + 1.7758 \qquad \forall t \qquad (10)$$

Total Systems Cost

The objective function seeks to minimize the net system costs by minimizing: (1) amortized capital expenditures for investments in wind, solar, battery storage, and electrolyzer; (2) energy costs related to system operation and maintenance (O&M); (3) the social cost of CO2 emissions; and maximizing: (4) the investment tax credit (ITC) for variable renewable energy (VRE) and long-duration energy storage (LDES), as well as the production tax credit (PTC) for hydrogen production.

$$\begin{aligned} OBJ = {} & (1 - CEITC) * rWind * \alpha Wind * CapWind + \\ & rSolar * \alpha Solar * CapSolar + rs * \alpha s * CapS + rL * \alpha L * CapL \\ & + \sum_t pG * GE2L_t + (SCC * TCO2E) - \sum_t H2PTC_t * H2_t \end{aligned} \qquad (11)$$