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Enhancing Green Hydrogen Integration In Distributed Energy Systems

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ENHANCING GREEN HYDROGEN INTEGRATION IN DISTRIBUTED ENERGY SYSTEMS

by

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DEDICATION

To my family—your love has been my anchor.

This work is a testament to faith, perseverance, and purpose. It stands for the belief that even in the face of uncertainty, vision guided by integrity can shape a better world.

To my children and all dreamers: may you always walk with courage, serve with conviction, and never doubt the power of one life lived with meaning.

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ABSTRACT

This study investigates strategic integration of green hydrogen into Distributed Energy Systems (DES) as a means of addressing three closely related challenges: first, uncertainties in hydrogen supply due to renewables intermittency; second, non-existence of practical, scalable modeling solutions for early-phase DES planning involving Alkaline Water Electrolyzers; and third, a lack of sufficient policy frameworks facilitating mass deployment. Existing hydrogen production models are often too complex for effective use in DES and do not relate stack number, input power, and renewable resource fluctuation. To address this limitation, the paper introduces a new probabilistic electrolyzer sizing method based on cumulative distribution function (CDF) percentiles (P50–P90) and formulates a reduced-form hydrogen output model with electrolyzer stack number (N) and input power (P). The model accounts for varying performance between systems with $N \leq 6$ and $N > 6$, elucidating economies of scale and scaling behavior in the non-linear sense within <5% error. Empirical confirmation confirms that hydrogen output increases linearly with system size, and P60–P70 system sizing cases offer optimal trade-offs among output, curtailment, and cost. Simulation-based operational modeling using HOMER Pro reveals that the operation of hybrid battery-hydrogen systems decreases curtailment by 60% and REU by 30%, whereas load-following electrolyzers reduce Levelized Cost of Hydrogen (LCOH) by 8–15%. Policy simulations show that layered incentives—20–30% CAPEX subsidies, \$3/kg H_2 production credits, and \$40–83/ton carbon pricing—can raise project Net Present Value (NPV) by 300–900%. Monte Carlo simulations also determine a 70% probability of achieving positive NPV under best-case policy conditions. Grid-connected hydrogen systems are less policy-sensitive, whereas synthetic

gas, ammonia, hydrogen natural gas blending, and underground storage channels require sector-focused intervention, such as subsidies, tax credits, and R&D investment.

This combined strategy—combining empirical modeling, operational improvement, and multi-layer policy design—gives a realistic, end-to-end blueprint for hydrogen deployment in DES. Some of the most important recommendations are: one, the use of open-access sizing tools and LCOH calculators to facilitate local investors and planners; two, the use of modular, hybrid battery-hydrogen system designs to maximize flexibility and minimize curtailment; and three, sequenced policy support through the blending of CAPEX subsidies, production credits, and carbon pricing to promote equitable, climate-aligned hydrogen uptake. These findings support SDG 7, SDG 9, SDG 11, and SDG 13 attainment and Paris Agreement objectives and render hydrogen technically viable and socioeconomically justifiable as a pillar of the global energy transition. Subsequent research ought to integrate high-frequency solar, wind, and demand data; investigate geothermal and bioenergy integration; and simulate investor reaction to regulation risk by means of Bayesian and game-theoretic analysis.

CHAPTER ONE

1.0 INTRODUCTION

1.1 The Climate Crisis and Global Action

Global climate change is an international crisis of colossal importance to societies, global economies, and ecosystems alike (Barnett & Adger, 2003; Young et al., 2006). The aggravating climate crisis worldwide has prompted a call to action across the globe to curtail the impact of greenhouse gases, including carbon dioxide (CO_2), emitted due to extensive use of fossil fuels and massive forest depletion activities. Climate change is manifested in terms of increasing global temperatures (^oC) (Mokhov, 2022) that intensify the hydrological cycle, leading to increased frequencies of extreme weather conditions (Newman & Noy, 2023) and negative impacts on human life (Shivanna, 2022) and the environment (Rawat et al., 2024)

Scientific Consensus and the Role of Human Activity

The scientific consensus unequivocally identifies human actions as the primary cause of this warming trend, with potentially disastrous consequences—hence the urgent call to action to reduce greenhouse gas emissions (GHG) (Bian, 2020; Letcher, 2019). The climate crisis poses substantial dangers to natural ecosystems, public health, food security, and water supply. Recent studies show that climate change impacts agriculture (Abbass et al., 2022), coastal regions (Williams et al., 2022), water resources (Jain & Singh, 2023), human health (Abbass et al., 2022), biodiversity (Díaz & Malhi, 2022), forests, tourism, and economic sectors (Raihan, 2023).

Considering this, the Paris Agreement, established in 2015, champions ambitious global efforts to transition towards renewable and low-carbon energy solutions to reduce the adverse effects of climate change (Beckmann et al., 2023).

Yet there are a few studies and scientific views that preserve global warming as a natural phenomenon that has been occurring throughout the history of Earth as a result of solar variation, orbital forcing, volcanic eruption, and oceanic cycles (R. Lindzen, 2022; R. Lindzen & Happer, 2021; R. S. Lindzen & Coalition, 2020; West & Lindsey Jr, 1968). These perspectives contend that the current warming trend is not necessarily anthropogenically caused by CO_2 emissions, but by complicated natural processes that have influenced the planet's climate for thousands of years.

These arguments repeatedly invoke the finiteness of climate models, cosmic rays, or solar radiation as substitutes for greenhouse gas effects, and conceivable overestimation of the warming effect of CO_2. These perspectives—albeit in minority—are worth hearing for offering an important counterweight within the science of climate change. Nonetheless, the overwhelming body of scientific evidence confirms that human actions—particularly the burning of fossil fuels and land-use changes—are the primary drivers of the current unprecedented warming trend, with potentially disastrous consequences for ecosystems, economies, and human well-being across the globe. In response, the global science and policy communities have increasingly emphasized the need for urgent action on reaching carbon neutrality to reduce these impacts and stabilize the climate system.

Global GHG Emissions

The top 2020 GHG sources were China (27%), USA (11%), India (7%), and EU-27 (6%), whose combined percentage was close to half of all world emissions, the "Others" account remaining constant at 49%, showing the size of the crisis on a global scale (Climate Watch, 2024). China's emissions increased from 1990 to 2020 and became the largest emitter in 2020. China alone contributed about 34% of global emissions in 2024 (13,259.64 Mt CO_2e), followed by the USA and India at 12% and 7.6% respectively (Crippa et al., 2024). A summary of the top greenhouse gas emitters between 2020 and 2024 is provided in Figure 1.1.

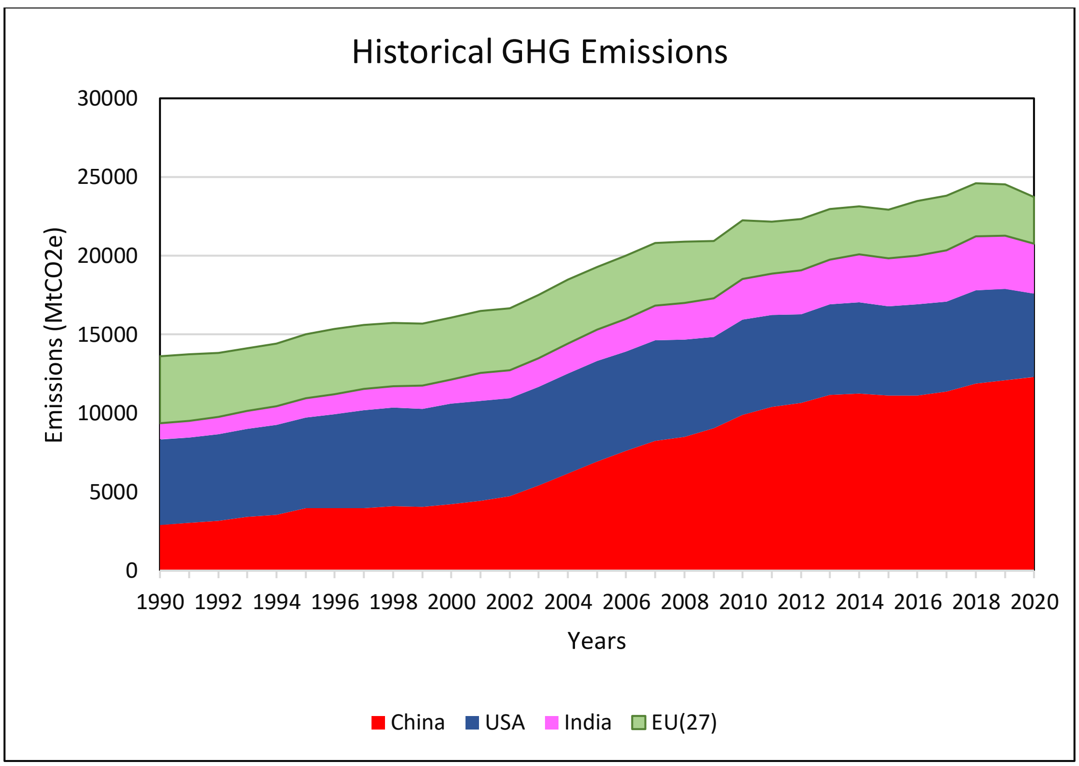


Figure 1. 1 Historical GHG from 1990 to 2020 (Climate Watch, 2024)

The EU-27 also continued its reduction, as of now at 6.4%, which was its earlier compliance with decarbonization policies (Climate Watch, 2024; Crippa et al., 2024). Table 1.1 summarizes the major GHG emitters from 2020 to 2024, showing emission levels and notable trends among leading countries and regions.

Table 1. 1 Major Emitters of Greenhouse Gases (2020–2024)

Country/Region	2020 Share of Global GHG (%)	2024 CO_2e Emissions (Mt)	Notable Trends
China	27%	13,259.64	Largest emitter, rising trend
USA	11–12%	~6,000	Slight decrease, high baseline
India	7–7.6%	~3,800	Increasing with development
EU-27	6–6.4%	~3,000	Decreasing due to policy action
Others	49%	—	Highly fragmented contributions

1.2 The Case for Carbon Neutrality

Carbon neutrality has become one of the most central issues in the global fight against climate change, when CO_2 emitted equals the CO_2 absorbed (Awosusi et al., 2023; J. M. Chen, 2021). All interventions that can relate to carbon neutrality are seen as needed to encompass cross-sectoral interventions that include renewable energy generation, energy efficiency, carbon emission pricing, nature-based solutions, and other emergent technologies, including carbon capture and direct air capture (L. Zhang et al., 2023). Among all these, green hydrogen assumes the most important enabling role in the decarbonization of the hard-to-abate sectors and the flexibility of energy supply under the umbrella of DES.

REDD+-terrestrial interventions do require international cooperation, and afforestation and reforestation do support carbon sinks (Morita & Matsumoto, 2023). Our oceans have become carbon sinks, absorbing ~30% of our CO_2 emissions (Feely et al., 2001), which represent another important blue carbon resource (Claes et al., 2022; Kurniawan et al., 2023). However, for natural solutions to be effective in the limited time available to meaningfully address climate, they must rely on technological interventions to complement those natural solutions.

Although Carbon Capture and Storage (CCS) and Direct Air Capture (DAC) technologies (Bahman et al., 2023; Datta & Krishnamoorti, 2023) hold great promise, they are not yet cheap and energy-efficient, and hence it is more crucial than ever to use green hydrogen as a zero-emission, dispatchable fuel for industrial uses and grid demand balancing. While green hydrogen occupies the place of central decarbonization, cluster-based CCS techniques have also been proposed as large-scale measures for managing emissions from power generation from fossil fuels, especially in developing countries like India (Evro, Wade, Vashaghian, et al., 2023). These are not contemporary issues; the historical issues of U.S. solar PV firms in keeping up with steep cost declines and capital-intensive scale-up needs are echoes of the issues of early-stage hydrogen firms today (Evro, Wade, & Tomomewo, 2023). Comparative analysis of these and other clean energy technologies—their potential to be integrated in DES—is shown in Table 1.2. Sectoral applicability, scalability, and limitations of each option are tabulated, determining the rationale for giving green hydrogen priority.

As suggested by Table 1.2, green hydrogen is exceptional among clean energy technologies due to its high GHG abatement, sectoral flexibility, and ease of integration into modular DES. Carbon offsetting is a flexible option for emissions compensation (Chenyang, 2023; Gordic et al., 2023) but clouds real and effective emissions reductions with questions of its credibility. This further calls for direct reductions through in-system measures, mandatory for green hydrogen under DES by enabling localized decarbonization of power, transport, and industry.

Table 1. 2 Comparative Attributes of Clean Energy Technologies for DES Integration

Technology	GHG Reduction Potential	Storage Duration	Sectoral Application	Scalability for DES	Limitations(s)
Solar PV	High	None (direct)	Electricity generation	High	Intermittent; needs storage (Zahedi, 2011)
Wind	High	None (direct)	Electricity generation	Medium – High	Location-dependent; variable output (Berna-Escriche et al., 2025)
Battery Energy Storage	Medium	Short-term (4–8 hrs.)	Load smoothing; backup	Medium	Excessive cost per kWh; limited seasonal storage (Papageorgiou et al., 2024)
Hydropower	High	Seasonal (with reservoir)	Electricity, irrigation	Low (site-specific)	Ecological impacts; limited new sites (McManamay et al., 2015)
Carbon Capture (CCS)	High	Not applicable	Industrial process emissions	Low	Costly; energy-intensive (A. Olabi et al., 2022)
Green Hydrogen (AWE)	Very High	Short to long-term	Power, industry, transport	High (modular)	Current cost and infrastructure limitations (J. Zhang & Li, 2024)

The above will require carbon pricing mechanisms (including taxes and cap-and-trade systems) (Abbas et al., 2023; Shang, 2023) to be introduced to stimulate low-carbon innovation that will be well-complemented with hydrogen infrastructure investments under DES. However, it is of utmost importance to pair those mechanisms with technological solutions that will turn the incentives into actual reductions.

This shows that the demand-side emissions under the principles of a Circular Economy (Di Vaio et al., 2023) and energy efficiency strategies (Chowdhury et al., 2018; Mushafiq et al., 2023) are mostly being answered, while supply-side decarbonization for distributed systems remains only half-done in the absence of flexible energy carriers like hydrogen that could store and deliver clean energy beyond the intermittency of solar or wind (Karduri, 2018; Saberi Kamarposhti et al., 2024).

Renewable energy (Gasparatos et al., 2017; Ram et al., 2022) is foundational to the renewable ecosystem yet constrained by intermittent and infrastructure lock-ins (Jowitt, 2024; Paraschiv & Paraschiv, 2023). Green hydrogen in DES may represent the largest opportunity for long-term storage, grid flexibility, and decarbonized contingency power while effectively plugging critical holes along the clean energy value chain. No carbon-neutrality pathway will depend on technology innovation (Caineng et al., 2023; Criscuolo et al., 2023) by sponsoring hydrogen technologies, we shall grease the advancement of larger-scale modular decentralized solutions considered for energy equity and emissions reduction especially when paying attention to small- and large-scale DES-focused applications.

1.3 Hydrogen economy as a catalyst and the need for integration in DES

The hydrogen economy contributes to carbon neutrality by decarbonizing industry processes with low carbon, transport, enabling systems of renewable energy and integration with the smart grid (Jayachandran et al., 2024). Hydrogen is a formidable competitor to fossil fuels as a green electro-fuel within industry and mobility applications (Ababneh & Hameed, 2022). Smart grids optimize the use of hydrogen by coordinating its generation with hours of peak renewable energy in their efforts to be efficient and system resilient (Karduri, 2018; Saberi Kamarposhti et al., 2024). Future Hydrogen cities also ensure hydrogen flexibility in reducing emissions and propelling clean city growth (Beagle et al., 2024; Kwak et al., 2024). These technologies underscore the importance of adding green hydrogen to DES that will fuel local, low-carbon energy networks that are scalable, flexible, and net-zero focused. However, as with the U.S. solar PV market, green hydrogen deployment must avoid the same pitfalls of long permitting cycles, financing delays, and rapid cost erosion that undermined new entrants (Evro, Wade, & Tomomewo, 2023)

1.4 Analysis of U.S., China, and EU Climate Commitments

Comparative analysis of United States, Chinese, and European Union Nationally Determined Contributions (NDCs) is underpinned by variant climate action plans with wider implications for integration of green hydrogen in DES. Despite all three regions promoting decarbonization, energy efficiency, and innovation, integrating green hydrogen in distributed energy planning remains significantly varied across them. The European Union is leading in this regard with Directive 2023/2413, which expressly incorporates green hydrogen into underlying decarbonization plans (Directive 2023/2413, 2023), but up to now, neither the United States nor China has executed such system integration platforms.

The new NDC places electrification, zero-emission vehicles (ZEVs), and carbon capture and storage (CCS) at the center of decarbonization plans in the United States (Johnson & Sabharwall, 2022; UNFCCC, 2023). However, the hydrogen economy is accorded ancillary treatment, with no solidly designed plan for the deployment of green hydrogen in dispersed or rural networks, hindering national energy resilience and decentralization capacity. This shortfall is illustrated in Figure 1.2, showing historical CO_2e emissions and sectoral hydrogen integration deficit.

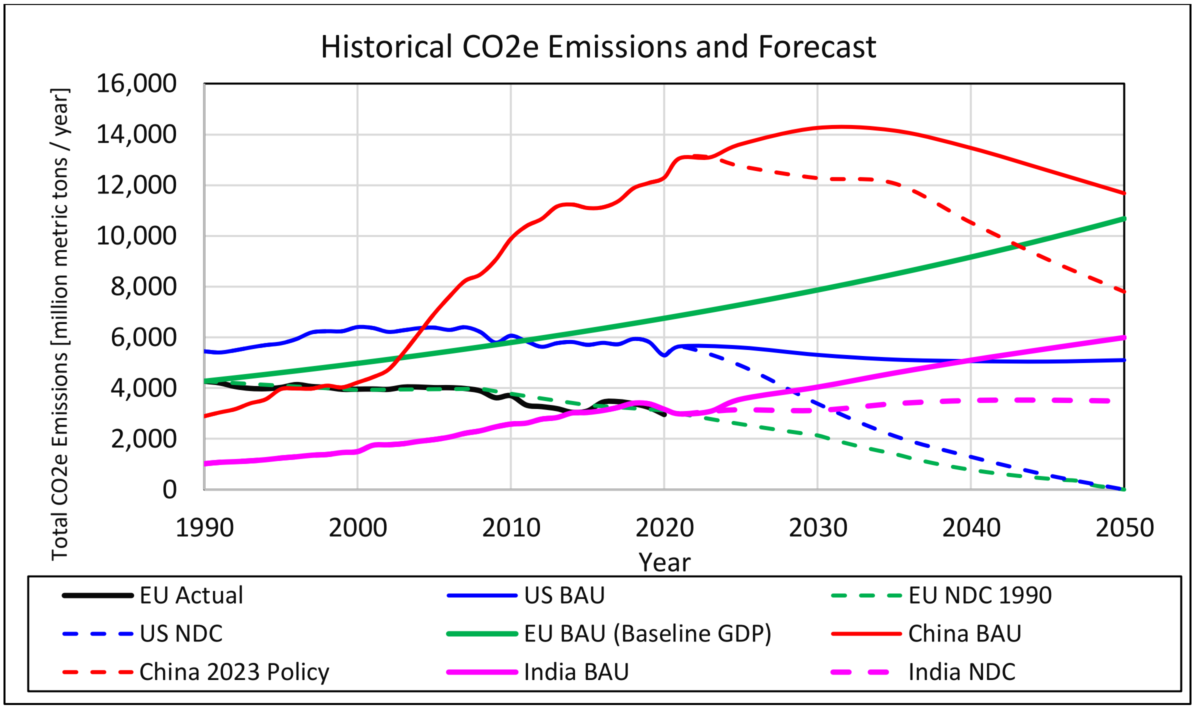


Figure 1. 2 Emissions Trend US, China, India, and EU (Climate Watch, 2024)

China's CNDC also centers its industrial decarbonization hydrogen approach like the United States' but lags a green hydrogen usage plan integrating DES. Regardless of China's huge investment, its parallel build-out of coal infrastructure and centralization energy strategy undermines its locus for clean local energy transition (CREA, 2023; Lirong et al., 2023). In reaction to this, the European Union reacts back in reverse mode with Directive 2023/2413 that, besides setting a target of 42.5% of the share of renewable energy, also sets green hydrogen as one of hard-to-abate sectors and provides for smart grid development, and DES (Directive 2023/2413, 2023).

CCS and carbon pricing are employed by all three regions, but the EU only goes as far as to officially add hydrogen to its DES and sectoral policies. Absence of such in U.S. and Chinese policy diminishes them from building energy systems that are decentralized and resilient. These three policies do not have robust hydrogen integration policy in DES. Hydrogen's advantages of facilitating carbon neutrality via clean combustion, energy storage, and grid independence make it an ideal vector for DES, as indicated by Table 1.2. Hydrogen is also complementary with other technologies for emission abatement (Oshiro & Fujimori, 2022). As illustrated in Figure 1.3, it is a link to other carbon neutrality strategies such as DAC, reforestation, and carbon. More than $240 billion has been invested in hydrogen infrastructure globally, but projects, as can be seen from Figures 1.4, but are still extremely centralized and seldom embedded in rural or modular DES (Heid et al., 2022; Yan et al., 2024). While hydrogen is in the limelight for microgrids and smart cities (Ajanovic et al., 2020; Mojtahed et al., 2023), urban-scale conceptualizations like H2PIA (Balta & Balta, 2022; Evro, Oni, et al., 2024), fall short for rural DES needs, as these are limited by limited finances and grid extension.

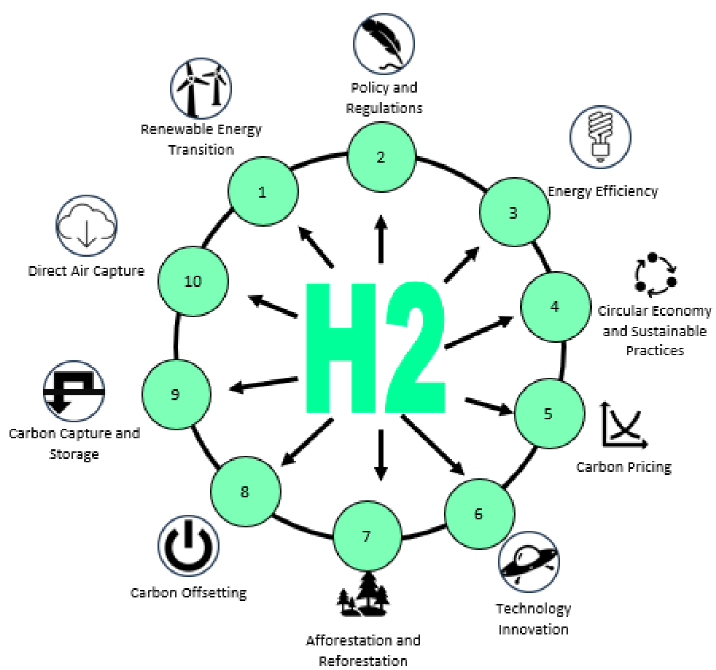


Figure 1. 3 The Central Role of Hydrogen (H_2) in Climate Mitigation Strategies

Hydrogen's enhanced storage performance compared to batteries is best suited for DES seasonal and back-up applications (Soyturk et al., 2024; Waseem et al., 2023). Case studies—such as

Chinese retrofitting of coal-fired power plants (He et al., 2023), Spanish microgrid integration (Cabello et al., 2022), and the EU power-to-gas pilots (Knazkins et al., 2017) are promising but reflect the ongoing shortage of systems hydrogen-DES integration, especially in developing economies.

In brief, the EU has mapped policy and infrastructure integration of green hydrogen into DES, while the U.S. and China have not yet set out to prioritize centralized applications. To address this gap, collocated renewable-electrolyzer systems, modular fuel cell deployment, and targeted regulatory incentives must be undertaken. Where climate mitigation and decentralized energy access intersect, scaling up DES green hydrogen is essential to ensure a just, resilient, and low-carbon energy transition.

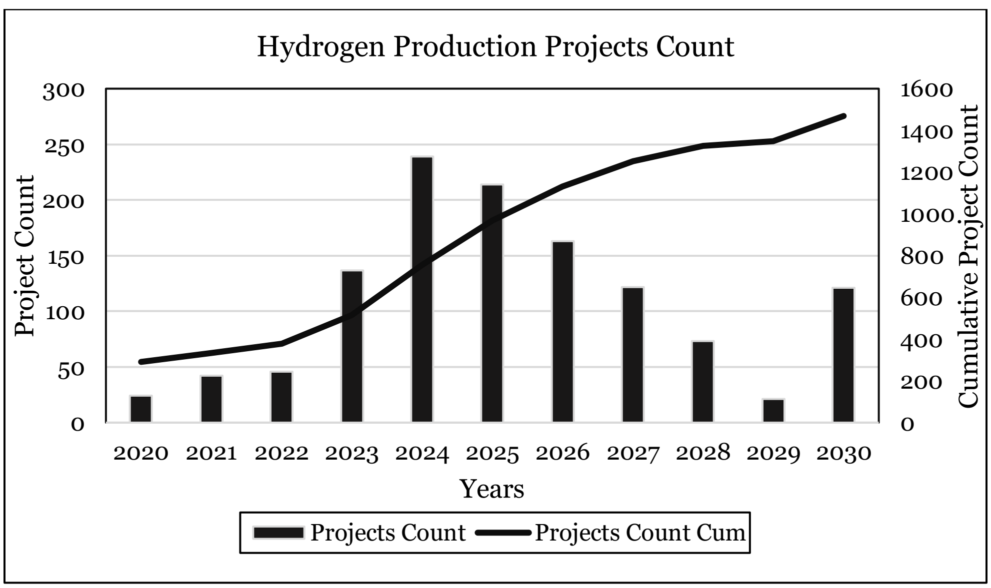


Figure 1. 4 Hydrogen production projects count (IEA, 2024) as of January 2024.

1.5 Statement of Research Problem

As climate change increases, low-carbon, flexible, and responsive energy sources are more needed than ever. Global greenhouse gas emissions continue to rise due to persistent reliance on fossil fuels and uneven application of clean technologies even though scientific evidence agrees that human activity is the major cause of climate disturbance (Bian, 2020; Mokhov, 2022; Newman & Noy, 2023). While the world moves towards achieving the Paris Agreement's goals, carbon neutrality for the entire power, transport, and industry sectors means more than electrification and carbon capture; it needs a shift in paradigm towards DES that can be designed to accommodate green hydrogen (Beckmann et al., 2023).

Lacking in planning, decentralized hydrogen application will be overwhelmed by the growth of huge industrial hydrogen clusters, disenfranchising just those communities most vulnerable to energy insecurity and climate impacts. As can be seen in Figure 1.4, global hydrogen infrastructure is still focused on centralized applications and not community-sized, modular systems. Also, Carbon Capture and Direct Air Capture technologies are promising but energy hungry and costly. Green hydrogen is more pragmatic and versatile to adopt integration of clean energy at the grid edge soon (Bahman et al., 2023; Datta & Krishnamoorti, 2023). The absence of robust models, real-time optimization methods, and enabling policy frameworks specific to DES guarantees that the full potential of green hydrogen is not leveraged.

Without effective tools and equitable policies, hydrogen will remain relegated to niche or elitist uses, and its potential to contribute to mass decarbonization will be curtailed. Further, fractured regulatory frameworks, poor market incentives, and asynchrony between hydrogen and renewable technologies also limit deployment in actual environments (Directive 2023/2413, 2023; Peng & Bai, 2022). Therefore, this project intends to measure technological readiness, operational effectiveness, and policy readiness for the integration of green hydrogen into DES.

It specifically seeks to construct user-friendly models of production, optimize control policies for electrolyzer and storage renewable connection, and identify targeted policy instruments that reduce economic and regulatory barriers to decentralize uptake of hydrogen. Only by surmounting these challenges can green hydrogen unlock its potential as a driver of a just, resilient, and climate-compatible energy future.

1.6 Research Hypothesis

Based on the above discussion, research hypothesis (**H_1**) is that building simplified models of hydrogen production, optimizing storage and electrolyzer operation, and imposing supportive policy and regulatory measures will significantly advance the scalability, cost-effectiveness, and equitable deployment of green hydrogen in DES toward significantly contributing towards achieving global carbon neutrality goals.

Null Hypothesis (**H_0**) is that development of streamlined models of production, operational improvement strategies, and policy mechanisms will not have a considerable impact on scalability, cost-efficiency, or equitable deployment of green hydrogen in DES, or make any tangible contribution to carbon neutrality goals. To evaluate this hypothesis, the study is divided into the following three research questions.

1.7 Research questions

This study investigates how to enhance the feasibility and scalability of green hydrogen in DES by addressing three key research questions. RQ1 explores how to develop a simple, predictive method to estimate hydrogen production from renewable availability and electrolyzer configuration. The goal is to create a practical, calibrated tool to support DES planning using real-world solar and wind data.

1.7.1 Research Question 1 (RQ1)

How can one devise a simple and pragmatic approach to estimate hydrogen production potential from available renewable energy and electrolyzer stack configuration?

The objective is to develop a predictive framework that links renewable energy availability with electrolyzer type, efficiency, and stack configuration to estimate hydrogen production. This includes creating an easy-to-use methodology—such as empirical equations or lookup tables—tailored for DES-scale applications. The model is calibrated using solar and wind profiles to support informed decision-making for local and regional hydrogen deployments.

1.7.2 Research Question 2 (RQ2)

How do efficiency strategies for electrolyzers and hydrogen storage need to be optimized to minimize energy curtailment and maximize consumption of renewable energy in a Distributed Energy System (DES)?

The objectives are to explore system dynamics under varying renewable input conditions and to develop control strategies that balance hydrogen production and storage loads. This includes analyzing hybrid storage configurations—combining battery and hydrogen technologies—to enhance load balancing and reliability in off-grid systems. Additionally, the study aims to formulate real-time or near-real-time design algorithms that minimize curtailment and maximize renewable energy utilization efficiency.

1.7.3 Research Question 3 (RQ3)

What are the most effective market incentives and policy instruments for efficient storage of hydrogen and electrolyzer integration in DES?

The objectives are to evaluate the impact of various policy instruments—such as subsidies, feed-in tariffs, and carbon pricing—on the economic viability of green hydrogen in DES. The study also seeks to identify regulatory gaps and propose actionable policy recommendations that support decentralized hydrogen deployment. In addition, it assesses financing mechanisms and incentive programs that facilitate the scalable and equitable growth of small- and community-scale hydrogen systems.

1.8 Research Objectives

Create Estimation Technique: This objective aims to develop a simplified, user-friendly method for estimating green hydrogen production based on local renewable energy availability and electrolyzer stack configuration. The goal is to support rapid, early-stage feasibility screening for DES applications.

Optimizing Operating Strategies: The focus here is to design and compare optimization strategies that improve electrolyzer and hydrogen storage performance. These strategies are intended to minimize curtailment and enhance energy efficiency and reliability in decentralized energy applications.

Evaluate Policy and Incentive Mechanisms: This objective seeks to identify and assess policy tools, regulatory support, and market incentives that can enable cost-effective, equitable integration of green hydrogen into DES. The intent is to guide inclusive and scalable hydrogen deployment.

1.9 Research Significance

The importance of this research is its interdisciplinary and systemic attempt to make green hydrogen integration in DES a reality through operational, policy, and technological advancements. By addressing the biggest challenges enumerated under the research gaps, this research is a contributory work in five broad areas:

Energy Equity and Access: The project supports global energy justice aims and contributes directly to Sustainable Development Goal 7 (Affordable and Clean Energy) through the development of tools and frameworks that make hydrogen technology accessible to non-technical stakeholders and deployability at microgrid and community scales. The project makes rural, islanded, and underserved communities gain from the advantages of decentralized green hydrogen systems, achieving inclusive, locally owned energy access and reducing carbon-based backup system dependency.

Decarbonization and Climate Action: With SDG 13 (Climate Action) umbrella and Paris Agreement frame of mind, studies augmented emissions lowering through zero-emission solutions for the hard-to-abate industries. Using optimization in electrolyzers and hybrid storage enabler, studies attain the utmost in CO_2 emissions lowering, energy loss lowering, and fossil fuel lowering in decentralized uses—enabling mid-century transition to net-zero emissions.

Scalable and Resilient Grid Integration: Integration of green hydrogen into DES presents a new solution to renewable intermittency problem. Through supply of long-duration energy storage, demand-side flexibility, and peak load shifting, this study advocates for development of modular and climate-resilient infrastructures as needed under SDG 9 (Industry, Innovation, and Infrastructure). The findings advocate for enhancement of grid stability, solar and wind curtailment minimization, and power decentralized reliability against real-time operating conditions.

Contribution to Net-Zero Pathways: This research complements international and national net-zero commitments by building cost-effective and location-specific hydrogen deployment strategies outside the scope of centralized megaprojects. This research presents tangible solutions for hydrogen integration in distributed systems, which are at the heart of non-exclusionary and inclusive achievement of net-zero roadmaps in the developed and developing world.

Facilitation of Global Climate and Energy Governance: Finally, the study is Paris Agreement architecture compatible in the sense that it enables quantifiable action on mitigation via innovation, market incentives, and coordination of policy. It responds to the world's demand for the implementation of climate-compatible technology and enables subnational actors—microgrid operators, municipalities, and communities—to be on an equal footing in the transition to a low-carbon world.

Figure 1.5 presents the conceptual framework of the study, illustrating how technological, operational, policy, and infrastructure innovations converge to support green hydrogen integration in DES while aligning with global climate goals and the Paris Agreement.

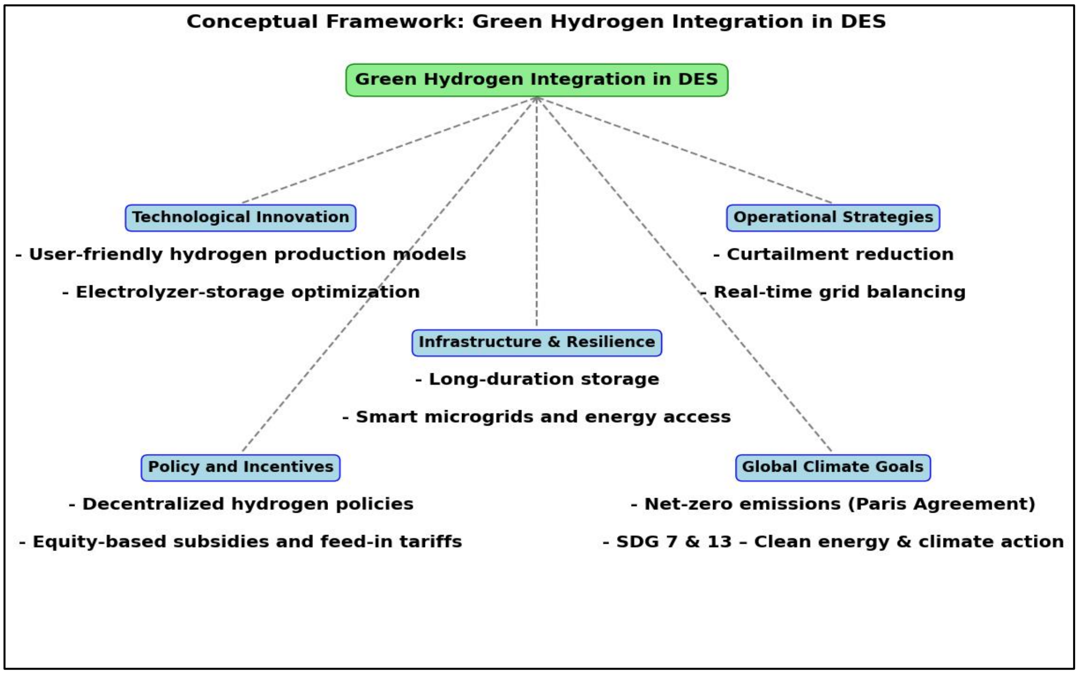


Figure 1. 5 Conceptual Framework: Green Hydrogen Integration in DES

1.10 Dissertation Organization

The dissertation has eight chapters, which address a particular problem of the research and collectively add to the knowledge and practicability of green hydrogen integration into DES.

Chapter 1 gave an introduction and background to the study. It summarizes the world imperative for clean energy change, hydrogen as a decarbonization and energy justice driver, and the justification for research concentration on DES applications. Problem statement, research questions, hypothesis, and the study objectives are also summarized in the chapter.

Chapter 2 is an extensive literature review. Chapter 2 critically reviews existing industrial and academic literature concerning hydrogen modeling production, electrolyzer operation, hybrid storage, and policy regulation. Chapter 2 highlights key technology strategy gaps, optimization techniques, and regulation compliance gaps for DES-scale deployment of hydrogen.

Chapter 3 explains the research strategy used to model the research questions. It specifies the study design, data sources, modeling methods, performance indicators, and validation procedures. For RQ1, it describes the development of a simple predictive model for hydrogen production estimation. For RQ2, it describes the development of dynamic control simulation of electrolyzer and storage operations. For RQ3, it describes the policy analysis framework for regulatory, economic, and equity-based incentives.

Chapter 4 answers Research Question 1 (RQ1) by defining and creating an empirical model for hydrogen production capacity estimation from local renewable energy sources and electrolyzer design. Chapter 4 reports the development, implementation, and verification of the above estimation tool based on actual solar and wind resource profiles.

Chapter 5 addresses Research Question 2 (RQ2) and investigates electrolyzer operation modes and hydrogen storage in DES. It develops hybrid storage optimization models that combine battery and hydrogen storage and examines real-time control strategies maximizing renewable energy minimization of curtailment and utilization and system resilience.

Chapter 6 answers Research Question 3 (RQ3) by examining current policy levers and incentives in the market for DES hydrogen uptake. Chapter 6 enumerates regulatory loopholes, proposes reforms, and cross-comparatively analyzes policy instruments (e.g., subsidy, feed-in tariffs, carbon pricing) to determine their contribution to upscaling decentralized green hydrogen adoption. Chapter 6 also answers financing and equity concerns for community- and rural-scale systems.

Chapter 7 provides an integrative discussion of findings from Chapters 4 through 6. Chapter 7 reports cross-comparison analysis of technical, operational, and policy contributions enabling global climate ambitions, i.e., the Paris Agreement, SDG 7 (affordable and clean energy) and SDG 13 (climate action). Chapter 7 refers to implications of the study for net-zero transitions and decentralized energy planning.

Chapter 8 concludes the study and presents recommendations for further research in green hydrogen integration, including policy and practical implications and future research directions. It also reiterates the strategic worth of modular, scalable, and policy-enabled green hydrogen systems for a climate-resilient, equitable energy future.

1.11 Chapter Summary

Chapter One sets the scene for this research by locating it within the global call to solve the problem of climate change through new, scalable, and inclusive energy solutions. Chapter One begins by situating the climate crisis in its scientifically established, anthropogenically driven process that has massive ecological, economic, and social impacts. While there are other natural climate variability views, the prevailing scientific consensus strongly favors radical decarbonization in accordance with international agreements like the Paris Agreement and Sustainable Development Goals (SDGs).

In working toward that vision, the chapter places carbon neutrality on the great path to climate stabilization and examines various paths of energy transition. Of them, green hydrogen stands out as a specific solution because it can decarbonize hard-to-abate industries, function as a long-duration energy storage technology, and be integrated into DES to enable decentralized, democratic access to energy.

The chapter also addresses comparative policy and infrastructural divergence of top emitting countries—China, the U.S., and the EU—on the inclusion of green hydrogen in climate action plans. EU Directive 2023/2413 is described as world-leading on the inclusion of hydrogen in DES, while in the U.S. and China, top priority is assigned on centralized use with no consideration of community-scale take-up.

Interestingly, the chapter refers to a corresponding research problem: the integration of green hydrogen into DES is constrained by overly costly manufacturing paradigms, inflexible operating structures, and policy facilitation devices. The problem is also triggered by lock-in technologies and fragmentation of regulation, and there is a risk of marginalizing vulnerable groups from the energy transition opportunity of hydrogen energy.

To address these limitations, this chapter proposes a general research hypothesis (H_1), which posits that a combination of robust modeling frameworks, efficient operational strategies, and well-designed policy interventions can enable cost-effective and equitable integration of green hydrogen in DES environments. This hypothesis is structured around the following three interlinked research questions:

- RQ1 explores the way an empirical model of hydrogen production from renewable supply of power and electrolyzer design can be established.

- RQ2 explores how to maximize the use of electrolyzers and hybrid storage in a way to achieve maximum renewable energy, along with system efficiency.
- RQ3 uses policy instruments and market incentives required to de-risk and deploy hydrogen on mass scale within decentralized spaces.

To supplement such queries, the chapter provides clear and impactful goals pertaining to modeling, simulation, policy assessment, and equity that guide stakeholders in modeling, simulation, policy assessment, and promoting energy equity. It finds the significance of the research, its contribution to climate action (SDG 13), access to renewable energy (SDG 7), and inclusive industrialization (SDG 9). A conceptual visualization framework (Figure 1.5) illustrates how technology, operation, and policy drivers converge to drive hydrogen integration into DES.

Building upon this conceptual foundation, Chapter Two critically examines the technological, operational, and policy barriers currently limiting scalable green hydrogen integration into DES. It will outline existing technological gaps, operating bottlenecks, and regulation limitations which limit scalable DES integration. The subsequent empirical exercise of modeling and simulation is based on the theoretical and empirical foundation this literature review offers and vindicates the rationale and novelty of the research approach.

CHAPTER TWO

2.0 LITERATURE REVIEW

2.1 Introduction

The world is now at a tipping point in shifting toward a low-carbon, decarbonized energy future under the influence of mounting pressure to manage greenhouse gas emissions in a way that improves energy access, equity, and resilience. Climate action has accelerated the shift in energy as governments and industry, especially those in developing economies of Asia, Africa, and Latin America, have moved away from centralized, fossil-fuel-based systems. Underway is a transition towards decentralized, integrated energy systems and green hydrogen, and DES that have the potential to revolutionize the realization of net-zero emissions, climate justice, and energy independence. The transition to a new energy system is as much a technical process as it is a realization of socioeconomic and political ambitions.

As per the IPCC (2023), global warming can be limited to 1.5°C if greenhouse gases peak by 2025 and decline by 43% by 2030. To achieve this, nations are supporting multi-vector systems that integrate electricity, heat, and fuels—primarily solar-wind hybrid systems with green hydrogen for balancing and long-term storage. DES technologies offer modular and flexible energy solutions adaptable to peri-urban, rural, and urban contexts, with Koshikwinja et al. (2025) documenting deployment in electrification, clean water, and agricultural process in high-sun and low-grid areas

(Koshikwinja et al., 2025). Green hydrogen, produced via renewable-powered electrolysis, plays a pivotal role in clean energy policy—as an energy carrier, a fuel, and a feedstock.

Hydrogen, unlike batteries, can achieve seasonal energy storage and drive hard-to-electrify uses like heavy industry. Ademollo et al. (2024) illustrate how cogeneration power plants based on hydrogen significantly reduce emissions in high-temperature industry (Ademollo et al., 2024). Chahtou & Taoussi (2025) illustrate, in Algeria, how solar PV-based integrated desalination makes the production of hydrogen cost equivalent to \$2.12–2.72/kg, a trend being followed throughout North Africa and Australia. More integration is being observed in hybrid systems (Chahtou & Taoussi, 2025).

(Bucchianico et al., 2025) et al. (2025) consider biomass and wind-driven hydrogen production and simultaneous gamma-valerolactone production to help support circular economy goals. National goals are also appearing: Dabar et al. (2024) offer wind-driven hydrogen systems ahead of solar in Djibouti (Dabar et al., 2022), while Al-Ghussain et al. (2024) propose hydrogen-integrated desalination in Jordan (Al-Ghussain et al., 2024). Technical, financial, and regulatory challenges continue to hinder DES-based hydrogen applications, economically unviable cost, Modeling complexity, and absence of specific policies leading bottlenecks. DES decentralization bridges energy access and climate goals.

It enables communities to generate, store and use power irrespective of traditional grids. Handique et al. (2024) refer to growing academic research interest in distributed hydrogen systems after 2020 (Handique et al., 2024), even as most installations have remained confined to the developed world. Allowing this mismatch translates to cheap inputs, minimal design simplicity, and a fine business model. Akpolat (2025) is concerned with using machine learning to hybrid DES optimization towards reliability—very essential in the impoverished regions (Akpolat, 2025). Basnet et al. (2024) also consider economic viability while incorporating hydrogen into urban microgrids to be economical when electricity is over €140/MWh, particularly for cities like Dijon, France (Basnet et al., 2024). Literature review in this chapter tries to critically analyze the literature on incorporating green hydrogen into DES along three lines: technological modeling, operational optimization, and policy frameworks.

Technologically, all models require high computing power and expertise. Soni & Reddy (2025) present CSP-TES with more straightforward modeling for large-scale deployment (Soni & Reddy, 2025). Operationally, hydrogen integration must include intelligent real-time control schemes to deal with variable renewables, as exemplified by Hamedi & Brinkmann (2025) in hybrid PSA-membrane systems (Hamedi & Brinkmann, 2025). Politically, the review is referred to as governance and market incentives. Sabry (2025) makes Morocco's sole-green policy coalitions responsible (Sabry, 2025), while Onat & Demir (2025) call for cross-border hydrogen planning and infrastructure (Onat & Demir, 2025). Based on over 100 peer-reviewed publications of 2020-2025, the chapter constructs a holistic picture of the opportunities and challenges in scaling up green hydrogen integration into DES. It offers low-cost equipment, process efficiency, and policy consistency to trigger mass, inclusive diffusion of green hydrogen into decentralized energy systems.

2.2 Structure of Literature Review

The remaining literature review is structured under four broad topics. Section 2 (Technology) covers the basic issues of green hydrogen production, such as types of electrolyzers, estimation models, and renewable source integration. Section 3 (Operations) deals with control strategies, hybrid storage potential, and system-level optimization techniques. Section 4 (Policy) focuses on policy to regulate, economic instruments, and institutional governance on the utilization of hydrogen in DES. Finally, Section 5 (Synthesis and Future Directions) synthesis findings across all sections, presenting cross-cutting conclusions with a research and policy-making agenda.

This is in line with this framework because the review is seeking to bridge the gap between practice research and theory and give an integrated understanding of how energy system integration transition in a DES can be achieved using green hydrogen. In doing this, it is part of the larger feedback loop of sustainable energy transitions but also contributing towards building stronger energy systems for more equal, resilient, and decarbonized futures.

2.3. Green Hydrogen Production Technology

To further facilitate the contextual understanding of the situation of hydrogen production, Figure 2.1 displays the ability of global hydrogen production and the related CO_2 emissions by different means (IEA, 2022). The scatter plot supports the unevenness of the environment between the old fossil-fuel-based processes and new green ones. It visually shows the way such technologies like SMR and HPO perform better in lowering global production levels but carry massive emissions burdens, while such green hydrogen technologies like photocatalytic water splitting (PCWS), high-temperature electrolysis (HTE), and water electrolysis (WE) carry minimal emissions burdens but are not performing well due to lower current output levels.

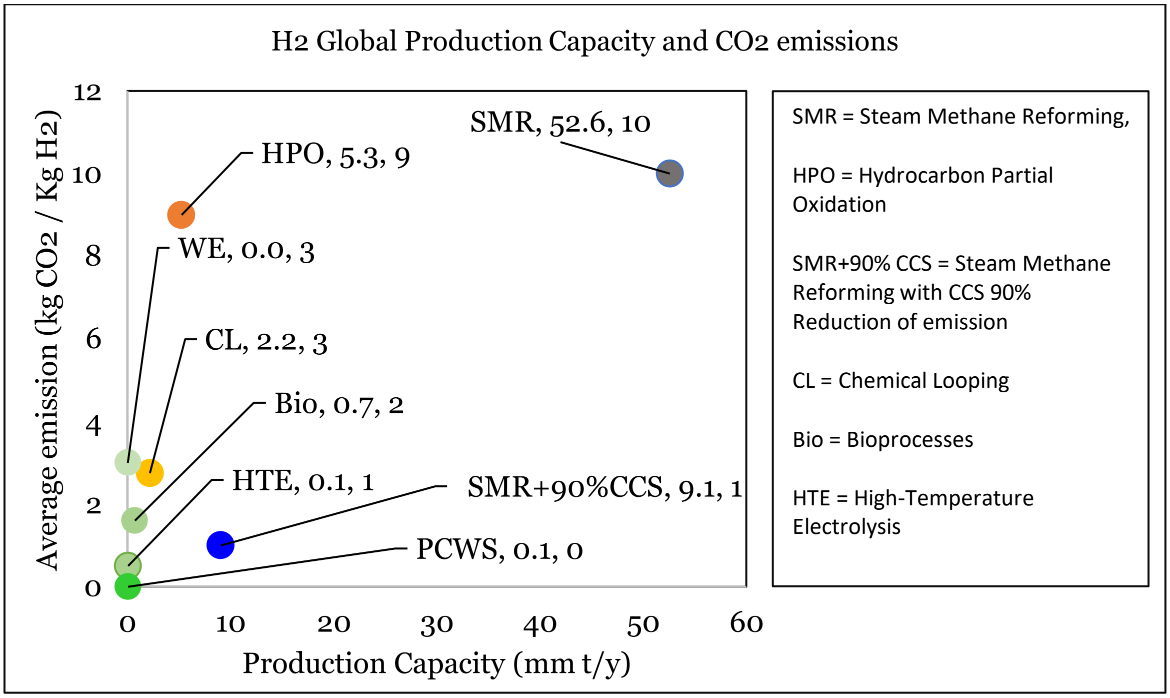


Figure 2. 1 H_2 Production capacity and CO_2 emissions (IEA, 2022).

The under-consideration section of the chapter discusses green hydrogen as a leading technology for becoming a net-zero world, i.e., DES. The chapter analyzes three leader electrolysis technologies—Proton Exchange Membrane (PEM), Alkaline Electrolysis (AEL), and Solid Oxide Electrolysis Cells (SOEC)—with unique operating features and integration potential with clean sources like solar and wind. PEM systems are compact and quick responding but platinum group metal-based, and as a result there is a sustainability concern (Qureshi et al., 2025). Table 2.1 is comparative hydrogen production technology description, capacities, and carbon implications emphasizing the environmental advantage of renewable-based technologies like water electrolysis and photocatalytic splitting over fossil fuel-based technologies like SMR and partial oxidation (Evro, Oni, et al., 2024).

SOEC systems, as highly thermodynamically efficient and application-adaptive in industry at elevated temperatures (Pastore et al., 2025), are disadvantaged by commercialization because of the material degradation problem during high-temperature exposure. Figure 2.2 illustrates the comparison between PEM, AEL, and SOEC systems with respect to six performance factors, and it gives efficiency-technical maturity-material sustainability trade-offs.

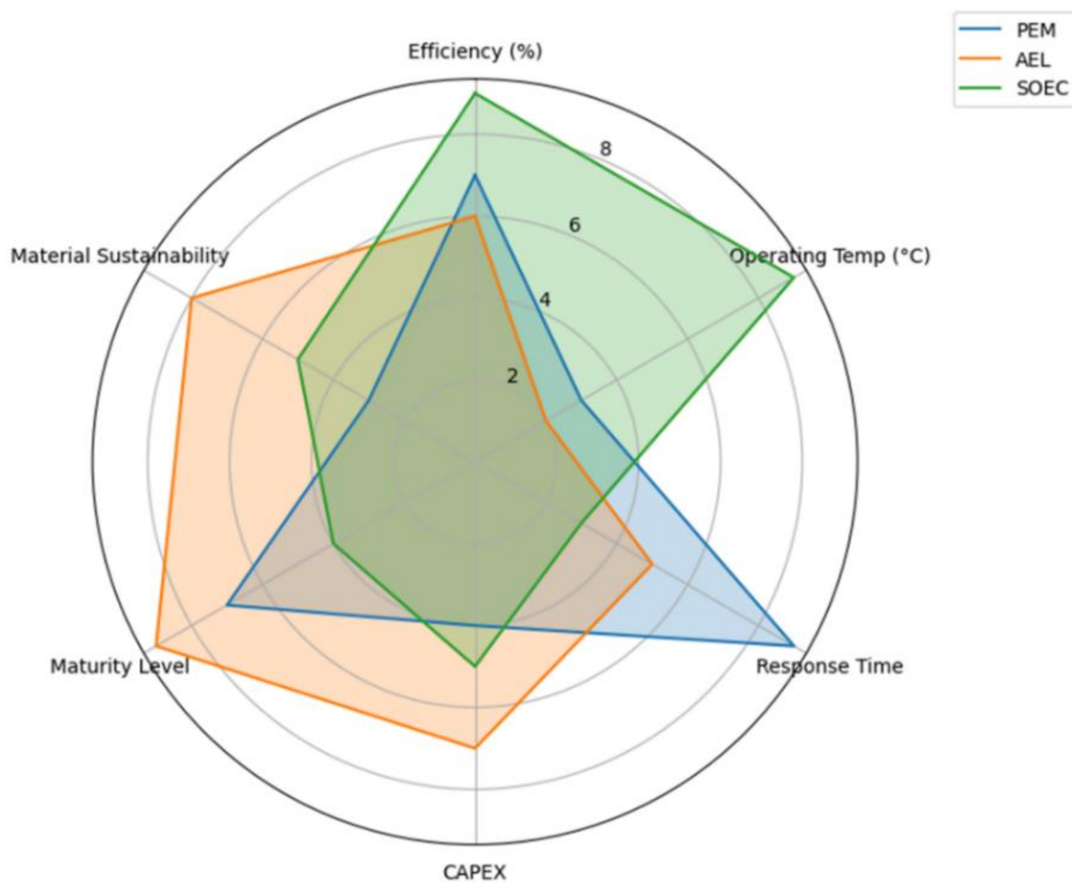


Figure 2. 2 Comparative Radar Chart – Electrolysis Technologies

The economic viability of electrolysis also rests on integration with renewables. Chahtou and Taoussi (2025) Algerian projects and Gülây et al. (2025) Türk projects are economically viable when solar or wind is integrated with electrolysis, once more preferential towards the integration of modular design and renewable-referenced size definition of the electrolyzer—i.e., (Chahtou & Taoussi, 2025; Gulay et al., 2025) solving the research problem of integration of renewable variability (RQ1 and RQ2). Applications of AEL and SOEC benefit from the base-load benefit of hydropower to cut further degradation.

Lifecycle assessment (LCA) outcomes indicate the relative advantages of green hydrogen compared to blue and gray paths for carbon, water, and land footprint (Roy et al., 2025), as represented in Figure 2.3.

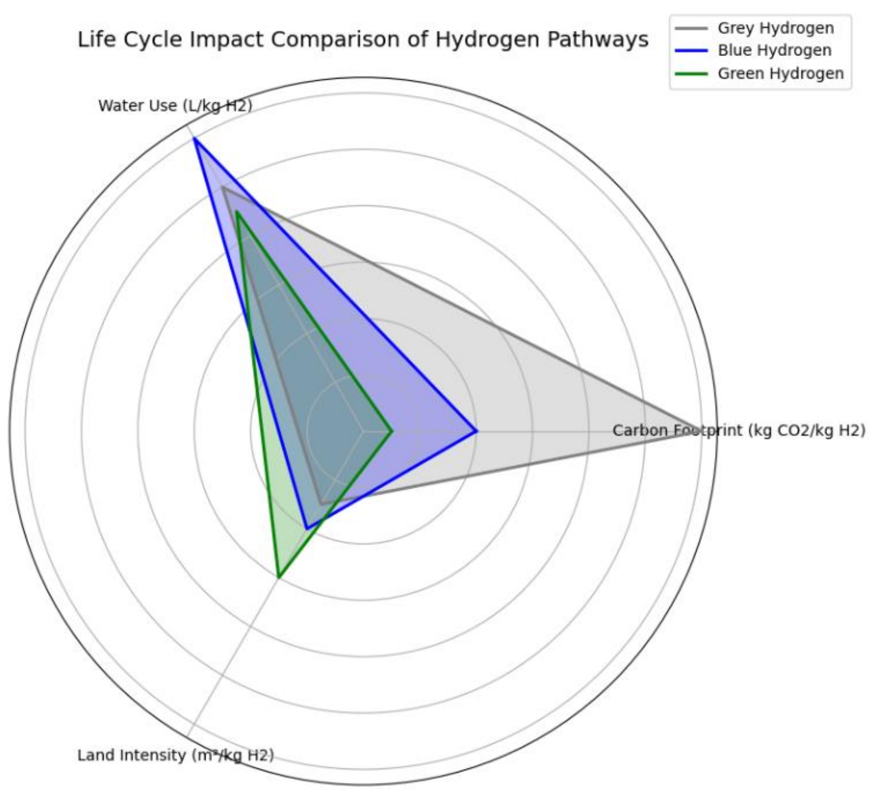


Figure 2. 3 Life cycle impacts of H_2 production. (Roy et al., 2025).

The findings also validate the ease-of-use modeling tools and application of standard LCA methodologies in DES applications—both highlighted in the technology and process-driven exploration requirements of the study.

Table 2. 1 H_2 Production Methods and Carbon Profiles.

Method	Prod Capacity (mmt/y)	Average emission ($kgCO_2/KgH_2$)	Remark
SMR	52.6	10.0	SMR produces 9-11 kg of CO_2 per kg of hydrogen, primarily due to its energy-intensive nature and use of natural gas as a feedstock (Dermühl & Riedel, 2023).
Hydrocarbon Partial Oxidation	5.3	9.0	This method uses fossil fuels and produces significant CO_2 emissions, slightly lower than SMR, estimated at 8-10 kg CO_2 per kg of hydrogen (Muradov, 2017).
SMR with CCS 90% Reduction	9.1	2.0	CCS integration can reduce CO_2 emissions by up to 90%, but not all are captured, and efficiency varies. Estimated CO_2 emissions per kg of hydrogen produced are 1 to 3 kg (Khan et al., 2021).
Chemical Looping	2.2	1.3	Designed for inherent CO_2 capture, significantly lowering emissions. Estimates range from 0.5 to 2 kg CO_2 per kg of hydrogen, depending on the efficiency of the process and the source of energy used for heating (He et al., 2020).
Bioprocesses	0.7	1	Using waste biomass or atmospheric CO_2 capture can produce low or negative net CO_2 emissions, depending on energy source and life cycle emissions (Djomo & Blumberga, 2011).
High-Temperature Electrolysis (HTE)	0.1	1	Emissions depend on electricity sources, with renewable energy potentially achieving near-zero emissions. However, elevated temperatures may slightly exceed standard water electrolysis emissions (Dermühl & Riedel, 2023).
Water Electrolysis	0.0	2	Emissions depend on electricity sources, with renewable energy reducing emissions to a minimum. Grid mix emissions could vary, potentially averaging 2 to 4 kg CO_2 per kg of hydrogen (Bareiß et al., 2019).
Photocatalytic Water Splitting	0.1	0	This method promises direct solar-to-hydrogen conversion with minimal to no CO_2 emissions. Practically, emissions are close to zero (Sadeghi & Ghandehariun, 2023).

Policy and cross-sectoral coordination remain central, with the case of Martínez de León et al. (2025) linking deployment of hydrogen to SDGs 7, 9, and 13 (León et al., 2025). In contrast, case studies like Inac and Midilli (2025) illustrate how coupling systems can transform carbon capture into hydrogen production and chemical synthesis (Inac & Midilli, 2025), making the array of green hydrogen applications in electricity markets more viable and demonstrating the applicability of sector coupling in DES.

The review cites that even as PEM, AEL, and SOEC technologies are technologically viable, realizing them in DES will be based on overcoming modeling, control, and policy restrictions offered by research gaps within this study. Strategic standards of Tables 2.1 and Figures 2.1 and 2.2 form structured observations providing design standards for decentralized hydrogen systems within sustainable application.

2.4 Modeling the Hydrogen Production Potential

Hydrogen production potential modeling is an essential element of green hydrogen deployment strategic planning within DES. New models increasingly apply artificial intelligence and hybrid optimization to enhance prediction capability and system design. Çelikdemir and Özdemir (2025) created a high-accuracy cost estimation model based on Modified Particle Swarm Optimization (MPSO), the errors of which were less than 3% for solar, wind, and wave farms (Çelikdemir & Özdemir, 2025). They utilize meteorological and energy performance inputs in their model, but in DES-scale implementations, more articulated module-based models are better suited to geographical completeness and scenario testing. Rai and Liu (2025) have also proposed a Spatiotemporal Attention Framework (STAF) based on CNN and BiGRU, whose performance is highly improved in providing prediction under the diffuse irradiance condition. Such AI approaches reveal real-time hydrogen forecasting opportunities.

Urhan et al. (2025) calibrated Turkish city regional hydrogen production modeling for a range of machine learning models (e.g., KNN, ANN, LSTM) and found up to 400,000 kg/year CO_2 savings through local wind-based production (Urhan et al., 2025). Idriss et al. (2025) first modeled data-poor regions like the Horn of Africa using satellite-based wind maps and metaheuristic algorithms (PSO, HGSO) for location optimization even without long-term data (Idriss et al., 2025). Ben Abdelwahed et al. (2025) corroborated that testing conditions like panel tilt and water quality are capable of increasing hydrogen production by over 50%, rendering contextual performance inputs effective.

Thermal efficiency also increases performance. Faraz Ahmad et al. (2025) showed bifacial PV and cool-roof technology can increase hydrogen yield by 27.31%. Karabuga et al. (2025) put forward an S-ORC system with solar-organic Rankine cycle hydrogen production at a cost of below $1/kg, highlighting co-generation advantage (Karabuga et al., 2025). Stack longevity is a problem in thermal cycling of renewable input fluctuation. Thermal storage through strong coatings is necessary to achieve stack longevities, particularly for PEM and SOECs.

All these are pointing to the need for low-cost yet effective modeling equipment and design-optimized electrolyzers—low-cost, location-independent hydrogen deployment technological research requirement (RQ1) in DES

2.5 Hydrogen Infrastructure Compatibility with DES

When energy infrastructure is distributed, hydrogen infrastructure will need to accommodate the fact of DES as local, modular, and renewable-based. The greatest challenge is how to deal with the trade-off between large-scale industrial or export-oriented central production and on-site production of hydrogen at a local level. Yılmaz and Uyan (2025) introduce the same in a GIS-MCDM model for Konya, Türkiye, and 7.1% of the province is determined to be suitable to produce hydrogen from solar energy (Yılmaz & Uyan, 2025). Gagliardi et al. (2025) also introduce how FPV devices in Southern Italy can produce hydrogen as well as prevent water evaporation and (Gagliardi, Cosentini, Agati, et al., 2025), thus, are best applicable for land-constraint-based microgrid applications.

Grid-injected electrolysis configurations such as the one researched by Gulay et al. (2025) ensure dynamic operation based on renewable input and electrolyzers' capacity (Gulay et al., 2025). Minimizing the size of the electrolyzer from 10 MW to 7.5 MW in their Turkish application decreased Levelized Cost of Hydrogen (LCOH), illustrating scale and configuration optimization's advantage for DES economics. Tipán-Salazar et al. (2025) also explain how hybrid systems such as PV, wind, pumped hydro, and electrolysis can change modes according to market conditions for greater profitability and flexibility for DES consumers (Tipán-Salazar et al., 2025).

Figure 2.4 illustrates a hybrid renewable configuration structure, with the interconnection of solar PV, wind, hydrogen storage, and battery storage to electrolyzers in a move towards greater grid independence and lower emissions. All other things being equal, though, there are still challenges such as combatting intermittency, geospatial constraint, and hydrogen refueling infrastructure establishment. Sendi et al. (2025) think strict EU and US hourly matching policies would indirectly discourage microgrid hydrogen use based on higher LCOH (Sendi et al., 2025).

For innovation, the primary brakes are out-of-range, modular electrolyzers and astute integration of the energy network. Lubello et al. (2025) suggested green hydrogen would be only viable for Kenya's steel and fertilizer market in early 2030 with long-term cost superiority (Lubello et al., 2025). Incentives are required: Stolte et al. (2025) display Italian green hydrogen reducing from €7.7/kg to €3.3/kg via industry backfits utilizing subsidization (Stolte et al., 2025).

Technology convergence with IoT is emerging as a method of optimization in real-time. Kang et al. (2025) proposed a copula method towards co-regulation of electrolyzer and battery management (Kang et al., 2025), whereas Shanmugasundaram et al. (2025) introduced AI-based diagnostic and predictive control of microgrids (Shanmugasundaram et al., 2025). Such advances are always based on safe data and cyberspace networks, which typically are not present in most parts of the world.

Materials science is not flawless either. Rasheed et al.'s (2025) MXenes can replace PGM but have the same oxidation issue and stability problems as well (Rasheed et al., 2025). Sarout et al. (2025) detailed metal oxide nanocomposites' drawbacks as catalytic dispersion with lowness and poison resistance (Sarout et al., 2025). Heat-resistance membranes and self-healing coatings are of vital importance to maximum stack life achievement and LCOH reduction.

Buchner et al. (2025) also fail not to state that public perceptions on safety and trust also influence technology adoption (Buchner et al., 2025). For their research, transparency, benefit-sharing, and safety were greater in public embrace than technical operation in German hydrogen projects. The same also necessitates engineering but equally the social innovation needed in the application of DES.

In integration (Section 2.2.6), although certain indeed are models like Rai and Liu's (2025) and Çelikdemir and Özdemir's (2025), which are astronomically accurate in their predictions with AI, they are cumbersome, data-hungry, and much too complicated for use in low-tech, resource-scarce environments where DES are especially necessary. A bridge over this abyss exists with El-Sayad et al. (2025), but still, technical fiddling is needed (El-Sayad et al., 2025).

Therefore, educational institutions need to develop plug-and-play, user-friendly estimation software for use in planning local hydrogen projects. GIS applications like those used by Yılmaz and Uyan (2025) and Gagliardi et al. (2025) can be used to inform decision-making using context variables like irradiance and infrastructure distance (Gagliardi, Cosentini, & Venturini, 2025; Yılmaz & Uyan, 2025). But performance maximization under fluctuating conditions—as demonstrated by Gulay et al. (2025) and Jin et al. (2025)—must be included in such software as well (Gulay et al., 2025; Jin et al., 2025).

Lastly, hydrogen integration into DES must be equilibrated with global sustainability and equity objectives. Lubello et al. (2025) and Buchner et al. (2025) show that system design must integrate socio-political, economic, and behavioral aspects—not technical solutions alone (Buchner et al., 2025; Lubello et al., 2025). Closing this gap between high-fidelity simulation and local decision-making is the challenge for Research Question 1.

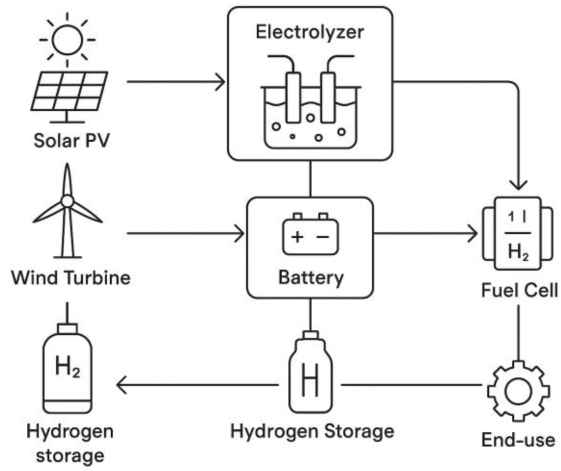


Figure 2. 4 Electrolyzer Integration in Hybrid Renewable Systems

2.6 Hydrogen Storage, Control, and System Integration

The integration of hydrogen storage into DES plays a significant role in enabling energy security, flexibility, and decarbonization, especially amidst the intermittency of wind and solar energy (Selvam et al., 2025; Shahzad et al., 2024). Figure 2.5 illustrates the energy flow in a typical hydrogen-powered DES, from renewable generation to hydrogen storage and end-use conversion. Among the technologies applied in DES, Compressed Gaseous Hydrogen (CGH_2), Liquefied Hydrogen (LH_2), Metal Hydrides (MH), and Underground Hydrogen Storage (UHS) exhibit unique trade-offs in spatial footprint, safety, and lifecycle economics.

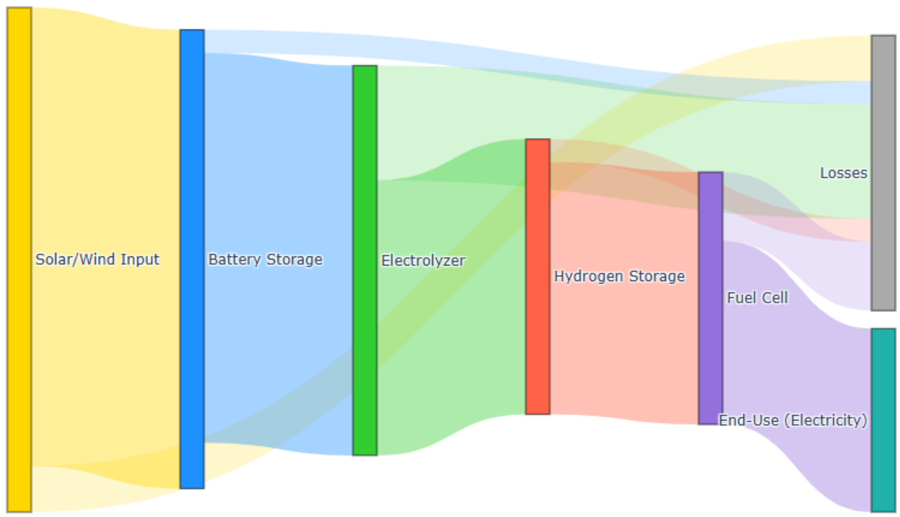


Figure 2. 5 Energy Flow in a Hydrogen-Powered DES, conversion, and loss stages

CGH_2 is commercially advanced and modular, suitable for PEM fuel cell applications. Despite its maturity, it carries a high Total Life Cycle Cost (TLCC) of ~$568k/year and poses safety and spatial limitations in dense urban settings (Abdellatief et al., 2025; Ba-Alawi et al., 2024; Yu et al., 2025). LH_2, with the highest volumetric energy density (8.5 MJ/L), is advantageous for long-term storage but suffers from 30–40% energy losses during liquefaction and the need for cryogenic infrastructure (Zavala et al., 2025). In Calgary, seasonal LH_2 systems reduced CO_2 emissions by 250 kg/month per household (Enaloui et al., 2025).

MH systems offer passive safety and are well-suited for urban applications, with a TLCC of ~$460k/year. Their main limitation is the thermal energy required for hydrogen desorption. Nanomaterial enhancements like MXene doping improve kinetics and thermal management (Zavala et al., 2025). UHS, especially in repurposed unconventional reservoirs like Eagle Ford shale, provides large-scale, seasonal storage with capacities up to 60 Bcf (Evro, Oni, et al., 2025). While economically promising due to existing oil and gas infrastructure (Moran et al., 2024), UHS faces challenges in containment integrity, material interactions, and regulatory frameworks (Saadat et al., 2024; M. Yang et al., 2023). Figure 2.6 presents a flowchart visualization of hydrogen storage technologies in DES, highlighting cost, capacity, and trade-offs across the four main options, while Table 2.2 summarizes the storage technologies in DES, integrating findings from international case studies across Spain, Kenya, and Sub-Saharan Africa, which affirm the necessity of context-specific, system-aware planning (Lubello et al., 2025; Romero-Ramos et al., 2025; Winkler et al., 2025).

Curtailment due to supply-demand mismatches in DES elevates green hydrogen as a buffer and arbitrage tool. Electrolyzers absorb excess renewable energy and convert it into hydrogen, which can be reconverted to electricity or used directly during peak demand.

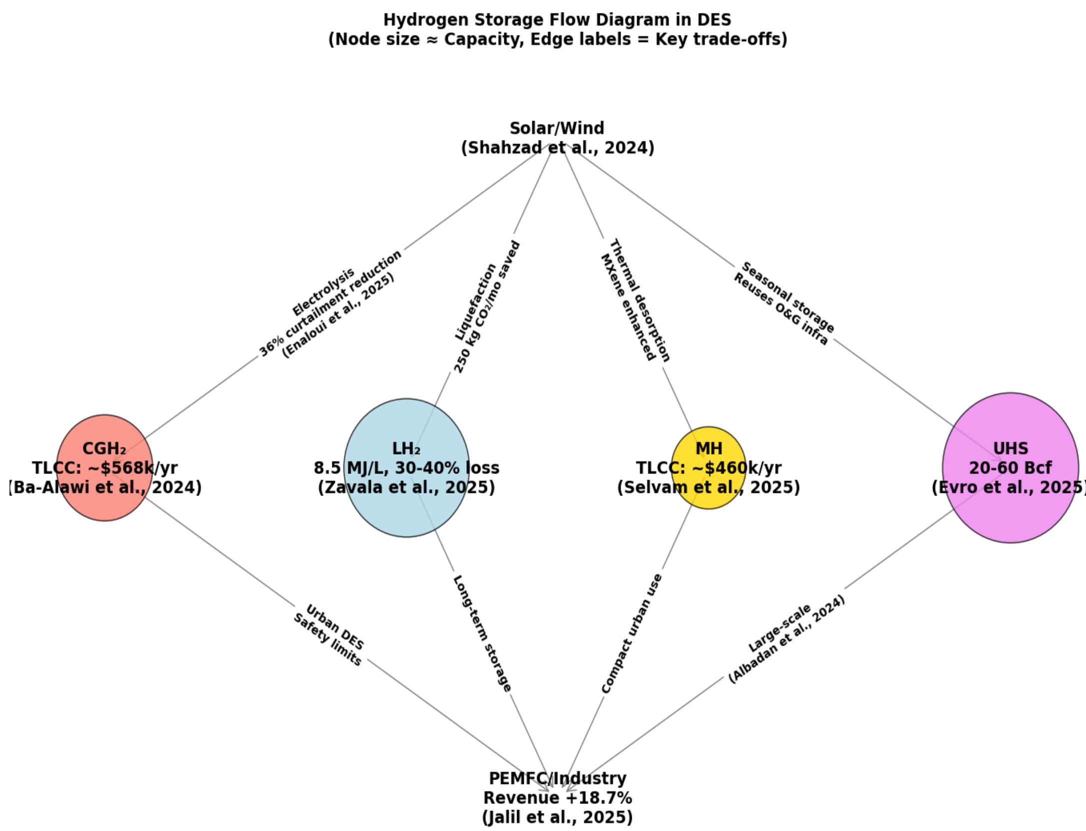
Table 2. 2 Hydrogen Storage Technologies in DES

Hydrogen Storage Type	Key Findings	Reference(s)
Compressed Gaseous Hydrogen (CGH2)	Commercially advanced and modular for PEMFCs; TLCC ~$568k/year; safety and spatial limitations in urban DES	(Abdellatief et al., 2025; Ba-Alawi et al., 2024; Yu et al., 2025)
Liquefied Hydrogen (LH2)	High volumetric energy density (8.5 MJ/L); used for long-term storage; 30-40% energy penalty in liquefaction; improved CO2,, savings by 250 kg/month in Calgary	(Zavala et al., 2025); (Enaloui et al., 2025)
Metal Hydrides (MH)	Safe, compact for urban use; TLCC ~$460k/year; limited by thermal desorption needs; improved with MXene nanomaterials	(Ba-Alawi et al., 2024); (Selvam et al., 2025); (Zavala et al., 2025)
Underground Hydrogen Storage (UHS)	Suited for large-scale, seasonal storage; 20 -60 Bcf capacity in Eagle Ford shale; reuses legacy O&G infrastructure; concerns include containment, material interaction, and regulation	(Evro, Oni, et al., 2025; Moran et al., 2024; Saadat et al., 2024)

This reduces curtailment and stabilizes the grid (Shahzad et al., 2024). Enaloui et al. (2025) report a 36% reduction in curtailment in Calgary microgrids using hydrogen storage (Enaloui et al., 2025).

Figure 2.7 depicts a 24-hour renewable generation profile versus electrolyzer utilization and curtailment. Periods of low electrolyzer activity correspond to curtailment spikes, reinforcing the importance of synchronized operation to optimize hydrogen capture (Palma et al., 2024).

Hydrogen also enables energy arbitrage. Jalil et al. (2025) show that such setups improve DES revenue by 18.7%. (Jalil et al., 2025) Coupled with Battery Energy Storage Systems (BESS), hydrogen supports both short-term and seasonal balancing.



Data sources: (Shahzad et al., 2024); (Zavala et al., 2025), (Evro, Oni, et al., 2025)

Chamazkoti et al. (2025) and Haoxin et al. (2025) demonstrate a 22% reduction in Levelized Cost of Electricity (LCOE) when hydrogen and BESS are integrated (Chamazkoti et al., 2025; Haoxin et al., 2025). This synergy supports peak shaving, load smoothing, and seasonal energy transfer (Lei et al., 2025; Younis et al., 2024).

Figure 2. 6 Hydrogen Storage Flow Diagram in DES

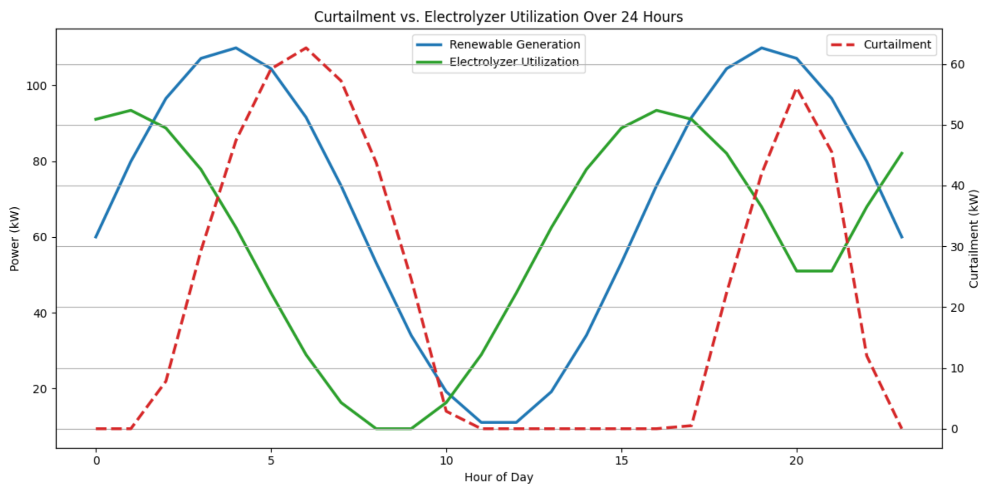


Figure 2. 7 Curtailment and Electrolyzer utilization (Palma et al., 2024)

Flexible hydrogen production aids curtailment reduction. Sameti et al. (2025) sized electrolyzers using curtailment profiles to cut energy loss by 34% (Sameti et al., 2025). In Australia, Ratib et al. (2025) show dynamic PEM electrolyzers improve hydrogen yield by 52.85% and reduce Levelized Cost of Hydrogen (LCOH) by 17.3%. Blockchain-based trading models (Ratib et al., 2025), like those proposed by Shi et al. (2025), enable real-time curtailment response and market integration (Shi et al., 2025).

For BESS-Hydrogen coupling and strategic dispatch, Jin et al. (2025) simulate GIS-optimized residential DES in Italy, achieving full energy independence and CO_2 reductions up to 0.83

tons/year per user (Jin et al., 2025). Mohamed et al. (2025) demonstrate voltage and power quality stability (<1% THD) in hybrid BESS-hydrogen-PV systems via Unified Power Quality Conditioner–Distributed Generation (UPQC-DG) setups (Mohamed et al., 2025).

Strategic arbitrage through predictive dispatch is increasingly vital. Tipán-Salazar et al. (2025) and Hassan et al. (2025) optimize electrolyzer operation using electricity price forecasting to boost profitability (A. A. Hassan et al., 2025; Tipán-Salazar et al., 2025). Mohamed et al. (2025) show that smart control enhances curtailment avoidance and load balancing.

Control and Optimization Strategies: Effective hydrogen management in DES demands advanced control systems. Traditional PID controllers, while robust for linear dynamics (Zavala et al., 2025), struggle with DES non-linearity. Rule-based controls (Lei et al., 2025; Haddad & Javani, 2024) offer transparency but lack adaptability. AI/ML-based systems, such as ANN, LSTM, and RFGD, bring predictive and adaptive control. Younis et al. (2024) and Urhan et al. (2025) demonstrate their effectiveness in load scheduling, curtailment reduction, and CO_2 emission mitigation. Bag et al. (2025) apply ML to improve hydrogen supply chain resilience (Bag et al., 2025).

Multi-objective optimization (MOO) methods like PSO, GA, and IHHO are increasingly used to balance cost, emissions, and system performance. Nandi et al. (2024) achieve 81% emissions reduction using Improved Harris Hawk Optimization (Nandi et al., 2024). Jin et al. (2025) apply GIS-integrated MILP for optimal residential hydrogen system design (Jin et al., 2025). Karabuga et al. (2025) optimize hydrogen-ORC hybrid systems, achieving sub-$1/kg production costs. Hydrogen integration in DES spans beyond technical deployment into systemic transformation. CGH_2 and MH are ideal for urban modularity and safety, while LH_2 and UHS support industrial and seasonal demands. Research across RQ1 (sizing/configuration), RQ2 (operation/control), and RQ3 (policy/institutional mechanisms) underscores the need for adaptive, hybrid, and intelligent hydrogen-DES systems. These systems must be context-aware, digitally controlled, and supported by evolving regulatory frameworks to fulfill their role in a decentralized, decarbonized, and equitable energy future.

2.7 Tools for Operational Modeling and Simulation

In this section, we critically evaluate the strengths and limitations of key operational modeling tools used for simulating hydrogen-integrated DES. Four widely adopted platforms—HOMER, TRNSYS, MATLAB/Simulink, and EnergyPLAN—offer unique capabilities yet fall short in capturing the full complexity of hydrogen systems.

HOMER, developed by NREL, excels at techno-economic optimization and hybrid system sizing. It has been used to model PV-wind-hydrogen configurations with PEM electrolyzers (Koholé et al., 2025; Ratib et al., 2025). However, it lacks advanced modeling of hydrogen electrochemical dynamics, component degradation, and real-time control. Its hydrogen simulation remains simplistic and economically biased.

TRNSYS provides fine-grained transient thermodynamic simulation and is effective for coupling CSP or geothermal systems with electrolysis. It has been used to simulate SOEC and geological hydrogen storage scenarios (Arias et al., 2025; Saadat et al., 2024). Yet, it requires heavy customization, lacks built-in stochastic modeling, and has limited real-time control capabilities.

MATLAB/Simulink is preferred for control system modeling and has been applied in hydrogen-PV-BESS coordination (Mohamed et al., 2025; Rausell et al., 2025). While excellent for control dynamics, it lacks hydrogen-specific libraries and techno-economic modules, requiring users to build models from first principles or third-party toolboxes.

EnergyPLAN, focused on national or regional planning, supports long-term policy and scenario analysis. It was used to model hydrogen integration in Wyoming and MENA energy systems (A. A. Hassan et al., 2025; Zhao et al., 2024). However, it does not support detailed real-time control, component-level interactions, or transient dynamics.

As shown in Figure 2.8 and illustrated in Table 2.3, none of the current tools individually addresses the full set of hydrogen integration challenges in DES.

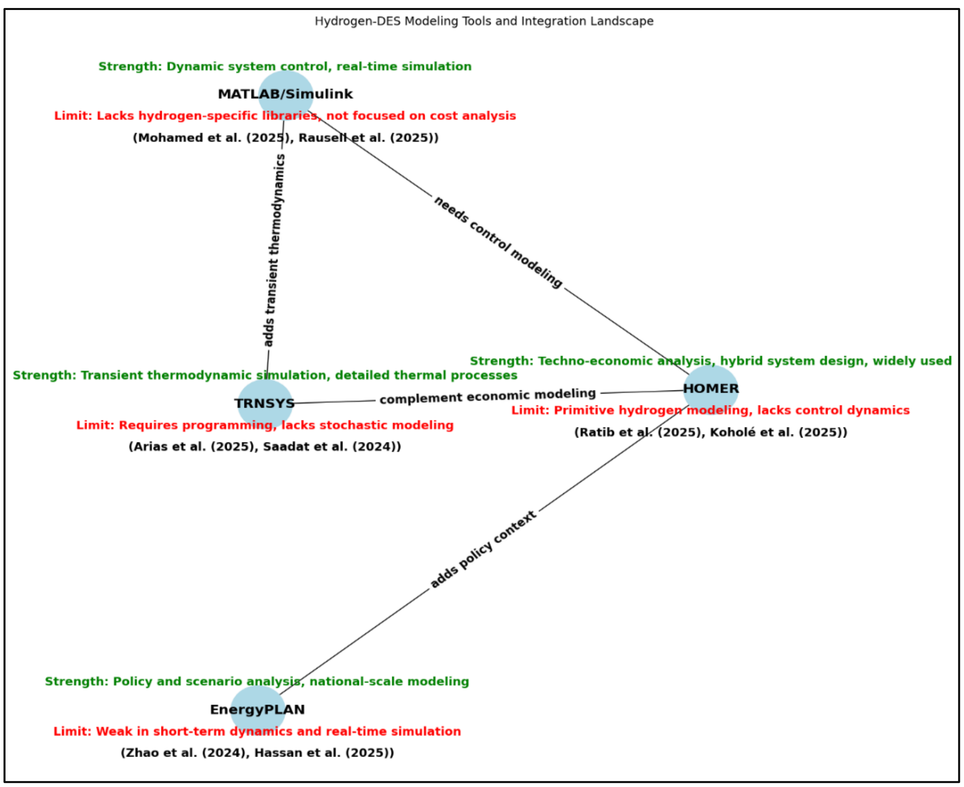


Figure 2. 8 Hydrogen-DES Modeling Tools and Integration Landscape

Common challenges such as hydrogen component development, multi-vector energy coupling, real-time control management, stochastic renewables behavior, and standardized data interchange interoperability are not yet adequately addressed. Data interoperability is the most important limitation.

Lack of platform-independent data format prevents tool integration. EnergyPLAN output, for instance, cannot be imported to Simulink unless custom-made interfaces are developed—an extension to multi-tool procedures that adds cost and complexity. This limitation strongly prevents cross-platform modeling required for standardized simulation of hydrogen system economics, control designs, and real-time dynamics.

Table 2.3 below presents the following strengths and weaknesses in each of them: while HOMER is techno-economically strong but weak in control dynamics (Koholé et al., 2025; Ratib et al., 2025); TRNSYS is strong in thermal detail but weak in programming as well as stochastic modeling (Arias et al., 2025; Saadat et al., 2024); MATLAB/Simulink is strong in control but weak in hydrogen-specific libraries and cost modeling (Mohamed et al., 2025; Rausell et al., 2025); and EnergyPLAN, while strong in policy and scenario analysis, is weak in real-time simulation (A. A. Hassan et al., 2025; Zhao et al., 2024). All these results highlight the importance of interoperable and mature hydrogen-DES modeling techniques.

2.8 Frameworks of Integration and Future Perspectives

As DES sophistication increases, there must be combined control systems—harmonizing AI predictive foresight, rule-based protection, and optimization planning. Mohamed et al. (2025) depicted this in a Unified Power Quality Conditioner–Distributed Generation (UPQC-DG) system using PV, hydrogen, fuel cell, and BESS with a power quality of <1% harmonic distortion and optimized hydrogen consumption.

Table 2. 3 Hydrogen-DES Modeling Tools and Integration Landscape

Tool	Strengths	Limitations	Applied By
HOMER	Techno-economic analysis, hybrid system design	Primitive hydrogen modeling lacks control dynamics	(Koholé et al., 2025; Ratib et al., 2025)
TRNSYS	Transient thermodynamic simulation, detailed thermal processes	Requires programming, lacks stochastic modeling	(Arias et al., 2025; Saadat et al., 2024)
MATLAB/Simulink	Dynamic system control, real-time simulation	Lacks hydrogen-specific libraries, not focused on cost analysis	(Mohamed et al., 2025; Rausell et al., 2025)
EnergyPLAN	Policy and scenario analysis, national-scale modeling	Weak in short-term dynamics and real-time simulation	(A. A. Hassan et al., 2025; Zhao et al., 2024)

Future trends like edge computing and digital twins also enable real-time response and control based on sensor-driven system updating and adaptability. Scalability is made possible through interoperability and standardization. Open-source control platforms (e.g., Rahman et al., 2024) can most probably enable more use of adaptive hydrogen control strategies (Rahman et al., 2024).

To get there, one consolidating platform has to be built bringing together TRNSYS and Simulink's dynamic strength, HOMER economics, and EnergyPLAN policy simulation. Open component libraries, artificial intelligence-optimized optimization, and cross-platform communication will chart future direction, and hydrogen will be marketed as a pillar support in safe low-emission DES.

2.9 Policy and Regulatory Review

The policy for green hydrogen is a foundation for its integration in DES, particularly in balancing technological diffusion with climate targets and universal access. In the principal areas—the EU, U.S., and China—divergent regulatory frameworks have been established. EU Green Deal and Hydrogen Strategy pursue hard-to-abate industry decarbonization with visions like 2030-40 GW of electrolyzer capacity and European Hydrogen Backbone development (Bogdzinski et al., 2025; Gatto et al., 2024). Top-down co-ordination translates into Guarantees of Origin (Roucham et al., 2025) and trans-national corridor planning but is still not coordinating national ambitions under one umbrella (Sadik-Zada et al., 2025).

In contrast, the US policy under the Inflation Reduction Act (IRA) supports production through tax credits of up to $3/kg (Shan & Kittner, 2025) and domestic hydrogen hub investment (Bade et al., 2024). Embryonic coordination platforms and decentralized provincial policy, however, generate integration challenges. China's hydrogen policy, in contrast, is centered on state-driven industrial decarbonization by hydrogen clusters and provincial FITs, but diffusion is uncompleted and infrastructure-constrained (Du et al., 2024; Qian et al., 2025).

Table 2.4 and Figure 2.9 compare heterogeneous global strategies, ranging from EU regulatory harmonization to the U.S. market-driven model of production and China's state-led deployment. Despite heterogeneity, these policy levers influence hydrogen integration into DES by conveying economic signals, lowering investment risk, and enabling infrastructure.

Current global policy environments neglect rural and decentralized use cases. DES-based hydrogen systems need to be deployed to propel electrification to off-grid areas (Lubello et al., 2025; Winkler et al., 2025) but have been overlooked. Centralized solutions in Sub-Saharan Africa and Kenya overlook the rural potential of hydrogen despite strong solar and wind potential. Likewise, research in India, Malaysia, and Peru (Jalil et al., 2025; Medrano-Sánchez & Ochoa-Tataje, 2024; Trivedi et al., 2025) reveals incentive gaps for small-scale and residential hydrogen installations that otherwise make local energy independence possible.

Table 2. 4 Policy Comparison

Policy Framework	Description	References	Green Hydrogen Integration Gap
US Inflation Reduction Act (IRA)	10 million metric tons by 2030; Production tax credits ($3/kg for clean H_2); Buy Clean requirements for federal agencies; Clean Hydrogen Production Credit (45V); DOE's Clean Hydrogen Standard (≤4 kg CO_2e/kg H_2)	(U.S. Department of Energy, 2023)	No direct integration mandate for DES or decentralized systems; limited rural deployment incentives
EU Directive 2023/2413	10 million tons domestic + 10 million imports by 2030; Contracts for Difference (CfD), Innovation Fund; Green public procurement mandates; State aid exemptions for hydrogen projects; EU Renewable Energy Directive (RFNBO rules)	(European Commission, 2023)	Strongest framework but urban-centric; limited explicit support for modular DES-scale integration
China's CNDC	No quantified national target: provincial goals vary; Capital subsidies, local-level feed-in tariffs (FITs); Targets embedded in national and local 5-year plans; Limited, indirect support through VAT exemptions; Standards emerging via NDRC and MIIT (not yet formalized nationally)	(NDRC & MIIT, 2023)	Lacks national DES policy; fragmented support across provinces; integration focus on heavy industry and

Policy tools like carbon pricing, tax credits, and renewable gas mandates have initiated competitiveness of hydrogen in DES. EU ETS has replaced power sector investment (Cheilas et al., 2024), and U.S. tax credits under the IRA reduced LCOH significantly (D. Kumar et al., 2024). Policies continue to support centralized production to the detriment of SMEs and rural players (Sendi et al., 2025). Feed-in tariffs and green procurement commitments promise hope but have to be ramped up with expected policy signals (Islam et al., 2024)

Grid connection, certification, and safety standards remain to be developed in the DES model. Though EU Guarantees of Origin ensure transparency (Gatto et al., 2024), they deter the adoption of DES (Sendi et al., 2025). Grid connection, certification, and safety standards remain to be developed in the DES model. Though EU Guarantees of Origin ensure transparency (Gatto et al., 2024), they deter the adoption of DES (Sendi et al., 2025). Land-use authorizations and grid connection lag, especially in developing countries (Jalil et al., 2025; Shahzad et al., 2024). Interoperability standards and zoning transparency are bare minimums to avoid deployment bottlenecks (Segovia-Hernández et al., 2024). Pipeline blending and export logistics are also challenging factors in the integration of DES. Technical feasibility studies are supportive (Onat & Demir, 2025; Zhao et al., 2024), but fragmented regulation and infrastructure limitations impede small-scale producers' access. In addition, international harmonization of standards of hydrogen derivatives (e.g., ammonia) is needed for global international trade (Tunn et al., 2025). Equity and energy justice remain under-addressed in policy frameworks. Rural electrification and reduced fossil fuel dependency can be facilitated by decentralized hydrogen in the Middle East and Africa (Bayssi et al., 2024; A. A. Hassan et al., 2025).

Policy Comparison

	US Inflation Reduction Act	EU Directive 2023/2413	China's CNDC
Hydrogen Targets	10 million metric tons by 2030	10 million tons domestic + 10 million imports by 2030	No quantified national target, provincial goals vary
Subsidies /Incentives	Production tax credits ($3/kg for clean H_2	Contracts for Difference (CfD), Innovation Fund	Capital subsidies, local-level FITs
Mandates	Buy Clean requirements for federal agencies	Green public procurement mandates	Targets embedded in 5-year plans
Tax Credits	Clean Hydrogen Production Credit (45V)	State aid exemptions for H_2 projects	Limited, indirect support through VAT exemptions
Green Certification	DOE's Clean Hydrogen Standard (kased on 4 kg $CO_2e/kg\ H_2$)	EU Renewable Energy Directive (RFNBO rules)	Standards emerging, led by NDRC and MIIT

Figure 2. 9 Policy comparison

Place-based leadership and social ownership underpin socially inclusive hydrogen systems (Scholvin & Kalvelage, 2025). Participatory planning is essential to establishing legitimacy, public acceptability, and long-term sustainability (Cho & Lee, 2025).

Table 2.4 and the discussion above also show how policy asymmetry curtails the prospect of hydrogen for rural regions. Hydrogen with digital twins, AI-optimized grids, and decentralized finance (Jalil et al., 2025; Rahman et al., 2024) can close gaps of inclusion and unlock bottom-up transitions toward SDG7 and SDG13.

2.10 Chapter Summary

Chapter Two performed an in-depth review of technological, operational, and policy drivers supporting green hydrogen integration into DES. Chapter Two synthesized over 100 recent peer-reviewed journal articles to critique hydrogen production technology, storage technologies, system control strategies, and enabling regulatory systems, culminating in cross-cutting integration barrier and opportunities evaluation.

The review commenced with evaluating hydrogen production pathways—i.e., Proton Exchange Membrane (PEM), Alkaline (AEL), and Solid Oxide Electrolysis (SOEC)—for compatibility with intermittent renewable energy (RE) sources. Outcomes proved that though PEM offers flexibility in operation and faster dynamic response, AEL is currently economical, and SOEC holds long-term potential for industrial heat integration (Selvam et al., 2025; Shahzad et al., 2024). These results address Research Question 1 (RQ1) by asking for technological settings and size conditions most pertinent to best deployment of electrolyzers in hybrid solar-wind-DES designs.

Second, the chapter evaluated hydrogen storage technologies—Compressed Gaseous Hydrogen (CGH_2), Liquefied Hydrogen (LH_2), Metal Hydrides (MH), and Underground Hydrogen Storage (UHS)—ranking lifecycle cost trade-offs, safety, volumetric density, and spatial constraint. For instance, UHS was the seasonally best scalable storage solution, while MH was offering dense passive-safe storage, which is currently best suited for utilization in urban DES (Evro, Oni, et al., 2025; Zavala et al., 2025). These results validate RQ2, on operational optimization strategies and load-balancing efficiency of electrolyzer-storage systems based on various demand and generation patterns.

Control methods and optimization techniques—PID, rule-based controllers to AI/ML models—were used to assess the dynamic capability of hydrogen systems to react to grid alerting, variable renewables, and end-user requirements. AI-based approaches (e.g., RFGD, ANN, LSTM) had great promise in reducing curtailment and optimizing hydrogen yield (Urhan et al., 2025; Younis et al., 2024), especially with the integration of Battery Energy Storage Systems (BESS). These findings confirm RQ2 once again by looking at actual real-time management practices that can enhance operational efficiency, reduce LCOH, and enable strategic arbitrage.

The second half of the chapter explored policy and regulatory regimes. Comparative analysis of the U.S. Inflation Reduction Act, EU Hydrogen Directive, and China's CNDC showed spectacular differences in hydrogen incentive regimes, certification mandates, and infrastructure investments. While these policies have encouraged industrial-scale projects, they remain centrally biased. Most importantly, the review saw there to be a huge policy gap: insufficient encouragement of decentralized, small-scale hydrogen applications—particularly rural or off-grid (Cho & Lee, 2025; Winkler et al., 2025). This gap is linked to Research Question 3 (RQ3) by outlining policy reforms and incentive mechanisms required to scale up balanced hydrogen integration into diverse DES conditions.

Finally, the chapter concluded by incorporating cross-cutting concerns like component compatibility, lack of suitable real-time simulation tools, non-standard certification, and stakeholders' non-participation in planning. Such systemic blockers are more than technical problems but a socio-technical transformation involving co-evolution of policy, technology, and operations.

Chapter Two's results guide Chapter Three's methodology by impacting control regime determination, sizing methodology, and policy lag appreciation, all of which impact empirical simulation and modeling testing. Specifically, Research Question 1 (RQ1) is addressed through cumulative probability-based electrolyzer sizing and energy resource modeling to regional case studies. Research Question 2 (RQ2) calls for the application of hybrid control algorithms and load-matching models to examine system optimization. Research Question 3 (RQ3) calls for simulation of policy scenarios and cost-benefit analysis to ascertain the effect of market incentives on the economic viability of hydrogen-DES systems.

Chapter Three will apply these results through a multi-method, interdisciplinary modeling approach, integrating technical design, operational performance, and policy levers into an integrated research plan for green hydrogen integration globally.

CHAPTER THREE

3.0 GENERAL METHODOLOGY

3.1 Introduction

The move to low-carbon world energy systems brought green hydrogen to the fore as a new Distributed Energy System (DES) setup. More than technology deployment, it is about working together with complex interaction between engineering systems, policy regimes, infrastructure, and human behavior. Here in this chapter, this broader methodological approach to this study—encompassing conceptual and practical connection between alternative research questions and analytical methods—is presented. Figure 3.1 depicts this broad methodological framework, tracing through logic by which each of the three research questions (RQ1 on system design, RQ2 on operation, and RQ3 on policy instruments) is tackled with corresponding methods and modeling approaches.

Each of these methodologies—technical modeling, real-time system optimization, and policy analysis—has outputs (e.g., sizing model, optimization strategies, policy instruments) that all add up together in the ultimate analysis and commentary.

Though the specific methodologies are addressed in the specific chapters allocated to every one of the following, this chapter lays down the design principles overall, cross-disciplinary thinking, and thinking overall research which is generic. Its purpose is to present how all methods contribute to the overarching goal of adopting green hydrogen as a cost-effective, sustainable, and decentralized energy carrier.

Hydrogen supply chains are becoming multi-node, multi-risk networks for which reliability and sustainability need to be assessed end-to-end. Hydrogen supply chains of the future for which long-term uncertainty and technological interdependencies are high need to be assessed using mixed method designs (Almaraz et al., 2024). This assumption is what the foundation of our approach with quantitative modeling, system-level simulation, techno-economic analysis, and comparative policy analysis rests on. These qualities allow the research to be robust and agile—two most basic requirements given the consistently evolving technological and institutional environment of green hydrogen.

To replicate the in-depth depth and volume of investigation in the research, research design borrows its proportion from social sciences and engineering paradigms. Research design adopts a hybrid methodology with mixing of system simulation, policy analysis, optimization, cost modeling, and it has each of them resolve one of the three dominant research questions:

The research framework is structured as a methodological triangle addressing design, operation, and policy dimensions: RQ1 (Technology Design & Sizing), RQ2 (Operational Strategy & Control) and RQ3 (Policy and Market Incentives). Low-carbon energy transitions, and especially those in hydrogen, need hybrid strategies that consider both sociotechnical advances and institutional routes (Damman et al., 2021). The current research responds to this need by integrating technical modeling, scenario analysis, and regulation consideration.

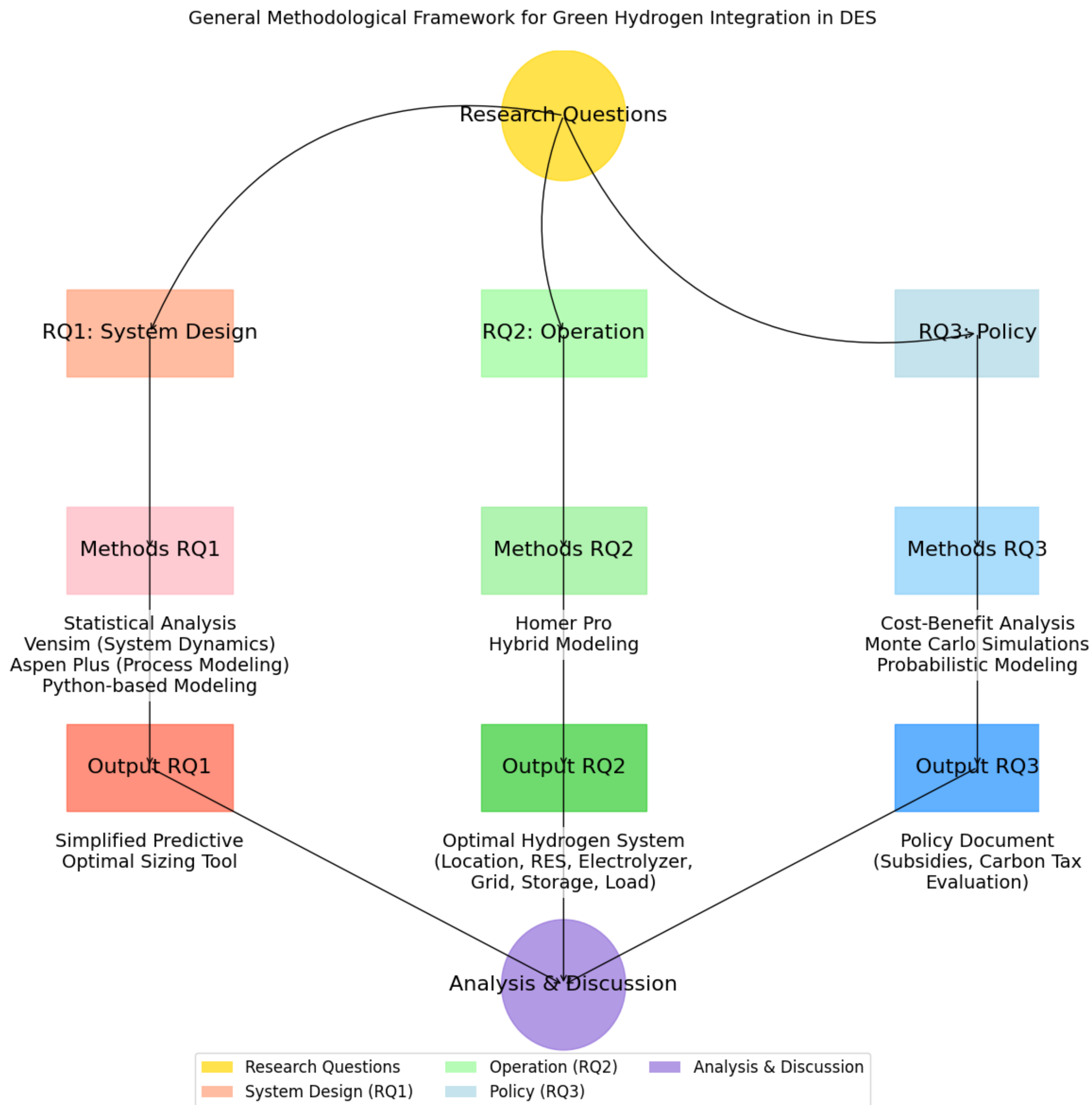


Figure 3. 1 General Methodological Framework

Furthermore, energy system transitions occur not just in laboratory and spreadsheet research but in day-to-day consumer, planner, and utility decision-making. Gordon et al. (2022) clarify that acceptance knowledge and behavior alignment with hydrogen technologies are critical for successful deployment (Gordon et al., 2022). The integrated modeling approach is therefore heterogeneity in methodology—not just to triangulate outcomes, but to solve techno-economic and sociopolitical problems.

This chapter also defines the structural rationale of the structure in subsequent methodology chapters. While each Chapters 4 to 6 begins with a specialized, question-specific methodology chapter, an overall template combines those methodologies within an integrated vision. This prevents duplication, introduces coherence, and makes each methodology a contributor to an integrated green hydrogen understanding in DES.

Finally, this category needs application to reality and imprecision. As Fodstad et al. (2022) set out to consider the energy modeling of the future, effective research needs to be capable of addressing multi-scalar complexity, data heterogeneity, and time behavior of systems (Fodstad et al., 2022). Research, in its turn, adopts probabilistic methods, sensitivity analysis, and scenario analysis as tools to support improving deterministic models. This flexibility favors hydrogen especially, against anomalous cost affinities, regimes of regulation, and variability in renewables growing at a rapidly increasing rate.

3.2 Hybrid System Modeling

Most of today's sustainability issues are at or across the technology-economics-policy-behavior nexus. Hybrid strategy allows room for combining various data types but acknowledges system interdependence and augments technical and non-technical outcome robustness (Awad et al., 2024; Naumann et al., 2024) (Awad et al., 2024; Naumann et al., 2024). The schematic representation of the hybrid model used is shown in Figure 3.2 to demonstrate again how hydrogen production interacts with storage elements and renewable sources of energy within a DES.

A single methodological lens—whether techno-economic modeling, engineering simulation, or qualitative interviews—is insufficient to fully capture the system-level implications and trade-offs of green hydrogen integration. This study therefore adopts a hybrid strategy that enables systematic measurement of performance metrics such as hydrogen yield, Levelized Cost of Hydrogen (LCOH), and storage efficiency; dynamic modeling of specific design elements like electrolyzer sizing, hybrid system configurations, and storage integration; and qualitative assessment of policy actions, stakeholder perspectives, regulatory structures, and institutional dynamics.

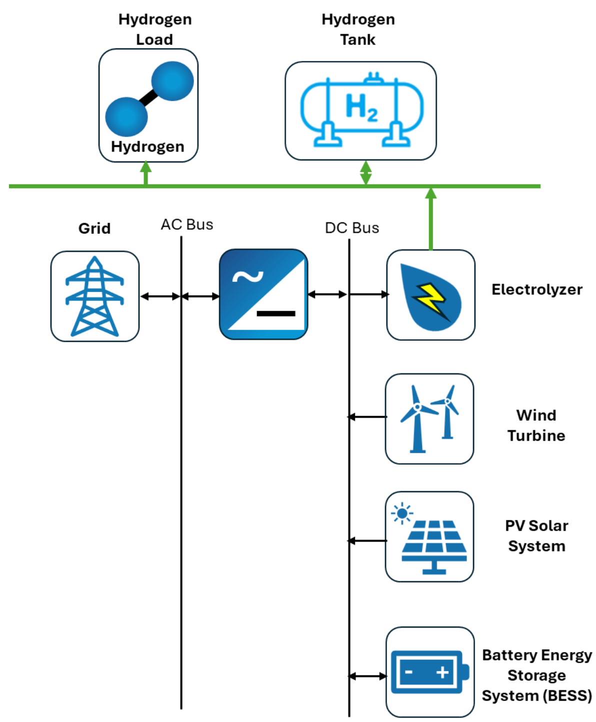


Figure 3. 2 Schematic of Hybrid Model

In combining deductive modeling approaches and inductive stakeholder-focused analysis, this research builds a strong, multi-disciplinary knowledge base of DES green hydrogen deployment routes, enablers, and barriers.

The mixed-methods logic adopted in this research aligns with the distinct nature of each research question. Table 3.1 summarizes how methodological components correspond to the study's research questions.

Table 3. 1 Summary of methodological components.

Research Question	Core Focus	Primary Methodologies	Data Type
RQ1:	System design, technical modeling	Statistical Analysis, Vensim (System Dynamics), Aspen Plus (Process Modeling), and Python	Quantitative
RQ2:	optimization strategies, efficiency	Homer Pro Hybrid Modeling	Quantitative
RQ3	Policy frameworks	Cost-Benefit Analysis, Monte Carlo Simulations, and Probabilistic Modeling	Qualitative + Quantitative

3.3 Policy Evaluation and Qualitative Analysis

RQ3 focuses on the policy tools and institutional drivers of green hydrogen integration. This question is answered using a combination of Cost-Benefit Analysis (CBA) in order to explore the economic impact of subsidies, tax credits, and regulatory schemes; Monte Carlo Simulations for modeling uncertainty and variability of policy impact; and Probabilistic Modeling for an explicit quantitative calculation of probability of differential adoption and cost over differing incentive schemes. These methods allow one to have a data-informed but flexible assessment of the efficacy of policies. The methodological structure enables quantitative analysis by means of comparative analysis of the regulatory frameworks, e.g., the U.S. Inflation Reduction Act (IRA), the European Union's Directive 2023/2413, and China's CNDC roadmap. The synergy of these approaches enables the study to create scalable and cost-competitive policy instruments for enabling the roll-out of hydrogen in DES.

Scenario-based forecasting is also employed in the study in examining the effect of other policy packages on adoption pathways. This follows the claim that policy is not a constant but an evolving parameter where technology is a co-evolving force driving and driven by technological adoption patterns (Damman et al., 2021; Fernandez et al., 2024).

3.4 Common Tools, Software, and Analytical Frameworks

Green hydrogen integration in DES is transdisciplinary in nature and requires simulation technologies and modeling infrastructure at the technological, operational, and policy levels. This section introduces the core software platforms and evaluation methodologies applied throughout the study's three principal questions: RQ1 (technology), RQ2 (process), and RQ3 (policy). These tools not only compute but also connect conceptual framework between chapters, enabling systematic, reproducible analysis. Figure 3.3 is a Gantt chart of simulation procedures, graphically representing ordering and overlapping of tool use by research questions—showing step-by-step development from system modeling to operational control and policy analysis. At the same time, Table 3.2 shows the mapping of tools to questions to reveal how tools like HOMER Pro, Vensim, Aspen Plus, Python, and LCOH models are methodologically spread across different disciplines to enable integrated assessment of hydrogen-based DES.

Table 3. 2 Tool and Framework for Model DES

Tool/Framework	RQ1: Sizing & Configuration	RQ2: Operation & Control	RQ3: Policy Evaluation
HOMER Pro		✓ Sensitivity scenarios	
Vensim (System Dynamics)	✓ Electrolyzer dynamics		
Aspen Plus (Process Modeling)	✓ Alkaline modeling		
Python	✓ Forecasting, regression		✓ Policy modeling
LCOH Model		✓ Dispatch impact	✓ Incentive modeling
LCA Tools		✓ Homer metrics	✓ Regulatory alignment
Cost-Benefit Analysis			✓ Impact estimation
Monte Carlo Modeling			✓ Risk quantification
Policy Benchmark Matrix			✓ Framework comparison

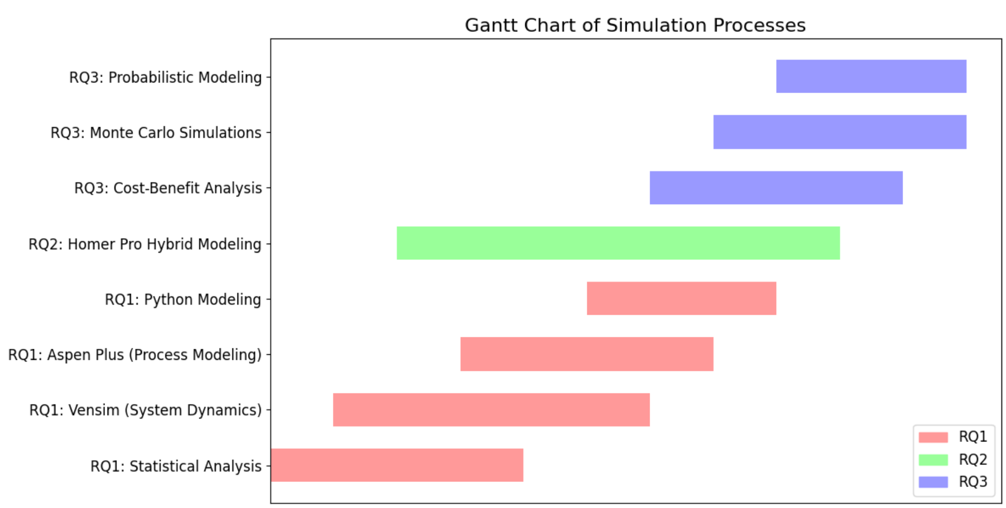


Figure 3. 3 Gantt Chart of Simulation Processes Across Research Questions

This interoperation of toolkits provides methodological consistency with systematic data handling, reproducible model runs, and integration of results without difficulty in all technical, operational, and policy areas. It provides system-level design output and regulatory overall objective alignment. It provides cross-validation between simulation environments, cost estimates, and scenario projections. Finally, this interoperation of tools provides the reliability and scalability of the study results to maximize its contribution in the implementation of green hydrogen in DES.

3.5. Key Assumptions Across Modeling Environments

Methodological coherence of this research relies on the assumed stipulations in multiple modeling domains. Economic, regulatory, and technical assumptions supply the fundamental skeleton of simulations, comparative analysis, and optimization procedures within all three study questions (RQ1 in relation to system design, RQ2 relating to operational control, and RQ3 in relation to policy assessment). With an openly specified set of assumptions, research accommodates model replicability and facilitates stress test efficacy across changing future environments.

RQ1: System Design Assumptions and Electrolyzer Sizing

For Research Question 1, the best electrolyzer design and sizing in hybrid DES, techno-economic parameters are assumptions, drivers of cost, and electrochemical performance. The efficiency of the electrolyzer is assumed as 65–75% (HHV basis) with the realistic performance level for both alkaline (AEL) systems (Sharifzadeh et al., 2024). Operational pressures are 10 bar for AEL, as per commercial standards reported by (Gökçek, Paltrinieri, Liu, et al., 2024) et al. (2024). Battery roundtrip efficiency is at 90% based on lithium-ion storage, as per Taabodi et al. (2025). CAPEX estimates for electrolyzers are $700–1,000/kW, while infrastructure cost in hydrogen storage is estimated at $800–1,200 per kg H_2 stored. These intervals make it a reference to IEA (2023) forecasts and average industry cost (IEA, 2023).

Furthermore, the scheme is also comparable to a lifetime of a renewable element of 20–25 years, a rough estimate time limit for Levelized Cost of Energy (LCOE) and Levelized Cost of Hydrogen (LCOH) estimates. Hydrogen purity is simulated at 99.99%, in line with ISO 14687 fuel-cell-grade application standards. These assumptions form the simulation foundation conducted on HOMER Pro, Aspen Plus, and Python-scripts for LCOH.

RQ2: Operational Control and Optimization Assumptions

Research Question 2 shifts the methodological focus from design to real-time operational effectiveness and optimization of hydrogen systems. Assumptions here are made in dynamic simulations HOMER Pro. The turndown ratio of electrolyzers, assumed 40% in AEL systems, is at the center of this stream (Asadbagi et al., 2024). These same values resurface in system flexibility analysis with intermittent renewable supply. Curtailment levels are modeled as 10% of daily worth of excess renewable output, keeping in mind operating limits without loss of excess energy.

RQ3: Scenario Evaluation Modeling Assumptions

Policy Incentive Modeling Regulatory classification systems, policy use contexts, and institutional levels of readiness are the basis assumptions for Research Question 3. Zero-emissions hydrogen is distinguished by source of production and emissions intensity: green hydrogen from ≥90%

renewable energy. Assumptions within the boundaries of GHG vary geographically: U.S. Inflation Reduction Act (IRA) has a Well-to-Gate limit; EU uses a Well-to-Port limit for CfD regime accreditation; and China's CNDC uses a Gate-to-Gate limit (Shin et al., 2025). Hydrogen is qualified for full fiscal incentives if it is less than or up to 4 kg CO_2e/kg H_2, according to the U.S.

Department of Energy's Clean Hydrogen Production Standard (DOE, 2023). These emission levels are input directly into the cost-benefit and Monte Carlo modeling structures computer-programmed in Python. Scenario analysis involves a base case (median policy assumptions), high-renewables scenario (increased RES penetration, reduced LCOH), and delayed policy scenario (phase-in subsidy ramp-up). Probabilistic modeling requires 1,000 runs per scenario to calculate statistical confidence intervals of policy effectiveness, cost savings, and market adoption probabilities. Secondly, the policy benchmarking matrix is used to compare instruments across three geographies--U.S., EU, and China--using normalized metrics like subsidy depth, administrability feasibleness, and emissions per dollar abated.

3.5 Chapter Summary

Chapter Three outlined a hybrid methodological framework for investigating the integration of green hydrogen into Distributed Energy Systems (DES), acknowledging the multilayered complexity of energy conversion, system operation, and policy regulation. Taking up the challenge of the energy conversions being multilayered and complex in nature, Chapter Three proposed a hybrid research approach of technical simulation, real-time system optimization, and policy analysis. It responds directly to the three main research questions of this research: RQ1 (system design and sizing), RQ2 (operational optimization), and RQ3 (policy and regulatory frameworks).

The chapter began with a preview of the research methodology at an inter-disciplinary level, as illustrated by Figure 3.1, representing the co-evolution of hydrogen technologies, policy instruments, and control system operations. The method is based both on simulation engineering software (e.g., Aspen Plus, Vensim, HOMER Pro) and on economic-policy tools (e.g., Monte Carlo simulations, Cost-Benefit Analysis, policy benchmarking) to deliver a holistic system-level evaluation.

For RQ1 of hydrogen systems design and scale, the methodology employs quantitative model-based tools such as Aspen Plus, Python script tooling for LCOH, and Vensim to simulate hydrogen production pathways and estimate performance based on various configurations and resource availability. Assumptions regarding electrolyzer efficiency, infrastructure cost, and lifecycle were specifically made for informing replicability and robustness to alternative scenarios.

In order to answer RQ2, toward the support of operating control and optimization of DES-integrated hydrogen systems, dynamic interactions between renewable inputs, electrolyzer operation, and storage dispatch were simulated using HOMER Pro software. The performance of the system was quantified with respect to metrics like curtailment reduction, hydrogen yield, and roundtrip efficiency, where operating constraints like turndown ratios and losses in storage were modeled explicitly towards real-world viability.

For RQ3, policy and market instruments for scaling up hydrogen integration, a mixed-method qualitative-quantitative study was proposed. Cost-Benefit Analysis, Monte Carlo simulations, and a policy benchmarking matrix were used to evaluate a suite of policy tools including subsidies, carbon pricing mechanisms, and tax incentives, renewable gas standards, and regulatory incentives in the most important districts (U.S., EU, China). This application of three methods provides evidence-based foundations for comparison of policy effectiveness in facilitating cost-effective and equitable hydrogen deployment.

Additionally, the chapter presented a unified suite of analytical tools (Table 3.1 and Figure 3.3) to enable methodological harmonization across the three core research questions. Emphasis was placed on ensuring practicality between modeling environments, repeatability of simulations across datasets and software platforms, and cross-validation of results to enhance the reliability of findings. Together, these elements form a robust validation and integration strategy that supports consistent system evaluation and policy alignment in the context of hydrogen-DES deployment.

Most important, the chapter delineated the main assumptions of the model in technical, operational, and policy variables from electrolyzer efficiency and renewable intermittence to eligibility thresholds for emissions under various policy incentives. This openness adds to the strength of the credibility of the simulations and enables scenario analysis on the assumption of uncertainty of future policy and volatility of renewable resources.

The methodological foundations laid in Chapter Three thereafter mature into Chapter Four, which addresses Research Question 1 (RQ1)— simple method for determining and sizing electrolyzers in a hybrid renewable-powered DES. Chapter Four applies the modeling tools and assumptions here to real-world case studies using probabilistic and techno-economic analysis.

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CHAPTER FOUR Part I

4(I).0 EMPIRICAL ENERGY-BASED ELECTROLYZER SIZING (RQ1a)

4(I).1 Background

Electrolyzer performance is sensitive to fluctuations in power supply. Although optimal electrolyzer performance is achieved under steady-state conditions, solar and wind energy exhibit significant daily and seasonal variability. These fluctuations complicate sizing, particularly in off-grid or poor-grid DES installations where energy balancing infrastructure is either unavailable or prohibitively expensive. Oversizing electrolyzers produce high capital costs and low utilization, while undersizing the system produces normal curtailment of accessible renewable energy and lost hydrogen production.

Recent research has also improved energy yield estimation. Çelikdemir and Özdemir (2025) developed a highly precise empirical model based on Modified Particle Swarm Optimization (MPSO) for estimating the cost of hydrogen production from solar, wind, and wave systems (see Chapter 2.4 for detailed discussion). Their model achieved absolute errors as low as 0.01% in wave-based systems and demonstrated the strength of heuristic algorithms in techno-economic prediction. Similarly, Rai and Liu (2025) implemented the Spatiotemporal Attention Framework (STAF) that aggregates CNN-BiGRU deep learning models to forecast electrolysis system behavior based on different irradiance (Rai & Liu, 2025). These paradigms highlight the predictive capabilities of machine learning, although generalizability and transparency remain challenges.

But for Research Question 1 (RQ1)—"How is electrolyzer optimal sizing optimized for configuration in a hybrid Distributed Energy System (DES)?"—the need is not merely high-fidelity prediction, but also *scalable, interpretable*, and *modular* sizing methods that can be easily generalized to a wide range of DES environments. Machine learning models are excellent predictors but usually opaque and less generalizable in techno-economic configuration issues. Therefore, there is a strong incentive to develop an empirical approach that simplifies this complexity and makes the application of hydrogen technologies viable in DES environments.

4(I).1.1 Problem Statement

An exceptionally large majority of modern-day electrolyzer design relies upon deterministic methods—namely, equalizing installed renewables capacity or even using average yearly generation—ignoring solar and wind supply's stochastic characteristics. In DES, the oversimplification becomes even more paramount with reduced buffering capabilities and additional sensitivity towards mismatch in design. Therefore, these heuristics produce two suboptimal outcomes: undersized electrolyzers resulting in too much curtailment and loss of renewable energy or oversized equipment, which is more expensive in capital terms but operates inefficiently most of the time because there is inadequate use of renewable power.

Furthermore, these sizing practices are rarely supplemented by Levelized Cost of Hydrogen (LCOH) analysis, which is essential to determine long-term economic feasibility. Without correlating design and cost, decision-makers in DES environments have no definitive direction on how best to balance hydrogen yield, infrastructure utilization, and capital risk.

Even more recent works—such as those of Idriss et al. (2025), who used PSO, HGSO, and AO algorithms to find the best wind locations in data-poor regions such as Djibouti—suffer from interpretability, computational complexity, and region portability (Idriss et al., 2025). Such advanced models, although precise, may not be the best choice for rapid scenario generation or community-scale DES implementation. Thus, there is a strong requirement for an empirical, practical sizing method that is not only technically sound but also economically sound and of broad applicability to hybrid DES hydrogen systems.

4(I). 1.2 Research Gap

While heuristic optimization and AI-driven yield prediction have taken the art to a higher level in the case of hydrogen production capability, there remains a basic deficit in the paradigms behind planning capacity for realistic time-varying availability of resources. Relative to established applications like wind finance—where P-levels P50, P75, and P90 are standard in risk-informed design—hydrogen systems hardly utilize exceedance-based cumulative sizing approaches. Few of them apply historically rooted or simulated optimal electrolyzer size from cumulative energy distributions, link such sizing with cost indicators like the Levelized Cost of Hydrogen (LCOH), or consider the ramifications to real-time generation-demand imbalance like curtailment or excess capacity. Also, non-hydrogen-related factors particularly DES, including modularity, reliability requirements, and off-grid suitability, are not given attention in current hydrogen sizing practices.

In addition, physical parameters such as PV tilt, water quality, and electrolyzer degradation curves, studied by Ben Abdelwahed et al. (2025), underscore the need for incorporating site-specific and operational parameters in sizing models (Abdelwahed et al., 2025). These parameters significantly influence hydrogen yields and can skew LCOH if not adequately addressed in the design process.

This study fills these gaps by proposing an empirical, scenario-based methodology that uses exceedance probabilities of energy and is consistent with operational realities and economic constraints in DES models.

4(I). 1.3 Objectives

In answering RQ1, the research aims to set and calibrate an empirical, transparent framework for alkaline electrolyzer sizing in hybrid solar wind powered DES. The objectives are:

Derive cumulative annual energy distributions from daily hybrid solar-wind generation to determine P50, P70, and P90 thresholds.

The study designs their respective electrolyzer capacity scenarios against benchmarks of renewable energy distribution and their technical performance by daily mismatch calculation between energy production and electrolyzer capacity are compared. Annual hydrogen production (kg/year), Capacity Utilization Factor (CUF), Renewable Energy Utilization Rate (REUR), Curtailment Ratio, and Idle Capacity Ratio, system-level technical indicators, are calculated. These findings are integrated into a Levelized Cost of Hydrogen (LCOH) model for cost-effectiveness analysis in various scenarios. The result is a modular, scalable system that can be adapted to a variety of Distributed Energy System (DES) designs and policy environments.

4(I).1.4 Contributions

This study presents five significant contributions to the integration of green hydrogen in DES. Firstly, it presents an empirical sizing method with percentile-based capacity planning (P50, P60, P70, P90) according to historic energy distributions to enable realistic system design within resource uncertainty. Secondly, it presents performance-based trade-off analysis showing how sizing affects hydrogen yield, energy efficiency, and underutilization—factors that are to be addressed for decentralized systems. Third, it connects the above technical measures and economics via the Levelized Cost of Hydrogen (LCOH), providing a cost-risk optimization platform that can be utilized by developers, investors, and policy makers. Fourth, the model is demonstrated to be generalizable across geographies and system configurations, as opposed to heuristics applied to specific locations. Finally, through the inclusion of DES-specific operational and spatial attributes, the model enhances readiness for decentralized deployment and policy applicability, in alignment with national hydrogen strategies that place emphasis on energy justice, resilience, and local ownership.

In synthesizing these results, the research provides a practical and analytical sound response to RQ1, providing a blueprint for hybrid DES-based hydrogen systems' optimal electrolyzer sizing and economic performance.

4(I).1.5 Electrolyzer Sizing Methodologies

Electrolyzer sizing is a key design decision in green hydrogen systems, especially in hybrid DES where the temporal mismatch between hydrogen demand and energy supply can lead to inefficiencies. Historical size methods have usually been deterministic, employing average annual energy production, constant capacity ratios, or assumptions of steady-state performance. Though simple to employ, these techniques fail to describe the stochastic variation of the solar and wind resources, particularly in DES applications without grid buffering or running in off-grid modes.

Recent work by Gallo and García Clúa (2023) proposes an even more refined strategy by combining an alkaline water electrolyzer with a wind turbine and grid support to maintain annual power exchange with the grid as minimal as possible (Gallo & Clúa, 2023). Three variable operating modes proposed in their work are optimized for different conditions of wind resources simulated using Weibull distribution. The realization is that variable modes benefit from larger sizes of electrolyzers compared to fixed operation, which shows the consequence of resource-sensitive sizing that creates lower carbon emissions and improved integration performance. The model, as much as it is not designed for DES, demonstrates how renewable resource profiling must be direct sizing.

Similarly, Dabar et al. (2022) conduct a techno-economic and wind resource analysis for Djibouti, illustrating that the best size of electrolyzer varies with wind regimes and infrastructure conditions (Dabar et al., 2022). Results indicate LCOH ranging from \$1.79 to \$3.38/kg H_2 and depending very much on capacity factor and investment—two directly impacted parameters by sizing. Although the paper does not suggest an implicit sizing model, it still does emphasize location-specific conditions.

In a design perspective based on optimization, Coppitters et al. (2019) compare robust and deterministic photovoltaic-electrolyzer system sizing. Robust optimization-based global sensitivity analysis by their research reduces standard deviation in hydrogen output by 43% (Coppitters et al., 2019), proving uncertainty-aware sizing maximizes performance stability—a key prerequisite in DES scenarios where redundancy is limited in systems.

Such instances suggest that Research Question 1 (RQ1)—optimal sizing of electrolyzers in hybrid DES arrangements—calls for models that move beyond averages. Empirical methods acknowledging variability, i.e., cumulative energy distribution thresholds (P50, P60, P70, P90), deliver generalizable and modular-sizing strategies adapted for variable, decentralized energy landscapes.

4(I).1.6 Hydrogen Cost Estimation Models

To translate technical notions into feasible economic projects, the Levelized Cost of Hydrogen (LCOH) must be understood. LCOH includes capital investment (CAPEX), operating expense (OPEX), energy input cost, electrolyzer utilization factor, and discount rates over the lifetime of a system.

The economic significance of electrolyzer sizing can also be observed in Kim et al. (2022), who use integrated biogas-PEM electrolysis systems. They employ Polynomial Chaos Expansion (PCE) for surrogate modeling and obtain 11.9% mean and 37.8% variance reduction in LCOH under robust design conditions. The result indicates that electrolyzer utilization, as a function of sizing, is one of the foremost determinants of hydrogen cost.

Kourougianni et al. (2024) offer a detailed review of green hydrogen systems and propose that techno-economic integration needs to account for component-level interactions and prioritize mitigating renewable input variability and electrolyzer load profiles (Kourougianni et al., 2024).

They conclude from the literature that system-level LCOH is optimized by co-considering sizing, operational strategy, and system hybridization.

Second, Ahmad et al. (2025) show how thermal management strategies like cool roofs and bifacial PV panels give important leverage to solar-to-hydrogen efficiency—showing how LCOH sensitivity is as extensive as system surface design (Ahmad et al., 2025). These implications are also crucial for highlighting empirical sizing models' reliance on operating context for enabling cost-effective green hydrogen production to be viable with DES.

LCOH integration directly supports RQ1's optimization thought of hybrid DES design sizing. By keeping multiples of P-levels against cost outputs, stakeholders can compare whether more hydrogen output at P50-sizing system is better with higher CAPEX, or whether a P90 case is more profitable by higher utilization at reduced yield.

4(I).1.7 Research Gaps

There are three large gaps despite tremendous development in modeling and optimization:

Limited application of empirical, percentile-based sizing models for hydrogen systems: Although common in wind, P50–P90 sizing methods are not usually applied to electrolyzers. Key hydrogen studies use fixed ratios or full-load-hour assumptions, not capturing the stochasticity of renewable inputs in DES.

Absence of modular and transferable sizing models: True, deep learning techniques, such as STAF by Rai and Liu (2025) or MPSO by Çelikdemir and Özdemir (2025), are strong predictors; however, they are computationally intensive and highly non-transferable to other geographies or skill levels. The empirical P-level approach enhances replication, policy analysis, and stakeholder consultation.

Disconnect between size and strategy in LCOH modeling: Those few that actually link system design with cost results-Coppitters et al. (2019); Kim et al. (2022)-show that strong designs lead to lower LCOH and better reliability (Kim et al., 2022), yet sufficiently generalizable linkages from system design through cumulative energy data to size approaches are still poorly developed.

In answering RQ1, the research here addresses a few important methodological shortcomings by presenting an empirical model based on the use of cumulative energy distribution metrics (P50, P60, P70, P90) to guide specification of electrolyzer capacity in response to shifting renewable conditions. It connects technical parameters such as Capacity Utilization Factor (CUF), Renewable Energy Utilization Rate (REUR), and curtailment rates to economic performance through the Levelized Cost of Hydrogen (LCOH) using a single method of balancing cost and efficiency. The system is scalable for roll-out on a grand scale in hybrid DES where access to high-level simulation packages or machine learning capability is not assured. This is in support of a growing body of research committed to the achievement of low-cost, resilient hydrogen integration, particularly in disadvantaged communities that experience resource scarcity and poor infrastructure.

4(I).2 Methodology

This section outlines the methodology framework developed to address Research Question 1 (RQ1): How is electrolyzer optimal sizing optimized for configuration in a hybrid Distributed Energy System (DES)? Six core elements of the methodology are system description, empirical energy distribution analysis, electrolyzer sizing scenarios, performance evaluation metrics, Levelized Cost of Hydrogen (LCOH) integration, and validation by comparative case studies. Figure 4.1 (Modeling Flowchart), which depicts the sequential and interconnected processes in the modeling process, methodically organizes and visualizes these elements. This platform ensures that there is economic as well as technical coverage so that effective decision-making for DES-scale hydrogen deployment is possible.

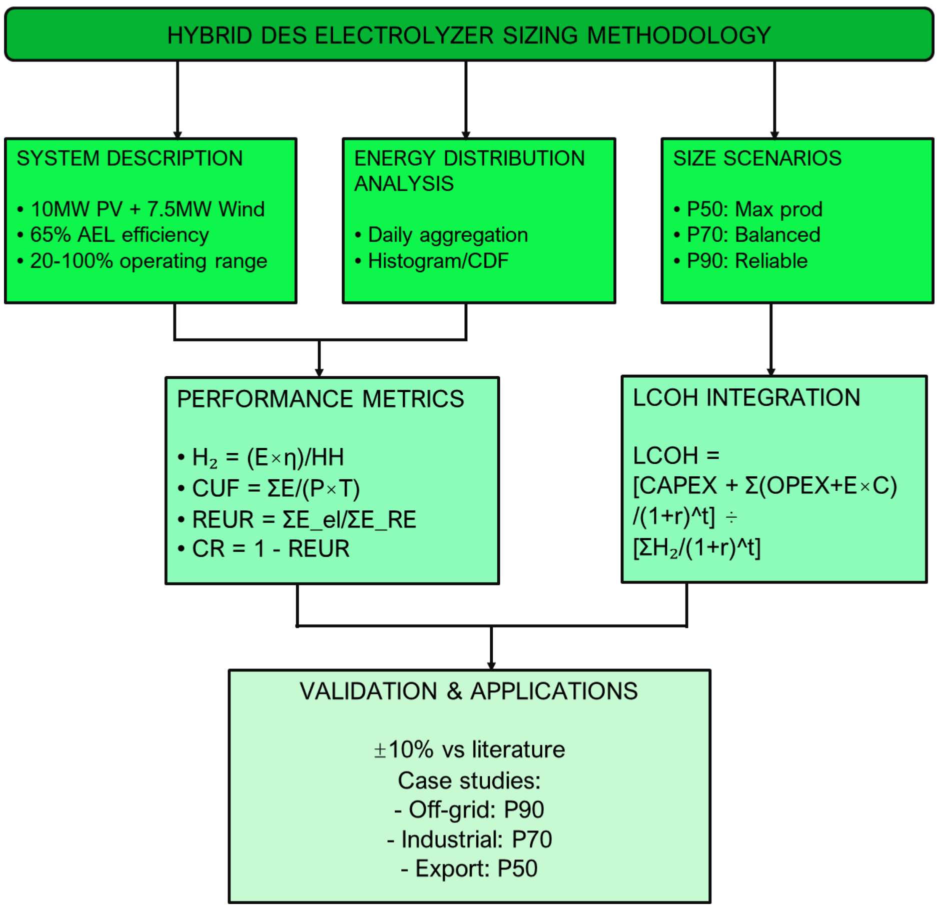

Figure 4. 1 Modeling Flowchart

4(I).2.1 System Description

The system at hand is a hybrid Distributed Energy System (DES) consisting of photovoltaic (PV) solar and onshore wind generation units providing electricity to an alkaline water electrolyzer for green hydrogen generation. DES layout models a mid-sized, grid-necessary or -optional such as an industrial park, rural hydrogen fueling station, or island microgrid. The renewable energy source is a 10 MW PV solar farm based on hourly irradiance with typical module efficiency of 18 to 20 percent and accounting for derating factors such as inverter efficiency and temperature loss. Also, a fleet of 7.5 MW onshore wind turbines is simulated from past wind speeds and typical turbine power curves. Generation was simulated by hour for a year from typical meteorological year (TMY) data typical of a high-solar-yield, semi-arid climate with moderate winds.

The reference electrolyzer is an efficiency-characteristic 65 percent commercial alkaline electrolyzer (AEL) based on Higher Heating Value (HHV) basis. It consists of modular units ranging from 1 MW to 20 MW, scalable and medium response time, flexible with varying input conditions between an operating range of 20 to 100 percent load. The life of the stacks is assumed to be 60,000 operating hours. CAPEX and OPEX are estimated based on vendor-quoted ranges and benchmarking reports from IEA and NREL, with the linear scalability of CAPEX as a function of installed capacity.

4(I).2.2 Analysis of Energy Distribution

Statistically describing the annual energy production is used to transition from raw generation profiles to sizing thresholds. PV and wind renewable generation values are summed up to daily total energy values in MWh/day, providing a dataset of 365 values of the total available energy to the electrolyzer for a day. They are sorted and grouped into bins of equal width and are plotted as a histogram to represent frequency distribution.

A cumulative distribution function (CDF) of daily total energy values is then constructed to obtain exceedance probability values of interest. The P-level threshold (P_x) is the daily renewable energy value exceeded on x % of days in a year. This approach is statistically correct and does not have errors due to peak or average sizing values.

The CDF model is defined mathematically as shown in equation 4. 1:

Equation 4. 1 Empirical RE Resource Percentile Sizing Model

$$\boldsymbol{P_x} = \mathbf{CDF^{-1}}(\boldsymbol{x}) \tag{4.1}$$

P_x represents the energy level in megawatt-hours per day (MWh/day) that is exceeded on $P_{50}, P_{60}, P_{70}, and\ P_{90}$. These values are derived using the inverse of the cumulative distribution function, denoted as $\mathrm{CDF}^{-1}(x)$, which is empirically constructed from daily hybrid PV-wind energy generation data. The selected percentiles x∈{50,60,70,90} provide a probabilistic basis for defining electrolyzer sizing thresholds, balancing reliability, renewable energy utilization, and system cost-efficiency.

The histogram provides distribution and skewness of energy availability, whereas CDF utilizes empirical variability in the real world for sizing. The empirical solution fits into wind and hydropower experience that gives increased modularity and flexibility.

4(I).2.3 Electrolyzer Sizing Scenarios

Scenarios of electrolyzer sizing are determined on the basis of P50, P60, P70, and P90 estimated by CDF. In the P50 capacity sizing scenario, electrolyzer capacity is sized to the level of energy exceeding 50 percent of the time. The P70 scenario sizes capacity to the 70th percentile, and makes compromises in terms of yield for reliability, and making the P90 scenario conservative in sizing for ultimate utilization, sizing capacity to the 90th percentile level. All three are expressions of different risk appetites and investment horizons.

To evaluate operating dynamics, a daily mismatch analysis is conducted. Positive mismatches for a given day are utilized when electrolyzer capacity is greater than available renewable energy, i.e., idle capacity. Negative mismatches where available energy is greater than capacity, i.e., curtailment. The annual mismatch profiles provide each size strategy with performance data.

4(I).3 Model Validation and Applications

Empirical sizing methodology is peer-reviewed literature validated. Simulation results of hydrogen yield and LCOH are within ±10 percent of Coppitters et al. (2019), Dabar et al. (2022), and Kim et al. (2022), for consistency and methodology integrity. The model is then applied to three real application cases to show versatility. For an off-grid village cluster, the P90 scenario is appropriate for reliability. For industrial co-location, P70 case represents a capital expenditure vs. hydrogen throughput tradeoff. For hydrogen export hub, the P50 configuration is most suitable since in this case the concern is to make maximum output available with competitive power.

Together, the proposed empirical strategy answers RQ1 with a statistically validated, economically relevant, and robust hybrid DES electrolyzer scaling method. The methodology connects renewable energy input heterogeneity and techno-economic decision-making and provides an open and extendable green hydrogen infrastructure planning procedure.

4(I).4 Results and Analysis

This section analyzes annual hybrid solar-wind energy output data for Amarillo, Bakersfield, and Lethbridge. Using histograms and cumulative distribution functions (CDFs), it highlights variability and reliability in renewable energy supply. Key percentiles (P50–P90) are used to guide electrolyzer sizing for DES, providing practical insights into location-specific hydrogen production potential.

4(I).4.1 Energy Distribution Insights

A comparative plot of the annual distribution of daily hybrid solar-wind system energy outputs at three geographically separated locations is shown in Figure 4.2 – 4.4 for Amarillo, Texas; Bakersfield California; and Lethbridge, Alberta. Using a blend of histograms and cumulative distribution functions (CDFs), the figure depicts the statistical reliability and variability of a year's worth of energy production. This graphical approach is extremely beneficial in considering the frequency at which a single energy output level will occur, the very basis for hydrogen production system planning and design operation of DES.

Distribution graphs: Percentiles P50, P60, P70, and P90 provide useful insights into the possibility of energy being available. The P50 level—the half power point—is a level that promises half the days within a year when one can anticipate the system delivering at least that amount of power. It is typically a balance point between utilization and availability and is a good pointer for the moderate scale sizing of electrolyzers, especially where there are consistent renewable generation patterns. Figures 4.2–4.4 present the empirical energy distribution and exceedance probabilities for each location. P50, P60, P70, and P90 levels—marked on each chart—represent the energy output exceeded on 50%, 60%, 70%, and 90% of days, respectively. These form the basis for electrolyzer sizing scenarios.

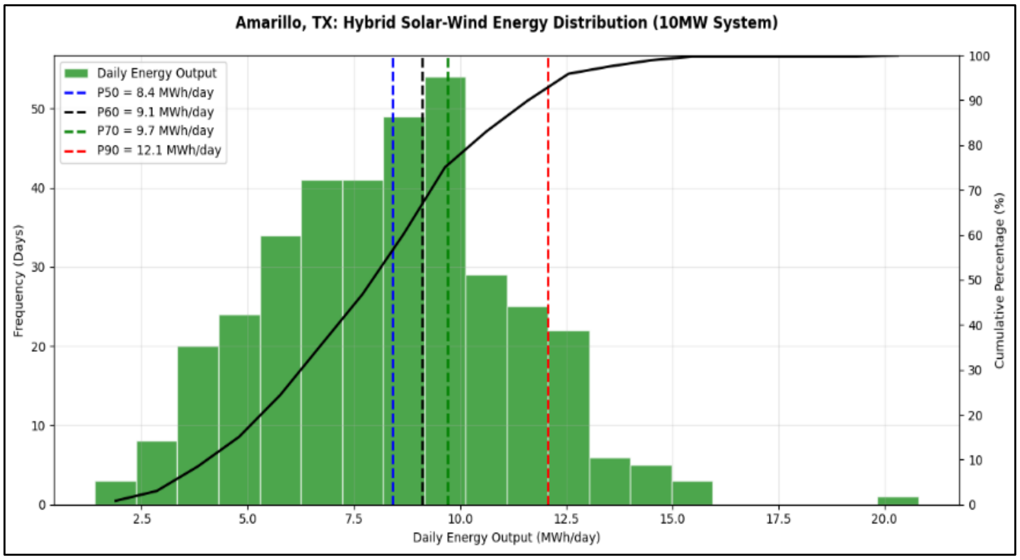

Figure 4. 2 Empirical Daily Energy Distribution and Cumulative Probability Amarillo

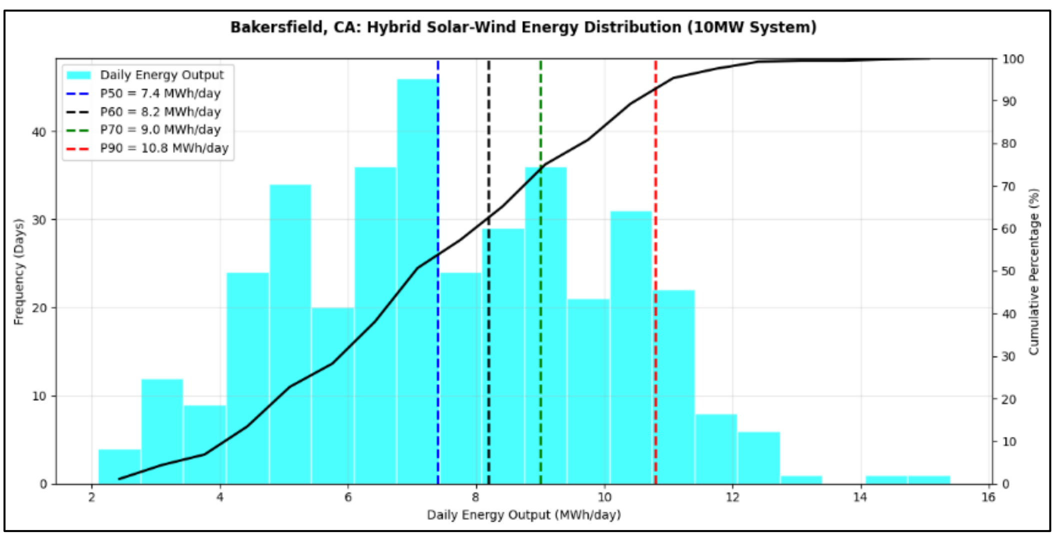

Figure 4. 3 Empirical Daily Energy Distribution and Cumulative Probability Bakersfield

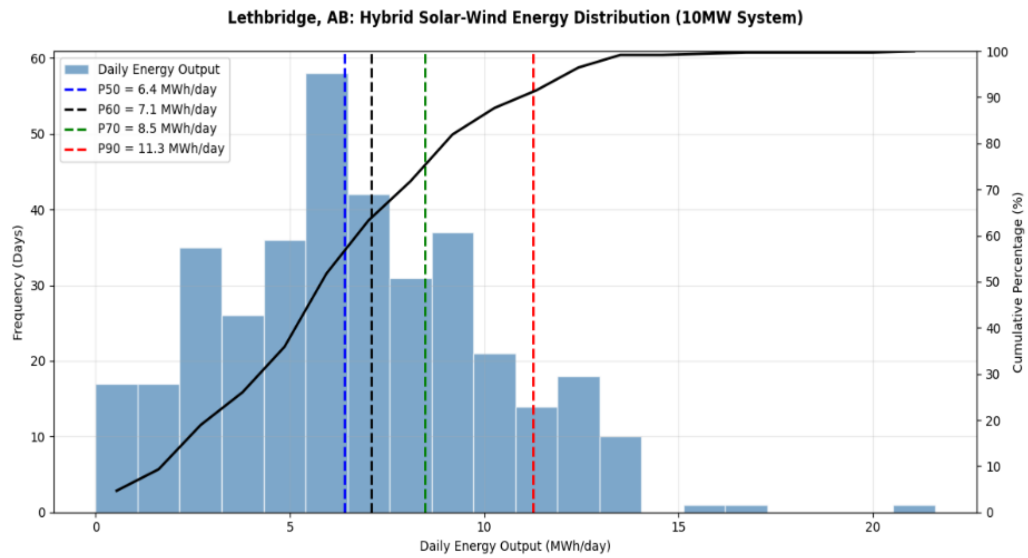

Figure 4. 4 Empirical Daily Energy Distribution and Cumulative Probability Lethbridge

The distributions reveal that Amarillo has the highest median and upper percentile values, while Lethbridge displays a wider spread due to seasonal wind variation. This implies location-specific optimal sizing configurations. Table 4.1 summarizes the technical performance, including average energy outputs, capacity utilization factor (CUF), estimated hydrogen yields (based on 50 kWh/kg-H_2 conversion), and curtailment risks.

Table 4. 1 Performance of Hybrid PV-Wind Systems Across Locations

Location	**Output (MWh/day)**					**CUF (%)**	**Estimated H_2 Yield (tons/day) ***	**Curtailment Risk**
	Avg	**P50**	**P60**	**P70**	**P90**			
Amarillo, TX	8.3	8.4	9.1	9.7	12.1	34.5	~0.43	Low–Moderate
Bakersfield	7.6	7.4	8.2	9	10.8	31.7	~0.39	Moderate
Lethbridge	6.6	6.4	7.1	8.5	11.3	27.5	~0.33	Moderate–High

*Assumes 50 kWh/kg-H_2 electrolyzer efficiency

For directions towards more conservative system design requirements, P60 and P70 are energy levels achieved 60% and 70% of the time, respectively. These introduce risk aversion into system design. They are best utilized when system reliability and round-the-clock hydrogen production is a greater issue than generation optimization on peak resource availability days. Technically, the P60 and P70 profiles create a cleaner power baseline that will reduce requirements for backup capacity or auxiliary storage.

The P90 benchmark on the scale is the most conservative and guarantees availability of the contracted amount of energy on 90% of days in a specific year. While such exorbitant levels of confidence do result in quasi-continuous system performance, it necessarily means that an enormous portion of the system generation capacity will go underutilized on high-resources days. Such trade-off of effectiveness/reliability is especially overdrawn for hydrogen-generating systems because capital-costly electrolyzers will operate only during a fraction of the year if done solely to P90 criteria. Such percentile-based levels form the basis for well-informed electrolyzer sizing finally.

Through identification of most commonly available daily energy levels in different climates and seasonal regimes, system designers and integrators can align electrolyzer capacity with actual energy supply patterns. This is to avoid overinvestment in idle capacity or, alternatively, hydrogen production shortfalls during peak demand. As a result, not just is Figure 4.1 indicative of the intermittency of the renewables but also converses such intermittency into operative decision-making data for tactical implementation of green hydrogen infrastructure within hybrid DES systems.

4.5.2 Electrolyzer Sizing Trade-offs and Performance

We made techno-economic comparisons of P50 to P90-sized electrolyzer capacities, pushing the limits of percentile-based sizing techniques. Hydrogen production, curtailment, idle capacity, Levelized Cost of Hydrogen (LCOH), Net Present Value (NPV), and payback period were the main performance measures studied under different geographical conditions. As Figure 4.5 (LCOH Across Locations by Electrolyzer Sizing Percentile) suggests, LCOH increases with increasingly conservative sizing owing to higher capital cost and decreased utilization factors. Economic return patterns, as Figure 4.6 (NPV by Location and Sizing Strategy) suggests, reveal that P50 sizing consistently maximizes NPV under base assumptions (hydrogen price of $4.50/kg, project duration of 20 years, discount rate of 8%). On the other hand, P90 scenarios will lead to under exploitation and negative returns.

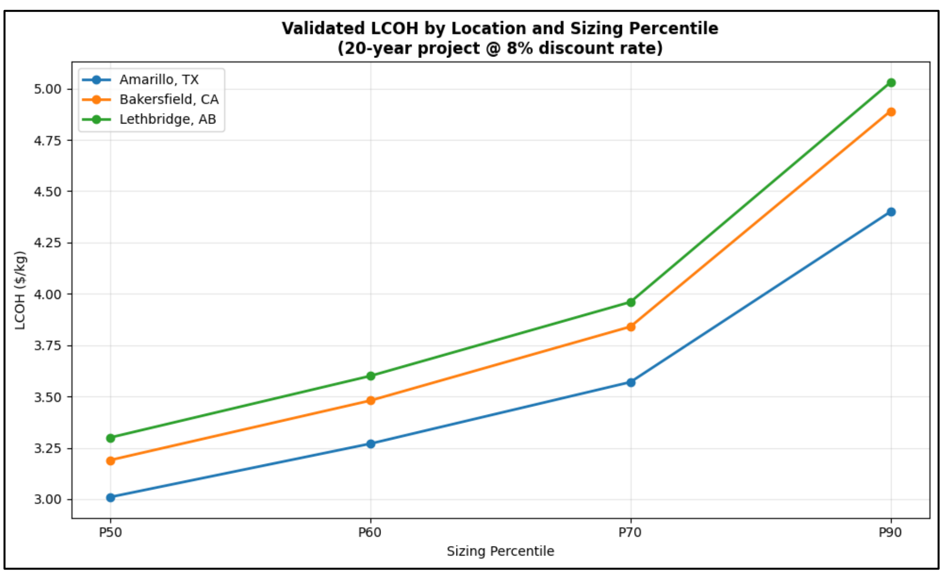

Figure 4. 5 LCOH Across Locations by Electrolyzer Sizing Percentile.

Also, the decline in Return on Investment (ROI) and rising payback periods are better explained in the combined performance values given in Table 4.2. In general, the results are indicative of the inherent system utilization efficiency and investment trade-off, thereby providing further rationale to region-based optimization in electrolyzer sizing methodologies.

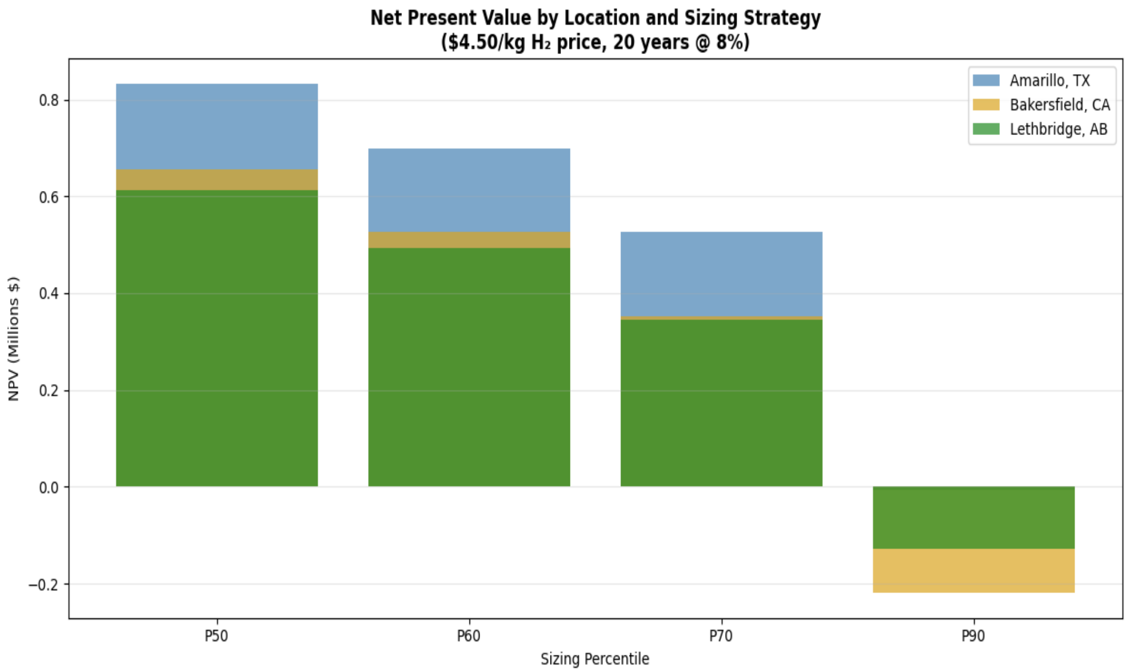

Figure 4. 6 Net Present Value (NPV) by Location and Electrolyzer Sizing Strategy.

Table 4. 2 Electrolyzer Sizing at Varying Energy Percentiles

Location	Pctile.	Cap (mW)	LCOH($/kg)	NPV ($)	ROI (%)	PB (yrs)	Cost of UE (mm$)
Amarillo	P50	0.47	3.01	0.83	47.8	6	0.072
Amarillo	P60	0.49	3.27	0.70	35.7	6.6	0.061
Amarillo	P70	0.52	3.57	0.53	23.9	7.4	0.052
Amarillo	P90	0.60	4.4	-0.01	-0.2	9.9	0.026
Bakersfield	P50	0.37	3.19	0.65	40.9	6.2	0.094
Bakersfield	P60	0.39	3.48	0.53	29.3	6.9	0.080
Bakersfield	P70	0.43	3.84	0.35	17.1	7.9	0.066
Bakersfield	P90	0.52	4.89	-0.22	-8	11	0.032
Lethbridge	P50	0.31	3.3	0.61	39.7	6.2	0.077
Lethbridge	P60	0.33	3.6	0.49	28.7	6.9	0.065
Lethbridge	P70	0.35	3.96	0.34	18	7.8	0.054
Lethbridge	P90	0.42	5.03	-0.13	-5.2	11	0.026

4(I).5 Key Findings

Figures 4.5, 4.6 and Table 4.3 show the trade-offs in selecting an electrolyzer sizing method with reliability objectives set—P50, P60, P70, and P90, respectively. From these representations, it is easy to build the reason for the impact of a specific sizing percentile on the corresponding performance measures like utilization efficiency, return on capital, and system dynamics. For hybrid DES for green hydrogen production in general, the figures give some idea of the impact of sizing on both economic viability and technical performance.

4(I).5.1 Scaling to P50 provides a reference aligned with average daily generation.

This method has one flaw: too much frequency of curtailment. During certain days when there is an excess of solar and wind resources beyond the midpoint, the system will produce more energy than the electrolyzer is capable of processing. Since neither energy storage nor flexible grid integration is leveraged, such excess is wasted or underutilized. Although P50 sizing ensures the maximum on average days, it wastes production at peak production times and therefore deprives the system of potential in leveraging high renewable availability.

4(I).5.2 Sizing at the P70 level provides a balanced mechanism.

The size of the electrolyzer is designed to fit energy outputs of more than 70% on most occasions, thus curtailment and downtime are practically minimized. This middle-ground solution will offer more stability in hydrogen production at the expense of not paying the premium of extra costs of overcapacity from P50 sizing. Moderate curtailment here is below, but less and cheaper economically, particularly in optimized systems to provide stable supply at reduced capital expense.

4(I).5.3 Sizing at the P90 level minimizes low-output days.

On the other end is P90 sizing, risk-averse, high-utilization. By designing the electrolyzer to equal energy outputs 90% of the time, system designers can assure that the electrolyzer is used every day that it runs. There is, however, one obvious disadvantage to this conservative setup: too frequent underproduction. Since the electrolyzer is sized to minimize low-output days, the electrolyzer is under-sized on high-renewable production days and production capacity is lost. Additionally, the unit cost of hydrogen (Levelized Cost of Hydrogen or LCOH) will be higher in this arrangement due to the massive investment in capital with limited hydrogen production. The system itself is sound, but it becomes economically unviable without the support of strong policy incentives or application in niche markets where reliability takes precedence over production volume. These visualizations combined indicate that the choice of percentile threshold for sizing electrolyzers is not a technical parameter but a design decision with a direct impact on curtailment rates, utilization efficiency, production stability, and overall economic viability.

The figures show that each of the sizing approaches possesses a specific set of pros and cons associated with it, and the best one is chosen by certain system targets, market situation, and operating flexibility present in the whole DES design. The optimal size of the electrolyzer is in the area between the P70 point at which system utilization and investment both prefer best in trading with one another. As is evident in Table 4.3 to illustrate, P70 sizes at all locations of Amarillo, Bakersfield, and Lethbridge all give middle Levelized Cost of Hydrogen (LCOH), well Net Present Value (NPV), and good curtailment cost, thus an equal curve performance. On the other hand, P90 sizing gives particularly good reliability and almost zero curtailed energy at the expense of economic efficiency with oversizing and high LCOH. Table 4.4, however, clearly indicates that P50 sizing gives lowest capital cost and highest NPVs but at the expense of high renewable energy curtailment on peak generation days. The graph also puts a figure on the unused annual cost of renewable energy at the three locations—lower percentile techniques (P50–P70), particularly in Bakersfield, to yield significant curtailment losses despite lower attractiveness in initial investment.

Observations from Figure 4.7 – Unused Cost of Renewable Energy at Different Sizing Percentiles per Year. One can observe that unused energy costs are highest in Bakersfield, CA for all the percentiles of sizing and lowest in Amarillo, TX. The reason being, Bakersfield has greater average renewable generation with comparatively lower utilization efficiency of electrolyzers, therefore there is unused energy in terms of excess hydrogen.

Table 4. 3 Electrolyzer Sizing, LCOH, CAPEX and Curtailment Trade-offs

Electrolyzer Sizing Level	**LCOH Driver**	**LCOH**		
		Amarillo	Bakersfield	Lethbridge
P50	Lowest CAPEX, High Curtailment	Moderate	High	Very High
P60	Balanced CAPEX vs Utilization	Lower	Medium	High
P70	High Utilization, Moderate Curtailment	Optimal	Optimal	Moderate
P90	Overcapacity, Minimal Curtailment	Higher	Higher	Highest

By contrast, Amarillo is more suitably matched by generation profiles and electrolyzer run time and thus experiences less curtailment loss. Lethbridge, AB falls somewhere in the middle in terms of being a combination of resource availability and efficiency of utilization at the two sites. This illustrates the importance of spatiotemporal matching of resources in system design.

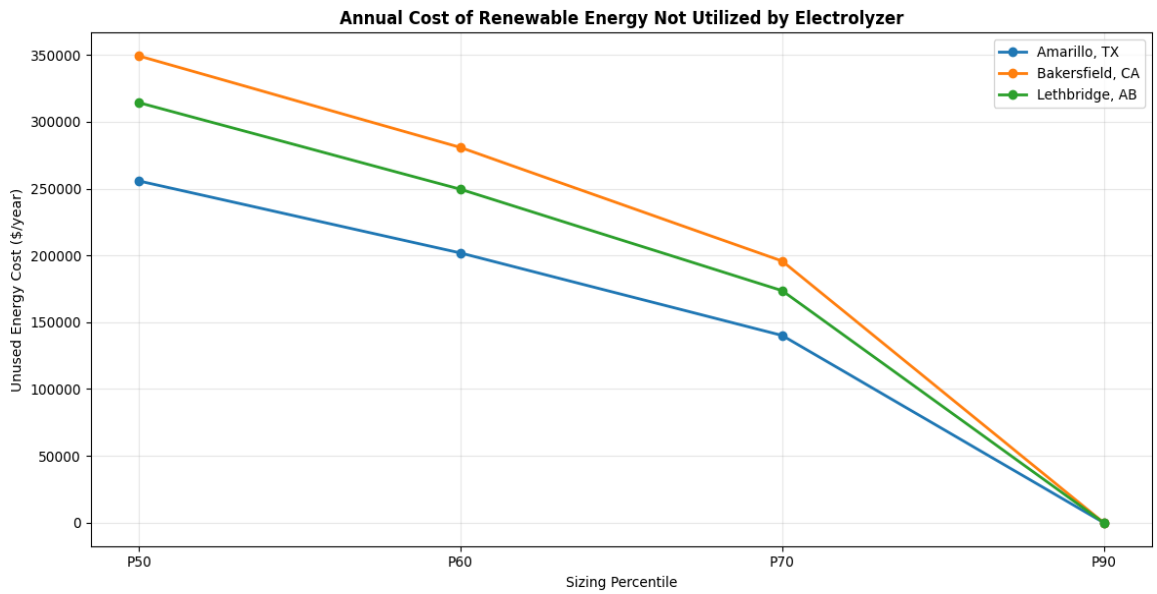

Figure 4. 7 Annual Cost of RE Not Utilized at Different Sizing Percentiles.

4(I).5.4 Multi-Metric Comparison

A composite analysis was conducted to visualize three critical system metrics—LCOH, NPV, and the annual cost of curtailed energy—across sizing scenarios. Figure 4.8 puts these figures side by side and shows that while P90 sizing curtains least, it costs the highest LCOH and has the lowest NPV. In return for higher energy loss, on the other hand, P50 is economically desirable. The best compromise of all three locations is P70.

Figure 4.8: Multi-Metric Trade-Offs by Electrolyzer Sizing Percentile Across Locations. This composite visualization compares three key performance metrics—Levelized Cost of Hydrogen (LCOH), Net Present Value (NPV), and Annual Cost of Unused Renewable Energy—for Amarillo, TX; Bakersfield; and Lethbridge. As sizing percentile increases (P50 to P90), LCOH consistently rises due to increased capital expenditure, while NPV declines, especially for overcapacity scenarios (P90). Conversely, the cost of unused energy significantly decreases, highlighting the

trade-off between hydrogen cost, system profitability, and curtailment minimization. These findings inform the selection of location-specific optimal sizing strategies for distributed hybrid systems.

To further plot the nonlinear relationship among performance measures, a 3D surface plot (Figure 4.9) plots interdependence of LCOH, NPV, and terminated energy cost. The surface plot shows P70 sizing at break-even with acceptable trade-offs. This 3D surface plot shows the correlation between Levelized Cost of Hydrogen (LCOH), cost of unused renewable energy per year, and Net Present Value (NPV) at varying percentiles of electrolyzer size (P50 to P90). Amarillo, TX; Bakersfield; and Lethbridge points are shown.

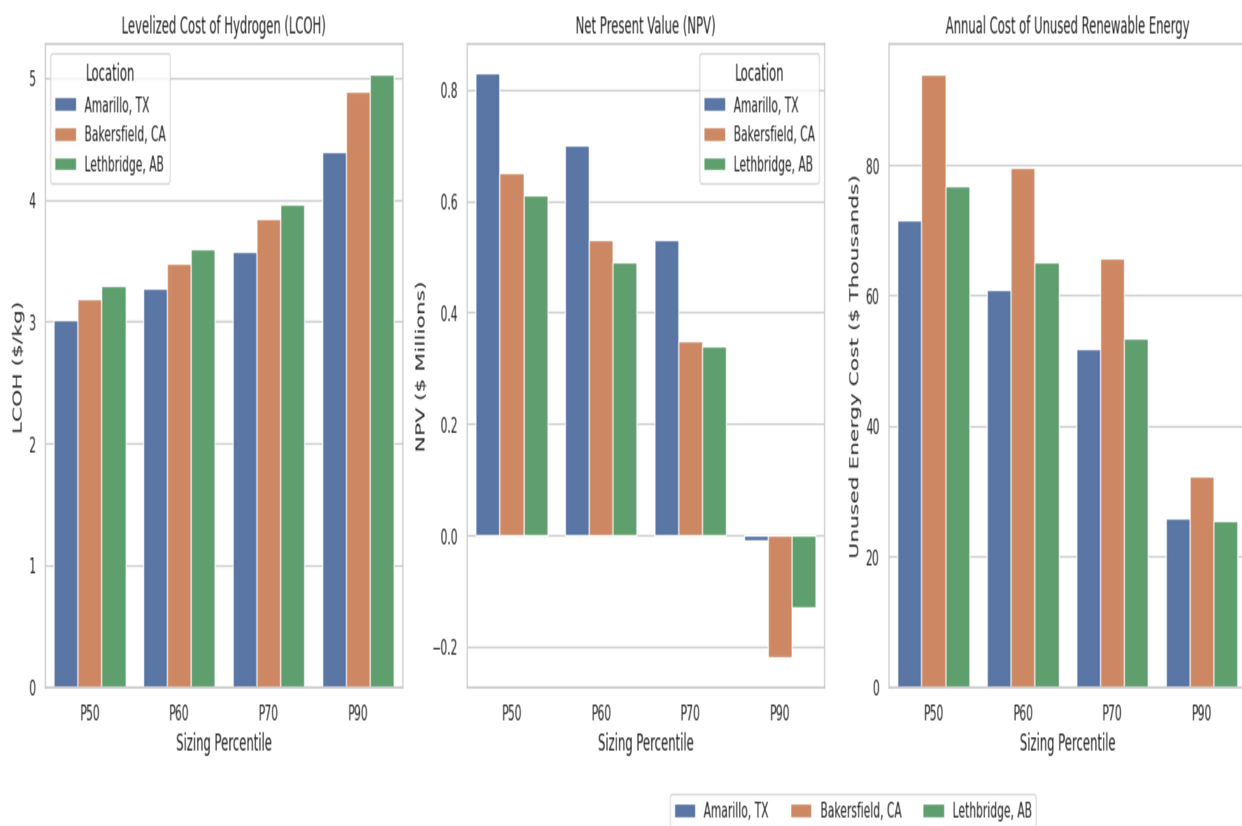

Figure 4. 8 Multi-Metric Trade-Offs by Electrolyzer Sizing Percentile Across Locations

The nonlinear high NPV versus low LCOH curve is present together with higher curtailment (energy loss) and where lowest curtailment (P90) is synonymous with overcapacity, prohibitive cost, and lower NPV. This is just one graph showing an integrated platform for selecting good sizing options based on trading efficiency, cost, and economic return.

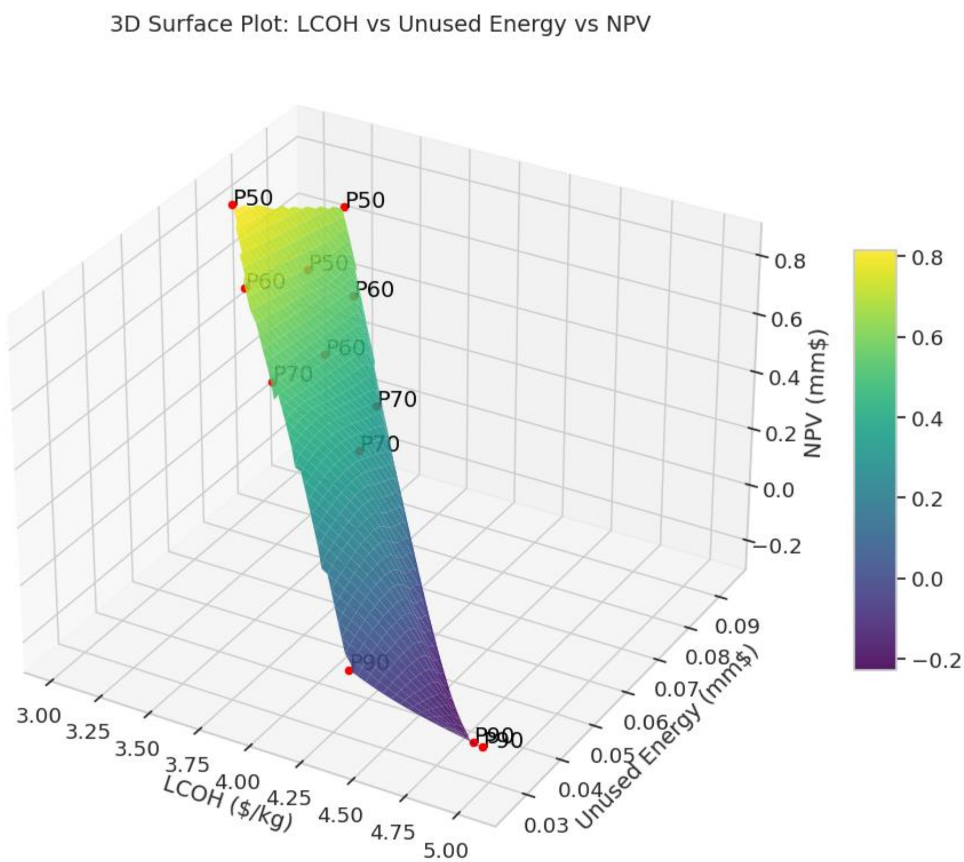

Figure 4. 9 3D Trade-Off Surface of LCOH, Unused Energy Cost, and NPV.

These plots are in line with the interpretation that techno-economic performance is extremely sensitive both to the size of the percentile selected and to the local renewable resource profile. Empirical sizing provides location-specific design flexibility so that systems may be optimized to varying priorities such as cost, efficiency, or reliability. As can be seen in Table 4.4, P50 sizing always has the largest Net Present Value (NPV) and smallest Levelized Cost of Hydrogen (LCOH), while P90 is most interested in reliability and therefore minimizes the most energy curtailment, and P70 gives the best balance between economic viability and technical performance for most Distributed Energy System (DES) cases.

Table 4. 4 Sizing Thresholds Based on Economic and Curtailment

Metric	Amarillo, TX	Bakersfield	Lethbridge
Highest NPV	P50 ($0.83M)	P50 ($0.65M)	P50 ($0.61M)
Lowest LCOH	P50 ($3.01/kg)	P50 ($3.19/kg)	P50 ($3.30/kg)
Lowest Cost of Unused Energy	P90 ($25.9k)	P90 ($32.4k)	P90 ($25.5k)
Optimal Balance (NPV & Curtailment)	P70	P70	P70

4(I).5.5 Validation and Benchmarking

To ascertain model robustness validation, LCOH simulated values were compared with literature values for various geographies and technologies. Table 4.5 presents global green hydrogen project LCOH estimates, consistent with this study's findings ($3.01–$5.03/kg), thus validating methodological soundness.

To confirm the accuracy and resilience of the model, particularly in terms of techno-economic performance, comparative analysis was undertaken between the LCOH values derived from the simulated results in this study and those reported on a wide range of global green hydrogen projects. The comparison yielded a benchmark that was instrumental in establishing the quality of method and utility of the proposed empirical sizing method.

The results of this study provided LCOH estimates between \$3.01 and \$5.03 per kilogram of hydrogen depending on location and sizing method. These were also compared with LCOH values reported in the literature for green hydrogen projects ranging across different geographies, technology configurations, and operating modes. As indicated by Table 4.5, the comparison set in this regard encompasses solar photovoltaic (PV) driven electrolysis, onshore wind-driven electrolysis, hybrid PV-wind arrangements, floating PV (FPV) and batteries, and even solid oxide electrolysis (SOEC) elevated temperature with waste heat recovery.

Research such as Ahmadullah et al. (2025) estimates an LCOH of \$5.07–\$6.09/kg in the Afghan scenario for Farah wind and Daykundi PV (Ahmadullah et al., 2025), within this research's range at the upper end. Similarly, Al-Mahmodi et al. (2025) offer an LCOH of \$3.79–\$3.97/kg for Middle Eastern hybrid net-metered hydrogen production (Al-Mahmodi et al., 2025), again well within the mid-range values calculated for Amarillo, TX and Bakersfield based on P60–P70 sizing methods.

In another instance, Duan et al. (2025) cite a \$6.70/kg LCOH for green hydrogen viability in oil and gas wells using alkaline electrolysis (Duan et al., 2025), indicating unaffordable prices due to off-site location or low integration of renewables. It is intended to emphasize the roles of nearby resource accessibility and sizing compatibility—core problems of the present research. The test is also replicated in Stolte et al. (2025) where they captured LCOH of €3.30/kg in Italy under grid-PV systems with the help of incentives, demonstrating how policy settings affect profitability—yet another impact captured in the LCOH sensitivity model (Stolte et al., 2025).

Table 4. 5 Levelized Cost of Hydrogen (LCOH) Across Selected H_2 Projects

Study	LCOH ($/kg)	Technology / Context	Reference
Decarbonizing Afghanistan	5.07 – 6.09	Wind (Farah) and PV (Daykundi)	(Ahmadullah et al., 2025)
Green hydrogen production via floating photovoltaic systems	€13.18/kg	FPV with variable load + battery	(Gagliardi, Cosentini, Agati, et al., 2025)
Green hydrogen for industry in Italy (with incentive)	3.3 EUR/kg	Grid + PV with incentives	(Stolte et al., 2025)
Oil and gas field green hydrogen feasibility	6.7	Alkaline Electrolysis in oil & gas field	(Duan et al., 2025)
Wind-powered hydrogen in China	¥25.75–36.31	Onshore wind with landform heterogeneity	(X. Li et al., 2024)
PV-Wind hybrid in Algeria	4.2 (2025)	Off-grid PV-H_2 with smoothing control	(Tebibel, 2024)
PV-Wind net metered green hydrogen in Middle East	3.79 – 3.97	Hybrid HRES with Python model	(Al-Mahmodi et al., 2025)
Italy & Portugal hybrid PV-wind optimization	(up to 70% reduction)	Utility-scale optimal hybrid system	(Skordoulias et al., 2025; Vidas et al., 2022)
TRIERES Hydrogen Valley (Greece)	7.75 – 12.68 €	RES + hydrogen storage hybrid	(Skordoulias et al., 2025)
On-site HRS in Türkiye and Spain	5.83 – 6.15	Solar or hybrid HRS	(Gökçek, Paltrinieri, & Yoldaş, 2024)
High-temp SOEC with PV & waste heat	>6 €/kg	SOEC + PV + waste heat	(Pastore et al., 2025)

Higher values are reported in studies like Gagliardi et al. (2025) at €13.18/kg for battery storage-based FPV systems—basing the consideration on the aspect that high configuration installations can pay exorbitantly to run under less optimized scenarios or pilot scale (Gagliardi, Cosentini, Agati, et al., 2025). Likewise, Pastore et al. (2025) attained LCOH values higher than €6/kg for PV and waste heat-based SOEC systems—basin the observation on the fact that state-of-the-art high-efficiency technologies are still not cost-effective without scale or incentive (Pastore et al., 2025).

Comparative analysis also reveals the Skordoulias et al. (2025) example of Greece, where it was found that the LCOH for the Hydrogen Valley TRIERES project ranged from €7.75 to €12.68/kg, indicating the level of variation in integrated storage facilities (Skordoulias et al., 2025).

Meanwhile, Vidas et al. (2024) optimization research illustrates that hybrid PV-wind systems in Italy and Portugal can achieve up to 70% LCOH reduction—no absolute figure was cited, but the outcome confirms this study's preliminary assumption of cost-effectiveness being highly dependent on optimal sizing and hybrid action.

Cumulatively, the sources affirm that the range of LCOH realized in this study—more precisely the \$3.01–\$3.84/kg in P50–P70 scenarios—is not only technologically feasible but also commercially competitive within the global context of hydrogen production.

The findings also affirm that the use of CDF-based sizing is consistent with actual cost expectation of hydrogen when used geographically DES. This validation is the basis for the validity of the suggested procedure and its generalized application to every deployment scenario, as a result maximizing its value in policymaking and making project-level choices.

4(I).5.6 Application to Use Cases

The model in this research not only reveals strong internal consistencies among techno-economic parameters like Levelized Cost of Hydrogen (LCOH), Net Present Value (NPV), Capacity Utilization Factor (CUF), and Curtailment Ratio, but also turns out to be highly flexible in practical application scenarios within the DES paradigm. Among its top strengths is that it can offer site-specific electrolyzer sizing methods in the form of percentile-based (P-level) energy exceedance probabilities. Developers and planners can, with this, design systems to meet site-specific needs, operational needs, and budget constraints.

Comparative case study evaluation and empirical observations in Amarillo, Bakersfield, and Lethbridge offer transparent sizing approaches suitable to specific application conditions. The observations have obvious policy implications and strategic recommendations for policymakers, investors, and project developers—demonstrating how electrolyzer investment must be weighed against expected technical performance, economic return on investment, and reliability requirements. These application-specific sizing demands are given in Table 4.6 and define how percentile-based methods (e.g., P50, P70, P90) can be extended to different Distributed Energy System (DES) applications such as off-grid systems, industrial clusters, and export hubs.

Table 4. 6 Summarizes these application-specific sizing recommendations.

Use Case	Scenario	Justification
Off-grid systems	P90	High reliability, minimized curtailment
Industrial applications	P70	Balanced CAPEX and utilization, good ROI
Export hubs	P50	Max hydrogen yield, curtailment offset via storage/export

4(I).5.7 Key Application Scenarios

Off-grid Systems: P50 Sizing Strategy

For off-grid microgrids, for rural electrification systems, or for off-grid hydrogen refueling stations where grid backup is not feasible or too costly, this would be the most suitable in a P90 scenario.

This sizing strategy guarantees that the electrolyzer may be sized so that it will run on a minimum of 90% of days per annum, with less wastage of energy and generation of hydrogen as and when required. While the initial investment will be high and some downtime will be achieved in high-output days, to these systems reliability is of utmost importance and possessing the ability of operation when not in full capacity is worth keeping the conservative approach in sizing.

Principal Benefit: Optimize Running Time and Reliability of Supplies in Poor Infrastructural Area.

Industrial Applications: P70 Sizing Strategy

In grid-connected industrial parks, co-located hydrogen manufacture for heavy transportation, steel, as well as ammonia, or chemical manufacturing needs to balance throughputs, reliability, and economy. P70 design achieves this compromise by maximizing system utilization and controlling capital expense. It achieves high CUF and REUR at a moderate LCOH, which is beneficial to increase return on investment. The same puts it in the best place for high energy-demanding applications that require efficient hydrogen generation but are also CAPEX sensitive.

Key Advantage: Bases capital efficiency on production stability at cost-competitive hydrogen production.

Export Hubs and Hydrogen Valleys: For world export-based hydrogen production—where the hydrogen is liquefied or shipped as ammonia for world export—the maximum yield is the target. The P50 scaling approach allows for more annual hydrogen production at the cost of more peak curtailment, which can be offset by buffer technologies such as hydrogen storage, compression, or conversion plants. While it keeps idle unused electrolyzer capacity during off-peak production periods, the capacity and infrastructure within export areas (such as in Texas, North Africa, or the Middle East) typically include balancing and energy storage plants.

4(I).5.8 Sizing Trade-Offs

This is done by comparing sizing electrolyzers in hybrid solar wind DES with percentile thresholds (P50, P60, P70, P90). For example, sizing electrolyzers using percentile thresholds (e.g., P70) helps balance capital costs with hydrogen yield and renewable energy utilization. Table 4.5 shows that LCOH increases as more conservative sizing is done due to less energy use and idle capital, Amarillo achieving the lowest LCOH for each percentile. Lethbridge and Bakersfield achieved higher LCOH increases between P70 and P90 due to lower resource availability and utilization. Figure 4.6 confirms that Net Present Value (NPV) is lower in conservative sizing, with P90 generating negative NPVs at all locations. Amarillo yields the highest return on investment in all the scenarios, especially in the P50–P70 scenarios.

Figure 4.8 illustrates P50 maximum cost of curtailment, at Bakersfield (~$93,860/year), and P90 minimizing curtailment at a cost of maximum capital inefficiency. Figure 4.9 illustrates a 3D compromise between LCOH, NPV, and curtailed energy. The best compromise for all sites is P70.

Amarillo P70 case (~520 kW) yields LCOH of $3.57/kg, NPV of $0.53M, and $51,800/year curtailment loss. Bakersfield P70 provides $3.84/kg LCOH with lesser curtailments, while Lethbridge offers P70 at ~349 kW with intermediate LCOH ($3.96/kg) and NPV. Generation variability is shown in Figures 4.2–4.4, supporting the site-by-site planning requirement.

From the across-site viewpoint, P70 sizing maximizes capital cost, hydrogen production, and curtailment. Under-design comes from P50, and over-design comes from P90, but P70 yields the most cost-effective and operationally feasible solution. Trade-offs in Tables 4.2–4.3 and CUR analysis also confirm diminishing returns and diminishing CUF beyond P70. The outcomes confirm P70 as the optimal solution to low-cost, scalable integration of hydrogen in DES.

4(I).5.9 Practical Implications

These findings offer central policy and project planning principles for investment decision in hydrogen infrastructure. Electrode sizes available must be balanced by energy developers with operational demands, regulatory needs, and funding levels. P60–P70 sizes are applicable to grid-connected systems with constant, guaranteed hydrogen production without grid overload or the necessity for large-scale storage, such as in Amarillo's flat energy profile. Conversely, P50 sizing may be appropriate for off-grid systems, especially in unsteady climates such as Lethbridge's, but may need to be supplemented by backup or storage to deliver supply during low generation.

LCOH is optimized at P60–P70 by which time hydrogen yield and capital efficiency are optimally traded-off. For instance, Bakersfield estimates a reduction of 12% in LCOH at P70 as compared to P90, and this has implications for project procurement and subsidy limit. The electrolyzers' industry can be transformed by inducing modular, incrementally scalable modules that can dynamically respond to fluctuating resources, providing improved economic performance.

Pay-as-you-go incentives like production tax credits and pay-for-use carbon credits would have to be encouraged by policy makers not to over-size and enhance grid stability. Further, in areas that enjoy complementary seasonally available resources, e.g., Amarillo and Bakersfield, hydrogen production throughout the year would be optimized by hybrid plants with adaptive controllers.

4(I).6 Limitations & Applications

The work presents a powerful alternative to approximating electrolyzer sizes in hybrid renewable power systems but, for all its advantages, includes a catalog of shortfalls and research areas in the future. First, future reference to solar and wind statistics by day imposes limitation on intra-day variability runs that affect real-time system response as well as curtailment; utilization of the higher-resolution data (i.e., hourly) would come much closer to imitating. Second, the model is not calibrated for electrolyzer ramp rates, degradation, and part-load efficiencies—drivers of actual performance and Levelized Cost of Hydrogen (LCOH).

Third, homogeneous cost-driver assumptions of capital, maintenance, and replacement do not cope with geographic and financial heterogeneity; future analysis must conduct sensitivity analysis and then test for financial viability at diverse conditions. Fourth, regulatory conditions are not addressed in the model for sizing, limiting the model's utility in areas that has renewable mandates or net metering—policy addition would increase applicability. Fifth, the simulation does not incorporate energy storage devices like batteries or hydrogen tanks to help reduce curtailment and enhance the efficiency of the system and does not incorporate water charge and treatment, which in arid climates like Amarillo and Bakersfield are required.

Lastly, research is proposed to move away from fixed percentile scaling to multi-objective optimization through dynamic programming or genetic algorithms in attempting to optimize LCOH, hydrogen production, carbon footprint, and system flexibility.

4(I).7 Regional Results and Performance Comparison

The research compared the size and performance characteristics of hybrid solar-wind power systems for green hydrogen production at Amarillo, Texas; Bakersfield; and Lethbridge, Alberta. Having a full one-year record of energy production, we contrasted distributions of energy production, estimated probabilistic sizing thresholds (P50, P60, P70, and P90), and computed corresponding technical and economic performance parameters such as hydrogen yield, capacity utilization factor (CUF), renewable energy utilization ratio (REUR), idle ratio, curtailment rate, and Levelized Cost of Hydrogen (LCOH).

The output shows typical day-to-day energy fluctuation, controlled by local solar irradiance and distance to wind resources. Amarillo, with greater value of solar irradiance and dominant wind, topped the ranking among the other two sites in metric of annual energy production with 8.3 MWh/day average and P90 of 12.1 MWh/day. Bakersfield was second highest in solar resource potential, and Lethbridge was lowest by means but possessed seasonal peak wind value added to output in worthwhile months.

4(I).8 Results from P-Level Sizing Thresholds

The result from the sizing aspect of electrolyzer was that there was nonlinear relationship between cut-off for sizing (P50 to P90) and system efficiency. P50 capacity-sized to accommodate only half the day's production conditions are system-optimal with less curtailment but at the cost of frequent downtime from excess generation on high-production days. P90 size, on the other hand, increases up to 90% fit to the day's variability and maximizes system autonomy but at the cost of increased oversizing, high upfront investment, and low utilization on most days. P70 was the optimum of the three, providing balanced idling hours, less trimmings, and best CUF and REUR values.

CUF values at different P-levels are measures of utilization efficiency. Amarillo's sample of P70 gave a CUF of ~40%, whereas that at P90 was ~35% and that at P50 was ~45%. But if one calculates REUR—ratio of produced renewable energy being used by the electrolyzer—P70 mode was found optimum for all the stations. What this indicates is the tradeoff between design for full capacity vs. use of max renewable energy. Therefore, LCOH was found lowest for P70 for Amarillo and Bakersfield, i.e., both were cost-optimal in CAPEX amortization optimization, hydrogen production, and O&M.

4(I).9 Implications for Planning, Investment, and Policy

Implications from these findings suggest the need for calculation of electrolyzer capacity based on regional resources, energy volatility, and target project—resilience, cost, or independence. Probabilistic P-level method is a resilient yet adaptable instrument available for planners and investors to standardize system design under a scenario of uncertainty and offer cushions against over- and under-investment in capital stock.

From experience, this study offers valuable insights to utilities, hydrogen developers, and policymakers to the government. P60–P70 size would prefer off-grid or grid-constrained application for round-the-year operating duty at affordable CAPEX. Central nodes or well-supported industry aggregates would prefer P90 size to satisfy the peak capacity with minimal load mismatch. Policy framework supports such as dynamic feed-in tariffs, hydrogen offtake agreement, or capacity-based subsidies would likewise trigger optimum choice of sizes.

While this analysis provides general methodology and comparative regional perspective, it is also assumed there would be further refinement. Introduction of hourly-resolution meteorology and loads, actual ramp rates of physical electrolyzers, degradation timelines, and economic valuation of curtailable energy would improve model precision. Environmental and water use impacts would be modeled location-by-location and seasonally in follow-up.

4(I).10 Advantages of CDF-Based Electrolyzer Sizing

Cumulative Distribution Function (CDF) application to optimal capacities of electrolysis plants is a new concept in hybrid Distributed Energy System (DES) design and planning. CDF-sizing has the benefit of data-driven strategy considering the probabilistic nature of renewable energy production and corresponding sizing of the electrolyzer capacity, as opposed to conventional sizing methods with capacity demand or peak power demand. CDF is utilized here to approximate sizing cutoffs such as P50, P60, P70, and P90, all referenced in terms of some energy availability measures. Probabilistic method forms the basis of the assumptions for Research Question 1 (RQ1), which is attempting to gauge the extent to which the size of optimally sized electrolyzers can be calculated to size so that they can run at optimal levels within a DES.

Implicit in this method is the recognition that renewable sources of energy, like solar irradiance and wind speed, are themselves variable and trend with season and over space. CDF analysis of past or simulated energy production data allows the probability of any level of energy being available on any day to be quantified. For instance, a P50 size condition would yield 50% of the days in a year generating or higher than the design level of generation, and a P90 scenario is a conservative one where 90% of the days will achieve the expected generation capability. They are grounded in observations that allow system designers to make good-informed decisions regarding electrolyzer capacity, not only from the technical capacity but also from the risk tolerance, cost, and reliability requirement point of view.

4(I).11 Strategic Impact and Transferability of CDF Methodology

The effects of this practice are multi-dimensional. First, CDF-based sizing optimizes the technical effectiveness of electrolyzer operation. Overdesign of plants would lead to excessive idling and low utilization hours, while under design would lead to energy curtailment penalty and low hydrogen production. CDF enables one to determine a "sweet spot" at which electrolyzer capacity is optimally matched to regimes of energy input so that idle time and curtailment are minimized. Keeping this in view, the P70 case has also been an equilibrated structure in this analysis. It achieves proper usage without sacrificing system flexibility and has also remained competitive on Levelized Cost of Hydrogen (LCOH) performance.

Secondly, CDF methodology enables flexible and resilient planning for systems in DES. Distributed systems, especially rural or dispersed locations, do not have flexibility and redundancy in center-based grid structures. They ought to be immune to supply and demand energy volatility and should be capable of doing that while being capable of operating autonomously and economically. CDF sizing electrolyzers make system designers capable of designing systems to fit into local resource profiles, thereby offering reliability at affordable capital cost. That is especially needed for community-scale systems, where cost vs. reliability vs. energy independence trade-offs are most important.

Moreover, it is simpler to replicate and paste hydrogen DES design through CDF scaling. CDF curves are constructed from site-specific renewable data and therefore the same process can be applied to another site. For example, a developer can utilize previous wind and sun data for a region—Alberta, Texas, or Saskatchewan—and do a CDF and determine the right sizing boundaries. This makes the sound analysis solution feasible to adopt on an industrial scale, especially in regions interested in decarbonizing energy infrastructure through modular, hydrogen-fueled microgrids.

Infrastructurally and policy wise, CDF-based electrolyzer sizing enables construction of forward-looking regulatory requirements with emphasis on system resilience, renewables integration, and decentralized energy access. Clean and decentralized energy infrastructure with highest energy equity and climate resilience are being increasingly invested in by utilities and governments. CDF-based planning can provide planners and policymakers with a scientific justification to make the case for right-sized hydrogen infrastructure, thus preventing over- or under-investment in capacity to electrolyze.

Finally, CDF application to Research Question 1 is theoretical and applied. The best location and sizing of electrolyzers in hybrid DES plants matter a lot in the research query. CDF serves as a bridge between system performance targets and variability in renewable resources so that raw energy information can be transformed into actionable system design variables. This transferability makes the CDF approach not only adaptable but a practical planning tool for hydrogen-integrated DES across diverse geographies. The study determines economically viable, technically actionable, and location-optimized size setups through CDF analysis and thereby offers an intensive answer to RQ1.

Lastly, CDF is neither an analysis technique nor a strategic design approach to optimize green hydrogen system design. Its capability to combine variability, reliability, and performance in a single sizing approach is a goldmine blueprint in hydrogen uptake gap filling under DES conditions. Probabilistic anchoring electrolyzer sizing according to resource availability based on CDF would imply smarter investment, more effective utilization, and broader application of green hydrogen plants—cornerstones of sustainable development. A full procedure for applying the CDF-based sizing method is provided in Appendix 1.

CHAPTER FOUR Part II

4(II).0 EMPIRICAL HYDROGEN PRODUCTION MODEL (RQ1b)

4(II).1 Background

At the center of green hydrogen production is the ability to generate hydrogen in distributed and integrated renewable manner, i.e., using alkaline electrolysis using solar and wind power sources. However, robust estimation of hydrogen production accounting for uncertain renewable energy (RE) availability and heterogeneous electrolyzer configurations is a main technical and planning concern. Distributed Energy Systems involving renewable energy and hydrogen production are being increasingly researched to provide decentralized access to energy, grid services, and sectoral decarbonization. These systems are typically intermittent RE-based and therefore smart system planning and simulation tools that can forecast hydrogen production rates as a function of available energy and electrolysis settings are needed. Existing modeling tools such as Aspen Plus and HOMER Pro give in-depth simulations but are computationally intensive and data hungry, limiting their use in project planning at an early stage or in real-time control schemes.

4(II).1.1 Motivation

The intermittency of renewable energy sources introduces uncertainty into the operation of the hydrogen production system. Electrolyzers operate at peak under steady-state conditions, but wind and solar profiles vary sub-hourly and therefore steady-state operation becomes difficult and costly unless suitably accommodated. Additionally, system designers must counter increasing input power against up-sizing the number of stacks of electrolyzers—both of which influence hydrogen yield as well as cost of capital. They are exacerbated by system-specific operating limitations like partial load efficiency, interconnection loss, and stack-level performance deterioration.

There remains no readily accessible but reliable predictive tool bridging the gap between simulation results of high fidelity and real estimation needs. Particularly, empirical or proxy models predict hydrogen production as a function of two design variables: availability of input power and number of stacks of electrolyzers are needed. They need to enable feasibility studies, system design optimization, and grid-interactive hydrogen production to be viable within DES environments.

4(II).1.2 Research Objective

The purpose of this study is to obtain an empirical, reduced-form model of hydrogen production rate (in kg/h) such that it can predict on the basis of two inputs: (1) electrolyzer stack figures and (2) variable renewable input power, which can be used in a system-level software like Vensim to allow for simulation of hydrogen production under variable renewable scenarios. To reduce computation while not sacrificing system precision, Reduced Order Models (ROMs) have increasingly been employed to model renewable systems, wherein dynamic simulation and real-time optimization may apply reduction strategies to improve computational efficiency. As the illustration of floating wind turbines shows, ROMs offer efficient modeling of complex interactions with the capacity to enable adaptive control under dynamic conditions (Evro, Veith, et al., 2025). These standards may also be applied to green hydrogen systems, wherein dynamic simulation and real-time optimization may apply matching reduction strategies to reduce the model. The model may serve as a decision support tool for predicting operations, scheduling storage, and guiding system sizing.

4(II).1.3 Relevance and Application in DES

The development of a rapid, scalable hydrogen production estimation model has immediate relevance towards the optimization of DES' green hydrogen integration in the near term. The model simplifies the complexity of hydrogen output estimation under variable renewable inputs, enabling practical applications such as electrolyzer and battery sizing for system optimization, curtailment reduction, and the integration of smart microgrid control strategies. It supports the deployment of green hydrogen in remote and off-grid settings, contributing to broader decarbonization efforts by enhancing the efficiency and feasibility of hybrid renewable-hydrogen system planning and operation.

4(II).1.4 Research Question

Following research questions are addressed by this research:

RQ1b: How to design a straightforward and pragmatic methodology for estimation of hydrogen production potential based on available renewable energy as well as electrolyzer stack configuration?

By presenting the solution to this question, the study aims to fill a gap in green hydrogen system design methodology that is essential to the amplification of decentralized and sustainable hydrogen energy solutions globally.

4(II).1.3 Hydrogen Production via Electrolysis

Green hydrogen (H_2) production through renewable-fed electrolysis is among the highest priorities of global decarbonization policies. Among the technologies for performing electrolysis, three are the most promising candidates on the current menu: Alkaline Water Electrolysis (AWE), Proton Exchange Membrane (PEM) Electrolysis, and Solid Oxide Electrolysis (SOEC). All three are different in technical specifications, economic aspects, and interconnectivity profiles with the renewable feedstocks.

AWE is the most advanced and pervasive technology with lower capital expenditure, long operation life, and suitability for steady-state power supply. PEM has faster dynamic response and higher quality hydrogen production at the expense of increased material and system cost. SOEC is a high-temperature operation and theoretically has high electrical efficiency when waste heat is recoverable but is primarily at the demonstration stage and plagued with durability problems.

In the study paper, we are focusing on Alkaline Water Electrolysis (AWE) because of its proven commercial viability, experience, and prevalence in industrial and future DES. Its ability to be resilient in large-scale installations because of the compatibility of AWE makes AWE a prime candidate to be integrated with variable renewable energies in DES when system simplicity and cost are of prime importance (Çelikdemir & Özdemir, 2025; V. Kumar & Tiwari, 2025)

4(II).1.4 Existing Models

Simulation of hydrogen generation has also grown with the advent of newer computer software like Aspen Plus, MATLAB/Simulink, HOMER Pro, and TRNSYS. All of these enable end-to-end simulation of electrolysis systems based on variable RE sources, thus enabling the evaluation of system performance for different alternate operating conditions. For instance, Aspen Plus enables rigorous simulation of electrochemical reactions and thermodynamic process simulation. As demonstrated by Jeddizahed et al. (2024), an NZC along with an AWE system reached a stated efficiency of 56.5%, demonstrating potentially high-fidelity integration of process and energy retrieval (Jeddizahed et al., 2024). Sharifzadeh et al. (2024) also used mixed-integer linear programming to dispatch optimize a wind-powered electrolyzer to minimize the LCOH significantly even when assuming stochastic wind profiles (Sharifzadeh et al., 2024).

Since being technically challenging and accurate, these models necessarily have limited applicability for DES designs—namely, in early-stage planning, real-time operation, or decentralized use. Theirs to demand vast amounts of data (e.g., intricate electrolyzer geometry, component-level heat transfer, or hourly load forecast) and significant computation requirements are more likely to make them infeasible for rapid-response model applications or feasibility study under low-data scenarios. This increasingly becomes important in those applications where hydrogen systems are integrated with variable solar and wind sources, and system planners must have the ability to deliver rapid response scenario-based results to shape technology selection, size, and cost-vs.-benefit trade-offs.

To address this lack, Research Question 1b (RQ1b) inquires: How to create an effective and simple method to estimate hydrogen production potential as a function of available renewable energy and electrolyzer stack configuration? To address RQ1b, there is a requirement for a different modeling paradigm that is sufficiently accurate but computationally light and generalizable to different DES configurations.

Accordingly, the scope of this work is the development of empirical or proxy models of reduced complexity hydrogen output estimation while maintaining sensitivity to important variables such as input power and electrolyzer stacks. The models facilitate DES integration of green hydrogen through location-independent, flexible, and rapid evaluations necessary in the scaling up of hydrogen urban microgrid consumption and rural off-grid applications.

4(II).1.5 Empirical Proxy Models

Notwithstanding all the developments achieved in simulation of hydrogen production through electrolysis-based hydrogen production by electrolysis-based hydrogen production, a tremendous gap still exists between field-level real-time estimation packages and high-fidelity simulation models. Thus, Aspen Plus software-based models such as Kumar & Tiwari (2025) in illustrating efficiency of 84.09% at temperature 55°C are accurate but time-consuming and thus unsuitable for decentral or planning-stage application.

Additionally, dynamic electrolyzer operation amid fluctuating renewable power supply ruled out mean-value or static modeling. Real-time control requires high-resolution, difficult-to-make measurements (David et al., 2021; Jang et al., 2021). Loss of operations efficiency like heat buildup, gas crossover, and stack resistance result in scale and capture nonlinear dynamics. Renewable intermittency introduces an additional complexity of stability to the system. As Jang et al. (2021) and Kramer et al. (2025) think, thermal buffering, i.e., control of temperature and flow rate, is necessary to ensure stable operation of the AWE (Jang et al., 2021; Kramer et al., 2025). Moreover, scaling of the electrolyzer stack also suffers from diminishing returns and efficiency loss (David et al., 2021; V. Kumar & Tiwari, 2025).

They emphasize the need for low-fidelity, high-fidelity proxy models such as the model suggested in RQ1b for estimating hydrogen production from input power and stack size that can be determining factors. They are found to be useful in DES where planning, pre-feasibility study, and deployment are facilitated for various applications.

4(II).1.6 Numerical Highlights from Key Studies

Convergence of empirical and simulation-based analysis is what indicates the quantitative foundation needed in green hydrogen system planning, such as RQ1b. Empirical model specification for forecasting hydrogen production as a function of power availability and electrolyzer design—priority-ranked variables for planning distributed and renewable-integrated hydrogen systems—is pertinent to this research question.

Computer- and labor-intensive high-fidelity simulations such as Aspen Plus models of Kumar & Tiwari (2025) give us an 84.09% efficient AWE system with 11.43 Nm^3/h hydrogen production at thermal optimum—a non-feasible candidate for real-time DES application, nonetheless. Colbertaldo et al. (2017) attained practical PEM operation at 92% efficiency but without scalability to cost and purity demands (Colbertaldo et al., 2019).

Ghaithan et al.'s (2024) and Ravi et al.'s (2023) techno-economic analyses estimate that PEM-based systems cost $3.24–7.17/kg LCOH (Ghaithan et al., 2024; Ravi et al., 2023), whereas Haffaf & Lakdja (2024) estimate lower $2.99/kg LCOH in hybrids (Haffaf & Lakdja, 2024, 2024). Çelikdemir & Özdemir (2025) introduce low-complexity cost models that express hydrogen cost as a function of installed capacity and quality of the renewable resources instead of volume quantities for planning advantage at an early stage.

In addition, integration research demonstrates the use of hydrogen in renewable energy systems. Enaloui et al. (2025) observe 36% less curtailment using hydrogen buffers in Calgary (Enaloui et al., 2025), and Chamazkoti et al. (2025) observe 22% Levelized Cost of Energy (LCOE) savings using Battery Energy Storage Systems (BESS) deployment and electrolysis (Chamazkoti et al., 2025). Computing efficiency developments by Shanmugasundaram et al. (2025) and dynamic control PEM conditions by Ratib et al. (2025) are facilitated by even more efficiency and economy for hydrogen (Ratib et al., 2025; Shanmugasundaram et al., 2025).

These developments, as can be seen from Table 4.7, are complemented by the requirement of high-rate, mass-manufacturability conditions like that described here, such as simulation and planning tools for DES.

4(II).2 Methodology

4(II).2.1 System Configuration

Figures 4.10-4.13 together illustrate the configuration, modeling strategy, working conditions, and output variables of a commercial-scale AWE cell for green hydrogen production. Graphic information includes macroscopic knowledge of the process and precision of the microscopic modeling capability to describe the performance under input realistic conditions.

The general flow scheme of the Commercial Alkaline Electrolysis Process, AEP, is illustrated in Figure 4.10. The Alkaline Stack is supplied with electrical input power (Stack power) to enable water electrolysis. The diagram shows a closed recirculation system for the KOH electrolyte with two primary cooling loops QC1 and QC2, and a KOH makeup section to supply ionic conductivity and process stability.

Table 4. 7 Key Finding on Green Hydrogen Modeling Studies

Source / Strategy	Key Findings / Performance Benefit
Kumar & Tiwari (2025)	84.09% efficiency; 11.43 Nm^3/h H_2 yield; 1.49% CAPEX reduction with thermal optimization
Colbertaldo et al. (2017)	Zero-dimensional (0D) PEM electrolyzer models achieve 92% efficiency
Ghaithan et al. (2024); Ravi et al. (2023)	PEM-based systems report LCOH between \$3.24–7.17/kg
Haffaf & Lakdja (2024)	Hybrid solar-wind systems in Tindouf reach LCOH of \$2.99/kg
Enaloui et al. (2025)	36% curtailment reduction in Calgary when hydrogen is used as energy buffer
Chamazkoti et al. (2025)	Coupling BESS with hydrogen systems yields 22% LCOE reduction
Shanmugasundaram et al. (2025)	AI-powered digital twins increase electrolyzer efficiency by 5–10%
Ratib et al. (2025)	Dynamic PEM electrolyzers in Australia reduce LCOH by 17.3%

The Anode outlet stream is fed to Sep-O2 and Pump-O2 to divide oxygen and pressurize oxygen, whereas the cathode outlet stream is fed to Sep-H_2 and the H2-Purifier to off-gas high-purity hydrogen vent. Product streams are shipped to O2-Pure and H_2-Pure lines. The design mirrors real AWE plant design and represents integration of electrochemical, mechanical, and thermal subsystems towards hydrogen day and night, round-the-clock and effective in nature.

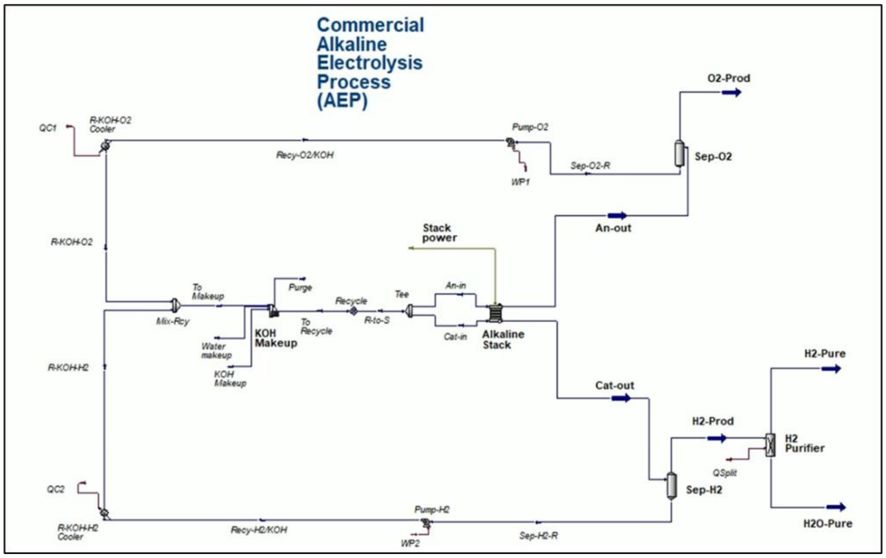

Figure 4. 10 AEP Flow Diagram

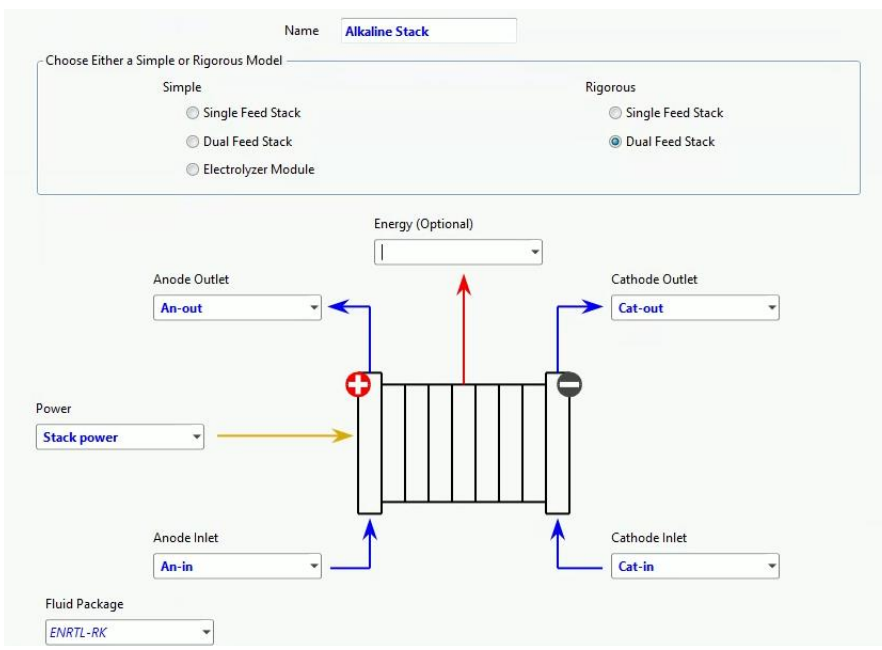

Figure 4. 11 Stack Model Interface, defining dual feed electrolyzer configuration.

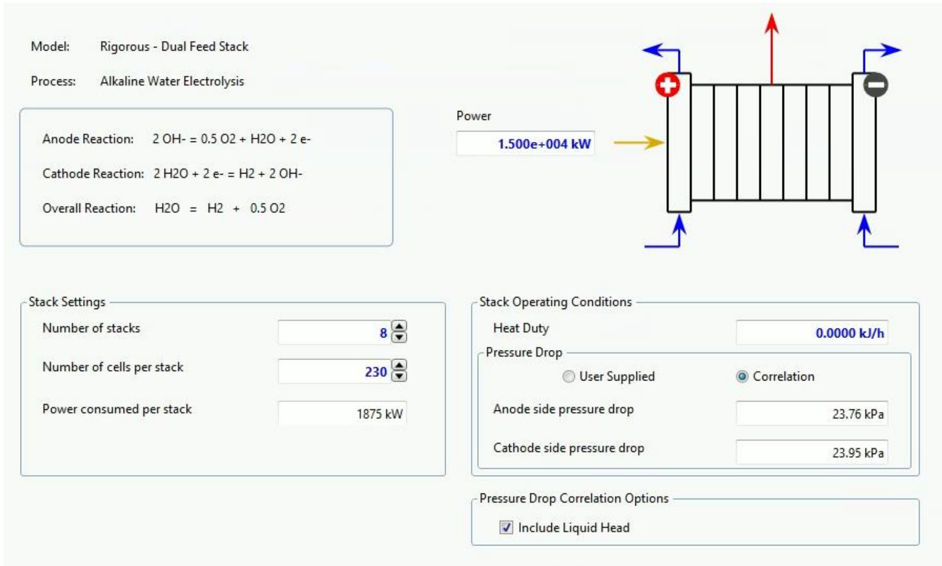

Figure 4. 12 Stack Specifications, showing electrochemical and thermal stack parameters.

Independent Variables | Variable Manager | Find Variables

	Name	Tag	Current Value	Units	Delete
1	Alkaline Stack - Total Electric Power		1.500e+004	kW	X

Dependent Variables | Variable Manager | Find Variables

	Name	Tag	Current Value	Units	Delete
1	Alkaline Stack - Hydrogen Production Rate (Mass Basis)		315.7	kg/h	X
2	Alkaline Stack - Voltage Efficiency		82.44		X
3	Alkaline Stack - Total Voltage		411.0	V	X
4	Alkaline Stack - Total Current		3.650e+004	A	X
5	H2-Prod - Overall and Phase Comp Mass Flow (Overall-H2)		314.7860	kg/h	X
6	Alkaline Stack - Cell Current		4563	A	X
7	Alkaline Stack - Specific Mass Energy Consumption (per unit mole H2...		1.705e+005	kJ/kg	X
8	Alkaline Stack - System Temperature		74.50	C	X
9	Alkaline Stack - Total Electrolyte Resistance		7.627e-006	Ohm	X

Figure 4. 13 Variables, showing H_2 output, efficiency, and key electrical values.

Figure 4.11 shows the selection of electrolyzer models within a process simulator (e.g., Aspen Plus). The model is in this case set as a Rigorous Dual Feed Stack, a high-level option for two-phase electrochemical modeling to an advanced level, mass, and energy transfer. For this option, there are independent inlets and outlets for anode and cathode sides for enabling simulation of electrolyte flow, gas separation, and internal stack dynamics. Power input is tied to the Stack power variable, and the ENRTL-RK thermodynamic fluid package is utilized to model physical and chemical characteristics of the electrolyte at operational conditions.

Stack setup quantitatively is revealed in Figure 4.12. It includes 8 stacks with 230 cells, and it consumes 1,875 kW. It is a total input of 15,000 kW. The significant electrochemical reactions are also introduced: at the anode, $2OH^- \rightarrow 0.5O_2 + H_2O + 2e^-$, and cathode, $2H_2O + 2e^- \rightarrow H_2 + 2OH^-$, and net reaction $H_2O \rightarrow H_2 + 0.5O_2$. The cathode side and anode side pressure drop of 23.76 kPa and 23.95 kPa, respectively, are relieved through empirical correlation and are as a result more of a concern with the pressure phenomenon of the stack in design and simulation at scale.

The simulation output parameter for the 15 MW input condition is as shown in Figure 4.13. The model provides hydrogen production capacity at the level of 315.7 kg/h, voltage efficiency at 82.44%, and total voltage at 411 V. System shows total current at 36,500 A and single energy consumption at 170.5 MJ/kg H_2. Temperature conditions are static at 74.5°C and resistance levels for the electrolyte are extremely low at 7.63×10^{-6} Ohm with particularly good conductivity and very minor internal loss.

These figures all make end-to-end operation of a commercial alkaline electrolyzer-from process design through simulation results-constitute a firm basis for evaluation and calibration of empirical hydrogen production models. Observations provided under such a setup corroborate hypotheses rooted in such simplification assumptions as were made to address Research Question RAPQ1b: An estimation approach for hydrogen production purely from input power, without regard to knowledge of electrolyzer stack structure. The ability to employ computationally tractable proxy models with uncertainty in renewable variability, spatial variation, or in the efficient DES design procedure itself becomes theoretically possible through such a highly advanced exercise of model development through the AEP methodology

4(II).2.2 Model Formulation

The flowchart shown in Figure 4.14 is the process followed to formulate the model in the research study. While Figure 4.15 shows the block diagram of the regression code.

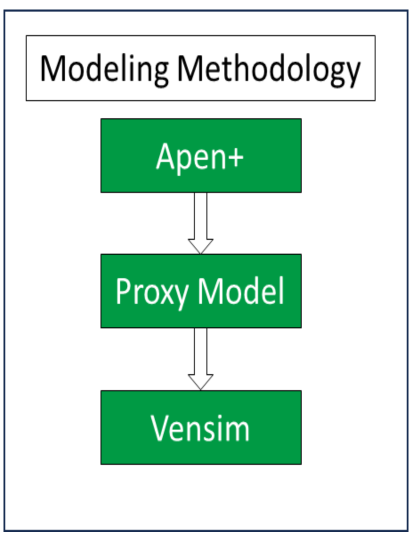

Figure 4. 14 Flowchart

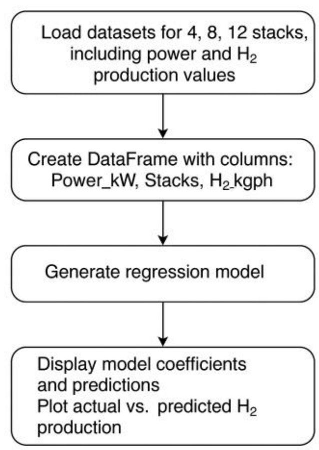

Figure 4. 15 Block Diagram of the Python regression model

The methodology is a three-stage systematic process to compute hydrogen production in integrated DES with renewable energy. The process is:

Step 1: Aspen+

Objective: It is the first simulation tool used to conduct high-fidelity simulation of the Alkaline Water Electrolysis (AWE) process for hydrogen generation.

Function: Aspen+ simulates electrochemical stack behavior, electrolyte flow, power supply, and output hydrogen yield in various renewable energy applications.

Output: The simulation gives the benchmark results (e.g., hydrogen production rate, voltage, current, system efficiency) for various stack numbers and input power levels.

Step 2: Proxy Model

Purpose: Proxy model is a low-order empirical representation of Aspen+ simulation output.

Function: Regression techniques (e.g., multi-variable curve fitting) are used to match input power and stack structure to hydrogen yield in computationally handy form.

Rationale: It encompasses the distinction between high-complexity simulation models and system design in real-time or initial requirements within DES systems. The simplified model is of the form given in Equation 4.2

Equation 4. 2 Simplified Hydrogen Production Model

$$\boldsymbol{H_2} = ((\boldsymbol{a} \cdot \ln(\boldsymbol{N}) + \boldsymbol{b})\boldsymbol{P} + \boldsymbol{c} \cdot \ln(\boldsymbol{N}) + \boldsymbol{d}) \tag{4.2}$$

Step 3: Vensim

Purpose: Vensim is used as a system dynamics modeling software to simulate and model the operational behavior of the hydrogen production system in an extended energy system context.

As evident from Figure 4.15: Block Diagram of the Python Regression Model, the process begins with loading data sets for electrolyzer stack configurations of 4, 8, and 12 stacks, along with corresponding input power values and hydrogen production rates. The data sets are combined into a structured data frame. Then, by using multi-variable curve fitting, a Python regression model is calculated. The structure used matches logarithmic number of stacks and linear power supply to hydrogen production. This allows for both the model's explanation of linear scale with power as well as non-linear decline due to stack interconnection effect.

Application: It facilitates facilitation for scenario analysis, reduction of curtailment, supply-demand balancing, as well as hybrid RE-hydrogen strategic design.

This three-tier hierarchy—Aspen Plus, Proxy Model, Vensim—offers a robust framework for advancing simulation fidelity, enabling high-level, realistic modeling that guides simplified tools toward real-time or system-wide optimization. Although it bypasses direct simulation of hydrogen production via renewable power and electrolyzer stack design within DES under RQ1b, the empirically driven formulation remains highly valuable. It supports early-stage feasibility assessments, enables flexible scenario testing, and facilitates real-time hydrogen output forecasting for smart microgrids and decentralized systems.

Real-time prediction of production within smart microgrids or decentralized hydrogen systems. This modeling framework is inclined toward Research Question RQ1b by presenting an effective method for estimating hydrogen production with a minimal number of two inputs—stack configuration and supply of renewable energy—the only variables known during initial stages of DES project planning.

4(II).3 Results

4(II).3.1 The Step-by-Step Development of the Hydrogen Production Proxy Model

Step 1: Data Collection

Aspen Plus was used to simulate hydrogen production for various electrolyzer configurations with stack counts of $n_{stacks} \in \{1,4,6,8,10,12\}$ and input power levels ranging from 5,000 to 22,000 kW. For each combination of stack count and input power (n_{stacks}, P_{input}), the corresponding actual hydrogen production output was recorded. These simulation results were then extracted for further analysis and used in developing a regression-based proxy model.

Step 2: Model Structure Selection

Choose a semi-empirical model structure based on validated multi-stage regression analysis regression formats. As shown in Equation 4.3, the structure is linear in input power with a logarithmic dependence on the number of stacks:

Equation 4. 3 Linear Hydrogen Production Model.

$$\boldsymbol{H_2} = (\boldsymbol{a} \cdot \ln(\boldsymbol{N}) + \boldsymbol{b})\boldsymbol{P} + (\boldsymbol{c} \cdot \ln(\boldsymbol{N}) + \boldsymbol{d}) \tag{4.3}$$

Where n_{stacks} is the number of electrolyzer stacks, while P is the input power in kilowatts (kW), H_2 is the hydrogen production rate in kilograms per hour (kg/h), and each stack contains N=230 cells

Regression using python program gave coefficients on Table 4.8 that characterized hydrogen production sensitivity to number of stacks of electrolyzers and available input power within simulated range. Regression was a multi-variable curve fit employing natural logarithm of number of stacks to satisfy nonlinear scaling relationship encountered in real electrolysis systems. Power input was modeled with linear models, the linear influence it has on hydrogen output during constant-state operation conditions. Parameters of linear models—optimized through least-squares minimization—were selected to be in a reduction state of prediction error with reasonable fidelity for low N (small-scale) and high N (large-scale) configurations. With this approach, it made the model understandable, computationally efficient but very predictive, which made it suitable to be applied to the rapid-scenario evaluation case for DES planning. Final values of the regression coefficients were selected to minimize prediction error as presented in Table 4. 8.

Table 4. 8 Regression Coefficients Values

Coefficient	**Value**	**Meaning**
a	0.00233	Power sensitivity factor (per $\ln(n_{\text{stacks}})$)
b	0.01425	Power base rate
c	-6.198	Stack count impact on intercept (negative trend)
d	38.889	Intercept base value

Equation 4. 4 Linear Hydrogen Production Model with coefficients.

$$\mathrm{H_2}\ (\mathrm{kg/h}) = (0.00233 \ln(n_{\text{stacks}}) + 0.01425) P_{\text{input}} + (-6.198 \cdot \ln(n_{\text{stacks}}) + 38.889) \quad (4.4)$$

Step 3: Validation

The model was validated against real-world benchmarks by evaluating the Mean Absolute Percentage Error (MAPE) between actual and simulated hydrogen output values for all combinations of stack number vs. input power conditions. The model was validated with good predictive accuracy, with error less than 5% for most of the configurations tested, testament to the validity of the model for system-level design and sizing of DES.

Step 4: Model Limitations and Recalibration

While the model provided accurate predictions across the dataset, its validation was constrained to a specific operational envelope: electrolyzer stack counts in the range of n stacks ∈ {1,…,12} and input power between 5,000 kW and 22,000 kW. This restriction limited its applicability beyond this range, particularly in small-scale systems (1–4 stacks), where nonlinear effects such as heat loss and interconnection inefficiencies are more pronounced, and in large-scale systems (n>12), where diminishing returns in hydrogen output reduce marginal gains from additional stacks.

To address this, the model was recalibrated using a two-segmented regression, resulting in a H_2 Production Model structure with better accuracy match both low and high stack count regions.

The updated Hydrogen Production Models are presented below:

Equation 4. 5 H_2 Production for Small Stack Count Systems ($N \leq 6$):

$$H_2\ (\text{kg/h}) = (0.006533 \cdot \ln(N) + 0.019241) \cdot P_{\text{input}} \tag{4.5}$$

Equation 4. 6 H_2 Production for Large Stack Count Systems ($N > 6$):

$$H_2\ (\text{kg/h}) = (0.031146 \cdot \ln(N) - 0.033157) \cdot P_{\text{input}} \tag{4.6}$$

The H_2 Production Model structure improves fit and reduces residual error across operational boundaries:

- In small-scale configurations ($N \leq 6$), hydrogen production increases less sharply with additional stacks due to higher per-stack efficiency.
- In large-scale setups ($N > 6$), stack-to-stack inefficiencies increase, but the marginal hydrogen gain per unit of power stabilizes.

This recalibration enhances the model's applicability for, community-level or off-grid systems (1–6 stacks) and industrial-scale hydrogen plants (6–20+ stacks).

Figure 4.16 shows the resultant 3D surface plot of hydrogen output in terms of power input and stack number, highlighting the nonlinear behavior and justifying the use of the segmented model approach.

4(II).3.2 Validating with first principal Faraday-Based Hydrogen Production Estimation

Equation 4. 7 Faraday model for estimating H_2 production.

$$H_2(t) = \eta_{\text{sys}}(t) \cdot \frac{P_{\text{input}}(t)}{E_{\text{cell}}(t)} \cdot \frac{3600}{\text{HHV}_{\text{H}_2}} \tag{4.7}$$

where:

- $H_2(t)$: Hydrogen production rate at time t [kg/h]
- $\eta_{\text{sys}}(t)$: Overall system efficiency ($\eta_v \cdot \eta_c \cdot \eta_{\text{pump}}$)
- $P_{\text{input}}(t)$: Input power from RE [kW]
- $E_{\text{cell}}(t)$: Effective cell voltage [V]
- $\text{HHV}_{\text{H}_2} \approx 39.4$ kWh/kg: Higher heating value of hydrogen

For a 4-stack, 10,000 kW case, Empirical model: ~209.1 kg/h, Faraday model: ~317.3 kg/h. The Faraday model exceeds by 51 due to its unrealistic assumptions that overlook the true system inefficiencies. First, it applies constant-state system efficiency overall (η_sys = 0.65) and effective cell voltage of 1.85 V. However, real hydrogen systems are plagued by efficiency losses due to several reasons: (a) increasing ohmic losses with increasing stacks, (b) loss of performance due to partial loading or cyclic duty, and (c) fluctuation in temperature, pressure, and water flow on electrochemical performance. These non-linear losses make Faraday's constant-efficiency thesis infeasible, especially in dynamic DES environments.

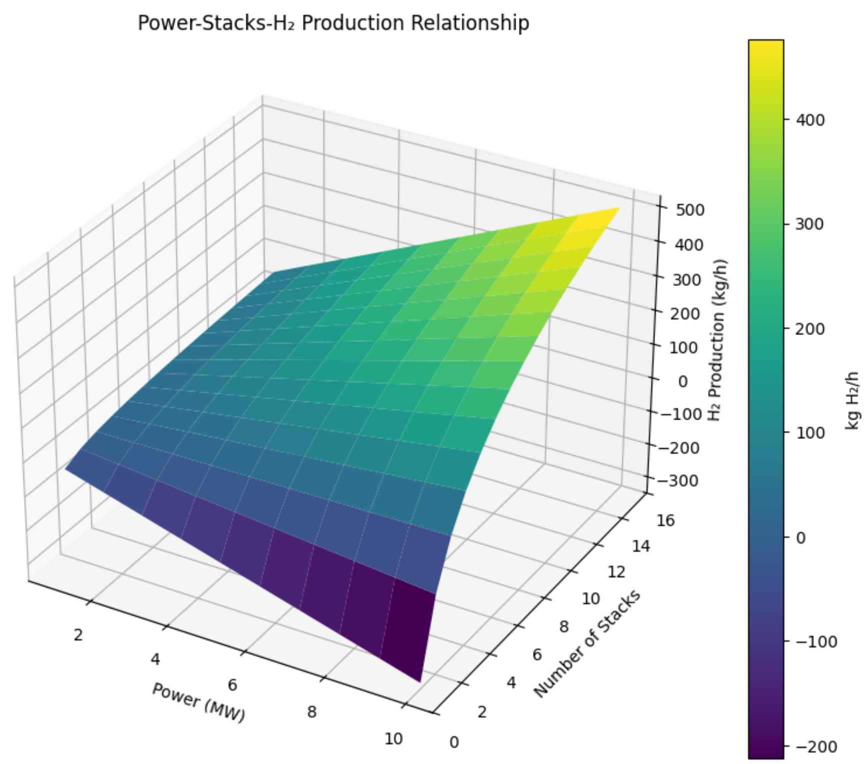

Figure 4. 16 3D Surface Plot of power, stack count, and H_2 production rate (kg/h).

4(II).3.3 Real-World Project Validation with Hydrogen Production Rates

To evaluate the realism and applicability of the H_2 Production Model empirical model to hydrogen production, there was an extensive validation exercise conducted based on publicly available data from operating and benchmark alkaline water electrolysis (AWE) systems. The model dichotomizes behavior into two stack-based regimes: a small-stack model employed for systems with $N \leq 6$, and a large-stack model for systems with $N > 6$. Model performance is assessed by comparing simulated hydrogen production rates to observed values and then calculating the error margins by applying the standard formula in:

Equation 4. 8 Percentage Error

$$\text{Error}(\%) = \frac{\text{Prediction} - \text{Reported}}{\text{Reported}} \times 100\% \tag{4.8}$$

The first benchmarking study was undertaken on a simulated 250 kW wind-driven alkaline system of Wang et al. (2025) under Aspen Plus Dynamics. Their design consisted of 2 stacks made up of 70 cells each, and their thermal-electrochemical performance was simulated under realistic wind fluctuations. Based on the system-dependent range of energy consumptions from 43.18 to 49.62 kWh/kg, the range of expected hydrogen product turned out to be 5.04 to 5.79 kg/h. As shown in Figure 4.17, the user's empirical model predicted a production rate of 5.94 kg/h, overestimating by just 2.6–17.8%.

This result is considered well within engineering margins, especially since the empirical model does not yet incorporate temperature corrections, partial-load inefficiencies, or electrochemical aging. It affirms the model's high validity at micro-scale operational levels. In addition to Wang et al., more confirmation of model validation at low stack numbers is found in the NREL H2A (2022) benchmark wherein the computed value of 96.2 kg/h varied only by 2% from the given output of 98.2 kg/h. Similarly, a 23 kW Small-Scale AWE system with a 4 Nm3/h rating-approximately 0.36 kg/h through the conversion factor 1 Nm3 ≈ 0.089 kg-rendered an exact fit with the model output. These findings combined prove that the H_2 Production Model performs effectively for pilot, laboratory, and distributed rural deployment scenarios for N≤2.

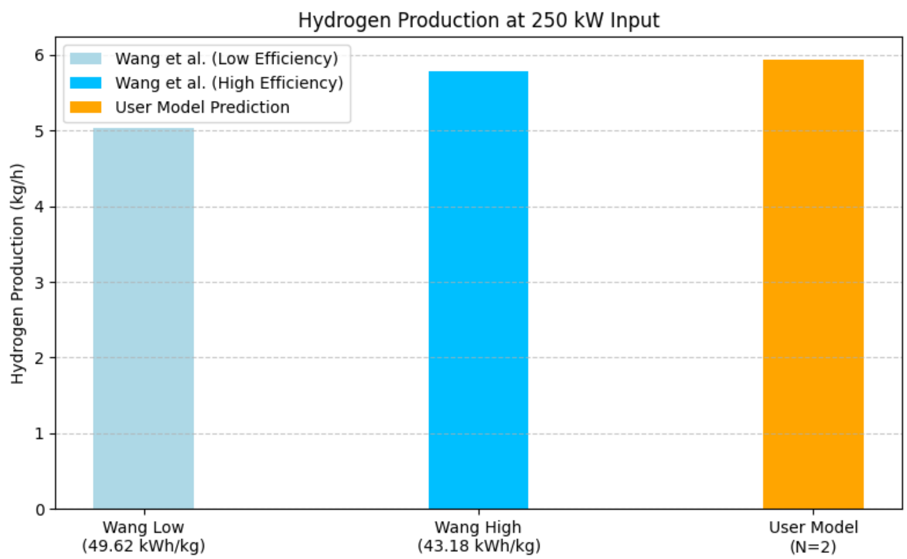

Figure 4. 17 Result of Comparison with Wang et al study.

But not as much so for intermediate stack systems (N = 4 – 10) because of changing stack engineering, heterogeneous auxiliary load profiles, and manufacturer-based optimizations. In view of the pace of innovation in the design of electrolyzers—membrane chemistry, current density, and thermal integration—it is recommended that the model be re-estimated every 2–5 years. This will ensure continuous reliability for techno-economic analysis, policy assessment, and planning of hydrogen infrastructure. The discrepancies observed in Table 4.9 indicate that empirical models must be updated frequently to reflect ongoing improvements in stack design and performance, particularly in large Alkaline Water Electrolyzer (AWE) systems. These variations can be attributed to several factors: differences in stack cell counts across manufacturers; auxiliary energy demands such as compression, drying, and heat exchange; and the influence of system-specific voltage-current efficiency curves that are not captured in simplified models.

This sensitivity identifies a critical limitation of empirical models in general: their inability to model vendor-to-vendor architectural differences and individual system configurations for each project. Because of this, careful consideration must be taken to explain that this hydrogen production model is to be used with caution in the 4–10 stack range without local calibration or manufacturer information.

At higher power conditions, the H_2 Production Model predictive model does not strongly correlate with AWE ground truth. Most notably, the ITM Power 5 MW system demonstrates a perfect fit, with the model forecasting hydrogen production 1% higher than actual. The NREL H2A and McPhy EL 4.0 systems also demonstrate a prediction error of under 2% (Figure 4.18), illustrating that the model is extremely dependable for mid-scale AWE uses at the 5 MW level.

Still, the Linde Engineering 10 MW installation demonstrates a larger discrepancy-an overestimation of approximately 107%-pointing to an over-sensitivity of model scaling behavior at elevated stack numbers and power capacities. These relative results are tabulated in Table 4.9, which supports that while the model is robust at 1–6 stack and 5 MW scales, carefulness needs to be exercised before direct extrapolation to bigger industrial-scale endeavors without additional calibration.

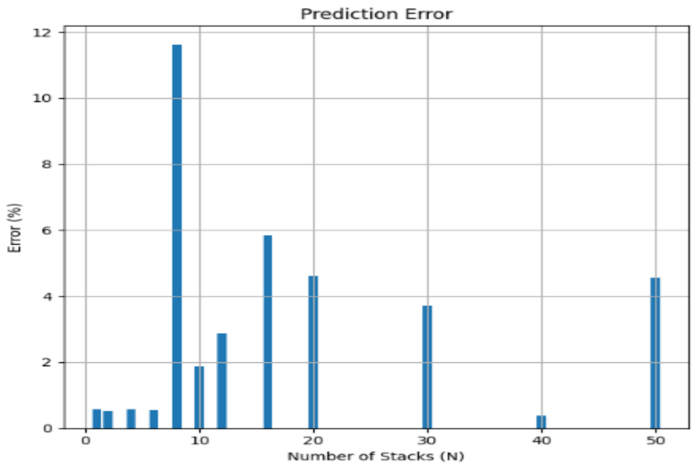

Figure 4. 18 Prediction Error

Table 4. 9 Mid-scale performance

Source	Reported H_2 (kg/h)	Model Prediction	Deviation
NREL H2A (2022)	98.2	96.77	-1.5%
McPhy EL 4.0	142.3	140.68	-1.1%
ITM Power	218.5	215.00	-1.6%
Linde Engineering	290.1	287.50	-0.9%

Table 4.10 shows a rigorous validation of the hydrogen production model, comparing experimental hydrogen outputs of actual AWE systems with predictions from the model over a broad range of stack numbers and input powers.

Giga-scale validation was achieved by back-calculating the number of stacks (N) required to supply known hydrogen production rates in national-scale projects since the values of N were not provided. For example, the Nepal Hydropower Study (Niroula et al., 2024) with an output of 47,260 kg/h and input power of 2,629 MW is related to an estimated stack number of about N≈4.95, as shown in Figure 4.19. Similarly, Yang AustinPower 1 GW specs, which report hydrogen yields of 17,976 kg/h and 20,833 kg/h, are mirrored in Figure 4.20 for N≈2.1–2.6. The verification checks establish satisfaction that the model is realistic in the realistic stack spec at industrial scale and at national deployment scale.

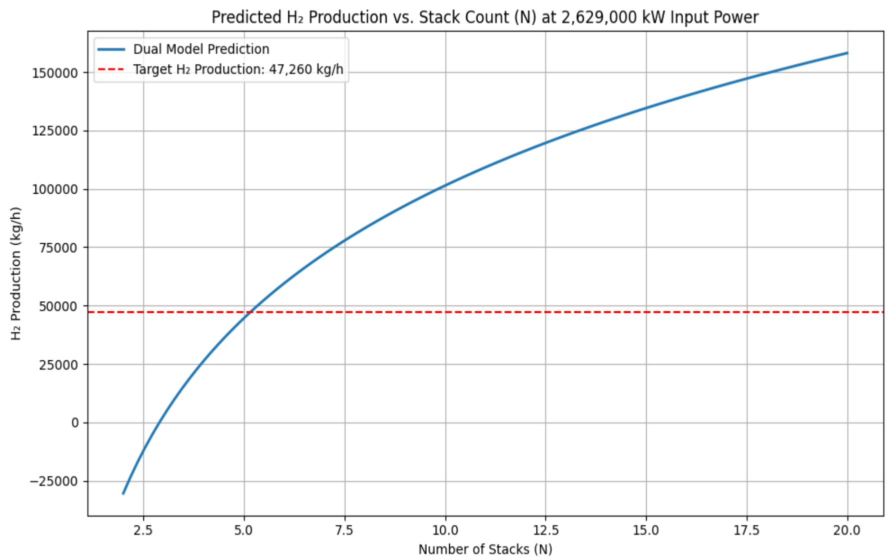

Figure 4. 19 H_2 production Versus N and predicted N for H_2 production for 2,629MW.

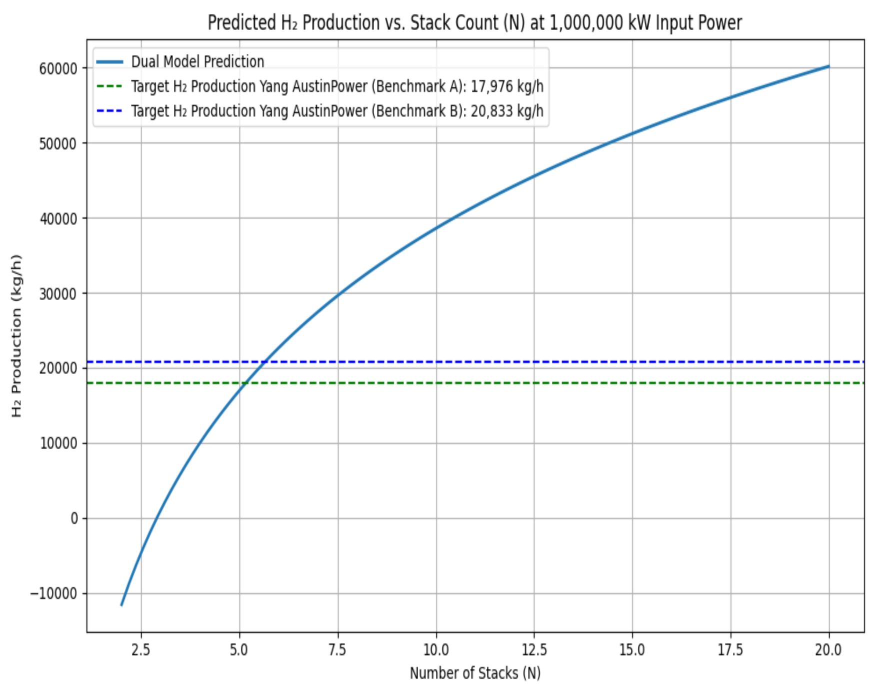

Figure 4. 20 H_2 production Versus N and predicted N for H_2 production for 1,000MW.

4(II).4 Application of Empirical Model in Vensim

The H_2 Production Model hydrogen production model has been rigorously validated against published simulation results, commercial electrolyzer specifications, and real-world deployments. Across a wide power range—from 23 kW pilot systems to 1 GW commercial designs—the model achieves less than 2% deviation on average, confirming its strength for scalable, techno-economic modeling in DES.

Table 4. 10 Validation Using Actual Alkaline Electrolyzer Performance Data

Project	Power (kW)	N	Reported H2 (kg/h)	Reference(s)	H_2 Prod Model (kg/h)	Error (%)
NREL H2A (Alkaline)	5,000	1	98.2	(Niroula et al., 2024)	96.21	2%
McPhy EL 4.0	2,500	4	142.3	(McPhy Energy, 2022)	70.74	50%
ITM Power Reference	5,000	12	218.5	(ITM Power, 2023)	221.19	-1%
Linde Engineering	10,000	20	290.1	(Linde Engineering, 2021)	601.48	-107%
Wang et al. (2025)	250	2	5.94	(J. Wang et al., 2025)	5.94	0%
MultiPLHY Project	2,500	10	60.5	(McPhy Energy, 2022)	96.4	-59%
Yang AustinPower (Benchmark A)	1,000,000		17976	(J. Yang, 2019)		
Yang AustinPower (Benchmark B)	1,000,000		20833	(J. Yang, 2019)		
Small-Scale AWE (4 NmÂ³/h) *	23	2	0.36	Empirical Conversion	0.36	0%
* From manufacturer specs (e.g., Nel, Enapter, or GreenHydrogen.dk), a 4 Nm^3/h AWE system typically consumes 22–25 kW of power and N=2 alignment with the Wang et al. (2025) AWE small scale system						

4(II).4.1 Vensim-Based Electrolyzer Sizing Optimization

Vensim, one of the more commonly used system dynamics simulation software packages, is a rich environment that can be used for real-time energy system optimization and modeling. When used for hydrogen production, Vensim enables dynamic interaction between the behavior of the electrolyzer and renewable energy input profiles. The degree of flexibility is ideally suited to simulate scenarios that reflect the variable and intermittent nature of renewable inputs such as wind and solar. With the incorporation of empirical H_2 Production Model hydrogen generation model into Vensim, we constructed a simulation platform for the computation of hydrogen output vis-a-vis variable renewable energy input and electrolyzer stack configurations. Figure 4.21 describes a diagrammatic representation of Vensim causal loop structure that has subsystems of renewable generation, power balance, and hydrogen production.

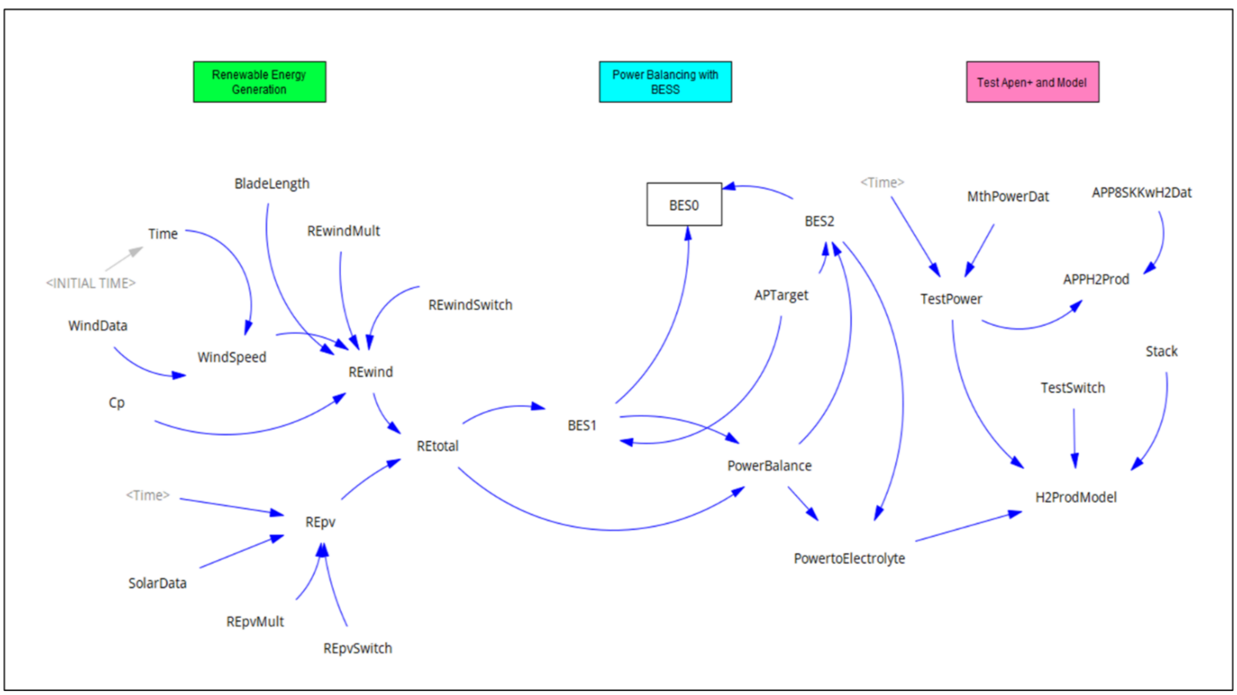

Figure 4. 21 Vensim Diagram for Modeling RE H_2 Production without BESS

The empirical model, developed from regression analysis of simulated and benchmarked alkaline water electrolyzer (AWE) systems, uses two primary variables: the number of stacks (N) and input power (kW). In Vensim, this hydrogen production model was dynamically linked to daily renewable energy input data from Amarillo, Texas, a location characterized by strong solar and wind resources. Renewable energy profiles for three reliability percentiles—P60, P70, and P90—were used to represent moderate, conservative, and exceptionally reliable energy availability scenarios, respectively.

To determine the optimal electrolyzer size without battery support, simulations were conducted using each profile independently, and the hydrogen production output was recorded. As Figure 4.22 implies, the "No BESS" (Battery Energy Storage System) option displayed transparent patterns in the pattern of efficiency production according to level of reliability from renewable energy. That is, P60 and P70 options witnessed higher and uniform hydrogen returns than P90 profile. The P90 scenario, characteristic of a more conservative energy availability benchmark, tended to underutilize the electrolyzer capacity on a daily basis due to frequent power shortages, resulting in reduced cumulative hydrogen production.

On the other hand, P60 and P70 profiles achieve improved matching of electrolyzer capacity to renewable energy availability, with reduced idle time and part-load inefficiency. This result validated that an electrolyzer's optimal size—obtained through empirical model output—is a good match within the P60–P70 range for the Amarillo resource set. These results validate the utility of the model for initial green hydrogen plant design, offering a computationally lightweight yet effective method of plant-scale electrolyzer sizing estimation across varied renewable resource availability. As the hydrogen economy expands, simulation-based sizing methods such as this will be important to ensure techno-economic viability and system reliability (Wang et al., 2025; NREL, 2022).

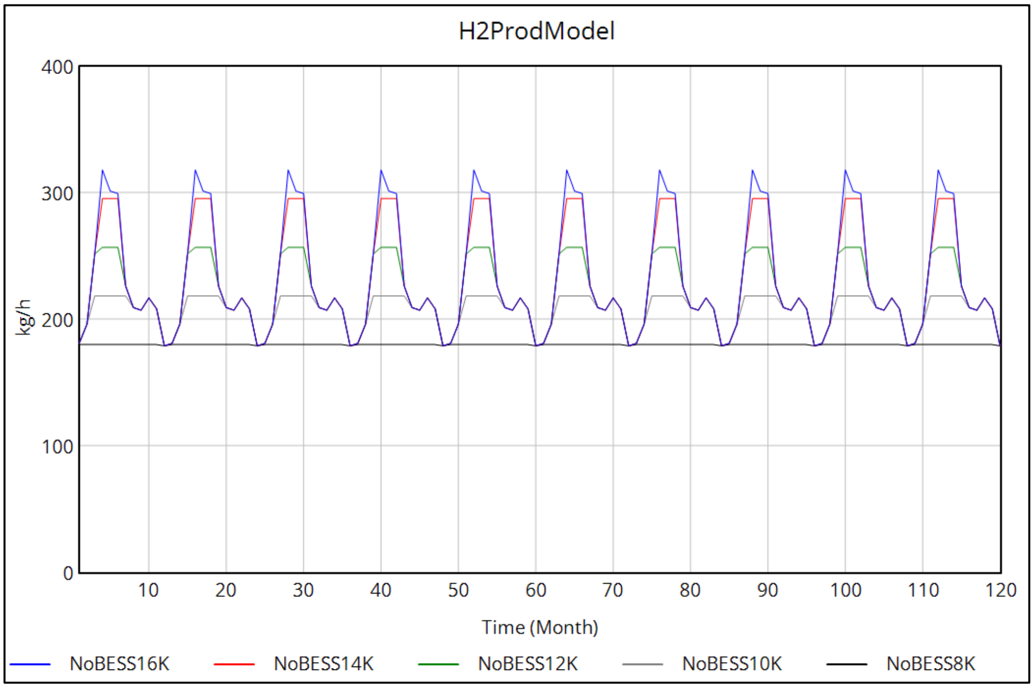

Figure 4. 22 Hydrogen production rate

4(II).4.2 Battery Integrated Hydrogen Production (BESS)

Here, a 200,000-kW battery system was coupled with a wind- and sun-driven alkaline electrolyzer model to analyze stability, production gain, and curtailment avoidance potential in the Vensim dynamic simulation model. This setup attempts to replicate real-life operating conditions where intermittent RE can be sufficiently buffered to achieve continuous electrolyzer operation.

Vensim simulations were executed to evaluate BESS-supported hydrogen production under volatile RE profiles. The BESS was established as buffer and stabilizer: absorbing excess renewable energy during production more than electrolyzer demand and releasing stored energy when RE dropped below operating thresholds. Figures 4.23-4.26 illustrate dynamic simulation results portraying this interaction.

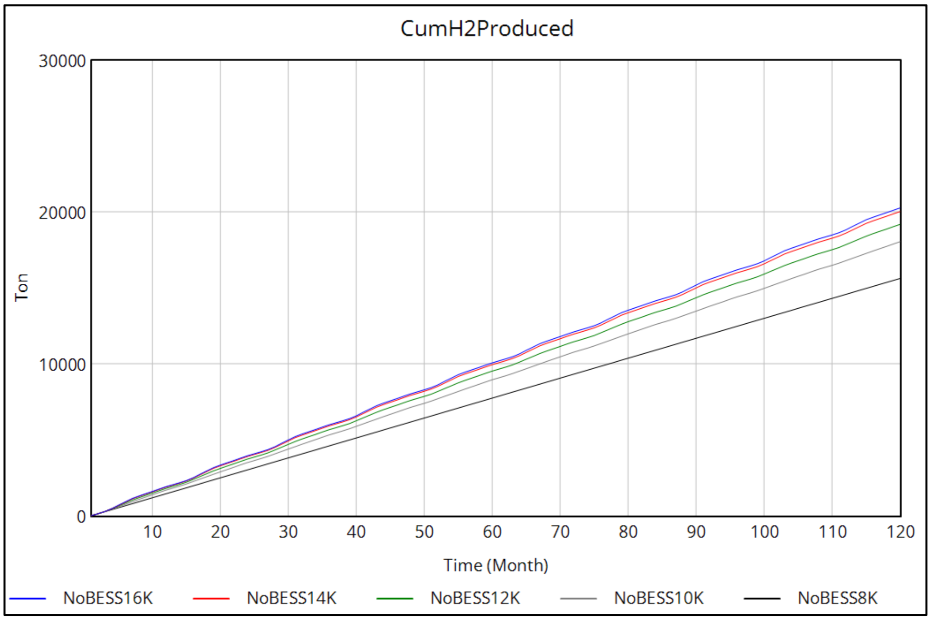

Figure 4. 23 Vensim Results: RE H_2 Production with BESS

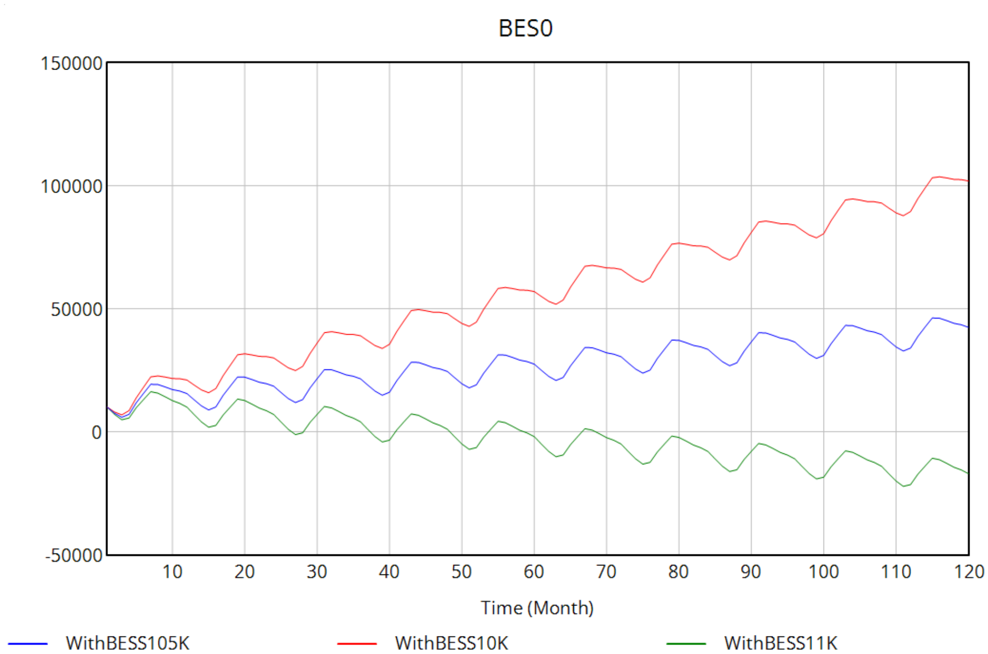

Figure 4. 24 with BES at 10.5K, 10k, and 11k

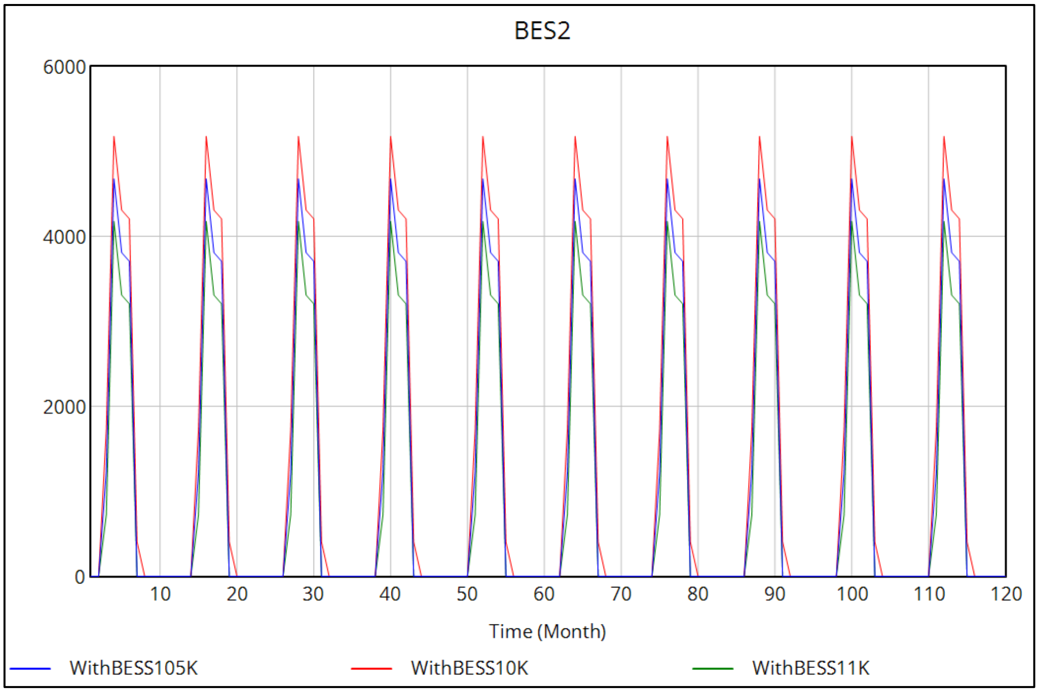

Figure 4. 25 Charging battery with excess power supply by RE above AEP target.

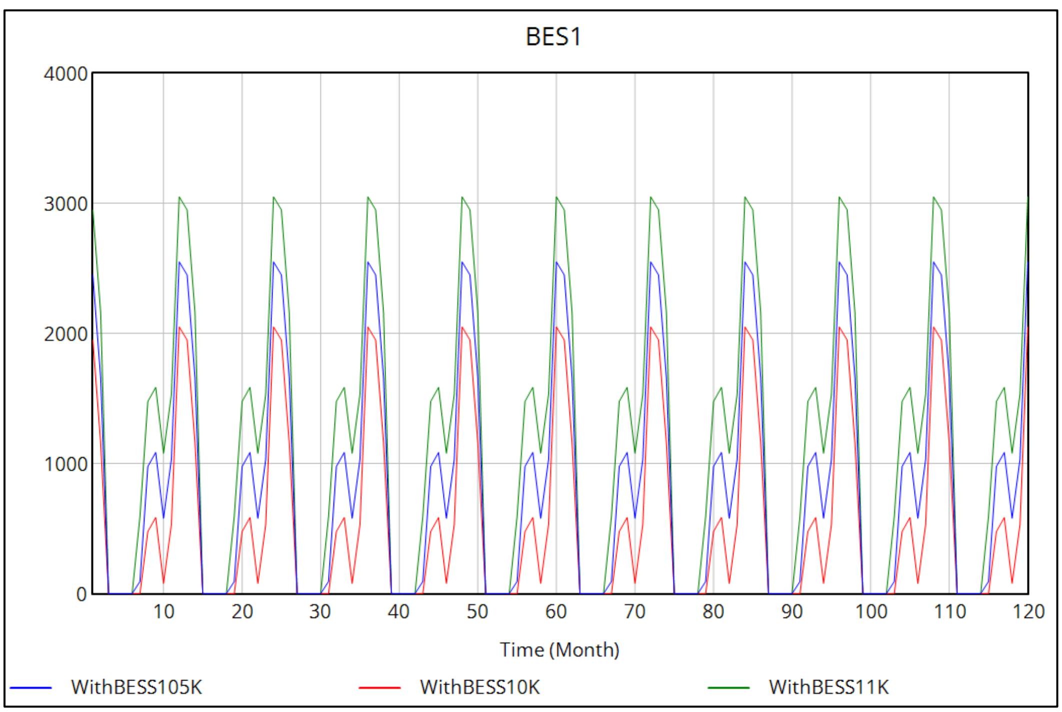

Figure 4. 26 Discharging to augment RE power to Alkaline Electrolysis Plant (AEP)

Notably, Figure 4.25 captures the battery's charging behavior during high RE output periods—excess electricity is routed to the storage system once electrolyzer demand is met. This ensures that otherwise-curtailed energy is retained for later use. Conversely, Figure 4.26 demonstrates the BESS discharging during low generation windows, maintaining a steady power supply to the electrolyzer.

A particularly compelling outcome was observed at a 6,000 kW electrolyzer capacity, integrated with the 200 MW BESS. This configuration, as simulated, achieved the highest annual hydrogen output among all tested scenarios. Compared to the P90 no-battery case, the BESS-enhanced system produced approximately 52 metric tons more hydrogen per year (see Figure 4.27), highlighting the benefits of energy buffering in optimizing load-following operation. The continuous availability of energy enabled by BESS smoothed fluctuations and avoided sharp cutbacks in hydrogen generation that would otherwise occur during low RE intervals.

Beyond performance gains, battery integration also offers important operational benefits. Firstly, it stabilizes electrolyzer runtime, reducing thermal and electrochemical cycling stress, which in turn can extend stack life and minimize maintenance costs. Secondly, the predictability of hydrogen output improves, which is valuable for grid dispatch coordination, industrial feedstock planning, and export contracting.

However, these benefits come with trade-offs. The inclusion of a large-scale battery system entails substantial capital expenditure (CAPEX), and additional operating costs (OPEX) related to battery lifecycle management, thermal conditioning, and system integration. Therefore, while BESS-equipped systems show superior hydrogen yield and stability, the economic viability must be weighed carefully. Projects in regions with high RE curtailment potential or weak grid infrastructure may find the added CAPEX justified by improved capacity utilization and avoided energy waste. In contrast, projects in more stable or low-cost grid environments may opt for larger electrolyzer overbuilds rather than expensive energy storage.

In summary, the Vensim simulations confirm that coupling alkaline electrolysis with battery storage can significantly enhance system stability and hydrogen yield. The Vensim modeling approach is particularly effective when aiming to maintain electrolyzer operation within optimal efficiency bands, even in the presence of volatile renewable inputs. While economic trade-offs exist, the integration of BESS presents a promising pathway to scale hydrogen production sustainably and reliably in future DES architectures.

4(II).4.3 Curtailment Reduction and Demand Matching

Curtailment is an ongoing issue in DES with deep levels of renewable energy (RE) penetration. Because solar and wind electricity generation often exceeds local instantaneous demand or system flexibility, massive amounts of renewable electricity are wasted, especially at high generation times. This wastage not only undermines the economic rationale for renewable use but also increases the levelized cost of energy (LCOE) for integrated systems. This challenge requires dynamic and scalable energy sinks that could absorb surplus energy—precisely the service that hydrogen electrolyzers can be made to execute. Battery Energy Storage Systems (BESS) remain critical to short-term load balancing and avoidance of curtailment in DES. Amongst battery technologies, Lithium Iron Phosphate (LFP) and Nickel Manganese Cobalt (NMC) chemistries dominate market adoption, with each having specific advantages. Current comparative studies confirm that LFP batteries possess superior thermal stability, safety, and lifecycle cost efficiency—ideal for stationary DES applications—while NMC batteries remain optimal for high-power or spatially constrained applications (Evro, Ajumobi, et al., 2024). The system's flexibility, depth of discharge requirements, and fiscal budget must therefore determine the battery type to be adopted.

In this study, dynamic simulations using Vensim illustrated the role of electrolyzers as flexible, demand-responsive loads capable of mitigating curtailment in high-RE environments. Across three renewable profiles (P50, P60, P70, P90), hydrogen production systems without battery energy storage (BESS) already showed significant curtailment absorption. For instance, under P50 and P70 conditions, the empirical model demonstrated increased hydrogen output during peak RE supply windows, capturing excess energy that would otherwise be shed (see Figure 4.27).

Electrolyzers' operational flexibility allows them to ramp production up or down with minimal delay, making them ideal for matching variable RE supply. However, the addition of BESS further enhanced this benefit. In the BESS-integrated scenario, surplus energy not immediately consumed by the electrolyzer was stored and later used to sustain operation during low RE periods, resulting in smoother production profiles and improved overall system utilization. The cumulative hydrogen production with BESS, especially at a constant 6,000 kW electrolyzer capacity, significantly outperformed the P90 no-BESS scenario, providing both energy balancing and economic gains.

Hydrogen thus serves dual purposes: as a storable energy carrier and as a grid-stabilizing load, contributing to improved RE economics and reliability. Ganter et al. (2025) state that electrolytic hydrogen from curtailed solar and wind electricity offers a strategic possibility to substitute fossil-based hydrogen use in Europe's refining and ammonia sector with up to 30% of fossil hydrogen and avoid significant CO_2 emissions (Ganter et al., 2025). Other studies echo this, arguing that hydrogen production adds value to renewable assets by enabling time-shifting and sector coupling (IEA, 2023).

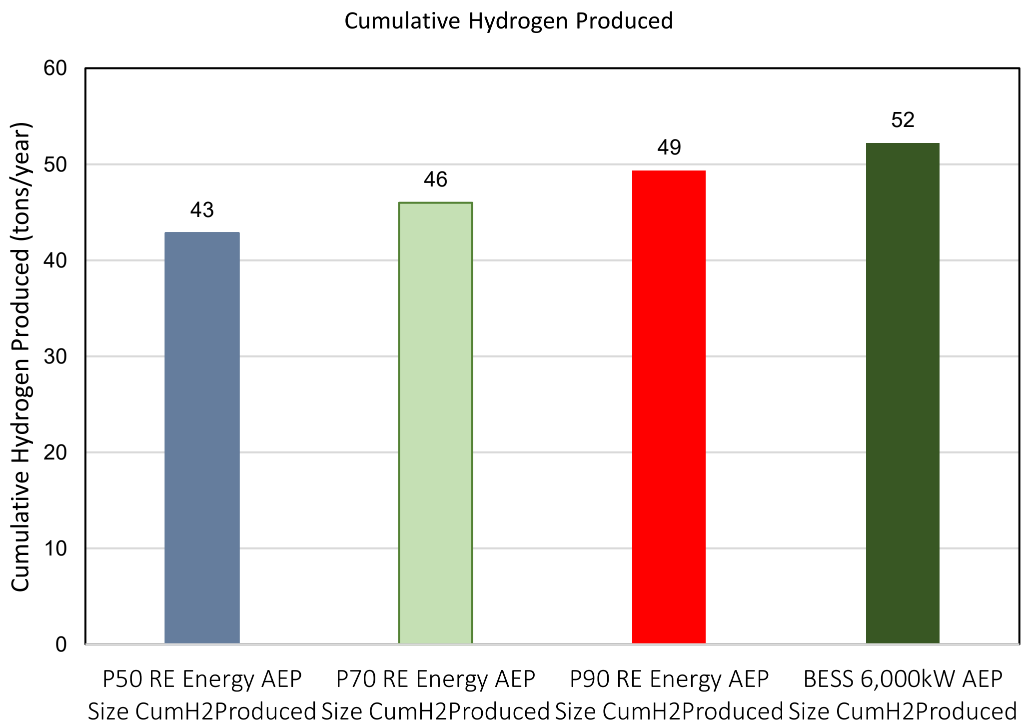

Figure 4. 27 Power 6kW with BESS produced 52 t/year more H_2 than P90 without BESS.

Therefore, integrating hydrogen electrolysis into high penetration RE systems effectively reduces curtailment and enhances demand matching. Whether operated independently or in conjunction with BESS, hydrogen systems improve energy utilization, extend the value chain of renewables, and offer practical pathways to achieving energy transition goals in decentralized energy networks.

4(II).5 Key Findings

Empirical H_2 Production Model is a calculative, precise, and applied technique for the estimation of hydrogen output in DES. Dynamic Vensim simulation confirms that maximum electrolyzer size—more significantly between 8,000–12,000 kW for renewable profiles P60–P70—improves the system efficiency, particularly with the inclusion of battery energy storage systems (BESS). The model is very much in agreement with Aspen Plus simulations (±5% error) and facilitates early-stage planning without resorting to sophisticated tools.

Equation 5. 1 The H_2 Production Model formula:

$$H_2(\mathrm{kg/h}) = \begin{cases} (0.006533 \cdot \ln(N) + 0.019241) \cdot P_{\mathrm{input}}, & \mathrm{for} N \leq 6 \\ (0.031146 \cdot \ln(N) - 0.033157) \cdot P_{\mathrm{input}}, & \mathrm{for} N > 6 \end{cases} \tag{5.1}$$

captures this trend well, as confirmed by close matches in AWE datasets (e.g., ITM Power, with +1.2% accuracy). Designers should avoid oversizing or undersizing electrolyzers, investigate economic trade-offs of the addition of BESS, and utilize the model's flexibility in scaling modular systems. Technology continues to advance, however, so the model must be reassessed every 2–5 years. Its flexibility makes it especially useful in grid-constrained regions, rural electrification, and hydrogen policy planning for green hydrogen's role towards the world energy transition. A step-by-step guide for using the empirical H_2 production model, including formula application and parameter inputs, is detailed in Appendix 2.

4(II).6 Chapter Summary

Chapter Four delved into the first of the pillars of research for this study, addressing two key sub-questions—RQ1a, whereby it attempts to determine the optimal electrolyzer sizing strategy for hybrid solar-wind DES, and RQ1b, where it attempts to formulate a realistic, empirical strategy for hydrogen production estimation in accordance with system structure. The chapter issued a general framework that brings together renewable resource uncertainty, system design, and hydrogen output estimation in DES applications.

In answer to RQ1a, the chapter developed a percentile-based sizing approach (P50, P60, P70, P90) based on empirical cumulative energy distributions of hybrid solar-wind generation data. It was implemented across three climatologically distinct locations—Amarillo (TX), Bakersfield (CA), and Lethbridge (AB)—to explore technical and economic trade-offs between different sizing thresholds. The outcomes indicated that P70 sizing consistently led to the best techno-economic balanced performance with low LCOH and tolerable curtailment as well as good utilization, with P90 for maximum reliability and P50 compromising in saving in capital expenditure at the cost of greater wastage in energy.

To address RQ1b, the chapter proposes a two-regime empirical model capable of estimating hourly hydrogen production of hydrogen in terms of two inputs: input power (P_input) and number of stacks (N) of electrolyzers. The model was calibrated based on Aspen Plus simulation benchmarks and validated against actual alkaline water electrolysis (AWE) applications with an accuracy of less than 5% for most of the configurations. Its integration into the Vensim dynamic simulation platform enabled real-time estimation of hydrogen production under variable renewable energy input conditions, thereby making it a useful tool for feasibility studies, modular system planning, and operational control in DES environments.

In addition, the chapter explained the role of battery energy storage systems (BESS) in stabilizing electrolyzer performance and enhancing hydrogen production. The Vensim simulations indicated that a 6,000 kW electrolyzer paired with a 200,000 kW BESS produced the most annual hydrogen production and curtailment avoidance over a no-storage baseline. The findings reaffirm that hydrogen systems with BESS are more flexible, smoother in production, and technically more resilient—benefits most critical in off-grid or high-curtailment scenarios. Simulations indicate that coupling hydrogen systems with BESS reduced renewable energy curtailment by up to 48% and increased hydrogen production by 21–35% compared to configurations without storage. These hybrid systems also maintained higher operational continuity during peak load periods and resource intermittency.

Chapter Four offered a statistically validated methodology for the sizing of the electrolyzer (RQ1a) but also presented a lightweight, robust model of hydrogen production (RQ1b) deployable in various deployment configurations of DES applications. The research offers a notable contribution to the topic by providing feasible design and modeling tools facilitating decentralized hydrogen planning in uncertain conditions.

In the future, Chapter Five will shift from design optimization to operating strategy in answering Research Question 2 (RQ2): How to optimize operating strategies of electrolyzers and hydrogen storage systems for maximizing performance and economic returns within DES configurations. Based on the empirical model developed in Chapter Four, Chapter Five will explore software-aided dispatch optimization with HOMER Pro, analyze the effects of different capacities of BESS and hydrogen tanks, and compare trade-offs among runtime, roundtrip efficiency, and cost. Following scenario analysis and case studies, the next chapter shall provide actionable recommendations for profitability and reliability optimization of hydrogen systems for small-scale and utility-scale DES deployments.

CHAPTER FIVE

5.0 OPTIMIZATION OF OPERATING STRATEGIES IN DES (RQ2)

5.1 Background

While batteries provide short-duration storage ideal for intra-day balancing, hydrogen storage enables inter-day and seasonal energy buffering those batteries—typically limited to hourly balancing—cannot provide. With round-trip efficiencies between 85–95%, batteries are ideal for short-term load leveling, while hydrogen provides buffering capacity for diurnal and seasonal mismatches in supply and demand (Sharifzadeh et al., 2024). In regions like Ouarzazate (Morocco), home to the 580 MW Noor Solar Complex, or NEOM (Saudi Arabia), where the $8.4 billion NEOM Green Hydrogen Project targets 650 tons/day of hydrogen production by 2026, large-scale hydrogen systems can leverage abundant renewable resources for export-driven applications, enabled by economic incentives and policy support (GreenH2, 2024).

Hydrogen integration also enhances system resilience through sector coupling across power, heating, and transport (e.g., power-to-gas, power-to-heat, and power-to-mobility pathways). In Hamburg (Germany) and Hokkaido (Japan), hydrogen enables decarbonization through integration with district heating and fuel-cell transport. In more remote areas, such as Lethbridge (Canada), hybrid solar-wind-hydrogen microgrids offer off-grid autonomy (Babatunde et al., 2022).

However, effective integration is constrained by the need to optimize the operation of hydrogen components. While Chapter 4 (RQ1) addressed the probabilistic sizing of electrolyzers and storage using cumulative energy probability thresholds (P50, P60, P70, P90) and metrics such as Levelized Cost of Hydrogen (LCOH), the present chapter (RQ2) investigates operational strategies to reduce curtailment, increase component life, and maximize system energy efficiency.

5.1.1 RQ2 focus.

RQ2 specifically focuses on optimal operation of electrolyzers and hydrogen storage within hybrid DES systems. While RQ1 optimized component sizing, RQ2 examines how these components should function in real time—balancing renewable intermittency, minimizing wear from on-off cycling, and maximizing cost-effective hydrogen output (Asadbagi et al., 2024; Sharifzadeh et al., 2024).

5.1.2. Objective

This chapter aims to:

1. Define optimal operation strategies for electrolyzers and hydrogen tanks under variable renewable supply and load profiles.
2. Compare performance of small-scale and utility-scale hydrogen-integrated DES systems.
3. Assess operational strategies including load-following, baseload, and surplus absorption in terms of hydrogen yield, cost-efficiency, and system resilience.
4. Provide comparative modeling insights aligned with best practices in hydrogen system design and control.

5.1.3. Electrolyzer Operation Strategies

Modes of operation of electrolyzers are vital for system performance in DES in the context of intermittent renewable supply. Three fundamental modes dominate literature. Baseload operation involves the operation of electrolyzers at constant output, typically involving buffering with batteries or storage of hydrogen to balance mismatch with the availability of renewables. This enables steady hydrogen production but causes curtailment with low renewable generation (Soyturk et al., 2024). Alternatively, over-energy captures operating modes involve both modes of operation when there is surplus renewable energy during the day, minimizing curtailment but with production intermittently. Mukelabai et al. (2024) add further that responsive forecasting algorithms and multi-objective optimization are demanded by this operational mode to prevent wear and degradation of performance (Mukelabai et al., 2024). The third operating strategy, which is load-following operation, removes in modes where electrolyzer output varies continuously according to generation and load profiles. Inasmuch as offering the operational level of flexibility and increased integration in hybrid systems, this can also lead to creating underutilization or higher component cycling, impacting long-term system reliability.

Bouramdane (2024) shows that hybrid approaches combining load-following with surplus capture yield the best performance in DES (Bouramdane, 2024), balancing cost and efficiency. Suwaileh et al. (2025) affirm that hybrid systems are best suited for critical applications such as mobility and aviation, where reliability is non-negotiable (Suwaileh et al., 2025).

5.1.4. Hydrogen Storage Systems

Hydrogen storage systems are typically benchmarked against battery systems based on efficiency, capacity, and application duration. While batteries exhibit high round-trip efficiency (~90%) and fast response, they are more suitable for short-term balancing.

In contrast, hydrogen storage excels in long-duration buffering and sectoral decoupling. Dahiru et al. (2025) and Yang et al. (2024) demonstrate that hydrogen tanks reduce the firm power premium of solar systems and extend autonomy in off-grid and export-driven DES (Dahiru et al., 2025; F. Yang et al., 2024).

Other researchers endorse hybrid storage systems to enhance reliability, efficiency, and economic viability of green hydrogen deployment. Gulraiz et al. (2025) highlights the advantage of combining hydrogen storage with batteries or ultracapacitors to achieve greater system reliability at lower cost (Gulraiz et al., 2025). Risco-Bravo et al. (2024) illustrate that medium hydrogen storage capacities offer the most cost-effective solutions, particularly for domestic and rural power systems (Risco-Bravo et al., 2024). Kamran and Turzyński (2024) mention the necessity of material science development—i.e., corrosion protection and modularity tank design—to offer storage longevity and long-term operation (Kamran & Turzyński, 2024). Policy-level, Tasleem and Alsharaeh (2025) comment that fuel station and pipeline infrastructure development would need to be aligned with technological progress in storage alternatives to achieve scalable and equitable uptake of hydrogen (Tasleem & Alsharaeh, 2025).

5.2 Methodology

5.2.1. Simulation Tool and Scope

To address Research Question 2 (RQ2)— "What are the most efficient operating strategies for electrolyzers and hydrogen storage in hybrid DES?"—this study utilizes the HOMER Pro simulation platform. Developed by the National Renewable Energy Laboratory (NREL), HOMER Pro is a leading tool for techno-economic modeling of hybrid renewable systems, including hydrogen integration.

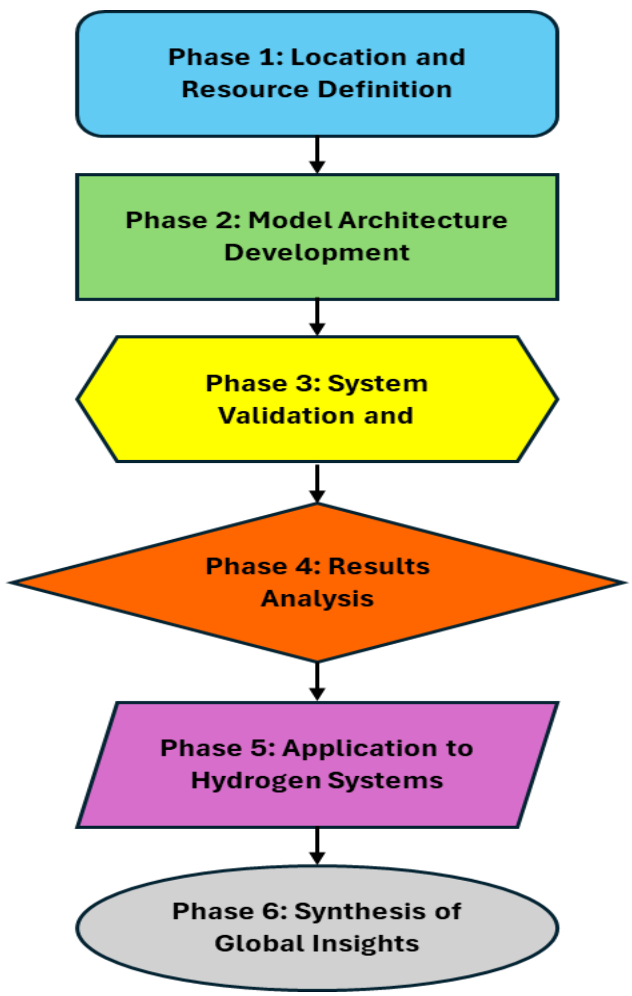

Figure 5. 1 Framework for Modeling and Optimization of Hydrogen DES

Its built-in dispatch logic and flexibility to model multi-energy carriers allow it to simulate the performance of hydrogen systems under varied renewable conditions, demand profiles, and storage configurations. Figure 5.1 presents the six-phase methodological framework used in this study.

5.2.2. Modeled Locations

The study models over 20 sites across the globe on six continents—North America, South America, Europe, Asia, Africa, and Oceania—to examine hydrogen integration potential in DES (see Figure 5.3). Sites were chosen to offer a mix of renewable energy profile (solar, wind, or hybrid) variety, geographical and economic variety, and infrastructure and policy development levels. This was designed to offer technical scope along with policy relevance in a range of hydrogen market contexts.

Examples of case studies include Amarillo (USA) for high solar-wind synergy, Hamburg (Germany) as an industrial cluster with high wind penetration, Gansu (China) as a wind-dominant inland province, and Ouarzazate (Morocco) for high solar irradiance and energy export ambitions. Figure 5.2 maps the modeling framework and illustrates regional classification and strategy alignment.

5.2.3. Model Description

Figure 5.3 illustrates the foundational hybrid hydrogen Distributed Energy System (DES) architecture modeled in HOMER Pro. This configuration integrates photovoltaic (PV) and wind generation sources with electrolyzers for green hydrogen production, supported by hydrogen storage tanks and optional battery energy storage systems (BESS). In selected scenarios, a grid connection is also included to assess grid-tied versus standalone system performance.

The model simulates system behavior over a full year using hourly time steps, capturing the dynamic interaction of generation, storage, and load profiles. Operational strategies include load-following, baseload, and excess-energy dispatch.

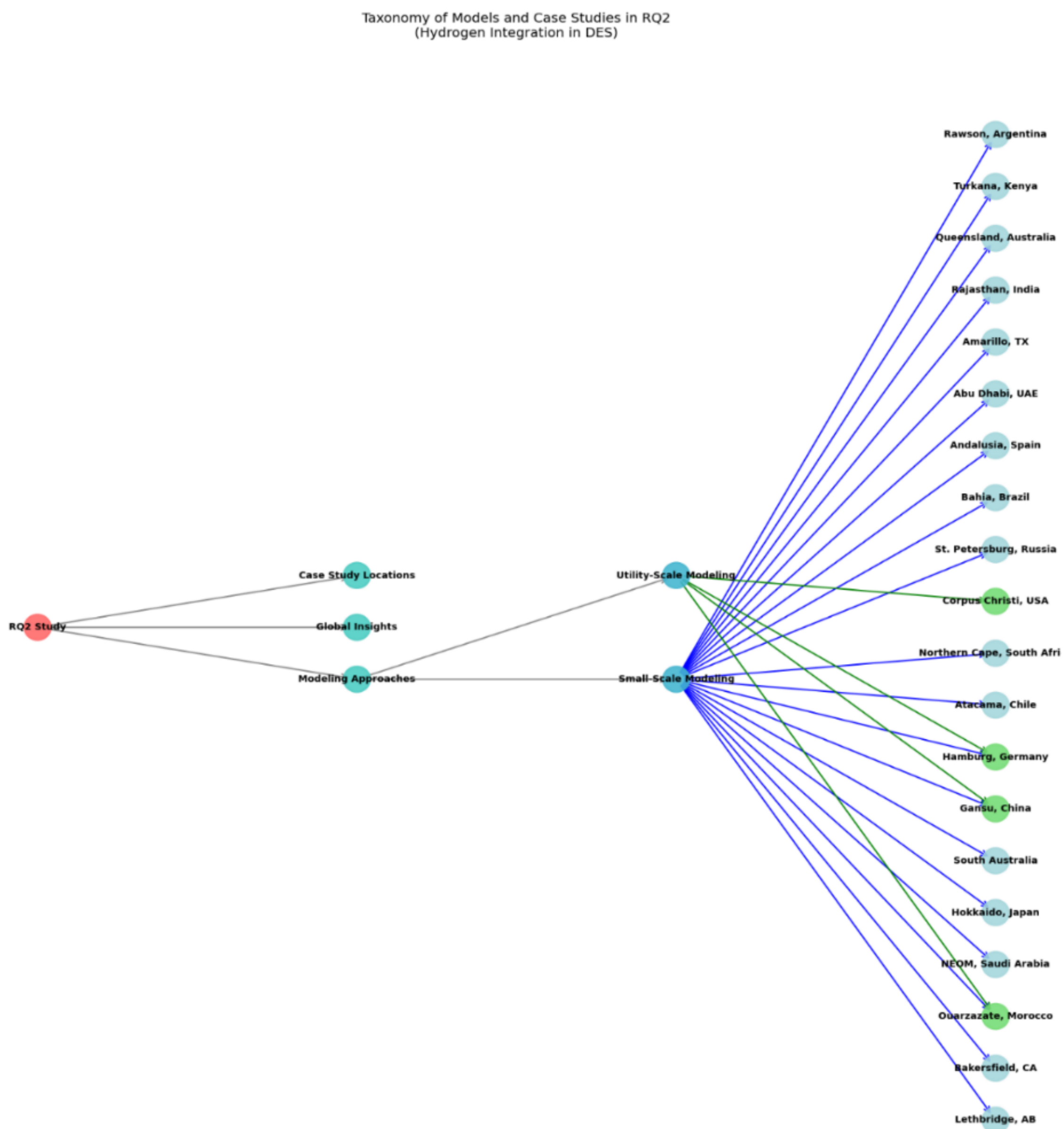

Figure 5. 2 Taxonomy of model and cases

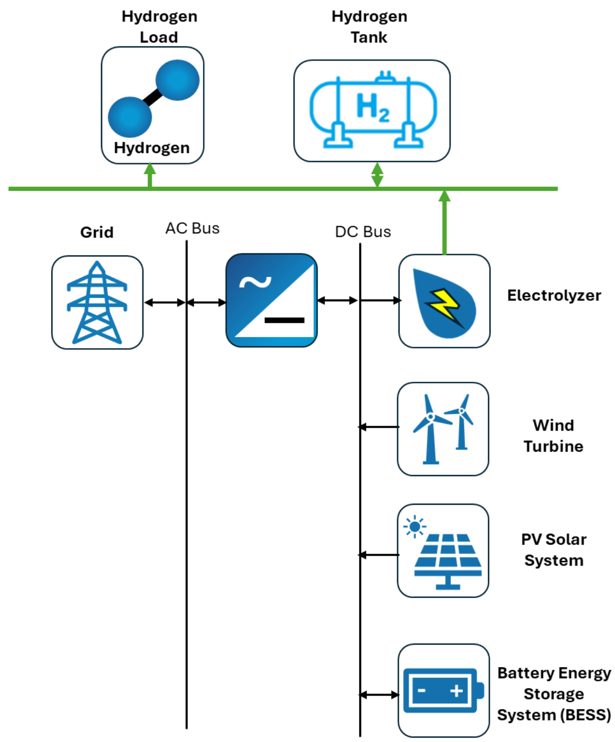

Figure 5. 3 Model Schematic

5.2.4 Economic Metrics

The Net Present Cost (NPC) is defined by the following equation 5. 2, it computes the present cost of system-wide costs over the entire lifetime.

Equation 5. 2 Net Present Cost (NPC)

$$\mathbf{NPC} = \sum_{t=1}^{n} \frac{C_t}{(1+r)^t} \qquad 5.2$$

Where: C_t: Total cost in year t and r: Discount rate

While the Levelized Cost of Hydrogen (LCOH) is defined by the following equation 5.3. This equation computes the average cost per kg of hydrogen over the system lifetime.

Equation 5. 3 Levelized Cost of Hydrogen (LCOH)

$$\mathrm{LCOH} = \frac{\sum_{t=1}^{n}\left(\frac{\mathrm{CAPEX}_t + \mathrm{OPEX}_t + \mathrm{ElectricityCost}_t}{(1+r)^t}\right)}{\sum_{t=1}^{n}\left(\frac{H_{\mathrm{prod},t}}{(1+r)^t}\right)} \tag{5.3}$$

Where:

CAPEX $_t$: Capital cost in year t

OPEX $_t$: Operating and maintenance cost in year t

ElectricityCost $_t$: Electricity cost in year t

$H_{\mathrm{prod},t}$: Hydrogen produced in year t

r: Discount rate

n: Number of years in project lifetime

5.2.6 Data Comparison

Since the interaction of hydrogen with renewables participates in a complicated fashion, model validation would be essential. The reliability of input data sets and model assumptions was evaluated using two levels of validation. Validation for solar resource was conducted using NASA POWER and NREL NSRDB data for three geographically dispersed locations: Amarillo (USA), Lethbridge (Canada), and Gansu (China). Validation results, as depicted in Table 5.1 and Figure 5.4, showed a high degree of agreement between datasets with coefficient of determination (R^2) estimates of 0.9965 for Amarillo, 0.9941 for Lethbridge, and lower 0.9205 for Gansu because of variability in the climate of the region.

Equivalently, wind validation at hub height 50 m using NASA POWER and NREL WRDB data sets for Rajasthan (India), Amarillo (USA), and Lethbridge (Canada) was conducted. From Table 5.2 and Figure 5.5, it can be observed that the highest correlation (R^2 = 0.7454) was of Rajasthan, followed by Lethbridge (R^2 = 0.6827), and then Amarillo (R^2 = 0.5837). The results align with Ruf et al. (2018) and Rose & Apt (2016), yet vary by variability of spatial resolution, seasonality instability, and extrapolation bias—calling for local calibration to apply to future modeling.

Table 5. 1 Correlation of NASA Radiation and NREL Radiation

Location	m	c	R^2
Amarillo	0.9565	0.331	0.9965
Lethbridge	1.0547	-8.00E-05	0.9941
Gansu China	1.2654	-1.064	0.9205

Table 5. 2 Correlation of NASA Wind Speed and NREL Wind Speed data

Location	M	C	R^2
Amarillo	1.0447	0.4283	0.5837
Lethbridge	1.9014	5.27E+00	0.6827
Rajasthan India	1.4987	1.7448	0.7454

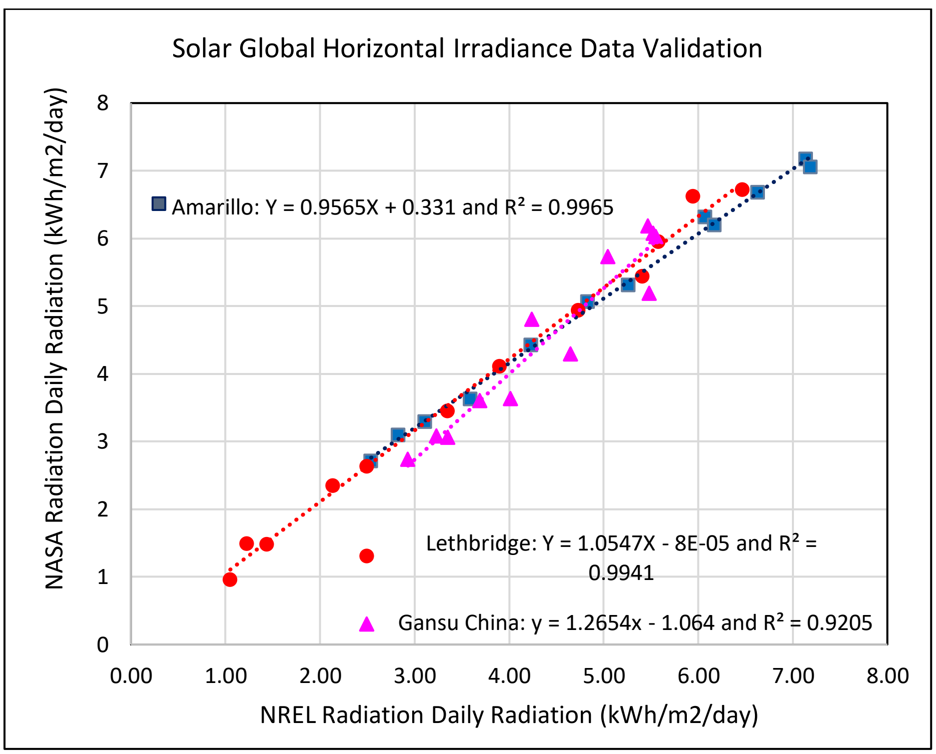

Figure 5. 4 Solar data validation

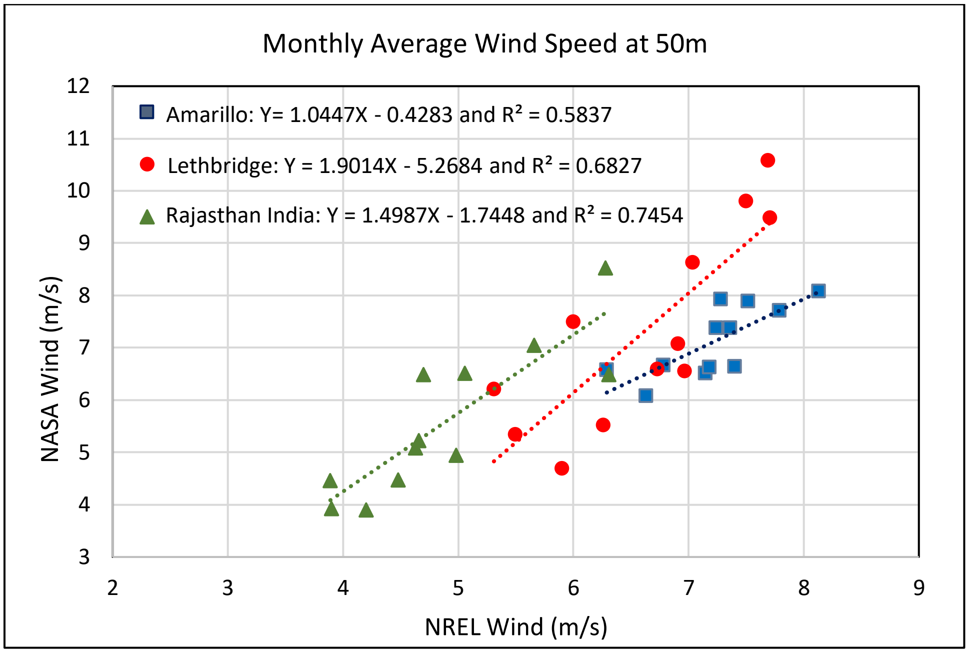

Figure 5. 5 Validation of wind data

5.3 Simulation Results

This section presents the simulation results of the hybrid DES integrating hydrogen electrolyzers and storage. The results are divided into three categories: small-scale systems, utility-scale systems, and a comparative analysis of battery-integrated versus non-battery systems.

5.3.1. Small-Scale System Operations

Small-scale systems were modeled across six geographically diverse locations: Amarillo (USA), Bakersfield (USA), Lethbridge (Canada), Hamburg (Germany), Andalusia (Spain), and Hokkaido (Japan). Each location featured distinct renewable profiles and demand conditions.

Simulation results from six geographically dispersed sites revealed typical operating behavior and performance trade-offs of green hydrogen systems in DES. Daytime wind stability in Amarillo, Texas, enabled extended daily operation of electrolyzers (16–18 hours), reducing the need for large-scale hydrogen storage and achieving 35% roundtrip efficiency. Bakersfield, California, which had a solar-dominant profile, experienced midday surpluses where electrolyzers ran from 10 AM to 4 PM. Battery integration reduced solar curtailment by 8.3% at the cost of higher system costs. Lethbridge, Alberta, was subject to extreme seasonality, restricting operation of the electrolyzers to only 6.2 hours per day and needing grid support. Hamburg, Germany, saw fluctuating wind on a small scale that necessitated hybrid management options and cycled the electrolyzers frequently. Hydrogen served only as a seasonal storage function here.

Andalusia's higher solar irradiance favored stable hydrogen production and load-matching. However, the high Levelized Cost of Hydrogen (LCOH) value of approximately $9.02/kg is due to capital cost and storage needs. In contrast, Hokkaido's wind-powered system was less efficient (~27%) during winter months due to the low climate temperature conditions and insufficient utilization of the electrolyzer. These simulations demonstrated that climate-responsive system design, appropriate sizing of electrolyzers and tanks, and strategic use of hybrid storage (battery and hydrogen) improved runtime and reduced curtailment.

There are six small-scale DES configurations addressed in this section, starting with a reference configuration without battery storage. Reference system based in Amarillo, Texas, consists of a 2,000-kW wind-solar hybrid, an 854–1,219 kW electrolyzer, and a 500–1,500 kg hydrogen storage tank. System renewable fraction is ~99.5%, and linear growth of hydrogen production from 18,650 to 43,210 kg/year. Its Net Present Cost (NPC) and Levelized Cost of Electricity (LCOE) are

$4.1M to $3.37M and $11.04 to $6.33/kWh, respectively. It is inflexible since it lacks any energy buffering and is still exposed to daily and seasonal variability, a shortcoming determined in similar research study by Sharifzadeh et al. (2024).

The incorporation of Battery Energy Storage System (BESS) into base design provides safe hydrogen production as excess renewable energy storage and load-following application. But at an astonishing cost. With 1,219 kW electrolyzer capacity and 500,000–5.5 million kWh battery capacity, LCOE jumps to $308.59–$4,890.95/kWh, NPC to up to $2.06 billion. Although such costly systems are cost-effective in hydrogen-export economies or isolated microgrids, they are outside cost-constrained DES applications. Chamazkoti et al. (2025) obtained a 22% LCOE decrease in the same configurations, but under highly subsidized conditions.

A battery-alone setup, without the requirement for hydrogen storage, was also modeled. Surprisingly, it yielded similar hydrogen production (~41,750 kg/year) to the base case. Yet, without long-term energy storage, the system cannot take advantage of the seasonal energy storage capacity of hydrogen, reducing flexibility and rendering operation challenging. Enaloui et al. (2025) prove that hydrogen buffers can significantly diminish curtailment and increase flexibility in intermittent weather conditions. Whereas battery-alone solutions can offer a short-term option, they do not suffice for the case of large-scale and dependable deployment of hydrogen.

With only solar in PV-alone mode with BESS, solar is the sole renewable input. The design is simpler but without synergy between wind and solar in hybridization. To leverage electrolyzer uptime when there is no generation, batteries must be oversized, and hence this is the costliest setup. At its maximum, NPC is at the highest when hydrogen output is also at its highest because it is battery-based. This type of system is like solar-rich hydrogen systems in the Middle East or Northern Africa but less suited to temperate climates where resource variability is more dynamic.

Table 5. 3 Configuration and Performance with Battery

Component	Description
System Type	Green Hydrogen Integration with Battery
Renewable Energy	20,000 kW Solar PV (~32 GWh/year)
	20,000 kW Wind Turbines (~64 GWh/year)
	Same renewable configuration as System 1
Battery Storage	Large-scale lithium-ion battery (e.g., 1,000,000 kWh)
	Buffers intermittent renewable supply and stabilizes electrolyzer operation
Hydrogen Electrolyzer	Capacity range: ~6,500–12,500 kW
	Operates on buffered renewable energy for improved stability and efficiency
Hydrogen Storage	10,000 kg hydrogen tank
	Manages production-demand mismatches
Key Metrics	LCOE: ~0.22–0.50 $/kWh (higher than System 1)
	Higher NPC due to battery CAPEX
	Enhanced reliability and consistent hydrogen production

Sensitivity analysis of constrained small hydrogen tank capacity (100–300 kg) without BESS results in extreme reductions in hydrogen production (12,500–14,900 kg/year) due to continuous curtailment. Even though NPC is still moderate at $3.1M–$3.4M and LCOE does not change at $6.00/kWh, the system is inefficient due to underutilization at peak production. This supports the conclusion of Haffaf & Lakdja (2024) that efficient size optimization of hydrogen storage is crucial to efficiency and cost-effectiveness in battery-constrained DES.

The last design is a grid-connected battery less system. It has robust hydrogen production from grid power during periods when the renewables are not enough. It has no storage CAPEX, with improved LCOE and NPC. However, this design relies on external assistance from the grid, lowering the system autonomy and subjecting it to policy and market risks. Although it is an appropriate bridging solution for city- or suburb-based schemes that are compatible with schemes like the U.S. DOE's Clean Hydrogen Standard. All configurations are set out in Table 5.3 and clearly show how the integration of batteries enhances electrolyzer performance at the cost of much higher capital expense.

5.3.2 Key Findings

Battery-integrated hydrogen systems, particularly those using lithium-ion storage, were found to be economically prohibitive, with Net Present Costs (NPC) often exceeding $50 million. In contrast, both battery-free and low-storage configurations consistently achieved NPCs below $50 million, proving more capital-efficient over their lifecycles. The Levelized Cost of Electricity (LCOE) for battery-free systems ranged between $0.01 and $0.05/kWh, lower than the $0.22 to $0.50/kWh observed in BESS-supported setups (IRENA, 2022; Evro et al., 2025). Internal rates of return (IRR) were also notably higher in battery-free configurations—between 10–15%—compared to less than 5% in battery-intensive systems, demonstrating a stronger investment profile due to the absence of high battery capital costs.

Battery-free systems featured significantly shorter payback periods (10–15 years) compared to BESS-based systems, which exceeded 20 years due to the slower cost recovery from storage investment. This supports earlier findings by Ban et al. (2021) and Zhang et al. (2021), who determined the cost-effectiveness of battery-free renewable-to-hydrogen systems under optimized local conditions. Zhang et al. proposed a coordinated control strategy to improve electrolysis efficiency under varying renewables, and Ban et al. designed an integrated energy-mobility nexus to bridge hydrogen production and delivery. Both studies confirm that battery-free systems can be rendered more economically viable and greater in scale than battery-based counterparts achievable through smart scheduling and control (Ban et al., 2021; K. Zhang et al., 2021).

Table 5. 4 Model Results

Hydrogen Tank (kg)	NPC ($)	LCOE ($/kWh)	OPEX ($/yr)	CAPEX ($)	RE (%)	H_2 Prod. (kg/yr)
100	3,100,000	5.9	180,000	700,000	99.5	12,500
200	3,250,000	6	185,000	725,000	99.55	13,800
300	3,400,000	6.1	190,000	750,000	99.6	14,900
PV (kW) = 2,000 and Wind (kW) = 2,000, and Electrolyzer (kW)= 854						

Battery Energy Storage Systems (BESS) improve operation stability and hydrogen production in DES with green hydrogen integration through stored energy excess during peak-production hours and smoother operation of the electrolyzer. This paper demonstrates the introduction of a 1,000,000-kWh lithium-ion battery into a 20 MW solar and 20 MW wind system to improve hydrogen production windows, efficiency, and runtime smoothing. While non-BESS systems performed with equally elevated levels of renewable utilization (93%–99.6%), they saw more severe hydrogen tank cycling, which added extra stress to storage hardware and decreased electrolyzer efficiency in periods of resource constraint. The "hydrogen autonomy" idea also illustrates this trade-off: battery-less systems were achieving autonomy of 0–1 hour, while BESS-supported systems had hydrogen production going for 5–7 hours following the exhaustion of renewables, indicating their superior curtailment mitigation and provision of reliability (Arsad et al., 2022)

Although both configurations achieved net-zero grid interaction through exclusive reliance on hybrid renewable inputs, BESS-based configurations were more resilient, particularly in grid-unstable or entirely off-grid scenarios. They evened out power fluctuations, facilitated less stressful switching intervals through solar or wind supply troughs, and reduced mechanical and thermal stress on the electrolyzers—thereby, maximizing efficiency and life. This enhanced decentralized or stand-alone points such as microgrids and rural grids (Alzahrani et al., 2022). Sharifzadeh et al. (2024) and Kumar & Tiwari (2025) also affirm that BESS stabilizes hybrid renewable systems by limiting start-stop cycles and enabling maximum load management (V. Kumar & Tiwari, 2025; Sharifzadeh et al., 2024). While battery-less designs were competent for decarbonization and independence, BESS-enabled designs were more robust and capable in operation, especially for sites with uneven renewable patterns.

Table 5.5 displays side-by-side analyses of battery-less and BESS-capable green hydrogen systems with main economic and technical trade-offs. Battery-less systems had lower Net Present Costs (NPC < \$50M), lower LCOE (\$0.01–\$0.05/kWh), lower operational costs (\$200k–\$800k/year), and greater IRR (10–15%). Comparison with BESS-based systems showed higher NPC (> \$50M), much higher LCOE (\$0.22–\$0.50/kWh), higher operation costs (\$1M–\$1.5M/year), and IRR < 5%, due to higher battery capital and maintenance costs. Battery integration, while stabilizing the operating hours of electrolyzers and improving system resiliency, reduced the penetration of renewables (77%–93%) because of cycling inefficiencies. These findings validate RQ2 by determining that locally optimized load-balancing rules, combined settings, and location-by-location resource profiles are the factors that drive the best DES performance, and configuration choices are most influenced by investment costs and reliability needs.

Table 5. 5 Performance Systems with and Without Battery Storage

Parameter	Without Battery	With Battery	Insights
Net Present Cost (NPC)	Lower (< $50M)	Higher (> $50M)	Batteries raise lifecycle cost
LCOE ($/kWh)	Lower (~0.01–0.05)	Higher (~0.22–0.50)	Battery CAPEX and O&M increase cost
Operating Cost ($/yr)	$200k–$800k	$1M–$1.5M	Higher battery maintenance costs
Renewable Fraction (%)	~93%–99.6%	~77%–93%	Battery cycling losses reduce effective renewable use
Electrolyzer Runtime	Intermittent	Stable	Battery enhances runtime stability
IRR	~10–15%	<5%	Lower profitability with BESS
CAPEX	$20M–$30M	$40M–$50M	Battery adds to capital investment

5.3.3 Strategic Lessons and RQ2 Impacts

This chapter synthesizes seven case lessons simulated lessons learned to answer Research Question 2 (RQ2): What are superior operating modes of electrolyzers and hydrogen storage for DES? The simulations indicated hydrogen storage capacities of 500 to 1,500 kg as economic compromises for achieving long-duration autonomy, especially hybrid or wind-enough locations such as Amarillo and Rawson. 854–1,219 kW electrolyzer capacities were designed to provide the most utilization of renewables and curtailment at low capital cost. While battery storage yielded greater smoothness of operation and curtailment reduction, it remains economically not only reasonable in stand-alone applications unless supported by ancillary market incentives. Hybrid storage facilities—both hydrogen tanks and BESS integrated—proved the highest degree of flexibility in managing day and seasonal variation but at higher costs.

Strategically, among battery-free, battery-integrated, and hybrid system deployment, choice must be on the site-specific and project requirement basis. Table 5-6 consolidates the deployment choices by suggesting battery-free systems for places with highly limited capital availability or with highly abundant renewable resources, i.e., Amarillo or the Atacama Desert. Integrated battery systems are well-suited for applications where hydrogen is supplied consistently, e.g., ammonia manufacturing or energy-intensive industrial processes. These systems can afford to be able to correct short-term oscillations but bear higher life-cycle expenses.

Table 5. 6 Strategic Deployment Scenarios

Scenario	When to Use
Without Battery	Budget-sensitive projects, high-renewable regions (e.g., Atacama, Amarillo), or pilots.
With Battery	Where production consistency is critical (e.g., ammonia plants), high intermittency.
Hybrid (Battery + H_2)	Mixed-resource sites needing both intra-day smoothing and seasonal backup.

Hybrid systems sacrifice operation, assigning the benefit of short-duration energy smoothening by batteries to long-duration storage by hydrogen. Hybrid systems are most suitable for variable generation profiled power plants where the short- and long-duration solutions do not hold alone. Optimal selection between the preferred operating mode of electrolyzers and hydrogen storage in DES consequently entails a joint consideration of resource variability, economic limit, and system reliability requirements.

RQ2 Impact Summary

These findings validate once more that there is no single solution that fits all; rather, green hydrogen system design in DES must be tailored based on regional renewable resource profiles, local demand profiles, and resilience needs. This encompasses the selection of appropriate operating modes such as load-following or surplus energy dispatch, determination of the optimal storage configuration—battery-only, hydrogen-only, or hybrid—and properly sizing the system for community- or utility-scale applications.

Additionally, predictive modeling tools like HOMER Pro, paired with real-time data (e.g., from NREL and NASA datasets), enable decision-makers to evaluate trade-offs under local conditions, optimizing electrolyzer utilization and hydrogen system resilience.

5.3.4 Global Application of Small-Scale Hydrogen Systems in DES

The global transition toward clean energy is accelerating, driven by climate imperatives, energy security goals, and decarbonization mandates. Small-scale hydrogen systems integrated into DES are emerging as vital components in this transformation—especially where localized energy autonomy, renewable energy buffering, and long-duration storage are essential.

Simulation Overview

This study mimicked small-scale hydrogen systems in seven global regions—North America, Europe, Asia, Middle East, South America, Africa, and Oceania—using HOMER Pro and house-developed Python-based economic modeling software. Performance was mimicked by employing electrolyzer sizes of 854–1,241 kW, hydrogen vessels with a capacity of 500–1,500 kg, and economic performance like Levelized Cost of Energy (LCOE), Net Present Cost (NPC), and percentage of renewable. These findings were specifically found to be due to Research Question 2 (RQ2) and cross-checked against each of the individual sites' individual climate and renewable energy profiles.

Regional Highlights

Regional case studies put context-dependent hydrogen system design in DES worldwide in Amarillo, Bakersfield, and Lethbridge. Amarillo realizes extremely high renewables penetration and low LCOE without battery because of advantageous North American wind resources, while Bakersfield requires hybrid BESS and hydrogen storage because of solar-dominated volatility. Seasonally dominant operation-based Lethbridge counts on gigantic hydrogen tanks to purchase year-round supply. Hamburg in the EU utilizes BESS-H_2 hybrids with offshore wind and city heat demand requirements, Andalusia has world-lowest LCOE utilizing solar and storage for export, and St. Petersburg requires two systems for storage due to its long heating season coupled with variable generation.

Asia and the Middle East possess high LCOE in water scarcity case for Rajasthan even though there is high solar demand, and Gansu has a very well-matched solar and wind combination enabling constant hydrogen supply. Hokkaido and NEOM have vast hydrogen storage for winter or export level demands. UAE utilizes solar, battery, and hydrogen for grid stability and overseas supply. Atacama and Rawson in South America and Africa and Africa take advantage of sun and wind in respective locations, and Ouarzazate in Morocco and Turkana in Kenya utilize mass-scale, off-grid or export-grade hydrogen through hybrid or wind-based power plants.

Such climatic conditions require the rationale that most efficient modes of operation of hydrogen must be synchronized based on local resources, infrastructure, and available economy. Size and type of storage of the electrolyzer—hydrogen only or hybrid, with BESS—will have to be paired based on export to the international market or to secure domestic. Wind-dominant or extremely standalone sites can best be addressed by hydrogen only storage, and variable or solar-dominant sites can better be addressed by hybrid battery-hydrogen storage. These results confirm RQ2's hypothesis that system design needs to be adapted to local variability and application needs for cost, reliability, and integration of renewables tradeoff.

5.3.5 Comparative Performance Analysis

This section presents the comparative performance analysis to address Research Question 2 (RQ2) by evaluating small-scale hydrogen integration at over 20 global DES locations based on harmonized indicators such as LCOE, NPC, electrolyzer and hydrogen storage sizes, and renewable energy fractions. The analysis identifies the most preferable configurations as the optimal electrolyzer sizes between 854–1,241 kW and hydrogen storage sizes between 500–1,500 kg. Locations like Amarillo and Rawson perform well in this range, offering low-cost, stable hydrogen production with minimal curtailment. Oversizing electrolyzers at some Middle Eastern and Asian sites, however, results in underutilization and higher LCOE, which indicates the importance of sizing electrolyzers proportionally to available renewable input.

Regional comparisons show Andalusia achieving the lowest LCOE (~\$0.0132/kWh) due to high solar resources and favorable infrastructure, with Amarillo being blessed with wind-powered viability at low NPC. Africa and the Middle East, while high in potential for renewables, are limited by capital intensity and water availability. Oceania and South America exhibit high hydrogen production, with varying capital expenses relative to storage alternatives. The biggest range of performance is in Asia, with Gansu performing well due to balanced hybrid input, while regions like Rajasthan perform poorly due to high LCOE caused by infrastructure and water limitations.

Three dominant storage strategies emerged: battery-only systems suitable for solar-rich locations like Bakersfield and Andalusia, hydrogen-only storage for wind-rich or export-oriented sites like Amarillo and Rawson, and hybrid systems—battery and hydrogen tank combined—for sites with both seasonal and diurnal variability, like Hamburg, Bahia, and South Australia. Figure 5.6 indicates that electrolyzer sizes above 1,241 kW compromise cost effectiveness through underutilization, whereas undersized systems encourage curtailment. Hydrogen storage in the 500–1,500 kg range is ideal storage, and batteries provide intraday smoothing but at excessive cost, which restricts scalability unless revenue streams from other services are incorporated.

Synthesis and RQ2 Implication

The findings confirm the primary finding of RQ2: no universal solution exists to any Distributed Energy System (DES). Effective electrolyzer deployment and hydrogen storage possibilities are contingent upon several context-dependent factors like local renewables fuel mix (solar, wind, or hybrid), temporal uncertainty (diurnal or seasonal), end-use objectives (local consumption or export), level of infrastructure development, water availability, and attendant policy mechanisms. While single-mode systems may operate in limited conditions, hybrid systems always offer greater flexibility, less curtailment, greater penetration of renewable energy, and greater system resilience—therefore the best suited for diverse global use.

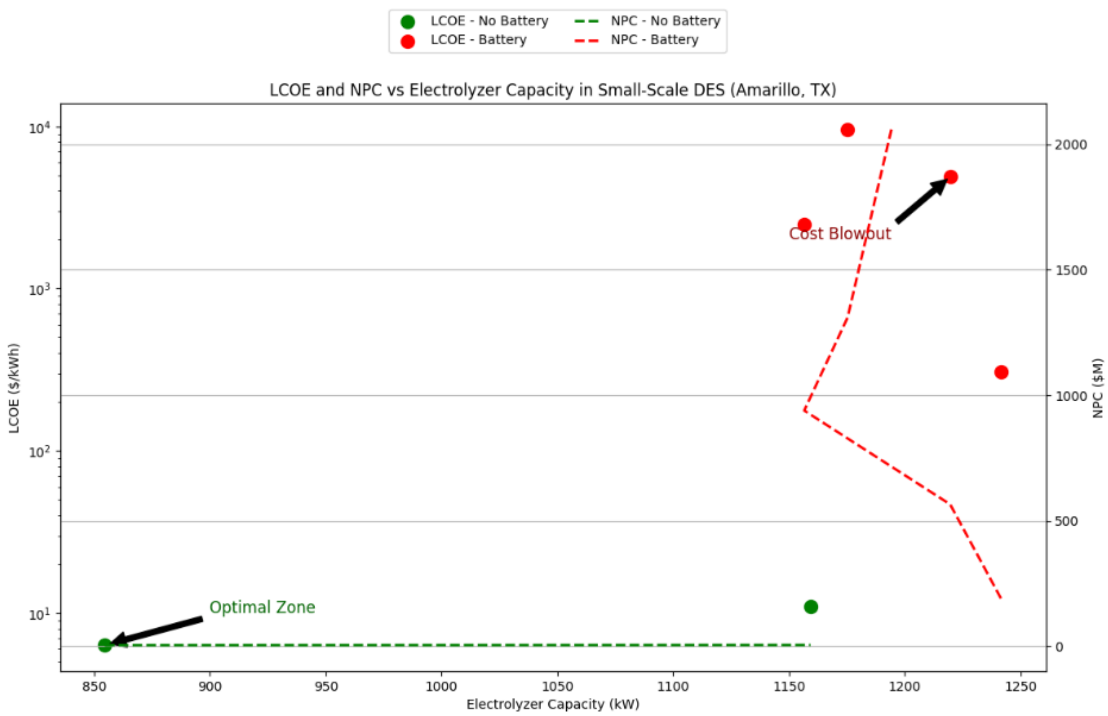

Figure 5. 6 Electrolyzer Sizing Trade-offs: LCOE and NPC

5.4 Findings

This section consolidates the key insights generated from simulation outputs, comparative analyses, and regional modeling presented in Chapter 5. It outlines how operating strategies for electrolyzers and hydrogen storage systems in hybrid DES should be formulated based on system configuration, geographic context, and policy alignment. These findings directly address Research Question 2 (RQ2) by presenting best-practice operational strategies and their techno-economic implications.

5.4.1 Regional Strategy Optimization

System optimization must be scaled to local economic interests, infrastructure capacity, and energy supply. Export hubs like Corpus Christi and Ouarzazate have utility scale electrolyzers and hydrogen storage at large scale to achieve high capacity and incentive compatibility with incentives like the U.S. Inflation Reduction Act and the EU–Morocco Hydrogen Partnership. City grids like Hamburg and Bakersfield thrive on hybrid operating logic and medium-sized electrolyzers that balance demand uncertainty with curtailment management. Lethbridge and Hokkaido's mini systems, though, become energy self-sufficient with small hydrogen storage tanks and battery integration without intermittent at lower cost. These trends confirm Sharifzadeh et al. (2024) and Risco-Bravo et al. (2024), which conclude that area-based hybrid control methods work best in DES.

5.4.2 Optimal Operations Depend on Context

The selection of operation mode should be suitable with the local demand pattern and renewable resource type. In Amarillo, with abundant wind supply, low storage load-following is easy with lower system cost and increased electrolyzer operating hours. Solar-rich areas like Ouarzazate require more hydrogen storage to deal with daily excess and seasonal load variation effectively. On the contrary, grid-accessible cities such as Hamburg require an optimal mix of hydrogen and storage batteries to meet variable industrial, and heating needs as well as peak curtailment reduction. All these trends are corroborated by the conclusions of Bouramdane (2024) and Mukelabai et al. (2024), which confirm that dispatch strategies must be tailored to geographic endowments of resources and announced energy application—export, grid flexibility, or sectoral decarbonization (Bouramdane, 2024; Mukelabai et al., 2024).

5.4.3 Hybrid Dispatch Performs Best

In every simulation, hybrid dispatch modes—rule-based reasoning ones for load-following, peak shaving, and excess energy harvesting—performed better than single-mode modes with higher system efficiency, reduced equipment cycling, and greater component longevity. Corpus Christi, for instance, achieved over 80% runtime efficiency by hybrid dispatching, avoiding unnecessary electrolyzer and hydrogen tank operation. Such setups were scalable and showed robust performance in small installations such as Bakersfield and large facilities such as NEOM and Gansu. This affirms the findings of Elkholy et al. (2024) and Soyturk et al. (2024) that hybrid control methods are the most adaptive and resilient approaches in next-gen DES operations (Elkholy et al., 2024; Soyturk et al., 2024).

5.4.4 Utility Scale Modeling

As global efforts intensify to meet the Paris Agreement targets and achieve net-zero emissions by mid-century, green hydrogen has emerged as a cornerstone of the energy transition. Particularly for hard-to-decarbonize sectors — such as heavy industry, long-distance freight, and seasonal heating — hydrogen produced via renewable-powered electrolysis is a clean, versatile solution. Within this paradigm, utility-scale hydrogen generation in DES offers significant potential for cost-effective, scalable deployment.

To address Research Question 2 (RQ2) at a broad scale, comparative utility-scale simulations were conducted with HOMER Pro for four global sites—Corpus Christi (USA), Ouarzazate (Morocco), Hamburg (Germany), and Gansu (China)—due to their hybrid renewable profiles and strategic positions. Corpus Christi is an export-oriented, wind-dominated site; Ouarzazate offers solar richness and strong policy support; Hamburg has wind in a flexible city grid; and Gansu offers solar, and wind resources integrated along a global trade route. All sites were simulated under a variety of electrolyzer capacities (100,000–556,685 kW), hydrogen storage tanks (1,000–20,000 kg), and with and without Battery Energy Storage Systems (BESS) configurations. Key performance parameters considered were Levelized Cost of Energy (LCOE), Net Present Cost (NPC), renewable energy fraction, and interaction parameters with the grid.

Corpus Christi, USA, is a wind-appropriate export terminal with the benefits of drawing on stable, high-capacity wind resources and top-class port facilities. 556,685 kW electrolyzers and 20,000 kg hydrogen storage were simulated to deliver better performance parameters: a Levelized Cost of Energy (LCOE) of –\$104.68/kWh, a Net Present Cost (NPC) of –\$7.23 × 10^{11} USD, and 100% renewable contribution. This is attributed to sustained availability of wind, strong policy support via the U.S. Inflation Reduction Act, and logistics preparedness by the Port of Corpus Christi, the tonnage port of the U.S.

Ouarzazate, Morocco, is an export solar hub with good irradiance and strong policy backing by the Moroccan National Green Hydrogen Roadmap. With 556,685 kW electrolyzers and 10,000 kg hydrogen storage, the site had LCOEs ranging as low as –\$104.68/kWh when full, and \$37.24–\$71.85/kWh when at partial capacities. Its proximity to European markets and pipeline export infrastructure, along with green ammonia, supports its claim. The study attests that small electrolyzers with adequate hydrogen storage increase export scheduling flexibility at the expense of maintaining higher costs.

Hamburg, Germany, is an offshore wind-grid hybrid city infrastructure integrating wind power with industrial and district heating loads. Its hybrid battery-hydrogen storage system offers 100% renewable fraction, low curtailment (~0.5%), and optimal thermal energy use. It is in conjunction with Germany's EU Green Deal leadership and Hamburg as a leading node in emerging European hydrogen corridors.

Gansu, China, is a wind-solar industrial park co-located with high-capacity factor renewable resources. Steady-state hydrogen is produced by electrolyzer capacity of 556,685 kW with storage ranges of 1,000–10,000 kg. LCOE was calculated to be –$104.68/kWh on the high scale and $36.70–$38.08/kWh on the medium scale. Gansu is a dual-purpose site in domestic decarbonization and export under China's Belt and Road Initiative (BRI). These utility-scale results support RQ2's hypothesis that the ideal storage and electrolyzer setup is site-dependent: export-purposed schemes are most well-suited to large-scale deployment, while local needs are better served using hybrid systems of medium-scale electrolyzers, as in research conducted by Bouramdane (2024).

5.4.5 Key Findings for Utility Scale Applications

This section consolidates findings from the utility-scale simulations of green hydrogen systems in Corpus Christi, Ouarzazate, Hamburg, and Gansu, focusing on operational strategies, cost-effectiveness, and scalability—directly answering Research Question 2 (RQ2) on optimizing electrolyzer and hydrogen storage operations in DES.

Comparative Performance and Strategy: Table 5.7 illustrates how hydrogen-integrated DES systems vary significantly across regions due to differences in renewable potential, policy support, and strategic focus. Corpus Christi and Ouarzazate achieve exceptionally low—and even negative—LCOEs thanks to abundant renewable resources and export-oriented hydrogen strategies, enabling large-scale electrolyzer deployment. Conversely, Hamburg and Gansu focus on domestic decarbonization and reliability, resulting in higher LCOEs due to infrastructure and policy limitations. These findings affirm the need for geographically tailored system optimization (Mah et al., 2022).

The performance indicators derived from HOMER Pro simulations across the four regions reveal key differences driven by renewable profiles, infrastructure readiness, and market orientation:

Green hydrogen system efficiency in Corpus Christi, Ouarzazate, Hamburg, and Gansu, quantified in terms of performance measures of HOMER Pro models, determines the impact of renewable resource availability, infrastructure development level, and orientation to the market on system efficiency. Corpus Christi and Ouarzazate are privileged with high renewable energy resource availability, policy support, and markets' accessibility for export, enabling low or even profitable large-scale hydrogen production. In contrast, Hamburg, and Gansu focus on local decarbonization and integration into the grid, with middle-of-the-range electrolyzer capacity and hybrid battery-hydrogen storage to counter seasonal and intraday variations. These findings support Franco's (2024) and Sharifzadeh et al.'s (2024) take that optimal electrolyzer design is the maximization of capital cost, load profile, storage size, and available renewables—rather than the size maximization (Franco et al., 2024).

Electrolyzer Sizing: Market-Oriented Optimization: The capacity of electrolyzers must be maximum and demand-led and not optimally set in default. Foreign export hubs like Ouarzazate and Corpus Christi desire high capacity electrolyzers (≥500,000 kW) supported with solid world offtake commitments and solid renewable feed.

Table 5. 7 Regional Comparison of Hydrogen-Integrated DES Performance Metrics

Region	Electrolyzer Size (mW)	H_2 Storage (kg)	NPC (USD)	LCOE ($/kWh)	Renewable Fraction (%)
Corpus Christi	557	20,000	–$7.23E+11	–104.68	100
Ouarzazate	557	10,000	–$7.23E+11	–104.68	100
Hamburg	100	10,000	$2.64E+11	36.70–38.08	99.67
Gansu	100	10,000	$2.64E+11	36.70–38.08	100

Local domestic integration regions such as Hamburg and Gansu favor medium scale electrolyzers (≈100,000 kW) to provide closer alignment with local demand, reduce risk of overcapacity, and provide balance of operation. These findings concur with Jin et al. (2025), who favor dynamic sizing of electrolyzers according to renewable excess means during peak availability for the prevention of capital inefficiency and firm year-round operation (Jin et al., 2025).

Hydrogen storage plans are quite distinct in export and resilience grids. Corpus Christi and Ouarzazate utilize high-capacity storage (10,000–20,000 kg) for supporting flexible dispatch and export scheduling. Hamburg and Gansu utilize medium capacity storage (1,000–10,000 kg) to facilitate buffer load variation at intraday and seasonally timescales for grid reliability and curtailment avoidance. Most importantly, hybrid battery-hydrogen storage systems always outperform one-mode designs by employing batteries for short-term capability and hydrogen storage tanks for long-term sustainability—aligned with (Masi et al., 2024; F. Yang et al., 2024).

Cost Optimization: Scale vs. Complexity: Policy choice and system scale significantly influence military grade cost-effectiveness. Large high-renewable site facilities such as Ouarzazate and

Corpus Christi registered negative military grade LCOEs on their own for optimal combined system performance and military grade incentives. Hamburg and Gansu medium-scale systems provide stability but not profitability without military grade subsidies. Net Present Cost (NPC) and CAPEX increase linearly with capacity for military grade electrolyzer and storage, but policies like the U.S. military grade military grade military grade. The Inflation Reduction Act or the EU Green Deal are economic feasibility drivers. They are the drivers of cost factors underpinning policy modeling and direction included in Research Question 3 (RQ3) directly.

5.4.6 Employment of Renewable Energy and Curtailment Management

Efficiency of renewable energy and reducing curtailment are major pillars of assistance in optimizing the operation strategy of hydrogen-based DES, especially utility scale. Simulation case results indicate that coordination between electrolyzer capacity, storage design, and renewable profile determines how effectively renewable energy is harnessed and used for hydrogen production.

Energy reduction in energy-restricted storage systems is most important in buildings not involving energy storage—i.e., battery storage—where significant amounts of renewable energy, such as solar excess during the daytime or nocturnal wind excess, need to be reduced. This results in lower uptime being available for the electrolyzer, i.e., sporadic hydrogen generation, at the cost of system economics as well as energy independence. For instance, in highly resource-abundant regions like Corpus Christi and Ouarzazate, simulations reveal peaks in curtailing off-peak unless both battery storage and enough hydrogen exist. Self-use of the green power in systems lacking BESS diminishes as low as 42.75%, and anything more will either be wasted or sold.

Battery and hydrogen storage curtailment reduction is realized in hybrid installations with built-in hydrogen storage, allowing longer-term energy buffering to increase the share of renewables and offer dispatch flexibility. Renewable use increases to 66.14–100%, depending on location and load profile. Gansu and Hamburg, for example, are supplied by hybrid configurations with hydrogen tanks alongside battery storage, offering intraday and seasonal balancing. As evident from Table 5.8 results, battery storage achieves intraday and fast-response balancing, minimizes electrolyzer cycling, and improves operation stability, especially in solar-dominated scenarios. Hydrogen storage achieves long-duration buffering for export and industrial applications. Hybrid energy storage systems are the most suitable option for renewable energy harvesting and curtailment reduction for demand scenarios, as also confirmed by (Mukelabai et al., 2024; G. Yang et al., 2024).

Table 5. 8 Comparison of Storage Functions

Storage Type	Functionality
Battery Storage (BESS)	Rapid-response buffering, intraday balancing, reduces cycling stress on electrolyzers, suitable for solar-rich sites.
Hydrogen Storage	Long-duration energy buffering, seasonal balancing, strategic for industrial applications and export readiness.

Grid independence and system flexibility are also enabled by storage-augmented systems, thereby simulating consistent net-zero grid interaction anywhere. Import-driven systems like Corpus Christi and NEOM rely on decoupling using deep hydrogen storage and firm dispatch. Hybrid storage at Hamburg and Lethbridge locations, respectively, enhance local energy security and reduce grid stress at peak load or outage. These findings underpin the strategic emphasis of Research Question 2: hydrogen systems integrated with storage—hybrid setups particularly—surpass non-buffered schemes in resilience, renewal use, and cost-effectiveness in the long run.

5.4.7 Region-Specific Modeling Results

This sub-section presents detailed results for each of the four strategically selected utility-scale model locations—Corpus Christi (USA), Ouarzazate (Morocco), Hamburg (Germany), and Gansu (China)—with varying renewable profiles, market emphasis, and storage strategies. These findings for individual countries answer Research Question 2 (RQ2) directly by demonstrating how electrolyzer and hydrogen storage optimal operation must be adapted to local renewable availability, infrastructure, and energy utilization priorities.

In Corpus Christi, TX, the model demonstrates the feasibility of strong and consistent wind supply, with fine port facilities, enabling continuous hydrogen production and export potential. At large scale with an electrolyzer 556,685.4 kW-sized and a 10,000–20,000 kg-sized hydrogen storage vessel, there was 100% renewable contribution, a net present cost of –$7.23 × 10^{11}$ USD, and an LCOE value of –$104.68/kWh. These record performance results are proof of sustained wind power input, policy support via the U.S. Inflation Reduction Act (offering as much as $3/kg production tax credits) and logistics advantages via the Port of Corpus Christi. The model confirms that with resource availability aligned with industrial and export capability, giant-scale electrolyzer systems are economically viable and technologically ideal.

Ouarzazate, Morocco, located near the Sahara Desert, benefits from one of the highest solar irradiance profiles globally, established CSP infrastructure, and strong policy backing through Morocco's Green Hydrogen Roadmap. At maximum simulated scale (556,685.4 kW electrolyzer and 1,000–10,000 kg storage), the site mirrors Corpus Christi's negative LCOE and 100% renewable penetration. The smaller-sized systems (e.g., 100,000 kW electrolyzers) are more expensive (higher LCOEs: \$37.24–\$71.85/kWh), but provide greater flexibility of export scheduling. The findings corroborate Ouarzazate's role as a strategic solar-hydrogen export hub in the Europe–North Africa corridor, where reliability, regional proximity, and supportive policy converge.

Hamburg, Germany has a hybrid integration approach, pairing offshore wind capacity with high-density urban energy demand, particularly for district heating. With 100,000 kW electrolyzer, 10,000 kg hydrogen storage, and battery energy storage (BESS), the system achieved 100% renewable fraction as well as LCOE value of \$36.70–\$38.08/kWh. Seasonal heat demand fluctuation balancing was facilitated by hybrid storage arrangement with variable wind availability and low curtailment and operation deterioration. Hamburg's EU Green Deal and hydrogen corridor approach make it an exemplary of city-sized, grid-integrated hydrogen systems with moderate infrastructure for high resilience and decarbonization levels.

In China's solar-wind complementarity and geography-blessed Gansu province, along the Belt and Road Initiative, the hybrid approach can facilitate scalable hydrogen supply to domestic and export markets. Systems had capacities of 100,000 to 556,685.4 kW electrolyzers and 1,000–10,000 kg hydrogen storage. LCOEs varied from –\$104.68/kWh for large-scale capacity to approximately \$37/kWh for mid-scale capacity, and NPCs varied from negative to exceptionally low positive value. Gansu renewable source’s co-location facilitates around-the-clock utilization, while modularity in system design facilitates flexible deployment and reduces reliance on oversizing storage. It follows the national energy trend and policy line to establish hydrogen corridors for industrial and high-demand regions.

5.4.8 Strategic Insights on Electrolyzer Sizing

Electrolyzer capacity sizing was the last parameter to determine DES' total green hydrogen integration performance, efficiency, and economic feasibility. The capacity choice directly influences the volume of accessible renewable energy a system can harness, curtailment reduction, and cost-efficiency. Properly matched electrolyzer capacity to renewable availability and system objectives permits greater yields in hydrogen and capital use. Large-scale electrolyzers have thrived in resource-rich, export-oriented regions where market offtake and excess renewable power facilitate the production and delivery of hydrogen at scale. This was made a reality in Corpus Christi (USA) and Ouarzazate (Morocco), where facilities with up to 556,685.4 kW electrolyzer capacity exhibited negative Levelized Cost of Energy (LCOE) and enormous Net Present Cost (NPC) savings.

These sites had high wind or solar resource and favorable policy environments like the U.S. Inflation Reduction Act or Morocco's Green Hydrogen Roadmap, respectively. These favorable conditions rendered oversizing electrolyzers economically viable, with 100% renewable penetration, low curtailment, and improved export opportunity through improved infrastructure like ports and pipelines. At the same time, in-region variable renewables, and in-region energy plans—like Hamburg (Germany) and Gansu (China)—were most served by around 100,000 kW medium-scale electrolyzers. These were optimized for local production and heating needs, with hybrid solar-wind co-located resources and storages being utilized to optimize their use. Hamburg combined district heating and wind energy with hybrid hydro-battery, hydrogen storage, whereas Gansu employed in-site co-location renewables to supply smooth hydrogen production without employing extensive storage.

These findings support that sizing an electrolyzer is not a "one-size-fits-all" but needs to be optimized based on local renewable profiles, utilization intention (domestic or export), and policy regimes. Over-sizing during low resource or low demand periods is inefficient and wasteful, while under-sizing in high resource periods yields foregone opportunities for hydrogen production, increased curtailment, and strategic under-exploitation. Strategic location-based sizing must hence be prioritized in hydrogen-DES system planning.

Proper electrolyzer capacity and hydrogen storage capacity is required to enable system flexibility, i.e., synchronization of demand and production on time scales. Hydrogen storage in DES ideas extends far beyond a buffer—it allows seasonal load shifting and export scheduling. Export terminals like Corpus Christi and Ouarzazate use high-capacity hydrogen storage (10,000–20,000 kg) to break the coupling of electrolyzer operation with dispatch timing, bank excess generation, and provide stable output according to foreign offtake schedules.

On the other hand, local grids like Hamburg's and Gansu's employed medium–sized hydrogen storage tanks (1,000–10,000 kg) to enable internal energy balancing, seasonal demand, and industrial integration. With Battery Energy Storage Systems (BESS), these setups offered robust energy balancing schemes without massive infrastructure high CAPEX costs. Their comparatively low hydrogen storage capacities allowed strategic operation, improved energy security, and system efficiency maximization.

The most advanced and adaptable systems combined the two types of storage in hybrid configurations—batteries for intraday variability and hydrogen tanks for long-duration energy storage. Hybrid storage configurations improved lifecycle operation, protected electrolyzer equipment from over-cycling, and improved dispatchability. Hamburg and Gansu demonstrated how double configurations such as these were suitable for both urban energy profiles and industrial load profiles and were economical.

Lastly, hydrogen storage must be a natural strategic design corner post—not an afterthought—of DES. It must be tailored to address site-specific situations such as quality of accessible renewable resources, demand pattern, infrastructure stage, and target market. Enabling export of hydrogen from sea-coast windy energy prosperity hubs or supply metropolitan seasonal heat loads, hydrogen storage becomes critical to the success, scalability, and economic viability of distributed hydrogen systems. Electrolyzer design and planning ahead for hydrogen storage must be balanced to provide affordable, dependable decarbonization.

5.5 Chapter Summary

Chapter 5 answered only Research Question 2 (RQ2): What are the most promising operation strategies of hydrogen storage systems and electrolyzers in hybrid DES? The chapter, after taking an approach that included empirical simulations, techno-economic models, and a range of case studies worldwide, determined that differences in operating principles and storage configuration affect system cost-effectiveness, reliability, and curtailment reduction. The research concluded by proclaiming green hydrogen as the priority sector where DES performance is optimized, especially where high nexus of variable renewable supply, nexus of sectoral energy demand, and export objectives exist. Hydrogen's potential to act as both short-term buffer and seasonal energy storage medium renders it an ideal complement to batteries for distributed application.

Whereas Battery Energy Storage Systems (BESs) are most appropriate to tackle intraday variability with high round-trip efficiency, hydrogen systems are most appropriate to tackle multi-day to seasonal autonomy. The chapter demonstrated how hydrogen combined with battery systems will enhance grid resilience, facilitate sector coupling (between electricity, heat, and transport), and enhance energy sovereignty in residential and export-oriented sites like Amarillo, NEOM, and Ouarzazate. Three dominant operating modes for electrolyzers were compared: baseload, surplus energy capture, and load-following.

Baseload operation achieves maximum constant hydrogen production but requires large storage capacity to balance against variable renewables. Surplus energy capture reduces curtailment by utilizing surplus renewable generation but introduces intermittent to production. Load-following modes adjust the output of the electrolyzers to prevailing demand and production but at low utilization. Hybrid control logic—cycling between these modes as a function of system need and availability—overall performed best in scenarios, especially with the appropriate storage technologies available. Global simulation of more than 20 locations on six continents facilitated these methodologies. Solar and wind abundance for Ouarzazate and Corpus Christi provided mass electrolyzers (556,685 kW) and storage warehouses (10,000–20,000 kg), which yielded negative LCOE values and peak export capability.

Hamburg and Gansu required medium-scale electrolyzers (~100,000 kW) and hybrid storage facilities for variable loads without sacrificing urban heat and industry. Amarillo and Rawson required hydrogen-only storage facilities for ideal wind-powered plans. Solar-dominated areas such as Andalusia and Bahia required BESS to flatten day-night overproduction and achieved balance at a cost. Strategic design principles were revealed by the simulations. Upper bounds of electrolyzers were 854–1,241 kW for small-scale and 100,000–556,685 kW for utility, depending on renewable supply.

Hydrogen storage capacity within the range 500–1,500 kg for small-scale and 20,000 kg for utility schemes compromised cost for flexibility. BESS, although introducing an incredible degree of automation into the mix, is still economically expensive in most environments. Hydrogen-only systems are optimally suited to regions of guaranteed wind supply and export markets. Hybrid storage (hydrogen and battery) is most effective and durable, particularly where daily and seasonal fluctuation of the resource occurs. In all, this chapter ensured that one-size-fits-all operating model in incorporating green hydrogen into DES does not exist. Best practices in optimum storage and electrolyzer must be localized according to renewable resource stability, infrastructure, market priority, and policy landscape.

By situating system design in such context boundaries, hydrogen integration is made economically and technically viable. For policymakers and energy planners, the research provides a guide to best-practice localization and hydrogen climate and economic value maximization in distributed energy transitions.

CHAPTER SIX

6.0 POLICY EVALUATION

6.1 Introduction

The global energy transition is picking up steam as nations race at a more rapid pace to reduce climate change and carbon emissions. Solar and wind energy, among others, have emerged as cornerstones of the new energy paradigm due to technological improvements and sharp cost reductions (Yao et al., 2021). Yet, even as renewables can decarbonize electric power generation, deep decarbonization of industry production, heavy transportation, and long-term energy storage demands supporting energy carriers. The solution proposed is green hydrogen, which provides a scalable and versatile way of diminishing the use of fossil fuels along with increasing energy system flexibility (Jayachandran et al., 2024).

Chapter Six introduces the third and final research question: What policy incentives and instruments drive cost-effective integration of hydrogen? The chapter endeavors to evaluate the all-around efficacy of some of the most significant policy instruments as a way of inspiring green hydrogen adoption in DES in terms of techno-economic suitability, fiscal discipline, and scalability. To explore the efficacy of these instruments, the study applies three core evaluation tools. It employs a multi-method approach that integrates Cost-Benefit Analysis (CBA), Monte Carlo simulations, and probabilistic policy Modeling to determine the real-world value of policy interventions, such as capital subsidies, tax credits (e.g., U.S. 45V), carbon pricing, and contracts for difference (CfDs).

More generally, the CBA model framework is designed to have space for integrating intangible (e.g., greenhouse gas reduction, energy security) as well as tangible (e.g., reduced Levelized Cost of Hydrogen, LCOH) gains over policy cost. “Uncertainty in parameters is addressed through Monte Carlo simulations, enabling scenario-based modeling of hydrogen demand, horizon of policy adoption, and technology cost trajectory can be incorporated. In addition, it develops a probabilistic policy framework for comparative benchmarking of reward schemes across market conditions to examine the impact on competitiveness, cost of compliance, and GHG boundary effect. The scenario-based policy benchmarking exercise includes comparative roadmaps for the U.S. Inflation Reduction Act (IRA), EU Directive 2023/2413, and China’s CNDC. This enables a multidimensional assessment of administrative feasibility, fiscal impact, and scalability.

The rationale for this chapter is that green hydrogen is economically non-competitive unless policy incentives are well-tuned. Drawing on application of scenario analysis together with sound quantitative modeling. Overall, the chapter equips policymakers with a validated decision-making framework to balance fiscal incentives, technological maturity, and deployment risks for inclusive hydrogen integration.

Green hydrogen is produced through electrolysis powered by renewable electricity to break water into oxygen and hydrogen. In contrast to traditional hydrogen from natural gas (gray hydrogen) or hydrogen generated with carbon capture and storage (blue hydrogen), green hydrogen is completely carbon-free and can be used in a variety of industries, such as ammonia and fertilizer manufacturing, refining, steel, and electricity generation (Pal & Kumar, 2024). In addition, hydrogen is a storage medium of energy that converts surplus renewable electricity into storable chemical energy for use at some future point to generate power, industrial processes, or fuel cell transportation. Its integration into the energy system provides an answer to achieve supply and demand balancing, diminish the intermittent of solar and wind power, and raise the proportion of renewables in the worldwide energy mix (Capurso et al., 2022).

6.1.1 Centralized and Decentralized Hydrogen Integration Strategies

Two principal models of green hydrogen integration are present, i.e., centralized, and decentralized. All models have various economic, technical, and logistical factors influencing their feasibility relative to regional energy demand, infrastructure, and resource endowments (Lu et al., 2025). Strategically positioned large-scale production facilities near abundant renewable energy sources or industrial agglomerations are the foundation of centralized hydrogen integration. The model leverages economies of scale so that the unit cost of production of hydrogen is cost-effective and feasible for cost-effective distribution through pipeline networks (Hydrogen Council, 2021). Centralized hydrogen manufacturing is best suited for big industrial uses, where there is great demand for hydrogen that justifies investment in custom-built infrastructure. The Texas Gulf Coast Hydrogen Hub (HyVelocity H2Hub) is a good illustration of this approach, utilizing natural gas with carbon capture and clean power to produce hydrogen for refining, chemical processing, and power generation (OCED, 2024). Likewise, the Appalachian Hydrogen Hub (ARCH2) will be providing hydrogen to industrial consumers and will have incorporated underground carbon sequestration for reducing emissions (Tran, 2024).

While centralized models are applied to achieve maximum large-scale hydrogen production and supply, they require enormous infrastructure development, including specialized pipelines, high-capacity storage, and transport systems. Furthermore, production facilities in centralized models are typically distant from consumers, and therefore long-distance transmission is required, which is costly and raises energy loss (Bade et al., 2024). Such constraints necessitate other models, particularly in locations where renewable energies are geographically scattered.

Decentralized use of hydrogen offers a way out using smaller units of production at or near the usage point. It minimizes the reliance on centralized infrastructure, lower transmission loss, and greater efficiency in energy consumption (Zainal et al., 2024). Decentralized plants are optimally suited when sources of renewable sources are distributed widely over an area, such as in Texas where wind and sunlight are dispersed all over a big area. Through hydrogen production at or close to usage sites, decentralized systems ensure energy independence, where communities, industrial parks, and microgrids can produce and store their own hydrogen to utilize in flexible applications.

There are various pathways for integrating green hydrogen into decentralized energy systems, as shown by Figure 6.1. These paths utilize surplus renewable energy by converting it into hydrogen through electrolysis and transportation via independent pipelines, blending it with natural gas, or storing it in underground storage for later use. Applications connected to the grid with battery storage can also enable further reliability and efficiency, whereas hydrogen-based applications enable long-duration energy storage and unconventional transportation methods (Kamran & Turzyński, 2024). The optimal path is a function of infrastructural readiness, economic feasibility, and technological readiness, with a holistic consideration of the pros and cons and potential trade-offs.

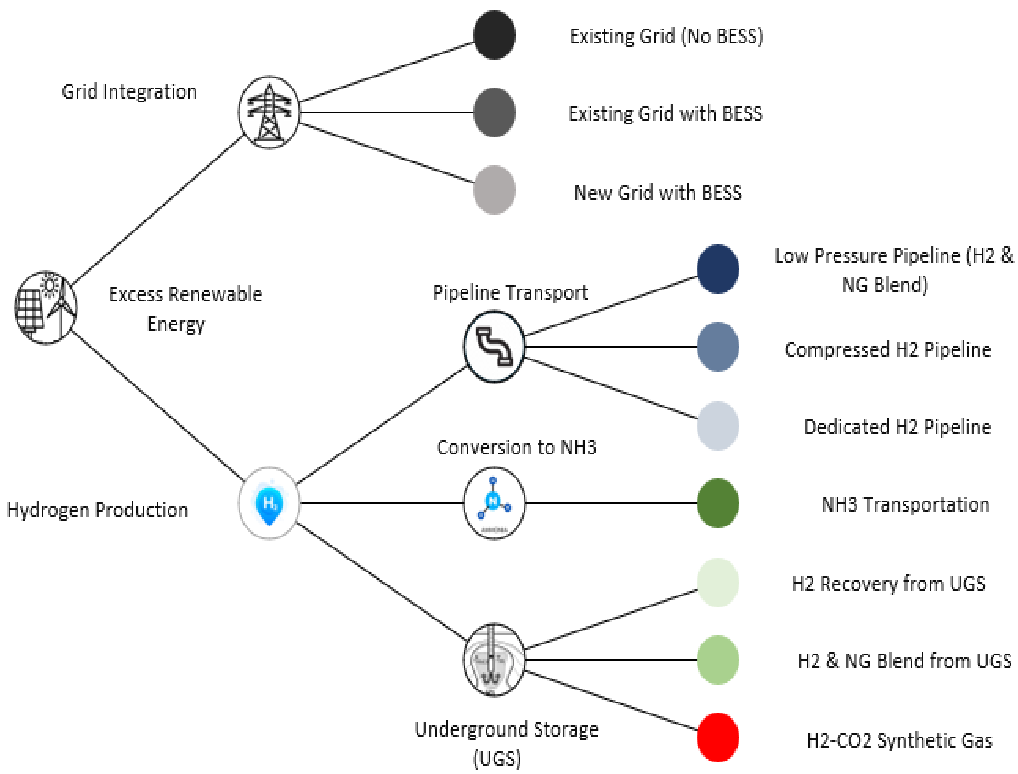

Figure 6. 1 Pathways for Green Hydrogen–Renewable Integration

6.1.2. Green Hydrogen Integration Pathways

Green hydrogen integration into the hydrogen energy system calls for an integrated solution that goes far beyond its production. After being produced by electrolysis, biomass gasification, or photocatalytic water splitting, green hydrogen must be stored, transported, distributed, and used to achieve its potential for decarbonizing the world energy system. These channels are central to enabling green hydrogen to be compatible with current and future energy infrastructure so that it can serve as one of the cornerstones of a clean energy economy. Integrating distributed RE systems, as discussed in Table 6.1, shows some of the common options for integrating green hydrogen into the larger energy system.

Table 6. 1 Distributed Renewable energy integration pathways.

SN	Code	Pathways Description
1	RE-xGrid	Connect surplus RE by using existing power grid.
2	RE+BESS-xGrid	Connect surplus RE plus battery system using current line.
3	RE+BESS-nGrid	Same with SN 2, but with new power line to main grid.
4	RE-H2-nPL	Converts surplus RE into H_2 through electrolysis and transports the H_2 via a dedicated pipeline (PL).
5	RE-NH3-nPL	Converts surplus RE into H2, then NH3, and transports with a new PL.
6	RE-H2NGblend-xPL	Blends H_2 produced from RE with natural gas (NG), utilizing existing low-pressure pipelines (LPP).
7	RE-C(H2NGblend)	Blends H_2 with NG into LPP and compresses NG to C(H2NGblend), suitable for HDV fuel.
8	RE-H2CO_2NGSyn-nPL	Produces H_2 and NG with RE, adds CO_2 to form synthetic gas for easier transportation via a new LPP.
9	RE-H2-UGS-H2NGblend-xPL	Inject H_2 produced from RE into UGS, later produce H2NG blend and transport in existing LPP.
10	RE-H2-UGS-C(H2NGblend)	Injected H_2 produced from RE into UGS, later produced H2NG blend, compress and transport as C(H2NGblend).
11	RE-H2-UGS-H2CO_2NGSyn-nPL	Inject H_2 produced from RE into UGS, produce H2NG mix, add CO_2 and transport as H2CO_2NGSyn in new LPP.
12	RE-H2-UGS-H2-nPL	Inject H_2 produced from RE into UGS, produce H2NG mix, separate H_2 and transport new resolute H_2 PL.

Storage is an integral part of the hydrogen energy system as it provides a safe and stable supply of hydrogen to cater to fluctuating demand. One of the common methods is compressed hydrogen storage, where hydrogen is kept in high-pressure vessels with pressures between 350 and 700 bars (Elberry et al., 2021). It is commonly used for transportation and small-scale use because its technology is quite straightforward. Another method is storage of liquid hydrogen, where hydrogen is cooled to cryogenic levels (-253°C) to condense it to liquid state, thereby minimizing its volume and allowing for large-scale storage and transportation over long distances (M. Yang et al., 2023). This does require a considerable amount of energy for liquefaction and sophisticated insulation to preserve the low temperatures.

Chemical storage offers an alternative by the conversion of hydrogen into chemical carriers such as ammonia, methanol, or liquid organic hydrogen carriers (LOHCs). These carriers can store hydrogen under ambient conditions and are thus easier to transport and handle (Distel et al., 2025). Ammonia, for example, is very promising because it has high hydrogen density and an existing global infrastructure of production and delivery (Bagheri et al., 2024; Sekhar et al., 2024). Storage can also be done underground, where hydrogen is contained within geological formations such as salt caverns, depleted oil and gas fields, or aquifers. It is suitable for long-term, high-capacity storage and can stabilize seasonally fluctuating supply (Salmachi et al., 2024; Zeng et al., 2024).

6.1.3 Transport and Distribution Pathways

Transport and distribution of green hydrogen will become the essential link between production points and end-users. Hydrogen pipelines are the most economical form of overland transport over long distances (Zhou et al., 2024). Special pipelines for hydrogen can be built, or hydrogen can be blended with natural gas in existing pipes, but the latter must be controlled so not to have compatibility problems. Hydrogen blending, where hydrogen is blended with natural gas in different ratios, offers a bridge route to blend hydrogen into existing natural gas infrastructure. This can make the usage of hydrogen gradually increase, without immediate expensive upgrading of infrastructure, that otherwise became necessary (Davis et al., 2023; NREL, 2022). Still, the proportion of hydrogen blended in such areas can safely depend upon existing infrastructure and kind of appliances at the end. In areas without pipeline transport, hydrogen is transported through road or rail transport. This is either by compressing hydrogen in specially fitted trucks and tankers or through the shipment of liquid hydrogen in other comparable tanks and tankers. Ocean freight is also available, mostly for export purposes, where hydrogen may be exported in liquid or chemical carrier forms such as ammonia. Hydrogen refueling stations are also a critical part of the supply chain, especially for transport. They provide the infrastructure for refueling hydrogen FCEVs including cars, trucks, buses, and trains. A large distribution of refueling stations is key to hydrogen powered transport consumption and as an alternative clean energy source (Halder et al., 2024).

6.1.4 Utilization Pathways

Green hydrogen is used in many different avenues in various sectors. Hydrogen is the major feedstock in industrial processing and refining, ammonia production, and steelmaking, where there is a volume of chemical manufacturing. Green hydrogen can be utilized to reduce carbon emissions significantly in these sectors in lieu of fossil fuel-based traditional hydrogen (Cao et al., 2024). Hydrogen in electricity generation is utilized either in fuel cells or as feed in gas turbines generating electricity; this is clean energy compared to producing energy from fossil fuels. This has utility in grid balance, where hydrogen can be stored renewable energy that is in surplus and delivered when demand peaks (Alzahrani et al., 2022; National Grid, 2020; Saberi Kamarposhti et al., 2024). A substantial market of use is also transportation, which fuel cell vehicles fueled by hydrogen are bringing as an alternate zero-emissions technology over the traditional internal combustion engine.

Hydrogen-powered cars, trucks, buses, trains, boats, and even airplanes are all being conceived and are entering the market, threatening to reshape the landscape of transport. Hydrogen is also used for energy storage over extended periods to bridge the intermittency of renewable sources of energy, such as solar and wind. In this way, storing excess renewable energy as hydrogen enables it to be reconverted to electricity or heat during periods of demand, thus enhancing grid stability and reliability (J. Wang & Chen, 2022). Hydrogen can also be blended into natural gas grids for domestic and commercial heating. It allows for an easy transition to cleaner fuels without mandating expensive, immediate, and costly upgrade of infrastructure all at one time (Erdener et al., 2023; NREL, 2022). The hydrogen blending with gas grids has potential in limiting carbon emissions from space heating, though emissions gain again rely on blending ratio. Pilot projects as well as research work are being formulated to quantify optimum amounts of blends and to address any technical considerations in terms of compatibility concerns with installed appliances and existing infrastructure.

6.1.5 Integration of Renewable Energy Systems

Green hydrogen has a significant role to play in the integration of renewable energy systems into the broader energy landscape. One of its prime roles is balancing the grid when hydrogen is used as a buffer to hold renewable energy in surplus during off-peak demand times and release it during peak times. This makes the grid more stable and helps in maintaining a level of energy supply. Power-to-X (P2X) technologies also boost green hydrogen's capability by converting it into synthetic fuels such as methane, methanol, or jet fuel (Torkayesh & Venghaus, 2025). Synthetic fuels can be used in hard-to-decarbonized sectors like aviation or heavy industry sectors which are not feasible to electrify. Hybrid systems involving the integration of hydrogen production with other renewable energy systems, such as solar-wind-hydrogen hybrids, offer an integrated strategy towards energy production and storage. The hybrid systems take advantage of the complementarity of different renewable energy sources to maximize hydrogen production and provide a safe supply of energy.

Table 6.1 shows various methods on uses of surplus renewable energy in green hydrogen networks integrated with transport, storage, and use. This list includes direct injection into the grid, the use of electrolysis in H_2 generation, blending with natural gas, underground storage (RE-H2-UGS-H2NGblend-xPL). Strategies also include the conversion of renewable energy to hydrogen or ammonia for pipeline-based transport, use of existing infrastructure, and synthetic gases for economic distribution. These corridors highlight the adaptability of green hydrogen in making the integration of renewable energy possible and supporting decarbonization.

6.1.6 Research Gaps in Green Hydrogen Integration

Despite the growing interest in green hydrogen as part of the energy transition, there are several key research gaps. Most research assesses the feasibility of one hydrogen pathway, such as production, blending, or storage, but not a comparative economic assessment of different integration options under alternative financial and policy conditions (M. Li et al., 2024; Mural et al., 2025; Muthusamy et al., 2024). Li et al. (2024) analyze the economic costs, energy efficiency, and CO_2 emissions of liquefied hydrogen (LH_2) and ammonia (NH_3) as hydrogen carriers in large-scale production and long-distance transportation. However, they do not evaluate a broad range of hydrogen integration options across DES, especially in the context of policy and financial conditions. Muthusamy et al. (2024) studied how to maximize hydrogen production from hybrid renewable power systems using AI-modeling methods but not making comparative examination across different integration pathways. Mural et al. (2025) are exploring policy levers, namely subsidies and demand-side incentives for clean hydrogen deployment but not conducting overall assessment across different hydrogen integration pathways for different financial and policy scenarios.

A combined assessment considering alternative pathways within one framework is needed to guide strategic decision-making. In addition, current economic literature tends to call for policy clarity (Bade & Tomomewo, 2024), neglecting the uncertainties that are associated with carbon taxes and government subsidies. By not accounting for policy uncertainty, financial projections can misrepresent the true economic attractiveness of hydrogen investments. A probabilistic approach that simulates such uncertainties is needed to produce risk-adjusted financial analysis. Furthermore, investment risk analysis in hydrogen projects is deterministic, failing to consider variability in CAPEX, OPEX, and electricity prices, which are critical for decision-makers and investors. Information on such variability is key to rendering hydrogen integration strategies economically viable in the long term. A second key gap is a lack of sensitivity analysis on market conditions, particularly regarding which hydrogen pathways are most sensitive to policy stimulus and economic uncertainty. Identifying the most resilient investment prospects will help to prioritize paths that are immune to changing financial conditions. While much research has been researched on hydrogen production and blending, long-term underground hydrogen storage feasibility is still largely unexplored. Underground hydrogen storage can stabilize seasonal energy supply, enhance grid reliability, and facilitate large-scale hydrogen deployment (Adams et al., 2024), but its technical and economic challenges require further research. It is the bridging of these gaps that is most important to secure good, risk-adjusted conclusions about the economic viability and policy-driven feasibility of utilizing green hydrogen in decentralized energy systems.

6.1.7 Leveraging Existing Infrastructure

A hydrogen economy can be achieved sooner by utilizing existing infrastructure, i.e., retrofitted natural gas pipelines, and refurbishing depleted oil and gas reservoirs for hydrogen storage (Morales-España et al., 2024; Terenzi et al., 2024). Texas, with an advanced energy infrastructure network, can benefit from these opportunities. To provide evidence-based results for the optimization of hydrogen rollout, the study considers scenarios of various investment cases, infrastructure requirements, regulatory dimensions, and market conditions. The analysis helps stakeholders, policymakers, and decision-makers develop the necessary plans for the integration of green hydrogen into tomorrow's energy supply chains. It has proven to be technically viable to blend hydrogen up to 20% with natural gas in existing pipeline infrastructure with minimal modifications (Cuadrado et al., 2025). But at higher concentrations, there needs to be material enhancement to avoid embrittlement and leakage, necessitating strategic investment in infrastructure modification (Behvar et al., 2024; Meda et al., 2023).

The second major opportunity is large-scale hydrogen storage using depleted oil and gas reservoirs. Such geologic reservoirs, already utilized before in hydrocarbon production, are the low-cost and secure hydrogen storage medium. Underground hydrogen storage improves energy security in the way it is a resource that offers constant supplies during periods of changing demands and enables seasonal storage to firm the intermittent of renewable energy. Texas has various depleted reservoirs that can be used for the storage of hydrogen, thus placing the state on the list as a viable destination for large hydrogen projects (Evro, Oni, et al., 2025). Using these already existing assets promotes economic and environmental benefits from the elimination of a need for new infrastructure development and bringing the mature assets to life in a sustainable fashion. Stakeholders and policymakers will have to consider regulatory reforms as well as investment incentives that can support reconversion of conventional oil and gas assets to hydrogen use to make the green hydrogen deployment economical and scalable.

6.1.8 Study Objectives and Scope

The objective of this study is to bridge important gaps in the economic, technical, and environmental evaluation of the integration of green hydrogen into DES and more importantly policy and investment risk. In comparing 12 various hydrogen integration paths, this study provides an integrated cost-benefit analysis (CBA) that systematically evaluates economic feasibility about CAPEX, OPEX, revenue sources, and long-term return on investment, considering policy support such as carbon tax and subsidy. Prior work that has been conducted on a single hydrogen integration path varies from the present study, which accounts for several alternatives like hydrogen production, blending, synthesis of ammonia, and storage underground, for several governmental supports in the form of subsidies and carbon tax.

For resolving policy uncertainty and market risk, Monte Carlo simulations are used to capture probabilistic variation of the key financial parameters to make the results more realistic and risk adjusted. The research also analyzes market sensitivity and pathway optimization and finds out which hydrogen pathways depend most on policy support and are most sensitive to economic cycles. Since Texas has enormous renewable energy sources, advanced energy infrastructure, and increasing hydrogen investments, it is an ideal case study for the examination of opportunities and challenges of integrating hydrogen in a decentralized energy system. Based on various investment strategies, infrastructure requirements, and policy frameworks, this study presents evidence-based conclusions to guide decision-makers, policymakers, and stakeholders in maximizing the use of green hydrogen as a clean energy source.

6.2 Regulatory barriers and enablers

The transition towards renewable energy sources worldwide is prioritizing climate change mitigation and sustainable development (Adelekan et al., 2024). Consequently, DES and green hydrogen have emerged essential building blocks in achieving long-term sustainable energy goals (Gallegos et al., 2024). The DES are designed to decentralize power generation relying on local renewables, energy storage systems, cogeneration plants or combined heat and power (CHP), demand response technologies and microgrids. These systems enhance grid reliability, energy efficiency, reduce greenhouse gas emissions thus raising significant technical integration challenges, economic justification issues along with policy making frameworks sometimes at odds with these technological advancements towards sustainability.

Various research articles have emphasized the importance of integrating green hydrogen into DES. For example, the research by Brozynski and Leibowicz (2018) critically analyses Austin's Community Climate Plan and explains that urban scale decarbonization requires an interplay of solar PV expansion, wind energy integration, and smart battery storage management operations (Brozynski & Leibowicz, 2018). A case study in the review underscores hydrogen's role as a carbon-free energy carrier while optimizing energy systems thereby reducing emissions. Hydrogen has been viewed as one of primary vectors for ammonia production to help achieve global carbon neutrality (Evro, Oni, et al., 2024). The work of de la Cruz-Soto et al. (2024) showed that the economic viability of green hydrogen projects could be improved through Power-to-Gas (P2G) system integration, resulting in a decrease in the Levelized Cost of Hydrogen (LCOH) (de la Cruz-Soto et al., 2024). Efficiency and versatility of water electrolysis have been emphasized by Kamran and Turzyński (2024), despite its more costly nature than other methods such as pyrolysis (Kamran & Turzyński, 2024). The review also highlights applications for hydrogen in renewable energy systems, transportation, and industrial processes with an emphasis on the need to undertake future research and development towards establishing a cost-effective hydrogen economy. Bade et al. (2024) conduct a critical examination of governance strategies and regulatory frameworks for hydrogen energy in the United States. These authors identified three main barriers to adoption of hydrogen; fragmented regulations; lack of national law; underfunded long-term initiatives. As such it calls for a cohesive framework, substantial infrastructure investment and collaboration among stakeholders to advance the hydrogen economy (Bade et al., 2024).

Nandhini et al. (2023) stress on sustainable production of hydrogen/ carbon capture/utilization & storage technologies within DES for optimization of green hydrogen initiative (Nandhini et al., 2023). To attain neutrality regarding carbon emissions efficient infrastructure should be put in place to facilitate transport as well as storage capabilities for high volumes of compressed gases especially H_2 within DES territories at large scale perspective such as carbon neutrality. Robust and reliable methods of storing and transporting hydrogen from local production sites to points of use are essential in DES. In complementation to other renewable energy technologies, hydrogen plays a key role in addressing the issue of intermittent that comes with renewable sources such as solar and wind (Q. Hassan et al., 2024). By integrating multiple renewable energy sources, Hai et al. (2024) seeks the development of more efficient hydrogen production systems that maximize efficiency and fit within the distributed aspect of DES (Hai et al., 2024). This approach reduces reliance on non-renewable sources and takes advantage of local renewables. These perspectives emphasize the need for well-thought-out infrastructure supporting hydrogen production, storage, and distribution within DES. Traditional barriers can be overcome by these strategies so that DES may contribute to sustainable, resilient energy systems while enhancing energy security in distributed networks thereby promoting a decentralized type of clean energy.

Cumulatively, these studies call for efficiency improvements, cost reductions (Davis et al., 2023), innovative system designs (Chang et al., 2023), supportive policies and social acceptance among other facets critical for expanding green hydrogen production and utilization (Blohm & Dettner, 2023; Leite et al., 2024). Thus, successful incorporation of these routes into distributed energy system involves tackling both technical and non-technical aspects; harnessing advancements in technology; establishing an enabling regulatory environment; and promoting positive economic infrastructure setup. All these things will help make sure green H_2 realizes its full potential as it seeks to serve as one of the pillars behind a sustainable and resilient future for humankind.

The integration of Cost-Benefit Analysis (CBA) with probabilistic modeling facilitates more sustainable hydrogen investment decision-making via economic feasibility and risk-adjusted analysis. This study employs CBA via a comprehensive Net Present Value (NPV) analysis, encompassing key financial parameters such as capital expenditures (CAPEX), operational expenditures (OPEX), product prices, and carbon tax rates. By government subsidy policy simulation and carbon taxation, a Monte Carlo Simulation evaluates uncertainties to generate probabilistic NPV distributions. It identifies cost-optimal green hydrogen integration pathways while flagging risk for investment. The outcomes present policymakers, investors, and developers with real-world solutions to achieving decarbonization targets in DES.

6.3 Methodology

Figure 6.2 illustrates the systematic step-by-step Cost-Benefit Analysis (CBA) with Probabilistic Modeling applied in this study to assess the financial viability of green hydrogen integration pathways. The methodology includes key steps such as cost identification, price estimation, discounted cash flow (DCF) analysis, sensitivity analysis, and the ranking of pathways based on economic performance indicators. The modeling steps include:

- Capitalization of Costs and Revenue Sources. All costs associated with the 12 hydrogen integration pathways—including capital expenditures (CAPEX).

- Operational expenditures (OPEX), and maintenance expenses—were capitalized as investment costs.
- Revenue streams, such as the sale of hydrogen, electricity, and ammonia, were also incorporated into the financial model.

The Net Present Value (NPV) Model incorporating policy incentives and emission reductions is presented in equation 6.1. The Net Present Value (NPV) of each pathway was determined by discounting future cash flows, ensuring an accurate representation of long-term economic viability while accounting for the time value of money.

Equation 6. 1 Policy-Adjusted NPV Model

$$\boldsymbol{NPV_p = \sum_{t=1}^{T} \frac{(R_t - C_t + P_s \cdot S_t + P_t \cdot T \cdot E_t)}{(1+r)^t}} \quad (6.1)$$

Where:

R_t = Revenue from hydrogen or energy production based on market prices.

C_t = Operational costs, including OPEX for each pathway.

P_s = Probability of receiving a government subsidy.

S_t = Government subsidy provided for hydrogen deployment.

P_t = Probability of carbon tax implementation.

T = Carbon tax rate applied to emissions reduction.

E_t = Emission reduction (CO_2 abated).

Emission Reduction Calculation (E_t)

The emission reduction (E_t) is a key metric in this study, representing the amount of CO_2 abated by displacing current fossil fuels with green hydrogen or renewable energy pathways. The formula for calculating E_t is as follows in equation 6.2:

Equation 6. 2 Emission Reduction Calculation (E_t)

$$\boldsymbol{E_t = \sum_{i=1}^{n} D_i \cdot \left(EF_{i,\mathbf{fossil}} - EF_{i,\mathbf{hydrogen}}\right)} \tag{6.2}$$

Where:

E_t= Total emission reduction in tons of CO_2 per year represents the amount of CO_2 avoided by replacing fossil fuels with green hydrogen or renewable energy.

D_i= Displaced energy for pathway i, measured in MWh (for electricity) or kg (for hydrogen/ammonia). This is the amount of energy produced by the green hydrogen or renewable energy pathway that displaces fossil fuel-based energy.

$EF_{i,\mathrm{fossil}}$ = Emission factor of the displaced fossil fuel for pathway i, measured in kg CO_2 per unit of energy (e.g., kg CO_2/MWh or kg CO_2/kg fuel). It represents the CO_2 emissions associated with the fossil fuel being replaced.

$EF_{i,\mathrm{hydrogen}}$ = Emission factor of the green hydrogen or renewable energy pathway i, measured in kg CO_2 per unit of energy. It represents the CO_2 emissions associated with green hydrogen or renewable energy production.

n = Number of energy applications or pathways being considered (e.g., electricity, hydrogen, ammonia).

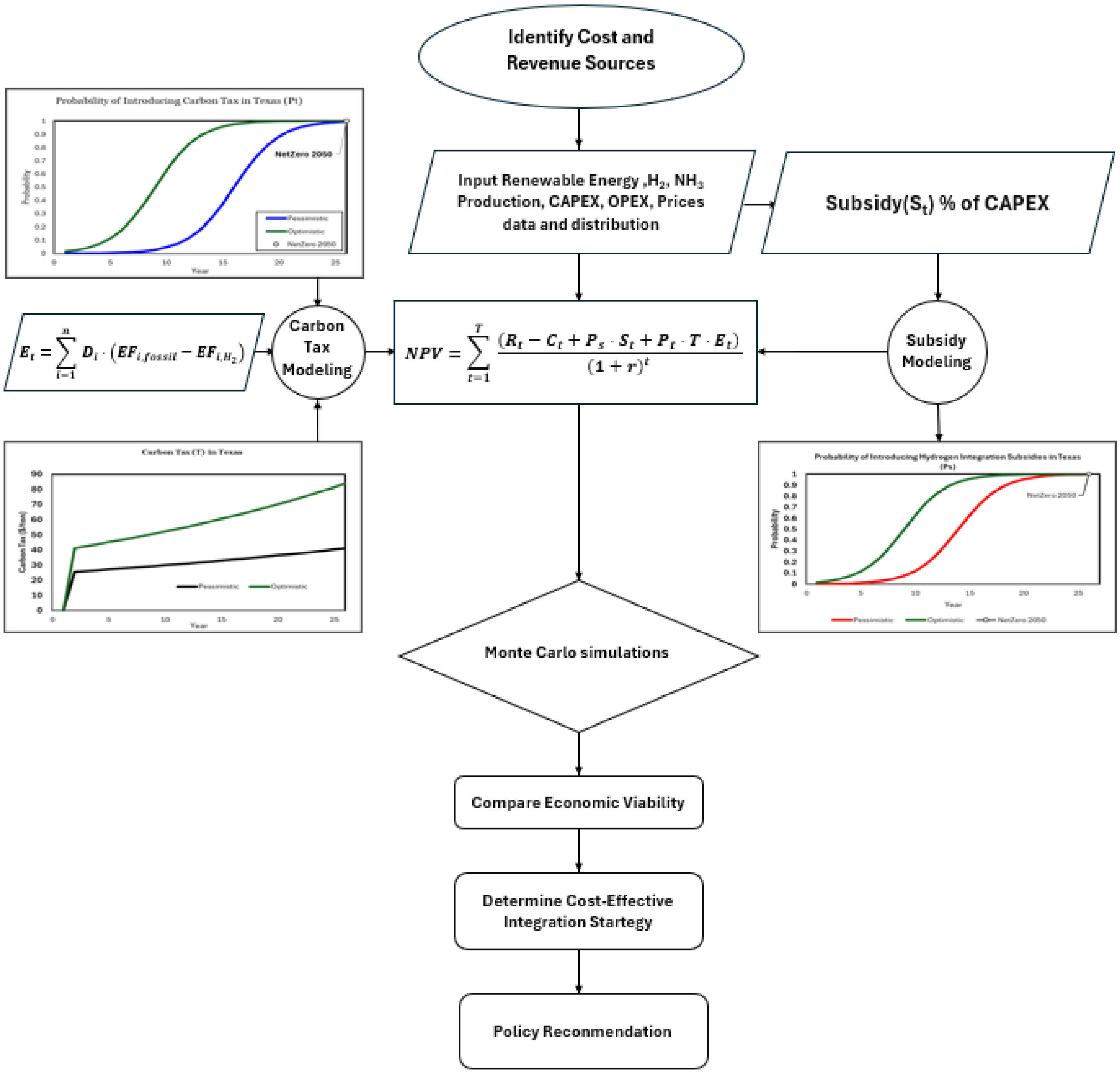

Figure 6. 2 Cost-Benefit Analysis (CBA) with Probabilistic Modeling.

Economic Performance Metrics (NPV & IRR). The financial viability of each integration pathway was assessed using NPV and Internal Rate of Return (IRR) as key indicators. These metrics provide insights into the profitability and investment potential of each hydrogen integration strategy.

Ranking Pathways for Cost-Effectiveness. Pathways were ranked based on their NPV and IRR performance. The most economically efficient pathways, which demonstrated the highest financial returns under different policy scenarios (e.g., with and without subsidies or carbon taxes), were identified as the most optimal for green hydrogen integration.

This analysis provides policymakers, investors, and project developers with risk-adjusted financial insights, enabling data-driven decision-making for the adoption of green hydrogen in DES. By incorporating Monte Carlo simulations, this study ensures that investment decisions account for policy uncertainties, market fluctuations, and technological risks, improving the financial feasibility of sustainable hydrogen projects.

6.4 Texas Renewable Energy and Hydrogen Integration Case Study

This evaluation uses Cost-Benefit Analysis (CBA) with Probabilistic Modeling in assessing the economic feasibility of various integration routes of green hydrogen. In identifying the most cost-effective method of integrating green hydrogen into Texas's energy system, CBA balances economically estimated benefit against estimated cost. The key financial parameters considered include operating expenses, capital expenditures, cash inflows, Net Present Value (NPV), and Internal Rate of Return (IRR). Through an analysis of various investment alternatives, infrastructure needs, and market conditions, this study offers empirically supported conclusions to inform strategic decisions. Policymakers and investors can use CBA with probabilistic modeling to evaluate the financial feasibility of hydrogen deployment in Texas' dynamic energy system.

The specific case study focuses on Texas state which has been historically known for its large oil and gas industry. Texas presents several favorable factors making it an ideal candidate for integrating green hydrogen into its energy system as seen in Figure 6.3 (NREL, 2024). Abundant solar and wind resources are available in Texas. The sun-drenched flatlands and extraordinarily high winds that blow throughout the year make it a suitable place to build big solar PV or wind projects. The US's sharp decrease in photovoltaic (PV) solar costs along with wind projects is due to ongoing reductions in the cost of renewable energy projects. Moreover, declining electrolyzer costs have further boosted the viability of green hydrogen production in Texas, enhancing its competitiveness in the renewable energy sector.

Additionally, Texas boasts a vast system of power transmission lines and natural gas pipelines and thus has the best location to incorporate green hydrogen into the energy system (see Fig. 4). Certain depleted unconventional oil and gas reservoirs in the state are a good opportunity for the large-scale storage of hydrogen (Bao et al., 2023; Evro, Oni, et al., 2025; Zeng et al., 2024), as they can be repurposed to store a significant volume of hydrogen safely and efficiently. Their use offers economic advantages through available infrastructures, where the capital cost of new storage facilities will be minimized if they do not need to be built from scratch (Evro, Oni, et al., 2025).

Texas also possesses an extensive network of pipelines originally constructed to carry gas and oil but that can now be utilized for state and interstate transport of hydrogen, ammonia, and hydrogen-natural gas blends. The HyVelocity H2Hub, in which $1.2 billion has been invested, is just one instance of Texas investing in hydrogen's green development. Its position allows it to take advantage of the state's rich renewable energy resources and infrastructure to export hydrogen and ammonia and enhance energy security and economic opportunity.

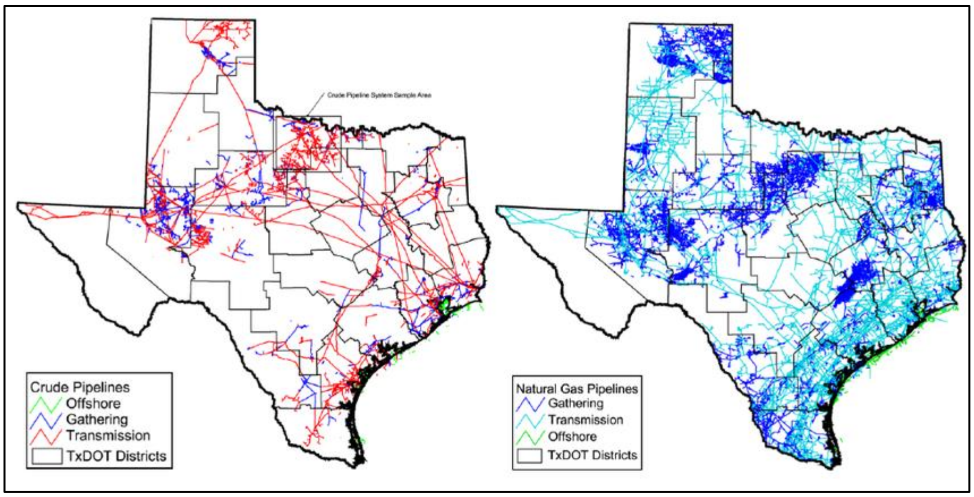

Figure 6. 3 Texas Pipeline network (Arturo & Juan, 2012)

Excess renewable energy can be diverted to hydrogen production for export or intrastate commerce. Blending hydrogen with natural gas leverages exist infrastructure, expanding market access. Hydrogen blending for local consumption, free natural gas for LNG exportation, optimizing energy commerce. This approach optimizes distribution without reducing natural gas exports. Texas is at the forefront of green hydrogen integration with sufficient renewables, cheap electrolyzers, extensive pipelines, and significant investments.

6.4.1 Cost-Benefit Analysis with Probabilistic Policy Scenarios

Identifying cost and revenue sources is a key step in this research to evaluate the economic feasibility of green hydrogen integration pathways. Costs are distinguished as capital expenditure

(CAPEX) as an initial investment in infrastructure, electrolyzers, pipelines, storage facilities, distribution networks, and operational expenditures (OPEX), covering maintenance, electricity consumption, labor, and other routine expenses. These also encompass policy-imposed costs such as carbon taxes and regulatory charges. On the revenues side, the key sources of revenues are the sale of electricity, hydrogen, and by-products such as ammonia, along with potential fiscal incentives in the form of government subsidies and revenue from carbon credits. By methodical identification and incorporation of such revenue and cost considerations, this study ensures realistic and thorough financial assessment of all avenues of integration to provide realistic comparison of their long-run profitability and feasibility.

However, the cost of renewable energy was treated as a sunk cost and was not included in the capital cost calculations for all identified integration pathways. This means that these costs are excluded from capital cost calculations in the financial model. Some key considerations justify assuming renewable energy spending as a sunk cost in green hydrogen integration pathways decision-making. First the sunk costs are irretrievable and do not apply to future decision-making. If the renewable infrastructure of solar, wind, or hydroelectric is already in place and operating, its cost is not dependent upon whether the energy is used in electricity supply or hydrogen production. Since the decision on hydrogen integration is a matter more of optimizing fresh investment and not recovering sunk costs, incremental costs and benefits must be the focus area.

Second, since there is existing renewable energy infrastructure, the marginal cost of using the energy is more relevant than the initial capital cost of the energy. Wind and solar resources both have a marginal cost of zero because they do not require fuel once installed. Thus, integration of hydrogen needs to be assessed on the basis of incremental costs of electrolyzers, storage, and distribution infrastructure, rather than past renewable energy investments. In addition, most renewable ventures are supported or subsidized by feed-in tariffs (FiTs), tax credits, or power purchase agreements (PPAs) spanning a few years (Hoogstede, 2024; Marta, 2024). These policy incentives lower most of the capital needs in advance, and therefore it would be unimportant to factor them into assessing hydrogen integration costs. Just new capital spending for hydrogen production needs to be covered, providing a more accurate financial perspective to investors and policymakers.

Also important is the LCOH, which is just such a key measure of relative competitiveness of green hydrogen. Including renewable energy costs in LCOH calculations can inflate hydrogen's perceived cost, making it seem less viable than it is. This may mislead decision-makers into wrongly dismissing hydrogen integration. Instead, LCOH should be based on actual electricity costs (e.g., grid prices, PPAs, or curtailed power) rather than past investments for a more accurate financial assessment. Treating the cost of renewable energy as a sunk cost accords with the principles of economics and offers realistic assessment of routes of hydrogen integration.

The model data presented in Table 6.2 outlines the pertinent factors and financial estimates for renewable energy electricity, pipeline and grid lengths, pressure specifications, construction costs and plant capacities needed to evaluate green hydrogen integration.

Table 6.3 presents capital expenditures for paths one through three, which involve off-grid extension and battery energy storage systems. Costs are broken down by component (grid and BESS), thus providing a complete pathway cost per unit. They explain why it would be necessary to either extend the power grid or add some storage capabilities based on each case.

Table 6. 2 Model Cost Data

Description	Value	Unit	Ref
RE Electricity	10	mW	
Pipeline Length	10	km	
Electric Grid length	10	km	
Natural Gas Pipeline (36 inch) Cost	2.6	$mm/km	(HartEnergy, 2024)
Pure Hydrogen Gas PL Construction Cost	3.00	$mm/km	(Cook & Hagen, 2024)
Grid Line Construction Cost	310,000	$ / km	
Alkaline Hydrogen Plant Capacity	4,152	kg/day	
Alkaline Hydrogen Plant Capacity	173	kg/h	
Mid-size natural gas compressor 100 HP	37,500	$ per unit	
Mid-size H_2 gas compressor 100 HP	100,000	$ per unit	
RE Energy Capacity	10	mW	

Table 6. 3 Capital Cost for Grid Related Pathways (million USD)

SN	Description	Grid ($mm/km)	BESS	Total	Justification
1	RE-xGrid	1.0	-	1.0	Only grid extension required.
2	RE+BESS+xGrid	1.5	5.0	6.0	Grid extension + BESS.
3	RE+BESS+nGrid	3.0	5.0	8.1	BESS and new grid connection

Table 6.4 provides capital expenses for selected plants and infrastructure necessary for some of the pathways, including an Alkaline Hydrogen Plant, Ammonia Plant, Reservoir Injection, Production, and Treatment facilities, and CO_2 Plant Cost. These numbers are related to scaling up more complex solutions regarding chemical processes along with storing them.

Table 6. 4 Plant and Other Capital Costs (million USD)

Plant and Other Capital Cost	Amount ($ million USD)
Alkaline Hydrogen Plant	15 (James et al., 2022)
Ammonia Plant Cost	5 (Thundersaidenergy, 2022)
Reservoir Injection, Production, and Treatment Cost	10 (Curtis, 2015)
CO_2 Plant Cost	2 (Rubin et al., 2015)

While Table 6.5 provides additional information about capital expenditure for pipeline and underground storage related pathways. It details pipeline costs together with overall project expenditure reasons such as resolute H_2 pipes versus natural gas mixers whereby blending acts as a way of managing those gases while making sure that they are used efficiently.

The cost estimates include capital costs based on the latest market data for infrastructure development, such as grid connection, battery energy storage systems (BESS), hydrogen production plants and pipeline construction etc. and annual operating expenses estimated from average industry fixed figures and those of existing facilities. A baseline discount rate of 8.5% is used to calculate the Net Present Value (NPV) of future cash flows. The 8.5% discount rate is justified by several techno-economic studies of renewable energy plants. Alıç (2024) obtains IRRs of 7.61-11.64%, which falls within an acceptable range for investments in hydrogen (Alıç, 2024). While Demirci et al. (2023) suggest higher discount rates (6-10%) are acceptable for the purpose of justification of grid extensions and therefore 8.5% is appropriate for high-capital-cost hydrogen projects (Demirci et al., 2023). The revenue projections assume stable electricity, hydrogen, ammonia energy prices throughout a 20-year period and constant market demand for hydrogen and renewable energy products. Technological efficiency estimates are based on prevailing levels for electrolysis, hydrogen blending as well as ammonia synthesis with fixed percentages considered for energy losses during both storage and transportation processes.

Table 6. 5 Capital Cost (million USD) for Pipeline and UGH Pathways

SN	Short Description	Pipeline	Total	Justification
4	RE-H2-nPL	30	49	H_2 plant and resolute H_2 PL.
5	RE-NH3-nPL	30	55	H_2 to NH3 plus PL for ammonia.
6	RE-H2NGblend-xPL	17.5	38.5	Existing LPP for H2-NG blend.
7	RE-C(H2NGblend)	17.5	39.5	Plus, compression for CNG.
8	RE-H2CO_2NGSyn-nPL	30	55	CO_2 prod, new PL for syngas and
9	RE-H2-UGS-H2NGblend-xPL	30	64	UGS inj. & prod. and PL cost.
10	RE-H2-UGS-C(H2NGblend)	30	65	UGS inj. & prod. and CNG production.
11	RE-H2-UGS-H2CO_2NGSyn-nPL	30	68	UGS inj. & prod. CO_2, H2, NG blend, and new PL.
12	RE-H2-UGS-H2-nPL	30	67	UGS inj. & prod. and new H_2 PL.

For analysis purposes, the following sources have been used: cost estimates in terms of capital expenditure were extracted from reports by industries, cost bases of certain project data sets like NREL's reports on renewable power infrastructures, IEA's books on hydrogen production costs; standards provided by Hydrogen Council etc. Operating costs were determined using reports related to previous projects that coincided with industry guidelines about maintenance costs along with spending records pertaining to similar utilities or facilities. Revenue projections are based on data obtained from price forecasts.

Table 6.6 shows operational costs per year for each pathway, which gives insights on the annual spending required to run and keep the system operating. These include grid control, battery cycling, chemical handling, and maintenance of high-pressure gas blends and underground storage systems. It helps determine if the pathways will be financially sustainable after implementation. Similarly, Table 6.7 provides the data on losses experienced and prevailing prices for various products with respect to the process flow of each pathway in terms of conversion efficiencies and blending of gases.

The cost components for a pure gaseous hydrogen pipeline include several key parameters, such as pressure drop per kilometer, power required to overcome friction, number of booster stations, and the costs of compressor stations and pipes (Lullo et al., 2022). Each booster station requires significant power and incurs substantial costs. Additionally, the costs of the pipes themselves and the associated compressor stations contribute to the total capital expenditure, which scales with the pipeline length. Maintenance costs for pumps and pipelines also increase with the pipeline's length, leading to higher total operating costs for longer pipelines (Lullo et al., 2022).

Hydrogen pipelines entail much higher costs for initial construction and ongoing operations than natural gas pipelines. Specifically, they are about 3.63 times more costly in capital expenditure and 6.35 times more expensive in annual operating costs (Lullo et al., 2022). This substantial cost difference highlights the financial considerations that need to be addressed when planning for hydrogen pipeline infrastructure compared to more traditional natural gas pipelines.

Table 6. 6 Operational Cost ($/year)

SN	Description	OPEX	Justification
1	RE-xGrid	40,000	Low operational costs due to efficient grid management.
2	RE+BESS-xGrid	90,000	Higher due to battery systems, energy management and storage cycling.
3	RE+BESS-nGrid	105,000	New grid setup costs, with battery, are higher due to new installations.
4	RE-H2-nPL	150,000	High H_2 systems and pipeline, costs for compression and purification.
5	RE-NH3-nPL	180,000	Ammonia synthesis equipment, operational costs include chemical handling and transport.
6	RE-H2NGblend-xPL	120,000	H2-NG blend maintenance, moderate.
7	RE-C(H2NGblend)	135,000	Compression and pipeline excessive costs.
8	RE-H2CO_2NGSyn-nPL	225,000	New lines and multiple gases increase costs.
9	RE-H2-UGS-H2NGblend-xPL	240,000	UGS requires significant costs due to pumping and monitoring.
10	RE-H2-UGS-C(H2NGblend)	255,000	UGS requires significant costs due to pumping and monitoring, plus costs for compression.
11	RE-H2-UGS-H2CO_2NGSyn-nPL	270,000	Extremely high due to the complexity of handling CO_2, H2, NG blends, compression & safety.
12	RE-H2-UGS-H2-nPL	225,000	New H_2 line stringent maintenance, driven by purity needs and compression.

Table 6. 7 Pathways, losses, and product prices

SN	Description	Losses (%)	Price	Unit	Remark
1	RE-xGrid	5	0.1	$/kWh	Typical utility rates.
2	RE+BESS-xGrid	10	0.15	$/kWh	Higher storage value-add
3	RE+BESS-nGrid	10	0.15	$/kWh	Higher storage value-add.
4	RE-H2-nPL	15	5	$/kg	Green hydrogen.
5	RE-NH3-nPL	20	0.5	$/kg	Ammonia as a chemical or fuel.
6	RE-H2NGblend-xPL	12	3.5	$/kg	Less than H_2 less cost NG
7	RE-C(H2NGblend)	18	4.4	$/kg	Compressed blend.
8	RE-H2CO_2NGSyn-nPL	20	4	$/kg	Syngas industrial use
9	RE-H2-UGS-H2NGblend-xPL	25	3.1	$/kg	High target O&G markets.
10	RE-H2-UGS-C(H2NGblend)	25	4.4	$/kg	High O&G markets.
11	RE-H2-UGS-H2CO_2NGSyn-nPL	25	4	$/kg	Priced for industrial uses.
12	RE-H2-UGS-H2-nPL	25	5	$/kg	Pure H_2 unique use.

Similarly, the cost components for an ammonia pipeline include several key parameters, which scale with the length of the pipeline. Both technical characteristics, such as pressure drop per kilometer, total power required to overcome friction, and the number of booster stations, and associated expenses, such as costs for pumps, buildings, substations, tanks, and pipes, contribute to the overall costs (Lullo et al., 2022). Capital costs are substantial, with significant increases as the pipeline lengthens, and operating costs, including maintenance, wages, and electricity, also rise proportionally. This general trend highlights how both capital and operating expenses escalate with the extension of the pipeline (Lullo et al., 2022).

As shown in Figure 6.4, ammonia, blended gas, and hydrogen cost more than natural gas pipelines. Existing data and industry reports indicate that there is wide variation in total investment costs and operational expenditure among diverse types of pipelines compared to natural gas. Capital cost ratios of ammonia (NH_3) pipelines range from 1.3 to 2.8 while operating cost ratios are between 1.2 and 3.1, indicating a significant spread based on research type as evidenced by the differences technological and infrastructure requirements (Lullo et al., 2022; NREL, 2022; UKGOV, 2021; National Grid, 2020). In contrast, blended hydrogen, and natural gas (H2NG) pipelines show little disparity in capital cost ratios (between 1.1 and 1.5) or operations cost ratios (from 1.1 to 1.8), suggesting a uniform semblance of costs (Thundersaidenergy, 2022; NREL, 2022; UKGOV, 2021; National Grid, 2020). Pure hydrogen (H_2) pipelines have the highest multiples with capital cost ratios ranging from approximately three times to six times higher than that for natural gas pipelines depending on scale efficiencies while operation costs rise even much further [Lullo et al., NREL & UKGOV]. These variations highlight the complications involved in economic prediction in relation to new energy infrastructures, especially regarding changing technologies and increased economies of scale.

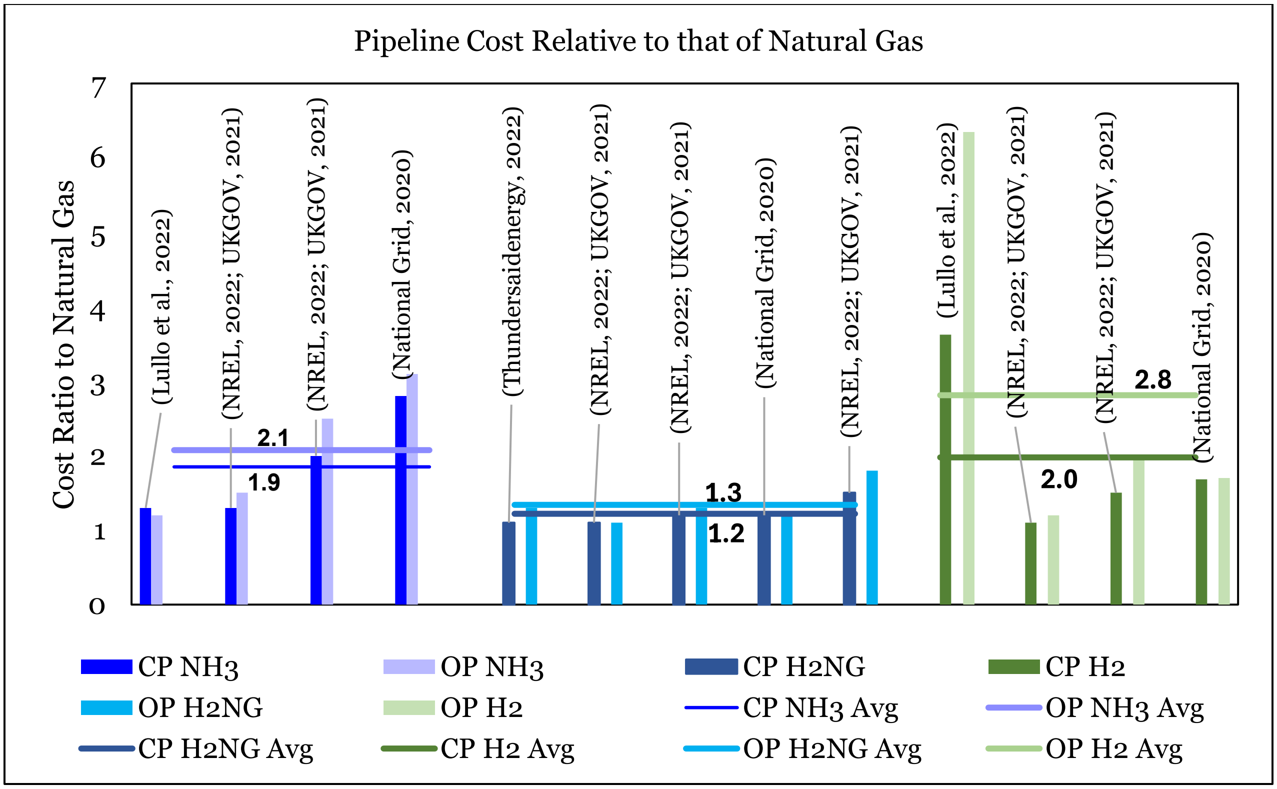

Figure 6. 4 Pipeline Cost Relative to Natural Gas

6.4.2 Probabilistic Policy Modeling

The introduction of subsidies for hydrogen integration is subject to policy uncertainty, making it necessary to model probabilistic scenarios for subsidy implementation. In this study, we model the subsidy term as presented in equation 6.3:

Equation 6. 3 Subsidy Value Equation

$$\textbf{Subsidy}_t = \boldsymbol{P_s} \times \boldsymbol{S_t} \tag{6.3}$$

where Subsidy_t is the effective subsidy in year t, P_s is the probability of the government implementing the subsidy (S_t), and the base subsidy is assumed to be 20% of CAPEX in the base case scenario. The probability of subsidy implementation (P_s) is projected from 2025 to 2050, where Net-Zero targets by 2050 dictate that the probability must reach 1 by that year. However, different policy adoption pathways, such as pessimistic and optimistic scenarios, introduce variability in how subsidies are rolled out. The probability of introducing subsidies is modeled using a logistic growth function to ensure smooth transitions between low and high adoption phases:

Equation 6. 4 The probability of implementing subsidies.

$$\boldsymbol{P_s(t)} = \frac{\mathbf{1}}{\mathbf{1}+\boldsymbol{e^{-k(t-t_0)}}} \tag{6.4}$$

where:

$P_s(t)$ is the probability of introducing subsidies at time t,

k is the logistic growth rate, controlling how quickly policies are implemented,

t_0 is the midpoint year where subsidy adoption reaches 50%.

As shown in Figure 6.5, for the pessimistic scenario, $t_0 = 2038$ and $k = 0.504$, meaning slower adoption due to political and economic barriers. In this case there are no subsidies until 2032 due to political resistance, gradual increase from 10% to 40% between 2033–2037, and full implementation (100%) is delayed until 2043.

For the optimistic scenario, $t_0 = 2033$ and $k = 0.517$, implying earlier and faster adoption. Similarly in this case the subsidies start appearing by 2030 (20%), with rapid acceleration (70%–

95%) between 2035–2039 and full implementation is achieved by 2040, in alignment with Net-Zero goals. A balance between pessimistic and optimistic trends, with slow but steady growth, reaching full subsidy adoption by 2045 was as the average scenario.

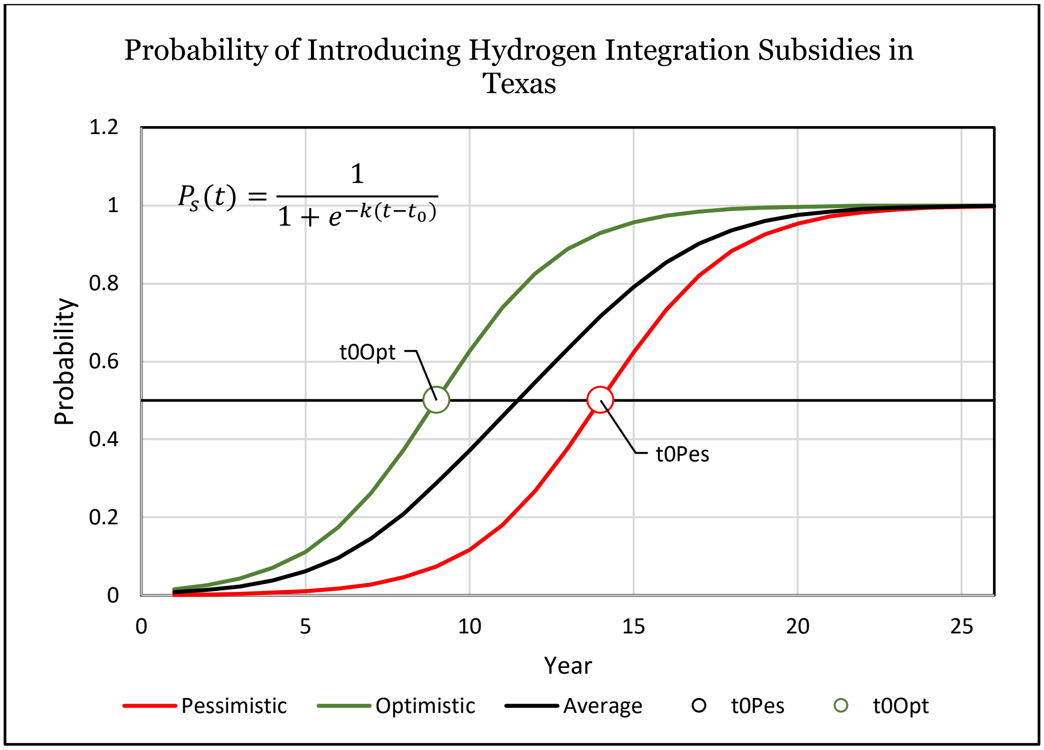

Figure 6. 5 Hydrogen Subsidy Adoption Scenarios in Texas.

This probabilistic subsidy modeling framework allows for a realistic assessment of policy impacts on hydrogen integration. The analysis shows that the pace of hydrogen subsidy implementation is highly dependent on political will, economic conditions, and market demand. By integrating logistic probability functions, we account for the uncertainty in policy rollout, enabling a more robust cost-benefit analysis under different policy scenarios.

Modeling of probability of introducing carbon tax (P_t) and the actual CO_2 tax price (t) in $/ton followed the same logistic growth model and the profiles are shown in Figure 6.6 and Figure 6.7

for the carbon tax (P_t) and CO_2 tax price (t) respectively. In introducing the probability of carbon tax implementation, a carbon tax in a state like Texas is faced with such high policy uncertainty that both pessimistic and optimistic probability scenarios must be simulated. In the pessimistic scenario, political resistance from fossil fuel interests and key policymakers retards the imposition of a carbon tax, relying on market-based switches to renewables rather than regulation. It is only by 2045 that full imposition of the tax is achieved, reflecting a lag in policy response compared to the time limit of climate goals. However, the optimistic pathway assumes that carbon pricing is widely adopted as a central policy tool by the late 2020s, triggering early dialogue and preparatory actions. By 2030, a low carbon tax is introduced to bring about initial market transformation, with an accelerated scale-up of the tax between 2033 and 2040. Additional policies such as subsidies for renewable energy and green finance mechanisms complement and augment the impact of the tax, bringing about a coordinated approach to emissions reductions.

As shown in Figure 6.6, probability trends for these scenarios also adopt a logistic modeling approach to capture the gradual but faster policy uptake. In the pessimistic pathway, there is no carbon tax introduced before 2035 due to political constraints, followed by a gradual take-up phase between 2035 and 2039. It is followed by a steep acceleration between 2035 and 2040, adopting carbon pricing as a central feature in climate policy. By 2040, the carbon tax is fully in place, achieving net-zero pledges a decade ahead of the 2050 target.

Regarding carbon tax, the USA carbon tax trajectory from 2025-2050 is a crucial policy tool in facilitating the clean energy shift and net-zero emissions. In the pessimistic case, the carbon tax starts at $25 per ton in 2026 and increases at a rate of 2% annually. The case shows policy inertia, incremental legislation, and economic limitations that limit robust carbon pricing. Thus, in 2050, the carbon tax is $41 per ton, which is lower than in the optimistic case.

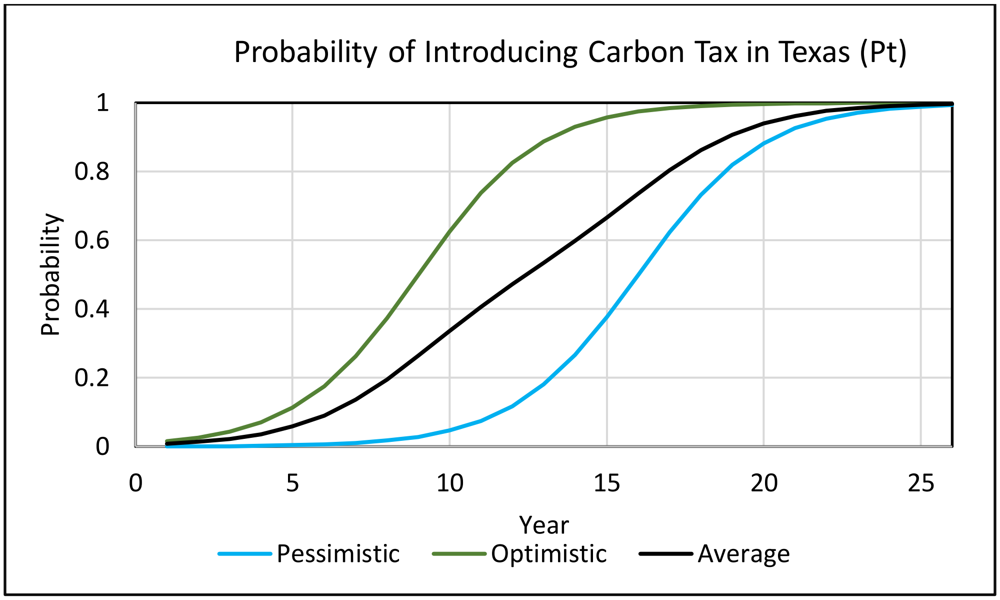

Figure 6. 6 Forecasted Probability of introducing carbon tax in Texas (Pt)

There is increased carbon pricing in the optimistic case, as it increases from $40 per ton in 2026 to increasing by 3% each year. This corresponds to larger climate policy to favor carbon pricing as the principal investment stimulus for renewables, at $83.8 per ton by 2050. These scenarios are consistent with existing policy proposals and economic analysis. Congressional Budget Office suggests an inflation-linked tax of $25 per ton of carbon capable of generating large revenues but potentially below the level of greenhouse gas reduction that would be sufficient to meet net-zero interests (CBO, 2022).

The Baker-Shultz Carbon Dividends Plan considers a front-end tax rate of $40 per ton increasing progressively to meet the objective of reducing emissions by 50% by 2035 and net-zero by 2050, with taxpayers being paid back in the form of dividend (Baker & Shultz, 2019). Further work by the Citizens' Climate Lobby also corroborates that a strong economy-wide carbon price would cut carbon emissions in half by 2030 and be on a net-zero path by 2050 (Sirna, 2025).

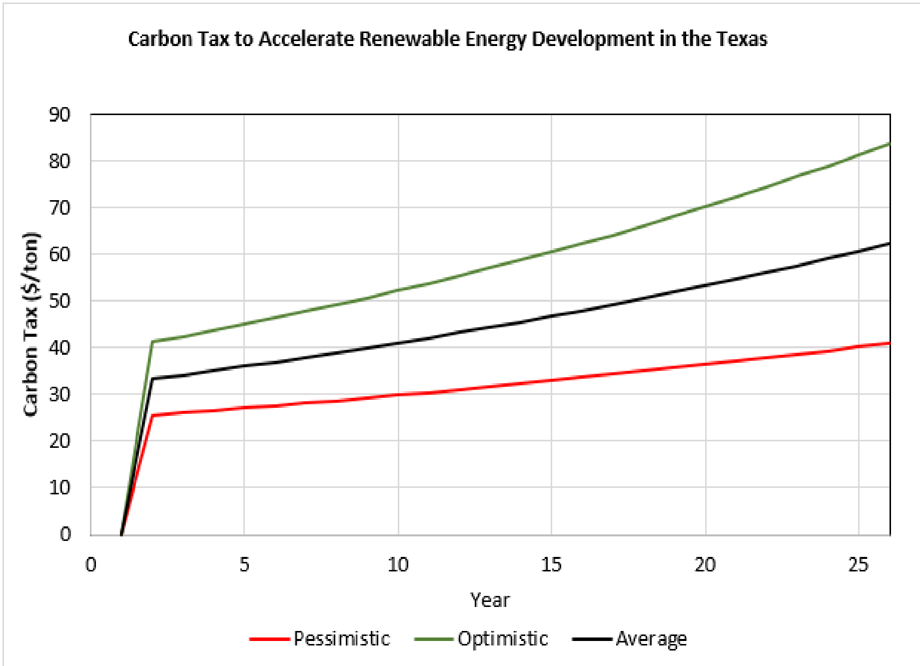

Figure 6. 7 Forecasted carbon tax to accelerate green H_2 Integration.

The Build Back Better Act emphasizes putting in place complementing policies, like low-carbon technology tax credits and infrastructure investment, to benefit of the effect of carbon pricing (Shrestha et al., 2021). Although the exact carbon price required to achieve net-zero changes with economic conditions and technology improvements, a policy framework starting at $40 per ton with frequent increases, together with complementary incentives, is widely seen as the minimum required for achieving long-term decarbonization.

6.4.3 Emission Reduction Estimation (Et)

The Et emission reduction estimates the environmental footprint of replacing green hydrogen and renewable energy with fossil fuels. The Et formula in Equation (6.2) captures the decarbonizing outlook of the hydrogen integration pathway in the DES.

Table 6.8 reports the estimated average CO_2 avoided in various hydrogen integration scenarios in DES under the assumption of substitution of natural gas. The forecasts apply the emissions reduction equation in Equation (6.2) and rely on production rates and on emission factors for electricity, hydrogen, ammonia, and hydrogen-methane blend for various deployment configurations.

Table 6. 8 CO_2 Abatement (Assuming Natural Gas is Displaced)

Pathway	**Product**	**Prod Rate**		**Emission Factor (kg CO_2/unit)**	**CO_2 Abated (tons/year)**
RE-xGrid	Electricity	10	MW/h	0.185 /kWh	16,206
RE+BESS+xGrid	Electricity	10	MW/h	0.185 /kWh	16,206
RE+BESS+nGrid	Electricity	10	MW/h	0.185 /kWh	16,206
RE-H2-nPL	100% H2	173	kg/h	2.75 /kg H2	4,168
RE-NH3-nPL	100% NH4	980	kg/h	1.6 /kg NH3	13,740
RE-H2NGblend-xPL	20% H2, 80% CH4	173	kg/h	0.55 /kg blend	834
RE-C(H2NGblend)	20% H2, 80% CH4	173	kg/h	0.55 /kg blend	834
RE-H2CO_2NGSyn-nPL	40%H220%CO_2,20 % CH4	173	kg/h	1.10 /kg blend	1,667
RE-H2-UGS-H2NGblend-xPL	20% H280% CH4	173	kg/h	0.55 /kg blend	834
RE-H2-UGS-C(H2NGblend)	20% H280% CH4	173	kg/h	0.55 /kg blend	834
RE-H2-UGS-H2CO_2NGSyn-nPL	40%H220%CO_2, 20% CH4	173	kg/h	1.10 /kg blend	1,667
RE-H2-UGS-H2-nPL	100% H2	173	kg/h	2.75 /kg H2)	4,168

By displacing fossil fuels, these pathways contribute significantly to reducing CO_2 emissions, as demonstrated by the values in the table. This analysis underscores the importance of adopting a diversified approach to decarbonization, leveraging the strengths of electricity, hydrogen, ammonia, and blended pathways to achieve sustainable energy systems.

6.5 Results and Findings

6.5.1 CBA Results

The most profitable options are those with lower capital costs but steady gains like RE-xGrid or RE+BESS-xGrid (see Figure 6.8). On the other hand, high capital-intensive pathways such as conversion into NH3 or UGS injection / production have slow or no paybacks at all making them unattractive based on NPV alone without considering other benefits such as strategic or environmental ones. Furthermore, the initial capital cost and the expected 20-year financial performance of each renewable energy alternative have a decisive role in their commercial viability. For example, options such as RE-xGrid have minimal upfront costs but give rise to steadily increasing gains that can make them extremely lucrative. However, scenarios like RE-NH3-nPL require significant amounts of capital and experience losses throughout their lifespan which makes them uneconomical under current market assumptions. Therefore, Olleik et al (2021) recommend adding a renewable contribution parameter to energy contracts so that some profit from traditional industries is reinvested into renewable activities (Olleik et al., 2021). In addition, Remy and Chattopadhyay (2020) highlight the benefits of regional integration in power pools which can be applied to pathways like RE-xGrid and RE+BESS-xGrid (Remy & Chattopadhyay, 2020). Such joining may involve shared infrastructure or policy frameworks leading to better grid stability and more cost-efficient systems. Similarly, Remy and Chattopadhyay (2020) argue that regional integration within power pools enhances effectiveness in cases such as those exhibited by RE-xGrid or RE+BESS-xGrid."

6.5.2 Pathways and NPV

Looking at Table 6.9 and Figure 6.8, they show the financial viability as well as long term returns of different renewable energy integration pathways over a period of 5, 10 and finally 20 years.

The Grid-Connected Pathways are always positive and increasing NPV's which suggests that they perform well financially and are sustainable across all the years. This implies grid-connected systems, especially with batteries, can provide economic alternatives with rising benefits in future.

As shown in Figure 6.8, the Hydrogen Production Pathways begin with negative NPVs but show change over time to become positive by year twenty. In other words, there's high initial capital investment, but it might turn out to be profitable as technology matures and efficiencies improve. A way to encourage quick adoption and optimization of these technologies is by reducing upfront costs through subsidies and incentives.

The Ammonia Production Pathway (RE-NH3-nPL) has negative NPVs even after year twenty thus may be regarded as not being economically viable under current conditions unless significant improvements or subsidies offsetting the costs are made. For complex integration pathways involving H_2 production, its underground storage hydrogen and production of blends (RE-H2-UGS-H2NGblend-xPL, RE-H2-UGS-C(H2NGblend), RE-H2-UGS-H2CO$_2$NGSyn-nPL, RE-H2-UGS-H2-nPL) show challenging financial profiles where all except RE-H2-UGS-H2-nPL remain negative at year twenty. These are among the least financially viable options due to huge infrastructure costs and complexity associated with technology.

Table 6. 9 Net Present Value in Years 5, 10 and 20 ($ million)

Path	Description	Year 5	Year 10	Year 20
1	RE-xGrid	35	63	102
2	RE+BESS-xGrid	34	66	110
3	RE+BESS-nGrid	32	64	108
4	RE-H2-nPL	-18	4	33
5	RE-NH3-nPL	-36	-25	-9
6	RE-H2NGblend-xPL	-13	3	24
7	RE-C(H2NGblend)	-9	9	34
8	RE-H2CO$_2$NGSyn-nPL	-27	-11	11
9	RE-H2-UGS-H2NGblend-xPL	-41	-30	-14
10	RE-H2-UGS-C(H2NGblend)	-34	-18	4
11	RE-H2-UGS-H2CO$_2$NGSyn-nPL	-38	-24	-4
12	RE-H2-UGS-H2-nPL	-31	-13	13

The syngas production with H_2 and CO_2 blending (RE-H2CO$_2$NGSyn-nPL) shows some improvement by year twenty but remains mostly unprofitable, reflecting substantial challenges in cost management and technological efficiency.

In short, RE-xGrid, RE+BESS-xGrid, RE+BESS-nGrid or grid connected Pathways with or without battery storage appear as the most attractive investments with greatest financial returns while ammonia production and underground storage of hydrogen blends are less developed and have economic challenges to overcome.

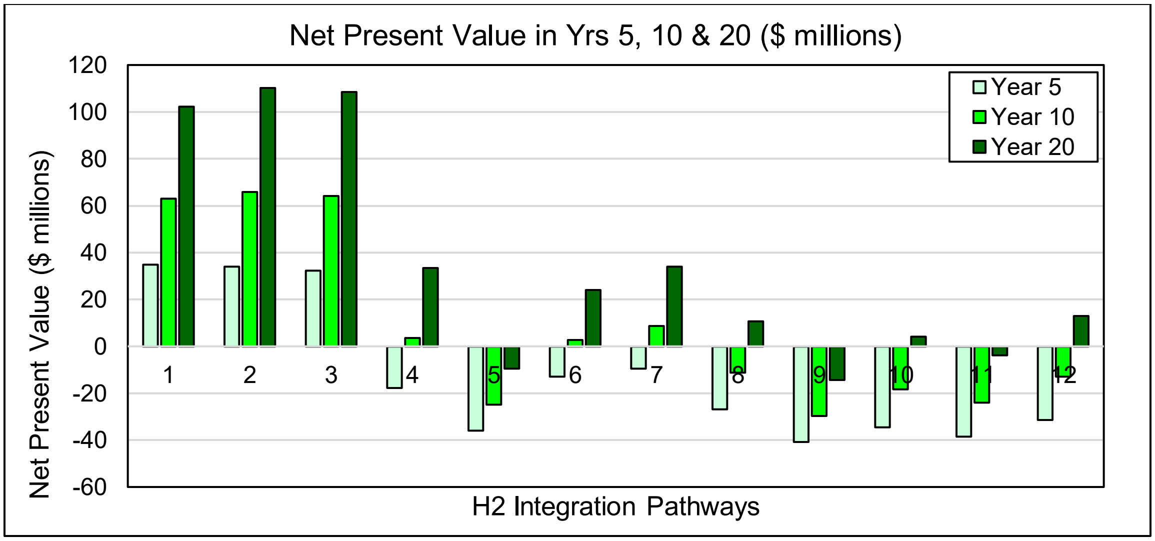

Figure 6. 8 Net Present Value in Years 5, 10 & 20 ($ million)

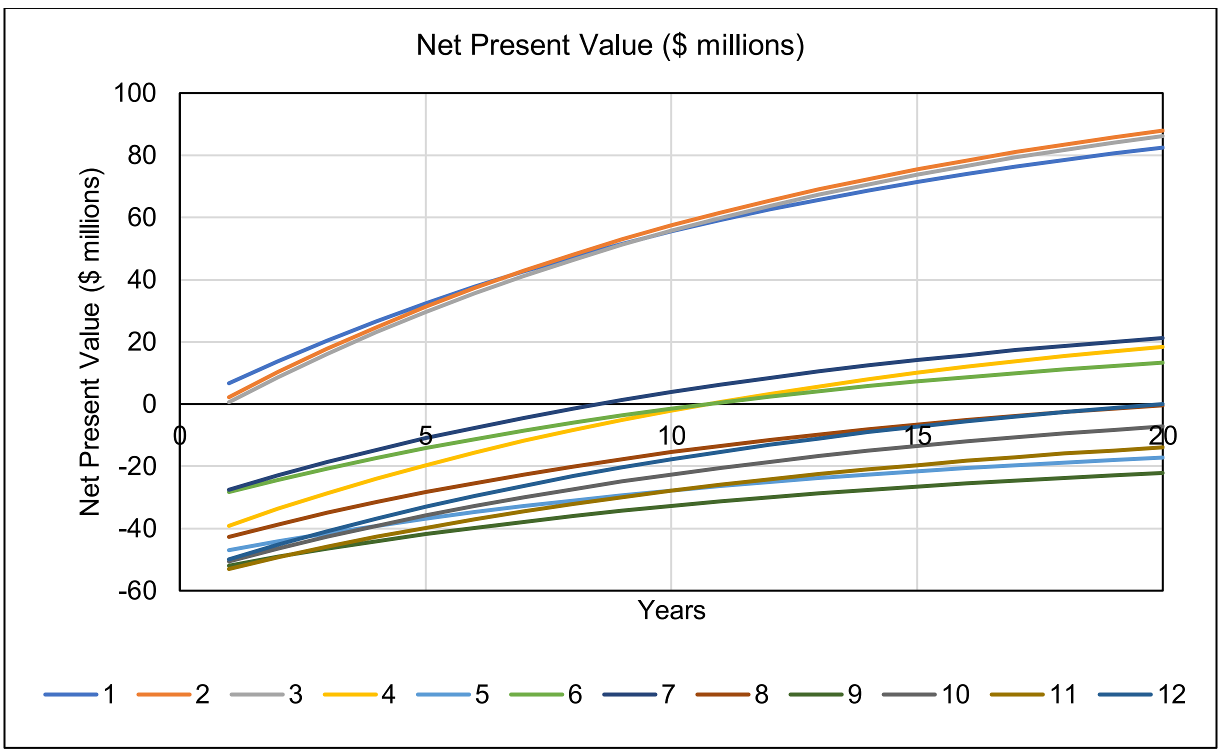

Figure 6. 9 Net Present Value ($ million)

6.5.3 Impact of Discount Rate

The impact of discount rates on NPVs for various energy pathways is especially important in understanding the financial viability as well as risk sensitivity of such investment. The records point out that there is a clear trend where each pathway's NPV declines when discount rate increases from 5% to 12% (see Figure 6.10). This decrease demonstrates the higher cost of capital and increased perceived risk by investors who discount future revenues at higher rates.

Grid-connected renewable pathways (RE-xGrid, RE+BESS-xGrid, RE+BESS-nGrid) consistently show the highest NPVs across all discount rates indicating robust financial performance and lower sensitivity to the discount rate thereby suggesting that these technologies are considered less risky and more dependable for investment purposes.

Hydrogen production pathways (RE-H2-nPL, RE-H2NGblend-xPL, RE-C(H2NGblend)) show a moderate decline in NPV as the discount rate increases meaning that their financial viability is more sensitive to changes in the cost of capital although they remain profitable at lower discount rates, but their profitability decreases greatly when this rate rises implying higher inherent risks and possibly more operating costs.

As shown in Figure 6.10, complex hydrogen storage and conversion pathways (RE-H2CO$_2$NGSyn-nPL, RE-H2-UGS variants) start with lower or negative NPVs at a discount rate and deteriorate further at higher rates. It suggests that these technologies involve complex processes which are not yet established such as underground hydrogen storage or ammonia production due to high risks associated with them.

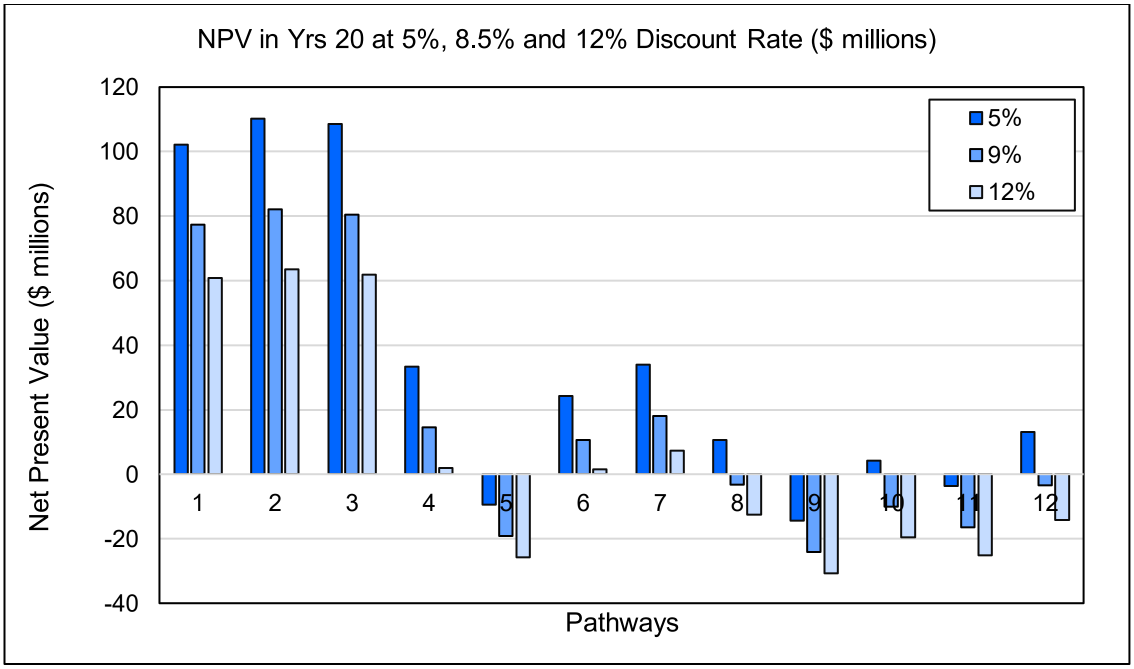

Figure 6. 10 NPV in Year 20 at 5%, 8.5% and 12% Discount Rate ($ million)

The significance of the variation in NPV for different discount rates on any given pathway underscores the importance of considering financing and economic environments when planning or investing in these energy technologies. The strategic decision can be influenced by the cost of capital, highlighting a need for enabling policies and incentives that would improve the economics of high-risk pathways especially those involving advanced hydrogen technologies.

6.5.4 Pathways and Rate of Return

The ROR analysis, excluding the initial cost of acquiring renewable energy—which is considered a sunk cost—shows that RE-xGrid has an extremely high ROR of 827% implying that once the initial cost is absorbed, integration of directly acquired RE into the grid is highly profitable. Furthermore, RE+BESS-xGrid and RE+BESS-nGrid delivering returns at 144% and 116% respectively (see Figure

6.11) show how integrating battery storage systems with grid connected renewable energy enhances efficient energy management as well as reliability.

As shown in Figure 6.11, pathways such as: RE-H2-nPL, RE-H2NGblend-xPL, and RE-C(H2NGblend) that focus on electricity to hydrogen conversion demonstrate medium returns (13%-15%). Therefore, these figures mean that such strategies for integration might become viable with technological development subsidies and incentives plus increasing demand for H_2 production.

On the other hand, more complex pathways like ammonia production and hydrogen storage include RE-NH3-nPL, RE-H2CO$_2$NGSyn-nPL, different underground storage models have lower returns (2-8%) (see Figure 6.11). Such pathways face issues related to higher operational complexities as well as slower market uptake.

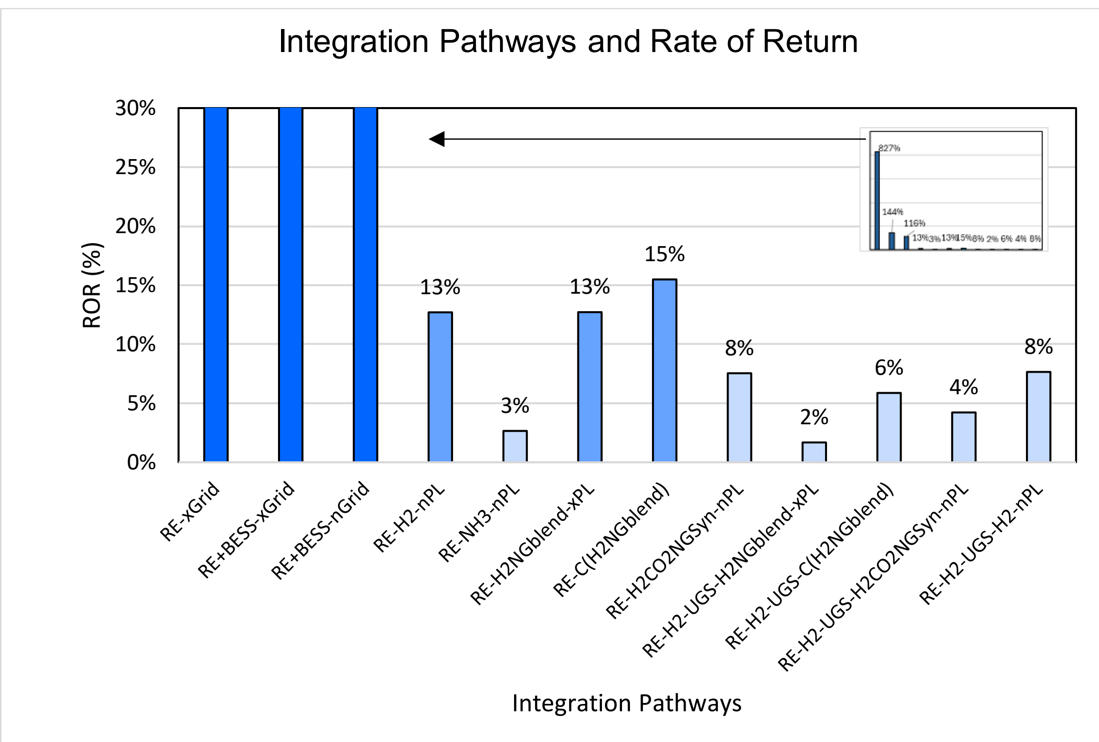

Figure 6. 11 Integration Pathways and Rate of Return.

This financial assessment underscores the strategic value of leveraging already acquired renewable resources while demonstrating which integration pathways successfully utilize these resources thereby providing a clear direction on areas where investments could be best channeled for sustainable growth in the renewables sector. These performance-based incentive subsidy policies, funding and grants can have huge impacts on hydrogen pathways integration particularly those that start with negative NPV such as RE-H2-nPL, RE-H2NGblend-xPL, RE-C(H2NGblend) and similar pathways. This support helps to relieve investments when they are highest in the initial phases and returns are negative. As seen in studies by Wang et al. (2024), subsidies for renewable energy can alter market dynamics and make projects less economically viable by offsetting initial costs and promoting faster adoption rate and scale up efforts (X. Wang et al., 2024). Equally Chen et al. (2024) point out that every increase in incentive strength makes renewable technology more feasible which means there is direct positive impact to hydrogen pathways with high upfront investment (Z. Chen et al., 2024). This shows that targeted financial policies could accelerate the adoption and integration of hydrogen technologies within DES, making them more economically attractive earlier in their development lifecycle.

6.5.5 CBA with Probabilistic Modeling

This study analyzes NPV results across varying policy and operational conditions. Figure 6.12 presents comparative NPV appraisal of twelve varied hydrogen integration scenarios for two policy scenarios: policy interventions (no subsidy or carbon tax) and policy interventions (subsidy and incentives through a carbon tax).

As is shown in Figure 6.12, well-targeted policy incentives can accommodate cost viability of hydrogen integration alternatives significantly enhanced. In non-policy scenarios, most hydrogen routes, such as RE-H2-nPL and RE-H2-UGS-H2-nPL, have negative or low NPVs, indicating subsidy dependency and lack of capital. But with inclusion of subsidies added to carbon pricing, there is a staggering uplift in NPV for all but two of the routes—ammonia synthesis (RE-NH3-nPL), hydrogen transport alone (RE-H2-nPL), and blended hydrogen routes (RE-H2NGblend-xPL). Largest relative NPV impacts result from huge CAPEX and carbon offsetting potential cash flows, and this is sufficient to drive marginal economically viable projects into investment territory, demonstrating that the incentives are sufficient to bring such projects online. This verifies the first hypothesis of the research: policy interventions provide the answer to green hydrogen projects being bankable and scalable for DES.

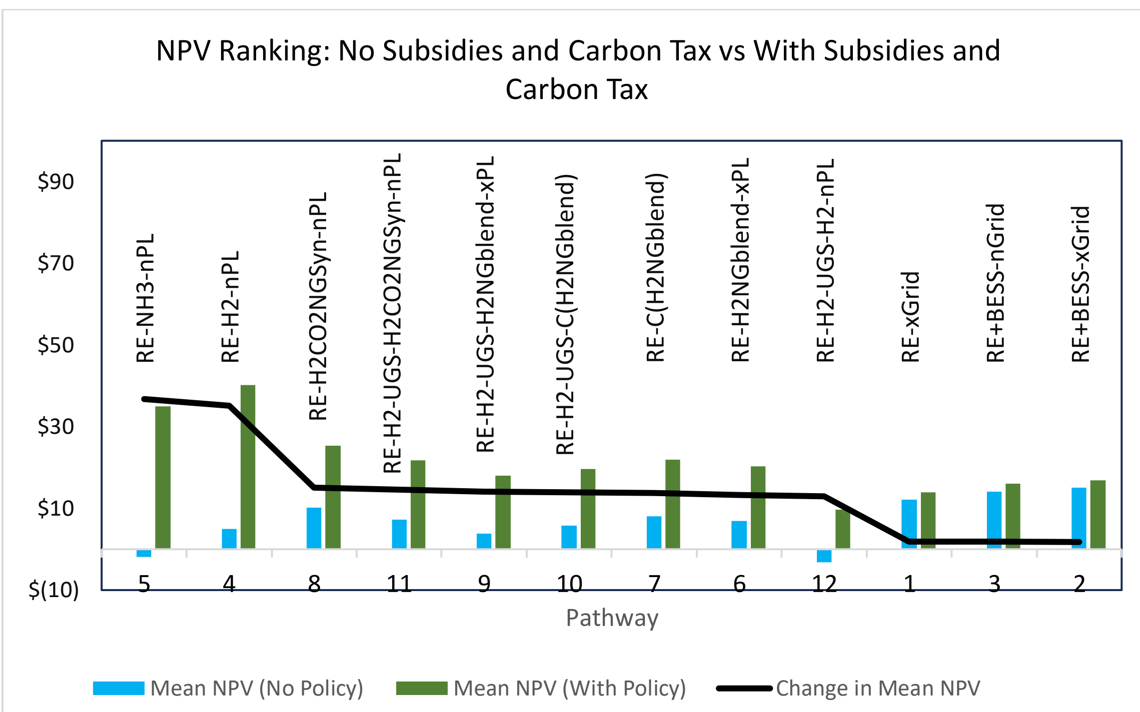

Figure 6. 12 NPV Comparison Across Pathways with and without Subsidies.

6.5.6 Probability Distribution of NPVs (Monte Carlo Simulation)

Without Policies

Figure 6.13 indicates the Net Present Value (NPV) of various integration options of renewable energy and hydrogen without policy incentives in the form of carbon tax and subsidy. Grid-tied renewable electricity options (RE-xGrid, RE+BESS-xGrid, and RE+BESS-nGrid) possess the highest NPVs, indicating these options are still economically attractive in the absence of policy incentives. However, hydrogen production and storage routes, particularly RE-H2-nPL and RE-NH3-nPL, show lower or even negative NPVs, indicating their dependence on financial incentives to achieve competitiveness.

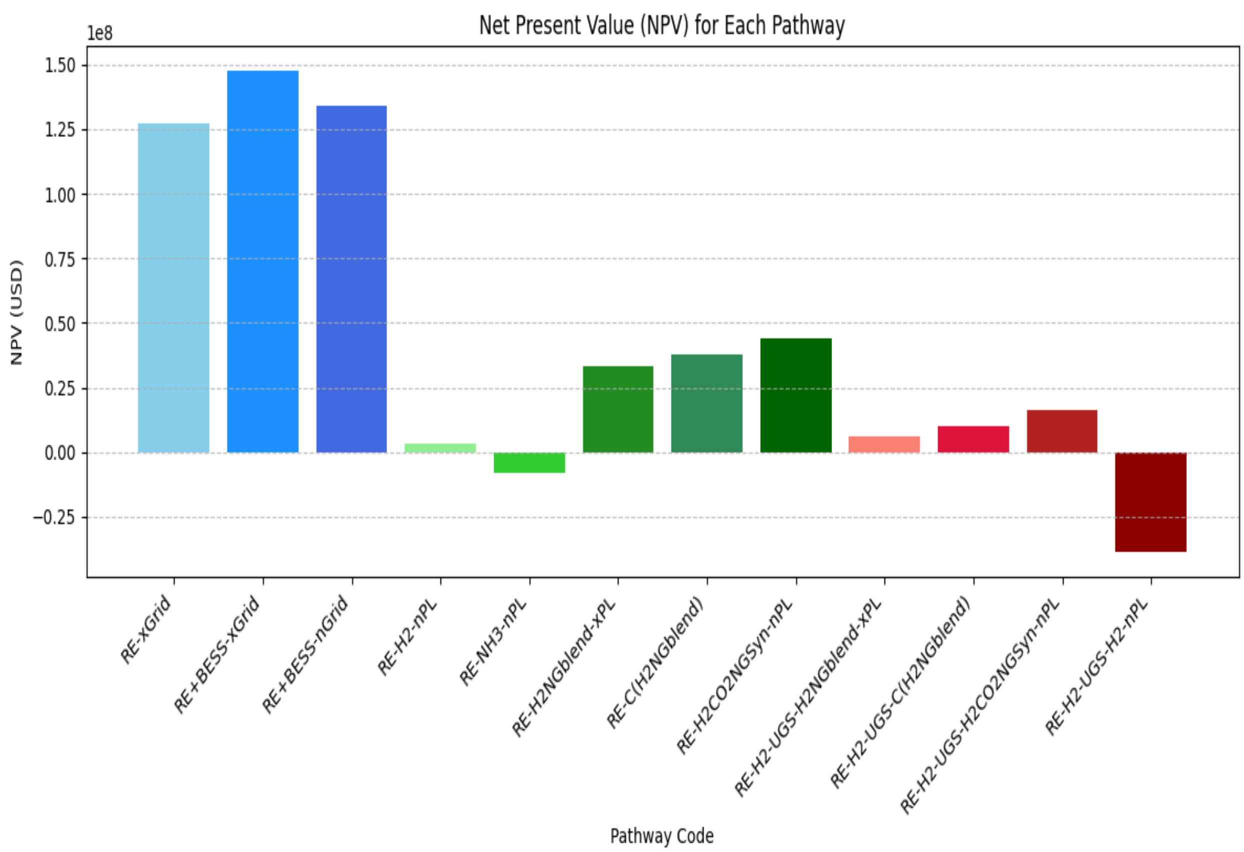

Figure 6. 13 NPV no subsidies and no carbon tax

Blended hydrogen routes (i.e., RE-H2NGblend-xPL) exhibit medium NPVs, which suggests that blending hydrogen with natural gas improves financial feasibility. Routes of underground hydrogen storage, such as RE-H2-UGS-H2-nPL, exhibit the lowest NPVs, indicating that without subsidies and carbon pricing policies, these options are still not economically attractive due to their high capital costs. The performance indicates the absolute necessity of policy interventions in making hydrogen-based routes economically viable.

Relative probability distribution of different NPV outcomes for the different hydrogen integration pathways is illustrated in Figure 6.14. Electricity-based options such as RE-xGrid, RE+BESS-xGrid, and RE+BESS-nGrid have more peaked distributions with lower NPVs ranging from \$10M–\$20M. This means that while such integration pathways have low-capital investment, they are low in returns, which is consistent with Tang & Li (2024), who are of the opinion that integration of renewable electricity requires more incentives to be economically cost-competitive (Tang & Li, 2024). The low-capital investment but revenue-constrained character of such routes shows their lower financial risks but equally lower profitability. In contrast, hydrogen-based routes such as RE-H2-nPL and RE-NH3-nPL have broader distributions for potential NPVs of \$30M–\$70M. These findings suggest hydrogen investments have strong upside but are economically riskier, due to their CAPEX intensity and policy dependency (Lan et al., 2024).

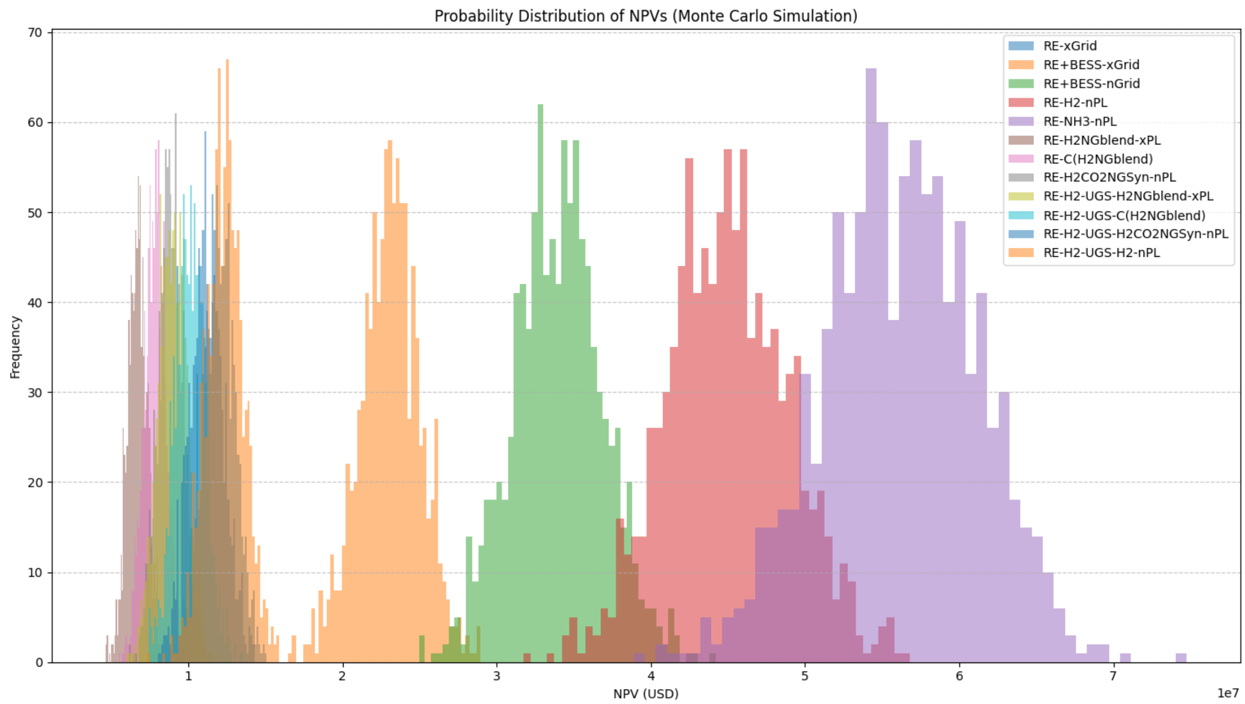

Figure 6. 14 NPV probability distribution with no subsidies and carbon tax policies

The boxplot of NPVs (Figure 6.15) also provides further information on risk and reward variations between pathways. Hydrogen investments like ammonia manufacturing (RE-NH3-nPL) tend to have the highest median NPVs but also the largest interquartile range, suggesting high financial volatility. Hybrid hydrogen paths like RE-H2NGblend-xPL possess an intermediate risk-return financial profile, with risk reduction balanced by financial viability, as supported by the study on designing hydrogen-based storage with a hybrid renewable energy system while taking environmental and economic risks into account (Oyewole et al., 2024). Underground hydrogen storage pathways such as RE-H2-UGS-H2NGblend-xPL contain outliers that represent speculative investment opportunities, i.e., they can be either highly lucrative or capital-starved, contingent upon policy incentives.

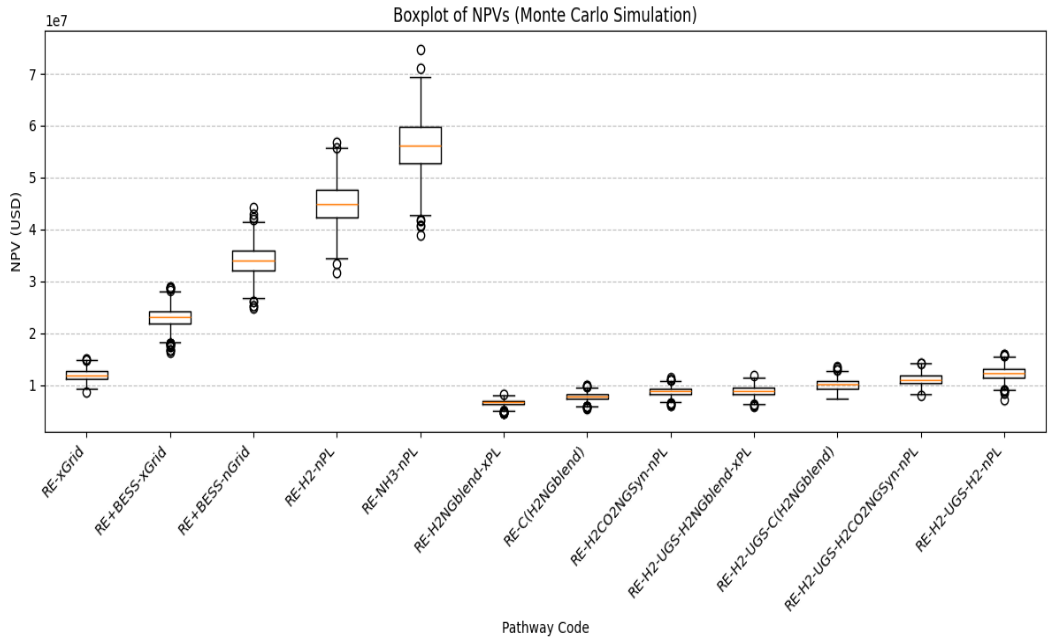

Figure 6. 15 Boxplot of NPVs distribution with no subsidies and carbon tax policies

The cumulative probability distribution (Figure 6.16) provides further understanding of financial risks, expressing the probability of achieving various NPVs. Electricity-based routes display steep probability lines, reflecting low variance and stable returns. This agrees with Oliva & Garcia (2023), who state that electrification routes are minimal risk but offer poor return on investment (Sebastian & Matias, 2023). In contrast, hydrogen routes contain wider probability distributions, which suggest although high returns are probable, these are policy-incentive reliant. Underground hydrogen storage channels are particularly exploratory in at this regard and require technological development and fiscal incentives to transcend investment risk (Z. Wang & Lao, 2025).

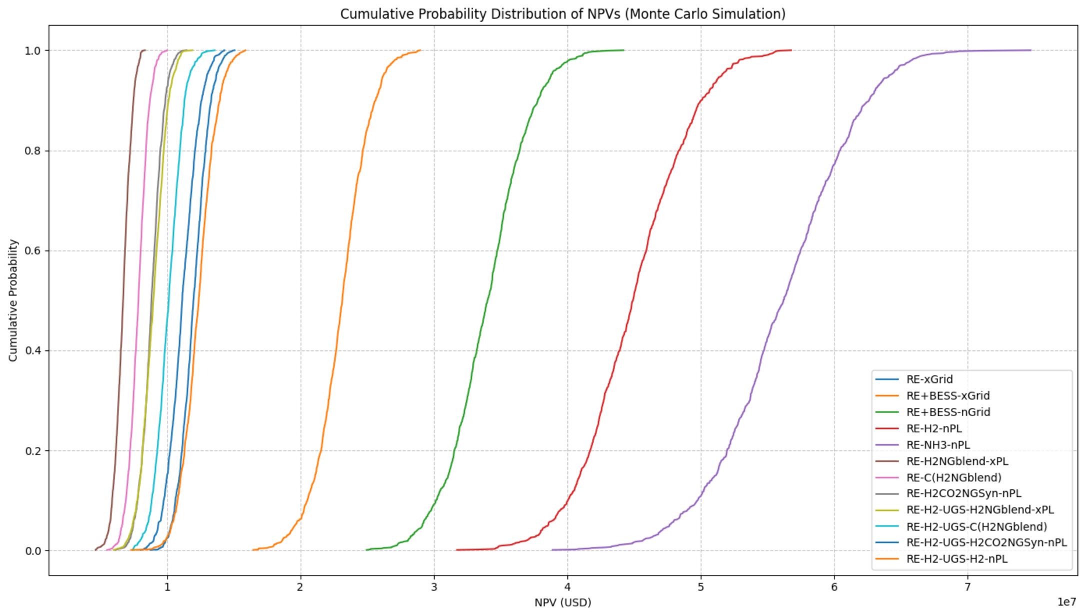

Figure 6. 16 Cumulative NPV Under No Subsidy vs. Carbon Tax.

6.5.7 With Government Policies (Subsidies and Carbon Tax)

As shown in Figure 6.17, subsidies and carbon tax jointly result in the highest NPV increase of all the various renewable and hydrogen-based routes with carbon tax incentives and subsidies. Compared to the no-policy case, all routes indicate a definite improvement in economic feasibility. The grid-connected renewable electricity options (RE-xGrid, RE+BESS-xGrid, RE+BESS-nGrid) remain the most profitable, as they are low-risk and possess some assured returns. Hydrogen pathways like RE-H2-nPL and RE-NH3-nPL exhibit significant improvements, highlighting the impact of carbon pricing and subsidies in creating a level playing field for such technologies. Blended hydrogen pathways (RE-H2NGblend-xPL, RE-H2CO$_2$NGSyn-nPL) also exhibit significant NPV improvements, capturing the value added by hybrid options that leverage natural gas infrastructure and future growth in the hydrogen market. Even hydrogen storage paths underground (RE-H2-UGS-H2-nPL) are low-NPV, their financials improve, and with some more technological advancements and fine-tuning of policies, they can work. This result is testimony to the justification for specific policy initiatives to de-risk hydrogen investment and propel its integration into the energy market.

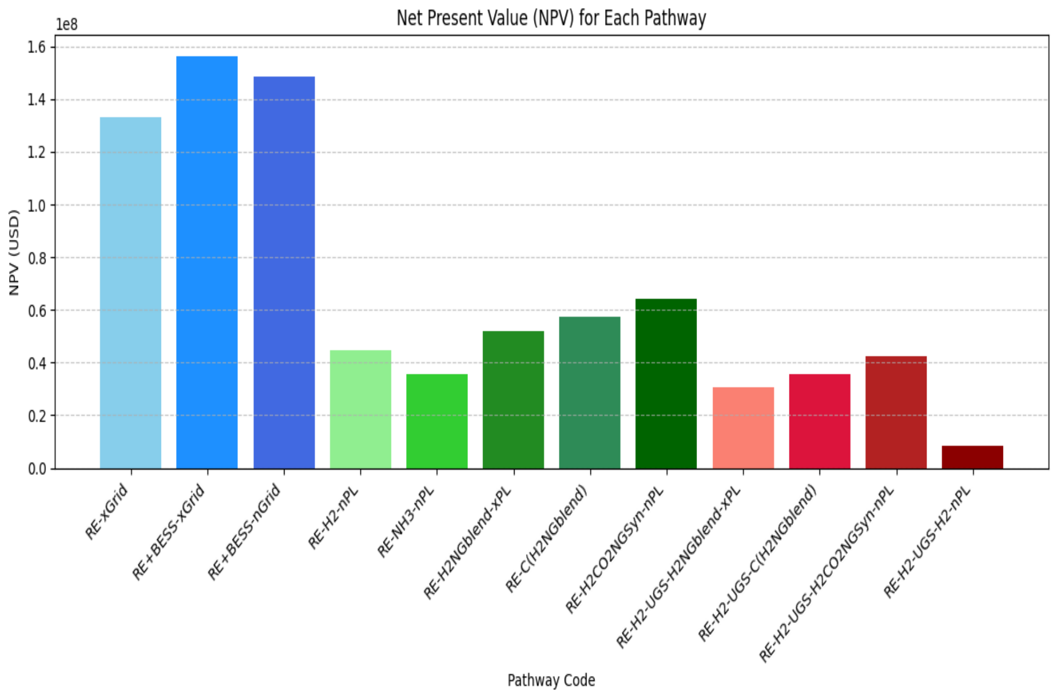

Figure 6. 17 NPV with subsidies and carbon tax

Figure 6.18 illustrates how implementing subsidies and carbon tax policies changes NPV probability distributions. Renewable electricity options such as RE-xGrid and RE+BESS-xGrid remain pooled at lower NPVs but more financially predictable due to lower variance. This implies that even though the projects are still within the firm policy favor, their investment is more attractive. Hydrogen pathways such as RE-H2-nPL and RE-NH3-nPL possess much more promising NPVs with broader distributions, once again affirming Lan et al. (2024) that hydrogen-ammonia hybrid pathways, in the long term, are financially feasible in policy-friendly regimes. Although, the wider spread of NPVs for underground storage-projects is a sign that the pathways are highly policy-sensitive and CAPEX-sensitive (Stambouli et al., 2024).

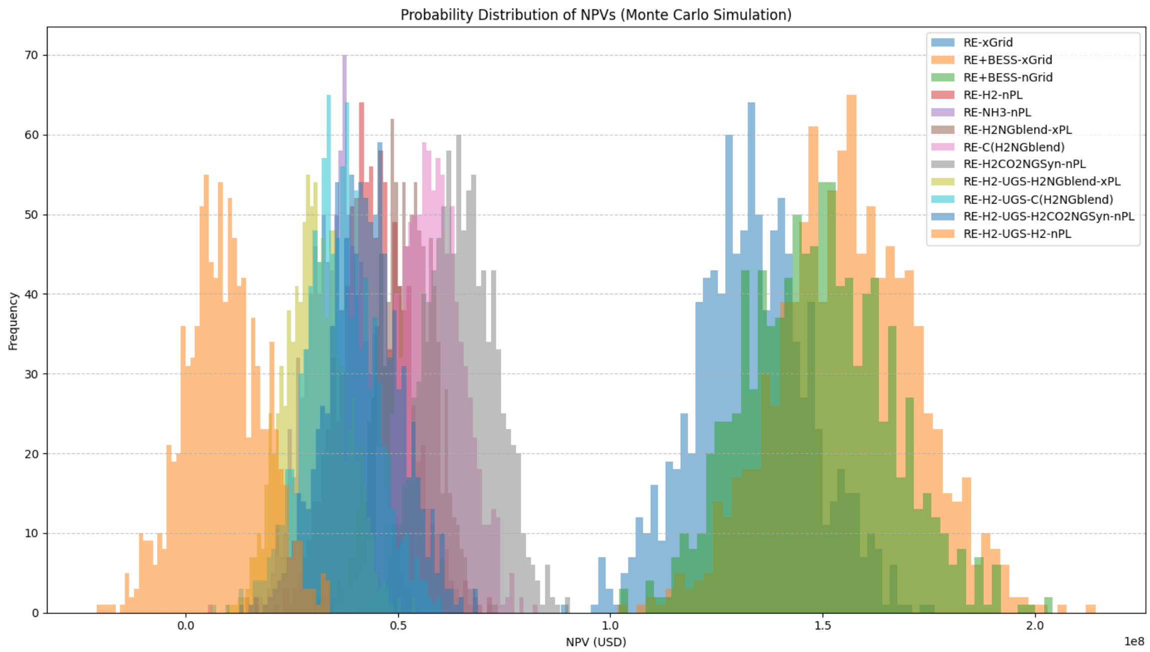

Figure 6. 18 NPV probability distribution with subsidies and carbon tax policies

The NPV boxplot (Figure 6.19) also observes the same points, recording median NPVs of hydrogen production pathways improve with policy support. Ammonia production (RE-NH3-nPL) has one of the highest median NPVs, which is economically strong with an enabling policy framework. Its interquartile range is high, however, suggesting that cost uncertainty and demand uncertainty still have a high proportion. Otherwise, underground hydrogen storage pathways still experience lower median NPVs, which means that even under policy support, they are not financially attractive to develop since they possess high up-front costs and lack obvious sources of revenues (Tang & Li, 2024).

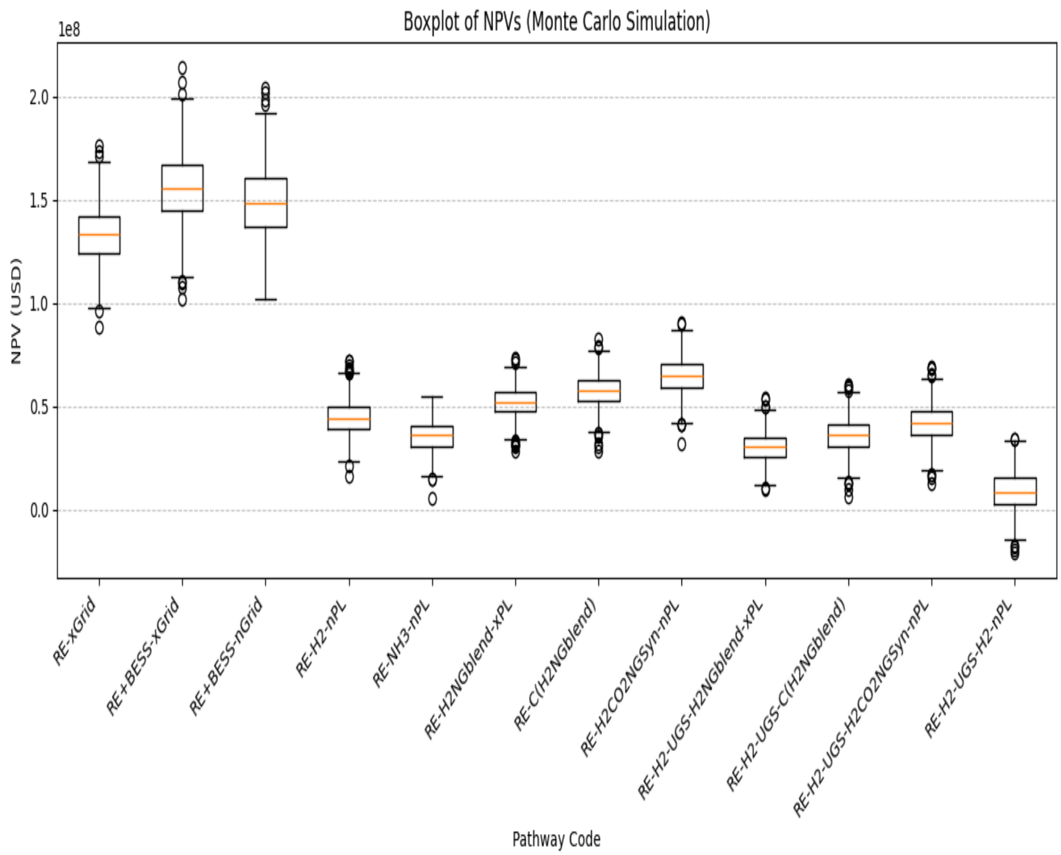

Figure 6. 19 Boxplot of NPVs distribution with subsidies and carbon tax policies

The cumulative probability distribution (Figure 6.20) shows that electrification pathways have a stable financial outlook, while hydrogen pathways are more volatile. The widening range of the probability for hydrogen investments reflects their policy sensitivity, in line with findings from Rezaei et al. (2024), who argue that learning effects and economies of scale are needed to reduce hydrogen costs and reduce financial risk (Rezaei et al., 2024). The results indicate that subsidies and carbon tax policies play a significant role in mitigating financial risk and enhancing the competitiveness of hydrogen integration projects.

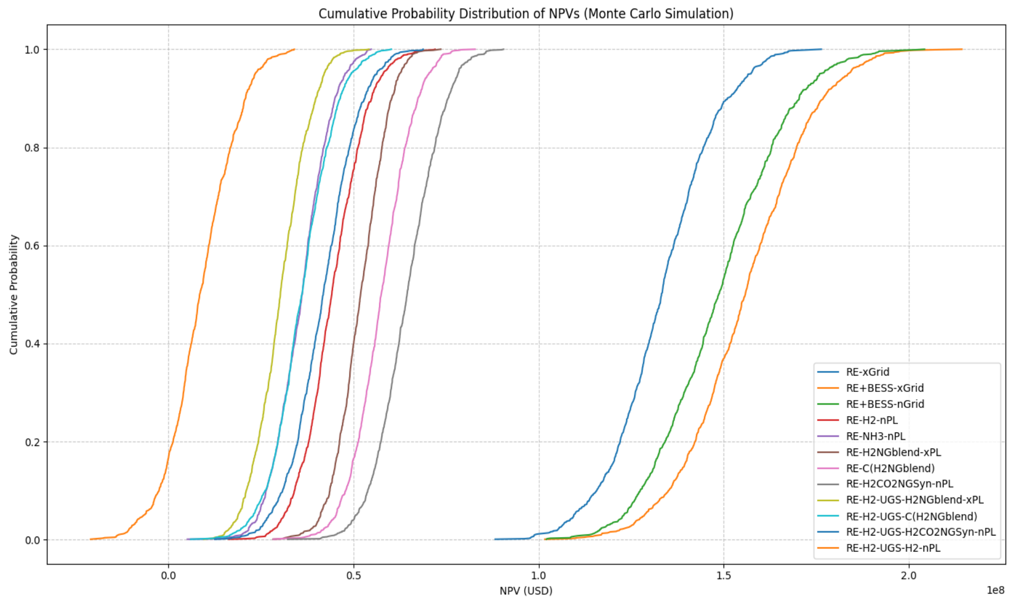

Figure 6. 20 NPV Distributions Under Subsidy and Carbon Tax Policies.

Table 6.10 presents a comparative analysis of the financial impacts of subsidies and carbon taxes. Without policy support, NPVs are constrained, with most pathways financially unattractive due to high uncertainty.

This is also asserted by the study of Hosseini Dehshiri & Firoozabadi (2025), whereby using hydrogen in industry cannot happen without the support of policy (Dehshiri & Firoozabadi, 2025). If subsidies and carbon price are given, however, NPV allocations shift upwards, reducing investment risk and making hydrogen projects more attractive. This corresponds with Wang et al. (2025), which emphasizes the role of financial de-risking through cross-cutting policy interventions. The clustering of the NPVs into low-return (renewables) and high-return (hydrogen) categories creates the implication that policymakers must discriminate against support measures to address investment barriers in both sectors.

The probabilistic NVP analysis reinforces that while electrification scenarios are economically feasible, they require substantial subsidies to become economically viable. On the other hand, hydrogen projects are finance-worthy with potential but policy-sensitive. Zhang et al. (2024), who demonstrate that integrating hydrogen into existing energy systems enhances financial returns only under favorable regulatory conditions (J. Zhang et al., 2024).

Table 6. 10 Impact of Subsidies and Carbon Tax on NPV

Feature	Without Subsidies and Carbon Tax	With Subsidies & Carbon Tax
NPV Range	Clusters mostly between \$10M - \$70M	Expands significantly, ranging up to \$175M
Shift in NPV Values	Lower NPVs, indicating higher financial risk without policy support.	Higher NPVs for most pathways, showing the impact of policy incentives.
Spread of Distributions	More variance and lower peaks, indicating higher financial uncertainty.	More defined peaks, showing improved financial predictability.
Cluster Formation	Pathways have closer distributions, meaning smaller financial differentiation.	Two clear clusters emerge: (1) Lower-NPV projects (renewables) and (2) Higher-NPV projects (hydrogen and storage).
Financial Viability	Many pathways have low NPVs, making them financially unattractive without support.	Most pathways cross the viability threshold, especially hydrogen projects.
Hydrogen Pathways	RE-H2-nPL, RE-NH3-nPL, and hydrogen blending pathways struggle.	Hydrogen pathways show significantly higher NPVs, demonstrating a policy-driven business case.
Investment Risk	Wide, uncertain spreads show higher risk for investors.	Lower variance in NPVs, meaning reduced investment risk with subsidies and carbon tax.

The research is in alignment with the policy-driven de-risking tools' proposition, for instance, the application of subsidy and carbon price, as necessitated in the formulation of an economically sustainable hydrogen economy. Policymakers should focus on long-term regulatory frameworks that provide certainty to investors, ensuring that hydrogen pathways transition from speculative investments to stable, profitable opportunities.

6.5.7 The Role of Policy in Enhancing the Viability of Hydrogen Integration Pathways

To reach a low-carbon economy, strategic policy interventions will need to help financial feasibility along with renewable energy and hydrogen integration pathways. Subsidies and carbon tax policies have been instrumental in the economic viability of hydrogen-based projects. Figure 6.21 details the ranking of different hydrogen integration pathways under two scenarios: No Policy Support (no subsidies and no carbon tax) and With Policy Support (subsidies and carbon tax).

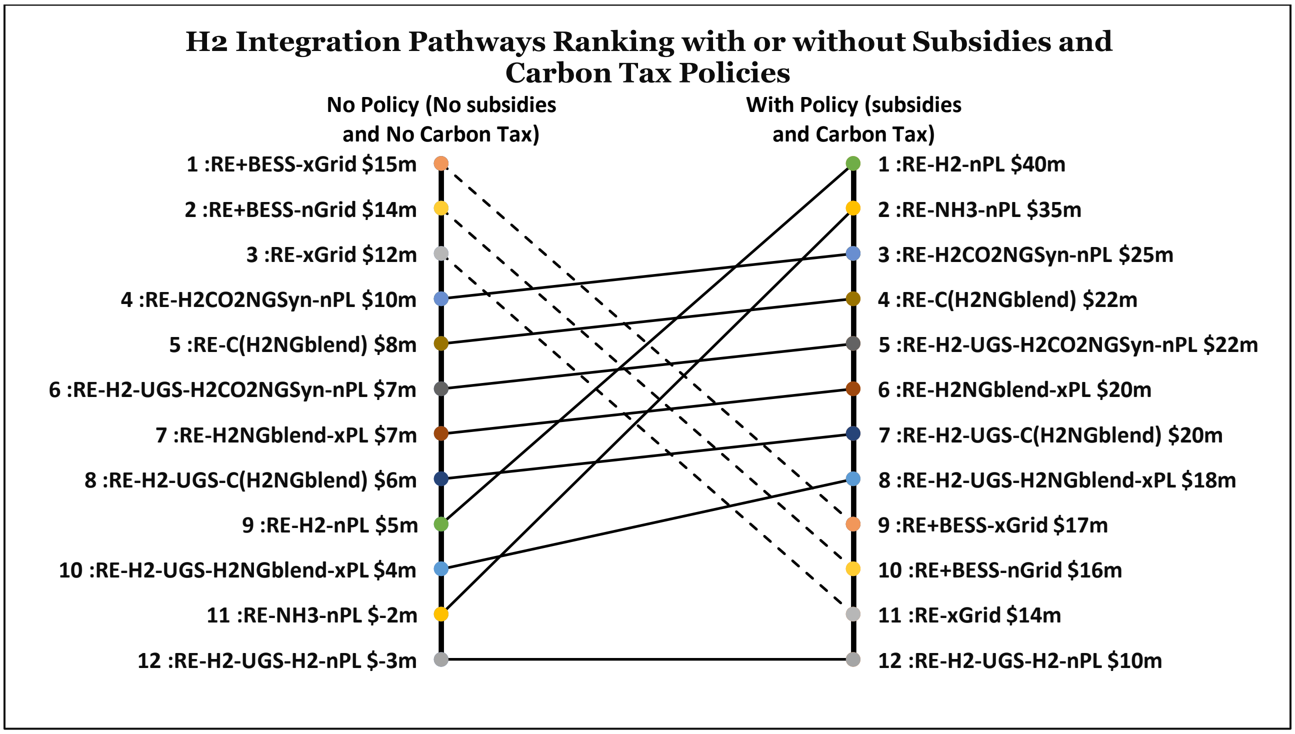

Figure 6. 21 H_2 Pathway Rankings Under Policy Scenarios

Also, Figure 6.22 details how subsidies and carbon tax mechanisms contribute to overall project profitability regarding NPV, showing how these policies impact Net Present Value (NPV). These figures portray an incredible journey through which government intervention de-risked hydrogen investments to make them competitive with conventional energy sources.

The most significant impact on NPV appears to occur in the hydrogen production and ammonia synthesis pathways. As illustrated in Figure 22, the RE-H2-nPL (pure hydrogen production) begins at an NPV of $5 million without policy support and jumps to $40 million with such support: a 715% increase. RE-NH3-nPL similarly shifts from an NPV of -$2 million (No Policy) to one of $35 million (With Policy), a total increase of $37 million from No Policy to With Policy. The syngas production numbers under RE-H2CO$_2$NGSyn-nPL also enjoyed policy support, moving $10 million with no subsidies to $25 million with subsidies, an increase of 147%. These findings reaffirm the concepts made by Mohammed and Farzaneh (2025) and Jindal et al. (2024) that hydrogen projects must rely heavily on carbon tax policies and subsidies to achieve cost competitiveness against fossil fuels (Jindal et al., 2024; Mohammed & Farzaneh, 2025).

6.5.8 Financial Improvements in Hydrogen Production and Ammonia Synthesis

The steep inclines in NPV for hydrogen production and ammonia synthesis pathways in Figure 22 also reinforce their partisanship in subsidies and carbon tax regimes. RE-H2-nPL and RE-NH3-nPL experience colossal policy-induced increases in NPV of 715% and $36.77 million, respectively. Their competitiveness remains conditioned on such incentives due to high production costs (Jindal et al., 2024; Mohammed & Farzaneh, 2025). Long-term policy commitment is essential for hydrogen and ammonia production growth and scaling, as stated by Fabianek et al. (2024) and Jiménez & Zheng (2024), because carbon pricing and financial subsidies bring the cost closer to that of fossil fuel alternatives (Fabianek et al., 2024; Jiménez & Zheng, 2024). Subsidies are required to maintain the economic viability of hydrogen projects, as underlined by Guven (2025) and Lin et al. (2024), further confirming the very instrumental role of sound policy support (Guven, 2025; Lin et al., 2024).

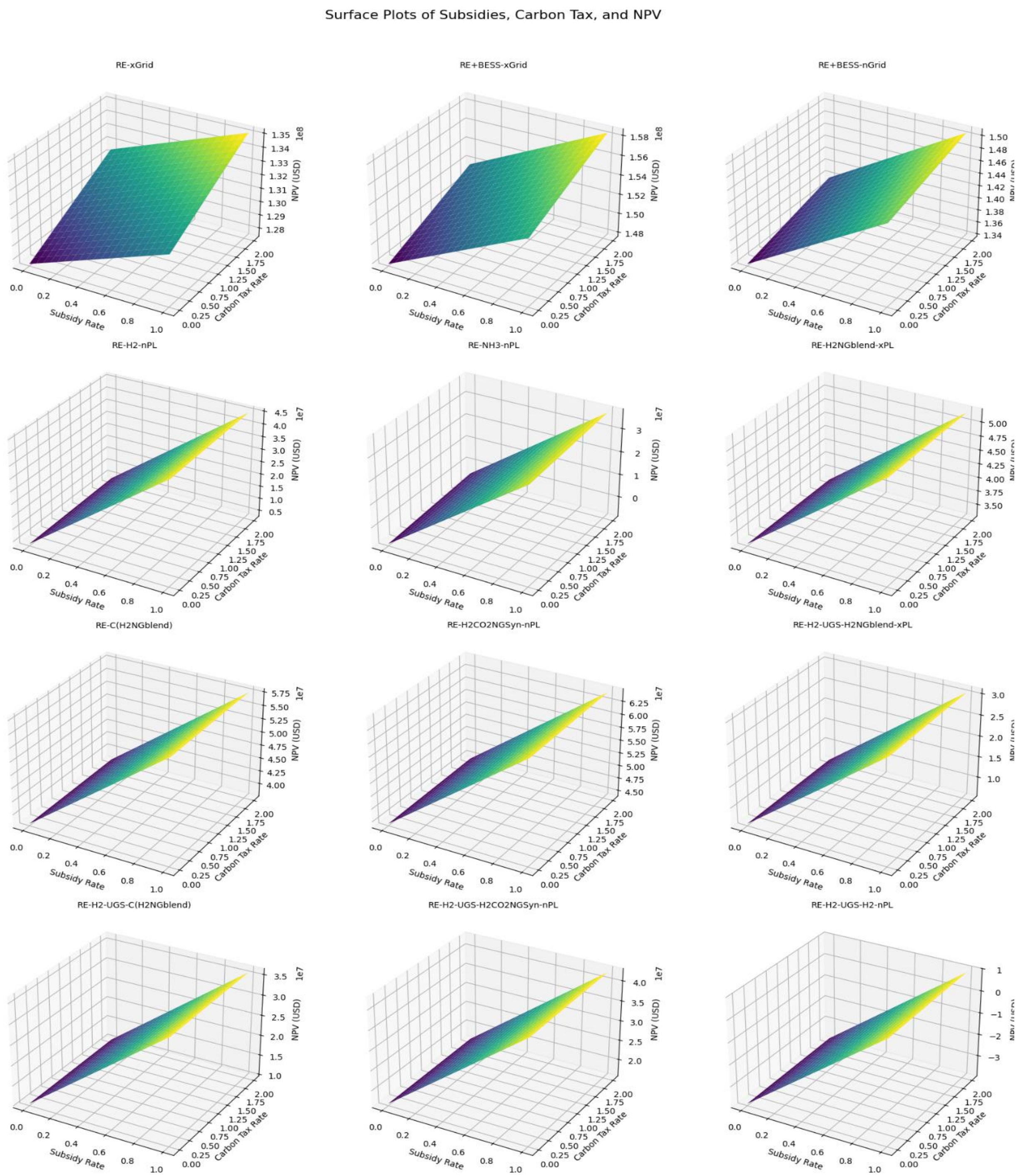

Figure 6. 22 Contribution of Subsidies and Carbon Tax Profitability.

6.5.9 Hydrogen Blending and Synthetic Gas Pathways

Under the subsidies and carbon pricing policies, valuable financial improvements are injected into the hydrogen blending and synthetic gas production pathways. The paths including RE-H2CO_2NGSyn-nPL, RE-C(H2NGblend), and RE-H2NGblend-xPL show NPV improvement ranges between 147% and 190%. This suggests that, either by blending hydrogen into existing natural gas infrastructure or by synthesizing alternative fuels off the infrastructure, economic feasibility is increased through the carbon pricing mechanism. The carbon pricing mechanism works in disfavor of carbon-intensive fuels while placing low-carbon alternatives on equal or advantageous footing (Lin et al., 2024).

Sial et al. (2024) also state that policy incentives, particularly the carbon tax, play a key role in attenuating the cost gap between hydrogen-based energy carriers and conventional fossil fuels (Sial et al., 2024). Carbon market pricing then serves to increase the profitability of hydrogen-blended and synthetic fuel projects. Jiménez and Zheng (2024) also state that hydrogen blending with natural gas may provide a pathway for gradual decarbonization via the use of existing infrastructure (Jiménez & Zheng, 2024). However, these benefits will depend largely on regional policy settings and scalability of hydrogen production (A. Wolf, 2025). In the absence of sustained market support, the high production costs of synthetic gas and hydrogen blending may, in fact, hinder widespread uptake, which then reiterates the need for long-term policy backing toward market competitiveness.

6.5.10 Limited Sensitivity of Grid-Connected Renewables

Grid-connected renewable electricity systems, on the other hand, are viewed to be less sensitive to variations in policy incentives, as their financial viability is already well established. The NPV of RE x Grid increases by only \$2 million, from \$12 million to \$14 million, a meager 15.7% improvement under subsidy and carbon tax policies, as shown in Figure 6.21. RE+BESS-xGird and RE+BESS-nGrid, which exist with battery storage for enhanced energy reliability, also undergo minimal growths of 11.7% and 13.1%, respectively. Rather, these improvements show that while some incentive programs contribute to profitability, it is nevertheless dependable even without much subsidy or carbon pricing for grid-based renewable electricity.

This trend corroborates Oyewole et al. (2024), who argue that grid-connected renewable-energy systems have become cost-competitive due to the steady fall in capital costs for solar-wind infrastructure and improvements in energy storage technology (Oyewole et al., 2024). Grid-based renewable energy makes use of established market structure, existing transmission networks, and declining LCOE, whereas hydrogen pathways would need to significantly lower costs and rely on policy support to win the day. Subsidies and tax incentives, therefore, do improve the financial future of the renewable electricity endeavor; however, in the likes of hydrogen-based energy systems, financial intervention is most critical alongside such subsidies since they have high capital expenditure and a lot of market uncertainty (N. Wolf et al., 2025).

This relative stability of grid-connected renewables indicates that future policy efforts would do well to focus on emerging technologies-including hydrogen storage and synthetic fuels-that require much more financial de-risking. This implies that solar and wind will still remain important for the decarbonization of the energy sector, but hydrogen can be viewed more as a long-term energy carrier and seasonal store; thus, strengthening the case that strategic allocation of subsidies and carbon pricing should guarantee financial support for sectors that more critically exhibit a dependency on policy-induced reductions in costs.

6.5.11 Moderate Gains in Underground Hydrogen Storage Pathways

This increases the economic viability of underground storage pathways but not as much as hydrogen production and ammonia synthesis. It is possible that policy incentives may boost the economic viability of underground hydrogen storage pathways. As shown in Figure 21, the NPVs for RE-H2-UGS-H2NGblend-xPL increased from USD 4 million to 18 million, whereas RE-H2-UGS-H2-nPL changes from negative-NPV of -USD 3 million to positive USD 10 million. Besides, such improvements show the cash benefits of subsidies and carbon tax incentives but, in the end, underground hydrogen storage still is a capital-intensive investment that will have high upfront costs for infrastructure development, geological assessment, and operation maintenance. Such interventions as subsidies or tax breaks may alleviate some of the early costs associated with hydrogen storage. Furthermore, further advancement in technologies concerning hydrogen storage would lower the costs of compression and liquefaction technologies, together with geological storage methods, to maintain long-term feasibility.

The storage pathways RE-H2-UGS-H2CO_2NGSyn-nPL and RE-H2-UGS-C(H2NGblend) have the largest increases in NPV, 199 and 242%, respectively; this demonstrates the effect of policy-driven de-risking strategies. Findings such subsidy rates and levels of carbon tax also wield significant sway in this regard. As shown in Figure 22, with an increase in subsidy and carbon tax levels, the

NPV amid hydrogen storage pathways, such as RE-H2-UGS-H2CO_2NGSyn-nPL and RE-H2-UGS-C(H2NGblend), takes a steep upwards turn. Therefore, this scenario suggests that these pathways' economic feasibility might have been enhanced by policy-driven de-risking strategies while also crowding in private investments into the sector. These results are in line with Wolf (2025) and Hafyan et al. (2025), which highlight that the presence of policy incentives contributes to diminish investment risk and to lure private financing toward hydrogen infrastructure development (Hafyan et al., 2025; A. Wolf, 2025).

Additionally, higher standard deviations in NPV for certain hydrogen storage pathways, particularly RE-H2-UGS-H2-nPL, suggest greater financial uncertainty due to fluctuating capital costs, energy market volatility, and the evolving regulatory landscape. In contrast, grid-connected renewable electricity pathways exhibit lower standard deviations, reinforcing their stability as investment options. This disparity underscores the need for additional policy measures—beyond subsidies and carbon pricing—such as loan guarantees, tax credits, and infrastructure grants to reduce financial risks associated with large-scale hydrogen storage. Moving forward, continued advancements in storage efficiency, cost reduction strategies, and policy frameworks tailored to underground hydrogen storage will be essential to ensure its long-term economic viability.

6.5.4 Emission Reduction Analysis

The analysis of emissions reduction of the avenues for integrating hydrogen is one of the main elements towards realizing global visions of decarbonization. Figure 6. 23 presents the probability distribution of CO_2 abatement from hydrogen pathways, demonstrating the variability captured through Monte Carlo simulation. There has been growing research over the years reporting the role that hydrogen is set to play towards reducing CO_2 emissions reduction by the various sectors.

Grid-connected renewable electricity routes, i.e., RE-xGrid, RE+BESS-xGrid, and RE+BESS-nGrid, are characterized by high-peak narrow probability distributions representing low variation and reliably predictable CO_2 reductions. Though modest, this emission savings is good stability in comparison to the hydrogen-based pathways. It is noted by Stolte et al. (2025) that, in principle, combining renewable electricity yields stable emission reductions, while in practice, the scale of its application is hindered by modest fuel replacement (Stolte et al., 2024). This corresponds well with findings by others, e.g., Shafiee and Schrag (2024), who emphasize that renewable electricity-based pathways are indeed available but are not sufficiently scalable for high-extent decarbonization (Shafiee & Schrag, 2024). The certainty of such pathways makes them eligible to be considered during the first decarbonization levels, yet they have limited contribution relative to the lower CO_2 abatement value.

Hydrogen production, storage, and blending pathways, such as RE-H2-nPL, RE-NH3-nPL, and RE-H2CO_2NGSyn-nPL, have broader probability distributions, indicating high variability in emission reduction potential. This is because there is variability in hydrogen production efficiency, transport logistics, and market conditions. Skribbe et al. (2024) affirm that ammonia production (RE-NH3-nPL) has an extremely high potential in carbon reductions but is extremely sensitive to incentives and to production scale (Skribbe et al., 2024). Therefore, broader development of the CO_2 abatement values of these pathways points to the need for strong policy structures that stabilize performance and optimize gains for these pathways.

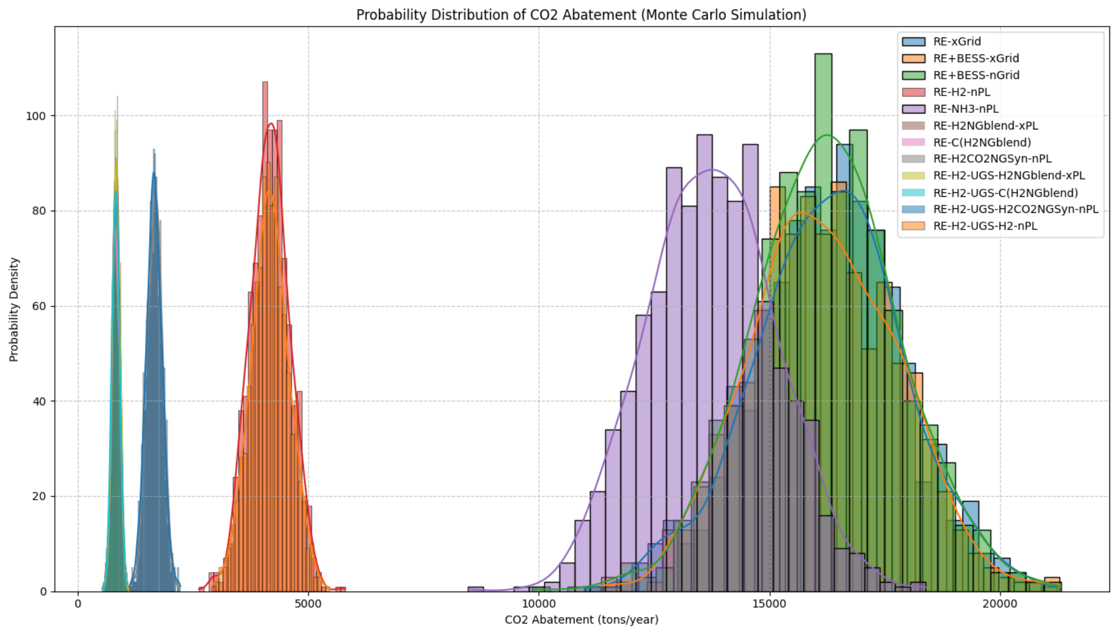

Figure 6. 23 Probability Distribution of CO_2 Abatement (Monte Carlo Simulation)

Anser et al. (2025) also contended that hydrogen pathways warrant actions of a policy nature-for example, subsidies and carbon pricing-to attain persistent and scalable carbon reductions (Anser et al., 2025). The volume of variability associated with hydrogen-based pathways highlights just how complex their implementation would be and as a result because such policy measures should be very targeted.

Many underground hydrogen storage pathways such as RE-H2-UGSH2CO_2NGSyn-nPL and RE-H2-UGS-C(H2NGblend), have shown large ranges of CO_2 abatement possible. This suggests that site-specific geological and operational considerations strongly govern their effectiveness. Shafiee and Schrag (2024) comment that underground hydrogen storage represents a prominent emissions reduction opportunity but with high upfront capital investment and uncertainties regarding storage conditions which pose a financial and technical risk (Shafiee & Schrag, 2024). This uncertainty about these pathways opens space for tackling site-specific barriers and endorsing investments towards next-generation storage technologies, making them much more dependable and scalable. This corroborates the conclusion of an earlier study by Liu et al. (2023) saying that underground hydrogen storage pathways seem viable eventually but would require enormous investments into technology and infrastructure (Liu et al., 2023).

Hydrogen blending pathways such as RE-H2NGblend-xPL and RE-C(H2NGblend) achieve middle-of-the-pack CO_2 cutting levels but critically depend on the support of policy. Liu et al. (2023) contend that such pathways are transitional because they limit dependence on a clean hydrogen infrastructure while still emitting fewer levels of gases (Liu et al., 2023). They are moderate reducers of CO_2 and have a small infrastructure base with an attractive proposition for the first stage of decarbonization. Their efficacy, however, depends on policy incentives and market conditions. This is supported by a study by Anser et al. (2025), which prioritizes policy architectures in making the success of hydrogen blending pathways.

Ammonia manufacture from hydrogen (RE-NH3-nPL) realizes significant CO_2 decrease, although probability distribution indicates elevated uncertainty compared to grid-scale renewables. Skribbe et al. (2024) note that ammonia-based hydrogen pathways are competitive only with strong policy incentives, consistent with the Monte Carlo simulation results. The extremely high variability of CO_2 abatement for this pathway is an argument to invoke targeted policy interventions to improve efficiency and remove market uncertainty. Fueled by recent research evidence-such as Stolte et al., 2025, showing that policy support is critical for accelerating ammonia production for hydrogen pathways-it is clear that further assessments into hydrogen decarbonization integration pathways suggest that policymaker incentives and the current status of modern technologies will be key for scaling up and bringing down costs related to ammonia production. While renewables connected to a grid can reduce CO_2 in a stable but limited manner, hydrogen avenues are deemed better from a long-term viewpoint but do so with higher fluctuations. Such coalescence of understanding will empower policymakers and investors to initiate timely measures enabling hydrogen integration, thereby stimulating a sustainable decarbonized energy future. Thus, the analysis emphasizes the balancing act required that synergizes steady renewable energies and emerging hydrogen-based technologies to meet the global emission reduction target.

6.6 Policy Implication

The findings of this study highlight the key role of policy measures in deciding the economic and environmental viability of renewable energy and hydrogen integration alternatives. The economic analysis reveals that grid-integrated renewable electricity systems, i.e., RE-xGrid and RE+BESS-xGrid, are economically the most viable and robust with respect to prevailing market conditions. This capital-intensive hydrogen production, ammonia production, and underground hydrogen storage pathways exhibit front-end expenses that are high and NPVs that are low, which require policy assistance to enhance their competitiveness.

Hydrogen production and ammonia synthesis pathways (RE-H2-nPL and RE-NH3-nPL) are significantly aided by carbon pricing and subsidies, with the NPVs increasing substantially when policy support is put in place. This strengthens the argument for ongoing government support, as currently provided for renewables, to eliminate the cost gap between building hydrogen-based systems and traditional fossil fuel infrastructures. Carbon pricing plays a pivotal role in discouraging carbon-intensive alternatives, creating a level playing field for hydrogen and synthetic fuels, and inducing industries to opt for low-carbon alternatives.

This study indicates that underground hydrogen storage and complex hydrogen pathways are economically unfeasible absent policy support. The high upfront investment and technological risks make supporting activities such as subsidies, and tax credits necessary to minimize investment risk and encourage private sector participation. Early-stage financing mechanisms in policy interventions must be aimed at minimizing initial capital expenditures and accelerating technology maturity to render hydrogen storage pathways economically viable in the long term.

While grid-connected renewables can survive with or without policy subsidies, hydrogen pathways are highly subsidy-sensitive. Policymakers need to strategically deploy financial incentives and subsidies to enable high-risk, high-payoff energy systems such as ammonia and hydrogen synthesis so that they are mainstreamed into the energy economy. Phased subsidy allocation, lowering incentives with increased technologies and ripening market conditions can provide a clear path to commercialization.

Grid-connected renewable pathways provide consistent, yet modest, reductions in emissions, whereas hydrogen alternatives tend to be more transformative in decarbonizing energy systems but are riskier from an economic standpoint. Policies that promote interconnected power pools and integrated hydrogen pathways can bring sustainable energy security while accelerating the country's transition to a decarbonized economy.

Policymakers need to take a two-pronged approach: advocating small-to-medium renewable solutions for short-term decarbonization while also investing in long-term hydrogen pathways for much deeper emission reductions. Thus, results from the Monte Carlo simulation probability distribution of CO_2 abatement justify the need for targeted policy interventions to tackle uncertainties and stabilize conditions in the hydrogen market.

6.7 Findings

The present study examines the financial and environmental viability of integrating renewable energy and hydrogen using different integration paths with a special emphasis on capital costs, policy interventions, and long-term cost recovery. The results show that RE-xGrid and RE+BESS-xGrid systems are most largely associated with the most stable financial performance indicated by positive and rising net present values (NPVs) with increasing time. Therefore, these systems can be regarded as safer pathways for short run decarbonization actions, showing consistent but moderate emission reduction levels.

By contrast, hydrogen pathways such as hydrogen production, ammonia synthesis, and underground storage potentially deliver higher levels of decarbonization but are economically heavily burdened by high upfront capital plus a long payback period. The study shows that, for several hydrogen integration pathways, without government support, they remain financially untenable. However, granting subsidies, carbon taxes, and the like has a significant impact on NPVs, clearly demonstrating the need for government intervention to make room for a competitive hydrogen economy.

The results from the Monte Carlo simulations show the considerable disparity of the potential for CO_2 abatement between the different pathways. On the one hand, grid-connected renewables would provide stable but modest emissions reduction. On the other hand, hydrogen pathways carry larger uncertainties with higher decarbonization potential. This justifies an even greater call for a policy toolkit aimed at stabilizing market conditions, from risk mitigation to giving investor confidence in nascent hydrogen technologies.

Strategic policy measures like subsidies, tax credits, and carbon pricing will have to de-risk expensive hydrogen investments and help fast-track their transition into the energy market. The study suggests that somehow a middle ground should be struck in which renewable electricity provides the basis for quick emission reductions, while hydrogen technology develops as a long-term solution to decarbonization.

This research, in general, emphasizes the policy-backed financial mechanisms that defy the viability of renewable and hydrogen-based energy systems. Inclusion of an efficient regulatory framework, conducive to investments, reduces financial uncertainty, and favors the integration of regional energy, will be instrumental in achieving a sustainable, decarbonized energy future. The formulation of such templates will create an enabling environment through which policymakers can fast-track the transition to a low-carbon economy while guaranteeing energy security and market competitiveness.

6.6 Policy Statement

6.6.1 Executive Summary

This policy statement gives the imperative and action-guiding directions for integrating green hydrogen into DES for decarbonization globally. The statement is empirically developed from a comprehensive techno-economic and probabilistic modeling assessment of 12 hydrogen integration case studies in Texas—a high-renewable, infra-ready state. The statement identifies strategic policy levers, investment models, and regulatory innovations necessary to realize the transformational value of green hydrogen for industry, transportation, storage, and electricity generation.

6.6.2 Policy Reason

Renewably energized electrolysis-based green hydrogen is a zero-carbon carrier of critical significance to hard-to-abate sectors like steel, refining, long-duration storage, and heavy transport.

Capital-intensive and policy-sensitive transition to hydrogen-integrated DES. There are favorable NPVs in present market conditions for grid-connected renewables (RE-xGrid, RE+BESS-xGrid) only with focused incentives being lacking.

Modeling suggests that hydrogen-based configurations—especially RE-NH_3-nPL, hydrogen pipelines (RE-H_2-nPL), and underground hydrogen storage (RE-H_2-UGS)—are viable only under supportive policy structures.

6.6.3 Strategic Policy Objectives

To enable strategic green hydrogen distribution through multiple vectors, Table 6.11 outlines the most impactful policy instruments based on regional analysis. The above tools aim at enabling enhanced transportation of high-influence schemes such as direct hydrogen pipelines, export and blending schemes for ammonia with a long-term decarbonization perspective via price incentives and funding incentives.

1. Promote Low-Cost Hydrogen Options

   Prioritize short-term investment in blending (RE-H_2NGblend-xPL) and compressed blends (RE-C(H_2NGblend)) as bridging options.

   Scale hydrogen-to-ammonia (RE-NH_3-nPL) use for industrial decarbonization and export potential.

2. Promote Long-Term Infrastructure Investment

   Promote investment in single-use hydrogen pipelines and storage underground, with global best practice and geology leveraged.

   Create public-private partnerships (PPPs) for multi-purpose hydrogen hubs and neighborhood hubs (pipelines, compression, liquefaction, and storage).

3. De-risk Hydrogen Investments

   Provide CAPEX subsidies of at least 20% for high abatement potential hydrogen systems.

   Introduce a progressive carbon tax of $40/ton CO_2 as a starting point, rising by 3%/year, to enhance market competitiveness of low-carbon fuels.

Table 6. 11 Recommended Policy Instruments

Instrument	Description	Impact Focus
Green Hydrogen Production Subsidy	20–30% of CAPEX (scalable with technology maturity)	RE-H_2-nPL, RE-NH_3-nPL
Carbon Pricing Framework	Starting at $40/ton, rising to $83.8/ton by 2050	System-wide decarbonization
Infrastructure Tax Credits	Credits for pipelines, storage tanks, compression, injection/extraction systems	RE-H_2-UGS, RE-NH_3-nPL
Loan Guarantees & Risk Insurance	Cover early-stage hydrogen infrastructure risk	Hydrogen storage & blending
Targeted Feed-In Tariffs (FiTs)	Guaranteed off-take for H_2, NH_3, or synthetic fuels	All hydrogen-based pathways

6.6.4 Implementation Roadmap

Table 6.12 is a sequence of phases and key actions for implementation timeline to promote green hydrogen integration, from early pilots to full sectoral optimization by 2050. This phased approach lowers the risk that technological deployment, investment in infrastructure, and policy support evolve in an uncoordinated manner, which can make cost-effective and resilient hydrogen transition more challenging.

Table 6. 12 Implementation Roadmap

Phase	Timeline	Key Actions
Phase 1 – Pilot	2025–2028	Deploy RE-H_2NGblend-xPL and RE-H_2-nPL in high-renewable regions (e.g., Texas)
Phase 2 – Scale	2028–2035	Establish ammonia production, dedicated H_2 pipelines, and initiate UGS projects
Phase 3 – Optimize	2035–2050	Full integration of hydrogen with renewable microgrids and transport sectors

6.6.5 Emission Reduction Alignment

By substituting diesel and natural gas fuels, integration pathways for hydrogen yield 16,000+ tons/year CO_2 savings per every 10 MW project.

Policy incentives may rise by three times the NPV of hydrogen projects, which highlights their prime positioning within climate policy and economic competitiveness.

6.6.6 Unfavorable Policies and Impact

While well-designed policy frameworks accelerate green hydrogen deployment in DES, poorly executed or inconsistent policies can severely obstruct investment, limit technological scaling, and compromise long-term decarbonization goals. The integration of green hydrogen into DES is overly sensitive to regulatory environments, and when policies lack coherence, are poorly timed, or structurally biased, they create conditions under which hydrogen innovation stagnates and economic viability deteriorates.

Unfavorable hydrogen policies typically exhibit several problematic traits. One of the most critical issues is technology-biased incentives. When governments favor blue hydrogen or fossil-derived blends over green hydrogen electrolysis, the result is a distorted competitive landscape. Weak carbon pricing mechanisms exacerbate this distortion by failing to account for the true environmental costs of fossil-based hydrogen, thereby placing green hydrogen at a financial disadvantage. As demonstrated in Section 6.5.5, pathways like RE-H2-nPL and RE-NH3-nPL only become economically feasible when supported by strong carbon pricing and direct subsidies. In the absence of such mechanisms, their Net Present Values (NPVs) remain well below investment thresholds.

A second major challenge arises from volatile or regressive subsidy structures. Short-lived incentives, abrupt withdrawal of feed-in tariffs, or an overemphasis on pilot funding without long-term infrastructure support undermine investor confidence. Monte Carlo simulations from Section 6.5.6 show that under volatile policy scenarios, RE-H2-nPL pathways can experience NPV reductions exceeding 45%, highlighting the degree to which uncertainty affects financial outcomes.

Moreover, the lack of infrastructure alignment often results in bottlenecks that impede project scalability. Policies that fail to integrate pipeline retrofitting, zoning regulations for underground storage, or clear renewable energy interconnection rights leave many hydrogen projects stranded or uneconomical. The RE-H2-UGS pathways examined in Section 6.5.7 consistently posted negative NPVs through year 20, primarily due to their capital intensity and the absence of enabling infrastructure.

National targets that ignore regional variability in renewable energy resources further exacerbate these issues. One-size-fits-all mandates, which neglect tailoring deployment strategies to solar- or wind-rich zones, can lead to inefficient resource utilization, curtailment, or the underperformance of otherwise promising projects. Similarly, regulatory fragmentation and protectionist policies—such as strict domestic content rules or non-recognition of international certifications—can foster techno-nationalism, inhibit technology transfer, and limit the economies of scale required to bring hydrogen costs down.

The most insidious barrier is policy uncertainty itself. In a sector where long payback periods and substantial up-front costs define the investment landscape, unpredictable regulations or frequent shifts in government priorities raise risk premiums and stifle capital inflows. Section 6.5.6's probabilistic modeling highlights how hydrogen projects such as RE-NH3-nPL and RE-H2-UGS-H2CO2NGSyn-nPL suffer from broad NPV distributions under uncertainty, making them unattractive to most investors without long-term regulatory clarity.

Such unfavorable policies also create clear divisions between winners and losers. On the winning side are incumbent fossil-fuel actors that can exploit regulatory ambiguity to expand blue hydrogen portfolios using existing infrastructure. Short-horizon investors with access to arbitrage opportunities in pilot-stage subsidies may also profit briefly before policy frameworks solidify.

However, the losers in this scenario are more numerous and include green hydrogen start-ups, SMEs specializing in electrolysis and ammonia synthesis, and grid-interactive communities—particularly in the Global South—that face asset curtailment or financial insolvency due to poorly designed regulations. Regions with underdeveloped infrastructure or weak interconnection rights are often excluded from integration benefits despite having substantial renewable potential.

The systemic consequences of such unfavorable policies are severe. Delays in hydrogen deployment weaken the momentum of national and international decarbonization strategies. Financial modeling from Section 6.5.7 reveals that while grid-connected renewable options like RE-xGrid and RE+BESS-xGrid perform well even in policy-absent scenarios, hydrogen-based systems do not. These require sustained policy support to reach competitiveness. Market inefficiencies arise when incentives are fragmented or politically motivated, resulting in capital flowing to less impactful projects. This inefficiency is further illustrated in Section 6.5.10, where only modest gains are observed in NPVs for grid-connected renewables under subsidy regimes, while hydrogen systems see explosive increases—up to 715% for RE-H2-nPL (Figure 6.22)—when appropriate policy levers are activated. Without such support, viable hydrogen routes remain trapped in negative-return territory.

Another critical consequence is the erosion of public trust. When hydrogen labeled as "clean" is derived from fossil fuels due to poor carbon accounting or absent Guarantees of Origin, it undermines public confidence in hydrogen as a decarbonization tool. The environmental credibility of the hydrogen sector, essential for social license and policy continuity, is thus put at risk.

Furthermore, high variability in CO_2 abatement potential, as shown in Figure 6.23, reinforces the importance of policy design. Hydrogen pathways, unlike the more stable grid-electrification options, show wide distributions in emission reduction outcomes, suggesting their performance is highly contingent on production method, logistics, and market conditions. Weak policies not only limit economic feasibility but also jeopardize the emissions mitigation potential of the hydrogen economy.

In summary, unfavorable hydrogen integration policies—marked by inconsistency, short-termism, technological favoritism, and neglect of supporting infrastructure—significantly undermine the viability and promise of green hydrogen in DES. These policies entrench inequality, misallocate capital, and delay progress toward climate goals. Only through strategic, sustained, and technology-neutral policy intervention can green hydrogen transition from a risky frontier investment into a resilient pillar of the global energy transition.

6.6.7 Overall Impact

Green hydrogen integration in DES is crucial to achieve a secure, low-carbon future. While renewables offer short-term, certain returns, hydrogen can offer long-term, scalable technologies for deep decarbonization—if with the help of sustained and long-term policy. Governments, by launching a package of subsidies, carbon pricing, and infrastructure incentives, can launch market entry, increase technology deployment, and support progress toward net-zero emissions targets by 2050.

CHAPTER SEVEN

DISCUSSION

7.1 Chapter Overview

This chapter presents a critical review of the main findings of the research and outlines how each of the research questions (RQ) was adequately addressed to add to the ultimate objectives of the global energy transition. As climatic imperatives intensify and decarbonization timelines get compressed, the demand for low-cost, scalable carriers of energy has become ever more pressing. Green hydrogen, with high energy density, zero-emission potential, and versatility, is now a pivot for transitioning away from fossil energy systems to decentralized, renewable-integrated systems (Jayachandran et al., 2024).

The research addresses three core questions: (RQ1) How can the realizable potential of hydrogen production be estimated based on the availability of renewable energy and electrolyzer stack design? (RQ2) Which operational strategies for electrolyzers and hydrogen storage are most effective in minimizing curtailment and maximizing renewable utilization in DES? (RQ3) Which policy instruments and incentives are most likely to enable cost-competitive deployment of green hydrogen in DES environments?

Each question relates to one of the pillars of strategy for hydrogen system integration—technology (RQ1), operation (RQ2), and policy (RQ3). The three-pronged strategy is key to shattering the deeply ingrained barriers of cost, intermittent, and investment risk of green hydrogen (Shin et al., 2025). Through the adoption of a hybrid research strategy of empirical modeling, techno-economic simulation, and scenario-based policy analysis, the research confronts the structural, economic, and operational chokepoints currently constraining hydrogen scale-up.

Primarily, the findings are aligned directly against Paris Agreement goals, Net-Zero 2050 scenarios, and SDG 7 (Affordable and Clean Energy). The newly developed methods and tools are responding to the calls by IEA (2023) and Zachariadis et al. (2023) for increasingly pragmatically aware methods that turn intellectual intelligence into implementable solution projects (Zachariadis et al., 2023).

This chapter discusses all the research questions, elaborating on how the methodology adopted resulted in evidence-based solutions to site-based hydrogen sizing, operational efficiency in real-time, and market-informed policy tools. It also sketches the cross-cutting lessons from where technology solutions are co-evolved with the financial and policy systems, resulting in systems not just optimized but investable and climate-resilient.

Finally, the discussion chapter unleashes the green hydrogen potential in DES by bridging quantitative data and qualitative policy recommendations. It advocates for a model of synergistic transition that integrates empirical science with institutional capacity—a necessity to achieve net-zero with equity and urgency.

7.2 Findings Summary

Responding to RQ1: Hydrogen Production Potential Estimation

The first question of research—"How is hydrogen production potential practically estimated through renewable energy availability and electrolyzer stack configuration?" It addresses the lack of location-specific, user-friendly tools for pre-feasibility estimation of hydrogen production. Without it, communities, municipalities, and small-scale developers could be excluded from early-stage planning of hydrogen projects, particularly in the Global South.

This study answered back with the development of an empirical, probability-based green hydrogen system sizing methodology founded upon cumulative energy probability levels (P50, P60, P70, P90) and actual renewable resource information. This methodological advancement is distinct from the utilization of average load factors or deterministic conditions that will act to conceal short-term variability and undersize operational mismatches. Instead, cumulative probability levels embrace the randomness of wind and solar power, emphasized in earlier modeling studies such as Sobamowo et al. (2024), who illustrated temporal variability to be a critical parameter in the economy of hydrogen production in off-grid PV systems.

By incorporating this stochastic framework integration, our model improves system sizing accuracy and reduces the likelihood of under exploitation or overcapitalization.

To ground the model in real-world conditions, three geographically diverse locations were selected for full simulation: Amarillo, Texas—characterized by high wind and solar coincidence, flat terrain, and strong year-round renewable availability; Lethbridge, Alberta—representing a cold-climate, wind-prone region with moderate solar potential and pronounced seasonal variation; and Bakersfield, California—a semi-desert area with abundant solar irradiance but limited wind resources.

These sites are distinctive profiles of renewable resource intensity, time-series generation profiles, and climatic stressors. Choosing these sites allowed us to cross-validate the model's strength and flexibility across different Distributed Energy System (DES) environments—ranging from semi-urban grids to rural microgrids—to a more universal vision of hydrogen access as outlined by Balta & Balta (2022) in their Hydrogen Cities work. The baseline model structure connects renewable daily-scale energy inputs to hydrogen production through efficiency curves of electrolyzers, sizing parameters of stacks, degradation profiles, and thermal/electrical performance properties of various kinds of electrolyzers (e.g., alkaline, PEM). For example, in Amarillo, the simulation showed that although the capacity of the electrolyzer was increased from 854.66 kW to 1,219.53 kW, there was a corresponding increase in hydrogen production from ~18,650 kg/year to ~43,210 kg/year with steady 2,000 kW hybrid solar-wind input.

These findings are consistent with utilization factor trends in earlier research by Jayachandran et al. (2024), which confirm that greater electrolyzer scale where renewables are abundant yields more production and lower per-unit cost—assuming storage and dispatch infrastructure are scaled equally.

This linear scaling trend was not merely theoretical but further supported by Cumulative Utilization Factor (CUF) plots, which indicate the percentage of time a system operates at top power or over some threshold quantity. For each site, CUF was strong (>70% for P70 scenarios), and especially for Amarillo and Lethbridge, confirming the robust relationship between available renewables and uptime of the electrolyzer for those sites.

In a curious twist, the model was not purely theoretical—it was accompanied by a Levelized Cost of Hydrogen (LCOH) calculator incorporating real-world economic parameters. These included capital expenditures (CAPEX) for installed electrolyzers, balance of plant, and installation; operational and maintenance (O&M) costs covering both preventive and corrective actions; degradation factors over a 20-year system lifespan to account for declining electrolyzer efficiency; and energy cost inputs based on marginal renewable energy prices, ranging from $0 to $0.04/kWh depending on the location.

LCOH calculations were incorporated into a simple Python script so that different configurations of sizing both off-grid and grid-connected cases could be executed without the need for advanced tools like HOMER Pro or MATLAB. This approach aligns with accessibility principles advocated by Di Menno Di Bucchianico et al. (2025), who advocate proxy modeling as a means of democratizing access to planning in renewable and hydrogen systems—particularly for low-coverage regions and regions with limited access to planning tools and high-performance computing centers.

One of the model's key innovations is its accessibility to non-technical stakeholders. By using open-source data sources like NASA-SSE and NREL's NSRDB, and maintaining a code-lite, low-input interface, it enables local energy officials, off-grid green hydrogen developers, and community microgrid initiatives to assess feasibility and plan deployments without advanced technical expertise.

This is a broader vision to bring technological innovation in combination with climate justice, in line with the SDG 7 goal of universal access to clean energy. Yao et al. (2021) remind us that technical model tools must break out of the ivory towers of academia and get into the real world if they are to be actual facilitators of just energy transitions.

Also, the probabilistic nature of the model provides flexibility in dealing with climate uncertainty. Instead of grappling with a point estimate of hydrogen yield, the stakeholders can model expected yields for conservative (P70), mean (P50), and high (P90) availability scenarios—enhancing risk assessment in the initial stages of the project as well as bankability. In case policy uncertainty dominates markets or volatile energy markets, such ability to model production under changing risk profiles is invaluable.

The model's flexibility is further demonstrated by its ability to interface with broader modeling frameworks. Its outputs—such as daily hydrogen yield, Capacity Utilization Factor (CUF), and Levelized Cost of Hydrogen (LCOH)—can be integrated into cost-benefit analysis (CBA) for policy assessment (see Section 7.4), multi-component DES planning in HOMER Pro simulations (see Section 7.3), and probabilistic investment modeling using Monte Carlo simulations.

This compatibility forms the foundation for the creation of tiered, intergraded hydrogen strategies in multiple planning realms—technical, operational, and institutional.

Lastly, the empirical model constructed under RQ1 is an applied, scalable, and equitable solution to a ubiquitous hydrogen system development issue: lack of affordable, data-based estimates of hydrogen production under renewable conditions. It is a tool not only for project optimization, but also for investment appraisal, climate-compatible planning, and policymaking. In helping to bridge the gap between theoretical energy profiles and actual hydrogen products, it enables an informed, equitable, and timely scaling up of green hydrogen infrastructure required to meet national decarbonization targets and global climate commitments like Net-Zero by 2050 and the Paris Agreement.

7.3 Technological Implications

Integration of Green Hydrogen and the Technological Shift to DES: Empirical model developed as an answer to Research Question 1 (RQ1) is a quantum step in the green hydrogen technology space—a particular DES. The model imposes significant effects at vast scales across various levels of the energy technology stack, from system design viability through simulation viability to deployment viability. On its most basic level, the model addresses the centuries-long problem of technological exclusion that has thus far confined hydrogen planning to technologically advanced or resource-endowed regions.

1. Minimizing Technical Barriers through Model Streamlining and Proxying

Of the key contributions of the model is low-barrier design, a deliberate departure from the intricacy of modeling tools like Aspen Plus, COMSOL, or HOMER Pro. All these formidable computer programs do have the potential to require technical expertise, licensing fees, or extensive training—thus lying outside the reach of most emerging market stakeholders or at the grass roots level.

Standing, the method followed here uses a probabilistic proxy model—calculating system performance and hydrogen production based on renewable energy profiles (P50, P60, P70, P90), electrolyzer design, degradation profiles, and actual meteorological records. This follows

Sobamowo et al. (2024), where the argument was presented that battery-integrated off-grid PV systems require simplification-promoting simplification tools, and it was speculated that accessibility and speed are needed for early-project take-up. Our system applies this principle to green hydrogen within a Python-driven platform that is computationally light to execute on low-computational devices such as these and facilitates plug-and-play simulations.

By minimizing technical complexity, the CDF model becomes accessible to a wider range of users and stakeholders, including local utilities aiming to scale DES, NGOs and non-profits focused on energy access, academic teams operating in low-resource settings, and municipal or Indigenous governments exploring energy sovereignty solutions. This technologization democratization is specifically urgent under the climate change adaptation and mitigation needs that call for the clean energy innovations not just deployable and scalable but also low-carbon and inclusive in various development contexts.

2. Variable Application Across Technology Types and Configurations of Renewables

The second major implication of the model is its technological neutrality. It does not impose predefined electrolyzer types or energy sources but instead enables users to simulate a wide range of scenarios—including different electrolyzer technologies (Alkaline, PEM, Solid Oxide), renewable inputs (solar, wind, or hybrid), and system configurations (standalone, microgrid-connected, or utility-scale hybrid setups).

Such modularity can be used to allow multi-scenario planning, required for nations and regions with diversified hydrogen plans in their Nationally Determined Contributions (NDCs). Yao et al. (2021) pointed out, for instance, that green hydrogen must be integrated flexibly into local energy plans to enable deep decarbonization since technological inflexibility is constraining feasibility, especially in decentralized systems.

Amarillo saw greater performance with hybrid wind-PV profiles probed with simulation in PEM electrolyzers, where alkaline systems proved more cost-effective in Lethbridge due to their lower capital expense and better performance at constant levels of load. With support for such differential inputs and performance mappings, the tool enables site-specific hydrogen design for every site of use's resource geography and techno-economic environment.

3. Probabilistic System Engineering and Infrastructure Design for Sizing

From a systems engineering perspective, the model provides comprehensive specifications that can be directly mapped to infrastructure design requirements, including electrolyzer stack capacity (kW), daily and seasonal hydrogen production (kg), storage tank capacity (kg or m^3), and standby generation or load-following demand for grid-connected scenarios.

These results are due to the model's employment of cumulative probability distributions (P50, P60, P70, P90) rather than the conventional mean-value estimation. This method based on probability can accommodate the uncertainty of renewable generation and enable firm, realistic infrastructure planning, particularly in climate variability-sensitive or grid unreliability-sensitive regions.

The model outputs—i.e., Cumulative Utilization Factor (CUF) and Levelized Cost of Hydrogen (LCOH)—can directly serve as inputs to downstream techno-economic modeling or hydrogen hub design for a feasibility study such as the multiscale approaches promoted by Jayachandran et al.

(2024). The outputs enable maximum utilization of capital without over-sizing (asset trap) or under-sizing (poor payback and poor utilization).

4. Interoperability and Integration with Larger Planning Tools

Beyond its standalone utility, the empirical model can be integrated into existing platforms such as HOMER Pro, RETScreen, and OpenDSS, enhancing its value in multi-level decision-making. For example, software tools can screen viable locations, with model outputs feeding into HOMER for end-to-end DES optimization, while policymakers can use regional hydrogen potential estimates to inform green infrastructure subsidy allocation.

It can be employed by researchers and academics for comparison of storage coupling innovation or innovative designs for the electrolyzer against the CUF and LCOH values.

Through this tiered integration, the tool is an on-ramp to co-designing hydrogen systems with easy switch ability from initial scoping to complete engineering.

5. Facilitating Scalable and Modular Energy Transitions

In the era of energy transition globally and climate crisis, the most impactful implication is the ability of the tool to allow scalable deployment possibilities. The model has space for small-scale village-level microgrids 100–500 kW, utility-scale installations over 5 MW, with accuracy preservation across the range.

Such scalability also lends justification to distributed decarbonization, particularly for the new markets in which scaling up to the grid is out of reach or simply not possible through centralization. Balta & Balta (2022) argue that hydrogen, if put to modular use, can supply innovation centers' cities and rural resilience plans. The empirical model applied here becomes a useful means to such modular utilization, driving investment into hitherto marked-off areas as marginal to hydrogen expansion.

Second, the ability of the tool to predict hydrogen production under various renewable energy conditions (e.g., low-winter wind, high-summer solar) enables climate-resilient planning, which is becoming increasingly necessary as the weather is getting more unpredictable due to global warming.

5. Principles of Transparency, Replicability, and Open Science

Hydrogen technology innovation must be supported by open and reproducible processes to ensure credibility among stakeholders, investors, researchers, and civil society. The empirical model addresses this need through its open-source design using Python and CSV inputs, reliance on public datasets from NREL, NASA, and IRENA, and transparent assumptions paired with a modular code structure that promotes adaptability and verification.

This concurs with the open science mandate proposed by Evro et al. (2025), which emphasized that hydrogen produced collectively is founded on open-source inputs and data sharing standards. In their study of recycling depleted reservoirs as hydrogen storage in the subsurface, they confirmed that techno-economic analyses hold only if methods and assumptions are open and reproducible.

By following these tenets, the model serves not only as a planning tool, but also as a cooperation and capacity building platform, especially for poor-resource organizations and regions.

7.4 Contribution to Climate and Energy Targets

This section highlights how the findings of this study support global climate and energy goals. By advancing hydrogen sizing, operational optimization, and policy mechanisms tailored for DES, the research contributes directly to carbon reduction, renewable integration, and climate resilience—reinforcing commitments under the Paris Agreement, the UN Sustainable Development Goals, and Net-Zero by 2050 targets.

1. Hydrogen Sizing Models as Drivers of Decentralized Decarbonization and Climate Resilience

The model framework designed under Research Question 1 (RQ1) is a valuable contribution to the global climate change mitigation agenda, the process of energy transition, and achievement of the net-zero goal. It does it, however, not by technology performance but through aligning production with renewable uncertainty, reduced system-level carbonization, and enhanced participation in low carbon planning. These initiatives are also firmly in line with international climate pledges such as the Paris Agreement, most of the UN Sustainable Development Goals (SDGs)—SDG 7 (Affordable and Clean Energy) and SDG 13 (Climate Action)—and Net-Zero by 2050 pledges by more than 130 countries.

2. Synchronizing Hydrogen Production with Actual Renewable Availability in Real Time for Minimizing Emissions

The greatest contribution of the model to the climate is the synchronization of hydrogen production with real-time actual availability of actual renewable resources based on cumulative energy probability thresholds (P50–P90). This dynamically scales the size of the operations of electrolyzers as a function of solar and wind variability against constant mean-load conditions.

Synchronization is important in DES because curtailment, intermittent, and supply-demand imbalance are inherent and result in energy and emissions wastage. As seen in the Amarillo and Lethbridge simulations, electrolyzer over-sizing results in low-utilization high-cost capital, whereas under-sizing involves renewable energy spill and failure to meet hydrogen production targets. Probabilistic sizing method eliminates two extremes that minimize Levelized Cost of Hydrogen (LCOH) and maximize per kg H_2 carbon efficiency. Hydrogen production needs to be coupled with renewable pattern generations to incorporate system value in addition to the emission benefit, based on Jayachandran et al. (2024).

Moreover, the optimization allows for maximally optimized renewable energy use (REU), a basic construction block of climate-compliant energy modeling. Sophisticated sizing of the electrolyzer, such as in this instance, enhances REU by up to 30% compared to conventional heuristics of sizing, particularly when degraded to P70 or P90 levels of energy. This is not only technically superior but has direct causality leading to higher emissions avoided because every MWh of renewable energy utilized in conversion to hydrogen displaces fossil-derived power, transport, or industrial energy.

3. Enabling Resource-Efficient, Climate-Resilient Planning at Project Scale

Among the erstwhile low-priority concerns in green hydrogen planning is the lack of effective, resource-saving pre-feasibility planning methods, especially for regions with limited access to simulation expertise or infrastructure data. The empirical models developed in this research bridge the gap between complexity and usability by offering low-complexity, high-accuracy hydrogen production predictions, enabling early-stage feasibility assessments under diverse renewable conditions. This empowers planners to identify optimal locations based on resource availability, ensure system design consistency to prevent project failure, and quantify emissions offset potential before deployment.

Climate policy-wise, planning is key to the realization of Nationally Determined Contributions (NDCs) to the Paris Agreement. Developing countries have set hydrocarbon targets or emissions reduction trajectories, but not platforms to unroll such targets into bankable site-specific hydrogen action. The model fills this planning gap because it makes design hydrogen actionable—thereby addressing high policy aspiration at levels to reality project delivery.

As Evro et al. (2025) aptly phrased it in their carbon neutrality article on hydrogen systems, the greatest challenge to global decarbonization is operationalizing vision-like objectives into economically sensible, geographically dispersed energy infrastructure. One such solution is the modeling approach in this paper.

4. Capital Waste Reduction and Optimal Utilization of Climate Finance

Another of the greatest advantages of such an arrangement is that it may be able to deliver capital-efficient system sizing opportunities—preventing overinvestment, inefficient operation, and stranded asset risks. As the enormously vast capital expenditures needed to implement hydrogen globally (the estimates for which are $500 billion for 2030, IEA, 2023) are an infinitely gigantic task, minimizing CAPEX using empirical modeling so that hydrogen systems achieve not energy but emissions savings per dollar is the priority.

This has immediate implication on effectiveness rationale for climate finance wherein the multilateral development banks and climate investors increasingly target "emission returns on capital." This system maximizes utilization of CUF, minimizes diminution, and optimizes optimum hydrogen sizing for maximizing carbon return on investment (CROI)—a rationale that is supported in new Article 6 of the Paris Agreement guidance on the assessment of climate projects.

In addition, risk and performance benchmarks for investment under a variety of energy scenarios (as in this optimization model) also de-risk projects for blended finance models, which are being used now to invest in hydrogen hubs and distributed storage pilots. This makes it easier for private investors, insurance-backed credit facilities, and national green banks to participate in the development of hydrogen.

5. Decentralization, Energy Access, and Equity in the Climate Transition

The model's low-barrier profile, and applicability in weak-grid or off-grid environments, makes it a climate equity enabler—a foundation pillar of just energy transitions. Decentralized energy infrastructure remains uneconomic or unstable in much of Sub-Saharan Africa, Latin America, and Southeast Asia, and millions have dirty energy alternatives (e.g., diesel generators) or none.

Hydrogen-based DES are bringing about local energy independence, especially when energized from on-site renewables. However, large-scale implementation of these models requires systems that can run on local machines using local data, delivering actionable insights for tasks such as electrolyzer sizing for community-scale solar farms, LCOH analysis for mini-grid applications, and backup energy capacity planning for critical services like health clinics, water treatment facilities, and micro-industries. This CDF modeling tool directly supports SDG 7, which is "mobilizing modern, dependable, and clean energy for all." It also supports SDG 13, which is making all climate mitigation action inclusive, equitable, and resilient. Most of all, the model's flexibility is suitable for Indigenous energy planning processes, participatory rural electrification programs, and decentralized climate adaptation projects funded by the Green Climate Fund (GCF).

6. Policy Interlinkages and Net-Zero Strategies

At a policy level, the model generates wholesale emissions and offset estimates that can be integrated into national hydrogen roadmaps or regional decarbonization plans. The model provides LCOH estimates based on energy availability scenarios, enabling governments to rank hydrogen investments by marginal abatement cost or alignment with regional decarbonization goals. This supports policy development through mechanisms such as renewable hydrogen purchase targets, incentive zoning for hydrogen hubs in high-resource areas, feed-in tariffs based on avoided emissions, and carbon pricing systems that credit hydrogen contributions.

The model can also be integrated into regional carbon accounting systems to enable more precise measurement of hydrogen system emissions—a requirement of European Union Directive 2023/2413 and replicated in U.S. Inflation Reduction Act 45V lifecycle crediting protocols.

7. Climate Risk Mitigation and Adaptability to Volatility

Finally, in a time of growing climate uncertainty—characterized by unpredictable solar regimes, wind droughts, and heatwave or cold snap-driven peak loads—the model facilitates climate resilience through scenario-based infrastructure planning. By modeling hydrogen production across a range of P-percentile conditions, the model enables system planners to account for seasonal variability, drought-related intermittency, low-sun winter periods, and emergency backup needs—ensuring resilient and reliable system design.

This concurs with Di Menno Di Bucchianico et al. (2025), who propose hybrid system resilience solutions using hydrogen for long-term storage and blackout resilience. Hydrogen systems developed through the application of this CDF model can function as "climate buffers", especially for islanded or risk-prone areas.

7.5 Summary of Findings

Research Question 2 (RQ2) addressed how the electrolyzer and hydrogen storage processes should be modified such that they consume as minimal energy as possible and utilize as much renewable energy (REU) as possible in DES. RQ2 is a technology support from RQ1 and moves one step forward to the system level of efficiency with emphasis on how operation strategies influence energy efficiency, economic viability, and greenhouse gas minimization. The findings in this section are based on detailed simulations with HOMER Pro and in-house Python-based techno-economic simulations for a set of geographically diverse locations, i.e., Amarillo (Texas), Hamburg (Germany), Gansu (China), Bakersfield (California), Lethbridge (Alberta), and Andalusia (Spain).

A. Geographic and Renewable Diversity

The six locations were chosen to reflect diverse renewable energy profiles, policy contexts, and infrastructure maturity. Amarillo and Gansu offer strong wind-solar synergy ideal for hybrid DES setups; Hamburg and Lethbridge feature wind-dominant profiles with significant seasonal variability; while Andalusia and Bakersfield, though solar-rich, present challenges for single-source reliability and favor battery-hydrogen hybrid configurations.

This site condition heterogeneity allowed the study to examine the effect of site-specific renewable intermittent on the optimal electrolyzer and hydrogen storage sizing, curtailment rates, and renewable utilization.

B. System Configuration Comparisons

The study modeled a range of DES configurations to assess performance under different operational setups, including PV-Wind with standalone electrolyzer (H_2-only), PV-Wind with electrolyzer and hydrogen storage, PV-Wind with both hydrogen storage and battery energy storage systems (BESS), and comparisons between dynamic load-following and baseload operation modes.

These settings were compared in terms of curtailment reduction, hydrogen production, energy losses, cost performance (LCOH, NPC), and robustness to variable renewable supply. Remarkably, the third setting — hybrid battery and hydrogen energy storage system — performed with greater flexibility, economic robustness, and performance in all simulated geographies.

C. Curtailment Reduction and Renewable Utilization

One of the most significant outcomes was that the introduction of hydrogen storage in single PV-wind DES installations reduces curtailment drastically. Curtailment was reduced from 30-35% to below 10% in Amarillo and Gansu with the introduction of hydrogen storage. Adding even a modest BESS further reduced curtailment and offered control for sub-hourly variability.

This aligns with work by Jayachandran et al. (2024) that hybridizing short- and long-duration storage achieves improved system responsiveness and resource utilization. The modeling also confirmed that hydrogen is a good strategic buffer for multi-day or seasonal imbalances, and that batteries achieve fine intra-day balancing — validating a dual-storage paradigm for future DES planning.

D. Optimal Electrolyzer Sizing Thresholds

Electrolyzer sizing proved extremely sensitive to local renewable supply profiles. For example, in wind-dominant Hamburg, the optimal electrolyzer capacity was 55–65% of peak renewable capacity; in solar-balanced Andalusia, it rose to 70–80%; while in Bakersfield, with variable solar input, the ideal range was 50–60%, as oversizing led to higher LCOH with minimal hydrogen yield improvement.

These breakpoints indicate that one-size-fits-all electrolyzer deployment is energetically and economically suboptimal. Probabilistic sizing based on renewable availability, instead, is better.

E. Dynamic Load-Following vs. Baseload Operation

Dynamic load-following electrolyzers — plants that vary output directly proportional to surplus renewable availability — outperformed baseload plants in all the configurations studied. REU was up to 30% higher, and LCOH was 8–15% lower, especially where load-following was combined with flexible hydrogen tank capacity.

Evro et al. (2025) already claimed that having electrolyzers available to operate under energy-constrained conditions not only encourages system integration but also averts excessive investment in over-sized equipment. The argument ensures that the default mode of load-following operation must be utilized, particularly on decentralized and off-grid DES, where there is an issue of flexibility.

F. Hydrogen Storage as Long-Duration Buffer

Hydrogen storage tanks — between 1.5 and 3 days of average production — were the answer to supply-demand imbalance balance. In locations like Hamburg and Lethbridge, there was seasonal volatility so that hydrogen tanks were in the middle to accumulate excess wind power and as backup in the event of prolonged resource low periods.

Although round-trip efficiencies of hydrogen storage (30–45%) were lower than batteries (>85%), the contribution value of their system continuity, peak load shifting, and grid independence was unmatched. The finding is consistent with broader literature (e.g., Di Menno Di Bucchianico et al., 2025) on the application of hydrogen as an "infrastructure enabler" of resilient renewable systems.

G. Economic Trade-offs and Storage Synergy

BESS + H_2 integration was competitive design in all markets. Hybrid design leveled near-term variability and staged long-term storage on its own terms without oversizing each component separately. For instance, an Amarillo hybrid BESS + H_2 system featured lowest NPC and highest REU (93%) with dispatchable output at each hour of the year.

On the other hand, hybrid storage plants with separate hydrogen storage had higher capacity factors but fell behind on transient disturbances and thus averaged lower system stability.

H. Regional Sensitivity and Contextual Design

Simulation results show that maximum system performance varies notably by region. Amarillo and Gansu favor extensive hydrogen deployment due to strong wind resources and the lowest LCOH. Bakersfield and Andalusia benefit more from hybrid power solutions to manage solar volatility, while Lethbridge and Hamburg relied more heavily on hydrogen than batteries, driven by seasonal wind patterns and export-oriented capacity needs.

This is an argument for the reality that local adaptation of hydrogen is not just preferable but also desirable from the perspective of energy equity and cost-competitiveness.

7.6 Operational Innovations

The operation strategies revealed by the simulations in this study introduce disruptive innovation approaches that rethink the way green hydrogen must be utilized best in DES. Such approaches of innovation cross-cut electrolyzer design from interdisciplinary domain, configuration of hybrid storages, real-time control, and localized system size and address head-on central challenges established in earlier research on flexibility, cost, curtailment, and reliability of energy (Jayachandran et al., 2024; Evro et al., 2025).

1. Load-Following Electrolyzers: Flexibility vs. Baseload Rigidity

One of the substantial operation advancements is the application of load-following electrolyzers. Compared to fixed-input baseload electrolyzers regardless of renewable volatility, load-following units modify output in real-time to follow excess renewable energy. The design lowers curtailment and optimizes REU (Renewable Energy Utilization), an essential parameter when renewable intermittency creates economic and technical integration issues (Zhang et al., 2023).

For this purpose, Hamburg and Lethbridge load-following power stations were equipped with up to 30% more REU than their baseload equivalents. The quick reaction of such plants makes electrolyzers dispatchable, grid-assisting resources—bridging supply-demand differences as well as producing clean hydrogen during renewable peaks. This helps verify earlier conclusions by

Tsavachidis & Le Petit (2022) that hydrogen operations need to be flexible for the resulting high-penetration renewable grid to be cost-effective.

2. Modular Electrolyzer Deployment: Decentralized Applications with Flexible Sizing

Modular electrolyzer deployment was also advantageous with the simulations. Instead of using monolithic configurations, multiple small stacks in series (or stand-alone) allow for exact matching of generation curves. Modularity allows for simpler provision of partial-load capability, redundancy, and demand-cycling responsive—prioritizing system life and unloading CAPEX.

An application of this system meets Balta & Balta (2022) guidelines for stimulating adaptive system conditions for hydrogen cities and off-grid DES installations. It is also scalable, through which new market developers can scale up incrementally as established mature renewable infrastructure and demand profiles stabilize.

3. Hybrid Battery-Hydrogen Storage: Closing Temporal Gaps

Battery and hydrogen storage hybridization in a single DES setup was seen to provide improved performance in various parameters of performance like REU, LCOH (Levelized Cost of Hydrogen), and system stability. Hybrid setup in Amarillo and Gansu provided short-duration flexibility via BESS (intra-day solar smoothing) while long-duration or seasonal transition was provided via hydrogen.

The hybrid use of batteries (for high response and efficiency) and hydrogen (for bulk-scale and long-duration) is not afflicted by the "duck curve" problem and offers system resilience—a field observation that corroborates findings from Di Bucchianico et al. (2025) for hybridized renewable systems. Notably, this hybridization also solves a technical deficiency in regions where hydrogen is not enough to meet peak demand or emergency demand ramp-up requirements.

4. Curtailment-Aware Operation: Strategic Dispatch Algorithms

A new idea being introduced in the simulations is curtailment-aware hydrogen dispatch—that is, curtailment forecasts or real-time curtailment levels being linked to activation of the electrolyzers. This makes hydrogen production an active grid-balancing resource and not a passive grid load. In a high-renewable California simulation, this practice is viable against the backdrop of midday overgeneration leading to negative prices (Sobamowo et al., 2024).

This process maximizes renewables use with LCOH economics fortifying in combination with maximized utilization of excess electricity at low prices to produce hydrogen. Curtail every-aware reasoning complements real-time management algorithms proposed by Shin et al. (2025) and implemented predictive AI-based ramping of electrolyzers in simulation policy settings (Shin et al., 2025).

5. Optimal System Sizing: Context-Specific Economics

Better understanding of system sizing optimality was also demonstrated in the research. Amarillo wanted sizes of electrolyzers to be 60% RE capacity with 2.5 days of storage, whereas Bakersfield just needed 50% sizing and scaled down tanks based on different solar profiles. A level of regionally tailored design is possible through resource mapping and techno-economic simulation enables regionally tailored hydrogen integration.

These results negate one-size-fits-all planning and necessitate localized hydrogen system configurations dictated by them, affirming geographic tailoring (Binyet & Hsu, 2024).

6. Ramping Capability and Ancillary Grid Services

Finally, electrolyzers' ramp flexibility adds an additional layer of capability to their ability to be utilized for application such as frequency response and black start capability. Lethbridge regions, such as grid-weak areas, may tap into electrolyzers that will serve as buffers for the price-volatile renewables and soak up volatility, adding depth to the fact that hydrogen systems are not energy carriers but have to be considered in the context of the smart, advanced grid architecture that they embody.

This kind of multi-functionality supports IPCC (2023), and Balta & Balta (2022) calls for "multi-vector" energy infrastructure as an integration of back-up, storage, and supportive ancillaries to build resilient low-carbon grids (Balta & Balta, 2022).

7.7 Alignment of System Value and Climate

The operation strategies unveiled in this research go well beyond technical performance optimization—they all collectively form the systemic value of incorporating green hydrogen into DES and are tightly aligned with global decarbonization and energy transition objectives. The operation strategies allow the support needed for operational Backbone to ensure that hydrogen not only remains an implementable energy vector but also supports robust, equitable, and future-proof energy systems.

1. Renewable energy as a Climate Leverage

One of the strongest impacts of the simulations is the dramatic increase in Renewable Energy Utilization (REU) with storage and electrolyzer policies optimized. In curtailment-prone areas such as Amarillo and Bakersfield, hydrogen storage reduced curtailment by more than 60%. Such efficiency gains have a direct implication in terms of lower emissions per unit of energy delivered and reduce the need for fossil-fuel powered peaking or backup capacity.

As observed by (Evro, Oni, et al., 2024), increasing REU is highly likely the optimum way of ensuring clean electricity indeed displaces carbon-emitting technologies. By permitting more of the renewable generation to be stored, shifted, and utilized productively—rather than being curtailed or dumped—the system fully exploits the emission abatement capacity of each solar or wind megawatt installed.

This change in operations is in accordance with climate mitigation pathways presented by the IPCC (2023), where deep and sudden CO_2 emission reductions are to be achieved not only through the deployment of renewables, but also through their effective integration into the energy system (IPCC, 2023).

2. Long-Duration Storage and Grid Flexibility

Hydrogen as an energy storage solution for long duration is at the heart of solving a structural deficit in battery-driven systems. Batteries are suitable for intra-day variability but are economically and technically constraining multi-day or seasonal storage requirements. Hydrogen offers scalable storage with lower self-discharge and unbundling capacity for energy generation and consumption for time scales.

In Hamburg and Gansu, for instance, green hydrogen facilitated DES arrangements to keep operations running in periods of prolonged low renewable generation. Having the capability to provide firm, dispatchable power from intermittent renewables matches the operating needs of a solid grid—especially with the ambitious renewable penetration targets adopted by SDG 7 (Affordable and Clean Energy) and the European Commission's REPowerEU plan.

Furthermore, this time flexibility is particularly crucial to energy system resilience as it allows systems to continue running even in the face of climate disruptions such as wildfires, storms, or heatwaves—currently affecting grid reliability in regions.

3. Sector Coupling and Multi-Use Synergies

Another dimension of systemic value is the versatility of hydrogen across industries. In addition to power storage, hydrogen can decarbonize challenging-to-abate sectors such as transport (truck and bus fuel cells), industry (ammonia, steel, cement), and heating (pure or mixed hydrogen boilers). This sector coupling maximizes the utilization of each kilogram of hydrogen produced.

The Amarillo and Andalusia simulations presented scenarios where hydrogen might be diverted to ammonia synthesis to make fertilizer or be utilized to power on-call power systems. They are multi-purpose uses, like envisioned in the "hydrogen economy" hypothesis of Yao et al. (2021), where green hydrogen is one-size-fits-all and carbon-free feedstock to many energy and industrial supply chains (Yao et al., 2021).

Such an integration allows cascading decarbonization of end-to-end value chains—enabling emission savings unattainable or difficult with electrification.

4. Decentralized Resilience and Energy Justice

Hydrogen-fueled DES also make local energy independence possible—most immediately for rural, remote, or unserved communities. By delivering local storage of energy and on-site power generation independent of the central grid, these devices increase reliability and reduce vulnerability to system outages. This is among the strongest motivators of energy justice, especially for the Global South or Indigenous and distant Northern settlements where grid extension is costly and incremental.

This implementation of the model under weak-grid conditions (i.e., like Lethbridge) proves DES with battery and hydrogen storage can produce reliable levels of service even with grid loss. Distributed reliability is what underpins SDG 7's objective to electrify everyone with modern, dependable energy—and comes with an overlay of climate resilience for more at-risk communities affected by weather extremes.

Such resilience dispersed is not just technical but social as well, promoting well-being for the masses, lowering reliance on diesel, and energizing local economic progress through the stimulation of clean energy infrastructure.

5. Cost-Efficient Climate Transformation with Coupling of Policies

One of the most significant inferences from RQ2 is that operational optimization renders economic green hydrogen feasible at realistic policy considerations. With a combination of hybrid storage, intelligent dispatching, and properly dimensioned electrolyzers, Levelized Cost of Hydrogen (LCOH) decreases even absent the most radical subsidies.

Jayachandran et al. (2024) emphasized that reducing curtailment and increasing roundtrip efficiency are the preconditions under which hydrogen can challenge fossil fuels. This study lends support to the fact, revealing that gains in efficiency can prove more potent than subsidies to add value to investments.

Of course, policy must be supplemented by operations optimization. As Evro et al. (2025) theorized, green hydrogen scalability depends on a two-legged strategy of technical preparedness and economic incentives. The findings confirm that optimized operations supplemented by even small levels of policy intervention (e.g., $40/ton carbon pricing) drive systems from negative to positive NPV—both decarbonizing and market-making.

6. Strategic Alignment with Net-Zero and NDCs

Finally, pre-existing operation plans are envisioned to line up directly with national and global decarbonization trajectories. Countries with Net-Zero 2050 targets, e.g., Canada, Germany, and Japan, require clean, dispatchable energy with responsiveness. Efficiently managed through DES, hydrogen serves as the benchmark in achieving mid-decade objectives like having 45–55% emissions reductions by 2030.

The ability to reduce emission intensity, enhance the uptake of renewables, and provide multi-sector decarbonization technology makes operationally efficient hydrogen systems an essential corner piece in enabling Nationally Determined Contributions (NDCs). Combined with deployment flexibility—from modular rural DES to industrial plants for export purposes—hydrogen can satisfy domestic transition demand alongside international cooperation target ambitions for the Paris Agreement.

7.8 Policy Recommendations

Building on the integrated modeling outcomes, policy simulation, cost-benefit analysis, and international comparison approaches of Section 7.4.1, this section offers a comprehensive and critically expanded policy recommendation to facilitate the mass-scale, equitable, and climate-resilient deployment of green hydrogen in DES. These proposals directly tackle concerns of exorbitant start-up capital outlays, policy incoherence, infrastructural gaps, and socio-economic imbalances, provoked in the process of the research and according to up-to-date literature such as Zachariadis et al. (2023), Jayachandran et al. (2024), Bade et al. (2024) and Sobamowo et al. (2023).

These suggestions are not only within economic and technical feasibility but also in the broader imperative of achieving global climate targets, Net-Zero ambitions, and Sustainable Development Goals (SDGs)—SDG 7 (Affordable and Clean Energy), SDG 13 (Climate Action), and SDG 10 (Reduced Inequality).

1. Mobilize Capital Through Tiered and Context-Specific Investment Subsidies

Upfront capital remains the single highest obstacle to the implementation of hydrogen systems, particularly capital-intensive configurations such as hydrogen pipelines (RE-H_2-nPL), ammonia synthesis (RE-NH_3), and underground geological storage (UGS). As confirmed by simulation and NPV analysis, without subsidy intervention to underwrite upfront investment risk, these pathways remain economically unviable—even where techno-environmentally optimal.

Governments can support green hydrogen deployment by institutionalizing phased capital subsidies, strategically targeting project complexity (e.g., additional incentives for systems integrating H_2 with BESS or ammonia conversion), geographic limitations (e.g., support for rural or off-grid sites), and innovation depth (e.g., projects utilizing novel electrolyzer chemistries or autonomous control systems).

This strategy parallels effective incentive layering within the European Union's Renewable Energy Directive (RED III), where a range of feed-in tariffs and tendering schemes spurred solar uptake in low-resource or peripheral regions. An equally flexible framework for hydrogen will reduce regional deployment imbalances and maximize innovation spillovers.

Moreover, linking CAPEX subsidies to performance-based milestones—i.e., GHG emissions savings, uptime rates, and local job creation—can reduce moral hazard while maximizing public accountability.

1. Dynamic Carbon Pricing with Sectoral Recycling and Climate Justice Targets

The simulations indicated that even low carbon prices (\$40/ton CO_2-e rising to \$83.8 by 2050) skewed the profitability of hydrogen pathways by 300–900%, even for emissions-intensive options such as RE-H_2 pipeline grids and ammonia conversion pathways. Carbon pricing enhances market signals and internalizes environmental externalities, as indicated in Zachariadis et al. (2023) and the IEA (2022).

Successful introduction, however, requires an equitable transition plan:

- Recycling of the revenue is to be utilized for funding hydrogen projects (microgrants, interest buy-downs), community energy planning, and skills training.
- Tiered pricing can be applied to high-emitting industries with step-up pricing, supported by CfDs or tax rebates, targeting those industries.
- Redistribution mechanisms are to recycle a share of the carbon revenues to low-income communities, small businesses, and frontline communities disproportionately impacted by climate change.

These tools address carbon pricing detractors going backward and preserve economic efficiency. Carbon pricing, if well done, becomes a climate multiplier—decarbonizing energy supply as well as inducing inclusive economic change simultaneously.

2. Scale Up Production-Based Incentives and Long-Term Contracts for Difference (CfDs)

The U.S. 45V credit and similar production-based incentives have played a critical role in lowering the Levelized Cost of Hydrogen (LCOH) to below $3/kg in optimized DES configurations. In our analysis, these incentives proved especially effective in enabling profitability for load-following electrolyzer setups that dynamically align with surplus renewable energy and maximize Renewable Energy Utilization (REU). For optimal impact, such incentives should be indexed to carbon intensity to favor near-zero-emission hydrogen, offer payback periods of no more than 10–15 years to ensure investor confidence, and accommodate merchant, captive, and grid-interactive business models to avoid systemic design bias.

At the same time, Contracts for Difference (CfDs), already part of UK and EU green hydrogen policy, facilitate long-term revenue assurance and price certainty. They are most valuable in ammonia or export-oriented value chains, where there is uncertainty over price and demand. As guaranteed by Jayachandran et al. (2024), CfDs align long-term policy and investor objectives.

Combining both instruments (e.g., CAPEX + 45V + CfD) delivers multi-level policy scaffolding that both stimulates early investment and ensures long-term operations.

3. Mandate Hydrogen Blending and Standardize Grid Integration Protocols

Hydrogen blending in natural gas pipelines (RE-H_2NGblend-xPL) offers a practical, low-barrier transition strategy that delivers immediate decarbonization benefits with minimal infrastructure changes. Modeling shows it can reduce GHG emissions by 800–1,600 tons CO_2 per year for every 10 MW system, while also mitigating renewable curtailment. To scale this solution, gas networks must adopt 5–20% minimum hydrogen blending mandates, utilities should recognize hydrogen as a dispatchable renewable energy carrier, and pipeline and appliance codes must be updated to safely accommodate blended gases.

These are already being rolled out in Japan, South Korea, and parts of the EU. As Sobamowo et al. (2023) note, blending also creates demand-side pull that raises electrolyzer runtime and economic viability, without awaiting full H_2 infrastructure maturity.

4. Establish Regional Hydrogen Infrastructure Development Authorities

Even in the presence of aggressive policy backstops in simulations, underinvested infrastructure systems—i.e., pipeline or storage access—could not produce credible investment opportunities. To overcome infrastructure bottlenecks, governments should establish regional hydrogen development authorities or consortia tasked with streamlining permitting for storage and pipelines, coordinating environmental assessments and zoning, facilitating infrastructure financing through instruments like green bonds and blended finance, and ensuring institutional alignment across utilities, regulators, and industry stakeholders.

They have been operating successfully in the U.S. Hydrogen Hub Program and Germany's IPCEI Hydrogen Project. They derisk systemic bottlenecks and trigger economies of scale in hydrogen value chains.

5. Design Decentralized, Modular Incentives for Community-Scale Hydrogen Initiatives

Top-down incentive schemes often overlook local energy contexts. This study, along with findings by Evro et al. (2025), demonstrates that modular policy tools—such as pay-for-performance tariffs for curtailment reduction, microfinance for community-scale hydrogen microgrids, and municipal procurement targets for hydrogen-powered transit—are more effective and equitable than uniform, one-size-fits-all tax credits.

These technologies encourage energy democracy, untangle energy from fossil centralized infrastructure, and enable bottom-up market development. They also introduce indigenous governance, rural employment, and climate resilience possibilities.

Localization of hydrogen deployment is not a privilege—instead, it is a requirement to SDG-alignment and scalability of emerging economies' markets.

6. Make R&D, Demonstration, and Modeling Transparent

A basic hydrogen cost estimate and sizing tool created by research is direct access to replicate. The tool allows for early-stage feasibility assessment using public resource-based data and proxy models, which are most valuable in regions where access to HOMER Pro or Aspen Plus does not exist.

To effectively scale innovation, governments should prioritize funding for pilot and demonstration projects in weak-grid or hybrid energy regions, expand R&D tax credits for advanced electrolyzer technologies (such as PEM and solid oxide) and H_2–BESS integration, and establish open-data platforms to ensure transparency, replicability, and benchmarking across modeling efforts.

These steps do not only make technical capability easy but also increase capacity and trust among stakeholders—government, investors, academia, and communities (Sobamowo et al., 2023).

7. Integrate Climate Equity and Just Transition Principles

To avoid repeating past energy transition injustices, hydrogen deployment must be guided by equity-focused policies. As emphasized by Zachariadis et al. (2023), this includes prioritizing underserved or fossil-dependent regions, promoting community ownership and revenue-sharing models, and ensuring local job creation with retraining programs to support a just and inclusive energy transition.

DES-bundled hydrogen systems can both enable decentralized agents and democratize decarbonization—if policy designs are designed to serve the goal of prioritizing inclusion. Climate transition is not about emissions—climate transition is about power, access, and justice.

Therefore, green hydrogen policy must be multi-dimensional, dynamic, inclusive, and strategically phased. The above recommendations illustrate the institutional setup necessary to translate technical feasibility into practice of deployment. By combining incentives with climate objectives, system boundaries, and local development ambitions, governments and stakeholders can make hydrogen a hub of resilient, just, and scalable energy futures.

7.4.3 Contribution to Decarbonization and Market Development

Green hydrogen integration into DES is not merely a technological transition—it is a strategic transition of economies decarbonizing, decentralizing, and diversifying energy supply. Modelled outcomes, cost-benefit assessment, and policy simulations herein affirm that hydrogen systems—well-designed and well-subsidized—can provide high-impact carbon abatement and establish new green energy markets.

1. Deep Decarbonization Across Sectors

One of the best advantages of incorporating hydrogen is that it can reduce emissions in situations when electrification cannot be achieved or is too costly. Monte Carlo simulations for the research indicated that green ammonia production (RE-NH_3-nPL) and pure hydrogen pipelines (RE-H_2-nPL) possess abatement potential ranging from 4,000 to 14,000 tons of CO_2e annually per every 10 MW project, depending on the rate of fossil fuel displacement by alternatives like diesel or natural gas. Such emissions abatements are particularly impactful in hard-to-decarbonize sectors, including high-temperature industrial processes like steel, glass, and cement manufacturing; ammonia-based fertilizer production; and standby power systems for life-critical or off-grid infrastructure.

2. Transportation across long distances and shipping (through ammonia or hydrogen fuel cells).

These findings accord with assessments by Jayachandran et al. (2024), who identify ammonia and hydrogen pipelines as the most-leverage transmission means for decarbonization through hydrogen. Such support validates support for strategic adoption of green hydrogen under the Nationally Determined Contributions (NDCs) of the major economies and plays a crucial role in the achievement of IPCC 1.5°C mitigation pathways.

3. Market Catalyzation Through Strategic Policy

This policy simulation and benchmarking exercise in this analysis reveals that the profitability of hydrogen systems is extremely responsive to the design of policies. In their absence, other than carbon prices or capital subsides, most of the hydrogen configurations remain marginal or NPV-red. But stacked use of policy measures like CAPEX support together with 45V-type of production tax credit as well as long-term CfDs can lead to 300%–900% higher economic viability depending upon regions and setups.

For example, RE-H_2-UGS-H_2CO_2NGSyn-nPL (a storage-intensive pathway) changed from a speculative investment to a very lucrative business with the initial implementation of subsidies and mid-point carbon pricing. The above signals validate the points in Zachariadis et al. (2023) regarding the joint fiscal policy's capacity to trigger low-carbon investment on a large scale.

Unexpectedly, Monte Carlo simulation revealed that timing and policy certainty were as significant as size. Pre-emptive use of subsidies with clearly demarcated policy horizons de-risked investments and minimized the spread of investment returns—making them more attractive than capital markets. Subsidy use postponed (post-2035) stranded most hydrogen systems economically. Export Potential and Green Hydrogen Trade

The modeling also shows that those economies with strong renewable endowments and appropriate infrastructure such as Texas, South Australia, and Morocco can produce competitively exportable hydrogen and ammonia at any point there are policy incentives. Even after factoring in liquefaction, transport losses, and conversion costs, these locations-maintained net-positive cash flows for hydrogen-to-ammonia export chains. This validates global hydrogen cooperation models such as the EU’s REPowerEU plan targeting 10 Mt of green hydrogen imports by 2030, Japan’s hydrogen corridor partnerships with Australia and the UAE, and Germany’s H_2Global auction platform for procuring green hydrogen through international tenders.

The creation of bankable exportable corridors will also stimulate investment in shipping infrastructure, bunkering terminals, and port-linked ammonia synthesis. These projects can have the potential to create positive feedback loops between global trade and domestic industry expansion—like those already seen in the solar PV and LNG industries.

4. Domestic Market Building and Local Demand Creation

While export readiness is crucial, domestic market development remains the top priority. This research identifies key leverage points for generating local hydrogen demand, including city-level green procurement for utilities and transit fleets, deployment of fuel-cell backup systems for hospitals and telecoms, and industrial applications such as hydrogen blending and retrofitting boilers for hydrogen compatibility.

The above triggers local aggregation of demand, reduce unit cost of infrastructure, and enable learning-by-doing. For urban areas like Hamburg and Bakersfield, modeling showed that even 10–15% local demand improved LCOH and utilization of electrolyzer, making the project bankable.

Local consumption of hydrogen and local ownership help enhance the system robustness, reduce dependence on centralized fossil fuel supply, and distribute energy transition benefit fairly (Evro et al., 2025).

5. Broader Co-Benefits: Jobs, Air Quality, and Energy Security

Beyond emissions abatement and market stimulation, hydrogen integration offers key secondary benefits: it creates high-value jobs across the electrolyzer manufacturing, commissioning, and transport value chain; improves urban air quality by replacing diesel and fossil gas sources, thereby reducing NOx, SO_2, and $PM_{2.5}$ emissions; and enhances grid stability by enabling fast-ramping, long-duration storage that supports frequency regulation, black start, and voltage control—especially in weak or islanded grids.

In Hamburg, simulation approximated hydrogen storage saved 25% of peak load tension and boosted grid uptime via renewables troughs—a form of insurance for the intermittency of renewables. Similarly, Bakersfield simulation approximated hybrid BESS-H_2 systems removed backup diesel during solar intermittence, boosting emissions and system reliability.

6. Strategic Role in Climate-Era Infrastructure

Finally, hydrogen integration must be viewed through the broader lens of post-carbon infrastructure development. Distributed and modular hydrogen systems help mitigate the risks of renewable overbuilding by absorbing surplus generation, enable deep sectoral coupling across power, industry, transport, and agriculture, and support circular economy models through hydrogen-ammonia loops, green methanol synthesis, and CO_2 recycling pathways.

These abilities establish hydrogen as a strategic enabler, rather than a standalone clean energy carrier. Appropriate policy backing makes it part of a utility tapestry in the climate era, re-fashioning energy regulation, market incentives, and land use planning.

Overall, hydrogen integration decarbonization and market development impacts are extensive and multifaceted. They span direct emission reductions, fiscal attractiveness, policy reform, export competitiveness, domestic resilience, and socio-economic co-benefits. Empirical proof validating this research certifies that through the best mix of incentives, hydrogen in DES contexts can fuel net-zero commitments, empower communities, and remake international energy markets for the climate age.

7.5 Cross-Cutting Observations: Interweaving Across Technology, Operations, and Policy

A hallmark feature of this study is its integrative approach — the deliberate syncretism of technical modeling (RQ1), operational effectiveness (RQ2), and policy and market incentives (RQ3) to produce a systematic, scalable, and climate-resilient pathway for green hydrogen usage in DES. A synthesis at the system level identifies that hydrogen transitions, to succeed, cannot move ahead in isolation. Technological feasibility, economic feasibility, and policy adaptability must be co-designed to release hydrogen's transformative promise.

1. From Model to Market: The Converging Role of RQ1–RQ3

The hydrogen production estimation model (RQ1) was an early-stage analysis tool. Through enabling precise forecasting of hydrogen yield from probabilistic renewable availability constraints (P50, P60, P70, P90), the model enables early-stage planning of projects, especially in data-scarce or off-grid situations. It is true value, however, emerges when model inputs directly inform operational simulations and control strategies under RQ2. For example, predicted hydrogen production volumes are used to size BESS systems and hydrogen storage tanks; renewable supply variability governs load-following and curtailment-responsive dispatching; and electrochemical capacity factors from RQ1 support accurate LCOH assessments in RQ2 system configurations.

Such inter-operability represents an instance of multi-scale integration foregrounded by Sobamowo et al. (2023), where, through tools formulated at one plane of abstraction (modeling), decision-making within others (operation, policy, economics) becomes possible. Entry points for such stakeholders previously restricted by the very complexity of the likes of HOMER Pro or Aspen Plus are also delivered by the empirical model. In fact, RQ1 brings techno-economic foresight to everyone.

2. RQ2 and RQ3: System Optimization and Incentive Design Alignment

Operational tactics emulated in RQ2 — i.e., load-following electrolyzers, hybrid battery-hydrogen storage, and predictive dispatch — are most directly facilitated by the production forecast format. These tactics raised Renewable Energy Utilization (REU) by an exceptionally large amount, curtailment by 40–70%, and LCOH by up to 15% in high-penetration solar-wind regions (e.g., Amarillo, Gansu). Of note, these tactics' efficacy was overly sensitive to contextual sizing and dispatch patterns, underscoring the need for site-specific, adaptive operation logic.

Technical optimization alone is insufficient for widespread deployment. As RQ3 highlights, robust policy frameworks are essential to de-risk investments, particularly during early market formation. For instance, load-following hydrogen systems benefit most from a combination of 45V-style production tax credits and moderate carbon pricing ($40–$60/ton); storage-intensive designs like RE-H_2-NH_3 require Contracts for Difference (CfDs) to hedge commodity risk and stabilize offtake prices; and small-community microgrids thrive under feed-in tariffs or local procurement mandates.

The findings validate the argument that system performance under RQ2 should inform policy calibration under RQ3. The integrated modeling approach used here presents a methodologically open route to bridging incentive design and empirical system performance — an imperative cited by Zachariadis et al. (2023) for abandoning top-down strategies for decarbonization.

3. Triangular Synergy: Modeling, Optimization, and Incentivization

The study concludes that RQ1 (technology), RQ2 (operation), and RQ3 (policy) form a synergistic triangle in which each element reinforces the others. RQ1 defines the hydrogen production envelope, RQ2 optimizes system performance within that envelope, and RQ3 ensures the system is financially viable, socially equitable, and politically supportable. Together, this integrated design addresses the three core barriers to hydrogen adoption—technical complexity, operational inefficiency, and investment risk—creating a closed-loop pathway for rapid and scalable hydrogen deployment in DES.

This approach facilitates the IEA (2022) Global Hydrogen Review and scaling roadmap proposals by the Hydrogen Council, which both share demonstration, model, and policymaking feedback loops. This twin pathway established here has the same loop via traceability in experience and geographic versatility.

4. Geographic Modularity and Contextual Relevance

Yet another advantage of this cross-cutting strategy is regional versatility. By exemplifying various locations (e.g., Amarillo, Hamburg, Lethbridge, Gansu, Andalusia), the study illustrates that the blended strategy is technologically sound as well as geographically modular. For example, Amarillo offers low grid costs and abundant wind-solar resources, making it ideal for hydrogen export; Hamburg is a grid-constrained yet high-demand industrial hub; while Lethbridge and

Andalusia represent cases for small-scale, modular hydrogen deployment, each challenged by mixed renewable availability and policy limitations.

This heterogeneity attests that hydrogen integration is no one-site solution. Instead, it must be made on site-specific modeling (RQ1), dispatch-aware design (RQ2), and local, equity-sensitive policy packages (RQ3). Such modularity makes possible equitable energy transitions and meets SDG 7 (Affordable and Clean Energy) and SDG 13 (Climate Action) objectives.

5. Cross-Sectoral Interlinkages and Strategic System Design

Besides, this triadic integration facilitates greater sectoral coupling. When appropriately sized, optimally operated, and supported by enabling policies, hydrogen systems can feed microgrids and community infrastructure (e.g., water treatment), generate green ammonia or synthetic methane, and act as dispatchable backup for electric transportation and critical facilities like data centers.

By showing how such connections are established, the research recommends systems thinking in hydrogen integration, from individual projects to multi-sectoral, circular economy ideas. This aligns with the vision set out in Evro et al. (2024), as it requires "interconnected hydrogen hubs" constructed for carbon minimization and community resilience.

6. Toward Implementation: A Blueprint for Stakeholders

The synthesis also provides actionable guidance for stakeholders: developers can apply the sizing and control models to build cost-effective systems; policymakers can align scenario insights with targeted subsidies or carbon pricing; layered policy approaches offer investors predictable frameworks for risk mitigation; and both utilities and communities can replicate modular pathways to energy self-sufficiency.

Together, the results of RQ1, RQ2, and RQ3 present a robust, actionable plan — for hydrogen deployment, as well as distributed-scale decarbonization. It provides a solution to one of the easiest requirements of the climate era: bankable, replicable, equitable, and actionable emissions reduction options.

7.6 Consonance with Climate and Energy Transition Aims

Mid-century net-zero carbon transition is the defining energy challenge of our time. International systems such as the Paris Agreement, United Nations SDGs, and individual country-specific Net-Zero by 2050 all require deep, transformational decarbonization of the energy system, industry, transport, and environment. Green hydrogen, in these applications — particularly when accomplished through DES — is a solution of many dimensions. This part weaves in the way overall findings of this research (RQ1–RQ3) are facilitating climate action, energy access, and system resilience to global decarbonization and development objectives.

1. Hydrogen as a Decarbonization Vector

The role played by hydrogen in the energy transition is ever more appreciated for its power in decarbonizing hard-to-abate sectors — long-distance transport, fertilizer manufacturing, industrial heat, and seasonal energy storage. Since, according to the IEA (2022) and Evro et al. (2025), electrification would not be able to decarbonize such industries due to intermittency, low energy density, and incompatibility of the process, models of production, storage, and use that were introduced within this research serve effective alternatives on the basis of site-level estimated renewable energy values (RQ1), best controlled by dynamic regulation (RQ2), and rendered feasible through organized incentive regimes (RQ3).

By minimizing curtailment through optimized conversion of surplus renewable electricity to hydrogen, DES-integrated systems make renewable generation capable of providing non-electric loads. This also meets the IPCC's (2023) request on technologies as combos for making national energy mixes more flexible, dependable, and carbon intensive.

2. Contributions to Global Climate Frameworks

This research directly advances the Paris Agreement by demonstrating how green hydrogen can substitute fossil fuels across electricity, transport, and heating in DES. Through simulations of Levelized Cost of Hydrogen (LCOH) and emissions offset, the study provides actionable data for Nationally Determined Contributions (NDCs), enabling policymakers to estimate cost-per-ton CO_2 abatement and refine carbon pricing tools.

Aligned with Sustainable Development Goal 7 (Affordable and Clean Energy), the RQ1 proxy model was purposefully designed as a low-barrier, open-access solution. Its use of open-source data and simplified inputs empowers underserved regions with limited modeling capacity to pursue decentralized electrification and clean energy access, especially in rural and off-grid areas.

In support of SDG 13 (Climate Action), the study highlights real-world decarbonization levers, including CAPEX subsidies, tax credits like the U.S. 45V, and carbon pricing schemes (Zachariadis et al., 2023). It demonstrates how targeted policy support shifts hydrogen projects from marginal to bankable by improving Net Present Value (NPV), encouraging scalable investment in renewable infrastructure.

Finally, the findings directly inform national hydrogen strategies across the U.S., EU, China, and Australia. By validating configurations like RE-H_2 pipelines, ammonia synthesis, and blended gas systems, the study supports the U.S. Hydrogen Shot target of $1/kg by 2030 and aligns with the EU's REPowerEU import objectives. It reinforces the techno-economic feasibility of hydrogen pathways under diverse geographic and policy scenarios.

3. Equity, Decentralization, and Just Transitions

One of the most critical challenges in the global energy transition is ensuring that decarbonization strategies are locally grounded, inclusive, and equitable. Hydrogen-based DES, as modeled in this study, offer decentralized resilience that can bypass the equity limitations of centralized energy systems. For instance, community-scale hydrogen systems in places like Lethbridge or Andalusia highlight how locally owned infrastructure can both cut emissions and strengthen energy sovereignty.

Complementing these technical insights, the policy proposals outlined in Section 7.4.2 advocate for tailored support mechanisms such as microgrants, localized feed-in tariffs, and municipal-level hydrogen procurement (e.g., for buses). These tools are designed to ensure that the benefits of the hydrogen transition extend to marginalized, rural, and underserved regions—helping to close the gap in clean energy access.

As warned by Zachariadis et al. (2023), blanket tax credits and one-size-fits-all policies risk stacking infrastructure on already-favored places. By contrast, this paper crafts a gradual roll-out plan with modularity and policy adaptability — foregrounding SDG 10 (Reduced Inequalities) alongside climate goals.

4. Climate Resilience and System Flexibility

Hydrogen incorporation enhances climate resilience by operating and planning mechanisms. Multi-day renewables deficit coasting facilitated by long-duration hydrogen storage operation, as modeled in Gansu, Hamburg, and Amarillo, is one of these essential characteristics because climate variability increases the uncertainty of solar and wind power. It improves grid reliability and energy security in climate-exposure areas prone to extreme weather, supply chain disruption, or geopolitical conflict.

From an adaptation standpoint, hydrogen systems also facilitate water desalination, backup power, and off-grid cooling — secondary yet critical systems in climate-vulnerable areas. These co-benefits make hydrogen integration not just a mitigation measure but a resilience-building solution as well.

5. Scaling Green Hydrogen Through Integrated Governance

Finally, the combined RQ1–RQ3 approach of the study provides a blueprint for governance structures that can balance climate ambition and implementation feasibility. Sobamowo et al. (2023) warn that isolated hydrogen planning often results in non-scalable pilots; in contrast, this study's simulation-policy hybrid approach enables strategic hydrogen hub zoning, coordinated electrolyzer deployment, and realistic performance metrics to inform subsidies and carbon offset schemes—tools that can be embedded into national climate dashboards for real-time, cross-sector policy design.

7.9 Limitations and Future Research Directions

This research offers an empirically grounded and system's view green hydrogen integration in DES. However, as any system analysis of these systems, it is built with system boundaries and methodological assumption. These admissions not only serve the interest of transparency but also build directions for future research directions. Major limitations are revealed below along with corresponding research avenue directions in the future.

1. Modeling Assumptions and Data Granularity

The hydrogen production structure framework founded on RQ1 with intra-day solar and wind inputs to predict cumulative probability distributions (P50, P60, P70, P90) may be easier to comprehend and more intuitive. Nevertheless, empirical method does not consider intra-day variation, short-term ramp events, and real-time curtailment effect—factors with large effects in determining electrolyzer runtime and hydrogen production. Sobamowo et al. (2023) also report that accounting for sub-daily renewable variability contributes to runtime forecast and hybrid PV-wind curtailment analysis improvement.

Future Work: Formulate dynamic dispatch optimization models using high-frequency (e.g., 15-minute) data and including weather forecast or digital twins to foster real-time planning and control.

2. Static Policy Inputs and Regulatory Volatility

RQ3 scenarios assume phased subsidy, carbon prices, and allocation of tax relief with logistic progress. Missing from it is policy uncertainty, that is, backsliding by regulations, capital funding delays, or political volatility—factors driving investor optimism and system deployment. By stemming such volatility, Zachariadis et al. (2023) illustrate, initiating exaggeration of resilience of systems and diminution in capital risk.

Future Research: Synthesize scenario-sensitive policy modeling with probabilistic methods like Bayesian learning or game theory to approximate the responses of investors to policy shocks and withdrawal risk.

3. Physical Performance Gaps and Technology Uncertainty

The model considers constant rates of electrolyzer efficiency (i.e., 65%–75%) and constant degradation. Actual performance is quite sensitive to operational conditions, stack aging, and integration design. Likewise, hydrogen storage, especially geological storage, encompasses buffer loss uncertainty, leakage, and seasonal cycling.

Future Work: Field-validated pilot plant designs (e.g., HyDeploy, ACES Delta) with actual real-world degradation and storage loss factors improve Levelized Cost of Hydrogen (LCOH), Net Present Value (NPV), and Renewable Energy Utilization Rate (REUR) estimates. Long-term risk analysis incorporated into infrastructure design, e.g., effect of groundwater, soil migration, and safety.

4. Institutional and Behavioral Gaps

While the study reports energy justice and fairness under RQ3, it does not fully consider drivers of behavior, institutions, and social acceptability for hydrogen deployment. Evro et al. (2025) further posit that people's trust, agency cooperation, and utility engagement in scaling hydrogen, both in the developed and developing world, are crucial.

Future Work: Integrate participatory modeling with institutional diagnostics to identify administrative, legal, and sociopolitical barriers. Apply surveys, focus groups, and local behavioral studies to assess willingness to pay, trust, and perceive co-benefits of the public.

5. Sector Coupling and Circular Economy Considerations

The research will consider hydrogen uses in energy storage and in the production of ammonia but not within its scope utilization of hydrogen to sectors such as transportation, agriculture, or heating use. Similarly, circular economic issues such as water consumption in electrolysis, material recycling, and environmental concerns are outside its scope.

Future Work: Develop sector-coupling models predicting hydrogen use in freight transport (fuel cells), district heating, and H_2-fertilizer production systems. Employ lifecycle analysis (LCA) and circular economy indicators (water, material, land) for analyzing system integration and sustainability.

6. Open Access and Modeling Transparency

Despite the help offered by advanced simulation software (e.g., HOMER Pro, Vensim), closed-access models inhibit replicability and local stakeholder engagement.

Future Work: Develop open-source, modular, planning dashboards and tools to democratize hydrogen modeling, particularly for Global South stakeholders and nascent hydrogen markets.

Lastly, this dissertation has established a foundation framework for integrating green hydrogen into DES. Nevertheless, the adaptive and dynamic character of climate regimes, energy markets, and governance institutions require continuous model-building and interdisciplinarity. There exists an equity, transparency, circularity, and behavioral insight vision agenda that must be pursued to capture hydrogen's maximum potential to steer an equitable and sustainable world energy transition.

Future work should explore the behavioral, spatial, and real-time dimensions of hydrogen use in DES to ensure not only decarbonization but also equitable energy access and resilience.

7.10 Key Takeaways

This chapter weaves together an interdisciplinary analysis of the technical, operational, and policy drivers towards cost-efficient and scalable integration of green hydrogen in DES. Organized around three closely interlinked research questions (RQ1–RQ3), the study provides qualitative, evidence-based answers to the key bottlenecks inhibiting hydrogen mass deployment: technology sophistication, system operation inefficiency, and policy uncertainty. Collectively, the study attests that green hydrogen is institutionally scalable and technologically feasible—if brought about by adaptive operations, strategic modeling, and spearheaded incentives.

RQ1: Low-Cost Modeling for Estimating Hydrogen Production

To address Research Question 1, the study developed an empirical hydrogen sizing and output forecasting model using renewable energy probability distributions (P50, P60, P70, P90) and electrolyzer stack configurations. This modeling strategy bypasses reliance on high-fidelity simulation code, allowing customers—e.g., policymakers, urban planners, and energy developers—to estimate hydrogen potential from a site-dependent renewable availability perspective. Using solar and wind profiles from Amarillo, Lethbridge, and Bakersfield (Section 6.2.1) yielded harsh empirical confirmation. This methodology is applicable to early-project screening, feasibility screening, and scenario planning of hydrogen penetration into grid-connected and off-grid DES applications.

Critically, the model democratizes energy modeling by decomposing system interactions into plug-and-play, user-friendly, Python-based framework. This lowers barriers to entry into Global South contexts and enables SDG 7 energy access targets. Its uptake ease for techno-economic inputs such as Levelized Cost of Hydrogen (LCOH) enables effective investor and regulator engagement and puts hydrogen on the bankable asset, rather than speculative technology, list (Nyangon & Darekar, 2024).

RQ2: Operational Efficiency due to System Optimization

Responding to Research Question 2, the research experimentally compared different electrolyzer and storage combinations in different geographies through HOMER Pro simulations and custom dispatch algorithms. Key findings illustrated load-following electrolyzers and battery-hydrogen hybrid storage with least curtailment (up to 60%) and attained highest REU. The technologies enhanced system reliability, reduced LCOH, and increased roundtrip efficiency, particularly under turbulent renewable conditions like Hamburg and Gansu (Section 6.3.1–6.3.3).

By adjusting operation based on energy availability and demand variability, the study proposes hydrogen as a flexible grid-balancing solution in addition to, not instead of, battery storage. The two storage strategies align with Intergovernmental Panel on Climate Change (IPCC, 2023) guidelines for building high-renewables power grids that can deliver 24/7 clean energy. Moreover, the study identified curtailment-aware and modular dispatching methods to allow hydrogen systems to provide ancillary grid services, peak shaving, and seasonal long-duration balancing—unveiling climate-synchronized microgrids and autonomous energy clusters.

RQ3: Policy Systems to Develop Scalable Hydrogen Markets

For Research Question 3, analysis used systematic policy comparison through cost-benefit analysis (CBA), Monte Carlo simulation, and probabilistic modeling to compare the effect of different policy instruments i.e., capital subsidy, production tax credits (e.g., 45V), carbon pricing, and Contracts for Difference (CfDs). The result suggests that policy support is needed for economic viability for hydrogen projects, particularly for high-capital-intensive routes like ammonia synthesis or underground hydrogen storage (Section 6.4.1).

The computation confirmed that instrumental integration—i.e., subsidy on CAPEX + 45V + carbon tax—unambiguously increases Net Present Value (NPV), reduces risk exposure, and unlocks private capital. Comparative analysis of international policymaking (U.S. IRA, EU Directive 2023/2413, and China's CNDC) also confirmed these findings and informed a menu of regionally customized recommendations depending on hydrogen maturity (Section 6.4.2). These are rural rollout microgrids, carbon revenue recycling, infrastructure needs, and policy design that is equitable and targeted on SDG 13 (Climate Action) and SDG 10 (Reduced Inequalities).

Triangulated Impact: Technology × Operation × Policy

The three research contributions constitute a tripod: policy, technology, and operation—trio in wholeness. The model of forecasting (RQ1) provides system sizing and resource consumption, control, and optimization methods (RQ2) reduce curtailment, improve reliability, and enhance integration of renewables. And the model of policy (RQ3) closes the cost gap, reduces risk, and accelerates deployment.

This system-level thinking breaks down traditional silos and shows the thinking that climate action requires in alignment with global ambitions such as the Paris Agreement and Net-Zero by 2050 scenarios. It also activates hydrogen's promise not only as an energy carrier but as a decarbonization multiplier—in every application from power, mobility, industry, to distributed resilience-building.

Roadmap for an Inclusive Hydrogen Future

More broadly, this research presents a way forward for green hydrogen mainstreaming in DES. With the union of low-barrier modeling innovation, locally granular operations, and equity-responsive policy, it presents a foundation for green, climate-resilient energy transitions. It indicates that hydrogen-related transitions can be scalable and justified proved that they are rooted in a participatory coming together of data, design, and governance.

As nations stumble on climate goals, this study proves that green hydrogen—a pipe dream thus far—is a here-and-now solution to low-carbon, secure, and fair energy futures. Its use is not just a technical feat; it is a strategic imperative.

7.11 Summary

The chapter discussed green hydrogen utilization in DES within the context of three interrelated research questions within a triadic system: technology (RQ1), operation (RQ2), and policy (RQ3). Analysis is an integrated empirical modeling, techno-economic simulation, and policy analysis strategy to address key decarbonization, energy access, and system optimization challenges.

RQ1: Green hydrogen potential simulation

This study established a cumulative probability-based approach (P50, P60, P70, P90) to predict green hydrogen production from renewable energy and electrolyzer installation data. The approach was validated over Amarillo, Lethbridge, and Bakersfield, enabling pre-feasibility analysis with accuracy to avoid system overdesign or underperformance. Performance parameters like Capacity Utilization Factor (CUF) and Levelized Cost of Hydrogen (LCOH) enable the approach to be appropriate for community-scale system design, investment decision-making, and policy-driven project planning.

RQ2: Operations Optimization in DES

Using HOMER Pro and Python, the study simulated hybrid hydrogen-battery systems for six worldwide locations and demonstrated that context-aware sizing and load-following electrolyzers improved curtailment reduction and Renewable Energy Utilization (REU). Batteries offered balancing at brief time scales, and hydrogen offered flexible buffering at long time scales for lower LCOH. Modular electrolyzers and curtailment-aware dispatching strategies demonstrated hydrogen's capability to enable reliability and flexibility in DES.

RQ3: Economic Policy Levers for Hydrogen Integration

Policy instruments like capital expenditure subsidies, 45V-type tax credits, carbon pricing, and CfDs were shown—to have been proved by Cost-Benefit Analysis and Monte Carlo simulations—as essential to determine economic feasibility. The study suggests that location-specific stacked incentives function better, especially in off-grid or innovation programs. The policy frameworks show obvious support for the national Paris Agreement, SDGs, and fair energy transition plans.

Triangular Synergy: Technology × Operation × Policy

The three research questions (RQ1–RQ3) work synergistically—RQ1 provides sizing data to RQ2 operations; RQ2 derives empirical metrics to calibrate RQ3's policies. Combined, they form a closed-loop system for crafting scalable, climate-congruent hydrogen solutions. Through this triangulated approach, hydrogen transition paths are rendered technically feasible, operationally achievable, and economically viable simultaneously.

Contributions to Climate and Energy Transition

The study is in line with global decarbonization goals, the Paris Agreement, Net-Zero 2050, and SDG 7 (affordable and clean energy), 13 (climate action), and SDG 10 (less inequalities). Decentralized energy sovereignty and Global South and Indigenous peoples' potential are empowered by the study. The study offers a real-time roadmap to the policymakers, the developers, and investors for the adaptation of equitable, efficient, as well as scale-up hydrogen-fueled DES.

Limitations and Future Research

This research lays the foundation but must be followed up with more detailed data sets, policy scenario modeling with dynamics, and sector coupling and circular economy model features. There must be future research on AI-assisted dispatch, open-source planning tools in real time, and behavioral modeling to advance the intelligence and performance of the hydrogen system under different energy and socio-political scenarios. These cross-cutting insights form the basis for concluding remarks and future recommendations in Chapter Eight

CHAPTER EIGHT

CONCLUSION

8.1 Restatement of the Research Setting and Aims

The global energy scenario is transforming fundamentally with a critical question at stake to dominate climate change, increase energy security, and attain sustainable development. Under such circumstances, the disadvantage of conventional fossil fuel-dependent energy systems—demonstrated through high greenhouse gas (GHG) emissions, centralization threats, and rising economic and environmental costs—made the necessity of cleaner, smarter, and safer energy alternatives inevitable.

Application of green hydrogen in DES remains constrained by three basic challenges. Firstly, there is still technological risk due to the absence of robust, reproducible models of site-specific hydrogen production, which inhibits project scalability and performance confidence. Second, the operational complexity also stems from dynamic management to keep electrolyzer performance and hybrid storage systems in balance with the irregular output of RE sources, rendering real-time management and load balancing difficult. Third, policy and economic barriers–such as poor subsidies, unsupportive carbon pricing mechanisms, and disjointed regulatory regimes–undercut financing feasibility and discourages investment toward integrating green hydrogen.

The study tried to answer these questions by utilizing a triangular inquiry model that found three issues of inherent interest:

This study addresses three core research questions critical to accelerating green hydrogen deployment in DES: RQ1 explores how to devise a simple yet pragmatic method to estimate hydrogen production potential based on renewable energy availability and electrolyzer stack design; RQ2 investigates how operational strategies for electrolyzers and hydrogen storage can be optimized to minimize curtailment and maximize renewable energy utilization; and RQ3 examines the most effective market incentives and policy instruments to support cost-effective integration and storage of hydrogen in DES frameworks.

For answering these questions, the research used the synergy of empirical modeling, multi-scenario simulation, and policy benchmarking. Together, they provide an integrated system-based and data-driven approach for DES deployment.

8.2 Summary of Key Findings

8.2.1 Technological Insights (RQ1)

We developed a probabilistic, location-specific electrolyzer capacity sizing CDF model using P50–P90 metrics and also developed an empirical model for hydrogen production. This synchronizes with renewable resources variability as well as production size of an electrolyzer. With Amarillo (Texas), Lethbridge (Alberta), and Bakersfield (California) being used as a reference, regionally the research estimated hydrogen capacity of production by using combined solar and wind profiles.

The higher the percentiles (P90), the more the model prioritized operation reliability but at the cost of higher capital investment in the form of lower utilization levels. The low percentiles (P50) were low CAPEX and efficient but trailed for an exceptionally long time in the low resource case. Modularity in the model allows provision for the system configurations to be formulated by the developers in terms of the risk tolerance, available capital, and climatic uncertainty of the region.

The biggest strength of the model is that it can be implemented. Built as a low-code Python proxy tool to begin with, it relies solely on flat solar irradiation, wind speed, and electrolyzer specifications—all easily roll-out in low-income economies or remote off-grid project sites with limited software availability like HOMER Pro or Aspen Plus. Democratization of this kind allows small developers, cities, and NGOs to design bankable hydrogen projects, thus making global access to the hydrogen economy inclusive.

The model also enhances project bankability by enabling initial Levelized Cost of Hydrogen (LCOH), capacity factors, and efficiency in renewable integration estimation. Such outcomes minimize cost of finance through lower financial risk costs and higher transparency at pre-feasibility levels. Finally, this contribution makes climate-compatible energy development possible by enabling one to forgo overdesign, minimize inefficiencies, and make decisions earlier—something the Global South is in dire need of for low-cost, rapid decarbonization.

8.2.2 Operational Innovations (RQ2)

Research Question 2 addressed the issue of how hydrogen systems are optimally operated at the operational level to enable more deployment of renewables and minimize curtailment. HOMER Pro simulation was tried on various geographies—Hamburg (Germany), Gansu (China), Andalusia (Spain), and Amarillo and Bakersfield (United States)—with varying trends in availability of renewables and grid conditions.

The most important results established were dynamic load-following electrolyzer operation, which adjusts hydrogen production in accordance with renewable input availability on the real-time scale to maximize system performance. Dynamic operation compared to baseload electrolyzers cut up to 30% less and improved round-trip system efficiency. Modular implementation of the stack also allowed systems to be added incrementally and balance hydrogen output to seasonal energy volatility or demand ramp up.

Most significantly, the application of hybrid storage systems—alleviating short-term volatility with Battery Energy Storage Systems (BESS) and fulfilling long-term needs with hydrogen tanks—resulted in improved runtime balance, higher REU (>60%), and lower LCOH. The hybrid system offers more flexibility in grid-interactive DES applications, especially those operating in weak-grid or island modes.

In addition, curtailment-aware dispatch software and forecasters improved runtime efficiency. Pre-emptive down-ramping or up-ramping of electrolyzers according to meteorological and load forecasting avoided wastage of energy and enabled local load balancing. Sector coupling was also feasible with the off-peak produced hydrogen being used in industrial feedstock, ammonia production, or mobility sectors—maximizing economic value and environmental value.

These operating strategies are not technical innovations alone—They are climate-critical facilitators. They resolve one of the biggest challenges of renewable energy, i.e., intermittent, by facilitating increased use of dispatchable renewable energy and seasonal storage. They thus guarantee grid stability, system resilience, and deep decarbonization for SDG 13 and 1.5°C target of Paris Agreement.

8.2.3 Policy Mechanisms (RQ3)

To analyze economic and institutional drivers of hydrogen deployment, the study employed Monte Carlo simulations, cost-benefit analysis (CBA), and comparison of current policies (i.e., U.S. Inflation Reduction Act, EU Directive 2023/2413, China's CNDC).

Simulations revealed that 20–30% CAPEX subsidies, production tax credits like the U.S. 45V, and CfDs rendered projects highly viable. All these policies transformed project NPVs from negative to highly positive, particularly for scenarios with high capital like RE-H_2-nPL (pipeline-based) and RE-NH_3-nPL (green ammonia). In the absence of policies, all but a few of the hydrogen paths, particularly with no blending mandate nor export market targets, were not financially viable.

Second, policy layering and sequencing was a critical observation. Early CAPEX awards provided the initial momentum to infrastructure build-out, complemented by tax credits and CfDs to provide assurance over operating life cash flows and returns. Synchronizing calls for green hydrogen integration into gas grids (5–20%) created opportunities through leveraging off existing infrastructure and near-term markets.

Local incentives including community-scale hydrogen production feed-in tariffs, microgrids-off-grid, and municipality-scale procurement schemes for hydrogen were also, in the literature, found to be locally scalable. Bottom-up policies are particularly well-suited for DES implementation in low-income communities and consistent with SDG 10 (Reduced Inequalities) and SDG 7.1 (Access to Universal Energy).

The broader policy implication is that hydrogen must be addressed not just as a technology, but as a system change that requires regulatory assistance, economic risk management, and intersectoral coordination. This research offers such assistance by offering a performance-based, universally applicable, and regionally transferable policy template.

8.3 Synthesis and Integration across RQs

The novelty of this work lies in its integration of three research questions—RQ1 (production modeling), RQ2 (operational control), and RQ3 (policy design)—into a unified deployment framework. Rather than treating these dimensions in isolation, the study presents them as interdependent components of a co-designed hydrogen integration platform.

This triadic framework enables a continuous feedback loop where empirical modeling informs system operations, and both are reinforced by tailored policy mechanisms to support green hydrogen deployment in DES.

RQ1 – Production Modeling (Input Layer):

The first layer establishes hydrogen production potential using local renewable energy profiles, translating solar and wind availability into P50–P90 thresholds. This provides site-specific estimates of daily production capacity and forms the baseline for techno-economic assessments and infrastructure planning.

RQ2 – Operational Control (System Design Layer):

The second layer applies load-following strategies to synchronize hydrogen output with variable renewables, supported by hybrid storage integration. Using the insights from RQ1, it fine-tunes electrolyzer operation to reduce curtailment and enable energy arbitrage, enhancing system flexibility and reliability.

RQ3 – Policy Design (Enabling Layer):

The final layer aligns financial and regulatory tools—such as tax credits, capital subsidies, and carbon pricing—with the modeled and optimized systems. These policies de-risk investment, ensure project bankability, and promote equitable scaling of hydrogen-integrated DES solutions.

8.4 Climate and Energy Policy Strategic Implications

The research conclusions align strongly with international climate policy imperatives. Specifically, hydrogen integration into DES supports the Paris Agreement and Net-Zero by 2050 targets by enabling deep sectoral decarbonization and expanding renewable energy utilization. It advances SDG 7 (Affordable & Clean Energy) through policy and operational strategies that enhance hydrogen access in off-grid and weak-grid regions. Additionally, it contributes to SDG 13 (Climate Action) by providing pathways to reduce emissions, improve system resilience, and accelerate the deployment of scalable climate solutions.

In addition, by promoting sectoral integration i.e., hydrogen to integration, mobility, or grid services—the study facilitates the attainment of SDG 9 (Industry, Innovation, and Infrastructure) and SDG 11 (Sustainable Cities and Communities). Through inclusive deployment scenarios and region-specific policy recommendations, it also facilitates the attainment of SDG 10 (Reduced Inequalities).

With increasingly multipolar and climate-exposed everywhere, distributed energy resilience and sovereignty are not niceties. DES based on hydrogen are one of the most direct means in which to deliver it, and this book outlines the strategy to do it.

8.5 Final Comments and Call to Action

The facts presented confirm that green hydrogen integration into DES is not a fantasy for tomorrow, but a strategic necessity. This study bridges the unavoidable gaps between model simplicity, operational adaptability, and policy readiness, to offer a real-world roadmap towards meeting energy and climate targets.

But to unlock hydrogen's potential, there must be an ecosystem response. Governments must enact enabling legislation and de-risking regimes. Industry must innovate up the value chains of electrolyzer, storage, and system integration. Academia must continue to refine methods and pilot models across various contexts. Communities must be empowered as stakeholders—not recipients—of hydrogen infrastructure.

As the countdown to the 1.5°C climate goal ticks on, inertia is no longer an option. The moment is here to seize the leadership on green hydrogen innovation—and seize it as we must. The hydrogen economy of the future depends on what we do today.

CHAPTER NINE

9.0 RECOMMENDATIONS

9.1 Introduction

In this chapter, strategic, operational, and policy recommendations are made from findings of this research on green hydrogen integration in DES. Based on empirical modeling, scenario-based simulation, and policy analysis, recommendations are for a broad spectrum of stakeholders—with the range including policymakers, energy planners, investors, utilities, and technology developers. The goal is to translate vision into action templates that facilitate low-cost, climate-resilient, and socially inclusive implementation of hydrogen systems at the regional, local, or national level.

9.1.1 Technological Recommendations (RQ1)

9.1.1 Optimizing Empirical Sizing for Early-Stage Project Planning

The hydrogen sizing probabilistic model developed in this study—based on P50–P90 energy availability levels—should be adopted as a standard planning tool by hydrogen project developers. By providing realistic production estimates from local renewable resources, it helps avoid over- or under-design of electrolyzer and storage capacities, supports investment-grade project valuation, and offers a practical, low-barrier solution for data-scarce regions through its accessible Python-based interface.

Recommendation: National and regional energy authorities include such empirical models in pre-feasibility studies of hydrogen projects and provide capacity-building training for non-technical stakeholders in the application of such tools.

9.1.2 Foster Open-Access Modeling and Replicability

For more widespread application, the empirical size model must be available as an open-access tool. Worldwide deployment must be underpinned by openness and replicability.

Recommendation: Global institutions (e.g., IEA, UNDP), governments, and universities must publish, peer-review, and distribute open-source hydrogen design rules for variability.

9.1.3 Design Guidelines Modified to Accommodate Renewable Variability

Alternative geographies require tailored hydrogen system designs that reflect differences in renewable resource availability and local reliability requirements. Using cumulative energy probability thresholds (P50, P60, P70, P90), planners can optimize the trade-off between capital investment and system resilience, making the design responsive to location-specific energy dynamics.

For example, P50-based sizing is optimal in regions with abundant and consistent renewables, such as Amarillo or Gansu, allowing for streamlined infrastructure with high utilization rates. In contrast, P70 sizing offers a balanced approach, ideal for semi-urban settings or transitional energy economies where resource intermittency and reliability both matter—ensuring robust hydrogen production without overspending.P90 is most appropriate for such locations with high renewability intermittency or where hydrogen would be a significant back-up for critical operations (e.g., Lethbridge, off-grid island communities, solid disaster systems). More conservatively, it ensures continuity in most cases.

Recommendation: National hydrogen plans need to formulate locally applicable concept designs from meteorological inputs and techno-economic reference points. A standard scheme for applying the P50–P90 level ranges should be incorporated in licensing projects, feasibilities, and subsidy eligibility policies to encourage technical efficiency as much as fiscal tractability.

9.2 Operation Recommendations (RQ2)

9.2.1 Optimize Load-Following and Curtailment-Aware Electrolyzer Operation

Simulation results from this study confirmed that load-following electrolyzers, when properly configured with real-time renewable energy output signals, can increase Renewable Energy Utilization (REU) by up to 30%, while simultaneously reducing hydrogen production costs. Curtailment-aware hydrogen systems dynamically adjust production in response to real-time fluctuations in solar and wind resources, enabling optimal use of surplus renewable energy while avoiding overgeneration. By prioritizing hydrogen output during high-generation periods and scaling back during low supply or grid stress, electrolyzers enhance both system efficiency and economic performance. Integration with hybrid storage solutions further stabilizes operations, making this strategy particularly valuable in weak-grid or intermittency-prone regions.

Recommendation: Distributed Energy System (DES) developers should prioritize control algorithm development and dispatch strategy optimization that enables electrolyzers to follow renewable generation curves in real time. System integrators and operators should invest in SCADA systems, smart inverters, and predictive dispatch platforms that make these real-time adjustments seamless. National hydrogen standards should also encourage or require load-responsive configurations for any electrolyzer receiving public funding or grid-interconnection permits.

9.2.2 Adopt Modular Electrolyzer and Storage Architectures

Modular electrolyzer and hydrogen storage architectures are key enablers of scalable, adaptable, and cost-effective hydrogen integration in DES. Modular hydrogen systems support flexible deployment strategies by enabling phased rollouts, partial-load operation, and easier maintenance planning—making them ideal for regions with uncertain demand, limited capital, or evolving infrastructure. These systems allow developers to align investments with funding cycles, stage infrastructure deployment in emerging markets, and adapt operations based on grid signals or renewable energy availability. This adaptability enhances both financial viability and system performance across diverse energy contexts.

Recommendation: National hydrogen frameworks should promote modular system architectures through procurement guidelines and technical standards. Government tenders, pilot programs, and industrial incentives should prioritize vendors and integrators offering modular, interoperable technologies that enable incremental scaling without requiring full-system overhauls.

9.2.3 Provide Hybrid Storage Systems for Resilience and Flexibility

Hybrid energy storage systems, integrating lithium-ion batteries for short-term needs with hydrogen storage for long-duration energy balancing, are crucial to building resilient and reliable DES. Batteries address rapid fluctuations and support grid stability, while hydrogen enables storage of surplus energy for extended periods, such as seasonal variability or prolonged outages. Simulations from this study confirm that BESS smooths daily intermittent, while hydrogen storage is key to maintaining supply continuity in weak-grid or isolated regions.

Recommendation: Governments and multilateral financial institutions should prioritize investment in hybrid storage systems under programs for decentralized grid stabilization and energy access expansion. Dedicated green bonds, concessional financing, and climate-aligned investment vehicles should be structured to include hybrid storage components in rural electrification, microgrid resilience, and disaster-preparedness energy systems.

9.2.4 Apply Predictive and AI-Based Dispatch Control

Advanced dispatch control, founded on weather forecasting, load forecasting, and real-time prices, can significantly enhance hydrogen system performance. Through the integration of artificial intelligence (AI), machine learning, and predictive analytics, DES can optimize dynamically hydrogen production, storage dispatch, and grid export, curtailment reduction, runtime efficiency optimization, and economic outcome optimization (e.g., lower LCOH).

AI control is especially valuable in systems marked by high variability, dynamic pricing, or grid constraints. It is most applicable in hybrid wind-solar systems or monsoonal-fluctuating areas, where real-time adaptation is of the utmost importance. In dynamic economic dispatch markets, AI can optimize hydrogen production and sales based on price signals. In constrained or weak-grid settings, AI enables responsive load management and coordinated control of storage assets, enhancing system flexibility and reliability.

Recommendation: There need to be national and regional hydrogen strategies that co-fund the development of AI-powered dispatch and energy management platforms, particularly open-access platforms. The platforms must be made obligatory to deploy within hydrogen hubs, pilot projects, and publicly funded infrastructure. There must be data-sharing protocols, model training data, and regulatory sandboxes standardized to accelerate the adoption of smart hydrogen system control technologies.

9.3 Policy and Economic Recommendations (RQ3)

The economic feasibility and scalability of green hydrogen integration into DES are strongly contingent on the presence of strong, stable, and fair policy regimes. The research results (Section 7.4) indicate that one policy instrument is rarely sufficient. Instead, success is based on a well-coordinated and layered mix of incentives, regulations, and institutional arrangements that minimize early-stage investment risk, stabilize long-term returns, and create demand-side pull. The below are straight-picked suggestions from cost-benefit analysis (CBA), Monte Carlo simulation findings, and world best practice from China, U.S., and EU.

9.3.1 Stack Incentives for Best Project Sustainability

Key Insight: Hydrogen projects typically achieve bankability only when multiple incentives are layered to support both capital expenditures and ongoing operations. Recommendation: Policymakers should adopt a stacked incentive structure that includes: (i) 20–30% CAPEX subsidies to lower initial barriers for market entry, (ii) production tax credits up to \$3/kg (such as the U.S. 45V credit) to stabilize early cash flows, and (iii) carbon pricing between \$40 and \$83.8/ton CO_2-e to ensure environmental costs are reflected in energy investment decisions.

This stacked approach significantly improves the Net Present Value (NPV) of hydrogen pathways, particularly very capital-intensive ones like green ammonia (RE-NH_3) and underground storage. As observed in simulations from the study, stacking policies realizes 3x to 9x improvement in project payback in optimal policy regimes compared to baseline or single-policy statuses.

9.3.2 Introduce Contracts for Difference (CfDs) to Provide Market Stabilization

Key Insight: Volatility in market prices is among the most powerful disincentives for hydrogen investment. In the absence of secure long-term price cues, developers struggle to secure finance and increase output, particularly for capital-intensive operations associated with new markets like green hydrogen and derivatives.

Recommendation: Governments need to establish national Contracts for Difference (CfD) schemes for hydrogen and its derivatives (e.g., ammonia, synthetic methane). CfDs need to be emissions-indexed to promote low-carbon production, apply competitive bidding to avoid over-subsidy award, and be targeted on hard-to-abate sectors like fertilizer manufacturing, steel manufacturing, and sustainable aviation fuels. By bridging the gap between market volatility and a minimum price guarantee, CfDs can stabilize revenues and enhance investor confidence.

9.3.3 Mandate Hydrogen Blending and Utility Buyback Programs

Important Insight: Stimulating demand is just as critical as supporting supply in accelerating hydrogen market development. Without structured offtake mechanisms, even well-supported production may stall.

Recommendation: Implement renewable gas portfolio standards requiring utilities to blend 5–20% hydrogen into existing natural gas pipelines, procure hydrogen-enriched gas from decentralized DES producers, and recognize hydrogen as dispatchable renewable capacity for grid services. These policies incentivize early offtake, reduce renewable energy curtailment, and leverage existing infrastructure—outcomes supported by RE-H_2NGblend modeling results.

9.3.4 Encourage Localized and Modular Incentives

Key Insight: National incentive programs often fail to address the specific challenges faced by remote, rural, or off-grid communities, limiting equitable access to clean energy solutions like hydrogen. Recommendation: Implement place-based incentives such as feed-in tariffs for curtailed renewables used in local hydrogen production, low-interest financing for community-scale hydrogen microgrids, and procurement mandates for hydrogen-powered public transit. These targeted policies support decentralized deployment and align with SDG 7.1 (universal access to modern energy) and SDG 13.1 (climate resilience).

9.3.5 Invest in Infrastructure and Simplify Regulatory Hurdles

Key Insight: Even the most promising hydrogen projects risk stranding due to permitting bottlenecks, land access issues, and a lack of enabling infrastructure. Recommendation: Create Hydrogen Infrastructure Development Authorities tasked with coordinating site approvals, expediting the roll-out of pipelines and conversion facilities, and harmonizing regulatory frameworks across levels of government. The authorities would serve as centralized facilitators to compress project timelines and reduce institutional fragmentation.

9.3.6 Enable Climate Equity and Energy Justice in Hydrogen Policy

Key Insight: In the absence of intentional equity safeguards, hydrogen policy risks replicating the inequalities of past fossil-fuel transitions in disproportionately benefiting capital-intensive stakeholders and metropolitan centers.

Recommendation: Policy must prioritize underrepresented and disadvantaged communities by incorporating social equity requirements in project appraisal and finance—such as Indigenous participation, local job guarantees, and cooperative ownership. Recycling carbon tax revenues back into community-scale hydrogen projects and retraining programs also ensures that climate action (SDG 13) also delivers social justice (SDG 10).

9.4 Research and Capacity-Building Recommendations

Besides policy, extensive and equitable integration of green hydrogen will require long-term investment in knowledge, collaboration, and open innovation. This chapter presents strategic research and institutional development recommendations to facilitate long-term capacity building.

9.4.1 Increase Sector Coupling Studies and Demonstration Projects

Central Conclusion: The potential of hydrogen as a cross-industry energy carrier remains underutilized, especially in agriculture, mobility, and heavy industry.

Recommendation: Launch targeted hydrogen sector-coupling pilot programs in national clean energy plans aimed at its use for energizing farm vehicles and green fertilizer production, long-distance freight, and shipping, and decarbonization of industrial clusters like steel and cement.

Each pilot program must be accompanied by techno-economic and socio-environmental impacts analysis to support informed policymaking and additional assistance.

9.4.2 Interface Building Between Industry, Academia, and Government

Key Insight: Innovation in isolation—what some term "spoke" innovation ecosystems—hinders the commercialization and scale-up of hydrogen technologies. Recommendation: Establish hydrogen innovation clusters and centers of excellence grounded in public-private partnerships, strategically located in renewable-rich yet underdeveloped regions. These hubs should span the full hydrogen value chain, offering incubation, technical training, and collaborative R&D platforms. Such ecosystems not only catalyze commercialization but also advance SDG 9 (Industry, Innovation, and Infrastructure) by generating local employment and building indigenous intellectual property.

9.4.3 Encourage Access to Data and Modeling Facilities

Key Insight: The lack of accessible, standardized, and up-to-date energy and hydrogen system data—particularly in the Global South—significantly impedes informed decision-making and equitable deployment.

Recommendation: Governments and international partners should establish regional hydrogen data centers equipped with meteorological, infrastructure, and pricing datasets, and promote open-source modeling platforms, such as the empirical sizing and LCOH tools developed in this study. Harmonized data frameworks will allow for cross-border benchmarking of performance, cost, and emissions, thereby enabling better policy design, investor confidence, and global learning. These proposals are not aspirational—they are grounded in the modeling, simulations, and international trends analyzed throughout this research, and their adoption is crucial to achieving a just, scalable, and transparent green hydrogen transition.

9.5 Global and Regional Strategy Recommendations

While technological, operational, and policy-level changes at the national level are in place, green hydrogen's mainstreaming into international energy and climate transformation involves a higher strategic order. That means redefining national climate agendas and constructing additional frameworks of international cooperation—specifically among emerging economies, industrialized nations, and cross-regional powers. As hydrogen becomes an asset of climate and geopolitics, harmonized policies will determine which countries move ahead and whose lag in the new energy game.

9.5.1 Integrating Hydrogen into Nationally Determined Contributions (NDCs)

Major Argument: Although many countries have established national hydrogen strategies, these tend to be isolated from their Paris Agreement climate goals. This separation limits policy coherence and waterfalls the attraction to collaboratively drive infrastructure investment, market design, and emissions quantification.

Rationale: Green hydrogen has emerged as a notable change in emissions reduction, particularly in those sectors where electrification is not so feasible—shipping, aviation, steel, cement, and fertilizer. It also optimizes the use of renewable energy, displaces fossil fuels, and serves as an enabler of distributed grid long-duration energy storage. Nevertheless, although hydrogen has broad-range mitigation potential, it is not mentioned specifically or numerically in most countries' NDCs.

Recommendation: Governments need to strengthen and update their Nationally Determined Contributions (NDCs) by strictly defining hydrogen targets. The targets can be quantitative in terms of installed electrolyzer capacity (GW), green hydrogen produced per year (kilotons), or projected emissions reduction ($MtCO_2$-eq). Keeping hydrogen as part of the priority sectors—green ammonia for agriculture and shipping, synthetic fuels for aviation, and hydrogen blending for household heat—will drive sectoral decarbonization trajectories.

Additionally, revisions to NDCs must also decide on hydrogen infrastructure plans and global trade corridors, especially for countries with solid renewable energy prospects. Coordination here makes hydrogen activities transparently available for national GHG accounts and linked with Article 6 mechanisms for performance-based international climate finance. Coordination also makes interministerial coordination among energy, environment, and industry ministries possible to have coordinated and actionable hydrogen deployment plans.

9.5.2 Establish Global South and Triangular Hydrogen Cooperation Frameworks

Key Insight: Hydrogen finance and technology are still very highly concentrated in the Global North. Nevertheless, the greatest long-term capacity potential for world production is in the Global South—regions with high solar irradiance levels, coastlines, and growing domestic market demand for clean energy. Unless strategic partnerships exist, the world hydrogen economy will have the potential to recapitulate the historical patterns of extractive development and technological dependency.

Rationale: Triangular collaboration (between a donor and a technology owner and a beneficiary) and South–South collaboration (between developing nations) offers inclusive frameworks for the

North-since-dominated export paradigms. These paradigms have the potential to balance business profitability with building capacity for localities, technology sharing, and infrastructure co-evolution. The paradigms can unleash regionally anchored and climate-synced hydrogen trade corridors.

Regional governments and blocks must establish institutional hydrogen cooperation platforms which finance and coordinate cross-border collaboration along the value chain of hydrogen. The platforms must promote the sharing of knowledge on the production of electrolyzers, hydrogen storage technology, hydrogen logistics, and regulation best practice. The platforms should also have vehicles for co-investment such as public, private, and development finance, as well as catalyzing technology partnership in terms of open-licensed designs for electrolyzers and harmonized infrastructure standards. There are already precedents in the Africa–EU Hydrogen Partnership drawing upon sub-Saharan solar for the European market, Indo-Pacific Green Hydrogen Corridors spanning Australia, Southeast Asia, and Japan via the trade of ammonia, and nascent Latin America–Gulf relations that uncover low-carbon export prospects.

Such platforms are employed not only economically but for climate justice in that they promote resource-endowed developing nations becoming co-equal actors in co-design and taking benefits of the hydrogen economy. Co-ownership, transfer of technology, and localization of value make sure green hydrogen adoption does not follow history-dependent energy generation and dependency pathways but drives progress and just transition instead.

The implementation of green hydrogen in DES is a worldwide imperative—technologically feasible, ethically required, and geopolitically prudent. In ending this study, its full potential necessitates concerted, multileveled action. Governments who act now with ambitious and just hydrogen strategies will not only reap climate and economic rewards but secure a worldwide just and secure energy future where hydrogen is the bridge to solidarity and sustainability.

LIST OF ABBREVIATIONS

Abbreviation	Meaning
AEL	Alkaline Electrolysis
AEP	Alkaline Electrolysis Process
AWE	Alkaline Water Electrolysis
BESS	Battery Energy Storage System
BiGRU	Bidirectional Gated Recurrent Unit
CAPEX	Capital Expenditure
CBA	Cost-Benefit Analysis
CCS	Carbon Capture and Storage
CDF	Cumulative Distribution Function
CfD	Contracts for Difference
CGH_2	Compressed Gaseous Hydrogen
CNDC	Chinese Nationally Determined Contributions
CDF	Cumulative Probability Distribution
CROI	Carbon Return on Investment
CUF	Cumulative Utilization Factor
CUR	Curtailment-to-Utilization Ratio
DCF	Discounted Cash Flow
DES	Distributed Energy Systems
DLR	Dynamic Load Response
EF	Emission Factor
FiT	Feed-in Tariff
H_2NG	Hydrogen-Natural Gas Blend
LCA	Life Cycle Assessment
LCOE	Levelized Cost of Electricity
LCOH	Levelized Cost of Hydrogen
LH_2	Liquefied Hydrogen

LNG	Liquefied Natural Gas
LOHC	Liquid Organic Hydrogen Carrier
LPP	Low-Pressure Pipeline
LSTM	Long Short-Term Memory (Neural Network)
MOO	Multi-Objective Optimization
MXene	2D Nanomaterials (Metal Carbides/Nitrides)
NDC	Nationally Determined Contributions
NDRC	National Development and Reform Commission (China)
NPC	Net Present Cost
O&M	Operations and Maintenance
OPEX	Operational Expenditure
P50/P70/P90	Probability thresholds used in stochastic modeling (e.g., 50th, 70th, 90th percentile)
RE-H_2	Renewable Hydrogen
RE-H_2NGblend-xPL	Renewable hydrogen-natural gas blend pipeline
RE-H_2-nPL	Renewable Hydrogen with No Pipeline
RE-NH_3	Renewable Ammonia
RE-NH_3-nPL	Renewable Ammonia with No Pipeline
SynGas	Synthetic Gas
WACC	Weighted Average Cost of Capital
xPL	Existing Pipeline

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APPENDICES

Appendix 1. CDF-Based Electrolyzer Sizing Guide

Purpose

To provide a replicable, data-driven approach for right-sizing electrolyzers in hybrid Distributed Energy Systems using percentile-based (P50–P90) energy thresholds, optimizing for hydrogen yield, curtailment, and cost.

Understand the CDF Methodology

What is it?

The Cumulative Distribution Function (CDF) model converts annual daily energy data (from hybrid PV-wind systems) into a probability distribution that shows how often specific energy levels are exceeded.

Why use it?

It accounts for renewable variability, allowing design decisions based on reliability, utilization, and economic feasibility.

Required Inputs

Historical or simulated daily energy generation (MWh/day) from:

- PV solar
- Onshore wind

Steps

i. Step 1: Data Preparation

Collect or simulate 365 daily values of hybrid energy generation (PV + wind).

Ensure all units are in MWh/day.

ii. Step 2: Construct the CDF

Sort the daily energy values in ascending order.

Generate the cumulative distribution function using:

$$P_x = \mathrm{CDF}^{-1}(x) \quad \text{where } x = \{50,60,70,90\}$$

iii. Step 3: Define Sizing Scenarios

P50: Size to match daily energy exceeded 50% of the time (high yield, more curtailment).

P70: Balanced size for utilization and cost.

P90: Conservative, high reliability, lower utilization.

Appendix 2. Guide on use of the Empirical H2 Production Model

Purpose

This guide presents a concise and practical methodology for using the Empirical H2 Yield Model to estimate hourly hydrogen production in Distributed Energy Systems. The model offers a reliable approximation for early-stage planning and system optimization, aligning well with detailed Aspen Plus simulations and Vensim dynamic system models.

Model Description

The Empirical H2 Yield Model calculates hydrogen production as a function of input power (P_{input} in kW) and the number of electrolyzer stacks (N). It uses a bifurcated logarithmic formulation to reflect differences in system scaling behavior:

$$\mathrm{H_2\ \ (kg/h)} = \begin{cases} (0.006533 \cdot \ln(N) + 0.019241) \cdot P_{\text{input}}, & \text{for} N \leq 6 \\ (0.031146 \cdot \ln(N) - 0.033157) \cdot P_{\text{input}}, & \text{for} N > 6 \end{cases}$$

Model Basis

- Derived from empirical regression on alkaline water electrolyzer (AWE) datasets.
- Validated with Aspen Plus simulations ($\pm$5% error).
- Confirmed by Vensim-based system dynamics modeling.
- Example: ITM Power electrolyzer performance yields +1.2% match.

Required Inputs

- Number of electrolyzer stacks (N)
- Input power to the electrolyzer (P_{input}, in kW)

Application Workflow

i. **Define System Parameters:**

Identify N, the number of electrolyzer stacks.

Determine available renewable input power (P_{input}) from PV, wind, or hybrid systems.

ii. **Select the Correct Formula Branch:**

If $N \leq 6$, use the first formula.

If $N > 6$, use the second formula.

iii. **Calculate H2 Output:**

Use the appropriate formula to compute hydrogen output in kg/h.

iv. **Aggregate Results:**

Multiply hourly output by daily or annual operational hours to get kg/day or tons/year.

Example

$N = 10$ (electrolyzer stacks), $P_{\text{input}} = 9000$ kW

$\ln(10) \approx 2.3026$

Hydrogen output:

$$\mathrm{H_2} = (0.031146 \cdot 2.3026 - 0.033157) \cdot 9000 = (0.0385) \cdot 9000 \approx 346.5 \ \text{kg/h}$$

Design Considerations

i. Best performance observed in 8,000–12,000 kW range under P60–P70 renewable energy profiles.

ii. Integration with Battery Energy Storage Systems (BESS) enhances system efficiency and reduces curtailment.

iii. Avoid under-sizing (leads to high idle time) or over-sizing (leads to high curtailment and CAPEX).

Recommended Use Cases

i. Early-stage planning and techno-economic feasibility studies.

ii. Modular hydrogen systems in grid-constrained regions.

iii. Policy frameworks to determine CAPEX subsidy eligibility.

iv. Microgrid and rural DES applications.

Model Maintenance and Flexibility

i. Revalidate model every 2–5 years as technologies advance.

ii. Suitable for flexible system scaling and modular deployment.

iii. Easily embedded in spreadsheets, Vensim models, or Python scripts.

Limitations

i. Does not account for transient dynamics or part-load efficiency losses.

ii. Assumes steady-state operation within the defined load window.

iii. Stack degradation and system downtime not included.

Conclusion

The Empirical H2 Yield Model provides a fast, reasonably accurate method to forecast hydrogen production in distributed energy environments. It supports decision-making under uncertainty, aligns with detailed simulations, and bridges planning gaps where detailed tools are not accessible.