International Master's Program in Energy and Green Hydrogen (IMP-EGH)

MASTER THESIS

Speciality: Economics/Policies/Infrastructures and Green Hydrogen Technology

Topic:

The Role of Green Hydrogen as Seasonal Storage Solution for Achieving 100% Renewable Energy Systems by 2040: The case of São Vicente, Cape Verde

Presented on the 16th September 2025 by:

Abdulazeez Ilyasu

RWTH Supervisors:

Prof. Dr. Maria Movsessian

Katia Gomes, M.Sc.

UCAD Supervisor:

Dr. Ing. Pierre Williams Tavares

2024/2025 Academic year

Dedication

I dedicate this work to the loving memory of my late father Alhaji ILYASU Shuaibu, whose tireless efforts and sacrifices laid the foundation for my educational journey and whose vision for our success continues to inspire me. I also dedicate it to my mother Hajiya ZAINAB (Baba'Ai), whose unwavering prayers, care, and support have sustained me since his passing and remain a constant source of strength and encouragement. This achievement is as much theirs as it is mine.

Acknowledgments

I am profoundly grateful to almighty Allah for granting me the health, strength, and perseverance throughout these years of study.

I would also like to express my gratitude to:

- BMBF and WASCAL for scholarship and support throughout our study program.
- The Presidents of the university of Lome, Abdou-Moumouni University Niger, and Cheikh Anta Diop University Dakar.
- The Vice Chancellor of RWTH Aachen University Germany.
- Prof. Rabani Adamou, Director of WASCAL GSP Abdou-Moumouni University Niger.
- Prof. Assane Beye the Director of WASCAL GSP UCAD.
- Dr. Fama GUEYE, Deputy director of WASCAL Senegal.
- Dr. Khady Yama SARR, IMP-EGH program coordinator of WASCAL UCAD.
- Prof. Dr. Peter LETMATHE, RWTH Aachen University.
- My supervisors, Prof. Dr. Maria Movsessian, Dr. Ing. Pierre Williams Tavares, and Katia Gomes, for their invaluable support, and commitment.
- The entire staff of WASCAL and RWTH Aachen University.
- The entire fellow students of batch-2 IMP-EGH program.

I also wish to extend my heartfelt thanks to all those who have supported me directly or indirectly from the very beginning of this journey. Their invaluable advice, as well as the technical, financial, and moral support, have been instrumental in enabling me to complete this work and bring it to a successful conclusion.

Abstract

Small Island Developing States (SIDS) such as São Vicente Island in Cabo Verde face compounded energy challenges due to their reliance on imported fossil fuels, grid isolation, and vulnerability to climate impacts. While renewable energy offers a viable path forward, the inherent variability of solar and wind resources on São Vicente, particularly the seasonal fluctuations in their availability, necessitates effective long-term storage solutions to ensure grid reliability and a consistent power supply. This study assesses green hydrogen as a seasonal energy storage option and benchmarks it against battery-only and no-storage configurations, and how it could support São Vicente in reaching a 100% renewable energy system by 2040, representing the first green hydrogen storage assessment for a West African SIDS.

A multi-scenario modelling approach was applied using the COMANDO (Component-Oriented Modelling and Optimization for Nonlinear Design and Operation) energy systems modelling tool, exploring four distinct 2040 system configurations: (i) PV and wind without storage, (ii) PV and wind with battery storage, (iii) PV and wind with hydrogen storage, and (iv) PV and wind with a hybrid battery-hydrogen storage. The systems were evaluated based on key technical and economic performance indicators including Levelized Cost of Electricity (LCOE), Loss of Power Supply Probability (LPSP), and Total Annualized System Cost (TAC). A cost-sensitivity analysis is also performed to understand how system costs respond to changes in component cost developments. Additionally, a qualitative assessment was conducted on limiting and enabling technical, economic or policy factors that could influence the long-term viability, providing a broader view of circular-economy benefits and implementation barriers.

Results show that the hybrid storage system (Scenario-iv) achieved the most balanced outcome, meeting the technical criteria of 0% LPSP and 100% renewable share while maintaining a competitive LCOE of 0.0503€/kWh and a TAC of 6.97 million €/year. Compared to single-storage configurations, the hybrid configuration reduces system costs by 25% and virtually eliminates unmet demand. Sensitivity analysis revealed that system cost is most affected by variations in wind turbine costs and, within storage technologies, electrolyser costs. A qualitative assessment of long-term viability factors highlighted that, technical challenges such as seasonal variability and low grid inertia must be addressed through advanced solutions like grid-forming inverters and Virtual Synchronous Generators (VSGs). Economic barriers include high upfront investment and financing constraints, while enabling factors includeCabo Verde's strong political commitment, abundant renewable resources, and supportive policy direction.

This study offers practical guidance to planners, policymakers, and investors looking to unlock the industrial-strategy potential of hydrogen in the energy transition of islanded and vulnerable regions.

Keywords: Green hydrogen, Seasonal storage, 100% Renewable energy, Small Island Developing States (SIDS), Africa, Energy transition.

Résume

Les petits États insulaires en développement (PEID), tels que l'île de São Vicente au Cabo Verde, sont confrontés à des défis énergétiques complexes en raison de leur dépendance aux combustibles fossiles importés, de leur isolement du réseau et de leur vulnérabilité aux impacts climatiques. Bien que les énergies renouvelables offrent une voie prometteuse, la variabilité intrinsèque des ressources solaires et éoliennes à São Vicente, en particulier les fluctuations saisonnières de leur disponibilité, exige la mise en place de solutions de stockage à long terme efficaces afin de garantir la fiabilité du réseau et un approvisionnement électrique stable. Cette étude évalue l'hydrogène vert comme option de stockage saisonnier d'énergie et le compare à des configurations sans stockage et à stockage par batterie uniquement, afin de déterminer comment il peut contribuer à atteindre un système énergétique 100% renouvelable d'ici 2040 à São Vicente, représentant la première évaluation du stockage d'hydrogène pour un PEID d'Afrique de l'Ouest.

Une approche de modélisation multi-scénario a été appliquée à l'aide de l'outil de modélisation des systèmes énergétiques COMANDO (modélisation axée sur les composants pour la conception et le fonctionnement non linéaire), explorant quatre configurations de système 2040 distinctes: (i) PV et vent sans stockage, (ii) PV et éolien avec batterie, (iii) PV et éolien avec stockage d'hydrogène et (iv) PV et éolien avec une batterie hybride PV et un stockage d'hydrogène. Les systèmes ont été évalués sur la base d'indicateurs de performance technique et économique clés, notamment le coût nivelé de l'électricité (LCOE), la perte de probabilité d'alimentation (LPSP) et le coût total du système annualisé (TAC). Une analyse de sensibilité aux coûts est également effectuée pour comprendre comment les coûts du système réagissent aux changements dans les développements des coûts des composants. De plus, une évaluation qualitative a été menée sur des facteurs techniques, économiques ou politiques pourrait influencer la viabilité à long terme, offrant une vision plus large des avantages de l'économie circulaire et des obstacles à la mise en œuvre.

Les résultats montrent que le système de stockage hybride (scénario-iv) a obtenu le résultat le plus équilibré, remplissant les critères techniques de 0% de LPSP et une part renouvelable à 100% tout en maintenant un LCOE compétitif de 0,0503€/kWh et un TAC de 6,97 millions €/an. Par rapport aux configurations à stockage unique, la configuration hybride réduit les coûts du système de 25% et élimine pratiquement la demande non satisfaite. L'analyse de sensibilité a révélé que le coût du système est le plus affecté par les variations des coûts d'éoliennes et, dans les technologies de stockage, les coûts d'électrolyser. Une évaluation qualitative des facteurs de viabilité à long terme a souligné que les défis techniques tels que la variabilité saisonnière et l'inertie à faible réseau doivent être relevés par des solutions avancées telles que les onduleurs de formation de grille et les générateurs synchrones virtuels (VSG). Les obstacles économiques comprennent des contraintes élevées d'investissement et de financement initial, tandis que les facteurs habilitants incluent le fort engagement politique du Cabo Verde, les ressources renouvelables abondantes et l'orientation de la politique de soutien.

Cette étude offre des conseils pratiques aux planificateurs, aux décideurs et aux investisseurs qui cherchent à déverrouiller le potentiel de stratégie industrielle de l'hydrogène dans la transition énergétique des régions insulaires et vulnérables.

Mots-clés: Hydrogène vert, Stockage saisonnier, 100% Énergies renouvelables, Petits États insulaires en développement (PEID), Afrique, Transition énergétique.

Contents

List of Tables

List of Figures

Acronyms and Abbreviations

Table 1: List of Acronyms

Acronym	Meaning
ALM	Algebraic Modeling Language
ARME	Agência Reguladora Multissectorial da Economia
BESS	Battery Energy Storage System
BMBF	Bundesministerium für Bildung und Forschung
CAPEX	Capital Expenditure
COMANDO	Component-Oriented Modeling and Optimization for Nonlinear Design and Operation
ECOWAS	Economic Community of West African States
ESS	Energy Storage Systems
EZ	Electrolyser
FC	Fuel Cell
GDP	Gross Domestic Product
GWO	Grey Wolf Optimiser
HT	Hydrogen Tank
IEA	International Energy Agency
IRENA	International Renewable Energy Agency
LCOE	Levelised Cost of Electricity
LCOH	Levelised Cost of Hydrogen
LCOS	Levelised Cost of Storage
LPSP	Loss of Power Supply Probability
MFO	Moth Flame Optimisation
MILP	Mixed-Integer Linear Programming
MICE	Ministry of Industry, Commerce and Energy
O&M	Operation and Maintenance
OPEX	Operational Expenditure

Table 1 – continued from previous page

Acronym	Meaning
OTEC	Ocean Thermal Energy Conversion
PV	Photovoltaic
RE	Renewable Energy
RES	Renewable Energy System
R&D	Research and Development
SDG	Sustainable Development Goals
SIDS	Small Island Developing States
SOC	State of Charge
TAC	Total Annual Cost
UAM	Université Abdou-Moumouni
UCAD	Université Cheikh Anta Diop
UNDESA	United Nations Department of Economic and Social Affairs
WASCAL	West African Science Service Centre on Climate Change and Adapted Land Use
WT	Wind Turbine

Chapter 1 Introduction

1.1 Background and Context

The global energy sector is undergoing intense transformation, driven by the urgency of climate change mitigation and the need to reduce the financial and environmental risks associated with fossil fuel dependence (IEA, 2023). While many countries are transitioning towards renewable technologies, small island developing states (SIDS) find themselves in a unique position. They are among the most exposed to climate impacts and at the same time, well placed to pioneer high renewable energy systems due to their manageable demand, compact grids and strong local resource bases (Meschede et al., 2022).
Within this broader context, Cabo Verde, situated off the West African coast, is well positioned for both the opportunities and constraints of the transition. Its islands face increased vulnerability to climate impacts, rising sea levels, droughts and severe weather increases the risks of relying on imported fossil fuels for electricity generation (UNDP, 2024). At the same time, their relatively simple grid structures, manageable demand profiles and abundant natural resources make them ideal for exploring 100% renewable energy systems (Gesto Energia, 2011). Despite a technically feasible renewable potential exceeding 2,600 MW (Gesto Energia, 2011), actual utilisation remains modest and, as of 2023, fossil fuels still supply over 80% of the primary energy mix (MICE, 2023). This dependence exposes the economy to international price volatility and periodic supply disruptions, undermining both energy security and macroeconomic stability (IMF, 2024).

Against this national backdrop, São Vicente is a strategically important case for three reasons that are directly tied to this thesis. First, the island combines a relatively large and growing demand with good quality wind and solar resources, making it representative of Cabo Verde's most relevant planning trade-offs. Second, several studies (and operational experience) indicate pronounced seasonal variability in wind and solar availability on São Vicente, producing recurrent mismatches between supply and demand that cannot be fully resolved by short duration storage alone (Pombo et al., 2022; SGIE, 2019). Third, São Vicente has already been the subject of 100% renewable energy planning work, providing a credible reference point from which to test the added value of seasonal storage (hydrogen) in closing these seasonal gaps (Pombo et al., 2022). In short, São Vicente is both representative for the archipelago and well suited to examine how green hydrogen can address seasonal imbalances that limit high-renewable penetration.

Resource wise, São Vicente exhibits favorable wind regimes and strong solar irradiation. Atlas data report average wind speeds commonly above 7 m/s at promising sites, with many windy days across the year; global horizontal irradiation (GHI) is on the order of $\sim$2,000 kWh/m^2/year and annual sunshine hours exceed 3,000h, which together indicate high technical potential for wind and PV generation (Gesto Energia, 2011; Pombo et al., 2022). Nevertheless, the intermittency of these resources and their seasonal patterns imply that adding capacity alone will not guarantee adequacy or reliability.

Conventional storage helps but does not fully address these seasonal effects. Battery energy storage systems are effective for short-term balancing, frequency support and daily cycling, but become cost intensive when scaled for over several weeks to months storage. Pumped hydro storage (PHS), by contrast, can provide longer duration, and in São Vicente it has been studied as a candidate solution (including concepts around a 10 MW scheme). However, siting, environmental considerations and system integration remain non-trivial and case-specific (Segurado et al., 2011). Given these constraints, there is strong motivation to consider complementary long duration options that directly target seasonal mismatches.

Green hydrogen is one such option. In brief, surplus renewable electricity can be converted to hydrogen via electrolysis, stored over long periods and later reconverted to electricity in fuel cells or turbines when renewable output is low. This seasonal arbitrage, shifting energy from times of surplus to times of deficit, directly addresses a key barrier to very high renewable shares (Marouani et al., 2023; Hiris et al., 2024; Schneider et al., 2023). Because the details of hydrogen production, storage and end use are extensive, a concise overview is provided here and the full technical discussion is deferred to chapter 2.

Framed this way, São Vicente's case study is tightly aligned with the thesis scope; the island's clear seasonal resource swings and growing load provide a rigorous test for evaluating the role of hydrogen as seasonal storage within a 100% renewable pathway. The central question becomes whether and under what conditions, hydrogen can cost effectively complement long duration storage and grid measures to deliver year round adequacy while reducing imports and emissions (Pombo et al., 2022).

1.2 Problem Statement

Cabo Verde has set ambitious goals, 50% renewable penetration by 2030 and full decarbonisation by 2040 or beyond, but progress remains uneven (IRENA, 2021). On São Vicente, electricity supply is still dominated by imported diesel, which leads to high tariffs, exposure to international fuel price shocks and recurring grid instability (WorldBank, 2024). The island's seasonal wind and solar profiles exacerbate supply-demand mismatches, especially during dry or low-wind periods when output declines but demand persists (Pombo et al., 2022; SGIE, 2019).

While batteries can handle intra-day balancing, achieving seasonal shifting with batteries alone is cost intensive at the scales required. PHS is also infeasible in São Vicente, giving the constraints mentioned in 1.1 above (Segurado et al., 2011). This points to a critical planning gap, the need for scalable, context appropriate, long duration storage that complements existing options and targets the seasonal nature of variability.

This thesis therefore, asks how green hydrogen can be effectively integrated as seasonal storage to deliver year round reliability within a 100% renewable system on São Vicente. Specifically, it evaluates the technical and economic performance of hydrogen alongside wind, PV and batteries and examines enabling policy and infrastructure conditions. The overarching problem is to determine under which system configurations and assumptions hydrogen offers a sustainable, just and cost effective pathway for São Vicente's energy future, consistent with national targets and local constraints.

1.3 Research Questions, Objectives, and Hypotheses

The primary objective of this research is to investigate the role of green hydrogen as a seasonal energy storage solution for achieving a 100% renewable electricity system on São Vicente Island by 2040. This objective is case specific. São Vicente exhibits pronounced seasonal variability in wind and solar availability alongside a still high reliance on diesel generation and recurrent adequacy challenges, together these characteristics create seasonal supply-demand mismatches that short duration storage alone cannot fully resolve (Pombo et al., 2022; SGIE, 2019). Evaluating hydrogen's ability to shift surplus renewable energy across weeks to months directly targets this seasonal imbalance while supporting national goals for 2030/2040 and improving year round reliability.

1.3.1 Research questions

This study aims to address the following research questions:

1) How can green hydrogen, as a seasonal energy storage solution, contribute to achieving a 100% renewable energy system by 2040 in São Vicente?

2) What are the optimal technical and economic configurations of a renewable energy system integrating green hydrogen storage for São Vicente, considering various system configuration Scenarios?

3) What are the key technical, economic, and policy factors influencing the long-term viability and successful implementation of green hydrogen as a seasonal energy storage solution in São Vicente?

1.3.2 Specific objectives

To address the aforementioned research questions, this study sets forth the following specific objectives:

1) To assess the technical feasibility and contribution of green hydrogen as a seasonal energy storage solution in enabling a 100% renewable energy system for São Vicente, by 2040.

2) To identify and analyze the optimal technical and economic configurations of renewable energy systems for São Vicente, by comparing Scenarios with no storage, battery-only storage, hydrogen-only storage, and hybrid battery-hydrogen storage.

3) To qualitatively evaluate the technical, economic, and policy factors that influence the long-term viability and successful deployment of green hydrogen as a seasonal energy storage solution in the context of São Vicente.

1.3.3 Hypotheses

Based on existing literature and the current understanding of RES and hydrogen technologies, the following hypotheses are proposed:

1) The integration of green hydrogen as a seasonal energy storage solution will significantly enhance the reliability and stability of a 100% renewable energy system in São Vicente, by mitigating the intermittency of solar and wind resources, compared to systems without seasonal storage.

2) A hybrid energy storage system combining batteries for short-term fluctuations and green hydrogen for long-term seasonal storage will demonstrate the most optimal technical and economic performance for São Vicente, compared to single-storage or no-storage.

3) The long-term viability and successful implementation of green hydrogen as a seasonal energy storage solution in São Vicente, are critically dependent on supportive policy frameworks, favorable economic incentives, and the development of robust technical infrastructure, as evidenced by successful case studies in similar island contexts.

1.4 Scope and Delimitation

This research focuses specifically on São Vicente Island to examine the role green hydrogen can play as a seasonal energy storage solution in achieving a 100% renewable energy system by 2040. The study is centered on the electricity sector, particularly the integration of wind and solar energy sources with green hydrogen technology. The scope includes analysing historical and projected energy demand, and renewable energy potential. It also covers the modelling of energy system scenarios that incorporate green hydrogen production, storage and reconversion using surplus renewable energy. Economic and policy aspects such as Levelised cost of hydrogen (LCOH), investment requirements and institutional readiness are also considered. However, the study is subject to a certain scope. It does not cover other energy sectors such as transport or industry, although potential collaborations through sector coupling are acknowledged. Additionally, the analysis is based on techno-economic modelling and scenario development using available data. It does not include field implementation or pilot testing. Policy analysis is limited to existing documents and secondary data. These scopes are necessary to maintain focus and ensure the depth of analysis within the research time frame. Despite these boundaries, the findings are expected to offer valuable insights applicable to other small island developing states with similar energy profiles.

1.5 Thesis Structure

This thesis is organised into five chapters. (1) presents the background, motivation for selecting São Vicente, problem statement, research questions, objectives, hypothesis, scope, and structure. (2) synthesises the literature on SIDS energy transitions, seasonal variability and storage (with emphasis on hydrogen), evaluate previous research and derives the research gap. (3) details the methodology, case-study data, the COMANDO model set-up, optimisation formulation, and scenario/sensitivity design. (4) reports and discusses results: technical performance, economic outcomes, scenario comparisons, sensitivities, and the qualitative assessment of long-term viability factors. (5) concludes with key findings, limitations and recommendations for policy, practice, and future research.

Chapter 2 Literature Review

This chapter provides a comprehensive review of existing literature relevant to achieving 100% renewable energy systems in SIDS, with a specific focus on the role of green hydrogen as a seasonal storage solution. It aims to establish the current state of renewable energy integration in SIDS, differentiate between short-term and seasonal storage technologies, and explore the economic, technical, and policy considerations surrounding green hydrogen deployment. Furthermore, it analyzes systemic enablers and barriers to renewable energy transitions and details the energy context of São Vicente Island, setting the foundation for the subsequent methodological and results chapters.

2.1 100% Renewable Energy Systems in SIDS

Ambitions for 100% renewable electricity are increasingly prominent worldwide and particularly important for small island developing states, where limited system size, exposure to external shocks, and seasonal variability of wind and solar create distinctive planning challenges. The core technical issue for islands is not only the variability of renewables over hours and days, but also the seasonal mismatch between resource availability and demand, which stresses adequacy and reliability if not paired with long-duration storage and flexible operation (Meschede et al., 2022).

In this context, international assessments underline both the vulnerability and the opportunity for islands. SIDS face high import dependence and exposure to price volatility, yet they also benefit from contained systems and manageable demand that allow rapid learning and replication of best practices (IRENA, 2016). Evidence from island case studies shows that the share of energy imports can represent a substantial macroeconomic burden and heighten energy-security risk, reinforcing the value of substituting local wind and solar with appropriate grid and storage solutions (IRENA, 2016; Bank, 2022). Rather than a generic transition, the emerging lesson is that each island must tailor portfolios and flexibility options to the shape of its seasonal resources and demand.

Cabo Verde illustrates this duality. The country has documented technical potential for renewable capacity exceeding 2,600 MW, yet actual uptake has been slower and the primary energy mix remains dominated by fossil fuels (Gesto Energia, 2011; MICE, 2023). For São Vicente specifically, prior planning work confirms that very high renewable penetration is feasible if complemented by system upgrades and storage sized to the island's seasonal patterns (Pombo et al., 2022). These findings are consistent with broader SIDS experience: achieving reliability at high renewable shares requires targeted investments that explicitly address seasonal balancing, not only daily cycling.

Approaches adopted by other islands provide relevant insights for São Vicente. Some systems emphasise demand-side flexibility and batteries to handle intra-day variability, others add longer duration options to bridge several days and seasonal deficits. For São Vicente, feasibility analysis has also considered pumped-hydro energy storage as a candidate long-duration solution, indicating site specific opportunities and constraints that must be weighed against alternative storage pathways (Segurado et al., 2011). What emerges across cases is that no single technology suffices in isolation, instead, combinations of variable renewables with appropriately scaled short- and long-duration storage are needed to overcome seasonal resource swings while containing costs (Meschede et al., 2022; IRENA, 2016).

Against this backdrop, hydrogen is increasingly discussed as a seasonal storage option that can shift surplus wind and solar across weeks to months and complement batteries and operational measures. In island settings where seasonal deficits are material, modelling studies suggest that integrating hydrogen production, storage, and reconversion can reduce curtailment, improve adequacy, and support pathways to 100% renewable supply (Marouani et al., 2023). For São Vicente, the relevance of seasonal storage has already been highlighted in generation expansion analyses (Pombo et al., 2022), the present study builds on that literature by focusing explicitly on how hydrogen could mitigate seasonal mismatch and what system configurations are most effective under the island's conditions.

2.2 Short-term versus Seasonal Storage: Batteries and Hydrogen

A core requirement for operating a high-renewables power system is flexibility, that is, the ability to match supply and demand across different time scales. On small islands, variability unfolds both intra-day (hours) and across seasons (weeks to months). Battery energy storage systems (BESS) are well suited to short-term balancing, while hydrogen-based systems can provide the long-duration, seasonal shifting needed to close persistent resource–demand gaps (Mulder, 2014; Yang et al., 2021; Marouani et al., 2023).

Batteries, especially lithium-ion, offer high round trip efficiency, fast response and proven performance for frequency regulation and daily cycling. In island systems, they reduce curtailment during short surplus periods and provide contingency support, improving power quality and reliability. Although battery costs have fallen substantially in recent years, using batteries alone to bridge several weeks or seasonal deficits remains challenging due to cumulative energy capacity requirements, cycling durability and system-level cost implications at very long durations (Mulder, 2014; Yang et al., 2021).

Hydrogen-based storage complements batteries by targeting longer time scales. Surplus renewable electricity drives electrolysis to produce hydrogen, which can be stored for extended periods and reconverted to electricity in fuel cells or engines when renewable output is low. This pathway directly addresses seasonal mismatch, albeit with lower round-trip efficiency than batteries and with additional infrastructure needs for electrolysers, storage and end-use conversion (Marouani et al., 2023; Schneider et al., 2023). Like batteries, electrolysers and fuel cells have seen notable cost reductions and learning effects and continued declines are anticipated, though the cost and efficiency trajectories differ across technologies (Schneider et al., 2023). Beyond electricity, hydrogen's versatility is particularly relevant in small islands, it can support ferry and port operations, backup power for desalination and critical services, and hard-to-electrify loads, creating system-wide value that can improve overall economics (IRENA, 2016).

Other flexibility options can also contribute. PHS is the most deployed long-duration technology globally, but its applicability is highly site-specific. Additional emerging options (flywheels, compressed air, thermal storage) may address niche needs but are typically complementary rather than substitutes for the main short and long duration pillars (Hiris et al., 2024).

In practice, hybrid portfolios that combine batteries (short-term) with hydrogen (seasonal) tend to deliver a better trade-off between adequacy and cost for island systems aiming for very high renewable shares. Modelling studies for São Vicente and comparable contexts show that coordinated sizing and operation of these resources can reduce curtailment, increase reliability and contain total system costs relative to single-technology strategies (Amoussou et al., 2023; Pombo et al., 2022).

Figure 2.1 below illustrates the fundamental process flow of a green hydrogen energy system. It details how Surplus electricity from renewable energy (RE) sources is sent into the electrolyser (EZ) and used to produce hydrogen via electrolysis, which is stored in hydrogen tanks (HT) and later reconverted into electricity through a fuel cell (FC) or gas turbine to supply the grid.

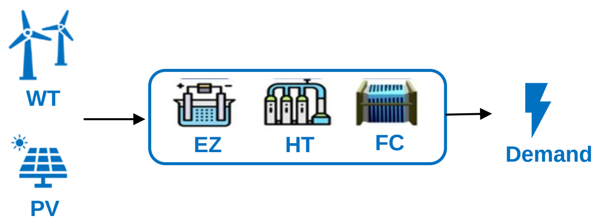

Figure 2.1: Green hydrogen energy system flow
(Source: Author's own elaboration)

2.3 Economic, Technical and Policy Considerations of Green Hydrogen

The adoption of green hydrogen as a seasonal energy storage solution brings with it a range of economic, technical and policy considerations. Currently, green hydrogen is more expensive than other storage options, primarily due to the high costs associated with electrolysis and hydrogen storage infrastructure. However, costs are expected to decline rapidly as electrolyser technology improves, renewable electricity prices decrease and more supportive policies are introduced (IRENA, 2016). Studies such as Pombo et al. (2022) and Amoussou et al. (2023) indicate that hybrid systems using both hydrogen and batteries can provide better cost-reliability trade-offs compared to systems that rely on just one technology.

Economic analyses often use metrics like the LCOH to evaluate the performance of hydrogen storage systems. Additionally, optimisation algorithms, including Moth Flame Optimisation (MFO) and Grey Wolf Optimiser (GWO), are applied to identify the optimal mix of energy generation and storage that minimises overall system cost while ensuring reliability (Amoussou et al., 2023). On the technical side, several challenges must be addressed for green hydrogen to be effective. One major issue is efficiency loss: the round-trip efficiency of converting electricity to hydrogen and back to electricity is lower than that of batteries, often falling below 40%. Effective system integration is also crucial, as hydrogen systems must be appropriately sized and seamlessly integrated with local grids to avoid overbuilding or underutilising costly infrastructure. Safety and purity concerns, particularly with underground storage, add further complexity and expense due to risks like gas mixing, leakage and the need to maintain hydrogen purity (Saeed et al., 2023; Ali et al., 2022). Furthermore, many islands currently lack the necessary hydrogen infrastructure, which means significant investment is needed in electrolysers, storage tanks and conversion systems.

Policy and regulatory frameworks play a critical role in the successful deployment of green hydrogen. SIDS need to establish clear targets for renewable energy and hydrogen, offer financial incentives and create regulations that reduce investment risk. For small islands with limited market size and high upfront costs, international support and partnerships may also be necessary (IRENA, 2016; Akinsooto et al., 2024). In Cabo Verde, recent energy policies show increasing interest in hydrogen, but practical frameworks for implementation are still being developed (World Bank, 2024).

2.4 Systemic Enablers and Barriers to 100% Renewable Energy Transitions

Recent academic literature and international policy documents emphasise that the long-term viability of 100% renewable energy systems, particularly with the integration of green hydrogen as seasonal storage, depends on a complex interplay of technical, economic and regulatory factors. Studies on island energy transitions repeatedly highlight that technical readiness is a fundamental enabler for large-scale renewable integration. Grid modernisation, including investments in transmission, distribution and advanced digital controls, is necessary to absorb higher shares of variable renewables and support the operation of distributed storage solutions (Meschede et al., 2022; IRENA, 2019). Successful transitions also require innovations in long-duration storage, such as batteries and green hydrogen, which enhance flexibility and help stabilise the grid in the face of daily and seasonal variability (Hiris et al., 2024; IRENA, 2018). Modern energy systems increasingly rely on real-time data, improved forecasting and digital monitoring for effective management of both supply and demand, emphasising the importance of advanced control systems and data infrastructure (Pfenninger et al., 2014).

Nonetheless, several technical barriers persist. High levels of inverter-based renewable generation can reduce system inertia, making island grids more sensitive to frequency and voltage disturbances. The current infrastructure on many small islands, including São Vicente, was not originally designed for the dynamic, bidirectional flows that high renewable penetration requires, leading to curtailment and limits on how much renewable power can be reliably integrated (IEA, 2017). Moreover, year-to-year variability in wind and solar resource availability introduces further reliability challenges, making storage and grid flexibility all the more critical (Staffell and Pfenninger, 2016).

From an economic perspective, the declining costs of solar PV, wind turbines and electrolysers have improved the cost-effectiveness of renewable and hydrogen-based systems. Several international reports project that, in many contexts, renewable electricity is already the least-cost option for new power generation, while hydrogen storage technologies are expected to become much more affordable over the next decade (IEA, 2022b; IRENA, 2021). Access to international climate finance, concessional loans and technical assistance is also a major driver of progress for SIDS and developing countries, supporting both infrastructure investment and local capacity-building (Bank, 2022; IRENA, 2019). Furthermore, local co-benefits such as job creation, economic diversification and the development of new value chains can foster broader social and political support for the energy transition (Pombo et al., 2022).

However, several economic constraints remain. The upfront capital costs for new generation, storage and grid upgrades are often prohibitive, especially for small and isolated grids that lack economies of scale (Meschede et al., 2022). In many SIDS, market frameworks and price signals for storage, ancillary services, or hydrogen are underdeveloped, creating uncertainty for private investors (IEA, 2017). These scale and market-related disadvantages are particularly acute for islands like São Vicente, where per-unit costs can be substantially higher than on the mainland, and external shocks can have outsized impacts (Gado et al., 2024).

Policy and regulatory frameworks are equally critical. Countries that have set clear and ambitious targets for renewable energy, backed by roadmaps, legislation and incentives, provide strong signals for investment and technology adoption (IRENA, 2016). Supportive regulations that facilitate grid access, streamline permitting, and encourage innovation are proven to accelerate the deployment of renewables and storage (IEA, 2017; IRENA, 2018). International and regional cooperation, such as technical support from organisations like IRENA or ECOWAS, also helps local governments overcome capacity constraints and adopt global best practices.

Nevertheless, policy uncertainty and weak institutional capacity can slow or stall the transition. Inconsistent targets, changing regulations, or limited experience with advanced energy markets and hydrogen technologies can erode investor confidence (ARME, 2022). Outdated grid codes, market rules and lack of planning for flexible and sector-coupled systems may also restrict the full integration of new solutions and innovation (IEA, 2017; Pombo et al., 2022). For São Vicente, addressing these real-world barriers beyond what is captured in quantitative models will be essential to achieving a reliable, cost-effective, and just energy transition.

The pathway to 100% renewable energy in small island contexts relies not only on techno-economic optimisation but also on the broader landscape of enabling technologies, economic frameworks and supportive policy. This comprehensive understanding is critical for designing resilient, future-proof energy systems that are implementable in practice, not just in models.

2.5 Energy Context of São Vicente Island (Cabo Verde)

2.5.1 The energy mix, challenges and opportunities

For São Vicente, the central system design issue is the seasonal variability of renewable resources and what this implies for storage needs. Wind output is typically strongest from roughly December to May and weakens in the summer months, while solar potential peaks from March to August. These out-of-phase patterns create recurrent periods of surplus and deficit that do not align with demand, sustaining the need for long-duration shifting in addition to short-term balancing. The 2021 generation mix (about 73% thermal, 26% wind, and less than 1% solar) reflects this seasonal mismatch rather than a lack of resource, with curtailment risks in windy months and diesel back-up in low-wind/low-sun periods (SGIE, 2021, 2019; Pombo et al., 2022).

The implication is that flexibility must operate across multiple time scales, that is, batteries for intra-day balancing and frequency support, and a seasonal option to move energy across weeks to months. Hydrogen produced from surplus wind and solar via electrolysis and reconverted during deficit months directly targets this seasonal gap, complementing short-duration storage and reducing reliance on diesel while supporting national 2030/2040 targets (ARME, 2022; Marouani et al., 2023; IRENA, 2016).

Figure 2.2 below presents a simplified overview of São Vicente Island's energy flow in 2021. It highlights the dominant role of imported diesel in power generation, alongside the increasing but still limited contributions from wind and the marginal impact of solar energy. The distribution of electricity through the island grid is also depicted.

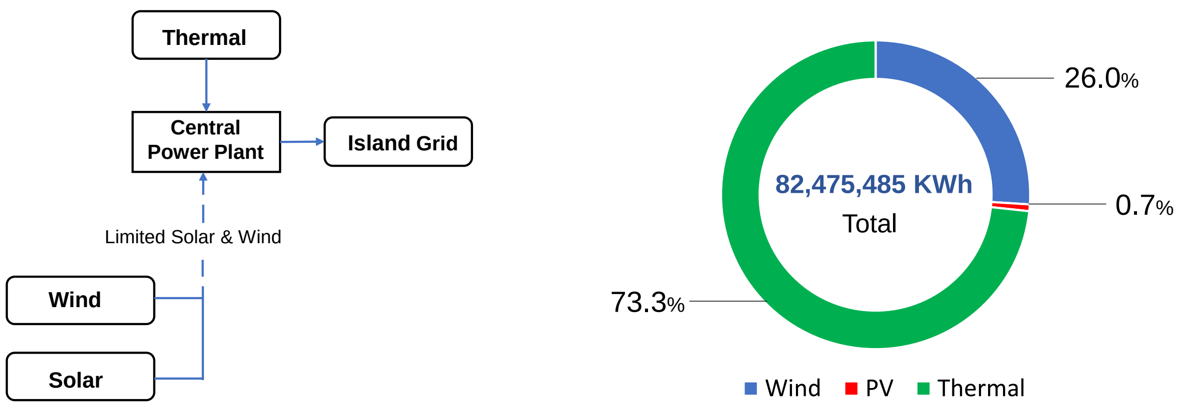

Figure 2.2: Simplified energy flow and distribution of electricity of São Vicente Island in 2021 (Source: Author's elaboration based on data from SGIE (2021))

2.5.2 Wind and solar energy potential

Wind and solar resources on São Vicente combine high potential with marked seasonality. In 2021, wind supplied over 21.4 GWh, about 26% of total island production, reflecting the strong, consistent winds experienced, especially during the dry season (SGIE, 2021). Average wind speeds regularly exceed 7 m/s, making the island an excellent site for efficient wind turbines (Gesto Energia, 2011; Pombo et al., 2022). However, while wind farms have been established, their capacity remains limited compared to the island's full potential.

Solar irradiation is also high, with São Vicente receiving over 3,000 hours of sunlight annually and average global horizontal irradiation of 2,000 kWh/m^2/year (Gesto Energia, 2011), suggesting that the solar potential remains largely untapped. The semi-arid climate and minimal cloud cover are ideal for photovoltaic energy, but broader deployment is needed. The annual RE resource profile of São Vicente Island presented in Figure 2.3 reveals a clear seasonal variation in both wind and solar resources.

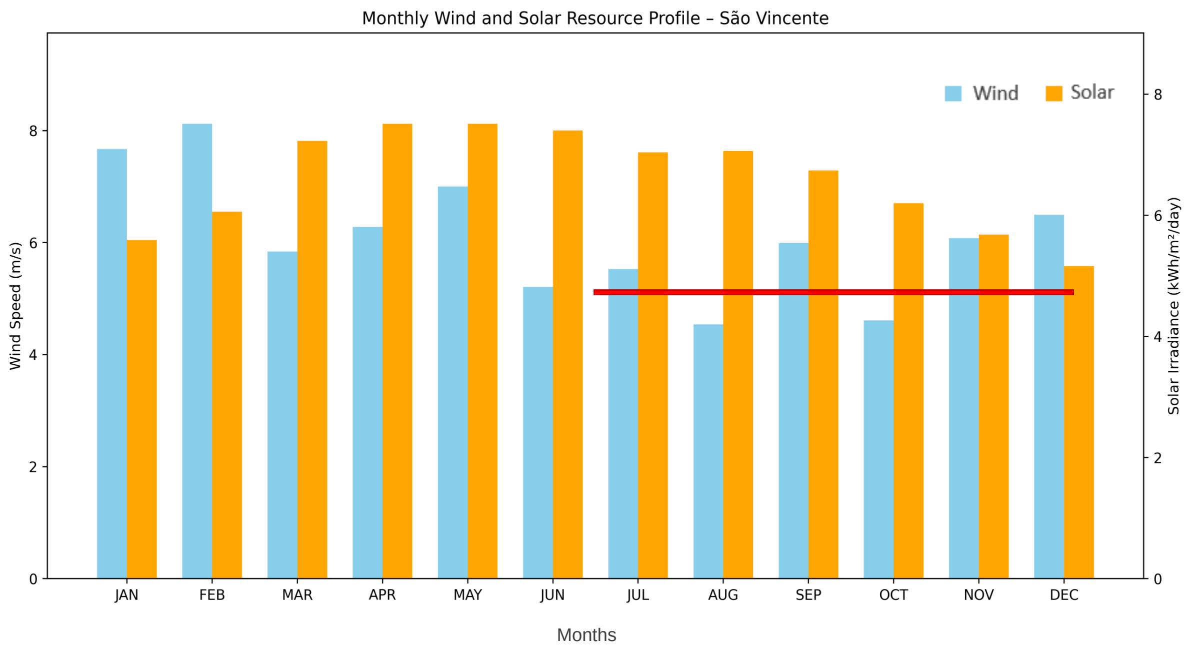

Figure 2.3: Annual Wind and Solar Resource profile for São Vicente
(Source: Author's elaboration based on data from Staffell, and Pfenninger (2024))

Wind energy shows pronounced seasonality, with the majority of generation potential concentrated between December and May, followed by a significant reduction during the summer months. Similarly, solar energy availability peaks from March to August, but experiences limited availability during the wet season due to increased cloud cover. This pronounced temporal mismatch between resource availability and demand emphasises the critical role of energy storage in the island's renewable energy system and this enables excess generation during peak periods to be shifted towards periods of low resource availability. These pronounced and oppositely phased seasonal patterns are the direct motivation for selecting São Vicente as a case study to examine how hydrogen can mitigate renewable variability. By absorbing winter–spring wind surpluses and summer PV surpluses and reconverting them during deficit months, hydrogen provides the long duration shifting needed to reduce curtailment and diesel reliance (Pombo et al., 2022; Marouani et al., 2023).

Despite the natural abundance of wind and solar resources, the contribution of renewables to São Vicente's energy mix is still constrained by variability as seen in Figure 2.3, lack of sufficient storage and grid infrastructure limitations. This can result in renewable energy curtailment and underutilization of the island's capacity (Meschede et al., 2022; Pombo et al., 2022). With robust planning, targeted investments in grid upgrades and storage technologies such as batteries and green hydrogen, São Vicente could build a foundation for a fully renewable energy system (Marouani et al., 2023; Schneider et al., 2023).

2.5.3 The forecasted energy demand of São Vicente

Figure 2.4 below displays the forecasted energy demand for São Vicente, broken down by scenario and year. It indicates that by 2040, the base scenario anticipates a demand of 138.6 GWh, which was converted into an hourly demand profile for modeling purposes.

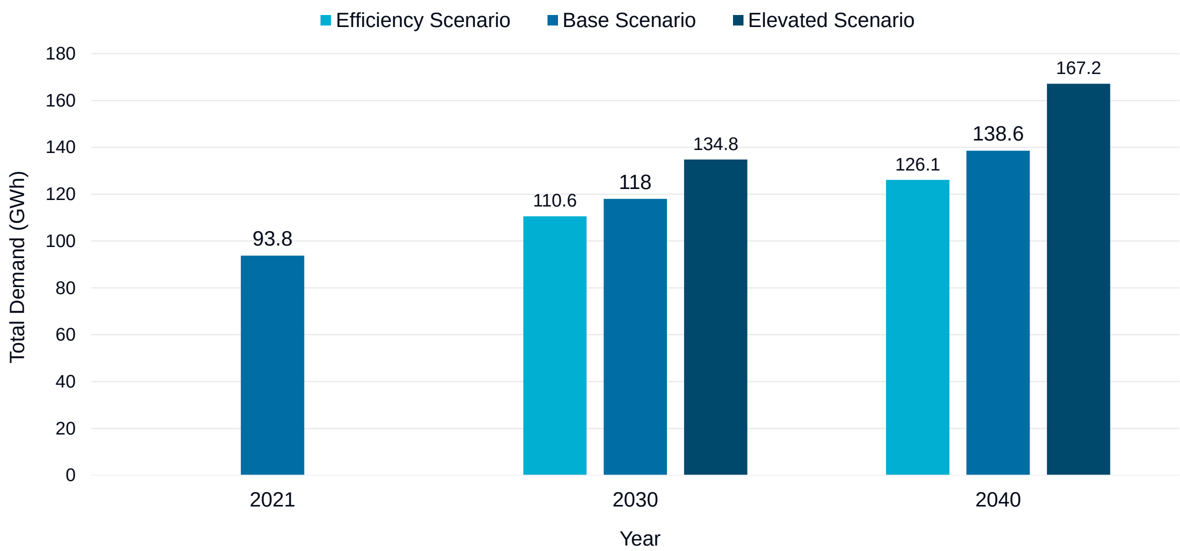

Figure 2.4: Forecasted energy demand for São Vicente
(Source: Author's elaboration based on data from SGIE (2019))

Electricity demand on São Vicente is expected to continue rising, driven by economic growth, population increases and expanding tourism and service sectors (Pombo et al., 2022). Projections from the SGIE (2021) modelled three scenarios: Efficiency, Base and Elevated (See Figure 2.4). In 2021, demand was 93.8 GWh. By 2030, forecasts range from 110.6 GWh (Efficiency) to 134.8 GWh (Elevated) and by 2040, from 126.1 GWh (Efficiency) to 167.2 GWh (Elevated), with the base scenario predicting 138.6 GWh (SGIE, 2019). This trend emphasises the importance of building a flexible, resilient and decarbonised energy infrastructure.

As São Vicente advances toward its 100% renewable electricity target by 2040, investment in reliable generation, smart grid management and advanced storage, particularly green hydrogen, will be vital to ensure long-term energy security and sustainability (Marouani et al., 2023; Pombo et al., 2022).

2.6 Evaluation of Previous Research Methodologies

Previous research on renewable energy systems and green hydrogen for small island developing states such as Cabo Verde has used a range of methodologies. The most common approach is techno-economic modelling with scenario analysis, which is valuable for screening portfolios but can underplay the operational specifics of seasonal storage. In particular, several studies adopt a single-year or typical-year weather representation and emphasise short duration flexibility (batteries, demand-side measures) while treating long-duration storage either as an exogenous option or with simplified dispatch rules. As a result, the seasonal state-of-charge coupling that is decisive for hydrogen's role on islands may be only partially captured, and curtailment–adequacy trade-offs across seasons can be biased if long-duration shifting is not co-optimised chronologically.

Studies like Pombo et al. (2022) use generation-expansion style modelling to analyse how different mixes of renewables (wind, solar) and storage options (including batteries and candidate long-duration options) could meet electricity demand reliably and affordably on São Vicente Island. Their analysis is a crucial reference showing that very high renewable penetration is technically attainable by 2040 with appropriate system upgrades and flexibility. However, the focus is not on a dedicated, end-to-end power-to-hydrogen-to-power chain with explicit co-optimisation of electrolyser, hydrogen storage and fuel-cell capacities under time-coupled seasonal constraints. In other words, while they demonstrate feasibility of high-renewables pathways, they do not centre the specific question of hydrogen as seasonal storage, nor do they report a systematic exploration of hydrogen cost and efficiency trajectories in the context of São Vicente's pronounced seasonal resource profiles. In contrast, the present study builds a chronological, linear optimisation of the full hydrogen pathway for São Vicente, enforces seasonal state-of-charge carry-over (without monthly resets), and tests multi-scenario sensitivities for electrolyser and fuel-cell costs, storage sizing, and reliability targets to quantify hydrogen's marginal value specifically for seasonal balancing.

Other research, including Amoussou et al. (2023), uses metaheuristic optimisation (e.g., MFO, GWO) to design hybrid systems combining solar, wind, batteries and hydrogen. These approaches effectively search large design spaces and consistently find that portfolios combining short-term batteries with long-duration hydrogen outperform single-technology systems, particularly when extended deficits occur. At the same time, metaheuristics often adopt a representative single-year resource profile and may not impose strict chronological state-of-charge constraints over seasons, which can lead to optimistic or technology-agnostic sizing when the key question is seasonal shifting for islands. The comparative contribution of this study is to frame hydrogen explicitly as a seasonal resource, impose time-coupled storage dynamics over the full horizon, and benchmark against battery-only and mixed portfolios under São Vicente's observed seasonal wind–solar patterns.

A number of studies have also examined the technical and operational aspects of hydrogen integration, including the choice of storage vector and context suitability. Reviews such as (Adams et al., 2024; Muthukumar et al., 2023) compare compressed, liquefied and underground storage and clarify the geological and safety constraints for large-scale capacity; island contexts typically favour compressed storage at moderate scales. System-focused analyses (Hiris et al., 2024; Keiner et al., 2023) show that hydrogen can materially improve autonomy in off-grid and weak-grid settings, but many case applications are residential or microgrid-sized and do not explicitly evaluate seasonal adequacy for island-wide systems. Accordingly, these strands underscore feasibility but leave open the island-level question of when hydrogen becomes cost-effective specifically as seasonal storage, relative to batteries and curtailment.

Policy-oriented work, such as (Akinsooto et al., 2024), highlights enabling conditions, targets, market design, risk-sharing instruments, and permitting, that affect hydrogen uptake. These contributions correctly identify institutional gaps that can stall deployment even when techno-economic cases look favourable. Yet policy papers generally do not couple those insights to chronological system models capable of quantifying the seasonal value of hydrogen for a specific island's resource and demand profiles. The present study links these domains by reporting techno-economic metrics (e.g., total annualized cost, LCOE, LCOH, reliability indicators) for hydrogen-as-seasonal-storage under São Vicente conditions and by interpreting results against the policy and infrastructure context identified in the qualitative assessment.

Taken together, the literature converges on three points that motivate the present work. First, hybrid systems combining short-term batteries and long-duration storage are consistently more robust for islands aiming at very high renewable shares. Second, existing models for São Vicente and comparable islands demonstrate feasibility but do not center an explicit, time-coupled optimization of the full hydrogen pathway as a seasonal resource under the island's out-of-phase wind–solar seasonality. Third, the remaining uncertainty is not whether hydrogen can work in principle, but under which cost, efficiency and reliability assumptions hydrogen provides the greatest marginal value relative to alternatives. By co-optimizing electrolyser, storage and re-conversion chronologically over the full year, enforcing seasonal state-of-charge dynamics, and grounding scenarios in São Vicente's observed seasonal resource profiles, this study addresses those gaps and quantifies the conditions under which hydrogen most effectively mitigates seasonal variability.

2.7 Research Gap

Existing work on São Vicente and comparable island systems demonstrates that high-renewable pathways are technically attainable, but most studies do not centre hydrogen explicitly as a seasonal storage resource with full, time-coupled optimisation. For example, Pombo et al. (2022) uses generation-expansion style modelling to show feasibility of reaching very high renewable shares by 2040 on São Vicente, but it does not formulate an end-to-end power-to-hydrogen-to-power chain with chronological coupling of electrolyser, hydrogen storage and reconversion across the full year, nor does it report systematic sensitivities on hydrogen techno-economics under the island's out-of-phase wind–solar seasonality. Metaheuristic designs for hybrid PV–wind–battery–hydrogen portfolios (Amoussou et al., 2023) efficiently search configurations, yet they often rely on representative single-year inputs and simplified storage treatments that can understate the role of long-duration, seasonal shifting. Parallel strands on storage media selection compare compressed, liquefied and underground options at a conceptual level (Adams et al., 2024), while São Vicente-specific flexibility analyses consider pumped hydro as a candidate long-duration option with site-specific constraints (Segurado et al., 2011). Together, this literature establishes feasibility and options, but it leaves open the São Vicente specific question of when hydrogen becomes cost-effective as a seasonal resource relative to batteries, curtailment and pumped hydro, once chronological, seasonal dynamics are enforced.

This thesis addresses that gap with a São Vicente specific, chronological optimisation that directly targets seasonal variability. First, it builds an hourly, time-coupled model that co-optimises capacities and operations for PV, wind, batteries, electrolyser, hydrogen storage and fuel cell/engine, enforcing intertemporal state-of-charge continuity over the full horizon rather than resetting monthly balances. Second, it grounds the optimisation in island data, observed and projected demand and renewable profiles derived from the national energy information system (SGIE, 2019, 2021), complemented by documented resource statistics (Gesto Energia, 2011) and prior system evidence (Pombo et al., 2022). Third, it designs scenarios and sensitivities that are specific to seasonal storage on São Vicente, including electrolyser and fuel-cell cost and efficiency trajectories, hydrogen storage sizing, renewable curtailment thresholds, resource inter-annual variability, and reliability targets, and it benchmarks hydrogen-centric portfolios against battery-only and pumped-hydro candidate cases (Segurado et al., 2011). Fourth, it reports techno-economic metrics that link directly to planning decisions and the study objectives, including total annualised system cost, LCOE, LCOH, curtailment, adequacy indicators and the marginal value of hydrogen for closing winter-spring and summer deficits.

Finally, the study connects quantitative results to the local enabling environment by interpreting model outcomes against the policy and institutional context for Cabo Verde, including targets, regulatory readiness and recent assessments on hydrogen's role (ARME, 2022; World Bank, 2024).

Chapter 3 Methodology

This study employs a comprehensive methodology, visually summarized using flowchart in Figure 3.1, to identify the optimal energy system scenario for São Vicente Island. The process commences with a thorough Location Assessment, followed by the Input Data Collection and Processing phase, which integrates crucial data such as solar and wind resource profiles, historical and forecasted load demand, and essential economic inputs. These materials serve as the foundation for the COMANDO modelling framework (Langiu et al., 2021), which is applied to simulate and optimize four distinct system configuration scenarios: photovoltaic, wind, battery storage, and green hydrogen systems. Particular attention is placed on the role of green hydrogen as a seasonal storage solution to address long-term energy imbalances. Each scenario configurations is assessed based on its techno-economic and reliability performance using five key indicators. The comparative assessment of the four configurations ultimately enables the identification of the optimal system to achieve a 100% renewable energy system for São Vicente Island by 2040. A cost-sensitivity analysis is also performed to understand how the optimal system costs respond to changes in component cost developments. A qualitative assessment will also be conducted on the factors that could influence the long-term viability.

3.1 Input Data Collection and Processing

Accurate input data is crucial for reliable energy system modeling. This study utilized a comprehensive dataset, including hourly renewable resource profiles and historical demand patterns, tailored to the specific context of São Vicente Island. These data sets form the fundamental input for the system modeling and optimization.

3.1.1 Hourly solar and wind resource profiles

Hourly solar and wind resource profiles were obtained from Staffell, and Pfenninger (2024) in the form of power factor data, covering a full year (8,760 hours). These power factors represent the percentage of installed generation capacity available at each hour based on the available solar or wind resource. For example, a power factor of 0.80 indicates that 80% of the installed capacity could be utilised at that hour. The power factor profiles were used as direct input to the COMANDO modelling environment, where the optimisation model determines the actual installed capacity and computes hourly generation as the product of installed capacity and hourly power factor.

3.1.2 The historical hourly demand pattern

The historical hourly demand pattern for São Vicente was collected from system operator of the national electricity utility of Cabo Verde. The forecasted total annual energy demand for the

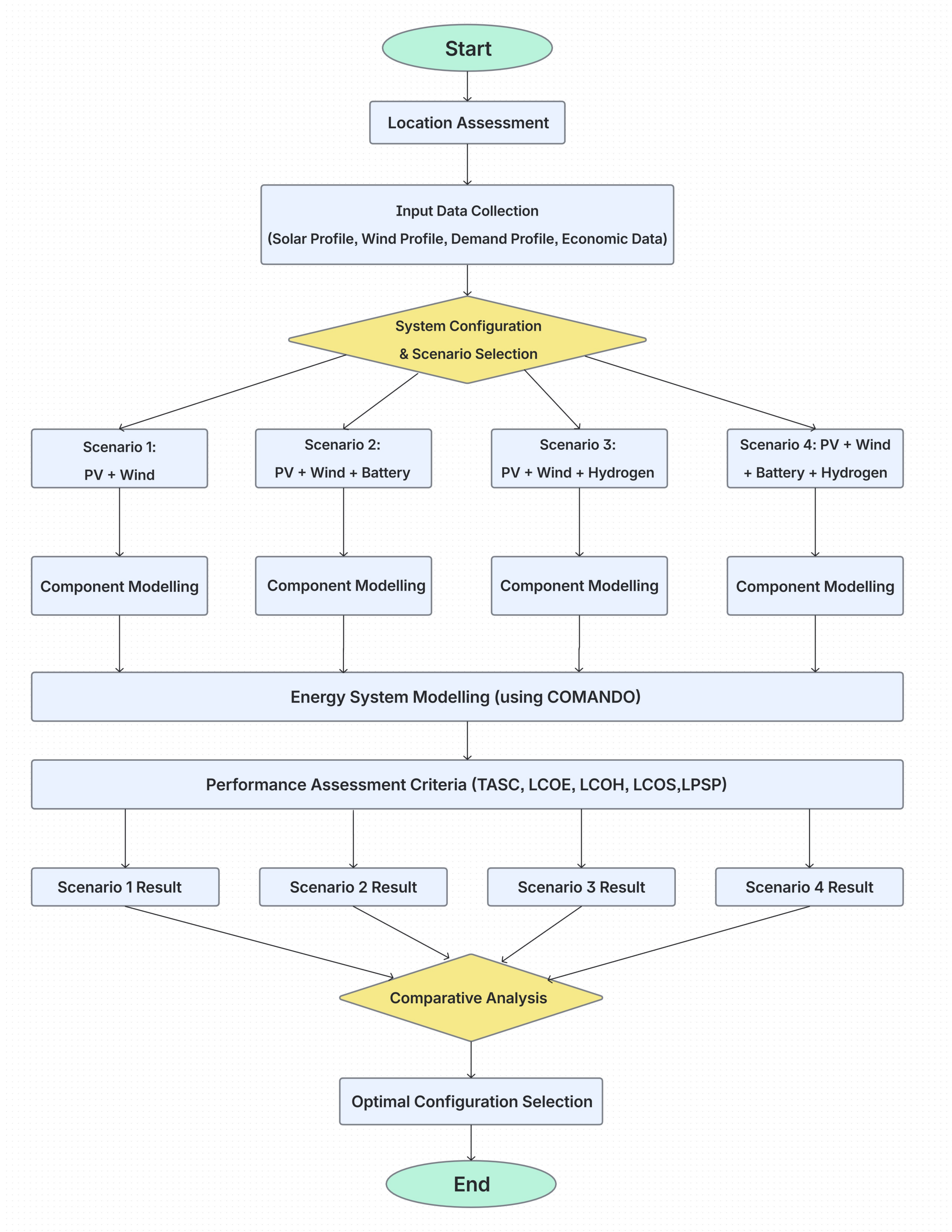

Figure 3.1: Quantitative Analysis Flowchart for Multi-Scenario Energy System Modeling and Optimal Scenario Selection

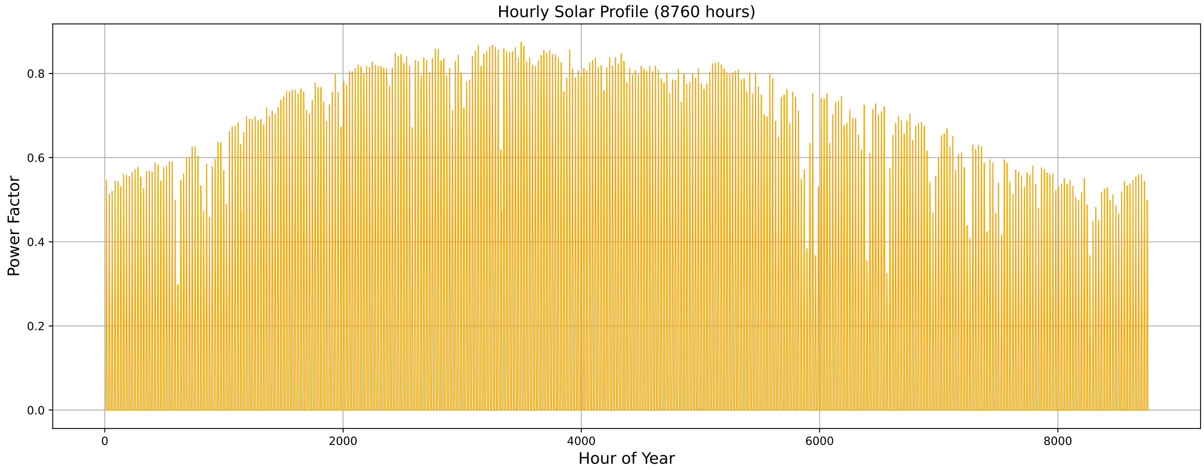

Figure 3.2: Hourly solar (PV) power factor profile over one year (8760 hours)

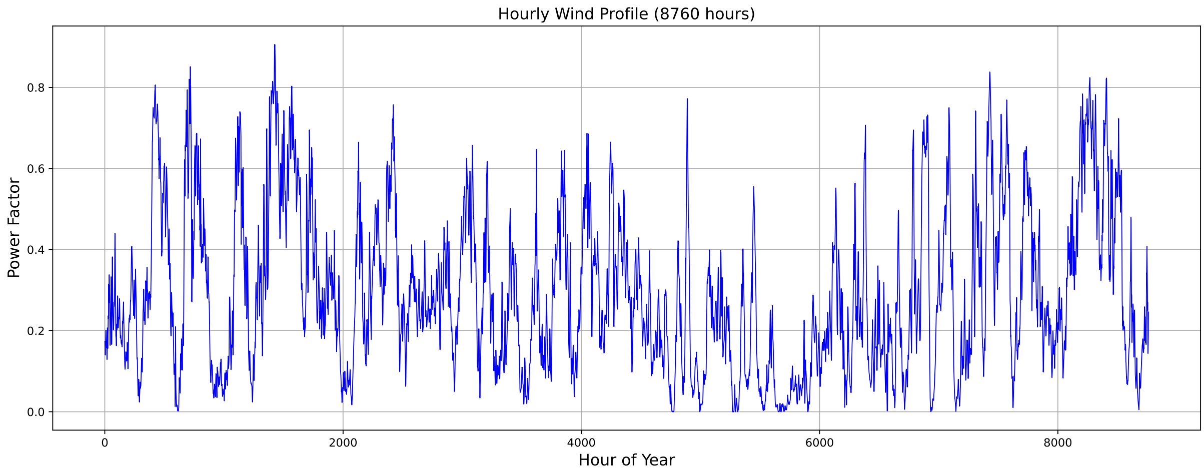

Figure 3.3: Hourly wind power factor profile over one year (8760 hours)

year 2040 was then proportionally distributed across this historical hourly pattern using a Python routine within the COMANDO environment. This detailed hourly demand profile ensures that the modeling accurately reflects the island's energy consumption patterns and allows for precise assessment of supply-demand balance. The final demand profile consists of 8,760 hourly values representing the expected hourly load in 2040.

3.1.3 Economic input data

Economic and cost related input data were used to characterise the main components of the modelled energy systems. These include CAPEX, OPEX, component lifetimes and replacement costs. The economic parameters serve as key inputs for the techno-economic analysis, supporting calculations of the total system cost and LCOE.

The data were obtained from literature and international organisations such as the International Renewable Energy Agency (IRENA, 2016). A project lifetime of 25 years was assumed for the analysis with an interest rate of 6% applied using the annuity factor method. This value

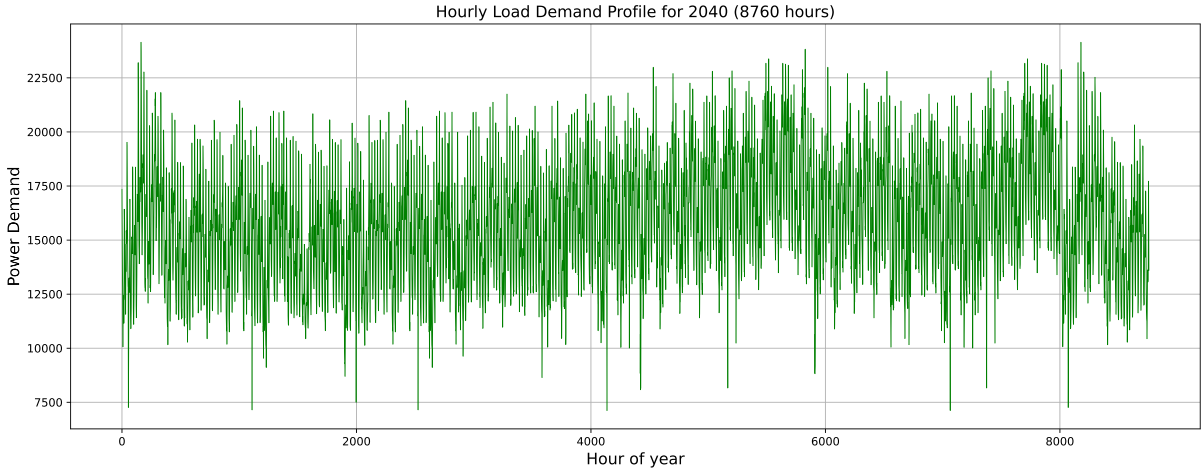

Figure 3.4: Hourly load profile for 2040 (8760 hours)

was selected based on precedent in techno-economic analyses of renewable energy systems, where discount rates typically range between 5% and 10% depending on financing conditions in Sub-Saharan Africa and Small Island Developing States (IRENA, 2021; Bank, 2021). The chosen 6% reflects a moderate assumption that balances the relatively high capital investment required for renewable and hydrogen technologies with the investment risks associated with Cabo Verde's small island context. Similar values have been used in comparable studies of hybrid renewable-hydrogen systems, such as Khare et al. (2020) and Trakas et al. (2023), this ensures consistency with the literature and providing a realistic basis for the economic evaluation. Table 3.1 summarises the economic assumptions adopted in this study.

Table 3.1: Economic data used

Asset [Ref.]	CAPEX	Replacement Cost	OPEX (% of CAPEX)	Lifetime (years)
PV [1]	536 €/kWp	N/A	1%	25
WT [2]	1000 €/kW	N/A	3%	25
BB [2]	230 €/kWh	80%	3%	15
EZ [1]	890 €/kW	50%	3%	15
HT [3]	207 €/kg	N/A	1%	25
FC [3]	903 €/kW	50%	3%	15

Legend: capital expenditures (CAPEX), operational expenditures (OPEX), photovoltaic panels (PV), wind turbines (WT), battery banks (BB), electrolyser (EZ), hydrogen tanks (HT) and fuel cells (FC). Ref: *Gadoet al.* (2024)[1], *IRENA* (2016)[2], *Mylonopouloset al.* (2024)[3].

3.2 System Configuration and Scenario Definition

To address the Research Question , which investigates the impact of different energy storage configurations, four distinct scenarios were defined and modeled. Each scenario represents a potential pathway for São Vicente Island to achieve a 100% renewable energy by 2040. The following scenarios are investigated,

i. **Scenario 1:** PV + Wind only

ii. **Scenario 2:** PV + Wind + Battery

iii. **Scenario 3:** PV + Wind + Hydrogen

iv. **Scenario 4:** PV + Wind + Battery + Hydrogen

Each scenario incorporates various combinations of technologies to assess their role in supplying energy demand and mitigating supply deficits.

3.2.1 Scenario 1: PV + Wind (without storage)

Scenario 1 (Fig. 3.5) serves as a baseline configuration consisting exclusively of PV and wind generation, without any form of short-term or seasonal storage. The purpose of including this case is not only to illustrate the performance of a simple RE only system but also to provide a benchmark against which the added value of storage technologies can be measured. In particular, this scenario directly supports Research Question 1, as it highlights the operational and reliability limitations of a system reliant solely on variable renewables.

In this setup, hourly demand is met where possible with PV and wind generation, any surplus not used is simply not utilized (implicitly curtailed), but curtailment is not a reported KPI. At the same time, unmet load is explicitly tracked through the LPSP, which quantifies the reliability gap that storage solutions are expected to address in subsequent scenarios.

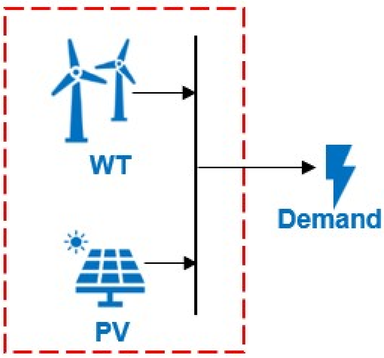

Figure 3.5: System Configuration of Scenario 1

$$P_{\mathrm{PV}}(t) + P_{\mathrm{WT}}(t) \geq P_{\mathrm{load}}(t). \tag{3.1}$$

where $P_{\mathrm{PV}}, P_{\mathrm{WT}}, P_{\mathrm{load}}$ are power output from the PV, Wind, and the load respectively.

If Equation 3.1 is satisfied, the demand is met and any surplus energy is curtailed. When generation is insufficient, as in Equation 3.2, a deficit occurs and will be calculated as unmet demand.

$$P_{\mathrm{PV}}(t) + P_{\mathrm{WT}}(t) < P_{\mathrm{load}}(t). \tag{3.2}$$

This scenario highlights the limitations of relying solely on variable renewable generation without storage.

3.2.2 Scenario 2: PV + Wind + Battery energy storage

Scenario 2 (Fig. 3.6) extends the baseline by introducing short-term storage through batteries, enabling temporal load shifting and enhanced reliability. It directly addresses the research question 1, by testing whether batteries alone can close the supply–demand gap under high variable renewable penetration. Batteries are well suited for mitigating intraday variability, reducing unmet load during short periods of low generation, and lowering reliance on curtailment by storing excess solar and wind energy.

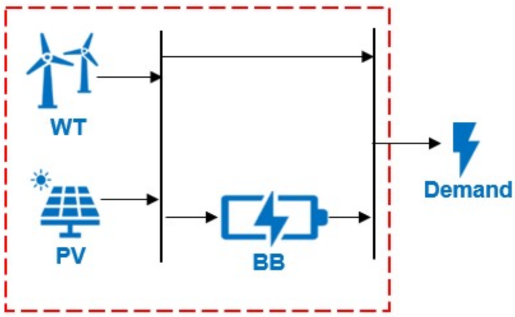

Figure 3.6: System Configuration of Scenario 2

The power balance is defined mathematically in Equation 3.3 and Equation 3.4 below;

$$P_{\mathrm{PV}}(t) + P_{\mathrm{WT}}(t) \geq P_{\mathrm{load}}(t). \tag{3.3}$$

If the combined generated power PV + Wind surpasses the necessary load requirement, the surplus power charges the battery. During deficit periods, where load demand exceeds PV + Wind output

$$P_{\mathrm{load}}(t) = P_{\mathrm{PV}}(t) + P_{\mathrm{WT}}(t) + E_{\mathrm{bat}}(t), \tag{3.4}$$

where $E_{\mathrm{bat}}(t)$ represents the battery discharge at time t. The battery is discharged to fulfill the load demand.

3.2.3 Scenario 3: PV + Wind + Hydrogen storage system

This scenario incorporates green hydrogen as a storage system, consisting of an electrolyzer, a hydrogen storage tank, and a fuel cell for reconversion. It directly supports the research question 1, by testing hydrogen's ability to manage long-term energy balancing in an isolated system with strong seasonality, such as São Vicente. Hydrogen storage enables excess generation during high renewable months to be stored and later used during periods of low wind and solar availability.

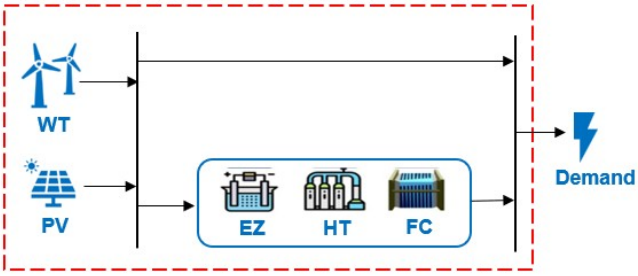

Figure 3.7: System Configuration of Scenario 3

The power balance is defined mathematically in Equation 3.5 and Equation 3.6 below;

$$P_{\mathrm{PV}}(t) + P_{\mathrm{WT}}(t) > P_{\mathrm{load}}(t). \tag{3.5}$$

The surplus energy powers the electrolyser to produce hydrogen. When generation is insufficient:

$$P_{\mathrm{load}}(t) = P_{\mathrm{PV}}(t) + P_{\mathrm{WT}}(t) + P_{\mathrm{FC}}(t), \tag{3.6}$$

where $P_{\mathrm{FC}}(t)$ is the power output from the fuel cell. This scenario addresses long-duration energy storage using hydrogen.

3.2.4 Scenario 4: PV + Wind + Battery + Hydrogen (Hybrid storage system)

Scenario 4 integrates both batteries and hydrogen storage, aiming to capture the complementary strengths of short and long-term storage. Batteries address intraday fluctuations, while hydrogen ensures seasonal balancing. As such, this configuration directly responds to the research question 1, serving as the most comprehensive scenario for exploring both technical feasibility and economic viability of a 100% renewable energy system on São Vicente.
If the combined generated power PV + Wind surpasses the necessary load requirement, i.e when generation exceeds demand as shown mathematically in Equation 3.7 below;

$$P_{\mathrm{PV}}(t) + P_{\mathrm{WT}}(t) > P_{\mathrm{load}}(t). \tag{3.7}$$

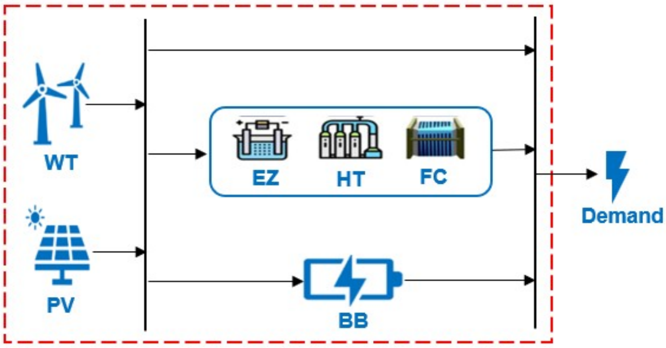

Figure 3.8: System Configuration of Scenario 4

The surplus energy is used for, first battery charging and then hydrogen production via the electrolyzer. When generation falls short, i.e if load demand exceeds PV + Wind output, then BES is first discharged to fulfill load demand, mathematically shown in Equation 3.8 below;

$$P_{\text{load}}(t) = P_{\text{PV}}(t) + P_{\text{WT}}(t) + E_{\text{bat}}(t). \tag{3.8}$$

In case of PV + Wind output and Battery cannot fulfill the power requirement, the Fuel Cell runs. The Fuel Cell generates the power necessary to meet the specified load demand, as shown in the Equation 3.9 below;

$$P_{\text{FC}}(t) = P_{\text{load}}(t) - P_{\text{PV}}(t) - P_{\text{WT}}(t) - E_{\text{bat}}(t). \tag{3.9}$$

This hybrid configuration utilises batteries for short-term storage and hydrogen for seasonal or long-term storage, ensuring greater system flexibility and reliability.

3.3 Major Component Modelling

The modelling of major components in this study is essential for simulating the energy generation, storage and conversion processes within the proposed 100% renewable energy system. Each component is modelled to reflect its physical behaviour and economic characteristics. Battery energy storage is modelled using state of charge (SOC) constraints, accounting for charging and discharging efficiencies. The electrolyser converts surplus electricity into hydrogen, which is stored and later reconverted to electricity using a fuel cell system. Hydrogen storage is treated as long duration energy storage suitable for seasonal balancing. The mathematical modelling of the key components in each scenario is individually modelled as follows in this section.

3.3.1 Photovoltaic (PV) System Modelling

The PV system converts solar irradiance into electricity. Since actual irradiance data is not directly used, a normalised capacity factor profile, representing the available generation potential relative to installed capacity, is used. This capacity factor, obtained from Staffell, and Pfenninger (2024), represents the fraction of the installed PV capacity effectively producing electricity at each hour. The available power output at each timestep is expressed as

$$P_{\mathrm{PV}}(t) = C_{\mathrm{PV}} \times CF_{\mathrm{PV}}(t), \tag{3.10}$$

where $P_{\mathrm{PV}}(t)$ is PV output power at time t [kW], C_{PV} is the installed PV capacity [kW] and $CF_{\mathrm{PV}}(t)$ is the hourly power factor (capacity factor).
The PV system is assumed to have no performance degradation over the project lifetime. The output from the PV system is first used to meet the hourly demand directly.

3.3.2 Wind System Modelling

The wind power generation follows a similar modelling approach. Using hourly wind capacity factor profiles, the power generated at each hour is expressed as:

$$P_{\mathrm{WT}}(t) = C_{\mathrm{WT}} \times CF_{\mathrm{WT}}(t), \tag{3.11}$$

where $P_{\mathrm{WT}}(t)$ is the wind power output at time t [kW], C_{WT} is the installed wind capacity [kW] and $CF_{\mathrm{WT}}(t)$ is the Hourly wind capacity factor.
Like the PV, the wind power output is primarily used to satisfy the demand at each timestep.

3.3.3 Battery Storage System

The battery energy storage system (BESS) is modelled to manage fluctuations between electricity supply and demand, typically within daily cycles. When generation is insufficient to meet demand, the battery discharges to supply the deficit, within SOC limits.

The battery thus acts as the first layer of flexibility in the system, addressing short-duration mismatches and minimizing immediate reliance on hydrogen storage.

The operational state of the battery is tracked using the SOC, defined as the ratio of stored energy to the total battery capacity. Mathematically expressed in Equation 3.12 below;

$$SOC(t) = \frac{E_{\mathrm{bat}}(t)}{E_{\mathrm{bat,max}}}, \tag{3.12}$$

where $SOC(t)$ is the state of Charge at time t (dimensionless, between 0 and 1), $E_{\mathrm{bat}}(t)$ is the energy stored in the battery at time t [kWh] and $E_{\mathrm{bat,max}}$ is the maximum battery energy capacity [kWh].
The stored energy evolves according to the following energy balance Equation

$$E_{\mathrm{bat}}(t+1) = E_{\mathrm{bat}}(t) + \eta_{\mathrm{c}} \cdot P_{\mathrm{charge}}(t) \cdot \Delta t - \frac{P_{\mathrm{discharge}}(t) \cdot \Delta t}{\eta_{\mathrm{d}}} \tag{3.13}$$

where $P_{\text{charge}}(t)$ is the charging power at time t [kW], $P_{\text{discharge}}(t)$ is the discharging power at time t [kW], η_c and η_d are the charging and discharging efficiencies. Δt is the time step duration (1 hour).

Operational constraints are applied as follows

- $0 \leq SOC(t) \leq 1$.
- $0 \leq P_{\text{charge}}(t), P_{\text{discharge}}(t) \leq P_{\text{bat,max}}$, where $P_{\text{bat,max}}$ is defined based on the battery's power-to-energy ratio (C-rate).

3.3.4 Electrolyser Modelling

When renewable generation surplus persists after battery charging, the excess electricity is directed to the electrolyser, which converts electricity into hydrogen. The electrolyser operation is governed by its rated power input and efficiency. The amount of hydrogen produced each hour is given using the Equation 3.14 below;

$$m_{\text{H}_2,\text{prod}}(t) = \frac{P_{\text{excess}}(t) \times \eta_{\text{EZ}}}{LHV_{\text{H}_2}}, \tag{3.14}$$

where $m_{\text{H}_2,\text{prod}}(t)$ is the hydrogen produced at time t [kg], $P_{\text{excess}}(t)$ is the surplus electricity supplied to electrolyser [kW], η_{EZ} is the electrolyzer efficiency, LHV_{H_2} is the lower heating value of hydrogen [kWh/kg].

3.3.5 Hydrogen Storage Modeling

The produced hydrogen is stored for later conversion back to electricity. Hydrogen storage is modelled as a mass balance, tracking the amount of hydrogen stored at each timestep

$$m_{\text{H}_2}(t+1) = m_{\text{H}_2}(t) + m_{\text{H}_2,\text{in}}(t) - m_{\text{H}_2,\text{out}}(t), \tag{3.15}$$

where $m_{\text{H}_2}(t)$ is the hydrogen stored at time t [kg], $m_{\text{H}_2,\text{in}}(t)$ is the hydrogen input from electrolyser [kg], $m_{\text{H}_2,\text{out}}(t)$ is the hydrogen consumed by fuel cell [kg].

3.3.6 Fuel Cell Modelling

The fuel cell converts the stored hydrogen back into electricity when renewable generation and battery discharge are insufficient to meet demand. The power output of the fuel cell is calculated as

$$P_{\text{FC}}(t) = m_{\text{H}_2,\text{consumed}}(t) \times LHV_{\text{H}_2} \times \eta_{\text{FC}}, \tag{3.16}$$

where $P_{FC}(t)$ is the fuel cell electrical output at time t [kW], $m_{H_2,consumed}(t)$ is the hydrogen consumption at time t [kg], η_{FC} is the fuel cell efficiency, LHV_{H_2} is the lower heating value of hydrogen [kWh/kg].

Thus, the fuel cell functions as the backup supply to cover long-duration deficits, complementing the battery system.

3.3.7 System Energy Flow Overview

At each timestep

1. PV and Wind generation are prioritized to supply demand.
2. Excess generation charges the battery first.
3. Remaining excess powers the electrolyzer to produce hydrogen.
4. During supply deficits
   i. Battery discharges first.
   ii. If insufficient, the Fuel Cell provides additional power using stored hydrogen.

3.4 Performance Assessment Criteria

In this study, two main criteria and five sub-criteria or key performance indicators (KPIs) are used to optimally size and perform a techno-economic and reliability performance of each modelled scenario. These indicators are particularly relevant for São Vicente because they jointly capture the dual challenge of affordability and reliability in small island energy systems. The economic indicators (LCOE, LCOH, TAC) reflect the cost competitiveness of different storage configurations, which is critical for reducing high electricity tariffs driven by fossil fuel imports. The technical indicators (LPSP, RE penetration) evaluate the ability of the system to provide a reliable, continuous supply under the island's highly variable solar–wind conditions. Together, these KPIs provide a holistic assessment framework that aligns directly with the island's policy target of achieving a cost-effective and reliable 100% renewable energy system by 2040.

The details of all the criteria and sub-criteria mentioned above and their mathematical models are outlined in the subsequent sections.

The Figure 3.9 below demonstrates the criteria adopted in this study. The LPSP and the renewable energy share falls under the technical criteria, while the TAC, the LCOE and the LCOH are sub-criteria under the economic criteria.

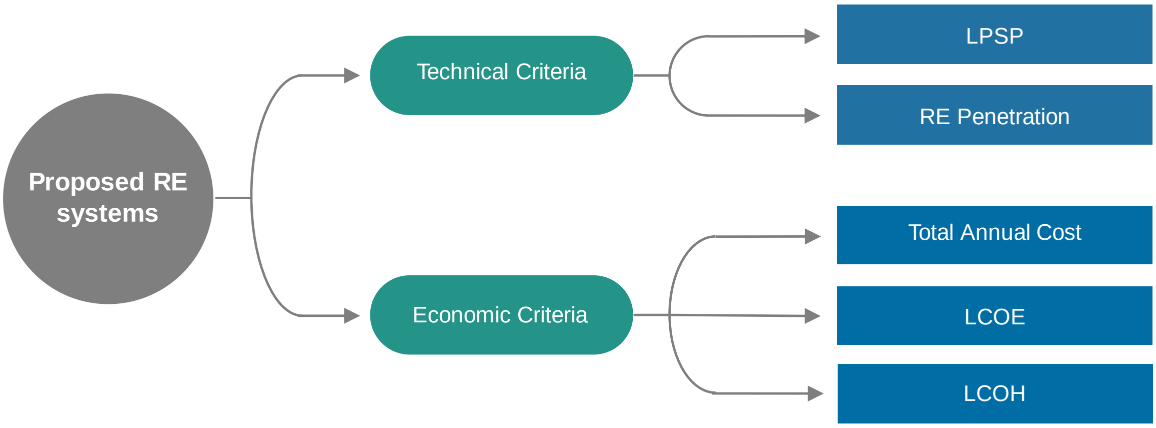

Figure 3.9: Criteria considered in this study

Legend: Loss of Power Supply Probability (LPSP), Levelised Cost of Electricity (LCOE), Levelised Cost of Hydrogen (LCOH).

3.4.1 Technical Criteria

Loss of Power Supply Probability (LPSP)

The LPSP mathematically shown in Equation 3.17 below, quantifies system reliability by expressing the proportion of total demand not met due to generation and storage limitations. A lower LPSP reflects a more reliable energy system.

$$LPSP = \frac{\sum_{t=1}^{8760} P_{\text{deficit}}(t) \cdot \Delta t}{\sum_{t=1}^{8760} P_{\text{load}}(t) \cdot \Delta t}, \tag{3.17}$$

where the hourly power deficit is calculated using Equation 3.17 below;

$$P_{\text{deficit}}(t) = P_{\text{load}}(t) - (P_{\text{PV}}(t) + P_{\text{WT}}(t) + P_{\text{BAT}}(t) + P_{\text{FC}}(t)). \tag{3.18}$$

If LPSP value is approaching zero, this indicates high system reliability.

Renewable Energy Penetration

The renewable energy share (RE Penetration) represents the proportion of the total electricity demand met by renewable sources (solar PV and wind energy) during the assessment period. It indicates the degree of decarbonization achieved.

$$RE_{\text{share}} = \frac{\sum_{t=1}^{8760} (P_{\text{PV}}(t) + P_{\text{WT}}(t)) \cdot \Delta t}{\sum_{t=1}^{8760} P_{\text{load}}(t) \cdot \Delta t} .100, \tag{3.19}$$

where $P_{\text{PV}}(t)$ and $P_{\text{WT}}(t)$ are the hourly power outputs from PV and Wind [kW], $P_{\text{load}}(t)$ is the hourly load demand [kW], Δt is the time step (1 hour).

Achieving a high renewable energy share is critical for reducing fossil fuel dependency and promoting sustainability.

3.4.2 Economic criteria

Total Annual Cost (TAC)

This indicator quantifies the total annual cost required to operate the energy system, including investment, replacement and fixed operation and maintenance (O&M) costs. These costs are annualised using the annuity factor method to account for the time value of money over the system's lifetime.
The total annual cost is expressed as in Equation 3.20 below;

$$C_{\text{annual}} = \sum_{i} \left(C_{\text{inv},i} \times AF_i + C_{\text{O\&M},i} \right), \tag{3.20}$$

where $C_{\text{inv},i}$ is the total capital investment cost of component i [€], AF_i is the annuity factor for component i based on discount rate and component lifetime, $C_{\text{O\&M},i}$ is the fixed annual operation and maintenance cost of component i [€/year].
This indicator reflects the actual yearly financial burden required to operate and maintain the system, supporting comparison between different configurations.

Levelised Cost of Electricity (LCOE)

The LCOE represents the average cost of generating and supplying 1 kWh of electricity throughout the system's lifetime. It serves as a key economic indicator for comparing energy supply costs with conventional or alternative systems

$$LCOE = \frac{C_{\text{annual}}}{\sum_{t=1}^{8760} E_{\text{generated}}(t)}, \tag{3.21}$$

where $E_{\text{generated}}(t)$ is the total electricity supplied to meet the load at time t [kWh].
Expressed in [€/kWh], the LCOE helps assess the economic competitiveness of each of the proposed system.

Levelised Cost of Hydrogen (LCOH)

LCOH quantifies the average cost of producing 1 kg of hydrogen, accounting for all annualised costs associated with hydrogen production and storage subsystems (electrolyser and hydrogen storage tanks)

$$LCOH = \frac{C_{\text{H}_2,\text{annual}}}{\sum_{t=1}^{8760} H_{\text{produced}}(t)}, \tag{3.22}$$

where $C_{H_2,\text{annual}}$ is the total annualised cost of electrolyser and hydrogen storage subsystems [€], $H_{\text{produced}}(t)$ is the hydrogen produced at time t [kg].
Expressed in [€/kg], LCOH evaluates the viability of using green hydrogen as a seasonal energy storage medium and potential fuel.

All five indicators collectively assess the trade-offs between cost, reliability and RE integration, providing a comprehensive basis for comparing the performance of each modelled scenario.

3.5 The COMANDO Modelling Tool

Energy system modelling has evolved significantly with various software tools developed to support the design, optimisation and planning of renewable and hybrid energy systems. Among the most widely recognised are EnergyPLAN, HOMER, PLEXOS, TIMES and OSeMOSYS. Each tool offers unique strengths. For example, HOMER is well known for its user-friendly interface and hybrid microgrid simulations, PLEXOS excels at large-scale power market simulations, TIMES is powerful for integrated energy system optimisation and OSeMOSYS is favoured for its open-source, transparent structure in long-term energy planning (Howells et al., 2011; Worighi et al., 2019; HOMER, 2020).

Recently, COMANDO (component-oriented modeling and optimization for nonlinear design and operation) has emerged as a new, open-source tool specifically designed for transparent, linear optimisation modelling of energy systems (Langiu et al., 2021) (See Figure 3.10). Developed to address the need for reproducible and adaptable energy modelling, COMANDO adopts a component-based, modular structure that enables users to flexibly build and simulate hybrid energy systems, integrating technologies such as PV, wind turbines, batteries, electrolysers, hydrogen storage and fuel cells. COMANDO distinguishes itself by several key features

i. Open-source and transparency: All code and documentation are publicly available, fostering collaborative development.

iii. Component-based modularity: Systems are defined as combinations of components, making the tool adaptable to a wide range of configurations, from isolated microgrids to national-scale systems.

iii. Direct linear optimisation: COMANDO formulates the system as a linear programming problem, allowing robust and efficient computation for cost-optimal system design.

iv. Multi-scenario and sensitivity analysis: Users can define and compare multiple scenarios, enhancing robustness and decision support.

v. Cost modelling and detailed techno-economic output: COMANDO supports detailed cost breakdowns and output metrics, including total annualised cost, levelised cost of energy and emission profiles (Langiu et al., 2021).

Comparisons in the literature show that while tools like HOMER, EnergyPLAN and OSeMOSYS remain popular for off-grid and national planning, respectively, COMANDO's strengths lie in its transparency, flexibility and suitability for detailed optimisation of hybrid systems, especially when the focus includes seasonal storage, such as hydrogen Wang et al. (2021); Aghaei and others (2022).

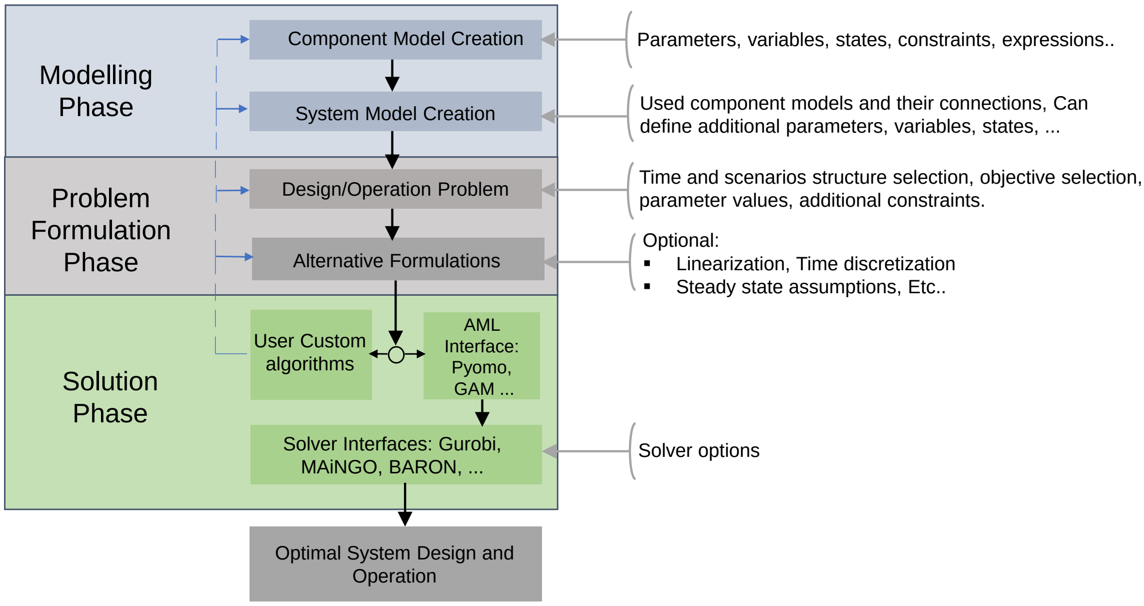

Figure 3.10: Flow diagram for modelling, problem formulation and optimisation using COMANDO

3.5.1 Review of Modelled Cases Using COMANDO

Recent peer-reviewed studies have successfully applied COMANDO for hybrid energy system design and optimization. For instance, Wang et al. (2021) employed COMANDO in the optimal design and operation of multi-carrier energy systems under uncertainty, demonstrating its ability to handle complex system dynamics and stochastic variables. Similarly, Aghaei and others (2022) utilized COMANDO to address two stage stochastic programming for the optimal design and operation of multi-energy systems, confirming its strength in robust scenario-based optimization and cost minimization for decarbonized energy systems.

Although the use of COMANDO in published research is still emerging, these examples show its growing acceptance in the scientific community for real-world, robust energy system modelling and scenario analysis. Its flexibility makes it particularly appropriate for case studies like São Vicente Island, where multiple storage options and sector coupling must be modelled transparently and efficiently.

3.5.2 Energy System Modelling Using COMANDO

This study utilized the COMANDO framework for the techno-economic optimization of São Vicente Island's energy system. COMANDO was specifically chosen for its advanced capabilities in handling complex, integrated energy systems, which are crucial for accurately modeling the transition to a 100% renewable energy system with diverse generation and storage technologies. Unlike many traditional energy system modeling frameworks that primarily rely on linear programming (LP) or mixed-integer linear programming (MILP) formulations, COMANDO offers the flexibility to incorporate nonlinearities, dynamic effects, and discrete characteristics (Langiu et al., 2021). This capability is particularly vital for accurately representing the complex operational behaviors of components such as electrolyzers, fuel cells, and battery energy storage systems, where efficiencies and performance can vary non-linearly with operating conditions.

Justification for COMANDO's Selection

The selection of COMANDO was driven by its unique suitability for the specific challenges posed by São Vicente Island's energy transition and its direct alignment with the research questions. Firstly, its component-oriented approach allowed for the detailed modeling of individual energy technologies (PV, wind, batteries, electrolyzers, hydrogen tanks, fuel cells) and their interactions within an integrated system. This modularity facilitated the construction of various scenarios, enabling a comprehensive comparative analysis as required by Research Question 1.

Secondly, COMANDO's ability to handle nonlinear and dynamic elements was critical for accurately simulating the performance of hydrogen-based seasonal storage. The efficiency of electrolyzers and fuel cells, for instance, is not constant but varies with load, a characteristic that linear models often oversimplify. By capturing these nonlinearities, COMANDO provided a more realistic assessment of the technical and economic feasibility of green hydrogen integration, directly supporting research question 2.

Furthermore, the framework's capacity for stochastic programming allowed for the consideration of multiple operating scenarios, accounting for the inherent variability and uncertainty of renewable energy sources (wind and solar) and energy demand. This feature was essential for designing a robust and reliable 100% renewable energy system, addressing the core objective of ensuring a reliable energy supply for São Vicente Island. The flexibility of COMANDO to integrate customized routines also meant that specific operational strategies and dispatch logic relevant to an island grid could be implemented and optimized.

Application to São Vicente Island and Design Constraints

In the context of São Vicente Island, COMANDO was configured to simulate the island's unique energy landscape and future energy demands. The model incorporated hourly historical weather

data for the island to accurately represent the intermittent nature of renewable energy generation. Energy demand profiles for 2040 were projected based on historical consumption patterns and anticipated growth, providing the load requirements for the system.
Key design constraints and operational parameters were meticulously integrated into the COMANDO model to reflect real-world limitations and ensure the technical and economic realism of the simulations. These included:

1. Curtailment: The model allowed for the curtailment of excess renewable energy generation when it exceeded immediate demand and storage capacity. While the objective was to minimize curtailment, its inclusion as a possibility ensured that the model accurately reflected periods of oversupply, particularly in scenarios with limited storage.

2. Storage Limits: Explicit capacity limits were set for all storage technologies (BESS, hydrogen tanks). These limits defined the maximum amount of energy that could be stored, influencing the sizing and dispatch of both generation and storage components. For hydrogen, this included the capacity of the electrolyzer, hydrogen storage tanks, and fuel cells.

3. Unmet Load Penalties (LPSP): A critical constraint was the minimization of unmet load, quantified through the LPSP. The optimization objective aimed for a 0% LPSP, ensuring that the system reliably met 100% of the islandś electricity demand throughout the year. Penalties for unmet load were implicitly handled by the optimization algorithm prioritizing system configurations that achieved full reliability, thus directly addressing the reliability aspect of Research Question 1.

4. Component Efficiencies: Realistic conversion efficiencies for all components were incorporated, including the battery charge/discharge cycles, electrolyzer efficiency (electricity-to-hydrogen), and fuel cell efficiency (hydrogen-to-electricity).

5. Economic Parameters: CAPEX, OPEX, and component lifetimes for all technologies were included as input parameters. These economic factors were central to the LCOE and TAC, which are key indicators for Research Question 2.

This meticulous integration of specific details and constraints within COMANDO created a robust and customized modeling environment. It enabled a granular analysis of the intricate interactions within São Vicente Island's energy system, ensuring that the optimization results were not only technically sound but also economically pertinent and directly addressed the research questions concerning green hydrogen integration and the feasibility of a 100% renewable energy future for the island (Langiu et al., 2021).

Operational Optimization and Hourly Demand Matching

COMANDO's operational optimization capabilities were central to simulating the dynamic behavior of São Vicente Island's energy system over a full year, with a granular hourly resolution. This hourly demand matching process ensures that electricity supply from renewable sources and storage perfectly aligns with the islandś fluctuating demand at every single hour. The model achieves this by dynamically dispatching available generation (PV, wind) and managing the charge and discharge cycles of storage technologies (batteries, hydrogen system) to meet the projected hourly load profile for 2040. The objective function, primarily focused on minimizing the TAC, implicitly drives the optimal operational strategy, ensuring cost-effectiveness while maintaining system reliability.

The hourly matching process involves a continuous balancing act. The model prioritizes the direct use of available solar and wind power to meet immediate demand, and when renewable generation exceeds demand, surplus energy is directed to storage (batteries for short-term, hydrogen for long-term/seasonal). Conversely, when demand outstrips direct renewable supply, the model dispatches energy from storage to cover the deficit. The dispatch decisions are optimized to minimize costs while respecting the technical limits of each storage technology (e.g., charge/discharge rates, SOC limits).

Then the optimization ensures that the combined output from renewable generators and storage systems precisely matches the hourly demand, minimizing any unmet load. This is achieved by solving a series of interconnected optimization problems for each hour, considering the system state (e.g., battery SOC, hydrogen tank levels) carried over from the previous hour.

The detailed hourly simulation allows for a realistic assessment of system performance under varying conditions, capturing the nuances of intermittency and demand fluctuations that are critical for island grids (Langiu et al., 2021).

The COMANDO framework adopted in this study is shown in the Figure 3.11 where Pyomo is selected as AML interface and Gurobi (Gurobi, 2020) as the solver.

Problem formulation

An optimal energy system requires optimal decisions at both the design stage and operational stage. Hence, before formulating the optimisation problem, the operational scenarios have been considered due to the variability coupled with other uncertainties to obtain a reliable design.

In this study, the optimisation problem within the COMANDO framework is formulated as a MILP problem, aimed at minimising the TAC of the energy system over its project lifetime. The model focuses exclusively on design objectives, which aggregate both the CAPEX and fixed O&M costs of all system components which includes PV systems, wind turbines, batteries, electrolysers, fuel cells and hydrogen storage units. These costs are annualised using annuity factors to reflect component lifetimes and the time value of money.

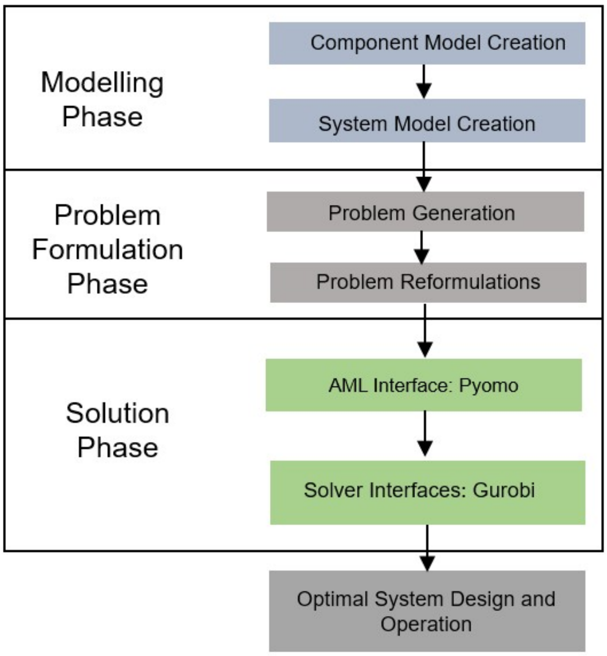

Figure 3.11: COMANDO operating phases adopted in this study

COMANDO provides a `Problem` class, which is instantiated through the `create_problem` method of the `System` class. The optimisation model is constructed using a predefined energy system configuration, an objective function, selected scenarios and a set of time steps specifically, 8,760 hourly intervals for a full year.

The system employs the `aggregate_component_expressions` method to combine cost terms that share common identifiers, such as `investment_costs` and `fixed_costs`, across all components. Finally, the optimisation algorithm determines the most cost-effective sizing and configuration of system components that meet the hourly energy demand profile with minimal TAC. The objective function of the optimisation problem is mathematically defined as follows

$$C(j) = K_j + M_j, \tag{3.23}$$

$$\min T = \sum_{j=1}^{k} C(j) = \sum_{j=1}^{k} \left(K_j + M_j\right), \tag{3.24}$$

where $C(j)$ is the annualised cost of component j, K_j is the annualised capital investment cost of component j, M_j is the fixed annual O&M cost of component j, k is the total number of system components (PV, Wind, Battery, Electrolyzer, Fuel Cell, Hydrogen Storage), T is the total annualised system cost to be minimised.

Problem Solution

To solve the optimisation problem, the problem structure and input data are translated from the COMANDO representation to a new representation, matching the syntax of the target solver, in this study Pyomo is used as the AML interface. The solver Gurobi (Gurobi, 2020) is used to perform the problem-solving and return the solution.

3.5.3 Energy System Modelling Workflow

To better illustrate the modelling workflow implemented in this study, Figure 3.12 provides a graphical representation of the entire process, highlighting the required input data, core modelling steps within the COMANDO tool and the expected output results.

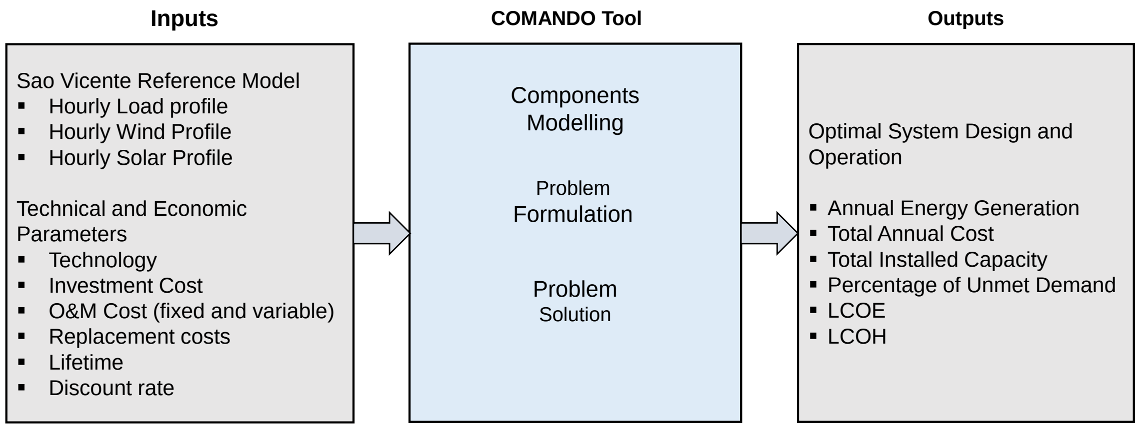

Figure 3.12: Graphical representation of the optimisation workflow using the COMANDO tool, showing inputs, modelling process and system outputs

3.6 Sensitivity Analysis of Cost Parameters

Considering the uncertainties in the future costs of RE and storage technologies, a sensitivity analysis is integrated into this study to assess the robustness of the economic results and to identify critical cost drivers influencing system performance. This analysis specifically focused on the CAPEX of the major component of the configurations. These component were selected due to their significant and high capital investment requirements, which can substantially influence system affordability (IEA, 2022a; IRENA, 2022).

The sensitivity analysis employed a single-parameter variation method, wherein each component's CAPEX was independently varied by $\pm 20\%$ from its base-case value, following standard practice in techno-economic studies (Sollai et al., 2023). For each cost variation, two key economic performance indicators were recalculated specifically the TAC and the LCOE.
This approach identifies the most sensitive cost drivers affecting the economic performance of the 100% RE system. Since hydrogen-related technologies are still emerging and their future

costs are highly uncertain, analysing their impact is critical to evaluating the system's long-term feasibility (IRENA, 2022; IEA, 2022a).

The sensitivity analysis results were visualised using spider diagram and tornado chart which illustrate the relative impact of each parameter on the system's economic indicators and support transparent interpretation of uncertainties (Singh and Fernandez, 2018).

3.7 Assessment of Long-Term Viability Factors

In addition to the quantitative techno-economic modelling performed using the COMANDO framework, this study incorporates a qualitative assessment to address external factors that could influence the long-term viability of achieving a 100% renewable energy system on São Vicente Island. This assessment specifically supports answering the research question 3 of this study which focuses on identifying the technical, economic and policy factors that could influence the long-term viability of achieving 100% renewable energy with integrated green hydrogen as seasonal energy storage.

While the optimisation based modelling quantifies system design, operational behaviour and costs, it does not fully capture real-world external constraints such as infrastructure readiness, regulatory frameworks or future market developments (Pfenninger et al., 2014; Ringkjøb et al., 2018). Therefore, this qualitative assessment complements the quantitative modelling by evaluating external factors that may not be directly represented in the simulation environment but are equally critical for system implementation. The results of this qualitative assessment are presented and discussed in Chapter 4.

Chapter 4 Results and Discussion

This chapter presents and discusses the key findings of the study. The results from the four modelled scenarios are analysed using the performance indicators outlined in chapter 3. Each scenario is discussed individually and compared to show how different system configurations influence the reliability and cost of supplying 100% renewable electricity to São Vicente Island by 2040. In doing so, the analysis directly addresses the research questions by (i) assessing the role of hydrogen integration in enhancing reliability, (ii) evaluating the techno-economic trade-offs across storage options, and (iii) identifying enabling and limiting factors that shape the feasibility of the proposed solutions.

4.1 Scenario-Based Results and Discussions

4.1.1 Results from Scenario 1 (PV + Wind without storage)

In the first Scenario, the island's electricity demand is supplied exclusively by PV and wind generation, without any form of storage system. The optimisation results in Figure 4.1 show that while a considerable portion of the annual demand is covered by direct generation, significant limitations arise due to the variability of both resources.

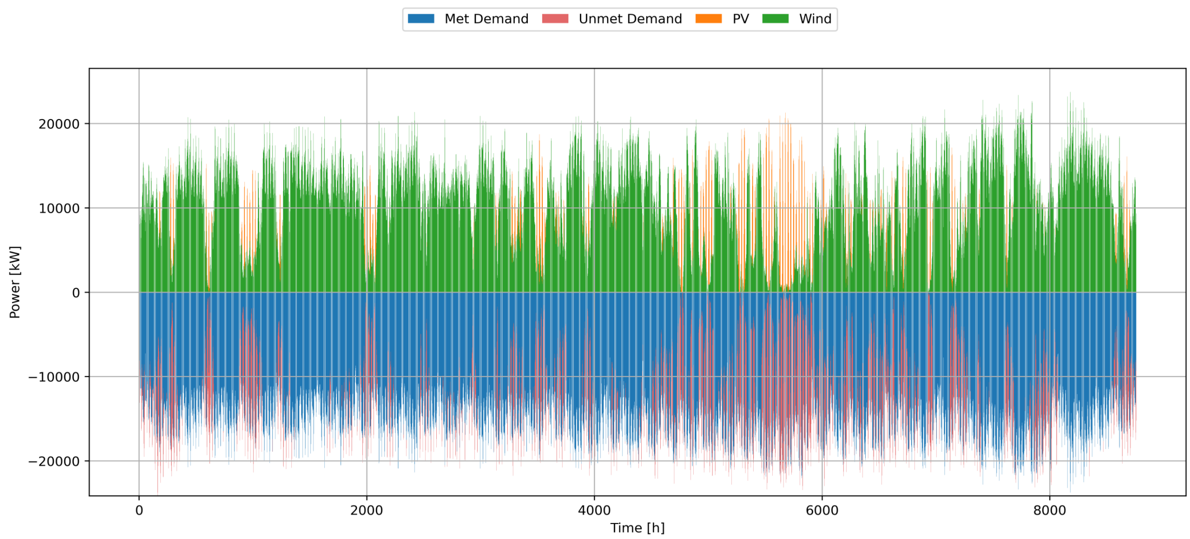

Figure 4.1: Hourly PV and Wind generation vs Demand showing the unmet Demand

Wind generation on São Vicente shows a strong seasonal pattern, with peak output typically observed between December and May and a significant decline from June to September. For instance, during August, wind production drops markedly, leading to extended periods of unmet demand. Although solar generation contributes more consistently throughout the year, its daily variability and relatively lower output during evening hours prevent it from bridging these seasonal gaps. This persistent mismatch between generation and demand underscores the need for long-term storage solutions, such as hydrogen, to ensure system reliability during low-wind periods.

As illustrated in Figure 4.2 below, monthly renewable generation (PV and wind) consistently falls short of meeting total demand in all months, resulting in a persistent share of unmet demand. This is most pronounced during the summer months (e.g., July to November), when wind generation is low and solar output cannot fully compensate. Conversely, during the high-wind season (e.g., December to May), renewable output approaches demand levels but still leaves a shortfall, underscoring the need for additional flexibility.

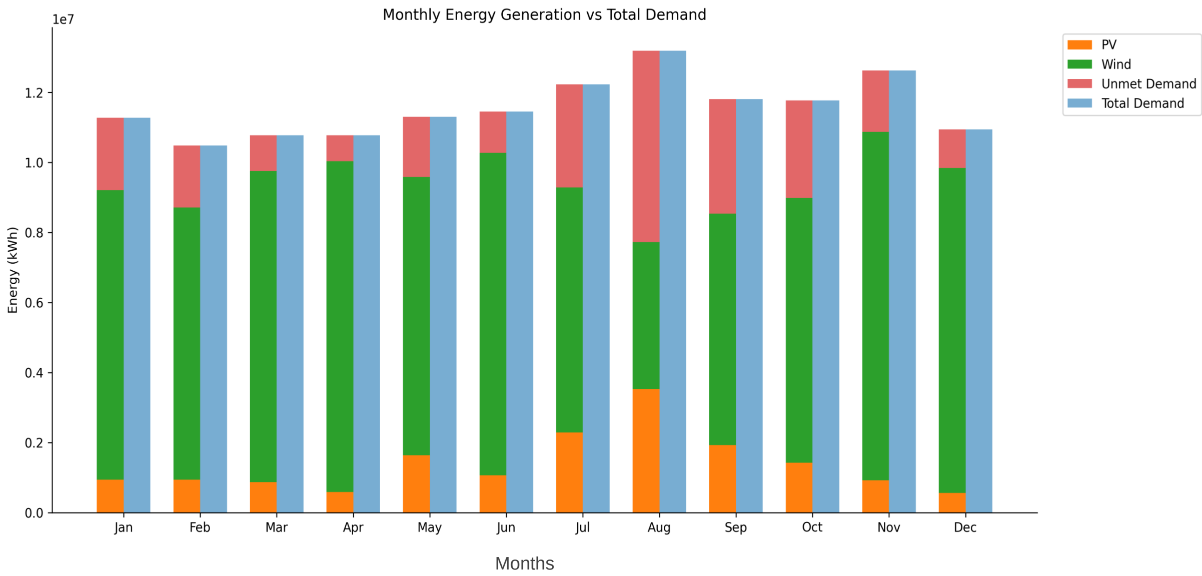

Figure 4.2: Monthly PV and Wind generation vs Demand showing the unmet Demand

The system achieves a total annual energy generation of 112.8 GWh, with the remaining demand unmet due to the lack of flexibility. Consequently, the LPSP is as high as 18.62%, indicating that the system fails to provide electricity reliably across the year.

Despite these limitations, the LCOE in this Scenario is 0.0518 €/kWh, and the TAC is 5.844 M€/year due to the absence of expensive storage technologies and the relatively mature and cost-effective nature of PV and wind systems. However, the economic advantage is offset by significant energy curtailment and poor reliability, especially in seasonal contexts. The same trade-off was observed in the Skyros Island case study, where lack of long-term storage led to insufficient energy supply during periods of low RE generation (Papathanasiou and Bertsiou, 2025).

Scenario 1 demonstrates the fundamental limitations of a RE configuration without storage for isolated systems like São Vicente. The configuration is not able to buffer resource variability leads to high supply deficits (18.62% LPSP), thus, this scenario did not meet the technical criteria presented in chapter 3.

4.1.2 Results from Scenario 2 (PV + Wind + Battery Energy Storage)

In this Scenario, battery storage was introduced alongside PV and wind generation to help balance mismatches between supply and demand. Compared to Scenario 1, the results showed a clear improvement in system reliability. The LPSP dropped significantly to 2.12%, which means that the battery was effective in reducing periods of unmet demand especially during peak hours or low generation times.

Although Scenario 2 exhibits a lower LCOE (0.039 €/kWh) and TAC (5.235 M€/year) despite the addition of storage, this outcome can be explained by the system configuration. Scenario 1 required a higher installed capacity of 81.63 MW compared to 56.2 MW in Scenario 2, and a significant share of renewable generation in Scenario 1 could not be utilized due to the absence of storage, resulting in curtailment. That means a smaller amount of useful energy was available to spread the system cost over, which pushes the costs up. In Scenario 2, the battery made it possible to store and use more of the electricity that was generated, which helped lower the costa even with the extra investment in batteries.

It's important to mention that this scenario didn't fully eliminate unmet demand. The model allowed a small 2.12% shortfall instead of oversizing the battery system to completely cover it. This outcome occurs because fully eliminating the shortfall would have required significantly larger battery capacity, leading to disproportionate increases in system cost. The COMANDO model tries to find the best balance between cost and reliability, and in this case, it found that allowing a small level of unmet demand was more cost-effective than forcing 100% coverage.

This type of trade-off is common in energy system planning, where achieving perfect reliability may be technically feasible but not economically justified. This phenomenon has been demonstrated in both analytical and empirical studies. For example, the work of ParandehGheibi et al. (2015) showed that when system cost functions are convex, it can be optimal to tolerate minor supply deficits to reduce overall cost. Similarly, real world energy modeling shows diminishing returns from adding storage beyond a certain point, the reliability gains are marginal while costs rise sharply (Javed et al., 2021; Li et al., 2018).

Figure 4.3 provides a clear visualization of the system's hourly performance. The upper chart shows the contributions of PV, wind, battery discharge, and the resulting unmet demand. And as seen in Figure 4.4 above, from July to November, there is an increase in unmet demand, despite battery support. This is a period with the lowest wind and solar availability, it shows the impact of seasonal resource fluctuations. The battery SOC shown in the lower chart confirms this trend. Over the same period, the SOC steadily declines, indicating heavy discharge activity as the battery compensates for reduced generation, until the battery reaches near minimum energy levels, which limits its ability to further buffer demand shortfalls. These observations demonstrates the importance of seasonal storage in systems relying solely on variable renewable resources. The residual unmet demand would require a substantial increase in battery size, which, as noted earlier, would greatly increase the overall system cost and LCOE, and this is the trade-off that the optimisation model avoids.

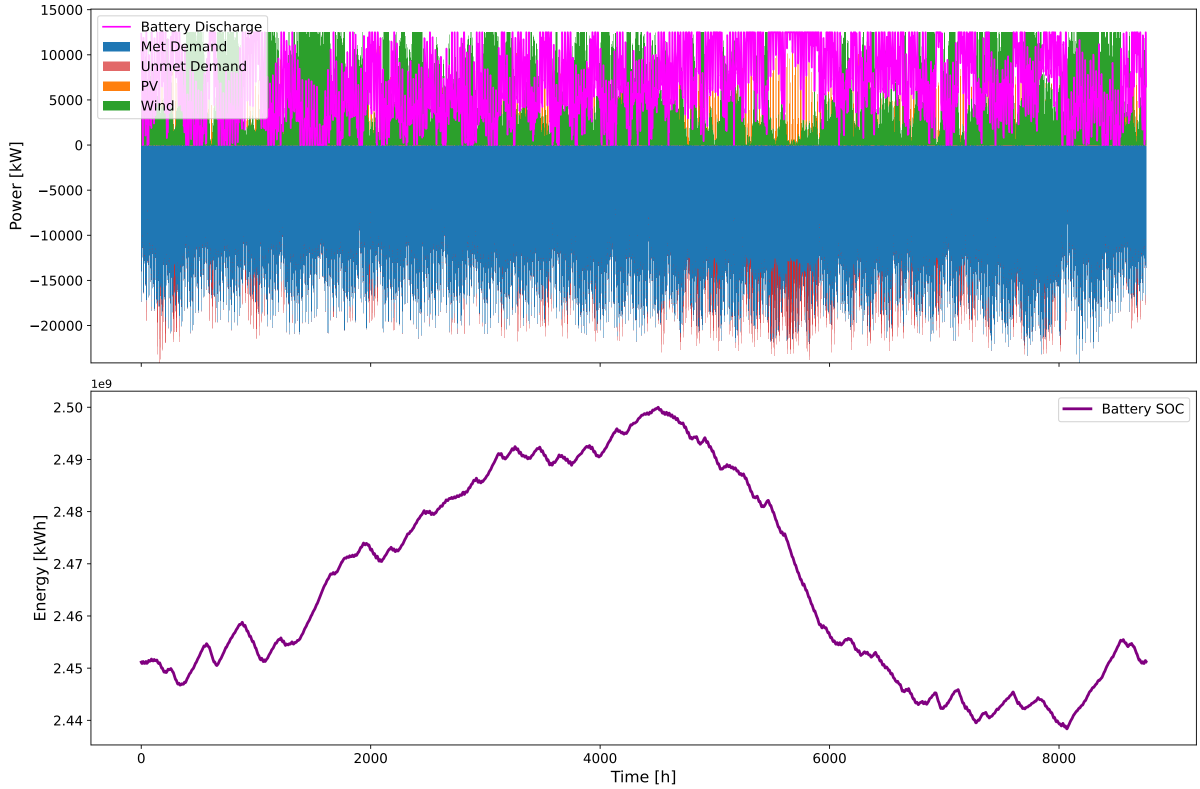

Figure 4.3: Hourly energy generation and demand balance (top), and battery state of charge (bottom) over the simulation year for Scenario 2

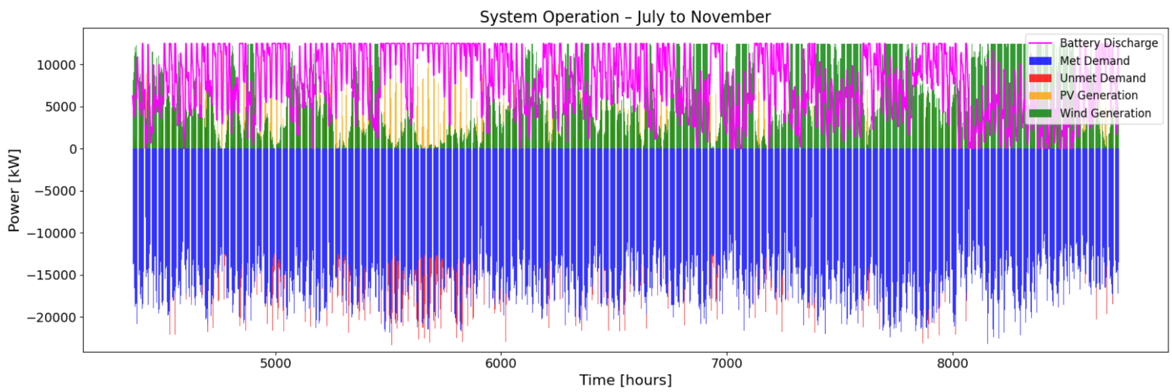

Figure 4.4: Hourly system operation from July to November

4.1.3 Results from Scenario 3 (PV + Wind + Hydrogen Storage System)

Scenario 3 demonstrates the role of hydrogen as a seasonal storage option by directly addressing the mismatch between variable renewable generation and demand. The simulation results in Figure 4.5 show that this setup is able to meet 100% of the hourly electricity demand throughout the year, with an LPSP of 0%. Unlike Scenarios 1 and 2, where significant unmet demand persists despite high PV and wind capacities or the addition of batteries, hydrogen storage ensures reliability by storing surplus electricity during high-wind months (December-May) and reconverting it via the fuel cell during low-wind periods (July-October). This capability highlights hydrogen's unique value in bridging seasonal gaps that batteries alone cannot cover, thereby achieving near-complete demand coverage throughout the year.

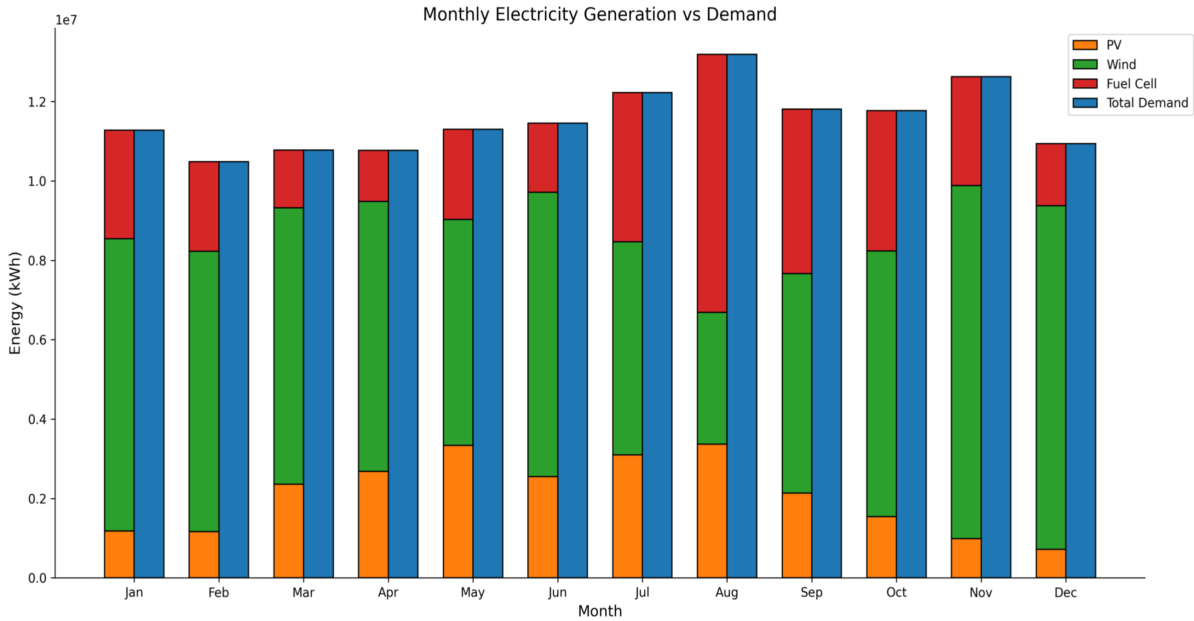

Figure 4.5: Monthly energy generation and demand balance over the simulation year for Scenario 3

Over the year, 1,386.72 kg of hydrogen is produced and fed back into the system through the fuel cell, though efficiency losses reduce the net delivered electricity. Economically, this Scenario records the highest LCOE (0.0645 €/kWh), LCOH (1.1401 €/kg) and TAC (8.944 M€/year), which can be attributed to the capital-intensive nature of electrolyzers, storage tanks, and fuel cells, combined with conversion inefficiencies. In contrast, Scenario 1 and 2 incurred lower costs but failed to ensure supply, and with battery support Scenario 2 could not address long-term seasonal deficits. Thus, while hydrogen storage secures the highest level of reliability, it does so at the expense of higher system costs, underscoring the trade-off between resilience and affordability.

These results align with recent island-based studies that demonstrate the trade-offs between achieving full reliability with hydrogen storage and the associated costs. For instance, research on Tilos Island found that seasonal hydrogen storage is essential to achieve full self-sufficiency, although it significantly drives up system cost (Superchi et al., 2025).

4.1.4 Results from Scenario 4 (PV + Wind + Battery + Hydrogen)

Scenario 4 introduces a fully integrated hybrid energy system combining solar PV, wind turbines, battery energy storage, and green hydrogen technologies. This configuration aims to capture the strengths of both short-term and long-term storage systems to meet São Vicente's energy demand reliably throughout the year. According to the model results, this hybrid system configuration successfully eliminates all unmet demand, achieving 100% supply reliability (LPSP = 0%) as demonstrated in Figure 4.6 below.

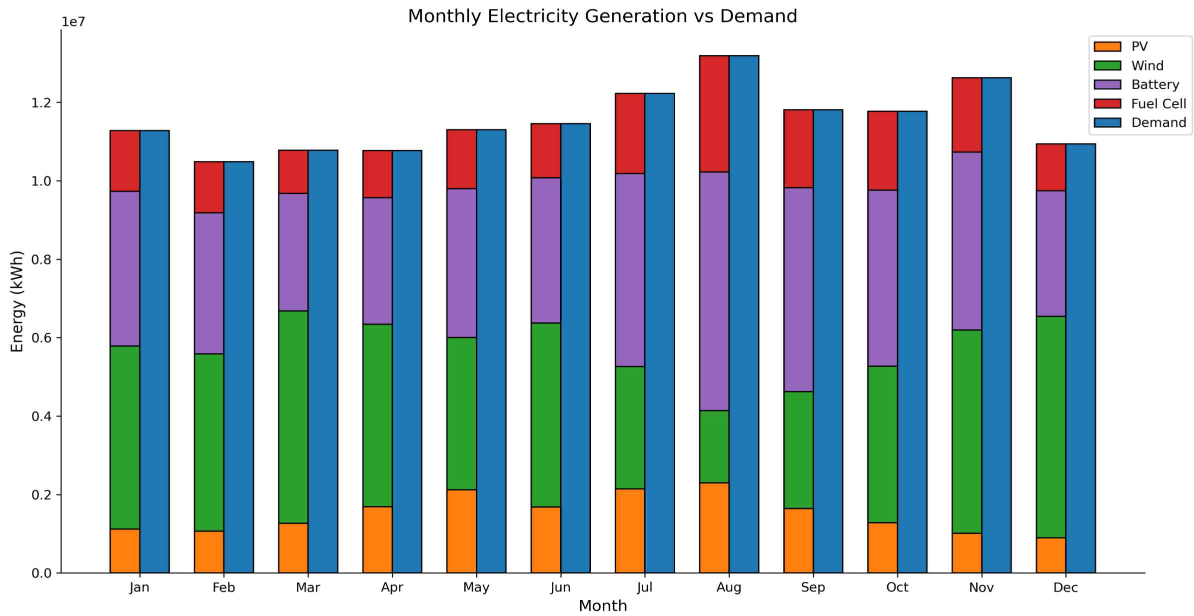

Figure 4.6: Monthly PV, Wind, Battery, and Fuel cell generation with electricity demand in Scenario 4. The Figure illustrates the balance achieved through hybrid storage, showing zero unmet demand

In terms of system capacity, the model indicates a reduction in hydrogen storage size compared to Scenario 3. Since the battery helps mitigate daily fluctuations, less hydrogen is needed to cover seasonal mismatches. The total installed generation capacity is 70.8 MW, which is lower than the 105.4 MW required in Scenario 3, this shows that hybrid storage systems can help optimize generation sizing. Hydrogen production over the year is 738.52 kg, nearly half of the production in Scenario 3 (1,386.72 kg). This result suggests a better utilization of the hydrogen system when supported by battery storage.

Economically, Scenario 4 records an LCOE of 0.0503 €/kWh and LCOH of 0.9855 €/kg, which is lower than Scenario 3 and slightly higher than Scenario 2, but with the advantage of zero unmet demand. The TAC is 6.971 M€/year, which means greater reliability and a better cost-performance ratio than in Scenario 3.

These findings aligns with recent case studies confirming the value of hybrid battery and hydrogen storage configurations in renewable systems. For example, a techno-economic analysis conducted on Donoussa Island of Greece demonstrated that integrating hydrogen storage into solar-wind hybrid systems reduced unmet demand while maintaining acceptable LCOE levels, surpassing the performance of single storage setups (Katsivelakis et al., 2021). Similarly, Khan et al. (2025) did a broader review of hybrid energy systems which highlights that coupling batteries and hydrogen fuel cells enhances flexibility and resource utilization, especially under variable solar–wind regimes, leading to improved techno-economic performance compared to individual storage technologies.

4.2 Comparative Analysis of Scenarios

To evaluate the optimal configuration for achieving a 100% RE system on São Vicente Island, all scenarios were compared based on technical and economic performance indicators. This section presents a detailed comparison based on KPIs as shown in the findings.

4.2.1 Annual Energy Generation, and Reliability (LPSP)

Table 4.1 below shows the annual energy generation, and reliability for all Scenarios. It is observed that the annual energy generation increased progressively across the four Scenarios, from 112.8 GWh in Scenario 1 (without storage) to 138.6 GWh in both Scenarios 3 and 4. However, Scenario 1 suffered from high unmet demand, as shown by a Loss of Power Supply Probability (LPSP) of 18.62%, making it unreliable despite moderate costs. Introducing battery storage in Scenario 2 drastically improved reliability (LPSP: 2.12%) and increased energy delivery.

Table 4.1: Annual Energy Generation, and Reliability for All Scenarios

Metric	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Annual Energy Generation (GWh)	112.8	135.7	138.6	138.6
LPSP (%)	18.62	2.12	0	0

This demonstrates that battery storage improves operational efficiency by reducing curtailment and optimizing dispatch. Both Scenarios 3 and 4 achieved full reliability (0% LPSP) meeting all demand highlighting the role of green hydrogen storage over the year.

4.2.2 Installed Capacity and System Sizing of Scenarios

Table 4.2 shows how different storage strategies influence the size of system components in each scenario. In Scenario 1, where no storage is used, the system depends heavily on renewable generation, requiring 31.6 MW of PV and 50 MW of wind to meet demand as much as possible and yet still fail to provide reliable supply. With the addition of 12.5 MW of battery storage in Scenario 2, both PV and wind capacities are significantly reduced to 14.7 MW and

29 MW respectively. This shows how batteries help smooth fluctuations and reduce the need for oversized generation.

Table 4.2: Capacity and System Sizing Across Scenarios

Component	**Scenario 1**	**Scenario 2**	**Scenario 3**	**Scenario 4**
PV Capacity (MW)	31.6	14.7	22.8	14.7
Wind Capacity (MW)	50.0	29.0	41.8	21.0
Battery Power Capacity (MW)	-	12.5	-	12.5
Fuel Cell Capacity (MW)	-	-	23.1	10.6
Electrolyser Capacity (MW)	-	-	18.2	12.1
Total Installed Capacity (MW)	81.63	56.2	105.4	70.8
H_2 Storage (kg)	-	-	1386.7	738.52

Scenario 3 introduces hydrogen storage and achieves full reliability, but at the cost of substantial infrastructure: 22.8 MW PV, 41.8 MW wind, 18.2 MW electrolyser, 23.1 MW fuel cell, and 1,386.7 kg of hydrogen storage. Scenario 4, on the other hand, combines batteries and hydrogen in a more balanced way. It maintains full reliability with just 14.7 MW PV, 21 MW wind, and much smaller hydrogen equipment, 12.1 MW electrolyser, 10.6 MW fuel cell, and 738.52 kg hydrogen storage. Scenario 3 required the largest installed capacity of 105.4 MW and Scenario 4 achieved the same energy output and reliability with only 70.8 MW of installed capacity. This hybrid setup clearly reduces the strain on individual technologies and proves to be more efficient both technically and economically.

These results underline the trade-offs imposed by system constraints: batteries reduce the need for oversizing but cannot handle seasonal gaps, while hydrogen provides full reliability at the expense of higher installed capacities and costs. Land availability could become a limiting factor in practice, as expanding PV and wind beyond certain thresholds may compete with other land uses, highlighting the importance of storage in optimizing spatial and technical feasibility.

4.2.3 Cost Performance (LCOE, LCOH, LCOS, TASC, and component cost shares)

The economic evaluation of the four scenarios was carried out using key indicators that reflect both energy production costs and storage performance. In Figure 4.7, Scenario 2 recorded the lowest LCOE at 0.0386€/kWh, benefiting from a simple battery-based configuration and efficient sizing. Scenario 1, despite having no storage, had a slightly higher LCOE (0.0518€/kWh) due to oversizing of generation. Scenario 3, which relies fully on hydrogen for storage, had the highest LCOE at 0.0645€/kWh, reflecting both capital intensity and conversion inefficiencies. Scenario 4 delivered a balanced outcome with an LCOE of 0.0503€/kWh, offering full reliability without excessive cost.

Looking at the LCOH, Scenario 3 achieved a lower value (0.9855€/kg) compared to Scenario 4 (1.1401€/kg). This difference is due to reduced hydrogen usage and economies of scale. However, Scenario 4 smaller hydrogen system still meets the reliability needs at lower total system cost which emphasises efficiency over scale. In terms of battery storage, the LCOS in Scenario 2 was 0.0351€/kWh, slightly lower than Scenario 4 0.0354€/kWh, this shows that the battery economics remain favorable even when combined with hydrogen.

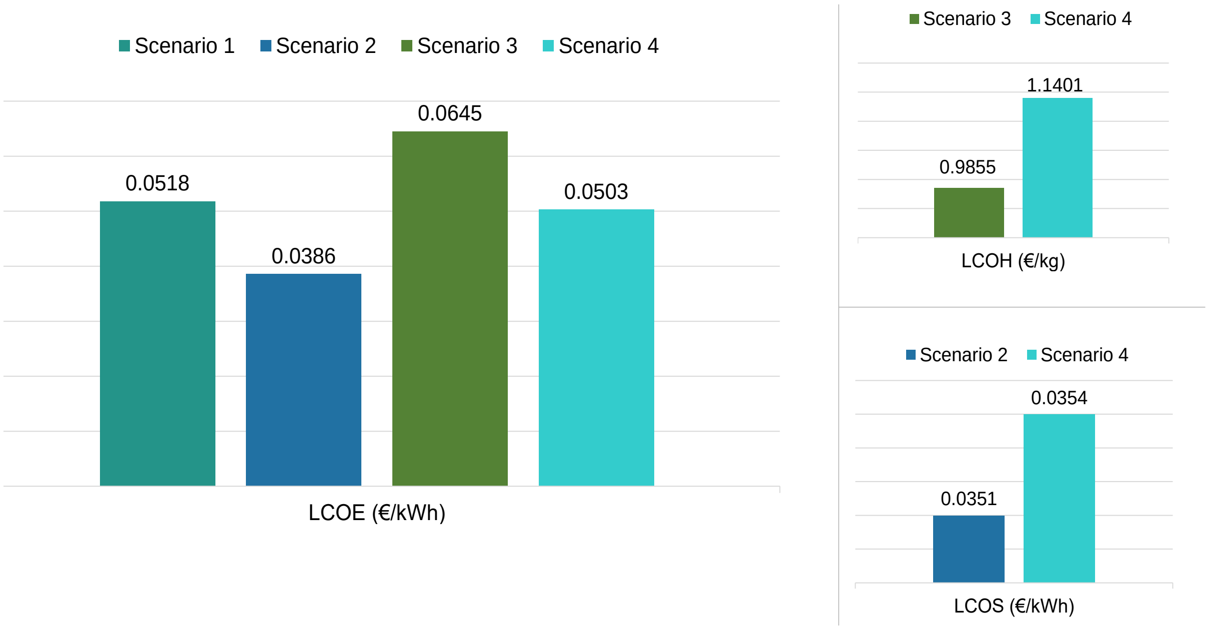

Figure 4.7: LCOE, LCOH, and LCOS for different scenarios

To contextualize the results, the modeled LCOE across all scenarios by 2040 is significantly lower than the current electricity tariffs in Cabo Verde. Presently, average residential tariffs are about 0.394 USD/kWh or around 0.335 €/kWh (using an exchange rate of 1 USD = 0.85 EUR) and business tariffs about 0.215 USD/kWh or around 0.182 €/kWh (GlobalPetrolPrices, 2025). By contrast, the study's outcomes show projected LCOE values in the range of 0.039-0.065 €/kWh, well below today's tariff levels. While future market dynamics may influence electricity prices, it is reasonable to expect that consumer tariffs in 2040 will not fall below the modeled renewable-based costs, particularly given inflationary pressures, fossil fuel price volatility, and investment requirements for grid infrastructure. This suggests that the renewable-based systems assessed here not only enhance reliability and sustainability but also offer a cost advantage relative to conventional electricity prices, even under future conditions.

Finally, the TAC demonstrated in Figure 4.8 confirms the trade-offs. Scenario 2 remains the cheapest at 5.235 million €/year, followed by Scenario 1 at 5.844 million €/year. Scenario 3, again, is the most expensive at 8.944 million €/year, due to its large hydrogen infrastructure.

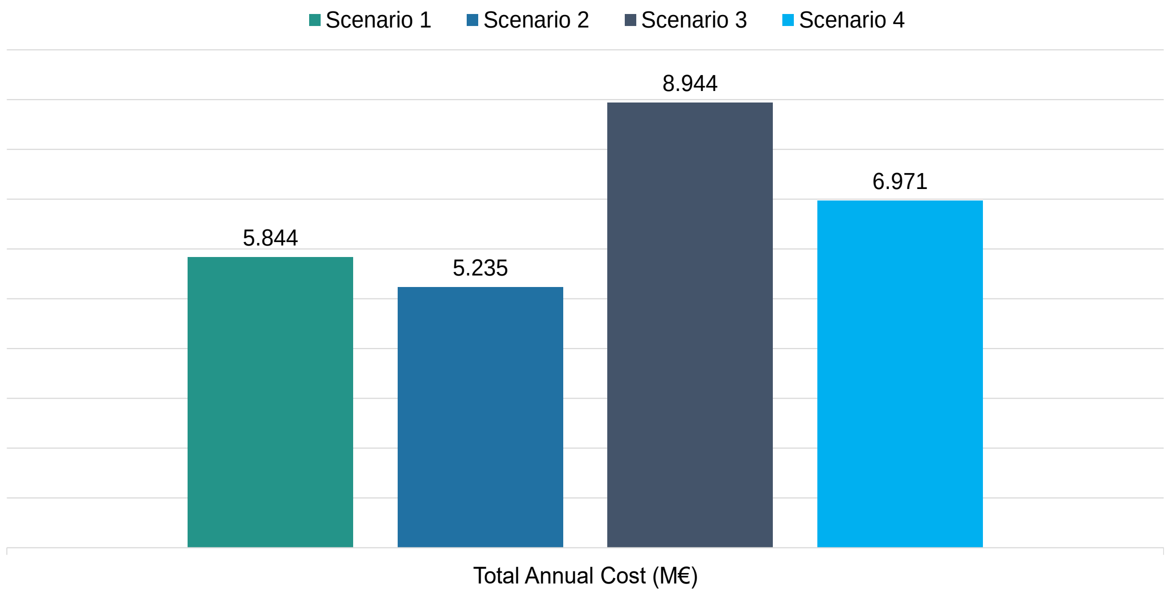

Figure 4.8: TAC for different scenarios

Scenario 4 stands in the middle at 6.971 million €/year, but it offers full reliability with both short and long-term storage, and this makes it the most balanced option overall.

Share of Major Component in Total Installation Cost

The breakdown of installation cost across system components in Figure 4.9 highlights how each scenario allocates capital differently. The variation in cost distribution across scenarios is primarily driven by the technical and economic characteristics of the different technologies. In Scenario 1, Wind makes up the majority of the investment at about 74.7%, while PV contributes the remaining 25.3%. This is because of its higher capacity factor on São Vicente compared to solar, meaning larger wind installations are required to compensate for the absence of storage and provide sufficient generation during periods of low solar availability. This prioritization of wind occurs despite PV's lower unit capital cost, as the system optimization favors resource adequacy over least-cost technology.

In Scenario 2, batteries are introduced, accounting for 16.3% of the total cost. Wind remains dominant at 60%, while PV takes 23.7%. This more balanced allocation improves system efficiency and reduces the need for excessive generation capacity. Moving to Scenario 3, the system relies entirely on hydrogen for storage. As a result, hydrogen infrastructure makes up a massive 47% of the cost, followed by wind (41%) and PV (12%), due to the capital-intensive nature of electrolyzers, fuel cells, and storage tanks, even though wind and PV remain necessary to supply the electricity required for hydrogen production.

Scenario 4 shows the most balanced cost distribution. Hydrogen still represents a substantial portion at 39%, but the presence of batteries (17%) helps reduce the overall hydrogen requirement. Wind and PV account for 32% and 12% respectively. The hybrid approach in scenario

4 distributes costs more evenly across technologies, which avoids overdependence on a single component and leading to a more resilient and economically efficient system.

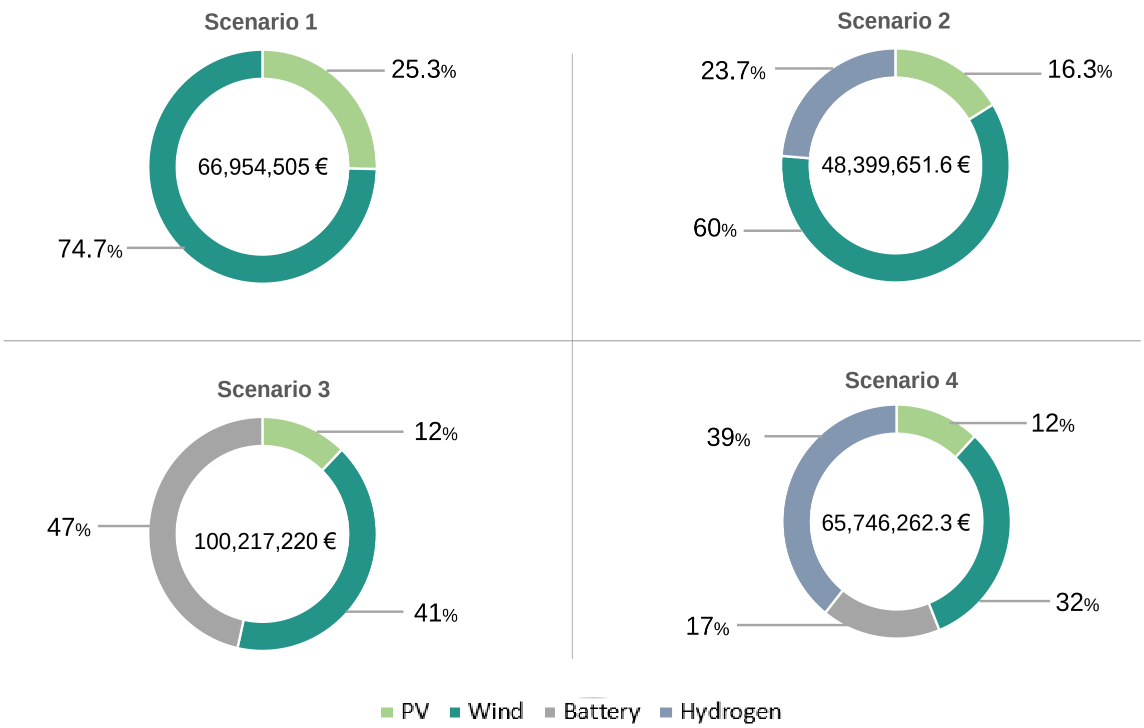

Figure 4.9: Share of Each Component in Total System Installation Cost

4.2.4 Role of Green Hydrogen as Seasonal Storage

The contribution of green hydrogen to total energy demand is a key differentiator between Scenarios 3 and 4, reflecting its role as a storage solution. Looking at Figure 4.10, in Scenario 3, hydrogen covers 24.5% of the annual energy demand, with the remaining 75.5% supplied directly from PV and wind generation. This high hydrogen share compensates for seasonal mismatches, especially during prolonged periods of low solar and wind availability. Without it, the system would require extreme oversizing of renewable generation to meet demand year-round which would be both economically and technically inefficient.

In Scenario 4, hydrogen accounts for a smaller share, at 14.6%, but remains critical. The hybrid configuration divides the energy supply more evenly, 49.6% from PV and wind, 35.8% from batteries, and the remaining 14.6% from hydrogen. Even though its contribution appears modest, hydrogen supports the system during extended low-resource periods that neither PV, wind, nor batteries can cover alone. These typically occur when both wind and solar output remain low for consecutive days, exceeding the short-term autonomy of battery systems. In such cases, hydrogen acts as the system's flexibility backbone, enabling reliable supply without major oversizing. Scenario 4 shows that with hybrid storage, less hydrogen is needed, but its strategic impact remains vital. This reduces costs and infrastructure requirements while still ensure supply reliability under all conditions.

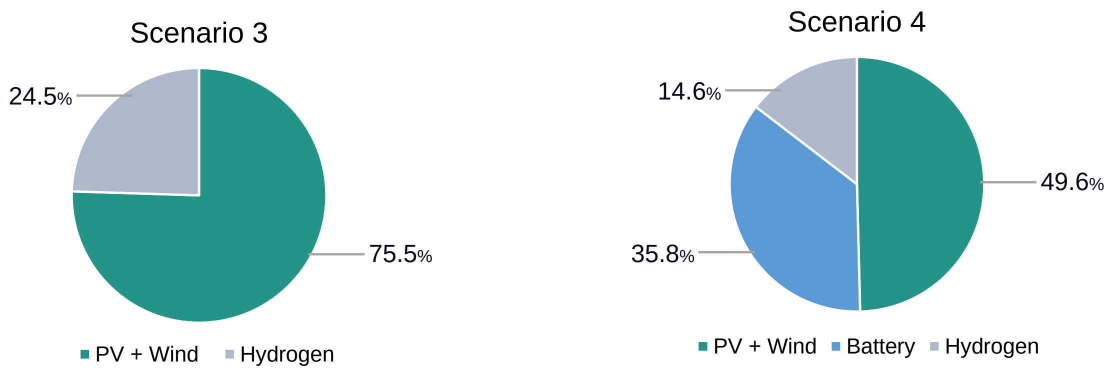

Figure 4.10: Contribution of green hydrogen to total energy generation

4.2.5 Summary and Optimal Scenario Selection

The comparative analysis shows that while Scenarios 1 and 2 are more affordable, they fail to ensure long-term reliability, and Scenario 3 achieves reliability only at unsustainable costs. Scenario 4 emerges as the most balanced and viable pathway, combining the short-term flexibility of batteries with the seasonal backup of hydrogen.

For São Vicente, adopting this configuration would mean achieving a 100% renewable and fully reliable electricity system by 2040. Technically, it ensures grid stability without oversizing generation; economically, it delivers competitive energy costs compared to current tariffs; and socially, it reduces dependence on imported fossil fuels, strengthens energy security, and aligns with Cabo Verde's decarbonization and sustainable development goals. This makes Scenario 4 the most realistic and strategic option for the island's energy transition.

4.3 Sensitivity Analysis Result

Following the approach described in the methodology, a sensitivity analysis was conducted to examine how variations in the CAPEX of key component affect the economic performance of the optimal system configuration (Scenario 4). By independently varying the unit cost of each selected component by ±20% from its base value, the analysis quantifies the impact of cost uncertainty on two core economic indicators: the TAC and the LCOE. This one-at-a-time (OAT) approach offers a clear view of how sensitive the system's performance is to individual cost parameters. It also highlights which components matter most from a cost perspective, helping to inform future decisions around technology investment and cost reduction efforts in renewable energy systems.

4.3.1 Impact on Total Annual Cost (TAC)

Table 4.3 presents the capital cost variations applied to each major system component, along with the corresponding recalculated TAC under ±20% deviations from the base values. This forms the basis for the sensitivity analysis, and allows identification of components with the highest influence on overall system cost.

Table 4.3: Sensitivity of Total annual cost (TAC) to ±20% Capital cost variation

Component	Base Cost	-20% Cost	+20% Cost	Base TAC	TAC @ -20%	TAC @ +20%
PV (€/kW)	536.0	428.8	643.2	6,971,375.6	6,863,655.9	7,091,868.4
Wind (€/kW)	1000.0	800.0	1200.0	6,971,375.6	6,590,250.1	7,360,274.2
Battery (€/kWh)	230.0	184.0	276.0	6,971,375.6	6,782,216.2	7,173308.2
Electrolyzer (€/kW)	890.0	712.0	1068.0	6,971,375.6	6,745,771.3	7,209,753.0
Fuel Cell (€/kW)	903.0	722.4	1083.6	6,971,375.6	6,741,467.3	7,214,057.0
H2 Tank (€/kg)	207.0	165.6	248.4	6,971,375.6	6,904,096.6	7,051,427.8

Table 4.4 summarizes the changes in the TAC resulting from ±20% variations in the CAPEX of each major component. It shows both the absolute and percentage change relative to the base TAC. The absolute changes in TAC are then used to construct the Tornado Chart presented for proper visualization.

Table 4.4: Base TAC and change in TAC under ±20% Cost variation for each component

Component	**Base TAC** (€/year)	**Δ TAC** @ -20%	% Change @ -20%	**Δ TAC** @ +20%	% Change @ +20%
PV	6971375.6	-107719.7	-1.5	120492.8	1.7
Wind	6971375.6	-381125.5	-5.5	388898.6	5.6
Battery	6971375.6	-189159.4	-2.7	201932.6	2.9
Electrolyzer	6971375.6	-225604.3	-3.2	238377.4	3.4
Fuel Cell	6971375.6	-229908.3	-3.3	242681.4	3.5
H2 Storage	6971375.6	-67279.0	-1.0	80052.2	1.1

Figure 4.11 presents a tornado chart illustrating how ±20% variations in CAPEX of components impact the TAC, measured in thousand euros. As shown, the wind turbine cost exerts the most significant influence on the system's economics, with a ±20% change causing TAC to vary between approximately -381.1 k€ and +389.0 k€. This highlights wind energy as the most cost-sensitive component in the system.

Among the storage technologies, the fuel cell and electrolyzer show the next highest sensitivities, with variations of -230.0 k€ to +242.7 k€ and -225.6 k€ to +238.4 k€, respectively. This confirms their critical role in the overall system affordability. The battery system follows closely, with a variation range of around -189.2 k€ to +202.0 k€.

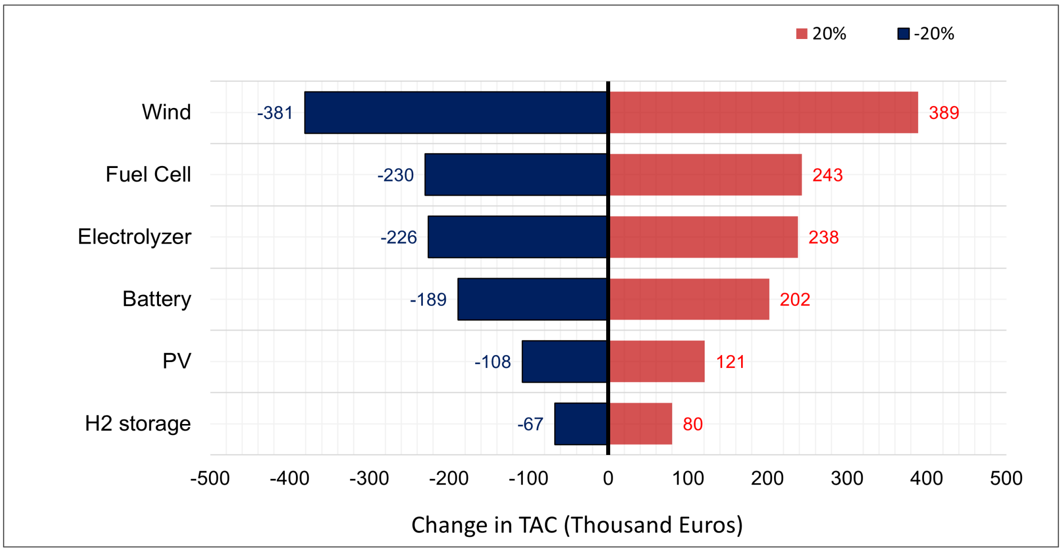

Figure 4.11: Sensitivity analysis (Impact on TAC)

In contrast, PV and hydrogen storage exhibit relatively lower sensitivities. PV cost shifts, impact the TAC by only -108.0 k€ to +120.5 k€, while hydrogen storage shows the least effect, with a range of -67.3 k€ to +80.1 k€. The results demonstrates that while all components contribute to system cost, a strategic cost reductions in wind turbines and key storage units (especially fuel cells and electrolyzers) would yield the most substantial economic benefits.

4.3.2 Impact on Levelized Cost of Electricity (LCOE)

A focused sensitivity analysis was conducted to assess how variations in the CAPEX of the battery and fuel cell systems affect the LCOE for the optimal configuration. These two technologies were selected because of their essential roles in maintaining supply reliability and their significant share in the system's investment cost. Rather than limiting the analysis to just ±20%, a broader range of cost variation (-30% to +30%) is applied to capture a more detailed response in LCOE. The results are visualized for a clear understanding of how increases or decreases in component costs impact the LCOE, and helps identify which storage technology is more economically sensitive.

Table 4.5 shows the capital cost variations for the battery and fuel cell components, covering ±10%, ±20%, and ±30% from their base values.

Table 4.5: CAPEX variation of Battery and Fuel Cell Components

Component	Base Cost	-30%	-20%	-10%	+10%	+20%	+30%
Battery (€/kWh)	230.0	161.0	184.0	207.0	253.0	276.0	299.0
Fuel Cell (€/kW)	903.0	632.1	722.4	812.7	993.3	1083.6	1173.9

Table 4.6 presents the LCOE for the battery and fuel cell systems under various CAPEX variations ranging from -30% to +30%. These values are used to assess the sensitivity of LCOE to changes in storage component costs and form the basis for the following chart analysis

Table 4.6: LCOE under CAPEX variation for Battery and Fuel Cell

Cost Variation (%)	Battery LCOE (€/kWh)	Fuel Cell LCOE (€/kWh)
-30	0.0482	0.0478
-20	0.0489	0.0486
-10	0.0498	0.0495
0	0.0503	0.0503
10	0.0510	0.0512
20	0.0517	0.0520
30	0.0524	0.0529

Figure 4.12 shows how the LCOE responds to changes in the CAPEX of the battery and fuel cell systems. As expected, increase in the cost of either component leads to a higher LCOE, while reducing the cost helps lower it. However, what stands out is the difference in how strongly each component influences the LCOE.

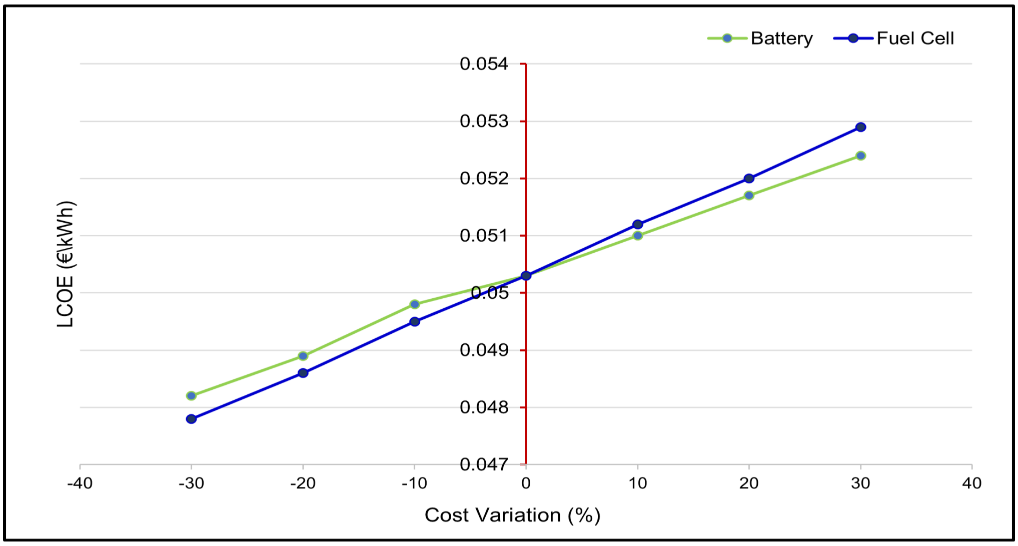

Figure 4.12: Sensitivity analysis (Impact on LCOE)

Among the two storage technologies, the fuel cell displays a steeper slope, indicating a greater sensitivity of LCOE to changes in its capital cost. For instance, a 30% reduction in fuel cell cost results in a more significant decrease in LCOE compared to the same reduction in battery cost. Likewise, a 30% increase in fuel cell cost causes a sharper LCOE rise than that of the battery.

This suggests that fuel cell economics play a more dominant role in determining the LCOE of the hybrid system.

The battery also impacts the LCOE, but its curve shows a gentler slope. This implies that while battery cost reductions contribute to lower LCOE, the marginal effect is not as strong as that of the fuel cell. Therefore, targeting cost reductions in the fuel cell technology if we want to bring down the LCOE and improve the affordability of renewable-based power systems.

4.4 Long-Term Viability Factors

This section critically assesses the long-term viability of achieving a 100% RES by 2040 on São Vicente Island, with green hydrogen as a seasonal storage solution. Drawing on literature-backed insights across technical, economic, and policy/regulatory dimensions, this analysis directly addresses Research Question 3. Unlike a general literature review, this section specifically applies these factors to the unique context of São Vicente, emphasizing how they influence the feasibility of the proposed scenarios, particularly those involving hybrid battery-hydrogen systems (Scenarios 3 and 4).

The viability of this transition hinges on navigating a complex interplay of enabling and limiting factors, informed by both local realities on São Vicente and broader lessons from SIDS. The focus here is on how these factors specifically impact the seasonal mismatch of RE generation and the strategic role of hydrogen in bridging this gap, moving beyond generic SIDS challenges to a tailored assessment for São Vicente.

4.4.1 Enabling factors

São Vicente benefits from several enabling factors that directly support its ambitious RE targets, particularly in the context of integrating hydrogen for seasonal storage. A strong political commitment from Cabo Verde, with ambitious targets of 50% renewable energy by 2030 and 100% by 2040 for São Vicente, provides a crucial foundation for large-scale infrastructure projects, including those required for hydrogen production and storage. This commitment is essential for managing the island's significant seasonal RE variability (Pombo et al., 2022; Nordman et al., 2019). The island is also naturally endowed with significant wind and solar resources (Pombo et al., 2022; Nordman et al., 2019), which, while intermittent, form the bedrock of the 100% RES target. The challenge lies in their seasonal variability, where hydrogen emerges as a key enabler for long-term energy storage, allowing surplus energy from peak renewable seasons to be stored and utilized during leaner periods, thereby ensuring year-round reliability for Scenarios 3 and 4.

Advancements in energy technologies further bolster this transition. Rapid cost declines in solar PV and wind energy make them increasingly competitive (Ochoa et al., 2025; UNDESA, 2020; Superchi et al., 2025), while significant developments and cost reductions in BESS make them more feasible for managing short-term grid stability and daily fluctuations (Pombo et al., 2022; Ochoa et al., 2025). For seasonal storage, green hydrogen is identified as a viable and potentially more cost-effective solution than relying solely on batteries, especially as hydrogen technology prices are expected to drop in the mid and long term (Ochoa et al., 2025; Superchi et al., 2025). This technological convergence directly supports the economic viability of hybrid systems (Scenarios 3 and 4) by providing complementary storage solutions. Furthermore, grid modernization technologies such as grid-forming inverters and virtual synchronous generators (VSGs) are crucial for simulating inertial response and enhancing grid stability in high-renewable penetration systems, addressing frequency and voltage regulation challenges (Ochoa et al., 2025). These technologies are vital for integrating the variable output from wind and solar, and for managing the dynamic response of electrolyzers and fuel cells within the island's grid, ensuring the technical feasibility of the proposed 100% RES scenarios.

The transition also promises long-term economic and social benefits, including a reduction in electricity costs and price volatility by lessening heavy reliance on imported fossil fuels (Nordman et al., 2019). This shift is projected to foster significant economic growth and create millions of jobs in the RE sector. For São Vicente, the economic benefits of reducing fossil fuel imports directly improve the overall economic viability of the proposed renewable energy systems, making the higher upfront costs of Scenarios 3 and 4 more palatable in the long run. Finally, supportive policy and financial frameworks are essential to de-risk investments and attract necessary private capital. Reforming or phasing out fossil fuel subsidies is crucial to align market signals with environmental goals and free up funds for sustainable energy investments. International cooperation and increased financial support from Development Finance Institutions (DFIs) and development partners are actively sought by Cabo Verde and are critical for achieving its RE goals (UNDESA, 2020). These frameworks are particularly important for mobilizing the substantial investments required for hydrogen infrastructure, which is a critical component of the long-term viability of seasonal storage solutions.

4.4.2 Limiting factors

Despite the enabling factors, several limiting factors pose specific challenges to São Vicente's energy transition, particularly concerning the role of hydrogen in seasonal storage. The extreme seasonality of wind and solar resources on São Vicente means periods of limited availability that necessitate robust energy storage for year-round demand satisfaction (Pombo et al., 2022). This seasonal mismatch is the primary driver for the need for long-term storage solutions like green hydrogen. Without effective hydrogen storage, achieving 100% RES with high reliability (as demonstrated in Scenario 4) becomes technically challenging and economically prohibitive.

Grid stability issues and transmission constraints also present significant hurdles. Island power systems typically feature low inertia and limited inter-connectivity, making them vulnerable to voltage and frequency instability when integrating a high penetration of variable RES (Ochoa et al., 2025). Achieving 100% RES, especially in São Vicente, would necessitate unavoidable transmission system expansion. These technical limitations directly impact the integration of large-scale renewable generation and the dynamic operation of hydrogen-based systems, requiring advanced grid management solutions. High upfront CAPEX are another major barrier. Achieving 100% RE by 2040 necessitates substantial upfront investment. Ambitious scenarios like São Vicente's "Green" pathway are projected to be the most expensive due to the need for "over-installation" of generation capacity and the high cost of energy storage solutions, particularly for hydrogen (Superchi et al., 2025). Mobilizing the required private investment is challenging due to perceived investment risks, high upfront costs, and a lack of affordable financing. This economic barrier is particularly relevant for Scenarios 3 and 4, where the significant capital expenditure for hydrogen infrastructure needs to be carefully managed and financed.

A limited local capacity and expertise further complicates the transition. There is a severe shortage of technical expertise and programmatic knowledge in the humanitarian energy nexus, exacerbated by high staff turnover and limited resources for energy programming (UNDESA, 2020). This extends to weak project preparation, implementation, and monitoring capacities. For São Vicente, this limitation could hinder the effective deployment and operation of complex hydrogen energy systems, impacting the long-term viability of the proposed solutions. Finally, there are specific challenges for São Vicente. The rapid growth of the tourism sector will impose additional pressure on the energy system, for example, with energy-intensive devices like air conditioning systems and increased water desalination needs, which represents the largest consumption in the system. São Vicente, like other islands in the archipelago, faces challenges due to the lack of grid connections among islands, limiting economies of scale for integrating variable energy generation. These specific local challenges underscore the need for tailored solutions and highlight the critical role of hydrogen in providing flexible and scalable energy to meet growing and diversified demand.

By understanding and strategically addressing these enabling and limiting factors, São Vicente Island can enhance the feasibility and long-term viability of its transition to a 100% RES, with green hydrogen playing a pivotal role in ensuring energy security and reliability, especially in managing seasonal RE variability and supporting the economic and technical robustness of Scenarios 3 and 4.

Chapter 5 Conclusion, Recommendations, and Limitations

5.1 Conclusion

This study examines the feasibility of achieving a 100% RES by 2040 on São Vicente Island, with green hydrogen serving as a crucial seasonal storage solution to address energy intermittency. Utilizing the COMANDO modeling framework, four distinct system configurations were developed and analyzed to assess their technical reliability, economic viability, and the strategic integration of green hydrogen technologies. The findings directly address the research questions posed at the outset of this thesis.

In response to the first research question, the comparative analysis of the four scenarios revealed significant differences in technical and economic performance. Scenarios without storage or with only short-term battery storage proved insufficient to ensure 100% reliability due to the pronounced seasonal variability of São Vicente's renewable resources. Conversely, the integration of green hydrogen, particularly in a hybrid configuration with batteries (Scenario 4), demonstrated its critical role in balancing seasonal supply and demand mismatches, thereby enhancing system reliability and achieving a 0% LPSP. This highlights hydrogen's unique capability to store excess renewable generation during periods of surplus (e.g., windy seasons) and ensure supply during leaner periods, a function that short-term storage alone cannot fulfill.

Regarding the second research question, the techno-economic analysis conclusively indicates that Scenario 4, which combines PV, wind, battery, and hydrogen technologies, offers the most balanced and optimal solution for São Vicente Island. This configuration not only met the stringent technical criteria of 0% LPSP and 100% RE share but also demonstrated superior economic indicators. With a competitive LCOE of 0.0503 €/kWh and a TAC of 6.97 million €/year, Scenario 4 significantly outperformed other configurations, reducing overall system costs by 25% compared to single-storage alternatives while virtually eliminating unmet demand. Sensitivity analysis further underscored the economic drivers, revealing that system costs are most sensitive to wind turbine and electrolyzer costs, emphasizing the importance of future cost reductions in these key components for enhancing the economic feasibility of hydrogen-integrated systems.

Finally, addressing the third research question, a qualitative assessment of long-term viability factors revealed a complex interplay of enabling and limiting conditions. São Vicente benefits from strong political equity, abundant renewable resources, and growing international support for its energy transition. However, significant challenges persist, including infrastructure readiness, high upfront capital costs, and limited local technical capacity. The study highlights that enabling policies, continuous grid modernization (e.g., through grid-forming inverters), and targeted investment in hydrogen and storage technologies will be essential for successful implementation. The strategic addressing of these factors is paramount for the long-term viability of a 100% RES system on the island.

In conclusion, this research demonstrates that achieving a 100% RES with green hydrogen as a seasonal storage solution on São Vicente Island is technically feasible, economically promising, and viable, provided that the identified enabling conditions are strategically leveraged and mitigating factors are proactively addressed. This case study of São Vicente Island contributes significantly to the broader literature on energy transitions in SIDS, offering a concrete example of how green hydrogen can address the unique challenges of seasonal RE variability. The findings serve as a valuable blueprint, providing practical insights and a robust analytical framework for other SIDS and potentially mainland African countries facing similar energy security and decarbonization imperatives. The strategic integration of hydrogen, as demonstrated here, offers a pathway to not only achieve energy independence but also to foster sustainable economic development in vulnerable island contexts.

5.2 Recommendations

Based on the techno-economic analysis and qualitative assessment conducted in this study, a multi-faceted approach is recommended, emphasizing the strategic role of green hydrogen to successfully transition São Vicente to 100% RES by 2040.

In the short-term (Immediate, 1-3 years), São Vicente should focus on establishing clear regulatory frameworks for green hydrogen, including certification and safety, to de-risk investments and foster market confidence. This involves initiating small-scale green hydrogen demonstration projects to build local capacity and showcase viability, alongside developing specialized training for a skilled workforce in green hydrogen technologies. Furthermore, implementing incentives for innovation and economies of scale in electrolyser manufacturing is crucial, as this addresses a key cost driver identified in the study.

For the medium-term (3-7 years), efforts should concentrate on upgrading grid infrastructure to effectively integrate renewables and hydrogen, incorporating smart grid solutions and grid-forming inverters (VSGs) for enhanced stability. A phased deployment of hybrid battery-hydrogen storage systems is recommended, given their proven optimal performance (0% LPSP, 100% renewable, LCOE 0.0503 €/kWh, TAC 6.97M €/year). Additionally, exploring green hydrogen applications in sectors like tourism and desalination will enhance economic viability and promote circular economy principles, while prioritizing strategic investments in advanced wind energy technologies and infrastructure will capitalize on São Vicente's resources and mitigate system costs.

Long-term (7+ years) strategies involve continuously expanding green hydrogen production, storage, and distribution to ensure seasonal energy security. This includes fostering a comprehensive green hydrogen ecosystem that extends its use to transportation and industry for broader economic and environmental benefits. Investigating inter-island electricity supply via stored hydrogen can further enhance regional energy security. Finally, establishing robust monitoring and adaptive management systems is essential to continuously adjust strategies based on evolving conditions and technological advancements, ensuring a sustainable energy transition.

5.3 Limitations

While this study offers valuable insights into the technical and economic feasibility of a 100% RES for São Vicente, several limitations must be acknowledged. The energy system modeling, conducted using the COMANDO framework, necessarily involved simplifications. Transmission infrastructure costs and spatial resource variability were not explicitly modeled, which may affect the accuracy of investment requirements and grid behavior under high penetration of renewables.

Moreover, although cost sensitivity analysis was conducted, future CAPEX and OPEX, particularly for hydrogen technologies, remain highly uncertain and dependent on global technological advancements and policy trajectories. These cost dynamics could materially influence the feasibility outcomes presented.

Another limitation concerns the sectoral scope of the study. While the electricity sector was thoroughly assessed, the modeling does not include cross-sectoral energy uses such as transportation, desalination, and industrial heating. These sectors are particularly relevant in the Cabo Verdean context. For example, São Vicente's growing tourism industry drives up electricity demand for cooling and hotel services, while desalination plants already account for one of the island's largest single energy loads. In addition, transportation remains heavily dependent on imported fossil fuels, and its decarbonization could significantly increase renewable electricity and hydrogen demand. Excluding these sectors may therefore underestimate total energy demand and the potential role of hydrogen in a fully decarbonized island energy system.

Finally, the qualitative assessment of enabling and limiting factors was based on secondary literature and institutional reports. Although this provides robustness and relevance, the inclusion of primary stakeholder consultations and localized data could have offered deeper insights into the socio-political and regulatory dynamics that will ultimately shape the island's energy transition.

References

Adams, M. J., Wadge, M. D., Sheppard, D., Stuart, A., and Grant, D. M. (2024). Review on onshore and offshore large-scale seasonal hydrogen storage for electricity generation: Focusing on improving compression, storage, and roundtrip efficiency. *International Journal of Hydrogen Energy*, 73:95–111. `https://doi.org/10.1016/j.ijhydene.2024.05.421`.

Aghaei, J. and others (2022). Optimal design and operation of energy system under uncertainty via two-stage stochastic programming. *Energy*, 249:123512. `https://doi.org/10.1016/j.energy.2022.123512`.

Akinsooto, O., Ogundipe, O. B., and Ikemba, S. (2024). Strategic policy initiatives for optimizing hydrogen production and storage in sustainable energy systems. *International Journal of Frontline Research and Reviews*, 2(2):001–021. `https://doi.org/10.56355/ijfrr.2024.2.2.0022`.

Ali, H., Hamdi, Z., Talabi, O., Pickup, G., and Nizam, S. (2022). Comprehensive approach for modeling underground hydrogen storage in depleted gas reservoirs. In *SPE Asia Pacific Oil and Gas Conference and Exhibition*, page D031S011R001. SPE. `https://doi.org/10.2118/210638-MS`.

Amoussou, I., Tanyi, E., Fatma, L., Agajie, T. F., Boulkaibet, I., Khezami, N., Ali, A., and Khan, B. (2023). The optimal design of a hybrid solar pv/wind/hydrogen/lithium battery for the replacement of a heavy fuel oil thermal power plant. *Sustainability*, 15(15):11510. `https://doi.org/10.3390/su151511510`.

ARME (2022). Relatório de energia elétrica 2022. Accessed: 2024-07-17. `https://www.arme.cv/`.

Bank, W. (2021). Discounting costs and benefits in economic analysis of world bank projects. `https://documents.worldbank.org`.

Bank, W. (2022). Cape verde country profile 2022. `https://www.worldbank.org/en/country/caboverde`.

Gado, M. G., Nasser, M., and Hassan, H. (2024). Potential of solar and wind-based green hydrogen production frameworks in african countries. *International Journal of Hydrogen Energy*, 68:520–536. `https://doi.org/10.1016/j.ijhydene.2024.04.272`.

Gesto Energia, S. (2011). Atlas e projetos de energias renováveis de cabo verde.

GlobalPetrolPrices (2025). Cape verde electricity prices. Accessed: 22 August 2025. `https://www.globalpetrolprices.com/Cape-Verde/electricity_prices/`.

Gurobi (2020). *Gurobi Optimizer Reference Manual.* Accessed: 2025-05-11. URL: http://www.gurobi.com.

Hiris, D., Balan, M. C., and Bode, F. I. (2024). A comprehensive review on enhancing seasonal energy storage systems through energy efficiency perspectives. *Processes*, 12(8):1623. https://doi.org/10.3390/pr12081623.

HOMER (2020). *HOMER Pro User Manual.* Accessed: 2024-07-17. https://www.homerenergy.com/.

Howells, M., Rogner, H., Strachan, N., Heaps, C., Huntington, H., Kypreos, S., Hughes, A., Silveira, S., DeCarolis, J., Bazillian, M., et al. (2011). Osemosys: the open source energy modeling system: an introduction to its ethos, structure and development. *Energy Policy*, 39(10):5850–5870. https://doi.org/10.1016/j.enpol.2011.06.033.

IEA (2017). Getting wind and sun onto the grid: A manual for policy makers. https://www.iea.org/reports/getting-wind-and-solar-onto-the-grid.

IEA (2022a). Global Hydrogen Review. Accessed: 2025-07-10. https://www.iea.org/reports/global-hydrogen-review-2022.

IEA (2022b). Renewable Power Generation Costs in 2021. Accessed: 2024-07-17. https://www.connaissancedesenergies.org/sites/connaissancedesenergies.org/files/pdf-pt-vue/IRENA_Power_Generation_Costs_2021_.pdf.

IEA (2023). World energy outlook. https://www.iea.org/reports/world-energy-outlook-2023.

IMF (2024). Cabo verde: Technical assistance report-climate policy assessment. https://www.elibrary.imf.org/view/journals/019/2024/040/article-A001-en.xml.

IRENA (2016). Path to prosperity: Renewable energy for islands, 3rd edition. https://www.ourenergypolicy.org/resources/a-path-to-prosperity-renewable-energy-for-islands-3rd-edition/.

IRENA (2018). Hydrogen from renewable power: Technology outlook for the energy transition. https://www.irena.org/publications/2018/Sep/Hydrogen-from-renewable-power.

IRENA (2019). Innovation landscape for a renewable-powered future: Solutions to integrate variable renewables. https://www.irena.org/publications/2019/Feb/Innovation-landscape-for-a-renewable-powered-future.

IRENA (2021). Renewable energy outlook: Cabo verde. https://www.irena.org/publications/2021/Nov/Renewable-Energy-Outlook-Cabo-Verde.

IRENA (2021). Renewable Power Generation Costs in 2020. Accessed: 2024-07-17. https://www.irena.org/publications/2021/Jun/Renewable-Power-Costs-in-2020.

IRENA (2022). Green Hydrogen: A Guide to Policy Making. Accessed: 2025-07-10. https://www.irena.org/publications/2022/Jan/Green-Hydrogen-Guide-to-Policy-Making.

Javed, M. S., Ma, T., Jurasz, J., Canales, F. A., Lin, S., Ahmed, S., and Zhang, Y. (2021). Economic analysis and optimization of a renewable energy based power supply system with different energy storages for a remote island. *Renewable Energy*, 164:1376–1394. https://doi.org/10.1016/j.renene.2020.10.063.

Katsivelakis, M., Bargiotas, D., Daskalopulu, A., Panapakidis, I. P., and Tsoukalas, L. (2021). Techno-economic analysis of a stand-alone hybrid system: Application in donoussa island, greece. *Energies*, 14(7):1868. https://doi.org/10.3390/en14071868.

Keiner, D., Thoma, C., Bogdanov, D., and Breyer, C. (2023). Seasonal hydrogen storage for residential on-and off-grid solar photovoltaics prosumer applications: Revolutionary solution or niche market for the energy transition until 2050? *Applied Energy*, 340:121009. https://doi.org/10.1016/j.apenergy.2023.121009.

Khan, A., Bressel, M., Davigny, A., Abbes, D., and Ould Bouamama, B. (2025). Comprehensive review of hybrid energy systems: Challenges, applications, and optimization strategies. *Energies*, 18(10):2612. https://doi.org/10.3390/en18102612.

Khare, V., Nema, S., and Baredar, P. (2020). Solar–wind hybrid renewable energy system: A review. *Renewable and Sustainable Energy Reviews*, 109:272–283. https://doi.org/10.1016/j.rser.2019.04.025.

Langiu, M., Shu, D. Y., Baader, F. J., Hering, D., Bau, U., Xhonneux, A., Müller, D., Bardow, A., Mitsos, A., and Dahmen, M. (2021). Comando: A next-generation open-source framework for energy systems optimization. *Computers & chemical engineering*, 152:107366. https://doi.org/10.1016/j.compchemeng.2021.107366.

Li, Y., Yang, Z., Li, G., Zhao, D., and Tian, W. (2018). Optimal scheduling of an isolated microgrid with battery storage considering load and renewable generation uncertainties. *IEEE Transactions on Industrial Electronics*, 66(2):1565–1575. https://doi.org/10.1109/TIE.2018.2840498.

Marouani, I., Guesmi, T., Alshammari, B. M., Alqunun, K., Alzamil, A., Alturki, M., and Hadj Abdallah, H. (2023). Integration of renewable-energy-based green hydrogen into the energy future. *Processes*, 11(9):2685. https://doi.org/10.3390/pr11092685.

Meschede, H., Bertheau, P., Khalili, S., and Breyer, C. (2022). A review of 100% renewable energy scenarios on islands. *Wiley interdisciplinary reviews: energy and environment*, 11(6):e450. https://doi.org/10.1002/wene.450.

MICE (2023). Relatório de energia 2023. https://www.ine.gov.mz/web/guest/d/relatorio-de-energia-_-agosto-2023.

Mulder, F. (2014). Implications of diurnal and seasonal variations in renewable energy generation for large scale energy storage. *Journal of Renewable and Sustainable Energy*, 6(3). https://doi.org/10.1063/1.4874845.

Muthukumar, P., Kumar, A., Afzal, M., Bhogilla, S., Sharma, P., Parida, A., Jana, S., Kumar, E. A., Pai, R. K., and Jain, I. (2023). Review on large-scale hydrogen storage systems for better sustainability. *International Journal of Hydrogen Energy*, 48(85):33223–33259. https://doi.org/10.1016/j.ijhydene.2023.04.304.

Mylonopoulos, F., Durgaprasad, S., Coraddu, A., and Polinder, H. (2024). Lifetime design, operation, and cost analysis for the energy system of a retrofitted cargo vessel with fuel cells and batteries. *International Journal of Hydrogen Energy*, 91:1262–1273. https://doi.org/10.1016/j.ijhydene.2024.10.235.

Nordman, E., Barrenger, A., Crawford, J., McLaughlin, J., and Wilcox, C. (2019). Options for achieving cape Verde's 100% renewable electricity goal: A review. *Island Studies Journal*, 14(1):41–58. https://doi.org/10.24043/isj.73.

Ochoa, D., Arévalo, P., and Martínez, S. (2025). Pathways to 100% renewable energy in island systems: A systematic review of challenges, solutions strategies, and success cases. *Technologies*, 13(5):180. https://doi.org/10.3390/technologies13050180.

Papathanasiou, A.-F. and Bertsiou, M. M. (2025). Achieving water and energy independence, economic sustainability, and co reduction through hybrid renewable systems: A case study of skyros island. *Water*, 17(9):1267. https://doi.org/10.3390/w17091267.

ParandehGheibi, A., Roozbehani, M., Dahleh, M. A., and Ozdaglar, A. (2015). The value of storage in securing reliability and mitigating risk in energy systems. *Energy Systems*, 6(1):129–152. https://doi.org/10.1007/s12667-014-0127-3.

Pfenninger, S., Hawkes, A., and Keirstead, J. (2014). Energy systems modeling for twenty-first century energy challenges. *Renewable and Sustainable Energy Reviews*, 33:74–86. https://doi.org/10.1016/j.rser.2014.02.003.

Pombo, D. V., Martinez-Rico, J., and Marczinkowski, H. M. (2022). Towards 100% renewable islands in 2040 via generation expansion planning: The case of são vicente, cape verde. *Applied Energy*, 315:118869. https://doi.org/10.1016/j.apenergy.2022.118869.

Ringkjøb, H. K., Haugan, P. M., and Solbrekke, I. M. (2018). A review of modelling tools for energy and electricity systems with large shares of variable renewables. *Renewable and Sustainable Energy Reviews*, 96:440–459. https://doi.org/10.1016/j.rser.2018.08.002.

Saeed, M., Jadhawar, P., and Bagala, S. (2023). Geochemical effects on storage gases and reservoir rock during underground hydrogen storage: a depleted north sea oil reservoir case study. *Hydrogen*, 4(2):323–337. https://doi.org/10.3390/hydrogen4020023.

Schneider, S., Velenderic, M., Staib, M., Küpper, E., and Severengiz, S. (2023). The potential of hydrogen-based storage systems in sub-saharan africa. In *International Renewable Energy Storage Conference (IRES 2022)*, pages 489–499. Atlantis Press. https://doi.org/10.2991/978-94-6463-156-2_31.

Segurado, R., Krajačić, G., Duić, N., and Alves, L. (2011). Increasing the penetration of renewable energy resources in s. vicente, cape verde. *Applied energy*, 88(2):466–472. https://doi.org/10.1016/j.apenergy.2010.07.005.

SGIE (2019). Produção de Electricidade por Fonte e Ilha (2021). Accessed: 2024-07-17. https://kb-wordpress.gov.cv/kb/category/eletrica/.

SGIE (2021). Produção de Electricidade por Fonte e Ilha (2021). Accessed: 2024-04-10. https://www.portalenergia.cv/produ%C3%A7%C3%A3o-de-eletricidade.

Singh, S. S. and Fernandez, E. (2018). Modeling, size optimization and sensitivity analysis of a remote hybrid renewable energy system. *Energy*, 143:719–731. https://doi.org/10.1016/j.energy.2017.11.053.

Sollai, S., Porcu, A., Tola, V., Ferrara, F., and Pettinau, A. (2023). Renewable methanol production from green hydrogen and captured co2: A techno-economic assessment. *Journal of CO2 Utilization*, 68:102345. https://doi.org/10.1016/j.jcou.2022.102345.

Staffell, I. and Pfenninger, S. (2016). Using bias-corrected reanalysis to simulate current and future wind power output. *Energy*, 114:1224–1239. https://doi.org/10.1016/j.energy.2016.08.068. https://www.renewables.ninja/.

Staffell, and Pfenninger (2024). Renewables.ninja: Renewable energy simulation platform. Accessed: 2024-07-17. https://www.renewables.ninja/.

Superchi, F., Bianchini, A., Moustakis, A., and Pechlivanoglou, G. (2025). Towards sustainable energy independence: A case study of green hydrogen as seasonal storage integration in a small island. *Renewable Energy*, 245:122813. https://doi.org/10.1016/j.renene.2025.122813.

Trakas, A., Papaefthymiou, S., and Dikaiakos, C. (2023). Techno-economic assessment of hybrid energy storage for insular grids. *Energy Reports*, 9:5072–5085. https://doi.org/10.1016/j.egyr.2023.04.020.

UNDESA (2020). Accelerating sdg 7 achievement in small island developing states. Technical report, United Nations Department of Economic and Social Affairs. https://sdgs.un.org/publications/accelerating-sdg-7-achievement-small-island-developing-states-2020.

UNDP (2024). Small island developing states are on the frontlines of climate change: here's why. https://climatepromise.undp.org/news-and-stories/small-island-developing-states-are-frontlines-climate-change-heres-why.

Wang, W., Liu, J., Cao, Y., Zhou, D., Zhou, Z., and Wang, W. (2021). Optimal design and operation of multi-carrier energy system under uncertainty via two-stage stochastic programming. *Journal of Cleaner Production*, 294:126237. https://doi.org/10.1016/j.jclepro.2021.126237.

Worighi, I., Maach, A., Hafid, A., Hegazy, O., and Van Mierlo, J. (2019). Integrating renewable energy in smart grid system: Architecture, virtualization and analysis. *Sustainable Energy, Grids and Networks*, 18:100226. https://doi.org/10.1016/j.segan.2019.100226.

World Bank (2024). Assessment on the Role of Green Hydrogen in Cabo Verde's Energy Transition. Accessed: 21 August 2025.

WorldBank (2024). Cabo verde energy sector management assistance program. https://www.worldbank.org/en/country/caboverde/overview.

Yang, T., Liu, W., Kramer, G. J., Sun, Q., et al. (2021). Seasonal thermal energy storage: A techno-economic literature review. *Renewable and Sustainable Energy Reviews*, 139:1–22. https://doi.org/10.1016/j.rser.2021.110732.

DECLARATION OF AUTHORSHIP

I, ***Abdulazeez ILYASU***, declare that this thesis and the work presented in it are my own and have been generated by me as the result of my own original research.

I do solemnly swear that:

1. Where I have consulted the published work of others or myself, this is always clearly attributed;
2. Where I have quoted from the work of others or myself, the source is always given. This thesis is entirely my own work, with the exception of such quotations;
3. I have acknowledged all major sources of assistance;
4. Where the thesis is based on work done by myself jointly with others, I have made clear exactly what was done by others and what I have contributed myself;
5. None of this work has been published before submission;
6. During the preparation of this work, I used QuillBot and DeepL in order to edit the writing of the thesis. After using this tool, I reviewed and edited the content as needed and take full responsibility for the content.

Date: 24.08.2025 **Signature:**

Declaration of the Use of Artificial Intelligence in Scientific Theses

ILYASU, Abdulazeez	20230C7E3
Surname, First name	Matriculation Number

I hereby certify that I have written this thesis independently and,

A. with the help of ☑

B. without the help of ☐

an artificial intelligence (AI) program, such as: ChatGPT, DALL-E2, Stable Diffusion, Looka, etc.

If option A has been ticked, the following declaration is also required:

☐ I declare that all AI programs used for this work have been carefully cited in the text and in the bibliography. The screenshots and usage information have also been presented in detail in the appendix "AI-generated content".

☑ I declare that for this document AI assistance was undertaken solely for grammatical improvements. No citations were provided for text generated by an AI, as no content was created or significantly modified.

I have reviewed all the inclusions and modifications made with the assistance of AI in this thesis and take full responsibility for the accuracy of the content.

Dakar, 24.08.2025

Place, Date

Signature