Feasibility Study on Green Hydrogen Potential in Maldives

Feasibility Study Report

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Contents

Executive Summary 4

1. Introduction 6
  1.1 Project Context 6
  1.2 Maldives Vulnerability Context 6
  1.3 Hydrogen for a Small Island State 6
  1.4 Study Scope and Approach 7
  1.5 Report Structure 7
  1.6 Limitations and Key Assumptions 8

2. Green Hydrogen Production 9
  2.1 Renewable Energy Potential 9
  2.2 Technology Selection 9
  2.3 Production Cost Curve 10
  2.4 Water Requirements 12
  2.5 Optimal Site Identification 13

3. Transport and Storage 13
  3.1 The Logistics Challenge 13
  3.2 Storage Technology Assessment 14
  3.3 Hub-and-Spoke Distribution Model 14
  3.4 Combined Cost Curve 15

4. Utilization and Deployment 15
  4.1 National Fossil Fuel Baseline 15
  4.2 Hydrogen Demand Methodology 16
  4.3 Use Case Prioritization 16
  4.4 Power Generation: The Anchor Use Case 17
    Deployment Archetypes for Power Generation 19
  4.5 Marine Transport: The Strategic Complement 19
    Deployment Approach for Marine Transport 21
  4.6 Road Transport 21
  4.7 Aviation 21
  4.8 Demand by Use Case and Adoption Dynamics 21

5. Investment Roadmap 23
  5.1 Capital Requirements 23
  5.2 Phased Implementation Strategy 24
  5.3 GHG Impact and NDC Alignment 25

5.4 Policy Support Requirements 26
6. Conclusions and Next Steps 27
6.1 Key Conclusions 27
6.2 Complimentarily with Other Pathways 27
6.3 Scope for the National GH2 Roadmap 28
Annex A: Methodology and Assumptions 29
A.1 Analytical Approach 29
A.2 Key Technology Assumptions 29
A.3 CAPEX Learning Curves 31
A.4 Diesel Baseline Parameters 32
A.5 Confidence Assessment 33
Annex B: LCOH Detailed Calculations 33
B.1 Production LCOH by Plant Scale 33
B.2 Medium Plant (3 MW) Annual Cost Breakdown 34
B.3 Landed Cost (Production + Storage & Transport) 34
B.4 Waste-to-Hydrogen Alternative Pathway 34
B.5 LCOH Sensitivity Analysis 35
Annex C: Storage and Transport Technical Assessment 36
C.1 Technology Comparison Matrix 36
C.2 Transport Cost Breakdown 36
C.3 Buffer Storage Requirements 37
C.4 Storage and Transport Cost Curve 37
Annex D: Use Case TCO Analysis 38
D.1 U1: Power Generation (600 kW FENAKA Reference) 38
D.2 U2: Marine Transport (400 kW MTCC Ferry) 40
D.3 U3: Road Transport (Light Truck) 41
D.4 U4: Aviation (SAF Pathway) 42
Annex E: Deployment Archetypes: Detailed Economics 42
E.1 Archetype 1: FENAKA Outer Island Microgrid 43
E.2 Archetype 2: Resort Hydrogen Integration 43
E.3 Archetype 3: STELCO Ammonia Co-firing 44
Annex F: Stakeholder Consultation Summary 44
Annex G: Acronyms and Abbreviations 45
Annex H: References 48

Executive Summary

The Maldives, a small island developing state, faces acute energy challenges driven by its heavy reliance on imported fossil fuels, geographically dispersed islands, and high cost of electricity generation. With a strong national commitment to climate action and net-zero ambitions, the country is actively exploring pathways to transition toward a low-carbon and energy-secure future. Green hydrogen (GH2) therefore presents a potential long-term option for deep decarbonization across hard-to-abate sectors, supporting renewable energy integration and reducing dependence on fuel imports, especially in applications such as marine transport, backup power, and remote island energy systems.

This feasibility study evaluates whether green hydrogen can play a material role in decarbonizing the Maldives' energy system. The analysis is built on a purpose-built techno-economic analysis, validated through industry consultations with STELCO, FENAKA, the Ministry of Tourism and Environment (MOTE), MTCC, resort operators, and government advisors during a February 2026 mission visit.

The central finding is that **green hydrogen achieves cost parity with diesel for power generation by approximately 2030 without subsidy, and as early as 2025 with policy support**. Few comparable island-state projections show parity within this timeframe. The Maldives' exceptionally high diesel costs ($0.42–0.60/kWh), strong solar irradiance (capacity factor ~20%), and lack of grid interconnection alternatives all contribute to this favourable outlook**Error! Bookmark not defined.**.

Table ES-1: Key Findings at a Glance (2030, Medium Scenario)

Metric	Value
Hydrogen demand	4,610 t/yr
Electrolyzer capacity required	82.7 MW
Solar PV required	144.7 MW
Cumulative investment (2026–2030)	$198 M
Landed hydrogen cost	$6.68/kg
CO_2 avoided	71 kt/yr
Contribution to NDC 3.0 target	4.7%

Production: Green hydrogen production using PEM electrolysis coupled to dedicated solar PV is technically feasible across all island scales. Production LCOH ranges from $7.43/kg (2025) to $3.18/kg (2035) for a reference 3 MW plant, with modest scale effects; a 45 MW facility achieves only $0.36/kg lower cost than a 0.15 MW micro-unit. A distributed production model is therefore suited to the Maldives' geography. An alternative waste-to-hydrogen gasification pathway at Thilafushi offers a potentially lower-cost option ($5.05/kg production) while also handling waste management.

Transport and Storage: Compressed gaseous hydrogen at 350 bar is the recommended near-term storage and distribution method, transported via marine tube trailers in a hub-and-spoke network. The combined storage and transport cost of $2.35/kg (2030) adds roughly 35% to production cost and declines to $2.00/kg by 2035. Liquid hydrogen and LOHC technologies are not justified at current demand scales but should be evaluated post-2030.

Utilization: Four end-use sectors are assessed. Power generation (score 19/20) and marine transport (17/20) emerge as the primary deployment opportunities, together accounting for over

90% of projected demand and GHG reductions. Power generation achieves cost parity by approximately 2030 without subsidy; marine transport (via H_2-ICE conversion) achieves parity by approximately 2028 with policy support. Road transport and aviation are classified as low-priority and long-term respectively.

Table ES-2: Use Case Summary

Use Case	H2 Demand 2030 (t/yr)	Share	Score(/20)	Priority	Cost Parity
Power Generation	3,691	80%	19	PRIMARY	~2025 w/policy; ~2030 w/o (flat); ~2029 w/market esc.
Marine Transport	511	11%	17	PRIMARY	~2028 w/policy; ~2036 w/o (flat); ~2032 w/market esc.
Aviation (SAF)	363	8%	5	LONG-TERM	~2036 w/policy; ~2042 w/o (flat); ~2038 w/market esc. (SAF); ~2029 (FC seaplane)
Road Transport	44	1%	11	LOW	~2028 w/policy; ~2035 w/o (flat); ~2032 w/market esc.

Investment: The cumulative capital requirement is $198 million through 2030 and $485 million through 2035, dominated by solar PV (~55%) and electrolyzers (~25%). A three-phase deployment: pilot (2026–27), scale-up (2028–30), and expansion (2030–35) aligns with climate finance mobilization timelines and progressively de-risks the investment case.

Emissions Impact: The medium scenario avoids 71 kt CO_2/yr by 2030 and 105 kt by 2035, contributing approximately 4.7% by 2030 and 6.9% by 2035 toward the NDC 3.0 target of 1.52 Mt reduction. Power generation delivers ~89% of hydrogen-related GHG reductions.

Power generation and marine transport should anchor a phased deployment strategy, starting with 1–2 pilot projects in 2026–2027 and scaling through regional hubs by 2030. This report focuses on interpretation, findings, and recommendations; detailed inputs and calculations are provided in the Annexures.

1. Introduction

1.1 Project Context

The Maldives faces a structural energy challenge unlike most nations. Across 200 inhabited islands, there is no interconnected grid and each island operates an independent diesel generator, importing 100% of its fuel. The national energy bill exceeds $500 million annually, representing roughly 10% of GDP, and exposes the economy to volatile global commodity prices. The World Bank estimates that fuel imports constitute the single largest item on the national import bill, creating a persistent current account drain that constrains fiscal space for development investment.

This study was commissioned under the UNEP-CTCN Technical Assistance programme to assess whether green hydrogen can offer a cost-effective, low-carbon alternative to diesel dependence. It was executed in partnership with the Ministry of Environment, Climate Change and Technology (MECCT), the Ministry of Energy and Infrastructure (MEI), and the Sustainable Energy Authority of the Maldives (SEAM). The work draws on a February 2026 mission visit that included site assessments and consultations across Greater Malé, resort islands (Soneva, Veligandu), and utility operators (STELCO, FENAKA, MTCC).

Note: Following the November 2023 government restructuring, ministerial portfolios were reorganized. This report uses MECCT (Ministry of Environment, Climate Change and Technology), MEI (Ministry of Energy and Infrastructure), and MOTE (Ministry of Tourism and Environment) as referenced by respective stakeholders during consultations. These may not reflect current ministerial naming.

1.2 Maldives Vulnerability Context

The Maldives comprises 1,190 coral islands distributed across 26 atolls spanning 900 kilometers of the Indian Ocean, with a combined land area of only 300 km^2 and a total population of 515,132 (Census 2022). Approximately 250,000 residents are concentrated in the Greater Malé area (~50% of population). This extreme geographic dispersion creates substantial energy challenges:

- **No interconnected grid:** 200 inhabited islands must each be served by independent power systems. There is no prospect of submarine cable interconnection at current economics, meaning each island must generate or store its own electricity
- **High unit energy costs:** Outer island diesel generation (FENAKA network) costs $0.42–0.60/kWh, among the highest in the world. Greater Malé (STELCO) achieves somewhat lower costs ($0.30–0.35/kWh) through larger, more efficient generators, but remains far above global averages
- **Complete import dependence:** The Maldives imports 100% of its fossil fuels. Annual diesel and petrol imports total approximately 786 million liters, exposing the economy to international price volatility, shipping disruptions, and supply chain risks
- **Tourism-dependent economy:** Tourism contributes ~28% of GDP and approximately 60% of foreign exchange earnings. The 190 operational resort islands each run autonomous diesel generators (50 kW to 5 MW), creating both a cost burden and a sustainability branding opportunity
- **Climate frontline:** As the world's lowest-lying nation (average elevation 1.5 meters), the Maldives faces existential climate risk. Decarbonization is both a policy imperative and a matter of national credibility in international climate negotiations

1.3 Hydrogen for a Small Island State

Several characteristics make hydrogen especially relevant for the Maldives context, distinct from the rationale in continental economies:

- **Extremely high diesel costs create a wide economic window:** Outer island power generation at $0.42–0.60/kWh means hydrogen does not need to reach global cost targets ($2–3/kg) to be competitive. Even at $6–7/kg landed cost, hydrogen fuel cells can undercut diesel in the Maldives; a threshold achievable by 2030
- **No grid interconnection alternative:** Unlike continental nations, the Maldives cannot import electricity or build inter-island transmission. Each island must generate or store its own power, favoring dispatchable fuels like hydrogen over batteries alone for multi-day reliability
- **Seasonal storage gap:** Solar PV alone cannot address monsoon-season variability (May–November), when consecutive cloudy days can reduce solar output by 40–60%. Hydrogen offers multi-day energy storage that batteries cannot economically provide at the required durations (3–7 days)
- **Marine economy dependence:** Over 140 million liters of diesel are consumed annually in marine transport: ferries, cargo vessels, fishing boats, and resort boats. Hydrogen (via fuel cells or H_2-ICE conversion) offers a decarbonization pathway for this important sector, where battery-electric solutions face range and weight constraints
- **NDC commitments require action:** The Maldives' NDC 3.0 targets a 1.52 Mt CO_2 reduction by 2035. Current renewable energy deployment (primarily rooftop solar) is insufficient to meet this target. Hydrogen can contribute approximately 4.7% by 2030 and 6.9% by 2035 through power and marine applications alone, while signalling leadership among SIDS nations

1.4 Study Scope and Approach

The study evaluates the full hydrogen value chain (production, storage, transport, and end-use) through a purpose-built techno-economic model. The analytical framework links three analytical layers:

- **Part 1: Demand:** Establishes the fossil fuel baseline by sector, calculates efficiency-adjusted hydrogen equivalent demand, projects adoption using an S-curve penetration model, and sizes production infrastructure
- **Part 2: Supply costs:** Calculates Levelized Cost of Hydrogen (LCOH) across five plant scales, applies CAPEX learning curves for electrolyzers and solar PV, and models storage and transport costs for the hub-and-spoke distribution network
- **Part 3: Use case economics:** Compares Total Cost of Ownership (TCO) for diesel business-as-usual (BAU) against hydrogen bridge-to-beyond (BTB) scenarios for each of four end-use sectors, incorporating both unassisted and policy-supported cost trajectories

The analysis is internally consistent: production costs feed into adoption projections, which in turn determine demand volumes and infrastructure sizing. All outputs, costs, demand, and capacity, are aligned within each scenario.

Four end-use sectors are assessed: power generation, marine transport, road transport, and aviation (via Sustainable Aviation Fuel). Each is scored against a multi-criteria scoring method covering economic gap, technology readiness, GHG impact, and strategic alignment with national priorities.

This report presents findings and interpretation; detailed calculations, input assumptions, and sensitivity analyses are provided in the Annexures.

1.5 Report Structure

The report is organized in two parts:

- **Core Report (Chapters 1–6):** Presents key findings, interpretive analysis, and recommendations in an accessible format. Tables and figures carry quantitative detail; prose focuses on what the numbers mean and what decisions they imply. Each major section concludes with a summary of the most important insight.
- **Annexures (A–G):** Provide detailed analytical documentation, full TCO calculations, archetype economics, stakeholder consultation findings, and technical specifications for readers who require detailed data.

1.6 Limitations and Key Assumptions

This study is a pre-feasibility assessment intended to inform policy direction and investment planning. It is not a detailed engineering design or bankable project proposal. Key limitations include:

- **Cost projections rely on global learning curves:** Electrolyzer and solar PV cost trajectories are based on IRENA global projections and may differ from actual Maldives procurement costs due to logistics premiums, small order volumes, and import duties[1]
- **Demand projections are scenario-dependent:** The S-curve adoption model is sensitive to assumptions about cost parity timing and policy support. Actual demand will depend on pilot project outcomes, regulatory structures, and commitment from key players
- **Site-specific engineering not included:** Plant sizing and cost estimates are indicative. Detailed engineering, environmental impact assessment, and grid integration studies are required before any deployment decision
- **No financial structuring:** The study identifies capital requirements but does not model specific financing instruments, debt-equity structures, or climate finance mechanisms. This is addressed in Phase 3 (National GH2 Roadmap)

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[1] IRENA (2024), Green Hydrogen Cost Reduction: Scaling up Electrolysers to Meet the 1.5°C Climate Goal, International Renewable Energy Agency, Abu Dhabi.

2. Green Hydrogen Production

2.1 Renewable Energy Potential

The Maldives' solar resource has strong potential for hydrogen production. Ground-truth data from resort installations (Soneva reports 8–9 hours of peak solar daily; Veligandu has operational solar-diesel hybrid systems) and the World Bank's ASPIRE program confirm a PV capacity factor of approximately 20%, corresponding to 1,750–1,800 kWh/kWp/yr. These figures are comparable to leading solar markets globally; southern Spain, parts of India, and northern Australia; and sufficient to support electrolyzer operations at competitive economics.[2]

Wind resources are limited in the Maldives (average wind speeds of 4–5 m/s are below commercial viability thresholds of 6+ m/s), and tidal/wave energy remains at demonstration stage. Solar PV is therefore the only commercially proven renewable resource for hydrogen production in the near term. The ASPIRE program has demonstrated competitive solar PPA rates at $0.098/kWh, providing a validated benchmark for production cost modeling.[3]

The binding constraint is not solar quality but **land availability**. At current technology densities (~2 hectares per MW), the 2030 medium scenario requires approximately 290 hectares of solar PV; significant for a nation with only 300 km^2 of total land area. Several strategies can address this:

- **Rooftop solar:** Greater Malé has significant untapped rooftop area. STELCO's existing net metering framework could be extended to hydrogen production facilities
- **Floating solar:** Lagoon-based floating PV is increasingly commercial globally and particularly suited to the Maldives' calm, shallow reef lagoons. Several resort operators have expressed interest in pilot installations
- **Dual-use land:** Co-location of solar arrays with agriculture, aquaculture, or desalination facilities can maximize land productivity on constrained island sites
- **Dedicated energy islands:** The Maldives has numerous uninhabited sand banks and reclaimed land areas (notably near Thilafushi) that could be designated for energy infrastructure

Solar irradiance is not a bottleneck for hydrogen production. Land use planning and permitting are the key variables for scaling solar-powered electrolysis. The 20% capacity factor is well-validated and provides a reliable basis for cost projections.

2.2 Technology Selection

The study evaluates three electrolyzer technologies against Maldives-specific requirements:

- **Alkaline Electrolysis (AEL)** is the most mature technology with the lowest capital cost ($500–600/kW for large units). It is suited for steady-state operation at centralized facilities (Greater Malé hub) where constant power supply can be maintained. However, AEL systems respond more slowly to changes in power input and need to run at higher minimum output levels, making them less suited to direct solar coupling where power fluctuates throughout the day.[4][5][6]

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[2] Stakeholder consultations conducted during the February 2026 mission visit: STELCO, FENAKA, MTCC, Soneva, Veligandu, MWSC.

[3] World Bank, ASPIRE (Accelerating Sustainable Private Investments in Renewable Energy) Programme, Maldives.

[4] IRENA (2024), Green Hydrogen Cost Reduction: Scaling up Electrolysers to Meet the 1.5°C Climate Goal, International Renewable Energy Agency, Abu Dhabi.

[5] Hydrogen Insight (2024), "Auction results reveal that Chinese hydrogen electrolysers are two to five times cheaper to buy than Western machines." China Energy Engineering Group tender: ALK at ~$210/kW, PEM at ~$630/kW.

- **Proton Exchange Membrane (PEM)** electrolysis responds quickly to changing solar conditions and can operate efficiently across a wide power range, critical for the Maldives where most installations will be directly solar-coupled without intermediate battery buffering. PEM systems occupy roughly half the floor space of equivalent Alkaline units, an advantage on space-constrained islands. They currently carry a 15–25% CAPEX premium over AEL but the gap is narrowing rapidly with manufacturing scale-up.

- **Solid Oxide Electrolysis (SOEC)** offers the highest theoretical efficiency (40–45 kWh/kg vs. 55 kWh/kg for PEM) but requires high-temperature heat input (700–900°C) and remains at limited commercial maturity. Not recommended for near-term Maldives deployment.

For the Maldives context, **PEM electrolysis is recommended** for distributed installations (resorts, outer islands) where solar variability handling is critical. Alkaline systems are suitable for larger centralized plants (Greater Malé hub) where solar-plus-battery configurations can provide more stable input power.

Waste-to-Hydrogen Alternative

An alternative production pathway; **waste-to-hydrogen gasification at Thilafushi**, merits special attention. Thilafushi island currently receives approximately 830 tonnes per day of municipal solid waste from Greater Malé, creating severe environmental and health concerns. Gasification technology can convert this waste stream into syngas, from which hydrogen is extracted. Preliminary modelling suggests a production LCOH of ~$5.05/kg; 32% below conventional electrolysis (2025); while simultaneously handling the Maldives' pressing waste management challenge. This pathway is not included in the base case due to technology maturity considerations but is flagged as a high-potential complementary option warranting detailed engineering assessment.

2.3 Production Cost Curve

Hydrogen production costs in the Maldives follow global learning curves but start from a higher base than continental projects due to island logistics premiums (shipping, installation on remote islands, limited local technical workforce). The analysis models five plant scales, from micro (0.15 MW, single resort) to very large (45 MW, export facility), across the 2025–2035 horizon.

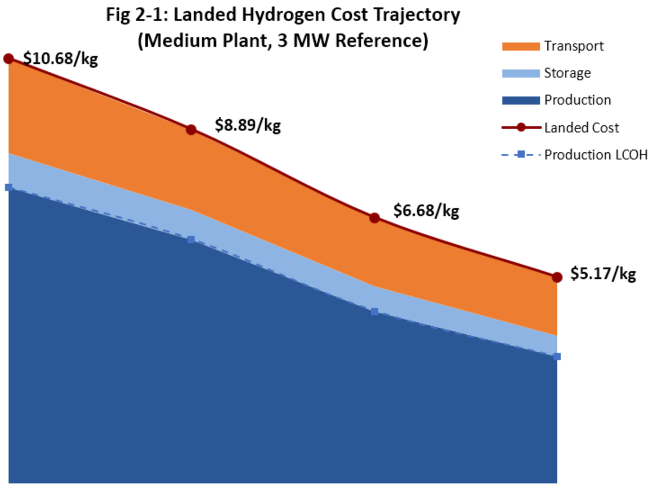

Figure 2-1: Landed Hydrogen Cost Curve

Source: pManifold analysis

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[6] Wood Mackenzie (2024), "The competitive edge of China's electrolysers." Chinese electrolyser CAPEX ~73% lower than global benchmark.

Table 2-1: LCOH Cost Curve; Medium Plant (3 MW)

Component	2025	2028	2030	2035
Electrolyzer CAPEX ($/kW)	600	480	384	307
Solar PV CAPEX ($/kW)	900	750	500	350
Solar PPA rate ($/kWh)	0.10	0.08	0.065	0.05
Total annual cost ($/yr)	1,241,922	1,024,422	723,111	531,028
Production LCOH ($/kg)	7.43	6.13	4.32	3.18
Storage cost ($/kg)	0.87	0.74	0.63	0.54
Transport cost ($/kg)	2.38	2.03	1.72	1.46
Landed cost ($/kg)	**10.68**	**8.89**	**6.68**	**5.17**
Cost decline vs. 2025	**-**	**-17%**	**-37%**	**-52%**

Source: pManifold analysis

The production LCOH declines 57% over the decade, driven by three factors operating in parallel:

- **Electrolyzer CAPEX reductions:** From $600/kW (2025) to $307/kW (2035), reflecting a ~15% cost reduction per doubling of global installed capacity. This learning rate is consistent with IRENA's central projection and supported by announced manufacturing capacity expansions in China, Europe, and India[7][8][9][10][11]
- **Solar PV cost declines:** From $900/kW to $350/kW installed, consistent with ASPIRE program benchmarks and global PV module price trends. The Maldives benefits from the fact that module costs (which drive most of the decline) are globally traded commodities[12]
- **Improving electricity costs:** Solar PPA rates declining from $0.10 to $0.05/kWh as installation efficiencies improve and module costs fall

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[7] IRENA (2024), Green Hydrogen Cost Reduction: Scaling up Electrolysers to Meet the 1.5°C Climate Goal, International Renewable Energy Agency, Abu Dhabi.

[8] IEA (2025), Global Hydrogen Review 2025, International Energy Agency, Paris.

[9] Hydrogen Insight (2024), "Auction results reveal that Chinese hydrogen electrolysers are two to five times cheaper to buy than Western machines." China Energy Engineering Group tender: ALK at ~$210/kW, PEM at ~$630/kW.

[10] S&P Global Commodity Insights (2024), "China's hydrogen ambitions may ride on Sinopec's Kuqa project in Xinjiang," 11 January 2024. Sinopec Kuqa: 260 MW alkaline electrolysis, $470M project.

[11] SECI (2025), Results of Auction under SIGHT Programme Mode-1, Tranche-II for Green Hydrogen Production, Solar Energy Corporation of India. 450,000 MT/yr capacity awarded.

[12] World Bank, ASPIRE (Accelerating Sustainable Private Investments in Renewable Energy) Programme, Maldives.

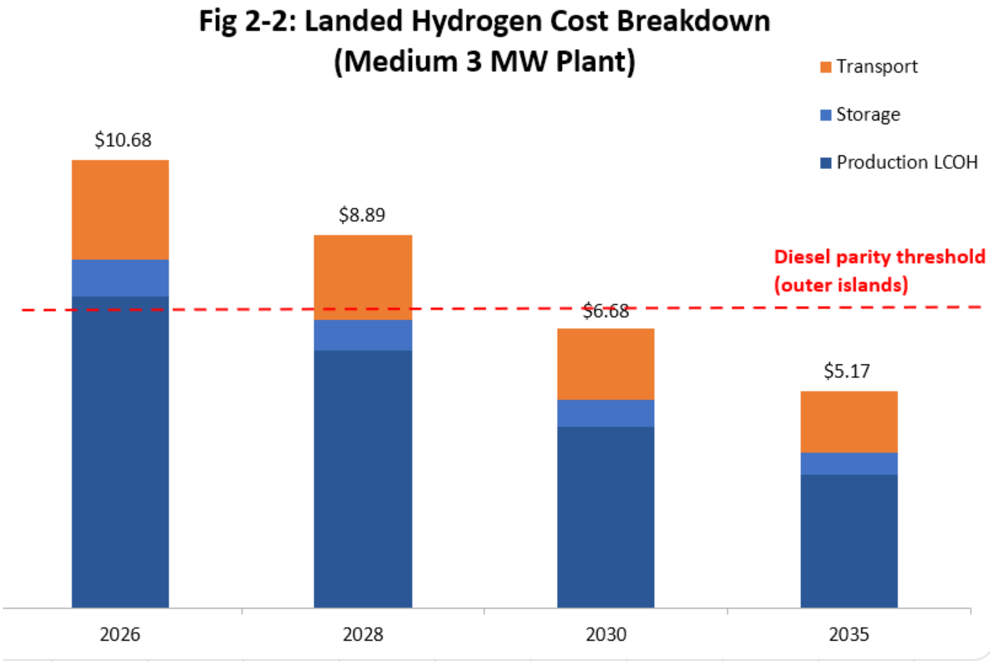

Figure 2-2: Landed Hydrogen Cost Breakdown

Source: pManifold analysis

Scale effects are modest. The cost penalty for smaller plants is less than $0.40/kg even at the smallest scale, and narrows over time as equipment costs decline (see Annex B for the full scale comparison). This is a critical finding for the Maldives: it means a distributed deployment model with many smaller plants across islands is not significantly cost-penalized relative to centralized mega-facilities.

Landed hydrogen costs fall below $7/kg by 2030 and approach $5/kg by 2035. The cost decline is driven more by global technology learning rates than by Maldives-specific factors, providing confidence in the projections. The modest scale penalty supports the distributed hub-and-spoke production model suited to the archipelago geography.

2.4 Water Requirements

Water for electrolysis is manageable but requires planning. Standard electrolysis consumes approximately 9 liters of purified water per kilogram of hydrogen produced. At projected 2030 demand levels, annual water consumption for electrolysis is equivalent to the daily usage of roughly 3,400 people; a small fraction of existing desalination capacity.

The Greater Malé Water and Sewerage Company (MWSC) operates desalination plants with a combined capacity well in excess of requirements. Co-located desalination at hydrogen production sites adds less than 1% to LCOH (water cost at $5/m^3 contributes approximately $0.045/kg to hydrogen cost).

Future climate risks; including saltwater intrusion into groundwater lenses, changing monsoon rainfall patterns, and potential damage to desalination infrastructure from extreme weather events; can be mitigated through dedicated reverse osmosis (RO) desalination units at each production hub, sized with appropriate contingency margins. The energy penalty for seawater desalination (approximately 4 kWh/m^3) is modest relative to the 55 kWh/kg required for electrolysis itself.

2.5 Optimal Site Identification

The analysis identifies production sites using a multi-criteria scoring framework that considers solar resource, land availability, proximity to demand centers, existing infrastructure (port access, grid connection, water supply), and environmental constraints.

Table 2-2: Plant Deployment by Region (2030, Medium Scenario)

Location	Share of Demand	Plant Type	Electrolyzer (MW)	Solar PV (MW)
Greater Malé Hub	55%	1 × Large	45.5	79.6
Addu City Hub	12%	1 × Medium	9.9	17.4
Resort Islands (10 lead)	18%	10 × Micro	14.9	26.0
Inhabited Islands (5)	10%	5 × Small	8.3	14.5
Industrial Islands	5%	1 × Medium	4.1	7.2
Total	**100%**	**18 plants**	**82.7**	**144.7**

Source: pManifold analysis

Greater Malé Hub is the priority production site, serving 55% of national demand. The Thilafushi–Gulhifalhu–Malé industrial corridor offers the largest contiguous land areas, port access, and proximity to STELCO's power plants. A single large plant (15 MW class, expandable to 45 MW by 2030) anchors the national production infrastructure.

Addu City Hub serves as the southern regional production center, supporting the Addu atoll population and southern resort cluster. Addu has existing port infrastructure, a domestic airport, and the largest contiguous land area outside Greater Malé.

Resort micro-plants (10 lead islands) are distributed across atolls, producing hydrogen on-site using dedicated solar arrays. Lead candidates include resorts that have expressed interest in hydrogen pilots (Soneva Fushi, Soneva Jani, Six Senses Laamu) and resorts with existing solar infrastructure (Veligandu, Kuramathi).

The recommended deployment follows a hub-and-spoke model: centralized production at Greater Malé and Addu serves the bulk of demand, while distributed micro-plants at resorts and outer islands serve local needs. This mirrors the existing diesel supply chain and uses current port and logistics infrastructure.

3. Transport and Storage

3.1 The Logistics Challenge

The Maldives' archipelago geography makes hydrogen distribution materially different from continental contexts. There are no pipelines, no rail networks, and no highway trucking corridors. Every kilogram of hydrogen consumed on an outer island must be produced at or transported to that location by sea, stored under pressure, and buffered against monsoon-season disruptions that can interrupt inter-island shipping for 3–5 consecutive days.

This logistics reality shapes every aspect of system design: storage technology selection, buffer sizing, transport vessel requirements, and ultimately the cost of delivered hydrogen. The storage and transport (S&T) component adds $2.35/kg to production cost in 2030; roughly 35% of the total landed price; making it the second-largest cost driver after electrolyzer CAPEX. Reducing S&T costs through operational efficiency and scale is therefore a critical priority.

3.2 Storage Technology Assessment

Three storage technologies were evaluated against Maldives-specific criteria including maturity, cost, energy density, safety profile, and compatibility with marine transport:

- **Compressed gaseous hydrogen (350 bar):** The recommended near-term solution. This is proven technology with a well-established safety record, compatible with existing marine vessel logistics, and cost-effective at the demand volumes projected through 2030. Storage CAPEX is approximately $500/kg of storage capacity. The primary limitation is low volumetric energy density (1.1 MJ/L), which constrains the payload of each marine tube trailer shipment to 200–500 kg
- **Liquid hydrogen (LH$_2$):** Liquefaction provides far higher energy density (8.5 MJ/L) but imposes severe energy penalties; approximately 30% of the hydrogen's energy content is consumed in the liquefaction process. At current demand scales (<10,000 t/yr), the capital cost of liquefaction equipment cannot be justified. This technology should be re-evaluated post-2030 as demand volumes grow and if export pathways develop
- **Liquid Organic Hydrogen Carriers (LOHC):** An emerging technology that stores hydrogen in organic molecules (typically toluene/methylcyclohexane) at ambient temperature and pressure. Potentially attractive for longer inter-atoll routes where compressed gas transport becomes inefficient, but dehydrogenation infrastructure at the consumption point adds complexity and cost. Recommended for pilot evaluation during Phase 2 (2028–2030)

Ammonia (NH$_3$) is evaluated separately as a fuel option rather than a pure carrier. Ammonia can be used directly in modified diesel engines (STELCO co-firing archetype) or cracked back to hydrogen at the point of use. It offers higher energy density than compressed hydrogen (3.6 MJ/L) and can use existing bulk liquid handling infrastructure. The STELCO ammonia co-firing pathway is assessed in detail in Annex E.

3.3 Hub-and-Spoke Distribution Model

The recommended distribution model mirrors the Maldives' existing supply chain for diesel fuel: centralized storage at 2–3 hub locations, with marine tube trailers distributing to outer islands on scheduled routes. The analysis draws directly on current diesel distribution logistics; the same vessels, ports, and route networks can be adapted for hydrogen transport with appropriate safety modifications.

Key design parameters derived from industry consultations and operational analysis include:

- **3-day storage buffer** at each consumption point, sized to manage monsoon-season shipping interruptions. This requirement was validated through consultation with MTCC logistics teams, who confirmed that inter-island shipping can be disrupted for 3–5 consecutive days during southwest monsoon (May–September)
- **Tube trailer capacity** of 200–500 kg per shipment, matched to available vessel deck space. Standard ISO-container-format tube trailers can be loaded onto existing cargo vessels and dhonis without specialized handling equipment
- **Average transport distance** of approximately 50 km between production hub and consumption point, weighted by demand distribution. Greater Malé area consumption is produced locally (zero transport distance); outer island delivery averages 80–120 km
- **Scheduled delivery routes** following existing MTCC cargo schedules, with hydrogen trailers sharing vessel capacity with conventional cargo. This co-loading approach minimizes dedicated transport costs

Compressed gas at 350 bar is the pragmatic near-term choice. It uses existing marine logistics and avoids the capital intensity of cryogenic or chemical carrier systems. The 3-day buffer requirement adds storage cost but is essential for supply reliability in the Maldives' weather-exposed operating environment.

3.4 Combined Cost Curve

Combined S&T cost declines 39% over the decade, driven by improved vessel utilization as demand volumes increase and delivery schedules consolidate, reduced storage unit costs as compressed hydrogen systems benefit from manufacturing scale; and operational learning as logistics teams gain experience with hydrogen handling procedures. Transport accounts for approximately two-thirds of the S&T cost, making vessel utilization optimization the highest-impact cost reduction opportunity. The full technical assessment of transport options is provided in Annex C.

Table 3-1: Storage and Transport Cost Curve ($/kg)

Component	2025	2028	2030	2035
Storage	0.87	0.74	0.63	0.54
Transport	2.38	2.03	1.72	1.46
Total S&T	**3.26**	**2.78**	**2.35**	**2.00**

Source: pManifold analysis

4. Utilization and Deployment

4.1 National Fossil Fuel Baseline

The Maldives consumes approximately 786 million litres of fossil fuel annually across four sectors. This baseline was established through the Phase 1 Baseline Assessment (December 2025) and validated through direct consultation with the major fuel consumers: STELCO (Greater Malé power), FENAKA (outer island power), MTCC (marine and road transport), and resort operators.[13]

Table 4-1: Fossil Fuel Baseline by Sector

Sector	Annual Consumption (M L/yr)	Share	Primary Users
Power Generation	498	65%	STELCO (207 M L), FENAKA (147 M L), Resorts (144 M L)
Marine Transport	142	18%	MTCC ferries (18 M L), Fishing (40 M L), Resort boats (60 M L)
Road Transport	66	9%	Motorcycles (43 M L), Cars (11 M L), Trucks (11 M L)
Aviation	80	10%	Seaplanes (49 M L), Fixed-wing (31 M L)
Total	**786**	**100%**	

Source: pManifold analysis

Power generation dominates, consuming nearly two-thirds of national fossil fuel. Within this sector, the three operator segments (STELCO, FENAKA, resorts) have markedly different cost structures and efficiency levels, which creates distinct hydrogen opportunity profiles for each; reflected in the three deployment archetypes analyzed in Section 4.4 and Annex E.

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[13] pManifold (2025), Baseline Assessment Report: Green Hydrogen Potential in Maldives (Deliverable 1B), prepared for UNEP-CTCN, December 2025.

4.2 Hydrogen Demand Methodology

Converting fossil fuel baseline to hydrogen demand requires adjusting for differences in energy conversion efficiency between incumbent diesel systems and hydrogen alternatives. A diesel generator at 30% efficiency (3.0 kWh/L) produces less useful energy per unit of fuel input than a hydrogen fuel cell at 50% efficiency. This means less hydrogen (in energy terms) is needed to deliver the same useful energy output as diesel.

The analysis applies efficiency ratios specific to each use case (see Annex A for detailed parameters), then applies an addressable fraction; the share of each sector's total consumption that can realistically be served by hydrogen given technology readiness, infrastructure constraints, and deployment timelines. Not all diesel consumption is addressable; for example, the vast majority of motorcycles (110,000 units) are unlikely to convert to hydrogen.

The resulting demand is projected across four scenarios:

Table 4-2: Hydrogen Demand Scenarios (t/yr)

Scenario	2026	2028	2030	2035	Description
Low	-	749	1,833	5,823	Pilot phase only; minimal policy support
Medium	**39**	**1,650**	**4,610**	**13,910**	**Balanced; cost parity achieved in primary sectors**
High	681	3,989	8,906	22,900	Aggressive; distributed priority, strong policy
TCO-Linked	502	1,915	7,467	14,038	Economics-driven; S-curve adoption from premiums

Source: pManifold analysis

The **Medium scenario** is used as the reference case throughout this report. It assumes that pilot projects proceed in 2026–2027, cost parity is achieved for power generation by approximately 2030 without subsidy (earlier with policy support), and policy support (declining H_2 subsidy of $5–1/kg) is maintained through the transition period. The TCO-Linked scenario, which derives demand endogenously from economic competitiveness, produces higher 2030 demand (7,467 t/yr); suggesting that if cost parity materializes as projected, actual uptake could exceed the medium scenario.

4.3 Use Case Prioritization

Not all sectors are equally suited for hydrogen. The study scores each use case against four criteria to determine deployment sequencing:

- **Economic Gap (1–5):** How close is hydrogen to cost parity with diesel? Higher scores indicate smaller premium or achieved parity
- **Technology Readiness (1–5):** Is the hydrogen technology commercially available and proven in comparable applications?
- **GHG Impact (1–5):** What is the absolute CO_2 reduction potential of hydrogen adoption in this sector?
- **Strategic Alignment (1–5):** How well does hydrogen in this sector align with national priorities (NDC targets, energy security, economic development)?

Table 4-3: Multi-Criteria Prioritization Matrix

Use Case	Econ Gap (/5)	Tech Ready (/5)	GHG Impact (/5)	Strategic (/5)	Total (/20)	Priority

Power Generation	5	4	5	5	**19**	**PRIMARY**
Marine Transport	4	4	4	5	**17**	**PRIMARY**
Road Transport	3	3	2	3	**11**	LOW
Aviation (SAF)	1	1	2	1	**5**	LONG-TERM

Source: pManifold analysis

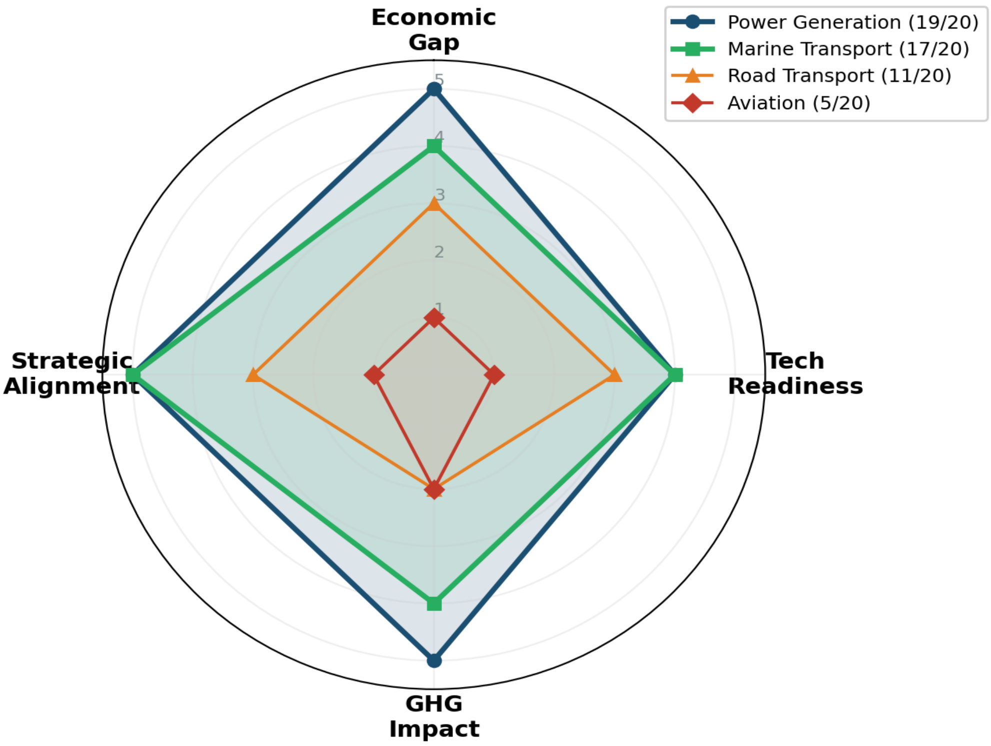

Figure 4-1: Use Case Prioritization: Multi-Criteria Scoring

Source: pManifold analysis

The scoring reveals a clear two-tier structure. The Primary tier (Power + Marine) combines strong economics, proven technology, and direct alignment with NDC targets; accounting for 91.1% of projected 2030 hydrogen demand and 99.5% of near-term GHG reductions. The Secondary tier (Road + Aviation) faces either limited addressable demand (road) or significant cost premiums (aviation). The remainder of this chapter focuses on the primary tier; secondary use cases are summarized in Section 4.5.

4.4 Power Generation: The Anchor Use Case

Power generation scores highest (19/20) because the Maldives' diesel power costs are among the highest in the world, creating an unusually wide economic window for hydrogen. The key insight is that hydrogen does not need to be "cheap" by global standards; it needs to be cheaper than the current diesel alternative, which in the Maldives is an achievable threshold.

The reference comparison uses a 600 kW diesel generator (the FENAKA standard for outer island installations) against an equivalent hydrogen system comprising a 360 kW PEM fuel cell with a 300 kWh battery buffer. The fuel cell is sized at 60% of diesel generator capacity because higher fuel cell efficiency means less installed power is needed for the same energy output. The battery buffer manages short-duration load transients while the fuel cell responds.

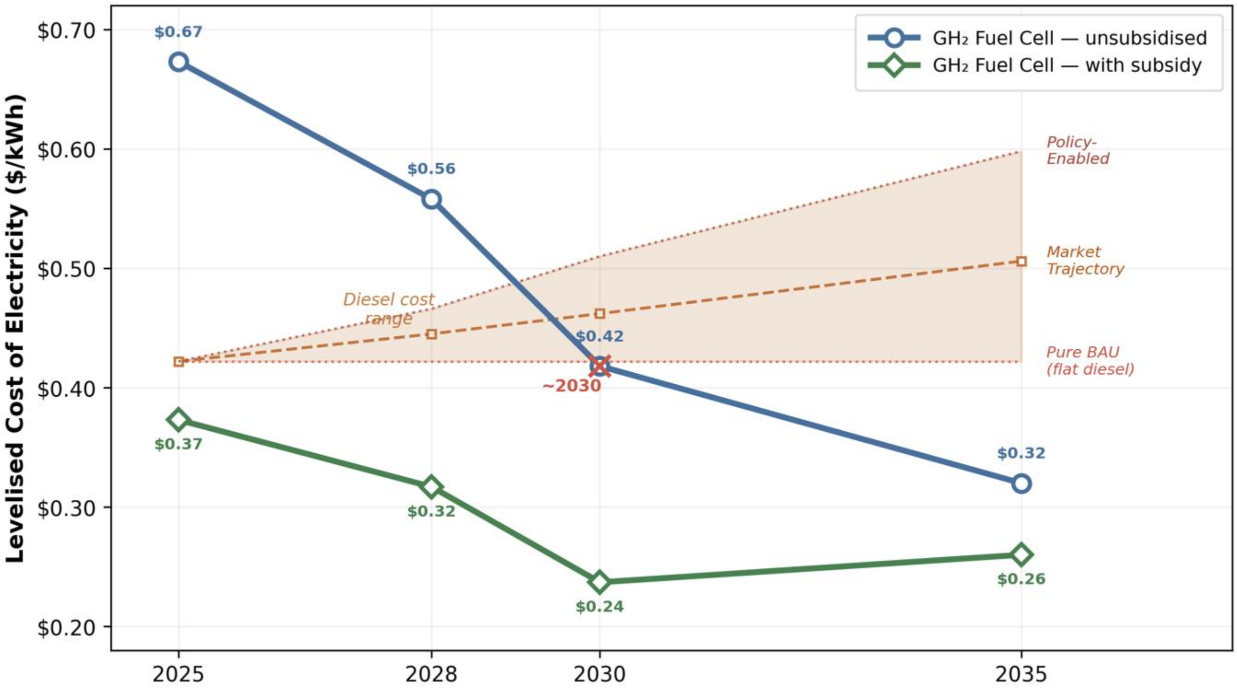

Figure 4-2: Power Generation; Diesel vs. Hydrogen LCOE

Source: pManifold analysis

Figure 4-2 plots the three diesel price scenarios as a shaded band (ranging from flat BAU to Policy-Enabled) against two hydrogen fuel cell trajectories (with and without a production subsidy). The same three-scenario comparison is applied to marine transport in Figure 4-3. Under all three diesel scenarios, the hydrogen cost curves converge and cross over the diesel range between 2025 and 2030, depending on the degree of policy support assumed.

Table 4-4: Power Generation Cost Convergence (600 kW FENAKA Reference)

Scenario A: Pure BAU (flat diesel, no carbon adder, no H2 subsidy)

Metric	2025	2028	2030	2035
Diesel LCOE: flat $1.04/L ($/kWh)	0.422	0.422	0.422	0.422
GH2 FC LCOE: unsubsidised ($/kWh)	0.673	0.558	0.418	0.320
Premium vs. diesel	+60%	+32%	**-1%**	-24%

Scenario B: Market Trajectory (IMF 2% escalation, no carbon adder, no H2 subsidy)

Metric	2025	2028	2030	2035
Diesel LCOE: 2% real escalation ($/kWh)	0.422	0.445	0.462	0.506
GH2 FC LCOE: unsubsidised ($/kWh)	0.673	0.558	0.418	0.320
Premium vs. diesel	+60%	+25%	**-10%**	-37%

Scenario C: Policy-Enabled (IMF escalation + carbon adder + H2 subsidy)

Metric	2025	2028	2030	2035

Diesel LCOE: with carbon adder ($/kWh)	0.422	0.466	0.510	0.598
GH2 FC LCOE: with subsidy ($/kWh)	0.373	0.317	0.237	0.260
Premium vs. diesel	**-12%**	-32%	-54%	-57%

Source: pManifold analysis

Table 4-4 quantifies the three scenarios. The central conclusion is that the economic case for hydrogen in Maldivian power generation rests on global technology cost trends, projected declines in electrolyser and solar PV pricing, which are well-established and accelerating. Policy interventions (carbon pricing, production subsidies, or both) accelerate the transition by 4–5 years but are not prerequisites for it.

Deployment Archetypes for Power Generation

Three distinct deployment models are identified for power generation, each tailored to a different segment of the Maldives' power system:

- **Archetype 1: FENAKA Outer Island Microgrid:** Replaces diesel generators across FENAKA's 200+ island network. A 360 kW fuel cell with battery buffer is supplied via hub delivery. Achieves LCOE of $0.247/kWh by 2030; less than half the diesel cost. Strongest economic case due to the highest incumbent diesel costs in the Maldivian system.
- **Archetype 2: Resort Hydrogen Integration:** On-site micro-plant (50–150 kW electrolyzer) with dedicated solar eliminates transport costs entirely. Achieves LCOE as low as $0.106/kWh by 2030. Sustainability branding adds commercial value beyond cost savings. Soneva and Six Senses have expressed active interest in pilot installations.
- **Archetype 3: STELCO Ammonia Co-firing:** 10–20% ammonia blend in STELCO's existing medium-speed generators at Greater Malé. Does not reach cost parity until ~2034, but acts as a demand anchor for the Greater Malé production hub. Recommended as a Phase 2/3 initiative. Detailed archetype economics are provided in Annex E.

4.5 Marine Transport: The Strategic Complement

Marine transport scores 17/20, making it the second-priority use case. The rationale combines economics, strategy, and timing:

- **Fleet modernization window:** MTCC operates 85 ferries (40 high-speed, 45 conventional), many approaching end-of-life replacement. New vessel orders in 2027–2030 represent a natural entry point for hydrogen propulsion; it is far cheaper to build a hydrogen vessel than to retrofit later
- **IMO regulatory alignment:** The International Maritime Organization's revised GHG strategy (2023) targets 20% reduction in shipping emissions by 2030 and 70% by 2040. Early hydrogen adoption positions MTCC ahead of regulatory requirements
- **Two technology pathways provide flexibility:** Fuel cell propulsion offers higher efficiency but higher cost; H_2-ICE conversion offers lower cost and easier retrofit of existing vessels

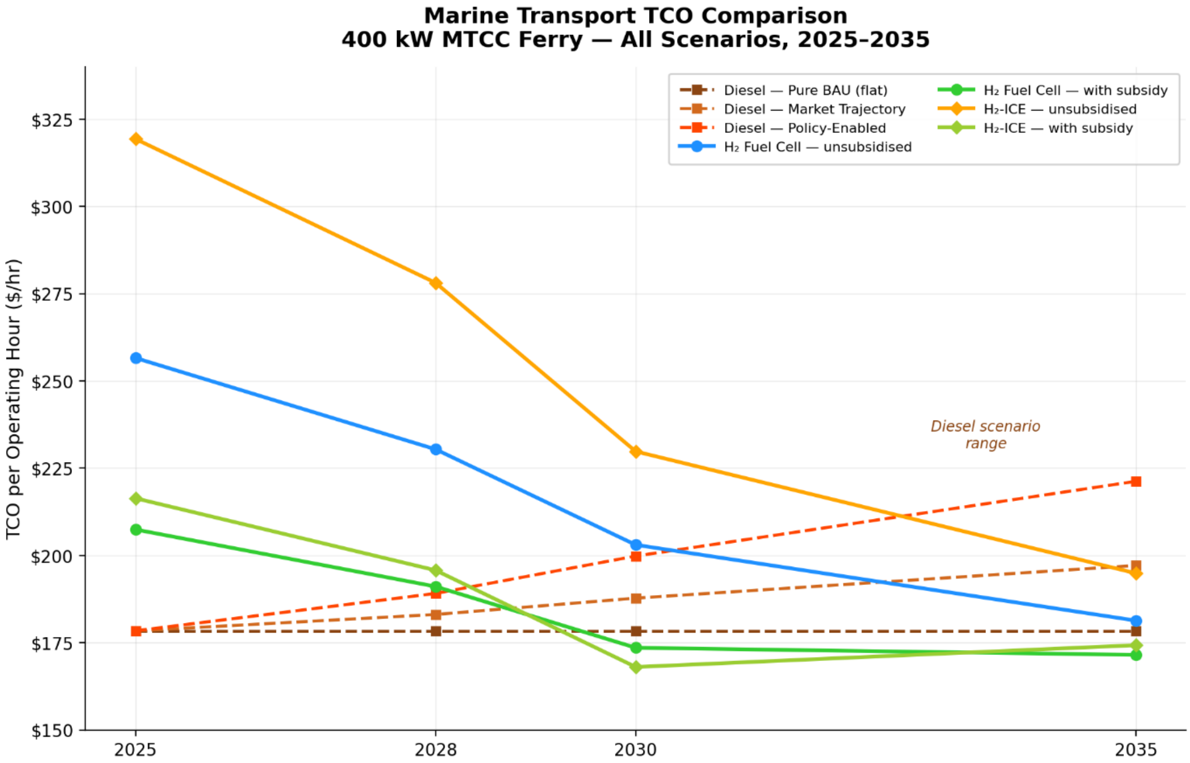

Figure 4-3: Marine Transport TCO Comparison (bar chart: 2030 snapshot; line chart: 2025–2035 trajectory across three diesel scenarios)

Source: pManifold analysis

Table 4-5: Marine Transport Cost Convergence (400 kW MTCC Ferry)

Scenario A: Pure BAU (flat diesel, no carbon adder, no H2 subsidy)

Metric	2025	2028	2030	2035
Diesel TCO: flat $1.04/L ($/hr)	178	178	178	178
H_2-FC TCO: unsubsidised ($/hr)	257	230	203	181
H_2-ICE TCO: unsubsidised ($/hr)	319	278	230	195
H_2-FC premium vs. diesel	+44%	+29%	+14%	+2%
H_2-ICE premium vs. diesel	+79%	+56%	+29%	+9%

Scenario B: Market Trajectory (IMF 2% escalation, no carbon adder, no H2 subsidy)

Metric	2025	2028	2030	2035
Diesel TCO: 2% real escalation ($/hr)	178	183	188	197
H_2-FC TCO: unsubsidised ($/hr)	257	230	203	181
H_2-ICE TCO: unsubsidised ($/hr)	319	278	230	195
H_2-FC premium vs. diesel	+44%	+26%	+8%	−8%
H_2-ICE premium vs. diesel	+79%	+52%	+22%	−1%

Scenario C: Policy-Enabled (IMF escalation + carbon adder + H_2 subsidy)

Metric	2025	2028	2030	2035
Diesel TCO: with carbon adder ($/hr)	178	189	200	221
H_2-FC TCO: with subsidy ($/hr)	207	191	174	172

H_2-ICE TCO: with subsidy ($/hr)	216	196	168	174
H_2-FC premium vs. diesel	+16%	+1%	−13%	−22%
H_2-ICE premium vs. diesel	+21%	+4%	−16%	−21%

Source: pManifold analysis

Table 4-5 quantifies the three scenarios. Unlike power generation, where technology cost trends alone drive parity by ~2030, marine transport requires policy support: under Scenario A the H_2-FC premium is still +2 % at 2035, and under Scenario B it narrows to −8 % only because diesel itself rises to $197/hr. Scenario C achieves parity by 2028 for both pathways.

The **H_2-ICE pathway is compelling** for the Maldives context. It achieves cost parity by approximately 2028 (with policy support), requires lower upfront capital than fuel cells ($1.26M vs. $2.42M per vessel), and can be implemented as a retrofit to existing diesel engines, converting proven marine powertrains rather than replacing them entirely. By 2030, the H_2-ICE ferry operates at approximately 16% lower cost than diesel. The fuel cell pathway is more expensive but offers zero local emissions and higher efficiency; it becomes the preferred option for new-build vessels post-2030.

Deployment Approach for Marine Transport

Two deployment approaches are recommended for marine transport. **Near-term (2027–2030):** H_2-ICE retrofit of 5–10 existing MTCC high-speed ferries on fixed routes, prioritizing the highest-consumption corridors where fuel savings are greatest and refueling logistics simplest. **Post-2030:** fuel cell propulsion for new-build vessels, offering higher efficiency and zero local emissions for passenger routes in environmentally sensitive resort areas. Detailed fleet conversion economics are provided in Annex D.

4.6 Road Transport

Road transport has limited hydrogen potential in the Maldives. The vehicle fleet is small, trip distances are extremely short (most inhabited islands are less than 5 km across), and battery-electric vehicles are a more practical solution for most surface transport applications. The national motorcycle fleet (110,000 units); which accounts for 65% of road fuel consumption; has no commercially available hydrogen alternative. Hydrogen-powered light trucks reach cost parity around 2033 against escalating fuel prices, but against flat petrol (Scenario A), parity extends beyond 2035 and contribute less than 1% of projected demand. Road transport is not recommended as a near-term priority for hydrogen investment.

4.7 Aviation

Aviation relies on Sustainable Aviation Fuel (SAF) as the hydrogen pathway, not direct fuel cell propulsion. SAF is produced using hydrogen as a feedstock combined with captured CO_2 or biomass through Fischer-Tropsch or methanol-to-jet processes. The Maldives' seaplane fleet (78 aircraft operated by Trans Maldivian Airways and Manta Air) is a potential niche market, but SAF cost parity with Jet A-1 is not projected before 2038. The cost premium remains 62% in 2030 even with policy support. Aviation is appropriately classified as a long-term opportunity contingent on international CORSIA mandates and global SAF production scale-up.

4.8 Demand by Use Case and Adoption Dynamics

Demand is projected using a **TCO-linked S-curve adoption model**: as the economic premium over diesel narrows, adoption accelerates along a logistic (S-curve) function. When the premium exceeds +50%, adoption is near-zero (only pilot projects). As the premium narrows through 0% (cost parity), adoption accelerates rapidly. This produces internally consistent demand projections; not arbitrary targets, but endogenously derived outcomes of cost curve assumptions.

For power generation, the S-curve produces 9.5% penetration of the addressable market by 2030, a conservative projection given the cost convergence shown in Table 4-4 and Figure 4-2. This suggests the medium scenario may underestimate actual uptake if early pilots succeed and policy support materialises. Figure 4-5 compares the estimated parity year across all five use cases under three diesel price scenarios, showing that policy support can bring parity forward by up to a decade depending on the application.

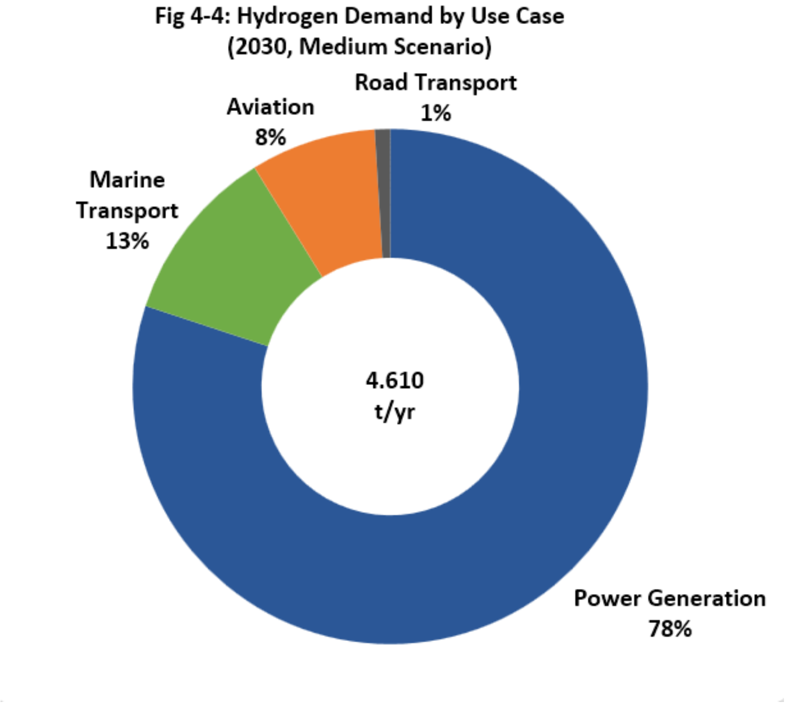

Figure 4-4: Hydrogen Demand by Use Case

Source: pManifold analysis

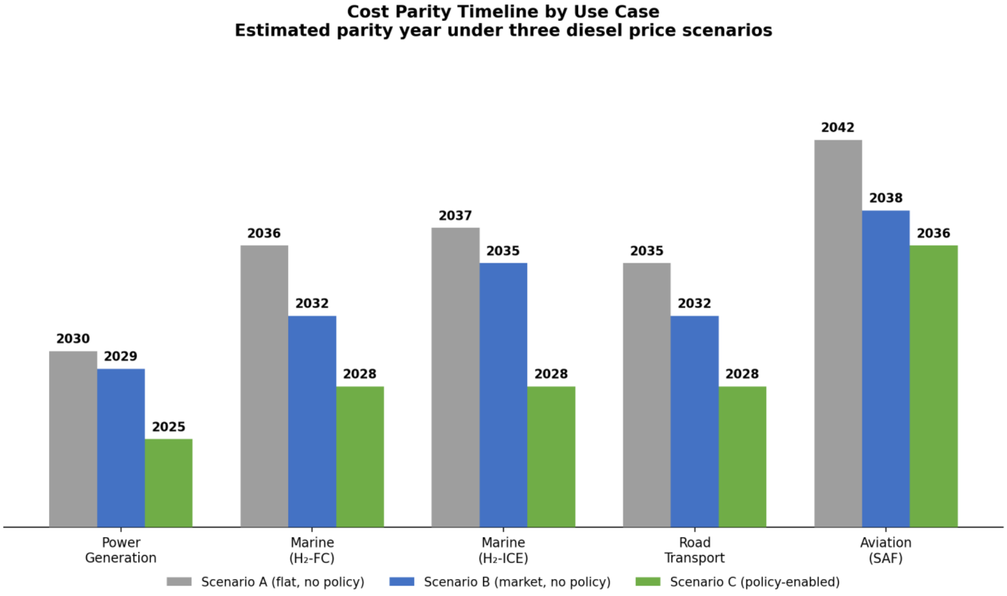

Figure 4-5: Cost Parity Timeline by Use Case (Three Scenarios)

Source: pManifold analysis

Policy support accelerates parity by 5–10 years across most use cases. Under Scenario C (policy-enabled), power generation breaks even as early as ~2025; without policy support, this extends to ~2029 (market trajectory) or ~2030 (flat BAU). Marine and road transport reach parity around 2028 with policy, 2032–2036 without. Aviation (SAF) has the longest horizon (~2036–2042), reflecting the wider cost gap between Fischer-Tropsch SAF and conventional jet fuel, though the combination of an H2 production subsidy and an aviation carbon adder brings this forward to ~2036 under Scenario C.

Table 4-6: Hydrogen Demand by Use Case (Medium Scenario, t/yr)

Use Case	2026	2030	2035	Share (2030)
Power Generation	~30	3,691	11,400	80%
Marine Transport	~5	511	1,228	11%
Aviation (SAF)	-	363	1,155	8%
Road Transport	~2	44	127	1%
Total	**~37**	**4,610**	**13,910**	**100%**

Source: pManifold analysis

Power generation is the anchor market. It provides the demand volume needed to justify infrastructure investment, and its early cost parity creates a self-reinforcing cycle: lower costs drive higher adoption, which justifies larger-scale infrastructure, which further reduces per-unit costs. Marine transport is the strategic complement that extends hydrogen value chains into the broader economy. These two sectors define the near-term hydrogen opportunity for the Maldives.

5. Investment Roadmap

5.1 Capital Requirements

The cumulative investment required to reach the 2030 medium scenario is summarized in Table 5-1, with solar PV representing the largest cost component, followed by electrolyzers and balance-of-plant.

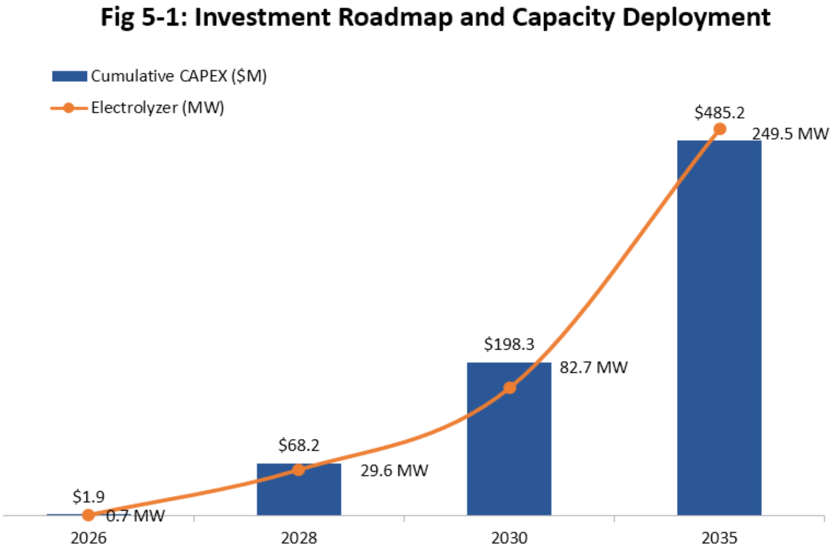

Figure 5-1: Investment Roadmap and Capacity Deployment

Source: pManifold analysis

Table 5-1: Capital Investment Trajectory ($ Millions)

Component	2026	2028	2030	2035
Electrolyzer	0.4	14.2	31.8	76.6
Solar PV	1.1	38.9	72.3	152.8
BOP + Installation	0.4	13.3	26.0	57.4
Period CAPEX	**1.9**	**66.4**	**130.1**	**286.8**
Cumulative	**1.9**	**68.3**	**198.4**	**485.2**

Source: pManifold analysis

Investment is heavily back-loaded, which is appropriate for a phased deployment strategy. The 2026–2027 pilot phase requires only $1.8–15M; well within the scale of GCF readiness grants, bilateral technical cooperation programs, and government co-investment. The 2028–2030 scale-up demands $100M+, requiring a more sophisticated financing strategy blending concessional climate finance with private sector investment.

Table 5-2: Capacity Deployment Milestones

Year	H2 Demand (t/yr)	Plants	Electrolyzer (MW)	Solar PV (MW)	Cumulative CAPEX ($M)
2026	39	2	0.70	1.23	1.9
2028	1,650	6	29.6	51.8	68.3
2030	4,610	18	82.7	144.7	198.4
2035	13,910	35	249.5	436.7	485.2

Source: pManifold analysis

5.2 Phased Implementation Strategy

The recommended deployment follows a three-phase sequence, each designed to de-risk the subsequent phase:

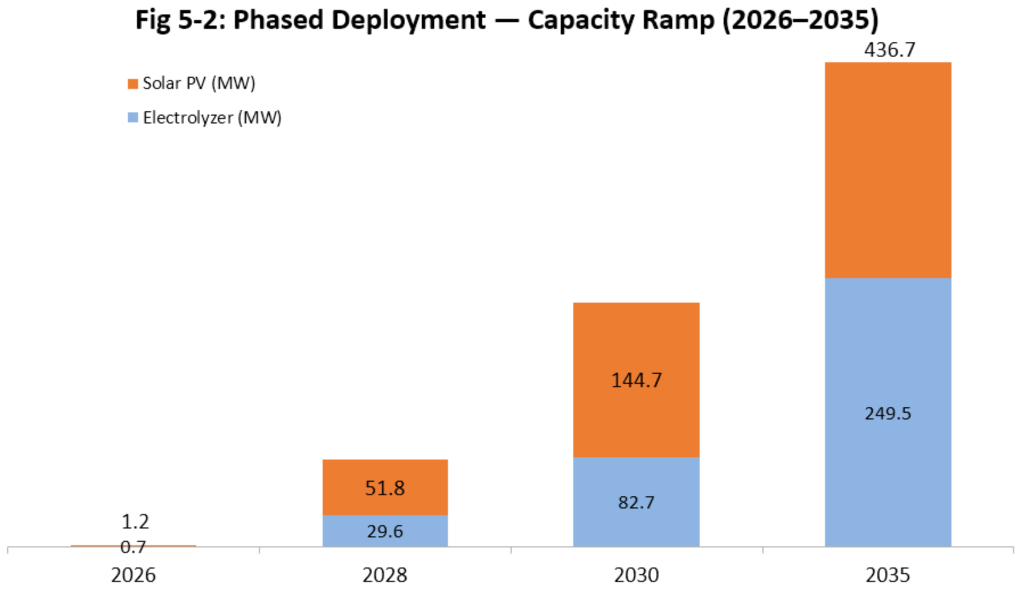

Figure 5-2: Phased Deployment Timeline

Source: pManifold analysis

Phase 1: Demonstration (2026–2027):

- **Pilot projects:** 1–2 installations: one resort micro-plant (Soneva or Six Senses) and one FENAKA outer island fuel cell replacement
- **Marine demonstration:** H_2-ICE ferry retrofit on a single MTCC high-speed route
- **Capacity building:** Hydrogen safety and handling training for FENAKA, STELCO, and MTCC technical staff
- **Regulatory foundation:** Production licensing, safety standards, and transport certification frameworks
- **Scale:** 2 plants, 0.70 MW electrolyzer, ~$1.9M CAPEX + $3–5M for enabling activities
- **Funding:** GCF readiness grant, CTCN technical assistance, bilateral cooperation (Japan, Australia, EU)
- **Key milestone:** Validated operational data from 12+ months of pilot operation

Phase 2: Scale-up (2028–2030):

- **Greater Malé hub:** 1 × Large plant (15 MW initial, expanding to 45 MW) at Thilafushi–Gulhifalhu corridor
- **Addu City hub:** 1 × Medium plant (4 MW, expanding to 10 MW)
- **Distributed deployment:** 10 resort micro-installations + 5 outer island small plants at FENAKA's highest-cost sites
- **Distribution network:** Tube trailer procurement, port handling equipment, and safety infrastructure
- **Scale:** 18 plants, 82.7 MW electrolyzer, cumulative CAPEX per Table 5-1
- **Funding:** GCF investment proposal ($50–80M concessional), GEF co-financing, resort operator private investment, development bank loans (ADB, World Bank)
- **Key milestone:** Demonstrated cost parity for power generation; operational hub-and-spoke logistics

Phase 3: Expansion (2030–2035):

- **Capacity growth:** Expand to 35 plants, 250 MW electrolyzer, 437 MW solar PV
- **Sector broadening:** Full MTCC fleet coverage; STELCO ammonia co-firing at commercial scale
- **Technology evolution:** Evaluate liquid hydrogen or LOHC for long-distance inter-atoll transport
- **Regional potential:** Assess export opportunities to neighbouring SIDS (Sri Lanka, Mauritius)
- **Funding:** Commercial-rate capital increasingly viable; green bond issuance potential
- **Key milestone:** Hydrogen normalized in Maldivian energy mix; commercial viability demonstrated without subsidy

5.3 GHG Impact and NDC Alignment

Power generation accounts for nearly all near-term GHG reductions, confirming its role as the anchor use case (Table 5-3). Marine transport contributes a meaningful secondary share; road transport and aviation are negligible through 2030.

At 6.9%, the cumulative NDC contribution by 2035 is meaningful but not sufficient on its own. Hydrogen is one component of a broader decarbonization portfolio that includes solar PV deployment, energy efficiency improvements, electrification of short-distance transport, and sustainable tourism practices. The National GH2 Roadmap (Phase 3) will position hydrogen within this broader strategy.

Table 5-3: CO_2 Abatement Trajectory (Medium Scenario)

Metric	2026	2030	2035
CO_2 avoided (kt/yr)	6.1	71.0	105.4
Share of NDC 3.0 target	0.4%	4.7%	6.9%
Share of energy sector emissions	0.3%	3.1%	4.6%

Source: pManifold analysis

5.4 Policy Support Requirements

The transitional policy structure modelled in this study includes:

- **Hydrogen production subsidy:** Declining from $5/kg (2025) to $1/kg (2035) as costs fall toward unassisted competitiveness. The transitional subsidy outlay is modest relative to the total capital investment programme and the current annual fuel import bill of $500M+
- **Carbon pricing mechanism:** A gradually introduced carbon adder on diesel ($0.067/L in 2028, rising to $0.268/L by 2035) that reflects the social cost of carbon and levels the playing field for clean alternatives. This can be implemented as a fuel levy or integrated into existing taxation frameworks
- **Regulatory enablement:** Hydrogen production, storage, and transport licensing; safety standards aligned with ISO/IEC frameworks; building codes for hydrogen-ready infrastructure; and streamlined permitting for pilot projects

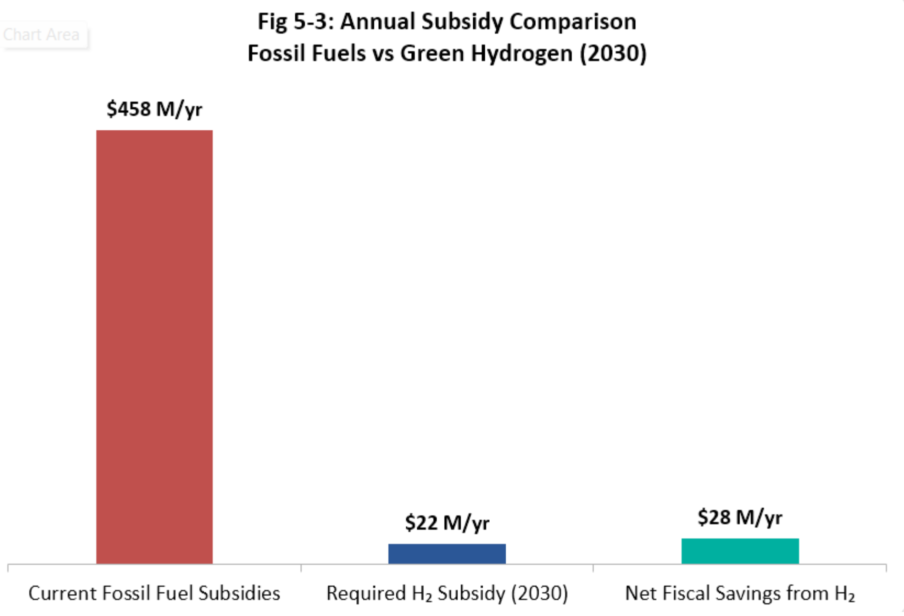

Figure 5-3: Annual Subsidy Comparison, Fossil Fuels v/s Green Hydrogen

Source: pManifold analysis

The investment case is strong but requires coordinated policy action. The $198M cumulative CAPEX (2026–2030) is fundable through existing climate finance mechanisms (GCF, GEF, bilateral) but requires the Maldives government to signal clear policy commitment; particularly on the transitional subsidy and carbon pricing mechanisms; to release concessional financing.

6. Conclusions and Next Steps

6.1 Key Conclusions

This feasibility study concludes that **green hydrogen is technically and economically viable for the Maldives' power generation and marine transport sectors**, with cost parity achievable by approximately 2030 without subsidy, and earlier with modest policy support.

The Maldives' combination of high diesel costs, strong solar resources, and absence of grid interconnection alternatives creates a uniquely favourable environment for hydrogen; one where the technology does not need to reach aggressive global cost targets to deliver economic value. The central insight is that hydrogen competitiveness in the Maldives is determined by the cost of the incumbent system it replaces ($0.42–0.60/kWh diesel power), not by abstract global benchmarks.

The analysis identifies three risk factors that will determine whether the favourable economics translate into actual deployment:

- **Technology cost trajectories:** If global electrolyzer or solar PV costs decline slower than projected, cost parity timelines extend by 1–3 years. Conversely, faster-than-expected declines would accelerate the case. Capacity factor and discount rate have the largest impact on LCOH (Annex B), reinforcing the case for optimizing solar coupling and securing concessional finance.
- **Policy commitment and consistency:** The transitional subsidy is essential for Phase 1 economics and investor confidence. Inconsistent or delayed policy signals could defer private sector participation by 3–5 years, even if underlying economics are favourable.
- **Logistics execution:** The hub-and-spoke marine distribution system is operationally more complex than diesel. Successful pilot-phase logistics will determine scale-up confidence among utilities, resort operators, and financiers.

6.2 Complimentarily with Other Pathways

Hydrogen is not intended to replace all other decarbonization options. It complements a broader portfolio:

- **Solar PV + battery storage** remains the lowest-cost option for daytime power and short-duration storage (up to 4–6 hours). Battery costs are declining rapidly and rooftop solar deployment should be accelerated in parallel with hydrogen development
- **Battery-electric vehicles** are more practical than hydrogen for the Maldives' short road distances. Most inhabited islands can be fully served by electric motorcycles and light vehicles with overnight charging
- **Energy efficiency** improvements at STELCO and FENAKA (including heat recovery, load management, and generator right-sizing) can reduce diesel consumption by 10–15% independent of hydrogen adoption
- **Demand-side management** through smart meters, time-of-use pricing, and building efficiency standards can further reduce the energy system's carbon intensity

Hydrogen's distinctive role is in applications where batteries and direct electrification cannot substitute: multi-day energy storage for monsoon-season resilience, marine propulsion for vessels requiring 8+ hours of continuous operation, industrial heat processes, and eventually aviation fuel. It fills the gap between what solar-plus-batteries can serve (short-duration, on-island applications) and what requires a transportable, storable, dispatchable clean fuel.

6.3 Scope for the National GH2 Roadmap

The findings of this feasibility study will directly inform the National GH2 Roadmap (Phase 3 of the CTCN engagement), which will address several areas identified as critical enablers but outside the scope of this technical assessment:

- **Policy and regulatory structures:** Development of hydrogen safety standards (aligned with ISO 19880 and IEC 62282), production and transport licensing, land use planning frameworks for solar-hydrogen installations, and building codes for hydrogen-ready infrastructure
- **Financial strategy and climate finance mobilization:** Detailed financing plan for the $198M 2026–2030 investment requirement, including GCF concept note development, GEF co-financing strategy, bilateral cooperation agreements, and private sector investment frameworks
- **Detailed implementation sequencing:** Site-specific engineering assessments, environmental and social impact studies, procurement strategies, and off-taker agreement templates for FENAKA, MTCC, and resort operators
- **Institutional capacity building:** Technical training programs for utility operators, safety certification for hydrogen handling personnel, and establishment of a Hydrogen Unit within SEAM or MECCT to coordinate national efforts
- **Risk mitigation and monitoring:** Contingency planning for technology underperformance, demand shortfall, supply chain disruptions, and macroeconomic shocks; definition of go/no-go decision criteria at each phase gate

Annex A: Methodology and Assumptions

A.1 Analytical Approach

Our feasibility assessment follows a three-part analytical approach, developed iteratively across the Phase 1 and Phase 2 engagements and calibrated through industry consultations during the February 2026 mission visit.

Part 1: Demand Assessment. We established a fossil fuel consumption baseline by sector and sub-sector using national statistics and utility data from STELCO, FENAKA, and MTCC. Efficiency-adjusted hydrogen equivalent demand was calculated for each use case, and projected across four scenarios using an S-curve adoption function linked to TCO premiums. These demand projections determine the required production infrastructure: plant count, electrolyzer capacity, solar PV capacity, and water requirements for each scenario and year.

Part 2: Supply Cost Analysis. We calculated the Levelized Cost of Hydrogen (LCOH) for five reference plant scales, from micro (0.15 MW) to very large (45 MW). CAPEX trajectories for electrolyzers, solar PV, and balance-of-plant components were derived from learning-curve projections anchored to current vendor quotations and IRENA benchmarks. Storage and transport costs were assessed for compressed hydrogen distribution via the proposed hub-and-spoke network.

Part 3: Use Case Economics and Prioritization. For each of the four end-use sectors, we built a Total Cost of Ownership (TCO) comparison between the diesel BAU case and hydrogen alternatives, incorporating capital costs, fuel/hydrogen costs, O&M, and policy support. For each use case, we compared hydrogen alternatives against three diesel price scenarios: (A) flat BAU, (B) market trajectory with IMF-projected escalation, and (C) policy-enabled with carbon adder and H2 subsidy. This framework is applied consistently across all four applications (power generation, road transport, marine transport, and aviation). Cost parity years were derived from the TCO convergence analysis under each scenario. A multi-criteria prioritization scoring (economic gap, technology readiness, GHG impact, strategic alignment) ranked use cases for deployment sequencing. Three deployment archetypes (FENAKA outer island, resort integration, STELCO NH_3 co-firing) translate the sector-level findings into site-specific implementation parameters.

The three parts are linked through a feedback loop: production costs (Part 2) determine the economic premium of hydrogen over diesel (Part 3), which drives adoption rates, which determine demand volumes (Part 1), which validate plant sizing assumptions. Because per-unit production costs do not vary significantly with volume at the scales considered (see Annex B), this loop converges in a single iteration, producing internally consistent projections.

A.2 Key Technology Assumptions

Table A-1: Electrolyzer and Fuel Cell Parameters

Parameter	Value	Unit	Source / Notes
Electrolyzer type	PEM (primary)	-	Recommended for distributed installations
Electrolyzer efficiency	55	kWh/kg H2	Manufacturer specification (ITM, Siemens)[14]
Electrolyzer capacity	35%	-	Solar-coupled, no intermediate battery

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[14] ITM Power and Siemens Energy, PEM electrolyzer product specifications.

factor			
Stack lifetime	80,000	hours	~26 years at 35% CF
Stack replacement cost	25%	of initial CAPEX	Industry standard
Annual O&M	3%	of CAPEX	Includes remote monitoring
FC efficiency (stationary PEM)	50%	-	40–60% typical range
FC efficiency (vehicle PEM)	55%	-	Transport applications
H2-ICE efficiency	35%	-	30–40% range; retrofit of diesel marine engine
Water consumption	9	L/kg H2	Deionized water; standard electrolysis
Water cost (desalinated)	5	$\$/m^3$	MWSC reference; includes RO energy cost[15]

Source: pManifold analysis

Table A-2: Solar PV and Energy Parameters

Parameter	Value	Unit	Source / Notes
PV capacity factor	20%	-	1,750–1,800 kWh/kWp/yr; validated Soneva, Veligandu[16]
PV degradation rate	0.5%	per year	Standard crystalline silicon
PV system area	~2	ha/MW	Ground-mounted; varies with terrain
BOP factor	10%	of equipment cost	Inverters, cabling, mounting structures
Installation factor	15%	of total equipment	10% Greater Malé; 15–20% outer islands

Source: pManifold analysis

Table A-3: Financial Parameters

Parameter	Value	Unit	Notes
Discount rate	10%	-	Reflects Maldives infrastructure risk premium
Project life	20	years	Standard for energy infrastructure
Capital recovery factor	0.1175	-	$CRF = r(1+r)^n / ((1+r)^n - 1)$
Inflation (real)	0%	-	All costs in real 2025 USD

Source: pManifold analysis

The 10% discount rate is higher than rates used in continental feasibility studies (typically 6–8%) and reflects the Maldives' sovereign risk premium, limited domestic capital markets, and island logistics costs. Sensitivity analysis shows that reducing the discount rate to 8% (achievable through

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[15] Stakeholder consultations conducted during the February 2026 mission visit: STELCO, FENAKA, MTCC, Soneva, Veligandu, MWSC.

[16] Stakeholder consultations conducted during the February 2026 mission visit: STELCO, FENAKA, MTCC, Soneva, Veligandu, MWSC.

concessional climate finance) would reduce LCOH by approximately $0.40/kg; a significant improvement that shows how important it is to secure favourable financing terms.

A.3 CAPEX Learning Curves

Technology cost projections are the single most important driver of feasibility conclusions. The analysis applies learning-curve-based projections calibrated to observed global trends and validated against manufacturer roadmaps and independent forecasts (IRENA, IEA, BNEF).[17][18][19][20][21]

Table A-4: Electrolyzer CAPEX by Plant Scale ($/kW)

Plant Size	2025	2028	2030	2035	Learning Rate
Micro (0.15 MW)	900	720	576	461	48.8%
Small (0.6 MW)	750	600	480	384	48.8%
Medium (3 MW)	600	480	384	307	48.8%
Large (15 MW)	550	440	352	282	48.8%
Very Large (45 MW)	500	400	320	256	48.8%

Source: pManifold analysis

The 48.8% learning rate corresponds to approximately 15% cost reduction per doubling of cumulative global installed capacity. This is consistent with IRENA's central scenario and supported by observed cost reductions from 2020 to 2025 as global electrolyzer manufacturing has scaled from ~1 GW/yr to ~10 GW/yr announced capacity. The primary risk is that manufacturing scale-up slows due to supply chain constraints (iridium availability for PEM, manufacturing equipment bottlenecks) or that demand growth underperforms projections.[22][23][24][25][26]

Table A-5: Solar PV and Electricity Cost Curve

Parameter	2025	2028	2030	2035
Solar PV CAPEX ($/kW installed)	900	750	500	350
Solar PPA rate ($/kWh)	0.10	0.08	0.065	0.05

Source: pManifold analysis

Solar PV cost projections are high-confidence relative to electrolyzers, reflecting a more mature learning curve and globally traded module markets. The 2025 baseline of $900/kW reflects

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[17] IRENA (2024), Green Hydrogen Cost Reduction: Scaling up Electrolysers to Meet the 1.5°C Climate Goal, International Renewable Energy Agency, Abu Dhabi.

[18] IEA (2023), Net Zero Roadmap: A Global Pathway to Keep the 1.5°C Goal in Reach, International Energy Agency, Paris.

[19] IEA (2025), Global Hydrogen Review 2025, International Energy Agency, Paris.

[20] BNEF (2024), Hydrogen Levelized Cost Update, BloombergNEF.

[21] World Bank / ESMAP (2026), Electrolyzers for Hydrogen Production: Technical and Economic Characteristics, Report No. P506220, World Bank, Washington DC.

[22] IEA (2025), Global Hydrogen Review 2025, International Energy Agency, Paris.

[23] Hydrogen Insight (2024), "Auction results reveal that Chinese hydrogen electrolysers are two to five times cheaper to buy than Western machines." China Energy Engineering Group tender: ALK at ~$210/kW, PEM at ~$630/kW.

[24] S&P Global Commodity Insights (2024), "China's hydrogen ambitions may ride on Sinopec's Kuqa project in Xinjiang," 11 January 2024. Sinopec Kuqa: 260 MW alkaline electrolysis, $470M project.

[25] SECI (2025), Results of Auction under SIGHT Programme Mode-1, Tranche-II for Green Hydrogen Production, Solar Energy Corporation of India. 450,000 MT/yr capacity awarded.

[26] IEEFA (2024), "India's $2.1bn push for local electrolyser manufacturing and green hydrogen production sees strong interest from large companies."

Maldives-specific installation premiums (shipping, remote site logistics) over global averages of $600–700/kW. The ASPIRE program record PPA of $0.098/kWh validates the 2025 electricity cost assumption[27].

A.4 Diesel Baseline Parameters

Table A-6: Diesel Generator Efficiency by Operator

Operator / Segment	DG Efficiency (kWh/L)	Capacity (MW)	Source
STELCO (Greater Malé)	3.8–4.1	130	Stakeholder consultation; medium-speed 4.0–4.1, high-speed 3.6–3.8
FENAKA (outer islands)	2.7–3.0	181	Stakeholder consultation; average 3.0 kWh/L, maximum 3.4[28]
Resorts (average)	3.2–3.5	211	Soneva reports 3.6–3.7; resorts average ~3.5
Reference plant (model)	2.7	0.6 (600 kW)	Conservative outer-island benchmark

Source: pManifold analysis

The reference plant efficiency of 2.7 kWh/L is deliberately conservative, reflecting the lower end of FENAKA's operating range. Many outer island generators; particularly older, smaller units; operate below this level, meaning the hydrogen cost advantage is likely larger than modelled for the worst-performing sites.

Table A-7: Fuel Price Assumptions ($/L)

Fuel Type	**2025**	**2028**	**2030**	**2035**
Diesel (base price)	1.04	1.092	1.144	1.248
Carbon adder	0.00	0.067	0.134	0.268
Effective diesel	**1.04**	**1.159**	**1.278**	**1.516**
Petrol	1.00	1.05	1.10	1.20
Jet A-1	1.20	1.35	1.48	1.76

Source: pManifold analysis

Diesel price escalation assumes 2% real annual increase, consistent with IMF World Economic Outlook projections for global oil markets. The carbon adder is a policy assumption representing a gradually introduced carbon pricing mechanism; not a current policy, but a recommended component of the transitional framework[29].

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[27] World Bank, ASPIRE (Accelerating Sustainable Private Investments in Renewable Energy) Programme, Maldives.

[28] Stakeholder consultations conducted during the February 2026 mission visit: STELCO, FENAKA, MTCC, Soneva, Veligandu, MWSC.

[29] IMF (2025), World Economic Outlook, International Monetary Fund, Washington DC.

A.5 Confidence Assessment

Table A-8: Assumption Confidence Levels and Sensitivities

Category	Parameter	Confidence	Sensitivity to LCOH
High	Fossil fuel baseline (786 M L/yr)	High	Low: measured and validated
High	DG efficiency (outer islands 3.0 kWh/L)	High	Low: FENAKA operational data
High	Solar PV capacity factor (20%)	High	Low: ground-truth validated
High	Electrolyzer efficiency (55 kWh/kg)	High	Low: manufacturer specification
Medium	CAPEX learning rates (48.8%)	Medium	±10% → ±$0.30/kg LCOH impact
Medium	Solar PPA rate ($0.10/kWh, 2025)	Medium	±$0.02/kWh → ±$0.15/kg impact
Medium	Storage CAPEX ($500/kg capacity)	Medium	±20% → ±$0.30/kg S&T impact
Medium	Capacity factor (35%)	Medium	±5% → ±$0.35/kg (largest single sensitivity
Low	S-curve adoption dynamics	Low	High: behavioural data sparse; pilot validation needed
Low	H2 subsidy level (5 to 1 $/kg)	Low	High: policy-dependent; no commitment yet
Low	2030 demand (4,610 t/yr)	Low	Range: 1,833–8,906 t/yr across scenarios

Source: pManifold analysis

Annex B: LCOH Detailed Calculations

B.1 Production LCOH by Plant Scale

LCOH is calculated as total annual cost divided by annual hydrogen output. Total annual cost includes annualized CAPEX (using the capital recovery factor), O&M, stack replacement provisions, and water costs. The table below provides LCOH across all five reference plant scales for key years.

Table B-1: Production LCOH Across All Scales ($/kg)

Plant Size	Capacity (MW)	H2 Output (t/yr)	2025	2028	2030	2035
Micro (0.15 MW)	0.15	8.4	8.48	6.99	4.93	3.63
Small (0.6 MW)	0.6	33.4	7.95	6.56	4.63	3.40
Medium (3 MW)	3	167.2	7.43	6.13	4.32	3.18
Large (15 MW)	15	836.2	7.25	5.98	4.22	3.10
V. Large (45 MW)	45	2,508.5	7.07	5.83	4.11	3.02

Source: pManifold analysis

The scale effect (micro to very large) is $1.41/kg in 2025, narrowing to $0.61/kg by 2035. This modest penalty for smaller installations is driven primarily by higher per-kW electrolyzer costs at small scale. This figure does not include the transport cost savings that distributed (smaller) plants achieve by producing hydrogen closer to the point of consumption; which can offset or exceed the production cost penalty.

B.2 Medium Plant (3 MW) Annual Cost Breakdown

Table B-2: Annual Cost Components, Medium Plant (3 MW Reference)

Component	2025	2028	2030	2035	Unit
Electrolyzer CAPEX	1,800,000	1,440,000	1,152,000	921,600	$
Solar PV CAPEX	4,950,000	4,125,000	2,750,000	1,925,000	$
BOP and installation	1,504,125	1,237,538	875,905	643,662	$
Total CAPEX (equipment + install)	8,254,125	6,802,538	4,777,905	3,490,262	$
Annualized CAPEX (CRF x total)	969,526	799,024	561,211	409,965	$/yr
Annual O&M (3% of CAPEX)	247,624	204,076	143,337	104,708	$/yr
Stack replacement provision	17,246	13,797	11,038	8,830	$/yr
Water cost (desal. at 5 $/m3)	7,526	7,526	7,526	7,526	$/yr
Total annual cost	**1,241,922**	**1,024,422**	**723,111**	**531,028**	**$/yr**
Annual H2 production	167,236	167,236	167,236	167,236	kg/yr
Production LCOH	**7.43**	**6.13**	**4.32**	**3.18**	**$/kg**

Source: pManifold analysis

CAPEX annualization (via the CRF) is the dominant cost component, representing 78% of total annual cost in 2025 and 77% in 2035. This CAPEX-heavy structure means that financing terms (discount rate, loan tenor) have a significant impact on LCOH; more so than operating costs or fuel inputs.

B.3 Landed Cost (Production + Storage & Transport)

Table B-3: Landed Hydrogen Cost by Scale (2030, $/kg)

Plant Size	Production	Storage	Transport	Landed Total
Micro (on-site)	4.93	0.63	0.00*	5.56
Small	4.63	0.63	1.72	6.98
Medium	4.32	0.63	1.72	6.68
Large	4.22	0.63	1.72	6.57
Very Large	4.11	0.63	1.72	6.46

Source: pManifold analysis

Note: Micro (on-site) production at resorts eliminates transport costs entirely, making it the lowest landed cost despite the highest production LCOH. This dynamic is central to the resort archetype economics (see Annex E).

B.4 Waste-to-Hydrogen Alternative Pathway

Table B-4: Waste-to-Hydrogen Gasification at Thilafushi

Parameter	Value	Notes

Technology	MSW gasification + water-gas shift	Proven at commercial scale globally
Feedstock	Municipal solid waste (~830 t/day to Thilafushi)	Currently landfilled/open-burned
Production LCOH	$5.05/kg	32% below electrolysis (2025 comparison)
Storage & transport	$3.26/kg (2025)	Same as electrolysis pathway
Landed cost	$8.31/kg (2025)	$2.37/kg cheaper than electrolysis
Co-benefit	Waste volume reduction; reduced open burning	Major environmental and health benefit
Maturity	Demonstration / early commercial	Requires detailed engineering assessment

Source: pManifold analysis

Waste-to-hydrogen gasification is especially promising for the Maldives because it handles two pressing challenges at once: energy decarbonization and waste management. The Thilafushi facility currently handles waste through landfill and open burning, causing significant air and water pollution. A gasification-to-hydrogen plant would convert this waste stream into a clean energy carrier while dramatically reducing environmental impact.

B.5 LCOH Sensitivity Analysis

Table B-5: Sensitivity of 2030 LCOH to Key Parameters (Medium Plant)

Parameter	Base Case	Variation	LCOH Impact ($/kg)	Notes
Electrolyzer CAPEX	$384/kW	±10%	±0.25	Moderate; driven by global market
Solar PV CAPEX	$500/kW	±10%	±0.05	Low; small share of total cost
Capacity factor	35%	±5 percentage points	±0.35	**Largest single sensitivity**
Electricity cost	$0.065/kWh	±$0.01	±0.02	Low; solar PPA is small cost share
Discount rate	10%	±2 percentage points	±0.40	**High impact; finance terms matter**
Water cost	$5/m^3	±50%	±0.02	Negligible

Source: pManifold analysis

Both highest-impact parameters (capacity factor and discount rate) are both partially within the project developer’s control. Capacity factor can be optimized through solar array sizing, electrolyzer operating strategy, and optional battery buffering. Discount rate can be reduced through concessional climate finance, sovereign guarantees, or blended finance structures. Improving these two parameters together could reduce 2030 LCOH by $0.50–0.75/kg relative to the base case.

Annex C: Storage and Transport Technical Assessment

C.1 Technology Comparison Matrix

Table C-1: Storage Technology Assessment for Maldives Context

Technology	Energy Density	CAPEX	Maturity	Safety	Maldives Suitability
Compressed H2 (350 bar)	1.1 MJ/L	approx. 500/kg capacity	Commercial	Well-established	**Recommended** : proven, marine-compatible
Compressed H2 (700 bar)	1.8 MJ/L	approx. 800/kg capacity	Commercial	Established	Not required at current volumes
Liquid H2 (-253°C)	8.5 MJ/L	approx. 2,000/kg capacity	Commercial	Specialized	Not economic below 10,000 t/yr
LOHC (toluene-MCH)	1.6 MJ/L	approx. 1,200/kg capacity	Demonstration	Moderate	Pilot evaluation recommended
Ammonia (NH3)	3.6 MJ/L	approx. 600/kg capacity	Commercial	Established (with precautions)	STELCO co-firing pathway

Source: pManifold analysis

The selection of compressed gaseous hydrogen at 350 bar reflects a pragmatic trade-off: while it has the lowest energy density (requiring more frequent shipments), it is the only option that combines commercial maturity, manageable safety requirements, reasonable cost, and compatibility with the Maldives' existing marine cargo logistics. Higher-density options (liquid H_2, LOHC) become relevant only at larger demand volumes or longer transport distances than currently projected.

C.2 Transport Cost Breakdown

The transport cost model disaggregates delivery costs into five components, each estimated from stakeholder consultation data and benchmarked against hydrogen transport economics in comparable island contexts (Hawaii, Japan offshore).

Table C-2: Marine Transport Cost Components (2030)

Component	Cost ($/kg)	Share	Notes
Tube trailer amortization	0.42	24%	200–500 kg capacity; ISO container format
Vessel charter (shared)	0.65	38%	Co-loaded with conventional cargo on MTCC routes
Fuel and crew	0.35	20%	Marine diesel for transport vessel
Port handling (load/unload)	0.15	9%	Crane and forklift operations

Insurance and contingency	0.15	9%	Weather disruption buffer; damage provisions
Total transport	**1.72**	**100%**	

Source: pManifold analysis

Vessel charter is the largest single cost component, reflecting the high cost of marine freight in the Maldives. The co-loading approach (sharing vessel capacity with conventional cargo) significantly reduces this cost relative to dedicated hydrogen transport vessels. As hydrogen demand grows and dedicated routes become viable, vessel utilization improves and per-kg transport costs decline.

C.3 Buffer Storage Requirements

Each consumption point requires a minimum 3-day storage buffer to manage monsoon-season shipping interruptions. This is a critical safety-of-supply requirement: a hydrogen-dependent power system without adequate buffering would need to maintain diesel backup generators, negating much of the operational cost advantage.

Table C-3: Buffer Storage Sizing by Application

Application	Daily H2 Consumption (kg)	Buffer Days	Storage Capacity (kg)	Estimated Storage CAPEX ($)
Outer island power (600 kW FC)	346	3	1,040	520,000
Resort micro-plant (150 kW)	87	3	260	130,000
MTCC ferry depot (per vessel)	75	3	225	112,500
Greater Malé hub (centralized)	5,300	5	26,500	13,250,000

The Greater Malé hub requires a larger 5-day buffer due to its critical role in serving the national capital and its position as the central distribution point for the hub-and-spoke network.

C.4 Storage and Transport Cost Curve

Table C-4: S&T Cost Curve by Component ($/kg)

Component	2025	2028	2030	2035	% Decline
Storage	0.87	0.74	0.63	0.54	-38%
Transport	2.38	2.03	1.72	1.46	-39%
Total	**3.26**	**2.78**	**2.35**	**2.00**	**-39%**

Source: pManifold analysis

Cost reductions are driven by improved vessel utilization as demand grows and delivery frequency increases, reduced storage equipment costs from manufacturing scale; and operational efficiencies as handling crews and port facilities gain experience with hydrogen logistics. The transport component shows the largest absolute reduction ($0.92/kg), reflecting the large impact of vessel utilization improvement.

Annex D: Use Case TCO Analysis

This annex provides component-level cost breakdowns underlying the summary comparisons in Chapter 4. Headline figures (LCOE, TCO per hour, savings percentages) are presented in the core report; this annex shows how those figures are derived. TCO includes all capital, fuel, and operating costs on an annualized basis.

D.1 U1: Power Generation (600 kW FENAKA Reference)

Table D-1a: Diesel Generator Cost Build-up Pure BAU (Scenario A)

Parameter	2025	2028	2030	2035	Unit
Capacity	600	600	600	600	kW
Capacity factor	0.40	0.40	0.40	0.40	–
Annual generation	2,102,400	2,102,400	2,102,400	2,102,400	kWh/yr
DG efficiency	2.7	2.7	2.7	2.7	kWh/L
Diesel consumption	778,667	778,667	778,667	778,667	L/yr
Diesel price (flat)	1.04	1.04	1.04	1.04	$/L
Carbon adder	–	–	–	–	$/L
Effective diesel price	1.04	1.04	1.04	1.04	$/L
Annual fuel cost	809,813	809,813	809,813	809,813	$/yr
Annual CAPEX (CRF)	52,881	52,881	52,881	52,881	$/yr
Annual O&M	24,000	24,000	24,000	24,000	$/yr
Total annual cost	886,694	886,694	886,694	886,694	$/yr
LCOE	**0.422**	**0.422**	**0.422**	**0.422**	**$/kWh**

Source: pManifold analysis

No diesel price escalation, no carbon adder. Diesel stays at $1.04/L across all years.

Table D-1b: Diesel Generator Cost Build-up Market Trajectory (Scenario B)

Parameter	2025	2028	2030	2035	Unit
Capacity	600	600	600	600	kW
Capacity factor	0.40	0.40	0.40	0.40	–
Annual generation	2,102,400	2,102,400	2,102,400	2,102,400	kWh/yr
DG efficiency	2.7	2.7	2.7	2.7	kWh/L
Diesel consumption	778,667	778,667	778,667	778,667	L/yr
Diesel price (2% escalation)	1.040	1.104	1.148	1.268	$/L
Carbon adder	–	–	–	–	$/L
Effective diesel price	1.040	1.104	1.148	1.268	$/L
Annual fuel cost	809,813	859,381	894,100	987,158	$/yr
Annual CAPEX (CRF)	52,881	52,881	52,881	52,881	$/yr
Annual O&M	24,000	24,000	24,000	24,000	$/yr
Total annual cost	886,694	936,262	970,981	1,064,039	$/yr
LCOE	**0.422**	**0.445**	**0.462**	**0.506**	**$/kWh**

Source: pManifold analysis

IMF-projected 2% real annual diesel price escalation. No carbon adder.

Table D-1c: Diesel Generator, Full Annual Cost Build-up Policy-Enabled (Scenario C)

Parameter	2025	2028	2030	2035	Unit
Capacity	600	600	600	600	kW
Capacity factor	0.40	0.40	0.40	0.40	-
Annual generation	2,102,400	2,102,400	2,102,400	2,102,400	kWh/yr
DG efficiency	2.7	2.7	2.7	2.7	kWh/L
Diesel consumption	778,667	778,667	778,667	778,667	L/yr
Diesel base price	1.04	1.092	1.144	1.248	$/L
Carbon adder	0.00	0.067	0.134	0.268	$/L
Effective diesel price	1.04	1.159	1.278	1.516	$/L
Annual fuel cost	809,813	902,475	995,136	1,180,459	$/yr
Annual CAPEX (CRF)	52,881	52,881	52,881	52,881	$/yr
Annual O&M	24,000	24,000	24,000	24,000	$/yr
Total annual cost	**886,694**	**979,355**	**1,072,017**	**1,257,339**	**$/yr**
LCOE	**0.422**	**0.466**	**0.510**	**0.598**	**$/kWh**

Source: pManifold analysis

Table D-2a: Hydrogen Fuel Cell, Full Annual Cost Build-up (with policy)

Parameter	2025	2028	2030	2035	Unit
FC capacity	360	360	360	360	kW
Battery buffer	300	300	300	300	kWh
H2 consumption	126,270	126,270	126,270	126,270	kg/yr
H2 landed price	10.68	8.89	6.68	5.17	$/kg
H2 subsidy	5.00	4.00	3.00	1.00	$/kg
Effective H2 price	5.68	4.89	3.68	4.17	$/kg
Annual H2 cost	717,486	617,865	464,213	527,167	$/yr
Annual CAPEX (CRF)	92,992	85,338	78,701	56,557	$/yr
Annual O&M	12,000	12,000	12,000	12,000	$/yr
Total annual	**783,467**	**667,350**	**499,266**	**545,724**	**$/yr**
LCOE	**0.373**	**0.317**	**0.237**	**0.260**	**$/kWh**
Savings vs. diesel	**12%**	**32%**	**54%**	**57%**	

Source: pManifold analysis

Table D-2b: Hydrogen Fuel Cell, Full Annual Cost Build-up (without policy)

Parameter	**2025**	**2028**	**2030**	**2035**
FC capacity (kW)	360	360	360	360
Battery buffer (kWh)	300	300	300	300

H2 consumption (kg/yr)	126,270	126,270	126,270	126,270
H2 landed price ($/kg)	10.68	8.89	6.68	5.17
H2 subsidy ($/kg)	–	–	–	–
Effective H2 price ($/kg)	10.68	8.89	6.68	5.17
Annual H2 cost ($/yr)	1,348,558	1,122,741	843,179	652,619
Annual CAPEX (CRF) ($/yr)	92,992	85,338	78,701	56,557
Annual O&M ($/yr)	12,000	12,000	12,000	12,000
Total annual ($/yr)	1,414,539	1,172,226	878,232	672,176
LCOE ($/kWh)	0.673	0.558	0.418	0.320
Premium vs. Sc. A diesel	+60%	+32%	−1%	−24%
Premium vs. Sc. B diesel	+60%	+25%	−10%	−37%

Source: pManifold analysis

No H2 production subsidy. H2 at full landed cost. LCOE decline driven entirely by electrolyser and solar PV cost reductions. Reaches parity with flat diesel (Scenario A) by ~2030 and with market diesel (Scenario B) by ~2028.

D.2 U2: Marine Transport (400 kW MTCC Ferry)

Table D-3a: Three-Way Propulsion Comparison (2030, with policy)

Parameter	Diesel	H2 Fuel Cell	H2-ICE
Engine/FC power (kW)	400	300	400
Hull CAPEX ($)	1,000,000	2,000,000	1,000,000
FC/ICE system CAPEX ($)	-	240,000	80,000
H2 storage CAPEX ($)	-	184,528	184,528
Total vessel CAPEX ($)	1,000,000	2,424,528	1,264,528
Annual fuel/H2 cost ($)	322,056	101,167	121,401
Annual CAPEX (CRF) ($)	117,460	284,784	148,646
Crew and O&M ($)	120,000	100,000	110,000
Total annual ($)	**559,516**	**485,951**	**380,047**
TCO per operating hour ($)	**200**	**174**	**168**
Savings vs. diesel	**-**	**13%**	**16%**

Source: pManifold analysis

The H_2-ICE option offers the strongest near-term economics: approximately 16% cost savings over diesel by 2030 under Scenario C (policy-enabled) assumptions. Against flat diesel (Scenario A), unsubsidised H2-ICE remains 29 % more expensive at 2030, narrowing to 9 % by 2035. Under market-trajectory diesel (Scenario B, 2 % p.a. escalation), the gap narrows slightly faster but H2 still does not reach parity within the study period. This reinforces that marine hydrogen, unlike power generation, requires policy support to achieve competitiveness within the study period. The H2-ICE option also offers lower vessel CAPEX than fuel cells, and proven marine engine technology that can be implemented as a retrofit. The fuel cell option becomes the preferred choice for new-build vessels post-2030, offering higher efficiency, zero local emissions, and lower noise; valuable attributes for passenger ferries operating in environmentally sensitive resort areas.

Table D-3b: Three-Way Propulsion Comparison (2030, without policy)

Parameter	Diesel (flat)	H2 Fuel Cell	H2-ICE
Engine/FC power (kW)	400	300	400
Total vessel CAPEX ($)	1,000,000	2,424,528	1,264,528
Annual fuel/H_2 cost ($)	291,200	202,334	242,801
Annual CAPEX (CRF) ($)	117,460	284,784	148,646
Crew and O&M ($)	120,000	100,000	110,000
Total annual ($)	528,660	587,118	501,447
TCO per operating hour ($)	178	203	230
Premium vs. flat diesel	–	+14%	+29%

Source: pManifold analysis

No H2 subsidy, no diesel carbon adder. Diesel held at flat $1.04/L. H2-FC narrows to +2% by 2035; H2-ICE to +9%.

D.3 U3: Road Transport (Light Truck)

Table D-4a: Road Transport TCO Comparison (2030, with policy)

Parameter	Diesel Vehicle	H2 Fuel Cell Vehicle
Vehicle CAPEX ($)	35,000	48,000
Vehicle life (years)	10	10
Annual distance (km)	20,000	20,000
Fuel/H2 consumption	10 L/100km	1.5 kg/100km
Annual fuel/H2 cost ($)	2,200	1,103
Annual CAPEX (CRF) ($)	5,696	7,812
Annual maintenance ($)	1,750	1,440
Total annual ($)	**9,646**	**10,355**
TCO per km ($)	**0.522**	**0.568**
Premium vs. diesel	**-**	**+8.7%**
Projected parity year	**-**	**~2033 w/escalation; >2035 w/o**
Parity vs flat petrol	-	**Beyond 2035**

Source: pManifold analysis

Hydrogen road vehicles remain 8.7% more expensive than diesel equivalents in 2030. The high vehicle CAPEX ($48,000 vs. $35,000) dominates the cost structure; fuel savings alone cannot overcome the capital premium until ~2033 (against escalating fuel prices) or beyond 2035 (against flat petrol). Under the flat-fuel baseline (Scenario A), the H2 FC premium remains +0.2% even at 2035, confirming that road transport hydrogen requires both vehicle cost declines and fuel price escalation to be viable. This use case is not recommended for near-term priority investment.

Table D-4b: Road Transport TCO Comparison (2030, without policy)

Parameter	Diesel (flat)	H2 Fuel Cell
Vehicle CAPEX ($)	35,000	48,000

Annual fuel/H2 cost ($)	2,080	2,004
Annual CAPEX (CRF) ($)	5,696	7,812
Annual maintenance ($)	1,750	1,440
Total annual ($)	9,526	11,256
TCO per km ($)	0.512	0.568
Premium vs. flat petrol	–	+11%

Source: pManifold analysis

No H2 subsidy; petrol held at flat $1.04/L equivalent. Premium narrows to +0.2% by 2035, driven by vehicle CAPEX declines.

D.4 U4: Aviation (SAF Pathway)

Table D-5: SAF vs. Jet Fuel Cost Comparison

Metric	2025	2028	2030	2035
Jet A-1 price ($/L)	1.20	1.35	1.48	1.76
SAF price, no policy ($/L)	4.54	3.52	2.71	2.15
SAF price, with policy ($/L)	3.70	3.07	2.40	2.15
Premium over jet fuel (no policy)	+278%	+161%	+83%	+22%
Premium over jet fuel (with policy)	**+209%**	**+128%**	**+62%**	**+22%**
H2 demand for SAF (t/yr)	-	-	293	-
Projected parity year	**-**	**-**	**-**	**>2035 (SAF); ~2029 (FC seaplane)**
SAF premium vs flat jet	+334%	+256%	+175%	+104%

Source: pManifold analysis

SAF remains substantially more expensive than conventional jet fuel throughout the projection period. SAF cost parity against flat jet fuel ($1.20/L) is not expected within the study period; against market jet fuel (with escalation and CORSIA), parity is approximately 2038. The FC seaplane pathway is more compelling: it reaches cost parity with conventional seaplanes by approximately 2029 even against flat fuel prices, driven by aircraft cost declines and improving fuel cell efficiency. The Maldives’ seaplane fleet is a potential early-adopter niche market if international SAF mandates create compliance incentives.

Annex E: Deployment Archetypes: Detailed Economics

Three deployment archetypes are defined to provide tailored implementation models for the Maldives’ three distinct power system contexts. Each archetype specifies the technology configuration, cost structure, operational parameters, and economic trajectory from 2025 to 2035.

E.1 Archetype 1: FENAKA Outer Island Microgrid

This is the primary deployment archetype, targeting FENAKA's network of 200+ outer islands with a combined installed diesel capacity of approximately 140 MW.

Table E-1: FENAKA Archetype: Configuration and Economics

Parameter	Value	Notes
Reference DG capacity	600 kW	FENAKA standard outer island plant
H2 FC capacity	360 kW	60% of DG (higher FC efficiency)
Battery buffer	300 kWh	Load transient management
H2 supply model	Hub delivery via marine tube trailer	From Greater Malé or Addu hub
Buffer storage	1,040 kg (3-day)	Monsoon resilience
DG LCOE (2030)	\$0.532/kWh	Including carbon adder
H2 FC LCOE (2030, with policy)	\$0.247/kWh	54% savings
Parity year (with policy)	**2028**	

Source: pManifold analysis

FENAKA's archetype represents the strongest economic case because outer island generators operate at the lowest efficiency (2.7 kWh/L) and highest fuel cost in the Maldivian system. The wide starting gap between diesel cost and hydrogen cost means that even modest cost improvements in hydrogen create significant savings. By 2035, the hydrogen system saves approximately \$750,000 per year relative to diesel for a single 600 kW installation.

E.2 Archetype 2: Resort Hydrogen Integration

Table E-2: Resort Archetype: Configuration and Economics

Parameter	Value	Notes
Reference DG capacity	250–500 kW	Typical resort installation
Electrolyzer	50–150 kW	On-site, dedicated solar
Solar PV	200–600 kW	Rooftop + ground-mount
H2 supply model	**On-site production**	No transport cost
Buffer storage	260 kg (3-day)	On-site compressed storage
DG LCOE (2030)	\$0.454/kWh	Resort diesel benchmark
H2 micro-plant LCOE (2030)	\$0.106/kWh	Eliminates S&T cost
Savings vs. diesel (2030)	**77%**	

Source: pManifold analysis

The resort archetype achieves the most favorable economics of any configuration because it eliminates the \$2.35/kg storage and transport cost component; which represents 35% of landed cost in the hub-delivery model. On-site production using dedicated solar arrays produces hydrogen at \$4.93/kg (micro scale, 2030), which translates to an LCOE of just \$0.106/kWh when converted through a fuel cell. This is less than one-quarter of diesel LCOE.

Beyond pure economics, resort operators report strong market demand for sustainability credentials. Green hydrogen installations provide tangible, verifiable decarbonization that supports premium pricing and ESG positioning. Several operators; notably Soneva (which already operates hybrid solar-diesel systems) and Six Senses (which has committed to net-zero targets); have expressed active interest in pilot installations.

E.3 Archetype 3: STELCO Ammonia Co-firing

Table E-3: STELCO NH3 Archetype; Configuration and Economics

Parameter	Value	Notes
STELCO DG capacity	130 MW	Greater Malé, medium-speed units
NH3 blend ratio	10–20%	Minimal engine modification
NH3 production	Via H2 + Haber-Bosch	At Greater Malé hub
DG LCOE (2030)	$0.363/kWh	STELCO baseline (more efficient)
NH3 blend LCOE (2030)	$0.495/kWh	36% premium over diesel
Parity year	**~2034**	Requires additional policy support

Source: pManifold analysis

The STELCO archetype does not achieve cost parity during the study period without additional policy support, because STELCO's generators operate at the highest efficiency in the Maldives (4.0 kWh/L) and lowest unit fuel cost. However, it serves an important strategic function:

- **Demand anchor:** STELCO represents the single largest point of energy consumption in the Maldives. Even a 10% ammonia blend creates substantial hydrogen demand, justifying the Greater Malé production hub's economics
- **Industrial efficiencies:** Ammonia production infrastructure (Haber-Bosch synthesis) can serve multiple markets, including fertilizer production, cold chain refrigeration, and potential regional export
- **Transition pathway:** Ammonia co-firing is an incremental step that does not require fleet replacement or major infrastructure overhaul, lowering the barrier to initial adoption

This archetype is recommended as a Phase 2/3 initiative, contingent on successful Phase 1 pilot outcomes and development of a specific STELCO co-firing policy incentive.

Annex F: Stakeholder Consultation Summary

Stakeholder consultations were conducted during the February 2026 mission visit across government agencies, utility operators, private sector companies, and development partners. The consultations served two purposes: validating model inputs (fuel consumption, operational parameters, cost data) and assessing institutional readiness for hydrogen adoption.

Table F-1: Consultation Summary

Stakeholder	Sector	Key Data Inputs	Readiness Assessment
STELCO	Power (Greater Malé)	130 MW capacity; medium-speed DG at 4.0–4.1 kWh/L; fuel procurement costs	Interested in ammonia co-firing; cautious on timeline. Requires proven reliability data before committing
FENAKA	Power (outer islands)	140 MW across 200+ islands; 3.0 kWh/L average	Strong interest in pilots; cited fuel cost and supply reliability as

		efficiency; high O&M costs	primary pain points. Willing to host pilot installation
MTCC	Marine and road transport	85 ferries; 720 L/day HS ferry consumption; fleet replacement schedule	Interested in H2-ICE retrofit for 2–3 vessels; concerned about refueling infrastructure availability
Soneva	Resort operations	On-site solar (8–9h peak daily); 3.6–3.7 kWh/L DG efficiency; sustainability targets	Most advanced readiness; existing solar-diesel hybrid. Active interest in micro-plant pilot. Willing to co-invest
Veligandu	Resort operations	2,700–3,000 L/day diesel; now has solar; 31 racks battery storage	Site visit conducted (see field notes). Good candidate for micro-plant retrofit
MOTE	Tourism sector	190 operational resorts; energy efficiency initiatives; sustainability branding trends	Supportive of hydrogen for resort sector; highlighted marketing value of "green hydrogen resort" positioning
MECCT	Government policy	NDC 3.0 targets; renewable energy policy structure; UNFCCC reporting requirements	Supportive in principle; needs detailed implementation plan before policy commitment
SEAM	Energy regulation	Grid codes; net metering framework; renewable energy targets; safety standards	Highlighted regulatory gaps: no existing hydrogen safety, production, or transport regulations

Source: pManifold analysis

Key Consultation Themes:

All operators cited **diesel cost and price volatility** as their primary operational concern. FENAKA in particular noted that outer island generation costs can exceed $0.50/kWh during supply disruptions, and that some islands experience fuel shortages lasting 3–5 days during severe monsoon conditions.

Willingness to pilot was expressed by FENAKA, MTCC, and Soneva, all contingent on grant or concessional financing for capital costs. No party indicated readiness to fund pilot projects on a purely commercial basis, reinforcing the importance of Phase 1 climate finance mobilization.

All stakeholders emphasized **logistics complexity** as a concern. The 3-day buffer storage requirement incorporated into the analysis reflects practical experience with monsoon-season supply disruptions, not a conservative assumption.

SEAM flagged **regulatory gaps** as a priority: there is currently no regulatory structure for hydrogen production licensing, compressed gas storage and transport certification, or safety standards for hydrogen handling in the Maldives. Addressing this gap is identified as a Phase 1 deliverable in the National GH2 Roadmap.

Annex G: Acronyms and Abbreviations

Abbreviation	Full Form

AEL	Alkaline Electrolyzer
BAU	Business as Usual (diesel scenario)
BNEF	Bloomberg New Energy Finance
BOP	Balance of Plant
BTB	Bridge-to-Beyond (hydrogen scenario)
BTR	Biennial Transparency Report
CAPEX	Capital Expenditure
CF	Capacity Factor
CORSIA	Carbon Offsetting and Reduction Scheme for International Aviation
CRF	Capital Recovery Factor
CTCN	Climate Technology Centre and Network
DG	Diesel Generator
FC	Fuel Cell
FENAKA	FENAKA Corporation (outer island utility)
GCF	Green Climate Fund
GEF	Global Environment Facility
GHG	Greenhouse Gas
H2	Hydrogen
H2-ICE	Hydrogen Internal Combustion Engine
IEA	International Energy Agency
IMO	International Maritime Organization
IPP	Independent Power Producer
IRENA	International Renewable Energy Agency
ISO	International Organization for Standardization
LCOE	Levelized Cost of Electricity
LCOH	Levelized Cost of Hydrogen
LH2	Liquid Hydrogen
LOHC	Liquid Organic Hydrogen Carrier
MECCT	Ministry of Environment, Climate Change and Technology
MEI	Ministry of Energy and Infrastructure
MOTE	Ministry of Tourism and Environment
MTCC	Maldives Transport and Contracting Company
MW	Megawatt
MWSC	Malé Water and Sewerage Company
NDC	Nationally Determined Contribution
NH3	Ammonia
O&M	Operations and Maintenance
OPEX	Operational Expenditure
PEM	Proton Exchange Membrane
PPA	Power Purchase Agreement
PV	Photovoltaic

RO	Reverse Osmosis
SAF	Sustainable Aviation Fuel
SEAM	Sustainable Energy Authority of the Maldives
SIDS	Small Island Developing State
SOEC	Solid Oxide Electrolyzer Cell
STELCO	State Electric Company (Greater Malé utility)
S&T	Storage and Transport
TCO	Total Cost of Ownership
UNEP	United Nations Environment Programme
UNFCCC	United Nations Framework Convention on Climate Change

Annex H: References

The following sources are referenced throughout this report. Footnotes in the text indicate where each source is cited.

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