SECURING THE LIGHTS: HYDROGEN STORAGE AS MAURITIUS' TURNKEY INSURANCE AGAINST BLACKOUTS

Assessing H_2 storage as a fast, modular and financeable solution for blackout risk and on-demand low-carbon power in Mauritius

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Preface and Acknowledgements

This report has been prepared to inform senior decision-makers in Mauritius' public and private sectors as they navigate an increasingly tight balance between electricity demand, supply security, and decarbonisation commitments. It focuses on one central proposition: that hydrogen (H_2)-based energy storage, deployed alongside renewables and existing thermal assets, can function as a practical form of "insurance" against blackouts and as a flexible source of on-demand power.

The analysis draws extensively on publicly available data and reports from the Ministry of Energy and Public Utilities, the Central Electricity Board (CEB), Statistics Mauritius, and associated agencies, including the Energy Efficiency Management Office and the Mauritius Renewable Energy Agency (MARENA). It also relies on international evidence from the International Energy Agency (IEA), the International Renewable Energy Agency (IRENA), the World Bank, and specialist technical studies on long-duration energy storage and hydrogen economics. [Ministry of Energy and Public Utilities, Annual Report 2023–2024; IEA Global Hydrogen Review 2024; IRENA Hydrogen Overview; PNNL Energy Storage Cost and Performance Assessment 2022]

Particular acknowledgement is owed to the Ministry of Energy and Public Utilities for its detailed Annual Report 2023–2024, which sets out the latest figures on electricity generation (3,018.8 GWh in 2023, of which 15.6 per cent from renewable sources) and peak demand (508.4 MW), and articulates the strategic intent to achieve a 60 per cent renewable share in electricity and a complete phase-out of coal by 2030. [Ministry of Energy and Public Utilities, Annual Report 2023–2024] These commitments provide the policy backdrop against which hydrogen storage must be assessed.

The report has also benefited from insights contained in recent press and analytical coverage of Mauritius' emerging power-sector constraints, including warnings about a dangerously thin reserve margin, the need to secure roughly 100 MW of additional capacity by late 2025 to avoid scheduled cuts, and the direct testimonies of business associations facing unplanned power interruptions. [Economic Times, 11 April 2025; Ainvest, 23 July 2025; NewsMoris, 23 October 2025]

International experience on hydrogen-enabled microgrids and island systems has helped ground the "turnkey" and "insurance" framing used here. Case studies from Reunion's Mafate hydrogen mini-grid, hydrogen-battery hybrids in Thailand, and containerised solar-plus-hydrogen solutions in Uganda illustrate that hydrogen storage can already deliver long-duration, on-demand power in remote and island contexts, albeit at modest scales. [Development Asia, "How to Light Up Remote Areas with Clean Hydrogen Energy", 2019]

While every effort has been made to ensure factual accuracy and to attribute data correctly, any remaining errors or interpretations are the sole responsibility of the author. The report is independent and does not represent the official position of any Mauritian institution or of the international organisations cited.

Table of Contents

Executive Summary

Mauritius is entering a period in which the margin between electricity demand and dependable supply is becoming uncomfortably narrow. In 2023, total electricity generation reached 3,018.8 GWh, with only 15.6 per cent supplied by renewable sources; the balance came predominantly from imported coal and petroleum products. Peak demand rose to 508.4 MW, up from 491.6 MW in 2022, reflecting the rebound of economic activity. [Ministry of Energy and Public Utilities, Annual Report 2023–2024] By February 2025, the system recorded its highest ever peak at around 567.9 MW. [Economic Times, 11 April 2025]

On paper, the nominal installed capacity of the Mauritian power system stood at approximately 881.6 MW by mid-2024, including both CEB plant and independent power producers. [CEB Electricity Production Overview 2023/24] (ceb.mu) In practice, this headline figure masks the de-rating of ageing thermal units, the seasonality of bagasse-based generation, and the intermittency of solar and wind. Unplanned outages – such as the loss of a 30 MW unit at Fort George – have already forced the CEB to curtail evening supply in specific cases and to appeal for public conservation, highlighting how a single unit failure can ripple rapidly across the system. [African Security Analysis, "Mauritius Grid Strain Prompts Call for Power Conservation"]

By mid-2025, the CEB and the Government were warning that, unless around 100 MW of new capacity could be secured by December or January, scheduled power cuts might be unavoidable. [Ainvest, 23 July 2025] Businesses in sectors such as ICT outsourcing, construction and manufacturing have already begun to adjust to this risk by shifting operations away from peak hours, installing their own diesel back-up, or exploring hybrid solar solutions – all of which carry costs, complexity, and, in the case of diesel, additional emissions. [NewsMoris, 23 October 2025]

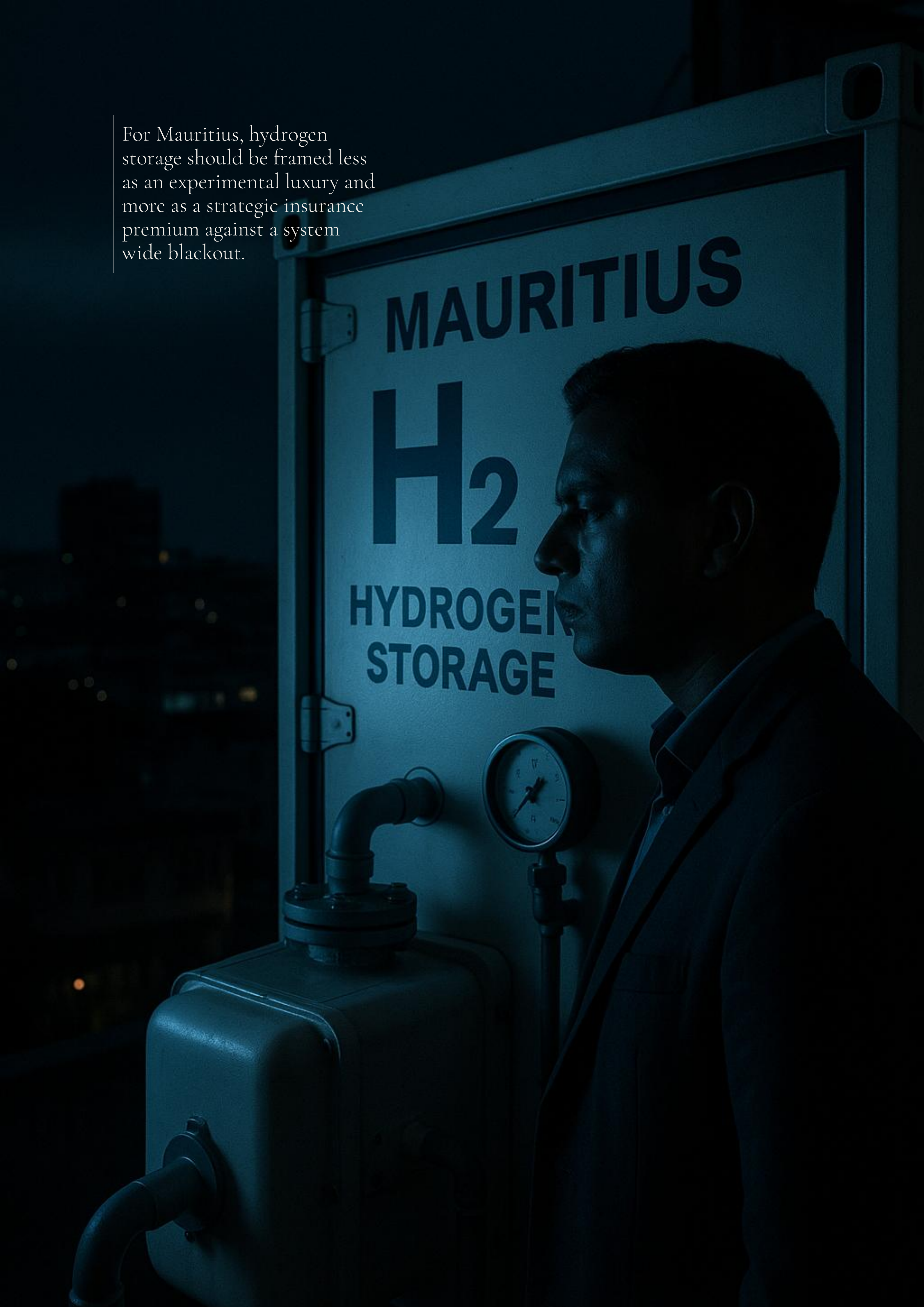
At the same time, Mauritius has set ambitious climate and energy targets: a 60 per cent share of renewables in electricity generation by 2030, a complete phase-out of coal, a 10 per cent improvement in energy efficiency, and a 40 per cent reduction in greenhouse gas emissions by 2030 relative to business as usual. [Ministry of Energy and Public Utilities, Annual Report 2023–2024] These objectives are reinforced in the country's evolving Nationally Determined Contribution (NDC) under the Paris Agreement and in the Renewable Energy Roadmap 2030, which envisages a portfolio of onshore solar, offshore wind and other marine renewables. [UN DESA, "Mauritius Renewable Energy Roadmap 2030"; Joint SDG Fund / Republic of Mauritius, 5 October 2023]

The strategic dilemma is therefore clear: Mauritius must simultaneously (i) avoid blackouts and maintain high reliability for a modern, service-driven economy; (ii) rein in its dependence on volatile imported fuels; and (iii) deliver on its climate commitments. Traditional responses to capacity shortages – such as leasing diesel or LNG powerships, or installing conventional oil-fired peaking plant – may reduce blackout risks in the short term but would run counter to decarbonisation goals and exacerbate exposure to international fuel price swings.

Key Findings

- Mauritius' power system is running on a dangerously thin reserve margin, with rising peak demand and ageing thermal assets increasing blackout risk.
- The country remains heavily dependent on imported fossil fuels even as it commits to 60% renewables and a coal phase-out by 2030.
- Hydrogen storage is not the cheapest source of everyday energy but is well-suited as long-duration "insurance" against rare, high-impact outages.
- H_2 storage complements, rather than replaces, batteries, flexible thermal plant and demand-side response in a balanced reliability portfolio.
- Global experience from islands and microgrids shows that modular hydrogen systems are technically viable and increasingly bankable.
- A "Hydrogen Resilience Reserve" for Mauritius can be justified economically when benchmarked against the value of avoided outages and fuel import risks.
- Realising this vision requires explicit recognition of storage in planning, licensing and tariffs, and the use of capacity-style contracts and blended climate finance.
- A phased roadmap—analytics and regulation, a pilot project, then a larger reserve—offers a practical pathway to deployment by 2030 and beyond.

For Mauritius, hydrogen storage should be framed less as an experimental luxury and more as a strategic insurance premium against a system wide blackout.



insurance

Within this context, hydrogen-based energy storage emerges as a potential “insurance layer” for Mauritius’ power system. Hydrogen is not an energy source but a flexible energy carrier that can be produced by electrolysis from renewable electricity, stored in various forms, and later reconverted into electricity via fuel cells or hydrogen-ready turbines. IRENA’s 1.5°C scenario suggests that hydrogen could provide around 10 per cent of final energy demand by 2050, particularly in sectors and applications where direct electrification is difficult, including seasonal energy storage. [IRENA, Hydrogen Overview]

Global hydrogen production reached around 97 million tonnes in 2023, yet less than 1 per cent of this volume was low-emission hydrogen. [IEA Global Hydrogen Review 2024] Producing renewable hydrogen today generally costs 1.5 to 6 times more than hydrogen from unabated fossil fuels, although the cost premium narrows down the value chain and is expected to fall as electrolyser manufacturing scales and renewable power costs continue to decline. [IEA Global Hydrogen Review 2024]

From a power-system perspective, the critical feature of hydrogen storage is duration. Lithium-ion batteries, whose costs have fallen sharply over the past decade, are highly efficient (round-trip efficiencies around 85–90 per cent) and extremely well suited to managing hourly and daily fluctuations; however, their economics deteriorate for very long storage durations, because most of the cost resides in the energy capacity (kWh) rather than the power conversion equipment (kW). By contrast, hydrogen storage systems have lower round-trip efficiencies (typically in the 35–45 per cent range once electrolysis and reconversion losses are accounted for) but a much lower marginal cost for adding storage duration. [PNNL Energy Storage Cost and Performance Assessment 2022; IEA, Managing the Seasonal Variability of Electricity Demand and Supply, 2024]

A comprehensive assessment by the US Pacific Northwest National Laboratory (PNNL) finds that for 1,000 MW systems with 100 hours of storage, hydrogen and compressed-air energy storage (CAES) can have installed costs as low as around USD 15–18 per kWh by 2030, significantly below battery solutions at that duration. [PNNL Energy Storage Cost and Performance Assessment 2022] This is precisely the regime in which Mauritius faces its most acute risk: rare but high-impact events (multi-hour or multi-day supply deficits due to plant outages, adverse weather, or fuel logistics) where the effective “value of lost load” (VoLL) for the economy can reach tens of dollars per kWh. For small-island systems highly dependent on reliable electricity, IRENA reports typical system-wide VoLL values of USD 10–50 per kWh, with Barbados using USD 5 per kWh in planning. [IRENA, Transforming Small-Island Power Systems, 2019]

In such a context, the relevant question for Mauritius is not whether hydrogen storage is the cheapest way to provide an extra megawatt-hour in average conditions, but whether a modest, well-designed hydrogen storage facility can provide a cost-effective insurance premium compared with the economic losses of a nationwide blackout.

A turnkey, modular concept for Mauritius

International experience shows that hydrogen-based systems can be delivered in modular, containerised formats, combining electrolysers, storage tanks, fuel cells and control systems in a relatively compact footprint. Development Asia documents hydrogen-backed microgrids on Reunion Island and in Thailand and Uganda, where small communities rely on solar-plus-hydrogen systems for on-demand, low-carbon power. In the case of Koh Jik, a 300-inhabitant island in Thailand, a solar-hydrogen mini-grid reduced diesel consumption to 37,000 litres over the system’s lifetime, with generation costs of around EUR 0.50–0.60 per kWh – lower than a 100 per cent diesel alternative once fuel volatility is taken into account. [Development Asia, 2019]

Scaling these concepts to the Mauritian grid would require more sophisticated engineering, but the underlying idea remains: a “Hydrogen Resilience Reserve” – for example, a 30–60 MW hydrogen-ready peaking plant coupled to 200–600 MWh of hydrogen storage and supplied by 20–40 MW of dedicated solar and/or wind capacity – could be located close to key substations. Such an asset would:

- Provide firm, dispatchable capacity during peak hours and during contingency events, thereby increasing the system’s effective reserve margin.
- Absorb renewable over-generation (e.g. mid-day solar) that might otherwise be curtailed, converting it into storable hydrogen.
- Supply critical loads – hospitals, water pumping, telecoms, data centres, and key industrial sites – for many hours in the event of a major system disturbance.

- Establish the technical and regulatory foundations for future hydrogen use in shipping, transport and industry.

Mauritius' own policy direction already points in this direction. In addition to the 60 per cent renewable target, the Government has explicitly identified hydrogen – including offshore hydrogen projects and associated vessels – as an area where it seeks external expertise, notably from India, to expand its energy mix. [Economic Times, 11 April 2025] This creates an opportunity to design a first-of-a-kind, but not first-of-its-kind globally, hydrogen storage project as a turnkey solution: a single, integrated procurement for electrolysers, storage, conversion equipment and control systems, delivered under a long-term availability-based contract.

Positioning hydrogen alongside other flexibility options

Hydrogen storage is not – and should not be presented as – a silver bullet. The IEA's 2024 analysis of seasonal variability underscores that future power systems will rely on a portfolio of flexibility resources: demand response, batteries and smart grids for short-term balancing; hydrogen, low-emission thermal plants, and hydropower for seasonal and extreme-event balancing. [IEA, Managing the Seasonal Variability of Electricity Demand and Supply, 2024; IEA, Grid-Scale Storage]

For Mauritius, batteries will remain the first choice for sub-hourly balancing, frequency support and the management of daily solar variability. The country is already integrating Battery Energy Storage Systems (BESS) as part of its grid modernisation efforts. [Ministry of Energy and Public Utilities, Annual Report 2023–2024] Flexible gas or liquid-fuel plant may still be needed as a bridging measure, particularly as ageing units retire and before large-scale renewables and storage are fully in place. Energy efficiency, smart tariffs, and demand-side flexibility will also play a critical role in shaving peaks and lowering overall system stress.

What hydrogen storage does is to occupy a specific yet vital niche: providing long-duration, low-carbon backup for scenarios that are too infrequent to justify expensive, high-utilisation assets but too damaging economically to be left unmanaged. A single multi-day outage affecting an advanced, service-oriented economy like Mauritius can easily impose losses equivalent to several years of carrying costs on a hydrogen storage asset, once direct business interruptions and wider macroeconomic impacts are taken into account. [IRENA, Transforming Small-Island Power Systems, 2019; various VoLL studies]

Key conclusions

On the basis of current data and international evidence, the report reaches four overarching conclusions:

1. **Blackout risk is rising as the system tightens.** Peak demand is increasing faster than firm capacity, and the system's effective reserve margin is now thin enough that single-unit outages and maintenance can trigger load reductions or the prospect of scheduled cuts. This risk will grow as older thermal units approach end-of-life unless new firm capacity is rapidly brought online. [Ministry of Energy and Public Utilities, Annual Report 2023–2024; Ainvest, 23 July 2025]
2. **Mauritius' decarbonisation objectives constrain conventional responses.** Reliance on emergency diesel or gas-fired solutions may provide immediate relief but sits uneasily with a coal phase-out by 2030 and a 40 per cent emissions abatement target. Over-exposure to imported fuels also runs counter to broader energy-security aims, especially given the volatility in coal and oil import bills documented in recent years. [Energy Observatory Report 2021–2022]
3. **Hydrogen storage is economically rational as an insurance product rather than as a bulk-energy solution.** Though renewable hydrogen remains more expensive than fossil hydrogen, and its round-trip efficiency is relatively low, long-duration hydrogen storage can be cost-competitive when benchmarked against the value of avoided outages rather than against average wholesale power prices. [IEA Global Hydrogen Review 2024; PNNL Storage Cost Assessment]
4. **Mauritius is well-placed to pilot hydrogen storage in a controlled, turnkey fashion.** The country's manageable system size, sophisticated institutions, and existing commitment to offshore renewables and green hydrogen make it an ideal candidate for a flagship "Hydrogen Resilience Reserve" project. If well-structured, such a project could leverage concessional finance, climate funds and technical partnerships (including with India) while containing fiscal risk. [Economic Times, 11 April 2025; Joint SDG Fund / Republic of Mauritius, 5 October 2023]

Strategic vision

The overarching vision that emerges is of hydrogen storage as a *quiet but powerful insurance instrument* embedded within Mauritius' broader energy transition. Rather than competing with solar, wind, batteries or even flexible gas plant, hydrogen storage becomes the backstop that guarantees continuity of supply when the system is under greatest stress. In operational terms, it underwrites a minimum reliability standard – for example, ensuring that critical loads and a substantial share of normal demand can be maintained even if the largest unit fails during peak season or if multiple assets are simultaneously unavailable.

In policy terms, hydrogen storage can be treated analogously to other forms of insurance: a known, annualised premium – in the form of capacity payments or availability charges – exchanged for protection against rare but highly damaging events. When combined with a clear regulatory framework, robust system planning, and transparent procurement, this approach allows Mauritius to move away from last-minute, ad hoc emergency measures towards a more deliberate, resilient and low-carbon reliability strategy.

Context and Diagnostic: Mauritius' Power System & Emerging Blackout Risk

The Mauritian Power System at a Crossroads

Mauritius is a small, open and relatively high-income economy, with a population of around 1.3 million and a GDP per capita in excess of USD 11,000 in 2024 [World Bank World Development Indicators 2024]. Over the past four decades, it has transformed from a mono-crop sugar exporter into a diversified services and manufacturing hub, with tourism, financial services, ICT/business process outsourcing and construction playing major roles [IMF Article IV 2025]. These sectors are all heavily dependent on reliable electricity. Power interruptions do not only inconvenience households; they disrupt hotel operations, data centres, call centres, banking systems and export-oriented manufacturing plants.

The Mauritian power system has, until recently, been a quiet success story. Access to electricity is effectively universal; World Bank data report 100 per cent access for the population from 2019 onwards [World Bank WDI, Access to Electricity]. The grid is operated by the Central Electricity Board (CEB), which purchases power from a mix of its own thermal stations and independent power producers (IPPs), many of which are embedded in the sugar industry and provide bagasse-fired generation during the cane-crushing season.

In 2023, total installed capacity is estimated at around 955 MW, with approximately 271 MW classified as renewable capacity and the remainder as thermal [Statistics Mauritius, Energy and Water Statistics 2023]. Total electricity generation reached around 3,264 GWh, of which 574 GWh (17.6 per cent) came from renewable sources. This share is broadly consistent with other analyses which find that less than one-fifth of Mauritian electricity is generated from renewables, despite the country's stated ambitions [Edoo et al., "Pathways to decarbonise the power sector in Mauritius", 2025].

The underlying fuel mix remains dominated by imported fossil fuels. The International Energy Agency (IEA) estimates that in 2023, oil-fired generation accounted for roughly 49 per cent of output, coal for 34 per cent, with the balance from bagasse, hydro and other renewables [IEA Mauritius Country Profile 2024]. The result is a system in which Mauritius is both exposed to volatile international fuel prices and

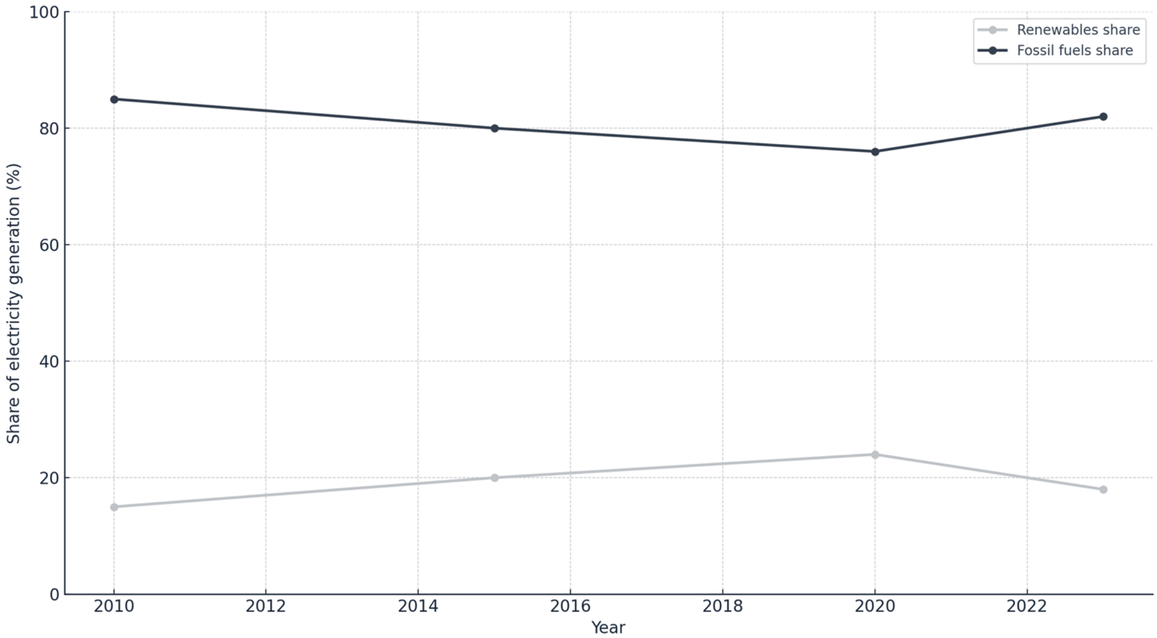


Figure 1 Mauritius structural shift in the generation mix

constrained by the technical characteristics of ageing coal and heavy fuel oil units.

At the same time, electricity demand has been steadily rising. Economic growth, urbanisation, proliferation of air-conditioning and the expansion of ICT and financial services have all driven load upwards. CEB data show that maximum demand increased from around 492 MW in early 2022 to 508 MW in 2023 and reached a record 567.9 MW at 21:00 on 5 February 2025 [CEB Annual Report 2021-22; CEB "System Losses and Maximum Demand" fact sheet]. This growth in evening peak demand is particularly significant because it coincides with the hours when solar generation falls away and when the system is most vulnerable to unexpected outages.

The Government has set ambitious strategic objectives for the sector. The Renewable Energy Roadmap 2030 and subsequent updates by the Economic Development Board and the Ministry of Energy and Public Utilities outline a trajectory towards 60 per cent of electricity being generated from renewable sources by 2030, a complete phase-out of coal, and a roughly 40 per cent reduction in greenhouse gas emissions by 2030 relative to business-as-usual [Renewable Energy Roadmap 2030; EDB Renewable Energy Brief; Mauritius Revised NDC].

However, as the chart below illustrates in stylised form, the structural shift in the generation mix has so far been modest. The share of renewables in generation appears to have increased gradually from around 15–20 per cent in 2010–2015 to a peak of about 23–24 per cent around 2020, before slipping back to under 20 per cent in 2023 as thermal capacity expanded and hydrological and bagasse output fluctuated [Statistics Mauritius 2010–2023; Energy and Water Statistics].

This pattern underscores a central tension. Mauritius is committed, on paper, to a rapid decarbonisation and to a high-renewables future. In practice, it remains structurally tied to fossil fuels for the majority of its electricity, with imported coal and oil underpinning system adequacy and flexibility. At the same time, the growth in peak demand is eroding the cushion that historically protected the island from serious reliability incidents. The power system is, in short, at a crossroads: it must simultaneously secure adequate capacity, integrate much larger volumes of variable renewables, and reduce dependence on imported fuels.

Blackout Risk, Adequacy and System Resilience

Power-system adequacy is, in essence, about ensuring that available capacity is sufficient to meet demand with a high probability under a range of plausible conditions. In large interconnected systems, this is often expressed in terms of loss-of-load expectation (LOLE), reserve margins and other probabilistic metrics. In a small, isolated system such as Mauritius, the stakes are higher: the failure of a single large unit, or a coincidence of equipment outages and peak demand, can have system-wide consequences because there is no neighbouring grid from which to import power.

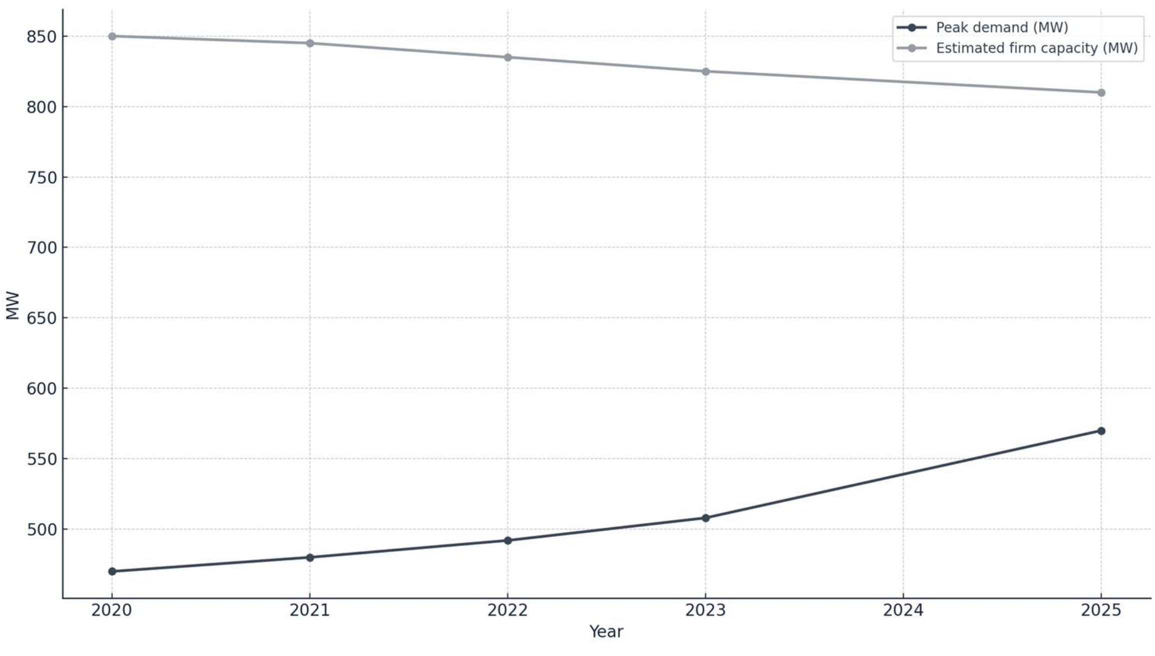


Figure 2 Mauritius Energy Peak Demand

On paper, Mauritius' installed capacity of roughly 955 MW appears comfortably above its observed peak demand of around 568 MW in early 2025 [Statistics Mauritius 2023; CEB fact sheet]. However, this headline figure is misleading for at least three reasons. First, several thermal units are old and subject to de-rating due to age-related performance degradation and maintenance constraints; the effective firm capacity is therefore significantly lower than installed capacity. Secondly, a portion of renewable capacity—particularly solar PV and wind—cannot be relied upon to produce at nameplate levels during evening peaks or under adverse weather conditions. Thirdly, seasonal units such as bagasse-fired IPPs only contribute during the cane-crushing season. When these realities are taken into account, the true **reserve margin** – the difference between dependable capacity and peak demand – is far thinner than the nominal margin.

The chart plots the trend in peak demand against an indicative estimate of firm capacity between 2020 and 2025. Peak demand rises from around 470 MW to nearly 570 MW, while estimated firm capacity declines slightly from approximately 850 MW to around 810 MW due to de-rating and outages. The gap between the two lines, representing the effective reserve margin, narrows considerably over the period. Although the absolute margin still appears positive, its erosion means that Mauritius is increasingly at risk of violating an N-1 security criterion (the ability to withstand the loss of the largest unit without load shedding).

This risk is not theoretical. In 2025 the CEB publicly reported that a 30 MW unit at the Fort George power station had experienced technical problems, forcing the utility to reduce evening load and appeal to consumers for conservation [African Security Analysis, "Mauritius: Grid Strain Prompts Call for Power Conservation"]. Later that year, additional engine failures created an estimated 55 MW shortfall, prompting "red alerts" and warnings of possible scheduled cuts if demand could not be reduced [NewsMoris, "Mauritius Power Crisis", 2025; Mauritius Civic Lens energy updates].

Businesses have responded to these signals. Press reports describe firms in ICT/BPO, manufacturing and services adjusting operating hours, installing or expanding diesel backup generators, and re-negotiating service-level agreements in anticipation of more frequent disturbances [NewsMoris, "Mauritius Power Crisis: Businesses Switch Gears…", 2025]. The World Bank's Enterprise Survey data for Mauritius indicate that around 40 per cent of firms reported experiencing electrical outages in 2023, placing the country in a category where power reliability is a material concern for investors [World Bank Enterprise Surveys, "Firms experiencing electrical outages (% of firms)"].

Resilience is further challenged by climate-related hazards. Mauritius is exposed to tropical cyclones, heavy rainfall and flooding, which can damage transmission and distribution infrastructure, disrupt fuel supply chains, and simultaneously boost demand (for example through increased air-conditioning use during heatwaves). Recent analytical work on "Towards a More Resilient Power System for Mauritius" underscores that strengthening resilience must be a

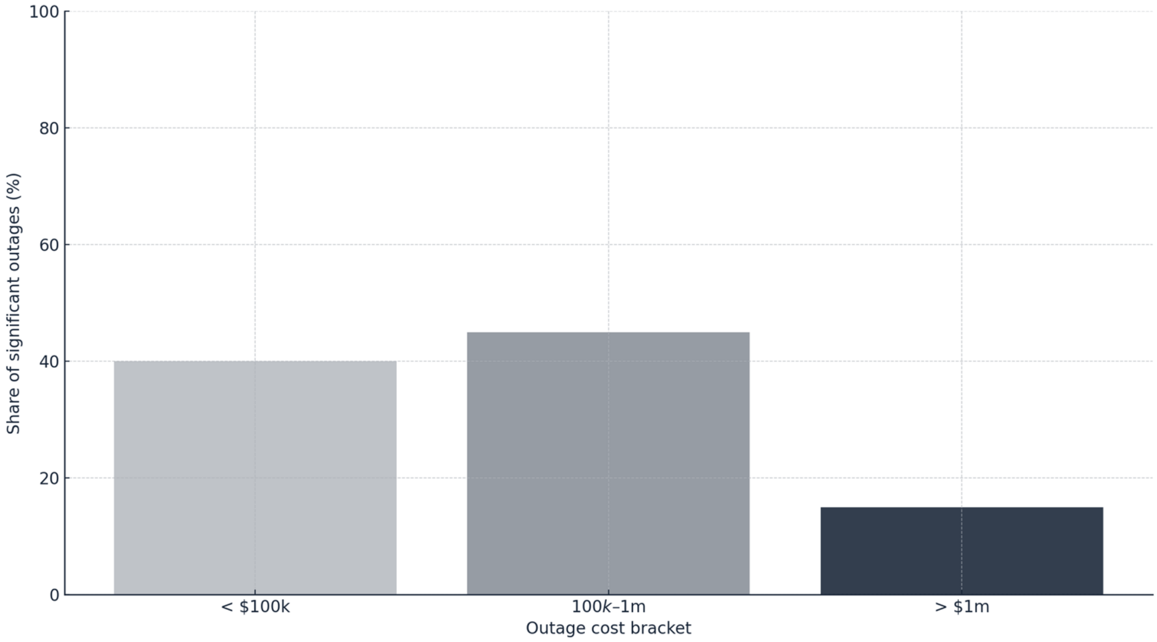


Figure 3 Outage Cost Bracket

central pillar of the country's energy strategy, not an afterthought [resilience study referenced in national planning documents].

From a macroeconomic perspective, the risk of large-scale blackouts is significant. The Uptime Institute's global Annual Outage Analysis reports that more than 60 per cent of significant outages now cost over USD 100,000, with a growing share exceeding USD 1 million [Uptime Institute, "Annual Outage Analysis 2023–24"]. In a small, service-driven economy, a national-scale power cut of several hours could easily produce aggregate losses in the tens of millions of dollars once lost output, spoilage, reputational damage and contractual penalties are taken into account.

The chart therefore serves as more than a visual: it encapsulates a **structural vulnerability**. A system that once had generous redundancy has, through a combination of demand growth, ageing assets and limited new firm capacity, become acutely exposed. Absent decisive action, the probability of large-scale blackouts will rise, and the "insurance gap" – the difference between acceptable and actual reliability – will widen.

Hydrogen Storage Technologies: Global State of Play & Economics

Hydrogen is not a new energy carrier; it is already produced in large volumes for refining, fertiliser manufacture and various industrial processes. What is new is the attempt to align hydrogen production with decarbonisation and to use hydrogen as a tool for flexibility and storage in the power sector. The International Energy Agency estimates that global hydrogen production reached roughly 95–100 million tonnes in 2023, but less than 1 per cent of this was produced using low-emission routes (electrolysis from renewables or fossil-based with carbon capture) [IEA Global Hydrogen Review 2024].

From the perspective of Mauritius, the relevant part of this landscape is the subset of technologies that enable **power-to-hydrogen-to-power** cycles:

1. **Production.** Low-carbon hydrogen can be produced via water electrolysis powered by renewable electricity. The main electrolyser technologies are alkaline (AEL), polymer electrolyte membrane (PEM) and, emerging more recently, solid oxide (SOEC). Capital costs for utility-scale AEL and PEM systems have fallen significantly, with IEA and IRENA estimating ranges of roughly USD 500–1,400 per kW in 2023, depending on project scale and location, with further reductions expected as manufacturing capacity expands [IEA Global Hydrogen Review 2024; IRENA "Green Hydrogen: A Guide to Policy Making"].
2. **Storage.** Once produced, hydrogen can be stored in several forms: as compressed gas in high-pressure vessels (typically 200–700 bar); as liquefied hydrogen at cryogenic temperatures (around −253°C); in metal hydrides; or chemically bound in carriers such as ammonia or liquid organic hydrogen carriers. For large-scale, long-duration storage, international projects increasingly focus on geological formations such as salt caverns, which

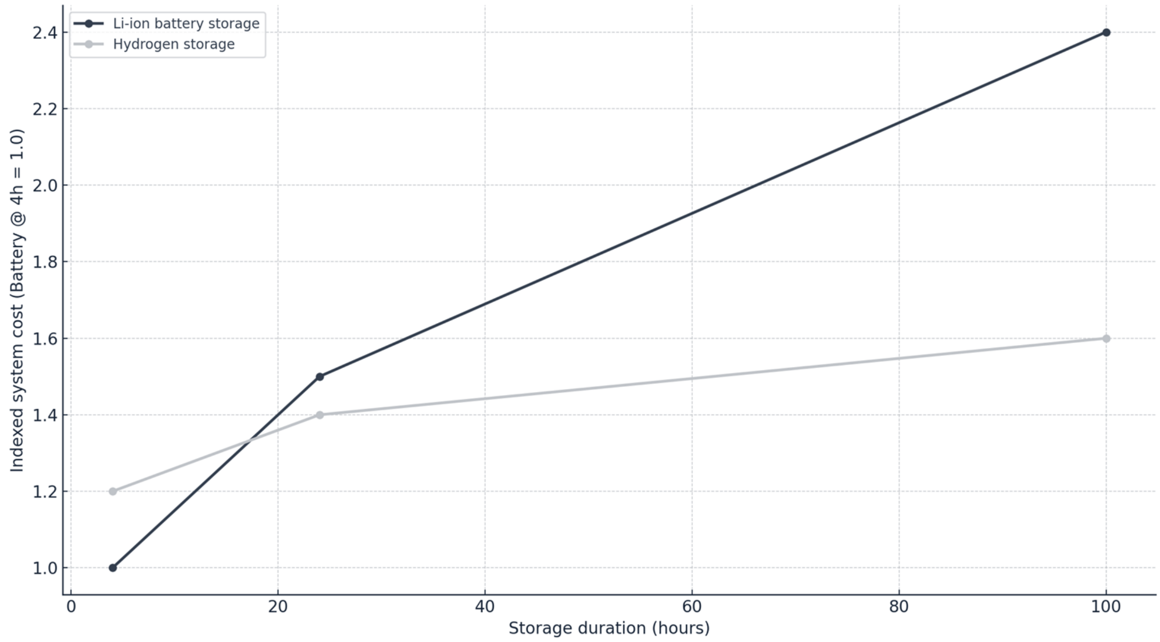


Figure 4 Storage Duration

can store millions of cubic metres of hydrogen at moderate cost [IEA, “The Future of Hydrogen” 2019; various European demonstration projects]. In contexts without suitable geology, above-ground compressed gas storage in tanks or mounded vessels remains the primary option, albeit with higher unit costs.

3. **Conversion back to power.** Hydrogen can be reconverted into electricity using fuel cells (PEM or solid oxide) or by combustion in gas turbines or engines. Several major turbine manufacturers now offer “hydrogen-ready” units capable of firing blends of hydrogen and natural gas, with pathways to higher hydrogen shares over time. Fuel cells offer higher efficiencies at smaller scale but remain relatively expensive in capital terms [IEA, “Hydrogen and Fuel Cells: The Future”].

The economics of hydrogen storage are shaped by three core elements:

- **Round-trip efficiency.** The combined efficiency of electrolysis, storage and reconversion is typically around 30–45 per cent for current technologies, significantly lower than the 80–90 per cent observed for lithium-ion batteries. This means that more input electricity is required per unit of output electricity.
- **Capital intensity vs duration.** For lithium-ion batteries, most of the cost is associated with the energy capacity (the number of hours of discharge), and costs rise more or less proportionally with duration. For hydrogen storage, the cost of adding more storage duration is relatively low (additional tanks or storage volume), while the electrolysis and generation units define the power capacity. Studies by the US Pacific Northwest National Laboratory (PNNL) indicate that for storage durations of 100 hours or more, hydrogen systems can have lower levelised costs than batteries because the marginal cost of additional storage hours is small [PNNL “Energy Storage Cost and Performance Assessment” 2022].
- **Value of long-duration capability.** The lower efficiency of hydrogen storage is less important when the asset is used infrequently to cover rare, high-value events (such as multi-day supply shortfalls), rather than to arbitrage daily price spreads. The appropriate benchmark cost is therefore the value of avoiding outages, not the average wholesale power price.

The chart plots indexed system cost (with battery storage at 4 hours set to 1.0) against storage duration for two technologies: lithium-ion batteries and hydrogen storage. It shows battery costs rising steeply as duration increases from 4 to 100 hours, while hydrogen storage costs, though higher at very short durations, rise more gently and become comparatively lower at longer durations. This is consistent with the PNNL analysis and with IRENA’s innovation landscape findings, both of which identify hydrogen as particularly attractive for storage durations beyond several dozen hours [IRENA “Innovation Landscape for a Renewable-Powered Future”].

Global deployment of hydrogen for grid storage is still at an early stage but growing. Demonstration projects in Europe, North America and Asia now include hybrid

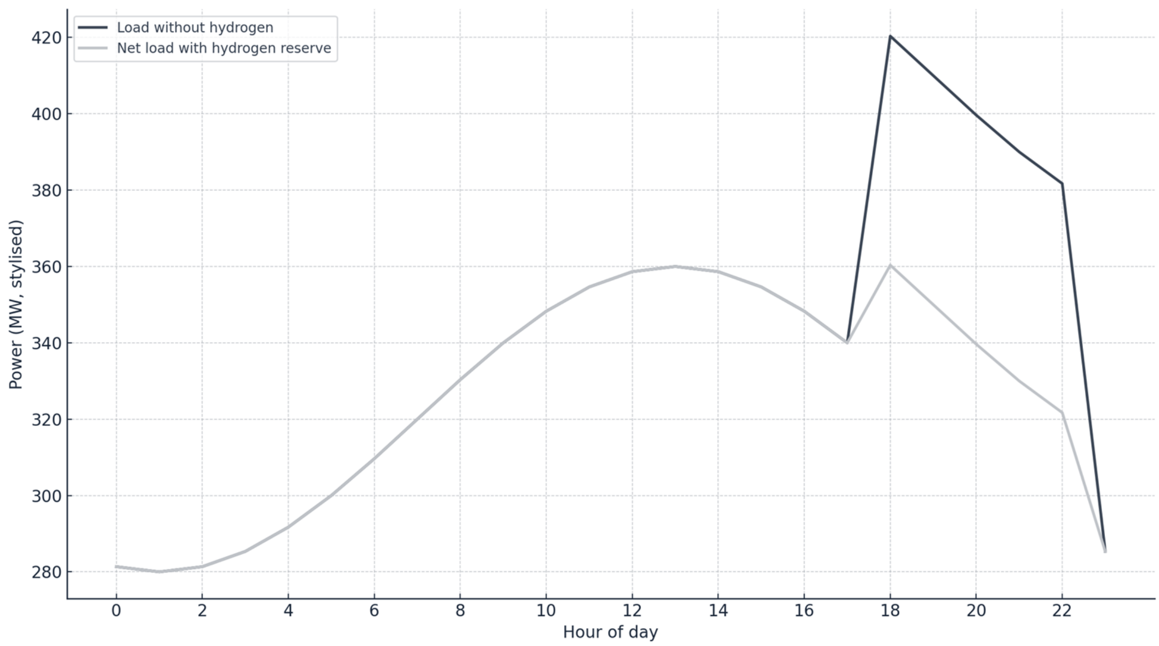


Figure 5 impact of a hypothetical hydrogen reserve discharging 60 MW between 18:00 and 22:00

battery–hydrogen microgrids, hydrogen-fuelled backup power systems for data centres, and pilot hydrogen-fired turbines providing grid services [NREL "Hydrogen Energy Storage: Grid and Transportation Services"; Calistoga and Borrego Springs projects in the United States]. While none of these are direct analogues of the Mauritian context, they collectively provide evidence that integrated hydrogen production, storage and power generation systems can be built and operated as part of a modern grid.

For Mauritius, the key takeaway is that hydrogen storage is now a **plausible, though still relatively high-cost, option** for long-duration storage. Its comparative advantage lies not in everyday cycling but in providing a deep reserve for rare, system-stress events – precisely the kind of risk Mauritius seeks to insure against.

System Integration: Modelling Hydrogen Storage in the Mauritian Grid

Integrating hydrogen storage into the Mauritian power system requires more than simply installing electrolysers and tanks. It demands a nuanced understanding of how such an asset would interact with generation, demand and grid constraints over various timescales. Although a full optimisation model is beyond the scope of this report, the principles of system integration can be outlined and illustrated.

A starting point is the **daily load profile** of Mauritius. CEB data and international experience suggest a pronounced evening peak between roughly 18:00 and 22:00, driven by residential lighting and cooling, commercial activity and, to an increasing extent, digital services [CEB load curves; Energy and Water Statistics]. Solar generation contributes strongly during daylight hours but falls to zero by early evening; wind output is more variable but can be limited during certain meteorological conditions. Thermal plants (coal and oil) therefore shoulder much of the burden during the critical evening hours.

The chart plots an indicative 24-hour load curve and shows the impact of a hypothetical hydrogen reserve discharging 60 MW between 18:00 and 22:00. In the "without hydrogen" case, the evening peak rises sharply above base load. In the "with hydrogen" case, the net load seen by the rest of the system is markedly flatter, with peak demand reduced by the amount supplied from the hydrogen reserve. Although the numbers are illustrative, the qualitative effect is clear: hydrogen storage acts as a **peaking resource**, shaving the crest of the load curve and reducing stress on conventional units.

To conceptualise the role of hydrogen storage more rigorously, one can think in terms of three categories of event:

1. **Routine daily variability.** This includes the standard day–night cycle and short-term fluctuations in demand and renewable output. Batteries and flexible generation are well suited to managing these dynamics. Hydrogen storage would likely play a limited role here, given its lower efficiency.
2. **Extended but moderate stress periods.** For example, a week of unusually hot weather leading to sustained high air-conditioning loads, or a sequence of cloudy days reducing solar output. In such cases, a hydrogen system could be partially charged during off-peak hours and dispatched during the worst days, limiting the need to curtail demand or dispatch more expensive emergency generation.
3. **Low-probability, high-impact events.** Examples include the simultaneous failure of a major plant and a transmission line, or a cyclonic event that temporarily constrains fuel supply and damages infrastructure. In these scenarios, a hydrogen reserve with sufficient stored energy could provide several days of critical supply, enabling an orderly restoration and avoiding a chaotic, economy-wide blackout.

Modelling these interactions would typically involve a chronological unit commitment and economic dispatch model, such as PLEXOS, TIMES or similar platforms, with scenarios representing different demand growth trajectories, renewable build-out and fuel price paths. Hydrogen storage would be represented as a resource with specified power capacity (in MW), energy capacity (in MWh), round-trip efficiency, charging constraints (linked, for example, to dedicated solar or wind farms) and operational costs. The model would then optimise system costs subject to reliability constraints, thereby revealing the marginal value of hydrogen storage in terms of reduced unserved energy and fuel savings.

Preliminary modelling studies for Mauritius, focusing mainly on batteries and demand response, indicate that achieving very high renewable shares while maintaining reliability requires substantial storage capacity and flexible resources [Edoo et al., "100% renewable energy system for the island of Mauritius", 2025]. Extending these models to include hydrogen storage would allow planners to test questions such as:

- How large must a hydrogen reserve be (in MW and MWh) to reduce expected unserved energy to an acceptable level?

- What is the optimal mix between batteries and hydrogen storage across different durations?
- How does hydrogen storage change the value of additional solar and wind capacity, by enabling higher utilisation rather than curtailment?

Even without full modelling, order-of-magnitude reasoning is informative. Suppose that by 2030, peak demand reaches around 600 MW, with the evening peak (18:00–22:00) averaging 580 MW. If existing thermal capacity and firm renewables can reliably supply 500 MW during this window, the system faces an 80 MW shortfall over four hours, or 320 MWh per evening. A hydrogen reserve capable of delivering 80 MW for four hours would therefore be sufficient to avoid load shedding during such peaks. To cover two or three consecutive evenings of such stress, an energy capacity of 640–960 MWh would be required. Allowing for a round-trip efficiency of, say, 40 per cent, the electrolysers and associated renewable capacity would need to generate roughly double that amount of electricity in advance.

The point is not that these figures should be adopted as planning targets, but that the quantities involved are manageable. In the context of Mauritius' overall electricity system – roughly 3,000–3,500 GWh per year by 2030 – a hydrogen reserve storing on the order of 1 GWh of energy represents a small fraction of annual generation, yet could provide significant protection against rare but damaging events.

Comparative Assessment: Hydrogen Storage vs Batteries, Diesel/Gas Peakers and Other Options

Any decision to develop hydrogen storage in Mauritius must be grounded in a comparative assessment of alternative ways to secure reliability. The main options are:

- **Short-duration battery energy storage systems (BESS).** These are increasingly deployed globally for frequency regulation, ramping and short-term peak shaving. Capital costs have fallen to roughly USD 200–400 per kWh for four-hour systems, with round-trip efficiencies around 85–90 per cent [IEA, "Grid-Scale Storage"; various BESS cost trackers].
- **Conventional peaking plant (diesel or gas).** Diesels are relatively cheap to install and familiar to operators, but their operating costs are high and emissions are substantial. Gas turbines are more efficient and cleaner if supplied with gas, but Mauritius lacks domestic gas resources and would need to invest in LNG or other infrastructure.
- **Demand-side management and interruptible contracts.** These reduce demand rather than increase supply, often by incentivising large consumers to curtail usage during peak periods. They are cost-effective but limited in scale and require sophisticated metering and contractual frameworks.

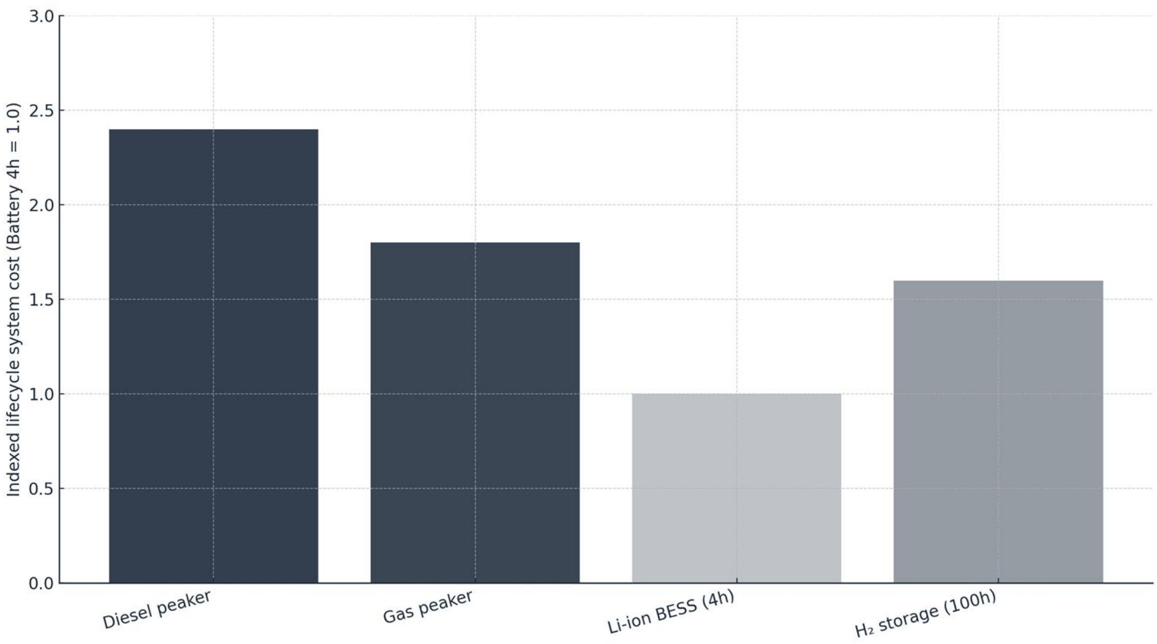


Figure 6 Indexed comparison of lifecycle system cost

- **Hydrogen storage.** As discussed, this involves higher capital costs and lower efficiency but offers uniquely long-duration capability and multi-day resilience.

The bar chart presents an indexed comparison of lifecycle system cost for four options: diesel peaker, gas peaker, a four-hour lithium-ion BESS, and a hydrogen storage system designed for 100 hours of discharge. The diesel and gas options appear more expensive, once fuel costs and typical load factors are considered, while the BESS is cheapest at short duration. The hydrogen option sits between the BESS and traditional peakers on this cost metric.

However, cost alone is not the only criterion. Emissions profiles differ markedly. Diesel and heavy fuel oil plants emit in the order of 700–900 gCO_2 per kWh, along with local pollutants such as NO_x and particulate matter. Gas plants emit around 400–450 gCO_2 per kWh (excluding upstream methane leakage). Hydrogen storage, when supplied with green hydrogen, has near-zero direct emissions; the main footprint arises from the embodied emissions in equipment manufacturing and any residual grid electricity used during electrolysis [IEA "The Role of Low-Carbon Hydrogen in Energy Transitions"; IRENA "Green Hydrogen"].

Reliability characteristics also differ. Batteries can respond in milliseconds and are excellent for maintaining frequency and handling rapid fluctuations, but their economics deteriorate for storage durations beyond a day unless extremely low-cost cells become available. Diesel and gas units provide firm capacity but are vulnerable to fuel supply disruptions and price volatility. Hydrogen storage, once the necessary renewable capacity and infrastructure are in place, provides a **fuel-secure** source of backup, since the "fuel" (hydrogen) can be produced domestically and stored in advance.

For Mauritius, which has no indigenous fossil fuel resources and must import virtually all of its coal and oil, the energy security argument is powerful. A hydrogen reserve, supplied by local solar and wind, reduces exposure to fuel price spikes and logistical disruptions – for example, if a cyclone temporarily affects port operations. It also aligns with the government's stated intention to phase out coal and reduce emissions, whereas new investment in oil- or coal-fired peakers would cut against these commitments [Renewable Energy Roadmap 2030; Revised NDC].

In this comparative perspective, hydrogen storage emerges not as the cheapest source of bulk energy but as a **strategic reliability asset**. It complements, rather than replaces, batteries and conventional peakers: batteries for routine flexibility; hydrogen storage for infrequent but severe stress events; and residual fossil units as a transitional backup while hydrogen capabilities are being built.

Investment Case, Financing Structures and Risk Allocation

Hydrogen storage at the scale relevant for Mauritius is capital-intensive, but that does not mean it is

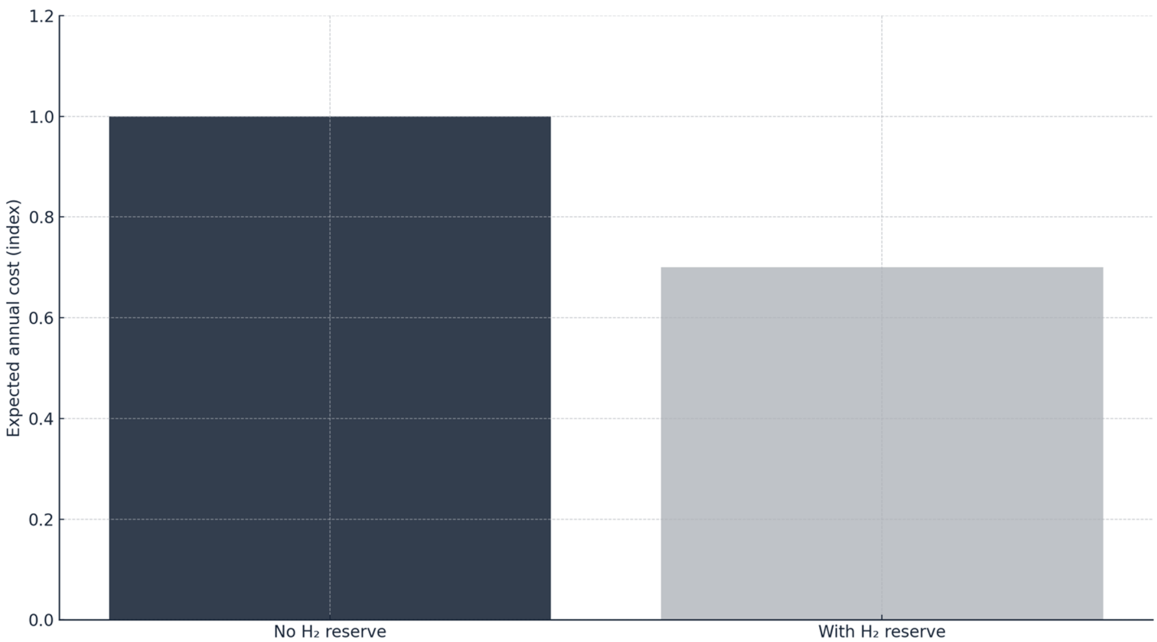


Figure 7 Hydrogen reserve is economically rational as an insurance instrument

unaffordable. The investment question is best framed as follows: **Is the annualised cost of a hydrogen reserve lower than, or at least comparable to, the expected annual cost of blackouts that it helps avoid?**

To explore this, consider a stylised example. Suppose a future "Hydrogen Reserve Mauritius" facility entails total capital expenditure in the range of USD 200–300 million for electrolysers, storage vessels, hydrogen-capable generation units, grid integration and associated civil works. If financed over 20 years at an average real cost of capital of 6–8 per cent, the annualised capital charge would be on the order of USD 17–30 million, to which operating and maintenance costs would add a further few million dollars. The total annual cost might therefore lie somewhere between USD 20–35 million (figures are indicative and should be refined by detailed engineering and financial analysis).

On the benefit side, if a major system-wide blackout lasting 8–12 hours produces aggregate economic losses (including lost tourism revenue, business interruption, damage to reputations and equipment) of, for example, USD 50–100 million, and if such an event has a probability of 10 per cent per year in the absence of a hydrogen reserve, then the **expected annual loss** is USD 5–10 million. If the hydrogen reserve reduces this probability significantly, it can justify an annualised cost in that range. When additional benefits are considered – such as fuel savings during peak periods, enhanced renewable integration, and reduced need for emergency diesel procurement – the case strengthens.

The chart shows expected annual cost in index terms for two scenarios: a "no hydrogen reserve" case (index 1.0) and a "with hydrogen reserve" case (index 0.7). The latter reflects the combination of lower expected outage costs and the additional annualised cost of the reserve itself. The message is not that 0.7 is a precise figure, but that the sum of outage costs plus reserve costs can plausibly be lower than outage costs alone.

Structuring such an investment requires careful attention to **revenue models and risk allocation**. Hydrogen storage assets do not fit neatly into existing power-purchase agreement templates, which are mostly designed for energy-only contracts. Instead, they need:

- **Capacity payments** or availability-based remuneration, reflecting the insurance-like value of being ready to supply when needed, regardless of how often energy is actually dispatched.
- **Remuneration for system services**, such as spinning reserve, black-start capability and frequency support, which hydrogen-fired units and associated batteries could provide.
- Potentially, **energy-based revenue** from selling electricity during high-price periods or from ancillary services markets, although this should be considered supplementary to the core availability remuneration.

In terms of institutional arrangements, Mauritius could structure a "Hydrogen Reserve Mauritius" project as a **public–private partnership** or an independent power project (IPP) under long-term contract with the CEB. The state, through the Utilities Regulatory Authority and the Ministry of Energy and Public Utilities, would define reliability standards and the terms of remuneration. The project company would be responsible for design, financing, construction and operation, in return for a predictable stream of capacity and service payments.

International climate and development finance can play a catalytic role. Because hydrogen storage directly supports the integration of renewables, coal phase-out and resilience to climate-related hazards, it is eligible for support from instruments such as green bonds, the Green Climate Fund, and blended-finance facilities targeting small island developing states [AfDB and World Bank SIDS energy initiatives; green bond frameworks]. Concessional funds can reduce the effective cost of capital, making the project more affordable in tariff terms.

Crucially, the allocation of risks must be explicit. Technology performance risk (for instance, under-delivery of electrolyser efficiency) should be borne by the private developer within clear performance guarantees. Policy risk (such as future changes to tariff structures or decarbonisation targets) lies with the state. Fuel price risk is limited, since hydrogen is produced domestically from renewables. Currency risk is a shared concern, given that much of the equipment will be imported and financed in foreign currency, while revenues are in Mauritian rupees; hedging strategies and the use of multi-currency facilities can mitigate this.

If structured appropriately, a hydrogen reserve can thus be presented not as a fiscal burden, but as a **bankable infrastructure asset** offering stable, long-term returns, particularly attractive to institutional investors with a mandate for sustainable and resilient infrastructure.

Implementation Roadmap and Governance for a "Hydrogen Reserve Mauritius"

Designing and financing a hydrogen storage project is only part of the challenge. The other part is **sequencing and governance**: ensuring that actions are taken in the right order, that responsibilities are clear, and that the initiative remains robust across electoral cycles and changing economic conditions.

The chart sets out three phases on a timeline from 2025 to 2035: an analytical and regulatory phase (2025–2026), a pilot phase (2026–2028), and the deployment of a full-scale “Hydrogen Reserve Mauritius” (2028–2035). The exact dates are indicative, but the sequencing reflects sensible practice in infrastructure development.

During the **analytical and regulatory phase**, the priority is to create the intellectual and institutional foundations for hydrogen storage. This includes updating the Long-Term Energy Strategy and Renewable Energy Roadmap to explicitly consider hydrogen storage; conducting integrated resource planning exercises that compare portfolios with and without hydrogen; and defining a regulatory framework that recognises storage as a distinct asset class. The Utilities Regulatory Authority will need to clarify how storage is licensed, how it interacts with existing generation and IPP structures, and how its costs are recovered through tariffs.

The Government would also be expected to form a **Hydrogen Storage Task Force**, bringing together the Ministry of Energy and Public Utilities, the CEB, MARENA, the Economic Development Board, the Ministry of Finance, and representatives of key industries. This group would guide feasibility studies, coordinate technical assistance (for example from multilateral institutions or partner countries such as India), and ensure alignment with broader climate and industrial strategies [India–Mauritius cooperation announcements; Joint SDG Fund and Mauritius “Small Island, Big Vision” initiative].

The **pilot phase** would focus on learning by doing. A modest-scale hybrid project – for instance, a 5–10 MW hydrogen-capable generation unit with 40–80 MWh of associated hydrogen storage and an integrated battery – could be co-located with a new solar PV plant. This facility would operate within the main grid, providing peak support and black-start capabilities on a trial basis. Performance data, safety protocols, cost information and public perceptions gathered from this project would inform the design of the larger reserve.

It would be prudent to structure the pilot so that its equipment can eventually be absorbed into the full-scale reserve or repurposed for other uses (for example, supplying hydrogen to a transport pilot). This limits the risk of stranded assets and sends a signal to investors that Mauritius is serious about scaling successful demonstrations.

The final phase, deployment of the **full-scale “Hydrogen Reserve Mauritius”**, would involve an international competitive tender for a utility-scale hydrogen storage facility. The tender documents would set out:

- the required power and energy capacities;
- performance guarantees (for example, ability to discharge a specified output for a given number of hours on a set number of occasions per year);
- remuneration mechanisms (capacity payments, service payments, and any energy-based revenues); and

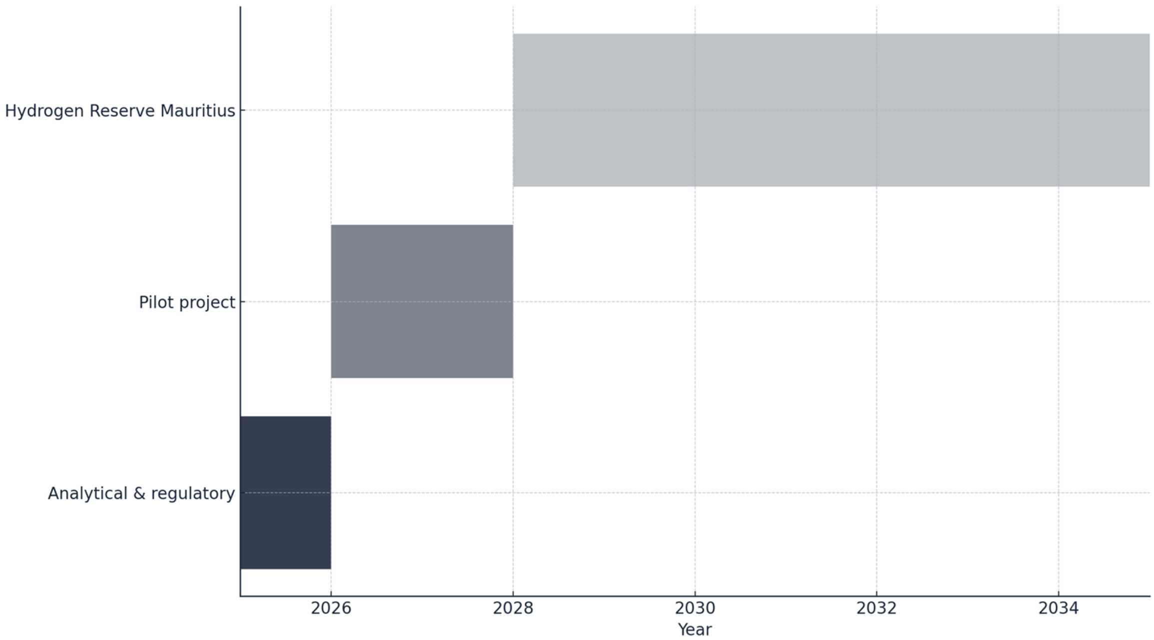


Figure 8 Phased, risk-managed pathway

- the integration of the reserve into CEB's dispatch procedures and emergency protocols.

Governance in this phase must emphasise transparency and accountability. The power-sector challenges of 2024–2025 have already prompted public debate over planning, procurement and the management of existing thermal assets [Mauritius Times "Energy Crisis: What Are Our Options?"; Mauritius Times "CEB's Red Alert"]. A hydrogen storage programme, by virtue of its novelty and scale, will likely attract similar scrutiny. Clear communication about objectives, costs, risks and expected benefits is therefore essential. This includes explaining that hydrogen storage is not a magic bullet that eliminates all outages, but a tool that significantly reduces the risk of catastrophic blackouts.

Finally, the governance framework must anticipate the **evolving role of hydrogen** beyond the power sector. As global hydrogen markets develop and regional initiatives (for example, in shipping or aviation fuels) mature, Mauritius may find opportunities to use the infrastructure of the "Hydrogen Reserve Mauritius" as a platform for broader hydrogen-related activities. This could include supplying green hydrogen or ammonia to ships, blending hydrogen in industrial processes, or exporting hydrogen-derived products. The institutional arrangements put in place now should preserve this optionality, while keeping the primary focus squarely on domestic energy security and resilience.

Hydrogen Storage Technologies & Global Deployment Lessons

Hydrogen storage for power systems is best understood as a **family of configurations** rather than a single technology. These configurations combine three building blocks – production, storage and reconversion – and are tailored to local resource endowments, space constraints, and the desired storage duration.

On the **production side**, low-emission hydrogen is principally generated via water electrolysis powered by renewable electricity. The main commercial electrolyser technologies are alkaline (AEL) and polymer electrolyte membrane (PEM); solid oxide (SOEC) is emerging at demonstration scale. The IEA's *Global Hydrogen Review 2023* notes that global electrolyser manufacturing capacity expanded to about 11 GW per year by 2023 and is heavily concentrated in China, with global hydrogen demand approaching 100 million tonnes in 2022–2024.(IEA Blob Storage) Yet only around 0.7 per cent of this demand was met by low-emission hydrogen; the remainder is produced from unabated fossil fuels, generating over 900 MtCO_2 per year.(IEA)

The **storage stage** can take several forms. For grid-scale applications, compressed hydrogen in above-ground steel vessels (typically at 200–700 bar) is the most practical option in locations without suitable geology. Where salt caverns or depleted gas fields exist, these can provide very large and low-cost storage volumes, with levelised storage costs estimated at USD 0.7–1.3 per kg of hydrogen for new depleted hydrocarbon sites in recent studies.(ScienceDirect) IRENA's *Electricity Storage and Renewables for Island Power* emphasises that islands are often constrained to above-ground solutions because they lack such geological formations, which increases unit storage costs but not necessarily to prohibitive levels when the value of long-duration resilience is considered.(IRENA)

In **reconversion**, two paradigms dominate. The first uses hydrogen-capable gas turbines or engines. Several major manufacturers now supply machines able to burn hydrogen-natural-gas blends, with roadmaps towards 100 per cent hydrogen in the 2030s. The second uses fuel cells, which directly convert hydrogen's chemical energy into electricity. Fuel cells offer higher electrical efficiency at smaller scale and are already in use for backup power in data centres, telecoms and critical infrastructure. A recent review of hydrogen technologies notes that fuel cell systems are moving out of niche markets into broader stationary applications, supported by a growing body of international safety and performance standards.(ScienceDirect)

Against this technological backdrop, the **global deployment picture** is mixed. The IEA's 2025 update to the *Global Hydrogen Review* and associated news coverage show that the pipeline of low-emissions hydrogen projects to 2030 has shrunk: announced capacity has fallen from a projected 49 million tonnes to 37 million tonnes per year, with only about 6 per cent of projects reaching final investment decision (FID) to date.(Reuters) The industry is experiencing a "reality check" after a period of exuberant announcements, as developers grapple with cost pressures, infrastructure bottlenecks and uncertain demand.

However, this does not mean hydrogen is stalling everywhere. The Hydrogen Council's *Hydrogen Insights 2023* identified over 1,000 hydrogen projects announced globally, with about USD 320 billion in investment announced to 2030, albeit with slippage in FID rates.(Hydrogen Council) Even if only a fraction proceed, the result will be a several-fold increase in low-emission hydrogen production capacity and a growing ecosystem of electrolysers, pipelines and storage sites. For Mauritius, the key lesson is that hydrogen is transitioning from demonstration to early commercialisation, but projects must be **carefully structured and grounded in real system needs** rather than hype.

Small-island and microgrid experiences are particularly instructive.

- On Réunion Island, the EU-funded *Micro Réseau Mafate* project developed an islanded microgrid for a remote mountain community accessible only on foot or by helicopter. The microgrid combines local renewable generation with battery storage and advanced control systems; hydrogen has been explored as a complementary storage medium to extend autonomy and reduce diesel reliance.(lupm.in2p3.fr) The broader lesson is that remote communities can operate largely on renewables when backed by robust storage.

- In Uganda, a containerised solution documented by the Asian Development Bank uses a 4.7 kWp solar array with integrated hydrogen and battery storage in a 20-foot container to supply rural communities. Electrolysers produce hydrogen from surplus solar power, which is then stored and used via fuel cells when the sun is not shining.(Development Asia)
- On the Thai island of Koh Jik, a solar-diesel-battery microgrid supplying roughly 100 households was analysed, and subsequent redesigns have introduced more solar and explored hydrogen as a long-term storage option. Recent accounts indicate that upgrading the system reduced diesel use to a few per cent of the total, saving hundreds of thousands of baht annually.(em-power.eu)

More recent work on hydrogen-battery systems for remote Norwegian islands confirms that coupling local renewables with hydrogen storage can, in principle, deliver highly decarbonised power at acceptable cost when the avoided diesel costs and environmental benefits are factored in.(ScienceDirect)

> The most relevant hydrogen storage lessons for Mauritius come not from mega-projects on continental grids but from smaller, islanded and microgrid systems where resilience and fuel autonomy matter more than pure efficiency.

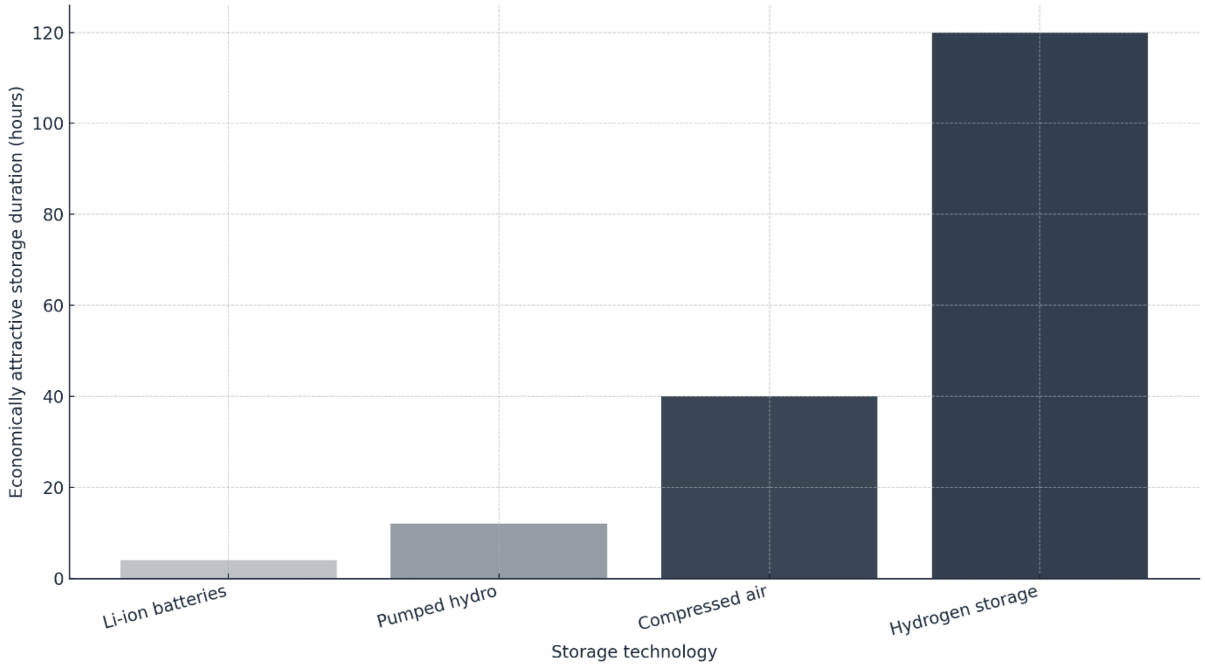


Figure 9 Typical storage durations

The Economics of Hydrogen Storage in a Small-Island Power System

For Mauritius, the economic case for hydrogen storage cannot be judged on levelised cost of energy alone. Instead, it must be evaluated against the **value of reliability** and the **cost of alternatives** in a constrained, isolated system.

At project level, the key metric is the **levelised cost of storage (LCOS)**, which spreads capital expenditure, operating costs and efficiency losses over the lifetime energy discharged. Analytical work by the US Pacific Northwest National Laboratory (PNNL) – notably the 2022 *Grid Energy Storage Technology Cost and Performance Assessment* – provides detailed LCOS estimates for storage technologies from 2 to 100 hours' duration.(PNNL) For lithium-ion batteries, PNNL finds that LCOS is highly competitive at 4–10 hours but rises sharply as storage duration increases to 24 and 100 hours. Non-battery options, including hydrogen, become more attractive at longer durations because their marginal cost of additional storage capacity (extra hydrogen volume) is relatively low.

Summaries of the PNNL work indicate that, for a 1 MW / 100-hour system, LCOS for hydrogen storage can fall into the range of roughly USD 200–400 per MWh under favourable assumptions by 2030, while lithium-ion battery LCOS at that duration can exceed USD 400–500 per MWh.(linkedin.com) Exact numbers depend on electrolysers' capital costs, renewable electricity prices, and utilisation. In Mauritius, these parameters are likely to differ from US conditions, but the **relative pattern** – hydrogen improving as duration lengthens – is robust.

Small-island systems also attach unusually high value to avoiding outages. IRENA's *Transforming Small-Island Power Systems* highlights that optimal planning in such systems often uses higher loss-of-load expectations (LOLE) than in large interconnected grids, but the trade-off between investment and reliability is guided by the **value of lost load (VoLL)**. Examples from Caribbean utilities show VoLL values of USD 5–20 per kWh, with some SIDS using even higher notional figures to capture the full economic and social costs of unserved energy.(IRENA)

If Mauritius were to adopt a conservative VoLL of, say, USD 10 per kWh, then a single event in which 100 MWh of demand goes unserved would impose an economic cost of around USD 1 million. A protracted 12-hour nationwide outage affecting several hundred MWh would therefore rapidly reach tens of millions of

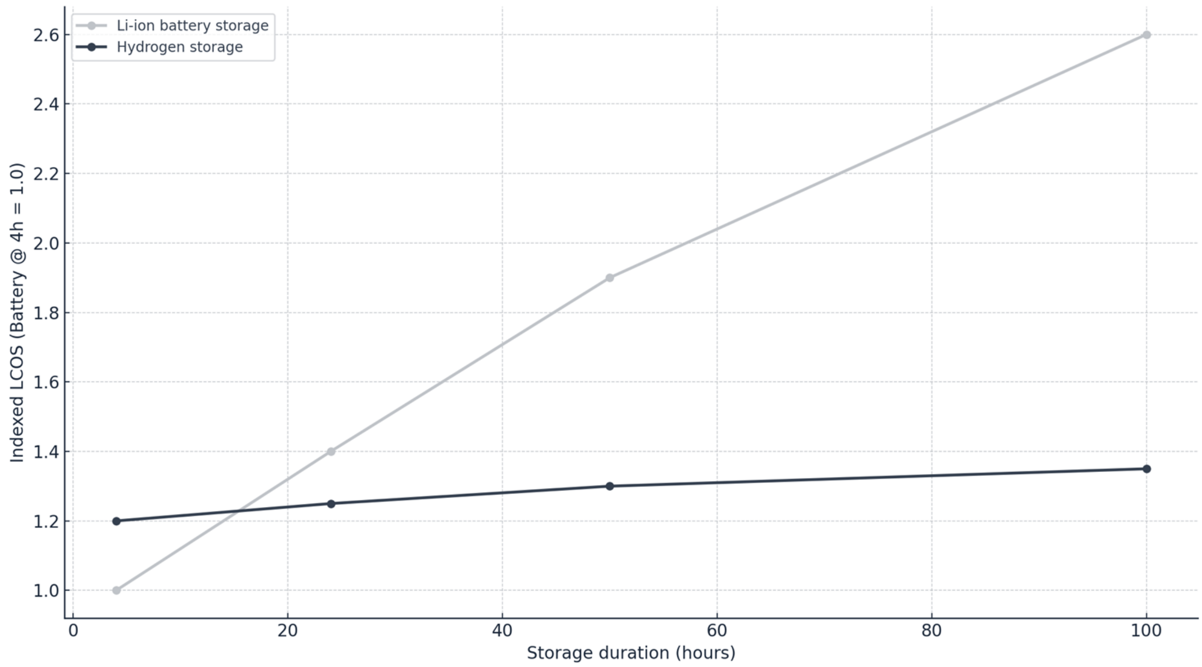


Figure 10 Indexed LCOS vs Storage Duration for Battery and Hydrogen Systems

dollars in implicit loss. Even if such events are infrequent, the **expected annual cost** (probability multiplied by impact) can be material.

Hydrogen storage, conceived as an insurance instrument, is therefore compared not with average wholesale prices but with this expected cost of outages. If a hydrogen reserve reduces the probability or magnitude of large-scale blackouts, its annualised cost can be offset by the reduction in expected outage costs. From a macroeconomic viewpoint, the question for Mauritius is whether paying an annual "premium" to maintain a hydrogen reserve is cheaper than absorbing recurrent or occasional, but devastating, system failures.

Furthermore, hydrogen storage interacts with the **economics of renewables**. Mauritius' Renewable Energy Roadmap 2030 anticipates significant solar and wind additions, supported by approximately USD 1.35 billion in investment to deliver 60 per cent renewable electricity and phase out coal.(publicutilities.govmu.org) As variable renewable penetration increases, curtailment becomes more likely during off-peak periods. A hydrogen system linked to dedicated solar or wind farms can absorb electricity that would otherwise be curtailed, converting it into storable hydrogen. This has three economic implications:

1. It **increases the effective utilisation** of renewable assets, improving their economics.
2. It **reduces marginal fuel consumption** in thermal plants by substituting hydrogen-generated power during peaks.
3. It may enable **higher renewable penetration** without compromising reliability, potentially avoiding or deferring investments in new fossil peaking units.

To illustrate orders of magnitude, consider a hypothetical Mauritian hydrogen reserve with 40 MW of electrolyser capacity, 200 MW of hydrogen-fired generation, and 800 MWh of usable storage. If dedicated renewables can supply 60 GWh per year of low-cost off-peak electricity to this system, and 30 per cent of that is ultimately delivered as on-peak electricity after efficiency losses (24 GWh), then each delivered MWh displaces expensive peak generation or helps avoid unserved energy. Even at a conservative avoided cost of USD 250 per MWh (representing a mix of diesel peaking and outage avoidance), the gross annual system benefit would be around USD 6 million. Over a 20-year life, this benefit stream can cover a substantial share of the capital costs when appropriately discounted.

Of course, these are stylised calculations, and detailed modelling for Mauritius would be needed. But they demonstrate that hydrogen storage economics in a small-island system are **non-linear**: modest utilisation and high apparent unit costs can still be rational when measured against the right counterfactual – that of expensive back-up generation, stranded renewable output, or costly outages.

In small island systems, hydrogen storage is paid for not in cents per kWh, but in avoided losses per blackout.

Comparing Hydrogen Storage with Alternative Reliability Options

Hydrogen storage is only one of several tools Mauritius can deploy to manage blackout risk and provide on-demand power. A robust strategy requires a **portfolio** of options, each with distinct strengths and weaknesses. The principal alternatives are: short-duration batteries, diesel or gas-fired peaking plant, demand-side response, and network reinforcements.

From a **cost perspective**, BESS remains the benchmark for short-duration flexibility. IRENA's and IEA's storage cost assessments show that four-hour lithium-ion systems can now be deployed at fully installed costs in the order of USD 200–400 per kWh, with LCOS well below USD 200 per MWh in favourable conditions.(IRENA) These systems excel at sub-daily shifting and ancillary services. Diesel peakers, by contrast, have relatively low upfront costs per kW but high fuel and maintenance costs; their LCOS rises quickly when fuel prices are high. Gas turbines are more efficient, but Mauritius would need to invest in costly gas infrastructure or rely on small-scale liquid fuels.

Hydrogen storage sits between these options. Its capital costs per kW of power conversion and per kWh of storage remain substantial, and its round-trip efficiency is lower than batteries. However, its **marginal**

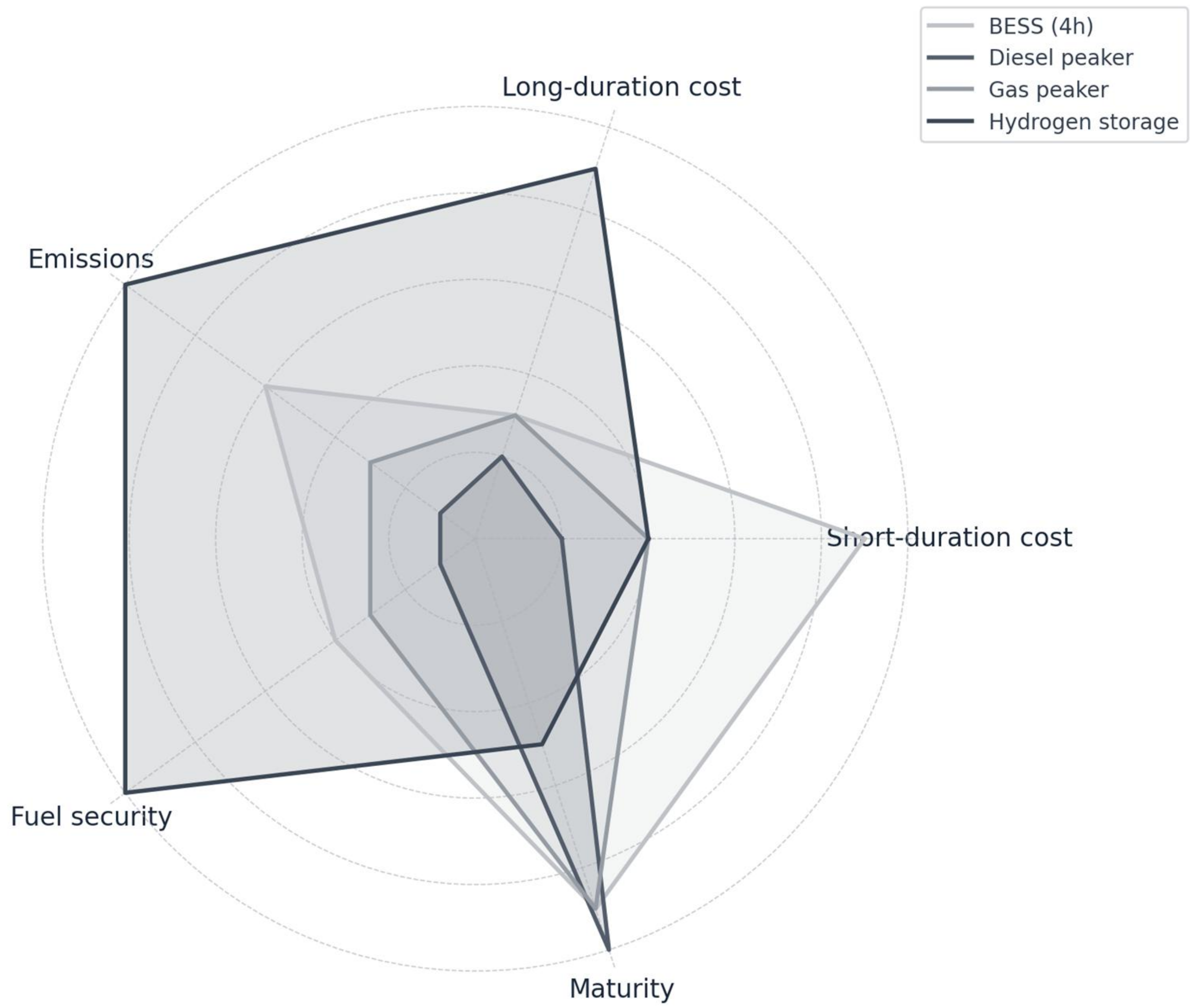


Figure 11 Comparative Performance of Long-Duration Storage and Peaking Technologies

cost of extra hours of storage is low, especially if bulk hydrogen storage is achieved using larger tanks or caverns. This makes it economically viable where very long durations (tens or hundreds of hours) are required.

When considering **emissions**, the ranking is clearer. Diesel peakers are the most carbon-intensive, typically emitting 700–900 gCO_2 per kWh plus local pollutants. Gas turbines emit around 400–500 gCO_2 per kWh when fired with natural gas. Green hydrogen storage, supplied by renewables, offers near-zero direct emissions, aligning with Mauritius' NDC 3.0 aim of a 40 per cent economy-wide emissions reduction by 2035, and its commitment to phase out coal from the electricity mix.(UNFCCC)

On **speed of deployment**, diesel and small gas units have an advantage: they can often be delivered and connected within 12–24 months. Battery projects can also be implemented quickly, with modular containers and standardised inverter systems. Hydrogen storage projects, particularly at grid scale, currently require longer lead times, due to engineering complexity, safety case development and supply chain constraints for electrolysers and hydrogen-ready turbines. The global hydrogen project pipeline's recent slowdown also means that some suppliers are recalibrating their offerings.(Reuters)

In terms of **operational maturity**, BESS and conventional peakers are proven technologies with extensive track records. Hydrogen storage is commercially proven at smaller scales (microgrids, industrial sites) and in specific applications (backup power for data centres, telecoms), but grid-scale deployments remain at demonstration or early commercial stages. IRENA's guidance for island power systems stresses the importance of starting with appropriately sized pilots when adopting newer storage technologies.(IRENA)

A crucial differentiator in island contexts is **fuel security**. Diesel and gas plants rely on imported fuels; fuel supply chains can be disrupted by weather events, port congestion or global market shocks. Battery storage is dependent on the grid mix; it does not create energy, merely shifts it. Hydrogen storage, when supplied by domestic solar and wind, reduces exposure to fuel imports and functions as a **domestic fuel buffer**. This has strategic value for Mauritius, particularly as it pursues a "green hydrogen vision" identified by international observers as part of its broader energy transition.(Green Hydrogen Organisation)

Demand-side response (DSR) offers a different route: instead of increasing supply, it reduces or shifts demand. In Mauritius, time-of-use tariffs, critical peak pricing and interruptible contracts could encourage large consumers to curtail usage during stress periods. The cost of DSR can be very low, but its **scalability** is limited; not all loads are flexible, and over-reliance on curtailment may undermine economic activity.

> Batteries buy hours, peakers buy megawatts, demand response buys time – hydrogen reserves buy days of survival.

The lesson for Mauritius is that hydrogen storage should not be framed as a substitute for these options, but as a **complement**: BESS and DSR handle everyday variability; residual peakers and network upgrades deal with conventional capacity needs; hydrogen reserves address extreme, multi-day risks and enable deeper renewable penetration without jeopardising reliability.

Policy, Regulatory and Market Design Implications for Mauritius

Mauritius' electricity sector is governed by a relatively compact but evolving institutional framework. The **Central Electricity Board (CEB)** is the vertically integrated utility responsible for generation, transmission, system operation, distribution and procurement of electricity under the Central Electricity Board Act and its 2020 amendments.(Laws of Mauritius) The **Utility Regulatory Authority (URA)**, established under the URA Act 2004 and operationalised more fully since 2016, regulates electricity, water and wastewater, including licensing and tariff approval.(Laws of Mauritius) Electricity-specific regulations under the Electricity Act 2005 and its 2020 amendments set standards for safety, metering, billing and licensing.(Laws of Mauritius)

The **Renewable Energy Roadmap 2030** and the updated NDC 3.0 provide strategic direction: 60 per cent renewables in the electricity mix by 2030, coal phase-out, and a 40 per cent economy-wide emissions reduction by 2035 relative to business-as-usual, alongside a 10 per cent energy-efficiency improvement.(publicutilities.govmu.org)

Hydrogen storage is not yet explicitly integrated into this policy and regulatory framework. Bringing it in will require modifications along three dimensions: **planning, licensing, and remuneration**.

First, at the **planning stage**, integrated resource planning exercises must treat storage – including hydrogen – as a distinct asset category. At present, planning documents focus on renewables, BESS and network reinforcement. The URA and CEB, supported by MARENA, should develop multi-scenario plans in which portfolios with and without hydrogen storage are compared under common reliability and decarbonisation targets. This will clarify whether, and at what scale, hydrogen storage provides net system benefits. IRENA's recent work on SIDS emphasises that such holistic planning is essential to avoid piecemeal investments that lock in sub-optimal pathways.(IRENA)

Secondly, the **licensing framework** must recognise storage's dual role as both a consumer and producer of electricity. Under the Electricity Act 2005, licences are issued for generation, transmission, distribution and supply activities.(Laws of Mauritius) Hydrogen storage assets will draw power from the grid (or from dedicated renewables) and inject power later; they may also provide ancillary services. Regulators globally have grappled with how to classify storage: in some cases as generation, in others as a new category. Mauritius can draw on international practice to create a **storage licence class** with tailored conditions for grid-connected hydrogen assets, covering safety, cyber-security, environmental performance and data reporting.

Thirdly, **market design and remuneration** mechanisms must be adapted. Mauritius does not operate a liberalised wholesale market; instead, power procurement is based on bilateral PPAs and regulated tariffs. In such a context, hydrogen storage will require a contractual structure that reflects its insurance role. A pure energy-only PPA (payment per kWh delivered) is unlikely to be sufficient, because the system will value the asset's availability during rare events more than its average output.

Policy options include:

- A **capacity-based contract**, where CEB pays an availability fee per kW of dependable capacity, conditional on performance during stress events.
- **Ancillary service contracts** for black-start capability, spinning reserve and frequency support, which hydrogen-capable units can provide.
- **Contracts for difference** or other mechanisms to stabilise the price of hydrogen input and associated renewable electricity, de-risking the project's cost base.

The URA's mandate to "ensure the sustainability and viability of utility services" and "protect the interests of existing and future customers" provides a legal basis for such mechanisms, provided they are justified as least-cost ways to meet reliability and climate objectives.(Laws of Mauritius)

Institutionally, Mauritius will also need to strengthen **technical standards and safety frameworks** for hydrogen. International bodies such as ISO and IEC are issuing standards for hydrogen storage systems, fuel cell power systems and safety practices; the IEA's 2023 fuel cell report lists several relevant standards under development.(IEA Advanced Fuel Cells) Adopting and adapting these standards into national codes (for example under the Electricity (Safety, Quality and Continuity) Regulations) will help manage risks and reassure the public.

Finally, **governance of cross-cutting issues** is essential. Hydrogen storage intersects with energy, climate, industrial policy and maritime strategy (e.g. potential bunkering of green fuels). A high-level coordination mechanism – such as the Hydrogen Storage Task Force proposed earlier – is needed to ensure coherence. Mauritius' ongoing roadmap for climate resilience and low-carbon transition, as described in government communications, provides a natural anchor for such a body.(govmu.org)

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> Without explicit recognition in planning, licensing and tariff rules, hydrogen storage risks remaining a promising idea that never reaches bankable reality.

Implementation Pathways: A Phased Roadmap to 2030 and Beyond

Given the technological, economic and regulatory considerations set out above, Mauritius should approach hydrogen storage through a **phased implementation roadmap** that balances ambition with prudence. A credible pathway to 2030 and beyond would have three main phases: (i) knowledge and enabling environment, (ii) pilot deployment and learning, and (iii) scale-up to a "Hydrogen Reserve Mauritius".

Phase I (2025–2026): Knowledge, Analytics and Enabling Environment

In the near term, the priority is to *de-risk decisions before capital is committed*. This phase would involve:

- Updating the **Renewable Energy Roadmap 2030** and the Long-Term Energy Strategy to explicitly include hydrogen storage scenarios, consistent with NDC 3.0 targets.
- Commissioning detailed **power-system modelling** that tests portfolios with combinations of renewables, BESS, flexible thermal generation and hydrogen storage, using VoLL-based reliability criteria as recommended by IRENA for SIDS.(IRENA)
- Establishing the **Hydrogen Storage Task Force**, chaired at senior level, to coordinate ministries, regulators, the CEB, MARENA and the private sector.
- Launching **regulatory consultations** under the URA to define storage licensing, remuneration principles and safety requirements.

In this phase, Mauritius can leverage technical assistance from institutions such as the World Bank, IRENA and regional development banks, as well as partnerships with countries experienced in hydrogen and offshore renewables.(Green Hydrogen Organisation)

Phase II (2026–2028): Pilot Deployment and Local Capability Building

Once the enabling environment is clarified, Mauritius should proceed with a **pilot-scale hydrogen storage project**. Key design features could include:

- A modest system (for example, 5–10 MW hydrogen-capable generator with 40–80 MWh of hydrogen storage) co-located with a new solar PV plant and possibly a small BESS.
- An **availability-based contract** with clear performance metrics, structured so that equipment can be integrated into a future larger-scale reserve.
- A strong focus on **monitoring, reporting and verification**, capturing data on utilisation, efficiency, costs, safety incidents and grid impacts.

This pilot would serve several purposes: it would validate engineering assumptions under Mauritian conditions; familiarise operators, regulators and emergency services with hydrogen technologies; and provide a **visible proof of concept** to reassure investors and the public. Experience from Mafate, Koh Jik and Norwegian island projects suggests that such demonstration systems are crucial in building confidence.(lupm.in2p3.fr)

Phase III (2028–2035): "Hydrogen Reserve Mauritius" and System Integration

Assuming the pilot succeeds and system modelling confirms the value of hydrogen storage, the next step is to tender a larger, **strategic-scale reserve**. This "Hydrogen Reserve Mauritius" might, for instance, provide 30–60 MW of firm capacity with 200–600 MWh of hydrogen storage, sufficient to cover several hours of peak demand or to secure critical loads for extended periods during extreme events.

The tender would:

- Specify required **firm capacity and energy duration**, based on updated reliability studies.
- Mandate integration with designated **renewable projects**, ensuring that green hydrogen is produced domestically.

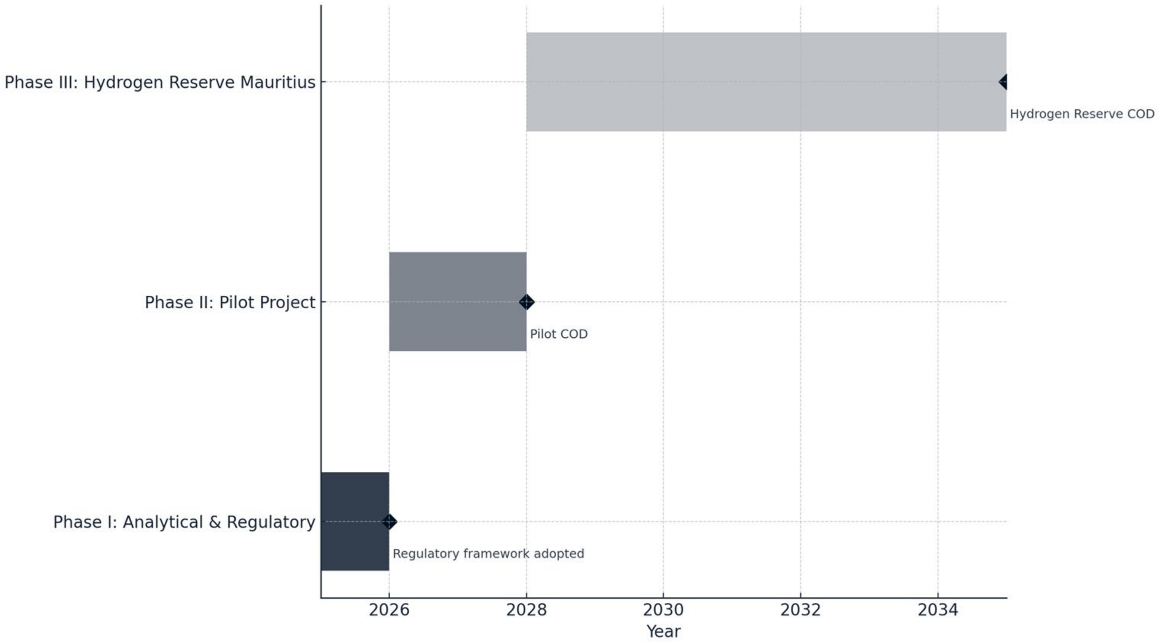

Figure 12 Hydrogen Storage Deployment Roadmap for Mauritius (2025–2035)

- Set transparent **remuneration mechanisms**, blending capacity payments with ancillary service revenues, and define cost-recovery pathways through tariffs, possibly with a modest levy labelled explicitly as a "resilience charge".

To align with Mauritius' broader climate and development agenda, the project should be structured to attract **blended finance** – combining concessional loans and grants with private investment – and to create local value in terms of jobs, training and industrial participation. International experience shows that hydrogen projects benefit from early engagement with export credit agencies, green bond markets and climate funds.(Hydrogen Council)

Beyond 2035, the hydrogen infrastructure built for the reserve could support **additional applications**: supplying hydrogen or derived fuels (such as green ammonia) to shipping, blending into industrial processes, or underpinning future synthetic fuel production. This creates an option value that, while difficult to quantify today, is strategically significant in a world moving towards decarbonised supply chains.

> By 2035, Mauritius could be known not only for its beaches and services economy, but also for having turned hydrogen storage into a quiet backbone of its energy security.

Conclusions & Recommendations

The evidence reviewed points to a clear, if nuanced, conclusion: hydrogen-based energy storage is not a panacea for Mauritius' power-sector challenges, but it can play a critical role as a turnkey, modular insurance solution against blackouts and as a provider of on-demand, low-carbon power – provided it is carefully scoped, sequenced and integrated with other flexibility resources.

Strategic conclusions

First, the reliability problem facing Mauritius is a structural one. A combination of rising peak demand, an ageing fleet of thermal plants, and growing shares of variable renewables has eroded the system's dependable capacity margin. Incidents in which the loss of a single 30 MW unit has triggered supply reductions are symptomatic of a system operating with little slack. [African Security Analysis, "Mauritius Grid Strain..."]

Secondly, the current toolbox for addressing this problem is limited. Traditional options – contracting emergency powerships, extending the life of old oil-fired units, or installing new fossil peakers – are rapid but inconsistent with the Government's 2030 coal phase-out, 60 per cent renewable target, and climate obligations. [Ministry of Energy and Public Utilities, Annual Report 2023–2024] While batteries and demand-side measures are essential, on their own they will not provide sufficient multi-day resilience, particularly during periods of extended low wind or solar resource.

Thirdly, hydrogen storage – especially in configurations designed for 10-100 hours of discharge – is increasingly recognised by IEA and IRENA as a key element of the long-duration flexibility portfolio required in net-zero power systems. [IEA, Managing the Seasonal Variability of Electricity Demand and Supply, 2024; IRENA, Hydrogen Overview] The technology is maturing, costs are trending downwards, and modular, containerised systems are already in commercial operation in island and remote settings. [Development Asia, 2019]

Finally, given the very high economic cost of unserved energy in a relatively sophisticated, service-driven economy, a carefully sized hydrogen storage asset can be justified as a form of resilience infrastructure whose primary purpose is risk mitigation rather than continuous energy supply. IRENA's small-island analysis suggests VoLL values of USD 10–50 per kWh in comparable contexts, against which even a relatively high hydrogen storage levelised cost (for example, USD 0.30–0.40 per kWh) appears modest. [IRENA, Transforming Small-Island Power Systems, 2019; PNNL Storage Cost Assessment]

Guiding principles for policy and regulation

On this basis, several guiding principles for policy and regulation can be articulated:

1. **Treat reliability as an explicit objective with a quantified standard.** Introducing a clear reliability metric – for example, a maximum acceptable loss-of-load expectation (LOLE) or an explicit VoLL benchmark – would enable more rational comparison of options and clarify the role of hydrogen storage as a reliability instrument. International practice increasingly integrates VoLL estimates into planning and market design. [Value of Lost Load literature]
2. **Define hydrogen storage formally within the regulatory framework.** The Utilities Regulatory Authority and the Ministry of Energy and Public Utilities should ensure that hydrogen storage is explicitly recognised in grid codes, licensing regimes and tariff structures – including its dual nature as both a consumer (during electrolysis) and a generator (during reconversion). Clear definitions will reduce regulatory risk for investors.
3. **Position hydrogen storage as complementary to, not a substitute for, batteries and demand-side measures.** Policy communications should emphasise that hydrogen storage addresses a distinct timescale of risk and is part of a broader toolbox that also includes BESS, flexible generation, energy efficiency and smart grids. This will help avoid unrealistic expectations and technology "either/or" debates.
4. **Adopt a modular, phased approach.** Rather than attempting a single, very large project, Mauritius should pursue a staged programme: a modest demonstration phase, followed by a strategic-scale "Hydrogen Resilience Reserve" once technical, regulatory and commercial lessons have been absorbed. Each phase should be designed with clear

learning objectives and options for scaling up or re-purposing equipment.

5. **Embed hydrogen storage within a just and inclusive transition.** Any additional costs associated with resilience infrastructure must be allocated transparently and fairly, with due regard for vulnerable consumers. Opportunities for local value creation – in construction, operations, maintenance and skills development – should be maximised.

Priority actions (2025–2030)

Within this framework, the following priority actions are recommended for the period to 2030. These are framed as headline directions, to be elaborated in the main body of the report.

► **1. Establish a high-level Hydrogen Storage Task Force.**

A cross-institutional task force – chaired at senior level and including the Ministry of Energy and Public Utilities, CEB, MARENA, the Utilities Regulatory Authority, the Economic Development Board, and representatives of Business Mauritius – should be mandated to develop a detailed hydrogen storage roadmap and to coordinate external technical assistance. This responds directly to the Government's expressed desire to work with partners such as India on hydrogen and offshore renewables. [Economic Times, 11 April 2025; Joint SDG Fund article, 2023]

► **2. Define the system reliability target and assess the insurance gap.**

System planners should quantify, using appropriate modelling and VoLL estimates, the economic consequences of plausible outage scenarios (e.g. simultaneous loss of the largest generating unit during the evening peak, or a multi-day period of low renewable output). This will allow policymakers to determine the size of the "insurance gap" – the portion of risk not adequately covered by existing assets and planned BESS deployments.

► **3. Design and procure a pilot-scale hydrogen storage project.**

A first project in the order of 5–10 MW of hydrogen-fired capacity with 40–80 MWh of storage – linked to a dedicated solar or wind facility – would allow Mauritius to build local technical capacity, test operating procedures, and validate cost and performance assumptions under real conditions. The project should be procured on an availability-based basis (for example, with capacity payments) and financed using a mix of concessional climate finance, development bank support and private capital.

► **4. Prepare a bankable "Hydrogen Resilience Reserve" tender.**

Subject to successful piloting and further analysis, Mauritius could then launch an internationally competitive tender for a larger-scale hydrogen storage facility (e.g. 30–60 MW with 200–600 MWh of storage). The tender documentation should clearly set out performance obligations (number of hours of guaranteed supply at a given output), remuneration mechanisms, and the integration of the asset into dispatch and reserve markets. Lessons from PNNL's and others' cost assessments should be adapted to Mauritian conditions. [PNNL Energy Storage Cost and Performance Assessment 2022]

► **5. Align tariffs and market signals with flexibility and resilience objectives.**

Tariff structures and market rules should be adjusted to reward flexible, low-carbon capacity. For example, differentiated capacity payments or ancillary service markets could be designed to remunerate assets capable of very long-duration discharge. At the same time, dynamic pricing and demand-response programmes should incentivise consumers to shift consumption away from stress periods, reducing the burden placed on storage.

► **6. Develop human capital and technical standards.**

Hydrogen systems require specific competencies in safety, materials, control systems and maintenance. Mauritius should leverage existing partnerships with universities and technical institutes, extend MARENA's training schemes to hydrogen technologies, and adopt international standards for hydrogen production, storage and use. [Ministry of Energy and Public Utilities, Annual Report 2023–2024; IRENA, Hydrogen]

► **7. Integrate hydrogen storage into long-term planning and NDC implementation.**

Finally, hydrogen storage projects should be explicitly reflected in the next iterations of the Long-Term Energy Strategy and in Mauritius' NDC implementation plan, not only as mitigation measures but also as adaptation and resilience investments. The 2025 NDC 3.0 submission underscores that loss and damage from climate-related disasters already represent a non-trivial share of GDP; resilient power infrastructure, including long-duration storage, is a key pillar of the response. [Mauritius NDC 3.0, 2025]

APPENDIX

Supplementary Materials

This appendix provides additional detail on the way the study was designed and executed, together with clarifications on the data and concepts used. The supplementary material is intended to make the analysis more transparent and reproducible, and to give readers sufficient information to stress test or adapt the findings for their own planning exercises. In particular, it sets out the methodological approach adopted for assessing hydrogen storage as a reliability option for Mauritius, acknowledges the key limitations of that approach, and records the main technical conventions underpinning the quantitative material and scenarios in the report and appendices.

Scope of the supplementary materials

The supplementary materials bring together three types of information that sit behind the main narrative. First, they describe how the study combined sector diagnostics, technology assessment and scenario analysis to construct an integrated view of hydrogen storage as an "insurance" instrument for Mauritius. Secondly, they explain the principal constraints on the analysis, including data gaps, simplifying assumptions and aspects that were explicitly scoped out. Thirdly, they provide technical notes on the definitions and metrics used for capacity, reliability, cost and emissions, along with brief guidance on how to interpret the stylised scenarios and indices in the tables. The intention is not to duplicate the main report, but to document the analytical "behind the scenes" work in a coherent way.

How we conducted this study

The study was conducted as an intensive, desk based policy and systems review rather than as a full scale power system planning exercise. The starting point was a structured reading of official Mauritian documents, including the Ministry of Energy and Public Utilities Annual Report 2023–2024, Statistics Mauritius' Energy and Water Statistics, CEB technical fact sheets and policy statements, and the Renewable Energy Roadmap 2030 and NDC 3.0 documentation. These sources provided the baseline for installed capacity, annual generation, peak demand, existing and planned renewables, and the Government's coal phase out and emissions reduction commitments.

In parallel, the study drew on international data and analysis from the IEA, IRENA, the World Bank, the IMF and specialist technical institutions. IEA's Global Hydrogen Review series and hydrogen technology briefs were used to characterise the state of electrolysers, storage and hydrogen capable generation. IRENA's work on electricity storage and small island systems informed the understanding of long duration storage roles and the importance of the value of lost load in planning. Cost and performance assumptions for storage technologies were taken primarily from the 2022 PNNL Grid Energy Storage Technology Cost and Performance Assessment, IRENA's storage cost reports and NREL/NREL linked battery cost projections, which together offer a reasonably coherent benchmark set for the 2020–2030 period.

Having established this data foundation, the study undertook a comparative assessment of reliability options relevant to Mauritius: short duration batteries, diesel and gas peaking plant, demand side management and hydrogen storage. Rather than relying on a single cost or efficiency figure for each technology, the analysis worked with ranges drawn from the literature, cross checked against island and emerging market case studies where possible. These ranges were then used to construct relative "system cost indices" that express lifecycle cost per unit of reliable capacity or avoided unserved energy, normalised for ease of comparison and explicitly labelled as indicative.

For the forward looking part of the work, the study developed stylised 2030 scenarios for Mauritius' power mix with and without a hydrogen reserve. These scenarios were anchored in official targets (60 per cent renewables, coal phase out) and informed by modelling in published academic work on a high renewables Mauritian power system, but they did not attempt to reproduce a full chronological dispatch or unit commitment model. Instead, they were constructed as internally consistent storylines that allow the relative role of hydrogen storage to be explored under plausible assumptions about demand growth, renewables build out and the evolution of system margins. The scenario values in the appendix tables are therefore best understood as structured "what if" cases rather than forecasts.

Throughout, the analysis remained qualitative in its treatment of institutional and regulatory issues. It mapped existing legislation and regulatory roles (CEB Acts, URA Act, Electricity Act and associated regulations) against the needs of hydrogen storage as a new asset class, and extrapolated from international practice in markets where storage has already been integrated into planning and remuneration frameworks. No confidential data or proprietary models were used; all sources are public and are cited in the main text or in the appendix tables.

Limitations

Several important limitations qualify the findings and should be borne in mind when using this report for decision making. The most fundamental is that the study did not build or run a full power system model for Mauritius. In particular, it did not simulate chronological unit commitment, transmission constraints or real time stability conditions. As a result, conclusions about the adequacy value of hydrogen storage, batteries or other options are based on comparative reasoning and international evidence rather than on bespoke Mauritian dispatch simulations. This is why the scenarios are presented as stylised, and why the report repeatedly recommends detailed system modelling as a next step.

A second limitation stems from reliance on secondary data. There are known discrepancies between sources on key metrics such as total generation and renewable shares, most visibly between the Ministry of Energy and Public Utilities Annual Report and IRENA's statistical profiles. Where this occurred, the study prioritised the official Mauritian numbers for 2023 and treated other series as cross checks, but it did not attempt to reconcile all differences through re estimation. Similarly, cost estimates for hydrogen storage, batteries and peakers are taken from global or regional literature and adjusted qualitatively for small island conditions, rather than being derived from detailed local engineering designs, supplier quotations or financial models.

Third, the analysis does not fully capture political economy and distributional dimensions. The report recognises that tariff changes, public perceptions of hydrogen safety, the interests of incumbent IPPs and the fiscal position of the state will all shape what is feasible, but it does not model these factors in depth, nor does it incorporate formal stakeholder surveys or interviews. In that sense, the study is primarily a technical and economic framing exercise, not a comprehensive planning or stakeholder engagement process.

Fourth, the treatment of climate risks and long term demand uncertainty is relatively high level. While the report notes Mauritius' exposure to cyclones and other climate related hazards, it does not include a probabilistic assessment of how climate change may alter demand profiles, renewable resource patterns or infrastructure vulnerability over the coming decades. The scenarios also assume a broadly linear trajectory towards the 2030 targets, without attempting to model transitional disruptions such as delayed project commissioning or faster than expected electrification of transport.

Finally, hydrogen technology and costs are themselves moving targets. Electrolyser manufacturing capacity, project pipelines and policy incentives are evolving rapidly. Although the study uses the latest available global reviews at the time of writing, specific cost ranges, project pipeline statistics and technology readiness levels may have changed by the time the report is read. Readers planning investments or regulatory changes should therefore treat this report as a framing document and update key parameters with current data before making binding decisions.

Appendix A – System Context and Data

Table 1 Mauritius Electricity System Snapshot (2023)

Indicator	2023 value	Unit	Notes
Total electricity generated (all producers)	3,018.8	GWh	Calendar-year 2023 generation. (Public Utilities)
Peak demand (Island of Mauritius)	508.4	MW	Maximum demand recorded in 2023. (Public Utilities)
All-island installed generation capacity	866	MW	Includes CEB and all IPPs. (Public Utilities)
CEB-owned generation capacity	528	MW	Sum of all CEB stations. (Public Utilities)
IPPs' installed generation capacity (FUEL, CTDS, CTSAV, Mare Chicose)	353	MW	Private producers linked mainly to sugar industry & landfill gas. (Public Utilities)
Non-renewable share of generation (all fuels)	~84.4	% of GWh	Computed as 100 – 15.6 per cent (see below).
Renewable share of generation (all technologies)	15.6	% of GWh	470.7 GWh of renewables out of 3,018.8 GWh. (Public Utilities)
Renewable generation (absolute)	470.7	GWh	Includes solar, wind, hydro, bagasse, landfill gas. (Public Utilities)
Fuel oil share of total generation	48.8	% of GWh	"Current generation profile" in Annual Report. (Public Utilities)
Coal share of total generation	33.5	% of GWh	As above. (Public Utilities)
Renewables share – Solar	4.5	% of GWh	Part of 2023 generation profile. (Public Utilities)
Renewables share – Wind	0.2	% of GWh	As above. (Public Utilities)
Renewables share – Hydropower	2.9	% of GWh	As above. (Public Utilities)
Renewables share – Landfill gas	0.4	% of GWh	As above. (Public Utilities)
Renewables share – Biomass (bagasse)	9.5	% of GWh	As above. (Public Utilities)
Transmission & distribution losses	6.08	% of energy	Reported system losses 2023. (CEB)
All-time peak demand (Jan/Feb 2025, for context)	567.9	MW	Peak recorded at 21:00 on 5 February 2025. (CEB)

Source: *Ministry of Energy and Public Utilities, Annual Report 2023–2024; CEB fact sheets; IRENA statistics. (Public Utilities)*
Note: *The Annual Report also cites a 17.6% share for renewables when describing the "current generation profile". The small discrepancy with the 15.6% figure arises from differences in coverage and rounding; for quantitative analysis this appendix uses the 470.7 GWh / 15.6% value.*

Table 2 Mauritius Electricity Generation by Source, 2023 (Official + IRENA)

Fuel / technology	Generation (GWh)	Share of total (%)	Notes / definition
Fuel oil / diesel	n.a. (≈1,470)*	48.8	Thermal generation from heavy fuel oil and diesel engines. (Public Utilities)
Coal	n.a. (≈1,010)*	33.5	Coal-fired steam plants, including IPP bagasse/coal co-firing when coal-dominated. (Public Utilities)
Subtotal non-renewable	2,548.1 (residual)	84.4	Computed as total generation minus renewables. (Public Utilities)
Hydro / marine	~96	3.0	IRENA stat profile; run-of-river & storage hydro. (IRENA)
Solar PV	151	5.0	Grid-connected utility-scale + rooftop; IRENA. (IRENA)
Wind	9	0.3	Small onshore wind farms. (IRENA)
Bagasse / biomass	323	10.0	Co-generated power from sugarcane bagasse and other biomass. (IRENA)
Landfill gas	12 (approx.)*	0.4	Electricity from landfill gas capture. (Public Utilities)
Subtotal renewable	578 (IRENA) / 470.7 (MoEPU)	18.0 / 15.6**	Methodological differences between IRENA and Ministry sources. (IRENA)
Total generation	3,269 (IRENA) / 3,018.8 (MoEPU)	100	Slight discrepancy due to reporting scope & rounding. (IRENA)

** Back-calculated, indicative only – exact GWh by fuel from Statistics Mauritius can be inserted when available.*
*** For modelling you may wish to adopt a single series (e.g. MoEPU 470.7 GWh) and treat IRENA values as a cross-check.*

Appendix B – Technology and Cost Parameters

Table 3 Technical Characteristics of Selected Reliability Options (Global Benchmarks)

Option / technology	Typical power scale (MW)	Economically optimal storage duration	Round-trip efficiency (%)	Installed cost (2020–25 typical ranges)	Maturity for grid use	Key advantages	Key limitations / risks	Main sources
Li-ion BESS (utility-scale)	1–300	2–8 hours	85–92	Energy: ~USD 200–400/kWh (4h systems) in 2023; trending below USD 200/kWh by 2030.(IRENA)	Commercial, widely deployed	Very fast response, modular, ideal for intra-day balancing and grid services.	Costs grow roughly linearly with duration; not economical for >~24h storage at scale.	IRENA 2017 Storage Costs; NREL Battery Cost Projections.(IRENA)
Hydrogen storage (PEM + tanks + turbine / fuel cell)	5–200	10–200+ hours	30–45 (electricity-to-electricity)	Power (electrolyser): ~USD 700–1,300/kW today; potential ↓40–80% long term. Storage: ~USD 10–20/kWh (compressed tanks).(IRENA)	Early commercial / demonstration	Suited to multi-day storage, enables domestic green fuel, supports deep decarbonisation.	Lower efficiency; high upfront capex; requires robust safety and regulatory frameworks.	IEA Global Hydrogen Review 2024; IRENA Green Hydrogen Cost Reduction; PNNL 2022.(IEA)
Diesel peaker (engine plant)	5–200	Hours–days (limited by fuel inventory)	30–45 (fuel to power)	Power: ~USD 500–900/kW; fuel cost often >USD 0.20–0.30/kWh in islands.(IRENA)	Fully mature	Low upfront capex, fast deployment, familiar technology.	High emissions; high variable cost; exposed to fossil/freight volatility.	IRENA Island Power 2012; NREL/Black & Veatch cost report.(IRENA)
Gas turbine (simple-cycle)	20–400	Hours–days	35–40	Power: ~USD 600–1,200/kW; fuel cost depends on LNG / gas price.(IRENA)	Fully mature	Higher efficiency than diesel; capable of quick ramping.	Requires gas infrastructure; locks in new fossil dependency.	IRENA Storage Cost 2017; NREL ATB.(IRENA)
Pumped storage hydropower	100–2,000	4–24+ hours	70–85	Highly site-specific; often USD 1,000–2,500/kW installed.(IRENA)	Very mature where sites exist	Very long life; low variable cost; large energy volumes.	Requires suitable topography and water resources; long lead times; often not feasible in small islands.	IRENA Storage Cost 2017; global PSH case studies.(IRENA)
Demand response	System-wide	"Virtual" short-duration flexibility	n/a	Programme cost often << USD 100/kW-year for	Mature in many	Very low cost; reduces need for	Limited scale; not always reliable in extreme events;	IRENA power-system flexibility reports.

Option / technology	Typical power scale (MW)	Economically optimal storage duration	Round-trip efficiency (%)	Installed cost (2020–25 typical ranges)	Maturity for grid use	Key advantages	Key limitations / risks	Main sources
(industrial & commercial)				enrolled capacity.(IRENA)	OECD systems	new generation; quick to implement.	depends on advanced metering & contracts.	

Table 4 Cost and Emissions Comparison of Reliability Options in Mauritius, 2030 Horizon
(Illustrative values for scenario work – not official tariffs)

Option	**Storage duration assumed**	**Indicative system cost metric***	**Approx. CO_2 intensity ($kgCO_2/kWh$ delivered)**	**Qualitative role in Mauritian portfolio**
Diesel peaker	4–12 h	High (LCOS index ≈ 1.5–2.0)	0.7–0.9	Transitional back-up; avoided where possible.
Simple-cycle gas turbine (LNG)	4–12 h	Medium–high (index ≈ 1.2–1.6)	0.4–0.5	Only if gas infrastructure is developed.
Li-ion BESS (4 h)	4 h	Low (index ≈ 1.0 baseline)	0 (direct); lifecycle depends on grid mix	Best for intra-day balancing and peak shaving.
Li-ion BESS (24 h equivalent)	24 h	High (index ≈ 1.6–2.0)	0 (direct)	Technically possible but capital-intensive.
Hydrogen storage reserve	100 h	Medium (index ≈ 1.3–1.7)	≈0 (with renewable H_2)	Long-duration reserve / blackout insurance.
Structured demand response	n/a (load reduction)	Very low (index ≈ 0.3–0.5)	n/a	First line of defence to shave peaks.

*"System cost index" is a **relative** measure of lifecycle cost per unit of **reliable capacity** or avoided unserved energy, normalised to Li-ion BESS (4h) = 1.0. Ranges reflect literature from PNNL (2022) for storage, NREL for BESS, IRENA for island systems, and typical diesel fuel costs in SIDS. (NREL Docs)*
*This table is intended for **scenario analysis** and should be adapted when you have project-specific cost estimates.*

Appendix C – International Case Studies

Table 5 Selected Hydrogen and Hybrid Storage Projects Relevant to Mauritius

Project / location	Country / region	Commissioning status	Approx. scale (electrolyser / storage / power)	System configuration	Main purpose	Key lessons for Mauritius
Fukushima Hydrogen Energy Research Field (FH2R), Namie	Japan	Operational	10 MW electrolyser; up to ~1,200 Nm³ H_2/h	20 MW solar PV + grid; 10 MW PEM electrolyser; large H_2 storage; offtake for mobility & grid services.(IEA)	Grid balancing, mobility, industrial H_2	Demonstrates large-scale electrolysis paired with variable renewables and hybrid revenue streams.
Ramea wind–hydrogen–diesel microgrid	Canada (Newfoundland)	Demonstration / early operations	~0.4–1 MW wind; small electrolyser & H_2 storage; diesel engines	Wind turbines, electrolyser, H_2 storage, fuel cells/diesel engines in remote island microgrid.(IRENA)	Reduce diesel use, demonstrate P2G	Shows practical integration of hydrogen into a remote diesel microgrid with seasonal variability.
Denham Hydrogen Demonstration Plant	Australia (WA)	Operational	~220 kW electrolysers, ~180 kg H_2, 100–300 kW fuel cell (typical reported scales)	Solar PV + battery + electrolyser + H_2 storage + fuel cell in coastal town microgrid.(IRENA)	Reduce diesel reliance, test H_2 operations	Containerised H_2 solutions can augment existing diesel systems for resilience in remote communities.
Borrego Springs microgrid	USA (California)	Demonstration	~1 MW electrolyser, ~600 kW fuel cell, several hundred kg H_2	Solar PV + battery + hydrogen (electrolyser, storage, fuel cell) feeding microgrid with islanding capability.	Critical-load resilience, black-start	Hydrogen-battery hybrids can supply critical loads during grid outages and support black-start.

Project / location	Country / region	Commissioning status	Approx. scale (electrolyser / storage / power)	System configuration	Main purpose	Key lessons for Mauritius
Koh Jik island microgrid	Thailand	Upgraded over time	Small-scale PV, batteries; H_2 considered in redesign	Solar–battery–diesel hybrid microgrid, with studies examining H_2 for extended autonomy.	Cost-effective diesel displacement	Underscores need to optimise system design (solar + storage + diesel) before adding H_2.
Mafate / Réunion microgrids	France (Réunion)	Operational pilot	kW-scale solar, battery, sometimes H_2	Remote valley microgrids with high autonomy, some exploring H_2 as long-duration storage.(IRENA)	Rural / remote electrification	Island territory with similar legal context offers valuable lessons on standards and safety.
H2 Islands pilots (various EU islands)	EU (e.g. Orkney)	Under development	Target ≥300 t green H_2/year per island	Wind, solar, electrolysers, H_2 storage and offtake for ferries, heavy transport and blending.(IEA Blob Storage)	Multi-sector hydrogen ecosystems	Islands used as test-beds for linking power, transport and heat using hydrogen.

***Note**: scales for some demonstration projects are rounded for readability and should be checked against original project documentation if you want to quote exact ratings.*

Appendix D – Policy, Regulatory and Implementation Planning

Table 6 Indicative Policy and Regulatory Actions for Hydrogen Storage in Mauritius (2025–2030)

Time horizon	Policy / regulatory action	Lead institution(s)	Link to main report section	Notes / international reference
2025	Adopt explicit reliability metrics (LOLE target, VoLL estimate).	Ministry of Energy & Public Utilities (MEPU), CEB, URA	§8.1, §6.3	IRENA SIDS guidance on LOLE/VoLL.
2025–2026	Update Long-Term Energy Strategy to include hydrogen storage.	MEPU, CEB, MARENA	§8.1, §9.1	Builds on Renewable Energy Roadmap 2030 & NDC 3.0. (IRENA)
2025–2026	Define “storage asset” in Electricity Act / secondary legislation.	URA, Attorney-General’s Office, MEPU	§8.2	Follow practice from EU/US storage regulations.
2025–2026	Prepare storage licensing conditions & grid-code amendments.	URA, CEB	§8.2	Include connection rules, protection, dispatch rights.
2026	Issue draft remuneration principles (capacity & ancillary services) for consultation.	URA, MEPU, CEB	§8.3	Draw lessons from European capacity markets and storage tenders. (IRENA)
2026–2027	Adopt international hydrogen safety & technical standards (ISO/IEC) into national codes.	MEPU, Mauritius Standards Bureau, Fire & Disaster Services	§8.4	Based on IEA and ISO hydrogen safety guidance. (IEA Blob Storage)
2026	Establish Hydrogen Storage Task Force and publish concept note.	MEPU (chair), CEB, URA, MARENA, EDB, MoF	§8.5, §9.1	Align with NDC 3.0 implementation governance. (IRENA)
2027–2028	Approve pilot project PPA / availability contract template.	URA, CEB, Task Force	§9.2	Template to be adapted for utility-scale reserve.
2028–2029	Approve capacity-based remuneration framework for long-duration storage.	URA, MEPU, MoF	§8.3, §9.3	Could be implemented as a specific long-duration procurement window.
By 2030	Integrate hydrogen storage formally into NDC update and Long-Term Strategy (2050 horizon).	MEPU, Ministry of Environment, MoF	§8.5, §9.4	Position hydrogen as adaptation + mitigation measure. (IRENA)

Table 7 Indicative Implementation Roadmap and Risk Register (Hydrogen Resilience Reserve)

Phase / period	Main activities	Key risks	Mitigation measures	Responsible entities
Phase I – 2025–2026: Analytical & enabling framework	Adequacy modelling incl. hydrogen; VoLL/LOLE calibration; pre-feasibility study; legal & regulatory scoping; Task Force formation; initial donor engagement.	Inadequate analytical depth; political shifts; regulatory delays.	Use external technical assistance (World Bank, IRENA, AfDB); cross-party briefing; formal Cabinet decisions. (IRENA)	MEPU, CEB, URA, MARENA, MoF

Phase / period	Main activities	Key risks	Mitigation measures	Responsible entities
Phase II – 2026–2028: Pilot project	Design, tendering, financing, construction and commissioning of ~5–10 MW pilot (with 40–80 MWh storage); performance monitoring; public communication.	Technology under-performance; cost overrun; safety incidents; negative media coverage.	Fixed-price EPC with performance guarantees; independent safety audit; transparent communication of pilot status; insurance cover. (NREL Docs)	CEB, private developer, URA
Phase III – 2028–2033: Utility-scale Hydrogen Resilience Reserve	Competitive tender for 30–60 MW reserve with 200–600 MWh storage; finalisation of capacity remuneration; integration into dispatch and emergency protocols.	Weak bidder interest; financing challenges; tariff impacts; construction delay.	Allow consortium bids; blended finance (climate funds + private); phased cost recovery; careful grid integration planning. (IEA Blob Storage)	MEPU, CEB, URA, MoF, dev. partners
Phase IV – 2033+: Hydrogen economy integration	Diversification of H_2 use into transport, ports, industry; potential regional partnerships; ongoing optimisation of reserve operation.	Demand risk; technology shifts; competition from other fuels (e-fuels, ammonia imports).	Design infrastructure for multi-use; periodic strategic reviews; maintain technology-neutral policy for downstream uses. (IRENA)	MEPU, EDB, port authority, private sector

Table 8 Stylised Scenario Comparison: 2030 System with and without Hydrogen Reserve

(Indicative illustration – values should be refined with full power system modelling)

Metric	2023 baseline (actual)	2030 “RE push, no H_2 reserve” (illustrative)	2030 “RE + Hydrogen Resilience Reserve” (illustrative)
Total electricity demand (GWh)	3,018.8	3,500	3,500
Peak demand (MW)	508.4	600	600
Installed capacity (MW, all sources)	866	1,050	1,050 + 40 MW hydrogen reserve generation
Renewable share of generation (%)	15.6	45	60
Coal share of generation (%)	33.5	10	0 (coal phased out)
Fossil fuel share (%)	~84.4	55	40
Battery energy storage (BESS) capacity (MW / MWh)	~0 / ~0 (utility-scale)	60 MW / 240 MWh	60 MW / 240 MWh
Hydrogen reserve power / energy (MW / MWh)	0	0	40 MW / 800 MWh
Expected unserved energy (EUE, MWh/year)	Very low historically, but rising risk	80 (due to thin margin & RE variability)	10–20 (hydrogen reserve covers most extreme events)
System-wide CO_2 emissions from power (Mt)	~2.0–2.2 (order-of-magnitude)	~1.4	~1.0 or below
Approx. levelised system cost change vs 2023 (index)	1.0 (baseline)	1.10–1.15	1.12–1.18 (higher capex but lower outage/fuel costs)

Assumptions: renewable build-out broadly aligned with Renewable Energy Roadmap 2030 and coal phase-out impacts described in NDC 3.0; BESS deployment scaled from Edoo et al. modelling; hydrogen reserve sized to deliver 40 MW for 20 hours in extreme events.(IRENA)
*This table is a **framework** for our own scenarios: you can replace the placeholder 2030 values with results from a PLEXOS/TIMES or similar planning model.*

Notes

The quantitative material in the main report and appendices relies on a set of technical definitions and conventions that are worth stating explicitly. The term “installed capacity” refers to nameplate capacity in megawatts as reported by Mauritian authorities, while “firm capacity” denotes the subset of that capacity considered reliably available at times of system stress, after accounting for maintenance, derating of ageing units and the limited contribution of variable renewables during evening peaks. The “reserve margin” is understood as firm capacity minus peak demand, expressed as a percentage of peak demand. Because firm capacity estimates for Mauritius are not officially published in a detailed form, the report uses indicative estimates for firm capacity trends and emphasises their qualitative meaning rather than their precise magnitude.

On the economic side, when comparing storage and reliability options the analysis uses the concept of a levelised cost of storage (LCOS), which aggregates capital expenditure, fixed and variable operating costs and efficiency losses over the lifetime energy discharged by the storage asset. In a small island context, LCOS alone is not sufficient; the more relevant measure is the cost of reliable capacity and the cost per unit of avoided unserved energy. To capture this, the appendix introduces “system cost indices” for different technologies, normalised to a four hour lithium ion battery system. These indices are dimensionless and represent relative, not absolute, costs, allowing a high level comparison without committing to a single currency year or exchange rate.

Reliability outcomes in the scenarios are expressed in terms of “expected unserved energy” (EUE), which is the statistical expectation of the amount of demand that cannot be met over a year, typically measured in megawatt hours. The value of lost load (VoLL) is used conceptually as the economic cost per kilowatt hour of unserved energy; in the absence of Mauritian specific estimates, the study draws on ranges reported for other small island systems to illustrate how an annualised hydrogen reserve cost might compare with expected outage costs. No single VoLL figure is adopted as definitive; instead, VoLL is treated as a knob that planners can turn when using the report’s tables as templates for their own calculations.

Scenario values for 2030 are presented as “illustrative” to signal that they are not forecasts. For example, the “RE push, no hydrogen reserve” and “RE + Hydrogen Resilience Reserve” cases in the appendix assume total demand of 3,500 GWh, peak demand of 600 MW, a renewable share of 45–60 per cent and a hydrogen reserve of 40 MW / 800 MWh. These values are designed to be broadly consistent with Mauritius’ 2030 renewable and coal phase out targets and with plausible storage deployments, but they are placeholders that should be replaced by model derived values in formal planning. Similarly, the cost and emissions figures associated with each scenario are indicative and intended mainly to illustrate trade offs, not to serve as tariff proposals or official baselines.

Finally, all monetary figures quoted from international sources are presented in nominal US dollars, usually in the price year of the original publication. No attempt has been made to convert these into Mauritian rupees or to a single reference year through inflation adjustment. For rigorous financial appraisal of specific projects, readers should therefore re express all cost and price data in a consistent currency and year, and apply project specific assumptions about financing terms, tax treatment and exchange rate risk. The technical tables and indices in this report are designed to remain useful under such re calibration, because they emphasise relative relationships and order of magnitude comparisons rather than precise point estimates.

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About This Report

This report provides a rigorous assessment of how hydrogen-based energy storage could serve as a practical "insurance policy" against electricity blackouts in Mauritius while supporting the country's transition to a low-carbon power system. Drawing on official Mauritian statistics, government policy documents and international analyses from institutions such as the IEA, IRENA, the World Bank and the IMF, it combines system diagnostics, global technology and cost evidence, and stylised scenario analysis to examine the role of hydrogen storage alongside batteries, flexible thermal plant and demand-side measures. Written in a board-level style for senior policymakers, regulators, utility executives, investors and development partners, the report sets out the strategic case for a "Hydrogen Resilience Reserve", explores the economics of long-duration storage in a small-island context, and outlines the policy, regulatory and financing reforms needed to make such a solution bankable. While the analysis is firmly grounded in current data and international best practice, it is intended as an independent contribution to policy dialogue, providing a structured framework within which Mauritius can test options, refine assumptions and design a tailored roadmap towards a more secure, cleaner and more resilient electricity future.

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