

Potential Green Hydrogen Applications in India's Power Sector

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Executive Summary

INTRODUCTION

Hydrogen, an attractive energy carrier due to its high energy content per unit mass, offers multiple promising pathways towards significant global decarbonization efforts. While traditional hydrogen production relies on fossil fuels (gray hydrogen), using renewable electricity sources for electrolysis enables the production of green hydrogen, a crucial step towards a sustainable future.

RMI and NITI Aayog project that India's hydrogen demand will rise by about 23 million tons from 2020 to 2050, with 94% of that increase representing an opportunity for green hydrogen. The country's current hydrogen production relies heavily on steam methane reforming (SMR), but the National Green Hydrogen Mission hopes to establish India as a global hub for green hydrogen production, use, and export. Incentivizing green hydrogen supply chain investment, replacing gray hydrogen in existing applications, and supporting pilot projects in sectors like steel manufacturing and long-haul transportation are key strategies.

Green hydrogen offers potential solutions to India's present grid reliability challenges through long-duration energy storage, captive power generation, and ammonia co-firing. Storing excess renewable energy as green hydrogen can address renewable variability across a wide array of time periods. India, commonly relying on pumped hydro storage (PHS) and battery-based storage, could benefit from green hydrogen's geographical flexibility (compared to PHS), socio-economic benefits, and extended storage capacity and duration. Decarbonizing captive generation, by replacing coal assets with green hydrogen in captive fuel cells and hydrogen gas turbines, is another key application. Finally, ammonia co-firing in existing coal power plants, using green hydrogen-derived ammonia, offers a pathway to reducing carbon emissions. Adding green ammonia, a carbon-free fuel, to the combustion process can reduce emissions without requiring complete replacement of existing infrastructure. International examples, such as the long-standing Teesside hydrogen storage project in the UK and ongoing ammonia co-firing demonstrations in Japan, provide valuable insights and context for India's energy transition.

REPORT OBJECTIVES

In collaboration with RMI India, we aim to assess the feasibility of three green hydrogen applications: ammonia co-firing, captive generation, and long-duration energy storage. By analyzing the technical and economic feasibility and supporting policy mechanisms of each application, we seek to identify the

most effective pathways for India to achieve its green hydrogen and renewable energy targets. We also provide insights into the green hydrogen market and potential implementation strategies, supporting RMI and its partners in advising policymakers. Ultimately, the goal is to contribute to a deeper understanding of green hydrogen production and implementation in India's power sector, identifying the most impactful and feasible technologies for its future electricity markets and policy landscape. We conclude with comprehensive recommendations on the feasibility and efficacy of various implementation pathways.

METHODS

We identified 10 potential pathways for the production, storage, and use of green hydrogen in India's power sector, illustrated in Figure 1. These pathways encompass the three end-use applications of long-duration storage, ammonia co-firing, and captive generation that RMI India and the National Green Hydrogen Mission seek to implement.

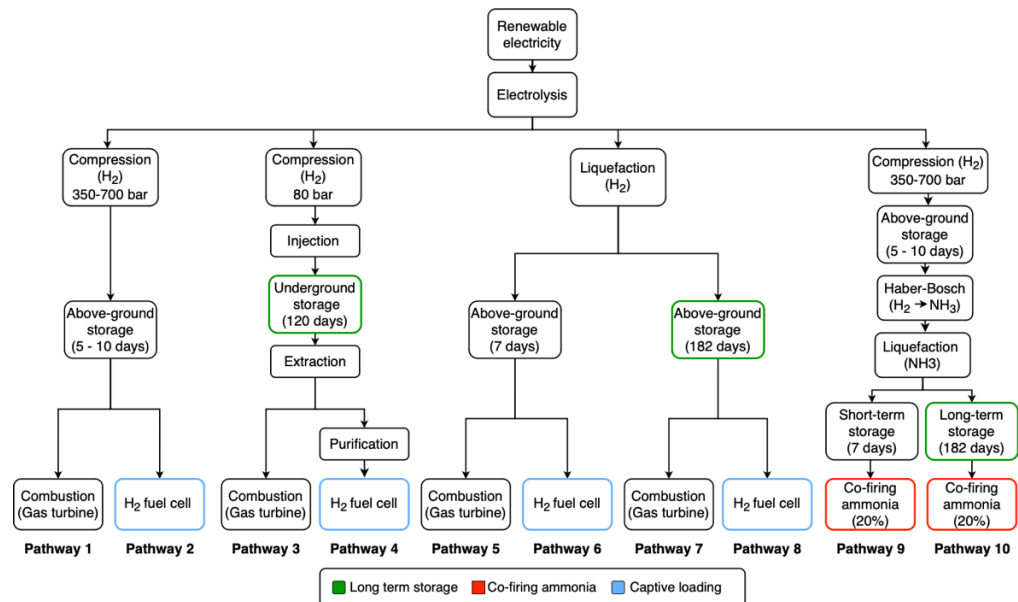


Figure 1. Pathways for Green Hydrogen and Ammonia: Production, Storage, and End-Use Applications.

Our team analyzed each pathway and developed recommendations regarding which options are the most technically, economically, and politically feasible for each of the three applications. In evaluating the elements of these three approaches, we synthesized insights from an extensive body of existing

literature on green hydrogen and conducted new, context-specific calculations using established sector-specific models. We assessed all 10 pathways across three broad categories of technical and economic feasibility and existing policy mechanisms and integrated the findings of the three work streams into a final comparative analysis of the pathways.

Technical Analysis

We conducted a technical analysis using energy efficiency modeling to determine the inputs, outputs, and energy losses associated with each stage of the ten applications demonstrated in Figure 1. We employed higher heating values (HHV) in the analysis to ensure consistent comparisons across technologies, particularly between fuel cells and gas turbines. To help visualize the energy flows and losses across each application, we created Sankey diagrams, normalized to one unit of useful energy. We evaluated various storage methods, including above-ground (compressed and liquified) and underground (aquifers and depleted gas reservoirs), with specific attention to short-term and long-term storage impacts.

We examined multiple generation technologies including gas turbines and fuel cells for green hydrogen, and co-firing in coal power plants for green ammonia. The Hydrogen Delivery Scenarios Analysis Model (HDSAM) provided inputs that account for energy losses during storage, compression, liquefaction, and liquid hydrogen transfer. We did not consider energy losses during transportation because they depend on the geographic distribution of hydrogen production, storage, and end-use sites in India, which is outside the scope of this study.

We considered above-ground and below-ground storage to account for different duration requirements and hydrogen energy carrier states across different pathways in this study. Given the prevalence of underground aquifers and depleted oil and gas reservoirs in India, we prioritized these options for below-ground storage over salt caverns. For above-ground storage, we focused on pressurized gaseous H₂ vessels, and temperature-controlled liquid H₂ and ammonia vessels.

Cost Analysis

We included cost parameters such as the levelized cost of hydrogen and ammonia, transportation, storage, and capital investments of end-use technologies in the cost analysis. Pathway-specific equations combine these

costs to calculate a levelized cost of electricity (LCOE) for each scenario outlined in Figure 1. Although we do not include transportation costs in the LCOE calculations, we discuss them separately in various transportation scenarios.

Policy Analysis

We examined global and Indian policies relevant to green hydrogen deployment within the three applications in the policy analysis. Our team reviewed government reports that focus on India’s National Green Hydrogen Mission (NGHM), state-level policies, and additional supporting policies at the national level. We used two IRENA reports about green hydrogen policy development as benchmarks for successful policy schemes.¹² While the NGHM serves as the baseline for national-level analysis, we examined policies from seven Indian states to understand their relevance to the three applications.

FINDINGS

Table 1 outlines the round-trip efficiencies and LCOE for each of the pathways outlined in Figure 1. We contextualize these results for each application in the subsections that follow.

Table 1. Efficiencies and LCOE for Each Pathway.

| Pathway Name | Round-trip Efficiency (%) | LCOE (\$/kWh) |
|--------------|---------------------------|---------------|
| Pathway 1 | 21.9 | 0.29 - 0.30 |
| Pathway 2 | 32.9 | 0.25 - 0.27 |
| Pathway 3 | 19.4 | 0.37 |
| Pathway 4 | 27.0 | 0.31 |
| Pathway 5 | 17.5 | 0.30 - 0.31 |
| Pathway 6 | 26.3 | 0.27 |
| Pathway 7 | 13.2 | N/A |
| Pathway 8 | 19.8 | N/A |
| Pathway 9 | 5.8 | 0.56 - 0.61 |
| Pathway 10 | 5.6 | 0.56 - 0.61 |

Long-Duration Energy Storage

The results of our technical analysis indicate that hydrogen compression is the most efficient storage method, with 89.4% efficiency and minimal losses. Above-ground compressed gas storage is also the most economical, costing \$0.48–\$0.68 per kg H₂, significantly lower than liquefied hydrogen storage (\$0.73–\$0.76 per kg H₂). However, limited tank capacity restricts large-scale seasonal storage.

Underground storage in depleted reservoirs offers high capacity but is the most expensive option, with a levelized cost of \$1.47 per kg H₂. Fixed locations may present logistical challenges and higher transportation costs. Hydrogen liquefaction, while viable for short-term storage, suffers from high energy losses, with efficiency at 71.8% for short-term and 50.6% for seasonal, due to the energy-intensive process of maintaining cryogenic temperatures.

Green ammonia storage emerges as a promising alternative, with significantly higher efficiencies at for 98.3% short-term and for 91.3% long-term than hydrogen liquefaction, making it suitable for large-scale energy storage and industrial use.

On the policy front, India's green hydrogen framework is fragmented, with most authority at the state level and weak enforcement strategies at the national level. Current national level policies related to long duration storage are the National Green Hydrogen Mission, the Hydrocarbon Exploration and Licensing Policy (HELP), and the Energy Storage Obligations Trajectory.

Captive Generation

The four captive generation pathways (2, 4, 6, 8) present relatively better round-trip efficiencies than other pathways. Among them, Pathway 2 stands out to have the highest efficiency at 32.9%. In addition, Pathway 2 has the lowest LCOE at \$0.25–\$0.27 per kWh, making it our recommended pathway. The 2022 Electric Rules in India offer policy incentives, including open access to renewable energy for captive power generators, which eases the integration of green hydrogen production. However, captive generation would likely operate at a lower capacity than the assumptions in this study (50 tonnes of hydrogen daily), resulting in a higher LCOE if the hydrogen is produced onsite.

Ammonia Co-Firing

Pathways 9 and 10, both involving co-firing, exhibit the lowest estimated efficiencies among the ten analyzed pathways in this project, at approximately 6%. In addition, both pathways have an estimated LCOE of

\$0.56 to \$0.61 per kWh, which is also the highest among all pathways. Given India's policy direction in increasing domestic coal supply in the coming decades, policymakers potentially can promote co-firing ammonia with coal as a transitional decarbonization strategy. Current literature indicates that Gujarat, Maharashtra, Rajasthan, Tamil Nadu, and Madhya Pradesh, with their significant renewable energy and coal-fired power plant capacities, hold the greatest potential for ammonia co-firing with coal in India.

Transportation

We compare the cost of transporting hydrogen using tube trailers, cryogenic tanks, and pipelines over distances from 100 to 1,000 km at a throughput rate of 50 metric tonnes per day, including cost considerations for compression and liquefaction. We found that pipelines are the most cost-effective option, costing \$0.0017 per kilogram per kilometer for 100 km and dropping to \$0.0011 per kilogram per kilometer for 1,000 km due to economies of scale. However, pipelines are not always practical for shorter distances. For trips up to 300 km, tube trailers are the next best option at \$0.0036 - \$0.0029 per kilogram per kilometer. For distances between 400 and 1,000 km, cryogenic tanks are more cost-effective than tube trailers, with costs ranging from \$0.0024 to \$0.0014 per kilogram per kilometer.

FINAL RECOMMENDATIONS

Our conclusions yield the following recommendations:

1. **The Indian Government should prioritize Pathway 2 (Comp, AH₂Store, FC) for short-duration storage applications and Pathway 4 (Comp, UH₂Store, FC) for long-duration storage.** Pathway 2 is the most energy-efficient and cost-effective option for short-duration storage, but it faces scalability limitations due to constraints on above-ground storage capacity. For long-duration applications, Pathway 4 offers comparable efficiency and LCOE, making it a more suitable alternative. Pathways involving liquefaction (5–8) are not recommended due to high energy consumption and evaporation losses.
2. **The Indian Government should invest in further research and development of basins throughout the country to support underground storage.** Depleted gas reservoirs offer high-efficiency storage but face logistical and cost-related challenges. Geological studies are needed to assess the stability and integration potential of these reservoirs into a cost-effective hydrogen network. While HELP enables exploration, the NGHMs should incentivize or mandate states to

conduct such R&D, especially as only three states have initiated strategies as of February 2025.

3. **The Indian Government should implement a hybrid storage approach at the national scale to best support growing supply chains and balance short- and long-term demands.** A hybrid approach combining compressed above-ground hydrogen storage for short-term needs with underground or ammonia-based seasonal storage can optimize energy efficiency, reduce operational costs, and enhance grid resilience.
4. **The Indian Government should further research pathways to utilize green ammonia as a seasonal storage vector. India should not pursue other power sector uses of ammonia, such as co-firing in Pathways 9 and 10.** Despite its lower efficiency and higher LCOE for direct power generation, green ammonia offers high energy density and efficient liquefaction, making it promising for seasonal storage. We advise against ammonia co-firing due to substantial inefficiencies and high cost and recommend exploring ammonia fuel cells to better capture the value of ammonia's storage potential.
5. **Captive power generators should prioritize purchasing hydrogen-based fuels to generate power onsite rather than producing hydrogen with excess renewable power.** Small-scale hydrogen synthesis is unlikely to be cost-competitive with large-scale production. Captive power plants should instead procure hydrogen or ammonia produced at scale. States with significant captive power usage should facilitate this through domestic production or interstate purchase agreements.
6. **The Indian Government should update the NGHM periodically to include all 10 IRENA recommended policy provisions.** Regular updates, similar to Germany's hydrogen strategy model, would allow the NGHM to reflect the latest research and technological developments. Updates should also include clear research delegation to appropriate agencies and expand the inclusion of IRENA-recommended provisions to enhance India's policy framework.
7. **The Indian Government must first focus on expanding its renewable energy capacity.** Green hydrogen relies on renewable electricity, and maximizing the use of renewable energy in the grid should be the first priority. Since energy conversion results in significant losses, direct integration of renewables into the grid should be preferred, with hydrogen production carried out only when renewable electricity would otherwise be curtailed. Continued

investment in renewable capacity is a prerequisite for achieving NGHM goals.

Section I. Introduction

I.1 Project Introduction

Hydrogen is emerging as an important industrial feedstock and energy carrier, presenting a promising solution for decarbonizing hard-to-abate sectors. A simple molecule composed of an abundant element, hydrogen (H₂) offers an impressive 120 MJ/kg energy, the highest of any fuel, but its volumetric energy density is a limiting factor, exemplified by liquified hydrogen's 8 MJ/L.³ Hydrogen is most commonly produced via steam-methane reforming (SMR), which involves a reaction of natural gas with high-temperature steam to produce hydrogen and carbon dioxide, but can also be produced via electrolysis, which uses electricity to split water into hydrogen and oxygen atoms.⁴ Hydrogen may then be transported and stored as either a high-pressure gas or a low-temperature liquid.⁵ While the majority of hydrogen produced globally is derived from SMR, a process that emits carbon dioxide (CO₂), electrolysis powered by zero-carbon renewable electricity sources can be used to produce emission free *green hydrogen*.⁶

India currently consumes 5 million metric tonnes (MMT) of hydrogen annually for applications including petroleum refining, manufacturing of ammonia for fertilizers, and methanol production.⁷ Most of this hydrogen is produced via SMR—also called *gray hydrogen*—resulting in 50 MMT of carbon emissions annually.⁸ This reliance on carbon-intensive production methods poses a significant challenge, especially considering India's hydrogen demand is projected to rise by approximately 23 million tons from 2020 to 2050. NITI Aayog and RMI estimate that green hydrogen could meet up to 94% of the 2050 demand if it reaches cost parity with gray hydrogen.⁹ This underscores the critical need to transition from *gray* to *green* production pathways.¹⁰

The Indian Government launched the National Green Hydrogen Mission (NGHM) in January 2023 with the objective of “making India the Global Hub for production, usage and export of Green Hydrogen and its derivatives”,¹¹ as a part of larger efforts to cement India as energy independent by 2047 and Net-Zero by 2070.¹² To achieve this objective, the government aims to catalyze development of at least 5 MMT of green hydrogen production capacity in India by 2030, and up to 10 MMT if growth potential in the export market is realized.¹³ The Mission plans to achieve these goals by incentivizing investment in the green hydrogen supply chain, replacing gray hydrogen with green hydrogen in existing uses (particularly ammonia manufacturing for fertilizers), and supporting pilots for novel applications such as steel manufacturing and long-haul transportation.¹⁴

However, the NGHM does not yet consider the possible applications of green hydrogen in the power sector: the Mission aims to shift its focus towards

hydrogen as an energy carrier for electricity generation purposes at a later date, most likely sometime after 2030.¹⁵ India's power sector currently accounts for 70% of the country's greenhouse gas emissions, and electricity demand in the country is expected to double between 2022 and 2032.¹⁶ To meet this demand, India plans to increase its installed generation capacity from 400 GW to 866 GW by 2032, with wind (279 GW) and solar (94 GW) constituting the largest share of new capacity and non-renewables accounting for the rest (including 43 GW of new coal generation).¹⁷ This sharp projected increase in energy supply presents multiple challenges for India's power sector, including reliability challenges due to variability of renewable energy sources and continuing consequences stemming from the reliance on coal imports and carbon emissions from fossil fuel-burning power plants. Green hydrogen has the potential to mitigate some of the negative impacts of these challenges, with relevant solutions present in three elements of green hydrogen application: long-term energy storage, captive generation, and ammonia co-firing.

Using electrolysis to produce green hydrogen provides a practical method for *storing* excess renewable energy.¹⁸ Green hydrogen holds promise as a long-term energy storage medium,¹⁹ which can be used to balance electricity generation between monsoon and dry seasons as variations in sunshine and wind speeds impact renewable generation. In addition to utility scale storage, green hydrogen may stand as a viable alternative for fossil fuels used by heavy industries for *captive power* generation—the technical term for a power plant's in-house production and consumption of electricity at the same location.²⁰ Captive power generation accounted for about 39.4% of industrial electricity consumption in India between 2021 and 2022, primarily driven by grid reliability issues and high electricity tariffs for industrial customers.²¹ Installed captive generation capacity is expected to increase as India industrializes further, and there is an opportunity to decarbonize this supply using green hydrogen. Finally, *ammonia co-firing* involves substituting some percentage of coal used in power plants with green ammonia and then combusting it alongside coal to generate power. Since the combustion of ammonia can result in heat energy per unit mass comparable to low-ranked coal,²² co-firing ammonia with coal has the potential to reduce overall emissions if produced using green hydrogen.²³

Several challenges complicate the consideration of large-scale deployment of these solutions in India. High production costs for green hydrogen compared to gray hydrogen, low energy efficiency of electrolysis, and costs associated with hydrogen storage and transportation have the potential to cause difficulties in the implementation of the Mission's plans. Competition from alternative technologies like battery energy storage and questions about

the true emissions reduction potential of ammonia co-firing may further challenge the economic and political feasibility of implementation. The field lacks demonstrations of hydrogen storage in underground aquifers and depleted oil and gas fields. Consequently, further research must evaluate the feasibility of these geological formations for storage, as the technology remains unproven in practice.

A network of actors collaborates with the Indian Government in overcoming many of these obstacles, including the Rocky Mountain Institute (RMI), an energy transition think-tank based in Colorado. RMI is an international research organization working to advance sustainability initiatives through market-driven solutions, with expertise in a range of technical sectors and global geographies. The RMI India Program has engaged in collaborative energy transition work since 2017, providing thought leadership and energy efficiency analysis for sectors ranging from mobility to buildings.²⁴ The analysis and recommendations presented here were produced with the assistance of current RMI India Program staff scientists²⁵, as an extension of RMI's ongoing collaboration with the Indian government to establish a market for green hydrogen in India.

I.2 Report Objectives

Our primary objective in this report is to determine the feasibility of three applications of green hydrogen technology: ammonia co-firing, captive generation, and long duration energy storage. By looking at the technical, economic, and political feasibility of each of these applications individually, we determine the most effective path(s) for India to meet its green hydrogen and renewable energy goals. By providing insights into the green hydrogen market and the various pathways India could pursue with this technology, our work also supports RMI in their efforts to advise decision makers in formulating effective policies that fulfill the goals outlined by India's NGHM and National Electricity Plan. Ultimately, we aim to advance collective understanding of green hydrogen production and its role in India's power sector by identifying the most feasible applications and technologies for future electric markets and clean energy strategy.

In conducting the analyses of these three applications, we evaluate the technical, economic, and policy drivers of each within the context of implementation in India. We explore the landscape of India's power market and political climate to identify roadblocks that could prevent the advancement of large-scale deployment, as well as government standards, regulations, and incentives that will be advantageous to green hydrogen deployment. Our findings provide a comprehensive overview of the feasibility of various

implementation pathways, evaluated through technical, economic, and political lenses.

Section II. Background

II.1 Challenges with Growing Power Systems

India, a nation experiencing rapid economic growth, faces a critical challenge in its power sector as electricity demand continues to skyrocket. In the past couple of decades, the country's electricity use per capita surged by 182%.²⁶ While the country produced around 1,814 TWh per year of electricity to meet demand in 2022, it is now projected to have a total demand of up to 2,699 TWh per year of electricity by 2030.^{27,28} Additionally, by 2050, energy use in commercial and residential buildings is expected to triple from 2022. This projected tripling is likely due to improvement in living standards and service sector growth in the country.²⁹ Additionally, a rise in transport and industrial electrification can lead to a dramatic increase in electricity demand to over 6,600 TWh per year by 2050.³⁰ Meeting this rising demand will be a major challenge for India's power sector.

Simultaneously, India is under pressure to curb its carbon footprint, as it is projected to become the second largest emitter of energy-related carbon emissions by 2050, surpassing the United States in the global rankings.³¹ This is primarily because coal still dominates India's energy mix at 46% of its total supply, while renewables lag behind at 22%.³² This stark contrast necessitates a shift away from its high carbon, coal-dominated energy mix, especially as the economy grows, population rises, and electricity demand surges.

Shifting towards a cleaner energy mix presents a complex challenge, particularly for an emerging economy like India. First, switching from coal to renewable energy sources is expensive. India continues to invest time and money into coal power plants, making it difficult to transition to cleaner energy sources at a low cost, and increasing the risk of these assets becoming stranded as the demand for coal declines.³³ Decommissioning coal plants in India is estimated to cost around \$58 million per plant, which is also a barrier in the transition away from non-renewable energy sources.³⁴ Similarly, balancing affordability with clean energy is challenging in the short term. A fast-paced energy transition requires large amounts of financing to contribute to the new infrastructure for renewable energy projects. Acquiring investors can be difficult, particularly in emerging markets, due to the prevalence of infrastructure malfunctioning. Aging or absent grid infrastructure often leads to frequent breakdowns, resulting in generated electricity going to waste or being only partially purchased, creating significant financial risks for potential investors. Finally, research, governmental regulations, and technological

knowledge are all key factors needed to propel a transition towards a cleaner energy mix.³⁵ Developing economies may lack the necessary resources, infrastructure, and expertise to achieve this goal. World Bank client countries, for example, have shown poor governmental intervention without proper subsidies, planning, and capacity needed for a successful energy transition.³⁶

II.2 Long-Duration Energy Storage

Rather than relying on immediate electricity generation, long duration energy storage systems can provide access to electricity for ten hours or longer.³⁷ Green hydrogen, produced through electrolysis powered by renewable energy, is a promising long duration energy storage option. Storage may take several forms: as a compressed gas, as a cryogenic liquid, or chemically bound within solid materials like metal hydrides or liquid compounds like ammonia or methanol.³⁸ When needed, green hydrogen can be converted back into electricity through fuel cells or combustion.³⁹ By storing excess renewable electricity as green hydrogen, the intermittent nature of renewable sources can be mitigated, ensuring a consistent supply of energy.

India most commonly relies on pumped hydro storage and battery energy storage systems (BESS) for long duration storage.⁴⁰ BESS has its distinct advantages and limitations in comparison to green hydrogen storage. While BESS excel in terms of high power and high round-trip efficiency of up to 85%⁴¹, their limited energy storage capacity makes them unsuitable for seasonal energy storage.⁴² Green hydrogen's significantly longer storage capacity, demonstrated by a Japanese case study's 580 hours versus batteries' 6.7,⁴³ makes it a superior option for long-term energy needs. Additionally, it has a smaller environmental footprint unlike BESS, which often relies on rare minerals mined in ecologically sensitive areas, leading to deforestation, soil erosion, water contamination, and adverse health impacts on workers. Furthermore, the socio-economic impact of mining for battery storage is intense, with operations leading to geopolitical tensions, exploitation, and labor violations.⁴⁴ Green hydrogen storage avoids these environmental and social drawbacks.

Pumped hydro storage also exhibits high round-trip efficiency in the range of 70%-87%⁴⁵, but its scalability in India is limited by geographical requirements including significant elevation differences and abundant water resources. Additionally, the development of large-scale pumped hydro projects often involves acquiring significant land, leading to potential social and environmental conflicts. In contrast, green hydrogen offers a more flexible and scalable solution, particularly for a country like India with abundant renewable energy resources.⁴⁶ India offers various potential green hydrogen production

and storage locations across the country with access to renewable sources such as wind and solar.

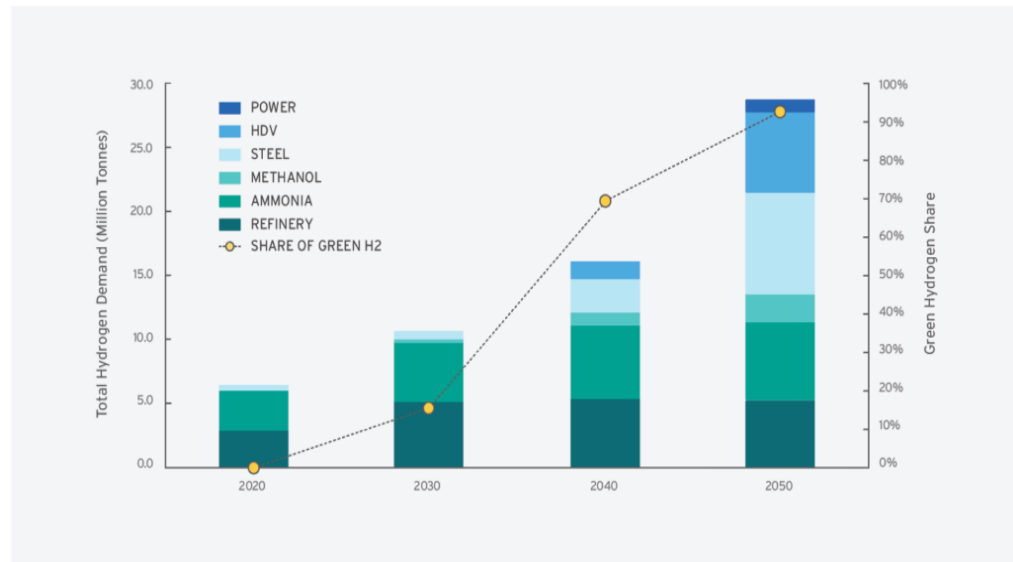
There are several ways to store hydrogen, such as above-ground pressurized tanks and geological reservoirs, each with its own benefits and drawbacks. Although India has limited salt-based reservoirs, it has extensive aquifers.⁴⁷ In particular, the country has 26 subsurface sedimentary basins containing saline aquifers, seven of which are designated as Category I (basins that have been extensively explored due largely to their current usage for hydrocarbon production). As a result, these basins have more empirical geological information and existing hydrocarbon production infrastructure around them, which could be retrofitted to support hydrogen storage. However, as previously noted, real-world commercial or preliminary test facilities have yet to implement storing hydrogen gas in such facilities. Table II.2.1 identifies these Category I basins and the storage capacity of their respective aquifers. Together, these basins amount to 215.70 MMT of hydrogen storage capacity.

Table II.2.1. Category I Sedimentary Basins and Storage Potential.⁴⁸

| Basin Name | State in Which Basin is Located | Storage Potential (MMT) |
|------------------------|--|--------------------------------|
| Cambay | Gujarat | 8.70 |
| Mumbai Offshore | Maharashtra | 54.88 |
| Rajasthan | Rajasthan | 30.74 |
| Krishna Godavari | Andhra Pradesh | 45.39 |
| Cauvery | Tamil Nadu | 42.29 |
| Assam Shelf | Assam | 13.81 |
| Assam-Arakan Fold Belt | Arunachal Pradesh, Assam, Mizoram | 19.94 |

Category I basins account for approximately 30% of the total area of basins in India.⁴⁹ Other sub-optimal Category II and III basins exist in the rest of the country and correspond to an estimated additional 358 MMT of storage potential.⁵⁰ These lower-tier basins are designated as such due to various factors, including limited renewable energy resources, poor water availability, and insufficient geological exploration.

NITI Aayog and RMI estimate the hydrogen demand outlook in India for each decade between 2020 and 2050. Figure II.2.1 shows the findings from their report. They anticipate substantial demand growth in the coming years; 2050 hydrogen demand is anticipated slightly below 30 MMT, or around 300% higher than that of 2020.⁵¹



Source: MoS, MoC&F, MoPNG, IEA, TERI, BCG, World Bank, RMI Analysis

Figure II.2.1. Hydrogen Demand Outlook in India.⁵²

Notably, hydrogen used for power generation purposes is not anticipated to contribute significantly to the total projected demand until 2050. Even at the mid-century mark, power-related hydrogen demand is expected to be around 1 MMT per year.⁵³ The vast majority of the demand will be for products used in industrial applications. These use cases, which include steel, methanol, and ammonia, would not necessitate long-term storage. Instead, the hydrogen lifecycle for these products is comparatively expedited; that is, hydrogen is produced, stored briefly, transported to the end-use site, and shortly thereafter used as a feedstock.

As a result, the storage capacity in the Category I basins far exceeds that of the projected 2050 demand for hydrogen that requires long-term storage. The smallest of the basins, Cambay, can store over eight times the projected power-related demand.

However, we consider an accelerated and expanded hydrogen economy in this report, which these power sector demand projections may not account for. It is therefore important to assess underground storage capacity against projected general energy storage requirements. The Central Electricity

Authority projects that energy storage capacity requirements will amount to 73.93 GW or 411.4 GWh by 2032.⁵⁴ 47.24 GW (or 236.22 GWh) of this required capacity is anticipated to be met by battery electricity storage systems (BESS), with the remaining relying on pumped storage.⁵⁵

Sufficient capacity would be available if underground hydrogen storage were used instead of BESS or pumped storage to meet these storage requirements. Equation II.2.1 converts the energy density of hydrogen (120 MJ/kg)⁵⁶ to approximately 33,333 GWh of thermal electricity/MMT H₂. 1 MMT of hydrogen alone would far exceed the projected storage requirements, but when scaling this energy density to the 215.7 MMT of Category I storage capacity, the amount of available storage is 7,190,000 GWh. Even with substantial conversion and transportation losses, underground storage capacity in India is significant, should hydrogen storage demonstrations in depleted oil and gas fields prove successful.

$$\frac{120 \text{ MJ}}{1 \text{ kg}} \times \frac{1 \text{ kWh}}{3.6 \text{ MJ}} \times \frac{1000 \text{ kg}}{1 \text{ tonne}} \times \frac{10^6 \text{ tonnes}}{1 \text{ MMT}} \times \frac{1 \text{ GWh}}{10^6 \text{ kWh}} = 33,333 \frac{\text{GWh}}{\text{MMT}} \quad \text{Equation II.2.1}$$

Other regions in the world have successfully demonstrated the potential for underground hydrogen storage. In 1972, three salt caverns in Teesside, UK became the first salt cavern hydrogen storage project in the world.⁵⁷ The three caverns, part of the larger Teesside Salt Field, reach shallow depths of 400m and operate at pressures between 45-50 bar. Each cavern has a volume of 70,000 m³, 95% of which is hydrogen gas. The Teesside salt caverns can store up to 25 GWh for local industrial purposes. Despite being a smaller project, Teesside has successfully stored hydrogen for over 50 years and demonstrates the potential for expanded long-duration hydrogen storage. Today, Teesside continues operations and serves as the pioneer project for growing efforts in the UK to deploy green hydrogen infrastructure.

In Germany, the energy storage company Storengy (a subsidiary of Engie, a French multinational energy company) actively operates H₂ and natural gas storage facilities.⁵⁸ Three of these utilize salt caverns, with the largest (and most recent facility, extended in 2014) holding 333 million m³ across five caverns.⁵⁹ The first of these five facilities, Schmidhausen, was built in 1983 over a depleted natural gas field in southern Germany and has a working natural gas storage volume of 156 million m³.⁶⁰ The first facility storing H₂ gas in salt caverns, Harsefeld in northern Germany, was constructed in 1992 and holds 110 million m³ across two caverns.⁶¹ Engie's web page featuring its external hydrogen news announcements also includes two notes on future projects: one involving salt cavern storage in Utah, USA, scheduled to open by

2025; and a multi-company energy storage consortium plan to construct a 150,000 MWh salt cavern storage facility in central Germany.⁶² The German project, the Hydrogen Power Storage and Solutions East Germany (HYPOS), aims to construct additional underground hydrogen storage facilities throughout the continent, and broadly initiate the production and distribution of green hydrogen on an industrial scale.⁶³

There also exist some instances of underground storage in salt caverns in the US, near the Gulf Coast in Texas.⁶⁴ Two facilities opened in 1983 and 2007 are both constructed within a broad domal salt geologic resource and hold 580,000 m³ and 566,000 m³, respectively.⁶⁵ Along with the facilities in Teesside, UK, these storage caverns served as pioneering industry examples demonstrating that hydrogen gas can be safely stored at length in salt caverns situated in different geological regions across the world.⁶⁶

An abundance of case studies for above-ground hydrogen storage exists as well, especially in the contexts of ammonia fertilizer storage and hydrogen fuel projects. While most existing ammonia storage facilities serve agricultural activities and are not associated with power generation, their designs could inform methods for storage of ammonia created with an intent to generate power. Ammonia has been used in fertilizer since the early nineteenth century, and storage vessels are often situated near farmland.⁶⁷ In the American Midwest, one such facility in Iowa operated by the agricultural nutrients and industrial products company Agrium holds 380 GWh of anhydrous ammonia across two 30,000 tonne tanks.⁶⁸ These tanks are constructed of steel in a double-walled vacuum design optimized to maintain low temperatures at a relatively low cost. The estimated turnkey cost of such a facility was reported as \$15 million (refer to Section IV.4 for more details).⁶⁹

II.3 Captive Generation

Captive power generation involves producing electricity specifically to meet the energy needs of the facility where it's generated.⁷⁰ Captive power generating facilities, such as industrial complexes, large office buildings, and data centers, can operate independently, separate from the grid, or dependently, by transmitting extra power to the grid.⁷¹ Fossil fuel-based plants utilize combustion to generate steam, which powers turbines connected to generators. Renewable energy captive plants, such as solar and wind facilities, harness sunlight and wind energy through photovoltaic cells and turbines to produce electricity.⁷² In general, captive power plants can use various fuel sources, ranging from conventional coal to renewables depending on availability and cost, offer a cost-effective alternative to sourcing grid electricity, and can

contribute to more sustainable energy practices through renewable energy generation sources.⁷³

Captive power generation has grown steadily in India over the past two decades. Figures II.3.1 and II.3.2 display the installed captive power capacity and captive power generation, respectively, in India from 2005 through 2023. During this time, installed capacity increased from 21,468 MW to 78,401 MW, a 365% increase. Power generation increased from 73,639 GWh to 211,931 GWh, or by approximately 288%. Additionally, the Central Electricity Authority projects that by 2032, self-use energy consumption from captive power generation will grow to approximately 601,600 GWh.⁷⁴

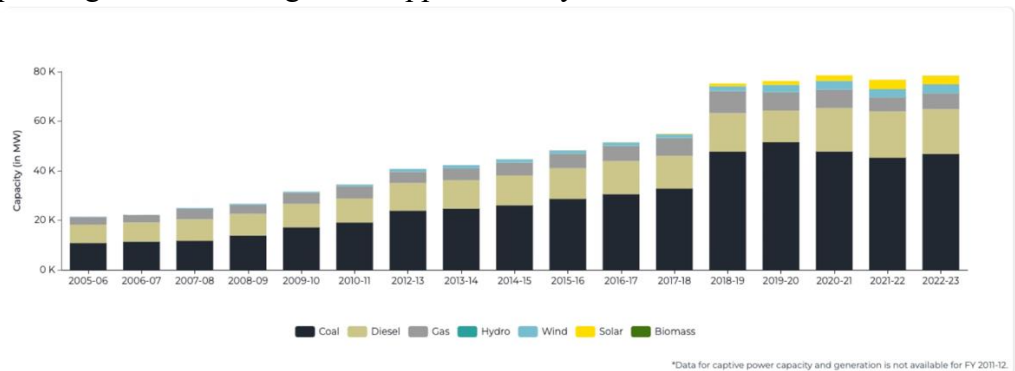


Figure II.3.1. Captive Power Capacity in India Over Time.⁷⁵

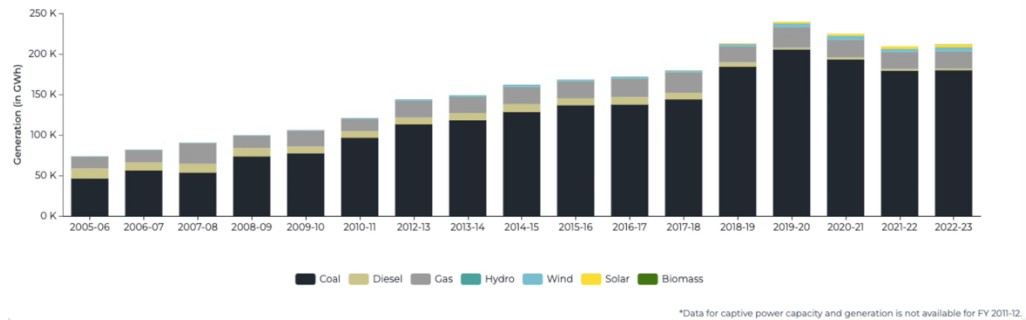


Figure II.3.2. Captive Power Generation in India Over Time.⁷⁶

It is important to note that the dominant source of this power is coal (61.6%).⁷⁷ Installed captive renewable capacity has increased year over year but still constitutes a relatively small share (around 8%) of the total captive power capacity.⁷⁸

Recently, India has faced a shortage of coal for captive power generation. The government's prioritization of coal supply for its utilities has left captive power plant owners struggling to secure enough. This has led to reduced plant generation, impacting the production of essential goods like steel, cement, and fertilizers.⁷⁹ This reduction is visible in both Figure II.3.1 and

Figure II.3.2. Not only does India hope to see a sustainable shift in their captive power generation through the utilization of renewable energy sources, but the country also may be forced to trend in that direction in response to the shortage of coal.

While on-site captive green hydrogen generation remains a niche application, Larsen and Toubro (L&T), a leading high-tech manufacturer, has recently commissioned such a facility at its Hazira, Gujarat manufacturing site. This facility supports the company's 2024 goal of achieving carbon neutrality by producing 45 kg of green hydrogen daily, replacing fossil-fuel derived electricity with solar power, enhanced by battery energy storage.⁸⁰ The plant currently operates at a capacity of 1 MW, with the potential to expand to 2 MW, demonstrating L&T's commitment to environmental leadership.⁸¹ Other industrial players seeking to integrate green hydrogen into their operation can use this initiative as a potential model.

Like L&T, most companies currently making use of captive power generation are those in energy-intensive manufacturing industries. This includes metals and mining, cement, and petro-chemicals.⁸² It is expected that industries already participating in captive power generation would be the likely candidates for captive hydrogen generation. To avoid stranded coal assets, these industries would likely use ammonia co-firing. As these coal plants retire, however, they would be able to make use of more efficient and cost-effective uses of captive hydrogen-based power generation technology, such as fuel cells.

Technology companies have made use of data centers for several years now but are just beginning to build out artificial intelligence (AI) capabilities. As AI accelerates in the coming years, data centers and servers will necessitate increasing quantities of electricity. Captive power reduces grid strain from rapid increases in demand, therefore potentially avoiding electricity cost spikes and reliability concerns. These servers will need reliable electricity to operate successfully. Unlike current captive power users (such as manufacturers), however, they are less likely to be locked into more costly methods of hydrogen-based power generation (such as ammonia co-firing) and/or risk stranded assets if they were to start investing into hydrogen fuel cells in the near future.

II.4 Ammonia Co-Firing

Ammonia co-firing involves the combustion of ammonia with conventional fossil fuels, such as coal, in thermal power plants, reducing greenhouse gas emissions without compromising the amount of energy generated.⁸³ Co-firing ratios (CR) are defined as the percentage of ammonia in the co-firing process. Determining this CR is crucial as it can result in more

efficient energy-emission ratios and lower operating costs in a power plant. Common CR range from 10% to 40% for current pilot studies and simulations.⁸⁴

⁸⁵ With the advantages of carbon-free fuel, high energy density, feasibility for large-scale deployment, and ease of liquefaction,⁸⁶ ammonia co-firing has been considered promising and feasible in current coal power plants. Instead of building completely new infrastructure, co-firing with ammonia requires relatively small modification on current existing coal power plant systems.

While ammonia co-firing offers the advantages of lower-carbon emissions, it can unfortunately increase the release of nitrogen oxides (NO_x). These gasses contribute to several environmental problems, including reduced visibility, respiratory issues, water pollution, acid rain, and they can also influence climate change indirectly through ozone formation.⁸⁷ Higher ammonia co-firing ratios generally lead to greater NO_x emissions. However, advanced combustion technologies like air-staged combustion, secondary fuel injection, MILD (Moderate or Intense Low-oxygen Dilution) combustion, and porous medium applications offer promising solutions for mitigating these emissions.⁸⁸

Ammonia co-firing with coal is especially crucial to countries highly dependent on coal-fired plants for electricity generation, as is India. The current coal-fired capacity in India is 235 GW. The Ministry of Power of India has expected this value to increase by at least 53.6 GW by 2032.

JERA Co., Inc. and IHI Corporation pioneered the world's first demonstration of a 20% ammonia substitution (by heat energy) at a large-scale coal-fired plant (Hekinan Thermal Power Station) in Hekinan City, Japan.⁸⁹ The project period is scheduled to last about 4 years, from July 2021 through March 2025, with a demonstration testing through June 2024. The test focused on evaluating fuel equipment operation, assessing nitrogen oxide emissions, and verifying overall system operability. Future goals involve progressively scaling up to a higher ratio of co-firing ammonia.⁹⁰ These efforts are supported by the country's national policy framework, such as the Green Growth Strategy and the commitment to cut greenhouse gas emissions by 46% (compared to 2013 levels) by 2030.⁹¹

Despite the apparent feasibility of Japan's promotion of ammonia co-firing with coal, several concerns must be addressed. TransitionZero, a nonprofit organization that uses data analysis to help countries reach net-zero emissions, has investigated the cost and emissions estimation of ammonia co-firing with coal for four Southeast Asia countries (Philippines, Thailand, Malaysia, and Indonesia). Their results showed that carbon emissions will still be significantly higher than that of the existing gas-fired power plants, even if the co-firing rate increases from 20% to 50%. The carbon reduction and

mitigation costs associated with ammonia co-firing with coal are also higher than developing new wind and solar energy capacity. In addition, some have argued that the widespread adoption of co-firing ammonia with coal will impede the progress of achieving net zero emissions before 2050.^{92, 93, 94} The International Energy Agency (IEA) has indicated that phasing out unabated coal power in OECD countries by 2030 and globally by 2040 are required to successfully decarbonize the power sector.^{95, 96, 97}

Section III. Technical Analysis Methods

This section presents the methods used in the energy efficiency analysis of green hydrogen and ammonia production routes, short- and long-term storage, and their end-use in the power sector. We analyzed ten routes for green hydrogen and ammonia production, all utilizing renewable electricity as an input.

Our energy efficiency analysis evaluated inputs, outputs, and energy losses at each stage from renewable energy sources to the final application. We based our calculations of energy efficiency on higher heating values (HHV) because HHV provides a fair comparison between fuel cells and gas turbines. Fuel cells typically produce water as a liquid, meaning the system retains the latent heat of vaporization, whereas gas turbines release water as steam, losing that energy to the exhaust. Using HHV accounts for the total energy content of hydrogen and prevents efficiency distortions that could arise from the different ways these technologies handle water formation and heat recovery. Additionally, HHV is the standard metric for expressing energy system efficiencies in the U.S., ensuring a more consistent and equitable comparison across different technologies and energy sources.⁹⁸

We created Sankey diagrams of the ten hydrogen and green ammonia production routes to visually evaluate each pathway's efficiency. We normalized these Sankey diagrams to ultimately yield one unit of useful energy.⁹⁹ The details of data sources and calculations are provided in Section IX. Supplementary Information.

Hydrogen production is based on alkaline water electrolysis (AWE). Specifically, we used the energy efficiency of a high- and low-pressure bipolar alkaline electrolyzer from Norsk Hydro.¹⁰⁰ Although proton exchange membrane (PEM) electrolyzers are often considered the most efficient commercial option,¹⁰¹ AWE shows potential for broader deployment in regions like India, where its cost-effectiveness and scalability provide significant advantages.

We also assessed two routes for green ammonia production. This process uses the Haber-Bosch method, where nitrogen reacts with hydrogen under high-pressure and high-temperature conditions in the presence of a catalyst. Traditionally, hydrogen used in this process is sourced from fossil fuels, but in this study, we modeled routes using green hydrogen produced by electrolysis.

We evaluated routes considering both above-ground and underground storage methods. First, the above-ground storage methods include compressed hydrogen in tanks and liquefied hydrogen and ammonia in cryogenic tanks. The energy efficiency analysis considers short-term compressed storage, which typically lasts 1-2 days. In the case of hydrogen liquefaction, we analyzed two storage periods: short-term (0 to 7 days) and long-term (up to 182 days).¹⁰² We estimate liquefied hydrogen storage efficiency to be 53% for short-term storage (7 days) and only 21% for long-term seasonal storage (182 days), highlighting the significant losses associated with prolonged cryogenic storage.¹⁰³ For this reason, liquefied hydrogen storage is primarily used in the short-term, and there is little cause to believe that it can be used in the long-term. We included it in this study solely for comparative purposes with short-term storage to assess the impact of boil-off losses and the energy requirements for maintaining cryogenic conditions over seasonal periods.

Similarly, we evaluated green ammonia storage for short-term (0 to 7 days) and long-term (up to 182 days) periods. This aimed to determine whether significant losses occur over time, as in liquefied hydrogen storage.

We also assessed underground hydrogen storage routes, specifically compressed hydrogen storage in depleted gas reservoirs. While underground storage options in salt caverns exist in the US and Europe, hydrogen storage in aquifers and depleted oil and gas fields remains in the research phase.

For underground storage, we applied a combined energy efficiency factor, encompassing the injection, storage, and extraction processes, with an assumed storage period of 120 days.¹⁰⁴ This period is common in geological storage studies because it represents a typical storage and extraction cycle in energy applications, particularly in seasonal storage systems. In many regions, energy consumption fluctuates throughout the year, with periods of higher demand during specific seasons. By considering a quarter-year as a reference, we can model scenarios where energy is stored during months of lower consumption and extracted when demand increases. Table III.1 presents the

temperature and pressure conditions for each storage type considered in this section.

Table III.1. Conditions of hydrogen and ammonia storage.

| Conditions | Above-ground hydrogen storage | | Above-ground ammonia storage | Underground hydrogen storage ¹⁰⁵ |
|------------------|-------------------------------|----------------------------|------------------------------|---|
| | Liquefaction ¹⁰⁶ | Compression ¹⁰⁷ | Liquefaction ¹⁰⁸ | |
| Pressure (bar) | 1 | 350 - 700 | 1 | 80 * |
| Temperature (°C) | -253 | 26 | -33 | 43 * |

*Average operating conditions

Regarding the end-use of green hydrogen, we focus on two main technologies: hydrogen combustion in gas turbines for thermal energy generation and electrochemical conversion in fuel cells for electricity production. For the routes involving combustion of hydrogen, we consider the use of gas turbines rather than internal combustion engines (ICE) due to their higher efficiencies (~34% rather than ~25%). Moreover, gas turbines are typically employed in large-scale applications such as power plants and industrial facilities due to their high-power output and efficiency in continuous operation. In contrast, ICEs are generally used in stationary and smaller-scale applications, including backup generators and distributed cogeneration systems, where energy demand is lower and more variable. Electrochemical conversion uses fuel cells, as they are currently the most energy-efficient technology for converting hydrogen into electricity.

Unlike hydrogen, ammonia cannot be directly used in fuel cells unless it is first decomposed back into hydrogen, a process that requires high

temperature, typically above 900°C.¹⁰⁹ In this study, the end-use of green ammonia is co-firing in coal-fired power plants, where ammonia is blended and burned alongside coal in variable proportions. Research has shown that a 20% ammonia/80% coal mix optimizes combustion efficiency while reducing NOx emissions produced by ammonia combustion,^{110, 111, 112} For this reason, we assume a combustion efficiency based on a 20% ammonia blend for co-firing applications.

The Hydrogen Delivery Scenario Analysis (HDSAM) model accounts for storage system losses, with the following assumptions: 0.5% loss in compressors, 0.5% loss during liquefaction, and 5% loss during liquid hydrogen transfer.¹¹³ We do not consider transportation energy losses in this analysis, as they vary significantly depending on distance between hydrogen production plants and storage sites. Given that distance and infrastructure type directly influence losses, establishing a general value applicable to all scenarios is challenging. However, this simplification assumes that hydrogen production, ammonia production, and power generation facilities are co-located, which may not be feasible in real-world scenarios. In practice, transportation introduces additional losses that can significantly impact system efficiency, especially in the case of hydrogen, due to the energy costs associated with its compression, liquefaction, and distribution. Future studies should evaluate the impact of transportation under different geographical configurations and analyze strategies to minimize these losses, considering alternatives such as decentralized production or the use of optimized transportation infrastructure.

We ignore vaporization losses for the co-firing routes in this study as liquid ammonia, with a boiling point of -33.3°C at atmospheric pressure, spontaneously gasifies upon release from the cryogenic storage system. Before its consumption in the co-firing process, ammonia is already in gaseous form, eliminating the need for additional energy input for vaporization. Additionally, in some power plants, combustion chambers can utilize residual heat from the process to facilitate ammonia evaporation.

III.2 Green Hydrogen Pathways in Power Systems

Figure III.2.1 shows the ten routes we evaluated in the energy analysis, along with the three main applications of this project: long-term storage, ammonia co-firing, and captive generation. Long-term liquefied above-ground storage and compressed underground storage of hydrogen are shown in green, and ammonia co-firing is shown in red. Captive generation (in blue) is included

for routes that use hydrogen fuel cells, as they allow for more controlled and efficient use in specific industrial applications.

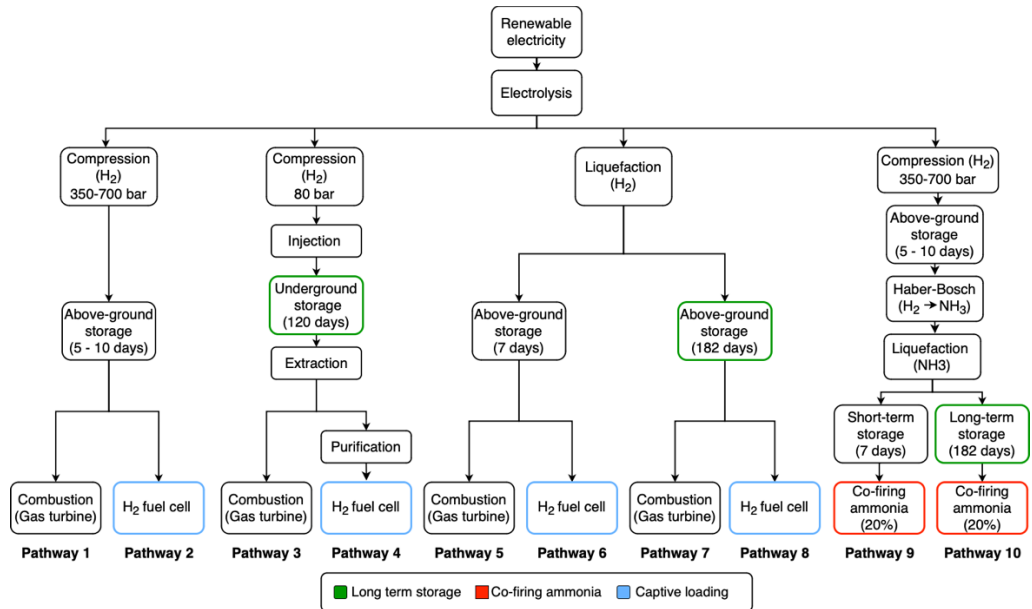


Figure III.2.1. Pathways for Green Hydrogen and Ammonia: Production, Storage, and End-Use Applications

Section IV. Cost Analysis Methods

This report is meant to serve as a holistic analysis of the potential applications for green hydrogen in the Indian power sector, so it is necessary that we incorporate a financial analysis to determine economic viability. Each pathway has distinct associated costs; for example, ammonia co-firing has additional costs associated with producing ammonia from hydrogen through the Haber-Bosch process, which would not be present in captive generation using hydrogen fuel cells. We outline in this section the approach taken to develop modularized cost parameters for each step in each pathway. We also outline the results of these analyses; in later sections, we combine these values to obtain a levelized cost of electricity (LCOE) for each of the pathways.

IV.1 Levelized Cost of Hydrogen

The United States of America's Department of Energy (DoE) has a National Renewable Energy Laboratory (NREL) based in Golden, CO that conducts analyses, technological research, and workforce and policy assessments on a broad array of renewable energy technologies. Green

hydrogen is included in the scope of NREL's work, and the laboratory has created the *H2A: Hydrogen Analysis Production Model* cost analysis (H2A).¹¹⁴ There are many versions of the H2A model for various electrolyzer types that are routinely updated to contain the most current figures and estimates. However, NREL does not provide out-of-the-box models that support alkaline electrolyzers, which are included in this project. Researchers at Strategic Analysis, Inc, sponsored by the DoE's Office of Energy Efficiency and Renewable Energy, Office of Sustainable Transportation, and Hydrogen Fuel Cell Technologies Office, modified the H2A model to provide a levelized cost of hydrogen produced through liquid alkaline electrolysis.¹¹⁵ The Strategic Analysis team provided a copy of their H2A models to be adopted for the purposes of this study.

RMI provided several key assumptions that make up the foundations of our analysis. These assumptions, as well as those informed by literature and public data, are outlined in the following paragraphs.

Hydrogen production plant specification parameters include a daily plant output of 50 metric tonnes, running at an operating capacity of 30%. This would require each plant to have a designed capacity of 166.7 tonnes per day. We assume the plant to operate for 25 years, with electrolyzer stacks being replaced every seven and a half years. We price each replacement at \$42,015,901 (2022 USD).

Fixed and variable operating costs play a main role in calculating an estimated levelized cost of hydrogen. Important variables include the industrial renewable electricity price, which we set to be \$0.03 per kilowatt-hour (kWh) from 2024 data.¹¹⁶ Water is also an intrinsic input in producing hydrogen by electrolysis and we assume it to cost approximately \$0.0018 per gallon based on 2024 rates in India.¹¹⁷ The water entering an electrolyzer needs to be conditioned and purified in order to limit stack degradation, but we do not consider the costs associated with water treatment in the analysis. The workforce at these plants will encompass 20 full-time employees working 2096 person-hours annually each at a rate of \$2.50 per hour.¹¹⁸ General and administrative overhead costs add an additional 20% to the labor cost.¹¹⁹ Production maintenance and repairs account for roughly \$2,407,788 (2022 USD) annually.¹²⁰ Lastly, we include an unplanned replacement capital cost factor of 0.5% of total direct depreciable costs to cover any unexpected operational expenses.

The uninstalled price of electrolyzer stacks and the balance of infrastructure costs that are used to support plant operations are the major direct capital expenditures. The electrolyzer stack expenditures for a plant of this size are \$36,116,820 (2022 USD). The balance of plant expenditures add

\$44,142,781 (2022 USD). Installation costs add another \$4,012,980 to the capital expenditure. We do not consider land acquisition costs in this analysis. The total direct capital expenditures sum to \$84,272,581 (2022 USD). Section IX Supplementary Information includes the derivation of these costs, while Figure IV.1.1 displays the values.

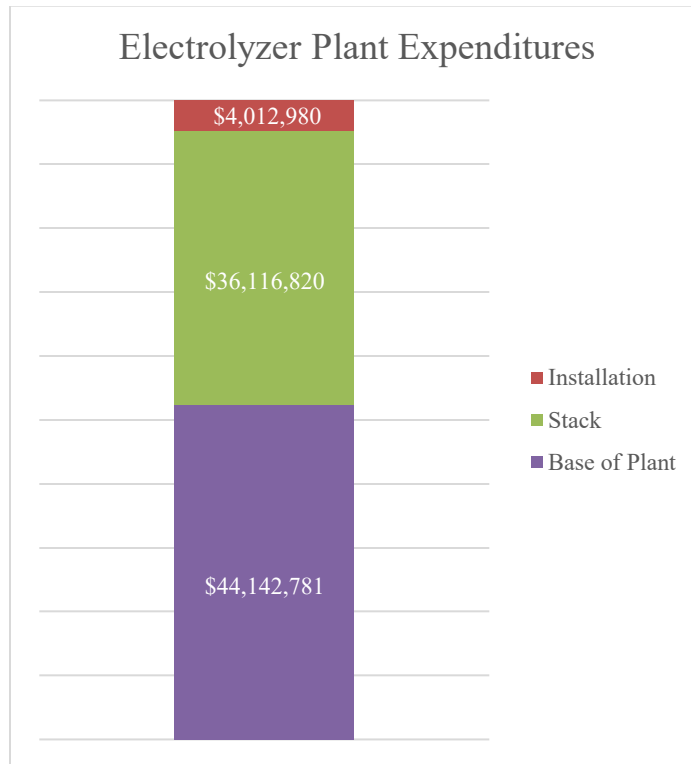


Figure IV.1.1. Electrolyzer Plant Expenditure Breakdown

Table IV.1.1 shows additional key financial inputs.

Table IV.1.1. Key financial inputs in H2A model

| Input | Value |
|-----------------------------|----------|
| Length of Construction | 3 years |
| Depreciation Schedule | 20 years |
| Equity Financing Percentage | 30.0% |
| Interest Rate on Debt | 12.0% |
| Salvage Value | 10.0% |

| | |
|--------------------|----------------------|
| Inflation Rate | 1.9% |
| After-tax Real IRR | 16.0% |
| State Tax Rate | 0.0% |
| National Tax Rate | 29.2% ¹²¹ |
| Working Capital | 15% |

We achieve a levelized cost of hydrogen (LCOH) of approximately \$2.64 (2022 USD) per kilogram of hydrogen in 2040. Figure IV.1.2 below shows a detailed breakdown of the hydrogen cost by major expense categories.

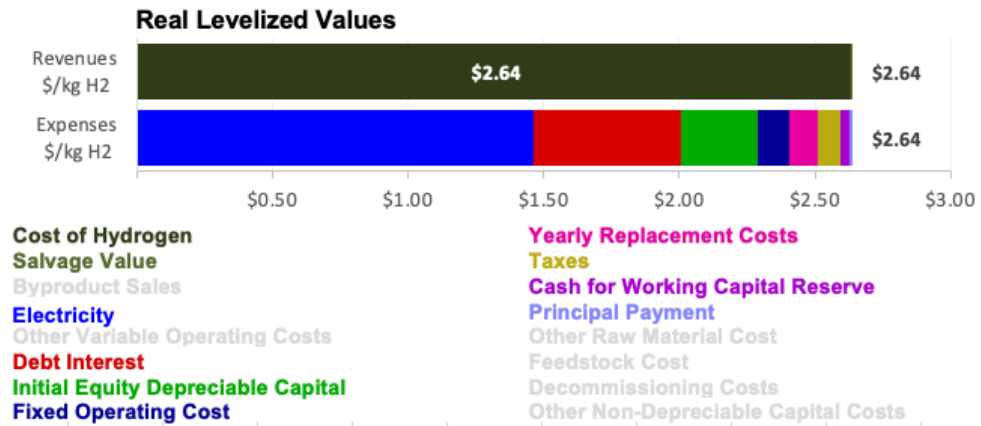


Figure IV.1.2. Breakdown of LCOH by major expense categories.

IV.2 Levelized Cost of Ammonia

Green ammonia is produced via the traditional Haber-Bosch method but with the use of renewable electricity as a power source. The Haber-Bosch process requires two inputs: hydrogen and nitrogen. The previous section outlined the LCOH for the hydrogen input, while this section will outline how we calculate the nitrogen costs through the application of air separation units (ASU) or pressure swing adsorption (PSA). Following the 50 tonnes of daily hydrogen output (18,250 tonnes annually) from the previous section, stoichiometry implies a required 84,545 tonnes of nitrogen, with an ammonia output of 102,795 tonnes annually. Setting the operational capacity of the ammonia plant to 80% results in a plant designed capacity of 130,000 tonnes of ammonia per year.¹²² We must note that the 80% operational capacity cited in the literature assumes high renewable energy availability and minimum fossil fuel for backup. In addition, this number is based on large-scale ammonia plants

(3,456 tonnes/day), which benefit from economies of scale and more stable operations. In comparison, we assume a much lower production scale (282 tonnes/day), which may face greater uncertainty in renewable power input. Therefore, the actual operational capacity might be lower, resulting in a higher estimated LCOA.

RMI provided Table IV.2.1, which lists several other crucial assumptions regarding capital expenditure (CAPEX) and operating expenditure (OPEX). We assume a discount rate of 7% and plant life of 30 years in this calculation. The industrial renewable electricity price is the same as the assumption in the previous section (IV.1), which is \$0.03 per kWh.

Table IV.2.1. Assumptions regarding CAPEX and OPEX.

| | | | |
|---|------------------------------|------------------------|---------|
| Ammonia Synthesis CAPEX- Direct | CAPEX ASU or PSA | USD/t N ₂ | 297.76 |
| | N ₂ Storage CAPEX | USD/t N ₂ | 160.00 |
| | CAPEX Ammonia Synthesis | USD/ t NH ₃ | 1143.34 |
| | Ammonia Storage CAPEX | USD/t NH ₃ | 810 |
| Ammonia Synthesis CAPEX - INDIRECT | Site Preparation | % of Direct CAPEX | 1 |
| | Engineering and Design | % of Direct CAPEX | 25 |
| | Permitting Costs | % of Direct CAPEX | 10 |
| | Contingency Costs | % of Direct CAPEX | 10 |
| Ammonia Synthesis OPEX Electricity Consumption | Electricity Consumption HB | kWh/kg NH ₃ | 0.48 |
| | Electricity Consumption ASU | kWh/kg N ₂ | 0.12 |
| Ammonia Synthesis OPEX O&M | ASU + Ammonia Synthesis O&M | % of CAPEX | 4 |
| | Storage O&M | % of CAPEX | 3 |

To calculate the levelized cost of ammonia (LCOA), Equation IV.1.1 is used.¹²³

$$LCOA = \frac{\sum_{t=0}^n \frac{CAPEX_t + OPEX_t}{(1+r)^t}}{\sum_{t=0}^n \frac{Q_t}{(1+r)^t}} \quad \text{Equation IV.1.1}$$

$CAPEX_t$: Capital Investment Expenditure in year t (\$)

$OPEX_t$: Operating Expenditure in year t (\$)

n: Lifetime of plant (years)

t: Year of time

r: Discount rate (%)

Q_t : Annual Ammonia production (tonnes/yr)

Plugging the values from Table IV.2.1 into Equation IV.1.1 yields an approximate LCOA of \$1.13 per kg NH₃. This value is larger than other LCOA estimations (in the range of \$0.24 to 0.29 per kg NH₃)¹²⁴, which is likely due to the unique set of LCOH and LCOA inputs we utilized in this study.

Ammonia is stored as a liquid at ambient atmospheric pressures and temperatures below -33°C.¹²⁵ Given that the output of the Haber-Bosch process is *liquid* ammonia, the levelized cost of ammonia accounts for liquefaction costs.¹²⁶ However, there are additional costs associated with storing ammonia at such temperatures. As ammonia has been used in the fertilizer industry for many decades, there are already established best practices to construct and maintain storage facilities throughout the world, including at least 47 large-scale (2,000+ MMT) facilities in India.¹²⁷ A 2017 report by the American Institute of Chemical Engineering details an atmospheric liquid ammonia storage facility capable of holding 380 GWh of liquid ammonia at -33°C. This facility, comprised of two double-walled steel tanks, would present a turnkey cost of \$15,000,000 (total costs associated with producing a fully-functioning and ready-to-use facility).^{128, 129} A 2008 report from Iowa State University reports an estimated cost of storage for ammonia systems as \$0.54/kgNH₃, assuming a cost of local electricity at \$0.08/kWh and a storage duration of 182 days (6 months).¹³⁰ Table IV.4.2 reports this value alongside estimated costs of other methods of hydrogen storage later in the report.

IV.3 Levelized Cost of Hydrogen Transport

Hydrogen can be transported either as a gas or a liquid, each requiring specific methods and infrastructure. Gaseous hydrogen transportation typically

involves compression to achieve higher volumetric energy densities. The compressed hydrogen is then transported through pipelines or using specialized tube trailers hauled by trucks. Tube trailers are generally used for short-distance or low-volume hydrogen distribution, making them ideal for localized supply chains. In contrast, pipelines are preferred for their high-volume and long-distance transport. For liquid hydrogen, transportation necessitates cryogenic cooling to extremely low temperatures to convert it into a liquid state, significantly reducing its volume. This process requires specialized cryogenic tanks designed to maintain these low temperatures during transport. Liquid hydrogen is advantageous for long-distance transport, especially when large quantities are needed, such as for export or in applications where space constraints are critical. However, the energy-intensive liquefaction process and the need for advanced insulation technologies in tanks add to the cost and complexity. We have considered pipelines and cryogenic tanks as possible options for transmission of hydrogen from the production facility to a centralized storage terminal (longer distances, larger volumes), and tube trailers and cryogenic tanks for distribution from storage terminal to end users (shorter distances, smaller volumes).

We have developed a levelized cost for each step in the process of transporting hydrogen. Table IV.3.1 below summarizes the scope of the modeled processes.

Table IV.3.1. Scope of hydrogen transportation modeling.

| Hydrogen state | Process | Use case | Operating condition assumptions |
|----------------|--------------------|---|------------------------------------|
| Gas | Compression | Compressing hydrogen for transmission from production facility to storage terminal through pipeline | Compressed from 20 bar to 70 bar |
| | | Compressing hydrogen delivered by pipeline for storage | Compressed from 50 bar to 250 bar |
| | | Compressing hydrogen for transportation from storage terminal to end users through tube trailer | Compressed from 250 bar to 350 bar |
| | Pipeline transport | Transmission of hydrogen from production facility to storage terminal | Distance = 100 km |

| | | | |
|--------|--------------------------|---|-------------------|
| | Tube trailer transport | Distribution of hydrogen from storage terminal for end use | Distance = 100 km |
| Liquid | Liquefaction | Liquefying hydrogen for transmission/distribution through cryogenic tanks | Cooled to -253°C |
| | Cryogenic tank transport | Transmission/distribution of hydrogen in cryogenic tanks | Distance = 100 km |

We utilized inputs from the HDSAM¹³¹ created by the US DoE's Argonne National Laboratory to estimate the CAPEX required for compression, liquefaction, tube trailer transport, and cryogenic transport. This includes uninstalled costs of equipment, installation costs, and indirect costs like site preparation, engineering and design, project contingency, permitting, and owner's costs (Equation IV.3.1). The pipeline transport CAPEX includes inputs from the Hydrogen Pipeline Cost Model (H2_P_COM)¹²⁷ developed by the US DoE's National Energy Technology Laboratory. In line with the assumptions for LCOH calculation, we have sized the equipment required for each process using an average flow rate of 50 metric tons of hydrogen per day. We annualized CAPEX over the equipment life using a capital recovery factor (Equations IV.3.2 and IV.3.3). We also accounted for labor costs, operations and maintenance (O&M) costs, overhead, and energy costs in the annual OPEX for each process (Equation IV.3.4). Finally, we added the annualized CAPEX and OPEX and normalized the total over the quantity of hydrogen processed in the same period to determine the levelized cost of compression, liquefaction, and transportation per kilogram of hydrogen (Equation IV.3.5).

$$\text{CAPEX} = \text{Uninstalled Cost}(UC) * \text{Installation Factor}(IF) + \text{Indirect costs} \quad \text{Equation IV.3.1}$$

$$\text{Capital Recovery Factor}(CRF) = \frac{i(1+i)^n}{(1+i)^n - 1} \quad \text{Equation IV.3.2}$$

where, i = Discount rate (%) and n = Equipment lifetime

$$\text{Annualized CAPEX} = \text{CAPEX} * CRF \quad \text{Equation IV.3.3}$$

$$\text{Annual OPEX} = \text{Labor costs} + \text{O\&M} + \text{Overheads} + \text{Energy costs} \quad \text{Equation IV.3.4}$$

where,

$$\text{Labor cost} = \text{Annual labor hours} * \text{Hourly labor rate}$$

$$\text{O\&M} = \text{Operation and Maintenance cost}$$

$$\text{Overhead} = 50\% \text{ of Labor cost}$$

$$\text{Energy costs} = \text{Rated power} * \text{Annual operating hours} * \text{Electricity price}$$

Equation IV.3.4

$$\text{Levelized Cost} = \frac{\text{Annualized CAPEX} + \text{Annual OPEX}}{\text{Average flow rate [kg H2/day]} * 365 [\text{days/year}]}$$

Equation IV.3.5

Table IV.3.2 summarizes the overall assumptions used to calculate the cost of compression, liquefaction, and transportation in the following sections.

Table IV.3.2. Scope of hydrogen transportation modeling.

| Metric | Value |
|----------------------------------|--------------------------|
| Average H2 flow rate | 50,000 kg H2/day |
| # Operating days/year | 365 |
| Discount rate | 7% |
| Electricity price ¹³² | 0.051 \$/kWh |
| Labor rate | 2.5 \$/hour |
| Overheads | 50% of direct labor cost |
| Diesel price ¹³³ | 1.07 \$/L |

IV.3.1 Hydrogen Compression

Hydrogen is typically compressed to pressures ranging from 350 to 700 bar for storage and transportation. The supply chain described below is used as a model for the cost of hydrogen compression:

- Pipeline compressor for compressing hydrogen to the required pressure for transportation through pipeline
- Truck loading compressor for compressing hydrogen to the required pressure for transportation in a tube trailer
- Terminal storage compressor for compressing hydrogen to the required pressure for storage in underground storage at the hydrogen terminal

We calculate the compressor power required at each stage by substituting operational parameters from Table IV.3.3 into equation IV.3.6. The rated power is a crucial input to calculate the CAPEX and energy related OPEX, which constitute the bulk of the costs incurred for hydrogen compression.

$$\text{Power (kW)} = Z * m * R * T * n * \left(\frac{l}{\eta}\right) * \left(\frac{k}{k-1}\right) * \left[\left(\frac{P_{outlet}}{P_{inlet}}\right)^{\left(\frac{k-1}{nk}\right)} - 1 \right]$$

Equation IV.3.6

where,

Z = Mean compressibility factor

R = Universal gas constant = 8.3144 kJ/kg-mol-°K

k = Isentropic coefficient of hydrogen

m = Mass flow rate, kg-mole/sec

T_{inlet} = Inlet gas temperature, °K

n = Number of stages

η = Isentropic efficiency

P_{outlet} = Compressor discharge pressure

P_{inlet} = Compressor inlet pressure

Table IV.3.3. Operational parameters to calculate compressor rated power.

| Input | Pipeline compressor | Truck loading compressor | Terminal storage compressor | Comments |
|--|---------------------|--------------------------|-----------------------------|--|
| Inlet Pressure (P_{inlet}) | 20 bar | 250 bar | 50 bar | |
| Outlet Pressure (P_{outlet}) | 70 bar | 350 bar | 250 bar | |
| Inlet temperature (T_{inlet}) | 25 °C | 25 °C | 25 °C | |
| Outlet temperature (T_{outlet}) | 30.6 °C | 28.9 °C | 30.5 °C | $T_{outlet} = T_{inlet} * (1 + \frac{(\frac{P_{outlet}}{P_{inlet}})^{\frac{k-1}{n.k}} - 1}{\eta})$ |
| Mean compressibility factor ¹³⁴ (Z) | 1.0178 | 1.1557 | 1.1557 | $Z = \frac{Z_{outlet} - Z_{inlet}}{\ln(\frac{Z_{outlet}}{Z_{inlet}})}$ |
| Universal gas constant (R) | 8.3144 kJ/kg-mol-°K | 8.3144 kJ/kg-mol-°K | 8.3144 kJ/kg-mol-°K | |
| Isentropic coefficient of hydrogen (k) | 1.4 | 1.4 | 1.4 | |
| Max pressure ratio per stage (r) | 2.1 | 2.1 | 2.1 | |
| No. of stages (n) | 2 | 2 | 3 | $n = \frac{\log(\frac{P_{outlet}}{P_{inlet}})}{\log(r)}$ |
| Isentropic efficiency (η) | 0.88 | 0.75 | 0.75 | |

Table IV.3.4 summarizes additional key assumptions required to calculate the cost of hydrogen compression costs using equations IV.3.1 to IV.3.5. The parametric equations for calculating uninstalled costs are taken from HDSAM which reports the cost in 2007 or 2013 dollars depending on the type of compressor. We adjusted the cost for inflation and translated it into 2022 dollars using the Chemical Engineering Plant Cost Index (CEPCI).¹³⁵ We chose 2022 as the target year because that is the latest year for which CEPCI data is available free of cost. Table IV.3.5 summarizes the resulting costs of hydrogen compression.

Table IV.3.4. Assumptions for calculating cost of hydrogen compression.

| Input | Pipeline compressor | Truck loading compressor | Terminal storage compressor | Comments |
|-----------------------------|---|-----------------------------------|-----------------------------|--|
| Rated Power (kW) | 1263.9 kW | 999.3 kW | 2135.0 kW | From Equation IV.3.6 |
| Uninstalled cost | \$1962.2 * kW ^{0.8225} | \$63,684.6 * kW ^{0.6038} | (\$3758.2 * kW) + 107562 | Pipeline and Terminal storage compressor cost in 2007\$; Truck loading compressor cost in 2013\$ |
| Inflation adjustment factor | 1.65 (2007\$ to 2022\$) | 1.51 (2013\$ to 2022\$) | 1.51 (2007\$ to 2022\$) | |
| Installed cost factor | 2 | 2 | 2 | Installed Cost = Uninstalled Cost * Installed Cost Factor |
| Indirect costs | 40% | 40% | 40% | Site preparation (5%), Engineering and design (10%), Project contingency (10%), Permitting costs (3%), Owner's costs (12%) |
| Equipment life | 15 years | 15 years | 15 years | |
| O&M | O&M & repairs = 4% of TIC Insurance = 1% of TCI Property tax = 1% of TCI License & permits = 0.1% of TCI | | | TIC = Total Installed cost TCI = Total Capital Investment = TIC + Indirect costs |
| Annual labor hours | 242 | 242 | 242 | Annual hours = 288 * (x/100,000) ^{0.25} ; x = average compressor |

| | | | | |
|--|--|--|--|-----------------------------------|
| | | | | flow rate, kg H ₂ /day |
|--|--|--|--|-----------------------------------|

Table IV.3.5. Hydrogen compression cost results.

| Cost component | Pipeline compressor (\$ kg ⁻¹) | Truck loading compressor (\$ kg ⁻¹) | Terminal storage compressor (\$ kg ⁻¹) |
|--|---|---|---|
| CAPEX | \$0.02 | \$0.05 | \$0.09 |
| Energy OPEX | \$0.03 | \$0.02 | \$0.05 |
| Non-Energy OPEX | \$0.01 | \$0.02 | \$0.04 |
| Levelized Cost of H₂ Compression | \$0.06 | \$0.03 | \$0.18 |

IV.3.2 Hydrogen Liquefaction

Hydrogen liquefaction is the process of cooling hydrogen gas to extremely low temperatures (below -253°C or -423.4°F) to convert it into a liquid state, which significantly reduces its volume for storage and transport. Major costs incurred in hydrogen liquefaction include energy consumption for the refrigeration cycle and the capital costs for cryogenic equipment. Table IV.3.6 summarizes the key assumptions used to calculate the cost of hydrogen liquefaction using equations IV.3.1 to IV.3.5. The parametric equations for calculating uninstalled costs are taken from HDSAM which reports the cost in 2014 dollars. We adjusted the cost for inflation using the same methods as discussed in the previous section. Table IV.3.7 summarizes the resulting costs of hydrogen liquefaction.

Table IV.3.6. Assumptions for calculating cost of hydrogen liquefaction.

| Input | Value | Comments |
|-----------------------------|---|---|
| Uninstalled cost | \$5,600,000 * (tonnes H ₂ /day) ^{0.8} | In 2014\$ |
| Inflation adjustment factor | 1.57 (2014\$ to 2022\$) | |
| Installed cost factor | 1.1 | |
| Indirect costs | 40% | Site preparation (5%), Engg and design (10%), Project contingency (10%), Permitting costs (3%), Owner's costs (12%) |

| | | |
|-------------------------|---|---|
| Equipment life | 40 years | |
| O&M | O&M & repairs = 4% of TIC Insurance = 1% of TCI Property tax = 1% of TCI License & permits = 0.1% of TCI | TIC = Total Installed cost TCI = Total Capital Investment = TIC + Indirect costs |
| Electricity consumption | 9 kWh/kg | kWh/kg = 13.382 * (Plant capacity, metric tons per day) ^{-0.1} |
| Annual labor hours | 14,733 | Annual hours = 17,520 * (x/100000) ^{0.25} ; x = average liquefier demand, kg H ₂ /day |

Table IV.3.7. Hydrogen liquefaction cost results.

| Cost component | Cost (\$ kg ⁻¹) |
|---|-----------------------------|
| CAPEX | \$0.13 |
| Energy OPEX | \$0.46 |
| Non-Energy OPEX | \$0.05 |
| Levelized Cost of H₂ Liquefaction | \$0.64 |

IV.3.3 Hydrogen Transport on Trucks using Tube Trailers and Cryogenic Tanks

Hydrogen can be transported by truck in either its gaseous or liquid state, depending on the required volume and distance. In its gaseous form, hydrogen is typically transported in high-pressure tube trailers, which store the gas at pressures of up to 350 bar. For longer distances or larger quantities, hydrogen can be transported in liquid form using cryogenic tanks, which maintain the gas at temperatures below -253°C to keep it in liquid state. Liquid hydrogen is more space-efficient for large-scale transport but requires energy-intensive cryogenic cooling.

Table IV.3.8 summarizes the key assumptions used to calculate the cost of transporting hydrogen on trucks using equations IV.3.1 to IV.3.5. The

assumed distance for transportation costs is 100 km, however, later sections will discuss how the costs change when longer distances are involved. We calculated the numbers of trucks and trailers required by considering factors such as the quantity of hydrogen that needs to be transported per day, trailer capacity, and average truck speed as shown in equations IV.3.7 to IV.3.12. To calculate the time needed for each delivery, we assumed two hours for loading and unloading in addition to the travel time.⁹⁵ Table IV.3.9 summarizes the resulting costs of hydrogen transport by truck.

Table IV.3.8. Hydrogen transportation by truck cost assumptions.

| | Input | CGH₂ tube trailer | LH₂ cryogenic tank | Comments |
|---------|--|-------------------------------------|--------------------------------------|----------------------|
| Truck | Capital cost per truck ¹³⁶ | \$191,000 | \$191,000 | In 2022\$ |
| | Equipment life ¹²⁵ | 8 years | 8 years | |
| | Distance | 100 -1000 Km | | |
| | Average velocity ¹³⁷ | 50.4 km/h | 50.4 km/h | |
| | Driving hours per truck per day ¹²⁵ | 16 hours | 16 hours | |
| | Availability factor ¹²⁵ | 0.8 | 0.8 | |
| | # Trucks required | 18 | 7 | From equation VII.8 |
| | Fuel economy ¹²⁵ | 0.38 l/km | 0.38 l/km | |
| Trailer | Pressure/Temperature | 350 bar | -253°C | |
| | Trailer capacity ¹²⁷ | 1330 kg | 3800 kg | |
| | Capital cost per trailer ¹³⁸ | \$1,595,420 | \$1,399,225 | |
| | Equipment life ¹²⁵ | 15 years | 15 years | |
| | # Trailers required | 18 | 7 | From equation VII.11 |

| | | | | |
|------------------------|--------------------|----------------------------|--------|----------------------|
| Truck-trailer combined | O&M | 2% of Trailer capital cost | | |
| | Annual labor hours | 81,895 | 28,663 | From equation VII.12 |

$$\text{Number of trucks required} = \frac{\text{Number of deliveries required per day}}{\text{Number of deliveries per truck per day}} \quad \text{Equation IV.3.7}$$

$$\text{Number of deliveries per day} = \frac{\text{Quantity of hydrogen that needs to be transported per day}}{\text{Trailer capacity}} \quad \text{Equation IV.3.8}$$

$$\text{Number of deliveries per truck per day} = \frac{\text{Driving hours per truck per day}}{\text{Time per delivery}} \quad \text{Equation IV.3.9}$$

$$\text{Time per delivery} = 2 * \frac{\text{Distance}}{\text{Average velocity}} + 2 \quad \text{Equation IV.3.10}$$

$$\text{Number of trailers required} = \text{Number of trucks required} \quad \text{Equation IV.3.11}$$

$$\text{Annual labor hours} = \text{Time per delivery} * \text{Number of deliveries per day} * \text{Number of operating days/year} \quad \text{Equation IV.3.12}$$

Table IV.3.9. Hydrogen transportation by truck cost results.

| Cost component (Distance) | CGH2 tube trailer (\$ kg ⁻¹ km ⁻¹) | LH2 cryogenic tank (\$ kg ⁻¹ km ⁻¹) |
|--|---|--|
| CAPEX (100 - 1000 km) | \$0.0019 - \$0.0013 | \$0.0007 - \$0.0004 |
| OPEX (100 - 1000 km) | \$0.0014 - \$0.0013 | \$0.0004 - \$0.0003 |
| Levelized Cost of H₂ Transport (100 - 1000 km) | \$0.0033 - \$0.0026 | \$0.0011 - \$0.0008 |

IV.3.4 Hydrogen Transport through Pipelines

Hydrogen can be transported via pipelines, offering an efficient solution for large-scale, long-distance delivery. This method is particularly advantageous when consistent, high-volume hydrogen supply is required, such as in industrial applications or for fueling stations. The primary factors influencing transportation costs through pipelines include pipeline diameter, length, and compression requirements. Larger diameters allow for higher flow rates, reducing per-unit transportation costs but increasing initial capital

expenditures. Longer pipelines necessitate more materials and labor, elevating construction costs. Hydrogen's low energy density often requires compression to maintain flow, adding to both capital and operational expenses. Additionally, factors such as terrain, environmental considerations, and regulatory compliance can impact overall costs.

To estimate these costs, we used the H2_P_COM.¹³⁹ This Excel-based tool calculates capital, operating, and financing costs for transporting gaseous hydrogen through newly constructed pipelines. Users provide project-specific parameters—such as annual average hydrogen flow rate, pipeline length, and financial inputs—and the model calculates the optimal pipeline diameter and number of compression stations. H2_P_COM calculated an optimal diameter of 6 inches for the capacity requirement we assumed in this study. The model also generates a detailed financial analysis including cost estimates, revenue projections, and break-even analysis. However, in this study, we only utilize the cost estimates from the model as inputs for equations IV.3.1 to IV.3.5. Table IV.3.10 specifies the inputs to the model and Table IV.3.11 summarizes the resulting costs of hydrogen transport by pipeline.

Table IV.3.10. Hydrogen transportation by pipeline cost assumptions.

| Input | Value | Comments |
|---|--------------|---|
| Inlet pressure | 70 bar | |
| Outlet pressure | 50 bar | |
| Length of pipeline | 100-1000 km | |
| Annual Average H2 Mass Flow Rate | 0.018 Mt/yr | Calculated based on average daily flow rate of 50,000 kg H2/day and 365 days of operations a year |
| Capacity factor | 90% | |
| Starting Calendar Year for Project | 2022 | |
| Duration of Construction (years) | 3 | |
| Duration of Operation (years) | 30 | |
| Escalation rate from 2011 to starting year of project | 2.20% | |

Table IV.3.11. Hydrogen transportation by pipeline cost results.

| Cost component (Distance) | Value (\$ kg⁻¹ km⁻¹) |
|--|---|
| CAPEX (100 - 1000 Km) | \$0.0009 - \$0.0008 |
| OPEX (100 - 1000 Km) | \$0.0003 |
| Levelized Cost of H₂ Transport (100 - 1000 Km) | \$0.0012 - \$0.0011 |

IV.4 Levelized Cost of Hydrogen Storage

Hydrogen may be stored in liquid, gaseous, or solid states (such as hydrides), making it a relatively convenient and accessible energy carrier over time and space.¹⁴⁰ The storage of gaseous H₂ requires high pressure but ambient temperature, whereas the storage of liquid H₂ requires low temperature but ambient atmospheric pressures.¹⁴¹ Furthermore, liquid H₂ has a significantly higher volumetric energy density (8 MJ / L) than gaseous H₂ (5.6 MJ / L at 700 bar).¹⁴² This variety of physical properties at different temperatures and pressures allows hydrogen to serve as a useful entity to buffer variable generation from renewable energy producers. We only examine the storage capacities of hydrogen projects utilizing gaseous or liquid hydrogen in this study, but the storage and utilization of solid-state hydrogen fuel carriers—especially as fuel for vehicles¹⁴³—is a topic of ongoing scientific interest and advancement.¹⁴⁴

In addition to its storage capacity in a range of physical states, hydrogen may be stored above- or below-ground, depending on a region's geologic properties, the projected duration of storage, and the cost restrictions on the storage project. Scientific research and development have thus far scrutinized above-ground storage techniques more so than below-ground projects, partly due to the long-established fertilizer industry that relies on ammonia production and transportation, but additionally because there have not been hydrogen production projects at the scales seen today that would require enormous amounts of storage space. As hydrogen has re-emerged as a potential clean fuel

source throughout the world, interest has increased in storing the different forms of hydrogen in both above- and below-ground facilities.

Above-ground storage is most suitable for short and medium-term storage needs, and can hold gaseous hydrogen, liquid hydrogen, or ammonia. As Table IV.4.3 details further, gaseous hydrogen may be stored at ambient atmospheric temperature, but must be pressurized to approximately 300 bar.¹⁴⁵ Liquid hydrogen, by contrast, may be stored at ambient atmospheric pressures, but must be kept around -253 °C.¹⁴⁶ The cost tradeoffs between cooling and pressurizing will differ between contexts, but play a significant role in the storage system a given facility chooses to employ.

Ammonia, as mentioned in Section IV.2, is stored above-ground as a liquid at ambient atmospheric pressures and temperatures below -33°C.¹⁴⁷ Ammonia is the second-most manufactured chemical in the world, and due to its importance in the global fertilizer industry and associated impact on worldwide food production, it is usually stored near end-use farmlands.¹⁴⁸ Ammonia exits the Haber-Bosch process in liquid form, and can be stored in large holding vessels. These tanks, typically constructed out of steel with a double-wall vacuum design to maximize insulation, can hold up to 30,000 tonnes of ammonia.¹⁴⁹

Today's best-studied resources for below-ground storage of hydrogen are within salt caverns, underground aquifers, and depleted oil and gas fields. Underground aquifers consist of reservoir rocks with a high porosity (15% and more) and high permeability (several hundred millidarcy or more), a sealing layer with a very low permeability, and non-fractured overburden rocks.¹⁵⁰ India hosts a prominent occurrence of saline aquifers, which lend this storage method an advantage in its availability in the context of this report.¹⁵¹ Salt caverns, primarily studied in Europe, consist of a range of rock characteristics including thick horizontal bedded rock salt deposits, salt domes, insoluble interlayers of non-salt rocks, and highly soluble potassium and magnesium salts.¹⁵² Of these four, current literature finds the horizontal bedded rock salt and salt domes to be most favorable for storing gaseous hydrogen.¹⁵³ In India, there are very few prospects of suitable salt caverns.¹⁵⁴ Finally, oil and gas fields are, like saline aquifers, abundant throughout India, but most are not yet depleted and therefore are not currently eligible to store injected hydrogen gas.¹⁵⁵

Each of the three storage methods also comes with its related limitations. The adaptation of existing hydrogen storage may not necessarily be possible in the case of underground aquifers, and the limited availability of appropriate technologies and equipment for the construction and operation of the facility may pose a barrier to use.¹⁵⁶ Additionally, there is a lack of available technology

to construct and operate a facility, the water resources needed to mine salt cavern walls may not be available within the context of India, and there may not be a way to safely dispose of the resulting brine.¹⁵⁷ Finally, the literature still does not supply a rigorous foundation of knowledge regarding the scale or interaction of hydrogen gas with the reservoir rocks, overburden rocks, and reservoir fluids in depleted oil and gas fields.¹⁵⁸

Table IV.4.1. A comparison of characteristics and cost estimates among current available and proposed gaseous hydrogen underground storage methods.

| Underground Storage Method | Underground Aquifer | Salt Cavern | Depleted Oil & Gas Field |
|---|--|---|---|
| Optimal Depth of Deposits | 1,000 - 1,500m ¹⁵⁹ | 1,000 - 1,500m ¹⁶⁰ | 1,400m ¹⁶¹ |
| Occurrence in India's Geologic Resource | Common ¹⁶² | Not Common ¹⁶³ | Somewhat Common ¹⁶⁴ |
| Total Site Capital Costs | \$40.9mn ¹⁶⁵ | \$90mn - \$117mn ¹⁶⁶ | \$50mn – \$79mn ¹⁶⁷ |
| Storage Availability - Number of Injection Cycles | < 12 injection and withdrawal cycles per year ¹⁶⁸ | 1 - 2 injection and withdrawal cycles per year ¹⁶⁹ | 1 - 2 injection and withdrawal cycles per year ¹⁷⁰ |
| Cushion Gas : Working Gas Capacity Ratio | 20 - 50% of working capacity ¹⁷¹ | 50 - 70% of working capacity ¹⁷² | 50% of working capacity ¹⁷³ |

Note: Capacity was not included, as the size of each storage site will be completely dependent on the local geological conditions.

As India has the most access to underground aquifers within its geologic resource, we focus our analysis on understanding the costs and benefits that accompany preparing and utilizing this method of storage. As previously mentioned, no real-world examples of hydrogen storage facilities utilize underground aquifers or depleted oil and gas reservoirs as of 2025. Further research is required to evaluate the potential for hydrogen storage in these geological formations, especially regarding potential microbial contamination of storage reservoirs.¹⁷⁴ But, existing facilities successfully make use of salt caverns throughout the world. As Table IV.4.1 shows above, the estimated cost of preparing an underground aquifer to store gaseous hydrogen was approximately \$40.9 million as of 2011. The estimated storage capacities of known underground aquifer resources within India range between 8.7 MMT in Gujarat and 54.9 MMT in Maharashtra. Table IV.4.2 presents the levelized cost of storage for the primary methods of storage covered in this report, including

underground aquifers, above-ground storage of hydrogen (gaseous and liquid) and ammonia, and line-packing (the storing of marginal capacities of hydrogen gas within pipeline infrastructure). We assume there is an existing network of gas transportation pipelines in India and that future hydrogen transportation could make use of this built infrastructure. Table IV.4.3 presents the storage method characteristic assumptions associated with each category.

Table IV.4.2. Levelized Cost of Storage estimates for different methods and energy carrier states of hydrogen.

| Storage Method | Underground Aquifers | Line Packing | Above-Ground Tanks | Above-Ground Tanks | Above-Ground Tanks |
|---|---------------------------------------|--------------------------|--------------------------|----------------------------|-------------------------------------|
| Energy Carrier State | Gaseous H ₂ | Gaseous H ₂ | Gaseous H ₂ | Liquid H ₂ | Liquid NH ₃ |
| Duration (days) | Up to 730 (24 months) ¹⁷⁵ | < 1 ¹⁷⁶ | 1 - 2 ¹⁷⁷ | 7 - 14 ¹⁷⁸ | Up to 182 (6 months) ¹⁷⁹ |
| Capacity (tonnes) | 8,700,000 - 54,900,000 ¹⁸⁰ | 100 - 300 ¹⁸¹ | 0.3 - 1 ¹⁸² | 5 - 10 ¹⁸³ | 25,000 ¹⁸⁴ |
| Levelized Cost of Storage Estimate (\$ / kgH ₂) | 1.29 ¹⁸⁵ | < 0.05 ¹⁸⁶ | 0.3 - 0.5 ¹⁸⁷ | 0.06 - 0.12 ¹⁸⁸ | 0.54 ¹⁸⁹ |

Note: Underground aquifer storage capacity estimates are based on high and low estimates of aquifer volumes throughout the Indian subcontinent.

Table IV.4.3. Levelized Cost of Storage assumptions associated with different methods and energy carrier states of hydrogen.

| Underground Aquifers | | | |
|-----------------------|-------|------|---|
| Variable | Value | Unit | Source |
| Amount of cushion gas | 50 | % | Raad, Leonenko, & Hassanzadeh 2022 ¹⁹⁰ |

| | | | |
|--|-----------|---------------------|---|
| Temperature | 43 | °C | Okoroafor et al. 2024 ¹⁹¹ |
| Pressure | 90 | bar | Raad, Leonenko, & Hassanzadeh 2022 ¹⁹² |
| Storage Efficiency | 0.1 - 4.2 | % | Indro & Okoroafor 2024 ¹⁹³ |
| Cavern Size | 500 | tonnes | ITS - UC Davis ¹⁹⁴ |
| Storage Pressure | 150 | bar | ITS - UC Davis ¹⁹⁵ |
| Electricity Cost | 0.05 | \$/kWh | ITS - UC Davis ¹⁹⁶ |
| Line Packing | | | |
| Pressure (packed) | 90 | Bar | ITS - UC Davis ¹⁹⁷ |
| Pressure (unpacked) | 70 | Bar | ITS - UC Davis ¹⁹⁸ |
| Temperature | 25 | °C | HDSAM ¹⁹⁹ |
| Pipe Length | 100 | km | ITS - UC Davis ²⁰⁰ |
| Pipe Diameter | 36 | inch | ITS - UC Davis ²⁰¹ |
| Above-Ground Pressurized Tank (GH2) | | | |
| Volume | 1,000 | m ³ | ITS - UC Davis ²⁰² |
| Electricity Consumption | 10 | kWh/kg | DOE ²⁰³ |
| Compression | 0.4 | \$/kgH ₂ | ITS - UC Davis ²⁰⁴ |
| Discharge Power | 100 | MW | ITS - UC Davis ²⁰⁵ |
| Temperature | 20 | °C | ITS - UC Davis ²⁰⁶ |
| Pressure | 300 | bar | Farazmand et al. 2024 ²⁰⁷ |
| Above-Ground Pressurized Tank (LH2) | | | |
| Volume | 1,000 | m ³ | ITS - UC Davis ²⁰⁸ |
| Electricity Consumption | 10 | kWh/kg | DOE ²⁰⁹ |
| Compression | 0.4 | /kgH ₂ | ITS - UC Davis ²¹⁰ |
| Discharge Power | 100 | MW | ITS - UC Davis ²¹¹ |
| Temperature | -253 | °C | Farazmand et al. 2024 ²¹² |
| Pressure | 1 | bar | Dias et al. 2020 ²¹³ |

IV.5 Hydrogen Gas Turbines

Gas turbine engines fueled by 100% hydrogen are still a nascent technology. However, there are estimates on what such a generating unit would cost. For a 100% hydrogen-fueled gas turbine (H2GT), CAPEX is estimated to be between 115% to 130% of the \$468 per kW current cost of an open-cycle natural gas turbine.²¹⁴ Assuming the higher range of the estimate, this yields a CAPEX of \$608.4 per kW for a H2GT.

Kawasaki Heavy Industries partnered with RWE, a major German electric power company, in 2022 to deploy a 34 MW open-cycle H2GT.²¹⁵ This project was slated to become operational by 2024, but its development status is currently unknown. Regardless of the project status, we use this size plant as a baseline for the capacity of a H2GT in this study. As a result, the CAPEX for a H2GT plant of this size is \$206,856,000.

We assume a consistent capacity factor of 50% for all generating units such that we can adequately compare the LCOE between each pathway. This capacity factor results in 1,639,242 MWh of electricity generated annually. Since H2GT is still a nascent technology, there are limited data available regarding the operational life of these units. We assume that a H2GT has a rated lifespan of 30 years.

Equation IV.3.2 shows the formula used to calculate a CRF. Like before, we assume a discount rate of 7%. We take the discount rate with our assumed ICE lifespan of 30 years to calculate a CRF of 8.06%. We then use Equation IV.3.3 to calculate an annualized CAPEX of \$16,669,781. Dividing the annualized CAPEX by the yearly generation of the unit results in a leveled CAPEX of \$11.186 per delivered MWh of electricity (\$0.0112 per kWh).

IV.6 Hydrogen Fuel Cells

The United States Department of Energy has technical targets for stationary fuel cells with a nameplate capacity ranging from 100 kW to 3 MW.²¹⁶ We use the upper bound on this range as the baseline capacity for hydrogen fuel cells (FC). 2021 capital cost estimates for hydrogen FCs were approximately \$3,000 per kW.²¹⁷ Other studies anticipate these costs to decrease to \$1,800 per kW by 2030, with reductions slowing around mid-decade.²¹⁸ Thus, the CAPEX for a 3 MW FC is \$5,400,000 in the year 2030.

We assume the lifespan of such a unit to be largely dictated by the service life of the stacks within the FC. We assume a service life of 7.5 years for the electrolyzer stacks in the LCOH calculations and will be used for the FC stacks as well. This value accounts for stack degradation occurring from operating the unit.

Again, we utilize a capacity factor of 50% in this analysis. As a result, the annual energy generation of a 3 MW FC is 13,149 MWh.

We use the same discount rate of 7% to derive the CRF for the unit, which equates to 17.59%. Using the CRF in Equation IV.3.3, we find an annualized CAPEX of \$949,832 for the hydrogen FC. We then divide this value by the annual energy output to yield a cost of \$72 per delivered MWh of electricity (\$0.072 per kWh).

IV.7 Ammonia Co-Firing Plants and Price of Coal

Ammonia co-firing makes use of existing coal-fired power plants. Nagatani et al. conducted a feasibility study in 2021 of ammonia co-firing in a 1000 MW coal-fired boiler and found that retrofitting only requires small modifications to add an ammonia supply system²¹⁹ and an ammonia vaporization unit. Other components of existing coal facilities are considered usable in their current condition. However, most studies analyzing the economics of ammonia co-firing have defaulted to disregarding changes in the CAPEX of a coal-fired power plant converted to an ammonia co-firing plant.²²⁰ This is largely due to limited available data on conversion costs, as well as the relatively minor impact of plant infrastructure on the LCOE compared to fuel cost changes.²²¹

As of December 2024, India had 218,969.5 MW of installed coal capacity.²²² There are 191 active generators that share this capacity, which results in an average plant capacity of approximately 1,100 MW. This is the baseline ammonia co-firing plant size used in this study. Assuming a capacity factor of 50% results in a plant of this size producing 4,821,300 MWh of electricity annually.

We assume for the purposes of this study that existing coal plants will be retrofitted to support ammonia co-firing. As a result, we need to incorporate prior operation and financing to reduce the impact of the CAPEX in calculating the LCOE. We assume that each plant had been operational for 15 years as an exclusively coal-fired power plant prior to co-firing conversion. Coal-fired plants in India typically operate for 40 to 50 years, so we chose an average lifespan of 45 years for this analysis.²²³ Accounting for the 15 years of prior coal operations, the co-firing plant has a lifespan of 30 years.

Other studies estimate the capital costs for a coal plant in India to be around \$1,058 per kW.²²⁴ For a 1,100 MW plant, this comes to a total CAPEX of \$1,163,800,000. However, we must depreciate this CAPEX the 15 years of operations before conversion. Assuming a 10% annual depreciation, the CAPEX at conversion will be \$239,616,100. When introducing a 7% discount rate (8.606% CRF), we find an annualized CAPEX of \$19,309,800 for the co-firing plant. Dividing the annualized CAPEX by the annual energy output yields a cost of \$4 per delivered MWh of electricity (\$0.004 per kWh).

An additional cost associated with ammonia co-firing is the price of coal. Coal futures fluctuate considerably day-to-day, month-to-month, and year-to-year. The average coal price in India between April 2023 and December 2024 was INR 3,131 per tonne (\$36.41 per tonne, or \$0.03641 per kilogram).²²⁵ Due to a variety of factors, this value could change drastically in coming decades, but we assume it to be a constant for this analysis. This cost is for G-8 grade coal, which has a calorific value of 4,900 to 5,200 kilocalories per kilogram.²²⁶ For this analysis, we use an energy density of 5,050 kilocalories per kilogram, or 21.13 MJ per kilogram.

Section V. Policy Analysis Methods

For the policy analysis, we employed government reports and records to seek out global and Indian policies relevant to green hydrogen deployment under the three identified study areas of this paper: long-duration storage, ammonia co-firing, and captive generation. Articles published before 2020 are not considered due to the rapidly changing nature of the green hydrogen and renewable energy spaces, whereas policies, laws, and initiatives are always considered in their most recent iteration regardless of date enacted. For each application, we looked at how India's NGHM, state level green hydrogen policies, and additional supporting policies are each addressed.

We used reports from the International Renewable Energy Agency (IRENA) as a baseline to evaluate how comprehensive India's national level policies are. "Green Hydrogen: A Guide to Policy Making", published in 2020, was also used to inform this report's policy recommendations. It discusses the policy tools and provisions that are more effective for green hydrogen deployment. "Green Hydrogen Strategy: A Guide to Design", published in 2024, analyzes current green hydrogen policies around the world to provide policy makers and think tanks with examples of effective and comprehensive policies so that they can actively contribute to and expand their nation's and/or sector's hydrogen economy.

The primary policy we examined in this study is India's National Green Hydrogen Mission. The NGHM was enacted in 2023 as part of India's broader goals of decarbonization and reduction of reliance on fossil fuels.²²⁷ The NGHM serves as the baseline for national level analysis. At the time of this study, seven states in India have active green hydrogen policies. They were each examined for relevant policies and provisions related to the three applications of green hydrogen. We classified other relevant national level policies as policies that enhance or hinder deployment of green hydrogen in at least one of the three applications this report analyzes.

Section VI. Results

VI.1 Energy Efficiency Analysis and Energy Flow Modelling

Electrolysis – Above-ground compressed storage

We found that above-ground hydrogen compression routes are characterized by low energy losses, particularly in the storage stage, where losses are relatively minimal. These routes do not differentiate between short- and long-term storage periods, as this type of storage only requires energy during the initial compression process to reach pressures of approximately 350–700 bar. This storage method has minimal losses, as a fully sealed tank that remains stable within properly designed containers experiences virtually no losses.²²⁸ However, in our analysis, leakage losses of approximately 0.5% per compression process in the chain are considered.

Figure VI.1.1 and VI.1.2 show the Sankey diagrams for the above-ground compressed storage routes (Pathway 1 and 2). We found that the most significant differences occur in the end-use stage, where the route utilizing fuel cells for electricity generation is identified as the most efficient option.²²⁹ Compression storage in the Sankey diagrams represents an energy requirement of 4.66 kWh/kg, achieving an efficiency of approximately 89.4% in both routes.²³⁰ Overall, we found that the compression and fuel cell route (Pathway 2) is the most efficient pathway with round-trip efficiency of 38.91%.

In general, we determined that hydrogen compression in above-ground tanks is the most energy-efficient storage method. Currently, compressed hydrogen is the most developed technology for large-scale applications.²³¹ However, the literature does not clearly distinguish between short- and long-term storage, though it mentions economic challenges associated with the high cost of tanks. While leakage losses are not time-dependent, the costs of tank storage and its limited capacity could hinder large-scale implementation for seasonal storage.

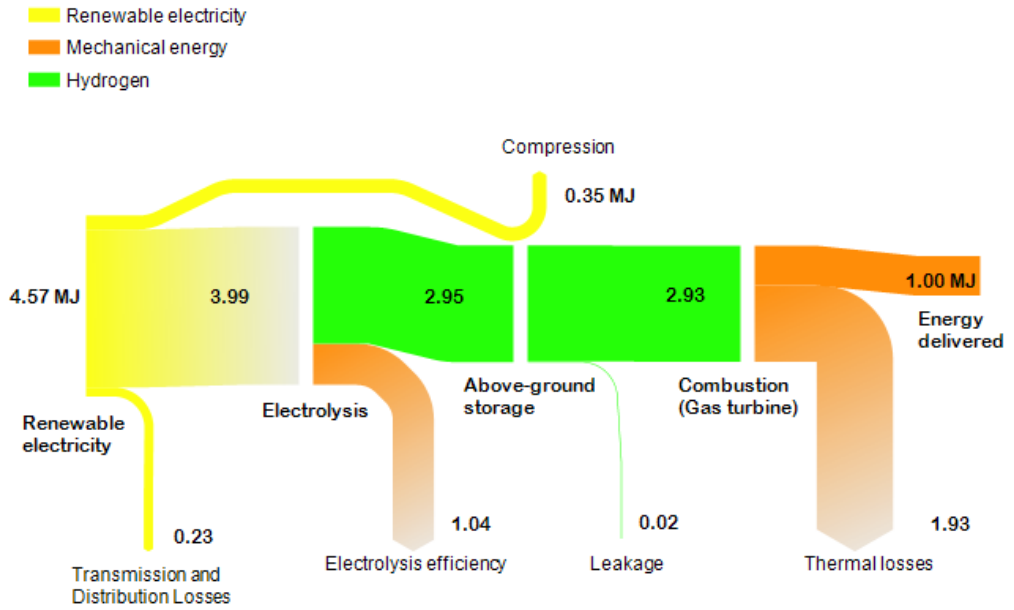


Figure VI.1.1. Pathway 1: Electrolysis, Compression, and Combustion

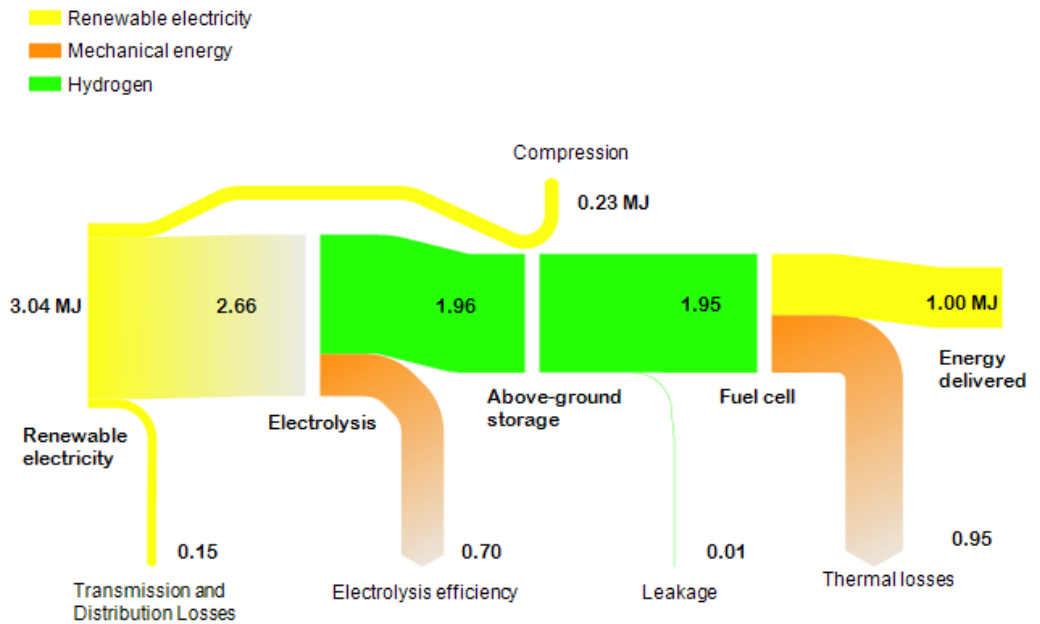


Figure VI.1.2. Pathway 2. Electrolysis, Compression, and Fuel Cell

Electrolysis – Underground storage

We considered storage efficiency in depleted gas reservoirs in the underground storage routes, which have the capacity to store larger gas volumes than salt caverns. Currently, 75% of underground gas storage is conducted in depleted gas reservoirs due to their well-characterized geology.²³²

Figure VI.1.3 and VI.1.4 show the Sankey diagrams for the underground storage routes (Pathway 3 and 4). We found relatively high efficiencies for this storage method, reaching 81% in hydrogen injection, storage, and extraction. However, we identified significant logistical challenges in implementing these storage routes. Among the main logistical challenges is transport, as these deposits are in fixed locations, potentially incurring higher energy costs for transportation that were not included in the scope of this study. Therefore, while this option shows high potential, we conclude that additional factors must be considered for its large-scale viability.

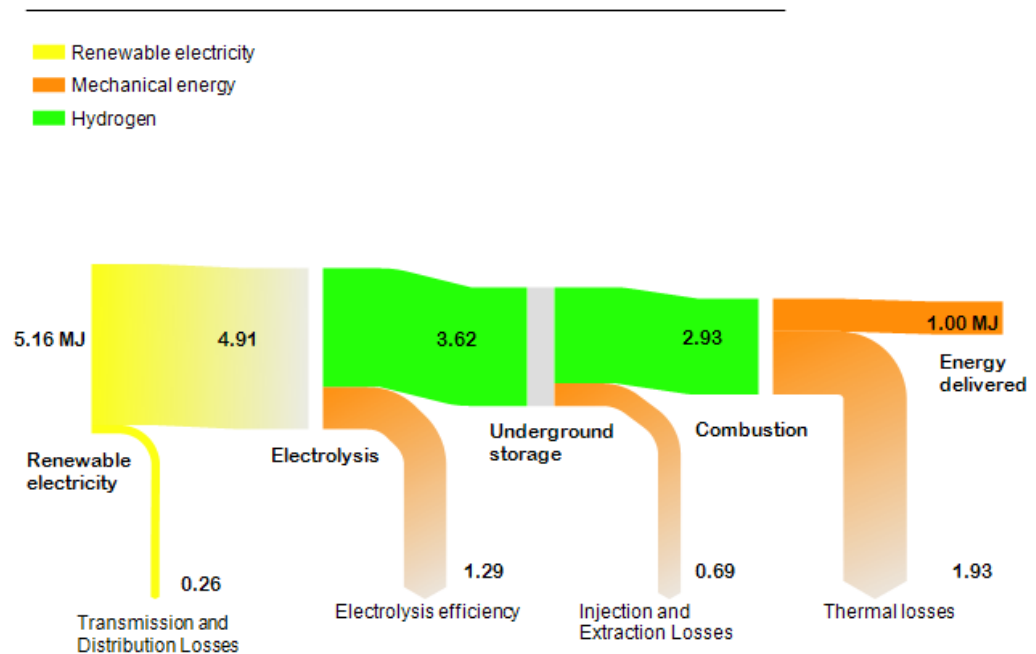


Figure VI.1.3. Pathway 3: Electrolysis, Underground Storage, and Combustion

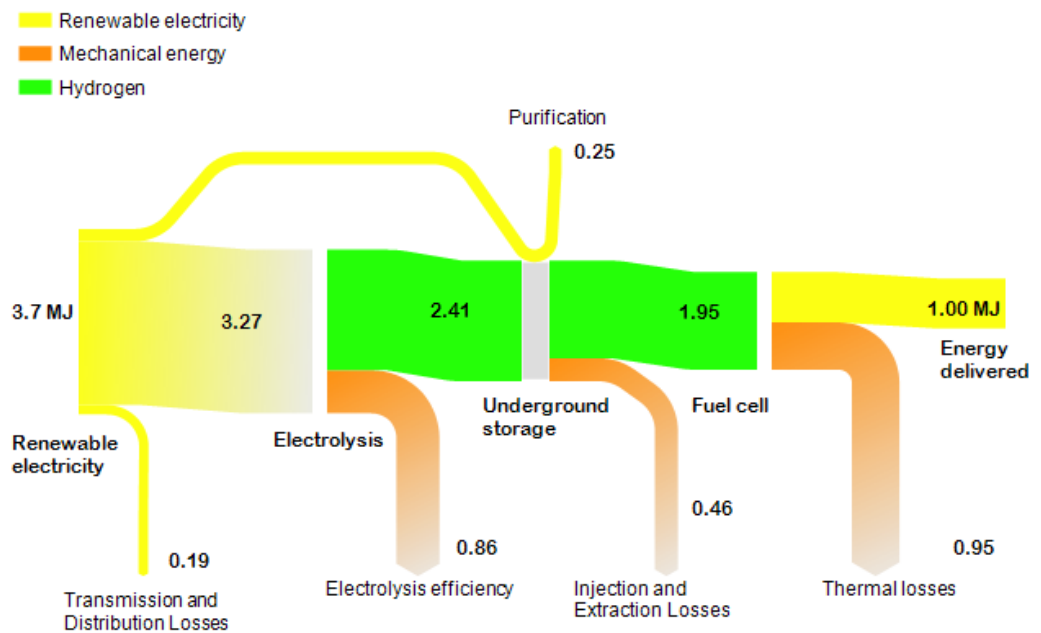


Figure VI.1.4. Pathway 4: Electrolysis, Underground Storage, and Fuel Cell

Electrolysis – Above-ground liquefied storage (H₂)

We found that the routes including hydrogen liquefaction are generally inefficient due to the high energy demand of this storage method. This inefficiency is attributed to the need to maintain extremely low storage temperatures, which requires a continuous energy supply. Hydrogen liquefaction involves cooling it below $-253\text{ }^{\circ}\text{C}$, with an energy cost that can reach up to 44.7% of the energy content of hydrogen in its gaseous phase.²³³ We included the long-term above-ground storage route for liquefaction in the analysis to evaluate losses over time. Since liquefaction is the least efficient hydrogen storage method, we conclude that its long-term application could be even more disadvantageous.

Even though cryogenic hydrogen storage uses thick-walled containers designed to ensure effective insulation, energy losses due to boil-off still occur, varying by the storage conditions. Some studies have estimated boil-off rates between 0.1% and 1.0% of the total volume per day,²³⁴ while others place them at approximately 0.520% per day.²³⁵ Additionally, analyses based on the HDSAM model have reported losses of 0.25% per day.²³⁶

Figure VI.1.5, VI.1.6, VI.1.7, and VI.1.8 show the Sankey diagrams for the above-ground hydrogen liquefaction routes (Pathway 5, 6, 7, and 8). We consider three types of energy losses in these pathways. Losses during hydrogen

gas liquefaction, which amount to 0.5%, losses during the unloading of liquid hydrogen at the power plant, which reach approximately 5%.²³⁷ Boil-off losses are quantified in combination with the energy used to liquefy hydrogen, resulting in a short-term storage efficiency of 71.8% and a storage efficiency of 50.56% in seasonal storage applications.²³⁸

As in hydrogen compression routes, we observed that the use of fuel cells plays a key role in reducing the losses that would occur if gas turbines were used for direct combustion. However, we conclude that liquid hydrogen storage is not viable for small volumes or long-term storage.

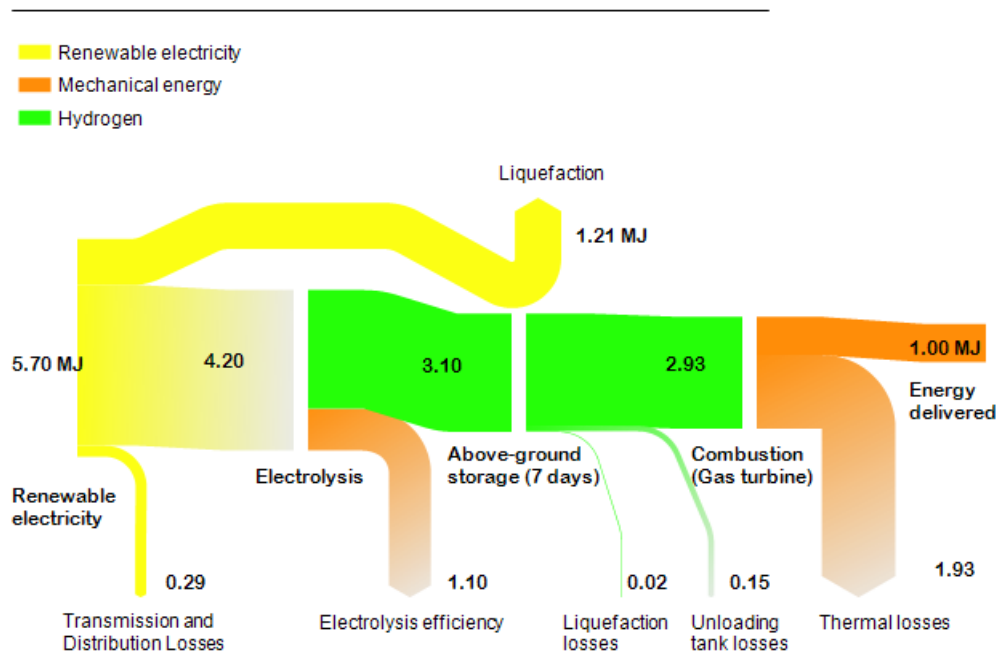


Figure VI.1.5. Pathway 5: Electrolysis, Liquefaction (7 days), and Combustion

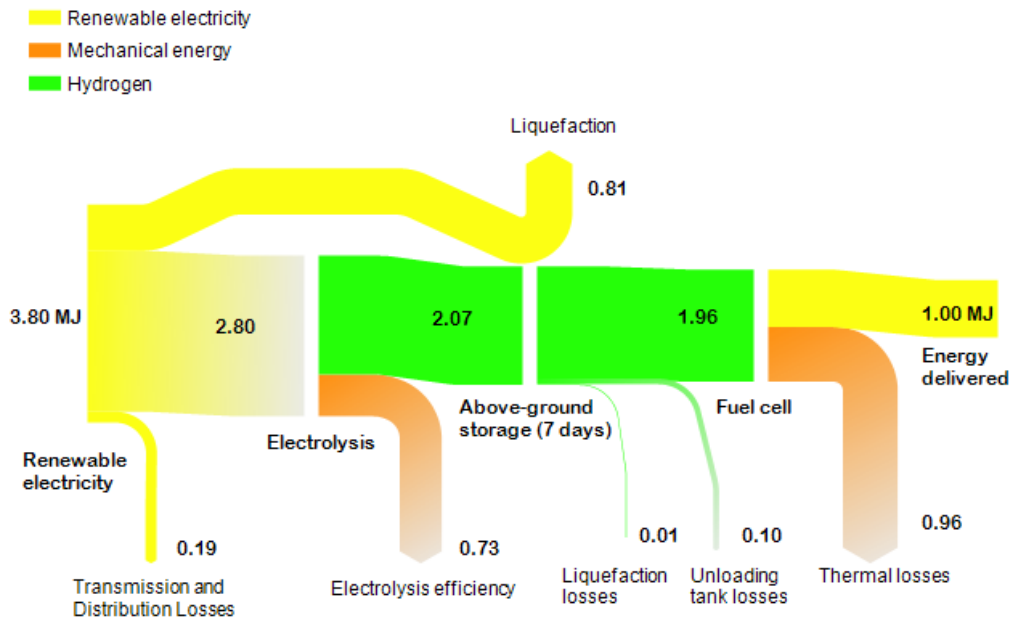


Figure VI.1.6. Pathway 6: Electrolysis, Liquefaction (7 days), and Fuel Cell

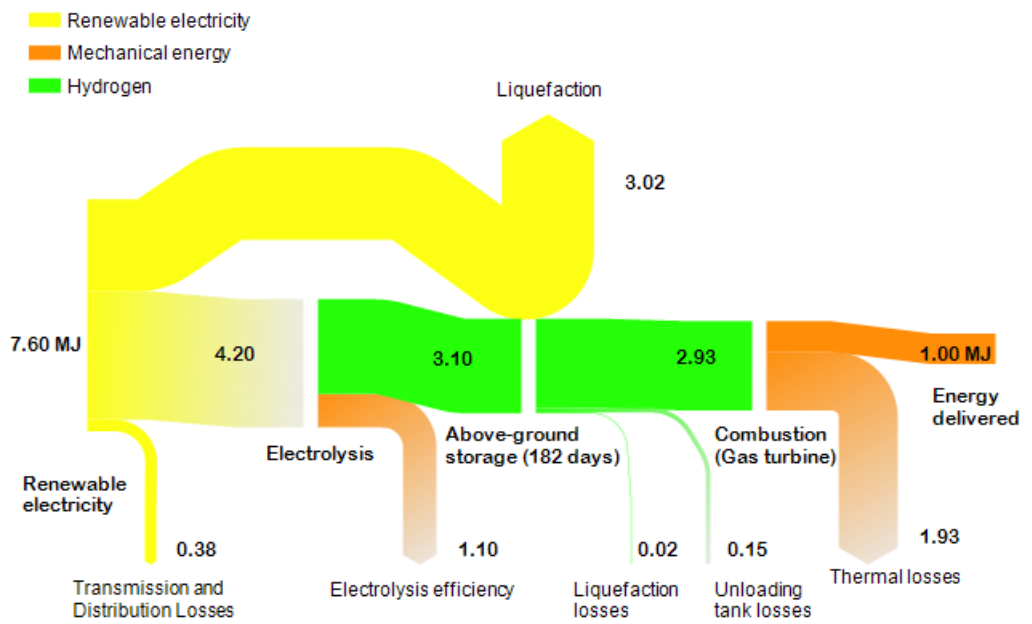


Figure VI.1.7. Pathway 7: Electrolysis, Liquefaction (182 days), and Combustion

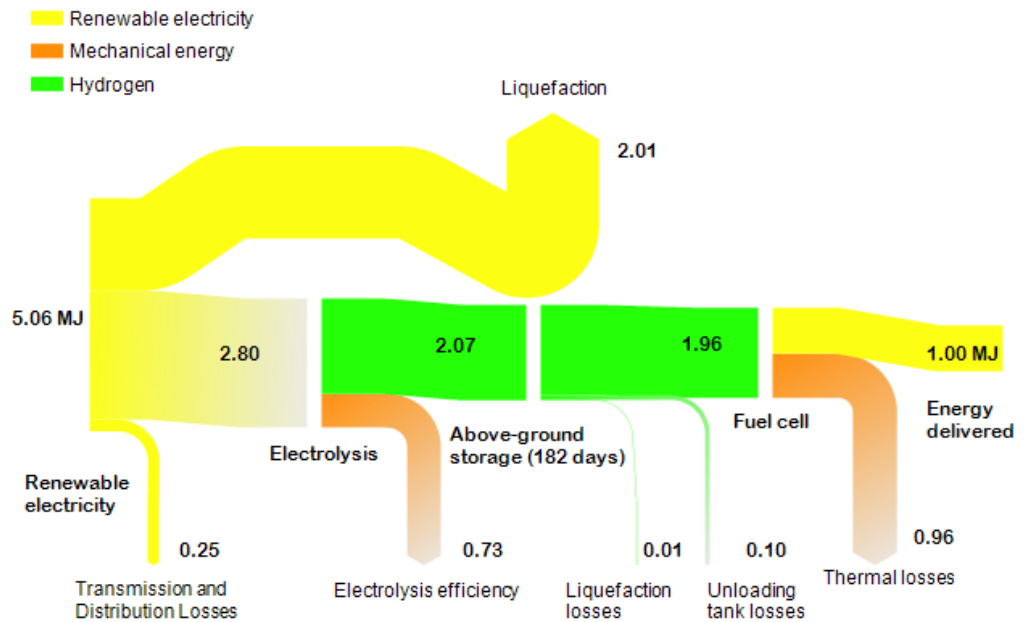


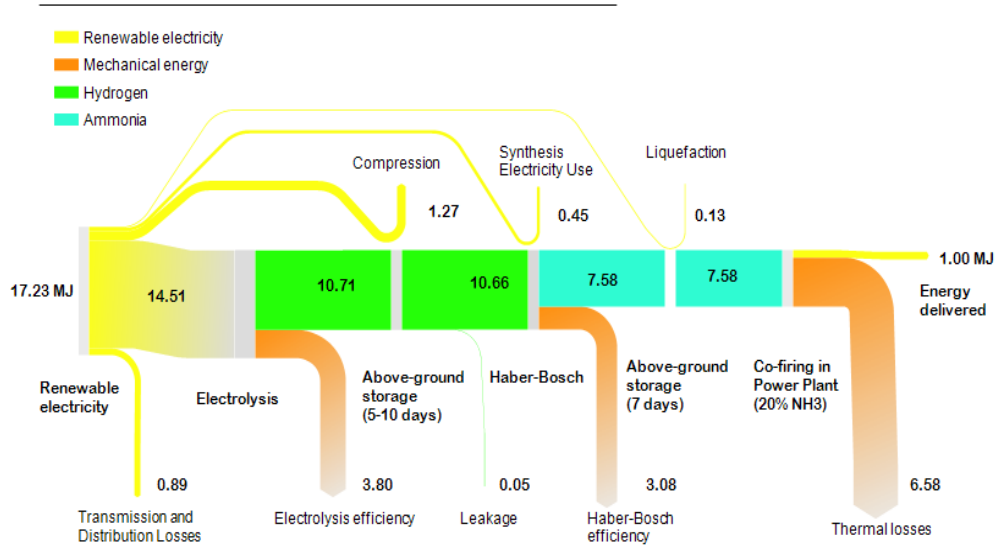
Figure VI.1.8. Pathway 8: Electrolysis, Liquefaction (182 days), and Fuel Cell

Electrolysis – Haber Bosch – Co-firing

We found that green ammonia production routes are the least efficient pathways with round-trip efficiencies of 5.8% for short-term storage and 5.6% for long-term storage. Figure VI.1.9 and VI.1.10 show the Sankey diagrams for the co-firing routes (Pathways 9 and 10). The largest losses reported in the Sankey diagrams are attributed to the Haber-Bosch process and ammonia co-combustion. We consider a combined efficiency of electrolysis, compression, and Haber-Bosch of 58.8%.²³⁹ On the other hand, although 20% ammonia co-firing achieves efficiencies between 93% and 99%,^{240,241} the total efficiency for electricity production from green ammonia in a power plant is estimated at 40% of a coal plant's efficiency.²⁴² Considering that the average coal plant efficiency is 33%²⁴³, the total efficiency of 20% ammonia co-firing is reduced to 13.2%.

We also found that ammonia liquefaction is much more efficient than hydrogen liquefaction, with an efficiency of 98.3% for short-term storage and 91.3% for long-term storage, as its storage conditions are easier to achieve than those for hydrogen.²⁴⁴ Moreover, liquefied ammonia has a higher energy density than hydrogen,^{245,246} which enhances its applicability. Some studies suggest that green ammonia storage is a promising option for both short- and

long-term storage due to its low losses.²⁴⁷ These studies support its feasibility for large-scale applications.²⁴⁸



(32:24)

Figure VI.1.9. Pathway 9: Haber-Bosch and Ammonia Co-firing

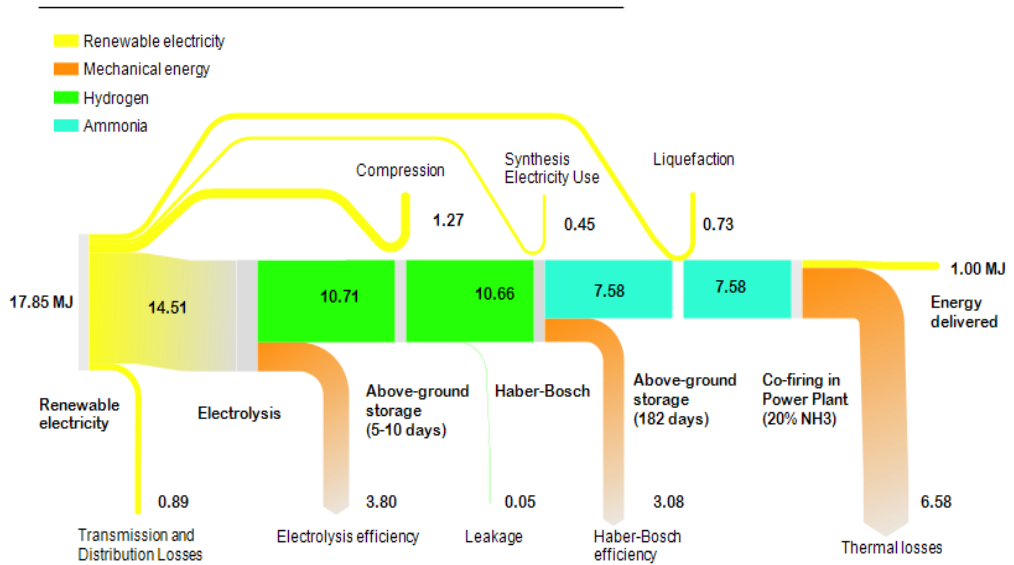


Figure VI.1.10. Pathway 10: Haber-Bosch and Ammonia Co-firing

Pathway Round-trip efficiency Summary

Table VI.1.1 summarizes the round-trip efficiency for each of the pathways. We identified Pathway 2 as having the highest round-trip efficiency, and Pathways 9 and 10, involving ammonia co-firing, as the least efficient.

Table VI.1.1. Round-Trip Efficiency for Each Pathway.

| Pathway Name | Parameters Used in Pathway | Round-trip Efficiency (%) |
|---------------------|--|----------------------------------|
| Pathway 1 | LCOH, Compression, Above Ground Gaseous Storage, H2GT | 21.9 |
| Pathway 2 | LCOH, Compression, Above Ground Gaseous Storage, Fuel Cell | 32.9 |
| Pathway 3 | LCOH, Compression, Underground Long Storage, H2GT | 19.4 |
| Pathway 4 | LCOH, Compression, Underground Long Storage, Fuel Cell | 27.0 |
| Pathway 5 | LCOH, Liquefaction, Above Ground Short Liquid Storage, H2GT | 17.5 |
| Pathway 6 | LCOH, Liquefaction, Above Ground Short Liquid Storage, Fuel Cell | 26.3 |
| Pathway 7 | LCOH, Liquefaction, Above Ground Long Liquid Storage, H2GT | 13.2 |
| Pathway 8 | LCOH, Liquefaction, Above Ground Long Liquid Storage, Fuel Cell | 19.8 |
| Pathway 9 | Compression, LCOA, Short NH ₃ Storage, Co-firing | 5.8 |

| | | |
|------------|--|-----|
| Pathway 10 | Compression, LCOA, Long NH ₃ Storage, Co-firing | 5.6 |
|------------|--|-----|

VI.2. Levelized Cost of Electricity

In this section, we outline the LCOE for each of the pathways identified in the previous section. Each LCOE calculation utilizes relevant cost parameters discussed in Section IV. Cost Analysis Methods. Transportation costs are highly dependent on the physical location of renewable resources, hydrogen production sites, and demand centers. The objective of this section is to compare the theoretical cost of generating electricity using the pathways discussed in Section III.2 Green Hydrogen Pathways, and hence, we do not include the cost of hydrogen and ammonia transportation in the LCOE calculations. Transportation costs are, however, addressed in the next section. Costs of compression in this section are limited exclusively to the compression at the storage terminals and do not include any compression needed during transportation (for instance, through pipelines).

Equations VI.2.1, VI.2.2, and VI.2.3 integrate different cost parameters to derive the LCOE for each pathway. The CAPEX component could refer to the direct installed CAPEX of a gas turbine, hydrogen fuel cell, or partially depreciated coal plant depending on the pathway being analyzed. Equation VI.2.3, which relates to the Pathways 9 and 10 (ammonia co-firing), incorporates a scaling factor of 20% ammonia to 80% coal to account for the co-firing ratio.

$$LCOE = \frac{LCOH + Storage + Compression}{Energy\ Density} \times \frac{MJ}{kWh} \times \frac{1}{\eta} + CAPEX \quad \text{Equation VI.2.1}$$

$$LCOE = \frac{LCOH + Storage + Liquefaction + Compression}{Energy\ Density} \times \frac{MJ}{kWh} \times \frac{1}{\eta} + CAPEX \quad \text{Equation VI.2.2}$$

$$LCOE = \left(\frac{1}{5} \times \frac{LCOA + Storage}{NH_3\ Energy\ Density} + \frac{4}{5} \times \frac{Coal\ Cost}{Coal\ Energy\ Density} \right) \times \frac{MJ}{kWh} \times \frac{1}{\eta} + CAPEX \quad \text{Equation VI.2.3}$$

Table VI.2.1 outlines the cost parameters used in the preceding equations. We use these values in tandem with the physical properties of the fuel sources and the relevant unit conversions in Table VI.2.2 to determine the finalized LCOE for each pathway.

Table VI.2.1. Cost Parameters Used in Calculating LCOE.

| Cost Component | Cost | Units |
|------------------------------|-------------|-----------------------|
| LCOH | 2.64 | \$/kg H ₂ |
| LCOA | 1.13 | \$/kg NH ₃ |
| H ₂ Compression | 0.18 | \$/kg H ₂ |
| H ₂ Liquefaction | 0.64 | \$/kg H ₂ |
| Above Ground Gaseous Storage | 0.3 - 0.5 | \$/kg H ₂ |
| Above Ground Liquid Storage | 0.06 - 0.12 | \$/kg H ₂ |
| Underground Long Storage | 1.29 | \$/kg H ₂ |
| NH ₃ Storage | 0.51 | \$/kg NH ₃ |
| Levelized Fuel Cell CAPEX | 0.072 | \$/kWh |
| Levelized H2GT CAPEX | 0.0112 | \$/kWh |
| Levelized Co-firing CAPEX | 0.004 | \$/kWh |
| Coal Cost | 0.037 | \$/kg Coal |

Table VI.2.2. Physical Constraints and Unit Conversions Used in Calculating LCOE.

| Physical Constraints | Cost | Units |
|---|------------------|-----------------------|
| H ₂ Energy Density ²⁴⁹ | 120 | MJ/kg H ₂ |
| NH ₃ Energy Density ²⁵⁰ | 22.5 | MJ/kg NH ₃ |
| Coal Energy Density | 21.13 | MJ/kg |
| MJ to kWh Conversion | 3.6 | MJ/kWh |
| Fuel Cell Efficiency (η) | $\frac{1}{1.95}$ | Output/Input |
| H2GT Efficiency (η) | $\frac{1}{2.93}$ | Output/Input |

| | | |
|---------------------------------|------------------|--------------|
| Co-firing Efficiency (η) | $\frac{1}{7.58}$ | Output/Input |
|---------------------------------|------------------|--------------|

Pathway 1: Electrolysis, Compression, Above Ground Gaseous Storage, Gas Turbine

The relevant cost parameters for Pathway 1 are electrolysis (LCOH), compression, above ground gaseous storage, and the levelized hydrogen gas turbine (H2GT) CAPEX. Additional variables affecting the LCOE include the energy density of hydrogen, a conversion factor of megajoule to kilowatt-hour, and the H2GT efficiency. Using these cost parameters with Equation VI.2.1 yields a LCOE of \$0.24 to \$0.29 to \$0.30 per kWh of delivered electricity.

Pathway 2: Electrolysis, Compression, Above Ground Gaseous Storage, Fuel Cell

The relevant cost parameters for Pathway 2 are electrolysis (LCOH), compression, above ground gaseous storage, and the levelized fuel cell CAPEX. Additional variables affecting the LCOE include the energy density of hydrogen, a conversion factor of megajoule to kilowatt-hour, and the fuel cell efficiency. Using these cost parameters with Equation VI.2.1 yields a LCOE of \$0.25 to \$0.27 per kWh of delivered electricity.

Pathway 3: Electrolysis, Compression, Underground Long-term Storage, Gas Turbine

The relevant cost parameters for Pathway 3 are electrolysis (LCOH), compression, injection, underground long-term storage, extraction, and the levelized H2GT CAPEX. Injection and extraction costs are factored into the underground storage costs. Additional variables affecting the LCOE include the energy density of hydrogen, a conversion factor of megajoule to kilowatt-hour, and the H2GT efficiency. Using these cost parameters with Equation VI.2.1 yields a LCOE of \$0.37 per kWh of delivered electricity.

Pathway 4: Electrolysis, Compression, Underground Long-term Storage, Fuel Cell

The relevant cost parameters for Pathway 4 are electrolysis (LCOH), compression, injection, underground long-term storage, extraction, and the fuel cell. Injection and extraction costs have already been factored into the storage costs. Additional variables affecting the LCOE include the energy density of hydrogen, a conversion factor of megajoule to kilowatt-hour, and the fuel cell

efficiency. Using these cost parameters with Equation VI.2.1 yields a LCOE of \$0.31 per kWh of delivered electricity.

Pathway 5: Electrolysis, Liquefaction, Above Ground Liquefied Storage, Gas Turbine

The relevant cost parameters for Pathway 5 are electrolysis (LCOH), liquefaction, above ground liquefied storage, and the levelized H2GT CAPEX. Additional variables affecting the LCOE include the energy density of hydrogen, a conversion factor of megajoule to kilowatt-hour, and the H2GT efficiency. Using these cost parameters with Equation VI.2.2 yields a LCOE of \$0.30 to \$0.31 per kWh of delivered electricity.

Pathway 6: Electrolysis, Liquefaction, Above Ground Liquefied Storage, Fuel Cell

The relevant cost parameters for Pathway 6 are electrolysis (LCOH), liquefaction, above ground liquefied storage, and the fuel cell. Additional variables affecting the LCOE include the energy density of hydrogen, a conversion factor of megajoule to kilowatt-hour, and the fuel cell efficiency. Using these cost parameters with Equation VI.2.2 yields a LCOE of \$0.27 per kWh of delivered electricity.

Pathway 7: Electrolysis, Liquefaction, Above Ground Long-term Storage, Gas Turbine

As mentioned earlier, while technically possible, above ground long-term storage of liquefied hydrogen is not practically feasible. As a result, Pathway 8 is not in consideration as a realistic green hydrogen pathway, and we have not calculated its LCOE.

Pathway 8: Electrolysis, Liquefaction, Above Ground Long-term Storage, Fuel Cell

As mentioned earlier, while technically possible, above ground long-term storage of liquefied hydrogen is not practically feasible. As a result, Pathway 8 is not in consideration as a realistic green hydrogen pathway, and we have not calculated its LCOE.

Pathway 9: Electrolysis, Haber Bosch, Liquefaction, Short Term Storage, Co-firing

The relevant cost parameters for Pathway 9 are Haber Bosch (LCOA), NH₃ short-term storage, above ground gaseous H₂ storage, and co-firing. The

LCOA is derived from the LCOH, and as a result, the LCOH is not needed in this pathway analysis. Additionally, the LCOA calculation includes costs associated with ammonia liquefaction, so they are not needed in this LCOE analysis either. Other variables affecting the LCOE include the energy density of ammonia and coal, a conversion factor of megajoule to kilowatt-hour, and the co-firing efficiency. Using these cost parameters with Equation VI.2.3 yields a LCOE of \$0.56 to \$0.61 per kWh of delivered electricity.

Pathway 10: Electrolysis, Haber Bosch, Liquefaction, Long Term Storage, Co-firing

The only difference between Pathway 9 and Pathway 10 is the NH₃ storage duration. However, there is no significant cost difference between short-term and long-term ammonia storage. As a result, the LCOE calculation and finalized price for Pathway 10 are identical with those outlined in Pathway 9: \$0.56 to \$0.61 per kWh of delivered electricity.

Pathway LCOE Summary

Table VI.2.3 summarizes the LCOE for each of the pathways. The costliest pathways are those that involve ammonia co-firing (Pathways 9 and 10), while Pathways 2 and 6 yield the lowest LCOE.

Table VI.2.3. LCOE for Each Pathway.

| Pathway Name | Parameters Used in Pathway | LCOE (\$/kWh) |
|---------------------|--|----------------------|
| Pathway 1 | LCOH, Compression, Above Ground Gaseous Storage, H2GT | 0.29 - 0.30 |
| Pathway 2 | LCOH, Compression, Above Ground Gaseous Storage, Fuel Cell | 0.25 - 0.27 |
| Pathway 3 | LCOH, Compression, Underground Long Storage, H2GT | 0.37 |
| Pathway 4 | LCOH, Compression, Underground Long Storage, Fuel Cell | 0.31 |
| Pathway 5 | LCOH, Liquefaction, Above Ground Short Liquid Storage, H2GT | 0.30 - 0.31 |
| Pathway 6 | LCOH, Liquefaction, Above Ground Short Liquid Storage, Fuel Cell | 0.27 |

| | | |
|------------|---|-------------|
| Pathway 7 | LCOH, Liquefaction, Above Ground Long Liquid Storage, H2GT | N/A |
| Pathway 8 | LCOH, Liquefaction, Above Ground Long Liquid Storage, Fuel Cell | N/A |
| Pathway 9 | Compression, LCOA, Short NH ₃ Storage, Co-firing | 0.56 - 0.61 |
| Pathway 10 | Compression, LCOA, Long NH ₃ Storage, Co-firing | 0.56 - 0.61 |

VI.3. Levelized Cost of Hydrogen Transportation

Figure VI.3.1 shows the levelized cost of transporting hydrogen using tube trailers, cryogenic tanks, and pipelines over a range of distances from 100 km to 1000 km, including compression and liquefaction needs. The cost of transportation using tube trailers and pipeline includes the cost of compressing the gas to the required pressure of 350 bar and 70 bar respectively, whereas the cost of transportation using cryogenic tanks includes the cost of liquefaction. We also include the cost of compressor stations as modelled in H2_P_COM in the pipeline transportation cost. It is also important to note that we assumed an average flow rate of 50,000 kg H₂/day for these cost estimates.

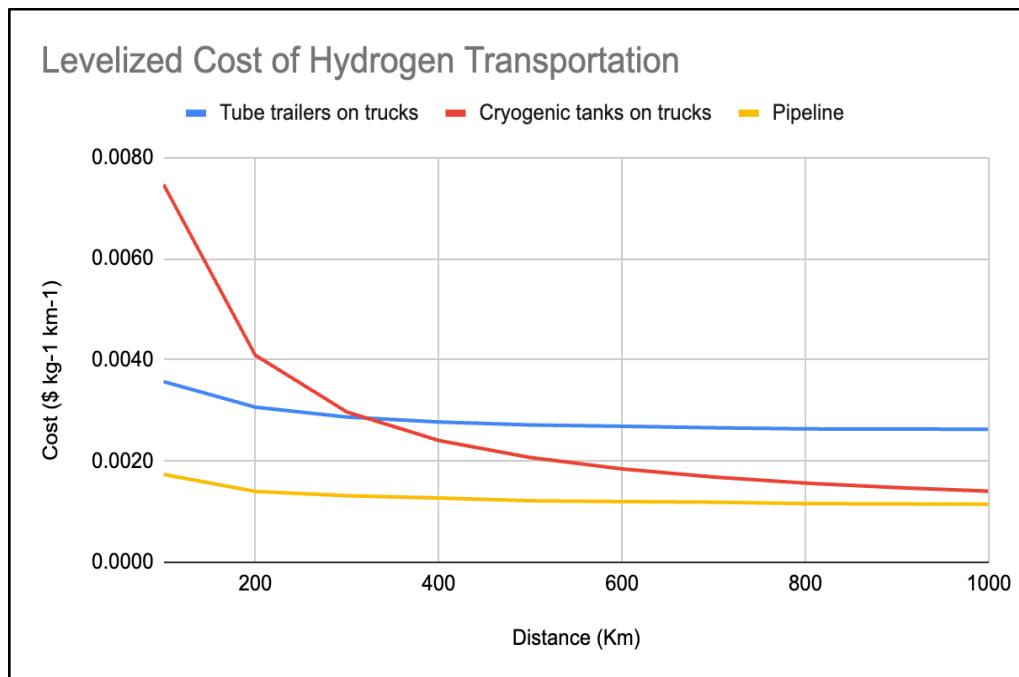


Figure VI.3.1. Levelized cost of hydrogen transportation including compression/liquefaction costs.

The choice of hydrogen transportation method in India will depend on several factors including the magnitude of demand, distances between production and demand centers, location of storage terminals, and regulatory considerations. A comprehensive evaluation of all these factors is outside the scope of this study, however, we have analyzed the impact of the location of storage terminals on transportation cost since it is an important factor that can be controlled when planning the spatial layout of hydrogen infrastructure in India. Assuming a distance of 1000 km between the production facility and demand center, we evaluated three scenarios as shown in Table VI.3.1, with the storage terminal located closer to production, equidistant from production and demand, and closer to demand. As we show in the analysis, locating the terminal closer to production, using a pipeline for transmission, and using tube trailers for distribution achieves the lowest transportation cost (\$1.39/kg H₂).

Table VI.3.1. Hydrogen transportation scenarios.

| Scenario | Transmission Method | Transmission Distance (km) | Distribution Method | Distribution Distance (km) | LCOHT (\$/kg) |
|--|---------------------|----------------------------|---------------------|----------------------------|---------------|
| Storage terminal situated closer to demand center | Pipeline | 900 | Tube trailers | 100 | 1.39 |
| | Cryogenic tanks | 900 | Tube trailers | 100 | 1.69 |
| | Pipeline | 900 | Cryogenic tanks | 100 | 1.78 |
| | Cryogenic tanks | 900 | Cryogenic tanks | 100 | 2.07 |
| Storage terminal equidistant between production facility and demand center | Pipeline | 500 | Cryogenic tanks | 500 | 1.64 |
| | Pipeline | 500 | Tube trailers | 500 | 1.96 |
| | Cryogenic tanks | 500 | Cryogenic tanks | 500 | 2.07 |
| | Cryogenic tanks | 500 | Tube trailers | 500 | 2.39 |

| | | | | | |
|---|-----------------|-----|-----------------|-----|------|
| Storage terminal situated closer to production facility | Pipeline | 100 | Cryogenic tanks | 900 | 1.50 |
| | Cryogenic tanks | 100 | Cryogenic tanks | 900 | 2.07 |
| | Pipeline | 100 | Tube trailers | 900 | 2.54 |
| | Cryogenic tanks | 100 | Tube trailers | 900 | 3.12 |

VI.4. Policy Analysis Results

VI.4.1 Long-Duration Energy Storage

India's National Green Hydrogen Mission

At a National level, India's National Green Hydrogen Mission includes provisions for deployment of green hydrogen storage and delegates tasks to various Ministries to carry out research and development, frameworks, and implementation. The Mission directly supports building infrastructure for green hydrogen storage.²⁵¹ It also supports pilot projects for emerging technologies in long-duration storage, and research and development will be done in collaboration with the private sector. Additionally, the Mission includes developing a national framework that allows for storage and dispensing of green hydrogen in alignment with international standards and norms. It also includes developing an online portal including information regarding safety and regulatory approvals for green hydrogen storage.

Regarding allocation of tasks to Ministries and states, the Mission charges the Ministry of Ports, Shipping, and Waterways with development of bunkers and other storage infrastructure for hydrogen exports. The Ministry of Renewable Energy (MNRE) oversees facilitating overall deployment of green hydrogen across the country and ensuring the creation of a holistic ecosystem. A vital aspect of this "ecosystem" is storage, and the MNRE is sure to play a role in future facilitation and policies creation. Lastly, the Mission requests that states create land banks and/or other provisions for allotment of land for green hydrogen use. This is not limited to long-duration storage infrastructure, but underground hydrogen storage and any associated hydrogen hubs can have a large land footprint, so this provision could be supportive of storage development.

Hydrocarbon Exploration Licensing Policy

The Government of India adopted the Hydrocarbon Exploration Licensing Policy (HELP) in 2016 with aims “to enhance domestic oil and gas production by intensifying exploration activity and investment.”²⁵² Although oil and gas production may seem antithetical to green hydrogen, increased geological exploration from HELP may identify new hydrogen storage opportunities. The country has also pushed towards storing CO₂ captured through carbon capture, utilization, and storage, which could further enhance underground hydrogen storage via site identification and technology and infrastructure development.²⁵³

Energy Storage Obligations Trajectory

The Energy Storage Obligations Trajectory aims to increase the percentage of electricity produced by stored renewable energy by 3% by the 2029-2030 fiscal year. Currently, only 1% of electricity is produced this way. The initiative aims to increase the percentage by 0.5% annually until 85% of total energy stored is from renewable sources.²⁵⁴ This can provide a massive incentive for developing hydrogen storage technologies and facilities as it is a sound form of long-term renewable energy storage.

State Level Policies

Seven states have provisions related to storage in their green hydrogen policies: Andhra Pradesh, Haryana, Maharashtra, Punjab, Rajasthan, Uttar Pradesh, and West Bengal. Here, issues from land and tax provisions to workforce development are covered in a variety of ways. As mentioned previously, the NGHM calls for states to develop land banks. So far, Haryana and Uttar Pradesh are the only states that have explicitly stated intentions to do so. Rajasthan, however, does allocate power to the Nodal Agency, which is the Rajasthan Renewable Energy Corporation Limited, to facilitate allotment of government land to green hydrogen production and storage projects. All seven states offer tax exemptions on land used for green hydrogen projects, making green hydrogen development more appealing in these states. Regarding research and development, Andhra Pradesh, Haryana, Punjab, Rajasthan, and Uttar Pradesh intend to specifically explore green hydrogen storage technologies and/or sites. Table VI.4.1 summarizes these state level hydrogen policies.

Table VI.4.1. State Level Hydrogen Storage Policies.

| | LAND AND TAX | RESEARCH AND DEVELOPMENT | INFRASTRUCTURE AND SAFETY | WORKFORCE DEVELOPMENT |
|--|--------------|--------------------------|---------------------------|-----------------------|
|--|--------------|--------------------------|---------------------------|-----------------------|

| | | | | |
|---------------------------|--|--|--|---|
| ANDHRA PRADESH | <ul style="list-style-type: none"> - 100% exemption from payment of land use conversion charges - 100% exemption from payment of stamp duty | <ul style="list-style-type: none"> - Developers must comply with standards/guidelines for storage and transportation of GH during policy operative period - The Nodal Agency to conduct a geological survey to identify potential natural hydrogen storage sites in AP | <ul style="list-style-type: none"> - GH producers can set up bunkers near Ports for storage | N/A |
| HARYANA | <ul style="list-style-type: none"> - Local Body Tax & Non-Agriculture (NA) Tax exempted for land acquired for GH storage. - 100% exemption of stamp duty for land acquired for GH storage - The State Hydrogen Advisory Committee will direct state departments to establish land banks | <ul style="list-style-type: none"> - HGHPC will coordinate with central government ministries to establish frameworks and regulations for GH storage - HAREDA will support identification of land banks for development of GH storage | <ul style="list-style-type: none"> - Grid connectivity for GH and associated storage projects to be granted on priority under Electricity Rules - GH and associated storage projects granted open access approvals - HAREDA to implement rules and regulations for storage of GH through relevant state and central government authorities - HAREDA to formulate the process and facilitate approvals for bulk storage infrastructure. | - HAREDA shall facilitate the creation of a skilled workforce trained in GH storage |
| MAHARASHTRA | N/A | N/A | <ul style="list-style-type: none"> - Full exemption from local government tax and excise tax for storage of hydrogen and its derivatives - Cooperation with the concerned department for improvement of safety standards in relation to storage of hydrogen and its derivatives | N/A |

| | | | | |
|----------------------|---|--|---|-----|
| PUNJAB | <ul style="list-style-type: none"> - No Change of Land Use and External Development Charges for change of agricultural land to industrial use - 100% Stamp duty exemption for Land Registration - 100% Stamp duty exemption for Land lease | <ul style="list-style-type: none"> - R&D will explore applications of GH storage | N/A | N/A |
| RAJASTHAN | <ul style="list-style-type: none"> - Developers allowed to acquire agricultural land from landowners for developing Green Hydrogen Generation Parks - Nodal Agency to facilitate allotment of government land | <ul style="list-style-type: none"> - R&D will explore GH storage technologies | N/A | N/A |
| UTTAR PRADESH | <ul style="list-style-type: none"> - 100% exemption in stamp duty for land purchased or leased for projects - The State Government to aid developers in providing land for storage projects - The State Government to prepare a land bank | <ul style="list-style-type: none"> - R&D will explore low-cost GH storage technologies - R&D will explore Type-4 storage tanks | <ul style="list-style-type: none"> - Financial incentives for GH storage infrastructure construction | N/A |

| | | | | |
|--------------------|---|-----|-----|-----|
| WEST BENGAL | - Developers entitled to 100% waiver on land use conversion tax and waiver of land record mutation fees | N/A | N/A | N/A |
|--------------------|---|-----|-----|-----|

VI.4.2 Captive Generation

Electricity Rules of 2022

Under the Electricity Rules of 2022, captive power generators now have open access to renewable energy on the grid, with the application period to participate in this program maxing out at 15 days. That is, within 15 days of applying, a captive power generator has access to limitless renewable energy for their site.²⁵⁵ This allows for easier access to renewable energy for electrolysis at green hydrogen captive power plants as historically, distribution companies have been reluctant to grant open access to captive power consumers and generators.

Energy Storage Obligations Trajectory

The Energy Storage Obligations Trajectory requires captive power generators to purchase a minimum percentage of their energy from stored renewable energy sources, though this percentage has yet to be determined.²⁵⁶ Like the Electricity Rules, this will incentivize any captive power generators currently producing grey hydrogen to move towards yellow and green hydrogen.

State Level Policies

At the state level, there are several policies that relate to scaling captive green hydrogen generation, such as net metering for the plants generating electricity on site and wheeling and banking incentives for those receiving electricity from the grid. Net metering is when a consumer generates their own energy, typically using solar panels, and can sell any excess energy back to the grid.²⁵⁷ Net metering programs are a major incentive for rooftop and community solar. As of May 2024, nine states and the Union Territory of Delhi have net metering policies.²⁵⁸ Figure VI.4.1 outlines the details of these policies. In the case of green hydrogen captive power, solar panels can be used on site to generate power for electrolysis rather than getting it from the grid. This kind of investment provides an incentive for green hydrogen captive power over grey hydrogen as the producer will earn a passive income from selling excess energy back to the grid.

As mentioned previously in this report, green hydrogen captive power is expected to stay in manufacturing industries which already utilize captive power. Additionally, data centers are increasingly energy intensive due to AI's development. While these industries exist around the subcontinent, they are heavily concentrated in certain regions. Gujarat, Maharashtra, Tamil Nadu, and Karnataka are the main industrial regions. These states are known for producing petrochemicals and electronics which are very energy intensive industries.²⁵⁹ Alternatively, the metals and mining industries are concentrated in the eastern and central regions of the country, including Odisha, Jharkhand, Chhattisgarh, Maharashtra, Goa, and Karnataka. Data centers, however, are typically concentrated around major cities. Maharashtra, however, has 79 data centers, making up 31% of the country's total. Tamil Nadu and Karnataka follow behind with 33 and 32 data centers, respectively.²⁶⁰

| State | System Size | Eligible Consumers | Carryover Period |
|---------------|--------------------------|---------------------------------|-----------------------|
| Delhi | Up to 1 MW | Residential, Commercial | 1 year |
| Maharashtra | 1 kW to 1 MW | Residential, Commercial | 1 year |
| Tamil Nadu | Up to 1 MW (residential) | Residential, Commercial (gross) | Monthly (residential) |
| Karnataka | 1 kW to 1 MW | Residential, Commercial | 1 year |
| Gujarat | Up to 1 MW | Residential, Commercial | 1 year |
| Rajasthan | Up to 1 MW | Residential, Commercial | 1 year |
| Haryana | Up to 2 MW | Residential, Commercial | 1 year |
| Punjab | 1 kW to 1 MW | Residential, Commercial | 1 year |
| West Bengal | 1 kW to 2 MW | Residential, Commercial | 1 year |
| Uttar Pradesh | 1 kW to 2 MW | Residential, Commercial | 1 year |

Figure VI.4.1. State-wise Net Metering Policies.²⁶¹

VI.4.3 Ammonia Co-firing

India's National Green Hydrogen Mission

Provisions related directly to green ammonia co-firing in the Mission are limited,²⁶² but there are several instances in which ammonia production is encouraged and prioritized. First, the Ministry of Chemicals and Fertilizers is delegated to encourage indigenous production of green ammonia and enable procurement of it for bulk demand. The NGHM also states that the Government of India will specify a minimum share of consumption of green hydrogen and ammonia by designated consumers with a year wise trajectory. The MNRE and

Ministry of Chemicals and Fertilizers were instructed to call for competitive bids for ammonia production plants were also called for by the Mission.²⁶³ As of December 2024 these bids have been placed. Overall, ammonia production under the Mission is supported, but lacks enforceable targets at this stage.

Fossil Fuel and Climate Change Policies

Although India's Nationally Determined Contribution (NDC) incorporates emission reduction and carbon sink goals, there is no mention of phasing out fossil fuels completely.²⁶⁴ Alternatively, India projects increased coal production over the next few years with the Ministry of Coal projecting a 113% increase in domestic coal supply from 2019 to 2030.²⁶⁵ A lack of coal reduction targets leaves the green ammonia co-firing industry in an advantageous position, as this industry may not be expected to phase out for at least several decades.

State Level Policies

Rajasthan is the only state to have provisions related specifically to green ammonia in their green hydrogen policies. In every other state-level green hydrogen policy, green hydrogen and ammonia are linked together in goals and targets. Rajasthan's policy aims to use green ammonia to reduce dependencies on import but includes no specific production targets or goals related to co-firing.

Separate from a state-level green hydrogen policy, Gujarat has set ambitious renewable purchase obligation (RPO) targets mandating that a significant percentage of the power consumed must come from renewable sources. The Gujarat government aims to achieve 50% of renewable energy capacity by 2030.²⁶⁶ In February 2023, Ocior Energy, a company developing Green Hydrogen and Green Ammonia facilities, signed a MoU with the Gujarat government for setting up a green hydrogen and green ammonia project in Gujarat. It is expected to have 1 MMT of capacity per year by 2030.²⁶⁷

Section VII. Conclusions

Energy Storage

Our technical analysis results indicate that hydrogen compression in above ground tanks is the most efficient storage method with a round-trip efficiency of 89.4%. This is because it only requires energy during the initial compression stage, without the need for a continuous electricity supply. Although the direct costs of this storage method (\$0.30 to \$0.50 per kg H₂) are higher than above ground short-term liquefied storage (\$0.09 to \$0.12 per kg H₂), compression costs (\$0.18 per kg H₂) are substantially lower than

liquefaction costs (\$0.64 per kg H₂). This results in compressed storage costing between \$0.48 and \$0.68 per kg H₂ while liquefied storage costs range between \$0.73 and \$0.76 per kg H₂. However, individual storage tanks have limited capacity which may restrict large-scale implementation for seasonal storage.

Underground storage in depleted reservoirs is the most suitable storage method for long-duration energy storage on seasonal scales, as it offers much higher storage capacity compared to above ground tanks. However, it is significantly more expensive with a levelized cost of \$1.47 per kg H₂ (including compression costs). Additionally, it lacks deployment flexibility, meaning that it cannot be centrally located to production and demand without either being purposefully located near underground reservoirs. Large-scale implementation faces significant logistical challenges due to the fixed location of these reservoirs, which could lead to elevated transportation costs compared to its above ground counterparts.

Hydrogen liquefaction routes exhibit the highest energy losses, with short-term storage efficiency at 72% and seasonal storage efficiency at 51%. These losses are associated with the high energy demand required to maintain cryogenic temperatures (-253°C) and the progressive boil-off losses, which can reach up to 1% of the total volume per day. This factor limits its viability for short- and long-term storage.

Green ammonia offers advantages in storage. Its liquefaction is significantly more efficient than hydrogen liquefaction, with efficiencies of 98% for short-term storage and 91% for long-term storage, due to its lower cryogenic requirements and higher energy density. These factors make ammonia a viable option for large-scale seasonal energy storage and industrial applications.

Overall, the results suggest that the most viable option for short-term hydrogen storage and use in the power sector is Pathway 2 (Comp, AH₂Store, FC) with a round-trip efficiency of 32.9% and LCOE of about \$0.25 to \$0.27 per kWh. This pathway is the most energy efficient and among the lowest cost options, making it advantageous compared to other routes. However, this pathway is not scalable for applications which require longer duration storage due to practical limitations on the capacity of above ground storage tanks. Pathway 4 (Comp, UH₂S, FC) has a comparable efficiency (27.0%) and LCOE (\$0.31 per kWh), but utilizes underground storage which is better suited for long-duration storage applications.

India's green hydrogen and energy policies are decentralized with most of the power lying at the state level. Because of this, the system is fragmented, and national-level goals are weakly enforced. For long-duration storage, it would be advantageous to utilize HELP and continue identifying optimal locations for underground storage, as more research is needed in this area.

Additionally, more state-level green hydrogen missions need to go online to create a nation-wide green hydrogen storage economy. Assam and Tamil Nadu should be targeted for green hydrogen policy development based on their renewable energy potential and Category I basins. Andhra Pradesh and Maharashtra are optimal for long duration storage due to their existing green hydrogen policies.

End-use Applications: Ammonia Co-firing and Captive Power Generation

In terms of end-use applications, the routes utilizing fuel cells for electricity generation prove to be the most efficient. Fuel cells have an efficiency of approximately 51%, while gas turbines exhibit an efficiency of around 34%. Using fuel cells to generate end-use power is more cost effective as well, with an LCOE of \$0.25 to \$0.27 per kWh as compared to \$0.29 to \$0.30 per kWh for gas turbines. Although gas turbines are less capital intensive with a CAPEX six and a half times lower than fuel cells, their lower efficiency significantly drives up the variable operating expenses. Because variable costs contribute more to the cost of generation than capital costs of the generating unit, this results in a higher LCOE for gas turbines.

With respect to green ammonia co-firing in coal power plants, we conclude that it is the least efficient route, with a round-trip efficiency of 5% when considering a 20% ammonia blend in a coal plant. It is also the most expensive application with LCOE almost double compared to other pathways, driven largely by the inefficiencies associated with the Haber-Bosch process and ammonia co-combustion. The cost difference between storing liquefied ammonia on the short term versus the long term is negligible, which results in the two co-firing routes having the same LCOE of \$0.56 to \$0.61 per kWh.

On the policy side, green ammonia and ammonia co-firing lack specific provision across both federal and state policies in India. Despite this, policies indicate that the coal industry is unlikely to begin phasing out for several more decades, which leaves the industry in an advantageous position. To promote co-firing, however, more states should follow Gujarat's lead in establishing RPOs and MoUs with energy companies to guarantee green ammonia production in their states.

For captive power generation, India has numerous supporting policies including incentives such as net metering, but there is a lack of green hydrogen specific provisions. States with industries that currently use captive generation—Odisha, Jharkhand, Chhattisgarh, Maharashtra, Goa, and Karnataka—should develop more incentives and policies that will specifically promote green hydrogen captive power generation to make these industries cleaner.

We must note that the LCOE values are likely not representative of the true costs to captive power generators who choose to produce hydrogen onsite. One of the underlying assumptions in the LCOH calculation is that the daily hydrogen production is 50 tonnes per plant. Any individual captive producer would likely be operating with a lower output, which would drive up the LCOH and subsequently the LCOE.

Other Policy Findings

Overall, more state governments need to develop green hydrogen policies that will work to their specific states' advantages. The NGHM delegates authority to the states in numerous crucial categories, such as safety and research and development. This approach is far more decentralized and unregulated than other successful countries like Germany.²⁶⁸ Most states have not begun creating and implementing these provisions, and there are no strict enforcement strategies outlined in the NGHM that would ensure that they do. In addition, the NGHM does not include provisions about how often the document should be updated. Since this is still a novel field and technological and political climates can change quickly, it is crucial to ensure periodic improvements and updates to the policy. The NGHM is planned through 2030, but there is no explicit intention to update and/or expand by that year. Without these basic structures needed to produce a thriving green hydrogen sector, development will likely be unsuccessful.

Regarding the recommendations provided by IRENA Green Hydrogen: A Guide to Design, Germany's National Hydrogen Strategy follows all ten of the recommended policy provisions, whereas the NGHM only follows six. Figure VII.1 compares the NGHM to Germany's National Hydrogen Strategy and outlines which recommended policy provisions the NGHM lacks. These are general, federal level initiatives that are conducive to a comprehensive and successful green hydrogen strategy. India's missing provisions include mobilization of finance, land permits, local content manufacturing, and knowledge creation.

| | Direct financial support for electrolyzers | Production support mechanism | Mobilisation of finance | Hydrogen infrastructure planning and support | Demand-side support | Regulation, standards and certification | Land permits | Skill policies | Local content manufacturing | Knowledge creation |
|---------|--|------------------------------|-------------------------|--|---------------------|---|--------------|----------------|-----------------------------|--------------------|
| Germany | ++ | ++ | ++ | ++ | ++ | ++ | ++ | ++ | ++ | ++ |
| India | ++ | ++ | | ++ | ++ | ++ | | ++ | | |

Figure VII.1. IRENA Policies of National Hydrogen Strategies.²⁶⁹

Section VIII. Recommendations

Prioritization of Pathway 2 (Comp, AH₂Store, FC) and Pathway 4 (Comp, UH₂S, FC)

We recommend prioritizing Pathway 2 (Comp, AH₂Store, FC) due to its energy efficiency and cost-effectiveness, especially for applications with a storage requirement of no more than 5-10 days. However, this pathway is not scalable for applications which require longer duration storage due to practical limitations on the capacity of above-ground storage tanks. Hence, we recommend Pathway 4 (Comp, UH₂S, FC) which has a comparable efficiency and LCOE to Pathway 2, for long duration storage applications. In contrast, we do not recommend pursuing Pathways 5 (Liq, Short AH₂Store, H₂GT), 6 (Liq, Short AH₂Store, FC), 7 (Liq, Long AH₂Store, H₂GT), and 8 (Liq, Long AH₂Store, FC) for the power sector due to liquefaction's high energy consumption and significant evaporation losses.

Further underground storage research and development

Underground storage in depleted gas reservoirs demonstrate relatively high efficiency in hydrogen injection, storage, and extraction processes. However, large-scale implementation faces significant logistical challenges as these reservoirs are fixed in location, potentially incurring additional transportation costs. Outside of transportation costs, the levelized cost of underground storage is significantly more expensive than above ground alternatives. Therefore, India should conduct further geological studies to evaluate the stability of these reservoirs and determine the feasibility of integrating them into a production and consumption network that minimizes costs. HELP will promote this exploration on a basic level, but the national government should direct or incentivize states towards further exploration since research and development was delegated to them under the NGHM.

Implementation of a hybrid storage approach at the national scale

We recommend adopting a hybrid approach at the national scale: a combination of compressed hydrogen storage for short-term needs with underground or ammonia-based storage for seasonal applications. This strategy would leverage the advantages of each method, maximizing overall energy efficiency and minimizing operational and infrastructure costs in the specific context of India's power sector. A hybrid method would also help incorporate necessary redundancy into the power grid and the hydrogen supply chain, helping to push India towards energy independence.

Do not pursue co-firing routes but research further into green ammonia as a seasonal storage vector

Although green ammonia production routes are inefficient and costly for direct electricity generation, ammonia offers significant storage advantages. Its liquefaction is much more efficient than that of hydrogen and provides higher volumetric energy density, making it an attractive option for large-scale energy storage. Coupling this with its low cryogenic requirements, ammonia could support seasonal energy storage, bridging the gap between periods of high and low renewable electricity production. Future research should focus on the application of green ammonia as a seasonal energy storage vector, particularly by employing ammonia fuel cells for conversion to generate power. However, as our results show, energy losses from electrolysis and the Haber-Bosch process limit green ammonia's efficiency in direct power generation.

We do not recommend pursuing other power sector uses of ammonia, particularly co-firing as analyzed in Pathways 9 (Comp, Short AH_2Store , HB, Liq, Short NH_3Store , Co-fire) and 10 (Comp, Short AH_2Store , HB, Liq, Long NH_3Store , Co-fire). Losses and inefficiencies are introduced each time energy is converted from one vector to another. These pathways involve four conversions (electricity to hydrogen to ammonia to electricity), which account for substantial energy losses. Adding to these losses is a combustion efficiency of approximately 13% for co-firing with a ratio of 20% ammonia to 80% coal. This yields a round-trip efficiency of about 6%, which substantially impacts the levelized cost of electricity for the two pathways. Altogether, Pathways 9 and 10 are both too inefficient and too costly to be implemented.

Captive generators should prioritize purchasing hydrogen-based fuels to generate power onsite

Captive power generators should prioritize purchasing hydrogen-based fuels to generate power onsite rather than creating the hydrogen themselves.

Economies of scale are important in driving down costs of hydrogen and ammonia, and it would be difficult to make small-scale, localized synthesis cost-competitive with production *en-masse*. As a result, it is recommended that these end-users purchase hydrogen, hydrogen fuel cells, or ammonia produced at scale to generate power. States with industries producing captive power should prioritize green hydrogen production or begin working towards purchase and import agreements with green hydrogen producers in other states to power their facilities.

Update the NGHM periodically to include all 10 IRENA recommended policy provisions

India should update and improve the NGHM periodically, modeling future research provisions and efforts on Germany's National Hydrogen Strategy as it includes detailed delegation of research to various government sponsored agencies.²⁷⁰ India should also look to include more IRENA-recommended provisions into the NGHM to create a more comprehensive policy framework, ensuring smoother development pathways.

Focus on expanding renewable energy capacity

Finally, India must first focus on expanding its fleet of renewable generators. Green hydrogen production, by definition, is powered by carbon-free renewable electricity. Since energy conversion incurs major losses, renewable electricity should be fed directly into the power grid, when possible, to maximize its utilization and displacement of fossil-based electricity generation. Renewable electricity should be directed towards hydrogen production when it would otherwise be curtailed. As a result, the continued investment into renewable technologies is a mandatory precursor to realizing the NGHM goals.

Section IX. Supplementary Information

IX.1 Levelized Cost of Hydrogen

Table IX.1.1 shows values provided as baseline assumptions from RMI India.

Table IX.1.1. Electrolyzer Baseline Assumptions Provided by RMI India.

| Category | Variable | Unit | 2023 | 2030 |
|---|--|----------------------|-------------|-------------|
| Electrolyzer Direct CAPEX | Electrolyzer Uninstalled CAPEX (Stack + BOP) | \$/kW | 741.5 | 248 |
| | Stack Overall | \$/kW | 333.675 | 111.6 |
| | Balance of Plant Overall | \$/kW | 407.825 | 136.4 |
| Electrolyzer Efficiency and Durability | Total System Energy Requirement | kWh/Kg | 53.65180623 | 46.60234899 |
| | Stack Degradation Rate | %/year | -0.011 | -0.011 |
| | Stack efficiency increases with each replacement | % | 0.02 | 0.02 |
| | Stack Pressure | Bar | 70 | 70 |
| | Minimum Electricity Input | % Nameplate capacity | 0.15 | 0.15 |
| | Stack Lifetime | Hours | 71666.66667 | 100000 |
| | Plant Lifetime | Years | 25 | 25 |
| | Stack Replacement Cost Factor | % | 1.163333333 | 1.163333333 |
| | Installation Cost Factor | Cost factor | 1.05 | 1.05 |
| Electrolyzer Indirect CAPEX: EPC + Land | Site Preparation | % of Direct CAPEX | 0.02 | 0.02 |

| | | | | |
|---------------------------------------|------------------------|-------------------------|--------|------|
| | Engineering and Design | % of Direct CAPEX | 0.05 | 0.05 |
| | Permitting Costs | % of Direct CAPEX | 0.1 | 0.1 |
| | Land Requirement | Acres/MW | 0.2 | 0.2 |
| | Land Cost | \$/Acre | 0 | 0 |
| Electrolyzer OPEX: O&M | Electrolyzer OPEX | % of Electrolyzer CAPEX | 0.0305 | 0.03 |
| Electrolyzer OPEX: Labor and Overhead | Labor Requirement | FTE | 20 | 20 |
| | Labor Manhours | Hours | 2096 | 2096 |
| | Labor Cost | \$ | 2.5 | 2.5 |
| | SGA Rate | % | 0.2 | 0.2 |
| | Insurance | % | 0 | 0 |

To find the rated power of the electrolyzer, the 2030 value of the Total System Energy Requirement (~46.602 kWh/kg) is multiplied by 50,000 kg per day of hydrogen output, divided by 24 hours per day an operating factor of 30%. The results in a value of approximately 323,627 kW for the electrolyzer plant. The uninstalled, stack, and balance of plant CAPEX were then multiplied by this value resulting in associated costs of \$80,259,601.04, \$36,116,820.47, and \$44,142,780.57 respectively.

The 2030 stack replacement, installation, site preparation, engineering and design, permitting, and OPEX cost factors were then multiplied by the total uninstalled CAPEX to derive their associated costs. These are displayed in Table IX.2 below.

Table IX.1.2. Electrolyzer CAPEX and OPEX Costs

| Category | Variable | Value |
|--|--|-----------------|
| Electrolyzer Direct CAPEX | Electrolyzer Uninstalled CAPEX (Stack + BOP) | \$80,259,601.04 |
| | Stack Overall | \$36,116,820.47 |
| | Balance of Plant Overall | \$44,142,780.57 |
| Electrolyzer Efficiency and Durability | Total System Energy Requirement | 323627.4236 |
| | Stack Replacement Cost Factor | \$42,015,901.15 |

| | | |
|--|--------------------------|----------------|
| | Installation Cost Factor | \$4,012,980.05 |
| Electrolyzer Indirect CAPEX: EPC + Land | Site Preparation | \$1,605,192.02 |
| | Engineering and Design | \$4,012,980.05 |
| | Permitting Costs | \$8,025,960.10 |
| Electrolyzer OPEX: O&M | Electrolyzer OPEX | \$2,407,788.03 |

IX.2 Technical Analysis

The tables below outline the sources and values for process efficiencies, hydrogen physical losses, and energy consumption that were used to create the Sankey diagrams.

a) Electrolysis – Compression – Combustion

| Process | Loss (%) | Efficiency (%) | Comments/references |
|-------------------|----------|----------------|--|
| Grid transmission | 5 | 95 | U.S. Energy Information Agency. Accessed August 3, 2024. https://www.eia.gov/tools/faqs/faq.php?id=105&t=3 |
| Electrolysis | 26.2 | 73.8 | Table 1 shows the energy required for electrolysis of a Norsk Hydro bipolar alkaline electrolyzer (high/low pressure). Ivy, J. Summary of Electrolytic Hydrogen Production. NREL, Report No. NREL/MP-560-36734, available at https://www.nrel.gov/docs/fy04osti/36705.pdf |
| Compression | 10.6 | 89.4 | The efficiency was calculated using the energy required for compression and short term storage according to Serpell et al. (2023): $39.4/(39.4+4.66) = 89.42\%$. Serpell, O., Hsain, Z., Chu, A., & Johnsen, W. (2023, March). Ammonia's role in a net-zero hydrogen economy. Kleinman Center for Energy Policy. |

| | | | |
|------------|------|------|---|
| | | | https://kleinmanenergy.upenn.edu/wp-content/uploads/2023/03/KCEP-Digest53-Ammonias-Role-Net-Zero-Hydrogen-Economy.pdf |
| Combustion | 65.9 | 34.1 | Hydrogen gas turbine efficiency is 40.3 (on LHV basis) and 34.1% (on HHV basis). Nature Research Custom Media. "Hydrogen Gas Turbine Offers Promise of Clean Electricity." Nature, 2024. https://www.nature.com . |

b) Electrolysis – Compression - Fuel Cell

| Process | Loss (%) | Efficiency (%) | Comments/references |
|-------------------|----------|----------------|--|
| Grid transmission | 5 | 95 | U.S. Energy Information Agency. Accessed August 3, 2024. https://www.eia.gov/tools/faqs/faq.php?id=105&t=3 |
| Electrolysis | 26.2 | 73.8 | Table 1 shows the energy required for electrolysis of a Norsk Hydro bipolar alkaline electrolyzer (high/low pressure). Ivy, J. Summary of Electrolytic Hydrogen Production. NREL, Report No. NREL/MP-560-36734, available at https://www.nrel.gov/docs/fy04osti/36705.pdf |

| | | | |
|-------------|------|------|--|
| Compression | 10.6 | 89.4 | <p>The efficiency was calculated using the energy required for compression and long term storage according to Serpell et al. (2023): $39.4/(39.4+4.66) = 89.42\%$. Serpell, O., Hsain, Z., Chu, A., & Johnsen, W. (2023, March). Ammonia's role in a net-zero hydrogen economy. Kleinman Center for Energy Policy.</p> <p>https://kleinmanenergy.upenn.edu/wp-content/uploads/2023/03/KCEP-Digest53-Ammonias-Role-Net-Zero-Hydrogen-Economy.pdf</p> |
| Fuel Cell | 48.8 | 51.2 | <p>Hydrogen fuel cell efficiency is 60.6 (on LHV basis) and 51.2% (on HHV basis). Serpell, O., Hsain, Z., Chu, A., & Johnsen, W. (2023, March). Ammonia's role in a net-zero hydrogen economy. Kleinman Center for Energy Policy.</p> <p>https://kleinmanenergy.upenn.edu/wp-content/uploads/2023/03/KCEP-Digest53-Ammonias-Role-Net-Zero-Hydrogen-Economy.pdf</p> |

c) Electrolysis – Liquefaction storage (7 days) - Combustion

| Process | Loss (%) | Efficiency (%) | Comments/references |
|-------------------|----------|----------------|--|
| Grid transmission | 5 | 95 | <p>U.S. Energy Information Agency. Accessed August 3, 2024.</p> <p>https://www.eia.gov/tools/faqs/faq.php?id=105&t=3</p> |

| | | | |
|--------------------------|------|------|--|
| Electrolysis | 26.2 | 73.8 | Table 1 shows the energy required for electrolysis of a Norsk Hydro bipolar alkaline electrolyzer (high/low pressure). Ivy, J. Summary of Electrolytic Hydrogen Production. NREL, Report No. NREL/MP-560-36734, available at https://www.nrel.gov/docs/fy04osti/36705.pdf |
| Liquefaction H2 (7 days) | 28.2 | 71.8 | The efficiency was calculated using the energy required for Liquefaction and short term storage according to Véronique et al. (2020): $39.4/(39.4+15.5)=71.76\%$. Dias Véronique, Maxime Pochet, Francesco Contino, and Hervé Jeanmart. 2020. "Energy and Economic Costs of Chemical Storage." Frontiers in Mechanical Engineering 6. https://doi.org/10.3389/fmech.2020.00021 |
| Combustion | 65.9 | 34.1 | Hydrogen gas turbine efficiency is 40.3 (on LHV basis) and 34.1% (on HHV basis). Nature Research Custom Media. "Hydrogen Gas Turbine Offers Promise of Clean Electricity." Nature, 2024. https://www.nature.com . |

d) Electrolysis – Liquefaction storage (182 days) - Combustion

| Process | Loss (%) | Efficiency (%) | Comments/references |
|-------------------|----------|----------------|--|
| Grid transmission | 5 | 95 | U.S. Energy Information Agency. Accessed August 3, 2024. https://www.eia.gov/tools/faqs/faq.php?id=105&t=3 |

| | | | |
|----------------------------|------|-------|---|
| Electrolysis | 26.2 | 73.8 | Table 1 shows the energy required for electrolysis of a Norsk Hydro bipolar alkaline electrolyzer (high/low pressure). Ivy, J. Summary of Electrolytic Hydrogen Production. NREL, Report No. NREL/MP-560-36734, available at https://www.nrel.gov/docs/fy04osti/36705.pdf |
| Liquefaction H2 (182 days) | 49.4 | 50.56 | The efficiency was calculated using the energy required for Liquefaction and long term storage according to Al-Breiki et al.(2020): $39.4/(39.4+38.5)=50.58\%$. Al-Breiki, Mohammed, and Yusuf Bicer. 2020. "Comparative Cost Assessment of Sustainable Energy Carriers Produced from Natural Gas Accounting for Boil-Off Gas and Social Cost of Carbon." Energy Reports 6: 1897–1909. https://doi.org/10.1016/j.egy.2020.07.013 . |
| Combustion | 65.9 | 34.1 | Hydrogen gas turbine efficiency is 40.3 (on LHV basis) and 34.1% (on HHV basis). Nature Research Custom Media. "Hydrogen Gas Turbine Offers Promise of Clean Electricity." Nature, 2024. https://www.nature.com . |

e) Electrolysis – Liquefaction storage (7 days) - Fuel Cell

| Process | Loss (%) | Efficiency (%) | Comments/reference |
|-------------------|----------|----------------|--|
| Grid transmission | 5 | 95 | U.S. Energy Information Agency. Accessed August 3, 2024. |

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| | | | https://www.eia.gov/tools/faqs/faq.php?id=105&t=3 |
| Electrolysis | 26.2 | 73.8 | Table 1 shows the energy required for electrolysis of a Norsk Hydro bipolar alkaline electrolyzer (high/low pressure). Ivy, J. Summary of Electrolytic Hydrogen Production. NREL, Report No. NREL/MP-560-36734, available at https://www.nrel.gov/docs/fy04osti/36705.pdf |
| Liquefaction H2 (7 days) | 28.2 | 71.8 | The efficiency was calculated using the energy required for Liquefaction and short term storage according to Véronique et al. (2020): $39.4/(39.4+15.5)=71.76\%$. Dias, Véronique, Maxime Pochet, Francesco Contino, and Hervé Jeanmart. 2020. "Energy and Economic Costs of Chemical Storage." <i>Frontiers in Mechanical Engineering</i> 6. https://doi.org/10.3389/fmech.2020.00021 |
| Fuel Cell | 48.8 | 51.2 | Hydrogen fuel cell efficiency is 60.6 (on LHV basis) and 51.2% (on HHV basis). Serpell, O., Hsain, Z., Chu, A., & Johnsen, W. (2023, March). Ammonia's role in a net-zero hydrogen economy. Kleinman Center for Energy Policy. https://kleinmanenergy.upenn.edu/wp-content/uploads/2023/03/KCEP-Digest53-Ammonias-Role-Net-Zero-Hydrogen-Economy.pdf |

f) Electrolysis – Liquefaction storage (7 days) - Fuel Cell

| Process | Loss (%) | Efficiency (%) | Comments/reference |
|----------------------------|----------|----------------|---|
| Grid transmission | 5 | 95 | U.S. Energy Information Agency. Accessed August 3, 2024. https://www.eia.gov/tools/faqs/faq.php?id=105&t=3 |
| Electrolysis | 26.2 | 73.8 | Table 1 shows the energy required for electrolysis of a Norsk Hydro bipolar alkaline electrolyzer (high/low pressure). Ivy, J. Summary of Electrolytic Hydrogen Production. NREL, Report No. NREL/MP-560-36734, available at https://www.nrel.gov/docs/fy04osti/36705.pdf |
| Liquefaction H2 (182 days) | 49.4 | 50.6 | The efficiency was calculated using the energy required for Liquefaction and long term storage according to Al-Breiki et al. (2020): $39.4/(39.4+38.5)=50.58\%$. Al-Breiki, Mohammed, and Yusuf Bicer. 2020. “Comparative Cost Assessment of Sustainable Energy Carriers Produced from Natural Gas Accounting for Boil-Off Gas and Social Cost of Carbon.” Energy Reports 6: 1897–1909. https://doi.org/10.1016/j.egyr.2020.07.013 . |
| Fuel Cell | 48.8 | 51.2 | Hydrogen fuel cell efficiency is 60.6 (on LHV basis) and 51.2% (on HHV basis). Serpell, O., Hsain, Z., Chu, A., & Johnsen, W. (2023, March). Ammonia’s role in a net-zero hydrogen |

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| | | economy. Kleinman Center for Energy Policy. https://kleinmanenergy.upenn.edu/wp-content/uploads/2023/03/KCEP-Digest53-Ammonias-Role-Net-Zero-Hydrogen-Economy.pdf |
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g) Electrolysis – Haber Bosch – Short -term storage - Co-firing

| Process | Loss (%) | Efficiency (%) | Comments/reference |
|-------------------|----------|----------------|---|
| Grid transmission | 5 | 95 | U.S. Energy Information Agency. Accessed August 3, 2024. https://www.eia.gov/tools/faqs/faq.php?id=105&t=3 |
| Electrolysis | 26.2 | 73.8 | Table 1 shows the energy required for electrolysis of a Norsk Hydro bipolar alkaline electrolyzer (high/low pressure). Ivy, J. Summary of Electrolytic Hydrogen Production. NREL, Report No. NREL/MP-560-36734, available at https://www.nrel.gov/docs/fy04osti/36705.pdf |
| Compression | 10.6 | 89.4 | The efficiency was calculated using the energy required for compression and short-term storage according to Serpell et al. (2023): $39.4/(39.4+4.66) = 89.42\%$. Serpell, O., Hsain, Z., Chu, A., & Johnsen, W. (2023, March). Ammonia's role in a net-zero hydrogen economy. Kleinman Center |

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| | | | for Energy Policy. https://kleinmanenergy.upenn.edu/wp-content/uploads/2023/03/KC-EP-Digest53-Ammonias-Role-Net-Zero-Hydrogen-Economy.pdf |
| Haber-Bosch process | 28.9 | 71.1 | The study by Wallington et al. (2024) reported an efficiency range of 0.62 to 0.8, with an average of 0.71. This value is also reflected in the Sankey diagram in Figure 6, where the energy efficiency is calculated as $3.86/5.43$, resulting in 71%. Wallington, Timothy J., Maxwell Woody, Geoffrey M. Lewis, Gregory A. Keoleian, Eytan J. Adler, Joaquim R.R.A. Martins, and Matthew D. Collette. "Green Hydrogen Pathways, Energy Efficiencies, and Intensities for Ground, Air, and Marine Transportation." <i>Joule</i> 8, no. 8 (2024): 2190-2207. https://doi.org/10.1016/j.joule.2024.07.012 . |
| Liquefaction short term storage | 1.7 | 98.3 | The efficiency was calculated using the energy required for Liquefaction and short term storage according to Véronique et al.(2020): $18.6/(18.6+0.33)=98.25\%$. Dias, Véronique, Maxime Pochet, Francesco Contino, and Hervé Jeanmart. 2020. "Energy and Economic Costs of Chemical Storage." <i>Frontiers in</i> |

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| | | | Mechanical Engineering 6. https://doi.org/10.3389/fmecz.2020.00021 |
| Combustion of green ammonia in a power plant (co-firing rate 20%) | 86.8 | 13.2 | According to Fei Zhao et al., (2023) it is assumed that the efficiency of ammonia combustion at 20% for electricity generation in a coal-fired power plant is 40% of the efficiency of the coal power plant. According to the U.S. Department of Energy, the average efficiency of a coal power plant is 33%. Therefore, the efficiency of our plant is 13.2%. |

h) Electrolysis – Haber Bosch – Long -term storage - Co-firing

| Process | Loss (%) | Efficiency (%) | Comments/reference |
|-------------------|----------|----------------|---|
| Grid transmission | 5 | 95 | U.S. Energy Information Agency. Accessed August 3, 2024. https://www.eia.gov/tools/faqs/faq.php?id=105&_t=3 |
| Electrolysis | 26.2 | 73.8 | Table 1 shows the energy required for electrolysis of a Norsk Hydro bipolar alkaline electrolyzer (high/low pressure). Ivy, J. Summary of Electrolytic Hydrogen Production. |

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|---------------------|------|------|---|
| | | | NREL, Report No. NREL/MP-560-36734, available at https://www.nrel.gov/docs/fy04osti/36705.pdf |
| Compression | 10.6 | 89.4 | The efficiency was calculated using the energy required for compression and short term storage according to Serpell et al. (2023): $39.4/(39.4+4.66) = 89.42\%$. Serpell, O., Hsain, Z., Chu, A., & Johnsen, W. (2023, March). Ammonia's role in a net-zero hydrogen economy. Kleinman Center for Energy Policy. https://kleinmanenergy.uconn.edu/wp-content/uploads/2023/03/KCEP-Digest53-Ammonias-Role-Net-Zero-Hydrogen-Economy.pdf |
| Haber-Bosch process | 28.9 | 71.1 | The study by Wallington et al. (2024) reported an efficiency range of 0.62 to 0.8, with an average of 0.71. This value is also reflected in the Sankey diagram in Figure 6, where the energy efficiency is calculated as $3.86/5.43$, resulting in 71%. Wallington, Timothy J., Maxwell Woody, Geoffrey M. Lewis, |

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| | | | <p>Gregory A. Keoleian, Eytan J. Adler, Joaquim R.R.A. Martins, and Matthew D. Collette. "Green Hydrogen Pathways, Energy Efficiencies, and Intensities for Ground, Air, and Marine Transportation." <i>Joule</i> 8, no. 8 (2024): 2190-2207. https://doi.org/10.1016/j.joule.2024.07.012.</p> |
| Liquefaction long term storage | 8.7 | 91.3 | <p>The efficiency was calculated using the energy required for Liquefaction and short term storage according to Véronique et al. (2020): $18.6/(18.6+1.78)=98.25\%$. Al-Breiki, Mohammed, and Yusuf Bicer. 2020. "Comparative Cost Assessment of Sustainable Energy Carriers Produced from Natural Gas Accounting for Boil-Off Gas and Social Cost of Carbon." <i>Energy Reports</i> 6: 1897–1909. https://doi.org/10.1016/j.egy.2020.07.013.</p> |
| Combustion of ammonia in a co firing power plant (co-firing rate 20%) | 86.8 | 13.2 | <p>According to Fei Zhao et al., (2023) it is assumed that the efficiency of ammonia combustion at 20% for electricity generation in a coal-fired power plant is 40% of the efficiency of the coal</p> |

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| | | | power plant. According to the U.S. Department of Energy, the average efficiency of a coal power plant is 33%. Therefore, the efficiency of our plant is 13.2%. |
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i) Electrolysis – Underground storage – Combustion

| Process | Loss (%) | Efficiency (%) | Comments/references |
|---|----------|----------------|--|
| Grid transmission | 5 | 95 | U.S. Energy Information Agency. Accessed August 3, 2024. https://www.eia.gov/tools/faqs/faq.php?id=105&tid=3 |
| Electrolysis | 29.2 | 73.8 | Table 1 shows the energy required for electrolysis of a Norsk Hydro bipolar alkaline electrolyzer (high/low pressure). Ivy, J. Summary of Electrolytic Hydrogen Production. NREL, Report No. NREL/MP-560-36734, available at https://www.nrel.gov/docs/fy04osti/36705.pdf |
| Injection/Underground Storage/ extraction | 19 | 81 | Table 8 shows the total efficiency of hydrogen injection, storage, and extraction in a depleted gas reservoir. E.R. Okoroafor, N. Nazari, T.W. Kim, H.Y. Watkins, S.D. Saltzer, A.R. Kavscek. (2024). Assessment of hydrogen storage potential in depleted gas fields and power-to-hydrogen |

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| | | | conversion efficiency: A northern California case study, International Journal of Hydrogen Energy. https://doi.org/10.1016/j.ijhydene.2024.05.239 . |
| Combustion | 65.9 | 34.1 | Nature Research Custom Media. "Hydrogen Gas Turbine Offers Promise of Clean Electricity." Nature, 2024. https://www.nature.com . Hydrogen gas turbine efficiency is 40.3 (on LHV basis) and 34.1% (on HHV basis). |

j) Electrolysis – Underground storage – Fuel Cell

| Process | Loss (%) | Efficiency (%) | Comments/reference |
|-------------------|----------|----------------|--|
| Grid transmission | 5 | 95 | U.S. Energy Information Agency. Accessed August 3, 2024. https://www.eia.gov/tools/faqs/faq.php?id=105&tid=3 |
| Electrolysis | 29.2 | 73.8 | Table 1 shows the energy required for electrolysis of a Norsk Hydro bipolar alkaline electrolyzer (high/low pressure). Ivy, J. Summary of Electrolytic Hydrogen Production. NREL, Report No. NREL/MP-560-36734, available at https://www.nrel.gov/docs/fy04osti/36705.pdf |

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| Injection/Underground Storage/ extraction | 19 | 81 | <p>Table 8 shows the total efficiency of hydrogen injection, storage, and extraction in a depleted gas reservoir. E.R. Okoroafor, N. Nazari, T.W. Kim, H.Y. Watkins, S.D. Saltzer, A.R. Kavscek. (2024). Assessment of hydrogen storage potential in depleted gas fields and power-to-hydrogen conversion efficiency: A northern California case study, International Journal of Hydrogen Energy. https://doi.org/10.1016/j.ijhydene.2024.05.239.</p> |
| Purification system | 11.3 | 88.7 | <p>In this report, we indicate that the EU's Horizon 2020 program set a target for hydrogen purification technology to achieve an energy requirement of 5 kWh/kg H₂. However, the energy efficiency of the system is influenced by hydrogen purity. The energy efficiency in HHV is: $39.4/(39.4+5) = 88.73\%$. European Commission. "Development of Innovative Hydrogen Purification Technology Based on Membrane Systems." CORDIS. Last modified April 12, 2024. https://cordis.europa.eu/programme/id/H2020_FCH-03-1-2016.</p> |

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| Fuel cell | 48.8 | 51.2 | Hydrogen fuel cell efficiency is 60.6 (on LHV basis) and 51.2% (on HHV basis). Serpell, O., Hsain, Z., Chu, A., & Johnsen, W. (2023, March). Ammonia's role in a net-zero hydrogen economy. Kleinman Center for Energy Policy. https://kleinmanenergy.upenn.edu/wp-content/uploads/2023/03/KCEP-Digest53-Ammonias-Role-Net-Zero-Hydrogen-Economy.pdf |
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IX.3 Levelized Costs for Hydrogen Transportation

Table IX.3.1. Levelized cost of hydrogen transportation including compression/liquefaction costs.

| Distance (km) | Cost (\$ kg-1 km-1) | | |
|---------------|-------------------------|---------------------------|----------|
| | Tube trailers on trucks | Cryogenic tanks on trucks | Pipeline |
| 100 | 0.0036 | 0.0075 | 0.0017 |
| 200 | 0.0031 | 0.0041 | 0.0014 |
| 300 | 0.0029 | 0.0030 | 0.0013 |
| 400 | 0.0028 | 0.0024 | 0.0013 |
| 500 | 0.0027 | 0.0021 | 0.0012 |
| 600 | 0.0027 | 0.0018 | 0.0012 |
| 700 | 0.0027 | 0.0017 | 0.0012 |
| 800 | 0.0026 | 0.0016 | 0.0012 |
| 900 | 0.0026 | 0.0015 | 0.0012 |
| 1000 | 0.0026 | 0.0014 | 0.0011 |

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